



Final Director's Report
for Northern Indiana Public Service Company
(NIPSCO's) 2018 Integrated Resource Plan
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Dr. Bradley Borum
Director of Research, Policy and Planning
on behalf of the Indiana Utility Regulatory Commission

IRP submitted by Northern Indiana Public Service Company, LLC

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Final Director's Report Applicable to Northern Indiana Public Service Company's (NIPSCO) 2018 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

By statute¹ and rule,² integrated resource planning requires each utility that owns generating facilities to prepare an Integrated Resource Plan (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.³

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 IRP, 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.⁴ By identifying uncertainties and their associated risks, utilities will be better

¹ Indiana Code § 8-1-8.5-3.

² 170 IAC 4-7; see also "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: <http://www.in.gov/iurc/2843.htm> ("Draft Proposed Rule")

³ 170 IAC 4-7-2.2(g)(3).

⁴ In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

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 factors⁵ 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 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. As Northern Indiana Public Service Company, LLC (NIPSCO) correctly states on page 1 of its reply comments, "[t]he IRP process is a point-in-time forecast over the next 20 years, which is always evolving..."

II. INTRODUCTION AND BACKGROUND

Northern Indiana Public Service Company, LLC (NIPSCO) submitted a very well developed IRP that includes a Request for Proposals (RFP) from all types of resources without predetermining specific resources.⁶ From the Director's perspective, this combination of IRP analysis and an objective and reasonably transparent all-source RFP demonstrates an important evolution of state-of-the-art long-term resource planning, provided that the RFP is actionable rather than merely an attempt to *test the waters*. The combination of a legitimate RFP and the integration of the RFP information into its IRP enables NIPSCO to understand the uncertainties to help maintain a high degree of optionality and minimize adverse risks.

⁵ A primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

⁶ 2018 IRP, NIPSCO issued a formal Request for Proposals (RFP) to help inform the planning process, and to gain better information on available, real projects at real costs from within the marketplace. All energy technologies were eligible to participate, and NIPSCO received 90 proposals—the sum of which represented over three times NIPSCO's current generating capacity. Evaluating each source of electric generation for its total cost, environmental benefits, reliability, impact on the electric system and risks is an important step in the IRP. Results from the RFP provided better information that could be incorporated into the analysis and decision-making process. Specific screening criteria include energy source availability, technical feasibility, commercial availability, economic attractiveness and environmental compatibility. Executive Summary Page 5 of IRP

IRPs should be continually evolving in scope (e.g., integrating information from the planning and operations of both wholesale markets and their distribution systems) and rigor of analytics. NIPSCO's continued improvement of its IRP analysis from the prior IRP is largely due to the utilization of improved long-term resource planning tools. NIPSCO stated, in response to questions from the Director, that it intends to continue to improve the comprehensiveness and credibility of its IRPs by evaluating next generation planning tools and methods.

NIPSCO's utilization of state-of-the-art long-term planning models is a necessary, but not solely sufficient, condition for ongoing improvements in the IRP processes. To this end, NIPSCO has committed to continually assess its planning tools and its methodologies for modeling complex topics such as load forecasting, energy efficiency, demand response, and all other forms of distributed energy resources. NIPSCO has also made great strides to integrate probabilistic (or stochastic) analysis into its IRP. NIPSCO and its consultants provided an excellent discourse on the value of utilizing traditional scenario analysis with probabilistic analysis. As NIPSCO and its consultants have demonstrated, scenario and probabilistic analysis are complementary rather than being substitutes.

However, unless there are significant enhancements to the quality and quantity of data to support the advanced analytical models and analytical methods, the IRP analysis will not make the improvements necessary to address future uncertainties and risks. In large part, the suggested enhancements are to help NIPSCO better understand its customers, such as continual improvements in load forecasting, integration of DSM, and treating customer-owned resources on a comparable basis to all other resources. These areas of continued improvement would benefit from better load data and more detailed information about customers.⁷ Suggested improvements will be discussed throughout this Report.

One particularly notable exception to the concerns about data is NIPSCO's actionable Request for Proposals (RFP). The RFP provided vast amounts of credible data on the cost of resource alternatives. This empirical information enhances the credibility of NIPSCO's IRP. More than any other Indiana utility to date, NIPSCO has conducted a robust and transparent analysis of the wholesale market opportunities, uncertainties, and risks that confront its company. NIPSCO's efforts to integrate the RFP information into its IRP was well done.

⁷ NIPSCO should give due consideration to conducting total home / business load research, end-use load research on a representative sample of major end-uses, load research on DSM and DER customers, conducting surveys of appliances / end-uses, collecting demographic information, and developing and maintaining the North American Industry Classification System (NAICS). Especially with the need to refresh this research every few years, the Director recognizes this will take considerable effort and it will entail a non-trivial amount of time and money to support the effort. However, by knowing more about current and future customers, NIPSCO's risk is reduced which should result in associated cost avoidance benefits (e.g., more precise distribution system improvements and resource options). NIPSCO might also wish to coordinate with other Indiana utilities to reduce costs.

In addition to the IRP, NIPSCO developed a short-term action plan for 2019 through 2021 that addresses immediate resource requirements and strategy.

[The] plan will focus on the retirement process for all of the coal units [14,15,17, and 18] at R. M. Schahfer Generating Station (“Schahfer”) and selecting/acquiring replacement projects to fill the capacity gap as a result of the retirements in 2023. The retirements of the Units at Schahfer will likely require upgrades to NIPSCO’s transmission system to maintain system reliability... NIPSCO will rely on the Midcontinent Independent System Operator, Inc. (“MISO”) market, short term purchase power agreements (“PPAs”), or other bilateral agreements for short term capacity and energy as needed. NIPSCO will continue to monitor technology and MISO market trends while staying actively engaged with project developers and asset owners to maintain flexibility and optionality. NIPSCO expects to conduct another All-Source RFP to acquire resources to fill the remainder of the 2023 supply that was not met in the 2019-2021 time frame. *(Page 1 of NIPSCO’s IRP)*

This Report also addresses the IRP stakeholder processes. The Director commends NIPSCO for its stakeholder process and the participation by NIPSCO’s top management in the meetings and follow-up discussions.⁸ To NIPSCO’s credit, they worked assiduously to involve all sectors/stakeholders, including its employees and communities. Given the importance of the issues under consideration, NIPSCO’s transparent process was appropriate and sets a high standard for other utilities. Beginning in March and concluding in October 2018, NIPSCO held five stakeholder meetings *(Page 2 of Executive Summary of NIPSCO’s IRP)* as well as one-on-one conversations that were very useful and provided information that other utilities have been reluctant to provide. The Director also commends NIPSCO for retaining outside experts and state-of-the-art planning tools to augment NIPSCO’s expertise. The collaboration between NIPSCO and Charles River Associates in developing well-reasoned scenarios, sensitivities, portfolios, and the RFP, was particularly noteworthy.

Finally, the Director is appreciative of NIPSCO’s consideration of issues/concerns raised in the previous Director’s Report *(Page 10 of NIPSCO’s IRP)*. In NIPSCO’s reply comments, it acknowledged its intention to make improvements compared to its 2016 IRP:

[a] lesson learned in 2016 was that NIPSCO needed to provide additional discussion in the narrative to help clarify certain aspects of the modeling. Based on the comments received regarding the 2018 IRP, it is clear that improvements have been made to the narrative. However, NIPSCO commits to continue increasing clarity regarding its modeling efforts in future IRP submissions. *(Page 3 of NIPSCO’s Reply Comments)*

⁸ Beginning on March 23, 2018, and concluding with the Meeting October 18, 2018, NIPSCO hosted six meetings. Four meetings were in-person, one was a webinar (meeting 3) on initial results of the RFP, and a technical webinar to address the integration of the all-source RFP into the IRP analysis, and several one-on-one or small group discussions of specific topics and concerns.

III. THREE PRIMARY AREAS OF FOCUS

The Director recognizes the inherent complexity of the several elements that are normally considered in the development of IRPs. NIPSCO's incorporation of the all-source RFP, combined with the significant decisions being considered, added to the complexity as well as the credibility of the IRP. While all of the elements of the IRP are essential, the Director selected the following three topics to highlight: load forecasting, demand side management (DSM), and risk management. In the three focus areas, the Director recognizes there is no right or wrong way to conduct the analysis. Different approaches have been useful to advance the understanding of the various elements of IRPs, but it is premature to standardize those elements.

A. Load Forecasting

NIPSCO produced a base case load forecast, a high load forecast, and low load forecast over a 20-year planning horizon. For the base case, NIPSCO is projecting total energy sales to be flat and peak demand is expected to grow at 0.2% annually. *(Page 28 of NIPSCO's IRP)* For the 2018 IRP modeling, NIPSCO utilized the MISO Coincident peak demand forecast. The methods, assumptions and detailed forecast results are provided in Section 3. *(Pages 17 through 35 of NIPSCO's IRP)*

NIPSCO offered the following:

- NIPSCO's jurisdictional energy sales are projected to remain flat on average over the next 20 years;
- The Residential and Commercial compound annual growth rates are projected to be 0.8% and 0.7%, respectively, during the period 2018-2039. The Industrial class is projected to decrease at a rate of 0.7% during this same period;
- NIPSCO's internal peak demand is expected to grow from 3,051 MW in 2018 to 3,169 MW by 2039 representing an annual growth rate of 0.2% during the period 2018 to 2039;
- NIPSCO MISO coincident peak demand is expected to grow from 2,907 MW in 2018 to 2,970 MW in 2039 representing an annual growth rate of 0.1% during the period 2018 to 2039. *(Page 17 of NIPSCO's IRP)*

NIPSCO's long-term forecast incorporates historical customer usage and its relationship to economic, demographic, end use, and weather data. The load forecast reflects historical effects of past conservation and DSM programs. Regional saturation and efficiency trends are provided by Itron. Economic and demographic data utilized in the forecast is from IHS Global Insight. *(Page 17 of NIPSCO's IRP)*

NIPSCO utilizes individual forecast models for Residential, Commercial, Industrial, Street Lighting, Public Authority, Railroad, and Company use. The forecast relies upon a 60-minute peak demand model. Each of the individual forecast models utilizes methods that account for the unique characteristics of each class. The Residential, Commercial, and Street Lighting energy and total peak demand forecast models use an econometric approach to forecast long-term electric energy sales and peak hour demands.

In response to a question from the Director about projected changes in reduced energy sales and changes in demand characteristics, NIPSCO cited Section 3.12 of the 2018 IRP and a discussion on alternative low growth scenario.

[T]he demand from all large industrial customers is reduced to minimum operating levels. Table 3-13 of the 2018 IRP shows both the NIPSCO internal peak and the MISO coincident peak under the low growth scenario for selected years through 2038. NIPSCO has not identified any reduced energy consumption for the five largest customers based on the proposed Rate 831 rate structure. *(NIPSCO's Response 1-019)*

NIPSCO states that MISO's Coincident Peak and NIPSCO's maximum system peak occur at about the same time. On average, the MISO coincident peak level forecast is about 95% of NIPSCO's internal peak level. It is unclear if NIPSCO's peak demand will be as coincident with MISO's peak demand if NIPSCO's largest industrial customers reduce or eliminate their reliance on NIPSCO's resources.

i. Residential Load Forecast

Residential Load Forecast is based on the average residential use per customer projections multiplied by the total residential customers to produce "the total Residential energy forecast."

The residential use per customer model is a function of the residential price of electricity, appliance saturations, and efficiencies as defined in an end use variable supplied by Itron, Inc. and real per capita income. Other forecast considerations integrated into the Residential forecast model include residential customer counts, CDDs and HDDs.

The Residential customer count is a function of a five-year outlook for new construction provided by NIPSCO's New Business team...This approach includes conducting interviews with real estate developers and builders. The longer term customer outlook is modeled as a function of housing starts. Both the short- and long term forecasts are adjusted for customer attrition applied at an average historic rate... *(Page 19 of NIPSCO's IRP)*

The residential econometric equation is:

- Residential New Customer Equation: $\text{New Residential Customers} = f(\text{Local Housing Starts})$
- Residential Usage Per Customer Equation: $\text{Residential kWh per Customer} = f(\text{Residential Electric Price, Itron Index, Real Per Capita Income, HDD, and CDD})$

In this equation, the Itron Index is an end use variable based on appliance saturations and efficiencies using data developed by the Energy Information Administration.

ii. Commercial Load Forecast

Commercial Load Forecast utilizes the econometric Commercial Energy Forecast Model which includes the functional relationships among commercial energy consumption, commercial electric price, number of commercial customers, employment, Cooling Degree Days (CDD), and Heating Degree Days (HDD). As with the Residential load forecast model, NIPSCO conducts a five-year outlook by NIPSCO's New Business team. The longer term commercial forecast model states that the number of commercial customers is a function of population, real gross county product, and historic attrition rate. The commercial use equation is a function of commercial customers, employment, commercial electric prices, cooling degree days, and heating degree days. *(Pages 20 and 21 of NIPSCO's IRP)*

- Commercial Customer Equation: Commercial Customers = f(Population, Real Gross County Product)
- Commercial Usage Equation: Commercial Total Use = f(Commercial Customers, employment, Commercial Electric Price, CDD, HDD)

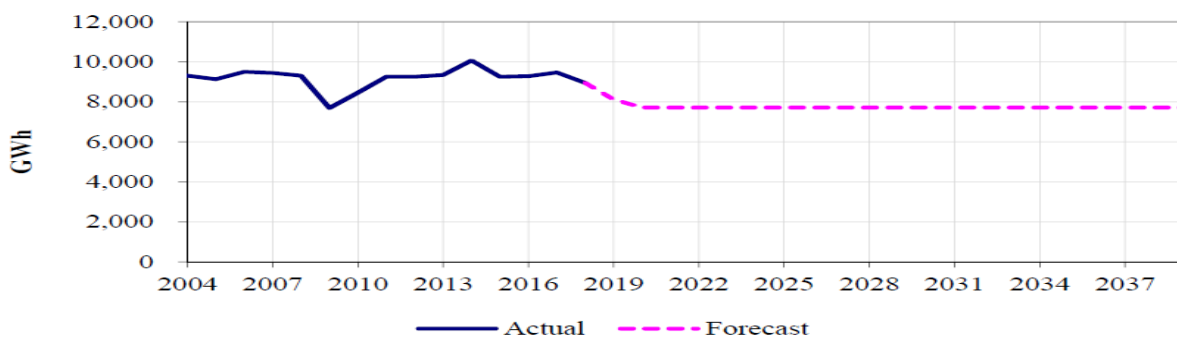
iii. Industrial Load Forecast

NIPSCO states that the Industrial Energy Forecast Model forecasts rely heavily on conversations with its 25 largest industrial customers.

As a part of these discussions, the projected effect of the customer's energy efficiency programs are already taken into account with the forecast provided to NIPSCO. The goals, plans, and concerns outlined in these one-on-one discussions form the basis of a recommendation for each customer's forecast. Other items considered in the development of the forecast include historical consumption, industry trade publications, global market news, business outlook conferences, and routine customer interaction. Notably, for the development of NIPSCO's industrial energy forecast for the 2018 IRP, this forecast integrates the economic and business projections of these customers... *(Page 22 of NIPSCO's IRP)*

NIPSCO's forecast for the remaining industrial customers is based primarily on historical data from the past six years with greater weight given to the most recent year. *(Page 23 of NIPSCO's IRP)*

Table 3-5: Industrial Energy Sales *(Page 23 of NIPSCO's IRP)*



iv. Street Lighting

NIPSCO's econometric model is driven by the number of hours of darkness and NIPSCO states the model accounts for "anticipated future trends" (*Page 24 of NIPSCO's IRP*). NIPSCO's forecast of street lighting is based on the following equation. (*Page 24, Section 3.6 of NIPSCO's IRP*)

- Street Lighting Energy Use = f(Number of hours of dark).

v. Customer Self-Generation

Customer Self-Generation assumes that most of NIPSCO's large electric customers with self-generation utilize the generation as a by-product of process steam production needs. This type of generation is difficult to predict by NIPSCO, and, therefore, challenging to dispatch by NIPSCO without significant coordination between the customer and utility. (*Page 26 of NIPSCO's IRP*). NIPSCO stated they have some customers using Rider 778 for Purchases from Cogenerating Facilities and Small Power Production facilities, but NIPSCO provides no discussion of how existing or future customer self-generation is modeled.

vi. Peak Demand Forecast

The Peak Demand Forecast is a regression model with energy sales by class, cooling degree hours (summer), heating degree hours (winter), and relative humidity at peak hour as drivers. The model also accounts for recent historical load factor levels and patterns associated with its large industrial customers. This is done in a two-step approach. Step 1 accounts for the impact of Residential, Commercial, and small Industrial and weather at the time of the peak. Step 2 accounts for NIPSCO's large Industrial customers. Total peak is the sum of the peaks from steps 1 and 2.

vii. Alternative Cases – High and Low Growth

On page 32 of its IRP, NIPSCO discusses the high- and low-load growth cases that were constructed from the base case forecast models, and used optimistic and pessimistic economic and demographic data. The forecast models are estimated at the 95% confidence level and reflect the high and low model bands. The industrial scenarios are constructed individually for each forecasted customer. Table 3-13 on page 32 of its IRP reflects NIPSCO's base, high and low energy, internal demand, and MISO coincident demand load forecast scenarios for 2018 to 2038 in five-year increments. Based on the description in the IRP, it is not clear how the alternative forecasts for the smaller industrial load were developed.

>>>Director's Comments – Load Forecasting

NIPSCO has made some improvements in its load forecasting methodology. However, many of the Director's questions or concerns from previous IRPs are still relevant. For example, the Director is concerned that NIPSCO's forecasting process for all types of customers relies too heavily on historic methods and professional judgment with too little consideration for evaluating the efficacy of prior methods or considering new approaches. While this concern is especially apparent in the industrial forecasts, it even seems to be a

significant element in the Public Authority load forecast and, to a lesser extent, in the residential and commercial forecasts.

As NIPSCO stated, the Residential sales forecast is the result of a residential customer forecast multiplied by a residential use per customer forecast. The use-per-customer model is an econometric model with a standard and appropriate set of drivers, including appliance saturations and efficiencies, real per capita income, electricity price, and weather. The customer model is comprised of a five-year outlook for new construction provided by NIPSCO's New Business Team, and the longer term forecast is based on housing starts. The short-term and longer-term outlooks are both adjusted for historical customer attrition. In response to a question from the Director, the number of new customers is added to the number of existing customers and then adjusted for an estimate of attrition applied at an average historic rate. NIPSCO confirmed the reliance on the New Business Team in responses to the Director and provided no discussion of the efficacy of relying on information from the New Business Team, except to note the move from the three-year customer outlook used in the 2016 IRP to a five-year outlook for customer additions in the 2018 IRP synchronized with the NiSource five-year plan. It is not clear to the Director that NIPSCO gave any consideration to other means of getting supplemental, improved, and more detailed customer demographic, appliance/end-use data, and usage information. In response to a question from the Director about whether NIPSCO is doing enough to capture future changes, NIPSCO stated: "NIPSCO has not directly considered that household demographics might be changing. However, indirectly, changing household demographics are part of NIPSCO's regression models..."

Given NIPSCO's "Challenged Economy" was a low load scenario that may be reflective of initially higher rates for other customers, it is surprising that NIPSCO did not assess the effect of potential price increases on future customer usage. Scenarios with significant short-term rate implications should be evaluated. NIPSCO's response to a question from the Director was: "NIPSCO has not completed a price elasticity analysis for reasons explained in Response 1-014."⁹

Since regression analysis is based largely on history, it is unlikely that econometrics alone will capture emerging paradigm changes such as those caused by changing demographics or penetration of new technologies such as electric vehicles, microgrids, etc. NIPSCO's response to DSM question 3 stated:

To date, NIPSCO has not analyzed the potential implications for electric vehicles or other technological changes on its system. However, NIPSCO continues to monitor trends related to electric vehicles and distributed energy resources and will make

⁹ "...Numerous variables impact customers' usage decisions. In fact, base rates are not the only factor changing as part of the electric price signal. Other changes impacted the electric price signal include the federal corporate tax rate, fuel prices and tracker rates. The Company is confident in its ability to model customers' usage." Question 1-014.

adjustments to its forecasting if and when those technologies are seen to have an impact on the system that would warrant such analysis. (*NIPSCO Response 2-003*)

Based on NIPSCO's Electric Vehicle (EV) pilot program, EV energy use was approximately 31% of the average home consumption, which is significant. NIPSCO seems to recognize the growing importance of EVs in Chapter 10, even if it is relatively minor now, and recognizes that its forecasting process does not adequately capture the potential for new electrification. The Director recognizes the inherent uncertainty of trying to predict the timing and magnitude of increased electrification, but it seems likely there will be new technologies that require thoughtful consideration in future IRPs.

In NIPSCO's Around Town charge program, NIPSCO had 382 customer enrollment requests by the end of January 2018 and installed 80 public charging stations providing 159 charging ports for residential, commercial, and industrial customers. In counties served by NIPSCO, the number of EV grew from 321 in 2014 to 888 in 2017 – a compound growth rate of 37%. The absence of operational information on EVs and charging stations combined with the lack of demographic surveys to better predict changes in the EV market is shortsighted. The demographics suggest that generations that follow the Baby Boomers are much more interested in environmental concerns and reducing energy use. As subsequent generations become financially stronger and the pricing of EVs becomes more economical, it seems likely that the penetration of EVs (and other new electric technologies) will also increase. NIPSCO also found that EV owners are responsive to discounted energy prices during the off-peak periods (*Page 188 of NIPSCO's IRP*) but it is not clear how this informed rate or DSM decisions that would alter future forecasts. These demographic changes and elasticity responses are likely to shift the load curve and could shift the peak demand which, in turn, affects resource decisions, demand response potential and the risks faced by NIPSCO. By extension, it is concerning that NIPSCO may not fully appreciate the significant ramifications for the planning and operations of NIPSCO's distribution system as well as MISO facilitated power market.

To summarize, NIPSCO's use of regression analysis is appropriate. For future IRPs (and hopefully for distribution system planning and coordination of DR and other DERs), NIPSCO should include variable(s) to estimate the effects of EVs (and other technologies) on the electrification trend. For this purpose, EV car registration may be useful, at least initially, as a proxy. Since econometric analysis is reliant on the variable specification and data, NIPSCO should be developing the requisite databases.

The Commercial sales forecast model is driven by commercial customer count, employment, commercial electric prices, CDD, and HDD. The commercial customer count is constructed similar to the residential one with the first five years from NIPSCO's New Business Team and the longer term load projections based on local population and actual gross county product, adjusted for the historical attrition rate. Employment and HDD are new drivers in this model and Real County Retail Sales has been removed since the 2016 IRP.

As with the residential forecast, there was no significant discussion of the value of the New Business Team's input into the commercial forecast. It is not clear that NIPSCO has considered other means of improving the load forecasting processes for its diverse commercial class of customers or, even if it did, it apparently did not have the requisite data. NIPSCO said it is considering the use of commercial customer surveys but has not elected to do so at this time. Nor has NIPSCO considered conducting end-use load research or trying to segment customers using North American Industrial Classification System (NAICS) information into more homogenous groupings.¹⁰ NIPSCO, in response to a question from the Director, said that the load forecast is impacted by how much and when customers use electricity and does not find the end-use to matter in developing the forecast (*IURC Request 1-021*). In the very short run, this perspective of a static stock of appliances/end-uses has appeal. Beyond a few years, however, the relationship between historic total usage and changes in the stock of appliances/end-uses seems certain to be stressed. In addition to changes in efficiency, commercial customers (e.g., hotels, office buildings, restaurants, stores, hospitals, colleges, government offices, etc.) may, over the next few years, offer EV charging stations. Some of these customers may also install their own distributed resources that will change their usage.

NIPSCO forecasts the 25 largest Industrial customer use based largely on the information provided to NIPSCO by its Major Account Division employees. Smaller industrial customers are forecast separately. To generate the total industrial class forecast, the large individual customer forecasts are combined with the portion of the forecast representing the balance of the Industrial class load. (*Page 17 of NIPSCO's IRP*) NIPSCO, in its reply to a question posed by the Director, confirmed that, beyond recent historical usage that serves as a baseline, the Major Account employees attempt to get information from the largest industrial customers on their expected use over the next five years. Even for the next five years, the Director recognizes that industrial customers, in particular, are reluctant to disclose information that may compromise their competitive position. NIPSCO said it included "recent historical industrial sales trends and regional and global trends for specific industries" (*Page 22 of NIPSCO's IRP*) but does not offer any discussion of how this information is integrated into the load forecast. In response to a question from the Director, NIPSCO said it also incorporated macroeconomic data but, again, how the macroeconomic data affected the industrial forecast is not clear.

The longer-term forecast of the remaining industrial load was also a simple extrapolation based largely on history. NIPSCO analyzed historical billed kWh for all smaller industrial customers for the period of January 2010 through October 2016. The analysis consisted of calculating the historical average, minimum, and maximum annual kWh for these customers. The most current year at the time, 2016, included ten months of actual billed kWh and two months of forecasted kWh. In response to a question from the Director,

¹⁰ In response to a question from the Director, NIPSCO stated: "The NAICS codes in NIPSCO's database are not sufficiently accurate to use for demand forecasting...In addition, NAICS codes will be utilized as part of the new Market Potential study to help inform decision making related to demand-side management." It is not clear how the NAICS data base can be appropriate for DSM and not be useful for load forecasting. It also is not clear that NIPSCO planned to make any improvements to the quality of NAICS data.

NIPSCO stated “the annual billed kWh for the most recent years of 2013 through 2015 and the partially projected year 2016 are quite consistent. NIPSCO had no information to support a diversion from the recent historical usage. Therefore, the partially projected year of 2016 was used as the annual forecast for all years of the IRP.” (*NIPSCO response to Director’s Question 11*) Accepting the reasonableness of the extrapolation of the usage by smaller industrial customers for this IRP due to a lack of data, NIPSCO should be alert to gradual – perhaps imperceptible in the near term – changes in this relationship.

Since NIPSCO’s industrial load forecast continues its past practice of projecting flat load beyond five years (*Pages 23 and 30 of NIPSCO’s IRP*), the impression is that NIPSCO is not planning for the possibility of new customers, expanded use from existing customers, existing customers leaving, or current customers reducing usage due to improved technologies or distributed energy resources. The long-term flat line projections do not seem credible and warrant better data to reduce the potential consequences of over- or under-forecasting. The Director recognizes NIPSCO’s over-reliance on informed opinion might be regarded as necessary because NIPSCO is in the somewhat unique position of having fewer than 1% of its customers accounting for more than 50% of its load. NIPSCO’s largest customers can cause very large swings in demand at any time and pose other significant risks to NIPSCO’s operations and planning. Nevertheless, it is the Director’s opinion that NIPSCO’s industrial forecasts are too heavily based on discussions between NIPSCO personnel and the industries.

NIPSCO’s high- and low-load growth cases methodology was discussed fairly well but it was still not entirely clear how the high and low cases were developed. Based on a follow up question from the Director, NIPSCO clarified the high and low cases were developed using the base equations and substituting the base economic data inputs from IHS Global Insight with the optimistic and pessimistic economic data from IHS Global Insight (*IURC Request 1-001*).

NIPSCO produces weather normalized historical energy forecast for residential and commercial loads but not the industrial sector. In response to a question from the Director about weather normalization and whether usage varies with weather for the industrial sector, NIPSCO contended that there was a very weak correlation between use and Heating Degree Days as well as use and Cooling Degree Days for its largest customers. In the Director’s opinion, given that this correlation exists, even if it is weak, it is probably a good idea to weather normalize the forecast so that future forecasts are not subjected to this criticism. If NIPSCO no longer has responsibility for the resources of its largest customers, it may be that the usage of the next tier of large customers will have a higher correlation with HDD and CDD.

NIPSCO’s forecasts for Public Authority, Railroads, Company Use, and Losses are forecast using current consumption levels and anticipated trends. Street Lighting is now forecasted with a monthly econometric model that uses the number of hours of dark and an auto regression which allows previous months’ street lighting energy consumption to help explain future months’ consumption. However, it is not clear how new or improved technologies are integrated into the load forecast. As LEDs and smart lighting increase

their penetration, it would seem appropriate for NIPSCO to give consideration of these in its forecasts of lighting needs by Public Authorities.¹¹ Recognizing that much of the change is replacing less efficient lighting with LEDs, at some time in the future, the rate of LED penetrations seems likely to diminish. NIPSCO, in response to a question from the Director, stated:

The anticipated future trends considered by NIPSCO are related to the conversion of streetlights in the Company's service territory to light emitting diode ("LED") lights from high pressure sodium ("HPS"). As part of its current Transmission, Distribution, and Storage System Improvement Charge (TDSIC) plan, NIPSCO is replacing all Company-owned lights with LED lights, but has not considered any other "smart" advancements such as auto-dimming at this time. Many municipalities are also transitioning customer-owned HPS lights to LED lights. Because of this, NIPSCO has seen an increase in the number of LED streetlights and expects that trend to continue. This has been factored into the forecasting. Of the 41,764 Company-owned streetlights on NIPSCO's system, 10,344 have been converted to LED streetlights. (*IURC Request 1-013*)

Because NIPSCO's discussion of forecasting customer-owned resources had virtually no specifics, we are left to speculate that cogeneration and small power production is treated as merely a reduction in the reliance on NIPSCO's resources. It isn't even clear that NIPSCO is acquiring load data, price responsiveness, demographics and other information that could be used in forecasting these types of customers.

The increasing penetration of EVs has the potential to change the trajectory of electric use. DERs also have implications for future electric use. These, and potentially other technologies, highlight the increasing interrelationships of the distribution system with NIPSCO's IRP, NIPSCO's distribution system planning, and the MISO. All of these planning functions need to know the location and operational characteristics of EVs and all forms of DERs. The Director encourages NIPSCO to develop its forecasting processes to better anticipate all forms of DERs and EVs and their potential beneficial and non-beneficial operational and locational attributes. To its credit, NIPSCO, in response to a question from the Director, stated: "It continues to monitor trends regarding distributed energy resources" but NIPSCO offers no plan to develop sufficient data for a long-term forecast. The Director hopes NIPSCO will recognize not only the transformation of the resource mix but also possibly a paradigm change in the use of electricity.

B. Demand-Side Management and other Distributed Energy Resources

¹¹ In NIPSCO's responses to question 12 posed by the Director, NIPSCO stated that "For street lighting customers, as part of the Transmission, Distribution, and Storage System Improvement Charge (TDSIC) Plan, NIPSCO is replacing all company-owned high pressure sodium (HPS) with LED streetlights. Most municipalities are also converting customer-owned lights to LED streetlights. Therefore, ultimately, most of the streetlights in NIPSCO's service territory will be LED lights and there will be a leveling off of the savings to be achieved from that sector.

NIPSCO contends that energy efficiency (EE) is integral to its short- and long-term resource planning. To this end, NIPSCO has devoted considerable analytical effort to understand the value proposition for energy efficiency.

Promoting energy efficiency not only is good for customers, it can play an important role in helping ensure that we can meet future energy needs. NIPSCO offers a variety of programs to help residential and business customers save energy. The programs are tailored to customers and designed to help ensure energy savings. Since 2010, NIPSCO customers have saved more than 1 million megawatt hours of electricity by participating in the range of energy efficiency programs offered by NIPSCO. Technologies continue to change, and it's important that we constantly evaluate our offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings. *(Page 6 of NIPSCO's IRP)*

NIPSCO uses third party vendors to implement the cost-effective EE programs. Lockheed Martin is the vendor selected to implement two programs - one for residential and one for commercial and industrial sectors for the period 2019 through 2021. The 2019-2021 plan filed with the Indiana Utility Regulatory Commission by NIPSCO includes the projected energy savings and total program budget (accounts for implementation, NIPSCO administration and marketing, and evaluations, measurement and verification by year) for each of various EE residential and C&I programs. *(Page 65 of NIPSCO's IRP)*

For the DR component of DSM, NIPSCO offers Riders and Rates to allow customers to exercise some control over their electricity costs by accepting some level of interruptions and/or curtailments. The DR programs are intended to reduce electric usage during periods of high demand when electricity is more costly and/or reliability is at issue. *(Pages 73 and 74 of NIPSCO's IRP)*

GDS Associates (GDS) was retained by NIPSCO to prepare the DSM Savings Update Report to determine the DSM resource potential. This GDS report updates DSM program costs and savings for the period 2019 through 2048. GDS reviewed the latest information available from the NIPSCO 2016 Market Potential Study ("MPS") and other reports, which were used as input for the 2016 IRP. For modeling EE and DR programs in this IRP, GDS grouped DSM program measures into bundles. EE programs were bundled according to each measure's cost of saved energy over its measure life. DR program bundles were calculated using the levelized cost per cumulative kW over 30-year lifetime program. *(Pages 74-75 of NIPSCO's IRP)* In a response to a question from the Director, NIPSCO stated:

...[its] portfolio analysis in the IRP evaluated supply side and demand side options on equal footing when assessing future resource needs, and two of the demand side management (DSM) bundles were found to be economic versus many other alternatives, while the third DSM bundle and additional demand response (DR) bundles were not selected in the modeling. *(NIPSCO's Response 1-024)*

For the 2018 IRP, GDS updated several inputs and assumptions with respect to the 2016 IRP's assumptions. GDS used a new load forecast to calculate the percent of electric MWh

sales and peak demand saved each year by DSM programs. GDS also updated the general inflation rate estimates, escalation rates for NIPSCO electric rates, the utility discount rate, line losses by class of service, and NIPSCO's planning reserve margin (*Page 76 of NIPSCO's IRP*). GDS also reviewed and updated, where appropriate, the assumptions for measure costs, savings and useful lives included in the existing 2019 to 2021 NIPSCO DSM plan. The largest adjustment for a measure assumption was to the baseline EE level for residential light bulbs using a new efficacy standard for lightning. This change was expected to decrease the achievable potential for lightning savings. (*Page 77 of NIPSCO's IRP*)

The DSM Savings Update Report also takes into account the impacts of federal appliance and equipment efficiency standards that are currently in place or expected to be implemented by the U.S. Department of Energy after 2021. In comparison to the 2016 IRP, in this one, several new additional residential and commercial and industrial EE measures were added to the 2019-2021 Plan by GDS based on the NIPSCO's 2016 MPS, NIPSCO's stakeholders' recommendations, and/or the Utility Cost Test. In the current IRP, unlike the prior IRP, program administrative costs were not included in the process of calculating cost effectiveness of the programs at the measure level. Then, after determining the cost effectiveness of the EE programs, they were grouped into three bundles for the energy efficiency base case scenario for residential and C&I customers. Five DR options were considered to realize the demand reductions from eligible customers during the highest load hours but three were modeled. (*Page 91 of NIPSCO's IRP*)

The potential demand savings estimates of these programs are based on program performance of current or past programs and on secondary research for new programs. The Interruptible Rider impact was scaled to match actual program performance or take an average of existing and past program performance from programs in the state. Finally, the per-customer load reductions, mainly obtained from the 2016 MPS, were used for estimating the potential reductions of these programs.

After identifying all the EE and DR programs from the MPS and the DSM Electric Savings Update processes, NIPSCO conducted an in-depth review to determine the achievable amount of savings for its service territory. Following this review, NIPSCO incorporated the three EE bundles and three DR bundles into a model to be selected across all six portfolios of the IRP. (*Page 93 of NIPSCO's IRP*) For this 2018 IRP, Aurora XMP's ¹² modeling capabilities allowed these bundles, previously organized by cost, to be treated equally with other supply resources for a potential selection in the portfolio optimization model across

¹² NIPSCO made the following characterization of the Aurora XMP model: "The Aurora model performs 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 produces projections of asset level dispatch and the total variable costs associated with serving load. It also produces estimates for other key metrics, such as carbon dioxide ("CO₂") emissions over time and capacity and generation by fuel type. The Aurora output is then used by CRA's 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 produces annual and net present value estimates of revenue requirements." (Page13 of IRP)

all six portfolios. (*Page 93 of NIPSCO's IRP*) Specifically, in response to question from the Director, NIPSCO stated:

The following provides an overview of the sequencing of events in the analysis and how the demand side management ("DSM") bundles were compared with other resources:

- Three energy efficiency and three demand response ("DR") bundles were constructed as part of the DSM study. As discussed on p. 93 of the 2018 IRP, "NIPSCO incorporated 3 energy efficiency DSM bundles and 3 DR bundles into the model for selection as resources. As defined above, energy efficiency measures were bundled according to each measure's cost of saved energy over its measure life and the DR programs were bundled by calculating the levelized cost per cumulative kW over the 30-year lifetime of the program." Two sets of bundles were developed, one for residential measures and another for commercial and industrial measures. The bundles were then aggregated together into the three cost-based bundles for energy efficiency and DR. Appendix B to the 2018 IRP specifies all annual costs and annual savings for each bundle.
- All six bundles were available to the Aurora model in the portfolio optimization process. The bundles were defined with an annual projection of costs and annual peak and total energy savings. The bundles had unique hourly shapes for energy savings.
- Across all of NIPSCO's retirement and replacement analysis, all bundles were available for selection on equal footing with the various supply-side options that were evaluated.
- NIPSCO found that the low-cost and mid-cost energy efficiency bundles were selected across all retirement portfolios and all replacement portfolios. Neither the three DR bundles nor the high-cost energy efficiency bundle were selected. NIPSCO focused its presentation of results in the stakeholder meetings and on p. 160 of the IRP on the energy efficiency bundles given that they were selected and given that they represented larger savings than the DR bundles. However, all six bundles were evaluated and available throughout the analysis.

In summary, NIPSCO optimized all six bundles, rather than just two, with other resource options and found that two were highly competitive on a cost basis. All DSM options were, therefore, evaluated as comparably as possible to all other resource options.

The 2018 IRP differs from the 2016 IRP in significant ways. In contrast to the above summary, the 2016 IRP selected 22 EE groupings and four DR DSM groupings which were broken down into various end uses and optimized against an array of supply-side options using Strategist®. This was done because this software did not have the ability to optimize

all 26 DSM groupings simultaneously. Finally, the expected peak load and total energy sales savings for this IRP are selected from the bundles optimally chosen by the model. Figure 4-4 on page 50 depicts the contribution of NIPSCO's demand-side management programs¹³ to Resource Adequacy. DSM includes demand response and energy efficiency programs but DR programs are the largest component of MW reduction created by DSM as a whole.

>>>Director's Comments - Demand Side Management and Other Distributed Energy Resources

NIPSCO's energy efficiency evaluation process seems to be well reasoned, but more rigorous analytical treatment should be conducted for other Distributed Energy Resources in future IRPs. It is essential to develop methodologies that accurately model all DERs based on dynamic changes in the cost of power. It was noteworthy and gratifying that NIPSCO gave effect to the proposal advanced by the Citizens Action Coalition of Indiana, Inc., Earth Justice Indiana, Distributed Energy Association, Sierra Club, and Valley Watch (CAC Joint Commenters) to model EE.¹⁴ The fact that NIPSCO's treatment of EE and the CAC Joint Commenters' proposed treatment of EE resulted in similar outcomes seems to be a good indicator that the two processes were reasonable.

The Director asked NIPSCO to address the two different approaches to modeling EE and its results. The following is NIPSCO's Response to that question:

NIPSCO does agree that the different approaches for demand side management (DSM) suggested by the Citizens Action Coalition of Indiana, Inc. ("CAC") and by NIPSCO yielded similar results. With regard to the similarities in approach, NIPSCO has identified the following:

- Both approaches rely on a need to specify DSM energy efficiency parameters for evaluation in a detailed portfolio modeling tools (such as Aurora).
- Both approaches rely on cost savings to be calculated for the entire portfolio in an integrated portfolio modeling framework, inclusive of avoided energy and capacity costs.

¹³ NIPSCO currently has three Demand Response programs described as (1) an interruptible offering under Rider 775 whereby large industrial customers can sign up to offer interruptible service used for both economic and reliability reasons, (2) a Demand Response Resource offering under Rider 781 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy, and (3) an Emergency Demand Response Resource offering under Rider 782 allowing industrial customers the opportunity to offer a load reduction into the MISO Market as energy for use only during emergency operations. (Andrew Campbell, Testimony in Cause 45159, Page 33).

¹⁴ The Director is aware that CAC - Joint Commenters believe NIPSCO only "performed a truncated version" of CAC- Joint Commenters' proposed EE methodology. CAC Joint Commenters also questioned NIPSCO's capping the EE decrements at the potential identified by NIPSCO's market potential study and used decrements that were too large. CAC Joint Commenters also noted that NIPSCO did not make this analysis a formal part of its IRP. (Page 14 of CAC Joint Commenters' Comments)

- Both approaches appear to rely on a net present value cost and benefit calculus.

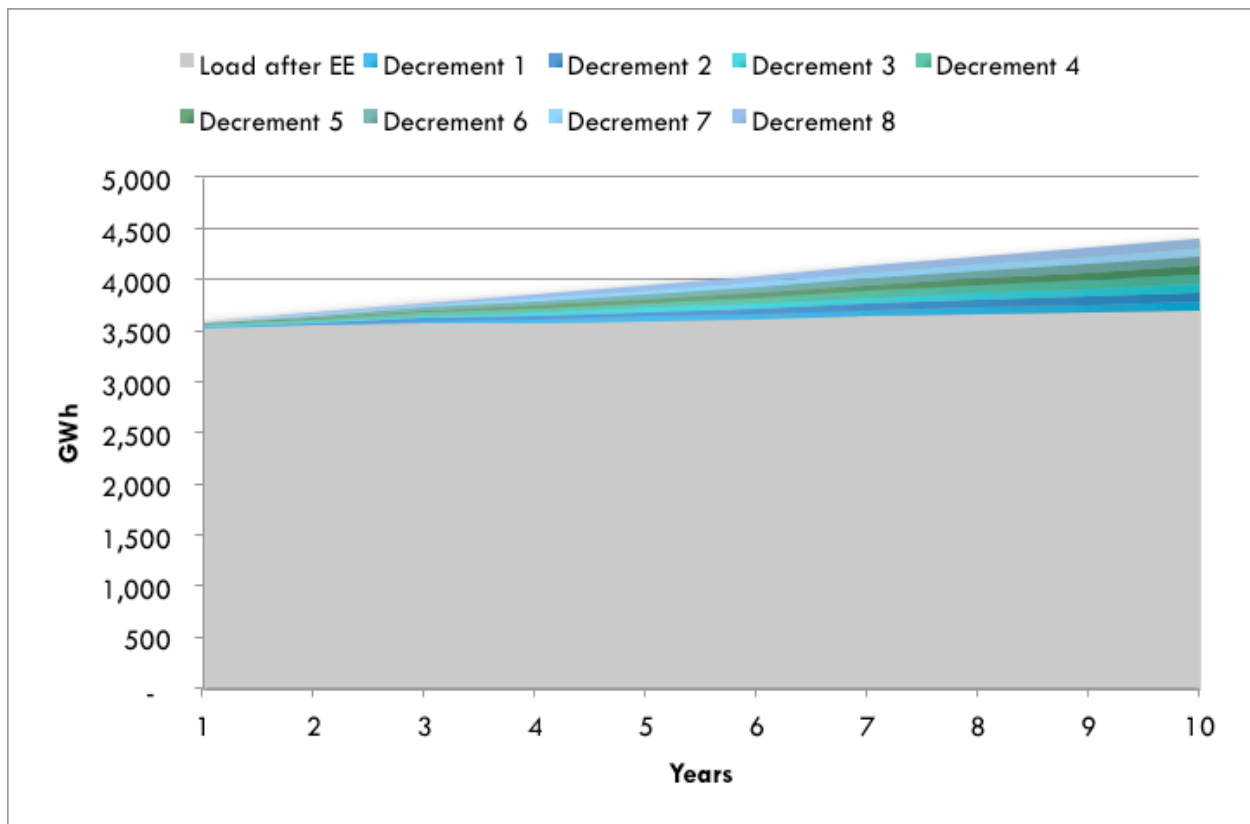
In the October stakeholder meeting on Page 2, NIPSCO and Pat Augustine identified some key differences in the two approaches. A comparative table from that stakeholder presentation is provided below. Overall, the differences fall into the following categories:

- How to quantify savings to evaluate – NIPSCO’s approach identifies and develops specific bundles; CAC’s approach is agnostic to the size of bundles and can evaluate any decrement.
- How to quantify costs associated with savings; NIPSCO’s approach identifies and develops annual costs for each bundle of savings; CAC’s approach does not require any cost inputs to be developed (only savings are recorded).
- Resource selection – NIPSCO’s approach allows for DSM bundles to be “selected” in IRP models in portfolio development; CAC’s approach would appear to record savings and then be able to conclude that any decrements with savings greater than costs should be part of the preferred portfolio.

	NIPSCO 2018 IRP	Decrements Approach
EE/DSM input development – energy savings	GDS Associates, Inc. (“GDS”) study identified 3 bundles based on a bottom-up program review, organized by cost	Could use decrements of any size (but NIPSCO preserved 3 bundles for hourly shape integrity in its decrements evaluation)
EE/DSM input development – cost	GDS study produced cost estimates for each bundle by residential or commercial and industrial sector	No cost estimates are required, but savings can be compared to costs, as available
Resource selection process	Aurora portfolio optimization evaluates energy efficiency /DSM bundles on equal footing with other supply-side resources (as determined by the request for proposal responses)	No “selection” of resources, as decrements are all “hard-coded” to record savings
Evaluation criteria	Net present value revenue requirement (“NPVRR”) within IRP structure	NPVRR of savings, with potential to move cost-effectiveness questions into more detailed DSM study phase

NIPSCO’s aggregation of EE into selectable bundles for modeling, while an improvement over the more traditional approach to modeling EE of subtracting EE and DR impacts from the load forecast and then optimizing only using supply-side resources, is not without methodological questions. The construction of the bundles necessitates the development of a single common load shape encompassing residential, commercial and small industrial end-uses in each bundle. While the formation of some type of aggregate load shape is necessary for this method of modeling EE for optimization analysis, it raises questions about the development of the common EE load shape. Even if the bundles were predicated on the highest load savings achievable in a given hour, there is still an assumption of significant homogeneity that may not capture important differing end-use load characteristics. The long-term treatment of EE is even more problematic because it suggests that, within the individual bundles and for the comparison among all the three bundles, there will be similar load shapes over the 20-plus years. The CAC Joint Commenters’ decrement approach ¹⁵ was developed as a means to address what it sees as a

¹⁵ The CAC Joint Commenters and their consultants (referred to as the CAC), like NIPSCO recognizes that it is difficult to project DSM over several years and particularly over the 20 year planning horizon. The CAC Joint Commenters took issue with NIPSCO’s achievable potential claiming that it is based on adoption rates rather than best practices. As a result, adoption rates will not increase unless there is an incremental increase in the cost of electricity. [Ms. Anna Sommer’s presentation at the 2018 Contemporary Issues Technical Conference]. The CAC Joint Commenters suggested an “avoided cost decrement approach” (referred to as the decrement approach) that would incorporate EE avoided cost benefits not included in the IRP such as transmission and distribution related costs. (*CAC Joint Commenters’ Comments on NIPSCO’s IRP*)



problem of relying on long-term estimates of EE market potential. The decrement approach developed by CAC Joint Commenters is a reasoned alternative (or supplement) to other methods in an attempt to ensure all cost-effective EE is considered. However, the implicit assumption is that the load shape decrements assume a uniform percent that remains constant throughout the year, which strains credulity. If this is an accurate characterization, the problem could be ameliorated by more granular load shape information that depicts the changing load shapes with the year and for the planning horizon. A fundamental question is whether this methodology understates the value of certain end-use EE measures that provide savings when avoided costs are higher compared to EE measures that might save more energy when avoided costs are lower.

Both methods focus on the cost of the bundles which is a traditional and reasoned approach, but they may not give full effect to the discrete hourly or even sub-hourly changes in the value of EE, DR, and other DERs. For future IRPs, and in hopes of deriving a more efficacious methodology, consideration might be given to ranking EE, DR, and DER programs on their respective and unique values to the hourly or sub-hourly changes in the system load characteristics.

NIPSCO's method considered the DR bundles with the highest use days which gives some recognition to the general value of changing load shapes, but it probably is not sufficiently discrete (e.g., responding to the real-time value) to capture the real value of the load shape changes. (*Page 91 of NIPSCO's IRP*) The Director recognizes that NIPSCO does not have the requisite granular load data required to construct load shapes for different types of customers and at different times. However, the acquisition and maintenance of this data should be a high priority, regardless of the method used to establish the value of the resource.

The discrete usage information mentioned above should be combined with more customer specific information (e.g., surveys, by NAICS, information from pilot programs etc.). Given the uncertainties and risks that NIPSCO is confronting, it is incumbent on NIPSCO to significantly improve its databases, methodologies, and planning models (NIPSCO noted the limitations of Strategist to optimize multiple bundles as one reason to move to its new Aurora modeling system). There should be a sense of urgency because, depending on the type of data, it can take a few years to develop the appropriate databases.

For future IRPs, detailed customer information provides an opportunity for a broader discussion of value at the wholesale and distribution level which should inform the design of specific programs. Obtaining specific and detailed load data and constructing load shapes can also assure appropriate treatment for all EE, DR, and other DERs. The Director appreciates that the acquisition of better data can be expensive, but so, too, can be the risks of NIPSCO not knowing its customers as well as it should.

To reiterate from prior Director Reports, the Director recognizes that the question of how best to analyze DSM (DER, and renewables) is not unique to NIPSCO. Industry practices and methodologies are evolving with no agreed-on set of best practices. Thus a willingness to evaluate and possibly use different approaches to model DERs on a reasonably comparable basis to other resources may contribute to more informed results over time.

Overall, for this IRP, NIPSCO's energy efficiency evaluation process seems to be a significant improvement over past IRPs, but considerable work remains. It is gratifying that NIPSCO demonstrated a willingness to consider alternative approaches as evidenced by its analysis of the proposal advanced by the CAC Joint Commenters, but expeditious improvements in NIPSCO's databases is imperative.

C. Resource Optimization and Risk Analysis

Given the enormity of the decisions faced by NIPSCO, the Company appropriately devoted considerable effort to identify and assess potential uncertainties and their attendant risks in both the IRP and the all-source Request for Proposals. NIPSCO (*Pages 2 through 4 of the Executive Summary, Page 11, and Section 9, Pages 149 and 150 of NIPSCO's IRP*) identified some emerging issues and risks such as cost to customers, risks associated with serving a concentration of customers tied to a single industry, environmental stewardship, fuel security, impact on employees and the local economy, reliability, market risk, environmental regulations, and technological changes. NIPSCO's recognition of risks to the company and its customers were insightful and served as a road map for the IRP and RFP.

To better enable NIPSCO to address uncertainties and mitigate adverse risks in its IRP, NIPSCO retained Charles River Associates' (CRA) Auctions and Competitive Bidding practice to conduct the RFP in 2018. During NIPSCO's first Public Advisory meeting, an overview of the RFP design was provided to stakeholders and comments were solicited. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the RFP on May 14, 2018, and closed the window for proposals on June 29, 2018. Information developed through the RFP was a fundamental input to NIPSCO's IRP and was a significant factor in improving the factual basis on which NIPSCO's IRP analysis is based.

The risk and uncertainty analysis conducted by NIPSCO started with the development of a fundamentals-based set of key Base Case market drivers and assumptions. The major market assumptions for the base case and the scenarios were developed using a set of fundamental market models utilized by CRA, including the Natural Gas Fundamentals (NGF) model for natural gas price projections, the NEEM model for electric sector capacity expansion and retirement decisions and coal pricing, and the Aurora model for granular power price projections. NIPSCO's intent was to develop consistent commodity prices. (*Page 12 of NIPSCO's IRP*)

Scenarios and stochastics were used to assess risk and uncertainty. NIPSCO identified five major drivers of uncertainty, including commodity prices, especially for natural gas, power and coal, carbon cost, economic growth, NIPSCO load growth, and technology costs for new resources. After identifying the major drivers of uncertainty, NIPSCO then assessed whether they should be addressed through scenario or stochastic analysis. Three scenarios

were constructed by NIPSCO to supplement the Base Case. They are aggressive environmental regulation scenario, challenged economy scenario and booming economy & abundant natural gas scenario. Stochastic distributions were developed for natural gas and power commodity prices and evaluated in concert with the ranges established through a fundamental scenario development process. *(Pages 2 and 3 of NIPSCO's IRP)*

The portfolio development process was conducted first for a retirement analysis and then for a full replacement analysis. Portfolio optimization analysis was conducted with the Aurora XMP model's portfolio optimization tool to develop least-cost portfolio concepts under a variety of constraints. Both supply side and demand side resources were evaluated in the portfolio optimization framework. *(Page 12 of NIPSCO's IRP)*

After portfolios were constructed, each of them was evaluated in CRA's suite of resource planning tools, primarily Aurora and a utility financial model, PERFORM. An integrated scorecard methodology was used to evaluate retirement and replacement portfolios. Key planning objectives and specific metrics incorporated into the scorecard methodology were identified before running IRP analysis to avoid bias. The planning criteria used in the 2018 IRP included cost to customer, cost certainty, cost risk, fuel security, environmental stewardship, and impact to employees and the local economy. *(Page 13 of NIPSCO's IRP)*

Retirements of electric generating units pose unique modeling challenges. Until relatively recently, modeling retirements was more of an academic exercise since most of the large coal-fired generating units were built in the late 1960s through the early 1990s and, with plant-life extension, the traditional notion of a power plant's economic life-span changed. Also until recently, retirements of coal-fired units were likely replaced by coal-fired units. The dramatic change in the fuel markets, combined with precipitous declines in the cost of renewable resources, have been major factors in the new replacement analysis that also poses significant analytical and modeling issues. Of particular note, NIPSCO considered other risk factors such as reliability, effect on employees, and ramifications for localities, which are beyond the traditional objective function of minimizing the net present value of revenue requirements.

As in the 2016 IRP, NIPSCO performed a retirement analysis in its 2018 IRP to evaluate the preferred coal retirement strategy over time. Given the number of permutations around the magnitude and timing of potential retirements, NIPSCO determined that it was most efficient and effective to evaluate retirement decisions on a stand-alone basis, while performing an additional replacement analysis to assess a number of replacement resource strategies. Although performed in two steps, the retirement and replacement analyses are both based on the same major inputs and assumptions, which are described in earlier parts of Section 8 and below. NIPSCO believes that performing a retirement analysis requires careful planning and consideration of several factors in addition to the cost of generation. To that end, NIPSCO has used an integrated scorecard methodology to evaluate retirement portfolios. In addition to the net present value of revenue requirements in the Base Case, NIPSCO has also considered cost certainty and cost risk metrics based on a full stochastic analysis, the ability to confidently transition resources and maintain

system and customer reliability, and the effect of unit retirements on NIPSCO's employees, the local economies of the communities it serves, and the environment.
(Page 145 of NIPSCO's IRP)

>>>Director's Comments - Resource Optimization and Risk Analysis:

NIPSCO conducted an unbiased and reasonably comprehensive analysis of potential risks in formulating its IRP. However, the cost uncertainty focuses on higher costs and seems to ignore risks of lower costs. Integrating the RFP and the IRP provided realistic price assumptions about resource options, which added to the credibility of the IRP. This effort is a solid foundation for future IRPs and RFPs.

NIPSCO conducted a reasonably thorough analysis of risk and uncertainty using a two-step process to first review the potential alternative unit retirement combinations and then develop potential replacement resource portfolios. The results of each step were evaluated using a scorecard of performance metrics with some variation, depending on if it was the retirement or a replacement portfolio stage. Retirement scorecard metrics included the following:

1. Cost to Customer measured by the overall net present value of revenue requirements (NPVRR);
2. Cost Certainty measured the certainty that the NPVRR falls within the 75th percentile of cost to the customer in the stochastic analysis.
3. Cost Risk measures the unacceptable, high-cost outcomes and is quantified by the 95th percentile of cost to the customer in the stochastic analysis.
4. Reliability Risk assessed NIPSCO's ability to confidently transition its portfolio of resources and maintain customer and system reliability. This measure considered the activities and timelines, and 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.
5. Other factors such as the loss of work for employees and property tax base.

The Director appreciates the necessity and qualitative nature of the assessment required to properly account for Reliability Risk. It is exactly this type of assessment that is critical when evaluating the retirement and replacement of one or more generation facilities. This does not mean that quantification is not desirable, but rather that it is often difficult (or impossible). Much can be done with a thorough discussion of the elements that make up a particular metric and how it interacts with the interpretation of other metrics. Nevertheless, the Director encourages quantification when reasonably possible and appropriate. For future IRPs, the Director urges NIPSCO to be clearer on how the likelihood of the various scenarios were derived or how they generated separate distributions for each scenario.

As a part of the retirement analysis, NIPSCO performed preliminary studies to evaluate the impact of the 2018 IRP preferred retirement path that calls for retirement of Schahfer units 14, 15, 17, and 18 by 2023 and replacement with primarily wind and solar/storage resources in central and southern Indiana. The studies identified five separate transmission upgrades to address reliability impacts with a high level cost estimate of \$150 million included in the replacement portfolio analysis.

The purpose of the replacement portfolio analysis was specifically designed to address several key planning considerations. The first consideration was built around the commitment duration of specific resource options; e.g., is the commitment five years or less, or something longer? Power purchases can be of a shorter term while utility owned options are usually multi-decade commitments. The second consideration was built around the potential portfolio's diversity with regard to carbon emission intensity. NIPSCO decided that replacement portfolio concepts could be evaluated across two duration levels (shorter and longer) and three diversity levels (all fossil fuel replacements, a mix of fossil and renewable replacements, and all renewable replacements). Thus NIPSCO explored the implications of six different resource replacement portfolios. The evaluation of each portfolio necessitated the models be constrained in some manner but it appears stochastic analysis was only used for natural gas and power price uncertainties and ignores technology and load uncertainty. Ignoring the uncertainty of future technology costs might understate the variance for the scenarios with a large renewable portfolio (C and F) in the replacement analysis on page 159.

The Replacement Scorecard metrics differed from those in the Retirement Scorecard. The Replacement Metrics included two not in the Retirement Metrics and excluded one metric. The new metrics included fuel security, defined as the percentage of capacity sourced from resources other than natural gas, and environmental intensity, defined as the total carbon emissions from the full generation portfolio in 2030. The Retirement Metric excluded from the Replacement scorecard was the reliability risk metric.

The lack of an explicit reliability risk metric in the scorecard does not mean the potential future risks associated with a replacement portfolio heavily reliant on renewable resources is not recognized by NIPSCO in the IRP. On pages 176-178 of NIPSCO's IRP, there is a good discussion in which NIPSCO acknowledges that system planning with renewable resources is more complex than with dispatchable resources, and that assumptions based on today's market constructs may ultimately change. NIPSCO believes the path it has outlined in the IRP is one with low regrets because the resource plan provides flexibility to adjust as circumstances warrant.

Furthermore, NIPSCO recognizes that its planning for future resources is inseparable from developments in the broader MISO markets, operations, and planning processes. NIPSCO explicitly references changes to the MISO ancillary services market as examples, renewable resource availability/capacity credit forecasts, seasonal market constructs, etc. The Director appreciates NIPSCO's recognition that this places a significant burden on it to monitor and regularly evaluate in future IRPs and resource acquisition processes how changing circumstances might affect future resource decisions.

Despite the reasonableness of the two-stage analysis, both its rationale and the implementation, the Director would have liked to have seen a resource optimization with the timing of retirements and replacement options minimally constrained. We recognize that there are good reasons why the resulting portfolio might be unreasonable, but it still would have been a useful point of comparison.

Among the MISO activities that NIPSCO must monitor closely is MISO's Resource Availability and Need analysis process. This was initiated with a whitepaper¹⁶ that raised concern that reliability issues are increasing and could occur at any time throughout the year. As a result, the traditional reserve margins based on NIPSCO's contribution to the MISO's maximum annual demand is not the only reliability metric that is important for future IRPs and RFPs.

Increased electric rates may dampen sales of electricity, but there is a longer-term potential that electric vehicles will, over time, alter the trajectory of NIPSCO's load forecasts. Significant penetration of EVs may, however, cause significant changes in the timing and magnitude of the peak demands, which could compromise reliability and increase costs to other customers. Offering price signals that better reflect the wholesale market's real-time price should assure cost-effectiveness. The Director agrees with NIPSCO that the penetration of electric vehicles is very low now. However, it is important for NIPSCO to establish a baseline so the next IRP can more accurately address how NIPSCO intends to influence customer usage for the mutual benefit of its customers and the electric system.

Future reliability concerns, maintaining resource optionality, and minimizing rate increases will be significantly hampered if NIPSCO does not improve its load forecasting and the resulting inability to adequately anticipate the future electric characteristics of its different customers. The paucity of both quality and the quantity of fundamental information also adversely affects NIPSCO's ability to credibly evaluate, measure, and verify energy efficiency, demand response, the operational characteristics of other diverse distributed energy resources, and new technologies like electric vehicles.

While every utility will, to varying extents, struggle with the same issues, NIPSCO's unwillingness to improve its customer knowledge is somewhat unique to NIPSCO compared to the other four investor-owned utilities that are installing Advanced Metering Infrastructure to enable more discrete (shorter time intervals) and end-use load research. As discussed in the Load Forecasting critique, NIPSCO would also benefit from more precise characterizations of the diverse commercial class of customers by establishing and maintaining accurate North American Industrial Classification System data, conducting customer surveys for commercial and residential customers, and integrating distribution system planning with IRP and information from the MISO. The Director urges NIPSCO to reconsider the following statement.

¹⁶ Resource Availability and Need – Issue Statement Whitepaper, March 30, 2018.

More discrete load shapes for each class and for differences within the rate class would improve the efficacy of the demand side management (“DSM”) and distributed energy resources (“DER”) analysis, but that must be balanced with complexity of gathering such granular customer information that is not readily available and the costs associated with doing so. NIPSCO will continue to evaluate the costs and benefits of more discrete load shapes for these programs and will make adjustments as appropriate. In addition, NIPSCO’s new market potential study will include data from end-use surveys which will provide more information for NIPSCO to utilize as it develops DSM offerings. NIPSCO is monitoring trends in DER and will continue to assess how best to analyze how those resources impact its system. IURC Request 2-002

NIPSCO is commended for advancing the use of stochastic analysis in combination with scenario analysis. Because probabilistic analysis is often more complex than scenario analysis, the Director urges NIPSCO to continually refine the narrative to describe the integration of stochastic and scenario analysis as a means of providing additional insights into long-term resource planning. This effort should also enhance the development of “scorecard” to better assess the different portfolios. The Director is appreciative that NIPSCO realized the importance of greater stakeholder involvement in the development of the metrics used in the scorecard.

NIPSCO had an excellent stakeholder process. NIPSCO had an exemplary degree of transparency; this is not to say that the degree of transparency could not still be enhanced. NIPSCO encouraged a robust stakeholder process that allowed stakeholders to actively participate in the construction of scenarios and offer their own scenarios. NIPSCO agreed this was worthwhile. The Director is gratified that NIPSCO incorporated “lessons learned” and has confidence that it will continue to further enhance the stakeholder process.

IV. FUTURE ENHANCEMENTS TO NIPSCO’S IRP PROCESSES

NIPSCO and its stakeholders recognized the difficulty of constructing meaningful, internally consistent, and objective scenarios. NIPSCO made a significant effort to mitigate those difficulties. As NIPSCO explained:

[S]cenarios and stochastics serve different, but complementary, purposes in the analysis of uncertainty in an IRP. NIPSCO will aim to provide further commentary on how stochastic analysis provides value in future IRPs and will consider additional narrative regarding some of the key elements of the process:

- Which variables lend themselves to stochastic analysis treatment vs other scenario approaches?
- More illustrative example of stochastic iterations and how they are different from deterministic price paths.
- Fuller description of the interpretation of probability distributions and the interpretation of output results. (*NIPSCO’s response to Question 3-007*)

NIPSCO has improved its forecast and recognized the need for future improvements and specifically mentions Distributed Energy Resources. NIPSCO's response to the Director's Question 2:

NIPSCO plans to explicitly analyze scenarios around different DER futures in the load forecasting exercise in its next IRP. Furthermore, NIPSCO plans to evaluate DER resources as supply side options more directly in its next IRP. This analysis will require additional review of various cost and benefit streams for DERs. The potential benefits would include energy, capacity, and ancillary services value, along with potential attributes associated with avoided transmission and distribution investment costs and other reliability and avoided line loss values. Lastly, NIPSCO plans to examine its current distribution system planning processes that are largely deterministic forecasts around peak load, to a probabilistic approach that incorporates stochastics and time series analysis to account for reliability as well as DER adoption and usage.

NIPSCO's integration of an actionable Request for Proposals was very farsighted and added significant credibility to the IRP. As a result of the combination IRP and RFP, NIPSCO appropriately recognized that for NIPSCO's future resource mix, maintaining maximum flexibility was a reasonable pursuit, based on the information available at the time. During stakeholder meetings, Charles River Associates and NIPSCO provided an excellent discussion of the risk and uncertainties that are particularly suited to stochastic analysis (*Pages 141 through 144, Section 8.4 – IRP Stochastics Development*). The stochastic analysis, along with reasonable scenario analysis, fostered greater confidence in the results of NIPSCO's IRP. The Director appreciates the integration of risk analysis into IRPs is not easily understood so NIPSCO's offer to provide additional explanations of the application of risk and uncertainty in future IRPs is most welcome.

NIPSCO's recognition that DERs may have significant positive and, potentially, negative implications for NIPSCO's distribution system planning and operations, combined with its ongoing planning work with MISO (*e.g., Pages 96 and 97 of NIPSCO's IRP*) should add impetus for NIPSCO to more fully integrate all aspects of resource planning.

Continual improvements in NIPSCO's forecasting data and processes would be appropriate. NIPSCO still relies too heavily on interviews with the customers (i.e., the New Business Team and Major Accounts Department), and it considers industry-sector level information and macro-economic information in developing its final forecast for each customer without any clarity as to how this data is used. It also does not seem to appreciate the need for more granular load data (e.g., AMI), the need to conduct well-designed periodic surveys of appliances/end-uses and obtain demographic data, and group customers into more homogenous groups by usage, and type of customer (e.g., NAICS). In two separate responses to the Director, NIPSCO stated: "NIPSCO has not directly considered that household demographics might be changing. However, indirectly, changing household demographics are part of NIPSCO's regional models." and "The NAICS codes in NIPSCO's database are not sufficiently accurate to use for demand forecasting."

Improvements in load forecasts would also foster advances in all aspects of DSM and other Distributed Energy Resources, and new technologies such as Electric Vehicles.^{17 18}

Optionality is important. The Director concurs with NIPSCO's overall resource planning methodology and the intention to maintain flexibility in future resource decisions to make course corrections if necessary. It is clear that, barring an unexpected paradigm change, the retirement analysis was appropriately tied to competitive wholesale and retail market signals. The value of the actionable Request for Proposals was significant. In response to Resource Optimization and Risk Analysis Question 9, NIPSCO said the lessons learned were invaluable and will be reflected in future RFPs.

Future IRPs will build on lessons learned from the 2018 IRP. In a specific response to a question posed by the Director, NIPSCO stated:

NIPSCO will use the 2018 IRP results to continue to target new renewable procurements in the near-future and will explore enhancements to future RFPs that allow for fuller participation of new resource options. This might include the incorporation of more distributed energy resource options and demand side resources. Such efforts might include modifying the scoring metrics as well as the IRP models to appropriately value such resource options. There are other enhancements NIPSCO is considering or planning as discussed in other responses to the Commission's questions. NIPSCO welcomes any feedback the Commission has in how it can continue to improve its IRP process.

NIPSCO appreciated the opportunity to share the lessons learned during the recent IRP Contemporary Issues Technical Conference. During that presentation, NIPSCO discussed three primary categories of lessons learned. These included:

- Communication with bidders;

¹⁷ As NIPSCO correctly stated on page 4 of their reply comments: "In the future, changing market constructs may require more granular analysis of capacity value, as well as an understanding of value associated with sub-hourly market operations, ancillary services, and distributed energy resources. NIPSCO will monitor these market trends and advance its modeling accordingly." The Director continues to urge NIPSCO to make a concerted effort to increase the information about their customers by developing a comprehensive load research program that includes end-use and DER operational data, conducting appliance /end-use surveys, obtaining demographic data, developing and maintaining North American Industrial Classification System (NAICS), developing industry specific forecast data, performing DER pilot projects, etc.

¹⁸ NIPSCO's response to question 21: "NIPSCO continues to discuss the use of residential and commercial customer survey, but has not elected to do so at this time. This will continue to be discussed as appropriate.

A. As part of the demand forecasting process, NIPSCO has not considered conducting end-use load research. However, NIPSCO is conducting end-use surveys as part of the next market potential study for demand side management.

B. As part of the demand forecasting process, NIPSCO has not considered segmenting customers by NAICS. The forecast is impacted by how much and when customers use electricity and does not find the end-use to matter in developing the forecast. However, it could be useful in developing demand side management programs. As such, data regarding end-use customers will be utilized in the next market potential study."

- Management of data from the RFP into the IRP; and
- Communication with IRP stakeholders

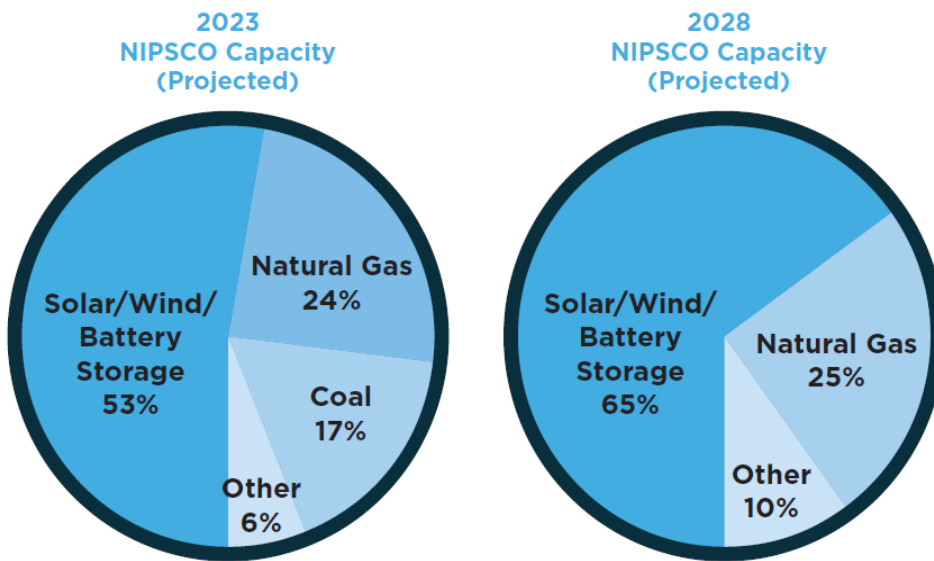
Slide (19) from NIPSCO’s presentation during the 2019 IRP Contemporary Issues Technical Conference on April 15 summarized these major lessons learned from that presentation is below:

Ensuring bidders understood the integrated process was critical in order to yield aggressive, market-based bids and pricing
<ul style="list-style-type: none"> – An integrated IRP / RFP timeline will be longer than a standalone RFP – Bidders need to be informed of the process timeline and understand the constraints
Management of data between IRP and RFP phases was critical
<ul style="list-style-type: none"> – Need to consider approach for organizing bid data early on in the process – IRP and RFP teams need to be highly coordinated (yet independent) – Data should be organized to allow for a range of portfolio concepts
Stakeholder engagement throughout the process was important
<ul style="list-style-type: none"> – Buy-in on process and format of the RFP was valuable for the bidders to assure that a future transaction was likely – Understanding of how the data was being used in the IRP helped provide stakeholders confidence in the analysis

NIPSCO’s scenario and risk analysis was well done. Market drivers were clearly identified. Projections of the market drivers were reached through solid analysis and modeling. The basic assumptions used to produce projections of market drivers are consistent with those used in the optimization model. Both scenario and stochastic analysis were used to evaluate risk and uncertainty. Portfolio analysis started with retirement analysis, followed by replacement analysis. Each portfolio was evaluated across scenarios and against the 500 sets of stochastic inputs. The integrated scorecard method was employed to make portfolio comparison straightforward, which lead to the selection of the preferred portfolio.

To reduce uncertainty and mitigate financial and reliability risks, NIPSCO’s issued its all-source RFP. The resource costs from the actionable RFP were reasonably integrated into the IRP. This provided a more realistic valuation of resource costs and a good vehicle for minimizing NIPSCO’s investment in capital intensive resources while maintaining adequate reliability.

With so much at stake resulting from the transformation of NIPSCO’s resource mix, NIPSCO’s use of outside consultants to assist with commodity price forecasting for coal, natural gas, MISO market projections, and a range of potential emission allowance prices was very appropriate. The following graphic depicting the potential change in resources is on page 6 of the ES. This type of visualization is very helpful for the Commission and stakeholders.



Given the risks and uncertainties, NIPSCO should make an aggressive and concerted effort to improve its knowledge of its customers. This would be reflected in NIPSCO’s load forecasts and its assessment of all forms of DERs. The potential changes in the composition of resources, especially DERs, make coordination of the operations and planning of the distribution system, the IRP, and the MISO imperative.

V. STAKEHOLDER COMMENTS

(Director’s responsive comments are indented and in italics):

The Director is pleased with the extraordinary public input which is, in large part, due to NIPSCO’s stakeholder process, the increased rigor of NIPSCO’s analysis, NIPSCO’s reliance on the 2018 IRP as NIPSCO’s actionable resource plan documenting the significant investments and risks, and the recognition by stakeholders of the importance of this IRP as evidenced by the quality of comments and the analytical effort of stakeholders. It is also noteworthy that NIPSCO’s IRP represents the first time a utility has integrated its IRP with an actionable Request for Proposals (RFP) which provided empirical pricing information that substantially enhanced the credibility of NIPSCO’s analysis. The following comments are intended to be a representative sampling of the public input into NIPSCO’s 2018 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.

**Comments on NIPSCO’s 2018 Integrated Resource Plan
Citizens Action Coalition (CAC), Earth Justice Indiana, Distributed Energy Association
(IndianaDG), Sierra Club, and Valley Watch (CAC Joint Commenters)**

Commenters recognized the improvements in NIPSCO's IRP processes that gave effect to comments raised in prior Director's Reports and stakeholders. Commenters also noted that continued improvements should be made to enhance the development of scenarios, development of market potential studies for energy efficiency, and reliability analysis.

We acknowledge and commend the substantial leadership demonstrated by NIPSCO in its current IRP analysis – including an array of best practices, such as: conducting an all-source request for proposals (“RFP”) to inform model inputs which gives NIPSCO an unusual level of credibility from which to the forecast the cost of utility-scale, supply-side generators; transparent inclusion of input forecasts, outputs, and assumptions; a thorough description of most aspects of screening and portfolio selection; and fair consideration of a wide range of supply-side alternatives without arbitrary limitations on the amount of those resources that can be selected or unsupported cost additions. *(Page 3 of CAC Joint Commenters' Comments)*

Table 1 on page 5 provides an excellent summary that NIPSCO's IRP largely satisfied the requirements of the IRP Rule. With regard to energy efficiency, CAC Joint Commenters expressed concern that the Market Potential Study did not adequately capture large-scale shifts in end uses and load curves over the 30-year planning horizon. The CAC Joint Commenters also stated that NIPSCO's IRP did not provide sufficient detail for the energy efficiency bundles. CAC Joint Commenters were concerned that scenarios were constructed based on storylines that conflated ideas rather than explored explicit risks to NIPSCO. More specifically, CAC Joint Commenters question the meaning and import of NIPSCO's alternative scenarios and finds them to conflate unrelated characteristics into irrelevant storylines.

Director's Response: The Director is appreciative of the very detailed analysis of NIPSCO's IRP prepared by the Commenters and largely agrees with Commenters on both the significant improvements in NIPSCO's IRP and the need for continued improvement in the development of scenarios, sensitivities, risk analysis, and modeling of energy efficiency and other Distributed Energy Resources (DERs).

The decremental approach offered by the CAC Joint Commenters has spurred an important conversation about the methods for modeling energy efficiency. Consistently, over the last several IRPs, the CAC Joint Commenters has made a concerted effort to improve the IRP processes generally and energy efficiency most specifically. However, the Director notes a continued lack of consensus on how utilities should develop energy efficiency bundles and integrate energy efficiency into the IRPs to compete with other resources on as level a playing field as possible.

Historically, utilities merely subtracted their Demand Side Management (DSM including EE and Demand Response) from the load forecast and optimized the supply-side resources based on the reduced load forecast. One of the concerns is that the CAC's decrement method is similar in at least one respect to the historic approach in that it would be based on reductions in forecasted load approach. To be clear, we understand the rationale is different in that it seeks to show how much DSM is viable. Another concern is that the CAC Joint Commenters' approach does not necessarily result in the

most cost-efficient (highest value) selection of DSM programs. The valuation of DSM raises a third concern. Specifically, if we understand the CAC Joint Commenters' approach correctly, is the use of a consistent load decrement throughout the year which may over-state the value of EE in some periods and understate the value in other periods. Especially if consistent load shapes are used throughout the year for EE, it raises a fourth concern about how the decremental approach interacts with the characterization of other DERs with differing and unique contributions to changing load shapes. As a result, it is possible that the contributions of EE may be improperly comingled with other DERs. Of course, the Director recognizes that NIPSCO and other utilities thus far have had little substantive analysis of other DERs in considerable part because of other DERs minor impact to this point.

It seems likely that developing more accurate load shapes using discrete (hourly and sub-hourly) load data should improve the modeling of energy efficiency (and other DERs) and, as a result, alter the debate on how best to model energy efficiency and other DERs. To this end, the Commission staff will be working with Lawrence Berkeley Laboratory (LBNL), utilities, and stakeholders on projects that may advance the modeling of DSM and other forms of DERs.

In summation, throughout NIPSCO's extensive stakeholder processes, the Commenters have made significant contributions. The Director is very appreciative of the Commenters well-written and comprehensive comments. In particular, the efforts made by the CAC Joint Commenters to stimulate thinking on the important topics of modeling energy efficiency and, by extension, other distributed energy resources is a significant contribution to the IRP process. The Director recognizes the significant investment, the dedication, analytical skills, and expertise that the CAC Joint Commenters have brought to bear.

**Clean Grid Alliance's (CGA) and American Wind Energy Association's (AWEA)
Comments Regarding Northern Indiana Public Service Company's 2018 Integrated
Resource Plan**

Comments by CGA and AWEA addressed a number of points including that NIPSCO's wind cost assumptions were valid; that NIPSCO should use verified third-party data sources; and that NIPSCO is correct to focus on MISO's ongoing changes to renewable resource capacity factors because these values will likely affect the value stream of resources selected after 2023.

CGA and AWEA placed particular emphasis on NIPSCO acquiring and appropriately using the best data available. "As a result of reviewing third-party sources and incorporating its All-Source Request for Proposals ("RFP") results into its Integrated Resource Plan ("IRP") input assumptions, NIPSCO's current wind cost assumptions are valid. NIPSCO took an appropriate first step in screening third-party sources for new resource cost and operational parameter estimates. In particular, the National Renewable Energy Laboratory ("NREL") Annual

Technology Baseline (“ATB”) is one of the most comprehensive, and accurate, resources for energy resource inputs, and is used by regional transmission organizations (“RTO”) including the Midcontinent Independent System Operator (“MISO”) in their planning processes.” *(Page 2 of CGA and AWEA Comments)*

NIPSCO also acted prudently in conducting an All-Source RFP process to further inform the IRP. RFP results provide up-to-date information on the cost and performance characteristics of wind energy available in the regional market. With those results NIPSCO was able to evaluate multiple configurations for renewable resources with different performance levels and pricing assumptions. Further, the RFP results reduced uncertainty associated with any significant cost assumption ranges that showed up in the third-party screening. *(Page 2 of CGA and AWEA Comments)*

NIPSCO developed multiple cost tranches based on the RFP results, including two PPA tranches for standalone wind projects, one PPA tranche for wind/solar/storage projects, one asset sale tranche for standalone wind projects, and one asset sale tranche for wind/solar/storage projects. The two cost assumptions for standalone wind PPAs were \$25.54/megawatt hour (“MWh”) and \$38.11/MWh, with \$28.68/MWh assumed for hybrid projects. All assumptions are based on being available to serve customers by 2023 and account for use of the federal Production Tax Credit (“PTC”). LBNL reports taking advantage of the 100% PTC value reduces onshore wind levelized cost of energy (“LCOE”) by approximately \$15-\$19/MWh. This cost reduction is reflected in the LBNL Annual Wind Technologies Market Report, which shows the national average price for wind PPAs signed in 2017 to be less than \$17/MWh. In the Great Lakes region, including MISO Local Resource Zone 6, recent PPA prices average \$33/MWh. This price aligns with the midpoint between the two PPA tranches identified by NIPSCO for standalone wind projects. In addition, NIPSCO assumed a \$1,486/kW asset sale price for standalone wind projects, with \$1,406/kW assumed for hybrid projects. This assumption is consistent with third-party sources. The 2018 NREL ATB reports an average capital cost of \$1,579/kW for U.S. onshore wind projects installed in 2018. The average capital cost can be considered a proxy for asset sale price, as it incorporates all expenditures required to achieve commercial operation, including wind turbine materials, balance of system, and financial costs. *(Pages 3 and 4 of CGA and AWEA Comments)*

Director’s Response: The Director agrees with CGA and AWEA that NIPSCO (all utilities) consistent with the IRP Rule’s requirement for on-going improvements, should continually review their methods, databases, and analytical tools.

In this regard, the Director appreciates CGA’s and AWEA’s discussion on pages 10-11 of their comments that NIPSCO should closely monitor opportunities to more accurately evaluate both the capacity and energy services provided by renewable resources. As renewables become a greater share of the resource portfolio (and DERs become more impactful) it will become necessary to better understand the operational impacts of resources on a sub-hourly basis.

NIPSCO could satisfy this growing customer demand with a well-designed green tariff program allowing eligible customers to buy a bundled renewable energy product from specific renewable energy projects... NIPSCO currently offers the Green Power Program, in which participating customers pay a surcharge on their retail electricity bill to cover 25%, 50%, or 100% of their monthly electricity demand with Green-E Certified RECs purchased by NIPSCO. This program, however, does not offer customers the opportunity to purchase a bundled renewable energy product, or to realize the benefits that would come from said product, such as being able to enter into a long-term contract that hedges against future fuel price volatility. *(Page 15 of CGA and AWEA comments)*

Director's Response: Again, consistent with the IRP Rule's continual improvement directive, the Director agrees with CGA and AWEA that NIPSCO (like all utilities) should continually consider improvements in rate design. The rapid transformation in NIPSCO's resource mix makes it imperative to continually reexamine rate design. While discussion of the merits of specific rate designs are appropriate in IRPs, it is not a function of the Director's Report to advocate any specific rate re-design. Because of the complexities, rate redesign is a matter best suited to a rate case or, perhaps, well-designed and limited pilot programs.

INDIANA COALITION FOR AFFORDABLE AND RELIABLE ELECTRICITY (ICARE) COMMENTS ON NIPSCO'S 2018 INTEGRATED RESOURCE PLAN

ICARE argues that there are numerous methodological, data, and assumption errors that undermine NIPSCO's IRP analysis and results. Beginning on page 1 and continuing to page 3 of the ICARE's critique, based on ICARE's witness' testimony, Mr. Charles Griffey's testimony in Cause No. 45159, states:

...[T]aking these combined flaws into account, NIPSCO's IRP does not demonstrate that its preferred resource portfolio is a reliable, efficient and cost-effective way to meet electric system demand, nor does its analysis properly consider the appropriate costs, risks and uncertainties. Ultimately, these flaws appear calculated to produce a result in which NIPSCO prematurely retires its coal generation fleet and replaces it with expensive new renewable resources...A major flaw in the IRP is that NIPSCO justifies the coal plant retirements by comparing the cost of its coal fleet portfolios against resource portfolios it has no intention of using. This is a bait and switch. *(Citation needed)*

ICARE contends: "Notwithstanding, NIPSCO's own analysis—unadjusted for any errors—shows that, in every scenario, the portfolio wherein Michigan City 12 operates until 2035 is economically preferable to the Preferred Portfolio F that NIPSCO recommends, by hundreds of millions of dollars..." *(Page 4 of ICARE Comments)*

The *Director's Final Report for the 2016 IRPs* noted that 'NIPSCO performed much of the retirement analysis prior to the resource optimization,' and also indicated that 'NIPSCO recognized the modeling limitations and said it intends to procure modeling software that is better able to simultaneously optimize more resources and reduce the reliance on pre-processing important decisions.' Two years later, NIPSCO has engaged in the same type of analysis—one that is insufficient... (Page 6 of ICARE Comments)

Director's Response: The Director will not address the data and assumption related questions here but instead will focus on the more significant methodological issues raised by ICARE. The largest criticism appears to be ICARE's belief that the two-stage retirement and replacement portfolio analysis is fundamentally wrong.

ICARE accuses NIPSCO of using a bait and switch in which NIPSCO uses replacement options in the retirement analysis that it does not intend to use in the resource replacement analysis. But NIPSCO makes clear in the IRP the reasons for performing the resource replacement analysis using the six resource combinations (labelled A-F) the company developed. When ICARE compares one resource portfolio from the retirement analysis to a resource portfolio in the replacement analysis, ICARE is failing to recognize the two portfolios have been developed for entirely different purposes. It is difficult for bias to exist where the purpose for performing an analysis a particular way is clearly stated in the IRP and at public stakeholder meetings.

In response to ICARE, NIPSCO stated "A single - round optimization approach, on the other hand, would have resulted in early retirement of all coal units as soon as possible and a replacement with cost optimized renewable resources. By not taking this approach, NIPSCO was able to evaluate the tradeoffs of different retirement timings and different replacements that incorporated different amounts of gas and renewable resources and incorporated different ownership and contracting opportunities (owned resources versus different PPA commitment durations). ICARE's efforts to compare portfolios from the two stages of NIPSCO's analysis ignores this fact as well as the point that NIPSCO found that early coal retirements were cost - effective whether replaced with MISO market purchases or renewable resources based on RFP bids." (Page 5 of NIPSCO's Reply Comments)

ICARE also raised a number of questions that might be broadly classified as to questioning whether NIPSCO reasonably accounted for renewable resource characteristics that will probably change and how these characteristics might impact system operations and costs over time. Among these are the possibility of increased congestion and transmission costs, increased ancillary services costs, and changes to the effective load carrying capacity (ELCC) of renewable resources. For example, ICARE noted that NIPSCO's IRP has not included any estimate of higher ancillary service costs from portfolios that rely primarily on renewable resources. As more renewable resources are added to the MISO system, NIPSCO may see higher costs as MISO procures more spinning reserve, non-spinning reserve and regulation reserve products to fill in the gaps left by intermittent resources. Utilities elsewhere have

estimated the cost of additional ancillary services to support renewables. There is no reason for NIPSCO not to perform such estimates in its IRP. *(Page 12 of ICARE Comments)*

Director's Response: The Director agrees with ICARE that additional renewable resources may require additional ancillary services. However, NIPSCO routinely procures ancillary services from the MISO market. Moreover, projecting the timing, cost, type, and characteristics of specific future ancillary services – over the relevant planning horizon for these decisions - is a significant undertaking which could easily strain credulity. More generally, NIPSCO acknowledged in the IRP and its reply comments that long-term resource planning with a heavy dependence on renewable resources is complex and requires considerable attention to how technology, economics, and RTO operations and markets are changing and the need to understand how these changes might affect resource decisions over time. Another consideration is that NIPSCO's analysis supports a measured acquisition of resources over a period of time that allows for the ability to change direction in the type of resources being acquired if circumstances warrant.

ICARE was concerned about NIPSCO's use of a 30-year planning horizon as being too long and inconsistent with the IRP rule.

Director's Response: The Director appreciates ICARE's confusion about going beyond the IRP's required 20-year planning horizon. The Director agrees with NIPSCO's explanation discussed below:

"[T]he use of a 30-year NPVRR is used to account for the life of assets that are depreciated over a long time horizon. As is standard practice in utility resource planning, "end-effects" extrapolations like this are often performed to extend the analysis time period in order to account for the value of long-lived assets and the relative difference in portfolio costs that have developed after 20 years of fundamental modeling." (Citation needed)

The Director would also observe that ignoring end-effects could bias the decision against capital intensive facilities. That is, long-term resource planning models may not select a capital intensive resource near the later years of a 20-year planning horizon.

INDIANA COAL COUNCIL'S (ICC) COMMENTS ON NIPSCO 2018 INTEGRATED RESOURCE PLAN

The load forecast, which is an underlying foundation for the IRP, will radically change if the IURC approves the new large industrial rate structure proposed in the Rate Case. As a result, the load forecast in the IRP is no longer relevant and should not be the basis of any subsequent decisions. The IRP should be withdrawn, corrected, and resubmitted. *(Page 1 of the ICC's Comments)*

Director's Response: The Director agrees that it would have been helpful if NIPSCO had more explicitly thoroughly examined a scenario in which the industrial load was significantly reduced as a result of service restructuring. But the Director also believes the ICC unreasonably understates the value of NIPSCO's Challenged Economy scenario which was based on a large reduction of industrial load followed by very slow growth. Optimization of the Challenged Economy scenario showed that retiring coal early and replacing with renewable resources was beneficial.

The ICC alleges that "NIPSCO's IRP is biased against continued operations of remaining coal plants calling into question its conclusions... NIPSCO was indifferent to considering a path that would have mitigated rate shock on customers by determining what could be done to maintain existing coal capacity as long as possible." (Page 2 and Page 8 of ICC's comments reiterates the assertion)

Director's Response: The Director found no basis for ICC's statement that NIPSCO's analysis was biased. To the contrary, NIPSCO has a long history of reliance on coal. For NIPSCO, and all Indiana utilities, the use of coal-fired generation has historically served Indiana well and the transformation of the resource mix has been a difficult paradigm change.

As a stakeholder, the ICC requested NIPSCO make specific modeling runs based on the ICC's specifications of assumptions. To NIPSCO's credit, they obliged as follows:

NIPSCO transparently shared the fundamental drivers of its scenarios in its initial public stakeholder meetings, introduced a robust stochastic analysis to broaden the range of uncertainties considered in the 2018 IRP, and analyzed customized scenario inputs offered by stakeholders, including the ICC. Interestingly, the ICC's comments are silent regarding the customized assumptions for coal prices, carbon prices, natural gas prices, and environmental capital expenditures that it requested NIPSCO evaluate, as the comments focus only on NIPSCO's core four scenarios. In ICC's customized scenarios, which all address its perceived issues with NIPSCO's four IRP scenarios, the preferred portfolio of retiring coal early was lower cost than retaining the units longer. ICC has not disputed the results of NIPSCO's analysis of these customized scenarios, nor has it pointed out any flaws or concerns with the calculations. Therefore, NIPSCO considers the claim of bias to be without merit, especially considering that all scenario assumptions were transparently shared early in the IRP process and that all requests for alternative analyses were completed in a timely fashion and included in the IRP submitted on October 31, 2018. (Page 6 of NIPSCO's reply comments)

The Director agrees with NIPSCO that the salient point is, even using the ICC's assumptions, the results did not refute the general conclusions reached by NIPSCO.

The Director agrees with the ICC that different scenarios and assumptions that had reasonable probabilities of occurrence may have marginally altered NIPSCO's analysis but the Director is highly skeptical, barring a scenario that was composed of combinations of extremely low probability events, that NIPSCO's analysis would have

altered the fundamental conclusions. For example, the ICC took issue with the construction of the Challenged Economy Scenario:

“[T]he Challenged Economy Scenario assumes slow economic growth with zero carbon pricing. NIPSCO was specifically asked why this was done when the two are unrelated. NIPSCO agreed the comment was fair (which can only be interpreted that NIPSCO agreed the two are unrelated.” (Page 8 of ICC’s Comments)

The real question is whether the totality of NIPSCO’s scenario analysis combined with the probabilistic analysis provides a sufficient range of possible futures to understand how different resource portfolios might perform under a range of futures. The CAC Joint Commenters also had concerns with the alternative scenarios develop by NIPSCO but then concluded “NIPSCO’s development of future scenarios allows for an unbiased assessment of coal unit retirements.” (Page 34 of CAC Joint Commenters’ Comments)

As noted above, the Director also thinks ICARE and ICC unreasonably undervalued the usefulness of the information provided by the Challenged Economy scenario. One does not have to concur with the specifics of each scenario but rather should focus on the totality of the analysis performed and the openness with which it was undertaken. Both of which is unsurpassed by another Indiana utility up to this time.

The Director’s overarching concern is the on-going need for NIPSCO and all Indiana utilities to redouble their efforts to construct meaningful and logically consistent narratives to explain the rationale. Despite NIPSCO’s exemplary stakeholder engagement, eliciting greater stakeholder involvement in the initial stages of scenario development would be beneficial. With regard to the Challenged Economy scenario mentioned by the ICC, the Director agrees with ICC that NIPSCO could have constructed logical scenarios with more combinations of coal and natural gas prices (or other resources). (Page 8 of ICC Comments).

However, the range of scenarios was sufficient for this IRP. Consistently, the Director has encouraged utilities to provide a reasoned narrative to explain specific scenarios and NIPSCO’s narratives were reasonable. NIPSCO provided not only alternative scenarios that have reasonable possibilities of occurrence but lower probability risks. This is not to say that NIPSCO could not do more in assessing potential risks in future IRPs but the Director is satisfied that NIPSCO’s scenarios captured most of the relevant risks, especially in the near term. NIPSCO’s long-term resource planning retained considerable optionality to make course corrections if there are substantial changes to the drivers of future resource decisions.

To NIPSCO’s credit, they handled the ramifications of the difficult resource decisions with considerable sensitivity. Even if some believe there was bias, the relevant question is whether NIPSCO’s analysis was unduly biased. Over the two IRP cycles and the several stakeholder meetings where the data, assumptions, and scenarios were painstakingly vetted, there was no evidence that NIPSCO deliberately constructed the analysis to produce the results contained in the IRP. In sum, NIPSCO’s analysis was objective.

NIPSCO failed to consider customer rate impacts despite the IURC's requirement that the IRPs describe how the utility plans to deliver safe, reliable, and efficient electricity at just and reasonable rates." A NPV comparison is not a proxy for rate analysis. "NIPSCO should prepare an annual rate analysis for residential customers under all scenarios as part of the IRP. (Page 1 and 2 of ICC Comments)

Director's Response: The Director thinks that NIPSCO's calculation of projected annual revenue requirements for all scenarios and portfolios within the IRP provides a reasonable indicator of future rate levels. The purpose of a long-term resource optimization process is to compare the relative economics of different resource portfolios over many years. NPVRR is the standard industry tool to appropriately make such a comparison when combined with consideration of other characteristics that are important to resource decisions such as risks and uncertainty. The Director also disagrees with the ICC's request for NIPSCO to conduct an annual rate analysis because it is not clear what ICC means. It is possible to estimate at a high level indicative average class (residential, commercial, and industrial) rates but more specificity is problematic for reasons noted below. IRPs typically develop equations where the objective function is to minimize the NPVRR and NIPSCO's analysis addresses NPVRR and other metrics. The Director also agrees with NIPSCO that, to the best of our knowledge, the use of NPVRR as a metric was not challenged by the ICC throughout the stakeholder process.

Moreover, as noted by the CAC Joint Commenters (Page 28 of Reply Comments), the algorithms that would be necessary to integrate into the IRP models to project future rates are difficult to design; especially since cost of service studies and resulting rate designs are very transitory and subject to rate cases that may produce unexpected outcomes. Even for a utility that anticipates little change in infrastructure or other costs, it is difficult to meaningfully speculate on rate design over a 20 year planning horizon. By way of examples, it is difficult to speculate on the type of rate designs that might be offered to increase energy efficiency, demand response, and DERs. For utilities, like NIPSCO, that anticipate significant changes to their infrastructure, requiring annual rate analysis would be extraordinarily difficult, time consuming, costly and with little merit.

The Director understands that it would be a nice feature if there was a feed-back loop through which the planning models calculated a rate or price derived from projected costs resulting from a resource portfolio with the new rate being feed into the load forecast to recalculate the resource optimization. The iterations would continue until there is some degree of convergence in the prices used to develop the load forecasts and the prices resulting from the resource portfolio being reviewed. It is the Director's understanding that such an iterative process is not a normal part of the long-term resource planning models available on the market so an iterative approach would have to be an add on created by the utility or its consultants. Based on the modeling system description included in the IRP on pages 10-13, no such feedback loop was included. To the Director's knowledge such a feedback iterative process is only used by the SUFG.

Again, such an iterative process would be a nice methodological improvement but is not currently widely done across the industry.

MIDWEST ENERGY EFFICIENCY ALLIANCE (MEEA)

An alternative to trying to forecast specific use and costs for efficiency measures is using ‘generic’ blocks of energy efficiency with an escalating cost curve – the ‘decrement approach’ discussed in some of the stakeholder meetings. We saw a version of this used in Vectren’s 2016 IRP and we think it was a useful approach that should be explored further in future IRPs. *(Page 2 of MEEA’s Comments)*

Director’s Response: The Director is gratified that MEEA participated in the NIPSCO’s stakeholder process and provided comments. MEEA’s identification of the difficulty in developing an efficacious method for calculating energy efficiency and, by extension, all Distributed Energy Resources, may be the most vexing analytical problems confronting long-term resource planning. It is premature to suggest that any current method provides the correct method, with increasing computational capabilities it is possible to better optimize energy efficiency, demand response, other forms of DERs, and renewable resources with traditional utility resources. The use of Advanced Metering Infrastructure (AMI) provides an opportunity to provide more granular usage data that may better reflect the value of all forms of DER and renewable resources. To this end, the Commission staff is working with LBNL on projects that, if successful, will advance the objective of accurately characterizing the contribution of DERs and renewable resources. The Commission staff would welcome MEEA’s involvement.

In our comments on the previous NIPSCO IRP, we had concerns about over-screening of energy efficiency through the MPS – concerns that were somewhat alleviated by the changes in methodology for the 2018 Savings Update. MEEA hopes that NIPSCO will continue to refine the ways that it determines the energy efficiency potential that it uses in its IRPs. *(Page 3 of MEEA’s Comments)*

Director’s Response: The willingness by MEEA to remain involved in the IRP process is most appreciated. As noted in prior comments, the development of a more efficacious means of modeling energy efficiency, demand response, other Distributed Energy Resources and renewable resources is an elusive but critical quest.

“As the TRM v.2.2 continues to age, it will be important for the utilities and the Commission to establish a process for developing ongoing periodic updates to a statewide TRM.” *(Page 3 of MEEA Comments)*

Director’s Response: The Director concurs that this should be a priority for all interested stakeholders. The TRM provides a foundation for DSM planning, IRPs, and EM&V to establish the performance of EE and DR over time which is an important input to future DSM development and IRP processes.

**OFFICE OF UTILITY CONSUMER COUNSELOR (“OUCC”)
COMMENTS ON NORTHERN INDIANA PUBLIC SERVICE COMPANY’S
2018 INTEGRATED RESOURCE PLAN**

The OUCC commentary is complimentary of NIPSCO’s consideration of DSM but was skeptical of the DSM estimates for projections through 2048. The OUCC was also supportive of NIPSCO’s use of Aurora XMP for long-term resource planning but had reservations that the retirement of resources may have been sub-optimal (*Page 3 of OUCC’s Comments*). The OUCC deemed NIPSCO’s issuance of an All-Source Request for Proposals as “useful.” (*Page 3 of OUCC’s Comments*) The OUCC recognized that utilities may consider factors beyond the lowest Net Present Value of Revenue Requirements in selecting the utilities preferred plan. (*Page 4 of OUCC’s Comments*)

Director’s Response: The Director agrees with the OUCC that DSM estimates through 2048 may not be realized. As the OUCC correctly points out, the truism that short-term forecasts are more credible than long-term forecasts but that giving effect to DSM, over the entire planning horizon is necessary because DSM will always be an element of any resource mix.

“All other things equal, the OUCC would prefer that the lowest cost portfolio be selected. When other factors are considered, it is not always unreasonable to select a higher cost portfolio. Additionally, this result, was supported under the three scenarios modeled and in the stochastic analysis conducted.” (*Page 4 of OUCC’s Comments*)

Director’s Response: While it is preferable to allow the long-term resource models to determine all resources and avoid putting a thumb on the scale, the analytics for retirement of resources is increasingly difficult. Historically, utilities tended to use the age of a resource as the basis for retirements. With plant life extension, there was widespread recognition that a more detailed examination was required. Now, objective retirement analysis has become significantly more complex with market dynamics (e.g., dramatic changes in relative fuel costs, the cost of renewable resources, the potential for distributed energy resources, and public policy), that result in very different perspectives on future uncertainties and risks for each utility.

Prior Director’s reports have emphasized it is the utility’s prerogative, under the IRP statute, to select their Preferred Plan, even if that plan does not result in the projection of the lowest NPVRR. That is, the IRP statute and rule recognizes that there are other factors beyond NPVRR that may be considered and tip the balance among competing resource portfolios. One such factor is the utility’s perception of risk (short and long-term). However, the Director agrees with the OUCC’s general contention that IRPs benefit from a clear rationale for departing from NPVRR.

The OUCC raised an important point about NIPSCO being dependent on a robustly competitive wholesale regional market that can readily accommodate NIPSCO resource acquisition decisions over time along with similar decisions being made by other utilities throughout the MISO region.

Given the essential nature of electric service, reliability is of the utmost importance and the OUCC raises concerns elsewhere in these comments about the practical ability to serve load with the high level of intermittent resources envisioned by NIPSCO. The OUCC also has concerns that MISO may change its rules pertaining to the valuing and treatment of intermittent resources if other utilities plan their systems in a manner similar to how NIPSCO has in this IRP. *(Page 5 of OUCC Comments)*

The high penetration of intermittent generating resources implies there will be a considerable amount of imported and exported power, depending on weather, seasons and the availability and price of external resources such as MISO. As renewables increase, transmission upgrades may also be required, costs which will likely ultimately be borne by ratepayers. The modeling conducted by NIPSCO shows a net amount of future power purchases from MISO and is similar to what NIPSCO sees in today's market. For economic reasons, NIPSCO currently supplies only 80% of its energy needs from self-owned generation. Due to the high cost of operating Schahfer and Michigan City, these units are sometimes not selected by MISO to run. Because today's market contains excess capacity and relatively inexpensive energy based primarily on thermal generation, NIPSCO can relatively easily acquire its other energy needs. *(Page 6 of OUCC Comments)*

*“The modeling assumes this overproduction is fully absorbed by the MISO market and purchases made to supplement intermittent or low production are always available.”
(Page 6 of OUCC Comments)*

Director's Response: Director concurs with the OUCC that the IRP planning processes should be informed by the regional planning processes conducted by the Midcontinent ISO and the PJM. Over the last few years, utilities seem to be better at reflecting a regional long-term resource planning perspective in their IRPs.

The Director concurs with the points made by the OUCC but has noted elsewhere in this document that NIPSCO itself in the IRP and in reply comments readily acknowledges the complexity of resource planning when the share of renewable resources in the portfolio is likely to grow throughout the region and the need to be ever vigilant to changing circumstances.

**PEABODY'S COMMENTS ON
NIPSCO'S 2018 INTEGRATED RESOURCE PLAN**

Peabody asserts NIPSCO's cost assumptions were exaggerated for compliance with the Coal Combustion Residual (CCR) Rule, and the Effluent Limit Guidelines (ELG), Mercury and Air Toxics Standards (MATS), the Cross State Air Pollution Rule (CASPR) capital costs, and O&M costs. (Pages 2 and 3 of Peabody's Comments)

Director's Response: The Director appreciates Peabody's concern that there is considerable uncertainty and attendant risks associated with speculating on future environmental compliance. To illustrate this uncertainty and risk:

"Given the uncertainty in the ELG regulations and the upcoming final rule in December 2019, it is difficult to pinpoint a numerical estimate as to what ELG compliance costs could be." (Page 6 Peabody Comments)

To mitigate the environmental compliance risks, NIPSCO has maintained considerable opportunities to make course corrections. Moreover, NIPSCO conducted sufficient analysis – including a portfolio with no new environmental capital costs for the coal units and determined that retirements provided significant savings - to attest that even significant reductions in environmental costs would not have dramatically changed the fundamental conclusions for early retirements.

To address Peabody's comments directly, the Director is not persuaded that NIPSCO over-stated the costs of environmental compliance (e.g., in Section 7 of NIPSCO's IRP). These topics were well vetted during the stakeholder process. Even if NIPSCO's estimates of on-going environmental compliance costs ultimately prove to be too high, NIPSCO made their assessment on the basis of the information available. It should also be remembered that the IRP Rule gives considerable deference to the utility management's expertise and experience. As such, the Director defers to NIPSCO's statement:

ICARE's and Peabody's concerns regarding cost assumptions for the ongoing operations of NIPSCO's coal fleet are not valid and don't raise any legitimate questions with projections developed by NIPSCO's experts who have extensive experience operating the plants and extensive knowledge of current and future environmental rules. For example, ICARE claims that capital expenditures for the coal units should be the same regardless of the retirement date. The Claim is without merit and demonstrates a lack of knowledge regarding the operation of large generating plants. Retiring a plant early reduces the expected maintenance capital that is required, due to a reduced need to continue investing the asset for long-term use... (Pages 8 and 9 of NIPSCO's Reply Comments)

Empirically, as evidenced by similar decisions of utilities throughout the region and nation, the immediate decisions and the tentative longer-range decisions were broadly consistent with market driven metrics (e.g., the projected frequency that specific units would be too often out of the money in regional dispatch to be economically viable). Consistently, prior Director's Reports have emphasized that no utility or stakeholder

should put their finger on the scale to bias the analysis to achieve a non-objective outcome.

VI. FINAL COMMENTS REGARDING NIPSCO'S 2018 IRP

Director's Response to CAC Joint Commenters and NIPSCO's Response to Other Stakeholders

A. CAC Joint Commenters' Comments on NIPSCO's Draft Director's Report

The Director agrees with many of the points raised by the CAC Joint Commenters and its consultants Ms. Anna Sommer and Ms. Chelsea Hotaling of the Energy Futures Group in its reply comments. The Director also appreciates the intellectual effort in developing the "decrement to forecasted load approach." However, the Director believes the CAC Joint Commenters, misunderstood the intention of the Draft Director's Report. Specifically, the Draft Report intended to express the opinion that neither the decrement nor the different bundling approaches accurately reflect the time value of energy efficiency (or other DERs, electric vehicles, and new technologies) and should not, therefore, be regarded *as being as good as it gets*. Consistent with the IRP Rule for continual improvements, our comments numbered below address both the current IRP and future IRPs.

1. Traditional bundling and the decremental approach have their merits and demerits. Both methods are largely constrained by data and computation capabilities. We understood comments from Ms. Sommer and Ms. Hotaling about the decrement approach is that it is only applicable to deriving the cost-effective level of EE rather than other DERs and is not intended to reflect the time-dependent value of EE. In other words, the decrement seems to be designed for a fixed (static) load shape for non-dispatchable EE. Of additional concern is that the decrement approach is not appropriate for modeling other DERs including DR and battery storage that are dispatchable and can be used to shift load or reduce peak demands depending on system conditions.
2. The Director believes that increasing use of more discrete information (e.g., AMI data) may over-come some of the current concerns about modeling of EE (or other DERs, EVs, and new technologies). The Director believes that transforming AMI and supporting information into load shapes, for a wide variety of customers, will provide detailed information about how and when customers use electricity. The Director agrees with CAC Joint Commenters that deployment of AMI and obtaining supporting data may take a few years to realize the benefits but we should expedite the process where reasonable. The real question is how best to use information that might be available from AMI data to better evaluate all resources, but especially EE, DR, DG, and DERs in general.
3. The Director appreciates the CAC Joint Commenters' recognition that stochastic analysis is appropriate for some but not all analysis as an additional perspective rather than a substitute for traditional scenario or sensitivity analysis. While the list of variables suggested by the CAC Joint Commenters has merit, it is assumed the CAC Joint Commenters' list was not intended to be all encompassing.
4. The time value of EE (and other DERs, EVs, and new technologies) should also be confirmed by enabling a more dynamic avoided cost analysis to be conducted.

With regard to the first observation, both the Joint Commenters and NIPSCO's approaches have their merits and demerits and all methods are largely constrained by data and computation capabilities. Based on the following comment on pages 5 and 6 from the CAC Joint Commenters' response and their cite to LBNL's work on the *Time Value of EE*, it appears we have common ground on the fundamental need for improved data and computational capabilities.

We are just not clear how one would use this information to significantly benefit the consideration of EE within an IRP. It may be that there is a middle ground here. We suspect that the Director is well aware of literature on the topic of the time-value of EE including Lawrence Berkeley National Laboratory's ("LBNL") report, "Time-varying value of electric energy efficiency." The authors conclude, not surprisingly, that:

[I]n both California and Massachusetts, savings with a residential air conditioning load shape have significantly more value than measures with other load shapes... Page 5 of CAC and Joint Commenters' Response to the Director's Report.

The Director believes the CAC Joint Commenters and NIPSCO would also agree with the following statement from LBNL below.¹⁹

Most energy efficiency measures produce energy savings that vary over the course of the year. The value of the hourly electricity savings also varies over the course of the year because the cost of generating, transmitting, and distributing electricity during peak demand periods may be significantly higher than during off-peak, or lower load hours... Furthermore, consideration of energy efficiency in electricity planning and programs has changed over time. A variety of trends are changing the electricity system, including increased adoption of other distributed energy resources, electrification of buildings and vehicles, and relative costs for natural gas-fired and renewable energy generation. Knowing **when** energy efficiency occurs and the **value** of the energy and demand savings to the electricity system – the time-sensitive value of efficiency – provides public utility commissions, utilities, and other decision makers with key information to procure the optimal value of energy efficiency for their system. For example, in the United States, changes due to increased adoption of distributed energy resources, technology cost reductions, and generation retirement make the time-sensitive value of efficiency critical to resource planning. {emphasis added}

¹⁹ Time-Sensitive Value of Efficiency: Use Cases in Electric Sector Planning and Programs, Natalie Mims Frick and Lisa Schwartz, November 2019. (Executive Summary, page viii)

The thrust of the LBNL papers²⁰ are to improve modeling of EE (as well as other DERs, EVs, and new technology) and IRPs generally. However, the Director would like to highlight another observation that could be derived from the LBNL study. Our shared goal should be to promote cost effective energy efficiency but not at the expense of resources that are more cost-effective. In this regard, the Director has concerns about the CAC Joint Commenters' comment:

[T]he decrements are intended to represent EE specifically and other DERs can be modeled separately.... (Footnote 5 on Page 2 of the CAC Joint Commenters' Response Comments)

The IRP Rule is clear that, to the extent possible, all resources should be evaluated on a comparable basis. This includes energy efficiency, all DERs, renewable resources, and more traditional resources. As such, it is preferable to work together to find a better method or a combination of methods that can treat all resources as comparably as possible. This is not intended to be dismissive of the excellent work that NIPSCO or the CAC Joint Commenters routinely provides. Rather, we hope the improvements in data, computational capabilities, and analysis will be evolutionary but expeditious.

Further, we interpret the graphic of I&M's normalized load and aggregated energy efficiency bundles²¹ as demonstrating that both the decrement approach and traditional bundling have

²⁰ <https://emp.lbl.gov/publications/time-sensitive-value-efficiency-use>. Natalie Mims Frick and Lisa Schwartz, Berkeley Lab, David Nemetzow, U.S. Department of Energy (DOE)

²¹ The I&M energy efficiency bundles (CAC's Response to Director's Draft Report on the NIPSCO 2018 IRP November 6, 2019, Page 4

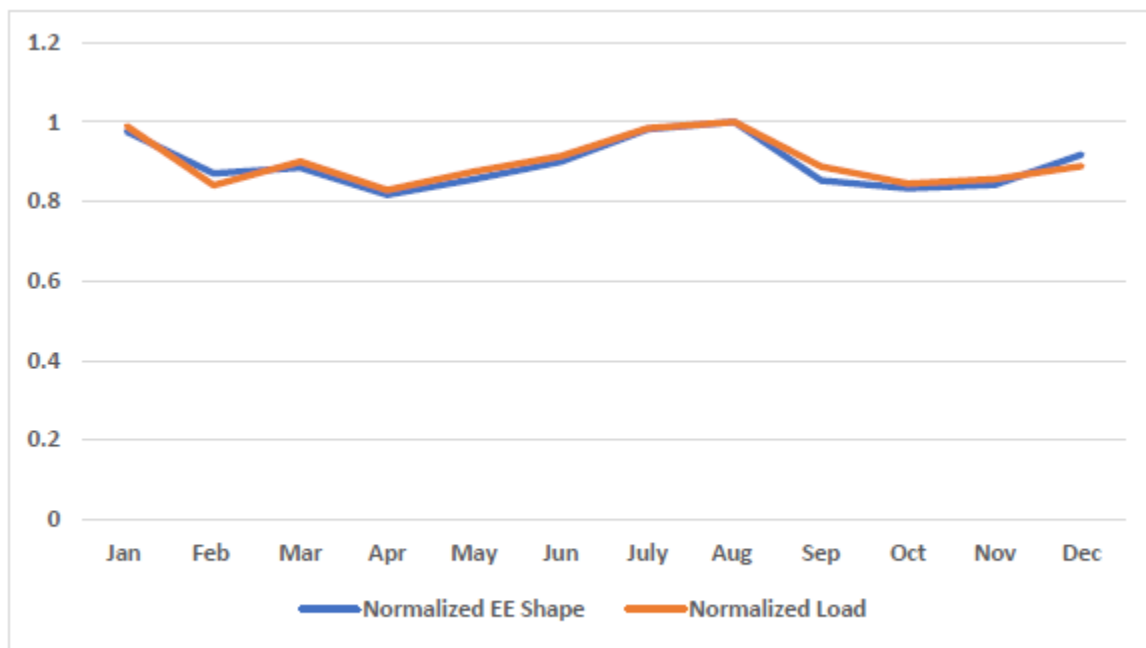


Figure 1. Shape of Normalized 2018 I&M Load and Aggregated EE Bundles⁷

similar results at an aggregated level but neither may accurately reflect the time value of energy efficiency or other DERs, electric vehicles, and new technologies. That is, the Director's interpretation of Figure 1 (footnote 21), may be different than the CAC Joint Commenters' and their consultants because the average monthly load data does not show the volatility of the hourly or sub-hourly loads. As a result of the smoothing effect of using more aggregated loads rather than hourly or sub-hourly loads, the value of EE savings are overstated during some periods and understated during other periods.

The second observation is consistent with the first observation. Specifically, the Director believes that increasing use of more discrete (i.e., hourly or, ideally, intra-hourly interval data) information from AMI data for total use and end-uses may over-come some of the current concerns about modeling resources for a very short but significant period to better capture the effects of volatility on market prices and system operations. It is also worth noting that, as evidenced by the MISO RAN analysis that these reliability concerns often occur randomly.²² Given the CAC Joint Commenters comments in support of developing hourly or sub-hourly load shapes the Director is surprised by the CAC Joint Commenters' comment:

“We do not believe the use case for AMI has been sufficiently developed in Indiana nor that it can be cost-effectively used to provide more information about EE or whom to target for EE measures where AMI does not already exist.” *(Page 6 of the CAC Joint Commenters' Response Comments)*

With regard to the Director's third observation, the Director appreciates the CAC Joint Commenters' recognition that stochastic analysis and scenario analysis are complimentary *(Page 7 of CAC Joint Commenters' Response Comments)*. The Director agrees it is possible that there could be over-reliance on either scenario analysis or stochastic analysis but, so far, the Director has not found an over-reliance on either. Moreover, the CAC Joint Commenters' list of variables that are most amenable to stochastic analysis seems reasonable but there should be an openness to including (excluding) specific variables.

We agree with the Director that “scenario and probabilistic analysis are complimentary rather than being substitutes.” We would go a step further and say that sensitivity and probabilistic analysis are complementary rather than substitutes and that not all variables of significance are appropriate for stochastic analysis. As we have stated in several pre-IRP stakeholder workshops, we strongly believe that stochastic analysis is appropriate only for variables with volatility, with randomness. Variables such as the capital cost of new resources are not volatile or random, but

²² The LBNL paper “Time-Sensitive Value of Efficiency: Use Cases in Electricity Planning and Programs” *Time-sensitive demand and energy value of efficiency require data on what devices (e.g., appliances, equipment, lights) are consuming electricity...These data are obtained through end-use load research...to obtain information on its demand on a sub-hourly, hourly, daily, weekly, monthly, seasonal, or annual basis. End-use load research is used for a variety of other electricity planning functions, including load forecasting, demand-side management and evaluation, capacity planning and demand response, IRP, renewable energy integration, smart-grid investments, rates and pricing, and customer service...Page 4*

uncertain. For IRP purposes, we think stochastics are best limited to market prices, fuel prices, and load. Furthermore, the probability distributions that underlie stochastic simulation are projections themselves and complex enough that they are often subjective, black box assumptions with significant implications for the overall IRP and preferred plan selection. For many variables that the Indiana utilities subject to stochastic analysis, e.g., carbon prices, the data does not reasonably exist to develop meaningful probability distributions. For all these reasons, we remain concerned about the overreliance on stochastic analysis amongst the Indiana utilities. [Emphasis added] (CAC's – Joint Commenters' Response to the Director's Report, Page 7)

The Director's fourth observation is an elaboration on the first two observations that the time value of EE (and other DERs, EVs, and new technologies) would benefit from a more dynamic avoided cost analysis. The Director and the CAC Joint Commenters seem to be in agreement that continued exploration of methods to better calculate the avoided costs is prudent. The Director is confident the CAC Joint Commenters would agree that avoided costs are dynamic and difficult to quantify, in large part, due to the lack of sub-hourly data (*Page 2 of CAC Joint Commenters' Response Comments*). The Director hopes the CAC Joint Commenters will agree that the difficulties of improved avoided cost calculations should not dissuade us from the effort to enhance the quality and quantity of data. Ideally, and despite the inherent difficulties, avoided costs should be integral to each utility's resource plan, the utilities' distribution system planning and operations, as well as wholesale market operations and planning. This information can also improve rate design, integration of renewable resources, and planning and operations of all forms of distributed energy resources.

“[T]he avoided costs of energy efficiency do not necessarily remain the same per unit of energy saved (as it is often assumed in cost-benefit analyses of EE) and therefore some exploration of avoided costs is prudent.” (Page 2 of CAC Joint Commenters' Response Comments to the Director's Report)

The Director wishes to emphasize that state-of-the-art analysis of energy efficiency, demand response, other forms of DERs, electric vehicles, and potentially new technologies have ramifications for the IRPs, for distribution system planning and operations, as well as for the wholesale markets. It is, therefore, important to have a better understanding of the relevant avoided costs and how they change as a result of customer actions and a changing resource portfolio.

The Director is not as pessimistic as the CAC Joint Commenters and their consultants' contention that, "most IRP models cannot use hourly and sub-hourly data in resource optimization (Page 4)." While it is true that some models optimize resource portfolios over a sub-set of hours and/or representative days (particularly true for capacity expansion models), the current state-of-the-art models can utilize hourly and sub-hourly data to construct load and resource characteristics such as load shapes for total use and sub-metered for selected end-uses. We believe the production cost models (e.g., such as AURORA, PLEXOS, and PROMOD) can dispatch resources on an hourly or sub-hourly basis.

Since IRPs are futuristic and we anticipate advances in computational capabilities and speed, we urge utilities and stakeholders to be receptive to new methods and to develop the requisite data to support new methods. We also urge stakeholders and utilities to be receptive to new applications of improved data and computational capabilities such as greater integration of distribution system operations and planning with their IRPs and with RTO's operations and planning to get greater value for customers and lower costs for utilities.

The Director wants to reiterate appreciation for the CAC Joint Commenters, Ms. Anna Sommer and Ms. Chelsea Hotaling of the Energy Futures Group. Consistently, over the last several years, the CAC Joint Commenters and their consultants have significantly advanced the IRP processes with their thoughtful and insightful analysis.

B. NIPSCO's Reply Comments to Various Stakeholders

The Director agrees with NIPSCO's responses to various stakeholders.

1. MEEA is not correct in stating that the RFP focused on supply-side options only. Demand-side options were eligible and NIPSCO did receive a demand response bid. This bid was evaluated and included in the portfolio analysis, but not part of the preferred portfolio. However, the Director recognizes that the modeling of energy efficiency, DR, and other DERs is evolving. Ultimately, better modeling *may* result in less controversy about the modeling of all DERs, electric vehicles, and new technologies.
2. Using the process on an annual basis, as CGA/AWEA suggests, is not practical since the need for additional resources does not necessarily change annually, is a complex undertaking, and may skew results if the RFP does not require a significant amount of new resources which may result in fewer bidders. It may also lock in decisions that, ultimately prove to be uneconomic. In addition, the RFP was successful because it was based on specific capacity needs over the planning horizon. There is an expectation for bidders that a transaction of some kind was likely at the end of the process – an actionable RFP. As a result, participation was significant, and bids were competitive and grounded in real projects. If NIPSCO were to conduct an annual process more akin to a Request for Information (RFI), the participation might not be as robust and the price data would not be as reliable.

The Director agrees with NIPSCO that the use of Aurora ^{XMP} is an improvement over prior resource planning models. The Director also agrees with CGA/AWEA that NIPSCO should continue to evaluate software, consistent with the IRP Rule requiring continual improvements. Recognizing the evolution of software will necessitate improved data to more fully utilize the computational capabilities of new software, the Director has continually urged NIPSCO to improve its data quality and quantity.

As NIPSCO noted:

In the future, changing market constructs may require more granular analysis of capacity value, as well as an understanding of value associated with sub-hourly market operations, ancillary services, and distributed energy resources. NIPSCO will monitor these market trends and advance its modeling accordingly. *(Page 4 of NIPSCO's Response Comments)*

3. Although the ICC commented that the RFP led to a bias against coal, in actuality, it provided NIPSCO a formal mechanism to measure how its coal-fired generation measures up against other technologies in meeting capacity needs. In that way, it truly was an all-source RFP in that all types of resources were considered, including existing resources. Bids that provided cost and operational data for existing resources were evaluated on equal footing with new project proposals and NIPSCO's current fleet.