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 82 APPROVED: DEC 2 2 2009

JLS

BY THE COMMISSION:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On October 28, 2009, pursuant to Ind. 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 October 30, 2009 and November 5, 2009, Duke Energy Indiana Industrial Group ("Industrial Group") and Steel Dynamics, Inc. ("SDI") filed, respectively, Petitions to Intervene in this proceeding. The Presiding Officers granted SDI's Petition to Intervene on November 17, 2009, and the Industrial Group's Petition on December 15, 2009. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on December 2, 2009. On December 3, 2009, the Commission issued a docket entry to the OUCC requesting that the OUCC respond to questions regarding its prefiled testimony, to which the OUCC responded on December 8, 2009.

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 10, 2009, at 9:30 a.m., in Room 222, of the National City Center, 101 West Washington Street, Suite 1500 East, Indianapolis, Indiana. Duke Energy Indiana offered into evidence its Verified Application in this Cause, including exhibits thereto, the direct verified testimonies, including corresponding exhibits, of Ms. Mary Ann Amburgey, Mr. Scott A. Burnside, Ms. Diana L. Douglas, Mr. Stephen M. Herrera, Mr. Vincent E. Stroud, and Mr. John D. Swez. The OUCC offered the testimonies and exhibits of Mr. Gregory T. Guerrettaz and Mr. Michael D. Eckert. All evidence and exhibits were admitted into the record without objection. 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. **Commission Jurisdiction and Notice.** 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, *et seq.*, 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, Premier Boxboard Limited LLC ("Premier").

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 ECR3 through 42061 ECR13, the November 20, 2007 Order in Cause Nos. 43114 and 43114-S1 ("IGCC Order") and the Orders in Cause No. 43114 IGCC1 and IGCC2.** 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 August 19, 2009, update in Cause No. 42061 ECR13 ("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 ECR3, 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 May 13, 2009, update in Cause No. 43114 IGCC2, 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 ECR3 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, 2009, to be $353,525,000. No party objected 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. Vincent E. Stroud, Vice President, Regulated Fuels, testified regarding Duke Energy Indiana's fuel procurement practices. Petitioner generally purchases coal under long-term contracts. All of Duke Energy Indiana's major generating stations are covered by long-term contracts except Edwardsport Station. For 2009, Gibson, Wabash River, Gallagher and Cayuga Stations are supplied by long-term agreements for more than 90% of their annual requirements. Mr. Stroud stated that Edwardsport is an older station and is used by the Company essentially for peaking; therefore, a long-term contract is not necessary. The requirements for Edwardsport are supplied by either diverting contract tonnages from other stations or from spot market purchases. Mr. Stroud noted that many of the long-term contracts either contain provisions for periodic price re-opener negotiations, some type of price escalation, or a mechanism to adjust prices based upon a published market price index. In addition, all of the Company's coal transportation contracts in Indiana contain fuel price surcharge provisions that are based upon published fuel price indices.

Mr. Stroud testified that Duke Energy Indiana's average cost of coal per million BTU applicable to its long-term contracts has historically been lower than the cost of the coal the Company would have incurred on the open market. During the twelve month period ended August 31, 2009, coal purchased under long-term commitments comprised approximately 95.23% of total coal receipts. Mr. Stroud 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 15 to 16 million tons annually. Mr. Stroud 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. Stroud discussed other steps the Company takes to keep coal prices down.

Mr. Stroud also stated that because of the global economic downturn, the demand for electricity has been significantly lower than was forecasted for 2009. He explained that mild weather in the Midwest last summer also contributed to lower coal demand. Mr. Stroud testified that coal production has exceeded consumption for most of the year, which has resulted in depressed spot market prices in many regions. He testified that industry reports indicate that in 2009, coal companies will curtail production by as much as 120 million tons and that the EPA has recently rejected permits for large scale surface mining. He also testified that the Company expects uncertainty for the demand for coal because of uncertainty with respect to U.S. and world economic conditions. Mr. Stroud explained that all of this leads the Company to anticipate continued coal pricing volatility over the next couple of years.

Mr. Stroud explained the Company's coal inventory positions. He testified that as the demand for electricity has been lower than was forecasted for 2009, and coal deliveries under long-term contracts have exceeded consumption, coal inventory is at full or nearly full capacity at each of Duke Energy Indiana's coal-fired generating facilities. He testified that because of the significant increase in coal inventories, the Company has amended supply contracts to reduce or defer contracted deliveries to prevent or limit the extent to which coal inventories exceed plant storage capacity. He explained that Duke Energy Indiana has taken steps to cancel or defer over 1.9 million tons of coal in 2009 and over 2.2 million tons in 2010. Mr. Stroud further testified that the coal pile at Duke Energy Indiana's Gallagher station is full and the Company is utilizing a third party to store additional coal destined for Gallagher station off-site. In addition, he stated that the Company is implementing or actively exploring coal storage options for coal shipments to other Duke Energy Indiana generating stations, such as Gibson and Cayuga Generating

Stations. Mr. Stroud explained that Duke Energy Indiana will continue to closely monitor its anticipated coal requirements and inventories and take actions to cost-effectively control coal inventories. Based upon current contract commitments and anticipated demand for electricity, Mr. Stroud stated that the Company expects inventories to remain near capacity through 2011 and not return to more normal levels until 2012.

Mr. Stroud explained that if Duke Energy Indiana were simply to default on its coal purchase obligations, the Company would be exposed to damage claims related to its not taking the contracted deliveries. In addition, Mr. Stroud explained other reasons to avoid default, including avoiding the termination of a contract with a low priced supplier, causing the shut-down of a mine that may be needed for future deliveries, or causing a financially weak supplier to go out of business, could hurt competition over the long term. He testified that the Company viewed negotiating to buy-out certain coal contracts as a last resort, as this was not as practical as taking steps to control inventories through less drastic means such as contract amendments, appropriate force majeure claims, the use of additional coal storage facilities or the use of the "must-run" dispatch methodology of the coal units to the extent necessary to meet native load requirements. He pointed out it is important to be careful not to over react in taking steps to reduce contracted quantities. He explained that given the illiquid nature of the coal market in Indiana, relatively small changes in supply and demand can give rise to significant price volatility. He testified that, as the economy improves and electric demand rises, Duke Energy Indiana's units will consume more coal. He stated that it is in the long-term interest of Duke Energy Indiana and its customers not to take actions that hurt the long-term viability of the regional coal industry.

OUCC witness Mr. Michael D. Eckert testified that the OUCC does not oppose the actions currently being taken by Duke Energy Indiana in response to the Company's rising coal inventory situation. Mr. Eckert stated that the OUCC will be monitoring the situation closely and recommended that Duke Energy Indiana provide an update to the Commission on the coal inventory situation in the next FAC proceeding.

Mr. Stroud testified that in his opinion, Duke Energy Indiana is purchasing coal at the lowest cost reasonably possible. Mr. Stroud concluded his testimony by offering his opinion that oil purchased by Duke Energy Indiana for peaking units, unit cycling purposes and Duke Energy Indiana's one oil-fired boiler at Edwardsport Station is purchased at the lowest cost reasonably possible.

Mr. John D. Swez, Director, Bulk Power Marketing and Trading, discussed Duke Energy Indiana's natural gas purchasing contracts and practices. Mr. Swez described how the price of natural gas has changed over the three-month period from June to August 2009, with the Company experiencing about a 24% decrease in the price of delivered natural gas at its gas burning generation stations during this period. However, Mr. Swez also stated that the trend of decreasing gas prices has reversed itself in recent months, with current October spot gas purchases being priced higher than June's prices. Mr. Swez testified that, in his opinion, Duke Energy Indiana is purchasing natural gas at the lowest cost reasonably possible.

Mr. Stephen M. Herrera, Director, Financial Trading, Bulk Power Marketing and Trading, testified concerning the volatility of power and natural gas prices. He explained that through the end of August 2009, the average peak daily Midwest ISO CIN Hub real-time LMP was \$55.81/MWH. However, there was a wide range of prices during this period, from as low as \$18.59/MWH to as high as \$188.99/MWH. He also noted significant volatility in natural gas prices.

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 shall provide an update on the status of its coal inventories in its FAC83 proceeding as recommended by the OUCC.

6. Hedging Activities. In his testimony, Mr. Herrera 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. Herrera discussed the results of, and the factors influencing the results of, the gas hedging for the June through August 2009 reconciliation period. He noted that below normal temperatures during July (2nd coldest on record in Indianapolis dating back to 1871) and August led to a decrease in cooling demand. Further, below normal temperatures throughout the Midwest during this time period caused a decrease in the use of gas fired generation which resulted in less gas consumed. In addition, a larger than expected natural gas supply led to a high level of underground natural gas storage and dampened spot gas prices in the report period. The economic climate and unexpectedly high domestic on-shore production caused spot gas prices to be lower than the Company's hedged price, causing a loss in the gas hedges. He also stated that the Company may purchase February and March 2010 forward contracts to hedge approximately one-half of its expected burn for January and February 2010.

Mr. Herrera also cited recent historical occurrences of power price volatility and explained the Company's use of forward power purchase contracts to hedge against this volatility. Mr. Herrera explained that the Company has been making power hedging purchases since January 2006. Mr. Herrera explained that the Company's methodology for making purchases has remained constant since that time. If the forward purchase price of power is less than the cost of running the incremental generating units required to meet the forecasted load, the the Company may purchase a forward power hedge. Mr. Herrera also explained the Company is constantly assessing conditions and adapting its forward power positions accordingly with the goal of maintaining forward power hedges only in the amount necessary to economically cover its forecasted load.

Mr. Herrera discussed the results of, and the factors influencing the results of, the power hedging for the June through August 2009 reconciliation period. He stated the Company experienced realized power hedging losses (exclusive of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") virtual trades) for the period of \$8,724,751 and explained that this loss was a result of lower energy prices within the Midwest ISO footprint. He noted that the Midwest ISO's market monitor reported that energy prices within the Midwest ISO were more than 60% lower in the 3rd quarter of 2009 than in the 3rd quarter of 2008. These lower prices were primarily due to below average temperature, lower fuel prices, and the current recession, which has reduced the demand for electricity.

Mr. Herrera also explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC68 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 approximately 150 MW of expected load unhedged on a forward forecasted basis.

Mr. Herrera also noted that since the last FAC proceeding, the Company has held discussions with the OUCC and the consultant that has been retained to develop their power hedging audit plan.

Mr. Herrera stated that the Company has recently instituted one minor modification to its power hedging plans. Due to declining demand and power prices, the Company's forecast would have required it to hedge more than it has historically done. Subsequent to discussions with the OUCC, the Company made a determination to raise its internal risk limit, effectively providing the Company with more flexibility in determining how much to hedge (still leaving at least 150 MW unhedged) in the face of changing economic conditions, and also allowing the Company to be more consistent with its historic power hedging amounts when warranted.

Mr. Herrera offered his opinion 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.

In her testimony, Ms. Douglas explained that the amount included in fuel costs for hedging activity in this proceeding was a realized net loss of $603,958 for gas hedging activity and a realized net loss of $8,724,751 for power hedging activity (exclusive of Midwest ISO virtual activity).

OUCC witness Mr. Eckert testified that the OUCC and the Company have been meeting collaboratively to discuss Duke's hedging transactions pursuant to the settlement agreement in Cause No. 38707 FAC68 S1. He also stated that the OUCC has issued, and is issuing, data requests on this issue.

The Commission's Order in Cause No. 38707 FAC67, dated April 6, 2006, found gas hedging activities to be reasonable. The Company has included a negative gas hedging value of $603,958 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 FAC68 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. Under the Settlement terms, the parties agreed that all cost recovery issues through February 29, 2008, were resolved and that any power hedging activities entered into by Duke Energy Indiana from November 30, 2007, through July 31, 2008, would not be challenged on the basis that Duke Energy Indiana utilized a flat hedging methodology. However, such hedging activities entered into during that time period could be challenged on the basis of other prudence criteria. No party has expressed concerns regarding the realized net loss for power hedging included in the fuel costs in this proceeding or challenged the prudence of the power hedging activities that gave rise to the realized net loss. 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 $8,724,751 of realized power hedging losses in the calculation of fuel costs in this proceeding.

7. Orders in Cause Nos. 42685, 38707 FAC70, 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 FAC77 and Cause No. 38707 FAC80.

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 2009, consistent with the Phase II Order, as well as prior period adjustments for charges and credits incurred for January through May 2009.

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)	Jun 09	Jul 09	Aug 09
Regulation Cost Dist	0.0876	0.0826	0.0760
Spinning Cost Dist	0.0523	0.0394	0.0357
Supplemental Cost Dist	0.0041	0.0043	0.0043

Ms. Douglas testified that in this proceeding changes have been implemented to the calculation of average fuel cost for native load customers to more appropriately reflect the impact of ASM cost distribution charges in those calculations. She explained that effective with the implementation of ASM, the Company began incurring three cost distribution charges for purchase of regulation, spinning and supplemental ancillary services for its load bid into the Midwest ISO's markets. Ms. Douglas stated that in accordance with the Commission's Order in Cause No. 43426, the Company in its Cause No. 38707 FAC81 included ASM cost distribution charges in its calculation of average fuel costs. Therefore, such cost distribution amounts were averaged into and spread across all native load kWh included in the calculation. She further explained that certain wholesale formula rates native load customers are billed directly by the Midwest ISO for these cost distribution amounts, and therefore the costs included in the invoices Duke Energy Indiana receives from the Midwest ISO do not include any costs for these particular customers and should be charged to all other native load customers. Ms. Douglas testified that effective with this FAC proceeding, the Company has modified the computation of the average system fuel cost for native load customers to allocate Duke Energy Indiana's average system costs for regulation, spinning and supplemental cost distribution amounts to all retail and wholesale customers, except for the aforementioned certain wholesale formula rates customers. She stated that the generation fuel and all other cost types not billed directly to these customers by the Midwest ISO continue to be allocated across all native load customers, including these customers.

OUCC witness Mr. Eckert testified that Petitioner's ratemaking treatment for the new ASM Charge types follows the treatment ordered by the Commission in its Phase II Order. He also noted that Petitioner has reported the average monthly distribution costs of Regulation, Spinning, and Supplemental Reserves charge types in accordance with the Commission's Phase II Order. With regard to the Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts charge types being moved from Rider 68 to the FAC proceedings, Mr. Eckert testified that that the OUCC does not oppose the proposed treatment of RSG charges by Duke Energy Indiana.

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 FAC70, as well as our Phase I and Phase II Orders in Cause No. 43426.

8. <u>Participation in the Energy and ASM Markets and Midwest ISO Directed Dispatch</u>. 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 described Duke Energy Indiana's participation in the energy markets and testified that it was consistent with the testimony presented in Cause No. 42685.

In the Phase I Order, the Commission approved certain changes in the operations of Duke Energy Indiana as a result of the implementation of the ASM. Specifically, we found that Duke Energy Indiana (and the other electric utilities participating in Cause No. 43426) "are authorized to transfer additional balancing authority functions in accordance with the Amended Balancing Authority Agreement and implement the operational changes necessary to permit Joint Petitioners to participate in the Midwest ISO's ASM." *Id.* at p. 23. Mr. Swez explained that, up until the start of the ASM on January 6, 2009, Duke Energy Indiana continued to provide regulation and contingency reserve service through the intra five-minute dispatch of its generating units; however, once ASM began Duke Energy Indiana offers these ancillary services to, and purchases these ancillary services from, the ASM. He also described the Company's experience thus far under ASM. Mr. Swez explained that to his knowledge the ASM has functioned without any major issues. Duke Energy Indiana's generators have been able to follow real-time signals from the Midwest ISO with minimal issues. Day-ahead and real-time Market Clearing Prices for Regulating, Spinning, and Supplemental Reserves appear to be at reasonable price levels consistent with market conditions. In addition, he opined that Duke Energy Indiana's generating units appear to be appropriately receiving day-ahead and real-time awards for Regulating, Spinning, and Supplemental Reserves.

Mr. Swez testified that, as a result of Duke Energy Indiana's current coal inventory capacity levels at its coal-fired generating facilities, the Company has offered specific coal units to the Midwest ISO on a must-run basis more frequently than usual for purposes of meeting the Company's forecasted native load. He stated that typically this practice would only affect coal units that might be cycled off-line on weekends, but it could also affect certain marginal units on weekdays. He explained that this offer protocol is consistent with how Duke Energy Indiana's generating units have generally been offered in the past. Mr. Swez testified that this dispatch protocol would be subject to applicable operating constraints affecting each unit, such as start-up and shut-down limitations and the operating limitations applicable to the Gallagher 1 and 3 units related to the NSR lawsuit, as discussed later in this Order. He explained that the units will be committed more frequently if they are offered as "must run," but the level at which must-run units are dispatched above the minimum load designated as an operating constraint remains subject to the dispatch orders of the Midwest ISO.

Mr. Swez testified that the economic costs of keeping marginal units on line should take into account the costs avoided for shut-down and start-up of the units. Further, he said it is appropriate in this market to consider the incremental costs avoided of maintaining excess coal inventory in commitment orders. In addition, he explained that due to high coal inventory levels at Duke Energy Indiana's Gallagher Generating Station and the use of off-site coal storage, as explained by Mr. Stroud, on March 15, 2009, Duke Energy Indiana started incorporating avoided costs related to off-site coal storage into the dispatch and commitment costs of all units at Gallagher Station. He explained that this was done to reflect the correct unit economics of avoided off-site coal storage costs. He stated that the dispatch and commitment costs of each unit were reduced for purposes of Duke Energy Indiana's offers of these units to the Midwest

ISO by the off-site coal storage costs that could be avoided if the unit would be cleared for dispatch by the Midwest ISO.

Mr. Swez testified that, given off-site coal storage and reclaim costs are recovered as a part of fuel costs in FAC proceedings when the coal being stored is ultimately burned, Duke Energy Indiana believes it makes sense to try to avoid some of these storage costs by offering the units with the storage costs subtracted from the other unit operating costs. He testified that to the extent the units are dispatched, coal coming to the station is consumed and off-site storage costs are avoided, Duke Energy Indiana's customers ultimately benefit. He further stated that once the need for the off-site coal storage is eliminated, this change to the Gallagher Unit dispatch and commitment costs for purposes of offering the units to the Midwest ISO will be removed.

Mr. Swez testified that the Company would implement similar changes in its dispatch and commitment costs for other coal-fired units to reflect new temporary storage facilities. He further explained that the Company believes it should act reasonably to try to avoid incremental coal storage and reclaim costs that customers would ultimately have to pay caused by excess coal inventories. Reducing the dispatch and commitment costs of units by the amount of incremental coal storage costs so as to dispatch such units more frequently is one way to try to reduce such storage costs. Mr. Swez said, for example, the Company instituted this approach related to a temporary coal storage facility at Gibson Station beginning on August 1, 2009.

As noted previously, OUCC witness Mr. Eckert testified that the OUCC does not oppose the actions currently being taken by Duke Energy Indiana in response to the Company's rising coal inventory situation.

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. Further, we find the Company's bidding of its units, specifically the taking into account of incremental storage costs, is a reasonable response to the Company's rising inventory levels, is consistent with economic dispatch and is in the best interests of customers. Additionally, as we noted in Cause No. 38707 FAC 81, we appreciate the potential need to bid units as "must-run," but also recognize that the associated dispatch results, should such bidding strategy alter the native/non-native load assignment of such units, may be subject to further prudence review.

9. <u>New Source Review ("NSR") Impacts on Operations</u>. Mr. Swez provided testimony about the NSR lawsuit brought against Duke Energy Indiana in the U.S. District Court for the Southern District of Indiana. He explained that in addition to the Court ordering the shutdown of Wabash River Units 2, 3, and 5 by September 30, 2009, the Judge ordered Duke Energy Indiana to run Wabash River Units 2, 3, and 5 at a rate not to exceed the pre-project baseline emissions until the time the units are shut down (unless the Company could show the Court good cause for running those units above the baseline). In addition, he stated that the Court ordered Duke Energy Indiana to permanently surrender SO_2 emission allowances (equal to the SO_2 emissions from Wabash River Units 2, 3, and 5) for the period May 22, 2008, through shut down of the units on September 30, 2009.

Mr. Swez testified that Duke Energy Indiana decided not to seek a stay of the shutdown based upon the results of the Midwest ISO's Attachment Y Study, which assessed the reliability impacts of shutting down the Wabash River Units 2, 3 and 5. Mr. Swez noted that on September 21, 2009, the Company initiated an appeal of the May 29, 2009 decision with the Seventh Circuit Court of Appeals. He confirmed that the units were shut down on September 30, 2009, but stated that they could be brought back on-line if the remedy order is reversed on appeal. Mr. Swez testified that the Company currently has adequate generating resources needed to meet its customers' electricity requirements with these units shut down.

Mr. Swez also testified that in the liability phase of the May 2009 NSR lawsuit the jury found against the Company with regard to Gallagher Units 1 and 3 pulverizer projects, and the remedy trial is set for January 25, 2010. He said the Company anticipates an order during the second quarter of 2010. Mr. Swez outlined the government's proposed remedy related to the Gallagher units and commented that the Company was still analyzing its options for the proposed remedy. Mr. Swez explained that currently Duke Energy Indiana is voluntarily operating these units under pre-project NSR baseline levels for 2009 in order to limit annual emissions, but did not anticipate this operation limitation would have any effect on these units' generation dispatch and commitment in 2009 on an annual basis due to lower power prices this year.

OUCC witness Mr. Eckert testified that the Company's witness Mr. Swez provided testimony regarding the status of NSR related to Wabash River Station Units 2, 3 and 5 and Gallagher Units 1 and 3. Mr. Eckert recommended that in its next FAC proceeding Duke Energy Indiana update the Commission on: (1) how the shutdown of Wabash River Units 2, 3 and 5 will impact the Company's ability to meet future summer peak demands; (2) how Duke intends to meet those future summer peak demands; and (3) the Seventh Circuit Federal Court of Appeals proceeding. With regard to Gallagher Units 1 and 3, Mr. Eckert also recommended that Duke Energy Indiana should provide information in its next FAC filing for: (1) how the potential shutdown of Gallagher Units 1 and 3 will impact the Company's ability to meet future summer peak demands; and (2) how Duke Energy Indiana intends to meet those future summer peak demands if Gallagher Units 1 and 3 are shut down.

10. **Operating Expenses.** The provisions of Ind. Code § 8-1-2-42(d)(2) require 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, 2009. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $792,586,000. For the 12-month period ended August 31, 2009, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,034,594,000. 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 Indiana Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge which 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 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.

The fuel cost charge test period used for earnings test computations in this Cause was the 12 months ended August 31, 2009. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $214,088,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $353,525,000. 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, 2009.

Further, the prefiled testimony of Ms. Douglas included an explanation of a restatement of the actual earned return for the period covered by Cause No. 38707 FAC81. The results of this restatement did not require that additional credits be made to customers for the period of restatement (*i.e.*, the applicable period's expense and earnings test were satisfied). No Party objected to the restatement as proposed. Therefore, the Commission finds that the actual jurisdictional electric operating income level was $218,207,000, for the 12 months ended May 31, 2009.

12. 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.

13. Estimation of Fuel Costs. Duke Energy Indiana estimates that its prospective average fuel cost for the months of January through March 2010 will be $66,312,667 or $0.024523 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period June through August 2009, 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 2009	27.016	27.162	(0.54)
July 2009	26.073	28.010	(6.92)
August 2009	24.933	28.008	(10.98)
Weighted Average	25.969	27.731	(6.35)

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 (6.35)%. No party in this Cause disputed 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 2010 should be accepted and we so find.

14. 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 FAC45, 38708 FAC45, 38707 FAC56, and 38707 FAC59. The benchmarks are as follows:

Month / Year	Benchmark $/MWh 1/	Facility
June 2009	186.36	Connersville 1
July 2009	178.18	Connersville 1
August 2009	172.57	Connersville 1

1/ Calculated using most efficient unit heat rate.

No Party objected to these calculations. 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 2009 reconciliation period.

15. 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 2010 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.024523
Net Variance	(0.000730)
Adjusted Fuel Cost Factor	0.023793
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.009309
Adjustment for Utility Receipts Tax	0.000142
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.009451

The net variance factor shown above reflects $5,200,894 of over-billed fuel costs applicable to retail customers that occurred during the period June through August 2009. Coal, gas, and power price trends affecting fuel costs were discussed in the testimonies of Mr. Swez, Mr. Herrera and Mr. Stroud, as outlined in Findings Nos. 5 and 6 above.

Ms. Douglas testified that beginning in June 2009, Duke Energy Indiana began receiving proceeds from the sales of Benton County Renewable Energy Certificates ("RECs") that were received in conjunction with the Company's power purchase agreement with Benton County Wind Farms, LLC. She stated that in accordance with the Commission's Order in Cause No. 43097, the Company is using the net proceeds received from the sales of these RECs to reduce fuel costs for native load customers. Ms. Douglas explained that the net proceeds from these RECs sales are included on Exhibit A, Schedule 7, Page 1 through 3 as a credit reducing native load fuel costs in June, July and August 2009.

OUCC witness Mr. Gregory Guerrettaz testified, among other matters, 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 that the fuel cost adjustment for the quarter ended August 31, 2009, 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. With regard to net proceeds from sales of the Benton County RECs, Mr. Guerrettaz noted the inclusion of this new item and stated that he would be working with the OUCC staff to analyze the net proceeds data and that he may have further comments on this item in Cause No. 38707 FAC83.

16. **Effect on Residential Customers.** The approved factor represents an increase of \$0.000315 per kWh from the factor approved in Cause No. 38707 FAC81. The typical residential customer using 1,000 kWhs per month will experience an increase of \$0.31, or 0.4%, on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC81 (excluding various tracking mechanisms and sales tax).

17. **Fuel Adjustment for Steam Service.** On December 30, 1992, the Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Agreement between Duke Energy Indiana and Premier, which included a change in the method used to calculate Premier's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for Premier of \$1.0187457 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 2010 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 Premier that resulted in a \$57,862 payable to Premier for the months of June through August 2009.

The Commission finds that Duke Energy Indiana's proposed change in the fuel cost adjustment factor for Premier of \$1.0187457 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 \$57,862 payable to Premier has been properly determined and should be approved.

18. **Shared Return Revenue Credit Adjustment for Premier.** In accordance with the June 18, 1992 Settlement Agreement, Premier 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 2009. Therefore, we find Premier is not due a shared return revenue credit.

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. 15, 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 2010, 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. This Order shall be effective on and after the date of its approval.

HARDY, GOLC, LANDIS AND ZIEGNER CONCUR; ATTERHOLT ABSENT:

APPROVED: DEC 2 2 2009

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