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 MAY, JUNE AND JULY 2013, 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 98 APPROVED: APR 24 2013

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ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Jeffery A. Earl, Administrative Law Judge

On January 31, 2013, 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 during the billing cycles of May, June, and July 2013 and for ratemaking treatment for the cost of wind power purchases. On that same day, Petitioner also prefiled its direct testimony and exhibits. On February 6, 2013, NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officers granted in a Docket Entry dated February 14, 2013. On March 7 and 8, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause along with its direct testimony.

Pursuant to notice 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, the Commission held an Evidentiary Hearing at 9:30 a.m. on March 19, 2013, in Hearing Room 224, 101 W. Washington Street, Indianapolis, Indiana. At the hearing, Petitioner, the OUCC, and the Industrial Group appeared by counsel. Petitioner offered its prefiled testimony and exhibits and the OUCC offered its prefiled testimony and exhibits, all of 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.** Notice of the hearing in this Cause was given and published as required by law. Petitioner is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Petitioner's fuel cost charge. Thus, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **Petitioner's Characteristics.** NIPSCO is a public utility corporation incorporated under the laws of the State of Indiana. Petitioner's principal office is located at 801 East 86th Avenue, Merrillville, Indiana. Petitioner renders electric public utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such service to the public.

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. Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of October, November, and December 2012 averaged \$0.028413 per kWh.

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current charge of \$0.003286 per kWh to a charge of \$0.000953 per kWh for bills rendered during the billing cycles of May, June, and July 2013.

The requested fuel cost adjustment includes a variance of \$3,665,877 that was over-collected during October, November, and December 2012. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of April, May, and June 2013, is \$39,889,580, and its estimated monthly average sales for that period are 1,329,610 MWh.

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;
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> (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;
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> (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.
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> (4) The utility's estimates of its prospective average fuel costs for each such three (3) calendar months are reasonable after taking into consideration:

(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 December 31, 2012, were $23,016,429 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 December 31, 2012, were $109,301,270 above the levels approved in the 43969 Order. We find that Petitioner's actual increase in fuel costs for the twelve months ending December 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.** Kevin A. Strnatka, Director, Fuel Supply, for NIPSCO, 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 for the three months ended December 31, 2012, Petitioner's primary fuel for generation of electric energy is coal (81.06%) and the remainder is natural gas (18.94%).

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; the mercury 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 NIPSCO will have four long-term contracts in 2013. 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 two of NIPSCO's long-term contracts have firm prices that increase each year as set out in the contract. He stated that one 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 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 December 31, 2012, was \$50.85 per ton or \$2.531 per million Btu. The delivered coal cost for the reconciliation period (October, November, and December 2012) was \$50.21 per ton or \$2.493 per million Btu. Mr. Strnatka stated NIPSCO did not solicit 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 \$10.47 per ton for Powder River Basin ("PRB") coal, \$37.35 per ton for Illinois Basin ("ILB") high sulfur coal, and \$59.24 per ton for Pittsburgh #8 ("Pitt#8") 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 weather, natural gas pricing, and weak coal demand in both the domestic and international markets. Consequently, spot market pricing across all coal regions remained relatively soft. Mr. Strnatka said that NIPSCO took delivery of spot PRB shipments in the reconciliation period that were purchased off of a Request for Proposal ("RFP") in the third quarter and that NIPSCO took delivery of spot ILB shipments in the reconciliation period that were purchased off a second RFP in the third quarter. He stated these spot coal prices were very competitive and led to the reduction in the delivered cost of coal in the reconciliation period. He stated that all other coal requirements during the reconciliation period were met with contract-priced coal. Mr. Strnatka testified that NIPSCO's delivered cost of coal during the reconciliation period decreased compared to the third quarter of 2012 from \$50.70 per ton or \$2.521 per million Btu to \$50.21 per ton or \$2.493 per million Btu. He stated this decrease was attributed to the competitive pricing gained under the spot purchases of PRB and ILB coal. Mr. Strnatka testified that fuel surcharges remained relatively flat during the reconciliation period.

Daniel T. Williamson, Executive Director of Energy Supply and Trading for NIPSCO, stated that 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. Mr. Williamson testified NIPSCO has made every reasonable effort to purchase natural gas so as to provide electricity to customers at the lowest reasonable price.

Based on the evidence presented, we find that NIPSCO has adequately explained its coal and gas procurement decision making and we find that its acquisition process is reasonable.

b. <u>Renewable Energy Credits ("RECs").</u> 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 that 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 that 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 that NIPSCO will pass the proceeds from the sale of RECs back to customers through the "Purchased Power other than MISO" line item. He stated that 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.

NIPSCO shall 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 that NIPSCO incorporated the Electric Hedging Program that was approved by the Commission's July 13, 2011 in Cause No. 43849 ("2011 Hedging Program") in this FAC proceeding. He testified that in October, NIPSCO purchased 76 gas contracts and 207 power contracts. In November, NIPSCO purchased 66 gas contracts and 63 power contracts. And in December, NIPSCO purchased 68 gas contracts and 0 power contracts. He stated the execution of these contracts is consistent with the 2011 Hedging Program. Mr. Williamson stated the impact of the hedges entered into for the Electric Hedging Program for this proceeding was a gain of $559,260 during the reconciliation period, plus broker fees and clearing exchange fees, which totaled $4,107, for a total impact of $555,153. He noted that broker fees represented 0.02% of the total value of the transactions that occurred during this reconciliation period. Mr. Williamson testified that decisions were made based on 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.

NIPSCO shall continue to include in its quarterly FAC filings testimony and evidence of its electric hedging costs and any gains/losses resulting from hedging transactions for which it is seeking recovery through the FAC.

d. <u>Purchased Power Over The Benchmark.</u> 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 2,878.28 MWhs of purchased power in October, 3,139.16 MWhs of purchased power in November, and 948.38 MWhs of purchased power in December that were in excess of the Purchased Power Daily Benchmark. Mr. Williamson testified that in accordance with the procedures outlined in the 43526 Order, the Purchases over the Purchased Power Benchmark were made to supply jurisdictional load that offset available NIPSCO resources that were not dispatched by MISO or were otherwise eligible under the procedures outlined in the 43526 Order and are therefore recoverable. Michael D.

Eckert, Senior Utility Analyst in the OUCC's Electric Division, 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.

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.

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 October, November, and December 2012 was $652,639.

9. **Interruptible Credits.** Mr. Williamson testified that 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 did not interrupt any of the industrial customers taking service under Rider 675. The evidence shows that NIPSCO paid a total of $9,357,016 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 $2,339,254, through the FAC for the billing months of May, June, and July 2013.

10. **Estimation of Fuel Cost.** Petitioner estimated that its prospective total average fuel costs for months of April, May, and June 2013 will be $39,889,580 on a monthly basis.

Mr. Strnatka testified that NIPSCO anticipates that its delivered coal cost during the forecast period of April, May, and June 2013 will be approximately $49.48 per ton or an estimated $2.555 per million Btu. Mr. Strnatka testified the average spot market prices for calendar year 2013 (which do not include cost of transportation) are currently $10.60 per ton for PRB coal, $38.17 per ton for ILB coal and $59.94 per ton for Pitt#8 coal.

Mr. Strnatka explained that 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 the 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 NIPSCO's production cost modeling system.

With respect to the factors NIPSCO believes to have the greatest impact on the supply, demand, and cost of coal during the forecast period, Mr. Strnatka cited the price of natural gas. He testified that if natural gas-fired generation remains competitive, and effectively displaces coal-fired generation, coal pricing will be very economical. Also, relative to coal supply concerns, there have been a number of coal producers closing or idling mines and deferring any new mine expansion until the market improves, and there could be another round of potential production cutbacks if the market doesn't rebound. He stated that the Energy Information Administration is estimating that for the first time since 1993, United States coal production will fall below one billion tons; but there are other coal producers that have expanded, banking on the increasing installation of SO_2 scrubbers, particularly in the eastern United States. Additionally, international demand for coal appears to be soft, weather will be a contributing factor impacting demand for coal, and the National Mining Association is taking steps to improve mine safety in 2013, which will ultimately impact mining cost. Finally, the evolving federal regulations and the effect on utility generating stations will continue to be evaluated. He stated that NIPSCO had two transportation agreements that expired at the end of 2012. He stated that one of the transportation agreements will not be needed for Bailly Generating Station since NIPSCO will supply both this station and R.M. Schahfer Generating Station with ILB coal shipped by the same rail carrier. He stated that terms and conditions of the second transportation agreement have been agreed upon by both parties, but a formal agreement has not yet been executed. An important part of this transportation agreement negotiation included the establishment of a new West Texas Intermediate ("WTI") benchmark price that will significantly lessen the volatility of this rail carrier's fuel surcharges. He stated that all other term transportation agreements that carryover to 2013 have annual contractual transportation price increases that commenced January 1, 2013. He stated these price increases will effectively raise the delivered cost of coal in 2013. The prices of WTI crude and On Highway Diesel fuel have remained relatively stable and with the negotiation of a new WTI benchmark for one railroad, 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 during the forecast period. The existing challenge will be to manage NIPSCO's coal inventory. He stated that NIPSCO experienced its lowest annual coal burn in 2012, twenty-seven percent (27%) less burn than 2011. He stated that weather, natural gas prices, units in planned outages during the shoulder months and carryover tons from 2012 will continue to impact NIPSCO's inventory through the forecast period. Consequently, NIPSCO's total coal inventory is currently thirty-five percent (35%) above its system target level. However, NIPSCO is forecasting that by the end of the forecast period total system inventory will be within the normal range of its system target. To achieve this inventory reduction, NIPSCO will supply both Bailly Generating Station and R.M. Schahfer Generating Station from its one ILB contract until the excess inventory is depleted, burn through NIPSCO's limited PRB contractual commitments plus carryover tons from 2012, and possibly burn any excess blend coal in high sulfur coal units that is targeted for PRB low sulfur units. He stated that NIPSCO will not incur any liquidated damages for transportation contracts covering 2012 shipments.

In the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90 ("FAC 90 Order"), we ordered NIPSCO to provide detailed testimony and information regarding: (1) the 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 the FAC 90 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 for October, November, and December 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
October	$0.029172/kWh	$0.027643/kWh	5.53%
November	$0.029951/kWh	$0.029119/kWh	2.86%
December	$0.029903/kWh	$0.028481/kWh	4.99%
Weighted Average Estimating Error			**4.44%**

Based on NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for October, November, and December 2012, we find that NIPSCO's estimate of its prospective average fuel cost is reasonable for months of April, May, and June 2013.

11. Return Earned. Petitioner's exhibits demonstrate that for the twelve months ending December 31, 2012, Petitioner earned a return of $163,978,967. This is less than Petitioner's authorized amount of $194,430,197 approved in Cause No. 43969 plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the period beginning with the 43969 Order through December 31, 2012. Therefore, we find that during the twelve months ending December 31, 2012, 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 discussed above, 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 $(0.000919) per kWh and a recoverable interruptible factor of $0.000586 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of May, June, and July 2013, in the amount of $0.030001 per kWh. This results in a fuel cost adjustment factor of $0.000953 per kWh after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. Mr. Eckert calculated that a residential customer using 1,000 kWh per month will experience an overall decrease of $2.34 on his or her electric bill from the currently approved factor.

13. OUCC Report. Gregory T. Guerrettaz, President of Financial Solutions Group, Inc., testified that: (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 December 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 December 31, 2012 greater than that granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending December 31, 2012, has been properly applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending December 31, 2012.

Mr. Eckert testified that: (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 follows the treatment ordered by the Commission's June 30, 2009 Phase II Order in Cause No. 43426 ("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 among the lowest in the State of Indiana; (5) NIPSCO's coal inventory is 35% above its target levels; however, NIPSCO believes that by the end of the forecast period its total system inventory will be within the normal range; (6) the OUCC will continue to monitor and inform the Commission about NIPSCO's coal inventory in future FAC filings; and (7) the OUCC reviewed NIPSCO's hedges and believes the hedging costs were reasonable. Finally, Mr. Eckert testified that the OUCC recommends the Commission approve the implementation of NIPSCO's requested FAC factor.

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

15. **Confidential Information.** On January 31, 2013, Petitioner filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information supported by the Affidavit of Kevin A. Strnatka, which asserted that documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. On February 14, 2013, the Presiding Officers issued a Docket Entry granting a preliminary finding that the information was confidential. We find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. Petitioner's requested fuel cost adjustment to be applicable to bills rendered during the billing cycles of May, June, and July 2013, as set forth in Section 12, above is approved on an interim basis subject to refund as set out in Section 14 above.

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

3. 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, as discussed in Section 7(b) above, and testimony regarding any electric hedging transaction costs and gains/losses for which it is seeking recovery through the FAC, as discussed in Section 7(c) above. Petitioner shall also include in its quarterly FAC filings the

information required by the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, as discussed in Section 10 above.

4. The confidential information filed by Petitioner in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2- 3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

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

APPROVED: APR 24 2013

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