<u>RELIABLE ENERGY'S COMMENTS ON NIPSCO'S 2021 INTEGRATED RESOURCE PLAN</u>
March 24, 2022

I. INTRODUCTION AND SUMMARY

Reliable Energy participated in the stakeholder process and conducted a review of the Integrated Resource Plan (IRP) that Northern Indiana Public Service Company (NIPSCO) submitted to the Indiana Utility Regulatory Commission (IURC or Commission) on November 15, 2021. Reliable Energy is a trade association formed in 2020 by representatives of Alliance Coal and Hallador Energy. Reliable Energy understands the changing energy landscape, and works with numerous industry partners and association members to advocate for reliable and affordable energy prices, as well as clean coal technologies that can power Indiana's economy.

Reliable Energy appreciates the opportunity to participate in the informal stakeholder process. However, based on our experience with many Indiana IRPs over the last several years, it has become apparent that in the absence of the Commission's active participation in the development of IRPs to balance interests of monopoly utilities and their captive customers, the informal stakeholder process has done little to improve the quality of IRPs. While IRPs represent only a snapshot in time and are not definitive action plans, NIPSCO will likely use this IRP and its Preferred Portfolio as the basis for seeking IURC approval to build and/or buy new generation resources. Yet, NIPSCO's IRP is problematic for a variety of reasons including:

- 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;
- Assumption flaws in the models raised by consumer stakeholders were ignored by the utility, resulting in a "garbage in, garbage out" phenomenon; and
- 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.

Plant retirements in the PJM Interconnection (PJM) and the Midcontinent Independent System Operator (MISO) will continue to complicate making an accurate assessment of appropriate resource planning and reliability for Indiana. Since Indiana utilities plan to purchase the power needed to replace retired coal generation and MISO imports capacity regularly from PJM, a much more holistic review is warranted in order for "the Commission to develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity", as is required by law under IC 8-1-8.5-3(a)--and which the Commission has *never really done*. When the IURC considers resource adequacy issues in just one IRP or one case at a time, it creates a dangerous myopic view of resource planning and reliability. Retirements continue to be accelerated in Indiana and throughout the Midwest without a true assessment of what impact it will have on reliability and cost to ratepayers.

II. CONCERNS REGARDING NIPSCO'S IRP

A. PROCESS AND EVIDENTIARY ISSUES

The 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. During the informal process, utilities can (and have) refused to address the concerns of stakeholders, controlled (or attempted to control) the timing and content of stakeholder feedback, and denied requests for data and supporting documentation that would normally be available to parties in a formal proceeding. The utilities simply refuse, and there is no Commission forum available to the stakeholders to resolve the issue. Absent a Commission order on a motion to compel, the utilities unilaterally deny requests for information at will, and can refuse to change position based on stakeholder feedback. While the Final IURC Director's Report is always helpful, it comes so late in the process as to have little impact on the current IRP. For example, NIPSCO filed its last IRP on October 31, 2018, and the Final Director's Report was issued on February 10, 2020. Given the Director's Report is by its very nature, informal guidance from the Commission's staff, the utility may also choose to ignore it.

While one might argue that the opportunity for formal scrutiny of the IRP process comes during 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 shut down of existing plants, and entering into contractual arrangements with project developers. Often these actions are started before consumers even have the opportunity to file comments with the Commission on the IRP. The "toothpaste is out of the tube" by the time a Certificate of Public Convenience and Necessity (CPCN) case is filed. At that point, the opportunity has passed to fix a problem or error that could have changed the outcome of the IRP, and the action the utility undertook as a result. Although nonbinding, IRPs certainly set expectations for future resource procurement, rate and cost recovery, and customer demand side management (DSM) programs. Utilities are not retiring coal generation because of a desire to "save the planet", but as a way to increase profits. A prime example of that true intention is Consumers Energy, which just last week threatened to abandon plans to retire its coal-fired power plant fleet by 2025 if the Michigan Public Service Commission (PSC) refused to approve its cost recovery proposal.[1] There is no counter-balancing influence in the informal IRP process to the utilities' financial incentive to rapidly retire reliable baseload generating resources that still have significant useful lives, and invest their capital in new generation at above-market prices, so they can receive the highest returns for their investors.

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[1] https://www.utilitydive.com/news/consumers-energy-threatens-coal-retirement-plans-irp-michigan-psc/620391/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202022-03-15%20Utility%20Dive%20Newsletter%20%5Bissue:40381%5D&utm_term=Utility%20Dive

No change in law is necessary for the Commission to formalize its involvement in IRP development. If a formal process was used and utilities were required to update IRP data when seeking approval for new generation projects, the following substantive flaws in NIPSCO's IRP could be considered and corrected:

- 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.
- 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.
- Overreliance on pricing indicators from Requests for Proposals (RFPs), which results in the exclusion of viable generation options, including: self-built projects, retrofitting existing plants, and new technologies.
- The price risks associated with increasing reliance on capacity and energy purchases in a time of great change in energy markets.
- Failure to consider what impact similar portfolio shifts by other nearby utilities happening at the same time will have on the energy market and available capacity resources.

The Commission has authority to initiate an investigation into all matters relating to any public utility pursuant to IC 8-1-2-58. A formal IRP proceeding would include:

- The IRP and its supporting documentation becoming part of the evidentiary record, making the process (and the generation decisions that eventually stem from it) transparent, and more likely to be fairer to customers;
- The utility, as well as intervening stakeholders, would have the opportunity to provide sworn testimony through witnesses during public hearings to formally support or critique the IRP;
- The Presiding Officers would be available to resolve discovery disputes that cannot be resolved among the parties;
- Parties would receive official notice of new developments in the proceeding, such as deadlines and filed comments from others, rather than relying on periodic checks of the Commission's IRP website for updates.

Regardless of what procedure is used by the Commission, because of the dynamic nature of power and energy markets, an IRP cannot substitute for a full evidentiary justification of future resource requests when they are filed. However, the outcome of a formal IRP process could include the Commission:

- Providing guidance as the IRP development process unfolds, such as requests to the utility for particular actions to avoid errors, balance interests, and encourage reasonable outcomes;

- Balancing requests for changes to the IRP modeling, taking into consideration awareness of market and regulatory constraints, as well as motivations and interests of the parties;
- Providing specific comments on the methodologies, assumptions, programs, etc.;
- Defining how customer affordability is measured uniformly and accurately across utility IRPs;
- Addressing issues of reliability and resilience, and protecting the public interest;
- Clarifying questions or seeking additional information regarding the IRP;
- Discussing past IRP analysis, Director Report recommendations, or regulator actions on IRPs in other states where the utility operates; and
- Supporting the parties in working together towards new solutions or alternative approaches to IRP development.

Reliable Energy respectfully urges the IURC to formalize the Commission's involvement the development of utility IRPs, and to balance the interests of utilities and consumers. **Formal feedback from the Commission on an IRP or its development process would not pre-approve any project, nor would it bind the utility to any particular course of future action.** Reliable Energy has confidence that a far more balanced result would occur from formal IRP proceedings before the Commission.

B. ASSUMPTION FLAWS IN THE MODELS

Reliable Energy notes it provided detailed comments to NIPSCO following the very first stakeholder meeting in March 2021. These were largely ignored, and rather than repeating them in detail herein, they are attached for the Commission's reference. Of particular concern is that NIPSCO continued to use of a 30-year Net Present Value (NPV) and its false analogy that the NPV is an accurate measure of "Affordability and Rate Stability". NIPSCO's scorecard metrics for its generation replacement analysis is shown below:[2]

Figure 9-16: Scorecard Metrics for Replacement Analysis

Objective	Indicator	Description and Metrics
Affordability	Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	Cost Certainty	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75th % range vs. median
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and 95th % conditional value at risk (average of all outcomes above 95th % vs. median)
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and 5th % range vs. median

Utility rates are *not set based on levelized costs*, and thus NIPSCO's "affordability" analysis does nothing to show real rate impact to customers. Not only is determining that a generating asset

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[2] IRP at p. 228.

is the lowest cost option based upon a projection of prices 30 years in advance illogical, but it also is inconsistent with NIPSCO's own acknowledgement that resources were only considered for 20-year period.[3] Using levelized costs over a 30-year timeframe results in understating costs in the long-term, and overstating costs in the near term. Two projects can also have an identical NPV over 30 years, but very different cost impacts on customers, particularly in the near term.

When NIPSCO adopted the 30 year NPV calculation a few years ago, the Indiana Coal Council determined the "switch" supported the company's desired result, i.e., stretching the NPV to 30-years for the renewable projects provided needed savings at the end of the project life to justify the company's short-term position of a rapid switch to a renewable portfolio. Notably, NIPSCO took a different NPV approach than Southern Indiana Gas and Electric Company (formerly Vectren South and now known as CenterPoint Energy Indiana South (CEIS)),[4] Indianapolis Power & Light Company (now known as AES Indiana),[5] Duke Energy Indiana (DEI),[6] and Indiana Michigan Power Company (I&M),[7] all of which measured NPV requirements over a 20-year period.

C. THE UTILITY'S IRP ANALYSIS SHOULD BE UPDATED WHEN CPCN FILINGS ARE MADE

The IURC should mandate by administrative rule that any new request for a CPCN must contain the following:

- A updated analysis of complete portfolio options, providing a "level playing field" for all generation resource types and taking into meaningful account the risks associated with energy market price increases, overreliance on market purchases, supply chain disruptions, regulatory lag, and natural gas price increases;
- An accurate analysis of the first 10-year rate impacts of the modeling on customers; and
- A revisiting of the prudency of the retirement dates for its remaining coal units, based upon the updated analysis.

While utilities are always careful to say that their IRPs are not definitive plans, they lack any form of "back up plan" if their preferred portfolios do not pan out. In fact, history at the Commission shows that the utilities tend to stick with their IRP plans, even when the passage of time shows the results to be unreasonable or imprudent. They do this because the risk of error in their actions rests almost entirely on their customers once the CPCNs are approved. Below,

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[3] IRP, p. 4 "Our IRP charts a path to best meet the energy needs of our customers for the next 20 years…"

[4] The CEIS 2019/2020 IRP states: "For the Affordability objective, the metric used is the mean value for the 20-year Net Present Value of Revenue Requirements (NPVRR), expressed in millions of dollars." (p. 84).

[5] AES Indiana's 2019 IRP identified three primary cost metrics: (1) a 20-year Present Value Revenue Requirement (PVRR); an Annual Revenue Requirement; and (3) a levelized $/kWh rate. (p 150).

[6] DEI's 2021 IRP states that "The EnCompass model solves for the least cost resource portfolio that meets the planning reserve margin requirement, as measured by the present value of revenue requirements (PVRR) over the 20-year planning period." (p. 51).

[7] I&M's 2021 IRP states that: "The affordability objective metrics used are the mean value of the 20-year Net Present Value Cost to Serve Load (NPVCTSL) and the 10-year NPVCTSL, expressed in million dollars." (p. 17).

we discuss the problems associated with NIPSCO's IRP, and how updating its IRP results would be beneficial, both to the utility and its ratepayers.

1. The Preferred Portfolio is Not Dispositive with Respect to the Cost of the Resource Additions

As shown in NIPSCO's IRP Figure 9-43, the "Preferred Portfolio Capacity Additions by 2027", there is not one proposed capacity resource addition that has confirmed terms or pricing. Firm pricing is not available for the Sugar Creek Uprate, no specific projects are identified (or costed) for the Solar + Storage DER Opportunities, no details are provided on the thermal capacity contracts, the DSM value is estimated, and the solar, storage and natural gas peakers are not defined. Yet, NIPSCO apparently believes this is the capacity plan upon which to act.

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

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

Unfortunately, the IURC has seen how the components of the preferred portfolio capacity in a utility's IRP can fall apart in reality for one reason or another. For example, in 2019, CEIS was denied a CPCN for a new 850 MW combined cycle gas turbine (CCGT) project in part because the Commission found:

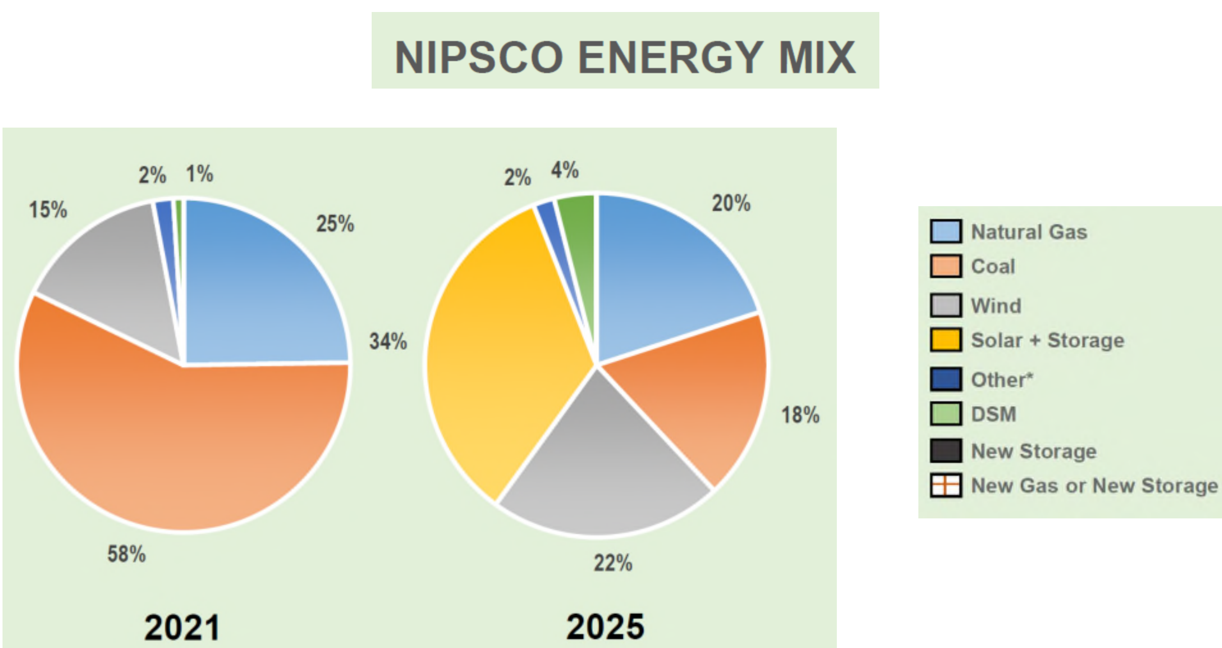
> "We agree that Vectren South had adequate time and opportunity to update its risk analysis modeling prior to this filing, and that it has sufficient time to do so now before moving forward. Vectren South updated inputs in its possession for multiple factors, including: solar capital costs; variable production costs and revenue requirement assumptions for existing units; forecasted cost for wholesale market capacity and energy; delivered fuel prices for gas and coal; and costs associated with new energy efficiency programs. Pet. Ex. 6 at 9-10. Vectren South also had a higher capital cost estimate for its preferred build. We know Vectren South had time to use these inputs to re-run the model because (a) it did just that

with some of its Strategist modeling and (b) Mr. Vicinus testified that it would have taken just three months to re-run the risk analysis modeling. Tr. p. D-66. Mr. Vicinus opined that updated risk modeling would not change the result, but we are skeptical given the number and import of the updated inputs and the significance of the proposed portfolio changes. *See Indianapolis Pwr. & Light,* Cause No. 44339, 2014 WL 2091348, Order p. 27 (IURC May 14, 2014) ("[W]e believe that IPL could have reasonably updated the [model] given the extent of changes in data inputs and assumptions and provided a more robust analysis."). Before proposing a portfolio change of this magnitude, Vectren South should have taken the three months necessary to update its risk analysis modeling. Updated risk modeling may not be necessary in all cases, but it is warranted here given the size and cost of the proposed CCGT."[8]

It would be far more useful and avoid a waste of Commission resources for utilities to be required to update their most recent IRPs as part of their case-in-chief when requesting a CPCN.

2. NIPSCO's IRP Fails to Take Into Consideration Several Significant Project Risks and Unexpected and Unplanned Changes in Power Markets Which Could Make Their Preferred Portfolio Unviable

The IRP also does not discuss the risks surrounding the timing and cost of renewables. As shown in the IRP, renewables accounted for about 15% of energy in 2021 and are expected to account for 56% in 2025.[9]

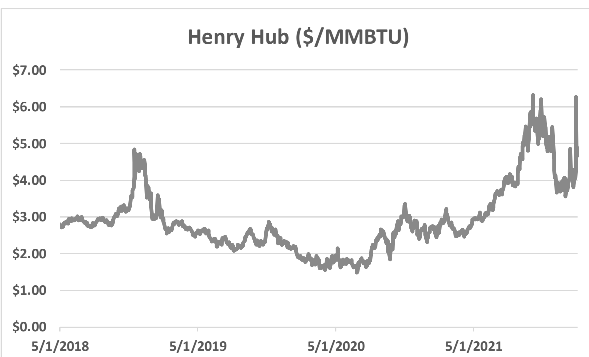


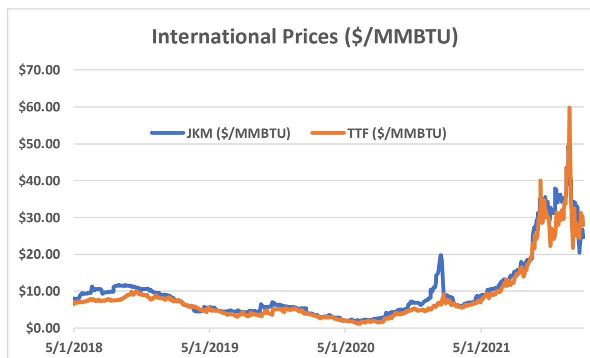
[8] *Verified Petition Of Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc.*, Cause No. 45052 (Final Order, April 24, 2019).
[9] IRP at p. 14.

While is it common for the IURC to require independent power producers to report on renewable construction projects on a quarterly basis, it would do well to require the same of investor-owned utilities. Renewable project delays in 2022 could have a ripple effect on 2023 and beyond, and the planned shutdown of coal projects without sufficient replacement resources could be disastrous. NIPSCO's CPCN testimonies also remain as silent on these very real risks for new renewable generation projects as its IRP does.

There is no question that COVID-19 has resulted in unexpected consequences that were not apparent when NIPSCO began to prepare its IRP in early 2021. While the dip in demand and the beginning of the economic recovery was acknowledged, NIPSCO did not anticipate some major market events which occurred in the second half of 2021. These market events, all of which affect the selection, cost, and timing of new generating resources, included the following: (1) increases in global commodity costs; (2) supply chain disruptions; and (3) labor shortages.

Natural gas prices in the U.S. and overseas increased significantly from 2019 and 2020 levels. In the U.S., Henry Hub more than doubled.[10] Overseas, the two most relevant indices, Japan Korea Marker (JKM)[11] and Title Transfer Facility (TTF),[12] increased more than five-fold:

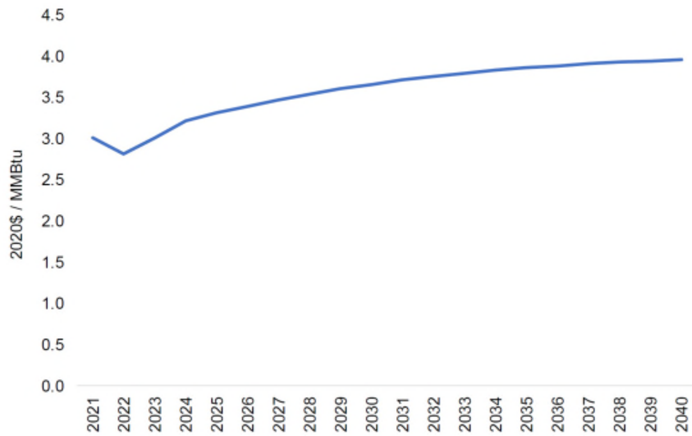




The increases were caused for a variety of reasons, some of which are believed to be situational, while others are believed to be structural. Regardless, the significant and somewhat sustained increase suggests increased pricing volatility and higher levels than assumed in the IRP:

[10] Source: CME Group: https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.html.
[11] *Id*.
[12] Source: Gas United Transport Service: https://www.gasunietransportservices.nl/.

Figure 8-12: Reference Case Gas Price Forecast



The IRP also does not address the impact of the retirement of substantial amounts of coal capacity on natural gas prices. Coal and natural gas prices have capped each other over the last decade. This means when gas prices are high, coal generation increases, which reduces the demand for and price of natural gas. With the rapid retirement of coal plants, natural gas combined cycle plants will increasingly serve as the swing base load, yet there will be no coal generation to cap high gas prices.

Finally, the IRP fails to even mention concerns about uncertainty in the industry around the ability to construct new natural gas pipelines. Recently, several major natural gas pipelines have been cancelled, including the Atlantic Coast Pipeline and the PennEast Pipeline. Closer to home, the Texas Gas Transmission, LLC (Texas Gas) lateral that CEIS needs to supply its proposed new CTs at the A.B. Brown site is being challenged at the Federal Energy Regulatory Commission (FERC).[13] Despite Texas Gas arguing for a brief review needed under a simpler "Environmental Assessment" (EA) process, FERC is requiring a much more comprehensive Environmental Impact Analysis (EIS) be conducted by the U.S. Environmental Protection Agency under the National Environmental Policy Act.[14] While technically the process could be completed in a year, according to a 2020 report prepared by the Council on Environmental Quality (CEQ), the average EIS completion time between 2010 and 2018 across Federal Agencies was 4.5 years.[15] There simply is no guarantee that an interstate permit will ever be awarded for the project. The regulatory uncertainty around permitting of new natural gas pipelines puts significant risk on natural gas fired electric generation projects.

Specifically, it does not mention the importance of critical minerals in the development of renewable energy. The international Energy Agency (IEA) has been raising a red flag related

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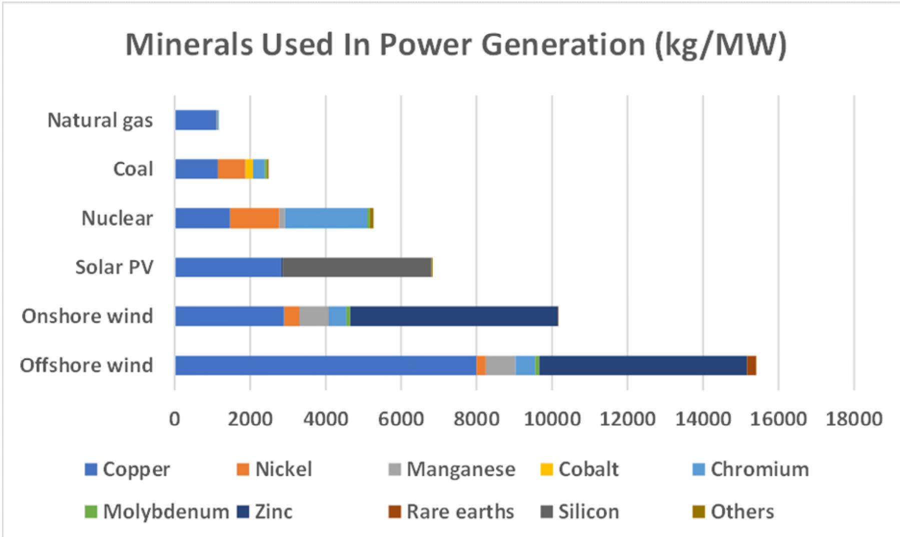
[13] *Texas Gas Transmission, LLC - Henderson County Expansion Project*, FERC Docket No. CP21-467-000 (pending).

[14] *Id*., see FERC letter to EPA, Document Accession #: 20220203-3036 (February 3, 2022).

[15] https://ceq.doe.gov/docs/nepa-practice/CEQ_EIS_Timeline_Report_2020-6-12.pdf

to the availability and cost of these minerals. IEA's estimate of critical minerals by generating source is shown below.[16]



The World Economic Forum (WEF) in November 2021 reported on concerns about delays in solar projects. Citing the independent energy research company Rystad Energy, WEF noted that "...rising shipping and equipment costs are threatening to postpone or cancel 56% of worldwide utility-scale solar projects planned for 2022."[17] WEF states that shipping costs have increased roughly six-fold from pre-pandemic levels. WEF further states costs have increased because of rising costs of solar panel components, particularly polysilicon, which is consistent with IEA's concerns above.[18]

Supply chain concerns are widely reported upon across the world. Tim Uy of Moody's Analytics said in a recent report that "…as the global economic recovery continues to gather steam, what is increasingly apparent is how it will be stymied by supply-chain disruptions that are now showing up at every corner."[19] As McKinsey just reported "supply-chain disruptions now outweigh COVID-19 concerns as the biggest risks executives see to domestic and corporate growth."[20]

NIPSCO's Gibson Solar Project has recently reported a nine-month delay.[21] A number of renewable projects planned for construction in 2022 (e.g., Indiana Crossroads Wind II, Greensboro Solar, and Brickyard Solar) could also be delayed, as there is no indication from

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[16] Source: https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions/executive-summary
[17] https://www.weforum.org/agenda/2021/11/supply-chain-problems-solar-power-renewable-energy/
[18] *Id*.
[19] https://www.sourcetoday.com/market-insights/article/21180892/how-procurement-is-managing-the-ongoing-supply-chain-shortages
[20] https://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/the-coronavirus-effect-on-global-economic-sentiment
[21] *In the Matter of the Petition of Gibson Solar*, IURC Cause No. 45500, 4th Quarter 2021 Report (filed January 28, 2022).

NIPSCO or its development partners that construction has begun. It is also well known that interconnection review has been seriously and repeatedly delayed by MISO. Some projects have had interconnection study due dates extended three, four, or five times. Thus, even if supply-chain disruptions are not an issue for a particular project, MISO regulatory lags could easily delay the project significantly.

The fault in NIPSCO's IRP is that it is unreliable, because it assumes that the utility's development of renewable projects will continue in the future as it has in the past, and fails to consider these significant real-world risks to future project development. NIPSCO should seriously consider these risks and realities by delaying its planned coal plant retirements until there is some market certainty and have a meaningful alternative action plan that is not dependent upon natural gas.

3. Overreliance on RFPs Leads to the Exclusion of Viable Resource Options

There has been a change over time in how resource costs are estimated in IRPs. For example, NIPSCO didn't use RFPs in its 2014 IRP. Instead, the utility focused on self-build options considering a full range of traditional resources, renewables and distributed generation through a commissioned Sargent & Lundy engineering study.[22] Currently, NIPSCO and other Indiana utilities are using Requests for Proposals as the *primary method for determining resource costs*. As the IURC may remember, the use of RFPs in the IRP process was originally intended to improve cost estimates for renewables.

RFPs were not meant to substitute for vigorous analysis of all resource options. While RFPs can be useful, they should not be used to the exclusion of other means of analysis. In the current IRP, NIPSCO suggests that two resource options (i.e., carbon capture utilization and storage (CCUS) and small modular nuclear reactors (SMRs)) were not fully considered because they had not been bid in response to the RFP. It is understandable why SMRs and CCUS were not bid, as these technologies are not typically developed by third parties. RFPs are a fine tool for arriving at estimated costs of various resource options, but NIPSCO needs to thoroughly evaluate and get pricing of all options – even those sources for which no RFP response was received.

With respect to CCUS, the IRP notes that the RFP did not generate any CCUS bids "so specific modeling (was) not performed for this technology."[23] Nevertheless, the IRP acknowledged "the MISO market scenario analysis incorporated CCUS technology as a plausible generation resource option under scenarios with significant carbon rejection technologies."[24] NIPSCO states the CCUS is most relevant for the Sugar Creek combined cycle where a net zero standard could require CCUS. However, in none of the scenarios is a carbon capture retrofit assumed. Yet in all but two scenarios, Sugar Creek is assumed to continue to operate for the

[22] NIPSCO 2014 IRP at p. 90.
[23] IRP, page 107.
[24] IRP, page 107.

entire term of the IRP. One of NIPSCO's scenarios assumes closure in 2032 and one scenario assumes conversion to hydrogen:

Figure 9-1: Overview of Existing Fleet Portfolios

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

Short term (1–6) Longer term (7–7H)

Not a viable pathway due to implementation timing

Using the RFP as the basis for wholly eliminating an entire type of technology is short-sighted. NIPSCO should conduct such analysis, which can and has been done. For example, the U.S. Department of Energy's National Energy Technology Laboratory (NETL) conducted a study that examined the regional electricity and environmental markets impacts of maintaining coal-fired generating units identified for retirement in the 2019 PacifiCorp IRP through retrofit with CCUS.[25] The study proposes an alternative least cost resource portfolio that includes a CCUS option. This alternative portfolio is estimated to produce a lower CO2 emissions footprint and a lower cost to the consumer than the proposed IRP from PacifiCorp.

While NIPSCO's discussion of CCUS was more complete than its SMR discussion, NIPSCO focused exclusively on the relevance of CCUS for natural gas, i.e., not other fossil or biofuels. With respect to SMR's, the IRP states that "SMR is still in the early stages of development and **NIPSCO did not receive any bids related to this technology in the RFP,** even in an unpriced information fashion….**As a result, NIPSCO has not evaluated SMR technology as a realistic resource option** associated with the implementation of its preferred portfolio over the next several years."[26] Notably, the General Assembly just passed Senate Bill 271, which supports the development in Indiana of SMRs of less than 350 MW. Unlike NIPSCO, Indiana's legislature thinks SMR development is in fact, a realistic generation resource option.

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[25] Pena-Cabra, C. E. Logan, K. Labarbara, R. Wallace, R. Hoesly, S. Lin, P. Shirley, A. Harker Steele, P. Myles, A. Noring and J. Brewer, "Wyoming CCUS Study: Regional Electricity and Environmental Markets," National Energy Technology Laboratory, Pittsburgh, August 23, 2020.
[26] IRP, page 111.

At first, one might assume that SMR was not meaningfully considered because the technology is untested; however, it is clear that NIPSCO is willing to include otherwise untested technologies in its IRP analysis. For example, NIPSCO appears to take seriously the possiblity that green hydrogen[27] should be considered as a commercially viable future resource. NIPSCO states that "mutliple bidders offered projects associated with either electrolysis-based hydrogen production (in the form of a small-scale pilot program) or enablement of natural gas turbines to burn the fuel. Such bidder interest confirmed the viability of the technology and prompted NIPSCO to develop hydrogen cost projections over time for use in the IRP portfolio modeling."

The IRP summary of the RFP results tells a different story.[28] As shown below, NIPSCO reported that only two bids for hydrogen projects were received. Of the two bids received, one was for the small scale pilot; the other appears to be for the enablement of natural gas pipelines to burn the fuel.[29]

Figure 4-4: Summary of Number of Proposals Received by Technology Type

Proposal Count by Technology and Transaction Structure

	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
Asset Sale	1	2	6	4	-	-	-	13
PPA	15	20	8	10	7	2	4	66
Both	37	60	-	2	-	-	4	103
Total	**53**	**82**	**14**	**16**	**7**	**2**	**8**	**182**
States Represented	**IL, IN, KY**	**IL, IN, KY, WI**	**IN, WI**	**IL, IN, KY**	**IL, IN, MO**	**IN**	**MISO**	

Figure 4-9: Summary of PPA RFP Tranches Used in Modeling

Tranche	ICAP (MW)	Heat Rate (Btu/kWh)	Energy Price ($/MWh)	Capacity Price ($/kW-mo)	First Eligible Start Year**	PPA Term (years)	Escalation Rate
Wind P1	500		$48.37		2025	20	0%
Wind P2 (Non-LRZ 6)	835		$33.28		2024	15	0%
Solar P1	825		$49.73		2024	20	0%
Solar P2	588		$37.50		2024	17	0.9%
Solar + Storage P1	300:150^		$39.00	$7.43	2025	15	0%
Solar + Storage P2	1,135:478^		$44.49	$6.14	2023	20	0%
Storage P1	863			$11.95	2025	19	0.2%
Gas Peaking P1	443	10,244	*	$6.47	2026	20	0%
Gas Peaking P2	193	10,238	*	$8 – $9	2025	20	2.1%
Gas CC P1	1,365	6,627	$0.98*	$8.89	2024	20	0.1%
Other Thermal P1	50	12,500	$2 – $3*	$5 – $6	2024	10	
Other Thermal P2	150			$3 – $4	2026	10	2.0%
Hydrogen P1 – Enabled Peaker	193	10,238	*	$9 – $10	2025	20	
Hydrogen P2 – Electrolyzer Pilot	20			$25 – $30	2026	20	

[27] Green hydrogen is produced using carbon free energy and electrolysis to split water and is distinct from grey hydrogen, which is produced from methane and releases GHG emissions and blue hydrogen which requires carbon capture and sequestration.
[28] IRP, page 86.
[29] IRP, page 90.

Almost a full 12 pages of the IRP are focused on hydrogen because of the two bidders, only one of which was actually relevant to green hydrogen production. The IRP discusses several business constructs for NIPSCO if green hydrogen production is pursued. Yet, there continues to be no certainty that green hydrogen can ultimately be produced economically. The other RFP response is apparently related to the enablement of natural gas turbines to burn hydrogen, which at best is premature given the uncertainty of a competitive hydrogen supply.

NIPSCO's limited half-page discussion of SMRs in the IRP failed to reflect the true status of this technology. For example: the Carbon Free Power Project is a NuScale SMR being built by Utah Associated Municipal Power Systems (UAMPS) at the Idaho National Laboratory;[30] TerraPower's announced plans to build an SMR in Kemmerer, Wyoming;[31] the six Early Site Pemits awarded by the Nuclear Regulatory Commission;[32] and the first SMR site license to the Tennessee Valley Authority (TVA) for at its Clinch River site.[33] While nuclear projects used to be taboo, that attititude is changing. For example, West Virginia recently eliminated the ban on nuclear power.[34] Ironically, SMR's and CCUS equipped fossil plants could support the production of green hydrogen in an environmentally friendly manner.

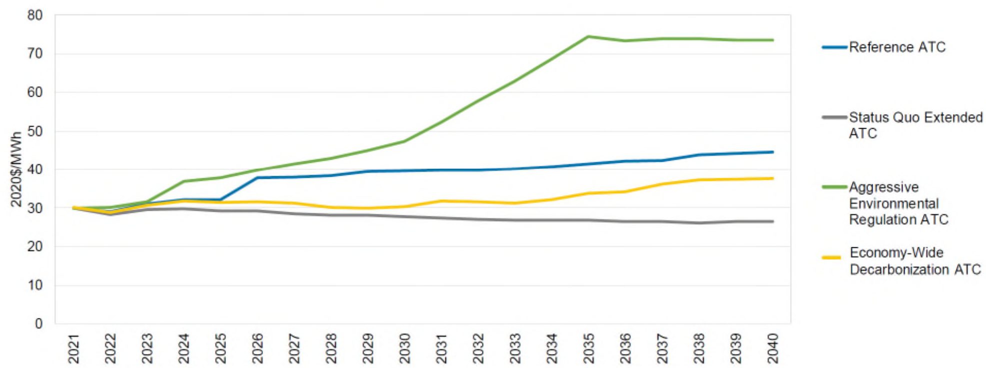
A regulated utility with an obligation to serve should be fully considering all options equally, even if they are not bid into an RFP. Nonetheless, as NIPSCO itself acknowledges, such technologies could be very attractive and as such it is incumbent upon the utility to consider them particularly if they could affect the choice of near-term resource decisions. Limiting pricing analysis only to RFP bids creates a "stacked deck" of resources which excludes reasonable and traditional options such as self-build, developing new technologies, and the retrofit and continuing operation of existing plants.

4. With the Closure of All Coal Capacity, NIPSCO Will be Increasing Its Reliance on Capacity and Energy Purchases, Which Risks Increased Costs to Ratepayers

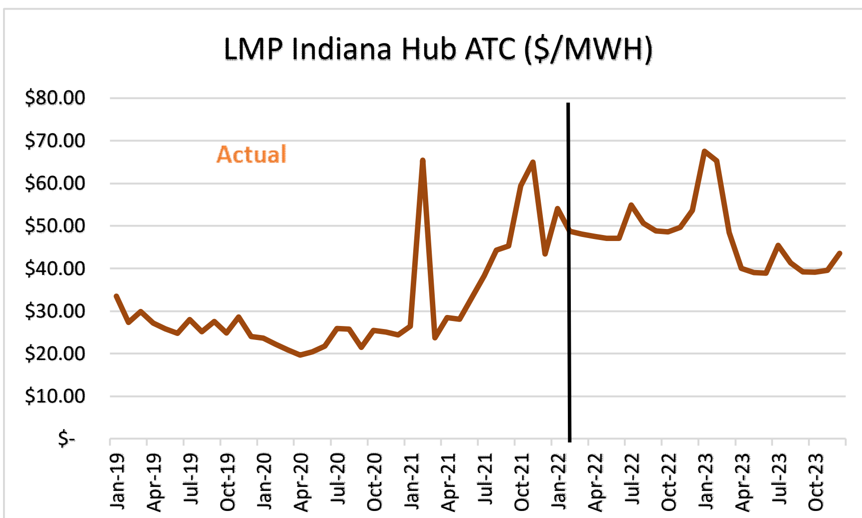
The replacement of base load coal capacity largely with intermittent renewables will increase NIPSCO's reliance on energy purchases from MISO. The outlook for MISO Zone 6 prices[35] did not reflect the high power prices experienced in 2021 and is similarly well below the forward curve for 2022 and 2023:

[30] https://www.uamps.com/nu-scale-modular-reactor
[31] https://www.cnbc.com/2021/11/17/bill-gates-terrapower-builds-its-first-nuclear-reactor-in-a-coal-town.html
[32] https://www.nrc.gov/reactors/new-reactors/esp.html
[33] https://www.world-nuclear-news.org/Articles/US-regulator-approves-first-SMR-site-licence
[34] https://www.npr.org/2022/02/08/1079339405/west-virginia-ban-nuclear-power-coal
[35] IRP at p. 195.

Figure 8-43: MISO Zone 6 ATC Power Prices across Scenarios



Meanwhile, Locational Marginal Prices (LMPs) continue to rise in comparison to historical MISO market costs:[36]



NIPSCO acknowledges in the IRP that natural gas price drives power prices.[37] As a result of NIPSCO's reliance on relatively low natural gas prices, its estimates of power prices are similarly a concern because they are also too low. Overreliance on capacity and energy market purchases in a time of high gas and high electric prices will cause consumer costs to skyrocket.

5. The Coal Plant Retirement Analysis Should be Revisited

As described above, there have been significant and unexpected changes in the power and energy markets since the IRP stakeholder process began in March 2021. The net results of

[36] Source: Historical MISO pricing data and Energy Ventures Analysis forecast.

[37] "Rising natural gas and carbon prices drive the AER scenario's prices highest, while the SQE and EWD scenarios have flatter pricing in real terms due to lower gas price expectations, the lack of a carbon price, and expectations for growing renewable penetration. (NIPSCO 2021 IRP, p. 195).

these changes, with respect to NIPSCO, are higher than expected power and natural gas prices, slower replacement of capacity, and greater exposure to market capacity and energy purchases than had originally been expected. Further, and not considered at all by NIPSCO, is the fact that other utilities in Indiana may be similarly situated, i.e., they will also need to purchase higher levels of energy and capacity in the next few years than forecast.

NIPSCO would not be the first utility to reconsider the timing of coal plant retirements to address these market changes. CEIS has announced it no longer plans to retire its Culley #2 station in 2023, as the replacement cost of capacity was higher than the cost of keeping the unit available. This is also true outside of Indiana. In October 2020, Big Rivers Electric Corporation (BREC) filed its IRP. The IRP concluded "Big Rivers' optimal plan (least cost option) for meeting its Member-Owners' native load requirements under the base case scenario is to idle the Green coal plant, add the three proposed solar facilities, and find partners to add the optimum amount of a natural gas combined cycle generation at Big Rivers' Sebree site."[38] On March 1, 2021, BREC filed an application for a CPCN to convert the Green station to natural gas.[39] Subsequent to the IRP, BREC determined that the cost to replace 300 MW of capacity, which it appears to have assumed to be about $2,660,850 per year, would in fact be $28,199,535 per year, a tenfold increase.[40] At this price point, converting the Green station to gas became the economic option.

It is also important to consider MISO's strong comments to the Environmental Protection Agency (EPA) on the impact of denying extensions to 40 C.F.R § 257.103(f)(1) to allow Coal Combustion Residuals (CCR) to continue to receive waste streams at facilities comprised of 3.1 GW of coal fired generation in the MISO footprint. MISO noted that "The loss of any significant portion of the 3.1 GW [from the five MISO plants affected by EPA's decision] . . . would push resource adequacy . . . into dangerous territory."[41] At the same time, the IURC's 2021 Annual Report continues to show 3.7 GW of planned coal-fired retirements by the end of 2023 and an additional 4.7 GW by the end of 2028.[42] If that plan holds true, then 8.4 GW of coal will be retired in Indiana alone. Meanwhile, MISO is warning of the danger of losing only 3.1 GW. This does not even take into account the impact of plant closures in PJM on Indiana, such as Energy Harbor's plan to deactivate more than 3 GW of coal-fired generation in 2023.[43]

PJM is only considering the formal requests for unit deactivation and currently believes that only 18,000 MW of coal will retire by 2050. In contrast, America's Power believes 24,000 MW will retire by 2030. Despite these wildly different, yet strikingly huge predictions, MISO and PJM are not coordinating with states and utilities on a long-term strategy related to reliability.

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[38] https://psc.ky.gov/pscecf/2020-00299/roger.hickman%40bigrivers.com/09212020071904/Big_Rivers_2020_IRP_with_Appendices.pdf, Page 174.

[39] https://psc.ky.gov/pscscf/2021%20Cases/2021-00079//20210611_PSC_ORDER.pdf

[40] Page 6 of order

[41] *In re Receipt of Waste from Dallman Power Station Based on an Interim EPA Determination*, U.S. Environmental Protection Agency, EPA-HQ-OLEM-2021-0588 *et seq*., Feb. 23, 2022 at p. 16.

[42] https://www.in.gov/iurc/files/IURC-2021-AR-WEB.pdf at p. 35.

[43] https://www.prnewswire.com/news-releases/energy-harbor-transitions-to-100-carbon-free-energy-infrastructure-company-in-2023-301501879.html

With so much uncertainty and the absence of a comprehensive energy transition plan, industry stakeholders should be working very closely together on the planning for resource adequacy and resiliency on a longer timeframe to prevent a Texas-like failure of the power grid. Fragmented and incomplete planning, paired with an increased number of regulatory risks being presented by Federal agencies, and the use of environmental, social and governance criteria and climate change risk are being used to justify early plant retirements. States must begin to weigh the impacts of closures and retirements beyond the individual utility IRP, or risk being left without adequate resources to meet demand.

It is looking more and more likely that utilities in Indiana are going to be capacity short, potentially resulting in a greater reliance on capacity purchases from third parties and/or an increase in the MISO capacity price. In addition, given the replacement of dispatchable resources with largely non-dispatchable resources, the need for and cost of energy is likely to rise. NIPSCO's presumption that capacity will be affordable and energy prices will be unaffected is not reasonable. This is why NIPSCO's IRP analysis should be updated when new generation projects are presented to the Commission. NIPSCO has an obligation to reconsider all options prior to filing for any CPCN for new investment decisions. If extended operation of the coal plants to 2028 reduces customer exposure to higher rates, NIPSCO's failure to revise its plan to consider that option upon filing its next CPCN would be imprudent.

CONCLUSION

Energy markets are changing, as is the IRP process, and thus the Commission's review of those IRPs should change as well. IRPs are regularly used as an evidentiary basis for billions of dollars in generation investment, as well as billions in plant retirements. Yet, IRP development is not subject to due process, public hearing, or formal scrutiny by the Commission, which is already within the IURC's authority to do. In the absence of the Commission's hand to place a balance on utility versus consumer interests in the development of IRPs, monopoly utilities control the flow of information, impose their own biases on the preferred outcome of the IRP process, which results in the elimination or demotion of otherwise reasonable and economic portfolio alternatives. Therefore, Reliable Energy recommends:

1. The Commission formalize its involvement in the IRP development process.

2. Upon NIPSCO's next filing of a request for approval to build or buy new generation (whether via a CPCN proceeding or a declination of Commission jurisdiction request), the Commission require NIPSCO to update its IRP modeling to reflect current market and regulatory conditions.

Implementing these two recommendations would allow the Commission and interested parties to address the significant concerns about NIPSCO's IRP:

a. Use of a 30-year Net Present Value (NPV), which inaccurately measures "Affordability and Rate Stability" on a levelized basis, when this is not how customer rates are set by the Commission.

b. Failure to recognize the risks associated with the deliverability and cost 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 Requests for Proposals (RFPs), which results in the exclusion of viable generation options, including: self-built projects, retrofitting existing plants, and new technologies.

d. Imprudent assumption of 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 available capacity resources.

Reliable Energy appreciates the opportunity to participate in the IRP stakeholder process and to offer comments on an ongoing basis. Reliable Energy also appreciates NIPSCO's willingness to engage in a robust discussion of the issues. Reliable Energy would be happy to discuss the issues raised above further and to make its consulting experts available to NIPSCO for in-depth discussions.

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Reliable Energy, Inc.

Comments on NIPSCO's March 19, 2021 IRP stakeholder meeting and slide deck

1. METRICS

Objective	Indicator	Description and Metrics
Affordability	Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Rate Stability	Cost Certainty	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75th percentile of cost to customer
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and **95th percentile conditional value of risk (average of all outcomes above 95th percentile)** of cost to customer
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and/or 5th percentile of cost to customer
Environmental Sustainability	Carbon Emissions	• Carbon intensity of portfolio • Metric: Total annual carbon emissions (2030 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	Operational Flexibility	• The ability of the portfolio to be controlled to provide energy "on demand," including during peak hours • Metric: % of dispatchable MW in gen. portfolio
	Resource Optionality	• The ability of the portfolio to flexibly respond to changes in NIPSCO load, technology, or market rules over time • Metric: MW weighted duration of generation commitments
Positive Social & Economic Impacts	Employees	• Net impact on NiSource jobs • Metric: Approx. number of permanent NiSource jobs associated with generation
	Local Economy	• Affect on the local economy from new development and ongoing property taxes • Metric: NPV of property taxes or land leases from the entire portfolio

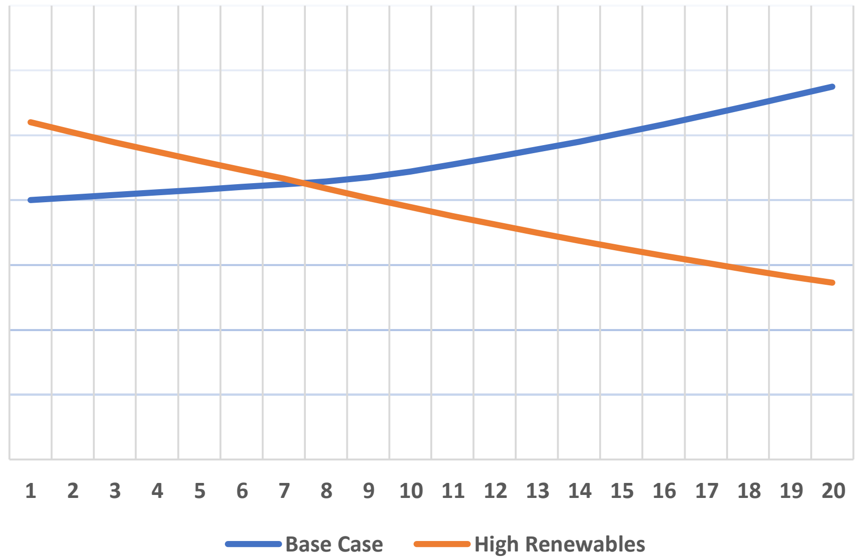
Reliable Energy presents for consideration the following issues with the proposed metrics.

A. Affordability

While it is appropriate for NIPSCO to consider the impact to customer bills, a 30-year net present value (NPV) is not a proxy for customer rates or affordability. A 30-year NPV is the discounted forecast of 30 years of annual revenue requirements. This is inappropriate for determining rate impacts for the following reasons:

- The revenue requirements are based on levelized costs: customer rates are based on undepreciated capital.

- A 30-year NPV can mask significant near-term costs with low future-year costs. For example, the following is a potential NPV of 20 years of annual revenue requirements.



The NPVs for this example are as follows:

NPV Term	High Renewables vs. Base Case
5 Years	21%
10 Years	12%
20 Years	-3%

Note the 20-year NPV is lower, but it is only lower because of the projected savings in the latter years when there is greater uncertainty about future costs. To the extent, NPVs are used to assess customer affordability, the analysis should include consideration of NPVs the earlier periods, e.g., five and 10 years, when there is greater certainty as to costs and the future savings do not mask near-term costs.

B. Rate Stability

Cost certainty, cost risk, and lower cost opportunity are the three metrics proposed to rank rate stability. For all three metrics, NIPSCO again relies on 30-year NPVs. In addition to the reasons provided above arguing against the use of the 30-year NPVs for the affordability metric, it is inappropriate to use the statistical distribution to measure rate stability.

The addition of significant new resources based on estimated costs are included in the NPVs. Using NIPSCO's last IRP as an example. NIPSCO materially underestimated the cost of new renewable generation in the prior IRP. While confidentiality limited public disclosure of the understatement, the Indiana Office of Utility Consumer Counselor (OUCC) filed testimony in October 2020, stating that not only were the resource costs higher than what had been assumed in NIPSCO's 2018, the IURC should consider whether the entire conclusions of the IRP be reconsidered.

This is no small issue considering that the wellbeing of NIPSCO's residential customers and the competitiveness of its business customers relies on keeping rates as low as reasonably possible. NIPSCO apparently made a misjudgment in its Short-Term Action Plan that solar resource prices would not substantially increase in the short term, leading to NIPSCO receiving much higher cost responses than available just two years ago in its first request for proposal ("RFP"). The effects of these misjudged costs will grow as NIPSCO presents additional solar resource proposals grounded in its Short-Term Action Plan, since the installed capacity from its current proposals represents about only 21% of the total amount of solar capacity envisioned in that Plan.[1]

Vectren had similar experiences with its RFP. Vectren is currently experiencing a delay and significant cost overrun on a project for which it received approval. In May 2018 in Cause 45086, Vectren sought and ultimately received approval to construct, own, and operate a solar energy facility, referred to as the Solar Project. As part of the approval, Vectren is required to provide quarterly reports on the construction of the Solar Project. The report at the end of Q1 2020 indicated a significant problem and at least a four-month delay, which Vectren alleged to be related to COVID-19 although at the end of March 2020 there were limited COVID-19 impacts. Further, the EPC contractor withdrew. The report at the end of Q2 2020 showed over a 20 percent increase in project costs. This project had been challenged on the basis of need and cost and ultimately only went forward due to a settlement with the OUCC and the Citizen's Action Coalition.

The lessons from the recent experiences of both NIPSCO and Vectren are that the IRP assumptions regarding renewable pricing may not be achievable and that even an all-source RFP is not dispositive. Vectren, which had chosen to rely heavily on the results of the RFP, admitted as much. In the 4th Stakeholder Meeting Minutes provided in Volume 2 of the 2020 IRP, Vectren "found there are many difficulties with (the all-source RFP) process. The long timeframe makes it difficult for developers to hold their projects and pricing plus many projects are picked up by other groups while the IRP analysis is being performed." (Vectren Submitted IRP Volume 2 of 2 Part 1, p. 393 of 851).

At a minimum, the conclusion is that any preferred plan resulting from an IRP must be subject to a firm bidding process achieving equal or superior economics <u>or</u> must re-justify the resource decision in the context of the definitive economics when applying for a CPCN.

To state the obvious, using the IRP based upon non-binding RFP results could result in the understatement of actual renewable costs which would not support rate stability.

[1] Cause 45403, Redacted Testimony of OUCC Witness Peter M. Boerger, Ph.D., September 8, 2020, pp. 5-6 (internal footnote omitted). Mr. Boerger further states: "If NIPSCO's solar resources had in its 2018 IRP been modeled to be [redacted] higher, other resource options would have been more attractive and NIPSCO's model may have selected a different resource mix. Thus, the higher solar costs NIPSCO is now seeing call into question whether the resources in this case, which are part of NIPSCO's Short-Term Action Plan, should be reconsidered."

C. Environmental Sustainability

NIPSCO's measure of environmental sustainability is carbon intensity, i.e., pounds per MWh generated in 2030. For reasons discussed more fully below, the entire approach NIPSCO has adopted for carbon is misplaced. The focus needs to be on the glide path to net zero carbon emissions, not intensity in 2030. The strategy to get to net zero is very different than the strategy to have lower carbon intensity in 2030. For example, new gas could reduce carbon intensity but is contrary to the glide path for a low-cost strategy for achieving net zero by a date certain.

D. Reliable, Flexible, and Resilient Supply

Reliable Energy agrees with this metric in concept, but the measuring metrics may not fully analyze the metric. For example, from the identified metrics "percent dispatchable" and "MW weighted duration of generation commitments" it is unclear how this metric would address other elements of reliability, flexibility, and resiliency, such as on-site fuel inventory, protection against gas supply disruptions, and insuring adequate transmission upgrades.

Following the 2021 events in ERCOT and the 2020 events in California, it is clear there are enormous risks and challenges related to the changes in generation portfolio. The five-day cost impact on ERCOT was in the billions of dollars and much of those costs will be borne by ratepayers.

E. Positive Social and Economic Impacts

Reliable Energy again agrees with this metric but is concerned the measuring metrics are misplaced. To begin with, the measuring metrics should be compared to current employment and tax bases. Further, they should include the multiplier effect of such employment and tax base losses.

2. NET PRESENT VALUE

NIPSCO, like other utilities, uses NPV as the primary metric for evaluating scenarios. In Indiana, the NPV is usually calculated over 20 years. While this can vary by jurisdiction, 20-years is the most common planning horizon.[2] The most recent Appalachian Power (WV), Wheeling Power (WV), and Kentucky Power (KP) IRP's are for 10 years. In Michigan, the utilities use 20 years.[3] PacifiCorp also uses a 20-year planning horizon across its multiple states.[4]

In the last IRP, it appeared that NIPSCO used a 30-years NPV because it produced the utility's desired result. It is unfortunate that NIPSCO has continued this practice despite this revelation. A 30-year NPV relies too heavily on unknowns and extends well beyond a reasonable planning period.

[2] http://www.eewv.org/current-campaigns/least-cost-planning
[3] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231usAAA
[4] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

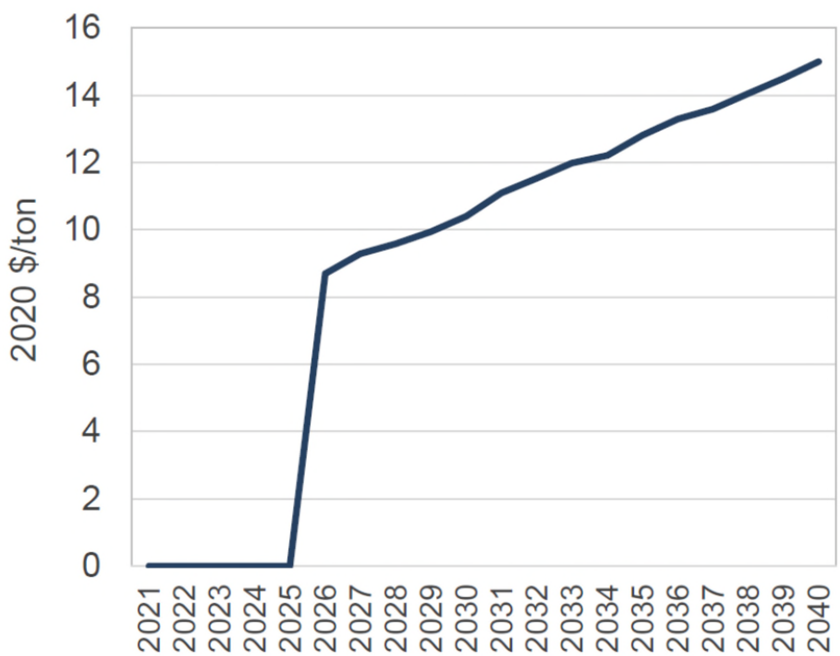
If NIPSCO persists in using a 30-year NPV despite objections, then it should also include the following data:

- Annual Revenue Requirements for each year;
- Five-year NPVs;
- Ten-Year NPVs; and
- 20-Year NPVs.

In the recent Draft Director's Report of the Indianapolis Power & Light's IRP, the Director noted the inclusion of annual revenue requirements is a helpful addition. (Draft Director's Report for Indianapolis Power Light's 2019 Integrated Resource Plan, p. 26).

3. CARBON

NIPSCO is proposing to use a carbon tax in its reference case, which it developed using Aurora modeling to achieve a certain level of reductions.



Reliable Energy objects strongly to using only a carbon tax scenario as the proxy for a carbon restriction regime for the following reasons.

Carbon taxes have been proposed and rejected for over 30 years.[5] For a variety of reasons, carbon taxes have not been legislated in Indiana or at a national level, and carbon taxes are unlikely to be legislated in the future. The problem with using a carbon tax to model a carbon restriction regime is that a carbon tax is not a proxy for all types of carbon restrictions.

[5] https://priceoncarbon.org/business-society/history-of-federal-legislation-2/

Specifically, it is particularly not a good proxy for a net zero carbon goal by 2035, 2040, or 2050, which appears to be the carbon restriction path that the Democrat-controlled Congress and the Biden administration will pursue. A carbon tax is especially unlikely considering the current composition of the Senate—a 50/50 tie—and that fact that Senator Manchin (D-WV), who heads the Energy and Natural Resources Committee, has publicly stated his opposition to a carbon tax.[6]

Correspondingly, there has been significant momentum related to carbon restriction in the states through adoption of Renewable Portfolio Standards (RPS) and Clean Energy Standards (CES).[7] A Federal RPS or net-zero emissions goal is far more likely to occur than a carbon tax.

The modeling of net-zero plans versus carbon tax plans will produce different results. With respect to modeling, the largest difference is how new investments in fossil generation are handled. The modeling of new fossil generation should either consider the new investment over a truncated period or with carbon capture. If the investment is considered over a truncated period, e.g., 12-15 years, then the full capital expense should be justified over that truncated period. On the other hand, if the investment incorporates carbon capture, the full capital expense, including CCS costs, can be justified for the entire life of the facility, but the modeling should only assume 12 years of known 45Q credits if construction begins by January 1, 2024.

4. NATURAL GAS SUPPLY AND PRICING CONCERNS

Reliable Energy is concerned about natural gas supply and does not think the overview/price forecast adequately address concerns and costs related to the following:

- Future ability related to pipeline construction;
- Lack of natural gas storage growth as growth in consumption continues;
- Physical and cyber risks to pipeline delivery;
- Cost of Firm and Interruptible Transportation;
- Potential linkage between LNG and domestic natural gas pricing; and
- Methane controls at the wellhead.

5. RENEWABLE INTEGRATION

MISO has repeatedly announced that renewable integration above 30 percent will significantly increase costs. NIPSCO states as much in the RIIA Report summary. It is not clear in the presentation how such increased costs will be modeled. More detail is required to understand the specifics. For example, what is the declining UCAP credit? What is the level of the higher transmission integration costs? Etc.

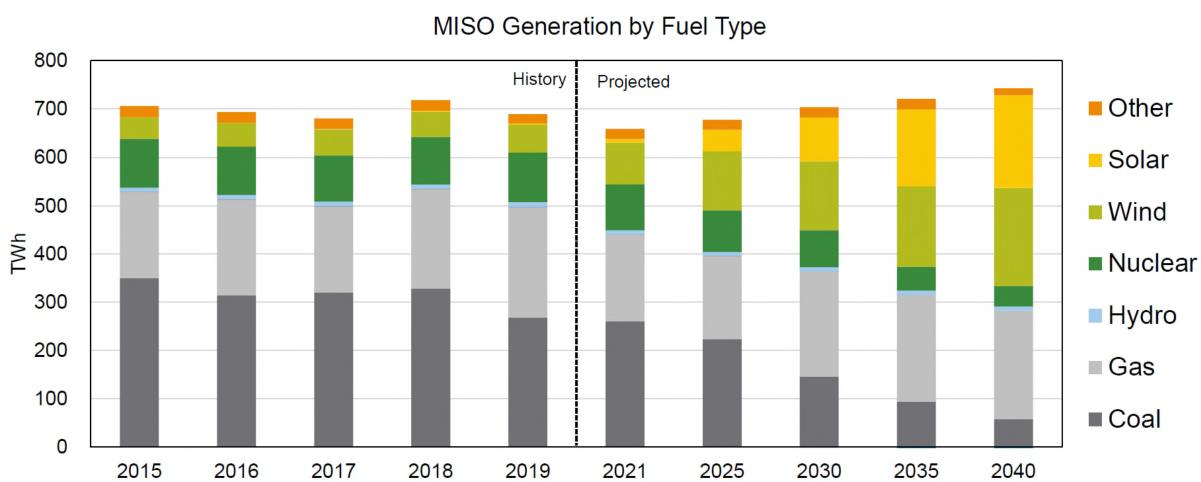
[6] https://www.eenews.net/stories/1063724469

[7] https://www.c2es.org – 29 states have binding RPS, seven have CES, and another eight have voluntary programs.

RIIA REPORT INSIGHTS PROVIDES RELEVANT RELIABILITY INSIGHTS FOR NIPSCO IRP

MISO Focus Area	RIIA Report Insight	MISO Response	Plan to Address in NIPSCO IRP
Resource Adequacy	Risk of losing load compresses into a small number of hours and shifts into the evening or winter	Market redesign, with seasonal capacity construct	Both summer and winter reserve margins will be tracked and implemented as constraints
	A system with >30% renewables will impact grid performance	ELCC capacity credit methodology to reflect changing value over time	ELCC accounting by season with a range of expected solar declines over time
	Diversity of technology and geography improves renewables' ability to serve load	Allow for technology-specific and location-specific capacity credit	Renewable output variability analysis is location specific
Energy Adequacy	With renewable penetration >40%, a greater need for ramping services will develop	Explore flexibility incentives for market redesign and assess other gas-power risks	Include "Operational Flexibility" as a metric in scorecard to measure dispatchable MW, ramp rates; consider ancillary services value
	Grid technology needs to evolve, with more integrated system planning	Explore more integrated MISO-level planning across functions, including software, process, and data needs	Incorporate DER options into IRP resource candidates; move towards integrated grid planning
	Storage paired with renewables and transmission help optimize the delivery of energy	Explore concept and ways to align benefits with outcomes	NIPSCO already pivoting to integrate storage and expects to ask for storage resources in RFP

In addition, the forecast of MISO generation by fuel exceeds the levels at which MISO believes it can successfully integrate without significantly higher costs.



6. STOCHASTIC MODELING

Reliable Energy believes the emphasis on stochastic modeling is misplaced. Recent efforts by NIPSCO and other utilities have provided little value from the stochastic modeling while deterministic modeling has yielded considerably better information. Reliable Energy suggests scaled down stochastics, applying such analysis only to those variables appropriately considered volatile and increased modeling of more scenarios with deterministic assumptions.

7. LARGE INDUSTRIAL CUSTOMERS

The assumed retention of large industrial customers is surprising. Scenario Impacts to load should consider an alternative outlook regarding a reduction in load for large industrial customers. Given recent legislative changes allowing large industrial customers to acquire energy directly through the wholesale market and the increasing likelihood that large industrial customers will install behind-the-meter renewable and co-generation to meet company carbon reduction goals, there is a substantial possibility of significantly reduced large industrial load.

8. CONCLUSION

Reliable Energy appreciates the opportunity to participate in the IRP stakeholder process and to offer comments on an ongoing basis. Reliable Energy also appreciates NIPSCO's willingness to engage in a robust discussion of the issues and give stakeholder feedback serious consideration. Reliable Energy would be happy to discuss the issues raised above further and to make its consulting experts available to NIPSCO for in-depth discussions.