FILED
June 17, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE AND FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3, AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	)))))))))	**CAUSE NO. 38707-FAC128**

SUBMISSION OF APPLICANT'S PROPOSED FORM OF ORDER

Duke Energy Indiana, LLC ("Duke Energy Indiana"), by counsel, respectfully submits its Proposed Form of Order in the above-captioned Cause to the Indiana Utility Regulatory Commission ("Commission").

Counsel for Duke Energy Indiana is authorized to represent that the Indiana Office of Consumer Counselor adopts all portions of the Proposed Form of Order.

Respectfully submitted,

DUKE ENERGY INDIANA, LLC

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing Submission electronically this 17th day of June 2021 to the following:

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PROPOSED FORM OF ORDER

Presiding Officers:
David E. Ziegner, Commissioner
David Veleta, Senior Administrative Law Judge

On April 28, 2021, Duke Energy Indiana, LLC ("Applicant") filed its Verified Application and direct testimony and exhibits for approval by the Indiana Utility Regulatory Commission ("Commission") of a change in its fuel adjustment charge ("FAC") to be applicable during the billing cycles of July, August and September 2021 for electric and steam service and to update monthly benchmarks for purchased power costs. On May 4, 2021, Citizens Action Coalition of Indiana, Inc. ("CAC") filed a Petition to Intervene, which was subsequently granted on May 26, 2021. On June 2, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony.

A public evidentiary hearing was held in this Cause on June 17, 2021, at 9:30 a.m. via WebEx. Counsel for Applicant, CAC and the OUCC participated in the hearing. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. **Notice and Commission Jurisdiction.** Notice of the hearing in this Cause was given as required by law. Applicant is a public utility within the meaning of Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's rates and charges related to adjustments in fuel costs. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Applicant's Characteristics.** Applicant is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Applicant is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. Applicant also renders steam service to one customer, International Paper.

3. Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income. On June 29, 2020, the Commission issued an Order in Cause No. 45253 ("June 29 Order") approving base retail electric rates and charges for Applicant. The Commission's June 29 Order found that Applicant's base cost of fuel should be 26.955 mills per kWh. Applicant has begun phasing-in the new authorized jurisdictional operating income level approved in the June 29 Order, as adjusted for the Company's Step 1 amounts and for impacts of investments remaining in two Company riders. Until the new authorized jurisdictional net operating level is fully phased-in, the Applicant should continue to reflect a pro-rata portion of the authorized jurisdictional net operating income of $267,500,000 for the months prior to August 2020. This operating income amount is based on the Commission's Order in Cause No. 42359 issued May 18, 2004 ("May 18 Order"), prior to any additional return on investments approved by the Commission in various rate proceedings not taken into account in the May 18 Order.

Applicant's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of February 2021, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.036157 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders, Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending February 28, 2021, to be $537,057,000 (*see* Applicant's Ex. 6, p. 10). No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. Fuel Purchases and Coal Procurement Plan. Mr. Brett Phipps testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Phipps testified that as of February 28, 2021, coal inventories were approximately 1,450,005 tons (or 27 days of coal supply), which is a decrease over inventories reported in FAC 127. Mr. Phipps reported that the decrease can be attributed to increased demand during the winter months. He testified that coal inventories are projected to increase over the next quarter and added that Applicant continues to evaluate a host of options in order to effectively manage its coal inventory. Mr. Phipps stated that as inventory levels dictate, Applicant explores options to store or defer contract coal or resell surplus coal into the market. Due to continued weak coal market conditions, resale opportunities will continue to be extremely difficult in the near term. Given the continued decline in coal burns due to falling power prices, Applicant began a coal decrement in March of 2020. Mr. Phipps testified that it was his opinion that Applicant is purchasing coal and oil at prices as low as reasonably possible.

Mr. Phipps testified that spot natural gas prices are dynamic, volatile, and can change significantly day to day based on market fundamental drivers. During the three-month period from December 2020 through February 2021, the price Applicant paid for delivered natural gas at its gas burning stations was between $2.21 per million BTU and $65.92 per million BTU. He testified natural gas prices for the period were above those experienced in the FAC 127 review period. Mr.

Phipps testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness, Mr. Michael D. Eckert, testified that Applicant is actively trying to manage its coal purchases and inventory. He recommended Applicant continue to update the Commission on its coal inventory and 2021 projected coal burn and coal purchases.

Mr. Bradley Daniel testified that Applicant continues to submit an incremental cost offer for its share of Benton County Wind Farm in accordance with the settlement agreement with Benton County Wind Farm discussed in FAC 113.

Based on the evidence presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during December 2020 through February 2021. With regard to its coal inventory levels, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. Hedging Activities. Applicant's witness Mr. Wenbin (Michael) Chen testified Applicant takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that Applicant realized a gain of $16,174,667 from natural gas hedges purchased for December 2020 through February 2021. He testified that market price for gas realized lower values than the hedged prices in December and January due to warmer than normal weather. However, due to a strong cold front in February, natural gas pipelines put restrictions on gas usage which contributed to huge price spikes. As a result, Petitioner's gas hedges realized a gain of more than $16 million in February. He testified Applicant experienced net realized power hedging gains for the period of $823,695 primarily attributable to high power prices during the February 2021 cold weather. Ms. Sieferman testified that Applicant realized a total net hedging gain of $16,997,129 during the period for all native gas and power hedging activities other than MISO virtual energy market participation (including prior period adjustments).

Mr. Chen explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1 ("FAC 68 S1 Order"), beginning on August 1, 2008, Applicant has not utilized its flat hedging methodology. Rather, Applicant will hedge up to approximately flat minus 150 MW on a forward, monthly and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave Applicant with at least 150 MW of expected load unhedged on a forward forecasted basis. Mr. Chen opined Applicant's gas and power hedging practices are reasonable. He stated Applicant never speculates on future prices, and that its hedging practice is economic at the time the decision is made and reduces volatility because Applicant is transacting in a less volatile forward market, as opposed to more volatile spot markets.

No evidence was offered in this Cause noting issues with the realized net amounts for power and gas hedging included in the fuel costs in this proceeding or challenging the prudence of the activities that gave rise to the realized net amounts. In addition, Applicant presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order (*see* Applicant's Ex. 3, pp. 10-11). Thus, we allow Applicant to include $16,997,129 of net gains from native gas and power hedges in the calculation of fuel costs in this proceeding.

6. <u>Participation in the Energy and ASM Markets and MISO-Directed Dispatch</u>. On June 1, 2005, the Commission issued an Order in Cause No. 42685 ("June 1 Order"), in which we approved certain changes in the operations of the investor-owned Indiana electric public utilities that are participating members of MISO. In this proceeding, Mr. Daniel testified that Applicant included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Applicant's load, including: (1) Energy Markets charges and credits associated with Applicant's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full LMP at Applicant's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; (4) credits and charges related to auction revenue rights ("ARRs") and Schedule 27 and Schedule 27-A; and (5) fuel related charges and credits received from PJM Interconnection LLC from the operation of Madison Generation Station as approved in Cause No. 45253.

Mr. Daniel testified that beginning in early March 2020 a coal price decrement was applied to the dispatch costs of Gibson Units 1-5, Cayuga Units 1-2, and Edwardsport (syngas only) to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. He stated that, to the extent that the price decrement results in units being dispatched that otherwise would not be, coal coming to the station is consumed, other potential costs are avoided, and customers ultimately benefit because higher cost alternatives to manage the inventory are avoided. Mr. Daniel testified the price decrement has worked as designed as Applicant initially saw an increase in generation output from these units. As the level of the coal price decrement decreased over time as inventories decreased, the economic need to burn excess coal decreased. He testified that on January 22, 2021 the coal price decrement dropped to zero and remained at zero, so there is no difference between the non-decremented dispatch price and the as-offered price of a generating unit. Mr. Daniel testified Applicant continues to perform the decrement calculation and if it shows that a decrement is economic in the future, one will be added at that time. In the October 30, 2013 Order in Cause No. 38707 FAC 96, the Commission ordered Applicant to present the inputs to its calculation of the coal price decrement applicable to each FAC filing as support for the reasonableness of its pricing. Mr. Daniel provided the confidential coal stacks for the time period December 2020 through February 2021 in Confidential Ex. 4-A. Mr. Daniel testified that Applicant continues to forecast its coal inventory position as part of the normal course of business, but currently does not have a need to decrement coal units in its offers to MISO.

Mr. Daniel testified that revisions to the EPA's Cross State Air pollution Rule ("CSAPR") were issued on March 15, 2021. The revised rule has yet to establish an effective date so the impact on the dispatch of Applicant's generating units is still unknown.

Mr. Daniel testified Gallagher units 2 and 4 will retire June 1, 2021, as approved by MISO. He also provided an update on the cold weather event of February 2021, stating that Applicant was well prepared and able to maintain reliable service to customers throughout the period.

Applicant's witness Ms. Mary Ann Amburgey testified as to the procedures followed by Applicant to verify the accuracy of the charges and credits allocated by MISO to Applicant. She also discussed the process by which MISO issues multiple settlement statements for each trading day and the dispute resolution process with respect to such statements. She stated that every daily settlement statement received by Applicant from MISO is reviewed utilizing the computer software tools described in her testimony. Ms. Amburgey testified that she is confident that the amounts paid by Applicant to MISO, net of any credits, are proper and that such amounts billed to customers through the FAC are proper.

In its Phase II Order in Cause No. 43426 ("Phase II Order") the Commission authorized Applicant and the other Joint Petitioners to recover costs and credit revenues related to the ASM. Mr. Daniel explained that Applicant has included various ASM charges and credits in this proceeding incurred for December 2020 through February 2021, consistent with the Phase II Order, as well as appropriate period adjustments.

Applicant's witness Mr. Scott A. Burnside testified that Applicant, in accordance with the Phase II Order, has calculated the monthly average ASM Cost Distribution Amounts it has paid for Regulation, Spinning and Supplemental Reserves. These amounts are as follows:

(in $ per MWh)	Dec-20	Jan-21	Feb-21
Regulation Cost Dist.	0.0490	0.0499	0.1022
Spinning Cost Dist.	0.0245	0.0217	0.0668
Supplemental Cost Dist.	0.0037	0.0030	0.0874

OUCC witness Mr. Eckert testified that Applicant's treatment of ASM charges follows the treatment ordered by the Commission in its Phase II Order.

Based upon the evidence presented, we find Duke Energy Indiana's participation in the Energy and Ancillary Services Markets and utilization of the coal price decrement constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. Further, as we noted in our Orders in Cause Nos. 38707 FAC 81 and 38707 FAC 82, should Applicant's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

Additionally, based upon the evidence presented, the Commission finds that Applicant's treatment of the Energy and ASM charges and credits in its cost of fuel is consistent with the June 1 Order, the December 28, 2006 Order in Cause No. 38707 FAC 70, as well as our Phase I and Phase II Orders in Cause No. 43426 and should be approved.

7. **Major Forced Outages.** In the December 28, 2011 Order in Cause No. 38707 FAC 90, the Commission ordered Applicant to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Daniel testified during this FAC period there were three outages that met these criteria. Mr. Daniel testified that no Root Cause Analysis ("RCA") was performed for any of these outages.

8. **<u>Operating Expenses</u>.** Ind. Code § 8-1-2-42(d) (2) requires the Commission to determine whether actual increases in fuel costs have been offset by actual decreases in other operating expenses. Accordingly, Applicant filed operating cost data for the 12 months ended February 28, 2021 (*see* Applicant's Ex. 6-A, p.3). Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $1,084,799,000. For the 12-month period ended February 28, 2021, Applicant's jurisdictional operating expenses (excluding fuel costs) totaled $1,382,477,000. Accordingly, Applicant's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Applicant's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

9. **<u>Return Earned</u>.** Ind. Code § 8-1-2-42(d)(3), subject to the provisions of Ind. Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge that would result in regulated utilities earning a return in excess of its applicable authorized return. Should the fuel cost adjustment factor result in the utility earning a return more than its applicable authorized return, it must, in accordance with the provisions of Ind. Code § 8-1-2-42.3, determine if the sum of the differentials between actual earned returns and authorized returns for each of the 12-month periods considered during the relevant period is greater than zero. If so, a reduction to the fuel adjustment clause factor is deemed appropriate.

In accordance with Applicant's June 27, 2012 order in Cause No. 42736-RTO 30, the proposal for Schedule 26-A treatment of costs or revenues associated with the Applicant's Company-owned Multi-Value Projects ("MVPs") should be addressed at the time any such projects have been completed and are included for recovery. Ms. Sieferman testified that the first of such projects were included for the first time in MISO billing effective June 2019. Applicant proposed that the costs and revenues associated with Company-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test, which is consistent with the treatment of its Company-owned RECB projects beginning in Cause No. 38707 FAC 86. Applicant has provided more detail as it relates to the RTO rider in its filing in Cause No. 42736 RTO 56. Based upon the evidence presented, the Commission approves the Applicant's exclusion of revenues and expenses associated with Company-owned MVPs. In Cause No. 38707 FAC 122 the Company's proposed treatment for these revenues and expenses were approved on an interim basis, subject to refund, pending the outcome of Applicant's RTO 56 filing. The Commission issued its RTO 56 Order on February 24, 2021.

In accordance with previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $480,047,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $537,057,000 (*see* Applicant's Ex. 6, pg. 10). Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended February 28, 2021.

10. **<u>Estimation of Fuel Costs</u>.** Applicant estimates that its prospective average fuel cost for the months of July through September 2021, will be $71,077,187 or $0.027459 per kWh (*see* Verified Application Ex. A, Schedule 1). Applicant previously made the following estimates of its fuel costs for the period December 2020 through February 2021, and experienced the following actual costs, resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	Percent Actual is Over (Under) Estimate
Dec 2020	22.877	24.143	(5.24)
Jan 2021	27.127	24.272	11.76
Feb 2021	29.441	24.985	17.83
Weighted Average	26.497	24.451	8.37

A comparison of Applicant's actual fuel costs with the respective estimated costs for these three periods results in a weighted average percentage difference of 8.37. (Verified Application, Ex. A, Schedule 10). Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound and its estimates for July through September 2021 should be accepted.

11. Purchased Power Benchmark. As a result of the July 29, 2020 Order in Cause No. 45253, changes in Applicant's stacking became effective July 2020 as follows: Applicant's stacking occurs on a real-time metered basis rather than both day-ahead and real-time; certain short-term wholesale trades are classified as non-native rather than native; and stacking is based on incremental rather than average production cost. Mr. Burnside testified that the Sumatra Model used the new stacking logic for September 2020 through February 2021. In addition, July 2020, reconciled in FAC 127 using the prior stacking logic, was rerun with the new stacking logic and included in this filing.

12. Fuel Cost Factor. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 26.955 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to July through September 2021 billing cycles is computed as follows (Verified Application, Ex. A, Schedule 1):

	$ / kWh
Projected Average Fuel Cost	0.027459
Net Reconciliation Factor	0.001341
Adjusted Fuel Cost Factor	0.028800
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	(0.001845)

Ms. Sieferman testified that the net variance factor shown above reflects $19,251,030 of under-billed fuel costs applicable to retail customers that occurred during the period December 2020 through February 2021, spread over a six-month period instead of the normal three-month recovery period. Ms. Sieferman testified that the sizeable under-collection for this reconciliation period is a result of the extreme winter weather and spikes in natural gas and LMP prices during February 2021. By spreading it over six months, the proposed reconciliation factor in this proceeding includes one-half of the under-collection ($9,625,515).

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended February 2021 had been properly applied by Applicant. In addition, he stated the figures used in the Application for a change in the FAC were supported by Applicant's books and records, Sumatra, and source documentation of Applicant for the period reviewed.

13. **<u>Effect on Residential Customers</u>.** The approved factor represents an increase of \$0.002518 per kWh from the factor approved in Cause No. 38707-FAC127. The typical residential customer using 1,000 kWhs per month will experience an increase of \$2.52 or 2.0% on his or her total electric bill compared to the factor approved in Cause No. 38707-FAC127 (excluding sales tax). (Applicant's Ex. 6, pp. 12-13).

14. **<u>Interim Rates</u>.** Because we are unable to determine whether Applicant's actual earned return will exceed the level authorized by the Commission during the period that this fuel cost adjustment factor is in effect, the Commission finds that the rates approved herein should be approved on an interim basis, subject to refund, in the event an excess return is earned.

15. **<u>Fuel Adjustment for Steam Service</u>.** On December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Applicant and Premier Boxboard, formerly referred to as Temple-Inland, n/k/a International Paper which included a change in the method used to calculate International Paper's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for International Paper of \$1.2338795 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the July through September 2021 billing cycles. Exhibit B, Schedule 2, of the Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in \$48,641 charge to International Paper for the months of December 2020 through February 2021.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of \$1.2338795 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 39483, and that such factor should be approved. We further find that Applicant's reconciliation amount of \$48,641 charge to International Paper has been properly determined and should be approved.

16. **<u>Shared Return Revenue Credit Adjustment for International Paper</u>.** In accordance with the June 18, 1992 Settlement Agreement, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 10, Applicant did not have excess earnings for the 12 months ended February 2021. Therefore, we find International Paper is not due a shared return revenue credit.

17. **<u>Information for Statutory Summary Proceeding</u>.** The Commission's Order in Cause No. 38707 FAC 123 S1 encouraged Applicant and the OUCC to work together to develop a more quantified decision-making process that may aid the OUCC in its statutory summary proceeding review. The Order required Applicant and the OUCC to meet within 30 days to discuss ways to improve the audit information stream and for Applicant to report on progress related to this effort in its quarterly FAC filings. Ms. Sieferman testified that preliminary discussions had occurred and Applicant will report on continued progress in the next FAC filing.

OUCC witness Mr. Eckert testified that preliminary discussions occurred within thirty days of the Order and Applicant has agreed to provide certain additional information as part of the standard audit package. Mr. Eckert will report on continued progress in the next FAC proceeding.

18. Confidential Information. On April 28, 2021 Applicant filed a motion requesting protection of confidential and proprietary information along with supporting affidavits. On May 10, 2021 the Presiding Officers made preliminary determinations and/or clarifications that trade secret information should be subject to confidential procedures, as supported by Applicant's affidavits, including its coal stack for every decrement update between December 2020 and February 2021. The Commission finds such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and should be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Duke Energy Indiana's fuel cost adjustment factor for electric service to be billed jurisdictional customers, as set forth in Finding No. 12, and the fuel cost adjustment for steam service as set forth in Finding No. 15 of this Order are hereby approved on an interim basis, subject to refund, in accordance with all of the Findings above.

2. Duke Energy Indiana's inclusion of Energy and Ancillary Services Markets charges and credits in its cost of fuel, as described in Finding No. 6 of this order, is hereby approved.

3. Duke Energy Indiana is authorized to recover the $19,251,030 of under-collected fuel costs experienced in December 2020 through February 2021 over a six-month period instead of the normal three-month recovery period as set forth in Finding No. 12 above.

4. Prior to implementing the authorized rates, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rates shall be effective on or after the date of approval for all bills rendered.

5. Duke Energy Indiana shall provide an update on the status of its coal inventories in its next FAC filing, as described in Finding No. 4 of this Order.

6. The material submitted to the Commission under seal is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code §8-1-2-29.

7. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, OBER AND ZIEGNER CONCUR:

APPROVED:

I hereby certify that the above is a true
and correct copy of the Order as approved.

____

Dana Kosco
Secretary to the Commission