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 94 APPROVED: DEC 27 2012

ORDER OF THE COMMISSION

Presiding Officers:
James D. Atterholt, Chairman
Gregory R. Ellis, Administrative Law Judge

On October 31, 2012, 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 January, February, and March 2013 for electric and steam service and to update monthly benchmarks for purchased power costs. On November 1, 2012, Steel Dynamics, Inc. ("SDI") filed its Petition to Intervene in this proceeding. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on December 5, 2012. On December 6, 2012, the Duke Energy Indiana Industrial Group ("Industrial Group") filed its Petition to Intervene in this proceeding. Although Duke Energy Indiana challenged the intervention of the Industrial Group as untimely, the Commission granted the Petitions to Intervene on the record at the evidentiary hearing.

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 December 12, 2012, at 1:30 p.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, Applicant, the Industrial Group, and the OUCC appeared by counsel. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. Neither SDI nor the Industrial Group offered any evidence into the record at the evidentiary hearing. The Industrial Group asked the Commission to take administrative notice of its Orders in Cause Nos. 41363 and 38707 FAC 56. As there were no objections, the Commission took notice of its previous orders. No members of the general public appeared.

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 Applicant 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, Temple-Inland, Inc. ("Temple-Inland").

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 August 2012, 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 $0.028804 per kWh as shown on Exhibit A, Schedule 9. In accordance with previous Commission Orders[1], Duke Energy Indiana calculated its authorized jurisdictional net operating income level for the 12-month period ending August 31, 2012, to be $403,430,000. 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. Elliott Batson, Jr. testified regarding Duke Energy Indiana's coal procurement practices and its coal inventories. Mr. Batson testified that as of October 3, 2012, coal inventories were approximately 3,255,000 tons (or 53 days of coal supply), slightly higher than what was reported in Cause No. 38707 FAC 93. Mr. Batson testified that the Company continues to evaluate a host of options in order to effectively manage the growing inventories. Mr. Batson

[1] The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061, and subsequent update Orders, up to and including the August 29, 2012, update in Cause No. 42061 ECR 19, 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 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.

testified that the Company has entered into a short-term storage agreement with one supplier to store coal at the supplier's mine facilities and began storing coal at this location during September. He further stated that Duke Energy Indiana shaped and compacted the Gibson Remote Pile for receipt of additional coal for storage. He stated the Company continues to actively explore options to 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. Batson testified that it was his opinion that the Company is purchasing coal and oil at prices as low as reasonably possible.

Mr. John D. Swez 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 June 2012 through August 2012 with a range of delivered prices between $2.30 per million BTU to $3.40 per million BTU. Mr. Swez testified that, in his opinion, Duke Energy Indiana purchased natural gas at the lowest cost reasonably possible.

The OUCC did not raise any concerns regarding fuel purchases, but its witness, Mr. Michael Eckert recommended Duke Energy Indiana continue to update the Commission on its coal inventory, including the development of alternatives to manage the Company's supply of coal.

Mr. Swez 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 at the end of February 2012 and continuing through May 2012, BCWF began to receive persistent negative day-ahead and real-time LMPs at the generator node. In addition, BCWF began to once again receive negative LMPs briefly in September and October, but these were not as significant as seen in the spring. BCWF is currently registered at the Midwest Independent Transmission System Operator, Inc. ("MISO") as an Intermittent Resource, which means that it has no ability to be committed or decommitted by, or follow the setpoint instructions, of MISO. 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 has a commitment status of must run, meaning that MISO will clear the generator at any LMP 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 is also possible to receive negative revenues in the real-time market. Mr. Swez testified that in order to rectify this situation, the Company is involved in discussions with BCWF and MISO to better understand the situation and work towards a solution. He testified that under the MISO's rules, Duke Energy Indiana, as the Market Participant, must register BCWF as a Dispatchable Intermittent Resource ("DIR") by December 15, 2012, and BCWF, as the generation resource, must be fully functional as a DIR by March 1, 2013. MISO's creation of the DIR construct will allow MISO to curtail the output of intermittent resources, thereby allowing for better management of congestion in certain areas. It is believed that the DIR construct will help to alleviate this negative LMP situation at BCWF.

OUCC witness Mr. Eckert recommended that Applicant report to the Commission any updates and resolutions to the negative LMP situation at BCWF in Duke Energy Indiana's next FAC filing.

Based upon the evidence presented, we find that Duke Energy Indiana 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. 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.** Mr. Wenbin 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 gain of $129,529 from hedges bought for July 2012 native gas burn. He further testified the Company experienced realized power hedging gains (exclusive of MISO virtual trades and including prior period adjustments) for the period of $680,342.

Mr. Chen also 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 July 10, 2012) as required by the FAC 68 S1 Order.

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 gains 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 gains. 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 will allow Petitioner to include $129,529 of gains from native gas hedges as well as $680,342 of realized power hedging gains 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.

Ms. Mary Ann Amburgey testified as to the procedures followed by the Company to verify

the accuracy of the charges and credits allocated by the 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 June, July, and August 2012, consistent with the Phase II Order, as well as appropriate period adjustments.

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)	June-12	July-12	Aug-12
Regulation Cost Dist.	0.0527	0.0658	0.0580
Spinning Cost Dist.	0.0434	0.1117	0.0301
Supplemental Cost Dist.	0.0269	0.0125	0.0247

OUCC witness Mr. Eckert testified that Applicant 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, 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 1 Order of 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 MISO 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 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 there were a number of operating conditions that affect the dispatch of Applicant's operating units. He testified that as discussed in the last few FAC proceedings, low natural gas prices, extremely mild winter weather, increased wind generation, and other factors caused the energy price in the MISO market to drop in 2011 and into the first half of 2012, causing

the Company's coal generating facilities to experience lower dispatch levels and even periods of economic shutdown which led to increased coal inventories.

He stated that beginning in late February 2012, a price decrement was applied to the dispatch costs of Gibson Units 1-5, Wabash River Units 2-6, and Cayuga Units 1-2 to 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 has seen a significant increase in generation output from these units.

Mr. Eckert testified the coal decrement pricing should be a short-term solution and not a long-term response to market competition. He stated that if the Company continues this practice, the OUCC reserves its rights in future FACs or other proceedings with respect to this below cost bidding strategy and its impact on customers.

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. <u>Addition of MISO Demand Response Allocation Uplift Charge</u>. Ms. Ambergey testified to the MISO Demand Response ("DR") Allocation Uplift charge that began on June 12, 2012. She testified that the existing and planned MISO market structures seek to provide opportunities for Demand Response Resources ("DRRs") to participate on a comparable basis as supply side resources. The basis of this structure came from the Federal Energy Regulatory Commission ("FERC") Order 745 that was issued on March 15, 2011, whereby it addressed an approach to compensate DRRs that helps ensure the competiveness of the organized wholesale markets and remove barriers for DRRs to participate. As part of this Order, FERC determined that each Independent System Operator or Regional Transmission Organization with a tariff that allows demand response to participate in its energy markets as a supply resource must pay any DRR that can balance supply and demand, the LMP for its energy reduction, after passing a FERC-approved net benefits test so that a determination can be made if a DRR is cost effective on a monthly basis. Ms. Amburgey added that the allocation method for these payments to DRRs must be made to wholesale buyers in the energy market area(s) where the demand response reduced the energy market price(s) at the time the DRR was committed or dispatched. MISO complied with this Order by establishing a monthly Net Benefit Price Threshold ("NBPT"). Generally speaking, the NBPT is a market-wide price threshold modeled to represent the Hourly LMP price in which DRR becomes beneficial to the Market. The NBPT for June 2012 was $25.10. According to Ms. Amburgey, if the LMP at the DRR node is less than the NBPT, the costs for all of the DRR energy reduction for that resource gets billed directly to the Load Serving Entity ("LSE") for that specific DRR through the Real Time ("RT") Asset Energy charge type, since it was energy that the LSE would have purchased if not for the DRR. If the LMP at the DRR node is greater than the NBPT, then the cost is allocated through the new DRR Uplift charge type in the applicable Ancillary Services Reserve Zone which in effect the DRR is supplying reserves for this zone. Ms. Amburgey testified that if

there are more DRR volumes than RT Energy Purchases, then the excess above the RT Energy Purchases is allocated to Revenue Neutrality Uplift under a new DRR compensation bucket.

Mr. Blackwell testified that DRRs now have a mechanism in place that gives them the ability to make consumption decisions based on the value of energy consumed relative to the prevailing market price. He testified that this mechanism helps facilitate MISO in balancing supply and demand, and thereby helps produce just and reasonable energy prices. Customers who choose to respond will signal to MISO and the energy market their willingness to reduce demand on the grid, which may result in reduced dispatch of higher-priced resources to satisfy load and may also reduce RT Revenue Sufficiency Guarantee ("RSG") Make Whole Payments. Additionally, Mr. Blackwell testified that these DRRs may be called on as an ancillary service. The cost allocation to Load Serving Entities such as Duke Energy Indiana for this compensation to DRRs will be settled through either RT Asset Energy or RT Demand Response Resource Uplift depending on whether the DRR LMP is above or below the Net Benefit Price Threshold established by MISO. Mr. Blackwell added that these costs are considered a fuel component, which is similar to the recovery of Real Time RSG First Pass which is also considered a fuel component. RSG First Pass are charges resulting from compensation made to generation resources that are committed by MISO and are then made whole when production and no load costs are below market prices. Therefore, Mr. Blackwell concluded that the DR Allocation Uplift charge is a fuel-related MISO charge.

No party to this proceeding objected to the treatment of DR Allocation Uplift Charge as a fuel related charge. Further, we note the Commission has approved similar treatment of this charge type for similarly situated utilities.[2]

Based upon the evidence presented, we find that the DR Allocation Uplift Charge is properly includable as a fuel-related charge in Duke Energy Indiana's FAC proceedings.

9. <u>Major Forced Outages</u>. 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 regarding the outages which occurred during the reporting period that met this criteria. He stated that significant derates and outages occurred during the summer at Wabash River and Cayuga Stations to comply with the Company's NPDES permit limits at each station. These restrictions limit the discharge of hot water into the Wabash River at the Wabash River and Cayuga generatmg stations. He stated that below average rain caused the flow of the Wabash River at Terre Haute, Indiana to average approximately 1,500 cubic feet per second (cfs) for the months of June through August versus a historical average of approximately 3,000 to 5,000 cfs for the same time period. Mr. Swez stated that in addition to the lack of rainfall, the summer saw significantly above average temperatures, with July being the hottest month ever on record. The first outage occurred on June 29, 2012, when Wabash River 6 became unavailable due to thermal limitations. The Company took advantage of the forced outage to perform planned maintenance on the unit that was originally scheduled for the fall. The unit returned to available status on August 10, 2012. Cayuga Units 1 and 2 were also affected by the thermal derates. Cayuga 2 was unavailable from July 1 through July 8, and again from July 14 through August 1. Cayuga 1 was unavailable from July 6 through July

[2] See *Northern Indiana Public Service Company,* Cause No. 38706-FAC 96 (IURC 10/31/12), *Southern Indiana Gas and Electric Company,* Cause No. 38708-FAC 96 (IURC 10/31/12), and *Indianapolis Power and Light Company,* Cause No. 38703-FAC 97 (IURC 11/21/12).

11, 2012. Mr. Swez testified that there was one additional outage that met the criteria. Wheatland 2 had an outage from July 2 until July 9, 2012, due to a blown diode and fuse on the voltage regulator.

10. **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 May 31, 2012. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $816,137,000. For the 12-month period ended August 31, 2012, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,151,965,000. 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.** 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 $265,570,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $403,430,000. 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, 2012.

12. **Estimation of Fuel Costs.** Duke Energy Indiana estimates that its prospective average fuel cost for the months of January through March 2013 will be $78,740,333 or $0.029127 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period June through August 2012, 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 2012	29.886	31.442	(4.95)
July 2012	39.219	30.204	29.85
August 2012	28.980	30.162	(3.92)
Weighted Average	32.878	30.572	7.54

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 7.54%. We note that

the moderate weighted average result includes a significant estimation error of 29.85% for July 2012. No party attributed this large error to the estimating techniques used by the Applicant, but rather to the specific weather conditions of the month. Based on the evidence of record, we find Duke Energy Indiana's estimating techniques appear reasonably sound and its estimates for January through March 2013 should be accepted.

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 the 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 2012	289.79	Connersville 1
July 2012	299.48	Miami Wabash 3
August 2012	276.58	Connersville 1

[1/] Calculated using most efficient unit heat rate.

At the evidentiary hearing, the Industrial Group raised the question of the appropriateness of the benchmarks in meeting their intent as defined in the Orders cited above. The implementation of an energy market as discussed above would seem to create a landscape that is different than that which existed when the underlying benchmark methodology was developed in Cause No. 41363. We encourage informal dialogue among the parties to explore how these changes over time may have impacted the value of the applied benchmark methodology.

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 2012 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 2013 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.029127
Net Variance (current reconciliation period)	0.003399
Adjusted Fuel Cost Factor	0.032526
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.018042
Adjustment for Utility Receipts Tax	0.000278
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.018320

The net variance factor shown above reflects $24,914,540 of under-billed fuel costs applicable to retail customers that occurred during the period of June through August 2012, of which $27,512,747 was incurred during the month of July.

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 August 31, 2012, 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.

15. **Effect on Residential Customers.** The approved factor represents an increase of $0.004390 per kWh from the factor approved in Cause No. 38707 FAC 93. The typical residential customer using 1,000 kWhs per month will experience an increase of $4.39 or 4.9% on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC 93 (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, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement 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.[3] The fuel cost adjustment factor for Temple-Inland of $1.4809914 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 2013 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 $63,533 payable from Temple-Inland for the months of June 2012 through August 2012.

The Commission finds that Duke Energy Indiana's proposed fuel cost adjustment factor for Temple-Inland of $1.4809914 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 $63,533 payable 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 2012. Therefore, we find Temple-Inland is not due a shared return revenue credit.

[3] 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.

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. 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's inclusion of charges related to the MISO Demand Response Allocation Uplift have been properly included as a fuel-related charge as described in Finding No. 8 and may be included in future FAC proceedings.

4. 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 2013, 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.

5. 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.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: DEC 27 2012

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