ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF (1) A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING CYCLES OF FEBRUARY, MARCH, AND APRIL 2024, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NOS. 45159 AND 45772, AND (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLSALE PURCHASE AND SALE AGREEMENTS FOR WIND AND SOLAR ENERGY APPROVED IN CAUSE NOS. 43393, 45194, 45195, 45310, 45462, AND 45524.	)	**CAUSE NO. 38706 FAC 141** **APPROVED: JAN 31 2024**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Kristin E. Kresge, Administrative Law Judge

On November 13, 2023, Northern Indiana Public Service Company LLC ("NIPSCO") filed a Verified Petition in this Cause seeking approval from the Indiana Utility Regulatory Commission ("Commission") of (1) a fuel cost adjustment to be applicable during February through April 2024 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, pursuant to Ind. Code § 8-1-2-42 and Cause Nos. 45159 and 45772, and (2) ratemaking treatment for the costs incurred under wholesale purchase and sale agreements for wind and solar energy approved in Cause Nos. 43393, 45194, 45195, 45310, 45462, and 45524. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company employee Kelleen M. Krupa, Lead Regulatory Analyst, and the testimony and exhibits of the following NIPSCO employees:

- Rosalva Robles, Manager of Planning, Regulatory Support;
- John Wagner, Manager, Fuel Supply; and
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division.

On November 13, 2023, NIPSCO also filed a motion requesting confidential treatment for certain information ("Confidential Information"). In a docket entry issued December 20, 2023, the requested confidential treatment was granted on a preliminary basis.

On November 14, 2023, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on December 20, 2023.[1]

On December 5, 2023, NIPSCO filed a Submission of Correction to Direct Testimony, in which it corrects Mr. Wagner's direct testimony. On December 13, 2023, NIPSCO filed a Submission of Correction to Direct Testimony, in which it corrects Ms. Robles' direct testimony.

On December 18, 2023, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony and exhibits of the following:

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

On December 21, 2023, the OUCC filed a revised redacted testimony of Mr. Eckert.

The Commission noticed this matter for an evidentiary hearing at 11:00 a.m. on December 27, 2023 in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. By docket entry dated December 7, 2023, the evidentiary hearing was continued to 11:00 a.m. on January 10, 2024 in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. By docket entry dated December 28, 2023, the evidentiary hearing was continued to 9:30 a.m. on January 16, 2024 in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in this evidentiary hearing, and the testimony and exhibits of NIPSCO and the OUCC were admitted without objection.

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

1. **Commission Jurisdiction and Notice.** Notice of the evidentiary hearing in this Cause was 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 is a limited liability company organized under Indiana law with its principal office in Merrillville, Indiana. NIPSCO renders electric public utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of such service.

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 most recent base rate case approved in the Commission's August 2, 2023 Order in Cause No. 45772 ("45772 Order") was $0.033674 per kilowatt hour ("kWh"). NIPSCO's cost of fuel to generate electricity and the

[1] The members of the Industrial Group in this proceeding are Cleveland-Cliffs Steel LLC, Jupiter Aluminum Corporation, Linde, Inc., United States Steel Corporation and USG Corporation.

cost of fuel included in the cost of purchased electricity for the months of July, August, September 2023 averaged $0.030331 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment from the current fuel cost factor charge of $(0.006676) per kWh for bills rendered during the November 2023, December 2023, and January 2024 billing cycles to a fuel cost charge of $(0.007122) per kWh for bills rendered during the February, March, and April 2024 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes a variance of $13,621,781 that was over-collected during July 2023 through September 2023 ("reconciliation period"). NIPSCO's estimated monthly cost of fuel to be recovered in this proceeding for February 2024 through April 2024 ("forecast period") is $27,603,706, and its estimated monthly average sales for that period are $868,592 MWhs.[2]

5. Statutory Requirements. Ind. Code § 8-1-2-42(d) states that the Commission shall grant a fuel cost adjustment charge if it finds:

> (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 section 42.3 [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; and
>
> (4) the utility's estimate[s] of its prospective average fuel costs for each such three calendar months are reasonable after taking into consideration:
>
>> (A) the actual fuel costs experienced by the utility during the latest three calendar months for which actual fuel costs are available; and

[2] The average cost of fuel and estimated monthly average sales to be recovered in this proceeding for the forecasted billing period of February, March, and April 2024 are based on the estimated averages for January, February, and March 2024 as shown on Schedule 1.

(B) the estimated fuel costs for the same latest three calendar months for which actual fuel costs are available.

6. **Fuel Costs and Operating Expenses.** NIPSCO's Attachment 1-F shows fuel costs for the 12 months ending September 30, 2023 were $210,464,952, above the amount the Commission approved in its Order in Cause No. 45159 ("45159 Order) and the 45772 Order. NIPSCO's Attachment 1-F also shows its total operating expenses, excluding fuel, for the 12 months ending September 30, 2023, were $26,956,824 above the amounts approved in the 45159 and 45772 Orders. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending September 30, 2023, that 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.** Mr. Wagner 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 during the reconciliation period, of the energy produced by NIPSCO's fossil-fueled generation, NIPSCO's coal-fired generation provided 48.8% of energy generated and 51.2% of the energy generated was gas-fired. He stated NIPSCO's coal-fired generation consumes coal from various supply regions, with Michigan City Generating Station ("Michigan City") consuming a mix of Powder River Basin ("PRB") and Northern Appalachian ("NAPP") coal and Unit 17 and 18 at R.M. Schahfer Generating Station ("Schahfer") consuming Illinois Basin ("ILB") coal.

A. **Fuel Procurement.** In discussing NIPSCO's coal procurement process, Mr. Wagner identified several factors NIPSCO considers when evaluating purchases for a specific generating unit, including the delivered cost, operational costs, cost of emission controls, and management of coal combustion byproducts. In addition, a coal's combustion and emission characteristics are critical and may eliminate a coal from consideration if these characteristics adversely affect a generating unit's reliability, drastically increase the total cost of generation (fuel and operational costs) or inhibit NIPSCO's ability to comply with emission limits. He testified the reliability of the coal source and the reliability of coal transportation from that source are also critical factors NIPSCO considers.

Mr. Wagner stated NIPSCO purchased coal during the reconciliation period under three supply contracts. These contracts were with Arch Coal Sales Company for PRB coal; American Consolidated Natural Resources for NAPP coal; and Peabody COALSALES, LLC for ILB coal. Mr. Wagner confirmed that NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified that producers and customers are generally reluctant to execute long-term contracts with fixed prices without some type of market price adjustment mechanism. He opined that maintaining a price close to market is beneficial to both parties; therefore, a producer and customer may work together to establish an equitable price adjustment methodology. Mr. Wagner testified that, historically, market-based price adjustments in term supply agreements tend to reduce the buyer's cost of hedging since future prices are generally higher than spot and year-ahead prices. In addition to base price adjustments, quality price adjustments are used to maintain the underlying economics of the agreement on a dollar per million British thermal unit ("Btu") basis when the shipment-quality varies from guaranteed quality specifications. Mr. Wagner testified that one of NIPSCO's term coal contracts in effect during the reconciliation period had mostly fixed prices specified in the contract, and a portion of the volume under this contract was priced using a coal market index. Another contract had rates that are indexed to generating unit hourly Day-Ahead Locational Marginal Prices ("LMPs"). In addition, all of NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications.

Mr. Wagner testified the cost of coal consumed for NIPSCO for the 12 months ending September 30, 2023, was \$80.32 per ton, or \$3.860 per million Btu. The cost of coal consumed during the reconciliation period was \$70.84 per ton, or \$3.449 per million Btu. When compared to the prior reconciliation period, Mr. Wagner stated NIPSCO's delivered cost of coal consumed per ton decreased by \$3.81 and the cost was down \$0.224 per million Btu. Mr. Wagner testified several factors contributed to the change in system cost of coal expensed during several factors contributed to the change in the system cost of coal expensed during the reconciliation period. The main driver of the decrease was the reduction in the delivered cost of ILB coal for Schahfer due to the lower contract price of ILB coal relative to the inventory cost. Another factor that contributed to the decrease was increased utilization of Michigan City relative to the prior quarter. Michigan City consumes predominantly PRB coal which is lower in price than ILB coal used at Schahfer. In addition, railroad fuel surcharges decreased during the reconciliation period as On-Highway Diesel Fuel prices trended lower during the quarter.

Ms. Robles testified there have been no changes to NIPSCO's gas purchasing practices for NIPSCO's generation located off NIPSCO's gas distribution system (Sugar Creek Generating Station) during the reconciliation or forecast period. She further testified that NIPSCO has made every reasonable effort to purchase natural gas to provide electricity at the lowest reasonable price. Based on the evidence presented, the Commission finds NIPSCO has adequately explained its coal and gas procurement decision making, and its acquisition process is reasonable.

B. Coal Decrement Pricing. Mr. Wagner testified NIPSCO is not currently utilizing decrement pricing but will continue to update the Commission about decrement pricing in its future FAC filings.

OUCC witness Eckert asked that if coal decrement pricing is used in the future, NIPSCO provide justification and documentation supporting the need for, and utilization of, coal decrement pricing and specify when it expects the coal decrement pricing to end, as well as provide inputs to its calculation of the coal price decrement.

The Commission finds, based on the evidence, that decrement pricing is not included in NIPSCO's forecast for purposes of this FAC proceeding. If coal decrement pricing is included in NIPSCO's forecast or has been used, NIPSCO shall file testimony, schedules, and workpapers in its future FAC proceedings addressing any need for and the reasonableness of any utilization of coal decrement pricing and shall provide inputs to its calculation of the coal price decrement consistent with the Commission's July 17, 2019 Order in Cause No. 38706 FAC 123.

C. **<u>Renewable Energy Credits ("RECs")</u>.** Ms. Robles provided an update on NIPSCO's treatment of RECs associated with its energy purchases under wind and solar purchased power agreements ("PPAs"). She testified that pursuant to the Commission's (1) July 24, 2008 Order in Cause No. 43393 ("43393 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreements for wind energy from Barton Wind Farm on April 10, 2009 and Buffalo Ridge Wind Farm on April 15, 2009; (2) August 7, 2019 Order in Cause No. 45194 ("45194 Order"), NIPSCO began receiving power and seeking recovery of costs associated with wholesale purchase and sale agreement for wind energy from Rosewater on November 20, 2020; (3) June 5, 2019 order in Cause No. 45195 ("45195 Order") NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Jordan Creek on December 2, 2020; (4) February 19, 2020 order in Cause No. 45310 ("45310 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Indiana Crossroads Wind Generation LLC on December 17, 2021; (5) May 5, 2021 Order in Cause No. 45462 ("45462 Order") NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Dunn's Bridge I Solar Generation LLC on August 4, 2023; and (6) July 28, 2021 in Cause No. 45524 ("45224 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Indiana Crossroads Solar Generation LLC on August 9, 2023. Consistent with the 43393, 45194, 45195, 45310, 45462, and 45524 Orders, NIPSCO is also crediting any off-system sales created by its wind and solar PPAs. For the reconciliation period, NIPSCO received 93,693 MWhs (July), 122,849 MWhs (August), and 105,083 (September).

Ms. Robles testified that pursuant to the Commission's September 1, 2021 Order in Cause No. 45541, NIPSCO anticipates receiving power in January 2024 and is seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Indiana Crossroads Wind II LLC ("Crossroads Wind II"). Therefore, she stated costs associated with the wholesale purchase and sale agreement for wind energy with Crossroads Wind II are included in NIPSCO's projected fuel costs.

Ms. Robles testified that each megawatt hour of power generated from a qualified resource can be awarded a REC. Since no national standard currently exists, she stated each jurisdiction has set its own regulations upon how to qualify and account for RECs. Ms. Robles testified that NIPSCO receives RECs associated with the power it purchases from Barton, Buffalo Ridge, Jordan Creek, Rosewater, Crossroads Wind, Dunn's Bridge I, and Crossroads Solar. She explained all RECs are and will be tracked in a renewable energy tracking system. During this FAC period, Ms. Robles testified current vintage RECs were sold with the block size and proceeds from the sales as follows:

Transaction	RECs Sold	Net Proceeds
1	100,000	$ 665,918
2	11,489	$ 77,656
3	130,640	$ 965,103
4	25,000	$ 381,250
5	50,000	$ 525,000
6	25,000	$ 331,250
7	64,950	$ 719,727
8	40,000	$ 334,900
9	50,000	$ 406,313
10	25,000	$ 184,688
Total	522,079	$ 4,591,805

Ms. Robles testified that during the reconciliation period, NIPSCO transferred RECs to the Green Power Rider program with the block size and proceeds from the sales as follows:

Transaction	RECs Sold	Net Proceeds
1	26,262	$ 66,968
Total	26,262	$ 66,968

Ms. Robles testified that NIPSCO has passed and anticipates continuing to pass the proceeds from the sale or transfer of RECs back to its customers through the "Purchased Power other than MISO" line item. She noted that REC prices are increasing, which is resulting in increasing revenues from REC sales being passed back to customers. Per Ms. Robles, NIPSCO continually monitors and evaluates the marketability for all RECs, and as the possibility for future legislation evolves, NIPSCO will make appropriate changes to its REC strategy.

Ms. Robles stated that NIPSCO now has 25 approved solar and wind customers with facilities registered in M-RETS, with nameplate capacities ranging between 0.05 MW and 2.0 MW. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, Ms. Robles testified that current vintage solar and wind feed-in tariff ("FIT") RECs were sold. The block size and proceeds from the sales were:

Transaction	RECs Sold	Net Proceeds
1	9,687	$ 25,186
Total	9,687	$ 25,186

Ms. Robles stated NIPSCO has and anticipates continuing to pass the proceeds from the sale of FIT RECs back to customers through the "Purchased Power other than MISO" line item. She noted NIPSCO continues to have discussions with brokers and market participants to determine the best means of marketing the FIT RECs.

Ms. Robles testified NIPSCO did not enter any third-party energy transactions for physical power that are reflected in the forecast period. She stated that NIPSCO did not enter into any third-party energy transactions for physical power that impacted the reconciliation period; however, NIPSCO will continue to consider entering into a short-term, third-party agreements for purposes of protecting customers from market influences.

Ms. Robles testified NIPSCO incorporated forecasted FIT purchases in this filing. She explained that NIPSCO projects FIT purchases for the forecast period based on the average actual FIT purchases incurred for the 12-month period ending September 30, 2023.

Ms. Robles stated NIPSCO has incorporated forecasted REC sales and quarterly Joint Venture ("JV") cash distributions for the forecast period and explained the credit for forecasted REC sales is based on the average of actual REC sales for the 12-month period ending September 30, 2023. She testified that the credit for forecasted quarterly JV cash distributions is based on the average of actual JV cash distributions credited to the FAC customer for the 12-month period ending September 30, 2023.

The Commission finds that NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind and solar purchases being recovered through the authority granted in 43393, 45194, 45195, 45310, 45462, and 45524 Orders and any other future renewable purchases. NIPSCO shall also continue to incorporate forecasted REC sales and quarterly JV cash distributions using the forecasting methodology employed in this Cause.

D. Electric Hedging Program. Ms. Robles testified NIPSCO is operating under the updated 2023-2025 Hedging Plan ("Hedging Plan"), which began in July 2023, and that the following hedging contracts were purchased during the reconciliation period:

Month	**Power Contracts**		**Gas Contracts**	
	Actual	**Var to Plan**	**Actual**	**Var to Plan**
July 2023	125	0	35	3
August 2023	105	0	43	3
September 2023	75	0	36	3

Ms. Robles stated the execution of these contracts is consistent with the Hedging Plan through September 2023. However, she explained that the Hedging Plan overstated the need for additional 2023 gas contracts, which led NIPSCO to purchase an additional three gas contracts for each month of the reconciliation period. She noted that the total impact of the error is immaterial. Ms. Robles testified that NIPSCO's 2023 mid/fall year review determined a need for additional power hedges for the months of November and December due to the decline in forward market prices. She testified these types of adjustments are consistent with NIPSCO's past practices of adjusting the hedging plan for these differences and to the extent NIPSCO updates its plan further, future FAC filings will disclose any additional deviations from the approved plan.

Ms. Robles testified the impact of the hedges entered into for the Hedging Plan during the reconciliation period was a loss of $3,214,499, with the end total impact (including broker and clearing exchange fees) of $3,238,986. Broker fees represented 0.18% of the total value of the transactions occurring during the reconciliation period. Ms. Robles testified decisions were made based upon the conditions known at the time of the transactions, and NIPSCO used the same broker it uses for other transactions to limit transaction costs, with the transactions all made in accordance with NIPSCO's Commission-approved Hedging Plan. She stated NIPSCO will continue to solicit input and work with interested stakeholders on any potential changes to its Hedging Plan as the Company's generating portfolio continues to transition.

Mr. Eckert testified that the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs are reasonable. He affirmed that NIPSCO entered into 114 gas and 305 power contracts during the three-month period under review. Mr. Guerrettaz testified that the OUCC reviewed the additional gas hedge contracts that NIPSCO entered above its the planned amount and stated that the OUCC agrees the current impact is immaterial. He also confirmed that NIPSCO set new internal controls in place going forward to prevent entering into unnecessary contracts.

The Commission finds that NIPSCO shall continue to include in its FAC filings testimony and evidence of its electric hedging costs and any gains/losses resulting from hedging transactions for which NIPSCO seeks recovery through the FAC.

E. <u>Purchased Power Over the Benchmark</u>. Ms. Robles described the Purchased Power Benchmark that applies to NIPSCO's purchased power transactions approved in the Commission's August 25, 2010 Order in Cause No. 43526 ("43526 Order"). She testified that in the 43526 Order, the Commission established a mechanism to determine the reasonableness of purchased power costs. Each day, the cost of any power NIPSCO purchases directly from Midcontinent Independent System Operator, Inc. ("MISO") is compared to the Benchmark price. This price is equal to the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a $0.17.Mbtu transportation charge, and then multiplied by the 12,500 btu/kWh heat rate of a generic gas turbine. Ms. Robles stated that power NIPSCO purchased at a price greater than the daily Benchmark price is not recoverable from NIPSCO's customers through the FAC. She explained that the purchased power transactions subject to the Purchased Power Daily Benchmark are those power purchases that are used to serve FAC load (excluding backup and maintenance contracts) as determined by NIPSCO's Resource Cost and Allocation System, including bilateral purchases for loan and MISO Day Ahead and Real Time purchases, except wind power purchases which are excluded in accordance with the 43393, 45194, 45195, and 45310 Orders. In addition to the wind purchases, swap transactions and MISO virtual transactions for generation and load are not subject to the Purchase Power Daily Benchmark. NIPSCO had no swap or virtual transactions during the reconciliation period.

Ms. Robles testified that 169,020 MWhs of purchased power in July 2023, and 10,917 MWhs of purchased power in August 2023 were in excess of the Purchased Power Benchmark. She testified that in accordance with the procedures outlined in the 43526 Order, NIPSCO determined that 3,098 MWhs at an average purchased power cost of $58.10/MWh in July 2023 and 2,207 MWhs at an average purchased power cost of $41.68/MWh in August 2023 exceeded the Purchased Power Benchmark and a portion of those purchases is non-recoverable. The remainder of the MWhs in excess of the Purchased Power Benchmark were made to supply jurisdictional load that offset available NIPSCO resources MISO did not dispatch or are otherwise eligible under the procedures outlined in the 43526 Order and are, therefore, recoverable.

Ms. Robles testified that on August 2, 2023, the Commission issued the 45772 Order, approving NIPSCO's request to eliminate the Purchased Power Benchmark established in Cause No. 41363 from the FAC. She stated that the Benchmark is applicable to the reconciliation period in this filing, but that NIPSCO will remove the Benchmark from its FAC 142 filing.

Mr. Guerrettaz testified about the MWhs that exceeded the Purchased Power Benchmark and stated the purchases over the benchmark have been determined to be recoverable.

Mr. Eckert testified that Ms. Robles' testimony and workpapers accurately reflect the methodology approved in the 43526 Order regarding purchased power over the Benchmark. Mr. Eckert stated that he has created a working model of Ms. Robles' purchased power over the Benchmark calculations, and he agrees with Ms. Robles' purchased power over the Benchmark calculation.

Based on the evidence, the Commission finds NIPSCO's identified purchase power costs are properly included in the fuel cost calculation and NIPSCO has made every reasonable effort to acquire fuel and generate and/or purchase power 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 July, August, and September 2023 was $14,013,875.

Ms. Robles testified the Real Time Non-Excessive Energy was $2,272,084 in July 2023, $2,659,369 in August, and $2,581,594 in September 2023, primarily driven by unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market, as well as differences in actual wind production compared to forecast, due mainly to wind speeds. As to the Day Ahead Marginal Congestion Component plus actual monthly Auction Revenue Rights/Financial Transmission Rights ("ARR/FTR") expenses, less actual monthly ARR/FTR revenues that exceeded a cost of $2 million in any month during the reconciliation period, Ms. Robles testified there were none.

9. <u>Estimation of Fuel Cost</u>. NIPSCO estimates its total average fuel costs for February, March, and April 2024 will be $27,603,706 monthly.[3]

Ms. Robles noted NIPSCO incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek.

Mr. Wagner testified that as of November 8, 2023, NIPSCO's estimated F.O.B. mine spot market prices for delivery during the forecast period were $13.95 per ton for PRB coal, $38.25 per ton for ILB coal, and $51.00 per ton for NAPP coal. Mr. Wagner testified that market dynamics appear to have put downward pressure on coal demand globally and should ease supply constraints for coal-fired utility generators in 2023 and 2024. He stated there are multiple factors that may impact supply and demand during the forecast period including, but not limited to, power prices, natural gas prices, railroad and coal supplier performance, generating unit performance, weather conditions, and labor disruptions. Regarding NIPSCO's supply and demand, contracted purchases are forecasted to meet NIPSCO's 2023 coal delivery requirements and coal producers are obligated to perform under these agreements. He noted that NIPSCO has had discussions with all its coal suppliers in which the suppliers indicated they will meet NIPSCO's contracted coal supply requirements. Regarding the cost of coal, the price of coal used for the forecast period consists of mostly fixed prices. One coal supply agreement has pricing that is indexed to station LMPs where coal price is estimated using forecasted LMPs. Therefore, if power prices continue to decrease, there may be decreases in the cost of coal under the indexed coal supply agreement. This contract has maximum rates and ultimately hedges price exposure. Lastly, if demand exceeds the forecast and current supply obligations, NIPSCO may need to purchase additional supply, which may impact fuel costs during the forecast period. Mr. Wagner stated the average spot market price of coal during the reconciliation period, when compared to the prior reconciliation period, was $13.99 per ton (down $0.49) for PRB coal, $54.40 per ton (down $14.22), and $53.07 per ton (down $12.10) for NAPP coal. He stated these are average F.O.B. mine spot market prices only, which do not include the cost of transportation, and actual prices may vary from published indices.

In identifying energy market trends and factors affecting the market for coal and transportation during the reconciliation period, Mr. Wagner stated wholesale electricity prices were roughly 63% lower during the reconciliation period when compared with the same period in 2022 and coal prices continued to decline. Mild weather in the U.S. and low natural gas prices contributed to the reduction in wholesale energy prices and key drivers that had kept upward pressure on electric prices during most of 2022, including strong global energy demand, rising electric demand, high natural gas prices, high coal prices, and high railroad fuel surcharges, continued to ease during the reconciliation period. API 2 prices (coal delivered to Amsterdam, Rotterdam, and Antwerp ("ARA")) that had bolstered domestic coal prices earlier in 2022 continued to decline. The U.S. Energy Information Administration ("EIA") expects these conditions to drive the U.S. electric energy supply mix as follows: renewable generation should contribute to 22% of the mix in 2023 and is expected to increase to 24% in 2024, natural gas-fired generation is expected to provide 42% of electric generation in 2023 and is expected to decline to 41% in 2024, and coal-fired generation may supply 16% in 2023 to less than 585 million tons with

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[3] The estimated total average fuel costs for January, February, and March 2024 as shown on Schedule 1 is used to calculate the amounts to be recovered in this proceeding for the forecasted billing period of February, March, and April 2024.

another 18% decrease expected in 2024. The EIA expects natural gas prices to trend modestly higher during the remainder of 2023 and through 2024. The EIA expects pricing to increase to $3.40 per MMBTU during the winter and average $3.38 per MMBTU during 2024. Bituminous coal prices are roughly 72% lower than year-ago levels, but lower natural gas and electric prices have pushed coal-fired generation to the marginal energy source, and this should keep coal pricing relatively soft. In the long run, coal demand will continue to fall driven by lower natural gas prices and coal generation being phased out of energy markets worldwide.

Mr. Wagner testified these dynamics have continued to drive prices lower in all energy markets during the reconciliation period. He said that coal pricing into Europe (delivered to ARA) has fallen precipitously since 2022. API 2 prices were roughly 42% lower year over year during the reconciliation period. In addition, coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand. That said, strong exports and improved domestic demand during 2022 provided coal producers and coal transporters with increased sales opportunities and price improvements. He noted the EIA expects coal exports should total 97 million tons annually through 2024, which may offset some of the losses in domestic markets. Mr. Wagner testified that Class I railroads have struggled to meet the surge in demand over the last two years and have limited customer shipments for not only coal, but other commodities and products they transport. He stated coal supply constraints have been caused by reduced investment in coal production and coal transportation projects, supplier bankruptcies, and mine closures over the last several years, and these supply and capacity reductions could lead to market volatility if energy prices rebound. However, with lower coal demand and the slowing of railroads' other lines of business, railroad performance has stabilized and improved during 2023. Notwithstanding, the EIA is forecasting domestic electric power coal demand to decline by nearly 19% in 2023 largely due to decreases in the electric power sector driven by coal-fired generation retirements, low natural gas prices, and increased renewable generation. In addition, U.S. economy grew 2.4% in 2023 and is expected to grow by 1.5% in 2024 and likely keeping a floor on energy prices.

Mr. Wagner testified that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period is $68.86 per ton or $3.434 per million BTU.

Mr. Wagner testified that in developing the estimate for the forecast period, NIPSCO's fuel supply group incorporates coal contract prices inclusive of adjustments specified in the agreement, dust treatment costs, freeze conditioning (seasonal) costs, railcar lease cost, railcar maintenance costs, estimates of contract prices (fixed prices and indexed contract rates using forward LMP forecasts), transportation fuel surcharges using the monthly average price of U.S. On-Highway Diesel Fuel ("HDF"), the Association of American Railroad's All-Inclusive Index Less Fuel adjustments and estimates of future coal purchase prices. He testified that in addition, the fuel supply group provides a forecast of beginning inventory values in dollars and quantities in tons for each generating station. These assumptions are provided to NIPSCO's energy supply and optimization group to develop the forecast.

Ms. Robles testified that NIPSCO completed its forecast for this FAC filing on November 8, 2023, using its production cost modeling system, PROMOD,[4] and made reasonable decisions under the circumstances known at that point in time.

The Fuel Cost Factor is forecasted to be $31.780 compared to a Base Cost of Fuel of $33.674. Ms. Robles explained that (1) steam and combined cycle generation is projected to be higher compared to FAC 140; (2) the credit associated with the Off System Sales Adjustment is forecasted to be higher than in FAC 140 due to increased opportunities for such sales; (3) NIPSCO has incorporated in this FAC, for the first time, forecasted credits associated with renewable energy credit sales and JV cash distributions; and (4) although the forecasted cost per MWh is higher than in FAC 140, it is projected to be lower compared to recent pricing.

Ms. Robles stated that to ensure NIPSCO provides electricity to its retail customers at the lowest fuel cost reasonably possible, NIPSCO has utilized the approved Hedging Plan from FAC 138, which became effective July 1, 2023, and NIPSCO will continue to utilize financial hedges under the Hedging Plan to mitigate economic impacts and volatility within each FAC. Second, NIPSCO has added additional wind and solar resources and will continue to add new resources to its portfolio, which do not have variable fuel costs and are much cheaper relative to utilizing coal-fired (steam) generation. She stated NIPSCO will continue to utilize its ever-growing wind, solar, and solar plus storage fleet of assets to economically serve customers as well.

Mr. Wagner testified there are two key factors that could impact coal transportation costs during the forecast period. One factor, power prices, may impact coal transportation costs under two transportation contracts that are indexed to station LMPs. Contract transportation rates are forecasted using forward energy prices and have maximum rates that ultimately hedge price exposure. A second factor is the price of HDF. Two coal transportation agreements also have mileage-based fuel surcharges that vary with changes in HDF which impact transportation costs. Fuel surcharges under these agreements are calculated monthly using the average weekly spot price of HDF. Fuel surcharge estimates are included in rate projections used to develop comprehensive transportation costs for the forecast period. He stated that, for reference, the spot price of HDF as of November 6, 2023 was $4.366 per gallon. This is a 18% year-over-year decrease. The EIA expects global oil inventories to decrease modestly during the first half of 2024 and expects diesel prices to average $4.26 per gal during 2024. Therefore, fuel surcharges under NIPSCO's transportation agreements are expected to remain relatively stable during the forecast period.

Mr. Wagner testified NIPSCO is proactively administering coal and rail transportation agreements to address any potential coal supply and/or coal transportation shipment issues. All anticipated coal supply requirements for 2023 should be met under current supply and transportation agreements. Specifically, market dynamics have changed significantly from 2022 and demand for both coal and coal transportation globally has lessened and the stress on the coal supply chain has been reduced. NIPSCO also continues to work closely with its rail carriers to ensure coal deliveries meet demand during the forecast period.

[4] PROMOD is NIPSCO's electric forecasting model.

Mr. Wagner stated the days of coal inventory supply at Schahfer was approximately 58 days (up five days from the prior quarter) at the end of the reconciliation period. He testified solid railroad performance and lower consumption resulted in relatively stable inventory at Schahfer. Michigan City's PRB coal inventory was at 22 days and the NAPP inventory was at 35 days at the end of the reconciliation period. Mr. Wagner testified NIPSCO has made every reasonable effort to acquire fuel to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Mr. Wagner testified NIPSCO's fleet size was 866 railcars (six sets with 13.4% spares) at the end of the reconciliation period. The typical spare railcar pool ranges between 3% and 8%. NIPSCO is actively collecting railcars for return, and this has led to variations in the spare railcar count. According to Mr. Wagner, during the reconciliation period, NIPSCO utilized roughly 53% of its railcar fleet. He explained that NIPSCO stored three sets at Schahfer at the start of the reconciliation period and had two sets stored there at the end of the period. This was largely due to lower consumption due to station maintenance outages (planned and unplanned). Michigan City held one set at the station and one set was stored with the Chicago South Shore Railroad due to lower than anticipated consumption. Michigan City was returned to service in late July and the fleet utilization was 72% at the end of the reconciliation period. NIPSCO continuously evaluates its railcar needs considering peak demand, delivery requirements (forecasted and actual), and railroad performance. NIPSCO determined that the fleet size should be reduced to 784 railcars (six-unit trains with roughly 4% spares) during 2023. Consistent with that plan, NIPSCO returned 180 railcars since the beginning of 2023 through the end of the reconciliation period and will return another 82 railcars by the end of the 2023. Consumption during 2023 has trended well below forecast and coal shipments were reduced to manage inventory levels. This dynamic has impeded NIPSCO's ability to sort, collect, and provide cars to the return location. Inconsistent railroad service also hampered railcar return efforts. NIPSCO will continue to use commercially reasonable efforts to return the remaining cars to the lessor before the end of the year.

Mr. Wagner testified that during the reconciliation period, NIPSCO returned 123 railcars and 57 more railcars were delivered to the return location. At the beginning of the reconciliation period, NIPSCO also stored one set of railcars at a third-party location as is typical when Michigan City enters a planned maintenance outage or if market conditions keep the unit in service. The set was removed from storage during the reconciliation period when Michigan City returned to service. Whenever possible, NIPSCO will utilize Michigan City's or Schahfer's trackage (a zero-cost option) or sublease railcars to minimize cost. Mr. Guerrettaz testified that NIPSCO presented a detailed "Railcar Fleet Plan" during the audit, which projects railcars out until November 2025, including the train cycle times in days. He stated the chart presented by NIPSCO was very helpful during the audit and that the OUCC will continue to review NIPSCO's railcar fleet size.

Mr. Wagner testified NIPSCO has continued to survey the market to find potential third-party customers interested in sub-leasing railcars; however, there were no viable third-party customers and subleasing railcars was not an option. He said he is aware that some large utilities are holding on to "excess" railcars out of concern that it may be difficult and/or more expensive to lease cars back if demand improves. The number of railcars available in the market has decreased substantially because scrap rates of coal gondola railcars have been aggressive over the last few years and railcar lease rates have increased drastically, which supports the concern of a potential shortage. Overall, NIPSCO's plan to reduce the coal railcar fleet from eight sets to six sets by the end of the year is a prudent balancing of economics and reliability.

In the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, NIPSCO was ordered, at a minimum, 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. The Commission finds that NIPSCO provided sufficiently detailed testimony and information in this matter to support its forecasted fuel costs. NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding these five factors.

In the Commission's October 21, 2015 Order in Cause No. 38706 FAC 108, NIPSCO was ordered to include in its FAC filings testimony regarding efforts to mitigate costs incurred for unused train sets. The Commission finds NIPSCO provided testimony and information in this proceeding regarding mitigation of storage costs associated with unused train sets, as ordered in Cause No. 38706 FAC 108, and NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding its unused train sets and efforts to mitigate storage related costs.

NIPSCO's estimated and actual fuel costs for the reconciliation period are as follows:

Month	**Actual Fuel Cost $/kWh**	**Estimated Fuel Cost $/kWh**	**Estimating Error: Over (Under)**
July	$0.033788	$0.038512	13.98%
August	$0.030285	$0.034461	13.79%
September	$0.026836	$0.032511	21.15%
Weighted Average Estimating Error			**16.38%**

Ms. Robles testified the 16.38% difference led to a variance factor of ($5.228) primarily driven by a combination of (1) lower than anticipated market prices and reduced availability at NIPSCO's coal-fired generation stations in the reconciliation period, and (2) REC sales, which helped to mitigate potential increases in the impact during the reconciliation period. At the time the forecast was prepared neither NIPSCO nor the market anticipated an approximate 28% decrease in the all-hours average power price in MISO ($32.87/MWh actual LMP compared to $45.40/MWh estimated LMP) for this reconciliation period.

Based on the evidence presented, including Mr. Guerrettaz's testimony upon the reasonableness of NIPSCO's fuel cost and power sales projections, the Commission finds NIPSCO's estimate of its prospective average fuel cost to be recovered during the February, March, and April 2024 billing cycles is reasonable.

10. **<u>Return Earned</u>.** Ind. Code § 8-1-2-42.3 and Ind. Code § 8-1-2-42(d)(3) requires the Commission to find that the FAC applied for will not result in the electric utility earning a return over the return authorized by the Commission in the last proceeding in which the basic rates and charges of the utility were approved. NIPSCO's evidence demonstrates that for the 12 months ending September 30, 2023, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $259,805,258. This is $44,008,898 less than NIPSCO's authorized amount of $303,814,156, which includes $278,666,245 approved in the applicable rate cases, plus $25,147,731 of actual TDSIC operating income during the 12 months ended September 30, 2023. NIPSCO calculates the overall earnings bank (sum of the differentials) for the relevant period as $7,612,705; therefore, under Ind. Code § 8-1-2-42.3, NIPSCO did not earn in excess of its authorized net operating income, and no refund is required.

Based on the evidence presented, the Commission finds that for the 12 months ended September 30, 2023, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

11. **<u>OUCC Report</u>.** Mr. Guerrettaz testified: (1) the fuel cost element of NIPSCO's power purchases has been calculated by including the additional requirements of various Commission Orders; (2) the variance for the quarter ending September 30, 2023, was computed in conformity with Ind. Code §§ 8-1-2-42, -42.3, and relevant orders; (3) NIPSCO did not have a level of net operating costs greater than granted in NIPSCO's last two general rate case proceedings prorated for period under review; and (4) the fuel cost adjustment for the quarter ending September 30, 2023 has been properly applied in conformity with the requirements of Cause No. 38706 FAC 138 and 139. Mr. Guerrettaz states the OUCC recommends NIPSCO's proposed FAC factor of ($0.007122) per kWh be approved. Mr. Guerrettaz also recommended the Commission order NIPSCO to continue to provide (1) the monthly railcar inventory and explain any deviations that occur from the Plan as represented during the audit and present all information impacting the cost per ton for the railcar maintenance increase; (2) detailed coal cost charts from each supplier to each station for the three actual months on a going forward basis setting forth the components of coal and transportation; (3) a copy of all new Requests For Proposals ("RFPs") and contracts for transportation and coal; and (4) enhance the testimony covering the gas component of fuel, as NIPSCO agreed to provide more information in this area and to break out the power and gas hedging gains and losses in testimony.

Mr. Eckert testified: (1) he has created a working model of Ms. Robles' purchased power over the benchmark calculation and agrees with this calculation; (2) NIPSCO's treatment of Ancillary Services Market ("ASM") charges follows the treatment the Commission ordered in its June 30, 2009 Phase II Order in Cause No. 43426 ("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's steam generation costs are higher than the other large electric investor owned utilities in Indiana and NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor owned utilities in Indiana; (5) NIPSCO should continue to update the Commission on its coal inventory and coal price decrement; (6) if coal decrement pricing is used, NIPSCO should provide justification and documentation supporting the need for and utilization of coal decrement pricing, as well as specify when it expects coal decrement pricing to end and provide inputs to its calculation of the coal price decrement; (7) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (8) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, Rosewater, and Indiana Crossroads; and (9) NIPSCO provided an update on the status of the Railroad Litigation.[5] Mr. Eckert further testified a residential customer using 1,000 kWhs in December 2023 will pay $178.34 (excluding taxes), which consists of $175.54 in base charges set in NIPSCO's last approved rate case (Cause No. 45772), $(6.68) in a fuel adjustment clause credit, and $9.48 in non-FAC trackers.

12. **Fuel Cost Adjustment Factor.** Based on the evidence, we find 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 ($0.05228) per kWh to be added to the estimated cost of fuel for bills rendered during the February, March, and April 2024 billing cycles in the amount of $0.026552 per kWh. This results in a fuel cost adjustment factor of ($0.007122) per kWh, after subtracting the cost of fuel in base rates. A residential customer using 1,000 kWh per month will experience a decrease of $0.44 on his or her electric bill from the currently approved factor.

13. **Interim Rates.** As discussed in Paragraph 16 below, the OUCC recommended NIPSCO's FAC factor be made "interim subject to refund pending satisfactory discussion and explanation of the Sugar Creek Generating Station outage." Because the Commission is unable to determine whether NIPSCO will earn an excess return while this Order is in effect and based on our discussion and findings in Finding No. 16 below, the Commission finds the rates approved herein should be interim rates, subject to refund.

14. **Major Forced Outages.** Consistent with past Commission Orders, Mr. Saffran sponsored Petitioner's Exhibit 4, Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the third quarter of 2023, including the length and cause of each major forced outage, the generating unit involved, and proposed solutions to prevent such outages from reoccurring. For purposes of his presentation, a major forced outage is a unit forced outage lasting longer than three consecutive days. He also sponsored Confidential Attachment 4-B providing a root cause analysis for forced outages (if an analysis was completed at the time of the FAC filing).

15. **Status of Railroad Litigation.** In accordance with the Commission's Order in Cause No. 38706 FAC 125, Ms. Krupa testified the Railroad Litigation remains pending, and as of September 30, 2023, NIPSCO has deferred $4,796,228 in associated legal costs. Mr. Wagner advised the Railroad Litigation remains consolidated for pre-trial purposes in Multi-District Litigation with the expert discovery phase nearing completion. He stated defendants' experts provided their responsive expert reports on August 15, 2023, and NIPSCO's counsel participated in depositions of the defendants' experts over the ensuing three months. NIPSCO's expert is scheduled to provide his rebuttal expert report on November 15, 2023 pursuant to the procedural schedule issued by the judge. All parties have been directed by the judge to submit a joint status report by December 1, 2023, proposing a schedule for further proceedings, including a briefing schedule for any anticipated motions. No substantive determinations have occurred in the Railroad

[5] On September 30, 2019, NIPSCO filed a complaint in the United States District Court for the District of Columbia against the Union Pacific Railroad Company, BNSF Railway Company, CSX Transportation, Inc., and Norfolk Southern Railway Company (currently pending in Civil Action No. 1:19-cv-02927-PLF) for illegally conspiring to use rail fuel surcharges as a mechanism to fix, raise, maintain, and stabilize the prices of rail freight transportation services sold in the United States (the "Railroad Litigation").

Litigation. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so.

16. **Sugar Creek Planned Outage.** Based on the events described in his confidential testimony, Mr. Eckert testified that the OUCC recommends NIPSCO's FAC factor be made "interim subject to refund" pending further discovery and review regarding the Sugar Creek extended outage and that NIPSCO provide an updated to the Commission in its next FAC regarding the status of three events and the resolution between NIPSCO and its contractor. Mr. Eckert stated that the OUCC intends to issue additional discovery and have further discussions with NIPSCO about the outage.

In his rebuttal testimony, Mr. Sangster stated he is unaware of any requirement that NIPSCO must report on its planned outages in its quarterly FAC filings and that NIPSCO provided planned outage information, including its actual and projected outage schedule for 2023 and 2024, in response to the OUCC's standard FAC audit discovery in this proceeding. He stated that NIPSCO also provided additional information related to the Sugar Creek outage before the OUCC's testimony was due and that NIPSCO did not, in any way, obfuscate Sugar Creek's outage status, the relevant events, or the Company's related actions. Mr. Sangster explained that NIPSCO's diligence throughout the course of this planned outage uncovered equipment issues through proactive inspections that avoided further damage and NIPSCO is working with industry experts to remediate damage appropriately and as quickly as reasonably possible. Mr. Sangster stated that NIPSCO can commit to updating the Commission and the parties in the next FAC regarding the status of the Sugar Creek planned outage and the events and actions described in his confidential testimony. He testified that NIPSCO does not believe setting its FAC 141 factor interim subject to refund is necessary or appropriate given these facts, but in the spirit of cooperation, NIPSCO does not object to the OUCC's recommendation, provided that the Commission's language in an order in this proceeding is clear that any potential refund would result only if the Commission were to make a finding that NIPSCO took imprudent action related to the Sugar Creek planned outage and that imprudent action directly resulted in a negative financial impact to NIPSCO's customers.

We have previously recognized the summary nature of FAC proceedings and the limitation that they can present for record development. Accordingly, the Commission adopts NIPSCO's agreement to update the Commission and the parties in FAC 142 regarding the status of the Sugar Creek Planned outage and the events and actions described in the confidential testimony in this Cause. Further, consistent with Finding No. 13 above, we find the rates approved herein should be interim rates, subject to refund.

17. **Confidential Information.** On August 18, 2023, NIPSCO filed a motion for protective order which was supported by an affidavit showing document to be submitted to the Commission contained trade secrets within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. In an August 29, 2023 docket entry, such information was found to be preliminarily confidential, after which NIPSCO submitted the information under seal. The Commission finds such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held by the Commission as confidential and protected from public access and disclosure.

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 February, March, and April 2024 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 12 above, is approved on an interim basis subject to refund as set out in Finding No. 13 above.

2. Prior to implementing the approved rates, NIPSCO shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rates shall be effective on or after the Order date subject to Division review and agreement with the amounts reflected.

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 Finding No. 7C above, and testimony regarding any electric hedging transaction costs and gains/losses for which NIPSCO is seeking recovery through the FAC, as discussed in Finding No. 7D above.

4. NIPSCO shall also continue to 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 Finding No. 9 above.

5. NIPSCO shall also include in its quarterly FAC filings information related to Day Ahead Marginal Congestion Component and the cost of coal stacks from each supplier to each station for the three actual months on a going forward basis and shall also provide a copy of all new RFPs and contracts for transportation and coal to the extent such are issued.

6. If coal decrement pricing is used or forecast, NIPSCO shall file in its future FAC proceedings appropriate testimony, schedules, and work papers addressing the need for and reasonableness of utilizing coal decrement pricing, as well as when NIPSCO anticipates coal decrement pricing resuming and/or ending, as discussed in Finding No. 7B above.

7. NIPSCO shall continue to include in its quarterly FAC filings an update on the status of the Railroad Litigation required by the Commission's January 22, 2020 Order in Cause No. 38706 FAC 125, as discussed in Finding No. 15 above.

8. NIPSCO shall update the Commission and the parties in FAC 142 regarding the status of the Sugar Creek Planned outage and the events and actions described in the confidential testimony in this Cause.

9. The information filed in this Cause pursuant to NIPSCO's motion for protective order is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 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.

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

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED: JAN 31 2024

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

Dana Kosco
Digitally signed by Dana Kosco
Date: 2024.01.31 10:14:06 -05'00'

Dana Kosco
Secretary of the Commission