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

Contents:

Rebuttal Testimony and Exhibits of
David D. Marshall, Donald J. Clayton, Michael M. Schnitzer,
Morgan K. O'Brien & James A. Lahtinen

Duquesne Statement No. 1-R

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REBUTTAL TESTIMONY OF DAVID D. MARSHALL

Q. Please state 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. Are you the same David Marshall that previously filed direct testimony in this proceeding?

A. Yes.

I. SUMMARY OF REBUTTAL TESTIMONY

Q. What issues do you address in your rebuttal testimony?

A. My rebuttal testimony addresses intervenor testimony on the following topics: (i) the valuation of Duquesne's generating assets and the related calculation of Duquesne's stranded costs; (ii) the proposed disallowance of prudently incurred investments on the basis of a "sharing" of stranded costs; (iii) the appropriate methodology for calculating customer generating credits ("CGCs") during the transition period; and (iv) the potential early retirement of Duquesne's generating units that may not be economic.

Q. Before summarizing Duquesne's response on each issue, please indicate whether Duquesne is proposing any significant modifications to its Customer Choice Plan?

A. Duquesne has sought to respond to the concerns of the intervenor parties with appropriate modifications of its Customer Choice Plan. Other Duquesne witnesses describe the modifications that relate to their topics. I will address two important

modifications here because they relate to market valuation, an issue I discuss in some detail.

First, Duquesne will, if the Commission deems it appropriate, divest all its generating units in the year 2003 to establish a final valuation for those assets. The only real criticism of Duquesne's market-based proposal for valuing its generating assets was that Duquesne had not committed to a sale of those assets. To eliminate unproductive disputes regarding the relative accuracy of differing market-based valuation techniques, Duquesne will allow the Commission to order an auction in the year 2003. The year 2003 was selected using the market price forecasts and operating cost assumptions of the Office of Consumer Advocate ("OCA"). As explained in the testimony of Mr. Schnitzer, even if Duquesne accepts the more optimistic market price assumptions of the OCA (other than the proposal to "share" stranded costs), Duquesne will not fully recover its stranded costs until the end of 2003. Duquesne is therefore proposing to file a petition with the Commission no later than December 31, 2002 instituting a final valuation and, at the Commission's option, instituting an auction of the generating assets. Duquesne also is adopting a "trigger" mechanism that accelerates the date for a final valuation should market prices begin to rise even higher than the levels forecast by the OCA. The specifics of Duquesne's final valuation proposal, as amended, are described later in my testimony.

Second, Duquesne is offering to modify its proposal to calculate CGCs during the transition period. As most witnesses agree, it is critical that the CGC during each year of the transition period accurately reflect the market price of power during that

year. Duquesne has proposed using the results of a competitive power sale auction (or "RFP") to set the CGC during each year of the transition period. However, several parties have criticized the contract terms for the proposed power sale. Duquesne's response is two-fold. First, Duquesne is willing to submit its proposed power sale auction (both the proposed contracts and the solicitation procedures) to the Commission for prior approval. Consequently, the Commission will have the opportunity to satisfy itself that the terms of the solicitation are adequate to set a market-based CGC. Second, Duquesne will cease using the RFP process if an index for market clearing prices is established in the Duquesne area that is representative of the market prices for Duquesne-supplied generation. While such an index does not exist today, it is possible that during the transition period one may develop. Should such an index be established, the need for an RFP would no longer exist and Duquesne would petition the Commission to substitute index prices for the prices resulting from Duquesne's RFP.

Q. Please summarize your conclusions regarding the four major points you are addressing.

A. The first issue is the appropriate method by which to value Duquesne's generating assets. It is a fundamental premise of Duquesne's Customer Choice Plan that this valuation be made by the market, not by expert witnesses using computer models to forecast market prices and operating costs twenty to forty years into the future. Most parties agree that it is inappropriate to calculate stranded costs using such long-term forecasts. The simple reason is that long-term forecasts have historically proven inaccurate; indeed, reliance on them has greatly contributed to the stranded costs that exist today, particularly the costs of above-market power purchase obligations. Yet,

despite the nearly unanimous agreement on this basic point, most parties oppose Duquesne's final valuation procedure because it does not include divestiture. Duquesne has now offered such a commitment and thereby should have eliminated most disputes regarding the valuation of its assets.

The second issue is the proposed disallowance of Duquesne's investment in generating plant. Three parties, the OCA, DII and the Environmentalists, propose that the Commission disallow recovery of a portion of Duquesne's investments in its generating plants. Each of these parties contends that a "sharing" of stranded costs is supported, if not required, by the Customer Choice Act. As explained below, and in the testimony of Messrs. Clayton and Schnitzer, Duquesne strongly disagrees. The stranded cost sharing proposals find no support in the Customer Choice Act because they penalize Duquesne without regard to its ability, whether past or future, to mitigate its stranded costs. They are also unfair, and contrary to sound ratemaking principles, because they deprive Duquesne's shareholders the opportunity to earn a fair return on prudently incurred costs. Finally, these witnesses incorrectly assert that their proposed disallowances are consistent with past ratemaking practice in Pennsylvania. I am not aware of a single instance in which a utility's prudent investment was disallowed on the basis of a comparison of its embedded generation costs to forecasts of spot market purchases over the remaining lives of those assets. Mr. Clayton and Mr. Schnitzer also provide a detailed rebuttal to these proposals.

The third issue I address is the computation of CGCs during the transition period. The intervenor proposals represent polar opposites. The parties representing

customers (e.g., the OCA and DII) argue for a fixed CGC that is set in advance, contending that this gives customers the "certainty" they need to make power purchase decisions. The suppliers (e.g., MAPSA and NEV), by contrast, argue for a CGC that is adjusted each year, contending that otherwise the CGC could be set too low and customers would have an artificial incentive to return to Duquesne because of the rate cap. Duquesne agrees with the suppliers that, because of the rate cap, the CGC must be adjusted each year during the transition period to reflect changing market prices. However, Duquesne disagrees with the suppliers to the extent they propose to inflate the CGC above actual market prices, thereby introducing an artificial incentive to leave Duquesne. This important issue also is addressed by Mr. Schnitzer and Mr. Lahtinen.

The fourth issue I address is the potential that one or more generating assets will be uneconomic over their useful lives and therefore should be shut down prematurely in an effort to mitigate costs. Several parties contend that certain units (e.g., Perry and Elrama) are uneconomic and should be shut down. As discussed by Mr. Schnitzer, however, these parties have not considered the costs that can, and cannot, be avoided by the early retirement of a particular unit. Mr. Clayton and Mr. Schnitzer discuss this factual issue in some detail in their testimonies. The purpose of my testimony, by contrast, is to present Duquesne's proposal for addressing early retirement decisions in a fair and comprehensive manner. Specifically, Duquesne is proposing to submit, on or before January 1, 1999, a study that addresses whether particular units should be shut down and, if so, the appropriate treatment of the related costs. This study can be

critiqued by all interested parties and any resulting modifications to rates would be made retroactive to January 1, 1999.

II. THE VALUATION OF DUQUESNE'S GENERATING ASSETS

Q. Before responding to the intervenor testimony, please provide a brief recap of Duquesne's proposal to value its generating assets.

A. Duquesne proposed to refer the final valuation question to an arbitration panel in the year 2003. The panel would be directed to use then-existing indicia of market prices, such as comparable asset sales, forward contracts, and futures prices. Duquesne submitted this proposal because (i) a market-based valuation is far superior to a long-range forecast based on computer models, (ii) such a final valuation was more appropriately conducted at a time when power markets were more fully developed, and (iii) the rate cap imposed by the Customer Choice Act limits the ability of the Commission to make a one-time determination of stranded costs accompanied by a fixed schedule of CTCs and CGCs.

Q. Is this proposal supported by other parties?

A. Yes. As I indicated in the summary of my testimony, Duquesne's proposal to use a market-based valuation is supported by nearly all parties. Certain parties, however, have criticized the nature of the valuation and, specifically, the failure of Duquesne to commit to auction its assets.

Q. Please be more specific in describing the views of the other parties on this issue.

A. I will describe the testimony of the six parties that support the use of a market-based valuation of Duquesne's generating assets. It is important to recite each witness'

position because it shows their near unanimity on this issue. The party most fully supportive of Duquesne's approach is the Office of Trial Staff ("OTS"). Mr. Metro, an OTS witness, agrees with Duquesne that:

> In my opinion, Duquesne's market value approach to stranded costs is superior to a "regulator administered" approach. In a regulator administered approach, the projection of market rates over a 30 year period would be necessary to attempt to determine the net present value of the company's stranded costs. The regulator administered approach is not accurate by any account.
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> * * *
>
> No analyst can project the market prices accurately over the long run (more than three years), or even the short run (up to three years). I believe that any utility's stranded cost claim is in error if it is based on 30 year market rate projections.

OTS *Statement No. 4 at 16-17. The only modifications to Duquesne's proposal* recommended by Mr. Metro are (i) extending the transition period if necessary to recover the stranded costs identified in the final valuation, and (ii) use of a return on equity of 10.5%, rather than 11.5% as proposed by Duquesne. Id. at 14.

Q. Do other parties concur with Duquesne and the OTS?

A. Yes. With the exception of the OCA and DII, all other parties of which I am aware agree with the proposition that the Commission should rely on market forces, not administrative forecasts, in determining stranded costs. Notably, however, all other parties believe that an auction of Duquesne's generating assets is the only method that would provide an accurate valuation. Rather than summarizing these positions, in the interest of accuracy I will continue to quote directly from the testimony of each witness. I will first describe the positions of parties that represent customer interests.

The Environmentalists are strongly supportive of Duquesne's approach, particularly the timing of the valuation (i.e., to be held in several years, rather than today). Mr. Schoengold, their witness, stated:

> We currently do not have a competitive marketplace for power. . . . Thus, we cannot reliably extrapolate from current market prices to estimate future market prices. *While we have theoretical models of how the markets are supposed to* work, theoretical models do not always predict real world behavior. Small differences in market prices can make large differences in stranded costs. It is best to wait and see what the actual market prices are and calculate stranded costs after the fact, rather than guess at market prices ahead of time and lock into probable mistakes.

Environmentalists' Statement No. 1 at 10. On deposition, Mr. Schoengold indicated that he would agree with using an auction to value the assets, provided that it is conducted several years from now:

> Q. Would an auction of all the generating assets be a reasonable procedure for a true-up valuation of the assets?
>
> A. . . . [I]f the auction were taking place a few years down the road, when we do have a competitive market in place or when it's presumed that there will be a competitive market, I would say that would be a good way of doing it.

Schoengold Deposition at 10-11.

The City of Pittsburgh also agrees that long-range forecasts are unreliable and that a market-based valuation is preferable. Mr. Seiple, the City's witness, stated:

> One of the major weaknesses of administrative valuation techniques that Mr. Schnitzer points out in his testimony is that it is very difficult to forecast future market prices. I agree with this assertion and also agree with his claim that one of the most widely ignored aspects of forecasting is that "Costs and hence 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." (Citing Schnitzer Testimony at 8.)

City of Pittsburgh Statement No. 1 at 7. Like Mr. Schoengold, Mr. Seiple prefers an auction to any other market valuation approach: "[t]he most preferable method would have Duquesne commit to selling off a substantial portion of its generating assets to determine market value." Id. at 16.

Finally, the Hospital Shared Services witness, Mr. Weisenmiller, also is critical of administrative forecasts and would support a market-based valuation if it involved an auction of Duquesne's generating assets. Direct Testimony of Robert Weisenmiller at 141-48.

Q. What about parties representing suppliers? Do they concur with Duquesne on these issues?

A. Yes, although they focus on the related issue of calculating CGCs, not a total level of stranded costs. (The two suppliers addressing this issue, MAPSA and New Energy Ventures, do not take a position on the overall level of stranded costs that should be recovered.) The witness for NEV is Mr. Boonin, the Commission's former Chief Economist. He agrees with Duquesne that the market, not administrative forecasts, should determine the level of CGC (and hence CTC) charged each year during the transition period. He states:

> For the Commission to estimate a fixed price for generation in an unbundled, full service tariff it must make and lock in numerous assumptions. Generally, when estimating a price, "normal" assumptions are made about weather, fuel, prices, economic conditions, supply availability, etc. These assumptions are for extended periods. There is almost no possibility that these normal estimated costs will produce a price at prevailing market rates at every time let alone at most times.

* * *

> I propose that the unbundled price for generation is to be determined by the market. This is necessary in order to make choice a reality for retail customers while treating all affected parties equitably.

NEV Statement No. 1 at 5, 3. Mr. Boonin proposes that prices from a regional power exchange be used to set the CGC, rather than using the RFP as proposed by Duquesne. Id. (Inexplicably, however, Mr. Boonin's testimony also appears to contemplate a one-time determination of total stranded costs, such that his market-based proposal would apply only to the determination of the amount of stranded costs recovered each year in the CTC. He thus seems concerned only that suppliers not be harmed by one-time determinations used to set the CGC, but not concerned as to whether shareholders are harmed by one-time determinations to set total stranded cost recovery.)

The MAPSA witness, Mr. Russell, also concurs with the criticisms of administrative forecasts: "[o]ne could rely upon experts to project future market prices, but, as noted in the Company's testimony, experts have proven remarkably unprescient in predicting future energy prices" (MAPSA Statement No. 1 at 6). Unlike Mr. Boonin, however, Mr. Russell is not content to set the CGC at the actual market price of power. He recommends setting the CGC at the cost of constructing a new generating unit, seeking to encourage customers to switch away from purchases from Duquesne.

Q. You have described the testimony of six parties that support market-based valuation methods. Do any parties disagree with these statements?

A. No. While The OCA and Duquesne Industrial Intervenors ("DII") support a one-time determination of stranded costs based on long-range forecasts, I note that, in deposition, their witnesses agreed that an auction of Duquesne's assets would provide a more

accurate valuation. Mr. Baron, DII's witness, stated that "the best valuation would be achieved by a divestiture and a sale of the assets." Baron Deposition at 9. Mr. Kahal, OCA's witness, agreed that "a divestiture would probably produce a more reliable estimate" than "the kind of price and cost forecast that the OCA has presented," although he questioned whether the sale of Duquesne's nuclear assets was possible. Kahal Deposition at 31.

Q. I take it then that all parties agree that the best approach is to value Duquesne's generating assets through an auction. Please explain Duquesne's position on this issue.

A. Duquesne agrees that an auction of its generating assets will provide an accurate valuation for those assets and equally important it will, unlike an administrative forecast, provide Duquesne compensation for those assets at the same level that is used to calculate the CTC. As indicated in the summary of my testimony, Duquesne is willing to commit to such an auction to narrow or eliminate unproductive disputes in this case over market valuation.

Q. Are you aware that, under the Customer Choice Act, the Commission cannot compel such an auction of Duquesne's assets?

A. Yes. I am aware that Section 2804(5) provides that "[t]he commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure." Duquesne will waive this protection, provided that the auction is conducted in 2003 (unless market prices rise and trigger an early valuation).

Q. Why is the timing of the auction important? Why not just hold it today?

A. As I will explain in more detail below, the timing is critically important because of Duquesne's obligation to serve its customers under the rate cap throughout the transition period. Moreover, given Duquesne's substantial stranded costs, there is no need to perform the valuation today, and there are good reasons (as expressed by several parties) to postpone that valuation until markets are more fully developed.

Q. Please continue.

A. As discussed by Messrs. Clayton and Schnitzer, Duquesne selected the year 2003 using the more optimistic market value estimates of the OCA. As they explain, using OCA's assumptions (with the exception of the "sharing" disallowance), Duquesne can fully amortize and depreciate its stranded costs by the end of 2003. (If less optimistic assumptions were used, Duquesne would not fully recover its stranded costs until after 2005. See Ex. DJC-21.) Mr. Schnitzer also explains that, if market prices in the next few years rise above the levels predicted by the OCA, Duquesne will accelerate the valuation procedure – again, with the purpose of avoiding any overrecovery of stranded costs. Finally, in the unlikely event that the auction produces a value that exceeds the remaining book value of Duquesne's generating assets, Duquesne will reimburse customers for any overcollections through future credits to their bills.

Q. Please explain how the valuation process would commence.

A. Duquesne will petition the Commission no later than December 31, 2002 to institute the a final valuation. The petition will give the Commission two options: (i) order Duquesne to auction all its generating assets, or (ii) appoint an arbitration panel to determine the value of those assets using the best market evidence available. Duquesne

is providing the Commission with both options because it is possible that the Commission could chose not to order divestiture due to (i) concerns of employees associated with a sale of the plants, or (ii) the difficulty in selling Duquesne's nuclear assets. In any event, the choice is that of the Commission, not Duquesne. Once Duquesne files its petition, all interested parties can comment on whether the Commission should order Duquesne to auction its assets or, instead, to utilize a board of experts.

Q. Please return to the issue of the timing of the auction and why that is so important to Duquesne?

A. The reason is the rate cap imposed by Section 2804(4) and Duquesne's continuing obligation to serve its customers under Section 2807(e). These two provisions, taken together, create the obligation to provide generation service at rates capped at current levels while the CTC is being collected.

There are two problems with holding an auction today that stem from this obligation. The first is that, if Duquesne were to auction its generating assets today, it would have no generation remaining with which to fulfill its obligation to serve. It is not clear that the Commission would allow the Company to simply fulfill that obligation using spot market purchases or whether, instead, the Company would have to secure longer term contracts to supply customers. Duquesne would strongly oppose the latter, given that customers have the option, but not the obligation, to continue purchasing from Duquesne. Any such long term arrangements would risk the incurrence of additional stranded costs.

The second, and equally serious, problem is that Duquesne would bear the risk, during the transition period, that market prices would rise above the level implicit in the auction price. The reason is the rate cap imposed by the Customer Choice Act. Under the rate cap, Duquesne cannot charge more than currently approved rates and this limits Duquesne's ability to fix, in advance, a schedule of CTCs. That is because, by doing so, one also implicitly fixes a CGC schedule for each year. Yet, if market prices rise above the level forecast in the CGC, Duquesne cannot pass the cost of market purchases through to its customers. As an example, if the auction resulted in a CGC of 2 cents/kWh, but market prices rose to 2.5 cents/kWh during the transition period, Duquesne would have no choice but to purchase power at 2.5 cents/kWh in the market and resell it to returning customers at 2 cents/kWh. The resulting economic losses to Duquesne could be substantial, presenting an unacceptable risk to Duquesne's shareholders. Conversely, customers would reap the benefits if market prices turned out below the levels implicit in the auction price. I will discuss the relationship between the rate cap and the methodology for setting CGCs later in my testimony as well.

Q. What about GPU's recent announcement to divest its generating assets? How is GPU addressing the rate cap issue?

A. I have read GPU's recent announcement, but I am not aware that GPU has set forth a specific plan or timetable regarding divestiture. It may be that GPU anticipates reaching a settlement with affected parties that removes its continuing obligation to serve under rates capped at current levels. In the absence of any such agreement, Duquesne has no choice but to propose that the valuation be conducted in later years. In addition, as Mr.

Schnitzer, Mr. Schoengold and Mr. Russell seem to agree, there will be more abundant evidence of market values in the future and this is an additional reason to postpone the valuation for several years.

Q. Has Duquesne considered proposing that the rate cap provisions be waived?

A. Yes. Duquesne made such a proposal as part of its pilot program, but the proposal was rejected. To explain, Duquesne proposed an option by which customers could receive a fixed CTC during the transition period if they waived their right to return to service from Duquesne at the rate cap. The purpose was to address the potential that certain customers would prefer a fixed CTC over one that varied each year with market prices. The fixed CTC would have been set on the basis of the levelized price from a long-term firm power sale by Duquesne.

Q. What was the reaction to Duquesne's proposal?

A. The proposal was uniformly criticized by intervening parties on the basis that it "conflicted" with the Customer Choice Act. For whatever reason, the parties were unpersuaded by the fact that it was the customer's choice to select this option. The Commission agreed with those parties and rejected the proposal. Duquesne therefore did not resubmit the proposal in this proceeding. I should note, however, that if the parties wish to revisit this issue, Duquesne is willing to consider resubmitting this proposal (or one with a similar effect). But they cannot have it both ways: a fixed CTC schedule, but a right to return to service under the rate cap whenever market prices rise above pre-determined levels. If they truly desire certainty, it must come with accountability -- i.e., the willingness to accept the associated market price risks.

Q. I understand from Mr. Clayton's testimony that the final valuation, and hence the auction, could be triggered prior to the year 2003. Would your concerns regarding the rate cap arise if this occurred?

A. They would arise if the values produced from the auction were not sufficient to terminate, within a short period, collection of the CTC. This could occur, for example, if market prices were rising above levels predicted by the OCA, and hence an early valuation was conducted, but the auction price was lower than expected, thereby leaving a CTC in place for a year or more. In such an instance, a solution to the rate cap problem would have to be devised. It could involve an agreement to remove the cap or an arrangement with the purchaser of the assets to sell Duquesne power at a fixed price (a "call option"). Duquesne's willingness to auction its assets is predicated on an assurance that the Commission will fairly address this issue if and when it arises.

Q. Are there any other implementation issues associated with Duquesne's final valuation proposal.

A. Yes. Duquesne is authorizing the Commission to order it to auction up to 100% of its generating assets. If the Commission chooses to require Duquesne to sell less than 100% of its generating assets, the remaining assets would be valued pursuant to the arbitration panel proposal outlined in my direct testimony. The reason is that generating assets are not fungible. For example, the auction of Duquesne's fossil units would not provide a fair valuation of Duquesne's nuclear units.

Q. Do you expect this aspect of the proposal to be controversial?

A. No. It is my understanding that the main witnesses in this case fully agree with the statements in the prior paragraph. See Baron Deposition at 18; Kahal Deposition at 32; Russell Deposition at 20; Weisenmiller Deposition at 4-5.

Q. What would happen if the Commission ordered the sale of all the units, but there was not a buyer for some of the assets?

A. The auction would set the value of only those assets that were actually sold. For the assets that could not be sold, the absence of any market interest would cap their value at zero. The matter would then be referred to the arbitration panel for a determination of whether there was a negative value (e.g., costs that could not be avoided by shutting the unit(s) down). The panel would then submit its recommendation on that issue to the Commission for review and approval.

Q. Is Duquesne proposing that it be permitted to submit a bid to purchase its generating assets?

A. As a stand alone company, Duquesne is simply too small to remain in the generation business. Therefore, as a stand alone company, Duquesne has no expectation of submitting a bid. However, the issue need not be addressed today. If Duquesne or its affiliate desires to participate in the auction, Duquesne will make such a request in its petition and propose appropriate safeguards to ensure that it does not have an advantage over other, nonaffiliated bidders.

II. PROPOSALS TO DISALLOW STRANDED COSTS

Q. Please describe the proposals of the intervenors to disallow the recovery of stranded costs.

A. There are three main proposals. The first is the OCA proposal, which would disallow any return (equity or debt) on Duquesne's stranded generating assets. The second is the DII proposal, which would disallow any equity return on Duquesne's stranded generating assets (i.e., would not permit a return on the equity portion of the capital invested in such assets). The third is the Environmentalists proposal, which would allow recovery of no more than 60% of Duquesne's stranded costs. Each, however, has a common thread: the proposed "sharing" of stranded costs between ratepayers and shareholders.

Q. What is Duquesne's response to these proposals?

A. Mr. Schnitzer and Mr. Clayton provide a detailed response to these proposals in their rebuttal testimony. I will limit my response to the following three points.

First, the proposals should be rejected because they bear no relation to any cost mitigation that Duquesne could have taken to reduce its cost of service. The parties concede this point. DII Statement No. 1 at 15 ("I am not challenging DLC's mitigation efforts in this proceeding"); Kahal Deposition at 89 (witness does not "make any representations or claims with regard to the prudence of the company in incurring any investments"). The proposals thus are not only arbitrary in that they bear no relation to any actions that Duquesne took or could have taken, but they also conflict with the Customer Choice Act. The Act specifically states that, in considering the appropriate level of stranded cost recovery, the Commission may take into account the utility's mitigation efforts, but it makes no reference at all to a generic "sharing" of stranded costs.

Second, as Mr. Clayton explains in more detail, the proposals would not allow Duquesne an opportunity to earn a fair return on its prudently incurred capital. The parties do not seriously contend otherwise, nor have they even bothered to estimate the impacts on Duquesne. For example, Mr. Kahal suggests that "Duquesne has the potential to achieve earnings on its nuclear plants in the competitive market if cost control and operations are successful" (OCA Statement No. 1 at 43), but Mr. Kahal has not even undertaken to calculate the financial impact of his proposal on Duquesne (Kahal Deposition at 45-46). Moreover, as Mr. Clayton demonstrates, the OCA adjustment eliminates any return on equity even if one assumes that the operational improvements to which Mr. Kahal refers (which were projected by Duquesne) are achieved.

Mr. Schoengold's testimony also is misleading. He contends that, if his proposal is accepted, "the stockholders will end up having made a reasonable return (9.0 percent for Duquesne . . .) on bad investments." Environmentalists Statement No. 1. Yet Mr. Schoengold does not analyze whether a 9% return is "reasonable"; he just assumes that it is. Moreover, he fails to provide any support or explanation for his calculations and thus, as discussed by Mr. Clayton, it is impossible even to model their impacts with any accuracy to determine whether his predicted "return" is accurate. In any event, as Mr. Clayton testifies, Mr. Schoengold's proposal, if adopted, would have severe economic consequences for Duquesne and would not permit Duquesne to earn, on a going forward basis, anything close to a 9% return on equity.

Third, Messrs. Baron and Kahal contend that their proposals are consistent with past ratemaking practice in Pennsylvania. This is not true, although I note at the outset that this issue not dispositive; the real issue is whether such a disallowance is fair and reasonable on the facts of this case. Putting that aside, however, I am unaware of any case (and the parties do not refer to one) in which the Commission disallowed the recovery of embedded generation costs on the basis of a comparison of those costs to market price forecasts, which assumed that the capacity could be replaced by purchases in the spot market. No such assumption would have been appropriate, given that utilities have had an obligation to serve their loads on a long-term basis. That obligation has never been discharged through reliance solely on the spot market (or the "coordination" market as it has been called traditionally).

In fact, the "practice" in Pennsylvania is just the opposite of that posited by the intervenors. The practice in Pennsylvania that is most relevant here is that of rate of return regulation -- in which rates are set on the assumption that the utility will earn no more, and no less, than its allowed return. Under this practice, it is irrelevant if the utility's assets turn out to be above, or below, their market value. In each instance, rates are set on the basis of allowed returns.

A good (and very recent) example is the Ft. Martin sale. There, Duquesne reached an agreement with the OCA and the Commission regarding the appropriate disposition of the sale of Duquesne's share in the Ft. Martin plant. As noted by many witnesses here, the sale price exceeded the book value of Duquesne's interest, but the proceeds were not used to increase the returns to shareholders beyond approved levels;

rather, consistent with rate of return regulation, the gain was used to accelerate the amortization and depreciation of strandable assets. Thus, Duquesne's shareholders did not "share" the gains. It is therefore neither fair nor consistent for the OCA (and others) to contend that, for the remaining plants – where market values are below book values – it is "just and reasonable" for shareholders to bear an economic loss. To the contrary, provided that Duquesne has adequately mitigated its cost of service (including through actions such as the sale of Ft. Martin, which was the only one of its kind in Pennsylvania), shareholders should continue to have the opportunity to earn a fair return, no more and no less.

III. THE METHODOLOGY FOR DETERMINING THE CGC

Q. Please describe the scope of this section of your testimony.

A. In this section I will briefly discuss one important policy issue: the need to set CGCs during each year of the transition period on the basis of the then-prevailing market price of power.

Q. This seems to be an intuitive result. Is it controversial?

A. Yes. The reason is the rate cap imposed by the Customer Choice Act. The rate cap produces a situation in which customers cannot be harmed if the CGC differs from actual market prices, but suppliers and the incumbent utility (Duquesne) can be substantially harmed. This dynamic is the reason the Commission is presented with starkly different proposals from customer and supplier groups.

I will first address the customer proposals. The OCA and DII propose to set CGCs at a fixed level throughout the transition period, using their computer forecasts

of market prices. They readily concede that, under this approach, if market prices rise to levels above the fixed CGC, customers will return to Duquesne and take service at the rate cap. "Taking service at the rate cap" means, for purposes here, purchasing unbundled generation from Duquesne at a price equal to the CGC. When market prices rise above that level, purchasing from Duquesne is clearly preferable to paying a marketer the actual (higher) market price. In such a scenario, the customer is protected and Duquesne is protected, given that the CGC was set on the basis of a market price prediction that, in retrospect, was too low. However, the suppliers are harmed (they contend) because customers will have an artificial incentive to return to service from Duquesne.

Now consider the opposite scenario -- in which market prices fall below that projected in the CGC. In this situation, customers are again protected because they are not required to purchase power from Duquesne at the CGC. Consequently, one would expect them to purchase power in the open market at lower rates. Suppliers too will benefit under this scenario, given that customers are less likely to continue purchasing from Duquesne under the rate cap. The loser in this scenario, of course, is Duquesne. Duquesne will fail to fully recover its stranded costs because the fixed CGC, in retrospect, was set too high and, hence, the CTC was set too low.

As the foregoing illustrates, customers have a natural incentive to "lock in" the CGC because they gain "certainty" without any adverse economic effects associated with the resulting loss of accuracy in forecasting the CGC. The suppliers, on the other hand, have the incentive to adjust the CGC on an annual basis to reflect actual market

prices. Suppliers also, however, have an incentive to fix the CGC in advance, provided that it is set so far above market prices that they bear no material risk of market prices exceeding the CGC in any year. The latter incentive is illustrated by Mr. Russell's proposal to set the CGC on the basis of the cost of constructing a new generating unit, even though he concedes that ECAR has excess capacity.

Q. In view of these conflicting incentives, what is Duquesne's proposal?

A. The only fair resolution is to set the CGC at the market price and that is precisely the purpose of Duquesne's RFP proposal. I recognize that many parties have criticized the RFP as producing prices that are "too low". While this is not the point -- the goal is to establish a method that measures actual market prices -- I note that the market prices produced by the eight-year RFP are nearly identical to those forecast by the OCA, with the sole exception of an artificial "bump" in market prices that OCA predicts will occur in 2003 due to the addition of new capacity. Whether or not this spike in prices actually occurs is, of course, a matter of speculation, but, from the results of the eight-year RFP, the market is predicting that it will not occur. More to the point, however, none of the parties (with the exception of Mr. Boonin) offers any concrete alternative for calculating the true market price of power in the Duquesne region. In the absence of any such alternative, the Commission should accept Duquesne's proposal, modified in the manner mentioned in the summary of my testimony. (I also note that Mr. Lahtinen discusses this issue in greater detail in his testimony.)

IV. THE POTENTIAL EARLY RETIREMENT OF GENERATING ASSETS

Q. Please summarize the intervenor testimony regarding the early retirement of generating facilities.

A. There are a range of proposals, but they each have the common thread is that a particular generating unit be shutdown permanently if it is not forecast to provide an economic benefit over its remaining useful life. Alternatively, the witnesses would deny Duquesne the recovery of the losses associated with continued operation of such a unit if Duquesne chose to keep it running.

Q. What is Duquesne's response to these proposals?

A. Duquesne agrees that a unit should not continue to operate if it is clear that it will no longer provide economic benefits. However, as Mr. Schnitzer and Mr. Clayton explain, the intervenors have not factored in all the costs associated with shutting down particular generating units. These include current costs that cannot be avoided, or at least cannot be avoided entirely in the year the unit is retired. As these witnesses explain, once all such costs are factored in, it is not clear that any of Duquesne's units should be retired at this time.

However, Duquesne agrees that the economics of retiring these units is a complicated issue and that it merits continued attention during the transition period. Consequently, Duquesne is proposing to submit a detailed study, on or before January 1, 1999, regarding the economics of shutting down any of its existing units. This study

will be noticed for public comment and the Commission can make the determination of whether any units should be shut down.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-00974104
Duquesne Light Company Application to approve restructuring plan pursuant to 66 Pa. C.S. S 2806(d)	)	

- - -

DEPOSITION OF

STEPHEN J. BARON

November 18, 1997

10:00 a.m.

J. Kennedy and Associates, Inc.

35 Glenlake Parkway

Suite 435

Atlanta, GA 30328

Wanda L. Robinson, RMR, CRR-B-1973

Q. Would it be fair to say then that you believe that that methodology is superior to the valuation produced by the sale of the assets?

A. I would say that the accuracy of the valuation, the precision in the valuation, the best valuation would be achieved by a divestiture and a sale of the assets.

Q. Would an auction of Duquesne's fossil units provide an accurate valuation of Duquesne's nuclear units?

A. It's possible that one could derive an accurate valuation of the nuclear units from the auction of the fossil units. It wouldn't necessarily be the case.

COPY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

In re	
DUQUESNE LIGHT COMPANY Application to approve restructuring plan pursuant to 66 Pa. C.S. Section 2806.	Docket No. R-00974104

Washington, D.C.

Friday, November 21, 1997

Deposition of

MATTHEW KAHAL

a witness, called for examination by counsel for Applicant pursuant to notice and agreement of counsel, beginning at approximately 11:08 a.m. at the law offices of Skadden Arps Slate Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Is there any better way to determine the market value of Duquesne's generating assets than the kind of price and cost forecast that the OCA has presented?

A Yes, I think there is.

Q Could you elaborate?

A I think a divestiture would probably produce a more reliable estimate, although I -- even I would have to concede, though, that a divestiture at the present time of nuclear assets is very problematic.

Q And as I understand the caveat, the general proposition would be that if Duquesne's fossil units were sold, that sale price wouldn't necessarily be a good valuation for the nuclear --

A That's right. To put it another way, I'm want sure that there is much of a market right now for nuclear assets. That is, the -- my comments about the divestiture process were really predicated on the notion that there is a broad competitive market for generation assets. I think that there are so few buyers in the nuclear asset field right now that I wouldn't be confident that that would produce an efficient market price.

Q Have you made any calculations of

what you would expect Duquesne's earnings to be were the OCA proposal to be accepted?

A I have not done that, no.

Q Any calculations regarding the financial impact of those proposals on the company?

A No.

Q Does your testimony make any representations or claims with regard to the prudence of the company in incurring any investments?

A No.

COPY

PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application for approval of restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Monday, November 17, 1997

Deposition of

WHITFIELD RUSSELL

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 2:20 p.m., at the offices of Skadden Arps Slate Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Would the auction of Duquesne's fossil units provide an accurate valuation of the value of its nuclear units?

A No.

Q Would the auction of one of Duquesne's fossil units provide an accurate valuation for all of its fossil units?

A Probably not.

PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application for approval of restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Monday, November 17, 1997

Deposition of

DAVID SCHOENGOLD

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 2:20 p.m., at the offices of Skadden Arps Slate Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Well, let's take it step by step.

Would an auction of all the generating assets be a reasonable procedure for a true-up valuation of the assets?

A There is -- it's a good approach with one problem to it. The problem being the question of when the auction takes place.

If the auction were to take place -- and, here again, we're referring to all of the generating assets. If the auction were to take place at this moment, we don't have an open competitive market for generation, so there -- it's not clear that a price that would be determined at such an auction would really reflect the value of those facilities in the same way it would if we had in place an open competitive market. And so I would say if the auction were taking place a few years down the road, when we do have a competitive market in place or when it's presumed that there will be a competitive market, I would say that would be a good way of doing it. If it's done now, it's -- there are some potential problems with that approach.

THE PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application to approve restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Wednesday, November 19, 1997

Deposition of

ROBERT B. WEISENMILLER, PH.D.

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 11:25 a.m., at the Law Firm of Skadden, Arps, Slate, Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q Would an auction of Duquesne's fossil assets provide an accurate valuation of the nuclear assets?

A No, an auction of the fossil assets

should provide, if done properly, should provide a valuation of the fossil assets.

Q Would an auction of one fossil asset provide an accurate valuation of the remaining fossil assets?

A Depending upon how representative that one asset was, it might at least give you a data point, but it would not be as indicative as an auction of all of those assets.

Duquesne Statement No. 2-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
Donald J. Clayton

Contents:

Response to Intervenor Testimony Regarding Cost Mitigation Efforts, Stranded Cost Calculations and Recovery, Regulatory Assets, and Other Financial Matters

REBUTTAL TESTIMONY OF DONALD J. CLAYTON

I. INTRODUCTION

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: Have you previously testified in this proceeding.?

A. Yes. I submitted direct testimony (Duquesne Statement No. 2) and various supporting exhibits (DJC-1 through DJC-9) with Duquesne Light Company's August 1, 1997 restructuring filing.

Q: What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to discuss the Company's proposed modifications to its original proposals with respect to stranded cost. I will then discuss the Company's position with respect to the proposals of the various intervenors on stranded cost and stranded cost recovery, adjustments to regulatory assets, adjustments to nuclear and fossil decommissioning, life extension of certain generating plants, shut down of certain generating plants , ECR roll in, ROE spillover, and asset securitization. I will also update the Company's range of stranded costs as of December 31, 2005 and discuss the negative impact on Duquesne's financial viability under the "sharing proposals" which have been advanced by various parties.

Q: Will you summarize the positions of the various parties relative to stranded cost and stranded cost recovery?

A. Yes, four parties, the OCA, OTS, DII and HSS/ARI, have made more or less

comprehensive assessments of the Company's stranded cost and stranded cost recovery. These parties have commented on virtually every aspect of the Company's stranded cost and stranded cost recovery proposals. (However, OTS and HSS/ARI have not proposed an independent valuation of the Company's owned-generation stranded costs as of December 31, 1998.) Other parties have made proposals which would impact the Company's claims but have not made comprehensive proposals of their own. In general, there was fair agreement among the parties on the amount of the Company's generation plant assets and there was a large degree of overlap on regulatory assets. In contrast, there was a fairly wide range of opinion on the market value of Duquesne's generating plants and there was a significant difference of opinion among the parties on the amount of stranded cost recovery which should be allowed. Exhibit DJC-10 shows the relative positions of OCA, OTS, DII and HSS/ARI with respect to the Company's level of stranded cost as stated on a consistent basis with the Company's positions as of December 31, 1998. Exhibit DJC-11 shows the total impact on revenues of the various proposals and Exhibit 12 shows the sharing proposals of the OCA and DII. In the sections that follow, I will detail the Company's position with respect to each of the major adjustments proposed by the various parties and show why each of the proposed adjustments should be rejected by the Commission.

II. MODIFICATIONS TO THE COMPANY'S PROPOSALS ON STRANDED COST

Duquesne's proposed modifications address many of the concerns raised

Q. Given the testimony of the other parties to this proceeding, has the Company changed any of its original proposals with respect to the determination of or recovery of stranded costs?

A. Yes. The Company has modified its proposal in three ways that I will discuss. First, the Company has agreed to divestiture, at the Commission's option, in 2003 as the method to determine market value. Second, the Company will revise the market price trigger to reflect the OCA market price line. Third, the Company has eliminated the deadband around the proposed ROE for purposes of the ROE spillover mechanism.

Q. Please elaborate on the Company's first proposed modification.

A. Duquesne will commit to allow the Commission to order Duquesne to auction its generation in 2003. Several parties have suggested that divestiture of the company's generating plants is the only way to arrive at a definitive market value for the Company's generating plants. While the Company does not agree that this is the only way, the Company does recognize that asset divestiture is a proper way to establish market value. As such, as part of its stand alone restructuring proposal the Company will modify its final valuation proposal to include an option whereby the Commission could order the Company to divest its generating assets in 2003 (or sooner if there is an early trigger of the final valuation). Under this modified proposal, the Commission could order the Company to offer for sale its entire generating portfolio including both its fossil

and nuclear units. The divestiture would be conducted so as to maximize the value of the generation portfolio and the Commission would approve the procedures to be used to complete the divestiture.

Q. Is the Company still proposing an arbitration panel of experts for the final market valuation?

A. Yes. If the Commission does not elect to order Duquesne to determine market value by conducting an auction of its generation assets, then a market-based valuation without a divestiture would take place. This valuation procedure would rely on all the market evidence described in Duquesne's direct case for the arbitration panel. However, because the Commission is given the initial option to order divestiture, if it did not exercise that option and Duquesne objected to the market valuation determined by the panel, then Duquesne would have the further option to undertake divestiture to determine generation plant value as set out in Duquesne's direct case.

Q. Would divestiture settle all issues regarding market value?

A. Most, but not necessarily all. If no bids were received for a generation unit, then that would establish the market value ceiling for the unit of zero. The arbitration panel would then have to determine if there were unavoidable costs of shutting down the unit and, hence, whether the value of the unit was negative and in what amount. This circumstance could, for example, arise with respect to the sale of the nuclear units, given that, at present, there appears to be minimal demand for the purchase of nuclear assets.

Q. Why is the Company proposing to wait until 2003 to trigger the divestiture option?

A. The Company is proposing to wait until 2003 for a number of reasons. The most important reason for waiting is that under the restructuring legislation the Company will retain the obligation to serve customers at the generation price cap and will serve as the supplier of last resort. Second, as discussed in the direct case, the Company believes that by 2003 the electricity markets will be more fully developed than they are today. As such, a reasonable final market valuation may be able to be easily determined based on methods other than an ordered divestiture.

Q. Would the trigger mechanisms discussed in your direct testimony still apply to accelerate the final valuation, including the Commission option to order divestiture?

A. Yes. If the early valuation is triggered, the Company would be willing to divest at that time under the Commission ordered divestiture option discussed above. Mr. Schnitzer discusses the use of the OCA market price line as a benchmark for assessing whether Duquesne will have sufficiently amortized and depreciated its stranded cost. I propose below a trigger based on the OCA price line. Other than the change to the market price trigger discussed by Mr. Schnitzer, the two triggers would operate as proposed in Duquesne's direct case.

Q. What is the Company's second modification?

A. The second modification is to adopt the price line of the OCA for the purposes of determining the early trigger points for the final valuation. Under the Company's original proposal, Duquesne would have triggered an early valuation in either 2001 or 2002 if the market price from its annual solicitation was greater than $28.5/MWh in 2001 or $29.2 in 2002.

As Mr. Schnitzer demonstrates in his testimony, under the OCA's assumptions (except for sharing/disallowance) the Company's market and book values for generation assets would be approximately equal at year end 2003. The OCA market values beyond 2003 are predicated on the jump in prices forecast by OCA witness Doug Smith in Exhibit DCS-5 in the year 2003. The Duquesne weighted generation market price line of the OCA for 2003 shown in Exhibit DCS-5 is $29.28/MWh based on an average capacity factor of approximately 75% for all Duquesne's units. The Company proposes to reset the triggers at 90% of that 2003 price deflated to 2001 and 2002 at the OCA's inflation rates. This would result in a lowering of the trigger price in 2001 from $28.5 to $24.9 and in 2002 from $29.2 to $25.6. These lower price triggers add conservatism to the Company's case, given that they make it more likely that an early valuation will occur. The price used to determine if the trigger price was exceeded would be the 75% capacity factor price from the 1 year solicitation used to establish the CTC for 2001 and 2002 respectively. If an alternative means were used to establish the market price (and the CGC/CTC) as discussed in Mr. Marshall's testimony, then that standard (adjusted to a 75% capacity factor) would be used to determine if an early final valuation would be triggered.

Q. What is the third proposed modification?

A. The Company will eliminate the bandwidth around the proposed ROE of 11.5%. Duquesne has been criticized for its ROE spillover proposal which includes an 11.5% ROE with a ½% collar for the determination of the entries to the proposed deferred revenue account. The Company proposed the collar to avoid making

insignificant accounting entries and not to try to gain approval for a 12% ROE as some have suggested. In fact, the Company believes that it will be difficult enough to reach the 11% floor given its proposed minimum amortization commitment of $1.7 billion between 1999 and 2005. However to avoid controversy over this item, the Company would remove the collar from its proposal and record all entries to the deferred revenue account based on an 11.5% ROE.

Q. How do these proposed modifications to the Company's original filing improve the Company's plan?

A. These changes are intended to answer criticisms raised by intervenors and demonstrate Duquesne's continuing commitment to a fair market-based determination of stranded costs. The option for the Commission to order divestiture in 2003, the revised early valuation trigger and the removal of the ROE collar will address a number of concerns raised by various parties, including life extension, fossil and nuclear decommissioning, plant shut down, future market price of power, and possible efficiency gains. Several parties believe that an asset divestiture is the only true way to establish the value of the Company's generating units. The Company believes that a fair, timely and independent valuation is important to the determination of stranded costs and recognizes divestiture and the early trigger modification as means to these ends. The Company's position is and always has been that it should recover no more (and no less) than its fully mitigated stranded costs and that on a present value basis it should only receive what it could have expected to receive under traditional

ratemaking. The ROE spillover without a collar and the other proposed modifications should further ensure this result.

Q. Specifically how does the early trigger modification respond to concerns raised by others?

A. By modifying the early trigger, the Company can assure the OCA and others that it will not over recover its stranded cost prior to the final valuation in 2003 if market prices rise above the levels anticipated by the OCA.

Q. How does the removal of the ROE collar address concerns raised by other parties?

A. By eliminating the collar there is assurance that the Company will only be able to earn up to, and in no circumstances, over its exact authorized ROE level.

III. STRANDED COST AND STRANDED COST RECOVERY

Duquesne's Rate Cap Proposal is Justified

Q. Several parties (e.g., OCA, HSS/ARI, and City of Pittsburgh) have argued that the Company has failed its own test to justify continuation of a rate cap because the Company may fully recover its stranded costs before 2006. Is the Company's current position inconsistent with the Company's position in its original filing given the corrections which were made to your testimony subsequent to the date of the original filing?

A. No, quite the contrary. In its original filing the Company discussed the difficulties with determining stranded costs as of December 31, 1998 and developed a second stage valuation proposal with early triggers and an ROE

spillover to ensure that there would be no over recovery of stranded cost. The early triggers and the ROE spillover were specifically designed to make certain that stranded costs would be recovered as quickly as possible and were incorporated as part of the Company's proposals in contemplation of a situation in which stranded costs could be fully collected before 2006. As part of the discovery process the Company updated and corrected its exhibits (DJC-3,DJC-4 and DJC-7) supporting its likely range of stranded costs remaining at the end of 2005. This correction has been reproduced and included as Exhibit DJC-21. The Company's updated exhibits show that under a high market price scenario that there would be a $233 million benefit in 2005. This does not mean that the Company doesn't have any stranded costs; it simply means that the Company would be able to recover its stranded costs before 2006. Under that scenario, the Company would fully recover its stranded costs sometime in 2004 assuming that rates were charged at current levels. This point is more fully developed in Mr. Schnitzer's testimony.

Q. Does Duquesne's proposal mean that it will in all circumstances charge rates up to its rate cap through the end of 2005?

A. No. The company has proposed to charge rates up to its allowed rate cap only until its stranded costs are recovered.

Q. Before the Company updated and corrected its Exhibits, was there a scenario that would have shown the Company could collect its stranded costs before 2006?

A. Yes. In the Company's original filing, merger synergies of $200 million were identified which indicated that full recovery of stranded costs would likely occur before 2006 under the company's high market price scenario. Under this

scenario the company showed a net of $8 million of stranded cost less $200 million for merger synergies or a $192 million net benefit as of December 31, 2005.

Q. Does the Pennsylvania restructuring legislation permit the Company to continue to charge rates at existing levels so long as it is mitigating stranded costs?

A. Yes. Section 2804(4)(v) of the Act states that a Company "shall not be required to reduced rates below the capped level" if it is continuing to mitigate stranded costs. So long as a utility is mitigating (reducing) its stranded costs, capped rates can be charged and need not be reduced until the Company no longer has stranded costs. If a utility has any level of stranded costs, then capped rates can continue to be charged until these stranded costs are fully mitigated through accelerated amortization. This sub-section does not link use of the rate cap to any specific time period for the recovery of stranded costs.

Q. Under the forecasts of OCA or DII, would Duquesne recover its stranded costs prior to the time the Company proposes that the market determination of its stranded costs be made?

A. No. Even under the OCA and DII views of the world, there is simply not enough room under the rate cap to reduce the book value of Duquesne's generation assets to market levels before the end of 2003. Mr. Schnitzer has prepared sensitivity studies which show the points at which stranded costs would be recovered (i.e., that book and market values would be equal) under the OCA and DII proposals, adopting -- for purposes of argument -- their views on market prices, operating costs, plant shutdowns and life extensions, and discount rates. Even when all of

the adjustments (other than the confiscatory sharing proposals are considered), the Company's rate cap would extend to the end of 2003.

Duquesne has a Significant Level of Stranded Cost

Q. Several parties have criticized Duquesne for failing to make a definitive projection of its stranded costs. How do you respond?

A. It seems to me that these parties are missing the point. Duquesne's Customer Choice Plan seeks to avoid a contest of numerical calculations, focusing instead on choosing the best methodology for valuing Duquesne's generating assets and, hence, for calculating known and measurable stranded costs. Through use of such a market-based methodology, Duquesne will recover no more than its known and measurable stranded costs.

Q. Does this mean that Duquesne's direct case failed to quantify stranded costs?

A. No. Duquesne calculated a range of stranded costs, recognizing that stranded costs vary with the level of market prices that are assumed. These calculations were updated on October 16, 1997, showing the likely range as of December 31, 2005 to be a $233 million benefit to a $423 million stranded cost.

Q. Most other parties projected stranded costs as of December 31, 1998. Why did Duquesne calculate stranded costs as of 2005?

A. Duquesne did so to project the date on which the Company could cease collecting a CTC, assuming it could charge rates up to currently approved levels during the transition period, per Section 2804(4)(v), with any excess earnings being used to accelerate the amortization of stranded costs.

Q. Is it possible to translate your earlier calculations into projected stranded costs

as of December 31, 1998, such that Duquesne's projections can be compared to those of the intervenors?

A. Yes. Duquesne has calculated pro-forma stranded costs as of December 31, 1998 in Exhibit DJC-20. These calculations were made based on the all hours spot prices from Company Exhibit MMS-4 for the years 1999 to 2005 (adjusted for each unit based on the Promod output) and the three post-2005 market price scenarios identified in Mr. Schnitzer's direct testimony identified as Low, Delayed Entry, and High. The stranded costs resulting from these calculations are, as follows:

	Without Merger(1) ($000)	With Merger ($000)
Low	$1,916	$1,716
Delayed Entry	$1,695	$1,495
High	$1,537	$1,337

Q. Which of the above stranded cost scenarios does the Company believe is most likely to occur?

A. Based on the market price evidence from its recent RFP and the testimony of Mr. Schnitzer, it is likely that actual market prices will be closest to the Company's low market price scenario, which is $1,916 billion in stranded costs as of December 13, 1998.

Q. Have other parties to Duquesne's restructuring proceeding identified significant stranded costs for Duquesne?

A. Yes. Several parties have identified significant levels of stranded cost for Duquesne. I have summarized the positions of the various parties and have

quantified stranded costs as of December 31, 1998 in Exhibit DJC-10 after making adjustments to present the data in a consistent format, as follows:

	Without Merger	With Merger
Office of the Consumer Advocate	$1,258	$1,058
Office of Trial Staff[1]	$ 658	-
Duquesne Industrial Intervenors	$1,455	-
HSS/ARI	$ 84	-

Q: Why has Duquesne included a line item for PV of Costs Independent of Operation in its estimate of stranded costs set out on Exhibit *DJC-10*?

A. These costs represent sunk costs that will be incurred regardless of whether Duquesne operates the units. Exhibit DJC-13 presents an avoidable cost analysis of Duquesne units that would otherwise show a negative present value ("PV") of operating margin as of December 31, 1998. In calculating the market value of these units, Duquesne has adopted the convention of setting the PV of the margin to zero when the result is negative. For example, under the Low market price line, the market value of the Duquesne generation is only $27 million on a PV basis as of December 31, 1998. This cumulative value reflects significant negative margins for Cheswick, Perry, Beaver Valley II and Elrama that have been set to zero[2]. Another output of the avoidable cost analysis is to show which costs cannot be avoided by shutting down a

[1]The OTS has not made an estimate of owned-generation stranded cost see testimony of OTS Witness Metro at pp. 19 and 20.

[2]The consequence of calculating a negative margin is not of necessity that the unit must be shut down.

generation plant. The breakdown of plant costs into avoidable and unavoidable costs is sponsored in the rebuttal testimony of Messrs. O'Brien, Duckworth and Nelson. The present value of the unavoidable costs of the plant independent of operation is shown in Exhibit DJC-10.

Q. Why were these costs not identified in the earlier margin analysis as of December 31, 2005?

A. The 2005 margin analysis reflected the present value of operating margins in 2006 and beyond. The one-time analysis as of 1998 reflects the low market prices in the years 1999-2005. Under Duquesne's original two-stage proposal, the final valuation of generation would not take place until 2003. Mr. Schnitzer's direct testimony establishes that Duquesne would have the proper incentives to shut down uneconomic generating units during the transition period. However, if Duquesne were asked to present a one-time analysis of stranded costs, the actual economics facing the Company must be reflected in the stranded cost estimate. Duquesne cannot shut these units down without facing certain unavoidable costs independent of operation. Duquesne also has sunk costs that will not be recovered if the plants are shut down.

Q. What conclusions do you draw from the range of stranded costs identified by the other parties to Duquesne's restructuring proceeding?

A. First, it is likely that the Company has a significant level of stranded cost. Second, stranded costs span a wide range of possible values giving further credence to the Company's position that it would be more desirable to determine stranded costs in the future once the markets for electricity in a competitive environment are more fully developed.

Q. Will you comment on the HSS/ARI stranded cost estimate.?

A. Yes. It appears that HSS/ARI is an outlier in this process. In his deposition HSS/ARI witness Weisenmiller admitted that although he concluded the Company had no owned-generation stranded costs as of the end of 2005 (using assumptions no other party makes), he had done no analysis to support this conclusion as of the end of 1998. Weisenmiller deposition at 136. In short, Mr. Weisenmiller has made no analysis of stranded costs. Although the Company is tempted to simply dismiss HSS/ARI's testimony as unsupportable and sophomoric, I will address the specifics of the most egregious positions taken by HSS/ARI elsewhere in my testimony. In general the HSS/ARI estimate of $84 million of regulatory asset stranded cost for Duquesne relies on adjustments which include one sided accounting entries, questionable allocation methods, a biased estimates of plant values, and proposals which are contrary to past Commission practice in Pennsylvania and contrary to the provisions of the Act.

Duquesne's Regulatory Asset Claims are Appropriate

Q. Please summarize this portion of your testimony.

A. The witnesses have accepted a large portion of the total dollar value of the regulatory assets claimed by the Company. The only exception is the witness for HSS/ARI, Dr. Weisenmiller. Dr. Weisenmiller basically denies recovery of substantially all of the Company's claim.

Q. Are there any disputes regarding the appropriate standard for determining whether an asset qualifies as a regulatory asset?

A. Yes. Several witnesses contend (or their analysis implies) that the appropriate standard is whether each asset has previously been determined by the Commission, in a specific rate order, to be recovered from ratepayers in some future period. That, however, is not the standard adopted in the Customer Choice Act, nor is it the standard under generally accepted accounting principles. The Customer Choice Act defines a regulatory asset as "assets or other *deferred charges typically recoverable under current regulatory practice.*" Thus, the standard is whether an asset is "typically recoverable" under current "regulatory practice," not, as some intervenors suggest, whether an asset is "specifically recoverable" under a "specific rate order."

Q. Has there been any prior review by the Commission or third parties into whether the Company has properly classified and recorded its regulatory assets?

A. Yes. There have been numerous audits of the Company's financial statements. These audits include audits performed by regulatory bodies such as the Chief Accountant's office of the Federal Energy Regulatory Commission (FERC), and Bureau of Audits for the Pennsylvania PUC. These audits also include audits by the Company's independent auditors, Deloitte & Touche, LLP, as well as acceptance of the audited financials by the Securities and Exchange Commission (SEC). A listing of these audits and orders were provided in response to interrogatories HSS-1-043, HSS-1-092 and HSS-2-023, attached hereto (without attachments due to their bulk) as Exhibit DJC-22.

Q. You previously referred to generally accepted accounting principles. Please describe what are the criteria, from an accounting standards perspective, when

a company can record a regulatory asset.

A. Specifically, Statement of Financial Accounting Standards No. 71 (SFAS No. 71), provides the accounting guidelines for establishing and maintaining a regulatory asset. The standard requires that rate actions of a regulator can provide reasonable assurance of the existence of an asset. If certain criteria are met, then a company can capitalize an incurred cost that would otherwise be charged to expense under generally accepted accounting principles (GAAP).

Q. Describe the specific criteria established for creating a regulatory asset.

A. It must be proven to be probable that future revenue will result from inclusion of the specific cost in costs allowed for ratemaking purposes. The criteria for meeting the probability test is to either have a specific order which provides for the specific recovery of the costs or to show that the costs are typically recoverable in the specific regulatory jurisdiction and that there have not been any regulatory actions which would prohibit the recovery of the specific costs. As previously indicated, the regulatory bodies which govern the accounting rules for regulatory assets all concur on the Company's accounting. These bodies include the SEC, the FERC, and the Audit Bureau of the Pennsylvania PUC.

Q. Will you describe the guiding principle under which the Company developed its claims for regulatory assets and other deferred charges?

A. Yes. The Company developed its claim for regulatory assets based on the principle that it was only entitled to a revenue requirement which, on a present value basis, was equal to the revenue requirement which would have been

normally identified and typically recoverable under current Pennsylvania ratemaking practice.

Q. Have you prepared a schedule which demonstrates that the Company's claim for each of its regulatory assets is equal, on a present value basis, to the revenue requirement computed on a present value basis?

A. Yes. Exhibit DJC-15 shows the revenue requirements computed both under traditional ratemaking and as included in the Company's filing for each of the regulatory assets claimed by the Company. Exhibit DJC-15 demonstrates that on a present value basis, the Company's claim is equivalent to (or in some cases, slightly less than) what would have been computed under traditional ratemaking.

Q. Are the categories under which the Company classified its regulatory assets important?

A. No, not particularly. The Company did classify some items as regulatory assets which could have been included in plant or other deferred charges such as the Warwick mine, the cold reserved portions of Phillips and Brunot Island, the present value of the Beaver Valley Unit No. 2 lease payments, SFAS 109 plant, and several other smaller items. Reclassification of these items would not change the Company's stranded cost claim.

Q. Will you identify the recommended adjustments to Duquesne's claims for recovery of regulatory assets as advanced by the other parties in this proceeding?

A. Yes. Exhibit DJC-10 shows the regulatory assets claimed by the Company and the adjustments to these amounts as identified by the other parties in this

proceeding who made more or less comprehensive assessments of the Company's regulatory assets and generating plant values. I have presented all of the proposed adjustments on a consistent basis and have attempted to accurately quantify the positions of the other parties relative to Duquesne's positions. The adjustments made by other parties to the Company's claims were either not quantifiable (e.g., Environmentalists) or less than comprehensive. I will discuss these types of adjustments as appropriate in the sections which follow.

Each of the Company's Disputed Regulatory Asset Claims Are Appropriate

Q. Will you discuss the Company's claim for the SFAS 109 regulatory tax receivable and any proposed adjustments?

A. Yes. The regulatory tax receivable represents the unamortized portion of the regulatory asset which was booked when the Company adopted SFAS 109. Mr. Catlin, on behalf of the OCA, Mr. Kollen, on behalf of DII, and Dr. Weisenmiller, on behalf of HSS/ARI have taken issue with the Company's claim. Mr. Catlin and Mr. Kollen do not dispute Duquesne's right to recover the SFAS 109 regulatory asset nor do they disagree with the amount that Duquesne has recorded as the generation-related portion of this asset. Mr. Catlin has adjusted downward the total claim because the portion relating to "basis differences" is included in nuclear plant balances for determining stranded costs according to the OCA methodology. Mr. Kollen has made a similar adjustment to eliminate any double counting of this asset. Dr.

Weisenmiller of HSS/ARI is the only party to adjust the Company's claimed regulatory tax receivable. Dr. Weisenmiller asserts that the Company has not supported this regulatory asset because the Company has not had a base rate case in ten years, does not have a valid regulatory order for this item, and further, that the Company should not be allowed to earn a return on the unamortized balance. Dr. Weisenmiller concludes his analysis of this item by disallowing the entire balance.

The Company takes exception to Dr. Weisenmiller's testimony. Dr. Weisenmiller introduces a definition and criteria of regulatory assets which conflicts with GAAP, the FERC's accounting guidelines and, most importantly, with the Pennsylvania statute. Dr. Weisenmiller asserts that a "valid regulatory order" is a "basic threshold test" for a regulatory asset. As indicated, however, under the statute the test for regulatory assets is far different from the characterization of Dr. Weisenmiller's "basic threshold test". In Section 2803(1), Transition or Stranded Costs include "regulatory assets and other deferred charges typically recoverable under current regulatory practice" (emphasis added). It appears that the statute contemplates the very situation where a regulatory order has not been received, but future recovery was expected under current regulatory practice.

Under the statute, there are no special rules for companies which have not had a rate case within a specified time such as ten years. Dr. Weisenmiller's attempt to impugn the validity of the Company's balance sheet for this reason

is undermined by his own testimony which indicates that after a recent audit by the PUC staff, only about $2 million of unrecorded retirements were noted on a gross plant value of more than $2.8 billion. Clearly, the PUC staff audit should provide Dr. Weisenmiller with some comfort that the Company's additions since the last rate case are not overstated.

In addition, the amounts disallowed as a regulatory asset meet the definition of regulatory assets under GAAP, as well as under FERC accounting guidelines. Specifically, FERC's audit staff under direction of the FERC's Chief Accountant's office reviewed the Company's adoption of SFAS 109 as a change in accounting method and accepted the Company's adoption.

Further, Dr. Weisenmiller's adjustment is a one-sided accounting entry and is typical of the types of biased adjustments he has proposed on behalf of HSS/ARI. As stated in my direct testimony, if the regulatory asset related to the SFAS 109 tax receivable is removed, then the deferred tax balance for each plant should be increased by a like amount. If both sides of the accounting entry are removed, the net present value of revenue requirements is unchanged and the resulting effect on the Company's stranded cost is zero. If, however, only one side of the accounting entry is removed, as Dr. Weisenmiller does, this will affect revenue requirements and is clearly unfair and biased.

Finally, Dr. Weisenmiller asserts that Duquesne's claim for the entire amount

of the regulatory asset is not justified. He proposes that post-2005 costs are stranded with the relevant portion of the premium amortized over the remaining life of the plant. Dr. Weisenmiller ignores the reality that post-2005, there will be no mechanism for the Company to recover these costs. Under his proposed scenario, the Company would suffer an impairment loss for the post-2005 unamortized balance.

Q. Will you discuss the Company's claim for unamortized debt costs and any proposed adjustments?

A. Yes. Unamortized debt costs represent premiums and discounts paid by the Company to issue and refinance its debt. Typically this item has been recoverable through interest expense as a reduction to the debt balance outstanding and as an amortization amount included in interest expense. With the move to competition, the generation-related portion of this item will no longer be recoverable through interest expense beyond 2005. As such, the Company has proposed to recover the present value of the post-2005 portion of this item by the end of 2005. The OCA has proposed to exclude the pre-2005 portion of this item from interest expense and would allow recovery of the entire amount as a regulatory asset. A similar adjustment is proposed for the recovery of the premiums and financing costs associated with the Beaver Valley Unit No. 2 lease.

Although on the surface the OCA's adjustment appears to be reasonable, it penalizes the Company in two ways. First, the adjustment lowers the Company's overall cost of capital by lowering the computed debt cost to a level

below that typically allowed under Pennsylvania ratemaking and second, it raises the apparent leverage of the Company to levels which are higher than typically would have been determined under current Pennsylvania ratemaking practice. There is no justification for the adjustments made by the OCA other than to deny the Company a reasonable return.

HSS/ARI admits that these amounts typically would be recoverable under current Pennsylvania ratemaking practice (see Weisenmiller, p. 109, lines 8-10). HSS/ARI offers no reasonable alternative for the recovery of the post-2005 amount of this item and, absent regulation (or divestiture under the HSS/ARI proposal), this amount would have to be written off by the Company. Again, witness Weisenmiller has proposed an unfair adjustment which even he recognizes would have to be dealt with in a divestiture scenario.

DII witness Kollen also would eliminate post-2005 debt premiums because he believes that the Company has unfairly used a higher cost of capital to discount margins beyond 2005 (see Kollen, p. 13, lines 1-9). Both witnesses Weisenmiller and Kollen fail to appreciate that the Company's proposal for determining stranded cost as of December 31, 2005 is based on a future determination of the value (i.e., the final valuation in 2003) of the Company's generating stations and the Company's current cost of capital simply is not relevant to that determination, which will be based on the capital markets at that time. Further, they both ignore the reality that post-2005, there will be no mechanism for the Company to recover these costs. Under their proposed

scenario, Duquesne would suffer an impairment loss for the post-2005 unamortized balance. Also, the Company's calculation beyond 2005 was developed to illustrate that the Company has a relatively wide range of potential stranded costs depending on the future market price of electricity.

Q. Will you discuss the Company's claim for unamortized sale/leaseback premiums and any proposed adjustments?

A. Yes. The Company's position with respect to sale/leaseback premiums is similar to that of debt discounts and premiums. That is, the present value of the post-2005 amounts must be recovered as a regulatory asset. Witness Catlin for the OCA proposes to include the present value of all future lease expense in the generating plant values. The Company has no particular quarrel with this treatment which could result in an amount mathematically equivalent to the amount claimed. However, since the OCA is proposing an equity return disallowance on the Company's stranded generating assets, and would allow a return on regulatory assets, the Company is not indifferent to this adjustment. Under current regulatory practice in Pennsylvania, the Commission could be expected typically to allow operating lease payments in cost of service, including the amortization of any associated financing costs. Since the Company has only claimed the present value of these amounts in its regulatory asset claim, any proposals which exclude amounts beyond 2005 are unfounded since in the future there will no longer be a mechanism to collect these post-2005 costs.

Q. Will you discuss the Company's claim for deferred rate synchronization costs and any proposed adjustments?

A. Yes. The Company's claim for deferred rate synchronization costs or "early window" costs are the costs incurred by the Company at Perry and Beaver Valley Unit No. 2 between the time the plants went into utility service and the time rates which reflected these units went into effect. This item was specifically addressed in the Ft. Martin Plan. In 1996, the Company took a one-time $9 million write-down of this amount and began amortization of the remaining balance over a 10-year period beginning in June 1996. Under the Company's proposal, the Company would amortize the unamortized balance of deferred rate synchronization costs by the end of 2005. The Company's proposed amortization represents approximately a one-year acceleration of what had been approved under the Ft. Martin Plan. Both the OCA and the OTS accept the Company's amount as claimed.

DII proposes to adjust the stranded cost balance to reflect the present value of the amortization which would have been made through 2006 instead of 2005. The proper amount of the adjustment to the Company's stranded cost claim is $0.5 million -- not $8.5 million as DII has proposed (see Exhibit DJC-14). The Company has already excluded the total amount of these regulatory assets from its determination of rate base and did not earn a return on these items. Hence, a minor adjustment to reflect the one-year acceleration of amortization is proper and should be recognized by the Company.

Again, Dr. Weisenmiller introduces a definition and criteria of regulatory assets which conflicts with GAAP, FERC accounting guidelines and the

Pennsylvania statute. The amounts he disallows as a regulatory asset clearly meet the definition of regulatory asset under the relevant accounting and statutory standards.

Q. Will you discuss the Company's claim for deferred employee costs and any proposed adjustments?

A. Yes. Deferred employee costs represent timing differences between the accrual of, and cash payment of, injuries and damages and compensated absences. Under past Commission practice, this item has been required to be placed on the balance sheet and amortized as a regulatory asset. Clearly then, this asset meets the criteria as provided in § 2803(1) as having been typically recoverable. The Company has always been allowed to recover these amounts in each of its previous rate cases. In addition, the Commission has allowed recovery of similar amounts in other utilities more recent rate cases.

DII suggests that it is inappropriate to recover this regulatory asset because it will eventually reverse. DII's witness Mr. Kollen concludes that these costs represent the differences between accrual and cash recognition of expenses, and thus, are not appropriate for recovery. However, Mr. Kollen has failed to realize that all regulatory assets represent the timing difference between accrual and cash recognition of expenses. If Mr. Kollen's standard was applied, no regulatory asset would be recovered.

The Company has sought recovery of this item such that, on a present value basis, the revenue requirement is actually less than what would have been al-

lowed under current regulatory practice (see Exhibit DJC-15). Although the Company could have taken the position that it should gross-up this item, it has claimed only the amortization of this amount over a seven-year period.

HSS/ARI opposes this item on the basis that the Company has not had a recent base rate case, and that the Company has not shown any of the amounts to be generation related. The HSS/ARI adjustment is clearly misguided. The Company has allocated this item on the basis of direct labor dollars. Apparently, HSS/ARI would argue that this is an inappropriate allocator for the item even though this item clearly is related to labor. I can not think of a more reasonable allocation basis, but if it is truly a matter of misallocation, then the Company's transmission and distribution regulatory assets should be increased accordingly, since there has been no proposed adjustment of the Company's total regulatory asset for this item.

Q. Will you discuss the Company's claim for deferred coal costs and any proposed adjustments?

A. Yes. The Company has claimed $13.5 million in deferred coal costs as a regulatory asset. This amount represents costs which historically have been above the cost caps which limited the amounts that could be included in the Company's annual ECR. Several parties (OCA, DII, and HSS/ARI) have indicated that this amount should not be allowed to be recovered in this proceeding because the Company has not shown that its coal costs will be below market at any time in the future. They argue that if this is the case, Duquesne's shareholders, and not its ratepayers, should be responsible for this

cost. Duquesne's Exhibits clearly show that fuel costs are expected to decline in the year 2000 (see Exhibit DJC-3 revised p. 3).

When the Company entered into the settlements in Docket Nos. P-890386 and P-890387, the Company knew that its fuel costs would decline dramatically once the long-term contracts at Mansfield expired and the Warwick mine costs were recovered, and that recovery of any deferred amounts would be likely to occur in the year 2000. The Company had every right to believe that it would recover these amounts under the terms of the settlements and it should be allowed to recover these amounts in this proceeding.

Further, the Company believes that these assets clearly fall into the definition of a regulatory asset based on the definition specifically provided in § 2803(1) as costs which typically are recoverable. The Company has always been allowed the opportunity to recover its deferred fuel costs. The assertion that there needs to be an assurance of recovery in order to be treated as a recoverable transition/stranded cost does not exist in the statute. In addition, the Company is projecting to be able to recover its deferred fuel cost under traditional rate making policy beginning in 2000. Thus, the Company should be allowed recovery of its deferred fuel costs since absent deregulation, it would have had the opportunity to recover these deferred fuel costs in 2000.

Q. Will you discuss the Company's claim for deferred caretaker costs?

A. Yes. I will address this item with the discussion of cold reserved units elsewhere in my testimony.

Q. Will you discuss the Company's claim for the pre-accrual of nuclear outages and any proposed adjustment?

A. Yes. The Company has proposed to recover a regulatory asset associated with the pre-accrual for nuclear outage costs. The Company believes that this accounting method is preferable in that it more closely matches the expense of outages with the production from the unit. The Company currently uses this method for its fossil stations. In 1993, the Company changed its method of accounting for fossil station outage costs to a preaccrual methodology. This change required an opinion letter by Deloitte & Touche LLP that the new methodology was consistent with GAAP, as well as preferable to any other accounting methodology under GAAP. This opinion letter approving the Company's proposal was reviewed by the SEC and approved. Later, during its normal audit, FERC reached the same conclusion that this was a preferable method of accounting under GAAP based upon its review of other non-regulated industries' accounting practices.

The OCA, DII and HSS/ARI have challenged this proposal as being inconsistent with past practice. The OCA (see Catlin, p. 11, ll. 14-22) has indicated that under its method, the full cash cost of outages should be recognized in the year incurred and hence will not be "double counted." The Company's claim does not double count this item because it is not included in future operating expenses, and it provides a reasonable way for the Company to recover outage costs consistent with preferable accounting methods. If this claim is disallowed, the Company should increase its operating expenses in the years that outages actually occur.

Mr. Kollen's assertion that the deferrals would not exist after generation

supply becomes competitive because it would not be consistent with GAAP is completely inconsistent with the opinions of Deloitte & Touche, LLP, the Company's independent auditors, the SEC and FERC.

Q. Will you discuss the Company's claim for transition costs and any proposed adjustments?

A. Yes. The Company has claimed $18.1 million of transition costs as a regulatory asset and has reduced the amount of depreciation it will accelerate in 1998 by an additional amount of $11.25 million in 1998 due to a higher pilot program incentive credit than was originally anticipated when the Company made its filing on August 1, 1997. DII suggests that it is inappropriate to include restructuring implementation expense as a valid transition cost and excludes $8.3 million from Duquesne's claim. HSS/ARI takes the extreme position that none of the Company's claim is valid because the Company failed to reference the relevant sections of the Act which permit recovery of such items. Recovery of the types of costs identified by the Company are specifically permitted under the Act (Sections 2803 and 2804). The cost of implementation of restructuring is clearly a transition cost which should be allowed. Also, it would be allowed under current ratemaking practices in Pennsylvania which historically have allowed the costs of legislative mandates and rate case expenses to be included in rates. Finally, in response to Mr. Kollen, there are no CARS expenses included in this claim. All of the costs associated with the CARS project have been included as a distribution operating cost.

Q. Will you discuss the Company's claim for recovery of SFAS 106 costs?

A. Mr. Kollen, on behalf of the DII and Dr. Weisenmiller, on behalf of HSS/ARI have proposed to deny all costs associated with SFAS 106. Dr. Weisenmiller provides that only some of the costs are generation related and even these do not qualify for recovery through the CTC because there is no showing that they will not be recovered in the competitive market. Mr. Kollen also believes these costs must be a regulatory liability.

First, there is a misunderstanding as to how SFAS 106 expense is computed. SFAS 106 liability is effectively stated on a present value basis. Second, the transition amount the Company is seeking is a "GAAP" liability which exists today, not a regulatory liability. Because this is a liability incurred during the regulated generation period, the customers should incur the costs of these expenses. Thus, it is appropriate to include these costs in the Company's stranded cost calculations.

Q. Will you discuss the Company's claim for recovery of its Warwick Mine investment?

A. Dr. Weisenmiller, on behalf of HSS/ARI, proposes to deny recovery of Duquesne's Warwick Mine investment. He is the only intervening party who proposes to deny recovery of this item. Dr. Weisenmiller states that because Warwick has been excluded from rate base since 1981, the Company should not be permitted a return unless the cost of the coal is below a previously established cost cap. He also believes that the Company has not exhausted the options to mitigate costs of the mine.

The Company currently has earned a return on its investment in Warwick through the sale of coal. Thus, the Company believes that these clearly fall

into the definition of a regulatory asset based on the definition specifically provided in § 2803(1) as costs which typically are recoverable.

Q. Will you discuss the Company's claim for recovery of its pilot program incentive and customer education expenses?

A. Dr. Weisenmiller, on behalf of HSS/ARI, proposes to deny recovery of these costs. Dr. Weisenmiller believes these costs do not meet the definition as transition costs.

Section 2803 specifically provides for the inclusion of customer education expenses as transition costs. In addition, the Company's pilot implementation order issued by the PUC provides for pilot program incentive recovery through the adjustment of the Company's accelerated depreciation of nuclear generation plants or through the CTC. Thus, it is appropriate to recover this regulatory asset since the Pennsylvania PUC specifically has addressed and allowed the recovery of this item.

Duquesne Should be Allowed to Fully Recover the Cost of Its Cold Reserved Units

Q. Will you identify the claim the Company is making for its cold reserved units?

A. Yes. In the mid-1980s, the Company placed a portion of the Brunot Island power station and all of the Phillips power station into cold reserve status. These units were accounted for as plant held for future use and the Company suspended depreciation and ceased to earn a return on these items. At this time, the Company does not believe that these units can be economically returned to service. As such, the Company is seeking to begin amortizing

these amounts and to include the unamortized amount of these items in its rate base for purposes of computing its equity returns throughout the transition period.

Q. If the Company had been able to return these units to service would ratepayers have received a benefit?

A. Yes. As evidenced by the settlement decision related to the GPU transaction, the Company would have received a regulated return and Duquesne's ratepayers would have received a significant benefit (i.e., a rate reduction through a credit determined annually similar to the Company's ECR mechanism).

Q. Did the Company make other attempts to sell or otherwise maximize the value of the cold reserved units?

A. Yes. For a number of years the Company was trying to make long-term firm power sales which would have allowed the Company to return all or a part of its cold reserved units to service. In recent years, the "For Sale" sign has been out on both Phillips and Brunot Island. To date there have been no offers for either Phillips or the cold reserved portion of Brunot Island.

Q. Have the Company's shareholders suffered as a result of the Company placing these units into cold reserve?

A. Yes. The Company's shareholders have suffered because both the recovery of and the return on these units has been forgone for more than ten years.

Q. Will you discuss the caretaker costs associated with these units?

A. Yes. In order to be able to return these units to service, costs were incurred to maintain the units. These are relatively small amounts but were necessary to preserve the option to return the units to service. To deny recovery of these

amounts would further burden shareholders who have already been severely penalized as described above.

Q. What options did the Company have other than to cold reserve the units?

A. The Company could have simply retired the units. As described by Mr. O'Brien in his direct testimony (see p. 15, ll. 5-11), under current regulatory practice, if the Company had retired the units, it would have credited plant and debited the depreciation reserve. This would have had no net effect on the Company's rate base and the Company would have recovered the net book value and a return over the remaining life of the Company's other fossil units.

Q. Why didn't the Company retire the units?

A. Until recently, the Company thought that there would be more value for both ratepayers and shareholders if the units were maintained in cold reserved status.

Q. Has the Company agreed to return any future value which might be derived from these units to ratepayers if the Company's position is adopted?

A. Yes. One hundred percent of any future benefit received from cold reserved units would be passed along to ratepayers. Under the Company's proposal, the cold reserved units would be included in the final valuation and any positive value for these units would be a direct reduction to the Company's stranded cost.

Q. Are other parties to the case recommending that cold reserved units not be allowed in the Company's stranded cost?

A. Yes. The OTS and HSS/ARI are both recommending that cold reserved units be removed from the Company's claim. Also, the OCA make a small adjust-

ment to the cold reserved plant balances based upon its novel interpretation of the Ft. Martin settlement. The OCA's position that the Company somehow agreed to credit $5 million without recovery or return is not supported by the agreement. The OTS takes the position that the Company's cold reserved units should be classified as non-utility property and not included in the Company's determination of stranded costs. HSS/ARI contends that the Company is not entitled to any recovery because the Company has acknowledged that the assets may have to be written off and because the GPU transaction did not go forward (see Weisenmiller, pp. 103 and 104).

Q. Will you summarize the Company's position with respect to its cold reserved units?

A. Yes. The Company's claim for its cold reserved units and the associated caretaker costs represents the only fair treatment for a mitigation strategy of which the Commission was well aware, but that ultimately proved unsuccessful. The Company has pursued a number of successful mitigation strategies and should not be penalized because it was unable to make a silk purse out of a sow's ear on these particular assets.

The Company's treatment of decommissioning is consistent with current regulatory practice

Q. Has the Company made a specific claim for recovery of nuclear or fossil plant decommissioning above currently approved levels during the transition period ending December 31, 2005?

A. No. The Company has only deducted the estimated unfunded portion of its

nuclear decommissioning cost and an estimate of fossil decommissioning cost from the range of present values estimated for its generating stations as of December 31, 2005. Also, please refer to the rebuttal testimony of Mr. LaGuardia on the subject of decommissioning.

Q. How does the Company's final valuation proposal consider fossil and nuclear decommissioning?

A. Under the Company's final valuation proposals, dismantlement of its units would be included in the final market value determination.

Q. Would the final valuation also consider future site value, life extension or other value which would tend to offset or reduce the present value of future decommissioning costs?

A. Yes.

Duquesne has Presented a Fully Mitigated Cost of Service

Q. Will you comment on the suggestions that the Company could further mitigate its stranded costs by shutting down some of its units?

A. Yes. The OCA and other have suggested that the shut down of certain generation stations could be used as a strategy to further mitigate stranded costs. While on the surface this appears to be a reasonable suggestion, it is premature to consider this option. Currently there is a great deal of uncertainty as to the future market price of electricity. Given this uncertainty, it would not be prudent at this time to make such irreversible decisions and, as discussed below, temporary shutdown of units is not technically feasible or financially viable. Also, many of costs shown in the Company's margin analysis are not immediately avoidable and hence should be excluded in a proper shut down

analysis. The economic basis for this analysis was discussed at length in the direct testimony of Mr. Schnitzer.

Q. Has the Company made an analysis of the costs which are truly avoidable for the plants which are recommended for shutdown by the OCA?

A. Yes. Exhibit DJC-13 shows the economic implications of shutting down Elrama, Cheswick, Beaver Valley Unit No. 2 and Perry. Exhibit DJC-13 clearly shows that, when unavoidable costs are considered, Perry, Beaver Valley Unit No. 2, and Cheswick should not be shut down at this time. The present value of the margins of each of these units is positive when only the truly avoidable costs are considered.

Q. What are the implication of the negative margin value for Elrama?

A As a generating unit, the avoidable "to go" economics of Elrama are not favorable even after removing unavoidable costs from the analysis. We have not done a formal option value analysis, although this would tend to reduce the absolute size of the negative margin value, and make an economic shut-down of the unit less likely.

Q. Based on this preliminary analysis, does Duquesne intend to close Elrama?

A. Not at this time. Although the analysis indicates that Elrama has a negative margin value as a generating unit, the impact of closing Elrama on the Duquesne transmission system must be considered. As discussed in Mr. Karl's rebuttal testimony, the Elrama station provides both reactive and real support to the southeast side of Duquesne's transmission system, and serves as a first contingency. A decision to close Elrama would require a significant expenditure of T&D capital to build a new 345 kV line to ensure the contin-

ued reliability of the Duquesne system. Alternatively, Mr. Karl discusses other options that might be less costly and could be completed more quickly, and would provide the necessary real and reactive power on the Duquesne system. These options include a partial shutdown of Elrama, installation of capacitors, and installation of new peaking capacity at the existing site. When the avoided costs of alternative sources of voltage support are considered, a decision to shut down Elrama would be premature as the Company has not made a detailed evaluation of these options. Mr. Marshall, in his rebuttal testimony, has indicated that the Company will commit to providing the Commission with a full shut down analysis for Elrama including an evaluation of the various voltage support options before the end of 1998.

Q. Will you comment on the suggestions of the OCA and others that certain units such as Cheswick could be temporarily removed from service as a viable mitigation strategy?

A. Yes. Temporary shut down of Cheswick is not a practical mitigation strategy at this time. Many costs are not truly avoidable as shown in Exhibit DJC-13 and when the costs incurred to return the unit to service are added, this alternative is even less economically attractive. The Company's own experience with Phillips suggests that it would cost more than $100 million to return this station to service and Brunot Island could cost more than $50 million.

Q. Will the company have the proper incentives to take economic actions under its proposals?

A. Yes, definitely. Under a rate cap with an ROE spillover and a minimum depreciation and amortization commitment the Company will be operating

with all of the incentives needed to ensure that it makes economic decisions.

Q. Would these incentives extend to such actions as plant shutdown and life extension?

A. Yes. The Company would be equally incented to take these and any other actions which would allow it to earn up to its authorized level.

Q. Is it true that the Duquesne would have an incentive 'gold plate' its plants if it was going to earn above the spillover amount in a given year?

A. No. Given the Company's entire proposal, 'gold plating' or accelerating maintenance or capital expenditures would be a zero sum game considering the Company's final valuation. Such expenditures would raise the final value of the Company's plants and would be likely to result in the same stranded cost determination as without the increased expenditures.

Q. If the Company's cost projections are incorrect how are ratepayers protected from an over recovery of stranded costs on the part of the Company?

A. The Company believes that its cost projections are aggressive and represent its fully mitigated costs. The OCA chose to adjust some of Duquesne's cost projections by using a higher inflation rate and lower availability factors for some of the Company's units. As such it will be difficult enough for the Company to reach an 11.5% ROE. On the other hand the ROE spillover gives the ratepayers the benefits of lower costs. It should be reemphasized that the Company has made a minimum commitment to amortization and depreciation and has no recourse should there be worse than expected cost performance. The result is an ROE spillover that gives ratepayers the full benefits of aggressive performance projections. This gives the Company strong incen-

tives to minimize costs and take appropriate economic actions during the transition period.

Q. Are there any other comments you have on the intervenor testimony with respect to regulatory assets or stranded costs?

Yes. Mr. Schoengold for the environmentalists alludes to the fact that Duquesne's stranded costs are overstated because he could not reconcile the minimum amortization of the Company with the net book value calculations at December 31, 2005 (See Schoengold testimony, pp. 26, ln. 15 to 27 ln.6). As shown in discovery ENV-3-148, the Company's claim is completely reconciled when the proper deferred tax effect is applied to the minimum amortization commitment for purposes of determining the Company's net book value as of December 31, 2005. A copy of the response to ENV-3-148 is included as Exhibit DJC-23.

IV. STRANDED COST SHARING PROPOSALS

Return Disallowances are Unfounded

Q. How have the intervenors calculated their estimates of appropriate "sharing" amounts for determining stranded cost disallowances?

A. Most of the intervenors who addressed the issue proposed some form of return disallowance. The OCA has indicated that no return of any kind on stranded generating plant should be allowed because such plant is not used and useful. According to the OCA, economic excess capacity penalties imposed on the Company in the past should be expanded to disallow all return on nuclear units that have stranded costs. DII proposes to disallow an equity return on

stranded generating plant assets for reasons similar to those of the OCA. The environmentalists contend that only a 60% allowance of stranded cost recovery should be approved because the Company's investors would have received a "reasonable" return as calculated by Mr. Shoengold. HSS/ARI does not really address sharing because they propose to disallow nearly all of the Company's stranded cost claims, as discussed previously, thereby mooting the "sharing" issue.

Q. How do you respond to the OCA "sharing" proposal?

A. The OCA, through witness Kahal, has attempted to misapply ratemaking principles which are not applicable to the Company's current circumstances. First a total return disallowance under the used and useful standard is inappropriate. The Company's generating assets (except for its cold reserved units) are serving its customers every day and the prudence of the Company's investment in its generating assets has already been determined. It cannot now be retroactively determined that such investments were somehow imprudent and so long as these assets continue to serve the Company's customers there is no question as to the used and usefulness of these assets to the Company's customers. Further, even if certain assets should be removed from service because they are not economic in a competitive environment (e.g., cold reserved units) this is the very definition of stranded costs: Under the Act, so long as the Company has fully mitigated its costs, the Company is entitled to an opportunity to fully recover its stranded cost including a fair return on its prudently incurred investment. The OCA's second argument is as meritless as its first. To argue that an economic excess capacity penalty

should be applied in a situation where, by definition, the Company's stranded costs are not economic is circular reasoning. It is also interesting to note that witness Kahal went to great lengths to adjust the Company's projections so that it could be shown that the Company's stranded cost is "almost entirely" nuclear related. In the Company's last base rate case economic excess capacity penalties were applied to the Company's new nuclear investment. Even if an economic excess return penalty were found to continue to apply, Mr. Kahal's calculations would be grossly in error because the economic excess capacity penalties from the Company's last base rate case only were applied to the equity related to Beaver Valley Unit No. 2 and the total return on $31.2 million of rate base related to Perry. The Company has since sold Beaver Valley and has almost no equity in the plant, and the depreciated value of the Perry adjustment is currently less than $20 million. Accordingly, there would be a relatively small revenue requirement reduction if this adjustment were calculated properly and would not be a $460 million adjustment to the Company's revenue requirements as shown in Exhibit DJC-12. The OCA's proposed "sharing" plan is nothing more than a thinly veiled attempt to retry the Company's 1988 base rate case and disallow a fair return on prudently incurred investment which is inconsistent with traditional ratemaking in Pennsylvania.

Q. How do you respond to the DII proposal with respect to sharing?

A. The Commission should reject the DII's sharing proposal for the same reasons it should reject the OCA's sharing proposals.

Q. How would the Company respond to Mr. Schoengold's sharing proposal he

presented for the Environmentalists?

A. Mr. Schoengold has attempted to show that with only a 60% allowance of stranded costs (whatever that may be since he has not made a determination of the Company's stranded costs) the Company's investors would receive a reasonable return on their investment because they have already achieved some return and should be allowed enough to repay debt holders. Mr. Schoengold's analysis must be rejected because it attempts to carve out specific assets and assess whether or not investors have received a hypothetical return. This carving out of specific assets to assess investor returns is preposterous. Investors invest in the Company as a whole and intend to earn an overall return. It is not possible to credibly remove any particular group of assets from the Company to assess whether or not investor's have been fairly treated. Since the magnitude of stranded costs is not known under Mr. Schoengold's proposal it is not possible to assess the full financial impact of his proposed "sharing". If, however, the Company's estimate of stranded costs are used, the environmentalist's proposal would be very similar in magnitude to the OCA's proposal as shown in the next section and would have an equally devastating effect on the financial health of the Company. The Environmentalist's proposal must be rejected as it is arbitrary and not consistent with traditional ratemaking in Pennsylvania.

Q. Are there any additional "sharing" amounts which have been proposed by the various parties?

A. Not explicitly. However based on the revenue requirement calculations proposed by OCA witness Lee Smith in Exhibit LS-5 and DII witness Stephen

Baron in Exhibits SJB-3 and SJB-5 there are implicitly additional sharing amounts which are related to the amortization of stranded costs which underlie the proposed revenue requirements related to stranded cost recovery. It is impossible to tell whether these were inadvertent omissions from their revenue requirements calculations or another form of "sharing".

Q. How does this additional "sharing" occur?

A. The amortization amounts from Exhibits LS-5 and SJB-3 were derived based on net plant amounts which are also net of deferred taxes. Although it is proper to derive returns based on net of deferred tax amounts it is not proper to exclude certain deferred taxes for purposes of developing an amortization amount to be included in revenue requirements. The amortization of stranded plant must be on developed using net plant excluding all but the FAS 109 related accumulated deferred taxes. By using a stranded plant amount which is net of all deferred taxes both the OCA and DII have under stated the revenue requirements associated with their own proposals and hence imposed additional sharing amounts on the Company.

Q. Have you quantified the additional revenue requirement which would be need to amortize the OCA and DII quantifications of stranded cost?

A. Yes. On Exhibit DJC-12 have quantified the amount of amortization which would be required given the DII stranded cost amount on page 2 of 4 and the OCA amount on page 4 of 4. I have also computed the present value of revenue requirements differences between the unadjusted and full revenue requirement amounts and have shown the difference at the bottom the page as "sharing".

Q. Why do the estimated stranded plant amounts on Exhibit DJC-12 differ from the amounts shown on DJC-10.

A. The amounts on DJC-10 were developed to put each of the different stranded cost estimates on a basis consistent with the Company's presentation of its stranded costs. The amounts shown in Exhibit DJC-12 were taken directly from the Exhibits of the OCA and DII.

V. IMPACT OF INTERVENOR PROPOSALS ON FINANCIAL INTEGRITY

The Intervenor Proposals would Harm the Financial Health of the Company

Q. Have you estimated the effects of adopting the intervenor proposals with respect to stranded cost and stranded cost recovery on the financial integrity of the Company?

A. Yes. I have examined the impacts of the proposals of the OCA, OTS, DII and HSS/ARI on the financial integrity of the Company.

Q. Will you summarize the results of your examination?

A. Yes. All four of the proposals related to stranded cost and stranded cost recovery including "sharing" would have a negative impact on the financial health or financial integrity of the Company. The OCA, DII and HSS/ARI proposals would severely damage the financial integrity of the Company. Specifically:

- The OCA, OTS, DII and HSS would cause write-offs of $658 million, $181 million, $461 million and $1.8 billion in 1998.
- The OCA, DII and HSS/ARI write-offs would cause Duquesne to be in default of its BV2 sale/leaseback agreement which would also trigger a cross-default of other debt and bank agreements.
- Given the OCA, DII or HSS/ARI proposals, the credit rating agencies would likely downgrade the Company's debt to "junk bond" level.

This downgrade would severely impact the Company's ability to access the financial markets.

- Earnings per share and cash flow would drop putting a strain on any effort to raise capital in the equity markets.

These negative financial impacts would have a detrimental effect on Duquesne's ability to access capital markets and attract investors and to provide reliable service to its customers.

Q. Please describe the term "financial integrity".

A. Financial integrity relates to the financial "health" of a company or the ease (or difficulty) with which a firm can continue to finance both its operations and new construction. This is accomplished through internal cash generation and by access to the debt and equity capital markets. For capital intensive industries such as electric utilities, access to the capital markets is critical.

Q. How do you measure financial integrity?

A. The most common and important measures of a capital intensive firm's financial integrity are its internal cash flow and access to capital markets. Many times this can be judged by a firm's securities ratings which measure its creditworthiness. Major credit rating agencies such as Standard & Poor's, Moody's, Fitch and Duff & Phelps rate a company's debt and preferred securities. Generally, the rating agencies make an annual reviews using current and projected public and non-public financial data and Company forecasts. The agencies publish reports on the Company's debt and preferred securities, and ascribe ratings on scales which range from AAA (highest) to D (lowest) or other similar scales. Other important indicators of financial integrity are total return to equity investors and a company's level of internal cash generation.

Q. Please describe the Company's current credit ratings.

A. Exhibit DJC-16 lists Duquesne's current ratings from the four principal credit rating agencies who rate the Company's debt and preferred securities.

Q. What does the Company's current BBB+ rating by Standard & Poor's mean?

A. Standard & Poor's states that an obligation rated BBB "exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation". A "BBB-" rating is the lowest rating that is considered investment quality; below that (BB or lower) an obligation is considered a "junk bond". Standard & Poor's further states that "obligations rated BB, B, CCC, CC and C (below investment grade) are regarded as having significant speculative characteristics". Standard & Poor's comments that these obligations "will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions".

Q. How does the Company's BBB+ rating compare to the industry?

A. Of the roughly 120 electric utilities rated by Standard & Poor's, approximately 60% have ratings of A- or better. These ratings are superior to Duquesne's BBB+.

Q. Please describe a rating agency's criteria for determining creditworthiness?

A. Standard & Poor's, one of the four agencies that rate the company's debt, has a two pronged approach to analyzing a company; business profile and an analytical financial profile. The business profile focuses on the qualitative characteristics of regulation, markets, operations, competitiveness and man-

agement. Business profiles are expressed on a scale of 1 (strong) to 10 (weak). Duquesne's current business profile is 6, a below average rating. The financial profile focuses on analytic measures determining the company's ability to generate cash flow to finance operations, service debt and to fund new investment. The financial profile utilizes five key analytical measures:

- Funds from operations as a percentage of total debt.
- Funds from operations interest coverage.
- Net cash flow as a percentage of capital expenditures.
- Funds from operations interest coverage.
- Total debt to total capitalization.

Both business and financial profiles are used to determine the overall rating.

Q. Have you analyzed the effect of the intervenors' proposals on Duquesne's creditworthiness?

A. Yes. All four of the proposals result in an adverse effect on the Company's credit quality ratios. The OCA, DII and HSS proposals have a severe effect on the financial health of the Company going forward. Exhibit DJC-17 summarizes key financial data. In terms of revenue requirements, OCA recommends a 39% disallowance of the revenue requirement that Duquesne would otherwise be entitled to earn under the rate cap. DII recommends a 15% disallowance of this revenue requirement and OTS recommends an 11% disallowance of this revenue requirement. HSS recommends a confiscatory 96% disallowance. Under GAAP, the intervenors' proposals would require Duquesne to write-off in 1998 $658 million, $181 million, $461 million and $1.8 billion for OTC, OTS, DII and HSS, respectively. In addition, earnings would drop from $6 to $60 million annually, a drop of 5% to almost 50 percent compared to 1996 actual Duquesne's earnings. Cash flow would

also be negatively effected by all proposals. The combined effect would be devastating to financial integrity and Duquesne's ability to access the capital markets.

Q. What effect would the intervenors' proposals have on financial ratios and bond ratings?

A. Based on the intervenors' proposals, I have calculated the 5 key financial ratios for the term of the transition period (1999-2005). On a pro forma basis, these ratios are shown in Exhibit DJC-18 along with anticipated bond ratings which would likely result from those ratios. The bond ratings are estimates using Standard & Poor's published guidelines. For the OCA, DII and HSS proposals, it is anticipated that Duquesne's debt will fall to the "junk bond" level. This would have severe consequences in terms of Duquesne's financial integrity.

Q. Please describe the effect on the Company's financial health should the securities drop to "junk bond" status.

A. A below investment grade rating would impair the Company's ability to readily access the debt market. Most investment funds are limited in the amount of junk bonds allowed in their portfolio and many funds, especially pension and retirement funds, are precluded from investing in junk bonds. Junk bonds are often used to finance speculative ventures or start-up companies. Junk bond status is clearly not consistent with a financially healthy firm that has a continuing obligation to deliver and to be supplier of last resort. Public utility debt (also called fixed income securities) is often purchased by pension and retirement funds and individuals for financial security for their

retirement. Junk bond status is inconsistent with their investment goals.

Q. What would be the cost to the Company of a "junk bond" rating?

A. As the Company's current debt matures and as new capital expenditures require the issuance of new debt, the ability to issue cost effective debt is affected by the credit rating. This is key to controlling costs in a regulated environment as well as a major distinguishing feature in a competitive business environment. Junk bond status would substantially increase the Company's cost of debt. As Exhibit DJC-18 shows, the increase in coupon rate is required by the capital markets as credit quality changes. The increase in cost is especially pronounced when a company's securities drop below BBB-, the lowest rating which is still investment grade. For example, a drop from the current level of BBB+ to BB- taken over the Company's $1.4 billion long term debt would require the Company to pay a coupon rate 160 basis points higher. This translates into an increased interest expense of $22.5 million per year, the equivalent of an almost 2% across the board rate cut or the equivalent of 375 full time positions.

Q. Who are the holders of the Company's debt?

A. Some is held directly by individuals; most is held by pension and retirement or other funds, many of which are owned by Pennsylvania residents.

Q. So wouldn't the effect of the intervenors' proposals hurt the people the intervenors want to protect?

A. Yes. On one hand, the ratepayer who is a bondholder would see a drop in his monthly electric bill, but on the other hand see an increased risk to the stream of payments used to pay for his retirement.

Q. What about access to the equity markets?

A. The equity markets view the attractiveness of a company's common stock in terms of total return; the prospect of dividends plus an increase in the stock's price. Key drivers to this aspect of financial integrity are earnings per share and dividends, as well as cash flow. Variations to these factors determine the attractiveness of a company's stock and thus, the firm's ability to access the equity markets.

Q. Does a negative bond rating affect access to the equity markets?

A. Yes. Equity analysts often use credit rating agency reports in their stock valuation analysis decisions since under SEC rules, rating agencies are "insiders" and have access to non-public financial forecasts. Therefore, a negative rating may not only impact access to the debt market, but the equity market as well.

Q. What other financial effects would the intervenors' proposals have?

A. Duquesne has a number of financial covenants as part of its bank loan and other debt agreements. In the letter of credit reimbursement agreement related to the sale lease-back of the Beaver Valley II Nuclear Plant, among other covenants, the company is required to maintain a minimum consolidated net worth of $825 million. The proposals by OCA, DII and HSS would require the company to write-off $658 million and $1.8 billion after-tax. This would fall below the minimum requirement specified and thus put Duquesne in default of the agreement. Most of the company's other loan debt and loan agreements contain cross-default insurance wherein if the company defaults on any other agreement, the other agreements are judged to be in default.

Putting the agreements in default could force the company into bankruptcy. Therefore, the resulting impact of the write-offs caused by the intervenors' proposals could cause a devastating series of financial events to occur.

Q. Would a common dividend cut solve the financial problems caused by the intervenors' proposals?

A. No. Duquesne's parent DQE already has one of the lowest dividend payout ratios in the industry. Further, in 1986 when the steel industry in Pittsburgh severely contracted, Duquesne cut its dividend 30%, one of the first electric utilities ever to do so. The current effective dividend rate has still not reached the 1986 level. Investors therefore still penalize DQE stock for that cut. A further cut would severely impact the financial community's view of the stock and severely impair the Company's access to the equity market.

VI. ASSET SECURITIZATION

The Company Should not be Required to Securitize its Stranded Costs

Q. Should the Company be required to securitize its stranded costs?

A. No. Witness Kollen for DII has suggested that the Commission should require *asset securitization to further mitigate the Company's stranded cost.* The Company has shown that replacing its relatively low cost debt with higher cost debt would not be economic. Also, the Company currently has the highest degree of debt leverage of any electric utility in the state. When the Company's leverage is further adjusted by the sale/leaseback debt the Company is even more highly leveraged than the Company's balance sheet would indicate. The Company has already achieved many of the benefits which others might be able

to achieve through asset securitization by employing high leverage. These benefits are already reflected in the Company's cost of service and its proposed transition plan.

Q. Could the Company reduce it common equity beyond what is shown in its transition plan without adverse consequences?

A. No. The Company has shown that over the transition period that it will reduce its common equity from $940 million to $636 million. If the Company tried to reduce its equity below the levels already contemplated, the covenants under the sale/leaseback would be violated and the Company would be in default under the terms of the sale/leaseback. To have the operative covenants revised would require approval of the both the BV-2 lessors and bondholders. At best, the necessary approvals would be costly to obtain because both the lessors and bondholders would want to be paid for granting approval. At worst, such approval would not be granted at all.

Q. Under the Act, can the Commission require the Company to securitize its stranded assets?

A. Not in my opinion. There are no provisions under the Act which allow the Commission to mandate securitization. The Commission can consider the effects of securitization in determining whether or not the Company has fully mitigated its stranded costs. The Company believes that its record on mitigation is strong and many of the benefits which others may be able to achieve through securitization have already been achieved by the Company through other means. The Company has indicated that it will continue to review asset securitization and may request approval to securitize all or a portion of its stranded costs at

some time in the future if it can be shown that such action is beneficial.

VII. OTHER ISSUES

Rebuttal to Mr. Weisenmiller

Q. Mr. Weisenmiller contends that past studies of the value of Duquesne's generating assets conflict with Duquesne's current estimates. Mr. Weisenmiller also claims that the price of the Ft. Martin sale should be used to set the value all Duquesne's generating units. What is your response?

A. Mr. Weisenmiller's claims are less than credible and they are not even internally consistent. I will first comment on his use of past assessments of the market value of Duquesne's generating assets (some performed by Duquesne and others by third parties). These studies contained wide ranges of predicted market value. These ranges of value were influenced by a number of factors, including the expected market price of power, as the documents themselves indicate. It is thus not surprising that the documents predict a positive value for Duquesne's plants when market prices are assumed to be high, while also predicting no value if market prices are assumed to be low. Mr. Weisenmiller's testimony, however, avoids mentioning this. In his zeal to characterize the Company has having billions of dollars in market value, he apparently found it unhelpful to provide the reader a more balanced characterization of these studies.

I also find it surprising that he would even rely on the valuation and market price projections contained in these documents. His testimony is apparently predicated on the belief that such predictions are inherently speculative. (In this regard, he

agrees with the Company.) I thus cannot understand why he places great weight on (selected portions of) prior projections, but no weight at all on current projections. If his point is simply that Duquesne's assets will have positive value if market prices are substantially above the high end of Mr. Schnitzer's range, he could have done so without such a laborious (and one-sided) review of these documents.

Q. Mr. Weisenmiller also contends that the market value of all Duquesne's assets should be set on the basis of the value received from the Ft. Martin sale. Please comment.

A. I also find this assertion not credible and it also is inconsistent with other statements of the witness. In contrast to his claim in testimony that the Ft. Martin sale should be used to value all the assets, he readily conceded on deposition that the sale of one fossil unit does not set the value for the remaining fossil units (much less the nuclear units); rather, it would only provide one "data point":

> Q. Would an auction of one fossil asset provide an accurate valuation of the remaining fossil assets?
> A. Depending upon how representative that one asset was, it might at least give you a data point, but it would not be as indicative as an auction of all of those assets.

Weisenmiller Deposition at 5. It is thus inconceivable to me why he would recommend using the Ft. Martin sale to value all the remaining assets -- particularly when this "data point" is contrary to every other market price projection in this case. Moreover, his contention regarding the indicative value of Ft. Martin is undermined by his own admission in testimony that the price paid by APS was based on market price projections that bear no resemblance to current market conditions. See Weisenmiller Testimony at 23. Here too, all he

has demonstrated is that if one assumes high market prices, one will assume low (or no) stranded costs for Duquesne's plants. That contention was made in the Company's case, and hardly required 150 pages of responsive testimony from Mr. Weisenmiller.

In conclusion, I find Mr. Weisenmiller's assertions to be meritless. I would add, however, that the Company's proposal to auction its generating assets in 2003 (or earlier if there is a triggering event) should moot any dispute with HSS/ARI over the valuation of the assets. Mr. Weisenmiller has stated that his preferred method of valuation is divestiture (testimony at 141).

Rebuttal to Mr. Hughes

Q. Please describe the topic you address in the next portion of your testimony.

A. In this portion of the testimony, I address certain points made by Mr. Hughes regarding the Perry and Beaver Valley 2 (or BV2) plants. Mr. Hughes makes a number of points, which I will address in turn.

Q. Please address the first point.

A. Mr. Hughes, by his own admission, devotes a significant portion of his testimony to "historical issues" relating to these units (Hughes Test. at 6), including the need to construct those units, the prudence of construction and their economics. It is Duquesne's view, however, that these historical issues are simply that: issues of historical interest, not matters that have any relevance to this case.

Q. Please explain.

A. The issues of whether (i) the construction of Perry and BV2 was prudent, and (ii)

the units represented economic excess capacity were both decided in Duquesne's last base rate proceeding (R-870651). I will recite the relevant findings briefly. As to prudence, the Commission determined that (i) all of Perry's construction costs had been prudently incurred, and (ii) found that a relatively small amount of Duquesne's share of BV2 costs were imprudent (approx. $12 million), but no adjustment to rate base was necessary due to Duquesne's sale and leaseback of the facility at a book value loss in excess of that amount. With respect to economic excess capacity, the Commission held that both units represented economic excess capacity. As to Perry, the Commission imposed a disallowance (removal of Elrama 1 and a portion of Elrama 2 from rate base) that had a revenue requirement impact of approximately $5 million annually. As to BV2, the Company agreed to a settlement with the OCA and OTS that, among other things, imposed a disallowance of the equity return on BV2 and accepted a sale-leaseback of the unit which mitigated the cost impacts of the disallowance.

Q. Is Mr. Hughes attempting to raise these issues again here?

A. It is not clear. While he does not specifically so contend, he (i) devotes significant attention to whether these units were needed to serve load reliably, (ii) contends that he will supplement his testimony with further analysis of whether these units were needed, and (iii) contends that this case "presents yet another opportunity for the Commission to address the issue of the just and reasonable-ness of Duquesne's base rates." Page 10. From this, I can only conclude that he is contending that these issues should be relitigated in this proceeding. As indicated, however, I strongly disagree.

Q. Mr. Hughes devotes significant attention to a quotation from your direct

testimony regarding the loss of steel industry load and contends that he will submit additional testimony on this issue. What is the relevance of this testimony?

A. As should be obvious from its context, this portion of my direct testimony was included for the purpose of explaining the rather obvious fact that the loss of steel industry load had a significant revenue impact on Duquesne. Its purpose was not to relitigate whether Duquesne, and the other CAPCO companies, were reasonable in planning to construct significant nuclear capacity, as Mr. Hughes seems to portray it.

Q. Did Mr. Hughes' 1994 complaint attempt to relitigate these prudence issues or other matters related to the 1987 rate case?

A. No, as Mr. Hughes then stated: "I am not asking the Commission to revisit its decision in the prudency or rate base cases. . . ." (See David Hughes Response to Duquesne Light Company's Supplemental Brief at 3, Pa. PUC Dkt. No. C-00945953 (May 7, 1996).)

Q. Does Mr. Hughes make any specific recommendations regarding the rates that should be approved in this proceeding?

A. No. His only statement is that the Commission has a range of options, including the disallowance of costs associated with Perry and BV2. Testimony at p. 10.

Q. What is your response?

A. His rather vague suggestions should be rejected for all the same reasons as discussed in my testimony, as well as the testimony of Messrs. Marshall and Schnitzer, regarding proposals to disallow the recovery of prudently incurred stranded costs.

Rebuttal Regarding the ECR Roll-In

Q. OCA witness Kahal has opposed the Company's proposal to roll its approved ECR of 14.7 mills into base rates under Section 2804(4)(v). Please comment.

A. The Company's position is that it is entitled under Section 2804(4)(v) to roll in the 14.7 mills approved in the Fort Martin settlement which is cost justified (see Exhibit DJC-24). However, even if we assume witness Kahal is correct that the 14.7 mill level cannot currently be rolled into base rates, it does not follow that Duquesne is limited to roll-in only the 12.822 level currently being charged to Duquesne's customers based on 1995 data.

Q. Please explain. What ECR did the Company propose in its filing on February 28, 1997?

A. The Company's filing sought an adjustment to the ECR of negative 2.369 mills from the 16.45 mills currently in base rates. The net effect of this adjustment would have been to set the ECR at 14.081 for 1997. However, the Commission in its March 27, 1997 Order effectively deferred any adjustment to the ECR pending resolution of the restructuring case.

The negative 2.369 mill adjustment included .428 mills of correction for over-collection in 1996. Under traditional regulatory treatment of the ECR, when there is an adjustment to base rates any corrections for over- or under-collection are not included in the rolled-in amount. In this case, Duquesne is proposing to roll-in the ECR under Section 2804(4)(v). Therefore, if the roll-in were based on the 1997 filing – which produced an ECR below the 14.7 level approved under

Fort Martin – the appropriate treatment would be to exclude the over-collection amount of .428 mills grossed-up to include GRT. The result would be a total ECR of 14.529 mills to be rolled-in to rates.

Q. Assume that witness Kahal is correct and the ECR based on 1995 data should be used to determine the rate cap under the restructuring legislation. Is 12.822 mills the correct number or does a similar adjustment for over-collection need to be made?

A. Based on 1995 data, an ECR adjustment of negative 3.628 mills reduced the ECR from the base rate amount of 16.45 mills to 12.822. But, the 1995 data included an even larger adjustment for over-collection of .851 mills. Grossing-up this over-collection amount for GRT and netting it from the 3.628 mill adjustment would result in an ECR of 13.712 for purposes of the roll-in. Even if witness Kahal is right that the 1995 data should be used for the roll-in, he has conveniently ignored the well recognized Pennsylvania regulatory practice of not including amounts for over-collection or under-collection when rolling ECR adjustments into base rates.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit No. DJC-10

Duquesne Light Company

Summary of Stranded Cost Estimates
As of December 31, 1998
($ Millions)

	DLCo	OCA	OTS	DII	HSS/ARI
Generating Plant					
Net Book Value of Gen. Plant	$917.61	$913.02	$852.03	$917.61	N/A
Working Capital	0.00	61.53 (5)	0.00	61.53 (5)	N/A
M&S and Fuel-Related Sunk Costs	41.11	0.00	0.00	0	N/A
PV of BV2 Lease Expense (1)	278.24 (1)	300.35 (6)	287.19 (8)	278.24	N/A
Net Book Value	1,236.96	1,274.90	1,139.22	1,257.38	N/A
P V of Decommissioning	123.90	44.47	45.10	42.96	N/A
PV of Costs Independent of Operation	208.23	0.00	N/A	0.00	0.00
Estimated Market Value	(27.40)	(392.05) (10)	N/A	(128.23)	N/A
Stranded Generating Plant	1,541.69	927.32	N/A	1,172.11	0.00
Regulatory Assets	(2)	(7)	(7)	(7)	(7)
SFAS 109	$179.00	$179.00	$179.00	$179.00	$0.00
Post-2005 - Unamortized Debt Cost	19.04	18.67	19.04	0.00	0.00
Pre-2006 - Unamortized Debt Cost	9.80	9.61	9.80	0.00	9.80
Deferred Rate Sync. Costs	30.26 (3)	24.57	30.26	22.79	0.00
Deferred Employee Costs	17.80	14.24	17.80	0.00	0.00
Deferred Nuclear Maintenance	1.90	1.90	1.90	1.90	1.90 (9)
DOE Decom and Decon.	4.19	3.35	4.19	4.19	4.19 (9)
Deferred Coal Costs	13.50	0.00	13.50	0.00	0.00
Deferred Caretaker Costs	3.92	0.00	0.00	0.00	0.00
BV2 Training Costs	1.58	1.58	1.58	1.58	1.58 (9)
Low Level Rad. Waste	2.27	2.27	2.27	2.27	2.27 (9)
Coal Cost Equalization	0.12	0.12	0.12	0.12	0.12 (9)
Other	0.53	0.53	0.53	0.74	0.53 (9)
Pre-Accrue Nuclear Outages	13.25	0.00	13.25	0.00	0.00
Gain on Sale/Leaseback	55.13	55.13	55.13	55.13	55.13 (9)
Deferred Rate Sych. Costs (Tax)	0.27	0.22	0.27	0.27	0.00
BV-2 (Tax)	0.17	0.17	0.17	0.17	0.17 (9)
Deferred Fuel Cost	8.66	6.92	8.66	8.66	8.66 (9)
Transition Costs	10.59	10.59	10.59	5.73	0.00
SFAS 106	2.47	1.97	2.47	0.00	0.00
SFAS 109 Plant	0.00 (4)	0.00	0.00	0.00	0.00
Total Regulatory Assets	374.45	330.84	370.53	282.55	84.35
Total Stranded Cost	$1,916.13	$1,258.16	N/A	$1,454.66	$84.35
Percent of Company Claim	100.00%	65.66%	N/A	75.92%	4.40%

1) Includes premiums and unamortizaed debt costs.
2) Duquesne's Regulatory Assets are shown net of deferred taxes.
3) Reflects adjustment based on DII proposal.
4) Included in plant as of 12/31/98.
5) Item not claimed by the Company.
6) Net of tax amount based on OCA gross amount of $513.36 million.
7) Regulatory assets adjusted to reflect net of deferred tax amounts.
8) PV is based on OTS recommended cost of capital.
9) Not specifically addressed by HSS/ARI.
10) Includes OCA's proposed productivity ($25.32) and life extension benefits ($170.72).

Exhibit No. DJC-11

Duquesne Light Company

Impact of Intervenors' Proposals Regarding Stranded Cost Recovery on Revenue Requirements

($ Millions)

Party	1999	2000	2001	2002	2003	2004	2005	Total	% of Company Rate Cap*
DLC	**440.7**	**429.9**	**418.2**	**407.2**	**402.1**	**395.8**	**407.2**	**2,901.0**	**100%**
OCA	311.3	308.4	311.7	278.6	184.9	171.6	141.7	1,708.3	59%
OTS	398.5	385.9	373.3	362.2	355.6	344.5	357.5	2,577.5	89%
DII	440.7	429.9	418.2	318.1	-	-	-	1,606.8	55%
HSS / ARI	19.9	19.1	18.4	17.6	16.9	16.1	15.3	123.3	4%

*Note: Duquesne does not believe that it is likely that it will fully recover its stranded cost prior to 12/31/2005.

Duquesne Light Company
Stranded Cost "Sharing" Analysis
($ 000)

DII Estimated Stranded Plant	**995,872**

No Equity return

Year	Unamortized Stranded Plant Balance	Pre-Tax Return @ 5.51%	Annual Amortization	Total Annual Rev. Req.	PV of Annual Rev. Req. @ 7.84%
Beg. Bal	995,872				
1999	853,605	51,280	142,267	193,547	185,621
2000	711,337	43,441	142,267	185,708	164,717
2001	569,070	35,602	142,267	177,869	145,907
2002	426,802	27,763	142,267	170,030	128,994
2003	284,535	19,924	142,267	162,191	113,799
2004	142,267	12,085	142,267	154,352	100,160
2005	(0)	4,246	142,267	146,514	87,928
Total		194,340	995,872	1,190,212	927,125

Full Equity return

Year	Unamortized Stranded Plant Balance	Pre-Tax Return @ 13.39%	Annual Amortization	Total Annual Rev. Req.	PV of Annual Rev. Req. @ 7.84%
Beg. Bal	995,872				
1999	853,605	124,616	142,267	266,884	256,005
2000	711,337	105,567	142,267	247,834	219,870
2001	569,070	86,517	142,267	228,784	187,720
2002	426,802	67,467	142,267	209,735	159,162
2003	284,535	48,418	142,267	190,685	133,836
2004	142,267	29,368	142,267	171,636	111,418
2005	(0)	10,319	142,267	152,586	91,614
Total		472,272	995,872	1,468,144	1,159,625

"Sharing" =	**232,500**

Duquesne Light Company
Stranded Cost "Sharing" Analysis
($ 000)

DII Estimated Stranded Plant	**995,872**

DII Amortization Calculation

Year	Annual Amortization	PV of Annual Rev. Req. @ 7.84%
1999	142,267	136,441
2000	142,267	126,186
2001	142,267	116,702
2002	142,267	107,931
2003	142,267	99,820
2004	142,267	92,318
2005	142,267	85,380
Total	995,872	764,779

Full Revenue Requirement Calculation

Year	Net Plant Plus W.C.	Amortization	FAS 109 Related Deferred Taxes	Net Amortization	PV of Annual Rev. Req. @ 7.84%
Beg. Bal	1,448,792				
1999	1,241,822	206,970	33,783	173,187	166,095
2000	1,034,851	206,970	33,783	173,187	153,611
2001	827,881	206,970	33,783	173,187	142,066
2002	620,911	206,970	33,783	173,187	131,389
2003	413,941	206,970	33,783	173,187	121,514
2004	206,970	206,970	33,783	173,187	112,382
2005	(0)	206,970	33,783	173,187	103,936
Total		1,448,792	236,480	1,212,312	930,994

"Sharing" =	**166,215**

Duquesne Light Company
Stranded Cost "Sharing" Analysis
($ 000)

OCA Estimated Stranded Plant	**1,139,190**

No Equity return

Year	Unamortized Stranded Plant Balance	Pre-Tax Return @ 0%	Annual Amortization	Total Annual Rev. Req.	PV of Annual Rev. Req. @ 6.88%
Beg. Bal	1,139,190				
1999	976,449	0	162,741	162,741	156,835
2000	813,707	0	162,741	162,741	146,437
2001	650,966	0	162,741	162,741	136,728
2002	488,224	0	162,741	162,741	127,662
2003	325,483	0	162,741	162,741	119,198
2004	162,741	0	162,741	162,741	111,294
2005	(0)	0	162,741	162,741	103,915
Total		0	1,139,190	1,139,190	902,069

Full Equity return

Year	Unamortized Stranded Plant Balance	Pre-Tax Return @ 11.76%	Annual Amortization	Total Annual Rev. Req.	PV of Annual Rev. Req. @ 6.88%
Beg. Bal	1,139,190				
1999	976,449	141,003	162,741	303,744	292,793
2000	813,707	120,759	162,741	283,500	255,208
2001	650,966	98,968	162,741	261,709	219,979
2002	488,224	77,177	162,741	239,918	188,300
2003	325,483	55,386	162,741	218,127	159,855
2004	162,741	33,595	162,741	196,336	134,353
2005	(0)	11,804	162,741	174,545	111,531
Total		538,690	1,139,190	1,677,880	1,362,020

"Sharing" =	**459,951**

Duquesne Light Company
Stranded Cost "Sharing" Analysis
($ 000)

OCA Estimated Stranded Plant	**1,139,190**

DII Amortization Calculation

Year	Annual Amortization	PV of Annual Rev. Req. @ 6.88%
1999	162,741	156,077
2000	162,741	144,346
2001	162,741	133,497
2002	162,741	123,464
2003	162,741	114,185
2004	162,741	105,603
2005	162,741	97,667
Total	1,139,190	874,840

Full Revenue Requirement Calculation

Year	Net Plant Plus W.C.	Amortization	FAS 109 Related Deferred Taxes	Net Amortization	PV of Annual Rev. Req. @ 6.88%
Beg. Bal	1,430,559				
1999	1,226,193	204,366	33,783	170,583	163,597
2000	1,021,828	204,366	33,783	170,583	151,301
2001	817,462	204,366	33,783	170,583	139,930
2002	613,097	204,366	33,783	170,583	129,413
2003	408,731	204,366	33,783	170,583	119,687
2004	204,366	204,366	33,783	170,583	110,692
2005	(0)	204,366	33,783	170,583	102,373
Total		1,430,559	236,480	1,194,079	916,991

"Sharing" =	**42,152**

Exhibit DJC-13

Duquesne Light Company
Calculation of Unavoidable Costs
($Millions)

	PV as of 12/31/98			
	Perry	BV 2	Cheswick	Elrama
PV of Margin using Avoidable and Unavoidable Costs	(91.8)	(3.8)	(67.1)	(86.7)
PV of Unavoidable Costs				
Fixed O& M	4.6	2.5	5.3	6.7
Overhead Allocation	40.3	21.1	71.9	25.9
Property Taxes	43.3	0.0	0.0	0.0
FICA Taxes	0.0	0.0	0.2	0.2
Capital Stock Taxes	9.7	1.8	2.9	1.1
Employee Severance	4.1	4.1	3.6	4.7
Take-or Pay Contracts	0.0	0.0	6.7	2.0
Accelerated Decimmissioning Costs	24.6	14.1	10.5	4.9
Accelerated Shutdown Costs	6.7	6.1	0.0	0.0
Total Unavoidable Costs	133.2	49.6	101.0	45.5
PV of Margin using Avoidable Costs	41.4	45.8	33.9	(41.1)
Sunk Costs not included in Net Plant Values				
M&S Inventories	3.8	3.8	4.1	3.6
Unamortized Fuel Costs	13.5	12.3	0.0	0.0
Total M&S and Fuel-Related Sunk Costs	17.3	16.1	4.1	3.6

Exhibit DJC-14

Duquesne Light Company
Adjustment to Deferred Rate Synchronization Costs
($ Millions)

Def. Rate Synch. Costs =	33.16	
Remaining life=	7.417	7.000
Discount Rate =	7.83%	

	Amortization			
	Company		DII	
	Nominal	PV	Nominal	PV
1999	4.666	4.493	4.471	4.306
2000	4.666	4.167	4.471	3.993
2001	4.666	3.864	4.471	3.703
2002	4.666	3.584	4.471	3.434
2003	4.666	3.323	4.471	3.185
2004	4.666	3.082	4.471	2.954
2005	4.666	2.858	4.471	2.739
2006	0.000	0.000	1.863	1.058
Revised Claim	32.659	25.371	33.160	25.371
Adjustment	0.5015			
Original Claim	33.160			

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
10-K Regulatory Assets																
(Allocated to Generation & Recovered Through Transition Plan)																
Unamortized Debt Premium/Discount	34.23	21.82														
Transition Plan Revenue Requirement																
Amortization			4.89	4.89	4.89	4.89	4.89	4.89	4.89							
Rate Base			21.82	18.71	15.59	12.47	9.36	6.24	3.12							
Revenue Requirement - Return on Rate Base			2.92	2.50	2.09	1.67	1.25	0.84	0.42							
Revenue Requirement - Amortization			4.89	4.89	4.89	4.89	4.89	4.89	4.89							
Total Revenue Requirement			7.81	7.39	6.98	6.56	6.14	5.73	5.31							
PV @ 1/1/99			35.01													
Traditional Ratemaking Revenue Requirement																
Total amortization Unamortized Debt			0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.25	3.25	3.25	3.25	3.09	3.08	3.07
Percent allocated to generation (gross plant)			60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%
Amortization Allocated to generation			0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.97	1.97	1.97	1.96	1.87	1.86	1.86
Unamortized Debt - BV2			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	0.43	0.43	0.43	0.43	0.43	0.43
Total Generation amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.39	2.39	2.39	2.39	2.30	2.29	2.28
Net of Tax			0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	1.40	1.40	1.40	1.34	1.34	1.34
Rate Base			21.82	21.82	21.82	21.82	21.82	21.82	21.82	21.82	20.30	18.77	17.24	15.72	14.28	12.80
Revenue Requirement - Return on Rate Base			2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.72	2.51	2.31	2.10	1.91	1.71
Revenue Requirement - Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.39	2.39	2.39	2.39	2.30	2.29	2.28
Total Revenue Requirement			2.92	2.92	2.92	2.92	2.92	2.92	2.92	5.32	5.11	4.91	4.70	4.40	4.20	4.00
PV @ 1/1/99			36.28													
PV Difference			(1.27)													
Beaver Valley 2 Sale/Leaseback Premium	16.51	9.66														
Transition Plan Revenue Requirement																
Amortization			2.36	2.36	2.36	2.36	2.36	2.36	2.36							
Rate Base			9.66	8.28	6.90	5.52	4.14	2.76	1.38							
Revenue Requirement - Return on Rate Base			1.29	1.11	0.92	0.74	0.55	0.37	0.18							
Revenue Requirement - Amortization			2.36	2.36	2.36	2.36	2.36	2.36	2.36							
Total Revenue Requirement			3.65	3.47	3.28	3.10	2.91	2.73	2.54							
PV @ 1/1/99			16.51													
Traditional Ratemaking Revenue Requirement																
Amortization schedule			0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.51	1.51	1.51	1.51	1.51	1.51	1.51
Net of Tax			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Rate Base			9.66	9.66	9.66	9.66	9.66	9.66	9.66	9.66	8.78	7.90	7.02	6.14	5.26	4.38
Revenue Requirement - Return on Rate Base			1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.18	1.06	0.94	0.82	0.70	0.59
Revenue Requirement - Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.51	1.51	1.51	1.51	1.51	1.51	1.51
Total Revenue Requirement			1.29	1.29	1.29	1.29	1.29	1.29	1.29	2.80	2.68	2.56	2.44	2.33	2.21	2.09
PV @ 1/1/99			16.51													
PV Difference			0.00													
Deferred Rate Synch. Costs	32.66	30.26														
Transition Plan Revenue Requirement																
Amortization			4.67	4.67	4.67	4.67	4.67	4.67	4.67							
Revenue Requirement			4.67	4.67	4.67	4.67	4.67	4.67	4.67							
PV @ 1/1/99			24.43													
Traditional Ratemaking Revenue Requirement																
Amortization			4.40	4.40	4.40	4.40	4.40	4.40	4.40	1.83						
Revenue Requirement			4.40	4.40	4.40	4.40	4.40	4.40	4.40	1.83						
PV @ 1/1/99			24.06													
PV Difference			0.37													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate
Gross Receipts Tax Rate
Discount Rate
Return on Rate Base
Revenue Requirement for Return

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
10-K Regulatory Assets																	
(Allocated to Generation & Recovered Through Transition Plan)																	
Unamortized Debt Premium/Discount																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Total amortization Unamortized Debt	2.92	2.58	2.57	2.49	2.49	2.43	2.30	2.30	2.29	1.86	1.28	0.79	0.32	0.18	0.17	0.14	0.11
Percent allocated to generation (gross plant)	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%	60.47%
Amortization Allocated to generation	1.76	1.56	1.55	1.51	1.51	1.47	1.39	1.39	1.39	1.12	0.77	0.47	0.20	0.11	0.10	0.09	0.07
Unamortized Debt - BV2	0.43	0.43	0.43	0.04	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
Total Generation amortization	2.19	1.99	1.98	1.55	1.51	1.47	1.39	1.39	1.39	1.12	0.77	0.47	0.20	0.11	0.10	0.09	0.07
Net of Tax	1.28	1.16	1.16	0.91	0.88	0.86	0.81	0.81	0.81	0.66	0.45	0.28	0.11	0.06	0.06	0.05	0.04
Rate Base	11.34	9.94	8.68	7.42	6.43	5.47	4.53	3.65	2.76	1.86	1.16	0.67	0.36	0.24	0.17	0.10	0.05
Revenue Requirement - Return on Rate Base	1.52	1.33	1.16	0.99	0.86	0.73	0.61	0.49	0.37	0.25	0.16	0.09	0.05	0.03	0.02	0.01	0.01
Revenue Requirement - Amortization	2.19	1.99	1.98	1.55	1.51	1.47	1.39	1.39	1.39	1.12	0.77	0.47	0.20	0.11	0.10	0.09	0.07
Total Revenue Requirement	3.71	3.32	3.14	2.54	2.37	2.20	2.00	1.88	1.76	1.37	0.93	0.56	0.24	0.14	0.13	0.10	0.07
PV @ 1/1/99																	
PV Difference																	
Beaver Valley 2 Sale/Leaseback Premium																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization schedule	1.51	1.51	1.51	1.46	0.00												
Net of Tax	0.88	0.88	0.88	0.86	0.00												
Rate Base	3.50	2.62	1.74	0.86	0.00												
Revenue Requirement - Return on Rate Base	0.47	0.35	0.23	0.11	0.00												
Revenue Requirement - Amortization	1.51	1.51	1.51	1.46	0.00												
Total Revenue Requirement	1.97	1.86	1.74	1.58	0.00												
PV @ 1/1/99																	
PV Difference																	
Deferred Rate Synch. Costs																	
Transition Plan Revenue Requirement																	
Amortization																	
Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization																	
Revenue Requirement																	
PV @ 1/1/99																	
PV Difference																	

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3886%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Deferred Employee Costs	17.80	17.80	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			2.54	2.54	2.54	2.54	2.54	2.54	2.54							
Revenue Requirement			2.54	2.54	2.54	2.54	2.54	2.54	2.54							
PV @ 1/1/99			13.32													
Traditional Ratemaking Revenue Requirement																
Amortization			17.80													
Revenue Requirement			17.80													
PV @ 1/1/99			16.51													
PV Difference			(3.19)													
Deferred Nuclear Maintenance	3.25	1.90														
Transition Plan Revenue Requirement																
Amortization			0.46	0.46	0.46	0.46	0.46	0.46	0.46							
Rate Base			1.90	1.63	1.35	1.08	0.81	0.54	0.27							
Revenue Requirement - Return on Rate Base			0.25	0.22	0.18	0.15	0.11	0.07	0.04							
Revenue Requirement - Amortization			0.46	0.46	0.46	0.46	0.46	0.46	0.46							
Total Revenue Requirement			0.72	0.68	0.64	0.61	0.57	0.54	0.50							
PV @ 1/1/99			3.24													
Traditional Ratemaking Revenue Requirement																
Amortization			2.16	1.08												
Rate Base			1.90	0.63												
Revenue Requirement - Return on Rate Base			0.25	0.08												
Revenue Requirement - Amortization			2.16	1.08												
Total Revenue Requirement			2.42	1.17												
PV @ 1/1/99			3.24													
PV Difference			0.00													
DOE Decom & Decon	7.18	4.19														
Transition Plan Revenue Requirement																
Amortization			1.03	1.03	1.03	1.03	1.03	1.03	1.03							
Revenue Requirement			1.03	1.03	1.03	1.03	1.03	1.03	1.03							
PV @ 1/1/99			5.37													
Traditional Ratemaking Revenue Requirement																
Amortization			1.31	1.31	1.31	1.31	1.31	0.65								
Revenue Requirement			1.31	1.31	1.31	1.31	1.31	0.65								
PV @ 1/1/99			5.65													
PV Difference			(0.28)													
Deferred Coal Costs	13.50	13.50	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			1.93	1.93	1.93	1.93	1.93	1.93	1.93							
Rate Base			7.90	6.77	5.64	4.51	3.39	2.26	1.13							
Revenue Requirement - Return on Rate Base			1.06	0.91	0.76	0.60	0.45	0.30	0.15							
Revenue Requirement - Amortization			1.93	1.93	1.93	1.93	1.93	1.93	1.93							
Total Revenue Requirement			2.99	2.83	2.68	2.53	2.38	2.23	2.08							
PV @ 1/1/99			13.50													
Traditional Ratemaking Revenue Requirement																
Amortization			6.75	6.75												
Rate Base			7.90	3.95												
Revenue Requirement - Return on Rate Base			1.06	0.53												
Revenue Requirement - Amortization			6.75	6.75												
Total Revenue Requirement			7.81	7.28												
PV @ 1/1/99			13.50													
PV Difference			0.00													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Deferred Caretaker Costs	6.77	3.92														
Transition Plan Revenue Requirement																
Amortization			0.97	0.97	0.97	0.97	0.97	0.97	0.97							
Rate Base			3.92	3.36	2.80	2.24	1.68	1.12	0.56							
Revenue Requirement - Return on Rate Base			0.52	0.45	0.37	0.30	0.22	0.15	0.07							
Revenue Requirement - Amortization			0.97	0.97	0.97	0.97	0.97	0.97	0.97							
Total Revenue Requirement			1.49	1.42	1.34	1.27	1.19	1.12	1.04							
PV @ 1/1/99			6.75													
Traditional Ratemaking Revenue Requirement																
Amortization			0.97	0.97	0.97	0.97	0.97	0.97	0.97							
Rate Base			3.92	3.36	2.80	2.24	1.68	1.12	0.56							
Revenue Requirement - Return on Rate Base			0.52	0.45	0.37	0.30	0.22	0.15	0.07							
Revenue Requirement - Amortization			0.97	0.97	0.97	0.97	0.97	0.97	0.97							
Total Revenue Requirement			1.49	1.42	1.34	1.27	1.19	1.12	1.04							
PV @ 1/1/99			6.75													
PV Difference			0.00													
BV2 Training Costs	2.42	1.58														
Transition Plan Revenue Requirement																
Amortization			0.35	0.35	0.35	0.35	0.35	0.35	0.35							
Rate Base			1.58	1.36	1.13	0.90	0.68	0.45	0.23							
Revenue Requirement - Return on Rate Base			0.21	0.18	0.15	0.12	0.09	0.06	0.03							
Revenue Requirement - Amortization			0.35	0.35	0.35	0.35	0.35	0.35	0.35							
Total Revenue Requirement			0.56	0.53	0.50	0.47	0.44	0.41	0.38							
PV @ 1/1/99			2.49													
Traditional Ratemaking Revenue Requirement																
Amortization			0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Rate Base			1.58	1.52	1.46	1.41	1.35	1.29	1.23	1.17	1.11	1.05	1.00	0.94	0.88	0.82
Revenue Requirement - Return on Rate Base			0.21	0.20	0.20	0.19	0.18	0.17	0.16	0.16	0.15	0.14	0.13	0.13	0.12	0.11
Revenue Requirement - Amortization			0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Total Revenue Requirement			0.30	0.29	0.29	0.28	0.27	0.26	0.25	0.25	0.24	0.23	0.22	0.21	0.21	0.20
PV @ 1/1/99			2.58													
PV Difference			(0.10)													
Low Level Rad. Waste	2.27	2.27	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.32	0.32	0.32	0.32	0.32	0.32	0.32							
Rate Base			1.33	1.14	0.95	0.76	0.57	0.38	0.19							
Revenue Requirement - Return on Rate Base			0.18	0.15	0.13	0.10	0.08	0.05	0.03							
Revenue Requirement - Amortization			0.32	0.32	0.32	0.32	0.32	0.32	0.32							
Total Revenue Requirement			0.50	0.48	0.45	0.43	0.40	0.38	0.35							
PV @ 1/1/99			2.27													
Traditional Ratemaking Revenue Requirement																
Amortization			0.32	0.32	0.32	0.32	0.32	0.32	0.32							
Rate Base			1.33	1.14	0.95	0.76	0.57	0.38	0.19							
Revenue Requirement - Return on Rate Base			0.18	0.15	0.13	0.10	0.08	0.05	0.03							
Revenue Requirement - Amortization			0.32	0.32	0.32	0.32	0.32	0.32	0.32							
Total Revenue Requirement			0.50	0.48	0.45	0.43	0.40	0.38	0.35							
PV @ 1/1/99			2.27													
PV Difference			0.00													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate
Gross Receipts Tax Rate
Discount Rate
Return on Rate Base
Revenue Requirement for Return

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Deferred Caretaker Costs																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
PV Difference																	
BV2 Training Costs																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09				
Rate Base	0.76	0.70	0.64	0.59	0.53	0.47	0.41	0.35	0.29	0.23	0.18	0.12	0.06				
Revenue Requirement - Return on Rate Base	0.10	0.09	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.03	0.02	0.02	0.01				
Revenue Requirement - Amortization	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09				
Total Revenue Requirement	0.19	0.18	0.18	0.17	0.16	0.15	0.14	0.14	0.13	0.12	0.11	0.11	0.10				
PV @ 1/1/99																	
PV Difference																	
Low Level Rad. Waste																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
PV Difference																	

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.8057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Coal Cost Equalization	0.12	0.12	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Rate Base			0.07	0.06	0.05	0.04	0.03	0.02	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.01	0.01	0.01	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Total Revenue Requirement			0.03	0.02	0.02	0.02	0.02	0.02	0.02							
PV @ 1/1/99			0.12													
Traditional Ratemaking Revenue Requirement																
Amortization			0.08	0.04												
Rate Base			0.07	0.02												
Revenue Requirement - Return on Rate Base			0.01	0.00												
Revenue Requirement - Amortization			0.08	0.04												
Total Revenue Requirement			0.09	0.04												
PV @ 1/1/99			0.12													
PV Difference			0.00													
Deferred Oxford Centre Costs	0.12	0.12	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Rate Base			0.07	0.06	0.05	0.04	0.03	0.02	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.01	0.01	0.01	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Total Revenue Requirement			0.03	0.03	0.02	0.02	0.02	0.02	0.02							
PV @ 1/1/99			0.12													
Traditional Ratemaking Revenue Requirement																
Amortization			0.03	0.03	0.03	0.03										
Rate Base			0.07	0.05	0.03	0.02										
Revenue Requirement - Return on Rate Base			0.01	0.01	0.00	0.00										
Revenue Requirement - Amortization			0.03	0.03	0.03	0.03										
Total Revenue Requirement			0.04	0.04	0.03	0.03										
PV @ 1/1/99			0.12													
PV Difference			(0.00)													
PA Deregulation Expenses	0.14	0.14	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Rate Base			0.08	0.07	0.06	0.05	0.04	0.02	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.01	0.01	0.01	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Total Revenue Requirement			0.03	0.03	0.03	0.03	0.02	0.02	0.02							
PV @ 1/1/99			0.14													
Traditional Ratemaking Revenue Requirement																
Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Rate Base			0.08	0.07	0.06	0.05	0.04	0.02	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.01	0.01	0.01	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Total Revenue Requirement			0.03	0.03	0.03	0.03	0.02	0.02	0.02							
PV @ 1/1/99			0.14													
PV Difference			0.00													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Demand Side Management	0.10	0.10	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Rate Base			0.06	0.05	0.04	0.03	0.02	0.02	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.01	0.01	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Total Revenue Requirement			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
PV @ 1/1/99			0.10													
Traditional Ratemaking Revenue Requirement																
Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Rate Base			0.06	0.05	0.04	0.03	0.02	0.02	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.01	0.01	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Total Revenue Requirement			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
PV @ 1/1/99			0.10													
PV Difference			0.00													
Corporate Development Project	0.07	0.07	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Rate Base			0.04	0.03	0.03	0.02	0.02	0.01	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Total Revenue Requirement			0.02	0.01	0.01	0.01	0.01	0.01	0.01							
PV @ 1/1/99			0.07													
Traditional Ratemaking Revenue Requirement																
Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Rate Base			0.04	0.03	0.03	0.02	0.02	0.01	0.01							
Revenue Requirement - Return on Rate Base			0.01	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Total Revenue Requirement			0.02	0.01	0.01	0.01	0.01	0.01	0.01							
PV @ 1/1/99			0.07													
PV Difference			0.00													
Section 211	0.06	0.06	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Rate Base			0.04	0.03	0.03	0.02	0.02	0.01	0.01							
Revenue Requirement - Return on Rate Base			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Total Revenue Requirement			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
PV @ 1/1/99			0.06													
Traditional Ratemaking Revenue Requirement																
Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Rate Base			0.04	0.03	0.03	0.02	0.02	0.01	0.01							
Revenue Requirement - Return on Rate Base			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Total Revenue Requirement			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
PV @ 1/1/99			0.06													
PV Difference			0.00													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1996 Management Audit	0.03	0.03	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Rate Base			0.02	0.01	0.01	0.01	0.01	0.00	0.00							
Revenue Requirement - Return on Rate Base			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Total Revenue Requirement			0.01	0.01	0.01	0.01	0.01	0.00	0.00							
PV @ 1/1/99			0.03													
Traditional Ratemaking Revenue Requirement																
Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Rate Base			0.02	0.01	0.01	0.01	0.01	0.00	0.00							
Revenue Requirement - Return on Rate Base			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Total Revenue Requirement			0.01	0.01	0.01	0.01	0.01	0.00	0.00							
PV @ 1/1/99			0.03													
PV Difference			0.00													
Administrative & General	0.01	0.01	(no deferred tax, item will reduce current tax during period amortized)													
Transition Plan Revenue Requirement																
Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Rate Base			0.01	0.01	0.01	0.00	0.00	0.00	0.00							
Revenue Requirement - Return on Rate Base			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Total Revenue Requirement			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
PV @ 1/1/99			0.01													
Traditional Ratemaking Revenue Requirement																
Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Rate Base			0.01	0.01	0.01	0.01	0.01	0.01	0.01							
Revenue Requirement - Return on Rate Base			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Revenue Requirement - Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
Total Revenue Requirement			0.00	0.00	0.00	0.00	0.00	0.00	0.00							
PV @ 1/1/99			0.01													
PV Difference			(0.00)													
Pre-Accrue Nuclear Outages	22.65	13.25														
Transition Plan Revenue Requirement																
Amortization			3.24	3.24	3.24	3.24	3.24	3.24	3.24							
Revenue Requirement			3.24	3.24	3.24	3.24	3.24	3.24	3.24							
PV @ 1/1/99			16.95													
Traditional Ratemaking Revenue Requirement																
Amortization			15.10	7.55												
Revenue Requirement			15.10	7.55												
PV @ 1/1/99			20.50													
PV Difference			(3.55)													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3868%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Gain on Sale/Leaseback	55.13	55.13														
Transition Plan Revenue Requirement																
Amortization			7.88	7.88	7.88	7.88	7.88	7.88	7.88							
Rate Base			55.13	47.26	39.38	31.50	23.63	15.75	7.88							
Revenue Requirement - Return on Rate Base			7.38	6.33	5.27	4.22	3.16	2.11	1.05							
Revenue Requirement - Amortization			13.46	13.46	13.46	13.46	13.46	13.46	13.46							
Total Revenue Requirement			20.84	19.79	18.73	17.68	16.62	15.57	14.52							
PV @ 1/1/99			94.23													
Traditional Ratemaking Revenue Requirement																
Amortization			3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Rate Base			55.13	52.13	49.13	46.13	43.13	40.13	37.13	34.13	31.13	28.13	25.13	22.13	19.13	16.13
Revenue Requirement - Return on Rate Base			7.38	6.98	6.58	6.18	5.77	5.37	4.97	4.57	4.17	3.77	3.36	2.96	2.56	2.16
Revenue Requirement - Amortization			5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13	5.13
Total Revenue Requirement			12.51	12.11	11.70	11.30	10.90	10.50	10.10	9.70	9.30	8.89	8.49	8.09	7.69	7.29
PV @ 1/1/99			94.23													
PV Difference			0.00													
Deferred Rate Synch. Costs	0.27	0.27														
Transition Plan Revenue Requirement																
Amortization			0.04	0.04	0.04	0.04	0.04	0.04	0.04							
Revenue Requirement			0.04	0.04	0.04	0.04	0.04	0.04	0.04							
PV @ 1/1/99			0.20													
Traditional Ratemaking Revenue Requirement																
Amortization			0.04	0.04	0.04	0.04	0.04	0.04	0.04							
Revenue Requirement			0.04	0.04	0.04	0.04	0.04	0.04	0.04							
PV @ 1/1/99			0.20													
PV Difference			0.00													
Beaver Valley 2	0.17	0.17														
Transition Plan Revenue Requirement																
Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Rate Base			0.17	0.14	0.12	0.09	0.07	0.05	0.02							
Revenue Requirement - Return on Rate Base			0.02	0.02	0.02	0.01	0.01	0.01	0.00							
Revenue Requirement - Amortization			0.02	0.02	0.02	0.02	0.02	0.02	0.02							
Total Revenue Requirement			0.05	0.04	0.04	0.04	0.03	0.03	0.03							
PV @ 1/1/99			0.20													
Traditional Ratemaking Revenue Requirement																
Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Rate Base			0.17	0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.08	0.07	0.06	0.06	0.05
Revenue Requirement - Return on Rate Base			0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Revenue Requirement - Amortization			0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total Revenue Requirement			0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
PV @ 1/1/99			0.22													
PV Difference			(0.03)													
Deferred Fuel Cost	14.81	8.66														
Transition Plan Revenue Requirement																
Amortization			2.12	2.12	2.12	2.12	2.12	2.12	2.12							
Revenue Requirement			2.12	2.12	2.12	2.12	2.12	2.12	2.12							
PV @ 1/1/99			11.08													
Traditional Ratemaking Revenue Requirement																
Amortization			14.81													
Revenue Requirement			14.81													
PV @ 1/1/99			13.73													
PV Difference			(2.65)													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate
Gross Receipts Tax Rate
Discount Rate
Return on Rate Base
Revenue Requirement for Return

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gain on Sale/Leaseback																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization	3.00	3.00	3.00	3.00	1.13												
Rate Base	13.13	10.13	7.13	4.13	1.13												
Revenue Requirement - Return on Rate Base	1.76	1.36	0.95	0.55	0.15												
Revenue Requirement - Amortization	5.13	5.13	5.13	5.13	1.93												
Total Revenue Requirement	6.89	6.48	6.08	5.68	2.08												
PV @ 1/1/99																	
PV Difference																	
Deferred Rate Synch. Costs																	
Transition Plan Revenue Requirement																	
Amortization																	
Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization																	
Revenue Requirement																	
PV @ 1/1/99																	
PV Difference																	
Beaver Valley 2																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization	0.01	0.01	0.01	0.01													
Rate Base	0.04	0.03	0.02	0.01													
Revenue Requirement - Return on Rate Base	0.00	0.00	0.00	0.00	0.00												
Revenue Requirement - Amortization	0.01	0.01	0.01	0.01													
Total Revenue Requirement	0.01	0.01	0.01	0.01													
PV @ 1/1/99																	
PV Difference																	
Deferred Fuel Cost																	
Transition Plan Revenue Requirement																	
Amortization																	
Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization																	
Revenue Requirement																	
PV @ 1/1/99																	
PV Difference																	

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.8057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Transition Costs	18.10	10.59														
Transition Plan Revenue Requirement																
Amortization			2.59	2.59	2.59	2.59	2.59	2.59	2.59							
Rate Base			10.59	9.08	7.56	6.05	4.54	3.03	1.51							
Revenue Requirement - Return on Rate Base			1.42	1.22	1.01	0.81	0.61	0.41	0.20							
Revenue Requirement - Amortization			2.59	2.59	2.59	2.59	2.59	2.59	2.59							
Total Revenue Requirement			4.00	3.80	3.60	3.40	3.19	2.99	2.79							
PV @ 1/1/99			18.10													
Traditional Ratemaking Revenue Requirement																
Amortization			18.10													
Rate Base			10.59													
Revenue Requirement - Return on Rate Base			1.42													
Revenue Requirement - Amortization			18.10													
Total Revenue Requirement			19.52													
PV @ 1/1/99			18.10													
PV Difference			(0.00)													
FAS 106 (amortized through 2013)	4.22	2.47														
Transition Plan Revenue Requirement																
Amortization			0.60	0.60	0.60	0.60	0.60	0.60	0.60							
Revenue Requirement			0.60	0.60	0.60	0.60	0.60	0.60	0.60							
PV @ 1/1/99			3.16													
Traditional Ratemaking Revenue Requirement																
Amortization			0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Revenue Requirement			0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.02	1.02	1.02	1.02	1.02	1.02	1.02
PV @ 1/1/99			3.16													
PV Difference			(0.00)													
Pre-2006 Unamortized Debt Cost	16.76	9.80														
Transition Plan Revenue Requirement																
Amortization			2.39	2.39	2.39	2.39	2.39	2.39	2.39							
Rate Base			9.80	8.40	7.00	5.60	4.20	2.80	1.40							
Revenue Requirement - Return on Rate Base			1.31	1.12	0.94	0.75	0.56	0.37	0.19							
Revenue Requirement - Amortization			2.39	2.39	2.39	2.39	2.39	2.39	2.39							
Total Revenue Requirement			3.71	3.52	3.33	3.14	2.96	2.77	2.58							
PV @ 1/1/99			16.76													
Traditional Ratemaking Revenue Requirement																
Amortization			2.39	2.39	2.39	2.39	2.39	2.39	2.39							
Rate Base			9.80	8.40	7.00	5.60	4.20	2.80	1.40							
Revenue Requirement - Return on Rate Base			1.31	1.12	0.94	0.75	0.56	0.37	0.19							
Revenue Requirement - Amortization			2.39	2.39	2.39	2.39	2.39	2.39	2.39							
Total Revenue Requirement			3.71	3.52	3.33	3.14	2.96	2.77	2.58							
PV @ 1/1/99			16.76													
PV Difference			0.00													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Pre-2006 BV2 Unamortized Debt Cost	**3.02**	**1.77**														
Transition Plan Revenue Requirement																
Amortization			0.43	0.43	0.43	0.43	0.43	0.43	0.43							
Rate Base			1.77	1.52	1.26	1.01	0.76	0.51	0.25							
Revenue Requirement - Return on Rate Base			0.24	0.20	0.17	0.14	0.10	0.07	0.03							
Revenue Requirement - Amortization			0.43	0.43	0.43	0.43	0.43	0.43	0.43							
Total Revenue Requirement			0.67	0.63	0.60	0.57	0.53	0.50	0.47							
PV @ 1/1/99			3.02													
Traditional Ratemaking Revenue Requirement																
Amortization			0.43	0.43	0.43	0.43	0.43	0.43	0.43							
Rate Base			1.77	1.52	1.26	1.01	0.76	0.51	0.25							
Revenue Requirement - Return on Rate Base			0.24	0.20	0.17	0.14	0.10	0.07	0.03							
Revenue Requirement - Amortization			0.43	0.43	0.43	0.43	0.43	0.43	0.43							
Total Revenue Requirement			0.67	0.63	0.60	0.57	0.53	0.50	0.47							
PV @ 1/1/99			3.02													
PV Difference			0.00													
Pre-2006 BV2 Sale Leaseback Premium	**10.53**	**6.16**														
Transition Plan Revenue Requirement																
Amortization			1.50	1.50	1.50	1.50	1.50	1.50	1.50							
Rate Base			6.16	5.28	4.40	3.52	2.64	1.76	0.88							
Revenue Requirement - Return on Rate Base			0.82	0.71	0.59	0.47	0.35	0.24	0.12							
Revenue Requirement - Amortization			1.50	1.50	1.50	1.50	1.50	1.50	1.50							
Total Revenue Requirement			2.33	2.21	2.09	1.98	1.86	1.74	1.62							
PV @ 1/1/99			10.53													
Traditional Ratemaking Revenue Requirement																
Amortization			1.50	1.50	1.50	1.50	1.50	1.50	1.50							
Rate Base			6.16	5.28	4.40	3.52	2.64	1.76	0.88							
Revenue Requirement - Return on Rate Base			0.82	0.71	0.59	0.47	0.35	0.24	0.12							
Revenue Requirement - Amortization			1.50	1.50	1.50	1.50	1.50	1.50	1.50							
Total Revenue Requirement			2.33	2.21	2.09	1.98	1.86	1.74	1.62							
PV @ 1/1/99			10.53													
PV Difference			0.00													

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate	41.4935%
Gross Receipts Tax Rate	0.0000%
Discount Rate	7.8320%
Return on Rate Base	9.6057%
Revenue Requirement for Return	13.3866%

	Balance 12/31/98	Net Balance 12/31/98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
SFAS 109																
Transition Plan Revenue Requirement	236.48	179.00														
Amortization			33.78	33.78	33.78	33.78	33.78	33.78	33.78							
Rate Base			179.00	153.43	127.86	102.29	76.71	51.14	25.57							
Revenue Requirement - Return on Rate Base			23.98	20.54	17.12	13.69	10.27	6.85	3.42							
Revenue Requirement - Amortization			43.71	43.71	43.71	43.71	43.71	43.71	43.71							
Total Revenue Requirement			67.67	64.25	60.82	57.40	53.98	50.55	47.13							
PV @ 1/1/99			305.95													
Traditional Ratemaking Revenue Requirement																
Amortization			27.58	26.47	25.65	25.78	32.06	34.21	16.21	9.98	10.23	7.61	2.99	3.09	3.28	2.30
Rate Base			179.00	158.14	138.10	118.69	99.17	74.91	49.01	36.74	29.19	21.44	15.68	13.42	11.08	8.60
Revenue Requirement - Return on Rate Base			23.98	21.17	18.49	15.89	13.28	10.03	6.56	4.92	3.91	2.87	2.10	1.80	1.48	1.15
Revenue Requirement - Amortization			35.68	34.25	33.19	33.35	41.48	44.26	20.97	12.91	13.24	9.85	3.87	4.00	4.24	2.98
Total Revenue Requirement			59.62	55.42	51.67	49.24	54.75	54.29	27.53	17.83	17.14	12.72	5.97	5.79	5.73	4.13
PV @ 1/1/99			305.95													
PV Difference			0.00													

Total - All Regulatory Assets Itemized Above	519.37	394.82
Add: Present Value Beaver Valley 2 Lease	441.20	257.87
Total Regulatory Assets	960.58	652.68
Total Net Present Value Difference	(10.70)	

Reconciliation with DJC-4 Regulatory Assets		
Total Regulatory Assets at 12/31/98 per DJC-4	810.59	573.92
(1) Remove FAS 109 Plant	(62.94)	(45.38)
(2) Add: Difference PV BV2 Lease		
PV BV2 Lease per revised schedule	441.20	257.87
PV BV2 Lease per DJC-4	227.78	133.27
Difference	213.42	124.60
(3) Deduct: Difference Deferred Rate Synch. Costs		
Costs per revised schedule	32.66	30.26
Costs per DJC-4	33.16	30.72
Difference	(0.50)	(0.46)
Total Adjustments to DJC-4 (1)+(2)+(3)	149.99	78.76
Adjusted DJC-4	960.58	652.68

Analysis of Regulatory Asset Recovery
Transition Plan vs. Traditional Ratemaking
Excludes effect of Gross Receipts Tax

Effective Federal/StateTax Rate
Gross Receipts Tax Rate
Discount Rate
Return on Rate Base
Revenue Requirement for Return

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
SFAS 109																	
Transition Plan Revenue Requirement																	
Amortization																	
Rate Base																	
Revenue Requirement - Return on Rate Base																	
Revenue Requirement - Amortization																	
Total Revenue Requirement																	
PV @ 1/1/99																	
Traditional Ratemaking Revenue Requirement																	
Amortization	1.79	1.68	(0.52)	1.29	1.54	0.15	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.46			
Rate Base	6.88	5.50	4.25	4.64	3.66	2.50	2.38	2.10	1.81	1.52	1.23	0.95	0.66	0.37			
Revenue Requirement - Return on Rate Base	0.92	0.74	0.57	0.62	0.49	0.33	0.32	0.28	0.24	0.20	0.17	0.13	0.09	0.05			
Revenue Requirement - Amortization	2.32	2.15	(0.67)	1.67	1.99	0.19	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.63			
Total Revenue Requirement	3.23	2.88	(0.10)	2.29	2.48	0.53	0.81	0.77	0.73	0.70	0.66	0.62	0.58	0.68			
PV @ 1/1/99																	
PV Difference																	

Total - All Regulatory Assets Itemized Above
Add: Present Value Beaver Valley 2 Lease
Total Regulatory Assets

Reconciliation with DJC-4 Regulatory Assets
Total Regulatory Assets at 12/31/98 per DJC-4
(1) Remove FAS 109 Plant
(2) Add: Difference PV BV2 Lease
PV BV2 Lease per revised schedule
PV BV2 Lease per DJC-4
Difference
(3) Deduct: Difference Deferred Rate Synch. Costs
Costs per revised schedule
Costs per DJC-4
Difference
Total Adjustments to DJC-4 (1)+(2)+(3)
Adjusted DJC-4

Duquesne Light Company

Beaver Valley Unit No . Lease Payments
($ Millions)

Year	Rent	Cash Exp.	Amortization Original Premium	Amortization Refinancing Premium	Total Lease exp	0.0783 PV 1999 to 2017 @ 7.83%	PV Factors @ 7.83%	Lease Pmt. Check	Total Lease Rev Req.	Amortization Amount	Future Value Check
1997	44.0	2.0	0.4	1.5	47.9						
1998	44.1	2.0	0.5	1.5	48.1						
1997 to 1998	88.1	4.0	0.9	3.0	96.0						
1999	44.0	2.0	0.4	1.5	47.9	46.1	0.9630	47.9	95.6	47.7	77.9
2000	44.3	2.0	0.4	1.5	48.2	43.0	0.8931	48.2	95.9	47.7	72.2
2001	44.3	2.0	0.4	1.5	48.2	39.9	0.8282	48.2	95.9	47.7	67.0
2002	45.9	2.0	0.4	1.5	49.8	38.3	0.7681	49.8	97.5	47.7	62.1
2003	51.8	2.0	0.4	1.5	55.7	39.7	0.7123	55.7	103.4	47.7	57.6
2004	53.3	2.0	0.4	1.5	57.2	37.8	0.6606	57.2	104.9	47.7	53.4
2005	53.3	2.0	0.4	1.5	57.2	35.0	0.6126	57.2	104.9	47.7	49.5
1999 to 2005	336.9	14.0	2.8	10.5	364.2	279.8	5.4379	Levelized 51.5			439.7
									2005 PV of Future Pmts		
2006	53.3	2.0	0.4	1.5	57.2	32.5	0.5681		55.1		
2007	53.3	2.0	0.4	1.5	57.2	30.1	0.5269		51.1		
2008	53.3	2.0	0.4	1.5	57.2	27.9	0.4886		47.4		
2009	53.3	2.0	0.4	1.5	57.2	25.9	0.4531		43.9		
2010	53.3	2.0	0.4	1.5	57.2	24.0	0.4202		40.7		
2011	53.3	2.0	0.4	1.5	57.2	22.3	0.3897		37.8		
2012	53.3	2.0	0.4	1.5	57.2	20.7	0.3614		35.0		
2013	53.3	2.0	0.4	1.5	57.2	19.2	0.3352		32.5		
2014	53.3	2.0	0.4	1.5	57.2	17.8	0.3108		30.1		
2015	53.3	2.0	0.4	1.5	57.2	16.5	0.2883		27.9		
2016	53.3	2.0	0.4	1.5	57.2	15.3	0.2673		25.9		
2017	26.7	2.0	0	0.1	28.8	7.1	0.2479		12.1		
2006 to 2016	613.0	24.0	4.4	16.6	658.0	259.4	Levelized Fut Pmts.	47.7	439.7		
Total	1,038.0	42.0	8.1	30.1	1,118.2	539.2					

Exhibit DJC-16

Duquesne Light Company

Duquesne Light Security Ratings

	S&P 3/94	Moody's 5/95	D&P 7/95	Fitch 10/95
First Mortgage Bonds	BBB+	Baa1	A-	A-
Debentures	BBB	Baa2	BBB+	BBB+
Preferred	BBB	baa3	BBB	BBB+
MIPS	BBB	baa3	BBB	BBB+
Commercial Paper	A-2	P2	D-1-	F-1
Penn Fuel CP	A-2	P2	D-1-	N/R
DQU II Funding SLOBS	BBB	Baa3	BBB	N/R

Exhibit DJC - 17

Duquesne Light Company

Effect of Intervenors' Direct Case on Revenue, Earnings & Cash Flow, ROE

(Variance from Duquesne Direct Case in Millions of Dollars)

REVENUES

	1999	2000	2001	2002	2003	2004	2005
DLC	–	–	–	–	–	–	–
OCA	(141.7)	(142.0)	(126.1)	(147.1)	(234.7)	(240.9)	(271.3)
OTS	(46.8)	(57.0)	(57.1)	(56.2)	(56.9)	(61.1)	(48.6)
DII	(12.6)	(19.6)	(19.9)	(109.1)	(421.9)	(415.6)	(416.0)
HSS	(438.5)	(436.7)	(424.7)	(413.2)	(407.7)	(401.3)	(402.5)

EARNINGS AVAILABLE TO COMMON

DLC	–	–	–	–	–	–	–
OCA	(103.5)	(100.1)	(92.9)	(105.5)	(153.0)	(158.2)	(168.7)
OTS	(13.1)	(14.2)	(14.9)	(14.9)	(15.9)	(19.1)	(18.2)
DII	(224.9)	(220.1)	(215.8)	(199.3)	(155.8)	(151.8)	(142.1)
HSS	(124.0)	(116.8)	(108.9)	(100.2)	(92.7)	(87.5)	(78.2)

CASH FLOW (Funds from operations)

	1999	2000	2001	2002	2003	2004	2005
DLC	–	–	–	–	–	–	–
OCA	(79.3)	(79.4)	(70.5)	(82.3)	(131.3)	(134.7)	(151.7)
OTS	(26.2)	(31.9)	(31.9)	(31.4)	(31.8)	(34.2)	(27.2)
DII	(7.0)	(11.0)	(11.1)	(61.0)	(236.0)	(232.5)	(232.7)
HSS	(245.3)	(244.3)	(237.5)	(231.1)	(228.0)	(224.5)	(225.1)

Duquesne Light Company

Effects of Intervenors' Direct Case on Financial Ratios

FUNDS FROM OPERATIONS TO TOTAL DEBT

	1999	2000	2001	2002	2003	2004	2005
DLC	21.4%	19.6%	20.4%	22.9%	23.1%	23.6%	23.7%
Rating	BBB	BBB	BBB	A	A	A	A
OCA	16.1%	14.2%	15.3%	16.8%	13.3%	13.2%	11.7%
Rating	BBB	BB	BB	BBB	BB	BB	BB
OTS	19.6%	17.4%	18.1%	20.5%	20.6%	20.8%	21.4%
Rating	BBB	BBB	BBB	BBB	BBB	BBB	BBB
DII	21.0%	18.9%	19.7%	18.7%	6.1%	6.3%	5.8%
Rating	BBB	BBB	BBB	BBB	B	B	B
HSS	9.5%	3.9%	4.6%	6.9%	6.7%	6.9%	6.4%
Rating	B	CCC	B	B	B	B	B

FUNDS FROM OPERATIONS INTEREST COVERAGE

DLC	3.50	3.29	3.37	3.67	3.69	3.73	3.75
Rating	A	BBB	BBB	A	A	A	A
OCA	2.87	2.64	2.78	2.96	2.55	2.53	2.37
Rating	BBB	BBB	BBB	BBB	BBB	BBB	BB
OTS	3.25	2.99	3.07	3.36	3.36	3.37	3.46
Rating	BBB	BBB	BBB	BBB	BBB	BBB	BBB
DII	3.39	3.14	3.23	3.12	1.69	1.71	1.67
Rating	BBB	BBB	BBB	BBB	BB	BB	BB
HSS	1.70	1.44	1.52	1.78	1.76	1.78	1.73
Rating	BB	B	BB	BB	BB	BB	BB

Duquesne Light Company

Effects of Intervenors' Direct Case on Financial Ratios

PRE TAX INTEREST COVERAGE

	1999	2000	2001	2002	2003	2004	2005
DLC	2.08	2.06	2.05	2.03	2.14	2.32	2.36
Rating	BB	BB	BB	BB	BBB	BBB	BBB
OCA	0.99	0.92	0.97	0.73	0.13	0.18	(0.02)
Rating	B	B	B	B	CCC	CCC	CCC
OTS	1.98	1.89	1.87	1.85	1.94	2.08	2.14
Rating	BB	BB	BB	BB	BB	BB	BBB
DII	(0.39)	(0.45)	(0.46)	(0.32)	0.42	0.62	0.73
Rating	CC	CC	CC	CC	CCC	CCC	B
HSS	0.79	0.76	0.81	0.85	1.01	1.24	1.37
Rating	B	B	B	B	B	B	B

NET CASH FLOW TO CAPITAL EXPENDITURES

DLC	217.0%	189.2%	201.9%	245.8%	212.8%	166.7%	233.5%
Rating	AA	AA	AA	AA	AA	AA	AA
OCA	198.2%	165.6%	179.9%	219.6%	191.3%	161.4%	210.1%
Rating	AA	AA	AA	AA	AA	AA	AA
OTS	163.7%	129.3%	141.4%	178.7%	157.2%	134.0%	183.7%
Rating	AA	AA	AA	AA	AA	AA	AA
DII	377.4%	343.5%	357.5%	338.1%	98.9%	87.5%	100.9%
Rating	AA	AA	AA	AA	AA	A	AA
HSS	75.8%	42.2%	52.3%	88.5%	72.5%	57.0%	73.4%
Rating	A	BB	BBB	A	A	BBB	A

Duquesne Light Company

Effects of Intervenors' Direct Case on Financial Ratios

TOTAL DEBT TO TOTAL CAPITALIZATION

	1999	2000	2001	2002	2003	2004	2005
DLC	59.1%	59.3%	59.5%	59.8%	60.1%	60.3%	60.6%
Rating	BBB	BBB	BBB	BBB	BBB	BBB	BBB
OCA	78.8%	80.1%	81.5%	83.2%	85.0%	86.1%	88.1%
Rating	CCC	CCC	CC	CC	CC	CC	C
OTS	63.6%	64.0%	64.5%	65.0%	65.6%	65.9%	66.5%
Rating	BB	BB	BB	BB	BB	BB	BB
DII	71.4%	72.2%	73.2%	74.3%	75.4%	76.2%	77.4%
Rating	B	B	B	B	CCC	CCC	CCC
HSS	88.1%	88.2%	88.3%	88.4%	88.6%	88.6%	88.7%
Rating	C	C	C	C	C	C	C

COMPOSITE PROJECTED RATING

DLC	BBB	BBB	BBB	BBB	A	A	A
OCA	BB	BB	BB	BB	B	B	B
OTS	BBB	BBB	BBB	BBB	BBB	BBB	BBB
DII	BB	BB	BB	BB	B	B	BB
HSS	B	CCC	B	B	B	B	B

S & P Rating Benchmarks*

	AA	A	BBB	BB
Funds From Operations to Total Debt	32.0%	25.0%	19.0%	13.0%
Funds From Operations Interest Coverage	4.50	4.00	3.00	2.00
Pre Tax interest Coverage	4.00	3.50	2.50	1.75
Net Cash Flow to Capital Expenditures	110.0%	85.0%	60.0%	40.0%
Total Debt to Total Capitalization	42.0%	47.0%	54.0%	60.0%

*Benchmarks listed for average business position

Exhibit DJC-19

Duquesne Light Company

Relative Cost Changes Due To Credit Rating

	Credit Rating	Coupon Rate	Increased Cost Due To Credit Quality
	AA+/AA	6.72%	-
	AA-	6.75%	+ .03
	A+	6.81%	+ .06
Investment Grade	A	6.84%	+ .03
	A-	6.97%	+ .13
	BBB+	7.04%	+ .07
	BBB	7.16%	+ .12
	BBB-	7.23%	+ .07
	BB+	7.48%	+ .25
"Junk"	BB	8.05%	+ .57
	BB-	8.64%	+ .59

Duquesne Light Company
Summary of
Net Book Value and Range of
Market Values at
12/31/1998
$ Millions

Net Book Value	
Generating Plant Assets	$918
M&S and Fuel Related Sunk Costs	$41
PV of Beaver Valley 2 Lease Expense	$278
Regulatory Assets	$374
Total Net Book Value	$1,611
Costs Independent of Operation	
Low	$208
High	$80
Delayed Entry	$104
Market Value of Generation Portfolio	
Low	
Decommissioning	($124)
Plant Margin	$27
Total Low	($97)
High	
Decommissioning	($124)
Plant Margin	$278
Total High	$154
Delayed Entry	
Decommissioning	($124)
Plant Margin	$159
Total Delayed Entry	$35
Stranded Cost	
Low	**$1,916**
High	**$1,537**
Delayed Entry	**$1,680**

DUQUESNE LIGHT COMPANY
Plant Present Values
$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

MARGIN STREAM BEGINNING 1/1/99

	Plant Margin	Decommissioning	Net Plant Value
Fossil Plants:			
Cheswick	0.0	(13.9)	(13.9)
Sammis	0.0	(4.7)	(4.7)
Eastlake	0.0	(4.1)	(4.1)
Elrama	0.0	(20.7)	(20.7)
Mansfield 1	8.2	(7.4)	0.7
Mansfield 2	4.1	(0.5)	3.6
Mansfield 3	7.9	(1.4)	6.5
Brunot Island	0.0	(8.2)	(8.2)
Phillips	0.0	(5.6)	(5.6)
Total Fossil	**20.2**	**(66.5)**	**(46.3)**
Nuclear Plants:			
Beaver Valley 1	7.2	(25.5)	(18.3)
Beaver Valley 2	0.0	(10.3)	(10.3)
Perry	0.0	(21.6)	(21.6)
Total Nuclear	**7.2**	**(57.4)**	**(50.2)**
TOTAL PLANTS	**$27.4**	**($123.9)**	**($96.5)**

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

CHESWICK	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12
Unit Output (gwh)	3,791	3,837	3,662	4,017	3,922	3,471	4,147	4,235	4,062	4,425	4,231	3,707	4,413	4,249	4,062	4,374
Delivered Output (gwh)	3,608	3,652	3,485	3,823	3,733	3,303	3,947	4,030	3,866	4,211	4,027	3,528	4,200	4,044	3,866	4,163
Revenues	**69.28**	**74.18**	**74.65**	**86.08**	**88.41**	**82.99**	**103.34**	**136.32**	**134.03**	**149.66**	**146.69**	**131.73**	**160.72**	**158.62**	**155.44**	**171.57**
Fuel-Related Expenses																
Fuel Costs	44.97	47.14	46.27	51.78	51.87	47.65	58.41	61.67	60.69	68.62	70.81	65.11	79.74	79.21	78.70	88.19
Fuel Related ECR Costs	0.90	0.92	0.95	0.97	1.00	1.03	1.05	1.08	1.11	1.14	1.17	1.20	1.23	1.26	1.30	1.32
NOx Emissions	5.27	5.46	5.41	6.56	6.59	5.42	7.82	8.24	8.17	9.60	9.34	7.63	10.85	10.87	10.49	12.08
SO2 Emissions	0.63	0.73	3.41	4.27	4.42	3.86	5.59	6.16	6.23	7.64	7.69	6.64	9.49	9.68	9.71	11.70
Total Fuel	51.77	54.25	56.04	63.58	63.88	57.95	72.86	77.14	76.21	87.00	89.01	80.58	101.32	101.03	100.20	113.29
Non-fuel O&M Expenses																
Variable O&M	2.78	2.89	2.83	3.18	3.19	2.90	3.56	3.73	3.67	4.11	4.03	3.62	4.43	4.38	4.30	4.75
Fixed O&M	13.05	12.06	14.00	13.66	12.42	9.88	14.56	13.15	15.38	15.33	14.11	9.12	16.38	15.26	17.69	17.55
Overhaul	0.00	0.00	0.00	0.00	0.00	15.86	0.00	0.00	0.00	0.00	0.00	18.56	0.00	0.00	0.00	0.00
Subtotal	15.83	14.95	16.83	16.84	15.61	28.64	18.12	16.88	19.06	19.43	18.14	31.30	20.81	19.63	21.98	22.30
Carbon Injection Costs							2.68	3.01	2.80	2.81	3.09	2.52	2.93	3.33	3.13	3.07
FICA	0.47	0.50	0.53	0.53	0.48	0.42	0.52	0.53	0.57	0.58	0.52	0.43	0.58	0.60	0.67	0.68
Property Tax	0.84	0.84	0.84	0.84	0.84	0.84	0.84	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	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Total Non-fuel	18.02	17.16	19.08	19.09	17.82	30.79	23.05	22.14	24.14	24.54	23.47	35.96	26.04	25.28	27.50	27.76
Capital Expenditures	7.17	12.20	4.79	4.93	20.21	44.57	5.40	5.56	5.72	5.89	6.08	15.46	4.96	3.58	2.12	1.53
Direct Expenses	**76.95**	**83.62**	**79.91**	**87.61**	**101.90**	**133.30**	**101.31**	**104.83**	**106.07**	**117.43**	**118.55**	**132.01**	**132.31**	**129.89**	**129.82**	**142.58**
Direct Margin	**(7.68)**	**(9.44)**	**(5.26)**	**(1.52)**	**(13.49)**	**(50.32)**	**2.03**	**31.48**	**27.95**	**32.22**	**28.14**	**(0.28)**	**28.41**	**28.73**	**25.63**	**28.98**
Overhead Allocation	10.47	12.69	12.42	13.43	15.53	19.24	15.93	16.73	17.26	18.61	19.02	21.48	20.99	21.40	22.63	23.68
Expenses incl. Corp O/H	**87.42**	**96.31**	**92.33**	**101.04**	**117.43**	**152.54**	**117.24**	**121.57**	**123.33**	**136.04**	**137.57**	**153.49**	**153.30**	**151.29**	**152.45**	**166.27**
Margin after Corp O/H	**(18.15)**	**(22.12)**	**(17.68)**	**(14.96)**	**(29.02)**	**(69.56)**	**(13.91)**	**14.75**	**10.69**	**13.62**	**9.12**	**(21.76)**	**7.42**	**7.33**	**2.99**	**5.30**
Costs per kwh (cents)																
Fuel	1.51	1.56	1.69	1.75	1.80	1.84	1.94	2.01	2.07	2.16	2.31	2.39	2.52	2.61	2.70	2.84
Non-fuel	0.50	0.47	0.55	0.50	0.48	0.93	0.58	0.55	0.62	0.58	0.58	1.02	0.62	0.63	0.71	0.67
Capital Expenditures	0.20	0.33	0.14	0.13	0.54	1.35	0.14	0.14	0.15	0.14	0.15	0.44	0.12	0.09	0.05	0.04
Direct Expenses	**2.21**	**2.37**	**2.37**	**2.37**	**2.82**	**4.12**	**2.66**	**2.69**	**2.84**	**2.89**	**3.04**	**3.84**	**3.26**	**3.32**	**3.47**	**3.54**
Direct Margin	**(0.34)**	**(0.40)**	**(0.29)**	**(0.18)**	**(0.51)**	**(1.69)**	**(0.10)**	**0.69**	**0.63**	**0.67**	**0.60**	**(0.11)**	**0.57**	**0.60**	**0.55**	**0.58**
Overhead Allocation	0.29	0.35	0.36	0.35	0.42	0.58	0.40	0.42	0.45	0.44	0.47	0.61	0.50	0.53	0.59	0.57
Expenses incl. Corp O/H	**2.50**	**2.72**	**2.73**	**2.73**	**3.23**	**4.71**	**3.06**	**3.11**	**3.29**	**3.33**	**3.52**	**4.45**	**3.76**	**3.85**	**4.05**	**4.11**
Margin after Corp O/H	**(0.63)**	**(0.75)**	**(0.65)**	**(0.54)**	**(0.92)**	**(2.28)**	**(0.50)**	**0.27**	**0.18**	**0.23**	**0.13**	**(0.72)**	**0.07**	**0.07**	**(0.03)**	**0.01**
NPV of Margin after O/H	**(67.1)**							**23.6**								
NPV of Decommissioning	**13.9**							**23.6**								
NPV OF NET MARGIN	**(81.0)**							**0.1**								

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

SAMMIS	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73
Unit Output (gwh)	1,258	1,381	1,167	1,389	1,304	1,418	1,315	1,558	1,290	1,563	1,437	1,537
Delivered Output (gwh)	1,206	1,324	1,119	1,331	1,250	1,359	1,261	1,493	1,236	1,498	1,378	1,474
Revenues	**23.35**	**26.97**	**23.87**	**30.12**	**29.80**	**34.11**	**33.33**	**50.51**	**42.86**	**53.24**	**50.19**	**55.02**
Fuel-Related Expenses												
Fuel Costs	15.94	18.62	16.46	19.99	19.48	21.51	20.63	23.77	20.33	25.67	24.55	27.34
Fuel Related ECR Costs	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	1.67	2.05	1.77	2.24	2.15	2.39
SO2 Emissions	(0.70)	(0.65)	0.32	0.57	0.52	0.69	0.61	0.98	0.66	1.14	1.02	1.27
Total Fuel	15.26	18.00	16.80	20.59	20.02	22.23	22.94	26.83	22.80	29.08	27.75	31.03
Non-fuel O&M Expenses												
Variable O&M	1.68	1.83	1.51	1.84	1.78	1.97	1.88	2.29	1.93	2.40	2.26	2.48
Fixed O&M	5.72	3.68	3.33	3.71	5.00	4.01	5.22	4.29	3.75	4.80	4.63	4.71
Overhaul	0.00	0.00	3.45	0.00	0.00	0.00	0.00	0.00	4.00	0.00	0.00	0.00
Subtotal	7.39	5.51	8.29	5.54	6.78	5.98	7.10	6.58	9.68	7.19	6.89	7.18
FICA	0.22	0.18	0.15	0.18	0.21	0.20	0.21	0.21	0.17	0.21	0.20	0.24
Property Tax	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49
Cap Stock Tax	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Total Non-fuel	9.41	7.48	10.24	7.51	8.78	7.97	9.10	8.58	11.64	9.20	8.88	9.22
Capital Expenditures	1.33	0.19	3.59	1.11	1.36	0.44	1.43	0.22	4.16	0.49	1.59	0.52
Direct Expenses	**25.99**	**25.67**	**30.63**	**29.21**	**30.17**	**30.65**	**33.47**	**35.63**	**38.60**	**38.77**	**38.21**	**40.76**
Direct Margin	**(2.64)**	**1.30**	**(6.76)**	**0.92**	**(0.37)**	**3.46**	**(0.14)**	**14.88**	**4.26**	**14.47**	**11.98**	**14.26**
Overhead Allocation	3.54	3.89	4.76	4.48	4.60	4.42	5.26	5.69	6.28	6.14	6.13	6.63
Expenses incl. Corp O/H	**29.53**	**29.57**	**35.39**	**33.69**	**34.77**	**35.07**	**38.74**	**41.32**	**44.89**	**44.91**	**44.34**	**47.39**
Margin after Corp O/H	**(6.18)**	**(2.60)**	**(11.52)**	**(3.56)**	**(4.97)**	**(0.96)**	**(5.40)**	**9.19**	**(2.03)**	**8.33**	**5.85**	**7.62**
Costs per kwh (cents)												
Fuel	1.40	1.50	1.64	1.68	1.74	1.78	1.97	1.95	2.00	2.10	2.18	2.27
Non-fuel	0.78	0.57	0.91	0.56	0.70	0.59	0.72	0.57	0.94	0.61	0.64	0.63
Capital Expenditures	0.11	0.01	0.32	0.08	0.11	0.03	0.11	0.01	0.34	0.03	0.12	0.04
Direct Expenses	**2.29**	**2.08**	**2.87**	**2.33**	**2.56**	**2.40**	**2.80**	**2.54**	**3.28**	**2.75**	**2.94**	**2.93**
Direct Margin	**(0.42)**	**(0.11)**	**(0.79)**	**(0.14)**	**(0.25)**	**0.03**	**(0.24)**	**0.84**	**0.19**	**0.81**	**0.71**	**0.80**
Overhead Allocation	0.29	0.29	0.43	0.34	0.37	0.33	0.42	0.38	0.51	0.41	0.44	0.45
Expenses incl. Corp O/H	**2.59**	**2.37**	**3.30**	**2.67**	**2.92**	**2.73**	**3.22**	**2.92**	**3.79**	**3.16**	**3.38**	**3.38**
Margin after Corp O/H	**(0.72)**	**(0.40)**	**(1.22)**	**(0.48)**	**(0.61)**	**(0.30)**	**(0.66)**	**0.46**	**(0.32)**	**0.40**	**0.26**	**0.35**
NPV of Margin after O/H	**(8.2)**							**14.0**				
NPV of Decommissioning	**4.7**							**8.0**				
NPV OF NET MARGIN	**(12.9)**							**6.0**				

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

EASTLAKE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73	3.83
Unit Output (gwh)	1,216	1,097	1,230	1,078	1,105	1,187	1,004	1,206	1,367	1,208	1,205	1,267	1,123
Delivered Output (gwh)	1,158	1,045	1,172	1,027	1,053	1,131	956	1,149	1,302	1,151	1,148	1,207	1,069
Revenues	**22.32**	**21.06**	**25.08**	**23.20**	**24.87**	**28.08**	**25.27**	**38.85**	**45.13**	**40.91**	**41.82**	**45.08**	**40.92**
Fuel-Related Expenses													
Fuel Costs	13.25	12.29	14.20	12.83	13.52	14.93	13.05	15.96	18.60	16.95	17.43	18.85	17.19
Fuel Related ECR Costs	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.85	1.05	1.24	1.14	1.19	1.30	1.20
SO2 Emissions	2.44	2.23	3.77	3.47	3.84	4.50	3.97	5.26	6.57	6.12	6.57	7.51	7.00
Total Fuel	15.79	14.62	18.07	16.40	17.46	19.54	17.98	22.38	26.52	24.33	25.31	27.78	25.52
Non-fuel O&M Expenses													
Variable O&M	1.40	1.30	1.49	1.34	1.41	1.56	1.35	1.67	1.94	1.76	1.80	1.95	1.77
Fixed O&M	3.93	4.11	4.51	4.86	4.49	4.99	4.75	4.73	5.17	5.54	5.14	5.76	5.37
Overhaul	0.05	0.00	0.00	0.00	0.00	0.41	1.39	0.00	0.00	0.00	0.00	0.64	1.43
Subtotal	5.39	5.41	6.00	6.20	5.90	6.96	7.50	6.40	7.11	7.30	6.94	8.35	8.57
FICA	0.16	0.18	0.19	0.20	0.18	0.22	0.18	0.20	0.21	0.22	0.20	0.26	0.20
Property Tax	1.27	1.27	1.27	1.27	1.27	1.27	1.27	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	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Total Non-fuel	7.08	7.12	7.73	7.94	7.62	8.71	9.21	8.14	8.86	9.05	8.68	10.14	10.31
Capital Expenditures	2.02	0.55	5.38	6.00	1.68	3.16	3.60	2.39	0.66	0.91	0.91	1.06	0.78
Direct Expenses	**24.90**	**22.29**	**31.17**	**30.34**	**26.76**	**31.42**	**30.80**	**32.91**	**36.05**	**34.30**	**34.90**	**38.98**	**36.61**
Direct Margin	**(2.59)**	**(1.23)**	**(6.09)**	**(7.14)**	**(1.89)**	**(3.34)**	**(5.52)**	**5.94**	**9.08**	**6.61**	**6.91**	**6.09**	**4.31**
Overhead Allocation	3.39	3.38	4.84	4.65	4.08	4.54	4.84	5.25	5.87	5.43	5.60	6.34	5.81
Expenses incl. Corp O/H	**28.29**	**25.68**	**36.02**	**34.99**	**30.84**	**35.95**	**35.64**	**38.16**	**41.91**	**39.73**	**40.50**	**45.33**	**42.42**
Margin after Corp O/H	**(5.98)**	**(4.61)**	**(10.93)**	**(11.80)**	**(5.97)**	**(7.87)**	**(10.37)**	**0.69**	**3.21**	**1.17**	**1.31**	**(0.25)**	**(1.49)**
Costs per kwh (cents)													
Fuel	1.48	1.52	1.67	1.73	1.79	1.87	2.02	2.09	2.19	2.27	2.36	2.46	2.55
Non-fuel	0.61	0.68	0.66	0.77	0.72	0.77	0.96	0.71	0.68	0.79	0.76	0.84	0.96
Capital Expenditures	0.17	0.05	0.46	0.58	0.16	0.28	0.38	0.21	0.05	0.08	0.08	0.09	0.07
Direct Expenses	**2.27**	**2.26**	**2.79**	**3.09**	**2.68**	**2.92**	**3.36**	**3.01**	**2.92**	**3.13**	**3.20**	**3.39**	**3.59**
Direct Margin	**(0.40)**	**(0.29)**	**(0.71)**	**(0.90)**	**(0.37)**	**(0.49)**	**(0.80)**	**0.37**	**0.55**	**0.42**	**0.44**	**0.34**	**0.24**
Overhead Allocation	0.29	0.32	0.41	0.45	0.39	0.40	0.51	0.46	0.45	0.47	0.49	0.53	0.54
Expenses incl. Corp O/H	**2.56**	**2.58**	**3.20**	**3.54**	**3.06**	**3.32**	**3.87**	**3.47**	**3.37**	**3.61**	**3.69**	**3.92**	**4.13**
Margin after Corp O/H	**(0.69)**	**(0.61)**	**(1.12)**	**(1.35)**	**(0.75)**	**(0.89)**	**(1.31)**	**(0.09)**	**0.10**	**(0.05)**	**(0.04)**	**(0.18)**	**(0.30)**
NPV of Margin after O/H	(24.1)							2.5					
NPV of Decommissioning	4.1							7.0					
NPV OF NET MARGIN	(28.3)							(4.5)					

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

ELRAMA	1999	2000	2001	2002	2003	2004	2005	2006
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43		
Unit Output (gwh)	2,789	2,801	2,810	2,986	2,662	3,040		
Delivered Output (gwh)	2,502	2,513	2,521	2,679	2,388	2,728		
Revenues	**47.74**	**50.32**	**53.43**	**59.76**	**56.26**	**67.31**	**0.00**	
Fuel-Related Expenses								
Fuel Costs	31.50	30.75	31.73	34.55	31.94	37.27		
Fuel Related ECR Costs	6.63	6.81	7.00	7.45	7.15	7.90		
NOx Emissions	5.99	6.33	6.60	7.55	6.46	8.41		
SO2 Emissions	0.55	0.62	(0.31)	(0.29)	(0.40)	(0.32)		
Total Fuel	44.67	44.51	45.02	49.26	45.15	53.27		
Non-fuel O&M Expenses								
Variable O&M	2.80	2.89	2.98	3.24	2.97	3.48		
Fixed O&M	16.16	16.23	17.28	17.11	17.62	17.78		
Overhaul	3.80	1.70	0.00	0.00	3.00	0.00		
Subtotal	22.76	20.82	20.26	20.35	23.59	21.26		
FICA	0.56	0.63	0.64	0.65	0.64	0.70		
Property Tax	0.62	0.62	0.62	0.62	0.62	0.62		
Cap Stock Tax	0.65	0.65	0.65	0.65	0.65	0.65		
Total Non-fuel	24.60	22.72	22.17	22.27	25.50	23.24		
Capital Expenditures	6.13	8.54	5.66	2.73	1.51	1.05		
Direct Expenses	**75.39**	**75.78**	**72.85**	**74.26**	**72.16**	**77.56**		
Direct Margin	**(27.66)**	**(25.46)**	**(19.42)**	**(14.50)**	**(15.90)**	**(10.25)**		
Overhead Allocation	10.26	11.50	11.32	11.39	11.00	11.20		
Expenses incl. Corp O/H	**85.65**	**87.27**	**84.17**	**85.65**	**83.15**	**88.75**		
Margin after Corp O/H	**(37.92)**	**(36.95)**	**(30.73)**	**(25.88)**	**(26.90)**	**(21.44)**		
Costs per kwh (cents)								
Fuel	1.90	1.89	1.90	1.96	2.01	2.08		
Non-fuel	0.98	0.90	0.88	0.83	1.07	0.85		
Capital Expenditures	0.24	0.34	0.22	0.10	0.06	0.04		
Direct Expenses	**3.13**	**3.13**	**3.01**	**2.89**	**3.15**	**2.97**		
Direct Margin	**(1.26)**	**(1.16)**	**(0.93)**	**(0.70)**	**(0.84)**	**(0.54)**		
Overhead Allocation	0.41	0.46	0.45	0.43	0.46	0.41		
Expenses incl. Corp O/H	**3.54**	**3.59**	**3.46**	**3.32**	**3.61**	**3.38**		
Margin after Corp O/H	**(1.67)**	**(1.62)**	**(1.38)**	**(1.13)**	**(1.30)**	**(0.95)**		
NPV of Margin after O/H	**(86.7)**							**0.0**
NPV of Decommissioning	**20.7**							**35.0**
NPV OF NET MARGIN	**(107.4)**							**(35.0)**

DUQUESNE [redacted]HT

Costs of Fossil Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

MANSFIELD 1	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22
Unit Output (gwh)	1,721	1,378	1,860	1,869	1,693	1,885	1,886	1,519	1,973	1,978	1,781	1,973	1,973	1,632	1,865	1,973	1,951
Delivered Output (gwh)	1,561	1,249	1,687	1,695	1,535	1,709	1,710	1,377	1,789	1,794	1,615	1,789	1,789	1,480	1,691	1,789	1,769
Revenues	**30.36**	**25.36**	**35.66**	**37.70**	**35.93**	**42.28**	**44.52**	**46.58**	**62.02**	**63.74**	**58.83**	**66.79**	**68.46**	**58.06**	**67.98**	**73.72**	**74.72**
Fuel-Related Expenses																	
Fuel Costs	25.23	13.65	18.12	18.64	17.38	19.89	20.47	16.86	22.55	23.25	21.55	24.55	25.26	21.48	25.28	27.49	27.98
Fuel Related ECR Costs	3.27	2.72	3.70	3.81	3.57	4.05	4.16	3.49	4.58	4.71	4.38	4.95	5.08	4.36	5.08	5.51	5.59
NOx Emissions	3.04	2.31	3.67	3.84	3.55	4.21	4.40	3.36	5.02	5.23	4.76	5.67	5.92	4.68	5.94	6.70	6.86
SO2 Emissions	(0.13)	(0.19)	(0.21)	(0.23)	(0.28)	(0.26)	(0.28)	(0.39)	(0.31)	(0.33)	(0.41)	(0.39)	(0.43)	(0.58)	(0.53)	(0.53)	(0.58)
Total Fuel	31.41	18.49	25.28	26.06	24.21	27.88	28.75	23.32	31.84	32.87	30.28	34.77	35.84	29.95	35.76	39.16	39.85
Non-fuel O&M Expenses																	
Variable O&M	2.92	2.19	2.94	3.04	2.83	3.21	3.30	2.73	3.63	3.73	3.44	3.90	4.01	3.39	3.97	4.31	4.37
Fixed O&M	4.41	3.10	3.34	3.22	4.77	4.06	4.28	3.52	3.88	3.37	5.83	4.45	4.71	4.74	3.68	3.74	7.33
Overhaul	0.00	2.76	0.00	0.00	0.00	0.00	0.00	2.93	0.00	0.00	0.00	0.00	0.00	2.59	0.81	0.00	0.00
Subtotal	7.33	8.04	6.28	6.26	7.60	7.28	7.58	9.18	7.51	7.10	9.27	8.35	8.72	10.71	8.46	8.06	11.70
FICA	0.22	0.18	0.20	0.20	0.23	0.24	0.22	0.20	0.22	0.21	0.27	0.28	0.24	0.25	0.23	0.24	0.24
Property Tax	0.48	0.48	0.48	0.48	0.48	0.48	0.48	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	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Total Non-fuel	8.52	9.20	7.45	7.43	8.81	8.50	8.78	10.35	8.71	8.29	10.51	9.61	9.94	11.94	9.67	9.28	12.92
Capital Expenditures	0.92	3.41	0.45	0.84	2.97	1.97	0.70	3.20	0.40	0.75	3.45	0.43	0.82	3.72	0.47	0.89	0.86
Direct Expenses	**40.86**	**31.10**	**33.18**	**34.34**	**35.99**	**38.34**	**38.22**	**36.88**	**40.95**	**41.91**	**44.24**	**44.81**	**46.59**	**45.61**	**45.91**	**49.33**	**53.63**
Direct Margin	**(10.49)**	**(5.74)**	**2.48**	**3.36**	**(0.06)**	**3.93**	**6.29**	**9.70**	**21.07**	**21.83**	**14.58**	**21.98**	**21.87**	**12.45**	**22.08**	**24.40**	**21.09**
Overhead Allocation	5.56	4.72	5.16	5.27	5.48	5.54	6.01	5.89	6.66	6.64	7.10	7.29	7.39	7.51	8.00	8.19	9.42
Expenses incl. Corp O/H	**46.42**	**35.81**	**38.34**	**39.61**	**41.47**	**43.88**	**44.23**	**42.77**	**47.61**	**48.55**	**51.34**	**52.10**	**53.98**	**53.12**	**53.91**	**57.52**	**63.05**
Margin after Corp O/H	**(16.05)**	**(10.45)**	**(2.68)**	**(1.91)**	**(5.55)**	**(1.60)**	**0.28**	**3.81**	**14.41**	**15.19**	**7.49**	**14.69**	**14.48**	**4.94**	**14.07**	**16.20**	**11.67**
Costs per kwh (cents)																	
Fuel	2.20	1.65	1.67	1.72	1.76	1.82	1.87	1.89	1.98	2.04	2.09	2.16	2.23	2.25	2.35	2.43	2.50
Non-fuel	0.55	0.74	0.44	0.44	0.57	0.50	0.51	0.75	0.49	0.46	0.65	0.54	0.56	0.81	0.57	0.52	0.73
Capital Expenditures	0.06	0.27	0.03	0.05	0.19	0.11	0.04	0.23	0.02	0.04	0.21	0.02	0.05	0.25	0.03	0.05	0.05
Direct Expenses	**2.80**	**2.66**	**2.14**	**2.21**	**2.53**	**2.43**	**2.43**	**2.88**	**2.49**	**2.54**	**2.95**	**2.72**	**2.83**	**3.31**	**2.95**	**3.00**	**3.28**
Direct Margin	**(0.93)**	**(0.69)**	**(0.06)**	**(0.02)**	**(0.22)**	**(0.00)**	**0.13**	**0.51**	**0.97**	**1.01**	**0.69**	**1.01**	**1.00**	**0.61**	**1.07**	**1.12**	**0.95**
Overhead Allocation	0.36	0.38	0.31	0.31	0.36	0.32	0.35	0.43	0.37	0.37	0.44	0.41	0.41	0.51	0.47	0.46	0.53
Expenses incl. Corp O/H	**3.16**	**3.04**	**2.45**	**2.52**	**2.89**	**2.76**	**2.78**	**3.30**	**2.86**	**2.91**	**3.39**	**3.13**	**3.24**	**3.82**	**3.42**	**3.46**	**3.81**
Margin after Corp O/H	**(1.29)**	**(1.07)**	**(0.37)**	**(0.33)**	**(0.58)**	**(0.33)**	**(0.22)**	**0.08**	**0.60**	**0.64**	**0.25**	**0.60**	**0.59**	**0.10**	**0.60**	**0.66**	**0.41**
NPV of Margin after O/H	**8.2**							**46.9**									
NPV of Decommissioning	**7.4**							**12.6**									
NPV OF NET MARGIN	**0.7**							**34.3**									

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

MANSFIELD 2	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	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)	475	509	393	518	520	483	524	549	423	550	548	496	549	550	423	549	549	541
Delivered Output (gwh)	432	463	358	472	473	440	477	500	385	501	499	452	500	501	385	500	500	493
Revenues	**8.43**	**9.32**	**7.59**	**10.51**	**11.11**	**10.87**	**12.42**	**16.90**	**13.34**	**17.81**	**18.18**	**16.87**	**19.12**	**19.66**	**15.47**	**20.60**	**21.11**	**21.34**
Fuel-Related Expenses																		
Fuel Costs	6.89	4.97	3.79	5.11	5.27	5.04	5.62	6.02	4.77	6.39	6.55	6.10	6.95	7.16	5.66	7.56	7.78	7.89
Fuel Related ECR Costs	0.90	0.98	0.79	1.06	1.09	1.04	1.16	1.24	0.99	1.31	1.34	1.25	1.41	1.45	1.16	1.53	1.57	1.59
NOx Emissions	0.87	0.99	0.72	1.10	1.15	1.10	1.26	1.38	1.00	1.50	1.56	1.43	1.70	1.78	1.29	1.92	2.00	2.05
SO2 Emissions	(0.04)	(0.04)	(0.09)	(0.08)	(0.08)	(0.10)	(0.10)	(0.10)	(0.14)	(0.11)	(0.12)	(0.15)	(0.15)	(0.16)	(0.22)	(0.18)	(0.20)	(0.22)
Total Fuel	8.61	6.90	5.21	7.19	7.43	7.08	7.95	8.55	6.64	9.09	9.33	8.63	9.91	10.24	7.90	10.83	11.16	11.31
Non-fuel O&M Expenses																		
Variable O&M	0.81	0.81	0.62	0.85	0.87	0.79	0.92	0.99	0.78	1.04	1.06	0.99	1.12	1.15	0.90	1.21	1.23	1.25
Fixed O&M	1.20	0.84	0.91	0.88	1.30	1.11	1.16	0.96	1.05	0.92	1.58	1.21	1.28	1.29	1.00	1.02	2.01	1.59
Overhaul	0.00	0.00	0.92	0.00	0.00	0.00	0.00	0.00	0.82	0.00	0.00	0.00	0.00	0.00	0.95	0.00	0.00	0.00
Subtotal	2.01	1.65	2.45	1.72	2.17	1.90	2.08	1.95	2.65	1.96	2.65	2.20	2.40	2.44	2.85	2.22	3.24	2.83
FICA	0.06	0.05	0.05	0.05	0.07	0.06	0.06	0.06	0.05	0.06	0.08	0.07	0.07	0.07	0.06	0.07	0.07	0.10
Property Tax	0.13	0.13	0.13	0.13	0.13	0.13	0.13	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	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Total Non-fuel	2.33	1.97	2.76	2.04	2.50	2.23	2.41	2.27	2.98	2.28	2.99	2.53	2.73	2.78	3.18	2.56	3.58	3.20
Capital Expenditures	0.22	0.25	0.71	0.12	0.15	1.30	0.07	0.17	0.87	0.08	0.18	0.93	0.09	0.19	1.01	0.09	0.21	0.17
Direct Expenses	**11.16**	**9.12**	**8.68**	**9.36**	**10.08**	**10.61**	**10.43**	**10.99**	**10.48**	**11.45**	**12.49**	**12.10**	**12.73**	**13.21**	**12.08**	**13.48**	**14.94**	**14.68**
Direct Margin	**(2.72)**	**0.20**	**(1.10)**	**1.15**	**1.03**	**0.25**	**1.99**	**5.91**	**2.86**	**6.36**	**5.68**	**4.77**	**6.39**	**6.45**	**3.39**	**7.12**	**6.16**	**6.66**
Overhead Allocation	1.52	1.38	1.35	1.43	1.54	1.53	1.64	1.75	1.71	1.81	2.00	1.97	2.02	2.18	2.11	2.24	2.62	2.16
Expenses incl. Corp O/H	**12.68**	**10.51**	**10.03**	**10.79**	**11.62**	**12.14**	**12.07**	**12.74**	**12.18**	**13.27**	**14.50**	**14.07**	**14.75**	**15.38**	**14.19**	**15.72**	**17.57**	**16.84**
Margin after Corp O/H	**(4.24)**	**(1.18)**	**(2.45)**	**(0.28)**	**(0.51)**	**(1.28)**	**0.35**	**4.16**	**1.16**	**4.54**	**3.68**	**2.80**	**4.37**	**4.27**	**1.28**	**4.88**	**3.54**	**4.50**
Costs per kwh (cents)																		
Fuel	2.18	1.67	1.63	1.70	1.75	1.79	1.86	1.91	1.93	2.02	2.08	2.13	2.21	2.27	2.29	2.41	2.48	2.55
Non-fuel	0.54	0.43	0.77	0.43	0.53	0.51	0.51	0.46	0.77	0.46	0.60	0.56	0.55	0.55	0.83	0.51	0.72	0.65
Capital Expenditures	0.05	0.05	0.20	0.03	0.03	0.30	0.02	0.03	0.23	0.02	0.04	0.21	0.02	0.04	0.26	0.02	0.04	0.03
Direct Expenses	**2.77**	**2.15**	**2.60**	**2.16**	**2.31**	**2.59**	**2.38**	**2.40**	**2.93**	**2.49**	**2.72**	**2.90**	**2.77**	**2.86**	**3.38**	**2.94**	**3.24**	**3.23**
Direct Margin	**(0.90)**	**(0.18)**	**(0.52)**	**0.03**	**(0.00)**	**(0.16)**	**0.18**	**0.99**	**0.54**	**1.06**	**0.93**	**0.84**	**1.05**	**1.06**	**0.65**	**1.18**	**0.99**	**1.10**
Overhead Allocation	0.35	0.30	0.38	0.30	0.32	0.35	0.34	0.35	0.44	0.36	0.40	0.44	0.40	0.43	0.55	0.45	0.53	0.44
Expenses incl. Corp O/H	**3.12**	**2.44**	**2.98**	**2.47**	**2.64**	**2.94**	**2.72**	**2.75**	**3.37**	**2.86**	**3.12**	**3.33**	**3.18**	**3.30**	**3.92**	**3.39**	**3.76**	**3.67**
Margin after Corp O/H	**(1.25)**	**(0.47)**	**(0.90)**	**(0.28)**	**(0.33)**	**(0.51)**	**(0.16)**	**0.63**	**0.10**	**0.70**	**0.52**	**0.40**	**0.65**	**0.62**	**0.10**	**0.73**	**0.46**	**0.66**
NPV of Margin after O/H	4.1							15.3										
NPV of Decommissioning	0.5							0.9										
NPV OF NET MARGIN	3.6							14.4										

DUQUESNE LIGHT
Costs of Foss[illegible]nts
$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

MANSFIELD 3	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22	4.33	4.44
Unit Output (gwh)	778	897	910	697	913	917	826	945	945	749	945	945	855	948	945	738	935	948	855
Delivered Output (gwh)	720	830	842	645	845	848	764	875	875	693	874	875	791	877	875	683	865	877	791
Revenues	**13.79**	**16.59**	**17.69**	**14.28**	**19.72**	**20.88**	**19.81**	**29.59**	**30.33**	**24.61**	**31.83**	**32.66**	**30.27**	**34.41**	**35.17**	**28.15**	**36.54**	**37.98**	**35.10**
Fuel-Related Expenses																			
Fuel Costs	11.15	8.69	8.71	6.83	9.20	9.50	8.81	10.34	10.64	8.67	11.25	11.58	10.78	12.28	12.62	10.13	13.21	13.78	12.75
Fuel Related ECR Costs	1.52	1.77	1.85	1.48	1.95	2.01	1.87	2.18	2.24	1.85	2.36	2.42	2.26	2.56	2.62	2.14	2.74	2.85	2.65
NOx Emissions	1.67	2.07	2.20	1.61	2.40	2.51	2.30	2.83	2.95	2.25	3.19	3.33	3.04	3.64	3.78	2.80	4.04	4.30	3.91
SO2 Emissions	0.10	0.12	(0.13)	(0.17)	(0.15)	(0.16)	(0.19)	(0.18)	(0.19)	(0.26)	(0.23)	(0.25)	(0.29)	(0.29)	(0.31)	(0.41)	(0.36)	(0.38)	(0.46)
Total Fuel	14.43	12.66	12.62	9.75	13.40	13.86	12.79	15.17	15.64	12.50	16.58	17.09	15.79	18.20	18.71	14.65	19.63	20.54	18.85
Non-fuel O&M Expenses																			
Variable O&M	1.35	1.45	1.47	1.16	1.56	1.60	1.48	1.73	1.78	1.44	1.86	1.91	1.77	2.01	2.06	1.65	2.14	2.22	2.06
Fixed O&M	2.13	1.50	1.61	1.55	2.30	1.96	2.06	1.70	1.87	1.62	2.81	2.15	2.27	2.28	1.78	1.81	3.57	2.86	2.83
Overhaul	0.00	0.00	0.00	1.24	0.00	0.00	0.00	0.00	0.00	1.32	0.00	0.00	0.00	0.00	0.00	1.59	0.08	0.00	0.00
Subtotal	3.47	2.95	3.08	3.95	3.86	3.56	3.54	3.43	3.65	4.39	4.67	4.05	4.04	4.29	3.83	5.04	5.78	5.08	4.89
FICA	0.10	0.10	0.10	0.09	0.12	0.12	0.10	0.11	0.11	0.09	0.13	0.14	0.11	0.13	0.12	0.10	0.12	0.18	0.19
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	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	0.24	0.24	0.24	0.24	0.24
Total Non-fuel	4.05	3.52	3.65	4.51	4.45	4.15	4.11	4.01	4.23	4.95	5.28	4.66	4.63	4.90	4.42	5.62	6.37	5.74	5.55
Capital Expenditures	1.20	0.36	0.22	1.46	0.17	1.13	1.47	0.19	0.35	1.59	0.21	0.38	1.71	0.22	0.41	1.85	0.25	0.45	1.99
Direct Expenses	**19.69**	**16.54**	**16.49**	**15.72**	**18.02**	**19.13**	**18.37**	**19.37**	**20.22**	**19.04**	**22.06**	**22.14**	**22.13**	**23.32**	**23.55**	**22.12**	**26.25**	**26.72**	**26.39**
Direct Margin	**(5.89)**	**0.05**	**1.21**	**(1.44)**	**1.69**	**1.75**	**1.44**	**10.22**	**10.11**	**5.57**	**9.77**	**10.52**	**8.14**	**11.08**	**11.62**	**6.03**	**10.29**	**11.26**	**8.71**
Overhead Allocation	2.68	2.51	2.56	2.41	2.75	2.76	2.89	3.09	3.29	3.02	3.54	3.60	3.51	3.84	4.11	3.67	4.61	3.93	3.82
Expenses incl. Corp O/H	**22.37**	**19.04**	**19.05**	**18.13**	**20.77**	**21.90**	**21.26**	**22.46**	**23.51**	**22.06**	**25.60**	**25.74**	**25.64**	**27.16**	**27.65**	**25.79**	**30.85**	**30.65**	**30.21**
Margin after Corp O/H	**(8.57)**	**(2.46)**	**(1.36)**	**(3.85)**	**(1.05)**	**(1.01)**	**(1.45)**	**7.13**	**6.82**	**2.55**	**6.23**	**6.92**	**4.63**	**7.24**	**7.52**	**2.35**	**5.68**	**7.33**	**4.89**
Costs per kwh (cents)																			
Fuel	2.19	1.70	1.67	1.69	1.77	1.82	1.87	1.93	1.99	2.01	2.11	2.17	2.22	2.30	2.37	2.39	2.52	2.59	2.64
Non-fuel	0.56	0.42	0.43	0.70	0.53	0.49	0.54	0.46	0.48	0.71	0.60	0.53	0.59	0.56	0.51	0.82	0.74	0.65	0.70
Capital Expenditures	0.17	0.04	0.03	0.23	0.02	0.13	0.19	0.02	0.04	0.23	0.02	0.04	0.22	0.03	0.05	0.27	0.03	0.05	0.25
Direct Expenses	**2.92**	**2.17**	**2.13**	**2.62**	**2.32**	**2.44**	**2.60**	**2.41**	**2.51**	**2.96**	**2.74**	**2.75**	**3.02**	**2.89**	**2.93**	**3.48**	**3.28**	**3.30**	**3.60**
Direct Margin	**(1.05)**	**(0.20)**	**(0.05)**	**(0.43)**	**(0.01)**	**(0.01)**	**(0.04)**	**0.97**	**0.95**	**0.60**	**0.90**	**0.98**	**0.80**	**1.03**	**1.09**	**0.64**	**0.94**	**1.03**	**0.84**
Overhead Allocation	0.37	0.30	0.30	0.37	0.33	0.33	0.38	0.35	0.38	0.44	0.41	0.41	0.44	0.44	0.47	0.54	0.53	0.45	0.48
Expenses incl. Corp O/H	**3.29**	**2.47**	**2.44**	**2.99**	**2.64**	**2.77**	**2.98**	**2.77**	**2.89**	**3.39**	**3.14**	**3.16**	**3.47**	**3.33**	**3.40**	**4.02**	**3.81**	**3.75**	**4.08**
Margin after Corp O/H	**(1.42)**	**(0.50)**	**(0.36)**	**(0.80)**	**(0.33)**	**(0.34)**	**(0.42)**	**0.62**	**0.58**	**0.16**	**0.50**	**0.57**	**0.36**	**0.60**	**0.62**	**0.10**	**0.41**	**0.58**	**0.36**
NPV of Margin after O/H	7.9							30.1											
NPV of Decommissioning	1.4							2.3											
NPV OF NET MARGIN	6.5							27.7											

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

MANSFIELD 3	2018	2019
kwh Market Price (cents)	4.55	4.66
Unit Output (gwh)	945	940
Delivered Output (gwh)	875	870
Revenues	**39.79**	**40.56**
Fuel-Related Expenses		
Fuel Costs	14.49	14.80
Fuel Related ECR Costs	3.00	3.06
NOx Emissions	4.66	4.81
SO2 Emissions	(0.45)	(0.49)
Total Fuel	21.69	22.18
Non-fuel O&M Expenses		
Variable O&M	2.34	2.38
Fixed O&M	3.21	3.28
Overhaul	0.00	0.00
Subtotal	5.55	5.66
FICA	0.19	0.20
Property Tax	0.23	0.23
Cap Stock Tax	0.24	0.24
Total Non-fuel	6.21	6.33
Capital Expenditures	0.27	0.49
Direct Expenses	**28.17**	**29.00**
Direct Margin	**11.62**	**11.56**
Overhead Allocation	4.43	4.30
Expenses incl. Corp O/H	**32.60**	**33.30**
Margin after Corp O/H	**7.19**	**7.26**
Costs per kwh (cents)		
Fuel	2.75	2.82
Non-fuel	0.71	0.73
Capital Expenditures	0.03	0.06
Direct Expenses	**3.49**	**3.61**
Direct Margin	**1.06**	**1.06**
Overhead Allocation	0.51	0.49
Expenses incl. Corp O/H	**3.99**	**4.10**
Margin after Corp O/H	**0.55**	**0.56**
NPV of Margin after O/H		
NPV of Decommissioning		
NPV OF NET MARGIN		

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

BRUNOT ISLAND	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
kwh Market Price (cents)	9.35	9.85	10.40	10.95	11.55	12.15	12.80	16.91	17.34	17.77	18.21	18.67	19.13	19.61
Unit Output (gwh)	0	0	0	0	0	0	0	27	27	27	27	27	27	27
Delivered Output (gwh)	0	0	0	0	0	0	0	25.40	25.40	25.40	25.40	25.40	25.40	25.40
Revenues	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**4.30**	**4.40**	**4.51**	**4.63**	**4.74**	**4.86**	**4.98**
Fuel-Related Expenses														
Fuel Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Fuel Related ECR 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	0.00	0.00
NOx Emissions	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
SO2 Emissions	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
Total Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Non-fuel O&M Expenses														
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Fixed O&M	0.59	0.61	0.62	0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.79	0.00
Overhaul	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
Subtotal	0.59	0.61	0.62	0.64	0.65	0.67	0.69	0.74	0.76	0.78	0.80	0.82	0.83	0.03
FICA	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.00
Property Tax	0.33	0.33	0.33	0.33	0.33	0.33	0.33	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	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Total Non-fuel	1.27	1.29	1.30	1.32	1.34	1.36	1.38	1.43	1.44	1.47	1.48	1.51	1.51	0.70
Capital Expenditures	1.61	0.17	0.17	0.17	0.18	4.38	0.19	0.20	0.20	0.21	0.19	0.19	0.20	0.11
Direct Expenses	**2.88**	**1.46**	**1.47**	**1.50**	**1.52**	**5.74**	**1.57**	**4.09**	**4.18**	**4.27**	**4.34**	**4.45**	**4.53**	**3.71**
Direct Margin	**(2.88)**	**(1.46)**	**(1.47)**	**(1.50)**	**(1.52)**	**(5.74)**	**(1.57)**	**0.21**	**0.23**	**0.24**	**0.28**	**0.29**	**0.33**	**1.28**
Overhead Allocation	0.39	0.22	0.23	0.23	0.23	0.83	0.25	0.65	0.68	0.68	0.70	0.72	0.72	0.61
Expenses incl. Corp O/H	**3.27**	**1.68**	**1.70**	**1.73**	**1.75**	**6.57**	**1.81**	**4.74**	**4.86**	**4.95**	**5.04**	**5.17**	**5.25**	**4.32**
Margin after Corp O/H	**(3.27)**	**(1.68)**	**(1.70)**	**(1.73)**	**(1.75)**	**(6.57)**	**(1.81)**	**(0.44)**	**(0.45)**	**(0.44)**	**(0.41)**	**(0.43)**	**(0.39)**	**0.67**
Costs per kwh (cents)														
Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.82	10.09	10.36	10.64	10.93	11.22	11.52
Non-fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.61	5.68	5.77	5.84	5.95	5.96	0.00
Capital Expenditures	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.79	0.81	0.75	0.77	0.79	0.00
Direct Expenses	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**16.20**	**16.56**	**16.94**	**17.23**	**17.64**	**17.97**	**11.52**
Direct Margin	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.71**	**0.78**	**0.83**	**0.99**	**1.03**	**1.17**	**0.00**
Overhead Allocation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.57	2.68	2.66	2.74	2.85	2.83	0.00
Expenses incl. Corp O/H	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**18.77**	**19.23**	**19.60**	**19.97**	**20.49**	**20.80**	**11.52**
Margin after Corp O/H	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**(1.85)**	**(1.90)**	**(1.83)**	**(1.76)**	**(1.82)**	**(1.66)**	**0.00**
NPV of Margin after O/H	**(8.8)**							**(1.0)**						
NPV of Decommissioning	**8.2**							**13.9**						
NPV OF NET MARGIN	**(17.0)**							**(14.8)**						

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 1	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02
Unit Output (gwh)	2,726	2,874	3,373	2,864	2,864	3,382	2,864	2,864	3,373	2,874	2,864	3,373	2,864	2,874	3,373
Delivered Output (gwh)	2,564	2,703	3,172	2,694	2,694	3,181	2,694	2,694	3,172	2,703	2,694	3,172	2,694	2,703	3,172
Revenues	**48.26**	**53.21**	**65.93**	**59.40**	**62.30**	**77.57**	**69.71**	**91.12**	**109.97**	**96.05**	**98.13**	**118.43**	**103.10**	**106.02**	**127.53**
Fuel-Related Expenses															
Fuel Costs	11.11	11.27	13.25	11.59	11.49	13.94	12.30	12.50	15.20	13.39	13.75	16.73	14.67	15.17	18.38
Fuel Related ECR Costs	2.56	2.70	3.17	2.69	2.69	3.18	2.69	2.69	3.17	2.70	2.69	3.17	2.69	2.70	3.17
Total Fuel	13.68	13.97	16.42	14.29	14.19	17.12	14.99	15.20	18.37	16.09	16.45	19.91	17.37	17.88	21.55
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
Fixed O&M	30.76	24.97	25.62	26.29	27.00	27.73	28.48	29.19	29.92	30.67	31.44	32.22	33.03	33.85	34.70
Overhaul	16.39	13.68	0.00	14.40	14.79	0.00	15.60	16.02	0.00	16.88	17.32	0.00	18.25	18.74	0.00
Subtotal	47.15	38.65	25.62	40.69	41.79	27.73	44.08	45.21	29.92	47.55	48.76	32.22	51.28	52.60	34.70
FICA	1.42	1.45	1.48	1.51	1.54	1.57	1.60	1.64	1.67	1.70	1.74	1.77	1.81	1.84	1.88
Property Tax	2.06	2.06	2.06	2.06	2.06	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	2.15	2.15	2.15	2.15	2.15
Total Non-fuel	52.78	44.31	31.31	46.41	47.53	33.51	49.89	51.06	35.80	53.46	54.70	38.20	57.29	58.65	40.79
Capital Expenditures	6.76	5.69	5.84	5.99	6.16	6.33	6.50	6.68	6.86	7.04	7.23	7.43	7.63	7.84	8.06
	18.49														
Direct Expenses	**73.21**	**63.96**	**53.56**	**66.68**	**67.88**	**56.96**	**71.38**	**72.93**	**61.03**	**76.59**	**78.37**	**65.53**	**82.29**	**84.36**	**70.39**
Direct Margin	**(24.95)**	**(10.75)**	**12.36**	**(7.29)**	**(5.58)**	**20.61**	**(1.67)**	**18.19**	**48.94**	**19.45**	**19.76**	**52.89**	**20.81**	**21.65**	**57.14**
Overhead Allocation	9.96	9.70	8.32	10.23	10.35	8.22	11.23	11.64	9.93	12.14	12.57	10.66	13.05	13.90	12.27
Expenses incl. Corp O/H	**83.18**	**73.67**	**61.89**	**76.91**	**78.22**	**65.18**	**82.61**	**84.57**	**70.96**	**88.73**	**90.95**	**76.20**	**95.34**	**98.26**	**82.67**
Margin after Corp O/H	**(34.91)**	**(20.45)**	**4.04**	**(17.52)**	**(15.93)**	**12.39**	**(12.90)**	**6.55**	**39.01**	**7.32**	**7.18**	**42.23**	**7.76**	**7.75**	**44.87**
Costs per kwh (cents)															
Fuel	0.53	0.52	0.52	0.53	0.53	0.54	0.56	0.56	0.58	0.60	0.61	0.63	0.64	0.66	0.68
Non-fuel	2.06	1.64	0.99	1.72	1.76	1.05	1.85	1.90	1.13	1.98	2.03	1.20	2.13	2.17	1.29
Capital Expenditures	0.26	0.21	0.18	0.22	0.23	0.20	0.24	0.25	0.22	0.26	0.27	0.23	0.28	0.29	0.25
Direct Expenses	**2.86**	**2.37**	**1.69**	**2.48**	**2.52**	**1.79**	**2.65**	**2.71**	**1.92**	**2.83**	**2.91**	**2.07**	**3.05**	**3.12**	**2.22**
Direct Margin	**(0.99)**	**(0.40)**	**0.39**	**(0.29)**	**(0.21)**	**0.64**	**(0.09)**	**0.68**	**1.54**	**0.72**	**0.73**	**1.67**	**0.77**	**0.80**	**1.80**
Overhead Allocation	0.39	0.36	0.26	0.38	0.38	0.26	0.42	0.43	0.31	0.45	0.47	0.34	0.48	0.51	0.39
Expenses incl. Corp O/H	**3.24**	**2.73**	**1.95**	**2.85**	**2.90**	**2.05**	**3.07**	**3.14**	**2.24**	**3.28**	**3.38**	**2.40**	**3.54**	**3.64**	**2.61**
Margin after Corp O/H	**(1.37)**	**(0.76)**	**0.13**	**(0.66)**	**(0.59)**	**0.38**	**(0.51)**	**0.24**	**1.23**	**0.27**	**0.27**	**1.33**	**0.29**	**0.29**	**1.41**
NPV of Margin after O/H	**7.2**							**84.7**							
Overfunded Decomm.	**0.0**							**0.0**							
NPV OF NET MARGIN	**7.2**							**84.7**							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

BEAVER VALLEY 1	**2014**	**2015**
kwh Market Price (cents)	4.12	4.22
Unit Output (gwh)	2,864	3,336
Delivered Output (gwh)	2,694	3,137
Revenues	**111.03**	**132.52**
Fuel-Related Expenses		
Fuel Costs	16.10	19.31
Fuel Related ECR Costs	2.69	3.14
Total Fuel	18.79	22.44
Non-fuel O&M Expenses		
Variable O&M	0.00	0.00
Fixed O&M	35.57	36.46
Overhaul	19.77	0.00
Subtotal	55.33	36.46
FICA	1.92	1.95
Property Tax	2.06	2.06
Cap Stock Tax	2.15	2.15
Total Non-fuel	61.46	42.62
Capital Expenditures	8.28	8.51
Direct Expenses	**88.53**	**73.57**
Direct Margin	**22.50**	**58.95**
Overhead Allocation	14.71	12.92
Expenses incl. Corp O/H	**103.23**	**86.49**
Margin after Corp O/H	**7.79**	**46.04**
Costs per kwh (cents)		
Fuel	0.70	0.72
Non-fuel	2.28	1.36
Capital Expenditures	0.31	0.27
Direct Expenses	**3.29**	**2.35**
Direct Margin	**0.84**	**1.88**
Overhead Allocation	0.55	0.41
Expenses incl. Corp O/H	**3.83**	**2.76**
Margin after Corp O/H	**0.29**	**1.47**
NPV of Margin after O/H		
Overfunded Decomm.		
NPV OF NET MARGIN		

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 2	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02
Unit Output (gwh)	883	994	883	883	991	885	883	991	883	885	991	883	883	994	883
Delivered Output (gwh)	829	934	829	829	931	832	829	931	829	832	931	829	829	934	829
Revenues	**15.47**	**18.37**	**17.32**	**18.11**	**21.52**	**20.28**	**21.26**	**31.49**	**28.74**	**29.55**	**33.91**	**30.95**	**31.72**	**36.62**	**33.33**
Fuel-Related Expenses															
Fuel Costs	3.38	3.96	3.61	3.54	3.93	3.58	3.53	4.04	3.72	3.84	4.44	4.09	4.22	4.90	4.50
Fuel Related ECR Costs	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83
Total Fuel	4.21	4.90	4.44	4.36	4.86	4.41	4.36	4.97	4.54	4.68	5.38	4.92	5.05	5.84	5.32
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
Fixed O&M	8.88	7.22	7.41	7.61	7.81	8.02	8.24	8.45	8.66	8.87	9.10	9.32	9.56	9.79	10.04
Overhaul	3.02	0.00	3.10	3.18	0.00	3.36	3.45	0.00	3.64	3.73	0.00	3.93	4.03	0.00	4.25
Subtotal	11.90	7.22	10.51	10.79	7.81	11.38	11.69	8.45	12.29	12.60	9.10	13.25	13.59	9.79	14.29
FICA	0.40	0.41	0.42	0.43	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
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
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
Total Non-fuel	13.15	8.49	11.78	12.07	9.10	12.68	12.99	9.76	13.62	13.94	10.44	14.60	14.95	11.17	15.68
Capital Expenditures	6.65	4.86	4.99	5.12	5.26	5.40	5.54	5.70	5.84	6.00	6.15	6.32	6.49	6.67	6.85
Direct Expenses	**24.01**	**18.24**	**21.21**	**21.55**	**19.22**	**22.49**	**22.90**	**20.42**	**24.00**	**24.61**	**21.97**	**25.84**	**26.49**	**23.67**	**27.85**
Direct Margin	**(8.54)**	**0.13**	**(3.89)**	**(3.44)**	**2.30**	**(2.20)**	**(1.64)**	**11.07**	**4.74**	**4.94**	**11.94**	**5.11**	**5.23**	**12.95**	**5.48**
Overhead Allocation	3.27	2.77	3.30	3.30	2.93	3.25	3.60	3.26	3.91	3.90	3.52	4.20	4.20	3.90	4.85
Expenses incl. Corp O/H	**27.28**	**21.01**	**24.51**	**24.85**	**22.14**	**25.73**	**26.50**	**23.68**	**27.91**	**28.51**	**25.49**	**30.04**	**30.70**	**27.57**	**32.70**
Margin after Corp O/H	**(11.81)**	**(2.64)**	**(7.19)**	**(6.74)**	**(0.63)**	**(5.45)**	**(5.24)**	**7.81**	**0.83**	**1.04**	**8.42**	**0.91**	**1.03**	**9.05**	**0.63**
Costs per kwh (cents)															
Fuel	0.51	0.52	0.54	0.53	0.52	0.53	0.53	0.53	0.55	0.56	0.58	0.59	0.61	0.63	0.64
Non-fuel	1.59	0.91	1.42	1.46	0.98	1.52	1.57	1.05	1.64	1.68	1.12	1.76	1.80	1.20	1.89
Capital Expenditures	0.80	0.52	0.60	0.62	0.56	0.65	0.67	0.61	0.70	0.72	0.66	0.76	0.78	0.71	0.83
Direct Expenses	**2.90**	**1.95**	**2.56**	**2.60**	**2.06**	**2.70**	**2.76**	**2.19**	**2.90**	**2.96**	**2.36**	**3.12**	**3.20**	**2.54**	**3.36**
Direct Margin	**(1.03)**	**0.02**	**(0.48)**	**(0.41)**	**0.25**	**(0.27)**	**(0.20)**	**1.19**	**0.57**	**0.59**	**1.28**	**0.62**	**0.63**	**1.39**	**0.66**
Overhead Allocation	0.39	0.30	0.40	0.40	0.31	0.39	0.43	0.35	0.47	0.47	0.38	0.51	0.51	0.42	0.59
Expenses incl. Corp O/H	**3.29**	**2.25**	**2.96**	**3.00**	**2.38**	**3.09**	**3.20**	**2.54**	**3.37**	**3.43**	**2.74**	**3.62**	**3.70**	**2.95**	**3.94**
Margin after Corp O/H	**(1.42)**	**(0.28)**	**(0.88)**	**(0.81)**	**(0.07)**	**(0.66)**	**(0.64)**	**0.84**	**0.10**	**0.13**	**0.90**	**0.11**	**0.12**	**0.97**	**0.08**
NPV of Margin after O/H	**(3.8)**							**25.4**							
Underfunded Decomm.	**5.0**							**8.5**							
NPV OF NET MARGIN	**(8.8)**							**16.9**							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

BEAVER VALLEY 2	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	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)	883	991	883	883	991	883	883	991	883	883	991	883	991
Delivered Output (gwh)	829	931	829	829	931	829	829	931	829	829	931	829	931
Revenues	**34.16**	**39.33**	**35.89**	**36.79**	**42.35**	**38.65**	**39.62**	**45.61**	**41.62**	**42.67**	**49.11**	**44.83**	**51.60**
Fuel-Related Expenses													
Fuel Costs	4.64	5.38	4.94	5.09	5.89	5.43	5.59	6.46	5.97	6.13	7.09	6.56	6.73
Fuel Related ECR Costs	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83
Total Fuel	5.47	6.31	5.77	5.92	6.82	6.26	6.42	7.39	6.80	6.96	8.02	7.39	7.56
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
Fixed O&M	10.29	10.55	10.81	11.08	11.36	11.64	11.93	12.23	12.54	12.85	13.17	13.50	13.84
Overhaul	4.37	0.00	4.61	4.73	0.00	4.99	5.13	0.00	5.41	5.55	0.00	5.86	6.02
Subtotal	14.66	10.55	15.42	15.81	11.36	16.63	17.06	12.23	17.94	18.41	13.17	19.36	19.86
FICA	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
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
Total Non-fuel	16.05	11.95	16.86	17.26	12.82	18.11	18.55	13.73	19.46	19.93	14.71	20.91	21.42
Capital Expenditures	7.03	7.22	7.24	7.42	7.61	7.80	7.99	8.19	8.40	8.61	8.82	9.04	9.27
Direct Expenses	**28.55**	**25.48**	**29.87**	**30.60**	**27.25**	**32.16**	**32.95**	**29.32**	**34.65**	**35.50**	**31.55**	**37.34**	**38.25**
Direct Margin	**5.61**	**13.85**	**6.03**	**6.19**	**15.10**	**6.49**	**6.66**	**16.29**	**6.98**	**7.17**	**17.56**	**7.49**	**13.35**
Overhead Allocation	4.74	4.47	4.39	4.42	4.28	4.77	5.20	4.72	5.71	5.69	5.72	6.26	7.51
Expenses incl. Corp O/H	**33.29**	**29.96**	**34.25**	**35.03**	**31.54**	**36.93**	**38.15**	**34.03**	**40.36**	**41.19**	**37.27**	**43.60**	**45.76**
Margin after Corp O/H	**0.87**	**9.37**	**1.64**	**1.76**	**10.81**	**1.72**	**1.47**	**11.57**	**1.27**	**1.47**	**11.85**	**1.23**	**5.84**
Costs per kwh (cents)													
Fuel	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79	0.82	0.84	0.86	0.89	0.81
Non-fuel	1.94	1.28	2.03	2.08	1.38	2.18	2.24	1.48	2.35	2.40	1.58	2.52	2.30
Capital Expenditures	0.85	0.78	0.87	0.90	0.82	0.94	0.96	0.88	1.01	1.04	0.95	1.09	1.00
Direct Expenses	**3.44**	**2.74**	**3.60**	**3.69**	**2.93**	**3.88**	**3.98**	**3.15**	**4.18**	**4.28**	**3.39**	**4.50**	**4.11**
Direct Margin	**0.68**	**1.49**	**0.73**	**0.75**	**1.62**	**0.78**	**0.80**	**1.75**	**0.84**	**0.86**	**1.89**	**0.90**	**1.43**
Overhead Allocation	0.57	0.48	0.53	0.53	0.46	0.58	0.63	0.51	0.69	0.69	0.61	0.76	0.81
Expenses incl. Corp O/H	**4.02**	**3.22**	**4.13**	**4.23**	**3.39**	**4.46**	**4.60**	**3.66**	**4.87**	**4.97**	**4.00**	**5.26**	**4.92**
Margin after Corp O/H	**0.11**	**1.01**	**0.20**	**0.21**	**1.16**	**0.21**	**0.18**	**1.24**	**0.15**	**0.18**	**1.27**	**0.15**	**0.63**
NPV of Margin after O/H													
Underfunded Decomm.													
NPV OF NET MARGIN													

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

PERRY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02
Unit Output (gwh)	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256
Delivered Output (gwh)	1,195	1,347	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195
Revenues	**22.43**	**26.50**	**24.96**	**29.40**	**27.76**	**32.83**	**30.85**	**45.42**	**41.42**	**47.85**	**43.52**	**50.13**	**45.72**	**52.81**	**48.04**
Fuel-Related Expenses															
Fuel Costs	5.25	5.80	5.27	5.95	5.36	6.10	5.69	6.42	5.91	6.87	6.29	7.30	6.70	7.79	7.13
Fuel Related ECR Costs	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
Total Fuel	6.44	7.15	6.46	7.30	6.55	7.44	6.89	7.77	7.10	8.22	7.49	8.64	7.89	9.13	8.32
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
Fixed O&M	16.25	15.25	16.29	16.33	16.75	17.23	17.67	18.11	18.56	19.03	19.50	19.99	20.49	21.00	21.53
Overhaul	3.29	0.00	3.38	0.00	3.56	0.00	3.75	0.00	3.96	0.00	4.16	0.00	4.39	0.00	4.63
Subtotal	19.54	15.25	19.67	16.33	20.30	17.23	21.42	18.11	22.52	19.03	23.67	19.99	24.88	21.00	26.15
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
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
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
Total Non-fuel	33.25	28.95	33.37	30.04	34.00	30.94	35.12	31.81	36.22	32.73	37.37	33.69	38.58	34.70	39.86
Capital Expenditures	5.09	2.35	2.98	2.48	3.15	3.04	3.33	3.22	3.52	3.40	3.72	3.59	3.93	3.80	4.16
Direct Expenses	**44.78**	**38.44**	**42.81**	**39.81**	**43.70**	**41.42**	**45.34**	**42.80**	**46.84**	**44.34**	**48.57**	**45.92**	**50.41**	**47.63**	**52.34**
Direct Margin	**(22.35)**	**(11.94)**	**(17.85)**	**(10.41)**	**(15.95)**	**(8.58)**	**(14.50)**	**2.63**	**(5.43)**	**3.50**	**(5.05)**	**4.21**	**(4.69)**	**5.18**	**(4.30)**
Overhead Allocation	6.09	5.83	6.65	6.11	6.66	5.98	7.13	6.83	7.62	7.03	7.79	7.47	7.99	7.85	9.12
Expenses incl. Corp O/H	**50.87**	**44.27**	**49.47**	**45.91**	**50.37**	**47.40**	**52.47**	**49.63**	**54.47**	**51.37**	**56.37**	**53.40**	**58.40**	**55.48**	**61.46**
Margin after Corp O/H	**(28.44)**	**(17.78)**	**(24.50)**	**(16.51)**	**(22.61)**	**(14.56)**	**(21.63)**	**(4.20)**	**(13.05)**	**(3.52)**	**(12.84)**	**(3.26)**	**(12.68)**	**(2.67)**	**(13.42)**
Costs per kwh (cents)															
Fuel	0.54	0.53	0.54	0.54	0.55	0.55	0.58	0.58	0.59	0.61	0.63	0.64	0.66	0.68	0.70
Non-fuel	2.78	2.15	2.79	2.24	2.85	2.30	2.94	2.37	3.03	2.43	3.13	2.51	3.23	2.58	3.34
Capital Expenditures	0.43	0.17	0.25	0.18	0.26	0.23	0.28	0.24	0.29	0.25	0.31	0.27	0.33	0.28	0.35
Direct Expenses	**3.75**	**2.85**	**3.58**	**2.96**	**3.66**	**3.08**	**3.80**	**3.19**	**3.92**	**3.29**	**4.07**	**3.42**	**4.22**	**3.54**	**4.38**
Direct Margin	**(1.88)**	**(0.88)**	**(1.50)**	**(0.77)**	**(1.35)**	**(0.65)**	**(1.24)**	**0.20**	**(0.45)**	**0.26**	**(0.42)**	**0.31**	**(0.39)**	**0.38**	**(0.36)**
Overhead Allocation	0.51	0.43	0.56	0.45	0.56	0.44	0.60	0.51	0.64	0.52	0.65	0.56	0.67	0.58	0.76
Expenses incl. Corp O/H	**4.26**	**3.29**	**4.14**	**3.42**	**4.22**	**3.52**	**4.39**	**3.70**	**4.56**	**3.82**	**4.72**	**3.98**	**4.89**	**4.12**	**5.14**
Margin after Corp O/H	**(2.39)**	**(1.32)**	**(2.06)**	**(1.23)**	**(1.91)**	**(1.09)**	**(1.83)**	**(0.31)**	**(1.09)**	**(0.26)**	**(1.08)**	**(0.24)**	**(1.06)**	**(0.20)**	**(1.12)**
NPV of Margin after O/H	**(91.8)**							**(41.4)**							
Underfunded Decomm.	**6.5**							**11.0**							
NPV OF NET MARGIN	**(98.3)**							**(52.4)**							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

PERRY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	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)	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,416
Delivered Output (gwh)	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
Revenues	**55.34**	**50.47**	**58.30**	**53.03**	**61.08**	**55.71**	**64.36**	**58.52**	**67.42**	**61.49**	**71.04**	**64.61**	**74.63**
Fuel-Related Expenses													
Fuel Costs	8.25	7.58	8.80	8.04	9.29	8.49	9.82	8.71	9.79	8.71	9.82	8.71	2.43
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	0.33
Total Fuel	9.59	8.78	10.15	9.24	10.63	9.68	11.17	9.91	11.14	9.91	11.17	9.91	2.76
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
Fixed O&M	22.06	22.62	23.18	23.76	24.35	24.96	25.59	26.23	26.88	27.55	28.24	28.95	29.67
Overhaul	0.00	4.88	0.00	5.15	0.00	5.43	0.00	5.58	0.00	5.58	0.00	5.58	0.00
Subtotal	22.06	27.50	23.18	28.91	24.35	30.39	25.59	31.80	26.88	33.13	28.24	34.53	29.67
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
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
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
Total Non-fuel	35.77	41.20	36.88	42.61	38.06	44.10	39.29	45.51	40.59	46.83	41.95	48.23	43.38
Capital Expenditures	4.02	4.40	4.25	4.64	4.48	4.90	4.73	5.17	5.00	5.45	5.27	5.75	5.56
Direct Expenses	**49.38**	**54.37**	**51.28**	**56.49**	**53.17**	**58.67**	**55.19**	**60.58**	**56.72**	**62.19**	**58.38**	**63.89**	**51.70**
Direct Margin	**5.96**	**(3.90)**	**7.02**	**(3.46)**	**7.91**	**(2.96)**	**9.17**	**(2.06)**	**10.71**	**(0.70)**	**12.65**	**0.72**	**22.93**
Overhead Allocation	8.20	9.55	7.53	8.17	8.36	8.70	8.70	9.75	9.35	9.97	10.58	10.71	10.15
Expenses incl. Corp O/H	**57.58**	**63.92**	**58.81**	**64.66**	**61.53**	**67.37**	**63.89**	**70.33**	**66.06**	**72.17**	**68.97**	**74.60**	**61.85**
Margin after Corp O/H	**(2.24)**	**(13.45)**	**(0.51)**	**(11.63)**	**(0.45)**	**(11.66)**	**0.46**	**(11.81)**	**1.36**	**(10.67)**	**2.07**	**(9.99)**	**12.79**
Costs per kwh (cents)													
Fuel	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.83	0.83	0.83	0.83	0.83	0.21
Non-fuel	2.66	3.45	2.74	3.57	2.83	3.69	2.92	3.81	3.02	3.92	3.12	4.04	3.22
Capital Expenditures	0.30	0.37	0.32	0.39	0.33	0.41	0.35	0.43	0.37	0.46	0.39	0.48	0.41
Direct Expenses	**3.68**	**4.55**	**3.81**	**4.73**	**3.96**	**4.91**	**4.10**	**5.07**	**4.22**	**5.21**	**4.34**	**5.35**	**3.84**
Direct Margin	**0.44**	**(0.33)**	**0.52**	**(0.29)**	**0.59**	**(0.25)**	**0.68**	**(0.17)**	**0.80**	**(0.06)**	**0.94**	**0.06**	**1.70**
Overhead Allocation	0.61	0.80	0.56	0.68	0.62	0.73	0.65	0.82	0.70	0.83	0.79	0.90	0.75
Expenses incl. Corp O/H	**4.29**	**5.35**	**4.37**	**5.41**	**4.58**	**5.64**	**4.74**	**5.89**	**4.92**	**6.04**	**5.12**	**6.24**	**4.59**
Margin after Corp O/H	**(0.17)**	**(1.13)**	**(0.04)**	**(0.97)**	**(0.03)**	**(0.98)**	**0.03**	**(0.99)**	**0.10**	**(0.89)**	**0.15**	**(0.84)**	**0.95**
NPV of Margin after O/H													
Underfunded Decomm.													
NPV OF NET MARGIN													

DUQUESNE LIGHT COMPANY
Plant Present Values
$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

MARGIN STREAM BEGINNING 1/1/99

	Plant Margin	Decommissioning	Net Plant Value
Fossil Plants:			
Cheswick	33.7	(13.9)	19.8
Sammis	13.7	(4.7)	9.0
Eastlake	0.0	(4.1)	(4.1)
Elrama	0.0	(20.7)	(20.7)
Mansfield 1	54.3	(7.4)	46.8
Mansfield 2	18.1	(0.5)	17.5
Mansfield 3	37.1	(1.4)	35.7
Brunot Island	0.0	(8.2)	(8.2)
Phillips	0.0	(5.6)	(5.6)
Total Fossil	**156.8**	**(66.5)**	**90.3**
Nuclear Plants:			
Beaver Valley 1	86.1	(25.5)	60.6
Beaver Valley 2	35.4	(10.3)	25.1
Perry	0.0	(21.6)	(21.6)
Total Nuclear	**121.5**	**(57.4)**	**64.1**
TOTAL PLANTS	**$278.3**	**($123.9)**	**$154.4**

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

CHESWICK	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37
Unit Output (gwh)	3,791	3,837	3,662	4,017	3,922	3,471	4,147	4,235	4,062	4,425	4,231	3,707	4,413	4,249	4,062	4,374
Delivered Output (gwh)	3,608	3,652	3,485	3,823	3,733	3,303	3,947	4,030	3,866	4,211	4,027	3,528	4,200	4,044	3,866	4,163
Revenues	69.28	74.18	74.65	86.08	88.41	82.99	103.34	177.62	174.64	195.01	191.14	171.65	209.42	206.68	202.54	223.56
Fuel-Related Expenses																
Fuel Costs	44.97	47.14	46.27	51.78	51.87	47.65	58.41	61.67	60.69	68.62	70.81	65.11	79.74	79.21	78.70	88.19
Fuel Related ECR Costs	0.90	0.92	0.95	0.97	1.00	1.03	1.05	1.08	1.11	1.14	1.17	1.20	1.23	1.26	1.30	1.32
NOx Emissions	5.27	5.46	5.41	6.56	6.59	5.42	7.82	8.24	8.17	9.60	9.34	7.63	10.85	10.87	10.49	12.08
SO2 Emissions	0.63	0.73	3.41	4.27	4.42	3.86	5.59	6.16	6.23	7.64	7.69	6.64	9.49	9.68	9.71	11.70
Total Fuel	51.77	54.25	56.04	63.58	63.88	57.95	72.86	77.14	76.21	87.00	89.01	80.58	101.32	101.03	100.20	113.29
Non-fuel O&M Expenses																
Variable O&M	2.78	2.89	2.83	3.18	3.19	2.90	3.56	3.73	3.67	4.11	4.03	3.62	4.43	4.38	4.30	4.75
Fixed O&M	13.05	12.06	14.00	13.66	12.42	9.88	14.56	13.15	15.38	15.33	14.11	9.12	16.38	15.26	17.69	17.55
Overhaul	0.00	0.00	0.00	0.00	0.00	15.86	0.00	0.00	0.00	0.00	0.00	18.56	0.00	0.00	0.00	0.00
Subtotal	15.83	14.95	16.83	16.84	15.61	28.64	18.12	16.88	19.06	19.43	18.14	31.30	20.81	19.63	21.98	22.30
Carbon Injection Costs							2.68	3.01	2.80	2.81	3.09	2.52	2.93	3.33	3.13	3.07
FICA	0.47	0.50	0.53	0.53	0.48	0.42	0.52	0.53	0.57	0.58	0.52	0.43	0.58	0.60	0.67	0.68
Property Tax	0.84	0.84	0.84	0.84	0.84	0.84	0.84	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	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Total Non-fuel	18.02	17.16	19.08	19.09	17.82	30.79	23.05	22.14	24.14	24.54	23.47	35.96	26.04	25.28	27.50	27.76
Capital Expenditures	7.17	12.20	4.79	4.93	20.21	44.57	5.40	5.56	5.72	5.89	6.08	15.46	4.96	3.58	2.12	1.53
Direct Expenses	76.95	83.62	79.91	87.61	101.90	133.30	101.31	104.83	106.07	117.43	118.55	132.01	132.31	129.89	129.82	142.58
Direct Margin	(7.68)	(9.44)	(5.26)	(1.52)	(13.49)	(50.32)	2.03	72.79	68.57	77.57	72.59	39.64	77.11	76.80	72.73	80.98
Overhead Allocation	10.47	12.69	12.42	13.43	15.53	19.24	15.93	16.73	17.26	18.61	19.02	21.48	20.99	21.40	22.63	23.68
Expenses incl. Corp O/H	87.42	96.31	92.33	101.04	117.43	152.54	117.24	121.57	123.33	136.04	137.57	153.49	153.30	151.29	152.45	166.27
Margin after Corp O/H	(18.15)	(22.12)	(17.68)	(14.96)	(29.02)	(69.56)	(13.91)	56.06	51.30	58.97	53.57	18.16	56.12	55.39	50.10	57.29
Costs per kwh (cents)																
Fuel	1.51	1.56	1.69	1.75	1.80	1.84	1.94	2.01	2.07	2.16	2.31	2.39	2.52	2.61	2.70	2.84
Non-fuel	0.50	0.47	0.55	0.50	0.48	0.93	0.58	0.55	0.62	0.58	0.58	1.02	0.62	0.63	0.71	0.67
Capital Expenditures	0.20	0.33	0.14	0.13	0.54	1.35	0.14	0.14	0.15	0.14	0.15	0.44	0.12	0.09	0.05	0.04
Direct Expenses	2.21	2.37	2.37	2.37	2.82	4.12	2.66	2.69	2.84	2.89	3.04	3.84	3.26	3.32	3.47	3.54
Direct Margin	(0.34)	(0.40)	(0.29)	(0.18)	(0.51)	(1.69)	(0.10)	1.71	1.68	1.74	1.70	1.02	1.73	1.79	1.77	1.83
Overhead Allocation	0.29	0.35	0.36	0.35	0.42	0.58	0.40	0.42	0.45	0.44	0.47	0.61	0.50	0.53	0.59	0.57
Expenses incl. Corp O/H	2.50	2.72	2.73	2.73	3.23	4.71	3.06	3.11	3.29	3.33	3.52	4.45	3.76	3.85	4.05	4.11
Margin after Corp O/H	(0.63)	(0.75)	(0.65)	(0.54)	(0.92)	(2.28)	(0.50)	1.30	1.23	1.30	1.23	0.41	1.23	1.26	1.18	1.26
NPV of Margin after O/H	33.7							194.5								
NPV of Decommissioning	13.9							23.6								
NPV OF NET MARGIN	19.8							170.9								

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

SAMMIS	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87
Unit Output (gwh)	1,258	1,381	1,167	1,389	1,304	1,418	1,315	1,558	1,290	1,563	1,437	1,537
Delivered Output (gwh)	1,206	1,324	1,119	1,331	1,250	1,359	1,261	1,493	1,236	1,498	1,378	1,474
Revenues	**23.35**	**26.97**	**23.87**	**30.12**	**29.80**	**34.11**	**33.33**	**65.82**	**55.85**	**69.37**	**65.40**	**71.69**
Fuel-Related Expenses												
Fuel Costs	15.94	18.62	16.46	19.99	19.48	21.51	20.63	23.77	20.33	25.67	24.55	27.34
Fuel Related ECR Costs	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	1.67	2.05	1.77	2.24	2.15	2.39
SO2 Emissions	(0.70)	(0.65)	0.32	0.57	0.52	0.69	0.61	0.98	0.66	1.14	1.02	1.27
Total Fuel	15.26	18.00	16.80	20.59	20.02	22.23	22.94	26.83	22.80	29.08	27.75	31.03
Non-fuel O&M Expenses												
Variable O&M	1.68	1.83	1.51	1.84	1.78	1.97	1.88	2.29	1.93	2.40	2.26	2.48
Fixed O&M	5.72	3.68	3.33	3.71	5.00	4.01	5.22	4.29	3.75	4.80	4.63	4.71
Overhaul	0.00	0.00	3.45	0.00	0.00	0.00	0.00	0.00	4.00	0.00	0.00	0.00
Subtotal	7.39	5.51	8.29	5.54	6.78	5.98	7.10	6.58	9.68	7.19	6.89	7.18
FICA	0.22	0.18	0.15	0.18	0.21	0.20	0.21	0.21	0.17	0.21	0.20	0.24
Property Tax	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49
Cap Stock Tax	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Total Non-fuel	9.41	7.48	10.24	7.51	8.78	7.97	9.10	8.58	11.64	9.20	8.88	9.22
Capital Expenditures	1.33	0.19	3.59	1.11	1.36	0.44	1.43	0.22	4.16	0.49	1.59	0.52
Direct Expenses	**25.99**	**25.67**	**30.63**	**29.21**	**30.17**	**30.65**	**33.47**	**35.63**	**38.60**	**38.77**	**38.21**	**40.76**
Direct Margin	**(2.64)**	**1.30**	**(6.76)**	**0.92**	**(0.37)**	**3.46**	**(0.14)**	**30.18**	**17.24**	**30.60**	**27.18**	**30.93**
Overhead Allocation	3.54	3.89	4.76	4.48	4.60	4.42	5.26	5.69	6.28	6.14	6.13	6.63
Expenses incl. Corp O/H	**29.53**	**29.57**	**35.39**	**33.69**	**34.77**	**35.07**	**38.74**	**41.32**	**44.89**	**44.91**	**44.34**	**47.39**
Margin after Corp O/H	**(6.18)**	**(2.60)**	**(11.52)**	**(3.56)**	**(4.97)**	**(0.96)**	**(5.40)**	**24.50**	**10.96**	**24.46**	**21.05**	**24.30**
Costs per kwh (cents)												
Fuel	1.40	1.50	1.64	1.68	1.74	1.78	1.97	1.95	2.00	2.10	2.18	2.27
Non-fuel	0.78	0.57	0.91	0.56	0.70	0.59	0.72	0.57	0.94	0.61	0.64	0.63
Capital Expenditures	0.11	0.01	0.32	0.08	0.11	0.03	0.11	0.01	0.34	0.03	0.12	0.04
Direct Expenses	**2.29**	**2.08**	**2.87**	**2.33**	**2.56**	**2.40**	**2.80**	**2.54**	**3.28**	**2.75**	**2.94**	**2.93**
Direct Margin	**(0.42)**	**(0.11)**	**(0.79)**	**(0.14)**	**(0.25)**	**0.03**	**(0.24)**	**1.87**	**1.24**	**1.88**	**1.81**	**1.93**
Overhead Allocation	0.29	0.29	0.43	0.34	0.37	0.33	0.42	0.38	0.51	0.41	0.44	0.45
Expenses incl. Corp O/H	**2.59**	**2.37**	**3.30**	**2.67**	**2.92**	**2.73**	**3.22**	**2.92**	**3.79**	**3.16**	**3.38**	**3.38**
Margin after Corp O/H	**(0.72)**	**(0.40)**	**(1.22)**	**(0.48)**	**(0.61)**	**(0.30)**	**(0.66)**	**1.49**	**0.73**	**1.47**	**1.36**	**1.48**
NPV of Margin after O/H	13.7							51.0				
NPV of Decommissioning	4.7							8.0				
NPV OF NET MARGIN	9.0							43.0				

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

EASTLAKE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87	4.99
Unit Output (gwh)	1,216	1,097	1,230	1,078	1,105	1,187	1,004	1,206	1,367	1,208	1,205	1,267	1,123
Delivered Output (gwh)	1,158	1,045	1,172	1,027	1,053	1,131	956	1,149	1,302	1,151	1,148	1,207	1,069
Revenues	**22.32**	**21.06**	**25.08**	**23.20**	**24.87**	**28.08**	**25.27**	**50.62**	**58.80**	**53.30**	**54.49**	**58.73**	**53.33**
Fuel-Related Expenses													
Fuel Costs	13.25	12.29	14.20	12.83	13.52	14.93	13.05	15.96	18.60	16.95	17.43	18.85	17.19
Fuel Related ECR Costs	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.85	1.05	1.24	1.14	1.19	1.30	1.20
SO2 Emissions	2.44	2.23	3.77	3.47	3.84	4.50	3.97	5.26	6.57	6.12	6.57	7.51	7.00
Total Fuel	15.79	14.62	18.07	16.40	17.46	19.54	17.98	22.38	26.52	24.33	25.31	27.78	25.52
Non-fuel O&M Expenses													
Variable O&M	1.40	1.30	1.49	1.34	1.41	1.56	1.35	1.67	1.94	1.76	1.80	1.95	1.77
Fixed O&M	3.93	4.11	4.51	4.86	4.49	4.99	4.75	4.73	5.17	5.54	5.14	5.76	5.37
Overhaul	0.05	0.00	0.00	0.00	0.00	0.41	1.39	0.00	0.00	0.00	0.00	0.64	1.43
Subtotal	5.39	5.41	6.00	6.20	5.90	6.96	7.50	6.40	7.11	7.30	6.94	8.35	8.57
FICA	0.16	0.18	0.19	0.20	0.18	0.22	0.18	0.20	0.21	0.22	0.20	0.26	0.20
Property Tax	1.27	1.27	1.27	1.27	1.27	1.27	1.27	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	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Total Non-fuel	7.08	7.12	7.73	7.94	7.62	8.71	9.21	8.14	8.86	9.05	8.68	10.14	10.31
Capital Expenditures	2.02	0.55	5.38	6.00	1.68	3.16	3.60	2.39	0.66	0.91	0.91	1.06	0.78
Direct Expenses	**24.90**	**22.29**	**31.17**	**30.34**	**26.76**	**31.42**	**30.80**	**32.91**	**36.05**	**34.30**	**34.90**	**38.98**	**36.61**
Direct Margin	**(2.59)**	**(1.23)**	**(6.09)**	**(7.14)**	**(1.89)**	**(3.34)**	**(5.52)**	**17.71**	**22.76**	**19.00**	**19.58**	**19.75**	**16.72**
Overhead Allocation	3.39	3.38	4.84	4.65	4.08	4.54	4.84	5.25	5.87	5.43	5.60	6.34	5.81
Expenses incl. Corp O/H	**28.29**	**25.68**	**36.02**	**34.99**	**30.84**	**35.95**	**35.64**	**38.16**	**41.91**	**39.73**	**40.50**	**45.33**	**42.42**
Margin after Corp O/H	**(5.98)**	**(4.61)**	**(10.93)**	**(11.80)**	**(5.97)**	**(7.87)**	**(10.37)**	**12.46**	**16.89**	**13.57**	**13.98**	**13.41**	**10.91**
Costs per kwh (cents)													
Fuel	1.48	1.52	1.67	1.73	1.79	1.87	2.02	2.09	2.19	2.27	2.36	2.46	2.55
Non-fuel	0.61	0.68	0.66	0.77	0.72	0.77	0.96	0.71	0.68	0.79	0.76	0.84	0.96
Capital Expenditures	0.17	0.05	0.46	0.58	0.16	0.28	0.38	0.21	0.05	0.08	0.08	0.09	0.07
Direct Expenses	**2.27**	**2.26**	**2.79**	**3.09**	**2.68**	**2.92**	**3.36**	**3.01**	**2.92**	**3.13**	**3.20**	**3.39**	**3.59**
Direct Margin	**(0.40)**	**(0.29)**	**(0.71)**	**(0.90)**	**(0.37)**	**(0.49)**	**(0.80)**	**1.40**	**1.60**	**1.50**	**1.55**	**1.47**	**1.40**
Overhead Allocation	0.29	0.32	0.41	0.45	0.39	0.40	0.51	0.46	0.45	0.47	0.49	0.53	0.54
Expenses incl. Corp O/H	**2.56**	**2.58**	**3.20**	**3.54**	**3.06**	**3.32**	**3.87**	**3.47**	**3.37**	**3.61**	**3.69**	**3.92**	**4.13**
Margin after Corp O/H	**(0.69)**	**(0.61)**	**(1.12)**	**(1.35)**	**(0.75)**	**(0.89)**	**(1.31)**	**0.94**	**1.15**	**1.03**	**1.06**	**0.95**	**0.85**
NPV of Margin after O/H	**(2.9)**							**38.5**					
NPV of Decommissioning	**4.1**							**7.0**					
NPV OF NET MARGIN	**(7.1)**							**31.5**					

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

ELRAMA	1999	2000	2001	2002	2003	2004	2005	2006
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43		
Unit Output (gwh)	2,789	2,801	2,810	2,986	2,662	3,040		
Delivered Output (gwh)	2,502	2,513	2,521	2,679	2,388	2,728		
Revenues	**47.74**	**50.32**	**53.43**	**59.76**	**56.26**	**67.31**	**0.00**	
Fuel-Related Expenses								
Fuel Costs	31.50	30.75	31.73	34.55	31.94	37.27		
Fuel Related ECR Costs	6.63	6.81	7.00	7.45	7.15	7.90		
NOx Emissions	5.99	6.33	6.60	7.55	6.46	8.41		
SO2 Emissions	0.55	0.62	(0.31)	(0.29)	(0.40)	(0.32)		
Total Fuel	44.67	44.51	45.02	49.26	45.15	53.27		
Non-fuel O&M Expenses								
Variable O&M	2.80	2.89	2.98	3.24	2.97	3.48		
Fixed O&M	16.16	16.23	17.28	17.11	17.62	17.78		
Overhaul	3.80	1.70	0.00	0.00	3.00	0.00		
Subtotal	22.76	20.82	20.26	20.35	23.59	21.26		
FICA	0.56	0.63	0.64	0.65	0.64	0.70		
Property Tax	0.62	0.62	0.62	0.62	0.62	0.62		
Cap Stock Tax	0.65	0.65	0.65	0.65	0.65	0.65		
Total Non-fuel	24.60	22.72	22.17	22.27	25.50	23.24		
Capital Expenditures	6.13	8.54	5.66	2.73	1.51	1.05		
Direct Expenses	**75.39**	**75.78**	**72.85**	**74.26**	**72.16**	**77.56**		
Direct Margin	**(27.66)**	**(25.46)**	**(19.42)**	**(14.50)**	**(15.90)**	**(10.25)**		
Overhead Allocation	10.26	11.50	11.32	11.39	11.00	11.20		
Expenses incl. Corp O/H	**85.65**	**87.27**	**84.17**	**85.65**	**83.15**	**88.75**		
Margin after Corp O/H	**(37.92)**	**(36.95)**	**(30.73)**	**(25.88)**	**(26.90)**	**(21.44)**		
Costs per kwh (cents)								
Fuel	1.90	1.89	1.90	1.96	2.01	2.08		
Non-fuel	0.98	0.90	0.88	0.83	1.07	0.85		
Capital Expenditures	0.24	0.34	0.22	0.10	0.06	0.04		
Direct Expenses	**3.13**	**3.13**	**3.01**	**2.89**	**3.15**	**2.97**		
Direct Margin	**(1.26)**	**(1.16)**	**(0.93)**	**(0.70)**	**(0.84)**	**(0.54)**		
Overhead Allocation	0.41	0.46	0.45	0.43	0.46	0.41		
Expenses incl. Corp O/H	**3.54**	**3.59**	**3.46**	**3.32**	**3.61**	**3.38**		
Margin after Corp O/H	**(1.67)**	**(1.62)**	**(1.38)**	**(1.13)**	**(1.30)**	**(0.95)**		
NPV of Margin after O/H	(86.7)						0.0	
NPV of Decommissioning	20.7						35.0	
NPV OF NET MARGIN	(107.4)						(35.0)	

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

MANSFIELD 1	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50
Unit Output (gwh)	1,721	1,378	1,860	1,869	1,693	1,885	1,886	1,519	1,973	1,978	1,781	1,973	1,973	1,632	1,865	1,973	1,951
Delivered Output (gwh)	1,561	1,249	1,687	1,695	1,535	1,709	1,710	1,377	1,789	1,794	1,615	1,789	1,789	1,480	1,691	1,789	1,769
Revenues	**30.36**	**25.36**	**35.66**	**37.70**	**35.93**	**42.28**	**44.52**	**60.70**	**80.81**	**83.06**	**76.65**	**87.03**	**89.20**	**75.65**	**88.58**	**96.06**	**97.36**
Fuel-Related Expenses																	
Fuel Costs	25.23	13.65	18.12	18.64	17.38	19.89	20.47	16.86	22.55	23.25	21.55	24.55	25.26	21.48	25.28	27.49	27.98
Fuel Related ECR Costs	3.27	2.72	3.70	3.81	3.57	4.05	4.16	3.49	4.58	4.71	4.38	4.95	5.08	4.36	5.08	5.51	5.59
NOx Emissions	3.04	2.31	3.67	3.84	3.55	4.21	4.40	3.36	5.02	5.23	4.76	5.67	5.92	4.68	5.94	6.70	6.86
SO2 Emissions	(0.13)	(0.19)	(0.21)	(0.23)	(0.28)	(0.26)	(0.28)	(0.39)	(0.31)	(0.33)	(0.41)	(0.39)	(0.43)	(0.58)	(0.53)	(0.53)	(0.58)
Total Fuel	31.41	18.49	25.28	26.06	24.21	27.88	28.75	23.32	31.84	32.87	30.28	34.77	35.84	29.95	35.76	39.16	39.85
Non-fuel O&M Expenses																	
Variable O&M	2.92	2.19	2.94	3.04	2.83	3.21	3.30	2.73	3.63	3.73	3.44	3.90	4.01	3.39	3.97	4.31	4.37
Fixed O&M	4.41	3.10	3.34	3.22	4.77	4.06	4.28	3.52	3.88	3.37	5.83	4.45	4.71	4.74	3.68	3.74	7.33
Overhaul	0.00	2.76	0.00	0.00	0.00	0.00	0.00	2.93	0.00	0.00	0.00	0.00	0.00	2.59	0.81	0.00	0.00
Subtotal	7.33	8.04	6.28	6.26	7.60	7.28	7.58	9.18	7.51	7.10	9.27	8.35	8.72	10.71	8.46	8.06	11.70
FICA	0.22	0.18	0.20	0.20	0.23	0.24	0.22	0.20	0.22	0.21	0.27	0.28	0.24	0.25	0.23	0.24	0.24
Property Tax	0.48	0.48	0.48	0.48	0.48	0.48	0.48	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	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Total Non-fuel	8.52	9.20	7.45	7.43	8.81	8.50	8.78	10.35	8.71	8.29	10.51	9.61	9.94	11.94	9.67	9.28	12.92
Capital Expenditures	0.92	3.41	0.45	0.84	2.97	1.97	0.70	3.20	0.40	0.75	3.45	0.43	0.82	3.72	0.47	0.89	0.86
Direct Expenses	**40.86**	**31.10**	**33.18**	**34.34**	**35.99**	**38.34**	**38.22**	**36.88**	**40.95**	**41.91**	**44.24**	**44.81**	**46.59**	**45.61**	**45.91**	**49.33**	**53.63**
Direct Margin	**(10.49)**	**(5.74)**	**2.48**	**3.36**	**(0.06)**	**3.93**	**6.29**	**23.82**	**39.87**	**41.15**	**32.41**	**42.22**	**42.61**	**30.04**	**42.68**	**46.74**	**43.73**
Overhead Allocation	5.56	4.72	5.16	5.27	5.48	5.54	6.01	5.89	6.66	6.64	7.10	7.29	7.39	7.51	8.00	8.19	9.42
Expenses incl. Corp O/H	**46.42**	**35.81**	**38.34**	**39.61**	**41.47**	**43.88**	**44.23**	**42.77**	**47.61**	**48.55**	**51.34**	**52.10**	**53.98**	**53.12**	**53.91**	**57.52**	**63.05**
Margin after Corp O/H	**(16.05)**	**(10.45)**	**(2.68)**	**(1.91)**	**(5.55)**	**(1.60)**	**0.28**	**17.93**	**33.20**	**34.51**	**25.31**	**34.93**	**35.22**	**22.53**	**34.68**	**38.54**	**34.31**
Costs per kwh (cents)																	
Fuel	2.20	1.65	1.67	1.72	1.76	1.82	1.87	1.89	1.98	2.04	2.09	2.16	2.23	2.25	2.35	2.43	2.50
Non-fuel	0.55	0.74	0.44	0.44	0.57	0.50	0.51	0.75	0.49	0.46	0.65	0.54	0.56	0.81	0.57	0.52	0.73
Capital Expenditures	0.06	0.27	0.03	0.05	0.19	0.11	0.04	0.23	0.02	0.04	0.21	0.02	0.05	0.25	0.03	0.05	0.05
Direct Expenses	**2.80**	**2.66**	**2.14**	**2.21**	**2.53**	**2.43**	**2.43**	**2.88**	**2.49**	**2.54**	**2.95**	**2.72**	**2.83**	**3.31**	**2.95**	**3.00**	**3.28**
Direct Margin	**(0.93)**	**(0.69)**	**(0.06)**	**(0.02)**	**(0.22)**	**(0.00)**	**0.13**	**1.53**	**2.03**	**2.09**	**1.79**	**2.14**	**2.16**	**1.80**	**2.29**	**2.37**	**2.23**
Overhead Allocation	0.36	0.38	0.31	0.31	0.36	0.32	0.35	0.43	0.37	0.37	0.44	0.41	0.41	0.51	0.47	0.46	0.53
Expenses incl. Corp O/H	**3.16**	**3.04**	**2.45**	**2.52**	**2.89**	**2.76**	**2.78**	**3.30**	**2.86**	**2.91**	**3.39**	**3.13**	**3.24**	**3.82**	**3.42**	**3.46**	**3.81**
Margin after Corp O/H	**(1.29)**	**(1.07)**	**(0.37)**	**(0.33)**	**(0.58)**	**(0.33)**	**(0.22)**	**1.10**	**1.65**	**1.72**	**1.35**	**1.73**	**1.75**	**1.29**	**1.82**	**1.91**	**1.69**
NPV of Margin after O/H	54.3							125.0									
NPV of Decommissioning	7.4							12.6									
NPV OF NET MARGIN	46.8							112.4									

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

MANSFIELD 2	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	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)	475	509	393	518	520	483	524	549	423	550	548	496	549	550	423	549	549	541
Delivered Output (gwh)	432	463	358	472	473	440	477	500	385	501	499	452	500	501	385	500	500	493
Revenues	**8.43**	**9.32**	**7.59**	**10.51**	**11.11**	**10.87**	**12.42**	**22.03**	**17.38**	**23.20**	**23.69**	**21.98**	**24.92**	**25.61**	**20.16**	**26.84**	**27.50**	**27.81**
Fuel-Related Expenses																		
Fuel Costs	6.89	4.97	3.79	5.11	5.27	5.04	5.62	6.02	4.77	6.39	6.55	6.10	6.95	7.16	5.66	7.56	7.78	7.89
Fuel Related ECR Costs	0.90	0.98	0.79	1.06	1.09	1.04	1.16	1.24	0.99	1.31	1.34	1.25	1.41	1.45	1.16	1.53	1.57	1.59
NOx Emissions	0.87	0.99	0.72	1.10	1.15	1.10	1.26	1.38	1.00	1.50	1.56	1.43	1.70	1.78	1.29	1.92	2.00	2.05
SO2 Emissions	(0.04)	(0.04)	(0.09)	(0.08)	(0.08)	(0.10)	(0.10)	(0.10)	(0.14)	(0.11)	(0.12)	(0.15)	(0.15)	(0.16)	(0.22)	(0.18)	(0.20)	(0.22)
Total Fuel	8.61	6.90	5.21	7.19	7.43	7.08	7.95	8.55	6.64	9.09	9.33	8.63	9.91	10.24	7.90	10.83	11.16	11.31
Non-fuel O&M Expenses																		
Variable O&M	0.81	0.81	0.62	0.85	0.87	0.79	0.92	0.99	0.78	1.04	1.06	0.99	1.12	1.15	0.90	1.21	1.23	1.25
Fixed O&M	1.20	0.84	0.91	0.88	1.30	1.11	1.16	0.96	1.05	0.92	1.58	1.21	1.28	1.29	1.00	1.02	2.01	1.59
Overhaul	0.00	0.00	0.92	0.00	0.00	0.00	0.00	0.00	0.82	0.00	0.00	0.00	0.00	0.00	0.95	0.00	0.00	0.00
Subtotal	2.01	1.65	2.45	1.72	2.17	1.90	2.08	1.95	2.65	1.96	2.65	2.20	2.40	2.44	2.85	2.22	3.24	2.83
FICA	0.06	0.05	0.05	0.05	0.07	0.06	0.06	0.06	0.05	0.06	0.08	0.07	0.07	0.07	0.06	0.07	0.07	0.10
Property Tax	0.13	0.13	0.13	0.13	0.13	0.13	0.13	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	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Total Non-fuel	2.33	1.97	2.76	2.04	2.50	2.23	2.41	2.27	2.98	2.28	2.99	2.53	2.73	2.78	3.18	2.56	3.58	3.20
Capital Expenditures	0.22	0.25	0.71	0.12	0.15	1.30	0.07	0.17	0.87	0.08	0.18	0.93	0.09	0.19	1.01	0.09	0.21	0.17
Direct Expenses	**11.16**	**9.12**	**8.68**	**9.36**	**10.08**	**10.61**	**10.43**	**10.99**	**10.48**	**11.45**	**12.49**	**12.10**	**12.73**	**13.21**	**12.08**	**13.48**	**14.94**	**14.68**
Direct Margin	**(2.72)**	**0.20**	**(1.10)**	**1.15**	**1.03**	**0.25**	**1.99**	**11.04**	**6.90**	**11.75**	**11.19**	**9.88**	**12.19**	**12.40**	**8.07**	**13.36**	**12.56**	**13.12**
Overhead Allocation	1.52	1.38	1.35	1.43	1.54	1.53	1.64	1.75	1.71	1.81	2.00	1.97	2.02	2.18	2.11	2.24	2.62	2.16
Expenses incl. Corp O/H	**12.68**	**10.51**	**10.03**	**10.79**	**11.62**	**12.14**	**12.07**	**12.74**	**12.18**	**13.27**	**14.50**	**14.07**	**14.75**	**15.38**	**14.19**	**15.72**	**17.57**	**16.84**
Margin after Corp O/H	**(4.24)**	**(1.18)**	**(2.45)**	**(0.28)**	**(0.51)**	**(1.28)**	**0.35**	**9.28**	**5.20**	**9.94**	**9.19**	**7.91**	**10.17**	**10.23**	**5.97**	**11.12**	**9.93**	**10.97**
Costs per kwh (cents)																		
Fuel	2.18	1.67	1.63	1.70	1.75	1.79	1.86	1.91	1.93	2.02	2.08	2.13	2.21	2.27	2.29	2.41	2.48	2.55
Non-fuel	0.54	0.43	0.77	0.43	0.53	0.51	0.51	0.46	0.77	0.46	0.60	0.56	0.55	0.55	0.83	0.51	0.72	0.65
Capital Expenditures	0.05	0.05	0.20	0.03	0.03	0.30	0.02	0.03	0.23	0.02	0.04	0.21	0.02	0.04	0.26	0.02	0.04	0.03
Direct Expenses	**2.77**	**2.15**	**2.60**	**2.16**	**2.31**	**2.59**	**2.38**	**2.40**	**2.93**	**2.49**	**2.72**	**2.90**	**2.77**	**2.86**	**3.38**	**2.94**	**3.24**	**3.23**
Direct Margin	**(0.90)**	**(0.18)**	**(0.52)**	**0.03**	**(0.00)**	**(0.16)**	**0.18**	**2.01**	**1.59**	**2.14**	**2.03**	**1.97**	**2.21**	**2.25**	**1.86**	**2.43**	**2.27**	**2.41**
Overhead Allocation	0.35	0.30	0.38	0.30	0.32	0.35	0.34	0.35	0.44	0.36	0.40	0.44	0.40	0.43	0.55	0.45	0.53	0.44
Expenses incl. Corp O/H	**3.12**	**2.44**	**2.98**	**2.47**	**2.64**	**2.94**	**2.72**	**2.75**	**3.37**	**2.86**	**3.12**	**3.33**	**3.18**	**3.30**	**3.92**	**3.39**	**3.76**	**3.67**
Margin after Corp O/H	**(1.25)**	**(0.47)**	**(0.90)**	**(0.28)**	**(0.33)**	**(0.51)**	**(0.16)**	**1.66**	**1.15**	**1.78**	**1.63**	**1.53**	**1.81**	**1.81**	**1.32**	**1.98**	**1.74**	**1.97**
NPV of Margin after O/H	18.1							38.9										
NPV of Decommissioning	0.5							0.9										
NPV OF NET MARGIN	17.5							38.1										

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

MANSFIELD 3	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24	5.37	5.50	5.64	5.78
Unit Output (gwh)	778	897	910	697	913	917	826	945	945	749	945	945	855	948	945	738	935	948	855
Delivered Output (gwh)	720	830	842	645	845	848	764	875	875	693	874	875	791	877	875	683	865	877	791
Revenues	**13.79**	**16.59**	**17.69**	**14.28**	**19.72**	**20.88**	**19.81**	**38.55**	**39.52**	**32.07**	**41.48**	**42.56**	**39.44**	**44.83**	**45.83**	**36.68**	**47.61**	**49.49**	**45.74**
Fuel-Related Expenses																			
Fuel Costs	11.15	8.69	8.71	6.83	9.20	9.50	8.81	10.34	10.64	8.67	11.25	11.58	10.78	12.28	12.62	10.13	13.21	13.78	12.75
Fuel Related ECR Costs	1.52	1.77	1.85	1.48	1.95	2.01	1.87	2.18	2.24	1.85	2.36	2.42	2.26	2.56	2.62	2.14	2.74	2.85	2.65
NOx Emissions	1.67	2.07	2.20	1.61	2.40	2.51	2.30	2.83	2.95	2.25	3.19	3.33	3.04	3.64	3.78	2.80	4.04	4.30	3.91
SO2 Emissions	0.10	0.12	(0.13)	(0.17)	(0.15)	(0.16)	(0.19)	(0.18)	(0.19)	(0.26)	(0.23)	(0.25)	(0.29)	(0.29)	(0.31)	(0.41)	(0.36)	(0.38)	(0.46)
Total Fuel	14.43	12.66	12.62	9.75	13.40	13.86	12.79	15.17	15.64	12.50	16.58	17.09	15.79	18.20	18.71	14.65	19.63	20.54	18.85
Non-fuel O&M Expenses																			
Variable O&M	1.35	1.45	1.47	1.16	1.56	1.60	1.48	1.73	1.78	1.44	1.86	1.91	1.77	2.01	2.06	1.65	2.14	2.22	2.06
Fixed O&M	2.13	1.50	1.61	1.55	2.30	1.96	2.06	1.70	1.87	1.62	2.81	2.15	2.27	2.28	1.78	1.81	3.57	2.86	2.83
Overhaul	0.00	0.00	0.00	1.24	0.00	0.00	0.00	0.00	0.00	1.32	0.00	0.00	0.00	0.00	0.00	1.59	0.08	0.00	0.00
Subtotal	3.47	2.95	3.08	3.95	3.86	3.56	3.54	3.43	3.65	4.39	4.67	4.05	4.04	4.29	3.83	5.04	5.78	5.08	4.89
FICA	0.10	0.10	0.10	0.09	0.12	0.12	0.10	0.11	0.11	0.09	0.13	0.14	0.11	0.13	0.12	0.10	0.12	0.18	0.19
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	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	0.24	0.24	0.24	0.24	0.24
Total Non-fuel	4.05	3.52	3.65	4.51	4.45	4.15	4.11	4.01	4.23	4.95	5.28	4.66	4.63	4.90	4.42	5.62	6.37	5.74	5.55
Capital Expenditures	1.20	0.36	0.22	1.46	0.17	1.13	1.47	0.19	0.35	1.59	0.21	0.38	1.71	0.22	0.41	1.85	0.25	0.45	1.99
Direct Expenses	**19.69**	**16.54**	**16.49**	**15.72**	**18.02**	**19.13**	**18.37**	**19.37**	**20.22**	**19.04**	**22.06**	**22.14**	**22.13**	**23.32**	**23.55**	**22.12**	**26.25**	**26.72**	**26.39**
Direct Margin	**(5.89)**	**0.05**	**1.21**	**(1.44)**	**1.69**	**1.75**	**1.44**	**19.18**	**19.30**	**13.03**	**19.42**	**20.42**	**17.31**	**21.51**	**22.28**	**14.56**	**21.36**	**22.76**	**19.34**
Overhead Allocation	2.68	2.51	2.56	2.41	2.75	2.76	2.89	3.09	3.29	3.02	3.54	3.60	3.51	3.84	4.11	3.67	4.61	3.93	3.82
Expenses incl. Corp O/H	**22.37**	**19.04**	**19.05**	**18.13**	**20.77**	**21.90**	**21.26**	**22.46**	**23.51**	**22.06**	**25.60**	**25.74**	**25.64**	**27.16**	**27.65**	**25.79**	**30.85**	**30.65**	**30.21**
Margin after Corp O/H	**(8.57)**	**(2.46)**	**(1.36)**	**(3.85)**	**(1.05)**	**(1.01)**	**(1.45)**	**16.09**	**16.01**	**10.01**	**15.88**	**16.82**	**13.80**	**17.67**	**18.18**	**10.88**	**16.75**	**18.84**	**15.53**
Costs per kwh (cents)																			
Fuel	2.19	1.70	1.67	1.69	1.77	1.82	1.87	1.93	1.99	2.01	2.11	2.17	2.22	2.30	2.37	2.39	2.52	2.59	2.64
Non-fuel	0.56	0.42	0.43	0.70	0.53	0.49	0.54	0.46	0.48	0.71	0.60	0.53	0.59	0.56	0.51	0.82	0.74	0.65	0.70
Capital Expenditures	0.17	0.04	0.03	0.23	0.02	0.13	0.19	0.02	0.04	0.23	0.02	0.04	0.22	0.03	0.05	0.27	0.03	0.05	0.25
Direct Expenses	**2.92**	**2.17**	**2.13**	**2.62**	**2.32**	**2.44**	**2.60**	**2.41**	**2.51**	**2.96**	**2.74**	**2.75**	**3.02**	**2.89**	**2.93**	**3.48**	**3.28**	**3.30**	**3.60**
Direct Margin	**(1.05)**	**(0.20)**	**(0.05)**	**(0.43)**	**(0.01)**	**(0.01)**	**(0.04)**	**2.00**	**2.00**	**1.67**	**2.01**	**2.12**	**1.96**	**2.22**	**2.31**	**1.89**	**2.22**	**2.34**	**2.19**
Overhead Allocation	0.37	0.30	0.30	0.37	0.33	0.33	0.38	0.35	0.38	0.44	0.41	0.41	0.44	0.44	0.47	0.54	0.53	0.45	0.48
Expenses incl. Corp O/H	**3.29**	**2.47**	**2.44**	**2.99**	**2.64**	**2.77**	**2.98**	**2.77**	**2.89**	**3.39**	**3.14**	**3.16**	**3.47**	**3.33**	**3.40**	**4.02**	**3.81**	**3.75**	**4.08**
Margin after Corp O/H	**(1.42)**	**(0.50)**	**(0.36)**	**(0.80)**	**(0.33)**	**(0.34)**	**(0.42)**	**1.64**	**1.63**	**1.24**	**1.60**	**1.70**	**1.52**	**1.79**	**1.84**	**1.35**	**1.69**	**1.89**	**1.70**
NPV of Margin after O/H	37.1							79.6											
NPV of Decommissioning	1.4							2.3											
NPV OF NET MARGIN	35.7							77.3											

DUQUESNE [redacted]HT

Costs of Fossil Plants

$ in Millions

MANSFIELD 3	2018	2019
kwh Market Price (cents)	5.93	6.08
Unit Output (gwh)	945	940
Delivered Output (gwh)	875	870
Revenues	**51.85**	**52.86**
Fuel-Related Expenses		
Fuel Costs	14.49	14.80
Fuel Related ECR Costs	3.00	3.06
NOx Emissions	4.66	4.81
SO2 Emissions	(0.45)	(0.49)
Total Fuel	21.69	22.18
Non-fuel O&M Expenses		
Variable O&M	2.34	2.38
Fixed O&M	3.21	3.28
Overhaul	0.00	0.00
Subtotal	5.55	5.66
FICA	0.19	0.20
Property Tax	0.23	0.23
Cap Stock Tax	0.24	0.24
Total Non-fuel	6.21	6.33
Capital Expenditures	0.27	0.49
Direct Expenses	**28.17**	**29.00**
Direct Margin	**23.68**	**23.85**
Overhead Allocation	4.43	4.30
Expenses incl. Corp O/H	**32.60**	**33.30**
Margin after Corp O/H	**19.25**	**19.55**
Costs per kwh (cents)		
Fuel	2.75	2.82
Non-fuel	0.71	0.73
Capital Expenditures	0.03	0.06
Direct Expenses	**3.49**	**3.61**
Direct Margin	**2.44**	**2.47**
Overhead Allocation	0.51	0.49
Expenses incl. Corp O/H	**3.99**	**4.10**
Margin after Corp O/H	**1.93**	**1.97**
NPV of Margin after O/H		
NPV of Decommissioning		
NPV OF NET MARGIN		

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

BRUNOT ISLAND	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
kwh Market Price (cents)	9.35	9.85	10.40	10.95	11.55	12.15	12.80	22.04	22.59	23.15	23.73	24.33	24.93	25.56
Unit Output (gwh)	0	0	0	0	0	0	0	27	27	27	27	27	27	27
Delivered Output (gwh)	0	0	0	0	0	0	0	25.40	25.40	25.40	25.40	25.40	25.40	25.40
Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.60	5.74	5.88	6.03	6.18	6.33	6.49
Fuel-Related Expenses														
Fuel Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Fuel Related ECR 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	0.00	0.00
NOx Emissions	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
SO2 Emissions	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
Total Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Non-fuel O&M Expenses														
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Fixed O&M	0.59	0.61	0.62	0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.79	0.00
Overhaul	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
Subtotal	0.59	0.61	0.62	0.64	0.65	0.67	0.69	0.74	0.76	0.78	0.80	0.82	0.83	0.03
FICA	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.00
Property Tax	0.33	0.33	0.33	0.33	0.33	0.33	0.33	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	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Total Non-fuel	1.27	1.29	1.30	1.32	1.34	1.36	1.38	1.43	1.44	1.47	1.48	1.51	1.51	0.70
Capital Expenditures	1.61	0.17	0.17	0.17	0.18	4.38	0.19	0.20	0.20	0.21	0.19	0.19	0.20	0.11
Direct Expenses	2.88	1.46	1.47	1.50	1.52	5.74	1.57	4.09	4.18	4.27	4.34	4.45	4.53	3.71
Direct Margin	(2.88)	(1.46)	(1.47)	(1.50)	(1.52)	(5.74)	(1.57)	1.51	1.56	1.61	1.68	1.73	1.80	2.79
Overhead Allocation	0.39	0.22	0.23	0.23	0.23	0.83	0.25	0.65	0.68	0.68	0.70	0.72	0.72	0.61
Expenses incl. Corp O/H	3.27	1.68	1.70	1.73	1.75	6.57	1.81	4.74	4.86	4.95	5.04	5.17	5.25	4.32
Margin after Corp O/H	(3.27)	(1.68)	(1.70)	(1.73)	(1.75)	(6.57)	(1.81)	0.86	0.88	0.93	0.99	1.01	1.08	2.18
Costs per kwh (cents)														
Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.82	10.09	10.36	10.64	10.93	11.22	11.52
Non-fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.61	5.68	5.77	5.84	5.95	5.96	0.00
Capital Expenditures	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.79	0.81	0.75	0.77	0.79	0.00
Direct Expenses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.20	16.56	16.94	17.23	17.64	17.97	11.52
Direct Margin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.84	6.03	6.21	6.51	6.69	6.97	0.00
Overhead Allocation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.57	2.68	2.66	2.74	2.85	2.83	0.00
Expenses incl. Corp O/H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.77	19.23	19.60	19.97	20.49	20.80	11.52
Margin after Corp O/H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.27	3.36	3.55	3.76	3.84	4.14	0.00
NPV of Margin after O/H	(6.2)							3.5						
NPV of Decommissioning	8.2							13.9						
NPV OF NET MARGIN	(14.4)							(10.4)						

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 1	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24
Unit Output (gwh)	2,726	2,874	3,373	2,864	2,864	3,382	2,864	2,864	3,373	2,874	2,864	3,373	2,864	2,874	3,373
Delivered Output (gwh)	2,564	2,703	3,172	2,694	2,694	3,181	2,694	2,694	3,172	2,703	2,694	3,172	2,694	2,703	3,172
Revenues	**48.26**	**53.21**	**65.93**	**59.40**	**62.30**	**77.57**	**69.71**	**118.74**	**143.30**	**125.15**	**127.87**	**154.32**	**134.34**	**138.14**	**166.18**
Fuel-Related Expenses															
Fuel Costs	11.11	11.27	13.25	11.59	11.49	13.94	12.30	12.50	15.20	13.39	13.75	16.73	14.67	15.17	18.38
Fuel Related ECR Costs	2.56	2.70	3.17	2.69	2.69	3.18	2.69	2.69	3.17	2.70	2.69	3.17	2.69	2.70	3.17
Total Fuel	13.68	13.97	16.42	14.29	14.19	17.12	14.99	15.20	18.37	16.09	16.45	19.91	17.37	17.88	21.55
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
Fixed O&M	30.76	24.97	25.62	26.29	27.00	27.73	28.48	29.19	29.92	30.67	31.44	32.22	33.03	33.85	34.70
Overhaul	16.39	13.68	0.00	14.40	14.79	0.00	15.60	16.02	0.00	16.88	17.32	0.00	18.25	18.74	0.00
Subtotal	47.15	38.65	25.62	40.69	41.79	27.73	44.08	45.21	29.92	47.55	48.76	32.22	51.28	52.60	34.70
FICA	1.42	1.45	1.48	1.51	1.54	1.57	1.60	1.64	1.67	1.70	1.74	1.77	1.81	1.84	1.88
Property Tax	2.06	2.06	2.06	2.06	2.06	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	2.15	2.15	2.15	2.15	2.15
Total Non-fuel	52.78	44.31	31.31	46.41	47.53	33.51	49.89	51.06	35.80	53.46	54.70	38.20	57.29	58.65	40.79
Capital Expenditures	6.76	5.69	5.84	5.99	6.16	6.33	6.50	6.68	6.86	7.04	7.23	7.43	7.63	7.84	8.06
	18.49														
Direct Expenses	**73.21**	**63.96**	**53.56**	**66.68**	**67.88**	**56.96**	**71.38**	**72.93**	**61.03**	**76.59**	**78.37**	**65.53**	**82.29**	**84.36**	**70.39**
Direct Margin	**(24.95)**	**(10.75)**	**12.36**	**(7.29)**	**(5.58)**	**20.61**	**(1.67)**	**45.80**	**82.27**	**48.56**	**49.49**	**88.78**	**52.05**	**53.78**	**95.79**
Overhead Allocation	9.96	9.70	8.32	10.23	10.35	8.22	11.23	11.64	9.93	12.14	12.57	10.66	13.05	13.90	12.27
Expenses incl. Corp O/H	**83.18**	**73.67**	**61.89**	**76.91**	**78.22**	**65.18**	**82.61**	**84.57**	**70.96**	**88.73**	**90.95**	**76.20**	**95.34**	**98.26**	**82.67**
Margin after Corp O/H	**(34.91)**	**(20.45)**	**4.04**	**(17.52)**	**(15.93)**	**12.39**	**(12.90)**	**34.16**	**72.34**	**36.42**	**36.92**	**78.12**	**39.00**	**39.88**	**83.52**
Costs per kwh (cents)															
Fuel	0.53	0.52	0.52	0.53	0.53	0.54	0.56	0.56	0.58	0.60	0.61	0.63	0.64	0.66	0.68
Non-fuel	2.06	1.64	0.99	1.72	1.76	1.05	1.85	1.90	1.13	1.98	2.03	1.20	2.13	2.17	1.29
Capital Expenditures	0.26	0.21	0.18	0.22	0.23	0.20	0.24	0.25	0.22	0.26	0.27	0.23	0.28	0.29	0.25
Direct Expenses	**2.86**	**2.37**	**1.69**	**2.48**	**2.52**	**1.79**	**2.65**	**2.71**	**1.92**	**2.83**	**2.91**	**2.07**	**3.05**	**3.12**	**2.22**
Direct Margin	**(0.99)**	**(0.40)**	**0.39**	**(0.29)**	**(0.21)**	**0.64**	**(0.09)**	**1.70**	**2.59**	**1.80**	**1.84**	**2.80**	**1.93**	**1.99**	**3.02**
Overhead Allocation	0.39	0.36	0.26	0.38	0.38	0.26	0.42	0.43	0.31	0.45	0.47	0.34	0.48	0.51	0.39
Expenses incl. Corp O/H	**3.24**	**2.73**	**1.95**	**2.85**	**2.90**	**2.05**	**3.07**	**3.14**	**2.24**	**3.28**	**3.38**	**2.40**	**3.54**	**3.64**	**2.61**
Margin after Corp O/H	**(1.37)**	**(0.76)**	**0.13**	**(0.66)**	**(0.59)**	**0.38**	**(0.51)**	**1.27**	**2.28**	**1.35**	**1.37**	**2.46**	**1.45**	**1.48**	**2.63**
NPV of Margin after O/H	**86.1**							**218.4**							
Overfunded Decomm.	**0.0**							**0.0**							
NPV OF NET MARGIN	**86.1**							**218.4**							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

BEAVER VALLEY 1	**2014**	**2015**
kwh Market Price (cents)	5.37	5.50
Unit Output (gwh)	2,864	3,336
Delivered Output (gwh)	2,694	3,137
Revenues	**144.67**	**172.68**
Fuel-Related Expenses		
Fuel Costs	16.10	19.31
Fuel Related ECR Costs	2.69	3.14
Total Fuel	18.79	22.44
Non-fuel O&M Expenses		
Variable O&M	0.00	0.00
Fixed O&M	35.57	36.46
Overhaul	19.77	0.00
Subtotal	55.33	36.46
FICA	1.92	1.95
Property Tax	2.06	2.06
Cap Stock Tax	2.15	2.15
Total Non-fuel	61.46	42.62
Capital Expenditures	8.28	8.51
Direct Expenses	**88.53**	**73.57**
Direct Margin	**56.14**	**99.11**
Overhead Allocation	14.71	12.92
Expenses incl. Corp O/H	**103.23**	**86.49**
Margin after Corp O/H	**41.44**	**86.19**
Costs per kwh (cents)		
Fuel	0.70	0.72
Non-fuel	2.28	1.36
Capital Expenditures	0.31	0.27
Direct Expenses	**3.29**	**2.35**
Direct Margin	**2.08**	**3.16**
Overhead Allocation	0.55	0.41
Expenses incl. Corp O/H	**3.83**	**2.76**
Margin after Corp O/H	**1.54**	**2.75**
NPV of Margin after O/H		
Overfunded Decomm.		
NPV OF NET MARGIN		

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 2	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24
Unit Output (gwh)	883	994	883	883	991	885	883	991	883	885	991	883	883	994	883
Delivered Output (gwh)	829	934	829	829	931	832	829	931	829	832	931	829	829	934	829
Revenues	**15.47**	**18.37**	**17.32**	**18.11**	**21.52**	**20.28**	**21.26**	**41.03**	**37.45**	**38.50**	**44.19**	**40.33**	**41.34**	**47.72**	**43.43**
Fuel-Related Expenses															
Fuel Costs	3.38	3.96	3.61	3.54	3.93	3.58	3.53	4.04	3.72	3.84	4.44	4.09	4.22	4.90	4.50
Fuel Related ECR Costs	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83
Total Fuel	4.21	4.90	4.44	4.36	4.86	4.41	4.36	4.97	4.54	4.68	5.38	4.92	5.05	5.84	5.32
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
Fixed O&M	8.88	7.22	7.41	7.61	7.81	8.02	8.24	8.45	8.66	8.87	9.10	9.32	9.56	9.79	10.04
Overhaul	3.02	0.00	3.10	3.18	0.00	3.36	3.45	0.00	3.64	3.73	0.00	3.93	4.03	0.00	4.25
Subtotal	11.90	7.22	10.51	10.79	7.81	11.38	11.69	8.45	12.29	12.60	9.10	13.25	13.59	9.79	14.29
FICA	0.40	0.41	0.42	0.43	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
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
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
Total Non-fuel	13.15	8.49	11.78	12.07	9.10	12.68	12.99	9.76	13.62	13.94	10.44	14.60	14.95	11.17	15.68
Capital Expenditures	6.65	4.86	4.99	5.12	5.26	5.40	5.54	5.70	5.84	6.00	6.15	6.32	6.49	6.67	6.85
Direct Expenses	**24.01**	**18.24**	**21.21**	**21.55**	**19.22**	**22.49**	**22.90**	**20.42**	**24.00**	**24.61**	**21.97**	**25.84**	**26.49**	**23.67**	**27.85**
Direct Margin	**(8.54)**	**0.13**	**(3.89)**	**(3.44)**	**2.30**	**(2.20)**	**(1.64)**	**20.61**	**13.45**	**13.89**	**22.22**	**14.49**	**14.84**	**24.05**	**15.58**
Overhead Allocation	3.27	2.77	3.30	3.30	2.93	3.25	3.60	3.26	3.91	3.90	3.52	4.20	4.20	3.90	4.85
Expenses incl. Corp O/H	**27.28**	**21.01**	**24.51**	**24.85**	**22.14**	**25.73**	**26.50**	**23.68**	**27.91**	**28.51**	**25.49**	**30.04**	**30.70**	**27.57**	**32.70**
Margin after Corp O/H	**(11.81)**	**(2.64)**	**(7.19)**	**(6.74)**	**(0.63)**	**(5.45)**	**(5.24)**	**17.35**	**9.54**	**9.99**	**18.70**	**10.28**	**10.64**	**20.15**	**10.73**
Costs per kwh (cents)															
Fuel	0.51	0.52	0.54	0.53	0.52	0.53	0.53	0.53	0.55	0.56	0.58	0.59	0.61	0.63	0.64
Non-fuel	1.59	0.91	1.42	1.46	0.98	1.52	1.57	1.05	1.64	1.68	1.12	1.76	1.80	1.20	1.89
Capital Expenditures	0.80	0.52	0.60	0.62	0.56	0.65	0.67	0.61	0.70	0.72	0.66	0.76	0.78	0.71	0.83
Direct Expenses	**2.90**	**1.95**	**2.56**	**2.60**	**2.06**	**2.70**	**2.76**	**2.19**	**2.90**	**2.96**	**2.36**	**3.12**	**3.20**	**2.54**	**3.36**
Direct Margin	**(1.03)**	**0.02**	**(0.48)**	**(0.41)**	**0.25**	**(0.27)**	**(0.20)**	**2.21**	**1.62**	**1.67**	**2.39**	**1.75**	**1.79**	**2.58**	**1.88**
Overhead Allocation	0.39	0.30	0.40	0.40	0.31	0.39	0.43	0.35	0.47	0.47	0.38	0.51	0.51	0.42	0.59
Expenses incl. Corp O/H	**3.29**	**2.25**	**2.96**	**3.00**	**2.38**	**3.09**	**3.20**	**2.54**	**3.37**	**3.43**	**2.74**	**3.62**	**3.70**	**2.95**	**3.94**
Margin after Corp O/H	**(1.42)**	**(0.28)**	**(0.88)**	**(0.81)**	**(0.07)**	**(0.66)**	**(0.64)**	**1.86**	**1.15**	**1.20**	**2.01**	**1.24**	**1.28**	**2.16**	**1.29**
NPV of Margin after O/H	35.4							91.9							
Underfunded Decomm.	5.0							8.5							
NPV OF NET MARGIN	30.4							83.3							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

BEAVER VALLEY 2	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	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)	883	991	883	883	991	883	883	991	883	883	991	883	991
Delivered Output (gwh)	829	931	829	829	931	829	829	931	829	829	931	829	931
Revenues	**44.52**	**51.24**	**46.77**	**47.94**	**55.18**	**50.37**	**51.62**	**59.43**	**54.24**	**55.59**	**64.00**	**58.41**	**67.24**
Fuel-Related Expenses													
Fuel Costs	4.64	5.38	4.94	5.09	5.89	5.43	5.59	6.46	5.97	6.13	7.09	6.56	6.73
Fuel Related ECR Costs	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83
Total Fuel	5.47	6.31	5.77	5.92	6.82	6.26	6.42	7.39	6.80	6.96	8.02	7.39	7.56
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
Fixed O&M	10.29	10.55	10.81	11.08	11.36	11.64	11.93	12.23	12.54	12.85	13.17	13.50	13.84
Overhaul	4.37	0.00	4.61	4.73	0.00	4.99	5.13	0.00	5.41	5.55	0.00	5.86	6.02
Subtotal	14.66	10.55	15.42	15.81	11.36	16.63	17.06	12.23	17.94	18.41	13.17	19.36	19.86
FICA	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
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
Total Non-fuel	16.05	11.95	16.86	17.26	12.82	18.11	18.55	13.73	19.46	19.93	14.71	20.91	21.42
Capital Expenditures	7.03	7.22	7.24	7.42	7.61	7.80	7.99	8.19	8.40	8.61	8.82	9.04	9.27
Direct Expenses	**28.55**	**25.48**	**29.87**	**30.60**	**27.25**	**32.16**	**32.95**	**29.32**	**34.65**	**35.50**	**31.55**	**37.34**	**38.25**
Direct Margin	**15.97**	**25.76**	**16.90**	**17.34**	**27.93**	**18.20**	**18.67**	**30.11**	**19.59**	**20.10**	**32.45**	**21.07**	**28.98**
Overhead Allocation	4.74	4.47	4.39	4.42	4.28	4.77	5.20	4.72	5.71	5.69	5.72	6.26	7.51
Expenses incl. Corp O/H	**33.29**	**29.96**	**34.25**	**35.03**	**31.54**	**36.93**	**38.15**	**34.03**	**40.36**	**41.19**	**37.27**	**43.60**	**45.76**
Margin after Corp O/H	**11.22**	**21.29**	**12.52**	**12.91**	**23.65**	**13.43**	**13.47**	**25.39**	**13.88**	**14.40**	**26.73**	**14.81**	**21.48**
Costs per kwh (cents)													
Fuel	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79	0.82	0.84	0.86	0.89	0.81
Non-fuel	1.94	1.28	2.03	2.08	1.38	2.18	2.24	1.48	2.35	2.40	1.58	2.52	2.30
Capital Expenditures	0.85	0.78	0.87	0.90	0.82	0.94	0.96	0.88	1.01	1.04	0.95	1.09	1.00
Direct Expenses	**3.44**	**2.74**	**3.60**	**3.69**	**2.93**	**3.88**	**3.98**	**3.15**	**4.18**	**4.28**	**3.39**	**4.50**	**4.11**
Direct Margin	**1.93**	**2.77**	**2.04**	**2.09**	**3.00**	**2.20**	**2.25**	**3.23**	**2.36**	**2.42**	**3.49**	**2.54**	**3.11**
Overhead Allocation	0.57	0.48	0.53	0.53	0.46	0.58	0.63	0.51	0.69	0.69	0.61	0.76	0.81
Expenses incl. Corp O/H	**4.02**	**3.22**	**4.13**	**4.23**	**3.39**	**4.46**	**4.60**	**3.66**	**4.87**	**4.97**	**4.00**	**5.26**	**4.92**
Margin after Corp O/H	**1.35**	**2.29**	**1.51**	**1.56**	**2.54**	**1.62**	**1.63**	**2.73**	**1.67**	**1.74**	**2.87**	**1.79**	**2.31**
NPV of Margin after O/H													
Underfunded Decomm.													
NPV OF NET MARGIN													

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

$44.1/mwh in 2006 with escalations @ 2.5%

PERRY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	4.41	4.52	4.63	4.75	4.87	4.99	5.11	5.24
Unit Output (gwh)	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256
Delivered Output (gwh)	1,195	1,347	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195
Revenues	**22.43**	**26.50**	**24.96**	**29.40**	**27.76**	**32.83**	**30.85**	**59.19**	**53.97**	**62.35**	**56.71**	**65.32**	**59.57**	**68.82**	**62.60**
Fuel-Related Expenses															
Fuel Costs	5.25	5.80	5.27	5.95	5.36	6.10	5.69	6.42	5.91	6.87	6.29	7.30	6.70	7.79	7.13
Fuel Related ECR Costs	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
Total Fuel	6.44	7.15	6.46	7.30	6.55	7.44	6.89	7.77	7.10	8.22	7.49	8.64	7.89	9.13	8.32
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
Fixed O&M	16.25	15.25	16.29	16.33	16.75	17.23	17.67	18.11	18.56	19.03	19.50	19.99	20.49	21.00	21.53
Overhaul	3.29	0.00	3.38	0.00	3.56	0.00	3.75	0.00	3.96	0.00	4.16	0.00	4.39	0.00	4.63
Subtotal	19.54	15.25	19.67	16.33	20.30	17.23	21.42	18.11	22.52	19.03	23.67	19.99	24.88	21.00	26.15
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
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
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
Total Non-fuel	33.25	28.95	33.37	30.04	34.00	30.94	35.12	31.81	36.22	32.73	37.37	33.69	38.58	34.70	39.86
Capital Expenditures	5.09	2.35	2.98	2.48	3.15	3.04	3.33	3.22	3.52	3.40	3.72	3.59	3.93	3.80	4.16
Direct Expenses	**44.78**	**38.44**	**42.81**	**39.81**	**43.70**	**41.42**	**45.34**	**42.80**	**46.84**	**44.34**	**48.57**	**45.92**	**50.41**	**47.63**	**52.34**
Direct Margin	**(22.35)**	**(11.94)**	**(17.85)**	**(10.41)**	**(15.95)**	**(8.58)**	**(14.50)**	**16.39**	**7.13**	**18.00**	**8.14**	**19.40**	**9.17**	**21.18**	**10.26**
Overhead Allocation	6.09	5.83	6.65	6.11	6.66	5.98	7.13	6.83	7.62	7.03	7.79	7.47	7.99	7.85	9.12
Expenses incl. Corp O/H	**50.87**	**44.27**	**49.47**	**45.91**	**50.37**	**47.40**	**52.47**	**49.63**	**54.47**	**51.37**	**56.37**	**53.40**	**58.40**	**55.48**	**61.46**
Margin after Corp O/H	**(28.44)**	**(17.78)**	**(24.50)**	**(16.51)**	**(22.61)**	**(14.56)**	**(21.63)**	**9.56**	**(0.50)**	**10.98**	**0.34**	**11.93**	**1.17**	**13.34**	**1.14**
Costs per kwh (cents)															
Fuel	0.54	0.53	0.54	0.54	0.55	0.55	0.58	0.58	0.59	0.61	0.63	0.64	0.66	0.68	0.70
Non-fuel	2.78	2.15	2.79	2.24	2.85	2.30	2.94	2.37	3.03	2.43	3.13	2.51	3.23	2.58	3.34
Capital Expenditures	0.43	0.17	0.25	0.18	0.26	0.23	0.28	0.24	0.29	0.25	0.31	0.27	0.33	0.28	0.35
Direct Expenses	**3.75**	**2.85**	**3.58**	**2.96**	**3.66**	**3.08**	**3.80**	**3.19**	**3.92**	**3.29**	**4.07**	**3.42**	**4.22**	**3.54**	**4.38**
Direct Margin	**(1.88)**	**(0.88)**	**(1.50)**	**(0.77)**	**(1.35)**	**(0.65)**	**(1.24)**	**1.22**	**0.60**	**1.34**	**0.68**	**1.44**	**0.77**	**1.57**	**0.86**
Overhead Allocation	0.51	0.43	0.56	0.45	0.56	0.44	0.60	0.51	0.64	0.52	0.65	0.56	0.67	0.58	0.76
Expenses incl. Corp O/H	**4.26**	**3.29**	**4.14**	**3.42**	**4.22**	**3.52**	**4.39**	**3.70**	**4.56**	**3.82**	**4.72**	**3.98**	**4.89**	**4.12**	**5.14**
Margin after Corp O/H	**(2.39)**	**(1.32)**	**(2.06)**	**(1.23)**	**(1.91)**	**(1.09)**	**(1.83)**	**0.71**	**(0.04)**	**0.82**	**0.03**	**0.89**	**0.10**	**0.99**	**0.10**
NPV of Margin after O/H	**(34.3)**							**56.1**							
Underfunded Decomm.	**6.5**							**11.0**							
NPV OF NET MARGIN	**(40.8)**							**45.1**							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

PERRY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	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)	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,416
Delivered Output (gwh)	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
Revenues	**72.10**	**65.77**	**75.96**	**69.09**	**79.59**	**72.59**	**83.86**	**76.26**	**87.85**	**80.13**	**92.57**	**84.18**	**97.25**
Fuel-Related Expenses													
Fuel Costs	8.25	7.58	8.80	8.04	9.29	8.49	9.82	8.71	9.79	8.71	9.82	8.71	2.43
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	0.33
Total Fuel	9.59	8.78	10.15	9.24	10.63	9.68	11.17	9.91	11.14	9.91	11.17	9.91	2.76
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
Fixed O&M	22.06	22.62	23.18	23.76	24.35	24.96	25.59	26.23	26.88	27.55	28.24	28.95	29.67
Overhaul	0.00	4.88	0.00	5.15	0.00	5.43	0.00	5.58	0.00	5.58	0.00	5.58	0.00
Subtotal	22.06	27.50	23.18	28.91	24.35	30.39	25.59	31.80	26.88	33.13	28.24	34.53	29.67
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
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
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
Total Non-fuel	35.77	41.20	36.88	42.61	38.06	44.10	39.29	45.51	40.59	46.83	41.95	48.23	43.38
Capital Expenditures	4.02	4.40	4.25	4.64	4.48	4.90	4.73	5.17	5.00	5.45	5.27	5.75	5.56
Direct Expenses	**49.38**	**54.37**	**51.28**	**56.49**	**53.17**	**58.67**	**55.19**	**60.58**	**56.72**	**62.19**	**58.38**	**63.89**	**51.70**
Direct Margin	**22.73**	**11.39**	**24.68**	**12.60**	**26.42**	**13.92**	**28.67**	**15.68**	**31.14**	**17.93**	**34.18**	**20.30**	**45.55**
Overhead Allocation	8.20	9.55	7.53	8.17	8.36	8.70	8.70	9.75	9.35	9.97	10.58	10.71	10.15
Expenses incl. Corp O/H	**57.58**	**63.92**	**58.81**	**64.66**	**61.53**	**67.37**	**63.89**	**70.33**	**66.06**	**72.17**	**68.97**	**74.60**	**61.85**
Margin after Corp O/H	**14.53**	**1.84**	**17.15**	**4.44**	**18.06**	**5.22**	**19.97**	**5.93**	**21.79**	**7.96**	**23.60**	**9.59**	**35.40**
Costs per kwh (cents)													
Fuel	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.83	0.83	0.83	0.83	0.83	0.21
Non-fuel	2.66	3.45	2.74	3.57	2.83	3.69	2.92	3.81	3.02	3.92	3.12	4.04	3.22
Capital Expenditures	0.30	0.37	0.32	0.39	0.33	0.41	0.35	0.43	0.37	0.46	0.39	0.48	0.41
Direct Expenses	**3.68**	**4.55**	**3.81**	**4.73**	**3.96**	**4.91**	**4.10**	**5.07**	**4.22**	**5.21**	**4.34**	**5.35**	**3.84**
Direct Margin	**1.69**	**0.95**	**1.83**	**1.05**	**1.97**	**1.17**	**2.13**	**1.31**	**2.32**	**1.50**	**2.54**	**1.70**	**3.38**
Overhead Allocation	0.61	0.80	0.56	0.68	0.62	0.73	0.65	0.82	0.70	0.83	0.79	0.90	0.75
Expenses incl. Corp O/H	**4.29**	**5.35**	**4.37**	**5.41**	**4.58**	**5.64**	**4.74**	**5.89**	**4.92**	**6.04**	**5.12**	**6.24**	**4.59**
Margin after Corp O/H	**1.08**	**0.15**	**1.27**	**0.37**	**1.35**	**0.44**	**1.48**	**0.50**	**1.62**	**0.67**	**1.75**	**0.80**	**2.63**
NPV of Margin after O/H													
Underfunded Decomm.													
NPV OF NET MARGIN													

DUQUESNE LIGHT COMPANY

Plant Present Values

$ in Millions

DELAYED ENTRY

MARGIN STREAM BEGINNING 1/1/99

	Plant Margin	Decommissioning	Net Plant Value
Fossil Plants:			
Cheswick	0.0	(13.9)	(13.9)
Sammis	0.0	(4.7)	(4.7)
Eastlake	0.0	(4.1)	(4.1)
Elrama	0.0	(20.7)	(20.7)
Mansfield 1	36.9	(7.4)	29.4
Mansfield 2	13.0	(0.5)	12.5
Mansfield 3	28.0	(1.4)	26.6
Brunot Island	0.0	(8.2)	(8.2)
Phillips	0.0	(5.6)	(5.6)
Total Fossil	**77.9**	**(66.5)**	**11.4**
Nuclear Plants:			
Beaver Valley 1	55.3	(25.5)	29.8
Beaver Valley 2	25.8	(10.3)	15.5
Perry	0.0	(21.6)	(21.6)
Total Nuclear	**81.1**	**(57.4)**	**23.7**
TOTAL PLANTS	**$159.0**	**($123.9)**	**$35.1**

DUQUESNE [redacted]HT

Costs of Fossil Plants

$ in Millions

DELAYED ENTRY

CHESWICK	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99	5.11	5.24	5.37
Unit Output (gwh)	3,791	3,837	3,662	4,017	3,922	3,471	4,147	4,235	4,062	4,425	4,231	3,707	4,413	4,249	4,062	4,374
Delivered Output (gwh)	3,608	3,652	3,485	3,823	3,733	3,303	3,947	4,030	3,866	4,211	4,027	3,528	4,200	4,044	3,866	4,163
Revenues	69.28	74.18	74.65	86.08	88.41	82.99	103.34	122.74	132.80	163.19	176.03	173.96	209.42	206.68	202.54	223.56
Fuel-Related Expenses																
Fuel Costs	44.97	47.14	46.27	51.78	51.87	47.65	58.41	61.67	60.69	68.62	70.81	65.11	79.74	79.21	78.70	88.19
Fuel Related ECR Costs	0.90	0.92	0.95	0.97	1.00	1.03	1.05	1.08	1.11	1.14	1.17	1.20	1.23	1.26	1.30	1.32
NOx Emissions	5.27	5.46	5.41	6.56	6.59	5.42	7.82	8.24	8.17	9.60	9.34	7.63	10.85	10.87	10.49	12.08
SO2 Emissions	0.63	0.73	3.41	4.27	4.42	3.86	5.59	6.16	6.23	7.64	7.69	6.64	9.49	9.68	9.71	11.70
Total Fuel	51.77	54.25	56.04	63.58	63.88	57.95	72.86	77.14	76.21	87.00	89.01	80.58	101.32	101.03	100.20	113.29
Non-fuel O&M Expenses																
Variable O&M	2.78	2.89	2.83	3.18	3.19	2.90	3.56	3.73	3.67	4.11	4.03	3.62	4.43	4.38	4.30	4.75
Fixed O&M	13.05	12.06	14.00	13.66	12.42	9.88	14.56	13.15	15.38	15.33	14.11	9.12	16.38	15.26	17.69	17.55
Overhaul	0.00	0.00	0.00	0.00	0.00	15.86	0.00	0.00	0.00	0.00	0.00	18.56	0.00	0.00	0.00	0.00
Subtotal	15.83	14.95	16.83	16.84	15.61	28.64	18.12	16.88	19.06	19.43	18.14	31.30	20.81	19.63	21.98	22.30
Carbon Injection Costs							2.68	3.01	2.80	2.81	3.09	2.52	2.93	3.33	3.13	3.07
FICA	0.47	0.50	0.53	0.53	0.48	0.42	0.52	0.53	0.57	0.58	0.52	0.43	0.58	0.60	0.67	0.68
Property Tax	0.84	0.84	0.84	0.84	0.84	0.84	0.84	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	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Total Non-fuel	18.02	17.16	19.08	19.09	17.82	30.79	23.05	22.14	24.14	24.54	23.47	35.96	26.04	25.28	27.50	27.76
Capital Expenditures	7.17	12.20	4.79	4.93	20.21	44.57	5.40	5.56	5.72	5.89	6.08	15.46	4.96	3.58	2.12	1.53
Direct Expenses	76.95	83.62	79.91	87.61	101.90	133.30	101.31	104.83	106.07	117.43	118.55	132.01	132.31	129.89	129.82	142.58
Direct Margin	(7.68)	(9.44)	(5.26)	(1.52)	(13.49)	(50.32)	2.03	17.90	26.73	45.76	57.48	41.95	77.11	76.80	72.73	80.98
Overhead Allocation	10.47	12.69	12.42	13.43	15.53	19.24	15.93	16.73	17.26	18.61	19.02	21.48	20.99	21.40	22.63	23.68
Expenses incl. Corp O/H	87.42	96.31	92.33	101.04	117.43	152.54	117.24	121.57	123.33	136.04	137.57	153.49	153.30	151.29	152.45	166.27
Margin after Corp O/H	(18.15)	(22.12)	(17.68)	(14.96)	(29.02)	(69.56)	(13.91)	1.17	9.47	27.16	38.46	20.48	56.12	55.39	50.10	57.29
Costs per kwh (cents)																
Fuel	1.51	1.56	1.69	1.75	1.80	1.84	1.94	2.01	2.07	2.16	2.31	2.39	2.52	2.61	2.70	2.84
Non-fuel	0.50	0.47	0.55	0.50	0.48	0.93	0.58	0.55	0.62	0.58	0.58	1.02	0.62	0.63	0.71	0.67
Capital Expenditures	0.20	0.33	0.14	0.13	0.54	1.35	0.14	0.14	0.15	0.14	0.15	0.44	0.12	0.09	0.05	0.04
Direct Expenses	2.21	2.37	2.37	2.37	2.82	4.12	2.66	2.69	2.84	2.89	3.04	3.84	3.26	3.32	3.47	3.54
Direct Margin	(0.34)	(0.40)	(0.29)	(0.18)	(0.51)	(1.69)	(0.10)	0.35	0.60	0.99	1.33	1.09	1.73	1.79	1.77	1.83
Overhead Allocation	0.29	0.35	0.36	0.35	0.42	0.58	0.40	0.42	0.45	0.44	0.47	0.61	0.50	0.53	0.59	0.57
Expenses incl. Corp O/H	2.50	2.72	2.73	2.73	3.23	4.71	3.06	3.11	3.29	3.33	3.52	4.45	3.76	3.85	4.05	4.11
Margin after Corp O/H	(0.63)	(0.75)	(0.65)	(0.54)	(0.92)	(2.28)	(0.50)	(0.06)	0.15	0.55	0.86	0.48	1.23	1.26	1.18	1.26
NPV of Margin after O/H	(10.0)							120.4								
NPV of Decommissioning	13.9							23.6								
NPV OF NET MARGIN	(23.9)							96.9								

DUQUESNE LIGHT
Costs of Fossil Plants
$ in Millions

DELAYED ENTRY

SAMMIS	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93
Unit Output (gwh)	1,258	1,381	1,167	1,389	1,304	1,418	1,315	1,558	1,290	1,563	1,437	1,537
Delivered Output (gwh)	1,206	1,324	1,119	1,331	1,250	1,359	1,261	1,493	1,236	1,498	1,378	1,474
Revenues	**23.35**	**26.97**	**23.87**	**30.12**	**29.80**	**34.11**	**33.33**	**45.48**	**42.47**	**58.06**	**60.23**	**72.66**
Fuel-Related Expenses												
Fuel Costs	15.94	18.62	16.46	19.99	19.48	21.51	20.63	23.77	20.33	25.67	24.55	27.34
Fuel Related ECR Costs	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	1.67	2.05	1.77	2.24	2.15	2.39
SO2 Emissions	(0.70)	(0.65)	0.32	0.57	0.52	0.69	0.61	0.98	0.66	1.14	1.02	1.27
Total Fuel	15.26	18.00	16.80	20.59	20.02	22.23	22.94	26.83	22.80	29.08	27.75	31.03
Non-fuel O&M Expenses												
Variable O&M	1.68	1.83	1.51	1.84	1.78	1.97	1.88	2.29	1.93	2.40	2.26	2.48
Fixed O&M	5.72	3.68	3.33	3.71	5.00	4.01	5.22	4.29	3.75	4.80	4.63	4.71
Overhaul	0.00	0.00	3.45	0.00	0.00	0.00	0.00	0.00	4.00	0.00	0.00	0.00
Subtotal	7.39	5.51	8.29	5.54	6.78	5.98	7.10	6.58	9.68	7.19	6.89	7.18
FICA	0.22	0.18	0.15	0.18	0.21	0.20	0.21	0.21	0.17	0.21	0.20	0.24
Property Tax	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49
Cap Stock Tax	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Total Non-fuel	9.41	7.48	10.24	7.51	8.78	7.97	9.10	8.58	11.64	9.20	8.88	9.22
Capital Expenditures	1.33	0.19	3.59	1.11	1.36	0.44	1.43	0.22	4.16	0.49	1.59	0.52
Direct Expenses	**25.99**	**25.67**	**30.63**	**29.21**	**30.17**	**30.65**	**33.47**	**35.63**	**38.60**	**38.77**	**38.21**	**40.76**
Direct Margin	**(2.64)**	**1.30**	**(6.76)**	**0.92**	**(0.37)**	**3.46**	**(0.14)**	**9.85**	**3.86**	**19.29**	**22.01**	**31.90**
Overhead Allocation	3.54	3.89	4.76	4.48	4.60	4.42	5.26	5.69	6.28	6.14	6.13	6.63
Expenses incl. Corp O/H	**29.53**	**29.57**	**35.39**	**33.69**	**34.77**	**35.07**	**38.74**	**41.32**	**44.89**	**44.91**	**44.34**	**47.39**
Margin after Corp O/H	**(6.18)**	**(2.60)**	**(11.52)**	**(3.56)**	**(4.97)**	**(0.96)**	**(5.40)**	**4.16**	**(2.42)**	**13.14**	**15.88**	**25.26**
Costs per kwh (cents)												
Fuel	1.40	1.50	1.64	1.68	1.74	1.78	1.97	1.95	2.00	2.10	2.18	2.27
Non-fuel	0.78	0.57	0.91	0.56	0.70	0.59	0.72	0.57	0.94	0.61	0.64	0.63
Capital Expenditures	0.11	0.01	0.32	0.08	0.11	0.03	0.11	0.01	0.34	0.03	0.12	0.04
Direct Expenses	**2.29**	**2.08**	**2.87**	**2.33**	**2.56**	**2.40**	**2.80**	**2.54**	**3.28**	**2.75**	**2.94**	**2.93**
Direct Margin	**(0.42)**	**(0.11)**	**(0.79)**	**(0.14)**	**(0.25)**	**0.03**	**(0.24)**	**0.51**	**0.16**	**1.13**	**1.43**	**2.00**
Overhead Allocation	0.29	0.29	0.43	0.34	0.37	0.33	0.42	0.38	0.51	0.41	0.44	0.45
Expenses incl. Corp O/H	**2.59**	**2.37**	**3.30**	**2.67**	**2.92**	**2.73**	**3.22**	**2.92**	**3.79**	**3.16**	**3.38**	**3.38**
Margin after Corp O/H	**(0.72)**	**(0.40)**	**(1.22)**	**(0.48)**	**(0.61)**	**(0.30)**	**(0.66)**	**0.13**	**(0.35)**	**0.72**	**0.99**	**1.55**
NPV of Margin after O/H	**(1.6)**							**25.1**				
NPV of Decommissioning	**4.7**							**8.0**				
NPV OF NET MARGIN	**(6.3)**							**17.1**				

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

DELAYED ENTRY

EASTLAKE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99
Unit Output (gwh)	1,216	1,097	1,230	1,078	1,105	1,187	1,004	1,206	1,367	1,208	1,205	1,267	1,123
Delivered Output (gwh)	1,158	1,045	1,172	1,027	1,053	1,131	956	1,149	1,302	1,151	1,148	1,207	1,069
Revenues	**22.32**	**21.06**	**25.08**	**23.20**	**24.87**	**28.08**	**25.27**	**34.98**	**44.72**	**44.61**	**50.18**	**59.53**	**53.33**
Fuel-Related Expenses													
Fuel Costs	13.25	12.29	14.20	12.83	13.52	14.93	13.05	15.96	18.60	16.95	17.43	18.85	17.19
Fuel Related ECR Costs	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
NOx Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.85	1.05	1.24	1.14	1.19	1.30	1.20
SO2 Emissions	2.44	2.23	3.77	3.47	3.84	4.50	3.97	5.26	6.57	6.12	6.57	7.51	7.00
Total Fuel	15.79	14.62	18.07	16.40	17.46	19.54	17.98	22.38	26.52	24.33	25.31	27.78	25.52
Non-fuel O&M Expenses													
Variable O&M	1.40	1.30	1.49	1.34	1.41	1.56	1.35	1.67	1.94	1.76	1.80	1.95	1.77
Fixed O&M	3.93	4.11	4.51	4.86	4.49	4.99	4.75	4.73	5.17	5.54	5.14	5.76	5.37
Overhaul	0.05	0.00	0.00	0.00	0.00	0.41	1.39	0.00	0.00	0.00	0.00	0.64	1.43
Subtotal	5.39	5.41	6.00	6.20	5.90	6.96	7.50	6.40	7.11	7.30	6.94	8.35	8.57
FICA	0.16	0.18	0.19	0.20	0.18	0.22	0.18	0.20	0.21	0.22	0.20	0.26	0.20
Property Tax	1.27	1.27	1.27	1.27	1.27	1.27	1.27	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	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Total Non-fuel	7.08	7.12	7.73	7.94	7.62	8.71	9.21	8.14	8.86	9.05	8.68	10.14	10.31
Capital Expenditures	2.02	0.55	5.38	6.00	1.68	3.16	3.60	2.39	0.66	0.91	0.91	1.06	0.78
Direct Expenses	**24.90**	**22.29**	**31.17**	**30.34**	**26.76**	**31.42**	**30.80**	**32.91**	**36.05**	**34.30**	**34.90**	**38.98**	**36.61**
Direct Margin	**(2.59)**	**(1.23)**	**(6.09)**	**(7.14)**	**(1.89)**	**(3.34)**	**(5.52)**	**2.07**	**8.67**	**10.31**	**15.27**	**20.54**	**16.72**
Overhead Allocation	3.39	3.38	4.84	4.65	4.08	4.54	4.84	5.25	5.87	5.43	5.60	6.34	5.81
Expenses incl. Corp O/H	**28.29**	**25.68**	**36.02**	**34.99**	**30.84**	**35.95**	**35.64**	**38.16**	**41.91**	**39.73**	**40.50**	**45.33**	**42.42**
Margin after Corp O/H	**(5.98)**	**(4.61)**	**(10.93)**	**(11.80)**	**(5.97)**	**(7.87)**	**(10.37)**	**(3.18)**	**2.80**	**4.87**	**9.67**	**14.20**	**10.91**
Costs per kwh (cents)													
Fuel	1.48	1.52	1.67	1.73	1.79	1.87	2.02	2.09	2.19	2.27	2.36	2.46	2.55
Non-fuel	0.61	0.68	0.66	0.77	0.72	0.77	0.96	0.71	0.68	0.79	0.76	0.84	0.96
Capital Expenditures	0.17	0.05	0.46	0.58	0.16	0.28	0.38	0.21	0.05	0.08	0.08	0.09	0.07
Direct Expenses	**2.27**	**2.26**	**2.79**	**3.09**	**2.68**	**2.92**	**3.36**	**3.01**	**2.92**	**3.13**	**3.20**	**3.39**	**3.59**
Direct Margin	**(0.40)**	**(0.29)**	**(0.71)**	**(0.90)**	**(0.37)**	**(0.49)**	**(0.80)**	**0.04**	**0.52**	**0.74**	**1.17**	**1.54**	**1.40**
Overhead Allocation	0.29	0.32	0.41	0.45	0.39	0.40	0.51	0.46	0.45	0.47	0.49	0.53	0.54
Expenses incl. Corp O/H	**2.56**	**2.58**	**3.20**	**3.54**	**3.06**	**3.32**	**3.87**	**3.47**	**3.37**	**3.61**	**3.69**	**3.92**	**4.13**
Margin after Corp O/H	**(0.69)**	**(0.61)**	**(1.12)**	**(1.35)**	**(0.75)**	**(0.89)**	**(1.31)**	**(0.42)**	**0.07**	**0.27**	**0.69**	**1.02**	**0.85**
NPV of Margin after O/H	(15.9)							16.5					
NPV of Decommissioning	4.1							7.0					
NPV OF NET MARGIN	(20.0)							9.5					

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

DELAYED ENTRY

ELRAMA	1999	2000	2001	2002	2003	2004	2005	2006
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43		
Unit Output (gwh)	2,789	2,801	2,810	2,986	2,662	3,040		
Delivered Output (gwh)	2,502	2,513	2,521	2,679	2,388	2,728		
Revenues	**47.74**	**50.32**	**53.43**	**59.76**	**56.26**	**67.31**	**0.00**	
Fuel-Related Expenses								
Fuel Costs	31.50	30.75	31.73	34.55	31.94	37.27		
Fuel Related ECR Costs	6.63	6.81	7.00	7.45	7.15	7.90		
NOx Emissions	5.99	6.33	6.60	7.55	6.46	8.41		
SO2 Emissions	0.55	0.62	(0.31)	(0.29)	(0.40)	(0.32)		
Total Fuel	44.67	44.51	45.02	49.26	45.15	53.27		
Non-fuel O&M Expenses								
Variable O&M	2.80	2.89	2.98	3.24	2.97	3.48		
Fixed O&M	16.16	16.23	17.28	17.11	17.62	17.78		
Overhaul	3.80	1.70	0.00	0.00	3.00	0.00		
Subtotal	22.76	20.82	20.26	20.35	23.59	21.26		
FICA	0.56	0.63	0.64	0.65	0.64	0.70		
Property Tax	0.62	0.62	0.62	0.62	0.62	0.62		
Cap Stock Tax	0.65	0.65	0.65	0.65	0.65	0.65		
Total Non-fuel	24.60	22.72	22.17	22.27	25.50	23.24		
Capital Expenditures	6.13	8.54	5.66	2.73	1.51	1.05		
Direct Expenses	**75.39**	**75.78**	**72.85**	**74.26**	**72.16**	**77.56**		
Direct Margin	**(27.66)**	**(25.46)**	**(19.42)**	**(14.50)**	**(15.90)**	**(10.25)**		
Overhead Allocation	10.26	11.50	11.32	11.39	11.00	11.20		
Expenses incl. Corp O/H	**85.65**	**87.27**	**84.17**	**85.65**	**83.15**	**88.75**		
Margin after Corp O/H	**(37.92)**	**(36.95)**	**(30.73)**	**(25.88)**	**(26.90)**	**(21.44)**		
Costs per kwh (cents)								
Fuel	1.90	1.89	1.90	1.96	2.01	2.08		
Non-fuel	0.98	0.90	0.88	0.83	1.07	0.85		
Capital Expenditures	0.24	0.34	0.22	0.10	0.06	0.04		
Direct Expenses	**3.13**	**3.13**	**3.01**	**2.89**	**3.15**	**2.97**		
Direct Margin	**(1.26)**	**(1.16)**	**(0.93)**	**(0.70)**	**(0.84)**	**(0.54)**		
Overhead Allocation	0.41	0.46	0.45	0.43	0.46	0.41		
Expenses incl. Corp O/H	**3.54**	**3.59**	**3.46**	**3.32**	**3.61**	**3.38**		
Margin after Corp O/H	**(1.67)**	**(1.62)**	**(1.38)**	**(1.13)**	**(1.30)**	**(0.95)**		
NPV of Margin after O/H	(86.7)							0.0
NPV of Decommissioning	20.7							35.0
NPV OF NET MARGIN	(107.4)							(35.0)

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

DELAYED ENTRY

MANSFIELD 1	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99	5.11	5.24	5.37	5.50
Unit Output (gwh)	1,721	1,378	1,860	1,869	1,693	1,885	1,886	1,519	1,973	1,978	1,781	1,973	1,973	1,632	1,865	1,973	1,951
Delivered Output (gwh)	1,561	1,249	1,687	1,695	1,535	1,709	1,710	1,377	1,789	1,794	1,615	1,789	1,789	1,480	1,691	1,789	1,769
Revenues	**30.36**	**25.36**	**35.66**	**37.70**	**35.93**	**42.28**	**44.52**	**41.94**	**61.45**	**69.51**	**70.59**	**88.20**	**89.20**	**75.65**	**88.58**	**96.06**	**97.36**
Fuel-Related Expenses																	
Fuel Costs	25.23	13.65	18.12	18.64	17.38	19.89	20.47	16.86	22.55	23.25	21.55	24.55	25.26	21.48	25.28	27.49	27.98
Fuel Related ECR Costs	3.27	2.72	3.70	3.81	3.57	4.05	4.16	3.49	4.58	4.71	4.38	4.95	5.08	4.36	5.08	5.51	5.59
NOx Emissions	3.04	2.31	3.67	3.84	3.55	4.21	4.40	3.36	5.02	5.23	4.76	5.67	5.92	4.68	5.94	6.70	6.86
SO2 Emissions	(0.13)	(0.19)	(0.21)	(0.23)	(0.28)	(0.26)	(0.28)	(0.39)	(0.31)	(0.33)	(0.41)	(0.39)	(0.43)	(0.58)	(0.53)	(0.53)	(0.58)
Total Fuel	31.41	18.49	25.28	26.06	24.21	27.88	28.75	23.32	31.84	32.87	30.28	34.77	35.84	29.95	35.76	39.16	39.85
Non-fuel O&M Expenses																	
Variable O&M	2.92	2.19	2.94	3.04	2.83	3.21	3.30	2.73	3.63	3.73	3.44	3.90	4.01	3.39	3.97	4.31	4.37
Fixed O&M	4.41	3.10	3.34	3.22	4.77	4.06	4.28	3.52	3.88	3.37	5.83	4.45	4.71	4.74	3.68	3.74	7.33
Overhaul	0.00	2.76	0.00	0.00	0.00	0.00	0.00	2.93	0.00	0.00	0.00	0.00	0.00	2.59	0.81	0.00	0.00
Subtotal	7.33	8.04	6.28	6.26	7.60	7.28	7.58	9.18	7.51	7.10	9.27	8.35	8.72	10.71	8.46	8.06	11.70
FICA	0.22	0.18	0.20	0.20	0.23	0.24	0.22	0.20	0.22	0.21	0.27	0.28	0.24	0.25	0.23	0.24	0.24
Property Tax	0.48	0.48	0.48	0.48	0.48	0.48	0.48	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	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Total Non-fuel	8.52	9.20	7.45	7.43	8.81	8.50	8.78	10.35	8.71	8.29	10.51	9.61	9.94	11.94	9.67	9.28	12.92
Capital Expenditures	0.92	3.41	0.45	0.84	2.97	1.97	0.70	3.20	0.40	0.75	3.45	0.43	0.82	3.72	0.47	0.89	0.86
Direct Expenses	**40.86**	**31.10**	**33.18**	**34.34**	**35.99**	**38.34**	**38.22**	**36.88**	**40.95**	**41.91**	**44.24**	**44.81**	**46.59**	**45.61**	**45.91**	**49.33**	**53.63**
Direct Margin	**(10.49)**	**(5.74)**	**2.48**	**3.36**	**(0.06)**	**3.93**	**6.29**	**5.06**	**20.51**	**27.60**	**26.35**	**43.39**	**42.61**	**30.04**	**42.68**	**46.74**	**43.73**
Overhead Allocation	5.56	4.72	5.16	5.27	5.48	5.54	6.01	5.89	6.66	6.64	7.10	7.29	7.39	7.51	8.00	8.19	9.42
Expenses incl. Corp O/H	**46.42**	**35.81**	**38.34**	**39.61**	**41.47**	**43.88**	**44.23**	**42.77**	**47.61**	**48.55**	**51.34**	**52.10**	**53.98**	**53.12**	**53.91**	**57.52**	**63.05**
Margin after Corp O/H	**(16.05)**	**(10.45)**	**(2.68)**	**(1.91)**	**(5.55)**	**(1.60)**	**0.28**	**(0.83)**	**13.84**	**20.96**	**19.25**	**36.10**	**35.22**	**22.53**	**34.68**	**38.54**	**34.31**
Costs per kwh (cents)																	
Fuel	2.20	1.65	1.67	1.72	1.76	1.82	1.87	1.89	1.98	2.04	2.09	2.16	2.23	2.25	2.35	2.43	2.50
Non-fuel	0.55	0.74	0.44	0.44	0.57	0.50	0.51	0.75	0.49	0.46	0.65	0.54	0.56	0.81	0.57	0.52	0.73
Capital Expenditures	0.06	0.27	0.03	0.05	0.19	0.11	0.04	0.23	0.02	0.04	0.21	0.02	0.05	0.25	0.03	0.05	0.05
Direct Expenses	**2.80**	**2.66**	**2.14**	**2.21**	**2.53**	**2.43**	**2.43**	**2.88**	**2.49**	**2.54**	**2.95**	**2.72**	**2.83**	**3.31**	**2.95**	**3.00**	**3.28**
Direct Margin	**(0.93)**	**(0.69)**	**(0.06)**	**(0.02)**	**(0.22)**	**(0.00)**	**0.13**	**0.17**	**0.94**	**1.33**	**1.42**	**2.21**	**2.16**	**1.80**	**2.29**	**2.37**	**2.23**
Overhead Allocation	0.36	0.38	0.31	0.31	0.36	0.32	0.35	0.43	0.37	0.37	0.44	0.41	0.41	0.51	0.47	0.46	0.53
Expenses incl. Corp O/H	**3.16**	**3.04**	**2.45**	**2.52**	**2.89**	**2.76**	**2.78**	**3.30**	**2.86**	**2.91**	**3.39**	**3.13**	**3.24**	**3.82**	**3.42**	**3.46**	**3.81**
Margin after Corp O/H	**(1.29)**	**(1.07)**	**(0.37)**	**(0.33)**	**(0.58)**	**(0.33)**	**(0.22)**	**(0.26)**	**0.57**	**0.96**	**0.98**	**1.80**	**1.75**	**1.29**	**1.82**	**1.91**	**1.69**
NPV of Margin after O/H	**36.9**							**95.5**									
NPV of Decommissioning	**7.4**							**12.6**									
NPV OF NET MARGIN	**29.4**							**82.9**									

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

DELAYED ENTRY

MANSFIELD 2	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99	5.11	5.24	5.37	5.50	5.64
Unit Output (gwh)	475	509	393	518	520	483	524	549	423	550	548	496	549	550	423	549	549	541
Delivered Output (gwh)	432	463	358	472	473	440	477	500	385	501	499	452	500	501	385	500	500	493
Revenues	**8.43**	**9.32**	**7.59**	**10.51**	**11.11**	**10.87**	**12.42**	**15.22**	**13.22**	**19.42**	**21.81**	**22.28**	**24.92**	**25.61**	**20.16**	**26.84**	**27.50**	**27.81**
Fuel-Related Expenses																		
Fuel Costs	6.89	4.97	3.79	5.11	5.27	5.04	5.62	6.02	4.77	6.39	6.55	6.10	6.95	7.16	5.66	7.56	7.78	7.89
Fuel Related ECR Costs	0.90	0.98	0.79	1.06	1.09	1.04	1.16	1.24	0.99	1.31	1.34	1.25	1.41	1.45	1.16	1.53	1.57	1.59
NOx Emissions	0.87	0.99	0.72	1.10	1.15	1.10	1.26	1.38	1.00	1.50	1.56	1.43	1.70	1.78	1.29	1.92	2.00	2.05
SO2 Emissions	(0.04)	(0.04)	(0.09)	(0.08)	(0.08)	(0.10)	(0.10)	(0.10)	(0.14)	(0.11)	(0.12)	(0.15)	(0.15)	(0.16)	(0.22)	(0.18)	(0.20)	(0.22)
Total Fuel	8.61	6.90	5.21	7.19	7.43	7.08	7.95	8.55	6.64	9.09	9.33	8.63	9.91	10.24	7.90	10.83	11.16	11.31
Non-fuel O&M Expenses																		
Variable O&M	0.81	0.81	0.62	0.85	0.87	0.79	0.92	0.99	0.78	1.04	1.06	0.99	1.12	1.15	0.90	1.21	1.23	1.25
Fixed O&M	1.20	0.84	0.91	0.88	1.30	1.11	1.16	0.96	1.05	0.92	1.58	1.21	1.28	1.29	1.00	1.02	2.01	1.59
Overhaul	0.00	0.00	0.92	0.00	0.00	0.00	0.00	0.00	0.82	0.00	0.00	0.00	0.00	0.00	0.95	0.00	0.00	0.00
Subtotal	2.01	1.65	2.45	1.72	2.17	1.90	2.08	1.95	2.65	1.96	2.65	2.20	2.40	2.44	2.85	2.22	3.24	2.83
FICA	0.06	0.05	0.05	0.05	0.07	0.06	0.06	0.06	0.05	0.06	0.08	0.07	0.07	0.07	0.06	0.07	0.07	0.10
Property Tax	0.13	0.13	0.13	0.13	0.13	0.13	0.13	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	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Total Non-fuel	2.33	1.97	2.76	2.04	2.50	2.23	2.41	2.27	2.98	2.28	2.99	2.53	2.73	2.78	3.18	2.56	3.58	3.20
Capital Expenditures	0.22	0.25	0.71	0.12	0.15	1.30	0.07	0.17	0.87	0.08	0.18	0.93	0.09	0.19	1.01	0.09	0.21	0.17
Direct Expenses	**11.16**	**9.12**	**8.68**	**9.36**	**10.08**	**10.61**	**10.43**	**10.99**	**10.48**	**11.45**	**12.49**	**12.10**	**12.73**	**13.21**	**12.08**	**13.48**	**14.94**	**14.68**
Direct Margin	**(2.72)**	**0.20**	**(1.10)**	**1.15**	**1.03**	**0.25**	**1.99**	**4.23**	**2.74**	**7.97**	**9.32**	**10.18**	**12.19**	**12.40**	**8.07**	**13.36**	**12.56**	**13.12**
Overhead Allocation	1.52	1.38	1.35	1.43	1.54	1.53	1.64	1.75	1.71	1.81	2.00	1.97	2.02	2.18	2.11	2.24	2.62	2.16
Expenses incl. Corp O/H	**12.68**	**10.51**	**10.03**	**10.79**	**11.62**	**12.14**	**12.07**	**12.74**	**12.18**	**13.27**	**14.50**	**14.07**	**14.75**	**15.38**	**14.19**	**15.72**	**17.57**	**16.84**
Margin after Corp O/H	**(4.24)**	**(1.18)**	**(2.45)**	**(0.28)**	**(0.51)**	**(1.28)**	**0.35**	**2.48**	**1.03**	**6.15**	**7.31**	**8.21**	**10.17**	**10.23**	**5.97**	**11.12**	**9.93**	**10.97**
Costs per kwh (cents)																		
Fuel	2.18	1.67	1.63	1.70	1.75	1.79	1.86	1.91	1.93	2.02	2.08	2.13	2.21	2.27	2.29	2.41	2.48	2.55
Non-fuel	0.54	0.43	0.77	0.43	0.53	0.51	0.51	0.46	0.77	0.46	0.60	0.56	0.55	0.55	0.83	0.51	0.72	0.65
Capital Expenditures	0.05	0.05	0.20	0.03	0.03	0.30	0.02	0.03	0.23	0.02	0.04	0.21	0.02	0.04	0.26	0.02	0.04	0.03
Direct Expenses	**2.77**	**2.15**	**2.60**	**2.16**	**2.31**	**2.59**	**2.38**	**2.40**	**2.93**	**2.49**	**2.72**	**2.90**	**2.77**	**2.86**	**3.38**	**2.94**	**3.24**	**3.23**
Direct Margin	**(0.90)**	**(0.18)**	**(0.52)**	**0.03**	**(0.00)**	**(0.16)**	**0.18**	**0.65**	**0.51**	**1.38**	**1.65**	**2.03**	**2.21**	**2.25**	**1.86**	**2.43**	**2.27**	**2.41**
Overhead Allocation	0.35	0.30	0.38	0.30	0.32	0.35	0.34	0.35	0.44	0.36	0.40	0.44	0.40	0.43	0.55	0.45	0.53	0.44
Expenses incl. Corp O/H	**3.12**	**2.44**	**2.98**	**2.47**	**2.64**	**2.94**	**2.72**	**2.75**	**3.37**	**2.86**	**3.12**	**3.33**	**3.18**	**3.30**	**3.92**	**3.39**	**3.76**	**3.67**
Margin after Corp O/H	**(1.25)**	**(0.47)**	**(0.90)**	**(0.28)**	**(0.33)**	**(0.51)**	**(0.16)**	**0.30**	**0.07**	**1.02**	**1.25**	**1.60**	**1.81**	**1.81**	**1.32**	**1.98**	**1.74**	**1.97**
NPV of Margin after O/H	13.0							30.4										
NPV of Decommissioning	0.5							0.9										
NPV OF NET MARGIN	12.5							29.5										

DUQUESNE [redacted]HT

Costs of Fossil Plants

$ in Millions

DELAYED ENTRY

MANSFIELD 3	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99	5.11	5.24	5.37	5.50	5.64	5.78
Unit Output (gwh)	778	897	910	697	913	917	826	945	945	749	945	945	855	948	945	738	935	948	855
Delivered Output (gwh)	720	830	842	645	845	848	764	875	875	693	874	875	791	877	875	683	865	877	791
Revenues	**13.79**	**16.59**	**17.69**	**14.28**	**19.72**	**20.88**	**19.81**	**26.64**	**30.05**	**26.84**	**38.20**	**43.13**	**39.44**	**44.83**	**45.83**	**36.68**	**47.61**	**49.49**	**45.74**
Fuel-Related Expenses																			
Fuel Costs	11.15	8.69	8.71	6.83	9.20	9.50	8.81	10.34	10.64	8.67	11.25	11.58	10.78	12.28	12.62	10.13	13.21	13.78	12.75
Fuel Related ECR Costs	1.52	1.77	1.85	1.48	1.95	2.01	1.87	2.18	2.24	1.85	2.36	2.42	2.26	2.56	2.62	2.14	2.74	2.85	2.65
NOx Emissions	1.67	2.07	2.20	1.61	2.40	2.51	2.30	2.83	2.95	2.25	3.19	3.33	3.04	3.64	3.78	2.80	4.04	4.30	3.91
SO2 Emissions	0.10	0.12	(0.13)	(0.17)	(0.15)	(0.16)	(0.19)	(0.18)	(0.19)	(0.26)	(0.23)	(0.25)	(0.29)	(0.29)	(0.31)	(0.41)	(0.36)	(0.38)	(0.46)
Total Fuel	14.43	12.66	12.62	9.75	13.40	13.86	12.79	15.17	15.64	12.50	16.58	17.09	15.79	18.20	18.71	14.65	19.63	20.54	18.85
Non-fuel O&M Expenses																			
Variable O&M	1.35	1.45	1.47	1.16	1.56	1.60	1.48	1.73	1.78	1.44	1.86	1.91	1.77	2.01	2.06	1.65	2.14	2.22	2.06
Fixed O&M	2.13	1.50	1.61	1.55	2.30	1.96	2.06	1.70	1.87	1.62	2.81	2.15	2.27	2.28	1.78	1.81	3.57	2.86	2.83
Overhaul	0.00	0.00	0.00	1.24	0.00	0.00	0.00	0.00	0.00	1.32	0.00	0.00	0.00	0.00	0.00	1.59	0.08	0.00	0.00
Subtotal	3.47	2.95	3.08	3.95	3.86	3.56	3.54	3.43	3.65	4.39	4.67	4.05	4.04	4.29	3.83	5.04	5.78	5.08	4.89
FICA	0.10	0.10	0.10	0.09	0.12	0.12	0.10	0.11	0.11	0.09	0.13	0.14	0.11	0.13	0.12	0.10	0.12	0.18	0.19
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	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	0.24	0.24	0.24	0.24	0.24
Total Non-fuel	4.05	3.52	3.65	4.51	4.45	4.15	4.11	4.01	4.23	4.95	5.28	4.66	4.63	4.90	4.42	5.62	6.37	5.74	5.55
Capital Expenditures	1.20	0.36	0.22	1.46	0.17	1.13	1.47	0.19	0.35	1.59	0.21	0.38	1.71	0.22	0.41	1.85	0.25	0.45	1.99
Direct Expenses	**19.69**	**16.54**	**16.49**	**15.72**	**18.02**	**19.13**	**18.37**	**19.37**	**20.22**	**19.04**	**22.06**	**22.14**	**22.13**	**23.32**	**23.55**	**22.12**	**26.25**	**26.72**	**26.39**
Direct Margin	**(5.89)**	**0.05**	**1.21**	**(1.44)**	**1.69**	**1.75**	**1.44**	**7.27**	**9.83**	**7.80**	**16.14**	**20.99**	**17.31**	**21.51**	**22.28**	**14.56**	**21.36**	**22.76**	**19.34**
Overhead Allocation	2.68	2.51	2.56	2.41	2.75	2.76	2.89	3.09	3.29	3.02	3.54	3.60	3.51	3.84	4.11	3.67	4.61	3.93	3.82
Expenses incl. Corp O/H	**22.37**	**19.04**	**19.05**	**18.13**	**20.77**	**21.90**	**21.26**	**22.46**	**23.51**	**22.06**	**25.60**	**25.74**	**25.64**	**27.16**	**27.65**	**25.79**	**30.85**	**30.65**	**30.21**
Margin after Corp O/H	**(8.57)**	**(2.46)**	**(1.36)**	**(3.85)**	**(1.05)**	**(1.01)**	**(1.45)**	**4.18**	**6.54**	**4.78**	**12.60**	**17.39**	**13.80**	**17.67**	**18.18**	**10.88**	**16.75**	**18.84**	**15.53**
Costs per kwh (cents)																			
Fuel	2.19	1.70	1.67	1.69	1.77	1.82	1.87	1.93	1.99	2.01	2.11	2.17	2.22	2.30	2.37	2.39	2.52	2.59	2.64
Non-fuel	0.56	0.42	0.43	0.70	0.53	0.49	0.54	0.46	0.48	0.71	0.60	0.53	0.59	0.56	0.51	0.82	0.74	0.65	0.70
Capital Expenditures	0.17	0.04	0.03	0.23	0.02	0.13	0.19	0.02	0.04	0.23	0.02	0.04	0.22	0.03	0.05	0.27	0.03	0.05	0.25
Direct Expenses	**2.91**	**2.17**	**2.13**	**2.62**	**2.32**	**2.44**	**2.60**	**2.41**	**2.51**	**2.96**	**2.74**	**2.75**	**3.02**	**2.89**	**2.93**	**3.48**	**3.28**	**3.30**	**3.60**
Direct Margin	**(1.05)**	**(0.20)**	**(0.05)**	**(0.43)**	**(0.01)**	**(0.01)**	**(0.04)**	**0.63**	**0.92**	**0.92**	**1.63**	**2.18**	**1.96**	**2.22**	**2.31**	**1.89**	**2.22**	**2.34**	**2.19**
Overhead Allocation	0.37	0.30	0.30	0.37	0.33	0.33	0.38	0.35	0.38	0.44	0.41	0.41	0.44	0.44	0.47	0.54	0.53	0.45	0.48
Expenses incl. Corp O/H	**3.29**	**2.47**	**2.44**	**2.99**	**2.64**	**2.77**	**2.98**	**2.77**	**2.89**	**3.39**	**3.14**	**3.16**	**3.47**	**3.33**	**3.40**	**4.02**	**3.81**	**3.75**	**4.08**
Margin after Corp O/H	**(1.42)**	**(0.50)**	**(0.36)**	**(0.80)**	**(0.33)**	**(0.34)**	**(0.42)**	**0.28**	**0.55**	**0.48**	**1.23**	**1.77**	**1.52**	**1.79**	**1.84**	**1.35**	**1.69**	**1.89**	**1.70**
NPV of Margin after O/H	28.0							64.2											
NPV of Decommissioning	1.4							2.3											
NPV OF NET MARGIN	26.6							61.9											

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

MANSFIELD 3	2018	2019
kwh Market Price (cents)	5.93	6.08
Unit Output (gwh)	945	940
Delivered Output (gwh)	875	870
Revenues	**51.85**	**52.86**
Fuel-Related Expenses		
Fuel Costs	14.49	14.80
Fuel Related ECR Costs	3.00	3.06
NOx Emissions	4.66	4.81
SO2 Emissions	(0.45)	(0.49)
Total Fuel	21.69	22.18
Non-fuel O&M Expenses		
Variable O&M	2.34	2.38
Fixed O&M	3.21	3.28
Overhaul	0.00	0.00
Subtotal	5.55	5.66
FICA	0.19	0.20
Property Tax	0.23	0.23
Cap Stock Tax	0.24	0.24
Total Non-fuel	6.21	6.33
Capital Expenditures	0.27	0.49
Direct Expenses	**28.17**	**29.00**
Direct Margin	**23.68**	**23.85**
Overhead Allocation	4.43	4.30
Expenses incl. Corp O/H	**32.60**	**33.30**
Margin after Corp O/H	**19.25**	**19.55**
Costs per kwh (cents)		
Fuel	2.75	2.82
Non-fuel	0.71	0.73
Capital Expenditures	0.03	0.06
Direct Expenses	**3.49**	**3.61**
Direct Margin	**2.44**	**2.47**
Overhead Allocation	0.51	0.49
Expenses incl. Corp O/H	**3.99**	**4.10**
Margin after Corp O/H	**1.93**	**1.97**
NPV of Margin after O/H		
NPV of Decommissioning		
NPV OF NET MARGIN		

DUQUESNE LIGHT

Costs of Fossil Plants

$ in Millions

DELAYED ENTRY

BRUNOT ISLAND	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
kwh Market Price (cents)	9.35	9.85	10.40	10.95	11.55	12.15	12.80	15.23	17.18	19.38	21.86	24.65	24.93	25.56
Unit Output (gwh)	0	0	0	0	0	0	0	27	27	27	27	27	27	27
Delivered Output (gwh)	0	0	0	0	0	0	0	25.40	25.40	25.40	25.40	25.40	25.40	25.40
Revenues	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**3.87**	**4.36**	**4.92**	**5.55**	**6.26**	**6.33**	**6.49**
Fuel-Related Expenses														
Fuel Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Fuel Related ECR 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	0.00	0.00
NOx Emissions	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
SO2 Emissions	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
Total Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Non-fuel O&M Expenses														
Variable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Fixed O&M	0.59	0.61	0.62	0.64	0.65	0.67	0.69	0.71	0.73	0.75	0.77	0.79	0.79	0.00
Overhaul	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
Subtotal	0.59	0.61	0.62	0.64	0.65	0.67	0.69	0.74	0.76	0.78	0.80	0.82	0.83	0.03
FICA	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.00
Property Tax	0.33	0.33	0.33	0.33	0.33	0.33	0.33	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	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Total Non-fuel	1.27	1.29	1.30	1.32	1.34	1.36	1.38	1.43	1.44	1.47	1.48	1.51	1.51	0.70
Capital Expenditures	1.61	0.17	0.17	0.17	0.18	4.38	0.19	0.20	0.20	0.21	0.19	0.19	0.20	0.11
Direct Expenses	**2.88**	**1.46**	**1.47**	**1.50**	**1.52**	**5.74**	**1.57**	**4.09**	**4.18**	**4.27**	**4.34**	**4.45**	**4.53**	**3.71**
Direct Margin	**(2.88)**	**(1.46)**	**(1.47)**	**(1.50)**	**(1.52)**	**(5.74)**	**(1.57)**	**(0.22)**	**0.19**	**0.65**	**1.21**	**1.81**	**1.80**	**2.79**
Overhead Allocation	0.39	0.22	0.23	0.23	0.23	0.83	0.25	0.65	0.68	0.68	0.70	0.72	0.72	0.61
Expenses incl. Corp O/H	**3.27**	**1.68**	**1.70**	**1.73**	**1.75**	**6.57**	**1.81**	**4.74**	**4.86**	**4.95**	**5.04**	**5.17**	**5.25**	**4.32**
Margin after Corp O/H	**(3.27)**	**(1.68)**	**(1.70)**	**(1.73)**	**(1.75)**	**(6.57)**	**(1.81)**	**(0.87)**	**(0.49)**	**(0.03)**	**0.51**	**1.09**	**1.08**	**2.18**
Costs per kwh (cents)														
Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.82	10.09	10.36	10.64	10.93	11.22	11.52
Non-fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.61	5.68	5.77	5.84	5.95	5.96	0.00
Capital Expenditures	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.79	0.81	0.75	0.77	0.79	0.00
Direct Expenses	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**16.20**	**16.56**	**16.94**	**17.23**	**17.64**	**17.97**	**11.52**
Direct Margin	***0.00***	***0.00***	***0.00***	**0.00**	**0.00**	**0.00**	**0.00**	**(0.97)**	**0.62**	**2.44**	**4.63**	**7.01**	**6.97**	**0.00**
Overhead Allocation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.57	2.68	2.66	2.74	2.85	2.83	0.00
Expenses incl. Corp O/H	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**18.77**	**19.23**	**19.60**	**19.97**	**20.49**	**20.80**	**11.52**
Margin after Corp O/H	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**(3.54)**	**(2.06)**	**(0.23)**	**1.89**	**4.16**	**4.14**	**0.00**
NPV of Margin after O/H	(7.6)							1.1						
NPV of Decommissioning	8.2							13.9						
NPV OF NET MARGIN	(15.8)							(12.7)						

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

DELAYED ENTRY

BEAVER VALLEY 1	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99	5.11	5.24
Unit Output (gwh)	2,726	2,874	3,373	2,864	2,864	3,382	2,864	2,864	3,373	2,874	2,864	3,373	2,864	2,874	3,373
Delivered Output (gwh)	2,564	2,703	3,172	2,694	2,694	3,181	2,694	2,694	3,172	2,703	2,694	3,172	2,694	2,703	3,172
Revenues	**48.26**	**53.21**	**65.93**	**59.40**	**62.30**	**77.57**	**69.71**	**82.05**	**108.97**	**104.73**	**117.76**	**156.40**	**134.34**	**138.14**	**166.18**
Fuel-Related Expenses															
Fuel Costs	11.11	11.27	13.25	11.59	11.49	13.94	12.30	12.50	15.20	13.39	13.75	16.73	14.67	15.17	18.38
Fuel Related ECR Costs	2.56	2.70	3.17	2.69	2.69	3.18	2.69	2.69	3.17	2.70	2.69	3.17	2.69	2.70	3.17
Total Fuel	13.68	13.97	16.42	14.29	14.19	17.12	14.99	15.20	18.37	16.09	16.45	19.91	17.37	17.88	21.55
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
Fixed O&M	30.76	24.97	25.62	26.29	27.00	27.73	28.48	29.19	29.92	30.67	31.44	32.22	33.03	33.85	34.70
Overhaul	16.39	13.68	0.00	14.40	14.79	0.00	15.60	16.02	0.00	16.88	17.32	0.00	18.25	18.74	0.00
Subtotal	47.15	38.65	25.62	40.69	41.79	27.73	44.08	45.21	29.92	47.55	48.76	32.22	51.28	52.60	34.70
FICA	1.42	1.45	1.48	1.51	1.54	1.57	1.60	1.64	1.67	1.70	1.74	1.77	1.81	1.84	1.88
Property Tax	2.06	2.06	2.06	2.06	2.06	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	2.15	2.15	2.15	2.15	2.15
Total Non-fuel	52.78	44.31	31.31	46.41	47.53	33.51	49.89	51.06	35.80	53.46	54.70	38.20	57.29	58.65	40.79
Capital Expenditures	6.76	5.69	5.84	5.99	6.16	6.33	6.50	6.68	6.86	7.04	7.23	7.43	7.63	7.84	8.06
	18.49														
Direct Expenses	**73.21**	**63.96**	**53.56**	**66.68**	**67.88**	**56.96**	**71.38**	**72.93**	**61.03**	**76.59**	**78.37**	**65.53**	**82.29**	**84.36**	**70.39**
Direct Margin	**(24.95)**	**(10.75)**	**12.36**	**(7.29)**	**(5.58)**	**20.61**	**(1.67)**	**9.12**	**47.94**	**28.14**	**39.38**	**90.86**	**52.05**	**53.78**	**95.79**
Overhead Allocation	9.96	9.70	8.32	10.23	10.35	8.22	11.23	11.64	9.93	12.14	12.57	10.66	13.05	13.90	12.27
Expenses incl. Corp O/H	**83.18**	**73.67**	**61.89**	**76.91**	**78.22**	**65.18**	**82.61**	**84.57**	**70.96**	**88.73**	**90.95**	**76.20**	**95.34**	**98.26**	**82.67**
Margin after Corp O/H	**(34.91)**	**(20.45)**	**4.04**	**(17.52)**	**(15.93)**	**12.39**	**(12.90)**	**(2.53)**	**38.01**	**16.00**	**26.81**	**80.20**	**39.00**	**39.88**	**83.52**
Costs per kwh (cents)															
Fuel	0.53	0.52	0.52	0.53	0.53	0.54	0.56	0.56	0.58	0.60	0.61	0.63	0.64	0.66	0.68
Non-fuel	2.06	1.64	0.99	1.72	1.76	1.05	1.85	1.90	1.13	1.98	2.03	1.20	2.13	2.17	1.29
Capital Expenditures	0.26	0.21	0.18	0.22	0.23	0.20	0.24	0.25	0.22	0.26	0.27	0.23	0.28	0.29	0.25
Direct Expenses	**2.86**	**2.37**	**1.69**	**2.48**	**2.52**	**1.79**	**2.65**	**2.71**	**1.92**	**2.83**	**2.91**	**2.07**	**3.05**	**3.12**	**2.22**
Direct Margin	**(0.99)**	**(0.40)**	**0.39**	**(0.29)**	**(0.21)**	**0.64**	**(0.09)**	**0.34**	**1.51**	**1.04**	**1.46**	**2.86**	**1.93**	**1.99**	**3.02**
Overhead Allocation	0.39	0.36	0.26	0.38	0.38	0.26	0.42	0.43	0.31	0.45	0.47	0.34	0.48	0.51	0.39
Expenses incl. Corp O/H	**3.24**	**2.73**	**1.95**	**2.85**	**2.90**	**2.05**	**3.07**	**3.14**	**2.24**	**3.28**	**3.38**	**2.40**	**3.54**	**3.64**	**2.61**
Margin after Corp O/H	**(1.37)**	**(0.76)**	**0.13**	**(0.66)**	**(0.59)**	**0.38**	**(0.51)**	**(0.09)**	**1.20**	**0.59**	**1.00**	**2.53**	**1.45**	**1.48**	**2.63**
NPV of Margin after O/H	55.3							166.2							
Overfunded Decomm.	0.0							0.0							
NPV OF NET MARGIN	55.3							166.2							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

BEAVER VALLEY 1	**2014**	**2015**
kwh Market Price (cents)	5.37	5.50
Unit Output (gwh)	2,864	3,336
Delivered Output (gwh)	2,694	3,137
Revenues	**144.67**	**172.68**
Fuel-Related Expenses		
Fuel Costs	16.10	19.31
Fuel Related ECR Costs	2.69	3.14
Total Fuel	18.79	22.44
Non-fuel O&M Expenses		
Variable O&M	0.00	0.00
Fixed O&M	35.57	36.46
Overhaul	19.77	0.00
Subtotal	55.33	36.46
FICA	1.92	1.95
Property Tax	2.06	2.06
Cap Stock Tax	2.15	2.15
Total Non-fuel	61.46	42.62
Capital Expenditures	8.28	8.51
Direct Expenses	**88.53**	**73.57**
Direct Margin	**56.14**	**99.11**
Overhead Allocation	14.71	12.92
Expenses incl. Corp O/H	**103.23**	**86.49**
Margin after Corp O/H	**41.44**	**86.19**
Costs per kwh (cents)		
Fuel	0.70	0.72
Non-fuel	2.28	1.36
Capital Expenditures	0.31	0.27
Direct Expenses	**3.29**	**2.35**
Direct Margin	**2.08**	**3.16**
Overhead Allocation	0.55	0.41
Expenses incl. Corp O/H	**3.83**	**2.76**
Margin after Corp O/H	**1.54**	**2.75**
NPV of Margin after O/H		
Overfunded Decomm.		
NPV OF NET MARGIN		

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

DELAYED ENTRY

BEAVER VALLEY 2	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99	5.11	5.24
Unit Output (gwh)	883	994	883	883	991	885	883	991	883	885	991	883	883	994	883
Delivered Output (gwh)	829	934	829	829	931	832	829	931	829	832	931	829	829	934	829
Revenues	**15.47**	**18.37**	**17.32**	**18.11**	**21.52**	**20.28**	**21.26**	**28.35**	**28.48**	**32.22**	**40.69**	**40.87**	**41.34**	**47.72**	**43.43**
Fuel-Related Expenses															
Fuel Costs	3.38	3.96	3.61	3.54	3.93	3.58	3.53	4.04	3.72	3.84	4.44	4.09	4.22	4.90	4.50
Fuel Related ECR Costs	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83
Total Fuel	4.21	4.90	4.44	4.36	4.86	4.41	4.36	4.97	4.54	4.68	5.38	4.92	5.05	5.84	5.32
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
Fixed O&M	8.88	7.22	7.41	7.61	7.81	8.02	8.24	8.45	8.66	8.87	9.10	9.32	9.56	9.79	10.04
Overhaul	3.02	0.00	3.10	3.18	0.00	3.36	3.45	0.00	3.64	3.73	0.00	3.93	4.03	0.00	4.25
Subtotal	11.90	7.22	10.51	10.79	7.81	11.38	11.69	8.45	12.29	12.60	9.10	13.25	13.59	9.79	14.29
FICA	0.40	0.41	0.42	0.43	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
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
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
Total Non-fuel	13.15	8.49	11.78	12.07	9.10	12.68	12.99	9.76	13.62	13.94	10.44	14.60	14.95	11.17	15.68
Capital Expenditures	6.65	4.86	4.99	5.12	5.26	5.40	5.54	5.70	5.84	6.00	6.15	6.32	6.49	6.67	6.85
Direct Expenses	**24.01**	**18.24**	**21.21**	**21.55**	**19.22**	**22.49**	**22.90**	**20.42**	**24.00**	**24.61**	**21.97**	**25.84**	**26.49**	**23.67**	**27.85**
Direct Margin	**(8.54)**	**0.13**	**(3.89)**	**(3.44)**	**2.30**	**(2.20)**	**(1.64)**	**7.93**	**4.47**	**7.61**	**18.73**	**15.03**	**14.84**	**24.05**	**15.58**
Overhead Allocation	3.27	2.77	3.30	3.30	2.93	3.25	3.60	3.26	3.91	3.90	3.52	4.20	4.20	3.90	4.85
Expenses incl. Corp O/H	**27.28**	**21.01**	**24.51**	**24.85**	**22.14**	**25.73**	**26.50**	**23.68**	**27.91**	**28.51**	**25.49**	**30.04**	**30.70**	**27.57**	**32.70**
Margin after Corp O/H	**(11.81)**	**(2.64)**	**(7.19)**	**(6.74)**	**(0.63)**	**(5.45)**	**(5.24)**	**4.67**	**0.57**	**3.71**	**15.20**	**10.83**	**10.64**	**20.15**	**10.73**
Costs per kwh (cents)															
Fuel	0.51	0.52	0.54	0.53	0.52	0.53	0.53	0.53	0.55	0.56	0.58	0.59	0.61	0.63	0.64
Non-fuel	1.59	0.91	1.42	1.46	0.98	1.52	1.57	1.05	1.64	1.68	1.12	1.76	1.80	1.20	1.89
Capital Expenditures	0.80	0.52	0.60	0.62	0.56	0.65	0.67	0.61	0.70	0.72	0.66	0.76	0.78	0.71	0.83
Direct Expenses	**2.90**	**1.95**	**2.56**	**2.60**	**2.06**	**2.70**	**2.76**	**2.19**	**2.90**	**2.96**	**2.36**	**3.12**	**3.20**	**2.54**	**3.36**
Direct Margin	**(1.03)**	**0.02**	**(0.48)**	**(0.41)**	**0.25**	**(0.27)**	**(0.20)**	**0.85**	**0.54**	**0.92**	**2.01**	**1.81**	**1.79**	**2.58**	**1.88**
Overhead Allocation	0.39	0.30	0.40	0.40	0.31	0.39	0.43	0.35	0.47	0.47	0.38	0.51	0.51	0.42	0.59
Expenses incl. Corp O/H	**3.29**	**2.25**	**2.96**	**3.00**	**2.38**	**3.09**	**3.20**	**2.54**	**3.37**	**3.43**	**2.74**	**3.62**	**3.70**	**2.95**	**3.94**
Margin after Corp O/H	**(1.42)**	**(0.28)**	**(0.88)**	**(0.81)**	**(0.07)**	**(0.66)**	**(0.64)**	**0.50**	**0.07**	**0.45**	**1.63**	**1.31**	**1.28**	**2.16**	**1.29**
NPV of Margin after O/H	**25.8**							**75.6**							
Underfunded Decomm.	**5.0**							**8.5**							
NPV OF NET MARGIN	**20.8**							**67.1**							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

BEAVER VALLEY 2	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	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)	883	991	883	883	991	883	883	991	883	883	991	883	991
Delivered Output (gwh)	829	931	829	829	931	829	829	931	829	829	931	829	931
Revenues	**44.52**	**51.24**	**46.77**	**47.94**	**55.18**	**50.37**	**51.62**	**59.43**	**54.24**	**55.59**	**64.00**	**58.41**	**67.24**
Fuel-Related Expenses													
Fuel Costs	4.64	5.38	4.94	5.09	5.89	5.43	5.59	6.46	5.97	6.13	7.09	6.56	6.73
Fuel Related ECR Costs	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83
Total Fuel	5.47	6.31	5.77	5.92	6.82	6.26	6.42	7.39	6.80	6.96	8.02	7.39	7.56
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
Fixed O&M	10.29	10.55	10.81	11.08	11.36	11.64	11.93	12.23	12.54	12.85	13.17	13.50	13.84
Overhaul	4.37	0.00	4.61	4.73	0.00	4.99	5.13	0.00	5.41	5.55	0.00	5.86	6.02
Subtotal	14.66	10.55	15.42	15.81	11.36	16.63	17.06	12.23	17.94	18.41	13.17	19.36	19.86
FICA	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
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
Total Non-fuel	16.05	11.95	16.86	17.26	12.82	18.11	18.55	13.73	19.46	19.93	14.71	20.91	21.42
Capital Expenditures	7.03	7.22	7.24	7.42	7.61	7.80	7.99	8.19	8.40	8.61	8.82	9.04	9.27
Direct Expenses	**28.55**	**25.48**	**29.87**	**30.60**	**27.25**	**32.16**	**32.95**	**29.32**	**34.65**	**35.50**	**31.55**	**37.34**	**38.25**
Direct Margin	**15.97**	**25.76**	**16.90**	**17.34**	**27.93**	**18.20**	**18.67**	**30.11**	**19.59**	**20.10**	**32.45**	**21.07**	**28.98**
Overhead Allocation	4.74	4.47	4.39	4.42	4.28	4.77	5.20	4.72	5.71	5.69	5.72	6.26	7.51
Expenses incl. Corp O/H	**33.29**	**29.96**	**34.25**	**35.03**	**31.54**	**36.93**	**38.15**	**34.03**	**40.36**	**41.19**	**37.27**	**43.60**	**45.76**
Margin after Corp O/H	**11.22**	**21.29**	**12.52**	**12.91**	**23.65**	**13.43**	**13.47**	**25.39**	**13.88**	**14.40**	**26.73**	**14.81**	**21.48**
Costs per kwh (cents)													
Fuel	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79	0.82	0.84	0.86	0.89	0.81
Non-fuel	1.94	1.28	2.03	2.08	1.38	2.18	2.24	1.48	2.35	2.40	1.58	2.52	2.30
Capital Expenditures	0.85	0.78	0.87	0.90	0.82	0.94	0.96	0.88	1.01	1.04	0.95	1.09	1.00
Direct Expenses	**3.44**	**2.74**	**3.60**	**3.69**	**2.93**	**3.88**	**3.98**	**3.15**	**4.18**	**4.28**	**3.39**	**4.50**	**4.11**
Direct Margin	**1.93**	**2.77**	**2.04**	**2.09**	**3.00**	**2.20**	**2.25**	**3.23**	**2.36**	**2.42**	**3.49**	**2.54**	**3.11**
Overhead Allocation	0.57	0.48	0.53	0.53	0.46	0.58	0.63	0.51	0.69	0.69	0.61	0.76	0.81
Expenses incl. Corp O/H	**4.02**	**3.22**	**4.13**	**4.23**	**3.39**	**4.46**	**4.60**	**3.66**	**4.87**	**4.97**	**4.00**	**5.26**	**4.92**
Margin after Corp O/H	**1.35**	**2.29**	**1.51**	**1.56**	**2.54**	**1.62**	**1.63**	**2.73**	**1.67**	**1.74**	**2.87**	**1.79**	**2.31**
NPV of Margin after O/H													
Underfunded Decomm.													
NPV OF NET MARGIN													

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

DELAYED ENTRY

PERRY	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
kwh Market Price (cents)	1.87	1.97	2.08	2.19	2.31	2.43	2.56	3.05	3.44	3.88	4.37	4.93	4.99	5.11	5.24
Unit Output (gwh)	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256
Delivered Output (gwh)	1,195	1,347	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195	1,343	1,195	1,346	1,195
Revenues	**22.43**	**26.50**	**24.96**	**29.40**	**27.76**	**32.83**	**30.85**	**40.90**	**41.04**	**52.18**	**52.23**	**66.20**	**59.57**	**68.82**	**62.60**
Fuel-Related Expenses															
Fuel Costs	5.25	5.80	5.27	5.95	5.36	6.10	5.69	6.42	5.91	6.87	6.29	7.30	6.70	7.79	7.13
Fuel Related ECR Costs	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
Total Fuel	6.44	7.15	6.46	7.30	6.55	7.44	6.89	7.77	7.10	8.22	7.49	8.64	7.89	9.13	8.32
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
Fixed O&M	16.25	15.25	16.29	16.33	16.75	17.23	17.67	18.11	18.56	19.03	19.50	19.99	20.49	21.00	21.53
Overhaul	3.29	0.00	3.38	0.00	3.56	0.00	3.75	0.00	3.96	0.00	4.16	0.00	4.39	0.00	4.63
Subtotal	19.54	15.25	19.67	16.33	20.30	17.23	21.42	18.11	22.52	19.03	23.67	19.99	24.88	21.00	26.15
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
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
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
Total Non-fuel	33.25	28.95	33.37	30.04	34.00	30.94	35.12	31.81	36.22	32.73	37.37	33.69	38.58	34.70	39.86
Capital Expenditures	5.09	2.35	2.98	2.48	3.15	3.04	3.33	3.22	3.52	3.40	3.72	3.59	3.93	3.80	4.16
Direct Expenses	**44.78**	**38.44**	**42.81**	**39.81**	**43.70**	**41.42**	**45.34**	**42.80**	**46.84**	**44.34**	**48.57**	**45.92**	**50.41**	**47.63**	**52.34**
Direct Margin	**(22.35)**	**(11.94)**	**(17.85)**	**(10.41)**	**(15.95)**	**(8.58)**	**(14.50)**	**(1.90)**	**(5.80)**	**7.83**	**3.65**	**20.28**	**9.17**	**21.18**	**10.26**
Overhead Allocation	6.09	5.83	6.65	6.11	6.66	5.98	7.13	6.83	7.62	7.03	7.79	7.47	7.99	7.85	9.12
Expenses incl. Corp O/H	**50.87**	**44.27**	**49.47**	**45.91**	**50.37**	**47.40**	**52.47**	**49.63**	**54.47**	**51.37**	**56.37**	**53.40**	**58.40**	**55.48**	**61.46**
Margin after Corp O/H	**(28.44)**	**(17.78)**	**(24.50)**	**(16.51)**	**(22.61)**	**(14.56)**	**(21.63)**	**(8.73)**	**(13.43)**	**0.80**	**(4.14)**	**12.81**	**1.17**	**13.34**	**1.14**
Costs per kwh (cents)															
Fuel	0.54	0.53	0.54	0.54	0.55	0.55	0.58	0.58	0.59	0.61	0.63	0.64	0.66	0.68	0.70
Non-fuel	2.78	2.15	2.79	2.24	2.85	2.30	2.94	2.37	3.03	2.43	3.13	2.51	3.23	2.58	3.34
Capital Expenditures	0.43	0.17	0.25	0.18	0.26	0.23	0.28	0.24	0.29	0.25	0.31	0.27	0.33	0.28	0.35
Direct Expenses	**3.75**	**2.85**	**3.58**	**2.96**	**3.66**	**3.08**	**3.80**	**3.19**	**3.92**	**3.29**	**4.07**	**3.42**	**4.22**	**3.54**	**4.38**
Direct Margin	**(1.88)**	**(0.88)**	**(1.50)**	**(0.77)**	**(1.35)**	**(0.65)**	**(1.24)**	**(0.14)**	**(0.49)**	**0.58**	**0.31**	**1.51**	**0.77**	**1.57**	**0.86**
Overhead Allocation	0.51	0.43	0.56	0.45	0.56	0.44	0.60	0.51	0.64	0.52	0.65	0.56	0.67	0.58	0.76
Expenses incl. Corp O/H	**4.26**	**3.29**	**4.14**	**3.42**	**4.22**	**3.52**	**4.39**	**3.70**	**4.56**	**3.82**	**4.72**	**3.98**	**4.89**	**4.12**	**5.14**
Margin after Corp O/H	**(2.39)**	**(1.32)**	**(2.06)**	**(1.23)**	**(1.91)**	**(1.09)**	**(1.83)**	**(0.65)**	**(1.12)**	**0.06**	**(0.35)**	**0.95**	**0.10**	**0.99**	**0.10**
NPV of Margin after O/H	(48.3)							32.5							
Underfunded Decomm.	6.5							11.0							
NPV OF NET MARGIN	(54.8)							21.4							

DUQUESNE LIGHT

Costs of Nuclear Plants

$ in Millions

PERRY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
kwh Market Price (cents)	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)	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,416
Delivered Output (gwh)	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
Revenues	**72.10**	**65.77**	**75.96**	**69.09**	**79.59**	**72.59**	**83.86**	**76.26**	**87.85**	**80.13**	**92.57**	**84.18**	**97.25**
Fuel-Related Expenses													
Fuel Costs	8.25	7.58	8.80	8.04	9.29	8.49	9.82	8.71	9.79	8.71	9.82	8.71	2.43
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	0.33
Total Fuel	9.59	8.78	10.15	9.24	10.63	9.68	11.17	9.91	11.14	9.91	11.17	9.91	2.76
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
Fixed O&M	22.06	22.62	23.18	23.76	24.35	24.96	25.59	26.23	26.88	27.55	28.24	28.95	29.67
Overhaul	0.00	4.88	0.00	5.15	0.00	5.43	0.00	5.58	0.00	5.58	0.00	5.58	0.00
Subtotal	22.06	27.50	23.18	28.91	24.35	30.39	25.59	31.80	26.88	33.13	28.24	34.53	29.67
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
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
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
Total Non-fuel	35.77	41.20	36.88	42.61	38.06	44.10	39.29	45.51	40.59	46.83	41.95	48.23	43.38
Capital Expenditures	4.02	4.40	4.25	4.64	4.48	4.90	4.73	5.17	5.00	5.45	5.27	5.75	5.56
Direct Expenses	**49.38**	**54.37**	**51.28**	**56.49**	**53.17**	**58.67**	**55.19**	**60.58**	**56.72**	**62.19**	**58.38**	**63.89**	**51.70**
Direct Margin	**22.73**	**11.39**	**24.68**	**12.60**	**26.42**	**13.92**	**28.67**	**15.68**	**31.14**	**17.93**	**34.18**	**20.30**	**45.55**
Overhead Allocation	8.20	9.55	7.53	8.17	8.36	8.70	8.70	9.75	9.35	9.97	10.58	10.71	10.15
Expenses incl. Corp O/H	**57.58**	**63.92**	**58.81**	**64.66**	**61.53**	**67.37**	**63.89**	**70.33**	**66.06**	**72.17**	**68.97**	**74.60**	**61.85**
Margin after Corp O/H	**14.53**	**1.84**	**17.15**	**4.44**	**18.06**	**5.22**	**19.97**	**5.93**	**21.79**	**7.96**	**23.60**	**9.59**	**35.40**
Costs per kwh (cents)													
Fuel	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.83	0.83	0.83	0.83	0.83	0.21
Non-fuel	2.66	3.45	2.74	3.57	2.83	3.69	2.92	3.81	3.02	3.92	3.12	4.04	3.22
Capital Expenditures	0.30	0.37	0.32	0.39	0.33	0.41	0.35	0.43	0.37	0.46	0.39	0.48	0.41
Direct Expenses	**3.68**	**4.55**	**3.81**	**4.73**	**3.96**	**4.91**	**4.10**	**5.07**	**4.22**	**5.21**	**4.34**	**5.35**	**3.84**
Direct Margin	**1.69**	**0.95**	**1.83**	**1.05**	**1.97**	**1.17**	**2.13**	**1.31**	**2.32**	**1.50**	**2.54**	**1.70**	**3.38**
Overhead Allocation	0.61	0.80	0.56	0.68	0.62	0.73	0.65	0.82	0.70	0.83	0.79	0.90	0.75
Expenses incl. Corp O/H	**4.29**	**5.35**	**4.37**	**5.41**	**4.58**	**5.64**	**4.74**	**5.89**	**4.92**	**6.04**	**5.12**	**6.24**	**4.59**
Margin after Corp O/H	**1.08**	**0.15**	**1.27**	**0.37**	**1.35**	**0.44**	**1.48**	**0.50**	**1.62**	**0.67**	**1.75**	**0.80**	**2.63**
NPV of Margin after O/H													
Underfunded Decomm.													
NPV OF NET MARGIN													

Item Nos.: HSS-1-001, 21 (Supp.); HSS-2-22
OCA-1-8, 13, 21-23, 27, 43-45, 50, 53 (Supp.)
OCA-3-3, 5, 21, 22, 27, 29, 31, 50 (Supp.)
Env-3-149
OSBA-1-14 (Supp.)

Witnesses: Clayton, Schnitzer, Karl, Nelson, Duckworth

DUQUESNE LIGHT COMPANY

Supplemental Response:

1. Overview.

Duquesne has received several hundred discovery requests to date. Several of those requests have identified errors in the calculations contained in Duquesne's case-in-chief. Duquesne agrees that these errors should be corrected and is supplying the necessary corrections in the attached documents. Duquesne also is submitting corrections to reflect new information contained in the October 1, 1997 restructuring filing of Pennsylvania Power Company. In that filing, Penn Power presents updated projections regarding the costs and operation of the Perry, Sammis and Mansfield plants. (Duquesne has an ownership interest in these plants, but the plants are operated by Ohio Edison and Cleveland Electric.)

The enclosed supplemental discovery response explains and itemizes the foregoing corrections and discusses the impact of such corrections on Duquesne's restructuring proposal. Duquesne is supplying the corrections at this time (rather than reflecting them in rebuttal testimony or making the corrections on the witness stand) to provide intervenors the opportunity to review the corrections prior to the date for filing intervenor testimony. Duquesne anticipates that this may minimize or eliminate certain unnecessary disputes. Duquesne emphasizes that the corrections relate only to arithmetic errors or updates and do not modify the fundamental elements of Duquesne's Customer Choice Plan.

2. Description of corrections.

The corrections fall into two main categories. The first are corrections for which Duquesne has provided a separate estimate of the impact of the correction on Attachment A.[1] These corrections relate to the following errors: (i) fossil decommissioning costs were overstated because they included the full cost of decommissioning the jointly-owned units, rather than only Duquesne's share of the decommissioning expense for such units, (ii) the output of Duquesne's generating units was understated by assuming that the output was net of transmission and distribution losses, rather than reflecting the output of the units at the generator busbar, and (iii) Brunot Island's output was overstated by modeling the dispatch as a combined cycle unit, rather than as a peaking unit. The cost/revenue impact of these corrections is summarized below:

- The correction related to decommissioning increases the estimated value of the Company's generating plants (and reduces estimated stranded costs) at the end of 2005 by $73 million in both the high market price case and the low market price case. The $73 million is net of an offsetting increase in nuclear decommissioning of $18 million.

- The correction related to plant output increases the estimated value of the Company's generating plants (and reduces estimated stranded costs) at the end of 2005 by $109 million in the high market price case and by $62 million in the low market price case.

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[1] The impacts shown in Attachment A and the revised exhibits were calculated as follows. In making these corrections, Duquesne has rerun its Promod simulation and the spreadsheet financial models used to produce the Exhibits to Mr. Clayton's testimony. All these corrections have been made simultaneously to produce a single set of updated Exhibits and the effects are cumulative and presented on pages 44 and 56 of the revised Exhibit DJC-3. The identified impacts of the specific changes described herein and presented in Attachment A have been approximated in the financial models; these identified impacts are not based on a separate Promod analysis of differences for each correction. The Other category in Attachment A includes netted corrections that, when added to the specifically identified impacts, result in the cumulative changes to estimated net plant value and stranded cost.

- The correction related to the output of Brunot Island decreases the estimated value of the Company's generating plants (and increases stranded costs) at the end of 2005 by $32 million in the high market price case and by $12 million in the low market price case.

The second main category of corrections relates to (i) new information received from Pennsylvania Power Company regarding projections of cost and operating levels of the Sammis, Mansfield and Perry plants, and (ii) new operating and capital estimates for Duquesne's other plants. Both sets of information have become available within the last two weeks. The nature and effect of these corrections is as follows:

- The new information regarding the Sammis, Mansfield and Perry plants is taken from the restructuring filing of Penn Power (dated Oct. 1, 1997). In that filing, Penn Power provides updated projections regarding (i) operation and maintenance expense, (ii) the capital additions, and (iii) plant outages and operating levels. The revised exhibits submitted herewith reflect the Penn Power projections with the exception of the items identified in the attachment workpaper entitled "Adjustments to Ohio Edison Data."

- The new information regarding Duquesne's other plants is taken from operating plans approved this month by Duquesne. These plans contain updated O&M and capital projections.

- The foregoing corrections have the net effect of increasing the estimated book value of the Company's generation plant at December 31, 2005 by $14 million. These corrections also increase the estimated value of the Company's generating plants at the end of 2005 by $81 million in the high market price case and by $33 million in the low market price case. The combined effect of these corrections is to decrease stranded costs by $67 million in the high market price case and by $19 million in the low market price case.

In addition to these two main categories, additional updates and changes to the margin analysis have been made and identified in the Other category of Attachment A. These corrections include (i) corrections to Company A&G allocations to eliminate a double-counting of A&G expense and to correct omitted A&G capital expenditures post-2005, (ii) revisions to the allocation of the regulatory asset related to debt premiums between interest and amortization to reflect the

correct amounts to be recovered before 2006 as interest expense and the correct amounts to be recovered after 2005 as amortization, (iii) revisions to the nuclear trust fund balances to reflect actual rather than estimated balances and funding amounts, (iv) revisions to Mr. Clayton's Exhibits to capital expenditures to conform to Mr. Nelson's capital expenditure projections, (v) corrections to gross receipts tax calculations to reflect a 4.4% gross receipts tax rate, and (vi) corrections to CAPCO administrative and billing credits. The net effect of the changes grouped in Other is to decrease the estimated book value of the Company's generation plant at December 31, 2005 by $16 million. These corrections also increase the estimated value of the Company's generating plants at the end of 2005 by $8 million in the high market price case and by $1 million in the low market price case. The combined effect of these corrections on stranded costs is to decrease stranded costs by $24 million in the high market price case and by $17 million in the low market price case.

As the result of a combination of all the foregoing corrections, the Company's minimum commitment for generation-related depreciation and amortization will increase by $35 million from $1,747 million to $1,782 million.

3. Potential early termination of CTC.

After factoring in the effect of the foregoing corrections, Mr. Clayton's revised exhibits show a stranded "benefit" at the end of the year 2005 if rates are maintained at current levels throughout the transition period and market prices rise to the "high market price" estimate contained in Mr. Schnitzer's testimony. As stated in the testimony of Messrs. Marshall, Clayton and Schnitzer, however, Duquesne's restructuring plan includes commitments to ensure that the Company does not over-recover its stranded costs. Pertinent here, Duquesne has proposed an "early valuation procedure" under which an independent board of experts will perform a valuation of the Company's generation assets prior to the year 2003 if market prices have risen to specified levels (75% of the "high market price" scenario). If that valuation concludes that the transition period (and associated CTCs) can be terminated early, the Company will terminate the collection of a CTC to ensure that it does not over-recover its stranded costs.

Duquesne's initial projections showed that, even under the "high market price" scenario, Duquesne would need to maintain rates at current levels throughout the transition period, consistent with Customer Choice Act § 2804(4)(v). Duquesne nevertheless included a commitment to refer the valuation issue to an independent board if market prices rose to 75% of the high market price estimate. (This was a conservative approach designed to preclude any over-recovery of

stranded costs.) Given that Mr. Clayton's revised exhibits now show a stranded benefit under the high market price estimate, Duquesne must consider whether to adjust the 75% market price trigger downward to maintain the conservatism reflected in Duquesne's case-in-chief. Duquesne believes that it may be appropriate to do so; however, Duquesne intends to make any such adjustment in rebuttal testimony at the same time that it responds to intervenor comments regarding this and other aspects of the early valuation procedure. While Duquesne continues to believe that the "high market price" scenario is unlikely to occur, Duquesne also remains committed to a conservative approach to ensure that Duquesne does not overcollect its stranded costs. Duquesne looks forward to constructive intervenor comments on the valuation procedure that would further this goal.

4. Enclosed documents. The foregoing corrections are reflected in the following documents, which are being provided to each party to this proceeding (unless otherwise specified):

- Clayton -- Attached are and corrected Exhibits DJC-3; DJC-4; DJC-6; DJC-7 and Item No. L-5, pp. 3 to 35 and a corrected response to OCA-1-13, P. 2, and OCA-3-21, pp 2-12. Mr. Clayton also has enclosed revised workpapers. Computer diskettes have been provided to the parties that submitted the discovery requests identified in the first page of this document.

- Schnitzer -- Attached is a revision to the delayed entry calculation by Mr. Schnitzer that pertains to page 36 of his testimony. The workpapers associated with these corrections are attached.

- Karl -- Attached are revised exhibits MGK-3, MGK-6, MGK-7A, and MGK-7B. Mr. Karl's workpapers consist of Promod input data, which is voluminous and will be made available for review upon request. Computer diskettes have been provided to the parties that submitted discovery identified in the first page of this document.

- Nelson -- Attached are revised exhibits RLN-1, RLN-2, RLN-5, RLN-6. Mr. Nelson's workpapers are attached.

- Duckworth -- Attached are revised exhibits of Mr. Duckworth. Mr. Duckworth's workpapers, if any, will be provided promptly.

Duquesne also recognizes that the narrative contained in the testimony of the foregoing witnesses regarding these matters also will need to be corrected. This will be accomplished through a correction on the witness stand or through rebuttal testimony.

Attachment A

Duquesne Light Company

Summary of Corrections
($ Millions)

Item	Net Book Value @ 12/31/05	Estimated Market Value @ 12/31/05 High	Estimated Market Value @ 12/31/05 Low	Estimated Stranded Costs @ 12/31/05 High	Estimated Stranded Costs @ 12/31/05 Low	Mimimum Depreciation and Amortization Commitment
As Filed Exhibits DJC-3 &DJC-6	535	527	(47)	8	582	1,747
Decommissioning	0	73	73	(73)	(73)	0
Increase Plant Output	0	109	62	(109)	(62)	0
Brunot Island	0	(32)	(12)	32	12	0
Updated Information for Mansfield, Sammis, Perry and Beaver Valley	14	81	33	(67)	(19)	(2)
Other	(16)	8	1	(24)	(17)	37
Revised Exhibit DJC-3 & DJC-6	533	766	110	(233)	423	1,782

Revised Clayton Exhibits

EXHIBIT DJC-3
Page 1 of 67
Revised

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

Net Book Value of Generating Plant Assets	$533 million
Market Value of Generation Portfolio	
Low	$110 million
High	$766 million
Stranded Cost	
Low - Market Value	$423 million
High - Market Value	($233) million

Revenue Requirements Forecast
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total Duquesne Light									
Revenue from Customers	1081.7	1096.0	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	45.7	(26.7)	(19.0)	0.0	0.0	0.0	0.0
Off-system Sales	16.9	18.9	42.9	44.7	47.9	49.4	41.5	52.4	13.5
Other Revenues	34.3	32.8	35.9	36.0	36.1	36.2	36.3	36.3	32.2
Total Revenue	1132.9	1147.7	1,249.8	1,195.9	1,224.7	1,263.7	1,275.3	1,306.4	1,284.2
Operating Expenses									
Fuel & Purchased Power	201.5	214.5	241.3	222.7	229.7	243.6	251.4	263.9	288.5
Non Fuel O&M (production)	123.4	115.7	143.9	122.2	120.4	130.4	137.3	133.9	121.2
Outage Accounting	3.1	1.8	(8.4)	(1.7)	7.8	(1.2)	(3.1)	(0.3)	(4.4)
Non-production Expenses	219.0	231.1	237.5	237.1	250.4	257.3	264.3	270.2	263.6
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	184.0	188.6	188.9	184.2	196.1	225.6	212.1	209.9	168.3
Amortization	71.0	89.1	99.9	98.3	97.1	97.7	98.3	98.5	123.6
Operating Revenue Tax	47.6	48.2	51.5	49.1	50.2	51.8	52.7	53.6	54.5
Property Taxes	20.6	21.1	21.1	21.1	21.0	21.0	21.0	21.0	20.3
Other Taxes	12.4	15.1	19.8	19.9	20.1	20.3	20.5	20.7	20.2
Current Tax	100.0	99.3	96.3	122.4	125.5	122.3	128.2	147.9	138.2
Deferred Tax	(75.3)	(96.6)	(53.3)	(81.9)	(86.6)	(86.0)	(78.1)	(76.1)	(65.4)
ITC Amortization	(8.4)	(8.7)	(8.7)	(8.4)	(8.3)	(8.3)	(8.3)	(8.4)	(5.7)
Total Operating Expenses	907.6	927.9	1,038.6	993.6	1,032.1	1,083.2	1,105.0	1,143.6	1,131.8
Operating Income	225.3	219.8	211.2	202.2	192.6	180.5	170.3	162.9	152.4
Interest Expense	100.2	97.8	94.0	90.0	85.7	80.3	75.8	72.5	67.8
Net Income	125.0	122.0	117.2	112.2	106.9	100.2	94.5	90.4	84.6
Preferred Return	16.9	16.5	15.9	15.2	14.5	13.6	12.8	12.2	11.5
Income Available for Equity Return	108.1	105.5	101.3	97.0	92.4	86.6	81.7	78.1	73.1
Operating Income	225.3	219.8	211.2	202.2	192.6	180.5	170.3	162.9	152.4
Rate Base	2,345.2	2,287.9	2,198.5	2,105.4	2,004.7	1,879.3	1,772.6	1,695.4	1,586.7
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	940.0	917.0	881.2	843.8	803.5	753.2	710.5	679.5	636.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation									
Revenue from Customers	790.9	791.1	863.6	811.5	834.2	863.9	875.6	889.1	897.3
Off-system Sales	16.9	18.9	42.9	44.7	47.9	49.4	41.5	52.4	13.5
Other Revenues	15.3	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Total Revenue	823.1	823.9	920.6	870.2	896.1	927.3	931.1	955.5	924.8
Operating Expenses									
Fuel & Purchased Power	200.3	214.3	221.6	202.7	204.4	215.4	223.4	234.1	260.6
Emissions	1.2	0.3	19.7	20.0	25.4	28.2	28.0	29.9	27.9
Non Fuel O&M (production)	123.4	115.7	143.9	122.2	120.4	130.4	137.3	133.9	121.2
Outage Accounting	3.1	1.8	(8.4)	(1.7)	7.8	(1.2)	(3.1)	(0.3)	(4.4)
Non-production Expenses	109.1	111.5	114.0	115.8	125.8	129.6	133.4	135.9	125.5
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	136.8	140.6	141.1	138.7	152.4	180.5	165.8	162.3	119.4
Amortization	64.9	83.2	94.3	94.3	94.3	94.3	94.3	94.3	118.9
Operating Revenue Tax	34.8	34.8	38.0	35.7	36.7	38.0	38.5	39.1	39.5
Property Taxes	17.2	17.2	17.2	17.1	17.1	17.1	17.1	17.0	16.4
Other Taxes	4.3	7.0	11.6	11.6	11.7	11.8	11.9	11.9	10.7
Current Taxes	61.6	59.4	75.0	71.9	78.7	82.6	88.2	107.9	98.1
Deferred Tax	(71.0)	(91.9)	(68.0)	(68.5)	(77.8)	(85.5)	(78.4)	(76.9)	(66.7)
ITC Amortization	(6.4)	(6.7)	(6.7)	(6.5)	(6.4)	(6.4)	(6.4)	(6.4)	(3.7)
Total Operating Expenses	688.1	695.8	802.1	762.1	799.3	843.7	858.8	891.6	872.2
Operating Income	134.9	128.1	118.5	108.1	96.8	83.6	72.3	64.0	52.6
Interest Expense	60.0	57.0	52.7	48.1	43.1	37.2	32.2	28.5	23.4
Net Income	74.9	71.1	65.7	60.0	53.8	46.4	40.1	35.5	29.2
Preferred Return	10.1	9.6	8.9	8.1	7.3	6.3	5.4	4.8	4.0
Income Available for Equity Return	64.8	61.4	56.8	51.9	46.5	40.1	34.7	30.7	25.2
Operating Income	134.9	128.1	118.5	108.1	96.8	83.6	72.3	64.0	52.6
Rate Base	1,404.8	1,333.1	1,233.2	1,125.3	1,008.0	870.2	752.6	665.8	547.7
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	563.0	534.3	494.3	451.0	404.0	348.8	301.6	266.9	219.5
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation									
Revenue from Customers	361.2	345.6	329.3	309.7	326.0	347.3	301.3	256.0	264.6
Off-system Sales	5.0	6.1	12.5	13.9	15.2	14.5	12.4	16.6	4.6
Other Revenues	15.3	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Total Revenue	381.5	365.6	355.8	337.6	355.2	375.9	327.8	286.7	283.3
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	24.3	26.0	27.3	25.9	25.6	29.0	26.2
Non Fuel O&M (production)	70.8	49.8	78.6	61.1	55.8	67.8	69.9	56.3	77.2
Outage Accounting	(0.6)	10.8	(9.5)	(0.6)	7.0	(3.8)	(4.2)	11.2	(7.9)
Non-production Expenses	70.9	67.8	70.5	69.4	76.9	79.8	80.1	77.1	82.1
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	95.3	95.7	95.9	93.0	106.1	132.4	90.7	52.3	41.7
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	15.9	15.2	14.5	13.6	14.3	15.3	13.3	11.3	11.6
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	51.5	55.2	43.6	44.2	50.8	54.3	35.0	24.3	13.3
Deferred Taxes	(33.0)	(38.3)	(30.0)	(32.5)	(41.1)	(47.3)	(29.6)	(19.9)	(7.4)
ITC Amortization	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)	(2.4)
Total Operating Expenses	325.1	313.4	312.1	298.6	321.4	348.8	305.0	266.0	264.2
Operating Income	56.4	52.3	43.6	39.0	33.8	27.1	22.8	20.6	19.1
Interest Expense	25.1	23.3	19.4	17.4	15.0	12.0	10.1	9.2	8.5
Net Income	31.3	29.0	24.2	21.6	18.8	15.0	12.6	11.5	10.6
Preferred Return	4.2	3.9	3.3	2.9	2.5	2.0	1.7	1.6	1.4
Income Available for Equity Return	27.1	25.1	20.9	18.7	16.2	13.0	10.9	9.9	9.2
Operating Income	56.4	52.3	43.6	39.0	33.8	27.1	22.8	20.6	19.1
Rate Base	587.5	544.2	454.3	405.9	351.8	281.9	237.1	214.9	199.2
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	235.5	218.1	182.1	162.7	141.0	113.0	95.0	86.1	79.8
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
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Perry									
Off-system Sales Revenue	1.3	1.5	3.3	3.7	3.5	4.0	3.1	4.2	1.2
Revenue from Customers	146.6	139.6	130.3	122.6	133.3	152.2	105.1	66.0	65.7
Total Revenue	147.9	141.2	133.6	126.4	136.8	156.2	108.1	70.2	66.9
Operating Expenses									
Fuel	8.1	9.1	6.4	7.1	6.5	7.3	6.6	7.4	6.9
Non Fuel O&M (production)	17.0	12.2	19.5	15.2	19.7	16.3	20.3	17.2	21.4
Outage Accounting	0.0	2.8	(1.5)	1.7	(1.6)	1.8	(1.7)	1.9	(1.8)
Non-Production Expenses	7.4	6.5	7.1	6.8	7.7	7.1	7.7	6.9	8.2
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	2.2	2.2	2.2	2.2	2.2	2.2	2.2	5.6	7.7
Book Depreciation	58.3	58.3	58.2	56.5	70.4	96.2	53.9	14.7	3.3
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	6.4	6.1	5.7	5.4	5.9	6.7	4.6	2.9	2.9
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	30.8	30.9	27.0	26.4	29.5	39.5	19.3	4.2	(0.2)
Deferred Taxes	(21.7)	(23.0)	(21.4)	(22.1)	(26.7)	(38.8)	(19.7)	(4.9)	1.4
ITC Amortization	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)	(0.1)
Total Operating Expenses	119.6	116.0	114.2	110.2	124.5	149.2	104.1	66.8	63.6
Operating Income	28.3	25.2	19.4	16.2	12.3	7.0	4.1	3.3	3.3
Interest Expense	12.6	11.2	8.6	7.2	5.5	3.1	1.8	1.5	1.5
Net Income	15.7	14.0	10.8	9.0	6.8	3.9	2.3	1.8	1.8
Preferred Return	2.1	1.9	1.5	1.2	0.9	0.5	0.3	0.3	0.2
Income Available for Equity Return	13.6	12.1	9.3	7.8	5.9	3.3	1.9	1.6	1.6
Operating Income	28.3	25.2	19.4	16.2	12.3	7.0	4.1	3.3	3.3
Rate Base	294.3	261.8	201.8	168.6	128.4	72.7	42.3	34.7	34.0
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	104.9	80.9	67.6	51.5	29.1	17.0	13.9	13.6
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Nuclear Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Beaver Valley									
Off-system Sales Revenue	3.7	4.6	9.2	10.1	11.7	10.5	9.4	12.4	3.4
Revenue from Customers	214.6	206.0	198.9	187.1	192.7	195.1	196.3	190.0	198.9
Other Revenues	15.3	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Total Revenue	233.6	224.5	222.2	211.3	218.4	219.7	219.7	216.5	216.4
Operating Expenses									
Fuel	21.8	23.8	17.9	18.9	20.9	18.7	19.0	21.5	19.3
Non Fuel O&M (production)	53.8	37.6	59.0	45.9	36.1	51.5	49.6	39.1	55.8
Outage Accounting	(0.6)	8.0	(8.0)	(2.3)	8.6	(5.6)	(2.5)	9.3	(6.1)
Non-Production Expenses	63.5	61.3	63.4	62.6	69.1	72.7	72.3	70.2	73.9
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	6.5	6.5	6.5	6.5	6.5	6.5	6.5	3.2	1.0
Book Depreciation	36.9	37.4	37.7	36.6	35.7	36.2	36.8	37.5	38.4
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	9.4	9.1	8.8	8.2	8.5	8.6	8.6	8.4	8.8
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	20.8	24.3	16.6	17.8	21.3	14.8	15.6	20.2	13.4
Deferred Taxes	(11.3)	(15.3)	(8.6)	(10.4)	(14.4)	(8.5)	(9.9)	(15.0)	(8.8)
ITC Amortization	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.3)	(2.3)
Total Operating Expenses	205.5	197.4	197.9	188.5	197.0	199.6	200.9	199.2	200.5
Operating Income	28.2	27.1	24.3	22.8	21.5	20.1	18.7	17.3	15.9
Interest Expense	12.5	12.1	10.8	10.1	9.5	8.9	8.3	7.7	7.1
Net Income	15.6	15.1	13.5	12.7	11.9	11.2	10.4	9.6	8.8
Preferred Return	2.1	2.0	1.8	1.7	1.6	1.5	1.4	1.3	1.2
Income Available for Equity Return	13.5	13.0	11.6	10.9	10.3	9.6	9.0	8.3	7.6
Operating Income	28.2	27.1	24.3	22.8	21.5	20.1	18.7	17.3	15.9
Rate Base	293.2	282.3	252.5	237.4	223.4	209.2	194.8	180.2	165.2
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	117.5	113.2	101.2	95.1	89.5	83.9	78.1	72.2	66.2
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
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Beaver Valley 1									
Off-system Sales Revenue	2.7	3.6	7.0	7.5	9.3	8.0	7.0	9.9	2.6
Revenue from Customers	137.8	129.8	123.0	112.7	109.6	110.1	110.4	103.8	109.9
Other Revenues	11.9	10.8	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Total Revenue	152.4	144.2	140.8	131.1	129.8	129.0	128.2	124.5	123.4
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	13.7	14.0	16.4	14.3	14.2	17.1	15.0
Non Fuel O&M (production)	45.1	26.5	47.1	38.6	25.6	40.7	41.8	27.7	44.1
Outage Accounting	(3.8)	9.1	(7.0)	(4.4)	9.6	(4.6)	(4.7)	10.4	(5.0)
Non-Production Expenses	12.4	9.7	11.6	11.3	9.7	11.9	12.0	9.5	13.0
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	5.5	5.5	5.5	5.5	5.5	5.5	5.5	2.2	0.0
Book Depreciation	33.6	33.8	33.9	32.8	31.8	32.2	32.5	33.0	33.6
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	6.1	5.7	5.4	5.0	4.8	4.8	4.9	4.6	4.8
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	17.8	22.8	15.1	15.1	19.9	13.5	12.9	18.7	12.0
Deferred Taxes	(9.4)	(14.9)	(8.4)	(9.1)	(14.4)	(8.6)	(8.6)	(15.1)	(8.9)
ITC Amortization	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)
Total Operating Expenses	128.2	121.5	121.0	112.9	113.1	113.8	114.6	112.4	112.8
Operating Income	24.2	22.7	19.8	18.2	16.7	15.2	13.7	12.1	10.6
Interest Expense	10.8	10.1	8.8	8.1	7.4	6.8	6.1	5.4	4.7
Net Income	13.4	12.6	11.0	10.1	9.3	8.4	7.6	6.7	5.9
Preferred Return	1.8	1.7	1.5	1.4	1.3	1.1	1.0	0.9	0.8
Income Available for Equity Return	11.6	10.9	9.5	8.7	8.0	7.3	6.6	5.8	5.1
Operating Income	24.2	22.7	19.8	18.2	16.7	15.2	13.7	12.1	10.6
Rate Base	251.9	236.8	205.9	189.3	173.8	158.1	142.4	126.5	110.3
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	101.0	94.9	82.5	75.9	69.7	63.4	57.1	50.7	44.2
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
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Beaver Valley 2									
Off-system Sales Revenue	1.0	0.9	2.3	2.6	2.4	2.5	2.4	2.6	0.8
Revenue from Customers	76.8	76.2	76.0	74.4	83.1	85.1	85.9	86.3	89.0
Other Revenues	3.4	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Total Revenue	81.2	80.2	81.4	80.1	88.7	90.7	91.4	92.0	93.0
Operating Expenses									
Fuel	4.9	4.5	4.2	4.9	4.4	4.4	4.9	4.4	4.4
Non Fuel O&M (production)	8.7	11.1	11.9	7.2	10.5	10.8	7.8	11.4	11.7
Outage Accounting	3.2	(1.1)	(1.0)	2.1	(1.0)	(1.0)	2.2	(1.1)	(1.1)
Non-Production Expenses	51.1	51.7	51.8	51.3	59.4	60.8	60.3	60.6	60.9
Major Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Book Depreciation	3.3	3.6	3.8	3.8	3.8	4.0	4.3	4.5	4.8
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	3.4	3.4	3.3	3.3	3.7	3.7	3.8	3.8	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	3.0	1.6	1.5	2.6	1.3	1.4	2.8	1.4	1.4
Deferred Taxes	(2.0)	(0.4)	(0.2)	(1.3)	0.1	0.1	(1.3)	0.1	0.1
ITC Amortization	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
Total Operating Expenses	77.2	75.9	76.9	75.5	83.9	85.8	86.4	86.8	87.7
Operating Income	4.0	4.4	4.5	4.6	4.8	4.9	5.0	5.2	5.3
Interest Expense	1.8	1.9	2.0	2.1	2.1	2.2	2.2	2.3	2.3
Net Income	2.2	2.4	2.5	2.6	2.6	2.7	2.8	2.9	2.9
Preferred Return	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Income Available for Equity Return	1.9	2.1	2.1	2.2	2.3	2.4	2.4	2.5	2.5
Operating Income	4.0	4.4	4.5	4.6	4.8	4.9	5.0	5.2	5.3
Rate Base	41.3	45.5	46.5	48.0	49.6	51.1	52.4	53.7	54.9
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	16.6	18.2	18.7	19.3	19.9	20.5	21.0	21.5	22.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation									
Revenue from Customers	369.7	371.6	434.9	409.3	422.6	437.9	484.6	523.6	504.3
Off-system Sales	11.9	12.8	30.5	30.8	32.7	34.8	29.1	35.7	8.9
Other Revenues									
Total Revenue	381.6	384.4	465.4	440.1	455.3	472.7	513.7	559.3	513.2
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	197.3	176.7	177.0	189.4	197.8	205.1	234.4
Emissions	1.2	0.3	19.7	20.0	25.4	28.2	28.0	29.9	27.9
Non Fuel O&M (production)	52.6	65.9	65.3	61.1	64.6	62.6	67.4	77.6	44.0
Outage Accounting	3.7	(9.0)	1.1	(1.0)	0.8	2.6	1.1	(11.5)	3.5
Non-production Expenses	38.3	43.7	43.5	46.3	49.0	49.9	53.3	58.8	43.4
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	41.6	44.9	45.2	45.7	46.3	48.1	75.1	110.1	77.7
Amortization	(-)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	16.3	16.4	19.1	18.0	18.6	19.3	21.3	23.0	22.2
Property Taxes	3.4	3.4	3.4	3.3	3.3	3.3	3.3	3.2	2.6
Other Taxes	(2.6)	0.2	4.8	4.8	4.9	4.9	4.9	5.0	3.7
Current Taxes	27.0	15.0	34.3	32.4	34.5	36.8	46.5	53.0	45.9
Deferred Tax	(16.4)	(24.0)	(13.0)	(11.1)	(11.8)	(13.3)	(23.8)	(32.2)	(24.2)
ITC Amortization	(1.3)	(1.6)	(1.6)	(1.4)	(1.3)	(1.3)	(1.3)	(1.3)	(1.4)
Total Operating Expenses	334.0	336.4	419.0	394.7	411.3	430.4	473.7	520.7	479.7
Operating Income	47.5	48.0	46.4	45.4	44.1	42.3	40.0	38.6	33.5
Interest Expense	21.2	21.3	20.6	20.2	19.6	18.8	17.8	17.2	14.9
Net Income	26.4	26.6	25.7	25.2	24.5	23.5	22.2	21.4	18.6
Preferred Return	3.6	3.6	3.5	3.4	3.3	3.2	3.0	2.9	2.5
Income Available for Equity Return	22.8	23.0	22.2	21.8	21.1	20.3	19.2	18.5	16.1
Operating Income	47.5	48.0	46.4	45.4	44.1	42.3	40.0	38.6	33.5
Rate Base	495.0	499.4	482.7	472.6	458.7	440.2	416.7	401.6	348.5
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	200.2	193.5	189.4	183.9	176.4	167.0	161.0	139.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Elrama									
Off-system Sales Revenue	2.7	2.9	6.8	7.0	7.4	8.0	6.2	8.5	0.0
Revenue from Customers	94.6	104.4	105.8	107.3	108.0	111.3	107.1	113.2	12.3
Total Revenue	97.3	107.3	112.6	114.3	115.4	119.3	113.3	121.7	12.3
Operating Expenses									
Fuel	34.8	41.1	38.1	37.6	38.7	42.0	39.1	45.2	0.0
Emissions	0.0	0.0	6.5	7.0	6.3	7.3	6.1	8.1	0.0
Non Fuel O&M (production)	17.8	16.7	22.8	20.8	20.3	20.4	23.6	21.3	0.0
Outage Accounting	(0.7)	1.7	(2.8)	(1.0)	0.5	0.5	(2.9)	0.0	0.0
Non-production Expenses	11.1	11.6	12.0	13.4	13.2	13.2	12.8	13.0	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	14.7	16.2	17.1	18.1	19.0	19.8	20.5	21.5	12.3
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.2	4.6	4.7	4.7	4.8	4.9	4.7	5.0	0.5
Property Taxes	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0
Other Taxes	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	0.0
Current Taxes	7.4	8.7	7.0	8.0	8.7	8.7	7.1	8.3	2.7
Deferred Taxes	(3.6)	(4.9)	(3.5)	(4.7)	(5.7)	(6.1)	(5.0)	(6.7)	(3.0)
ITC Amortization	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)
Total Operating Expenses	87.4	97.3	103.3	105.5	107.3	112.3	107.6	117.2	12.3
Operating Income	9.9	9.9	9.2	8.8	8.1	7.0	5.7	4.4	0.0
Interest Expense	4.4	4.4	4.1	3.9	3.6	3.1	2.6	2.0	0.0
Net Income	5.5	5.5	5.1	4.9	4.5	3.9	3.2	2.5	0.0
Preferred Return	0.7	0.7	0.7	0.7	0.6	0.5	0.4	0.3	0.0
Income Available for Equity Return	4.8	4.8	4.4	4.2	3.9	3.4	2.8	2.1	0.0
Operating Income	9.9	9.9	9.2	8.8	8.1	7.0	5.7	4.4	0.0
Rate Base	103.5	103.3	96.1	91.9	84.1	72.9	59.7	46.1	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	41.5	41.4	38.5	36.8	33.7	29.2	23.9	18.5	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
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Cheswick									
Off-system Sales Revenue	3.5	3.7	9.8	10.2	10.2	11.4	9.6	10.2	3.9
Revenue from Customers	90.3	91.8	108.7	113.9	118.7	127.9	134.5	137.0	167.8
Total Revenue	93.8	95.6	118.5	124.0	128.9	139.3	144.2	147.2	171.7
Operating Expenses									
Fuel	39.9	36.8	45.9	48.1	47.2	52.8	52.9	48.7	59.5
Emissions	0.7	0.2	5.9	6.2	8.8	10.8	11.0	9.3	13.4
Non Fuel O&M (production)	11.0	24.6	15.8	14.9	16.8	16.8	15.6	28.6	18.1
Outage Accounting	2.7	(10.9)	2.2	2.2	2.2	2.2	2.2	(13.0)	3.1
Non-production Expenses	10.1	13.5	12.2	14.8	14.5	15.6	18.0	22.3	18.4
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	8.7	9.7	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	4.0	4.0	4.8	5.0	5.2	5.6	5.9	6.0	7.4
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	7.4	1.8	11.2	11.6	13.5	14.9	15.9	10.2	20.3
Deferred Taxes	(3.0)	2.7	(2.7)	(2.7)	(2.8)	(3.0)	(3.3)	2.3	(4.0)
ITC Amortization	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Total Operating Expenses	83.5	84.2	107.2	112.2	117.4	128.1	131.9	131.9	154.2
Operating Income	10.3	11.3	11.3	11.8	11.5	11.2	12.2	15.3	17.6
Interest Expense	4.6	5.0	5.0	5.3	5.1	5.0	5.4	6.8	7.8
Net Income	5.7	6.3	6.3	6.6	6.4	6.2	6.8	8.5	9.7
Preferred Return	0.8	0.9	0.9	0.9	0.9	0.8	0.9	1.2	1.3
Income Available for Equity Return	4.9	5.4	5.4	5.7	5.5	5.4	5.9	7.4	8.4
Operating Income	10.3	11.3	11.3	11.8	11.5	11.2	12.2	15.3	17.6
Rate Base	106.9	117.9	118.1	122.9	119.3	116.3	127.5	159.6	182.7
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	47.3	47.3	49.3	47.8	46.6	51.1	64.0	73.2
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
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Mansfield									
Off-system Sales Revenue	3.1	3.3	7.4	7.1	8.4	8.4	7.4	9.3	2.9
Revenue from Customers	89.9	97.6	101.6	78.0	82.9	82.0	89.6	90.7	98.9
Total Revenue	92.9	100.9	109.0	85.1	91.4	90.4	96.9	100.0	101.8
Operating Expenses									
Fuel	40.5	46.7	48.9	32.8	37.0	36.9	38.5	41.5	42.1
Emissions	0.0	0.0	5.5	5.3	6.2	6.1	6.6	7.3	7.4
Non Fuel O&M (production)	12.6	12.8	12.8	12.6	11.8	11.9	13.6	12.7	13.2
Outage Accounting	1.2	1.2	1.3	(2.7)	(0.4)	(1.1)	0.9	0.9	0.9
Non-production Expenses	9.5	10.8	11.4	10.0	10.6	10.6	11.3	11.4	12.2
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	8.2	8.4	8.4	8.0	7.5	7.6	7.8	8.0	8.2
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	4.0	4.3	4.5	3.4	3.6	3.6	3.9	4.0	4.4
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	5.8	6.3	6.5	4.6	5.3	5.0	5.7	5.6	5.5
Deferred Taxes	(1.7)	(2.2)	(2.7)	(0.9)	(1.7)	(1.5)	(2.3)	(2.3)	(2.3)
ITC Amortization	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Total Operating Expenses	81.9	90.0	98.5	75.0	81.6	81.0	87.8	91.1	93.3
Operating Income	11.0	10.9	10.4	10.1	9.7	9.4	9.1	9.0	8.5
Interest Expense	4.9	4.8	4.6	4.5	4.3	4.2	4.1	4.0	3.8
Net Income	6.1	6.0	5.8	5.6	5.4	5.2	5.1	5.0	4.7
Preferred Return	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.6
Income Available for Equity Return	5.3	5.2	5.0	4.8	4.7	4.5	4.4	4.3	4.1
Operating Income	11.0	10.9	10.4	10.1	9.7	9.4	9.1	9.0	8.5
Rate Base	114.7	113.0	108.8	105.2	101.2	97.6	95.2	93.4	89.0
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	46.0	45.3	43.6	42.2	40.6	39.1	38.2	37.5	35.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Sammis									
Off-system Sales Revenue	1.5	1.6	3.3	3.7	3.3	4.0	3.2	4.2	1.2
Revenue from Customers	32.7	35.6	35.4	35.7	36.9	39.2	40.7	40.5	46.4
Total Revenue	34.2	37.2	38.6	39.3	40.1	43.2	44.0	44.7	47.7
Operating Expenses									
Fuel	13.6	17.3	16.0	18.6	16.5	20.0	19.5	21.5	20.7
Emissions	0.2	0.0	(0.7)	(0.6)	0.3	0.6	0.5	0.7	2.3
Non Fuel O&M (production)	4.4	3.9	7.4	5.5	8.3	5.5	6.8	6.0	7.1
Outage Accounting	0.3	0.3	0.3	0.3	(1.6)	0.8	0.8	0.8	0.8
Non-production Expenses	3.6	3.8	4.1	4.5	5.5	5.2	5.3	5.1	6.1
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	4.3	4.3	4.3	4.1	4.2	4.3	4.4	4.5	4.7
Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Revenue Tax	1.4	1.6	1.6	1.6	1.6	1.7	1.8	1.8	2.0
Property Taxes	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2
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	2.5	2.4	1.7	2.6	2.6	2.5	2.4
Deferred Taxes	(0.5)	(1.1)	(1.2)	(1.2)	(0.5)	(1.4)	(1.5)	(1.5)	(1.6)
ITC Amortization	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Total Operating Expenses	30.1	33.3	35.0	35.9	36.7	39.9	40.9	41.9	45.1
Operating Income	4.1	3.8	3.6	3.4	3.4	3.3	3.1	2.8	2.6
Interest Expense	1.8	1.7	1.6	1.5	1.5	1.5	1.4	1.2	1.1
Net Income	2.3	2.1	2.0	1.9	1.9	1.8	1.7	1.6	1.4
Preferred Return	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Income Available for Equity Return	2.0	1.8	1.8	1.6	1.7	1.6	1.5	1.3	1.2
Operating Income	4.1	3.8	3.6	3.4	3.4	3.3	3.1	2.8	2.6
Rate Base	42.7	40.1	38.0	35.6	35.8	34.0	32.0	29.1	26.8
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	17.1	16.1	15.2	14.3	14.4	13.6	12.8	11.7	10.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Eastlake									
Off-system Sales Revenue	1.2	1.3	3.2	2.9	3.4	3.1	2.7	3.5	0.9
Revenue from Customers	29.5	27.7	32.4	31.1	37.2	36.7	37.1	40.0	41.1
Total Revenue	30.7	29.0	35.5	34.0	40.6	39.8	39.8	43.5	42.1
Operating Expenses									
Fuel	12.3	11.2	13.4	12.4	14.3	12.9	13.6	15.0	13.2
Emissions	0.3	0.1	2.4	2.2	3.8	3.5	3.8	4.5	4.8
Non Fuel O&M (production)	4.7	5.4	5.4	5.4	6.0	6.2	5.9	7.0	7.5
Outage Accounting	0.1	(1.4)	0.1	0.2	0.2	0.2	0.2	(0.2)	(1.3)
Non-production Expenses	3.4	3.5	4.0	3.9	5.6	5.4	4.7	5.3	5.6
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	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	1.3	1.2	1.4	1.4	1.6	1.6	1.6	1.8	1.8
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	1.9	2.0	2.2	2.4	2.3	2.0
Deferred Taxes	(0.6)	(0.0)	(0.7)	(0.7)	(0.8)	(0.9)	(1.1)	(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	27.3	25.5	32.1	30.8	37.2	36.1	36.3	40.0	38.7
Operating Income	3.4	3.4	3.4	3.2	3.4	3.6	3.5	3.5	3.4
Interest Expense	1.5	1.5	1.5	1.4	1.5	1.6	1.6	1.5	1.5
Net Income	1.9	1.9	1.9	1.8	1.9	2.0	1.9	1.9	1.9
Preferred Return	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.3
Income Available for Equity Return	1.6	1.6	1.6	1.5	1.6	1.7	1.7	1.7	1.6
Operating Income	3.4	3.4	3.4	3.2	3.4	3.6	3.5	3.5	3.4
Rate Base	35.5	35.8	35.2	32.9	35.6	38.0	36.4	36.0	35.4
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	14.2	14.3	14.1	13.2	14.3	15.2	14.6	14.4	14.2
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
(Revised)

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	6.0	5.6	5.4	5.2	5.1	6.7	5.8
Total Revenue	6.1	5.7	6.0	5.6	5.4	5.2	5.1	6.7	5.8
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)	0.7	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	0.5	0.3	0.3	0.3	0.3	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	2.0	2.0	2.1	2.0	1.9	1.9	1.9	2.3	2.3
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	0.2	0.2	0.2	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	1.3	1.3	1.2	1.1	1.1	1.1	1.3	1.2
Deferred Taxes	(0.7)	(0.6)	(0.7)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)	(0.7)
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	4.3	4.0	3.9	3.8	3.8	5.1	4.4
Operating Income	1.7	1.7	1.7	1.6	1.5	1.4	1.3	1.5	1.4
Interest Expense	0.8	0.8	0.8	0.7	0.7	0.6	0.6	0.7	0.6
Net Income	0.9	0.9	1.0	0.9	0.8	0.8	0.7	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	0.7	0.7	0.6	0.7	0.7
Operating Income	1.7	1.7	1.7	1.6	1.5	1.4	1.3	1.5	1.4
Rate Base	17.6	17.7	17.9	16.7	15.6	14.5	13.4	16.1	14.7
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	7.1	7.2	6.7	6.2	5.8	5.4	6.5	5.9
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
(Revised)

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	7.7	6.7	6.6	6.6	6.6	30.1	56.3	0.1
Total Revenue	7.2	7.7	6.7	6.6	6.6	6.6	30.1	56.3	0.1
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	1.0	0.0	0.0	0.0	0.0	24.4	53.6	0.4
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	0.3	0.3	1.3	2.5	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	1.9	1.5	1.6	1.6	1.6	11.2	22.2	(0.0)
Deferred Taxes	0.1	(0.1)	0.2	0.2	0.1	0.1	(10.0)	(22.2)	(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	2.9	1.9	1.9	1.9	1.8	26.7	55.9	0.1
Operating Income	4.8	4.8	4.8	4.8	4.8	4.8	3.4	0.4	(0.0)
Interest Expense	2.1	2.1	2.1	2.1	2.1	2.1	1.5	0.2	(0.0)
Net Income	2.7	2.7	2.7	2.7	2.6	2.6	1.9	0.2	(0.0)
Preferred Return	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.0	(0.0)
Income Available for Equity Return	2.3	2.3	2.3	2.3	2.3	2.3	1.6	0.2	(0.0)
Operating Income	4.8	4.8	4.8	4.8	4.8	4.8	3.4	0.4	0.0
Rate Base	50.1	50.2	50.0	49.8	49.7	49.6	35.2	3.8	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	20.0	19.9	19.9	14.1	1.5	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
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
B.I. Cold Reserve	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off-system Sales Revenue	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	30.0
Revenue	2.4	2.4	2.4	2.3	2.3	2.3	2.3	2.3	30.0
Total Revenue									
Operating Expenses	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	28.8
Book Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Amortization	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.3
Operating Revenue Tax	0.0	0.0	0.0	0.0	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	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	11.9
Current Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.9)
Deferred Taxes	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
ITC Amortization	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	30.0
Total Operating Expenses	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	(0.0)
Operating Income	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	(0.0)
Interest Expense	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	(0.0)
Net Income	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	(0.0)
Preferred Return	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	(0.0)
Income Available for Equity Return									
Operating Income	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	0.0
Rate Base	17.5	17.5	17.5	17.4	17.4	17.4	17.4	17.4	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	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	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
Fossil Generation
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Purchases & 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	1.7	(16.4)	21.2	25.3	24.6	26.6	38.0	36.9	101.7
Total Revenue	1.7	(16.4)	21.2	25.3	24.6	26.6	38.0	36.9	101.7
Operating Expenses									
Fuel	14.8	13.6	20.4	23.7	23.4	24.8	34.3	33.1	99.0
Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non Fuel O&M (production)	1.4	2.0	0.5	1.1	0.8	1.1	1.3	1.3	(2.6)
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	(0.6)	(0.6)	(0.6)	(0.5)	0.8	0.8	0.8
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	0.1	(0.7)	0.9	1.1	1.1	1.2	1.7	1.6	4.5
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	(3.0)	(11.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Taxes	(4.5)	(15.7)	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	1.7	(16.4)	21.2	25.3	24.6	26.6	38.0	36.9	101.7
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
(Revised)

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
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation Related Regulatory Assets									
Revenue	60.0	73.9	99.4	92.5	85.6	78.7	89.6	109.5	128.4
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	64.9	83.2	94.3	94.3	94.3	94.3	94.3	94.3	118.9
Operating Revenue Tax	2.6	3.3	4.4	4.1	3.8	3.5	3.9	4.8	5.6
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	(16.9)	(10.8)	(2.9)	(4.7)	(6.6)	(8.4)	6.8	30.5	38.9
Deferred Taxes	(21.6)	(29.6)	(24.9)	(24.9)	(24.9)	(24.9)	(24.9)	(24.9)	(35.1)
ITC Amortization	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	29.0	46.1	70.9	68.8	66.6	64.4	80.1	104.8	128.4
Operating Income	31.0	27.8	28.5	23.7	19.0	14.2	9.5	4.7	(0.0)
Interest Expense	13.8	12.4	12.7	10.6	8.4	6.3	4.2	2.1	0.0
Net Income	17.2	15.4	15.8	13.2	10.5	7.9	5.3	2.6	(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	14.9	13.4	13.7	11.4	9.1	6.8	4.6	2.3	(0.0)
Operating Income	31.0	27.8	28.5	23.7	19.0	14.2	9.5	4.7	(0.0)
Rate Base	322.3	289.6	296.2	246.8	197.5	148.1	98.7	49.4	0.0
Return on Operating Income	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.60%	0.00%
Rate Base - Equity	129.2	116.1	118.7	98.9	79.1	59.4	39.6	19.8	0.0
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.52%	11.51%	11.50%	11.49%	0.00%

Revenue Requirements Forecast
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Transmission									
Revenue from Customers	34.6	36.6	37.6	37.4	37.8	39.3	40.2	40.3	40.9
Other Revenues	6.3	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Total Revenues	40.9	42.7	43.6	43.5	43.9	45.4	46.2	46.4	46.9
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	5.5	5.5	5.4	5.3	5.1	5.2	5.3	5.3	5.4
Amortization	(0.8)	(0.8)	(0.7)	(0.6)	(0.5)	(0.3)	(0.1)	(0.1)	0.0
Operating Revenue Tax	1.5	1.6	1.7	1.6	1.7	1.7	1.8	1.8	1.8
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	1.6	1.6	1.6	1.6	1.7
Current Taxes	5.8	6.1	6.4	6.6	6.7	7.2	7.3	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	25.2	27.0	28.0	28.1	28.6	30.1	31.2	31.8	32.6
Operating Income	15.7	15.7	15.6	15.4	15.3	15.3	15.0	14.6	14.3
Interest Expense	7.0	7.0	6.9	6.9	6.8	6.8	6.7	6.5	6.4
Net Income	8.7	8.7	8.7	8.5	8.5	8.5	8.3	8.1	7.9
Preferred Return	1.2	1.2	1.2	1.2	1.1	1.2	1.1	1.1	1.1
Income Available for Equity Return	7.6	7.5	7.5	7.4	7.3	7.3	7.2	7.0	6.9
Operating Income	15.7	15.7	15.6	15.4	15.3	15.3	15.0	14.6	14.3
Rate Base	163.9	163.3	162.5	160.3	159.0	159.4	155.9	152.2	149.0
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	65.7	65.4	65.1	64.2	63.7	63.9	62.5	61.0	59.7
Return on Equity	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%

Revenue Requirements Forecast
(Revised)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005
Distribution									
Revenue from Customers	256.2	268.3	269.7	266.2	268.7	275.0	281.7	288.3	300.4
Other Revenues	12.7	12.8	15.9	16.0	16.0	16.1	16.2	16.3	12.1
Total Revenues	268.9	281.1	285.6	282.1	284.7	291.1	297.9	304.5	312.5
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	41.7	42.5	42.3	40.2	38.6	39.8	41.0	42.3	43.6
Amortization	6.9	6.6	6.3	4.6	3.3	3.7	4.1	4.3	4.6
Operating Revenue Tax	11.3	11.8	11.9	11.7	11.8	12.1	12.4	12.7	13.2
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	6.9	7.0	7.1	7.8
Current Taxes	32.6	33.7	33.8	32.8	32.2	32.4	32.7	32.7	32.7
Deferred Taxes	(3.2)	(3.7)	(3.5)	(1.8)	(0.5)	(0.3)	0.0	0.5	0.9
ITC Amortization	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)
Total Operating Expenses	194.3	205.1	208.5	203.4	204.2	209.5	214.9	220.2	227.0
Operating Income	74.6	76.0	77.1	78.7	80.5	81.6	83.0	84.3	85.5
Interest Expense	33.2	33.8	34.3	35.0	35.8	36.3	36.9	37.5	38.0
Net Income	41.4	42.2	42.8	43.7	44.7	45.3	46.1	46.8	47.4
Preferred Return	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4
Income Available for Equity Return	35.8	36.5	37.0	37.8	38.6	39.2	39.8	40.4	41.0
Operating Income	74.6	76.0	77.1	78.7	80.5	81.6	83.0	84.3	85.5
Rate Base	776.5	791.5	802.8	819.8	837.7	849.7	864.2	877.4	890.0
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	311.2	317.2	321.8	328.6	335.7	340.6	346.4	351.7	356.7
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
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Rate Base Summary										
Generation	1,101.07	1,082.48	1,043.54	937.01	878.49	810.55	722.12	653.85	616.44	547.71
Regulatory Assets	346.43	322.49	289.59	296.19	246.83	197.46	148.10	98.73	49.37	0.00
Transmission	165.12	163.94	163.29	162.48	160.29	159.04	159.38	155.85	152.25	148.97
Distribution	755.58	776.31	791.53	802.83	819.79	837.67	849.72	864.19	877.37	890.03
Total	2,368.20	2,345.22	2,287.94	2,198.52	2,105.40	2,004.72	1,879.31	1,772.63	1,695.43	1,586.71
Net Book Value Summary										
Generation	959.60	948.74	917.61	818.84	767.76	706.20	624.15	562.27	531.27	477.26
Regulatory Assets Included in Rate Base	346.43	322.49	289.59	296.19	246.83	197.46	148.10	98.73	49.37	0.00
Regulatory Assets Excluded from Rate Base	290.46	268.70	238.95	205.77	183.17	160.58	137.99	115.39	92.80	55.80
Transmission	158.13	157.37	157.14	156.74	154.96	154.11	154.86	151.75	148.55	145.68
Distribution	727.90	750.27	767.04	779.91	798.42	817.86	831.47	847.50	862.24	876.45
Total	2,482.52	2,447.58	2,370.33	2,257.45	2,151.14	2,036.22	1,896.57	1,775.64	1,684.22	1,555.20

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Net Plant										
Nuclear	906.88	839.70	763.62	623.27	543.12	450.83	332.01	255.91	218.42	192.08
Fossil	608.54	614.59	606.91	577.66	556.27	530.96	500.19	453.31	401.22	336.40
Transmission	198.76	195.74	193.43	191.28	188.09	186.05	186.05	182.76	179.49	176.81
Distribution	914.16	937.69	954.87	968.21	987.16	1,007.07	1,021.81	1,039.65	1,056.85	1,074.30
	2,628.34	2,587.73	2,518.83	2,360.42	2,274.65	2,174.91	2,040.06	1,931.61	1,855.97	1,779.58
Regulatory Assets										
Generation Regulatory Assets	455.14	421.26	371.37	387.78	323.15	258.52	193.89	129.26	64.63	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	33.48	34.25	34.94	35.50	36.03	36.37	36.52	36.60	36.58
Distribution	56.85	51.27	45.93	40.96	37.69	35.69	33.23	30.42	27.45	24.11
	544.67	506.01	451.56	463.68	396.34	330.24	263.49	196.19	128.68	60.69
Deferred Income Taxes										
Generation Regulatory Assets	(109.06)	(98.94)	(81.78)	(91.59)	(76.33)	(61.06)	(45.79)	(30.53)	(15.26)	0.00
Nuclear	(306.92)	(273.72)	(239.89)	(188.37)	(155.62)	(117.44)	(68.55)	(37.20)	(21.99)	(11.34)
Fossil	(171.03)	(160.68)	(148.62)	(136.05)	(124.81)	(113.32)	(101.06)	(77.68)	(40.74)	(17.95)
Transmission	(67.54)	(66.50)	(65.62)	(64.96)	(64.52)	(64.26)	(64.26)	(64.64)	(65.06)	(65.64)
Distribution	(220.21)	(217.52)	(214.31)	(211.36)	(210.09)	(210.12)	(210.36)	(210.90)	(211.95)	(213.41)
	(874.76)	(817.37)	(750.22)	(692.33)	(631.37)	(566.20)	(490.02)	(420.95)	(355.01)	(308.34)
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)	(51.88)	(46.78)	(41.68)	(36.57)	(31.47)	(26.37)	(21.27)	(16.14)	(13.79)
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)	(97.50)	(88.79)	(80.09)	(71.65)	(63.30)	(54.95)	(46.60)	(38.23)	(32.54)

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation Summary										
Original Cost	2,804.81	2,885.14	2,946.62	2,922.78	2,961.34	2,996.12	3,027.08	3,069.88	3,142.65	3,170.89
Accumulated Depreciation	(1,289.38)	(1,430.85)	(1,576.10)	(1,721.85)	(1,861.95)	(2,014.34)	(2,194.88)	(2,360.67)	(2,523.01)	(2,642.42)
Net Plant	1,515.43	1,454.29	1,370.53	1,200.93	1,099.39	981.78	832.20	709.21	619.64	528.47
Accumulated Deferred Taxes	(477.95)	(434.41)	(388.51)	(324.42)	(280.43)	(230.76)	(169.61)	(114.89)	(62.73)	(29.29)
Net Plant Less Accum. Deferred Taxes	1,037.48	1,019.89	982.02	876.51	818.96	751.02	662.59	594.32	556.91	499.18
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	1,082.48	1,043.54	937.01	878.49	810.55	722.12	653.85	616.44	547.71
Net Plant Less Accum. Deferred Taxes	1,037.48	1,019.89	982.02	876.51	818.96	751.02	662.59	594.32	556.91	499.18
Less: Accumulated ITC	(77.88)	(71.15)	(64.41)	(57.67)	(51.20)	(44.82)	(38.44)	(32.05)	(25.64)	(21.92)
Net Book Value	959.60	918.74	917.61	818.84	767.76	706.20	624.15	562.27	531.27	477.26

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Regulatory Assets Summary										
Book Cost	544.67	544.67	544.67	625.71	625.71	625.71	625.71	625.71	625.71	625.71
Accumulated Amortization	0.00	(38.66)	(93.11)	(162.03)	(229.37)	(295.47)	(362.22)	(429.52)	(497.03)	(565.02)
Net Book Cost	544.67	506.01	451.56	463.68	396.34	330.24	263.49	196.19	128.68	60.69
Accumulated Deferred Taxes	(198.24)	(183.52)	(161.97)	(167.49)	(149.51)	(132.78)	(115.40)	(97.46)	(79.31)	(60.69)
Net Plant Less Accum. Deferred Taxes	346.43	322.49	289.59	296.19	246.83	197.46	148.10	98.73	49.37	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	322.49	289.59	296.19	246.83	197.46	148.10	98.73	49.37	0.00
Regulatory Assets Excluded from Rate Base (Generation)										
Book Cost	459.49	459.49	459.49	441.39	441.39	441.39	441.39	441.39	441.39	441.39
Accumulated Amortization	0.00	(34.77)	(83.21)	(117.24)	(151.26)	(185.29)	(219.31)	(253.34)	(287.36)	(346.01)
Net Book Cost	459.49	424.71	376.28	324.15	290.13	256.10	222.08	188.05	154.03	95.38
Accumulated Deferred Taxes	(169.02)	(156.01)	(137.33)	(118.38)	(106.95)	(95.52)	(84.09)	(72.66)	(61.22)	(39.58)
Net Book Value	290.46	268.70	238.95	205.77	183.17	160.58	137.99	115.39	92.80	55.80

Rate Base and Net Book Value Forecast
(Revised)

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)	(125.76)	(131.25)	(136.70)	(141.98)	(147.13)	(152.35)	(157.64)	(162.96)	(168.32)
Net Plant	198.76	195.74	193.43	191.28	188.09	186.05	186.05	182.76	179.49	176.81
Accumulated Deferred Taxes	(34.88)	(33.03)	(31.36)	(30.02)	(29.02)	(28.23)	(27.89)	(28.12)	(28.46)	(29.06)
Net Plant Less Accum. Deferred Taxes	163.88	162.72	162.07	161.26	159.07	157.82	158.16	154.63	151.03	147.75
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	163.94	163.29	162.48	160.29	159.04	159.38	155.85	152.25	148.97
Net Plant Less Accum. Deferred Taxes	163.88	162.72	162.07	161.26	159.07	157.82	158.16	154.63	151.03	147.75
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	157.37	157.14	156.74	154.96	154.11	154.86	151.75	148.55	145.68

Rate Base and Net Book Value Forecast
(Revised)

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)	(469.19)	(511.68)	(553.97)	(594.21)	(632.79)	(672.58)	(713.57)	(755.83)	(799.39)
Net Plant	914.16	937.69	954.87	968.21	987.16	1,007.07	1,021.81	1,039.65	1,056.85	1,074.30
Accumulated Deferred Taxes	(163.69)	(166.42)	(168.38)	(170.40)	(172.41)	(174.43)	(177.12)	(180.48)	(184.51)	(189.30)
Net Plant Less Accum. Deferred Taxes	750.46	771.28	786.50	797.80	814.76	832.64	844.69	859.16	872.34	885.00
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	776.31	791.53	802.83	819.79	837.67	849.72	864.19	877.37	890.03
Net Plant Less Accum. Deferred Taxes	750.46	771.28	786.50	797.80	814.76	832.64	844.69	859.16	872.34	885.00
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	750.27	767.04	779.91	798.42	817.86	831.47	847.50	862.24	876.45

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation										
Perry										
Original Cost	868.19	879.29	883.92	846.79	849.14	852.12	854.60	857.75	860.79	864.13
Accumulated Depreciation	(394.20)	(452.54)	(510.87)	(569.07)	(625.52)	(695.94)	(792.16)	(846.06)	(860.79)	(864.13)
Net Plant	473.99	426.75	373.05	277.72	223.61	156.18	62.44	11.69	(0.00)	(0.00)
Accumulated Deferred Taxes	(165.73)	(144.07)	(122.17)	(86.25)	(64.85)	(37.50)	0.54	20.97	25.10	24.44
Net Plant Less Accum. Deferred Taxes	308.26	282.68	250.88	191.47	158.77	118.68	62.98	32.66	25.10	24.44
Working Capital	11.80	11.61	10.96	10.35	9.79	9.74	9.69	9.64	9.59	9.54
Rate Base	320.06	294.30	261.84	201.83	168.55	128.42	72.67	42.30	34.69	33.98
Net Plant Less Accum. Deferred Taxes	308.26	282.68	250.88	191.47	158.77	118.68	62.98	32.66	25.10	24.44
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	261.29	232.34	175.79	145.94	108.71	55.87	28.41	23.70	23.09

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation										
Beaver Valley 1										
Original Cost	653.69	664.58	672.66	659.50	665.19	671.02	677.02	683.17	689.50	696.00
Accumulated Depreciation	(275.30)	(308.90)	(342.74)	(376.65)	(409.44)	(441.28)	(473.44)	(505.94)	(538.98)	(572.60)
Net Plant	378.39	355.69	329.92	282.85	255.75	229.74	203.58	177.23	150.52	123.40
Accumulated Deferred Taxes	(123.51)	(112.58)	(101.44)	(84.83)	(73.93)	(63.47)	(52.96)	(42.37)	(31.60)	(20.62)
Net Plant Less Accum. Deferred Taxes	254.88	243.11	228.48	198.03	181.82	166.27	150.62	134.86	118.92	102.78
Working Capital	8.92	8.78	8.34	7.91	7.52	7.52	7.53	7.53	7.53	7.54
Rate Base	263.80	251.89	236.82	205.94	189.34	173.80	158.15	142.39	126.46	110.32
Net Plant Less Accum. Deferred Taxes	254.88	243.11	228.48	198.03	181.82	166.27	150.62	134.86	118.92	102.78
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	225.19	212.14	183.25	168.61	154.64	140.56	126.37	112.03	97.49

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Nuclear Generation										
Beaver Valley 2										
Original Cost	77.52	83.64	90.58	96.42	101.28	106.27	111.39	116.65	122.05	127.59
Accumulated Depreciation	(23.02)	(26.37)	(29.94)	(33.73)	(37.52)	(41.37)	(45.41)	(49.66)	(54.15)	(58.91)
Net Plant	54.50	57.27	60.64	62.70	63.76	64.91	65.98	66.98	67.90	68.68
Accumulated Deferred Taxes	(17.67)	(17.07)	(16.27)	(17.29)	(16.84)	(16.48)	(16.13)	(15.80)	(15.49)	(15.16)
Net Plant Less Accum. Deferred Taxes	36.82	40.19	44.37	45.41	46.92	48.43	49.86	51.18	52.41	53.52
Working Capital	1.12	1.10	1.12	1.13	1.12	1.17	1.21	1.26	1.30	1.35
Rate Base	37.95	41.30	45.49	46.54	48.05	49.60	51.07	52.44	53.71	54.87
Net Plant Less Accum. Deferred Taxes	36.82	40.19	44.37	45.41	46.92	48.43	49.86	51.18	52.41	53.52
Less: Accumulated ITC	(13.24)	(12.56)	(11.89)	(11.22)	(10.54)	(9.87)	(9.20)	(8.53)	(7.85)	(7.15)
Net Book Value	23.59	27.63	32.48	34.19	36.38	38.56	40.66	42.65	44.55	46.36

Rate Base and Net Book Value Forecast
(Revised)

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)	(152.46)	(168.68)	(185.74)	(203.84)	(222.85)	(242.69)	(263.21)	(284.71)	(297.04)
Net Plant	99.93	107.48	102.75	91.81	82.25	68.91	51.80	32.79	12.34	0.00
Accumulated Deferred Taxes	(18.75)	(14.84)	(10.61)	(5.95)	(0.83)	4.64	10.54	16.78	23.48	0.00
Net Plant Less Accum. Deferred Taxes	81.17	92.64	92.13	85.86	81.42	73.55	62.34	49.57	35.82	0.00
Working Capital	10.98	10.81	11.21	10.23	10.52	10.55	10.55	10.14	10.29	0.00
Rate Base	92.16	103.45	103.34	96.09	91.94	84.10	72.89	59.71	46.11	0.00
Net Plant Less Accum. Deferred Taxes	81.17	92.64	92.13	85.86	81.42	73.55	62.34	49.57	35.82	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	90.66	90.39	84.36	80.15	72.52	61.54	49.00	35.49	0.00

Rate Base and Net Book Value Forecast
(Revised)

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)	(104.68)	(114.33)	(124.24)	(134.37)	(144.37)	(154.68)	(166.49)	(181.96)	(197.88)
Net Plant	119.88	129.12	138.80	136.05	138.13	132.92	127.55	135.95	165.04	154.52
Accumulated Deferred Taxes	(34.85)	(33.00)	(31.15)	(29.35)	(27.54)	(25.62)	(23.54)	(21.09)	(17.96)	15.21
Net Plant Less Accum. Deferred Taxes	85.03	96.11	107.65	106.70	110.59	107.30	104.01	114.86	147.08	169.73
Working Capital	10.96	10.79	10.28	11.41	12.31	12.05	12.29	12.62	12.48	12.98
Rate Base	95.99	106.90	117.93	118.11	122.90	119.35	116.30	127.48	159.56	182.71
Net Plant Less Accum. Deferred Taxes	85.03	96.11	107.65	106.70	110.59	107.30	104.01	114.86	147.08	169.73
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	93.36	105.06	104.26	108.30	105.17	102.04	113.04	145.41	168.23

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Mansfield										
Original Cost	269.35	273.68	278.45	280.80	284.82	286.19	288.62	291.92	296.32	298.56
Accumulated Depreciation	(124.63)	(132.84)	(141.20)	(149.55)	(157.51)	(165.00)	(172.60)	(180.36)	(188.39)	(196.54)
Net Plant	144.72	140.84	137.25	131.25	127.30	121.19	116.03	111.56	107.93	102.02
Accumulated Deferred Taxes	(39.17)	(38.00)	(36.27)	(34.16)	(32.14)	(30.27)	(28.34)	(26.41)	(24.44)	(22.48)
Net Plant Less Accum. Deferred Taxes	105.54	102.84	100.98	97.09	95.17	90.92	87.68	85.15	83.49	79.54
Working Capital	12.04	11.86	12.01	11.69	10.04	10.28	9.96	10.04	9.96	9.45
Rate Base	117.59	114.69	112.99	108.78	105.21	101.20	97.64	95.20	93.45	88.99
Net Plant Less Accum. Deferred Taxes	105.54	102.84	100.98	97.09	95.17	90.92	87.68	85.15	83.49	79.54
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	96.35	94.81	91.23	89.62	85.68	82.76	80.54	79.19	75.55

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Sammis										
Original Cost	93.56	96.18	96.67	98.00	98.19	101.77	102.88	104.25	104.69	106.12
Accumulated Depreciation	(40.17)	(44.44)	(48.71)	(53.02)	(57.13)	(61.37)	(65.68)	(70.13)	(74.60)	(79.25)
Net Plant	53.39	51.73	47.96	44.97	41.05	40.41	37.20	34.12	30.09	26.87
Accumulated Deferred Taxes	(13.56)	(13.16)	(12.19)	(11.17)	(10.08)	(8.95)	(7.84)	(6.69)	(5.54)	(4.32)
Net Plant Less Accum. Deferred Taxes	39.84	38.58	35.77	33.80	30.97	31.45	29.36	27.43	24.55	22.56
Working Capital	4.16	4.09	4.30	4.18	4.65	4.36	4.61	4.54	4.57	4.23
Rate Base	43.99	42.67	40.06	37.98	35.62	35.81	33.97	31.97	29.12	26.79
Net Plant Less Accum. Deferred Taxes	39.84	38.58	35.77	33.80	30.97	31.45	29.36	27.43	24.55	22.56
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	35.93	33.31	31.53	28.89	29.56	27.65	25.91	23.23	21.42

Rate Base and Net Book Value Forecast
(Revised)

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)	(39.44)	(42.88)	(46.41)	(49.80)	(53.47)	(57.67)	(62.02)	(66.70)	(71.80)
Net Plant	42.66	41.94	41.84	40.33	37.49	39.20	41.00	38.33	36.81	35.30
Accumulated Deferred Taxes	(10.52)	(9.98)	(9.38)	(8.73)	(8.15)	(7.49)	(6.71)	(5.71)	(4.58)	(3.35)
Net Plant Less Accum. Deferred Taxes	32.15	31.96	32.46	31.60	29.34	31.71	34.28	32.62	32.23	31.96
Working Capital	3.61	3.55	3.31	3.60	3.58	3.87	3.68	3.75	3.80	3.44
Rate Base	35.76	35.51	35.77	35.19	32.93	35.58	37.97	36.38	36.03	35.40
Net Plant Less Accum. Deferred Taxes	32.15	31.96	32.46	31.60	29.34	31.71	34.28	32.62	32.23	31.96
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	30.36	30.97	30.22	28.07	30.54	33.22	31.67	31.38	31.21

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Brunot Island In-Service										
Original Cost	45.72	47.82	49.26	50.87	51.04	51.21	51.38	51.56	55.95	56.14
Accumulated Depreciation	(20.20)	(22.16)	(24.15)	(26.20)	(28.17)	(30.04)	(31.93)	(33.82)	(36.13)	(38.46)
Net Plant	25.52	25.66	25.12	24.67	22.87	21.17	19.46	17.75	19.82	17.68
Accumulated Deferred Taxes	(8.73)	(8.06)	(7.41)	(6.76)	(6.16)	(5.58)	(4.99)	(4.40)	(3.69)	(3.03)
Net Plant Less Accum. Deferred Taxes	16.79	17.60	17.71	17.91	16.72	15.59	14.47	13.35	16.13	14.66
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	17.71	17.91	16.72	15.59	14.47	13.35	16.13	14.66
Net Plant Less Accum. Deferred Taxes	16.79	17.60	17.71	17.91	16.72	15.59	14.47	13.35	16.13	14.66
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	6.92	17.06	17.31	16.16	15.08	14.00	12.93	15.75	14.32

Rate Base and Net Book Value Forecast
(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fossil Generation										
Phillips										
Original Cost	147.02	147.51	148.47	148.47	148.47	148.47	148.47	148.47	148.47	148.47
Accumulated Depreciation	(68.63)	(69.12)	(70.08)	(70.08)	(70.08)	(70.08)	(70.08)	(94.43)	(148.05)	(148.48)
Net Plant	78.40	78.40	78.40	78.40	78.40	78.40	78.40	54.05	0.43	(0.00)
Accumulated Deferred Taxes	(28.26)	(28.34)	(28.20)	(28.43)	(28.60)	(28.73)	(28.83)	(18.81)	3.36	0.00
Net Plant Less Accum. Deferred Taxes	50.14	50.06	50.20	49.97	49.80	49.67	49.57	35.24	3.79	(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	50.20	49.97	49.80	49.67	49.57	35.24	3.79	(0.00)
Net Plant Less Accum. Deferred Taxes	50.14	50.06	50.20	49.97	49.80	49.67	49.57	35.24	3.79	(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	48.89	48.85	48.86	48.93	49.01	34.86	3.60	(0.00)

Rate Base and Net Book Value Forecast
(Revised)

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)	(44.83)
Net Plant	28.76	28.76	28.76	28.76	28.76	28.76	28.76	28.76	28.76	(0.00)
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	(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	17.51	17.49	17.48	17.46	17.45	17.43	17.42	17.40	17.39	(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	(0.00)
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	(0.42)

Rate Base and Net Book Value Forecast
(Revised)

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

(Revised)

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Generation-Related Regulatory Assets										
Book Cost	455.14	455.14	455.14	536.18	536.18	536.18	536.18	536.18	536.18	536.18
Accumulated Amortization	0.00	(33.88)	(83.77)	(148.40)	(213.03)	(277.66)	(342.29)	(406.92)	(471.55)	(536.18)
Net Book Cost	455.14	421.26	371.37	387.78	323.15	258.52	193.89	129.26	64.63	0.00
Accumulated Deferred Taxes	(109.06)	(98.94)	(81.78)	(91.59)	(76.33)	(61.06)	(45.79)	(30.53)	(15.26)	0.00
Net Plant Less Accum. Deferred Taxes	346.08	322.32	289.59	296.19	246.83	197.46	148.10	98.73	49.37	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	322.32	289.59	296.19	246.83	197.46	148.10	98.73	49.37	0.00

Rate Base and Net Book Value Forecast
(Revised)

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	0.80	1.57	2.26	2.82	3.35	3.69	3.84	3.92	3.90
Net Book Cost	32.68	33.48	34.25	34.94	35.50	36.03	36.37	36.52	36.60	36.58
Accumulated Deferred Taxes	(32.66)	(33.47)	(34.25)	(34.94)	(35.50)	(36.03)	(36.37)	(36.52)	(36.60)	(36.58)
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
(Revised)

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	(5.58)	(10.91)	(15.88)	(19.16)	(21.16)	(23.61)	(26.43)	(29.40)	(32.74)
Net Book Cost	56.85	51.27	45.93	40.96	37.69	35.69	33.23	30.42	27.45	24.11
Accumulated Deferred Taxes	(56.52)	(51.10)	(45.93)	(40.96)	(37.69)	(35.69)	(33.23)	(30.42)	(27.45)	(24.11)
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	23.7	(23.6)	0.1
Sammis	14.0	(8.0)	6.0
Eastlake	2.5	(7.0)	(4.5)
Elrama	0.0	(35.0)	(35.0)
Mansfield 1	46.9	(12.6)	34.3
Mansfield 2	15.3	(0.9)	14.4
Mansfield 3	30.1	(2.3)	27.7
Brunot Island	0.0	(13.9)	(13.9)
Phillips	0.0	(9.5)	(9.5)
Total Fossil	**132.5**	**(112.9)**	**19.7**
Nuclear Plants:			
Beaver Valley 1	84.8	(0.0)	84.8
Beaver Valley 2	25.5	(8.5)	16.9
Perry	0.0	(11.0)	(11.0)
Total Nuclear	**110.2**	**(19.6)**	**90.7**
TOTAL PLANTS	**$242.7**	**($132.4)**	**$110.3**

DU[redacted]SNE LIGHT
Costs 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)	4,235	4,062	4,425	4,231	3,707	4,413	4,249	4,062	4,374
Delivered Output (gwh)	4,030	3,866	4,211	4,027	3,528	4,200	4,044	3,866	4,163
Revenues	136.32	134.03	149.66	146.69	131.73	160.72	158.62	155.44	171.57
Fuel-Related Expenses									
Fuel Costs	61.67	60.69	68.62	70.81	65.11	79.74	79.21	78.70	88.19
Fuel Related ECR Costs	1.08	1.11	1.14	1.17	1.20	1.23	1.26	1.30	1.32
NOx Emissions	8.24	8.17	9.60	9.34	7.63	10.85	10.87	10.49	12.08
SO2 Emissions	6.16	6.23	7.64	7.69	6.64	9.49	9.68	9.71	11.70
Total Fuel	77.14	76.21	87.00	89.01	80.58	101.32	101.03	100.20	113.29
Non-fuel O&M Expenses									
Variable O&M	3.73	3.67	4.11	4.03	3.62	4.43	4.38	4.30	4.75
Fixed O&M	13.15	15.38	15.33	14.11	9.12	16.38	15.26	17.69	17.55
Overhaul	0.00	0.00	0.00	0.00	18.56	0.00	0.00	0.00	0.00
Subtotal	16.88	19.06	19.43	18.14	31.30	20.81	19.63	21.98	22.30
Carbon Injection Costs	3.01	2.80	2.81	3.09	2.52	2.93	3.33	3.13	3.07
FICA	0.53	0.57	0.58	0.59	0.43	0.58	0.60	0.67	0.68
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	22.14	24.14	24.54	23.47	35.96	26.04	25.28	27.50	27.76
Capital Expenditures	5.56	5.72	5.89	6.08	15.46	4.96	3.58	2.12	1.53
Direct Expenses	104.83	106.07	117.43	118.55	132.01	132.31	129.89	129.82	142.58
Direct Margin	31.48	27.95	32.22	28.14	(0.28)	28.41	28.73	25.63	28.98
Overhead Allocation	16.73	17.26	18.61	19.02	21.48	20.99	21.40	22.63	23.68
Expenses Incl. Corp O/H	121.57	123.33	136.04	137.57	153.49	153.30	151.29	152.45	166.27
Margin after Corp O/H	14.75	10.69	13.62	9.12	(21.76)	7.42	7.33	2.99	5.30
Costs per kwh (cents)									
Fuel	1.91	1.97	2.07	2.21	2.28	2.41	2.50	2.59	2.72
Non-fuel	0.55	0.62	0.58	0.58	1.02	0.62	0.63	0.71	0.67
Capital Expenditures	0.14	0.15	0.14	0.15	0.44	0.12	0.09	0.05	0.04
Direct Expenses	2.60	2.74	2.79	2.94	3.74	3.15	3.21	3.36	3.43
Direct Margin	0.78	0.72	0.77	0.70	(0.01)	0.68	0.71	0.66	0.70
Overhead Allocation	0.42	0.45	0.44	0.47	0.61	0.50	0.53	0.59	0.57
Expenses Incl. Corp O/H	3.02	3.19	3.23	3.42	4.35	3.65	3.74	3.94	3.99
Margin after Corp O/H	0.37	0.28	0.32	0.23	(0.62)	0.18	0.18	0.08	0.13
NPV of Margin after O/H	23.7								
NPV of Decommissioning	23.6								
NPV OF NET MARGIN	0.1								

DUQUESNE LIGHT
Costs 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)	1,558	1,290	1,563	1,437	1,537
Delivered Output (gwh)	1,493	1,236	1,498	1,378	1,474
Revenues	50.51	42.86	53.24	50.19	55.02
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	2.29	1.93	2.40	2.26	2.48
Fixed O&M	4.29	3.75	4.80	4.63	4.71
Overhaul	0.00	4.00	0.00	0.00	0.00
Subtotal	6.58	9.68	7.19	6.89	7.18
FICA	0.21	0.17	0.21	0.20	0.24
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	8.58	11.64	9.20	8.88	9.22
Capital Expenditures	0.22	4.16	0.49	1.59	0.52
Direct Expenses	35.63	38.60	38.77	38.21	40.76
Direct Margin	14.88	4.26	14.47	11.98	14.26
Overhead Allocation	5.69	6.28	6.14	6.13	6.63
Expenses Incl. Corp O/H	41.32	44.89	44.91	44.34	47.39
Margin after Corp O/H	9.19	(2.03)	8.33	5.85	7.62
Costs per kwh (cents)					
Fuel	1.80	1.84	1.94	2.01	2.11
Non-fuel	0.57	0.94	0.61	0.64	0.63
Capital Expenditures	0.01	0.34	0.03	0.12	0.04
Direct Expenses	2.39	3.12	2.59	2.77	2.77
Direct Margin	1.00	0.34	0.97	0.87	0.97
Overhead Allocation	0.38	0.51	0.41	0.44	0.45
Expenses Incl. Corp O/H	2.77	3.63	3.00	3.22	3.22
Margin after Corp O/H	0.62	(0.16)	0.56	0.42	0.52
NPV of Margin after O/H	14.0				
NPV of Decommissioning	8.0				
NPV OF NET MARGIN	6.0				

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Costs 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)	1,206	1,367	1,208	1,205	1,267	1,123
Delivered Output (gwh)	1,149	1,302	1,151	1,148	1,207	1,069
Revenues	38.85	45.13	40.91	41.82	45.08	40.92
Fuel-Related Expenses						
Fuel Costs	15.96	18.60	16.95	17.43	18.85	17.19
Fuel Related ECR Costs	0.12	0.12	0.12	0.13	0.13	0.13
NOx Emissions	1.05	1.24	1.14	1.19	1.30	1.20
SO2 Emissions	5.26	6.57	6.12	6.57	7.51	7.00
Total Fuel	22.38	26.52	24.33	25.31	27.78	25.52
Non-fuel O&M Expenses						
Variable O&M	1.67	1.94	1.76	1.80	1.95	1.77
Fixed O&M	4.73	5.17	5.54	5.14	5.76	5.37
Overhaul	0.00	0.00	0.00	0.00	0.64	1.43
Subtotal	6.40	7.11	7.30	6.94	8.35	8.57
FICA	0.20	0.21	0.22	0.20	0.26	0.20
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	8.14	8.86	9.05	8.68	10.14	10.31
Capital Expenditures	2.39	0.66	0.91	0.91	1.06	0.78
Direct Expenses	32.91	36.05	34.30	34.90	38.98	36.61
Direct Margin	5.94	9.08	6.61	6.91	6.09	4.31
Overhead Allocation	5.25	5.87	5.43	5.60	6.34	5.81
Expenses Incl. Corp O/H	38.16	41.91	39.73	40.50	45.33	42.42
Margin after Corp O/H	0.69	3.21	1.17	1.31	(0.25)	(1.49)
Costs per kwh (cents)						
Fuel	1.95	2.04	2.11	2.21	2.30	2.39
Non-fuel	0.71	0.68	0.79	0.76	0.84	0.96
Capital Expenditures	0.21	0.05	0.08	0.08	0.09	0.07
Direct Expenses	2.87	2.77	2.98	3.04	3.23	3.42
Direct Margin	0.52	0.70	0.57	0.60	0.50	0.40
Overhead Allocation	0.46	0.45	0.47	0.49	0.53	0.54
Expenses Incl. Corp O/H	3.32	3.22	3.45	3.53	3.75	3.97
Margin after Corp O/H	0.06	0.25	0.10	0.11	(0.02)	(0.14)
NPV of Margin after O/H	2.5					
NPV of Decommissioning	7.0					
NPV OF NET MARGIN	(4.5)					

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DUQUESNE LIGHT
Costs 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)

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DUQUESNE LIGHT
Costs 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)	1,519	1,973	1,978	1,781	1,973	1,973	1,632	1,865	1,973	1,951
Delivered Output (gwh)	1,377	1,789	1,794	1,615	1,789	1,789	1,480	1,691	1,789	1,769
Revenues	46.58	62.02	63.74	58.83	66.79	68.46	58.06	67.98	73.72	74.72
Fuel-Related Expenses										
Fuel Costs	16.86	22.55	23.25	21.55	24.55	25.26	21.48	25.28	27.49	27.98
Fuel Related ECR Costs	3.49	4.58	4.71	4.38	4.95	5.08	4.36	5.08	5.51	5.59
NOx Emissions	3.36	5.02	5.23	4.76	5.67	5.92	4.68	5.94	6.70	6.86
SO2 Emissions	(0.39)	(0.31)	(0.33)	(0.41)	(0.39)	(0.43)	(0.58)	(0.53)	(0.53)	(0.58)
Total Fuel	23.32	31.84	32.87	30.28	34.77	35.84	29.95	35.76	39.16	39.85
Non-fuel O&M Expenses										
Variable O&M	2.73	3.63	3.73	3.44	3.90	4.01	3.39	3.97	4.31	4.37
Fixed O&M	3.52	3.88	3.37	5.83	4.45	4.71	4.74	3.68	3.74	7.33
Overhaul	2.93	0.00	0.00	0.00	0.00	0.00	2.59	0.81	0.00	0.00
Subtotal	9.18	7.51	7.10	9.27	8.35	8.72	10.71	8.46	8.06	11.70
FICA	0.20	0.22	0.21	0.27	0.28	0.24	0.25	0.23	0.24	0.24
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	10.35	8.71	8.29	10.51	9.61	9.94	11.94	9.67	9.28	12.92
Capital Expenditures	3.20	0.40	0.75	3.45	0.43	0.82	3.72	0.47	0.89	0.86
Direct Expenses	36.88	40.95	41.91	44.24	44.81	46.59	45.61	45.91	49.33	53.63
Direct Margin	9.70	21.07	21.83	14.58	21.98	21.87	12.45	22.08	24.40	21.09
Overhead Allocation	5.89	6.66	6.64	7.10	7.29	7.39	7.51	8.00	8.19	9.42
Expenses incl. Corp O/H	42.77	47.61	48.55	51.34	52.10	53.98	53.12	53.91	57.52	63.05
Margin after Corp O/H	3.81	14.41	15.19	7.49	14.69	14.48	4.94	14.07	16.20	11.67
Costs per kwh (cents)										
Fuel	1.69	1.78	1.83	1.87	1.94	2.00	2.02	2.12	2.19	2.25
Non-fuel	0.75	0.49	0.46	0.65	0.54	0.56	0.81	0.57	0.52	0.73
Capital Expenditures	0.23	0.02	0.04	0.21	0.02	0.05	0.25	0.03	0.05	0.05
Direct Expenses	2.68	2.29	2.34	2.74	2.51	2.60	3.08	2.71	2.76	3.03
Direct Margin	0.70	1.18	1.22	0.90	1.23	1.22	0.84	1.31	1.36	1.19
Overhead Allocation	0.43	0.37	0.37	0.44	0.41	0.41	0.51	0.47	0.46	0.53
Expenses incl. Corp O/H	3.11	2.66	2.71	3.18	2.91	3.02	3.59	3.19	3.22	3.56
Margin after Corp O/H	0.28	0.81	0.85	0.46	0.82	0.81	0.33	0.83	0.91	0.66
NPV of Margin after O/H	46.9									
NPV of Decommissioning	12.6									
NPV OF NET MARGIN	34.3									

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DUQUESNE LIGHT
Costs 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)	549	423	550	548	496	549	550	423	549	549	541
Delivered Output (gwh)	500	385	501	499	452	500	501	385	500	500	493
Revenues	16.90	13.34	17.81	18.18	16.87	19.12	19.66	15.47	20.60	21.11	21.34
Fuel-Related Expenses											
Fuel Costs	6.02	4.77	6.39	6.55	6.10	6.95	7.16	5.66	7.56	7.78	7.89
Fuel Related ECR Costs	1.24	0.99	1.31	1.34	1.25	1.41	1.45	1.16	1.53	1.57	1.59
NOx Emissions	1.38	1.00	1.50	1.56	1.43	1.70	1.78	1.29	1.92	2.00	2.05
SO2 Emissions	(0.10)	(0.14)	(0.11)	(0.12)	(0.15)	(0.15)	(0.16)	(0.22)	(0.18)	(0.20)	(0.22)
Total Fuel	8.55	6.64	9.09	9.33	8.63	9.91	10.24	7.90	10.83	11.16	11.31
Non-fuel O&M Expenses											
Variable O&M	0.99	0.78	1.04	1.06	0.99	1.12	1.15	0.90	1.21	1.23	1.25
Fixed O&M	0.96	1.05	0.92	1.58	1.21	1.28	1.29	1.00	1.02	2.01	1.59
Overhaul	0.00	0.82	0.00	0.00	0.00	0.00	0.00	0.95	0.00	0.00	0.00
Subtotal	1.95	2.65	1.96	2.65	2.20	2.40	2.44	2.85	2.22	3.24	2.83
FICA	0.06	0.05	0.06	0.08	0.07	0.07	0.07	0.06	0.07	0.07	0.10
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	2.27	2.98	2.28	2.99	2.53	2.73	2.78	3.18	2.56	3.58	3.20
Capital Expenditures	0.17	0.87	0.08	0.18	0.93	0.09	0.19	1.01	0.09	0.21	0.17
Direct Expenses	10.99	10.48	11.45	12.49	12.10	12.73	13.21	12.08	13.48	14.94	14.68
Direct Margin	5.91	2.86	6.36	5.68	4.77	6.39	6.45	3.39	7.12	6.16	6.66
Overhead Allocation	1.75	1.71	1.81	2.00	1.97	2.02	2.18	2.11	2.24	2.62	2.16
Expenses Incl. Corp O/H	12.74	12.18	13.27	14.50	14.07	14.75	15.38	14.19	15.72	17.57	16.84
Margin after Corp O/H	4.16	1.16	4.54	3.68	2.80	4.37	4.27	1.28	4.88	3.54	4.50
Costs per kwh (cents)											
Fuel	1.71	1.72	1.81	1.87	1.91	1.98	2.04	2.05	2.17	2.23	2.30
Non-fuel	0.46	0.77	0.46	0.60	0.56	0.55	0.55	0.83	0.51	0.72	0.65
Capital Expenditures	0.03	0.23	0.02	0.04	0.21	0.02	0.04	0.26	0.02	0.04	0.03
Direct Expenses	2.20	2.72	2.29	2.50	2.68	2.55	2.64	3.14	2.70	2.99	2.98
Direct Margin	1.18	0.74	1.27	1.14	1.06	1.28	1.29	0.88	1.42	1.23	1.35
Overhead Allocation	0.35	0.44	0.36	0.40	0.44	0.40	0.43	0.55	0.45	0.53	0.44
Expenses Incl. Corp O/H	2.55	3.17	2.65	2.91	3.11	2.95	3.07	3.69	3.15	3.52	3.42
Margin after Corp O/H	0.83	0.30	0.91	0.74	0.62	0.87	0.85	0.33	0.98	0.71	0.91
NPV of Margin after O/H	15.3										
NPV of Decommissioning	0.9										
NPV OF NET MARGIN	14.4										

DUQUESNE LIGHT
Costs 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)	945	945	749	945	945	855	948	945	738	935	948	855	945	940
Delivered Output (gwh)	875	875	693	874	875	791	877	875	683	865	877	791	875	870
Revenues	29.59	30.33	24.61	31.83	32.66	30.27	34.41	35.17	28.15	36.54	37.98	35.10	39.79	40.56
Fuel-Related Expenses														
Fuel Costs	10.34	10.64	8.67	11.25	11.58	10.78	12.28	12.62	10.13	13.21	13.78	12.75	14.49	14.80
Fuel Related ECR Costs	2.18	2.24	1.85	2.36	2.42	2.26	2.56	2.62	2.14	2.74	2.85	2.65	3.00	3.06
NOx Emissions	2.83	2.95	2.25	3.19	3.33	3.04	3.64	3.78	2.80	4.04	4.30	3.91	4.66	4.81
SO2 Emissions	(0.18)	(0.19)	(0.26)	(0.23)	(0.25)	(0.29)	(0.29)	(0.31)	(0.41)	(0.36)	(0.38)	(0.46)	(0.45)	(0.49)
Total Fuel	15.17	15.64	12.50	16.58	17.09	15.79	18.20	18.71	14.65	19.63	20.54	18.85	21.69	22.18
Non-fuel O&M Expenses														
Variable O&M	1.73	1.78	1.44	1.86	1.91	1.77	2.01	2.06	1.65	2.14	2.22	2.06	2.34	2.38
Fixed O&M	1.70	1.87	1.62	2.81	2.15	2.27	2.28	1.78	1.81	3.57	2.86	2.83	3.21	3.28
Overhaul	0.00	0.00	1.32	0.00	0.00	0.00	0.00	0.00	1.59	0.08	0.00	0.00	0.00	0.00
Subtotal	3.43	3.65	4.39	4.67	4.05	4.04	4.29	3.83	5.04	5.78	5.08	4.89	5.55	5.66
FICA	0.11	0.11	0.09	0.13	0.14	0.11	0.13	0.12	0.10	0.12	0.18	0.19	0.19	0.20
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	4.01	4.23	4.95	5.28	4.66	4.63	4.90	4.42	5.62	6.37	5.74	5.55	6.21	6.33
Capital Expenditures	0.19	0.35	1.59	0.21	0.38	1.71	0.22	0.41	1.85	0.25	0.45	1.99	0.27	0.49
Direct Expenses	19.37	20.22	19.04	22.06	22.14	22.13	23.32	23.55	22.12	26.25	26.72	26.39	28.17	29.00
Direct Margin	10.22	10.11	5.57	9.77	10.52	8.14	11.08	11.62	6.03	10.29	11.26	8.71	11.62	11.56
Overhead Allocation	3.09	3.29	3.02	3.54	3.60	3.51	3.84	4.11	3.67	4.61	3.93	3.82	4.43	4.30
Expenses Incl. Corp O/H	22.46	23.51	22.06	25.60	25.74	25.64	27.16	27.65	25.79	30.85	30.65	30.21	32.60	33.30
Margin after Corp O/H	7.13	6.82	2.55	6.23	6.92	4.63	7.24	7.52	2.35	5.68	7.33	4.89	7.19	7.26
Costs per kwh (cents)														
Fuel	1.73	1.79	1.81	1.90	1.95	2.00	2.08	2.14	2.15	2.27	2.34	2.38	2.48	2.55
Non-fuel	0.46	0.48	0.71	0.60	0.53	0.59	0.56	0.51	0.82	0.74	0.65	0.70	0.71	0.73
Capital Expenditures	0.02	0.04	0.23	0.02	0.04	0.22	0.03	0.05	0.27	0.03	0.05	0.25	0.03	0.06
Direct Expenses	2.21	2.31	2.75	2.52	2.53	2.80	2.66	2.69	3.24	3.03	3.05	3.34	3.22	3.33
Direct Margin	1.17	1.16	0.80	1.12	1.20	1.03	1.26	1.33	0.88	1.19	1.28	1.10	1.33	1.33
Overhead Allocation	0.35	0.38	0.44	0.41	0.41	0.44	0.44	0.47	0.54	0.53	0.45	0.48	0.51	0.49
Expenses Incl. Corp O/H	2.57	2.69	3.18	2.93	2.94	3.24	3.10	3.16	3.78	3.57	3.49	3.82	3.73	3.83
Margin after Corp O/H	0.81	0.78	0.37	0.71	0.79	0.59	0.83	0.86	0.34	0.66	0.84	0.62	0.82	0.83
NPV of Margin after O/H	30.1													
NPV of Decommissioning	2.3													
NPV OF NET MARGIN	27.7													

DUQUESNE LIGHT
Costs 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)	27	27	27	27	27	27	27
Delivered Output (gwh)	25.40	25.40	25.40	25.40	25.40	25.40	25.40
Revenues	4.30	4.40	4.51	4.63	4.74	4.86	4.98
Fuel-Related Expenses							
Fuel Costs	2.47	2.53	2.60	2.67	2.74	2.82	2.89
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	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Non-fuel O&M Expenses							
Variable O&M	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Fixed O&M	0.71	0.73	0.75	0.77	0.79	0.79	0.00
Overhaul	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.74	0.76	0.78	0.80	0.82	0.83	0.03
FICA	0.02	0.02	0.02	0.02	0.03	0.02	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	1.43	1.44	1.47	1.48	1.51	1.51	0.70
Capital Expenditures	0.20	0.20	0.21	0.19	0.19	0.20	0.11
Direct Expenses	4.09	4.18	4.27	4.34	4.45	4.53	3.71
Direct Margin	0.21	0.23	0.24	0.28	0.29	0.33	1.28
Overhead Allocation	0.65	0.68	0.68	0.70	0.72	0.72	0.61
Expenses incl. Corp O/H	4.74	4.86	4.95	5.04	5.17	5.25	4.32
Margin after Corp O/H	(0.44)	(0.45)	(0.44)	(0.41)	(0.43)	(0.39)	0.67
Costs per kwh (cents)							
Fuel	9.71	9.97	10.24	10.52	10.80	11.09	0.00
Non-fuel	5.61	5.68	5.77	5.84	5.95	5.96	0.00
Capital Expenditures	0.77	0.79	0.81	0.75	0.77	0.79	0.00
Direct Expenses	16.09	16.44	16.82	17.10	17.51	17.84	0.00
Direct Margin	0.83	0.90	0.95	1.11	1.16	1.30	0.00
Overhead Allocation	2.57	2.68	2.66	2.74	2.85	2.83	0.00
Expenses incl. Corp O/H	18.65	19.12	19.48	19.85	20.36	20.66	0.00
Margin after Corp O/H	(1.74)	(1.78)	(1.71)	(1.63)	(1.69)	(1.53)	0.00
NPV of Margin after O/H	(1.0)						
NPV of Decommissioning	13.9						
NPV OF NET MARGIN	(14.8)						

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)UQUESNE[redacted]GHT
:osts of Nuclear Plan
in Millions

$33.8/mwh in 2006 with escalations @ 2.5%

EAVER VALLEY I	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
wh Market Price (cents)	3.38	3.47	3.55	3.64	3.73	3.83	3.92	4.02	4.12	4.22
nit Output (gwh)	2,864	3,373	2,874	2,864	3,373	2,864	2,874	3,373	2,864	3,336
elivered Output (gwh)	2,694	3,172	2,703	2,694	3,172	2,694	2,703	3,172	2,694	3,137
evenues	91.12	109.97	96.05	98.13	118.43	103.10	106.02	127.53	111.03	132.52
uel-Related Expenses										
uel Costs	12.50	15.20	13.39	13.75	16.73	14.67	15.17	18.38	16.10	19.31
uel Related ECR Costs	2.69	3.17	2.70	2.69	3.17	2.69	2.70	3.17	2.69	3.14
Total Fuel	15.20	18.37	16.09	16.45	19.91	17.37	17.88	21.55	18.79	22.44
on-fuel O&M Expenses										
ariable O&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ixed O&M	29.19	29.92	30.67	31.44	32.22	33.03	33.85	34.70	35.57	36.46
verhaul	16.02	0.00	16.88	17.32	0.00	18.25	18.74	0.00	19.77	0.00
Subtotal	45.21	29.92	47.55	48.76	32.22	51.28	52.60	34.70	55.33	36.46
ICA	1.64	1.67	1.70	1.74	1.77	1.81	1.84	1.88	1.92	1.95
roperty Tax	2.06	2.06	2.06	2.06	.06	2.06	2.06	2.06	2.06	2.06
ap 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	51.06	35.80	53.46	54.70	38.20	57.29	58.65	40.79	61.46	42.62
apital Expenditures	6.68	6.86	7.04	7.23	7.43	7.63	7.84	8.06	8.28	8.51
Direct Expenses	72.93	61.03	76.59	78.37	65.53	82.29	84.36	70.39	88.53	73.57
Direct Margin	18.19	48.94	19.45	19.76	52.89	20.81	21.65	57.14	22.50	58.95
verhead Allocation	11.64	9.93	12.14	12.57	10.66	13.05	13.90	12.27	14.71	12.92
xpenses Incl. Corp O/H	84.57	70.96	88.73	90.95	76.20	95.34	98.26	82.67	103.23	86.49
largin after Corp O/H	6.55	39.01	7.32	7.18	42.23	7.76	7.75	44.87	7.79	46.04
osts per kwh (cents)										
uel	0.56	0.58	0.60	0.61	0.63	0.64	0.66	0.68	0.70	0.72
on-fuel	1.90	1.13	1.98	2.03	1.20	2.13	2.17	1.29	2.28	1.36
apital Expenditures	0.25	0.22	0.26	0.27	0.23	0.28	0.29	0.25	0.31	0.27
Direct Expenses	2.71	1.92	2.83	2.91	2.07	3.05	3.12	2.22	3.29	2.35
Direct Margin	0.68	1.54	0.72	0.73	1.67	0.77	0.80	1.80	0.84	1.88
verhead Allocation	0.43	0.31	0.45	0.47	0.34	0.48	0.51	0.39	0.55	0.41
xpenses Incl. Corp O/H	3.14	2.24	3.28	3.38	2.40	3.54	3.64	2.61	3.83	2.76
largin after Corp O/H	0.24	1.23	0.27	0.27	1.33	0.29	0.29	1.41	0.29	1.47
PV of Margin after O/H	84.8									
verfunded Decomm.	0.0									
PV OF NET MARGIN	84.8									

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DUQUESNE LI
Costs of Nuclear Plant
($ 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)	991	883	885	991	883	883	994	883	883	991	883	883	991	883	883	991	883	883	991	883	991
Delivered Output (gwh)	931	829	832	931	829	829	934	829	829	931	829	829	931	829	829	931	829	829	931	829	931
Revenues	31.49	28.74	29.55	33.91	30.95	31.72	36.62	33.33	34.16	39.33	35.89	36.79	42.35	38.65	39.62	45.61	41.62	42.67	49.11	44.83	51.60
Fuel-Related Expenses																					
Fuel Costs	4.04	3.72	3.84	4.44	4.09	4.22	4.90	4.50	4.64	5.38	4.94	5.09	5.89	5.43	5.59	6.46	5.97	6.13	7.09	6.56	6.73
Fuel Related ECR Costs	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83
Total Fuel	4.97	4.54	4.68	5.38	4.92	5.05	5.84	5.32	5.47	6.31	5.77	5.92	6.82	6.26	6.42	7.39	6.80	6.96	8.02	7.39	7.56
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	8.45	8.66	8.87	9.10	9.32	9.56	9.79	10.04	10.29	10.55	10.81	11.08	11.36	11.64	11.93	12.23	12.54	12.85	13.17	13.50	13.84
Overhaul	0.00	3.64	3.73	0.00	3.93	4.03	0.00	4.25	4.37	0.00	4.61	4.73	0.00	4.99	5.13	0.00	5.41	5.55	0.00	5.86	6.02
Subtotal	8.45	12.29	12.60	9.10	13.25	13.59	9.79	14.29	14.66	10.55	15.42	15.81	11.36	16.63	17.06	12.23	17.94	18.41	13.17	19.36	19.86
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	9.76	13.62	13.94	10.44	14.60	14.95	11.17	15.68	16.05	11.95	16.86	17.26	12.82	18.11	18.55	13.73	19.46	19.93	14.71	20.91	21.42
Capital Expenditures	5.70	5.84	6.00	6.15	6.32	6.49	6.67	6.85	7.03	7.22	7.24	7.42	7.61	7.80	7.99	8.19	8.40	8.61	8.82	9.04	9.27
Direct Expenses	20.42	24.00	24.61	21.97	25.84	26.49	23.67	27.85	28.55	25.48	29.87	30.60	27.25	32.16	32.95	29.32	34.65	35.50	31.55	37.34	38.25
Direct Margin	11.07	4.74	4.94	11.94	5.11	5.23	12.95	5.48	5.61	13.85	6.03	6.19	15.10	6.49	6.66	16.29	6.98	7.17	17.56	7.49	13.35
Overhead Allocation	3.26	3.91	3.90	3.52	4.20	4.20	3.90	4.85	4.74	4.47	4.39	4.42	4.28	4.77	5.20	4.72	5.71	5.69	5.72	6.26	7.51
Expenses Incl. Corp O/H	23.68	27.91	28.51	25.49	30.04	30.70	27.57	32.70	33.29	29.96	34.25	35.03	31.54	36.93	38.15	34.03	40.36	41.19	37.27	43.60	45.76
Margin after Corp O/H	7.81	0.83	1.04	8.42	0.91	1.03	9.05	0.63	0.87	9.37	1.64	1.76	10.81	1.72	1.47	11.57	1.27	1.47	11.85	1.23	5.84
Costs per kwh (cents)																					
Fuel	0.53	0.55	0.56	0.58	0.59	0.61	0.63	0.64	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79	0.82	0.84	0.86	0.89	0.81
Non-fuel	1.05	1.64	1.68	1.12	1.76	1.80	1.20	1.89	1.94	1.28	2.03	2.08	1.38	2.18	2.24	1.48	2.35	2.40	1.58	2.52	2.30
Capital Expenditures	0.61	0.70	0.72	0.66	0.76	0.78	0.71	0.83	0.85	0.78	0.87	0.90	0.82	0.93	0.96	0.88	1.01	1.04	0.95	1.09	1.00
Direct Expenses	2.19	2.90	2.96	2.36	3.12	3.20	2.54	3.36	3.44	2.74	3.60	3.69	2.93	3.88	3.98	3.15	4.18	4.28	3.39	4.50	4.11
Direct Margin	1.19	0.57	0.59	1.28	0.62	0.63	1.39	0.66	0.68	1.49	0.73	0.75	1.62	0.78	0.80	1.75	0.84	0.86	1.89	0.90	1.43
Overhead Allocation	0.35	0.47	0.47	0.38	0.51	0.51	0.42	0.59	0.57	0.48	0.53	0.53	0.46	0.58	0.63	0.51	0.69	0.69	0.61	0.76	0.81
Expenses Incl. Corp O/H	2.54	3.37	3.43	2.74	3.62	3.70	2.95	3.94	4.02	3.22	4.13	4.23	3.39	4.46	4.60	3.66	4.87	4.97	4.00	5.26	4.92
Margin after Corp O/H	0.84	0.10	0.13	0.90	0.11	0.12	0.97	0.08	0.11	1.01	0.20	0.21	1.16	0.21	0.18	1.24	0.15	0.18	1.27	0.15	0.63
NPV of Margin after O/H	25.5																				
Underfunded Decomm.	8.5																				
NPV OF NET MARGIN	16.9																				

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DUQUESNE L[redacted]

Costs of Nuclear Plant

$ 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)	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,416
Delivered 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
Revenues	45.42	41.42	47.85	43.52	50.13	45.72	52.81	48.04	55.34	50.47	58.30	53.03	61.08	55.71	64.36	58.52	67.42	61.49	71.04	64.61	74.63
Fuel-Related Expenses																					
Fuel Costs	6.42	5.91	6.87	6.29	7.30	6.70	7.79	7.13	8.25	7.58	8.80	8.04	9.29	8.49	9.82	8.71	9.79	8.71	9.82	8.71	2.43
Fuel Related ECR Costs	1.34	1.20	1.35	1.20	1.34	1.20	1.33	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	0.33
Total Fuel	7.77	7.10	8.22	7.49	8.64	7.89	9.13	8.32	9.59	8.78	10.15	9.24	10.63	9.68	11.17	9.91	11.14	9.91	11.17	9.91	2.76
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	18.11	18.56	19.03	19.50	19.99	20.49	21.00	21.53	22.06	22.62	23.18	23.76	24.35	24.96	25.59	26.23	26.88	27.55	28.24	28.95	29.67
Overhaul	0.00	3.96	0.00	4.16	0.00	4.39	0.00	4.63	0.00	4.88	0.00	5.15	0.00	5.43	0.00	5.58	0.00	5.58	0.00	5.58	0.00
Subtotal	18.11	22.52	19.03	23.67	19.99	24.88	21.00	26.15	22.06	27.50	23.18	28.91	24.35	30.39	25.59	31.80	26.88	33.13	28.24	34.53	29.67
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	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	31.81	36.22	32.73	37.37	33.69	38.58	34.70	39.86	35.77	41.20	36.88	42.61	38.06	44.10	39.29	45.51	40.59	46.83	41.95	48.23	43.38
Capital Expenditures	3.22	3.52	3.40	3.72	3.59	3.93	3.80	4.16	4.02	4.40	4.25	4.64	4.48	4.90	4.73	5.17	5.00	5.45	5.27	5.75	5.56
Direct Expenses	42.80	46.84	44.34	48.57	45.92	50.41	47.63	52.34	49.38	54.37	51.28	56.49	53.17	58.67	55.19	60.58	56.72	62.19	58.38	63.89	51.70
Direct Margin	2.63	(5.43)	3.50	(5.05)	4.21	(4.69)	5.18	(4.30)	5.96	(3.90)	7.02	(3.46)	7.91	(2.96)	9.17	(2.06)	10.71	(0.70)	12.65	0.72	22.93
Overhead Allocation	6.83	7.62	7.03	7.79	7.47	7.99	7.85	9.12	8.20	9.55	7.53	8.17	8.36	8.70	8.70	9.75	9.35	9.97	10.58	10.71	10.15
Expenses Incl. Corp O/H	49.63	54.47	51.37	56.37	53.40	58.40	55.48	61.46	57.58	63.92	58.81	64.66	61.53	67.37	63.89	70.33	66.06	72.17	68.97	74.60	61.85
Margin after Corp O/H	(4.20)	(13.05)	(3.52)	(12.84)	(3.26)	(12.68)	(2.67)	(13.42)	(2.24)	(13.45)	(0.51)	(11.63)	(0.45)	(11.66)	0.46	(11.81)	1.36	(10.67)	2.07	(9.99)	12.79
Costs per kwh (cents)																					
Fuel	0.58	0.59	0.61	0.63	0.64	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.83	0.83	0.83	0.83	0.83	0.21
Non-fuel	2.37	3.03	2.43	3.13	2.51	3.23	2.58	3.34	2.66	3.45	2.74	3.57	2.83	3.69	2.92	3.81	3.02	3.92	3.12	4.04	3.22
Capital Expenditures	0.24	0.29	0.25	0.31	0.27	0.33	0.28	0.35	0.30	0.37	0.32	0.39	0.33	0.41	0.35	0.43	0.37	0.46	0.39	0.48	0.41
Direct Expenses	3.19	3.92	3.29	4.07	3.42	4.22	3.54	4.38	3.68	4.55	3.81	4.73	3.96	4.91	4.10	5.07	4.22	5.21	4.34	5.35	3.84
Direct Margin	0.20	(0.45)	0.26	(0.42)	0.31	(0.39)	0.38	(0.36)	0.44	(0.33)	0.52	(0.29)	0.59	(0.25)	0.68	(0.17)	0.80	(0.06)	0.94	0.06	1.70
Overhead Allocation	0.51	0.64	0.52	0.65	0.56	0.67	0.58	0.76	0.61	0.80	0.56	0.68	0.62	0.73	0.65	0.82	0.70	0.83	0.79	0.90	0.75
Expenses Incl. Corp O/H	3.70	4.56	3.82	4.72	3.98	4.89	4.12	5.14	4.29	5.35	4.37	5.41	4.58	5.64	4.74	5.89	4.92	6.04	5.12	6.24	4.59
Margin after Corp O/H	(0.31)	(1.09)	(0.26)	(1.08)	(0.24)	(1.06)	(0.20)	(1.12)	(0.17)	(1.13)	(0.04)	(0.97)	(0.03)	(0.98)	0.03	(0.99)	0.10	(0.89)	0.15	(0.84)	0.95
NPV of Margin after O/H	(41.4)																				
Underfunded Decomm.	11.0																				
NPV OF NET MARGIN	(52.5)																				

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

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

	Plant Margin	Decommissioning	Net Plant Value
Fossil Plants:			
Cheswick	194.6	(23.6)	171.0
Sammis	51.0	(8.0)	43.0
Eastlake	38.5	(7.0)	31.5
Elrama	0.0	(35.0)	(35.0)
Mansfield 1	125.1	(12.6)	112.5
Mansfield 2	39.0	(0.9)	38.1
Mansfield 3	79.7	(2.3)	77.3
Brunot Island	3.5	(13.9)	(10.4)
Phillips	0.0	(9.5)	(9.5)
Total Fossil	**531.3**	**(112.9)**	**418.5**
Nuclear Plants:			
Beaver Valley 1	218.5	(0.0)	218.5
Beaver Valley 2	91.9	(8.5)	83.4
Perry	56.1	(11.0)	45.1
Total Nuclear	***366.6***	***(19.6)***	***347.0***
TOTAL PLANTS	**$897.9**	**($132.4)**	**$765.5**

DUQUESNE LIGHT
Costs of Fossil Plants
$ In Millions

Arithmetic Escalation to $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)	4,235	4,062	4,425	4,231	3,707	4,413	4,249	4,062	4,374
Delivered Output (gwh)	4,030	3,866	4,211	4,027	3,528	4,200	4,044	3,866	4,163
Revenues	177.62	174.64	195.01	191.14	171.65	209.42	206.68	202.54	223.56
Fuel-Related Expenses									
Fuel Costs	61.67	60.69	68.62	70.81	65.11	79.74	79.21	78.70	88.19
Fuel Related ECR Costs	1.08	1.11	1.14	1.17	1.20	1.23	1.26	1.30	1.32
NOx Emissions	8.24	8.17	9.60	9.34	7.63	10.85	10.87	10.49	12.08
SO2 Emissions	6.16	6.23	7.64	7.69	6.64	9.49	9.68	9.71	11.70
Total Fuel	77.14	76.21	87.00	89.01	80.58	101.32	101.03	100.20	113.29
Non-fuel O&M Expenses									
Variable O&M	3.73	3.67	4.11	4.03	3.62	4.43	4.38	4.30	4.75
Fixed O&M	13.15	15.38	15.33	14.11	9.12	16.38	15.26	17.69	17.55
Overhaul	0.00	0.00	0.00	0.00	18.56	0.00	0.00	0.00	0.00
Subtotal	16.88	19.06	19.43	18.14	31.30	20.81	19.63	21.98	22.30
Carbon Injection Costs	3.01	2.80	2.81	3.09	2.52	2.93	3.33	3.13	3.07
FICA	0.53	0.57	0.58	0.52	0.43	0.58	0.60	0.67	0.68
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	22.14	24.14	24.54	23.47	35.96	26.04	25.28	27.50	27.76
Capital Expenditures	5.56	5.72	5.89	6.08	15.46	4.96	3.58	2.12	1.53
Direct Expenses	104.83	106.07	117.43	118.55	132.01	132.31	129.89	129.82	142.58
Direct Margin	72.79	68.57	77.57	72.59	39.64	77.11	76.80	72.73	80.98
Overhead Allocation	16.73	17.26	18.61	19.02	21.48	20.99	21.40	22.63	23.68
Expenses Incl. Corp O/H	121.57	123.33	136.04	137.57	153.49	153.30	151.29	152.45	166.27
Margin after Corp O/H	56.06	51.30	58.97	53.57	18.16	56.12	55.39	50.10	57.29
Costs per kwh (cents)									
Fuel	1.91	1.97	2.07	2.21	2.28	2.41	2.50	2.59	2.72
Non-fuel	0.55	0.62	0.58	0.58	1.02	0.62	0.63	0.71	0.67
Capital Expenditures	0.14	0.15	0.14	0.15	0.44	0.12	0.09	0.05	0.04
Direct Expenses	2.60	2.74	2.79	2.94	3.74	3.15	3.21	3.36	3.43
Direct Margin	1.81	1.77	1.84	1.80	1.12	1.84	1.90	1.88	1.95
Overhead Allocation	0.42	0.45	0.44	0.47	0.61	0.50	0.53	0.59	0.57
Expenses Incl. Corp O/H	3.02	3.19	3.23	3.42	4.35	3.65	3.74	3.94	3.99
Margin after Corp O/H	1.39	1.33	1.40	1.33	0.51	1.34	1.37	1.30	1.38
NPV of Margin after O/H	194.6								
NPV of Decommissioning	23.6								
NPV OF NET MARGIN	171.0								

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DUQUESNE LIGHT
Costs of Fossil Plants
$ In Millions

	Arithmetic Escalation to $44.1/mwh in 2006 with escalations @				
SAMMIS	2006	2007	2008	2009	2010
kwh Market Price (cents)	4.41	4.52	4.63	4.75	4.87
Unit Output (gwh)	1,558	1,290	1,563	1,437	1,537
Delivered Output (gwh)	1,493	1,236	1,498	1,378	1,474
Revenues	65.82	55.85	69.37	65.40	71.69
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	2.29	1.93	2.40	2.26	2.48
Fixed O&M	4.29	3.75	4.80	4.63	4.71
Overhaul	0.00	4.00	0.00	0.00	0.00
Subtotal	6.58	9.68	7.19	6.89	7.18
FICA	0.21	0.17	0.21	0.20	0.24
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	8.58	11.64	9.20	8.88	9.22
Capital Expenditures	0.22	4.16	0.49	1.59	0.52
Direct Expenses	35.63	38.60	38.77	38.21	40.76
Direct Margin	30.18	17.24	30.60	27.18	30.93
Overhead Allocation	5.69	6.28	6.14	6.13	6.63
Expenses Incl. Corp O/H	41.32	44.89	44.91	44.34	47.39
Margin after Corp O/H	24.50	10.96	24.46	21.05	24.30
Costs per kwh (cents)					
Fuel	1.80	1.84	1.94	2.01	2.11
Non-fuel	0.57	0.94	0.61	0.64	0.63
Capital Expenditures	0.01	0.34	0.03	0.12	0.04
Direct Expenses	2.39	3.12	2.59	2.77	2.77
Direct Margin	2.02	1.39	2.04	1.97	2.10
Overhead Allocation	0.38	0.51	0.41	0.44	0.45
Expenses Incl. Corp O/H	2.77	3.63	3.00	3.22	3.22
Margin after Corp O/H	1.64	0.89	1.63	1.53	1.65
NPV of Margin after O/H	51.0				
NPV of Decommissioning	8.0				
NPV OF NET MARGIN	43.0				

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DUQUESNE LIGHT
Costs of Fossil Plants
$ in Millions

Arithmetic Escalation to $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)	1,206	1,367	1,208	1,205	1,267	1,123
Delivered Output (gwh)	1,149	1,302	1,151	1,148	1,207	1,069
Revenues	50.62	58.80	53.30	54.49	58.73	53.33
Fuel-Related Expenses						
Fuel Costs	15.96	18.60	16.95	17.43	18.85	17.19
Fuel Related ECR Costs	0.12	0.12	0.12	0.13	0.13	0.13
NOx Emissions	1.05	1.24	1.14	1.19	1.30	1.20
SO2 Emissions	5.26	6.57	6.12	6.57	7.51	7.00
Total Fuel	22.38	26.52	24.33	25.31	27.78	25.52
Non-fuel O&M Expenses						
Variable O&M	1.67	1.94	1.76	1.80	1.95	1.77
Fixed O&M	4.73	5.17	5.54	5.14	5.76	5.37
Overhaul	0.00	0.00	0.00	0.00	0.64	1.43
Subtotal	6.40	7.11	7.30	6.94	8.35	8.57
FICA	0.20	0.21	0.22	0.20	0.26	0.20
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	8.14	8.86	9.05	8.68	10.14	10.31
Capital Expenditures	2.39	0.66	0.91	0.91	1.06	0.78
Direct Expenses	32.91	36.05	34.30	34.90	38.98	36.61
Direct Margin	17.71	22.76	19.00	19.58	19.75	16.72
Overhead Allocation	5.25	5.87	5.43	5.60	6.34	5.81
Expenses incl. Corp O/H	38.16	41.91	39.73	40.50	45.33	42.42
Margin after Corp O/H	12.46	16.89	13.57	13.98	13.41	10.91
Costs per kwh (cents)						
Fuel	1.95	2.04	2.11	2.21	2.30	2.39
Non-fuel	0.71	0.68	0.79	0.76	0.84	0.96
Capital Expenditures	0.21	0.05	0.08	0.08	0.09	0.07
Direct Expenses	2.87	2.77	2.98	3.04	3.23	3.42
Direct Margin	1.54	1.75	1.65	1.71	1.64	1.56
Overhead Allocation	0.46	0.45	0.47	0.49	0.53	0.54
Expenses incl. Corp O/H	3.32	3.22	3.45	3.53	3.75	3.97
Margin after Corp O/H	1.08	1.30	1.18	1.22	1.11	1.02

NPV of Margin after O/H	38.5
NPV of Decommissioning	7.0
NPV OF NET MARGIN	31.5

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DUQUESNE LIGHT
Costs of Fossil Plants
$ in Millions

	Arithmetic Escalation to $44.1/mwh	
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)	

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DUQUESNE LIGHT
Costs of Fossil Plants
$ in Millions

Arithmetic Escalation to $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)	1,519	1,973	1,978	1,781	1,973	1,973	1,632	1,865	1,973	1,951
Delivered Output (gwh)	1,377	1,789	1,794	1,615	1,789	1,789	1,480	1,691	1,789	1,769
Revenues	60.70	80.81	83.06	76.65	87.03	89.20	75.65	88.58	96.06	97.36
Fuel-Related Expenses										
Fuel Costs	16.86	22.55	23.25	21.55	24.55	25.26	21.48	25.28	27.49	27.98
Fuel Related ECR Costs	3.49	4.58	4.71	4.38	4.95	5.08	4.36	5.08	5.51	5.59
NOx Emissions	3.36	5.02	5.23	4.76	5.67	5.92	4.68	5.94	6.70	6.86
SO2 Emissions	(0.39)	(0.31)	(0.33)	(0.41)	(0.39)	(0.43)	(0.58)	(0.53)	(0.53)	(0.58)
Total Fuel	23.32	31.84	32.87	30.28	34.77	35.84	29.95	35.76	39.16	39.85
Non-fuel O&M Expenses										
Variable O&M	2.73	3.63	3.73	3.44	3.90	4.01	3.39	3.97	4.31	4.37
Fixed O&M	3.52	3.88	3.37	5.83	4.45	4.71	4.74	3.68	3.74	7.33
Overhaul	2.93	0.00	0.00	0.00	0.00	0.00	2.59	0.81	0.00	0.00
Subtotal	9.18	7.51	7.10	9.27	8.35	8.72	10.71	8.46	8.06	11.70
FICA	0.20	0.22	0.21	0.27	0.28	0.24	0.25	0.23	0.24	0.24
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	0.5(	0.50	0.50	0.50	0.50	0.50	0.50
Total Non-fuel	10.35	8.71	8.29	10.5	9.61	9.94	11.94	9.67	9.28	12.92
Capital Expenditures	3.20	0.40	0.75	3.45	0.43	0.82	3.72	0.47	0.89	0.86
Direct Expenses	36.88	40.95	41.91	44.24	44.81	46.59	45.61	45.91	49.33	53.63
Direct Margin	23.82	39.87	41.15	32.41	42.22	42.61	30.04	42.68	46.74	43.73
Overhead Allocation	5.89	6.66	6.64	7.10	7.29	7.39	7.51	8.00	8.19	9.42
Expenses incl. Corp O/H	42.77	47.61	48.55	51.34	52.10	53.98	53.12	53.91	57.52	63.05
Margin after Corp O/H	17.93	33.20	34.51	25.31	34.93	35.22	22.53	34.68	38.54	34.31
Costs per kwh (cents)										
Fuel	1.69	1.78	1.83	1.87	1.94	2.00	2.02	2.12	2.19	2.25
Non-fuel	0.75	0.49	0.46	0.65	0.54	0.56	0.81	0.57	0.52	0.73
Capital Expenditures	0.23	0.02	0.04	0.21	0.02	0.05	0.25	0.03	0.05	0.05
Direct Expenses	2.68	2.29	2.34	2.74	2.51	2.60	3.08	2.71	2.76	3.03
Direct Margin	1.73	2.23	2.29	2.01	2.36	2.38	2.03	2.52	2.61	2.47
Overhead Allocation	0.43	0.37	0.37	0.44	0.41	0.41	0.51	0.47	0.46	0.53
Expenses incl. Corp O/H	3.11	2.66	2.71	3.18	2.91	3.02	3.59	3.19	3.22	3.56
Margin after Corp O/H	1.30	1.86	1.92	1.57	1.95	1.97	1.52	2.05	2.15	1.94

NPV of Margin after O/H	125.1
NPV of Decommissioning	12.6
NPV OF NET MARGIN	112.5

DUQUESNE LIGHT
Costs of Fossil Plants
$ In Millions

Arithmetic Escalation to $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)	549	423	550	548	496	549	550	423	549	549	541
Delivered Output (gwh)	500	385	501	499	452	500	501	385	500	500	493
Revenues	22.03	17.38	23.20	23.69	21.98	24.92	25.61	20.16	26.84	27.50	27.81
Fuel-Related Expenses											
Fuel Costs	6.02	4.77	6.39	6.55	6.10	6.95	7.16	5.66	7.56	7.78	7.89
Fuel Related ECR Costs	1.24	0.99	1.31	1.34	1.25	1.41	1.45	1.16	1.53	1.57	1.59
NOx Emissions	1.38	1.00	1.50	1.56	1.43	1.70	1.78	1.29	1.92	2.00	2.05
SO2 Emissions	(0.10)	(0.14)	(0.11)	(0.12)	(0.15)	(0.15)	(0.16)	(0.22)	(0.18)	(0.20)	(0.22)
Total Fuel	8.55	6.64	9.09	9.33	8.63	9.91	10.24	7.90	10.83	11.16	11.31
Non-fuel O&M Expenses											
Variable O&M	0.99	0.78	1.04	1.06	0.99	1.12	1.15	0.90	1.21	1.23	1.25
Fixed O&M	0.96	1.05	0.92	1.58	1.21	1.28	1.29	1.00	1.02	2.01	1.59
Overhaul	0.00	0.82	0.00	0.00	0.00	0.00	0.00	0.95	0.00	0.00	0.00
Subtotal	1.95	2.65	1.96	2.65	2.20	2.40	2.44	2.85	2.22	3.24	2.83
FICA	0.06	0.05	0.06	0.08	0.07	0.07	0.07	0.06	0.07	0.07	0.10
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	2.27	2.98	2.28	2.99	2.53	2.73	2.78	3.18	2.56	3.58	3.20
Capital Expenditures	0.17	0.87	0.08	0.18	0.93	0.09	0.19	1.01	0.09	0.21	0.17
Direct Expenses	10.99	10.48	11.45	12.49	12.10	12.73	13.21	12.08	13.48	14.94	14.68
Direct Margin	11.04	6.90	11.75	11.19	9.88	12.19	12.40	8.07	13.36	12.56	13.12
Overhead Allocation	1.75	1.71	1.81	2.00	1.97	2.02	2.18	2.11	2.24	2.62	2.16
Expenses Incl. Corp O/H	12.74	12.18	13.27	14.50	14.07	14.75	15.38	14.19	15.72	17.57	16.84
Margin after Corp O/H	9.28	5.20	9.94	9.19	7.91	10.17	10.23	5.97	11.12	9.93	10.97
Costs per kwh (cents)											
Fuel	1.71	1.72	1.81	1.87	1.91	1.98	2.04	2.05	2.17	2.23	2.30
Non-fuel	0.46	0.77	0.46	0.60	0.56	0.55	0.55	0.83	0.51	0.72	0.65
Capital Expenditures	0.03	0.23	0.02	0.04	0.21	0.02	0.04	0.26	0.02	0.04	0.03
Direct Expenses	2.20	2.72	2.29	2.50	2.68	2.55	2.64	3.14	2.70	2.99	2.98
Direct Margin	2.21	1.79	2.35	2.24	2.19	2.44	2.48	2.10	2.67	2.51	2.66
Overhead Allocation	0.35	0.44	0.36	0.40	0.44	0.40	0.43	0.55	0.45	0.53	0.44
Expenses Incl. Corp O/H	2.55	3.17	2.65	2.91	3.11	2.95	3.07	3.69	3.15	3.52	3.42
Margin after Corp O/H	1.86	1.35	1.98	1.84	1.75	2.03	2.04	1.55	2.22	1.99	2.23

NPV of Margin after O/H	39.0
NPV of Decommissioning	0.9
NPV OF NET MARGIN	38.1

DUQUESNE LIGHT
Costs of Fossil Plants
$ In Millions

Arithmetic Escalation to $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)	945	945	749	945	945	855	948	945	738	935	948	855	945	940
Delivered Output (gwh)	875	875	693	874	875	791	877	875	683	865	877	791	875	870
Revenues	38.55	39.52	32.07	41.48	42.56	39.44	44.83	45.83	36.68	47.61	49.49	45.74	51.85	52.86
Fuel-Related Expenses														
Fuel Costs	10.34	10.64	8.67	11.25	11.58	10.78	12.28	12.62	10.13	13.21	13.78	12.75	14.49	14.80
Fuel Related ECR Costs	2.18	2.24	1.85	2.36	2.42	2.26	2.56	2.62	2.14	2.74	2.85	2.65	3.00	3.06
NOx Emissions	2.83	2.95	2.25	3.19	3.33	3.04	3.64	3.78	2.80	4.04	4.30	3.91	4.66	4.81
SO2 Emissions	(0.18)	(0.19)	(0.26)	(0.23)	(0.25)	(0.29)	(0.29)	(0.31)	(0.41)	(0.36)	(0.38)	(0.46)	(0.45)	(0.49)
Total Fuel	15.17	15.64	12.50	16.58	17.09	15.79	18.20	18.71	14.65	19.63	20.54	18.85	21.69	22.18
Non-fuel O&M Expenses														
Variable O&M	1.73	1.78	1.44	1.86	1.91	1.77	2.01	2.06	1.65	2.14	2.22	2.06	2.34	2.38
Fixed O&M	1.70	1.87	1.62	2.81	2.15	2.27	2.28	1.78	1.81	3.57	2.86	2.83	3.21	3.28
Overhaul	0.00	0.00	1.32	0.00	0.00	0.00	0.00	0.00	1.59	0.08	0.00	0.00	0.00	0.00
Subtotal	3.43	3.65	4.39	4.67	4.05	4.04	4.29	3.83	5.04	5.78	5.08	4.89	5.55	5.66
FICA	0.11	0.11	0.09	0.13	0.14	0.11	0.13	0.12	0.10	0.12	0.18	0.19	0.19	0.20
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	4.01	4.23	4.95	5.28	4.66	4.63	4.90	4.42	5.62	6.37	5.74	5.55	6.21	6.33
Capital Expenditures	0.19	0.35	1.59	0.21	0.38	1.71	0.22	0.41	1.85	0.25	0.45	1.99	0.27	0.49
Direct Expenses	19.37	20.22	19.04	22.06	22.14	22.13	23.32	23.55	22.12	26.25	26.72	26.39	28.17	29.00
Direct Margin	19.18	19.30	13.03	19.42	20.42	17.31	21.51	22.28	14.56	21.36	22.76	19.34	23.68	23.85
Overhead Allocation	3.09	3.29	3.02	3.54	3.60	3.51	3.84	4.11	3.67	4.61	3.93	3.82	4.43	4.30
Expenses Incl. Corp O/H	22.46	23.51	22.06	25.60	25.74	25.64	27.16	27.65	25.79	30.85	30.65	30.21	32.60	33.30
Margin after Corp O/H	16.09	16.01	10.01	15.88	16.82	13.80	17.67	18.18	10.88	16.75	18.84	15.53	19.25	19.55
Costs per kwh (cents)														
Fuel	1.73	1.79	1.81	1.90	1.95	2.00	2.08	2.14	2.15	2.27	2.34	2.38	2.48	2.55
Non-fuel	0.46	0.48	0.71	0.60	0.53	0.59	0.56	0.51	0.82	0.74	0.65	0.70	0.71	0.73
Capital Expenditures	0.02	0.04	0.23	0.02	0.04	0.22	0.03	0.05	0.27	0.03	0.05	0.25	0.03	0.06
Direct Expenses	2.21	2.31	2.75	2.52	2.53	2.80	2.66	2.69	3.24	3.03	3.05	3.34	3.22	3.33
Direct Margin	2.19	2.21	1.88	2.22	2.33	2.19	2.45	2.55	2.13	2.47	2.60	2.45	2.71	2.74
Overhead Allocation	0.35	0.38	0.44	0.41	0.41	0.44	0.44	0.47	0.54	0.53	0.45	0.48	0.51	0.49
Expenses Incl. Corp O/H	2.57	2.69	3.18	2.93	2.94	3.24	3.10	3.16	3.78	3.57	3.49	3.82	3.73	3.83
Margin after Corp O/H	1.84	1.83	1.45	1.82	1.92	1.74	2.01	2.08	1.59	1.94	2.15	1.96	2.20	2.25

NPV of Margin after O/H	79.7
NPV of Decommissioning	2.3
NPV OF NET MARGIN	77.3

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DUQUESNE LIGHT
Costs of Fossil Plants
$ In Millions

	Arithmetic Escalation to $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)	27	27	27	27	27	27	27
Delivered Output (gwh)	25.40	25.40	25.40	25.40	25.40	25.40	25.40
Revenues	5.60	5.74	5.88	6.03	6.18	6.33	6.49
Fuel-Related Expenses							
Fuel Costs	2.47	2.53	2.60	2.67	2.74	2.82	2.89
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	2.47	2.53	2.60	2.67	2.74	2.82	2.89
Non-fuel O&M Expenses							
Variable O&M	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Fixed O&M	0.71	0.73	0.75	0.77	0.79	0.79	0.00
Overhaul	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.74	0.76	0.78	0.80	0.82	0.83	0.03
FICA	0.02	0.02	0.02	0.02	0.03	0.02	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	1.43	1.44	1.47	1.48	1.51	1.51	0.70
Capital Expenditures	0.20	0.20	0.21	0.19	0.19	0.20	0.11
Direct Expenses	4.09	4.18	4.27	4.34	4.45	4.53	3.71
Direct Margin	1.51	1.56	1.61	1.68	1.73	1.80	2.79
Overhead Allocation	0.65	0.68	0.68	0.70	0.72	0.72	0.61
Expenses Incl. Corp O/H	4.74	4.86	4.95	5.04	5.17	5.25	4.32
Margin after Corp O/H	0.86	0.88	0.93	0.99	1.01	1.08	2.18
Costs per kwh (cents)							
Fuel	9.71	9.97	10.24	10.52	10.80	11.09	0.00
Non-fuel	5.61	5.68	5.77	5.84	5.95	5.96	0.00
Capital Expenditures	0.77	0.79	0.81	0.75	0.77	0.79	0.00
Direct Expenses	16.09	16.44	16.82	17.10	17.51	17.84	0.00
Direct Margin	5.95	6.15	6.34	6.63	6.81	7.10	0.00
Overhead Allocation	2.57	2.68	2.66	2.74	2.85	2.83	0.00
Expenses Incl. Corp O/H	18.65	19.12	19.48	19.85	20.36	20.66	0.00
Margin after Corp O/H	3.38	3.47	3.67	3.89	3.96	4.27	0.00
NPV of Margin after O/H	3.5						
NPV of Decommissioning	13.9						
NPV OF NET MARGIN	(10.4)						

DUQUESNE LIGHT
Costs of Nuclear Plan
In Millions

Arithmetic Escalation to $44.1/mwh in 2006 with escalations @ 2.5%

BEAVER VALLEY 1	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Mwh 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)	2,864	3,373	2,874	2,864	3,373	2,864	2,874	3,373	2,864	3,336
Delivered Output (gwh)	2,694	3,172	2,703	2,694	3,172	2,694	2,703	3,172	2,694	3,137
Revenues	118.74	143.30	125.15	127.87	154.32	134.34	138.14	166.18	144.67	172.68
Fuel-Related Expenses										
Fuel Costs	12.50	15.20	13.39	13.75	16.73	14.67	15.17	18.38	16.10	19.31
Fuel Related ECR Costs	2.69	3.17	2.70	2.69	3.17	2.69	2.70	3.17	2.69	3.14
Total Fuel	15.20	18.37	16.09	16.45	19.91	17.37	17.88	21.55	18.79	22.44
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	29.19	29.92	30.67	31.44	32.22	33.03	33.85	34.70	35.57	36.46
Overhaul	16.02	0.00	16.88	17.32	0.00	18.25	18.74	0.00	19.77	0.00
Subtotal	45.21	29.92	47.55	48.76	32.22	51.28	52.60	34.70	55.33	36.46
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	51.06	35.80	53.46	54.70	38.20	57.29	58.65	40.79	61.46	42.62
Capital Expenditures	6.68	6.86	7.04	7.23	7.43	7.63	7.84	8.06	8.28	8.51
Direct Expenses	72.93	61.03	76.59	78.37	65.53	82.29	84.36	70.39	88.53	73.57
Direct Margin	45.80	82.27	48.56	49.49	88.78	52.05	53.78	95.79	56.14	99.11
Overhead Allocation	11.64	9.93	12.14	12.57	10.66	13.05	13.90	12.27	14.71	12.92
Expenses Incl. Corp O/H	84.57	70.96	88.73	90.95	76.20	95.34	98.26	82.67	103.23	86.49
Margin after Corp O/H	34.16	72.34	36.42	36.92	78.12	39.00	39.88	83.52	41.44	86.19
Costs per kwh (cents)										
Fuel	0.56	0.58	0.60	0.61	0.63	0.64	0.66	0.68	0.70	0.72
Non-fuel	1.90	1.13	1.98	2.03	1.20	2.13	2.17	1.29	2.28	1.36
Capital Expenditures	0.25	0.22	0.26	0.27	0.23	0.28	0.29	0.25	0.31	0.27
Direct Expenses	2.71	1.92	2.83	2.91	2.07	3.05	3.12	2.22	3.29	2.35
Direct Margin	1.70	2.59	1.80	1.84	2.80	1.93	1.99	3.02	2.08	3.16
Overhead Allocation	0.43	0.31	0.45	0.47	0.34	0.48	0.51	0.39	0.55	0.41
Expenses Incl. Corp O/H	3.14	2.24	3.28	3.38	2.40	3.54	3.64	2.61	3.83	2.76
Margin after Corp O/H	1.27	2.28	1.35	1.37	2.46	1.45	1.48	2.63	1.54	2.75
PV of Margin after O/H	218.5									
Overfunded Decomm.	0.0									
PV OF NET MARGIN	218.5									

DUQUESNE LIGHT

Costs of Nuclear Plant

$ in Millions

Arithmetic Escalation to $44.1/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)	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)	991	883	885	991	883	883	994	883	883	991	883	883	991	883	883	991	883	883	991	883	991
Delivered Output (gwh)	931	829	832	931	829	829	934	829	829	931	829	829	931	829	829	931	829	829	931	829	931
Revenues	41.03	37.45	38.50	44.19	40.33	41.34	47.72	43.43	44.51	51.24	46.77	47.94	55.18	50.37	51.62	59.43	54.24	55.59	64.00	58.41	67.14
Fuel-Related Expenses																					
Fuel Costs	4.04	3.72	3.84	4.44	4.09	4.22	4.90	4.50	4.64	5.38	4.94	5.09	5.89	5.43	5.59	6.46	5.97	6.13	7.09	6.56	6.73
Fuel Related ECR Costs	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83	0.93	0.83	0.83
Total Fuel	4.97	4.54	4.68	5.38	4.92	5.05	5.84	5.32	5.47	6.31	5.77	5.92	6.82	6.26	6.42	7.39	6.80	6.96	8.02	7.39	7.56
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	8.45	8.66	8.87	9.10	9.32	9.56	9.79	10.04	10.29	10.55	10.81	11.08	11.36	11.64	11.93	12.23	12.54	12.85	13.17	13.50	13.84
Overhaul	0.00	3.64	3.73	0.00	3.93	4.03	0.00	4.25	4.37	0.00	4.61	4.73	0.00	4.99	5.13	0.00	5.41	5.55	0.00	5.86	6.02
Subtotal	8.45	12.29	12.60	9.10	13.25	13.59	9.79	14.29	14.66	10.55	15.42	15.81	11.36	16.63	17.06	12.23	17.94	18.41	13.17	19.36	19.86
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	9.76	13.62	13.94	10.44	14.60	14.95	11.17	15.68	16.05	11.95	16.86	17.26	12.82	18.11	18.55	13.73	19.46	19.93	14.71	20.91	21.42
Capital Expenditures	5.70	5.84	6.00	6.15	6.32	6.49	6.67	6.85	7.03	7.22	7.24	7.42	7.61	7.80	7.99	8.19	8.40	8.61	8.82	9.04	9.27
Direct Expenses	20.42	24.00	24.61	21.97	25.84	26.49	23.67	27.85	28.55	25.48	29.87	30.60	27.25	32.16	32.95	29.32	34.65	35.50	31.55	37.34	38.25
Direct Margin	20.61	13.45	13.89	22.22	14.49	14.84	24.05	15.58	15.97	25.76	16.90	17.34	27.93	18.20	18.67	30.11	19.59	20.10	32.45	21.07	28.98
Overhead Allocation	3.26	3.91	3.90	3.52	4.20	4.20	3.90	4.85	4.74	4.47	4.39	4.42	4.28	4.77	5.20	4.72	5.71	5.69	5.72	6.26	7.51
Expenses Incl. Corp O/H	23.68	27.91	28.51	25.49	30.04	30.70	27.57	32.70	33.29	29.96	34.25	35.03	31.54	36.93	38.15	34.03	40.36	41.19	37.27	43.60	45.76
Margin after Corp O/H	17.35	9.54	9.99	18.70	10.28	10.64	20.15	10.73	11.22	21.29	12.52	12.91	23.65	13.43	13.47	25.39	13.88	14.40	26.73	14.81	21.48
Costs per kwh (cents)																					
Fuel	0.53	0.55	0.56	0.58	0.59	0.61	0.63	0.64	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79	0.82	0.84	0.86	0.89	0.81
Non-fuel	1.05	1.64	1.68	1.12	1.76	1.80	1.20	1.89	1.94	1.28	2.03	2.08	1.38	2.18	2.24	1.48	2.35	2.40	1.58	2.52	2.30
Capital Expenditures	0.61	0.70	0.72	0.66	0.76	0.78	0.71	0.83	0.85	0.78	0.87	0.90	0.82	0.94	0.96	0.88	1.01	1.04	0.95	1.09	1.00
Direct Expenses	2.19	2.90	2.96	2.36	3.12	3.20	2.54	3.36	3.44	2.74	3.60	3.69	2.93	3.88	3.98	3.15	4.18	4.28	3.39	4.50	4.11
Direct Margin	2.21	1.62	1.67	2.39	1.75	1.79	2.58	1.88	1.93	2.77	2.04	2.09	3.00	2.20	2.25	3.23	2.36	2.42	3.49	2.54	3.11
Overhead Allocation	0.35	0.47	0.47	0.38	0.51	0.51	0.42	0.59	0.57	0.48	0.53	0.53	0.46	0.58	0.63	0.51	0.69	0.69	0.61	0.76	0.81
Expenses Incl. Corp O/H	2.54	3.37	3.43	2.74	3.63	3.70	2.95	3.94	4.02	3.22	4.13	4.23	3.39	4.46	4.60	3.66	4.87	4.97	4.00	5.26	4.92
Margin after Corp O/H	1.86	1.15	1.20	2.01	1.24	1.28	2.16	1.29	1.35	2.29	1.51	1.56	2.54	1.62	1.63	2.73	1.67	1.74	2.87	1.79	2.31
NPV of Margin after O/H	91.9																				
Underfunded Decomm.	8.5																				
NPV OF NET MARGIN	83.4																				

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)UQUESNE LIGHT
Costs of Nuclear Plant
In Millions

Arithmetic Escalation to $44.1/mwh in 2006 with escalations @ 2.5%

'ERRY	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
wh 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
'nit Output (gwh)	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,412	1,256	1,416	1,256	1,416
'elivered 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
Revenues	59.19	53.97	62.35	56.71	65.32	59.57	68.81	62.60	72.10	65.77	75.96	69.09	79.59	72.39	83.86	76.26	87.85	80.13	92.57	84.18	97.25
Fuel-Related Expenses																					
'uel Costs	6.42	5.91	6.87	6.29	7.30	6.70	7.79	7.13	8.25	7.58	8.80	8.04	9.29	8.49	9.82	8.71	9.79	8.71	9.82	8.71	2.43
uel Related ECR Costs	1.35	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	0.33
Total Fuel	7.77	7.10	8.22	7.49	8.64	7.89	9.13	8.32	9.59	8.78	10.15	9.24	10.63	9.68	11.17	9.91	11.14	9.91	11.17	9.91	2.76
Non-fuel O&M Expenses																					
'ariable 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
ixed O&M	18.11	18.56	19.03	19.50	19.99	20.49	21.00	21.53	22.06	22.62	23.18	23.76	24.35	24.96	25.59	26.23	26.88	27.55	28.24	28.95	29.67
Overhaul	0.00	3.96	0.00	4.16	0.00	4.39	0.00	4.63	0.00	4.88	0.00	5.15	0.00	5.43	0.00	5.58	0.00	5.58	0.00	5.58	0.00
Subtotal	18.11	22.52	19.03	23.67	19.99	24.88	21.00	26.15	22.06	27.50	23.18	28.91	24.35	30.39	25.59	31.80	26.88	33.13	28.24	34.53	29.67
ICA	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	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	31.81	36.22	32.73	37.37	33.69	38.58	34.70	39.86	35.77	41.20	36.88	42.61	38.06	44.10	39.29	45.51	40.59	46.83	41.95	48.23	43.38
Capital Expenditures	3.22	3.32	3.40	3.72	3.59	3.93	3.80	4.16	4.02	4.40	4.25	4.64	4.48	4.90	4.73	5.17	5.00	5.45	5.27	5.75	5.56
Direct Expenses	42.80	46.84	44.34	48.57	45.92	50.41	47.63	51.34	49.38	54.37	51.28	56.49	53.17	58.67	55.19	60.58	56.72	62.19	58.38	63.89	51.70
Direct Margin	16.39	7.13	18.00	8.14	19.40	9.17	21.18	10.26	22.73	11.39	24.68	12.60	26.42	13.92	28.67	15.68	31.14	17.93	34.18	20.30	45.55
Overhead Allocation	6.83	7.62	7.03	7.79	7.47	7.99	7.85	9.12	8.20	9.55	7.53	8.17	8.36	8.70	8.70	9.75	9.35	9.97	10.58	10.71	10.15
Expenses Incl. Corp O/H	49.63	54.47	51.37	56.37	53.40	58.40	55.48	61.46	57.58	63.92	58.81	64.66	61.53	67.37	63.89	70.33	66.06	72.17	68.97	74.60	61.85
Margin after Corp O/H	9.56	(0.50)	10.98	0.34	11.93	1.17	13.34	1.14	14.53	1.84	17.15	4.44	18.06	5.22	19.97	5.93	21.79	7.96	23.60	9.59	35.40
Costs per kwh (cents)																					
Fuel	0.58	0.59	0.61	0.63	0.64	0.66	0.68	0.70	0.71	0.73	0.75	0.77	0.79	0.81	0.83	0.83	0.83	0.83	0.83	0.83	0.21
Non-fuel	2.37	3.03	2.43	3.13	2.51	3.23	2.58	3.34	2.66	3.45	2.74	3.57	2.83	3.69	2.92	3.81	3.02	3.92	3.12	4.04	3.22
Capital Expenditures	0.24	0.29	0.25	0.31	0.27	0.33	0.28	0.35	0.30	0.37	0.32	0.39	0.33	0.41	0.35	0.43	0.37	0.46	0.39	0.48	0.41
Direct Expenses	3.19	3.92	3.29	4.07	3.42	4.22	3.54	4.28	3.68	4.55	3.81	4.73	3.96	4.91	4.10	5.07	4.22	5.21	4.34	5.35	3.84
Direct Margin	1.22	0.60	1.34	0.68	1.44	0.77	1.57	0.86	1.69	0.95	1.83	1.05	1.97	1.17	2.13	1.31	2.32	1.50	2.54	1.70	3.38
Overhead Allocation	0.51	0.64	0.52	0.65	0.56	0.67	0.58	0.76	0.61	0.80	0.56	0.68	0.62	0.73	0.65	0.82	0.70	0.83	0.79	0.90	0.75
Expenses Incl. Corp O/H	3.70	4.56	3.82	4.72	3.98	4.89	4.12	5.14	4.29	5.35	4.37	5.41	4.58	5.64	4.74	5.89	4.92	6.04	5.12	6.24	4.59
Margin after Corp O/H	0.71	(0.04)	0.82	0.03	0.89	0.10	0.99	0.10	1.08	0.15	1.27	0.37	1.35	0.44	1.48	0.50	1.62	0.67	1.75	0.80	2.63
NPV of Margin after O/H	56.1																				
Underfunded Decomm.	11.0																				
NPV OF NET MARGIN	45.1																				

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