ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, INC. FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS 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 FAC 99 APPROVED: APR 02 2014

ORDER OF THE COMMISSION

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

On January 31, 2014, Duke Energy Indiana, Inc. ("Duke Energy Indiana", "Applicant" or "Company") filed its Verified Application and direct testimony and exhibits for approval of a change in its fuel adjustment charge ("FAC") to be applicable during the billing cycles of April, May and June 2014 for electric and steam service and to update monthly benchmarks for purchased power costs. On February 3, 2014, Steel Dynamics, Inc. ("SDI") filed its Petition to Intervene in this proceeding. The Duke Energy Indiana Industrial Group ("Industrial Group") filed its Petition to Intervene in this proceeding on February 6, 2014. The Commission granted those Petitions to Intervene on February 18, 2014. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on March 7, 2014. On March 7, 2014, the OUCC filed a *Motion for a Subdocket, or in the Alternative, an Investigation* ("Motion"). Duke Energy Indiana filed its rebuttal testimony on March 13, 2014. Duke filed its response to the Motion on March 17, 2014. The OUCC filed its reply on March 25, 2014.

Pursuant to public notice given and published as required by law, proof of which was incorporated into the record by reference, a public evidentiary hearing was held in this Cause on March 17, 2014, at 9:30 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, the Industrial Group, and the OUCC appeared at the hearing by counsel. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. Neither the Industrial Group nor SDI offered any evidence into the record at the evidentiary hearing. No members of the general public appeared or sought to testify at the hearing.

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

1. **Notice and Commission Jurisdiction.** Due, legal and timely notice of the hearing in this Cause was given as required by law. Duke Energy Indiana 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.** Duke Energy Indiana 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. Duke Energy Indiana 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. The Company also renders steam service to one customer, International Paper.[1]

3. **Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income.** On May 18, 2004, the Commission issued an Order in Cause No. 42359 ("May 18 Order") approving base retail electric rates and charges for Duke Energy Indiana. The Commission's May 18 Order found that Duke Energy Indiana's base cost of fuel should be 14.484 mills per kWh and that the Company's base rates for electric utility service should reflect an authorized jurisdictional net operating income of $267,500,000, prior to any additional return on qualified pollution control property approved by the Commission, pursuant to Ind. Code §§ 8-1-2-6.6 and 6.8, 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 November 2013, 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 $0.031682 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders,[2] Duke Energy Indiana calculated its authorized jurisdictional net operating income level for the 12-month period ending November 30, 2013, to be $488,087,000. No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Duke Energy Indiana, and we find it to be proper.

4. **Fuel Purchases.** Mr. Brett Phipps testified regarding Duke Energy Indiana's coal procurement practices and its coal inventories. Mr. Phipps testified that the Company utilized

[1] International Paper acquired Temple-Inland's corrugated packaging business on February 13, 2013.

[2] The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061, and subsequent update Orders, up to and including the August 14, 2013, update in Cause No. 42061 ECR 21, authorized Petitioner to add the value of certain qualified pollution control property to the value of the Company's property for ratemaking purposes. The Commission's Order in Cause No. 42061 ECR 3, dated March 11, 2004, stated that the applicable incremental increase to Duke Energy Indiana's authorized return, approved in that proceeding, shall be phased-in over the period of time that Petitioner's net operating income was affected by the applicable construction work in progress ("CWIP") update. The Commission's Order in Cause No. 43114 and subsequent update Orders, up to and including the September 11, 2013 update in Cause No. 43114 IGCC 10, authorized the Company to add the value of property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC Project") to the value of the Company's property for ratemaking purposes. The Company has applied the same phase-in concepts ordered by the Commission in its Order in Cause No. 42061 ECR 3 for CWIP updates to the IGCC Project updates in making the calculations for this filing.

the periodic price re-opener methodology to complete amendments to two Indiana coal agreements, resulting in lower mine prices for coal for 2013. Additionally, Mr. Phipps testified that Duke Energy Indiana exercised its right to reopen the contract price under its Bear Run contract in accordance with the terms of the contract. The parties have engaged in negotiations and reached an impasse, which requires resolution in accordance with the provisions of the contract, through arbitration. Mr. Phipps also testified that as of December 31, 2013, coal inventories were approximately 3,600,000 tons (or 58 days of coal supply), the same as what was reported in Cause No. 38707 FAC 98. Mr. Phipps added that the Company continues to evaluate a host of options in order to effectively manage the growing inventories. Furthermore, the Company has extended an existing storage agreement with one supplier to store coal at the supplier's mine facilities for up to one additional year. In addition, the Company has agreed to defer up to 475,000 tons of coal for delivery in 2014 to 2015 with one supplier. Mr. Phipps stated the Company continues to actively explore options to defer contract coal or resell surplus coal into the market; however, due to continued weak coal market conditions, resell opportunities will continue to be extremely difficult in the near term. Mr. Phipps testified that it was his opinion that the Company is purchasing coal and oil at prices as low as reasonably possible.

Mr. Phipps testified that the price of delivered natural gas at the Company's gas burning generation stations increased slightly but stayed at relatively low levels during the three-month period from September through November 2013 with a range of delivered prices between $3.45 per million BTU to $4.45 per million BTU. Mr. Phipps testified that, in his opinion, Duke Energy Indiana purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness Mr. Michael Eckert testified regarding Applicant's coal inventory and coal decrement pricing. He testified that Duke Energy Indiana has met with its suppliers, determined maximum storage at its facilities, is exploring options to resell surplus coal, and implemented decrement coal pricing. He recommended Duke Energy Indiana should continue to update the Commission on its coal inventory and coal decrement pricing, including the development of other potential alternatives to its below-cost bidding approach.

Mr. John D. Swez, of Duke Energy Indiana, testified regarding the Company's efforts to mitigate the negative Locational Marginal Price ("LMP") situation associated with power purchased from Benton County Wind Farm ("BCWF"), pursuant to the contract which was approved by the Commission in Cause No. 43097. He stated that starting in 2012, during various times primarily in the spring, fall, and winter seasons, BCWF received persistent negative day-ahead and real-time LMP's at the generator node. During this time, BCWF was registered at the Midcontinent Independent System Operator, Inc. ("MISO") as an Intermittent Resource, which means that it had no ability to be committed or decommitted by, or follow the setpoint instructions of, MISO during normal energy market operations. Mr. Swez indicated that due to the nature of the must-take contractual arrangement between the Company and BCWF and the way MISO treats offers from Intermittent Resources, the unit had a commitment status of must run with minimum and maximum loading equal to the expected output, meaning that MISO would clear the generator at any LMP at the forecasted amount in the day-ahead market. Mr. Swez testified that as a result of this, negative revenue (i.e., payments must be made to send the power into the MISO system) could be received by this generator in the day-ahead markets. It was also possible to receive negative revenues in the real-time market. Mr. Swez testified that on March 1, 2013, BCWF began operation as a Dispatchable Intermittent Resource ("DIR"). The DIR was designed to allow MISO to better manage the output of intermittent resources, thereby allowing for better management of congestion in certain areas, such as where BCWF is located. Mr. Swez testified that although it is early in the process, the DIR construct is giving MISO additional tools to manage congestion at BCWF and as a result, fewer negative LMP's are appearing.

Mr. Swez also testified that Duke Energy Indiana received an invoice on June 17, 2013 for payment from BCWF for March, April, and May 2013 liquidated damages for production that was not generated. He noted that Duke Energy Indiana has disputed this invoice and, as a result, there is no impact to this FAC proceeding. Although the Company and BCWF had continued negotiations regarding this invoice, BCWF filed a lawsuit against Duke Energy Indiana on December 16, 2013, alleging that the Company breached its contract with the wind farm. Once the dispute with Benton County Wind Farm is resolved, there is the potential for future adjustments for production that was not generated or changes in metered output due to power purchase share meter adjustments that may be reconciled in future FAC proceedings. He indicated that Duke Energy Indiana will provide an update on this situation in its next FAC filing.

Mr. Eckert recommended that Duke Energy Indiana report to the Commission any updates and resolutions to the Benton County Wind Farm LMP situation in its next FAC filing.

a. <u>OUCC's Motion</u>. On March 7, 2014, the OUCC filed its *Motion for a Sub-Docket, or in the Alternative, an Investigation*. In that Motion, the OUCC raised the issue of the cost of negative generation at Edwardsport that had occurred both in FAC 98 and the case at bar. The OUCC's witness Mr. Greg T. Guerrettaz, CPA, testified that for Edwardsport IGCC, there were hours of negative generation during September through November, 2013. He estimated the cost of negative generation to be $647,252 for September, $287,238 for October, and $580,387 for November. Mr. Guerrettaz recommended that the Commission exclude the fuel costs for the period when no energy was generated, reducing the final factor to 19.069 mills per kWh, a reduction of 0.242 mills per kWh from Duke Energy Indiana's requested factor.

In rebuttal testimony, Mr. Swez testified that these fuel costs should not be disallowed. He stated that Edwardsport IGCC is similar to the other coal generating units as it consumes fuel (natural gas) and auxiliary power when in start-up or off-line. Mr. Swez stated that although the amounts of negative generation and fuel consumed on start-up are different for Edwardsport IGCC when compared to other Duke Energy Indiana coal units, the fundamental consumption of auxiliary power and fuel is the same. Mr. Swez noted that the vast majority of negative generation occurred when the plant was in the start-up process. Additionally, the plant was down on a planned fall maintenance outage for almost 15 days during October and November. He explained that all generating plants have maintenance outages and the fuel or auxiliary power they use in or for that time period has historically been properly included as fuel through the FAC. He testified that during times when the plant was not in start-up, generating some power, or in planned outage, the plant also used a lesser amount of auxiliary power or fuel for basic plant operations, including the activity needed to prepare for start-up operations. Again, this is similar to other Company coal units which consume auxiliary power whenever they are off-line and not in start-up, which costs have historically been included as fuel through the FAC. Mr. Swez testified that there is no basis to disallow cost recovery of the same types of fuel costs at Edwardsport IGCC. Even if the net generation at Edwardsport IGCC is larger during this time period than at other plants, or than it will be at this plant once it has reached its ongoing level of availability, no party to this proceeding has demonstrated that the activities at Edwardsport IGCC during this time period to test, tune and optimize the plant were not reasonable or necessary to provide ongoing benefits to customers. He stated that to the contrary, these start-up fuels costs, auxiliary power, planned outage and other off-line fuel costs are necessary to the operation of the plant. Mr. Swez testified that during some negative generation hours, the station was actually on-line, producing energy because it was in start-up mode. Although the station was on-line and producing a positive gross generation, the auxiliary power consumed was greater than the gross generation produced, making the station net generation negative in that hour.

Mr. Swez testified that the fuel costs for Edwardsport IGCC have not been excessive or unreasonable. He testified that fuel costs for the Edwardsport IGCC plant have come in as expected and the rate at which the unit consumes fuel will decrease as the plant ramps up to its expected availability and reduces the number of start-ups. He stated that the station is performing within the original start-up plan and that activity during this testing, tuning, and optimization time period is important as it produces long-term benefits and efficiencies for the customer. He indicated these activities are a necessary and expected part of the initial IGCC operations which will allow the plant to reach its expected availability and efficiency over time.

Ms. Sieferman testified that Mr. Guerrettaz failed to explain his methodology in calculating his proposed disallowance, which changed from his methodology used in FAC98. Ms. Sieferman added that his calculation of the potential fuel cost associated with net negative generation is flawed. Ms. Sieferman testified that all fuel costs included in this FAC proceeding are costs which are properly includable in Account 151 of the applicable Uniform System of Accounts and, as such, are considered appropriate for inclusion in the FAC. She explained that once the project was declared in-service on June 7, 2013, the costs were properly chargeable to fuel expense as required by the Uniform System of Accounts. Ms. Sieferman testified that during the hours in which the negative generation occurred, it is possible that the Edwardsport IGCC plant was running on natural gas or syngas or purchasing power from MISO, or any combination of the three. She stated that in calculating the recommended disallowance, Mr. Guerrettaz simply assumed the Edwardsport IGCC unit was running on natural gas during each hour it was experiencing negative generation and, therefore, a percentage of the natural gas costs for each month should be disallowed.

We begin our discussion consistent with that of Duke Energy Indiana's previous FAC[3]; relative to the fuel costs in question, we note that no party has argued that the costs are not properly included in Account 151 of the applicable Uniform System of Accounts, and in general the costs included in that account are recoverable as FAC fuel costs.[4] In addition, no party has disputed the reasonableness of the cost Duke Energy Indiana paid for the acquisition of the fuel in question. Finally, the evidence supports that generating stations at times consume fuel when

[3] See Cause No. 38707-FAC98 at page 5 (IURC December 30, 2013).
[4] *See* Cause Nos. 33735-S1 and 33735-S2 (IURC March 24, 1976).

not producing electricity available for customer consumption and that such fuel costs have been historically included for recovery through the FAC. Therefore, these fuel costs have previously passed the test that such consumption represented a reasonable effort to acquire fuel for the provision of electricity. Accordingly, the evidence of record does not support exclusion of the costs in question at this time. Nonetheless, we acknowledge the OUCC's concerns and find that the public interest is served by a detailed review of the underlying causes of the Edwardsport IGCC plant negative generation amounts that is best accomplished outside the statutory time constraints of the FAC summary proceedings. Therefore, we grant the OUCC's Motion. A subdocket, Cause No. 38707 FAC 99 S1 is hereby created for further consideration of this issue. Further, we find these costs should be made subject to refund pending the outcome of this subdocket.

Based upon the evidence presented and as discussed throughout this Order, subject to the outcome of the subdocket created herein, we find that Duke Energy Indiana made reasonable efforts 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. With regard to its coal inventory levels and any updates to the situation with BCWF, Duke Energy Indiana will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. Hedging Activities. Duke Energy Indiana's witness Mr. Wenbin (Michael) Chen testified the Company takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified the Company realized a loss of $42,450 for gas hedges purchased for August 2013 expected native gas burn. He further testified the Company experienced net realized power hedging losses (exclusive of MISO virtual trades and including prior period adjustments) for the period of $104,698.

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, and continuing until permanent hedging protocols are developed and approved by the Commission, Duke Energy Indiana will not utilize its flat hedging methodology. Rather, Duke Energy Indiana 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 the Company with at least 150 MW of expected load unhedged on a forward forecasted basis.

Mr. Chen also noted the Company continues to hold discussions annually with the OUCC and its consultant (meeting most recently with the OUCC on June 27, 2013) as required by the FAC 68 S1 Order.

Mr. Chen testified that early in 2013 the Company implemented a change to extend its hedging horizon for both native and non-native power hedging programs to current month plus 6 months, replacing its practice of current month plus 3 months before the change. Mr. Chen opined the Company's gas and power hedging practices are reasonable. He stated the Company never speculates on future prices, and that its hedging practice is economic at the time the decisions are made. He also stated the hedging practice reduces volatility and benefits customers by reducing customers' risk of paying potentially higher spot market prices.

No evidence was offered in this Cause noting issues with the realized net losses for gas and power hedging included in the fuel costs in this proceeding or challenging the prudence of the activities that gave rise to the realized net losses. In addition, the Company presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order. Thus, we allow Applicant to include $42,450 of losses from native gas hedges as well as $104,698 of realized power hedging losses in the calculation of fuel costs in this proceeding.

6. **Ancillary Services Market ("ASM").** 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. Swez testified that Duke Energy Indiana included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Duke Energy Indiana's load, including: (1) Energy Markets charges and credits associated with Duke Energy Indiana's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full LMP at Duke Energy Indiana's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; and (4) credits and charges related to auction revenue rights ("ARRs") and Schedule 27 and Schedule 27-A, as authorized by the Commission in Cause Nos. 38707 FAC 77 and 38707 FAC 80.

Duke Energy Indiana's witness Ms. Mary Ann Amburgey testified as to the procedures followed by the Company to verify the accuracy of the charges and credits allocated by MISO to the Company. 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 the Company 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 Duke Energy Indiana 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 Duke Energy Indiana and the other Joint Petitioners to recover costs and credit revenues related to ASM. Mr. Swez explained that Duke Energy Indiana has included various ASM charges and credits in this proceeding incurred for September through November 2013, consistent with the Phase II Order, as well as appropriate period adjustments.

Duke Energy Indiana's witness Mr. Scott A. Burnside testified that Duke Energy Indiana, 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)	Sept-13	Oct-13	Nov-13
Regulation Cost Dist.	0.0548	0.0674	0.0624
Spinning Cost Dist.	0.0631	0.0724	0.0588
Supplemental Cost Dist.	0.0437	0.0630	0.0420

OUCC witness Mr. Eckert testified that Applicant reported the monthly average distribution costs for Regulation, Spinning, and Supplemental Reserves charge types in accordance with the Commission's Phase II Order.

Based upon the evidence presented, the Commission finds that Applicant's treatment of the new and modified 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. Participation in the Energy and ASM Markets and MISO-Directed Dispatch. As previously noted, the June I Order approved certain changes in the operations of Duke Energy Indiana as a result of the implementation of the Energy Markets. Specifically, we found that Duke Energy Indiana (and the other electric utilities participating in Cause No. 42685) "should be granted authority to participate in the Midwest ISO Day 2 directed dispatch and Day 2 energy markets as described in their testimony." *Id.* at 13. Mr. Swez generally described Duke Energy Indiana's participation in the MISO energy markets and testified that it was consistent with the testimony presented in Cause No. 42685. Mr. Swez discussed the offer process and noted there are a variety of reasons that Duke Energy Indiana will either offer a generating resource as must-run or self-schedule a unit to ensure the unit is operated as cost efficiently as possible.

Mr. Swez testified that beginning in late February 2012, a coal price decrement was applied to the dispatch costs of Gibson Units 1-5, Wabash River Units 2-6, and Cayuga Units 1-2 to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. He stated that, to the extent units are dispatched (when they wouldn't otherwise) with the price decrement in place, coal coming to the station is consumed, other potential costs are avoided, and customers ultimately benefit because higher cost options are not incurred. Mr. Swez testified the price decrement is working as designed as the Company initially saw a significant increase in generation output from these units. As the level of the coal price decrement has decreased over time, the impact of the decrement has lessened. Pursuant to the October 30, 2013 Order in Cause No. 38707 FAC96, Mr. Swez presented the inputs to Duke Energy Indiana's calculation of the coal price decrement applicable to the September through November 2013 reconciliation period.

Mr. Eckert provided testimony on behalf of the OUCC regarding ASM charges. He concluded Duke Energy Indiana reported ASM charges in accordance with the 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.

8. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC90, the Commission ordered Duke Energy Indiana to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Swez testified that there were three outages that met these criteria in this period. He stated that on September 27, 2013, Gibson 2 experienced a tube leak in the front platen superheater section of the boiler. After repairs were completed, the unit returned to an available status on October 1. He testified that on October 29, 2013, Wabash River 6 experienced a mill explosion with resulting ductwork damage. The damage was repaired and the unit returned to an available status on November 4. Mr. Swez testified that on November 13, 2013, Gibson 5 experienced a unit trip due to a failure of the phase bushing on the main power transformer. After completing repairs, the unit was returned to an available status on November 18, 2013.

9. Operating Expenses. 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, Duke Energy Indiana filed operating cost data for the 12 months ended November 30, 2013. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $861,398,000. For the 12-month period ended November 30, 2013, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,169,023,000. Accordingly, Duke Energy Indiana's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Duke Energy Indiana's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

10. Return Earned. 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 in excess of 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 previous Commission Orders, Duke Energy Indiana's calculated jurisdictional electric operating income level was $397,798,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $488,087,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended November 30, 2013.

11. Estimation of Fuel Costs. Duke Energy Indiana estimates that its prospective average fuel cost for the months of April through June 2014 will be $79,774,633 or $0.031629 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period September through November 2013, 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
September 2013	30.974	29.973	3.34
October 2013	31.347	29.724	5.46
November 2013	31.680	30.550	3.70
Weighted Average	31.331	30.076	4.17

A comparison of Duke Energy Indiana's actual fuel costs with the respective estimated costs for these three periods results in a weighted average percentage difference of 4.17%. Based on the evidence of record, we find Duke Energy Indiana's estimating techniques appear reasonably sound and its estimates for April through June 2014 should be accepted.

12. Purchased Power Benchmark. Duke Energy Indiana has calculated monthly purchased power benchmarks in accordance with the Commission's August 18, 1999 Order in Cause No. 41363 and the guidance of this Commission in Cause Nos. 38706 FAC 45, 38708 FAC 45, 38707 FAC 56, and 38707 FAC 59. The benchmarks are as follows:

Month / Year	**Benchmark $/MWh 1/**	**Facility**
September 2013	310.55	Connersville 1
October 2013	46.25	Vermillion 5
November 2013	45.04	Vermillion 2

1/ Calculated using most efficient unit heat rate.

Mr. Burnside testified that the Company did not exceed benchmarks for the reconciliation period at issue in this FAC proceeding. He noted however, that due to errors identified in the heat rate curves utilized in the Company's S14 PACE run, the benchmark reported in FAC98 for June 2013 was incorrect and the benchmark was actually exceeded during that month. Mr. Burnside testified that the revised June 2013 benchmark is $51.41/MWh at Vermillion 5. The weekly average cost of purchased power in week 5 of June 2013 averaged $51.67/MWh. He explained that Duke Energy Indiana purchased 102,980 MWh of power during the week of June 23 through 29 at an average cost of $51.67/MWh. The benchmark of $51.41/MWh is $0.26/MWh lower than the actual average purchase cost, yielding a difference of $26,774.80. Mr. Burnside testified that the amount of the difference allocated to wholesale customers is $2,883.75, with the remaining $23,891.05 amount of purchased power exceeding the benchmark allocated to retail customers. Mr. Burnside explained that the principal reason that the average purchased power cost was higher during this week in June was the higher than normal temperatures in the MISO footprint. Mr. Burnside testified that the Company proposes to recover the cost of purchased power allocated to retail customers exceeding the benchmark pursuant to the Commission's Order in Cause No. 41363. Mr. Burnside testified that the Company made reasonable decisions under the circumstances known at the time and acted appropriately in the operation of its generation and its participation in MISO to maintain safe, adequate, and reliable service to its retail customers. Mr. Burnside stated that without these particular purchases, the Company could not have met the demands of its retail customers while complying with MISO dispatch instructions.

The OUCC's witness Mr. Michael Eckert testified that under Duke Energy Indiana's current purchased power over the benchmark calculation, which uses an average purchased power price for the week which tends to smooth out high prices and low prices of the purchased power, it is unlikely that Duke will exceed the benchmark.

Mr. Burnside responded in testimony that Duke Energy Indiana's benchmark calculation was approved by the Commission in Cause 41363. He further noted that this methodology does not allow Duke Energy Indiana to "pass the test every time" as demonstrated during the week of June 23 through June 29 in which the weekly average cost of purchased power exceeded the benchmark.

Based on the evidence of record, the Commission finds that Duke Energy Indiana has met the requirements necessary to establish monthly benchmarks for power purchases that occurred during the September through November 2013 reconciliation period. The Commission further finds that Duke Energy Indiana's request for recovery of its purchased power over the benchmark for June 2013 is consistent with the Commission's Purchased Power Order and should be approved.

13. **Fuel Cost Factor**. As discussed in Finding No. 3 above, Duke Energy Indiana's base cost of fuel is 14.484 mills per kWh. The evidence indicates that Duke Energy Indiana's fuel cost adjustment factor applicable to April through June 2014 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.031629
Net Variance (current reconciliation period)	0.001874
Adjusted Fuel Cost Factor	0.033503
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.019019
Adjustment for Utility Receipts Tax	0.000292
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.019311

The net variance factor shown above reflects $12,048,847 of under-billed fuel costs applicable to retail customers that occurred during the period of September through November 2013. Ms. Sieferman testified that approximately $6 million of the $12 million under-collected amount is due to the continuation of the procedural schedule in FAC96. She stated that due to the continuation, the fuel factor from FAC95 was left in place instead of implementing the proposed FAC96 factor for September's billing cycles or the proposed FAC97 factor for the first billing cycle of October 2013. As a result, the amounts billed in both September and October 2013 did not reflect the estimated costs for those periods, which resulted in large under-collections for both months.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost element of the Company's proposed fuel cost adjustment has been calculated in conformity with Ind. Code §8-1-2-42 and numerous Commission Orders affecting this filing. He further concluded the fuel cost adjustment for the quarter ended November, 2013, had been properly applied by the Company. In addition, he stated the figures used in the Application for a change in the FAC were supported by the Company's books and records, Post Analysis Cost Evaluation, and source documentation of the Company for the period reviewed.

14. Effect on Residential Customers. The approved factor represents a decrease of $0.000292 per kWh from the factor approved in Cause No. 38707-FAC98. The typical residential customer using 1,000 kWhs per month will experience a decrease of $0.29 or 0.3% on his or her electric bill compared to the factor approved in Cause No. 38707 FAC 98 (excluding various tracking mechanisms and sales tax).

15. Interim Rates. Because we are unable to determine whether Duke Energy Indiana'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 in the event an excess return is earned.

16. Fuel Adjustment for Steam Service. On December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Duke Energy Indiana 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.[5] The fuel cost adjustment factor for International Paper of $1.7686031 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the April through June 2014 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 $16,019 payable to International Paper for the months of September through November 2013.

The Commission finds that Duke Energy Indiana's proposed fuel cost adjustment factor for International Paper of $1.7686031 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 Duke Energy Indiana's reconciliation amount of $16,019 payable to International Paper has been properly determined and should be approved.

17. Shared Return Revenue Credit Adjustment for International Paper. 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, Duke Energy Indiana did not have excess earnings for the 12 months ended November 2013. Therefore, we find International Paper is not due a shared return revenue credit.

[5] On January 25, 2012, this Commission issued an Order approving the fourth amendment to Steam Supply Agreement between Duke Energy Indiana and Temple-Inland, Inc., n/k/a International Paper.

18. **Confidential Information.** On November 7, 2013, Duke Energy Indiana filed its motion seeking a determination that designated confidential information involved in this proceeding be exempt from public disclosure under Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3. The request was supported by the affidavit and testimony of John D. Swez, showing documents offered into evidence at the evidentiary hearing were trade secret information within the scope of Ind. Code § 5-14-3-4(a)(4) and Ind. Code § 24-2-3-2. On November 21, 2013, the Presiding Officers issued a docket entry finding such information confidential on a preliminary basis. After reviewing the designated confidential information, we find all such information qualifies as confidential trade secret information pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. Duke Energy Indiana takes reasonable steps to maintain the secrecy of the information and disclosure of such information would cause harm to Duke Energy Indiana. Therefore, we affirm the preliminary ruling and find this information should be exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29, and held confidential and protected from public disclosure by this Commission.

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. 13, and the fuel cost adjustment for steam service as set forth in Finding No. 16 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 shall place into effect the fuel cost adjustment factors for electric service and steam service approved herein, applicable to all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of April 2014, upon filing with the Electricity Division of the Commission, a separate amendment to its rate schedules with clear reference therein that such factor is applicable to the rate schedules reflected on the amendment.

4. Duke Energy Indiana shall provide an update on the status of its coal inventories and the situation with Benton County Wind Farm in its next FAC filing, as described in Finding No. 4 of this Order.

5. The material submitted to the Commission under seal shall be and hereby 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.

6. A subdocket is hereby created consistent with Finding No. 4a above. A prehearing conference in the subdocket, Cause No. 38707 FAC 99 S1, is scheduled for 10:30 a.m. on April 23, 2014 in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana.

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

ATTERHOLT, MAYS, STEPHAN, WEBER, AND ZIEGNER CONCUR:

APPROVED: APR 02 2014

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission