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 2015, 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 105** **APPROVED:** JAN 28 2015

ORDER OF THE COMMISSION

Presiding Officer:
Jeffery A. Earl, Administrative Law Judge

On October 30, 2014, Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition in this Cause, seeking approval of a fuel cost adjustment to be applicable for bills rendered during the billing cycles of February, March, and April 2015. NIPSCO also prefiled the direct testimony and exhibits of the following:

- Katherine A. Cherven, Manager of Compliance in the Rates and Regulatory Finance Department at NIPSCO;
- Thomas P. Harmon, Manager of Financial Reporting at NIPSCO;
- Andrew S. Campbell, Manager of Planning and Regulatory Support at NIPSCO;
- Shirley Schultz, Manager, Fuel Supply at NIPSCO; and
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division at NIPSCO.

On November 12, 2014, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officer granted on November 20, 2014.

On December 4, 2014, 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. Guerrattaz, CPA, President of Financial Solutions Group, Inc.

The Commission held an evidentiary hearing at 2:30 p.m. on January 6, 2015, in Hearing Room 224, 101 W. 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 on the applicable law and the evidence presented, we find:

1. **Commission Jurisdiction and Notice.** Notice of the evidentiary 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 such 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 2014 averaged $0.030944 per kWh.

4. **Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment charge from the current charge of $0.007886 per kWh, for bills rendered during November and December 2014 and January 2015 to a charge of $0.003492 per kWh, for bills rendered during the billing cycles of February, March, and April 2015.

The requested fuel cost adjustment includes a variance of $6,312,550 that was over-collected during July, August, and September 2014. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of January, February, and March 2015 is $46,806,976, and its estimated monthly average sales for that period are 1,413,896 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 12 months ending September 30, 2014, were $132,523,836 above the levels approved in the 43969 Order, the last proceeding in which NIPSCO's basic rates and charges for electric service were approved. Petitioner's Exhibit No. 2-A also shows that the total operating expenses excluding fuel for the 12 months ending September 30, 2014, were $128,776,013 above the levels approved in the 43969 Order. The Commission finds that NIPSCO's actual increase in fuel costs for the 12 months ending September 30, 2014, 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. Schultz 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. She testified that NIPSCO's primary fuel for generation of electric energy was coal (90.94%) and the remainder was natural gas (9.06%) for the three months ended September 30, 2014.

A. Fuel Procurement. With respect to NIPSCO's coal procurement process, Ms. Schultz 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, 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 six long-term contracts in the third quarter of 2014. Ms. Schultz said that NIPSCO would meet any remaining coal requirements through spot purchases.

Ms. Schultz 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. Four 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.

Ms. Schultz testified that the delivered cost of coal for NIPSCO for the 12 months ending September 30, 2014, was $50.24 per ton or $2.481 per million Btu. The delivered coal cost for the reconciliation period (July, August, and September 2014) was $50.92 per ton or $2.495 per million Btu. NIPSCO purchased approximately 784,000 tons of spot coal from five different suppliers during the reconciliation period of July through September, 2014. The average spot market price of coal (excluding transportation costs) during the reconciliation period was $11.82 per ton for Powder River Basin ("PRB") coal, $38.56 per ton for Illinois Basin ("ILB") coal, and $59.06 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, Ms. Schultz testified that coal supply during the reconciliation period continued to be impacted by railroad congestion and shipment delays. Railroad fluidity and velocity have not fully recovered to normal levels, and all of NIPSCO's originating rail carriers continued to report locomotive and crew shortages throughout the reconciliation period. Additionally, the drawdown on coal inventory stockpiles throughout the industry during the first quarter led to increased demand for coal by other utilities during the reconciliation period, also contributing to the price increase on spot market coal. Spot market pricing decreased in the reconciliation period, compared to the second quarter of 2014, but remained higher than contract coal pricing for PRB and ILB coal. NIPSCO's delivered cost of coal during the reconciliation period increased compared to the second quarter of 2014 from $48.41 per ton or $2.447 per million Btu to $50.24 per ton or $2.481 per million Btu due to higher delivered cost of PRB coal (from $2.325/MMBtu to $2.380/MMBtu) and higher delivered cost of ILB coal (from $2.312/MMBtu to $2.333/MMBtu). Factors impacting the higher delivered costs of PRB and ILB coal include the purchase of additional tons of spot coal, which were higher in price than contract coal, and were required because actual consumption was greater than forecasted consumption. Fuel surcharges decreased slightly during the reconciliation period.

Mr. Campbell stated there have not been any changes to NIPSCO's gas purchasing practices for NIPSCO's generation located on or off NIPSCO's gas distribution system. Mr. Campbell 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. The only future contracts entered into are financial hedges in accordance with the Commission's order in Cause No. 44205 S2. Mr. Campbell 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. 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. The goal behind this method is to spread the sales of RECs over multiple time

periods 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 net proceeds of $46,075 and a block of 3,426 RECs were transferred to NIPSCO's Green Power Rider with proceeds of $3,254.70. NIPSCO has and will continue to pass the proceeds from the sale or transfer 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 as necessary.

Mr. Campbell stated there was not a sale of feed-in tariff RECs within the reconciliation period. NIPSCO is currently determining the most appropriate way to account for, reconcile, and market the RECs received from feed-in purchases. Currently, NIPSCO is in the process of setting up a test sale of feed-in tariff RECs in order to establish internal processes. Any future sale of RECs will be passed back through the FAC to include the net proceeds from this potential test sale.

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. Electric Hedging Program. Mr. Campbell testified NIPSCO incorporated the Electric Hedging Program that was approved by the Commission's July 13, 2011 Order in Cause No. 43849 in this FAC proceeding. In July, NIPSCO purchased 44 gas contracts and 44 power contracts. In August, NIPSCO purchased 48 gas contracts and 63 power contracts. In September, NIPSCO purchased 61 gas contracts and 273 power contracts. The execution of these contracts is consistent with NIPSCO's currently-effective electric hedging plan approved in Cause No. 44205 S2. The impact of the hedges entered into for the Electric Hedging Program for this proceeding was a loss of $710,145 during the reconciliation period. The net total impact of the hedging program in this proceeding was $719,445 during the reconciliation period. Broker fees represented 5% of the total value of the transactions that occurred during this reconciliation period. Mr. Campbell testified decisions were made based on the conditions known at the time of the transactions, 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 44205 S2 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. Purchased Power Over The Benchmark. Mr. Campbell 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"). NIPSCO did not have any swap or virtual transactions during this FAC period. NIPSCO is seeking to recover 3,805.80 MWh of purchased power in July 2014, 2,212.85 MWh of purchased power in August 2014 and 16,018.96 MWh of purchased power in September 2014 that were in excess of the Purchased Power Daily Benchmark. 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.

Mr. Eckert testified that Mr. Campbell's testimony and workpapers reflect 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, 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.

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 Cost of Fuel" included in the actual cost of fuel for the months of July, August, and September 2014 was $139,156.

Mr. Campbell testified that, pursuant to the agreement reached by the parties in FAC 104, the estimate for "MISO Components of Cost of Fuel" in this proceeding is based on the High - Low average of actual "MISO Components of Cost of Fuel" incurred for the twelve month period ending September 30, 2014, where the high and low quarters are replaced with a three year average of the same quarter. In this filing, NIPSCO has included an estimate of "MISO Components of Cost of Fuel" in the amount of $1,753,620 per month which represents an approximate 11.5% decrease from the last FAC filing.

9. **Interruptible Credits.** Mr. Campbell 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. During the reconciliation period, NIPSCO did initiate interruptions 9 separate days for a total of 45 hours under Option C and 39 hours under Option D. The evidence shows that NIPSCO paid a total of $9,373,544 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 $2,343,386, through the FAC for the billing months of February, March, and April 2015.

10. **Estimation of Fuel Cost.** NIPSCO's estimate for its prospective total average fuel costs for the months of January, February, and March 2015 will be $46,806,976 on a monthly basis.

Ms. Schultz testified that NIPSCO anticipates that its delivered coal cost during the forecast period of January, February, and March 2015 will be approximately $52.23 per ton or an estimated $2.572 per million Btu. The average spot market prices for calendar year 2015,

excluding transportation, are currently $12.89 per ton for PRB coal, $39.59 per ton for ILB coal and $59.12 per ton for Pitt8 coal.

Ms. Schultz 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 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.

Ms. Schultz stated that NIPSCO has coal supply agreements in effect for 2015 with firm pricing, and recently issued a solicitation for additional ILB spot coal to supplement the term purchases for January through March 2015. NIPSCO does not anticipate any issues in securing spot coal, if needed, during the forecast period. However, NIPSCO's originating rail carriers continued to report locomotive and crew shortages, and railroad fluidity and velocity have not yet recovered to normal levels. If these rail transportation issues continue into the forecasted period, coal supply could be impacted. NIPSCO has a transportation agreement for the delivery of shipments to its R.M. Schahfer Generating Station that will expire at the end of 2014 which is currently being negotiated to commence January 1, 2015, with the same counterparty. The renegotiation of this agreement is expected to result in an increase to the delivered cost of coal for the forecast period. NIPSCO's other transportation agreements remain in effect for 2015 with firm pricing (exclusive of fuel surcharges) so there will be no additional transportation price increases in the forecast period related to these existing transportation agreements. The prices of West Texas Intermediate crude decreased slightly in the last quarter. If this trend continues, NIPSCO would pay lower fuel surcharges to the railroad, and its delivered coal cost would be reduced during the forecast period. This impact, however, would be minimal.

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 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.

NIPSCO previously made the following forecasts of its fuel cost in July, August and September 2014 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	$0.033140/kWh	$0.029863/kWh	10.97%
August	$0.032609/kWh	$0.032375/kWh	0.72%
September	$0.033187/kWh	$0.030605/kWh	8.44%
Weighted Average Estimating Error			**6.56%**

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 FAC104. He stated that related to the forecast and the reduction in coal prices, the OUCC continues to review any coal or transportation price solicitations issued by NIPSCO.

Based on the evidence presented, including NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for July, August, and September 2014, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the February, March, and April 2015 billing cycles is reasonable.

11. **Return Earned.** NIPSCO's exhibits demonstrate that for the 12 months ending September 30, 2014, Petitioner earned operating income including ECRM and FMCA revenues of $191,767,525. This is less than NIPSCO's authorized amount of $224,611,880 approved in Cause No. 43969 plus NIPSCO's actual ECRM and FMCA operating income during the 12 months ended September 30, 2014. Mr. Harmon testified that consistent with the August 22, 2012 Order in Cause No. 44156 RTO 1, NIPSCO excluded operating revenues and O&M expenses adjusted for taxes associated with NIPSCO's multi-value projects. Based on the evidence presented, we find that during the 12 months ending September 30, 2014, NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

12. **OUCC Report.** Mr. Guerrettaz testified: (1) the fuel cost element of the proposed fuel cost adjustment has been calculated by including additional requirements set forth in various Commission orders; (2) the variance for the quarter ending September 30, 2014 was calculated in conformity with Ind. Code § 8-1-2-42; (3) NIPSCO did not have jurisdictional net operating income for the twelve months ending September 30, 2014, greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending September 30, 2014 has been accurately applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending September 30, 2014, 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 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 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 among the highest in the State of Indiana and that NIPSCO's actual monthly cost of fuel (mills/kWh) is among the highest in the State of Indiana; (6) NIPSCO's coal inventory is below normal target levels due to railroad congestion and shipment delays and NIPSCO is attempting to rebuild its inventory levels back to normal and that 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 NIPSCO disputes and has not paid until the dispute has been settled and NIPSCO pays the bill.

13. **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 ($0.001488) per kWh and a recoverable interruptible factor of $0.000552 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of February, March, and April 2015, in the amount of $0.033105 per kWh. As discussed above, we find the total amount that was over-collected during July, August, and September 2014 of $6,312,550 should be included in the FAC 105 fuel cost adjustment factor. This results in a fuel cost adjustment factor of $0.003492 per kWh, after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. The evidence shows that a residential customer using 1,000 kWh per month will experience an overall decrease of $4.39 on his or her electric bill from the currently approved factor.

14. **Interim Rates.** Because the Commission is unable to determine whether NIPSCO 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.

15. **Confidential Information.** On October 30, 2014, NIPSCO filed a motion for protective order which was supported by affidavit showing 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. By its November 20, 2014 docket entry, the Presiding Officer found such information to be preliminarily confidential, after which such information was submitted under seal by NIPSCO. We find that 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 2015, as set forth in Finding No. 13 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 therein 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. The information filed by NIPSCO in this Cause pursuant to NIPSCO's 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.

STEPHAN, MAYS-MEDLEY, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: JAN 28 2015

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