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December 6, 2019

Dr. Bradley Borum
Electricity Division Director
Indiana Utility Regulatory Commission
Attn: Research, Policy, Planning Division
101 W. Washington Street, Suite 1500 East
Indianapolis, IN 46204-3407
Email: bborum@urc.in.gov

RE: Comments to Duke's 2018 Integrated Resource Plan ("IRP")

Dear Dr. Borum:

The Industrial Group, by counsel, respectfully submits the following comments to Duke's 2018 IRP.

1. In Duke's currently pending rate case, Cause 45253, Duke is proposing to cease the Edwardsport IGCC rider and to roll the Edwardsport IGCC plant into base rates.

2. The total 2020 costs of O&M at Edwardsport is $106 million. These costs include $99.4 million of O&M, plus $6.6 million of annualized major seven year outage costs (i.e., $46.4 million/7).[1]

3. As the testimony of Industrial Group witness Michael P. Gorman explains, Duke has not demonstrated that its decision to continue running Edwardsport as a gasification plant is reasonable and prudent. The Industrial Group hereby incorporates the relevant portion of that testimony and exhibits into its comments to Duke's IRP as Attachment 1.

[1] Duke witness Gurganus Direct Testimony in Cause 45253 at 16; Duke's response to IG DR 2.13, included as Attachment MPG-1, page 9.

4. Duke's 2018 IRP does not support Duke's proposed treatment of Edwardsport, as Mr. Gorman explained. See Attachment 1 at pages 31-32. In particular:

a. In its 2018 IRP, Edwardsport was not considered for retirement.

b. Duke modeled Edwardsport O&M differently from its other plants for purposes of the IRP. As Duke explained in discovery:

> At a high level, just like the other Duke Energy Indiana units, forward forecast long-run O&M costs for Edwardsport are modeled with fixed and variable O&M components. The variable O&M cost component adjusts with the forward generation projection from the IRP model. Typically, Duke Energy Indiana models O&M costs (fixed and/or variable) used for long-term IRP modeling purposes as long-run costs. They are not generally intended to be comparable to any specific year of near-term cost projection that may be budgeted and/or otherwise forecasted with fine detail, including any expectations of timing for planned outages. However, for Edwardsport, an exception was made given the Company's request for levelization of the major outage costs, and specific annual costs for the major outages were depicted in the Edwardsport O&M cost for IRP modeling every seven years, at 2020, 2027, and 2034. Additionally, projecting forward from the near-term O&M budget costs, Duke Energy Indiana anticipates a downward trend of total O&M costs at Edwardsport, and this trend was reflected in the O&M costs used in the 2018 IRP. This expectation is based on our plans for continuing to tackle key equipment degraders, as well as continuing to find cost efficiencies and optimize our site operations and management processes. That may include further reductions in contractor staffing, ongoing efficiency improvements in the execution of outages, and maintenance cost reductions achieved from equipment reliability improvements.[2]

c. Thus, the IRP was based on assumptions rather than actual experience running the plant, despite the fact that Duke declared the plant in-service six years ago.[3]

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[2] Duke's response to IG 25.10(a), provided as Attachment MPG-1, pages 73-74.
[3] See also Duke's confidential response to Sierra Club DR 2.2 (relating to the Equivalent Forced Outage Rate), provided as Attachment MPG-1, pages 97-98.

d. In addition, Duke has stated that "The 'outage rate' used in the IRP model for all fossil units except Edwardsport is the Equivalent Unplanned Outage Rate (EUOR)… [I]n the absence of fully mature baseline period data, the outage rates shown for Edwardsport reflect an ongoing expected improvement in performance through 2022, after which the rate is held constant. The outage rate for Edwardsport represents the total unit outage rate, and was calculated as a standard equivalent forced outage rate (EFOR)."[4]

5. Moreover, Duke has not conducted and retained any evaluation regarding the potential financial merits of running Edwardsport as a natural gas unit.[5] This is true even though (1) the cost of natural gas is much lower than Duke anticipated when it brought the CPCN to the Commission seeking authority to build Edwardsport, and (2) the O&M costs are about twice as high as Duke anticipated during the CPCN case.[6] Though Duke has informally indicated that some analysis may have been conducted at some point, Duke discarded any such analysis prior to filing the rate case.[7]

6. Given the significant financial impact of the Edwardsport plant, Duke should have conducted an IRP that considered its options with respect to Edwardsport more broadly. In particular, Duke should be required to conduct IRP modeling in the following separate scenarios:

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[4] Duke's confidential response to Sierra Club DR 2.2 (relating to the Equivalent Forced Outage Rate), provided as Attachment MPG-1, pages 97-98.
[5] See Attachment 1 (Gorman Direct in Cause 45253) at 28-31 and associated attachments.
[6] See Attachment 1 (Gorman Direct in Cause 45253) at 23-27 and associated attachments.
[7] See Attachment 1 (Gorman Direct in Cause 45253) at 30-31.

a. Conduct the IRP analysis in a manner that permits the model to determine whether continuing to run Edwardsport as a syngas unit, running Edwardsport as a natural gas unit exclusively, or whether retiring Edwardsport is the most economic option (as well as the recommend timing of any such changes). In evaluating the option to run Edwardsport as a natural gas unit only, the model should include only the costs necessary to run Edwardsport as a natural gas unit, and remove other costs (including removing labor and other O&M costs, post-in-service capital costs, and other costs that are only necessary if the plant is run on syngas).

b. Conduct an IRP that models O&M and outages based on Duke's actual experiences with Edwardsport. Though Duke projects that O&M will decrease in the future, Duke's track record with Edwardsport is that actual costs (whether they are capital costs or O&M costs) have been consistently significantly higher than Duke's projections.

c. Conduct IRP modeling that evaluates the possibility of running Edwardsport as a natural gas unit.

Sincerely,

LEWIS KAPPES

/s/ Tabitha L. Balzer

Tabitha L. Balzer

TLB/ert

cc: Aaron A. Schmoll, via electronic mail

ATTACHMENT 1

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED
November 4, 2019
INDIANA UTILITY
REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	CAUSE NO. 45253

PUBLIC VERSION

Revised Verified Direct Testimony and Attachments of

Michael P. Gorman

On behalf of

The Duke Industrial Group

November 4, 2019

BRUBAKER & ASSOCIATES, INC.

Project 10686

Q WHAT IS THE CORRECT AMOUNT OF DUKE'S REQUESTED RATE INCREASE?

A Utility receipts tax associated with proposed rates is $41.2 million.[19] As such, Duke's proposed rate increase in this proceeding is $434.3 million.[20]

III. REVENUE REQUIREMENT ADJUSTMENTS AND OTHER REVENUE RECOMMENDATIONS

Q PLEASE DESCRIBE THIS PORTION OF YOUR TESTIMONY.

A I will explain each of the revenue requirement adjustments identified in Table 1 above in this part of my testimony. However, depreciation rate adjustments to the revenue deficiency will be addressed by Industrial Group witness Brian C. Andrews, and the jurisdictional allocation associated with changes in wholesale power market transactions will be discussed by Industrial Group witness James R. Dauphinais.

III.A. Edwardsport IGCC Overview

Q PLEASE DESCRIBE THE EDWARDSPORT GENERATING STATION.

A Edwardsport is an integrated gasification combined cycle ("IGCC") generating facility with a gross and net capacity of approximately 806 MW and 618 MW,[21] respectively. Edwardsport can operate using either synthetic gas (coal converted to natural gas) or natural gas. The syngas or natural gas is used to fire two combined cycle gas combustion turbines ("CCGT"). Edwardsport also includes one steam turbine, fueled by the CC turbine exhaust and with heat from the coal to gas conversion process.[22] Duke witness Cecil Gurganus provides an overview of the facility and a brief history of the previous Edwardsport proceedings in his direct testimony.

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[19] *Id.*
[20] Duke supplemental response IG 30.1, included in my Attachment MPG-1, page 82.
[21] Duke response to IG 22.17, included in my Attachment MPG-1, pages 63-64.
[22] Gurganus Direct at 3:15-22.

Q WHAT REQUEST IS DUKE INDIANA SEEKING WITH RESPECT TO THE EDWARDSPORT GENERATING STATION?

A Duke witness Brian Davey lists on his Petitioner's Exhibit 2-A (BPD) certain requests that the utility is making with respect to the Edwardsport generating station. Those include approval of the Edwardsport generating costs (current and major maintenance outage deferral), approval of capital additions, and a finding that this facility is used and useful.

Based on these findings, Duke is requesting the inclusion of Edwardsport cost in its retail base rates, including: (1) capital investments in 2018, 2019 and 2020 be included in its retail rate base; (2) approval for the Edwardsport materials and supplies inventory in rate base; (3) reflect its 2020 operation and maintenance expense; and (4) an adjustment to include a deferral of 2020 major maintenance outage costs.

Duke provided the revenue requirement impact of Edwardsport as Attachment IG 8.1-B, which I recreated as Attachment MPG-5, page 1. Duke's proposed revenue requirement includes approximately $493.2 million of Edwardsport costs in base rates. Currently, Duke is recovering $332.6 million of revenue requirement cost for Edwardsport in IGCC-17, Step 2.[23]

Q HAS THE COMPANY PROVIDED ADEQUATE SUPPORT FOR A FINDING THAT IT IS OPERATING THE EDWARDSPORT GENERATING STATION PRUDENTLY AND THAT IT IS ENTITLED TO THE LEVEL OF O&M BEING REQUESTED?

A No. Duke Indiana is seeking to include the Edwardsport generating unit in its base rates for the very first time in this proceeding. Since 2008, Duke has reflected certain Edwardsport cost in Rider 61 – IGCC Rider, under stipulated terms. After Duke

[23]Duke's response to IG 8.1, Attachment IG 8.1-A, provided as Attachment MPG-1, pages 19-21.

declared Edwardsport in service, Duke began recovering O&M in the tracker proceedings. However, since Duke declared Edwardsport in service in 2013, Duke has never recovered O&M outside the context of a settled tracker proceeding. In other words, this issue has never been fully litigated.

Duke is seeking to include the O&M associated with Edwardsport into base rates. Because Duke is terminating the IGCC tracker (Rider 61), there will be no further review of the appropriateness of Edwardsport O&M until Duke brings its next base rate case, which may not be for many years. As such, Duke has the burden of demonstrating to this Commission that its requested level of O&M is reasonable and necessary. Yet Duke has not shown that it has adequately investigated its options for running Edwardsport in the most efficient way. In particular, Duke has not demonstrated that it has given adequate consideration to whether Edwardsport should continue to be operated as an IGCC and run on syngas or whether Edwardsport should be run on natural gas.

III.A.1. History of Edwardsport IGCC Tracker Proceedings

Q YOU MENTIONED THAT SINCE DECLARING EDWARDSPORT IN SERVICE IN 2013, DUKE HAS NEVER RECOVERED O&M OUTSIDE THE CONTEXT OF A SETTLED TRACKER PROCEEDING, AND THAT THE COMMISSION HAS THEREFORE NEVER FULLY ADJUDICATED THIS ISSUE. PLEASE EXPLAIN.

A The explanation of this issue requires an understanding of the history of the Edwardsport IGCC proceedings.

The IGCC proceedings began in 2006 when Duke first requested preapproval via a Certificate of Public Convenience and Necessity (“CPCN”) to construct the IGCC plant at Edwardsport. Duke also sought authority to recover certain costs via a tracking mechanism, including construction work in progress ("CWIP") during construction of the plant, as well as depreciation expense and O&M after the plant was placed in-service.

In this initial case ("CPCN case"), Duke estimated that its construction costs would be $1.985 billion and sought preapproval of these costs. Duke also sought to implement the IGCC rider, and requested other financial incentives. In addition, Duke also submitted a rate impact analysis which projected that its annual total O&M expense in 2020 would be approximately <u>$51.6 million</u> in total (non-retail) facility costs.[24]

The Commission approved Duke's request for a CPCN to construct Edwardsport on November 20, 2007 order ("CPCN Order").[25] Then, in 2008 in the first IGCC Rider tracker proceeding, IGCC-1, Duke requested to increase its capital cost estimate from $1.985 billion to $2.350 billion. The Commission ultimately granted Duke's request, but limited the scope of one of the incentives that it had previously approved (related to deferred income taxes) to the initial $1.985 billion estimate.[26]

In 2009 in IGCC-4, Duke requested to increase its capital cost estimate again, seeking an increase to $2.88 billion. The Commission issued an interim order and established a subdocket (IGCC-4S1) to examine Duke's request. After opposition to its proposal, Duke entered into a settlement agreement with the OUCC, the Industrial Group, and Nucor Steel ("2012 Settlement Agreement"). The 2012 Settlement Agreement established a Hard Cost Cap of $2.595 billion. Given that the estimate to complete the project has risen to $3.3 billion at the time of the execution of the 2012 Settlement Agreement, the Settlement required Duke shareholders to absorb

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[24] Petitioner's Exhibit No. 28-E in Cause 43114 (Farmer Rebuttal) at Line 25, Columns AC and AD, attached to my testimony as Attachment MPG-6.

[25] *Duke Energy Indiana, Inc.*, Cause Nos. 43114 and 43114 S1 (IURC Nov. 20, 2007).

[26] *Duke Energy Indiana, Inc.*, Cause No. 43114 IGCC-1, at 21 (IURC Jan. 7, 2009).

approximately $700 million at the time, plus any subsequent construction cost overruns. The Hard Cost Cap did not govern O&M costs, which, according to FERC guidelines, begin after the in-service or commercial operational date of Edwardsport. The Commission approved the 2012 Settlement Agreement on December 27, 2012.

Q WHAT HAPPENED AFTER THE 2012 SETTLEMENT AGREEMENT?

A The 2012 Settlement Agreement largely resolved many issues in several IGCC rider proceedings as Duke continued to construct the Edwardsport facility. In IGCC-10, Duke anticipated that the IGCC plant would be placed in-service in June 2013, and began including a portion of its O&M (four out of six months) in its tracker.[27] Because Duke projected O&M costs for the tracker, the project had not yet been declared in service by Duke. Also, because only four out of six months were included, only 2/3 of the amount of O&M was recovered.

In IGCC-11, the Industrial Group submitted a motion for summary judgment challenging Duke's requested O&M. In consolidated IGCC-12/13, the Industrial Group and other consumer parties submitted testimony challenging Duke's requested O&M, arguing, among other points, that the plant was not "in-service" and therefore Duke should not be permitted to recover O&M in the IGCC rider. The Commission withheld issuing orders in IGCC-11 through IGCC-15 as the litigation ensued.

Ultimately, a settlement agreement was reached between Duke, the OUCC, the Industrial Group, Joint Intervenors, and Nucor Steel ("2016 Settlement Agreement.") As part of this settlement, the parties agreed that for accounting and ratemaking purposes, the in-service date of the IGCC plant would be Duke's declared date of June 7, 2013. In return, the settlement required Duke to write off $87.5 million of a regulatory

[27]The IGCC was not in-service during IGCC-10, however, because Duke recovers O&M based on future year projections, it was also projecting it would be placed in-service.

asset that had accrued and imposed temporary caps on O&M and post-in-service capital costs.

As part of the 2016 settlement, the parties agreed to a temporary fixed O&M cap on recovery in the IGCC in the tracker over the term of the settlement agreement. This agreement set recovery of O&M at $67.2 million for 12 months ending March 31, 2015, increasing to $76.8 million by calendar year 2017.[28] However, the level of O&M expenses in the settlement was part of a compromise of many components (notably including the $87.5 million write-off) and should not be construed as support for the level of O&M in the IGCC tracker for purposes of future proceedings. That is, the settlement terms were not intended to represent a finding on reasonable and necessary costs for the IGCC plant for periods after the settlement agreement was completed.[29]

Q WHAT HAPPENED AFTER THE 2016 SETTLEMENT AGREEMENT?

A IGCC-16 was subject to the O&M caps of the 2016 Settlement Agreement, so the next proceeding to address the O&M issue was IGCC-17. However, the O&M issue was not litigated in IGCC-17 either, because a settlement agreement was reached in IGCC-17 between several of the parties: Duke, the OUCC, the Industrial Group, and Nucor Steel-Indiana ("2018 Settlement Agreement")[30] prior to the prefiling date of the OUCC/Intervenor case-in-chief testimony.

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[28]2016 Settlement Agreement at ¶ 3(B) (attached to Final Order in *Duke Energy Indiana, Inc.*, Cause No 43114 IGCC-15, at 97 (IURC Aug. 24 2016).

[29]*See id*. at ¶ 3(B) ("The non-Duke Settling Parties shall retain all rights to make arguments related to Duke Energy Indiana's recovery of Edwardsport O&M starting with the 2018 IGCC Rider filing and afterwards"), *see also* ¶ 5(O) ("The positions taken by the Settling Parties in this Settlement shall not be deemed to be admissions by any of the Settling Parties and shall not be used as precedent, except as necessary to implement the terms of this Settlement Agreement.").

[30] 2018 Settlement Agreement is attached to my testimony as Attachment MPG-7.

Q WAS DUKE'S REQUESTED O&M AN ISSUE AT CONTROVERSY IN IGCC-17?

A Yes. As I explained in my Settlement Testimony, the Industrial Group had concerns with respect to the amount of O&M requested by Duke.[31]

Q HOW DID THE 2018 SETTLEMENT AGREEMENT ADDRESS THE CONCERN ABOUT THE AMOUNT OF O&M AND OTHER ISSUES?

A The 2018 Settlement Agreement offered significant customer benefits (notably including a $30 million write-off of the regulatory asset) in order to address these concerns and others until Duke's rate case. The 2018 Settlement was designed to act as a bridge to the rate case, which Duke had indicated at the time would be filed in 2019 (and ultimately was). As I explained in my settlement testimony, a rate case offers a better forum than a tracker proceeding to examine Edwardsport as a whole and in the context of Duke's entire system.[32]

Q DID THE 2018 SETTLEMENT AGREEMENT PRESERVE THE ABILITY OF THE NON-DUKE SETTLING PARTIES TO CHALLENGE DUKE'S REQUESTED O&M FOR EDWARDSPORT IN THE RATE CASE?

A Yes. The 2018 Settlement Agreement provided that O&M[33] incurred after January 1, 2020, will be addressed in the next rate case. The consumer parties reserved all rights

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[31] Settlement Testimony of Michael P. Gorman, Cause 43114 IGCC-17 (Sept. 20, 2018) at 5, attached to my testimony as Attachment MPG-8. In addition to the O&M concern, the Industrial Group also had concerns with respect to Duke's requested ROE and continuation of the IGCC tracker.

[32] Settlement Testimony of Michael P. Gorman, Cause 43114 IGCC-17 (Sept. 20, 2018) at 9, attached to my testimony as Attachment MPG-8.

[33] As explained later in more detail, the consumer parties also reserved all rights to make any and all arguments regarding the amount of and Duke's ability to recover post-in-service capital costs incurred after January 1, 2018. 2018 Settlement Agreement at Paragraph 3.

to make any and all arguments regarding the appropriate amount of and Duke's ability to recover O&M incurred after January 1, 2020.[34]

In addition, the Settlement contained a general reservation of rights. Specifically, the Settlement states that "Except as expressly provided herein or as otherwise provided in prior Edwardsport-related settlement agreements, the Settling Parties reserve all rights to raise any and all arguments regarding the treatment of Edwardsport including, but not limited to, costs and expenses in Duke's next rate case and in other future proceedings."[35]

III.A.2. Duke's Edwardsport Recommendations

Q HAS DUKE DEMONSTRATED THAT ITS OPERATION OF EDWARDSPORT REFLECTS THE MOST ECONOMIC UTILIZATION OF THIS RESOURCE?

A No. Edwardsport is a unique facility that can be operated either as an IGCC, or it can operated instead on natural gas. When it was originally developed it was expected that operation on the IGCC, as opposed to stand-alone operation on natural gas, would be the most economic utilization of this facility. However, the gas market has changed considerably since 2007 when the Company first received a CPCN for this facility.

At the time the CPCN was awarded, it was expected that natural gas would increase from around **[redacted]** during the study period and continue to increase out to approximately **[redacted]** over the forecast period for calendar years 2007 - 2026.[36] The Company argued in Cause No. 43114:

> Given the limited supplies and high prices and/or price volatility of oil and natural gas as well as abundant supplies, moderate prices and ready accessibility of coal, coal is and will likely remain the most practical fuel choice for baseload electric generation in the Midwest.

[34] 2018 Settlement Agreement at Paragraph 2(B).
[35] 2018 Settlement Agreement at Paragraph 6.
[36] Confidential Attachment IG 28.1-A, provided as Attachment MPG-1, pages 80-81.

> Energy from coal is cheaper than energy from oil and natural gas, while being more cost effective for increasing baseload capacity, than available renewable energy options.[37]

The range for 2020 to 2026 was between **[redacted]** to **[redacted]**. Significantly, around 2006, the time Duke was seeking the CPCN for Edwardsport, the NYMEX forward price of natural gas ranged from $8.90/dth to just below $6.01/dth.[38]

Q DID DUKE'S PROJECTION OF THE MARKET PRICE OF NATURAL GAS TURN OUT TO BE ACCURATE?

A No. The natural gas market has significantly changed since Duke requested a CPCN for the Edwardsport IGCC. The change in the natural gas market was likely attributable to the significant change in supply of natural gas in North America caused by the new fracking method of producing gas. In any event, natural gas prices now are much cheaper than they were expected to be when Duke sought to develop Edwardsport as an IGCC rather than a combined cycle gas facility.

Specifically, the current forward NYMEX price of natural gas at the Henry Hub ranges from $2.234/MMBtu to $3.280/MMBtu during the period 2019 to 2029.[39] This is far lower than Duke anticipated when it sought a CPCN for Edwardsport. Indeed, current forward prices are about 20% to 30% for natural gas compared to when the Edwardsport CPCN was initially sought by Duke.

A comparison of the various natural gas price forecasts is provided in Figure 1 below.

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[37] Cause No. 43114, Joint Petitioners' Exhibit No. 1 at 4:8-13, October 24, 2006.
[38] NYMEX.com Natural Gas Forward Prices as of December 29, 2006.
[39] S&P Global Market Intelligence, Natural Gas Forwards & Futures (Data), downloaded October 10, 2019.

[CONFIDENTIAL SECTION BEGINS]

[redacted]

[CONFIDENTIAL SECTION ENDS]

Q HAVE EDWARDSPORT IGCC COAL PRICES CHANGED SIMILAR TO THE DROP IN NATURAL GAS PRICES?

A Not based on the coal prices that have been reported in Duke Indiana's FERC Form 1. As shown in Table 2 below, I list the delivered coal and natural gas prices identified for Edwardsport IGCC in Duke Indiana's FERC Form 1s for calendar years 2013-2018. These are actual recorded costs of delivered coal and natural gas to Edwardsport. As shown in the table below, natural gas prices have decreased very significantly from 2013-2014 down to the 2015-2018 period. In contrast, coal prices have declined somewhat but not as dramatically as natural gas.

TABLE 2

Edwardsport IGCC
Avg Cost Fuel $/MMBTU

Year	Coal	Gas
2013	$2.65	$4.24
2014	$2.80	$5.44
2015	$2.20	$2.93
2016	$1.84	$2.87
2017	$1.87	$3.27
2018	$2.20	$3.48

Source: Duke Indiana FERC Form 1 (2013-2018).

Q HAVE THERE BEEN ANY OTHER CHANGED CONDITIONS SINCE DUKE BROUGHT ITS CPCN CASE IN 2006?

A Yes. The level of O&M that Duke contends is necessary to run Edwardsport is significantly higher than the estimate presented in the CPCN proceeding.

Q PLEASE EXPLAIN.

A As I noted above, in the 2006 CPCN case, Duke submitted a rate impact analysis which projected that its annual total O&M expense in 2020 would be approximately $51.6 million in total (non-retail) facility costs.[40] However, Duke's requested O&M in this proceeding is more than twice as high as Duke had anticipated. Specifically, Duke projects $99.4 million in total 2020 Edwardsport O&M costs, not including the $46.4 million of major maintenance outage costs proposed to be amortized over seven

[40] Petitioner's Exhibit No. 28-E in Cause 43114 (Farmer Rebuttal) at Line 25, Columns AC and AD, attached to my testimony as Attachment MPG-6.

years.[41] Including the annual major maintenance cost ($46.4 million total company / 7 years, or $6.6 million), the total Edwardsport 2020 O&M is $106 million.[42] Thus, the Edwardsport O&M proposed by Duke in this proceeding is more than twice the amount Duke projected in the 2006 CPCN case.

Q GIVEN THE MATERIAL CHANGES IN THE NATURAL GAS MARKET AND REFLECTING THE NOW KNOWN HIGHER O&M COSTS FOR AN IGCC, HAS DUKE DEMONSTRATED THAT IT IS ECONOMIC TO CONTINUE TO OPERATE EDWARDSPORT AS AN IGCC?

A No. Because natural gas prices are now much lower than they were at the time the IGCC was planned, and because Edwardsport IGCC O&M is significantly higher than projected at the time the CPCN for Edwardsport was sought, Duke has the burden to demonstrate that its request to continue to operate Edwardsport as an IGCC, on syngas (as opposed to change to operate it on only natural gas going forward) is a prudent decision. Duke has failed to satisfy this obligation or even address it. Therefore, Duke's proposed Edwardsport O&M should be reduced to a level more consistent with the costs of a natural gas combined cycle unit in this case.

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[41] Gurganus Direct in this Cause at 16.

[42] In addition to the Station O&M, Edwardsport is also incurring administrative and general benefit costs. See Duke's response to IG DR 2.13, included as Attachment MPG-1, page 9.

Q DID YOU ASK DUKE WHETHER DUKE HAS PERFORMED A STUDY TO DETERMINE WHETHER OPERATION OF THE EDWARDSPORT FACILITY AS AN IGCC WOULD BE MORE ECONOMICAL THAN OPERATING AS A NATURAL GAS FACILITY?

A Yes. In IG DR 8.4, IG asked Duke to make a net present value estimate of operating Edwardsport on natural gas compared to continued operation as an IGCC. IG also asked for an all-in cost of this comparison from calendar year 2020 through the end of the operating life. Duke objected "to the extent" the questions sought "a calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing." Duke did not provide any substantive answer to IG DR 8.4.[43] IG followed up regarding Duke's response to this question in IG DR 23.2, and Duke confirmed that it is not aware of having performed the requested analysis.[44]

From this, I conclude that Duke Indiana has not made a detailed assessment of whether its proposed operation of Edwardsport as an IGCC would be in the public interest, because it did not conduct a detailed assessment of whether operation of this unit as a natural gas facility now would be lower cost and more in the public interest.

Q HAS DUKE PROVIDED ADEQUATE DATA TO DETERMINE THE AMOUNT OF EDWARDSPORT IGCC COSTS THAT COULD BE AVOIDED IF IT WERE OPERATED AS A NATURAL GAS FACILITY INSTEAD OF CONTINUED OPERATION AS AN IGCC?

A No. We did seek information to try to separate the Edwardsport IGCC test year O&M costs and capital investment costs between the costs necessary to operate the combined cycle generating unit and the costs necessary to operate the coal handling

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[43]See Duke's response to IG 8.4, provided as Attachment MPG-1, page 26.
[44] See Duke's response to IG 23.2, provided as Attachment MPG-1, page 66.

and coal to gas conversion facilities. However, Duke Indiana simply was not able to provide the Edwardsport data as requested.

For example, in data request IG 8.3(a), we asked specific information related to the Edwardsport IGCC and its costs and operating parameters if it operated on natural gas from 2020 through the end of its life, and it continued to operate as an IGCC. We also asked the same question assuming the IGCC were to continue to run on either syngas or natural gas in IG DR 8.3(b).

Duke's response to this data request is included in my Attachment MPG-1, pages 23-24. Duke did not provide any response at all to IG DR 8.3(a) (the question relating to operations on natural gas only). As for IG DR 8.3(b) (the question relating to operations on syngas or natural gas), the only data provided by Duke was included in Confidential Attachment 8.3-A, included in my Confidential Attachment MPG-1, page 25, which does not provide adequate detail in order to assess the all-in cost of operating Edwardsport related to coal handling and coal to gas conversion costs versus operating only on natural gas. In IG DR 23.1, IG followed up regarding Duke's failure to respond to IG DR 8.3(a). Duke responded to IG DR 23.1 by confirming that it is not aware of having performed the requested analysis.[45]

Based on Duke's evidence and responses to discovery, there is no way to test whether Duke's proposal to continue to operate Edwardsport as an IGCC is economic and in the public interest. This is particularly problematic given the known significant change in the natural gas market and in increases to O&M. Hence, based on the Company's filing in this case, the Commission cannot conclude that Duke has met its burden in demonstrated that the level of O&M sought by Duke to run Edwardsport is reasonable and necessary.

[45] See Duke's response to IG 23.1, provided as Attachment MPG-1, page 65.

Q DID YOU FOLLOW UP WITH DUKE'S RESPONSE TO SET 8 BY ASKING A MORE BROADLY-WORDED QUESTION ABOUT WHETHER DUKE HAS ADEQUATELY EVALUATED ITS OPTIONS TO RUN EDWARDSPORT AS A NATURAL GAS UNIT?

A Yes. In IG DR 17.6, the Industrial Group asked whether Duke had ever examined the merits and/or costs of running Edwardsport as a natural gas unit only. Duke again objected "to the extent" the question sought "a calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing" and "to the extent" the question sought information protected by attorney work product or privilege. Duke then responded simply "N/A."[46] Duke's objections to IG DR 17.6 rendered its answer of "N/A" ambiguous as to whether Duke had performed the analysis sought and was refusing to provide it on privilege/work product grounds, or whether no such analysis had been performed. As such, the IG followed up to clarify this point with IG DR 21.3.

In response to IG DR 21.3, Duke indicated that it has done analysis regarding Edwardsport in the past under attorney-client privilege, "some of which may have been related to the request above and in IG 17.6." Duke subsequently supplemented this response by providing a short paragraph about examining the merits of running Edwardsport as a natural gas unit from a CO2 perspective and a similarly short attachment addressing the CO2 issue.[47] However, no analysis about the potential <u>cost</u> benefits of running Edwardsport as a natural gas unit was ever produced.

It is my general understanding that Duke has informally (outside the context of discovery) contended that other analysis on this issue may have been conducted at some point in time, but that Duke did not retain the analysis.[48] If Duke had conducted

[46] See Duke's response to IG 17.6, provided as Attachment MPG-1, pages 42.
[47] See Duke's Supplemental response to IG 21.3, provided as Attachment MPG-1, pages 47-49.
[48] See, e.g., Duke's responses to IG DR's 17.6, 21.3, 30.6, and 30.7, provided as Attachment MPG-1, page 42.

analysis of the potential financial merits of running Edwardsport as a natural gas unit, Duke should have retained this analysis so that the Commission and the parties could evaluate it in the rate case. At a minimum, however, Duke's failure to retain any record of such analysis is a failure by Duke to properly support its requested proposal to continue running Edwardsport as an IGCC and to recover the associated O&M in this case.

Q. DOES DUKE'S 2018 IRP SUPPORT DUKE'S PROPOSED TREATMENT OF EDWARDSPORT?

A. No. As explained above, Duke's answers to discovery demonstrate that Duke has not demonstrated that the Company adequately investigated its options to run Edwardsport as a natural gas unit. In addition, Duke modeled Edwardsport O&M differently from its other plants for purposes of the IRP.[49] Duke has stated as follows:

> At a high level, just like the other Duke Energy Indiana units, forward forecast long-run O&M costs for Edwardsport are modeled with fixed and variable O&M components. The variable O&M cost component adjusts with the forward generation projection from the IRP model. Typically, Duke Energy Indiana models O&M costs (fixed and/or variable) used for long-term IRP modeling purposes as long-run costs. They are not generally intended to be comparable to any specific year of near-term cost projection that may be budgeted and/or otherwise forecasted with fine detail, including any expectations of timing for planned outages. However, for Edwardsport, an exception was made given the Company's request for levelization of the major outage costs, and specific annual costs for the major outages were depicted in the Edwardsport O&M cost for IRP modeling every seven years, at 2020, 2027, and 2034. Additionally, projecting forward from the near-term O&M budget costs, Duke Energy Indiana anticipates a downward trend of total O&M costs at Edwardsport, and this trend was reflected in the O&M costs used in the 2018 IRP. This expectation is based on our plans for continuing to tackle key equipment degraders, as well as continuing to find cost efficiencies and optimize our site operations and management processes. That may include further reductions in contractor staffing, ongoing efficiency improvements in the execution of

[49] Duke's response to IG 20.2, provided as Attachment MPG-1, pages 43-44.

outages, and maintenance cost reductions achieved from equipment reliability improvements.[50]

Thus, the IRP was based on assumptions rather than actual experience running the plant, despite the fact that Duke declared the plant in-service six years ago.[51] Finally, I would note that in its IRP, Edwardsport was not considered for retirement.[52] For these reasons, a careful review of the most economic utilization of Edwardsport is critically needed.

Q BASED ON THE INFORMATION IN THIS RECORD, IS IT CLEAR THAT DUKE IS MINIMIZING ITS COST OF OPERATING EDWARDSPORT BY CONTINUING TO OPERATE IT AS AN IGCC, RATHER THAN RUNNING IT AS A NATURAL GAS FACILITY?

A No. Indeed, the information in this proceeding suggests there are significant costs that could be avoided for Edwardsport if it is operated as a natural gas facility, and no longer operated as an IGCC. I state this for the following reasons:

1. The dispatch cost of Edwardsport on natural gas going forward appears to be far cheaper than continuing to operate it as an IGCC. Indeed, a comparison of the Edwardsport fuel cost operating as an IGCC appears to be more expensive than simply buying power on a forward basis in most hours of the year from the Midcontinent Independent System Operator, Inc. ("MISO") energy market. Moreover, if Edwardsport were run as a natural gas unit, it could respond more quickly to price signal changes in the MISO market.

2. The Company incurs significantly higher fixed O&M expenses to operate Edwardsport than comparable natural gas combined cycle units. This fixed O&M differential incudes the cost of operating the coal gasification facilities and coal handling facilities. If Edwardsport is operated as natural gas, these fixed O&M costs associated with coal handling and coal gasification could be avoided.

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[50] Duke's response to IG 25.10(a), provided as Attachment MPG-1, pages 73-74.

[51] See also Duke's confidential response to Sierra Club DR 2.2 (relating to the Equivalent Forced Outage Rate), provided as Attachment MPG-1, pages 97-98.

[52] Duke 2018 IRP at 58-59, available at https://www.duke-energy.com/_/media/pdfs/for-your-home/indiana-irp/duke-energy-indiana-public-2018-irp.pdf.

3. Post-in-service capital investment costs for Edwardsport are more expensive than conventional natural gas CC units. Capital investments include the coal handling and coal conversion equipment, which could be avoided if Edwardsport is operated as a natural gas facility.

4. Also, Duke's information in the case indicates that there may be a detriment to converting Edwardsport to natural gas from an IGCC due to loss of potential net capacity output from this facility. However, as detailed in Mr. Dauphinais' testimony, Duke's forecast indicated that it has more capacity than needed to serve its retail load for many years after the test year. Hence, the reduction of Edwardsport capacity will not create the need for Duke to replace this resource capacity cost.

III.A.3. Edwardsport Dispatch Costs

Q WHY DO YOU BELIEVE THAT EDWARDSPORT'S DISPATCH COSTS MAY BE MORE ECONOMICAL OPERATING ON NATURAL GAS THAN CONTINUING TO OPERATE AS A COAL GASIFICATION FACILITY?

A I state this simply by a comparison of Edwardsport's expected variable fuel production costs as an IGCC compared to the costs which may be realized if it were converted to natural gas only. Specifically, operating Edwardsport as an IGCC requires significant amounts of ancillary use of electricity generated to handle the coal gasification and coal conversion procedures. This large ancillary use of energy generation results in a net cost of energy output for the facility to be far more expensive than it would be by simply operating the plant on natural gas.

When asked to identify the dispatch costs, Duke was not able to provide a dispatch cost on natural gas only because it has not performed the analysis.[53] Further, in estimating the operating heat rate of this facility on natural gas, Duke also commented that it could not identify what the heat rate would be on a stand-alone operation on natural gas because the Company has never operated the facility only on

[53] Duke response to IG 8.3, included in Attachment MPG-1, page 23-25.

natural gas and that some gasification systems are always in service. However, in that same response Duke provided the Edwardsport design heat rate for the combined cycle gas turbines that can be operated on either syngas or natural gas.[54]

Q CAN YOU APPROXIMATE THE ECONOMICS OF DISPATCHING EDWARDSPORT ON EITHER NATURAL GAS AND ITS CONTINUED DISPATCH ON SYNGAS?

A Yes. However, it is important to note that dispatching on syngas has two important implications. First, the actual energy cost for dispatch must reflect the amount of energy necessary to operate the coal handling and coal to gas conversion processes, and also based on Duke's prior testimony, the unit must operate as a must-run facility because its output cannot be modified in order to respond to the economics of normal economic dispatch operation.

Based on Edwardsport's 2018 heat rates on syngas and natural gas under its existing configuration, and the heat rate on natural gas that Duke provided, I estimated a $/MWh dispatch cost for each scenario using the forecasted fuel prices Duke provided in Confidential attachment IG 14.25-A. My analysis is provided as Confidential Attachment MPG-9 and summarized in Figure 2 below. As shown below, operating Edwardsport as an IGCC over the next 10 years will be more expensive then operating it as a natural gas unit.

[54] Duke response to IG 17.4, included in Attachment MPG-1, pages 40-41.

[CONFIDENTIAL SECTION BEGINS]

[redacted]

[CONFIDENTIAL SECTION ENDS]

In this dispatch cost I also used a proxy for the variable O&M for Edwardsport operated as an IGCC and a combined cycle generating unit. These proxy O&M statements were based on Energy Information Administration ("EIA") projections for these types of facilities. For an IGCC operation that represented $5.00/MWh, and as a relatively modern CCGT that represented approximately $3.50/MWh.[55]

[55]U.S. Energy Information Administration Independent Statistics & Analysis: "Capital Cost Estimates for Utility Scale Electricity Generating Plants," November 2016 at 7, and "Addendum: Capital Cost Estimates for Additional Utility Scale Generating Plants," April 2017 at 4.

Q WHAT DOES FIGURE 2 ABOVE TELL YOU ABOUT THE DISPATCH COSTS OF EDWARDSPORT ON EITHER NATURAL GAS OR AS A CONTINUED OPERATION AS AN IGCC?

A As shown in Figure 2 above, operating Edwardsport on natural gas would allow it to produce electricity at much lower cost than continuing to operate it as an IGCC. Projected for year 2020, based on NYMEX forward gas prices, Duke's forward gas prices, and Duke's forward coal prices for Edwardsport, IGCC dispatch costs would be around $24 to $25/MWh over the period 2020 through 2029. This is substantially lower than the projected dispatch cost for Edwardsport operating as an IGCC, which would include dispatch costs of around $28 up to around $30/MWh over this same time period. Also of significance, dispatch of this facility on natural gas would mean that this facility likely would be an economic resource option to MISO in the joint dispatch relative to the Indiana Hub. The outlook for the on-peak and off-peak prices for this hub suggest that Edwardsport operating as an IGCC may be dispatched during the on-peak period but would not be dispatched during the off-peak period. If it were dispatched on natural gas, its dispatch costs would be cheap enough to operate it during both on-peak and off-peak periods. As such, even if the capacity for Edwardsport is greater under IGCC operations, its dispatch costs may limit the economic utilization of this facility based on forward market energy clearing prices.

Q PLEASE DESCRIBE POTENTIAL ADVANTAGES OF OPERATING EDWARDSPORT AS A NATURAL GAS UNIT DUE TO MUST-RUN LIMITATIONS AS AN IGCC.

A When its gasifiers are available or operating, Duke offers Edwardsport into the MISO resource dispatch with a commitment status of must-run. With this commitment status, Edwardsport follows MISO's dispatch direction between the minimum and maximum capability of the unit.[56]

Duke has testified that its approach of offering Edwardsport into MISO as a "must-run" is typical of large coal generating units, because large coal units typically have longer start up times than natural gas units.[57] This is to account for the need to avoid cycling units with long lead times off when current market pricing indicates it would not be economic to run for a short period of time.[58] This issue may be even more pronounced at Edwardsport, which has, at least historically, required a longer start-up time and more start-up costs than is typical for a base load coal unit.[59]

Moreover, when Edwardsport is offered as a must-run such as is done when the unit is running on syngas, the unit is no longer eligible for certain make-whole payments from MISO. By offering Edwardsport as a must-run, it loses eligibility for either the Day Ahead make-whole payment or the real time make-whole payment.[60]

In contrast, the start-up time for Edwardsport on natural gas is relatively quick, and therefore Edwardsport could respond more quickly to price signals from MISO if it were run on natural gas.[61] During times when syngas is not available and the station is available on natural gas operation, Edwardsport is typically be offered to MISO with a commitment status of "economic" and can be committed and dispatched at MISO's discretion to minimize energy costs.[62]

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[56] Swez Direct in IURC 38707-FAC 121 (7/31/19) at 19, provided as Attachment MPG-10.

[57] Id., see also Swez Rebuttal in Cause 43114 IGCC-12/13 (1/15/15) at pg. 7, 11, attached to my testimony as Attachment MPG-11.

[58] Swez Rebuttal in Cause 43114 IGCC-12/13 (1/15/15) at pg. 7, 11, attached to my testimony as Attachment MPG-11.

[59] FAC 101 Transcript (cross-examination of Duke witness John D. Swez) (9/18/14) at 23, 40-41, provided as Attachment MPG-41.

[60] FAC 101 Transcript (cross-examination of Duke witness John D. Swez) (9/18/14) at 19, provided as Attachment MPG-41.

[61] FAC 101 Transcript (cross-examination of Duke witness John D. Swez) (9/18/14) at 42, provided as Attachment MPG-41.

[62] Swez Direct in IURC 38707-FAC 121 (7/31/19) at 19, attached to my testimony as Attachment MPG-10.

III.A.4. Fixed O&M Costs

Q WHY DO YOU BELIEVE THAT EDWARDSPORT'S FIXED O&M COSTS MAY BE SIGNIFICANTLY REDUCED IF IT WERE CONVERTED TO A NATURAL GAS ONLY FACILITY?

A If Edwardsport's dispatch costs are lower on natural gas, then all the fixed O&M costs associated with coal handling and operation of the coal to gas conversion facility can be avoided by shutting these facilities down or placing them in cold storage for use at a later time. Based on my assessment as described below, the fixed O&M costs associated with operating a traditional combined cycle unit, which Edwardsport could be operated as, are significantly lower than Edwardsport's fixed O&M costs it seeks to recover in this proceeding.

Q IS THERE A WAY OF APPROXIMATING THE POTENTIAL SAVINGS OF OPERATING EDWARDSPORT?

A Based on data responses, Duke was not able to separate Edwardsport fixed O&M costs from coal handling and coal to gas conversion from operating as strictly a combined cycle gas-fired unit.[63] Based on a comparison of Edwardsport to other similar vintage combined-cycle gas units ("CCGU"), it looks promising that Duke could avoid significant annual fixed O&M expense if it operated as a natural gas facility. I compared Edwardsport to other CCGUs that went into services within the last 10 years, are larger than 250 MW, and are in MISO or are operated by one of Duke Indiana's affiliate companies. My comparison is provided as Attachment MPG-12.

[63]Duke responses to IG 8.2, 8.3, and 8.4. Provided as Attachment MPG-1 pages 22, 23-25, and 26, respectively.

A comparison of Edwardsport IGCC to the fixed O&M cost of other similar vintage combined cycle generating units operating in MISO shows that Edwardsport's fixed non-fuel O&M cost on a dollar per kW-year is materially more expensive than operating a traditional CCGT unit. As shown in Table 3 below, Edwardsport's fixed non-fuel O&M on a five-year basis has been around **$155/kW-year**, where the most expensive of the proxy group or other CCGTs was around $**18.85/kW-year**.

TABLE 3

Combined Cycle Comparison
Non-Fuel Production Cost ($/kW-year)

Combined Cycle Unit	State	Operating Capacity	2014	2015	2016	2017	2018	5-year Average
Crystal River CC	Florida	1,640	N/A	N/A	N/A	N/A	$ 1.37	$ 1.37
Marshalltown Generating Station	Iowa	706	N/A	N/A	N/A	$ 5.98	$ 9.01	$ 7.50
W.S. Lee Combined Cycle Project	South Carolina	750	N/A	N/A	N/A	N/A	$ 8.98	$ 8.98
Eagle Valley CC	Indiana	671	N/A	N/A	N/A	N/A	$ 12.00	$ 12.00
Nelson Energy Center	Illinois	612	N/A	$ 12.23	$ 11.90	$ 12.60	N/A	$ 12.25
Ninemile 6	Louisiana	608	N/A	$ 9.64	$ 13.79	$ 14.33	$ 12.06	$ 12.46
St. Joseph Energy Center	Indiana	703	N/A	N/A	N/A	N/A	$ 12.71	$ 12.71
AMP Fremont Energy Center	Ohio	724	$ 12.20	$ 12.65	$ 12.50	$ 12.82	$ 13.40	$ 12.72
H.F. Lee Energy Complex	North Carolina	1,059	$ 13.73	$ 9.42	$ 24.36	$ 8.93	$ 10.60	$ 13.41
Moselle CC Plant	Mississippi	285	$ 12.74	$ 13.39	$ 13.99	$ 14.32	$ 15.06	$ 13.90
Buck CC	North Carolina	724	$ 17.05	$ 16.62	$ 13.63	$ 12.60	$ 15.31	$ 15.04
Dan River CC	North Carolina	718	$ 14.31	$ 19.29	$ 14.11	$ 17.46	$ 14.43	$ 15.92
Bartow CC	Florida	1,197	$ 14.91	$ 20.76	$ 22.32	$ 14.02	$ 15.69	$ 17.54
L V Sutton CC	North Carolina	719	$ 11.90	$ 19.02	$ 14.72	$ 14.83	$ 29.71	$ 18.04
Riverside Conversion	Minnesota	502	$ 18.76	$ 16.00	$ 17.21	$ 23.15	$ 19.15	$ 18.85
Edwardsport IGCC	**Indiana**	**618**	**$103.44**	**$142.01**	**$204.02**	**$170.34**	**$158.21**	**$ 155.60**

Source:
Attachment MPG-12.

As outlined in Table 3 above, while Edwardsport IGCC O&M costs have varied from year to year, they have consistently been substantially higher than combined cycle generating units of reasonably similar vintage as the Edwardsport facility.

Q DOES THIS COMPARISON OF THE EDWARDSPORT IGCC TO OTHER REGIONAL MISO COMBINED CYCLE UNITS PRODUCE A VALID WAY OF COMPARING THE ECONOMIC OPERATION OF EDWARDSPORT?

A Yes. This comparison to the cost of other resources is similar to the information provided by Duke Indiana to the IURC when it first sought a CPCN for approval to develop Edwardsport. Duke originally sought recovery of the IGCC from customers based on its projections presented to the Commission that showed that Edwardsport would be a low cost, and “competitive” energy resource that would be frequently dispatched, and ultimately that Edwardsport would be competitive with alternative resources available to Duke.[64] However, as shown on my Attachment MPG-12, Edwardsport is among the more expensive new combined cycle generating facilities.

Q WHY DOES THE EDWARDSPORT IGCC HAVE HIGHER O&M EXPENSES RELATIVE TO OTHER COMBINED CYCLE UNITS?

A One significant difference in O&M relates to the workforce required to run Edwardsport is much larger than what is required to run a comparable-sized natural gas facility. Edwardsport’s O&M expenses reflect significant labor and contract employee expenses. Duke provided a breakdown on employee and contractor costs in response to IG 2.11, included in my Attachment MPG-1, pages 5-8. In 2018, Edwardsport had an average of 202 employees and 24 matrixed employees. These employees represented $33.3 million of Edwardsport’s O&M costs. In the same year, Edwardsport had an average of 126 contractors representing $21.8 million of Edwardsport’s O&M costs. This is significantly higher than the 97 employees Duke projected in Cause No. 43114.[65]

Table 4 below shows that Edwardsport has the highest number of employees compared to the CCGUs in the tables above.

[64] Duke Energy Indiana, Inc., Cause No. 43114, at 9-10, and 15-22 (IURC Nov. 20, 2007).

[65] Cause No. 43114 Hearing Transcript (6/18/07), cross examination of Kay Pashos, page 58, relevant portions, provided as Attachment MPG-1, pages 99-102.

TABLE 4

Number of Employees

Unit	Average
Riverside Conversion	19
AMP Fremont Energy Center*	23
Nelson Energy Center*	24
Ninemile 6	29
Buck CC	45
Dan River CC	45
Moselle CC Plant*	54
L.V. Sutton CC	61
Bartow CC	65
H.F. Lee Energy Complex	71
Edwardsport IGCC	123

Sources:
FERC Form 1.
* Company's website.

An additional factor is simply that fixed O&M for traditional combined cycle units do not include the fixed cost associated with operating the coal to gas conversion process and coal handling equipment. As such, because Edwardsport already has the facilities in place to take delivery of natural gas, it is likely that a significant portion, or possibly all of the fixed O&M associated with the coal conversion and coal handling could be eliminated if it were operating strictly as a natural gas-fired combined cycle generating unit.

Q CAN YOU APPROXIMATE THE POTENTIAL SAVINGS OF FIXED O&M IF EDWARDSPORT IS OPERATED ON NATURAL GAS AS OPPOSED TO AN IGCC?

A I can approximate it but identifying a precise figure requires Duke to provide more information. Edwardsport's total O&M, including station and non-station department O&M but excluding payroll taxes, was $105.6 million in 2018. This equals a cost of

\$170.88 per kW-year.[66] I compared this to the non-fuel production cost for Edwardsport of \$158.21 per kW-year reported to FERC, for a difference of \$12.67/kW-year between the values used in my CCGU comparison above and the total O&M the Company proposes to include in rates. Edwardsport's historical and forecasted O&M costs is provided as Attachment MPG-13.

The highest comparable non-fuel production cost for a combined cycle unit in my Table 2 comparison was approximately \$19/kW-year. Using \$19/kW-year, and escalating for inflation and the \$12.67 kW-year difference between Edwardsport's total O&M and FERC non-fuel production costs, Edwardsport's O&M on natural gas for the forecasted test period is estimated at \$20.4 million. This results in a savings of \$81.6 million over Duke's forecasted Edwardsport O&M costs in 2020 of \$102.0 million. My analysis is included as Attachment MPG-14. This analysis excludes the 2020 major outage related O&M costs, which I address below.

My adjustment is shown on line 17 of Confidential Attachment MPG-5. The adjustment has a revenue requirement impact of **[redacted]** per year.[67]

Q IS THERE POTENTIAL SAVINGS FROM THE PERIODIC NON-ROUTINE MAJOR MAINTENANCE SAVINGS OF OPERATING EDWARDSPORT IF IT IS CONVERTED TO A NATURAL GAS FACILITY?

A I can approximate it but a precise figure requires more assessment and input from Duke. However, Duke is projecting significant outage-related O&M expenses in 2020. The outage will be Edwardsport's largest to date. The major outage is part of a seven year outage cycle at Edwardsport and Duke proposes to only include 1/7th of the \$46.4 million outage O&M expenses in base rates.

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[66] \$105.6 million / 618 MW.
[67] **[redacted]**.

Duke provided a breakdown of the outage expenses as Confidential Attachment IG 8.5-A, provided as Attachment MPG-1, pages 27-28. On this schedule, it shows that of the annual $46.4 million of major non-routine annual O&M costs, approximately **[redacted]** is related strictly to the gasification plant, **[redacted]** is related to common gasification and power block plant, and approximately **[redacted]** is related to the power block plant including the heat recovery, steam generator, combustion turbines and related equipment. As such, it appears that of the $46.4 million of major plant equipment, approximately **[redacted]** is related to coal gasification and only about **[redacted]** is related to the combined cycle generating unit. I proposed to remove these expenses from Duke's base rates. My adjustment is included on line 26 of Confidential Attachment MPG-5.

My adjustment has a revenue requirement impact of **[redacted]**.[68]

<u>III.A.5. Incremental Capital Investments</u>

Q WHY DO YOU BELIEVE THAT EDWARDSPORT'S INCREMENTAL CAPITAL INVESTMENTS (OR POST-IN-SERVICE CAPITAL COSTS) MAY BE REDUCED SIGNIFICANTLY IF IT WERE CONVERTED TO A NATURAL GAS ONLY FACILITY?

A Again, for a precise figure more data must be provided by Duke or a detailed assessment should be made by the utility. However, simply operating the unit as a natural gas facility should allow Duke to avoid most if not all capital improvements needed to coal handling and coal to natural gas conversion facilities. Therefore, just continuing to operate it as an IGCC should allow Duke the opportunity to avoid significant ongoing capital investments into Edwardsport.

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[68] **[redacted]**.

Q IS IT POSSIBLE TO ESTIMATE THE POTENTIAL RECURRING ANNUAL CAPITAL INVESTMENT SAVINGS IF EDWARDSPORT WERE CONVERTED TO A NATURAL GAS FACILITY?

A Yes, but again, a precise figure requires more study and data input from Duke.

Duke provided a breakdown of the Edwardsport 2018, 2019, and 2020 capital costs as Confidential Attachment OUCC 11.3, provided as Confidential Attachment MPG-1, pages 85-88. Examination of the costs incurred during this period is important because pursuant to the 2018 Settlement Agreement, post-in-service capital costs incurred after January 1, 2018 are to be reviewed in this rate case.[69] I compared Duke's proposed capital spending to my CCGU comparison group.

Table 5, below, reports the change in total plant for each unit as reported on the FERC Form 1. As shown in the table, the annual capital improvements for a natural gas combined cycle generating unit on a $/kW-year basis has averaged less than $7 for the proxy groups. In comparison, the annual capital expenditure for Edwardsport in 2019 and 2020 ranged from $30.74/kW-year up to $82.52/kW-year.[70] The annual capital improvements needed to maintain Edwardsport and its coal gasification facilities are again dramatically higher than the costs associated with a combined cycle generating unit. Indeed, it appears as though the capital expenditures needed for the coal handling and coal gasification could reduce annual capital additions to Edwardsport anywhere from 50% to 90% of annual capital additions. These find their way into the revenue requirement in this case by a reduction to the rate base, and related depreciation expense on Edwardsport.

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[69] 2018 Settlement Agreement at Paragraph 3, included in Attachment MPG-7.
[70] Gurganus Direct at 19. $19 million (2019 capital expenditures) / 618 MW = $30.74/kW-year and $51 million (2020 capital expenditures) / 618 MW = $82.52/kW-year.

TABLE 5

Change in Cost of Plant ($/kW-year)

Unit	2018	2017	Average
Edwardsport IGCC	$37.36	$18.35	$27.86
Bartow CC	($3.88)	$6.46	$1.29
Buck CC	($15.03)	$1.00	($7.02)
Dan River CC	$1.52	$4.74	$3.13
H.F. Lee Energy Complex	$2.14	$2.57	$2.35
L V Sutton CC	($13.95)	$125.36	$55.71
Marshalltown Generating Station	($3.12)	$0.00	($1.56)
Ninemile 6	$3.35	$0.83	$2.09
Riverside Conversion	($0.12)	($6.53)	($3.32)
Average (Excluding Edwardsport)			$6.58

Source:
2016-2018 Ferc Form 1 data, multiple utilities.

III.A.6. Other Operating Impacts

Q ARE THERE OTHER OPERATING BENEFITS, AND POSSIBLY DETRIMENTS, IF EDWARDSPORT WERE TO OPERATE AS ONLY A NATURAL GAS FACILITY?

A Yes. The potential detriment is the output of Edwardsport if it operates on natural gas. The net capacity rating of Edwardsport on syngas and on natural gas is identified in Table 6 below.

TABLE 6

<u>Edwardsport Capacity Output</u>
(MW)

Description	IGCC	Natural Gas
Summer Capacity Rating	595	434

Source: Duke response to IG 17.2, included in Attachment MPG-1, page 39.

There would, however, be significant potential operating savings if Edwardsport operated as a natural gas facility rather than an IGCC. These operating savings would be created by avoiding the fixed O&M costs associated with a coal handling and coal gasification facility, and avoiding capital investment costs for coal handling and coal gasification.

Q WOULD LOSS OF THE CAPACITY BY CONVERTING FROM AN IGCC TO NATURAL GAS PRESENT UNECONOMIC COSTS ON CUSTOMERS?

A I do not believe so because of the significant O&M and capital addition costs that likely could be avoided by operating Edwardsport as a natural gas-fired unit as opposed to continued operation of an IGCC. For example, the difference in capacity noted by Duke of 160 MW equates to higher O&M costs compared to a traditional IGCC of approximately $80 million. In addition, as discussed in more detail in IG witness Dauphinais' testimony, this loss of Edwardsport capacity will not result in the Company being capacity deficient in meeting its resource requirement to serve its retail customers' load demands. As outlined in Mr. Dauphinais' testimony, this reduction in Edwardsport capacity, along with the exclusion of allocation of certain wholesale capacity that had previously been used to serve wholesale customers to the retail customers' load will still leave the Company's capacity sufficient for many years beyond the test year.

Q DOES OPERATING EDWARDSPORT ON NATURAL GAS INSTEAD OF SYNGAS HAVE TAX INCENTIVE IMPLICATIONS.

A No, I do not believe so. I examined the impact of my proposal on three Edwardsport tax incentives.

First, Ms. Douglas states on page 69 of her direct testimony that Company received approval for a $133.5 million federal Advanced Coal Investment Tax Credit. The credit is not currently reflect in rates because Duke cannot realize the credit while the Company is operating at a loss. Duke estimates that it will be able to use the credit in 2022 and 2023.[71] When reflected in rates, the credit will be amortized over the remaining life of Edwardsport, approximately 23 years in 2022.[72] This results in an annual credit of $5.3 million.[73] In response to IG 9.1 (included in my Attachment MPG-1, page 29), the Company stated, "There are no further federal requirements necessary to satisfy eligibility for the federal tax investment tax credit." Therefore, I believe the Company may still be able to access the credit even if Edwardsport operates on natural gas.

Second, Ms. Douglas states on pages 59-60 of her direct testimony that Company has qualified for a Coal Gasification Technology Investment Tax Credit of $15.0 million per year for 10 years ("state tax credit"). Duke began receiving the credit in 2013 and will continue to receive it until 2022. Ms. Douglas's testimony suggests Edwardsport must continue to use Indiana coal to satisfy the requirements of the state

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[71] Panizza Direct at 9.
[72] Duke Response to IG DR 5.6(a).
[73] Duke Response to IG DR 5.6(b).

tax credit. The Company provided additional information on the state tax credit in response to IG 5.3, included in my Attachment MPG-1, page 10. This response does not claim the plant must continue to operate as an IGCC to receive a credit. However, even if the Company lost the state tax credit, the loss is more than offset by the savings I identified above given the amount of the tax credit and the fact that it expires in 2022.[74]

Third, Duke receives a property tax abatement for Edwardsport ("county tax abatement").[75] The amount of the county tax abatement reduces each year until it expires in 2022 or 2023,[76] and is $3.2 million (retail) in the test year of 2020. This county tax abatement is based on the number of jobs at Edwardsport. However, even if the Company lost the county tax abatement, the loss is more than offset by the savings I identified above, given that the amount of the tax credit and the fact that it expires in 2022 or 2023.[77]

Q DOES OPERATING EDWARDSPORT ON NATURAL GAS INSTEAD OF SYNGAS PRODUCE OTHER OPERATING BENEFITS?

A Yes. Duke provided a supplemental data response that states the Company examined the merits, but not the costs, of running Edwardsport on natural gas from an emissions perspective.[78] The analysis was performed as an alternative scenario for the Duke Energy Indiana 2018 IRP. Duke calculated that Edwardsport's current configuration would emit 3.4 million tons of CO2 in 2030. If Edwardsport was run only on natural

[74] Douglas Revised Direct at 75.
[75] Duke Response to IG 5.4, provided as Attachment MPG-1, pages 11-13.
[76] Douglas Revised Direct at 75 (indicating the county property tax abatement ends in 2022); Duke's Response to IG DR 5.4 (indicating the county property tax abatement ends in 2023.
[77] Douglas Revised Direct at 75 (indicating the county property tax abatement ends in 2022); Duke's Response to IG DR 5.4 (indicating the county property tax abatement ends in 2023.
[78] Duke supplemental response to IG 21.3. Provided as Attachment MPG-1, pages 47-49.

gas, Duke estimated the plant would emit 1.5 million tons of CO_2 in 2030, for a savings of 1.9 million tons.

<u>III.A.7. Edwardsport Recommended</u>

Q SHOULD THE COMMISSION FIND THAT DUKE HAS UPHELD ITS BURDEN TO DEMONSTRATE THAT IT IS REASONABLY AND PRUDENTLY OPERATING EDWARDSPORT AS AN IGCC AND THAT IS RESULTING O&M IS REASONABLE AND PRUDENT?

A No. As outlined above, Duke's rationale for developing an IGCC as opposed to a CC generating unit at Edwardsport was based on a very different gas market that existed in 2006 compared to the gas market today. This significant change in the structure and the cost of natural gas has created serious doubt about the economic cost of operating the Edwardsport IGCC as an integrated coal gasification unit. Indeed, this analysis strongly suggests that it would be more economical to operate Edwardsport as a natural gas-fired combined cycle generating unit over at least the intermediate term. As such, costs that can be avoided by operating Edwardsport as a natural gas facility should not be included in rates in this proceeding. Therefore, I recommend the Commission remove fixed costs needed for the operation of the coal gasification and coal handling facilities, and remove capital investment costs needed for these same facilities.

Q WHAT WOULD BE THE TOTAL COST IN THIS PROCEEDING IF EDWARDSPORT WERE OPERATED AS A NATURAL GAS FACILITY GOING FORWARD, AND ALL COAL GASIFICATION FACILITIES WERE EITHER SHUT DOWN OR PLACED IN STORAGE RESERVE FOR OPERATIONS IN FUTURE PERIODS?

A As outlined in this section of my testimony, my proposed adjustments to the Edwardsport IGCC costs, which reflect the allowance of only operating Edwardsport as a natural gas combined cycle unit include the following:

1. Fixed O&M costs reduction of **[redacted]**.
2. Annual recurring major maintenance costs: **[redacted]**.

III.B. Proposed Accounting Deferrals

Q HAS THE COMPANY PROPOSED TO INCLUDE DEFERRED COSTS, TREAT THEM AS REGULATORY ASSETS, AND AMORTIZE THEM TO COST OF SERVICE IN THIS PROCEEDING?

A Yes. The Company in total is proposing to include approximately $433.6 million of regulatory assets, to be amortized over various periods, for an amortization period on average equal to approximately 10.7 years.

Q WHAT DO YOU RECOMMEND WITH RESPECT TO THIS PROPOSAL?

A My proposed adjustments to the deferrals and the number of regulatory assets are outlined in Table 7 below.

SELECTED EXHIBITS FROM

THE PUBLIC VERSION OF THE

REVISED VERIFIED DIRECT

TESTIMONY AND ATTACHMENTS

OF MICHAEL P. GORMAN

IN CAUSE NO. 45253

IG
IURC Cause No. 45253
Data Request Set No. 2
Received: July 15, 2019

IG 2.13

Request:

Please refer to Mr. Gurganus' Direct testimony at page 16, line 20 to page 17, line 2.

a. Please identify with specificity what is included within the $6.7 million in miscellaneous administrative and general benefit costs for Edwardsport that were forecasted by other groups.

b. Please explain why the $6.7 million is not included within the Power Production O&M attributable to Edwardsport figure of $139.1 million.

c. Does the $46.4 million in expenses associated with the major outage include any portion of the $6.7 million in miscellaneous administrative and general benefit costs? If so, how much?

Response:

a. A summary of the 2020 Edwardsport O&M budget components is as follows:

Station O&M	$145.8
O&M from non-station departments	2.6
Total O&M	148.4
Less: A&G accounts (920-935)	9.3
Power production O&M accounts	$139.1

The $6.7 million is the $9.3 million of A&G costs from station and non-station departments less $2.6 million of O&M (Power Production and A&G) from non-station departments. $8.9 million of the $9.3 million A&G represents fringe benefit costs charged to FERC account 926. The remaining $0.4 million represents other A&G costs.

b. The $139.1 million represents station and non-station Power Production O&M in FERC accounts 500-514 for steam power generation O&M costs only. Additional costs attributable to Edwardsport in the 2020 forecast include A&G for Edwardsport and for non-station departments that support Edwardsport.

c. The $46.4 million in Power Production O&M expenses associated with the major outage does not include any A&G costs.

Witness: Cecil Gurganus

IG
IURC Cause No. 45253
Data Request Set No. 25
Received: September 26, 2019

IG 25.10

Request:

Please refer to DEI's response to IG DR 20.2, wherein DEI indicated that "*Generating facility direct company labor (unloaded) is identifiable as a fixed O&M cost category (with the exception of Edwardsport IGCC)...*" In the same answer, Duke also indicated that "*Due to the structure of how the Edwardsport O&M is forecasted for long-term IRP modeling purposes, these components [identified in the table above] are not individually broken out.*"

a. Please describe the structure of how Edwardsport O&M is forecasted for long-term IRP modeling purposes.

b. Why is the Edwardsport IGCC treated differently than other DEI generating units?

c. Please describe in detail the manner in which the Edwardsport IGCC O&M was modeled in the 2018 IRP.

d. Please identify all Edwardsport IGCC O&M modelling information used in the 2018 IRP.

Objection:

Duke Energy Indiana objects to this request as vague, ambiguous, overly broad and unduly burdensome, in particular as it relates to the "manner in which" Edwardsport was modeled is vague, and the request to "identify all" modeling information used is not reasonably limited in scope. Duke Energy Indiana further objects as this request is not reasonably calculated to lead to the discovery of admissible evidence in this proceeding.

Response:

Subject to and without waiving the above objection, Duke Energy Indiana responds as follows:

a. See objection. At a high level, just like the other Duke Energy Indiana units, forward forecast long-run O&M costs for Edwardsport are modeled with fixed and variable O&M components. The variable O&M cost component adjusts with the forward generation projection from the IRP model. Typically, Duke Energy Indiana models O&M costs (fixed and/or variable) used for long-term IRP modeling purposes as long-run costs. They are not generally intended to be comparable to any specific year of near-term cost projection that may be budgeted and/or otherwise forecasted with fine detail, including any expectations of timing for planned outages. However, for Edwardsport, an exception was made given the Company's request for levelization of the major outage costs, and specific annual costs for the major outages were depicted in the Edwardsport O&M cost for IRP modeling every seven years, at 2020, 2027, and 2034. Additionally, projecting forward from the near-term O&M budget costs, Duke Energy Indiana anticipates a downward trend of total O&M costs at Edwardsport, and this trend was reflected in the O&M costs used in the 2018 IRP. This expectation is based on our plans for continuing to tackle key equipment degraders, as well as continuing to find cost efficiencies and optimize our site operations and management processes. That may include further reductions in contractor staffing, ongoing efficiency improvements in the execution of outages, and maintenance cost reductions achieved from equipment reliability improvements.

b. Please see response to subpart (a) above. The root development of the Edwardsport O&M costs for IRP modeling purposes is currently conducted differently from the other units in the fleet because its cost forecast is still maturing (declining), whereas the costs for the rest of fleet are mature and can be modeled statically.
c. See objection, and response to subpart (a) above.
d. See objection.

Witness: Keith B. Pike / Cecil T. Gurganus

IG
IURC Cause No. 45253
Data Request Set No. 8
Received: August 5, 2019

IG 8.4

Request:

Concerning the Edwardsport IGCC plant, please provide the following:

a. An economic net present value revenue requirement projection of the all-in cost to customers if the plant is operated on natural gas only from 2020 through the end of its expected operating life.

b. The expected all-in net present value revenue requirement cost of operating the Edwardsport IGCC as both a syngas and natural gas facility from 2020 through its expected operating life.

c. Please identify the major assumptions and input factors used to construct the revenue requirement forecast in subparts a. and b. above.

d. Provide all calculations on electronic spreadsheet with all formulas intact.

Objection:

Duke Energy Indiana objects to this request to the extent it calls for speculation regarding events that may or may not occur. In addition, Duke Energy Indiana objects to this request to the extent it seeks a calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing.

Response:

See objections.

IG
IURC Cause No. 45253
Data Request Set No. 23
Received: September 24, 2019

IG 23.2

Request:

Please refer to DEI's response to IG DR 8.4. Duke did not provide a response, other than to say "*See objections.*" Duke's objection states that "*Duke Energy Indiana objects to this request to the extent it calls for speculation regarding events that may or may not occur. Duke Energy Indiana further objects to this request to the extent it seeks a calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing.*"

a. Is it DEI's position that DEI has never analyzed, in whole or in part, any of the information requested in the Industrial Group's data request?

b. Alternatively, is it DEI's position that DEI has conducted such analysis, in whole or in part, but objects to producing the analysis?

c. If the answer to subpart (b) above is yes, is the sole basis for DEI's objection to producing the discovery DEI's contention that "it calls for speculation regarding events that may or may not occur"? Please explain your answer in detail.

Objection:

Duke Energy Indiana objects to this request as not reasonably calculated to lead to admissible evidence in this proceeding.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Duke Energy Indiana is not aware of having performed the requested analysis.
b. No.
c. N/A

IG
IURC Cause No. 45253
Data Request Set No. 23
Received: September 24, 2019

IG 23.1

Request:

Please refer to DEI's response to IG DR 8.3(a). Duke did not provide a response, other than to say "*See objection.*" Duke's objection states that "*Duke Energy Indiana objects to this request to the extent it calls for speculation regarding events that may or may not occur. Duke Energy Indiana further objects to this request to the extent it seeks a calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing.*"

a. Is it DEI's position that DEI has never analyzed, in whole or in part, any of the information requested in the Industrial Group's data request?

b. Alternatively, is it DEI's position that DEI has conducted such analysis, in whole or in part, but objects to producing the analysis?

c. If the answer to subpart (b) above is yes, is the sole basis for DEI's objection to producing the discovery DEI's contention that "it calls for speculation regarding events that may or may not occur"? Please explain your answer in detail.

Objection:

Duke Energy Indiana objects to this request as not reasonably calculated to lead to admissible evidence.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Duke Energy Indiana is not aware of having performed the requested analysis.
b. No.
c. N/A

IG
IURC Cause No. 45253
Data Request Set No. 17
Received: September 5, 2019

SUPPLEMENTAL RESPONSE 10/8/19
SUPPLEMENTAL INFORMATION IS IN BOLD
IG 17.6

Request:

Has DEI (or any agent/contractor of DEI) examined the merits and/or costs of running the Edwardsport IGCC as a natural gas unit only? If so, please provide all reports, communications, analysis, and other documents relating to or discussing this issue.

Objection:

Duke Energy Indiana objects to this data request as the term "merits and/or costs" is vague and ambiguous. Duke Energy Indiana also objects to this request to the extent it seeks an analysis, calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing. Duke Energy Indiana further objects to this request to the extent that it seeks to discover information or the production of documents protected by the attorney-client privilege or the work product doctrine privilege.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: N/A

Supplemental Response:

See supplemental response to IG 21.3.

IG
IURC Cause No. 45253
Data Request Set No. 21
Received: September 20, 2019

IG 21.3
SUPPLEMENTAL RESPONSE 10/8/19
SUPPLEMENTAL INFORMATION IN BOLD

Request:

Please refer to DEI's response to IG DR 17.6. DEI was asked whether the company, or any agent/contractor of DEI, has examined the merits and/or costs of running the Edwardsport IGCC as a natural gas unit only, and to provide any such analysis if so. DEI objected and answered "N/A."

a. Is it DEI's position that no such analysis has been conducted?

b. Alternatively, is it DEI's position that such analysis has been conducted, but that DEI objects to producing it?

c. If the answer to subpart (b) is yes, please provide a privilege log.

Objection:

Duke Energy Indiana objects to this request as overbroad and unduly burdensome because it is not limited to a reasonable and relevant scope or time period. Duke Energy Indiana also objects to this request to the extent it seeks attorney-client privileged communications or attorney work product.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. No. Duke Energy Indiana has done analyses regarding Edwardsport in the past under attorney-client privilege, some of which may have been related to the request above and in IG 17.6.
b. See the Company's response to subpart (a).
c. Duke Energy Indiana will endeavor to provide a privilege log for any analyses performed in 2018 or 2019 as soon as practically possible.

Supplemental Response:

c. **In the spirit of cooperation, Duke Energy Indiana submits a description of a review of the merits only, of running Edwardsport IGCC on natural gas from a CO2 perspective. The review did not include an evaluation of the costs or the benefits or the challenges of running Edwardsport on natural gas only and/or coal.**

Duke Energy announced a Climate Goal of net-zero carbon emissions by 2050 on September 17, 2019. The company also sped up its goal for cutting emissions by 2030 from 40% to at least 50%. Using the reference case for the most recently filed IRPs in each Duke Energy jurisdiction, the 2030 50% goal can be achieved for the corporation as a whole if successful with planned retirements, new generation, additional EE and renewables. Alternatives to reduced CO_2 emissions were evaluated if planning assumptions changed and additional reductions were needed to meet the 50% goal. One alternative evaluated for additional CO_2 reduction was if Edwardsport ran on natural gas only. In the Duke Energy Indiana 2018 IRP, Edwardsport ran on syngas derived from coal as the primary fuel throughout the planning horizon, and was projected to emit 3.4 million tons of CO_2 in 2030. The emissions for running on natural gas only were estimated based on the lower CO_2 emission rate associated with natural gas and the lower heat rate associated with combined cycle generation; potential capacity and dispatch changes were not considered. The estimated emissions from running Edwardsport on natural gas only in 2030 are about 1.5 million tons of CO_2, for a total savings of 1.9 million tons. Please see Attachment IG 21.3-A.

Attachment IG 21.3-A

Edwardsport

			2030	Reference
Coal	CO2	Tons	3,446,000	2018 IRP
Coal	CO2 emission rate	#CO2/mmbtus	205	
Coal	heat rate	btus/kwhr	9,120	2018 IRP
Gas	CO2 emission rate	#CO2/mmbtus	120	
Gas	CC heat rate	btus/kwhr	6,800	estimated based on f-frame CC
Gas	CO2	Tons	1,504,031	Calculated from coal
Savings	**CO2**	**Tons**	**1,941,969**	

IG
IURC Cause No. 45253
Data Request Set No. 20
Received: September 16, 2019

IG 20.2

Request:

Please provide the following information regarding the projections used to prepare DEI's 2018 IRP. Please provide each answer in both real and nominal dollars.

a. Please identify the cost of labor (including salary, incentives, benefits, and payroll tax) associated with employees projected for each DEI generating unit for each year through 2037.

b. Please identify the cost of labor (including salary, incentives, benefits, and payroll tax) associated with contractors projected for each DEI generating unit for each year through 2037.

c. *For purposes of this question, "O&M expense" is defined in the same manner as the 2016 and 2018 Edwardsport settlement agreements. Specifically, "O&M expense" is defined to include operating and maintenance expenses, payroll taxes, property taxes, property insurance, and net of the credit for old Edwardsport operating expenses (but not fuel and depreciation).*

   Please identify the projected O&M expense for each DEI generating unit for each year through 2037.

Objection:

Duke Energy Indiana objects to this request to the extent it seeks an analysis, calculation or compilation that has not already been performed and that Duke Energy Indiana objects to performing.

Response:

Subject to and without waiving the above objections, and in the spirit of cooperation, Duke Energy Indiana responds as follows:

a. See objection.
b. See objection.
c. See objection

Explaining further, for long-term forecasting purposes for use in the IRP, Duke Energy Indiana does not prepare data in the requested categorization nor in the requested level of detail. Generating facility direct company labor (unloaded) is identifiable as a fixed O&M cost category (with the exception of Edwardsport IGCC), but labor loadings (benefits, etc.), corporate allocations, and administrative and general costs are grouped together and not separated. Further, contract labor costs may be mixed with contract material costs, and are not separated. Contractor costs can also be mixed between as-modeled fixed O&M categories and variable O&M (which is modeled with a lump-sum cost rate and is not separated).

Answering further and in the spirit of cooperation, please see Confidential Attachment IG 20.2-A, which represents fixed O&M data, as modeled for the 2018 IRP Preferred Portfolio in the Reference Carbon scenario. For all stations except Edwardsport, please see the tabs with definitions as follows:

Netted VOM	Movement of variable O&M costs in time to account for timing of outages
MMC FOM	Non-Outage Maintenance Materials and Contracts
OLMC FOM	Outage Labor Materials and Contracts not included in variable O&M
Labor FOM	Direct Company Labor
Alloc FOM	Labor Loadings, Corporate Allocations, and Administrative and General
Prop Tax FOM	Property Taxes
Insur FOM	Insurance
Envir FOM	Future Incremental Environmental Compliance O&M

In the spirit of cooperation and in full disclosure, in the assembly of this information for this response, an error was observed in the process for the 2018 IRP. The calculational tool used to produce these costs for the various scenario/portfolio combinations was not properly or completely populated with the necessary data from the modeling runs to be fully functional. However, the only data output affected here is the Netted VOM. The error predominantly affects the sensitivity of the tool in expensing the planned outage component of the variable O&M rate in time, as opposed to any absolute total of the costs over time. The impact of this would likely be timing (plus or minus some number of years in selecting an optimized retirement date), and would not necessarily lead to wholesale changes in the specific units or number of retirements selected in an optimized portfolio overall.

Due to the structure of how the Edwardsport O&M is forecasted for long-term IRP modeling purposes, these components are not individually broken out. Please see Confidential Attachment Sierra Club 1.19-A for Edwardsport's O&M costs used for the 2018 IRP Preferred Portfolio in the Reference Carbon scenario, as well as the as-modeled variable O&M costs for coal units that, together with the fixed O&M categories above, make up the total O&M.

Witness: Keith Pike

IG
IURC Cause No. 45253
Data Request Set No. 28
Received: October 10, 2019

IG 28.1

Request:

Referring to the testimony of Judah Rose in Cause 43114 dated October 24, 2006, please identify the natural gas price forecast that Duke relied upon in preparing its case in Cause 43114.

Objection:

Duke Energy Indiana objects to this request as not reasonably calculated to lead to admissible evidence in this proceeding.

Response:

Subject to and without waiving or limiting its objection, please see Confidential Attachment IG 28.1-A for the requested tables from Mr. Rose's testimony.

~~Confidential~~ Attachment IG 28.4-A

~~CONFIDENTIAL - EXCLUDED FROM PUBLIC ACCESS PER A.R. 9(G)~~

~~CONFIDENTIAL - NOT FOR PUBLIC ACCESS~~

Petitioners' Exhibit No. 28-E
Page 6 Of 15

Duke Energy Indiana, Inc.

Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)

(Dollars In Thousands)

Row	A	B Assumptions	D	E Factor (d)	F July 2008	G January 2009	H July 2009	I January 2010	J July 2010	K January 2011	L July 2011
8	RETURN ON INVESTMENT										
9	Return on Equity (ROE)		12.00%								
10	Weighted Average Cost Of Capital	(a)	8.77%								
12	Cumulative Project Expenditures At										
13	CWIP Cut-Off Date		100%		$ 170,282	$ 407,001	$ 701,720	$ 1,047,654	$ 1,404,791	$ 1,699,668	$ 1,849,902
14	Less: Accumulated Depreciation		100%		-	-	-	-	-	-	17,562
15	Less: Accumulated Deferred Income Taxes		100%		-	-	-	-	-	-	18,787
17	Net IGCC Investment Subject To										
18	CWIP Ratemaking				$ 170,282	$ 407,001	$ 701,720	$ 1,047,654	$ 1,404,791	$ 1,699,668	$ 1,813,553
20	Assumed Percentage Ownership		100%		100%	100%	100%	100%	100%	100%	100%
21	Net IGCC Investment Applicable To DEI				170,282	407,001	701,720	1,047,654	1,404,791	1,699,668	1,813,553
23	Return on OCD Investment		8.77%		$ 14,934	$ 35,694	$ 61,541	$ 91,879	$ 123,200	$ 149,061	$ 159,049
25	Est. Revenue Requirement Before Jurisdictional Allocation				$ 21,415	$ 51,184	$ 88,249	$ 131,753	$ 176,667	$ 213,752	$ 228,074
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis				$ 10,708	$ 25,592	$ 44,125	$ 65,877	$ 88,334	$ 106,876	$ 114,037
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES										
30	Variable O&M		100%	1.02130	-	-	-	-	-	-	-
31	Fixed O&M		100%	1.02130	-	-	-	-	-	-	-
32	Amortization of Plan Presentation Costs		100%	1.02130	150	-	150	-	-	-	-
33	Emission Allowance Savings		100%		-	-	-	-	-	-	-
34	Fuel Savings		100%		-	-	-	-	-	-	-
35	Est. O&M Expenses Before Jurisdictional Allocation				150	-	150	-	-	-	-
37	Depreciation Exp. Incl. Net Negative Salvage		100%	1.02130	-	-	-	-	-	-	16,873
39	Total Operating Expense Excl. Taxes				150	-	150	-	-	-	16,873
41	Revenue Requirement Applicable to O&M and Depreciation Expense				153	-	153	-	-	-	17,595
43	TAXES EXCLUDING FEDERAL & STATE INCOME										
44	Property Taxes		100%	1.02130	-	-	-	-	-	-	1,141
45	Less: TIF Savings		100%	1.02130	-	-	-	-	-	-	(1,013)
46	Less: Property Tax Abatement		100%	1.02130	-	-	-	-	-	-	-
47	Net Property Tax Expense				-	-	-	-	-	-	128
49	State Tax Credit	(f)	100%	1.71739	-	-	-	-	-	(6,065)	(6,066)
51	Federal Investment Tax Credit	(g)									
52	Ratable Flow through of Credit		100%	(133,500)	-	-	-	-	-	-	(1,113)
53	Effective at 100% Basis Reduction			0.35	-	-	-	-	-	-	390
54	Net Credit			1.63787					-	-	(723)
56	Total Taxes Excl. Fed. & State Income Taxes				-	-	-	-	-	(6,065)	(6,661)
58	Revenue Requirement Applicable to Taxes				-	-	-	-	-	(10,416)	(11,471)
60	REVENUE FROM SALE OF BYPRODUCTS		100%	1.02130	-	-	-	-	-	-	(250)
61	Revenue Requirement Applicable to Byproduct Sales				-	-	-	-	-	-	(255)
63	Revenue Requirement Prior to Edwardsport Credit				$ 10,861	$ 25,592	$ 44,278	$ 65,877	$ 88,334	$ 96,460	$ 119,906
65	Less: Credit for Edwardsport Operating Expenses Included in Rates		100%	1.02130	-	-	-	-	-	-	(1,439)
67	Rev Requirement Applicable to Edwardsport Credit				-	-	-	-	-	-	(1,470)
69	Total Revenue Requirement Before Jurisdictional Allocation				$ 10,861	$ 25,592	$ 44,278	$ 65,877	$ 88,334	$ 96,460	$ 118,436
70	Retail Allocation Factor		0.91791								
71	Total Retail Revenue Requirement				$ 9,969	$ 23,491	$ 40,643	$ 60,469	$ 81,083	$ 88,542	$ 108,714

Row	A	M January 2012	N July 2012	O January 2013	P July 2013	Q January 2014	R July 2014	S January 2015
13	CWIP Cut-Off Date	$ 1,910,122	$ 1,925,100	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126
14	Less: Accumulated Depreciation	52,706	87,850	122,994	158,138	193,282	228,426	263,570
15	Less: Accumulated Deferred Income Taxes	30,562	42,337	52,314	62,291	70,609	78,927	85,705
18	CWIP Ratemaking	$ 1,826,854	$ 1,794,913	$ 1,750,818	$ 1,705,697	$ 1,662,235	$ 1,618,773	$ 1,576,851
20	Assumed Percentage Ownership	100%	100%	100%	100%	100%	100%	100%
21	Net IGCC Investment Applicable To DEI	1,826,854	1,794,913	1,750,818	1,705,697	1,662,235	1,618,773	1,576,851
23	Return on OCD Investment	$ 160,215	$ 157,414	$ 153,547	$ 149,590	$ 145,778	$ 141,966	$ 138,290
25	Est. Revenue Requirement Before Jurisdictional Allocation	$ 229,746	$ 225,729	$ 220,184	$ 214,509	$ 209,044	$ 203,578	$ 198,306
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis	$ 114,873	$ 112,865	$ 110,092	$ 107,255	$ 104,522	$ 101,789	$ 99,153
30	Variable O&M	8,250	8,249	8,415	8,415	8,605	8,604	8,798
31	Fixed O&M	13,351	13,351	13,651	13,651	13,959	13,958	14,273
32	Amortization of Plan Presentation Costs	-	-	-	-	-	-	-
33	Emission Allowance Savings	-	-	-	-	-	-	-
34	Fuel Savings	-	-	-	-	-	-	-
35	Est. O&M Expenses Before Jurisdictional Allocation	21,601	21,600	22,066	22,066	22,564	22,562	23,071
37	Depreciation Exp. Incl. Net Negative Salvage	34,850	35,125	35,144	35,144	35,144	35,144	35,144
39	Total Operating Expense Excl. Taxes	56,451	56,725	57,210	57,210	57,708	57,706	58,215
41	Revenue Requirement Applicable to O&M and Depreciation Expense	58,380	58,660	59,155	59,155	59,664	59,662	60,181
44	Property Taxes	4,951	4,951	11,203	11,204	10,377	10,377	9,613
45	Less: TIF Savings	-	-	(503)	(504)	(933)	(932)	(1,296)
46	Less: Property Tax Abatement	(4,936)	(4,935)	(10,069)	(10,070)	(8,289)	(8,290)	(6,718)
47	Net Property Tax Expense	15	16	631	630	1,155	1,155	1,599
49	State Tax Credit	(6,065)	(6,066)	(6,065)	(6,066)	(6,065)	(6,066)	(6,065)
52	Ratable Flow through of Credit	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)
53	Effective at 100% Basis Reduction	779	779	779	779	779	779	779
54	Net Credit	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)
56	Total Taxes Excl. Fed. & State Income Taxes	(7,496)	(7,496)	(6,880)	(6,882)	(6,356)	(6,357)	(5,912)
58	Revenue Requirement Applicable to Taxes	(12,769)	(12,770)	(12,140)	(12,143)	(11,605)	(11,606)	(11,151)
60	REVENUE FROM SALE OF BYPRODUCTS	(500)	(500)	(500)	(500)	(500)	(500)	(500)
61	Revenue Requirement Applicable to Byproduct Sales	(511)	(511)	(511)	(511)	(511)	(511)	(511)
63	Revenue Requirement Prior to Edwardsport Credit	$ 159,973	$ 158,244	$ 156,596	$ 153,756	$ 152,070	$ 149,334	$ 147,672
65	Less: Credit for Edwardsport Operating Expenses Included in Rates	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)
67	Rev Requirement Applicable to Edwardsport Credit	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)
69	Total Revenue Requirement Before Jurisdictional Allocation	$ 157,034	$ 155,305	$ 153,657	$ 150,817	$ 149,131	$ 146,395	$ 144,733
71	Total Retail Revenue Requirement	$ 144,143	$ 142,556	$ 141,043	$ 138,436	$ 136,889	$ 134,377	$ 132,852

~~Confidential~~ Attachment IG 28.4-A

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~~CONFIDENTIAL~~ ~~NOT FOR PUBLIC ACCESS~~

Petitioners' Exhibit No. 28-E
Page 7 Of 15

	A	B	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
1	Duke Energy Indiana, Inc.																	
2																		
3	Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)																	
4																		
5	(Dollars in Thousands)																	
6			July	January	July	January	July	January	July	January	July	January	July	January	July	January	July	January
7		Assumption	2015	2016	2016	2017	2017	2018	2018	2019	2019	2020	2020	2021	2021	2022	2022	2023
8	RETURN ON INVESTMENT																	
9	Return on Equity (ROE)																	
10	Weighted Average Cost Of Capital	(a)																
11																		
12	Cumulative Project Expenditures At																	
13	CWIP Cut-Off Date		$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126
14	Less: Accumulated Depreciation		298,714	333,858	369,002	404,146	439,290	474,434	509,578	544,722	579,866	615,010	650,154	685,298	720,442	755,586	790,730	825,874
15	Less: Accumulated Deferred Income Taxes		92,483	97,842	103,200	107,241	111,282	114,109	116,936	119,564	122,191	124,816	127,440	130,068	132,695	135,320	137,944	140,572
16																		
17	Net IGCC Investment Subject To																	
18	CWIP Ratemaking		$ 1,534,929	$ 1,494,426	$ 1,453,924	$ 1,414,739	$ 1,375,554	$ 1,337,583	$ 1,299,612	$ 1,261,840	$ 1,224,069	$ 1,186,300	$ 1,148,532	$ 1,110,760	$ 1,072,989	$ 1,035,220	$ 997,452	$ 959,680
19																		
20	Assumed Percentage Ownership		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
21	Net IGCC Investment Applicable To DEI		1,534,929	1,494,426	1,453,924	1,414,739	1,375,554	1,337,583	1,299,612	1,261,840	1,224,069	1,186,300	1,148,532	1,110,760	1,072,989	1,035,220	997,452	959,680
22																		
23	Return on OCD Investment		$ 134,613	$ 131,061	$ 127,509	$ 124,073	$ 120,636	$ 117,306	$ 113,976	$ 110,663	$ 107,351	$ 104,039	$ 100,726	$ 97,414	$ 94,101	$ 90,789	$ 87,477	$ 84,164
24																		
25	Est. Revenue Requirement Before Jurisdictional Allocation		$ 193,033	$ 187,940	$ 182,846	$ 177,918	$ 172,991	$ 168,215	$ 163,440	$ 158,689	$ 153,940	$ 149,191	$ 144,440	$ 139,690	$ 134,940	$ 130,188	$ 125,439	$ 120,690
26																		
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis		$ 96,517	$ 93,970	$ 91,423	$ 88,959	$ 86,495	$ 84,108	$ 81,720	$ 79,345	$ 76,970	$ 74,596	$ 72,220	$ 69,845	$ 67,470	$ 65,094	$ 62,720	$ 60,345
28																		
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES																	
30	Variable O&M		8,798	9,018	9,017	9,199	9,198	9,405	9,405	9,617	9,617	9,857	9,857	10,055	10,054	10,281	10,280	10,512
31	Fixed O&M		14,272	14,594	14,593	14,922	14,922	15,258	15,257	15,601	15,601	15,952	15,952	16,311	16,311	16,678	16,678	17,054
32	Amortization of Plan Presentation Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Emission Allowance Savings		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Fuel Savings		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Est. O&M Expenses Before Jurisdictional Allocation		23,070	23,612	23,610	24,121	24,120	24,663	24,662	25,218	25,218	25,809	25,809	26,366	26,365	26,959	26,958	27,566
36																		
37	Depreciation Exp. Incl. Net Negative Salvage		35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144
38																		
39	Total Operating Expense Excl. Taxes		58,214	58,756	58,754	59,265	59,264	59,807	59,806	60,362	60,362	60,953	60,953	61,510	61,509	62,103	62,102	62,710
40																		
41	Revenue Requirement Applicable to O&M and Depreciation Expense		60,180	60,734	60,732	61,254	61,253	61,807	61,806	62,374	62,374	62,978	62,978	63,547	63,546	64,152	64,151	64,772
42																		
43	TAXES EXCLUDING FEDERAL & STATE INCOME																	
44	Property Taxes		9,612	8,905	8,906	8,251	8,252	7,646	7,647	7,087	7,086	6,535	6,534	5,983	5,982	5,431	5,430	4,879
45	Less: TIF Savings		(1,295)	(1,600)	(1,600)	(1,853)	(1,853)	(2,060)	(2,061)	(2,228)	(2,227)	(2,347)	(2,347)	(2,678)	(2,677)	(2,437)	(2,437)	(2,189)
46	Less: Property Tax Abatement		(6,718)	(5,334)	(5,334)	(4,118)	(4,118)	(3,052)	(3,053)	(2,121)	(2,122)	(1,304)	(1,304)	(17)	(17)	-	-	-
47	Net Property Tax Expense		1,599	1,971	1,972	2,280	2,281	2,534	2,533	2,738	2,737	2,884	2,883	3,288	3,288	2,994	2,993	2,690
48																		
49	State Tax Credit	(f)	(6,066)	(6,065)	(6,066)	(6,065)	(6,066)	(6,065)	(6,066)	(6,065)	(6,066)	(6,065)	(6,066)	-	-	-	-	-
50																		
51	Federal Investment Tax Credit	(g)																
52	Ratable Flow through of Credit		(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)
53	Effective at 100% Basis Reduction		779	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779
54	Net Credit		(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)
55																		
56	Total Taxes Excl. Fed. & State Income Taxes		(5,913)	(5,540)	(5,540)	(5,231)	(5,231)	(4,977)	(4,979)	(4,773)	(4,775)	(4,627)	(4,629)	1,842	1,842	1,548	1,547	1,244
57																		
58	Revenue Requirement Applicable to Taxes		(11,153)	(10,771)	(10,772)	(10,456)	(10,456)	(10,196)	(10,199)	(9,988)	(9,991)	(9,839)	(9,842)	990	990	689	688	379
59																		
60	REVENUE FROM SALE OF BYPRODUCTS		(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
61	Revenue Requirement Applicable to Byproduct Sales		(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)
62																		
63	Revenue Requirement Prior to Edwardsport Credit		$ 145,033	$ 143,422	$ 140,872	$ 139,246	$ 136,782	$ 135,208	$ 132,816	$ 131,220	$ 128,842	$ 127,224	$ 124,845	$ 133,871	$ 131,495	$ 129,424	$ 127,048	$ 124,965
64																		
65	Less: Credit for Edwardsport Operating Expenses Included in Rates		(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)
66																		
67	Rev Requirement Applicable to Edwardsport Credit		(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)
68																		
69	Total Revenue Requirement Before Jurisdictional Allocation		$ 142,094	$ 140,483	$ 137,933	$ 136,307	$ 133,843	$ 132,269	$ 129,877	$ 128,281	$ 125,903	$ 124,285	$ 121,906	$ 130,932	$ 128,556	$ 126,485	$ 124,109	$ 122,046
70	Retail Allocation Factor																	
71	Total Retail Revenue Requirement		$ 130,430	$ 128,951	$ 126,610	$ 125,118	$ 122,856	$ 121,411	$ 119,215	$ 117,750	$ 115,568	$ 114,082	$ 111,899	$ 120,184	$ 118,003	$ 116,102	$ 113,921	$ 112,027

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Duke Energy Indiana, Inc.

Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)

(Dollars In Thousands)

	A	B Assumption	AJ July 2023	AK January 2024	AL July 2024	AM January 2025	AN July 2025	AO January 2026	AP July 2026	AQ January 2027
8	RETURN ON INVESTMENT									
9	Return on Equity (ROE)									
10	Weighted Average Cost Of Capital	(a)								
12	Cumulative Project Expenditures At									
13	CWIP Cut-Off Date		$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126
14	Less: Accumulated Depreciation		861,018	896,162	931,306	966,450	1,001,594	1,036,738	1,071,882	1,107,026
15	Less: Accumulated Deferred Income Taxes		143,199	145,824	148,448	151,076	153,703	156,328	158,952	161,580
17	Net IGCC Investment Subject To									
18	CWIP Ratemaking		$ 921,909	$ 884,140	$ 846,372	$ 808,600	$ 770,829	$ 733,060	$ 695,292	$ 657,520
20	Assumed Percentage Ownership		100%	100%	100%	100%	100%	100%	100%	100%
21	Net IGCC Investment Applicable To DEI		921,909	884,140	846,372	808,600	770,829	733,060	695,292	657,520
23	Return on OCD Investment		$ 80,851	$ 77,539	$ 74,227	$ 70,914	$ 67,602	$ 64,289	$ 60,977	$ 57,665
25	Est. Revenue Requirement Before Jurisdictional Allocation		$ 115,939	$ 111,190	$ 106,441	$ 101,689	$ 96,940	$ 92,191	$ 87,440	$ 82,689
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis		$ 57,970	$ 55,595	$ 53,221	$ 50,845	$ 48,470	$ 46,096	$ 43,720	$ 41,345
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES									
30	Variable O&M		10,512	10,775	10,774	10,991	10,990	11,238	11,237	11,491
31	Fixed O&M		17,053	17,437	17,437	17,829	17,829	18,231	18,230	18,641
32	Amortization of Plan Presentation Costs		-	-	-	-	-	-	-	-
33	Emission Allowance Savings		-	-	-	-	-	-	-	-
34	Fuel Savings		-	-	-	-	-	-	-	-
35	Est. O&M Expenses Before Jurisdictional Allocation		27,565	28,212	28,211	28,820	28,819	29,469	29,467	30,132
37	Depreciation Exp Incl Net Negative Salvage		35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144
39	Total Operating Expense Excl. Taxes		62,709	63,356	63,355	63,964	63,963	64,613	64,611	65,276
41	Revenue Requirement Applicable to O&M and Depreciation Expense		64,771	65,432	65,431	66,053	66,052	66,716	66,714	67,393
43	TAXES EXCLUDING FEDERAL & STATE INCOME									
44	Property Taxes		4,879	4,327	4,327	3,899	3,899	3,899	3,899	3,899
45	Less: TIF Savings		(2,188)	(1,940)	(1,940)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)
46	Less: Property Tax Abatement		-	-	-	-	-	-	-	-
47	Net Property Tax Expense		2,691	2,387	2,387	2,151	2,151	2,151	2,151	2,151
49	State Tax Credit	(f)	-	-	-	-	-	-	-	-
51	Federal Investment Tax Credit	(g)								
52	Ratable Flow through of Credit		(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)
53	Effective at 100% Basis Reduction		779	779	779	779	779	779	779	779
54	Net Credit		(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)
56	Total Taxes Excl. Fed. & State Income Taxes		1,245	941	941	705	705	705	705	705
58	Revenue Requirement Applicable to Taxes		380	69	69	(172)	(172)	(172)	(172)	(172)
60	REVENUE FROM SALE OF BYPRODUCTS		(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
61	Revenue Requirement Applicable to Byproduct Sales		(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)
63	Revenue Requirement Prior to Edwardsport Credit		$ 122,610	$ 120,585	$ 118,210	$ 116,215	$ 113,839	$ 112,129	$ 109,751	$ 108,055
65	Less: Credit for Edwardsport Operating Expenses Included in Rates		(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)
67	Rev Requirement Applicable to Edwardsport Credit		(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)
69	Total Revenue Requirement Before Jurisdictional Allocation		$ 119,671	$ 117,646	$ 115,271	$ 113,276	$ 110,900	$ 109,190	$ 106,812	$ 105,116
70	Retail Allocation Factor									
71	Total Retail Revenue Requirement		$ 109,847	$ 107,988	$ 105,808	$ 103,977	$ 101,796	$ 100,227	$ 98,044	$ 96,487

	A	AR July 2027	AS January 2028	AT July 2028	AU January 2029	AV July 2029	AW January 2030	AX July 2030	AY January 2031
8	RETURN ON INVESTMENT								
9	Return on Equity (ROE)								
10	Weighted Average Cost Of Capital								
12	Cumulative Project Expenditures At								
13	CWIP Cut-Off Date	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126
14	Less: Accumulated Depreciation	1,142,170	1,177,314	1,212,458	1,247,602	1,282,746	1,317,890	1,353,034	1,388,178
15	Less: Accumulated Deferred Income Taxes	164,207	166,835	169,462	172,087	174,711	169,936	165,162	152,985
17	Net IGCC Investment Subject To								
18	CWIP Ratemaking	$ 619,749	$ 581,977	$ 544,206	$ 506,437	$ 468,669	$ 438,300	$ 407,930	$ 384,963
20	Assumed Percentage Ownership	100%	100%	100%	100%	100%	100%	100%	100%
21	Net IGCC Investment Applicable To DEI	619,749	581,977	544,206	506,437	468,669	438,300	407,930	384,963
23	Return on OCD Investment	$ 54,352	$ 51,039	$ 47,727	$ 44,415	$ 41,102	$ 38,439	$ 35,775	$ 33,761
25	Est. Revenue Requirement Before Jurisdictional Allocation	$ 77,940	$ 73,189	$ 68,440	$ 63,891	$ 58,939	$ 55,121	$ 51,301	$ 48,413
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis	$ 38,970	$ 36,595	$ 34,220	$ 31,646	$ 29,470	$ 27,561	$ 36,651	$ 24,207
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES								
30	Variable O&M	11,490	11,778	11,777	12,043	12,042	12,314	12,313	12,591
31	Fixed O&M	18,640	19,060	19,060	19,489	19,489	19,928	19,927	20,376
32	Amortization of Plan Presentation Costs	-	-	-	-	-	-	-	-
33	Emission Allowance Savings	-	-	-	-	-	-	-	-
34	Fuel Savings	-	-	-	-	-	-	-	-
35	Est. O&M Expenses Before Jurisdictional Allocation	30,130	30,838	30,837	31,532	31,531	32,242	32,240	32,967
37	Depreciation Exp Incl Net Negative Salvage	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144
39	Total Operating Expense Excl. Taxes	65,274	65,982	65,981	66,676	66,675	67,386	67,384	68,111
41	Revenue Requirement Applicable to O&M and Depreciation Expense	67,391	68,114	68,113	68,823	68,822	69,548	69,546	70,288
43	TAXES EXCLUDING FEDERAL & STATE INCOME								
44	Property Taxes	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899
45	Less: TIF Savings	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)
46	Less: Property Tax Abatement	-	-	-	-	-	-	-	-
47	Net Property Tax Expense	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151
49	State Tax Credit	-	-	-	-	-	-	-	-
51	Federal Investment Tax Credit								
52	Ratable Flow through of Credit	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)
53	Effective at 100% Basis Reduction	779	779	779	779	779	779	779	779
54	Net Credit	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)
56	Total Taxes Excl. Fed. & State Income Taxes	705	705	705	705	705	705	705	705
58	Revenue Requirement Applicable to Taxes	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)
60	REVENUE FROM SALE OF BYPRODUCTS	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
61	Revenue Requirement Applicable to Byproduct Sales	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)
63	Revenue Requirement Prior to Edwardsport Credit	$ 105,678	$ 104,026	$ 101,650	$ 99,986	$ 97,609	$ 96,426	$ 94,514	$ 93,812
65	Less: Credit for Edwardsport Operating Expenses Included in Rates	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)
67	Rev Requirement Applicable to Edwardsport Credit	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)
69	Total Revenue Requirement Before Jurisdictional Allocation	$ 102,739	$ 101,087	$ 98,711	$ 97,047	$ 94,670	$ 93,487	$ 91,575	$ 90,873
70	Retail Allocation Factor								
71	Total Retail Revenue Requirement	$ 94,305	$ 92,789	$ 90,608	$ 89,080	$ 86,899	$ 85,813	$ 84,058	$ 83,413

R:\Duke Energy - Indiana\IGCC\IGCC_RECAP_2020_confidential rev 5-29-07.xls\Summary-28B 5/31/2007

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	A	B	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ	BK	BL	BM	BN	BO
1	Duke Energy Indiana, Inc.																	
2																		
3	Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)																	
4																		
5	(Dollars In Thousands)																	
6			July	January	July	January	July	January	July	January	July	January	July	January	July	January	July	January
7		Assumption	2031	2032	2032	2033	2033	2034	2034	2035	2035	2036	2036	2037	2037	2038	2038	2039
8	RETURN ON INVESTMENT																	
9	Return on Equity (ROE)																	
10	Weighted Average Cost Of Capital	(a)																
11																		
12	Cumulative Project Expenditures At																	
13	CWIP Cut-Off Date		$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126
14	Less: Accumulated Depreciation		1,423,322	1,458,466	1,493,610	1,528,754	1,563,898	1,599,042	1,634,186	1,669,330	1,704,474	1,739,618	1,774,762	1,809,906	1,845,050	1,880,194	1,915,338	1,950,482
15	Less: Accumulated Deferred Income Taxes		140,809	128,632	116,456	104,279	92,103	79,926	67,750	55,573	43,397	31,220	19,044	-	-	-	-	-
16																		
17	Net IGCC Investment Subject To																	
18	CWIP Ratemaking		$ 361,995	$ 339,028	$ 316,060	$ 293,093	$ 270,125	$ 247,158	$ 224,190	$ 201,223	$ 178,255	$ 155,288	$ 132,320	$ 116,220	$ 81,076	$ 45,932	$ 10,788	$ (24,356)
19																		
20	Assumed Percentage Ownership		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
21	Net IGCC Investment Applicable To DEI		361,995	339,028	316,060	293,093	270,125	247,158	224,190	201,223	178,255	155,288	132,320	116,220	81,076	45,932	10,788	(24,356)
22																		
23	Return on OCD Investment		$ 31,747	$ 29,733	$ 27,718	$ 25,704	$ 23,690	$ 21,676	$ 19,661	$ 17,647	$ 15,633	$ 13,619	$ 11,604	$ 10,192	$ 7,110	$ 4,028	$ 946	$ (2,136)
24																		
25	Est. Revenue Requirement Before Jurisdictional Allocation		$ 45,525	$ 42,638	$ 39,749	$ 36,861	$ 33,971	$ 31,083	$ 28,194	$ 25,306	$ 22,418	$ 19,528	$ 16,640	$ 14,516	$ 10,196	$ 5,776	$ 1,357	$ (3,063)
26																		
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis		$ 22,763	$ 21,318	$ 19,874	$ 18,431	$ 16,986	$ 15,542	$ 14,097	$ 12,653	$ 11,209	$ 9,764	$ 8,320	$ 7,308	$ 5,098	$ 2,888	$ 679	$ (1,532)
28																		
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES																	
30	Variable O&M		12,590	12,874	12,874	13,164	13,163	13,460	13,459	13,763	13,762	14,072	14,072	14,389	14,388	14,712	14,712	15,043
31	Fixed O&M		20,375	20,834	20,834	21,303	21,303	21,782	21,782	22,273	22,272	22,774	22,773	23,286	23,286	23,810	23,809	24,346
32	Amortization of Plan Presentation Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Emission Allowance Savings		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Fuel Savings		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Est. O&M Expenses Before Jurisdictional Allocation		32,965	33,708	33,708	34,467	34,466	35,242	35,241	36,036	36,034	36,846	36,845	37,675	37,674	38,522	38,521	39,389
36																		
37	Depreciation Exp. Incl. Net Negative Salvage		35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144	35,144
38																		
39	Total Operating Expense Excl. Taxes		68,109	68,852	68,852	69,611	69,610	70,386	70,385	71,180	71,178	71,990	71,989	72,819	72,818	73,666	73,665	74,533
40																		
41	Revenue Requirement Applicable to O&M and Depreciation Expense		70,286	71,045	71,045	71,820	71,819	72,612	72,611	73,423	73,421	74,250	74,249	75,096	75,095	75,962	75,960	76,847
42																		
43	TAXES EXCLUDING FEDERAL & STATE INCOME																	
44	Property Taxes		3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899	3,899
46	Less: TIF Savings		(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)	(1,748)
45	Less: Property Tax Abatement		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Net Property Tax Expense		2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151	2,151
48																		
49	State Tax Credit	(f)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																		
51	Federal Investment Tax Credit	(g)																
52	Ratable Flow through of Credit		(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)	(2,225)
53	Effective at 100% Basis Reduction		779	779	779	779	779	779	779	779	779	779	779	779	779	779	779	779
54	Net Credit		(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)	(1,446)
55																		
56	Total Taxes Excl. Fed. & State Income Taxes		705	705	705	705	705	705	705	705	705	705	705	705	705	705	705	705
57																		
58	Revenue Requirement Applicable to Taxes		(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)	(172)
59																		
60	REVENUE FROM SALE OF BYPRODUCTS		(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
61	Revenue Requirement Applicable to Byproduct Sales		(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)
62																		
63	Revenue Requirement Prior to Edwardsport Credit		$ 92,366	$ 91,680	$ 90,236	$ 89,568	$ 88,122	$ 87,471	$ 86,025	$ 85,393	$ 83,947	$ 83,331	$ 81,886	$ 81,721	$ 79,510	$ 76,167	$ 75,956	$ 74,632
64																		
65	Less: Credit for Edwardsport Operating Expenses Included in Rates		(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)	(2,878)
66																		
67	Rev Requirement Applicable to Edwardsport Credit		(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)	(2,939)
68																		
69	Total Revenue Requirement Before Jurisdictional Allocation		$ 89,427	$ 88,741	$ 87,297	$ 86,629	$ 85,183	$ 84,532	$ 83,086	$ 82,454	$ 81,008	$ 80,392	$ 78,947	$ 78,782	$ 76,571	$ 75,228	$ 73,017	$ 71,693
70	Retail Allocation Factor																	
71	Total Retail Revenue Requirement		$ 82,086	$ 81,456	$ 80,131	$ 79,518	$ 78,190	$ 77,593	$ 76,265	$ 75,685	$ 74,358	$ 73,793	$ 72,466	$ 72,315	$ 70,285	$ 69,053	$ 67,023	$ 65,808

~~Confidential~~ **Attachment IG 28.4-A**

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	A	B	BP	BQ	BR	BS	BT
1	Duke Energy Indiana, Inc						
2							
3	**Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)**						
4							
5	(Dollars In Thousands)						
6			July	January	July	January	July
7		Assumption	2039	2040	2040	2041	2041
8	RETURN ON INVESTMENT						
9	Return on Equity (ROE)						
10	Weighted Average Cost Of Capital	(a)					
11							
12	Cumulative Project Expenditures At						
13	CWIP Cut-Off Date		$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126	$ 1,926,126
14	Less: Accumulated Depreciation		1,985,626	2,020,770	2,055,914	2,091,058	2,126,202
15	Less: Accumulated Deferred Income Taxes		-	-	-	-	-
16							
17	Net IGCC Investment Subject To						
18	CWIP Ratemaking		$ (59,500)	$ (94,644)	$ (129,788)	$ (164,932)	$ (200,076)
19							
20	Assumed Percentage Ownership		100%	100%	100%	100%	100%
21	Net IGCC Investment Applicable To DEI		(59,500)	(94,644)	(129,788)	(164,932)	(200,076)
22							
23	Return on OCD Investment		$ (5,218)	$ (8,300)	$ (11,382)	$ (14,465)	$ (17,547)
24							
25	**Est. Revenue Requirement Before Jurisdictional Allocation**		$ (7,484)	$ (11,903)	$ (16,323)	$ (20,743)	$ (25,161)
26							
27	**Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis**		$ (3,742)	$ (5,952)	$ (8,162)	$ (10,372)	$ (12,581)
28							
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES						
30	Variable O&M		15,043	15,382	15,381	15,728	15,727
31	Fixed O&M		24,345	24,893	24,893	25,454	25,453
32	Amortization of Plan Presentation Costs		-	-	-	-	-
33	Emission Allowance Savings		-	-	-	-	-
34	Fuel Savings		-	-	-	-	-
35	Est. O&M Expenses Before Jurisdictional Allocation		39,388	40,275	40,274	41,182	41,180
36							
37	Depreciation Exp. Incl. Net Negative Salvage		35,144	35,144	35,144	35,144	35,144
38							
39	Total Operating Expense Excl. Taxes		74,532	75,419	75,418	76,326	76,324
40							
41	**Revenue Requirement Applicable to O&M and Depreciation Expense**		**76,846**	**77,752**	**77,751**	**78,678**	**78,676**
42							
43	TAXES EXCLUDING FEDERAL & STATE INCOME						
44	Property Taxes		3,899	3,899	3,899	3,899	3,899
45	Less: TIF Savings		(1,748)	(1,748)	(1,748)	(1,748)	(1,748)
46	Less: Property Tax Abatement		-	-	-	-	-
47	Net Property Tax Expense		2,151	2,151	2,151	2,151	2,151
48							
49	State Tax Credit	(f)	-	-	-	-	-
50							
51	Federal Investment Tax Credit	(g)					
52	Ratable Flow through of Credit		(2,225)	(2,225)	(2,225)	(2,225)	(1,112)
53	Effective at 100% Basis Reduction		779	779	779	779	389
54	Net Credit		(1,446)	(1,446)	(1,446)	(1,446)	(723)
55							
56	Total Taxes Excl. Fed. & State Income Taxes		705	705	705	705	1,428
57							
58	**Revenue Requirement Applicable to Taxes**		**(172)**	**(172)**	**(172)**	**(172)**	**1,013**
59							
60	REVENUE FROM SALE OF BYPRODUCTS		(500)	(500)	(500)	(500)	(500)
61	**Revenue Requirement Applicable to Byproduct Sales**		**(511)**	**(511)**	**(511)**	**(511)**	**(511)**
62							
63	**Revenue Requirement Prior to Edwardsport Credit**		**$ 72,421**	**$ 71,117**	**$ 68,906**	**$ 67,623**	**$ 66,597**
64							
65	Less: Credit for Edwardsport Operating Expenses Included in Rates		(2,878)	(2,878)	(2,878)	(2,878)	(4,317)
66							
67	**Rev Requirement Applicable to Edwardsport Credit**		**(2,939)**	**(2,939)**	**(2,939)**	**(2,939)**	**(4,409)**
68							
69	**Total Revenue Requirement Before Jurisdictional Allocation**		**$ 69,482**	**$ 68,178**	**$ 65,967**	**$ 64,684**	**$ 62,188**
70	Retail Allocation Factor						
71	**Total Retail Revenue Requirement**		**$ 63,778**	**$ 62,581**	**$ 60,552**	**$ 59,374**	**$ 57,083**

[illegible]

5/31/2007

Corrosion inhibiters and chlorine scavengers

Acid Gas Removal Selexol make up

The annual cost of these reagents depends on operating hours because they are variable in nature. Current 2020 forecast for these chemicals is about $7 million. The level of reagents included in the 2020 forecast is similar to the 2018 historical amount despite the major outage due to expected improvements in reliability and generation levels.

Q. ARE YOU SPONSORING THE POWER PRODUCTION O&M AND CAPITAL EXPENDITURES IN THIS FORECAST?

A. I am sponsoring only a portion of the Power Production O&M and Capital Expenditures in this forecast related to Edwardsport operations. Duke Energy Indiana Witnesses Mr. James Michael Mosley, Mr. Timothy Thiemann and Mr. Andrew Ritch will also be sponsoring other portions of the Power Production O&M and Capital Expenditures forecast.

Q. WHAT LEVEL OF TOTAL O&M EXPENSES ARE REFLECTED IN DUKE ENERGY INDIANA'S 2020 FORECAST FOR EDWARDSPORT?

A. Duke Energy Indiana's total 2020 Edwardsport O&M test period forecast is $145.8 million. This includes $46.4 million in expenses associated with a major outage that occurs about once every seven years, as will be discussed below. Note that the $145.8 million includes the Power Production O&M attributable to Edwardsport of $139.1 million shown in the table below and provided to Company witness Mr. Chris Jacobi, plus $6.7 million in miscellaneous

IG
IURC Cause No. 45253
Data Request Set No. 2
Received: July 15, 2019

IG 2.13

Request:

Please refer to Mr. Gurganus' Direct testimony at page 16, line 20 to page 17, line 2.

a. Please identify with specificity what is included within the $6.7 million in miscellaneous administrative and general benefit costs for Edwardsport that were forecasted by other groups.

b. Please explain why the $6.7 million is not included within the Power Production O&M attributable to Edwardsport figure of $139.1 million.

c. Does the $46.4 million in expenses associated with the major outage include any portion of the $6.7 million in miscellaneous administrative and general benefit costs? If so, how much?

Response:

a. A summary of the 2020 Edwardsport O&M budget components is as follows:

Station O&M	$145.8
O&M from non-station departments	2.6
Total O&M	148.4
Less: A&G accounts (920-935)	9.3
Power production O&M accounts	$139.1

The $6.7 million is the $9.3 million of A&G costs from station and non-station departments less $2.6 million of O&M (Power Production and A&G) from non-station departments. $8.9 million of the $9.3 million A&G represents fringe benefit costs charged to FERC account 926. The remaining $0.4 million represents other A&G costs.

b. The $139.1 million represents station and non-station Power Production O&M in FERC accounts 500-514 for steam power generation O&M costs only. Additional costs attributable to Edwardsport in the 2020 forecast include A&G for Edwardsport and for non-station departments that support Edwardsport.

c. The $46.4 million in Power Production O&M expenses associated with the major outage does not include any A&G costs.

Witness: Cecil Gurganus