VERIFIED DIRECT TESTIMONY OF ROSALVA ROBLES

Q1. Please state your name, business address and title.

A1. My name is Rosalva Robles. I am the Manager of Planning – Regulatory Support for Northern Indiana Public Service Company LLC ("NIPSCO" or "Company"). My business address is 1500 165th Street, Hammond, Indiana 46320.

Q2. Please describe your educational and employment background.

A2. I graduated from Purdue University Calumet with a Bachelor of Science in Accounting and minor in International Business (2004), along with a Master of Business Administration with an Accounting Concentration (2006). In addition, in 2016, I began doctorate course work with Indiana Wesleyan University towards earning my Ph.D. in Organizational Leadership. I began my employment with NIPSCO in 2012 as a Senior Budget Analyst overseeing the capital budgets and accruals of various NIPSCO departments. In 2014, I transitioned to the role of Senior Operations Analyst and was later named Lead Operations Analyst, where I was responsible for the electric generation forecast modeling among other month-end close and regulatory support reporting duties. In June 2019, I was promoted to my current managerial role. Prior to joining NIPSCO, I worked in the steel and food manufacturing industries, where I performed tax, procurement, and accounting functions. As part of my previous role in the steel industry with supporting state and local taxes, I became a Level I and Level II Assessor Appraiser certified with the State of Indiana through the Department of Local Government Finance. My certification is not active at this time.

Q3. Please describe your responsibilities as Manager of Planning – Regulatory Support.

A3. As Manager of Planning – Regulatory Support, I am responsible for various planning, analytical, and support functions for both NIPSCO's electric and gas portfolios and NIPSCO's Fuel Adjustment Clause ("FAC"), Gas Cost Adjustment (GCA), Regional Transmission Organization (RTO), and Resource Adequacy (RA). This includes oversight responsibilities with generation forecasting and reporting for NIPSCO's electric assets, coordinating the reporting and forecasting for both internal and external parties and entities, and market support functions for NIPSCO's market forecasting models.

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Attachment 1-A</u>?

A4. Yes.

Q5. What is the purpose of your testimony in this proceeding?

A5. The purpose of my testimony is to (i) support the reasonableness of NIPSCO's purchase of electric energy from the Midcontinent Independent System Operation, Inc. ("MISO"), independent power producers, marketers, or other utilities; (ii) summarize cost variances during the January through March 2023 reconciliation period (the "Reconciliation Period"), as well as the generation and purchased power mix during this period; (iii) describe the costs associated with the wind and solar Purchase Power Agreement ("PPA") purchases included in this FAC proceeding and explain activity related to Renewable Energy Credits ("RECs") associated with those PPA purchases; (iv) describe the activity and impacts of NIPSCO's Electric Hedging Program initially approved in the Indiana Utility Regulatory Commission's ("Commission") July 13, 2011 Order in Cause No. 43849

("43849 Order"); (v) provide an overview of the MISO settlements process for the charges and credits that NIPSCO incurs as a result of its participation in the MISO energy and operating reserve markets as well as a description of any NIPSCO curtailments called by MISO; (vi) describe NIPSCO's coordination with MISO's energy market operations, which began on April 1, 2005, and its applicable costs; (vii) describe NIPSCO's coordination with MISO's ancillary services market ("ASM"), which began January 6, 2009, and its applicable costs; (viii) describe application of the Purchased Power Benchmark approved in the Commission's August 25, 2010 Order in Cause No. 43526 ("43526 Order") and the revenue sufficiency guarantee ("RSG") Benchmark approved in the Commission's June 30, 2009 Order in Cause No. 43665 ("43665 Order"); and (ix) address NIPSCO's gas purchasing practices for the purchase of natural gas when used as a fuel to serve the NIPSCO generation fleet.

Q6. Are you sponsoring any attachments to your direct testimony?

A6. I am sponsoring Attachment 2-A through Attachment 2-D, which were prepared by me or under my direction and supervision.

Q7. Please describe Attachments 2-A, 2-B, 2-C, and 2-D.

A7. Attachment 2-A is the calculation of the daily purchased power benchmark price. Attachment 2-B is the calculation of the RSG benchmark price. Attachment 2-C is the Hedge Impact on FAC Prices. Attachment 2-D shows a break out of Day Ahead and Real Time congestion costs by node.

Cost Variances During Reconciliation Period

Q8. How did the Company's actual fuel cost in the Reconciliation Period compare with the Company's forecasted fuel cost for those months?

A8. The total actual fuel cost in the Reconciliation Period was $89,086,106 while the forecasted fuel cost was $124,526,990 (Attachment 1-A, Schedule 5, page 4 of 10, line 43). The average actual fuel cost per kWh for the Reconciliation Period was 39.23% less than the forecast. This led to a variance factor of ($11.260) (Attachment 1-A, Schedule 1, Line 39a).

Q9. What were the primary drivers of the difference between the forecasted and actual fuel cost in the Reconciliation Period?

A9. The differences were primarily driven by (1) a combination of lower than anticipated market prices and reduced unit availability experienced for this reconciliation period; (2) a lower actual cost associated with the MISO Components Cost of Fuel; and (3) REC sales, which helped to mitigate potential increases in the impact during the reconciliation period. At the time the forecast was prepared neither NIPSCO nor the market as a whole anticipated (a) an approximate 62% decrease in the average natural gas prices ($2.598/Dth actual compared to $6.902/Dth estimated) for this reconciliation period; or (b) an approximate 67% decrease in the all-hours average power price in MISO ($29.93/MWh actual LMP compared to $91.47/MWh estimated LMP) for this reconciliation period.

The total actual fuel cost for January 2023 was $33,960,526, while the forecasted fuel cost was $45,209,123 (Attachment 1-A, Schedule 5, page 1 of 10, line 43). The difference was driven mostly by a decrease in the actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $17,565,016 (Attachment 1-A, Schedule 5, page 1 of 10, lines 22-26); a decrease in the actual MISO Components of Cost of Fuel (as compared to the forecast) of $1,063,645 (Attachment 1-A, Schedule 5, page 1 of 10, line 28). This was offset by an increase in the actual (as compared to the forecast) purchased power cost of $2,856,056 (Attachment 1-A, Schedule 5, page 1 of 10, lines 27 and 29-36); and a decrease in the actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $4,561,372

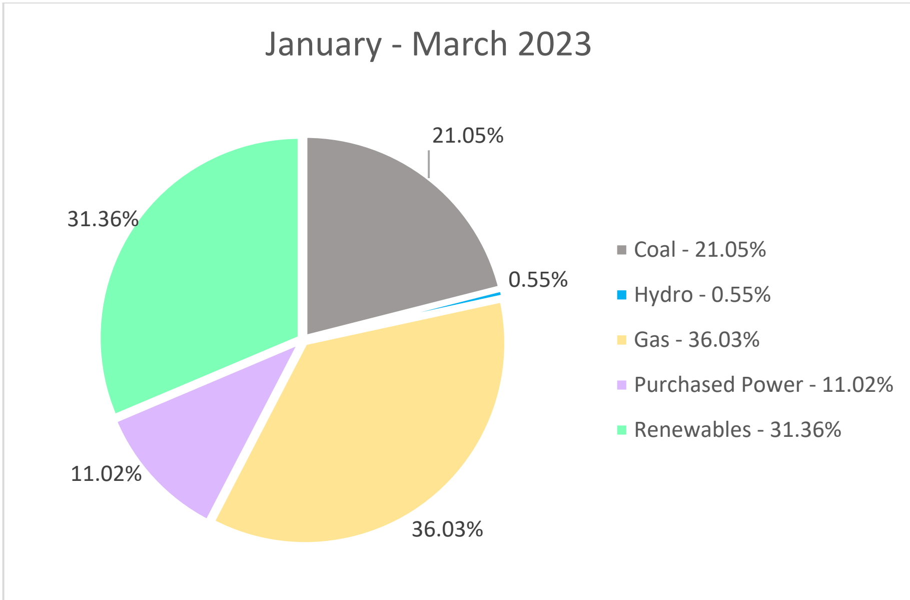
(Attachment 1-A, Schedule 5, page 1 of 10, lines 38 and 40. Additionally, NIPSCO realized 33,096 more MWh of "sales" than were forecasted (Attachment 1-A, Schedule 5, page 1 of 10, line 21).

The total actual fuel cost for February 2023 was $25,237,088, while the forecasted fuel cost was $42,363,500 (Attachment 1-A, Schedule 5, page 2 of 10, line 43). The difference was driven mostly by a decrease in the actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $16,526,666 (Attachment 1-A, Schedule 5, page 2 of 10, lines 22-26); a decrease in the actual (as compared to the forecast) purchased power cost of $1,322,648 (Attachment 1-A, Schedule 5, page 2 of 10, lines 27 and 29-36): and a decrease in the actual MISO Components of Cost of Fuel (as compared to the forecast) of $807,822 (Attachment 1-A, Schedule 5, page 2 of 10, line 28). This was offset by a decrease in the actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $1,014,903 (Attachment 1-A, Schedule 5, page 2 of 10, lines 38 and 40); and a decrease in the actual credit (as compared to the forecast) associated with the Wind PPA Adjustment of $557,004 (Attachment 1-A, Schedule 5, page 2 of 10, line 42).

The total actual fuel cost for March 2023 was $29,888,492, while the forecasted fuel cost was $36,954,367 (Attachment 1-A, Schedule 5, page 3 of 10, line 43). The difference was driven mostly by a decrease in the actual (as compared to the forecast) fuel usage and fuel cost for NIPSCO generation of $8,631,754 (Attachment 1-A, Schedule 5, page 3 of 10, lines 22-26); a decrease in the actual (as compared to the forecast) purchased power cost of $625,526 (Attachment 1-A, Schedule 5, page 3 of 10, lines 27 and 29-36). This was offset by a decrease in the actual credit (as compared to the forecast) associated with Intersystem Sales through MISO of $1,654,428 (Attachment 1-A, Schedule 5, page 3 of 10, lines 38 and 40); and a decrease in the actual credit (as compared to the forecast) associated with the Wind PPA Adjustment of $644,082 (Attachment 1-A, Schedule 5, page 3 of 10, line 42).

Q10. What was the generation and purchased power mix during the Reconciliation Period?

A10. The chart below provides the generation and purchased power mix percentages during the Reconciliation Period.



<u>Purchased Power Agreements and Renewable Energy Credits</u>

Q11. Are you familiar with the costs associated with NIPSCO's purchase of electric energy from other utilities and/or MISO?

A11. Yes.

Q12. Are any costs associated with wholesale purchase and sale agreements for wind and solar energy included in actual and/or forecasted fuel costs in this filing?

A12. Yes. Costs associated with the wholesale purchase and sale agreements for wind energy with Barton Windpower LLC ("Barton"), Buffalo Ridge I LLC ("Buffalo Ridge"), Jordan Creek Wind Farm LLC ("Jordan Creek"), Rosewater Wind Generation LLC ("Rosewater"), and Indiana Crossroads

Wind Generation LLC ("Crossroads Wind") are included in NIPSCO's actual and forecasted fuel costs. 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 agreement for wind energy from Barton on April 10, 2009 and Buffalo Ridge on April 15, 2009. Pursuant to the Commission's August 7, 2019, Order in Cause No. 45194 ("45194 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Rosewater on November 20, 2020. Pursuant to the Commission's June 5, 2019, Order in Cause No. 45195 ("45195 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Jordan Creek on December 2, 2020. Pursuant to the Commission's 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 Crossroads Wind on December 17, 2021. Pursuant to the 43393, 45194, 45195, and 45310 Orders, NIPSCO is also crediting any off-system sales created by its wind purchased power agreements. The credit is included in the Wind

PPA Adjustment shown on Attachment 1-A, Schedule 5, Pages 1 through 4, Line 42. For the Reconciliation Period, NIPSCO received 259,968 MWhs (January), 294,223 MWhs (February), and 326,494 MWhs (March), as reflected on Attachment 1-A, Schedule 5, Pages 1 through 3, Lines 8 and 10.

Pursuant to the Commission's May 5, 2021 Order in Cause No. 45462, NIPSCO expects to begin receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Dunn's Bridge I Solar Generation LLC ("Dunn's Bridge I") in July of 2023. Also, pursuant to the Commission's July 28, 2021 Order in Cause No. 45524, NIPSCO expects to begin receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Indiana Crossroads Solar Generation LLC ("Crossroads Solar") in May of 2023. Therefore, costs associated with the wholesale purchase and sale agreement for solar energy with Crossroads Solar and Dunn's Bridge I are included in NIPSCO's projected fuel costs.[1] The Wind PPA Adjustment for the period July, August, and September 2023 (the "forecast period") is based on the average of actual Wind PPA Adjustment incurred for the

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[1] Any test energy produced prior to this anticipated commercial operation date will be recovered at the reduced PPA price, pursuant to the terms of the applicable PPA.

twelve-month period ended March 31, 2023. The projected Wind PPA Adjustment is included on Attachment 1-A, Schedule 1, Line 34.

Q13. Please explain the RECs associated with the energy NIPSCO purchases under the wind purchased power agreements.

A13. Each megawatt hour of power generated from a qualified resource can be awarded a REC. Many state jurisdictions require sellers of renewable power to have such RECs to certify that the source is in fact a qualified renewable resource. As no national standard currently exists, each jurisdiction has set its own regulations as to how to qualify and account for these RECs. As each megawatt is sold by the qualified resource, the associated REC is sold to the buyer or is retired to prevent double counting. As of this filing, NIPSCO receives RECs associated with the power it purchases from Barton and Buffalo Ridge, Jordan Creek, Rosewater, and Crossroads Wind. All RECs are/will be tracked in a renewable energy tracking system. Because NIPSCO's solar projects have not reached commercial operation, NIPSCO has not received RECs for these projects, but will begin to receive RECs following commercial operation. Once these RECs are received, they are anticipated to be handled similarly to current RECs from wind projects.

Q14. Please provide an update on how NIPSCO has used RECs associated with the energy NIPSCO purchases under the wind purchased power agreements to maximize the value to its customers.

A14. During this FAC period, current vintage RECs were sold. The block size and proceeds from the sales are as follows:

Transaction	RECs Sold	Net Proceeds
1	70,000	$ 385,000
2	20,000	$ 109,335
3	20,000	$ 108,350
4	35,000	$ 189,613
5	20,000	$ 108,350
6	20,000	$ 106,380
7	14,231	$ 74,994
8	25,000	$ 131,744
9	50,000	$ 270,875
10	50,000	$ 263,488
11	50,000	$ 263,488
12	15,000	$ 88,650
13	1,000	$ 2,550
14	20,000	$ 117,000
15	35,769	$ 214,614
16	100,000	$ 581,150
17	5,000	$ 29,550
18	4,864	$ 14,592
19	20,000	$ 115,245
20	10,000	$ 56,638
21	10,000	$ 56,638
22	50,000	$ 283,188
23	33,816	$ 18,320
Total	679,680	$ 3,589,748

Also, during this reconciliation period, NIPSCO transferred RECs to the Green Power Rider ("GPR") program. The block size and proceeds from the sales are as follows:

Transaction	RECs Sold	Net Proceeds
1	83,975	$ 214,136
Total	83,975	$ 214,136

NIPSCO has passed and anticipates continuing to pass the proceeds from the sale or transfer of RECs back to customers through the Purchased Power other than MISO line item (Attachment 1-A, Schedule 5, Pages 1 through 4, line 35). As evidenced by the table above, REC prices are increasing, which is resulting in increasing revenues from REC sales being passed back to customers. NIPSCO continually monitors and evaluates the marketability for all RECs. As the possibility for future legislation evolves, NIPSCO will make appropriate changes to its REC strategy.

Q15. Please provide an update on the treatment of RECs received from Feed-In Tariff ("FIT") purchases.

A15. NIPSCO now has 25 approved solar and wind customers with facilities registered in M-RETS, with nameplate capacities ranging between 0.05 MW and 2.0 MW. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, no current vintage solar and wind FIT RECs were sold. NIPSCO has passed and anticipates continuing to pass the proceeds from the sale of FIT RECs back to customers through the Purchased

Power other than MISO line item (Attachment 1-A, Schedule 5, Pages 1 through 4, line 35). NIPSCO continues to have discussions with brokers and market participants to determine the best means of marketing the FIT RECs.

Q16. Does NIPSCO expect to buy any firm, long-term "Purchased Power"[2] during the forecast period?

A16. No.

Q17. Did NIPSCO enter into any third-party energy transactions for physical power that impacted the Reconciliation Period?

A17. No. However, NIPSCO will continue to consider entering into short-term third-party agreements for purposes of protecting customers from market influences.

Q18. Did NIPSCO enter into any third-party energy transactions for physical power that are reflected in the forecast period?

A18. No.

Q19. Has NIPSCO incorporated forecasted FIT purchases in this filing?

A19. Yes. NIPSCO incorporated forecasted FIT purchases for the forecast period

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[2] A long-term purchase is a purchase of power for greater than twelve (12) consecutive months.

based on the average of actual FIT purchases incurred for the twelve (12) month period ending March 31, 2023. The actual FIT purchases are included on Attachment 1-A, Schedule 5, Pages 1 through 4, Lines 7 and 29. The forecasted FIT purchases are included on Attachment 1-A, Schedule 1, Lines 7 and 25.

Q20. Has NIPSCO incorporated any forecasted known fixed transportation reservation charges and related credit associated with Sugar Creek in this filing?

A20. Yes. NIPSCO incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek. The actual transportation reservation charge is included on Attachment 1-A, Schedule 5, Pages 1 through 4, Line 25. The forecasted known transportation reservation charges and credit are included on Attachment 1-A, Schedule 1, Line 21.

Q21. Did NIPSCO make reasonable decisions under the circumstances that were known at the time that it forecasted its production and purchased power costs for the forecast period?

A21. Yes. NIPSCO completed its forecast for this FAC filing on May 10, 2023, using its production cost modeling system, PROMOD, and made reasonable decisions under the circumstances known at that point in time.

Q22. As reflected in Attachment 1-A, Schedule 1, Line 37, the Fuel Cost Factor is forecasted to be $36.804, compared to a Base Cost of Fuel (Line 41) of $26.736. What are the primary drivers of this higher forecasted Fuel Cost Factor?

A22. First, forecasted steam generation cost per MWh is anticipated to be higher in FAC-139 than in FAC-138, as reflected on Line 1 of Attachment 1-D, and it is projected to be higher compared to recent steam generation costs due to higher forecasted coal transportation and commodity pricing, as discussed by NIPSCO Witness Wagner. Second, Line 6 (purchases through MISO) is forecasted to be higher in FAC-139 on a total MWh basis than in FAC-138. And, the forecasted cost per MWh is higher in FAC-139 than in FAC-138, as reflected on Line 6 of Attachment 1-D.[3]

Q23. What is NIPSCO doing to ensure it provides electricity to its retail customers at the lowest fuel cost reasonably possible?

A23. NIPSCO utilized the approved Hedging Plan from FAC-134 (and

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[3] As always, the Purchased Power Benchmark will apply to MISO power purchases.

subsequently updated further in June 2022), which became effective July 1, 2022, and NIPSCO will continue to utilize financial hedges under the 2022 Hedging Plan to mitigate economic impacts and volatility within each FAC.[4] Second, NIPSCO has added additional wind resources and will continue to add new resources to its portfolio. These assets do not have variable fuel costs and are much cheaper relative to utilizing coal-fired (steam) generation.[5] NIPSCO will continue to utilize its ever-growing wind, solar, and solar plus storage fleet of assets to economically serve customers as well.

Q24. Has NIPSCO made every reasonable effort to acquire fuel and generate or purchase power or both to provide electricity to its retail customers at the lowest fuel cost reasonably possible?

A24. Yes.

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4 The Hedging Plan is discussed further below and was discussed in greater detail and supported by NIPSCO Witness Campbell in his testimony in Cause No. 38706-FAC-134.

5 As reflected on Lines 9 and 11 of Attachment 1-D, although the cost per/MWh for "wind energy purchases" and "wind joint venture purchases" are similar to "steam generation" (Line 1) and "combined cycle unit" (Line 4), it is noteworthy that any wind or solar-related purchases would include the costs associated with energy and capacity, *and* any associated benefits from REC sales. When comparing the "all-in" costs on a per/MWh basis, NIPSCO's Rosewater, Jordan Creek, and Indiana Crossroads wind facilities are among the most economical of NIPSCO's resources. Furthermore, as noted above, proceeds from REC sales are passed back directly to customers as an offset to FAC costs.

<u>**Electric Hedging Plan**</u>

Q25. How many hedging contracts were purchased during the Reconciliation Period?

A25. 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
January 2023	45	5	36	1
February 2023	45	0	34	1
March 2023	45	5	40	0

Execution of these contracts is consistent with NIPSCO's Commission-approved electric Hedging Plan through March 2023.

Q26. Are there other changes to the Hedging Plan?

A26. Yes. NIPSCO is operating under the updated 2022-2024 Hedging Plan which began in July of 2022. NIPSCO communicated the changes to the 2022-2024 Hedging Plan with its stakeholders on June 16, 2022. Also, please refer to Witness Campbell's testimony regarding the proposed 2023 Hedging Plan. To the extent the Company updates its plan further, future FAC filings will disclose any additional deviations from the filed and approved plan.

Q27. Please identify the gains or losses for the Hedging Plan during the Reconciliation Period.

A27. The impact of the hedges entered into for the Hedging Plan during the Reconciliation Period was a loss of $3,807,388. The net total impact, including broker and clearing exchange fees, of the Hedging Plan during the Reconciliation Period was $3,819,125. Broker fees represented 0.09% of the total value of the transactions that occurred during the Reconciliation Period. The monthly detail is shown in Attachment 2-C.

Q28. Do you believe NIPSCO's hedging practices are reasonable?

A28. Yes. Decisions were made based upon the conditions known at the time of the transactions, and NIPSCO used the same broker it uses for its other transactions to limit transaction costs. The transactions were all made in accordance with NIPSCO's Commission-approved electric Hedging Plan. NIPSCO will continue to solicit input and work with interested stakeholders on any potential changes to its Hedging Plan as the Company's generating portfolio continues to transition.

MISO

Q29. Are you generally familiar with the operations of MISO?

A29. Yes. I have responsibilities that oversee forecasting and I support market functions, such as, dispatching into MISO, offering of NIPSCO's generation to MISO energy market and ASM, and bidding in NIPSCO's load requirements.

Q30. Please describe the fuel-related MISO charges and credits that NIPSCO is seeking to recover in this proceeding.

A30. NIPSCO proposes to recover the fuel-related charges and credits assigned to NIPSCO by MISO and attributable to NIPSCO's retail electric customers in accordance with the Commission's June 1, 2005, Order in Cause No. 42685 ("42685 Order") and the Commission's Phase II Order in Cause No. 43426 ("43426 Order"). NIPSCO also proposes to recover the applicable RSG charges in accordance with the 43665 Order.

Q31. Is NIPSCO's proposed recovery of costs incurred during the Reconciliation Period consistent with your understanding of the 42685, 43426, and 43665 Orders?

A31. Yes.

Q32. Has NIPSCO verified the accuracy of the fuel-related charges and credits from MISO that are reflected in this filing?

A32. Yes.

Q33. Please describe the process to settle MISO energy and operating reserve market charges and credits as they apply to NIPSCO.

A33. For each operating day, MISO sends NIPSCO a settlement statement that sets forth Day Ahead market charges and credits, Real Time market charges and credits, charges and credits related to the Financial Transmission Rights ("FTRs") market, and charges and credits related to the ASM. The settlement statements set forth each charge type along with the underlying billing determinants used to calculate the charge. MISO's settlements process is described in detail in MISO's Business Practices Manual for Market Settlements (BPM-005).

Q34. How does NIPSCO verify the accuracy of the MISO settlement statements?

A34. NIPSCO utilizes PCI GenManager software tools to perform daily shadow settlements, to essentially "shadow" MISO's settlements systems, and verify MISO settlement statements and invoices. Using those tools, analysts in NIPSCO's settlements group download MISO settlements data and perform a detailed comparison by charge type and charge component against

NIPSCO's internal data. The tools highlight discrepancies that are immediately corrected or disputed depending on the source of the error. For charges and credits that are based solely on NIPSCO data, analysts can identify errors at the lowest level of granularity.

Q35. Are there any charges or credits related to resolved disputes that are being accounted for in this proceeding?

A35. No.

Q36. How will the resolution of disputed charges and credits be reflected in future FAC filings?

A36. Given the extended period of the MISO settlements process, adjustments to charges and credits incurred during a particular period may not be known or reflected in NIPSCO's books and records at the time of the quarterly FAC filing for that period. Indeed, adjustments could occur even after the S-105 settlement statement is issued. Consequently, it would be impractical to retroactively apply the effects of settlement statement adjustments to past customer bills. For those reasons, NIPSCO applies settlement statement adjustments that affect the cost of fuel or the cost of fuel of purchased power in a subsequent FAC filing.

Q37. Is NIPSCO's proposed recovery of ASM charges and credits consistent with your understanding of the 43426 Order?

A37. Yes.

Q38. Please provide an update regarding NIPSCO's involvement in the ASM.

A38. Day Ahead and Real Time market clearing prices ("MCP") for Regulation, Spinning, and Supplemental Reserves appear to be at reasonable levels consistent with market conditions. The average ASM prices per megawatt hour for the Reconciliation Period were:

Month	Regulation	Spinning	Supplement
January 2023	$0.0499	$0.0317	$0.0061
February 2023	$0.0393	$0.0205	$0.0044
March 2023	$0.0397	$0.0273	$0.0031

Q39. Is NIPSCO's proposed recovery of Day-Ahead and Real-Time RSG distribution amounts consistent with your understanding of the 43665 Order?

A39. Yes.

Q40. What are RSG payments and charges?

A40. RSG payments are make-whole payments that MISO makes to generators that do not earn sufficient real-time energy revenues to cover start-up and no-load costs. MISO recovers these RSG payments from participants in its Day-Ahead and Real-Time energy markets who contribute to RSG payments by submitting bids and offers that affect generation unit commitment or have deviations from their schedules that affect the commitment of generation.

Q41. Are you aware of any new or modified MISO charge types that impact this FAC?

A41. No.

Q42. How is the Company forecasting "MISO Components of Cost of Fuel"?

A42. The forecast of "MISO Components of Cost of Fuel" in this proceeding is based on the High – Low average of actual "MISO Components of Cost of Fuel" incurred for the twelve (12) month period ending March 31, 2023 where the high and low quarters are replaced with a three-year average of the same quarter. In this filing, NIPSCO has included a forecast of "MISO Components of Cost of Fuel" in the amount of $1,017,865 per month (Attachment 1-A, Schedule 1, Line 24).

Q43. Did Real Time Asset Energy,[6] Real Time Non-Asset Energy, Real Time Non-Excessive,[7] or Real Time Excessive Energy exceed a cost of $1 million in any month during the Reconciliation Period in this proceeding?

A43. Yes. As shown in Attachment 1-A, Schedule 7 (Line 25), Real Time Non-Excessive Energy was $1,553,550 in March 2023. The primary drivers of these amounts were 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).

Q44. Did Day Ahead Marginal Congestion Component plus actual monthly Auction Revenue Rights ("ARR")/FTR expenses less actual monthly ARR/FTR revenues exceed a cost of $2 million in any month during the Reconciliation Period?

A44. No.

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[6] Real Time Asset Energy charges are charges for the additional purchase of load from MISO in the Real Time market. This charge type does not contain any penalty charges and is strictly a balancing settlement between the Day Ahead and Real Time markets.

[7] Non-Excessive Energy charges are charges for the buyback of generation in the Real Time market. This charge type does not contain any penalty charges and is strictly a balancing settlement between the Day Ahead and Real Time markets. It is likely this type of charge will become more prevalent as the number of intermittent resources in NIPSCO's generation portfolio increases.

<u>**Benchmarks**</u>

Q45. Please describe the Purchased Power Benchmark approved in the 43526 Order.

A45. In its 43526 Order, the Commission established a mechanism to determine the reasonableness of NIPSCO's purchased power costs. Each day, the cost of any power purchased by the Company directly from MISO is compared to a benchmark price. This price is equal to the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a \$0.17/Mbtu transportation charge, and then multiplied by the 12,500 btu/kWh heat rate of a generic gas turbine. For example, if the daily price was \$3.00/Mbtu, the benchmark would be:

$$\left(\frac{\$3.00}{MBtu}+\frac{\$0.17}{MBtu}\right)\times\frac{12{,}500\;btu}{kWh}\times\frac{MBtu}{1{,}000{,}000\;btu}\times\frac{1000\;kWh}{MWh}=\boldsymbol{\$39.62/MWh}$$

Power purchased by NIPSCO at a price greater than the daily benchmark price is not recoverable from the Company's customers through the FAC. <u>Attachment 2-A</u> contains the purchased power benchmark prices during the Reconciliation Period.

Q46. Are all purchased power transactions subject to the Purchased Power Daily Benchmark?

A46. No. 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 & Allocation System, including bilateral purchases for load and MISO Day Ahead and Real Time purchases, except wind power purchases which are excluded in accordance with the 43393 Order, 45194 Order, the 45195 Order, and the 45310 Order. 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 did not have any swap or virtual transactions during the Reconciliation Period.

Q47. Is NIPSCO seeking to recover any MWhs of purchased power during the Reconciliation Period in excess of the Purchased Power Daily Benchmarks calculated pursuant to the 43526 Order?

A47. Yes. In January 2023, 18,676 MWhs exceeded the Purchased Power Benchmark at an average purchased power cost of $44.00/MWh. In February 2023, 18,465 MWhs exceeded the Purchased Power Benchmark at an average purchased power cost of $37.83/MWh. In March 2023, 15,951 MWhs exceeded the Purchased Power Benchmark at an average purchased power cost of $32.74/MWh. As a point of comparison, and as reflected in Attachment 2-A, the monthly average of the Purchased Power Daily Benchmarks were $42.71, $31.19, and $31.29 for January, February, and March 2023, respectively. While there were Power Purchases over the Benchmark, these purchases were not attributable to any one event or factor; rather, the recoverability for each purchase, under the terms of the 43526 Order, varies.

Q48. Have any purchases over the Purchased Power Benchmark during the Reconciliation Period been determined to be non-recoverable?

A48. No. In accordance with the procedures outlined in the 43526 Order, the purchases in excess of the Purchased Power Benchmark were made to supply jurisdictional load that offset available NIPSCO resources that were not dispatched by MISO or are otherwise eligible under the procedures outlined in the 43526 Order are therefore recoverable. The hourly detail of purchased power in excess of the Purchased Power Benchmark for this filing is included in the workpapers provided to the parties in this Cause.

Q49. Please describe the RSG Benchmark approved in the 43665 Order.

A49. In the 43665 Order, the Commission found that each day, a "Benchmark" is established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 Btu/kWh using the day ahead natural gas prices for the NYMEX Henry Hub, plus a $0.60/Mbtu gas transport charge for a generic gas-fired GT ("RSG Daily Benchmark"). The Commission did not order any change in the RSG Benchmark in its 44688 Order. Day-Ahead RSG Distribution Amounts as reported on NIPSCO's S-14 settlement statements are recovered as fuel costs in the FAC. Real-Time RSG First Pass Distribution Amounts ("RT RSG") as reported on NIPSCO's S-14 settlement statements at an hourly $/MWh rate are added to the Real-Time Marginal Energy Component of the Locational Marginal Price in each hour to compute an Hourly RSG Reference Point. This reference point is compared to the RSG Daily Benchmark. During those hours when the RSG Reference Point is at or below the RSG Daily Benchmark, the RT RSG charges incurred during those hours are recovered in the FAC. NIPSCO is not seeking recovery of any RT RSG charges above the RSG Daily Benchmark at this time. The RSG Benchmarks for the Reconciliation Period are set forth in <u>Attachment 2-B</u>.

Q50. During the Reconciliation Period, were any LMR curtailments for NIPSCO

called by MISO?

A50. No.

<u>**Gas Purchases for NIPSCO's Electric Generation**</u>

Q51. Have there been any changes to NIPSCO's gas purchasing practices for NIPSCO's generation located on NIPSCO's gas distribution system during the reconciliation or forecast period?

A51. No.

Q52. Have there been any changes to NIPSCO's gas purchasing practices for NIPSCO's generation located off NIPSCO's gas distribution system (Sugar Creek) during the reconciliation or forecast period?

A52. No.

Q53. Has NIPSCO made every reasonable effort to purchase natural gas so as to provide electricity to its customers at the lowest reasonable price?

A53. Yes.

<u>**Conclusion**</u>

Q54. Based on NIPSCO's ongoing generation portfolio transition, will NIPSCO continue to evaluate market conditions and take steps as determined appropriate to protect customers from market volatility?

A54. Yes. As set forth above, in the Reconciliation Period, over 31% of NIPSCO's energy was provided by its FIT and wind contracts. Over the last several years, NIPSCO has retired several coal-fired generating units and has also added new wind projects. Over the next few years, NIPSCO will also adding new wind, solar and solar plus storage projects. This is an important and dynamic time in NIPSCO's generation portfolio transition. The increased quantity of energy as part of the NIPSCO portfolio, together with the use of hedging and, as appropriate, energy contracts, will continue to be used to manage market volatility. NIPSCO will continue to utilize these tools into the future and will keep interested stakeholders informed of any future changes that may impact its FAC filings.

Q55. Does this conclude your prepared direct testimony?

A55. Yes.

VERIFICATION

I, Rosalva Robles, Manager of Planning – Regulatory Support for Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Rosalva Robles

Rosalva Robles Dated:

May 18, 2023

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Daily Purchase Power Benchmark Calculation
Cause No. 43526, Approved August 25, 2010
JANUARY, 2023

Line No.	Date	Heat Rate Btu/KWh	Fuel Cost * $/MMBtu	Transportation $/MMBtu	Fuel + Trans $/MMBtu	Benchmark $/MWh	Line No.
1	1/1/2023	12,500	3.405	0.17	3.575	44.69	1
2	1/2/2023	12,500	3.405	0.17	3.575	44.69	2
3	1/3/2023	12,500	3.405	0.17	3.575	44.69	3
4	1/4/2023	12,500	3.340	0.17	3.510	43.88	4
5	1/5/2023	12,500	3.430	0.17	3.600	45.00	5
6	1/6/2023	12,500	3.380	0.17	3.550	44.38	6
7	1/7/2023	12,500	3.250	0.17	3.420	42.75	7
8	1/8/2023	12,500	3.250	0.17	3.420	42.75	8
9	1/9/2023	12,500	3.250	0.17	3.420	42.75	9
10	1/10/2023	12,500	3.440	0.17	3.610	45.13	10
11	1/11/2023	12,500	3.100	0.17	3.270	40.88	11
12	1/12/2023	12,500	3.145	0.17	3.315	41.44	12
13	1/13/2023	12,500	3.360	0.17	3.530	44.13	13
14	1/14/2023	12,500	3.045	0.17	3.215	40.19	14
15	1/15/2023	12,500	3.045	0.17	3.215	40.19	15
16	1/16/2023	12,500	3.045	0.17	3.215	40.19	16
17	1/17/2023	12,500	3.045	0.17	3.215	40.19	17
18	1/18/2023	12,500	3.115	0.17	3.285	41.06	18
19	1/19/2023	12,500	2.985	0.17	3.155	39.44	19
20	1/20/2023	12,500	2.935	0.17	3.105	38.81	20
21	1/21/2023	12,500	3.070	0.17	3.240	40.50	21
22	1/22/2023	12,500	3.070	0.17	3.240	40.50	22
23	1/23/2023	12,500	3.070	0.17	3.240	40.50	23
24	1/24/2023	12,500	3.170	0.17	3.340	41.75	24
25	1/25/2023	12,500	3.130	0.17	3.300	41.25	25
26	1/26/2023	12,500	2.965	0.17	3.135	39.19	26
27	1/27/2023	12,500	2.780	0.17	2.950	36.88	27
28	1/28/2023	12,500	3.955	0.17	4.125	51.56	28
29	1/29/2023	12,500	3.955	0.17	4.125	51.56	29
30	1/30/2023	12,500	3.955	0.17	4.125	51.56	30
31	1/31/2023	12,500	3.160	0.17	3.330	41.63	31
					Average	42.71	

* Platt's Gas Daily Midpoint price for Chicago City Gate

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Daily Purchase Power Benchmark Calculation
Cause No. 43526, Approved August 25, 2010
FEBRUARY, 2023

Line No.	Date	Heat Rate Btu/KWh	Fuel Cost * $/MMBtu	Transportation $/MMBtu	Fuel + Trans $/MMBtu	Benchmark $/MWh	Line No.
1	2/1/2023	12,500	2.775	0.17	2.945	36.81	1
2	2/2/2023	12,500	2.690	0.17	2.860	35.75	2
3	2/3/2023	12,500	2.805	0.17	2.975	37.19	3
4	2/4/2023	12,500	2.330	0.17	2.500	31.25	4
5	2/5/2023	12,500	2.330	0.17	2.500	31.25	5
6	2/6/2023	12,500	2.330	0.17	2.500	31.25	6
7	2/7/2023	12,500	2.165	0.17	2.335	29.19	7
8	2/8/2023	12,500	2.375	0.17	2.545	31.81	8
9	2/9/2023	12,500	2.435	0.17	2.605	32.56	9
10	2/10/2023	12,500	2.345	0.17	2.515	31.44	10
11	2/11/2023	12,500	2.290	0.17	2.460	30.75	11
12	2/12/2023	12,500	2.290	0.17	2.460	30.75	12
13	2/13/2023	12,500	2.290	0.17	2.460	30.75	13
14	2/14/2023	12,500	2.265	0.17	2.435	30.44	14
15	2/15/2023	12,500	2.340	0.17	2.510	31.38	15
16	2/16/2023	12,500	2.385	0.17	2.555	31.94	16
17	2/17/2023	12,500	2.420	0.17	2.590	32.38	17
18	2/18/2023	12,500	2.145	0.17	2.315	28.94	18
19	2/19/2023	12,500	2.145	0.17	2.315	28.94	19
20	2/20/2023	12,500	2.145	0.17	2.315	28.94	20
21	2/21/2023	12,500	2.145	0.17	2.315	28.94	21
22	2/22/2023	12,500	2.140	0.17	2.310	28.88	22
23	2/23/2023	12,500	2.195	0.17	2.365	29.56	23
24	2/24/2023	12,500	2.280	0.17	2.450	30.63	24
25	2/25/2023	12,500	2.220	0.17	2.390	29.88	25
26	2/26/2023	12,500	2.220	0.17	2.390	29.88	26
27	2/27/2023	12,500	2.220	0.17	2.390	29.88	27
28	2/28/2023	12,500	2.400	0.17	2.570	32.13	28
					Average	31.19	

* Platt's Gas Daily Midpoint price for Chicago City Gate

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Daily Purchase Power Benchmark Calculation
Cause No. 43526, Approved August 25, 2010
MARCH, 2023

Line No.	Date	Heat Rate Btu/KWh	Fuel Cost * $/MMBtu	Transportation $/MMBtu	Fuel + Trans $/MMBtu	Benchmark $/MWh	Line No.
1	3/1/23	12,500	2.425	0.17	2.595	32.44	1
2	3/2/23	12,500	2.525	0.17	2.695	33.69	2
3	3/3/23	12,500	2.615	0.17	2.785	34.81	3
4	3/4/23	12,500	2.545	0.17	2.715	33.94	4
5	3/5/23	12,500	2.545	0.17	2.715	33.94	5
6	3/6/23	12,500	2.545	0.17	2.715	33.94	6
7	3/7/23	12,500	2.440	0.17	2.610	32.63	7
8	3/8/23	12,500	2.515	0.17	2.685	33.56	8
9	3/9/23	12,500	2.485	0.17	2.655	33.19	9
10	3/10/23	12,500	2.490	0.17	2.660	33.25	10
11	3/11/23	12,500	2.395	0.17	2.565	32.06	11
12	3/12/23	12,500	2.395	0.17	2.565	32.06	12
13	3/13/23	12,500	2.395	0.17	2.565	32.06	13
14	3/14/23	12,500	2.545	0.17	2.715	33.94	14
15	3/15/23	12,500	2.465	0.17	2.635	32.94	15
16	3/16/23	12,500	2.350	0.17	2.520	31.50	16
17	3/17/23	12,500	2.510	0.17	2.680	33.50	17
18	3/18/23	12,500	2.375	0.17	2.545	31.81	18
19	3/19/23	12,500	2.375	0.17	2.545	31.81	19
20	3/20/23	12,500	2.375	0.17	2.545	31.81	20
21	3/21/23	12,500	2.190	0.17	2.360	29.50	21
22	3/22/23	12,500	2.050	0.17	2.220	27.75	22
23	3/23/23	12,500	2.160	0.17	2.330	29.13	23
24	3/24/23	12,500	2.050	0.17	2.220	27.75	24
25	3/25/23	12,500	2.090	0.17	2.260	28.25	25
26	3/26/23	12,500	2.090	0.17	2.260	28.25	26
27	3/27/23	12,500	2.090	0.17	2.260	28.25	27
28	3/28/23	12,500	2.180	0.17	2.350	29.38	28
29	3/29/23	12,500	2.150	0.17	2.320	29.00	29
30	3/30/23	12,500	2.010	0.17	2.180	27.25	30
31	3/31/23	12,500	1.950	0.17	2.120	26.50	31
					Average	31.29	

* Platt's Gas Daily Midpoint price for Chicago City Gate

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Revenue Sufficiency Guarantee Benchmark Calculation
Cause No. 43665, Approved June 30, 2009
JANUARY, 2023

Line No.	Date	NG at Henry Hub $/mmbtu	NG Transportation $/mmbtu	GT Heat Rate btu/kwh	RSG Benchmark $/mwh	Line No.
1	1/1/2023	3.55	0.60	12,500	51.88	1
2	1/2/2023	3.55	0.60	12,500	51.88	2
3	1/3/2023	3.55	0.60	12,500	51.88	3
4	1/4/2023	3.65	0.60	12,500	53.13	4
5	1/5/2023	3.81	0.60	12,500	55.13	5
6	1/6/2023	3.755	0.60	12,500	54.44	6
7	1/7/2023	3.415	0.60	12,500	50.19	7
8	1/8/2023	3.415	0.60	12,500	50.19	8
9	1/9/2023	3.415	0.60	12,500	50.19	9
10	1/10/2023	3.665	0.60	12,500	53.31	10
11	1/11/2023	3.31	0.60	12,500	48.88	11
12	1/12/2023	3.35	0.60	12,500	49.38	12
13	1/13/2023	3.55	0.60	12,500	51.88	13
14	1/14/2023	3.435	0.60	12,500	50.44	14
15	1/15/2023	3.435	0.60	12,500	50.44	15
16	1/16/2023	3.435	0.60	12,500	50.44	16
17	1/17/2023	3.435	0.60	12,500	50.44	17
18	1/18/2023	3.415	0.60	12,500	50.19	18
19	1/19/2023	3.105	0.60	12,500	46.31	19
20	1/20/2023	2.93	0.60	12,500	44.13	20
21	1/21/2023	3.13	0.60	12,500	46.63	21
22	1/22/2023	3.13	0.60	12,500	46.63	22
23	1/23/2023	3.13	0.60	12,500	46.63	23
24	1/24/2023	3.385	0.60	12,500	49.81	24
25	1/25/2023	3.335	0.60	12,500	49.19	25
26	1/26/2023	3.08	0.60	12,500	46.00	26
27	1/27/2023	2.705	0.60	12,500	41.31	27
28	1/28/2023	2.745	0.60	12,500	41.81	28
29	1/29/2023	2.745	0.60	12,500	41.81	29
30	1/30/2023	2.745	0.60	12,500	41.81	30
31	1/31/2023	2.805	0.60	12,500	42.56	31

Sources:
For NG: MySource, Market Prices community, Gas Daily Prices, location Henry Hub,
Mid Point Price for Flow Date (not Transaction Date).
The same information can also be seen in Platts Gas Daily publication (this is a physical price and not a financial price)

Calculations:
Benchmark = ($/mmbtu + $0.60/mmbtu) * 12,500 btu/kwh * 1,000 kwh/mwh * mmbtu/1,000,000 btu

Symbols:
NG = Natural Gas GT = Gas Turbine RSG = Revenue Sufficiency Guarantee

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Revenue Sufficiency Guarantee Benchmark Calculation
Cause No. 43665, Approved June 30, 2009
FEBRUARY, 2023

Line No.	Date	NG at Henry Hub $/mmbtu	NG Transportation $/mmbtu	GT Heat Rate btu/kwh	RSG Benchmark $/mwh	Line No.
1	2/1/2023	2.675	0.60	12,500	40.94	1
2	2/2/2023	2.66	0.60	12,500	40.75	2
3	2/3/2023	2.645	0.60	12,500	40.56	3
4	2/4/2023	2.395	0.60	12,500	37.44	4
5	2/5/2023	2.395	0.60	12,500	37.44	5
6	2/6/2023	2.395	0.60	12,500	37.44	6
7	2/7/2023	2.185	0.60	12,500	34.81	7
8	2/8/2023	2.35	0.60	12,500	36.88	8
9	2/9/2023	2.415	0.60	12,500	37.69	9
10	2/10/2023	2.4	0.60	12,500	37.50	10
11	2/11/2023	2.37	0.60	12,500	37.13	11
12	2/12/2023	2.37	0.60	12,500	37.13	12
13	2/13/2023	2.37	0.60	12,500	37.13	13
14	2/14/2023	2.4	0.60	12,500	37.50	14
15	2/15/2023	2.425	0.60	12,500	37.81	15
16	2/16/2023	2.44	0.60	12,500	38.00	16
17	2/17/2023	2.485	0.60	12,500	38.56	17
18	2/18/2023	2.26	0.60	12,500	35.75	18
19	2/19/2023	2.26	0.60	12,500	35.75	19
20	2/20/2023	2.26	0.60	12,500	35.75	20
21	2/21/2023	2.26	0.60	12,500	35.75	21
22	2/22/2023	2.095	0.60	12,500	33.69	22
23	2/23/2023	2.075	0.60	12,500	33.44	23
24	2/24/2023	2.185	0.60	12,500	34.81	24
25	2/25/2023	2.345	0.60	12,500	36.81	25
26	2/26/2023	2.345	0.60	12,500	36.81	26
27	2/27/2023	2.345	0.60	12,500	36.81	27
28	2/28/2023	2.56	0.60	12,500	39.50	28

Sources:
For NG: MySource, Market Prices community, Gas Daily Prices, location Henry Hub,
Mid Point Price for Flow Date (not Transaction Date).
The same information can also be seen in Platts Gas Daily publication (this is a physical price and not a financial price)

Calculations:
Benchmark = ($/mmbtu + $0.60/mmbtu) * 12,500 btu/kwh * 1,000 kwh/mwh * mmbtu/1,000,000 btu

Symbols:
NG = Natural Gas GT = Gas Turbine RSG = Revenue Sufficiency Guarantee

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Revenue Sufficiency Guarantee Benchmark Calculation
Cause No. 43665, Approved June 30, 2009
MARCH, 2023

Line No.	Date	NG at Henry Hub $/mmbtu	NG Transportation $/mmbtu	GT Heat Rate btu/kwh	RSG Benchmark $/mwh	Line No.
1	3/1/2023	2.51	0.60	12,500	38.88	1
2	3/2/2023	2.59	0.60	12,500	39.88	2
3	3/3/2023	2.675	0.60	12,500	40.94	3
4	3/4/2023	2.665	0.60	12,500	40.81	4
5	3/5/2023	2.665	0.60	12,500	40.81	5
6	3/6/2023	2.665	0.60	12,500	40.81	6
7	3/7/2023	2.46	0.60	12,500	38.25	7
8	3/8/2023	2.52	0.60	12,500	39.00	8
9	3/9/2023	2.495	0.60	12,500	38.69	9
10	3/10/2023	2.505	0.60	12,500	38.81	10
11	3/11/2023	2.375	0.60	12,500	37.19	11
12	3/12/2023	2.375	0.60	12,500	37.19	12
13	3/13/2023	2.375	0.60	12,500	37.19	13
14	3/14/2023	2.445	0.60	12,500	38.06	14
15	3/15/2023	2.63	0.60	12,500	40.38	15
16	3/16/2023	2.44	0.60	12,500	38.00	16
17	3/17/2023	2.445	0.60	12,500	38.06	17
18	3/18/2023	2.41	0.60	12,500	37.63	18
19	3/19/2023	2.41	0.60	12,500	37.63	19
20	3/20/2023	2.41	0.60	12,500	37.63	20
21	3/21/2023	2.165	0.60	12,500	34.56	21
22	3/22/2023	1.925	0.60	12,500	31.56	22
23	3/23/2023	2.035	0.60	12,500	32.94	23
24	3/24/2023	2.075	0.60	12,500	33.44	24
25	3/25/2023	2.045	0.60	12,500	33.06	25
26	3/26/2023	2.045	0.60	12,500	33.06	26
27	3/27/2023	2.045	0.60	12,500	33.06	27
28	3/28/2023	2.035	0.60	12,500	32.94	28
29	3/29/2023	2.015	0.60	12,500	32.69	29
30	3/30/2023	1.945	0.60	12,500	31.81	30
31	3/31/2023	1.950	0.60	12,500	31.88	31

Sources:
For NG: MySource, Market Prices community, Gas Daily Prices, location Henry Hub,
Mid Point Price for Flow Date (not Transaction Date).
The same information can also be seen in Platts Gas Daily publication (this is a physical price and not a financial price)

Calculations:
Benchmark = ($/mmbtu + $0.60/mmbtu) * 12,500 btu/kwh * 1,000 kwh/mwh * mmbtu/1,000,000 btu

Symbols:
NG = Natural Gas GT = Gas Turbine RSG = Revenue Sufficiency Guarantee

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Hedge Impact on FAC Prices
Cause No. 43849, Approved July 13, 2011
January 2023 - March 2023

	Jan-23	Feb-23	Mar-23	Total
Hedging Gain / (Loss)	($1,369,736.00)	($1,165,574.00)	($1,272,077.60)	($3,807,387.60)
Broker and Exchange Fees	($2,256.07)	($5,613.28)	($3,868.00)	($11,737.35)
FAC-139 Impact				**($3,819,124.95)**
Total Value of Hedging Transactions*	$3,458,193.60	$5,595,382.00	$4,195,424.40	$13,249,000.00
Broker Fees as a percentage of the total value of the hedging transactions	0.07%	0.10%	0.09%	0.09%

* Note: This value represents the total value of all purchases and sales made as part of the Electric Hedging Program. Because this is a financial hedging program, there are two transactions per contract. One to enter into the hedge and the other being the contract settlement sale contract expiration. As gas and power prices fluctuate, broker fees will also fluctuate as a percentage of the value of the transactions.

NORTHERN INDIANA PUBLIC SERVICE COMPANY

DA/RT Congestion Cost

JANUARY, 2023

Line No.	Location	DA Congestion $	RT Congestion $	Total Congestion $	Line No.
1	Barton Wind Farm	$ (3,164)	$ 38,076	$ 34,912	1
2	Buffalo Ridge Wind Farm	$ 94,895	$ (11,292)	$ 83,603	2
3	Indiana Crossroads Wind Farm	$ (125,086)	$ (33,853)	$ (158,939)	3
4	Jordan Creek Wind Farm	$ (348,148)	$ 27,345	$ (320,803)	4
5	MCG 12	$ (188,405)	$ (10,151)	$ (198,556)	5
6	Norway	$ (4,387)	$ (315)	$ (4,702)	6
7	Oakdale	$ (6,258)	$ (906)	$ (7,164)	7
8	RMS 16A	$ (499)	$ -	$ (499)	8
9	RMS 16B	$ (41)	$ (27)	$ (68)	9
10	RMS 17	$ (103,078)	$ 7,528	$ (95,550)	10
11	RMS 18	$ (841)	$ (2,792)	$ (3,633)	11
12	Rosewater Wind Farm	$ 277,340	$ 51,452	$ 328,792	12
13	Sugar Creek	$ (695,284)	$ (8,107)	$ (703,391)	13
14	NIPS.NIPS	$ 914,658	$ (8,680)	$ 905,977	14
15	Total	$ (188,300)	$ 48,280	$ (140,020)	15

NORTHERN INDIANA PUBLIC SERVICE COMPANY

DA/RT Congestion Cost

FEBRUARY, 2023

Line No.	Location	DA Congestion $	RT Congestion $	Total Congestion $	Line No.
1	Barton Wind Farm	$ 45,857	$ 21,929	$ 67,786	1
2	Buffalo Ridge Wind Farm	$ 70,457	$ 71,299	$ 141,756	2
3	Indiana Crossroads Wind Farm	$ (60,266)	$ (40,278)	$ (100,544)	3
4	Jordan Creek Wind Farm	$ (237,833)	$ (39,997)	$ (277,829)	4
5	MCG 12	$ 5,675	$ (2,202)	$ 3,474	5
6	Norway	$ (6,523)	$ (635)	$ (7,159)	6
7	Oakdale	$ (7,014)	$ (1,149)	$ (8,163)	7
8	RMS 16A	$ 67	$ 282	$ 349	8
9	RMS 16B	$ (251)	$ -	$ (251)	9
10	RMS 17	$ (67,074)	$ 2,368	$ (64,706)	10
11	RMS 18	$ 4,786	$ (172,244)	$ (167,458)	11
12	Rosewater Wind Farm	$ 355,439	$ 136,159	$ 491,598	12
13	Sugar Creek	$ (765,517)	$ (9,261)	$ (774,778)	13
14	NIPS.NIPS	$ 597,162	$ (106,638)	$ 490,524	14
15	Total	$ (65,036)	$ (140,366)	$ (205,402)	15

NORTHERN INDIANA PUBLIC SERVICE COMPANY

DA/RT Congestion Cost

MARCH, 2023

Line No.	Location	DA Congestion $	RT Congestion $	Total Congestion $	Line No.
1	Barton Wind Farm	$ 46,932	$ 21,412	$ 68,344	1
2	Buffalo Ridge Wind Farm	$ 104,398	$ 2,362	$ 106,760	2
3	Indiana Crossroads Wind Farm	$ (41,838)	$ (10,066)	$ (51,904)	3
4	Jordan Creek Wind Farm	$ (183,295)	$ 44,853	$ (138,442)	4
5	MCG 12			$ -	5
6	Norway	$ (23,564)	$ 275	$ (23,288)	6
7	Oakdale	$ (17,416)	$ (707)	$ (18,123)	7
8	RMS 16A	$ 83	$ (136)	$ (53)	8
9	RMS 16B	$ -	$ -	$ -	9
10	RMS 17	$ (72,921)	$ 12,692	$ (60,229)	10
11	RMS 18	$ (119,149)	$ 14,250	$ (104,898)	11
12	Rosewater Wind Farm	$ 391,206	$ 112,823	$ 504,029	12
13	Sugar Creek	$ (631,390)	$ (13,129)	$ (644,519)	13
14	NIPS.NIPS	$ 494,161	$ 57,356	$ 551,517	14
15	Total	$ (52,793)	$ 241,985	$ 189,192	15