# 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 nearly seven years and have worked in the energy consulting industry for over sixteen 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 to purchase and acquire (indirectly through joint venture structures) in (1) Cause No. 45462 for a (a) 265 megawatt ("MW") solar joint venture (the Bridge I Project), (b) 435 MW solar and 75 MW energy storage joint venture (Bridge II Project), and (c) 200 MW solar and 60 MW energy storage joint venture (the Cavalry Project); (2) Cause No. 45511 for a 250 MW solar joint venture (the Fairbanks Project); (3) Cause No. 45524 for a 200 MW solar joint venture (the Crossroads Solar Project); (4) Cause No. 45529 for a 200 MW solar joint venture (the Elliott Project); (5) Cause No. 45194 for a 102 MW wind joint venture (Rosewater Project); and (6) Cause No. 45310 for a 302 MW wind joint venture (Crossroads Wind 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 Crossroads Wind II LLC; (2) Cause No. 45489 with Gibson Solar LLC; (3) Cause No. 45472 with Green River Solar, LLC; (4) Cause No. 45403 with (a) Brickyard Solar, LLC, and (b) Greensboro Solar Center, LLC; (5) Cause No. 45195 with Jordan Creek Wind Farm LLC; and (6) Cause No. 45196 with Roaming Bison Wind Farm LLC. I also provided testimony before the Commission in NIPSCO's last electric rate case in 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 testimony is to (i) provide an overview of NIPSCO's resource planning process, including the overall approach and quantitative analysis methodology; (ii) review the conclusions from NIPSCO's resource planning analyses over the last five years, including the Integrated Resource Plans submitted in 2018 and 2021 (the "2018 IRP" and "2021 IRP");[1] and (iii) describe the most recent generation portfolio analysis that NIPSCO has conducted in the context of recent market and portfolio developments.

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

A7. Yes. I am sponsoring Attachment 12-A, which is Section 9 – Portfolio Analysis of NIPSCO's 2021 IRP, as well as Confidential Attachment 12-B, which is a summary of the key inputs and outputs from additional modeling analysis CRA performed for NIPSCO in 2022, both of which were prepared by me or under my direction and supervision.

## OVERVIEW OF NIPSCO'S RESOURCE PLANNING PROCESS

**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 five 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

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[1] The public version of NIPSCO's Integrated Resource Plan submitted to the Commission on November 15, 2021 can be found at NIPSCO 2021 Integrated Resource Plan.

tradeoffs to support the selection of a preferred portfolio pathway. This process was used in NIPSCO's 2018 and 2021 IRPs.

**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 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 all IRP 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. What portfolio cost elements are incorporated in the financial revenue requirements model?**

A13. The financial revenue requirements model incorporates all generation-related cost components that comprise the costs faced by customers. This includes the variable costs of operation that are incorporated in the Aurora dispatch analysis, such as fuel, variable operations and maintenance ("O&M") costs, emissions costs, and net market purchases and sales with MISO; fixed O&M costs associated with existing or new resources; market capacity purchases, as applicable; and recovery of and on invested capital for existing and new resources, as well as associated income taxes. The financial model that CRA and NIPSCO have used thus allows for review of generation revenue requirements over time and through a net present value perspective. While input assumptions have evolved over time, and while

CRA and NIPSCO have incorporated different market perspectives and new portfolio concepts in response to changing market conditions, CRA has worked with NIPSCO to evaluate portfolio options and their expected cost impacts in a consistent fashion over the last five years.

**Q14. Which of these cost elements are part of the base rates that are at issue in this proceeding?**

A14. The recovery of and on invested capital is core to NIPSCO's base rate, while other O&M costs, fuel costs, and net market power purchases costs based on interactions with the MISO energy market are paid for by customers through NIPSCO's fuel adjustment clause. Additionally, as discussed by NIPSCO Witness Campbell, NIPSCO is proposing to recover a base level of capacity costs through base rates, while utilizing the Resource Adequacy tracker to credit or charge customers for any changes to actual costs incurred. Finally, NIPSCO Witness Whitehead discusses and supports a newly proposed tracker to recover non-labor, variable O&M costs associated with NIPSCO's coal-fired generation.

**Q15. How has NIPSCO used an integrated scorecard approach to evaluate portfolio options and select a preferred plan?**

A15. As part of its resource planning process, NIPSCO and CRA have compiled the results of the 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.[2] This framework has allowed NIPSCO to assess major tradeoffs and identify preferred portfolios that balance outcomes across the major objectives over time.

## NIPSCO'S INTEGRATED RESOURCE PLANNING ANALYSES SINCE 2018

**Q16. Please provide an overview of NIPSCO's preferred portfolio from the 2018 IRP.**

A16. NIPSCO's preferred portfolio called for the retirement of all four coal units at the R.M. Schahfer Generating Station ("Schahfer") by 2023 and the retirement of the Michigan City Generating Station ("Michigan City") coal plant in 2028. The

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[2] NIPSCO's portfolio analysis has evaluated retirement and replacement options in distinct phases, with individual scorecards for each phase. While the overall objectives are constant across phases, the specific metrics have been slightly different. For example, see Figure 9-4 and Figure 9-16 from NIPSCO's 2021 IRP (included in Attachment 12-A), which contain the Existing Fleet Analysis and Replacement Analysis scorecards, respectively.

preferred portfolio also included capacity replacements made up of energy efficiency and demand side management programs, wind, solar, and solar plus storage capacity. Section 9.3 of the 2018 IRP provides additional detail associated with the preferred replacement portfolio. 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."[3]

**Q17. From a cost perspective, how did NIPSCO's preferred portfolio compare with the alternatives that were evaluated?**

A17. 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

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[3] 2018 IRP, p. 5. See also the Executive Summary, which noted that "[c]hanges 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" and Section 9.3 on the Preferred Portfolio, which outlined the need to track how resource planning may evolve for non-dispatchable resources and which noted that, "[b]y 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 "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)

portfolio was for NIPSCO's customers. This was true across all NIPSCO's 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. Overall, although the new renewable additions were expected to add power purchase agreement expenses and capital expenditures to the portfolio, particularly in the short-term, such cost increases were projected to be offset by the avoidance of significant environmental control-related capital expenditures for the coal fleet, as well as reduced fuel and O&M expenses over the long-term. Thus, as NIPSCO seeks to include recovery of and return on the renewable generation additions in this case, it is not unexpected that this yields an increase in rates. These investments are necessary to realize long-term savings as NIPSCO's generation portfolio transitions.

**Q18. Please provide an overview of the 2018 IRP's Short-Term Action Plan and NIPSCO's implementation to date.**

A18. In the Short-Term Action Plan, which is detailed in Section 9.4 of the 2018 IRP, NIPSCO identified a phased approach to selecting and acquiring replacement resources needed to fill its anticipated capacity gap. The plan called for initially prioritizing replacement resources with expiring or declining tax credits from the All-Source RFP that was conducted as part of the 2018 IRP,[4] followed by additional RFPs (the "Phase II RFPs") to acquire resources to fill the remainder of the supply requirement.[5] In 2019, 2020, and 2021, NIPSCO requested approvals to either purchase and acquire or enter into power purchase agreements with multiple wind, solar, and solar plus storage projects. As part of its implementation of the 2018 IRP Short-Term Action Plan, two of the four coal units at the Schahfer station have retired, three wind projects are now in service, and additional wind, solar, and solar and storage projects are in various stages of development.

**Q19. Did NIPSCO perform any additional portfolio analysis after the 2018 IRP to support those resource acquisition approval requests?**

A19. Yes. Given evolving market conditions and new information received in the Phase II RFPs that NIPSCO conducted after the 2018 IRP, 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

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4 The prioritized replacement resources were wind projects looking to qualify for the full federal production tax credit ("PTC").

5 The Phase II RFPs identified primarily solar and solar plus storage resources, along with one additional wind resource.

assumptions related to NIPSCO's generation portfolio, NIPSCO's load forecast, and market commodity prices, and 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.

**Q20. What were the takeaways from this 2020 portfolio analysis?**

A20. The exercise demonstrated that when accounting for the latest expectations for NIPSCO's load requirements, commodity market prices, and expected market rules changes, the Phase II RFPs provided sufficient renewable capacity at a competitive cost to confirm the direction of the 2018 IRP's preferred portfolio. Furthermore, the analysis highlighted the opportunity to acquire more paired solar plus storage capacity to help mitigate risk associated with solar generation output, market energy prices, and capacity accreditation and to maintain flexibility in the portfolio.

**Q21. How did the portfolio conclusions developed in NIPSCO's 2021 IRP compare with the 2018 IRP's preferred portfolio and the subsequent 2020 portfolio analysis?**

A21. As in the 2018 IRP, NIPSCO's 2021 IRP performed a portfolio 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 the long-term. In addition, 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 an uprate to NIPSCO's existing Sugar Creek combined cycle, new thermal peaking capacity, new energy storage capacity, new distributed energy resources ("DERs"), and additional demand side management resources. The resulting preferred portfolio included resources with significantly less variable cost volatility and commodity market exposure than the current fleet and is expected to generate slightly more energy than NIPSCO's requirements on an annual basis. The preferred portfolio 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.

**Q22. On August 31, 2022, in Docket No. ER22-495, the Federal Energy Regulatory Commission ("FERC") approved MISO's request to transition to a seasonal resource adequacy construct, based on four distinct "Seasons." Did NIPSCO's 2021 IRP contemplate this potential?**

A22. Yes. Based on the recency of this order and complexity and importance of the approved changes to the MISO market and its Resource Adequacy construct, NIPSCO is still evaluating the potential impact of this order on its operations. However, NIPSCO's 2021 IRP anticipated FERC approval of MISO's change to a seasonal construct.[6] For example, winter and summer peak load projections were developed as part of NIPSCO's demand forecast; seasonal capacity ratings for new

[6] 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).

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 and explicitly tested portfolio concepts under a summer-only reserve margin relative to a year-round requirement. Although several details associated with the ultimate implementation of MISO's seasonal capacity construct are pending,[7] NIPSCO's preferred portfolio from the 2021 IRP was developed to meet resource adequacy requirements generally consistent with the market redesign that FERC recently approved.

**Q23. How were the various cost components of the 2021 IRP's preferred portfolio projected to evolve over time?**

A23. As in the 2018 IRP, the 2021 IRP's preferred portfolio included additional capital expenditures associated with new resource additions, largely in the near-term between 2023 and 2026, offset by projected declines in several other components of NIPSCO's revenue requirement, especially over the long-term. These other components include reduced fuel costs, particularly associated with coal, reduced

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[7] In particular, the specific seasonal reserve margin requirements and specific seasonal capacity accreditations have yet to be finalized as of the time of the filing of this testimony.

O&M costs at retiring units, and an evolving net energy sales position over time.[8] Overall, just as in the 2018 IRP, the 2021 IRP's preferred portfolio anticipated a shift towards new capital investment, largely in resources with no variable cost volatility, in exchange for reductions in several other costs. Therefore, in addition to lowering overall long-term costs, the preferred portfolio's cost shift is also expected to hedge customers' price exposure to volatile fuel and commodity prices.

**Q24. What were the key elements of the 2021 IRP's short-term action plan?**

A24. The 2021 IRP's short-term action plan called for the retirement of the last remaining coal unit in NIPSCO's fleet between 2026 and 2028 as well as the aging gas peaker units at Schahfer by 2025 and the integration of the wind, solar, and solar plus storage capacity under development from the 2018 IRP. To replace the retiring resources, the short-term action plan called for execution of near-term capacity contracts and for further diligence of thermal peaking, storage, solar, DERs, and Sugar Creek uprate opportunities, to facilitate future specific resource decisions within the IRP's preferred portfolio framework. The short-term action

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[8] Note that NIPSCO's net energy sales and purchases to and from MISO were projected to vary in accordance with the timing of resource retirements and new additions, but the overall trend resulted in lower costs for customers associated with net market sales and purchases over time.

plan explicitly 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 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."[9]

**Q25. Please provide an overview of NIPSCO's implementation of the 2021 IRP's short-term action plan to date.**

A25. Since the submission of the 2021 IRP, NIPSCO has continued to advance the development of the portfolio of Commission-approved projects from the 2018 short term action plan, has developed a plan to complete the capacity uprate at Sugar Creek in 2023, and has executed capacity contracts both from the 2021 RFP

[9] 2021 IRP, p. 260. See also NIPSCO's executive summary, which 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."

and to meet short-term capacity requirements.[10] NIPSCO is also continuing to perform diligence on the thermal peaking and storage capacity additions that were included in the preferred portfolio and recently issued an RFP to evaluate market alternatives for these technologies. NIPSCO plans to continue this further diligence through the remainder of 2022 and into 2023.

## PORTFOLIO TRANSITION PROGRESS AND CURRENT MARKET DYNAMICS

**Q26. Overall, how has NIPSCO's portfolio transition advanced relative to the action plans outlined in the 2018 and 2021 IRPs?**

A26. NIPSCO's generation portfolio has been evolving largely in line with the preferred portfolios identified in the last two IRPs. Since 2018, NIPSCO has retired two coal units at Schahfer, brought three wind projects totaling over 800 MW into service, and received regulatory approval for an additional wind project and several solar and solar plus storage projects, some of which are currently under construction. In the spirit of continuous generation planning and portfolio flexibility, NIPSCO has also been tracking policy, market, and technology change, including through

[10] NIPSCO Witness Campbell discusses the proposed cost recovery of NIPSCO's capacity costs.

additional RFP solicitations, and has conducted additional quantitative portfolio analysis to support portfolio actions.

**Q27. Have there been any changes to the expected timing of major components of NIPSCO's preferred portfolio?**

A27. Yes. Most notably, as explained further by NIPSCO Witness Campbell, multiple factors have delayed the development of several solar projects beyond their original expected online dates in 2022 and 2023. These factors include the extension of the Section 201 Tariffs on imported solar panels, a U.S. Department of Commerce Investigation into anti-dumping and anti-circumvention of such tariffs, and general global supply chain and labor availability issues. The delay in solar online dates results in less available new renewable capacity in the near-term than was originally contemplated in the preferred portfolios from the 2018 and 2021 IRPs and also led to NIPSCO's decision to delay retirement of Schahfer Units 17 and 18.[11]

**Q28. Has NIPSCO performed portfolio analysis to assess the impacts of these changes on the implementation of its preferred plan?**

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[11] Delaying retirement of Units 17 and 18 was one of a range of mitigating actions NIPSCO has taken to address current market conditions. Another example includes additional short-term capacity purchases.

A28. Yes. CRA has worked with NIPSCO this year to perform additional portfolio analysis to support near-term decisions, using the latest market information. In particular, this has included assessment of a retirement date extension for Schahfer Units 17 and 18 to 2025 and continued evaluation of mid-term and long-term portfolio options. The key input assumptions and outputs from this 2022 analysis are included in the 2022 analysis attached as Confidential Attachment 12-B.

**Q29. What changes to NIPSCO's system and other market conditions were updated in this 2022 analysis relative to what was used in the 2021 IRP?**

A29. From the market perspective, 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. In addition, clean energy and storage tax credit extensions as outlined in the recently passed Inflation Reduction Act ("IRA")[12] were incorporated for new NIPSCO resource options. The latest NIPSCO plant capacity ratings and other operational parameters for NIPSCO's

[12] In mid-August, the U.S. Congress passed and President Biden signed the Inflation Reduction Act into law. The new law includes long-term extensions to the production tax credit ("PTC") and investment tax credit ("ITC") for renewable resources, extends the eligibility of investment tax credits to stand-alone storage, and introduces a new PTC for hydrogen production, among other provisions. This outcome is broadly consistent with the assumptions in the Economy-Wide Decarbonization scenario from NIPSCO's 2021 IRP. Specific tax credit levels are dependent on project-specific details associated with labor standards, project location, and other factors, but the 2022 analysis assumed credits were available to new projects in line with historical levels.

existing resources were also incorporated, along with updated costs for new resource options. Finally, various known portfolio changes associated with the expected online dates and costs of the new solar and solar plus storage projects were included in the analysis. All other major assumptions from the 2021 IRP were maintained.

**Q30. What portfolio concepts were evaluated in this 2022 analysis?**

A30. NIPSCO and CRA ultimately developed three distinct portfolio options for evaluation based on the updated expectations for known solar and solar plus storage projects, the potential for further delays or cancellations of solar and solar plus storage projects, and alternative options associated with the operations of NIPSCO's remaining coal units. These portfolio options included:

- Portfolio 1: A modification to Portfolio F from the 2021 IRP with updates to the expected online dates and costs of certain solar projects and an assumption that four of NIPSCO's ten planned solar and solar plus storage projects are canceled, with extension of operations of Schahfer Units 17 and

18 until September 2025 and a return to the 2021 IRP's preferred portfolio mix thereafter;[13]

- Portfolio 2: A modification to Portfolio F from the 2021 IRP with updates to the expected online dates and costs of certain solar projects and an assumption that four of NIPSCO's ten planned solar and solar plus storage projects are canceled, with capacity needs after the retirement of Schahfer Units 17 and 18 met by market purchases through 2025 and a return to the 2021 IRP's preferred portfolio mix thereafter;

- Portfolio 3: A modification to Portfolio F from the 2021 IRP with updates to the expected online dates and costs of certain solar projects and an assumption that four of NIPSCO's ten planned solar and solar plus storage projects are canceled, with extension of operations of all NIPSCO's coal units through the end of 2035 and a subsequent delay in the return to the 2021 IRP's preferred portfolio mix until that point in time.

**Q31. What analysis was performed on these revised portfolio concepts?**

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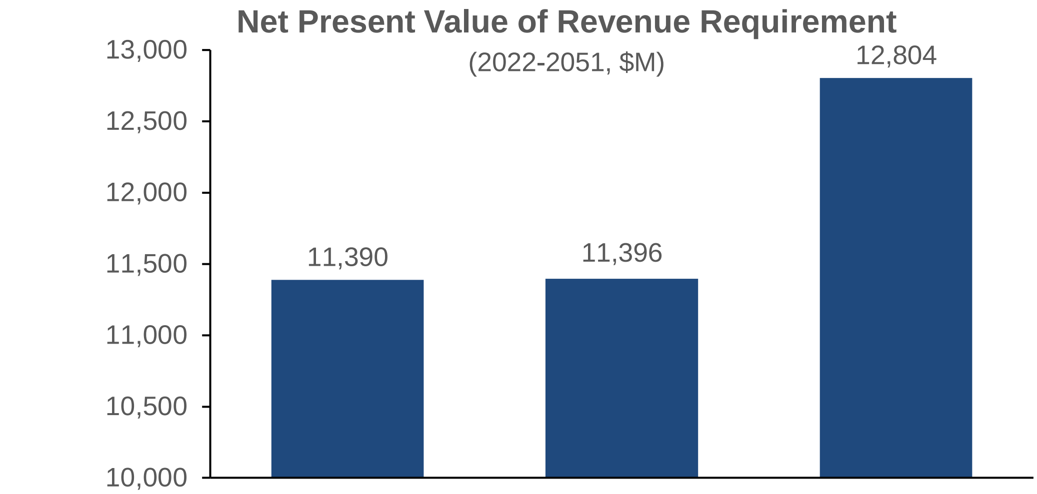
13 For all the portfolios that assume four of NIPSCO's ten project are canceled, this assumption was not a prediction that any specific project will be cancelled. It was an attempt to develop reasonable portfolio alternatives for modeling that account for challenges that solar projects have faced over the last several months.

A31. 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 2018 and 2021 IRPs. The analysis was performed against the updated reference case conditions and supplemented by a short-term risk analysis across a stochastic distribution of uncertainty around commodity prices.

**Q32. What did the analysis conclude regarding the net present value of revenue requirements ("NPVRR") for each of the portfolio options?**

A32. Figure 1 below summarizes the 30-year NPVRR for each of the three portfolio options under reference case conditions.

**Figure 1**




| Portfolio Concept | Solar Cancellations, 17/18 extension (1) | Solar Cancellations with Market Purchase bridge (no 17/18 Extension) (2) | Long Term Coal Extension (3) |
|---|---|---|---|
| **Current Solar Portfolio** | Selection of projects canceled | Selection of projects canceled | Selection of projects canceled |
| **Schahfer 17/18 Retirement** | Sept 2025 | May 2023 | Dec 2035 |
| **MC12 Retirement** | May 2026 | May 2026 | Dec 2035 |
| **Capacity Purchases** | Fill gaps as needed | Bridge from today to 2026 at CONE | Fill gaps as needed |
| **Rank (1=Least Cost)** | 1 | 2 | 3 |
| **Delta from Least Cost** | - | $6<br>.05% | $1,414M<br>12.4% |

The analysis concluded that maintaining Schahfer Units 17 and 18 in service through the summer of 2025 (Portfolio 1) is likely to result in slightly lower costs to customers than retiring the units in May of 2023 and relying on replacement energy and replacement capacity market purchases at MISO's cost of new entry

("CONE")[14] price (Portfolio 2). In other words, the additional fixed O&M, maintenance capital, fuel costs, variable O&M costs, and emissions costs associated with operating the coal units for two additional years are expected to be more than offset by the avoided energy and capacity purchases NIPSCO would need to make if the units were to retire by the middle of 2023. In addition, the analysis concluded that retaining NIPSCO's coal units for an additional decade beyond 2025 (Portfolio 3) is expected to be significantly higher cost than returning to the preferred portfolio mix defined in the 2021 IRP. This is because the capital and operating costs of the delayed solar and storage projects and the additional new resource options identified in the preferred portfolio from NIPSCO's 2021 IRP (notably solar, storage, and gas peaking capacity) are expected to be lower than the capital (including required environmental upgrades), O&M, fuel, and emissions costs that would be incurred to continue operating the existing coal fleet over the long-term.

**Q33. Please explain the stochastic analysis that was performed in more detail.**

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14 MISO sets the CONE price based on the cost of a new natural gas peaking unit, and this price, which is currently $236.66/MW-day, serves as a ceiling on the clearing price in MISO's annual Planning Reserve Auction ("PRA"). The PRA for the 2022/23 capacity delivery year cleared at the CONE price. Given current short-term reserve margin expectations in MISO, this price was used as a proxy for capacity purchases.

A33. The stochastic analysis varied natural gas price and MISO market power prices through 2025 based on an assessment of historical market volatility. CRA evaluated 200 different iterations or potential price paths in the analysis. This stochastic risk assessment did not calculate full revenue requirements, but instead focused on the variable portfolio cost risk associated with NIPSCO's energy position in the MISO market, particularly in light of the delays in solar project online dates.

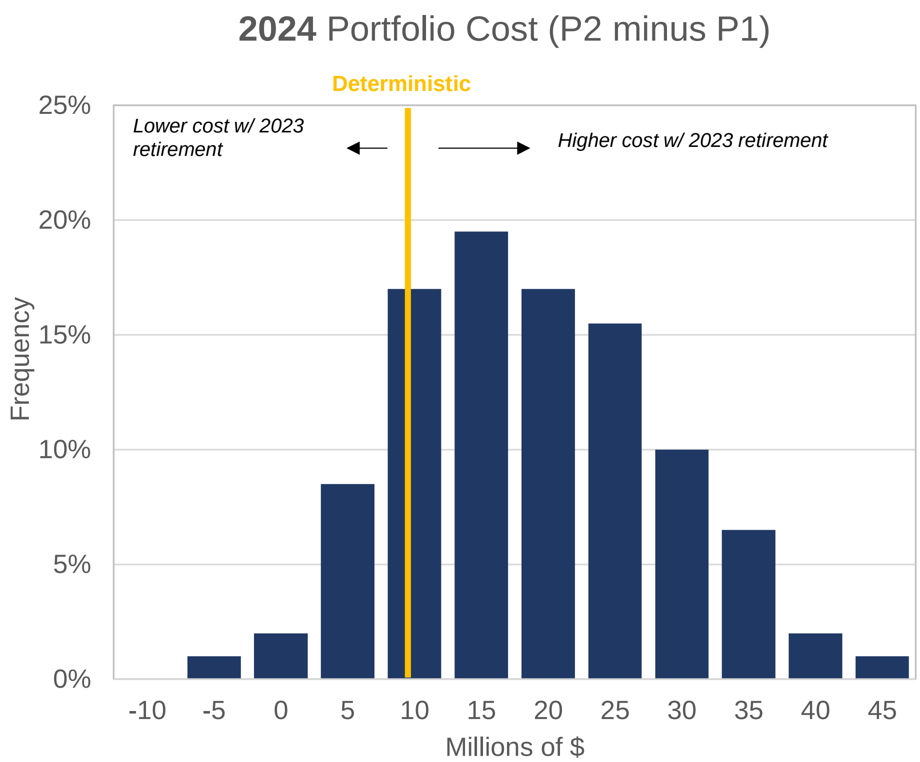
**Q34. How did this stochastic analysis measure such portfolio risk?**

A34. CRA's stochastic analysis focused on measures of cost *variability*, particularly between Portfolios 1 and 2, to assess near-term market risk exposure. The analysis recorded annual projected portfolio costs for each of the 200 potential outcomes and measured the difference in costs between portfolios across the distribution. For example, in 2024, the difference in portfolio costs between Portfolios 1 and 2 for all 200 iterations can be recorded and compared with the difference in costs in the reference case to assess the range of potential outcomes and the shape of the distribution.

**Q35. What was concluded from the stochastic analysis?**

A35. The stochastic analysis found that the portfolio that extended the life of Schahfer Units 17 and 18 through 2025 (Portfolio 1) reduced the range of upside cost uncertainty relative to the portfolio that relied only on market purchases to bridge the gap between the original 2023 retirement date for Units 17 and 18 and the time period at which new solar and solar plus storage capacity is expected to enter into service (Portfolio 2). This is shown in Figure 2 below, which graphs the distribution of portfolio cost outcomes for Portfolio 2 relative to Portfolio 1 for 2024. In this year, the reference case analysis suggested that portfolio costs for Portfolio 2 are expected to be about $7 million higher than those for Portfolio 1, while the stochastic analysis suggests a cost risk as high as $33 million at the 95th percentile or $41 million at the maximum of the 200 iterations. This upside risk is far greater than the potential for lower cost outcomes.

**Figure 2**




In other words, retaining coal capacity as a bridge to delayed renewable capacity additions mitigates against high market price conditions that could expose NIPSCO to higher net market purchases costs.

**Q36. Overall, what conclusions were made regarding the extension of the retirement date of Schahfer Units 17 and 18 beyond 2023?**

A36. Overall, the 2022 analysis concluded that retaining Schahfer Units 17 and 18 in NIPSCO's portfolio for two additional years is likely to result in lower costs and lower risk for customers relative to retiring the plants in mid-2023 and relying on market energy and capacity purchases. As further described by NIPSCO Witnesses Talbot and Campbell, extending the lives of Schahfer Units 17 and 18 is needed to maintain reliability and meet minimum reserve margin requirements, but given delays in solar project development and recent increases in natural gas and power market prices, life extension through 2025 also provides economic benefits for customers. However, the analysis also concluded that long-term retention of the coal capacity is still higher cost for customers, consistent with the conclusions from the 2018 and 2021 IRPs. This is due to the fact that the expected capital expenditures required for longer-term operations of the coal fleet, along with the expected ongoing O&M, fuel, and emissions costs for the coal units, are projected to be significantly higher than the expected costs of the alternative resources that make up NIPSCO's current preferred portfolio.

**Q37. What conclusions were made regarding the evolution of NIPSCO's portfolio beyond 2025?**

A37. The 2022 analysis broadly confirmed that retirement of NIPSCO's remaining coal capacity by 2028 and replacement with a diverse set of new resources, as outlined in NIPSCO's 2021 IRP and the associated short-term action plan, provides the best outcome for NIPSCO's customers. While the analysis suggests that continued implementation of the 2021 IRP's preferred portfolio after 2025 is cost-effective, NIPSCO recognizes that energy markets, federal policy, and the technology landscape continue to be dynamic, and is therefore currently working with CRA's Auctions and Competitive Bidding Practice to conduct another RFP in 2022 to identify potential new solar, thermal peaking, storage, or other projects to bring online after the eventual retirement of the coal fleet. As with prior planning analyses, RFP bids will be evaluated by NIPSCO and CRA within the IRP modeling framework and in light of recent market and policy developments.

**Q38. How does the analysis undertaken in 2022 align with the preferred portfolios from NIPSCO's 2018 and 2021 IRPs and their associated action plans?**

A38. The findings from the 2022 analysis are directionally consistent with the preferred portfolios and generation transition plans outlined by NIPSCO's 2018 and 2021 IRPs. Long-term operation of coal-fired capacity remains more costly than earlier retirement, and replacement with a diverse set of new resource types, predominantly comprising renewables, remains the preferred option. Furthermore, the analysis highlights the need for flexibility and continuous resource planning in response to market conditions. By allowing for flexibility in retirement dates and by not committing to one single resource type, NIPSCO's preferred portfolio can be flexible enough to respond to changes in markets, technology, and policy.

**Q39. Does this conclude your prefiled direct testimony?**

A39. 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 15, 2022

# Section 9. Portfolio Analysis

## 9.1 Existing Fleet Analysis

### 9.1.1 Process Overview

NIPSCO's 2018 IRP established a roadmap to retire all coal capacity by 2028 and developed a short-term action plan focused on a portfolio of renewable resource additions to replace retiring capacity at the Schahfer plant through 2023 (*See* Section 4 for more detail on the new renewable resources). After the implementation of that short-term action plan, approximately 65% of NIPSCO's generation fleet will be set for the next several years, with the 2021 IRP analysis evaluating potential retirement pathways for the remainder of NIPSCO's existing fleet. As discussed in more detail in Section 2, NIPSCO determined that it was most efficient and effective to evaluate retirement decisions for the existing fleet on a stand-alone basis, while performing an additional replacement analysis to assess a wide range of replacement resource strategies. Although performed in two steps, the existing fleet and replacement analyses are both based on the same major inputs and assumptions, which are described in parts of Section 8 and below.

NIPSCO believes that performing an existing fleet analysis requires careful planning and consideration of several factors. To that end, NIPSCO has used an integrated scorecard methodology to evaluate existing fleet portfolios, as described in Section 2. In addition to the net present value of revenue requirements in the Reference Case, NIPSCO has also considered multiple rate stability metrics, carbon emissions, and the effect of unit retirements on NIPSCO's employees and the local economies of the communities it serves.

### 9.1.2 Existing Fleet Analysis Methodology

The existing fleet analysis has been conducted according to the following steps:

- Identify plausible retirement and retention plans for the existing fleet and specify individual retirement/retention combinations or "portfolios."

- Identify the least-cost replacement capacity to fill the resulting capacity gap for each retirement portfolio based on the results from the RFP conducted by NIPSCO and other available supply-side and demand side resources (*See* Sections 4 and 5 for more detail on these resource options).

- Evaluate each portfolio, including its associated least-cost capacity replacement, in the IRP tools for each scenario (as defined in Section 8). The evaluation includes a full accounting of the ongoing operations of each existing plant and the costs of alternatives.

- Record costs, risks, and other metrics in the integrated scorecard to identify the preferred existing fleet strategy.

### 9.1.3 Identification of Existing Fleet Portfolios

NIPSCO's remaining fossil-fueled generation plants were evaluated for potential retirement throughout the IRP's planning horizon. This includes Michigan City Unit 12 (coal), Schahfer Units 16A and 16B (natural gas steam), and Sugar Creek (natural gas CCGT). NIPSCO identified eight existing fleet portfolios for analysis based on different combinations of unit retirements at different points in time, as summarized in Figure 9-1:

- The first four portfolios examine the retirement timing of Michigan City Unit 12, including bookend concepts that evaluate retention of the plant beyond its announced retirement date to the end of its book life in 2032 and an early retirement by 2024, a portfolio concept that is not viable from an implementation perspective.

- Portfolios 5 and 6 vary the retirement timing of Schahfer Units 16A/B between 2025 and the expected end of the units' useful operational life in 2028.

- Portfolios 7 and 7H evaluate long-term concepts for potential Sugar Creek retirement and hydrogen conversion, respectively. These portfolios were developed to provide a long-term view towards net-zero decarbonization pathways, although key implementation actions would be made more than a decade into the future.

**Figure 9-1: Overview of Existing Fleet Portfolios**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 7H |
|---|---|---|---|---|---|---|---|---|
| Portfolio Transition Target: | 15% Coal through 2032<br>MC 12 Through Book life | 15% Coal through 2028<br>2018 IRP Preferred Plan | 15% Coal through 2026<br>Early Retirement of MC 12 | 15% Coal through 2024<br>Early Retirement of MC 12 | 15% Coal through 2028<br>2018 IRP Preferred Plan + 2025 16AB retirement | 15% Coal through 2026<br>Early Retirement of MC 12 + 2025 16AB retirement | 15% Coal through 2028 Fossil Free by 2032<br>2018 IRP Preferred Plan + 2025 16AB ret. + 2032 SC ret. | 15% Coal through 2028 Option for Fossil Free by 2032<br>2018 IRP Preferred Plan + 2025 16AB ret. + 2032 SC conv. |
| Retain beyond 2032 | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | None | Sugar Creek converts to H2 (2032) |
| Michigan City 12 | Retire<br>2032 | Retire<br>2028 | Retire<br>2026 | Retire<br>2024 | Retire<br>2028 | Retire<br>2026 | Retire<br>2028 | |
| Schahfer 16AB | Retire<br>2028 | | | | Retire<br>2025 | | | |
| Sugar Creek | Retain | | | | | | Retire<br>2032 | Convert to H2<br>2032 |

Short term (portfolios 1–6) Longer term (portfolios 7–7H)

Not a viable pathway due to implementation timing

## 9.1.4 Existing Fleet Cost Assumptions

The evaluation of each existing fleet portfolio was performed through a full portfolio analysis that included dispatch in Aurora and financial accounting in PERFORM (*See* Section 2 for more detail on the overall modeling process). Market assumptions were consistent with those outlined earlier in Section 8 for the Reference Case and the three alternative scenarios. In addition to the major market inputs and the costs of replacement resources (see next section below), several relevant assumptions were made regarding the ongoing costs of the existing coal fleet.

Ongoing costs include fuel, fixed O&M costs, and maintenance capital, as well as the recovery of remaining book value associated with each plant as of April 2021. This recovery includes return of (depreciation), return on, and income and property taxes associated with the remaining net book value of NIPSCO's existing fleet.

Fixed O&M costs included all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. For all units, projections of fixed O&M costs were obtained for each year within 2021-2040. These costs were then escalated at 2.1% per year[100] for the 2041-2050 end effects modeling period. Additional detail is provided in Confidential Appendix

[100] The EIA's AEO assumes a 2.1% rate of inflation for "All Commodities," which is used as a long-term proxy of general cost inflation for the end effects extrapolation.

D. As an existing unit's projected retirement date moves up, the relative fixed O&M spend tended to decrease during the years leading up to retirement.

Maintenance capital costs included the projected capital expenditures necessary to keep the units running through the analysis period at the projected level of operations. For all units, projections of maintenance capital costs were obtained for each year within 2021-2040. These costs were then escalated at 2.1% per year 2041-2050 end effects modeling period. Additional detail is provided in Confidential Appendix D. Similar to fixed O&M costs, as an existing unit's projected retirement date moves up, the relative capital spend tended to decrease during the years leading up to retirement.

NIPSCO also included estimated transmission upgrade costs associated with Schahfer and Michigan City's retirements. An additional $6.7 million of capital expenditures was incorporated for transmission upgrades at the time Schahfer 16A/B retires in any existing fleet portfolio. An additional $82.9 million of capital expenditures was incorporated for transmission upgrades at the time Michigan City retires in any existing fleet portfolio.

Recovery of depreciation expenses on existing capital by 2033 has also been incorporated in the existing fleet analysis. NIPSCO assumes that each unit continues to depreciate at the same rate of 3.88% until 2033, regardless of whether the unit has been retired or not. This means that each retirement portfolio has the same depreciation schedule for existing capital. At 2033, the sum of all coal plants' NBV on existing capital is equal to the negative "cost of removal" for all the coal plants. The negative NBV on existing capital in 2033 lowers rate base in perpetuity. The cost of removal was estimated by John J. Spanos, an expert witness supporting NIPSCO's 2019 Electric Rate Case[101] In addition to the "return of" (depreciation) the net book value, NIPSCO continues to earn a "return on" the net book value equal to NIPSCO's assumed weighted average cost of capital. NIPSCO assumes that property and income tax will *not* be collected on the remaining NBV of the plant if it is retired.

### 9.1.5 Identification of Least-Cost Replacement Capacity

As in the 2018 IRP, NIPSCO's All-Source RFP provided insight into the supply and pricing of resource alternatives available to NIPSCO (*See* Section 4 for details on the process and the costs and operational parameters of the individual tranches used for evaluation). In addition, NIPSCO identified other resource options, including DERs (*See* Section 4), an uprate at the existing Sugar Creek facility (*See* Section 4), and bundles of DSM resource options over time (*See* Section 5).

With these resource options, a portfolio optimization was performed within Aurora's portfolio optimization tool under each of the eight retirement portfolio concepts to identify least-cost sets of replacement resources under Reference Case market conditions. The portfolio optimization modeling was performed for both the winter and summer peak seasons and was

[101] See Cause No. 45159.

designed to minimize the net present value of revenue requirements, with certain constraints for reserve margins, maximum off-system energy sales, and resource eligibility.[102]

Overall, the economic optimization model selected a diverse set of resources. Driven by a binding winter reserve margin and the energy resources already obtained from the 2018 IRP Preferred Plan, the indicative ordering of model selection preference tends to favor resources that offer greater levels of firm capacity relative to their energy contributions. When available for selection, the resources universally selected through 2027 included (all values in ICAP) included the following:

- Approximately 10 MW of NIPSCO-owned DERs with the largest distribution cost deferrals;
- The uprate to the existing Sugar Creek CCGT at the modeled level of 53 MW;
- Approximately 68 MW (summer peak credit)[103] of DSM resources by 2027, which includes the cumulative impact of both Tier 1 Residential and Commercial programs by 2027, with Commercial programs being most cost effective;[104]
- Thermal capacity contracts from the 2021 RFP up to 150 MW;

In addition, several different resource types were consistently selected at various sizes and timings based on retirement dates and resource eligibility. These included:

- A natural gas peaker up to 300 MW (hydrogen-enabled in Portfolio 7H);
- Various levels of stand-alone storage between 135 MW and 570 MW;
- Solar capacity up to 250 MW;
- Wind capacity up to 200 MW;
- A 20 MW electrolyzer pilot at Sugar Creek in Portfolio 7H.

Figure 9-2 provides a summary of the capacity resources that were selected under Portfolios 1-6, and Figure 9-3 provides a summary of the capacity resources that were selected under Portfolios 7 and 7H. Note that these portfolios do not represent NIPSCO's preferred replacement strategy, but only least-cost optimization outcomes that are used to evaluate retirement implications associated with the existing fleet.

[102] Portfolios were optimized against winter reserve margin constraints (9.4%), followed by summer to ensure compliance with both. A maximum net energy sales limit of 30% during the fleet transition (2023-2026), falling to 25% in 2030+, was enforced. Portfolios 7 and 7H are designed to achieve net zero emissions over the study horizon, so eligible resources were restricted. Portfolio 7 did not allow for new fossil resources, and Portfolio 7H "forced in" hydrogen-enabled resources

[103] Note that the winter peak impact of the selected DSM resources is approximately 46MW.

[104] Note that the Tier 1 Residential and Commercial DSM bundles were selected across all time horizons in the fundamental modeling period. Additional detail on bundle costs and savings is provided in Section 5.

### Figure 9-2: Summary of Least-Cost Replacement Capacity: Portfolios 1-6

More ↓ COST-EFFECTIVENESS ↓ Less

| Portfolio 1 | | |
|---|---|---|
| MC12 Through Book Life | | |
| Technology | ICAP MW | Year |
| NIPSCO DER | 10 | 2026 |
| Sugar Creek Uprate | 53 | 2027 |
| DSM* | 68 | 2027* |
| Thermal Contract | 50 | 2024 |
| Thermal Contract | 100 | 2026 |
| Gas Peaker | 300 | 2032 |
| Storage | 135 | 2027 |
| **Total** | **693** | |

| Portfolios 2 \| 3 \| 4 | | | | |
|---|---|---|---|---|
| 2018 IRP (MC 2028) \| MC 2026 \| MC 2028 | | | | |
| Technology | ICAP MW | Year P2 | Year P3 | Year P4 |
| NIPSCO DER | 10 | 2026 | 2026 | 2026 |
| Sugar Creek Uprate | 53 | 2027 | 2027 | 2027 |
| DSM* | 68 | 2027* | 2027* | 2027* |
| Thermal Contract | 50 | 2024 | 2024 | 2024 |
| Thermal Contract | 100 | 2026 | 2026 | 2026 |
| Gas Peaker | 300 | 2028 | 2026 | 2024 |
| Storage | 135 | 2027 | 2027 | 2025 |
| Solar | 100 / 200^ | 2026 | 2026 | 2026 |
| **Total** | **793 / 893^** | | | |

*^ P2/3 have 100 MW of solar; P4 has 200 MW*

| Portfolios 5 \| 6 | | | |
|---|---|---|---|
| Portfolio 2 w/ 16AB 2025 \| Portfolio 3 w/ 16AB 2025 | | | |
| Technology | ICAP MW | Year P5 | Year P6 |
| NIPSCO DER | 10 | 2026 | 2026 |
| Sugar Creek Uprate | 53 | 2027 | 2027 |
| DSM* | 68 | 2027* | 2027* |
| Thermal Contract | 50 | 2024 | 2024 |
| Thermal Contract | 100 | 2026 | 2026 |
| Gas Peaker | 300 | 2028 | 2026 |
| Storage | 135 | 2025 | 2025 |
| Solar | 100 | 2026 | 2026 |
| Wind | 200 | N/A | 2026 |
| **Total** | **993** | | |

### Figure 9-3: Summary of Least-Cost Replacement Capacity: Portfolios 7 & 7H

| Portfolio 7 | | |
|---|---|---|
| Fossil Free By 2032 | | |
| Technology | ICAP MW | Year |
| NIPSCO DER | 10 | 2026 |
| DSM* | 68 | 2027* |
| Storage | 235 | 2025 |
| Storage | 100 | 2026 |
| Storage | 235 | 2027 |
| Solar | 250 | 2026 |
| Wind | 200 | 2026 |
| **Total** | **1,020** | |

| Portfolio 7H | | |
|---|---|---|
| Fossil Free Option by 2032 w/ SC Conversion (incl. capital costs) | | |
| Technology | ICAP MW | Year |
| NIPSCO DER | 10 | 2026 |
| Sugar Creek Uprate | 53 | 2027 |
| DSM* | 68 | 2027* |
| Storage | 235 | 2025 |
| Storage | 135 | 2027 |
| Solar | 250 | 2026 |
| Wind | 200 | 2026 |
| Hydrogen-Enabled Gas Peaker | 193 | 2025 |
| SC Electrolyzer Pilot | 20 | 2026 |
| **Total** | **1,131** | |

## 9.1.6 Evaluation of Each Existing Fleet Portfolio – Scorecard Metrics

NIPSCO developed a set of decision criteria objectives and metrics against which to evaluate the full set of existing fleet portfolios. The analysis was then conducted to quantify the performance of each portfolio against each scorecard metric. The following section describes each of the key objectives and metrics in more detail:

- Cost to Customer is measured by the overall NPVRR under Reference Case Conditions.

- Cost Certainty measures the certainty that the net present value of revenue requirements falls within the range of the scenario outcomes and is quantified by the range in NPVRR across scenarios.

- Cost Risk measures the risk of unacceptable, high-cost outcomes and is quantified by the highest scenario NPVRR.

- Lower Cost Opportunity measures the potential for lower cost outcomes and is quantified by the lowest scenario NPVRR.[105]

- Carbon Emissions measures the carbon intensity of the portfolio and is quantified by the cumulative short tons of CO2 emitted from the generation portfolio from 2024 through 2040.[106]

- Employees and Local Economy measures the positive social and economic impacts of NIPSCO's existing generation fleet and are measured by the net impact on permanent jobs associated with the current generation fleet and the net present value of property taxes associated with the current fleet relative to the 2018 IRP's conclusions, respectively.

A summary of the decision criteria metrics for the existing fleet analysis is provided in Figure 9-4, noting that reliability metrics are addressed more fully in the replacement analysis that seeks to evaluate the tradeoffs of different replacement resources more comprehensively.

[105] Note that additional rate stability and risk metrics are included in the Replacement Analysis phase, including those associated with the stochastic analysis.
[106] These years represent the fundamental modeling horizon after the retirement of the Schahfer coal units, which is common to all portfolios.

**Figure 9-4: Scorecard Metrics for Existing Fleet Analysis**

| Objective | Indicator | Description and Metrics |
|---|---|---|
| **Affordability** | **Cost to Customer** | • Impact to customer bills<br>• Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results) |
| **Rate Stability** | **Cost Certainty** | • Certainty that revenue requirement within the most likely range of outcomes<br>• Metric: Scenario range NPVRR |
| | **Cost Risk** | • Risk of unacceptable, high-cost outcomes<br>• Metric: Highest scenario NPVRR |
| | **Lower Cost Opportunity** | • Potential for lower cost outcomes<br>• Metric: Lowest scenario NPVRR |
| **Environmental Sustainability** | **Carbon Emissions** | • Carbon intensity of portfolio<br>• Metric: Cumulative carbon emissions (2024-40 short tons of $CO_2$) from the generation portfolio |
| **Reliable, Flexible, and Resilient Supply** | **Reliability** | • *To be addressed in Replacement Analysis stage* |
| | **Resource Optionality** | |
| **Positive Social & Economic Impacts** | **Employees** | • Net impact on NiSource jobs<br>• Metric: Approx. number of permanent NiSource jobs associated with generation |
| | **Local Economy** | • Net effect on the local economy (relative to 2018 IRP) from new projects and ongoing property taxes<br>• Metric: NPV of existing fleet property tax relative to 2018 IRP |

*Additional risk metrics will be included in the Replacement Analysis, when broader set of resource types are evaluated*

## 9.1.7 Evaluation of Each Existing Fleet Portfolio – Results

*Reference Case Cost Results*

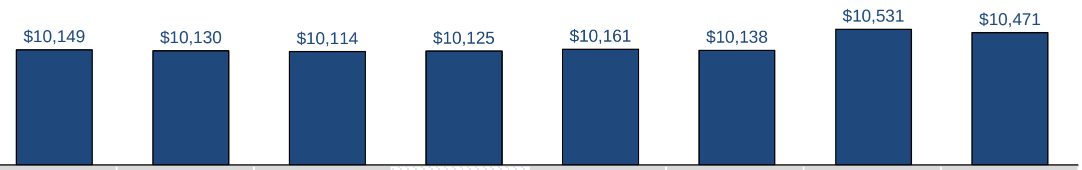
The eight existing fleet portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail) to estimate revenue requirements for each over time. The assessment was first performed across the Reference Case set of market assumptions and inputs to calculate baseline projections of the NPVRR over the thirty-year planning horizon, which are summarized in Figure 9-5.

Under the Reference Case market conditions, the difference in NPVRR from the highest cost to lowest cost portfolio is approximately $430 million. Consistent with NIPSCO's prior IRP findings, early retirement of coal is generally cost effective for customers, with Portfolio 3 (retirement of Michigan City 12 in 2026) having the lowest cost overall. However, the difference in cost across several portfolios is small, since much of the remaining portfolio is fixed and small changes in retirement dates are now being assessed. In addition, the analysis suggests that retaining Units 16A/B until 2028 may be cost effective, given the portfolio's capacity needs. However, this is contingent on the operational condition of these older vintage units, and the cost impacts of earlier retirement are well less than 1% in NPVRR.

## Figure 9-5: Cost to Customer Impacts – Existing Fleet Portfolios

**Net Present Value of Revenue Requirement**

(2021-2050, $M)




| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 7H |
|---|---|---|---|---|---|---|---|---|
| **Portfolio Transition Target:** | **15% Coal through 2032** | **15% Coal through 2028** | **15% Coal through 2026** | **15% Coal through 2024** | **15% Coal through 2028** | **15% Coal through 2026** | **15% Coal through 2028 Fossil Free by 2032** | **15% Coal through 2028 Option for Fossil Free by 2032** |
| **Retire:** | MC: 12 (2032) Schfr: 16AB (2028) | MC: 12 (2028) Schfr: 16AB (2028) | MC: 12 (2026) Schfr: 16AB (2028) | MC: 12 (2024) Schfr: 16AB (2028) | MC: 12 (2028) Schfr: 16 AB (2025) | MC: 12 (2026) Schfr: 16AB (2025) | MC: 12 (2028) Schfr: 16AB (2025) SC: (2032) | MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032) |
| **Retain beyond 2032:** | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | None | Sugar Creek converts to H2 (2032) |
| **Rank (1=Least Cost)** | 5 | 3 | 1 | 2 | 6 | 4 | 8 | 7 |
| **Delta from Least Cost** | $35M 0.3% | $16M 0.2% | - | $10M 0.1% | $47M 0.5% | $24M 0.2% | $417M 4.1% | $357M 3.5% |

Not a viable pathway due to implementation timing

*Scenario Cost Results*

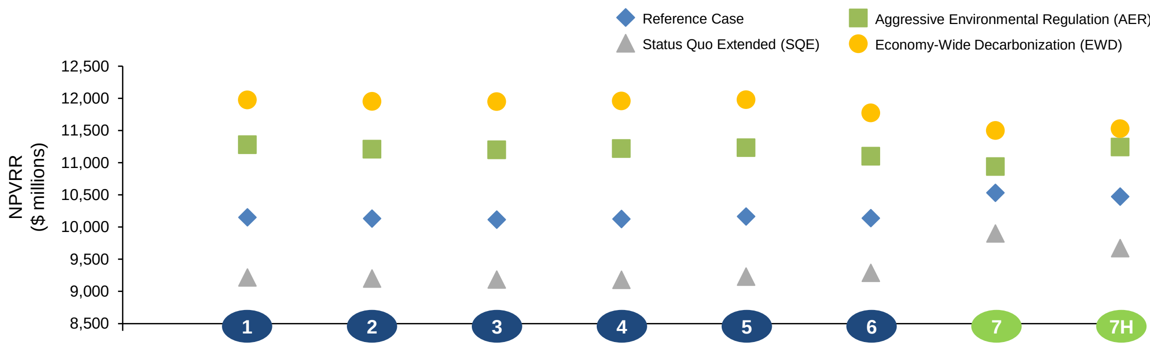
In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each existing fleet portfolio against each scenario described earlier in Section 8. The NPVRR for each retirement portfolio across each scenario is summarized in Figure 9-6, with additional details regarding the scenario results described below.

Under the SQE scenario, all portfolio costs are projected to decline due to no carbon price and lower gas and power prices. Given that the lower natural gas price outlook harms near-term coal plant performance, earlier retirement of Michigan City 12 is slightly lower cost than retaining the unit longer, although Portfolios 2-4 are all within $20 million on an NPVRR basis. The cost premium associated with moving towards a net zero strategy (Portfolios 7 and 7H) is highest under this scenario.

Under the AER scenario, higher carbon prices and higher gas prices drive higher portfolio costs, particularly for Portfolio 1, which retains Michigan City 12 until 2032. However, Portfolios 2 and 3 are lower cost than Portfolio 4, as the higher gas prices benefit Michigan City's performance for a few years until replacement resources can enter as the carbon price increases over time. Under this scenario, Portfolio 7 has the lowest NPVRR.

Under the EWD scenario, portfolio costs are the highest, given the highest load growth expectations and growing clean energy requirements. The relative ordering of Portfolios 1-4 is the same as in the Reference Case, but Portfolio 6 has the lowest NPVRR of the first six due to the benefit realized by higher levels of renewable energy additions taking advantage of the clean energy standard construct. In addition, Portfolios 7 and 7H are the lowest cost under this scenario, with the value of hydrogen energy providing 7H a significant cost benefit.

**Figure 9-6: Cost to Customer across All Scenarios – Existing Fleet Portfolios (30-year NPVRR – millions of $)**




| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 7H |
|---|---|---|---|---|---|---|---|---|---|
| | **Portfolio Transition Target:** | **15% Coal through 2032** | **15% Coal through 2028** | **15% Coal through 2026** | **15% Coal through 2024** | **15% Coal through 2028** | **15% Coal through 2026** | **15% Coal through 2028 Fossil Free by 2032** | **15% Coal through 2028; Option for Fossil Free by 2032** |
| | **Retire:** | MC: 12 (2032) Schfr: 16AB (2028) | MC: 12 (2028) Schfr: 16AB (2028) | MC: 12 (2026) Schfr: 16AB (2028) | MC: 12 (2024) Schfr: 16AB (2028) | MC: 12 (2028) Schfr: 16 AB (2025) | MC: 12 (2026) Schfr: 16AB (2025) | MC: 12 (2028) Schfr: 16AB (2025) SC: (2032) | MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032) |
| | **Retain beyond 2032:** | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | None | Sugar Creek converts to H2 (2032) |
| **Reference Case** | **Delta from Lowest Cost to Customer** | $35<br>0.3% | $16<br>0.2% | -<br>- | $10<br>0.1% | $47<br>0.5% | $24<br>0.2% | $417<br>4.1% | $357<br>3.5% |
| **Status Quo Extended** | **Delta from Lowest Cost to Customer** | $36<br>0.4% | $18<br>0.2% | $2<br>0.0% | -<br>- | $49<br>0.5% | $108<br>1.2% | $720<br>7.8% | $492<br>5.4% |
| **Aggressive Env. Reg.** | **Delta from Lowest Cost to Customer** | $336<br>3.1% | $269<br>2.5% | $259<br>2.4% | $277<br>2.5% | $292<br>2.7% | $157<br>1.4% | -<br>- | $303<br>2.8% |
| **Econ-Wide Decarbonization** | **Delta from Lowest Cost to Customer** | $477<br>4.1% | $454<br>3.9% | $449<br>3.9% | $459<br>4.0% | $478<br>4.2% | $276<br>2.4% | -<br>- | $29<br>0.3% |

Not a viable pathway due to implementation timing

*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

Overall, across scenarios, the following key observations were made:

- Retirement of Michigan City 12 in 2026 has a slightly lower NPVRR (less than $20 million) relative to retirement in 2028 across all scenarios.
- Retirement of Michigan City 12 in 2032 is always higher cost than earlier retirement, with the largest difference in the AER scenario.
- Portfolio 2 (retirement of Schahfer 16AB in 2028) is slightly lower cost than Portfolio 5 (retirement of Schahfer 16AB in 2025), although additional renewable additions with early 16AB retirement (Portfolio 6) results in a lower NPVRR under the two high carbon regulation scenarios.
- Portfolios 7 and 7H have the smallest range, as their future renewable, hydrogen, and storage investments hedge against high-cost power market outcomes.

*CO2 Emissions*

The retirement timing for Michigan City 12 is the major driver of CO2 emission differences across the eight portfolios, with Sugar Creek remaining the largest source of emissions into the 2030s. Therefore, earlier retirement of either unit results in lower overall CO2 emissions for the portfolio. Figure 9-7 illustrates the projected CO2 emissions by portfolio over time for the Reference Case, while Figure 9-8 presents the cumulative emissions over the 2024-2040 period for each scenario, along with a reporting of the scenario average. Emissions vary across scenarios based on different dispatch projections for the fossil units and the potential for hydrogen blending at Sugar Creek in the AER and EWD scenarios in Portfolio 7H.

**Figure 9-7: Annual CO2 Emissions for Existing Fleet Portfolios – Reference Case**

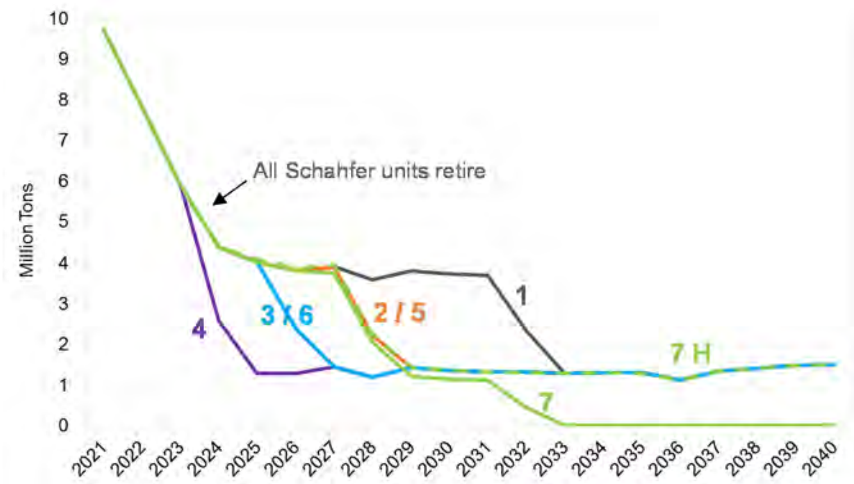
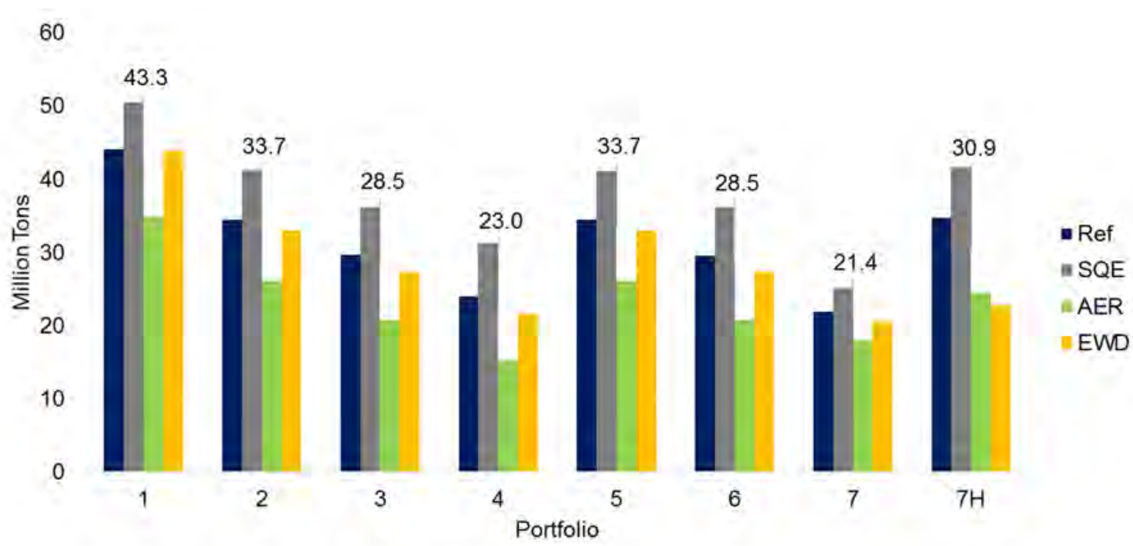



**Figure 9-8: 2024-2040 Cumulative Tons of CO2 Emissions for Existing Fleet Analysis – All Scenarios with Average**



## 9.1.8 Existing Fleet Analysis Scorecard Summary

Figure 9-9 presents a summary of all scorecard metrics for each of the eight existing fleet portfolios. This includes the cost metrics associated with the Reference Case NPVRR, the risk metrics associated with the scenario analysis, carbon emissions, NIPSCO employees, and the local economy, as described above.

### Figure 9-9: Retirement Portfolio Scorecard

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 7H |
|---|---|---|---|---|---|---|---|---|
| **Portfolio Transition Target:** | **15% Coal through 2032** | **15% Coal through 2028** | **15% Coal through 2026** | **15% Coal through 2024** | **15% Coal through 2028** | **15% Coal through 2026** | **15% Coal through 2028<br>Fossil Free by 2032** | **15% Coal through 2028<br>Fossil Free by 2032** |
| **Retire:** | MC: 12 (2032)<br>Schfr: 16AB (2028) | MC: 12 (2028)<br>Schfr: 16AB (2028) | MC: 12 (2026)<br>Schfr: 16AB (2028) | MC: 12 (2024)<br>Schfr: 16AB (2028) | MC: 12 (2028)<br>Schfr: 16 AB (2025) | MC: 12 (2026)<br>Schfr: 16AB (2025) | MC: 12 (2028)<br>Schfr: 16AB (2025)<br>SC: (2032) | MC: 12 (2028)<br>Schfr: 16AB (2025)<br>SC to H2: (2032) |
| **Retain beyond 2032:** | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | Sugar Creek | None | Sugar Creek converts to H2 (2032) |
| **Cost To Customer**<br>30-year NPV of revenue requirement (Ref Case) | $10,149<br>+$35<br>0.3% | $10,130<br>+$16<br>0.2% | $10,114<br>-<br>- | $10,125<br>$10<br>0.1% | $10,161<br>+$47<br>0.5% | $10,138<br>+$24<br>0.2% | $10,531<br>+$417<br>4.1% | $10,471<br>+$357<br>3.5% |
| **Cost Certainty**<br>Scenario Range (NPVRR) | $2,759<br>+$1,161<br>72.6% | $2,754<br>+$1,156<br>72.3% | $2,766<br>+$1,167<br>73.0% | $2,777<br>+$1,179<br>73.8% | $2,747<br>+$1,149<br>71.9% | $2,487<br>+$889<br>55.6% | $1,598<br>-<br>- | $1,855<br>+$257<br>16.1% |
| **Cost Risk**<br>Highest Scenario NPVRR | $11,974<br>+$477<br>4.1% | $11,951<br>$454<br>3.9% | $11,947<br>+$449<br>3.9% | $11,957<br>+$459<br>4.0% | $11,976<br>+$478<br>4.2% | $11,773<br>+$276<br>2.4% | $11,498<br>-<br>- | $11,527<br>+$29<br>0.3% |
| **Lower Cost Opportunity**<br>Lowest Scenario NPVRR | $9,215<br>+$36<br>0.4% | $9,197<br>+$18<br>0.2% | $9,181<br>+$2<br>0.0% | $9,179<br>-<br>- | $9,229<br>+$49<br>0.5% | $9,287<br>+$108<br>1.2% | $9,899<br>+$720<br>7.8% | $9,671<br>+$492<br>5.3% |
| **Carbon Emissions**<br>M of tons 2024-40 Cum. (Scenario Avg.) | 43.3<br>+22<br>102% | 33.7<br>+12<br>57% | 28.5<br>+7<br>33% | 23.0<br>+2<br>8% | 33.7<br>+12<br>57% | 28.5<br>+7<br>33% | 21.4<br>-<br>- | 30.9<br>+9<br>44% |
| **Employees**<br>Approx. existing gen. jobs compared to 2018 IRP* | +127 | 0 | -127 | -127 | -4 | -131 | -34 | -4 |
| **Local Economy**<br>NPV of existing fleet property tax relative to 2018 IRP | +$13 | $0 | -$10 | -$23 | $0 | -$10 | -$16 | +$13 |

*Adding replacement projects could have an impact on net jobs

Not a viable pathway due to implementation timing

The following key observations were made:

- Retaining Michigan City 12 beyond the currently planned retirement date of 2028 (Portfolio 1) is higher cost than the alternatives across all four scenarios.
- Retirement of Michigan City 12 in 2024 (Portfolio 4) is higher cost than later retirement in three out of the four scenarios and is not a viable pathway given insufficient timing to secure replacement capacity.
- Retirement of Michigan City 12 in 2026 (Portfolio 3) has the lowest Cost to Customer under the Reference Case and in three out of four scenarios and achieves the most significant CO2 reductions of the viable portfolios testing coal retirement.

- Retirement of Michigan City in 2028 (Portfolio 2) is very close to Portfolio 3 on all cost metrics, while also preserving jobs for NIPSCO employees and local property tax benefits for two additional years.

- Acceleration of the Schahfer 16A/B retirement to 2025 (Portfolios 5 and 6) is slightly higher cost than retaining the units until 2028, but early retirement could be influenced by unit operational condition and other external policy and technology factors, since additional renewable energy replacement (Portfolios 6) provides lower costs under scenarios with significant carbon regulation (AER and EWD).

- A retirement of Sugar Creek in the 2030s (Portfolio 7) offers the lowest carbon emission profile and, along with potential retrofit to reduce CO2 emissions (Portfolio 7H), provides a hedge against significant environmental regulations that would otherwise raise portfolio costs.

### 9.1.9 Preferred Existing Fleet Portfolio

NIPSCO's preferred existing fleet portfolio strategy is to retire Michigan City 12 between 2026 and 2028 , to optimize the retirement timing of Schahfer 16A/B between 2025 and 2028, and to keep open the option of retiring or retrofitting the Sugar Creek plant in the 2030s based on environmental policy evolution and technology advancement.

Overall, Portfolio 2 (2028 Michigan City 12 retirement) and Portfolio 3 (2026 Michigan City 12 retirement) were the lowest cost, viable existing fleet portfolio options, and preserving optionality for the Michigan City 12 retirement date will allow NIPSCO to perform full due diligence on RFP projects to confirm timing and costs, monitor ongoing market design and environmental policy changes, and react to technology evolution.

In addition, although Schahfer 16A/B may provide relatively low-cost capacity through 2028, NIPSCO will retain flexibility with retirement timing based on the ultimate Michigan City 12 retirement timing and associated replacement opportunities, Schahfer 16A/B's operational performance, and policy and technology developments.

Finally, while Portfolios 7 and 7H are higher cost under currently expected conditions, retirement or conversion of Sugar Creek in the 2030s, with additional early renewable additions, would be lower cost than continuing to operate the unit fully on natural gas in the event of a high carbon price or other aggressive clean energy policy implementation. Therefore, NIPSCO's preferred existing fleet portfolio strategy explicitly keeps such long-term options open regardless of the retirement dates for Michigan City and Schahfer 16A/B. As a result, the replacement analysis (described in more detail below) continued to evaluate such strategies in more detail.

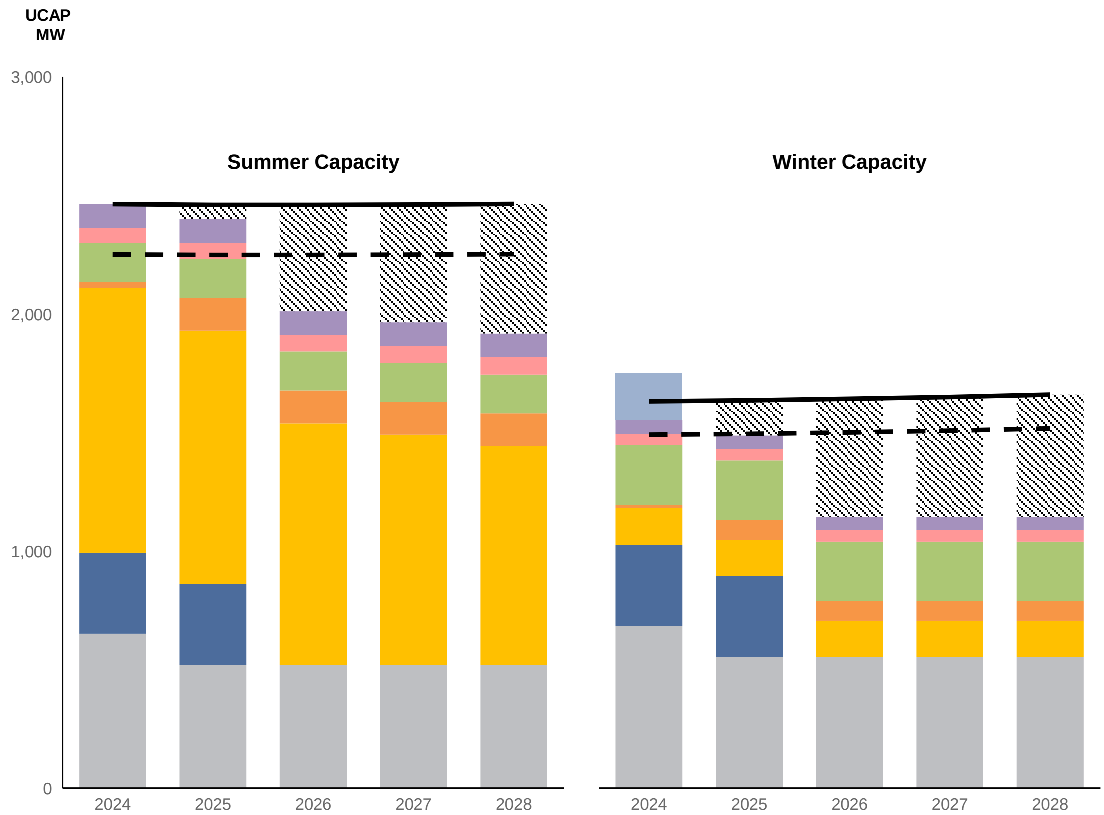
It is anticipated that NIPSCO's 2021 IRP preferred retirement strategy will require certain upgrades to the transmission system in order to maintain system reliability and remain compliant with NERC transmission planning standards, NIPSCO Planning criteria, and MISO requirements. As noted above, nearly $90 million in costs was assessed with the retirement of Michigan City 12 and the Schahfer 16 A/B units in the IRP analysis. This assumption will be validated once NIPSCO proceeds with filing the required forms with MISO (Attachment Y).

With its preferred existing fleet portfolio strategy, NIPSCO has balanced customer cost and cost risk, with portfolio flexibility and the ability to successfully and reliability transform its supply resources to meet its customers' needs. This option also balances other non-economic considerations such as environmental sustainability, portfolio flexibility, employee considerations, and property tax impacts.

Under such a portfolio, a capacity gap of up to 547 MW in the summer and up to 515 MW in the winter will open up by 2028,[107] as shown in Figure 9-10, which summarizes current and expected capacity resources against NIPSCO's Reference Case load forecast, inclusive of planning reserve margin requirements, and assuming the *earliest potential resource retirements* studied in the existing fleet analysis (Schahfer 16A/B in 2025 and Michigan City 12 in 2026). Uncertainty in the future capacity gap will be driven by load growth, MISO planning reserve margin targets, and realized renewable resource capacity credit over time. This capacity gap is the subject of the replacement analysis that is described next.

[107] The capacity gap would be slightly smaller in 2025 or 2026 if the Michigan City 12 and Schahfer 16AB units are retired at points in time prior to 2028. However, this represents the resulting gap by 2028 of any retirement strategy, as illustrated in Figure 9-10.

**Figure 9-10: Earliest Future Capacity Need Based on Unit Retirements**




## 9.2 Replacement Analysis

### 9.2.1 Process Overview

NIPSCO evaluated a range of potential resource replacement options to fill the capacity gap that would develop as the Michigan City 12 and Schahfer 16A/B units retire. For the replacement analysis, Portfolio 3 from the existing fleet analysis was used to assess portfolio selection under the earliest possible retirement of Michigan City 12, noting that Portfolio 2 (Michigan City 12 retirement in 2028) would have similar results, with small changes in resource addition timing.[108]

NIPSCO's replacement analysis was performed in a similar manner to the existing fleet analysis, with the following major steps:

- Identify replacement resource concepts for NIPSCO, primarily around considerations for CO2 emission intensity and resource dispatchability.

[108] This approach does not imply that NIPSCO has determined a specific Michigan City12 retirement date, but is useful for replacement resource selection, given that 2026 was deemed to be the earliest viable retirement date.

- Develop specific replacement portfolios within each concept using IRP optimization tools, bids from the RFPs, and expert judgment.
- Evaluate each replacement portfolio in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed in detail in Section 8).
- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred replacement portfolio strategy.

### 9.2.2 Identification of Replacement Resource Concepts

NIPSCO developed a matrix of replacement resource concepts based on two key planning considerations. The first consideration was structured around the "dispatchability" of the resource options. Broadly speaking, dispatchability refers to the ability of resources within the portfolio to provide energy "on demand," meaning that resources not reliant on external weather conditions and factors and resources with longer energy duration capabilities are considered more dispatchable. Across the dispatchability consideration, three categories were broadly defined:

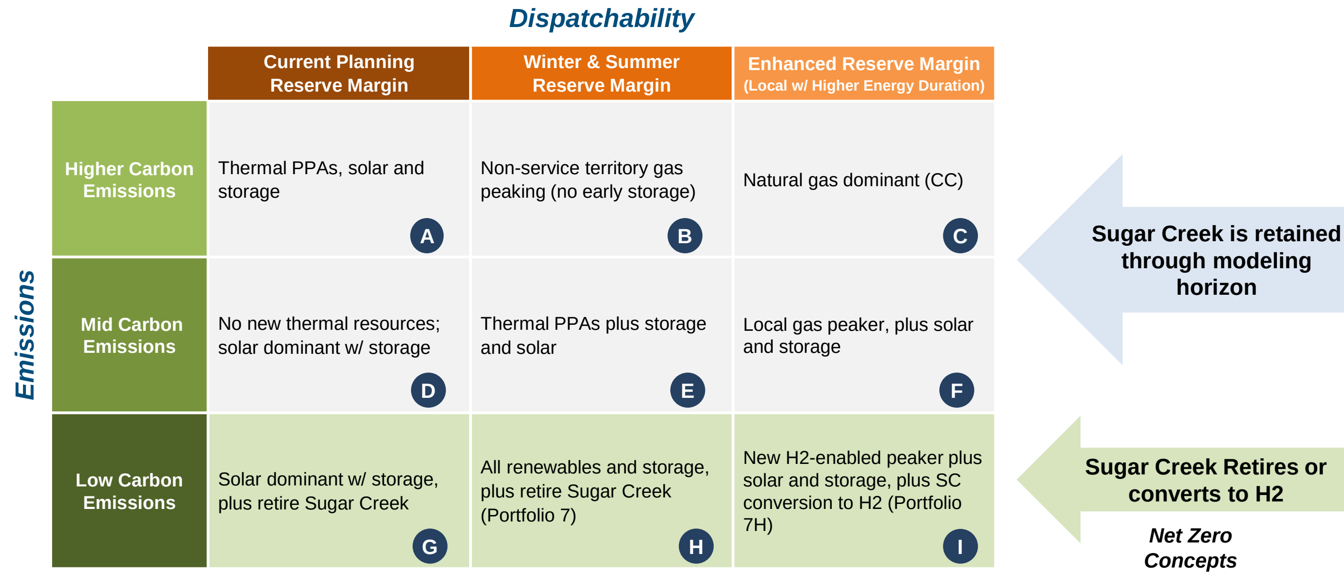
- Portfolios that meet only the existing summer reserve margin requirements over time and tend to contain more solar capacity than other dispatchable resource types;[109]
- Portfolios that meet both winter and summer reserve margin requirements over time and tend to contain additional thermal or storage capacity;
- "Enhanced" reserve margin portfolios that more fully rely on local resources with longer energy duration capabilities, especially thermal resources. Such a portfolio category recognizes the need for local resources during emergency conditions and anticipates future MISO market policy developments that may reduce the capacity credit for resources with limited energy durations, such as four-hour batteries.

The second consideration was structured around the $CO_2$ emission intensity of each potential portfolio option. While no specific emission intensities were defined, portfolios with more fossil-fired resource capacity were considered to have higher emission intensities, while portfolios with more renewable and storage capacity were considered to have lower emission intensities. In addition, specific net-zero emission concepts based on retirement or conversion to hydrogen of all fossil resources in the portfolio were developed.

Overall, nine different concepts were identified for more detailed portfolio development, as shown in Figure 9-11. These portfolios are referred to as Portfolios A-I throughout the rest of this Section.

[109] Given expectations for MISO market rules changes, these portfolio concepts are not viable, but were evaluated to assess their costs across scenarios along with other tradeoffs. Certain stakeholders also expressed an interest in evaluating this theme.

**Figure 9-11: Replacement Consideration Matrix**




### 9.2.3 Development of Specific Replacement Portfolios

Based on the nine replacement concepts, NIPSCO then developed specific portfolios to fit each theme. This was done through a combination of the Aurora model's portfolio optimization capability and expert judgment to adjust portfolio concepts based on optimization analysis and available RFP bids.

*DSM and DER Selection*

Across all portfolio themes, the following DSM bundles were incorporated based on the economic optimization analysis: (i) Tier 1 residential EE for 2024-2029, 2030-2035, and 2036-2041; (ii) commercial and industrial EE for 2024-2029, 2030-2035, and 2036-2041; and (iii) the residential DR rates programs after 2030. (*See* Section 5 for additional detail on the specific energy and peak savings contributions of each bundle). In addition, 10 MW of NIPSCO DER was incorporated in all portfolio themes, reflecting the DER opportunities with the largest investment deferral benefit (*See* Section 4 for additional detail).

*All-Source RFP Resource Selection*

Beyond DSM and DER additions, NIPSCO used the following approach to select RFP project additions for each of the portfolio themes, which are summarized in Figure 9-12 with incremental ICAP additions and in Figure 9-13 with new resource UCAP contributions shown in the context of the remaining portfolio and expected seasonal reserve margin requirements for 2027:

- Portfolios B, E, and F were based on the optimized portfolio themes from the existing fleet analysis, with specific RFP tranches to identify local versus remote gas peaking options (in Portfolios B and F) and to adjust the amount of gas peaking, storage, and solar capacity to fit the themes and meet reserve margin requirements.

- The net energy sales constraint enforced in the existing fleer analysis phase was relaxed to allow for fossil resources with higher energy contributions for Portfolio C, allowing for the inclusion of a combined cycle.

- Optimization testing was evaluated across Reference and high environmental regulation scenarios under summer reserve margin targets only to develop Portfolios A, D, and G with higher levels of solar and solar plus storage.

- Portfolios H and I were mapped to Portfolios 7 and 7H, respectively from the existing fleet analysis to capture the net zero concepts with Michigan City retirement in 2026.

Beyond the RFP selection period, NIPSCO relied upon the optimization analysis results from the existing fleet analysis phase, which suggested that generic solar and storage resources were most cost-effective additions over time to meet capacity needs and energy requirements associated with expectations for declining capacity factors for the Sugar Creek unit, expiring wind contracts, and solar degradation over time. Solar and storage addition amounts were adjusted to ensure reserve margin targets were met across each of the portfolio themes.[110] A summary of the total capacity additions through 2040 for all nine portfolios is shown in Figure 9-14, with a 2040 supply-demand balance on a UCAP basis summarized in Figure 9-15.

[110] Note that for portfolio development purposes, a mix of PPA and owned resources was assumed over the long-term, as opposed to a generic PPA least cost solution that was identified by the optimizer. This is consistent with NIPSCO's 2018 IRP preferred portfolio and does not necessarily represent NIPSCO's preferred procurement strategy for projects into the 2030s. Future IRPs will assess ongoing needs on a regular basis.

## Figure 9-12: Replacement Portfolio Resource Additions through 2027 (ICAP MW)

| *Emissions* \ *Dispatchability* | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) |
|---|---|---|---|
| Higher Carbon Emissions | **A**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Thermal PPA 150MW<br>Storage 135MW<br>Solar+Storage 450MW*<br>Solar 250MW | **B**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Gas Peaker** 443MW<br>Thermal PPA 150MW<br>Solar 100MW | **C**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Gas CC 650MW<br>*Portfolio violates normal net long energy sales constraints enforced in optimization* |
| Mid Carbon Emissions | **D**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Storage 135MW<br>Solar+Storage 450MW*<br>Solar 400MW | **E**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Thermal PPA 150MW<br>Storage 470MW<br>Solar 250MW | **F**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Gas Peaker** 300MW<br>Thermal PPA 150MW<br>Storage 135MW<br>Solar 100MW |
| Low Carbon Emissions | **G**<br>NIPSCO DER 10MW<br>Storage 135MW<br>Solar+Storage 450MW*<br>Solar 450MW | **H**<br>NIPSCO DER 10MW<br>Wind 200MW<br>Storage 570MW<br>Solar 250MW | **I**<br>NIPSCO DER 10MW<br>SC H2 Electrolyzer 20MW<br>SC Uprate 53MW<br>H2 Enabled Peaker 193MW<br>Wind 200MW<br>Storage 370MW<br>Solar 250MW |

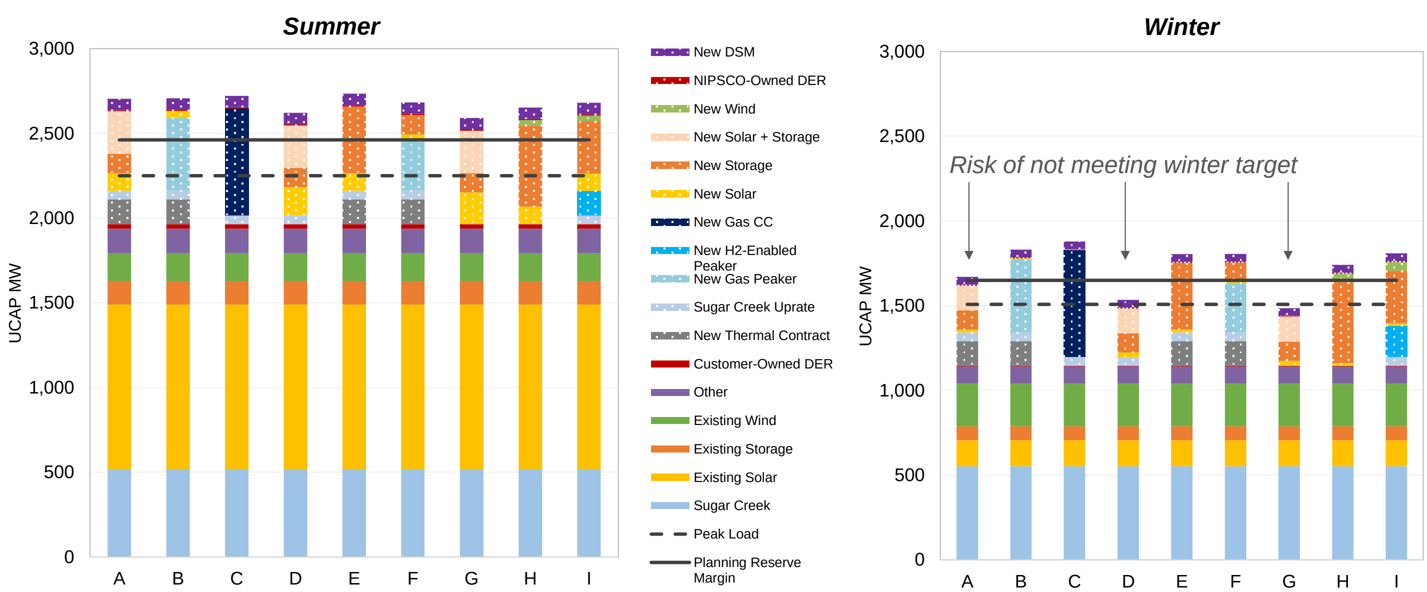
Sugar Creek is retained through modeling horizon

Sugar Creek Retires or converts to H2

*Net Zero Concepts*

*Note: Residential/Commercial DSM universally selected across portfolios*
**Represents 300 MW of solar and 150 MW of storage*
***Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

## Figure 9-13: 2027 Supply Mix by Replacement Portfolio (UCAP MW) – without Michigan City 12 and Schahfer 16AB



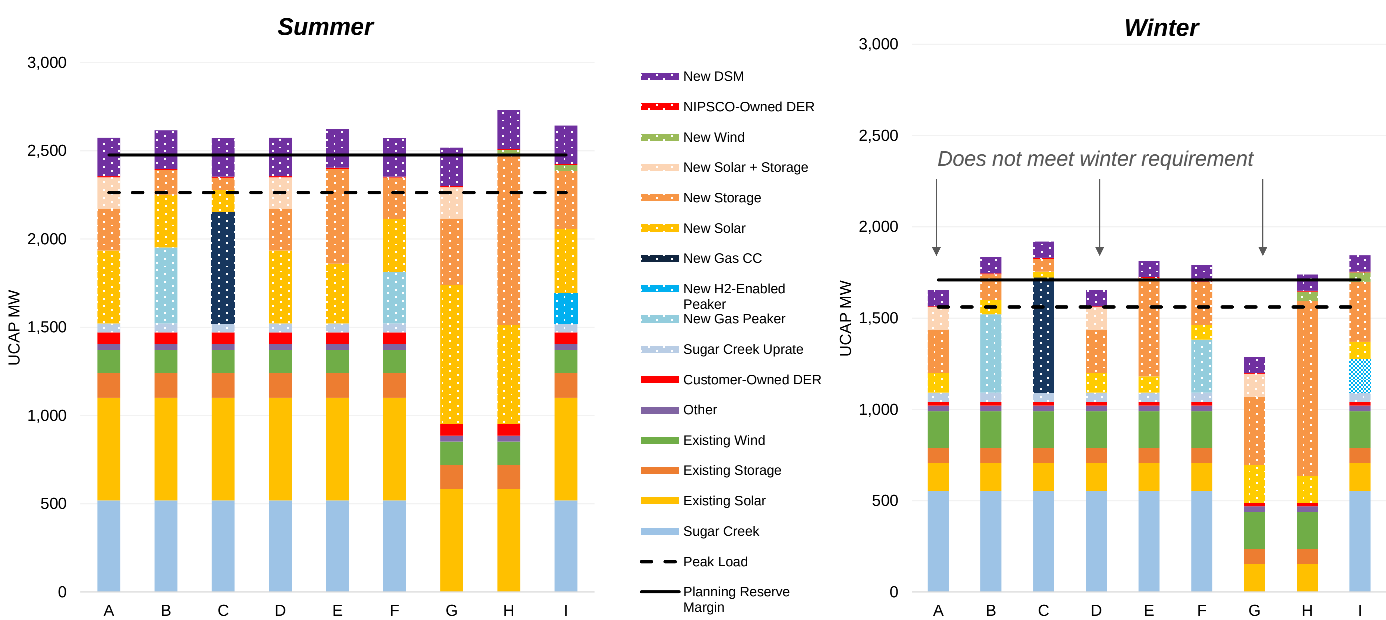
## Figure 9-14: Replacement Portfolio Resource Additions through 2040 (ICAP MW)

*Dispatchability*

| *Emissions* | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) | |
|---|---|---|---|---|
| Higher Carbon Emissions | **A**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Thermal PPA 150MW**<br>**Storage 335MW**<br>Solar+Storage 450MW*<br>**Solar 1,650MW** | **B**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Gas Peaker*** 443MW<br>Thermal PPA 150MW**<br>**Storage 200MW**<br>**Solar 1,200MW** | **C**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Gas CC 650MW<br>**Storage 100MW**<br>**Solar 500MW** | Sugar Creek is retained through modeling horizon |
| Mid Carbon Emissions | **D**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>**Storage 335MW**<br>Solar+Storage 450MW*<br>**Solar 1,650MW** | **E**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Thermal PPA 150MW**<br>**Storage 770MW**<br>**Solar 1,350MW** | **F**<br>NIPSCO DER 10MW<br>SC Uprate 53MW<br>Gas Peaker*** 300MW<br>Thermal PPA 150MW**<br>**Storage 335MW**<br>**Solar 1,200MW** | |
| Low Carbon Emissions | **G**<br>NIPSCO DER 10MW<br>**Storage 535MW**<br>Solar+Storage 450MW*<br>**Solar 3,150MW** | **H**<br>NIPSCO DER 10MW<br>Wind 200MW<br>**Storage 1,370MW**<br>**Solar 2,250MW** | **I**<br>NIPSCO DER 10MW<br>SC H2 Electrolyzer 20MW<br>SC Uprate 53MW<br>H2 Enabled Peaker 193MW<br>Wind 200MW<br>**Storage 470MW**<br>**Solar 1,450MW** | Sugar Creek Retires or converts to H2<br>***Net Zero Concepts*** |

*Note: Residential/Commercial DSM plus a DR Rates program universally selected across portfolios*
**Represents 300 MW of solar and 150 MW of storage*
***Ten-year PPA term would have this resource expire by mid-2030s*
****Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

## Figure 9-15: 2040 Supply Mix by Replacement Portfolio (UCAP MW)



### 9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics

Similar to the scorecard developed for the existing fleet analysis, NIPSCO developed a scorecard of objectives, indicators, and key metrics associated with the replacement analysis (*See* Figure 9-16). While major objectives remained consistent across stages of the analysis, some changes were made for the replacement scorecard relative to the existing fleet scorecard:

- Risk metrics associated with the stochastic analysis were added, which included several measurements of points on the stochastic distribution of revenue requirement outcomes relative to the median: (i) cost certainty was measured at the 75$^{th}$ percentile; (ii) cost risk was measured with the 95$^{th}$ percentile conditional value at risk, or the average of all outcomes above the 95$^{th}$ percentile; and (iii) lower cost opportunity was measured at the 5$^{th}$ percentile.

- Reliability was measured in an economic fashion through the potential value upside in the ancillary services markets and through the Reliability Assessment scoring (see additional detail later in this section).

- Resource optionality was measured through the MW-weighted commitment duration of generation commitments in the year 2027.

- Employee count was not recorded, given uncertainty with future project details.

**Figure 9-16: Scorecard Metrics for Replacement Analysis**

| Objective | Indicator | Description and Metrics |
|---|---|---|
| Affordability | Cost to Customer | • Impact to customer bills<br>• Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results) |
| Rate Stability | Cost Certainty | • Certainty that revenue requirement within the most likely range of outcomes<br>• Metric: Scenario range NPVRR and 75th % range vs. median |
| | Cost Risk | • Risk of unacceptable, high-cost outcomes<br>• Metric: Highest scenario NPVRR and 95th % conditional value at risk (average of all outcomes above 95th % vs. median) |
| | Lower Cost Opportunity | • Potential for lower cost outcomes<br>• Metric: Lowest scenario NPVRR and 5th % range vs. median |
| Environmental Sustainability | Carbon Emissions | • Carbon intensity of portfolio<br>• Metric: Cumulative carbon emissions (2024-40 short tons of $CO_2$) from the generation portfolio |
| Reliable, Flexible, and Resilient Supply | Reliability | • The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules<br>• Metric: Sub-hourly A/S value impact and Reliability Assessment scoring |
| | Resource Optionality | • The ability of the portfolio to flexibly respond to changes in NIPSCO load, technology, or market rules over time<br>• Metric: MW weighted duration of generation commitments (UCAP – 2027) |
| Positive Social & Economic Impacts | Employees | • *Addressed in Existing Fleet Analysis for existing generation assets; employee numbers will be dependent on specific asset replacements* |
| | Local Economy | • Effect on the local economy from new projects and ongoing property taxes<br>• Metric: NPV of property taxes from the entire portfolio |

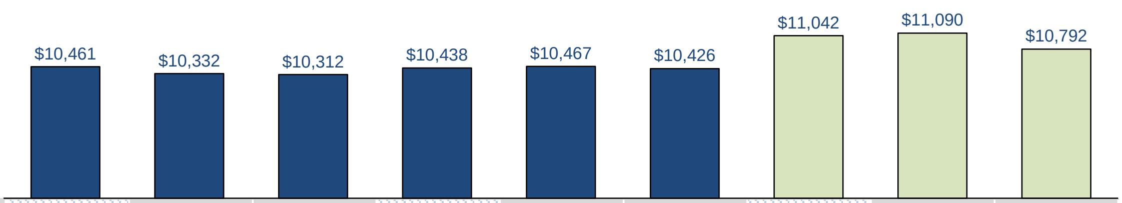
### 9.2.5 Evaluation of Replacement Portfolios – Core Analysis Results

*Reference Case Cost Results*

The nine replacement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail) to estimate revenue requirements for each over time. The assessment was first performed across the Reference Case set of market assumptions and inputs to calculate baseline projections of the NPVRR over the thirty-year planning horizon, which are summarized in Figure 9-17.

Under the Reference Case market conditions, Portfolios A through F are all within ~$150 million of each other on an NVPRR basis, with Portfolios B, C, and F (portfolios with natural gas capacity additions) having the lowest costs. Portfolio C has the lowest NPVRR, but develops a very net long position, with excess energy sales offsetting portfolio costs.[111] Portfolios G, H, and I (net zero concepts) are higher cost, with Portfolio I retaining the optionality to burn natural gas at Sugar Creek under Reference Case conditions.

**Figure 9-17: Reference Case Cost to Customer Impacts – Replacement Portfolios (30-year NPVRR – millions of $)**




| Replacement Theme | Thermal PPAs, solar and storage | Non-service territory gas peaking (no early storage) | Natural gas dominant (CC) | No new thermal resources; solar dominant w/ storage | Thermal PPAs plus storage and solar | Local gas peaker, plus solar and storage | Solar dominant w/ storage, plus retire Sugar Creek | All renewables and storage, plus retire Sugar Creek (Portfolio 7) | New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H) |
|---|---|---|---|---|---|---|---|---|---|
| | A | B | C | D | E | F | G | H | I |
| Carbon Emissions | Higher | Higher | Higher | Mid | Mid | Mid | Low | Low | Low |
| Dispatchability | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) |
| Rank (1=Least Cost) | 5 | 2 | 1 | 4 | 6 | 3 | 8 | 9 | 7 |
| Delta from Least Cost | $150<br>1.5% | $21<br>0.2% | - | $126<br>1.2% | $156<br>1.5% | $115<br>1.1% | $730<br>7.1% | $778<br>7.5% | $480<br>4.7% |

Not a viable pathway due to not meeting winter planning reserve margins

*Scenario Cost Results*

In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each replacement portfolio against each scenario described earlier in Section 8. The NPVRR for each replacement portfolio across each scenario is summarized in Figure 9-18, with additional details regarding the scenario results described below.

[111] This portfolio is also higher than several alternatives over a 20-year period, indicating that the long-term merchant energy margins contribute to the overall lower costs.

**Figure 9-18: Cost to Customer across All Scenarios – Replacement Portfolios (30-year NPVRR – millions of $)**

| Replacement Portfolio | Reference Case | Status Quo Extended | Aggressive Environmental Regulation | Economy-Wide Decarbonization |
|---|---|---|---|---|
| A | 10,461 | 9,657 | 11,356 | 12,015 |
| B | 10,332 | 9,400 | 11,444 | 12,182 |
| C | 10,312 | 9,309 | 11,637 | 12,518 |
| D | 10,438 | 9,644 | 11,338 | 11,965 |
| E | 10,467 | 9,588 | 11,373 | 12,126 |
| F | 10,426 | 9,495 | 11,489 | 12,243 |
| G | 11,042 | 10,485 | 11,573 | 11,809 |
| H | 11,090 | 10,458 | 11,482 | 12,011 |
| I | 10,792 | 9,933 | 11,550 | 11,848 |

*Note that Portfolio I was assessed with a hydrogen subsidy of $0.50/kg in the AER and EWD scenarios.

Under the SQE Scenario, with no carbon regulation and low natural gas prices, portfolios with more gas generation (particularly Portfolio C) are lower in cost. In addition, under this scenario, the cost of pursuing a net zero strategy increases, with the spread from the lowest to highest cost portfolios widening to over $1 billion in NPVRR

On the other hand, under a scenario with rising gas prices and strict environmental regulation (through a carbon price in the AER scenario), portfolios with more gas generation (particularly Portfolio C) are higher cost. Among viable options that meet expected summer and winter reserve margin requirements, Portfolio E (storage and solar, with no new gas capacity additions) is lowest cost

Finally, under the EWD scenario, similar trends as those observed in the AER scenario are also evident. However, clean energy resources have more value in this scenario, given the Clean Energy Standard construct and long-term extensions in federal tax credits, resulting in Portfolio I (assuming a future hydrogen subsidy)[112] having lowest costs among viable portfolios.

Overall, across scenarios, the following key observations were made:

- Portfolios that have the highest solar additions and meet only the summer reserve margin target (Portfolios A, D, G) perform best under high environmental regulation scenarios (AER and EWD), but are higher cost than alternatives in other scenarios and are not viable options, given expected market rule changes.

- Adding new combined cycle capacity (Portfolio C) results in the lowest costs under the Reference and SQE scenarios, but is highest cost in the AER and EWD

[112] As noted in Section 8, environmental regulation, particularly in the EWD scenario, could include subsidies for emerging technologies such as hydrogen. Section 4.6.4.1 discusses the development of green hydrogen costs for the 2021, including the $0.50/kg subsidy sensitivity evaluated here.

scenarios, illustrating how adding significant amounts of additional natural gas-fired energy to the portfolio contributes to higher levels of scenario risk.

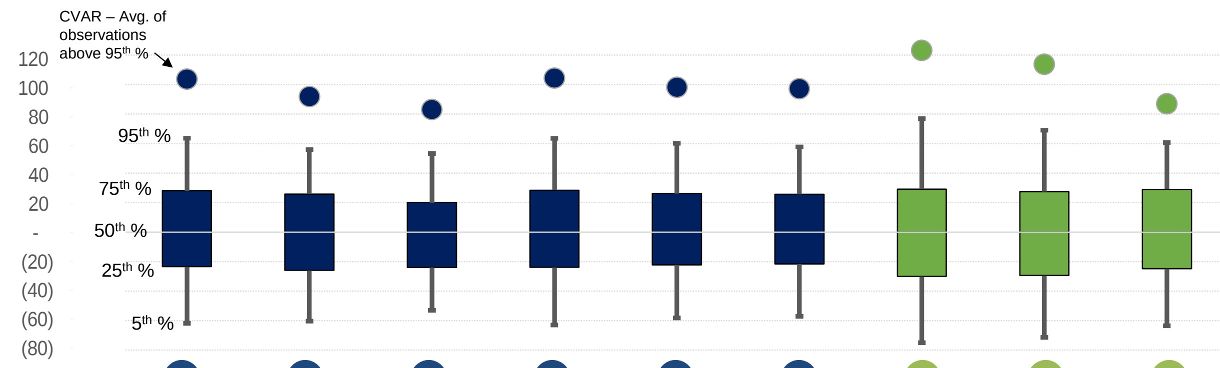
- While a portfolio approach that retires all thermal resources by 2032 and relies solely on renewables and storage (Portfolio H) provides a high level of scenario cost certainty, it is highest cost under Reference Case conditions.

*Stochastic Analysis Results*

In addition to assessing each replacement portfolio against each market scenario, NIPSCO has also evaluated the replacement options against the full stochastic distribution of potential outcomes for commodity prices and renewable output, as described in more detail in Section 8. The stochastic assessment is used to further evaluate the risk of each of the portfolios against a framework that is focused on short-term price and renewable output volatility as opposed to the long-term movement in macroeconomic or policy trends that are assessed across scenarios.

Figure 9-19 presents a summary of the stochastic results for each of the replacement portfolios, with the graphics highlighting the spread in NPVRR relative to the median ($50^{th}$ percentile) cost for each portfolio. The $25^{th}$ to $75^{th}$ percentile range is shown in the shaded box are, while the $5^{th}$ and $95^{th}$ percentiles are marked by the tails or "whiskers" shown below and above the box, respectively. The CVAR or average of the observations above the $95^{th}$ percentile is indicated with a dot. The key risk metrics associated with NIPSCO's integrated scorecard framework are shown in the table below the graphic.

**Figure 9-19: Summary of Stochastic Results – Replacement Portfolios (30-year NPVRR – millions of $)**



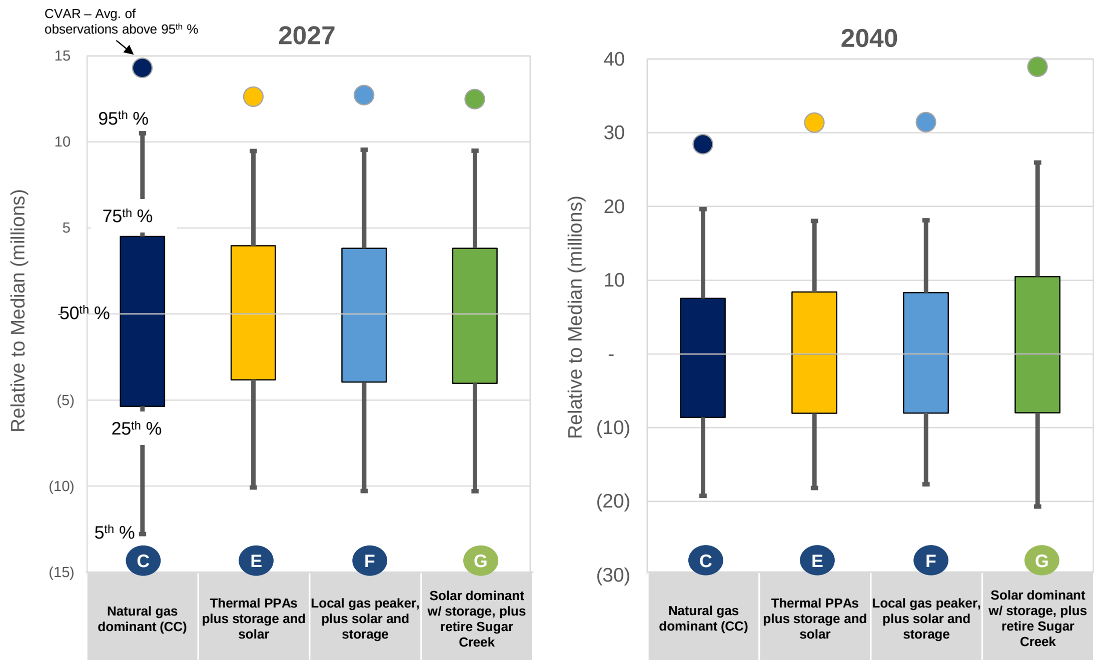

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| Replacement Theme | Thermal PPAs, solar and storage | Non-service territory gas peaking (no early storage) | Natural gas dominant (CC) | No new thermal resources; solar dominant w/ storage | Thermal PPAs plus storage and solar | Local gas peaker, plus solar and storage | Solar dominant w/ storage, plus retire Sugar Creek | All renewables and storage, plus retire Sugar Creek (Portfolio 7) | New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H) |
| Carbon Emissions | Higher | Higher | Higher | Mid | Mid | Mid | Low | Low | Low |
| Dispatchability | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) |
| $95^{th}$ % CVAR Delta from Low | 21 | 9 | - | 21 | 15 | 14 | 40 | 31 | 4 |
| $75^{th}$ % Delta from Low | 8 | 6 | - | 8 | 6 | 6 | 9 | 7 | 9 |
| $5^{th}$ % Delta from Low | 13 | 15 | 22 | 12 | 17 | 18 | - | 4 | 11 |

Overall, the magnitude of cost distributions across portfolios is narrower than the scenario range, suggesting that stochastic risk for these portfolio options is less impactful than the major policy or market shifts evaluated across scenarios. However, the stochastic analysis results do indicate that over the 30-year time horizon, dispatchability serves to mitigate tail risk, as portfolios that retain Sugar Creek or add natural gas, including with hydrogen enablement, or storage capacity (Portfolios B, C, E, F, and I) perform best at minimizing upside cost risk by resulting in the lowest difference in the $95^{th}$ CVAR relative to the median. Meanwhile, the lowest downside range is observed in renewable-dominant portfolios, showcasing that such portfolio strategies (illustrated through Portfolios A, D, G, and H) have the broadest range of outcomes.

The stochastic analysis also illustrates the changing risks likely to be faced by NIPSCO's portfolio over time. Under current market conditions, portfolios with larger amounts of natural gas energy are likely to be highly exposed to market price and dispatch risk. As a result, over the next several years, Portfolio C is likely to have a broader range of cost outcomes and higher tail risk. However, over time, as the market becomes more dominated by intermittent resources, renewable output uncertainty becomes more correlated to power prices, and NIPSCO portfolio strategies that rely most on intermittent renewable resources (Portfolio G, for example) have the greatest tail risk. This is because they expose the portfolio to high costs associated with low renewable output/high market price events.

This phenomenon is illustrated in Figure 9-20, which show the range of stochastic cost outcomes for a selection of four portfolios in the years 2027 and 2040. While Portfolio C has the greatest risk exposure in 2027 and Portfolio G has the greatest risk exposure in 2040, portfolios that integrate some level of dispatchable capacity in the form of peaking or storage resources (Portfolios E and F) perform similarly from a risk perspective over time and hedge against both near-term and long-term stochastic risk exposure.

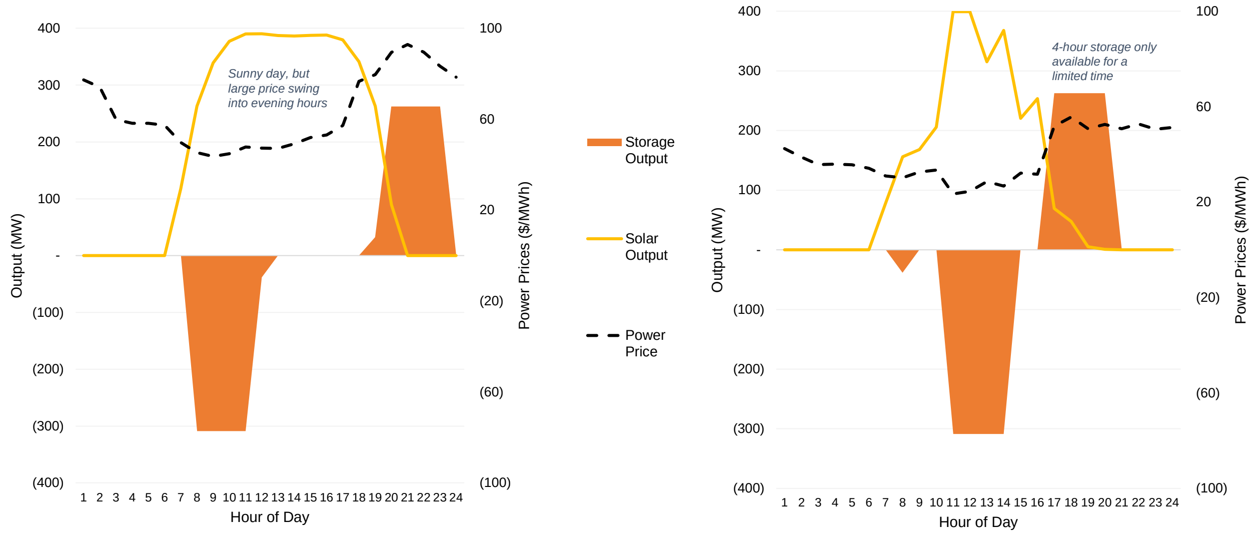
**Figure 9-20: Risk Profile Evolution for a Sample of Replacement Portfolios**



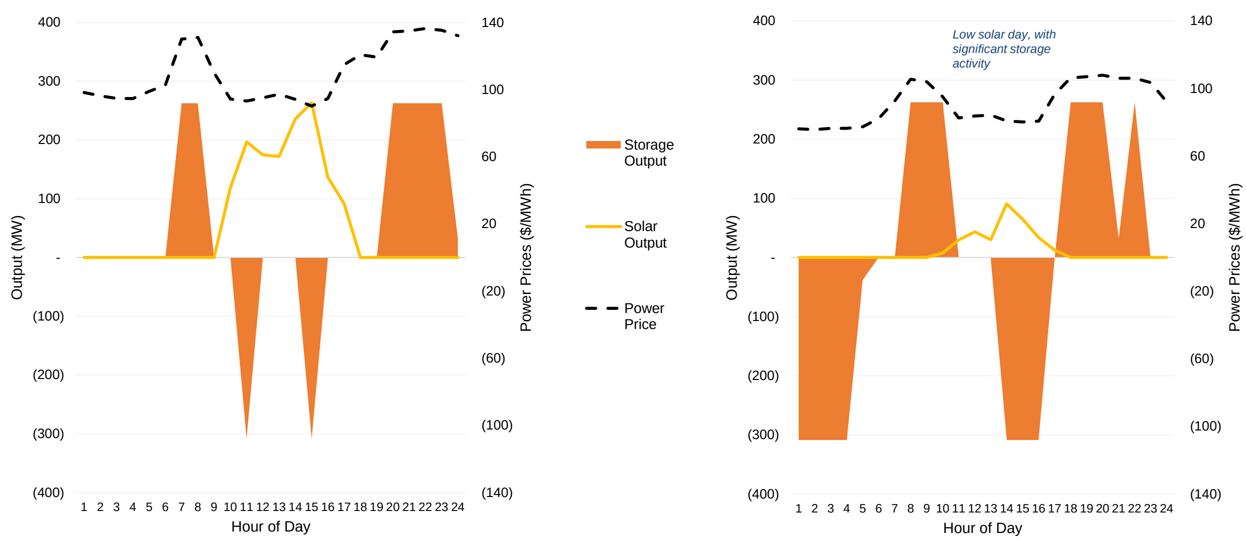

This conclusion can also be illustrated by evaluating a sample of daily outcomes from the stochastic analysis across seasons. As shown in Figure 9-21, during summer days, power prices are likely to be negatively correlated to solar output, with price dips during mid-day hours (when solar output is high) and price spikes in the evenings and overnight (when solar output is low). As a result, a portfolio dominated by solar capacity will have excess energy during low-priced hours and could be exposed to market purchases during high-priced hours. Portfolios that integrate storage or other dispatchable resources could mitigate this risk, which may be even more pronounced on days with low solar output (right graphic).

Figure 9-22 provides additional examples during the winter season, a time of year when solar output will be lower and potentially more volatile. As a result, during days with low solar output, significant market exposure is possible for portfolios without sufficient dispatchable capacity, particularly during the morning and evening peak load periods.

## Figure 9-21: Sample Stochastic Iterations for Summer Day Solar and Storage Output




## Figure 9-22: Sample Stochastic Iterations for Winter Day Solar and Storage Output




### *CO2 Emissions*

Across replacement portfolios, the biggest drivers of future CO2 emissions are whether the portfolio adds a significant new source of CO2 emissions in the form of a combined cycle (Portfolio C) and how Sugar Creek operates into the 2030s.[113] Therefore, Portfolio C has the highest emission profile over time, and Portfolios G and H (and Portfolio I if Sugar Creek converts to hydrogen) have the lowest emission profile. Figure 9-23 illustrates the projected CO2 emissions by portfolio over time for the Reference Case, while Figure 9-24 presents the cumulative emissions over the 2024-2040 period for each scenario, along with a reporting of the scenario average. As

[113] Note that the replacement portfolios were all evaluated under the assumption of a 2026 retirement date for Michigan City 12, which is not necessarily NIPSCO's preferred portfolio. See Figure 9-7 for the impact of retirement in 2026 versus 2028 on $CO_2$ emissions.

in the existing fleet analysis, emissions vary across scenarios based on different dispatch projections for the fossil units and the potential for hydrogen blending at Sugar Creek in the AER and EWD scenarios in Portfolio I.

**Figure 9-23: Annual CO2 Emissions for Existing Fleet Portfolios – Reference Case**

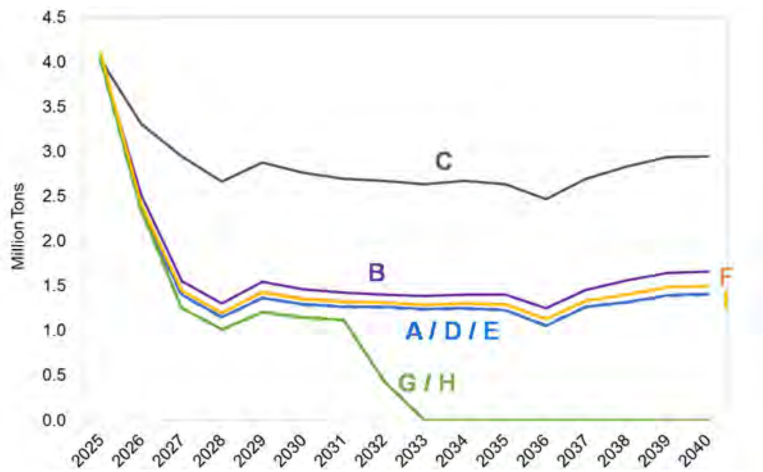
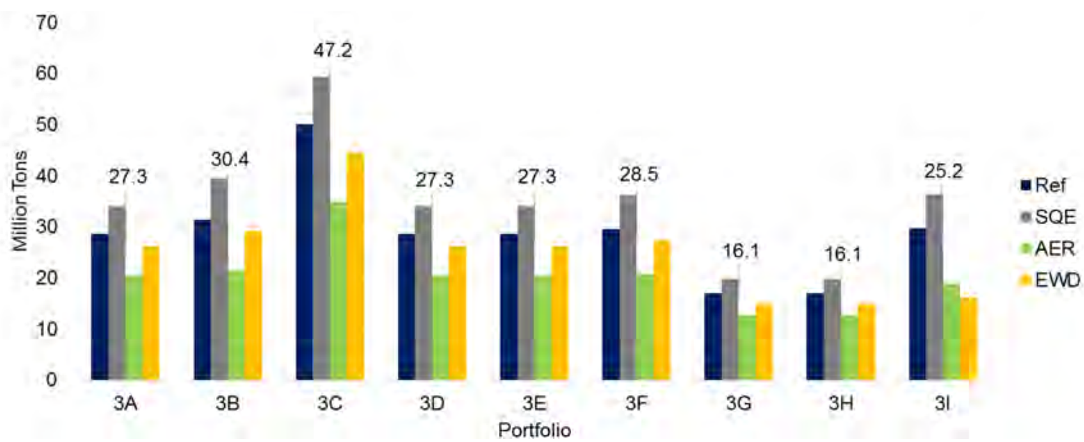



**Figure 9-24: 2024-2040 Cumulative Tons of CO2 Emissions for Existing Fleet Analysis – All Scenarios with Average**




*Additional DSM Analysis*

As noted earlier, all of NIPSCO's replacement portfolios contain several DSM measures that were found to be cost-effective in the optimization analysis. These included: (i) Tier 1 residential EE for 2024-2029, 2030-2035, and 2036-2041; (ii) commercial and industrial energy efficiency for 2024-2029, 2030-2035, and 2036-2041; and (iii) the residential DR rates programs after 2030. As discussed in Section 5, the core portfolio analysis was performed for RAP levels of DSM, although NIPSCO also evaluated the impact of using MAP levels, which includes additional savings available at higher costs, as summarized in Figure 9-25 and Figure 9-26,[114] respectively.

**Figure 9-25: MAP vs. RAP Annual GWh Savings – Residential Tier 1 and Commercial and Industrial Programs**

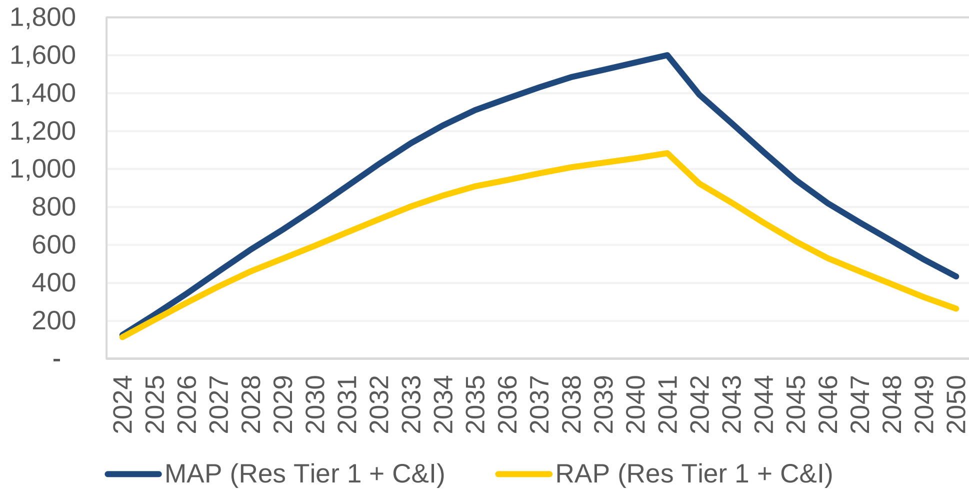



**Figure 9-26 : Levelized Costs ($/MWh) by DSM Bundle – RAP vs. MAP**

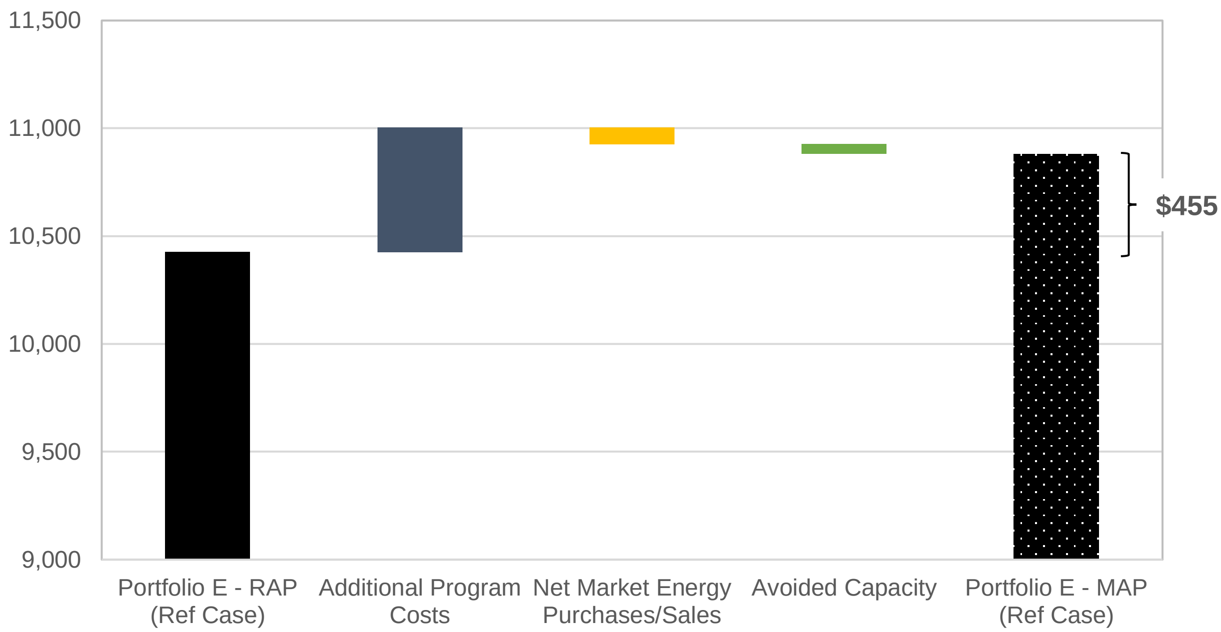
| | | RAP | MAP |
|---|---|---|---|
| 2024-2029 | Res Tier 1 | 53 | 140 |
| | C&I | 26 | 86 |
| 2030-2035 | Res Tier 1 | 60 | 160 |
| | C&I | 30 | 90 |
| 2036-2041 | Res Tier 1 | 65 | 165 |
| | C&I | 32 | 91 |

Using these inputs, NIPSCO evaluated the impact of moving to the MAP DSM bundles for a selection of replacement portfolios. This was done by effectively "forcing in" the same residential and commercial/industrial energy efficiency programs identified in the original optimization analysis, but at the MAP level instead of at the RAP level. This has the impact of both reducing energy requirements and mitigating the need for some long-term capacity additions. The impact of reduced energy requirements was evaluated through a re-dispatch of the portfolios in the Aurora portfolio model, while 100 MW of future storage additions in the 2030s were removed to reflect the reduced capacity obligation.

[114] Note that levelized costs are presented prior to cost adjustments for avoided T&D investment.

Under Reference Case conditions, NIPSCO's analysis found that moving from the RAP to the MAP DSM bundles would increase the 30-year NPVRR by $455 million for Portfolio F.[115] As illustrated in Figure 9-27, the additional program costs represent $578 million in NPVRR, while the value of saved energy associated with fewer net market purchases represented $78 million in NPVRR and the savings associated with avoided storage capacity additions represented $45 million in NPVRR. Alternative scenarios with higher costs of energy (especially the AER scenario) would increase the savings associated with net market energy purchases/sales, but still would not offset additional program costs. This analysis confirmed that the DSM programs contained in NIPSCO's preferred portfolio will be based on the RAP assumptions.

**Figure 9-27: 30-year NPVRR Impact of Shifting from RAP to MAP – Portfolio F Example**




## 9.2.6 Sub-Hourly Modeling with Ancillary Services

### 9.2.6.1 Background

Although the IRP's core economic analysis captures most portfolio cost elements, NIPSCO has broadened the scope of the 2021 IRP to assess additional elements of reliability, including Operating Reliability, as defined in MISO's RIIA report and summarized in Figure 9-28. Although all Operating Reliability elements cannot be evaluated in an economic fashion, MISO does operate markets for ancillary services which aim to enhance reliability at a very granular level and in real time.

[115] NIPSCO also tested the impact on Portfolio E and found that moving from the RAP to the MAP DSM bundles would increase the 30-year NPVRR by $429 million.

### Figure 9-28: Overview of Different Elements of Reliability and IRP Modeling Approach

| | Resource Adequacy | Energy Adequacy | Operating Reliability |
|---|---|---|---|
| **Definition:** | Having sufficient resources to reliably serve demand | Ability to provide energy in all operating hours continuously throughout the year | Ability to withstand unanticipated component losses or disturbances |
| **Forward Planning Horizon:** | Year-ahead | Day-ahead | Real-time or Emergency |
| **Reliability Factors:** | Reserve margin, ELCC and energy duration | Dispatchability, energy market risk exposure | Real Time Balancing System |
| **IRP Modeling Approach:** | Portfolio development constraints, with ELCC and seasonal accounting | Hourly dispatch analysis, including stochastic risk | **Ancillary services analysis (regulation, reserves), with sub-hourly granularity** |

*MISO Ancillary Services Market Overview*

MISO operates two energy and operating reserve markets: day-ahead and real-time. The day-ahead clears every hour, on the eve of the day of operations, on a co-optimized basis using SCUC, SCED, and SCED-pricing computer programs. On the day of operations, the real-time clears every 5-minutes on a co-optimized basis using SCED. The operating reserve market is composed of regulating reserves and contingency reserves. Resources are permitted to switch between markets, and there is no minimum threshold for continuous provision into a single market.[116] Currently, storage resources are only permitted to participate in the regulation market, but MISO is underway with tariff filings to allow them to participate in energy and other ancillary services markets.[117]

Resources participating in the day-ahead and real-time markets have the ability to specify, along other offer parameters, a commitment status which describes the ability or inability to dispatch. The five statuses are: economic, must-run (self-commit), outage, emergency, and not participating. “Economic” designates a resource available for commitment by the operator. “Must-run” designates a resource committed per market participant request and available for dispatch by MISO. “Outage” designates a resource not available in the energy or operating reserve markets because it is undergoing a planned or forced outage. “Emergency” designates a resource available for only emergency situations. “Not participating” designates a resource which will not participate in day-ahead or real-time energy market but is available.

Frequency regulation is used to address small mismatches between supply and demand. Regulating generators cleared in the day-ahead or real-time market must be fully deployable in regulation-up and regulation-down directions within a specified time period. Unlike some other

[116] MISO BPM 002 – p. 142
[117] BPM002 – p. 132, 170

RTOs that have separate markets for regulation-up and regulation-down, MISO has a single regulation market.

Contingency reserves are used to address unforeseen events such as a large generator tripping offline. Contingency reserves are composed of spinning and supplemental reserves. Spinning reserves are provided by units that are synchronized to grid, not generating at their maximum output, and able to ramp up their generation. Supplemental reserves are also provided by units that are not synchronized to the grid but are able to come online quickly if needed.

*FERC Order 841 Implications for Storage Market Participation*

The role of storage in the energy and ancillary services markets is likely to continue to evolve as the electricity markets comprise more intermittent resources. As a result, FERC issued Order No. 841 to boost competition in the storage sector and ensure that markets like MISO provide just and reasonable rates. Order No. 841 requires each RTO and ISO to revise its tariff to establish a participation model for electric storage resources consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, will help facilitate their participation in the RTO/ISO markets.

MISO is responsible for implementing this order and has been granted an extension for compliance through 2022. Some key elements of MISO's market design changes are likely to include the following:

- A proposal to establish a unique offer structure for ESR in both the Day-Ahead Market and the Real-Time Market and to provide flexibility to ESR owners by establishing a Commitment Status to communicate how the resource will be available to the markets.

- Enablement of ESR to provide energy and ancillary services, blackstart service, and reactive supply and voltage control.

- Allowance of ESR to qualify as Use Limited Resources to accommodate resources that may need or desire their commitment to be limited to four hours per day in order to reliably provide a service.

- Allowance for ESR to both receive and inject electric energy in a way that recognizes physical and operational characteristics and optimizes benefits to MISO and prevents conflicting dispatch instructions through a single offer curve made up of both discharge segments (i.e., price/MW pairs for positive values or injections) and charge segments (i.e., price/MW pairs for negative values or withdrawals). Resources will be paid or pay the LMP at the pricing node for, respectively, injections to discharge and withdrawals to charge. Efficiency losses will not be considered load or station power but will be included in energy schedules.

- Ability of ESR to participate and set prices in the Planning Reserve Auction, submit wholesale bids to buy energy though the Day-Ahead and Real-Time Energy Offer

Curves, participate in MISO's markets as price takers, self-schedule, and manage their State of Charge.

#### 9.2.6.2 Energy Storage Resource Operations Model Overview

Since the core Aurora market and portfolio model is fundamentally based on a day-ahead simulation, NIPSCO has performed additional analysis to estimate the incremental value streams that flexible resources can achieve by participating in markets beyond day-ahead energy. To do this, CRA employed its proprietary ESOP model,[118] an optimization model that computes revenues through participation in energy and A/S markets with five-minute granularity. Given simulated energy and ancillary services pricing information, ESOP solves for optimal dispatch decisions unique to a price-taking resource's technological characteristics and a regional market's participation rules. A comparison of the Aurora portfolio tool and the ESOP model is summarized in Figure 9-29.

**Figure 9-29: Comparison of Aurora Portfolio Tool and ESOP**

| Category | Aurora Portfolio Tool | ESOP |
|---|---|---|
| Market Coverage | Day-ahead energy | Energy plus ancillary services ("A/S") (frequency regulation and spinning reserves) |
| Time Granularity | Hourly, chronological | 5-minute intervals, chronological |
| Time Horizon | 20 years | Sample years (ie, 2025, 2030, 2035, 2040) |
| Pricing Inputs | MISO-wide fundamental analysis feed NIPSCO-specific portfolio dispatch | Historical data drives real-time and A/S pricing; specific asset types dispatched against price |
| Asset Parameters Used | Hourly ramp rate, storage cycle and depth of dispatch limits, storage efficiency | Sub-hourly ramp rate, storage cycle and depth of discharge limits, storage efficiency |
| Outputs | Portfolio-wide cost of service | Incremental value for specific asset type |

For the 2021 IRP, the MISO five-minute real-time markets for energy, frequency regulation,[119] and spinning reserves were evaluated, with a focus on the performance of storage, paired solar plus storage, and natural gas peaking resources in order to evaluate specific tradeoffs of these capacity-advantaged resource options in NIPSCO's portfolio.

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[118] Note that while the ESOP model was originally designed for storage evaluation, modified versions simulate the operations of other fast response resources such as natural gas peakers.

[119] MISO has a single market for regulation up and regulation down services. When providing regulation services, a unit will follow a signal from the system operator. Since it is impossible to know whether the regulation signal will dispatch a unit up or down and by how much ahead of time, ESOP assumes that a unit will be dispatched in both directions while participating in the regulation market. For battery storage, regulation down services can be provided when backing down from a discharge cycle or charging. Since the analysis has assumed that paired solar plus storage resources receive the investment tax credit, in order to participate in the regulation market, it was assumed that a battery resource must have sufficient ability to either back down from a discharge cycle or charge from the paired solar resource. Although such behavior is only required for the first five years of resource operation, for modeling simplicity, this assumption was maintained throughout the analysis.

#### 9.2.6.3 Development of Sub-Hourly Prices for Energy and Ancillary Services

ESOP is run with five-minute price streams for real-time energy, regulation, and spinning reserves prices. As Aurora's long-term capacity expansion tool is used to generate hourly price trajectories representative of the day-ahead energy market, CRA developed a methodology to estimate real-time price trajectories based on historical relationships between day-ahead energy and real-time energy and ancillary services prices, applied to the day-ahead energy prices forecasts developed for each of the four planning scenarios (*See* Section 8 for more detail on the MISO market scenario development process). As part of this process, the following historical data was gathered, based on the period June 1, 2018 to May 31, 2019:

- NIPS.AZ day-ahead hourly LMP[120]
- NIPS.AZ real-time five-minute LMP[121]
- MISO real-time hourly regulation and spinning reserve prices[122]
- Real-time five-minute LMP from NIPSCO node[123]

The relationship between historical hourly day-ahead LMP and five-minute real-time LMP was used to shape the MISO-scenario driven price forecasts to real-time five-minute LMP inputs for ESOP. Because historical regulation and spinning reserve prices services were unavailable at a five-minute granularity, a proxy for a five-minute price shape was taken from the neighboring PJM interface for the same historical period. Similarly, a relationship between hourly day-ahead LMP and sub-hourly ancillary service prices was taken to determine real-time inputs into ESOP.

ESOP was run for the following test years using five-minute real-time price inputs:

- June 1, 2025 to May 31, 2026
- June 1, 2030 to May 31, 2031
- June 1, 2035 to May 31, 2036
- June 1, 2040 to May 31, 2041

#### 9.2.6.4 Operational Parameters for Technology Options

While Section 4 of this report provides a summary of all key cost and operational inputs associated with the RFP bid resource tranches and used in the core economic portfolio analysis,

[120] ABB Energy Velocity Suite. ABB
[121] ABB Energy Velocity Suite. ABB
[122] MISO has one clearing price for regulation up and down. Prices gathered from ABB Energy Velocity Suite. Only hourly ancillary service clearing prices were available.
[123] PJM. PJM Data Miner 2 Tool. Five-minute RT LMP, NIPSCO node. http://dataminer2.pjm.com/feed/rt_fivemin_hrl_lmps.

evaluation in ESOP requires more granular operational input assumption development to assess sub-hourly ramp rates and other constraints. Therefore, CRA and NIPSCO reviewed individual bids to assess bidder expectations for key storage and gas peaker parameters and to develop assumptions for ESOP modeling, which are summarized in Figure 9-30.

**Figure 9-30: Resource Operational Parameter Input Assumptions for ESOP Analysis**

| **Lithium-Ion** | Units | Value |
|---|---|---|
| Duration (Energy/Power Ratio) | hours | 4 |
| Roundtrip Efficiency | % | 87% |
| Cycles per Year | # | 365 |
| Parasitic Load | %/hr | 0.50% |
| Ramp Rate | %/min | 100% |
| | | |
| State of Charge Lower Bound[124] | % | 0% |
| State of Charge Upper Bound | % | 100% |
| VOM | $/MWh | 0 |

| **Gas Combustion Turbine** | Units | Value |
|---|---|---|
| Heat Rate (Average Realized) | Btu/kWh | 10,000 |
| Ramp Rate | %/min | 17% |
| Forced Outage | % | 5.00% |
| Minimum Generation Percentage | % | 50% |
| | | |
| Max hours of operation / year | Hrs/yr | 3,000 |
| Min Downtime | Hrs | 4 |
| Min Runtime | Hrs | 2 |
| | | |
| Emission Rate | lb CO2/MMBtu | 119 |
| Start Costs | $/MW/start | 18 |
| VOM | $/MWh | 2 |

124 Note that multiple bidders indicated no limits to state of charge boundaries, although other sources suggest that lower and upper bounds of between 10-20% and 80-90%, respectively might be expected for lithium-ion battery technology. As a result, multiple assumptions were tested in the ESOP modeling, and it was determined that this parameter is not a significant driver of results.

### 9.2.6.5 Key Findings from ESOP Analysis

Based on the resource types that comprise NIPSCO's portfolio options (see discussion of portfolio composition and definition in the earlier sub-sections of this Section) and the types of resources likely to have opportunities for additional value in the sub-hourly energy and ancillary services markets beyond what is accounted for in the core portfolio analysis, CRA evaluated three distinct technology options in ESOP:

- Lithium-ion four-hour duration battery storage;
- Paired solar plus storage (lithium-ion four-hour duration) at a 2:1 ratio;[125] and
- Natural gas-fired combustion turbine peaker

As noted above, the three resource types were assessed over four sample future years in order to estimate the incremental value that might be available in the sub-hourly energy and ancillary services markets above what is captured in the Aurora model's day ahead hourly assessment. The analysis found that the most significant upside is for battery technology, particularly in the regulation market, as illustrated in the Reference Case margin projections summarized in Figure 9-31. Key findings by technology included:

- **Lithium-Ion battery**: As the most highly flexible resource option, the battery can respond rapidly in real time to changing price signals at five-minute granularity. Most notably, the resource can participate regularly in the regulation market, providing up and down service given its unique ability to charge or discharge. An illustration of simulated charging and discharging behavior along with energy and regulation price behavior is shown for a sample summer day in Figure 9-32. This shows how the battery can adjust its state of charge very rapidly to respond to 5-minute price signals, while also participating in the regulation market.

- **Paired solar plus storage**: As in the hourly Aurora modeling, the solar component provides significant energy value, while the upside from the ESOP analysis is primarily limited to participation in the regulation market. It is important to note that current ITC rules limit the battery's flexibility and ability to take advantage of the regulation market, given that the battery resource must charge predominantly from the solar component.

- **Natural gas-fired combustion turbine**: The gas peaking resource is able to monetize real-time sub-hourly volatility, providing value upside compared to the Aurora day ahead hourly modeling. However, regulation opportunities are only available when the unit is already operating for energy, limiting the upside when compared to the battery storage projections. Spinning reserve revenues are also likely to be available, but these are less valuable than regulation.

[125] Note that the most attractive RFP tranches, including those selected in the portfolio development phase, were at ratios of approximately 2:1 (solar:storage), so this configuration was analyzed in the ESOP analysis.

**Figure 9-31: Reference Case Annual Margin Comparison by Technology: Aurora Day Ahead Energy vs. ESOP Sub-Hourly Energy Plus Ancillary Services**

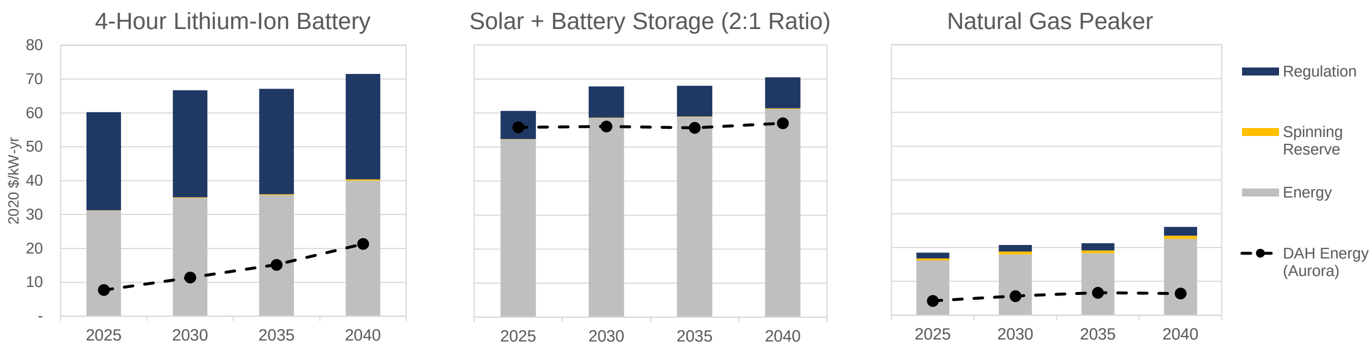
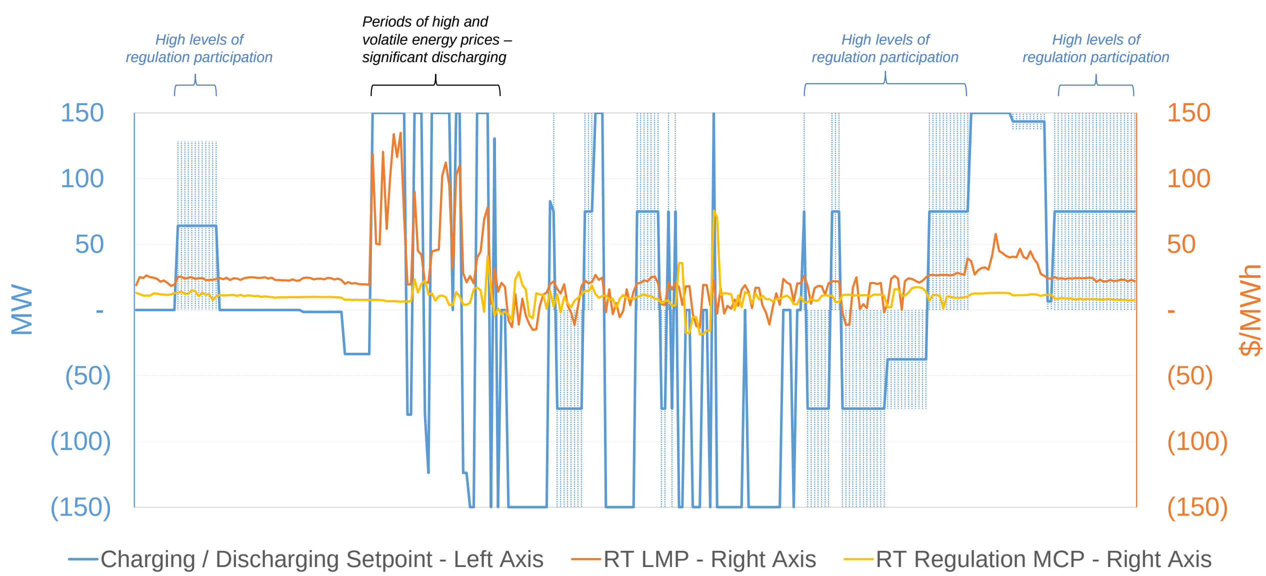
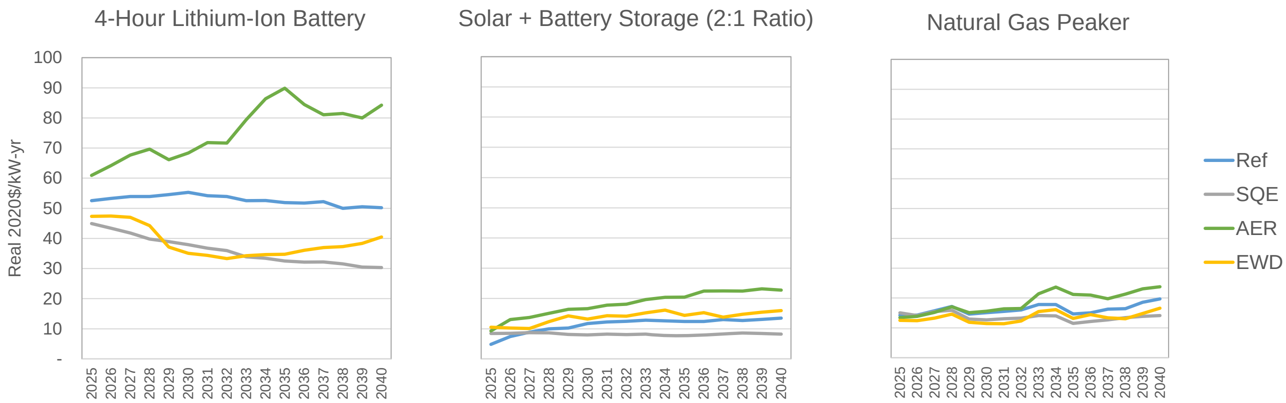



**Figure 9-32: Sample Summer Day of Battery Dispatch**




In addition to the Reference Case analysis, CRA evaluated the performance of the three resource options across the three alternative market scenarios (see Section 8 for more detail). Across all scenarios, the incremental value associated with the sub-hourly energy and ancillary services markets was projected to be greatest for the battery. This was especially the case in the AER, with high energy prices due to high carbon and natural gas prices, and high levels of renewable penetration driving larger price spreads across hours. A summary of the simulated incremental value by technology and scenario is shown in Figure 9-33.[126]

**Figure 9-33: Incremental Sub-Hourly Energy and Ancillary Services Value by Technology across Scenarios**



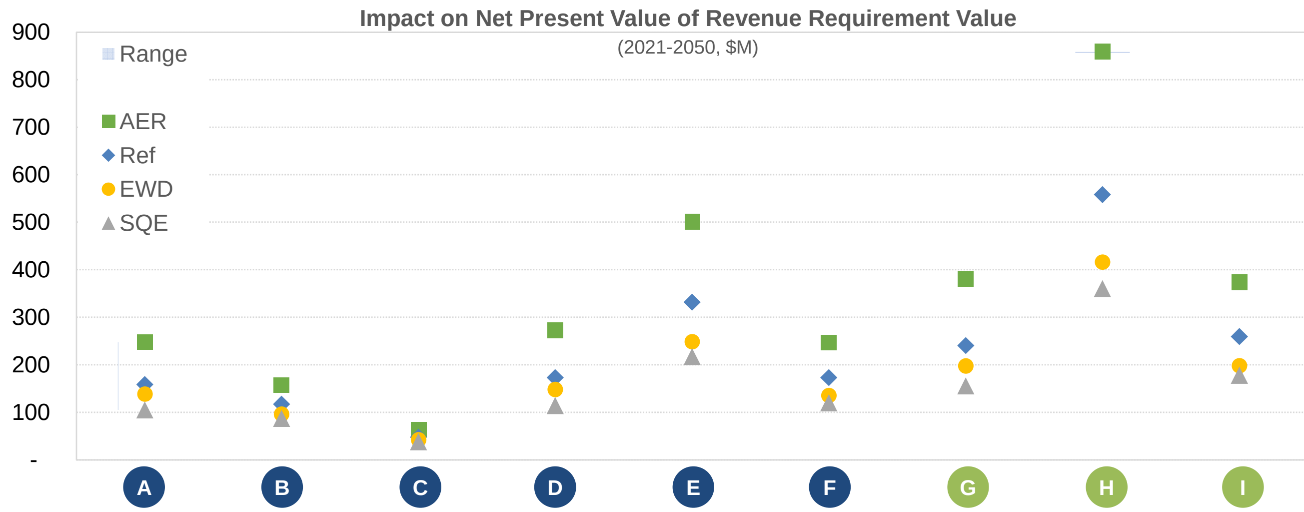

### 9.2.6.6 Portfolio Cost Implications

After performing the core ESOP analysis at the resource level, CRA and NIPSCO built up portfolio-level impacts according to the amounts of lithium-ion battery storage, paired solar plus storage, and natural gas peaking capacity in each of the nine replacement portfolios. This was accomplished by attributing the annual $/kW-yr incremental value shown in Figure 9-33 to each MW of storage, solar plus storage, or gas peaker in the portfolios to arrive at an aggregate total net present value impact. This is summarized by portfolio and across all scenarios in Figure 9-34 Overall, the analysis reached the following conclusions:

- Portfolios with the largest amounts of storage (Portfolios E and H) have the greatest potential to lower the NPVRR by capturing flexibility value that may manifest in the sub-hourly energy and ancillary services markets.
- A wide range of value is possible, with higher prices and price spreads in the AER scenario driving higher estimates and lower prices and lower price spreads in the SQE scenario driving lower estimates.
- While these estimates provide perspective on the relative performance of various portfolio strategies, significant uncertainty exists and the realization of such benefits is dependent on market rules evolution, MISO generation mix changes, and market participant behavior.

[126] Note that since the ESOP analysis was only performed for five sample years, estimates for the other model years were made through interpolation.

**Figure 9-34: Range of Additional Value Opportunity by Replacement Portfolio**




### 9.2.7 Non-Economic Reliability Assessment

Economic analysis alone does not capture the full suite of reliability attributes offered by various resources. As outlined in Section 6, NIPSCO participates in MISO in a variety of roles with various compliance standards and responsibilities, and any future resource decisions (retirement or replacement) will need to consider the non-economic implications for NIPSCO's ability to comply with both NERC and MISO standards and procedures now and into future.

Under normal system operating conditions, NIPSCO is tied to MISO and PJM's systems for dispatch of its resources and the balancing of energy. However, under emergency or blackout conditions ("islanded operation"), NIPSCO's resources should have the capability to reliably serve the critical demand of its customers.

With the goal of understanding the relative ability of replacement portfolios to support the reliable operation of the system, NIPSCO engaged Quanta Technology, a third-party technical expert, to perform a planning-level reliability assessment of all replacement generation resources under consideration. The Quanta Technology Reliability Assessment Final Report is attached as Confidential Appendix E. In this assessment, Quanta Technology identified reliability criteria and metrics that individually and collectively serve to enhance the reliability attributes of a given portfolio, developed a scoring methodology for individual technologies, and scored and ranked portfolios across these metrics. The results of the assessment were then incorporated into the Replacement scorecard to support overall portfolio evaluation.

#### 9.2.7.1 Study Methodology

The reliability assessment study was performed according to the steps outlined in Figure 9-35. The first two steps assessed NIPSCO's reliability needs and then reviewed, refined, and augmented the initial set of reliability metrics identified by NIPSCO.

The study then proceeded to conduct a series of system analyses, each quantifying the performance of each of the nine replacement portfolios against each measure, and where appropriate, determining the required mitigations to address any performance gaps. The nature of the study is akin to a series of analysis filters that ultimately help identify reliability concerns that would need mitigation.

Finally, a scoring matrix was developed with acceptable performance thresholds to provide a quantifiable score for each reliability measure. These scores were aggregated for each metric, and eventually for each portfolio. Portfolios were then ranked according to their reliability attributes with the highest scores to those with the least reliability concerns.

**Figure 9-35: Reliability Study Methodology**


#### 9.2.7.2 Reliability Criteria and Metrics

NIPSCO developed an initial set of reliability criteria that are important to the continued reliable operation of the grid and that enable NIPSCO to fulfill its obligations under NERC and MISO standards. Quanta Technology performed a critical assessment of these metrics, resulting in a final list of reliability and resilience criteria summarized in Figure 9-36.

**Figure 9-36: Reliability Criteria**

| | Criteria | Description | Rationale |
|---|---|---|---|
| 1 | Blackstart | Resource has the ability to be started without support from the wider system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, supply real and reactive power, frequency, and voltage control | In the event of a black out condition, NIPSCO must have a blackstart plan to restore its local electric system. The plan can either rely on MISO to energize a cranking path or on internal resources within the NIPSCO service territory. |
| 2 | Energy Adequacy | Portfolio resources are able to supply the energy demand of customers during MISO's emergency max gen events, and also to supply the energy needs of critical loads during islanded operation events. | NIPSCO must have long duration resources to serve the needs of its customers during emergency and islanded operation events. |
| 3 | Dispatchability and Automatic Generation Control | Resources will respond to directives from system operators regarding its status, output, and timing. The unit has the ability to be placed on Automatic Generation Control (AGC) allowing its output to be ramped up or down automatically to respond immediately to changes on the system. | MISO provides dispatch signals under normal conditions, but NIPSCO requires AGC attributes under emergency restoration procedures or other operational considerations |
| 4 | Operational Flexibility and Frequency Support | Resources are able to provide inertial energy reservoir or a sink to stabilize the system. The resource can adjust its output to provide frequency support or stabilization in response to frequency deviations with a droop of 5% or better | MISO provides market construct under normal conditions, but preferable that NIPSCO possess the ability to maintain operation during under-frequency conditions in emergencies |
| 5 | VAR Support | Resources can deliver VARs out onto the system or absorb excess VARs to control system voltage under steady-state and dynamic/transient conditions. Resources can provide dynamic reactive capability (VARs) even when not producing energy and have Automatic voltage regulation (AVR) capability ranging from 0.85 lagging (producing) to 0.95 leading (absorbing) power factor | NIPSCO must retain resources electrically close to load centers to provide this attribute in accordance with NERC and IEEE Standards |
| 6 | Geographic Location Relative to Load | Resources are located in NIPSCO's footprint (electric Transmission Operator Area) in Northern Indiana near existing NIPSCO 138kV or 345kV facilities and are not restricted by fuel infrastructure. Preferred locations are ones that have multiple power evacuation/deliverability paths and are close to major load centers. | Although MISO runs markets that value location, resources that are interconnected to buses with multiple power evacuation paths and those close to load centers are more resilient to transmission system outages and provide better assistance in the blackstart restoration process. |
| 7 | Predictability and Firmness of Supply | Ability to predict/forecast the output of resources and to counteract forecast errors. | Energy is scheduled with MISO in the day-ahead (DAH) hourly market and in the real-time (RT) 5-minute market. Deviations from these schedules have financial consequences, and the ability to accurately forecast the output of a resource up to 38 hours ahead of time for DAH and 30 minutes for RT is advantageous. |
| 8 | Short Circuit Strength Requirement | Resources help ensure the strength of the system to enable the stable integration of all inverter-based resources (IBRs) within a portfolio. | The retirement of synchronous generators within NIPSCO's footprint and across MISO and replacements with increasing levels of IBRs will lower the short circuit strength of the system. Resources that provide higher short circuit current provide a better future proofing without the need for expensive mitigation measures. |

After establishing the criteria, a set of quantified metrics were developed to measure the technical ability of resources to enhance a given criterion, as summarized in Figure 9-37. Quanta Technology performed detailed analysis at the resource level to evaluate each metric.

**Figure 9-37: Reliability Metrics**

| | Metric | Measure |
|---|---|---|
| 1 | Blackstart | Qualitative Assessment of Risk of not Starting |
| 2 | Energy Adequacy | Energy not Served during market emergencies (% of load consumption increase) |
| | | Energy Not Served when Islanded (Worst 1-week) % |
| 3 | Dispatchability and Automatic Generation Control | Dispatchable (%CAP, unavoidable VER Penetration) |
| | | Increased Freq Regulation Requirements (MW) |
| | | 1-min Ramp Capability (MW) |
| | | 10-min Ramp Capability (MW) |
| 4 | Operational Flexibility and Frequency Support | Inertia MVA-s |
| | | Inertial Gap FFR MW (islanded operation) |
| | | Primary Gap PFR MW (islanded operation) |
| 5 | VAR Support | Dynamic VAR to load Center Capability (MVAr) |
| 6 | Location | Average Number of Evacuation Paths |
| 7 | Predictability and Firmness | Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW |
| 8 | Short Circuit Strength | Required Additional Synchronous Condensers MVA |

### 9.2.7.3 Reliability Assessment Details

Based on the criteria and metrics summarized above, the study evaluated all nine replacement portfolios for the year 2030 across a variety of assessments summarized in Figure 9-38. Given the dynamic and uncertain nature of renewable energy developments associated with technology mix, sites, and sizes, as well as the future state of the transmission grid that will be required to enable the integration of these resources, this study attempted to provide an envelope of outcomes (and in many cases, best or optimistic outcomes) under a regime of well-coordinated or guided project development processes.

**Figure 9-38: Metrics and Measures Results – Raw Scores**

| System Condition | Reliability Assessment |
|---|---|
| Normal | • deliverability of dynamic reactive power to load centers<br>• short circuit strength<br>• predictability of portfolio output<br>• increased need for regulation reserves<br>• geographic location and ability to evacuate the power |
| Emergency – Max Gen | • energy adequacy – Need for market purchases |
| Isolated | • black start and restoration<br>• short circuit strength<br>• ability to control frequency (inertial and primary frequency response)<br>• power ramping capability<br>• energy adequacy to serve the critical demand of customers. |

Several assumptions were made in the study. For example, operating renewable resources economically require them to generate all the time at their maximum potential power levels as allowed by solar irradiance and wind speeds. This mode of economic operation precludes these resources from providing frequency response in the upward direction, as will be required when a generator or import is suddenly lost. Reducing the power output to enable participation in frequency response in the upward direction is very expensive. However, the speed of control of the IBRs makes them perfectly suited for participating in frequency response in the downward direction (i.e., curtailment), as will be required when a large load or export is suddenly lost.

Given that this was a planning level assessment, screening-level quantitative studies were conducted for a set of reliability standards, including inertial response, primary frequency response, secondary frequency response, short circuit strength, system ramping requirements, dynamic reactive support, and energy adequacy along with a qualitative assessment of blackstart and system restoration capability. Other areas of reliability assessment are outside the scope of this study, but might include system protection, power quality, flicker, and control interactions. Detailed system studies will be required to ascertain the reliability of the system once a portfolio is selected and the location, size, and technology of all portfolio resources are available.

#### 9.2.7.4 Summary of Results

The technical reliability assessment included a quantitative analysis of each measure, (except blackstart), using information associated with resource technology, size, location, and expected production. Blackstart was scored qualitatively by assessing the risk of successfully restoring the system based on a strategy of using standalone energy storage and synchronous generation within NIPSCO's service territory to start existing synchronous condensers and then other nearby resources of solar plus storage, solar PV, and wind technologies, in that order.

The assessment identified potential reliability gaps for each of the nine replacement portfolios and also suggested potential mitigations to these gaps. The mitigations take the form of grid-forming inverter technology, additional blackstart capability, additional fast power resources such as battery storage, super capacitors, or combustion turbines, and additional synchronous condensers. The key findings of this study included the following:

- Reliability concerns were identified for each portfolio, especially under emergency and islanded conditions, and mitigation measures were identified as follows:
  - Stand-alone energy storage should have grid-forming inverters (GFM) with additional capabilities including black start and fast frequency response (FFR). GFM inverters are not widely used today in the US market, but the technology is available and is recommended for portfolios with high penetration of IBRs.
  - Gas peakers and combined cycle units in portfolios C, F, and I should have blackstart capability.
  - Additional fast power resources may be needed in some portfolios. These have been quantified for energy storage technology. However, super capacitors or combustion turbines can also provide the same function, but the size should be determined for these technologies.
  - Specifications of short circuit ratio (SCR) of inverters should not exceed 3.
  - Provision of additional synchronous condensers should be considered to increase the grid's short circuit strength ranging from 0 to 802 MVAr.
- Many reliability areas were not covered by this study including:
  - The study assumed that any required grid upgrades will be implemented as part of MISO interconnection process.
  - Given that all IRP portfolios were designed to meet MISO's reserve margin targets, a separate portfolio-level resource adequacy study was not conducted.
  - All reliability assessments in this study applied screening-level indicative analyses. Detailed system studies are essential and should be conducted to properly assess system reliability of the preferred portfolio options.

#### 9.2.7.5 Scoring Methodology and Performance Thresholds

Figure 9-39 summarizes the thresholds that were used in the study to score each measure, along with the rationale for setting the threshold values. Measures that exceeded the upper threshold were deemed satisfactory (Pass) and given a score of 1, while those measures below the lower threshold were deemed problematic and given a score of 0. Measures in between were considered cautionary and given a score of ½. The scores of measures within each of the eight individual metrics were averaged to yield a single score for each metric. Metric scores were then added for each portfolio and compared. The maximum score of each portfolio was eight.

## Figure 9-39: Scoring Thresholds

| | Year 2030 | | 1 (Pass) | ½ (Caution) | 0 (Problem) | Rationale |
|---|---|---|---|---|---|---|
| 1 | Blackstart | Ability to blackstart using Storage & Synchronous Condensers | >50% | 25-50% | <25% | System requires real and reactive power sources with sufficient rating to start other resources. Higher rated resources lower the risk |
| 2 | Energy Adequacy | Energy not Served during market emergencies (% of load consumption increase) | <5% | 5-20% | >20% | Ability of portfolio resources to serve unanticipated growth in load consumption during MISO emergency max-gen events. |
| | | Energy Not Served when Islanded (Worst 1-week) % | <70% | 70-85% | >85% | Ability of Resources to serve critical loads for 1 week, estimated at 15% of total load. Adding other important loads brings the total to 30% |
| 3 | Dispatchability | Dispatchable (VER Penetration %) | <50% | 50-60% | >60% | Intermittent Power Penetration above 60% is problematic when islanded |
| | | Increased Freq Regulation Requirements | <2% of peak load | 2-3% of Peak Load | >3% of peak load | Regulation of Conventional Systems ≈1% |
| | | 1-min Ramp Capability | >15% of CAP | 10-15% of CAP | <10% of CAP | 10% per minute was the norm for conventional systems. Renewable portfolios require more ramping capability |
| | | 10-min Ramp Capability | >65% of CAP | 50-65% of CAP | <50% of CAP | 10% per minute was the norm for conventional systems. But with 50% min loading, that will be 50% in 10 min. Renewable portfolios require more ramping capability |
| 4 | Operational Flexibility and Frequency Support | Inertia (seconds) | >3xMVA rating | 2-3xMVA rating | <2xMVA rating | Synchronous machine has inertia of 2-5xMVA rating. |
| | | Inertial Gap FFR (assuming storage systems will have GFM inverters) | 0 | 0-10% of CAP | >10% of CAP | System should have enough inertial response, so gap should be 0. Inertial response of synch machine ≈ 10% of CAP |
| | | Primary Gap PFR MW | 0 | 0 - 2% of CAP | 2% of CAP | System should have enough primary response, so gap should be 0. Primary response of synch machine ≈ 3.3%of CAP/0.1Hz (Droop 5%) |
| 5 | VAR Support | VAR Capability | ≥41% of ICAP | 31-41% of ICAP | <31% of ICAP | Power factor higher than 95% (or VAR less than 31%) not acceptable. Less than 0.91 (or VAR greater than 41.5%) is good |
| 6 | Location | Average Number of Evacuation Paths | >3 | 2-3 | <2 | More power evacuation paths increases system resilience |
| 7 | Predictability and Firmness | Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW | ≥ 0 | -10% - 0% of CAP | <-10% of CAP | Excess ramping capability to offset higher levels of intermittent resource output variability is desired |
| 8 | Short Circuit Strength | Required Additional Synch Condensers MVA | 0 | 0-21.9% of CAP | >21.9% of CAP | Portfolio should not require additional synchronous condensers. 500MVAr is a threshold (same size as one at Babcock) |

### 9.2.7.6 Reliability Ranking of IRP Portfolios

Figure 9-40 presents the normalized resources for each replacement portfolio across each of the eight metrics, and Figure 9-41 summarizes the resulting portfolio scores and rankings.

**Figure 9-40: Normalized Results**

| | Year 2030 | | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Blackstart | Qualitative Assessment of Risk of not Starting | 25% | 0% | 75% | 25% | 50% | 100% | 25% | 50% | 100% |
| 2 | Energy Adequacy | Energy not Served during market emergencies (% of load consumption increase) | 10% | 2% | 2% | 21% | 2% | 3% | 26% | 3% | 2% |
| | | Energy Not Served when Islanded (Worst 1-week) % | 76% | 79% | 32% | 75% | 78% | 56% | 74% | 73% | 58% |
| 3 | Dispatchability and Automatic Generation Control | Dispatchable (%CAP, unavoidable VER penetration%) | 28% | 18% | 55% | 27% | 44% | 45% | 26% | 47% | 47% |
| | | | 58% | 45% | 42% | 63% | 50% | 45% | 65% | 51% | 51% |
| | | Increased Freq Regulation Requirement (% Peak Load) | 2.3% | 1.6% | 1.5% | 2.5% | 1.8% | 1.6% | 2.6% | 2.0% | 2.0% |
| | | 1-min Ramp Capability (%CAP) | 24.0% | 22.6% | 17.8% | 22.8% | 47.2% | 29.4% | 22.1% | 49.3% | 39.0% |
| | | 10-min Ramp Capability (%CAP) | 41.7% | 50.7% | 52.1% | 39.6% | 64.4% | 60.3% | 37.1% | 63.7% | 61.5% |
| 4 | Operational Flexibility and Frequency Support | Inertia (seconds) | 2.13 | 3.38 | 4.17 | 2.02 | 2.07 | 3.58 | 1.81 | 1.73 | 2.60 |
| | | Inertial Gap FFR (%CAP) | 11.2% | 32.1% | 10.7% | 11.0% | 0.0% | 6.1% | 11.6% | 0.0% | 0.0% |
| | | Primary Gap PFR (%CAP) | 18.8% | 44.7% | 25.9% | 17.9% | 0.0% | 19.1% | 17.7% | 0.0% | 1.3% |
| 5 | VAR Support | Dynamic VAR to load Center Capability (%CAP) | 47.8% | 47.8% | 35.1% | 48.5% | 44.7% | 43.6% | 49.1% | 47.4% | 47.1% |
| 6 | Location | Average Number of Evacuation Paths | 5 | 2.5 | N/A | 4.6 | 4.7 | 4.7 | 4.8 | 5.6 | 5.1 |
| 7 | Predictability and Firmness | Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW) | -4.1% | -8.0% | 11.4% | -5.0% | 14.9% | 15.8% | -5.3% | 17.4% | 17.1% |
| 8 | Short Circuit Strength | Required Additional Synch | 25% | 11% | 0% | 33% | 15% | 0% | 35% | 21% | 11% |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Condensers (%Peak Load) | | | | | | | | | |

VER: Variable Energy Resources (e.g., solar, wind)
CAP: Capacity credit of all resources including existing, planned, and portfolio

**Figure 9-41: Portfolio Scores and Ranking**

| | Year 2030 | | A | B | C | D | E | F | G | H | I | Weight |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Blackstart | Qualitative Assessment of Risk of not Starting | 1/2 | 0 | 1 | 1/2 | 1/2 | 1 | 1/2 | 1/2 | 1 | 12.5% |
| 2 | Energy Adequacy | Energy not Served during market emergencies (% of consumption increase) | 1/2 | 1 | 1 | 0 | 1 | 1 | 0 | 1 | 1 | 6.3% |
| | | Energy Not Served when Islanded (Worst 1-week) % | 1/2 | 1/2 | 1 | 1/2 | 1/2 | 1 | 1/2 | 1/2 | 1 | 6.3% |
| 3 | Dispatchability and Automatic Generation Control | Dispatchable (VER Power Penetration %) | 1/2 | 1 | 1 | 0 | 1/2 | 1 | 0 | 1/2 | 1/2 | 3.1% |
| | | Increased Freq Regulation Requirement (% Peak Load) | 1/2 | 1 | 1 | 1/2 | 1 | 1 | 1/2 | 1/2 | 1/2 | 3.1% |
| | | 1-min Ramp Capability (%CAP) | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 3.1% |
| | | 10-min Ramp Capability (%CAP) | 0 | 1/2 | 1/2 | 0 | 1/2 | 1/2 | 0 | 1/2 | 1/2 | 3.1% |
| 4 | Operational Flexibility and Frequency Support | Inertia (seconds) | 1/2 | 1 | 1 | 1/2 | 1/2 | 1 | 0 | 0 | 1/2 | 4.2% |
| | | Inertial Gap FFR (%CAP) | 0 | 0 | 0 | 0 | 1 | 1/2 | 0 | 1 | 1 | 4.2% |
| | | Primary Gap PFR (%CAP) | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 1/2 | 4.2% |
| 5 | VAR Support | Dynamic VAR to load Center Capability (%CAP) | 1 | 1 | 1/2 | 1 | 1 | 1 | 1 | 1 | 1 | 12.5% |
| 6 | Location | Average Number of Evacuation Paths | 1 | 1/2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12.5% |
| 7 | Predictability and Firmness | Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW) | 1/2 | 1/2 | 1 | 1/2 | 1 | 1 | 1/2 | 1 | 1 | 12.5% |
| 8 | Short Circuit Strength | Required Additional Synch Condensers (%Peak Load) | 0 | 1/2 | 1 | 0 | 1/2 | 1 | 0 | 1/2 | 1/2 | 12.5% |
| | **Portfolio Scores** | | **52%** | **56%** | **84%** | **47%** | **79%** | **92%** | **45%** | **76%** | **85%** | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | # 0 | 4 | 3 | 2 | 6 | 0 | 1 | 7 | 1 | 0 |
| | # 1/2 | 7 | 5 | 2 | 5 | 6 | 2 | 4 | 6 | 6 |
| | # 1 | 3 | 6 | 10 | 3 | 8 | 11 | 3 | 7 | 8 |
| | Total Measures | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |

The highest ranked portfolios across the eight reliability metrics are:

1. F (Score 92%)
2. I (Score 85%)

3. C (Score 84%)
4. E (Score 79%)
5. H (Score 76%)

### Replacement Analysis Scorecard Summary

Figure 9-42 presents a summary of all scorecard metrics for each of the nine replacement portfolios. This includes the cost metrics associated with the Reference Case NPVRR, the risk metrics associated with the major outcomes from the scenario and stochastic analyses, carbon emissions, reliability, resource optionality, and impacts on the local economy, as described above. The following key observations were made:

- Portfolios that have the highest solar additions and meet only the summer reserve margin target (Portfolios A, D, and G) are not viable options for NIPSCO, given expected MISO ruls changes, even though they perform best under high environmental regulation scenarios (AER and EWD).

- Although adding new combined cycle capacity (Portfolio C) results in lowest costs under the Reference and SQE scenarios and provides a new dispatchable energy resource to mitigate future intermittency risk, this strategy carries the highest scenario cost exposure and uncertainty, results in the highest CO2 emissions, and reduces future resource optionality.

- While a portfolio approach that retires all thermal resources by 2032 and relies solely on renewables and storage (Portfolio H) provides a high level of scenario cost certainty, the lowest emission profile, significant upside value opportunity associated with ancillary service markets, and significant additional local economic investment, it has the highest cost under Reference scenario conditions and exposes the portfolio to high stochastic tail risk, given high levels of intermittent resources.

- While portfolios that retain Sugar Creek and add some amount of new peaking and storage resources (Portfolios B, E, and F) do not score best on any single metric, they minimize cost risks, continue NIPSCO down a path of significant CO2 emission reductions, and allow for flexibility and optionality.

- A portfolio that includes additional renewables and storage, as well as options to pursue hydrogen at existing and new thermal facilities (Portfolio I), produces lower CO2 emissions than Portfolios B, E, and F, performs better under scenarios with high environmental regulation/incentives (particularly EWD), and mitigates stochastic tail risk.

- Portfolios with local thermal peaker and storage resources (particularly Portfolios F and I and to a lesser extent Portfolio E) provide the most reliability attributes and perform best on the composite reliability score.

### Figure 9-42: Replacement Portfolio Scorecard

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| Replacement Theme | Thermal PPAs, solar and storage | Non-service territory gas peaking (no early storage) | Natural gas dominant (CC) | No new thermal resources; solar dominant w/ storage | Thermal PPAs plus storage and solar | Local gas peaker, plus solar and storage | Solar dominant w/ storage, plus retire Sugar Creek | All renewables and storage, plus retire Sugar Creek (Portfolio 7) | New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H) |
| Carbon Emissions | Higher | Higher | Higher | Mid | Mid | Mid | Low | Low | Low |
| Dispatchability | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) | Current Planning Reserve Margin | Winter & Summer Reserve Margin | Enhanced Reserve Margin (Local w/ Higher Energy Duration) |
| **Cost To Customer**<br>30-year NPVRR (Ref Case) $M | $10,461<br>+$149 | $10,332<br>+$20 | $10,312<br>- | $10,438<br>+$126 | $10,467<br>+$155 | $10,426<br>+$114 | $11,042<br>+$730 | $11,090<br>+$778 | $10,792<br>+$480 |
| **Cost Certainty**<br>Scenario Range NPVRR $M | $2,359<br>+$1,035 | $2,782<br>+$1,458 | $3,208<br>+1,884 | $2,322<br>+$998 | $2,538<br>+$1,214 | $2,748<br>+$1,424 | $1,324<br>- | $1,553<br>+$229 | $1,855<br>+$531 |
| **Cost Risk** – High Scenario NPVRR $M | $12,015<br>+$206 | $12,182<br>+$373 | $12,518<br>+$709 | $11,965<br>+$156 | $12,126<br>+$317 | $12,243<br>+$434 | $11,809<br>- | $12,011<br>+$202 | $11,848<br>+$39 |
| **Cost Risk** – Stochastic 95% CVAR – 50% | $104<br>+$21 | $92<br>+$9 | $83<br>- | $104<br>+$21 | $98<br>+$15 | $97<br>+$14 | $123<br>+$40 | $114<br>+$31 | $87<br>+$4 |
| **Lower Cost Opp.**<br>Lowest Scenario NPVRR $M | $9,657<br>+$348 | $9,400<br>+$91 | $9,309<br>- | $9,644<br>+$335 | $9,588<br>+$279 | $9,495<br>+$186 | $10,485<br>+$1,176 | $10,458<br>+$1,149 | $9,933<br>+$684 |
| **Carbon Emissions**<br>M of tons 2024-40 Cum. (Scenario Avg.) | 27.3<br>+11.2 | 30.4<br>+14.3 | 47.2<br>+31.1 | 27.3<br>+11.2 | 27.3<br>+11.2 | 28.5<br>+12.4 | 16.1<br>- | 16.1<br>- | 25.2<br>+9.1 |
| **Reliability** – Composite reliability score (out of 8 possible points) | 3.67<br>-3.71 | 4.46<br>-2.92 | 5.21<br>-2.17 | 3.54<br>-3.84 | 6.08<br>-1.30 | 7.38<br>- | 3.38<br>-4.00 | 5.79<br>-1.59 | 6.79<br>-0.59 |
| **Reliability** – Reduction to 30-Year NPVRR (Ref Case) $M | ($158)<br>+$400 | ($117)<br>+$441 | ($48)<br>+$510 | ($173)<br>+$385 | ($332)<br>+$226 | ($173)<br>+$385 | ($240)<br>+$318 | ($558)<br>- | ($259)<br>+$299 |
| **Resource Optionality**<br>MW-weighted duration of 2027 gen. commitments (yrs.) | 20.01<br>+3.01 | 20.53<br>+3.53 | 23.55<br>+6.55 | 20.37<br>+3.37 | 21.15<br>+4.15 | 22.12<br>+5.12 | 17.00<br>- | 18.19<br>+1.19 | 21.46<br>+4.46 |
| **Local Economy**<br>NPV of property taxes | $420<br>-$66 | $388<br>-$98 | $451<br>-$35 | $417<br>-$69 | $413<br>-$73 | $416<br>-$70 | $486<br>- | $477<br>-$9 | $421<br>-$65 |

## 9.3 Preferred Replacement Portfolio

NIPSCO has identified Portfolio F as a preferred near term replacement portfolio concept, with the potential to pivot towards Portfolio I based on continued RFP bid diligence, technology evolution, and potential federal policy changes. Across each of these preferred concepts, NIPSCO has concluded that certain resources that provide near-term capacity (the Sugar Creek uprate, attractive DER opportunities, thermal capacity contracts, and demand side management programs) appear to be cost-effective additions to the portfolio and should be pursued in order to firm up the capacity position of the portfolio in the near-term and in anticipation of future retirements.

Beyond those capacity additions common to all candidate portfolios, solar, storage and natural gas peaking resources appear to be economic replacement options for Michigan City and Schahfer 16A/B.[127] Integrating dispatchable capacity into the portfolio over the long term (without materially increasing gas-fired energy exposure and CO2 emissions through a CCGT) tends to mitigate cost risk associated with intermittent resources and will help meet pending seasonal reserve margin requirements. However, the quantities and characteristics of storage and gas peaking resource additions require further study to confirm reliability can be maintained and to understand the value of each resource type given ongoing and potential market and policy changes.

Near-term capacity additions, including the Sugar Creek uprate, attractive DER, thermal capacity contracts, DSM, solar, storage, and a natural gas peaker, preserve flexibility in an environment of market, policy, and technology uncertainty. NIPSCO's preferred portfolio allows

[127] Portfolio I also contains some wind capacity, which NIPSCO may consider depending on future federal policy developments.

the Company to monitor technology and policy trends that will inform future action and maintain a pathway to a Net Zero emissions portfolio over the long term, including with emerging technology such as hydrogen.

Figure 9-43 summarizes the elements of NIPSCO's preferred plan, including the expected ranges of capacity additions by resource type through the 2027 period. As additional diligence is performed and as more information is obtained regarding market, policy, and technology change, NIPSCO will refine the specific capacity addition numbers.

**Figure 9-43: Preferred Portfolio Capacity Addition Ranges by 2027**

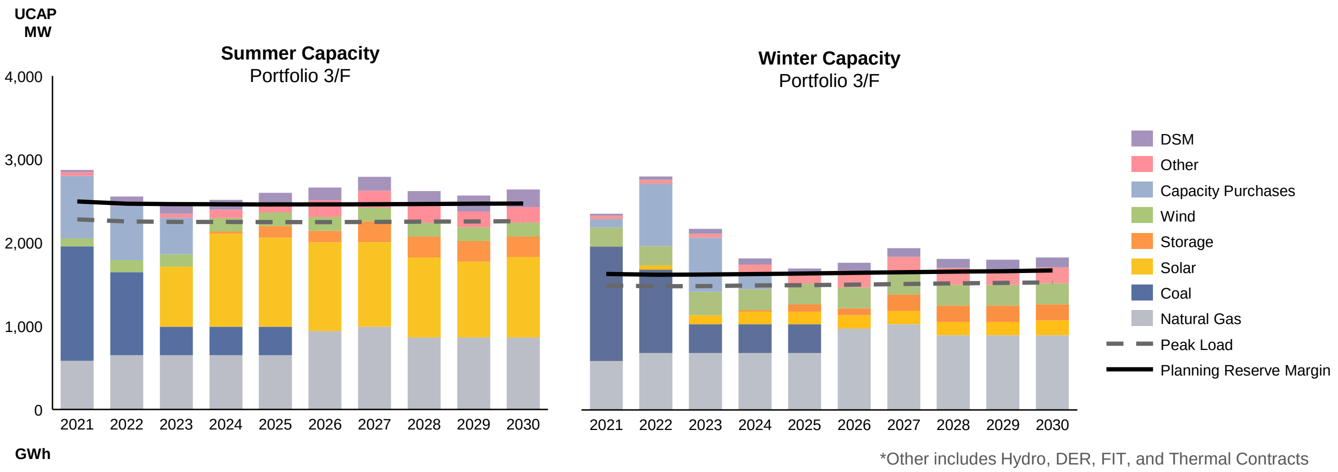
| Resource | MW by 2027 | Notes |
|---|---|---|
| Sugar Creek Uprate | 30-53 MW | Two options offered by the manufacturer; additional diligence will confirm pricing and timing |
| Solar + Storage DER Opportunities | ~10 MW | Specific projects to be identified, with distribution deferral opportunities consistent with attractive IRP tranche assumptions |
| Thermal Capacity Contracts | 150 MW | Likely up to 10-year term |
| DSM | ~68 MW | Represents Tier 1 residential plus all commercial energy efficiency programs (46 MW of winter peak) |
| Solar | 100-250 MW | Dependent on specific asset attributes and further bid diligence; Natural gas peaking capacity may be hydrogen-enabled. |
| Storage | 135-370 MW | |
| Natural Gas Peaker | Up to 300 MW | |

This preferred portfolio maintains NIPSCO on a trajectory that significantly shifts its generation mix from coal towards renewables and adds capacity-advantaged resources that are needed to meet future reserve margin requirements, protect against hourly energy market exposure, and preserve reliability for customers. As shown in Figure 9-44,[128] NIPSCO's preferred plan anticipates new capacity-advantaged resources entering into service by the middle of the decade, including storage, natural gas (the Sugar Creek uprate and new peaking capacity), and thermal capacity contracts. It also includes additional solar and new DSM programs.

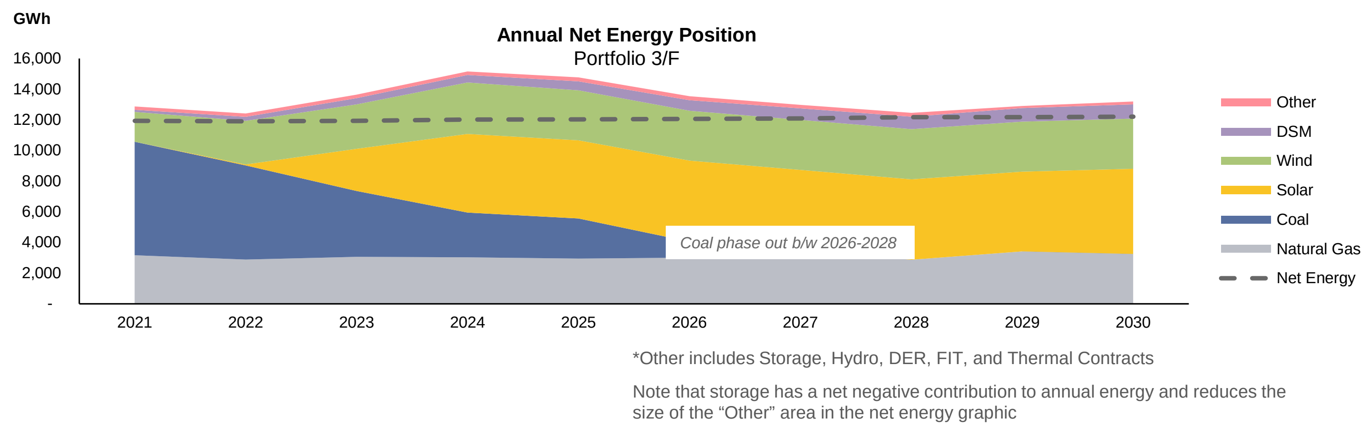
As shown in Figure 9-45, total energy from the preferred portfolio is projected to be roughly in balance with NIPSCO's load requirements, with flexibility around the ultimate timing of the Michigan City 12 retirement. Although new storage and gas peaking resources provide limited net energy contribution on an annual basis, they support the portfolio's energy adequacy when intermittent resources are unavailable.

[128] For illustrative purposes, Figure 9-44 and Figure 9-45 show Replacement Portfolio F based on Portfolio 3 from the Existing Fleet analysis.

### Figure 9-44: Preferred Portfolio Summer and Winter Capacity Mix




### Figure 9-45: Preferred Portfolio Energy Mix




## 9.3.1 Preferred Portfolio Summary

NIPSCO's preferred portfolio was developed to ensure that a reliable, compliant, flexible, diverse and affordable set of resources is available to meet future customer needs. As part of the portfolio selection process, NIPSCO also considered the impacts to its employees, the environment, reliability, and impacts on the local economy. The major components of the NIPSCO resource strategy are expected to:

- Continue to implement NIPSCO's portfolio transition by integrating new renewable projects and taking the necessary steps to retire the Michigan City coal plant by 2028;

- Continue the Company's commitment to EE and DR by executing the current filed DSM plan and continuing to plan for significant residential and commercial DSM programs over time;

- Provide a cost-effective portfolio for customers while also balancing other objectives associated with rate stability, environmental sustainability, and positive social and economic impacts;

- Ensure that system reliability is preserved as NIPSCO and the broader MISO market increase the amount of intermittent resource capacity;

- Reduce customer and NIPSCO exposure to market, policy, and technology risks by intentionally integrating modular, highly diverse new resource alternatives over the next several years;

- Preserve flexibility in resource procurement, particularly over the long-term;

- Continue to actively monitor federal policy, technology, and MISO market trends, while staying engaged with project developers and asset owners to understand the landscape of new resource options;

- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services;

- Continue to comply with NERC, MISO, and EPA standards and regulations.

It 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. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

### 9.3.2 Financial Impact

Figure 9-46 shows NIPSCO's financial impact of Replacement Portfolio F under the retirement dates from Existing Fleet Portfolio 3 over the planning period. While NIPSCO's preferred portfolio intentionally retains flexibility to incorporate elements of Portfolios 3 and 5 from the Existing Fleet analysis, as well as Portfolios F and I from the Replacement analysis, this summary is being provided as a baseline benchmark.

The 30-year NPVRR is broken down into operating and capital costs. The operating costs include the fixed and variable costs associated with both existing units and future resources, as well as contract costs and net market purchases. The capital costs include all capital related costs for existing units and costs related to the acquisition of new resources in the preferred portfolio. These costs include depreciation expenses, capital charges, and taxes. In order to present a levelized net present value rate summary, the total energy forecast for NIPSCO is also discounted over the 30-year period at the same rate.

**Figure 9-46: Financial Impact Summary[129]**

| Financial Impact Summary | |
|---|---|
| **Operating Costs ($000)** | 5,195,199 |
| **Capital Costs ($000)** | 5,231,167 |
| **Total Revenue Requirement ($000)** | 10,426,365 |
| **Total Energy Requirement (GWh)** | 146,316 |
| **Cents/kWh** | 7.13 |

Note that Total Energy Requirement is the discounted value of 30 years of energy forecasts, rather than a total sum. This is done to allow for the cents per kWh summary to be reflective of a levelized net present value calculation.

NIPSCO expects that existing cash balances, cash generated from operating activities, and funding through inter-company loan arrangements with its parent company will meet anticipated operating expenses and capital expenditures associated with NIPSCO's short-term action plan.

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from a number of sources including: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; (v) new equity capital and (vi) tax equity financing. NiSource, Inc. procures external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB at Fitch and Baa2 at Moody's.

### 9.3.3 Developments That Will Shape NIPSCO's Preferred Portfolio Implementation

As summarized in Section 2, NIPSCO identified several key themes that have influenced the development of this 2021 IRP and that will shape the ultimate implementation of NIPSCO's short-term action plan. As noted above, NIPSCO's preferred portfolio incorporates ranges of new resource additions to reflect the fact that several evolving external factors will influence final procurement decisions. These can broadly be categorized into factors associated with RFP bid negotiations and follow-up, MISO market rules changes, federal policy changes, and technology development.

*RFP Bid Negotiations*

Although the 2021 IRP involves smaller overall capacity changes than the 2018 IRP, in many ways the resource implementation will be more complex. This is largely due to the fact that specific diligence needs to be completed on a smaller sub-set of discrete projects, as opposed to

[129] The information is based on Replacement Portfolio F under the retirement date assumptions from Portfolio 3 from the Existing Fleet analysis. As discussed throughout this section, to preserve flexibility, NIPSCO's ultimate preferred portfolio may incorporate elements of Portfolios 3 and 5 from the Existing Fleet analysis and Portfolios F and I from the Replacement analysis.

the greater flexibility afforded NIPSCO in 2018 associated with identifying many renewable projects to fill a relatively large capacity target.

As NIPSCO proceeds with its short-term implementation plan, the following RFP bid diligence will be required:

- Review the best-performing gas peaker bids to confirm consistency with Reliability Assessment conclusions, assess opportunities for hydrogen enablement, and evaluate overall project viability and feasibility;

- Assess characteristics of storage bids to confirm consistency with Reliability Assessment, such as a preference for grid forming inverter technology, and other operational requirements; and

- Consider additional RFPs for capacity resources if needed to re-assess the landscape and ensure consistency with all IRP preferred portfolio requirements.

*MISO Market Rules Changes*

At the outset of its 2021 IRP process, NIPSCO identified several regulatory developments at the MISO level that would impact portfolio performance and ultimate implementation of the preferred plan. While MISO has advanced policy development implementation in many areas over the last year, several areas of uncertainty remain, requiring NIPSCO to ensure portfolio decisions are flexible enough to adapt to the changing environment. These include:

- Ongoing activities associated with MISO's RAN framework and the pending implementation of a seasonal capacity construct: Throughout 2021, MISO engaged with stakeholders regarding the implementation of a four-season capacity construct. While still not final, NIPSCO expects a filing on this proposal with FERC to be followed by implementation over the next few years. NIPSCO's 2021 IRP has explicitly planned for this, but portfolio adjustments may be needed in the event of different reserve margin targets (for example, a higher winter standard than modeled in the IRP) and evolving capacity accreditation rules.

- MISO's transition to an ELCC methodology to assess capacity credit for wind and solar resources over time and by season: NIPSCO's 2021 IRP incorporated a range of ELCC trajectories over time by scenario (*See* Section 8 for details across scenarios and earlier parts of this section for the impacts on NIPSCO's supply-demand balance) and assumed different summer and winter capacity credit ratings for intermittent technologies. However, as MISO implements new ELCC accounting procedures and the seasonal capacity construct, and as the amount of intermittent capacity in the broader market increases, credit values may evolve differently than what NIPSCO has assumed in the IRP. Therefore, resource procurement will need to remain flexible in order to ensure planning reserve margins are maintained.

- MISO's ongoing RIIA study: Although the 2021 IRP was designed specifically to evaluate reliability across the many dimensions identified in recent RIIA reports, NIPSCO will continue to track developments and their impact on the portfolio.

- MISO's implementation of market rules associated with FERC No. Order 841, which requires ISOs and RTOs to establish a participation model for storage resources in energy, capacity, and ancillary services markets: The 2021 IRP has identified significant value opportunities for storage resources in the sub-hourly energy and ancillary services markets. However, rules for storage implementation are not fully established, with MISO requesting implementation delays until 2022. As these rules are formalized, including for capacity accreditation and energy and ancillary services participation, NIPSCO will continue to track developments and adapt its resource procurement plans (particularly around storage) accordingly.

*Federal Energy and Environmental Policy Changes*

As of the time of the development of NIPSCO's 2021 IRP preferred portfolio, federal policymakers were debating significant changes to energy and environmental policy. While NIPSCO's scenarios have contemplated a broad range of policy outcomes largely consistent with the state of the debate (*See* Section 8 for more detail), certain outcomes could impact portfolio implementation decisions. The most relevant include:

- The potential implementation of a stand-alone storage ITC: NIPSCO's preferred portfolio contains a wide range of potential storage additions, and NIPSCO's scenario analysis indicated that storage resources perform better in scenarios that assume the implementation of a storage ITC. Therefore, if implemented, NIPSCO's preferred portfolio retains the flexibility to pivot towards higher levels of storage additions.

- Changes to current implementation of the ITC including, potential "direct-pay" provisions and Internal Revenue Service normalization rules.

- The potential implementation of a hydrogen PTC or other federal incentives for hydrogen development: NIPSCO's portfolio analysis suggested that federal subsidies for hydrogen production would improve the performance of portfolios that integrate this resource type into the mix. Therefore, if federal legislation includes direct subsidies or other incentives associated with hydrogen production or use, NIPSCO may adapt by exploring pilot programs or other initiatives designed to test and integrate hydrogen into its generation mix.

- The potential implementation of a carbon tax, clean energy standard or CEPP: Various recent policy proposals have offered several alternative means of incentivizing clean energy additions, and certain policy outcomes may influence the amount of new renewable capacity (both solar and wind) that NIPSCO ultimately adds to its portfolio through the short-term implementation plan.

*Technology Change*

As the power sector continues to navigate a period of significant change, NIPSCO expects that technology evolution will be rapid, requiring regular review of the supply-side resource marketplace and flexibility in the preferred portfolio. For example, as NIPSCO implemented the short-term action plan from its 2018 IRP, additional paired solar plus storage additions were made in response to improving technology and declining costs for lithium-ion battery storage. Going forward, NIPSCO expects power sector technology evolution to continue to impact both short-term procurement activities and long-term resource decisions. In particular, NIPSCO will continue to monitor the following:

- Stand-alone storage resource costs, efficiencies, and operational parameters, such as cycle limits, depth of discharge specifications, and ongoing expenses;
- Grid-forming inverter technology that could provide reliability benefits, such as blackstart, fast frequency response, and inertial response, to NIPSCO's system as it becomes more inverter-based;
- Hydrogen production developments, particularly associated with electrolysis of water with clean electricity sources ("green hydrogen") and the costs and capabilities of turbines and other thermal resources to burn hydrogen or blend hydrogen with natural gas;
- CCS costs and sequestration opportunities, particularly associated with the Sugar Creek facility;
- Long-duration storage technologies, including gravity storage, and their associated costs, efficiencies, and other value drivers;
- Other technologies that may emerge over the long term, including small modular reactors and other nuclear technology.

*Other Factors*

As with the implementation of NIPSCO's 2018 IRP, NIPSCO will again continue to perform project-specific analyses for any new resources that may enter the portfolio to evaluate items such as congestion and nodal price risk, energy deliverability, and other reliability topics. This may include detailed nodal and power flow modeling and other local transmission and distribution system analyses.

## 9.4 Short-Term Action Plan

NIPSCO's short-term action plan covers the period 2022 to 2027 and includes several elements, as summarized in

Figure 9-47. NIPSCO will initiate the planning process for the retirement of the Michigan City 12 and Schahfer 16AB units, leaving flexibility in ultimate timing, as described in the preferred existing fleet portfolio section above. During the retirement implementation period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire units, and NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements.

NIPSCO will also select replacement resources identified through the 2021 RFP evaluation process, prioritizing resources that were common across all portfolios that influenced the preferred portfolio selection. These include short-term thermal contracts and some solar resources. NIPSCO will also take the necessary steps to proceed with uprates to the Sugar Creek CCGT facility and identify opportunities for DER projects with distribution deferral costs consistent with the attractive tranche selected in the preferred portfolio. NIPSCO will also continue to implement the filed DSM plan for 2022 to 2024 and will continue to pursue longer-term DSM implementation consistent with the bundles selected in the preferred portfolio.

In addition, NIPSCO will perform due diligence on the short-list of gas peaker and storage bids and will conduct additional targeted RFP solicitations and associated portfolio analysis if current projects do not meet all reliability and other considerations inherent in the preferred portfolio. For the projects selected, NIPSCO will pursue the required approvals from the Commission to acquire those projects. Finally, to fill any short-term capacity needs during this period, NIPSCO will rely on MISO market purchases or short-term bilateral capacity contracts.

## 9.5 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost-effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This 2021 IRP incorporated several emerging trends and greatly expanded the analysis of risk and reliability to identify a preferred portfolio that is highly flexible to changing external conditions. It is no longer possible to view the world in terms of choosing a simple least cost option, and NIPSCO has identified an implementation roadmap that reflects the need to minimize future environmental impacts, maximize resource diversification, and preserve optionality over the long-term.

**Figure 9-47: Short-Term Action Plan Summary**

| |
|---|
| Complete and place in service 12 remaining renewable facilities approved by the IURC |
| Complete retirement and shutdown remainder of Schahfer coal units (17,18) by 2023 |
| Refine the retirement of Michigan City 12 to be between 2026 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate |
| Monitor the operating condition of the Schahfer 16A/B and plan for their retirement between 2025 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate, including preserving the optionality to use existing interconnection rights at the site through the MISO generator replacement process |
| Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B |
| Confirm Sugar Creek uprate options in more detail with the plant's turbine manufacturer and schedule the uprate in accordance with the plant's maintenance cycles |
| Identify candidate DER projects as part of NIPSCO's distribution planning activities and consistent with planning-level assumptions developed in the IRP; implement identified projects after additional project-specific diligence |
| Continue implementation of filed DSM Plan for 2022 through 2023 |
| Select replacement projects identified from the 2021 RFPs, initially prioritizing thermal PPA and solar resources |
| Perform deeper diligence on gas peaker and storage projects from the 2021 RFPs, selecting projects that conform to the preferred portfolio's requirements as NIPSCO tracks MISO guidelines, Commission requirements, and system reliability needs |
| As needed, conduct a subsequent RFP(s) to identify additional resources that may be available with attributes that are consistent with those required to implement the preferred portfolio |
| Explore potential pilot projects from the RFP associated with emerging technologies, such as long duration storage and hydrogen |
| File CPCN(s) and other necessary approvals for selected replacement projects |
| Procure short-term capacity as needed from the MISO market or through short-term bilateral capacity transactions |
| Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape |

| |
|---|
| Perform additional reliability analysis within the NIPSCO system as needed to ensure evolving portfolio meets all reliability needs and requirements |
| Comply with NERC, EPA, and other regulations |
| Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services |

**Confidential Attachment 12-B (Redacted)**