ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING MONTHS OF AUGUST, SEPTEMBER AND OCTOBER 2012, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR THE COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43393.	)	CAUSE NO. 38706 FAC 95 APPROVED: JUL 18 2012

ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On May 4, 2012, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") filed its petition for Commission approval of a fuel cost adjustment to be applicable for bills rendered by Petitioner during the billing months of August, September and October 2012. On that same day, Petitioner also prefiled its direct testimony and exhibits. NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene on May 9, 2012, which was granted by the Presiding Officers in a Docket Entry dated May 16, 2012. On June 8, 2012 the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause along with its direct testimony.

Pursuant to public notice, duly given and published as required by law, proof of which was incorporated into the record by reference and placed in the Commission's official file, an evidentiary hearing was held on July 3, 2012, at 10:00 a.m., in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. At the hearing, Petitioner, the OUCC, and the Industrial Group appeared by counsel. Petitioner and the OUCC offered their respective prefiled testimony and exhibits which were admitted into evidence without objection. No members of the general public appeared or sought to participate.

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

1. **Commission Jurisdiction and Notice.** Proper notice of the hearing in this Cause was given as required by law. Petitioner is a public utility corporation incorporated under the laws of the State of Indiana, operating electric utility properties in northern Indiana and is subject to the jurisdiction of this Commission as provided in the Public Service Commission Act, as amended, Ind. Code ch. 8-1-2. Thus, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Petitioner has its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric public utility service in the State of Indiana and owns, operates, manages and controls, among other things, plants and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public.

3. **Available Data on Actual Fuel Costs.** Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in Petitioner's last base rate case approved in the Commission's December 21, 2011 Order in Cause No. 43969 ("43969 Order") was $0.028729 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 30). Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of January, February and March 2012 averaged $0.027484 per kWh (Pet.'s Ex. B, Sch. 5, p. 4, Ln. 28).

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current credit of $0.000840 per kWh (Pet.'s Ex. 1-C, Ln. 8) to a credit of $0.002980 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 32) for all applicable bills rendered in August, September and October 2012 billing months. The requested fuel cost adjustment includes a variance of $19,262,075 (Pet.'s Ex. B, Sch. 1, Ln. 26) that was over-collected during January, February and March 2012. The requested fuel cost adjustment also includes $5,632,785 as the reconciliation of the final customer credit approved through December 27, 2011, which was authorized in the 43969 Order (Pet.'s Ex. B, Sch. 1, Ln. 26b). Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the period August, September and October 2012 is $43,060,190 (Pet.'s Ex. B, Sch. 1, Ln. 24), and its estimated monthly average sales for that period are 1,523,570 MWh (Pet.'s Ex. B, Sch. 1, Ln. 11).

5. **Statutory Requirements.** Ind. Code § 8-1-2-42(d) states that the Commission shall grant a fuel cost adjustment charge if it finds that:

> (1) The electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;
>
> (2) The actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the Commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;
>
> (3) The fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to Ind. Code § 8-1-2-42.3, if the fuel charge applied for will result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned.

(4) The utility's estimates of its prospective fuel costs for each such three (3) calendar months are reasonable after taking into considerations: (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and (B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

6. **Fuel Costs and Operating Expenses.** Petitioner's Exhibit 2-A, shows that fuel costs for the twelve months ending March 31, 2012, were $56,245,703 (p. 1, Ln. 15) above the levels approved in the 43969 Order, the last proceeding in which Petitioner's basic rates and charges for electric service were approved. Petitioner's Exhibit 2-A also shows that the total operating expenses excluding fuel for the twelve months ending March 31, 2012, were $25,965,219 (p. 1, Ln. 17) above the levels approved in the 43969 Order. The Commission finds that Petitioner's actual increase in fuel costs for the twelve months ending March 31, 2012 have not been offset by actual decreases in other operating expenses.

7. **Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost.** Petitioner's witness Strnatka testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that Petitioner's primary fuel for generation of electric energy is coal (68.22%) and the remainder by natural gas (31.78%) for the three months ended March 31, 2012 (Pet.'s Ex. 4, p. 2).

a. **Fuel Procurement.** With respect to NIPSCO's coal procurement process, Mr. Strnatka testified that NIPSCO considers several factors in purchasing coal, including the delivered price, the coal quality that is best suited for a particular generating unit, the sulfur content, and the economic and technical suitability of certain low cost fuels to be blended at NIPSCO's generating units to maintain the lowest, reasonably possible "as-burned" fuel cost. Mr. Strnatka testified that NIPSCO also considers the availability, reliability and diversity of particular coal suppliers and coal transporters in its fuel procurement practices. He stated that effective April 1, 2012, NIPSCO has five (5) long term contracts with four (4) coal producers and is currently negotiating a possible term contract with another coal supplier for future requirements of Powder River Basin ("PRB") coal. He stated that NIPSCO would meet any remaining coal requirements through spot purchases.

Mr. Strnatka explained that NIPSCO competitively bids all coal purchased under a long term agreement. He stated NIPSCO prepares a preliminary evaluation sheet incorporating all of the bidder information such as mine origin, Btu, sulfur, ash, available tons per year and price on both a per ton and $ per million Btu basis. He testified that the final evaluation sheet, in addition to the cost of coal, includes the transportation cost for each of the proposals and any adjustments required to place all bids on an equivalent basis. Mr. Strnatka stated that NIPSCO negotiates price and commercial terms and conditions with the low evaluated bidder(s).

Mr. Strnatka testified that due to volatility in the coal markets, producers and customers are reluctant to execute fixed price long term contracts without some type of market price adjustment mechanism and that maintaining a market price balance is beneficial to both parties. He explained that three (3) of NIPSCO's long term contracts have firm prices that increase each year as set out in the contract; one (1) long term contract has prices that are adjusted annually for the succeeding year based on the average weekly indexed prices of that particular coal in the previous year; and one (1) long term contract has an annual market price reopener that will determine the contract coal price for the succeeding year of the contract.

Mr. Strnatka testified that before NIPSCO agrees to a coal price increase based on contract provisions, NIPSCO's Fuel Supply Department, which is responsible for administering all coal contracts, verifies that only contract-allowable changes are made to the mine and transportation prices. He explained that after a price adjustment is received, NIPSCO requests supporting evidence in the form of actual invoices and records, as well as published government data, to justify the price adjustment. Mr. Strnatka testified that no price adjustments are made until NIPSCO is satisfied that the charges are in accordance with the contract, and are justified by actual costs or changes in cost indices.

Mr. Strnatka testified that the delivered cost of coal for NIPSCO for the twelve months ending March 31, 2011, was $51.08 per ton or $2.565 per million Btu. The delivered coal cost for the reconciliation period (January, February and March, 2012) was $50.62 per ton or $2.554 per million Btu. Mr. Strnatka stated NIPSCO did not make any spot purchases during the reconciliation period. He testified that the average market spot price of coal (excluding transportation costs) during the reconciliation period was $10.51 per ton for PRB coal, $47.08 per ton for Illinois Basin high sulfur coal, and $65.34 per ton for Pittsburgh #8 ("Pitt8") coal.

With respect to the market factors affecting the supply, demand, and cost of coal during the reconciliation period, Mr. Strnatka testified that coal supply during the reconciliation period continued to be impacted by the mild weather, the decrease in the price of natural gas and lackluster coal demand in both the domestic and international markets. He stated that inventories continue to grow and spot market pricing is sliding due to the overabundance of coal in the market. However, since electrical demand has decreased, requiring less coal to be burned, NIPSCO was not afforded any opportunities to buy coal in the spot market. Therefore, reduced coal requirements were fulfilled with strictly contract coal. The cost of coal represents all contract pricing during the reconciliation period. Mr. Strnatka testified that NIPSCO's delivered cost of coal during the reconciliation period increased compared to the fourth quarter of 2011 from $49.74 per ton or $2.522 per million Btu to $50.62 per ton or $2.554 per million Btu. This increase can be attributed to an increase effective January 1, 2012 in contractual price of PRB and Pitt8 coal that will be in effect for 2012. Transportation costs, including fuel surcharges were relatively flat during the reconciliation period.

Based on the evidence presented, we find that NIPSCO has adequately explained its coal procurement decision making and we find that its acquisition process is reasonable. Mr. Strnatka's testimony demonstrates NIPSCO has a diverse group of long-term coal contracts with different types of price adjustment mechanisms. Mr. Strnatka explained why NIPSCO and its coal suppliers are reluctant to execute fixed price long term contracts without some type of market price adjustment mechanism and that maintaining a market price balance is beneficial to both parties. Mr. Strnatka also explained in testimony how NIPSCO makes procurement decisions and the type of market data that NIPSCO tracks and reviews. Based on the record evidence, we find that NIPSCO has adequately demonstrated that its coal procurement policies are reasonable and prudent.

Petitioner's witness Williamson stated NIPSCO does not purchase natural gas under multiple year contracts. Instead, physical natural gas supplies are purchased on a spot basis when NIPSCO's gas-fired generation units are either economical to run or need to run for operational purposes. He stated NIPSCO recently changed its gas purchasing practices for generation located off its gas distribution system when it entered into a seven (7) month contract with a new gas marketer. Mr. William testified NIPSCO has made every reasonable effort to purchase natural gas so as to provide electricity to customers at the lowest reasonable price.

b. <u>Renewable Energy Credits ("RECs")</u>. With respect to NIPSCO's efforts to maximize the value of RECs for its customers, Mr. Williamson stated that Indiana does not currently have regulations that guide the certification and accounting for RECs. Consequently, NIPSCO has held the RECs on account with M-RETS in the event that the State of Indiana were to approve a renewable energy standard, and due to the RECs' relatively low market value. He noted the Indiana General Assembly passed Senate Bill 251 in 2011, which includes a voluntary renewable energy standard and the Commission conducted a rulemaking process to implement it. He testified that NIPSCO monitored the results of that legislation and rulemaking and is making changes in the way RECs are utilized.

Mr. Williamson provided an update on NIPSCO's treatment of RECs. He stated that NIPSCO's recent vintage RECs have significantly more value in regions of the market than older vintage RECs. Mr. Williamson testified NIPSCO has begun offering these recently acquired RECs to the renewable energy market when it acquires a minimum of 50,000, which is the standard REC contract. He stated that the amount of time it takes to accumulate a block of 50,000 RECs varies based on the MW output at the wind resources and noted that historically this has been roughly every two months. He stated the goal behind this method is to spread the sales of RECs over multiple time periods throughout the year. He stated that because the RECs market can at times be very illiquid, there is no guarantee that a sale transaction will occur at the time the 50,000 RECs are offered. Mr. Williamson testified NIPSCO will pass the proceeds from the sale of RECs back to customers through the Purchased Power other than Midwest Independent Transmission System Operator, Inc. ("MISO") line item. He stated NIPSCO continues to monitor and evaluate the marketability for all vintage RECs, potential future legislation that would consider NIPSCO's RECs as eligible to meet state renewable energy standards, and the Commission's Voluntary Clean Energy Portfolio Standard program rules and NIPSCO will make appropriate changes as necessary.

We find that NIPSCO should continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind purchases being recovered through the authority granted in Cause No. 43393 and any other future renewable purchases.

c. <u>Electric Hedging Program</u>. Mr. Williamson testified NIPSCO incorporated the Electric Hedging Program that was approved by the Commission's July 13, 2011 Order in Cause No. 43849 ("43849 Order") in this FAC proceeding. He testified that in January, NIPSCO purchased 15 gas contracts and 5 power contracts; in February, NIPSCO purchased 21 gas contracts and 10 power contracts; and in March, NIPSCO purchased 8 gas contracts and 6 power contracts. He stated the execution of these contracts is consistent with the NIPSCO's most recently filed hedging plan. Mr. Williamson stated the impact of the hedges entered into for the

Electric Hedging Program for this proceeding was a loss of $1,024,221 during the reconciliation period, plus broker fees and clearing exchange fees which totaled $3,451 during the reconciliation period, for a total impact of the hedging program in this proceeding of $1,027,672 during the reconciliation period. He noted that broker fees represented 0.11% of the total value of the transactions that occurred during this reconciliation period. Mr. Williamson testified decisions were made based upon the conditions known at the time of the transactions and NIPSCO used the same broker it uses for its other transactions to limit transaction costs, and the transactions were all made in accordance with the Electric Hedging Program approved by the 43849 Order.

We find that NIPSCO should continue to include testimony and evidence of its electric hedging costs, gains and/or losses resulting from its hedging transactions for which it is seeking recovery through the FAC in its quarterly FAC filings.

Based on the evidence, we find that Petitioner has made every reasonable effort to acquire fuel and generate or purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible, as hereinafter discussed.

d. Purchased Power Over The Benchmark. Mr. Williamson described the Benchmark that applies to Petitioner's purchased power transactions established in the Commission's August 25, 2010 Order in Cause No. 43526 ("43526 Order"). Mr. Williamson testified that NIPSCO did not have any swap or virtual transactions during this FAC period. Mr. Williamson testified that NIPSCO is seeking to recover 3,000.87 MWhs of purchased power in January, 9,383.96 MWhs of purchased power in February and 98,529.64 MWhs of purchased power in March that were in excess of the Purchased Power Daily Benchmark which were made to supply jurisdictional load that offset available NIPSCO resources that were not dispatched by the MISO or were otherwise eligible under the procedures outlined in the 43526 Order and are therefore recoverable. OUCC witness Mr. Eckert testified that NIPSCO's testimony and workpapers reflect the 43526 Order regarding purchased power over the benchmark and that he agreed with NIPSCO's calculation of purchased power over the benchmark. Based on the evidence, we find that NIPSCO's identified purchase power costs are properly included in the fuel cost calculation.

8. MISO Day 2 Energy Costs. NIPSCO included in its forecast the operational changes associated with the MISO Day 2 energy market, in accordance with the Commission's Orders in Cause Nos. 42685, 43426 and 43665. The total "MISO Components of Fuel Cost" included in the actual cost of fuel for the months of January, February and March 2012 was $2,518,056. (Pet.'s Ex. B, Sch. 5, p. 4, Ln. 19).

9. Interruptible Credits. Mr. Williamson testified the 43969 Order approved Rider 675 – Interruptible Industrial Service, which provides for credits to be paid to certain industrial customers that agree to interrupt their service if certain criteria are met. Mr. Williamson stated that during the reconciliation period, NIPSCO interrupted 12 hours on March 19, 2012. The evidence shows that NIPSCO paid a total of $9,377,976 interruptible credits through Rider 675 during the reconciliation period and, pursuant to the 43969 Order, NIPSCO is authorized to recover twenty-five percent (25%) of that total, or $2,344,494, through the FAC for the billing months of August, September and October 2012 (Pet.'s Ex. B, Sch. 8).

10. **Estimation of Fuel Cost.** Petitioner estimated that its prospective total average fuel costs for the billing months of August, September and October 2012 will be $43,060,190 (Pet.'s Ex. B, Sch. 1, Ln. 24) on a monthly basis.

Mr. Strnatka testified that NIPSCO anticipates that its delivered coal cost during the forecast period of July, August and September 2012 will be approximately $50.56 per ton or $2.553 per million Btu. He explained that since NIPSCO will likely be reducing any excess coal inventory, and not have a need to purchase spot coal, the delivered coal cost will be reflective of the existing coal and transportation agreements to fulfill projected burn requirements for the forecast period. He noted that NIPSCO is currently projecting a delivered coal cost of $2.553 per million Btu for the forecast period, which could be influenced by the volatility in the diesel fuel market. Mr. Strnatka testified the average spot market prices for calendar year 2013 (which do not include cost of transportation) are currently $13.18 per ton for PRB coal, $50.77 per ton for Illinois Basin coal and $68.84 per ton for Pitt8 coal.

Mr. Strnatka explained NIPSCO incorporates all current coal contract prices, estimates of any coal contract price adjustments that might be warranted, transportation contract prices, an assessment of the pricing impact of fuel surcharges on the delivered cost based on current price of crude oil, and an evaluation of the spot market price of coal in developing the estimate for the forecast period. These inputs are provided to NIPSCO's Generation Dispatch & Marketing Group to be used in PROMOD.[1]

With respect to the factors NISPCO believes will impact the supply, demand, and cost of coal during the forecast period, Mr. Strnatka cited the significant impact of historically low natural gas prices, continued mild weather furthering decreases in electrical demand, softening international demand for domestic coal, uncertainty regarding the duration of the CSAPR[2] stay and the outcome of the legal challenge to CSAPR, and the lack of economic growth. Since NIPSCO will rely on existing coal contract commitments to fulfill its coal consumption during the forecast period, the expectation is for relatively flat coal pricing. Mr. Strnatka testified NIPSCO believes the delivered cost of coal for the forecast period will be relatively flat. The November 2011 to March 2012 West Texas Intermediate crude prices have ranged between $98 to $109 per barrel. For the same time period, the highway diesel fuel prices have ranged between $3.83 to $4.13 per gallon. If the prices remain within this range NIPSCO's delivered coal cost will be minimally influenced by fuel surcharges paid to the railroads.

Mr. Strnatka testified NIPSCO does not anticipate any issues in securing coal or transportation this summer. He stated the challenge this summer will be to manage the excess coal inventory incurred due to the mild winter and the low natural gas pricing, effectively displacing coal fired generation. He stated consumption could further decline based on continuing mild weather and persistent low natural gas pricing. He testified NIPSCO will attempt to manage through any excess inventory by working with suppliers to defer tons as allowed in the coal supply agreements, and to redirect coal for consumption from one station to another if necessary, but at the same time attempting to meet the minimum volume commitments in its transportation agreements to forego paying liquidated damage penalties to the railroads.

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[1] PROMOD is NIPSCO's production cost modeling system. Pet.'s Ex. 3, p. 13.
[2] Cross-State Air Pollution Rule, 76 Fed. Reg. 48,208 (August 8, 2011)

In our April 27, 2011 Order in Cause No. 38706 FAC 90 (at 6), we ordered NIPSCO to provide detailed testimony and information regarding: (1) average spot market price of coal; (2) factors affecting the supply, demand, and cost of coal; (3) any known factors that significantly impact or affect the supply, demand, and cost of coal during the forecast and reconciliation periods; (4) any known factors that significantly impact the delivered cost of coal during the forecast and reconciliation period; and (5) the process NIPSCO utilizes to procure contracted coal supplies. We find that in this proceeding, NIPSCO provided sufficiently detailed testimony and information to support its forecasted fuel costs as required by our Order. We find that NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding these five factors.

Petitioner previously made the following forecasts of its fuel cost in January, February and March, 2012 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Over (Under) Estimate
January	\$0.031488/kWh	\$0.028343/kWh	11.10%
February	\$0.033409/kWh	\$0.026878/kWh	24.30%
March	\$0.032966/kWh	\$0.027188/kWh	21.25%
Weighted Average Estimating Error			**18.60%**

(Pet.'s Ex. B, Sch. 5, pp. 1-3, Lns. 28-29; Pet.'s Ex. B, Sch. 5, p. 4, Ln. 29).

Mr. Williamson identified the primary drivers for the lower than forecasted fuel cost as lower power prices in MISO as a result of lower natural gas prices, unseasonably mild weather and the stay of CASPR. At the time the forecast was prepared, NIPSCO did not, nor did the market, anticipate a 35% average drop in natural gas prices (Pet.'s Ex. 3, pp. 4-5).

OUCC Witness Gregory T. Guerrettaz testified that nothing had come to his attention that would indicate that the projections used by NIPSCO for fuel costs and sales of power were unreasonable considering a comparison of prior quarter actual and forecast fuel costs and sales figures. (Public's Ex. 1, p. 7).

Based on NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for January, February and March, 2012, we find that NIPSCO's estimate of its prospective average fuel cost is reasonable for the billing months of August, September and October 2012.

11. Return Earned. Petitioner's exhibits demonstrate that for the twelve months ending March 31, 2012, Petitioner earned a return of \$139,631,406 (Pet.'s Ex. 2-A, p. 1, Ln. 14b, Col. C). This is less than Petitioner's authorized amount of \$188,872,242 (Pet.'s Ex. 2-A, p. 1, Ln. 14b, Col. B) approved in Cause No. 43969. Mr. Plantz testified actual Environmental Cost Recovery Mechanism operating income is zero (Pet.'s Ex. 2-A, p. 1, Ln. 14a, Col. B) because there are no realized revenues eligible at March 31, 2012. Therefore, during the twelve months ending March 31, 2012, the Commission finds NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

12. **Fuel Cost Adjustment Factor.** As set forth herein, Petitioner has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. Petitioner's evidence presented a variance factor of ($0.002982) per kWh (Pet.'s Ex. B, Sch. 1, Ln. 27) and a recoverable interruptible factor of $0.000513 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 28) to be added to the estimated cost of fuel for the billing months of August, September and October 2012, in the amount of $0.028263 per kWh (Pet.'s Ex. B, Sch. 1, Ln. 25). This results in a fuel cost adjustment factor of ($0.002980) per kWh (Pet.'s Ex. B, Sch. 1, Ln. 32), after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. OUCC witness Mr. Eckert calculated that a residential customer using 1,000 kWh per month will experience an overall decrease of $2.14 on his or her electric bill from the currently approved factor. (Public's Ex. 2, p. 4).

13. **OUCC Report.** Mr. Gregory Guerrettaz testified: (1) NIPSCO calculated the fuel cost element of the proposed fuel cost adjustment by including additional requirements set forth in various Commission orders; (2) NIPSCO calculated a variance for the quarter ending March 31, 2012 in conformity with the requirement of Ind. Code § 8-1-2-42; (3) NIPSCO did not have jurisdictional net operating income for the twelve months ending March 31, 2012 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending March 31, 2012 has been properly applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending March 31, 2012 were supported by NIPSCO's books and records and source documents.

Mr. Michael Eckert testified: (1) he reviewed NIPSCO's testimony and workpapers regarding the purchased power over the benchmark calculation; (2) NIPSCO's treatment of Ancillary Services Market charges follow the treatment ordered by the Commission in its Phase II Order in Cause No. 43426 dated June 30, 2009("Phase II Order"); (3) NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (4) NIPSCO's steam generation costs are above average in the State of Indiana and that NIPSCO's actual monthly cost of fuel (mills/kWh) is above the average in the State of Indiana; (5) due to the mild weather and the low cost of natural gas, NIPSCO's coal fired generation units are not being dispatched as much and its coal inventory is growing; and (6) the OUCC will continue to monitor and inform the Commission about NIPSCO's coal inventory in future FAC filings. Mr. Eckert also provided an update regarding NIPSCO's Electric Hedging Plan approved in Cause No. 43849. Finally, Mr. Eckert testified that the OUCC recommends the Commission approve the implementation of the NIPSCO's requested FAC factor.

14. **Interim Rates.** Because the Commission is unable to determine whether Petitioner will earn an excess return while this Order is in effect, the Commission finds that the rates approved herein should be interim rates, subject to refund.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner's requested fuel cost adjustment to be applicable to bills rendered in the months of August, September and October 2012, as set forth in Finding No. 12 above is hereby approved on an interim basis subject to refund as set out in Finding No. 15 above.

2. Petitioner shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC and testimony regarding any electric hedging transaction costs, gains and/or losses for which it is seeking recovery through the FAC, both as set out in Finding No. 7 above. NIPSCO shall also include in its quarterly FAC filings information as set out in Finding No. 10 above.

3. Petitioner shall file with the Electricity Division of the Commission, prior to placing in effect the fuel cost adjustments herein approved, an amendment to its rate schedule with reasonable reference therein reflecting that such charges are applicable to the rate schedules reflected on the amendment.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:
APPROVED:

JUL 18 2012

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission