

STATE OF INDIANA

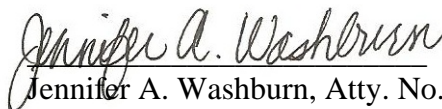
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, )  
LLC SEEKING APPROVAL TO REFLECT )  
COSTS INCURRED FOR THE )  
EDWARDSPORT INTEGRATED )  
GASIFICATION COMBINED CYCLE )  
GENERATING FACILITY PROPERTY, )  
INCLUDING POST-IN-SERVICE ONGOING )  
CAPITAL EXPENDITURES, IN ITS RATES )  
AND TO REFLECT APPLICABLE RELATED ) CAUSE NO. 43114 IGCC-17  
COSTS AND CREDITS, INCLUDING )  
OPERATING EXPENSES, DEPRECIATION, )  
TAX CREDITS, RECONCILIATION, AND )  
CERTAIN 2016 SETTLEMENT AGREEMENT )  
PROVISIONS, THROUGH ITS STANDARD )  
CONTRACT RIDER NO. 61 PURSUANT TO )  
INDIANA CODE §§ 8-1-8.8-11 AND -12 )

**SUBMISSION OF PUBLIC DIRECT TESTIMONY AND ATTACHMENT OF CAC**

Citizens Action Coalition of Indiana, Inc. (“CAC”), respectfully submit the public, redacted Testimony and Attachment of David A. Schlissel (CAC Exhibit 1) in the above referenced Cause to the Indiana Utility Regulatory Commission. The unredacted pages of Testimony which contain information Duke deems confidential will be submitted at a later date, under seal, should the Commission grant Duke’s forthcoming motion for confidential treatment of such.

Respectfully submitted,



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**CERTIFICATE OF SERVICE**


The undersigned counsel hereby certifies that a copy of the foregoing document was served via electronic mail, this 31<sup>st</sup> day of July, 2018:

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AND TO REFLECT APPLICABLE ) CAUSE NO. 43114 IGCC-17  
RELATED COSTS AND CREDITS, )  
INCLUDING OPERATING EXPENSES, )  
DEPRECIATION, TAX CREDITS, )  
RECONCILIATION, AND CERTAIN 2016 )  
SETTLEMENT AGREEMENT )  
PROVISIONS, THROUGH ITS STANDARD )  
CONTRACT RIDER NO. 61 PURSUANT TO )  
INDIANA CODE §§ 8-1-8.8-11 AND -12 )

**DIRECT TESTIMONY OF DAVID A. SCHLISSEL  
ON BEHALF OF  
CITIZENS ACTION COALITION OF INDIANA, INC.**

**JULY 31, 2018**

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1           **INTRODUCTION**

2   **Q.    Please state your name and business address.**

3   A.    My name is David A. Schlissel. I am the President of Schlissel Technical  
4        Consulting, Inc., 45 Horace Road, Belmont, MA 02478.

5   **Q.    On whose behalf are you testifying?**

6   A.    I am testifying on behalf of the Citizens Action Coalition of Indiana (“CAC”).

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

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

13       Since 1983 I have been retained by governmental bodies, publicly-owned utilities,  
14       and private organizations in 38 states to prepare expert testimony and analyses on  
15       engineering and economic issues related to electric utilities. My recent clients  
16       have included the U.S. Department of Justice, the Attorney General and the  
17       Governor of the State of New York, state consumer advocates, and national and  
18       local environmental and consumer organizations.

19       I have filed expert testimony before state regulatory commissions in Arkansas,  
20       Arizona, California, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana,  
21       Iowa, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota,  
22       Mississippi, Missouri, New Jersey, New Mexico, New York, North Carolina,  
23       North Dakota, Ohio, Oregon, Rhode Island, South Carolina, South Dakota, Texas,  
24       Vermont, Virginia, West Virginia, and Wisconsin and before an Atomic Safety &  
25       Licensing Board of the U.S. Nuclear Regulatory Commission.

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1 A copy of my current resume is included as Attachment DAS-1. Additional  
2 information about my work is available at [www.schlissel-technical.com](http://www.schlissel-technical.com).

3 **Q. Have you testified previously before this Commission?**

4 A. Yes. I have testified in Causes Nos. 38702-FAC-40-S1, 38045, 43114, 43114 S1,  
5 and 43114 IGCC-1, IGCC-4, IGCC-4S1, IGCC-8, IGCC-10, and IGCC-12&13,  
6 as well as Cause No. 44794.

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

8 A. I have been requested by CAC to assess the operating performance of the  
9 Edwardsport Integrated Gasification Combined Cycle plant (“Edwardsport” or  
10 “IGCC”) and to evaluate the impact that the plant has had, and will continue to  
11 have, on Duke Energy Indiana’s (“Duke,” “DEI” or “the Company”) ratepayers.

12 **Q. What materials have you reviewed in your preparation of this testimony?**

13 A. I have reviewed the testimony, exhibits and workpapers of DEI’s witnesses and  
14 the Company’s responses to discovery requests submitted by CAC and the other  
15 active parties in the proceeding, as well as the information in the evidentiary  
16 records developed in earlier IGCC sub-dockets and publicly available  
17 information.

18 **SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

19 **Q. Please summarize your principal conclusions.**

20 A. My principal conclusions are as follows:

- 21 1. Edwardsport was planned and proposed to the IURC as an integrated  
22 gasification combined cycle (“IGCC”) plant that would burn gasified coal  
23 (“syngas”).
- 24 2. By any reasonable measure such as heat rate, capacity factor, equivalent  
25 forced outage rate and availability on syngas, Edwardsport’s operating

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1 performance to date has been significantly worse than the Company  
2 repeatedly told the IURC it would be in all of the IGCC sub-dockets,  
3 culminating in the initial issuance and subsequent amendment of the  
4 plant's Certificate of Public Convenience and Necessity ("CPCN"),  
5 including, but not limited to, IGCC-1 and IGCC-4S1.

6 3. More specifically, during the current IGCC-17 review period of January 1  
7 through December 31, 2017:

8 a. The 60 percent capacity factor achieved by Edwardsport on syngas  
9 and the 73 percent capacity factor achieved on all fuels remained  
10 significantly below the 82 percent average capacity factor  
11 projected by Duke.

12 b. When operating on syngas, the plant consumed 28 percent of its  
13 gross generation to serve "parasitic loads," i.e., plant generation  
14 that was used to run onsite equipment and that, therefore, was not  
15 available to be sent into the grid. This was much higher than the  
16 parasitic loads of typical baseload coal and natural gas combined  
17 cycle plants.

18 c. Edwardsport's actual average heat rate in 2017 was slightly above  
19 11,200 BTU/KWh, which was significantly higher than the 9,313  
20 BTU/KWh heat rate forecasted by Duke. This higher heat rate  
21 meant it was more expensive to produce power; it also raised the  
22 fuel costs that DEI's customers must pay; and made the plant  
23 significantly less competitive in the MISO energy markets.

24 d. The plant's operating performance remained inconsistent in 2017,  
25 never achieving its 618 MW full power net capacity rating at any  
26 time during the year.

27 e. The plant experienced a 13.6 percent equivalent forced outage rate  
28 (EFOR) during 2017, which was more than twice the EFOR of the  
29 industry comparison group that Duke itself identified.

30 4. Consequently, although there was some improvement in Edwardsport's  
31 operations in 2017 compared to earlier years, it is not possible to  
32 characterize its performance as "strong" in any way or close to what was  
33 projected by Duke and approved by the Commission in the plant's CPCN.

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- 1           5.       There are a number of factors that show that Edwardsport’s operating  
2                               performance, especially on syngas, should not be expected to improve  
3                               significantly in the foreseeable future.
  
- 4                       a.       The plant continues to lose a significant portion of its potential  
5                               generation due to gasifier equipment problems, leading to its  
6                               extremely poor 40 percent capacity factor on syngas during its first  
7                               55 months of operations, far below the 79 percent average capacity  
8                               factor on syngas for this period projected by Duke.
- 9                       b.       Edwardsport’s gasification system equipment continues to operate  
10                              inconsistently and unreliably.
- 11                      c.       The plant continues to have extremely high parasitic loads and  
12                              high equivalent forced outage rates.
- 13                      d.       The plant’s heat rate continues to be extremely high.
- 14                      e.       The Company plans to continue to conduct both spring and fall  
15                              maintenance outages in coming years, maintaining a pattern of  
16                              expensive frequent outages to address essential repairs.
- 17                      f.       The plant continues to have a seasonal derate in the summer  
18                              months of June through September.
- 19                      g.       The Company is still unable to offer into the MISO markets the  
20                              plant’s maximum output of 618 MW during the non-summer  
21                              months, and 595 MW during the summer months.
  
- 22           6.       Edwardsport’s generation so far in 2018 offers no evidence that its  
23                              operating performance is improving. The plant has achieved only a 38  
24                              percent capacity factor on syngas during the first five months of the year,  
25                              with only a 70 percent capacity factor on all fuels. Meanwhile, it  
26                              continued to have a 26 percent parasitic load while operating on syngas.
  
- 27           7.       Edwardsport is very expensive to operate and maintain, with total  
28                              operating and maintenance (“O&M”) costs that ranged between \$73.33  
29                              per MWh in 2014 to \$49.84 per MWh in 2017. These costs do not reflect  
30                              the retail share of any fixed costs associated with the plant’s construction  
31                              costs or the retail share of capitalized maintenance expenditures. This is  
32                              far more expensive than:

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- 1 a. The cost of generating power at DEI's Gibson and Cayuga  
2 baseload coal plants; and
- 3 b. Buying power in the wholesale MISO markets; and
- 4 c. The cost of producing electricity at any of the five new natural gas-  
5 fired combined cycle plants built by DEI's Duke Energy affiliates  
6 between 2009 and 2013.
- 7 8. The high cost of producing power at Edwardsport has been due to its  
8 extremely high non-fuel operating and maintenance expenses, as its fuel  
9 costs have been relatively low in recent years.
- 10 a. In fact, Edwardsport's non-fuel O&M expenses are much higher  
11 than those at other DEI baseload coal plants and the five new Duke  
12 Energy natural gas-fired combined cycle units completed between  
13 2009 and 2013.
- 14 b. It appears that Edwardsport's extremely high non-fuel O&M costs  
15 are due, at least in large part, to the inconsistent and unreliable  
16 operation of its gasification systems, that is, the systems  
17 responsible for gasifying the coal for production of synthetic gas,  
18 and to the high cost of operating and maintaining those systems.
- 19 9. Given Edwardsport's very high O&M expenses, it is not reasonable to  
20 expect that the plant will produce a net economic benefit for ratepayers at  
21 any time in the foreseeable future.
- 22 a. The cost of operating and maintaining Edwardsport, without  
23 considering any capitalized expenditures, can be expected to  
24 remain significantly above both average monthly peak and off-  
25 peak energy market prices for at least the next ten years, although  
26 there may be some individual hours when it will be less expensive  
27 to generate power at the plant.
- 28 b. The all-in cost of Edwardsport, including Rider 61 revenues and  
29 fuel costs, averaged \$143.19 per MWh for DEI's ratepayers during  
30 the 55 months between June 2013 and December 2017.  
31 Consequently, ratepayers have paid \$1.76 billion for only 12.3  
32 million MWh from the plant.
- 33 c. This \$1.76 billion paid by ratepayers between June 2013 and  
34 December 2017 does not include the \$397 million in Rider 61  
35 costs that ratepayers paid for Edwardsport before the plant was  
36 declared to be in-service. Including those costs would increase the



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1 average cost for ratepayers from \$143.19 per MWh to \$175.53 per  
2 MWh.

3 d. During just the 55 months between June 2013 and December 2017,  
4 DEI's ratepayers paid \$1.4 billion more for power from  
5 Edwardsport than they would have paid for the same amounts of  
6 energy and capacity from the MISO markets. Including the \$397  
7 million in Rider 61 costs that ratepayers paid before the plant was  
8 declared in-service would drive this net economic loss up to nearly  
9 \$1.8 billion.

10 10. As a result, building and operating Edwardsport has been an economic  
11 catastrophe for DEI's ratepayers. And Edwardsport will continue to be a  
12 catastrophe for ratepayers unless the IURC takes strong and effective  
13 actions to protect them.

14 11. Design and technological improvements are driving down the costs of  
15 wind and solar resources. As more of these renewable resources are added  
16 to the MISO grid, they will make continued operation of Edwardsport  
17 even less economically viable as (a) energy market prices can be expected  
18 to remain low, if not decline over time, and (b) generation from  
19 Edwardsport will be displaced due to the availability of lower cost wind  
20 and solar energy.

21 12. Without both trains of its gasification plant operating as intended in  
22 tandem with both of its combustion turbines and its steam turbine to  
23 produce electricity economically dispatched by MISO at a net capacity  
24 factor averaging 82% or more when operating on syngas, Edwardsport as  
25 a whole cannot be considered to be "used and useful" as an Integrated  
26 Gasification Combined Cycle power plant to the extent projected in its  
27 CPCN proceedings.

28 **Q. Please summarize your recommendations.**

29 A. Approving the cost caps in the settlement agreement in Consolidated Cause 43114  
30 IGCC-15 was a good step in the right direction. However, any operational

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1 improvement over the past few years still has not begun to address that  
2 Edwardsport has been and continues to be an economic catastrophe for DEI's  
3 customers. I believe it is time for the IURC to take much stronger actions to  
4 protect ratepayers against the plant's grossly excessive costs and to rebalance  
5 ratepayer risks and rewards from the plant. Therefore, I am recommending that  
6 the IURC:

- 7 1. "[M]odify or revoke the certificate" for the Plant as the Commission  
8 should find that continued "implementation of the [clean coal] technology  
9 will not serve the public convenience and necessity" per IC § 8-1-8.7-5, an  
10 option afforded to the Commission by the legislature to protect ratepayers  
11 in situations just like this; or
- 12 2. Require DEI to file a rate case to determine how much of the investment  
13 in Edwardsport is actually fully "used and useful"; or
- 14 3. Initiate a special proceeding to consider options that would ensure that the  
15 fully embedded cost of the electricity from Edwardsport is comparable to  
16 the cost of alternative sources such as the MISO markets and/or other  
17 generating facilities on the Company's system;

18 and

- 19 4. "[R]emove any incentive approved in the order if the commission finds  
20 that the project no longer complies with the provisions of the order  
21 concerning the incentive" per IC § 8-1-8.8-15 insofar as DEI is still  
22 receiving favorable Rider 61 treatment with a rate of return despite the  
23 clear failures of DEI to reach the milestones and performance promised  
24 when Rider 61 treatment and incentives were awarded; and

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1           5.       Until the IURC modifies or revokes the CPCN, issues an order in a special  
2                   proceeding, or completes a rate case review of whether Edwardsport is  
3                   actually “used and useful” as recommended above, limit the Company’s  
4                   recovery of non-fuel O&M expenditures at Edwardsport to \$6.74 per  
5                   MWh. This represents the average non-fuel O&M expenditures at the five  
6                   Duke Energy NGCC units presented in Figure 9, below, and DEI’s own  
7                   Gibson and Cayuga baseload coal-fired plants for the years 2014-2017. At  
8                   the same time, the IURC should restrict the Company’s ability to recover  
9                   through rates capitalized Edwardsport maintenance expenditures in 2018  
10                  and 2019 to the same limit it approved in IGCC-15 for 2017, i.e. the lesser  
11                  of \$16,900,000 or actual expenditures.

12           **EDWARDSPORT OPERATIONS IN 2017**

13   **Q.    Do you agree with Duke witness Gurganus’ testimony that Edwardsport**  
14   **achieved “strong” operations in 2017?<sup>1</sup>**

15   A.    Although I agree that there has been some improvement in operations, I would not  
16           characterize the plant’s performance as “strong” in any way or even close to what  
17           was projected by Duke and relied upon by the Commission in approving the  
18           plant’s CPCN.

19           Indeed, Mr. Gurganus bases his claim that the plant had “strong operations  
20           throughout 2017” on its performance in just three months of the year: February,  
21           March and November. Rather than focusing on such short periods of time, as Mr.  
22           Gurganus has done, I agree instead with the testimony offered by Duke witness  
23           Stultz in IGCC-14 that it is better to assess the performance of Edwardsport over a  
24           “longer-term time period”:

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<sup>1</sup> Direct Testimony of Cecil T. Gurganus, Petitioner’s Exhibit 1, at page 3, lines 5-6.

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1 During the entire time I have been testifying about the anticipated  
2 and now the actual performance of Edwardsport, I have always  
3 cautioned that the performance of Edwardsport should be assessed  
4 over a longer-term time period. Performance data can often show  
5 significant variation month to month – and even year to year. It is  
6 difficult to really have a view into a generating unit’s long-range  
7 availability (for example) until it can be reviewed over the  
8 timeframe of a typical maintenance cycle of even several. The  
9 reason is, while forced events usually come in smaller, more  
10 frequent blocks of time, planned outages typically come in larger,  
11 less frequent blocks of time. For a baseload combustion turbine  
12 generator, such as Edwardsport, that could be in a time range of  
13 three to five years, while the typical maintenance interval on a  
14 steam turbine is eight to ten years.<sup>2</sup>

15 Thus, I believe that Edwardsport’s overall performance over the 55 months  
16 between the declaration that it was “in-service” in June 2013 and the end of the  
17 IGCC-17 review period in December 2017 offers a better base for (1) assessing  
18 how strong or poorly the plant has operated and (2) evaluating how well the unit  
19 can be expected to operate in coming years than merely focusing on three specific  
20 months in 2017, as Mr. Gurganus has done.

21 **Q. What did Duke forecast for Edwardsport’s operating performance when it**  
22 **was seeking IURC approval to build the plant?**

23 A. Duke initially claimed that Edwardsport would operate at an average 85 percent  
24 availability (that is, an average 82 percent capacity factor) from the moment it  
25 entered commercial service. However, after it was repeatedly pointed out that this  
26 was extremely optimistic, if not completely unrealistic, the Company revised its  
27 forecast to assume that the plant would operate on syngas at an average 75 percent  
28 availability (72 percent average capacity factor) during its first 15 months of  
29 operations, and an average 85 percent availability (82 percent capacity factor)  
30 thereafter.

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<sup>2</sup> [Direct Testimony](#) of Jack L. Stultz, IURC Cause No. 43114, IGCC-14, at page 14, line 17, to page 15, line 5.

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1 The Company also claimed that Edwardsport would achieve a 9,313 BTU/KWh  
2 heat rate.

3 **Q. Did Edwardsport achieve this projected operational performance during**  
4 **2017?**

5 A. No. For 2017 as a whole, Edwardsport achieved only:

6 1. An average 60 percent capacity factor on syngas, and

7 2. An average 73 percent capacity factor on both syngas and natural gas,

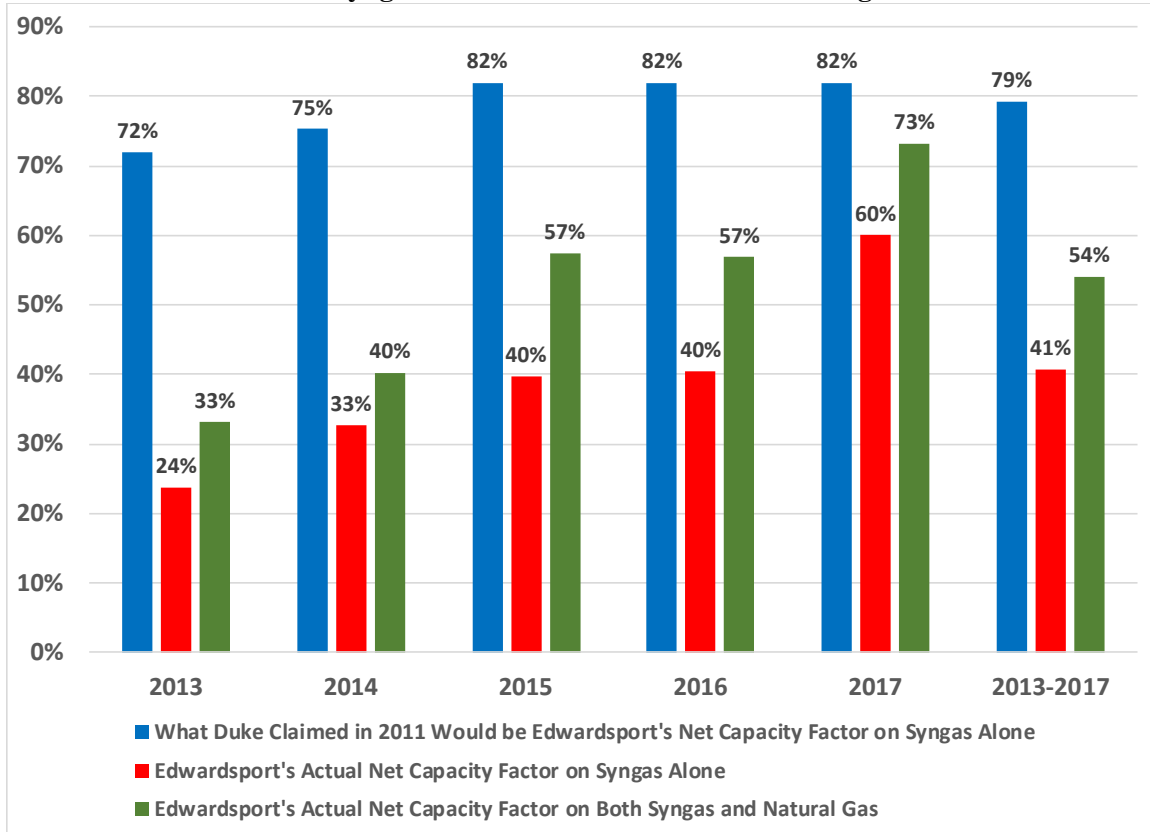
8 Both of these were below the 82 percent capacity factor, on syngas alone, that  
9 Duke had projected for the period after the plant's first 15 months of operation.

10 **Q. Has Edwardsport ever achieved an 82 percent average capacity factor on**  
11 **either syngas or both syngas and natural gas for any sustained period of time**  
12 **since the plant was declared to be "in-service" in June 2013?**

13 A. No. As shown in Figure 1, below, Edwardsport's actual cumulative capacity  
14 factor on syngas through December 2017 was only 41 percent, or barely half of  
15 what the Company forecasted in the modeling it presented to the IURC when it  
16 was seeking the certificate for the plant. The plant's overall capacity factor on  
17 both syngas and natural gas has been only 54 percent, or one-third less than what  
18 Duke projected in IGCC-4S1.

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**Figure 1: Edwardsport's Calendar Year and Cumulative Net Capacity Factors on Syngas for the Months of June 2013 through December 2017.<sup>3</sup>**



1 **Q. Why is Edwardsport's net capacity factor important?**

2 A. Net capacity factor is the most important measure of a plant's operating  
3 performance because it reflects how much energy (that is, how many MWh) the  
4 power plant actually generates to serve customers during a particular period of  
5 time. A plant's capacity factor is a function of how well and at what power levels  
6 it operates, and its relative operating and maintenance cost compared to the cost  
7 of other plants on the grid.

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<sup>3</sup> Sources for the data in Figure 1 include Duke's testimony and filings in IGCC proceedings and the Edwardsport data from EIA Form 923.

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1 Generation is what is important to Duke’s ratepayers. As Duke witness Hager  
2 explained in her March 2011 testimony in IGCC-4S1:

3 [T]he IGCC Project is projected to be the first Duke Energy  
4 Indiana plant dispatched to meet customers’ energy needs because  
5 of its projected low fuel costs. Thus, from the day it is operational,  
6 it will be displacing less efficient and less environmentally friendly  
7 units, serving to reduce operating costs and thereby benefitting  
8 customers.<sup>4</sup>

9 **Q. Please explain why the net generation from Edwardsport into the grid is so**  
10 **important to DEI’s ratepayers.**

11 A. Duke’s ratepayers are being forced to pay very high fixed costs for Edwardsport  
12 because of the plant’s expensive construction cost and fixed operating costs.  
13 Duke’s ratepayers are only able to offset even a portion of these very high fixed  
14 costs if the plant consistently generates large quantities of low cost energy (MWh)  
15 to displace higher cost power that would otherwise be generated at other Duke  
16 plants or purchased from the MISO energy market. For this reason, Duke’s  
17 ratepayers are vitally interested in how much energy the plant actually generates  
18 into the grid.

19 **Q. Why has Edwardsport’s net capacity factor been so poor?**

20 A. There are a number of significant reasons for the plant’s poor overall operating  
21 performance including the inconsistent and unreliable operation of its gasification  
22 system equipment and the fact that the gasification process consumes such a large  
23 fraction of the total power generated by the plant due to what are called “parasitic  
24 loads.” Also, the plant has had a very high equivalent forced outage rate  
25 (“EFOR”). EFOR measures how much of the time the plant is fully or partially  
26 required to reduce power as the result of unplanned equipment problems.

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<sup>4</sup> [Supplemental Testimony](https://iurc.portal.in.gov/entity/sharepointdocumentlocation/a4005c95-9184-e611-8124-1458d04ea8b8/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=dclack_hager_testimony_3_10_20114-37-28pm.pdf) of Janice Hager in IGCC-4S1, Duke Exhibit TT, March 10, 2011, page 3, lines 6-10, [https://iurc.portal.in.gov/entity/sharepointdocumentlocation/a4005c95-9184-e611-8124-1458d04ea8b8/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=dclack\\_hager\\_testimony\\_3\\_10\\_20114-37-28pm.pdf](https://iurc.portal.in.gov/entity/sharepointdocumentlocation/a4005c95-9184-e611-8124-1458d04ea8b8/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=dclack_hager_testimony_3_10_20114-37-28pm.pdf).

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1 For example, the Company makes an annual submission of Edwardsport data to  
2 the North American Electric Reliability Corporation (“NERC”) Generating  
3 Availability Data System (“GADS”) database. This database compiles  
4 information on the nature, cause, magnitude and duration of equipment events at  
5 operating power plants.

6 The Company’s submission to the NERC GADS database for 2017 showed that a  
7 substantial number of equipment problems caused Edwardsport to operate at  
8 reduced power levels reductions (called “derates”) during the year. These power  
9 derates led to the loss of slightly over [REDACTED] MWh of potential plant  
10 generation. Duke has attributed [REDACTED] of  
11 these lost MWh to “Gasification equipment problems.”

12 **Q. What is the significance of the high parasitic loads that you mentioned**  
13 **earlier?**

14 A. Running the equipment for the gasification portion of Edwardsport consumes a lot  
15 of power. A plant’s *gross* output is the total amount of power that it generates. Its  
16 *net* output is the amount of power that it actually sends out into the electric grid,  
17 i.e. net output is what matters to ratepayers. The difference between the plant’s  
18 gross and net power is its “parasitic” load which represents the amount of power  
19 that is needed to operate onsite auxiliary equipment.

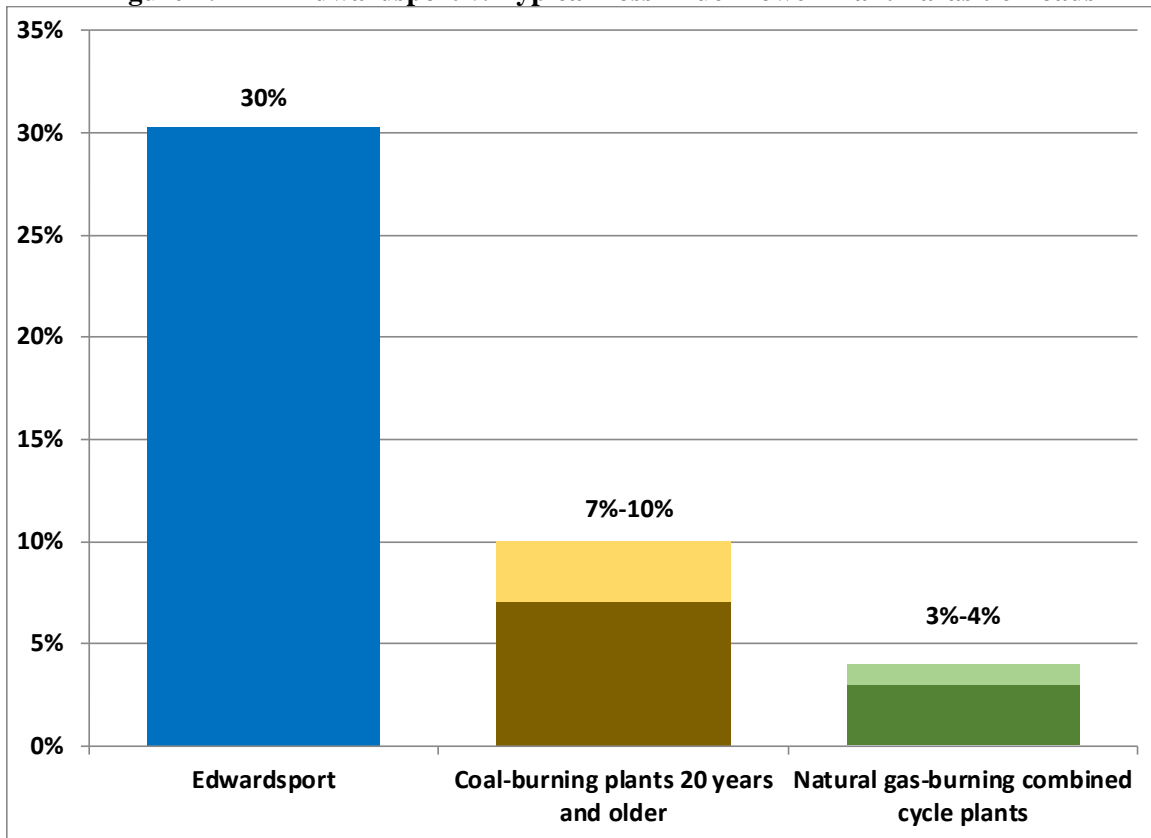
20 **Q. Don’t all fossil power plants need to use some of the power they generate to**  
21 **operate on-site auxiliary equipment?**

22 A. Yes, they do. However, as shown in Figure 2 below, Edwardsport’s parasitic  
23 loads when operating on syngas are much higher than those for typical baseload  
24 coal and natural gas-fired combined cycle units.



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**Figure 2: Edwardsport v. Typical Fossil Fuel Power Plant Parasitic Loads<sup>5</sup>**



1 For the entire 55-month period, June 2013 through December 2017,  
2 Edwardsport's parasitic load when operating on syngas was 30 percent of its gross  
3 generation. The plant's parasitic load was 28 percent in 2017.

4 These extremely high parasitic loads hurt DEI's ratepayers in several ways. First,  
5 the plant had to be built larger to produce the same net MW of power. This  
6 increased its total construction cost and the Rider 61 revenues its ratepayers must  
7 pay. Second, the plant has had to burn substantially more fuel in order to both  
8 operate the gasification system equipment and sell its net output into the grid.  
9 Both of these have meant, and will continue to mean, that ratepayers must pay

---

<sup>5</sup> The sources for Figure 2 are the Edwardsport data from EIA Form 923 for the years 2013-2017 and the DEI Monthly Compliance Reports to the Lt. Governor and IURC in Cause Nos. 43114 & 43114-S1.

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1 more for the electricity generated at Edwardsport than from other sources  
2 available to Duke to serve them.

3 **Q. Earlier you mentioned that Edwardsport had a very high heat rate in 2017.**  
4 **What was the plant's average heat rate last year?**

5 A. Edwardsport's actual heat rate was slightly above 11,200 BTU/KWh, or 1,900  
6 BTU/KWh, higher than the 9,313 BTU/KWh heat rate that the Company had  
7 projected in April 2010, when Duke witness Womack filed his Direct Testimony  
8 in IGCC-4S1.<sup>6</sup>

9 **Q. What is the importance of a power plant's heat rate?**

10 A. A power plant's heat rate measures how efficiently the plant burns fuel. The  
11 higher the heat rate, the less efficiently the plant burns fuel. The lower the heat  
12 rate, the more efficient the plant is. In other words, the higher the plant's heat rate,  
13 the more fuel it must burn to generate the exact same amount of electricity.  
14 Edwardsport's high heat rate makes the plant less economic for consumers and  
15 less competitive with other plants in the wholesale market.

16 **Q. Has Edwardsport achieved a 9,313 BTU/KWh heat rate on any sustained**  
17 **basis since it was declared to be in-service in June 2013?**

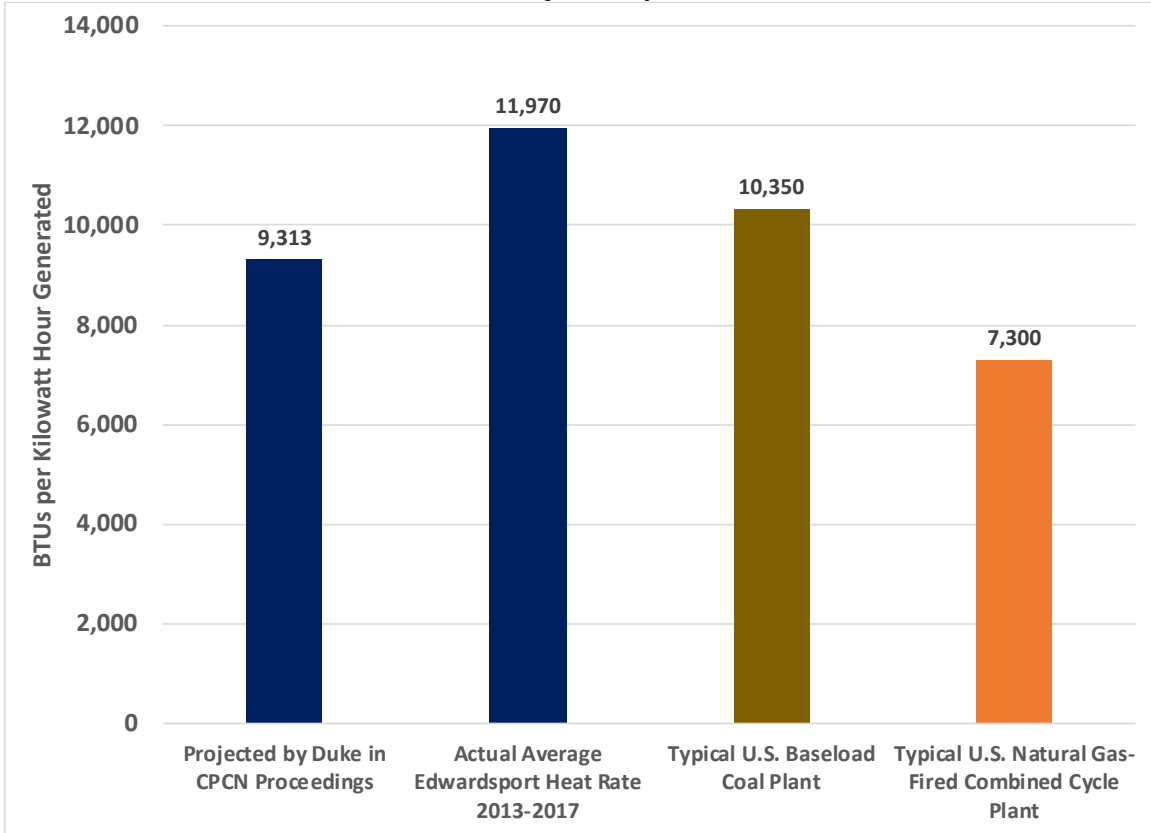
18 A. No. As shown in Figure 3, below, Edwardsport's actual heat rates have averaged  
19 nearly 12,000 BTU/KWh since the plant was declared to be in-service in June  
20 2013.

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<sup>6</sup> [Direct Testimony](#) of W. Michael Womack in IGCC-4S-1, filed in April 2010, at page 36.

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**Figure 3: Edwardsport’s Actual Average Heat Rate vs. the 9,313 BTU/KWh Plant Heat Rate Projected by Duke<sup>7 8</sup>**



- 1 **Q. Did Edwardsport operate at a consistently high power level in 2017?**
- 2 **A.** No. The plant’s performance remained inconsistent in 2017, and it never achieved
- 3 its 618 MW net full power net capacity rating at any time during the year.

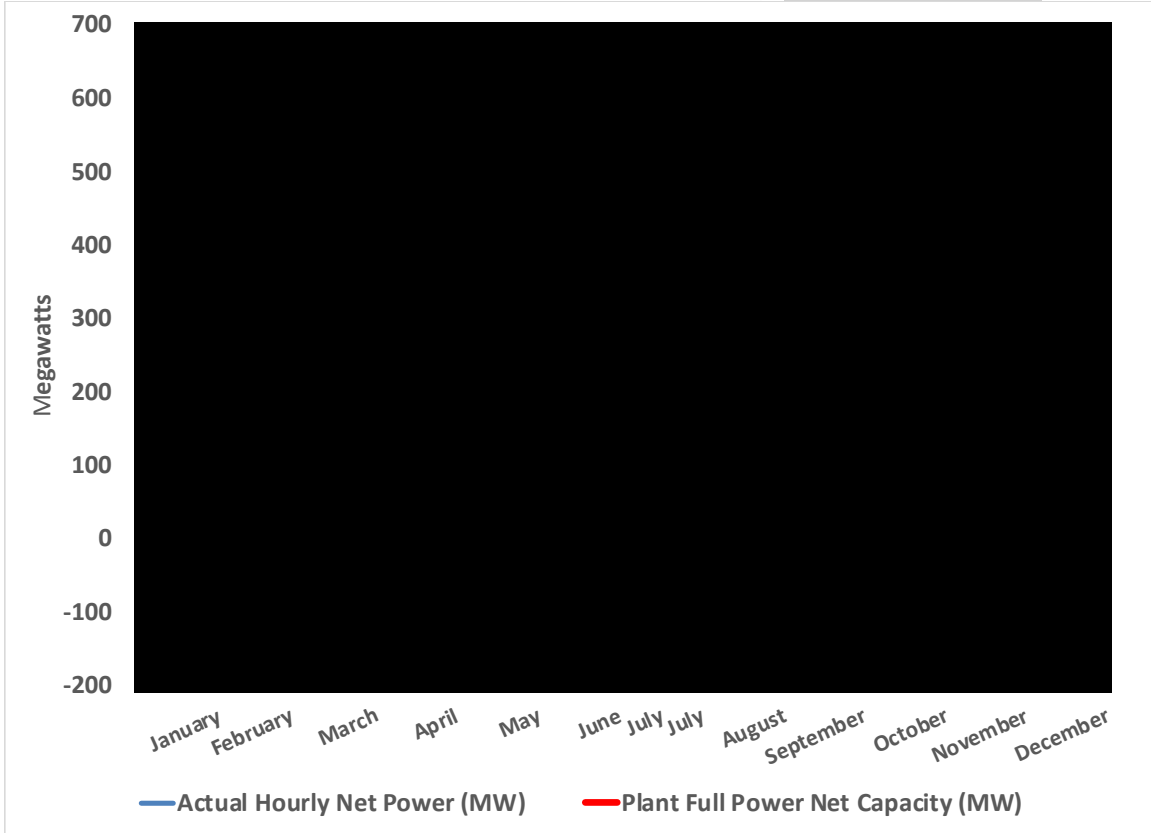
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<sup>7</sup> Edwardsport’s actual station heat rates are provided in Duke Energy Indiana’s annual FERC Form 1 filings.

<sup>8</sup> The typical baseload coal plant heat rate of 10,350 BTU/KWh is based on the average heat rates of DEI’s Gibson and Cayuga plants. The typical NGCC heat rate of 7,300 is based on the average heat rates of five NGCC plants built by Duke Energy in the same relative timeframe as Edwardsport.

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**Figure 4: Edwardsport's Actual Hourly Net Power Generation in 2017 vs. Projected Full Power Capacity Rating. [CONFIDENTIAL]<sup>9</sup>**



- 1 Thus, during 2017:
- 2 • Edwardsport never achieved its 688 MW net full power rated capacity at
- 3 any time during the year.
- 4 • The highest capacity Edwardsport generated in 2017 was [REDACTED] MW and
- 5 that was for only a single hour on February 17th.
- 6 • The plant generated [REDACTED] or more MW for only [REDACTED] hours in 2017, all of
- 7 which were on February 16 and 17.

---

<sup>9</sup> The actual hourly plant outputs shown in Figure 4 are from DEI's Confidential Attachment CAC-1.26-A, which is included in my workpapers.

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1 **Q. Does Edwardsport have a seasonal derate during the summer months of**  
2 **June through September?**

3 A. Yes. The plant is limited to a net full power capacity output of 595 MW during  
4 the months of June through September.<sup>10</sup>

5 As a result, Edwardsport’s highest dispatch during the months of June thru  
6 September 2017 was [REDACTED] MW, and that was for a single hour on June 8<sup>th</sup>. The  
7 plant generated [REDACTED] MW or more in just 22 hours, or less than one percent, of the  
8 2,928 hours in the four months. It generated [REDACTED] MW or more in only 244 hours,  
9 or only eight percent, of the 2,928 hours in the four months.

10 In contrast, the plant’s net power output was [REDACTED] MW or less in 759 hours, or 26  
11 percent, of the 2,928 hours in the four months. And the plant’s net power output  
12 was less than [REDACTED] MW in 349 hours, or twelve percent, of the 2,928 hours in the  
13 four months.

14 **Q. Did Duke consistently offer Edwardsport into the MISO Day Ahead (“DA”)**  
15 **and/or Real Time (“RT”) markets at its full power capacity of 618 MW?**

16 A. No. [REDACTED]  
17 [REDACTED]  
18 [REDACTED]  
19 [REDACTED]  
20 [REDACTED]  
21 [REDACTED] <sup>11</sup>

---

<sup>10</sup> Testimony of Duke witness Swez in Docket FAC-114, at Transcript page A-33, line 22.  
<sup>11</sup> Data from Duke’s response to CAC1.26, Confidential Attachment 1.26-A, which is included in my workpapers submission.

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1 **Q. Mr. Gurganus testifies that Edwardsport set or equaled a new record for**  
2 **gasifier availability in February 2017. What was Edwardsport’s gasifier**  
3 **availability for the entire year of 2017?**

4 A. Mr. Gurganus’ Revised Exhibit 1-C shows a 2017 average gasifier availability of  
5 78.34 percent, which was below the 85 percent average availability on syngas that  
6 Duke forecasted the plant would achieve after its first 15 months of operations.

7 **Q. What was the availability of Edwardsport’s gasifiers over the entire 55-**  
8 **month period between June 2013 and December 2017?**

9 A. Edwardsport’s gasifier availability averaged only 57 percent during the plant’s  
10 first 55 months of commercial operations, far below the 82 percent average  
11 availability Duke represented to the IURC it would achieve.<sup>12</sup>

12 **Q. In how many months has Edwardsport’s gasifier availability actually**  
13 **reached or exceed 85 percent?**

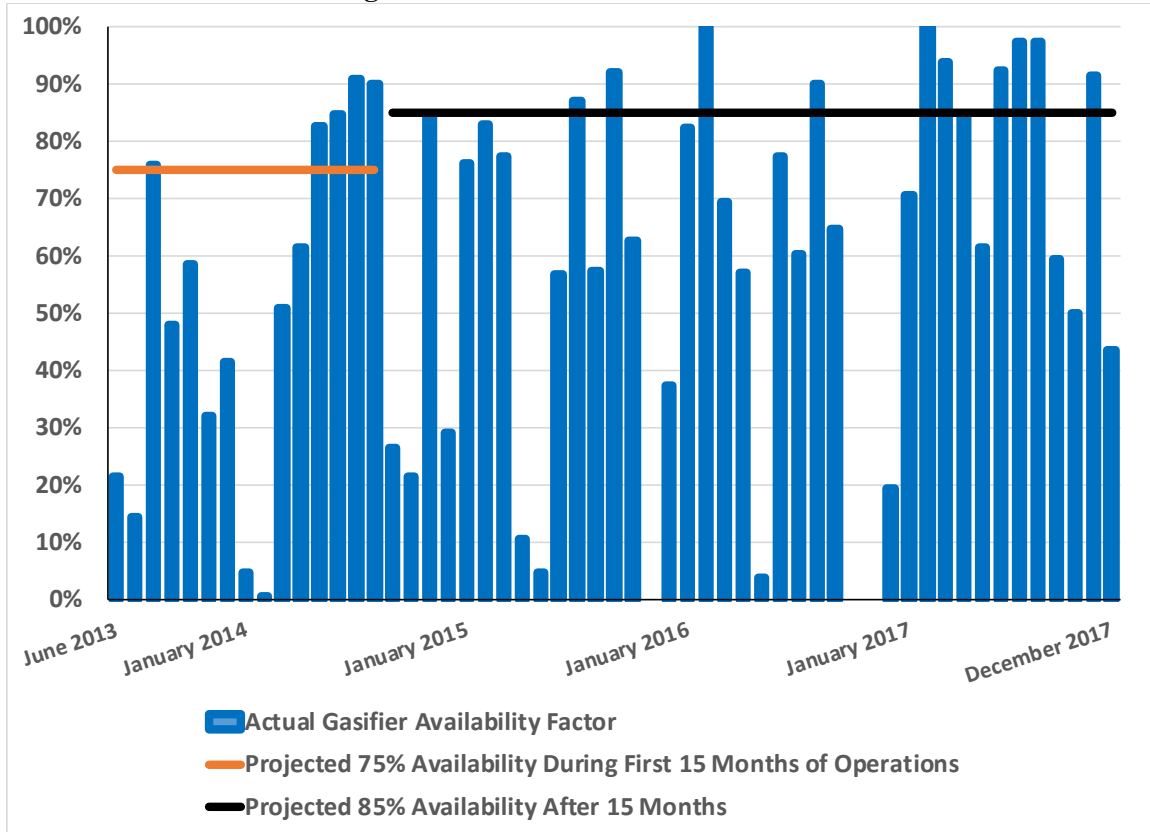
14 A. As shown in Figure 5, below, Edwardsport’s gasifier availability reached or  
15 exceeded 85 percent in only 13 of the 55 months from June 2013 through  
16 December 2017, although its gasifier availability was between 75 and 80 percent  
17 in three of its first 15 months of operation. Thus, the plant’s gasifiers achieved  
18 Duke’s targeted levels of performance in only 16, or 29 percent, of its first 55  
19 months of operations. This was significantly worse than Duke told the IURC it  
20 would be.

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<sup>12</sup> This 79 percent availability reflects the Company’s forecast that Edwardsport would gasifiers would operate at an average 75 percent availability during its first 15 months of operations, and at an average 85 percent availability in subsequent months.

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**Figure 5: Edwardsport’s Monthly Gasifier Availability from June 2013 through December 2017<sup>13</sup>**



1 **Q. It is reasonable to expect that the plant would have achieved the forecasted**  
2 **level of gasifier availability in every month?**

3 A. No. However, its average gasifier availability for the entire 55-month period, and  
4 the fact it achieved Duke’s forecasted levels of performance in just 29 percent of  
5 the individual months, illustrate how inconsistent and unreliable the plant’s  
6 gasification systems have been.

<sup>13</sup> The sources of monthly gasifier availability data in Figure 5 are DEI public data responses in IGCC-12/13 and attachments to the Company’s testimony in IGCC-14, IGCC-15, IGCC-16, and IGCC-17.

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1 **Q. Is availability the best measure to evaluate a generating facility's operating**  
2 **performance?**

3 A. No. A power plant's availability only measures the number of hours it is able to  
4 provide electricity to the grid, at any power level, during a certain period (e.g.,  
5 monthly or yearly), divided by the total number of hours in that period. It does not  
6 reflect the level of generation actually provided by the plant during that period.

7 For example, when calculating the availability factor, an hour in which a large  
8 generating facility like Edwardsport is able to provide one MW of power is  
9 considered the same as an hour in which the facility is able to operate at full  
10 power, which for Edwardsport is 618 MW. As one OUCC attorney put it in a past  
11 Edwardsport hearing, although my Stairmaster is available 100% of the time, it is  
12 not actually getting used. Most importantly, availability has nothing to say about  
13 the economics of a particular plant.

14 **Q. What are better measures of a plant's operating performance?**

15 A. Equivalent availability and capacity factor are far better measures of operating  
16 performance than its availability.

17 **Q. How does a plant's equivalent availability differ from its availability?**

18 A. A plant's equivalent availability reflects the power levels at which it actually  
19 operates. Therefore, unlike availability, equivalent availability reflects power  
20 derates -- that is reductions in the plant's power output even though it remains  
21 connected to the grid and capable of providing some power.

22 **Q. Has Duke provided Edwardsport's gasifier equivalent availability?**

23 A. No. The Company has only provided the equivalent availability for the entire  
24 plant. It has not provided the equivalent availability for just the gasification  
25 systems. Looking at equivalent availability is important because it provides a  
26 complete picture of how much of the time the plant had to reduce its power output



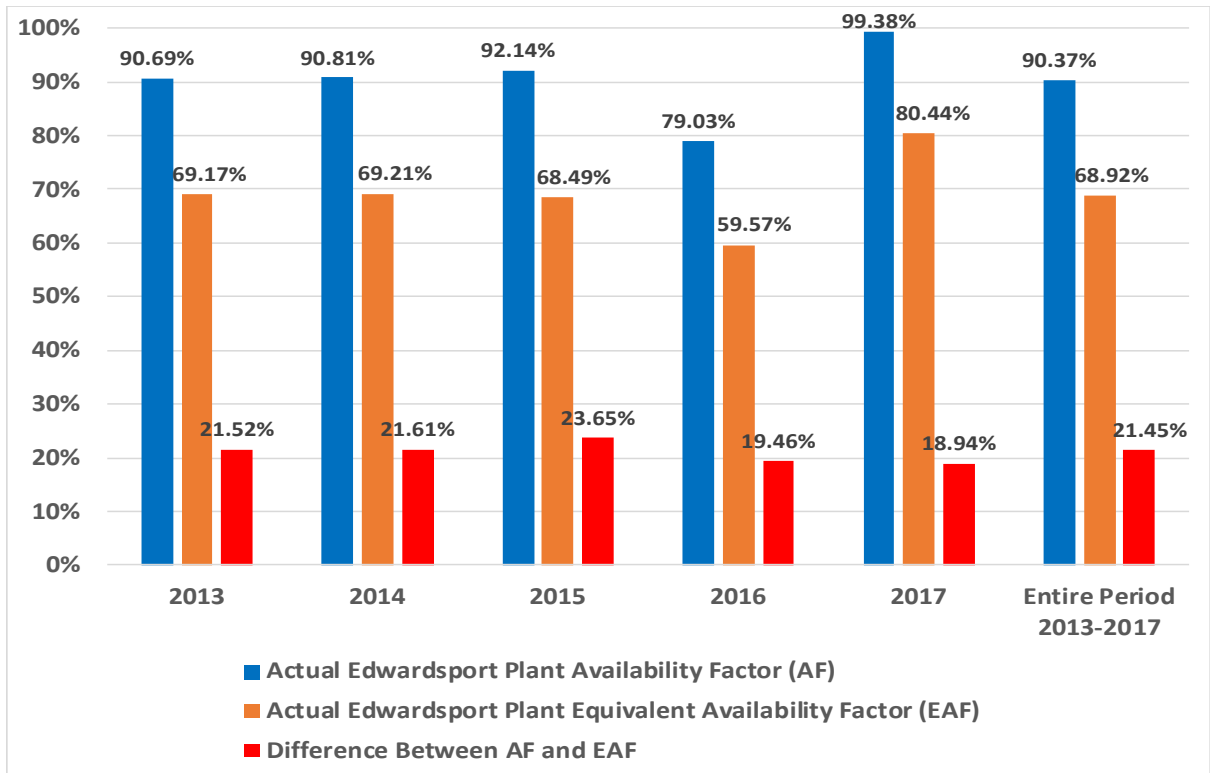
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1 because of gasifier equipment problems and not just the times when it had to  
2 disconnect from the grid.

3 **Q. Do the availability and equivalent availability for the entire Edwardsport**  
4 **plant give an approximate “ballpark” sense of what the equivalent**  
5 **availability might have been for just the gasification system?**

6 A. Yes. As shown in Figure 6, below, Company data shows that Edwardsport’s  
7 availability for the period June 2013 through December 2017 averaged slightly  
8 above 90 percent while its equivalent availability averaged 69 percent, or some 21  
9 percentage points lower.

10 **Figure 6: Edwardsport’s Overall Availability and Equivalent Availability<sup>14</sup>**



11

<sup>14</sup> The sources of the Edwardsport availability and equivalent availability data in Figure 6 are DEI data responses in IGCC-12/13 and attachments to the Company’s testimony in IGCC-14, IGCC-15, IGCC-16, and IGCC-17.

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1 If the same 21 percentage point decrease were applied to the gasification system,  
2 Edwardsport’s gasifier equivalent availability from June 2013 through December  
3 2017 would have been only about 36 percent.

4 **Q. Has Edwardsport been offered by Duke to MISO for economic dispatch in**  
5 **2017?**

6 A. Duke’s response to data request CAC 1.26-A Confidential [REDACTED]  
7 [REDACTED]  
8 [REDACTED]  
9 [REDACTED]  
10 [REDACTED]  
11 [REDACTED]  
12 [REDACTED]  
13 [REDACTED]

14 **Q. Is there any other commonly accepted measure by which the IURC should**  
15 **evaluate Edwardsport’s operating performance?**

16 A. Yes. Another commonly accepted measure for evaluating a power plant’s  
17 operating performance is its Equivalent Forced Outage Rate (“EFOR”). EFOR is  
18 a measure of the probability that a unit will not be available due to both (1) forced  
19 outages when the entire plant is forced out of service and (2) deratings of the plant  
20 below its rated full power net capacity (that is, where the plant is available to  
21 generate but only can produce a lower power output due to unplanned equipment  
22 problems or technical issues).

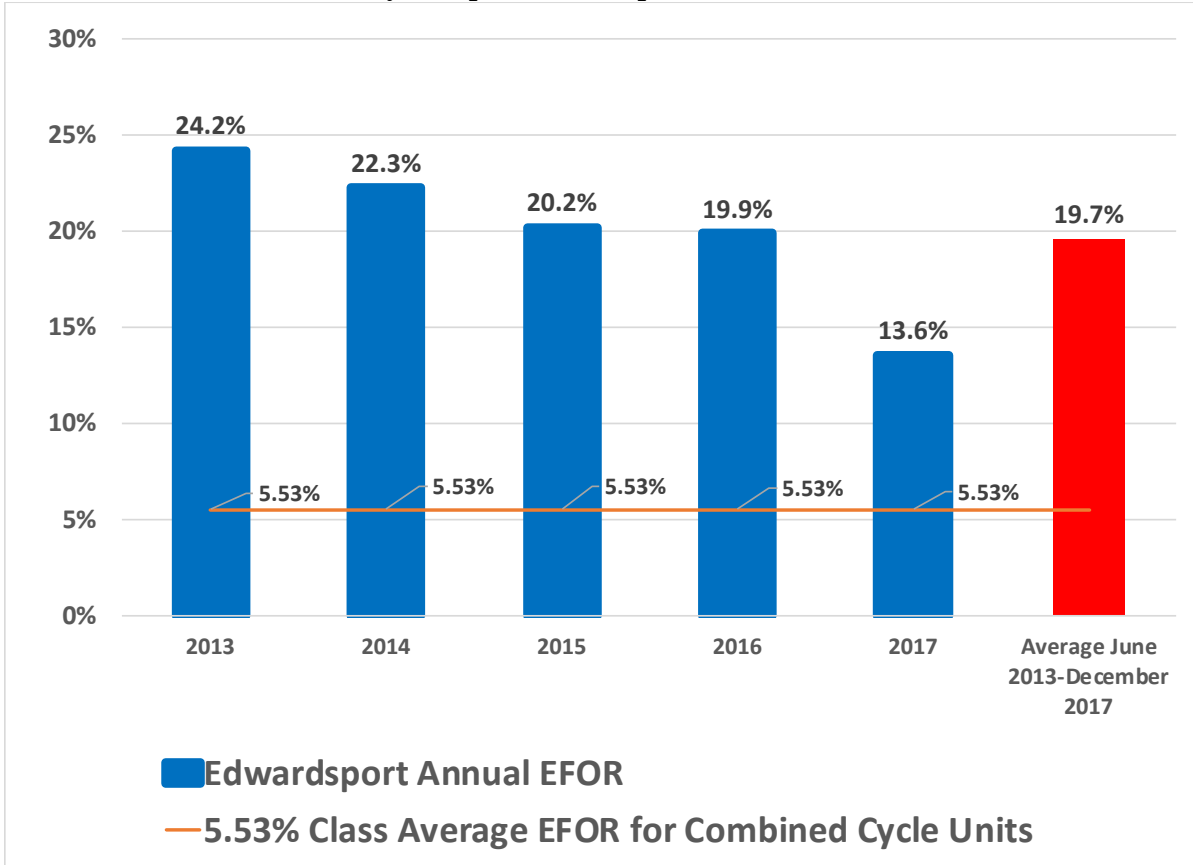
23 **Q. How does Edwardsport’s EFOR compare to that of comparable power**  
24 **plants?**

25 A. Figure 7, below, compares Edwardsport’s EFORs to the average EFOR for  
26 natural gas-fired combined cycle units. This was the comparison group that Duke  
27 used in its 2013 Generator Verification Test Capacity submission to MISO in

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1 2013. As can be seen from Figure 7, Edwardsport’s EFOR between June 2013  
2 and December 2017 was much worse than the average EFOR of the relevant  
3 industry comparison group that Duke itself identified.

4 **Figure 7: Edwardsport’s Equivalent Forced Outage Rate (EFOR) vs. Relevant**  
5 **Industry Comparison Group’s EFOR.<sup>15</sup>**



6  
7 In fact, Edwardsport had an average 19.7 percent EFOR for the entire period of  
8 June 2013 through December 2017. This was more than three times higher than  
9 the average EFOR of the industry comparison group.

---

<sup>15</sup> The sources of the Edwardsport EFOR data in Figure 7 are DEI data responses in IGCC-12/13 and exhibits to the Company’s testimony in IGCC-14, IGCC-15, IGCC-16, and IGCC-17.

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1 **Q. Should the IURC expect Edwardsport's operating performance to improve**  
2 **significantly in coming years over what it has achieved to-date?**

3 A. No. There are a number of factors that suggest that Edwardsport's operating  
4 performance, especially on syngas, should not be expected to improve  
5 significantly in the foreseeable future:

- 6 1. The plant continues to lose a significant portion of its potential generation  
7 due to gasifier equipment problems, leading to its extremely poor 40  
8 percent capacity factor on syngas during its first 55 months of operations.  
9 The plant's capacity factor on both syngas and natural gas also has been  
10 significantly below what Duke forecasted during the CPCN proceedings.
- 11 2. Edwardsport's gasification systems continue to operate inconsistently and  
12 unreliably.
- 13 3. The plant continues to have extremely high parasitic loads and high  
14 equivalent forced outage rates.
- 15 4. The plant continues to have extremely high heat rates.
- 16 5. The Company's plans to continue to conduct both spring and fall  
17 maintenance outages in coming years.
- 18 6. The plant is seasonally derated to 595 MW in the summer months of June  
19 through September.
- 20 7. The Company has not been able to offer into the plant into MISO markets  
21 at its 618 MW full power net capacity during the non-summer months, or  
22 at its 595 MW derated capacity during the summer months.

23 **Q. Does Edwardsport's generation so far in 2018 offer any evidence the plant's**  
24 **operating performance is improving this year?**

25 A. No. According to EIA Form 923 data submitted by Duke, Edwardsport achieved  
26 only an average 70 percent average capacity factor on all fuels in the first five  
27 months of 2018.

28 In particular, it is clear that the gasification systems have continued to experience  
29 serious problems during the first months of 2018 as Edwardsport's net capacity  
30 factor on syngas was only 38 percent through May.

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1 Finally, the plant has continued to experience very high parasitic loads so far  
2 during 2018, with a 26 percent parasitic load while operating on syngas during the  
3 first five months of the year.

4 **Q. Did CAC ask Duke to provide the full range of operating data for the first**  
5 **months of 2018 as Mr. Gurganus included in his Direct Testimony?**

6 A. Yes. CAC submitted a data request, CAC Data Request 2.2, that asked Duke to  
7 provide the data in Petitioner’s Revised Exhibit 1-C (CTG) for the first 4 months  
8 of 2018. That would have included such information as monthly plant and gasifier  
9 availability, plant equivalent availability, and net capacity factor on syngas + coal.  
10 However, the Company has to-date refused to provide this information, and I  
11 understand from CAC’s counsel that CAC filed a motion to compel this  
12 information from Duke.

13 **EDWARDSPORT’S IMPACT ON DUKE ENERGY INDIANA’S RATEPAYERS**

14 **Q. Is it very expensive to generate electricity at Edwardsport?**

15 A. Yes. The operating and maintenance cost of generating power at Edwardsport has  
16 been very high, ranging from \$73.33 per MWh in 2014 to \$49.84 per MWh in  
17 2017.

18 **Table 1**  
**The Operating and Maintenance (O&M) Cost of Producing Power at Edwardsport<sup>16</sup>**

	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>
<b>Total O&amp;M Expense per MWh</b>	<b>\$73.33</b>	<b>\$55.85</b>	<b>\$64.36</b>	<b>\$49.84</b>

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<sup>16</sup> Source Annual DEI FERC Form 1 Filings.

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1 **Q. Do the costs in Table 1 reflect the retail share of capital costs incurred during**  
2 **construction of the plant prior to it being declared in-service in June 2013?**

3 A. No, they do not reflect the approximately \$2.46 billion in retail share of the  
4 capital costs or the approximately \$400 million in Rider 61 revenues paid by  
5 ratepayers prior to Edwardsport being declared in-service in June 2013.  
6 Consequently, the total cost of producing power at Edwardsport is substantially  
7 higher than the even the cost figures presented in Table 1 would suggest.

8 **Q. Do the costs in Table 1 reflect the retail share of capital maintenance**  
9 **expenditures incurred since the plant was declared in service in June 2013?**

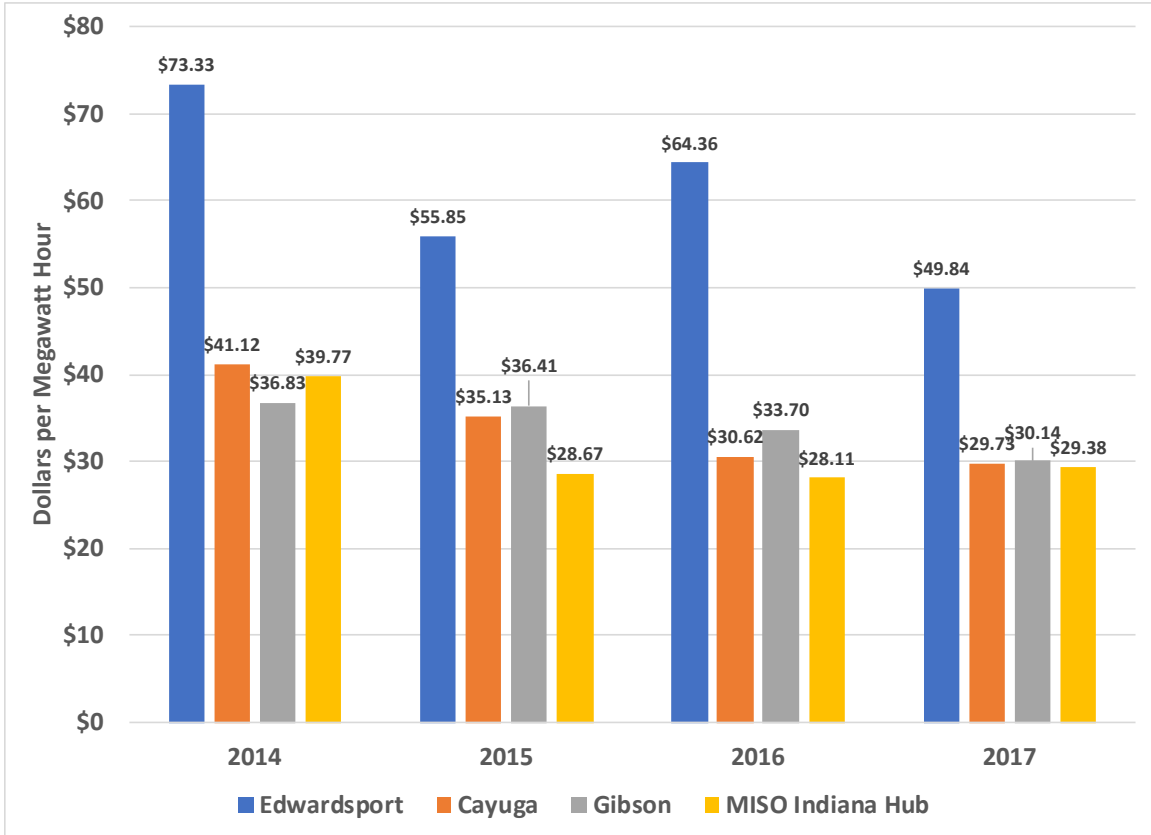
10 A. No. The costs in Table 1 also do not reflect the approximately \$90 million in retail  
11 share of post-in-service capitalized maintenance expenditures presented at  
12 Petitioner's Exhibit 2-B (DLD), page 7 of 10. Consequently, the total cost of  
13 producing power at Edwardsport is substantially higher than the even the cost  
14 figures presented in Table 1 would suggest.

15 **Q. How does the O&M cost of generating power at Edwardsport compare to the**  
16 **cost of producing power at DEI's baseload coal-fired plants or buying power**  
17 **from MISO markets?**

18 A. As shown in Figure 8, below, generating power at Edwardsport is far more  
19 expensive than producing it at DEI's Gibson or Cayuga plants or buying it in the  
20 wholesale MISO markets.

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**Figure 8: O&M Cost of Generating Power at Edwardsport v. Cost of Producing Power at Cayuga and Gibson or Buying it from MISO Markets<sup>17</sup>**



1 **Q. Did any Duke affiliates build new natural gas-fired combined cycle**  
 2 **(“NGCC”) plants at the same time that DEI was building Edwardsport?**

3 **A.** Yes. Duke affiliates in the Carolinas and Florida added five new NGCC units  
 4 between 2009 and 2013. These were Buck CC and Dan River CC built by Duke  
 5 Energy Carolinas, Bartow CC built by Duke Energy Florida, and Wayne County  
 6 and LV Sutton CC built by Duke Energy Progress.<sup>18</sup>

<sup>17</sup> Sources – Duke Energy FERC Form 1 Filings and information from S&P Global Market Intelligence.

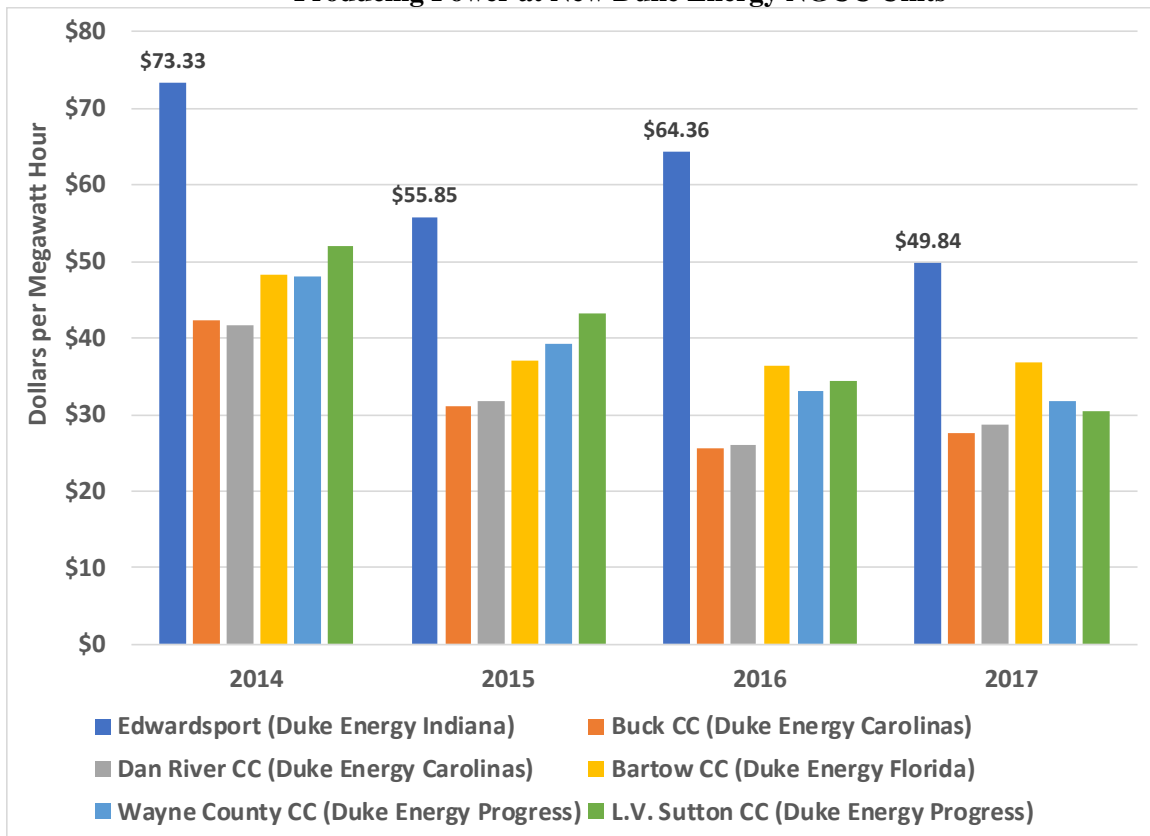
<sup>18</sup> Several additional NGCC units have been added by DEI’s Duke Energy affiliates since 2013. However, the cost data for those units is limited. Therefore, they are not included in this analysis.

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1 **Q. How have Edwardsport’s annual O&M expenses compared to the cost of**  
2 **producing electricity at these new NGCC units?**

3 A. Generating power at Edwardsport has been far more expensive than producing  
4 electricity at any of these other new Duke Energy plants.

**Figure 9: O&M Cost of Generating Power at Edwardsport v. Cost of Producing Power at New Duke Energy NGCC Units<sup>19</sup>**



5 **Q. Why has it been so expensive to generate power at Edwardsport?**

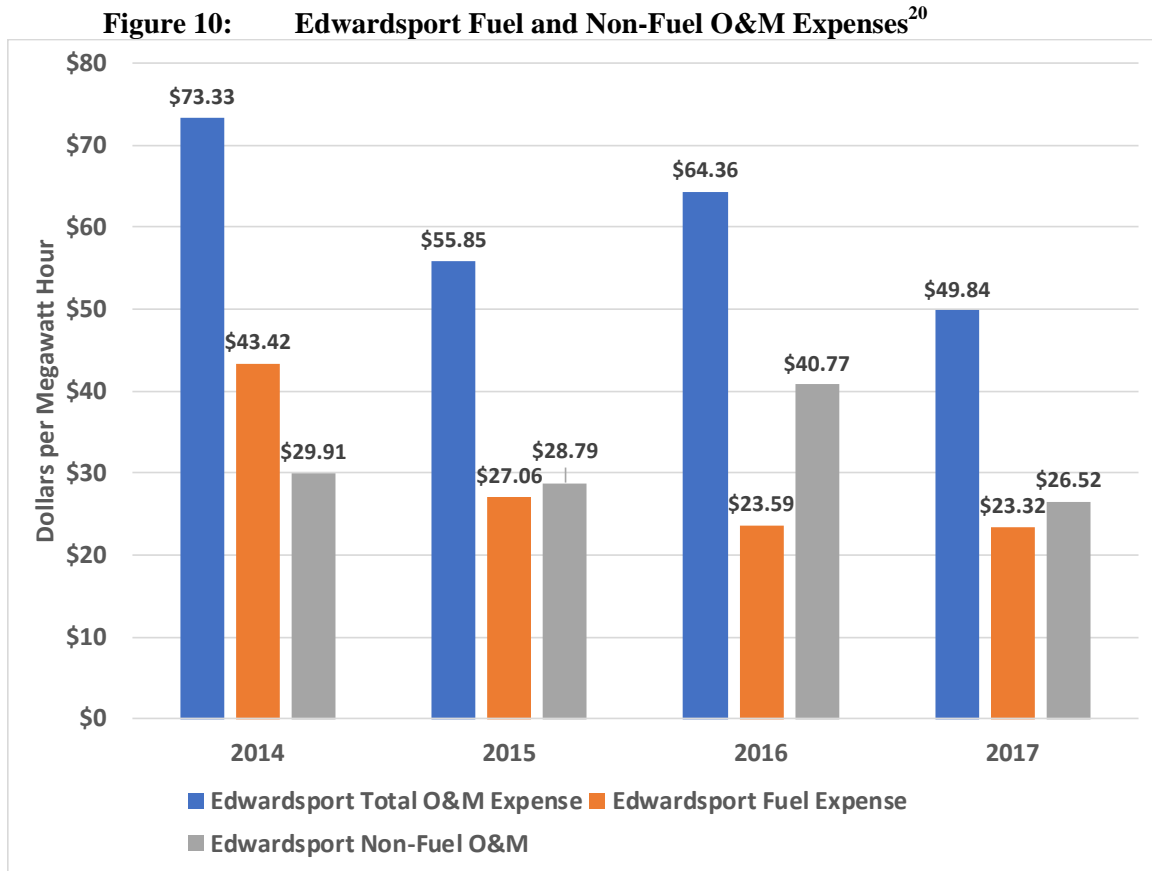
6 A. Edwardsport’s fuel costs have been relatively low in recent years. The high cost  
7 of producing power at the plant has been due to its extremely high non-fuel O&M  
8 expenses as shown in Figure 10, below.

---

<sup>19</sup> Sources – Duke Energy FERC Form 1 Filings and information from S&P Global Market Intelligence.



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1 Again, as in Table 1, these O&M expenses in Figure 10 do not include any  
2 capitalized construction or maintenance expenditures.

3 **Q. How do Edwardsport’s Non-Fuel O&M expenses compare with those at**  
4 **Duke Energy Indiana’s baseload coal plants and the new Duke Energy**  
5 **NGCC plants completed between 2009 and 2013?**

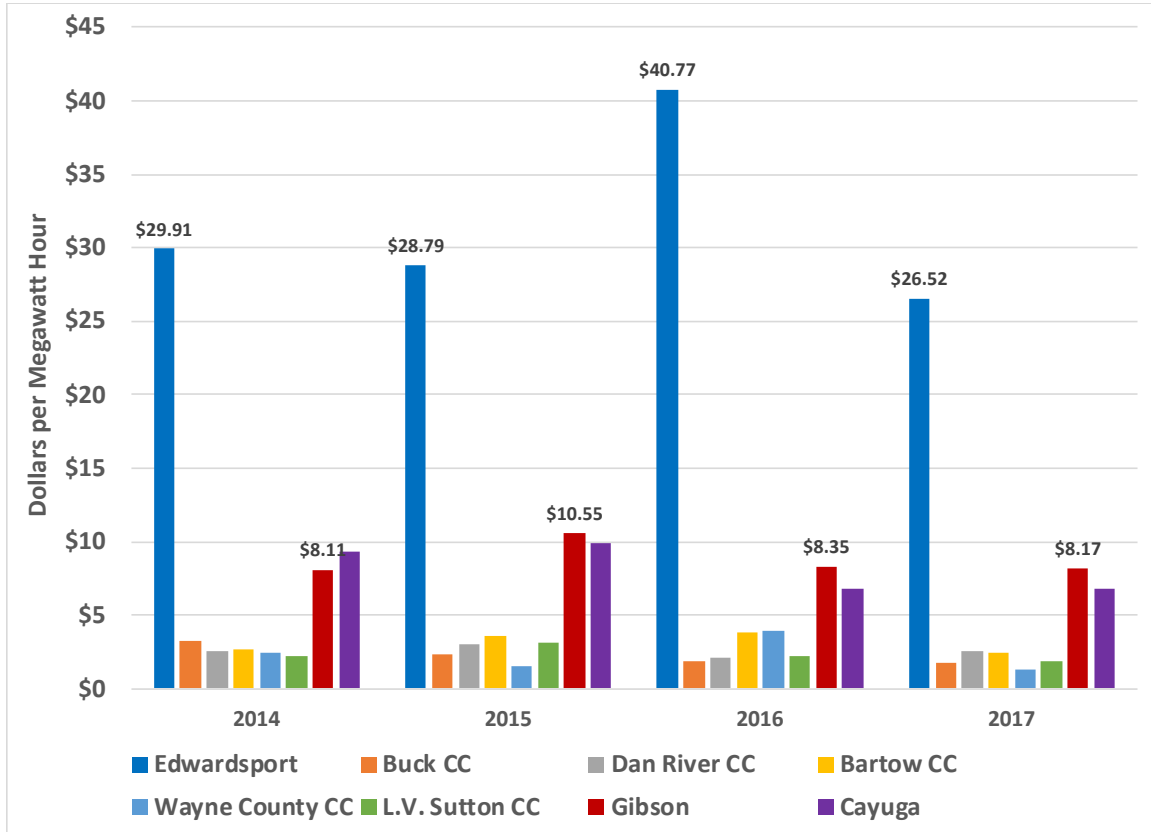
6 **A.** Edwardsport’s non-fuel O&M expenses are much higher than those at other DEI  
7 baseload coal plants and the five new Duke Energy NGCC units completed  
8 between 2009 and 2013.

---

<sup>20</sup> Source – DEI Annual FERC Form 1 filings.

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**Figure 11: Edwardsport Non-Fuel O&M Expenses v. Those of Other DEI Baseload Coal-Fired Plants and Recent Duke NGCC Units<sup>21</sup>**



1 Thus, Edwardsport’s non-fuel O&M expenses are much higher than those at  
2 DEI’s baseload coal and the Duke Energy NGCC units completed between 2009  
3 and 2013.

4 **Q. What is your understanding as to why Edwardsport’s non-fuel O&M is so**  
5 **dramatically higher than that of other DEI baseload coal and the comparable**  
6 **Duke Energy NGCC units?**

7 **A.** It appears that Edwardsport’s extremely high non-fuel O&M costs are due, at  
8 least in large part, to the high cost of operating and maintaining the gasification  
9 systems.

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<sup>21</sup> Costs from annual FERC Form 1 filings and S&P Global Market Intelligence.

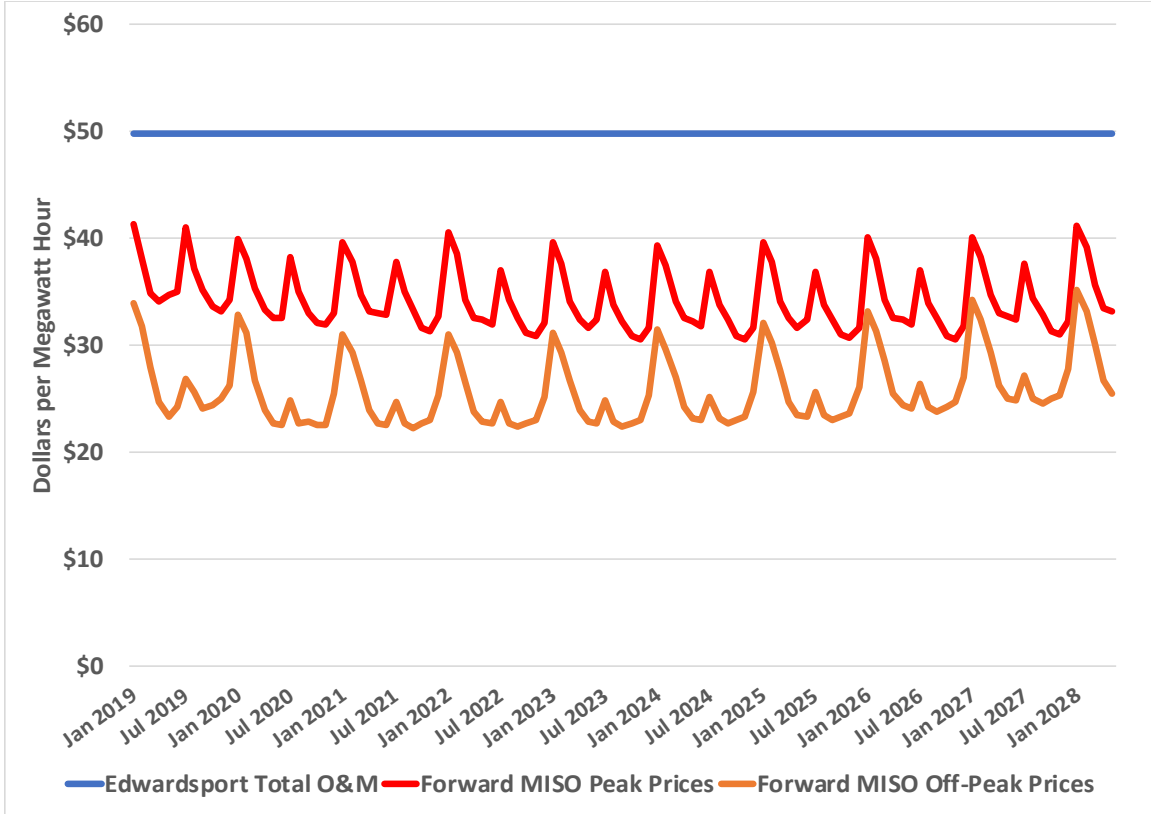
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1 **Q. Given Edwardsport's very high O&M expenses, it is reasonable to expect**  
2 **that the plant will produce a net economic benefit for ratepayers at any time**  
3 **in the foreseeable future?**

4 A. No. As I noted earlier, Duke justified the higher cost of building Edwardsport by  
5 claiming that the day it became operational it would benefit ratepayers by  
6 displacing less efficient and less environmentally friendly units and, thereby  
7 serving to reduce operating costs. Figure 8, above, shows that this has not been  
8 true so far, as the cost of producing power at Edwardsport has been significantly  
9 higher than the cost of purchasing power in the competitive wholesale MISO  
10 markets -- and it is extremely unlikely that producing power at the plant will  
11 become less expensive than purchasing that power from the MISO wholesale  
12 markets at any time in the foreseeable future. Instead, as shown in Figure 12,  
13 below, the cost of producing power at Edwardsport is likely to remain  
14 substantially more expensive than energy market prices even if Edwardsport  
15 O&M costs do not increase in coming years.

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**Figure 12: Edwardsport Total O&M Expenses v. Market Expectations for Future MISO Indiana Hub Energy Prices<sup>22</sup>**



1 Figure 12 shows that operating Edwardsport will continue to be uneconomic  
2 unless the Company is able to reduce its total O&M dramatically and/or energy  
3 market prices increase substantially above current expectations, both of which are  
4 very unlikely to happen in coming years.

5 **Q. Does Figure 12 mean that the cost of producing power from Edwardsport is**  
6 **expected to be higher than the cost of buying power from the MISO market**  
7 **in every hour of each month?**

8 A. No. The forward peak and non-peak prices shown in Figure 12 are averages for an  
9 entire month. There may be hours when it is less expensive to generate power at

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<sup>22</sup> Energy Market Forward Prices are from OTC Global Holdings, as reported by S&P Global Market Intelligence. Downloaded on June 28, 2018.

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1 Edwardsport. However, Figure 12 shows that Edwardsport can be expected to be  
2 the far more expensive source of energy for the Company's ratepayers, on  
3 average, during both peak and the non-peak hours. That is what matters to  
4 ratepayers.

5 **Q. How expensive is the all-in cost of Edwardsport for DEI's ratepayers?**

6 A. The all-in cost of Edwardsport, including Rider 61 revenues and fuel costs, is  
7 extremely expensive for DEI's ratepayers. In just the 55 months between June  
8 2013 and December 2017, ratepayers paid \$1.76 billion for only the 12.3 million  
9 MWh retail share of the generation from the plant during this period, for an  
10 average cost of \$143.19 per MWh.

11 **Q. Does this \$1.76 billion all-in cost reflect what ratepayers paid through Rider  
12 61 before Edwardsport was declared in-service in June 2013?**

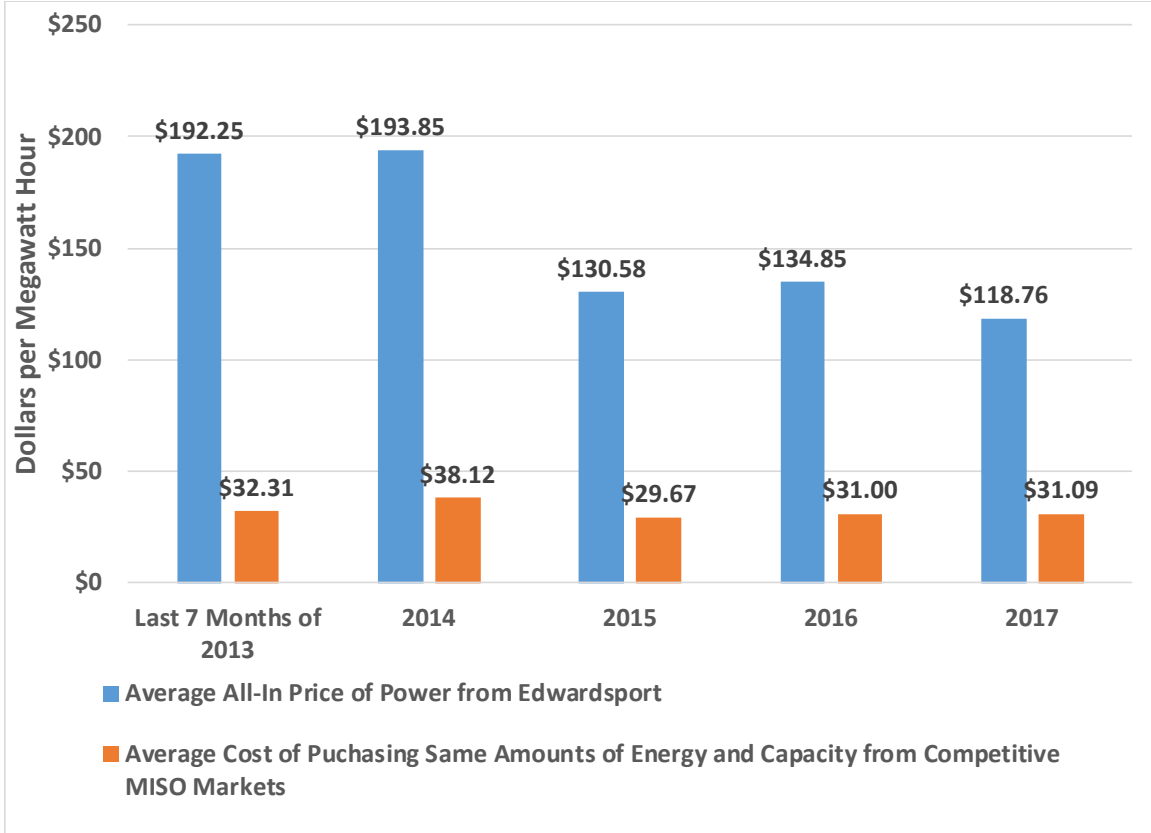
13 A. No. It does not include the \$397 million in Rider 61 costs that the ratepayers paid  
14 for Edwardsport before the plant was declared to be in-service. Including these  
15 costs would increase the average cost for ratepayers to \$175.53 per MWh.

16 **Q. How much more expensive has Edwardsport been compared to MISO energy  
17 market and capacity prices?**

18 A. There are two ways to answer that question. Figure 13, below, compares the  
19 average annual prices per MWh paid by DEI's customers for Edwardsport since  
20 the plant was declared in-service in 2013 to the average annual prices of what it  
21 would have cost to purchase the same amounts of energy and capacity from  
22 MISO markets.

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**Figure 13: Edwardsport’s All-In Cost v. the Cost of Buying the Same Energy and Capacity from MISO Markets (on a \$/MWh Basis)<sup>23</sup>**

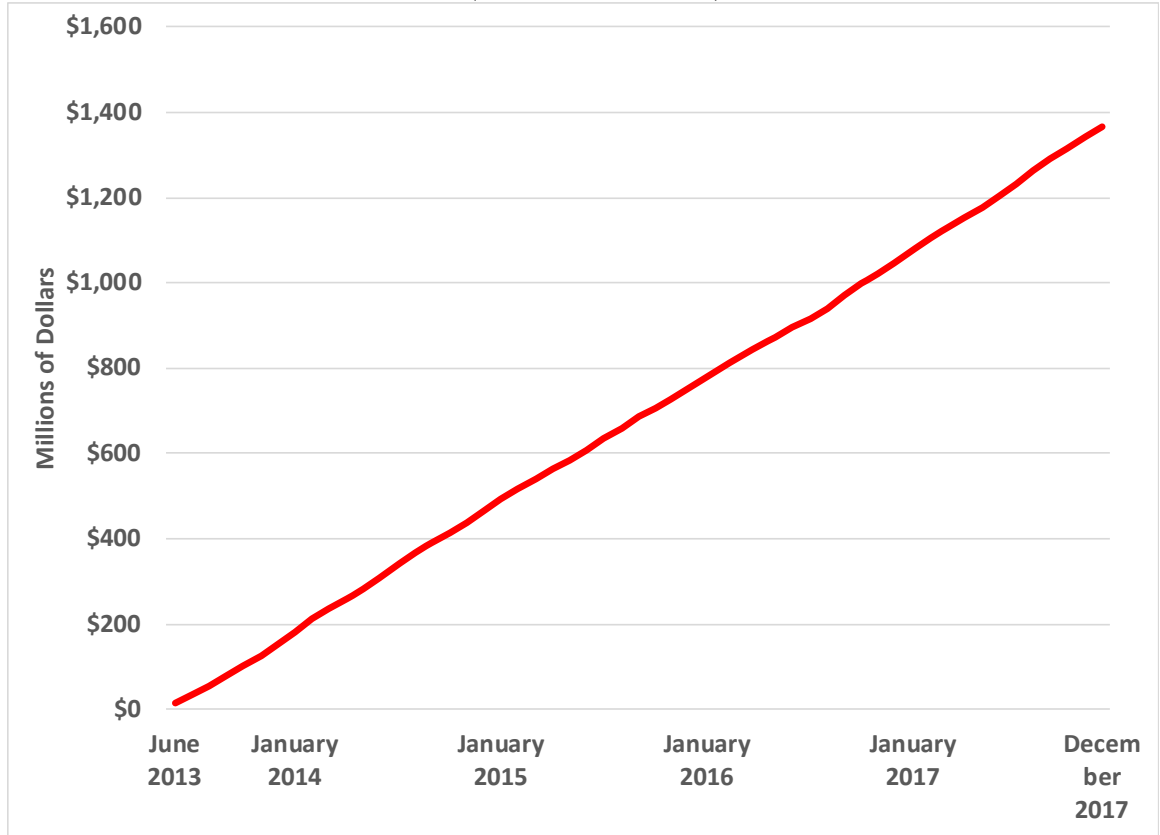


1 Figure 14 then shows the cumulative additional cost that DEI’s ratepayers have  
 2 borne, and continue to bear, due to the higher cost of Edwardsport compared to  
 3 what it would have cost to purchase the same amounts of energy and capacity in  
 4 the MISO markets.

<sup>23</sup> Edwardsport Rider 61 costs from attachments to the Direct Testimony of DEI witness Douglas. Edwardsport fuel costs are from DEI FERC Form 1 filings. MISO energy prices are from S&P Global Market Intelligence. MISO capacity prices are from MISO auction results.

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**Figure 14: Cumulative Net Economic Loss to DEI Ratepayers of Edwardsport's All-In Cost v. the Cost of Buying the Same Energy and Capacity from MISO Markets (in Nominal Dollars)<sup>24</sup>**



1 Figure 14 shows that the cumulative economic loss (or additional costs) that  
2 Edwardsport has imposed on DEI ratepayers was nearly \$1.4 billion through the  
3 end of 2017.

4 It must be emphasized that this \$1.4 billion loss represents only the 55 months  
5 between June 2013 and December 2017. The loss to ratepayers will continue to  
6 grow steadily in coming months and years and will almost certainly be many

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<sup>24</sup> Edwardsport Rider 61 costs from attachments to the Direct Testimony of DEI witness Douglas. Edwardsport fuel costs are from DEI FERC Form 1 filings. MISO energy prices are from S&P Global Market Intelligence. MISO capacity prices are from MISO auction results.

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1 times higher by the time the plant is retired, if it continues to operate through its  
2 planned service life.

3 **Q. Do Figures 13 and 14 reflect the \$397 million that DEI ratepayers paid for**  
4 **Edwardsport before the plant ever generated any power?**

5 A. No. Including those costs would boost the net economic loss to ratepayers as of  
6 the end of December 2017 to nearly \$1.8 billion.

7 **Q. Has Edwardsport produced any positive value for ratepayers?**

8 A. No, quite the contrary. Similar to the Kemper IGCC in Mississippi, building and  
9 operating Edwardsport has been an economic catastrophe for DEI's ratepayers in  
10 that they have paid \$1.37 billion more for the power from the plant than they  
11 would have had to pay for power from alternative sources, such as the MISO  
12 energy markets and capacity auction. And Edwardsport will continue to harm  
13 ratepayers unless the IURC takes effective actions to protect them.

14 **Q. Is it reasonable to expect that this situation will turn around at some point in**  
15 **the future and, consequently, that Edwardsport will produce a net economic**  
16 **benefit for ratepayers?**

17 A. No. Given the disparity in costs shown in Figures 13 and 14, and the expectation  
18 that market prices will remain low for the foreseeable future, there is absolutely  
19 no hope that Edwardsport will turn around and become an economically  
20 beneficial investment for DEI's ratepayers. There also is no hope that the DEI's  
21 ratepayers ever will recover the \$1.37 billion in higher costs they have paid in just  
22 the plant's first 55 months of operations.



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1 **Q. Are there any other factors that are likely to make the relative economics of**  
2 **Edwardsport even worse for DEI ratepayers in coming years?**

3 A. Yes. Design and technological improvements are driving down the costs of wind  
4 and solar resources. As more of these renewable resources are added to the MISO  
5 grid, it is likely that they will affect Edwardsport in two ways. First, their lower  
6 costs and increasing market shares can be expected to keep market clearing prices  
7 at their present levels, if not reduce them, thereby producing an even greater  
8 disparity between the average MISO prices and the cost to produce power at  
9 Edwardsport. Second, the extremely low operating costs of wind and solar  
10 resources will mean that they will be dispatched ahead of fossil-fired units like  
11 Edwardsport and, as a result, will likely displace generation that would otherwise  
12 be produced at Edwardsport.

13 **Q. Please summarize your recommendations.**

14 A. Approving the cost caps called for in the settlement agreement in Consolidated  
15 Cause No. IGCC-15 was a good step in the right direction. However, any  
16 improvements in the plant's operational performance over the past several years  
17 have not begun to address that Edwardsport is clearly an economic catastrophe for  
18 DEI's customers. Thus, I believe it is time for the IURC to take much stronger  
19 actions to protect ratepayers against the plant's grossly excessive costs and to  
20 rebalance ratepayer risks and rewards from the plant. Therefore, I am  
21 recommending that the IURC:

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- 1           1.       “[M]odify or revoke the certificate” for the Plant as the Commission  
2                    should find that continued “implementation of the [clean coal] technology  
3                    will not serve the public convenience and necessity” per IC 8-1-8.7-5, an  
4                    option afforded to the Commission by the legislature to protect ratepayers  
5                    in situations just like this; or
- 6           2.       Require DEI to file a rate case to determine how much of the investment  
7                    in Edwardsport is actually fully “used and useful”; or
- 8           3.       Initiate a special proceeding to consider options that would ensure that the  
9                    fully embedded cost of the electricity from Edwardsport is comparable to  
10                   the cost of alternative sources such as the MISO markets and/or other  
11                   generating facilities on the Company’s system;
- 12       And
- 13       4.       “[R]emove any incentive approved in the order if the commission finds  
14                   that the project no longer complies with the provisions of the order  
15                   concerning the incentive” per IC § 8-1-8.8-15 insofar as DEI is still  
16                   receiving favorable Rider 61 treatment with a historically high rate of  
17                   return despite the clear failures of DEI to reach the milestones and  
18                   performance promised when Rider 61 treatment and incentives were  
19                   awarded; and
- 20       5.       Until the IURC modifies or revokes the CPCN, issues an order in a special  
21                   proceeding, or completes a rate case review of whether Edwardsport is  
22                   actually “used and useful” as recommended above, limit the Company’s  
23                   recovery of non-fuel O&M expenditures at Edwardsport to \$6.74 per  
24                   MWh. This represents the average non-fuel O&M expenditures at the five  
25                   Duke Energy NGCC units presented in Figure 9, below, and DEI’s own  
26                   Gibson and Cayuga baseload coal-fired plants for the years 2014-2017. At  
27                   the same time, the IURC should restrict the Company’s ability to recover  
28                   through rates capitalized Edwardsport maintenance expenditures in 2018

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1 and 2019 to the same limit it approved in IGCC-15 for 2017, i.e. the lesser  
2 of \$16,900,000 or actual expenditures.

3 **Q. What is the basis for your first recommendation that the Commission modify**  
4 **or revoke the CPCN which DEI presently has for Edwardsport as an**  
5 **“energy” and “clean coal technology” project?**

6 A. To my knowledge, Edwardsport is unique in that it has been in commercial  
7 operation since June 7, 2013 but has never been proposed, reviewed, or  
8 incorporated in DEI’s rate base as “used and useful” “plant in service” in a  
9 general rate case pursuant to Ind. Code § 8-1-2-6. Instead, the capital investment  
10 in Edwardsport has continued to be treated for accounting and ratemaking  
11 purposes as “construction work in progress” for which a return is being earned, an  
12 incentive is being paid, and depreciation is being taken as an “energy” and “clean  
13 coal technology” project pursuant to the provisions of Ind. Code § 8-1-8.8-1 *et*  
14 *seq.* I have been advised by CAC’s counsel that Duke, the Commission, and the  
15 other parties to the ongoing IGCC subdocket of Cause No. 43114 interpret Ind.  
16 Code §§8-1-8.7-1 *et seq.*, and 8-1-8.8-1 *et seq.* to authorize this extraordinary  
17 treatment for Edwardsport.

18 In that context, I am reading Ind. Code §§8-1-8.7-1 *et seq.*, and 8-1-8.8-1 *et seq.*  
19 together and as a whole and recognizing that, from the language it chose to  
20 include in the statutes, the Indiana General Assembly has provided that so long as  
21 an “energy” or “clean coal technology” project is being treated for accounting and  
22 ratemaking purposes as “construction work in progress” for which DEI is still  
23 earning a return, being paid an incentive, and taking depreciation through a rider  
24 or tracker such as Rider 61 five years after it was declared to be in commercial  
25 operation but has yet to be proposed, reviewed or included in rate base in a  
26 general rate case, the Commission retains the authority to revoke or modify the  
27 project’s CPCN in accordance with the express provisions of the statutes.

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1 Bottom line, I am simply recommending that the Commission exercise what I  
2 have been advised is its express statutory authority at this critical time to address  
3 the various pressing issues and problems I have discussed in my testimony which  
4 have made Edwardsport an economic catastrophe for DEI ratepayers. The  
5 Commission should take these additional steps authorized by the legislature to  
6 assure “just and reasonable” Rider 61 rates for DEI retail customers and thereby  
7 extending and increasing the share of its ongoing capital and operating costs being  
8 borne by Duke and its shareholders.

9 **Q. What is the basis for the rest of your recommendations?**

10 Similarly, the Company’s previously approved capital investment to date in  
11 Edwardsport has not yet been incorporated in DEI’s rate base pursuant to IC § 8-  
12 1-2-6 because DEI has not had a base rates case since the plant was declared to be  
13 in commercial operation on June 7, 2013.

14 As a result, the Plant is still being categorized as “Construction Work in Progress”  
15 and both its incremental capital costs and its non-fuel O&M costs are being  
16 reviewed and recovered through Rider 61 pursuant to IC 8-1-8.5, IC 8-1-8.7 and  
17 IC 8-1-8.8 rather than through base rates.

18 Pursuant to IC § 8-1-2-48, the Commission is granted the following authority  
19 generally:

20 If, in its inquiry into the management of any public utility, the  
21 commission finds that the amount paid for the services of its  
22 officers, employees, or any of them, is excessive, or that the  
23 number of officers or persons employed by such utility is not  
24 justified by the actual needs of the utility, or that any other item of  
25 expense is being incurred by the utility which is either unnecessary  
26 or excessive, the commission shall designate such item or items,  
27 and such item or items so designated, or such parts thereof as the  
28 commission may deem unnecessary or excessive, shall not be  
29 taken into consideration in determining and fixing the rates which  
30 such utility is permitted to charge for the service which it renders.

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1 Pursuant to IC § 8-1-8.5-6(c), the Commission is also granted the following  
2 authority with respect to ongoing generating facility construction projects:

3 If the commission disapproves of all or part of the construction or  
4 cost of the portion of the facility under review, the commission  
5 may modify or revoke the certificate [of public convenience and  
6 necessity].

7 Similarly, pursuant to IC §§ 8-1-8.7(b) and (d):

8 In addition to the review of the continuing need for the clean coal  
9 technology system under construction prescribed in section 5 of  
10 this chapter, the commission shall at the request of the public  
11 utility maintain an ongoing review of that construction as the  
12 construction proceeds. The applicant shall submit each year during  
13 construction, or at other times as the commission and the public  
14 utility mutually agree, a progress report and any revisions in the  
15 cost estimates for the construction . . . .

16 If the commission disapproves of all or part of the construction or  
17 cost of the part of the clean coal technology system under review,  
18 the commission may modify or revoke the certificate.

19 Thus, as I have been advised by CAC counsel, the Commission plainly has the  
20 authority to revoke or modify the previously approved CPCN for Edwardsport  
21 under the circumstances documented in my testimony. In particular, the current  
22 and projected costs of continued implementation of the IGCC Project are grossly  
23 excessive and unreasonable compared to alternative sources of generation  
24 available to DEI to serve its customers.

25 Moreover, it is my understanding that, pursuant to IC 8-1-8.8, the Commission is  
26 granted authority to approve projected capital maintenance and operating  
27 expenses for “clean coal” technology and energy projects such as Edwardsport  
28 only “if the eligible business provides substantial documentation that the expected

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1 costs and expenses and the schedule for incurring those costs and expenses are  
2 reasonable and necessary.”

3 In addition, it is my understanding that the Commission has the authority in a  
4 Rider 61 proceeding to impose “caps” on both the actual capital maintenance and  
5 non-fuel operating expenses to be incurred for Edwardsport for 2018 and 2019 to  
6 assure they do not exceed levels which are “reasonable and necessary,” just as it  
7 did in IGCC-15 for the period April 2015 through December 2017.

8 **Q. Does this complete your testimony?**

9 A. Yes.

**VERIFICATION**

I, David A. Schlissel, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

David A. Schlissel

David A. Schlissel

July 30, 2018

July 30, 2018

# **ATTACHMENT 1**



## David A. Schlissel

Director of Resource Planning Analysis  
Institute of Energy Economics and Financial Analysis  
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### SUMMARY

I have worked since 1974 as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

### PROFESSIONAL EXPERIENCE

**Electric Resource Planning** - Analyzed the financial and economic costs and benefits of energy supply options. Examined whether there are lower cost, lower risk alternatives than proposed fossil and nuclear power plants. Evaluated the financial, economic and system reliability consequences of retiring existing electric generating facilities. Investigated whether new electric generating facilities are used and useful. Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Assessed the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets.

**Coal-fired Generation** – Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Analyzed the economic and financial risks of making expensive environmental and other upgrades to existing plants. Investigated whether plant owners had adequately considered the risks associated with building new fossil-fired power plants, the most significant of which are the likelihood of federal regulation of greenhouse gas emissions and construction cost increases.

**Power Plant Air Emissions** – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub>. Examined whether new state and federal emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

**Power Plant Water Use** – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proposed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

**Electric System Reliability** - Evaluated whether existing or new generation facilities and transmission lines are needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

**Power Plant Repowering** - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

**Power Plant Operations and Economics** - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

**Nuclear Power** – Reviewed recent cost estimates for proposed nuclear power plants. Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

**Transmission Line Siting** – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

**Electric Industry Regulation and Markets** - Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales, auctions, and power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

**Expert Testimony** - Presented the results of management, technical and economic analyses as testimony in more than 100 proceedings before regulatory boards and commissions in 35 states, before two federal regulatory agencies, and in state and federal court proceedings.

**Litigation and Regulatory Support** - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

## **TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS**

### **West Virginia Public Service Commission (Case No. 17-0296-E-PC) – August 2017**

The reasonableness of Monongahela Power's proposed acquisition of the 1,300 MW Pleasants Power Plant.

### **Indiana Utility Regulatory Commission (Cause No. 44794) – October & December 2016**

The economic viability of proposed environmental upgrades at the Petersburg Power Station.

### **Montana Public Service Commission (Docket Nos. D2013.5.33 and D2014.5.46) – May 2015**

The circumstances surrounding the extended outage of Colstrip Unit 4 from July 1, 2013 through January 23, 2014.

### **Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 12 & 13) – December 2014**

Whether Duke Energy Indiana's Edwardsport IGCC Project was in service between June 7, 2013 and March 31, 2014 and the Project's current operational performance and cost status and future prospects.

### **Public Service Commission of West Virginia (Case No. 14-0546-E-PC) – August 2014**

The reasonableness of American Electric Power's proposed transfer of 50 percent of the Mitchell Coal Plant to its regulated affiliates in West Virginia.

### **Mississippi Public Service Commission (Docket No. 2013-UN-189) – March and June 2014**

The prudence of Mississippi Power Company's management of the planning for the Kemper County IGCC Plant.

### **Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 8, 10, and 12) – June 2012, April 2013 and April 2014**

Startup and pre-operational testing delays at Duke Energy Indiana's Edwardsport IGCC Project.

### **Public Service Commission of West Virginia (Case No. 12-1655-E-PC) – June 2013 and July 2013**

The reasonableness of Appalachian Power Company's proposed acquisition of 2/3 of Unit 3 of the John E. Amos power plant and 1/2 of the two unit Mitchell power plant.

### **Public Service Commission of West Virginia (Case No. 12-1571-E-PC) – April 2013**

The reasonableness of Monogahela Power Company's proposed acquisition of 80 percent of the Harrison Power Station.

### **Virginia State Corporation Commission (Case No. PUE-2012-00128) – March 2013**

Whether Dominion Virginia Power's proposed Brunswick Project natural gas-fired combined cycle power plant is needed and in the public interest.

### **Arizona Corporation Commission (Docket No. E-01922A-12-0291 – December 2012**

Reasonableness of Tucson Electric Power's proposed Environmental Compliance Adjustor mechanism.

**U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR and 50-286-LR) – June 2012**  
Reply to testimony filed by Entergy Nuclear and NRC Staff concerning the relicensing of Indian Point Units 2 and 3.

**Mississippi Public Service Commission (Docket No. 2009-UA-014) – March 2012**  
Petition to Reopen the docket for the Kemper County IGCC Plant based on changed circumstances.

**Mississippi Public Service Commission (Docket No. 2009-UA-279) – February 2012**  
The financial and economic risks of retrofitting Mississippi Power Company's Plant Daniel Coal Plant.

**Georgia Public Service Commission (Docket No. 34218) – November 2011**  
The reasonableness of Georgia Power Company's proposed fossil plant decertification/retirement plan.

**Missouri Public Service Commission (Case No. EO-2011-0271) – October 2011**  
Reasonableness of Ameren Missouri's 2011 Integrated Resource Plan filing.

**Maryland Public Service Commission (Case No. 9271) – October 2011**  
The reasonableness of Constellation Energy Group's proposed divestiture of three coal-fired power plants as mitigation for market power concerns arising from its proposed merger with Exelon Corporation.

**Minnesota Public Utilities Commission (Docket No. E017/M-10-1082) – August and September 2011**  
Whether the proposed addition of the Big Stone Plant Air Quality Control System is a lower cost alternative for the ratepayers of Otter Tail Power Company than retirement of the Plant and replacement by a natural gas-fired combined cycle unit possibly combined with new wind capacity.

**Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – June, July, and October 2011 and June 2012**  
Duke Energy Indiana's imprudence and gross mismanagement of Edwardsport IGCC Project.

**Kansas State Corporation Commission (Docket No. 11-KCPE-581-PRE) – June 2011**  
The reasonableness of the proposed environmental upgrades at the La Cygne Generating Station Units 1 and 2.

**Arizona Corporation Commission (Docket No. E-01345A-10-0474) – May 2011**  
The reasonableness of Arizona Public Service Company's proposed acquisition of Southern California Edison's share of Four Corners Units 4 and 5.

**Public Utility Commission of Colorado (Docket No. 10M-245E) – September, October and November 2010**  
The reasonableness of Public Service of Colorado's proposed Emissions Reduction Plan.

**Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – July, November and December 2010**

The reasonableness of Duke Energy Indiana’s new analyses of the economics of completing the Edwardsport Project as an IGCC plant.

**Oregon Public Utility Commission (Docket LC 48) – May and August 2010**

Comments and Reply Comments on Portland General Electric Company’s 2009 Integrated Resource Plan.

**South Dakota Public Service Commission (Docket No. EL-09-018) – April 2010**

The reasonableness of Black Hills Power Company’s 2007 Integrated Resource Plan and the Company’s decision to build the Wygen III coal-fired power plant.

**Michigan Public Service Commission (Docket No. U-16077) – April 2010**

Comments on the City of Holland Board of Public Works’ 2010 Power Supply Study.

**Illinois Commerce Commission (Tenaska Clean Coal Facility Analysis) – April 2010**

Comments on the Facility Cost Report for the proposed Taylorville IGCC power plant.

**North Carolina Utilities Commission (Docket No. E-100, Sub 124) – February 2010**

The reasonableness of the 2009 Integrated Resource Plans of Duke Energy Carolinas and Progress Energy Carolinas.

**Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009**

The costs and risks associated with the proposed Kemper County IGCC power plant.

**Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009 and January 2010**

The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

**Public Service Commission of Wisconsin (Docket No. 05-CE-138) –September and October 2009**

The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

**Public Service Commission of Michigan (Docket No. U-15996) – July 2009**

Comments on Consumer Energy’s Electric Generation Alternatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant.

**Public Service Commission of Michigan (Docket No. U-16000) – July 2009**

Comments on Wolverine Power Cooperative’s Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant.

**Georgia Public Service Commission (Docket No. 27800-U) – December 2008**

The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

**Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and September 2008**

The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

**Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008**

The estimated cost of Duke Energy Indiana's Edwardsport Project.

**Public Service Commission of Maryland (Case 9127) – July 2008**

The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

**Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007**

AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

**U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009**

The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

**West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007**

Appalachian Power Company's application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

**Iowa Utility Board (Docket No. GCU-07-01) – October 2007**

Whether Interstate Power & Light Company's adequately considered the risks associated with building a new coal-fired power plant and whether that Company's participation in the proposed Marshalltown plant is prudent.

**Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007**

Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

**Louisiana Public Service Commission (Docket No. U-30192) – September 2007**

The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

**Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007**

The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

**North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008**

Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

**Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007**

The appropriate carbon dioxide (“CO<sub>2</sub>”) emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana’s proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

**Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – May and June 2007**

Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

**Florida Public Service Commission (Docket No. 070098-EI) – March 2007**

Florida Light & Power Company’s need for and the economics of the proposed Glades Power Park.

**Michigan Public Service Commission (Case No. 14992-U) – December 2006**

The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

**Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008**

Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

**North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007**

Duke’s need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

**New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006**

Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

**Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006**

Whether APS’s acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

**U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006**

Quantification of plaintiff’s business losses during an extended power plant outage and plaintiff’s business earnings due to the shortening and delay of future plant outages.

[Confidential Expert Report]

**Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006**

**South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006**

Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

**Georgia Public Service Commission (Docket No. 22449-U) – May 2006**

Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

**California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006**

The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

**New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006**

Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

**Virginia State Corporation Commission (Case No. PUE-2005-00018) – November 2005**

The siting of a proposed 230 kV transmission line.

**Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005**

The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

**New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005**

The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

**Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005**

Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

**Maine Public Utilities Commission (Docket No. 2005-17) – July 2005**

Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.



**Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005**  
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

**Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005**  
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

**Maine Public Utilities Commission (Docket No. 2004-771) – March 2005**  
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

**United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)**  
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company. [Confidential Expert Report]

**New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005**  
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

**Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005**  
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

**California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005**  
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

**United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004**  
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation. [Confidential Expert Report]

**California Public Utilities Commission (Application No. AO4-01-009) – August 2004**  
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

**Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004**

Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

**Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004**

Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

**Connecticut Siting Council (Docket No. 272) – May 2004**

Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

**Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004**

Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

**State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004**

Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

**State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003**

The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

**Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004**

Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

**New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003**

The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

**Wisconsin Public Service Commission (Case 6690-UR-115) - September and October 2003**

The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

**Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003**

Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

**Arkansas Public Service Commission (Docket 02-248-U) – May 2003**

Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

**Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003**

The physical nature of electricity and whether electricity is a tangible product or a service.

**Maine Public Utilities Commission (Docket 2002-665-U) – April 2003**

Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

**Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003**

Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

**New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003**

The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

**New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003**

The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

**Arizona Corporation Commission (Docket No. E-01345A-01-0822) – May 2002**

The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002**

Repowering NYPA's existing Poletti Station in Queens, New York.

**Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003**

Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

**Vermont Public Service Board (Case No. 6545) – January 2002**

Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

**Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001**

The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

**Connecticut Siting Council (Docket No. 208) – October 2001**

Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

**New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001**

The market power implications of the proposed merger between Conectiv and Pepco.

**Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001**

Commonwealth Edison Company's management of its distribution and transmission systems.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001**

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The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

**New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001**

The market power implications of the proposed merger between FirstEnergy and GPU Energy.

**Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000**

The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

**Illinois Commerce Commission (Docket 00-0361) - August 2000**

The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

**Vermont Public Service Board (Docket 6300) - April 2000**

Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

**Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000**

The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

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The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

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Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

**Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998**  
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

**Arkansas Public Service Commission (Docket 98-065-U) - October 1998**  
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

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Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

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Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

**Illinois Commerce Commission (Docket 97-0015) - May 1998**  
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

**Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998**

The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

**Illinois Commerce Commission (Docket 97-0018) - March 1998**

Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997**

The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

**New Jersey Board of Public Utilities (Docket ER96030257) - August 1996**

Replacement power costs during plant outages.

**Illinois Commerce Commission (Docket 95-0119) - February 1996**

Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

**Public Utility Commission of Texas (Docket 13170) - December 1994**

Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

**Public Utility Commission of Texas (Docket 12820) - October 1994**

Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

**Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994**

The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

**Public Utility Commission of Texas (Docket 12700) - June 1994**

Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

**Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994**

Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

**Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994**

Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

**Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993**

Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

**Public Utility Commission of Texas (Docket 11735) - April and July 1993**

Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995**

Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

**Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992**

United Illuminating Company off-system capacity sales. [Confidential Testimony]

**Public Utility Commission of Texas (Docket 10894) - August 1992**

Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992**

Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

**California Public Utilities Commission (Docket 90-12-018) - November 1991, April 1992, June and July 1993**

Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

**Public Utility Commission of Texas (Docket 9945) - June 1991**

Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

**Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991**  
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

**New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990**  
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

**Public Utility Commission of Texas (Docket 9300) - June and July 1990**  
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

**Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989**  
Boston Edison's corporate management of the Pilgrim Nuclear Station.

**Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989**  
United Illuminating Company's off-system capacity sales.

**Kansas State Corporation Commission (Case 164,211-U) - April 1989**  
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

**Public Utility Commission of Texas (Docket 8425) - March 1989**  
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

**Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989**  
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

**New Mexico Public Service Commission (Case 2146, Part II) - October 1988**  
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Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.



**Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989**

Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

**Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988**

Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

**Illinois Commerce Commission (Docket 87-0695) - April 1988**

Illinois Power Company's planning for the Clinton Nuclear Station.

**North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988**

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**Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987**

Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

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**New York State Public Service Commission (Case 29484) - May 1987**

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**Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987**

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**Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986**

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**Arizona Corporation Commission (Docket U-1345-85) - February 1986**

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**New York State Public Service Commission (Case 29124) – December 1985 and January 1986**

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A performance standard for the Shoreham nuclear power plant.

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*Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities*. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

*Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants*. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

*Determining the Need for Proposed Overhead Transmission Facilities*. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

*Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station*. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

*PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002.* An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

*Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants.* A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

*Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities,* on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

*The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability.* A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

*Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line.* A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

*ISO New England's Generating Unit Availability Study: Where's the Beef?* A Presentation at the June 29, 2001 Restructuring Roundtable.

*Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability.* A Synapse Report for the Clean Air Task Force. May 2001.

*Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability.* A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

*Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market,* a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

*Cost, Grid Reliability Concerns on the Rise Amid Restructuring,* with Charlie Harak, Boston Business Journal, August 18-24, 2000.

*Report on Indian Point 2 Steam Generator Issues,* Schlissel Technical Consulting, Inc., March 10, 2000.

*Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company,* October 28, 1999.

*Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation,* February 1997.

*Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant,* August 1996.

*Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs,* May, 1996.

*Nuclear Power in the Competitive Environment,* NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

*Nuclear Power in the Competitive Environment*, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

*The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations*, a report for the Environmental Law and Policy Center of the Midwest, 1995.

*Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs*, July 15, 1992.

*Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2*, December 1991.

*Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas*, April 1991.

*Nuclear Power Plant Construction Costs*, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

*Comments on the Final Report of the National Electric Reliability Study*, a report for the New York State Consumer Protection Board, February 27, 1981.

## **OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK**

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.



Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

## **WORK HISTORY**

- 2012- Director of Resource Planning Analysis, Institute for Energy Economics and Financial Analysis
- 2010 - President, Schlissel Technical Consulting, Inc.
- 2000 - 2009: Senior Consultant, Synapse Energy Economics, Inc.
- 1994 - 2000: President, Schlissel Technical Consulting, Inc.
- 1983 - 1994: Director, Schlissel Engineering Associates
- 1979 - 1983: Private Legal and Consulting Practice
- 1975 - 1979: Attorney, New York State Consumer Protection Board
- 1973 - 1975: Staff Attorney, Georgia Power Project

## **EDUCATION**

1983-1985: Massachusetts Institute of Technology  
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,  
Juris Doctor

1969: Stanford University  
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology  
Bachelor of Science in Astronautical Engineering,

## **PROFESSIONAL MEMBERSHIPS**

- New York State Bar since 1981