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 84 APPROVED: JUN 30 2010

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

On April 29, 2010, 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 May 3, 2010, Duke Energy Indiana Industrial Group ("Industrial Group") filed its Petition to Intervene in this proceeding. The Presiding Officers granted the Industrial Group's Petition on June 16, 2010. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on June 3, 2010. On June 9, 2010, the Industrial Group filed its direct testimony and request for a sub-docket to review the prudence of Duke Energy Indiana's actions and inactions prior to the decision of the United States District Court ordering Duke Energy Indiana to shutdown Wabash River Units 2, 3 and 5. Duke Energy Indiana filed its opposition to the Industrial Group's request for subdocket and the rebuttal testimony of Diane L. Jenner on June 11, 2010.

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 June 16, 2010, at 9:30 a.m., in Room 222, of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana, the OUCC, and the Industrial Group offered their respective testimony and exhibits. The parties also informed the Commission they had reached an agreement with respect to the request for a subdocket and said agreement was read into the record. 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 Indiana Code § 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, 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 ECR 3 through 42061 ECR 14, 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 3.** 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 January 27, 2010, update in Cause No. 42061 ECR 14 ("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 December 2, 2009, update in Cause No. 43114 IGCC 3, 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 February 28, 2010, to be $367,939,000. 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 and 2010, 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 a smaller, 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 February 28, 2010, coal purchased under long-term commitments comprised approximately 99.37% 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 14 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 explained the Company's coal inventory positions. He testified that as the demand for electricity was much lower than was forecasted for 2009 and 2010, and coal deliveries under long-term contracts exceeded consumption, such that by mid-2009 coal inventory was effectively at full capacity at each of Duke Energy Indiana's coal-fired generating facilities. Mr. Stroud further testified that over the past several months, the Company's inventory position has stabilized at all of its coal-fired generating facilities, though inventory levels at all stations remain high. He stated that the Company has recently begun taking steps to reclaim and reduce inventory levels at its remote storage locations. He testified that the coal inventory situation at Gallagher station continues to improve and that the Company estimates the third party storage site used for Gallagher's excess inventory will be emptied before the end of this year. 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.

OUCC witness Mr. Michael D. Eckert recommended that Duke Energy Indiana continue to update the Commission on the coal inventory situation in the next FAC proceeding.

Mr. Stroud testified that in his opinion, Duke Energy Indiana purchased coal at prices as low as 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 contracts and practices related to the transportation and purchase of natural gas, including its selection, through a competitive bidding process, of a new natural gas managing agent. Mr. Swez testified that the price of delivered natural gas at the Company's gas burning generation stations during the three-month period from December 2009 through February 2010 varied in a range of approximately $5.00 per million BTU to $7.00 per million BTU. Mr. Swez testified that, in his opinion, Duke Energy Indiana purchased natural gas at the lowest cost reasonably possible.

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 FAC85 proceeding as recommended by the OUCC.

6. __Hedging Activities.__ In his testimony, Mr. Chen 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 discussed the results of and the factors influencing the results of the gas hedging for the December 2009 through February 2010 reconciliation period. He noted that the Company's price risk exposure to natural gas as fuel was small for the past winter, due to the low load forecast and low power prices. The Company did not purchase gas hedges during this period, so no gain or loss was realized. He also stated that the Company may purchase August and September 2010 forward contracts to hedge approximately one-half of its expected burn for July and August 2010.

Mr. Chen 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. Chen explained that the Company has been making power hedging purchases since January 2006. He stated 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 Company may purchase a forward power hedge. Mr. Chen 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. Chen discussed the results of and the factors influencing the results of the power hedging for the December 2009 through February 2010 reconciliation period. He stated the Company experienced realized power hedging gains (exclusive of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") virtual trades) for the period of $242,789.

Mr. Chen 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 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 and its consultant to develop the OUCC's power hedging audit plan.

Mr. Chen 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. Chen 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 gain of $242,789 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.

The Commission's Order in Cause No. 38707 FAC 67, dated April 6, 2006, found gas hedging activities to be reasonable. However, the Company did not purchase gas hedges during this period, so no gain or loss was realized nor included in the computation of the current fuel adjustment clause factor.

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 gain 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 gain. In addition, the Company presented evidence that its hedging practices relevant to this proceeding were consistent with the Agreement. Thus, we will allow Petitioner to include $242,789 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 December 2009, and January and February 2010, 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)	Dec 09	Jan 10	Feb 10
Regulation Cost Dist	0.0897	0.0960	0.0965
Spinning Cost Dist	0.0488	0.0824	0.0939
Supplemental Cost Dist	0.0038	0.0054	0.0155

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 also noted 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. Mr. Swez also described the Company's experience thus far under ASM. Mr. Swez explained that to his knowledge the ASM has generally 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 also described some unique circumstances in recent months impacting the Company's generating unit commitment process to a limited extent. 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. In addition, 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. Mr. Swez concluded that, with the current market, weather, and retail loads, the Company is now generally committing units in the same manner as before the economic recession and the resulting build-up in coal pile inventories.

Mr. Swez also explained that because coal inventory levels for Duke Energy Indiana's Gallagher Generating Station have improved, Duke Energy Indiana has ceased incorporating avoided costs related to off-site coal storage into the dispatch and commitment costs of the Gallagher Station units. Mr. Swez testified that based upon expected burn at Gallagher Station and deliveries, as of January 1, 2010, the Company returned to a dispatch methodology for Gallagher Station that does not include a reduction of the offer price to the Midwest ISO for off-site coal storage costs. However, Mr. Swez testified that, at times, the Company may implement changes in its dispatch and commitment costs for other coal-fired units similar to what the Company previously implemented for Gallagher Station to reflect additional coal storage and reclaim costs resulting from temporary storage facilities. He said 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 noted, for example, that beginning on August 1, 2009, and continuing today, the Company instituted this approach related to a temporary coal storage facility at Gibson Station.

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 taking into account 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 83, 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") Litigation Impacts on Operations</u>.** Mr. Swez noted that in prior FAC proceedings he had discussed the shutdown of Wabash River Units 2, 3 and 5 on September 30, 2009, as a result of the U.S. District Court's decision in the NSR lawsuit. He testified that the Company's appeal with the Seventh Circuit Federal Court of Appeals is still pending. If the remedy order is reversed on appeal there is a possibility that the Wabash River units could be brought back on-line. Pursuant to the Commission's March 24, 2010 Order in Cause No. 38707 FAC 83, Mr. Swez provided the estimated fuel cost impact for July through September 2010 in light of the shutdown of Wabash River units 2, 3 and 5. He stated that a hypothetical view of what fuel costs would be if the Company was permitted to run these units for July, August, and September of 2010 is difficult to quantify as it requires multiple assumptions on various factors, such as customer demand, locational marginal prices ("LMP"), availability of other units, coal and gas prices, emission allowance prices and other unit operating costs. No projection could estimate how market prices, such as LMPs, would be different if the Company was able to run the units. Mr. Swez testified that he performed a simplified analysis, which demonstrated that because these units were generally low cost coal units, the units on average are replaced with higher priced options. He stated that for the months of July, August and September 2010, the Company's current estimate of the increase in fuel costs resulting from the shutdown of these units totals approximately $5.8 million. He noted that if these Wabash River units were able to operate for the months in question, the Company believes they would primarily displace purchased power, along with some gas fired generation in July and August. He also stated that the Company will meet its customers' load requirements without these units. Also, by making additional short-term purchases of capacity for July and August, the company will meet its Midwest ISO Resource Adequacy Requirements for the summer of 2010. He stated that no capacity purchases are needed for this purpose in June or September.

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. He testified that the remedy trial for Gallagher Units 1 and 3 had been stayed pending review of a proposed settlement filed by the parties to the NSR litigation on December 22, 2009. On March 18, 2010, the settlement (also referred to as the "Consent Decree") was approved by Judge McKinney. Mr. Swez explained that in the Consent Decree the Company agreed to retire or repower Gallagher Units 1 and 3 with natural gas. The Company can continue operating the units until a final decision is made on whether to retire or convert the units to natural gas by January 1, 2012. He explained that if the Company decides to repower these units, the conversion must occur by January 1, 2013. If the Company decides to retire these units, it must do so by February 1, 2012. In addition, beginning January 30, 2011, and continuing thereafter until the units are repowered or retired, the Company agreed to operate Gallagher Units 1 and 3 so that each unit achieves and maintains a 30-day rolling average emission rate for SO_2 of no greater than 1.70 lb./MMBTU. He also testified that, pursuant to the Consent Decree, these units are being operated under pre-project NSR baseline levels for 2010 to limit annual emissions. In addition, the Company will be required under the Consent Decree to surrender SO_2 allowances during the conversion period.

OUCC witness Mr. Michael Eckert testified that the ruling does impact actual costs in Duke's current FAC and that the forecast costs are higher due to Wabash River Units 2, 3, and 5 not being available for dispatch during the forecast period. Mr. Eckert recommended that the

Commission consider opening a subdocket on the fuel cost impact due to the shutdown of Wabash River units 2, 3 and 5 or, in the alternative, order the parties to meet between now and the Company's next FAC proceeding to discuss how the fuel cost will be impacted going forward. Mr. Eckert also recommended that, in its next FAC proceeding, Duke Energy Indiana again update the Commission on the following: (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 Energy Indiana intends to meet those future summer peak demands; and (3) the status of the Seventh Circuit Federal Court appeal. With regard to Gallagher Units 1 and 3, Mr. Eckert also recommended that Duke Energy Indiana provide information in its next FAC filing regarding how the potential shutdown of these units will impact the Company's ability to meet future summer peak demands and how Duke Energy Indiana intends to meet those future summer peak demands if Gallagher Units 1 and 3 are shut down.

Industrial Group witness Mr. Nicholas Phillips, Jr. testified that the Commission should establish a subdocket to review the prudency of the Company's actions and inactions prior to the decision of the United States District Court ordering Duke Energy Indiana to shutdown Wabash River units 2, 3 and 5. Mr. Phillips explained his reasoning for such recommendation as follows: (1) a significant amount of additional fuel cost is being incurred by the Company as a result of Wabash River units 2, 3 and 5 being shutdown; (2) Duke Energy Indiana has not presented detailed testimony in its FAC filings that shows its actions (and inaction) prior to the United States District Court shutdown of the units were prudent; (3) the fast pace of the quarterly FAC proceedings does not provide sufficient time to reasonably explore the prudency of Duke Energy Indiana's actions (or inactions) concerning these units; and (4) the United States District Court Order of May 29, 2009, suggests the Company did not prudently handle the emission issues associated with the units that led to the ordered shutdown.

In rebuttal testimony, Ms. Diane Jenner, Director, Regulatory Strategy, responded to Mr. Eckert's and Mr. Phillips' recommendations that the Commission establish a subdocket. She explained that by the end of the third quarter of 2010 the Company intends to file a case with the Commission addressing several of the impacts from the May 29, 2009 NSR litigation remedy order regarding Wabash River units 2, 3 and 5, as well as the Consent Decree that was approved by Judge McKinney on March 18, 2010, regarding Gallagher Station. She opined that it would be more efficient for interested parties to raise appropriate NSR-related issues, including any of the concerns the OUCC or Industrial Group have regarding fuel cost impacts resulting from the shutdown of Wabash River units 2, 3, and 5, in that case, rather than litigating similar issues in multiple cases. She noted that although the issues to be resolved in this separate NSR-related proceeding are intermixed and broader than the Industrial Group's concerns about fuel impacts, the Company believes this upcoming case will provide a forum to efficiently address concerns that the OUCC and Industrial Group wish to raise about the impacts of the NSR litigation. Ms. Jenner stated that the Company has no objection to meeting with the OUCC and the Industrial Group to discuss the future impacts of the NSR litigation and to discuss the defense of the NSR claims against Duke Energy Indiana.

Ms. Jenner specifically responded to the Industrial Group by stating that the Industrial Group is over-simplifying the issues addressed in the NSR litigation by focusing on only two paragraphs of a fifty-six page Order arising out of over nine years of litigation. A full reading of the record and the entire order would also negate the Industrial Group's impression that the Wabash River units would not have been ordered to be shut down if only the Company had taken different actions immediately following the jury verdict. Ms. Jenner explained that the Government's proposed remedy for Wabash River units 2, 3, and 5 was to either install scrubbers and SCRs on these units by 2013, or shut down these units within thirty days of the judge's order. The Government also advocated reductions in emissions and the surrender of emission allowances for Wabash River units 4 and 6, even though no liability had been found regarding projects on these units. Ms. Jenner testified that the Company investigated the Government's proposed remedy to install pollution controls on Wabash River units 2, 3, and 5 and determined that the units were too old for such modifications to be economical. With environmental restrictions becoming tighter over time, these smaller, older units would likely be shut down over time. Ms. Jenner testified that the Company proposed a remedy that would balance system reliability, environmental responsibility, and cost to customers. The Company's proposed remedy was to shut down Wabash River units 2, 3 and 5 by September 1, 2012, which would allow replacement capacity from the Edwardsport IGCC plant to be in service first and would allow transmission system improvements associated with the IGCC plant needed for reliability. In the interim, the Company proposed to limit the operation of these units to keep the emissions to "baseline" levels (as calculated by the Government's expert) that prevailed before the units were modified. The units would be operated to maximize their availability and use during the summer peak periods. She stated that the Company also maintained that the remedial relief requested by the Government beyond reductions at Wabash River 2, 3 and 5 was inequitable and had no nexus to the violations. The Judge ultimately agreed with the Company on this issue. Ms. Jenner stated that at the end of the day, the Company believes the facts will show Duke Energy Indiana acted in the best interests of its customers.

At the hearing, the parties summarized their agreement on the record related to the subdocket issue. The parties agreed to withdraw the request for a subdocket in Cause No. 38707 FAC 84 and future FAC cases based on the Industrial Group's motion and the OUCC's alternative recommendation for a subdocket. This agreement is based on Duke Energy Indiana's filing of a separate case with the Commission by September 30, 2010, that addresses several issues related to the NSR litigation, which may include, without limitation: Commission approval to convert Gallagher Units 1 and 3 to gas or retire such units; cost recovery for the installation of the dry sorbent injection system for Gallagher Station Units 2 and 4; and cost recovery for the surrender of SO_2 emission allowances as a result of the NSR litigation remedy order and Consent Decree. Duke Energy Indiana also agreed that it will not contend that such separate proceeding is an improper proceeding for the Industrial Group or the OUCC to raise the issue of the prudency of Duke's actions and inactions prior to the District Court decision ordering Duke Energy Indiana to shutdown Wabash River Station Units 2, 3, and 5 and any related increase in fuel costs, beginning with the fuel costs recovered by Duke Energy Indiana in FAC 84. Further, the parties agreed that the orders in FAC 84 and subsequent FAC cases will be subject to refund related to increased fuel costs as result of the shutdown of Wabash River Station Units 2, 3 and 5 pending the final order of the Commission in the separate proceeding to be filed by Duke Energy Indiana. The parties stated that they do not intend by their agreement to require any party to raise the subject of the prudency of increased fuel costs related to the shutdown of Wabash River Station Units 2, 3 and 5 in the separate proceeding to be filed. Finally, the parties agreed that Duke Energy Indiana would retain and not waive any substantive positions or defenses it may have with respect to the reasonableness of its acts or omissions involving the NSR issues.

Based upon the agreement of the parties, the Commission will not establish a subdocket in this Cause, but orders Duke Energy Indiana to file its petition initiating a new proceeding addressing the NSR litigation impacts, as set forth above, by September 30, 2010. The Commission further finds that the fuel costs approved in this FAC related to increased fuel costs as result of the shutdown of Wabash River Station Units 2, 3 and 5 shall be subject to refund pending the final order of the Commission in the proceeding filed by September 30, 2010, or further Order of the Commisison.

10. Operating Expenses. Provisions of Indiana 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 February 28, 2010. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $797,977,000. For the 12-month period ended February 28, 2010, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,041,491,000. 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 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.

The fuel cost charge test period used for earnings test computations in this Cause was the 12 months ended February 28, 2010. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $242,345,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Indiana Code § 8-1-2-42(d)(3), was $367,939,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended February 28, 2010.

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 July through September 2010 will be $69,026,000 or

$0.025270 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period December 2009 through February 2010, 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
December 2009	19.650	25.374	(22.56)
January 2010	25.735	24.482	5.12
February 2010	25.427	24.293	4.67
Weighted Average	23.591	24.726	(4.59)

A comparison of Duke Energy Indiana's actual fuel costs with the respective estimated costs for these three periods results in a weighted average percentage difference of (4.59)%.

Ms. Douglas testified that an accounting adjustment was made to fuel inventory during the reconciliation months as a result of the Company's completion of the annual aerial fuel stockpile survey. She stated that this resulted in an accounting adjustment to increase the Company's fuel inventory in December 2009. The adjustment resulted in a decrease in native load fuel costs of approximately $14 million, which has been credited against the fuel cost recovery requested in this proceeding and contributes to the material estimation error associated with the month of December 2009.

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 July through September 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 FAC 45, 38708 FAC 45, 38707 FAC 56, and 38707 FAC 59. The benchmarks are as follows:

Month / Year	**Benchmark $/MWh** 1/	**Facility**
December 2009	198.63	Connersville 1
January 2010	168.00	Wabash River Diesel
February 2010	182.39	Wabash River Diesel

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 December 2009 through February 2010 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 July through September 2010 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.025270
Net Variance	(.000755)
Adjusted Fuel Cost Factor	0.024515
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.010031
Adjustment for Utility Receipts Tax	0.000153
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.010184

The net variance factor shown above reflects $5,331,884 of over-billed fuel costs applicable to retail customers that occurred during the period December 2009 through February 2010.

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 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 February 28, 2010, 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.

16. **Effect on Residential Customers.** The approved factor represents an increase of $0.002447 per kWh from the factor approved in Cause No. 38707 FAC 83. The typical residential customer using 1,000 kWhs per month will experience an increase of $2.44, or 2.9%, on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC 83 (excluding various tracking mechanisms and sales tax).

17. **Fuel Adjustment for Steam Service.** On December 30, 1992, this 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 $1.0992391 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the July through September 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 $87,630 payable to Premier for the months of December 2009 through February 2010.

The Commission finds that Duke Energy Indiana's proposed change in the fuel cost adjustment factor for Premier of $1.0992391 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 $87,630 payable to Premier has been properly determined and should be approved.

18. **<u>Shared Return Revenue Credit Adjustment for Premier</u>.** 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 February 2010. 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 July 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. Duke Energy Indiana shall initiate a new proceeding as set forth in Finding No. 9 of this Order on or before September 30, 2010.

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

<u>HARDY, ATTERHOLT, LANDIS, MAYS AND ZIEGNER CONCUR</u>:

APPROVED: JUN 3 0 2010

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