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 NOVEMBER AND DECEMBER 2024 AND JANUARY 2025, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 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, 45524, 45541, AND 45936, PURSUANT TO IND. CODE § 8-1-2-42(d).	)	**CAUSE NO. 38706 FAC 144** **APPROVED: OCT 23 2024**

ORDER OF THE COMMISSION

Presiding Officer:
Kristin E. Kresge, Administrative Law Judge

On August 20, 2024, 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 the November 2024 through January 2025 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. 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, 45524, 45541, and 45936, pursuant to Ind. Code § 8-1-2-42(d). NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company ("NCSC") employee Kelleen M. Krupa, Lead Regulatory Analyst, and the testimony and exhibits of the following NIPSCO employees:

- Christa P. Hook, Manager of Market Settlements;
- John Wagner, Manager, Fuel Supply; and
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division;

On August 20, 2024, NIPSCO also filed a motion requesting confidential treatment for certain information ("Confidential Information"). In a Docket Entry issued September 9, 2024, the requested confidential treatment was granted on a preliminary basis.

On August 22, 2024, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on September 9, 2024.[1]

On September 24, 2024, 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 September 27, 2024, NIPSCO filed rebuttal testimony of Mr. Wagner.

The Commission noticed this matter for an evidentiary hearing at 1:30 p.m. on October 10, 2024, 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 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 cost of fuel included in the cost of purchased electricity for the months of April, through June 2024 averaged $0.033001 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment from the current fuel cost factor charge of $(0.005347) per kWh for bills rendered during the August, September, and October 2024 billing cycles to a fuel cost charge of $0.000690 per kWh for bills rendered during the November 2024 through January 2025 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing.

[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.

The requested fuel cost adjustment includes a variance of $3,162,922 that was under-collected during April, May, and June 2024 ("reconciliation period"). NIPSCO's estimated monthly cost of fuel to be recovered in this proceeding for November 2024 through January 2025 ("forecast period") is $27,831,260, and its estimated monthly average sales for that period are 840,558 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

(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 June 30, 2024, were $15,192,827 less than the amount the Commission approved in the 45159 and 45772 Orders. NIPSCO's Attachment 1-F also shows its total operating expenses, excluding fuel, for the 12 months ending June 30, 2024, were $3,978,782 above the amounts approved in the 45159 and 45772 Orders. The Commission finds there have been no increases in NIPSCO's actual fuel costs for the 12 months ending June 30, 2024, that have 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

[2] The average cost of fuel and estimated monthly average sales to be recovered in this proceeding for the forecasted billing period of November and December 2024 and January 2025 are based on the estimated averages for October, November, and December 2024 as shown on Schedule 1.

possible. He testified that during the reconciliation period, of the energy produced by NIPSCO's fossil-fueled generation, NIPSCO's coal-fired generation provided 24.6% of energy generated and 75.4% 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. <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 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 the 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 had three supply contracts that were effective during the reconciliation period. 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 longer 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, and that other price adjustments can occur due to governmental imposition or payment of damages. 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 agreement was priced using a coal market index. One contract had rates that decrease when shipments meet specific tonnage thresholds. In addition, all 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 June 30, 2024, was $68.42 per ton, or $3.332 per million Btu. The cost of coal consumed during the reconciliation period was $94.58 per ton, or $4.300 per million Btu. When compared to the prior reconciliation period, Mr. Wagner stated NIPSCO's delivered cost of coal consumed per ton increased by $23.67 and the cost was up $0.832 per million Btu. Mr. Wagner testified the main driver of the increase was a significant change in the mix of coals consumed during the reconciliation period. Specifically, during the reconciliation period, Schahfer consumed 94.5% of tonnage and Michigan City consumed 5.5% of tonnage, versus 42.1% and 57.9%, respectively.

The delivered cost of ILB coal was higher than the mix of coals used at Michigan City. Railroad fuel surcharges were stable as average on-highway diesel fuel prices were flat when compared to the prior quarter. PRB and NAPP delivered prices declined when compared to the reconciliation. These two factors offset some of the increase in the delivered cost of coal consumed for the system.

Ms. Hook described NIPSCO's two distinct processes for purchasing natural gas for electric generation: (1) purchasing gas as a large transport customer under Rate 228 from NIPSCO's gas local distribution company and (2) procuring natural gas for NIPSCO's Sugar Creek combined cycle plant, which is located on a Midwestern Gas Transmission interstate pipeline. 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. Renewable Energy Credits ("RECs"). Ms. Hook 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 the 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; (6) July 28, 2021 in Cause No. 45524 ("45524

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; and (7) September 1, 2021 Order in Cause No. 45541 (“45541 Order”), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Crossroads Wind II on December 22, 2023. Consistent with the 43393, 45194, 45195, 45310, 45462, 45524, and 45541 Orders, NIPSCO is also crediting any off-system sales created by its wind and solar PPAs. For the reconciliation period, NIPSCO received 378,911 MWhs (April), 225,539 MWhs (May), and 253,524 (June). The OSS Adjustment for the forecast period is included on Attachment 1-A, Schedule 1, Line 38.

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

Transaction	RECs Sold	Net Proceeds
1	22,344	$ 73,735
2	50,000	$ 160,063
3	50,000	$ 162,500
4	9,476	$ 20,847
5	150,000	$ 591,000
6	34,698	$ 111,077
7	100,000	$ 398,925
8	50,000	$ 197,000
9	75,000	$ 295,500
10	200,000	$ 768,300
11	100,000	$ 385,000
Total	841,518	$ 3,163,947

Ms. Hook 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. Per Ms. Hook 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. Hook stated during the reconciliation period, NIPSCO had 27 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. Hook testified current vintage solar and wind feed-in tariff (“FIT”) RECs were sold. The block size and proceeds from the sale are as follows:

Transaction	RECs Sold	Net Proceeds
1	11,817	$ 20,680
Total	11,817	$ 20,680

Ms. Hook 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. Hook 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 short-term, third-party agreements for purposes of protecting customers from market influences.

Ms. Hook 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 June 30, 2024.

Ms. Hook stated NIPSCO has incorporated 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 June 30, 2024. 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 June 30, 2024.

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, 45524, 45541, and 45936 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. <u>Electric Hedging Program</u>. Ms. Hook 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
April 2024	30	20	34	0
May 2024	60	5	25	0
June 2024	30	0	34	0

Ms. Hook stated the execution of these contracts is consistent with the Hedging Plan through June 2024; however, in the months of April and May, power hedges differed from the plan due to a change that was made in the updated 2022-2024 hedge plan due to supply chain issues and the Department of Commerce investigation that had taken place in 2022 which delayed the anticipated commercial operation date of NIPSCO's solar projects. She explained there are no other changes to the Hedging Plan and to the extent NIPSCO updates its plan further, future FAC filings will disclose any additional deviations from the approved plan.

Ms. Hook testified the impact of the hedges entered for the Hedging Plan during the reconciliation period was a loss of $2,185,350, with the net total impact (including broker and clearing exchange fees) of $2,195,851. Broker fees represented 0.10% of the total value of the transactions occurring during the reconciliation period. Ms. Hook 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 93 gas and 120 power contracts during the three-month period under review.

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.

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 April through June 2024 was $14,238,156

Ms. Hook testified the Real Time Non-Excessive Energy was $2,370,226 in June 2024 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). Ms. Hook 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, exceeded a cost of $2 million in April 2024. She explained the primary driver was the high average congestion prices at NIPSCO's NIPS.NIPS node during April 2024 that exceeded the average by approximately 16 times for the period of January through March 2024. She stated NIPSCO inquired of MISO as to the cause for the high congestion rates, to which MISO responded that the high level of congestion in April at the NIPS.NIPS node was due to several outages in the area.

9. Estimation of Fuel Cost. NIPSCO estimates its total average fuel costs for November 2024 through January 2025 will be $27,831,260 monthly.[3] Ms. Hook noted that NIPSCO incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek.

[3] The estimated total average fuel costs for October, November, and December 2024 as shown on Schedule 1 is used to calculate the amounts to be recovered in this proceeding for the forecasted billing period of November and December 2024 and January 2025.

Mr. Wagner testified that as of July 31, 2024, NIPSCO's estimated F.O.B. mine spot market prices for delivery during the forecast period were $13.55 per ton for PRB coal, $31.50 per ton for ILB coal, and $52.00 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 2024 and into 2025. 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 expected to meet most of NIPSCO's 2024 forecasted 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 decreases in price as shipments increase. A second contract has fixed prices and a portion of tonnage is priced at market. Both agreements have minimum and maximum rates that ultimately hedge customer price exposure. 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 $13.50 per ton (down $0.07) for PRB coal, $30.00 per ton (down $2.06) for ILB coal, and $50.50 per ton (down $1.50) 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 10% lower during the reconciliation period when compared with the same period in 2023 and coal prices were lower year over year. Overall energy market conditions remained soft as low natural gas prices, increasing renewable generation, and mild spring weather reduced coal demand. The U.S. Energy Information Administration ("EIA") calculated the U.S. electric energy supply mix for 2023 and projects mix expectations for 2024 and 2025 in its latest outlook as follows: (1) during 2023, renewable generation averaged 21% of the electric energy supply mix and is expected to increase to 23% in 2024 and 25% in 2025; (2) nuclear generation provided 19% of electric generation in 2023 and is expected to provide 19% in 2024 and 2025; (3) natural gas-fired generation provided 42% of electric generation in 2023 and is expected to provide 42% and 40% in 2024 and 2025 respectively; (4) coal-fired generation comprised 17% of the generation mix in 2023 and is expected to decline to 16% in 2024 and 16% in 2025; and (5) U.S. coal production fell by 2.1% in 2023 to 582 million tons and is expected to decrease 14% in 2024 and another 5% in 2025. The EIA is projecting Henery Hub spot pricing to decrease from the 2023 average of $2.54 per MMBTU to $2.30 per MMBTU during 2024 and rebound to $3.27 in 2025. Illinois Basin coal prices are down roughly 21% and PRB prices are 4% when compared to year-ago levels. Despite the substantial decline in coal prices over the last year and a half, falling natural gas prices and increasing renewable demand has kept coal-fired generation as the marginal energy source and this dynamic is expected to continue and will likely keep soft coal pricing and limit price volatility. NIPSCO expects coal demand will continue to fall in the long run driven by low natural gas prices and increased renewable production as coal generation is phased out of domestic energy markets.

Mr. Wagner testified these dynamics have continued to keep prices soft in all energy markets during the reconciliation period. He said that coal pricing into Europe (delivered to ARA) fell precipitously during 2023. API 2 prices were roughly 15% 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. Despite lower API 2 prices during 2023, export markets provided relatively steady sales opportunities during the year and coal exports totaled 99.8 million tons (5-year high) and the EIA expects coal exports may increase to 103.0 million tons in 2024 despite the collapse of the Francis Scott Key bridge that had impacted shipments through the Port of Baltimore in the early part of 2024. The EIA expect to reach 103.8 million tons in 2025. The outlook for global coal use is somewhat bullish and export opportunities are expected to remain steady or improve. Mr. Wagner testified transportation has also impacted energy markets as Class I railroads struggled to meet the surge in demand during 2021 through early 2023, which limited customer shipments for coal as well as other commodities and products. He stated railroad performance has improved since that period but that reduced investment in coal production and coal transportation projects, supplier bankruptcies, and mine closures over the last several years, have caused coal supply chain constraints, which may lead to market volatility if energy prices and demand rebound.

Mr. Wagner testified that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period is $76.63 per ton or $3.687 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 costs (seasonal), 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. Hook testified that NIPSCO completed its forecast for this FAC filing on August 8, 2024, 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 $33.110 compared to a Base Cost of Fuel of $33.674. Ms. Hook explained that in comparing FAC 144 to FAC 143, (1) combined cycle generation is projected to be lower on a total MWh basis and the forecasted cost per MWh is higher; (2) wind energy purchases and wind joint venture purchases are projected to be greater on a total MWh basis and the forecasted cost per MWh is lower; (3) MISO components cost of fuel is projected to be higher; and (4) steam generation is projected to be lower on a total MWh basis and the forecasted cost per MWh is higher.

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

Ms. Hook 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 have mileage-based fuel surcharges (governed by each carrier's fuel surcharge tariff) that 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 July 29, 2024 was $3.779 per gallon. This is an 8% year-over-year decrease. The EIA expects global oil inventories to decrease during the second quarter of 2024 due to flat production and increasing demand, driving the forecast for the remainder of 2024 and they expect HDF prices to average $3.84 per gal during 2024 and expects OPEC+ to hold production at or below their announced target. This supply demand balance is expected to keep global inventories at the bottom of the five-year average; however, increased production from non-OPEC+ countries and as the voluntary OPEC+ cuts unwind in 2025 that should limit the increase in pricing to an average of $3.87 per gallon in 2025. Based on this outlook, fuel surcharges under NIPSCO's transportation agreements are expected to increase modestly during the forecast period but remain below 2023 levels.

Mr. Wagner testified NIPSCO is proactively administering coal and rail transportation agreements to address any potential coal supply and/or coal transportation shipment issues. In addition, all anticipated coal supply requirements for 2024 should be met under current coal supply and transportation agreements. Coal market demand has softened significantly over the past 15 months and the stress on the coal supply chain has been reduced. However, if coal demand increases, utilities may struggle to schedule deliveries as railroads and coal producers have rationed assets, labor, and production, and it will take time for production and shipments to recover to meet any increase in demand. Notwithstanding, NIPSCO continues to work closely with its rail carriers to ensure coal deliveries meet demand during the forecast period.

Mr. Wagner stated the days of coal inventory supply at Schahfer was approximately 48 days (down 14 days from the prior quarter) at the end of the reconciliation period. He testified soft market conditions and low coal demand forced NIPSCO to park sets in Quarter 2 2024 to lower inventory at Schahfer. Sets were also parked for Michigan City as the unit was in economic reserve for most of the reconciliation period. Michigan City's PRB coal inventory was at 36 days and the NAPP inventory was at 33 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 785 railcars (six 125-car sets with 4.7% spares) at the end of the reconciliation period. The typical spare railcar pool ranges between 3% and 8%. NIPSCO is actively collecting 10 railcars for return and expects to have these cars returned to lessors by the end of September. According to Mr. Wagner, during the reconciliation period, NIPSCO utilized roughly 17% of its railcar fleet. He explained NIPSCO stored two sets at Schahfer at the start of the reconciliation period and had three sets stored at Schahfer, two sets stored at Michigan City, and one set stored at a third-party location by the end of the period. Storage of railcars was required from time to time during the reconciliation period as coal consumption continued to trend well below forecast due to extremely soft energy market conditions, strong renewable production, much better than expected railroad performance, planned and unplanned station maintenance outages, extended periods of coal units idle (economic reserve), and high inventory levels. NIPSCO continuously evaluates its railcar needs and considers forecasted and maximum demand coal demand, delivery requirements (forecasted and actual), railroad performance, station unloading performance, and the timing of lease expirations. NIPSCO determined that the fleet size should be held to 775 railcars (six-unit trains with roughly 3.3% spares) through the end of 2025. Consistent with that plan, NIPSCO returned 244 railcars during 2023, returned 17 railcars through the end of the reconciliation period and should complete returns by the end of September 2024. NIPSCO will continue to use commercially reasonable efforts to return the remaining cars to the lessor.

Mr. Wagner testified that to mitigate railcar cost while balancing reliability, NIPSCO reduced the fleet size driven by coal unit retirements. During the reconciliation period, NIPSCO reduced the fleet size in 2023 by 244 railcars and returned 17 railcars through the end of Quarter 2, 2024 and plans to return another 10 cars by the end of September 2024 to mitigate expense. During the reconciliation period, NIPSCO did have one set of railcars in long-term storage at a third-party location. Whenever possible, NIPSCO utilizes Michigan City's or Schahfer's trackage (a zero-cost option) or subleases railcars to minimize cost. Mr. Guerrettaz testified that NIPSCO provided a detailed chart by month that set forth the total railcars and the number of railcars returned.

Mr. Wagner testified although NIPSCO stored two sets at Michigan City and three sets at Schahfer, NIPSCO's coal demand was substantially lower than the forecast and inventories at both Michigan City and Schahfer were above targets. Notwithstanding, the railcar market for rotary coal gondolas is volatile and relying on that market to obtain railcars for short-term needs can adversely impact supply reliability and is not prudent. He stated that the nature of lease agreements and the time required to place cars into service or return cars to lessors is a costly and time-consuming process. Mr. Wagner testified it is not prudent, practical, or economic to dynamically increase or reduce the fleet size when coal demand deviates from the forecast. He noted that determination of fleet size is a forward looking, multivariate analysis (NIPSCO's system set requirements can vary by two to three sets depending on consumption, railroad performance, and station unloading performance assumptions) and it can take several months to bring cars into the fleet and it is an even longer process when returning cars. He said there are significant costs to place cars into service (out of route transportation charges, car mark stenciling costs, etc.) and when cars are returned (out of route charges, locomotive release charges, shop costs, return maintenance costs, car mark stenciling costs, etc.). Also, the timing of lease terms can preclude short-term fleet size changes. Mr. Wagner stated he is aware that some large utilities continue to hold "excess" railcars out of concern that it may be difficult and/or more expensive to lease cars if demand improves and that one industry expert indicated that there are essentially no rapid discharge coal railcars available in the market and very few, if any, rotary dump coal gondolas (railcars NIPSCO requires) available. Overall, the total number of railcars available in the market has decreased substantially over the last few years because scrap rates of coal railcars have been aggressive and the uncertainty in railcar availability has driven several utilities to hold and store railcars even with decline of coal demand. Therefore, the uncertainty of railcar supply in the market and the potential volatility in coal demand and railroad performance requires a conservative approach to fleet management.

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)
April	$0.032562	$0.032169	(1.21%)
May	$0.034207	$0.033426	(2.28%)
June	$0.032330	$0.029277	(9.44%)
Weighted Average Estimating Error			(4.47%)

Ms. Hook testified the (4.47%) difference led to a variance factor of ($1.254) primarily driven by (1) a higher actual cost associated with the MISO Components Cost of Fuel driven by a higher delta locational marginal price ("LMP") component; (2) a lower OSS adjustment credit; and (4) hedging losses associated with NIPSCO's Electric Hedging Program.

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 November 2024 through January 2025 billing cycles is reasonable.

10. Return Earned. 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 June 30, 2024, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $397,932,715. This is $5,371,203 more than NIPSCO's authorized amount of $392,561,512, which includes $381,361,459 approved in the applicable rate cases, plus $11,200,053 of actual TDSIC operating income during the 12 months ended June 30, 2024. NIPSCO calculates the overall earnings bank (sum of the differentials) for the relevant period as $134,918,010; 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 June 30, 2024, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

11. OUCC Report. Mr. Guerrettaz testified the fuel cost element of the proposed fuel cost adjustment has been calculated in conformity with Ind. Code §§ 8-1-2-42 and previous Commission orders; and the fuel cost adjustment for the quarter ending June 30, 2024 has been properly applied in conformity with the requirements of Cause No. 38706 FAC 141 and 142. Mr. Guerrettaz recommended the Commission approve NIPSCO's factor of 0.690 mills per kWh, and recommends the Commission order NIPSCO to (1) continue to provide the monthly railcar inventory, 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; (2) continue to provide 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) provide testimony in the next FAC covering the incremental increase in coal prices, the contract amendments (if any), and the amount sought for recovery and an economic analysis showing the benefit to the customer of the lower purchased power as compared to the offer price into MISO that NIPSCO is using.

In rebuttal, Mr. Wagner testified that NIPSCO's FAC 144 factor includes a liquidated damages payment that was approved by the Commission in in its FAC 143 Order. He stated that the OUCC recommends approval of NIPSCO's FAC 144 factor, but Mr. Guerrettaz also alleged that NIPSCO's evidence in this FAC and in FAC 143 was inadequate and did not demonstrate that customers are better off by NIPSCO paying the coal contract liquidated damages. Mr. Wagner pointed out that this statement ignores his FAC 143 rebuttal testimony, and the Commission's findings in the FAC 143 Order. He testified the FAC 143 Order acknowledged the customer benefits and savings associated with the 2023 shortfall tonnage, which resulted in an estimated reduction in customer fuel cost of roughly $1.9 million, as well as $677,000 resulting from NIPSCO negotiating a lower settlement rate and deferral of the lump sum payment to Peabody, for a total estimated customer benefit of roughly $2.6 million. He testified NIPSCO's fuel costs are prudently incurred to optimize value for NIPSCO's customers and manage inventory, and his

FAC 143 rebuttal testimony described, in detail, the evaluations and practices undertaken as part of NIPSCO's ongoing procurement and inventory management process, which is designed to make every reasonable effort to acquire and manage fuel supply to provide electricity at the lowest cost reasonably possible.

Mr. Eckert testified: (1) NIPSCO's treatment of Ancillary Services Market ("ASM") charges follow the treatment the Commission ordered in its June 30, 2009 Phase II Order in Cause No. 43426 ("Phase II Order"); (2) 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; (3) NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor owned utilities in Indiana; (4) NIPSCO's steam generation costs are higher than 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 and 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; (6) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (7) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, Rosewater, and Indiana Crossroads; and (8) NIPSCO provided an update on the status of the Railroad Litigation.[5] Mr. Eckert further testified a residential customer using 1,000 kWhs in September 2024 will pay $185.90 (excluding taxes), which consists of $180.24 in base charges set in NIPSCO's last approved rate case (Cause No. 45772), $(5.35) in a fuel adjustment clause credit, and $5.66 in non-FAC trackers.

12. <u>Fuel Cost Adjustment Factor</u>. OUCC witness Eckert recommended the Commission approve the proposed fuel cost factor as calculated by OUCC witness Guerrettaz. Mr. Guerrettaz testified the OUCC is recommending the Commission approve NIPSCO's factor of $0.690 mills per kWh. 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 ($0.001254) per kWh to be added to the estimated cost of fuel for bills rendered during the November 2024 through January 2025 billing cycles in the amount of $0.034364 per kWh. This results in a fuel cost adjustment factor of $0.000690 per kWh after subtracting the cost of fuel in base rates. A residential customer using 1,000 kWh per month will experience an increase of $6.04 on his or her electric bill from the currently approved factor.

13. <u>Interim Rates</u>. 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. <u>Major Forced Outages</u>. 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 first quarter of 2024, including the length and cause of

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[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").

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, 2024, NIPSCO has deferred $5,367,220 in associated legal costs. Mr. Wagner advised the Railroad Litigation remains consolidated for pre-trial purposes in multi-district litigation. The defendant railroads filed their summary judgment motions in July 2024 and both sides filed admissibility challenges regarding expert opinions on the same date. NIPSCO's counsel is now developing the response to the motions filed by the defendant railroads, which must be filed by October 18, 2024. 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. Confidential Information. On August 20, 2024, 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 a September 9, 2024 docket entry, such information was found to preliminarily be 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 November 2024 through January 2025 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. 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.

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

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

APPROVED: OCT 23 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: 2024.10.23 10:12:14 -04'00'

Dana Kosco
Secretary of the Commission