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 87** **APPROVED:** MAR 3 0 2011

<u>**BY THE COMMISSION:**</u>
Carolene R. Mays, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On January 27, 2011, pursuant to Indiana Code §§ 8-1-2-42 and 8-1-2-42.3, and various Orders of the Indiana Utility Regulatory Commission ("Commission"), Duke Energy Indiana, Inc. ("Duke Energy Indiana", "Company" or "Petitioner") filed with the Commission its Verified Application for approval of a change in its fuel cost adjustment for electric service, approval of a change in its fuel cost adjustment for steam service, and to update monthly benchmarks, together with its case-in-chief testimony. On February 4, 2011, Duke Energy Indiana filed corrected testimony of John D. Swez.

On February 7, 2011, Duke Energy Indiana Industrial Group ("Industrial Group") filed a Petition to Intervene in this proceeding. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on March 3, 2011. Duke Energy Indiana filed the rebuttal testimony of Elliott Batson, Jr. and Diana L. Douglas on March 11, 2011. The OUCC filed additional exhibits on March 15, 2011.

Pursuant to proper notice of hearing, published as required by law, proof of which was incorporated into the record by reference, a public evidentiary hearing was held in this Cause on March 16, 2011, at 10:00 a.m., in Room 222, of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana and the OUCC offered their respective testimony and exhibits into the evidentiary record without objection. The Presiding Officers granted the Industrial Group's Petition to intervene on the record at the evidentiary hearing. No members of the general public appeared or participated at the hearing.

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

1. <u>**Commission Jurisdiction and Notice.**</u> 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 Ch. 8-1-2, as amended, and is subject to the jurisdiction of

the Commission in the manner and to the extent provided by the laws of the State of Indiana. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Duke Energy Indiana's Characteristics.** Duke Energy Indiana is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Duke Energy Indiana is engaged in rendering electric utility service in the State of Indiana. The Company owns, operates, manages and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. The Company also renders steam service to one customer, Temple-Inland, Inc. ("Temple-Inland").

3. **Order in Cause No. 42359.** On May 18, 2004, the Commission issued an Order in Cause No. 42359 ("May 18 Order") approving base retail electric rates and charges for Duke Energy Indiana. Among other matters, the Commission's May 18 Order found that Duke Energy Indiana's base cost of fuel should be 14.484 mills per kWh and that the Company's base rates for electric utility service should reflect an authorized jurisdictional net operating income of $267,500,000, prior to any additional return on qualified pollution control property approved by the Commission, pursuant to Ind. Code §§ 8-1-2-6.6 and 6.8, not taken into account in the May 18 Order.

4. **Orders in Cause Nos. 41744 S1 and 42061, 42061 ECR 3 through 42061 ECR 15, the November 20, 2007 Order in Cause Nos. 43114 and 43114 S1 ("IGCC Order") and the Orders in Cause Nos. 43114 IGCC 1 through IGCC 4.** The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061 ("CWIP Order"), and subsequent update Orders up to and including the August 18, 2010, update in Cause No. 42061 ECR 15 ("CWIP Update"), authorized Petitioner to add the value of certain qualified pollution control property to the value of the Company's property for ratemaking purposes. The Commission's CWIP update order in Cause No. 42061 ECR 3, dated March 11, 2004, stated that the applicable incremental increase to Duke Energy Indiana's authorized return, approved in that proceeding, shall be phased-in over the period of time that Petitioner's net operating income was affected by the applicable CWIP update. The Commission's IGCC Order, and subsequent update Orders up to and including the July 28, 2010, update in Cause No. 43114 IGCC 4, authorized the Company to add the value of property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC Project") to the value of the Company's property for ratemaking purposes. The Company has applied the same phase-in concepts ordered by the Commission in its Order in Cause No. 42061 ECR 3 for CWIP updates to the IGCC Project updates in making the calculations for this filing. In accordance with these Orders, Duke Energy Indiana calculated its authorized jurisdictional net operating income level for the 12-month period ending November 30, 2010, to be $388,270,000. 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. Elliott Batson, Jr., 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. Gibson, Wabash River and Cayuga Stations

are supplied by long-term agreements for more than 90% of their annual requirements. Gallagher is supplied under a long-term contract, which can be supplemented by spot purchases when more coal is consumed than projected. Mr. Batson 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 using tonnages from other contracts or from spot market purchases. Mr. Batson 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. Batson testified that during the twelve month period ended November 30, 2010, coal purchased under long-term commitments comprised greater than 99% of total coal receipts. Mr. Batson testified that if the Company were to purchase all of its coal requirements on the open market, spot prices would be driven upward to accommodate a demand influx of approximately 13 to 16 million tons annually. Mr. Batson explained that when spot coal is required, the purchase commitments are usually made for small quantities, over short durations, and are based on the lowest delivered cost and best overall utilization characteristics. Mr. Batson discussed other steps the Company takes to keep coal prices down.

Mr. Batson explained the Company's coal inventory positions. He testified that after experiencing high inventories for most of 2009 and early in 2010, inventories at the stations have now returned to normal levels, with the exception of Gibson Station. He stated that inventories at Gibson Station remain above target levels, but are well below peak levels in 2009. He stated that the Company continues to take active steps to reclaim coal from the remote storage site at Gibson Station each month as opportunities allow. Mr. Batson testified that during 2010, the Company reclaimed approximately 181,000 tons from the Gibson Station remote storage site, and anticipates depleting all inventory at this remote storage site by Spring 2012. Mr. Batson stated that the overall Gibson Station inventory (including the remote pile) is expected to be near target levels by the end of 2011. Mr. Batson explained that Duke Energy Indiana will continue to closely monitor its anticipated coal requirements and take actions to cost-effectively control coal inventories.

Mr. Batson also discussed current conditions in the coal markets. He stated that production and market concerns for eastern US coal have started increasing the interest and demand for Illinois Basin coal. He testified that several eastern utilities that typically consume eastern US coal are currently evaluating its use and that several Illinois Basin producers have developed and implemented international marketing plans as a result of the strong global demand for coal. He stated that both mines and ports are developing infrastructure to increase exports. He opined that uncertainty exists around how much Illinois Basin coal can be utilized beyond normal markets due to differences in coal quality that impacts boiler or plant performance, how much can be transported to new markets, and how much and how quickly port infrastructure is developed. In his opinion, overall, these issues create upward pressure on coal prices with the biggest deterrent being the uncertainty around domestic demand. He testified that because of all the uncertainties, the Company anticipates coal pricing volatility in 2011 and continuing over the next several years. He said that recent history has shown small imbalances in coal supply and demand can cause large changes in coal market prices.

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. Batson testified that in his opinion, Duke Energy Indiana is purchasing coal at prices as low as reasonably possible. Mr. Batson concluded his testimony by offering his opinion that oil purchased by Duke Energy Indiana for peaking 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. Mr. Swez testified that the price of delivered natural gas at the Company's gas burning generation stations during the three-month period from September 2010 through November 2010 varied in a range of approximately \$3.65 per million BTU to \$4.25 per million BTU. Mr. Swez testified that, in his opinion, Duke Energy Indiana purchased natural gas at the lowest cost reasonably possible.

OUCC witness Mr. Eckert testified regarding a comparison he performed of the actual monthly fuel costs for the five large investor owned utilities and concluded that Duke Energy's monthly fuel cost is among the lowest in Indiana. Mr. Eckert also testified that he prepared a schedule which shows the timelines associated with each of Duke Energy Indiana's coal contracts. This schedule was not filed in the current FAC due to the concerns raised by Mr. Batson in his pre-filed testimony that public disclosure in the format presented by the OUCC provides a level of clarity into the Company's coal position that hurts the Company's leverage in negotiations for new coal contracts, to the detriment of customers. Mr. Eckert stated that the OUCC does not agree with Mr. Batson's position but will continue to work with Duke Energy Indiana to find a reasonable resolution to address these concerns.

OUCC witness Mr. Guerrettaz recommended that the Commission take administrative notice of the Company's Confidential Responses 4.10 and 4.11.[1] Mr. Guerrettaz offered his opinion that the costs detailed in these responses should not be charged to FERC Account 151.

Duke Energy Indiana offered the rebuttal testimony of Mr. Batson and Ms. Douglas in order to provide additional information regarding these costs and to explain the Company's accounting for these costs and the rationale behind the determination by the Company that these costs were appropriately accounted for in FERC Account 151. Mr. Batson testified that the railcar coal spill cleanup costs were the result of the premature opening of automatic bottom-dump doors on several of the Company's privately-leased railcars, which were en route from a coal mine to Gibson Station. The premature opening of the doors caused coal to spill on the Norfolk Southern ("NS") mainline tracks. Mr. Batson explained that the Company is required to abide by all Association of American Railroad ("AAR") interchange rules with respect to maintenance, repair, loss and damage to the Company's privately-leased railcars, pursuant to a Rail Transportation Contract with NS. In addition, Mr. Batson testified that pursuant to AAR

[1] Upon further discussion between Duke Energy Indiana and the OUCC, it was determined that the information contained in these data request responses was not confidential and the OUCC filed these responses as an exhibit in this proceeding.

Interchange Rules, all railcar owners (including lessees) have the responsibility to and are chargeable for the costs of maintaining and repairing privately-leased or owned railcars that are placed in service. He stated that unless the Company can demonstrate that the NS or another third party is responsible for damaging or causing the premature door openings, Duke Energy Indiana is responsible for any maintenance and/or repair problems with the doors on its private railcars, and any associated clean-up costs when the railcars fail to perform as required. Mr. Batson testified that investigation into the cause of the door openings continues. The Company has taken proactive and diligent steps to identify and remedy the problem. However, if these repair attempts fail to rectify the problem, Duke Energy Indiana may be required to procure an entire new set of 120 replacement railcars. Mr. Batson also testified that there are no insurance proceeds available to cover the costs of clean up of the spill.

Mr. Batson testified that pursuant to the Company's lease agreement with NS for track space near Gibson Station to store spare railcars and perform maintenance on its railcars, Duke Energy Indiana is required to maintain the track space free of debris. He testified that the Company has a fixed price brush clearing agreement with a vendor for this once per year service.

Ms. Douglas explained how Duke Energy Indiana accounted for the railcar coal spill cleanup costs and track brush clearing costs in this proceeding. She testified that Duke Energy Indiana recorded these costs to Account 151, Fuel Stock, based on the Company's interpretation of FERC's accounting guidance. She testified that the Company incurred approximately $39,000 in railcar coal spill cleanup costs and $30,000 of track brush clearing costs during the current reconciliation period. Ms. Douglas testified that because these costs were not expensed but rather charged to Account 151 and included in the cost of inventory, the full impact has not yet been reflected in the fuel cost being requested for recovery in this proceeding and will continue to have some impact on fuel expense in future FAC proceedings.

Ms. Douglas provided FERC's accounting guidance regarding costs that can appropriately be included in Account 151, Fuel Stock. She explained how the costs incurred for cleanup of spilled coal from the mainline railroad tracks meet FERC's accounting guidelines under Account 151, Fuel Stock. Ms. Douglas testified that the costs incurred were a direct result of Duke Energy Indiana's use of rail transportation and coal cars owned or leased by the Company to provide coal for generation to serve its customers. She testified that the spill did not occur on Duke Energy Indiana's property and occurred while coal was in the process of being transported to the Company's generating station. Ms. Douglas testified that the FERC guidance for Account 151 includes in Item 2 "other transportation charges", which Duke Energy Indiana believes these to be, because they were incurred as part of a transportation contract and in the process of transporting coal. She testified that in addition, Item 4 specifies that Account 151 include "operating, maintenance and depreciation and ad valorem taxes on utility-owned equipment used to transport fuel from the point of acquisition to the unloading point" and Item 5 includes lease or rental costs for transportation equipment used by the Company for similar purposes. Ms. Douglas testified that because these costs were incurred in the process of transporting fuel to the station, FERC directs utilities to include them in Account 151. She testified that Duke Energy Indiana views these required coal spill clean-up costs along the railway tracks, which would not have been incurred absent the Company's use of the railway and company-owned or leased railcars to transport coal to the generating station, as appropriately charged to Account 151, Fuel Stock, and appropriately included in native load fuel expense as the weighted average cost of Gibson Station's coal inventory is applied to the coal consumed at that station to generate electricity. Ms. Douglas also testified that in the event that the Company would receive insurance proceeds or any other reimbursement or recovery from a third party related to the cause of the problems that caused the coal spills, the Company would credit such recoveries to Account 151.

Ms. Douglas testified that the costs associated with the brush cutting and clearing around the leased track space were incurred as a result of Duke Energy Indiana's use of company-owned or leased railcars to transport coal. She stated that the FERC guidance for Account 151 specifies in Item 4 that Account 151 include "operating, maintenance and depreciation and ad valorem taxes on utility-owned equipment used to transport fuel from the point of acquisition to the unloading point" (and Item 5 includes lease or rental costs for transportation equipment used by the Company for similar purposes). Ms. Douglas testified that the leasing of track space and the required brush cutting and clearing services for such is necessary in order for the Company to manage and maintain the railcars that are used to transport coal to Gibson station. For this reason, Ms. Douglas believes these costs are appropriately charged to Account 151, Fuel Stock, and therefore are appropriately included in native load fuel expense as coal is consumed at the station for generation to serve native load customers.

Ms. Douglas stated that it is her opinion that the true test of whether or not a cost should be recorded to Account 151 is whether it meets the guidance outlined by the FERC for inclusion in Account 151 and not the dollar amount of the cost. Ms. Douglas testified that in making this determination the Company analyzed the nature of the costs and determined that these costs were directly related to transporting coal from the point of acquisition to the final destination station and therefore were appropriately chargeable to Account 151.

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 FAC 88 proceeding as recommended by the OUCC. Additionally, we find that Duke Energy Indiana has appropriately accounted for the coal spill clean-up costs as a coal transportation cost and the brush clearing costs as a coal transportation maintenance cost, which have been included in station fuel inventory in FERC Account 151, Fuel Stock, and, as such, such costs are appropriately included in native load fuel expense for FAC purposes as the coal in inventory is consumed at the station for generation for native load customers.

6. <u>Hedging Activities</u>. In his testimony, Mr. Wenbin (Michael) Chen, Manager, Portfolio Optimization, provided updates of the Company's gas and power hedging activities. He explained that the Company relies more on natural gas for fuel for the Company's peaking plants than it has in the past and cited recent historical occurrences of gas price volatility. He testified that, in his opinion, it makes sense for the Company to take advantage of the hedging tools available to protect against price fluctuations. Mr. Chen testified that since the last update to the Commission in the FAC 86 proceeding, the Company has not completed any gas hedging purchases. Mr. Chen discussed the results of the gas hedging for the September 2010 through

November 2010 reconciliation period. He testified that the Company realized a loss of $76,546 from hedges bought for August 2010 native gas burn.

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 September 2010 through November 2010 reconciliation period. He stated the Company realized power hedging losses (exclusive of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") virtual trades and including prior period adjustments) for the period of $49,127.

Mr. Chen also explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1, beginning on August 1, 2008, and continuing until permanent hedging protocols are developed and approved by the Commission, Duke Energy Indiana will not utilize its flat hedging methodology. Rather, Duke Energy Indiana will hedge up to approximately flat minus 150 MW on a forward, monthly and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave the Company with at least approximately 150 MW of expected load unhedged on a forward forecasted basis.

Mr. Chen also noted that the Company continues to hold discussions with the OUCC and its consultant and has responded to all data requests.

Mr. Chen stated that there have been no recent changes to its power hedging plans, but as discussed in prior FAC proceedings the Company previously 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. Diana L. Douglas, Director, Rates, explained that the amount included in fuel costs for hedging activity in this proceeding was a realized net loss of $76,546 for gas hedging activity and a realized net loss of $49,127 for power hedging activity (exclusive of Midwest ISO virtual activity and including prior period adjustments).

OUCC witness Mr. Dwight D. Etheridge testified on behalf of the OUCC in this proceeding regarding Duke Energy Indiana's electric hedging policies and practices. Mr. Etheridge stated that he had reviewed Duke Energy Indiana's application and testimony in this case, as well as various other information provided by the Company on its electric hedging transactions for the twelve months ended November 2010. In addition, Mr. Etheridge participated in several discussions with the OUCC and also attended a meeting with Duke Energy Indiana representatives at the OUCC's offices. Mr. Etheridge also described his review of electric hedging transactions for the 12 months ended November 2012 and recommended the OUCC continue to screen the electric hedging transactions in audits of future FAC proceedings. Based on his review, Mr. Etheridge testified that Duke Energy Indiana has a reasonable electric hedging policy in place and appears to be actively and effectively implementing that policy. Mr. Etheridge recommended that the Company continue to communicate and work collaboratively with the OUCC related to its electric hedging policy and in future audits.

The Commission's Order in Cause No. 38707 FAC 67, dated April 6, 2006, found gas hedging activities to be reasonable. The Company has included a gas hedging loss of $76,546 in the computation of the current fuel adjustment clause factor. The gas hedging amount was properly included, and we so find.

The issue of the appropriateness of the inclusion of realized gains/losses relating to the Company's power hedging activities in the computation of the fuel adjustment charge was the subject of a proceeding established by the Commission in Cause No. 38707 FAC 68 S1. On June 25, 2008, the Commission issued an Order approving a Stipulation and Agreement ("Settlement") between Duke Energy Indiana and the OUCC and resolving all disputed issues evaluated within that sub-docket. No 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 Agreement. Thus, we will allow Petitioner to include $49,127 of realized power hedging losses 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 September, October and November 2010, consistent with the Phase II Order, as well as appropriate period adjustments.

Mr. Scott A. Burnside, Accounting Manager, testified that Duke Energy Indiana, in accordance with the Phase II Order, has calculated the monthly average ASM Cost Distribution Amounts it has paid for Regulation, Spinning and Supplemental Reserves. These amounts are as follows:

(in $ per MWH)	Sep-10	Oct-10	Nov-10
Regulation Cost Dist	0.0792	0.0764	0.0787
Spinning Cost Dist	0.0440	0.0365	0.0315
Supplemental Cost Dist	0.0179	0.0181	0.0168

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. <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 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 and the Company has had no issues providing the resulting cleared reserves.

Mr. Swez testified that there have been recent changes regarding how the Midwest ISO assesses charges to generating units that may affect fuel costs reflected in this and future FAC proceedings. He explained that as a result of an August 30, 2010, FERC Order in Docket ER09-411-002, the Midwest ISO began assessing real time revenue sufficiency guarantee charges to intermittent generating units beginning August 31, 2010. Mr. Swez stated that for Duke Energy Indiana specifically this means that generation from its Markland hydro units and generation purchased from the Benton County Wind units may now be subject to such charges.

Mr. Swez testified that in recent months there have been no unique circumstances impacting the Company's generating unit commitment process. He stated that due to the current market, weather, and native loads, the Company is 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 Generating Stations have returned to normal, with the exception of Gibson Station, 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. 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. Accordingly, the Company continues to reduce the dispatch and commitment costs of the Gibson units by the amount of incremental coal storage costs and continues to evaluate the ongoing need to do so.

In addition, Mr. Swez noted another condition impacting dispatch of the Company's units; namely, that Gibson Unit 5 was forced out of service on September 25, 2010, as a result of a high bearing turbine vibration. To mitigate the impact of this outage, the Company moved the scheduled spring 2011 outage for Unit 5 to the current outage on Unit 5 and moved the fall 2010 scheduled outage of Gibson Unit 2 to the spring of 2011. He stated that on January 15, 2011, Gibson 5 returned to service and is currently capable of generating electricity at the unit's full capability.

Mr. Swez also testified that the existing Edwardsport Station must cease operations before the first firing of the auxiliary boiler on the new Edwardsport Integrated Gasification Combined Cycle ("IGCC") unit, which is scheduled for 2011. He stated that the Company notified the Midwest ISO of the planned shutdown, and the Midwest ISO has responded and notified the Company that Edwardsport Station may be retired without the need for the generators to be designated as System Support Resource units. Mr. Swez testified that shutdown of the existing Edwardsport units is anticipated to occur on March 1, 2011.

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

9. <u>New Source Review ("NSR") Litigation Impacts on Operations</u>. Mr. Swez noted that in the FAC 86 proceeding he had discussed the Seventh Circuit Federal Court of Appeals' reversal of the U.S. District Court's decision to shutdown Wabash River Units 2, 3 and 5 on September 30, 2009. He testified that on December 29, 2010, the request for rehearing by the U.S. Department of Justice on behalf of the Environmental Protection Agency ("DOJ") was denied and that the Company anticipates an Order from the District Court rescinding the shut down order in the near future. He stated that given this decision, the Company believes it is possible that Wabash River Units 2, 3, and 5 will be available again in the next few months. He explained that the Company is waiting to see if the DOJ appeals the case to the United States Supreme Court. Mr. Swez also testified that pursuant to the Consent Decree involving the Gallagher units in the NSR lawsuit, these units are being operated under pre-project NSR baseline levels for 2010 to limit annual emissions. He stated that this restriction has not impacted the units' generation in 2010 and is not expected to impact the units' generation in 2011. Mr. Swez also noted that effective December 1, 2010, the impact of dry sorbent injection costs have been added to the dispatch prices for the Gallagher Units 2 and 4 to reflect the correct variable costs for those units.

OUCC witness, Mr. Eckert, testified that the District Court's May 29, 2009 decision requiring shutdown of the Wabash River units does impact costs in Duke's current FAC. Mr. Eckert described the agreement addressed by the Commission in its FAC 84 Order, which required Duke Energy Indiana to file a separate case with the Commission by September 30, 2010 that addresses the NSR litigation impacts. Mr. Eckert testified that the Company did file such case with the Commission, captioned Cause No. 43956. Mr. Eckert also recommended that, in its next FAC proceeding, Duke Energy Indiana again update the Commission on the following: (1) how the shutdown and/or potential availability 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.

The Commission finds that the fuel costs approved in this FAC related to increased fuel costs as a result of the shutdown of Wabash River Station Units 2, 3 and 5 shall be subject to refund pending the final order of the Commission in Cause No. 43956, as discussed in the Commission's FAC 84 Order, or further Order of the Commission.

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 November 30, 2010. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $805,732,000. For the 12-month period ended November 30, 2010, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,069,801,000. 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.

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

The fuel cost charge test period used for earnings test computations in this Cause was the 12 months ended November 30, 2010. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $299,538,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Indiana Code § 8-1-2-42(d)(3), was $388,270,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended November 30, 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 April through June 2011 will be $65,763,333 or $0.025923 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period September 2010 through November 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
September 2010	24.836	24.474	1.48
October 2010	26.157	25.394	3.00
November 2010	26.417	24.747	6.75
Weighted Average	25.782	24.871	3.66

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 3.66%.

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 April through June 2011 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
September 2010	175.91	Wabash River Diesel
October 2010	175.23	Wabash River Diesel
November 2010	209.45	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 September through November 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 April through June 2011 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.025923
Net Variance	0.000890
Adjusted Fuel Cost Factor	0.026813
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.012329
Adjustment for Utility Receipts Tax	0.000188
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.012517

The net variance factor shown above reflects $5,710,628 of under-billed fuel costs applicable to retail customers that occurred during the period September through November 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 November 30, 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 a decrease of $0.001364 per kWh from the factor approved in Cause No. 38707 FAC 86. The typical residential customer using 1,000 kWhs per month will experience a decrease of $1.36, or 1.5%, on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC 86 (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 Boxboard, n/k/a Temple-Inland, which included a change in the method used to calculate Temple-Inland's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for Temple-Inland of $1.1701624 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the April through June 2011 billing cycles. Exhibit B, Schedule 2, of the Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to Temple-Inland that resulted in a $2,551 payable to Temple-Inland for the months of September 2010 through November 2010.

The Commission finds that Duke Energy Indiana's proposed fuel cost adjustment factor for Temple-Inland of $1.1701624 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 $2,551 payable to Temple-Inland has been properly determined and should be approved.

18. Shared Return Revenue Credit Adjustment for Temple-Inland. In accordance with the June 18, 1992 Settlement Agreement, Temple-Inland will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 11, Duke Energy Indiana did not have excess earnings for the 12 months ended November 2010. Therefore, we find Temple-Inland 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's charges, as described in Finding No. 5, were appropriately charged to FERC Account 151, Fuel Stock, and are appropriately included in native load fuel expense as coal is consumed at the station for generation to serve native load customers.

4. Duke Energy Indiana shall place into effect the fuel cost adjustment factors for electric service and steam service approved herein, applicable to all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of April 2011, upon filing with the Electricity Division of the Commission, a separate amendment to its rate schedules with clear reference therein that such factor is applicable to the rate schedules reflected on the amendment.

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

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

APPROVED: MAR 3 0 2011

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