ORIGINAL

Commissioner	Yes	No	Not Participating
Swinger			√
Bain	√		
Deig	√		
Jerrells	√		
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 FOR ELECTRIC SERVICES RENDERED ON OR AFTER NOVEMBER 1, 2026, WHICH WILL REMAIN IN PLACE FOR THE PERIOD NOVEMBER AND DECEMBER 2026 AND JANUARY 2027, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 46120, AND (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND AND SOLAR ENERGY APPROVED IN CAUSE NOS. 45194, 45195, 45310, 45462, 45472, 45524, 45541, 45887, AND 45908, PURSUANT TO IND. CODE § 8-1-2-42(d).	**CAUSE NO. 38706 FAC 152** **APPROVED: OCT 28 2026**

ORDER OF THE COMMISSION

Presiding Officer:
David E. Ziegner, Commissioner
Steve Henke, Administrative Law Judge

On August 20, 2026, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Petition in this Cause. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company employee Kelleen M. Krupa, Lead Regulatory Analyst, and the testimony and exhibits of the following NIPSCO employees:

- Rosalva Robles, Manager of Planning – Regulatory Support;
- Joseph Quenett, Principal Fuel Procurement;[1]
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division.

On August 21, 2026, Citizens Action Coalition of Indiana, Inc. ("CAC"), and the NIPSCO Industrial Group ("Industrial Group") filed petitions to intervene, both of which were granted.[2]

[1] NIPSCO initially filed the Verified Direct Testimony of John Wagner, but substituted this testimony for Mr. Quenett's, as noted below.

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

On September 24, 2026, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony and exhibits of the following:

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

NIPSCO filed a Notice of Intent Not to File Rebuttal Testimony and a Notice of Substitution of Witness on September 29, 2026.

The Commission held an evidentiary hearing at 10:30 a.m. on October 8, 2026, in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, CAC, 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. 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 ("FAC"). Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause. Notice of the evidentiary hearing in this Cause was published as required by law.

2. NIPSCO's Characteristics. NIPSCO is a limited liability company organized under Indiana law with its principal office in Merrillville, Indiana. NIPSCO renders electric 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 June 26, 2025 Order in Cause No. 46120 ("46120 Order") (as revised with the implementation of Step 2 rates) was $0.025032 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, May, and June 2026 averaged $0.027163 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks a fuel cost charge of $0.007154 per kWh for electric services rendered on or after November 1, 2026, to remain in place until replaced by a fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes federal Investment Tax Credits and Production Tax Credits of $17,430,733 and a variance of $26,120,264 consisting of $15,468,939 that was under-collected during April, May, and June 2026 ("reconciliation period") and $10,651,324 that

was the remaining portion of the FAC 151 variance deferred for recovery in this filing.[3] NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for November and December 2026 and January 2027 ("forecast period") is $23,890,154, and its estimated monthly average sales for that period are 832,258 megawatt hours ("MWhs").[4]

5. Fuel Costs and Operating Expenses. Petitioner's Exhibit 1, Attachment 1-F shows fuel costs for the 12 months ending June 30, 2026, were $55,952,573 above the amount the Commission approved in the 46120 Order. This attachment shows NIPSCO's total operating expenses, excluding fuel, for the 12 months ending June 30, 2026, were $151,351,817 above the amounts approved in the 46120 Order. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending June 30, 2026, that have not been offset by actual decreases in other operating expenses.

6. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost. Mr. Quenett testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that during the reconciliation period, of the energy produced by NIPSCO's fossil-fueled generation, 27.90% was coal-fired and 72.10% was gas-fired. He stated NIPSCO's coal-fired generation consumes coal from various supply regions, with a mix of Powder River Basin ("PRB") and Northern Appalachian ("NAPP") coal at the Michigan City Generating Station ("Michigan City").

A. Fuel Procurement. In discussing NIPSCO's coal procurement process, Mr. Quenett 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, combustion and emission characteristics are critical and may eliminate a coal source from consideration if these characteristics adversely affect a generating unit's reliability, 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 coal transportation from that source are also critical factors NIPSCO considers.

Mr. Quenett stated NIPSCO had three supply contracts that were effective during the reconciliation period: one with Peabody COALSALES, LLC for PRB coal, one with Core Natural Resources for PRB coal, and one with Core Natural Resources for NAPP coal. Mr. Quenett confirmed that NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Quenett testified that during the reconciliation period, NIPSCO did not renegotiate and/or amend any of its coal or transportation agreements and that all of NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications. All coal contracts had fixed base prices and did not have market adjustments. Mr. Quenett testified that producers and customers can be reluctant to execute longer term contracts

[3] The $10,651,324 Fuel Cost Variance Carryover from FAC-151 is the remaining portion of the FAC 151 variance deferred for recovery in this proceeding, as approved in the Commission's July 27, 2026 Order in Cause No. 38706 FAC 151.

[4] The average cost of fuel and estimated monthly average sales to be recovered in this proceeding for the forecast period were calculated from the estimated averages for October, November, and December 2026, as shown on Petitioner's Exhibit 1, Schedule 1.

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. Quenett 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 (such as levying taxes or changing rules that increase the cost of mining or production) or the payment of damages.

Mr. Quenett testified the cost of coal consumed by Michigan City generating station for the 12 months ending June 30, 2026, was $49.13 per ton, or $2.581 per million BTU. The cost of coal consumed during the reconciliation period was $51.03 per ton, or $2.682 per million BTU. When compared to the prior reconciliation period, Mr. Quenett stated NIPSCO's delivered cost of coal consumed per ton increased by $0.41, or $0.026 per million BTU. Mr. Quenett testified that most of the increase was due to the increase in the delivered cost of PRB coal and NAPP coal from railroad fuel surcharges.

Ms. Robles described NIPSCO's two distinct processes for purchasing natural gas for electric generation: (1) purchasing gas as a large transport customer under Rate 328 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 also described the general advantages of each arrangement. 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's coal and gas procurement decision making and acquisition process has been adequately explained and is reasonable.

B. <u>Coal Decrement Pricing</u>. Mr. Quenett testified that 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 recommended that if coal decrement pricing is used in the future, NIPSCO provide justification and documentation supporting the need for, and utilization of, coal decrement or increment pricing and specify when it expects the coal decrement or increment pricing to end, as well as provide all inputs to its calculation of the coal price decrement or increment.

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. Robles provided an update on NIPSCO's treatment of RECs associated with its energy purchases under wind and solar purchased power agreements ("PPAs"). She explained when NIPSCO began receiving power and seeking cost recovery associated with the PPAs in accordance with the Commission's Orders in Cause Nos. 45194, 45195, 45310, 45462, 45472, 45524, 45541, 45887, and 45908. She said, in accordance with those Orders, NIPSCO is also crediting any off-system sales ("OSS") created by its wind and solar PPAs. For the reconciliation period, NIPSCO received 516,520 MWhs (April), 398,767 MWhs (May), and 345,298 MWhs (June), as reflected on Petitioner's Exhibit 1, Attachment 1-A, Schedule 5, Pages 1 through 3, Lines 12 through 15. The corresponding OSS Adjustment for the forecast period is included in Petitioner's Exhibit 1, Attachment 1-A, Schedule 1, Line 42.

Ms. Robles 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. Robles testified that NIPSCO receives RECs associated with the power it purchases from Jordan Creek, Rosewater, Crossroads Wind, Dunn's Bridge I, Green River Solar, Crossroads Solar, Crossroads Wind II, Appleseed Solar, Calvary Solar, Dunns Bridge II Solar, Fairbanks Solar, Gibson Solar, and Carpenter Wind. She explained all RECs are tracked in a renewable energy tracking system. During this FAC period, Ms. Robles testified that current vintage RECs were sold with the block size and proceeds from the sales as follows:

Transaction	RECs Sold	Net Proceeds
1	104,857	$ 351,166
2	78,978	$ 241,159
3	102,578	$ 323,326
4	56,758	$ 142,562
5	100,760	$ 253,084
6	27,708	$ 70,960
7	57,445	$ 181,067
8	38,213	$ 118,460
9	22,890	$ 54,112
10	87,999	$ 281,597
11	61,981	$ 146,523
12	40,245	$ 95,139
13	33,713	$ 166,037
14	105,268	$ 243,669
15	143,154	$ 331,428
16	197,829	$ 448,119
17	147,773	$ 332,489
18	27,783	$ 152,807
19	98,930	$ 311,827
Total	1,534,862	$ 4,245,531

Ms. Robles testified 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. Robles, NIPSCO continually monitors and evaluates the marketability for all RECs, and as the possibility for future legislation evolves, NIPSCO will make appropriate changes to its REC strategy.

Ms. Robles stated that during the reconciliation period, NIPSCO had 25 approved solar and wind customers with facilities registered in M-RETS, with nameplate capacities ranging between 0.05 MW and 2.0 MW. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, Ms. Robles testified no current vintage solar and wind feed-in tariff ("FIT") RECs were sold.

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

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

Ms. Robles testified that 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, 2026.

Ms. Robles stated NIPSCO has incorporated REC sales and 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, 2026. She testified that the credit for forecasted 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, 2026.

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 by the Commission in its Orders in Cause Nos. 45194, 45195, 45310, 45462, 45472, 45524, 45541, 45887, and 45908 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. Robles testified consistently with NIPSCO's Commission-approved electric Hedging Plan through June 30, 2026, the following hedging contracts were purchased during the reconciliation period:

Month	**Power Contracts**		**Gas Contracts**	
	Actual	**Var to Plan**	**Actual**	**Var to Plan**
April 2026	10	0	39	0
May 2026	15	0	38	0
June 2026	40	0	41	0

Ms. Robles testified that the impact of the hedges entered into for the Hedging Plan during the reconciliation period was a loss of $750,612.00, with a net total impact (including broker and clearing exchange fees) of $756,965.75. Broker fees represented 0.06% of the total value of the

transactions occurring during the reconciliation period. She said 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 the 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 NIPSCO's generating portfolio continues to transition.

Mr. Eckert testified that the OUCC reviewed NIPSCO's hedges and stated the hedging profits, losses, and costs are reasonable. He affirmed that NIPSCO entered into 118 gas and 65 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.

7. Midcontinent Independent System Operator ("MISO") Day 2 Energy Costs. NIPSCO included in its forecast the operational changes associated with the MISO Day 2 energy market in accordance with the Commission's Orders in Cause Nos. 42685, 43426, and 43665. The total MISO Components of Cost of Fuel included in the actual cost of fuel for the reconciliation period was $15,376,648.

Ms. Robles testified that the Real Time Non-Excessive Energy in June 2026 was $1,815,006, which was 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 the actual wind production compared to the forecast. Ms. Robles 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 exceed a cost of $2 million in the reconciliation period. She explained that the net monthly ARR/FTR expense was $4,769,760 in June 2026, primarily driven by the high average congestion prices at NIPSCO's NIPS.NIPS node that exceeded the average by approximately 76 times in June 2026 when compared to the period January through December 2025. She stated the increase in the prices is attributable to several significant weather events that occurred during the quarter.

8. Estimation of Fuel Cost. NIPSCO estimates its total average fuel costs for the forecast period will be $23,890,154 monthly. Ms. Robles noted that NIPSCO incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek.

Mr. Quenett testified that as of July 31, 2026, NIPSCO's estimated free-on-board ("F.O.B.") mine spot market prices for delivery during the forecast period were $14.75 per ton for PRB coal, and $62.00 per ton for NAPP coal. Mr. Quenett testified that market dynamics appear to have kept coal demand somewhat stable and coal supply for utility generators in 2026 should be adequate. He stated given the uncertainty in the energy markets due to delayed coal generation retirements, projected increases in electricity demand due to the emergence of data centers, crypto mining, and other load growth drivers, there could be volatility in all energy commodity prices that could impact supply. That said, there are multiple factors that may impact coal 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. Notwithstanding, NIPSCO's 2026 purchases are expected to meet forecasted coal delivery requirements and coal producers are obligated to perform under these agreements. He noted that NIPSCO has discussions with all its coal suppliers on a regular basis, and suppliers have 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. 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. Quenett stated the average spot market price during the reconciliation period, when compared to the prior reconciliation period, was $15.13 per ton (down $0.06) for PRB coal, and $64.50 per ton (up $5.58) for NAPP coal. He stated these are average F.O.B. mine spot market prices only, which do not include the cost of transportation.

In identifying energy market trends and factors affecting the market for coal and transportation during the reconciliation period, Mr. Quenett stated wholesale, day-ahead electricity prices were roughly 10% higher during the reconciliation period when compared with the same period in 2025. A number of dynamics including increased demand, decreasing reserve margins, and transmission constraints drove energy prices higher during the second quarter of 2026 relative to Quarter 2 2025. The U.S. Energy Information Administration ("EIA") projects the U.S. electric energy supply mix for 2025 and 2026 in its latest outlook as follows: (1) Renewable generation (including hydro) provided 24% of the nation's energy mix in 2025 and is expected to provide 25% in 2026 and 27% in 2027; (2) nuclear comprised 18% of electric generation in 2025 and is expected to provide 18% of the mix in 2026 and 2027; (3) natural gas-fired generation provided 40% of the mix in 2025 and is expected to provide 40% in 2026 and 2027; (4) coal-fired generation provided 17% of the energy in 2025 and is expected to provide 15% of the mix in 2026 and 2027; and (5) U.S. coal production increased by 3.0% in 2025 when compared with 2024 levels and is expected to decrease 2.7% in 2026 and 3.5% in 2027. He noted that NIPSCO's station locational marginal pricing ("LMPs") were up in Quarter 2 2026 relative to Quarter 2 2025 and that in the long run, the EIA expects prices in the MISO to decline by 18%, from an average of $56/MWh during the summer of 2025 to $46/MWh this summer and is anticipating increases in solar generation combined with increases from natural gas, wind, solar, and nuclear. Henry Hub spot pricing is expected to average to $3.570 per MMBTU in 2026 and decrease to $3.440 per MMBTU in 2027. PRB spot coal prices are up 3.6%, and NAPP prices are up 9.3% when compared to year-ago levels. The EIA is projecting generation from natural gas renewables, and nuclear will move coal up the supply curve, which is anticipated to reduce coal consumption resulting in increased coal inventories during 2026 that will likely cap or put downward pressure on coal prices. Additionally, several planned U.S. coal generation retirements have been delayed due to the President's Executive Orders issued in April 2025, which created some optimism for coal demand. Near-term uncertainty and higher energy prices had allowed coal pricing to increase at the start of 2026, but long-term trends should limit price volatility and result in flat to lower pricing. EIA projects coal demand will likely decline in the long run, driven by the age of the coal units, retirements, and lower coal unit utilization, due to relatively low natural gas prices and increased renewable production.

Mr. Quenett testified that API 2 prices were roughly 22.6% lower during the reconciliation period compared to the same period in 2025. In addition, coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand

and export markets have provided relatively steady sales opportunities. The EIA reported coal exports reached 108.4 million tons in 2024 (5-year high); however, global coal demand has softened during 2025, and exports fell to 92.6 million tons; exports are expected to recover to 101.7 and 99.8 million in 2026 and 2027, respectively. Overall, the outlook for global coal use is somewhat stable and export opportunities are expected to remain steady. GDP grew by 2.1% in 2025 and projections used in the EIA's Short-term energy Outlook assumes GDP will be 2.0% in 2026 and 2.4% in 2027. Mr. Quenett testified that for transportation, railroad performance continues to trend better than historical norms and has been consistent but that reduced investment in coal production and coal transportation capacity, 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. In addition, variable coal demand impacts supply chain efficiency and can lead to unpredictable coal supplier and railroad performance. He stated that overall, the short-term market forces drove higher energy prices over the last several months. Market conditions are expected to stabilize, which should cap energy costs and keep energy supply stable. EIA projects MISO wholesale energy prices to increase 6% in 2026 and decline 6% in 2027.

Mr. Quenett testified that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period is $52.56 per ton or $2.761 per million BTU.

Mr. Quenett 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. Robles testified that NIPSCO completed its forecast for this FAC filing on August 7, 2026, using its production cost modeling system, PROMOD,[5] and made reasonable decisions under the circumstances known at that point in time.

NIPSCO's Fuel Cost is forecasted to be $28.705 compared to the Base Cost of Fuel of $25.032. Ms. Robles explained that in comparing to FAC 151, (1) Combined Cycle Unit is projected to increase in total MWh, (2) MISO Components of Cost of Fuel is projected to be higher in total cost, (3) Wind PPA and Joint Venture Purchases is projected to be higher in volume and total costs, and (4) OSS Adjustment is projected to be lower in total MWh with a forecasted credit projected to be lower.

Ms. Robles stated that to ensure NIPSCO provides electricity to its retail customers at the lowest fuel cost reasonably possible, NIPSCO has utilized the approved Hedging Plan from FAC 146, which became effective July 1, 2025, and NIPSCO will continue to utilize financial hedges

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

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.

Mr. Quenett 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 August 10, 2026 was $5.257 per gallon (a 38.2% year-over-year increase and 9.5% below the 5-year peak). The expectation is for oil production to increase during the balance of the year, and the EIA expects it will take time for oil inventories to be replenished after the closure and reopening of the Strait of Hormuz. Prices are expected to stay near current levels for the balance of the year and decline over the next two years on the expectation that supply will outpace demand. HDF prices averaged $3.66 per gallon during 2025 and are expected to average $4.850 in 2026 and decrease to $4.070 in 2027. Fuel surcharges under NIPSCO's transportation agreements have increased since the beginning of 2026 but, based on the EIA outlook, fuel surcharges are expected to decline through the end of 2027.

Mr. Quenett 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 2026 should be met under current coal supply and transportation agreements. Coal market demand has rebounded over the last year but declined in the second quarter and this dynamic has reduced pressure on the coal supply chain. However, if coal demand increases significantly, utilities may struggle to schedule deliveries as railroads and coal producers continue to rationalize assets, labor, and production, and it may take time for production and shipments to rise to meet any rapid increase in demand. That said, coal demand is expected to trend lower in 2026 and railroads should be in a solid position to meet demand. NIPSCO continues to work closely with its rail carriers to ensure coal deliveries meet demand during the forecast period.

Mr. Quenett stated Michigan City's PRB coal inventory was 35 days (down 5 days from the prior quarter) and the NAPP inventory was at 14 days (down 19 days from the prior quarter) at the end of the reconciliation period. Mr. Quenett testified that 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. Quenett testified NIPSCO's fleet size supporting Michigan City was 386 railcars (three 125-car sets with 2.9% spares) at the end of the reconciliation period. The typical spare railcar pool ranges between 2% and 15%. According to Mr. Quenett, NIPSCO utilized approximately 92% of the fleet and one set was stored at a third-party location at the start of the reconciliation period. Michigan City has limited coal inventory capacity, which drives storage decisions. Storage

requirements typically vary as coal consumption fluctuates due to planned and forced unit outages and changes in demand. Average coal unit consumption was roughly 52% of Michigan City's maximum coal demand rate during the reconciliation period and railcar utilization exceeded the station generation utilization rates. NIPSCO frequently evaluates its railcar needs and considers demand/delivery requirements (forecasted, historical, and actual), railroad performance, station unloading performance, and the timing of lease expirations. NIPSCO will continue to use commercially reasonable efforts to manage its railcar fleet to ensure economic, and reliable coal deliveries.

Mr. Quenett testified that NIPSCO minimized storage costs during the reconciliation period whenever possible with only one set of railcars at a third-party storage location at the start of April due to Michigan City's high inventory levels and lower consumption. Conditions improved and the set was removed from storage in the latter half of April. Notwithstanding, the availability of coal gondolas is extremely limited and relying on that market to obtain railcars for short-term needs can adversely impact supply reliability and is not prudent. In addition, the timing of lease terms can preclude fleet size changes as leasing decisions are made on a forward-looking basis. He noted the determination of fleet size is a 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. In addition, he stated that moving rail cars in and out of service is a costly process. Therefore, the forward-looking nature of lease agreements and the time and costs required to place cars in and out of service make it difficult to make short-term changes to the size of the fleet and it is not prudent, practical, nor economic to dynamically change the fleet size when coal demand deviates from the forecast. In addition, railcars provide deliverability and can be invaluable if demand increases and/or railroad performance degrades. Mr. Quenett stated NIPSCO also consults with industry experts and 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. Through discussions with industry experts, Mr. Quenett is aware that the market for coal cars is very tight and lease rates have increased dramatically. 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 this dynamic has reduced railcar availability and caused lease rates to increase. One industry expert expects that utilities may need to build railcars as the age of the fleet approaches end of life and as coal railcars continue to attrite. Therefore, NIPSCO's fleet must have sufficient capacity to react to increases in demand or decreases in railroad performance without depending on the market for railcars. For reference, NIPSCO's fleet size at the end of the Reconciliation Period can provide 76% of NIPSCO's maximum coal unit demand and at average railroad cycle times. Given the tight supply of railcars in the market and the uncertainty in demand and railroad performance, NIPSCO has taken a conservative approach to fleet management to ensure supply reliability.

In the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, NIPSCO was ordered, at a minimum, to provide detailed testimony and information regarding: (1) the average spot market price of coal; (2) factors affecting the supply, demand, and cost of coal; (3) any known factors that significantly impact or affect the supply, demand, and cost of coal during the forecast and reconciliation periods; (4) any known factors that significantly impact the delivered cost of coal during the forecast and reconciliation period; and (5) the process NIPSCO utilizes to procure

contracted coal supplies. The Commission finds that NIPSCO provided sufficiently detailed testimony and information in this matter to support its forecasted fuel costs. NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding these five factors.

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

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

Month	Actual Fuel Cost $/kWh	Estimated Fuel Cost $/kWh	Estimating Error: Over (Under)
April	$0.027886	$0.014442	(48.21%)
May	$0.029597	$0.016887	(42.94%)
June	$0.024445	$0.018106	(25.93%)
Weighted Average Estimating Error			(38.91%)

Ms. Robles testified the 39% difference led to a variance factor of $10.462 primarily driven by higher actual costs associated with Purchases through MISO driven by reduced availability at NIPSCO's generation facilities during the reconciliation period. The other drivers for the variance include higher actual costs associated with the MISO Components Cost of Fuel driven by a higher delta LMP component and a lower than forecasted OSS adjustment credit.

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 forecast period is reasonable.

9. Return Earned. Ind. Code § 8-1-2-42.3 and Ind. Code § 8-1-2-42(d)(3) require 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, 2026, NIPSCO earned a jurisdictional return, including TDSIC and GCT revenues, of $555,851,847. This is $108,391,463 less than NIPSCO's authorized amount of $664,243,310, which includes $636,275,246 approved in the applicable rate cases, plus $27,968,064 of actual TDSIC and GCT operating income during the 12 months ended June 30, 2026. NIPSCO calculates the overall earnings bank (sum of the differentials) for the relevant period as negative $314,084,596; 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, 2026, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

10. 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, 2026 has been properly applied in conformity with the requirements of Cause Nos. 38706 FAC 149 and 150. Mr. Guerrettaz testified that the OUCC does not oppose NIPSCO's proposed FAC factor.

Mr. Eckert testified: (1) NIPSCO's testimony and workpapers accurately reflect the methodology approved in the Commission's Cause No. 43526 order regarding purchased power over the benchmark; (2) NIPSCO's treatment of Ancillary Services Market 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 actual monthly cost of fuel (mills/kWh) is similar to the other large electric investor owned utilities in Indiana; (5) NIPSCO's steam generation costs are higher than the other large electric investor owned utilities in Indiana; (6) 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; (7) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (8) NIPSCO provided information regarding Jordan Creek, Rosewater, Crossroads Wind, Dunn's Bridge I, Crossroads Solar, Crossroads Wind II, Green River Solar, Appleseed Solar, and Carpenter Wind; (9) NIPSCO provided an update on the status of the Railroad Litigation,[6] and (10) NIPSCO's forecasted off system sales is accurate.

11. Fuel Cost Adjustment Factor. Based on the evidence, the Commission finds 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 $0.010462 per kWh to be added to the estimated cost of fuel for electric services rendered on or after November 1, 2026, which will remain in place until replaced by a fuel cost adjustment approved in a subsequent filing in the amount of $0.032186 per kWh. This results in a fuel cost adjustment factor of $0.007154 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 $7.15 on his or her electric bill from the currently approved factor.[7]

12. 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.

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[6] 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").

[7] The estimated customer impact associated with the remaining portion of the FAC 151 variance deferred for recovery in this filing is an approximate $2.87 increase for an average residential customer.

13. Major Forced Outages. Consistent with past Commission Orders, Mr. Saffran sponsored Petitioner's Exhibit 4, Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the second quarter of 2026, 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 included a confidential attachment to his testimony with root cause analyses for forced outages, if analysis was completed at the time of the FAC filing.

14. 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 June 30, 2026, NIPSCO has deferred $5,745,867.97 in associated legal costs. Mr. Quenett advised that NIPSCO's case remains on appeal at the U.S. Circuit Court of Appeals for the District of Columbia Circuit, where it is consolidated with other similar appeals and awaiting a decision. There are no additional scheduled filings, though the U.S. Circuit Court of Appeals may request oral argument before reaching a decision. NIPSCO's counsel continues to coordinate with the law firms for the other appellant parties for NIPSCO's appeal. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so.

15. Confidential Information. On August 18, 2026, NIPSCO filed a motion for protective order which was supported by an affidavit showing documents to be submitted to the Commission contain trade secrets as defined by Ind. Code § 24-2-3-2 and should be held confidential in accordance with Ind. Code §§ 8-1-2-29 and 5-14-3-4. In an August 28, 2026 docket entry, the 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, is exempt from public access and disclosure by Indiana law and shall continue to 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 fuel cost adjustment as modified in Finding No. 11 above, to be applicable for electric services rendered on or after November 1, 2026, which will remain in place until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 11 above, is approved on an interim basis subject to refund as set out in Finding No. 12 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

and testimony regarding any electric hedging transaction costs and gains/losses for which NIPSCO is seeking recovery through the FAC.

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.

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 requests for proposals and contracts for transportation and coal to the extent such new requests for proposals and/or contracts are issued.

6. If coal decrement pricing is used or forecast, NIPSCO shall include 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.

7. NIPSCO shall continue to include in its quarterly FAC filings an update on the status of the Railroad Litigation.

8. The information filed in this Cause pursuant to NIPSCO's motion for protective order is determined to be confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law, and shall continue to 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.

BAIN, DEIG, JERRELLS, AND ZIEGNER CONCUR; SWINGER ABSENT:

APPROVED: OCT 28 2026

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

Regina K Joyner Digitally signed by Regina K Joyner Date: 2026.10.28 10:53:26 -04'00' on behalf of

Dana Kosco
Secretary of the Commission