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 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	) **CAUSE NO. 43114 IGCC-17**

IURC
INTERVENOR'S - CAC
EXHIBIT NO. 1
12-14-18
DATE REPORTER

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

JULY 31, 2018

CONFIDENTIAL INFORMATION REDACTED

INTRODUCTION

Q. Please state your name and business address.

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

Q. On whose behalf are you testifying?

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

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

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

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

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

A copy of my current resume is included as Attachment DAS-1. Additional information about my work is available at www.schlissel-technical.com.

Q. Have you testified previously before this Commission?

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

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

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

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

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

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your principal conclusions.

A. My principal conclusions are as follows:

1. Edwardsport was planned and proposed to the IURC as an integrated gasification combined cycle ("IGCC") plant that would burn gasified coal ("syngas").

2. By any reasonable measure such as heat rate, capacity factor, equivalent forced outage rate and availability on syngas, Edwardsport's operating

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

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

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

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

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

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

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

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

5. There are a number of factors that show that Edwardsport's operating performance, especially on syngas, should not be expected to improve significantly in the foreseeable future.

   a. The plant continues to lose a significant portion of its potential generation due to gasifier equipment problems, leading to its extremely poor 40 percent capacity factor on syngas during its first 55 months of operations, far below the 79 percent average capacity factor on syngas for this period projected by Duke.

   b. Edwardsport's gasification system equipment continues to operate inconsistently and unreliably.

   c. The plant continues to have extremely high parasitic loads and high equivalent forced outage rates.

   d. The plant's heat rate continues to be extremely high.

   e. The Company plans to continue to conduct both spring and fall maintenance outages in coming years, maintaining a pattern of expensive frequent outages to address essential repairs.

   f. The plant continues to have a seasonal derate in the summer months of June through September.

   g. The Company is still unable to offer into the MISO markets the plant's maximum output of 618 MW during the non-summer months, and 595 MW during the summer months.

6. Edwardsport's generation so far in 2018 offers no evidence that its operating performance is improving. The plant has achieved only a 38 percent capacity factor on syngas during the first five months of the year, with only a 70 percent capacity factor on all fuels. Meanwhile, it continued to have a 26 percent parasitic load while operating on syngas.

7. Edwardsport is very expensive to operate and maintain, with total operating and maintenance ("O&M") costs that ranged between $73.33 per MWh in 2014 to $49.84 per MWh in 2017. These costs do not reflect the retail share of any fixed costs associated with the plant's construction costs or the retail share of capitalized maintenance expenditures. This is far more expensive than:

a. The cost of generating power at DEI's Gibson and Cayuga baseload coal plants; and

b. Buying power in the wholesale MISO markets; and

c. The cost of producing electricity at any of the five new natural gas-fired combined cycle plants built by DEI's Duke Energy affiliates between 2009 and 2013.

8. The high cost of producing power at Edwardsport has been due to its extremely high non-fuel operating and maintenance expenses, as its fuel costs have been relatively low in recent years.

a. In fact, Edwardsport's non-fuel O&M expenses are much higher than those at other DEI baseload coal plants and the five new Duke Energy natural gas-fired combined cycle units completed between 2009 and 2013.

b. It appears that Edwardsport's extremely high non-fuel O&M costs are due, at least in large part, to the inconsistent and unreliable operation of its gasification systems, that is, the systems responsible for gasifying the coal for production of synthetic gas, and to the high cost of operating and maintaining those systems.

9. Given Edwardsport's very high O&M expenses, it is not reasonable to expect that the plant will produce a net economic benefit for ratepayers at any time in the foreseeable future.

a. The cost of operating and maintaining Edwardsport, without considering any capitalized expenditures, can be expected to remain significantly above both average monthly peak and off-peak energy market prices for at least the next ten years, although there may be some individual hours when it will be less expensive to generate power at the plant.

b. The all-in cost of Edwardsport, including Rider 61 revenues and fuel costs, averaged $143.19 per MWh for DEI's ratepayers during the 55 months between June 2013 and December 2017. Consequently, ratepayers have paid $1.76 billion for only 12.3 million MWh from the plant.

c. This $1.76 billion paid by ratepayers between June 2013 and December 2017 does not include the $397 million in Rider 61 costs that ratepayers paid for Edwardsport before the plant was declared to be in-service. Including those costs would increase the average cost for ratepayers from $143.19 per MWh to $175.53 per MWh.

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

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

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

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

Q. Please summarize your recommendations.

A. Approving the cost caps in the settlement agreement in Consolidated Cause 43114 IGCC-15 was a good step in the right direction. However, any operational improvement over the past few years still has not begun to address that Edwardsport has been and continues to be an economic catastrophe for DEI's customers. I believe it is time for the IURC to take much stronger actions to protect ratepayers against the plant's grossly excessive costs and to rebalance ratepayer risks and rewards from the plant. Therefore, I am recommending that the IURC:

1. "[M]odify or revoke the certificate" for the Plant as the Commission should find that continued "implementation of the [clean coal] technology will not serve the public convenience and necessity" per IC § 8-1-8.7-5, an option afforded to the Commission by the legislature to protect ratepayers in situations just like this; or

2. Require DEI to file a rate case to determine how much of the investment in Edwardsport is actually fully "used and useful"; or

3. Initiate a special proceeding to consider options that would ensure that the fully embedded cost of the electricity from Edwardsport is comparable to the cost of alternative sources such as the MISO markets and/or other generating facilities on the Company's system;

and

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

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

EDWARDSPORT OPERATIONS IN 2017

Q. Do you agree with Duke witness Gurganus' testimony that Edwardsport achieved "strong" operations in 2017?[1]

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

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

[1] Direct Testimony of Cecil T. Gurganus, Petitioner's Exhibit 1, at page 3, lines 5-6.

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

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

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

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

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2 Direct Testimony of Jack L. Stultz, IURC Cause No. 43114, IGCC-14, at page 14, line 17, to page 15, line 5.

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

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

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

1. An average 60 percent capacity factor on syngas, and
2. An average 73 percent capacity factor on both syngas and natural gas,

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

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

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

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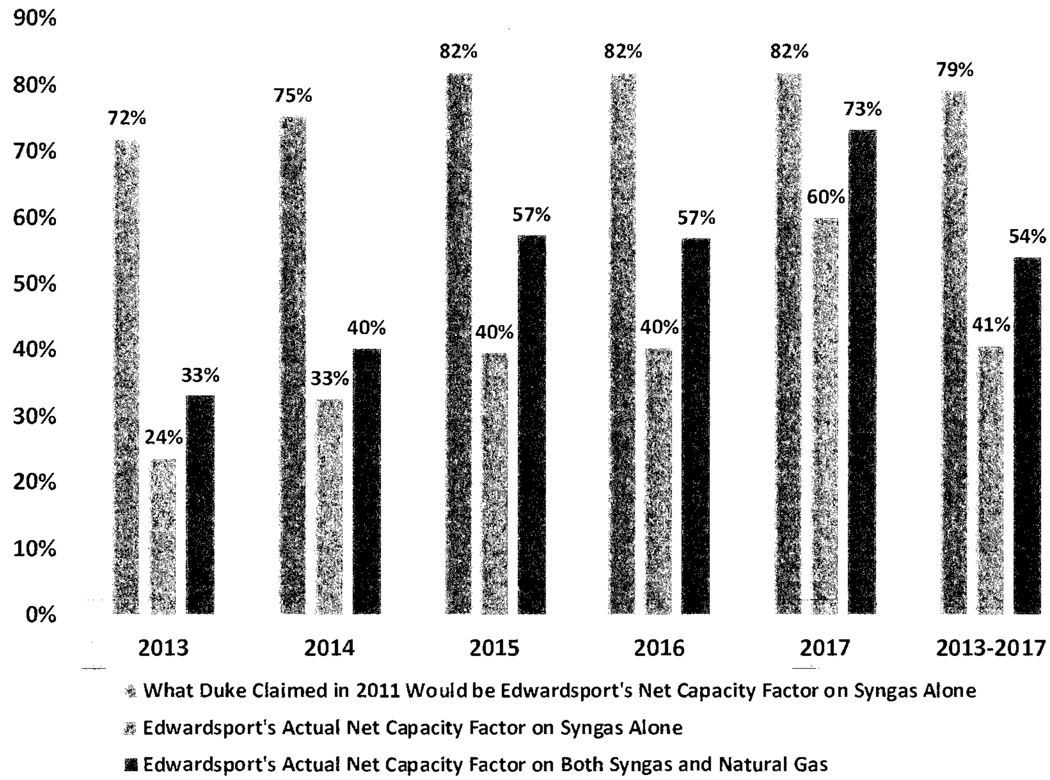
Figure 1: Edwardsport's Calendar Year and Cumulative Net Capacity Factors on Syngas for the Months of June 2013 through December 2017.[3]



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

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

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[3] Sources for the data in Figure 1 include Duke's testimony and filings in IGCC proceedings and the Edwardsport data from EIA Form 923.

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

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

Q. Please explain why the net generation from Edwardsport into the grid is so important to DEI's ratepayers.

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

Q. Why has Edwardsport's net capacity factor been so poor?

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

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4 Supplemental Testimony 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.

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

The Company's submission to the NERC GADS database for 2017 showed that a substantial number of equipment problems caused Edwardsport to operate at reduced power levels reductions (called "derates") during the year. These power derates led to the loss of slightly over [redacted] MWh of potential plant generation. Duke has attributed [redacted] of these lost MWh to "Gasification equipment problems."

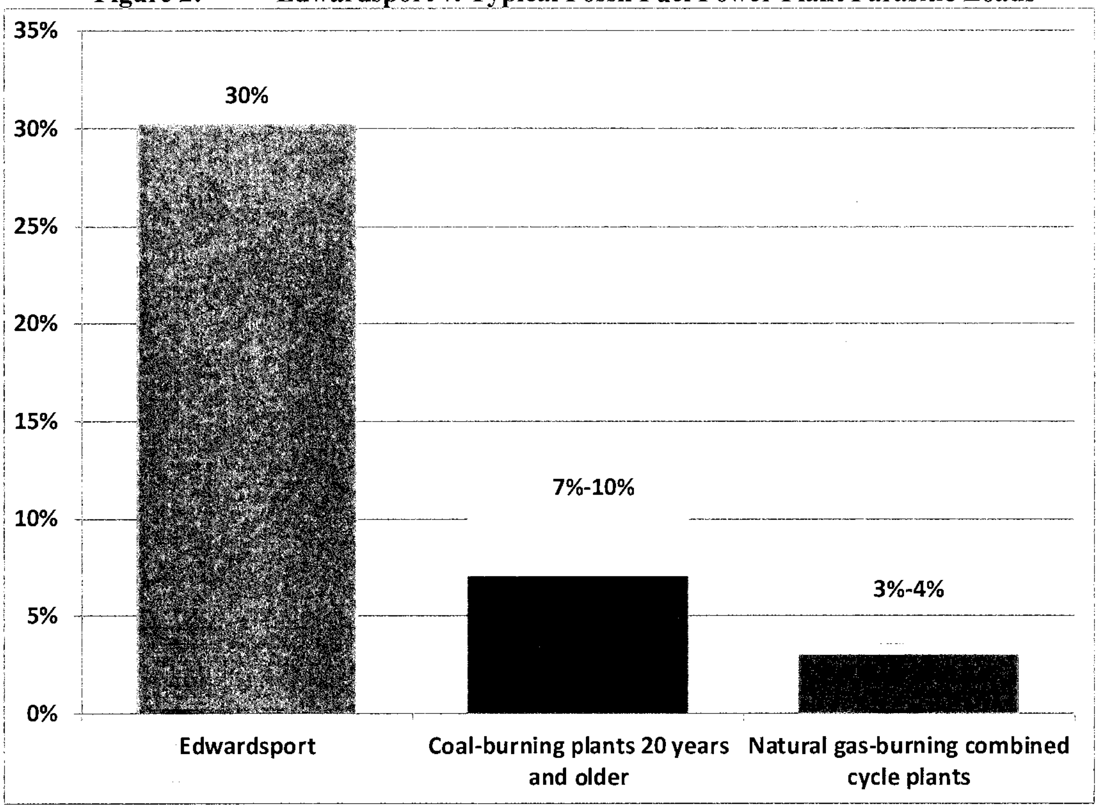
Q. What is the significance of the high parasitic loads that you mentioned earlier?

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

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

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

Figure 2: Edwardsport v. Typical Fossil Fuel Power Plant Parasitic Loads[5]



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

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

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5 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.

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

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

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

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

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

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

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

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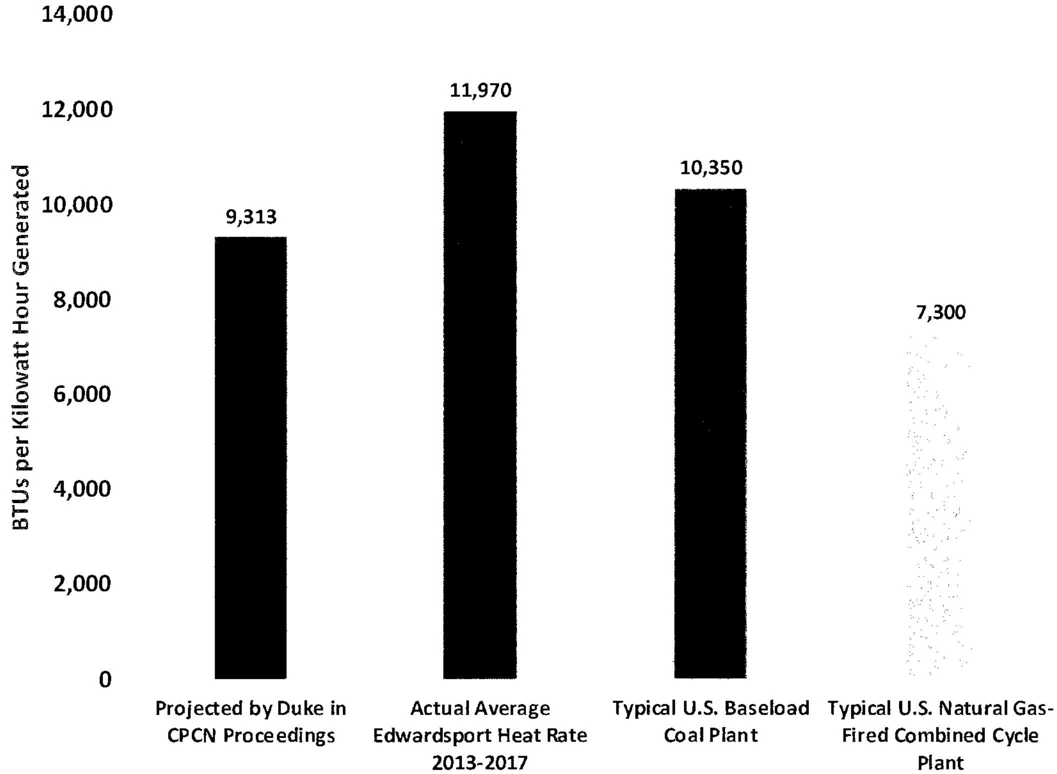
6 Direct Testimony of W. Michael Womack in IGCC-4S-1, filed in April 2010, at page 36.

Figure 3: Edwardsport's Actual Average Heat Rate vs. the 9,313 BTU/KWh Plant Heat Rate Projected by Duke[7] [8]



Q. Did Edwardsport operate at a consistently high power level in 2017?

A. No. The plant's performance remained inconsistent in 2017, and it never achieved its 618 MW net full power net capacity rating at any time during the year.

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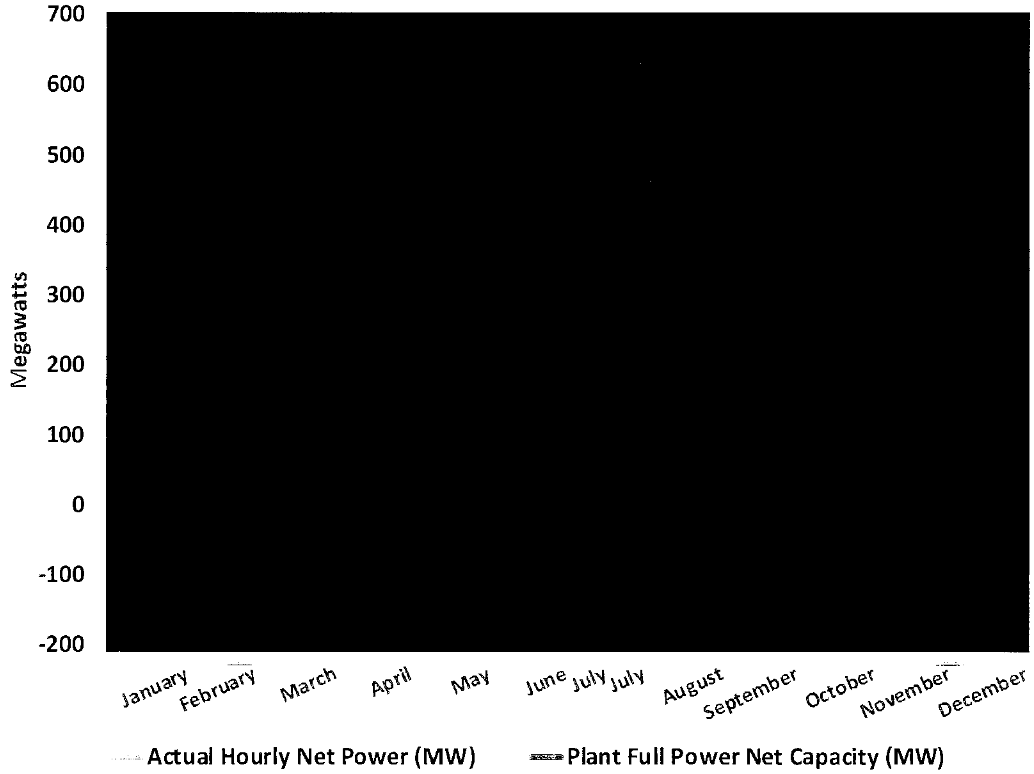
[7] Edwardsport's actual station heat rates are provided in Duke Energy Indiana's annual FERC Form 1 filings.

[8] 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.

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



Thus, during 2017:

- Edwardsport never achieved its 618 MW net full power rated capacity at any time during the year.
- The highest capacity Edwardsport generated in 2017 was [redacted] MW and that was for only a single hour on February 17th.
- The plant generated [redacted] or more MW for only [redacted] hours in 2017, all of which were on February 16 and 17.

9 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.

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

A. Yes. The plant is limited to a net full power capacity output of 595 MW during the months of June through September.[10]

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

In contrast, the plant's net power output was [redacted] MW or less in 759 hours, or 26 percent, of the 2,928 hours in the four months. And the plant's net power output was less than [redacted] MW in 349 hours, or twelve percent, of the 2,928 hours in the four months.

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

A. No. [redacted][11]

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[10] Testimony of Duke witness Swez in Docket FAC-114, at Transcript page A-33, line 22.

[11] Data from Duke's response to CAC1.26, Confidential Attachment 1.26-A, which is included in my workpapers submission.

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

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

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

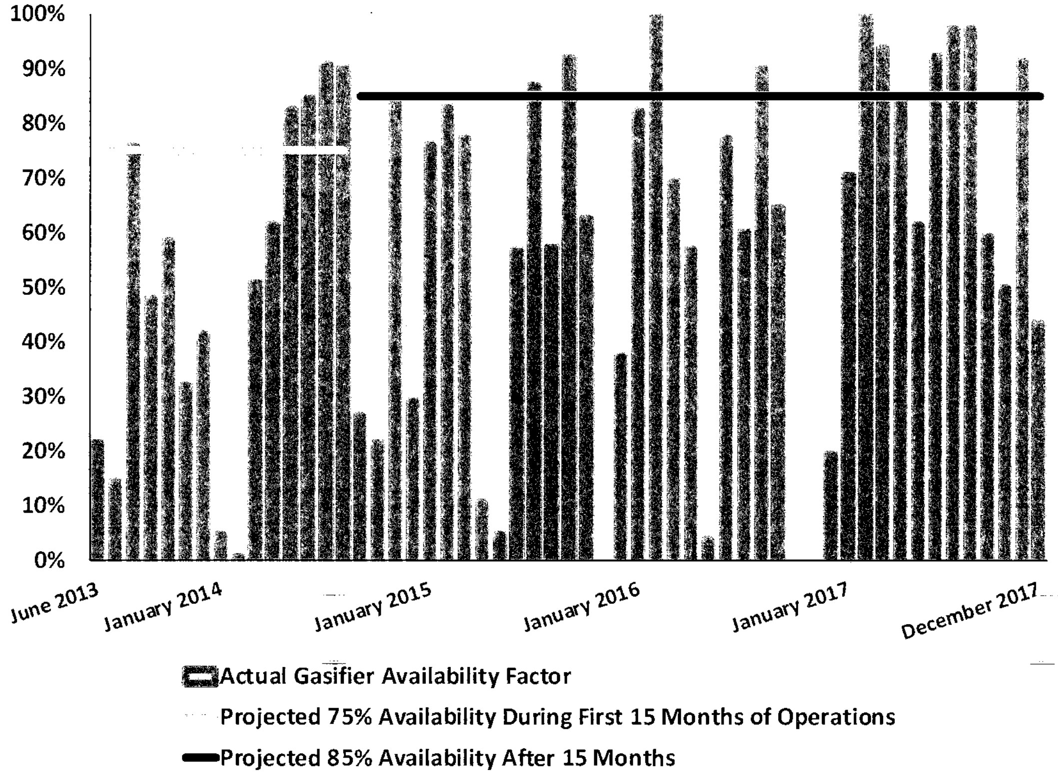
A. Edwardsport's gasifier availability averaged only 57 percent during the plant's first 55 months of commercial operations, far below the 82 percent average availability Duke represented to the IURC it would achieve.[12]

Q. In how many months has Edwardsport's gasifier availability actually reached or exceed 85 percent?

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

[12] 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.

Figure 5: Edwardsport's Monthly Gasifier Availability from June 2013 through December 2017[13]



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

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

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13 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.

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

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

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

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

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

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

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

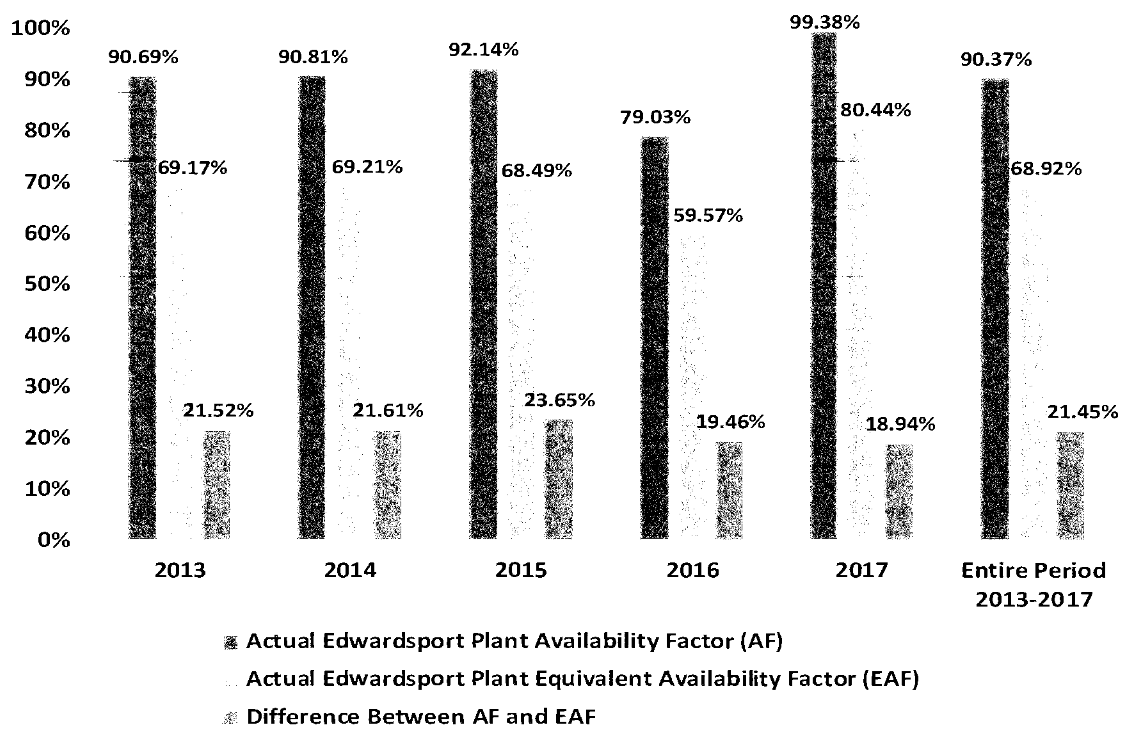
Q. Has Duke provided Edwardsport's gasifier equivalent availability?

A. No. The Company has only provided the equivalent availability for the entire plant. It has not provided the equivalent availability for just the gasification systems. Looking at equivalent availability is important because it provides a complete picture of how much of the time the plant had to reduce its power output because of gasifier equipment problems and not just the times when it had to disconnect from the grid.

Q. Do the availability and equivalent availability for the entire Edwardsport plant give an approximate "ballpark" sense of what the equivalent availability might have been for just the gasification system?

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

Figure 6: Edwardsport's Overall Availability and Equivalent Availability[14]



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[14] 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.

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

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

A. Duke's response to data request CAC 1.26-A Confidential [redacted]

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

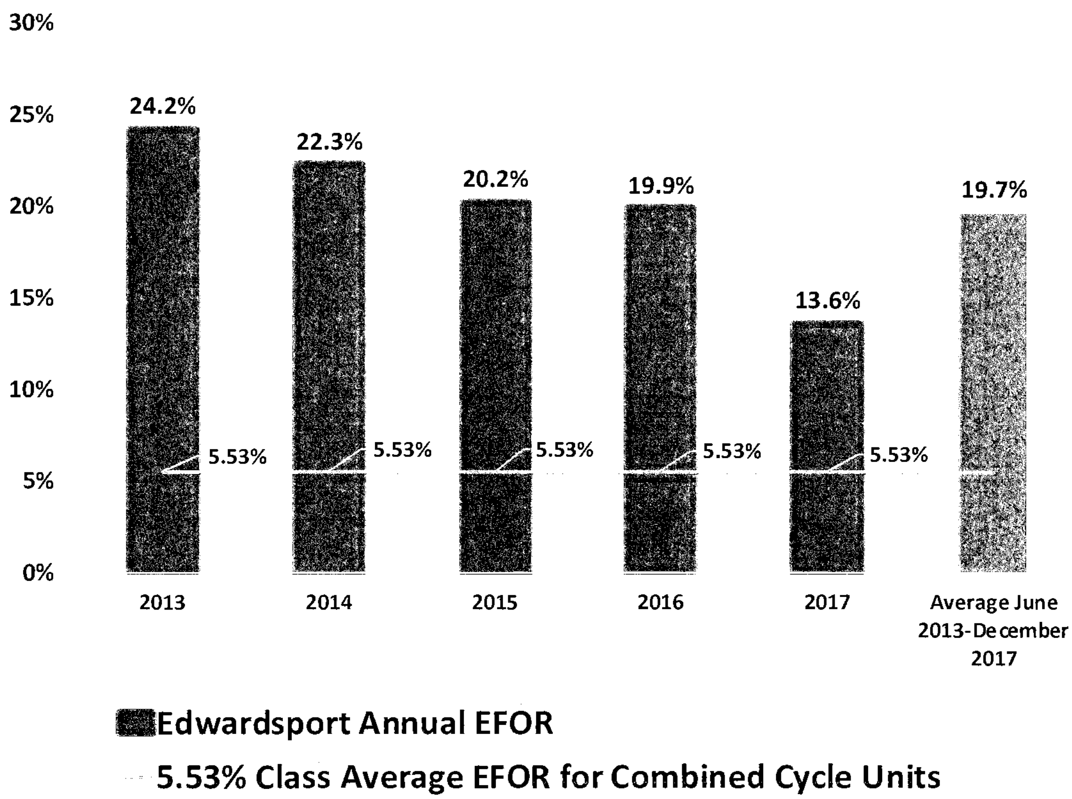
A. Yes. Another commonly accepted measure for evaluating a power plant's operating performance is its Equivalent Forced Outage Rate ("EFOR"). EFOR is a measure of the probability that a unit will not be available due to both (1) forced outages when the entire plant is forced out of service and (2) deratings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

Q. How does Edwardsport's EFOR compare to that of comparable power plants?

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

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

Figure 7: Edwardsport's Equivalent Forced Outage Rate (EFOR) vs. Relevant Industry Comparison Group's EFOR.[15]



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

15 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.

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

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

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

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

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

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

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

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

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

EDWARDSPORT'S IMPACT ON DUKE ENERGY INDIANA'S RATEPAYERS

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

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

Table 1
The Operating and Maintenance (O&M) Cost of Producing Power at Edwardsport[16]

	2014	2015	2016	2017
Total O&M Expense per MWh	**$73.33**	**$55.85**	**$64.36**	**$49.84**

16 Source Annual DEI FERC Form 1 Filings.

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

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

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

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

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

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

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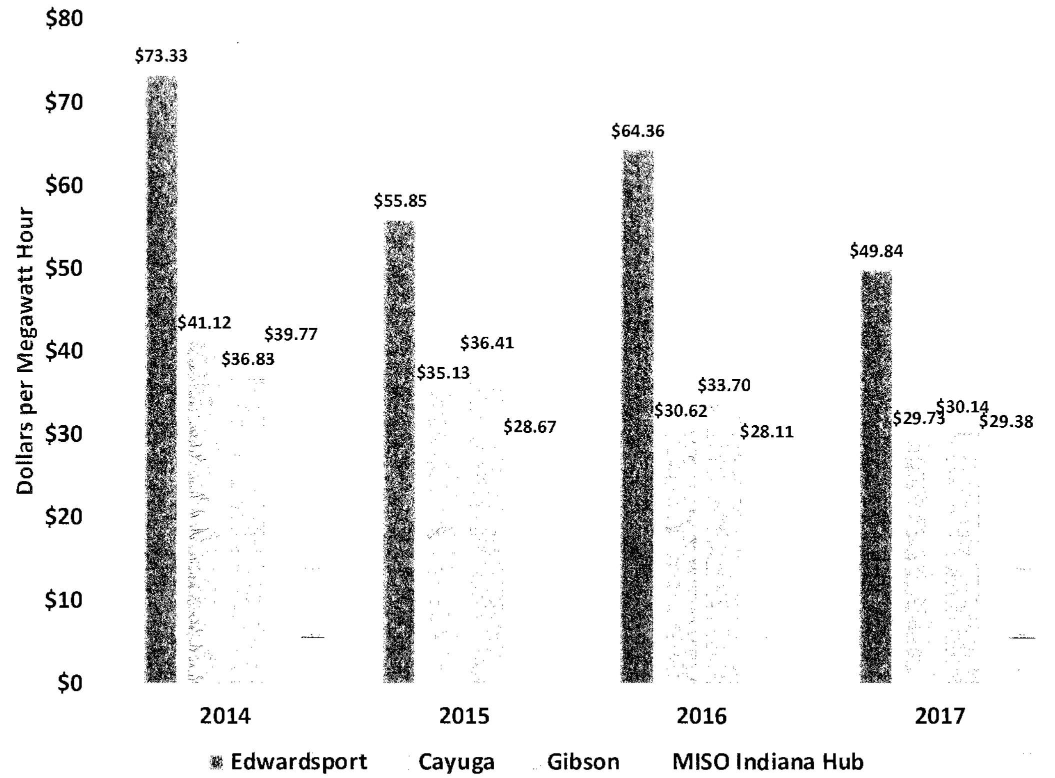
Figure 8: O&M Cost of Generating Power at Edwardsport v. Cost of Producing Power at Cayuga and Gibson or Buying it from MISO Markets[17]



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

A. Yes. Duke affiliates in the Carolinas and Florida added five new NGCC units between 2009 and 2013. These were Buck CC and Dan River CC built by Duke Energy Carolinas, Bartow CC built by Duke Energy Florida, and Wayne County and LV Sutton CC built by Duke Energy Progress.[18]

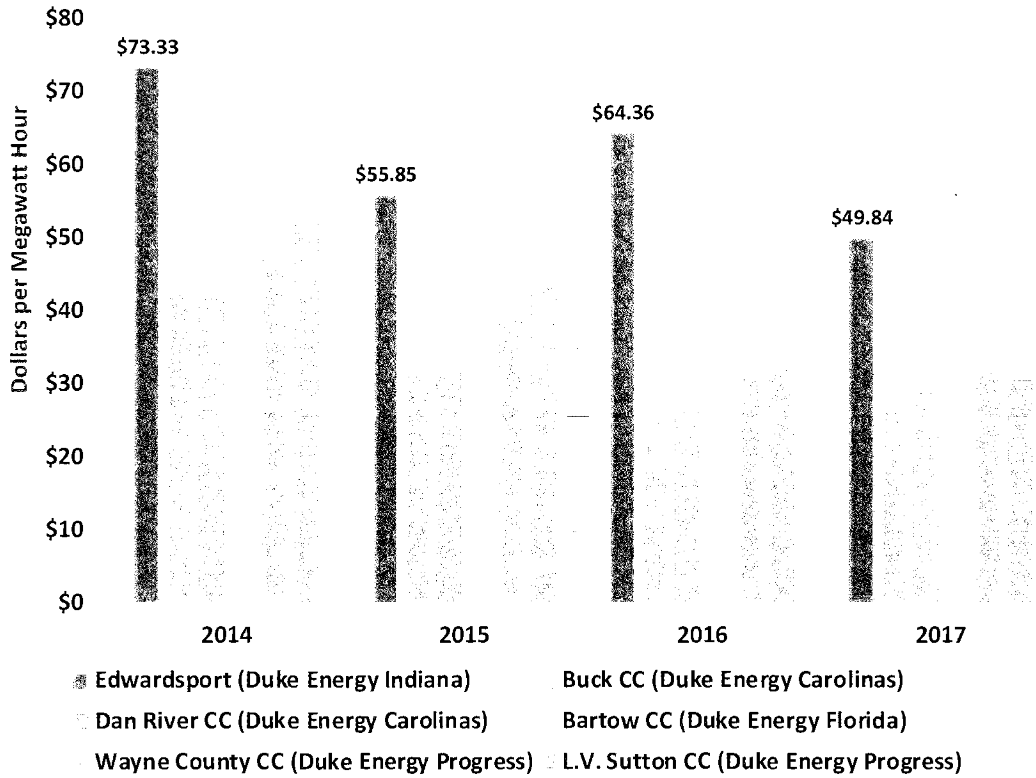
17 Sources – Duke Energy FERC Form 1 Filings and information from S&P Global Market Intelligence.

18 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.

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[19]



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.

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[19] Sources – Duke Energy FERC Form 1 Filings and information from S&P Global Market Intelligence.

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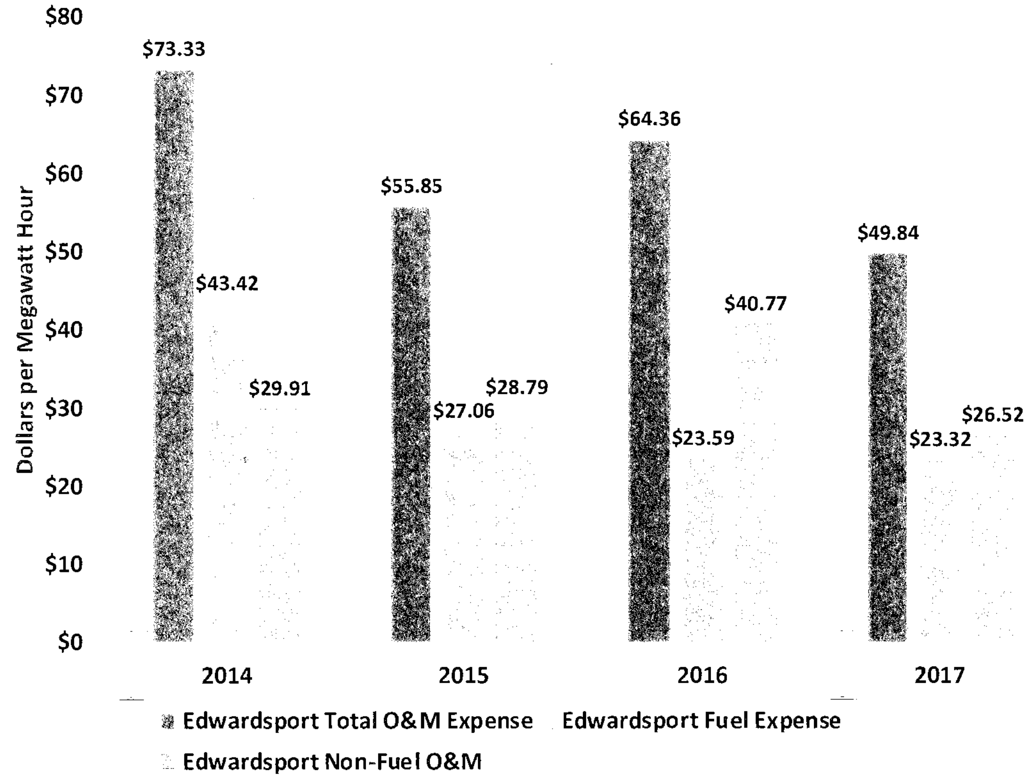
Figure 10: Edwardsport Fuel and Non-Fuel O&M Expenses[20]



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

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

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

20 Source – DEI Annual FERC Form 1 filings.

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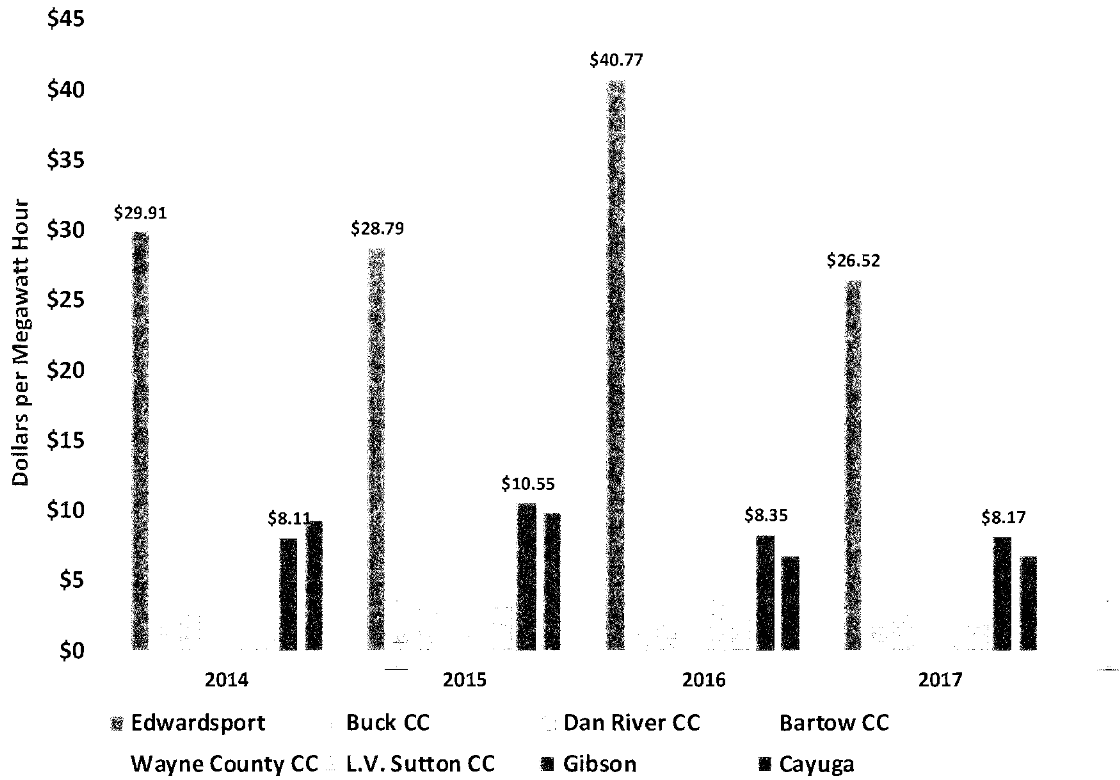
Figure 11: Edwardsport Non-Fuel O&M Expenses v. Those of Other DEI Baseload Coal-Fired Plants and Recent Duke NGCC Units[21]



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

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

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

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[21] Costs from annual FERC Form 1 filings and S&P Global Market Intelligence.

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

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

Figure 12: Edwardsport Total O&M Expenses v. Market Expectations for Future MISO Indiana Hub Energy Prices[22]

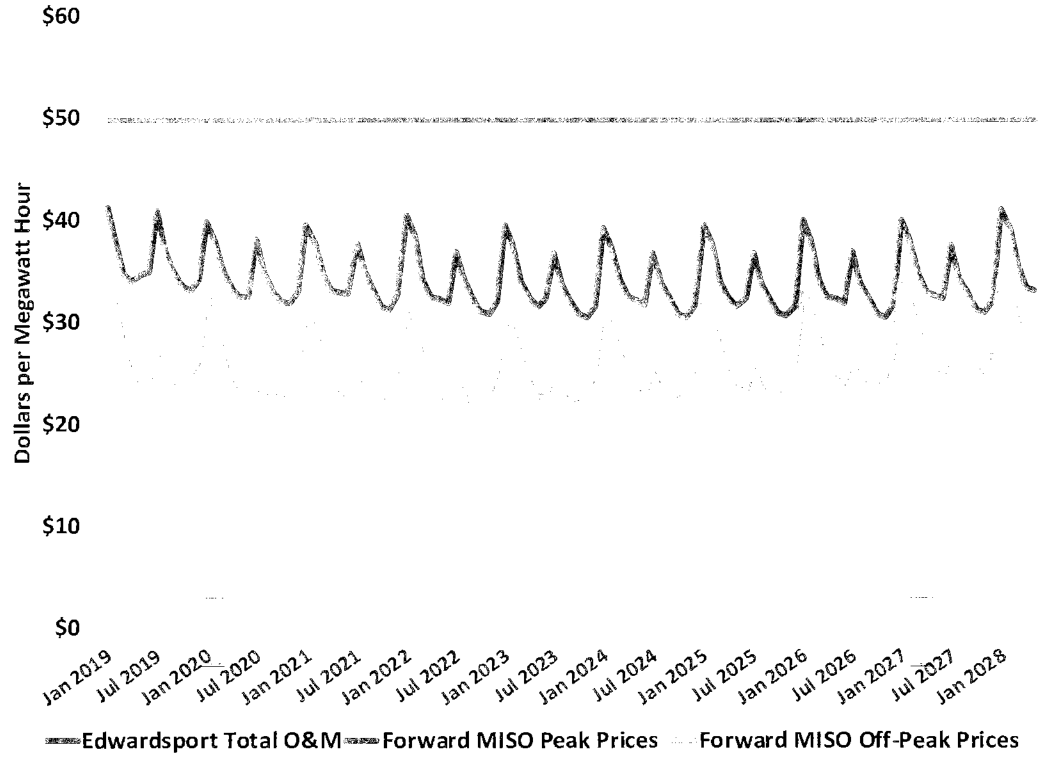

Figure 12 shows that operating Edwardsport will continue to be uneconomic unless the Company is able to reduce its total O&M dramatically and/or energy market prices increase substantially above current expectations, both of which are very unlikely to happen in coming years.

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

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

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

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

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

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

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

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

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

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

Figure 13: Edwardsport's All-In Cost v. the Cost of Buying the Same Energy and Capacity from MISO Markets (on a $/MWh Basis)[23]

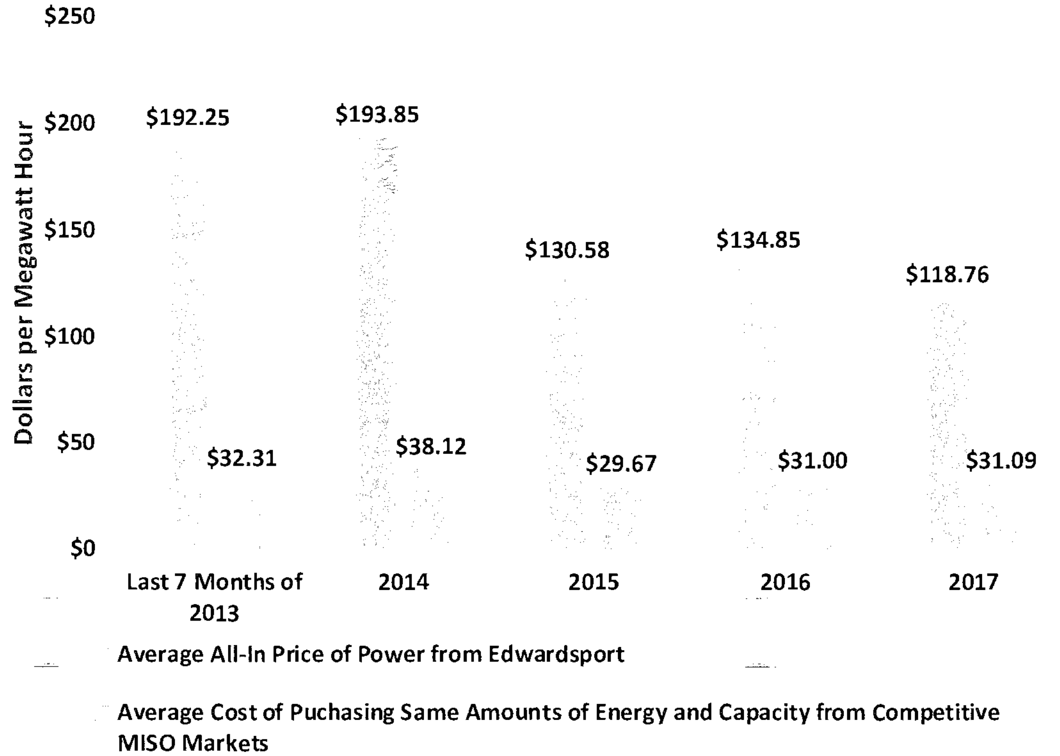

Figure 14 then shows the cumulative additional cost that DEI's ratepayers have borne, and continue to bear, due to the higher cost of Edwardsport compared to what it would have cost to purchase the same amounts of energy and capacity in the MISO markets.

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23 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)[24]

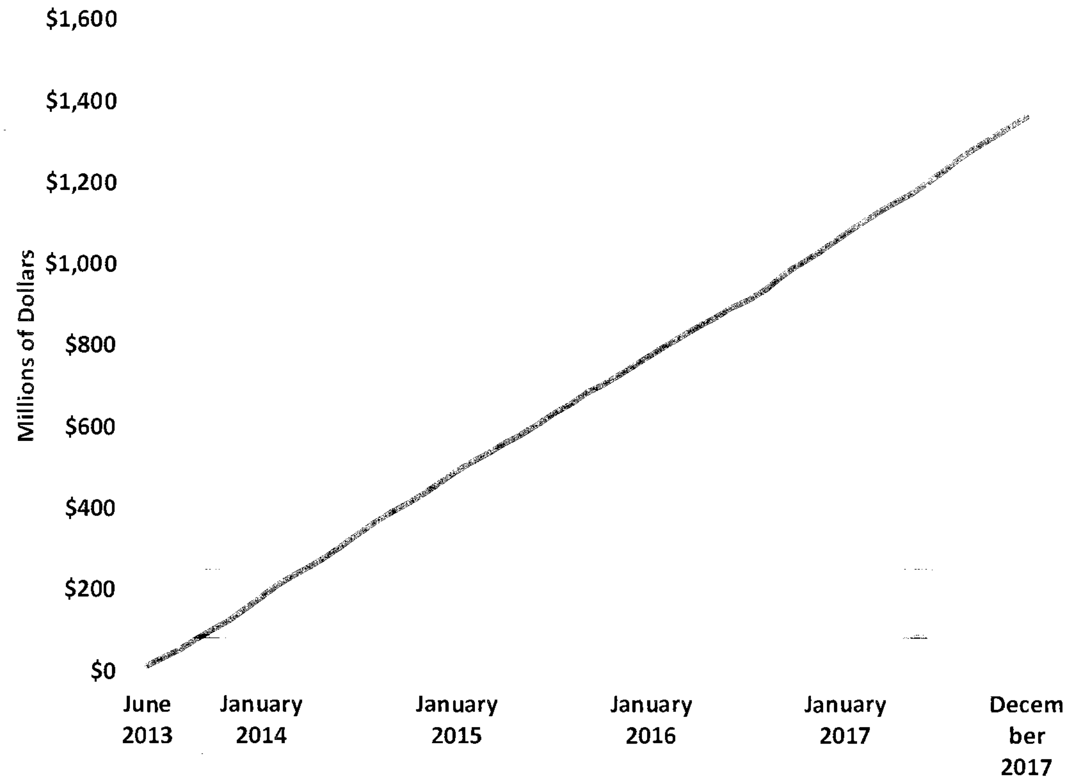

Figure 14 shows that the cumulative economic loss (or additional costs) that Edwardsport has imposed on DEI ratepayers was nearly $1.4 billion through the end of 2017.

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

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24 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.

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

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

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

Q. Has Edwardsport produced any positive value for ratepayers?

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

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

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

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

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

Q. Please summarize your recommendations.

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

1. "[M]odify or revoke the certificate" for the Plant as the Commission should find that continued "implementation of the [clean coal] technology will not serve the public convenience and necessity" per IC 8-1-8.7-5, an option afforded to the Commission by the legislature to protect ratepayers in situations just like this; or

2. Require DEI to file a rate case to determine how much of the investment in Edwardsport is actually fully "used and useful"; or

3. Initiate a special proceeding to consider options that would ensure that the fully embedded cost of the electricity from Edwardsport is comparable to the cost of alternative sources such as the MISO markets and/or other generating facilities on the Company's system;

And

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

5. Until the IURC modifies or revokes the CPCN, issues an order in a special proceeding, or completes a rate case review of whether Edwardsport is actually "used and useful" as recommended above, limit the Company's recovery of non-fuel O&M expenditures at Edwardsport to $6.74 per MWh. This represents the average non-fuel O&M expenditures at the five Duke Energy NGCC units presented in Figure 9, below, and DEI's own Gibson and Cayuga baseload coal-fired plants for the years 2014-2017. At the same time, the IURC should restrict the Company's ability to recover through rates capitalized Edwardsport maintenance expenditures in 2018

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

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

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

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

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

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

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

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

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

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

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

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

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

> In addition to the review of the continuing need for the clean coal technology system under construction prescribed in section 5 of this chapter, the commission shall at the request of the public utility maintain an ongoing review of that construction as the construction proceeds. The applicant shall submit each year during construction, or at other times as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction . . . .
>
> If the commission disapproves of all or part of the construction or cost of the part of the clean coal technology system under review, the commission may modify or revoke the certificate.

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

Moreover, it is my understanding that, pursuant to IC 8-1-8.8, the Commission is granted authority to approve projected capital maintenance and operating expenses for "clean coal" technology and energy projects such as Edwardsport only "if the eligible business provides substantial documentation that the expected costs and expenses and the schedule for incurring those costs and expenses are reasonable and necessary."

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

Q. Does this complete your testimony?

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

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_x, SO_2 and CO_2. 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 ½ 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 Alernatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant.

Public Service Commission of Michigan (Docket No. U-16000) – Juy 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 Sepember 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_2") 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
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
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.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
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.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.
Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
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.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
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.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
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
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
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
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

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.

North Carolina Utilities Commission (Docket E-2, Sub 526) - May 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - November 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and June 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) – December 1985 and January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.
New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - January 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

How the High Cost of Power from Prairie State is Affecting Bowling Green Municipal Utilities' Customers. July, 2014.

Overpriced Power: Why Batavia is Paying So Much for Electricity. Updated March 2014.

Huntley Generating Station: Coal Plant's Weak Financial Outlook Calls for Corporate & Community Leadership. January 2014. Co-authored with Cathy Kunkel and Tom Sanzillo.

When, Not If: Bridgeport's Future and the Closing of PSEG's Coal Plant.

Changing Course: A Clean Energy Investment Plan for Dominion Virginia Power. Co-authored with Jeff Loiter and Anna Sommer. August 2013.

Mountain State Maneuver: AEP and FirstEnergy try to stick ratepayers with Risky Coal Plants. September 2013. Co-authored with Cathy Kunkel.

Public Utility Regulation without the Public: The Alabama Public Service Commission and Alabama Power. Co-authored with Anna Sommer. March 2013

A Texas Electric Capacity Market: The Wrong Tool for a Real Problem. Co-authored with Anna Sommer. February 2013.

Dark Days Ahead: Financial Factors Cloud Future Profitability at Dominion's Brayton Point Power Plant. Co-authored with Tom Sanzillo. February 2013.

Report on the Kemper IGCC Project: Cost and Schedule Risks. November 2012.

The Prairie State Coal Plant: the Reality vs. the Promise. August 2012.

The Impact of EPA's Proposed 316(b) Existing Facility Rule on Electric System Reliability, July 2011.

The Economics of Existing Coal-Fired Power Plants, Presentation at EUCI Conference in St. Louis, MO, November 2010.

Presentation to the Indiana Utility Regulatory Commission on the Need for the Proposed Duke Energy Indiana Edwardsport IGCC Project, November 2010.

Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan, September 2010.

Presentation to the Oregon Public Utility Commission on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on the Facility Cost Report for Tenaska's Proposed Taylorville IGCC Plant, April 2010.

Comments on City of Holland Board of Public Work's 2010 Power Supply Plan, April 2010.

Phasing Out Federal Subsidies for Coal, April 2010.

Comments on Draft Portland General Electric Company 2009 Integrated Resource Plan, October 2009.

The Economic Impact of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia, August 2009.

Energy Future: A Green Energy Alternative for Michigan, report, July 2009.

Energy Future: A Green Energy Alternative for Michigan, presentation, July 2009.

Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan, June 2009.

The Financial Risks to Old Dominion Electric Cooperative's Consumer-Members of Building and Operating the Proposed Cypress Creek Power Station, April 2009.

An Assessment of Santee Cooper's 2008 Resource Planning, April 2009.

Nuclear Loan Guarantees: Another Taxpayer Bailout Ahead, Report for the Union of Concerned Scientists, March 2009.

New Hampshire Senate Bill 152: Merrimack Station Scrubber, March 2009.

The Risks of Building and Operating Plant Washington, Presentation to the Sustainable Atlanta Roundtable, December 2008.

The Risks of Building and Operating Plant Washington, Report and Presentation to EMC Board Members, December 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the University of California at Berkeley Energy and Resources Group Colloquium, October 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at Georgia Tech University, October 2008.

Nuclear Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Coal-Fired Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Synapse 2008 CO_2 Price Forecasts, Synapse Energy Economics, July 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the NARUC ERE Committee, NARUC Summer Meetings, July 2008.

Are There Nukes In Our Future, Presentation at the NASUCA Summer Meetings, June 2008.

Risky Appropriations: Gambling US Energy Policy on the Global Nuclear Energy Partnership, Report for Friends of the Earth, the Institute for Policy Studies, the Government Accountability Project, and the Southern Alliance for Clean Energy, March 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation to the New York Society of Securities Analysts, February 26, 2008.

Don't Get Burned, Report for the Interfaith Center for Corporate Responsibility, February 2008.

The Risks of Participating in the AMPGS Coal Plant, Report for NRDC, February 2008.

Kansas is Not Alone, the New Climate for Coal, Presentation to members of the Kansas State Legislature, January 22, 2008.

The Risks of Building New Nuclear Power Plants, Presentation to the Utah State Legislature Public Utilities and Technology Committee, September 19, 2007.

The Risks of Building New Nuclear Power Plants, Presentation to Moody's and Standard & Poor's rating agencies, May 17, 2007.

The Risks of Building New Nuclear Power Plants, U.S. Senate and House of Representative Briefings, April 20, 2007.

Carbon Dioxide Emissions Costs and Electricity Resource Planning, New Mexico Public Regulation Commission, Case 06-00448-UT, March 28, 2007, with Anna Sommer.

The Risks of Building New Nuclear Power Plants, Presentation to the New York Society of Securities Analysts, June 8, 2006.

Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs. Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities. Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

The 2003 Blackout: Solutions that Won't Cost a Fortune, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability. An Analysis for Riverkeeper, Inc. November 3, 2003.

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Entergy's Lost Revenues during Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems. An Analysis for Riverkeeper, Inc. November 3, 2003.

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