VERIFIED DIRECT TESTIMONY OF PATRICK N. AUGUSTINE

Q1. Please state your name, professional position, and business address.

A1. My name is Patrick N. Augustine. I am a Vice President in Charles River Associates' Energy Practice. My business address is 1201 F Street, NW, Washington, DC 20004.

Q2. On whose behalf are you submitting this direct testimony?

A2. I am submitting this testimony on behalf of Northern Indiana Public Service Company LLC ("NIPSCO").

Q3. Please briefly describe your educational and business experience.

A3. I received a Bachelor of Arts degree from Harvard University and received a Master of Environmental Management degree from the Nicholas School of the Environment at Duke University. I have been employed by Charles River Associates ("CRA") for over seven years and have worked in the energy consulting industry for seventeen years. Prior to joining CRA, I worked at Pace Global Energy Services, now a Siemens business, for over nine years, performing the roles of analyst, project manager, and director. At CRA, in my role as Vice

President, I oversee the maintenance of the firm's power market modeling tools and processes, I manage consulting assignments in the power and utilities sectors, and I supervise junior staff in performing market, policy, and strategic analyses for our clients.

Q4. Please describe CRA and the work you perform in more detail.

A4. CRA is a consulting firm that offers economic, financial, and strategic expertise to support our clients in business decisions, regulatory and litigation proceedings, and market and policy analysis. My professional experience within CRA's energy practice has focused on power market analysis and utility resource planning work to support project developers, electric utilities, investors, and lenders in energy market forecasting, power asset valuation, and utility portfolio planning. This work involves energy market research and analysis and the use of market models, particularly those that simulate the competitive electric power markets and those used for electric utility portfolio dispatch analysis and cost accounting.

Q5. Have you previously testified before this or any other regulatory commission?

A5. Yes. I previously submitted testimony before the Indiana Utility Regulatory Commission ("Commission") in NIPSCO's requests for a certificate of public convenience and necessity ("CPCN") to purchase and acquire (indirectly through

joint venture structures) in (1) Cause No. 45462 for a (a) 265 megawatt ("MW") solar joint venture (the Dunn's Bridge I Project), (b) 435 MW solar and 75 MW energy storage joint venture (Dunn's Bridge II Project), and (c) 200 MW solar and 60 MW energy storage joint venture (the Cavalry Project); (2) Cause No. 45936, which was recently filed seeking modification of the Order in Cause No. 45462 associated with the Dunn's Bridge II and Cavalry Projects; (3) Cause No. 45511 for a 250 MW solar joint venture (the Fairbanks Project); (4) Cause No. 45524 for a 200 MW solar joint venture (the Crossroads Solar Project); (5) Cause No. 45529 for a 200 MW solar joint venture (the Elliott Project); (6) Cause No. 45194 for a 102 MW wind joint venture (the Rosewater Project); (7) Cause No. 45310 for a 302 MW wind joint venture (the Crossroads Wind Project); and (8) Cause No. 45926 for a 200 MW solar joint venture (the Gibson Project). I also submitted testimony before the Commission in NIPSCO's request for approval and associated cost recovery of power purchase agreements in (1) Cause No. 45541 with Indiana Crossroads Wind II LLC (Crossroads Wind II); (2) Cause No. 45489 with Gibson Solar LLC (Gibson); (3) Cause No. 45472 with Green River Solar, LLC (Green River); (4) Cause No. 45403 with (a) Brickyard Solar, LLC (Brickyard), and (b) Greensboro Solar Center, LLC (Greensboro); (5) Cause No. 45195 with Jordan Creek Wind Farm LLC (Jordan Creek); and (6) Cause No. 45196 with Roaming Bison Wind Farm LLC (Roaming

Bison). I also recently submitted testimony in NIPSCO's request for approval and associated cost recovery of a (1) Solar Energy Purchase Agreement between NIPSCO and Appleseed Solar, LLC dated January 24, 2023 (Appleseed) currently pending in Cause No. 45887, (2) Wind Energy Purchase Agreement between NIPSCO and Templeton Wind Energy Center, LLC dated February 13, 2023 (Templeton) currently pending in Cause No. 45887, and (3) Wind Energy Purchase Agreement between NIPSCO and Carpenter Wind Farm LLC dated April 13, 2023 (Carpenter) currently pending in Cause No. 45908. I also provided testimony before the Commission in NIPSCO's last two electric rate cases in Cause No. 45772 and Cause No. 45159.

I have also provided testimony before the Kentucky Public Service Commission with regard to an application for approval of an environmental compliance plan and associated cost recovery in Case No. 2012-00063; on behalf of a power generating asset owner before the Michigan Public Service Commission in the course of a Certificate of Need proceeding in Case No. U-17429; before the Public Utilities Commission of Ohio with regard to the power market forecasts used in a distribution modernization plan in Case No. 18-1875-EL-GRD; before the Public Service Commission of Wisconsin associated with an electric utility's request for a Certificate of Authority to acquire and operate twelve solar facilities in Dockets

6680-CE-182 and 6680-CE-183; and before the Arkansas Public Service Commission, the Louisiana Public Service Commission, and the Public Utility Commission of Texas on behalf of an electric utility's request for various approvals associated with the acquisition of two wind projects and one solar project in Docket No. 22-019-U (Arkansas), Docket No. U-36385 (Louisiana), and Docket No. 53625 (Texas).

Q6. What is the purpose of your direct testimony in this proceeding?

A6. The purpose of my direct testimony is to support NIPSCO's request for a certificate of public convenience and necessity ("CPCN") to construct a natural gas combustion turbine ("CT") peaker plant (the "CT Project") on available property at NIPSCO's R.M. Schahfer Generating Station ("Schahfer") site. Specifically, I (i) provide an overview of NIPSCO's resource planning process and review the conclusions from NIPSCO's resource planning analyses over the last several years, particularly the Integrated Resource Plan submitted November 15, 2021 (the "2021 IRP"); (ii) review major market developments since NIPSCO's submission of the 2021 IRP; (iii) summarize the portfolio analysis that CRA and NIPSCO performed in 2023 based on these major market developments (the "2023 portfolio analysis"); and (iv) describe how the CT Project is consistent with the Short-Term Action Plan identified in the 2021 IRP and supported by the additional analyses NIPSCO has

performed since the submission of the 2021 IRP.

Q7. Are you sponsoring any attachments to your direct testimony?

A7. Yes. I am sponsoring Attachment 7-A, which is the public version of NIPSCO's 2021 IRP, Confidential Attachment 7-B, which is the confidential version of NIPSCO's 2021 IRP, Confidential Attachment 7-C, which is a summary of the key inputs and outputs associated with the 2023 portfolio analysis, and Confidential Attachment 7-D, which is the Flexible Resource Analysis. Each of these attachments was prepared by me or under my direction and supervision.

OVERVIEW OF NIPSCO'S RESOURCE PLANNING PROCESS AND RECENT IRP CONCLUSIONS

Q8. Please provide an overview of the resource planning process that CRA has deployed with NIPSCO over the last several years.

A8. CRA has worked with NIPSCO for approximately six years, implementing an industry-standard approach to resource planning that incorporates a structured review of objectives and metrics, development of market perspectives and NIPSCO portfolio concepts, quantitative modeling and analysis, and an integrated scorecard review of key tradeoffs to support the selection of a preferred portfolio. This process was used in NIPSCO's 2018 and 2021 IRPs.[1]

[1] Integrated Resource Plan submitted October 30, 2018 (the "2018 IRP").

Q9. How have market perspectives been developed in this process, especially with regard to risk and uncertainty evaluation?

A9. CRA and NIPSCO have evaluated risk using scenario-based and stochastic analyses for major market drivers of uncertainty. The major drivers of risk that have been evaluated in the resource planning process include commodity prices; environmental policy, particularly associated with carbon pricing and clean energy tax credits; economic growth, including its impact on electric sector load growth; and renewable intermittency, including uncertainty associated with wind and solar energy production and capacity accreditation. As part of the planning process, scenarios have been structured to assess major changes to specific market driver assumptions, along with related feedbacks, while stochastic inputs have been developed to evaluate volatility and tail risk, particularly in the commodity price markets and for renewable energy output.

Q10. How have NIPSCO's portfolio concepts been developed in the process?

A10. NIPSCO and CRA have developed portfolios through a combination of thematic concept development and least-cost portfolio optimization. This has allowed for a structured review of different plant retirement dates and a comprehensive review of alternative resource replacement strategies with a variety of demand side and supply side resource options. Central to the process has been the

integration of market data from requests for proposals ("RFP") into the IRP analysis.

Q11. Please explain the integration of RFPs within NIPSCO's IRP process in more detail.

A11. Since the 2018 IRP, NIPSCO has conducted RFPs to develop actionable resource cost data to be used in planning analysis that evaluates new resource options. Such integration has the benefit of allowing resource planning assumptions to be informed by real world assets and projects in the market, incorporating changing dynamics over time. As part of this process, CRA and NIPSCO have deployed an approach that translates RFP data into planning-level IRP assumptions that can be transparently shared with stakeholders and deployed in the analytical models.

Q12. What analytical tools and market models have been used in the quantitative modeling of the portfolio concepts against the market perspectives?

A12. As part of all resource planning activities performed with NIPSCO in recent years, CRA has deployed the Aurora model, an electric market forecasting and portfolio tool licensed by Energy Exemplar to evaluate power market outcomes across the Midcontinent Independent System Operator, Inc. ("MISO") region and simulate the performance of various portfolio options for NIPSCO. CRA has also deployed

other analytical tools, including a stochastic input development model, a sub-hourly dispatch model to evaluate the performance of certain resource options, and a financial revenue requirements model.

Q13. How has NIPSCO used an integrated scorecard approach to evaluate portfolio options and select a preferred plan?

A13. As part of its resource planning process, NIPSCO and CRA have compiled the results of portfolio analysis into an integrated scorecard framework that reports a series of key metrics across major planning objectives. NIPSCO's planning objectives have included affordability, rate stability, environmental sustainability, reliability, and impacts to the local economy, while specific metrics have evolved over time in response to changing market dynamics, but have generally included measures of customer cost, cost risk, carbon emissions, resource optionality, reliable and flexible supply, and employee impact. This framework has allowed NIPSCO to assess major tradeoffs and identify preferred portfolios that balance outcomes across the major objectives over time.

Q14. Using this process, what did NIPSCO's 2018 IRP conclude?

A14. NIPSCO's 2018 IRP identified a preferred portfolio that called for the retirement of all four coal units at Schahfer by 2023 and the retirement of the Michigan City

Generating Station ("Michigan City") coal plant by 2028. The preferred portfolio also included capacity replacements made up of energy efficiency and demand side management programs, wind, solar, and solar plus storage capacity. Importantly, the short-term action plan associated with NIPSCO's preferred portfolio explicitly emphasized the need for flexibility, acknowledging that changes in market conditions may occur and that "the preferred plan intentionally leaves room to evaluate market and technology changes on a dynamic basis in order to be flexible and responsive to change."[2]

Q15. From a cost perspective, how did the preferred portfolio from NIPSCO's 2018 IRP compare with the alternatives that were evaluated?

A15. Broadly speaking, across NIPSCO's scenario and stochastic-based retirement analysis, it was determined that the more coal-fired generation that was retained in the portfolio and the longer that it was retained, the more expensive the portfolio was for NIPSCO's customers. This was true across all of NIPSCO's

[2] 2018 IRP, p. 5. NIPSCO's IRP Executive Summary, page 2, also noted that "Changes that affect our plan may arise, which is why it's important for us to remain flexible and continually evaluate current market conditions, the evolution of technology—particularly renewables—and demand side resources, as well as laws and environmental regulations." Section 9.3 on the 2018 preferred portfolio outlined the need to track how resource planning may evolve for non-dispatchable resources and noted that, "By not committing to any single, large asset for the majority of UCAP needs, NIPSCO can flexibly adapt as rules and technologies change" (p. 177) and that "NIPSCO's short-term action plan does not commit to immediately filling the entire 2023 capacity gap but leaves room to evaluate market and technology changes on a dynamic basis." (p. 178)

scenarios, and the full stochastic distribution of uncertainties that was evaluated. It was also determined that the portfolios that included more renewable resources were more cost-effective and less risky than the alternatives.

Q16. Did NIPSCO perform any additional portfolio analysis after the 2018 IRP to evaluate specific renewable resource projects?

A16. Yes. Given evolving market conditions and new information received in the RFPs conducted in 2019, NIPSCO performed portfolio analysis in 2020 ("the 2020 portfolio analysis") as part of its ongoing and periodic review of its generation portfolio. This analysis included updated input assumptions related to NIPSCO's generation portfolio, NIPSCO's load forecast, and market commodity prices, and it also incorporated additional evaluation of renewable resource risk, including changes to solar resource capacity accreditation assumptions over time and the introduction of stochastic renewable output variability within a portfolio risk analysis. The 2020 portfolio analysis demonstrated that when accounting for the latest expectations of NIPSCO's load requirements, commodity market prices, and expected market rules changes, the 2019 RFPs provided sufficient renewable capacity at a competitive cost to confirm the direction of the 2018 IRP's preferred portfolio. Furthermore, the 2020 portfolio analysis highlighted the opportunity to acquire more solar paired with storage capacity to help mitigate risk associated

with solar generation output, market energy prices, and capacity accreditation and to maintain flexibility in the portfolio.

Q17. How did the portfolio conclusions developed in NIPSCO's 2021 IRP compare with the 2018 IRP's preferred portfolio and 2020 portfolio analysis?

A17. As in the 2018 IRP, NIPSCO's 2021 IRP performed a retirement analysis to assess different retirement dates for different elements of the existing fleet. Although the difference in costs between various retirement options was narrower in the 2021 IRP relative to the 2018 IRP due to different portfolio concepts under study, updated commodity price inputs, and updated new resource costs from the 2021 RFP, the IRP continued to affirm that earlier retirement of coal capacity resulted in lower costs for customers. In addition, the 2021 IRP concluded that new additions should be predominantly renewable resources, supplemented by a diverse mix of other technologies, including an uprate to NIPSCO's existing Sugar Creek combined cycle, new thermal peaking capacity, new energy storage capacity, new distributed energy resources ("DER"), and additional demand side management programs. These conclusions were informed by review of all metrics on NIPSCO's integrated scorecard, including cost to customer, scenario and stochastic-based cost risk, carbon emissions, resource optionality, impacts on the local economy, and a comprehensive quantitative reliability assessment, which

included analysis of ancillary services, blackstart requirements, dispatchability, and other technical reliability parameters. Given evolving MISO market rules related to intermittent resource accreditation, seasonal reserve margin planning, and other reliability planning considerations, relative to the 2018 IRP, the 2021 IRP concluded that additional dispatchable resources like thermal peaking capacity and storage were necessary additions to the portfolio.

Q18. Please provide additional detail regarding NIPSCO's assessment of reliability in the 2021 IRP.

A18. NIPSCO took a comprehensive approach to assessing reliability in the 2021 IRP, guided in large part by initiatives being undertaken at MISO. While NIPSCO is not independently responsible for all elements of reliability as a member of MISO, it must be prepared to meet changing market rules and standards. Hence, the 2021 IRP's reliability assessment was guided by three key elements identified in MISO's Renewable Integration Impact Assessment ("RIIA"): Resource Adequacy, Energy Adequacy, and Operating Reliability.[3] As noted in Section 2.3 of the 2021 IRP, several enhancements to NIPSCO's process were made, including an expanded view of resource adequacy across seasons and over time; a broadened stochastic

[3] *See* p. 14 of NIPSCO's 2021 IRP and MISO's summary RIIA report, which can be found here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

analysis to assess renewable output uncertainty; a sub-hourly ancillary services analysis; and an additional Non-Economic Reliability Assessment that analyzed standards and metrics that cannot be quantified via economic analysis alone.

Q19. Please describe the additional Non-Economic Reliability Assessment in more detail.

A19. NIPSCO conducted an additional technical reliability assessment to ensure that the non-economic implications of various portfolio options, particularly regarding compliance with MISO market rules and North American Electric Reliability Corporation ("NERC") standards, were accounted for. As part of the assessment, eight reliability criteria were identified, and different portfolio options were evaluated against each of them. The reliability criteria included blackstart capability, energy adequacy, dispatchability and automatic generation control, operational flexibility and frequency support, volt-ampere reactive (VAR) support or reactive power, geographic location relative to load, predictability and firmness of supply, and short-circuit strength sufficiency.

As outlined in Section 9.2.7 of the 2021 IRP, specific measures for each criterion were developed so that portfolios could be evaluated against each other. NIPSCO's analysis concluded that portfolios that included new thermal resources

(natural gas-fired peakers and combined cycles, including those with hydrogen enablement) scored better on the reliability criteria than portfolios reliant only on new renewables and storage and no new incremental thermal capacity.[4]

Q20. How do the reliability criteria evaluated in NIPSCO's 2021 IRP compare with reliability attributes that NIPSCO may need within its generation portfolio to satisfy NERC and MISO standards and rules in the future?

A20. NIPSCO Witness Austin describes NERC standards and reliability requirements in more detail. Within MISO, the Resource Adequacy Subcommittee ("RASC") is actively evaluating the system attributes that will be required in the future because of the growth in intermittent generation across the MISO footprint. While still in development and under review, in recent months the RASC has identified several system attributes that align well with those NIPSCO evaluated in the 2021 IRP. For example, in October 2022, the RASC published a presentation that noted the importance of key technical attributes like blackstart and detection of short circuit strength and prioritized a set of attributes associated with capacity, energy adequacy, flexibility, and essential reliability services. While specific market rule

[4] *See* Section 9.2.7.6 of NIPSCO's 2021 IRP for the detailed summary of reliability scoring, as well as the technical reliability assessment addendum in IRP Confidential Appendix E (included in Confidential Attachment 7-B).

or design changes have yet to be implemented, these priority attributes are quite consistent with the reliability criteria NIPSCO evaluated within the economic and non-economic assessments that were conducted during the 2021 IRP.

Q21. How do the criteria evaluated in NIPSCO's 2021 IRP compare with the Five Pillars for State energy policy identified by the 21st Century Energy Policy Development Task Force and codified in Ind. Code § 8-1-2-0.6?

A21. The Reliability, Resiliency, and Stability pillars directly relate to the criteria evaluated in NIPSCO's reliability analysis, while all Five Pillars (also including Affordability and Environmental Sustainability) were directly evaluated throughout the 2021 IRP and within NIPSCO's integrated scorecard framework.[5] The Task Force identified reliability as incorporating "adequacy and operating reliability," resiliency as the ability to "withstand and rapidly recover from disruptions," and stability as the "ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances."[6] These various system attributes directly tie to the metrics assessed in the technical

[5] NIPSCO Witnesses Becker and Walter also discuss this topic further.

[6] See Task Force Pillars summary at the Indiana Office of Energy Development site here: https://www.in.gov/oed/indianas-energy-policy/electricity/#:~:text=Indiana's%20electricity%20policy%20is%20laid,%2C%20affordability%2C%20and%20environmental%20sustainability.

reliability assessment and throughout the 2021 IRP. In addition, NIPSCO's integrated scorecard approach included objectives associated with "Reliable, Flexible, and Resilient Supply," "Rate Stability," "Affordability," and "Environmental Sustainability." Thus, both the economic and non-economic components of NIPSCO's 2021 IRP analysis were performed in a manner to arrive at a preferred portfolio and short-term action plan consistent with all Five Pillars identified by the Task Force as set out in Ind. Code § 8-1-2-0.6. NIPSCO Witness Walter speaks more about how NIPSCO keeps these Five Pillars in mind as it operates its current generation fleet and plans for its future generation fleet.

Q22. What were the key elements of the 2021 IRP's short-term action plan?

A22. The 2021 IRP's short-term action plan called for the retirement of the remaining coal units in NIPSCO's fleet, as well as the aging gas peaker units at the Schahfer site, by 2028 and the integration of the wind, solar, and solar plus storage capacity under development from the 2018 IRP. The short-term action plan did not identify an immediate action to implement thermal peaking, storage, renewables, or the Sugar Creek uprate, but it did call for ongoing diligence to evaluate these opportunities to facilitate future specific resource decisions within the IRP's preferred portfolio framework—the exact type of analysis that NIPSCO has undertaken since issuance of the 2021 IRP. The short-term action plan also called

for performing additional RFPs as needed and for continuous monitoring of ongoing changes in MISO market rules, federal and state policy, and new resource technology. As in the 2018 IRP, the 2021 IRP explicitly noted that IRPs are based on a snapshot in time and emphasized the importance of flexibility in the implementation plan, outlining a range of retirement dates for the Michigan City coal plant and the Schahfer 16A/B gas peaker units and a range of MWs for new resource additions depending on technology, policy, and market rules changes. By design, the preferred portfolio was constructed to "preserve flexibility in resource procurement, particularly over the long-term."[7]

Q23. Please provide an overview of NIPSCO's implementation of the 2021 IRP's short-term action plan to date.

A23. Since the submission of the 2021 IRP, NIPSCO has continued to advance in the acquisition of approved renewable projects, with over 800 MW of wind and 465 MW of solar now in service and one additional wind project near completion; has developed a plan to complete the capacity uprate at Sugar Creek in 2023; has

[7] 2021 IRP, p. 260. NIPSCO's Executive Summary, p. 6, also noted specifically that, "Changes that affect our plan may arise, which is why it's important for us to remain flexible and adaptable as we continually evaluate current market conditions, the evolution of technology—particularly energy storage and hydrogen-based technology —and demand side resources, as well as changing laws and environmental regulations."

executed capacity contracts both from the 2021 RFP and to meet short-term capacity requirements; and has conducted additional RFPs to evaluate new resource options, including the CT Project.

FLEXIBLE RESOURCE ANALYSIS

Q24. As part of the short-term action plan, did NIPSCO perform additional analysis after the 2021 IRP was submitted to further assess the reliability attributes of the preferred portfolio?

A24. Yes. As part of the further diligence of the thermal peaker option that was outlined in the 2021 IRP's short-term action plan, CRA worked with NIPSCO to perform a flexibility study to more fully assess the energy adequacy and flexibility characteristics of the IRP's preferred portfolio and to analyze the potential market exposure that could result from increasing reliance on renewable generation. The flexibility study was designed to (i) assess the portfolio's flexibility needs on an inter-hour and intra-hour basis, given the variability and intermittency of renewable resources; and (ii) perform sub-hourly analysis to provide insights into the type of market exposure NIPSCO could face as its portfolio evolves. The flexibility study was conducted to evaluate the risks associated with times of resource unavailability and market purchase exposure. The Flexible Resource Analysis is attached as Confidential Attachment 7-D.

Q25. Which specific metrics were evaluated in the flexibility study?

A25. The flexibility study primarily focused on evaluating NIPSCO's net load and net load ramp requirements. Net load can be defined as NIPSCO's load at any given time, net of solar and wind generation, while the net load ramp can be defined as the change in net load over a specific time period. For example, if NIPSCO customers demand 1,500 MW at a given point in time while 1,000 MW of wind and solar are generating, the net load would be 500 MW. If three hours later, customers demand 1,600 MW, while only 900 MW of wind and solar are generating, the net load would increase to 700 MW, and a 200 MW net load ramp would be required over that three-hour time period. The flexibility study was designed to measure these values at a sub-hourly granularity and compare them to NIPSCO's available dispatchable capacity. Particular attention was paid to the frequency and duration of events where the net load was simulated to be greater than available dispatchable capacity.

Q26. How do these metrics relate to those being considered by MISO's RASC?

A26. MISO's RASC has highlighted these metrics as important ones to consider as questions around reliability evolve. For example, in its April 2023 meeting, the RASC identified the need to evaluate flexibility and long-term duration energy

when assessing planning adequacy and called out ramping and long-duration capacity attributes in a review of operational analysis of resource adequacy.[8]

Q27. What were the key inputs to the flexibility study, and how were they developed?

A27. Given the flexibility study's focus on the frequency and duration of net load exposure events, uncertainty distributions for NIPSCO load, solar generation, and wind generation were the key inputs. Historical load, wind generation, and solar generation data were used to develop stochastic distributions for each key input at the sub-hourly level of granularity. Statistical simulation methodologies were deployed to simulate the stochastic nature of the key variables and account for seasonal variability and other weather variables like cloud cover for solar output. A single sample year of 2030 was evaluated to assess a range of potential net loads and compare them to the amount of dispatchable capacity identified in NIPSCO's preferred portfolio from the 2021 IRP. This comprised approximately 1,200 MW of dispatchable capacity and included NIPSCO's Sugar Creek combined cycle

[8] *See* slides 9 and 10 in the presentation on "Identification of Sufficient System Reliability Attributes" from the MISO RASC meeting from April 18, 2023: https://cdn.misoenergy.org/20230418-19%20RASC%20Item%2007%20Identification%20of%20Resource%20Attributes628503.pdf.

plant and new peaker and storage capacity associated with projects either under development or part of the 2021 IRP's preferred portfolio.

Q28. What were the key findings of the Flexible Resource Analysis?

A28. The Flexible Resource Analysis identified the following major conclusions:

- Given the increase in solar generation planned for NIPSCO's portfolio, net load exposure will shift to the evenings, while 3-hour ramp needs will be greatest as the sun sets.
- Across a wide distribution of potential load, wind, and solar uncertainty, the 2021 IRP's preferred plan for approximately 1,200 MW of flexible capacity by 2030 would be insufficient to meet net load and 3-hour ramp requirements in extreme conditions without reliance on the market.
- Additional flexible, dispatchable capacity resources could mitigate the number of potential hours of market exposure. The analysis concluded that even 100-200 MW of additional flexible capacity relative to the 2021 IRP's preferred portfolio could cut the number of hours of potential market exposure by half to two-thirds, thereby protecting customers from market risk.

- While the large majority of periods of market exposure are likely to be less than an hour, a few dozen events of longer than four hours were identified, suggesting that incremental flexible capacity of long-duration would help mitigate customers' market exposure risk. Thermal peaking capacity offers such long-duration flexible capacity, while battery storage projects can be technology-limited.

Overall, although the 2021 IRP's preferred portfolio, which included a new 300 MW thermal peaker capacity addition, was designed to meet current MISO market rules and capacity planning requirements, the Flexible Resource Analysis identified potential future risks associated with energy adequacy and resource flexibility. It concluded that more flexible, long-duration dispatchable capacity than the 300 MW natural gas peaker and 135 MW battery storage included in the preferred portfolio could help mitigate those risks. It was this additional need that contributed to NIPSCO increasing the size of the CT Project from approximately 300 MW to approximately 400 MW, as discussed by Witness Warren. Additionally, as explicitly acknowledged in NIPSCO's 2021 IRP, "[i]t is important to remember that this preferred portfolio as part of the 2021 IRP is a snapshot in

time and while it establishes a direction for NIPSCO, it is subject to change as the external operating environment changes."[9]

ADDITIONAL DEVELOPMENTS SINCE THE SUBMISSION OF NIPSCO'S 2021 IRP

Q29. What major developments in the policy, technology, and regulatory landscape have occurred since NIPSCO's submission of its 2021 IRP?

A29. Four major developments have occurred since the 2021 IRP submission: (i) MISO's seasonal resource adequacy construct was formally approved by the Federal Energy Regulatory Commission ("FERC") at the end of August 2022; (ii) the Inflation Reduction Act ("IRA") was passed by Congress and signed into law by President Biden in August 2022; (iii) supply chain constraints, tariff uncertainty, and inflationary cost pressures have delayed some of NIPSCO's solar projects and put the completion of others at risk; and (iv) NIPSCO has conducted additional RFPs with CRA to assess the latest market data for new resource costs. The first and fourth of these have the most direct impact on NIPSCO's proposal in this proceeding.

[9] 2021 IRP at Section 9.3.1; *see also* Section 1.2 ("It is important to note that the IRP is a snapshot in time, and while it establishes a direction for NIPSCO, it is subject to change as the energy landscape continues to evolve.") and Section 4.2 ("The IRP is an imperfect snapshot in time []... As always, NIPSCO will continue to monitor the markets and make adjustments as necessary.").

Q30. Please explain the FERC decision related to MISO's seasonal resource adequacy construct further.

A30. On August 31, 2022, in Docket No. ER22-495, FERC approved MISO's request to transition to a seasonal resource adequacy construct, which requires load serving entities to have sufficient capacity to meet peak load requirements across four distinct seasons. This means that instead of planning only for a single summer peak, NIPSCO must now ensure sufficient capacity is available during all seasons of the year. The seasonal construct has different reserve margin targets for each of the four seasons, and the capacity accreditation of NIPSCO's resources will vary by season. For example, although NIPSCO's peak load is significantly higher in the summer relative to the winter, MISO's winter reserve margin target is higher in the winter than the summer, and certain resource types like solar receive lower capacity accreditation in the winter relative to the summer. Thus, the new rules require dynamic planning across all seasons to reflect resource tradeoffs and ensure system reliability.

Q31. Did NIPSCO's 2021 IRP contemplate the potential for this rule change?

A31. Yes. NIPSCO's 2021 IRP anticipated FERC approval of MISO's change to a seasonal construct.[10] In the 2021 IRP, winter and summer peak load projections were developed as part of NIPSCO's demand forecast; seasonal capacity ratings for new utility-scale generation resource options, DERs, and demand side management measures were estimated; and the portfolio development process relied on least-cost optimization analysis for both the winter and summer seasons. Several new details regarding seasonal reserve margin targets and seasonal accredited capacity levels have since been published after the FERC approval,[11] but NIPSCO's 2021 IRP preferred portfolio was developed to meet resource adequacy requirements generally consistent with the market redesign that FERC approved.

Q32. What additional market information has NIPSCO acquired regarding trends in technology costs since the 2021 IRP?

A32. As described in further detail by NIPSCO Witness Baacke, CRA worked with NIPSCO to conduct multiple RFPs during 2022 to identify the costs and availability of resource options to fulfill the 2021 IRP's short-term action plan and

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[10] *See, e.g.*, 2021 IRP, pp. 13-15, Section 4.5, Section 8.2.4, Section 9.2, and Section 9.3 (including p. 262).

[11] For example, the winter reserve margin for the 2023/24 MISO planning year was set at 25.5%, with the summer planning reserve margin set at 7.4%.

to respond to changing market conditions, including an RFP for a gas-fired generation resource. The RFPs provided actionable resource cost data that incorporates the latest policy, technology, and macroeconomic information. Overall, the results of the RFPs confirmed that solar costs have escalated and that wind resource costs are more competitive given the tax credit provisions in the IRA. The RFPs also provided information related to the latest costs of storage resources and the viability of alternative natural gas peaker options.

2023 PORTFOLIO ANALYSIS

Q33. Has NIPSCO performed updated portfolio analysis to assess the impacts of the various developments on the implementation of its preferred plan?

A33. Yes. CRA worked with NIPSCO to perform the 2023 portfolio analysis (Confidential Attachment 7-C) to support near-term resource decisions using the latest market information. Similar to the 2020 portfolio analysis that reviewed NIPSCO's short-term action plan between the 2018 and 2021 IRPs, NIPSCO's 2023 portfolio analysis evaluated portfolio options with the benefit of the insights from the flexibility analysis, while using the latest technology cost information from the 2022 RFPs along with updated market and policy assumptions.

Q34. What changes to NIPSCO's resources and other market conditions were made in this 2023 portfolio analysis relative to the 2021 IRP?

A34. The following changes were made:

- Near-term adjustments to NIPSCO's generation resource portfolio were made to update project costs, purchase power agreement prices, and online dates for new solar and solar plus storage resources and the retirement date for Schahfer Units 17 and 18.[12] In addition, for modeling purposes, the retirement date for Michigan City 12 was set to 2028.[13] The latest NIPSCO plant capacity ratings and other operational parameters for NIPSCO's existing resources were also incorporated.
- The latest information associated with MISO's seasonal resource adequacy construct as of the time of the analysis, including seasonal capacity accreditation for intermittent resources and seasonal planning reserve margin targets, was incorporated.
- Commodity price inputs were updated to reflect the latest outlooks for natural gas and coal prices, the regional capacity mix across MISO, and the resulting power prices.

[12] In 2022, because of delays in solar project online dates, NIPSCO announced that the retirement date for Schahfer Units 17 and 18 would be extended through 2025.

[13] The 2021 IRP's short-term action plan noted that Michigan City 12 would be retired between 2026 and 2028. NIPSCO will continue to assess retirement timing as market conditions evolve.

- New resource costs were updated based on responses to NIPSCO's 2022 RFPs. As NIPSCO has done in past IRPs and portfolio analyses, RFP bids were aggregated into tranches according to resource type and ownership structure for use in the portfolio modeling.

- Clean energy and storage tax credit extensions as outlined in the IRA were incorporated for new NIPSCO resource options. This included 10-year extensions for the Production Tax Credit ("PTC") and Investment Tax Credit ("ITC"), extension of the ITC to stand-alone storage projects, and bonus credit eligibility for projects sited in "energy communities."[14]

Q35. What portfolio concepts were evaluated in the 2023 portfolio analysis?

A35. NIPSCO and CRA ultimately developed three distinct portfolio options for evaluation based on the updated market and portfolio conditions, leveraging the portfolio themes that were analyzed in the 2021 IRP. These included:

[14] The IRA awards a 10% bonus (a 10% adder to the ITC or a 10% increase in the PTC level in $/MWh) if a project is located within a newly defined "energy community." Energy communities are (i) census tracts containing, or adjoining to tracts containing, retired coal mines or coal-fired electric generating units; (ii) areas with historical employment in fossil industries and a higher unemployment rate than the national average; or (iii) properties with the potential presence of hazardous substances, pollutants, or contaminants. NIPSCO and CRA evaluated site locations for new projects and RFP bid information to identify energy community qualification assumptions for planning purposes.

- Portfolio 1: An update to 2021 IRP Portfolio E,[15] adjusted for the latest MISO seasonal resource adequacy construct and the results from the 2022 RFPs;
- Portfolio 2: An update to 2021 IRP Portfolio F,[16] adjusted for the latest MISO seasonal resource adequacy construct and the results from the 2022 RFPs; and
- Portfolio 3: A modification to Portfolio 2 incorporating the potential loss of four out of ten (or 700 MW of solar and 30 MW of storage) of NIPSCO's current solar and solar plus storage projects,[17] with replacement capacity based on the results from the 2022 RFPs.

Q36. What resource additions were included in each of the three portfolio concepts, and how do they compare to the additions incorporated in the 2021 IRP?

[15] Portfolio E included primarily storage and renewable resource additions with no new thermal capacity additions aside from short-term capacity contracts.

[16] Portfolio F was the 2021 IRP's preferred portfolio and included a mix of storage, renewable, and thermal peaking capacity.

[17] The assumptions in Portfolio 3 were not developed around predictions regarding any specific project cancellation; instead, they acknowledged the reality that NIPSCO's solar projects are currently facing challenges associated with global supply chain constraints, increasing costs, tariff risk, and zoning and permitting challenges. NIPSCO determined that a portfolio alternative with four projects canceled would reasonably represent the risks associated with its ten current projects and allow for an evaluation of alternatives based on the 2022 RFP results and the latest market conditions. Consistent with these initial assumptions, NIPSCO filed notices of termination for the Greensboro PPA, Gibson PPA, Brickyard PPA, and Elliott BTA in July 2023.

A36. Thematically, the resource additions were similar to those incorporated in the 2021 IRP's portfolio analysis, although adjustments were made as a result of the latest information associated with MISO's seasonal resource adequacy construct, IRA tax credits, and resource costs from the 2022 RFPs. For example, the assumption for MISO's winter planning reserve margin was set at 25.5% to reflect the 2023/24 planning year targets, a level that is higher than the assumption used in the 2021 IRP, meaning more winter resource capacity was required in the updated portfolio analysis.[18] In addition, the 2022 RFP results revealed higher costs for solar projects, likely due to the factors described above; additional wind options at competitive costs, likely a result of the IRA's extension of the production tax credit; and updated cost and project size information for storage and thermal peaking options.[19]

As a result of these updates, new wind resources were found to be more economic than new solar resources, and, importantly, larger amounts of dispatchable

[18] Note that during the winter season, solar resources were assumed to be accredited at approximately 6% of nameplate capacity, wind resources at 25% of nameplate capacity, storage resources at a rate declining from 90% to 70% over time, and thermal peaking resources at nameplate capacity derated for forced outage.

[19] One of the 2022 RFP events solicited dispatchable, blackstart capable resources at NIPSCO's existing Schahfer site. It was based on utilization of the MISO generator replacement interconnection process and requested 370-450 MW (UCAP). The capacity size request was larger than the 300 MW thermal peaker addition incorporated in NIPSCO's preferred portfolio from the 2021 IRP in part due to the key conclusions identified in the Flexible Resource Analysis (Confidential Attachment 7-D).

thermal or storage capacity were identified to meet NIPSCO's winter reserve margin needs relative to the levels evaluated in NIPSCO's 2021 IRP. Thus, the updated portfolio concepts included more wind capacity, less solar capacity, and more thermal peaking or storage capacity relative to the 2021 IRP portfolio concepts. In addition, since Portfolio 3 assumed that NIPSCO loses four of its currently planned near-term solar projects, additional incremental capacity relative to Portfolios 1 and 2 was incorporated. The table below summarizes the key portfolio attributes and resource additions by category for the three portfolio concepts.

#	2021 IRP Portfolio Theme	Current Solar Portfolio	Schahfer 17/18 Retirement	Michigan City 12 Retirement	New Gas	2026-2028 Solar	2026-2028 Storage	2026-2028 Wind	2030+
1	Portfolio "E"	Retain ***ALL*** solar projects	Sep 2025	May 2028	None	None	650 MW	200 MW	800 MW solar 350 MW storage
2	Preferred Portfolio "F"	Retain ***ALL*** solar projects	Sep 2025	May 2028	400 MW peaker	None	150 MW	200 MW	800 MW solar 300 MW storage
3	Preferred Portfolio "F" Adjusted for lost solar	Lose four current projects	Sep 2025	May 2028	442 MW peaker	200 MW	125 MW	400 MW	800 MW solar 450 MW storage

Q37. Was a gas conversion at one of NIPSCO's existing coal units considered as an option instead of a new gas peaker?

A37. NIPSCO evaluated the potential conversion of one or two units at its Schahfer plant in its 2018 IRP. The analysis found that conversion was higher cost than the

alternatives.[20] In addition, a refueled Unit 17 or 18 would not possess the fast-start/quick-ramping and reliability characteristics of a peaking facility that either the 2021 IRP or the 2023 portfolio analysis called for. As a result, conversion of existing coal units to gas is not a viable option in NIPSCO's 2021 IRP or in the 2023 portfolio analysis.[21]

Q38. What analysis was performed on these three portfolio concepts?

A38. CRA and NIPSCO performed detailed portfolio dispatch analysis and developed revenue requirement projections over a 30-year planning horizon in the same fashion as in the 2021 IRP. The analysis was performed with the latest market updates as described above.

Q39. What did the analysis conclude regarding the net present value of revenue requirements ("NPVRR") for each of the portfolio options?

A39. The figure below provides a summary of the 30-year NPVRR for the three portfolio options, indicating that Portfolio 3 was found to have the lowest costs, with Portfolio 2 having slightly higher costs.

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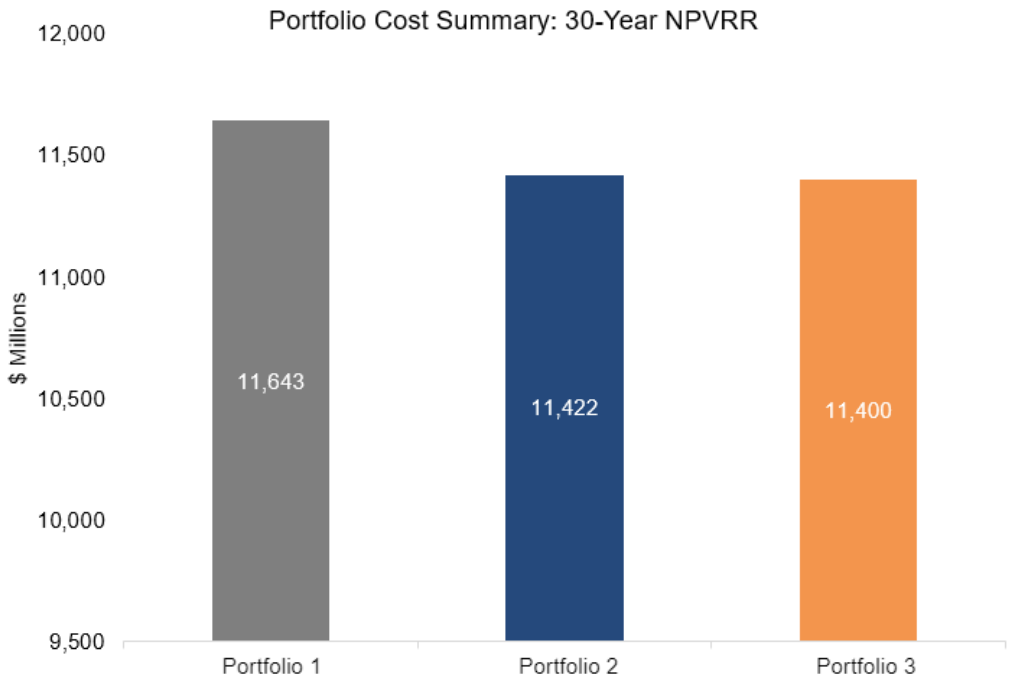
[20] *See* Sections 4.10.5 and 9.1.7 of NIPSCO's 2018 IRP. Section 4.10.5 noted that "Ultimately, the analysis showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the All-Source RFP results and replacing both units would cost customers at least $540 million more."

[21] NIPSCO Witness Walter discusses additional issues with a potential gas conversion.



Overall, the analysis arrived at two major conclusions:

- Similar to the results from the 2021 IRP, a portfolio with predominantly new storage additions and no new thermal peaking capacity (Portfolio 1) was found to be more costly than one that incorporates a gas peaker and only the most attractive storage projects (Portfolio 2). While these conclusions will be influenced by future uncertainties regarding ancillary services value, energy community bonus qualification, and other factors, the latest RFP information indicates that relying solely on storage additions for new dispatchable capacity needs is higher cost, even after incorporating IRA tax credits. This is largely due to the fact that a gas peaker resource is likely to

have significantly stronger capacity accreditation relative to a four-hour storage resource over time. In NIPSCO's 2021 IRP and in the 2023 portfolio analysis, the effective load carrying capability ("ELCC") of four-hour duration storage was assumed to decline to 70% by 2040, meaning that every 100 MW of storage capacity would only be accredited 70 MW for capacity planning purposes.[22] Meanwhile, a gas peaker is likely to have a stable ELCC around 95%. Furthermore, as summarized in the 2021 IRP, thermal peaking capacity provides additional reliability benefits.[23]

- NIPSCO has an opportunity to slightly pivot its portfolio towards more wind and a larger peaker relative to the 2021 IRP's preferred portfolio, particularly given the cancellation of some of NIPSCO's solar projects.[24] This pivot can provide cost savings to customers, as higher-cost solar projects that do not provide significant winter capacity accreditation are

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[22] Recent MISO analysis is supportive of the expectation that the capacity accreditation or ELCC of four-hour duration storage will decline over time as the amount of storage in the market increases and as the timing and duration of high-risk periods changes with the influx of intermittent generation. For example, MISO's recent (April 2023) assumptions documentation for its long-range transmission planning ("LRTP") analysis includes an expectation for storage ELCC to decline to 75% by 2037. (See p. 4 here: https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf.) In addition, MISO's RIIA report projected a decline in storage ELCC to 64% with 30 GW (ICAP) of storage capacity in the system, declining to as low as 19% with 100 GW (ICAP) of storage capacity. (*See* Figure RA-32 here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

[23] *See* Section 9.2.7 in the 2021 IRP. This topic is addressed further by NIPSCO Witness Austin.

[24] *See supra* footnote 17.

replaced by more cost-effective wind energy and thermal peaking and storage capacity.

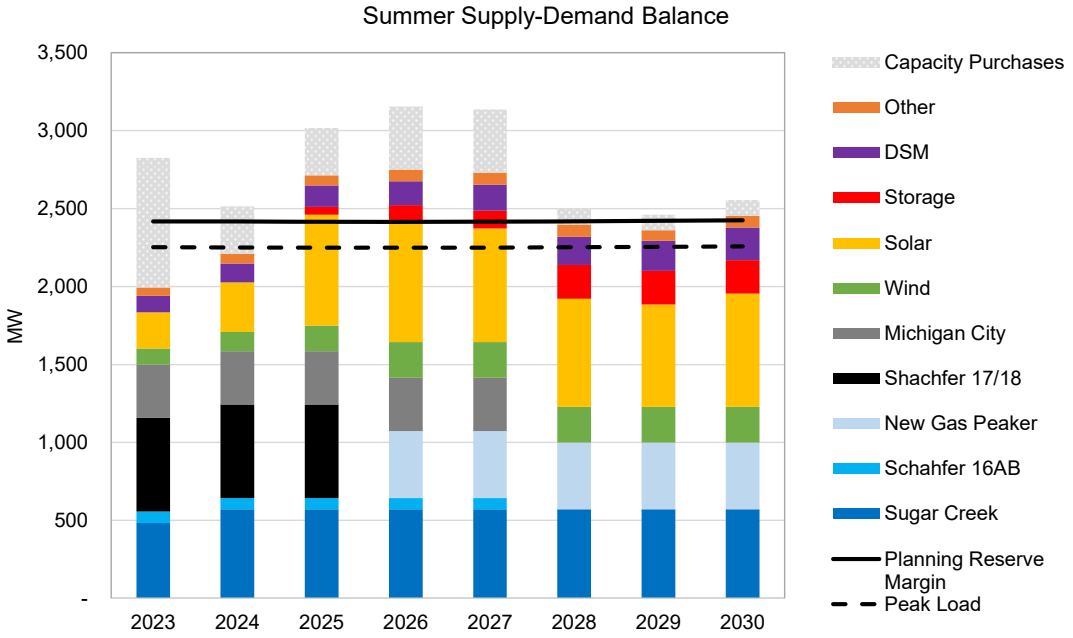
Q40. Please summarize the key components of this modified preferred portfolio relative to the 2021 IRP.

A40. NIPSCO's preferred portfolio now incorporates the cancellation of approximately 700 MW of solar (plus 30 MW of paired storage) out of approximately 2,400 MW of total solar and storage capacity, meets winter and summer reserve margins, and remains balanced from an energy perspective by pivoting towards more wind, some incremental solar, new storage, and an upsized thermal peaker plant. Through 2028, the preferred portfolio includes incremental capacity additions totaling 200 MW of solar, up to 400 MW of wind, between 400 and 442 MW of thermal peaking capacity,[25] and between 125 and 150 MW of new storage capacity. Relative to the 2021 IRP's preferred portfolio, larger capacity additions for wind and thermal peaking capacity are incorporated, while storage and new solar additions are comparable.[26] In addition, the same DSM, DER, Sugar Creek uprate,

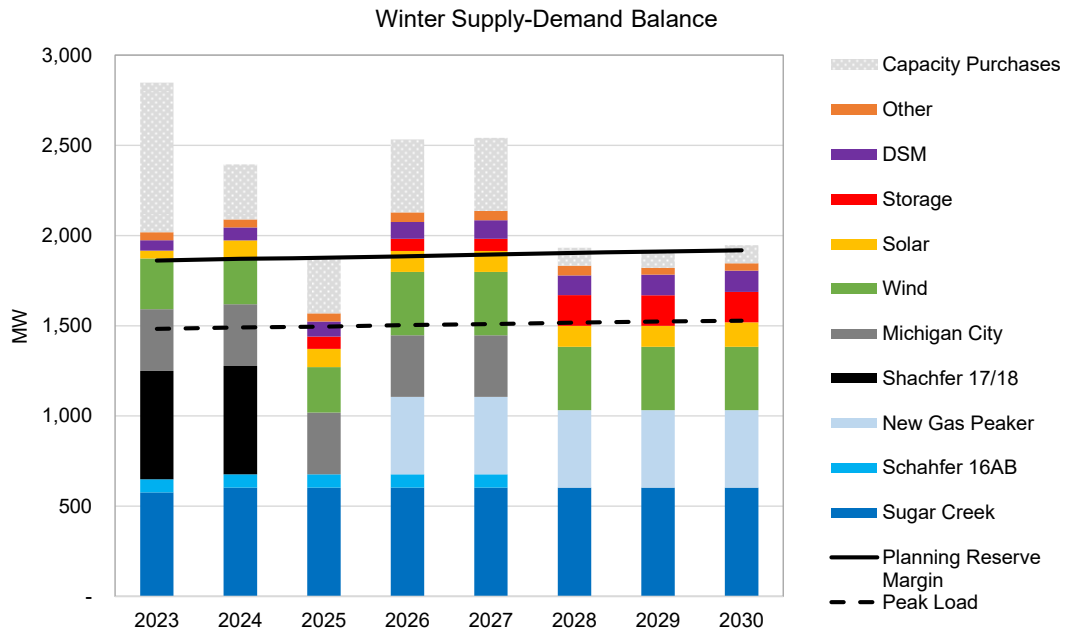
[25] Note that NIPSCO's 2023 portfolio analysis included gas peaker additions of 400 MW and 442 MW to cover a range of RFP bids. The current proposal for approximately 400 MW falls within this range.

[26] The updated preferred portfolio from the 2023 portfolio analysis includes 200 MW of new solar, which is consistent with the near-term solar additions contemplated in the 2021 IRP. However, as noted, the updated preferred portfolio contemplates the cancellation of several *existing* planned solar projects.

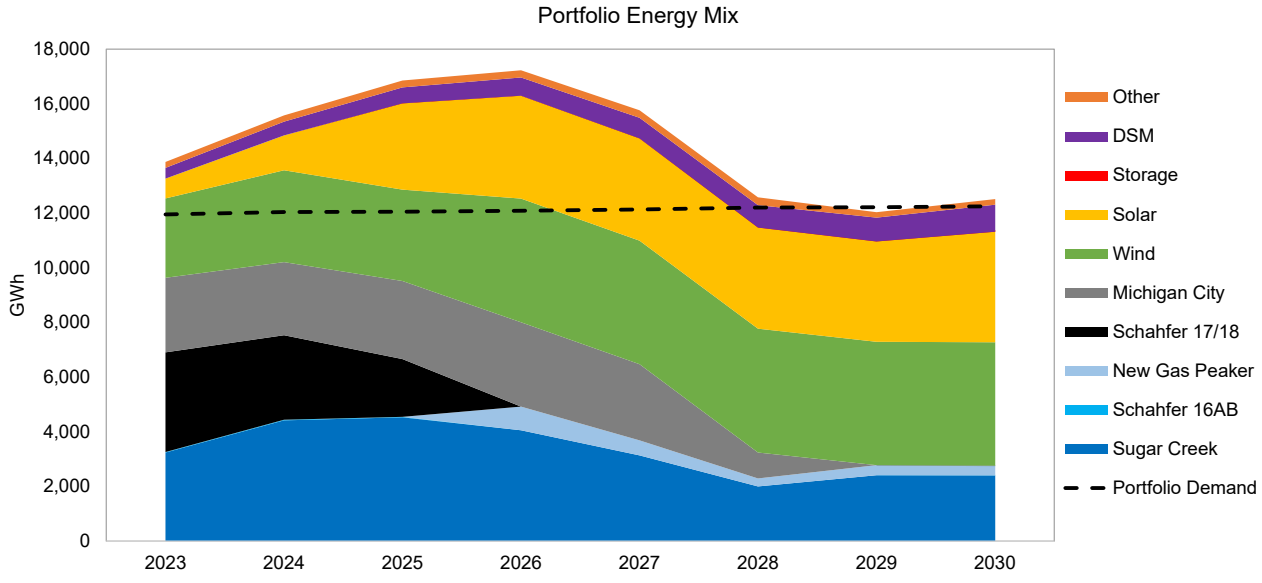
and short-term capacity contracts are included. The graphics below show the summer and winter supply-demand balances[27] and anticipated annual energy contributions by resource relative to NIPSCO's load requirements.



[27] Note that the "Capacity Purchases" block includes capacity contracts NIPSCO has already entered into (such as a ten-year, 100 MW purchase that was part of the 2021 IRP's preferred portfolio and procured from the 2021 RFP) plus additional short-term capacity blocks based on the information from the 2022 RFPs. NIPSCO's year-to-year capacity procurement strategy will be dependent on annual portfolio and market conditions and may vary somewhat from what has been modeled.


Winter Supply-Demand Balance
MW
3,000
2,500
2,000
1,500
1,000
500
-
2023
2024
2025
2026
2027
2028
2029
2030
Capacity Purchases
Other
DSM
Storage
Solar
Wind
Michigan City
Shachfer 17/18
New Gas Peaker
Schahfer 16AB
Sugar Creek
Planning Reserve Margin
Peak Load

1


Portfolio Energy Mix
GWh
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2023
2024
2025
2026
2027
2028
2029
2030
Other
DSM
Storage
Solar
Wind
Michigan City
Schahfer 17/18
New Gas Peaker
Schahfer 16AB
Sugar Creek
Portfolio Demand

2

PEAKER COST AND OPERATIONAL PERFORMANCE COMPARISONS

Q41. Are the key cost and operational characteristics of a gas peaker evaluated in the 2023 portfolio analysis consistent with the specific cost and operational characteristics expected for the CT Project?

A41. Yes. From a portfolio analysis perspective, the capital cost and the efficiency, or heat rate, of a gas peaker are the key drivers of its performance, and the assumptions used in the 2023 portfolio analysis are consistent with NIPSCO's current expectations.

Q42. What specific assumptions were used for the new thermal peaker capacity that was part of the preferred portfolio in the 2023 portfolio analysis?

A42. Based on bids received in the 2022 RFP, the thermal peaker resource incorporated in the preferred portfolio from the 2023 portfolio analysis had an assumed all-in direct capital cost of $1,440/kW and a heat rate of 9,450 Btu/kWh (HHV). The all-in direct capital cost includes assumed allowance for funds used during construction ("AFUDC").

Q43. How do these compare to the cost and operational expectations of the CT Project?

A43. The direct cost estimate, inclusive of AFUDC, for the CT Project is currently estimated to be $560,053,449, which is $1,400/kW for approximately 400 MW. The

expected heat rate of the CT project is 9,746 Btu/kWh (HHV), as documented in more detail by NIPSCO Witness Warren. Both of these cost and performance expectations are consistent with what was assumed in the 2023 portfolio analysis.

CONSISTENCY WITH THE 2021 IRP

Q44. How does the relief requested in this proceeding support the conclusions of NIPSCO's 2021 IRP and short-term action plan, as well as the subsequent analyses undertaken by NIPSCO?

A44. The operational and cost characteristics of the CT Project are fully consistent with the assumptions for new peaking thermal resources used in the 2023 portfolio analysis, which developed a preferred portfolio with between 400 MW and 442 MW of new nameplate thermal peaking capacity additions in the near-term. Meanwhile, NIPSCO's Flexible Resource Analysis (Confidential Attachment 7-D) concluded that increasing the amount of long-duration dispatchable capacity above the 300 MW identified in NIPSCO's 2021 IRP will contribute to risk mitigation for customers, and the 2023 portfolio analysis demonstrated that NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by pivoting towards a larger-sized, cost-effective thermal resource (as compared to more expensive storage additions). Overall, the CT Project will serve to ensure key Indiana Energy Task Force pillars like the reliability and resiliency

of NIPSCO's electric operations are met, provide stronger capacity accreditation under MISO's new seasonal resource adequacy construct, and provide a hedge against high energy market pricing in a growing number of days.

Q45. Please elaborate on the benefits that are expected from the CT Project in terms of both capacity accreditation and hedging against high energy market prices.

A45. The CT Project is expected to provide a firm source of capacity for NIPSCO's portfolio, while alternatives like storage are likely to have declining capacity accreditation over time as a result of their limited duration and the changing MISO capacity mix. Furthermore, with the implementation of the four-season construct discussed above, NIPSCO's planning reserve margin requirement in the winter increased significantly. Thus, the addition of a thermal resource, which has a much better year-round capacity accreditation than all other alternatives, is a key part of NIPSCO's generation portfolio.

With regard to hedging against high energy market prices, NIPSCO's Flexible Resource Analysis (Confidential Attachment 7-D) concluded that additional flexible capacity resources relative to the 2021 IRP's preferred portfolio could cut the number of hours of potential market exposure by half to two-thirds. Furthermore, given that the analysis identified the potential for market exposure

events of longer than four hours, long-duration dispatchable resources like the CT Project are positioned to provide the best hedge against the risk of high MISO market energy prices.

Overall, the addition of the CT Project to NIPSCO's portfolio is fully supported by and consistent with the conclusions of NIPSCO's Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP.

Q46. Does this conclude your prefiled direct testimony?

A46. Yes.

VERIFICATION

I, Patrick N. Augustine, Vice President, Charles River Associates, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Patrick N. Augustine

Dated: September 12, 2023

Attachment 7-A
[Public version of 2021 IRP - Filed separately]

Confidential Attachment 7-B (Redacted)

Confidential Attachment 7-C (Redacted)

Confidential Attachment 7-D (Redacted)