Final Director's Report

For Northern Indiana Public Service Company (NIPSCO) 2021 Integrated Resource Plan

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CONTENTS

Draft Director's Report Applicable to NIPSCO's 2021 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Northern Indiana Public Service Company, LLC's (NIPSCO's) 2021 Integrated Resource Plan (IRP) was submitted on Nov. 15, 2021. By statute and rule, integrated resource planning requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The IRP Director in the report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible, as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of integrated resource planning, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting. By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

Every Indiana utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors and, increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and the nation.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

II. Introduction and Background

NIPSCO's 2021 IRP builds on its 2018 IRP analysis, which showed that the Preferred Portfolio involved accelerating the retirement of a majority of NIPSCO's remaining coal-fired generation over a five-year period and all coal within the next 10 years. Replacement options pointed toward renewable energy resources such as wind, solar and battery storage technology.

From the Director's perspective, NIPSCO, like most utilities across the United States, is addressing unprecedented resource changes in an environment of extreme uncertainty regarding government policy, commodity prices, and technology. To better address these uncertainties, the 2021 IRP included several improvements compared to the 2018 IRP.

- The load forecast explicitly accounted for distributed energy resource (DER) modeling, electric vehicle (EV) modeling, and energy efficiency.
- Additional reliability and operational flexibility metrics were included in the scorecard for the evaluation of resource portfolios.
- Inclusion of renewable generation output risk, correlated with power price risk in stochastic analysis.
- Evaluation of the Preferred Portfolio's ability to meet both the summer and winter peak loads.

Further, NIPSCO developed its IRP with significant stakeholder input.

Consistent with the issues discussed above, the Director's report will focus on three broad areas: (1) load forecasting; (2) assessment of demand-side resources broadly defined to include energy efficiency, demand response resources, electric vehicles, and other DERs; and (3) portfolio analysis and the consideration of risk and uncertainty on different resource portfolios.

III. Load Forecasting

The NIPSCO load forecast includes several significant improvements. The industrial portion of the forecast accounts for the implementation of Rate 831 and its impact on large customer load. The new tariff gave several large industrial customers the option to procure most of their energy and capacity needs on their own. NIPSCO also developed monthly net energy and peak load projections to evaluate seasonal energy needs throughout the planning period. NIPSCO forecasted the impact of customer owned DERs and EVs on load across a range of adoption scenarios. NIPSCO's final forecasts combine the baseline econometric load projections with DER and EV analysis across planning scenarios to capture a range of future load growth outcomes.

NIPSCO offered the following highlights:

- NIPSCO's energy sales are projected to grow at a compound annual growth rate (CAGR) of approximately 0.2% over the planning period. Summer peak load is projected to decline at a CAGR of 0.2%, while winter peak load is projected to grow at a CAGR of 0.2%.
- Residential and commercial customer counts are projected to grow at CAGRs of 0.5% and 0.8%, respectively, with the small industrial customer count projected to grow at a rate of 0.3% annually.
- EV growth has the potential to add between approximately 150 to 1,000 GWh to the sales forecast and between 10 and 80 MW to peak load.
- Customer-owned DERs have the potential to reduce the sales forecast by approximately 125 and 450 GWh, while reducing summer peak load by between approximately 40 and 160 MW and winter peak load by up to 100 MW.

A. Electric Vehicles (EVs)

NIPSCO developed a range of potential EV penetration rates based on existing data for EV counts in Indiana counties and a top-down third-party projection. NIPSCO-specific and external information about electricity charging usage and hourly charging patterns was then used to estimate the impact on NIPSCO sales and peak load requirements for each of four market scenarios.

The EV fleet was broken down into four classes of vehicle fleets, which were independently forecasted:

- Light Duty Vehicles (LDVs)
- Transit vehicles, such as buses and shuttle vans
- Medium Duty Vehicles (MDVs)
- Heavy Duty Vehicles (HDVs)

Starting values for EV counts were developed using NIPSCO EV customer data for LDVs. For the other three vehicle classes, information from the 2019 National Transit Database with an estimate for the total vehicle count in the NIPSCO territory was used. To develop future projections of EV growth, NIPSCO used the EV forecast for MISO LRZ from the 2021 MTEP process. NIPSCO developed EV sales CAGR from the three MTEP Futures scenarios and mapped them to low, medium, and high scenarios. Information from Bloomberg New Energy Finance was used for the heavy-duty vehicle class.

For LDVs, NIPSCO applied two EV charging shapes to forecast scenarios to capture a variety of potential influences on charging behavior, such as rate design, public charging infrastructure availability and incentives, technology improvements in fast-charging, and smart charging infrastructure. The Low EV Penetration scenario charging shape was based on time-of-use data from NIPSCO's IN-Charge program. The high EV Penetration scenario charging shape was based on data from DOE's EV Project.

The same general approach was used to estimate fleet wide vehicle numbers, energy and peak demand impacts was applied to the transit vehicle sector. For the HDV class a forecast was developed only for the High scenario since electric trucking is unlikely without significant technology improvements.

The LDV forecast is the primary driver of the overall forecast levels and range with over 120 GWh in the low scenario and over 800 GWh in the high scenario by 2040. The MDV impact is expected to range from 25 to 120 GWh. Transit is expected to be 1.8 GWh in the low scenario and 10 GWh in the high scenario. The HDV forecast for the high scenario is 74 GWh in 2040.

B. Distributed Energy Resources

NIPSCO used CRA's agent-based model PenDER, customized and calibrated to NIPSCO's existing database of DER customers. NIPSCO focused on solar and storage technologies, excluding wind, biomass, and other resources. The study projected DER adoption for residential and commercial customers.

PenDER simulates the adoption decisions and interactions via social networks of thousands of autonomous agents to provide projections of DER adoption. Technical, economic, and demographic characteristics of the simulated agents contribute to an individual agent's probability to adopt DER based on an economic review of retail rate expectations, the costs of installing DER, and potential financial incentives.

An agent's decision to adopt DER is influenced by the combination of payback period and household budget as well as personal preferences and network effects.

NIPSCO used PenDER to estimate a range of DER penetration levels across four major planning scenarios.

C. Other Electrification

For the Economy-Wide Decarbonization (EWD) Scenario, NIPSCO included higher levels of electrification of some end uses based on the electrification study conducted by AEG for MISO's MTEP 2021. That study included potential electrification of residential and commercial/industrial heating, hot water, appliances, and processes. NIPSCO adopted the MISO projections for LRZ 6 to its service territory. The result of additional electrification was larger demand impacts in the winter than the summer, and the peak profile changed.

D. Industrial Load Risk

For the Status Quo Extended scenario, NIPSCO included the potential for additional load migration to the new industrial rate. The scenario included a reduction of firm industrial load in Rate 831 down to 70 MW.

Director's Comments – Load Forecasting

NIPSCO is to be commended for significant improvements in the load forecasting methods, all of which appear to be designed to better account for the significant uncertainty about future load growth. Load growth across the industry in the U.S. has seen large changes since the 1970s, but today's load forecasting environment is particularly complicated with many key considerations simply unknowable. Of course, this has always been the case. However, the combination of economic, policy, and technology uncertainties seems to be especially problematic now.

The result is a load forecast that includes a substantial range to account for this uncertainty. The Reference Case and the Aggressive Environmental Regulation (AER) scenarios project net energy sales to grow at a CAGR of just below 0.2% annually. These two scenarios use the same economic forecast and the EV and DER loads generally offset each other. The high EV and other electrification impacts in the EWD scenario cause annual growth of over 1.4% over the forecast period. The Status Quo Extended (SQE) scenario has negative growth (-0.28%) based on lower economic growth and industrial load loss.

Similar variation is seen in the projections of peak load. Summer peak load shows negative annual growth rates in three of the four scenarios. The Economy-Wide Decarbonization scenario has a CAGR of 0.62% compared to (0.16)% for the Reference Case, (0.40)% for the Status Quo Extended, and (0.30)% for the Aggressive Environmental Regulation scenarios.

Projected peak load growth rates for the winter are higher. The EWD scenario has a CAGR above 2%, largely driven by electrification of heating. The Reference case grows at an annual rate of 0.21%. the Aggressive Environmental scenario at 0.03%, and the Status Quo Extended decreases at a CAGR of (0.12)%.

The Director has several general comments and questions:

1. Are the monthly load factors by class projected to change over the forecast horizon? If so, how are those determined? (See page 33)
   Response of NIPSCO
   "Concerning the Director's question regarding load factors (page 7), the load factors shown in Figure 3-6 were assumed to remain constant over time in the core econometric load forecasting analysis. Please note, however, that several load elements that impact load factor trends were evaluated outside of the core econometric analysis. These include demand side management/energy efficiency ("DSM/EE"), electric vehicle ("EV") penetration, and customer-owned distributed energy resource penetration. The load factor impacts from these changes over time were incorporated in the net load forecast and the IRP analysis. "*(NIPSCO's comments on the Director's Draft Report, pp. 1-2)*
2. Where do the projected values for number of households (X_{ij}) come from? Does Moody's project that? (See page 27, equation 3-1)
   Response of NIPSCO
   "The answer is yes, Moody's projects the number of households at the state level. NIPSCO used the Moody's projection in its econometric forecast." *(NIPSCO's comments on the Director's Draft Report, p. 2)*
3. Do the numbers in Table 3-3 represent only the portions of counties served by NIPSCO or the entire county? This could be significant in a county like St. Joseph, where much of the county is served by another utility. If the numbers represent the entire county, were the numbers adjusted in any way prior to projecting the growth and being added to the load forecast? (See pages 37-38)
   Response of NIPSCO
   "The numbers in Table 3-3 represent data for the entire county. It is true that for certain counties, many of the vehicles could be in other service territories, but even if assuming all vehicles are in NIPSCO's service territory, the historical totals only amount to about 0.2% of total light duty vehicle stock. Given that NIPSCO's EV scenarios were based on the Midcontinent Independent System Operator, Inc. ("MISO") Transmission Expansion Plan penetration levels, the historical data was used only as a guide for a reasonable starting point to trend into the MISO penetration levels. As EV counts increase, NIPSCO will look to refine its data gathering processes to more precisely track vehicles within the service territory." *(NIPSCO's comments on the Director's Draft Report, p. 2)*
4. It is unclear whether separate weekday and weekend EV charging profiles are used. Figures 3-9 and 3-10 show different profiles that are apparently based on NIPSCO data and DOE data, respectively. Figure 3-11 only shows single profiles for low and high penetration and the text is not clear.
   Response of NIPSCO
   "[S]eparate weekday and weekend profiles were used in the analysis. For modeling purposes, a full 168-hour weekly shape was used, with the weekday shape for Monday through Friday and the weekend shape for Saturday and Sunday. Figure 3-11 was used to illustrate a sample weekday EV load shape relative to the hourly power price shape for each season. NIPSCO will endeavor to make this clearer in future IRPs." *(NIPSCO's comments on the Director's Draft Report, p. 2)*
5. In previous IRPs, NIPSCO relied heavily on conversations with its 25 largest customers to develop their load forecast. The forecast for the remaining industrial customers was based primarily on historical data from the past several years with greater weight given to the most recent year. In general, the industrial load forecast was based on informed judgement for the first few years and then held constant which was inconsistent with historical observations.

The move to Rate 831 necessitated a change in the industrial load forecast methodology. In the current IRP NIPSCO projects separately the large industrial Rate 831 Tier 1 load, the large industrial non-Rate 831 customer load, and the small industrial. The non-Rate 831 and small industrial customer loads are now modeled like the methodology used for the residential and commercial customer classes. However, more discussion of this change and more details would have been helpful.

Response of NIPSCO

"NIPSCO conducted additional analysis regarding industrial load growth as part of the load forecasting process, including econometric analysis of the small industrial group and customer-level assessments of its largest class of industrial users. For small industrial customers, NIPSCO developed forecasts based on new econometric variables such as manufacturing employment levels and assessed class-level monthly load factors for the first time. For the largest industrial customers, NIPSCO evaluated individual customer data and incorporated expected migrations to Rate 831 both in the Reference Case and as part of a low load case in the Status Quo Extended scenario. NIPSCO agrees that the underlying analysis associated with large industrial customer forecasts could have been more clearly described in its written report, and NIPSCO will take this concern into account when preparing subsequent IRPs." *(NIPSCO's comments on the Director's Draft Report, pp. 2-3)*

Director's Reply

The Director appreciates the additional information provided by NIPSCO in response to the above questions.

IV. Demand-Side Resources

The 2021 IRP included an assessment of future demand-side management (DSM) programs through a market potential study (MPS) and portfolio analysis of the various options. The savings for 2022 and 2023 in the IRP are informed by NIPSCO's currently approved DSM Plan and the DSM program costs and savings on the 2021 MPS are used to inform the remaining years of the IRP. Then, NIPSCO uses the results from the IRP to develop the DSM Action Plan. The DSM Action Plan will then be used to develop the DSM Request for Proposals (RFPs).

The MPS conducted by energy consultant GDS included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop separate estimates of energy efficiency (EE) and demand response (DR) technical, economic, and achievable potential. The MPS models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, savings of other fuels, and benefit/cost ratios over the 20-year time horizon (2024-2043). For the development of the MPS, GDS used the latest electric load forecast for 2020 through 2040 as input. However, since the original NIPSCO forecast included implied assumptions about future EE based on historical DSM performance, these historical impacts are added back into the MPS to avoid any potential over-counting of future EE potential.

For this IRP, NIPSCO also incorporated EE and DR bundles as a new resource option in the optimization market model (Aurora), therefore using the same software and similar resource selection process as in the 2018 IRP. The bundles were allowed to be selected across all portfolio themes and 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. DSM programs contained in NIPSCO's preferred portfolio are based on the Realistic Achievable Potential (RAP) assumptions, as opposed to the Maximum Achievable Potential (MAP) assumptions.

A. Energy Efficiency (EE) Resources

In the beginning, for the residential sector, there were 182 unique electric EE measures included for each end use in the EE potential analysis. These measures were then further broken out to include permutations across housing type (single-family vs. multifamily) and income type (income-qualified vs. market rate). For the C&I sector, there were 272 EE measures included in the analysis. In the end, NIPSCO considered 9 EE Residential programs and 3 EE Industrial programs.

The potential study evaluated two achievable potential scenarios: maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP) estimates. NIPSCO used the Utility Cost Test benefit/cost ratios (UCT) for the period 2024 to 2043 as the test for screening sector MAP and RAP measures for inclusion. For the IRP's DSM base case analysis, NIPSCO used the RAP identified in the MPS as the starting point for developing EE bundles. The GDS Team initially provided EE inputs at the aggregate sector level to minimize the chances that the IRP would only select the lowest cost measures and limit NIPSCO's ability to offer broad programs. Based on a review of these initial cost and savings inputs, the GDS Team further segmented the residential sector savings into high-cost measures (Tier 2) and low/mid cost measures (Tier 1). The GDS Team provided the energy efficiency IRP inputs across three different vintage bundles: 2024-2029, 2030-2035, and 2036-2041. The use of these vintage and tier classifications represents an improvement from the methodology used in the 2018 IRP. Additionally, the annual EE impacts (MWh and MW), hourly (8,760) shapes that reflect various measures and end-uses were provided to NIPSCO to allow the IRP model to assess the value of EE savings on an hourly basis.

The following four adjustments were applied to the MPS's RAP energy efficiency potential prior inclusion to the IRP: 1) converted the EE potential from gross savings to net savings; 2) aligned the level of income-qualified potential, identified in the RAP, with levels achieved historically by NIPSCO; 3) provided the RAP savings at the generator level (MPS savings are at the meter-level); and 4) re-screened the cost-effectiveness of measures under an alternative cost of avoided generation. The MPS's avoided cost of generation was based on a CCGT unit, now was re-screened using a lower avoided cost of generation associated with a combustion turbine (CT), or "peaking" unit.

A total of 12 EE bundles (two covering sectors, two cost tiers, and three different vintage bundles) are modeled as eligible resources in the portfolio optimization analysis and through additional portfolio evaluation.

B. Demand Response (DR) Resources

NIPSCO's 2018 rate case removed the Industrial Rider 775 and Rate 734 and added Rate 831. Prior to this rate case, NIPSCO's DR portfolio was comprised of load curtailment agreements from industrial customers. Now, NIPSCO only procures enough resources for a portion of these customers' loads ("firm" loads) because NIPSCO can no longer claim the remaining "non-firm" portion of these customers' loads as DR (Rate 831). For the 2021 MPS and current IRP, the "non-firm" load associated with Rate 831 customers was not included in the DR potential assessment.

The DR portion of the MPS considered various DR program types such as: residential smart thermostats, residential water heater DR, C&I load curtailment, and residential and small C&I dynamic rates. The cost-effectiveness of the programs is screened using the UCT and the MAP and the RAP. Each program is also assumed to reach full program capacity after two or three years, which reflects time required to market to and enroll customers in each program.

For the 2021 IRP modeling, NIPSCO considered DR alongside other supply resources. Furthermore, the DR program cost-effectiveness was also re-screened under an alternate avoided cost scenario, assuming the cost of a CT unit instead of a combined cycle facility. The result is a reduction in the total DR as well as overall program costs per kW of capacity. As a note, the RAP was selected as the 'base case' for purposes of IRP modeling based on the overall cost-effectiveness relative to the MAP. As with the EE inputs, the DR costs have been adjusted to represent program costs less the avoided transmission and distribution benefit from the programs. DR bundles were similarly incorporated into the IRP analysis with annual program potential and costs under three program sub-segments: Dynamic Rates, Residential, and C&I customers. DR bundles are included in the IRP modeling starting in 2024 for both the Residential and C&I DR programs while the Rate DR bundle is not offered until 2030. The Rate DR bundle is a critical peaking pricing rate for both residential and small C&I customer classes. The Rate DR offering is delayed until 2030 because that is when it is assumed enabling AMI will be in place.

Director's Comments – Demand-Side Resources

The evaluation of EE and DR resources included some basic features that are key for the analysis to be reasonable. First, the MPS was updated with the NIPSCO Oversight Board included in the process. Second, the MPS used a recent load forecast that was adjusted to remove the effects of historical DSM. Historical DSM impacts were added back to the load forecast used by the MPS vendor to avoid the potential for over-counting the potential for additional EE over the planning period. Third, NIPSCO developed shapes that reflect the measures and end-uses included in the bundles for use in the IRP model hourly (8760 hours) to assess the value of EE savings on an hourly level. The shapes differed for each EE sector (residential or C&I) and across the three vintages.

The Director was especially interested in the DR analysis given the large changes in NIPSCO's industrial load obligations with the creation of Rate 831 in the last rate case. NIPSCO noted that there are currently no DR programs offered given the removal of Rate 831 customer interruptible loads and the suspension in 2015 of the residential AC cycling via direct load control switches. The MPS analyzed the following programs: a residential smart thermostat, residential water heater DR, residential and small dynamic rates, and medium and large C&I load curtailment. The critical peak pricing program was assumed to be operational in 2030, the time by which AMI was assumed to be in place.

The Director appreciates the effort to evaluate the usefulness of a limited form of dynamic rates in the IRP but believes this is an area deserving of greater attention given the range of load uncertainty and increasing dependence on intermittent resources. Also, more attention should be paid to the interaction between EE and DR with each other.

Response of NIPSCO

> "NIPSCO agrees that dynamic rates warrant additional, future analysis given current uncertainties and increasing dependance on intermittent resources. For the 2021 IRP, the Company noted that the advanced metering infrastructure ("AMI") required to facilitate dynamic rates was not expected until 2030. Dynamic rates will likely be afforded increased attention in future studies as the rollout of advanced metering infrastructure is underway. In

addition, the market potential study ("MPS") considered the interaction of EE and DR regarding smart thermostats and direct load control of these devices. The DR Analysis considered the forecasted adoption levels of smart thermostats (from the energy efficiency MPS) on the future potential for direct load control. That same modeling framework will work well with other devices as more and more equipment becomes connected and controllable." *(NIPSCO's comments on the Director's Draft Report, p. 3)*

Director's Reply

The Director appreciates the additional information provided by NIPSCO in response to the above discussion.

Questions and Other Comments

- NIPSCO mentions that net realistic achievable potential savings were calculated by applying NIPSCO's 2019 program evaluation results and NTG ratios to the MPS estimates. It is unclear exactly how much is applied from the evaluation results and if these results and the NTG ratios are still relevant to best meet the current market conditions.

  Response of NIPSCO

  "All existing program measures included in the net realistic achievable potential leveraged the latest available program evaluation results for the basis of the assumed NTG ratio. These results are still highly relevant because the overall portfolio NTG ratio has been consistent each of the last five years. The overall portfolio-level NTG ratio in 2019 was 78%, and the average portfolio-level NTG ratio for the four years on either side of 2019 (2017-2018, and 2020-2021) is also 78%. This indicates, despite fluctuations in gross savings over time, the NTG ratio for NIPSCO portfolios has been remarkably consistent. For this reason, the estimates used in the study were and remain the best available data." *(NIPSCO's comments on the Director's Draft Report, p. 4)*
- NIPSCO affirms that the "income-qualified achievable savings were also scaled accordingly" as part of the adjustments applied to the MPS's realistic achievable energy efficiency potential savings. Also, another three adjustments were applied to these potential savings. More details regarding the technical parameters used to conduct these adjustments would clarify and facilitate the understanding of this process.

  Response of NIPSCO

  "The four adjustments to the MPS' realistic achievable potential are described on pages 133 and 134 of the IRP. The first adjustment converted the energy efficiency from gross savings to net savings. This was done by applying a measure-level NTG ratio multiplier, using the 2019 program evaluation results, which translates the gross measure-level savings to net measure-level savings. As noted in the question, the second adjustment aligned the level of income-qualified potential, identified in the realistic achievable potential, with levels achieved historically by NIPSCO. The third adjustment was to provide the achievable potential savings at the generator level. This involved simply multiplying the at-the-meter savings in the MPS by a line loss factor ("LLF") to translate these savings into at-the-generator savings. As noted on page 122 of the IRP (footnote 71), the peak residential LLF used in the analysis was 4.11%, and the peak commercial and industrial LLF were 3.76% and 2.41%, respectively. The fourth and final adjustment was to re-screen the cost-effectiveness under an alternative cost of generation. The base case avoided cost of generation is set to $129 per kW-year, and the alternative avoided cost of generation is set to $80 per kW-year. NIPSCO will seek to provide additional description regarding any needed DSM adjustments in future IRPs." *(NIPSCO's comments on the Director's Draft Report, p. 4)*

- What drives the drop from 1,137,101 MWh *(Table 5-17, Page 90)* in the total cumulative annual savings of all the EE bundles used in 2018 IRP for 2027 to only 387,917 MWh *(Table 5-14, Page 135)* in the bundles used in the most recent 2021 IRP for the same year? This is significant drop in the estimated EE savings used as resource options in the optimization model from the previous IRP to the current.

  Response of NIPSCO

  "There are two primary drivers in the differences noted. First, the 2018 IRP data referenced includes nine years of cumulative annual savings, whereas the 2021 IRP data referenced only includes four years of cumulative annual savings. This accounts for approximately 50% of the noted difference in savings. The remaining difference is a significant decrease in savings opportunities in the lighting end-use for both the residential and commercial/industrial sector in the 2021 IRP compared to the 2018 IRP. In the residential sector, light emitting diode lighting opportunities were significantly reduced in the 2021 IRP recognizing that much of the screw-based market has been transformed. Similarly, in the commercial sector, lighting opportunities were reduced based on updated market saturation estimates and a declining annual forecast for lighting savings (versus the increasing forecast for lighting savings used in the 2018 IRP)." *(NIPSCO's comments on the Director's Draft Report, p. 5)*

Director's Reply

The Director appreciates the additional information provided by NIPSCO in response to the above questions.

V. Portfolio Development and Scenario/Risk Analysis

A. Models

Charles River Associates (CRA) was hired by NIPSCO to produce forecasts for major inputs and conduct portfolio modeling. Portfolios were evaluated in CRA's suite of resource planning tools, namely Aurora and a utility financial model known as PERFORM. The Aurora model performed an hourly, chronological dispatch of NIPSCO's portfolio within the MISO power market, accounting for all variable costs of operation, all contracts or PPAs, and all economic purchases and sales with the surrounding market. Aurora produced projections of asset level dispatch and the total variable costs associated with serving load. It also produced estimates for other key metrics, such as carbon dioxide emissions over time and capacity and generation by fuel type. The Aurora output was then used by the PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, and financial accounting of depreciation, taxes, and utility return on investment. The PERFORM model produced annual and net present value estimates of revenue requirements. The full set of portfolio modeling is undertaken for all portfolio options for the Reference Case, each individual integrated market scenario, and a full stochastic distribution of potential outcomes associated with select commodity prices and hourly renewable generation. CRA also deployed its Energy Storage Operations (ESOP) model to evaluate sub-hourly energy and ancillary services value.

B. Method

NIPSCO used scenario analysis to evaluate four integrated, but divergent, future states-of-the world for commodity prices, load growth, carbon regulation, other environmental policy drivers, and the evolution of the MISO power market. The four scenarios are the Reference Case, Status Quo Extended Case (SQE), Aggressive Environmental Regulation Case (AER) and Economy-Wide Decarbonization Case (EWD). NIPSCO also explored the impact of EV adoption and DER adoption and incorporated the information in scenario design.

NIPSCO provides an extensive discussion of the Reference scenario. The scenario expects natural gas prices to rise toward $4/MMBtu (real) over the planning period. A price on carbon starts in 2026 at $9/ton (real) and steadily rises to $15/ton in 2040. The carbon price start date and trajectory over the planning period are meant to reflect several different potential paths for legislative or executive regulation. The Reference Case assumes energy generated by coal in the MISO region will continue to decrease reaching 20% by 2030 and less than 10% by 2040. According to NIPSCO, the SQE scenario was designed to represent a future with persistently low natural gas prices, limited federal regulation of carbon emissions from the power sector, and lower near-term economic growth. The scenario addresses the combined risks of low commodity prices for natural gas and power, no carbon price, and very low load growth for NIPSCO. Given the large amount of uncertainty related to federal action to control carbon emissions, the scenario specifically develops a future where carbon emissions are not restricted while conventional fuel prices remain low, testing the robustness of portfolios against this important risk.

The AER scenario was developed by NIPSCO to represent a future in which environmental regulations are more stringent than anticipated in the Reference Case. More specifically, the scenario contemplates a federal carbon tax or cap-and-trade framework that drives towards a net-zero emissions power sector and results in a significant price on carbon. In addition, the scenario includes the assumption that environmental policy restricts natural gas production and drives higher production costs for natural gas, resulting in a higher natural gas price outlook. Overall, the scenario was designed to address the risk of earlier and higher carbon prices and the risk of higher prices for natural gas and power.

The EWD scenario presents a possible future in which federal environmental regulations drive significant emission reductions throughout the economy without imposing a price on carbon. Instead, CO2 emission reductions are assumed to be the result of a power sector clean energy standard, extended and expanded federal tax credits for clean energy technologies, and measures that incentivize electrification of other parts of the economy, such as transportation and other residential, commercial, and industrial end uses. Electrification measures are projected to significantly increase power demand, particularly during the winter months. Overall, the scenario is supposed to address the risk of strict environmental regulation without the consequent increase in power prices that would be expected with a carbon price, as well as the risk of higher-than-expected NIPSCO load.

NIPSCO evaluated retirement decisions for the existing fleet on a stand-alone basis, while performing an additional replacement analysis to assess a range of replacement resource strategies. The existing fleet and replacement analyses were both based on the same major inputs and assumptions.

For existing fleet analysis, NIPSCO identified eight existing fleet portfolios based on different combinations of unit retirements at different points in time. 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 designed to minimize the net present value of revenue requirements, with certain constraints for reserve margins, maximum off-system energy sales, and resource eligibility. The evaluation of each existing fleet portfolio was performed through a full portfolio analysis that included dispatch in Aurora and financial accounting in PERFORM under the reference case scenario and alternative scenarios. A preferred existing portfolio strategy was identified based on key observations of the existing portfolios analysis. That 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.

For replacement analysis, NIPSCO first identified nine replacement resource concepts. Based on the nine replacement concepts, NIPSCO then developed specific portfolios to fit each theme. Based on the IRP document, 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. The nine replacement portfolios were then evaluated within the core IRP modeling tools under the Reference Case and alternative scenarios. 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. The stochastic assessment was 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.

For both the existing fleet analysis and the replacement analysis, NIPSCO used a scorecard to report key metrics for the different portfolio options to review tradeoffs and relative performance. The scorecard serves as a tool to facilitate and structure decision-making. The key objectives include Affordability; Rate Stability; Environmental Stability; Reliable, Flexible, and Resilient Supply; and Positive Social and Economic Impacts. The metrics used are like those used in the 2018 IRP, with a couple of significant modifications.

The existing fleet scorecard metrics included:

- Cost to Customer is measured by the overall 30-year 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.
- 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.
- 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.

The replacement analysis scorecard included some changes from the existing fleet metrics:

- Risk metrics based on the stochastic analysis were added, which included several measurements of revenue requirements relative to the median. These included (i) cost certainty was measured at the 75th percentile; (ii) cost risk was measured with the average of all outcomes above the 95th percentile; and (iii) lower cost opportunity was measured at the 5th percentile.

- Sub-hourly ancillary services market value impact and Reliability Assessment scoring.
- MW weighted duration of generation commitments in 2027.
- Employee count was not recorded, given uncertainty with future project details.

Director's Comments – Portfolio Development & Scenario/Risk Analysis

For the replacement analysis, NIPSCO developed nine portfolios based on nine company established concepts. Three of them are optimized portfolios with various constraints on resource type. The other six were designed by NIPSCO based on the concepts the company intended to pursue. Among the six, three of them were not viable due to not meeting MISO winter reserve margin requirements, only for the purpose of satisfying stakeholders' interest; another one violates net long energy sales constraints. It seems that all nine portfolios were developed from the Reference Case set of market assumptions and inputs, rather than having portfolios derived from various scenarios. In addition, not even one portfolio is based on economic optimization without restrictions on resource selection.

NIPSCO more than compensated for these limitations with particular attention to improved risk and uncertainty analysis and the impact of future resource choices on the ability to provide specific reliability characteristics.

NIPSCO developed a process to identify key uncertainties and drivers that could impact future resource portfolio performance over the long-term. These were grouped into four major categories:

- Commodity prices, especially gas and power.
- Environmental policy, particularly regarding carbon pricing and other greenhouse gas emission reduction policies.
- Load growth, including uncertainty around economic growth, EV penetration, DER penetration, electrification, and industrial load.
- The future value of intermittent resources associated with capacity credit hourly generation output.

NIPSCO then evaluated which of the major drivers would be best addressed using scenario or stochastic analysis. In the 2021 IRP, NIPSCO evaluated uncertainty variables using the following methods:

- Scenario variables:
  a. Annual and monthly natural gas prices.
  b. Carbon policy regulation.
  c. Technology incentives including extensions and expansions of the production and investment tax credits.
  d. Hourly MISO power market prices.
  e. NIPSCO and MISO load growth.
  f. Capacity credit for solar resources over time.
- Stochastic variables:
  a. Daily natural gas prices.
  b. Hourly MISO power market prices.
  c. Hourly renewable generation output for wind and solar resources.

NIPSCO's IRP included several improvements to the analysis of risk and uncertainty.

A. Carbon Emissions and Environmental Policy

NIPSCO's 2021 IRP has improved upon the 2018 report in how the analysis incorporates carbon policies. There is an expansion of NIPSCO's IRP planning scenarios to incorporate a range of environmental policy outcomes, including two scenarios with alternative policies: one with a carbon tax or cap-and-trade mechanism and one with a series of policy incentives and clean energy standard mechanisms. In addition to this, there has been an increased focus on net-zero portfolio concepts for NIPSCO that incorporate long-term options to retire or retrofit all fossil resources in the portfolio *(NIPSCO IRP pg.16).*

NIPSCO's reference case still incorporates a carbon policy in the US. In the reference case, these carbon prices are incorporated starting in 2026 *(NIPSCO IRP pg. 169)*. Like NIPSCO's 2018 IRP, NIPSCO uses third party projections (from CRA) which provide a carbon price between $9-15/ton. Interestingly NIPSCO uses a slightly wider range of values $8-16/ton in the reference case *(NIPSCO IRP pg. 169).*

NIPSCO improved the alternative scenarios by including two very different situations in which net-zero carbon is still achievable based on external pressure. These two alternative scenarios that include different levels of carbon pricing are: *(NIPSCO IRP pg. 52).*

- Aggressive Environmental Regulation – higher growth in DER, EV. The AER scenario assumes a significant price on carbon *(NIPSCO IRP pg. 183).*
- Economy-wide Decarbonization/Electrification – there is high growth across all drivers, without imposing a price on carbon. This absence of a carbon price is a scenario in which CO2 emission reductions are assumed to be the result of a power sector clean energy standard, extended and expanded federal tax credits for clean energy technologies, and measures that incentivize electrification of other parts of the economy *(NIPSCO IRP pg. 185).*

B. MISO Power Market Prices

MISO power market prices are addressed using both scenario and stochastic processes. Each scenario has the MISO generation mix changing over the planning period. MISO currently has approximately 30% clean energy resources (wind, solar, hydro, other renewables, and nuclear). The four scenarios project this level to increase to between 40% to 70% by 2030 and between 50% to 90% by 2040. Given these different portfolio mixes MISO energy prices are projected to vary considerably across the scenarios and time. These differences are seen in the MISO Zone 6 ATC power prices. The IRP also recognizes that the shape of hourly power prices under each scenario is likely to evolve very differently over time as the level of renewable resources enter the market.

C. Load Growth

NIPSCO's load scenarios are based on different assumptions about economic growth, EV penetration, DER penetration, other electrification, and industrial load loss risk. This is more fully discussed in the load forecast section.

D. Integrating Renewable Output Uncertainty

Another improvement in the IRP analysis was the integration of renewable energy output uncertainty into NIPSCO's stochastic analysis process. The idea was to account for the risk of renewable output uncertainty and the relationship with exposure to the energy market.

Higher levels of intermittent generation output are generally expected to depress power prices. Because of a lack of historical data, the size of the effect is unknown. For the stochastic analysis, NIPSCO used forward price formation using various levels of renewable penetration followed by regression analysis of hourly renewable availabilities and hourly power prices to quantify the impact.

Greater Analysis of Reliability in the IRP

The Director's Report for NIPSCO's previous IRP noted the retirement scorecard included a reliability risk metric while the replacement scorecard lacked an explicit reliability metric. In the retirement scorecard, the reliability risk metric assessed NIPSCO's ability to confidently transition its portfolio of resources and maintain customer and system reliability. This measure considered the activities and timelines, risks of the MISO retirement process, transmission system and reliability upgrades, remaining unit dependencies, outstanding fuel and other contracts, future resource procurement, and the percent of NIPSCO's supply resources turning over at the same time. The previous IRP replacement scorecard did not include a reliability metric. But the IRP had an extensive discussion of the potential future risks associated with a replacement portfolio heavily reliant on renewable resources. In the current IRP, NIPSCO directly addressed the inclusion of an explicit reliability metric in the replacement analysis by attempting to account for aspects of operating reliability – both those that could be accounted for economically and those that could not.

The Aurora model is based on a day-ahead simulation. To better account for the value of flexible resources, NIPSCO used the CRA ESOP model, an optimization model that computes revenues through participation in energy and ancillary service markets with a five-minute granularity. ESOP solves for optimal dispatch decisions given a price-taking resource's technological capabilities and the RTO's market participation rules.

The analysis in the IRP focused on the MISO five-minute real-time markets for energy, frequency regulation, and spinning reserves for storage, solar plus storage, and natural gas peaking resources to understand the tradeoffs of these resources in NIPSCO's portfolio. CRA evaluated the performance of these three resources across all four market scenarios. Across all scenarios, the incremental value from the sub-hourly and ancillary services market was projected to be the highest for the battery.

The above analysis was conducted at the resource level. NIPSCO and CRA developed portfolio impacts using the amounts of lithium-ion battery storage, paired solar plus storage, and natural gas peaking capacity in each of the nine replacement portfolios.

Recognizing that economic analysis cannot account for the full range of reliability characteristics offered by different resources, NIPSCO evaluated whether future resource choices will enable compliance with both NERC and MISO standards. NIPSCO contracted with Quanta Technology to perform a planning level reliability assessment of all replacement generation resources under consideration. Quanta Technology identified reliability criteria and metrics that individually and collectively enhance the reliability attributes of a given portfolio, developed a scoring methodology for individual technologies, and scored and ranked portfolios using these metrics. The results were included in the replacement scorecard to consideration in the overall portfolio evaluation. (The following three tables are from NIPSCO's 2021 IRP: Figure 9-36 is on p. 249, Figure 9-37 is on p. 250, and Figure 9-38 is on p. 251.)

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.

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

The Quanta study evaluated all nine replacement portfolios for the year 2030 across a variety of assessments summarized in Figure 9-38.

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

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

The assessment identified potential reliability gaps for each of the nine replacement portfolios and suggested potential mitigations to these gaps. It is important to note that not all areas of reliability assessment were addressed in the study. Also, detailed system studies will be required to evaluate the reliability of the system once a portfolio is selected and the location, size, and technology of all portfolio resources is known.

NIPSCO provided a well written integrated resource plan. Each step in the IRP development process through the selection of a preferred resource portfolio was clearly presented with attention on how a particular step fed into the next step of the IRP. It is important that a reader follow what information was developed at each stage, how this information was used at the next stage, and what results were considered more significant than others in the selection of a resource portfolio.

NIPSCO is ahead of other Indiana utilities in the pace of its resource portfolio evolution, so it was important for NIPSCO to discuss how it evaluated the impact of specific resources, and potential future resource portfolios, on its ability to provide reliable and economic service while operating within an RTO region experiencing similar resource changes. To the Director's knowledge, this is work at the forefront of integrated resource planning.

Consideration of how a utility makes resource choices within a broader region experiencing significant portfolio changes begins with a clear statement of the problem and the corresponding questions that need to be asked to reasonably structure the analysis. As is the case for any risk and uncertainty analysis, there is not likely to be a clear answer that satisfies all criteria. Rather, the key will be to develop the questions to be addressed, explore how these questions can be evaluated, and to provide a well-developed discussion of how the company used and interpreted the information.

NIPSCO, based on this initial effort, is well positioned to provide future analytical improvements.

VI. STAKEHOLDER COMMENTS

(Director's responsive comments are indented and in italics)

The following comments are intended to be a representative sampling of the public input into NIPSCO's 2021 Integrated Resource Planning. There were similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Wartsila North America, Inc.

Comments by Wartsila focused on two areas for improvement:

1. NIPSCO's Energy Storage Operations (ESOP) analysis conducted with Charles River Associates (CRA); and
2. NIPSCO's plan to acquire new gas peaking resources to replace Schahfer Units 16A and 16B in the 2026 – 2028 timeframe.

About the ESOP analysis, Wartsila notes that NIPSCO and CRA modeled the performance of four-hour duration lithium-ion battery storage, paired solar plus storage, and natural gas-fired combustion peakers. These resource types were based on individual bids received in the RFP process. Wartsila notes these resources do not fully capture the set of technologies available to address sub-hourly operational constraints and capture value in real-time energy and ancillary services markets. That reciprocating internal combustion engines (RICE) were excluded. Because RICE possess superior operational flexibility, NIPSCO should amend its ESOP analysis to include RICE technology.

NIPSCO's Short-Term Action Plan discusses the replacement of Schahfer Units 16A and 16B with 300 MW gas peaking capacity. Wartsila notes that combustion turbines are not the only resource available for meeting NIPSCO's peak load and broader reliability needs. RICE technology offers greater operational flexibility than CTs so NIPSCO should consider a broader range of resource options to replace the two Schahfer peaking units.

<u>NIPSCO Response to Wartsila</u>
NIPSCO responds that it will continue to assess and value any candidate resources that are viable. NIPSCO did not assess the performance of RICE because no such facilities were submitted in the RFP responses. NIPSCO stated it would review RICE options similar to that for other resources if this technology is offered in future RFP responses. *(NIPSCO Response Comments, page 8)*

> *Director's Response: The Director appreciates Wartsila's advocacy for NIPSCO to evaluate RICE options for the replacement of Schahfer Units 16A and 16B. The comments highlight the difficulty of performing a thorough IRP analysis in a complex policy, technology, and economic environment. IRPs are generally indicative of the types of resource characteristics a utility should evaluate and consider acquiring when commitments must be made. This is especially the case for resource acquisition decisions that are several years away; meaning there are one or more IRP cycles to account for evolving circumstances.*

Indiana Advanced Energy Economy (Indiana AEE)

Indiana AEE expressed support for several aspects of the IRP planning process implemented by NIPSCO. NIPSCO developed a strong IRP based on sound analysis and many industry best practices, including extensive modeling of EV demand and of customer-owned DERs. Additionally, NIPSCO considered MISO rules related to resource adequacy, seasonal reserves, capacity credits, FERC Order 841 implementation, and more.

Indiana AEE stated that NIPSCO continues to demonstrate to its peers how to balance reliability, flexibility, adaptability, and affordability while pursuing an ambitious, but responsible transition to clean advanced energy resources.

Indiana AEE offered three main considerations:

1. NIPSCO should further develop its energy efficiency and demand response programs.
2. NIPSCO should delay its proposed 300 MW natural gas CT and explore alternatives.
3. NIPSCO should further study strategically sited DER opportunities to defer substation and other distribution system investments.

NIPSCO has improved its consideration of EE within the 2021 IRP by assessing the value of energy savings on an hourly basis and evaluating EE on a more level playing field with supply-side resources. Nevertheless, NIPSCO should pursue all cost-effective EE, which includes levels beyond the 2021 Market Potential Study's realistically achievable potential.

Indiana AEE notes that meter-based pay-for-performance program designs, particularly when enabled by AMI, can enhance the value of EE and other DERs by increasing the ability of utilities to rely on these programs to meet grid needs.

Programs that shave peak loads or shift demand to off-peak hours, including through time-of-use rates, have proven to be allow-cost strategy to save customers money. Behavior-based solutions especially when combined with price signals can drive larger peak reductions and load shifting. Turning every residential household into grid assets.

Regarding the replacement of 300 MW of generation capacity, Indiana AEE argues NIPSCO begin preparing to engage with aggregation services in the near term and view these services as a way to incrementally meet the resource need of 300 MW. Indiana AEE encourages NIPSCO to more broadly consider that numerous studies show that advanced energy resources, including large-scale solar, wind, and energy storge, when combined with utility programs and rates that encourage smart and managed electricity usage and flexibility, can replace most, if not all fossil fuel generation.

Indiana AEE appreciates that NIPSCO has included elements of distribution system planning within this IRP and is exploring non-wires alternatives (NWA) to defer system upgrades. It is noted that NIPSCO is proposing 10 MW of utility owned DERs with distribution system cost deferrals. Indian AEE encourages expansion of this action with consideration of different ownership models to allow NIPSCO to gain experience working with DER aggregators and other providers capable of providing grid services.

<u>NIPSCO Response to Indiana AEE</u>
Indiana AEE suggested that NIPSCO should adjust its projections of DER growth upward. NIPSCO responded that it evaluated four different customer-owned DER penetration scenarios as part of the load forecasting exercise. NIPSCO will continue to assess DERs as it plans for the future. *(NIPSCO Response Comments, p. 3)*

Indiana AEE expressed concern with the inclusion of new natural gas peaking facilities in the near term. NIPSCO responded that it is committed to flexibility and diversity in the preferred portfolio and will continue to evaluate all candidate resource options that were a part of the IRP's portfolio analysis. NIPSCO performed a risk analysis and concluded the preferred portfolio provided a reasonable balance of cost and risk mitigation. Also, the Reliability Analysis pointed to the need for longer-duration, flexible resource additions. *(NIPSCO Response Comments, p. 9)*

> *Director's Response: The Director agrees with AEE that NIPSCO implemented a thorough planning process which incorporated several industry best practices. The evaluation of DERs of all forms will continue to evolve and improve as the industry learns through experience. NIPSCO has shown through actions that it is willing to explore and implement improvements.*

Indiana Office of the Utility Consumer Counselor (OUCC)

OUCC comments are confined to two general areas – environmental and hourly projected energy imbalance.

The environmental concerns involved NIPSCO's assumptions about future environmental compliance and sustainability measures focused heavily on regulating carbon dioxide emissions.

NIPSCO's Reference Case assumes a price on CO_2 emissions beginning in 2026 at $9/TON. The OUCC thinks the initial carbon price and rate of escalation is reasonable but thinks a 2026 start is unrealistic given the pushback against the setting of federal carbon standards. However, the OUCC recognizes that NIPSCO analyzed a range of scenarios involving different assumptions about carbon policies, including one with no federal carbon emission limits implemented over the planning period.

The OUCC also emphasized that potential future carbon regulations should not be the only consideration in future environmental compliance assumptions. The OUCC recommended that NIPSCO discuss other environmental regulations impacting the natural gas industry or the availability of renewable generation material in future IRPs.

The OUCC expressed concern with NIPSCO's hourly projected energy imbalance, especially after Michigan City 12 retires. It is acknowledged that NIPSCO identifies this issue in the IRP, but the OUCC fears that this imbalance will expose customers to the market to an unreasonable degree. It is also noted that such exposure implies a high degree of transmission capability will be required.

<u>NIPSCO Response to OUCC</u>
The OUCC noted that carbon dioxide should not be the only consideration in future environmental compliance assumptions. NIPSCO responded that it agrees. NIPSCO's preferred portfolio complies with all current and projected environmental requirements. Even though the 2021 IRP reflects carbon emissions as the key indicator of environmental sustainability, it was not the only indicator considered. *(NIPSCO Response Comments, page 4)*

The OUCC was concerned about NIPSCO's projected hourly energy balance, especially after the retirement of Michigan City. NIPSCO responded that the 2021 IRP was highly focused on this issue. NIPSCO provided the OUCC with significant hourly detail to show NIPSCO's projected net energy market position over time and the expected available resources in NIPSCO's portfolio above and beyond what might be dispatched economically in the MISO market. The IRP also quantified stochastic risk associated with market exposure and reliability risk with several additional, but related, metrics. NIPSCO also said that the inclusion of new storage and gas-fired peaking facilities in NIPSCO's preferred portfolio was directly responsive to the concern. *(NIPSCO Response Comments, page 8)*

> *Director's Response: The Director concurs with both the OUCC and NIPSCO. The OUCC is correct that the projected hourly energy imbalance is important to evaluate to attempt to understand the potential implications. NIPSCO is also correct that much time, effort, and discussion was devoted to the necessary analysis. The Director emphasizes that there are no ideal resource choices in a world characterized by unprecedented uncertainty and risk. The consideration of projected hourly imbalances is but one of several scorecard metrics that must be weighed in any future resource commitments.*

Reliable Energy

Reliable Energy said that NIPSCO's IRP is problematic for a variety of reasons including:

a. The informal process used to develop the IRP allows the utility to control the inputs and results of the modeling, as well as the selection of the preferred portfolio.
b. Assumption flaws in the models raised by consumer stakeholders were ignored.

c. A failure to consider or make updates to the IRP to reflect the rapidly changing regulatory and energy environment, as requests to build or buy new generation projects are made.

Reliable Energy notes that the ongoing plant retirements in the PJM and MISO complicate making an accurate assessment of the appropriate resource needs for Indiana. Also, that when the commission considers resource adequacy issues in just one IRP or one case at a time, the commission creates a dangerous myopic view of resource planning and reliability.

<u>Process and Evidentiary Issues</u>
According to Reliable Energy,

> "[t]he current informal stakeholder process, used in lieu of a formal Commission proceeding, allows monopoly utilities to control the flow of information, impose their own biases on the preferred outcome of the IRP process, and results in the elimination or demotion of otherwise reasonable and economic portfolio alternatives."
>
> While one might argue that the opportunity for formal scrutiny of the IRP process comes during the cases in which the utility is requesting authority to build or buy new generating resources, that is simply too little, too late. By the time those cases are filed, the utility has already taken significant action to implement its own "Preferred Portfolio" by issuing Requests for Proposals (RFPs), announcing the shutdown of existing plants, and entering into contractual arrangements with project developers…The "toothpaste is out of the tube" by the time a Certificate of Public Convenience and Necessity (CPCN) case is filed."

According to Reliable Energy substantive flaws in NIPSCO's IRP could be corrected if a formal commission review process were used:

a. Reliance on a 30-year net present value (NPV), an inaccurate measure of affordability and rate stability, when other utilities use a 20-year NPV and the Commission does not set customer rates on a levelized basis.
b. Failure to recognize the risks associated with the deliverability and costs of renewable energy projects given serious supply chain disruptions and delays in the federal regulatory review and approval process.
c. Overreliance on pricing indicators from RFPs, which results in the exclusion of viable generation options, including self-built projects, retrofitting existing plants, and new technologies.
d. The price risks associated with increasing reliance on capacity and energy purchases in a time of great change in energy markets.
e. Failure to consider what impact similar portfolio shifts by other nearby utilities happening at the same time will have on the energy market and the available capacity resources.

Reliable Energy thinks the Commission should initiate formal IRP proceedings that would include:

a. The IRP and supporting documentation to make the process transparent, and more likely to be fairer to customers.
b. The utility and intervening stakeholders would have the opportunity to provide sworn testimony during public hearings.
c. The Presiding Officers would be available to resolve discovery disputes that cannot be resolved by the parties.
d. Parties would receive official notice of new developments in the proceeding rather than relying on periodic checks of the Commission's IRP website for updates.

According to Reliable Energy, the Commission should mandate by administrative rule that any new request for a CPCN must contain:

a. An updated analysis of complete portfolio options considering the risks associated with energy market price increases, overreliance on market purchases, supply chain disruptions, regulatory lag, and natural gas price increases.
b. An accurate analysis of the first 10-year rate impacts of the modeled resource portfolios on customers.
c. A revisiting of the prudency of the retirement dates for the utility's remaining coal units, based on the updated analysis.

<u>NIPSCO Response to Reliable Energy</u>
Reliable Energy had concerns about NIPSCO's reliance on a 30-year net present value (NPV) as a measure of affordability. NIPSCO responded that during the public advisory process it provided 20-year NPV and annual revenue requirement projections (based on full rate base accounting, not levelized cost analysis) in the fifth Stakeholder meeting. Specifically slides 55-57 for that meeting, which are included in Appendix A of the IRP. According to NIPSCO, the use of various affordability metrics did not change the major conclusions associated with NIPSCO's preferred portfolio. *(NIPSCO Response Comments, Pages 3 – 4)*

NIPSCO also noted that Reliable Energy had concerns with how NIPSCO used RFP information in the IRP modeling. Reliable Energy thought NIPSCO's use of RFP responses may result in the exclusion of certain generation options, such as self-built projects and retrofitting existing facilities. NIPSCO responded the RFP was designed to address all solutions, regardless of technology. That the RFP provided potential actionable projects to meet near-term capacity needs. The RFP did not preclude future evaluation of any technology or resource alternative. *(NIPSCO Response Comments, p. 5)*

Reliable Energy suggested that NIPSCO ignored risks associated with MISO energy market changes, fuel price uncertainty, and new technologies. In response, NIPSCO cited the broad range of scenario and stochastic-based risks in the 2021 IRP compared to prior IRPs. The scenarios included a wide range of carbon policy outcomes (with and without carbon prices), a scenario with high natural gas prices based on assumed environmental restrictions on natural gas production, and a wide range of MISO-wide generation portfolios. NIPSCO's IRP also included an extensive treatment of stochastic risk associated with commodity prices and renewable generator output, broadening the risk assessment compared to that in the 2018 IRP. *(NIPSCO Response Comments, pages 2- 3)*

> *Director's Response: The Director appreciates Reliable Energy's well-intentioned thoughts on how to improve the IRP stakeholder process and, more generally, the development of the IRP methodology and content. Reliable Energy does an excellent job highlighting the difficulty of making utility-specific resource choices in a complex and rapidly changing environment. However, almost all of these difficulties were explicitly addressed in the IRP itself or the stakeholder meetings. Long-term resource planning is continually improving and NIPSCO has been at the leading edge in Indiana, if not the country, in thinking about how to address these issues. The Director believes that it is the responsibility of the utility to decide when to update an IRP and how extensively.*
>
> *Much of Reliable Energy's comments question the effectiveness of the IRP stakeholder process, the usefulness of the Director's review of the IRP and process, and the usefulness of any commission review in a subsequent regulatory proceeding. The Director appreciates that Reliable Energy is using these comments to address the Commission directly. The Director's*

response is that the process has seen a massive improvement in the IRP quality and stakeholder input. It is undeniable that there is room for improvement. It is also open to debate how much of these changes would have occurred anyway. Surely the process developed by the Commission has facilitated much of these improvements.

Response of Reliable Energy
Reliable Energy had a couple of broad comments on the Draft Director's NIPSCO IRP Report.

1. "IURC IRP rules (170 IAC 4-7-2.5) require, when a utility takes a resource action, such as filing a Certificate of Public Convenience and Necessity (CPCN), that the action be consistent with the most recent IRP submitted by the utility. Any departure from the IRP must be fully explained and justified with supporting evidence, including an updated IRP analysis. The fatal flaw in this rule is that it presumes that the IRP is the best result, even when stakeholders raise significant concerns regarding the process and substance of the IRP. The rule also ignores the fact that IRPs could be 2-4 years old when a CPCN is filed, and the Commission's rule does not require it to be updated unless the resource action changes. Consequently, if the utility adheres to its existing IRP, however outdated and potentially flawed, it avoids any duty to address substantive concerns with the IRP. The Commission can, and should, establish enhanced expectations for the presentation of updated IRPs in formal proceedings, as it has done by requiring reliability and regional transmission organization (RTO) related evidence in electric generation CPCN proceedings under General Administrative Order No. 2022-1.2 Evidence presented in support of a request for a CPCN should be evaluated not only for the purposes of the CPCN, but with an eye towards identifying necessary and corresponding revisions to the associated IRP in order to ensure consistency with current forecasts, regulatory requirements, and the like. Simply relying on the default assumption that the IRP is indefinitely valid is untenable. Therefore, Reliable Energy respectfully requests that the Director advocate for requiring an updated analyses in all requests for a CPCN to ensure that the CPCN reflects the appropriate decisions for ratepayers at the time the CPCN application is filed. The burden should be on the utility in a CPCN case to show why its IRP results are still valid. For example, if a CPCN is filed within just a few months of the IRP filing, perhaps that is true." *(Reliable Energy's comments on the Director's Draft Report, pp. 1-2)*

2. "However, the constructive criticisms laid out in the many pages of stakeholders' comments regarding the process and substance of the utility IRPs are generally addressed in just a handful of paragraphs. The Director is well aware of the factors that have resulted in a number of utilities in the State of Indiana and elsewhere delaying coal plant retirements, including but not limited to the material rise in natural gas prices, plunging coal prices, the increased permitting challenges for new pipelines, the passage of the Inflation Reduction Act (which materially increased the credits for carbon capture), and ongoing supply chain delays. While the Director is certainly not obligated to agree with any particular comment, the Director should directly and specifically address the substantive concerns raised regarding the IRP process, including: assumption flaws in the model (i.e., fundamental flaws in the 30 year net present value (NPV) analysis); the absence of a requirement to update the IRP when CPCNs are filed; the lack of confirmed pricing in the presumed cost of resource additions; failure to consider the rapidly changing energy markets or how the actions of other load-serving entities will impact pricing and reliability (e.g., the increased reliance on capacity and energy purchases by many utilities operated in Zone 6 could exceed supply); overreliance on RFPs; and the impact of market changes on coal plant retirement decisions." *(Reliable Energy's comments on the Director's Draft Report, p. 2)*

Reliable Energy concludes by encouraging "the Commission and Staff to develop additional IRP and CPCN requirements that balance the interests of utilities and their stakeholders, as well as recognizes the inherent advantage utilities have in the existing IRP process along with the impact of rapidly changing energy markets." *(Reliable Energy's comments on the Director's Draft Report, p. 2)*

Director's Reply

The response submitted by Reliable Energy again highlights the difficulty of performing long-term resource planning in a capital-intensive industry with long-lived assets when economics, government policies, technology, and commodity prices, among numerous other variables, are subject to vast degrees of risk and uncertainty in both the near-term and long-term. It appears that the fundamental criticism by Reliable Energy is that in this planning and resource acquisition environment an IRP is out of date the moment it is published, and that everyone, including the Director and the Commission, are oblivious to this possibility.

Such is not the case. It is generally understood that IRPs must be submitted to the Commission at least once every three years to account for changes in the planning environment. Also, 170 IAC 4-7-10 states, "(a) The utility may provide the director an update regarding substantial, unexpected changes that occur between IRP submissions. Copies of an update shall be provided to the OUCC and other interested parties. (b) Upon the request of the commission or its staff, the utility shall provide updated IRP information to the director, the OUCC, and interested parties." Lastly, the Director notes that it is a regular practice for the utility to update aspects of the most recent IRP when requesting a CPCN or approval of a PPA. This latter circumstance is a judgment that is the utility's responsibility to make, including when to update and what aspects to update.
It is the utility's burden to make its case when requesting a CPCN or seeking approval for cost recovery of a PPA. In the Director's opinion, the competence of the IRP planning process (and associated updates) and the interpretation and use of the resulting information by the utility is a key consideration that the Commission takes seriously.

Reliable Energy also takes the Director to task for not specifically responding to what Reliable Energy sees as substantive concerns and flaws in NIPSCO's planning process and modeling. Among these concerns is the lack of confirmed pricing for the cost of resource additions, failure to consider the impact of rapidly changing energy markets, failure to consider the impact of actions by other utilities in the region, overreliance on RFPs, and the impact of market changes on coal plant retirement decisions.

The Director understands that Reliable Energy disagrees with how NIPSCO dealt with these issues in the IRP planning process. Many of these areas of concern have no one correct assumption or methodology for analyses in the IRP. The use of judgment is inescapable when trying to include in the planning complex factors such as the implications of actions by utilities across the RTO region or even the Eastern Interconnection. The critical consideration in this planning environment is to try to understand what variables or factors drive changes in resource choices over the planning period, especially in the near-term. The sensitivity of these possible near-term resource choices, and the associated implications for later resource choices, is of critical importance. This places a heavy burden on a thorough exercise in risk and uncertainty analyses. This is how best to address most of the specific concerns raised by Reliable Energy.

Citizens Action Coalition, Earthjustice, and Vote Solar (Joint Commenters or JC)

The Joint Commenters said NIPSCO deserves significant credit for the leadership it has taken to set a high standard for integrated resource planning in Indiana. Reflecting the complexity of resource planning, the Joint Commenters had several areas of concern:

a. The IRP's Technical Appendix does not contain the information required under the Commission's administrative rule for integrated resource planning.
b. NIPSCO severely limited the resources that could be chosen during resource optimization modeling in the 2028 and 2029 period despite major resource decisions were being contemplated in this period for some portfolios.
c. NIPSCO did not evaluate adding EE at a level that would include all cost-effective EE identified in the Market Potential Study and exclude EE that was not cost effective.
d. NIPSCO made an important contribution to the way reliability is considered in portfolio selection. However, NIPSCO's analysis either understated the ability of renewables and battery storage to provide grid services or overstated the ability of thermal generators to provide services comparable to renewables and battery storage.
e. It is unclear to what degree NIPSCO will reevaluate its decision to pursue Portfolio F as it goes through the process of acquiring the resources in that plan, but prudence dictates that NIPSCO do so and maintain optionality as long as possible.

<u>Limitation on Resource Selection</u>
According to the JC, NIPSCO did not allow generic solar and battery storage resources to be selected until 2030, leaving at least two years in which very limited resources could be selected by the model. JP quoted a response by NIPSCO to questions about this limitation on resources for selection. In the response, NIPSCO emphasized the objective was to evaluate actual RFP projects that could be used to meet capacity needs that arise through 2026 rather than allow for more speculative resource costs in subsequent years to impact resource selection.

JC stated they were skeptical that an RFP issued in 2021 would capture the likely universe of proposals that would be available to NIPSCO six or more years down the road.

<u>Energy Efficiency</u>
JC believes NIPSCO implemented best practices around accounting for the T&D benefits of EE bundles and levelizing the bundle costs over the lifetime savings. The JC also appreciates that NIPSCO sought and included stakeholder input for the development of the MPS and working through how to model EE in Aurora.

Given the difficulty of the EE modeling, the JC had a couple of areas where NIPSCO could have done better. The JC noted that NIPSCO evaluated the impact of including the MAP level of EE for Portfolio F in the replacement analysis. JP said that it appeared NIPSCO forced in the higher MAP level for both residential and C&I programs but did not reoptimize the capacity expansion analysis. Furthermore, the JC argued that evaluating different levels of EE requires reoptimizing the capacity expansion analysis to see how different levels of EE changes the resource mix.

The JC also recommends that NIPSCO evaluate the residential MAP, the C&I MAP savings, and then mixed combinations of residential RAP and C&I MAP. They note that IRP results show the utility cost test (UCT) is positive for the C&I MAP level of EE. Given this it would have made sense to at least have modeled the C&I MAP along with the residential RAP savings. The residential MAP level of EE was much too expensive to have been modeled.

Reliability Analysis

The JC had extensive comments on the reliability analysis performed by NIPSCO. JC recognizes that this type of analysis in an IRP is important and that it is not a firmly established art. That there is plenty of room for judgment and, frankly, disagreements between reasonable people. Given that there are no right answers to most of the questions addressed by the analysis, JC's comments were aimed at "identifying positive refinements to what is NIPSCO's forward looking analysis." (JC Comments, page 38)

A. Regulation

NIPSCO's analysis looked at the incremental value from ancillary services with a focus on MISO's symmetric, single regulation market. JP noted that it was good that NIPSCO did the analysis on that basis; however, JC noted that most independent system operators have moved to asymmetric markets as wind and solar resources have increased. That having separate markets helps to release constraints on these resources.

B. Blackstart

The JP considers NIPSCO's blackstart analysis innovative and most welcome. According to the JC, the analysis correctly credits energy storage equipped with grid-forming inverters (GFM) as a credible resource for providing blackstart. But that there appears to be an assumption that the storage portion of solar+storage resources would not have GFM and could not be used for blackstart. The JC states this assumption seems to be contradicted by state-of-the-art practice in the industry. JC believes it is critical to correct any errors to ensure transparency and sound decision-making.

C. VAR Support

The JC says that NIPSCO correctly points out that inverter-based resources (IBRs), including solar and wind, have the capability to provide reactive power and to perform voltage regulation regardless of whether they are generating. BESS can provide voltage regulation whether facility is charging, discharging, or idle. Thermal resources, in comparison, must be committed and running. However, the JC note that the reliability metrics in the IRP give all options the same score as for those options with IBR options. In response to questions from the JC, NIPSCO responded, "Given the local nature of reactive power, the 'VAR Support' reliability metric is designed to quantify the ability of each portfolio to deliver its dynamic VARs to load centers. The availability of dynamic VARs, however, was not considered in the evaluation due to its dependence on commitment decisions that were beyond the scope of this investigation." *(See JC comments, page 41)*

D. Ramping

According to the JC, the aggregate dispatchability, particularly the 1-minute and 10-minute, ramping results seems unnecessarily constrained by traditional views of thermal generation as the primary resource for net load following. The JC argues that energy storage resources, or the combined resources of solar plus energy storage, can be available for ramping duty every hour of every day while acknowledging limits on capability imposed by the availability of sunlight and state of charge.

Also, the high scores for fossil resources fails to recognize the reality that these resources must be committed and dispatched to provide ramping services. These plants are subject to operating limitations that will impact their ability to provide ramping services when needed.

E. Short Circuit Strength

The JC recognize that the combined issues of sensitivity of IBRs to low short circuit levels and the potentially adverse impact of low short circuit current from the IBRs on protection are real. They note that both issues are receiving considerable attention from the industry. Also, that fossil resources only provide short circuit strength when the facilities are committed. In comparison, grid forming inverters from new energy storage (either stand-alone or in solar+storage facilities) can expect to be synchronized all the time.

JC goes on to say:

> NIPSCO is correct that grid forming inverters ("GFM") deliver some short circuit current, but not as much as a similarly sized synchronous machines. However, GFM inverters don't need short circuit current from the grid to operate properly, so they can tolerate a weak grid and therefore no condensers are needed. NIPSCO is improperly treating short circuit strength concerns as if they apply evenly across all portfolios. *(JC Comments, page 43)*

<u>NIPSCO Response to Joint Commenters</u>

The JC expressed concerns with the near-term focus of the RFP options and the consequent modeling of generic solar, battery storge, and wind resources. NIPSCO acknowledged that certain timing restrictions were enforced for generic resources, but that this was done to perform a fair evaluation of the RFP bids to meet projected capacity needs. That this process allowed for near-term requirements to be assessed with actionable bids rather than generic resources.

The JC suggested that NIPSCO (i) model two levels of potential coming out of the MP, by customer sector, to see which level is chosen by the capacity expansion model; (ii) reoptimize the capacity expansion model when evaluating different levels of EE; and (iii) evaluate the residential MAP, the C&I MAP, and mixed combinations. NIPSCO responded that the RAP bundles were evaluated in the core capacity expansion modeling. NIPSCO then replaced the RAP bundles with MAP levels of savings, which resulted in a 100 MW reduction in storage capacity additions. This confirmed to NIPSCO that higher levels of DSM do change the resource portfolio. NIPSCO then re-ran the dispatch model and revenue requirement estimates to calculate the economic impacts of moving from RAP to MAP. Given the cost increases caused by moving from RAP to MAP, NIPSCO did not evaluate residential MAP and C&I MAP savings. *(NIPSCO Response Comments, page 6)*

JC said it was concerned with NIPSCO's assumption that the storage (i.e., the battery energy storage portion) of the solar plus storage resources would not have grid forming inverters and therefore could not be used for blackstart operations. NIPSCO confirmed the assumption that stand-alone storage systems would have grid-forming inverters, while the storage component of solar plus storge resources would be fitted with grid-following inverters. NIPSCO explained that since solar plus storage resources may be configured with the storage system operating behind the solar inverter, it is unlikely for the combined inverter to be grid-forming. *(NIPSCO Response Comments, page 7)*

The JC provided comments on the measure of dispatchability, especially the one-minute and 10-minute ramping results. NIPSCO responded it made prudent assumptions and that NIPSCO developed a set of reliability criteria important to the continued reliable operation of the grid and enable NIPSCO to meet NERC and MISO obligations. An important consideration is the capability for a resource to respond to system operator directions, particularly to be placed on Automatic Generation Control, allowing its output to be ramped up or down in response to changes on the system. *(NIPSCO Response Comments, page 7)*

The JC also provided thoughts on the scoring for Ramping and short circuit strength. NIPSCO stated that all reliability assessments in the sturdy applied screening-level indicative analyses for assessing reliability in the IRP context. NIPSCO said it recognizes the nuance of operation and understands that detailed system analyses are essential. *(NIPSCO Response Comments, page 7)*

Lastly, the JC encouraged NIPSCO to continue evaluating the optimal retirement dates for Michigan City 12 and Schahfer Units 16A and 16B. NIPSCO stated it agreed that the IRP stated that flexibility was part of the planning process. *(NIPSCO Response Comments, page 9)*

> *Director's Response: The Director appreciates NIPSCO's focus on resource choices in the near term. This is particularly the case when these potential near-term decisions do not appear to unduly limit possible resource choices further out in time. This is consistent with the concept of maintaining resource optionality – not unreasonably limiting potential future courses of action with choices made today unless the implications are well understood.*
>
> *The Director also appreciates the initial analysis of reliability performed by NIPSCO and trusts that this process will evolve as we all learn going forward.*

Response of Joint Commenters
JC's comments emphasized the need for continued collaboration and improvement between stakeholders and NIPSCO for the next IRP filing.

> "We concur with the Director that there are significant changes that utilities are facing and need to incorporate into the planning process. We believe this underscores the need to seek input from stakeholders and to work collaboratively not just in the IRP process, but in subsequent, related steps such as RFPs. NIPSCO issued an RFP in 2022, but did not seek the input of stakeholders on the content of the RFP or the manner in which the capacity and energy requests were structured. In a conversation subsequent to the issuance of the RFP, NIPSCO seemed to agree to seek stakeholder feedback in the future. We look forward to the opportunity to continue a collaborative process with NIPSCO. NIPSCO has also indicated to CAC that it will provide an AURORA license in the future that would enable CAC and its consultants to view all of its modeling files. We appreciate the offer and will work with NIPSCO in the future to utilize this capability and information in our review." *(JC's comments on the Director's Draft Report, p. 2)*

JC appreciated NIPSCO's collaborative approach and encouraged NIPSCO to continue to work collaboratively in the next IRP and related proceedings.

Director's Reply
The Director believes all participants in the NIPSCO IRP stakeholder advisory process have sought to incorporate lessons learned from previous IRP processes. The Director appreciates JC's commitment to continue to work to improve the advisory process. Nothing in NIPSCO's recent IRP planning exercises causes one to question the company's commitment to continued improvements.