ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF (1) A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING CYCLES OF NOVEMBER AND DECEMBER 2022 AND JANUARY 2023, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 45159, (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND ENERGY APPROVED IN CAUSE NOS. 43393, 45194, 45195, AND 45310, AND (3) APPROVAL OF A CORRECTION TO NIPSCO'S EARNINGS BANK UNDER IND. CODE § 8-1-2-42(d)(3).	)	**CAUSE NO. 38706 FAC 136** **APPROVED: OCT 26 2022**

ORDER OF THE COMMISSION

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

On August 25, 2022, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed a Verified Petition in this Cause seeking approval from the Indiana Utility Regulatory Commission ("Commission") of: (1) a fuel cost adjustment to be applicable during the November and December 2022 and January 2023 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, pursuant to Ind. Code § 8-1-2-42 and Cause No. 45159; (2) ratemaking treatment for the costs incurred under wholesale purchase and sale agreements for wind energy approved in Cause Nos. 43393, 45194, 45195, and 45310; and (3) a correction to Petitioner's earnings bank. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company employees Kelleen M. Krupa, a Lead Regulatory Analyst, and Kevin J. Blissmer, Manager of Regulatory, and the testimony and exhibits of the following NIPSCO employees:

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

On August 25, 2022, NIPSCO also filed a motion requesting confidential treatment for certain information ("Confidential Information"). In a docket entry issued on September 9, 2022, the requested confidential treatment was granted on a preliminary basis.

On August 26, 2022, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on September 9, 2022.[1]

On September 2, 2022, NIPSCO filed a page that was inadvertently omitted from Ms. Krupa's Attachment 1-B, and on September 8, 2022, Petitioner filed corrected Attachment 1-H to Ms. Krupa's testimony.

The Indiana Office of Utility Consumer Counselor ("OUCC") on September 29, 2022, prefiled the direct testimony and exhibits of the following:

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

Also on September 29, 2022, the Industrial Group prefiled the direct testimony of Michael P. Gorman, a Managing Principal with Brubaker and Associates, Inc.

NIPSCO prefiled rebuttal testimony for Mr. Blissmer on October 5, 2022. A docket entry was issued on October 6, 2022, requesting NIPSCO provide information as to the income tax rate NIPSCO collects on its Federal Energy Regulatory Commission ("FERC") jurisdictional assets. NIPSCO's response to this docket entry was provided on October 7, 2022.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on October 11, 2022, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in this hearing, and their respective testimony and exhibits were admitted without objection.

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

1. Commission Jurisdiction and Notice. Notice of the evidentiary hearing in this Cause was published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to NIPSCO's fuel cost charge; therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. NIPSCO's Characteristics. NIPSCO is a limited liability company organized under Indiana law with its principal office in Merrillville, Indiana. NIPSCO renders electric public utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of such service.

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[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.

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 December 4, 2019 Order in Cause No. 45159 ("45159 Order") was $0.026736 per kilowatt hour ("kWh"). NIPSCO's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of April, May, and June 2022 averaged $0.048515 per kWh.

4. **Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment from the current fuel cost charge of $0.023033 per kWh for bills rendered during the August through October 2022 billing cycles to a fuel cost charge of $0.029820 per kWh for bills rendered during the November 2022 through January 2023 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing. The OUCC's proposed factor, per Mr. Guerrettaz's testimony, for the November 2022 through January 2023 billing cycles is $0.026058 per kWh.

The requested fuel cost adjustment includes a variance of $25,691,786 that was under-collected during April 2022 through June 2022. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecasted billing period of November 2022 through January 2023 is $39,860,400, and its estimated monthly average sales for that period are 856,225 MWhs.

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

> (1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;
>
> (2) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;
>
> (3) the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to section 42.3 [Ind. Code § 8-1-2-42.3] of this chapter, if the fuel charge applied for will result in the electric utility earning a return in excess of the return authorized by the commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned; and
>
> (4) the utility's estimate[s] of its prospective average fuel costs for each such three (3) calendar months are reasonable after taking into consideration:
>
> > (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and

(B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

6. Fuel Costs and Operating Expenses. NIPSCO's Attachment 1-F shows fuel costs for the 12 months ending June 30, 2022, were $164,792,291 above the amount the Commission approved in the 45159 Order. NIPSCO's Attachment 1-F also shows Petitioner's total operating expenses, excluding fuel, for the 12 months ending June 30, 2022, were $18,591,161 above the amount approved in the 45159 Order. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending June 30, 2022, that have not been offset by actual decreases in other operating expenses.

7. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost. Mr. Wagner testified that NIPSCO made every reasonable effort to acquire fuel 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 42.80% of the energy generated, and 57.20% of the energy generated was gas-fired. He stated NIPSCO's coal-fired generation consumes coal from various supply regions, with the Michigan City Generating Station ("Michigan City") consuming a mix of Powder River Basin ("PRB") and Northern Appalachian ("NAPP") coal, and Units 17 and 18 at the R.M. Schahfer Generating Station ("Schahfer") consuming Illinois Basin ("ILB") coal.

A. 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 emissions controls, and management of coal combustion byproducts. In addition, a coal's combustion and emission characteristics are critical and may eliminate a coal from consideration if these characteristics adversely affect a generating unit's reliability, drastically increase the total cost of generation (fuel and operational costs), or inhibit NIPSCO's ability to comply with emission limits. He testified the reliability of the coal source and coal transportation from that source are also critical factors NIPSCO considers.

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

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

Mr. Wagner testified the delivered cost of coal consumed by NIPSCO's generating stations for the 12 months ending June 30, 2022, was \$45.23 per ton or \$2.278 per million BTU. The cost of coal consumed during the reconciliation period (April, May, and June 2022) was \$61.06 per ton or \$3.007 per million BTU. The delivered cost of coal consumed during the prior reconciliation period was \$62.33 per ton or \$2.970 per million BTU. When compared to the prior reconciliation period, NIPSCO's delivered cost of coal consumed per ton decreased \$1.27, and the cost was up \$0.037 on a per million BTU basis. Mr. Wagner stated several factors contributed to the change in the cost of coal expensed during the reconciliation period, including an increase in the consumption of PRB coal relative to ILB coal consumption. He noted the PRB coal used at Michigan City is lower cost than the ILB coal used at Schahfer, and this worked to lower the unit cost per ton. Other contributing factors included increases in ILB coal prices due to higher coal and transportation costs that contributed to the increase in the system cost of coal on a per million BTU basis, but Mr. Wagner testified these increases were largely offset by the increased mix of PRB coal.

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

Ms. Robles testified Petitioner made every reasonable effort to purchase natural gas so as to provide electricity to its customers at the lowest reasonable price, and there have been no changes to NIPSCO's gas purchasing practices for NIPSCO's generation located off NIPSCO's gas distribution system (Sugar Creek Generating Station) during the reconciliation or forecast period.

Based on the evidence presented, the Commission finds NIPSCO has adequately explained its coal and gas procurement decision making, and its acquisition process is reasonable.

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

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

Based on the evidence, the Commission finds decrement pricing is not included in NIPSCO's forecast for purposes of this FAC proceeding. If in the future coal decrement pricing is included in NIPSCO's forecast or has been used, NIPSCO shall file testimony, schedules, and workpapers addressing the need for and reasonableness of such decrement pricing and related inputs consistent with the Commission's July 17, 2019 Order in Cause No. 38706 FAC 123.

C. Renewable Energy Credits ("RECs"). Ms. Robles provided an update on NIPSCO's treatment of RECs associated with its energy purchases under wind purchased power agreements ("PPAs"). She testified that pursuant to the Commission's July 24, 2008 Order in Cause No. 43393 ("43393 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreements for wind energy from Barton Windpower LLC ("Barton") on April 10, 2009, and from Buffalo Ridge I LLC ("Buffalo Ridge") on April 15, 2009. Consistent with the Commission's August 7, 2019 Order in Cause No. 45194 ("45194 Order"), NIPSCO began receiving power and seeking recovery of such costs for wind energy from Rosewater Wind Generation LLC ("Rosewater") on November 20, 2020, and per the Order in Cause No. 45195 ("45195 Order") from Jordan Creek Wind Farm LLC ("Jordan Creek") on December 2, 2020. Pursuant to the February 19, 2020 Order in Cause No. 45310 ("45310 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Indiana Crossroads Wind Generation LLC ("Indiana Crossroads") on December 17, 2021. Under the 43393, 45194, 45195, and 45310 Orders, NIPSCO is also crediting any off-system sales created by its wind PPAs. She stated the wind PPA adjustment for the forecast period is based on the average actual wind PPA adjustment incurred for the 12-month period ended June 30, 2022. For the reconciliation period of April, May, and June 2022, NIPSCO received 269,181 MWhs, 250,172 MWhs, and 153,421 MWhs, respectively.

Ms. Krupa testified there is a new entry for JV Distribution on Schedule 5 reflecting excess cash from NIPSCO's renewable joint venture projects that has been passed back to customers. She advised these amounts serve as a direct reduction to FAC costs on a dollar-for-dollar basis.

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

Transaction	RECs Sold	Net Proceeds
1	100,000	$ 513,563
2	25,000	$ 135,438
3	50,000	$ 270,875
4	100,000	$ 517,125
5	15,000	$ 92,344
6	15,000	$ 78,750
7	50,000	$ 325,000
8	25,000	$ 153,906
9	10,000	$ 61,563
10	62,725	$ 373,617
11	75,000	$ 476,250
12	2,000	$ 6,600
13	100,000	$ 590,575
Total	629,725	$ 3,595,604

Additionally, Ms. Robles advised that during this reconciliation period, NIPSCO transferred 15,876 RECs to its Green Power Rider program, with net proceeds of $52,391.

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

Ms. Robles stated NIPSCO now has 24 approved solar and wind feed-in tariff ("FIT") customers with facilities registered in the Midwest Renewable Energy Tracking System ("M-RETS"),[2] with nameplate capacities ranging between 0.05 MW and 2.0 MW. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, 8,096 current vintage solar and wind FIT RECs were sold, yielding net sale proceeds of $26,495. Ms. Robles stated NIPSCO has and will continue to pass the proceeds from FIT RECs sales back to customers through the Purchased Power other than MISO line item. She noted NIPSCO continues to discuss with brokers and market participants the best means of marketing the FIT RECs.

Mr. Guerrettaz confirmed that NIPSCO provided a $3,674,480 credit to its customers from the sale of RECs for this FAC. Without the RECs, hedge gain, and joint venture credit, he stated fuel costs for April through June 2022 would have been approximately 21% higher.

Ms. Robles testified NIPSCO is not expecting to buy firm, long-term purchased power during the forecast period and did not enter into third party energy transactions for physical power

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

that impacted the reconciliation period. She stated NIPSCO will, however, continue to consider entering into short-term third-party agreements to protect its customers from market influences.

Ms. Robles testified NIPSCO incorporated forecasted FIT purchases in this filing based on the average of actual FIT purchases incurred for the 12 months ending June 30, 2022. NIPSCO also incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek. Additionally, Ms. Robles advised that NIPSCO completed its forecast for this FAC filing on August 10, 2022, using its production cost modeling system, PROMOD, and made reasonable decisions under the circumstances known at that time.

The Commission finds NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind purchases being recovered through the authority granted in the 43393, 45194, 45195, and 45310 Orders and any other future renewable purchases.

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

Month	Power Contacts		Gas Contracts	
	Actual	**Var to Plan**	**Actual**	**Var to Plan**
April 2022	30	0	53	0
May 2022	65	0	56	0
June 2022	10	0	63	0

Ms. Robles stated the execution of these contracts was consistent with NIPSCO's approved electric hedging plan through June 2022. She stated NIPSCO continues to operate under the 2021-2023 hedging plan as approved in Cause No. 38706 FAC 130.

Ms. Robles testified the impact of the hedges during the reconciliation period was a gain of $8,068,911. The net total impact of the hedging plan in this FAC reconciliation period, including broker and clearing exchange fees, was $8,064,459. Broker fees represented 0.02% of the total value of the transactions occurring during the reconciliation period. Ms. Robles testified decisions were made based upon the conditions known at the time of the transactions, and NIPSCO used the same broker it uses for other transactions to limit transaction costs, with all transactions made in accordance with NIPSCO's approved electric hedging plan.

Mr. Eckert testified the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs are reasonable. He stated NIPSCO entered into 172 gas and 105 power contracts during April through June 2022.

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

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

Ms. Robles testified that 23,376 MWhs of purchased power in April 2022 at an average purchased power cost of $87.52/MWh, 11,415 MWhs of purchased power in May 2022 at an average purchased power cost of $117.82/MWh, and 83,865 MWhs of purchased power in June 2022 at an average purchased power cost of $146.22/MWh were in excess of the Purchased Power Benchmark. As a point of comparison, she stated the monthly averages of the Purchased Power Daily Benchmarks were $81.96, $99.53, and $94.88 for April, May, and June 2022, respectively. Ms. Robles testified the MWhs that exceeded the Benchmark in this reconciliation period were not attributable to any one event or factor; rather, the recoverability for each purchase under the terms of the 43526 Order varies.

Ms. Robles testified that in accordance with the procedures outlined in the 43526 Order, NIPSCO determined that in June 2022, 44,329 MWhs at an average purchased power cost of $158.43/MWh exceeded the Purchased Power Benchmark, and a portion of those purchases is non-recoverable. She stated the remaining MWhs in excess of the Purchased Power Benchmark were made to supply jurisdictional load that offset available NIPSCO resources MISO did not dispatch or are otherwise eligible under the procedures outlined in the 43526 Order and are, therefore, recoverable.

OUCC witness Guerrettaz testified that in the three months covered by this FAC, 23,376 MWhs exceeded the Purchased Power Benchmark, as Ms. Robles testified. He stated a majority of the purchases over the Purchased Power Benchmark were determined to be recoverable, and per OUCC witness Eckert, the OUCC recommends recovery. Mr. Eckert testified Ms. Robles' testimony and workpapers accurately reflect the methodology the Commission approved in the 43526 Order regarding purchased power over the Benchmark. Mr. Eckert noted he has created a working model of Ms. Robles' purchased power over the Benchmark calculations, and he agrees with her calculations.

Based on the evidence, the Commission finds NIPSCO's identified purchased power costs are properly included in the fuel cost calculation, and NIPSCO has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

8. <u>MISO Day 2 Energy Costs</u>. Ms. Robles stated NIPSCO included in its forecast the charges associated with the MISO Day 2 energy market in accordance with the Commission's Orders in Cause Nos. 42685, 43426, and 43665. The total MISO Components of Cost of Fuel included in the actual cost of fuel for April, May, and June 2022 was ($5,512,732).

Ms. Robles testified Real Time Non-Excessive Energy in May 2022 was $1,234,225 and $5,766,182 in June 2022 primarily due to unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market, as well as differences in actual wind production compared to forecast (due mainly to wind speeds), coupled with relatively high LMPs. She testified the Day Ahead Marginal Congestion Component plus actual monthly Auction Revenue Rights/Financial Transmission Rights ("ARR/FTR") expenses, less actual monthly ARR/FTR revenues, exceeded a cost of $2 million during two months within the reconciliation period. During April 2022, the net monthly ARR/FTR cost was $2,537,016 and in June 2022 was $2,702,356. Ms. Robles stated the primary driver was high average congestion prices at NIPSCO's NIPS.NIPS node that during April 2022 exceeded the average by approximately three times for the January 2022 through March 2022 period, and during June 2022 exceeded the average by approximately two times for the January 2022 through May 2022 period. Ms. Robles testified NIPSCO inquired of MISO as to the cause for the high congestion rates, and had not, as of the date her testimony was prefiled, received a response.

In his testimony, Mr. Guerrettaz recommended the Commission require NIPSCO to break out all congestion components in future FAC testimony.

The forecast of MISO Components of Cost of Fuel in this proceeding, per Ms. Robles, is based on the High – Low average of actual MISO Components of Cost of Fuel incurred for the 12-month period ending June 30, 2022, where the high and low quarters are replaced with a three-year average of the same quarter. She stated NIPSCO included a forecast in this filing of MISO Components of Cost of Fuel of $1,325,552 per month.

9. <u>Estimation of Fuel Cost</u>. NIPSCO estimates its total average fuel costs for October, November, and December 2022 will be $39,860,400 on a monthly basis.

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

Mr. Wagner testified that as of August 3, 2022, NIPSCO's estimated market prices for coal delivery in the forecast period of October, November, and December 2022 were $18.20 per ton for PRB coal, $168.00 per ton for ILB coal, and $178.00 per ton for NAPP coal, excluding transportation costs. He indicated spot market prices increased drastically during the reconciliation period for all coal types. As of August 3, 2022, the estimated spot market prices for shipments with September 2022 delivery were approximately $18.20 per ton for PRB coal, $168.00 per ton for ILB coal, and $178.00 per ton for NAPP coal, excluding transportation costs.

Concerning supply reliability, Mr. Wagner testified contracted purchases are forecasted to meet NIPSCO's 2022 coal delivery requirements, and coal producers are obligated to perform under their agreements. Mr. Wagner stated NIPSCO has had discussions with all its coal suppliers, and they indicated they will meet NIPSCO's contracted coal supply requirements. Mr. Wagner testified the average spot market price of coal during the reconciliation period, not including transportation costs (and change from the previous reconciliation period) was $16.58 per ton (down $5.75) for PRB coal, $118.20 per ton (up $28.30) for ILB coal, and $134.25 per ton (up $37.34) for NAPP coal. He stated these prices do not include the cost of transportation, and actual prices may vary from published indices.

In identifying factors affecting the market for coal and transportation during the reconciliation period, Mr. Wagner stated coal prices appeared to flatten out in early 2022; however, strong coal demand in Europe, combined with the Russia-Ukraine conflict, caused NAPP and ILB prices to push to new highs during the reconciliation period. He stated wholesale electricity prices climbed again during the reconciliation period due to several factors, including strong global energy demand, high natural gas prices, increased coal demand, and constrained coal supply and transportation. In addition, MISO LMPs increased significantly during 2021 and continued to increase during the reconciliation period largely driven by increased demand and higher energy commodity prices. Mr. Wagner stated Schahfer's average 2022 year-to-date LMPs are up roughly 79% versus 2021 and 115% above the five-year average. Mr. Wagner noted the Energy Information Administration ("EIA") projects renewables will contribute 22% of the energy in 2022, natural gas generation will be 37%, and coal will provide 21%, with United States coal production expected to increase three percent in 2022 (17 million tons). That said, Mr. Wagner testified coal will likely be the marginal energy source in the power market in the long run as natural gas prices fall and coal generation capacity is phased out of energy markets worldwide.

Mr. Wagner stated these dynamics created significant volatility in all energy markets during the reconciliation period, and although PRB prices have drifted lower since the beginning of 2022, NAPP and ILB prices again increased significantly during the reconciliation period. In addition, strong domestic coal demand and increased coal demand globally have supported higher coal prices. He testified coal pricing into Europe (delivered to Amsterdam, Rotterdam, and Antwerp) increased from $140.75 per tonne[3] in August 2021 to $309.00 per tonne in August 2022, yielding a 120% year-over-year increase, and strong European demand may keep upward pressure on both NAPP and ILB prices in the near term. Mr. Wagner stated coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand, with strong exports and improved domestic demand providing coal producers and coal transporters with increased sales opportunities and improved prices. Per Mr. Wagner, these market conditions have created coal supply shortages that led to considerably higher coal prices, and the EIA expects steam coal exports could increase four percent in 2022, driven by the higher natural gas prices.

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

Given the ongoing market tightness, Mr. Wagner stated NIPSCO has continued to informally survey coal suppliers, and they have indicated they have little to no surplus coal production and are, essentially, sold out for 2022, with limited availability for 2023.

Mr. Wagner testified Class I railroads are struggling to meet the surge in demand and have limited customer shipments for coal as well as the other commodities and products they transport. According to Mr. Wagner, coal supply constraints have been caused by reduced investment in coal production and coal transportation projects over the last several years. He stated these constraints, combined with the unanticipated surge in coal demand and the strong economic recovery, have strained the coal supply chain; consequently, strong coal demand both domestically and globally, combined with coal supply chain challenges, will likely keep upward pressure on coal prices in 2022 and into 2023, but the long-term global trend to aggressively reduce fossil fuel generation will continue to displace coal generation. Additionally, Mr. Wagner stated the economy is expected to contract into 2023, and this may put downward pressure on coal and transportation pricing.

Mr. Wagner testified NIPSCO's cost of coal consumed for generation in the forecast period of October, November, and December 2022 is estimated to be $79.62 per ton and $3.811 per million BTU. In developing the estimate for the forecast period, he stated NIPSCO's fuel supply group incorporates coal contract prices inclusive of adjustments specified in the agreement, dust treatment costs, freeze conditioning costs, railcar lease costs, railcar maintenance costs, estimates of contract prices, transportation fuel surcharges using the monthly average price of U.S. On-Highway Diesel Fuel ("HDF"), the Association of American Railroad's All-Inclusive Index Less Fuel ("AILLF") adjustments, and estimates of future coal market prices. Additionally, the fuel supply group provides a forecast of beginning inventory values in dollars and quantities in tons for each generation station. These assumptions are provided to NIPSCO's energy supply and optimization group which uses these assumptions to develop the forecast. Ms. Robles testified NIPSCO completed its forecast for this FAC filing on August 10, 2022, using its production cost modeling system, PROMOD,[4] and made reasonable decisions under the circumstances then known.

Ms. Robles advised the fuel cost factor is forecasted to be $46.554 compared to a base cost of fuel of $26.736. She identified three primary drivers for the higher forecasted fuel cost factor. First, forecasted steam generation cost per MWh is anticipated to be higher than in FAC 135, driven primarily by an increase in forecasted coal transportation and commodity pricing as Mr. Wagner discussed. Second, forward-looking natural gas prices are also projected to be significantly higher than seen in recent years, and third, purchased power costs are projected to be higher in FAC 136 than in FAC 135 and projected to be higher compared to recent historical pricing. She explained that while purchases through MISO are forecasted to be lower in FAC 136 on a total MWh basis than in FAC 135, the forecasted cost per MWh is higher than in FAC 135.

To ensure NIPSCO provides electricity to Petitioner's retail customers at the lowest fuel cost reasonably possible, Ms. Robles testified NIPSCO utilized the hedging plan approved in FAC 130 and will continue to utilize financial hedges under the 2022 Hedging Plan to mitigate economic impacts and volatility within each FAC. In addition, NIPSCO has added wind resources and will

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

continue adding new resources to its portfolio. She noted these assets do not have variable fuel costs and are much cheaper relative to utilizing coal-fired (steam) generation. She stated NIPSCO will continue to utilize its growing wind, solar, and solar plus storage assets to economically serve customers.

Mr. Wagner testified two key factors that could impact NIPSCO's coal transportation costs during the forecast period are power prices and the price of HDF. He stated power prices may impact coal transportation costs under two transportation contracts that are indexed to station LMPs. Per Mr. Wagner, contract transportation rates are forecasted using forward energy prices and have maximum rates that ultimately hedge price exposure. With respect to the second factor, i.e., the price of HDF, two coal transportation agreements also have mileage based fuel surcharges that vary with changes in HDF. Mr. Wagner testified fuel surcharges under these agreements are calculated monthly using the average weekly spot price of HDF, and fuel surcharge estimates are included in rate projections used to develop comprehensive transportation costs for the forecast period. He testified the spot price of HDF as of August 8, 2022, was $4.993 per gallon, noting this is a 48% year-over-year increase. Mr. Wagner stated EIA expects oil markets to be mostly balanced from the second quarter of 2022 through the end of 2023 and market conditions to remain balanced with little opportunity for prices to fall during 2022, but EIA is projecting lower pricing for diesel fuel in 2023. He testified short-term diesel fuel volatility may lead to variations in the actual cost of transportation during the forecast period.

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

Mr. Wagner stated the days of supply of coal inventory at Schahfer equaled approximately 38 days (down four days from the prior quarter) at the end of the reconciliation period. He testified improved delivery rates and lower consumption resulted in improved Schahfer inventory. Michigan City's PRB coal inventory was at 15 days, and its NAPP inventory was at 40 days at the end of the reconciliation period. Mr. Wagner testified NIPSCO has made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Mr. Wagner testified NIPSCO's railcar fleet during the reconciliation period was 1,046 railcars. This equated to eight sets with 4.4% spares. He testified the typical spare railcar pool is roughly eight percent, but NIPSCO has been in the process of collecting railcars for return, and that led to variations in the spare railcar count. Mr. Wagner testified that during the reconciliation period NIPSCO utilized roughly 58% of its railcar fleet. He advised that NIPSCO stored sets at Schahfer during Unit 17 and 18 outages in April 2022, and these outages contributed to lower utilization. Per Mr. Wagner, NIPSCO planned on operating at least 75% of the fleet starting in May, but the Union Pacific would not provide the locomotives required to meet NIPSCO's demand at Schahfer during the Reconciliation Period. He stated NIPSCO prioritized the use of locomotives for Michigan City because inventory levels were below 20 days during a portion of the reconciliation period. Mr. Wagner testified current market conditions have challenged coal deliveries nationwide, and higher transit times combined with higher demand may require NIPSCO to carry additional railcar capacity. Additionally, NIPSCO announced on May 4, 2022, that the operation of Units 17 and 18 at Schahfer will extend into 2025; therefore, given current market conditions, poor rail performance, and planned changes in the coal unit operations at Schahfer, Mr. Wagner testified NIPSCO has been re-evaluating its railcar needs. He stated NIPSCO is planning to return 230 railcars by the end of the second quarter of 2023, reducing NIPSCO's fleet to 816 railcars or approximately six unit trains with roughly eight percent spares.

Mr. Wagner noted NIPSCO reduced its fleet size by 393 railcars in 2021 and has no railcars stored at third party locations, eliminating storage costs. He testified planned maintenance, forced outages, and inadequate rail service during the reconciliation period lowered utilization, but NIPSCO had adequate storage capacity at Schahfer at no cost. Mr. Wagner stated NIPSCO anticipates higher railcar utilization during the forecast period. Mr. Guerrettaz noted NIPSCO provided a detailed chart that sets forth, by month, the total railcars and the number of railcars returned, and he testified it is the OUCC's opinion that over time NIPSCO is achieving a correct level of railcars.

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

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

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

Month	**Actual Fuel Cost $/kWh**	**Estimated Fuel Cost $/kWh**	**Estimating Error: Over (Under)**
April 2022	$0.044910	$0.036973	(17.67)%
May 2022	$0.036351	$0.034103	(6.43)%
June 2022	$0.062717	$0.035797	(42.92)%
Weighted Average Estimating Error			**(26.69)%**

Ms. Robles testified the total actual fuel cost in the reconciliation period was $125,397,647 while the forecasted fuel cost was $93,670,318. Thus, the average actual fuel cost per kWh for the reconciliation period was 26.69% greater than the forecast. This led to a variance factor of $10.002 primarily driven by volatility in commodity prices and a significant increase in purchased power volumes and costs because of reduced availability at NIPSCO's coal-fired generation stations due to unexpected outages during this reconciliation period. She explained that the following items varied from the time the forecast was prepared: (1) an approximate 101% increase in the average natural gas prices ($7.193/Dth actual compared to $3.582/Dth estimated) for this reconciliation period; (2) an approximate 78% increase in the all hours average power price in MISO ($75.33/MWh actual LMP compared to $42.33/MWh estimated LMP) for this reconciliation period; (3) an increase in the actual delivered cost of coal during this reconciliation period; and (4) higher actual costs associated with the MISO Components Cost of Fuel driven by a high delta LMP component for this reconciliation period. She advised REC sales and the performance of NIPSCO's hedging program helped to mitigate potential further increases in the impact during the reconciliation period.

Mr. Guerrettaz stated nothing came to the OUCC's attention during the review of NIPSCO's filing indicating the projections NIPSCO used for fuel costs and power sales were unreasonable when comparing actual prior quarter and forecasted fuel costs and sales figures. He testified that during the OUCC's audit, NIPSCO indicated natural gas and power prices have increased since NIPSCO's original forecast, with the cost of coal having increased due to new contracts, which is also driving up the forecast.

The Commission recognizes NIPSCO's forecasted cost of fuel is increasing, as both NIPSCO and the OUCC acknowledged; however, based on the evidence, including Mr. Guerrettaz's testimony upon the reasonableness of NIPSCO's fuel cost and power sales forecast, the Commission finds NIPSCO's estimate of its prospective average fuel cost to be recovered during the November 2022 through January 2023 billing cycles is reasonable.

10. <u>Return Earned</u>. NIPSCO's evidence demonstrates that for the 12 months ending June 30, 2022, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $306,471,440. This is $24,939,975 more than NIPSCO's authorized amount of $281,531,465, which includes $264,218,463 approved in the applicable rate case, plus $17,313,002 of actual TDSIC operating income during the 12 months ended June 30, 2022. To determine whether the fuel adjustment charge applied for will result in NIPSCO earning a return in excess of the return authorized in its last base rate case (Cause No. 45159), NIPSCO contends it is necessary in this FAC to make a correction to its non-jurisdictional tax expense. The propriety of this correction was, however, disputed as discussed below.

A. NIPSCO's Evidence Upon Earnings Bank Correction. Mr. Blissmer described the correction NIPSCO believes is necessary to non-jurisdictional tax expense for purposes of the Ind. Code § 8-1-2-42(d)(3) test in this FAC. He testified that NIPSCO performed additional review related to the Ind. Code § 8-1-2-42(d)(3) test after determining in April 2022 when preparing the first quarter earnings test calculation that the earnings bank would likely change from a cumulative under-earning position to a cumulative over-earning position in the second quarter of 2022 based on historical financial information and projections for the remainder of 2022. He advised that NIPSCO took a closer look at the adjustments being made to actual operating earnings to determine whether something other than fluctuations in revenue due to weather and customer count changes, as well as changes in incurred expenses, might be contributing to Petitioner's over-earnings position, appropriately or not. Per Mr. Blissmer, during this review NIPSCO discovered an error that inappropriately increased the calculation of earnings for purposes of the FAC earnings determination.

Mr. Blissmer explained the earnings test calculation starts with a rolling 12-month regulatory income statement and makes certain adjustments to make the results comparable to the authorized net operating income from Petitioner's last base rate case. He stated one of the adjustments removes the impact of non-jurisdictional revenue and expense, as these are not included in Indiana jurisdictional ratemaking and not part of NIPSCO's approved tariff. He explained that NIPSCO's non-jurisdictional revenue and expense are primarily related to NIPSCO's investment in MISO-approved, regionally cost-allocated transmission projects, which are collected through an approved FERC formula rate. Mr. Blissmer testified NIPSCO's review disclosed NIPSCO has been including in its FAC earnings test calculation a level of non-jurisdictional income tax expense that is not accurate, resulting in NIPSCO presenting an earnings calculation that overstates its actual jurisdictional earnings. Mr. Blissmer sponsored Attachment 5-A, which is a copy of Attachment 1-F from NIPSCO's last approved FAC (Cause No. 38706 FAC 135) and provided the following related discussion:

> Column B, Line 10, shows NIPSCO's Total Net Operating Income ("NOI") for purposes of the earnings test before allocation of $360,579,641. You will see that NIPSCO recorded income tax expense of $49,909,878, which means total operating income before tax is $410,489,519 ($360,579,641 + $49,909,878), which is shown in the newly created Row 11 to this schedule. However, NIPSCO did make a tax adjustment in FAC-135 in Column F of $5,510,356 so that total Adjusted Income Tax Expense is $55,420,234 as shown in Column B, Row 12. This is an effective tax rate of approximately 13.50% ($55,420,234/$410,489,519) shown in Column B, Row 13, which is far less than the statutory rate.
>
> Moving to the right on Attachment 5-A, NIPSCO presents various adjustments in Columns C through F to arrive at jurisdictional earnings precented in Column G. Column E is where the income tax error has occurred. Instead of allocating the portion of the total $55,420,234 income tax that corresponds to the non-jurisdictional revenues, NIPSCO instead applied a statutory tax rate of

> approximately 25% ($12,162,[080]/($36,534,192 + $12,162,080)). The actual effective tax rate for the non-jurisdictional revenues should be roughly equivalent to the total operating income effective tax rate (13.50%). Put another way – NIPSCO recorded a total income tax expense of $55,420,234 on total operating income before tax of $410,489,519 but allocated $12,162,080 to non-jurisdictional operating income before tax of only $48,696,272. So, an allocation of roughly 12% of the total net operating income before tax is taking with it approximately 22% of the income tax. That is an error, and this same error has been made during every FAC throughout the entire period covered by the 60-month earnings bank.

Petitioner's Exhibit No. 5 at pp. 6-7.

Mr. Blissmer testified the inaccurate earnings test calculation has not impacted the Commission-approved factor in NIPSCO's prior FACs, but it has resulted in a material error in the sum of the differential calculation. He stated the cumulative effect of the error over the 60-month earnings bank calculation overstates jurisdictional net operating income by $74,825,574, as shown in Attachment 5-B.

Mr. Blissmer sponsored Attachment 5-B which provides the calculation of a correction to the sum of the differentials included in Attachment 1-H to correct the non-jurisdictional income tax expense adjustment, and he provided the following discussion of this correction:

> Columns A through E reflect the sum of the differential's earnings bank from Attachment 1-H in NIPSCO's most recently approved FAC (Cause No. 38706-FAC-135) (Line 21, Column E). Column F shows NIPSCO's total Electric Operating Income Before Income Tax, and Column G shows NIPSCO's recorded Electric Income Tax Expense for each reporting period, with Column H showing the NIPSCO Electric Effective Tax Rate for each reporting period. Columns I and J show the Non-Jurisdictional Income Before Income Tax and Non-Jurisdictional Income Tax Expenses at Statutory Rates, with the Rolling 12-Month Statutory Tax Rate shown in Column K. The amounts provided in Columns F, G, I and J can be found on, or calculated from, Attachment 1-F for each respective FAC filing (FAC 116 through FAC 135). Column L calculates the Proportional Non-Jurisdictional Income Before Tax.
>
> For example, in the March 31, 2022 reporting period, the total NIPSCO Electric Income Effective Tax Rate shown in Column H is 13.50%, which is far less than the Rolling 12-Month Statutory Tax Rate shown in Column K of 24.98% because NIPSCO incurs savings from tax planning in its net operating income. This benefit of tax savings is also reflected in the revenue requirement set in NIPSCO's most recent rate case in Cause No. 45159. The gross revenue conversion factor in general rate cases reflects the full statutory rate because every additional dollar that comes in is taxed at the statutory rate. However, NIPSCO's 'pro forma present rates income tax expense' (from Cause No. 45159) reflects the tax savings (and is thus reflected in customer base rates) and therefore produces a much lower effective tax rate in base rates.

> The Proportional Non-Jurisdictional Income Before Tax (Column L) for each reporting period is determined by dividing the Non-Jurisdictional Income Before Income Tax (Column I) by the NIPSCO Electric Income Before Income Tax (Column F). This proportional rate in Column L is then used to allocate NIPSCO Electric Income Tax Expense (Column G) instead of using the Rolling 12-Month Statutory Tax Rate (Column K), resulting in the Proportion of Non-Jurisdictional Tax Expense (Column M). The Proportional Non-Jurisdictional Tax Correction (Column N) is determined by comparing the Proportional Non-Jurisdictional Tax Expense (Column M) to the Non-Jurisdictional Tax Expense at Statutory Rates (Column J).

Petitioner's Exhibit No. 5 at pp. 8-10.

Mr. Blissmer explained that base rates reflect the benefits of tax planning savings and how non-jurisdictional tax expense was reflected in the revenue requirement approved in NIPSCO's last electric rate case, Cause No. 45159. He stated income tax expense on non-jurisdictional sales was not reflected in the revenue requirement approved in Cause No. 45159. Per Mr. Blissmer, as shown in Adjustments RB2-19R, RB7-19R, Rev 10-19R, Dep 1B-19R, OM 2M-19R, and OTX 1-19R, NIPSCO adjusted rate base, revenues, operating expenses, depreciation, and property tax expense to remove the non-jurisdictional assets and the non-jurisdictional revenues and expenses from the calculation of rates. He stated income tax expense was then computed on a pro forma basis at present rates. Mr. Blissmer noted the calculated pro forma present rates income tax expense was $27,609,096 (Column C, Line 26) on pre-tax income of $159,970,578 (Column C, Line 15), or 17.25%. He testified that when NIPSCO then filed its Compliance Filing for Step 2 rates, it reflected total pre-tax operating income of $311,523,182 (Attachment A-S2, Page 2, Column P, Line 45) and total income tax of $46,896,399 (Attachment A-S2, Page 2, Column P, Line 47), or 15.05%, so NIPSCO's base rates reflect a level of income tax expense far below the statutory rates. He stated it is this mismatch in the way income tax is recovered in NIPSCO's base rates and NIPSCO's actual income tax before tax allocation as compared to its allocation to non-jurisdictional for purposes of the FAC earnings bank calculation that is in error and NIPSCO seeks to correct in this proceeding.

Mr. Blissmer testified no adjustment was made in Cause No. 45159 to allocate deferred income taxes on the non-jurisdictional plant. As a result, jurisdictional customers received the full benefit from the lower weighted average cost of capital from the non-jurisdictional deferred income tax.

Mr. Blissmer testified there was also no adjustment made in Cause No. 45159 to allocate the pass back of excess deferred income taxes associated with non-jurisdictional plant; therefore, customer rates set in Cause No. 45159 benefitted from the reduction to pro forma jurisdictional income tax expense caused by the pass back of excess accumulated deferred income taxes, including on non-jurisdictional plant. He noted NIPSCO is also passing back to customers the excess accumulated deferred income taxes on non-jurisdictional plant. He stated that from a tax perspective, it is his understanding this pass back raises income tax concerns related to proper normalization; consequently, NIPSCO plans to correct this error in its next electric rate case.[5]

Mr. Blissmer testified the earnings test calculation has reflected non-jurisdictional earnings at the higher statutory tax rate to determine the tax expense that should be removed; however, actual tax expense, including the pass back of excess accumulated deferred income taxes, should be allocated to non-jurisdictional earnings based on actual income before tax. He stated this difference results in reducing tax expense by an amount greater than what was incurred in every period of the earnings test calculation (FAC 116 through FAC 135) as this error has compounded over the full 60-month period, resulting in NIPSCO's cumulative earnings bank being $74,825,574 higher than what it should be.

Mr. Blissmer testified that NIPSCO is not seeking to change factors approved in prior FAC periods. Rather, he stated NIPSCO's re-calculation of its earnings bank for purposes of this FAC does not modify the Commission findings regarding the fuel adjustment charges or factors, inclusive of the determination of whether fuel costs should have been reduced due to over-earnings in past FACs. According to Mr. Blissmer, the earnings totals reflected in the sum of the differentials calculation for purposes of this proceeding are based on the evidence presented in this proceeding which appropriately reflects an accurate calculation of NIPSCO's earnings as a result of correcting the non-jurisdictional tax amount in NIPSCO's earnings that make up its FAC earnings bank applicable to the present period.

Mr. Blissmer stated the correction NIPSCO proposes is appropriate for this FAC period and should, going forward, be reflected in the overall earnings bank calculation (sum of the differentials) that is applied to arrive at an accurate determination of whether NIPSCO has earned a return exceeding that authorized. He contended NIPSCO should be allowed to present an accurate earnings bank calculation for the relevant period that matches the approach taken to calculate its jurisdictional earnings as opposed to continuing to perpetuate an error made in Petitioner's past FAC periods.

Mr. Blissmer testified that if the determination of NIPSCO's earnings were only corrected on a going-forward basis, only a small portion of the earnings test will be accurate, while the larger portion of the statutory test that relies on a present calculation of the earnings bank will remain inaccurate. He stated that given that customers continue to benefit from the amount of non-jurisdictional tax expense NIPSCO included in its revenue requirement to reduce its current base rates, it is appropriate in this FAC to fully correct the earnings calculation for the relevant period, and this entails both a correction to reflect accurate earnings and a correction to reflect an accurate earnings bank.

Mr. Blissmer testified the correction NIPSCO proposes is consistent with the FAC statute. He explained that in every FAC, Petitioner is required to show the earnings over the relevant period, and Ind. Code § 8-1-2-42.3(c) directs the Commission to calculate for the relevant period the sum of the differentials. Mr. Blissmer testified this calculation should be performed based upon correct inputs, and in this instance, the correction also makes the calculation of earnings for FAC

[55] In his rebuttal, Mr. Blissmer confirmed NIPSCO seeks to address this normalization issue in its electric base rate case filed on September 19, 2022 (Cause No. 45772).

purposes consistent with the manner in which base rates and, thus, authorized earnings were determined. Per Mr. Blissmer, if the FAC earnings bank continues to be calculated as it has been in the past and/or if the current cumulative bank amount is not adjusted as NIPSCO is proposing, the allocation of income tax expense to non-jurisdictional revenues for FAC earnings bank purposes will be incorrect. He stated the allocation should match the calculation of income tax expense on earnings before allocation.

Mr. Blissmer further testified that for purposes of calculating the sum of the differentials to determine the overall FAC earnings bank for this FAC, NIPSCO has shown the impact of the correction to non-jurisdictional tax expense for each period included in the earnings bank calculation presented in this FAC proceeding. He stated that to determine in this FAC whether any amount of over-earnings should be applied to reduce NIPSCO's requested fuel cost recovery, the sum of the differentials in the FAC earnings bank for the relevant period must be accurately calculated, and to achieve an accurate calculation, NIPSCO corrected its earnings calculation for each relevant period (i.e., the period that is being used to determine the overall amount of its FAC earnings bank that is to be applied as part of the earnings test in the current relevant period). Mr. Blissmer testified that absent this approach, NIPSCO will be left with accurate relevant period earnings being compared to an inaccurate earnings bank, yielding an inaccurate determination of NIPSCO's earnings test under Ind. Code § 8-1-2-42.3.

B. Industrial Group's Evidence Upon Correction. Mr. Gorman testified the alleged error NIPSCO is proposing to remove has been in place more than five years, and NIPSCO has had at least one base rate case during this time. He recommended any change to the methodology for the earnings bank calculation be addressed in NIPSCO's next base rate case and not in an FAC adjustment.

In support of his recommendation, Mr. Gorman stated Mr. Blissmer has not reconciled his proposed corrected FAC earnings test with the way NIPSCO's base rates were established; consequently, Mr. Gorman questioned whether Mr. Blissmer's proposed FAC earnings test correction aligns with how earnings are reflected in base rates. Specifically, Mr. Gorman testified that in Cause No. 45159, NIPSCO witness Jennifer Shikany, in supporting the settlement in that rate case, determined the settlement revenue requirement. He stated that while NIPSCO made several ratemaking and normalization adjustments, NIPSCO did remove non-jurisdictional plant in-service and depreciation expense from developing the retail revenue requirement that went into retail tariff base rates. He asserted that NIPSCO did not remove the non-jurisdictional cost of service components related to Multi-Value Projects ("MVPs"), Targeted Market Efficiency Projects ("TMEPs"), and Interregional Market Efficiency Projects ("IMEPs") in the same manner Mr. Blissmer is proposing in the revised FAC earnings test.

Mr. Gorman testified that customers could be harmed if the development of an FAC earnings test is not synchronized with the development of retail tariff rate base charges. He stated the earnings test should mirror the method of establishing the operating income in NIPSCO's last base rate case. He opined that Mr. Blissmer's proposal to change the earnings test at the FAC does not mirror the development of cost of service used to set base rates and stated this potentially can harm customers by understating the operating income produced through the ratemaking methodology established in Cause No. 45159 and currently used in the FAC earnings test. Additionally, Mr. Gorman stated Mr. Blissmer's subtraction from NIPSCO's total operating income, the operating income produced through non-jurisdictional customers, has not been well developed in this proceeding. Hence, to the extent he overstates this reduction to retail operating income adjustment, NIPSCO will be understating its actual earnings used in the earnings test for FAC reconciliations purposes.

Mr. Gorman also testified that while each FAC order states the FAC factors are interim pending a Commission determination upon whether NIPSCO earned more than authorized, for prior periods in each FAC, the Commission finalizes a utility's earnings based on the reported actual earnings. He testified that in FAC 135, NIPSCO's earnings were finalized through March 31, 2022, and because the earnings have been finalized for that period, the FAC charges to that date are no longer interim subject to refund. He stated that although his recommendation is that this issue be addressed in NIPSCO's next rate case, making any corrections to how the earnings test is calculated going forward, if the Commission were to make changes to NIPSCO's earnings in prior periods, such changes should only reflect changes in earnings from FAC 134 onward.

C. OUCC's Evidence Upon Correction. Mr. Guerrettaz testified there is an atypical issue impacting this FAC in that the factor NIPSCO used to allocate income taxes between jurisdictional and non-jurisdiction projects over at least the last five years "was incorrect." Public's Exhibit No. 1 at p. 3. He stated the amount of income tax allocated to non-jurisdictional projects was overstated, resulting in incorrect revenue requirements for the MVP, TMEP, and IMEP non-jurisdiction projects. To correct this error, Mr. Guerrttaz testified that in this FAC, NIPSCO restated five years or 60 months of tests since September 30, 2017, and filed this FAC's earnings using the correct tax rate. He confirmed that state and federal income taxes did tie back to the total electric income statements provided by month for the last five-year period. Per Mr. Gurrettaz, NIPSCO used a different method of calculating the total income tax than was done in NIPSCO's last rate case settlement (Cause No. 45159), and it is unclear exactly how this occurred. He stated NIPSCO's methodology to calculate income taxes for each non-jurisdictional project was different than other companies in that the more frequently used method computes the correct federal and state income taxes with all deductions on a monthly basis and then allocates out the actual computed amount from the total taxes per books to the two jurisdictions. NIPSCO, however, chose a simpler approach five years ago, which meant very detailed monthly calculations. He stated NIPSCO's workpapers detail out revenues and certain expenses for non-jurisdictional assets, but NIPSCO only computed the amount of total gross operating income, not net income.

Mr. Guerrettaz opined that the best calculation to produce the most detailed numbers for income taxes would be a monthly calculation of net income for jurisdictional and non-jurisdictional income. He disagreed that the difference is attributable to the statutory rates versus the effective rates for income taxes, indicating the difference is the application of all the income and deductible items for income taxes. He also disagreed with NIPSCO's statement that the effective rate is "X" for the determination of jurisdictional net income; therefore, non-jurisdictional is "X," stating it is the OUCC's position the effective rate will be lower than the statutory rate for the total company, given NIPSCO's investment in solar and wind with the related Investment Tax Credits, as well as other adjustments to income tax calculations. Mr. Guerrettaz testified that NIPSCO estimated the impact of the wrongly allocated income taxes at approximately $74.8 million and then subtracted that amount from its earnings bank, which had the effect of wiping out over-earnings and making the earnings bank a negative amount, thereby nullifying NIPSCO's over-earnings and resulting in a higher FAC factor.

Mr. Guerrettaz testified the OUCC recommends that going forward NIPSCO compute monthly net income using all appropriate income and deductions and then subtract that amount from the monthly per books income statement, starting with Cause No. 38706 FAC 137. He reviewed how the tax issue affected Schedules A, B, C, and D and provided two different factors, as calculated by the OUCC, versus NIPSCO's calculation in Schedule A. He noted NIPSCO made a new adjustment of $5,510,356 which was presented as a correction to the non-jurisdictional income tax issue, with the adjustments NIPSCO made resulting in an adjusted cumulative earnings bank of ($4,631,984).

OUCC witness Eckert testified the OUCC recommends the Commission create a subdocket to allow more detailed examination of the costs, calculations, and issues associated with NIPSCO's earnings bank.

D. NIPSCO Rebuttal Upon Correction. In his rebuttal testimony, Mr. Blissmer initially noted that neither Mr. Gorman nor Mr. Guerrettaz disagree that there is an error with NIPSCO's FAC earnings bank, but he stated both oppose NIPSCO's proposal to correct the FAC earnings bank in this FAC for purposes of the Ind. Code § 8-1-2-42(d)(3) test. Mr. Blissmer testified the statute requires the Commission to find in each-and-every FAC that under Ind. Code § 8-1-2-42 (d)(3), the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return the Commission authorized in the last proceeding in which the utility's basic rates and charges were approved, and if NIPSCO's earnings exceed those authorized, what the sum of the differentials is for the relevant period – 59 months. Mr. Blissmer testified a reduction in the FAC charge can be ordered "only if" there have been over-earnings under Ind. Code § 8-1-2-42(d)(2) and the sum of the differentials under Ind. Code § 8-1-2-42.3 is greater than zero.

Mr. Blissmer stated that absent the correction he presented for the twelve-month period and the relevant period of the FAC earnings bank, the earnings test and the sum of the differentials will be incorrectly calculated for this FAC; consequently, NIPSCO proposes to correct its earnings calculation in this FAC to accurately reflect its actual earnings as required under the FAC statute for the Commission to perform its evaluation and make the required findings. More specifically, Mr. Blissmer testified NIPSCO asks that the language in Ind. Code § 8-1-2-42.3 be applied as written. Otherwise, this FAC will not correctly present NIPSCO's earnings test or a correct calculation of NIPSCO's earnings bank in accordance with Ind. Code §§ 8-1-2-42 and 42.3, precluding the Commission from accurately making the statutorily-required findings—including as related to NIPSCO's operating income, its earnings bank (sum of the differentials), and whether NIPSCO is earning a return that exceeds what was authorized in its last base rate case.

Mr. Blissmer testified NIPSCO has demonstrated that to present an accurate earnings test calculation for purposes of this FAC, Petitioner's correction must be made, and it must be made for the entire relevant period for the earnings bank. He stated that fundamentally, not allowing NIPSCO to correct its FAC earnings test and earnings bank in this proceeding for the relevant period is inappropriate because it would require NIPSCO to knowingly overstate earnings for each FAC until either a subdocket is litigated or its base rates are reset. He explained that in this FAC, not making the correction will require NIPSCO to reduce fuel costs by one-quarter of its purported quarterly over-earnings—notwithstanding that this is necessary only because NIPSCO's earnings are overstated. Mr. Blissmer opined that this error should not be knowingly perpetuated. From his perspective, an accurate evaluation of actual NIPSCO earnings is essential in this FAC, and without the correction NIPSCO proposes, the statutory evaluation cannot be properly performed.

In response to Mr. Guerrettaz's testimony questioning whether NIPSCO's books and records need to be reviewed and adjusted further, Mr. Blissmer testified there is nothing about NIPSCO's books and records that needs adjustment. He stated the impact on the earnings test associated with the allocation of tax expense for non-jurisdictional assets is primarily driven by the Tax Cuts and Jobs Act ("TCJA"). Thus, because NIPSCO's correction addresses the previous five years (back to 2017, which predates the TCJA), issues involving federal income taxes before this time are minimal.

Mr. Blissmer also took issue with Mr. Guerrettaz's request that NIPSCO be required to perform a monthly calculation associated with tax expense and deductions, opining that NIPSCO has proposed a calculation method that is accurate and understandable; therefore, what Mr. Guerrettaz proposes is not necessary and will make this calculation more complicated than it needs to be. He stated NIPSCO also does not believe this kind of additional monthly calculation is necessary because: (a) the allocation issue relates to allocation within a single entity (NIPSCO) and is not about two standalone entities, and (b) since the FAC is quarterly, NIPSCO will present the relevant information for quarterly review, yielding no additional value to be gained by requiring a monthly breakdown. He also noted that NIPSCO utilizes an established quarterly close process, which aligns with the quarterly FAC proceedings. Mr. Blissmer stated a presentation of jurisdictional and non-jurisdictional assets and associated tax expense on a monthly basis will not change the issue NIPSCO seeks to correct or impact it going forward. Mr. Blissmer confirmed that NIPSCO is, however, committed to ensuring the OUCC and other stakeholders have the information necessary to review NIPSCO's quarterly FAC proceedings and will work with stakeholders to ensure they are provided this information in a mutually agreeable format.

Mr. Blissmer also testified that NIPSCO disagrees with Mr. Guerrettaz's assertion that the difference is the application of all the income and deductible items for income taxes. He stated that although Mr. Guerrettaz claims NIPSCO's investment tax credits attributable to solar and wind generation investments (and other adjustments to income tax calculations) mean NIPSCO's effective rate would be lower than the statutory rate, this has no bearing on the issue at hand since all tax credits attributed to NIPSCO's wind (and future solar) investments recorded for GAAP have been adjusted out of NIPSCO's regulated income tax expense. He testified that NIPSCO did not use an effective tax rate to calculate the non-jurisdictional income tax expense in its correction, but rather, it was the effective tax rate that informed NIPSCO that an error had been made in the past. Mr. Blissmer stated NIPSCO's method in past FACs has been to allocate all deductions to the jurisdictional assets, even those deductions that are allocable to the non-jurisdictional assets because NIPSCO simply uses the statutory rate to compute the non-jurisdictional income, but there are tax deductions applicable to the non-jurisdictional assets. He stated that is the fundamental error that has occurred.

Mr. Blissmer also testified that Mr. Guerrettaz's statement that the methodology of NIPSCO's proposed correction differs from what was done in NIPSCO's rate settlement is not a fair criticism because this claim is based on a misunderstanding about how the rate case pro forma income tax expense was calculated. He demonstrated step-by-step how NIPSCO removed the effects of non-jurisdictional assets in Cause No. 45159.

Mr. Blissmer stated that since implementation of the TCJA, NIPSCO has not allocated the amortization of EADIT tied to non-jurisdictional assets to non-jurisdictional income. Per Mr. Blissmer, the Internal Revenue Service rules prohibit NIPSCO from passing back protected EADIT greater than the amount computed under the average rate assumption method; consequently, total EADIT requires a non-jurisdictional adjustment to determine the amount of EADIT passing back to NIPSCO's jurisdictional customers through base rates so as to not overstate the amount of EADIT passed back in base rates, and NIPSCO is proposing this issue be addressed in its pending rate case, Cause No. 45772.

Mr. Blissmer also explained that separate and distinct from this base rate normalization issue, jurisdictional earnings should be correctly presented for the earnings bank. Thus, NIPSCO's jurisdictional earnings should not show the adjustment to income tax expense from the amortization of EADIT associated with non-jurisdictional plant. He testified it is appropriate, for purposes of the earnings test, for NIPSCO to allocate the non-jurisdictional EADIT to non-jurisdictional income and would be wrong for NIPSCO to not do so—both from an allocation standpoint and for purposes of separating these non-jurisdictional assets from base rates. Mr. Blissmer testified that if NIPSCO is not allowed to correct the earnings bank, this will result in passing the non-jurisdictional EADIT back to customers twice – once through pass-back of too much EADIT in base rates and again when NIPSCO is not allowed to recognize the non-jurisdictional EADIT for purposes of the FAC earnings bank.

In response to the OUCC's recommendation that the Commission approve a lower FAC factor in this FAC than NIPSCO is proposing, Mr. Blissmer testified this would not be appropriate as doing so would be based on an incorrect view of earnings under Ind. Code § 8-1-2-42(d)(3) and perpetuate the error that has been identified. He also noted Mr. Guerrettaz grossed up the refund amount impacting his calculation of the FAC factor by a revenue conversion factor, which he stated also would not be appropriate.

In responding to Mr. Gorman's position that the correction to the earnings bank calculation should be corrected in NIPSCO's next base rate case, Mr. Blissmer initially noted that Mr. Gorman does not disagree with NIPSCO's fundamental reason for seeking approval of this proposed correction—to present the correct allocation of income tax expense to non-jurisdictional income over the relevant period earnings bank. He testified that if NIPSCO is forced to present an incorrect calculation of the earnings bank, this results in overstating NIPSCO's jurisdictional net operating income by $74,825,574. Additionally, he testified that Mr. Gorman does not take issue with NIPSCO's revised earnings bank balance when incorporating the appropriate non-jurisdictional tax rate; instead, his position appears to be that NIPSCO is stuck with this error and should not be allowed to correct it until its next base rate case. Mr. Blissmer testified this is not appropriate and will knowingly overstate NIPSCO's actual earnings.

In response to Mr. Gorman's testimony that NIPSCO's proposed correction does not appear to be consistent with the development of the retail operating income used to set base rates in NIPSCO's last base rate case, Mr. Blissmer stated NIPSCO's non-jurisdictional income before income tax is adjusted out of the NIPSCO earnings in the same manner in the FAC earnings test as it was in NIPSCO's base rates established in Cause No. 45159. He stated that by subtracting non-jurisdictional results from the calculation of jurisdictional earnings for the relevant period, NIPSCO has reflected an excessive tax expense applicable to its non-jurisdictional earnings and, therefore, presented an inaccurate jurisdictional earnings total. He reaffirmed that income tax expense was computed in Cause No. 45159 solely on the basis of jurisdictional income before tax, and there was no calculation of non-jurisdictional income tax expense performed because income tax expense was computed from a bottoms-up approach based solely on the pro forma jurisdictional activities.

Mr. Blissmer testified that although the Commission's Order in Cause No. 45159 established a net operating income and authorized return for NIPSCO, and this has some relation to the FAC, as NIPSCO's earnings are evaluated in each FAC proceeding, the issues are distinct. He opined that fixing an erroneous input for purposes of the FAC earnings test is not a request to somehow modify what the Commission approved in Cause No. 45159; rather, it corrects the earnings test being used in the FAC proceedings so the requisite statutory evaluation can be accurately conducted. Mr. Blissmer stated Mr. Gorman's request that the issue not be corrected in this FAC but delayed until resolution of NIPSCO's next rate case is inconsistent with what the FAC statute requires.

Mr. Blissmer also responded to Mr. Gorman's assertion that if the Commission makes changes to NIPSCO's earnings bank for prior periods, any changes should only reflect changes in earnings from FAC 134 onward. He stated this is inconsistent with the FAC statute and reiterated that NIPSCO is not proposing to change prior FAC factors/charges but, rather, is asking that the language of Ind. Code §§ 8-1-2-42(d)(3) and 42.3 be applied in this FAC, and NIPSCO's earnings and the sum of the differentials be accurately calculated for the entire relevant period. He stated that absent the correction for the entire period of the FAC earnings bank, the sum of the differentials required under the statute will be incorrectly calculated for this FAC. Mr. Blissmer also testified that NIPSCO is not proposing to change any FAC factors or FAC charges—whether before or after March 31, 2022.

Per Mr. Blissmer, NIPSCO's purpose is simple—to present an accurate earnings test and earnings bank in this FAC, which he stated is necessary for the Commission to undertake the determination required under the FAC statute, including whether NIPSCO has earned a return in excess of that authorized by the Commission under Ind. Code § 8-1-2-42(d)(3) and whether the sum of the differentials evaluation under Ind. Code § 8-1-2-42.3(c) is greater than zero and, ultimately, whether any over-earnings occurred and a related reduction to the proposed FAC factor is required.

Mr. Blissmer stated NIPSCO requests that the Commission issue an order in FAC 136, including, but not be limited to, approval of NIPSCO's proposed FAC factor of 29.820 mills per kWh and find that based on NIPSCO's corrected FAC earnings test and earnings bank, NIPSCO has not over-earned for the twelve months ended June 30, 2022.

Mr. Blissmer testified that if the Commission believes additional investigation into this issue is warranted, NIPSCO believes a subdocket in an FAC proceeding is the more appropriate forum because the finding of the sum of the differentials must be made in the FAC. As such, this is a discrete FAC matter about the appropriate way to address non-jurisdictional tax expense for the FAC earnings bank. Mr. Blissmer stated the only FAC factor that is appropriate for the Commission to approve—the only FAC factor that has been supported by substantial evidence—is the FAC factor NIPSCO proposed. He stated it would be inappropriate, for example, to reduce the FAC factor (as the OUCC proposed) without substantial evidence supporting the accuracy of that factor, noting that Ind. Code § 8-1-2-42.3 provides for a reduction to the fuel charge "only if the amount determined under subsection (c) is greater than zero." He suggested that if the Commission has concern about the correction NIPSCO is proposing and its impact on the FAC factor, the Commission should, nonetheless, approve NIPSCO's proposed factor subject to refund based on the outcome of a subdocket.

Mr. Blissmer testified that in his opinion, the only issue to potentially be addressed in a subdocket is Mr. Eckert's statement that NIPSCO's $74.8 million correction is an estimate. He stated that while NIPSCO does not believe a subdocket is necessary, if the Commission concludes otherwise, the sub docket should be for purposes of determining whether NIPSCO's calculation of its FAC earnings bank is accurate and, if not, whether refunds to customers should be required.

E. Docket Entry Response. A docket entry was issued on October 6, 2022, requesting NIPSCO to identify the income tax rate NIPSCO collects on its FERC jurisdictional assets and provide a copy of NIPSCO's MISO Attachment O. NIPSCO filed its response to this docket entry on October 7, 2022, which included NIPSCO's 2021 FERC Formula Rate True-up Attachments O, MM, and GG. This information demonstrates NIPSCO's non-jurisdictional rates are not allocated at the statutory income tax rate as they have been historically in the FAC earnings test. Rather, they are set on an overall company income/rate base/tax rate type of allocation.

F. Commission Discussion and Findings Upon NIPSCO's Correction. As discussed above, NIPSCO proposes to change how it allocates non-jurisdictional tax expense for purposes of calculating its earnings under Ind. Code § 8-1-2-42(d)(3) in this FAC proceeding. NIPSCO's proposal also impacts the Commission's calculation of the sum of the differentials for the relevant period under Ind. Code § 8-1-2-42.3(c). The OUCC does not dispute that NIPSCO has overstated the amount of income tax allocated to non-jurisdictional projects for at least the last five years, but the OUCC and the Industrial Group urge the Commission to not approve NIPSCO's proposed correction in this FAC. Additionally, the OUCC requests that a subdocket be opened to further investigate this matter, while the Industrial Group recommends the issue be resolved in NIPSCO's next electric base rate case.

The Commission finds the evidence demonstrates that approval of the fuel charge NIPSCO supports will result in over-earnings. Although there is a difference in the amount of over-earnings NIPSCO and the OUCC calculate (*See* Petitioner's Exhibit No. 1, Att. 1-H, Column E, Line 1; Public's Exhibit No. 1, Sched. B-1), both calculations yield over-earnings; therefore, under Ind. Code § 8-1-2-42.3, the Commission proceeds to review the calculation of the sum of the differentials for the relevant period to determine if a reduction to the FAC factor is required. This calculation and whether a reduction to NIPSCO's fuel charge is required are impacted by NIPSCO's proposed adjustment to the allocation of non-jurisdictional tax expense.

Under the FAC statute, NIPSCO has the burden of demonstrating "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." Ind. Code § 8-1-2-42(d)(3). While there are over-earnings, whether this results in Petitioner earning an excess return depends upon the propriety of NIPSCO's revised allocation of non-jurisdictional income tax expense and whether Petitioner's change in methodology is appropriate and can be made in the context of this FAC proceeding. Once these issues are resolved, the Commission turns to Ind. Code § 8-1-2-42.3(c), which requires us to determine whether the "sum of the differentials" over the relevant period is less than zero, which also will depend upon our treatment of NIPSCO's non-jurisdictional income tax expense. As such, the disputed correction bears directly on the calculation of the FAC in this case under both calculations.

The Commission has previously found that creation of a subdocket is appropriate where the summary nature of FAC proceedings do not lend themselves to sufficient record development. *Application of Duke Energy Ind., LLC*, Cause No. 38707 FAC 111, 2017 WL 1632308, at *8 (IURC April 26, 2017); *see also Application of Duke Energy Ind., LLC*, Cause No. 38706 FAC 76 at pp. 4, 13 (IURC June 25, 2008). We find this proceeding does not present such a case. While the Industrial Group and the OUCC advocate against making the allocation correction in this FAC that NIPSCO proposes, the Commission finds Mr. Blissmer has shown this correction is reasonable and why it is appropriate, and no other party provided sufficient evidence upon which to conclude otherwise. Additionally, NIPSCO's docket entry response supports NIPSCO's premise that a fair allocation of income tax expense between NIPSCO's jurisdictional and non-jurisdictional components for purposes of the earning test calculation should not have the effect of applying a 25% income tax rate to the non-jurisdictional component. The method NIPSCO seeks to correct has such an effect; therefore, the Commission finds the correction NIPSCO proposes more accurately allocates non-jurisdictional tax expense than the existing method. The current method allocates $12.7 million although the non-jurisdiction rates, as shown in NIPSCO's docket entry response, are designed to recover $6.6 million. Accordingly, the Commission finds NIPSCO's proposed new method is a marked improvement, supported by NIPSCO's testimony, and the inaccurate allocation should be corrected in this FAC, not perpetuated, to more accurately make the required FAC statutory determinations, including whether the sum of the differentials over the relevant period is less than zero.[6] That said, no party is precluded from further investigating these matters, particularly in NIPSCO's pending base rate case, and demonstrating why further corrections may be appropriate on a forward application basis.

The mechanics of the earnings test includes Ind. Code § 8-1-2-42(d)(3), subject to Ind. Code § 8-1-2-42.3. In each unique FAC proceeding the earnings test is applied and a finding under these mechanics must be made in the Commission's approval of the fuel cost charge. As found above, the marked improvement of NIPSCO's proposed tax expense allocation should be corrected in this FAC. As such, for purposes of the required findings in this FAC, the Commission finds the application of the improved methodology to both the amount determined by Ind. Code § 8-1-2-42(d)(3) and Ind. Code § 8-1-2-42.3 is reasonable.

[6] In the Order in Cause No. 38707 FAC 120 approved on June 26, 2019, the Commission also approved revisions to previous errant FAC earnings calculations in that FAC when these were identified.

Having found NIPSCO's correction to non-jurisdictional tax expense for purposes of determining its earnings is reasonable, the overall earnings bank (sum of the differentials) for the relevant period is a negative $74,825,574, and the jurisdictional earnings for the 12 months ending June 30, 2022, equal over-earnings of $24,939,975 (Petitioner's Revised Attachment 1-H); therefore, under the mechanics of the applicable statutes it is not appropriate to require a refund of any excess return NIPSCO earned during the 12-month period ending June 30, 2022.

11. <u>OUCC Report</u>. In addition to the testimony referenced above, particularly in Finding No. 10, Mr. Guerrettaz testified: (1) the fuel cost element of NIPSCO's power purchases has been calculated by including the additional requirements of various Commission Orders; (2) the variance for the quarter ending June 30, 2022, was computed in conformity with Ind. Code §§ 8-1-2-42, -42.3, and relevant orders; (3) NIPSCO did have jurisdictional net operating income for the 12 months ending June 30, 2022, greater than granted in its last general rate case; (4) NIPSCO did not have decreases in other operating costs that could be used to offset fuel cost increases; and (5) the figures used in NIPSCO's application for a change in the FAC for the quarter ending June 30, 2022, were supported by Petitioner's books, records, and source documentation for the period reviewed. Mr. Guerrettaz stated the OUCC recommends the FAC factor of 0.026058 per kWh be approved. Mr. Guerrettaz also recommended the Commission order NIPSCO to continue to provide the monthly railcar inventory and explain any deviations from the expected forecast presented; provide a break out of all congestion components in future FACs; provide detailed coal cost statements from each supplier to each station for the three actual months on a going forward basis setting forth the components of coal and transportation; provide a copy of all new RFPs and contracts for transportation and coal; and explain the offer process for Sugar Creek for the three actual months in FAC 137.

Mr. Eckert testified: (1) he has created a working model of Ms. Robles' purchased power over the Benchmark calculation and agrees with this calculation; (2) NIPSCO's treatment of Ancillary Services Market ("ASM") charges follows the treatment the Commission ordered in its June 30, 2009 Phase II Order in Cause No. 43426 ("Phase II Order"); (3) NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (4) NIPSCO's steam generation costs are higher than the other large electric investor-owned utilities in Indiana, while NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor-owned utilities in Indiana; (5) coal prices increased dramatically over the last 12 months; (6) NIPSCO's coal inventory at Schahfer decreased to approximately 38 days, down four days from its prior FAC filing; (7) NIPSCO's PRB coal inventory at Michigan City Generating Station was at 15 days, and its NAPP coal inventory was at 40 days for the reconciliation period; (8) NIPSCO should continue to update the Commission on its coal inventory; (9) if coal decrement pricing is used, NIPSCO should provide justification and documentation supporting the need for and utilization of coal decrement pricing, as well as specify when it expects coal decrement pricing to end and provide inputs to its calculation of the coal price decrement; (10) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (11) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, Rosewater, and Indiana Crossroads; (12) NIPSCO provided an update on the status of the Railroad Litigation[7] and NIPSCO's deferral of associated legal costs and should continue providing such updates; (13) the OUCC recommends the Commission create a sub-docket to facilitate more detailed examination of the costs, calculations, and issues associated with NIPSCO's earnings bank; and (14) the OUCC recommends the Commission approve NIPSCO's proposed FAC factor as recalculated and confirmed by Mr. Guerrettaz.

12. Fuel Cost Adjustment Factor. Based on the evidence, the Commission finds NIPSCO has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. NIPSCO's evidence presented a variance factor of $0.010002 per kWh to be added to the estimated cost of fuel for bills rendered during the November 2022 through January 2023 billing cycles in the amount of $0.056556 per kWh. This results in a fuel cost adjustment factor of $0.029820 per kWh, after subtracting the cost of fuel in base rates and adjusting for applicable taxes. Ms. Krupa testified the estimated average monthly bill impact for a residential customer using 1,000 kWh per month is a $6.79 increase from the factor currently in effect.

13. Interim Rates. Because the Commission is unable to determine whether NIPSCO will earn an excess return while this Order is in effect, the Commission finds the rates approved herein should be interim rates, subject to refund.

14. Major Forced Outages. Consistent with past Commission Orders, Mr. Saffran sponsored Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the second quarter of 2022, including the length and cause of each major forced outage, the generating unit involved, and proposed solutions to prevent such outages from reoccurring. For purposes of his presentation, a major forced outage is a unit forced outage lasting longer than three consecutive days. He also sponsored Confidential Attachment 4-B providing a root cause analysis for the forced outages for which an analysis was completed at the time of the FAC filing.

15. Status of Railroad Litigation. In accordance with the Commission's Order in Cause No. 38706 FAC 125 ("FAC 125"), Ms. Krupa testified the Railroad Litigation remains pending, and as of June 30, 2022, NIPSCO has deferred $2,586,913 in associated legal costs. Mr. Wagner advised the Railroad Litigation remains in the discovery phase. He stated NIPSCO substantially completed document production in 2021, and NIPSCO's fact witness depositions are complete, but the possibility remains that a NIPSCO company witness will be deposed. He stated NIPSCO's counsel is preparing to depose the defendants' corporate representatives, with these depositions expected to occur later this year. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so in its FAC filings.

16. Confidential Information. On August 25, 2022, NIPSCO filed a motion for protection and nondisclosure of Confidential Information supported by an affidavit showing information to be submitted to the Commission contained trade secrets within the scope of Ind.

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

Code §§ 5-14-3-4 and 24-2-3-2. In a docket entry issued on September 9, 2022, such information was found to preliminarily be confidential, after which NIPSCO submitted the information under seal. The Commission finds such information is confidential under Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. NIPSCO's requested fuel cost adjustment to be applicable to bills rendered during the November and December 2022 and January 2023 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 12 above, is approved on an interim basis subject to refund as set out in Finding No. 13 above.

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

3. NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind and solar purchases being recovered through the FAC, as discussed in Finding No. 7.C. above, and testimony regarding any electric hedging transaction costs and gains/losses for which NIPSCO is seeking recovery through the FAC, as discussed in Finding No. 7.D. above.

4. NIPSCO shall also continue to include in its quarterly FAC filings the information required by the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90 and testimony regarding efforts to mitigate costs incurred for unused train sets, as discussed in Finding No. 9 above, and continue to provide updates on its railcar inventory and efforts to achieve an appropriate railcar level, explaining any deviations that occur as discussed in Finding No. 11 above.

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

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

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

8. NIPSCO shall break out all congestion components in its future FAC testimony, provide a cost of coal stacks from each supplier to each station for the three actual months on a

going forward basis, and provide a copy of all new requests for proposal and contracts for transportation and coal consistent with Finding No. 11 above.

9. The OUCC's request for a subdocket in this matter is denied, consistent with Finding No. 10 above.

10. The information filed in this Cause pursuant to NIPSCO's motion for protective order is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

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

APPROVED: OCT 26 2022

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

Regina K. Joyner Digitally signed by Regina K. Joyner Date: 2022.10.26 10:34:49 -04'00' on behalf of

Dana Kosco
Secretary of the Commission