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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 AUGUST, SEPTEMBER AND OCTOBER 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 103** **APPROVED:** JUL 30 2014

ORDER OF THE COMMISSION

Presiding Officer:
Jeffery A. Earl, Administrative Law Judge

On April 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 August, September and October 2014. Also on April 30, 2014, 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;
- Ronald G. Plantz, Controller at NiSource Corporate Services Company;
- Andrew S. Campbell, Manager of Planning and Regulatory Support at NIPSCO; and
- Shirley Lowry, Manager, Fuel Supply at NIPSCO.

On May 1, 2014, NIPSCO prefiled the direct testimony and exhibits of David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division at NIPSCO.

On May 5, 2014, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene, which the Presiding Officer granted on May 16, 2014.

On June 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. Guerrettaz, CPA, President of Financial Solutions Group, Inc.

On June 30, 2014, the Industrial Group filed the direct testimony and exhibits of James R. Dauphinais, Managing Principal of Brubaker & Associates, Inc. On July 11, 2014, The Industrial Group filed Revised Direct Testimony and Exhibits from Mr. Dauphinais.

On July 7, 2014, NIPSCO filed the rebuttal testimony and exhibits of Timothy R Caister, Director of Regulatory Policy at NIPSCO, and Mr. Campbell.

The Commission held an evidentiary hearing at 10:30 a.m. on July 15, 2014, 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 of record, 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 January through March 2014 averaged $0.036151 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment charge from the current charge of $0.003779 per kWh to a charge of $0.009699 per kWh, for bills rendered during the billing cycles of August through October 2014.

The requested fuel cost adjustment includes a variance of $22,408,544 that was under-collected during January, February, and March 2014. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of July, August, and September 2014 is $51,251,798, and its estimated monthly average sales for that period are 1,554,325 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 March 31, 2014, were $119,370,391 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 March 31, 2014, were $108,211,076 above the levels approved in the 43969 Order. The Commission finds that NIPSCO's actual increase in fuel costs for the 12 months ending March 31, 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. Lowry testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. She testified that NIPSCO's primary fuel for generation of electric energy is coal (75.22%) and the remainder is natural gas (24.78%) for the three months ended March 31, 2014.

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

Ms. Lowry 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 two long-term contracts have an annual market price reopener that will determine the contract coal price for the succeeding year of the contract.

Ms. Lowry testified that the delivered cost of coal for NIPSCO for the 12 months ending March 31, 2014, was \$50.13 per ton or \$2.480 per million Btu. The delivered coal cost for the reconciliation period (January, February, and March 2014) was \$51.17 per ton or \$2.517 per million Btu. NIPSCO did not make any spot coal purchases for the period of January through March 2014. The average spot market price of coal (excluding transportation costs) during the reconciliation period was \$11.85 per ton for Powder River Basin ("PRB") coal, \$40.66 per ton for Illinois Basin ("ILB") coal, and \$60.55 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. Lowry testified that coal supply during the reconciliation period continued to be impacted by colder weather and higher natural gas pricing. She stated that extreme winter weather conditions led to railroad congestion and shipment delays, which resulted in a drawdown on coal inventory stockpiles and that colder than normal weather during the reconciliation period produced higher natural gas prices and increased coal consumption. NIPSCO's delivered cost of coal during the reconciliation period increased compared to the fourth quarter of 2013 from \$50.84 per ton or \$2.465 per million Btu to \$51.17 per ton or \$2.517 per million Btu. Increased costs were due to higher rail transportation rates and a contributing factor was a fuel inventory adjustment that was made in February 2014 based upon an error found with the heat rate meter for the Bailly Generating Station and Unit 7 #2 coal feeder.

Mr. Campbell stated that NIPSCO does not purchase natural gas under multiple-year contracts. Instead, physical natural gas supplies are purchased on a spot basis when NIPSCO's gas-fired generation units are 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 S1. 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 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 100,000 RECs was sold with net proceeds of $105,756 and no RECs were transferred to NIPSCO's Green Power Rider. 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.

Mr. Campbell provided an update on the treatment of RECs received from feed-in-tariff purchases. NIPSCO is currently determining the most appropriate way to account for, reconcile, and market the RECs received from feed-in purchases. Any sale of these RECs will be passed back through the FAC.

NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind purchases being recovered through the authority granted in Cause No. 43393 and any other future renewable purchases.

C. <u>Electric Hedging Program</u>. Mr. Campbell testified that NIPSCO incorporated the Electric Hedging Program that was approved by the Commission's July 13, 2011 in Cause No. 43849 ("43849 Order") in this FAC proceeding. In January, NIPSCO purchased 36 gas contracts and 44 power contracts, in February, NIPSCO purchased 33 gas contracts and 60 power contracts and in March, NIPSCO purchased 26 gas contracts and zero power contracts. The execution of these contracts is consistent with NIPSCO's currently-effective electric hedging plan approved in Cause No. 44205 S1. The impact of the hedges entered into for the Electric Hedging Program for this proceeding was a gain of $1,070,469 during the reconciliation period. The net total impact of the hedging program in this proceeding was $1,068,426 during the reconciliation period. Broker fees represented 2% 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, 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 S1 Order. NIPSCO shall continue to include in its filings testimony and evidence of its electric hedging costs, and any gains/losses resulting from its hedging transactions for which it is seeking recovery through the FAC.

D. <u>Purchased Power Over The Benchmark</u>. Mr. Campbell 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 1,245.85 MWh of purchased power in January 2014, 425.16 MWh of purchased power in February 2014 and 17,443.43 MWh of purchased power in March 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. Mr. Eckert stated the fuel costs and purchased power over the benchmark were significantly higher than normal driven primarily by the extreme winter weather, as well as higher natural gas prices, higher power prices and increased demand. He testified that while the OUCC was very concerned with the high amounts of purchased power over the benchmark, after discussions with NIPSCO, participation in a presentation with NIPSCO on the issue and his review of weather data and information, the OUCC is not contesting the purchased power over the benchmark amounts.

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 January, February and March 2014 was $15,161,403. Mr. Campbell testified that the estimate for "MISO Components of Cost of Fuel" in this proceeding is based on the average of actual "MISO Components of Cost of Fuel" incurred for the 12-month period ending March 31, 2014. He stated NIPSCO has included an estimate of "MISO Components of Cost of Fuel" in the amount of $2,683,725 per month for the billing months in this FAC.

9. Industrial Group's Proposals. Mr. Dauphinais filed testimony in response to the large cost variance incurred during the reconciliation period and recommended that NIPSCO should (1) provide a detailed explanation in its rebuttal testimony with respect to why its Delta LMP variance during the FAC103 reconciliation period was so large and its Financial Transmission Rights ("FTR") hedging was ineffective at containing the large variance; (2) develop and provide, in its FAC audit materials, a detailed workpaper that clearly shows how NIPSCO calculates its actual Delta LMP costs for its reconciliation period and that identifies the source and cause of any large variances in this amount from its forecasted value; (3) develop a detailed plan to hedge its exposure to transmission congestion costs through the use of FTRs or other tools; (4) review the ability to potentially modify its fuel cost hedging for Sugar Creek in order to address the natural gas price exposure between the start of the month and the time of actual energy production by Sugar Creek; and (5) modify its forecast of the MISO Components of Cost of Fuel to be an average of the three most recent historical periods for the same three month period as the forecast period, with any severe market anomalies removed and any known and measurable historical trends reflected.

Regarding the forecast of the MISO Components of Cost of Fuel, Mr. Dauphinais testified that the issue with using NIPSCO's proposed 12-month rolling average is that the period of January through March 2014 had a severe market anomaly, which would inappropriately and unnecessarily elevate the estimate for MISO Components of Cost of Fuel for the forecast period and in turn the FAC 103 fuel factor. He stated this is especially problematic in light of the very large 5.136 mills per kWh forecast variance that would be recovered from customers in the proposed fuel factor of 9.699 mills per kWh. Exhibit JRD-3 shows the actual three-month total for MISO Components of Cost of Fuel for January through March of 2014 of $15,161,403 was anomalously high as it exceeded the five-year-average annual MISO Components of Cost of Fuel amount of $14,975,731 for 2009 through 2013. Mr. Dauphinais argues that due to its severely anomalous nature, the January through March 2014 data should not be included in any average of historical costs used to set NIPSCO's forecast estimate of the MISO Components of Cost of Fuel either now or anytime in the future. Mr. Dauphinais recommends that NIPSCO's monthly estimated MISO Components of Cost of Fuel for July through September of 2014 be set equal to the monthly average of NIPSCO's actual MISO Components of Cost of Fuel during the period of July through September in 2011, 2012, and 2013. He explained this eliminates the severely anomalous January through March 2014 period from the estimate and better reflects the historical level of these costs that NIPSCO has seen in the July through September portion of the year.

In response to Mr. Dauphinais's recommendation (1), Mr. Campbell testified that the Delta LMP component was the largest piece of the variance ("$7,750,138" of the "12,365,562" variance for the "MISO Cost Component of Fuel") in this FAC period. The main contributor to this variance was the extreme weather that occurred in the first quarter of 2014. This caused high market prices within the MISO footprint and caused operational issues at NIPSCO's generating facilities that were noted in testimony and in discussions with the OUCC and Industrial Group. He also testified that while Mr. Dauphinais's explanation of Delta LMP is at a high level correct, the magnitude of the charges or credits related to Delta LMP can also be attributed to generating unit and/or customer load performance in the MISO real time market relative to cleared volumes in MISO day ahead market. Mr. Campbell stated this "delta" is the difference between the day ahead and real time markets. In the case of a generator, for example, if it clears the day ahead market and then due to weather or some other operational issue cannot produce at the cleared volume in the real time, NIPSCO would be required to purchase back MWh that cleared day ahead and were not generated real time at the real time LMP. He testified that similar scenarios can exist with the cleared load versus real time actual. To the extent that these load and generator real time true-ups become part of the Delta LMP calculation, they can represent significant charges if prices are high as they were this past winter. Mr. Campbell testified that this true up of NIPSCO's generating nodes and load zone was a contributor to the variance experienced during the reconciliation period.

In response to Mr. Dauphinais's recommendation (2) that NIPSCO should develop and provide a more detailed workpaper regarding the calculation of the Delta LMP as part of its audit materials, Mr. Campbell testified that NIPSCO currently provides a monthly calculation of the Delta LMP as audit support in its FAC filings. He stated NIPSCO will evaluate its analytical process to determine if it can develop a workpaper that can be provided as audit support for future FAC filings that will provide the desired information without being unduly burdensome.

NIPSCO will provide updates of its progress on this detailed workpaper in future FAC filings until it is developed.

In response to Mr. Dauphinais's recommendation (3) that NIPSCO, as an extension of its hedging plan discussions with the OUCC and the Industrial Group, develop a detailed plan to hedge its exposure to transmission congestion costs through the use of FTRs or other tools, Mr. Campbell testified that NIPSCO has what it believes to be an effective process to mitigate exposure to congestion costs through the use of FTRs and ARRs that is regularly discussed with the OUCC during the OUCC's onsite audits. He stated NIPSCO would be happy to have these discussions with other stakeholders such as the Industrial Group. Due to the frequency of FTR and ARR activity, NIPSCO's FTR and ARR hedging strategy would not fit into an extension of the existing electric hedging framework most recently addressed in Cause No. 44205 S2, in which NIPSCO submits a hedging plan to the Commission for review and approval on an annual basis. NIPSCO believes the better approach to this issue is continued dialog with interested stakeholders similar to the discussions that occur during the OUCC's onsite audits.

In response to Mr. Dauphinais's recommendation (4) that NIPSCO, as part of its hedging plan discussions with OUCC and the Industrial Group, review the ability to potentially modify its fuel cost hedging for Sugar Creek in order to address the natural gas price exposure between the start of the month and the time of actual energy production by Sugar Creek, Mr. Campbell testified that NIPSCO continually reviews the electric hedging program (most recently approved in Cause No. 44205 S2) and meets annually with its stakeholders to discuss it. He stated that NIPSCO will work with its stakeholders to determine whether alternatives exist to increase the effectiveness of the Sugar Creek hedges.

Finally, in response to Mr. Dauphinais's recommendation (5) that NIPSCO should modify its forecast of the MISO Components of Cost of Fuel to be an average of the three most recent historical periods for the same three-month period as the forecast period, Mr. Campbell testified that for the purpose of calculating the FAC 103 factor, the Commission should approve the current method of forecasting the MISO Components of Cost of Fuel which uses a 12-month rolling average. Mr. Campbell testified that NIPSCO believes using the 12-month rolling average has a smoothing effect over multiple FAC periods. He stated that while Mr. Dauphinais suggests using a three-year average of the same filing period, NIPSCO believes this could result in higher volatility between adjacent FAC filings. Further, NIPSCO does not agree with Mr. Dauphinais's recalculation of the MISO Cost Component of Fuel shown in Exhibit JRD-4 and has provided a corrected calculation in Petitioner's Exhibit No. 7-C.[1] However, NIPSCO is open to evaluating alternative forecasting methods with its stakeholders, including the one proposed by Mr. Dauphinais, and will provide an update in its next FAC proceeding.

The parties' proposed orders indicate that they have reached agreement as to the next steps to address recommendations (1)-(4) from Mr. Dauphinais, and we find that NIPSCO should provide an update as to the status of these items in its testimony in future FAC proceedings. With respect to recommendation (5) regarding the method of estimating the MISO Components of Cost of Fuel, we find there is not sufficient evidence at this time to require a change from

[1] Mr. Dauphinais filed revised testimony on July 11, 2014 correcting his calculation, which is consistent with NIPSCO's.

NIPSCO's proposed methodology. Although there may be more than one reasonable method for estimating the MISO Components of Cost of Fuel, including the method proposed by Mr. Dauphinais, the evidence does not suggest that the current 12-month rolling average method is unreasonable.[2] We therefore conclude that the current method of forecasting the MISO Components of Cost of Fuel which uses a 12-month rolling average should be used for the purpose of calculating NIPSCO's FAC 103. NIPSCO has indicated that it will review and consider alternative methods of calculating this component, and we find that NIPSCO should provide an update as to the status of this effort in future FAC filings.

10. 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 on 10 separate days for a total of 149 hours under Option C and 6 hours under Option D. The evidence shows that NIPSCO paid a total of $9,356,568 in interruptible credits through Rider 675 during the reconciliation period and, pursuant to the 43969 Order, NIPSCO is authorized to recover 25% of that total, or $2,339,142, through the FAC for the billing months of August, September, and October 2014.

11. Estimation of Fuel Cost. NIPSCO estimated that its prospective total average fuel costs for the months of August, September, and October 2014 will be $51,251,798 per month.

Ms. Lowry testified that NIPSCO anticipates that its delivered coal cost during the forecast period of July, August, and September 2014 will be approximately $51.88 per ton or an estimated $2.541 per million Btu. The average spot market prices for calendar year 2015, excluding transportation, are currently $12.70 per ton for PRB coal, $40.96 per ton for ILB coal and $61.71 per ton for Pitt8 coal.

Ms. Lowry 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.

Ms. Lowry stated NIPSCO has coal supply agreements for 2014 with firm pricing, and recently issued solicitations for additional ILB and PRB spot coal; however if NIPSCO experiences a hot summer, which leads to increased coal burn, additional spot coal purchases may be needed to supplement term coal purchases. If spot coal purchases are required, the price of natural gas and rail transportation may have an impact on the supply, demand, and cost of coal during the forecast period. NIPSCO anticipates that if spot purchases are required, spot coal prices will be slightly higher than its existing term coal prices due to reduced inventories and higher demand for coal by other utilities. NIPSCO has transportation agreements in effect for 2014 with firm pricing (exclusive of fuel surcharges) so there will be no transportation price

[2] Although we do not approve a change in methodology in this Cause, we believe the proposed methodology presented in the Industrial Group's proposed order has some merit and should be evaluated by NIPSCO.

increases in the forecast period. If the prices of West Texas Intermediate crude remain relatively stable, NIPSCO's delivered coal cost will be minimally influenced by fuel surcharges paid to the railroads.

Ms. Lowry testified NIPSCO has coal and transportation contracts in place for ILB coal for Bailly and R. M. Schahfer Generating Station, and for PRB and Pitt8 coal for Michigan city and R. M. Schahfer Generating Stations for 2014. However, due to higher than anticipated coal consumption experienced in early 2014, and continued anticipated higher consumption through the forecast period, NIPSCO recently issued solicitations for ILB spot coal for the period of April through September 2014, and for PRB spot coal for the period of June through September 2014. Additionally, due to extreme winter weather conditions that led to railroad congestion, shipment delays and dumping delays in early 2014, NIPSCO's system inventory is currently below target level, and NIPSCO is working with coal and transportation suppliers to increase shipments in the upcoming months to resume target inventory levels. Ms. Lowry stated this issue is not specific to NIPSCO, but rather an industry issue. Many utilities are reporting low stockpiles of inventory and attempts to conserve coal to use for generation during a peak period.

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.

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 FAC102. He stated that related to the forecast and the reduction in coal prices, the OUCC continues to review any coal or transportation price solicitations and that NIPSCO, like several other utilities, has been able to reduce prices as a result of market changes.

A. <u>OUCC's Proposal to Spread Variance Over Two FAC Periods</u>. The requested fuel cost adjustment includes a variance of $22,408,544 that was under-collected during January, February, and March 2014. NIPSCO previously made the following forecasts of its fuel cost in January, February, and March 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
January	$0.031011/kWh	$0.034595/kWh	-10.36%
February	$0.031323/kWh	$0.036066/kWh	-13.15%
March	$0.030726/kWh	$0.037834/kWh	-18.79%
Weighted Average Estimating Error			**-14.21%**

Mr. Campbell testified the difference was primarily driven by higher power prices in MISO as a result of higher natural gas prices and extreme winter weather conditions experienced during this FAC period. At the time the forecast was prepared NIPSCO did not, nor did the market, anticipate a 72.9% all hours average increase in power prices in MISO, a 38.7% average increase in the delivered natural gas price at NIPSCO's Sugar Creek Plant and a 130% average increase in the NIPSCO city gate delivered gas price.

Mr. Campbell testified the total actual fuel cost for January 2014 was $53,651,408 while the forecasted fuel cost was $44,065,338. The difference was driven mostly by an increase in actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $6,194,011, an increase in actual (as compared to the forecast) MISO Components of Cost of Fuel of $3,939,942 and a decrease in the actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $1,161,898. This was offset by a decrease in actual (as compared to the forecast) purchase power volume of $732,898 and an increase in the actual credit (as compared to the forecast) associated with OSS Profits Generated by Wind Farms of $650,688.

Mr. Campbell testified that the total actual fuel cost for February 2014 was $53,113,477 while the forecasted fuel cost was $41,356,059. The difference was driven mostly by an increase in actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $17,154,697, and an increase in actual (as compared to the forecast) MISO Components of Cost of Fuel of $4,432,570. This was offset by a decrease in actual (as compared to the forecast) purchase power volume of $5,833,583 and an increase in the actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $4,013,838.

Mr. Campbell testified that the total actual fuel cost for March 2014 was $57,076,782 while the forecasted fuel cost was $42,782,426. The difference was driven mostly by an increase in actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $12,737,370, and an increase in actual (as compared to the forecast) MISO Components of Cost of Fuel of $3,993,050. This was offset by an increase in the actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $2,842,142.

Mr. Guerrettaz sponsored Schedule A-1. He testified Schedule A-1 is basically the same as Schedule A, except the variance factor has been reduced by 50%, resulting in a fuel cost adjustment charge of 7.26 mills per kWh. He stated the OUCC is proposing that the variance factor be spread over two quarters because of the high cost impact related to the very severe weather.

NIPSCO disagreed with Mr. Guerrettaz's proposal. Mr. Caister responded that the result would be contrary to past Commission-approved treatment of both over- and under-recoveries, would be inconsistent with the treatment of previous under-recoveries of a similar magnitude, and would simply delay the recovery of reasonable fuel costs incurred to provide service to customers during a winter period that already happened months ago. Mr. Caister argued that it would be inappropriate to spread certain variances over longer periods than others without any objective standard. Mr. Caister explained that some customer classes may benefit and some may not due to the customer usage in the quarterly periods of the two FAC periods over which the OUCC proposes to spread the variance. He stated that based on two years of historical FAC consumption information, the billing periods of August through October (FAC 103) compared to November through January (FAC 104) show a shift in the share of total consumption from the residential and commercial customers to the industrial customers of about 4%. He also explained that another concern is pushing additional costs into the next winter period as approximately 82% of electric customers are also gas customers.

Mr. Caister testified Mr. Guerrettaz's proposal would also move the variance to another filing in which there is no certainty that it would not also aggravate the variance in that filing. He explained that customers billed in the reconciliation period in this filing – the winter period – already received the timing benefit of not having all of the fuel cost reflected in that billing factor; it is not appropriate to further magnify this by pushing the incurred cost over a longer period of time. He stated that although the variance is not yet finalized for that next FAC filing, it could mitigate any over-recovery as well as add to any under-recovery. Mr. Caister testified this is not appropriate in one specific situation simply because the amount is driven by an unanticipated set of extreme weather events. He stated it leads to an arbitrary application of the FAC procedures, would affect customers disproportionately inside of FAC recovery periods (i.e., it will lead to winners and losers) and lead to subjective, unpredictable standards for future filings. Mr. Caister stated the current objective, predictable and consistently applied process to reflect the variance – regardless of an over- or under-recovery – in the next FAC quarter is reasonable and should be approved.

Based on the evidence presented, we decline to adopt the OUCC's recommendation to require NIPSCO to spread the variance over two FAC periods. The evidence shows that there is no dispute about the reasonableness of the fuel costs incurred during January, February and March 2014. While we have previously accepted utility-sponsored variance mitigation efforts, requiring such mitigation exposes the FAC 104 factor to costs outside its normal reconciliation period, which could potentially add to any under-recovery in that period. Further, we agree with NIPSCO that shifting half of the variance into the FAC 104 period would lead to a reallocation of that variance among the different customer classes because forecasted usage in the FAC 104 period will differ from the FAC 103 period. We therefore find that the total amount that was under-collected during January, February, and March 2014 of $22,408,544 should be included in the FAC 103 fuel cost adjustment factor.

Based on the evidence presented, including NIPSCO's estimate of its prospective fuel cost and its actual fuel costs for January, February and March 2014, we find that NIPSCO's estimate of its prospective average fuel cost to be recovered during the August, September, and October 2014 billing cycles is reasonable. As discussed above, we decline to adopt Mr. Dauphinais's recommendation that NIPSCO should modify its forecast of the MISO

Components of Cost of Fuel to be an average of the three most recent historical periods for the same three month period as the forecast period, but we direct NIPSCO analyze alternative methods of calculating this component and provide an update as to the status of this effort in future FAC filings.

12. Return Earned. NIPSCO's exhibits demonstrate that for the 12 months ending March 31, 2014, Petitioner earned operating income including ECRM revenues of $195,464,600. This is less than NIPSCO's authorized amount of $218,313,198 approved in Cause No. 43969 plus NIPSCO's actual Environmental Cost Recovery Mechanism operating income during the 12 months ended March 31, 2014. 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 presented, we find that during the 12 months ending March 31, 2014, NIPSCO did not earn a return more than that authorized in its last base rate case, as appropriately adjusted.

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 March 31, 2014 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 March 31, 2014 greater than granted in its last general rate case; (4) the fuel cost adjustment for the quarter ending March 31, 2014 has been accurately applied; and (5) the figures used in the application for change in fuel cost adjustment for the quarter ending March 31, 2014 were supported by NIPSCO's books, records and source documents. As discussed above, Mr. Guerrettaz recommended the variance factor should be spread over two quarters because of high cost impact related to the very severe weather

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 the recent extreme weather 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.

14. 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 $0.004806 per kWh and a recoverable interruptible factor of $0.000502 per kWh to be added to the estimated cost of fuel for bills rendered during the billing cycles of August, September, and October 2014, in the amount of $0.032974 per kWh. As discussed above, we find the total that the total amount that was under-collected during January, February, and March 2014 of $22,408,544 should be included in the FAC 103 fuel cost adjustment factor. We also find that the current method of forecasting the MISO Components of Cost of Fuel which uses a 12-month rolling average should be used for the purpose of calculating NIPSCO's FAC 103 factor. This results in a fuel cost adjustment factor of $0.009699 per kWh, after subtracting from that cost the cost of fuel in NIPSCO's base rates and adjusting for applicable taxes. The evidence indicates that a residential customer using 1,000 kWh per month will experience an overall increase of $5.89 on his or her electric bill from the currently approved factor.

15. 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.

16. Confidential Information. On April 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. During the July 14, 2014 evidentiary hearing, 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 August, September and October 2014, as set forth in Finding No. 15 above is hereby approved on an interim basis subject to refund as set out in Finding No. 16 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 include an update on the status of the items addressed in Paragraph 8 in its future FAC filings. 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, WEBER, AND ZIEGNER CONCUR:

APPROVED: JUL 30 2014

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

Shala M. Coe

Shala M. Coe
Acting Secretary to the Commission