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 CYCLES OF FEBRUARY, MARCH AND APRIL 2014, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND ENERGY APPROVED IN CAUSE NO. 43393.	**CAUSE NO. 38706 FAC 101** **APPROVED:** JAN 29 2014

ORDER OF THE COMMISSION

Presiding Officers:
James D. Atterholt, Chairman
Jeffery A. Earl, Administrative Law Judge

On November 4, 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 February, March, and April 2014. NIPSCO also prefiled the direct testimony and exhibits of the following:

- Katherine A. Cherven, Manager of Compliance in NIPSCO's Rates and Regulatory Finance Department;
- Ronald G. Plantz, Controller of NIPSCO at NiSource Corporate Services Company;
- Andrew S. Campbell, Manager of Planning & Regulatory Support for NIPSCO;
- Shirley Lowry, Manager of Fuel Supply for NIPSCO; and
- David Saffran, Generation Business Systems Administrator in NIPSCO's Operations Management Reporting Division.

On November 18, 2013, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officers granted. The Industrial Group did not prefile evidence in this Cause. On December 9, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the direct testimony and exhibits of the following:

- Michael D. Eckert, Senior Utility Analyst in the OUCC's Electric Division; and
- Gregory T. Guerrettaz, CPA, President of Financial Solutions Group, Inc.

The Commission held an evidentiary hearing in this Cause at 9:30 a.m. on January 7, 2014, in Hearing Room 224, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared at and participated in the hearing. No members of the general public appeared or sought to participate.

Based upon the applicable law and the evidence presented, we find:

1. **Commission Jurisdiction and Notice.** Notice of the hearing in this Cause was given and published as required by law. NIPSCO 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 NIPSCO's fuel cost charge. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **NIPSCO's Characteristics.** NIPSCO has its principal office at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders 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 electric utility service to the public.

3. **Available Data on Actual Fuel Costs.** NIPSCO's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in NIPSCO'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. NIPSCO's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of July, August, and September 2013 averaged $0.030745 per kWh.

4. **Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment charge from the current charge of $0.004040 per kWh to a charge of $0.003221 per kWh, for bills rendered during the billing cycles of February, March, and April 2014.

The requested fuel cost adjustment includes a variance of $1,317,737 that was under-collected during July, August, and September 2013. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of January, February, and March 2014, is $42,734,608, and its estimated monthly average sales for that period are 1,377,879 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;
>
> (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 average 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 No. 2-A, shows that fuel costs for the twelve months ending September 30, 2013, were $46,091,650 above the levels approved in the 43969 Order. Petitioner's Exhibit No. 2-A also shows that the total operating expenses excluding fuel for the twelve months ending September 30, 2013, were $102,795,472 above the levels approved in the 43969 Order. Based on the evidence presented, we find that NIPSCO's actual increase in fuel costs for the twelve months ending September 30, 2013, 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. Ms. Lowry 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. NIPSCO's primary fuel for generation of electric energy is coal (83.57%) and the remainder is natural gas (16.43%) for the three months ended September 30, 2013.

A. Fuel Procurement. Ms. Lowry testified about NIPSCO's coal procurement process. 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, 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. NIPSCO also considers the availability, reliability, and diversity of particular coal suppliers and coal transporters in its fuel procurement practices. NIPSCO had four long-term contracts in 2013, and planned to meet any remaining coal requirements through spot purchases. NIPSCO competitively bids all coal purchased under a long-term agreement. 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 dollars per million Btu basis. 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. NIPSCO negotiates price and commercial terms and conditions with the low evaluated bidder(s).

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. Two of NIPSCO's long-term contracts have firm prices that increase each year as set out in the contract. 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.

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. 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. 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.

NIPSCO's delivered cost of coal for the twelve months ending September 30, 2013, was \$50.27 per ton or \$2.499 per million Btu. The delivered coal cost for the reconciliation period (July, August, and September 2013) was \$49.11 per ton or \$2.432 per million Btu. NIPSCO purchased high sulfur spot coal for Bailly Generating Station and R. M. Schahfer Generating Station for the period July through September, 2013. The average market spot price of coal (excluding transportation costs) during the reconciliation period was \$10.83 per ton for Powder River Basin ("PRB") coal, \$39.24 per ton for Illinois Basin ("ILB") high sulfur coal, and \$63.71 per ton for Pittsburgh #8 ("Pitt#8") coal.

Ms. Lowry also testified about the market factors affecting the supply, demand, and cost of coal during the reconciliation period. Coal supply during the reconciliation period was 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 continued to remain relatively soft. NIPSCO's delivered cost of coal during the reconciliation period decreased compared to the second quarter of 2013 from \$49.63 per ton or \$2.506 per million Btu to \$49.11 per ton or \$2.432 per million Btu. Because NIPSCO does not have excess coal inventory, NIPSCO was able to participate in the coal market and procure very competitive ILB spot coal to meet its coal requirements, lowering its delivered coal cost during the reconciliation period. Fuel surcharges remained relatively flat during the reconciliation period.

Mr. Campbell 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 economical to run or need to run for operational purposes. Mr. Campbell testified that 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 that its acquisition process is reasonable.

B. <u>Renewable Energy Credits ("RECs")</u>. Mr. Campbell provided an update on NIPSCO's treatment of RECs associated with the energy NIPSCO purchases under the wind purchased power agreements. NIPSCO's recent-vintage RECs have significantly more value in regions of the market than older-vintage RECs. NIPSCO has been offering these recently acquired RECs to the renewable energy market when it acquires a minimum of 50,000, which is the standard REC contract. The amount of time it takes to accumulate a block of 50,000 RECs varies based on the MW output at the wind resources: historically, this has been roughly every two months. NIPSCO's goal is to spread the sales of RECs throughout the year. 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. During this FAC period a block of 50,000 RECs was sold with a net proceed of $52,138. NIPSCO passes the proceeds from the sale of RECs back to customers through the "Purchased Power other than MISO" line item. NIPSCO continues to monitor and evaluate the marketability for all vintage RECs, potential future legislation that would consider NIPSCO's RECs eligible to meet state renewable energy standards, and the Commission's Voluntary Clean Energy Portfolio Standard program rules, and NIPSCO will make appropriate changes to its treatment of RECs as necessary.

Mr. Campbell testified that in Cause No. 44198 GPR 2, NIPSCO requested approval to transfer RECs obtained in conjunction with wind energy purchases under NIPSCO's wind purchase power agreements with Barton and Buffalo Ridge I Wind Farms, which are currently held in an account for NIPSCO customers who pay the FAC, to the GPR program at market price. NIPSCO will provide an update on the status of this request in its FAC 102 filing, and if NIPSCO's proposal is approved in Cause No. 44198 GPR 2, NIPSCO expects to make a similar proposal in FAC 102.[1]

Mr. Campbell also provided an update on the treatment of RECs received from feed-in-tariff purchases. NIPSCO is currently determining the most appropriate way to account for, reconcile, and market the RECs received from feed-in-tariff purchases. Any sale of these RECs will be passed back through the FAC. 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. Campbell testified that NIPSCO purchased 66 gas contracts and 22 power contracts in July, 71 gas contracts and 0 power contracts in August, and 43 gas contracts and 160 power contracts in September. The execution of these contracts is consistent with NIPSCO's most recently filed hedging plan. The impact of the hedges entered into for the Electric Hedging Program for this proceeding was a loss of $304,406 during the reconciliation period. The net total impact of the hedging program in this proceeding was $307,766 during the reconciliation period. Broker fees represented 0.03% of the total value of the transactions that occurred during this reconciliation period. Mr. Campbell testified that 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. In addition, the transactions were all made in accordance with the Electric Hedging Program approved by the 44205 Order. NIPSCO shall continue to include in its filings testimony and evidence of its electric hedging costs, and any gains/losses resulting from its hedging transactions for which it is seeking recovery through the FAC.

D. <u>Purchased Power Over The Benchmark</u>. Mr. Campbell discussed the Benchmark established in the Commission's August 25, 2010 Order in Cause No. 43526

[1] The Commission approved NIPSCO's request in its December 30, 2013 Order in Cause No. 44198 GPR 2.

("43526 Order") that applies to NIPSCO's purchased power transactions. NIPSCO did not have any swap or virtual transactions during this FAC period. NIPSCO is seeking to recover 1,240.44 MWh of purchased power in July 2013, 3,631.76 MWh of purchased power in August 2013 and 4,927.26 MWh of purchased power in September 2013 that were in excess of the Purchased Power Daily Benchmark. The purchases over the Purchased Power Daily Benchmark were made to supply jurisdictional load that offset available NIPSCO resources that were not dispatched by the Midcontinent Independent System Operator, Inc. ("MISO") or were otherwise eligible under the procedures outlined in the 43526 Order and are therefore recoverable.

Mr. Eckert testified that Mr. Campbell's testimony and workpapers comply with the 43526 Order regarding purchased power over the benchmark and that he agreed with Mr. Campbell's calculation of purchased power over the benchmark. Based on the evidence presented, we find that NIPSCO's identified purchase power costs are properly included in the fuel cost calculation.

Based on the evidence presented, we find that NIPSCO 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.

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 July, August, and September 2013 was $9,300,093.

9. **Interruptible Credits.** Mr. Campbell testified that the 43969 Order approved Rider 675 – Interruptible Industrial Service, which allows credits to be paid to industrial customers that agree to interrupt their service if certain criteria are met. During the reconciliation period, NIPSCO initiated interruptions on 22 separate days for a total of 276 hours under Option C and 155 hours under Option D. The evidence shows that NIPSCO paid a total of $9,368,632 interruptible credits through Rider 675 during the reconciliation period and, pursuant to the 43969 Order, NIPSCO is authorized to recover 25% of that total, or $2,342,158, through the FAC for the billing months of February, March, and April 2014.

10. **Estimation of Fuel Cost.** NIPSCO estimated that its prospective total average fuel costs for the months of January, February, and March 2014 will be $42,734,608 on a monthly basis.

Ms. Lowry testified about NIPSCO's estimated fuel costs. NIPSCO anticipates its delivered coal cost in January, February, and March 2014 will be approximately $50.90 per ton or $2.55 per million Btu. The average spot market prices for calendar year 2014, excluding transportation, are currently $11.98 per ton for PRB coal, $40.02 per ton for ILB coal, and $64.03 per ton for Pitt#8 coal.

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 NIPSCO's production cost modeling system ("PROMOD").

Ms. Lowry also discussed the factors NIPSCO believes will have an impact on the supply, demand, and cost of coal during the forecast period, including the price of natural gas and the winter weather. Currently natural gas pricing is between \$3.50/mmBtu and \$4.00/mmBtu. If the pricing stays at this level or below during the forecast period, coal fired generation will be impacted.

Demand for ILB coal appears to be stronger than other coal basins. But with soft international pricing, ILB coal export potential has been significantly reduced, causing an apparent oversupply domestically, and keeping ILB pricing very competitive. PRB producers have idled production to balance supply and demand but demand for PRB coal is forecasted to grow and PRB prices are expected to rise in 2014. Currently PRB spot pricing is just above its estimated production cost. Utilities are gradually bringing coal stockpiles under control, and if the winter is colder than expected, coal demand will increase during the forecast period, but supply will not be an issue. Domestic coal producers have decreased their capital spend this year and this trend will continue into 2014. Additionally, because of market conditions and regulatory and political uncertainty, coal producers are selling off some of their marginal assets. The evolving federal regulations and their effect on utility coal-fired generating stations will continue to be evaluated.

Two of NIPSCO's transportation agreements expired at the end of 2012. In FAC 98, NIPSCO indicated that one of the transportation agreements would not be needed for Bailly Generating Station because NIPSCO was anticipating supplying both this station and R.M. Schahfer Generating Station with ILB coal shipped by the same rail carrier. However, NIPSCO has burned through its excess inventory faster than anticipated and Bailly Generating Station is currently being supplied by spot coal purchased through December 2013. Transportation was also purchased through the end of 2013 in anticipation of these spot purchases. NIPSCO is currently negotiating coal and transportation agreements for Bailly Generating Station to commence on January 1, 2014. NIPSCO has agreed to term, tons, and rates with the transportation provider, but both parties continue to negotiate an open contractual item that requires closure. NIPSCO and the transportation provider agreed to extend the negotiation period initially to March 31 and ultimately to October 31, 2013, giving both parties sufficient time to finalize the negotiation, or to move in another direction. Prices for WTI crude are presently less than \$100 per barrel and the forecast is for prices in the \$95 to \$100 per barrel in the future. If these prices remain in this range, NIPSCO would pay lower fuel surcharges to the railroads and its delivered coal cost would be positively impacted in the fourth quarter, and also during the forecast period.

Ms. Lowry testified NIPSCO does not anticipate any issues in securing coal or transportation during the forecast period. Currently, NIPSCO is negotiating ILB coal and transportation contracts for the Bailly Generating Station to commence on January 1, 2014. NIPSCO is also presently soliciting contracts for additional contract PRB coal for the Michigan City Generating Station and Units 14/15 at R. M. Schahfer Generating Station. These PRB contract(s) would also commence on January 1, 2014.

In our April 27, 2011 Order in Cause No. 38706 FAC 90, 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 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.

NIPSCO previously made the following forecasts of its fuel cost in July, August, and September 2013 and incurred the following actual costs, resulting in a percent error calculated as follows:

Month	Estimated Fuel Cost	Actual Fuel Cost	Over (Under) Estimate
July	\$0.031089/kWh	\$0.032283/kWh	-3.70%
August	\$0.030843/kWh	\$0.032861/kWh	-6.14%
September	\$0.029959/kWh	\$0.027120/kWh	10.47%
Weighted Average Estimating Error			**-0.31%**

Mr. 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. He also testified that during the onsite audit, he prepared a detailed analysis of the forecast workpapers which was updated from FAC 100. He stated positive changes are still projected to occur in the coal cost area, which should have a positive impact on the FAC factor going forward. Mr. Guerrettaz testified that these price reductions impacted the PROMOD model for FAC 101. With respect to the forecast and the reduction in coal prices, he stated the OUCC reviewed several of NIPSCO's solicitations and understands that this will also create positive impacts. He indicated that NIPSCO, like several other utilities, has been able to reduce prices as a result of market changes.

Based on NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for July, August, and September 2013, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the February, March, and April 2014 billing cycles is reasonable.

11. **Return Earned.** NIPSCO's exhibits demonstrate that for the twelve months ending September 30, 2013, NIPSCO earned a return of \$174,189,205. This is less than NIPSCO's authorized return amount of \$207,244,009 approved in Cause No. 43969 plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the twelve months ended September 30, 2013. Based on the evidence presented, we find that during the twelve months ending September 30, 2013, NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted

12. **Fuel Cost Adjustment Factor.** NIPSCO has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. NIPSCO's evidence presented a variance factor of $0.000319 per kWh and a recoverable interruptible factor of $0.000567 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of February, March, and April 2014, in the amount of $0.031015 per kWh. This results in a fuel cost adjustment factor of $0.003221 per kWh, after subtracting the cost of fuel already included 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 $0.82 on his or her electric bill from the currently approved factor.

13. **OUCC Report.** Mr. 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 September 30, 2013, 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 September 30, 2013, greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending September 30, 2013 has been accurately applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending September 30, 2013 were supported by NIPSCO's books, records and source documents.

Mr. Eckert testified: (1) he reviewed and agreed with Mr. Campbell's purchased power over the benchmark calculation; (2) NIPSCO's treatment of Ancillary Services Market charges follows the treatment ordered by the Commission in its Phase II Order in Cause No. 43426; (3) NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (4) NIPSCO has reported the average monthly ASM cost Distribution Amounts for Regulation, Spinning and Supplemental Reserves charges types pursuant to the Phase II Order; (5) 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; (6) NIPSCO's coal inventory is within normal target levels and the OUCC will continue to monitor and inform the Commission about NIPSCO's coal inventory in future FAC filings; (7) the OUCC reviewed NIPSCO's hedges and believes the hedging costs were reasonable; (8) NIPSCO is seeking full recovery of the wind invoices for energy received and at this time NIPSCO is not seeking recovery of the portion of curtailed invoices that it did not pay; and (9) the OUCC recommends NIPSCO be allowed to recover the wind invoice amount for energy received and NIPSCO not be allowed to recover the portion of the wind invoice amounts for curtailed energy that NISPCO disputes and has not paid until the dispute has been settled and NIPSCO pays the bill.

14. **Interim Rates.** Because we are unable to determine whether NIPSCO 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 November 4, 2013, Petitioner filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information supported by the affidavit of Mr. Campbell, 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 January 3, 2014, 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. NIPSCO's requested fuel cost adjustment to be applicable to bills rendered during the billing cycles of February, March, and April 2014, as set forth in Finding No. 12 above is approved on an interim basis subject to refund as set out in Finding No. 14 above.

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

3. NIPSCO 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 Paragraph 7(b) above, and testimony regarding any electric hedging transaction costs and gains/losses for which it is seeking recover through the FAC, as discussed in Paragraph 7(c) above. NIPSCO 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 Paragraph 10 above.

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

ATTERHOLT, MAYS, AND ZIEGNER CONCUR:

APPROVED: JAN 29 2014

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