ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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 2023, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 45159, AND (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND ENERGY APPROVED IN CAUSE NOS. 43393, 45194, 45195, AND 45310.	)	**CAUSE NO. 38706 FAC 137** **APPROVED: JAN 25 2023**

<u>ORDER OF THE COMMISSION</u>

Presiding Officers:
David E. Ziegner, Commissioner
Carol Sparks Drake, Senior Administrative Law Judge

On November 15, 2022, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") 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 the February, March, and April 2023 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 No. 45159; and (2) ratemaking treatment for the costs incurred under wholesale purchase and sale agreements for wind energy approved in Cause Nos. 43393, 45194, 45195, and 45310. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company employee Kelleen M. Krupa, a Lead Regulatory Analyst, and the testimony and exhibits of the following NIPSCO employees:

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

On November 15, 2022, NIPSCO also filed a motion requesting confidential treatment for certain information ("Confidential Information"). In a docket entry issued on November 30, 2022, the requested confidential treatment was granted on a preliminary basis.

On November 22, 2022, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on November 30, 2022.[1]

On December 15, 2022, NIPSCO filed supplemental direct testimony for Ms. Krupa, along with revised schedules, because NIPSCO's projected fuel cost charges for February through April 2023 decreased since NIPSCO initiated this FAC due to changing gas market conditions. After informing the other parties of this change, NIPSCO supplemented its filing to support a revised FAC factor that reduces the FAC factor originally requested.

The Indiana Office of Utility Consumer Counselor ("OUCC") on December 20, 2022, prefiled the direct testimony and exhibits of the following:

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

NIPSCO prefiled rebuttal testimony for Mr. Blissmer on December 27, 2022. A docket entry was issued on December 30, 2022, in which the OUCC and NIPSCO were each asked to provide certain revised adjustment journal entries, and the OUCC was requested to provide related information. NIPSCO filed its response to this docket entry on January 3, 2023, and the OUCC responded on January 4, 2023.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on January 6, 2023, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in this hearing, and the testimony and exhibits of NIPSCO and the OUCC were admitted without objection.

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

1. <u>Commission Jurisdiction and Notice</u>. 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. <u>NIPSCO's Characteristics</u>. 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. <u>Available Data on Actual Fuel Costs</u>. 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 December 4, 2019 Order in Cause No. 45159 ("45159 Order") was $0.026736 per kilowatt hour ("kWh"). NIPSCO's cost of fuel to generate

[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.

electricity and the cost of fuel included in the cost of purchased electricity for the months of July, August, and September 2022 averaged $0.056058 per kWh.

4. **<u>Requested Fuel Cost Charge</u>.** NIPSCO seeks to change its fuel cost adjustment from the current fuel cost charge of $0.029820 per kWh for bills rendered during the November 2022 through January 2023 billing cycles to a fuel cost charge of $0.034284 per kWh for bills rendered during the February 2023 through April 2023 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing. The OUCC's proposed factor, per Mr. Guerrettaz's testimony, for the February 2023 through April 2023 billing cycles is $0.033893 per kWh.

The requested fuel cost adjustment includes a variance of $41,742,874 that was under-collected during July 2022 through September 2022 ("reconciliation period") and a reduction of $4,483,560 from the earnings test. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecasted billing period of February 2023 through April 2023 is $41,508,997, and its estimated monthly average sales for that period are 883,783 MWhs.

5. **<u>Statutory Requirements</u>.** Ind. Code § 8-1-2-42(d) states 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] of this chapter, 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 (3) calendar months are reasonable after taking into consideration:
>
>> (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and
>>
>> (B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

6. <u>Fuel Costs and Operating Expenses</u>. NIPSCO's Revised Attachment 1-F shows fuel costs for the 12 months ending September 30, 2022, were $223,008,815 above the amount the Commission approved in the 45159 Order. NIPSCO's Revised Attachment 1-F also shows Petitioner's total operating expenses, excluding fuel, for the 12 months ending September 30, 2022, were $10,138,561 above the amount approved in the 45159 Order. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending September 30, 2022, that have not been offset by actual decreases in other operating expenses.

7. <u>Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost</u>. Mr. Wagner testified that NIPSCO made every reasonable effort to acquire fuel 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, NIPSCO's coal-fired generation provided 60.9% of the energy generated, and 39.1% of the energy generated was gas-fired. He stated NIPSCO's coal-fired generation consumes coal from various supply regions, with the Michigan City Generating Station ("Michigan City") consuming a mix of Powder River Basin ("PRB") and Northern Appalachian ("NAPP") coal, and Units 17 and 18 at the R.M. Schahfer Generating Station ("Schahfer") consuming Illinois Basin ("ILB") coal.

A. <u>Fuel Procurement</u>. 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 emissions 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 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. One of these contracts was with Arch Coal Sales Company for PRB coal; one agreement was with American Consolidated Natural Resources for NAPP coal, and the third agreement was with Peabody COALSALES, LLC for ILB coal. Mr. Wagner confirmed NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified producers and customers are reluctant to execute long-term contracts with fixed prices without some market price adjustment mechanism. He noted 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 stated 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 the guaranteed quality specifications. Mr. Wagner testified one of NIPSCO's term coal contracts in effect during the reconciliation period had mostly fixed prices specified in the contract, with a portion of the volume under this contract priced using a coal market index. Another contract had rates that are indexed to generating unit hourly Day-Ahead Locational Marginal Power Prices ("LMPs"). Additionally, all NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications. Mr. Wagner also advised that during the reconciliation period NIPSCO committed to a test coal supply agreement with Columbia Resource Group, Inc. He explained that the coal supplied under this agreement was recovered waste coal that consisted of predominately PRB coal with traces of western bituminous and ILB coals, with the coal cleaned before shipment to render it suitable for use in electric scale boilers.

Mr. Wagner testified the delivered cost of coal consumed by NIPSCO's generating stations for the 12 months ending September 30, 2022, was $60.99 per ton or $2.969 per million BTU. The cost of coal consumed during the reconciliation period was $68.86 per ton or $3.387 per million BTU. The delivered cost of coal consumed during the prior reconciliation period was $61.06 per ton or $3.007 per million BTU. When compared to the prior reconciliation period, NIPSCO's delivered cost of coal consumed per ton increased $7.80, and the cost was up $0.380 on a per million BTU basis. Mr. Wagner stated several factors contributed to the change in the cost of coal expensed during the reconciliation period, including an increase in the consumption of ILB coal relative to PRB coal consumption. He noted the PRB coal used at Michigan City is lower cost than the ILB coal used at Schahfer, and this difference in mix contributed to the higher unit cost. Other contributing factors included increases in ILB delivered coal expense, largely due to higher coal and transportation rates that are indexed to station power prices, and increases in railroad fuel surcharges driven by increased On-Highway Diesel Fuel prices.

Mr. Guerrettaz testified some components of coal costs include the base coal cost, dust treatment, freeze treatment, and miscellaneous projected coal quality costs. He stated transportation cost components include the base transportation costs, any fuel adjustments, pricing adjustments, incremental costs associated with operations, maintenance, and lease of railcars, and index pricing. Mr. Guerrettaz testified that due to the potentially large impact of index pricing, it is important to determine the resulting impact on delivery prices. He advised that NIPSCO purchased additional coal during this FAC reconciliation period from a current supplier at a higher market price than in the recent past.

Ms. Robles testified Petitioner made every reasonable effort to purchase natural gas so as to provide electricity to its customers at the lowest reasonable price, and 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.

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. <u>Coal Decrement Pricing</u>. 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.

Based on the evidence, the Commission finds decrement pricing is not included in NIPSCO's forecast for purposes of this FAC proceeding. If in the future coal decrement pricing is included in NIPSCO's forecast or has been used, NIPSCO shall file testimony, schedules, and workpapers addressing the need for and reasonableness of such decrement pricing and related inputs 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 purchased power agreements ("PPAs"). She testified that pursuant to the Commission's 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 Windpower LLC ("Barton") on April 10, 2009, and from Buffalo Ridge I LLC ("Buffalo Ridge") on April 15, 2009. Consistent with the Commission's August 7, 2019 Order in Cause No. 45194 ("45194 Order"), NIPSCO began receiving power and seeking recovery of such costs for wind energy from Rosewater Wind Generation LLC ("Rosewater") on November 20, 2020, and per the Order in Cause No. 45195 ("45195 Order") from Jordan Creek Wind Farm LLC ("Jordan Creek") on December 2, 2020. Pursuant to the 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 ("Indiana Crossroads") on December 17, 2021. Under the 43393, 45194, 45195, and 45310 Orders, NIPSCO is also crediting any off-system sales created by its wind PPAs. She stated the wind PPA adjustment for the forecast period is based on the average actual wind PPA adjustment incurred for the 12-month period ended September 30, 2022. For the reconciliation period of July, August, and September 2022, NIPSCO received 127,002 MWhs, 119,645 MWhs, and 140,936 MWhs, respectively.

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 as of this filing, NIPSCO receives RECs associated with the power it purchases from Barton, Buffalo Ridge, Jordan Creek, Rosewater, and Indiana Crossroads. All RECs are or will be tracked in a renewable energy tracking system. During this FAC period, she stated current vintage RECs were sold. The block sizes and proceeds from the sales were:

Transaction	RECs Sold	Net Proceeds
1	25,000	$ 125,000
2	50,000	$ 246,250
3	50,000	$ 241,325
4	25,000	$ 102,500
5	50,000	$ 232,500
6	50,000	$ 209,313
7	100,000	$ 390,000
8	25,000	$ 89,881
9	25,000	$ 91,250
10	25,000	$ 73,875
11	50,000	$ 179,763
12	100,000	$ 317,663
13	75,000	$ 222,750
14	50,000	$ 150,000
15	50,000	$ 147,750
16	50,000	$ 169,913
Total	800,000	$ 2,989,731

Ms. Robles testified NIPSCO will continue to pass the proceeds from the sale or transfer of RECs back to its customers through the Purchased Power other than Midcontinent Independent System Operator, Inc. ("MISO") line item. Per Ms. Robles, NIPSCO continually evaluates the marketability for all RECs, and as the possibility for future legislation evolves, NIPSCO will make appropriate changes its REC strategy.

Ms. Robles stated NIPSCO now has 24 approved solar and wind feed-in tariff ("FIT") customers with facilities registered in the Midwest Renewable Energy Tracking System ("M-RETS"),[2] 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, no current vintage solar and wind FIT RECs were sold. Ms. Robles stated NIPSCO has and will continue to pass the proceeds from FIT RECs sales back to customers through the Purchased Power other than MISO line item. She noted NIPSCO continues to discuss with brokers and market participants the best means of marketing the FIT RECs.

Mr. Guerrettaz confirmed that NIPSCO provided a credit to its customers from the sale of RECs for this FAC. Without the RECs and joint venture credit, he stated actual fuel costs for July through September 2022 would have been approximately 33% higher than estimated.

Ms. Robles testified NIPSCO does not expect to buy firm, long-term purchased power during the forecast period and did not enter into any third-party energy transactions for physical power that impacted the reconciliation period. She stated NIPSCO will, however, continue to

[2] M-RETS is a web-based system used by power generators, utilities, marketers, and qualified reporting entities in participating states and province.

consider entering into short-term third-party agreements to protect its 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 of actual FIT purchases incurred for the 12 months ending September 30, 2022. NIPSCO also incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek. Additionally, Ms. Robles advised that NIPSCO completed its forecast for this FAC filing on November 11, 2022, using its production cost modeling system, PROMOD, and made reasonable decisions under the circumstances known at that time.

The Commission finds 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 the 43393, 45194, 45195, and 45310 Orders and any other future renewable purchases.

D. <u>Electric Hedging Program</u>. Per Ms. Robles, the table below shows the hedging contracts purchased during the reconciliation period.

Month	**Power Contacts**		**Gas Contracts**	
	Actual	**Var to Plan**	**Actual**	**Var to Plan**
July 2022	130	45	39	4
August 2022	95	70	43	3
September 2022	35	45	36	0

Ms. Robles stated the execution of these contracts was consistent with NIPSCO's approved electric hedging plan through September 2022. She stated NIPSCO is operating under the updated 2022-2024 Hedging Plan that began in July 2022.

Ms. Robles testified the impact of the hedges during the reconciliation period was a gain of $6,698,318. The net total impact of the hedging plan in this FAC reconciliation period, including broker and clearing exchange fees, was $6,691,461. Broker fees represented 0.02% 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 all transactions made in accordance with NIPSCO's approved electric hedging plan.

Mr. Eckert testified the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs are reasonable. He stated NIPSCO entered into 118 gas and 260 power contracts during July through September 2022.

The Commission finds 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 NIPSCO's purchased power costs. Each day, the cost of any power NIPSCO purchases directly from MISO is compared to a benchmark price. This price is equal to the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a $0.17 per million BTU transportation charge, and then multiplied by the 12,500 BTU/kWh heat rate of a generic gas turbine. Ms. Robles stated power NIPSCO purchased at a price greater than the daily benchmark price is not recoverable from NIPSCO's customers through the FAC. She explained 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 load and MISO Day Ahead and Real Time purchases, except wind power purchases that 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 Purchased Power Daily Benchmark. NIPSCO had no swap or virtual transactions during this FAC reconciliation period.

Ms. Robles testified that 160,936 MWhs of purchased power in July 2022 at an average purchased power cost of $110.66/MWh, 92,494 MWhs of purchased power in August 2022 at an average purchased power cost of $124.95/MWh, and 131,328 MWhs of purchased power in September 2022 at an average purchased power cost of $113.79/MWh were in excess of the Purchased Power Benchmark. As a point of comparison, she stated the monthly averages of the Purchased Power Daily Benchmarks were $87.33, $105.94, and $89.88 for July, August, and September 2022, respectively. Ms. Robles testified the MWhs that exceeded the Benchmark in this reconciliation period were not attributable to any one event or factor; rather, the recoverability for each purchase under the terms of the 43526 Order varies.

Ms. Robles testified that in accordance with the procedures outlined in the 43526 Order, NIPSCO determined that in July 2022, 45,720 MWhs at an average purchased power cost of $133.07/MWh, 34,384 MWhs in August 2022 at an average purchased power cost of $132.67/MWh, and 36,730 MWhs in September 2022 at an average purchased power cost of $115.14/MWh exceeded the Purchased Power Benchmark, and a portion of those purchases is non-recoverable. She stated the remaining 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.

OUCC witness Guerrettaz testified that in the three months covered by this FAC, 384,758 MWhs exceeded the Purchased Power Benchmark, as Ms. Robles testified. He stated a majority of the purchases over the Purchased Power Benchmark were determined to be recoverable, and per OUCC witness Eckert, the OUCC recommends recovery. Mr. Eckert testified Ms. Robles' testimony and workpapers accurately reflect the methodology the Commission approved in the 43526 Order regarding purchased power over the Benchmark. Mr. Eckert noted he has created a working model of Ms. Robles' purchased power over the Benchmark calculations, and he agrees with her calculations.

Based on the evidence, the Commission finds NIPSCO's identified purchased power costs are properly included in the fuel cost calculation, and NIPSCO 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.

8. **MISO Day 2 Energy Costs.** Ms. Robles stated NIPSCO proposes to recover the fuel-related charges and credits MISO assigned to NIPSCO and attributable to NIPSCO's retail electric customers 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 2022 was ($7,650,349).

Ms. Robles testified Real Time Non-Excessive Energy in July 2022 was $6,501,947, in August 2022 was $8,810,029, and in September 2022 was $6,190,825 primarily due to 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), coupled with relatively high LMPs. She testified the Day Ahead Marginal Congestion Component plus actual monthly Auction Revenue Rights/Financial Transmission Rights ("ARR/FTR") expenses, less actual monthly ARR/FTR revenues, did not exceed a cost of $2 million in any month within the reconciliation period.

Mr. Guerrettaz stated NIPSCO provided a breakdown of congestion components, with this information enabling the OUCC to see that congestion is occurring on both day ahead and real time markets. He recommended NIPSCO continue providing this breakout of all congestion components in future FACs.

The forecast of MISO Components of Cost of Fuel in this proceeding, per Ms. Robles, is based on the High – Low average of actual MISO Components of Cost of Fuel incurred for the 12-month period ending September 30, 2022, where the high and low quarters are replaced with a three-year average of the same quarter. She stated NIPSCO included a forecast in this filing of MISO Components of Cost of Fuel of $1,285,974 per month.

9. **Estimation of Fuel Cost.** In its Second Revised Schedule 1, NIPSCO estimates its total average fuel costs for the billing months of February, March, and April 2023 will be $41,508,997 on a monthly basis.

Ms. Robles noted NIPSCO incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek. The actual and forecasted transportation reservation charges were included on NIPSCO's Attachment 1-A.

Mr. Wagner testified that as of November 7, 2022, NIPSCO's estimated market prices for coal delivery in the forecast period of January, February, and March 2023 were $16.25 per ton for PRB coal, $150.63 per ton for ILB coal, and $137.67 per ton for NAPP coal, excluding transportation costs. He indicated spot market prices increased during the reconciliation period for all coal types. As of November 7, 2022, the estimated spot market prices for shipments with December 2022 delivery were approximately $16.50 per ton for PRB coal, $164.50 per ton for ILB coal, and $137.67 per ton for NAPP coal, excluding transportation costs.

Concerning supply reliability, Mr. Wagner testified contracted purchases are forecasted to meet NIPSCO's 2022 coal delivery requirements, and coal producers are obligated to perform under their agreements. Mr. Wagner stated NIPSCO has had discussions with all its coal suppliers, and they indicated they will meet NIPSCO's contracted coal supply requirements. Mr. Wagner testified the average spot market price of coal during the reconciliation period, not including transportation costs (and change from the previous reconciliation period) was $17.42 per ton (up $0.84) for PRB coal, $179.87 per ton (up $61.67) for ILB coal, and $192.59 per ton (up $58.34) for NAPP coal. He stated these prices do not include the cost of transportation, and actual prices may vary from published indices.

In identifying factors affecting the market for coal and transportation during the reconciliation period, Mr. Wagner stated coal prices continued to climb during the reconciliation period, driven by strong coal demand in Europe with prices for coal delivered to Amsterdam, Rotterdam, and Antwerp spiking on March 8, 2022, to $458.65 per tonne[3] but back to $273.35 per tonne by the end of March. He stated prices rebounded and increased during the reconciliation period to nearly $400 per tonne in July, helping to drive NAPP and ILB prices to new highs. Wholesale electricity prices continued to climb during the reconciliation period, with the key drivers keeping upward pressure on electric prices including strong global energy demand, rising electric demand, high natural gas prices, high coal prices, increased railroad fuel surcharges and rates, and higher emission costs. Mr. Wagner testified the Energy Information Administration ("EIA") projects renewables will contribute 22% of the energy in 2022, natural gas generation will be 38%, and coal will provide 20% of the electric energy supply. He stated United States coal production is expected to increase by 3% in 2022. High natural gas and energy prices in later 2021 and during 2022, per Mr. Wagner, increased the competitiveness of coal domestically and internationally; however, the EIA expects natural gas prices to trend lower into 2023. Given high coal prices and downward pressure on natural gas prices, Mr. Wagner stated coal-fired generation will likely return to the marginal energy source in 2023, but in the long-run, Mr. Wagner testified coal demand will likely fall, driven by lower natural gas prices and as coal generation capacity is phased out of energy markets worldwide.

Mr. Wagner stated these dynamics created significant volatility in all energy markets during the reconciliation period, and although PRB prices have trended lower since February 2022, NAPP and ILB prices increased significantly during the reconciliation period. In addition, strong domestic coal demand and increased coal demand globally have supported higher coal prices. He testified coal pricing into Europe (delivered to Amsterdam, Rotterdam, and Antwerp) increased drastically in 2022 due to high demand and supply shortages in Europe. Mr. Wagner stated coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand, with strong exports and improved domestic demand providing coal producers and coal transporters with increased sales opportunities and improved prices. Per Mr. Wagner, these market conditions combined with constraints in the coal supply chain have created coal supply shortages that led to considerably higher coal prices. He stated the EIA expects steam coal exports to stay near an 84 million ton pace annually through the end of 2023 which will keep pressure on domestic supply in the near term.

[3] One tonne = Metric ton = 1.10231 United States short ton.

Mr. Wagner testified Class I railroads have struggled to meet the surge in demand over the last year and have limited customer shipments for coal as well as other commodities and products they transport. According to Mr. Wagner, 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. He stated these supply and capacity constraints, combined with the unanticipated surge in coal demand and the strong economic recovery, have strained the coal supply chain; consequently, strong coal demand both domestically and globally, combined with coal supply chain challenges, will likely keep upward pressure on coal prices into 2023, but the long-term global trend to aggressively reduce fossil fuel generation will continue to drive the retirement of coal-fired generation. Additionally, Mr. Wagner stated the economy is expected to contract into 2023, and this may put downward pressure on coal and transportation pricing.

Mr. Wagner testified NIPSCO's cost of coal consumed for generation in the forecast period of January, February, and March 2023 is estimated to be $78.20 per ton and $3.712 per million BTU. In developing the estimate for the forecast period, he stated NIPSCO's fuel supply group incorporates coal contract prices inclusive of adjustments specified in the agreement, dust treatment costs, freeze conditioning costs, railcar lease costs, railcar maintenance costs, estimates of contract prices, 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 ("AILLF") adjustments, and estimates of future coal market prices. Additionally, the fuel supply group provides a forecast of beginning inventory values in dollars and quantities in tons for each generation station. These assumptions are provided to NIPSCO's energy supply and optimization group which uses these assumptions to develop the forecast. Ms. Robles testified NIPSCO completed its forecast for this FAC filing on November 11, 2022, using its production cost modeling system, PROMOD,[4] and made reasonable decisions under the circumstances then known.

Ms. Robles advised the fuel cost factor is forecasted to be $46.967 compared to a base cost of fuel of $26.736. She identified three primary drivers for the higher forecasted fuel cost factor. First, forward-looking natural gas prices are projected to be significantly higher than seen in recent years, and purchased power costs are projected to be higher in FAC 137 than in FAC 136 and projected to be higher compared to recent historical pricing. In addition, although forecasted steam generation cost per MWh is anticipated to be higher in FAC 137 than in FAC 136, she explained it is projected to be higher compared to recent historical steam generation costs due to an increase in forecasted coal transportation and commodity pricing as Mr. Wagner discussed.

To ensure NIPSCO provides electricity to Petitioner's retail customers at the lowest fuel cost reasonably possible, Ms. Robles testified NIPSCO utilized the hedging plan approved in FAC 134 that became effective July 1, 2022, and will continue to utilize financial hedges under the 2022 Hedging Plan to mitigate economic impacts and volatility within each FAC. In addition, NIPSCO has added wind resources and will continue adding new resources to its portfolio. She noted these assets 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 growing wind, solar, and solar plus storage assets to economically serve customers.

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

Mr. Wagner testified two key factors that could impact NIPSCO's coal transportation costs during the forecast period are power prices and the price of HDF. He stated power prices may impact coal transportation costs under two transportation contracts that are indexed to station LMPs. Per Mr. Wagner, contract transportation rates are forecasted using forward energy prices and have maximum rates that ultimately hedge price exposure. With respect to the second factor, i.e., the price of HDF, two coal transportation agreements also have mileage based fuel surcharges that vary with changes in HDF which can impact transportation costs. Mr. Wagner testified fuel surcharges under these agreements are calculated monthly using the average weekly spot price of HDF, and fuel surcharge estimates are included in rate projections used to develop comprehensive transportation costs for the forecast period. He testified the spot price of HDF as of November 7, 2022, was $5.333 per gallon, noting this is a 43% year-over-year increase. Mr. Wagner stated EIA expects strong demand in diesel oil markets during November and expects all distillate prices to increase but anticipates retail diesel fuel prices will peak in November at $5.445 per gallon and decline to an average of $4.660 per gallon during 2023. He testified short-term diesel fuel volatility may lead to variations in the actual cost of transportation during the forecast period.

Mr. Wagner testified NIPSCO is proactively administering its coal and rail transportation agreements to address any potential coal supply and/or coal transportation shipment issues. In addition, he stated all the anticipated coal supply requirements for 2022 should be met under current supply agreements. That said, Mr. Wagner indicated the increased demand for coal and coal transportation globally has increased the stress on the coal supply chain. He stated most Class I railroads have struggled to meet customer demand during the first half of 2022 along all lines of their business, and Class I railroads are required to participate in bi-weekly conference calls with the Surface Transportation Board ("STB") to provide status reports and explain efforts to correct service deficiencies. Mr. Wagner testified NIPSCO and Union Pacific have worked through some of the near-term issues, and in addition to daily operations calls, NIPSCO is meeting bi-monthly with this carrier's operations management to ensure shipments meet forecasted delivery requirements. Mr. Wagner stated NIPSCO also continues to work closely with its other rail carriers to ensure coal deliveries meet demand during the forecast period, and NIPSCO has been able to rebuild inventories to target levels since the last quarter of 2021 despite significant supply chain challenges.

Mr. Wagner stated the days of supply of coal inventory at Schahfer equaled approximately 48 days (up 10 days from the prior quarter) at the end of the reconciliation period. He testified improved delivery rates resulted in increased Schahfer inventory. Michigan City's PRB coal inventory was at 26 days, and its NAPP inventory was at 39 days at the end of the reconciliation period. Mr. Wagner testified NIPSCO has made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Mr. Wagner testified NIPSCO's railcar fleet during the reconciliation period was 1,046 railcars. This equated to seven sets with 16.4% spares. He testified the typical spare railcar pool is roughly eight percent, but NIPSCO has been in the process of collecting railcars for return, and that led to variations in the spare railcar count. Mr. Wagner testified that during the reconciliation period NIPSCO utilized roughly 90% of its railcar fleet. He advised that NIPSCO stored sets at Schahfer during a Unit 18 outage in September 2022, but overall, utilization increased from the prior reconciliation period. Per Mr. Wagner, current market conditions have challenged coal deliveries nationwide, and higher transit times combined with higher demand. He stated that given current market conditions, poor rail performance (higher cycle times and lock of crews and locomotives) and planned changes in coal unit operations at Schahfer, NIPSCO has continued to re-evaluate its railcar needs. That said, Mr. Wagner testified NIPSCO is planning to return up to 230 railcars by the end of the second quarter of 2023, reducing NIPSCO's fleet to 816 railcars or approximately six unit trains with roughly eight percent spares.

Mr. Wagner noted NIPSCO reduced its fleet size by 393 railcars in 2021 and returned an additional 17 cars in 2022. He advised that NIPSCO suspended railcar returns due to extending the operation of Schahfer Units 17 and 18, poor railroad performance, and increased coal demand. Additionally, he stated poor railroad performance hampered NIPSCO's ability to collect and return railcars earlier in the year. NIPSCO has no railcars stored at third party locations and has not incurred any long-term storage costs. Mr. Wagner testified most storage requirements can be met by using NIPSCO-owned trackage at Schahfer, a zero cost option. Mr. Guerrettaz noted NIPSCO provided a detailed chart that sets forth, by month, the total railcars and the number of railcars returned, and he testified it is the OUCC's opinion that over time NIPSCO is achieving a correct level of railcars.

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 NIPSCO provided sufficiently detailed testimony and information 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 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, as well as updates upon its efforts to reduce the railcar fleet.

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 2022	$0.057097	$0.050486	(11.58)%
August 2022	$0.057563	$0.045284	(21.33)%
September 2022	$0.053393	$0.042649	(20.12)%
Weighted Average Estimating Error			**(17.24)%**

Ms. Robles testified the total actual fuel cost in the reconciliation period was $178,476,961 while the forecasted fuel cost was $141,539,583. Thus, the average actual fuel cost per kWh for the reconciliation period was 17.24% greater than the forecast. This led to a variance factor of $14.342 primarily driven by volatility in commodity prices and a significant increase in purchased power volumes and costs because of reduced availability at NIPSCO's coal-fired generation stations due to unexpected outages and reduced availability at NIPSCO's Sugar Creek generation station due to a planned outage during this reconciliation period. She explained that the following items varied from the time the forecast was prepared: (1) an approximate 40% increase in the average natural gas prices ($7.510/Dth actual compared to $5.375/Dth estimated) for this reconciliation period; (2) an approximate 21% increase in the all hours average power price in MISO ($85.63/MWh actual LMP compared to $70.60/MWh estimated LMP) for this reconciliation period; (3) an increase in the actual delivered cost of coal during this reconciliation period; and (4) higher actual costs associated with the MISO Components Cost of Fuel driven by a high delta LMP component for this reconciliation period. She advised REC sales and the performance of NIPSCO's hedging program helped to mitigate potential further increases in the impact during the reconciliation period.

Mr. Guerrettaz stated nothing came to the OUCC's attention during the review of NIPSCO's revised filing indicating the projections NIPSCO used for fuel costs and power sales were unreasonable when comparing actual prior quarter and forecasted fuel costs and sales figures. He stated it is the OUCC's opinion that NIPSCO's initial forecast was overstated.

The Commission recognizes NIPSCO's forecasted cost of fuel is increasing, as both NIPSCO and the OUCC acknowledged; however, based on the evidence, including Mr. Guerrettaz's testimony upon the reasonableness of NIPSCO's fuel cost and power sales forecast, the Commission finds NIPSCO's estimate of its prospective average fuel cost to be recovered during the February 2023 through April 2023 billing cycles is reasonable.

10. Return Earned. Subject to Ind. Code § 8-1-2-42.3, Ind. Code § 8-1-2-42(d)(3) requires the Commission to find the FAC applied for will not result in the electric utility earning a return over the return the Commission authorized in the last proceeding in which the utility's basic rates and charges were approved. As discussed below, NIPSCO's evidence demonstrates that for the 12 months ending September 30, 2022, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $295,462,926. This is $14,325,824 more than NIPSCO's authorized amount of $281,137,102, which includes $262,993,515 approved in the applicable rate case, plus $18,143,587 of actual TDSIC operating income during the 12 months ended September 30, 2022; therefore, the Commission finds NIPSCO is earning in excess of that authorized.

Because Petitioner's return exceeds the amount authorized, Ind. Code § 8-1-2-42.3 requires the Commission to determine the amount, if any, of the return to be refunded through the variance in this Cause. A refund is only appropriate if the sum of the differentials (both positive and negative) between the determined return and the authorized return during the relevant period, as defined by Ind. Code §8-1-2-42.3(a), is greater than zero. The overall earnings bank (sum of the differentials) for the relevant period is $52,899,578. As both the current 12-month test period and the sum of the differentials reflect a position of over-earnings, a reduction in the fuel charge is required; however, there is disagreement between NIPSCO and the OUCC as to the amount of excess earnings by which the proposed fuel cost factor should be reduced in this proceeding.

A. <u>NIPSCO's Return-Related Evidence</u>. Ms. Krupa sponsored Attachment 1-F showing NIPSCO's operating income per Petitioner's books for the 12 months ended September 30, 2022, with the electric operating income applicable to jurisdictional retail customers for the same period, to calculate: (1) the Ind. Code § 8-1-2-42(d)(2) test, showing the actual increases in jurisdictional fuel costs have not been offset by actual decreases in other operating expense, and (2) the Ind. Code § 8-1-2-42(d)(3) test to determine if the actual return applicable to NIPSCO's jurisdictional retail customers for the twelve months ended September 30, 2022, was higher than the authorized net electric operating income during the same period.

Ms. Krupa testified that because NIPSCO anticipated the earnings bank being depleted during the third quarter of 2022, NIPSCO began recording a liability of $5,200,000 estimated to result from the FAC 137 earnings test. She stated an adjustment was made to reverse the estimated liability of $5,200,000 and associated taxes (Attachment 1-F, Column F, Lines 1 and 8) and then reflect the actual reduction amount of $3,716,828 and associated taxes resulting from the earnings test calculation shown in Attachment 1-H, Column E, Line 25.

Ms. Krupa stated that although NIPSCO could have reflected the reduction amount in the earnings calculation for this FAC period or the next FAC period, because NIPSCO previously recorded a $5,200,000 estimated liability that impacted the financial statements for the 12 months ended September 30, 2022, the reduction amount in the earnings calculation for the 12 months ended September 30, 2022, is appropriate and consistent with accrual accounting. She explained that NIPSCO could have reflected the full $5,200,000 estimated liability in its FAC 137 earnings calculation but instead reduced earnings in this FAC period by the actual, lower reduction amount of $3,716,828, reducing the impact on FAC 137 earnings, which in turn, increases the FAC 137 actual reduction amount, thereby benefitting Petitioner's customers.

Ms. Krupa sponsored Attachment 1-H showing the historical earned returns for the "relevant period," defined in accordance with Ind. Code § 8-1-2-42.3. She stated the actual return applicable to jurisdictional customers of $296,004,416 from Attachment 1-F (Column H, Line 10) compared to the Authorized Return of $281,137,102 from Attachment 1-G, (Column D, Line 12) results in an over-earning amount of $14,867,314 as shown in Attachment 1-H (Column E, Line 1). Thus, the earnings for the 12-month period ended September 30, 2022, exceeded NIPSCO's annual authorized return. She stated that when the $14,867,314 of over-earnings in the current filing are added to the accumulated earnings to total $53,441,068, as shown in Attachment 1-H (Column E, Line 22), the sum of the differentials for the relevant period of $53,441,068 exceeded the annual authorized return; therefore, under Ind. Code § 8-1-2-42.3, a reduction in the fuel charge is required. Per Ms. Krupa, as specified in Ind. Code § 8-1-2-42.3(b), a reduction in the fuel factor was calculated, as both the current period and the sum of the differentials for the relevant period result in an amount greater than zero.

Ms. Krupa explained how NIPSCO determined the reduction amount reflected in the current FAC period in Attachment 1-H. She stated the current period ended September 30, 2022, results in a positive differential of $14,867,314 (Attachment 1-H, Line 1). The sum of the differentials totaling $53,441,068 (Attachment 1-H, Line 22) reflect the relevant statutory period from December 2017 (FAC 118) through September 2022 (FAC 137). Line 23 determines the basis for the reduction, which is the lesser of Line 1 and Line 22. In this instance, the current period differential shown on Line 1 is the lesser amount. Ms. Krupa stated this amount was multiplied by

25% on Line 24. She testified the resulting amount of $3,716,828 shown on Line 25, represents the basis for the reduction for the current FAC period, included as a reduction to fuel costs recoverable in the current FAC period, as shown on Attachment 1-A, Schedule 1, Line 38a.

Ms. Krupa also sponsored Attachment 1-I providing the calculation of a correction to the sum of the differentials included in Attachment 1-H to correct the non-jurisdictional income tax expense adjustment. She explained that Columns A through E reflect the sum of the differential earnings bank from Attachment 1-H in NIPSCO's Cause No. 38706 FAC 135 (Line 21, Column E); Column F shows NIPSCO's total Electric Operating Income Before Income Tax, and Column G shows NIPSCO's recorded Electric Income Tax Expense for each reporting period, with Column H showing the NIPSCO Electric Effective Tax Rate for each reporting period. She explained that Columns I and J show the Non-Jurisdictional Income Before Income Tax and Non-Jurisdictional Income Tax Expenses at Statutory Rates, with the Rolling 12-Month Statutory Tax Rate shown in Column K, and Column L reflects the Proportional Non-Jurisdictional Income Before Tax. Ms. Krupa testified the historical earned returns for the relevant period reflect the recalculation of the Ind. Code § 8-1-2-42(d)(3) test for the 12-month period ending September 30, 2022, as directed in the FAC 136 Order.

B. <u>The OUCC's Return-Related Evidence</u>. Mr. Guerrettaz testified the OUCC disagrees with NIPSCO's booking of an earnings reduction journal entry before the Commission issues a final Order in this FAC. Mr. Guerrettaz testified a journal entry before the final Order is problematic because the actual amount is not fixed, known, or measurable, and the impact will occur during a future FAC period even if the Commission Order requires a refund. He stated the OUCC corrected for the journal entries and determined a corrected overearnings of $4,414,611 and determined that using a revenue conversion factor of 1.2504 results in a reduction of $5,520,139. Mr. Guerrettaz supported a proposed FAC factor of 33.893 mills/kWh. Mr. Guerrettaz stated the adjustment to the overearnings affected Schedule A (two different factors, as calculated by the OUCC versus NIPSCO's revised calculation), Schedule B (earnings test as proposed by the OUCC), flowed through to Schedule C (earnings bank proposed by the OUCC), with the final difference found on Schedule D (operating expense test as proposed by the OUCC).

C. <u>NIPSCO's Return-Related Rebuttal</u>. In his rebuttal testimony, Mr. Blissmer discussed the differences to the earnings test calculation and refund the OUCC's witnesses proposed from what Petitioner originally filed, and he explained NIPSCO's recalculation of the earnings test and refund calculation set forth in his rebuttal. Mr. Blissmer advised that as compared to NIPSCO's original case-in-chief filing, the OUCC proposed two differences in calculating the refund associated with over-earnings. The first difference relates to the proper use of a conversion rate to determine the grossed-up refund amount that will achieve the appropriate reduction in over-earnings. Mr. Blissmer testified that following discussions with the OUCC's personnel and further review, NIPSCO concedes it is more appropriate to apply a conversion rate as the OUCC recommends. He stated the attachments included with his rebuttal testimony corrected for this. Mr. Blissmer provided a revised Schedule 1 (Sec. Rev. Schedule 1) reflecting an updated refund amount of $4,483,560, an increase of $766,732 from the $3,716,828 that was included in NIPSCO's case-in-chief, and he testified this results in a new proposed FAC factor of 34.284 mills/kWh. He also provided revised Attachments 1-C, 1-F, and 1-H, and a new Attachment 1-J providing an updated calculation of the conversion factor that reflects NIPSCO's capital structure at the end of the test period, September 30, 2022.

Mr. Blissmer stated Attachment 1-F was updated to reflect a corrected refund amount dependent upon the amount of over-earnings calculated on Attachment 1-H, which can be validated by comparing the earnings impact of the refund on Attachment 1-F, Column G, Line 10 with the amount of over-earnings applicable to this proceeding on Attachment 1-H, Column E, Line 25. Also, the refund amount of $4,483,560 on Attachment 1-F, Column G, Line 1 was corrected and is now calculated by multiplying the over-earnings amount of $3,581,456 by the conversion factor of 1.251882. Mr. Blissmer testified that as a result of these updates to the refund amount and the related impact to earnings during the test period in Attachment 1-F, this impacts the over-earnings calculated on Attachment 1-H. This was, therefore, also updated. He stated that because NIPSCO is applying accrual accounting and reflecting the refund in the test period, NIPSCO must solve for what is the appropriate refund amount needed to exactly reduce earnings to the point where Petitioner will no longer be over-earning, which is now the case with the revised attachments and schedules.

Mr. Blissmer testified it is appropriate to reflect a reserve for refund in the test period (as NIPSCO did in its case-in-chief), as opposed to delaying the timing and reflecting the refund earnings impact subsequent to the end of the test period because under Generally Accepted Accounting Principles ("GAAP")/accrual accounting, NIPSCO is required to record a reserve for a refund when that refund is: (a) probable and (b) estimatable; consequently, when NIPSCO identified over-earnings were probable and capable of being estimated, even though an Order had not yet been issued, these criteria were met. In turn, he stated NIPSCO was required and did record a reserve for refund at the end of the test period per the matching principle which dictates recording this refund in the period for which it relates. Mr. Blissmer opined that if NIPSCO delayed recognition of the refund to a future FAC test period, as the OUCC recommends, this will violate the matching principle and throw off the timing in a future FAC test period, resulting in NIPSCO providing an excess refund for the current test period and lowering a potential refund in a future test period, which is inappropriate. Additionally, if NIPSCO were required by the Commission to not recognize the over-earnings refund in the current test period and to recognize it in some future test period, then FAC earnings will not agree with NIPSCO's income statement, as a reserve has already been recorded.

D. <u>Docket Entry Responses</u>. A docket entry was issued on December 30, 2022, requesting the OUCC to confirm the OUCC's position with respect to Mr. Blissmer's rebuttal analysis. The OUCC was also requested to provide a copy of the corrected adjustment journal entries referenced in Mr. Guerrettaz's testimony and to confirm whether the OUCC agrees with NIPSCO's proposed revised FAC factor presented in Mr. Blissmer's rebuttal testimony, and if not, to explain why the OUCC does not agree. NIPSCO was also requested in the docket entry to provide a copy of its corrected and/or revised journal entries.

NIPSCO provided its pre-tax corrected adjustment journal entries on January 3, 2023. The journal entries reflect a $3,716,828 refund, as NIPSCO will make an additional $766,732 refund entry per its rebuttal testimony in the December 2022 close of its accounting books and records.

In the responses the OUCC filed on January 4, 2023, the OUCC continued to disagree with NIPSCO booking an earnings reduction journal entry before the Commission issues an Order in this FAC because the actual amount, per the OUCC, is not fixed, known, or measurable and when the impact will occur. The OUCC also stated that NIPSCO provided the corrected journal entry amounts to the OUCC using a more updated revenue conversion factor, with those journal entries provided by NIPSCO in responding to the docket entry. Additionally, the OUCC stated that using Mr. Blissmer's reasoning, the resulting FAC factor is 34.282 mills per kWh.

E. Commission Discussion and Findings. The Commission finds Petitioner's earnings for the period ending September 30, 2022, exceed the amount authorized. Although NIPSCO and the OUCC differ upon the amount of over-earnings they each calculate (*See* Petitioner's Exhibit 5-R, Attachment 5-R-B, Revised Attachment 1-H, Column E, Line 1; Public's Exhibit 1, Schedule B-1), both calculations yield over-earnings; therefore, under Ind. Code § 8-1-2-42.3, the Commission will review the calculation of the sum of the differentials for the relevant period to determine if a reduction to the FAC factor is required. This calculation and whether a reduction to NIPSCO's fuel charge is required are impacted by the calculation of over-earnings within the test period.

As discussed above, NIPSCO and the OUCC initially disagreed in two respects on the methodology to calculate the amount of excess earnings NIPSCO must refund through the FAC factor approved in this Cause: (1) the proper use of a conversion rate to "gross-up" the refund amount for taxes and (2) reflecting a reserve for refund in the test period rather than reflecting the refund earnings impact subsequent to the end of the test period.

As to the proper use of a conversion rate, in rebuttal, Mr. Blissmer conceded that applying a conversion rate as the OUCC recommends is appropriate. NIPSCO's rebuttal schedules and attachments, consequently, reflect a 1.251882 conversion rate, consistent with NIPSCO's capital structure as of September 30, 2022, the end of the test period. The Commission finds that applying a conversion rate to NIPSCO's excess earnings in the test period is reasonable and approves the 1.251882 conversion rate NIPSCO used in its rebuttal. This conversion factor is slightly more favorable for consumers than the 1.2504 the OUCC used.

Regarding the second disputed issue, Ms. Krupa and Mr. Blissmer testified that reflecting a reserve for refund in the test period is consistent with GAAP/accrual accounting, in that the refund is recorded in the period for which it relates. The OUCC opposes NIPSCO reflecting a reserve for refund in the test period, contending this journal entry before the Order is approved in this Cause is problematic as the actual amount is not fixed, known, or measurable. Per the OUCC's docket entry response, "the impact would occur in a FAC factor during a future FAC period prior to the Commission ordering a refund."

The Commission is not, however, persuaded by the OUCC with respect to this second issue. Because the mechanics of the FAC earnings test and requirements for when a refund is due are detailed in Ind. Code § 8-1-2-42.3, NIPSCO was able to estimate the refund amount when Petitioner identified that a refund is probable in this proceeding. The Commission finds this was shown to be consistent with GAAP/accrual accounting. Importantly, including the reserve for refund in the test period will ensure that FAC earnings and NIPSCO's income statement agree. Further, in its docket entry response, the OUCC appears to misunderstand that the FAC factor will be adjusted only after the Commission has ordered a refund, not before. The Commission finds NIPSCO's rebuttal schedules reflect the appropriate refund amount to reduce earnings in compliance with the mechanics of Ind. Code §8-1-2-42.3. We also note a comparable conceptual adjustment was made in Cause No. 38703 FAC 130 without challenge by the OUCC, and we are not persuaded to do otherwise in this FAC given the testimony that this is consistent with GAAP/accrual accounting.

In each unique FAC proceeding, a finding must be made under Ind. Code § 8-1-2-42(d) upon whether the FAC will result in the electric utility earning a return in excess of its authorized return and if so, the fuel charge applied for is to be reduced so no excess return will be earned, subject to the mechanics of Ind. Code §8-1-2-42.3. For purposes of the required findings in this FAC, the Commission finds the application of NIPSCO's proposed calculation of the over-earnings refund, as detailed in its rebuttal schedules and attachments, is reasonable and consistent with Ind. Code § 8-1-2-42(d)(3) and Ind. Code § 8-1-2-42.3. Having found NIPSCO's proposed refund calculation for purposes of determining its earnings is reasonable, the overall earnings bank (sum of the differentials) for the relevant period is $52,899,578, and the jurisdictional earnings for the 12 months ending September 30, 2022, equal over-earnings of $14,325,824 (Petitioner's Revised Attachment 1-H); therefore, under the mechanics of the applicable statutes, the Commission finds it is appropriate to reduce NIPSCO's fuel cost factor to reflect the excess return NIPSCO earned during the 12-month period ending September 30, 2022. This amount, after application of the conversion factor, is $4,483,560.

11. <u>OUCC Report</u>. In addition to the testimony referenced above, particularly in Finding No. 10, 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, 2022, was computed in conformity with Ind. Code §§ 8-1-2-42, -42.3, and relevant orders; (3) NIPSCO did have jurisdictional net operating income for the 12 months ending September 30, 2022, greater than granted in its last general rate case; (4) NIPSCO did not have decreases in other operating costs that could be used to offset fuel cost increases; and (5) the figures used in NIPSCO's application for a change in the FAC for the quarter ending September 30, 2022, were supported by Petitioner's books, records, and source documentation for the period reviewed. Mr. Guerrettaz stated the OUCC recommends the FAC factor of 0.033893 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 from the expected forecast presented; (2) a break out of all congestion components in future FACs; (3) detailed coal cost statements from each supplier to each station for the three actual months on a going forward basis setting forth the components of coal and transportation; and (4) a copy of all new RFPs and contracts for transportation and coal.

Mr. Eckert testified: (1) he 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, while NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor-owned utilities in Indiana; (5) coal prices increased dramatically over the last 12 months; (6) NIPSCO's coal inventory at Schahfer increased to approximately 48 days, up ten days from its prior FAC filing; (7) NIPSCO's PRB coal inventory at Michigan City Generating Station was at 26 days, and its NAPP coal inventory was at 39 days for the reconciliation period; (8) NIPSCO should continue to update the Commission on its coal inventory; (9) 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; (10) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (11) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, Rosewater, and Indiana Crossroads; (12) NIPSCO provided an update on the status of the Railroad Litigation[5] and NIPSCO's deferral of associated legal costs and should continue providing such updates; and (13) the OUCC recommends the Commission approve NIPSCO's proposed FAC factor as recalculated and proposed by Mr. Guerrettaz.

12. Fuel Cost Adjustment Factor. Based on the evidence, the Commission finds NIPSCO has complied with the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment and appropriately reduced NIPSCO's fuel cost factor to reflect the excess return NIPSCO earned during the 12-month period ending September 30, 2022. NIPSCO's evidence presented a revised variance factor of $0.014053 per kWh, composed of the reconciliation and earnings adjustment components, to be added to the estimated cost of fuel for bills rendered during the February 2023 through April 2023 billing cycles in the amount of $0.046967 per kWh. This results in a fuel cost adjustment factor of $0.034284 per kWh, after subtracting the cost of fuel in base rates. NIPSCO's revised estimated average monthly bill impact for a residential customer using 1,000 kWh per month is a $4.64 increase from the factor currently in effect.

13. 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 the rates approved herein should be interim rates, subject to refund.

14. Major Forced Outages. Consistent with past Commission Orders, Mr. Saffran sponsored Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the third quarter of 2022, 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 the forced outages for which an analysis was completed at the time of the FAC filing.

Per Mr. Eckert, although the OUCC generally reviews NIPSCO's unit commitment status, the OUCC's FAC audit process has focused more on the cost of fuel and the cost of purchased power; however, Mr. Guerrettaz advised the loss of the Sugar Creek generating station increased MISO purchases by a material amount. He testified NIPSCO's generation units' availability during the summer months is important, with Sugar Creek's unavailability during September 2022 causing NIPSCO to purchase a larger percentage of high priced power from the market.

[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 allegedly 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").

15. **<u>Status of Railroad Litigation</u>.** In accordance with the Commission's Order in Cause No. 38706 FAC 125 ("FAC 125"), Ms. Krupa testified the Railroad Litigation remains pending, and as of September 30, 2022, NIPSCO has deferred $3,255,333 in associated legal costs. Mr. Wagner advised the Railroad Litigation is in the discovery phase, with NIPSCO's counsel deposing the defendants' corporate representatives and providing support to NIPSCO's expert witness in developing the initial expert report upon which NIPSCO will rely. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so in its FAC filings.

16. **<u>Confidential Information</u>.** On November 15, 2022, NIPSCO filed a motion for protection and nondisclosure of Confidential Information supported by an affidavit showing information 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 a docket entry issued on November 30, 2022, such information was found to preliminarily be confidential, after which NIPSCO submitted the information under seal. The Commission finds such information is confidential under 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 2023 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 and solar purchases being recovered through the FAC, as discussed in Finding No. 7.C. 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. 7.D. 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, and continue to provide updates on its railcar inventory and efforts to achieve an appropriate railcar level, explaining any deviations that occur.

5. NIPSCO shall include in its quarterly FAC filings information related to the 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 assure the OUCC is provided with a copy of all new RFPs and contracts for transportation and coal that are issued.

6. If coal decrement pricing is used or forecast, NIPSCO shall file in its future FAC proceedings appropriate testimony, schedules, and workpapers 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. 7.B. above.

7. NIPSCO shall continue to include in its quarterly FAC filings an update on the Railroad Litigation consistent with the Commission's January 22, 2020 Order in FAC 125 and Finding No. 15 above.

8. NIPSCO shall continue to break out congestion components in its future FAC testimony, provide a cost of coal stacks from each supplier to each station for the three actual months on a going forward basis, and provide a copy of all new requests for proposal and contracts for transportation and coal consistent with Finding No. 11 above.

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, FREEMAN, KREVDA, VELETA, AND ZIEGNER CONCUR:

APPROVED: JAN 25 2023

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: 2023.01.25 10:35:11 -05'00'

Dana Kosco
Secretary of the Commission