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 MAY, JUNE AND JULY 2016, 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 110** **APPROVED:** APR 20 2016

ORDER OF THE COMMISSION

Presiding Officer:
Jeffery A. Earl, Administrative Law Judge

On January 28, 2016, 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 May, June, and July 2016. NIPSCO also prefiled the direct testimony and exhibits of the following witnesses:

- Katherine A. Cherven, Manager of Compliance in NIPSCO's Rates and Regulatory Finance Department;
- Thomas P. Harmon, Manager of Financial Reporting for NIPSCO at NiSource Corporate Service Company;
- Andrew S. Campbell, Manager of Planning and Regulatory Support at NIPSCO;
- Dennis S. Rackers, Manager, Fuel Supply at NIPSCO; and
- David Saffran, Generation Business Systems Administrator in NIPSCO's Operations Management Reporting Division.

On February 25, 2016, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officer granted on February 29, 2016.

On March 3, 2016, 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 9:30 a.m. on April 6, 2016, 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 upon 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 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, plant 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 October, November, and December 2015 averaged $0.028060 per kWh.

4. **Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment charge from the current credit of $0.001652 per kWh, for bills rendered during the billing cycles of February, March, and April 2016 to a credit of $0.003977 per kWh, for bills rendered during the billing cycles of May, June, and July 2016 or until replaced by a different fuel cost adjustment that is approved in a subsequent filing.

The requested fuel cost adjustment includes a variance of $12,323,548, which was over-collected during October, November, and December 2015. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of April, May, and June 2016 is $37,342,447, and its estimated monthly average sales for that period are 1,370,252 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. <u>Fuel Costs and Operating Expenses</u>. Petitioner's Exh. 2-A shows that fuel costs for the 12 months ending December 31, 2015, were $14,356,263 above the levels approved in the 43969 Order. Petitioner's Exh. 2-A also shows that the total operating expenses excluding fuel for the 12 months ending December 31, 2015, were $179,835,886 above the levels approved in the 43969 Order. The Commission finds that NIPSCO's actual increase in fuel costs for the 12 months ending December 31, 2015, have not been offset by actual decreases in other operating expenses.

7. <u>Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost</u>. Mr. Rackers 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 NIPSCO's primary fuel for generation of electric energy is coal (78.63%) and the remainder is natural gas (21.37%) for the three months ended December 31, 2015.

A. <u>Fuel Procurement</u>. With respect to NIPSCO's coal procurement process, Mr. Rackers testified that NIPSCO considers several factors in purchase evaluations for a specific generating unit, including the delivered cost plus the related costs of emissions control and management of coal combustion byproducts. Coal quality parameters (especially moisture, ash, sulfur, mercury, arsenic, and fouling and slagging characteristics) can be go/no-go criteria because they affect the unit's operational reliability and ability to comply with environmental emission limits. He testified that the schedule flexibility and reliability of individual coal supply sources and related transportation carriers are also considered in NIPSCO's fuel procurement practices. NIPSCO had six long-term supply contracts in the fourth quarter of 2015. Mr. Rackers said that the remainder of NIPSCO's coal requirement was met through a spot purchase.

Mr. Rackers testified that with the 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 contracts have firm prices that increase each year as set out in the contract. One contract has prices that are adjusted annually based on the average weekly indexed prices of that particular coal in the previous year and one (1) contract has an annual market price reopener that determines the contract coal price for next year.

Mr. Rackers testified that the delivered cost of coal for NIPSCO for the 12 months ending December 31, 2015, was $50.71 per ton or $2.482 per million Btu. The delivered coal cost for all coal shipments during the reconciliation period (October, November, and December 2015) was $49.66 per ton or $2.423 per million Btu. The delivered cost of coal for contract coal shipments during the reconciliation period was $50.78 per ton or $2.497 per million Btu. The delivered cost of coal for spot coal shipments during the reconciliation period was $40.26 per ton or $1.846 per million Btu. The average spot market price of coal (excluding transportation costs) during the reconciliation period was $10.47 per ton for Powder River Basin ("PRB") coal, $31.42 per ton for Illinois Basin ("ILB") coal, and $39.44 per ton for Pittsburgh #8 ("Pitt8") coal.

With respect to the market factors affecting the market for coal transportation during the reconciliation period, Mr. Rackers testified that low natural gas prices and mild temperatures depressed demand for coal-fired generation, and consequently inventory stocks continue to be well above targets. Coal unit retirements under the Mercury and Air Toxics Standard (MATS) rule are also reducing demand for coal, and spot market prices across all coal regions remained relatively soft. NIPSCO's delivered cost of coal during the reconciliation period was $49.66 per ton or $2.423 per million Btu. This decreased $0.82 per ton and $0.047 per million Btu from the $50.48 per ton or $2.470 per million Btu in the third quarter of 2015. The cost decrease was primarily due to a change in the mix of coals received. The volume of less expensive ILB spot shipments was up from the previous period, while the more costly Pitt8 shipments were down. Mr. Rackers testified that NIPSCO made payments for the first time under a new rail contract provision that requires payments for train detention time beyond the free unloading time allowed under the contract. To mitigate the impact of this new contract provision, NIPSCO has increased its efforts to expedite the unloading process and find a solution to the train delays.

Mr. Campbell testified 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. The only future contracts entered into are financial hedges made in accordance with NIPSCO's Electric Hedging Program. 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 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 than older vintage RECs in certain market regions. NIPSCO has been offering these recently acquired RECs to the renewable energy market when the Company 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 REC market can 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, 63,128 current vintage RECs were sold with net proceeds of $22,044. 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 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.

Mr. Campbell testified that did not sell feed-in tariff RECs within the reconciliation period and that NIPSCO is having a difficult time establishing a means for tracking (inventory reconciliation) feed-in tariff RECs received from feed-in purchases. NIPSCO has continued working with M-RETS to complete a test registration for one of the larger (greater than 1 MW) feed-in tariff generation resources. Once the process is established, NIPSCO will have a tracking system in place and will be able to market the RECs received and will look to continue registration of other feed-in tariff generation resources. NIPSCO will continue to explore sales opportunities and any net proceeds from the sale of these RECs will be passed back through the FAC in a manner consistent with how NIPSCO has credited the FAC customers from the sale of NIPSCO's wind RECs from its wind PPAs.

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 that NIPSCO incorporated the Electric Hedging Program approved by the Commission in Cause No. 43849 ("43849 Order") in this FAC proceeding. In October, NIPSCO purchased 33 gas contracts and 440 power contracts. In November, NIPSCO purchased 36 gas contracts and 320 power contracts. In December, NIPSCO purchased 65 gas contracts and 0 power contracts. The execution of these contracts is consistent with NIPSCO's currently-effective electric hedging plan approved in Cause No. 44205-S3. The impact of the hedges entered into for the Electric Hedging Program for this proceeding was a loss of $1,524,682 during the reconciliation period. The net total impact of the hedging program in this proceeding was $1,534,040 during the reconciliation period. Broker fees represented 0.08% 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, 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-S3 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 114,781.953 MWh of purchased power in October 2015, 162,827.277 MWh of purchased power in November 2015, and 188,598.88 MWh of purchased power in December 2015 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. <u>MISO Day 2 Energy Costs</u>. 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 October, November, and December 2015 was $1,897,190.

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 December 31, 2015 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 $930,251 per month.

9. <u>Interruptible Credits</u>. Mr. Campbell 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. During the reconciliation period, NIPSCO did not initiate any interruptions. The evidence shows that NIPSCO paid a total of $9,162,368 for 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 $2,290,592, through the FAC for bills rendered during the billing cycles of May, June, and July 2016.

10. <u>Estimation of Fuel Cost</u>. NIPSCO's estimate for its prospective total average fuel costs for the months of May, June, and July 2016 will be $37,342,447 on a monthly basis.

Mr. Rackers testified that NIPSCO anticipates that the cost of coal to be burned for generation in the forecast period of April, May, and June 2016 will be approximately $46.88 per ton or an estimated $2.373 per million Btu. The average spot market prices for calendar year 2016, excluding transportation, are currently $10.68 per ton for PRB coal, $32.10 per ton for ILB coal and $40.59 per ton for Pitt8 coal.

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

Mr. Rackers testified that the new contract for Pitt8 coal has pricing substantially less than that delivered under the contract that expired at the end of 2015. Contract prices for PRB coal are also lower after being indexed to 2016 market prices in the fourth quarter of 2015. NIPSCO has coal and transportation agreements in effect for 2016 with firm pricing (exclusive of fuel surcharges) and that pricing has been included in the projected pricing for the forecast period. If relatively low prices of domestic crude oil and highway diesel fuel continue, fuel surcharges for rail transportation of NIPSCO's coal will remain low. Rail carrier performance is expected to be adequate to meet NIPSCO's coal transportation needs in the forecast period.

Mr. Rackers testified that improved rail cycle time performance for NIPSCO coal movements is expected to continue into 2016 due to sluggish demand for rail transportation of all products and commodities. This performance along with reduced demand for coal-fired generation means that NIPSCO currently has idle equipment in its rail car fleet. Leases for five of NIPSCO's twelve train fleet will expire by January 1, 2017, and NIPSCO will continue to assess its future need for rail cars as it determines whether to renew these leases.

Mr. Rackers testified that NIPSCO does not anticipate any issues in securing coal or transportation during the forecast period. The large nation-wide inventory of natural gas in storage plus improved access for the upper Midwest region to the natural gas production from the Marcellus-Utica Shale region suggests that natural gas supply in MISO-North will be greater than that in second quarter of 2015. Greater natural gas supply generally means lower natural gas and power prices, and more displacement of coal-fired generation.

In our April 27, 2011 Order in Cause No. 38706-FAC 90 (at 6), we ordered NIPSCO to provide detailed testimony and information regarding: (1) 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.

In our October 21, 2015 Order in Cause No. 387060-FAC-108 (at 10), we ordered NIPSCO to include in its quarterly FAC filings testimony regarding efforts to mitigate costs incurred for unused train sets. We find that NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding its efforts to mitigate costs incurred for unused train sets.

NIPSCO previously made the following forecasts of its fuel cost in October, November and December 2015 and incurred the following actual costs, resulting in a percent error calculated as follows:

	Estimated Fuel Cost ($/kWh)	Actual Fuel Cost ($/kWh)	Over (Under) Estimate (%)
October	0.031249	0.029067	7.51
November	0.032112	0.029507	8.83
December	0.030359	0.025701	18.12
Wgt Avg Error			11.28

Mr. Campbell said that the primary driver of the estimation errors was lower power prices in MISO and lower natural gas prices. He noted that as compared to those estimated prices, MISO experienced an 18.2% all-hour, average decrease in power prices. Natural gas prices decreased 23.4% decrease during the FAC period. For the month of December 2015, there was 28.8% decrease in power prices and 29.1% natural gas price decrease. These decreases were not anticipated by either MISO or the market.

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 FAC108. He testified 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 and the level of coal inventory at each station.

Based on the evidence presented, including NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for October, November, and December 2015, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the May, June, and July 2016 billing cycles is reasonable.

11. Return Earned. NIPSCO's exhibits demonstrate that for the 12 months ending December 31, 2015, Petitioner earned operating income including ECRM, FMCA, and TDSIC revenues of $150,717,570. This is less than NIPSCO's authorized amount of $233,757,681, which includes the $188,872,242 approved in Cause No. 43969 plus NIPSCO's actual ECRM, FMCA, and TDSIC operating income during the 12 months ended December 31, 2015 of $44,885,439. 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 MVP projects for the purpose of Petitioner's Exhibit No. 2-A. Based on the evidence presented, we find that during the 12 months ending December 31, 2015, 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 that: (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 December 31, 2015 was computed by including the requirements in conformity with Ind. Code § 8-1-2-42; (3) NIPSCO did not have jurisdictional net operating income for the twelve months ending December 31, 2015 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending December 31, 2015 has been accurately applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending December 31, 2015 were supported by NIPSCO's books, records and source documentation.

Mr. Eckert testified that (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 and actual monthly cost of fuel (mills/kWh) are comparable to the other large investor owned utilities in the State of Indiana; (6) 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 did not over earn during the 12-month period covered in this proceeding; (9) 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 (10) 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 ($0.002998) per kWh and a recoverable interruptible factor of $0.000557 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of May, June, and July 2016, in the amount of $0.027252 per kWh. This results in a fuel cost adjustment factor of ($0.003977) per kWh, after subtracting the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. Ms. Cherven testified that a residential customer using 1,000 kWh per month will experience a decrease of $2.33 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 January 28, 2016, 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 February 12, 2016 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 May, June, and July 2016, as set forth in Finding No. 13 above is hereby approved on an interim basis subject to refund as set out in Finding No. 14 above.

2. Prior to implementing the authorized rates, Petitioner shall file the applicable rate schedules under this Cause for approval by the Commission's Energy Division.

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 and testimony regarding efforts to mitigate costs incurred for unused train sets, 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, HUSTON, AND ZIEGNER CONCUR, WEBER NOT PARTICIPATING:

APPROVED:

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission