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 MAY, JUNE, AND JULY 2024, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NOS. 45159 AND 45772, AND (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLSALE PURCHASE AND SALE AGREEMENTS FOR WIND AND SOLAR ENERGY APPROVED IN CAUSE NOS. 43393, 45194, 45195, 45310, 45462, 45524, 45541, AND 45936, AND (3) AN UPDATED HEDGING PLAN, INCLUDING RECOVERY OF CERTAIN COSTS ASSOCIATED WITH THAT PLAN, PURSUANT TO IND. CODE § 8-1-2-42(D).	)	**CAUSE NO. 38706 FAC 142** **APPROVED: APR 30 2024**

ORDER OF THE COMMISSION

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

On February 16, 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 May through July 2024 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, pursuant to Ind. Code § 8-1-2-42 and Cause Nos. 45159 and 45772, (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, and (3) an updated hedging plan, including recovery of certain costs associated with that plan, 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 employees Kelleen M. Krupa, Lead Regulatory Analyst, and Patrick d'Entremont, Manager of Planning and Commercial Support, and the testimony and exhibits of the following NIPSCO employees:

- Rosalva Robles, Manager of Planning, Regulatory Support;
- John Wagner, Manager, Fuel Supply;
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division;
- Christa Hook, Manager of Market Settlements; and
- Kurt Sangster, Vice President, Electric Generation.

On February 16, 2024, NIPSCO also filed a motion requesting confidential treatment for certain information ("Confidential Information"). In a docket entry issued March 22, 2024, the requested confidential treatment was granted on a preliminary basis.

On February 21, 2024, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on March 22, 2024.[1]

On February 23, 2024, NIPSCO filed Attachment 1-B. On March 22, 2023, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony and exhibits of the following:

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

On March 22, 2024, the Industrial Group filed a Motion for Subdocket to Investigate the Extended Outage of Sugar Creek and the Resulting Impact on Fuel Costs. On March 28, 2024, NIPSCO filed its Response in Opposition to Motion for Subdocket.

On April 1, 2024, NIPSCO filed its Rebuttal Testimony, which included the testimony of Thomas Harmon, Manager of Regulatory for NIPSCO at NiSource Corporate Services Company and Kurt Sangster.

On April 4, 2024, the Industrial Group filed its Reply in Support of Motion for Subdocket.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on April 8, 2024 in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. By docket entry dated March 1, 2024, the evidentiary hearing was continued to 9:00 a.m. on April 9, 2024 in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Due to cross-examination of witnesses Mr. Sangster and Mr. Eckert, the hearing was held in 222. 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. <u>Commission Jurisdiction and Notice</u>. Notice of the evidentiary hearing in this Cause was published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to NIPSCO's fuel cost charge; therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. <u>NIPSCO's Characteristics</u>. NIPSCO is a limited liability company organized under Indiana law with its principal office in Merrillville, Indiana. NIPSCO renders electric public

[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.

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 October, November, and December 2023 averaged $0.037601 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment from the current fuel cost factor charge of $(0.007122) per kWh for bills rendered February through April 2024 billing cycles to a fuel cost charge of $(0.002504) per kWh for bills rendered during the May, June, and July 2024 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes a variance of $925,605 that was over-collected during October through December 2023 ("reconciliation period"). NIPSCO's estimated monthly cost of fuel to be recovered in this proceeding for the forecasted billing period of May through July 2024 is $27,325,662, and its estimated monthly average sales for that period are 866,769 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

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

(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 December 31, 2023 were $113,297,230, above 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 December 31, 2023, were $17,618,810 above the amounts approved in the 45159 and 45772 Orders. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending December 31, 2023, that have not been offset by actual decreases in other operating expenses.

7. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost. Mr. Wagner testified NIPSCO made every reasonable effort to acquire fuel to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that during the reconciliation period, of the energy produced by NIPSCO's fossil-fueled generation, NIPSCO's coal-fired generation provided 97.6% of energy generated and 2.4% 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. Fuel Procurement. In discussing NIPSCO's coal procurement process, Mr. Wagner identified several factors NIPSCO considers when evaluating purchases for a specific generating unit, including the delivered cost, operational costs, cost of emission controls, and management of coal combustion byproducts. In addition, a coal's combustion and emission characteristics are critical and may eliminate a coal from consideration if these characteristics adversely affect a generating unit's reliability, drastically increase the total cost of generation (fuel and operational costs) or inhibit NIPSCO's ability to comply with emission limits. He testified the reliability of the coal source and the reliability of coal transportation from that source are also critical factors NIPSCO considers.

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

Mr. Wagner testified that producers and customers are generally reluctant to execute long-term contracts with fixed prices without some type of market price adjustment mechanism. He opined that maintaining a price close to market is beneficial to both parties; therefore, a producer and customer may work together to establish an equitable price adjustment methodology. Mr. Wagner testified that, historically, market-based price adjustments in term supply agreements tend to reduce the buyer's cost of hedging since future prices are generally higher than spot and year-ahead prices. In addition to base price adjustments, quality price adjustments are used to maintain the underlying economics of the agreement on a dollar per million British thermal unit ("Btu") basis when the shipment-quality varies from guaranteed quality specifications. Mr. Wagner testified that one of NIPSCO's term coal contracts in effect during the reconciliation period had mostly fixed prices specified in the contract, and a portion of the volume under this contract was priced using a coal market index. Another contract had rates that are indexed to generating unit hourly Day-Ahead Locational Marginal Prices ("LMPs"). In addition, all 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 December 31, 2023, was $76.70 per ton, or $3.715 per million Btu. The cost of coal consumed during the reconciliation period was $72.56 per ton, or $3.522 per million Btu. When compared to the prior reconciliation period, Mr. Wagner stated NIPSCO's delivered cost of coal consumer per ton increased by $1.72 and the cost was up $0.073 per million Btu. Mr. Wagner testified several factors contributed to the change in system cost of coal expensed during several factors contributed to the change in the system cost of coal expensed during the reconciliation period. The main driver of the increase was the change in mix of coal consumed during the reconciliation period. The mix of ILB coal used at Shahfer increased relative to the blend of PRB and NAPP coal used at Michigan City. The delivered cost of NAPP coal was higher during the reconciliation period and contributed to the increase as well. Railroad fuel surcharges also increased during the reconciliation period on an on-highway diesel fuel prices trended higher during the quarter. These increases were partially offset by reductions in the delivered cost of PRB and ILB coal.

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

OUCC witness Mr. 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 wholesale purchase and sale agreement for wind energy from Rosewater on November 20, 2020; (3) June 5, 2019 order in Cause No. 45195 ("45195 Order") NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Jordan Creek on December 2, 2020; (4) February 19, 2020 order in Cause No. 45310 ("45310 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Indiana Crossroads Wind Generation LLC on December 17, 2021; (5) May 5, 2021 Order in Cause No. 45462 ("45462 Order") NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Dunn's Bridge I Solar Generation LLC on August 4, 2023; and (6) July 28, 2021 in Cause No. 45524 ("45224 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Indiana Crossroads Solar Generation LLC on August 9, 2023. Consistent with the 43393, 45194, 45195, 45310, 45462, and 45524 Orders, NIPSCO is also crediting any off-system sales created by its wind and solar PPAs. For the reconciliation period, NIPSCO received 237,660 MWhs (October), 260,330 MWhs (November), and 240,689 (December).

Ms. Hook testified that pursuant to the Commission's September 1, 2021 Order in Cause No. 45541, NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Indiana Crossroads Wind II LLC ("Crossroads Wind II") on December 22, 2023. Therefore, she stated costs associated with the wholesale purchase and sale agreement for wind energy with Crossroads Wind II are included in NIPSCO's projected fuel costs.

Ms. Hook testified that each megawatt hour of power generated from a qualified resource can be awarded a REC. Since no national standard currently exists, she stated each jurisdiction has set its own regulations upon how to qualify and account for RECs. Ms. 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, and Crossroads Solar. 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	30,385	$ 157,128
2	50,000	$ 258,563
3	57,738	$ 317,559
4	50,000	$ 226,550
5	72,820	$ 331,331
6	62,736	$ 284,257
7	50,000	$ 235,000
8	50,000	$ 235,000
9	57,485	$ 278,802
10	80,602	$ 436,661
11	53,270	$ 275,472
Total	615,036	$ 3,036,324

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

Transaction	RECs Sold	Net Proceeds
1	11,413	$ 26,821
Total	11,413	$ 26,821

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. She noted that REC prices are increasing, which is resulting in increasing revenues from REC sales being passed back to customers. 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 that NIPSCO now has 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 no current vintage solar and wind feed-in tariff ("FIT") RECs were sold.

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 a 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 December 31, 2023.

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 December 31, 2023. She testified that the credit for forecasted quarterly JV cash distributions is based on the average of actual JV cash distributions credited to the FAC customer for the 12-month period ending December 31, 2023.

The Commission finds that NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind and solar purchases being recovered through the authority granted in 43393, 45194, 45195, 45310, 45462, 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**
October 2023	185	0	0	0
November 2023	135	45	21	3
December 2023	75	65	34	0

Ms. Hook stated the execution of these contracts is consistent with the Hedging Plan through December 2023. However, she explained that the Hedging Plan overstated the need for additional 2023 gas contracts, which led NIPSCO to purchase an additional three gas contracts for November. She noted that the total impact of the error is immaterial. Ms. Hook testified that NIPSCO's 2023 mid/fall year review determined a need for additional power hedges for the months of November and December due to the decline in forward market prices. She testified these types of adjustments are consistent with NIPSCO's past practices of adjusting the hedging plan for these differences and referenced Ms. Robles' testimony in this cause regarding NIPSCO's proposed 2024 Hedging Plan. She explained that 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 $2,165,976, with the net total impact (including broker and clearing exchange fees) of $2,188,376. Broker fees represented 0.19% 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 55 gas and 110 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.

E. NextEra 360. Mr. d'Entremont supported NIPSCO's request for recovery of service fees associated with NIPSCO's utilization of NextEra Analytics, Inc.'s ("NextEra") Energy Storage Systems Optimization Software Services ("NextEra 360"). Mr. d'Entremont stated NextEra 360 is a dynamic energy optimization software platform that manages energy assets with real-time analysis, custom planning, and optimization that includes (1) Automatic Trader, which maximizes the energy arbitrage opportunities of storage assets; and (2) Asset Monitoring, which assists with tracking and optimizing solar and storage performance. He testified NextEra 360 helps improve reliability and resiliency through real-time analysis and maximizes the return on investment on new and existing renewable energy assets with automated real time market trading.

Mr. d'Entremont testified that the NextEra 360 Energy Management Software will provide asset monitoring for NIPSCO's solar and battery energy storage system ("BESS") resources and offer parameters for BESS resources. NextEra 360 will automate asset monitoring and offer schedules of two sites in Midcontinent Independent System Operator, Inc. ("MISO"), of which NIPSCO is the owner: (1) Cavalry Solar and BESS, which are MISO co-located resources located in White County, Indiana, and (2) Dunns Bridge II Solar and BESS, which are MISO co-located resources located in Jasper County. NextEra 360 will provide valid offer parameters for the Cavalry Storage (45 MW) and Dunns Bridge II Storage (56.25 MW) resources to participate under the MISO Energy Storage Resource ("ESR") market participation model. He stated the offer parameters will aim to maximize revenues and minimize shortfall exposure while maintaining any operational requirements of NIPSCO. NextEra will coordinate with NIPSCO to ensure the BESS resource offer parameters account for solar resource offers, such that solar output takes priority over storage discharges. Mr. d'Entremont testified NIPSCO will receive offers from NextEra and then submit those offers to MISO. He noted NextEra 360 will provide critical data for operational monitoring of solar and BESS resources, as well as solar performance analysis to detect and classify underperformance in generation. Digital twins for each solar asset will be created for performance analysis. Operational and satellite data will be used to calculate expected generation for each asset, and deviations from actual results will be summarized by category. The NextEra 360 Energy Management Software includes data acquisition and analysis, custom user interfaces, robust offer strategies, and asset monitoring and analysis for NIPSCO.

NIPSCO is requesting approval to recover the costs associated with NextEra 360 through the FAC.[3] The amount of the service fee is reflective of the facility and BESS installed capacity. The NextEra 360 Subscription Agreement is for an initial term of three years and a renewal term of two years (the "Agreement"). The Agreement will commence on the commercial operation date of the deployment of the NextEra 360 software, which is anticipated to occur in June or July 2024. The Agreement includes a provision that if the Commission does not approve the cost recovery for the service fees as requested in this filing, NIPSCO may terminate the Agreement.

Mr. d'Entremont testified that if NIPSCO is able to optimize the Calvary and Dunns Bridge II assets through NextEra 360, the cost of purchased power should be lower. As such, costs associated with NextEra 360 affect NIPSCO's "cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity" under Ind. Code § 8-1-2-42(d). In addition, Ind. Code § 8-1-2-42(d)(1) requires the Commission make a finding within the FAC that an 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." Given that NextEra 360 can maximize revenues and minimize shortfall exposure for its new renewable resources, NIPSCO believes incurring this cost and engaging this service is part of its statutory obligation to make every reasonable effort to generate or purchase power to provide electricity to its retail customers at the lowest fuel cost reasonably possible. All of the benefit from NextEra 360 will flow directly to NIPSCO's customers.

Mr. d'Entremont stated that by optimizing asset level market offer strategies for storage assets in MISO, NIPSCO anticipates NextEra 360 will maximize energy arbitrage opportunities associated with the Cavalry and Dunns Bridge II Solar BESS resources in comparison to manual trading strategies. He explained the NextEra 360 Automatic Trader will allow NIPSCO to generate revenue by realizing energy arbitrage opportunities in which NIPSCO would seek to store surplus electricity when there's ample supply and lower prices and then providing that energy to the grid when demand is greater and therefore prices may be higher. He noted the algorithmic and automated nature of the Automatic Trader service will maximize revenues and minimize shortfall. He testified that all revenues generated from increased optimization of NIPSCO's renewable facilities through NextEra 360 will be reflected within the FAC; therefore, NIPSCO is requesting to recover the cost of the service fee, which is a relatively de minimis portion of NIPSCO's purchases through MISO and MISO components of cost of fuel. Mr. d'Entremont noted in 2023, the licensing fee of NextEra 360 would have been less than 1% of NIPSCO's purchases through MISO and MISO components of cost of fuel.

Mr. d'Entremont testified that the related MISO purchases and sales of energy, as well as the licensing fee, will be tracked in FERC Account 555 (Purchased Power). The NextEra 360 platform includes revenue tracking and reporting functionality to demonstrate the value created for customers. He stated NIPSCO tracks similar costs, such as broker fees and commissions related to energy hedging and fees to access the Intercontinental Exchange trading platform, in FERC Account 555.

[3] Represents the costs per month for the Initial Term (Years 1-3).

Mr. Guerrettaz testified that the OUCC disagrees that this cost should be accounted for as a FERC Account 555 but rather should be booked to FERC account 556 – System Control and Load Dispatching Costs, as they are not trackable through the FAC as Purchased Power cost.

In rebuttal, Mr. Harmon testified NIPSCO does not necessarily oppose the OUCC's proposed accounting treatment of the NextEra 360 software costs. He testified the decision of where to appropriately book these costs requires judgment, and in his professional opinion, the NextEra 360 software costs NIPSCO proposes to recover through the FAC could be properly booked in either Account 555 or Account 556. He stated booking NextEra 360 costs in Account 555 aligns the costs to acquire the power using NextEra's automatic trading features with the physical power purchased. He said while Mr. Guerrettaz references comments made by FERC's Chief Accountant in 1991 to support his claim that NextEra 360 costs should be booked to Account 556, he respectfully pointed out that while Account 556 addresses system load and dispatching costs that would pertain to the battery storage, it does not address costs to acquire power. Moreover, NIPSCO's FAC already includes similar costs such as broker fees and commissions related to energy hedging and fees to access the Intercontinental Exchange trading platform in Account 555.

Mr. Harmon testified booking the NextEra 360 costs in Account 555 or 556 does not affect whether the costs are appropriately recovered through the FAC. He testified that the algorithmic and automated nature of NextEra 360 will allow NIPSCO to maximize energy arbitrage opportunities in a manner that cannot be achieved under a manual trading strategy and to the benefit of NIPSCO's FAC customers. He stated it would be inappropriate to reflect only the additional revenue from energy sales generated from NextEra 360 sales within the FAC but not the attendant costs of the software itself.

Mr. Harmon testified that regardless of the FERC account in which these costs are booked, because utilization of NextEra 360 is consistent with NIPSCO's statutory obligation to make "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," recovery of NextEra 360 costs are appropriately recovered through the FAC as a part of NIPSCO's "cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity" under Ind. Code § 8-1-2-42(d) and should be approved.

Based on the evidence presented, the Commission finds the operating costs for the NextEra 360 software should be considered a FERC Account 555 cost for recovery through the FAC.

8. **<u>MISO Day 2 Energy Costs</u>.** NIPSCO included in its forecast the operational changes associated with the MISO Day 2 energy market in accordance with the Commissions Orders in Cause Nos. 42685, 43426, and 43665. The total MISO Components of Cost of Fuel included in the actual cost of fuel for October through December 2023 was $5,047,815.

Ms. Hook testified the Real Time Non-Excessive Energy was $1,643,836 in October 2023 and $1,307,260 in November 2023, primarily driven by unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market, as well as differences in actual wind production compared to forecast, (due mainly to wind speeds). As to the Day Ahead Marginal

Congestion Component plus actual monthly Auction Revenue Rights/Financial Transmission Rights ("ARR/FTR") expenses, less actual monthly ARR/FTR revenues that exceeded a cost of $2 million in any monthly during the reconciliation period, Ms. Hook testified there were none.

9. **__Estimation of Fuel Cost__.** NIPSCO estimates its total average fuel costs for May through July 2024 will be $27,325,662 monthly.[4]

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

Mr. Wagner testified that as of February 6, 2024, NIPSCO's estimated F.O.B. mine spot market prices for delivery during the forecast period were $13.60 per ton for PRB coal, $34.00 per ton for ILB coal, and $51.25 per ton for NAPP coal. Mr. Wagner testified that market dynamics appear to have put downward pressure on coal demand globally and should ease supply constraints for coal-fired utility generators in 2023 and 2024. He stated there are multiple factors that may impact supply and demand during the forecast period including, but not limited to, power prices, natural gas prices, railroad and coal supplier performance, generating unit performance, weather conditions, and labor disruptions. Regarding NIPSCO's supply and demand, contracted purchases are forecasted to meet NIPSCO's 2024 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 $13.87 per ton (down $0.12) for PRB coal, $37.25 per ton (down $17.15) for ILB coal, and $52.42 per ton (down $0.65) 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 50% lower during the reconciliation period when compared with the same period in 2022 and coal prices continued to decline. Mild weather in the U.S. and low natural gas prices contributed to the reduction in wholesale energy prices and key drivers that had kept upward pressure on electric prices during most of 2022, including strong global energy demand, rising electric demand, high natural gas prices, high coal prices, and high railroad fuel surcharges, continued to ease during the reconciliation period. API 2 prices (coal delivered to Amsterdam, Rotterdam, and Antwerp ("ARA")) that had bolstered domestic coal prices earlier in 2022 continued to decline. The EIA expects these conditions to drive the U.S. electric energy supply mix as follows: renewable generation should contribute to 22% of the mix in 2023 and is expected

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

to increase to 24% in 2024, and 26% in 2025; natural gas-fired generation is expected to provide 42% of electric generation in 2023, is expected to decline to 42% in 2024 and to 41% in 2025; coal-fired generation may supply 17% in 2023 and is expected to decline is 15% in 2024 and 14% in 2025; and U.S. coal production fell by 2.1% in 2023 to 582 million tons and is expected to decrease by 19% in 2024 and by another 3% in 2025. The EIA is protecting Henry Hub spot pricing to increase from the 2023 average of $2.54 per MMBTU to $2.65 per MMBTU during 2024 and $2.94 in 2025. Bituminous coal prices are roughly 71% lower than year-ago levels, but lower natural gas and electric prices have pushed coal-fired generation to the marginal energy source, and this should keep coal pricing relatively soft. In the long run, coal demand will continue to fall driven by lower natural gas prices and coal generation being phased out of domestic energy markets.

Mr. Wagner testified these dynamics have continued to drive prices lower in all energy markets during the reconciliation period. He said that coal pricing into Europe (delivered to ARA) has fallen precipitously since 2022. API 2 prices were roughly 55% lower year over year during the reconciliation period. In addition, coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand. That said, strong exports and improved domestic demand during 2022 provided coal producers and coal transporters with increased sales opportunities and price improvements. He noted the EIA expects coal exports should total 93 million tons annually through 2024. Mr. Wagner testified that Class I railroads have struggled to meet the surge in demand over the last two years and have limited customer shipments for not only coal, but other commodities and products. He stated coal supply constraints have been caused by reduced investment in coal production and coal transportation projects, supplier bankruptcies, and mine closures over the last several years, and these supply and capacity reductions could lead to market volatility if energy prices, and demand rebound. Railroad performance appears to have improved.

Mr. Wagner testified that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period is $70.00 per ton and $3.467 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, 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 ("AIILF") 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 February 8, 2024, using its production cost modeling system, PROMOD,[5] and made reasonable decisions under the circumstances known at that point in time.

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

The Fuel Cost Factor in FAC 142 is forecasted to be $31.526 compared to the Fuel Cost Factor in FAC 141 of $31.780. Ms. Hook explained that (1) combined cycle generation is projected to be lower compared to FAC 141; and (2) purchases through MISO are projected to be higher on a total MWh basis and the forecasted cost per MWh is lower in FAC 142 compared to FAC 141.

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 2023 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 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 February 5, 2024 was $3.899 per gallon. This is a 15% year-over-year decrease. The EIA expects global oil inventories to decrease during the first quarter of 2024 and remain flat during the remainder of 2024. He stated that HDF prices are forecasted to average $3.92 per gal during 2024 and decline to $3.89 per gal in 2025. Therefore, fuel surcharges under NIPSCO's transportation agreements are expected to remain relatively stable during the forecast period.

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

Mr. Wagner stated the days of coal inventory supply at Schahfer was approximately 59 days (up 1 day from the prior quarter) at the end of the reconciliation period. He testified solid railroad performance and steady consumption resulted in relatively stable inventory at Schahfer. Michigan City's PRB coal inventory was at 33 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 802 railcars (6 sets with 6.9% spares) at the end of the reconciliation period. The typical spare railcar pool ranges between 3% and 8%. NIPSCO is actively collecting railcars for return and this has led to variations in the spare railcar count. According to Mr. Wagner, during the reconciliation period, NIPSCO utilized roughly 80% of its railcar fleet. He explained that NIPSCO stored one set at Schahfer at the start of the reconciliation period and had two sets stored there at the end of the period. NIPSCO also subleased one set to a third party during the reconciliation period to improve utilization. Storage of railcars was required from time to time during the reconciliation period due to coal consumption trending below forecast and because of planned and unplanned station maintenance outages. Due to increasing consumption, subleasing and decreasing fleet size, railcar utilization was higher than in the prior period. NIPSCO continuously evaluates its railcar needs considering forecasted and maximum demand, delivery requirements, railroad performance, and station unloading performance. NIPSCO determined the fleet size should be reduced to roughly 769 railcars during 2023. NIPSCO returned 244 railcars during 2023 and expects to return another 33 railcars by the end of April 2024. NIPSCO will continue to use commercially reasonable efforts to return the remaining cars to the lessor.

Mr. Wagner testified that to mitigate 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 plans to return another 33 in early 2024 to mitigate expense. During the reconciliation period, NIPSCO did not have railcars in long-term storage at any third-party locations. Whenever possible, NIPSCO utilizes Michigan City's or Schahfer's trackage (a zero-cost option) or subleases railcars to minimize cost. Mr. Guerrettaz testified NIPSCO provided a detailed chart by month that set forth the total railcars and the number of railcars returned. He stated the return of the excess capacity in railcars should help with idled car cost going forward in 2024.

Mr. Wagner testified the railcar market for rotary coal gondolas is volatile and relying on that market to obtain railcars for short term needs is not prudent. He testified he is aware that some large utilities continue to hold "excess" railcars out of concern it may be difficult and/or more expensive to lease cars if demand improves. The number of railcars available in the market has decreased substantially over the last few years because scrap rates of coal gondola railcars have been aggressive, and this dynamic has reduced railcar availability and caused lease rates to increase. which supports the concern of a potential shortage and a more conservative approach to fleet management. Overall, NIPSCO's plan to reduce the coal railcar fleet from eight sets to six sets during 2023 is a prudent balancing of economics and reliability.

In the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, NIPSCO was ordered, at a minimum, to provide detailed testimony and information regarding: (1) the average spot market price of coal; (2) factors affecting the supply, demand, and cost of coal; (3) any known factors that significantly impact or affect the supply, demand, and cost of coal during the forecast and reconciliation periods; (4) any known factors that significantly impact the delivered cost of coal during the forecast and reconciliation period; and (5) the process NIPSCO utilizes to procure contracted coal supplies. The Commission finds that NIPSCO provided sufficiently detailed testimony and information in this matter to support its forecasted fuel costs. NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding these five factors.

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

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

Month	**Actual Fuel Cost $/kWh**	**Estimated Fuel Cost $/kWh**	**Estimating Error: Over (Under)**
October 2023	$0.039344	$0.038806	(1.37)%
November 2023	$0.037308	$0.035424	(5.05)%
December 2023	$0.036207	$0.037316	3.06%
Weighted Average Estimating Error			**(1.00)%**

Ms. Hook testified the average actual fuel cost per kWh for the reconciliation period was 1.00% less than the forecast resulting in a variance factor of ($0.356) primarily driven by (1) lower than anticipated market prices, and; (2) REC sales, which helped to mitigate potential increases in the impact during the reconciliation period. At the time the forecast was prepared neither NIPSCO nor the market as a whole anticipated (a) an approximate 37% decrease in the average natural gas prices ($2.349/Dth actual compared to $3.723/Dth estimated) in the month of December; or (b) an approximate 31% decrease in the all-hours average power price in MISO ($28.93/MWh actual LMP compared to $42.07/MWh estimated LMP) for this reconciliation period.

Based on the evidence presented, including Mr. Guerrettaz's testimony upon the reasonableness of NIPSCO's fuel cost and power sales projections, the Commission finds NIPSCO's estimate of its prospective average fuel cost to be recovered during the May, June, and July 2024 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 December 31, 2023, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $302,993,949. This is $29,918,045 less than NIPSCO's authorized amount of $332,911,994, which includes $309,414,760 approved in the applicable rate cases, plus $23,497,234 of actual TDSIC operating income during the 12 months ended December 31, 2023. NIPSCO calculates the overall earnings bank (sum of the differentials) for the relevant period as $50,248,285; 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 December 31, 2023, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

11. <u>OUCC Report</u>. Mr. Guerrettaz testified: (1) the variance for the quarter ending December 31, 2023, was computed in conformity with Ind. Code §§ 8-1-2-42, -42.3, and relevant orders; (2) NIPSCO did not have a level of net operating costs greater than granted in NIPSCO's last two general rate case proceedings prorated for period under review; and (3) the fuel cost adjustment for the quarter ending December 31, 2023 has been properly applied in conformity with the requirements of Cause No. 38706 FAC 139 and 140. Mr. Guerrettaz states the OUCC recommends NIPSCO's proposed FAC factor of ($0.002504) per kWh be approved. Mr. Guerrettaz also recommended the Commission order NIPSCO to continue to provide (1) 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) detailed coal cost charts from each supplier to each station for the three actual months on a going forward basis setting forth the components of coal and transportation; (3) a copy of all new Requests for Proposals ("RFPs") and contracts for transportation, coal and natural gas costs; and (4) in the next FAC covering the incremental increase in coal prices, the liquidated damages incurred by NIPSCO as well as the amount sought for recovery.

Mr. Eckert testified: (1) he has created a working model of Ms. Hook's purchased power over the benchmark calculation and agrees with this calculation; (2) NIPSCO's treatment of Ancillary Services Market ("ASM") charges follows the treatment the Commission ordered in its June 30, 2009 Phase II Order in Cause No. 43426 ("Phase II Order"); (3) NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (4) NIPSCO's steam generation costs are higher than the other large electric investor owned utilities in Indiana and NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor owned utilities in Indiana; (5) NIPSCO should continue to update the Commission on its coal inventory and coal price decrement; (6) if coal decrement pricing is used, NIPSCO should provide justification and documentation supporting the need for and utilization of coal decrement pricing, as well as specify when it expects coal decrement pricing to end and provide inputs to its calculation of the coal price decrement; (7) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (8) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, Rosewater, and Indiana Crossroads; and (9) NIPSCO provided an update on the status of the Railroad Litigation.[6] Mr. Eckert further testified a residential customer using 1,000 kWhs in March 2024 will pay $181.77 (excluding

[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").

taxes), which consists of $180.24 in base charges set in NIPSCO's last approved rate case (Cause No. 45772), $(7.12) in a fuel adjustment clause credit, and $8.65 in non-FAC trackers.

12. Fuel Cost Adjustment Factor. Based on the evidence, we find NIPSCO has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. NIPSCO's evidence presented a variance factor of ($0.000356) per kWh to be added to the estimated cost of fuel for bills rendered during the May, June, and July 2024 billing cycles in the amount of $0.031170 per kWh. This results in a fuel cost adjustment factor of ($0.002504) 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 $4.62 on his or her electric bill from the currently approved factor.

13. 2024 Hedging Plan.

A. Background and Relief Requested. In our July 13, 2011 Order in Cause No. 43849 (the "43849 Order"), the Commission directed NIPSCO to file a revised electric hedging plan by May 31 of each year, following the same general methodology used in developing NIPSCO's initial hedging plan approved in the 43849 Order. The OUCC and the Industrial Group agreed in that proceeding that NIPSCO's proposal regarding the process to file each subsequent electric hedging plan was workable and appropriate to provide the Commission with updated information while also providing stakeholders an opportunity to comment on the plan to be proposed for the next prospective two-year period. Ms. Robles testified this process called for NIPSCO to discuss the draft electric hedging plan with the OUCC and the Industrial Group two months before filing Petitioner's hedging plan at the end of May.

Ms. Robles stated that in the September 5, 2012 Order in Cause No. 44205 (the "44205 Order"), the Commission directed NIPSCO to begin filing its annual hedging plans by March 31 instead of May 31. She testified that in the 44205 Order the requirement that NIPSCO discuss the draft hedging plan with its stakeholders at least two months prior to its filing was maintained.

In its 44205 S4 Order, Ms. Robles stated the Commission expressed a preference to consolidate its annual review of NIPSCO's hedging plans into the FAC process. Ms. Robles stated that on September 30, 2016, in Cause No. 44205 S4, NIPSCO notified the Commission that NIPSCO, the OUCC, and the Industrial Group agreed to schedule and hold a call between December 10 and December 20 each year to discuss the annual electric hedging plan NIPSCO will propose in its February filing. She stated the interested stakeholders have the opportunity to weigh in on the proposal during the December call and file testimony concerning the proposal in NIPSCO's FAC proceeding, with this schedule providing interested stakeholders approximately nine weeks to consider the proposal before it is included in NIPSCO's February FAC filing and approximately five additional weeks after NIPSCO's February FAC filing to submit testimony.[7]

[7] Per Ms. Robles, in its Notice, NIPSCO stated that the stakeholders understand that weather events and market forces subsequent to the annual December call could cause NIPSCO to change its annual proposal between the date of the call and the date of its February FAC filing. In that event, NIPSCO will timely inform the stakeholders of the change and offer to discuss the reasons for the change before the plan is included in the February FAC filing.

In this proceeding, NIPSCO requests Commission approval of its updated energy supply plan covering the two-year period July 2024 through June 2026 (the "2024 Hedging Plan").

B. <u>Evidence Presented</u>. Ms. Robles filed testimony to present and support NIPSCO's 2024 Hedging Plan consistent with the framework and process approved by the Hedging Orders. Ms. Robles testified that NIPSCO met with the OUCC and the Industrial Group via a web meeting on November 28, 2023 to discuss the 2024 Hedging Plan. At the November 28, 2023 stakeholder meeting, NIPSCO, the OUCC, and the Industrial Group agreed to hold future stakeholder meetings by December 20. The 2024 Hedging Plan incorporates stakeholder input received from the meeting.

Ms. Robles explained the objectives of the 2024 Hedging Plan are to reduce the relative movement in the Fuel Adjustment Clause ("FAC") factor from one period to the next and to limit upside price exposure.

Ms. Robles explained that the Initial Hedging Plan assumed that all of the coal-fired generation facilities within the NIPSCO asset portfolio were fixed in price. She stated that since a majority of NIPSCO's coal contracts are between 3 and 5 years in length, and since coal pricing has historically been less volatile than natural gas pricing and the MISO market price of power, NIPSCO determined that any coal-fired generation used to meet the power supply needs of NIPSCO customers could be classified as a fixed price resource. In addition, renewable projects are also considered and classified as fixed price resources as per NIPSCO's contracted rates with each renewable facility. Ms. Robles stated that any remaining resources that would likely be needed to meet the power supply needs of NIPSCO customers, however, would be classified as floating in price and thus would be considered when developing the hedge plan. She stated the 2024 Hedging Plan also addresses NIPSCO's exposure to both natural gas and electricity price volatility associated with supplying electricity to native load customers.

Ms. Robles explained how the 2024 Hedging Plan is constructed. She stated that NIPSCO determines the monthly volume of MWhs to be hedged by reviewing the total number of on-peak MWhs that would be needed to serve NIPSCO's internal load. The expected number of on-peak MWhs for each month is determined through NIPSCO's demand forecasting process based upon historical usage, estimated economic growth rates, and normalized weather. The PROMOD model is run consistent with the FAC methodology to determine what resources will be used to meet this expected demand, with a special focus on determining the expected number of on-peak MWhs for each calendar month.

Ms. Robles explained that no modifications were made to the existing hedging Plan methodology. NIPSCO developed the 2024 Hedging Plan consistent with the FAC filing methodology, which is intended to better align the Hedging Plan with expected market exposure as presented in NIPSCO's FAC proceedings. The 2024 Hedging Plan (1) assumed forecasted generation based on the ProMod economic model; (2) made no adjustments to the hourly forward-looking power prices; (3) did not remove planned outages in year 2 of the plan for coal units; and (4) sought to achieve an approximate 10-20% hedge on total forecasted MISO purchased power and gas over the Hedging Plan program horizon as reflected in Figure 1. She noted that the plan is only hedging on-peak MISO purchases to achieve an approximate 10%-20% against total forecasted MISO Purchases. This results in higher hedging percentages when only looking at on-peak MISO Purchases.

Ms. Robles testified NIPSCO developed the 2024 Hedging Plan approach in consideration of its shifting portfolio, which historically was predominantly made up of traditional forms of generation but is transitioning to a portfolio with more renewable generation resources. Using the FAC filing methodology allows NIPSCO to align the hedge to actual market exposure. This allows NIPSCO to have a more direct point of comparison to its quarterly FAC filings, allowing for a clearer line to be drawn between the Hedging Plan and the FAC filings. She noted maintaining the Hedging Plan off the FAC filings allows NIPSCO to make any adjustments easily throughout the year as the availability of its generation fleet and deviations in expected load change over time.

Ms. Robles testified the proposed target hedging percentages were determined to avoid any stair step growth between the current Hedging Plan and the 2024 Hedging Plan proposed in this proceeding. NIPSCO intends to review this percentage annually with stakeholders, to ensure there is an appropriate level of hedging in place that balances the conflicting goals of ensuring access to low market pricing and shielding customers from market volatility.

Ms. Robles testified NIPSCO followed the 2023 Hedging Plan; however, NIPSCO made additional power hedges for the months of November and December 2023 due to the decline in forward market prices. NIPSCO discovered additional contracts purchased in error that had an immaterial impact. She stated NIPSCO expects to follow the updated 2023 Hedging Plan through June 2024; however, if there are any unforeseen, unplanned outages or if there is movement of planned maintenance outages on NIPSCO generating units, NIPSCO may further modify the updated 2023 Hedging Plan, which adjustments are consistent with NIPSCO’s past practice of adjusting the hedging plan for material differences in generating unit availability. To the extent NIPSCO updates its Plan further, future FAC filings will disclose any additional deviations from the updated 2023 Hedging Plan.

Ms. Robles testified, consistent with previous plans, the 2023 Hedging Plan is comprised of two types of futures contracts. The first type of futures contract (approved by the 43849 Order) will be used to hedge the on-peak MWhs exposure that relates to Sugar Creek, a CCGT plant that uses natural gas to generate power. She stated the modeled volumes of power from Sugar Creek are converted to dekatherms by multiplying the number of MWhs for each calendar month by the heat rate of the Sugar Creek plant, which is approximately 7.5 dekatherms per MWh. Once the number of dekatherms per calendar month is determined, this number is divided by 10,000 (the number of dekatherms in each natural gas futures contract) to arrive at the number of natural gas futures contracts to be purchased for each calendar month of delivery. Ms. Robles indicated these contracts settle financially as opposed to physically so they will not have any impact on the physical purchase and delivery of natural gas that is required to run the Sugar Creek plant. She noted that a natural gas futures contract settles financially by comparing the purchase price to the settlement price, netting the difference, and then multiplying this dollar difference by 10,000 to get the dollar amount per contract. Dollars change hands without any physical flow of the commodity itself.

Ms. Robles testified the second type of futures contract will be to hedge electric price volatility for the MISO power purchases. NIPSCO purchases its power from MISO on a Day Ahead basis at prevailing LMPs. In order to match the electric price volatility exposure with the most closely linked derivative product, NIPSCO will continue to utilize MISO Indiana Hub Day-Ahead Peak Calendar-Month Futures to hedge the MISO power purchases. This type of futures contract also settles financially as opposed to physically so there will be no impact to MISO supply including the dispatch of NIPSCO's generation facilities and NIPSCO's wholesale sales and purchases of electricity. If the fixed price is below the average Day Ahead LMP, NIPSCO will receive payment. If the fixed price is above the average Day Ahead LMP, NIPSCO will make a payment.

Ms. Robles testified the hedges under the 2024 Hedging Plan are being made solely to address native load fuel cost price exposure. She testified the hedges will not change the economic dispatch of NIPSCO's generation facilities or NIPSCO's wholesale electricity sales and purchases; therefore, NIPSCO continues to propose to pass all hedging gains and seek recovery of prudently incurred hedging losses through its FAC filings.

Ms. Robles stated that the natural gas futures contracts and the MISO Indiana Hub Day-Ahead Peak Calendar Month Futures contracts will be purchased according to specific schedules and will be purchased on a dollar cost averaging basis up to the second to last month before the month of delivery. She testified that the MISO Indiana Hub Day-Ahead Peak Calendar Month Futures contracts will be purchased on a dollar cost averaging basis up through and including the month prior to the delivery month. She stated the schedule is broken up into the different types of futures contracts to demonstrate when and what number of contracts would be purchased.

Ms. Robles testified NIPSCO intends to purchase the futures contracts on or around the third to last business day of each month to take market timing out of the purchase decision. NIPSCO will consider market conditions and circumstances known at that time and will use its best judgment in purchasing the futures contracts each month.

Ms. Robles sponsored an analysis to determine the possible impact the 2023 Hedging Plan would have on overall purchased power costs. The analysis shows an example of what additional power supply costs could be incurred if market prices increase by 20% from where market pricing was as of close of business on January 26, 2024. She stated that in the example in Attachment 5-E, there could be an additional $25,311,273 of power supply costs (inclusive of CCGT generation and MISO power purchases) if market prices rose by 20% for each month of the planned period. The plan period covers the July 2024 to June 2026 period. The analysis also includes the effect the 2024 Hedging Plan could have on these additional power supply costs. If these hedges were in place and the market was stressed upward by 20% for each month in the plan period, the additional power supply costs would be roughly 75% ($19,059,214) in Attachment 5-E of what they would be without the hedge plan in place. However, if prices were to move downward by 20%, power supply costs could have been reduced by $25,311,273 in Attachment 5-E through the plan period if no hedge plan had been implemented. The analysis demonstrates how a hedge plan can reduce volatility in power supply costs. While possible savings may be foregone when prices fall, the hedge plan reduces additional costs that may have been incurred when prices rise.

Ms. Robles testified market conditions are dynamic and the analysis is only intended to show the relative impact of the program assuming market conditions remain unchanged. The analysis provides an indication of the impact this program may have in the future.

Ms. Robles testified NIPSCO has in the past recommended adjustments to its hedging plan approach and continues to evaluate factors that could impact the viability of the currently proposed hedging methodology.

Ms. Robles provided an update on the intra-month hedge for Sugar Creek. She stated NIPSCO is planning to continue with the practice of converting 30% of the gas contracts expiring at the start of each January, February, and March into power contracts. She explained NIPSCO's proposal does not alter the current methodology of acquiring gas contracts for Sugar Creek but simply adds a layer of intra-month hedge protection to address historically higher intra-month price volatility in these months.

Ms. Robles testified that during the November 28, 2023 stakeholder meeting, there were no changes discussed or being proposed. NIPSCO did communicate to stakeholders that prior to the filing it would update pricing and any changes to its maintenance schedule to align with FAC 142. NIPSCO communicated to stakeholders that as the Company's generation portfolio changes further refinements to the 2024 Hedging Plan may be needed. She reiterated NIPSCO will continue to have discussions with its stakeholders around the effectiveness of the plan adjustment and may make additional recommendations in the future, and that NIPSCO appreciates the collaborative nature of discussions with the OUCC and Industrial Group around the overall hedge plan approach.

C. Commission Discussion and Findings. In Cause No. 43849, the Commission found:

> the mitigation of volatility in fuel procurement is consistent with the provisions of Ind. Code § 8-1-2-42(d), and that implementation of a process to evaluate the risk of fuel price volatility and mitigate such risk through a comprehensive and well-developed hedging plan, is a reasonable step in furtherance of the acquisition of fuel so as to provide electricity to customers at the lowest fuel cost reasonably possible.

The Commission finds NIPSCO's 2024-2026 Hedging Plan is consistent with the approach we approved in the 43849 Order.

Based on the evidence, the Commission finds the proposed 2024-2026 Hedging Plan is reasonable, consistent with the public interest, and should be approved. The evidence demonstrates that NIPSCO communicated with the OUCC and the Industrial Group in the interest of improving the plan consistent with prior Commission Orders, and the Commission finds NIPSCO should continue to do so and continue to consolidate the annual review of NIPSCO's hedging plan into the FAC process.

14. **Interim Rates.** As discussed in Finding No. 17 below, we decline to set NIPSCO's FAC factor as interim, subject to refund pending, as the OUCC recommends "any finding regarding negligence and the outcome of discussions, negotiations, and potential settlement between NIPSCO and the contractor regarding the Sugar Creek Generating Station outage." Because the Commission is unable to determine whether NIPSCO will earn an excess return while this order is in effect, the Commission finds the rates approved herein should be interim rates, subject to refund.

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

16. **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 December 31, 2023, NIPSCO has deferred $5,159,174 in associated legal costs. Mr. Wagner advised the Railroad Litigation remains consolidated for pre-trial purposes in Multi-District Litigation. He stated NIPSCO's expert provided his rebuttal expert report on November 15, 2023 and on December 18, 2023. The Judge issued an order setting forth that summary judgment and expert admissibility motions are due April 30, 2024. The second round of depositions of plaintiffs' experts is currently occurring and is scheduled to end on February 22, 2024. No substantive determinations have occurred in the Railroad Litigation. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so.

17. **Sugar Creek Planned Outage.** Mr. Sangster provided an update regarding the status of the Sugar Creek planned outage in his confidential direct testimony. Mr. Eckert recommends NIPSCO's FAC factor be made "interim subject to refund" pending any finding regarding negligence and the outcome of discussions, negotiations, and potential settlement between NIPSCO and the Contractor regarding the Sugar Creek Generating Station outage.

In his rebuttal testimony, Mr. Sangster noted there appears to be no dispute between the OUCC and NIPSCO regarding the facts surrounding the Sugar Creek outage, when the unit returned to partial service, or when it returned to full service. He stated NIPSCO provided the parties with its highly confidential Long-Term Services Agreement ("LTSA") for the Sugar Creek generating station with the Contractor, which was executed in 2004 and assumed by NIPSCO in 2008, including two amendments from 2018 and 2022. He explained the LTSA between NIPSCO and the Contractor does not allow for recovery of replacement power costs. He stated the exclusion of this type of consequential damage is reasonable considering NIPSCO's contractors do not and cannot control NIPSCO's offer strategy, the outage schedule of its other generating units, or any of the many other factors that may affect NIPSCO's need to purchase power. He stated that even if it were possible to expand the LTSA to include damages of this type, doing so would likely dramatically increase NIPSCO's cost to receive services from the contractor, as a contracting party would not expose itself to open-ended risk associated with replacement power costs unless its compensation under the contract were dramatically higher. He noted that it is his understanding that limiting consequential damages to exclude replacement power costs is standard industry practice for similar services agreements. Mr. Sangster does not agree with Mr. Eckert's recommendation that NIPSCO should be required to seek reimbursement for a cost clearly and reasonably excluded by its LTSA with the Contractor. NIPSCO asked the OUCC in discovery to identify any instance where an Indiana utility has been allowed to recover such costs under a similar contract, to which the OUCC responded that Mr. Eckert is unaware of any such contractual agreement. NIPSCO asked if the OUCC was aware of any long-term services agreement or materially similar contract arrangement that allows for recovery of purchased power costs as a consequential outage-related damage, to which the OUCC responded that Mr. Eckert is unaware of any such contractual agreement.

Mr. Sangster stated NIPSCO is not negotiating with the contractor to seek reimbursement of replacement power costs but is negotiating with the contractor to seek reimbursement of incremental costs NIPSCO incurred due to the Gas Turbine 1 rotor damage. None of these incremental costs will have any impact on NIPSCO's FAC. He explained that all of the costs to repair the Gas Turbine 1 rotor were paid for by the contractor. NIPSCO incurred incremental costs related to its own labor/materials that were used to perform work to address the rotor damage, including crane and fork-truck rental, as well as operators and fuel; professional support from electricians, safety, scheduling, and management; security; and site lighting. He testified any reimbursement of these incremental costs would not flow through the FAC, just as the costs did not flow through the FAC.

Mr. Sangster testified regarding the steam turbine, NIPSCO's proactive inspection that uncovered debris in the strainer basket of the valve, and the performance of a borescope on the first stage of the steam turbine. He stated that based on the condition of the first stage of the steam turbine, it was decided to open the high and intermediate pressure sections for further inspection, at this time the contractor advised that it could not be operated in the "as found" condition and that the first stage rotating and stationary blades would need to be replaced. At this point, the 2023 Sugar Creek Outage Recovery Plan was created, and in accordance with the plan, other blades and sections of the turbine were cleaned, repaired, and tested to be approved for operation.

Mr. Sangster testified the contractor verbally conveyed the condition of the GT1 rotor damage and stated that the turbine compressor blades could not be installed into the rotor due to the damage. The contractor conveyed the rotor could not be repaired, and the options were to either disassemble the rotor and replace the damaged section, which was estimated to take 18 weeks minimum, or replace the rotor. Mr. Sangster testified that because the direct cause of the rotor damage was known and quickly identified, and the Contractor admitted they caused the damage, no root cause analysis was necessary.

Mr. Eckert recommends NIPSCO's FAC factor be made interim subject to refund pending any finding regarding negligence and the outcome of discussions, negotiations, and potential settlement between NIPSCO and the Contractor regarding the Sugar Creek Generating Station outage" and that NIPSCO "provide an update to the Commission in its next FAC regarding status of this event and the resolution between NIPSCO and the Contractor." Mr. Sangster stated that this is the second FAC proceeding in which the OUCC has requested that NIPSCO's FAC factor be made interim subject to refund. He explained that (1) the OUCC and the Industrial Group have served and NIPSCO has responded to numerous discovery requests; (2) NIPSCO has been transparent and responsive and provided all information necessary, including copies of relevant contracts, outage reports, and other pertinent information; and (3) NIPSCO also participated in the OUCC audit of FAC 141 and FAC 142 and answered all of the auditor's questions related to the Sugar Creek outage.

Mr. Sangster testified the facts related to the Sugar Creek outage are undisputed – during the course of a planned outage at Sugar Creek, NIPSCO discovered that the first row of blades on the steam turbine required replacement; the blades were replaced, which prevented a critical failure that could have resulted in an extended forced outage, and the unit was returned to partial service on December 22, 2023; a section of the rotor on Gas Turbine 1 was damaged by the contractor during the planned outage and required replacement, which was completed and paid for by the contractor. Sugar Creek was returned to full service on January 24, 2024. He stated neither the OUCC nor Industrial Group have alleged NIPSCO took imprudent action related to the Sugar Creek planned outage and that any imprudent action directly resulted in a negative financial impact to NIPSCO's customers. Also, neither the OUCC nor Industrial Group have alleged NIPSCO was imprudent in how it managed its contractor during initial outage work or when performing repairs. Mr. Sangster stated setting NIPSCO's FAC 142 factor interim subject to refund is not necessary or appropriate. He stated there are no outstanding costs under the LTSA that would be passed through the FAC; therefore, it is unnecessary for NIPSCO to provide a formal update in its next FAC regarding the status of any negotiation between NIPSCO and the contractor. Mr. Sangster testified NIPSCO has shared all relevant information it has related to the impact of the Sugar Creek outage on NIPSCO's FAC factor in FAC 141 and in this FAC 142. NIPSCO can commit to provide an update to the Commission and its stakeholders in the FAC filing following the conclusion of the negotiations to assure the Commission and stakeholders that NIPSCO has received all compensation to which it is entitled under the LTSA.

There is no evidence in this Cause alleging any imprudent or unreasonable action or inaction by NIPSCO related to the Sugar Creek outage. Parties have conducted extensive discovery, and no party has alleged NIPSCO has withheld information critical to their evaluation. The Commission finds that the parties have had adequate opportunities to investigate the circumstances of the outage. The Commission rejects the OUCC's recommendation to set NIPSCO's FAC 142 factor interim subject to refund on the basis that further review of the Sugar Creek outage is necessary. NIPSCO will update the Commission and the parties in the FAC filing following the conclusion of its negotiations with its Contractor regarding the incremental costs described above.

18. Confidential Information. On February 16, 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 March 22, 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.

19. **Motion for Subdocket.** The Industrial Group did not file testimony in this proceeding. However, on March 22, 2024, the Industrial Group filed a motion seeking the creation of a subdocket in this proceeding for the purpose of permitting Industrial Group, and other parties, the ability to conduct a full investigation of the extension of the Sugar Creek planned outage and its consequent impact on fuel costs ("Industrial Group Motion").

In its Motion, the Industrial Group requests that (a) the FAC factor approved by the Commission in this Cause be on an interim basis, subject to refund, and (b) a subdocket in Cause No. 38706 FAC 142 be opened to allow further discovery and investigation into issues related to the Sugar Creek planned outage and the impact of the extension of the planned outage on the fuel costs included in this proceeding and in FAC 141, including "the extent to which NIPSCO, or its contractors, acted reasonably and prudently in connection with the events leading to the extension of the planned outage, taking into account the totality of the circumstances, in relation to the inspection, operation, and maintenance of Sugar Creek". In the event the Commission determines that a refund is appropriate, the Industrial Group further requested that the Commission, in the subdocket, determine an appropriate amount of interest to apply to the refund.

NIPSCO's March 28, 2024 Response and Opposition to the Motion for Subdocket ("Response") stated the evidence in this Cause demonstrates a subdocket is not necessary because no further investigation into the Sugar Creek outage is warranted. The Response argued the Industrial Group's Motion seeks to create an environment where a subdocket is opened anytime there is an extended or unplanned outage, even without an allegation of imprudence. The Response stated that after two FAC proceedings, which included prefiled testimony and discovery on the Sugar Creek outage, the Industrial Group did not respond to NIPSCO's evidence that establishes timely and reasonable actions taken, instead the Industrial Group opted to not file any testimony and claims the timing of this proceeding is insufficient to allow it to complete its due diligence. NIPSCO asserted the Industrial Group Motion improperly expands the standard by which NIPSCO's actions with regard to its independent contractor are measured and that the speculative analysis on any increase in native load fuel resulting from the Sugar Creek outage is not reason to create a subdocket in this Cause.

In the Industrial Group's Motion, they request that the FAC factor be approved on an interim basis. We denied the OUCC's similar request that the FAC factor approved by the Commission in this Cause be on an interim basis, subject to refund in Findings 14 and 17 above. There is nothing in the Industrial Group's motion or reply that convinces us differently. Therefore, for the same reasons stated above we deny this portion of the Industrial Group's motion.

A utility's "conduct is presumed to be prudent unless the [opposing] Parties present evidence that raises a question about [the utility's] actions." *Duke Energy Indiana, Inc.*, Cause No. 43114 IGCC4 S1 (IURC 12/27/2012), p. 111 (citing *Indiana Michigan Power Co.*, Cause No. 39314 (IURC 11/12/1993), pp. 5-6. Thus, without an allegation of imprudence with supporting facts, we find a subdocket is unnecessary. After having two FAC proceedings in which to evaluate the Sugar Creek outage, we find the intervenors in this Cause have had a sufficient opportunity to raise questions about NIPSCO's actions to support a claim of imprudence. We have recently found that, "in determining whether a utility acted prudently we must review the circumstances as they existed considering what was known or should reasonably have been known by the utility at the time of its actions." *Duke Energy Indiana, LLC*, Cause No. 38707 FAC 123-S1 (IURC 3/17/2021), p. 24. A review of the evidence establishes NIPSCO's prudent management of its Contractor and swift action to resolve operational issues at Sugar Creek. Mr. Sangster's direct and rebuttal testimony describes NIPSCO's frequent engagement with its Contractor to expedite progress in returning Sugar Creek to full service as well as the Contractor's recovery plan, which was completed in a timely manner such that Sugar Creek was brought back to full service at the end of January 2024.

No evidence was offered that would question the manner in which NIPSCO handled the initial outage, the inspection, or the extension of the outage. The evidence supports a finding that NIPSCO has prudently managed the work of its Contractor and resolved its operational issue expeditiously. A subdocket under the facts presented in this proceeding would potentially invite the creation of a subdocket anytime there is an unforced outage or an unexpected extension of a planned outage, even when no evidence of imprudence has been offered. This would be inappropriate and is not the standard the Commission has historically applied when determining whether a sub-docket should be created. Accordingly, we deny the Motion for Subdocket.

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 May, June, and July 2024 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 12 above, is approved on an interim basis subject to refund as set out in Finding No. 14 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's proposed 2024 Hedging Plan is approved, and NIPSCO shall continue to consult with interested stakeholders in developing future hedging plans.

4. 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.

5. 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.

6. 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.

7. 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.

8. 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. 16 above.

9. The Motion for Subdocket is denied.

10. NIPSCO shall update the Commission and the parties in the FAC filing following the conclusion of its negotiations with its contractor regarding the incremental costs NIPSCO incurred as a result of the Sugar Creek outage.

11. 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, 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.

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

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

APPROVED: APR 30 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: 2024.04.30 10:19:22 -04'00'

Dana Kosco
Secretary of the Commission