

**STATE OF IOWA
IOWA UTILITIES BOARD**

In Re:

**Interstate Power and Light
Company and FPL Energy
Duane Arnold, LLC,**

)
) **Docket No. SPU-05-15**
)
)

**Direct Testimony of
David A. Schlissel
Synapse Energy Economics, Inc.**

**On Behalf of the
Iowa Office of Consumer Advocate**

PUBLIC VERSION

September 28, 2005

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

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

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

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

6 **Q. Please describe Synapse Energy Economics.**

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

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

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

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

26 I have testified before state regulatory commissions in Arizona, New Jersey,
27 Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina,

1 South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and
2 Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear
3 Regulatory Commission.

4 A copy of my current resume is attached as Exhibit __DAS-1, Schedule A.

5 **Q. Have you previously submitted testimony before this Board?**

6 A. No.

7 **Q. What is the purpose of your testimony?**

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

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

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

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

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

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

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

11 **Q. Please summarize your conclusions in this investigation.**

12 A. I have reached the following conclusions:

- 13 1. The DAEC sales transaction is structured to maximize the cash sales
14 proceeds for shareholders.
- 15 2. Contrary to what IPL has claimed, the sale of DAEC does not have any
16 material potential to benefit the company's ratepayers, and has clear and
17 quantifiable detriment to the company's ratepayers.
- 18 3. There is no evidence that the proposed sale of DAEC achieves the
19 objective of maintaining or reducing long-term power supply costs for
20 IPL's ratepayers, and there is clear and quantifiable evidence of increased
21 long-term power supply costs for IPL's ratepayers.
- 22 4. IPL's claim that the proposed Power Purchase Agreement's capacity and
23 energy charges are designed to reflect what the company's ratepayers
24 would have paid in rates for its continued ownership of DAEC through
25 2014 is not credible.

- 1 5. Rather than protecting ratepayers, the terms of the proposed Power
2 Purchase Agreement commit IPL's customers to paying excessive O&M
3 costs and capital expenditures.
- 4 6. It is reasonable to expect that the Nuclear Management Company could
5 achieve a 90 percent average annual capacity factor if IPL continues to
6 own DAEC.
- 7 7. The proposed Power Purchase Agreement does not reflect the potential
8 Phase 3 uprate that would add another 24 MW of power to DAEC's
9 output.
- 10 8. It is reasonable to assume that whatever party may own DAEC in the
11 future will implement the Phase 3 power uprate.
- 12 9. There is only a very small risk that IPL would not be able to relicense
13 DAEC.
- 14 10. To date, the NRC has issued extended operating licenses for 33 nuclear
15 units. Applications to relicense another 16 nuclear units are currently
16 under review by the NRC. The owners of another 26-28 nuclear units have
17 expressed their intention to relicense their plants. There is no evidence
18 that any owner of a currently operating nuclear plant has announced that it
19 will not relicense its unit. The NRC has not refused to relicense any
20 nuclear unit.
- 21 11. Relicensing of DAEC by IPL can be expected to create significant
22 economic benefits for IPL's ratepayers both before and after 2014.
- 23 12. IPL has overstated the risks associated with continued ownership of
24 DAEC.
- 25 13. IPL does not address the risks associated with the sale of DAEC and the
26 subsequent construction and operation of a replacement coal-fired plant.
27 After 2014, if IPL does not relicense DAEC, it will lose its 70 percent

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

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

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

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

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

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

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

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

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

5 [REDACTED]²

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

- 9 ▪ Future of DAEC has been an issue since early 1990's
- 10 ▪ Cost-of-service (COS) rate regulation results in an unacceptable mismatch
11 between financial risk and earnings
- 12 ▪ Review of options resulted in two choices:
 - 13 ▪ Decommission DAEC in 2014
 - 14 ▪ Sell DAEC to buyer with opportunity for relicensing
- 15 ▪ Timing of decision driven by re-licensing³

16 There was no mention in Mr. Lacy's presentation of the potential benefit for
17 ratepayers as being one of the decision drivers of the proposed sale of DAEC.
18 Other internal company documents similarly focused on the proposed benefit of
19 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.

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

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

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

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

19 If sold, the mostly depreciated DAEC and its associated low cost power
20 ultimately would be replaced in or about 2014 by a new coal unit that would cost
21 hundreds of millions of dollars or more and have higher fuel costs. Although this
22 would boost revenues for shareholders when the investment in the new coal plant
23 is added to rate base, ratepayers would be forced to pay substantially higher rates
24 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.

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

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

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

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

- 1 **Q. Has any state regulatory commission directed that IPL provide a**
2 **quantitative and qualitative analysis of the choice between relicensing DAEC**
3 **and other options, such as the construction of a new coal plant?**
- 4 A. Yes. In December 2004, the Minnesota Public Utilities Commission directed that
5 IPL present such a quantitative and qualitative analysis of the choice between
6 relicensing DAEC and other options as part of its next resource plan.⁵
- 7 **Q. Didn't IPL tell the IUB in its last rate case that it would give "reasonable**
8 **consideration" to the long-term interests of both customers and investors**
9 **before making a decision on whether to extend DAEC's license?**
- 10 A. Yes. IPL witness Bruce Lacy made that commitment to the IUB in his testimony
11 in Docket No. RPU-04-1.⁶
- 12 **Q. If the goal of divesting DAEC was not selected because it has the most**
13 **potential to benefit customers, what was IPL's goal in selling the plant?**
- 14 A. IPL's primary goal was to maximize the cash price it received from bidders and to
15 eliminate what it perceived to be the risks for shareholders of continuing to own
16 the plant.
- 17 **Q. What actions did IPL take during the auction process that lead you to**
18 **conclude that maximizing the cash sale price that bidders would be willing to**
19 **pay was the primary goal?**
- 20 A. Through the proposed PPA capacity and energy charges in its March 2005
21 Confidential Offering Memorandum and revisions to the PPA distributed to
22 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.

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

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

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

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

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

15 **Table 1: IPL March and June PPA Capacity Charges**

16

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.

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

4 A. IPL has said that the [REDACTED] PPA charges distributed to bidders in June were due
5 to [REDACTED] in the estimated DAEC operating and capital costs contained in a
6 Preliminary 2005-2009 Business Plan that the Company received from NMC in
7 April 2005.¹⁰

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

11 A. No.

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

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

19 In fact, as late as early August IPL said that there had been no written
20 communications between the Company and NMC concerning the differences
21 between the NMC 2004-2008 NMC Business Plan and the Preliminary 2005-2009
22 NMC Business Plan.¹¹ As a result, IPL did not have any documentation prepared
23 by or for NMC or IPL that discussed, analyzed, evaluated or otherwise set forth
24 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).

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

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

11 **Q. Did the proposed energy charges increase significantly between the March**
12 **2005 Offering Memorandum and the revised PPA terms that were**
13 **distributed to bidders in June 2005?**

14 **A.**

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 However, the proposed fuel charges for the years 2013 and 2014 are [REDACTED]
20 [REDACTED] because they reflect the accelerated
21 amortization of the fuel assemblies placed in DAEC's core during the plant's
22 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.

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

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

11 For example, the only fuel cost that FPLE Duane Arnold will have to pay between
12 2014 and 2016 will be the cost of the roughly 40 percent of the new fuel that will
13 be loaded into the core during DAEC's 2014 refueling outage. IPL's customers
14 already will have paid the entire costs, and charged customers such costs through
15 the PPA, of the fuel assemblies loaded into DAEC's core in 2010 and 2012 that
16 would still be capable of producing heat and power in the core.

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

19 A. Yes. IPL has estimated that the accelerated amortization of fuel assemblies will
20 increase the fuel costs to be paid by IPL's ratepayers by \$5.1/MWh in 2013 and
21 \$4.4/MWh in 2014.¹⁶ Using the estimated MWhrs from the proposed PPA, these
22 cost increases translate into [REDACTED]
23 [REDACTED] Thus, under the proposed PPA charges, ratepayers will pay for
24 approximately [REDACTED] of nuclear fuel that FPLE Duane Arnold will be able
25 to use during DAEC's extended operating life after February 2014.

¹⁶ IPL's Response to OCA DR No. 163.

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

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

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

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

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

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

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

20 A. No. Both CIPCO and Corn Belt have indicated to potential bidders that they want
21 to retain the right of first refusal to power products associated with future uprates
22 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.

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

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

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

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

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

21 A. The benefits that ratepayers would receive from the higher cash price are minimal
22 and greatly more than offset by additional PPA charges. The only share of the
23 proceeds from the sale of DAEC that ratepayers would receive would be the
24 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.

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

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

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

11 First, IPL has not quantified the damages it has incurred to date as a result of the
12 DOE's failure to begin the taking of spent nuclear fuel on January 1, 1998.²⁴
13 Therefore, it is not possible to say how much of the damages from this delay will
14 be "shared" with FPLE Duane Arnold under the terms of the proposed sale
15 transaction.

16 Second, it is possible that a future settlement between the DOE and FPLE Duane
17 Arnold could involve discounts on future services or spent fuel charges in lieu of
18 payment by DOE of past monetary damages incurred by IPL while it was
19 DAEC's owner. Under the terms of the proposed sales transaction, IPL would not
20 share in any such discounts. FPLE would decide whether to bring these claims
21 and the litigation strategy it would employ; it would be in FPLE's interest to
22 secure an outcome more beneficial to its own interests which may not be
23 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.

1 Third, the possibility of IPL securing damages from the U.S. DOE is not as
2 speculative as IPL suggests. In fact, Federal courts have decided that the U.S.
3 government was unconditionally contracted to begin removing spent nuclear fuel
4 by January 31, 1998.²⁵ The Federal Court of Claims has subsequently determined
5 the individual utilities are owed damages resulting from the DOE's failure to
6 carry out this responsibility.²⁶ Only the size of the payments remains to be
7 determined and the amount of damages owed to individual utilities, like IPL, will
8 continue to grow as the DOE is further unable to remove spent nuclear fuel from
9 plant sites.

10 Indeed, Exelon settled its dispute with the U.S. Department of Energy in August
11 2004. According to published reports, Exelon was to immediately receive \$80
12 million in reimbursements for storage costs already incurred as a result of the
13 DOE's failure to begin taking spent nuclear fuel on January 31, 1998, with
14 additional amounts to be reimbursed annually for future costs. If the Yucca
15 Mountain national repository opens by 2010, and the DOE begins accept the spent
16 fuel, the amount owed to Exelon under the settlement would eventually total
17 about \$300 million. If the DOE should fail to accept spent fuel by 2010, the
18 amount paid to Exelon could exceed \$600 million by 2015.²⁷ The payments will
19 be made out of the federal Judgment Fund, which is available for court judgments
20 and DOJ settlements of actual or imminent lawsuits against the government.

21 Therefore, it is very reasonable to expect that at some point before DAEC is
22 ultimately decommissioned, IPL will receive payments from the DOE (or
23 equivalent services in lieu of payments) for increased spent fuel costs at DAEC,
24 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.

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

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

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

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

22 A. Pursuant to its contract with IPL, if the sale is successfully closed, Concentric's
23 payment is based primarily on the cash price obtained for IPL's share of DAEC.³⁰
24 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.

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

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

8 Estimated DAEC Operating Costs for the Years 2006-2014

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

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

- 18 ▪ The O&M and capital expenditure projections in the Preliminary 2005-
19 2009 Business Plan are significantly higher than the O&M and capital
20 expenditure estimates in the approved 2003-2007 and 2004-2008 Business
21 Plan for DAEC.
- 22 ▪ IPL has used the higher O&M and capital expenditure projections in the
23 Preliminary 2005-2009 without evaluating their reasonableness and
24 without approving the proposed plant budgets.
- 25 ▪ The increasing cost projections in the Preliminary 2005-2009 Business
26 Plan are inconsistent with recent costs and cost trends at DAEC.
- 27 ▪ IPL cannot say whether NMC is projecting similar increasing costs for the
28 other nuclear units in its fleet.

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

- 1 ▪ It appears that the costs of the current NMC fleet optimization effort are
2 reflected in the proposed PPA charges and the Preliminary 2005-2009
3 Business Plan. However, there is no evidence that either the proposed PPA
4 charges or the Business Plan reflect any of the net cost savings expected
5 from the NMC fleet optimization.
- 6 ▪ The higher cost projections in the Preliminary 2005-2009 Business Plan
7 are contradictory to the production cost goals set for DAEC by NMC and
8 IPL.
- 9 ▪ The higher cost projections in the Preliminary 2005-2009 Business Plan
10 are inconsistent with the production cost goals set by NMC for the
11 remaining units in its fleet.
- 12 ▪ The cost projections in the Preliminary 2005-2009 Business Plan are
13 inconsistent with recent trends in the nuclear industry as a whole.
- 14 ▪ The Phase 2 spent nuclear fuel campaign is by far the most expensive
15 capital project included in the Preliminary 2005-2009 Business Plan.
16 However, IPL is unable to provide even a single document to justify the
17 estimated \$21.8 million cost of the project included in the Preliminary
18 2005-2009 Business Plan.
- 19 ▪ It is reasonable to expect that the higher O&M and capital expenditures
20 forecast in the Preliminary 2005-2009 Business Plan would lead to
21 improved performance at DAEC. However, the 2005-2009 Business Plan
22 projects longer refueling outages and a higher forced outage rate for
23 DAEC than were forecast in the 2004-2008 Business Plan. This makes no
24 sense and further highlights my concern about IPL using a high cost PPA
25 to increase the cash proceeds for shareholders.

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

28 A. According to IPL, the inputs to the proposed PPA charges for the years 2006,
29 2007 and 2008 reflected one-half of the increases in estimated O&M and capital
30 expenditures between the 2004-2008 Business Plan for DAEC and the
31 Preliminary 2005-2009 Business Plan that was issued in April 2005.³² The inputs
32 to the proposed PPA charges for subsequent years were extrapolated from these
33 figures using the general rate of inflation. Therefore, in order to evaluate the
34 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.

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

3 **Q. How do the estimated O&M and capital expenditures in the Preliminary**
4 **2005-2009 NMC Business Plan for DAEC compare with recent actual**
5 **expenditures and the estimates in the 2004-2008 Business Plan?**

6 A. Table 2 below compares the online O&M expenditure estimates from the
7 Preliminary 2005-2009 Business Plan³³ with the actual total O&M expenditures in
8 2002 and 2003 and the estimated annual total O&M expenditures from the 2004-
9 2008 Business Plan (approved in October 2004).³⁴

10 **Table 2: Online O&M Estimates – Preliminary 2005-2009 Business Plan**
11 **compared to actual 2002-2004 and Estimates from the 2004-2008**
12 **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%

13
14 This table shows that the Preliminary 2005-2009 Business Plan estimated that
15 although online O&M will be about the same in 2005 as it was in 2004, there will
16 be about a \$10 million, or a thirteen percent increase, in DAEC's online O&M
17 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.

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

3 Table 3 then compares the refueling O&M expenditures projected in the
 4 Preliminary 2005-2009 Business Plan with the actual refueling O&M in the years
 5 2002 through 2004 and the estimates from the 2004-2008 Business Plans.

6 **Table 3: Refueling O&M Expenditures – Preliminary 2005-2009 Business**
 7 **Plan Estimates compared to actual 2002-2004 and Estimates from**
 8 **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%	

9
 10 Thus, the Preliminary 2005-2009 Business Plan projects that the cost of preparing
 11 for and conducting DAEC's 2007 refueling outage will be approximately \$20.6
 12 million (\$3.5 million in 2006 and \$17.2 million in 2007). This would be
 13 approximately 38 percent higher than NMC had estimated for the same outage
 14 only months earlier in the 2004-2008 Business Plan.

15 An estimated \$20.6 million cost for DAEC's 2007 refueling outage also is
 16 approximately \$2-3 million per outage, or about ten to fourteen percent, higher
 17 than would be suggested by averaging the costs of the last three refueling outages
 18 and escalating the resulting figure from 2003 to 2007 year dollars at IPL's
 19 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 Plan³⁵**

	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.

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

3 However, in the current circumstances concerning the proposed sale of DAEC,
4 the fact that the estimated O&M and capital expenditures have increased so
5 dramatically in only six months (after having been relatively the same in the
6 2003-2007 and 2004-2008 Business Plans) raises serious questions in my mind
7 concerning the credibility of those new estimates. This is especially true because
8 during this six month period IPL management decided to sell DAEC and higher
9 estimated O&M and capital expenditures could be expected to assist the company
10 both in achieving a higher sales price (through higher PPA capacity charges) and
11 in convincing the IUB that the sale of DAEC would not disadvantage IPL's
12 ratepayers.

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

16 A. No. IPL has not approved the O&M and capital expenditure estimates contained
17 in the Preliminary or Proposed 2005-2009 Business Plans.³⁶ Indeed, IPL's
18 response to OCA DR No. 120(a) in early August noted that there had been no
19 correspondence between IPL and NMC or any other documents explaining the
20 bases for the changes between the approved 2004-2008 Business Plan and the
21 Preliminary 2005-2009 Business Plan.³⁷ As late as August 22nd, IPL said that it
22 had "yet to conduct a full review of the proposed level of capital spending in the
23 proposed business plan" and, in fact, had made only a "cursory" review of the
24 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).

1 not even request support and documentation for the substantial budget increase
2 that was being proposed by NMC for 2006.³⁹

3 **Q. The Preliminary 2005-2009 Business Plan reflects an increase of**
4 **approximately \$9 million in online O&M between 2005 and 2006.⁴⁰ Has IPL**
5 **provided any explanation for this significant increase?**

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

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

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

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

20 A. No. Other than the claim that the cost increase was due to "NMC fleet
21 optimization," IPL was unable to either explain the reasons or factors which form
22 the basis for the estimated \$10.1 million increase in the Admin. and general
23 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.

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

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

7 A. Yes. IPL's response to OCA Data Request No. 167 attributes \$2 million of the
8 projected increase in online O&M for the year 2006 to "NMC fleet optimization."
9 At the same time, an October 2004 NMC Board Member Briefing for IPL
10 similarly suggests that the fleet optimization efforts would require \$3.2 million of
11 capital spending during the years 2004-2009.⁴⁴ These estimated costs are
12 significantly lower than the approximate \$10 million per year cost for the NMC
13 fleet optimization effort suggested by IPL's responses to OCA DRs Nos. 164 and
14 [REDACTED].

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

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

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

23 A. Yes. The October 2004 NMC Board Member Meeting for IPL identified a
24 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.

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

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

5 A. Yes. NMC estimated that the net cost savings for DAEC from the NMC fleet
6 optimization would be \$4.5 million lower O&M in 2007, \$5.2 million lower
7 O&M in 2008, and \$5.4 million lower O&M in 2009.⁴⁶ The fact that these are
8 called “net cost savings” suggests that these are the savings above and beyond the
9 annual costs of implementing the optimization efforts.

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

13 A. No. It appears that the costs of the current NMC fleet optimization effort are
14 reflected in the proposed PPA charges and the preliminary and proposed 2005-
15 2009 Business Plans. However, there is no evidence that either the proposed PPA
16 charges or the 2005-2009 Business Plans reflect any of the net cost savings
17 expected from the NMC fleet optimization.

18 In fact, the Preliminary and Proposed 2005-2009 Business Plans both forecast
19 continuing increases in online O&M expenditures at DAEC which appear, on
20 their face, to be inconsistent with the assumption that the NMC fleet optimization
21 effort will reduce the number of staff positions at DAEC by 77 and lead to lower
22 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.

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

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

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

13 A. Tables 5, and 6 below compare the estimated online O&M and capital
14 expenditures that were used as inputs for developing the proposed PPA charges
15 with the actual expenditures at DAEC from 2002-2004 and the estimates from the
16 2004-2008 Business Plan.

17 **Table 5: Online O&M Estimates used as inputs to PPA Charges as**
18 **compared to actual online O&M and estimates in 2004-2008**
19 **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.

1 **Table 6: Capital Expenditure Estimates used as inputs to PPA Charges as**
2 **compared to actual online O&M and estimates in 2004-2008**
3 **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

4
5 Thus, the inputs to the proposed PPA charges reflected online O&M estimates
6 that were slightly higher than those in the 2004-2008 Business Plan and capital
7 expenditure estimates that were significantly higher than the estimates in the
8 2004-2008 Business Plan.

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

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

15 A. Table 7 below compares the estimated fuel costs that were used by IPL in
16 developing the proposed PPA charges in its March Confidential Offering
17 Memorandum and June 2005 Offering Letter to DAEC's actual fuel costs in the
18 years 2002-2004 and the estimated fuel costs in the 2004-2008 and the
19 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.

1 **Table 7: Fuel Cost Estimates used as inputs to PPA Charges as compared to**
2 **actual fuel costs and estimates in 2004-2008 and Preliminary 2005-**
3 **2009 Business Plans**

4

5

6

7

8

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

10 A. Yes. Data from IPL's FERC Form 1 filing shows that DAEC's fuel costs
11 declined from \$8.18/MWh in 1995 to \$6.07/MWh in 2002 and \$5.78/MWh in
12 2004.⁵⁰

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

16 A. No. IPL's responses to OCA data requests reveal that IPL never approved or
17 even reviewed the reasonableness of the increased online O&M, capital
18 expenditures [REDACTED] before they were used to develop the proposed PPA
19 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.

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

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

9 For example, the levels of online O&M expenditures used to develop the
10 proposed PPA charges (and in the Preliminary and Proposed 2005-2009 Business
11 Plans) are [REDACTED] than the goals and targets that IPL and NMC set for
12 DAEC for the years 2006-2008.⁵³

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

17 A. No. The approved DAEC 2004-2008 Business Plan notes that NMC's fleet
18 production cost target is to reduce the production costs for the other plants
19 operated by NMC from \$22.50 in 2004 to \$19.70 in 2010, both in 2004 dollars.
20 This means that NMC's production cost goal is to reduce the combined non-fuel
21 O&M and fuel costs at these plants in real terms during this six year period. By
22 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.

1 costs will rise from \$26.19 in 2005 to \$31.56 in 2009.⁵⁴ This represents a real
2 increase of approximately 10 percent during the four year period 2005 to 2009.

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

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

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

12 A. No.

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

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

22

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).

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

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

11 Indeed, the Preliminary and Proposed 2005-2009 Business Plans assume that even
12 though NMC will spend substantially more on O&M and capital expenditures in
13 2006-2009 than it has spent on the facility in recent years, DAEC's minor or
14 forced outage rate will increase to 4 percent which is substantially above the
15 actual 2.4 percent annual forced outage rate that the plant averaged during the
16 years 2000-2004.⁵⁹ This makes no sense. If NMC is going to spend more money
17 on repairing and maintaining plant equipment and improving plant operating and
18 maintenance programs, those expenditures should result in improved, not
19 worsening, plant operating performance.

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

22 A. Yes. The Proposed 2005-2009 Business Plan includes expenditures during 2005,
23 2006, and 2007 for a condenser debris filter. The documentation for this project
24 notes that a shutdown of DAEC had occurred in each of the past three years due
25 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.

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

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

11 A. 
12 
13 
14 
15 
16 
17  ⁶¹

18 By way of contrast, IPL's inputs into the proposed PPA charges reflected online
19 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.

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

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

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

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

14 Expected DAEC Operating Performance during the Years 2006-2014

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

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

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

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

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

2 A. As noted by IPL witness Boston, DAEC has achieved an average annual 88.42
3 percent capacity factor during the years 2000-2004.⁶⁵ The plant achieved
4 performance records in 2002 and 2004, with a 96.6 percent capacity factor in
5 2004.⁶⁶ DAEC's last two refueling outages (in 2003 and 2005) have averaged 32
6 days in duration.⁶⁷ Moreover, DAEC averaged only a 2.4 percent annual forced
7 outage rate during the five year period 2000-2004.⁶⁸ With this strong recent
8 performance, it is reasonable to believe that NMC could achieve a 90 percent
9 average annual capacity at DAEC.

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

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

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

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

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

21 A. The U.S. Nuclear Regulatory Commission classifies nuclear units into peer
22 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.

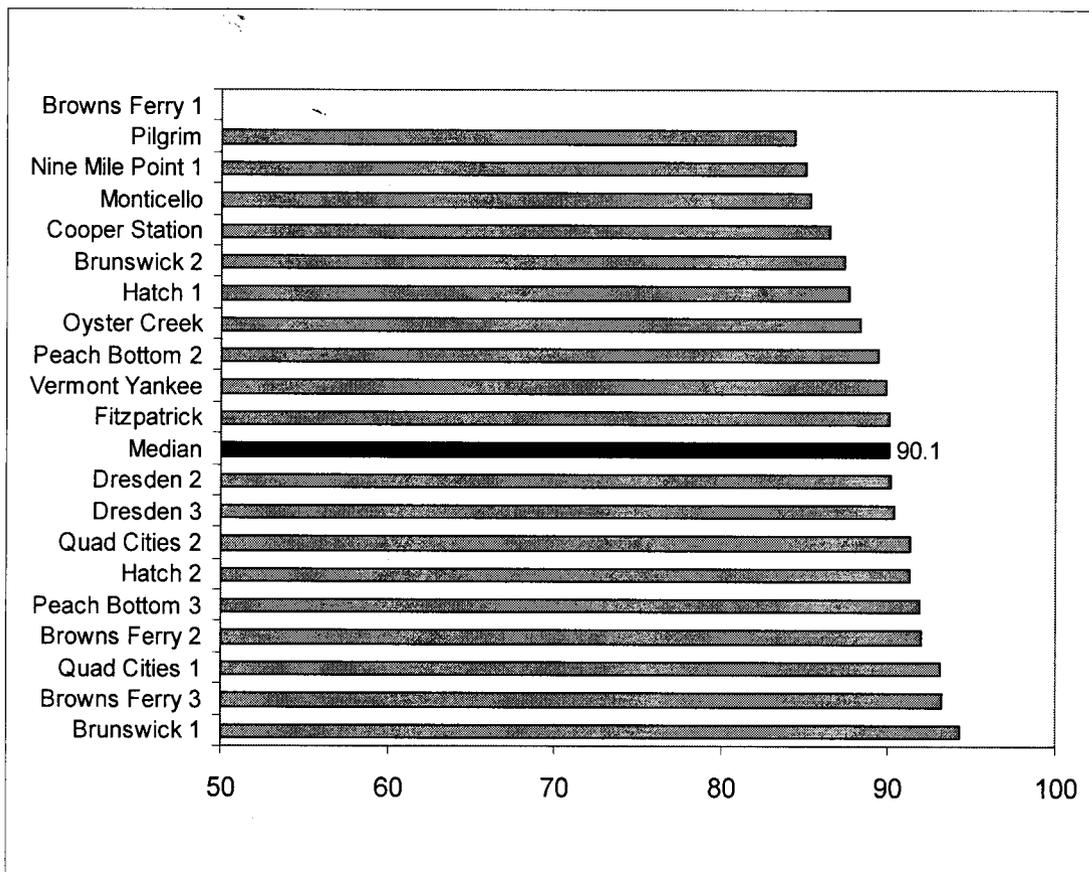
⁶⁹ IPL's Supplemental Response to OCA DR No. 25, at page 11 of 13.

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

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

6 As shown in Figure 1 below, these nineteen units have achieved an average 89.6
7 capacity factor during the six years, 1999-2004, with a median capacity factor of
8 90.1 percent during this period.

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



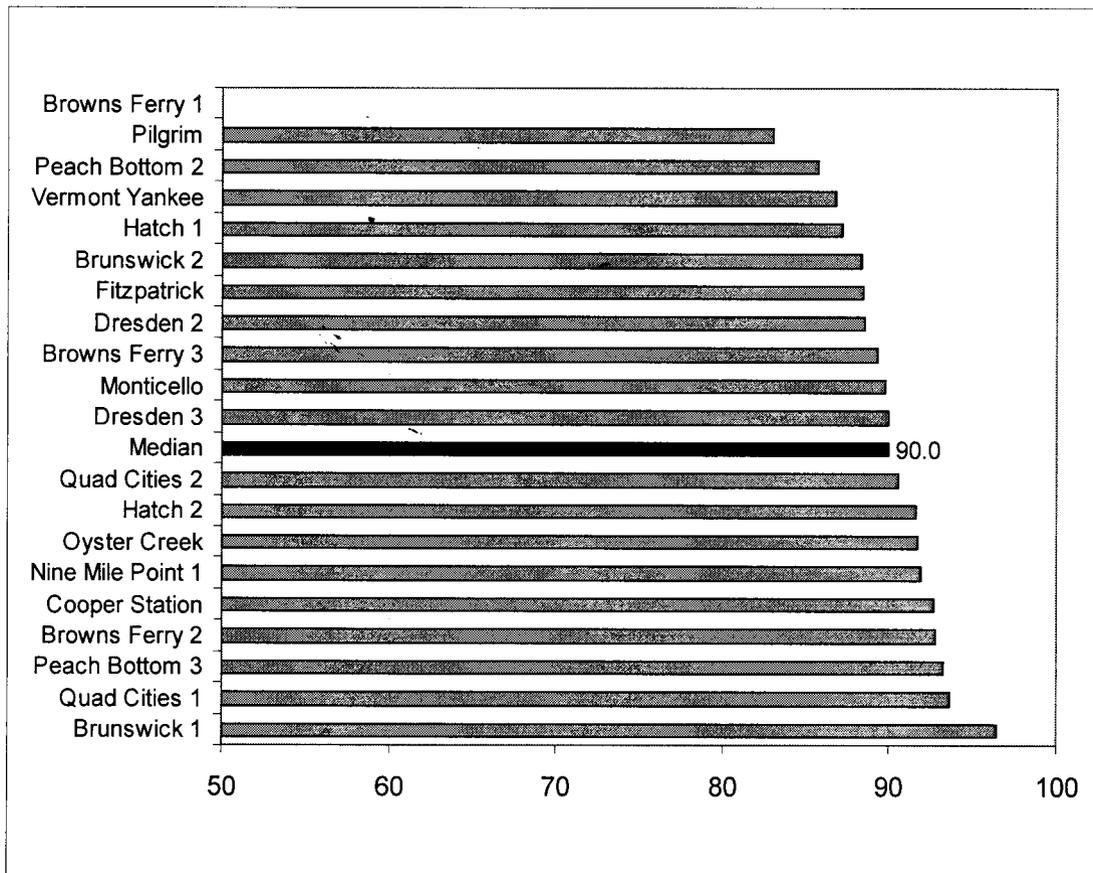
10

11

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

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

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



5
6 This performance by DAEC's peer plants shows that DAEC also can be expected
7 to achieve a 90 percent average annual capacity factor during the period January
8 1, 2006 through February 21, 2014.

plants have been permanently retired.

1 Future DAEC Power Uprate

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

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

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

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

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

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

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

22 A. IPL has estimated that the cost of the modifications and studies that would be
23 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.

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

3 A. [REDACTED]

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

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

9 A. [REDACTED]

10 [REDACTED]

11 [REDACTED] 74

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

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

17 **Q. Has IPL provided any economic analysis to support its exclusion of the Phase**
18 **3 uprate from its calculation of the proposed PPA charges?**

19 A. No. IPL has provided what it says is a preliminary NMC analysis of the
20 economics of the Phase 3 uprate.⁷⁵ This analysis appears to have been performed
21 in 2002. However, the analysis posits that it would cost approximately \$9 million
22 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.

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

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

11 Relicensing of DAEC for an Additional Twenty Years of Operating Life

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

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

19 In fact, as of the end of August 2005, the NRC had issued extended operating
20 licenses for 33 nuclear units.⁷⁷ At the same time, the NRC currently is
21 considering applications for license renewal for another sixteen nuclear units. In
22 addition, the owners of another 26-28 units have submitted letters to NRC
23 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

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

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

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

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

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

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

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

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

⁷⁸ IPL's Response to OCA DR No. 156.

1 by IPL in its response to OCA DR No. 156. Other than four plants that are
2 currently undergoing NRC relicensing review, none of these original operating
3 licenses expires before 2020. There is no NRC requirement that these companies
4 apply for license renewal this far ahead of the expiration date of the current
5 operating licenses. Therefore, it is not surprising that these companies have not
6 yet done so. Given the operating performance of these units, I fully expect the
7 owners to seek relicensing. In fact, Exelon and TVA already have applied for
8 renewed licenses for those units that they own whose licenses were originally
9 scheduled to expire before 2020.⁷⁹

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

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

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

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

23 This means that the owners of eighteen of DAEC's twenty peer plants have either
24 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.

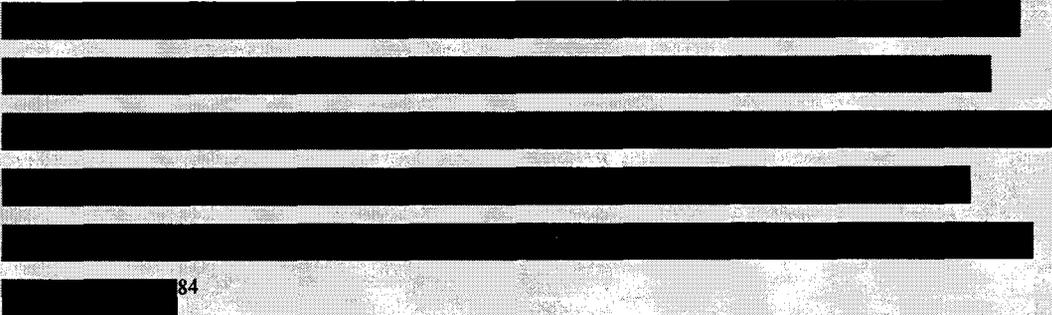
⁸¹ Browns Ferry 1, 2, and 3, Brunswick 1 and 2, Nine Mile Point 1, Monticello, and Oyster Creek.

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

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

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

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

16 A. 
17 
18 
19 
20 
21  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.

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

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

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

18 In fact, industry representatives have commended the NRC’s approach to license
19 renewal. For example, the President of the industry’s Nuclear Energy Institute
20 has said that the NRC’s review of the Calvert Cliffs and Oconee licenses renewal
21 applications “provides a clearly marked path for other electric companies
22 pursuing license renewal.”⁸⁶ At the same time, the Vice President for Nuclear
23 Generation at Duke Energy Company observed as early as 1999 that as the cost
24 for seeking license renewal comes down with experience gained on the initial
25 reviews and the NRC review time shrinks, “it becomes more likely that utilities
26 are going to line up [for license renewal].”⁸⁷ This prediction has been proven
27 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.

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

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

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

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

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

21 A. A substantial number of the nuclear plants that have been relicensed are owned by
22 utilities that are located in states which have not deregulated. Examples of
23 relicensed units owned by utilities in states that have not deregulated include
24 Oconee, Arkansas Nuclear One, Hatch, McGuire, Robinson, and Summer.
25 Moreover, other plant owners in regulated states either have filed applications or
26 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.

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

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

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

7 [REDACTED]
8 [REDACTED]
9 [REDACTED]⁹⁰

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

12 A. Yes. In its April 15, 2003 Order in Docket Nos. RPU-02-3, RPU-02-8, and ARU-
13 02-1, the IUB noted that “While IPL has not made a decision on license
14 extension, there is no reason to believe that the economic factors that have
15 prompted other nuclear plant owners to apply for extensions will be significantly
16 different for IPL.”⁹¹

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

20 A. Yes. I have seen the results of analyses of the economics of relicensing the
21 Monticello and Cooper Station nuclear plants. Like DAEC, both Monticello and
22 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.

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

3 In November 2004, the Board of the Nebraska Public Power District ("NPPD")
4 authorized its executive management to seek the relicensing of the Cooper
5 Station. Cooper's original operating license is scheduled to expire in January
6 2014, one month earlier than DAEC.

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

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

16 A. Xcel Energy compared the relicensing of the Monticello plant with the unit's
17 retirement in 2010 at the expiration of its current NRC license and the
18 construction of an alternative generating facility. Xcel found that the present
19 value revenue requirement benefit of relicensing ranged from \$395 million in
20 2004 dollars to approximately \$3 billion, depending on the assumed costs of fossil
21 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.

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

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

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

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

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

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

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

19 A. Yes. NMC prepared a Plan to Preserve the License Renewal Option at DAEC,
20 dated June 25, 2004. This Plan estimated that it would cost approximately \$17.4
21 million to secure NRC approval for the relicensing of DAEC. The NMC Plan
22 also estimated that future on-line O&M costs during the extended life period (i.e.,
23 2014-2034) would be \$75 million per year (in 2004 dollars).⁹⁶ NMC also
24 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.

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

6 [REDACTED]⁹⁸

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

10 A. The Xcel Energy study assumed that Monticello's capital costs would include an
11 annual \$10 million per year base investment for smaller routine equipment
12 refurbishments.⁹⁹ The study also assumed that another \$135 million of individual
13 incremental investments for larger non-routine equipment
14 refurbishments/replacements that would be necessary to support Monticello's
15 reliable operation to 2030.¹⁰⁰

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

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

21 A. [REDACTED]

22 [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.

1 [REDACTED]
2 [REDACTED]
3 [REDACTED]
4 [REDACTED]
5 [REDACTED]
6 [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED] 105

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

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

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

18 A. Yes. Decommissioning collections from ratepayers could be terminated when the
19 NRC issues the renewed license because relicensing DAEC and extending the
20 unit's operating life would allow an additional twenty years for the
21 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.

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

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

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

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

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

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

14 A. No.

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

17 A. Yes.

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

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

24 In the first analysis, I used the input data from IPL's Exhibit CAH-1 Schedule B-
25 3, to compare the funds that would be available in IPL's decommissioning trusts
26 in 2034 with the Company's 2004 Updated decommissioning cost estimate. In

1 this comparison, I escalated IPL's \$427,007,000 share, in 2005\$, shown on Line 1
2 of Exhibit CAH-1 Schedule B-3 to year 2034 dollars using the Company's
3 estimated 2.60 percent annual escalation rate. At the same time, I grew the
4 projected \$340 million balance in the decommissioning trusts as of January 1,
5 2011 to reflect trust earnings through the year 2034.

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

7 **Table 8: Adequacy of DAEC's Decommissioning Trust Funds in 2034,**
8 **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

9
10 In my base case, I used the 2.60 percent cost escalation rate that was presented in
11 IPL's Exhibit CAH-1 Schedule B-3. I also looked at a higher, 4.00 percent annual
12 rate to reflect higher decommissioning cost escalation.

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

18 **Q. Please explain.**

19 A. There is no NRC requirement or regulation that mandates that a nuclear unit's
20 decommissioning trusts be fully funded at the start of the decommissioning
21 process. In fact, the applicable language in 10 CFR 50.75 (e) allows a licensee
22 that has collected funds based on a site-specific cost estimate to take credit for
23 projected earnings on its external sinking funds using up to a 2 percent annual real
24 rate of return from the time of the future funds' collection through the
25 decommissioning period, provided that the site-specific estimate is based on a

1 period of safe storage that is specifically described in the estimate. The same
2 NRC regulation specifically notes that the decommissioning period includes the
3 periods of safe storage, final dismantlement, and license termination.

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

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

12 **Table 9: Adequacy of DAEC Decommissioning Trusts Assuming Continued**
13 **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

14
15 These results show that there would continue to be adequate funds to safely
16 decommission DAEC even if the real rate of growth on trust earnings fell below
17 the two per cent real rate that the NRC allows licensees to take credit for.

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

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

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

1 In addition, the Omaha Public Power District, the owner of the Fort Calhoun
2 nuclear station, ceased making annual decommissioning collections starting in
3 2002.¹⁰⁷ At the time that the Omaha Public Power District decided to terminate
4 decommissioning collections it was preparing an application to the NRC to
5 relicense Fort Calhoun.

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

8 A. NMC has presented a possible license renewal project schedule that would result
9 in the NRC's issuance of a renewed license for DAEC in late 2010.¹⁰⁸ This
10 schedule appears reasonable given the amount of time the NRC has required to
11 review other license renewal applications.

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

14 A. Given the uncertainties of looking 29 years into the future, I believe that the
15 economics of renewing DAEC's operating license should be evaluated by
16 examining a range of capacity factors. This range should include 90 percent, 80
17 percent and 75 percent average annual capacity factors. In addition, an aging
18 scenario in which DAEC's capacity factor declines as the unit ages also should be
19 examined. For this scenario I recommend assuming a 90 percent capacity factor
20 through 2013, an 80 percent capacity factor from 2014 through 2023, and a 70
21 percent capacity factor from 2024 through 2034. This recommendation was also
22 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.

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

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

11 Risks of Continued Operation

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

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

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

22 A. No.

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

25 A. Yes. There certainly is a cognizable risk that O&M and capital expenditures will
26 be higher or that DAEC will experience outage(s) as the result of events at other

1 operating nuclear power plants, new rules or regulations issued by the NRC or as
2 the result of deficiencies identified by the NRC at DAEC or other plants.

3 **Q. Do you agree with that claim by IPL witness Aller that “the NRC is quick to**
4 **establish new regulations, requiring significant investment, based on**
5 **incidents that occur at other nuclear facilities?”¹⁰⁹**

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

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

13 Today we can say with reasonable confidence that nuclear power
14 will continue as a major component of the nation’s energy supply
15 well into the new century....

16 This remarkable revival can be attributed to three factors: Stable
17 regulatory process, extraordinary plant performance, and the
18 impact of deregulation.

19 For many years, the Nuclear Regulatory Commission (NRC)
20 regulatory process was unstable. Beginning a few years ago, the
21 NRC, with the support and assistance of the industry, embarked on
22 a program of reform designed to be more objective, more focused
23 on safety significant matters, and reflecting a risk-informed
24 philosophy. As a result of these initiatives, the regulatory process
25 is much more predictable, thereby reducing investor uncertainty.

26 * * * *

27 Until recently, the unstable NRC regulatory process was regarded
28 by many, especially the financial community, as one of the most
29 significant commercial risks deterring investment in the industry.
30 The regulatory process was subjective, prescriptive and unevenly
31 focused on safety significant matters, and, hence, unpredictable.

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

1 So-called “regulatory outages” cost hundreds of millions of dollars
2 – and often driven by intense media attention – were common. To
3 its very credit, the Nuclear Regulatory Commission, over the past
4 15 months, has taken major steps to reform the process. Stability
5 is being restored and this change is widely viewed as one of the
6 most significant contributors to renewed confidence in the future
7 of nuclear power.

8 * * * *

9 I think that it is fair to say that in the past two years or so, the
10 industry has enjoyed a greater degree of stability than at any time
11 since the late 1970s. This is a tribute to the NRC and to those in the
12 industry who have helped to develop these initiatives through their
13 comments and suggestions. We believe that the NRC has
14 irreversibly changed direction toward a more fair, rational and
15 predictable regulatory program.¹¹⁰

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

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

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

30 A. No. The best that the Company could provide was a description of what it
31 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.

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

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

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

- 20 (i) That a modification is necessary to bring a facility into compliance with a
21 license of the rules or orders of the NRC, or into conformance with written
22 commitments by the licensee; or
23 (ii) That regulatory action is necessary to ensure that the facility provides
24 adequate protection to the health and safety of the public and is in accord
25 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).

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

4 The NRC also has a Committee for the Review of Generic Requirements
5 (“CRGR”) whose primary responsibilities include recommending to the NRC’s
6 Executive Director for Operations either the approval or disapproval of the NRC
7 Staff’s proposals of new or revised generic requirements and providing assistance
8 to the NRC’s program offices to help them implement the NRC’s backfit
9 policy.¹¹⁶

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

18 These processes help protect licensees against any attempts by the NRC to have a
19 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.

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

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

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

20 Similarly, in late 2003, the NRC discovered that licensees had failed to comply
21 with important fire protection regulations adopted after the Browns Ferry fire in
22 1975. Instead, of complying with one of the three fire protection options
23 specified by the NRC, licensees were relying on operator manual actions, that
24 were not approved by the NRC, to shut down the plant in case of a serious fire.
25 However, rather than requiring that licensees comply with the existing automatic
26 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.

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

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

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

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

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

25 [REDACTED]
26 [REDACTED]

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

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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?

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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:

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- 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.

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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.

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

30

31

- 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

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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.

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

4 ▪ A review of Mr. Reed's source documents reveals that the outages he cites
5 at the Vermont Yankee and Susquehanna were caused by events on the
6 non-nuclear sides of the facilities. These electrical system events could
7 have been experienced at any power plant, whether fossil-fired or
8 nuclear.¹²⁴ In spite of the 18 day outage in June 2004 cited by Mr. Reed,
9 Vermont Yankee still achieved an 89.32 percent capacity factor during the
10 three year period 2002-2004.

11 ▪ Mr. Reed's discussion of the Fermi plant outage is incorrect. The outage
12 did not cost \$12 million for a single day. A review of Mr. Reed's source
13 documents and the results of a LexisNexis search reveal that the plant was
14 shutdown for about two weeks.¹²⁵

15 Finally, the proposed PPA with FPLE Duane Arnold would not guarantee IPL
16 100 percent of the power from DAEC. The PPA will provide for only a 90 percent
17 capacity factor. This means that IPL will be required to obtain additional power,
18 on average, three days each month, or 36 days each year. This would be
19 equivalent to having to buy power during planned and forced outages if the
20 company continued to own DAEC.

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

23 A. The retirement of large numbers of nuclear industry workers over the next five to
24 ten years is a concern. However, I have seen no evidence that any nuclear plant
25 owner has decided to retire or sell its plant based on this risk. Instead, as indicated
26 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.

1 *News*,, the industry has undertaken comprehensive efforts to retain existing
2 workers and to recruit, train and educate new workers.¹²⁷

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

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

12 The first of the two NEIL policies for DAEC has a seventeen week deductible
13 period which would thereafter provide the owners of DAEC up to \$3.5 million per
14 week for weeks 18-23 of a sudden and accidental outage.¹³⁰ The second NEIL
15 policy would provide 100 percent coverage for the next 52 weeks and 80 percent
16 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.

1 Risks of Increasing Decommissioning Costs

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

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

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

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

23 A. The 2004 site-specific Decommissioning Cost Study reflects contingencies for
24 each line-item in the estimate. These contingencies represent the potential cost of
25 occurrences that have not been accounted for in the estimate such as inclement
26 weather, equipment/tool breakage, changes in the anticipated shutdown
27 conditions, labor disputes, etc..¹³² According to the 2004 Update, the overall
28 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.

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

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

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

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

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

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

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

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

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

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

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

17 A. Yes. In 1999, AmerGen was attempting to purchase the Vermont Yankee Nuclear
18 Plant from its then-current owners. AmerGen claimed that it could reduce the
19 cost of decommissioning Vermont Yankee by more effectively planning, and
20 standardizing its approach to decommissioning.¹³⁵ AmerGen further said that it
21 intended to “take advantage of both the synergies available to a large nuclear
22 operator and experience in achieving [its] decommissioning goals in a more
23 efficient manner than was possible for or foreseen by [the then-current Vermont
24 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.

1 company will have more resources to apply to decommissioning and will be able
2 to negotiate lower vendor prices.”¹³⁷

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

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

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

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

24 **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.

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

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

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

10 A. Yes. The 2004 Update of the Decommissioning Cost Study estimates that the
11 cost of decommissioning DAEC would have been \$587 million, in 2004 dollars, if
12 the U.S. DOE has begun taking spent nuclear fuel on January 31, 1998.¹⁴⁰ This
13 suggests that the U.S. DOE's failure to begin taking spent nuclear fuel on that
14 date will increase the cost of decommissioning DAEC by approximately \$40
15 million, in 2004 dollars.

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

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

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

23 A. Yes. As I noted earlier, Exelon entered into a settlement with the DOE in August
24 2004. According to published reports, Exelon was to immediately receive \$80
25 million in reimbursements for spent nuclear fuel storage costs already incurred as

¹⁴⁰ Exhibit ___ BAL-1, Schedule E-1, at page 24 of 26.

1 a result of the DOE's failure to begin taking spent nuclear fuel on January 31,
2 1998. Exelon will be reimbursed additional amounts for future costs.¹⁴¹

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

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

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

21 A. Yes. [REDACTED]

22 [REDACTED]

23 [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.

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[REDACTED]

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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?

20

A. No.

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24

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.

25
26

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.

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

12 **Risks of Coal-Fired Alternatives to DAEC**

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

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

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

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

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

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

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

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

9 The first multinational effort to regulate greenhouse gases began with the United
10 Nation Framework Convention on Climate Change (UNFCCC) in 1992. With the
11 1997 Kyoto Protocol, the Parties to the UNFCCC established legally-binding limits
12 to limit or reduce greenhouse gas emissions. Though the U.S. did not sign the
13 Kyoto Protocol, the agreement recently came into force with Russia’s ratification.

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

16 A. Over the past several years, legislation has been introduced in Congress to require
17 reductions in greenhouse gas emissions. Most notably, the McCain-Lieberman
18 bill would have created a national cap and trade program to reduce CO₂ emissions
19 to 2000 levels between 2010 and 2015. While legislation requiring mandatory
20 reductions has failed to pass to date, the Senate did pass a “Sense of the Senate”
21 resolution this year affirming the science of climate change, including global
22 warming, and recognizing the need for mandatory caps on greenhouse gas
23 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.

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

- 2 • In 1997 **Oregon** established the first formal standard for CO₂ emissions from
3 new electricity generating facilities in North America.¹⁴⁹ The standard holds
4 any proposed new or expanded power plant to a CO₂ emissions rate of 0.675
5 pounds per kWh, which is 17 percent less than the most efficient natural gas-
6 fired plant currently operating in the U.S. At the same time, the state also
7 created a non-profit corporation known as the Climate Trust to implement
8 CO₂ offset projects with funds provided by the electric generating industry. A
9 generator can choose to either meet the emissions standard or donate funds to
10 the Climate Trust. The donation level was originally set at \$0.57 per ton of
11 CO₂, but is subject to change based on the actual cost of CO₂ offsets.
- 12 • In 2001 **Massachusetts** was the first state to establish a cap on CO₂ emissions
13 from fossil fueled power plants. The Massachusetts Department of
14 Environmental Protection issued “Emissions Standards for Power Plants” (310
15 CMR 7.29) in April 2001. This multi-pollutant legislation requires emission
16 reductions including CO₂ reductions from the six highest emitting power
17 plants in the state. The CO₂ standard of 1,800 lbs/MWh by 2006 represents a
18 10 percent reduction from the historic baseline (1997-1999). Facilities are
19 allowed to meet their reduction requirements through offsite CO₂ reductions,
20 subject to DEP approval. The compliance deadline is extended to October
21 2008 for any facility that undergoes repowering. In addition to this legislation,
22 the state’s Energy Facilities Siting Board requires *new* power plants with a
23 capacity greater than 100 MW to offset 1 percent of the facility’s CO₂
24 emissions for the next 20 years, as long as the cost of offsets does not exceed
25 \$1.50 per ton.
- 26 • The **New Hampshire** “Clean Power Act” (HB 284), approved in May 2002,
27 requires CO₂ reductions from the three existing fossil-fuel power plants in the
28 state. The law requires the plants to stabilize their CO₂ emissions at 1990
29 levels (approximately three percent below their 1999 levels) by the end of
30 2006. This CO₂ emission reduction is consistent with the Climate Change
31 Action Plan adopted by the New England Governors and Eastern Canadian
32 Premiers (see below). Plants have the option to reduce their emissions on site
33 or to purchase emissions credits from outside of the state.
- 34 • In **New Jersey**, the Department of Environmental Protection released the New
35 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.

1 provides a framework for reducing greenhouse gas emissions to 3.5 percent
2 below their 1990 levels by 2005. Under the Plan, Public Service Enterprise
3 Group, the state's largest utility, pledged to reduce total emissions from all of
4 its fossil fuel-based plants by 15 percent below 1990 levels by 2005. This
5 would require its fossil fuel-fired units to limit their CO₂ emissions to 1450
6 lbs/MWh in 2005, compared to 1706 lb/MWh in 1990. If PSEG fails to
7 achieve the goal, it must pay the DEP \$1 per pound/MWh it falls short of its
8 goal, up to \$1.5 million. The fund will be used to support CO₂ reduction
9 projects within New Jersey.

- 10 • The state of **Washington** recently passed a law requiring that new power
11 plants either mitigate or pay for a portion of their carbon emissions.
12 Representative Jeff Morris, the bill's primary sponsor, said "Washington State
13 is not going to solve global warming, but we are doing our part."¹⁵⁰
- 14 • The **New York** Greenhouse Gas Task Force was created by Governor Pataki
15 in June 2001. The purpose of the Task Force is to develop recommendations
16 for ways to significantly reduce the state's emissions of greenhouse gases, and
17 New York is currently considering whether to adopt the recommendations of
18 the Greenhouse Gas Task Force. The 2002 State Energy Plan also
19 recommends that the state commit to a goal of reducing greenhouse gas
20 emissions by five percent below 1990 levels by 2010, and 10 percent below
21 1990 levels by 2020.¹⁵¹
- 22 • In addition to the regulations and programs described above, 25 states are
23 working with the U.S. Environmental Protection Agency ("EPA") to develop
24 **climate action plans** that identify cost-effective options for reducing
25 greenhouse gas emissions at the state level. At least 19 states have completed
26 an action plan to date.
- 27 • Many states have other policies such as renewable portfolio standards and
28 energy efficiency programs that serve to reduce CO₂ emissions from the
29 electricity sector; and many state energy plans and initiatives cite greenhouse
30 gas mitigation as a policy rationale or specific objective.

31
32 Action by individual states has been enhanced by several regional initiatives to
33 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.

- 1 ● **Nine Northeast and Mid-Atlantic states** (DE, ME, MA, NH, NJ, NY, RI,
2 VT) have formed “The Regional Greenhouse Gas Initiative” (RGGI) in a
3 cooperative effort to discuss the design of a regional cap-and-trade program
4 initially covering CO₂ emissions from power plants in the region.
5 Collectively, these states contribute to 9.3 percent of total US CO₂ emissions
6 and together rank as the fifth highest CO₂ emitter in the world. Pennsylvania,
7 Maryland, the District of Columbia, the Eastern Canadian Provinces, and New
8 Brunswick are official “observers” in the RGGI process. The states are
9 discussing adoption of a Memorandum of Understanding and a Model Rule in
10 2005. In this process, CO₂ emissions from fossil fuel fired electricity
11 generating units will be capped at specific levels.¹⁵²
- 12 ● In September 2003, the Governors of **California, Washington, and Oregon**
13 established the West Coast Governor’s Climate Change Initiative, stating that
14 “global warming will have serious adverse consequences on the economy,
15 health, and environment of the west coast states, and that the states must act
16 individually and regionally to reduce greenhouse gas emissions and to achieve
17 a variety of economic benefits from lower dependence on fossil fuels.”¹⁵³
18 Emissions in these three states are comparable to those of the RGGI states.
19 RGGI and the West Coast Governors’ Initiative have been communicating
20 with regard to potentially linking their cap and trade programs.¹⁵⁴
- 21 ● The Governors of **California and New Mexico** proposed that 18 western
22 states generate 30,000 MW of electricity from renewable source by 2015.
23 This proposal was unanimously adopted in June 2004.¹⁵⁵
- 24 ● In August 2001, in the first action of its kind in North America, the **New**
25 **England Governors and Eastern Canadian Premiers** signed an agreement
26 for a comprehensive regional Climate Change Action Plan.¹⁵⁶ The plan centers
27 on three main goals. The short-term goal of the Plan is to reduce regional
28 greenhouse gas emissions to 1990 levels by 2010. The mid-term goal is to
29 reduce regional GHG emissions by at least 10 percent below 1990 levels by
30 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.

1 the goals if necessary and set future emission reduction goals. The long-term
2 goal of the Plan is to reduce regional greenhouse gas emissions in proportions
3 consistent with reductions necessary worldwide to eliminate any dangerous
4 threat to the climate, which recent science suggests will require reductions of
5 75-85 percent below current levels. The Plan also provides for the
6 establishment of a regional standardized inventory and registry of greenhouse
7 gas emissions.

8
9 **Q. How should utilities plan for the impacts of impending regulations such as**
10 **these?**

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

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

20 A. From the establishment of criteria air pollutants by the 1970 Act to the Clean Air
21 Act Amendments through today, the standards for air pollutants have largely
22 become more stringent. For example, the recent Clean Air Interstate Rule (CAIR)
23 will reduce the total number of sulfur dioxide and nitrogen oxide emissions
24 allowed from electric generating units, building upon reductions mandated in the
25 1990 Amendments to the CAA. The 1990 Amendments, in turn, required a
26 reduction from previous standards for these pollutants. And CAIR may be
27 strengthened in the future. A number of environmental and public health groups,
28 such as the American Lung Association and Clear the Air, felt that CAIR should
29 and could have been stronger; mandating caps on SO₂ and NO_x of 1.8 million and
30 1 million tons by the end of the decade as opposed to the 3.6 million and 1.5
31 million ton caps, respectively, required under CAIR.

1 The trend towards more stringent regulation can also been seen in the National
2 Ambient Air Quality Standards (NAAQS). For example, the EPA has moved
3 towards more stringent regulation of particulate matter (“PM”). The first
4 particulate matter standard, promulgated in 1971, measured total suspended
5 particulate matter or particulates up to 45 µg in diameter. As scientific
6 understanding of particulate matter and public health matured, the EPA realized
7 that small particulates also posed a public health threat. It established the PM₁₀
8 standard in 1987, which was augmented by the PM_{2.5} standard in 1997 to address
9 even smaller particulates. The EPA recently further revised the PM_{2.5} standard
10 after scientific evidence pointed to the benefits of tightening the standard.
11 Clearly, coal-fired power plants are significant emitters of particulate matter.
12 There is no indication that the existing PM standards are sufficient and won’t be
13 strengthened in the future.

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

16 A. Utilities should anticipate that future coal-fired power plants will have to be
17 cleaner than today’s units. In addition, they should assume that today’s forward
18 prices for emissions are a *minimum* price. I would also note that under Iowa’s
19 proposed implementation of CAIR, a new coal-fired generating unit would
20 receive *no* allocation of SO₂ or NO_x allowances if construction commenced after
21 2008.¹⁵⁷ Similarly, it would receive no Hg allowances if construction commenced
22 after 2011. If a new unit needed to buy allowances in the market to cover its
23 emissions over its lifetime, the projected price of allowances through the two
24 phases of CAIR and CAMR should be taken as minimum costs and the builder of
25 the new unit should assume further tightening of SO₂, NO_x and Hg regulations
26 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.

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

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

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

10 **Q. What are the risks of coal waste regulation?**

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

19 In addition, the levels of Hg or other hazardous materials in CCWs may affect the
20 ability of a coal generator to sell or recycle by-products. For example, there is
21 some concern that mercury regulation will result in a mercury content in fly ash or
22 flue gas desulfurization sludge that renders both unusable for concrete and
23 gypsum wallboard production. Currently, about 30% of CCWs are reused or
24 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.

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

3 A. As I mentioned previously, there has been a significant upward trend in the price
4 of coal in the past few years. This has been motivated by various factors. The
5 first is increasing oil prices. Expenditures on oil are a significant cost in coal
6 mining and transport and therefore raise the delivered cost of coal. As utility
7 producers renew or secure coal supply contracts, they can expect that increased
8 transportation and mining costs will be passed on to them. Coal buyers should
9 not assume that this will be a short-term problem; crude oil futures are trading at
10 over \$60 a barrel on NYMEX¹⁶⁰ through the end of 2011.

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

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

22 Over 13,000 MW of new coal-fired generation is proposed for the Western United
23 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=>

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

3 **Q. Does this complete your testimony at this time?**

4 A. Yes.

5

6

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