# VERIFIED DIRECT TESTIMONY OF ANDREW S. CAMPBELL

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

A1. My name is Andrew S. Campbell. I am the Director of Portfolio Planning & Origination 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 Mechanical Engineering and graduate studies in Interdisciplinary Engineering. Additionally, I graduated with a Master of Business Administration from the University of Notre Dame. I began my employment with NIPSCO in June of 2009 as an Operations Analysis Engineer. In September of 2011, I was promoted to the Manager of Operations & Market Support and in May of 2013, assumed the role of Manager of Planning & Regulatory Support. In September of 2017, I was promoted to my current role as Director of Regulatory Support & Planning, which was subsequently updated to my current title of Director of Portfolio Planning & Origination. Prior to joining NIPSCO, I worked as an engineer for an industrial manufacturing company that specialized in engine attachments for marine and small power generation applications. I am also a veteran of the Army National Guard.

**Q3. What are your responsibilities as Director of Portfolio Planning & Origination?**

A3. As Director of Portfolio Planning & Origination, I am responsible for leading the regulatory support and financial planning functions for the Energy Supply & Optimization ("ES&O") department within NIPSCO, whereby my team supports NIPSCO's operations within the electric and natural gas markets. More specifically, my team is responsible for leading all commercial market support for electric and natural gas rate case-related activities for the ES&O department, management of Midcontinent Independent System Operator, Inc. ("MISO") meter data, MISO market and bilateral settlements, MISO asset registration and resource adequacy, supporting the forecast and reconciliation of NIPSCO's Fuel Adjustment Clause ("FAC"), Regional Transmission Organization Adjustment, Resource Adequacy ("RA") Adjustment, Green Power Rider, Gas Cost

Adjustment ("GCA"), Green Path Rider, leading the development of NIPSCO's natural gas and electric hedging programs, and supporting NIPSCO's financial and business planning cadence. I am also responsible for leading the commercial execution of NIPSCO's generation strategy outlined within its Integrated Resource Plan.

**Q4. Have you previously testified before this or any other regulatory commission?**

A4. Yes. I previously submitted testimony in NIPSCO's gas rate case in Cause No. 45621, NIPSCO's gas rate case in Cause No. 44988, and NIPSCO's electric rate case in Cause No. 45159. I also supported (1) NIPSCO's requests for a certificate of public convenience and necessity to purchase and acquire (indirectly through joint venture structures) in Cause Nos. 45194, 45310, 45462, 45511, 45524, and 45529; (2) NIPSCO's requests for approval and associated cost recovery of power purchase agreements in Cause Nos. 45195, 45196, 45403, 45472, and 45489; (3) NIPSCO's request for a modification of the Commission's Order in Cause No. 45310 authorizing a contract for differences as a third option in addition to the approved offtake agreements in Cause No. 45463; (4) NIPSCO's request for approval of its 2016 Hedging Plan (Cause No. 44205-S4), 2018 Hedging Plan in Cause No. 38706-FAC-118, 2019 Hedging Plan in Cause No. 38706-FAC-122, 2020 Hedging Plan in Cause No. 38706-FAC-126, and 2021 Hedging Plan in Cause No. 38706-FAC-130; (5) NIPSCO's request for approval of an amendment to NIPSCO's 2017-2018 financing authority in Cause No. 45020; (6) NIPSCO's request for approval of NIPSCO's proposed Green Path Rider currently pending in Cause No. 45730; and (7) in some of the following tracker filings: GCA tracker filings (Cause No. 43629-GCA-XX), FAC tracker filings (Cause No. 38706-FAC-XX, including the subdocket in Cause No. 38706-FAC-130-S1), RA Adjustment tracker filings (Cause No. 44155-RA-XX), and RTO Adjustment tracker filings (Cause No. 44156-RTO-XX).

**Q5. What is the purpose of your testimony?**

A5. The purpose of my testimony is to describe (1) Midcontinent Independent System Operator, Inc. ("MISO") and the associated markets, (2) NIPSCO's Generation Transition, (3) Wholesale Purchased Power Agreements, (4) Joint Venture Build Transfer Agreements ("BTA"), (5) Capacity – MISO Requirements, Resources, and Costs, (6) Demand Response Programs, (7) modification of Rate 831 – Industrial Power Service – Large; (8) modifications affecting NIPSCO's RA Adjustment, including NIPSCO's pro forma adjustment for capacity purchases, (9) modifications affecting NIPSCO's RTO Adjustment, (10) modifications affecting NIPSCO's FAC, (11) NIPSCO's PROMOD forecast, (12) new Rate 543– Station Power for Renewable Wholesale Generation Equipment, (13) the variability associated with operations and maintenance ("O&M") expenses for NIPSCO's coal-fired generation resources, (14) NIPSCO's pro forma adjustment for liquefied natural gas ("LNG") , which is sponsored by NIPSCO Witness Siegler, and (15) NIPSCO's pro forma adjustment for Demand Response Resource.

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

A6. I am sponsoring Confidential Attachment 11-A, which was prepared by me or under my direction and supervision.

**MISO and Associated Markets**

**Q7. Please briefly describe MISO.**

A7. MISO is a non-profit, member-based Regional Transmission Organization. MISO performs the North American Electric Reliability Corporation

("NERC") roles of Reliability Coordinator and Balancing Authority for NIPSCO utilizing an extensive network model of the MISO interconnected reliability region which includes NIPSCO and surrounding systems. MISO conducts an annual Resource Adequacy Process and manages one of the world's largest energy and operating reserves markets using security-constrained economic dispatch of generation. The MISO Energy and Operating Reserves Market (the "MISO Market") includes a Day-Ahead Market, a Real-Time Market, and a Financial Transmission Rights Market. These markets are operated and settled separately. MISO's charges to provide services are recovered pursuant to its Federal Energy Regulatory Commission ("FERC") tariff.

**Q8. Please provide a general overview of the MISO Resource Adequacy Process.**

A8. As a Load Serving Entity in MISO, NIPSCO is obligated to have sufficient Capacity Resources to cover its forecasted peak demand plus its Planning Reserve Margin Requirements. Capacity Resources consist of Generation Resources (electric generating units) and Demand Response Resources (loads that can be dispatched to reduce demand). MISO calculates the

Planning Reserve Margin Requirement based on MISO's forecast of its peak demand by resource zone considering planned maintenance or forced outages of generating equipment, deratings in the capability of Generation Resources and Demand Response Resources, system effects due to reasonably anticipated variations in weather, and variations in customer demands or forecast demand uncertainty. MISO conducts Loss of Load Expectation studies each year to make an annual determination of what the Planning Reserve Margin needs to be to attain compliance with NERC reliability standards. If NIPSCO does not have sufficient Capacity Resources to cover its forecasted peak demand and Planning Reserve Margin, NIPSCO may acquire additional capacity through bilateral transactions with other Market Participants or by bidding on capacity in MISO's annual Planning Resource Auction ("PRA"). If NIPSCO does have sufficient Capacity Resources to cover its forecasted peak demand and Planning Reserve Margin, NIPSCO may sell its additional capacity through bilateral transactions with other Market Participants or may offer its additional capacity in MISO's PRA.

Based on the August 31, 2022, FERC Order in Docket Nos. ER22-495-000 and ER22-495-001, MISO is now transitioning from the current Summer-based, annual construct to four distinct Seasons: June to August for Summer, September to November for Fall, December to February for Winter, and March to May for Spring. This change is taking effect for the 2023-2024 MISO Planning Year, which begins June 1, 2023. PRA will still be conducted one time per year, in the Spring before the applicable Planning Year, but will clear the requirements for each Season.[1]

**Q9. Please provide a general overview of NIPSCO's participation in the MISO Market.**

A9. NIPSCO participates in the MISO Market. NIPSCO offers the electricity produced by its generation facilities and buys the electricity necessary to serve its retail customers from the MISO Market on a day-ahead and real-time basis. The day-ahead market is a forward market in which energy and operating reserves are cleared on a simultaneously co-optimized basis for each hour of the next operating day using Security-Constrained Unit

[1] Based on the recency of this order, which was issued August 31, 2022, in Docket No. ER22-495, NIPSCO is still evaluating its potential impact on NIPSCO and its operations. However, as discussed by NIPSCO Witness Augustine, NIPSCO's 2021 IRP contemplated MISO's transition to a seasonal construct.

Commitment and Security-Constrained Economic Dispatch ("SCED") computer programs to satisfy the energy demand bids and operating reserve requirements of the day-ahead energy and operating reserve market. The results of the day-ahead energy and operating reserve market clearing include hourly locational marginal price ("LMP") values for energy demand and supply, hourly market clearing price ("MCP") values for regulating reserve, spinning reserve and supplemental reserve supply, hourly energy demand schedules, hourly energy supply schedules for each resource, and hourly regulating reserve, spinning reserve and supplemental reserve supply schedules for each qualified resource. The real-time market is a physical market in which energy and operating reserve are cleared on a simultaneously co-optimized basis every five minutes using SCED to satisfy the forecasted energy demand and operating reserve requirements of the real-time market based on actual system operating conditions, as described by MISO's state estimator. The results of the real-time market clearing include five-minute ex-ante LMPs for energy demand and supply, five-minute ex-ante MCP values for regulating reserve, spinning reserve, and supplemental reserve supply, and five-minute dispatch targets for each resource for energy, regulatory reserve, spinning reserve, and supplemental reserve. The real-time market dispatch is supported by a Reliability Assessment Commitment process to ensure sufficient capacity is online to meet real-time operating conditions.

**Q10. What are the benefits of participating in the MISO Market?**

A10. The MISO Market gives all participants open access to the transmission system and all available resources are centrally dispatched using simultaneous co-optimization. MISO provides a transparent and liquid energy market across its entire footprint. Furthermore, ongoing coordination between MISO and adjacent independent system operator systems increases grid reliability and makes it possible to regionally coordinate transmission expansion. The MISO Market allows NIPSCO to make economic purchases from the open market when NIPSCO's cost of generation is higher with the benefits flowing directly to its customers. In addition, the MISO Market provides an opportunity to reduce the overall amount of reserves being held by Market Participants thereby further reducing the cost of providing those reserves to customers. As further discussed below, NIPSCO's participation in the MISO Market is the primary reason NIPSCO is proposing to remove the power purchase benchmark from its FAC tracker proceeding.

**Q11. What are the costs of participating in MISO?**

A11. Charges from MISO are presented to NIPSCO on settlement statements. Settlement statements include charges/credits resulting from NIPSCO's participation in the Resource Adequacy Process and the MISO Market. Revenues from NIPSCO generation are netted against charges/credits to NIPSCO load. Settlement statement charges from MISO are categorized by NIPSCO as fuel and non-fuel.

**Q12. Please describe the MISO-related costs incurred by NIPSCO.**

A12. NIPSCO's MISO-related costs can be grouped into three categories: (1) non-fuel charges assessed by MISO pursuant to its tariff that has been accepted for filing by FERC;[2] (2) fuel-related costs incurred due to participation in MISO pursuant to its tariff that has been accepted for filing by FERC;[3] and (3) transmission costs accessed through Attachment FF and other transmission costs pursuant to rate schedules that have been

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[2] See IURC Order dated June 1, 2005, in Cause No. 42685 ("42685 Order") and IURC Order dated June 30, 2009, in Cause No. 43426 ("43426 Order").

[3] See 42685 Order and 43426 Order.

accepted for filing by FERC. NIPSCO's MISO-related costs are generally recovered through its RA and RTO semi-annual trackers.

<u>**Generation Transition**</u>

**Q13. Please provide an overview of NIPSCO's preferred portfolio as set forth in its Integrated Resource Plan submitted to the Commission on November 15, 2021 ("2021 IRP").**

A13. As in its 2018 IRP, NIPSCO's 2021 IRP included a retirement analysis to assess different retirement dates for different elements of its existing fleet. The 2021 IRP continued to affirm the retirement of coal-fired capacity as the most cost-effective pathway for customers. As explained further by NIPSCO Witness Augustine, the 2021 IRP concluded that the preferred replacement resources, in addition to the renewable additions planned from the 2018 IRP's Short-Term Action Plan, included additional solar capacity and a diverse mix of other resources including storage, flexible thermal generation resources/emerging technologies, and market purchases/capacity.

**Q14. Please provide an update on the planned coal retirements at NIPSCO's R.M. Schahfer Generating Station ("Schahfer").**

A14. On February 17, 2021, NIPSCO announced the retirement of two coal-fired units at Schahfer (Units 14 and 15) by the end of 2021. Both Units 14 and 15 were retired in October 2021. On May 4, 2022, NIPSCO announced that NIPSCO would be extending the operation of two coal-fired units at Schahfer (Units 17 and 18) through 2025.

**Q15. What led NIPSCO to the decision to extend the operation of Schahfer Units 17 and 18 through 2025?**

A15. NIPSCO's decision to extend the operation of Schahfer Units 17 and 18 through 2025 was based on delays to solar projects that had originally been expected to be online in 2022 and 2023. These delays were caused by factors beyond NIPSCO's control, including Section 201 Tariffs on imported solar panels, a United States Department of Commerce Investigation into anti-dumping and anti-circumvention of such tariffs, and a review of compliance with new forced labor prevention rules, along with general global supply chain and labor availability as a result of the COVID-19 pandemic. As further discussed by NIPSCO Witness Augustine, based on these broader market dynamics, NIPSCO engaged in additional analysis that led to this decision to delay the retirement of Schahfer Units 17 and 18.

**Q16. Please describe NIPSCO's planned solar projects that have been impacted by disruptions in the solar supply chain.**

A16. NIPSCO has the following approved solar projects that have been delayed past the end of the Forward Test Year (December 31, 2023):[4]

- Gibson Solar (approved in a June 29, 2021, Order in Cause No. 45489): Solar Energy Purchase Agreement between NIPSCO and Gibson Solar LLC dated November 24, 2020, with an installed capacity of approximately 280 megawatts ("MW") (nameplate capacity) for a term of 22 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Gibson Solar PPA in April 2024.
- Cavalry Solar (approved in a May 5, 2021, Order in Cause No. 45462): Solar Generation and Energy Storage BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Cavalry Energy Center, LLC with an aggregate nameplate capacity of approximately 200 MW solar plus 60 MW energy storage for a term of 15 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Cavalry Solar PPA or Contract for Differences in November 2024.
- Dunn's Bridge II Solar (approved in a May 5, 2021, Order in Cause No. 45462): Solar Generation and Energy Storage BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Dunn's Bridge Energy Storage, LLC with an aggregate

[4] NIPSCO notes that some of the anticipated in-service dates are present estimates and not necessarily reflective of a formal agreement between the project developer and NIPSCO.

nameplate capacity of approximately 435 MW solar plus 75 energy storage for a term of 15 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Bridge I Solar PPA or Contract for Differences in November 2024.

- Elliott Solar (approved in a July 28, 2021, Order in Cause No. 45529): Solar Energy Purchase Agreement or Contract for Differences between NIPSCO and Elliott Solar LLC with an aggregate nameplate capacity of approximately 200 MW for a term of 15 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Elliott Solar PPA in November 2025.

- Fairbanks Solar (approved in a June 29, 2021, Order in Cause No. 45511): Solar Energy Purchase Agreement or Contract for Differences between NIPSCO and Fairbanks Solar Energy Center LLC with an aggregate nameplate capacity of approximately 250 MW for a term of 15 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Fairbanks Solar PPA or Contract for Differences in November 2025.

- Green River Solar (approved in a May 5, 2021, Order in Cause No. 45472): Amended and Restated Solar Energy Purchase Agreement between NIPSCO and Green River Solar, LLC dated December 23, 2020, with an installed capacity of approximately 200 MW (nameplate capacity) for a term of 20 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Green River Solar PPA in December 2025.

- Brickyard Solar (approved in a January 27, 2021, Order in Cause No. 45403): Solar Energy Purchase Agreement between NIPSCO and Brickyard Solar, LLC dated June 30, 2020, with an installed capacity of approximately 200 MW (nameplate capacity, alternating current) for a term of 20 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Brickyard Solar PPA in December 2025.

- Greensboro Solar (approved in a January 27, 2021, Order in Cause

No. 45403): Solar Generation and Energy Storage Energy Purchase Agreement between NIPSCO and Greensboro Solar Center, LLC dated June 30, 2020, with an installed capacity of approximately 100 MW (nameplate capacity, alternating current), as well as an attached battery with an installed capacity of approximately 30 MW (nameplate capacity, alternating current), for a term of 20 years. NIPSCO anticipates receiving power from and beginning recovery of costs associated with the Greensboro Solar PPA in December 2025.

**Q17. Based on these delays, what steps is NIPSCO taking to ensure it can reliably and adequately serve its customers?**

A17. First, as mentioned above, NIPSCO has already announced a delay in the retirement of Schahfer Units 17 and 18. Second, NIPSCO is continuing to work with developers for all of its approved projects (including those listed above) to advance the projects to commercial operation as promptly as possible. To be clear, occurrences in the solar supply chain have already impacted expected in-service dates, and there are likely to be cost impacts to several of these projects as well. Third, in August 2022, NIPSCO issued a pair of requests for proposals ("RFPs") seeking potential projects or contractual arrangements to address any identified capacity needs. This included one "all source" RFP, as well as an RFP targeted to procure a resource(s) that is intended to provide peaking, blackstart capabilities, and other reliability attributes.

**Q18. Understanding NIPSCO has not fully completed its generation transition, have customer benefits associated with the transition started to be realized for the wind projects that are in service?**

A18. Yes. NIPSCO customers have already begun to see some of the benefits associated with NIPSCO generation transition, as NIPSCO retired Schahfer Units 14 and 15 in October of 2021[5] and has brought three wind generation projects online already—two under the Build Transfer Agreement ("BTA") or Joint Venture structure, and one under a power purchase agreement ("PPA") structure. Most directly, coming out of the 2018 IRP, NIPSCO focused on procuring wind generation facilities and was able to bring these three projects online in time to take advantage of the wind production tax credit ("PTC") which was scheduled to decline over time. Maximizing the available tax credits for the projects reduced the overall costs of the projects, which is a direct customer benefit.

There are several other examples of benefits currently being realized by customers from these wind projects. First, since NIPSCO's Rosewater

[5] NIPSCO notes that the retirement decision related to Schahfer Units 14 and 15 was made in early 2021 based on information and analysis available at that time, which was before any delays occurred related to approved solar projects.

Wind and Jordan Creek Wind projects went into service in late 2020, NIPSCO customers have been served by the energy produced by these facilities. The same is true for the Indiana Crossroads Wind facility that went into service in late 2021. Second, throughout this time, NIPSCO has also sold the renewable energy credits ("RECs") associated with this wind generation and returned all proceeds to customers as a credit in the Fuel Adjustment Clause ("FAC") proceeding on a dollar-for-dollar basis. Third, in periods where there has been more energy produced from the facilities than is needed to meet NIPSCO's load, NIPSCO has sold this excess energy into the MISO market and returned net proceeds (or margins) to customers through the FAC, through what is called "off-system sales," or OSS.[6] Finally, after an appropriate level of reserves or contingency was built up, NIPSCO has also recently begun to return excess cash distributions associated with Rosewater Wind and Indiana Crossroads Wind (the BTA projects) through the FAC.

With two solar BTA projects (Dunn's Bridge I and Indiana Crossroads)

[6] NIPSCO's proposal in this proceeding is to credit all OSS to customers through the FAC tracker going forward, instead of crediting OSS margins between the FAC tracker and the RTO tracker.

coming online in 2023, there will be additional benefits to customers even during the period when NIPSCO continues its transition away from coal-fired generation. The benefits listed above for the in-service wind projects will also be realized for the solar projects, but the quantity or materiality will continue to grow as additional projects are brought online.

**Q19. Has NIPSCO estimated the value customers are receiving for the "benefits" you listed above? If so, please explain these estimated benefits.**

A19. Yes. NIPSCO has estimated the annual benefits associated with three of these categories—credit of OSS, sales of RECs, and return of cash distributions from the Joint Ventures. As reflected in Confidential Attachment 11-A, NIPSCO's current estimate of the value associated with these three categories is approximately $54 million for the annualized forward test year ending December 31, 2023. This estimate is based on certain assumptions and is subject to variability based on actual market conditions and generation asset performance. While actual dollars for the categories could increase or decrease over time, NIPSCO is proposing to credit all proceeds through the FAC on a dollar-for-dollar basis and feels it is prudent to reflect this activity in the Fuel and Purchased Power ("FPP") calculation presented in this case (generally referred to as "Base Fuel"). This is discussed further by NIPSCO Witness Siegler.[7] In addition, as discussed by NIPSCO Witness Whitehead, NIPSCO is requesting to modify accounting related to the four renewables projects for which recovery is sought in this proceeding, which would allow a quicker return of cash distributions from the Joint Ventures to customers. For clarity, this proposal will not impact the cash at the Joint Venture for the 2023 test year.

<u>**Wholesale Purchase Power Agreements**</u>

**Q20. Please describe NIPSCO's approved wholesale purchase power agreements from which NIPSCO is or will be receiving power and recovering costs by the end of the Forward Test Year (December 31, 2023).**

A20. NIPSCO's approved wholesale purchase power agreements from which NIPSCO is or will be receiving power and recovering costs by the end of the Forward Test year are as follows:

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[7] See also Attachment 3-C-S2, Adjustments FPP 1B-23R (REC Sales), FPP 1C-23R (Cash Held at JV), and FPP 1D-23R (OSS Margin Credit).

- Barton Wind (approved in a July 24, 2008, Order in Cause No. 43393): Wholesale Purchase Power Agreements for Wind Energy dated November 7, 2008, between NIPSCO and Barton Windpower LLC with an aggregate nameplate capacity of approximately 50 MW for a term of 15 years. NIPSCO began receiving power and recovering costs associated with the Barton Wind PPA on April 10, 2009.

- Buffalo Ridge Wind (approved in a July 24, 2008, Order in Cause No. 43393): Wholesale Purchase Power Agreement for Wind Energy dated November 7, 2008, between NIPSCO and Buffalo Ridge I LLC with an aggregate nameplate capacity of approximately 50.4 MW for a term of 15 years. NIPSCO began receiving power and recovering costs associated with the Buffalo Ridge PPA on April 15, 2009.

- Jordan Creek Wind (approved in a June 5, 2019, Order in Cause No. 45195): Wind Energy Purchase Agreement dated January 3, 2019, between NIPSCO and Jordan Creek Wind Farm LLC with an installed capacity of approximately 400 MW nameplate capacity for a term of 20 years. NIPSCO began receiving power and recovering costs associated with the Jordan Creek Wind PPA on December 2, 2020.

- Indiana Crossroads Wind II (approved in a Cause No. 45541): Wind Energy Purchase Agreement between NIPSCO and Indiana Crossroads Wind II LLC dated February 19, 2021, with an installed capacity of approximately 200 MW (nameplate capacity) for a term of 15 years. NIPSCO anticipates receiving power and beginning recovery of costs associated with the Crossroads Wind II PPA by the end of 2023.

**<u>Joint Venture Build Transfer Agreements ("BTA")</u>**

**Q21. Please describe NIPSCO's approved joint venture agreements from which NIPSCO is or will be receiving power by the end of the Forward Test Year (December 31, 2023).**

A21. NIPSCO's approved joint venture agreements from which NIPSCO is or will be receiving power by the end of the Forward Test Year, all of which are rolling into rate base in this proceeding, are as follows:

- Rosewater Wind (approved in a August 7, 2019 Order in Cause No. 45194): Wind Energy Purchase Agreement between NIPSCO and Rosewater Wind Farm LLC with an aggregate nameplate capacity of approximately 102 MW for a term of 15 years. NIPSCO began receiving power and recovering costs associated with the Rosewater PPA on November 20, 2020.
- Indiana Crossroads Wind (approved in a February 19, 2020, Order in Cause No. 45310, as modified in March 29, 2021 Order in Cause No. 45463): Wind Energy Purchase Agreement/Contract for Differences between NIPSCO and Indiana Crossroads Wind Farm LLC dated October 21, 2019, with an aggregate nameplate capacity of approximately 302 MW for a term of 15 years. NIPSCO began receiving power and recovering costs associated with the Indiana Crossroads PPA on December 17, 2021.
- Indiana Crossroads Solar (approved in a July 28, 2021, Order in Cause No. 45524): Solar Generation Energy Contract for Differences between NIPSCO and Meadow Lake Solar Park LLC (d/b/a Indiana Crossroads Solar Park) with an aggregate nameplate capacity of approximately 200 MW for a term of 15 years. NIPSCO anticipates receiving power and beginning recovery of costs associated with the Crossroads Solar Contract for Differences in 2023.

- Dunn's Bridge I Solar (approved in a May 5, 2021, Order in Cause No. 45462): Solar Generation and Energy BTA Energy Contract for Differences between NIPSCO and Dunn's Bridge Solar Center, LLC with an aggregate nameplate capacity of approximately 265 MW solar for a term of 15 years. NIPSCO anticipates receiving power and beginning recovery of costs associated with the Bridge I Solar Contract for Differences in 2023.

**Q22. Above, you discussed OSS, joint venture cash distributions, and RECs associated with NIPSCO's renewable generation projects. Please provide an overview of how these three sources of revenue are treated for the renewable generation projects.**

A22. NIPSCO is crediting any OSS created by its purchase power agreements and joint venture BTAs in the same manner as NIPSCO's existing wind PPAs approved in Cause Nos. 43393 (Barton Wind / Barton Wind), 45194 (Rosewater Wind), 45195 (Jordan Creek Wind), and 45310 (Indiana Crossroads Wind), which has occurred in NIPSCO's FAC proceedings since 2009. NIPSCO has also begun to credit to customers in the FAC proceedings, cash distributions associated with its renewable joint venture projects.[8] Further, as reflected in the FAC proceedings, each megawatt

[8] Specifically, consistent with NIPSCO's commitments in the various certificate of public convenience and necessity filings related to its wind and solar joint venture projects, when the proceeds from the power purchase agreement between NIPSCO and the applicable joint venture exceed the joint venture's operating costs (and after a certain amount of contingency has

hour of power generated from a qualified resource can be awarded a REC. As of this filing, NIPSCO receives RECs associated with the power it purchases from Barton Wind, Buffalo Ridge Wind, Jordan Creek Wind, Rosewater Wind, and Indiana Crossroads Wind. NIPSCO also expects to receive these same benefits from Indiana Crossroads Wind II, Dunn's Bridge I Solar, and Indiana Crossroads Solar in 2023. The benefits related to proceeds from NIPSCO's renewable projects are also discussed by NIPSCO Witness Whitehead.

In addition to the joint ventures and purchases from the wholesale purchase power agreements, and pursuant to the Commission's March 4, 2015, Order in Cause No. 44393 ("44393 Order"), NIPSCO is able to recover costs of capacity and energy purchases made through its Electric Renewable Feed-In Tariff. The 44393 Order allows for up to 30 MW of installed capacity under the original Electric Renewable Feed-In Tariff (Cause No. 43922) and up to an additional 16 MW of installed capacity under phase 2 of the program (Cause No. 44393). Current in-service

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accumulated), NIPSCO credits the excess funds to its customers, serving as a direct reduction to FAC costs on a dollar-for-dollar basis. These credits began in March of 2022, and NIPSCO expects these joint venture cash distribution amounts to continue going forward.

projects under the original Electric Renewable Feed-In Tariff is 36.9 MWs of installed capacity.

NIPSCO recovers purchases of energy from eligible renewable resources through its Section 42(a) tracking mechanism, which is filed with its quarterly FAC proceedings in a manner consistent with NIPSCO's treatment of its wind purchases approved by the Commission and defers the costs of purchases of capacity under the Electric Renewable Feed-In Tariff for recovery through NIPSCO's Resource Adequacy Tracker. NIPSCO also credits any OSS and REC sales received from the Renewable Feed-In Tariff through the FAC.

**Capacity – MISO Requirements, Resources, Costs**

**Q23. Please describe MISO's current capacity market.**

A23. MISO's Resource Adequacy construct ensures that adequate capacity is maintained for each of the MISO-developed Local Resource Zones to meet the Planning Reserve Margin Requirement for the MISO footprint. NIPSCO's Planning Reserve Margin Requirement obligations will be fixed for the Planning Year and NIPSCO is required to have at least as many Zonal Resource Credits as its forecasted peak demand at the time of the

MISO system peak plus the Planning Reserve Margin in the zone in which NIPSCO serves load. NIPSCO can meet its Planning Reserve Margin Requirement by: (1) Self-Scheduling, (2) Fixed Resource Adequacy Plan, (3) Participating in the PRA, or (4) Paying the Capacity Deficiency Charge. As previously mentioned, MISO's transition from the current Summer-based annual construct to four distinct Seasons was recently approved by FERC.

**Q24. How does NIPSCO participate in the MISO capacity market?**

A24. NIPSCO meets its Planning Reserve Margin Requirement obligations under MISO's process by self-scheduling its resources[9] in the PRA up to its Planning Reserve Margin Requirement, wherein NIPSCO's forecasted peak demand at the time of the MISO system peak plus Planning Reserve Margin is netted against NIPSCO's identified supply-side generation and registered demand-side assets (e.g., under Rate 831). Any proceeds from the sale of excess capacity sold bi-laterally or through MISO's PRA are credited within NIPSCO's Resource Adequacy ("RA") Tracker. When NIPSCO purchases capacity to meet its Resource Adequacy obligations

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[9] This includes resources that NIPSCO owns and those it has contracted for.

either bi-laterally or through MISO's PRA, those costs are recovered through NIPSCO's RA Tracker.

__Demand Response Programs__

**Q25. Please describe NIPSCO's existing Demand Response programs.**

A25. NIPSCO currently has three Demand Response programs: (1) options within NIPSCO's Rate 831 whereby large industrial customers qualify as a Load Modifying Resource ("LMR"), (2) a Demand Response Resource offering under Rider 881 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy, and (3) an Emergency Demand Response Resource offering under Rider 882 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy for use only during emergency operations.

**Q26. Do these Demand Response programs qualify as Demand Response programs for purposes of MISO's Tariff Module E-1?**

A26. Options within NIPSCO's Rate 831 qualify as an LMR under MISO's Tariff Module E-1. This allows NIPSCO to receive Zonal Resource Credits for use against its Planning Reserve Margin Requirement obligation. Under

Riders 881 and 882, NIPSCO offers energy only Demand Response Resource and Emergency Demand Response Resource. These demand response programs do not qualify under MISO's Tariff Module E-1 because they are energy only and do not have the "must offer" obligation required to be awarded Zonal Resource Credits.

**<u>Modification of Rate 831 – Industrial Power Service – Large</u>**

**Q27. What was the driving force behind the creation of Rate 831 in NIPSCO's last electric rate case?**

A27. In its last electric rate case (Cause No. 45159), NIPSCO proposed a change in its large industrial service structure to address the changing economic landscape. Implementation of those changes in industrial service structure was a natural evolution from the interruptible service offering that was initiated in NIPSCO's 2010 electric rate case (Cause No. 43969) and expanded in its 2015 electric rate case (Cause No. 44688). Since 2010, NIPSCO had been allowing its industrial customers to assume more market risk in exchange for supporting less of NIPSCO's production costs. The new industrial service structure approved in NIPSCO's most recent electric rate case was the next step in that evolutionary process. In exchange for taking a set amount of contract demand for a period of up to five years, NIPSCO's largest, most sophisticated customers were allowed to make more decisions regarding their energy procurement. Transitioning much of NIPSCO's industrial load to the market-sensitive rate structure provided in Rate 831 required better cost recovery alignment, which resulted in a near term shift of some fixed costs that were then being recovered from the industrial customers to other customers but did establish a more sustainable rate platform going forward. NIPSCO realized that if the economics were to continue, and NIPSCO had not responded, there was a high probability that more industrial load would leave the system, and the chances that that load would return, at least in the near-term, were low.

**Q28. Please provide an overview of Rate 831.**

A28. Rate 831 has three (3) tiers of service: (1) Tier 1, Firm Service; (2) Tier 2, Non-Firm Market Price Service; and (3) Tier 3, Non-Firm Third Party Generation Service. Customers must demonstrate or document, to the Company's satisfaction, the ability to reduce demand to the Tier 1 elected level plus additional firm capacity procured, as allowed, under Tier 2 and

Tier 3. If a Customer's elected service results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction, that the Customer can reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3. This information is utilized to register the curtailable demand as an LMR with MISO. The Customer chooses to procure additional capacity to reduce or eliminate its curtailable obligations as an LMR through the PRA or by purchasing capacity through a third-party bilateral agreement. NIPSCO currently has seven large industrial customers taking service under Rate 831, all of whom have expressed an intention to continue to take service under the replacement of Rate 831 – Rate 531.

**Q29. In general, has Rate 831 functioned as intended?**

A29. Yes. Rate 831 has worked as originally intended. Rate 831 provides increased optionality for industrial customers to manage their own energy needs. As a result, NIPSCO's remaining FAC customers benefit from reduced market exposure. Rate 831 also provides clearer views of future capacity needs as NIPSCO looks to further advance in its generation transition.

**Q30. How has the current and expected level of industrial load informed or impacted NIPSCO's generation transition efforts?**

A30. With the approval and implementation of NIPSCO's Rate 831 industrial service structure, the level of firm demand NIPSCO is planning to serve is lower than it otherwise would have been. Although some of the current Rate 831 customers were previously registered with MISO, allowing these customers to directly access the wholesale market to meet their capacity and energy needs has reduced NIPSCO's total firm load expectations by approximately 789 MWs. In the absence of Rate 831/531, it is likely NIPSCO would need to procure multiple, additional generation projects to serve this load. At this time NIPSCO believes it would be very difficult to secure the capacity to serve these customers under a rate structure without Rate 831/531 continuing in its current/proposed form in this case. The progression and driving force behind the creation of Rate 831 outlined above suggest the need for a continued offering under Rate 831/531 is needed to today more than ever.

**Q31. Is NIPSCO proposing any significant changes to Rate 831 – Industrial Power Service – Large?**

A31. NIPSCO is not proposing any significant changes to how Rate 831 functions but is proposing changes to allocation. As proposed, and as more fully described by NIPSCO Witness Whitehead, the three general modifications of Rate 831 are: (1) production demand-related costs will be allocated to Rate 531 customers using 180 MWs and rates will be designed using contracted Tier 1 demand levels totaling 170 MWs (in Cause No. 45159, the allocation to this class was based upon 194 MWs, with commitments to the class at 177 MWs); (2) in future rate proceedings, the cost allocation to Rate 531 will continue to move the class toward the actual cost of service based on actual contract demands; and (3) the contract term for existing customers will expire on the earlier of (a) the effective date for new rates under NIPSCO's next electric rate case filing after this rate case, or (b) May 31, 2026. New customers will continue to have a term of the earlier of rate effectiveness in the next rate case or five years.

**Q32. Is NIPSCO proposing any minor changes to Rate 831 – Industrial Power Service – Large?**

A32. Yes. NIPSCO is proposing minor changes to Rate 831. First, in the section on "Customer Load Information," NIPSCO is including a requirement that a customer make best efforts to ensure its hourly load forecasts reflect actual operational and outage plans and provide updates to NIPSCO when forecasts change materially. Second, in several places, NIPSCO is incorporating language to ensure clarity that the terms of Rate 831/531 are "pursuant to the current Annual Resource Adequacy Construct or any successor constructs including a Seasonal Resource Adequacy Construct."

Any changes required as a result of the implementation of the MISO Seasonal Resource Adequacy construct will be separately addressed in tariff revisions within rebuttal in this case or in a separate proceeding depending upon the timing of MISO's implementation. As a practical matter, Rate 831 already has provisions linking to MISO Resource Adequacy and compliance with the MISO Tariff, but NIPSCO's proposed change is to ensure that is very clear. Changes to Rate 831 should be limited in that the MISO process is expected to still be annual but have four separate seasons for which resource adequacy is required.

**Q33. Please describe any curtailable service included in Rate 831 that qualifies for MISO capacity.**

A33. Rate 831 provides two (2) options of curtailable service (1) Tier 2 is "curtailments and/or MISO PRA capacity," and (2) Tier 3 is "curtailments, and/or MISO PRA capacity, and/or third-party capacity." Both options allow a customer to procure capacity to reduce or eliminate the curtailable portion of its load. In either circumstance, the load is covered from a MISO Resource Adequacy perspective. The amount of curtailable service is registered as an LMR with MISO with the size of any LMRs changing annually with any changes to coincident peak demand forecasts for the Rate 831 customers and/or MISO Planning PRA capacity, and/or third-party capacity. Since inception, customers have procured third-party capacity as well as maintained some level of LMRs which has decreased since the incorporation of Rate 831.

Additionally, as NIPSCO continues its transition away from more expensive coal-fired generation, which is set to be complete by 2026-2028 when Michigan City Unit 12 retires, the number of projects and total MWs of replacement capacity needed will be informed by expectations about total load, which is directly impacted by the total level of firm demand Rate 831/531 customers are contractually obligated to take.

**<u>Modifications Affecting RA Adjustment</u>**

**Q34. Please describe NIPSCO's RA Adjustment.**

A34. The Commission's August 25, 2010, Final Order in Cause No. 43526 (the "43526 Order") approved a purchase capacity cost recovery mechanism through which NIPSCO's prudently incurred capacity costs should be recovered. 43526 Order at 94.

The Commission's December 21, 2011, Final Order in Cause No. 43969 (the "43969 Order") approved the implementation of the RA Adjustment approved in the 43526 Order by approving NIPSCO's Rider 674 – Adjustment of Charges for Resource Adequacy and NIPSCO's Appendix F – Resource Adequacy Adjustment Factor. 43969 Order at 69-70. The 43969 Order specified that the RA Adjustment will be a semi-annual mechanism coordinated with the FAC audit process. The 43969 Order specified that the RA Adjustment will recover prudently incurred capacity costs and seventy-five percent (75%) of costs associated with any credits paid as a result of Rider 675 – Interruptible Industrial Service Rider. 43969 Order at 69. The 43969 Order also specified that due to the lag between payment and recovery of credits, the actual amount of credits paid will be deferred in a balance sheet account until they are recovered in the RA Adjustment, or in the case of the 25% portion, in the FAC. 43969 Order at 70. NIPSCO updates its RA Adjustment factors semi-annually in Cause No. 44155-RA-XX. The Commission's July 18, 2016, Order in Cause No. 44688 ("44688 Order") approved the demand allocators for the RA Adjustment (Joint Exhibit C to the Settlement), which were modified to reflect the amount of interruptible loads contained in Rates 732, 733, and 734.

The Commission's December 4, 2019, Order in Cause No. 45159 (the "45159 Order") approved, among other things, the removal of all embedded capacity costs and/or credits from base rates and the recovery of capacity costs as a charge/credit to customers through the RA Adjustment.

**Q35. Is NIPSCO proposing any changes to the RA Adjustment in this proceeding?**

A35. NIPSCO is not proposing any changes in how the RA Adjustment will function; however, in this proceeding, NIPSCO is proposing to include $22.4 million of capacity charges in base rates with any additional capacity costs or credits flowing through the RA Adjustment.

**Q36. How did NIPSCO determine the $22.4 million of capacity charges to include in base rates?**

A36. NIPSCO performed a historical analysis based on capacity prices for the most recent MISO Planning Years (2020–2021, 2021–2022, and 2022-2023) in which a 3-year, volume-weighted average price was used to calculate a $/MW-day charge.

**Q37. Is it possible that NIPSCO's total capacity charges could exceed $22.4 million per year?**

A37. Yes, that is possible. As noted above, NIPSCO utilized a 3-year, volume-weighted price to calculate the amount proposed for inclusion in base rates. However, 2022-2023 capacity pricing has been higher than in prior years. If this continues, total capacity charges could exceed $22.4 million, with charges flowing through the RA Adjustment.

**Q38. Is the inclusion of $22.4 million of capacity charges in base rates a potential benefit to customers?**

A38. Yes. NIPSCO believes the decision to include $22.4 million of capacity charges in base rates is a prudent measure to mitigate anticipated near-term volatility in the RA Adjustment. Specifically, because NIPSCO anticipates near-term capacity purchases that are higher (in terms of MWs and total dollars) than in recent years, the inclusion of $22.4 million of capacity costs in base rates will mitigate any peaks-and-valleys that could occur if all charges went through the RA Adjustment. Finally, the RA Adjustment will only recover actual capacity purchase costs and "track" from the amount built into base rates, with any additional capacity costs or credits flowing through the tracker. As NIPSCO progresses in its generation transition, it anticipates the charges for capacity to decrease over time as new assets come online.

**Q39. Please explain Adjustment OM 2J shown on <u>Petitioner's Exhibit No. 3</u>, Attachment 3-C-S2) that reflects an increase in future capacity purchases.**

A39. Adjustment OM 2J is to increase the electric operating expenses in the amount of $22,414,800 during the Forward Test Year to reflect the total amount of non-trackable capacity purchases that NIPSCO is seeking to recover in base rates. If this adjustment is not included, the Forward Test Year electric operating expenses would be understated.

**<u>Modifications Affecting RTO Adjustment</u>**

**Q40. Please describe NIPSCO's RTO Adjustment.**

A40. The Commission's 43526 Order found that NIPSCO's MISO non-fuel costs and revenues and OSS sharing should be included in one mechanism designated as the RTO Adjustment. 43526 Order at 93-94.

The Commission's 43969 Order authorized the implementation of the RTO Adjustment from Cause No. 43526 by approving NIPSCO's Rider 671 – Adjustment of Charges for Regional Transmission Organization and NIPSCO's Appendix C – Regional Transmission Organization Adjustment Factor. 43969 Order at 70. The 43969 Order specified that the RTO

Adjustment will be a semi-annual mechanism coordinated with the FAC audit process. *Id.*

The Commission's 44688 Order specified that the RTO Adjustment will recover MISO non-fuel costs and revenues that exceed $16,585,108 annually or $8,292,554 semi-annually (the amount of MISO non-fuel credits and charges included in base rates). The 44688 Order also reset the RTO benchmark to recover or pass back any amounts above or below this amount through the RTO Adjustment and reset the OSS margin credit to base rates to reflect the level of OSS included in the test year of $4,741,390. The 44688 Order also directed NIPSCO to flow through the RTO Tracker 100% of its OSS margins, below (down to zero) or above $4,741,390 annually (the level built into base rates).

The Commission's 45159 Order approved, among other things, NIPSCO's Rider 871 – Adjustment of Charges for Regional Transmission Organization and NIPSCO's Appendix C – Regional Transmission Organization Adjustment Factor, including approval to (1) remove MISO charges and credits previously included in base rates and collect 100% of MISO charges that are not included in the FAC through the RTO; (2)

remove positive or negative OSS margins currently included in base rates and flow back 100% of any OSS margins net of expenses through the RTO; (3) remove all back-up and maintenance margins previously included in base rates and pass back 100% of back-up, maintenance, and temporary services[10] margins net of expenses through the RTO; (4) change the allocation methodology to the 4 Coincident Peak allocation set out in Corrected Rate 831 Implementation Agreement Exhibit A to the approved Rate 831 Settlement;[11] and (5) remove the Utility Receipts Tax. The 45159 Order became effective January 1, 2020, with the implementation of Step 1 rates.[12]

The Commission's April 27, 2022, Order in Cause No. 44156-RTO-21, approved, among other things, a modification of Rider 871 – Adjustment of Charges for Regional Transmission Organization to include recovery of net non-fuel PJM Interconnect LLC ("PJM") costs and revenues.

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[10] BUM refers to Back-Up, Maintenance, and Temporary Services under Rider 876.

[11] Stipulation and Settlement Agreement on Rate 831 Implementation by and among NIPSCO, NIPSCO Industrial Group, NLMK Indiana, and United States Steel Corporation, filed in Cause No. 45159 (as revised June 7, 2019) (the "Rate 831 Settlement").

[12] The Commission approved, among other things, the treatment of Multi Value Projects, Targeted Market Efficiency Projects, and Interregional Market Efficiency Projects, as non-jurisdictional assets in Cause Nos. 44156-RTO-XX, 44156-RTO-13, and 44156-RTO-19, respectively.

**Q41. Please identify the RTO charges and credits included in the RTO Adjustment and the basis on which each is allocated (energy or demand) to customers.**

A41. The RTO charges and credits included in the RTO Adjustment and the basis on which each is allocated (energy or demand) to customers (allocated to customers in the same manner that they are allocated by MISO to NIPSCO and other market participants), is as follows:

| Schedule | Description | Customer Allocation Basis |
|---|---|---|
| MISO 1 | Schedule, System Control and Dispatch Service | Energy |
| MISO 2 | Reactive Supply and Voltage Control from Generation Source | Energy |
| N/A | Reactive Supply and Voltage Control from Generation and Other Sources Service – PJM | Energy |
| MISO 7 | Long-term Firm and Short-term Firm Point-to-Point Transmission Service | Energy |
| N/A | Long-term Firm and Short-term Firm Point-to-Point Transmission Service - PJM | Energy |
| MISO 8 | Non-firm Point-to-point Transmission Service | Energy |
| N/A | Non-Firm Point-to-Point Transmission Service - PJM | Energy |
| MISO 10 | MISO Cost Adder | Energy |
| MISO 10-FERC | FERC Annual Charges Recovery | Energy |
| MISO 11 | Wholesale Distribution Service | Energy |
| MISO 16 | Financial Transmission Rights Market Administration Amount | Energy |
| MISO 17 | Day Ahead and Real Time Market Administration Amount | Energy |
| MISO 24 | Day Ahead and Real Time Balancing Authority Allocation Amount | Energy |
| MISO 24 | Real Time Balancing Authority Distribution Amount | Energy |

| Schedule | Description | Customer Allocation Basis |
|---|---|---|
| MISO 26 | Network Upgrade Charge from Transmission Expansion Plan | Demand |
| MISO 26A | Multi Value Project Network Upgrade | Demand |
| MISO 26C | Cost Recovery for Targeted Market Efficiency Projects Constructed by MISO Transmission Owners | Demand |
| MISO 26D | Cost Recovery for Targeted Market Efficiency Projects Constructed by PJM Transmission Owners | Demand |
| MISO 26E | Cost Recovery for Interregional Market Efficiency Projects Constructed by MISO Transmission Owners | Demand |
| MISO 26F | Cost Recovery for Interregional Market Efficiency Projects Constructed by PJM Transmission Owners | Demand |
| MISO 26 | Network Upgrade Reimbursement from Transmission Expansion Plan | Demand |
| MISO 33 | Black Start Service | Energy |
| N/A | Black Start Service – PJM | Energy |
| MISO 37 | Expansion Plan Cost Recovery Plan from First Energy | Demand |
| MISO 38 | Expansion Plan Cost Recovery Plan from Duke Energy | Demand |
| MISO 49 | Cost Allocation for Available System Capacity Usage | Energy |
| N/A | MVP Distribution - MISO | Demand |
| N/A | Real Time Revenue Neutrality Uplift Amount - MISO | Energy |
| N/A | Real Time Miscellaneous Amount - MISO | Energy |
| N/A | Other Miscellaneous Transmission Costs - PJM | Energy |
| N/A | Other Miscellaneous Transmission Costs - MISO | Energy |

**Q42. What are Off-System Sales ("OSS")?**

A42. On an hourly basis, the generating units are sorted by highest fuel and production cost to lowest fuel and production costs which establishes a "stack" of units for that hour. The OSS volumes are allocated to the highest cost unit first and then down the stack based on each unit's incremental generation until the OSS volumes are satisfied. The sales price at each resulting generator is then multiplied by its generation and summed to realize the OSS revenue. Within the current RTO Adjustment, the incremental fuel and production cost from the same group of units is calculated and subtracted from the OSS revenue to calculate the OSS margin.

**Q43. Is NIPSCO proposing any changes to the RTO Adjustment in this proceeding?**

A43. Yes. As further explained below, in this proceeding, NIPSCO is proposing to remove OSS margins, net of expenses, from the RTO Adjustment and flow back 100% of any OSS, net of expenses, through the FAC. No other changes are being proposed.

**<u>Modification Affecting FAC</u>**

**Q44. Are there any changes being proposed to the FAC?**

A44. Yes. In this proceeding, NIPSCO is proposing to flow back 100% of all OSS through the FAC (instead of some OSS margins going through the RTO Adjustment), net of expenses, in a manner consistent with NIPSCO's treatment of its wind purchases approved by the Commission net of expenses. This affords a consolidated treatment of OSS rather than splitting them out for a bifurcated tracking approach with the RTO Adjustment and FAC. NIPSCO is proposing this change to pass OSS through the FAC to allow OSS to flow back to the customer quarterly (through the FAC) instead of annually (through the RTO Adjustment). This allows customers to receive the benefit in a timelier manner and in alignment with generation, OSS, and production costs which are realized through the FAC. The application of this change creates a single line item for all OSS (OSS Adjustment) on the FAC schedules whereby OSS revenues, net of expenses, are credited to customers within the applicable filings. This change is also reflected within Fuel and Purchased Power ("FPP") presented in this proceeding as OSS representing a direct offset to the base cost of fuel determination. NIPSCO is also proposing to eliminate the purchased power procedures established in Cause No. 41363 (the "Purchased Power Benchmark") from the FAC.

**Q45. Please describe NIPSCO's proposal to eliminate the Purchased Power Benchmark in the FAC.**

A45. NIPSCO proposes that the Purchased Power Benchmark be permanently waived upon the effective date of the Commission's order in this proceeding because the benchmark procedures are outdated. The procedures were initiated at a time when the MISO energy market did not yet exist, and purchases were executed on a negotiated bilateral basis. Since then, NIPSCO has become a full participant in the organized MISO energy market, and NIPSCO purchases all its energy requirements from the MISO. As a member of MISO, NIPSCO's generation, along with all generation participating in the MISO day-ahead and real-time energy markets, is economically dispatched and NIPSCO's customers have access to all generation resources in MISO to meet their needs. Purchases made from MISO are, by definition, the most economic purchase available to meet customer load. In addition, the impact of low natural gas prices and increasing renewable energy penetration has had a significant downward impact on the average market price of energy. These factors suggest that the risks the benchmark was intended to address have been heavily mitigated. NIPSCO's proposal in no way prohibits review of its purchase-power transactions, purchase-power costs, and its offers into MISO, as they will continue to remain subject to review and approval in each FAC filing. NIPSCO will continue to do what it does today: (1) discuss in FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours, (2) provide the root cause analyses that were performed, and (3) continue to supply the Indiana Office of Utility Consumer Counselor ("OUCC") day-ahead and real-time unit offers and awards for the test days it selects, all of which has worked well and provides the OUCC, and the Commission, relevant information on outages that meet those established thresholds. The Commission approved Duke's request for the elimination of the Purchased Power Benchmark in its June 29, 2020, Order in Cause No. 45253 (at 168).

**<u>NIPSCO's PROMOD Forecast</u>**

**Q46. What is PROMOD?**

A46. PROMOD is a software package that simulates the operation of an electric utility power system. It is a comprehensive production costing model that utilizes Monte Carlo simulation for projecting future operating costs.

**Q47. How was PROMOD used in this case?**

A47. NIPSCO's use of the PROMOD model is consistent with its approach when estimating fuel and purchased power costs as determined in its electric FAC filings whereby the dispatch and performance of NIPSCO's generating units are forecasted in a future MISO Market. In this case, NIPSCO used the PROMOD model in the calculation of (1) the 2023 fuel and purchased power expense, (2) production fuel, and (3) components of the revenue requirement related to variable operating expenses associated with NIPSCO's generation. The dispatch and performance of the generating units is shared with the broader NIPSCO organization for the formation of forecasted generation consumables and by-products such as chemicals for environmental controls, fly ash, consumables, and gypsum.

**Q48. NIPSCO Witness Blissmer discusses NIPSCO's proposed new Rider 594 – Adjustment of Charges for Variable Costs of Coal-Fired Generation (the "Variable Cost Tracker") and notes that the non-labor coal-fired generation costs are potentially variable or volatile, as well as outside of NIPSCO's control. Please explain why this is the case.**

A48. The frequency and duration with which NIPSCO's coal-fired generating units are dispatched dictates whether and at what amount NIPSCO must incur the associated non-labor O&M expenses. For example, much like fuel costs, the amount of expense NIPSCO incurs related to chemicals and NOx emission allowances depends entirely on the frequency and duration of the units' dispatch in the MISO Market. If the units are picked up by

MISO and for a long duration, NIPSCO will need to purchase the necessary chemicals and emission allowances to run the units in compliance with environmental standards. The cost of the chemicals to run the pollution control technology on NIPSCO's coal-fired generation and the cost of NOx emission allowances themselves are also subject to variability based on commodity market conditions.

Similarly, the frequency and duration of dispatch from NIPSCO's coal-fired generating stations also dictates the amount of non-trackable fuel handling costs NIPSCO will incur. NIPSCO incurs these costs through managing its on-site coal piles, which are directly affected by how often and how long NIPSCO's coal-fired generating stations are called on by MISO to run. NIPSCO makes real-time adjustments to how the coal piles are managed, which serve to either reduce or increase fuel-handling expenses. These expenses are not included in NIPSCO's quarterly FAC.

Expenses related to generation maintenance, planned outages, and forced outages are all driven by the variability of dispatch of NIPSCO's coal-fired generation, especially as these units move closer towards retirement. Less frequent dispatch from these units results in reduced maintenance expenses and fewer outages – both planned and forced. More frequent dispatch requires NIPSCO to conduct more maintenance on these units and can result in more planned and forced outages. The frequency and duration of dispatch can also affect NIPSCO's ability to conduct maintenance activities on an expected schedule, which increases the likelihood that a forced outage will occur – i.e., an outage driven by equipment failure.

These costs are also generally outside NIPSCO's control. NIPSCO bids its coal-fired generating units into the MISO market consistent with MISO's Business Practice Manuals. The extent to which MISO elects to dispatch NIPSCO's coal-fired generation is driven by MISO's market prices and is not controlled by NIPSCO. MISO's market prices are influenced by a confluence of factors, including the price of natural gas, the impact of renewables, and commodity and transportation pricing.

**New Rate 543 – Station Power for Renewable Wholesale Generation Equipment**

**Q49. Please describe NIPSCO's proposed Rate 543 – Station Power for Renewable Wholesale Generation Equipment.**

A49. NIPSCO's proposed Rate 543 – Station Power for Renewable Wholesale Generation Equipment is a new rate available for service to Renewable Wholesale Generation Equipment taking service at Transmission or Subtransmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Subtransmission capacity sufficient to meet the Customer's requirements. The term "Wholesale Generation Equipment" shall mean equipment which is: (a) either located at a single contiguous site or located at multiple geographic sites and aggregated by a collector line or substation; (b) exclusively used to produce electric energy that will be sold at wholesale; (c) owned and/or operated by a qualified member of MISO, PJM or other organized energy market or successor markets; and (d) part of a facility or project that is subject to an Interconnection Agreement under the MISO Open Access Transmission Tariff or PJM Open Access Transmission Tariff. The new rate will be available to NIPSCO's wholesale generating resources as well as two other existing customers that are currently taking service under Rate 824. This rate design for this new Rate will be determined based on the four eligible customers and those operating characteristics/data instead of all customers taking service under Rate 824. The new rate design is more in line with a wholesale energy rate because that is the market in which the assets exist. NIPSCO Witness Taylor sponsors the adjustment.

**LNG Adjustment**

**Q50. Please explain Adjustments REV 8-21, REV 8-23R, FPP 2-21, FPP 2-23R shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, REV 8 and FPP 2 to reflect a normalized volume of gas liquefaction.**

A50. For a variety of reasons, NIPSCO liquefied more gas in the Historic Base Period (period beginning January 1, 2021, and ending December 31, 2021) as compared to the volumes expected going forward. The 5-year average of actual gas liquefaction (2017-2021) was 769,794 MCF. NIPSCO believes the 5-year average is an accurate estimate of future liquefaction, compared to the 968,505 MCF that occurred during the Historic Base Period. Because the liquefaction process is a heavy consumer of electricity, the volume of gas liquefied creates variations in inter-company electric revenues and the associated fuel costs. NIPSCO Witness Siegler sponsors adjustments based on the 5-year average.

**<u>DRR Adjustment</u>**

**Q51. Please explain the basis for Adjustment REV 16-22 shown on <u>Petitioner's Exhibit No. 3</u>, Attachment 3-C-S2, REV 16.**

A51. NIPSCO is proposing to remove margins associated with its Rider 881 – Demand Response Resource Type 1 (DRR 1) – Energy Only (proposed Rider 581). NIPSCO offers the demand response program to allow NIPSCO's industrial customers a means of offering load drop into the MISO Market as a Demand Response Resource. The margin NIPSCO receives through the Rider is meant to compensate NIPSCO for its lost retail margin during the load drop event. It is appropriate to remove these margins from the Revenue Requirement due to NIPSCO's inability to predict the usage of the Rider by customers. Changing market dynamics and individual customer operating characteristics could increase or eliminate the activity under this Rider. Furthermore, the margin received through the Rider is offset by retail sales that occur should customers choose to discontinue usage of the Rider. The inability of NIPSCO to predict usage under this Rider and the fact that activity under this Rider is essentially a wash between lost retail margin and retail sales are both valid reasons that support the removal of any margin collected through this Rider. Adjustment REV 16-22 shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, REV 16, decreases the Historic Base Year by $947,909 to remove all Demand Response Resource margins, resulting in a Forward Test Year amount of zero.

**Q52. Does this conclude your prefiled direct testimony?**

A52. Yes.

**VERIFICATION**

I, Andrew S. Campbell, Director of Regulatory Support & Planning for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Andrew S. Campbell

Dated: September 29, 2021

# NORTHERN INDIANA PUBLIC SERVICE COMPANY
## ERC 2023 Test Year

| | |
|---|---|
| Annual REC Sales | $ 15,420,440 |
| Annual Off System Sales | $ 23,059,206 |
| Annual Cash at the JV | $ 15,616,284 |
| Total | $ 54,095,930 |

NORTHERN INDIANA PUBLIC SERVICE COMPANY

**ERC 2023 Test Year**

**REC Sales**

[redacted]

# NORTHERN INDIANA PUBLIC SERVICE COMPANY

## ERC 2023 Test Year

## Off System Sales

[redacted]

**NORTHERN INDIANA PUBLIC SERVICE COMPANY**
**ERC 2023 Test Year**
**Cash at the JV**

[redacted]