STATE OF IOWA
IOWA UTILITIES BOARD

In Re:

	)	
Interstate Power and Light	)	**Docket No. SPU-05-15**
Company and FPL Energy	)	
Duane Arnold, LLC	)	

Direct Testimony of

David A. Schlissel

Synapse Energy Economics, Inc.

On Behalf of the

Iowa Office of Consumer Advocate

PUBLIC VERSION

September 28, 2005

Table of Contents

List of Tables

List of Figures

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

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Iowa Office of Consumer Advocate (OCA).

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Staff of the Kansas State Corporation Commission, the Arkansas Public Service Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit___DAS-1, Schedule A.

Q. Have you previously submitted testimony before this Board?

A. No.

Q. What is the purpose of your testimony?

A. Synapse was asked by the OCA to assist in its evaluation of the proposed sale of the Duane Arnold Energy Center ("DAEC") to FLPE Duane Arnold by Interstate Power & Light Company. ("IPL" or "the Company") This testimony presents the results of our analyses.

Q. Please explain how Synapse conducted its investigations and analyses.

A. We completed the following tasks as part of this investigation:

1. Reviewed the testimony submitted by IPL and FLPE Duane Arnold.
2. Reviewed the responses to the data requests submitted by OCA.
3. Reviewed relevant IUB Orders.
4. Examined materials in Synapse files related to nuclear power plant costs and performance, other nuclear power plant sales, nuclear power plant decommissioning, and to issues related to the ownership of nuclear power plants by subsidiaries of multi-tiered holding companies.
5. Examined materials available in the U.S. Nuclear Regulatory Commission's public docket files related to DAEC and to nuclear plant performance, license renewal, power uprates, decommissioning issues and sales.

6. Reviewed other publicly available materials concerning nuclear power plants costs, performance, license renewal, power uprates, decommissioning issues sales and decommissioning related plans and cost issues.

Q. Have you evaluated the proposed sales of other nuclear power plants?

A. Yes. I have evaluated the reasonableness of the proposed sales of the Vermont Yankee, Millstone, Seabrook and Kewaunee nuclear power plants. As part of these evaluations, I also have looked in detail at the sales of other nuclear power plants such as Nine Mile Point Units 1 and 2, Indian Point Unit 2 and 3, Fitzpatrick, Pilgrim, Three Mile Island, Oyster Creek, Clinton, and Ginna.

Q. Please summarize your conclusions in this investigation.

A. I have reached the following conclusions:

1. The DAEC sales transaction is structured to maximize the cash sales proceeds for shareholders.

2. Contrary to what IPL has claimed, the sale of DAEC does not have any material potential to benefit the company's ratepayers, and has clear and quantifiable detriment to the company's ratepayers.

3. There is no evidence that the proposed sale of DAEC achieves the objective of maintaining or reducing long-term power supply costs for IPL's ratepayers, and there is clear and quantifiable evidence of increased long-term power supply costs for IPL's ratepayers.

4. IPL's claim that the proposed Power Purchase Agreement's capacity and energy charges are designed to reflect what the company's ratepayers would have paid in rates for its continued ownership of DAEC through 2014 is not credible.

5. Rather than protecting ratepayers, the terms of the proposed Power Purchase Agreement commit IPL's customers to paying excessive O&M costs and capital expenditures.

6. It is reasonable to expect that the Nuclear Management Company could achieve a 90 percent average annual capacity factor if IPL continues to own DAEC.

7. The proposed Power Purchase Agreement does not reflect the potential Phase 3 uprate that would add another 24 MW of power to DAEC's output.

8. It is reasonable to assume that whatever party may own DAEC in the future will implement the Phase 3 power uprate.

9. There is only a very small risk that IPL would not be able to relicense DAEC.

10. To date, the NRC has issued extended operating licenses for 33 nuclear units. Applications to relicense another 16 nuclear units are currently under review by the NRC. The owners of another 26-28 nuclear units have expressed their intention to relicense their plants. There is no evidence that any owner of a currently operating nuclear plant has announced that it will not relicense its unit. The NRC has not refused to relicense any nuclear unit.

11. Relicensing of DAEC by IPL can be expected to create significant economic benefits for IPL's ratepayers both before and after 2014.

12. IPL has overstated the risks associated with continued ownership of DAEC.

13. IPL does not address the risks associated with the sale of DAEC and the subsequent construction and operation of a replacement coal-fired plant. After 2014, if IPL does not relicense DAEC, it will lose its 70 percent

share of more than 600 MW of low cost base load generation which will be replaced by an extremely expensive new base load coal plant.

14. There is a risk that DAEC's O&M and capital expenditures will be higher or that DAEC will experience outages as the result of events at other operating nuclear power plants, new rules or regulations issued by the NRC or as the result of deficiencies identified at DAEC or other plants. However, the NRC is not quick to establish new regulations requiring significant investments, as IPL has claimed.

15. There is only a minor risk that the cost of decommissioning DAEC will be significantly higher than the $628.6 million, in 2004 dollars, currently estimated by IPL.

16. The construction and operation of new coal-fired plants involve significant regulatory and fuel risks which were not adequately considered by IPL.

The Proposed DAEC Sales Transaction is Structured to Maximize the Cash Sales Proceeds for Shareholders

Q. IPL witness Aller has testified that "IPL chose the divestiture alternative, primarily because it believes this option had the most potential to benefit customers."[1] Do you agree with Mr. Aller's claim that the potential benefit to ratepayers is the primary reason why IPL is seeking to sell DAEC?

A. No. It is clear from IPL's testimony and internal company documents that IPL is seeking to sell DAEC in order to maximize the cash sale price for shareholders and to reduce what it perceives to be shareholders' risk of continued ownership. The Company is seeking to achieve these goals even if ratepayers are disadvantaged by the sale.

1 Direct Testimony of Thomas Aller, at page 11, lines 15-19.

In fact, internal Company documents clearly note that benefiting shareholders is the primary driver for the sale. For example, the slides in a May 2004 DAEC Business Strategy Presentation to the Company's Strategic Planning Group acknowledged that the [redacted][2]

A presentation by IPL witness Lacy to the Central Iowa Power Cooperative in March 2005 similarly noted that the "decision drivers" for the proposed sale of DAEC included:

- Future of DAEC has been an issue since early 1990's
- Cost-of-service (COS) rate regulation results in an unacceptable mismatch between financial risk and earnings
- Review of options resulted in two choices:
  - Decommission DAEC in 2014
  - Sell DAEC to buyer with opportunity for relicensing
- Timing of decision driven by re-licensing[3]

There was no mention in Mr. Lacy's presentation of the potential benefit for ratepayers as being one of the decision drivers of the proposed sale of DAEC. Other internal company documents similarly focused on the proposed benefit of the sale for shareholders.

---

2 IPL's Confidential Response to OCA DR 94, Attachment B, Slide 5 of 9.

3 IPL's Confidential Supplemental Response to OCA DR 58, at page 19.

Q. Have you seen any evidence that before deciding to sell the plant the Company analyzed whether the sale of DAEC would, as Mr. Aller has testified, have the most potential to benefit ratepayers?

A. No. The analyses that I have seen from the Company's Strategic Planning Group, which are the same studies described by IPL witness Boston, evaluated the impact on shareholders of selling DAEC versus keeping the plant under different scenarios. I have seen no evidence that IPL examined the long-term impact of the proposed sale on ratepayers before it made the decision to sell DAEC.

Q. Mr. Aller also testifies that the proposed sale of DAEC achieves the objective of maintaining or reducing power supply costs for IPL's customers.[4] Do you agree with this claim?

A. No. Even if you accept all of the assumptions and claims made by IPL's witnesses in this proceeding, which I do not, at best the proposed sale would reduce ratepayer costs by only an extremely slight amount. However, the analysis of the impact of selling DAEC on ratepayers presented by IPL's witnesses is too short term and truncated in that it ignores the significant benefits that ratepayers can be expected to obtain from the relicensing of the facility by IPL for an additional twenty years of operating life.

If sold, the mostly depreciated DAEC and its associated low cost power ultimately would be replaced in or about 2014 by a new coal unit that would cost hundreds of millions of dollars or more and have higher fuel costs. Although this would boost revenues for shareholders when the investment in the new coal plant is added to rate base, ratepayers would be forced to pay substantially higher rates during the years 2014 to 2034 than if IPL continued to own DAEC.

---

[4] Direct Testimony of Thomas Aller, at page 17, lines 2-9.

Q. But hasn't IPL testified that it would not relicense DAEC if the plant were not sold?

A. Yes. However, it is inconceivable to me that prudent management would not seek to extend the operating life of a substantially depreciated nuclear unit with an annual 80-90 percent capacity factor unless it had prepared economic cost/benefit analyses showing that there were better alternatives for ratepayers. A prudently managed utility would greatly desire to retain a low cost, high capacity factor plant like DAEC to provide lower rates for customers and to encourage economic development in its service territory which would benefit both stockholders and ratepayers.

Q. Have you seen any evidence that before rejecting the potential relicensing of DAEC IPL performed any economic cost/benefit analyses to determine whether retirement in 2014 or relicensing was the more economic option for ratepayers?

A. No. I am aware that IPL's 2003 Resource Plan found that relicensing was the more economic option. However, I have seen no evidence that before deciding it would not relicense DAEC IPL conducted any subsequent analyses to determine whether relicensing continued to be the more economic option for ratepayers or whether retirement had become more economic. It is clear that IPL is rejecting relicensing based solely on its estimated effect on shareholders. Indeed, as I will discuss below, in its internal documents and testimony in this proceeding IPL acknowledges that relicensing will have significant benefits for ratepayers.

Q. Has any state regulatory commission directed that IPL provide a quantitative and qualitative analysis of the choice between relicensing DAEC and other options, such as the construction of a new coal plant?

A. Yes. In December 2004, the Minnesota Public Utilities Commission directed that IPL present such a quantitative and qualitative analysis of the choice between relicensing DAEC and other options as part of its next resource plan.[5]

Q. Didn't IPL tell the IUB in its last rate case that it would give "reasonable consideration" to the long-term interests of both customers and investors before making a decision on whether to extend DAEC's license?

A. Yes. IPL witness Bruce Lacy made that commitment to the IUB in his testimony in Docket No. RPU-04-1.[6]

Q. If the goal of divesting DAEC was not selected because it has the most potential to benefit customers, what was IPL's goal in selling the plant?

A. IPL's primary goal was to maximize the cash price it received from bidders and to eliminate what it perceived to be the risks for shareholders of continuing to own the plant.

Q. What actions did IPL take during the auction process that lead you to conclude that maximizing the cash sale price that bidders would be willing to pay was the primary goal?

A. Through the proposed PPA capacity and energy charges in its March 2005 Confidential Offering Memorandum and revisions to the PPA distributed to bidders in June 2005, IPL indicated to potential bidders its willingness to agree to

---

5 Order Accepting Resource Plan in Docket No. E-001/RP-03-2040, dated December 17, 2004, at pages 7 and 8.

6 Exhibit____DAS-1, Schedule B, at page 10, lines 3 through 10.

a [redacted] cost PPA.[7] As a result, if the sale is approved IPL ratepayers will be committed to paying above-market prices for energy from DAEC.[8]

IPL also structured the energy charges in the PPA so that the winning bidder would receive approximately 60 to 66 percent of a nuclear fuel load free when the plant begins its expected extended life starting in February 2014.

In addition, IPL offered bidders a cap on the amount of power that they would have to provide to IPL.[9] This would allow bidders to sell any additional power from DAEC into the market and, thereby, gain additional revenues and profits.

Q. What were the capacity charges provided to bidders in IPL's March Confidential Offering Memorandum and the June revisions to the PPA terms?

A. Table 1 below compares the total annual fixed capacity charges and unitized fixed charges that IPL told bidders it was willing to pay in the March and June 2005 submissions:

Table 1: IPL March and June PPA Capacity Charges

---

[7] The March 2005 Confidential Offering Memorandum is included as IPL witness Reed's Exhibit____JJR-1, Schedule C. The June 15, 2005 final transaction document to bidders is included as Exhibit____DAS-1, Confidential Schedule G.

[8] IPL's Response to OCA DR No. 176.

[9] IPL's Response to OCA DR No. 214.

Q. What was the basis for the [redacted] capacity charges that IPL told potential bidders in June 2005 that it was willing to pay as part of a PPA for power from DAEC?

A. IPL has said that the [redacted] PPA charges distributed to bidders in June were due to [redacted] in the estimated DAEC operating and capital costs contained in a Preliminary 2005-2009 Business Plan that the Company received from NMC in April 2005.[10]

Q. By the time that the Company issued the revised PPA terms in June 2005, had IPL approved that Preliminary NMC 2005-2009 Business Plan for DAEC?

A. No.

Q. Is there any evidence that IPL even had reviewed the reasonableness of the figures in the preliminary NMC 2005-2009 NMC DAEC Business Plan before [redacted] to potential bidders?

A. No. There is no evidence that IPL performed any reasonableness review of the higher costs in the Preliminary 2005-2009 NMC Business Plan before they used those costs as the basis for [redacted] the capacity payments that IPL (and its ratepayers) would be required to make under the proposed PPA.

In fact, as late as early August IPL said that there had been no written communications between the Company and NMC concerning the differences between the NMC 2004-2008 NMC Business Plan and the Preliminary 2005-2009 NMC Business Plan.[11] As a result, IPL did not have any documentation prepared by or for NMC or IPL that discussed, analyzed, evaluated or otherwise set forth the reasons for the changes from the Approved 2004-2008 Business Plan to the

---

[10] Direct Testimony of Bruce Lacy, at page 12, line 21, to page 13, line 7.

[11] IPL's Response to OCA DR No. 120(a).

Preliminary 2005-2009 Business Plan.[12] Nor did IPL have any correspondence, inquiries or other communications in which it had requested that NMC provide any justification(s) for the changes between the two plans or any correspondence from NMC providing any such justification(s).[13]

Consequently, it is clear that instead of carefully evaluating the reasonableness of the higher O&M and capital expenditures in the Preliminary 2005-2009 NMC Business Plan for DAEC, the Company rushed to revise its offering terms in order to [redacted] the PPA payments it would commit to making to potential bidders under its proposed PPA. Such [redacted] PPA charges would encourage bidders to submit high cash price bids for DAEC.

Q. **Did the proposed energy charges increase significantly between the March 2005 Offering Memorandum and the revised PPA terms that were distributed to bidders in June 2005?**

A. [redacted]

However, the proposed fuel charges for the years 2013 and 2014 are [redacted] because they reflect the accelerated amortization of the fuel assemblies placed in DAEC's core during the plant's refueling outages in 2010 and 2012.[15]

---

12 Ibid.

13 Ibid.

14 See IPL's responses to OCA DRs Nos. 40 and 86.

15 Direct Testimony of Bruce Lacy, at page 29, line 3, to page 30, line 2.

Q. What is the significance of this accelerated amortization of the cost of the fuel assemblies placed in DAEC's core during 2010 and 2012?

A. The shorter amortization period means that IPL's ratepayers will pay the entire costs of these fuel assemblies by the time the PPA is terminated in February 2014. However, the fuel assemblies will still be capable of producing additional thermal power after 2014. As a result, when it relicenses DAEC, as it has said it will, FPLE Duane Arnold will receive the benefit of these fuel assemblies that IPL's customers will have paid for through the pre-February 2014 PPA. This will enable FPLE Duane Arnold to generate power for several years at a lower fuel cost.

For example, the only fuel cost that FPLE Duane Arnold will have to pay between 2014 and 2016 will be the cost of the roughly 40 percent of the new fuel that will be loaded into the core during DAEC's 2014 refueling outage. IPL's customers already will have paid the entire costs, and charged customers such costs through the PPA, of the fuel assemblies loaded into DAEC's core in 2010 and 2012 that would still be capable of producing heat and power in the core.

Q. Is it possible to estimate the value of the unused nuclear fuel for DAEC that IPL's customers will have paid for through the proposed PPA?

A. Yes. IPL has estimated that the accelerated amortization of fuel assemblies will increase the fuel costs to be paid by IPL's ratepayers by \$5.1/MWh in 2013 and \$4.4/MWh in 2014.[16] Using the estimated MWhrs from the proposed PPA, these cost increases translate into [redacted] Thus, under the proposed PPA charges, ratepayers will pay for approximately [redacted] of nuclear fuel that FPLE Duane Arnold will be able to use during DAEC's extended operating life after February 2014.

---

16 IPL's Response to OCA DR No. 163.

Q. What was the basis for the fuel costs used in the March 2005 Offering Memorandum and the June 2005 letter to bidders?

A. IPL has said that the projected DAEC fuel costs used to develop the energy charges in the proposed PPA were provided by NMC without description of underlying assumptions or workpaper support.[17] However, IPL apparently used this information in developing the proposed PPA energy charges without approving, or even understanding, the bases for these fuel costs.

Q. Is there a cap on the amount of power that IPL will be able to purchase from DAEC under the PPA?

A. Yes. As explained by IPL witness Friedman, IPL will not be obligated to purchase any additional energy from DAEC in the event that FPLE Duane Arnold increases the power level at the plant.[18]

Q. What benefit does this cap provide for FPLE Duane Arnold?

A. In the likely event that another power uprate is implemented at DAEC after the plant is sold, the cap provides that FPLE Duane Arnold will have additional power to sell into the market. FPLE Duane Arnold will not be obligated to provide this power to IPL.

Q. Do the offers by CIPCO and Corn Belt have similar caps in the proposed PPAs they have offered to potential bidders?

A. No. Both CIPCO and Corn Belt have indicated to potential bidders that they want to retain the right of first refusal to power products associated with future uprates at DAEC during the term of the PPA.[19]

---

17 IPL's Response to OCA DR No. 46.

18 Direct Testimony of Richard Friedman, at page 7, lines 11-20.

19 Confidential Offering Memorandum, Exhibit____JJR-1, Schedule C, at pages 9-21 and 9-28.

Q. Do IPL's ratepayers benefit from the cap that IPL offered to potential bidders as compared to the right of first refusal offered by CIPCO and Corn Belt?

A. No. Even if IPL was concerned that the price of power from DAEC would be above market prices, it would have been more reasonable to retain a right of refusal on the power from such future uprates instead of demanding a cap. That would have assured ratepayers access to additional DAEC power if IPL determined, based on the future conditions when a power uprate was implemented (currently proposed for about 2009), that the price of such additional power was going to be below then forecast market prices.

Q: Do DAEC co-owners request other different bid terms that IPL elected not to request for its PPA?

A: Yes. Corn Belt required a PPA through 2034, the anticipated end of DAEC's NRC operating license following renewal of the existing license.[20] CIPCO required a primary term for a PPA through February 2014 but also required a right of first refusal to extend the term of the PPA should DAEC's license be extended.[21]

Q. Would ratepayers receive significant benefits from the higher cash price that IPL would receive from FPLE Duane Arnold due to these provisions in the PPA?

A. The benefits that ratepayers would receive from the higher cash price are minimal and greatly more than offset by additional PPA charges. The only share of the proceeds from the sale of DAEC that ratepayers would receive would be the treatment of $10 million as a regulatory liability to be used to offset the AFUDC

---

20 Confidential Offering Memorandum, Exhibit____JJR-1, Schedule C, at page 9-27.

21 Confidential Offering Memorandum, Exhibit____JJR-1, Schedule C, at page 9-23.

on new generation built in Iowa for the benefit of its customers.[22] However, ratepayers might not actually receive this offset for a number of years. Ratepayers would not receive any refunds or other cash benefits from the sale.

Q. IPL witness Aller cites the fact that FLPE Duane Arnold would share with IPL the cash recoveries from litigation against the U.S. Department of Energy over spent nuclear fuel as a benefit to the proposed sale transaction.[23] Do you agree that this would be a significant benefit for ratepayers?

A. No. There are several factors which suggest that the proposed sharing of cash recoveries from the U.S. Department of Energy over spent nuclear fuel would not be a significant benefit for ratepayers.

First, IPL has not quantified the damages it has incurred to date as a result of the DOE's failure to begin the taking of spent nuclear fuel on January 1, 1998.[24] Therefore, it is not possible to say how much of the damages from this delay will be "shared" with FPLE Duane Arnold under the terms of the proposed sale transaction.

Second, it is possible that a future settlement between the DOE and FPLE Duane Arnold could involve discounts on future services or spent fuel charges in lieu of payment by DOE of past monetary damages incurred by IPL while it was DAEC's owner. Under the terms of the proposed sales transaction, IPL would not share in any such discounts. FPLE would decide whether to bring these claims and the litigation strategy it would employ; it would be in FPLE's interest to secure an outcome more beneficial to its own interests which may not be maximize the cash proceeds paid by the DOE.

---

[22] Testimony of Thomas Aller, at page 25, lines 4-11.

[23] Testimony of Thomas Aller, at page 23, lines 13-22.

[24] IPL's Response to OCA DR No. 174.

Third, the possibility of IPL securing damages from the U.S. DOE is not as speculative as IPL suggests. In fact, Federal courts have decided that the U.S. government was unconditionally contracted to begin removing spent nuclear fuel by January 31, 1998.[25] The Federal Court of Claims has subsequently determined the individual utilities are owed damages resulting from the DOE's failure to carry out this responsibility.[26] Only the size of the payments remains to be determined and the amount of damages owed to individual utilities, like IPL, will continue to grow as the DOE is further unable to remove spent nuclear fuel from plant sites.

Indeed, Exelon settled its dispute with the U.S. Department of Energy in August 2004. According to published reports, Exelon was to immediately receive $80 million in reimbursements for storage costs already incurred as a result of the DOE's failure to begin taking spent nuclear fuel on January 31, 1998, with additional amounts to be reimbursed annually for future costs. If the Yucca Mountain national repository opens by 2010, and the DOE begins accept the spent fuel, the amount owed to Exelon under the settlement would eventually total about $300 million. If the DOE should fail to accept spent fuel by 2010, the amount paid to Exelon could exceed $600 million by 2015.[27] The payments will be made out of the federal Judgment Fund, which is available for court judgments and DOJ settlements of actual or imminent lawsuits against the government.

Therefore, it is very reasonable to expect that at some point before DAEC is ultimately decommissioned, IPL will receive payments from the DOE (or equivalent services in lieu of payments) for increased spent fuel costs at DAEC, either as the result of litigation or negotiation.

---

25 For example, see *Nucleonics Week*, September 7, 2000, at page 9, and *Megawatt Daily*, September 5, 2000.

26 The DOE has acknowledged that it is responsible for removing spent nuclear fuel and is liable for the damages resulting from its failure to do so. See the August 2, 2000 issue of the *Foster Electric Report*, at page 24.

Finally, through their rates IPL's ratepayers paid in cash the increased costs resulting from the DOE's failure to begin taking spent nuclear fuel from DAEC. Under the terms of proposed sales transaction, ratepayers would only get a share of the recoveries from the DOE. Moreover, as proposed by IPL, ratepayers would not receive their share of such recoveries in a refund.[28] Instead, their share of the recoveries would be placed in a regulatory liability account. The monetary damages recovered from the DOE would remain with IPL and its shareholders.

Q. Have all of the rights to the recoveries from litigation or negotiation with the DOE over spent nuclear fuel been transferred to the buyer in every plant sale?

A. No. In a number of plant sales transactions, the sellers have retained the rights to pre-closing liabilities and, in some cases, have filed litigation against the DOE. For example, IPL witness Reed's response to OCA DR No. 136 indicated that although in some sales transactions the rights to DOE litigation recoveries were transferred in whole or in part to the buyers, the sellers of the Nine Mile Point and Pilgrim nuclear power plants have filed litigation against the DOE. In addition, the rights to pre-closing DOE liabilities were retained by the seller of the Millstone nuclear units, Northeast Utilities.[29]

Q. Is the fee paid to Concentric Energy Advisors for assisting the Company in the sale of its share of DAEC based on the cash price IPL would receive or on the total value of all of components of the sale?

A. Pursuant to its contract with IPL, if the sale is successfully closed, Concentric's payment is based primarily on the cash price obtained for IPL's share of DAEC.[30] In addition, Concentric would be paid for services as management of outside

---

27 *Nuclear News*, September 2004, at page 17.

28 Direct Testimony of Thomas Aller, at page 23, lines 13-22.

29 IPL's Response to OCA DR No. 136.

30 IPL's Responses to OCA DRs Nos. 134 and 148.

contractors or attorneys, expenses, and services for regulatory support. If the sale is not successfully concluded, Concentric's payment would be limited to specified monthly retainers plus the same specified services.

Consequently, Concentric had an incentive to maximize the cash price the IPL received for its share of DAEC. A generous PPA and beneficial assignment of rights and liabilities of others to the purchaser greatly facilitates a higher cash price.

Estimated DAEC Operating Costs for the Years 2006-2014

Q. Company witness Aller has testified that the PPA capacity and energy charges are designed to reflect what IPL's customers would have paid in rates for IPL's continued ownership of DAEC through the end of its current operating life.[31] Do you find this testimony credible?

A. No. The PPA capacity and energy charges and the inputs to the company's revenue requirements analyses are based, in part, on the significantly higher O&M and capital expenditure projections contained in the Preliminary 2005-2009 Business Plan for DAEC. I have the following concerns about IPL's use of these O&M and capital expenditure projections:

- The O&M and capital expenditure projections in the Preliminary 2005-2009 Business Plan are significantly higher than the O&M and capital expenditure estimates in the approved 2003-2007 and 2004-2008 Business Plan for DAEC.
- IPL has used the higher O&M and capital expenditure projections in the Preliminary 2005-2009 without evaluating their reasonableness and without approving the proposed plant budgets.
- The increasing cost projections in the Preliminary 2005-2009 Business Plan are inconsistent with recent costs and cost trends at DAEC.
- IPL cannot say whether NMC is projecting similar increasing costs for the other nuclear units in its fleet.

---

31 Direct Testimony of Thomas Aller, at page 27, lines 14-20.

- It appears that the costs of the current NMC fleet optimization effort are reflected in the proposed PPA charges and the Preliminary 2005-2009 Business Plan. However, there is no evidence that either the proposed PPA charges or the Business Plan reflect any of the net cost savings expected from the NMC fleet optimization.
- The higher cost projections in the Preliminary 2005-2009 Business Plan are contradictory to the production cost goals set for DAEC by NMC and IPL.
- The higher cost projections in the Preliminary 2005-2009 Business Plan are inconsistent with the production cost goals set by NMC for the remaining units in its fleet.
- The cost projections in the Preliminary 2005-2009 Business Plan are inconsistent with recent trends in the nuclear industry as a whole.
- The Phase 2 spent nuclear fuel campaign is by far the most expensive capital project included in the Preliminary 2005-2009 Business Plan. However, IPL is unable to provide even a single document to justify the estimated $21.8 million cost of the project included in the Preliminary 2005-2009 Business Plan.
- It is reasonable to expect that the higher O&M and capital expenditures forecast in the Preliminary 2005-2009 Business Plan would lead to improved performance at DAEC. However, the 2005-2009 Business Plan projects longer refueling outages and a higher forced outage rate for DAEC than were forecast in the 2004-2008 Business Plan. This makes no sense and further highlights my concern about IPL using a high cost PPA to increase the cash proceeds for shareholders.

Q. What is the significance of the O&M and capital expenditure estimates presented in the Preliminary 2005-2009 NMC Business Plan for DAEC?

A. According to IPL, the inputs to the proposed PPA charges for the years 2006, 2007 and 2008 reflected one-half of the increases in estimated O&M and capital expenditures between the 2004-2008 Business Plan for DAEC and the Preliminary 2005-2009 Business Plan that was issued in April 2005.[32] The inputs to the proposed PPA charges for subsequent years were extrapolated from these figures using the general rate of inflation. Therefore, in order to evaluate the reasonableness of the proposed PPA charges, it is important to understand and

[32] Direct Testimony of Bruce Lacy, at page 12, line 10, to page 13, line 7.

assess the bases for the cost increases presented in the Preliminary 2005-2009 Business Plan.

Q. How do the estimated O&M and capital expenditures in the Preliminary 2005-2009 NMC Business Plan for DAEC compare with recent actual expenditures and the estimates in the 2004-2008 Business Plan?

A. Table 2 below compares the online O&M expenditure estimates from the Preliminary 2005-2009 Business Plan[33] with the actual total O&M expenditures in 2002 and 2003 and the estimated annual total O&M expenditures from the 2004-2008 Business Plan (approved in October 2004).[34]

Table 2: Online O&M Estimates – Preliminary 2005-2009 Business Plan compared to actual 2002-2004 and Estimates from the 2004-2008 Business Plan

	2002 ($000)	2003 ($000)	2004 ($000)	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)
Actual	$69,900	$74,900	$73,500				
2004-2008 Business Plan			$74,069	$76,536	$78,638	$80,352	$84,202
Preliminary 2005-2009 Business Plan				$74,067	$83,249	$82,859	$86,784
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (dollars)				-$2,469	$4,611	$2,507	$2,582
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (percentage)				-3.2%	5.9%	3.1%	3.1%

This table shows that the Preliminary 2005-2009 Business Plan estimated that although online O&M will be about the same in 2005 as it was in 2004, there will be about a $10 million, or a thirteen percent increase, in DAEC's online O&M between 2004 and 2006. This increase would be approximately $4 million, or

33 Although the Preliminary 2005-2009 Business Plan document did not disaggregate the estimates of total O&M expenditures into online and refueling O&M components, that disaggregation was provided in the Proposed 2005-2009 Business Plan. See IPL's Supplemental Response to OCA DR No. 25, at page 10 of 13.

34 DAEC's actual O&M expenditures from 2002-2004 were provided in IPL's Response to OCA DR No. 29.

about 5 percent, above the growth in online O&M expenditures than would be expected from the 2.5 percent overall annual rate of escalation projected by IPL.

Table 3 then compares the refueling O&M expenditures projected in the Preliminary 2005-2009 Business Plan with the actual refueling O&M in the years 2002 through 2004 and the estimates from the 2004-2008 Business Plans.

Table 3: Refueling O&M Expenditures – Preliminary 2005-2009 Business Plan Estimates compared to actual 2002-2004 and Estimates from the 2004-2008 Business Plan

	2002 ($000)	2003 ($000)	2004 ($000)	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)
Actual	$300	$16,500	$700				
2004-2008 Business Plan			$800	$14,411	$1,000	$14,000	$925
Preliminary 2005-2009 Business Plan				$15,976	$3,467	$17,175	$2,929
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (dollars)				$765		$5,642	
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (percentage)				5.0%		37.6%	

Thus, the Preliminary 2005-2009 Business Plan projects that the cost of preparing for and conducting DAEC's 2007 refueling outage will be approximately $20.6 million ($3.5 million in 2006 and $17.2 million in 2007). This would be approximately 38 percent higher than NMC had estimated for the same outage only months earlier in the 2004-2008 Business Plan.

An estimated $20.6 million cost for DAEC's 2007 refueling outage also is approximately $2-3 million per outage, or about ten to fourteen percent, higher than would be suggested by averaging the costs of the last three refueling outages and escalating the resulting figure from 2003 to 2007 year dollars at IPL's projected annual rate of inflation.

Table 4: Capital Expenditures - Preliminary 2005-2009 Business Plan Estimates compared to Actual 2002-2004 and Estimates from the 2004-2008 Business Plan[35]

	2002 ($000)	2003 ($000)	2004 ($000)	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)
Actual	$22,900	$22,000	$8,600					
2004-2008 Business Plan			$8,634	$19,983	$8,493	$14,983	$7,997	
Preliminary 2005-2009 Business Plan				$21,574	$17,606	$25,516	$19,697	$36,510
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (dollars)				$1,591	$9,113	$10,533	$11,700	$36,510
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (percentage)				8.0%	107.3%	70.3%	146.3%	NA

As can be seen, the April 2005 Preliminary 2005-2009 Business Plan projected significantly higher capital expenditures than had been forecast in the 2004-2008 Business Plan that had been approved only six months earlier in October 2004.

Q. How do the O&M and capital expenditure estimates in the Proposed 2005-2009 Business Plan that was issued in July 2005 compare to the estimates in the April 2005 Preliminary 2005-2009 Business Plan?

A. The estimated total O&M expenditures in the Proposed 2005-2009 Business Plan (dated July 15, 2005) are the same as those in the April 2005 Preliminary Business Plan. However, the annual capital expenditure estimates in the Proposed 2005-2009 Business Plan are even higher than the figures released in the Preliminary 2005-2009 Business Plan just three months earlier in April.

Q. Is it unreasonable to expect that O&M and capital expenditure forecasts will change over time at any nuclear power plants?

A. No. It is reasonable to expect that O&M and capital expenditure estimates will be revised over time to reflect cost control programs or any number of changed circumstances. Such changed circumstances could include emerging equipment

---

35 DAEC's actual capital expenditures for the years 2002 through 2004 were provided in IPL's Response to OCA DR No. 23.

problems, evolving technical or regulatory issues, or new labor agreements, to name a few.

However, in the current circumstances concerning the proposed sale of DAEC, the fact that the estimated O&M and capital expenditures have increased so dramatically in only six months (after having been relatively the same in the 2003-2007 and 2004-2008 Business Plans) raises serious questions in my mind concerning the credibility of those new estimates. This is especially true because during this six month period IPL management decided to sell DAEC and higher estimated O&M and capital expenditures could be expected to assist the company both in achieving a higher sales price (through higher PPA capacity charges) and in convincing the IUB that the sale of DAEC would not disadvantage IPL's ratepayers.

Q. Has the Company approved or even conducted a detailed review of the increased O&M and capital expenditures in either the April 2005 Preliminary or the July 2005 Proposed 2005-2009 Business Plans?

A. No. IPL has not approved the O&M and capital expenditure estimates contained in the Preliminary or Proposed 2005-2009 Business Plans.[36] Indeed, IPL's response to OCA DR No. 120(a) in early August noted that there had been no correspondence between IPL and NMC or any other documents explaining the bases for the changes between the approved 2004-2008 Business Plan and the Preliminary 2005-2009 Business Plan.[37] As late as August 22nd, IPL said that it had "yet to conduct a full review of the proposed level of capital spending in the proposed business plan" and, in fact, had made only a "cursory" review of the level of capital spending in that Plan.[38] Finally, until September 21, 2005 IPL did

36 IPL's Response to OCA DR No. 54 (a)-(c).

37 IPL's Response to OCA DR No. 120(a).

38 IPL's Responses to OCA DR No. 129(c)(2) and OCA DR No. 145 (b).

not even request support and documentation for the substantial budget increase that was being proposed by NMC for 2006.[39]

Q. The Preliminary 2005-2009 Business Plan reflects an increase of approximately $9 million in online O&M between 2005 and 2006.[40] Has IPL provided any explanation for this significant increase?

A. IPL's response to OCA DR No. 164 shows that the major factor for the significant growth in estimated online O&M expenditures between 2005 and 2006 is a projected increase of $10.1 million in the "Admin. and general" expenses. A subsequent data response indicated that the [redacted][41]

Q. Is this approximate $10 million increase in Admin and general expenses carried over to future years beyond 2006?

A. Yes. IPL's response to OCA DR No. 164 shows that this $10 million increase is carried over into projected online O&M for the years 2007 and beyond.

Q. Has IPL been able to identify any other factors in addition to the NMC fleet optimization effort that also may be responsible for the $10.1 million increase in the Admin. and general expenses after 2005?

A. No. Other than the claim that the cost increase was due to "NMC fleet optimization," IPL was unable to either explain the reasons or factors which form the basis for the estimated $10.1 million increase in the Admin. and general category of O&M expenditures between 2005 and 2006 shown in the Preliminary

---

[39] IPL Additional Response to OCA DR No. 234(c).

[40] IPL's Supplemental Response to OCA DR No. 25, at page 10 of 13.

[41] IPL's Response to OCA DR No. 215.

and Proposed 2005-2009 Business Plans.[42] Nor was IPL able to disaggregate the Admin. and general category of online O&M expenditures into its various subcategories of costs.[43]

Q. Would a projected increase of $10.1 million to reflect NMC fleet optimization initiatives appear to be inconsistent with the answers provided by IPL to any other OCA data requests?

A. Yes. IPL's response to OCA Data Request No. 167 attributes $2 million of the projected increase in online O&M for the year 2006 to "NMC fleet optimization." At the same time, an October 2004 NMC Board Member Briefing for IPL similarly suggests that the fleet optimization efforts would require $3.2 million of capital spending during the years 2004-2009.[44] These estimated costs are significantly lower than the approximate $10 million per year cost for the NMC fleet optimization effort suggested by IPL's responses to OCA DRs Nos. 164 and [redacted].

Q. Have you seen any evidence that the O&M expenditures at the other plants that NMC operates are being increased by $10 million per year to reflect the implementation of these fleet optimization initiatives?

A. No. As I mentioned earlier, IPL has not provided any documentation related to the Business Plans or O&M or capital spending for the other plants that NMC operates.

Q. Have you seen any evidence of any "benefits" projected for DAEC from the planned NMC fleet optimization effort?

A. Yes. The October 2004 NMC Board Member Meeting for IPL identified a number of benefits expected to be achieved from the planned NMC fleet

---

42 IPL's Response to OCA DR No. 229.

43 Ibid.

44 IPL's Response to OCA DR No. 233, Attachment A, at page 16.

optimization. These included a possible reduction in the staffing level at DAEC by 77 positions by 2007 and reduced future O&M costs.[45]

Q. Did NMC quantify these expected benefits for DAEC from fleet optimization?

A. Yes. NMC estimated that the net cost savings for DAEC from the NMC fleet optimization would be $4.5 million lower O&M in 2007, $5.2 million lower O&M in 2008, and $5.4 million lower O&M in 2009.[46] The fact that these are called "net cost savings" suggests that these are the savings above and beyond the annual costs of implementing the optimization efforts.

Q. Is there any evidence that any of the projected net cost savings from the NMC fleet optimization are reflected in either IPL's proposed PPA charges or the preliminary or proposed 2005-2009 Business Plans?

A. No. It appears that the costs of the current NMC fleet optimization effort are reflected in the proposed PPA charges and the preliminary and proposed 2005-2009 Business Plans. However, there is no evidence that either the proposed PPA charges or the 2005-2009 Business Plans reflect any of the net cost savings expected from the NMC fleet optimization.

In fact, the Preliminary and Proposed 2005-2009 Business Plans both forecast continuing increases in online O&M expenditures at DAEC which appear, on their face, to be inconsistent with the assumption that the NMC fleet optimization effort will reduce the number of staff positions at DAEC by 77 and lead to lower future O&M costs.

---

45 IPL's Response to OCA DR No. 233, Attachment A, at pages 8 and 13.

46 Ibid, at page 16.

Q. Have you seen any evidence that NMC is projecting any increases in the forecast O&M and capital expenditures for the years 2005 through 2009 for the other nuclear plants that it operates?

A. No. IPL has been unable to provide the information we have requested concerning projected O&M and capital spending expenditures for any of the other nuclear power plants operated by NMC.[47]

Q. IPL has said that is used only 50 percent of the increased expenditures forecast in the Preliminary 2005-2009 Business Plan to develop the proposed PPA charges.[48] How do the estimated O&M and capital expenditures that were used by IPL as inputs for developing the proposed PPA charges compare to DAEC's actual O&M expenditures in recent years and the estimated O&M in the 2004-2008 Business Plan?

A. Tables 5, and 6 below compare the estimated online O&M and capital expenditures that were used as inputs for developing the proposed PPA charges with the actual expenditures at DAEC from 2002-2004 and the estimates from the 2004-2008 Business Plan.

Table 5: Online O&M Estimates used as inputs to PPA Charges as compared to actual online O&M and estimates in 2004-2008 Business Plan

	2002 ($000)	2003 ($000)	2004 ($000)	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)
Actual	$69,900	$74,900	$73,500				
2004-2008 Business Plan			$74,069	$76,536	$78,638	$80,352	$84,202
Online O&M Inputs to PPA Charges					$80,944	$81,605	$85,501
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (dollars)					$2,306	$1,253	$1,299
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (percentage)					2.9%	1.6%	1.5%

47 IPL's Responses to OCA DRs Nos. 28, 98, and 140.

Table 6: Capital Expenditure Estimates used as inputs to PPA Charges as compared to actual online O&M and estimates in 2004-2008 Business Plan

	2002 ($000)	2003 ($000)	2004 ($000)	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)
Actual	$22,900	$22,000	$8,600					
2004-2008 Business Plan			$8,634	$19,983	$8,493	$14,983	$7,997	
Capital Inputs to PPA Charges				$20,270	$10,878	$16,071	$10,021	$23,974
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (dollars)				$287	$2,385	$1,088	$2,024	$23,974
Increases from 2004-2008 to Preliminary 2005-2009 Business Plans (percentage)				1.4%	28.1%	7.3%	25.3%	NA

Thus, the inputs to the proposed PPA charges reflected online O&M estimates that were slightly higher than those in the 2004-2008 Business Plan and capital expenditure estimates that were significantly higher than the estimates in the 2004-2008 Business Plan.

As noted in IPL witness Lacy's Exhibit BAL-1, the refueling O&M inputs to the proposed PPA charges reflected the average costs for DAEC's last three refueling outages escalated to 2007 dollars using the general rate of inflation.[49]

Q. How do the estimated fuel costs that were used by IPL as inputs to the proposed PPA charges compare to DAEC's fuel costs in recent years and the estimates in the 2004-2008 Business Plan?

A. Table 7 below compares the estimated fuel costs that were used by IPL in developing the proposed PPA charges in its March Confidential Offering Memorandum and June 2005 Offering Letter to DAEC's actual fuel costs in the years 2002-2004 and the estimated fuel costs in the 2004-2008 and the Preliminary 2005-2009 Business Plans.

[48] Direct Testimony of Bruce Lacy, at page 12, line 21, to page 13, line 7.

[49] Exhibit BAL-1, Schedule B-1, page 2 of 2.

Table 7: Fuel Cost Estimates used as inputs to PPA Charges as compared to actual fuel costs and estimates in 2004-2008 and Preliminary 2005-2009 Business Plans

[redacted]

Q. Was there a declining trend in DAEC's fuel costs even before 2002?

A. Yes. Data from IPL's FERC Form 1 filing shows that DAEC's fuel costs declined from \$8.18/MWh in 1995 to \$6.07/MWh in 2002 and \$5.78/MWh in 2004.[50]

Q. Did IPL approve or even evaluate the reasonableness of these higher online O&M, capital [redacted] estimates before they used them to develop the proposed PPA charges?

A. No. IPL's responses to OCA data requests reveal that IPL never approved or even reviewed the reasonableness of the increased online O&M, capital expenditures [redacted] before they were used to develop the proposed PPA capacity and energy charges submitted to bidders in June 2005.[51]

---

50 See OCA witness Habr's Schedule A.

51 For example, see IPL's Responses to OCA DRs Nos. 54, 120, 121, and 229.

Q. Are the increasing trends in estimated O&M [redacted] that are reflected in the proposed PPA charges and the Preliminary and Proposed 2005-2009 Business Plans consistent with the goals that IPL and NMC has set for DAEC?

A. No. The goals set by DAEC's owners in 2003 and 2004 directed NMC to reduce the plant's production costs from historical levels (i.e., non-fuel O&M, fuel and depreciation).[52] [redacted]

For example, the levels of online O&M expenditures used to develop the proposed PPA charges (and in the Preliminary and Proposed 2005-2009 Business Plans) are [redacted] than the goals and targets that IPL and NMC set for DAEC for the years 2006-2008.[53]

Q. Are the increasing trends in estimated O&M [redacted] that are reflected in the PPA charges and the Preliminary and Proposed 2005-2009 Business Plans for DAEC consistent with the goals that NMC has set for the other nuclear power plants it operates?

A. No. The approved DAEC 2004-2008 Business Plan notes that NMC's fleet production cost target is to reduce the production costs for the other plants operated by NMC from $22.50 in 2004 to $19.70 in 2010, both in 2004 dollars. This means that NMC's production cost goal is to reduce the combined non-fuel O&M and fuel costs at these plants in real terms during this six year period. By contrast, the Proposed 2005-2009 Business Plan project that DAEC's production

---

52 See IPL's August 7, 2003 letter to NMC, provided in its response to OCA DR No. 8; IPL's Response to OCA DR No. 22, Attachment C, at page 3, of 36; and IPL's Response to OCA DR No. 63, at page 15 of 27.

53 Compare Exhibit BAL-1, Schedule B-1, page 1 of 2, with the Online O&M Target figures presented in the 2004-2008 Business Plan in IPL's Response to OCA DR No. 22, at page 12 of 36.

costs will rise from $26.19 in 2005 to $31.56 in 2009.[54] This represents a real increase of approximately 10 percent during the four year period 2005 to 2009.

Q. Are the increasing trends in estimated O&M [redacted] that are reflected in the PPA charges and the Preliminary and Proposed 2005-2009 Business Plans for DAEC consistent with recent O&M and fuel cost trends in the nuclear industry?

A. No. Nuclear industry [redacted], non-fuel O&M and production costs all have decreased significantly since the early to mid 1990s.[55] IPL is suggesting a dramatic turnaround of these historic trends.

Q. Have you seen any evidence of a general industry-wide expectation of such a dramatic turnaround in nuclear plant production costs?

A. No.

Q. Was IPL able to provide project documents to justify all of the cost estimates for capital projects included in the Preliminary and Proposed 2005-2009 Business Plans?

A. No. The Spent Fuel Storage Campaign No. 2 is by far the most expensive capital project included in the Preliminary and Proposed 2005-2009 Business Plans, with an estimated cost of $21.8 million.[56] Nevertheless, IPL was unable to provide even a single page of supporting documentation for this estimated cost. IPL also admitted that only "a rough estimate [of the cost of this project] was utilized by NMC for the proposed 2005 business plan."[57]

---

54 IPL's Supplemental Response to DR. 25, at page 10 of 13.

55 See OCA witness Fuhrman's Exhibit____CEF-1, Schedule H.

56 See the Supplemental Response to DR No. 25, at page 13 of 13.

57 IPL's Response to DR No. 145(c).

Q. Do the Preliminary and Proposed 2005-2009 Business Plans assume improved DAEC operating performance as a result of the increased O&M and capital expenditures?

A. No. It is reasonable to expect that the higher O&M and capital expenditures projected in the Preliminary and the Proposed 2005-2009 Business Plans would lead to improved operating performance at DAEC. However, the 2005-2009 Business Plans actually assume longer refueling outages (36 days in 2007 and 30 days thereafter versus 25 days for all future refueling outages) and a slightly higher minor or forced outage rate (4 percent versus 3.50 percent) than had been forecast in the 2003-2007 and 2004-2008 Business Plans.[58]

Indeed, the Preliminary and Proposed 2005-2009 Business Plans assume that even though NMC will spend substantially more on O&M and capital expenditures in 2006-2009 than it has spent on the facility in recent years, DAEC's minor or forced outage rate will increase to 4 percent which is substantially above the actual 2.4 percent annual forced outage rate that the plant averaged during the years 2000-2004.[59] This makes no sense. If NMC is going to spend more money on repairing and maintaining plant equipment and improving plant operating and maintenance programs, those expenditures should result in improved, not worsening, plant operating performance.

Q. Have you seen any examples of proposed capital expenditures that are designed specifically to address the causes of recent forced outages at DAEC?

A. Yes. The Proposed 2005-2009 Business Plan includes expenditures during 2005, 2006, and 2007 for a condenser debris filter. The documentation for this project notes that a shutdown of DAEC had occurred in each of the past three years due to a condenser tube leak. According to the project documentation, these leaks

---

58 See IPL's response to OCA DR No. 22, Attachment C, at page 10 of 36 and the Supplemental Response to OCA DR No. 25, at page 11 of 13.

59 See IPL witness Lacy's Exhibit____BAL-1, Schedule G for the forced outage rates achieved by DAEC during the years 2000-2004.

would be eliminated by the installation of a condenser debris filter. The average duration of each shutdown has been 3.75 days.[60] The expenditure of the approximately $1.5 million estimated for this project should improve DAEC's capacity factor by reducing the plant's forced outage rate by approximately one percent per year. However, neither IPL's 2005-2009 Business Plans nor the inputs to the proposed PPA charges reflect this improvement.

Q. **How do the estimated O&M and capital expenditures in the Preliminary and Proposed 2005-2009 Business Plans and the figures used by IPL to develop the proposed PPA capacity charges compare with FPLE Duane Arnold's estimated plant operating and capital costs?**

A. [redacted][61]

By way of contrast, IPL's inputs into the proposed PPA charges reflected online O&M expenditures of $80.9 million in 2006 increasing to $90.2 million in 2010.[62]

---

60 IPL's Response to OCA DR No. 231, Attachment E, at page 3 of 9.

61 Confidential Exhibit___MO-1, Schedule B, Page 1 of 2.

62 Exhibit___ BAL-1, Schedule B-1, page 1 of 2.

Q. Are there any differences between the assumptions made by IPL in developing the proposed PPA capacity and energy charges and the Preliminary and Proposed 2005-2009 Business Plan?

A. Yes. The Preliminary 2005-2009 Business Plan reflected the full 18 MWe of increased power from the recent Phase 2 power uprate. However, the PPA only reflects 15 MWe.[63]

Q. Do you agree with the testimony of IPL witness Friedman that the principal benefit of the PPA is that it offers price protection from excessive O&M costs, capital expenditure over-runs, under performance or long-term outages?[64]

A. No. I am afraid that rather than protect ratepayers, the terms of the proposed PPA would commit IPL's customers to paying excessive O&M costs and capital expenditures.

Expected DAEC Operating Performance during the Years 2006-2014

Q. Is it reasonable to expect that DAEC could achieve a 90 percent average annual capacity factor for the years 2006 through February 21, 2014 if the plant continued to be owned by IPL and operated by NMC?

A. Yes. Given DAEC's recent strong operating performance and the operating performance of similar nuclear power plants, it is reasonable to expect that DAEC could achieve the same 90 percent capacity factor promised by FPLE Duane Arnold.

---

63 IPL's Response to OCA DR No. 167(a).

64 Direct Testimony of Richard Friedman, at page 11, lines 11-19.

Q. What has been DAEC's recent operating performance?

A. As noted by IPL witness Boston, DAEC has achieved an average annual 88.42 percent capacity factor during the years 2000-2004.[65] The plant achieved performance records in 2002 and 2004, with a 96.6 percent capacity factor in 2004.[66] DAEC's last two refueling outages (in 2003 and 2005) have averaged 32 days in duration.[67] Moreover, DAEC averaged only a 2.4 percent annual forced outage rate during the five year period 2000-2004.[68] With this strong recent performance, it is reasonable to believe that NMC could achieve a 90 percent average annual capacity at DAEC.

Q. What capacity factors does IPL project for DAEC in its EGEAS modeling?

A. IPL projects a mature forced outage rate of [redacted] percent, with [redacted] percent capacity factors in non-refueling years and [redacted] percent capacity factors in refueling years.

Q. Are the performance goals presented in the recent DAEC Business Plans consistent with a 90 percent average annual capacity factor?

A. Yes. For example, even the Proposed 2005-2009 Business Plan projects 30 day refueling outages for DAEC every 22 months and a minor outage rate of 4 percent.[69] These figures suggest capacity factors of about 96 percent in non-outage years and about 85-90 percent in outage years.

Q. What has been the recent operating performance of other nuclear power plants similar in design and vintage to DAEC?

A. The U.S. Nuclear Regulatory Commission classifies nuclear units into peer groups based on nuclear steam supply system vendor, product line, generating

---

65 Direct Testimony of John Boston, at page 9, lines 10-21.

66 *Power Markets Week*, February 28, 2005, at page 16.

67 IPL's Response to OCA DR No. 44.

68 Exhibit____BAL-1, Schedule G.

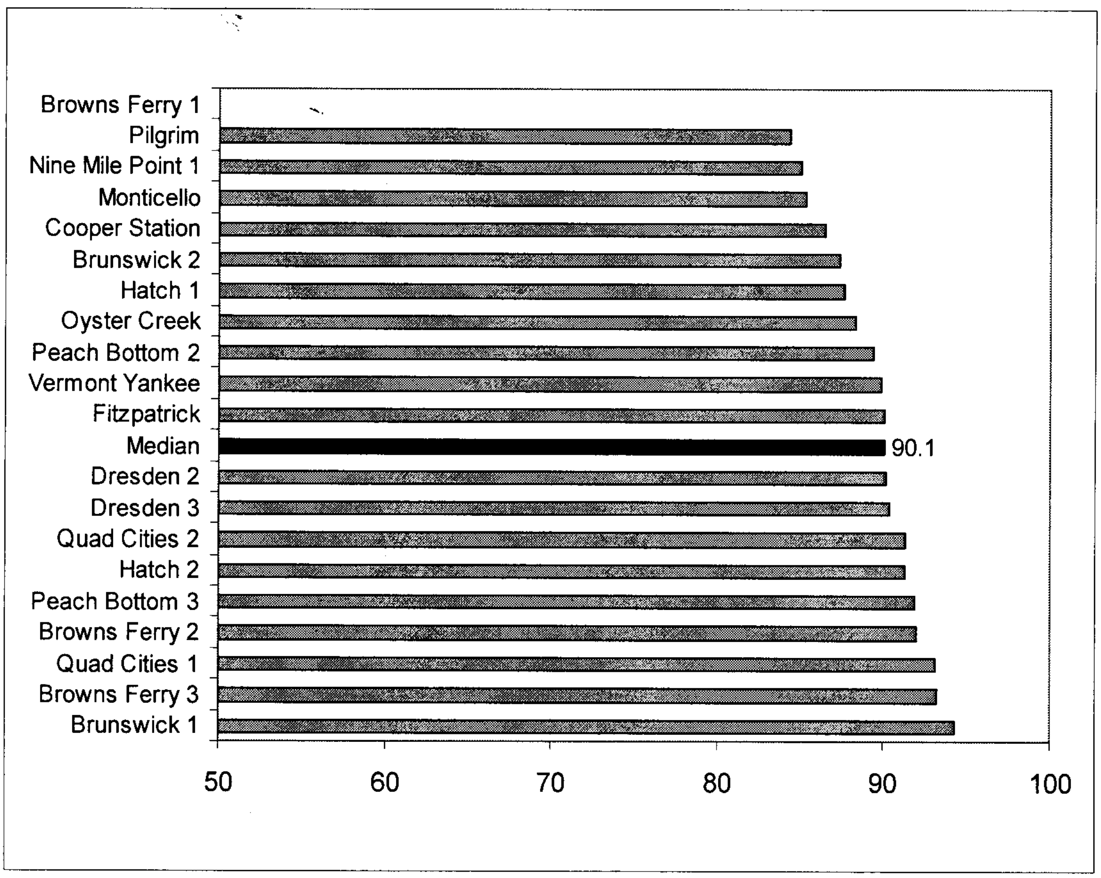
69 IPL's Supplemental Response to OCA DR No. 25, at page 11 of 13.

capacity, and licensing date. There are twenty-one nuclear units in the Pre-TMI General Electric Plant peer group to which DAEC belongs.[70]

One of these units, Browns Ferry 1, has been shut down since the mid-1980s. The other nineteen units besides DAEC have been operating and have achieved excellent operating performance over the past six years.

As shown in Figure 1 below, these nineteen units have achieved an average 89.6 capacity factor during the six years, 1999-2004, with a median capacity factor of 90.1 percent during this period.

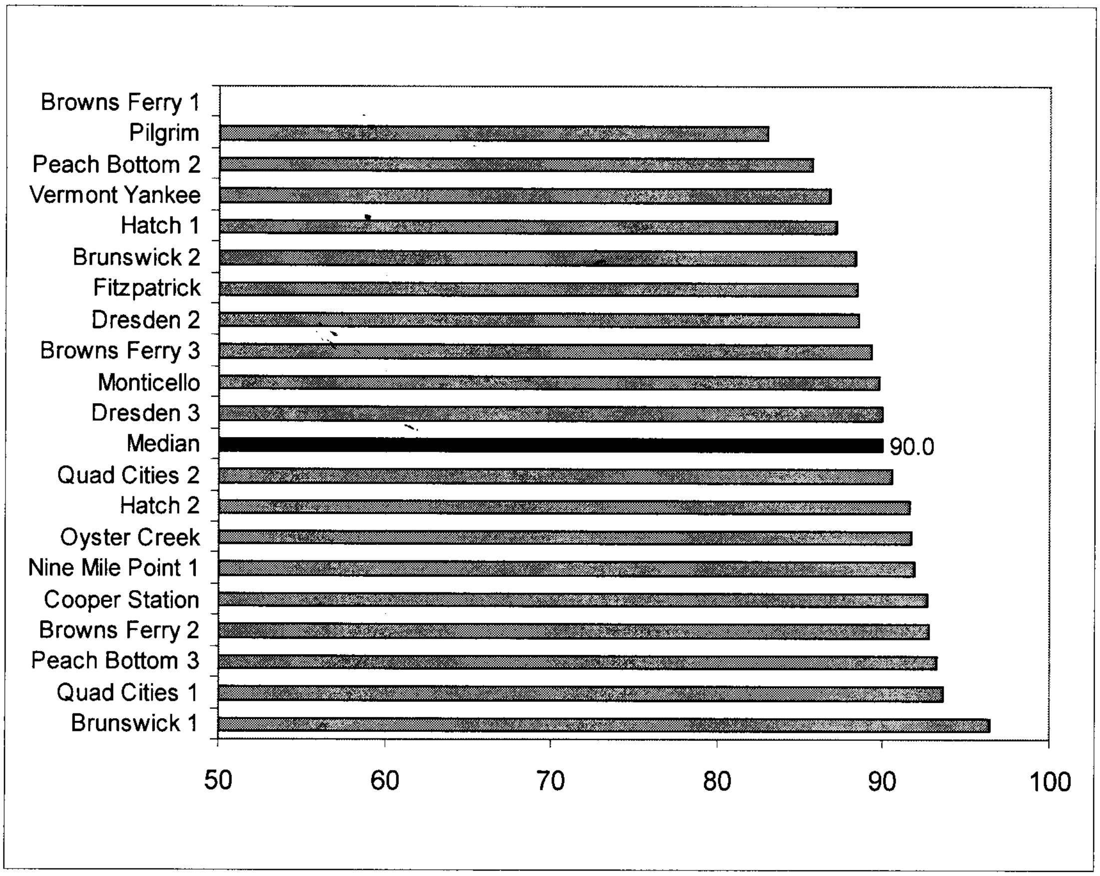
Figure 1: DAEC's Peer Nuclear Units, Capacity Factors 1999-2004



[70] There were originally 23 units in this peer group. However, the Big Rock Point and Millstone 1

As shown in Figure 2, DAEC's peer units also achieved a 90.1 percent average capacity factor during the more recent three year period 2002-2004, with a 90.0 median capacity factor during the same period.

Figure 2: DAEC's Peer Nuclear Units, Capacity Factors 2002-2004



This performance by DAEC's peer plants shows that DAEC also can be expected to achieve a 90 percent average annual capacity factor during the period January 1, 2006 through February 21, 2014.

plants have been permanently retired.

Future DAEC Power Uprate

Q. Do the proposed PPA charges and the underlying IPL's revenue requirements analyses reflect the full power level for which DAEC is licensed?

A. No. The analyses underlying the proposed PPA charges do not assume the full power level for which DAEC has been licensed by the NRC:

1. The PPA charges reflect only fifteen MWe of increased power from the recent Phase 2 power uprate as compared to the Proposed 2005-2009 Business Plan which reflects all 18 MWe of increased power from that uprate.[71]

2. The PPA charges do not reflect the potential Phase 3 uprate which would raise DAEC's power level from 1840 MWth to the licensed 1912 MWth.

Q. Is it reasonable to assume, as IPL has done in calculating the proposed PPA charges, that whatever party may own DAEC in the future will not implement the Phase 3 power uprate?

A. No. It is reasonable to expect that whatever party owns DAEC will implement the Phase 3 uprate in the near future given (1) the relatively low estimated capital cost of achieving the additional uprate and (2) the fact that the only other significant costs associated with the uprate would be additional fuel costs and the costs of purchasing additional storage casks.

Q. What is IPL's current estimate for the capital cost of the Phase 3 uprate?

A. IPL has estimated that the cost of the modifications and studies that would be required for the Phase 3 uprate would be approximately $13.2 million.[72]

---

71 IPL's Response to OCA DR No. 167(a).

72 IPL's Response to OCA DR No. 101.

Q. Has IPL indicated whether it might implement any of these projects even if it did not seek to complete the Phase 3 uprate?

A. [redacted]

Q. Has FPLE Duane Arnold estimated what the cost of the Phase 3 power uprate would be?

A. [redacted][74]

Q. What other additional costs would be associated with the Phase 3 power uprate?

A. The only other significant costs would be additional fuel costs and the costs of purchasing several additional storage casks for the ultimate storage of the extra spent fuel resulting from the uprate.

Q. Has IPL provided any economic analysis to support its exclusion of the Phase 3 uprate from its calculation of the proposed PPA charges?

A. No. IPL has provided what it says is a preliminary NMC analysis of the economics of the Phase 3 uprate.[75] This analysis appears to have been performed in 2002. However, the analysis posits that it would cost approximately $9 million to achieve an uprate of only 9 MWe which would be roughly $1,000 per KW.

---

[73] IPL's Response to OCA DR No. 100.

[74] FPLE Duane Arnold's Confidential Response to OCA DR No. 125, Document titled "Executive Summary Duane Arnold Unit Rating," at page 2.

[75] IPL's Response to OCA DR No. 146, Attachment A, page 11 of 14.

However, as noted above, IPL has estimated that it would cost approximately $13 million to achieve about a 24 MWe uprate. This would suggest a much lower cost of about $550 per KW.

Moreover, the incremental cost of achieving the power uprate, that is, the cost assuming that the supplemental feed pump will be purchased and the main transformer refurbished even if DAEC is not uprated, would be only $6 million or just $250 per kw. Clearly, the economics would favor the addition of this extra capacity especially when the very low nuclear fuel costs are considered. Of course, the economics of the power uprate improve if it is assumed that DAEC is relicensed as well as uprated.

Relicensing of DAEC for an Additional Twenty Years of Operating Life

Q. Please summarize the trends in the nuclear industry concerning the relicensing of power plants?

A. NRC regulations currently allow licensees to apply to renew the operating licenses of their nuclear units by an additional twenty years. All of the owners of nuclear plants, of which I am aware, are seeking to take advantage of these regulations and relicense their plants for an additional twenty years of operating life.[76]

In fact, as of the end of August 2005, the NRC had issued extended operating licenses for 33 nuclear units.[77] At the same time, the NRC currently is considering applications for license renewal for another sixteen nuclear units. In addition, the owners of another 26-28 units have submitted letters to NRC indicating their intent to apply for license renewal.

---

76 As early as 1999, Entergy's President warned other companies: "License renewal -- everybody's jumping on that bandwagon.... If you've not already decided, you better do it quickly because resources are going to get tight." *Inside NRC*, August 16, 1999, at page 1.

77 NRC website, at www.nrc.gov/reactors/operating/licensing/renewal/applications.html

This means that the owners of at least 75 of the 104 operating power reactors in the U.S. have decided to renew their operating licenses. The owners of the remaining reactors can be expected to do the same at the appropriate time.

Q. **Are you aware of any nuclear power plant owners that have decided not to relicense their nuclear unit(s)?**

A. No. I am not aware of any nuclear power plant owner that has said that it will not relicense its plant if it continues to maintain ownership of the facility.

Q. **Was IPL able to identify any nuclear power plant owners that have decided not to relicense their units?**

A. No. OCA DR No. 156 asked IPL to name any nuclear power plant owners, of which it was aware, that have announced that they will not relicense and extend the operating lives of their plants. IPL was unable to name even a single plant whose owner has decided to retire its facility at the end of its current NRC license and not to relicense.

The only answer that IPL was able to give was that there are 28 nuclear reactors with licenses which expire anytime between 2013 and 2035 whose owners have not made any public indications or NRC filings that they intend to seek license renewal. According to IPL, these nuclear units are owned by TVA, Pacific Gas & Electric, Exelon, Southern California Edison, Energy Northwest, Arizona Public Service, Union Electric, Detroit Edison, and North Atlantic Energy Service Corp.[78]

Q. **Does the fact that the owners of these 28 units have not made any public announcements or NRC filings mean that they have decided not to relicense?**

A. No. I have reviewed the expiration dates for the original NRC-issued operating licenses currently held by the nuclear units owned by each of the companies cited

[78] IPL's Response to OCA DR No. 156.

by IPL in its response to OCA DR No. 156. Other than four plants that are currently undergoing NRC relicensing review, none of these original operating licenses expires before 2020. There is no NRC requirement that these companies apply for license renewal this far ahead of the expiration date of the current operating licenses. Therefore, it is not surprising that these companies have not yet done so. Given the operating performance of these units, I fully expect the owners to seek relicensing. In fact, Exelon and TVA already have applied for renewed licenses for those units that they own whose licenses were originally scheduled to expire before 2020.[79]

Q. Are the owners of any of the other plants operated by NMC seeking to relicense their facilities?

A. Yes. The owners of the Point Beach, Monticello and Palisades units have submitted relicensing applications to the NRC. The owner of Prairie Island also has stated its intention of seeking to relicense that unit. Consequently, all of the other nuclear plants operated by NMC will be seeking relicensing.

Q. Have any other plants similar in design and vintage to DAEC been relicensed?

A. Yes. There are twenty other nuclear units in DAEC's NRC peer group. Eight of these units already have had their licenses renewed.[80] The NRC is currently reviewing relicensing applications for another eight of these units.[81] In addition, the owners of the Cooper and Pilgrim facilities have submitted letters of intent to apply for relicensing.

This means that the owners of eighteen of DAEC's twenty peer plants have either obtained renewed licenses, are currently seeking relicensing or have announced

79 Browns Ferry 1, 2, and 3, Dresden 2 and 3, Quad Cities 1 and 2, and Peach Bottom 2 and 3.

80 Hatch 1 and 2, Peach Bottom 2 and 3, Dresden 2 and 3 and Quad Cities 1 and 2.

81 Browns Ferry 1, 2, and 3, Brunswick 1 and 2, Nine Mile Point 1, Monticello, and Oyster Creek.

their intention of doing so. Entergy is the owner of the remaining two peer plants (Fitzpatrick and Vermont Yankee). Although Entergy has not formally notified the NRC of its intent to relicense these units, it has filed letters indicating its intention to relicense five unnamed plants. It is quite possible that Fitzpatrick and/or Vermont Yankee are among these unnamed plants.

Q. Company witness Aller has testified about the risks associated with seeking relicensing.[82] Is there a significant risk that IPL would not be able to renew DAEC's operating license?

A. No. The NRC has never denied an application for relicensing. In fact, I am aware of only one instance in which the NRC even has returned an application because it found that the application was too vague and incomplete to make a proper review possible. In this instance, the NRC is permitting the applicant to revise and supplement its original application.

Q. Has IPL acknowledged that there is only a small risk that it would not be able to renew DAEC's operating license?

A. [redacted][84]

---

[82] Direct Testimony of Thomas Aller, at page 14, line 13, to page 15, line 7.

[83] Confidential IPL Response to OCA DR No. 94, Attachment B, slide 5 of 9.

[84] Ibid.

Q. Is there a significant risk that the NRC will change its regulatory requirements to make it more difficult to relicense?

A. No. The emphasis of the NRC has been on learning from prior relicensing experience and streamlining the process for new applicants. Thus, the evidence is that the NRC has been working to improve the relicensing process for applicants, not issuing regulations that make it more difficult to relicense. For example, an article in Nuclear News, a monthly publication of the American Nuclear Society, has explained:

> The process is likely to improve as more plants go through the process and the NRC settles on what NRC commissioner Jeffrey Merrifield calls "the right regulatory touch – not asking for too much information, but [asking for] a sufficient amount so we can feel confident." Merrifield said the NRC needs to be disciplined to ensure that the requirements of the second wave of license renewal applicants are the same as the first, and that the agency needs to continually strive to operate "more efficiently, better, faster, and less expensively."[85]

In fact, industry representatives have commended the NRC's approach to license renewal. For example, the President of the industry's Nuclear Energy Institute has said that the NRC's review of the Calvert Cliffs and Oconee licenses renewal applications "provides a clearly marked path for other electric companies pursuing license renewal."[86] At the same time, the Vice President for Nuclear Generation at Duke Energy Company observed as early as 1999 that as the cost for seeking license renewal comes down with experience gained on the initial reviews and the NRC review time shrinks, "it becomes more likely that utilities are going to line up [for license renewal]."[87] This prediction has been proven correct.

---

[85] *Nuclear News*, August 1999, at page 41.

[86] *Nucleonics Week*, May 25, 2000, at page 1.

[87] *Inside NRC*, August 16, 1999, at page 1.

Q. Do you have any comment on the claim by IPL witness Reed that to date the plants that have received license renewal are largely stations which are part of a fleet of nuclear generating stations or have been sold?

A. Yes. I have two comments on Mr. Reed's claim. First, it is important to remember that DAEC is part of the fleet of nuclear power plants operated by NMC. Second, the owners of a number of power plants that are not part of fleets also are seeking to relicense their units.

For example, Fort Calhoun Station, which is owned by the Omaha Public Power District, and the V.C. Summer plant, which is owned by South Carolina Electric & Gas, both have been relicensed. Neither of these units is part of a fleet or has been sold. At the same time, applications have been submitted to relicense the Point Beach and Palisades plants. If Mr. Reed does not consider that DAEC is part of fleet even though it is operated by NMC then neither of these facilities can be considered to be parts of fleets because they also are operated by NMC.

In addition, the owners of the Wolf Creek, Susquehanna and Cooper Nuclear Stations also have announced that they intend to apply for license renewal. None of these plants is part of a "fleet" or has been sold.

Q. Please comment on the statement by IPL witness Lacy that relicensing under traditional cost of service regulation in Iowa is not an option for the Company.[88]

A. A substantial number of the nuclear plants that have been relicensed are owned by utilities that are located in states which have not deregulated. Examples of relicensed units owned by utilities in states that have not deregulated include Oconee, Arkansas Nuclear One, Hatch, McGuire, Robinson, and Summer. Moreover, other plant owners in regulated states either have filed applications or have announced that they will seek to relicense their nuclear plants. (e.g.,

88 Direct Testimony of Bruce Lacy, at page 8, lines 17-20.

Monticello, Point Beach) Obviously the owners of these plants found the relicensing of nuclear units of similar vintage age to DAEC to be economic.

Q. Has IPL acknowledged that relicensing would create significant benefits for ratepayers?

A. Yes. The testimony of IPL witnesses Aller, Collins and Friedman all acknowledge that there would be significant benefits from relicensing DAEC.[89]

[redacted][90]

Q. Has the IUB observed that relicensing of DAEC can be expected to produce economic benefits?

A. Yes. In its April 15, 2003 Order in Docket Nos. RPU-02-3, RPU-02-8, and ARU-02-1, the IUB noted that "While IPL has not made a decision on license extension, there is no reason to believe that the economic factors that have prompted other nuclear plant owners to apply for extensions will be significantly different for IPL."[91]

Q. Have you seen any estimates of the economic benefits that would be generated by the relicensing of nuclear power plants that are comparable to DAEC in design and vintage and that are similarly located?

A. Yes. I have seen the results of analyses of the economics of relicensing the Monticello and Cooper Station nuclear plants. Like DAEC, both Monticello and Cooper Station are Boiling Water Reactor plants that went into commercial

---

89 For example, see the Direct Testimony of Thomas Aller, at page 30, lines 10-17 and the Direct Testimony of Richard Friedman, at page 4, lines 17-21.

90 IPL's Confidential Response to OCA DR No. 94, Attachment B, slide 5 of 9.

91 At page 43.

service prior to the March 1979 accident at Three Mile Island. Both facilities are included in the NRC's peer group for DAEC.

In November 2004, the Board of the Nebraska Public Power District ("NPPD") authorized its executive management to seek the relicensing of the Cooper Station. Cooper's original operating license is scheduled to expire in January 2014, one month earlier than DAEC.

The NPPD decision was based on the results of a detailed study that assessed generation resources to be used to serve customers after 2014. The study examined nine different scenarios reflecting different frequencies for refueling outages and levels of plant power uprates. The study concluded that relicensing Cooper and extending its operating life until 2034 had an expected benefit of greater than $1 billion when compared to retiring the plant in 2014 and building a replacement coal fired facility.[92]

Q. What were the results of the study of the economics of relicensing the Monticello facility?

A. Xcel Energy compared the relicensing of the Monticello plant with the unit's retirement in 2010 at the expiration of its current NRC license and the construction of an alternative generating facility. Xcel found that the present value revenue requirement benefit of relicensing ranged from $395 million in 2004 dollars to approximately $3 billion, depending on the assumed costs of fossil fuels and the prices assumed for the emissions from the fossil-fired alternatives.[93]

---

[92] Exhibit____DAS-1, Schedule C, at page 19.

[93] Exhibit____ DAS-1, Schedule D, at pages 5-5 and 5-6.

Q. Have you seen any evidence concerning the relative economics of the relicensing of any other NMC operated nuclear power plants?

A. Yes. WE Energies has estimated that the continued operation of the Point Beach Nuclear Plant would save its customers approximately $474 million in current dollars compared to other options.[94]

Q: What type of analyses have the owners of these nuclear plants of similar vintage to DAEC employed in evaluating the decision to relicense?

A: Although it is not clear what specific models were used by each plant owner, the underlying methods appear to be similar to the analysis provided by OCA witness Dr. Shi.

Q. Earlier you mentioned that IPL examined the relative economics of relicensing DAEC as compare to retiring the plant in 2014 as part of its 2003 Resource Plan. What were the results of that analysis?

A. IPL's 2003 Resource Plan showed that the relicensing of DAEC would produce savings of approximately $584 million in cumulative present worth societal costs.[95]

Q. Has NMC projected what it would cost to relicense DAEC and to operate the plant during the period 2014-2034?

A. Yes. NMC prepared a Plan to Preserve the License Renewal Option at DAEC, dated June 25, 2004. This Plan estimated that it would cost approximately $17.4 million to secure NRC approval for the relicensing of DAEC. The NMC Plan also estimated that future on-line O&M costs during the extended life period (i.e., 2014-2034) would be $75 million per year (in 2004 dollars).[96] NMC also estimated that the refueling outage related costs would be $17 million (in 2004

[94] Exhibit____ DAS-1, Schedule E.

[95] See OCA witness Shi's Exhibit____XLS-1, Schedule D, page 1.

[96] IPL's Response to OCA DR No. 8, Attachment, at page 5 of 24.

dollars) per outage.[97] Capital costs would include an annual $10 million per year base investment for smaller routine equipment refurbishments as well as a collective $148 million for individual incremental investments for larger non-routine equipment refurbishments/replacements that would be necessary to support reliable operation to 2034. [redacted][98]

Q. How do these cost estimates compare to the estimated capital costs that would be needed at Monticello in order to support reliable operation of the that plant for an additional twenty years?

A. The Xcel Energy study assumed that Monticello's capital costs would include an annual $10 million per year base investment for smaller routine equipment refurbishments.[99] The study also assumed that another $135 million of individual incremental investments for larger non-routine equipment refurbishments/replacements that would be necessary to support Monticello's reliable operation to 2030.[100]

Unfortunately, the documents that I have obtained on the relicensing of Monticello do not contain the estimated on-line or refueling outage O&M estimates for the twenty years of extended life.

Q. How do FLPE Duane Arnold's estimates of the cost of relicensing compare to the estimates in the June 2004 NMC Plan?

A. [redacted]

---

97 Ibid.

98 IPL's Confidential Response to OCA DR No. 199.

99 Exhibit____DAS-1, Schedule D, at page 5-9.

100 Exhibit____DAS-1, Schedule D, at page 5-13.

[redacted][105]

Q. Does FPL, the parent company of FPLE Duane Arnold, have experience in relicensing nuclear power plants?

A. Yes. Four of FPL's nuclear units have been relicensed by the NRC. These units are Turkey Point 3 and 4 and St. Lucie 1 and 2.

Q. Would IPL's relicensing of DAEC produce any economic benefits for ratepayers before 2014?

A. Yes. Decommissioning collections from ratepayers could be terminated when the NRC issues the renewed license because relicensing DAEC and extending the unit's operating life would allow an additional twenty years for the decommissioning funds to grow through the reinvestment of earnings. This

---

[101] FPLE Duane Arnold's Confidential Response to OCA DR No. 125, Memorandum titled: Area of Focus: Duane Arnold Engineering Department, at page 3.

[102] Ibid.

[103] See FPLE Duane Arnold's Response to OCA DR No. 200 and IPL's Confidential Response to OCA DR No. 199.

[104] FPLE's Confidential Response to OCA DR No. 125, table entitled "Project Palmer CAPEX."

[105] FPLE Duane Arnold Response to OCA DR No. 200.

would immediately save ratepayers approximately $13 million per year although this figure would be offset some by the cost of obtaining the renewed NRC license.

Q: What does IPL's Application for Reorganization state with respect to IPL's relicensing of DAEC?

A: IPL refuses to consider this alternative. As OCA witnesses have shown, relicensing is the most economic alternative that exists. This alternative maximizes ratepayer interests, and furthers shareholder interests.

Q. Has IPL recently provided an economic analysis of relicensing DAEC?

A. Yes. Within the past few days IPL has provided such an analysis to the OCA. It may be necessary to supplement this testimony after having a reasonable opportunity to examine IPL's new relicensing analysis.

Q. Have you had an opportunity to review that analysis?

A. No.

Q. Are you reserving the right to supplement this testimony after you have had a reasonable opportunity to examine IPL's new relicensing analysis?

A. Yes.

Q. Please provide the details of the analyses that form the basis for the conclusion that decommissioning collections from ratepayers could be terminated when the NRC issues a renewed operating license for DAEC.

A. I have performed two analyses to examine the adequacy of IPL's decommissioning funds assuming that decommissioning collections from ratepayers would be terminated at the end of 2010.

In the first analysis, I used the input data from IPL's Exhibit CAH-1 Schedule B-3, to compare the funds that would be available in IPL's decommissioning trusts in 2034 with the Company's 2004 Updated decommissioning cost estimate. In this comparison, I escalated IPL's $427,007,000 share, in 2005$, shown on Line 1 of Exhibit CAH-1 Schedule B-3 to year 2034 dollars using the Company's estimated 2.60 percent annual escalation rate. At the same time, I grew the projected $340 million balance in the decommissioning trusts as of January 1, 2011 to reflect trust earnings through the year 2034.

The results of this comparison are presented in Table 8 below.

Table 8: Adequacy of DAEC's Decommissioning Trust Funds in 2034, Assuming Life Extension

Cost Escalation Rate	Decommissioning Cost (Millions of 2034$)	Funds in Trusts at Start of Decommissioning (Thousands of 2034$)
2.60%	$899	$1,401
4.00%	$1,332	$1,401

In my base case, I used the 2.60 percent cost escalation rate that was presented in IPL's Exhibit CAH-1 Schedule B-3. I also looked at a higher, 4.00 percent annual rate to reflect higher decommissioning cost escalation.

The results in Table 8 show that there should be sufficient funds in IPL's decommissioning trust at the end of 2010 to fund the decommissioning of DAEC in 2034. However, these results are conservative because they assume that IPL's decommissioning trusts would have to be fully funded when DAEC would be retired in 2034.

Q. **Please explain.**

A. There is no NRC requirement or regulation that mandates that a nuclear unit's decommissioning trusts be fully funded at the start of the decommissioning process. In fact, the applicable language in 10 CFR 50.75 (e) allows a licensee that has collected funds based on a site-specific cost estimate to take credit for projected earnings on its external sinking funds using up to a 2 percent annual real rate of return from the time of the future funds' collection through the decommissioning period, provided that the site-specific estimate is based on a period of safe storage that is specifically described in the estimate. The same NRC regulation specifically notes that the decommissioning period includes the periods of safe storage, final dismantlement, and license termination.

Q. **Have you evaluated how the provisions of 10 CFR 50.75(e) affect whether decommissioning contributions from IPL's ratepayers could be terminated at the end of 2010 if the unit is relicensed?**

A. Yes. I have examined the adequacy of the IPL decommissioning trusts assuming that contributions from ratepayers are ended on December 31, 2010. Unlike my first analysis, this second study reflects continued earnings on unspent decommissioning trust funds through the decommissioning period. The results of this study are presented in Table 9 below:

Table 9: Adequacy of DAEC Decommissioning Trusts Assuming Continued Earnings through the Decommissioning Period

Annual Decommissioning Cost Escalation	Nominal Annual Trust Earnings Rate	Real Trust Earnings Rate	Trust Balance at Conclusion of Decommissioning (millions of 2067)
4.39%	6.39%	2.00%	$443
4.50%	6.39%	1.89%	$40

These results show that there would continue to be adequate funds to safely decommission DAEC even if the real rate of growth on trust earnings fell below the two per cent real rate that the NRC allows licensees to take credit for.

Q. **Have any utilities actually stopped making decommissioning collections from ratepayers because their trusts are adequately funded?**

A. Yes. In 2000, the Arkansas Public Service Commission ordered that collections from ratepayers for decommissioning funds for Arkansas Nuclear One Units 1 and 2 should be terminated as of January 1, 2001 because the units' owner had applied for NRC approval of relicensing.[106]

[106] Arkansas Public Service Commission Order No. 32 in Docket No. 87-166-TF.

In addition, the Omaha Public Power District, the owner of the Fort Calhoun nuclear station, ceased making annual decommissioning collections starting in 2002.[107] At the time that the Omaha Public Power District decided to terminate decommissioning collections it was preparing an application to the NRC to relicense Fort Calhoun.

Q. What would be a reasonable schedule for obtaining a renewed operating license for DAEC?

A. NMC has presented a possible license renewal project schedule that would result in the NRC's issuance of a renewed license for DAEC in late 2010.[108] This schedule appears reasonable given the amount of time the NRC has required to review other license renewal applications.

Q. What capacity factor can DAEC be expected to achieve during the twenty year life extension period, 2014-2034?

A. Given the uncertainties of looking 29 years into the future, I believe that the economics of renewing DAEC's operating license should be evaluated by examining a range of capacity factors. This range should include 90 percent, 80 percent and 75 percent average annual capacity factors. In addition, an aging scenario in which DAEC's capacity factor declines as the unit ages also should be examined. For this scenario I recommend assuming a 90 percent capacity factor through 2013, an 80 percent capacity factor from 2014 through 2023, and a 70 percent capacity factor from 2024 through 2034. This recommendation was also the basis for Dr. Shi's EGEAS scenarios.

---

107 Omaha Public Power District May 12, 2003 Letter to the U.S. Nuclear Regulatory Commission forwarding the 2003 Biennial Decommissioning Funding Status Report, Revised, for Fort Calhoun Station Unit No. 1.

108 NMC Study presented in IPL's Response to OCA DR No. 8, at page 10 of 24.

Q. What O&M and capital expenditures can be expected for DAEC during the twenty year life extension period, 2014-2034?

A. I believe that the O&M and capital expenditures estimated by NMC should be used in a base case study. In that base case, these costs would be escalated at the overall rate of inflation. In additional sensitivities, annual O&M costs would be escalated at real rates of one and two percentage points above the overall rate of inflation. Those sensitivities also should reflect capital costs approximately ten and twenty percent higher than the capital costs used in the base case scenario. I believe that these sensitivities would reasonably allow for unpleasant surprises in the future in terms of currently unanticipated technical or regulatory issues.

Risks of Continued Operation

Q. Has IPL presented a reasonable and balanced assessment of the risks associated with continued ownership of DAEC and the risks associated with selling the plant?

A. No. It is true that IPL could reduce or eliminate qualitative risks if it ended its ownership of DAEC. However, IPL's witnesses overstate the benefits of the sale in reducing risks for ratepayers. At the same time, the company does not address the risks to which ratepayers would be exposed if DAEC is sold and a replacement coal-fired unit is built.

Q. Has IPL attempted to quantify the costs and benefits associated with eliminating the risks of continued ownership of DAEC?

A. No.

Q. Do you agree that there is risk of higher O&M and capital expenditures and plant outages if IPL continues to operate DAEC?

A. Yes. There certainly is a cognizable risk that O&M and capital expenditures will be higher or that DAEC will experience outage(s) as the result of events at other operating nuclear power plants, new rules or regulations issued by the NRC or as the result of deficiencies identified by the NRC at DAEC or other plants.

Q. Do you agree with that claim by IPL witness Aller that "the NRC is quick to establish new regulations, requiring significant investment, based on incidents that occur at other nuclear facilities?"[109]

A. No. I don't believe that it is realistic to claim that the "NRC is quick to establish new regulations." Indeed, Mr. Aller's claim ignores the numerous actions taken by the NRC over the past decade to lessen the burden on licensees and to stabilize the regulatory process.

A different view of the NRC regulatory process from the "quick-on-the-draw" image created by Mr. Aller's claim was provided by Michael Sellman, the President and Chief Executive Officer of NMC, in 2001:

> Today we can say with reasonable confidence that nuclear power will continue as a major component of the nation's energy supply well into the new century....
>
> This remarkable revival can be attributed to three factors: Stable regulatory process, extraordinary plant performance, and the impact of deregulation.
>
> For many years, the Nuclear Regulatory Commission (NRC) regulatory process was unstable. Beginning a few years ago, the NRC, with the support and assistance of the industry, embarked on a program of reform designed to be more objective, more focused on safety significant matters, and reflecting a risk-informed philosophy. As a result of these initiatives, the regulatory process is much more predictable, thereby reducing investor uncertainty.
>
> * * * *
>
> Until recently, the unstable NRC regulatory process was regarded by many, especially the financial community, as one of the most significant commercial risks deterring investment in the industry. The regulatory process was subjective, prescriptive and unevenly focused on safety significant matters, and, hence, unpredictable.

---

109 Direct Testimony of Thomas Aller, at page 15, lines 8 through 14.

> So-called "regulatory outages" cost hundreds of millions of dollars – and often driven by intense media attention – were common. To its very credit, the Nuclear Regulatory Commission, over the past 15 months, has taken major steps to reform the process. Stability is being restored and this change is widely viewed as one of the most significant contributors to renewed confidence in the future of nuclear power.
>
> *   *   *   *
>
> I think that it is fair to say that in the past two years or so, the industry has enjoyed a greater degree of stability than at any time since the late 1970s. This is a tribute to the NRC and to those in the industry who have helped to develop these initiatives through their comments and suggestions. We believe that the NRC has irreversibly changed direction toward a more fair, rational and predictable regulatory program.[110]

Rulemaking is one of the processes through which the NRC adopts new requirements for operating power plants. An NRC spokesman recently responded to requests that the NRC change its emergency planning rules by noting that:

> Changes in NRC regulations should not be expected any time soon, said Neil Sheehan, a spokesman for NRC's Region I, which includes New Jersey and New York. "It takes years for the rulemaking process to be carried out, and that's if the petition is accepted for review," he said. Two and a half years is a "benchmark" for NRC review of rulemaking, but some take "much longer," such as a worker-fatigue rule that has been under review for nine years, he noted.[111]

Q. Was IPL able to provide any concrete examples of the instances in the past five years which, it believes, the NRC was quick to establish new regulations based on incidents that occurred at other nuclear facilities?

A. No. The best that the Company could provide was a description of what it believes to be the current regulatory environment and three examples which

---

110 *America's Nuclear Renaissance*, presented at the Ninth International Conference on Nuclear Engineering on April 12, 2001, available at www.nmcco.com/newsroom/presentations/anr.htm

111 *Nucleonics Week*, dated July 14, 2005, at page 4.

illustrate aspects of this regulatory environment.[112] However, IPL did not provide any evidence that these were examples of recent instances in which the NRC was "quick" to establish new regulations based on incidents at other power plants. Moreover, one of the three examples provided by IPL involved the NRC's response to the extraordinary attack on the U.S. on September 11, 2001. But even here, IPL didn't demonstrate that the NRC was quick to establish new regulations.

Q. Please give some examples of the processes in place at the NRC to lessen the regulatory burden on licensees.

A. The NRC has a formal backfit rule which states that the Commission will require the backfitting of a plant only when it determines, based on a systematic and documented analysis, that there is a substantial increase in the overall protection of the public health and safety or the common defense and security to be derived from the backfit and that the direct and indirect costs of implementation for that facility are justified in view of this increased protection.[113] Among the information to be considered in this systematic analysis are the "installation and continuing costs associated with the backfit, including the cost of facility downtime or the cost of construction delay."[114] The requirements of the backfit rule do not apply, and, therefore, backfit analysis is not required, where the NRC or the NRC staff, find and declare, with appropriate documentation, either:

(i) That a modification is necessary to bring a facility into compliance with a license of the rules or orders of the NRC, or into conformance with written commitments by the licensee; or

(ii) That regulatory action is necessary to ensure that the facility provides adequate protection to the health and safety of the public and is in accord with the common defense and security; or

---

112 IPL's Response to OCA DR No. 158.

113 10 CFR 50.109(a)(3).

114 10 CFR 50.109(c).

(iii) That the regulatory action involves defining or redefining what level of protection to the public health and safety or common defense and security should be regarded as adequate.[115]

The NRC also has a Committee for the Review of Generic Requirements ("CRGR") whose primary responsibilities include recommending to the NRC's Executive Director for Operations either the approval or disapproval of the NRC Staff's proposals of new or revised generic requirements and providing assistance to the NRC's program offices to help them implement the NRC's backfit policy.[116]

To accomplish its mission, the CRGR reviews and evaluates proposed new and revised power reactor regulatory requirements, generic correspondence, regulatory guidance, and selected NRC staff guidance on licensing, inspection, assessment and enforcement that could impose a backfit.[117] The objectives of the CRGR review process have been described as eliminating unnecessary burdens to the licensees, reducing the exposure of workers to radiation in implementing new or changed regulatory requirements, and to conserve NRC resources while assuring the adequate protection of the public health and safety.[118]

These processes help protect licensees against any attempts by the NRC to have a quick trigger on establishing new regulations that will unnecessarily burden them.

---

115 10 CFR 50.109(a)(4).

116 September 23, 2003 Letter to the NRC Commissioners from William D. Travers, Executive Director for Operations, at page 2.

117 Ibid.

118 NRC SECY-97-052, dated February 27, 1997.

Q. Can you cite any recent instances in which the NRC has failed to require a licensee to shut down an operating plant or to enforce existing NRC regulations because of concerns over the financial impact of such actions on the licensee?

A. Yes. During the past decade there have been numerous instances in which the NRC allowed nuclear power plants to continue operating or failed to enforce existing NRC requirements because of the adverse financial impact on the licensee of doing so.

For example, in late 2001, the NRC allowed the Davis-Besse plant in Ohio to continue operating rather than shut down to conduct required inspections of the facility's reactor vessel head. When the plant was ultimately shut down in February 2002, the licensee found that corrosion extended through the 6 inch thick reactor vessel head and that only the one-third inch thick stainless steel lining prevented a possible and serious loss-of-coolant accident. The NRC's internal Office of Inspector General has concluded that the decision to allow the Davis-Besse plant to continue operating beyond December 31, 2001 without performing reactor vessel head inspections "was driven in large part by a desire to lessen the financial impact on the licensee that would result from an earlier shutdown."[119]

Similarly, in late 2003, the NRC discovered that licensees had failed to comply with important fire protection regulations adopted after the Browns Ferry fire in 1975. Instead, of complying with one of the three fire protection options specified by the NRC, licensees were relying on operator manual actions, that were not approved by the NRC, to shut down the plant in case of a serious fire. However, rather than requiring that licensees comply with the existing automatic safe-shutdown fire regulations, the NRC apparently has decided to change its

---

119 NRC NUREG-1100, Volume 20, at page 127, dated February 2004 and NRC Office of Inspector General Event Inquiry No. 02-3S, at pages 15-17.

regulations to permit what the industry is already doing. The high cost, on licensees and NRC staff, of enforcing the existing NRC fire-protection regulations was one of the main reasons cited for the change in policy.

Q. Has IPL provided any evidence that shows the magnitude of the NRC's requirements on capital investments at DAEC?

A. Yes. IPL's response to OCA DR No. 75, Attachment B, shows that the cost of those capital additions above $0.5 million wherein the primary drive and motivation was based on nuclear safety improvements driven by the NRC has declined dramatically since the late 1980s. In fact, the Company only identified approximately $3.6 million (IPL's 70% share) of such primarily NRC-driven capital additions at DAEC since 1997.

Q. IPL witness Reed discusses the risks associated with unplanned outages.[120] Do you agree that there is a risk that DAEC will experience unplanned outages in the future?

A. Yes. All power plants, even coal fired units, experience some unplanned outages. Moreover, if those plants are low-cost base-load facilities, the owners are likely to incur higher costs during those outages either to generate replacement power at other facilities or to buy replacement power in the market. The frequency and duration of such unplanned outages are one of the factors that must be considered in an analysis of the comparative risks of different generating alternatives. Instead of making such a comparison, however, Mr. Reed solely focuses on the obvious fact that some nuclear plants have experienced some unplanned outages. He ignores the fact that any fossil-fired alternative that IPL would build in place of DAEC also would experience unplanned outages. [redacted]

[120] Direct Testimony of John Reed, at page 9, line 5, through page 10, line 12.

[redacted]

Q. Do the specific examples cited by Mr. Reed show that DAEC is likely to have outages or incur similar replacement power costs as the nuclear plants he has discussed?

A. No. Although I agree that all plants can be expected to have unplanned outages, the specific examples cited by Mr. Reed are not highly relevant to the risk of continued ownership of DAEC. In particular:

- The two-year outage at Davis-Besse was caused by the discovery of a cavity in plant's reactor vessel head and by significant management deficiencies. The discovery of the cavity, and the potential for the development of a hole in the vessel head were considered very significant safety-related concerns.

  [redacted][121]

  There are two critical points to be made about the Davis-Besse incident. First, reactor vessel head corrosion is primarily an equipment and cost issue for Pressurized Water Reactor plants ("PWRs") while the underlying management deficiencies that led to the cavity are appropriately issues for both PWRs and Boiling Water Reactor plants ("BWRs") like DAEC. Second, properly managed power plants can avoid similar management issues and extended outages.

- The reactor vessel head replacements at the North Anna, Surry and Kewaunee, plants are issues for PWRs not BWRs like DAEC.

- The two week outage at the Salem plant cited by Mr. Reed was caused by an oil spill from an ocean-going tanker in the Delaware River not an oil spill at the plant as implied by Mr. Reed.[122] I do not believe that spills

---

[121] IPL's Confidential Response to OCA DR No. 99, Attachment A-1, at page 3 of 55.

[122] *Nuclear News*, January 2005, at page 13.

from these types of tankers is a concern at DAEC. In addition, Mr. Reed doesn't mention that the owners of the Salem plant are attempting to recover damages from the owner of the tanker.[123]

- A review of Mr. Reed's source documents reveals that the outages he cites at the Vermont Yankee and Susquehanna were caused by events on the non-nuclear sides of the facilities. These electrical system events could have been experienced at any power plant, whether fossil-fired or nuclear.[124] In spite of the 18 day outage in June 2004 cited by Mr. Reed, Vermont Yankee still achieved an 89.32 percent capacity factor during the three year period 2002-2004.
- Mr. Reed's discussion of the Fermi plant outage is incorrect. The outage did not cost $12 million for a single day. A review of Mr. Reed's source documents and the results of a LexisNexis search reveal that the plant was shutdown for about two weeks.[125]

Finally, the proposed PPA with FPLE Duane Arnold would not guarantee IPL 100 percent of the power from DAEC. The PPA will provide for only a 90 percent capacity factor. This means that IPL will be required to obtain additional power, on average, three days each month, or 36 days each year. This would be equivalent to having to buy power during planned and forced outages if the company continued to own DAEC.

Q. Mr. Reed has testified that an aging workforce at nuclear generating units also is a risk.[126] Do you agree?

A. The retirement of large numbers of nuclear industry workers over the next five to ten years is a concern. However, I have seen no evidence that any nuclear plant owner has decided to retire or sell its plant based on this risk. Instead, as indicated in Mr. Reed's source documents and articles in such industry journals as *Nuclear*

---

123 IPL's Response to OCA DR No. 212, Attachment A.

124 IPL's Response to OCA DR No. 212, Attachments B through F.

125 IPL's Response to OCA DR No. 212, Attachment G.

126 Direct Testimony of John Reed, at page 10, lines 13 through 24.

News,, the industry has undertaken comprehensive efforts to retain existing workers and to recruit, train and educate new workers.[127]

Q. Does IPL have any insurance that protects the Company and ratepayers against some nuclear outage risks?

A. Yes. IPL is part of industry insurance coverage provided by Nuclear Electric Insurance, Ltd. ("NEIL"). IPL's insurance policies through NEIL cover costs incurred during extended sudden and accidental outages. Covered accidents do not include any condition which develops, progresses or changes over time, or which is inevitable.[128] Covered outages also do not include plant shut downs due to government actions, decrees, orders, regulations, statutes or laws, such as orders of the NRC.[129]

The first of the two NEIL policies for DAEC has a seventeen week deductible period which would thereafter provide the owners of DAEC up to $3.5 million per week for weeks 18-23 of a sudden and accidental outage.[130] The second NEIL policy would provide 100 percent coverage for the next 52 weeks and 80 percent coverage for the subsequent 104 weeks, up to a total limit of $283,920,000.[131]

---

127 IPL's Response to OCA DR No. 213, Attachment A, page 1.

128 IPL's Response to OCA DR No. 225, Attachment A, page 23 of 32.

129 IPL's Response to OCA DR No. 225, Attachment A, page 10 of 32.

130 IPL's Response to OCA DR No. 220.

131 Ibid.

Risks of Increasing Decommissioning Costs

Q. Is there a significant risk that the cost of decommissioning DAEC will be significantly higher than the $628.6 million (in 2004 dollars) cost estimated in the most recent plant-specific cost study?

A. No. There are a number of factors that, I believe, demonstrate that the ultimate cost of decommissioning DAEC will not be much higher than the $628.6 million (in 2004 dollars) cost estimated in the most recent plant-specific cost study.

- The DAEC site-specific study already includes significant contingencies.
- There has been significant actual experience in decommissioning nuclear power plants since the mid-1990s.
- The DAEC site-specific cost estimate does not appear to reflect the synergies and efficiencies that would be achieved through the decommissioning of all of the NMC operated nuclear power plants.
- The DAEC site-specific cost estimate reflects substantial spent fuel related costs resulting from the failure of the U.S. Department of Energy to begin collecting spent fuel on January 31, 1998. It is possible that IPL will recover part or all of its share of these additional costs.
- The 2004 Updated cost estimate of $628.6 million reflects very high waste disposal costs even though it acknowledges that waste disposal costs may be substantially lower.

Q. What contingencies are included in the DAEC Decommissioning Cost Estimate 2004 Update?

A. The 2004 site-specific Decommissioning Cost Study reflects contingencies for each line-item in the estimate. These contingencies represent the potential cost of occurrences that have not been accounted for in the estimate such as inclement weather, equipment/tool breakage, changes in the anticipated shutdown conditions, labor disputes, etc..[132] According to the 2004 Update, the overall contingency in the estimate is around 18 percent.[133] The use of these

---

132 Exhibit BAL-1, Schedule E-1, at page 9 of 26.

133 Ibid.

contingencies increases the likelihood that the actual cost of decommissioning DAEC will fall at or below the $628.6 million estimate.

Q. Which nuclear power plants have been decommissioned since the mid-1990s?

A. There has been significant actual experience in decommissioning the Connecticut Yankee, Maine Yankee, San Onofre Unit 1, Trojan, Yankee Rowe, Rancho Seco, and Big Rock Point nuclear power plants. This actual experience should reduce the possibility and, consequently, reduce the risk that major unanticipated problems and costs will be experienced when DAEC is ultimately decommissioned at the end of its operating life. There may be some unpleasant surprises in future years, but not as many as could have been expected before there was any actual experience in decommissioning large commercial nuclear power plants.

Q. Please summarize the decommissioning-related activities that have been completed at these facilities.

A. The extent to which each plant has been decommissioned varies from site to site. However, in general, major primary and secondary system components at a number of plants, including the reactor vessels, reactor coolant pumps, and steam generators, have been decontaminated, removed and shipped to waste burial sites. In some cases, highly radioactive reactor internal structures have been cut and removed. The highly radioactive spent nuclear fuel is being transferred to long-term dry cask storage at some sites. Irradiated building structures also have been decontaminated and demolished.

Q. Does the nuclear industry share the lessons learned during the decommissioning of these plants?

A. Yes. The nuclear industry shares public information about actual decommissioning experience at conferences and through journal articles. For example, an article in the January 2003 issue of Nuclear News reported on a workshop at a recent conference sponsored by the American Nuclear Society'

Decommissioning, Decontamination and Reutilization Division. The title of the workshop was "Saving a Few Hundred Million Dollars: What Nuclear Power Plant Operators Should Be Learning from Plants in Decommissioning."[134] Panelists in the workshop reported on the lessons learned during the decommissioning of the Maine Yankee, Rancho Seco, and San Onofre Unit 1 nuclear plants.

Q. **Is it reasonable to expect that the operator of a number of nuclear power plants, such as NMC, will be able to reduce individual plant decommissioning costs through synergies and efficiencies that would not be available to the operator of a single nuclear unit?**

A. Yes. As the operator of number of nuclear plants, NMC should be able to achieve efficiencies and economies of scale through its involvement in the decommissioning of the nuclear power plants it now operates.

Q. **Have you seen any claims by nuclear operators that they would be able to obtain such synergies and efficiencies in decommissioning costs because they own and/or operate a number of nuclear plants?**

A. Yes. In 1999, AmerGen was attempting to purchase the Vermont Yankee Nuclear Plant from its then-current owners. AmerGen claimed that it could reduce the cost of decommissioning Vermont Yankee by more effectively planning, and standardizing its approach to decommissioning.[135] AmerGen further said that it intended to "take advantage of both the synergies available to a large nuclear operator and experience in achieving [its] decommissioning goals in a more efficient manner than was possible for or foreseen by [the then-current Vermont Yankee owners]."[136] AmerGen also argued that "a large on-going nuclear

---

134 *Nuclear News*, January 2003, at page 65.

135 Testimony of AmerGen witness Duncan Hawthorne in Vermont Public Service Board Docket No. 6300, at page 3.

136 Testimony of AmerGen witness Duncan Hawthorne in Vermont Public Service Board Docket No. 6300, at page 4, lines 6-9.

company will have more resources to apply to decommissioning and will be able to negotiate lower vendor prices."[137]

AmerGen further described the synergies and efficiencies that should be available to a large nuclear operator:

> I guess that there are a number of views we have taken of synergies coming from the part of the operator. Some of the synergies we contemplate in the operation of the facility are merged in the decommissioning process. Example being AmerGen's experience with a large fleet of nuclear plants. And to decommission plants from our own experiences is based on perhaps making some investments that are not cost effective for a single unit utility to make, but make a lot of sense for someone who owns a fleet of plants. Things like investment in mobile cranes, plasma cutters, lots of equipment to make the decommissioning process more effective and reduce the cost of that.[138]

Dominion Energy has expressed similar expectations concerning its ability, as the owner/operator of a number of nuclear plants, to achieve efficiencies and economies of scale in the decommissioning of the Kewaunee nuclear plant.[139]

Q. Have you seen any evidence that the 2004 DAEC site-specific decommissioning cost estimate reflects any such synergies or efficiencies from NMC's involvement in the decommissioning of the fleet of nuclear plants it now operates?

A. No.

---

137 AmerGen's response to Conservation Law Foundation Information Request 1AEC13 in Vermont Public Service Board Docket No. 6300.

138 Hearing of May 12, 2000 in Vermont Public Service Board Docket No. 6300, at Transcript page 163.

139 See Dominion's Response to Data Request 3-CUB-8 in PSCW Docket No. 05-EI-136.

Q. Has the U.S. Department of Energy's failure to begin taking spent nuclear fuel on January 31, 1998 impacted the estimated cost of decommissioning DAEC?

A. Yes. The failure by the U.S. DOE to begin taking spent nuclear fuel from nuclear power plants on January 31, 1998, as required by the Nuclear Waste Policy Act, has increased the estimated cost of decommissioning DAEC.

Q. Does the DAEC Decommissioning Cost Study 2004 Update estimate the amount by which the U.S. DOE's failure to begin taking spent nuclear fuel on January 31, 1998 will increase the cost of decommissioning DAEC?

A. Yes. The 2004 Update of the Decommissioning Cost Study estimates that the cost of decommissioning DAEC would have been $587 million, in 2004 dollars, if the U.S. DOE has begun taking spent nuclear fuel on January 31, 1998.[140] This suggests that the U.S. DOE's failure to begin taking spent nuclear fuel on that date will increase the cost of decommissioning DAEC by approximately $40 million, in 2004 dollars.

Q. Is it reasonable to expect that IPL will recover some of the additional costs that it will incur as a result of the DOE's failure to begin taking spent nuclear fuel starting in 1998?

A. Yes. As I noted earlier, it is reasonable to expect that IPL will recover at least some of the additional costs that it will incur as a result of DOE's failure to begin taking spent nuclear fuel starting in 1998.

Q. Have any utilities settled their disputes with U.S. DOE over spent fuel costs?

A. Yes. As I noted earlier, Exelon entered into a settlement with the DOE in August 2004. According to published reports, Exelon was to immediately receive $80 million in reimbursements for spent nuclear fuel storage costs already incurred as

140 Exhibit___BAL-1, Schedule E-1, at page 24 of 26.

a result of the DOE's failure to begin taking spent nuclear fuel on January 31, 1998. Exelon will be reimbursed additional amounts for future costs.[141]

Q. Does the DAEC Decommissioning Cost Study 2004 Update explain the basis for its estimated waste disposal costs?

A. Yes. The 2004 Updated Decommissioning Cost Study explains that it has used the very high rates historically charged for the disposal of low-level wastes at the Barnwell, South Carolina site. However, a second low-level waste disposal site, Envirocare, has opened. According to the 2004 Update, the disposal costs at this site are significantly lower than the costs of disposing low-level wastes at the Barnwell site. The 2004 Updated Study used the 2004 costs at Barnwell, however, because the use of those rates "provides substantial protection against increases in waste disposal costs at Envirocare and thus, there should be no reason that the low-level waste costs resulting from this study need to be escalated at a rate higher than the general rate of inflation used for other costs."[142] Because of the substantial contribution of the low-level waste disposal costs to the total estimated cost of decommissioning DAEC, the use of the higher Barnwell rate provides additional confidence that the total cost of decommissioning DAEC will not exceed the $628.6 million estimate.

Q. Has FPLE Duane Arnold provided its estimate of the cost of decommissioning DAEC?

A. Yes. [redacted][143]

---

141 *Nuclear News*, September 2004, at page 17.

142 Exhibit____BAL-1, Schedule E-1, at page 21 of 26.

143 FPLE Duane Arnold's Confidential Response to OCA DR No. 125, *Review and Cost Analysis for the Decommissioning of Duane Arnold Energy Center*, dated June 2005, at page 5 of 19.

[redacted]

[redacted]

[redacted][146]

Q. Is there a significant risk that IPL's decommissioning trusts will not be adequate to fund the Company's 70 percent share of the cost of decommissioning DAEC?

A. No.

As I have discussed earlier, if IPL continues to own DAEC and relicenses the plant the Company's decommissioning trusts will be adequate to fund its 70 percent share of an estimated $628.6 million cost, even if contributions from ratepayers are ended on December 31, 2010.

In the unlikely, unreasonable, and imprudent event that IPL continues to own part of DAEC, but does not relicense the plant, its ratepayers will continue to make

---

144 Ibid.

145 Ibid.

146 Ibid, at page 16 of 19.

decommissioning contributions through 2014 – the same as they will under the proposed PPA if the plant is sold. This should provide adequate funds to decommission the plant, especially in light of the fact that the trusts will continue earning returns on their investments even during the decommissioning period, as permitted by the NRC in 10 CFR 50.75 (e). But even if there are not adequate funds in IPL's decommissioning trusts in 2014, the NRC permits licensees to undertake delayed decommissioning after maintaining their permanently shut down plants in SAFSTOR conditions for up to twenty or more years. Therefore, if the DAEC decommissioning trusts are not fully funded in 2014, the owners would have the option of delaying the start of active decommissioning for a few years to permit the funds to continue to grow through the reinvestment of earnings.

Risks of Coal-Fired Alternatives to DAEC

Q. Did IPL consider the potential risks associated with selling DAEC in its testimony?

A. No. IPL did not consider the potential risks associated with selling DAEC and building the needed replacement unit(s), which, according to IPL probably would be coal-fired.

Q. What types of risks concern new coal-fired power plants?

A. The risks confronting new coal-fired power plants can be broadly categorized into two types: regulatory and fuel.

Regulatory risks arise from the public and environmental health impacts of burning coal which are in turn placed on coal-fired power plants in the form of regulations. These include the risk that emissions that are not currently regulated will be in the future, that existing emissions regulations will be tightened in the future, that the area in which the plant is located will fall into non-attainment for a criteria pollutant and that regulations governing coal waste will be strengthened in the future.

Q. Why do you believe that GHG regulation is a guarantee?

A. First, let me point out that I am by no means alone in holding this view. James Rogers, chairman, president and chief executive offer of Cinergy has stated "We are planning the future of our company around our belief that we will eventually be required to operate in a carbon-constrained world."[147] He is not the only utility executive that holds this view.

Second, there are many examples of multinational, federal, regional and state level initiatives to control greenhouse gas emissions.

The first multinational effort to regulate greenhouse gases began with the United Nation Framework Convention on Climate Change (UNFCC) in 1992. With the 1997 Kyoto Protocol, the Parties to the UNFCC established legally-binding limits to limit or reduce greenhouse gas emissions. Though the U.S. did not sign the Kyoto Protocol, the agreement recently came into force with Russia's ratification.

Q. What are the domestic movements towards regulating carbon dioxide emissions from the electricity sector?

A. Over the past several years, legislation has been introduced in Congress to require reductions in greenhouse gas emissions. Most notably, the McCain-Lieberman bill would have created a national cap and trade program to reduce CO_2 emissions to 2000 levels between 2010 and 2015. While legislation requiring mandatory reductions has failed to pass to date, the Senate did pass a "Sense of the Senate" resolution this year affirming the science of climate change, including global warming, and recognizing the need for mandatory caps on greenhouse gas emissions in the future.

---

147 Cinergy New Release, "Cinergy Releases Report on Potential Impact of Greenhouse Gas Regulation." December 1, 2004. http://www.cinergy.com/News/default_corporate_news.asp?news_id=478.

At the state level, there have been additional initiatives. These include:[148]

- In 1997 **Oregon** established the first formal standard for CO_2 emissions from new electricity generating facilities in North America.[149] The standard holds any proposed new or expanded power plant to a CO_2 emissions rate of 0.675 pounds per kWh, which is 17 percent less than the most efficient natural gas-fired plant currently operating in the U.S. At the same time, the state also created a non-profit corporation known as the Climate Trust to implement CO_2 offset projects with funds provided by the electric generating industry. A generator can choose to either meet the emissions standard or donate funds to the Climate Trust. The donation level was originally set at $0.57 per ton of CO_2, but is subject to change based on the actual cost of CO_2 offsets.

- In 2001 **Massachusetts** was the first state to establish a cap on CO_2 emissions from fossil fueled power plants. The Massachusetts Department of Environmental Protection issued "Emissions Standards for Power Plants" (310 CMR 7.29) in April 2001. This multi-pollutant legislation requires emission reductions including CO_2 reductions from the six highest emitting power plants in the state. The CO_2 standard of 1,800 lbs/MWh by 2006 represents a 10 percent reduction from the historic baseline (1997-1999). Facilities are allowed to meet their reduction requirements through offsite CO_2 reductions, subject to DEP approval. The compliance deadline is extended to October 2008 for any facility that undergoes repowering. In addition to this legislation, the state's Energy Facilities Siting Board requires *new* power plants with a capacity greater than 100 MW to offset 1 percent of the facility's CO_2 emissions for the next 20 years, as long as the cost of offsets does not exceed $1.50 per ton.

- The **New Hampshire** "Clean Power Act" (HB 284), approved in May 2002, requires CO_2 reductions from the three existing fossil-fuel power plants in the state. The law requires the plants to stabilize their CO_2 emissions at 1990 levels (approximately three percent below their 1999 levels) by the end of 2006. This CO_2 emission reduction is consistent with the Climate Change Action Plan adopted by the New England Governors and Eastern Canadian Premiers (see below). Plants have the option to reduce their emissions on site or to purchase emissions credits from outside of the state.

- In **New Jersey**, the Department of Environmental Protection released the New Jersey Sustainability Greenhouse Gas Action Plan in April 2000. The Plan

---

148 Johnston, Lucy, et. al. "Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value." September 20, 2005, p.10-13. A copy of this paper is attached as Exhibit___DAS-1, Schedule F.

149 Anne Egelston, "Oregon, Massachusetts Lead the Way in GHG Reductions," *Environmental Finance*, July-August 2001.

provides a framework for reducing greenhouse gas emissions to 3.5 percent below their 1990 levels by 2005. Under the Plan, Public Service Enterprise Group, the state's largest utility, pledged to reduce total emissions from all of its fossil fuel-based plants by 15 percent below 1990 levels by 2005. This would require its fossil fuel-fired units to limit their CO_2 emissions to 1450 lbs/MWh in 2005, compared to 1706 lb/MWh in 1990. If PSEG fails to achieve the goal, it must pay the DEP $1 per pound/MWh it falls short of its goal, up to $1.5 million. The fund will be used to support CO_2 reduction projects within New Jersey.

- The state of **Washington** recently passed a law requiring that new power plants either mitigate or pay for a portion of their carbon emissions. Representative Jeff Morris, the bill's primary sponsor, said "Washington State is not going to solve global warming, but we are doing our part." [150]

- The **New York** Greenhouse Gas Task Force was created by Governor Pataki in June 2001. The purpose of the Task Force is to develop recommendations for ways to significantly reduce the state's emissions of greenhouse gases, and New York is currently considering whether to adopt the recommendations of the Greenhouse Gas Task Force. The 2002 State Energy Plan also recommends that the state commit to a goal of reducing greenhouse gas emissions by five percent below 1990 levels by 2010, and 10 percent below 1990 levels by 2020.[151]

- In addition to the regulations and programs described above, 25 states are working with the U.S. Environmental Protection Agency ("EPA") to develop **climate action plans** that identify cost-effective options for reducing greenhouse gas emissions at the state level. At least 19 states have completed an action plan to date.

- Many states have other policies such as renewable portfolio standards and energy efficiency programs that serve to reduce CO_2 emissions from the electricity sector; and many state energy plans and initiatives cite greenhouse gas mitigation as a policy rationale or specific objective.

Action by individual states has been enhanced by several regional initiatives to reduce greenhouse gas emissions:

---

150 Washington House of Representatives Press Release, *Governor Signs Morris Bill to Clean Up Air Pollution,* March 31, 2004.

151 New York State Energy Research and Development Authority, *2002 State Energy Plan and Final Environmental Impact Statement*, June 2002.

- **Nine Northeast and Mid-Atlantic states** (DE, ME, MA, NH, NJ, NY, RI, VT) have formed "The Regional Greenhouse Gas Initiative" (RGGI) in a cooperative effort to discuss the design of a regional cap-and-trade program initially covering CO_2 emissions from power plants in the region. Collectively, these states contribute to 9.3 percent of total US CO_2 emissions and together rank as the fifth highest CO_2 emitter in the world. Pennsylvania, Maryland, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. The states are discussing adoption of a Memorandum of Understanding and a Model Rule in 2005. In this process, CO_2 emissions from fossil fuel fired electricity generating units will be capped at specific levels.[152]

- In September 2003, the Governors of **California, Washington, and Oregon** established the West Coast Governor's Climate Change Initiative, stating that "global warming will have serious adverse consequences on the economy, health, and environment of the west coast states, and that the states must act individually and regionally to reduce greenhouse gas emissions and to achieve a variety of economic benefits from lower dependence on fossil fuels."[153] Emissions in these three states are comparable to those of the RGGI states. RGGI and the West Coast Governors' Initiative have been communicating with regard to potentially linking their cap and trade programs.[154]

- The Governors of **California** and **New Mexico** proposed that 18 western states generate 30,000 MW of electricity from renewable source by 2015. This proposal was unanimously adopted in June 2004.[155]

- In August 2001, in the first action of its kind in North America, the **New England Governors and Eastern Canadian Premiers** signed an agreement for a comprehensive regional Climate Change Action Plan.[156] The plan centers on three main goals. The short-term goal of the Plan is to reduce regional greenhouse gas emissions to 1990 levels by 2010. The mid-term goal is to reduce regional GHG emissions by at least 10 percent below 1990 levels by 2020, and establish an interactive, five-year process, starting in 2005, to adjust

---

152 Information on this effort is available at www.rggi.org

153 See letter from the California Energy Commission and the California Environmental Protection Agency to interested parties, April 16, 2004, at: http://www.energy.ca.gov/global_climate_change/westcoastgov/.

154 Fontaine, Peter, "Greenhouse –Gas Emissions: A New World Order," *Public Utilities Fortnightly*, February 2005.

155 Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse – Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

156 New England Governors and Eastern Canadian Premiers, Climate Change Action Plan: 2001, August 2001.

> the goals if necessary and set future emission reduction goals. The long-term goal of the Plan is to reduce regional greenhouse gas emissions in proportions consistent with reductions necessary worldwide to eliminate any dangerous threat to the climate, which recent science suggests will require reductions of 75-85 percent below current levels. The Plan also provides for the establishment of a regional standardized inventory and registry of greenhouse gas emissions.

Q. How should utilities plan for the impacts of impending regulations such as these?

A. Because it would be infeasible for any individual utility to model the cumulative effect of all of the regulations mentioned above, a good proxy is to incorporate forecasts of carbon allowance prices under a cap and trade regime into a utility's planning. There are many examples of this in utility planning. Synapse Energy Economics, itself, has prepared forecasts of carbon allowance prices that are used in the EGEAS modeling performed by the OCA. These forecasts are supported by the testimony of OCA witness, Dr. Ezra Hausman.

Q. What evidence is there that existing emissions regulations could tighten in the future?

A. From the establishment of criteria air pollutants by the 1970 Act to the Clean Air Act Amendments through today, the standards for air pollutants have largely become more stringent. For example, the recent Clean Air Interstate Rule (CAIR) will reduce the total number of sulfur dioxide and nitrogen oxide emissions allowed from electric generating units, building upon reductions mandated in the 1990 Amendments to the CAA. The 1990 Amendments, in turn, required a reduction from previous standards for these pollutants. And CAIR may be strengthened in the future. A number of environmental and public health groups, such as the American Lung Association and Clear the Air, felt that CAIR should and could have been stronger; mandating caps on SO_2 and NOx of 1.8 million and 1 million tons by the end of the decade as opposed to the 3.6 million and 1.5 million ton caps, respectively, required under CAIR.

The trend towards more stringent regulation can also been seen in the National Ambient Air Quality Standards (NAAQS). For example, the EPA has moved towards more stringent regulation of particulate matter ("PM"). The first particulate matter standard, promulgated in 1971, measured total suspended particulate matter or particulates up to 45 µg in diameter. As scientific understanding of particulate matter and public health matured, the EPA realized that small particulates also posed a public health threat. It established the PM_{10} standard in 1987, which was augmented by the $PM_{2.5}$ standard in 1997 to address even smaller particulates. The EPA recently further revised the $PM_{2.5}$ standard after scientific evidence pointed to the benefits of tightening the standard. Clearly, coal-fired power plants are significant emitters of particulate matter. There is no indication that the existing PM standards are sufficient and won't be strengthened in the future.

Q. How will the risk that emission standards will be strengthened in the future affect the decision to build new coal-fired power plants?

A. Utilities should anticipate that future coal-fired power plants will have to be cleaner than today's units. In addition, they should assume that today's forward prices for emissions are a *minimum* price. I would also note that under Iowa's proposed implementation of CAIR, a new coal-fired generating unit would receive *no* allocation of SO_2 or NOx allowances if construction commenced after 2008.[157] Similarly, it would receive no Hg allowances if construction commenced after 2011. If a new unit needed to buy allowances in the market to cover its emissions over its lifetime, the projected price of allowances through the two phases of CAIR and CAMR should be taken as minimum costs and the builder of the new unit should assume further tightening of SO_2, NOx and Hg regulations and associated allowance price increases.

157 Iowa CAIR/CAMR Implementation Workgroup Meeting presentation, August 17, 2005, http://www.iowadnr.com/air/prof/caircamr/files/05aug17_presentation.pdf.

Q. What risks arise if the area in which a new coal-fired power plant is sited falls into non-attainment?

A. Assuming that emissions from the coal-fired power plant contributed to the non-attainment designation, the State could require that additional emission controls be installed at the plant. The technology required will be dictated by the specifics of the situation, but other states have certainly chosen to require additional controls at electric generating units in the past.

In addition, states have previously required limited run times or plant shutdowns. Such requirements affect the economics of the new plant.

Q. What are the risks of coal waste regulation?

A. Currently, coal combustion wastes (CCWs) have an exemption from regulation as hazardous wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA). These wastes include fly ash, bottom ash, boiler slag and flue gas desulfurization by-products. While EPA has shown no movement towards withdrawing this exemption, it has the ability to do so in the future. Indeed, it states "The EPA will re-evaluate the risk posed by managing coal combustion residues if levels of Hg or other hazardous constituents change due to any future Clean Air Act air pollution control requirements for coal burning utilities."[158]

In addition, the levels of Hg or other hazardous materials in CCWs may affect the ability of a coal generator to sell or recycle by-products. For example, there is some concern that mercury regulation will result in a mercury content in fly ash or flue gas desulfurization sludge that renders both unusable for concrete and gypsum wallboard production. Currently, about 30% of CCWs are reused or recycled for uses such as these.[159]

---

[158] Environmental Protection Agency, "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers." December 2001. http://www.epa.gov/ORD/NRMRL/pubs/600r01109/600R01109chap9.pdf

[159] Ibid.

Q. You mentioned that there are coal fuel price and supply risks. Can you describe these risks?

A. As I mentioned previously, there has been a significant upward trend in the price of coal in the past few years. This has been motivated by various factors. The first is increasing oil prices. Expenditures on oil are a significant cost in coal mining and transport and therefore raise the delivered cost of coal. As utility producers renew or secure coal supply contracts, they can expect that increased transportation and mining costs will be passed on to them. Coal buyers should not assume that this will be a short-term problem; crude oil futures are trading at over $60 a barrel on NYMEX[160] through the end of 2011.

Second, supply of Powder River Basin coal has recently become constrained. Heavy rain caused derailments earlier in the year on the Joint Line in Wyoming. The owners of the Joint Line have been working to repair the problem and maintenance and repair is expected to last through November 2005. Contributing to the transport problem are problems at the Powder River Basin mines themselves. Mines have been unable to load trains because of landslides in the pits, lack of coal inventory and upgrades to equipment.

Alliant (IPL's parent company) is not unfamiliar with the consequences of coal dependence. Its subsidiary, Wisconsin Power & Light recently filed a request for a 4.8% rate increase as a result of increased fuel and power purchase costs incurred in July.[161]

Over 13,000 MW of new coal-fired generation is proposed for the Western United States by 2012, meaning that any new coal-fired power plants will have to

160 NYMEX.com, September 15, 2005.

161 WP&L Press Release, "Wisconsin Power and Light Company files Fuel Rate Case." August 31, 2005, http://www.prnewswire.com/cgi-bin/stories.pl?ACCT=104&STORY=/www/story/08-31-2005/0004097535&EDATE=

compete for supply of a coal whose demand already outpaces production, in addition to the problems PRB coal buyers currently face.[162]

Q. Does this complete your testimony at this time?

A. Yes.

[162] Platts. "The Key Issues Facing the Coal Industry." http://www.platts.com/Coal/Resources/News%20Features/usthreat/index.xml