Northern Indiana Public Service Company LLC
2021 Integrated Resource Planning
Public Advisory Meeting #5
SUMMARY

October 21, 2021

Welcome and Introductions
Alison Becker, Manager Regulatory Policy, NIPSCO

Ms. Alison Becker, Manager, Regulatory Policy, welcomed participants to the virtual meeting and provided a safety moment on fire safety. She then discussed the Webex meeting protocols, emphasized the importance of stakeholder feedback, and walked through the agenda for the day. She then introduced Mike Hooper, President and Chief Operating Officer of NIPSCO, to kick off the meeting.

Welcome
Mike Hooper, President and COO, NIPSCO

Mr. Hooper welcomed participants and thanked them for the high level of participation and engagement. Mr. Hooper then highlighted the changing dynamics in the energy industry that are captured in the IRP: market rule changes, federal energy policy uncertainty and implications, and rapidly changing technology. Mr. Hooper then previewed NIPSCO's preferred portfolio and how it preserves the ability to adapt to expected changes in regulations, policies, and other market forces. Mr. Hooper noted that NIPSCO is well positioned to meet customers' annual energy needs with the execution of the "Your Energy, Your Future" electric generation transition plan. Mr. Hooper discussed how the 2021 preferred path provides a diverse, flexible, and scalable mix of incremental resources in the near term and direction on potential long-term solutions. He closed with an emphasis on NIPSCO's long-term strategy to provide customers with energy that is affordable, reliable, and sustainable.

Public Advisory Process and Resource Planning Activity Review
Fred Gomos, Director, Strategy and Risk Integration, NiSource

Mr. Fred Gomos began the section with an overview of NIPSCO's planning process and highlighted the Stakeholder Advisory Meeting Roadmap. He then reminded participants of the five step planning process core to NIPSCO's resource planning approach. He provided an overview of the key planning questions and themes in the 2021 IRP and reviewed the major elements of the integrated scorecard framework. He then walked through NIPSCO's process of developing external market perspectives, including the use of both scenarios and stochastic analysis to perform a robust assessment of risk. He then reviewed the major scenarios and stochastic components shared in previous stakeholder meetings. Finally, Mr. Gomos discussed the development of integrated resource strategies or portfolios, sharing NIPSCO's current capacity and energy positions on both an annual and hourly basis.

Participants had the following questions and comments, with answers provided after:

- Can you remind me what the winter wind effective load carrying capability ("ELCC") assumption was?
    - NIPSCO used a higher ELCC credit for the winter relative to the summer. Although still uncertain and subject to actual project operations, consistent with some recent MISO studies, we used 25% for winter wind capacity credit.

Existing Fleet Analysis Review
Pat Augustine, Vice President, Charles River Associates ("CRA")

Mr. Pat Augustine re-introduced the IRP's two-step analytical framework and the various reasons why the analysis is performed in two parts. Mr. Augustine presented the composition of eight existing fleet portfolios that evaluate different retirement dates for NIPSCO's remaining fossil units and then reviewed the existing fleet portfolio optimization results, including the deterministic cost to customer net present value of revenue requirement ("NPVRR") results and observations for all existing fleet portfolios. Next, Mr. Augustine summarized the results and observations across the four scenarios. He then shared the existing fleet analysis scorecard framework.

Participants had the following questions and comments, with answers provided after:

- Is the hydrogen resource zero carbon hydrogen or is it produced with fossil fuels? Commitment to green hydrogen?
    - As modeled, it is green hydrogen, meaning that it is hydrogen produced from clean renewable energy. Cost data was informed by request for proposal ("RFP") bids, including the type of upgrades that would be needed at natural gas facilities to be able to blend hydrogen with natural gas or burn hydrogen directly. Over the long term, we have modeled a cost associated with production of green hydrogen that includes electrolyzer costs, electricity costs, and other components.

Replacement Analysis
Pat Augustine, Vice President, CRA
Hisham Othman, VP, Transmission and Regulatory Consulting, Quanta Technology LLC

Mr. Augustine introduced the core questions and key decisions in the replacement analysis, the second part of the two-step IRP portfolio assessment. Mr. Augustine illustrated the expected supply-demand outlook following future resource retirements and shared the replacement concepts developed across frameworks that assess differing levels of emissions reduction and dispatchability. He explained that this framework drove the development of nine replacement portfolios, noting that resource combinations were constructed based on RFP projects. Mr. Augustine then provided an overview of the specific installed capacity additions in each of the nine portfolios, along with summer and winter supply-demand balance summaries. Mr.

Augustine presented cost to customer results and observations across each of the four scenarios. Mr. Augustine also discussed the stochastic analysis results across the nine portfolios and the changing risk profile of different resource options over time. He then shared the replacement analysis scorecard framework and described the economic and non-economic approaches to assessing reliability. He briefly reviewed the results of the economic assessment of sub-hourly ancillary services analysis that was detailed in the October 12, 2021 Technical Webinar. Mr. Augustine then introduced the non-economic assessment and introduced the guiding principles and goals of the assessment.

Mr. Augustine then introduced Mr. Othman, who reviewed feedback received during the Technical Webinar associated with the technical reliability assessment. Mr. Othman then discussed the technical reliability assessment approach and reviewed the reliability criteria, reliability metrics, thresholds, rankings, and results. He then transitioned back to Mr. Augustine who described how the reliability assessment results were incorporated into the replacement analysis scorecard.

Participants had the following questions and comments, with answers provided after:

- Pat, I had one other thought about potentially modeling representative emergency conditions. The current stochastic analysis does not vary load, but that would be really important for an extreme weather scenario. I have been mulling the idea of whether one could do regression based projections of both load and energy efficiency ("EE") performed under extreme weather, at least for the residential side. Is that something you all would entertain for next time?
    - Yes, I think so. Historically, NIPSCO has taken the view that regional load uncertainty is picked up in the power prices, and the analysis is simulating power price distributions that are associated with extreme weather events. However, when NIPSCO reliability and portfolio are viewed more granularly, there could be value in incorporating NIPSCO load uncertainty into that mix, perhaps with EE impacts, to provide a more robust view of risk. This could be done through the economic analysis or other reliability frameworks. So I think we would definitely be open to that dialogue for future enhancements.
    - This is an emerging area and NIPSCO really appreciates the sort of the thoughtfulness that you have offered with that comment and in prior one-on-one discussions. It makes a lot of sense to look at risk not only for the resource side but also the demand side as well. This might show the value of demand response and other resource attributes.
- Will the IRP more specifically articulate how you weighed the scorecard results in picking these plans? I'm curious, for example, if the reliability analysis tipped the balance towards Portfolios F and I for you?
    - NIPSCO tries not to put explicit weights behind any of these scores, because ultimately, while there are objective numbers here, when weighting it, it becomes a subjective exercise. It has been considered in the aggregate and NIPSCO has tried to balance the major objectives. Reliability is important and clearly we want to pick a portfolio that maximizes that, but economics are also important, and Portfolio F is pretty competitive relative to the other portfolios, which often have risk profiles that are disqualifying. In addition, the carbon intensity of the portfolio is also a factor, so all of those things help drive decision making. Overall, there is not one metric that overrides everything, and the decision-making process is really about driving a balance across the dimensions.

Responses to Stakeholder Feedback
Pat Augustine, Vice President, CRA

Mr. Augustine discussed stakeholder comments and responses related to two specific topics: demand side management ("DSM") and different customer cost summaries. Mr. Augustine reviewed the key DSM portfolio findings and discussed the additional DSM evaluations that were performed to assess maximum achievable potential impacts relative to realistic achievable potential levels. Mr. Augustine also reviewed 20-year NPVRRs, which were shown to be similar to the 30-year view. Finally, he summarized a sample of annual generation revenue requirements, which confirmed no significant short vs long term generation rate impact differences across portfolios that are not already present in the NPVRR summaries.

Preferred Resource Plan and Action Plan
Fred Gomos, Director, Strategy and Risk Integration, NiSource
Pat Augustine, Vice President, CRA

Mr. Gomos opened the section with a review of the preferred supply portfolio criteria. Mr. Gomos then transitioned to Mr. Augustine who highlighted the various tradeoffs in the existing fleet analysis scorecard and indicated the preferred pathways. Mr. Gomos then discussed key observations regarding the preferred existing fleet portfolios and implications for the NIPSCO fleet. Mr. Augustine then reviewed the various tradeoffs in the replacement analysis scorecard and provided an indication of the preferred pathways over both the near- and long-term. Mr. Augustine then transitioned to Mr. Gomos who discussed key observations of the preferred replacement portfolios and implications for future resources.

Mr. Gomos then summarized the key points of the preferred plan: refining the Michigan City Generating Station Unit 12 retirement date; establishing a retirement date range for Schahfer Generating Station Units 16A and B; and pursuing a diverse, flexible, scalable mix of replacement resources. Mr. Augustine then described the preferred plan's capacity and energy balance, including the elements of flexibility that could result in different mixes over time. Mr. Augustine also highlighted that the preferred plan remains on the carbon emission reduction pathway identified in the 2018 IRP. Mr. Gomos concluded the section by summarizing NIPSCO's implementation plan timing over the near-term, mid-term, and long-term, highlighting the flexible nature of the preferred pathway.

Participants had the following questions and comments, with answers provided after:

- Please explain the decision for a local build combustion turbine ("CT") plant in Portfolio F vs. thermal purchase power agreement ("PPA") in Portfolio E. Would not Portfolio F have more risk with potential natural gas price increases/carbon price and possible stranded asset risk?
    - Portfolios E and F both contain the thermal PPAs. They are short-term PPAs with attractive costs, and they help firm up the near-term capacity position. In terms of the other part of the question, as to what's driving the need for a gas peaker, the difference between Portfolio E and F for example, is really storage versus a gas peaking resource. Based on the reliability study, Portfolio F scored better, and from an emissions perspective, the peaker does not contribute much of an increase, as it only runs a limited number of hours throughout the year.
    - In terms of the risk element of that question, there are several considerations. The peaker plant in Portfolio F does not dispatch much and therefore does not expose the portfolio to significant risks associated with high gas prices or high

carbon regulations that were evident with the combined cycle in Portfolio C. On a scenario basis, Portfolio F is slightly higher cost than Portfolio E in the Economy-Wide Decarbonization ("EWD") and Aggressive Environmental Regulation ("AER") scenarios, partly due to the fact that commodity prices and carbon regulation are higher, but also due to the fact that storage investment tax credits are assumed. From the stochastic commodity and renewable risk perspective the analysis found both of these portfolios scored very similarly. While the combined cycle in Portfolio C had a lot of near-term stochastic risk associated with high commodity prices, the portfolios with a gas peaker or storage both had similar near-term risk profiles and provided similar long-term risk mitigation from a renewable output volatility perspective. So overall, there are a range of trade-offs, and it is probably not fair to say that a peaking facility substantially increases risks associated with higher carbon or gas prices.

- Is the peaker in Portfolio F likely to be outfitted with a clutch so it can be operated as a synchronous condenser?
    - Yes, and it might be addressed as the plan is implemented. One thing to note is that the IRP is picking technologies, but is not picking specific projects – that is the body of work that happens next. So there is going to be a team at NIPSCO and CRA that is going to go through all of the bids and look at all of the bidders that have been short-listed, and those are the types of evaluations to ensure that the right resources are selected to achieve the objectives outlined in the IRP.
- If a natural gas-dominant asset in NIPSCO's territory was rejected by NIPSCO, will NIPSCO re-evaluate the project if solar and batteries are added?
    - This is probably best addressed by the RFP manager. The RFP window has closed, but what NIPSCO wants to do is to continue to engage with developers and if you think that a change makes a project better, that conversation can take place in the future if that is what drove the rejection.
- What is the likely source of green hydrogen in Portfolio I?
    - From a modeling perspective, a mix of wind, solar, storage, and grid purchases at times of renewable oversupply would comprise the sources of green hydrogen. We have not specifically modeled additional wind, solar, or battery storage resources that would be devoted to electrolysis within the IRP portfolio assessment, but it has been proxied through an all-in price of hydrogen. This was done through an analysis that evaluates the optimal mix of wind, solar, storage and opportunistic grid purchases that would minimize the production costs for hydrogen on a dollar per kilogram basis or a dollar per MWh basis for use in the NIPSCO portfolio model. Going forward, there will be additional assessments required if NIPSCO were to look at large-scale hydrogen production. That would include review of specific renewable resources that would be devoted to hydrogen production; assessment of whether they may be opportunities to use some of the existing fleet's energy that might otherwise be liquidated in MISO at a low price for hydrogen production; or if there will be a larger hydrogen network where the commodity could be bought and used not only in the electric system but other parts of the broader NIPSCO gas portfolio, such as for industrial customers or other end users. So those are broader questions, but from a modeling perspective, the idea was to build up the mix of wind, solar, storage, and market purchases that would be green and come up with an all-in price of hydrogen that would be used for costing out the portfolio analysis and hydrogen plant dispatch.

- As I understand it, there are two preferred existing fleet pathways (Portfolios 3 & 5) and the replacement analysis is based on one of them (Portfolio 3). Have you looked at whether the replacement analysis would be different if it were based on Portfolio 5?
  - Not explicitly, but the optimized existing fleet portfolio mixes were nearly identical for Portfolios 3 and 5. The differences were only associated with the timing of when the gas peaking and storage capacity enters the portfolio. So the replacement analysis has not been rerun under Portfolio 5, but based on the composition of Portfolio 3 versus 5, it would be unlikely to see any difference in results. From a future execution perspective, there will be additional portfolio analysis that might be performed to confirm the ultimate retirement dates and replacement resource timings.
- Is the 300 MW CT a build-transfer unit or 2 units that NIPSCO takes title to? (Portfolio F)
  - As modeled and as based on the RFP inputs, it is a single existing unit, bid in as a build transfer.
- Back on slide 14 there is mention of the EWD scenario. This would involve a very significant load increase over the next 10 years. How does this possibility/likelihood figure into the scenarios presented here?
  - This was discussed in Stakeholder Meeting 2 with respect to potential impacts on load of electric vehicle penetration, distributed energy resources, and other electrification drivers. So that is factored into the modeling, and the analysis has shown that Portfolios I and H tend to be quite competitive from a cost to customer perspective in that state of the world.
  - From a modeling perspective, there is a higher load projection for NIPSCO in the EWD scenario, particularly in the winter season, so portfolios that have different resource mixes are going to have different market sales and purchases positions within MISO. In addition, higher load for NIPSCO means that there will be different capacity balance positions, with portfolios generally becoming shorter over time. As currently constructed, the replacement portfolios tend to exceed the minimum reserve margin requirement in the near-term, but over the long term, when demand is higher than the supply, additional market purchases are made at the prevailing capacity market price for the EWD scenario. So overall, the portfolios will have different net energy positions and different levels of long-term capacity purchases, particularly in the winter, under this scenario.
- What does 68 MW of DSM equal on an energy savings basis? Curious that same level of DSM is chosen in every portfolio. Also, did I hear you correctly earlier today that one possible missing resource/analysis is certain demand response (“DR”) potential? We are interested in NIPSCO looking into third party aggregation of smaller commercial and industrial (“C&I”) customers (now that Rider 775 is gone) to capture cost-effective interruptible tariff opportunities
  - It is around 500,000 MWh of new DSM savings on an energy perspective by the 2028-2030 time period. Slide 66 illustrates the different energy and capacity components. It is not very easy to see the details on the energy graphic, but the purple slice is showing DSM energy savings, and this includes both NIPSCO’s filed program plus the incremental bundles that were selected. The incremental additions represent about 500,000 MWh (or about 500 GWh on this graphic) by the 2028 to 2030 time period, although once added to the filed DSM programs that are also projected, the number will be quite a bit higher in total.
  - In terms of the second comment, from a portfolio optimization and development perspective, we have evaluated whether the incremental DSM is economic relative to any other resources. It tends to look good from a cost perspective,

particularly the commercial and industrial energy efficiency bundles. The residential bundle is a little bit higher cost, but at the Tier 1 aggregation, it appears economic across the board regardless of what portfolio we evaluated.

    - With regard to the final comment, from a demand response perspective, there were a set of residential rate DR programs that came out of the GDS market potential study which are part of the preferred portfolio, but they don't come in until after 2030 or so. They also involve some other rate design and technology improvements, but from a planning cost basis, those were attractive and selected in the optimization analysis, while other DR programs were not.
    - If there are proposals, particularly associated with interruptible structures, that stakeholders have and can bring to us, NIPSCO will be happy to entertain them. The Company has struggled with making a program work for smaller C&I customers because aggregation is not very cost effective under the current Midcontinent Independent System Operator, Inc. ("MISO") construct, but NIPSCO is happy to hear about any ideas that people have or programs that have worked in other states. It will be interesting to see how MISO responds to FERC Order 2222 in the next couple of months. Some other independent system operators have come up with their respective plans and NIPSCO is looking at them now, so the Company interested in your proposals. Note that NIPSCO planned to talk about this subject as part of the October Oversight Board meeting, but the Commission's Winter Preparedness Forum was scheduled for the same day, so that topic has been moved to a later date. NIPSCO welcomes the continued input from energy efficiency parties and interested stakeholders.
- Did the rejection of the Elkhart Solar Project zoning request by the Elkhart County Commission earlier in October affect the optimism NIPSCO has about finding enough new solar capacity in the next few years?
    - The short answer is no. NIPSCO has tried to select projects that economically support our service territory first, then Indiana, and then we'll go beyond the state borders if necessary. The Company wants to site and build these projects in places where there is community benefit and the community wants the project there and wants to be a partner with us, much like the Company has over the years with other elements of our generating fleet. So to the extent that NIPSCO can continue to do that and execute that effectively, that is what the Company will lean on. There were no projects in Elkhart County, but that particular issue does not give us any concern about continuing to find viable solar projects and executing on those that are already under development.

Wrap Up and Next Steps
Erin Whitehead, Vice President, Regulatory and Major Accounts, NIPSCO

Ms. Whitehead closed the session by thanking attendees for their participation and feedback. She encouraged participants to continue to engage with feedback and invited participants to reach out for one-on-one discussions. Ms. Whitehead then closed the session confirming the plan to submit the IRP by November 15, 2021.