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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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| 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 90<br><br>APPROVED:<br>DEC 28 2011 |

## ORDER OF THE COMMISSION

**Presiding Officers:**
**Kari A. E. Bennett, Commissioner**
**Aaron A. Schmoll, Senior Administrative Law Judge**

On November 4, 2011, pursuant to Indiana Code §§ 8-1-2-42 and 8-1-2-42.3, and various Orders of the Indiana Utility Regulatory Commission ("Commission"), Duke Energy Indiana, Inc. ("Duke Energy Indiana", "Company" or "Petitioner") filed with the Commission its Verified Application for approval of a change in its fuel cost adjustment for electric service, approval of a change in its fuel cost adjustment for steam service, and to update monthly benchmarks, together with its case-in-chief testimony.

On November 9, November 14, and November 29, 2011, respectively, Duke Energy Indiana Industrial Group ("Industrial Group"), Steel Dynamics, Inc. ("SDI") and Nucor Steel, a division of Nucor Corporation ("Nucor") filed Petitions to Intervene in this proceeding. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on December 12, 2011, and amended testimony on December 16, 2011.

Pursuant to proper notice of hearing, 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 December 20, 2011, at 2:00 p.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. The Presiding Officers granted the Petitions to Intervene on the record at the evidentiary hearing. No members of the general public appeared or participated 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 ch. 8-1-2, as amended, and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Duke Energy Indiana'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. The Company 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, Temple-Inland, Inc. ("Temple-Inland").

3. **Order in Cause No. 42359.** 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. Among other matters, 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.

4. **Orders in Cause Nos. 41744 S1 and 42061, 42061 ECR 3 through 42061 ECR 17, the November 20, 2007 Order in Cause Nos. 43114 and 43114-S1 ("IGCC Order") and the Orders in Cause Nos. 43114 IGCC 1 through IGCC 4.** The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061 ("CWIP Order"), and subsequent update Orders up to and including the July 27, 2011, update in Cause No. 42061 ECR 17 ("CWIP Update"), 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 CWIP update 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 CWIP update. The Commission's IGCC Order, and subsequent update Orders up to and including the July 28, 2010, update in Cause No. 43114 IGCC 4, 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. In accordance with these Orders, Duke Energy Indiana calculated its authorized jurisdictional net operating income level for the 12-month period ending August 31, 2011, to be $407,338,000. 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.

5. **Fuel Purchases.** Mr. Elliott Batson, Jr., Vice President, Regulated Fuels, testified regarding Duke Energy Indiana's fuel procurement practices. Mr. Batson testified that during the twelve month period ended August 31, 2011, coal purchased under long-term commitments comprised greater than 97% of total coal receipts. Mr. Batson testified that if the Company were to purchase all of its coal requirements on the open market, spot prices would be driven upward to accommodate a demand influx of approximately 13 to 16 million tons annually. Mr. Batson explained that when spot coal is required, the purchase commitments are usually made for small quantities, over short durations, and are based on the lowest delivered cost and best overall utilization characteristics.

Mr. Batson testified that as a result of the emerging environmental regulations such as the Cross State Air Pollution Rule ("CSAPR"), the Company currently projects substantially higher fuel costs and lower coal consumption levels for calendar year 2012 at Wabash River Station. He stated that due to the impending compliance requirements of CSAPR, the Company performed operational evaluations of and has competitively sourced supplies of lower sulfur coal for consumption in 2012 at Wabash River Station. He testified that the Company projects an overall increase in coal costs as of January 1, 2012 due to the expiration of one long-term coal contract at the end of 2011 and the market re-pricing of a second, long-term coal contract effective January 1, 2012. He explained that these two contracts have provided value to the customer over the past several years through pricing provisions that have been consistently below the published market pricing for such coals.

Mr. Barry F. Blackwell, Director, Rates, testified that the forecasted FAC reflects increased coal costs resulting from the expiration and re-pricing of the two long-term coal contracts as well as the estimated fuel impacts from the compliance with CSAPR.

Mr. Batson testified that inventories for the Company's coal fired plants remain near normal levels, with the exception of the continued existence of the Gibson remote pile. He stated that inventories on the Gibson Station main pile are now at target levels, with continued efforts to move coal from the adjacent remote storage pile to the station to ensure that the main pile inventories remain near target levels. He testified that the Company is continuing to test lower sulfur fuels at Wabash River Station, with the intent of drawing down inventories of mid-sulfur coal in the fourth quarter of 2011 and replacing it with a lower sulfur coal for compliance with CSAPR effective January 1, 2012. Mr. Batson testified that the Company continues to maintain the Gallagher station coal inventories slightly below target levels in anticipation of the potential retirement of two units in early 2012.

Mr. Batson testified that the Company made an adjustment to fuel inventory in the amount of $4 Million as a result of settling claims for additional compensation on coal shipments between 2008 and 2011 due to costs incurred as a result of changes in law stemming from the MINER Act of 2006.

Mr. Batson testified that in his opinion, Duke Energy Indiana is purchasing coal at prices as low as reasonably possible. Mr. Batson concluded his testimony by offering his opinion that

oil purchased by Duke Energy Indiana for peaking and cycling units is purchased at the lowest cost reasonably possible.

Mr. John D. Swez, Director, Regulated Portfolio Optimization, discussed Duke Energy Indiana's contracts and practices related to the transportation and purchase of natural gas. Mr. Swez testified that the price of delivered natural gas at the Company's gas burning generation stations during the three-month period from June through August 2011 decreased approximately $5.00 per million BTU to $4.00 per million BTU. Mr. Swez testified that, in his opinion, Duke Energy Indiana purchased natural gas at the lowest cost reasonably possible.

OUCC witness Mr. Michael D. Eckert, Senior Utility Analyst, testified regarding a comparison he performed of the actual monthly fuel costs for the five Indiana large investor owned utilities and concluded that Duke Energy's monthly fuel cost is among the lowest. Mr. Eckert also testified that he prepared a schedule that shows the timelines associated with each of Duke Energy Indiana's coal contracts. This schedule was not filed in the current FAC due to the concerns raised in FAC 87 by Mr. Batson in his pre-filed testimony that public disclosure in the format presented by the OUCC provides a level of clarity into the Company's coal position that would hurt the Company's leverage in negotiations for new coal contracts, to the detriment of customers. Mr. Eckert stated that the OUCC does not agree with Mr. Batson's position but has chosen not to file the exhibit due to the concerns raised by Mr. Batson.

Based upon the evidence presented, we find that Duke Energy Indiana has made reasonable efforts to acquire fuel for its own generation so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. We find that Duke Energy Indiana's coal storage actions are reasonable, prudent and in the best interest of customers. With regard to its coal inventory levels, Duke Energy Indiana will provide an update on the status of its coal inventories in its FAC 91 proceeding as recommended by the OUCC.

**6. <u>Hedging Activities</u>.** Mr. Wenbin (Michael) Chen, Manager, Portfolio Optimization, provided updates of the Company's gas and power hedging activities. He explained that the Company relies more on natural gas for fuel for the Company's peaking plants than it has in the past and cited recent historical occurrences of gas price volatility. He testified that, in his opinion, it makes sense for the Company to take advantage of the hedging tools available to protect against price fluctuations. Mr. Chen testified that since the last update to the Commission in the FAC 89 proceeding, the Company purchased February and March 2012 forward gas contracts to hedge up to 100% of the Company's expected native burn for January and February 2012. Mr. Chen discussed the results of the gas hedging for the June through August 2011 reconciliation period. He testified that the Company realized a loss of $31,420 from hedges bought for July 2011 native gas burn.

Mr. Chen discussed the results of and the factors influencing the results of the power hedging for the June through August 2011 reconciliation period. He stated the Company experienced realized power hedging gains (exclusive of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") virtual trades and including prior period adjustments) for the period of $1,034,908.

Mr. Chen also explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1, 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 approximately 150 MW of expected load unhedged on a forward forecasted basis.

Mr. Chen also noted that the Company continues to hold discussions with the OUCC (meeting most recently with the OUCC on July 12, 2011) and its consultant, has responded to all data requests, and has provided hedging audit information for the reconciliation months of this FAC filing.

Mr. Chen opined that the Company's gas and power hedging practices are reasonable. He stated that the Company never speculates on future prices, that its practice is economic at the time the hedging decisions are made, that it reduces volatility, and that it benefits customers by reducing customers' risk of paying potentially higher spot market prices.

Mr. Blackwell explained that the amount included in fuel costs for hedging activity in this proceeding was a realized loss of $31,420 for gas hedging activity and a realized net gain of $1,034,908 for power hedging activity (exclusive of Midwest ISO virtual activity and including prior period adjustments).

OUCC witness Mr. Eckert testified that there were no major issues related to hedging in this cause. He noted that the OUCC issued a data request regarding hedging and intends to discuss the responses with representatives from the Company, as appropriate, prior to the next FAC.

The Commission's Order in Cause No. 38707 FAC 67, dated April 6, 2006, found gas hedging activities to be reasonable. The Company has included a gas hedging loss of $31,420 in the computation of the current fuel adjustment clause factor. The gas hedging amount was properly included, and we so find.

The issue of the appropriateness of the inclusion of realized gains/losses relating to the Company's power hedging activities in the computation of the fuel adjustment charge was the subject of a proceeding established by the Commission in Cause No. 38707 FAC 68 S1. On June 25, 2008, the Commission issued an Order approving a Stipulation and Agreement ("Settlement") between Duke Energy Indiana and the OUCC and resolving all disputed issues evaluated within that sub-docket. No evidence was offered in this Cause noting issues with the realized net gain for power hedging included in the fuel costs in this proceeding or challenging the prudence of the power hedging activities that gave rise to the realized net gain. In addition, the Company presented evidence that its hedging practices relevant to this proceeding were consistent with the Settlement. Thus, we will allow Petitioner to include $1,034,908 of realized power hedging gains in the calculation of fuel costs in this proceeding.

7. **Orders in Cause Nos. 42685, 38707 FAC 70, and 43426.** On June 1, 2005, the Commission issued its final Order in Cause No. 42685 ("June 1 Order"). In the June 1 Order, we approved certain changes in the operations of Duke Energy Indiana and the other investor-owned Indiana electric public utilities that are participating members of the Midwest ISO. Additionally, we addressed the timing and manner of recovery of costs incurred by Duke Energy Indiana as a result of the Midwest ISO's implementation of day-ahead and real-time markets for electric energy (the "Energy Markets"). In the June 1 Order, we determined the Energy Markets charges and credits that should be included in the cost of fuel for purposes of subsequent fuel cost proceedings, including certain charges and credits listed on page 37 of the June 1 Order.

In this proceeding, Mr. Swez testified that Duke Energy Indiana included the following Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Duke Energy Indiana's load: (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 the Midwest ISO at the full locational marginal price ("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 involving Manual Re-Dispatch Make Whole Payments that resulted in credits from testing prior to the start of the Ancillary Services Market ("ASM"), as authorized by the Commission in Cause No. 38707 FAC 77 and Cause No. 38707 FAC 80.

Ms. Mary Ann Amburgey, Lead Accounting Analyst, testified as to the procedures followed by the Company to verify the accuracy of the charges and credits allocated by the Midwest ISO to the Company. She also discussed the process by which the Midwest ISO 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 the Midwest ISO 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 the Midwest ISO, net of any credits, are proper and that such amounts billed to customers through the fuel adjustment clause are proper.

On June 30, 2009, the Commission issued its Phase II Order in Cause No. 43426 ("Phase II Order") authorizing 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 June, July, and August 2011, consistent with the Phase II Order, as well as appropriate period adjustments.

Mr. Scott A. Burnside, Accounting Manager, 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) | June-11 | July-11 | Aug-11 |
|---|---|---|---|
| Regulation Cost Dist | 0.0659 | 0.0759 | 0.0751 |
| Spinning Cost Dist | 0.0442 | 0.0403 | 0.0445 |
| Supplemental Cost Dist | 0.0217 | 0.0229 | 0.0162 |

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

Based upon the evidence presented, we find that Duke Energy Indiana's inclusion 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.

**8. Participation in the Energy and ASM Markets and Midwest ISO Directed Dispatch.** As mentioned above, in the June 1 Order, the Commission 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 directed dispatch and energy markets as described in their testimony." *Id.* at p. 13. Mr. Swez generally described Duke Energy Indiana's participation in the Midwest ISO 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 there were a limited number of operating conditions that affect the dispatch of Petitioner's operating units. He testified that starting on July 21 and ending on August 5, 2011, at different times Wabash River Station units 2, 3, 5, and 6 experienced low river flow and high river temperature. He explained that at times during this period, these units were either derated or taken off-line to stay within required down-stream river temperature limits. He testified that thermal derates were also experienced at Cayuga 1 and 2, although to a much lesser extent.

Mr. Swez testified that CSAPR created four new interstate trading markets, of which Indiana is a member of three. He explained that these three markets are for Annual NOx, Seasonal NOx, and Group 1 $SO_2$ allowances. He testified that the allocation levels associated with this rule will require a significant reduction in emissions and the market prices associated with the allowances are likely to be considerably higher than emission allowance prices seen in recent years. He stated that market prices have been extremely volatile since the rule was announced and are likely to remain so for the near future. Mr. Swez testified that the Company's preliminary model runs show significant reductions in capacity factor are possible at non-scrubbed generating units. He reiterated that these results are preliminary and significant changes in forecasted capacity factors could occur by changing data inputs.

Mr. Swez testified that the Company is seeking approval of the purchase of a portion of a merchant plant from Duke Energy Vermillion II, LLC, in Cause No. 43956 which, if approved, would result in the potential shutdown of Gallagher Units 1 and 3. He testified that under the Consent Decree reached in the NSR lawsuit, the Company must make a final decision by January

1, 2012, concerning whether Gallagher Units 1 and 3 will be converted to gas or retired. If the Company receives approval for the purchase of a portion of the Vermillion Plant and the decision is made to retire the units, they must be retired by the end of January 2012. He stated that this acquisition would not negatively impact the Company's ability to meet future summer peak demands, as the additional capacity from acquiring Vermillion II, LLC is slightly larger than the lost capacity from retirement of Gallagher Units 1 and 3.

Based upon the evidence presented, we find that Duke Energy Indiana's participation in the Energy and Ancillary Services Markets constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible.

**9. New Source Review ("NSR") Litigation Impacts on Operations.** Mr. Swez noted that pursuant to the Consent Decree involving the Gallagher units in the NSR lawsuit, these units are being operated under pre-project NSR baseline levels to limit annual emissions. He stated that this restriction did not impact the units' generation in 2010 and is not impacting the units' generation in 2011. Mr. Swez also noted that effective December 1, 2010, the impact of dry sorbent injection costs have been added to the dispatch prices for the Gallagher Units 2 and 4 to reflect the correct variable costs for those units.

OUCC witness Mr. Eckert described the agreement addressed by the Commission in its FAC 84 Order, which required Duke Energy Indiana to file a separate case with the Commission by September 30, 2010 that addresses the NSR litigation impacts. Mr. Eckert testified that the Company did file such case with the Commission, captioned Cause No. 43956. Mr. Eckert recommended that in its next FAC proceeding, Duke Energy Indiana again update the Commission on how the potential shutdown of two Gallagher units and the acquisition of the merchant plant from Duke Energy Vermillion II, LLC, will impact the Company's ability to meet future demand levels.

The Commission finds that the fuel costs approved in this FAC related to increased fuel costs as a result of the shutdown of Wabash River Station Units 2, 3 and 5 are finalized and no longer subject to refund as set forth in the final order of the Commission in Cause No. 43956, as discussed in the Commission's FAC 84 Order.

**10. Operating Expenses.** Indiana 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 August 31, 2011. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $815,494,000. For the 12-month period ended August 31, 2011, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,148,547,000. 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.

**11. Return Earned.** Indiana 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 (earnings test). 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 Indiana 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.

Mr. Blackwell testified that, in compliance with the Commission's June 25, 2008 Order in Cause No. 42736-RTO 14, the Company has excluded applicable revenues and expenses from the FAC earnings test related to Company-owned Midwest ISO RECB transmission projects.

The fuel cost charge test period used for earnings test computations in this Cause was the 12 months ended August 31, 2011. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $287,143,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Indiana Code § 8-1-2-42(d)(3), was $407,338,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended August 31, 2011.

**12. Estimation of Fuel Costs.** Duke Energy Indiana estimates that its prospective average fuel cost for the months of January through March 2012 will be $86,217,645 or $0.031182 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period June through August 2011, 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 |
|---|---|---|---|
| June 2011 | 27.611 | 26.360 | 4.75 |
| July 2011 | 31.276 | 27.011 | 15.79 |
| August 2011 | 28.865 | 27.385 | 5.40 |
| Weighted Average | 29.344 | 26.931 | 8.96 |

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 8.96%.

Mr. Blackwell testified that in an attempt to improve the Company's forecast and to mitigate the under-collection of fuel costs that it has experienced in recent quarters, the Company refined its forecast assumptions for purchased power prices to use around the clock ("ATC") prices from the forward power curves rather than hourly prices. He stated that the Company has determined that utilizing hourly prices instead of ATC prices tends to understate purchased power cost estimates, and as a result Duke Energy Indiana has adjusted the purchased power pricing in this FAC to mitigate the under collection in future periods.

No evidence was offered in this Cause disputing the techniques or results of Duke Energy Indiana's forecasting methodology. Duke Energy Indiana's estimating techniques appear reasonably sound and its estimates for January through March 2012 should be accepted and we so find.

**13. 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 |
|---|---|---|
| June 2011 | 252.12 | Wabash River Diesel |
| July 2011 | 356.24 | Miami Wabash 1 |
| August 2011 | 257.20 | Wabash River Diesel |

1/ Calculated using most efficient unit heat rate.

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 June through August 2011 reconciliation period.

**14. 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 January through March 2012 billing cycles is computed as follows:

| | $ / kWh |
|---|---|
| Projected Average Fuel Cost | 0.031182 |
| Net Variance | 0.001401 |
| Adjusted Fuel Cost Factor | 0.032583 |
| Less: Base Cost of Fuel | 0.014484 |
| Fuel Cost Adjustment Before Applicable Taxes | 0.018099 |
| Adjustment for Utility Receipts Tax | 0.000276 |
| Fuel Cost Adjustment Factor Adjusted for Applicable Taxes | 0.018375 |

The net variance factor shown above reflects one-half of the $20,755,139 of under-billed fuel costs applicable to retail customers that occurred during the period June through August 2011. Mr. Blackwell testified that the Company proposes to spread the under-collected amount over a period of six months instead of the normal three-month recovery period, which results in the proposed factor in this proceeding including one-half of the under-collection ($10,377,570) to facilitate the six-month collection period. Mr. Eckert recommended that Petitioner's proposal to lengthen the recovery period be approved.

OUCC witness Mr. Gregory Guerrettaz, President, Financial Solutions Group, Inc., testified, among other matters, that the fuel cost element of the Company's proposed fuel cost

adjustment has been calculated in conformity with Indiana Code §8-1-2-42 and numerous Commission Orders affecting this filing. He further concluded that the fuel cost adjustment for the quarter ended August 31, 2011, had been properly applied by the Company. In addition, he stated that the figures used in the Application for a change in the fuel cost adjustment were supported by the Company's books and records, "PACE", and source documentation of the Company for the period reviewed.

Based upon the evidence of record, the Commission finds that the under-collected amount of $20,755,139 should be spread over a period of six months instead of the normal three-month recovery period, resulting in a proposed factor in this proceeding which includes one-half of the under-collection ($10,377,570).

**15.** **Effect on Residential Customers.** The approved factor represents an increase of $0.003159 per kWh from the factor approved in Cause No. 38707 FAC 89. The typical residential customer using 1,000 kWhs per month will experience an increase of $3.16, or 3.5%, on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC 89 (excluding various tracking mechanisms and sales tax).

**16.** **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.

**17.** **Fuel Adjustment for Steam Service.** On December 30, 1992, the Commission issued its Order in Cause No. 39483 approving the June 18, 1992 SettlementAgreement between Duke Energy Indiana and Premier Boxboard, n/k/a Temple-Inland, which included a change in the method used to calculate Temple-Inland's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for Temple-Inland of $1.7380084 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the January through March 2012 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 Temple-Inland that resulted in a $34,653 receivable from Temple-Inland for the months of June through August 2011.

The Commission finds that Duke Energy Indiana's proposed fuel cost adjustment factor for Temple-Inland of $1.7380084 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 $34,653 receivable from Temple-Inland has been properly determined and should be approved.

**18.** **Shared Return Revenue Credit Adjustment for Temple-Inland.** In accordance with the June 18, 1992 Settlement Agreement, Temple-Inland will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 11, Duke Energy Indiana did not have excess earnings for the 12 months ended August 2011. Therefore, we find Temple-Inland is not due a shared return revenue credit.

**19. Collaboration Concerning Outage Information.** The Commission's September 28, 2011 Order in Cause No. 38707 FAC 89 encouraged the parties to work collaboratively to develop a process that ensures timely information concerning outages during the FAC review period be provided to the parties that allows for appropriate review or examination of any outage impacts on fuel costs. Mr. Swez testified that the Company is willing to discuss major forced outages in its testimony for all forced outages of units of 100MW or more lasting more than 100 hours, and provide the complete outage schedule for the relevant period if requested in discovery by the parties. He stated that this is similar to the process used by Northern Indiana Public Service Company ("NIPSCO") as established in Cause No. 38706 FAC 71 S1. He stated it is his understanding that the Industrial Group and SDI would like Duke Energy Indiana to provide a financial impact analysis for all outages lasting more than 12 hours, as a single event or in the aggregate per unit. He testified that an attempt to quantify each outage invites increased litigation regarding assumptions in the quantification calculus, which is contrary to the summary nature of the FAC statute and proceeding.

Mr. Burnside testified that calculating the economic impact of each generator outage is nearly impossible given that generators do not operate independently but rather operate in conjunction with one another and market conditions. He stated that estimating the cost and/or impact associated with outages comes with a host of limitations and complications and requires multiple assumptions. He stated that the Company also does not have access to Midwest ISO's optimization software that makes these decisions, making any analysis that the Company would provide very limited.

Mr. Eckert testified that the OUCC recommended the NIPSCO resolution in Cause No. 38706 FAC71 S1, which the Company generally accepted, with the exception that it wanted the number of hours to be increased from 72 to 100 as a trigger for reporting. He stated that the Industrial Group and SDI continue to request that the outage reporting trigger be twelve hours. Mr. Eckert testified that the OUCC would refer the Commission generally to its decision in the NIPSCO case and declined to take a further position in the dispute between the Industrial Group, SDI and Duke Energy Indiana. SDI, NUCOR, and the Industrial Group did not provide testimony or otherwise offer a recommendation into the record on these issues.

The Commission acknowledges the efforts of the parties it encouraged in its FAC 89 Order. Absent evidence to the contrary, we conclude that the Company's proposal will provide for enhanced review or examination of the outage impacts on fuel costs by non-Company parties in future FACs. Accordingly, the Commission finds that the Company's proposal to discuss major forced outages in its testimony for all forced outages of units of 100MW or more lasting more than 100 hours, and provide the complete outage schedule for the relevant period if requested in discovery by the parties, is reasonable.

**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. 14, and the fuel cost adjustment for steam

service as set forth in Finding No. 17 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. 7 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 January 2012, 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. In future FAC proceedings, Duke Energy Indiana shall discuss major forced outages in its testimony for all forced outages of units of 100MW or more lasting more than 100 hours, and provide the complete outage schedule for the relevant period if requested in discovery by the parties.

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

**ATTERHOLT, BENNETT AND MAYS CONCUR; LANDIS AND ZIEGNER ABSENT:**

**APPROVED:** DEC 28 2011

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

Sandra K. Gearlds

**Sandra K. Gearlds**
**Acting Secretary to the Commission**