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 NOVEMBER AND DECEMBER 2013 AND JANUARY 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 100 APPROVED: OCT 23 2013

ORDER OF THE COMMISSION

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

On August 1, 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 November and December 2013 and January 2014. Petitioner also prefiled its direct testimony and exhibits. NIPSCO Industrial Group ("Industrial Group") filed its Petition to Intervene on August 13, 2013, which was granted by the Presiding Officers in a Docket Entry dated August 28, 2013. On September 4, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report in this Cause along with its direct testimony. NIPSCO prefiled its rebuttal testimony on September 10, 2013.

Pursuant to public notice given and published as required by law, the Commission held evidentiary hearing at 9:30 a.m. on September 17, 2013, in Hearing Room 224, 101 W. Washington Street, Indianapolis, Indiana. At the hearing, Petitioner, the OUCC, and the Industrial Group appeared and participated at the hearing. No members of the general public appeared or sought to participate.

Based on the applicable law and the evidence presented, the Commission finds:

1. **Commission Jurisdiction and Notice.** Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Petitioner's fuel cost charge. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

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

3. **Available Data on Actual Fuel Costs.** Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in Petitioner's last base rate case approved in the Commission's December 21, 2011 Order in Cause No. 43969 ("43969 Order") was $0.028729 per kWh. Petitioner's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of April, May and June 2013 averaged $0.031333 per kWh.

4. **Requested Fuel Cost Charge.** Petitioner seeks to change its fuel cost adjustment charge from the current charge of $0.000713 per kWh to a charge of $0.004040 per kWh, for bills rendered during the billing cycles of November and December 2013 and January 2014 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 $3,937,546 that was under-collected during April, May, and June 2013. Petitioner's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of October, November, and December 2013, is $43,526,861, and its estimated monthly average sales for that period are 1,394,790 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 June 30, 2013, were $43,835,619 above the levels approved in the 43969 Order, the last proceeding in which Petitioner's basic rates and charges for electric service were approved. Petitioner's Exhibit No. 2-A also shows that the total operating expenses excluding fuel for the twelve months ending June 30, 2013, were $112,839,783 above the levels approved in the 43969 Order. The Commission finds that Petitioner's actual increase in fuel costs for the twelve months ending June 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.** Petitioner's witness Strnatka testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that Petitioner's primary fuel for generation of electric energy is coal (85.48%) and the remainder is natural gas (14.52%) for the three months ended June 30, 2013.

A. **Fuel Procurement.** With respect to NIPSCO's coal procurement process, Mr. Strnatka testified that NIPSCO considers several factors in purchasing coal, including the delivered price, the coal quality that is best suited for a particular generating unit, the sulfur content, mercury content, and the economic and technical suitability of certain low cost fuels to be blended at NIPSCO's generating units to maintain the lowest, reasonably possible "as-burned" fuel cost. Mr. Strnatka testified that NIPSCO also considers the availability, reliability, and diversity of particular coal suppliers and coal transporters in its fuel procurement practices. He stated that NIPSCO has four long-term contracts in 2013. He stated that NIPSCO would meet any remaining coal requirements through spot purchases. Mr. Strnatka explained that NIPSCO competitively bids all coal purchased under a long-term agreement. He stated NIPSCO prepares a preliminary evaluation sheet incorporating all of the bidder information such as mine origin, Btu, sulfur, ash, available tons per year, and price on both a per ton and $ per million Btu basis. He testified that the final evaluation sheet, in addition to the cost of coal, includes the transportation cost for each of the proposals and any adjustments required to place all bids on an equivalent basis. Mr. Strnatka stated that NIPSCO negotiates price and commercial terms and conditions with the low evaluated bidder(s).

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

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

NIPSCO is satisfied that the charges are in accordance with the contract, and are justified by actual costs or changes in cost indices.

Mr. Strnatka testified that the delivered cost of coal for NIPSCO for the twelve months ending June 30, 2013, was $50.78 per ton or $2.527 per million Btu. The delivered coal cost for the reconciliation period (April, May, and June 2013) was $49.63 per ton or $2.506 per million Btu. Mr. Strnatka stated that NIPSCO purchased high sulfur spot coal and transportation for Bailly Generating Station for the period May through September 2013. He testified that the average spot market price of coal (excluding transportation costs) during the reconciliation period was $10.83 per ton for Powder River Basin ("PRB") coal, $39.36 per ton for Illinois Basin high sulfur coal, and $62.04 per ton for Pittsburgh #8 ("Pitt#8") coal.

With respect to the market factors affecting the supply, demand, and cost of coal during the reconciliation period, Mr. Strnatka testified that coal supply during the reconciliation period continued to be impacted by natural gas pricing and weak coal demand in both the domestic and international markets. Consequently, spot market pricing across all coal regions remained relatively soft. Mr. Strnatka testified that NIPSCO's delivered cost of coal during the reconciliation period decreased compared to the first quarter of 2013 from $53.50 per ton or $2.616 per million Btu to $49.63 per ton or $2.506 per million Btu. He stated this decrease was largely due to the completion of a planned dumper outage at R.M. Schahfer Generating Station enabling NIPSCO to increase its shipments of economical PRB coal during the reconciliation period. Mr. Strnatka testified that fuel surcharges remained relatively flat during the reconciliation period.

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

Mr. Campbell provided an update on NIPSCO's treatment of RECs. He stated that NIPSCO's recent vintage RECs have significantly more value in regions of the market than older vintage RECs. Mr. Campbell testified NIPSCO has begun offering these recently acquired RECs to the renewable energy market when it acquires a minimum of 50,000, which is the standard REC contract. He stated that the amount of time it takes to accumulate a block of 50,000 RECs varies based on the MW output at the wind resources and noted that historically this has been roughly every two months. He stated the goal behind this method is to spread the sales of RECs over multiple time periods throughout the year. He stated that because the RECs market can at times be very illiquid, there is no guarantee that a sale transaction will occur at the time the 50,000 RECs are offered. Mr. Campbell testified NIPSCO will pass the proceeds from the sale of RECs back to customers through the "Purchased Power other than MISO" line item. He stated NIPSCO continues to monitor and evaluate the marketability for all vintage RECs, potential future legislation that would consider NIPSCO's RECs as eligible to meet state renewable energy standards, and the Commission's Voluntary Clean Energy Portfolio Standard program rules and NIPSCO will make appropriate changes as necessary. 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 ("43849 Order") in this FAC proceeding.[1] He testified that in April, NIPSCO purchased 66 gas contracts and 0 power contracts, in May, NIPSCO purchased 69 gas contracts and 0 power contracts and in June, NIPSCO purchased 64 gas contracts and 0 power contracts. He stated the execution of these contracts is consistent with NIPSCO's most recently filed hedging plan. Mr. Campbell stated the impact of the hedges entered into for the Electric Hedging Program for this proceeding was a gain of $1,047,819 during the reconciliation period. The net total impact of the hedging program in this proceeding of $1,045,203 during the reconciliation period. He noted that broker fees represented 0.02% of the total value of the transactions that occurred during this reconciliation period. Mr. Campbell testified decisions were made based upon the conditions known at the time of the transactions and NIPSCO used the same broker it uses for its other transactions to limit transaction costs, and the transactions were all made in accordance with the Electric Hedging Program approved by the 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. 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"). Mr. Campbell testified that NIPSCO did not have any swap or virtual transactions during this FAC period. Mr. Campbell testified that NIPSCO is seeking to recover 9,032.35 MWhs of purchased power in May 2013 and 2,933.63 MWhs of purchased power in June 2013 that were in excess of the Purchased Power Daily Benchmark. Mr. Campbell testified that in accordance with the procedures outlined in the 43526 Order, the Purchases over the Purchased Power Benchmark were made to supply jurisdictional load that offset available NIPSCO resources that were not dispatched by MISO or were otherwise eligible under the procedures outlined in the 43526 Order and are therefore recoverable. OUCC witness 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

---

[1] The Commission approved NIPSCO's updated energy supply plan (2012 Hedging Plan") in its September 5, 2012 Order in Cause No. 44205 ("44205 Order").

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 Fuel Cost" included in the actual cost of fuel for the reconciliation period was $2,909,983.

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. Mr. Campbell stated that during the reconciliation period, NIPSCO did initiate interruptions 7 separate days for a total of 83 hours under Option C and 31 hours under Option D. The evidence shows that NIPSCO paid a total of $9,374,424 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 $2,343,606, through the FAC for the billing months of November and December 2013 and January 2014.

10. Estimation of Fuel Cost. Petitioner estimated that its prospective total average fuel costs for the months of October, November, and December 2013 will be $43,526,861 on a monthly basis.

Mr. Strnatka testified that NIPSCO anticipates that its delivered coal cost during the forecast period of October, November and December 2013 will be approximately $51.49 per ton or an estimated $2.58 per million Btu. Mr. Strnatka testified the average spot market prices for calendar year 2014 (which do not include cost of transportation) are currently $12.29 per ton for PRB coal, $40.32 per ton for Illinois Basin coal and $63.20 per ton for Pitt#8 coal.

Mr. Strnatka explained NIPSCO incorporates all current coal contract prices, estimates of any coal contract price adjustments that might be warranted, transportation contract prices, an assessment of the pricing impact of fuel surcharges on the delivered cost based on current price of crude oil, and an evaluation of the spot market price of coal in developing the estimate for the forecast period. These inputs are provided to NIPSCO's Generation Dispatch & Marketing Group to be used in PROMOD.[2]

With respect to the factors NIPSCO believes to have the greatest impact on the supply, demand, and cost of coal during the forecast period, Mr. Strnatka cited the price of natural gas and weather. He testified that currently natural gas pricing is below $4/mmBtu but coal fired generating units are continuing to be dispatched. He stated that utilities are bringing coal stockpiles under control, and if the warm weather continues through the remainder of the summer, utilities could be soliciting for spot market coal. He indicated that this may bolster coal prices, but cheap natural gas could effectively impact the competitiveness of coal fired generation. He stated

---

[2] PROMOD is NIPSCO's production cost modeling system.

that domestic coal producers are decreasing their capital spend this year and have cut production to balance supply and demand in an attempt to raise sagging coal prices. In addition, the evolving federal regulations and the effect on utility coal-fired generating stations will continue to be evaluated. Mr. Strnatka stated that NIPSCO had two transportation agreements that expired at the end of 2012. He stated that in FAC 98 NIPSCO indicated that one of the transportation agreements would not be needed for Bailly Generating Station since 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 September 2013. Transportation was also purchased through the end of 2013 in anticipation of another spot coal solicitation for the last quarter of 2013. Also, NIPSCO has agreed to term, tons and rates with the second 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, then May 31, and finally to September 30, 2013, in an effort to provide both parties sufficient time to finalize the negotiation, or to move in another direction. Currently, both parties are continuing to discuss potential resolutions to this unresolved item. Also, the Egyptian crisis is having a significant impact on the price of WTI crude. Prices for crude have been running in the $103 to $106 per barrel range. He stated that if these prices persist, NIPSC would pay higher fuel surcharges to the railroads and its delivered coal cost could be minimally impacted in the third quarter, and also during the forecast period.

Mr. Strnatka testified NIPSCO does not anticipate any issues in securing coal or transportation during the forecast period. However, due to much higher coal consumption experienced starting in March and continuing through July, NIPSCO will need to supplement its contractual coal requirements with potential spot coal purchases to maintain system target inventory levels. He stated that NIPSCO will continue to meet Bailly Generating Station's coal requirements with spot coal purchases for the remainder of this year, and R.M. Schahfer Generating Station will be served from its one ILB contract with potentially some additional high sulfur spot coal being purchased later this year.

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.

Petitioner previously made the following forecasts of its fuel cost in April, May, and June 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
April	$0.030145/kWh	$0.030341/kWh	-0.65%
May	$0.030216/kWh	$0.031624/kWh	-4.45%
June	$0.029669/kWh	$0.031972/kWh	-7.20%
Weighted Average Estimating Error			**-4.25%**

OUCC Witness Gregory T. Guerrettaz testified that nothing had come to his attention that would indicate that the projections used by NIPSCO for fuel costs and sales of power were unreasonable, considering a comparison of prior quarter actual and forecast fuel costs and sales figures. He also testified that during the onsite audit, he prepared a detailed analysis of the forecast workpapers, which was updated from FAC 99. He stated considerable changes are 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 appear to impact the PROMOD model in January 2014 in a material way and will be applicable to FAC 101. With respect to the forecast and the reduction in coal prices, he stated the OUCC reviewed NIPSCO's High Sulfur Price solicitation and understands that this will also create positive impacts. He indicated the 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 April, May and June 2013, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the November and December 2013 and January 2014 billing cycles is reasonable.

11. Return Earned. Petitioner's exhibits demonstrate that for the twelve months ending June 30, 2013, Petitioner earned a return of $171,042,844. This is less than Petitioner's authorized amount of $202,441,351 approved in Cause No. 43969 plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the twelve months ended June 30, 2013. Mr. Plantz 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, the Commission finds NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted

12. Fuel Cost Adjustment Factor. As we have set forth herein, Petitioner has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. Petitioner's evidence presented a variance factor of $0.000941 per kWh and a recoverable interruptible factor of $0.000560 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of November and December 2013 and January 2014, in the amount of $0.031207 per kWh. This results in a fuel cost adjustment factor of $0.004040 per kWh, after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. OUCC witness Mr. Eckert calculated that a residential customer using 1,000 kWh per month will experience an overall increase of $3.33 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 June 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 June 30, 2013 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending June 30, 2013 has been properly applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending June 30, 2013 were supported by NIPSCO's books, records and source documents. Mr. Guerrettaz stated that because of the issues developing with NIPSCO and various other utilities relating to wind purchased power, an adjustment to the factor was made.

Mr. Michael Eckert testified 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 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; and (7) the OUCC reviewed NIPSCO's hedges and believes the hedging costs were reasonable.

14. **Wind Purchased Power.** Mr. Eckert also testified concerning NIPSCO's wind purchased power. He noted that because NIPSCO and Buffalo Ridge and Barton ("Wind Farms") are disputing the curtailed energy wind invoice, 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. In rebuttal, NIPSCO witness Katherine A. Cherven stated NIPSCO does not oppose this recommendation so long as it is clear that in the event the commercial dispute between NIPSCO and the Wind Farms is resolved and NIPSCO pays disputed charges, NIPSCO will be allowed to recover those charges. Ms. Cherven sponsored revised schedules to remove the unpaid curtailed energy charges assessed by the Wind Farms. She testified the revised FAC factor of $0.004040 is a decrease of $0.000230 from what was initially requested.

We find the recommendation that 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 resolved and NIPSCO pays disputed charges is consistent with our recent Order in Cause No. 38703 FAC 100 as well as our Order in Cause No. 43393 in which the Commission approved NIPSCO's request to recover the purchased power costs incurred under the Barton and Buffalo Ridge I PPAs over their respective full twenty and fifteen-year terms. We therefore find that the OUCC's recommendation should be adopted and that NIPSCO's revised schedules should be used for purposes of determining the FAC factor in this case. The numbers and discussion throughout this order incorporate this finding.

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

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

1. Petitioner's requested fuel cost adjustment to be applicable to bills rendered during the billing cycles of November and December 2013 and January 2014, as set forth in Finding No. 12 above is hereby approved on an interim basis subject to refund as set out in Finding No. 15 above.

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

3. Petitioner shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC, as discussed in 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. Petitioner shall also include in its quarterly FAC filings the information required by the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, as discussed in Paragraph 10 above.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: OCT 23 2013

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission