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INDIANA UTILITY
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Northern Indiana Public Service Company LLC

2018
Integrated Resource Plan

October 31, 2018

YOUR ENERGY YOUR FUTURE

IRP

2018 Integrated Resource Plan Executive Summary

At NIPSCO, we're proud that our work provides the energy that northern Indiana families and businesses rely on to power their daily lives. We work each day with the goal of growing alongside our communities and responding to our customers' needs.

As our customers' needs have changed, so has the energy market. Now we stand at the crossroads of the future, with the opportunity to invest in balanced energy options and make energy more affordable and cleaner.

With an eye toward the future, we've been performing a comprehensive analysis of our future energy mix and meeting with our customers, our employees and local community leaders over the past year. The result of this process is an Integrated Resource Plan (IRP).

The plan—which presents over $4 billion in long-term cost savings—is a balanced, gradual transition that will strengthen our region now and put us on a path to a more cost-effective, cleaner and more sustainable future.

It's "Your Energy" and it's "Your Future."

NIPSCO®
A NiSource Company

About NIPSCO

More than 460,000 northern Indiana homes and businesses depend on NIPSCO each day for safe, reliable and affordable energy. Northern Indiana is fortunate to be home to some of the top production facilities in the United States. This has a unique impact on NIPSCO's energy demand profile. Five of our largest industrial customers, primarily in steel and oil refining, account for about 40 percent of NIPSCO's energy demand.

As a member of the regional transmission organization Midcontinent Independent System Operator (MISO), NIPSCO is able to supplement its own energy resources through other participating utilities in MISO's footprint. This relationship helps ensure reliability and cost-effective operations.

About the 2018 Integrated Resource Plan

To help ensure that we continue to meet the needs of our customers, we must have a road map to prepare for future energy needs. Our 2018 IRP charts a path for how best to meet those needs over the next 20 years. NIPSCO presents this plan to the Indiana Utility Regulatory Commission (IURC).

The electric industry, customer needs, expectations and the way energy is consumed continue to evolve. Technologies are rapidly changing and expanding. The electric generation landscape is shifting dramatically, not just for NIPSCO but for the country as a whole.

Portfolio

- ✓ **Affordable**
- ✓ **Reliable**
- ✓ **Compliant**
- ✓ **Diverse**
- ✓ **Flexible**

NIPSCO's 2018 Integrated Resource Plan

Resource planning is a complex undertaking, one that requires addressing the inherent uncertainties and risks that exist in the electric industry. Key factors referred to in the IRP include market conditions, fuel prices, environmental regulations, economic conditions and technology advancements.

Using in-depth data, modeling and risk-based analysis provided by internal and external subject matter experts, we project future energy needs and evaluate available options to meet those needs.

New to NIPSCO's IRP, we issued a formal Request for Proposals (RFP) solicitation to uncover the breadth of actionable projects that were available to NIPSCO within the marketplace across all technology types. The RFP also served to collapse uncertainty about the costs of various technologies, particularly renewables.

The projections included in our plan are based on the best available information at this point in time. Changes that affect our plan may arise, which is why it's important for us to remain flexible and continually evaluate current market conditions, the evolution of technology—particularly renewables—and demand side resources, as well as laws and environmental regulations.

Engaging Customer and Public Stakeholders

Resource planning requires the consideration of diverse points of view, which is one of the reasons that external stakeholder involvement is a critical component throughout the development of the IRP.

We engaged stakeholder groups and individuals in a variety of ways throughout the entirety of the planning process.

NIPSCO initiated stakeholder advisory efforts for its 2018 IRP in March, hosting a public meeting and launching a web page for interested stakeholders to follow the progress. Four additional public meetings followed in May, July, September and October. NIPSCO also hosted public forums to discuss specific topics arising from the IRP.

In addition to posting public invitations on our IRP web page, we sent an invitation to past IRP stakeholder participants. Members of our executive leadership team and several of our subject matter experts attended each meeting to hear feedback and answer questions.

Throughout the IRP process, stakeholders were also invited to meet with us on a one-on-one basis to discuss key concerns and perspectives. Each interaction provided a forum for discussion and feedback related to the many components of the IRP.

Valuable discussions arose in several key areas, including environmental regulations, fuel costs, load forecasting calculations, energy efficiency program analysis and renewable energy development.

The feedback gathered during the stakeholder process raised valuable questions, helped us better evaluate our options and improved the final plan. A summary of the meeting materials, including presentations and stakeholder questions, is available at NIPSCO.com/IRP.

Forecasting Future Customer Demand

Projecting customers' energy needs is another key component of the IRP process. Looking 20 years into the future does not come without challenges, so we rely on data-driven models to help develop our best estimates. Specific models are developed for residential users, commercial users and industrial users, as well as for all other types of customers, including street lighting, public authorities, railroads and company use.

Data sources used in creating the forecast include energy, customer and price data, economic drivers, weather data and appliance saturation. Given the unique makeup of NIPSCO's customer base, industrial operations are another significant variable. In order to best model their load requirements, we rely on discussions with our 20 largest industrial customers.

With this data, we developed multiple scenario forecasts to capture the range of uncertainty for both energy requirements and peak demand.

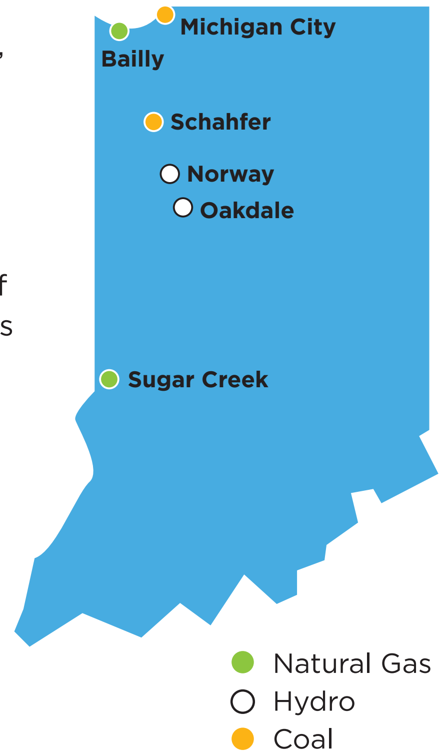
Current Supply

NIPSCO's current resource portfolio is composed of hydroelectric, wind, demand-side resources and natural gas-fired sources in addition to the company's coal-fired plants.

Coal remains the largest part of NIPSCO's fleet, accounting for more than half of total capacity, followed by natural gas-fired electric generation.

NIPSCO also offers a Net Metering Program and a Feed-in Tariff Program (FIT), which allows commercial and residential customers to generate their own power from renewable resources such as wind, solar, hydro and biomass.

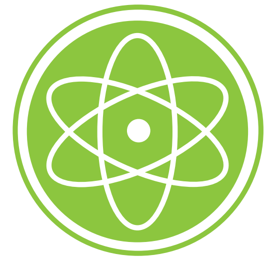
To further support renewable energy development, we give customers the power to choose green energy not only through the Net Metering and FIT Programs, but also through the Green Power Program, in which we buy renewable energy credits on customers' behalf.



NIPSCO Generating Resources

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	14	Coal	431	1976
	15	Coal	472	1979
	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
Subtotal			1,780	
Sugar Creek		NG	535	2002
Bailly	10	NG	31	1968
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
Subtotal			10	
Wind		Wind	100	2009
NIPSCO			2,925	

Analyzing Future Supply Options—Request for Proposals



New to the process in the 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.

2018 Proposals Submitted to NIPSCO

Technology	CCGT*	CT*	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
# of Bids	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

***CCGT**—Combined Cycle Gas Turbine
***CT**—Combustion Turbine

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.

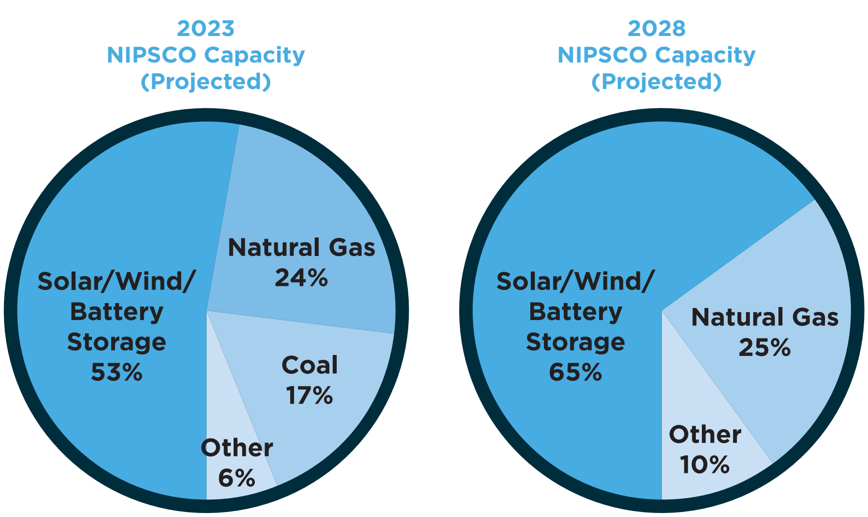
Findings and Next Steps

Throughout the IRP analysis, we are striving to balance the needs of our customers, employees and other community stakeholder interests.

Our goal as we look forward is to transition to the best-cost, cleanest electric supply mix available while keeping options open for the future as technologies and markets change.

Analysis shows that the most viable path for customers involves accelerating the retirement of a majority of NIPSCO's remaining coal-fired generation in the next five years and all coal within the next 10 years. Replacement options point toward lower-cost renewable energy resources such as wind, solar and battery storage technology.

As we gradually transition to creating a more diversified energy mix that will be more cost effective and better serve customers in the future, we are committed to ensuring that this plan limits the impact on local employees and our economy as a result of the remaining coal retirements.



Short-Term Action Plans (2019–Through 2021)

The objective of the plan is to ensure that NIPSCO can confidently transition to the least-cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility for technology and market changes during this period.

- Initiate retirement of R.M. Schahfer Coal-Fired Units 14, 15, 17, and 18 by 2023
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units
- Select replacement projects identified from the 2018 RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost
- File for Certificate(s) of Public Convenience and Necessity and other necessary approvals for selected replacement projects
- Procure short-term capacity as needed from the MISO market or through short-term PPA(s)
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
- Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)
- Continue implementation of filed Energy Efficiency Programs Plan for 2019 to 2021
- Comply with North American Electric Reliability Corporation, U.S. Environmental Protection Agency and other regulations
- Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

Long-Term Action Plans (2023–Beyond)

- Fully retire the R.M. Schahfer Coal-Fired Units 14, 15, 17, and 18 by the end of 2023 and the Michigan City Coal-Fired Unit 12 by the end of 2028
- Monitor market and industry evolution and refine future IRP plans

While NIPSCO will continue to update its long-term plan within the next IRP, we believe that these actions coming out of the 2018 IRP will place NIPSCO on a course to continue providing reliable power while enabling lower costs and providing significant environmental benefits.

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Section 1. Integrated Resource Plan

1.1 Short Term Action Plan

Northern Indiana Public Service Company ("NIPSCO" or "Company") developed a short term action plan consisting of the actions NIPSCO will take for the period 2019 through 2021. The objective of the plan is to ensure that NIPSCO can confidently transition to the least cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility for technology and market changes during this three year period.

NIPSCO's short term action plan will focus on initiating the retirement process for all of the coal units 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, and NIPSCO will identify and begin implementing the necessary upgrades during this period.

The robust response to the all-source request for proposal ("All-Source RFP") (discussed in more detail in Section 4) solicitation indicates that there are more than enough diverse resources and projects to meet NIPSCO supply needs in 2023. NIPSCO will adopt a phased-in approach to selecting and acquiring replacement resources, initially prioritizing replacement resources with expiring tax credits in order to maximize the benefits to customers. NIPSCO intends to make the necessary regulatory filings with the Indiana Utility Regulatory Commission ("IURC" or "Commission") in 2019. During the short-term action plan period, 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.

NIPSCO will continue the implementation of its current Demand Side Management ("DSM") plan through 2021.[1] NIPSCO will also continue to comply with exiting environmental regulations and all North American Electric Reliability Corporation ("NERC") compliance standards and requirements. Lastly NIPSCO will continue to invest and modernize its electric infrastructure to maintain the safe and reliable delivery of electricity to its customers

As described in greater detail in Section 9.4 the action items included in NIPSCO's short term action plan include those listed in Table 1-1:

[1] On September 12, 2018, the IURC issued an Order in Cause No. 45011 approving NIPSCO's proposed Electric DSM Program for the period of 2019-2021.

Table 1-1: 2018 IRP Short-Term Action Plan

Initiate retirement of Schahfer units 14,15,17,18 by making required notifications to MISO, NERC and other organizations.
Identify and implement required reliability and transmission upgrades resulting from retirement of the units.
Select replacement projects identified from the 2018 All-Source RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost.
File for certificate(s) of public convenience and necessity ("CPCN(s)") for selected replacement projects.
Procure short-term capacity as needed from the MISO market or through short-term PPA(s).
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape.
Conduct a subsequent All-Source RFP in to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage).
Continue implementation of approved DSM plan for 2019 to 2021.
Comply with NERC, United States Environmental Protection Agency ("EPA") and other regulations.
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services.

1.2 Plan Summary

NIPSCO's preferred portfolio plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply was available to meet future customer needs. NIPSCO carefully planned and considered the impacts to its employees, the environment and the local economy (property tax, supplier spend, employee base) as the plans were developed.

This plan was developed through substantial quantitative and qualitative analysis. NIPSCO completed a thoughtful analysis to evaluate NIPSCO's generation units relative to viable alternatives. (*See* Section 9.) NIPSCO utilized the All-Source RFP process to identify the best combination of supply- and demand-side resources, including those obtained through the market, to meet its capacity needs.

The All-Source RFP provided NIPSCO insight into the most relevant prices and types of resources available to meet customer needs. (*See* Section 4.9.) NIPSCO performed both the retirement and replacement analysis using robust scenario and risk-based (stochastic) analyses for different economic, environmental, cost, risk and regulatory uncertainty to inform the optimal plan. NIPSCO also evaluated the impact each of the retirement and replacement alternatives would have on reliability, the local communities and the Company's dedicated employees.

It is important to note that the IRP is a snapshot in time, and while it establishes a direction for NIPSCO, it is subject to change as the operating environment changes. NIPSCO will continue to engage its stakeholders and be transparent in its decisions following submission of this 2018 IRP.

NIPSCO's supply strategy for the next 20 years is expected to:

- Lead to a lower cost, cleaner, diverse and flexible portfolio by accelerating the retirement of 85% of NIPSCO's coal capacity by the end of 2023 and 100% by the end of 2028.
- Continue the Company's commitment to energy efficiency and demand response by executing DSM plans.
- Replace retired coal generation resources with lower cost renewables including wind, solar and battery storage.
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units.
- Reduce customer and Company exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply.
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape.
- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services.
- Continue to comply with NERC and EPA standards and regulations.

1.3 Rationale for NIPSCO 2018 IRP Update Filing

The 2016 IRP action plan was focused on the accelerated retirement of approximately 50% of NIPSCO coal fired generation. Specifically, it called for the retirement of Bailly Generating Station ("Bailly") Units 7 and 8 in 2018 and Schahfer units 17 and 18 in 2023. It projected that the 2023 retirements would create a capacity need of about 600 megawatts ("MW") that NIPSCO would have to address. An IRP in 2018 was necessary to preserve NIPSCO's ability to consider all resource options to meet the capacity need in 2023. Furthermore in light of expected future capital expenditures to comply with the Effluent Limitation Guidelines ("ELG") rules, the 2018 IRP was an opportunity to reexamine the long term viability of the Schahfer and Michigan City Generating Station ("Michigan City") coal units.

1.4 Emerging Issues

NIPSCO's preferred plan follows a diverse and flexible supply strategy, with a mix of market purchases and different low variable cost generation resources, to provide the best balanced mitigation against customer, technology and market risks.

1.4.1 Customer Risk

NIPSCO's five largest industrial customers (ArcelorMittal, US Steel, NLMK, BP and Praxair) account for approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis. Most of these customers are closely tied to global steel industry cycles. This concentration of customers tied to a single industry poses significant customer risk. Loss of one or more of these customers, for whatever reason, would result in a significant decline in billing revenues.

Residential, commercial, and smaller industrial customers comprise most of the remaining demand. While this load is diversified and not likely to change significantly, those sectors would likely see impacts from a loss of load from any of the large industrial customers who are major employers in NIPSCO's service territory.

1.4.2 Technology Risk

Technology risk can be thought of as two separate risks from the perspective of a regulated utility. Technology risks play a role in inducing market volatility, and it also has the potential to erode the value of existing assets. Technology changes drive a portion (but by no means all) of the volatility in market prices, both for capacity and energy. To the extent that a utility or its customers are exposed to market risk in general, they are exposed to this aspect of technology risk. Separately, technological and regulatory changes can render specific generation technologies obsolete and can force their premature retirement, which is currently happening to coal generation.

It is difficult to avoid exposure to one or the other type of technology risk when supplying demand using a traditional regulated utility approach. Fully avoiding technological obsolescence risk requires avoiding investing in generation, which exposes the utility and its customers to market risk. Investing in generation mitigates or eliminates market risk but exposes the utility and its customers to some amount of technological obsolescence risk.

Balancing these two risks in light of the technology choices available is key to mitigating overall supply portfolio risk. Currently available new build generation technologies, such as a combined cycle gas turbine ("CCGT") and renewable technologies, have very low fixed operating costs, so the likelihood of forced shutdown in the foreseeable future is likely lower than it has been for coal and nuclear which have very high fixed costs.

1.4.3 Market Risk

Historically, the MISO North region, of which Indiana is a part, has had excess capacity above and beyond the regional reliability requirement. This oversupply in the MISO Planning Resource Auction ("PRA"), has resulted in historically low capacity prices over the last few planning years. In the 2016/2017 planning year capacity prices rose to $72 per megawatt-day ("MWD") as reserve margins declined; however, in the 2017/2018 planning year prices fell to $1.50MW/MWD, driven by increases in renewable technologies and behind the meter supply resources and the relaxing of import constraints between MISO North and South. In the recent 2018/2019 planning year the capacity prices were $10/MWD and the expectation is for prices to remain relatively low for the foreseeable future under the current market design.

NIPSCO also participates in the energy market in MISO, since all resources are dispatched according to MISO market signals, as opposed to NIPSCO's load. The market is currently undergoing change as coal capacity retires and the generation mix shifts towards renewables and natural gas. In recent years, low natural gas prices have resulted in efficient natural gas plants displacing coal-fired generation in the dispatch stack. This dynamic has altered energy prices and has negatively impacted the economics of coal plants. Wind generation has also increased significantly in parts of MISO, and declining technology costs and federal tax credits are likely to result in increased penetration of solar and wind resources. This additional growth of intermittent resources has the potential to shift system peaks, impact capacity credit calculations, and alter the ancillary services markets.

NIPSCO recognizes that system planning with renewable resources is more complex than with dispatchable resources and that assumptions for capacity credit and resource value streams based on today's market constructs may ultimately change based on future MISO evaluation of Effective Load Carrying Capability and ancillary services market needs in a high renewable environment. NIPSCO also recognizes that congestion and nodal price risk is an important factor for renewable resources and that energy deliverability is critical to realize benefits from renewables. Given these major uncertainties and developments in the market, NIPSCO is committed to tracking market evolutions regarding ancillary services, renewable resource availability, and capacity credit calculations. The preferred plan intentionally leaves room to evaluate market and technology changes on a dynamic basis in order to be flexible and responsive to change.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2018 IRP stakeholder process focused on continuing to increase transparency around its planning process and enhance public involvement through extensive stakeholder interactions. At each stakeholder meeting, NIPSCO provided information on the processes and assumptions involved in the development of the IRP and solicited relevant input for consideration. Furthermore, to facilitate stakeholder outreach and ongoing communications, NIPSCO maintained a web page on its website with current information about the IRP. NIPSCO posted all meeting agendas, presentations, meeting notes and other relevant documents to the web page.

As part of the IRP process NIPSCO conducted an All-Source RFP solicitation to identify the most viable capacity resources currently available in the market place to best meet customer needs. NIPSCO sought input from stakeholders regarding the approach and design of the All-Source RFP to ensure a robust and transparent process that yield the desired results.

Stakeholders were invited to meet with NIPSCO throughout the IRP process to discuss key issues, concerns and perspectives. NIPSCO extended an invitation to participate in the stakeholder process to the Commissioners and Commission staff, the Indiana Office of Utility Consumer Counselor ("OUCC") and stakeholders that participated in previous IRP public advisory processes. NIPSCO's executive leadership and its subject matter experts attended each public advisory meeting. In the section that follows, NIPSCO provides an overview of its stakeholder process. A more comprehensive accounting of stakeholder meetings, presentations and meeting notes is included in Appendix A.

As part of the 2018 IRP process, NIPSCO hosted four in-person public advisory meetings and one webinar. As a follow up to the public advisory webinar, NIPSCO conducted an additional technical webinar to focus specifically on a single topic - the integration of the All-Source RFP results into the IRP analysis. For all meetings, NIPSCO posted an open invitation on its website for any party wishing to register.

In addition to the public advisory meetings, NIPSCO participated in a number of one-on-one meetings with individual stakeholders to address specific concerns and issues that were raised as a result of information presented and discussed at the public advisory meetings.

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held in Merrillville, Indiana on March 23, 2018. For those unable to join in person, a conference call was also made available. In this first meeting, NIPSCO explained the rationale for undertaking an update to its IRP and discussed the process improvements from the 2016 IRP being incorporated in the 2018 update. Furthermore, NIPSCO provided an overview of the resource planning approach, the key drivers of risk and uncertainty and the underlying data. NIPSCO also provided information regarding the All-Source RFP for new capacity, and discussed the public advisory process. Stakeholders requested clarification regarding (1) data points used in the IRP (e.g., percentage of renewables, technologies utilized, emissions, etc.), (2) assumptions regarding carbon pricing, (3) selection of supply-side and demand-side resources, and (4) how solar was included in the modeling. The meeting presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 1 are included in Appendix A, Exhibit 1.

2.1.2 Stakeholder Meeting 2

NIPSCO's second stakeholder meeting was held in Merrillville, Indiana on May 11, 2018. For those unable to join in person, a webinar format was also made available. In this second meeting, NIPSCO described the process for modeling risk and uncertainty, and the methodology for modeling DSM in the IRP. Furthermore, the meeting provided an overview of NIPSCO's existing generation resources including the operating costs and key environmental considerations. Lastly, the meeting described the proposed scorecard that would be used to inform the preferred plan, the framework for the retirement and replacement analysis and provided preliminary results from the analysis. Stakeholders requested clarification regarding (1) the construction of scenario themes and the use of stochastics, (2) environmental compliance, (3) scorecard metrics; and (4) All-Source RFP design. Three stakeholders, Dany Brooks; David Chiesa of S&C Electric Company; and a group comprised of Scott Houldieson (United Auto Workers), Barry Halgrimson, and Sam Henderson (Hoosier Environmental Council) provided stakeholder presentations. The meeting presentation (including the agenda), stakeholder presentations, terminology sheet, notes (including questions / responses), and registered participants for Meeting 2 are included in Appendix A, Exhibit 2.

2.1.3 Stakeholder Meeting 3

NIPSCO hosted its third stakeholder meeting as an on-line webinar on July 24, 2018, with the public also invited to attend at NiSource's South Lake or Indianapolis offices. The webinar focused on sharing the preliminary results from the All-Source RFP solicitation. NIPSCO and the All-Source RFP manager Charles River Associates ("CRA") provided an overview of the proposals received and a summary of the pricing. NIPSCO also explained how the All-Source RFP results would be integrated into the IRP analysis and important next steps for both the IRP and All-Source RFP process. Key issues for stakeholders included clarification relating to (1) number of bids vs projects, and (2) integrating the All-Source RFP results into the IRP. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 3 are included in Appendix A, Exhibit 3.

2.1.4 Technical Webinar

NIPSCO hosted a technical webinar on August 28, 2018. The webinar focused on addressing follow ups from the July 24, 2018 meeting. Key issues for stakeholders included clarification relating to (1) how the All-Source RFP results will be incorporated into the IRP; (2) tranche development and assessment; (3) portfolio creation; and (4) how unforced capacity ("UCAP") was determined from the bid data. The meeting presentation (including the agenda) and registered participants for the Technical Webinar is included in Appendix A, Exhibit 4.

2.1.5 Stakeholder Meeting 4

NIPSCO's fourth stakeholder meeting was held in Fair Oaks, Indiana on September 19, 2018. For those unable to join in person, a webinar format was also made available. In this fourth meeting, NIPSCO explained the preliminary findings from the modeling. Key issues for stakeholders included (1) an explanation of how NIPSCO plans for the future; (2) an update the energy and demand forecasts; (3) a discussion of how NIPSCO models uncertainties; (4) an overview of NIPSCO's preliminary retirement and replacement analyses; and (5) an update on stakeholder requested scenarios. In addition, the Sierra Club provided a stakeholder presentation. The meeting presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 4 are included in Appendix A, Exhibit 5. Please note, the Sierra Club did not provide an electronic version of its presentation to be included with the materials. If provided, the presentation will be available at nipsco.com/irp. The terminology sheet provided as the first meeting was also provided for the fourth meeting, but is not duplicated in Exhibit 5.

2.1.6 Stakeholder Meeting 5

NIPSCO's fifth stakeholder meeting was held in Fair Oaks, Indiana on October 18, 2018. For those unable to join in person, a webinar format was also made available. In this fifth meeting, NIPSCO provided its preferred plan and preliminary action plan. Key issues for stakeholders included (1) a recap of how NIPSCO plans for the future; (2) an update to the stakeholder requested analyses; (3) an update on the retirement and replacement analyses; and (4) NIPSCO's preferred resource plan. In addition, the Indiana State Conference of the NAACP and Indiana DG provided stakeholder presentations. The meeting presentation (including the agenda), stakeholder presentations, notes (including questions / responses), and registered participants for Meeting 5 are included in Appendix A, Exhibit 6.

2.1.7 One-on-one Stakeholder Meetings

NIPSCO held a number of one-on-one meetings with its stakeholders throughout the public advisory process. Generally, the meetings related to either (1) clarifications, (2) additional information regarding the All-Source RFP, or (3) running requested scenarios. Information relating to the results of the requested scenarios can be found in the presentation included in Appendix A, Exhibit 5 (Slides 48 through 52) and Appendix A, Exhibit 6 (Slides 11 through 23).

NIPSCO's 2018 IRP is the result of analysis performed by NIPSCO that includes consideration of stakeholder input. NIPSCO has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. NIPSCO appreciates the participation of its stakeholders, including the Commission staff, the OUCC, NIPSCO's largest industrial customers and community action groups, all of which participated extensively throughout the IRP development process. NIPSCO's stakeholders and Commission staff provided valuable feedback throughout the process, which has been considered and incorporated as applicable. Despite best efforts to address and resolve all input from stakeholders, there were instances wherein NIPSCO still incorporated, for example, methodologies that were not supported by all stakeholders.

2.2 IRP Planning Process

NIPSCO's 2018 IRP is in compliance with the Commission's Proposed Rule to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans ("Proposed Rule"). A matrix showing NIPSCO's compliance with each section of the Proposed Rule (providing a reference to the appropriate Section(s) of the IRP) is included in Section 10: Compliance with Proposed Rule.

Long term resource planning requires addressing risks and uncertainties and for NIPSCO, the first step in this process is to identify objectives and metrics. Next NIPSCO develops market perspectives for key variables such as customer demand, commodity prices and technology costs. An aspect of the developing market perspectives involves the creation of distinct thematic "states-of-the-world" that represent potential future operating environments for NIPSCO. Lastly NIPSCO constructs integrated resource portfolio strategies and performs detailed modeling and analysis to evaluate the performance of various resource portfolios across range of potential futures. NIPSCO's goal is to develop a resource plan that is reliable, compliant with all regulations, diverse, flexible and affordable for customers with careful consideration of all stakeholder viewpoints.

The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs. The short-term strategic plan identifies the steps NIPSCO will take over the next three years to implement the long-term strategic plan.

NIPSCO recognizes future economic and environmental changes are difficult to accurately predict. The 2018 IRP addresses the most likely contingencies based on uncertainty analyses. New information in NIPSCO's planning process is analyzed and incorporated as it becomes available.

NIPSCO's IRP team included experts from key areas of NIPSCO and its affiliate NiSource Corporate Services Company. The following energy and engineering consultants also provided input:

GDS Associates, Inc. ("GDS") 1850 Parkway Place, Suite800 Marietta, Georgia 30067	Developed DSM measures inputs for a long-term DSM forecast
Itron, Inc. 2111 North Molter Road Liberty Lake, Washington 99019	Provided historical and forecasted end use data
Charles River Associates 200 Clarendon Street Boston, Massachusetts 02116	Provided fundamental long term commodity price forecasts, portfolio modeling and analysis. A separate division of CRA provided assistance in administering the All-Source RFP and evaluating the responses.
Telvent DTN, Inc. 9110 West Dodge Road Omaha, Nebraska 68114	Provided hourly weather data for three Indiana weather stations

2.2.1 Contemporary Issues

NIPSCO also participated in the Commission's IRP Contemporary Issues Technical Conference held April 24, 2018. The meeting focused on using IRPs to develop avoided costs for energy efficiency, the planning models used by MISO, distribution system planning, load growth trends, using smart meter data, distributed energy resources and the potential for peak demand reduction. To the extent the information applicable and appropriate, NIPSCO included the items discussed during the technical conference in its analysis.

2.2.2 2016 IRP Feedback and 2018 Process Improvement Efforts

NIPSCO strives to continuously improve all aspects of its resource planning process and, for the 2018 IRP, NIPSCO reviewed the feedback from the 2016 IRP and implemented key improvements to its process. The process improvements in the 2018 IRP are primarily designed to incorporate advanced risk modeling techniques, as well as to continue to enhance the transparency and credibility of NIPSCO's long-term plans by using assumptions based on fundamentals driven analysis and market based data.

Table 2-1 shows feedback received on NIPSCO's 2016 IRP and the improvements that were included in its 2018 IRP process.

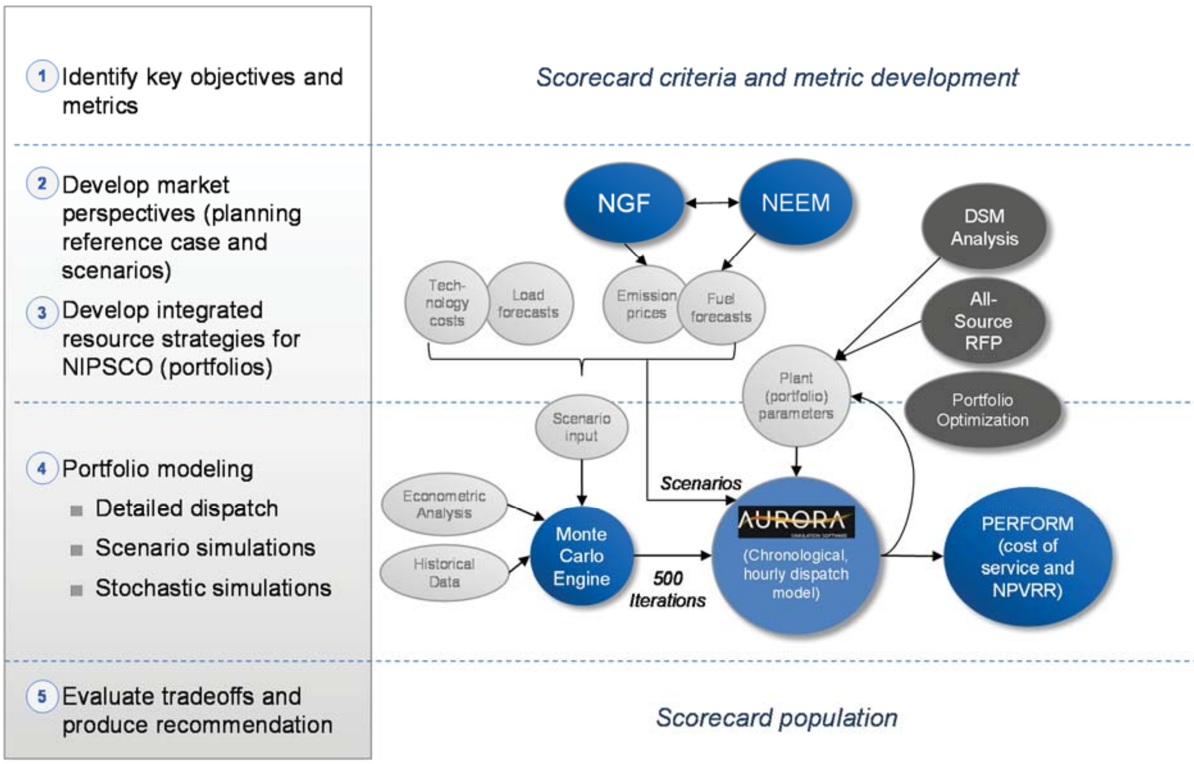
Table 2-1: Process Improvement

Subject	2016 IRP Feedback	2018 Improvement Plan
Commodity Price Forecasts	• Fuel price projections do not capture the nuanced and dynamic relationships between oil and natural gas, or whether the historic market correlations are evolving • No transparency and availability of underlying assumptions for fuel forecasts	• Utilized independently generated commodity price forecasts using an integrated market model • Provided transparent assumptions related to key inputs and outputs • Benchmarked against publicly available forecasts
Risk Modeling	• NIPSCO IRP planning model was limited to scenarios and sensitivities	• Implemented efficient risk informed (stochastics) analysis with the ability to flex key variables
Scenarios and Sensitivities	• NIPSCO's construction of scenarios and sensitivities in the 2016-2017 IRP is a significant advancement over the 2014 IRP. The clarity of the narratives was commendable and transparency was exceptional	• Built upon the progress made in the 2016 IRP with thematic and modeling informed selections for detailed cost analysis
Capital Cost Assumptions	• Capital cost estimates for new capacity resources were based on proprietary consultant information • No scenario or sensitivity covered uncertainties of resource technology cost	• Leveraged 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources • Conducted an "all-source" Request for Proposal solicitation for replacement capacity resources
Preferred Plan and Scorecard	• Provide additional details around selection of the Preferred Plan and the analysis used to develop • Provide a detailed narrative for those metrics that can be quantified as well as those that do not lead to quantification	• Provided detailed analysis on selection of the Preferred Plan • Developed enhanced scorecard methodology to include more quantifiable metrics that better evaluate tradeoffs
DSM Modeling	• DSM groupings are not getting quite the same treatment as the supply side resources	• Utilized new modeling capabilities to enable DSM to be treated equally with other supply side resources

2.3 Resource Planning Approach

Consistent with the principles set out in Section 1.1, the 2018 IRP identifies changes and additions needed over a 20 year planning horizon for NIPSCO to deliver reliable, compliant, flexible, diverse and affordable electric service to its customers. NIPSCO's 2018 IRP was performed according to the detailed planning approach process that is outlined in Figure 2-1 and described in more detail below. While structurally similar to the 2016 IRP process, the 2018 approach has incorporated new software, models and several process enhancements in order to respond to feedback that was received.

Figure 2-1: Overall Integrated Resource Planning Approach



Step 1: Identify key objectives and metrics

The first step in NIPSCO's planning approach was to identify key planning objectives and develop specific metrics against which to evaluate future portfolios. As in the 2016 IRP, this involved the development of multiple scorecard criteria prior to the commencement of any analysis. This ensures that the objectives and metrics are established without any bias that may come from the production of IRP model runs and analysis. The planning criteria used in the 2018 IRP includes cost to customer, cost risk, fuel security, environmental stewardship, and impact to employees and the local economy. Section 9 of this report describes the scorecard objectives and metrics in more detail.

Step 2: Develop market perspectives

Prior to performing any portfolio-specific analysis, NIPSCO developed perspectives on key market drivers and other major planning assumptions. This involved the use of several market models and forecasting approaches in order to arrive at a Base Case set of inputs and a set of scenarios against which to evaluate resource options. This step involved the following major tasks:

- Commodity price forecasting for fuel, emission, and power prices: NIPSCO commissioned CRA to develop forecasts for natural gas prices, coal prices, emission allowance prices, and power prices (energy and capacity) for the Base Case and three integrated market scenarios. The details of all Base Case and scenario forecasts are provided in Section 8. CRA relied on the following models to perform this work:

- CRA's Natural Gas Fundamentals ("NGF") model, which provides a bottom-up forecast of North American gas production and prices with a focus on shale gas supply and other unconventional resources. Key NGF outputs include a long-term price forecast for domestic natural gas, as well as breakeven costs and production data for major gas basins across the United States. NGF is a national model, useful for macroeconomic scenarios. CRA also licenses the Gas Pipeline Competition Model (GPCM) for regional basis analysis.

- CRA's North American Electricity and Environment Model ("NEEM"), which provides an assessment of emission allowance prices, coal consumption and coal pricing, generator retrofit decisions, and capacity expansion and retirements. The NEEM model estimates market prices and unit dispatch using a simplified transmission representation and a select number of representative demand points to produce a fundamentals-based outlook of key macroeconomic outputs for the electricity sector.

- The Aurora model, which CRA licenses, and which provides hourly MISO market prices at a zonal level based on a fundamental dispatch of the market. Market inputs for the Aurora model include fuel prices, emission prices, and capacity expansion and retirement, which are developed through CRA's other models. CRA also deploys a capacity market model, which produces an internally consistent capacity price outlook based on MISO market rules.

- Load forecasting, performed by NIPSCO's internal load forecasting team, and described in more detail in Section 3.

- Development of technology cost estimates for supply side resource options, which were initially produced on a planning-level basis through market research conducted by NIPSCO and CRA. NIPSCO and CRA's Auction and Competitive Bidding Practice then conducted an All-Source RFP, which provided real market data on the resource types available and their associated costs and operational parameters. Section 4 describes this process in more detail.

Step 3: Develop integrated resource strategies or portfolios

The third major step in the 2018 IRP process was to develop resource strategies or portfolios for further evaluation. The portfolio development process relied on multiple inputs and approaches. It was conducted first for a retirement analysis and then for a full replacement analysis, with key elements summarized as follows:

- The definition of retirement portfolio options was influenced by environmental policy considerations (as discussed in Section 7) and management input on feasible retirement paths.

- An update to NIPSCO's 2016 DSM Market Potential Study was conducted by GDS in order to provide a set of plausible DSM program bundles and associated costs for evaluation. The details of this study are provided in Section 5.

- Portfolio optimization analysis was conducted with the Aurora 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. The details of the process and a summary of the integrated portfolios that were evaluated are provided in Section 8.

Step 4: Portfolio Modeling

After detailed portfolios were constructed, each of them was evaluated in CRA's suite of resource planning tools, namely Aurora and a utility financial model known as PERFORM. 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 ("CO_2") 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.

The full set of portfolio modeling is undertaken for all portfolio options for the Base Case, each individual integrated market scenario, and a full stochastic distribution of potential outcomes associated with select commodity prices. The stochastic analysis relies on CRA's Monte Carlo engine, which simulates future price outcomes based on historical data analysis and specification of key statistical parameters. The details of the stochastic development process and the outputs of all portfolio modeling are discussed in more detail in Section 9.

Step 5: Evaluate tradeoffs and produce recommendations

The final step in NIPSCO's IRP process is to evaluate the various portfolios with an integrated scorecard and produce recommendations for a preferred plan. As discussed in Step 1, NIPSCO identified several planning objectives for its scorecard. In this step, metrics were recorded against all key planning criteria, and tradeoffs were evaluated. Ultimately, NIPSCO management is responsible for selecting the preferred portfolio based on the scoring of all options. This process and the preferred portfolio selection is described in Section 9.

2.3.1 Key Planning Assumptions

While many of the assumptions details are described further in subsequent sections of this report, the following information provides an introductory overview of several major planning inputs that drive the 2018 IRP.

Market Forecast Inputs

Market and commodity price forecasts are important drivers for NIPSCO's IRP, since they influence the variable costs of operation for many resources, the dispatch of certain power plants, and NIPSCO's interaction with the MISO market. As discussed above, CRA produced commodity price forecasts for major inputs, relying on support from NIPSCO's subject matter experts for certain details or assumptions that are specific to NIPSCO's current operating fleet. For example, for coal pricing, delivered coal contract details and expected coal transportation rates were provided by NIPSCO's fuel supply group in order to conform to near-term price expectations for the existing fleet of plants. Long-term fundamental forecasts were blended in over time. Figure 2-2 presents a summary of the source and reference information for each of the major market inputs.

Figure 2-2: Major Market Input Sources

Major Input	Source	Section Reference for More Detail
Natural Gas Prices	CRA forecasts and NIPSCO operations team	8 (fundamental forecasts, including scenarios and stochastics) 4 (current gas procurement strategies)
Coal Prices	CRA forecasts and NIPSCO fuel supply group	8 (fundamental forecasts, including scenarios and stochastics) 4 (coal procurement and current contracts/ transportation arrangements)
Emission Prices	CRA forecasts and NIPSCO environmental group	8
MISO Power Prices	CRA forecasts	8
MISO Capacity Prices	CRA forecasts	8

Environmental Planning Inputs

As noted above, emissions price assumptions were provided by CRA, with review provided by NIPSCO's environmental group. Estimates were developed by NIPSCO's Major Projects group for projects required to comply with current and future anticipated regulations pertaining to solid waste management, the Clean Water Act ("CWA"), and the Clean Air Act ("CAA"). A comprehensive review of key environmental planning drivers is provided in Section 7.

Energy and Demand Forecast

NIPSCO's internal load forecasting group produced load forecasts, including high and low cases, which were used in the IRP analysis. For the 2018 IRP modeling NIPSCO utilized the MISO Coincident peak demand forecast. All methods, assumptions and detailed forecast results are provided in Section 3.

Existing NIPSCO Portfolio Parameters

NIPSCO's IRP models incorporate all elements of the existing portfolio. NIPSCO's generation operations and planning groups provided the following characteristics for the existing set of resources: capacity, heat rates, emission rates, other operational characteristics of fossil-fired resources, variable operations and maintenance ("O&M") costs, fixed O&M costs, forced outage rates, maintenance schedules, must run schedules for coal units, energy and capacity contracts, feed-in-tariff contracts, existing DSM data, and renewable shapes. Certain details regarding the existing fleet are provided in Section 4.

New Resource Parameters

NIPSCO relied on multiple sources for major input assumptions associated with new resource options. DSM resource options and costs were developed by GDS, as described in Section 5. Supply-side resource options were developed according to the All-Source RFP conducted in 2018. The All-Source RFP provided cost information and resource operational characteristics, including capacities, heat rates, and expected capacity factors for renewable resources. This is described in further detail in Section 4.

Planning Reserve Margin Target

NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy. The MISO UCAP planning protocol was used to determine the planning reserve margin target to use in the 2018 IRP update, and NIPSCO set its target to 8.4%, as per current MISO standards. This target is based on NIPSCO's coincident peak in MISO. When performing portfolio optimization analysis, NIPSCO set a maximum reserve margin of 20% and a maximum level of off-system energy sales of 5%. This was done to avoid developing portfolios where NIPSCO would be relying on a significant level of excess energy and capacity sales to offset resource costs.

Financial Assumptions

Several financial assumptions are relevant to projecting annual revenue requirements, such as the expected return on equity and debt, tax rates, and the discount rate used when calculating the net present value ("NPV"). A summary of the major financial assumptions used in the 2018 IRP is provided in Figure 2-3.

Figure 2-3: Major Financial Assumptions

Financial Assumption	Value
Cost of Equity	9.98%
Cost of Debt	5.71%
Equity %	58.44%
Debt %	41.56%
After-Tax Weighted Average Cost of Capital	7.61%
Federal Income Tax Rate	21.00%
State Income Tax Rate	4.90%
Blended Income Tax Rate	24.87%
Property Tax Rate	2.16%
Discount Rate	7.61%
Allowance for Funds Used During Construction%	7.44%
Blended Depreciation Rate for Existing Assets	4.60%

Section 3. Energy and Demand Forecast

3.1 Major Highlights / High Level Summary / Discussion of Load

Some of the major highlights include:

- 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 3,051MW in 2018 to 3,169 MW by 2039 representing an annual growth rate of 0.2% during the period 2018-2039.
- NIPSCO MISO coincident peak demand is expected to grow from 2907MW in 2018 to 2970 MW in 2039 representing an annual growth rate of 0.1% during the period 2018 to 2039

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 impacts of past conservation and DSM programs. Regional saturation and efficiency trends are provided by Itron, Inc., a national utility consulting firm. Economic and demographic data utilized in the forecast is from IHS Global Insight.

3.2 Development of the Forecast – Method and Data Sources

NIPSCO's energy and peak forecast process reflects a system of dynamic models that are continually evaluated, updated and selected based on their ability to provide accurate projections of future energy needs of customers. Current modeling trends, statistical properties, data utilized in the forecast process and current peer utility approaches to forecasting are all considered during the forecast development. NIPSCO utilizes individual forecast models for Residential, Commercial, Industrial, Street Lighting, Public Authority, Railroad and Company use. The forecast also relies upon a 60-minute electric 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.

The Industrial Energy Forecast Model is developed in two parts. The first part uses a grassroots approach by developing forecasts for the largest individual industrial customers. The second part of the Industrial outlook represents all other customers included in the Industrial class. To generate the total industrial class forecast, the individual customer forecasts are combined with the portion of the forecast representing the balance of the Industrial class load. The Public Authority and Railroad class models rely on current usage levels and recent patterns. Projections for Company use and losses also rely on recent usage trends and levels. Historical DSM impacts and trends are reflected in the Residential and Commercial forecast. The Residential and Commercial outlook incorporate existing or past NIPSCO DSM programs by utilizing historical data in the modeling process. Past DSM impacts and trends are captured through the model structure and used in the calculation of the forecast. After the completion of the forecast process, NIPSCO completes regular internal forecast performance assessments for the Residential, Commercial and Industrial models to ensure the accuracy and reasonableness of the projections.

NIPSCO evaluates the forecast process on an ongoing basis looking to incorporate improvements that result in a more robust process. Currently, some of the improvements under consideration include incorporating electric vehicle impacts, the data frequency used in the forecast modeling, and testing alternative efficiency variables and estimation techniques to capture changing usage trends.

3.2.1 Data Sources - Internal

Class energy sales, number of customers by class, internal peak demand, historical interruptions and electric prices are all collected internally by NIPSCO. This information is used to develop the long term sales and demand forecast. NIPSCO uses North American Industrial Classification System (NAICS) coding for its non-residential customers.

3.2.2 Data Sources - External

Schneider Electric

NIPSCO uses two weather measures in the forecast, specifically cooling degree days (“CDD”) and heating degree days (“HDD”) as defined by the National Oceanic and Atmospheric Administration (“NOAA”). The Company purchases weather data for three NOAA stations: Valparaiso, South Bend and Fort Wayne. For modeling purposes, the weather from these three stations is represented as a weighted average with the weights based on the number of residential customers assigned to each station. For the forecast period, the Company assumes the weather data to be equal to the 1976-2010 average for both CDD and HDD. The weighted weather concepts for the peak hour model are cooling degree hours, heating degree hours and relative humidity.

IHS Global Insight

NIPSCO purchases national, state and county economic and demographic data from IHS Global Insight. Economic data used in the production of the forecast represents the most current information from the vendor at the time the forecast is developed.

Itron, Inc.

Historical and forecasted saturation and efficiency data are obtained from Itron, Inc., a national utility consulting firm. Itron, Inc. produces an annual statistically-adjusted end use model by census region reflecting historical and future saturation and efficiency trends. Itron, Inc. works closely with the United States Energy Information Agency (“EIA”) to embed EIA’s latest equipment saturation and efficiency trend forecasts into its annual models. NIPSCO utilizes this information reflecting the East North Central census region in the long-term Residential forecast model.

3.3 Residential

The Residential Energy Forecast Model is calculated in conjunction with NIPSCO's New Business team, using a residential customer model and an average residential use per customer model. Average residential use per customer projections are multiplied by the total residential customer count forecast to generate 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 and is developed using a grassroots approach. This approach includes conducting interviews with real estate developers and builders; thus, assuring that short-term housing market intelligence and recent trends are included in the forecast. The longer term customer outlook is modeled as a function of housing starts. Both short- and long-term forecasts are adjusted for customer attrition applied at an average historic rate. Total residential customers are calculated by incorporating the new customer outlook, existing customers and the historic attrition rate.

Econometric models are utilized to estimate the residential new customer and usage per customer models. Seventeen years of data was employed in the residential new customer model. The model produces an R-Square of 0.9687 in addition to strong T-Stats for each variable and directionally confirms the relationships expected between the independent and dependent variables. Sixteen years of historical data is used in the development of the residential use per customer long-term outlook. The model yielded an R-Square of 0.9333 and confirms statistically strong relationships between the independent and dependent variables.

- Residential New Customer Equation

  New Residential Customers = f(Local Housing Starts)

- Residential Usage Per Customer Equation

  Residential kWh per Customer = f(Residential Electric Price, Itron Index, Real Per Capita Income, HDD, and CDD)

Table 3-1: NIPSCO Residential Customers

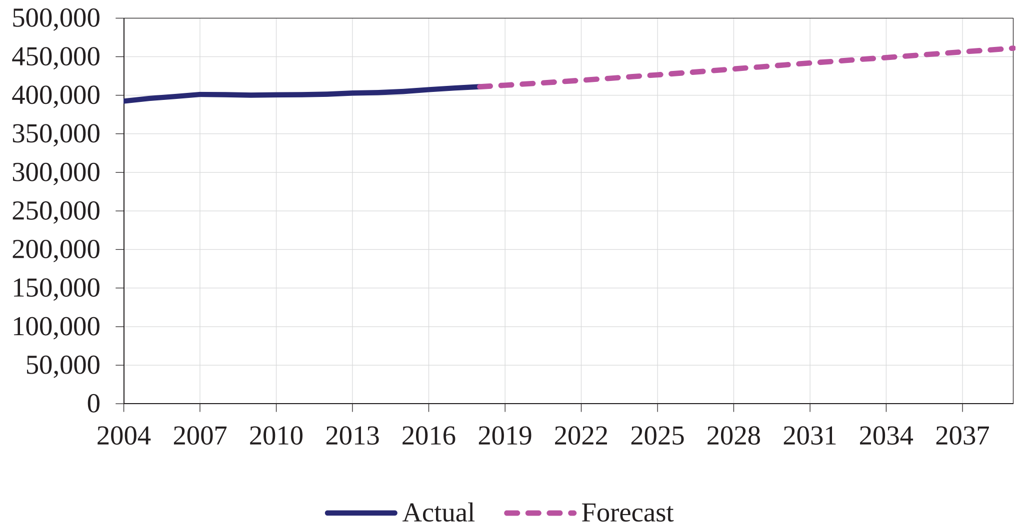
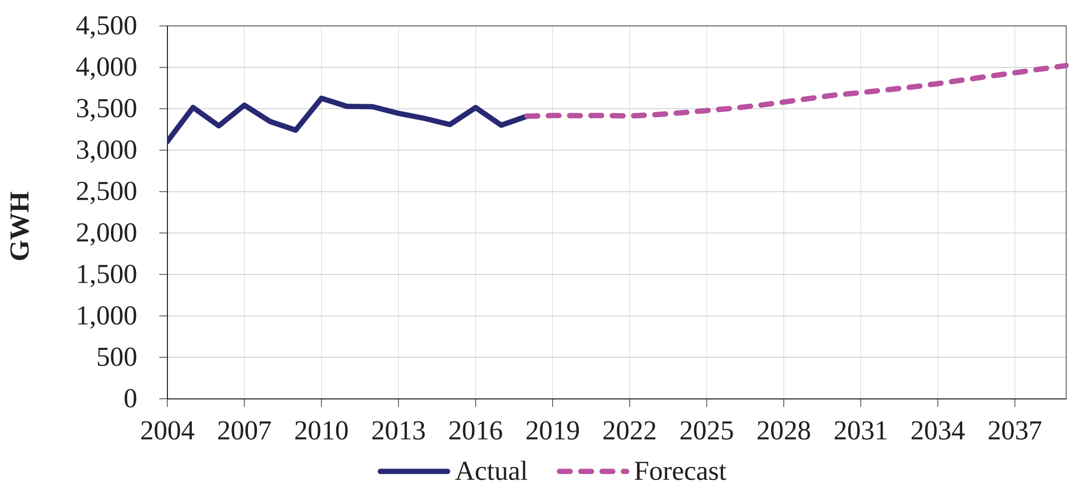


Table 3-2: NIPSCO Residential Energy Sales



3.4 Commercial

The Commercial Energy Forecast Model has been estimated using a total Commercial energy consumption model. Commercial energy consumption is a function of the commercial customer count, employment, commercial electric price, CDD, and HDD. As with Residential, the initial five-year outlook for Commercial customers is provided by NIPSCO's New Business team. The longer term view is modeled as a function of local population and real gross county product. The commercial customer count forecast also reflects a historical attrition rate.

Econometric models are utilized to estimate the commercial customer and total usage models. Twenty one years of historical data was employed in the commercial customer model. The model produces an R-Square of 0.9950 in addition to strong T-Stats for each variable and directionally confirms the relationships expected between the independent and dependent variables. Fifteen years of data was used in the development of the commercial energy long-term outlook. The model yielded an R-Square of 0.9833 and confirms statistically strong relationships between the independent and dependent variables.

- 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)

Table 3-3: NIPSCO Commercial Customers

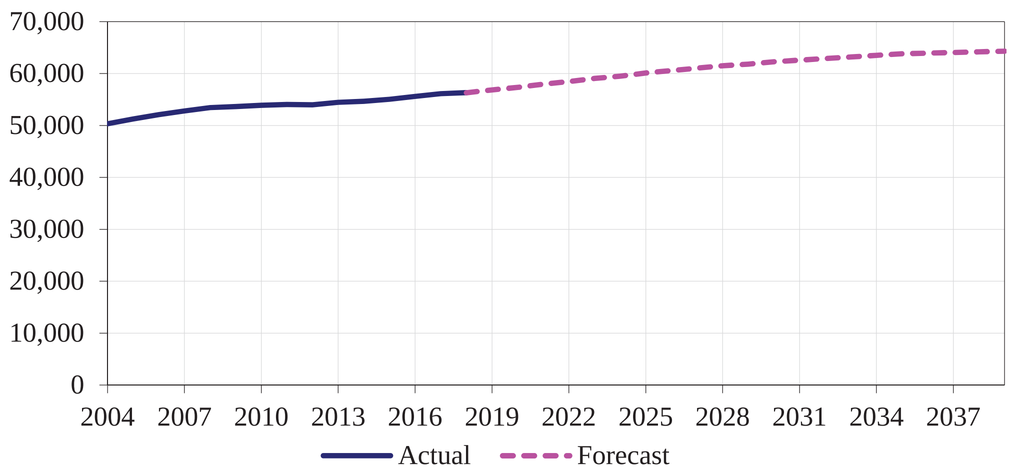
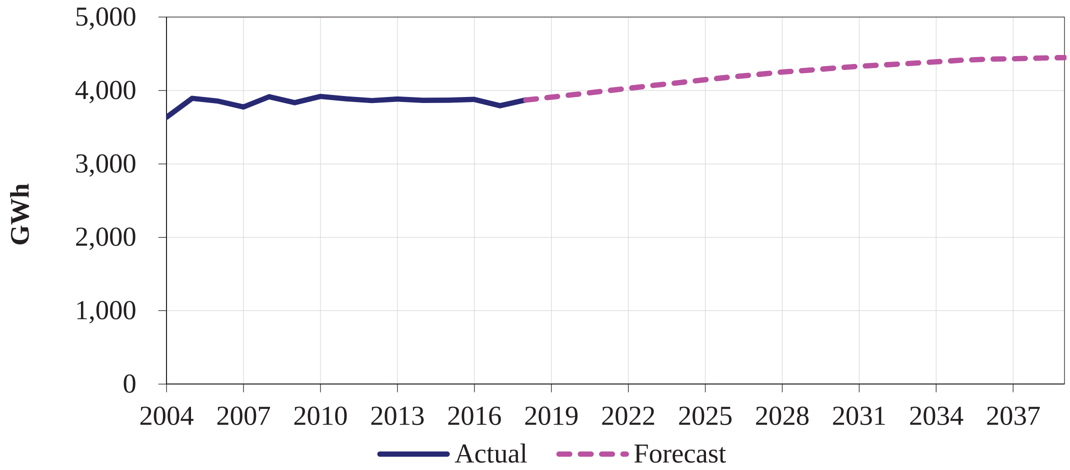


Table 3-4: NIPSCO Commercial Energy Sales



3.5 Industrial

The Industrial Energy Forecast Model projects the expected level of industrial energy sales in NIPSCO's service territory based on individual discussions with its largest industrial customers, recent historical industrial sales trends, and regional and global trends for specific industries. Accordingly, the Industrial Energy Forecast Model contains individual forecasts for the major industrial account customers. This year, the loss of energy demand from a major industrial account customer caused NIPSCO's industrial energy sales forecast to trend downwards compared to previous years' forecasts.

Information specific to the creation of the Industrial sales forecast is obtained through outreach by the NIPSCO Major Accounts Department to each of its 25 individually-forecasted industrial customer accounts. NIPSCO discusses individual business, economic and strategic objectives with each of its individually forecasted industrial accounts. 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. The resulting forecast incorporates the outlook for steel producers, refiners, industrial gases and a variety of other industrial manufacturing companies in NIPSCO's service territory. 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 and their consumption related to each of their major industrial production sites in NIPSCO's service territory.

The industrial sales forecast model also integrates a sales forecast for the remaining industrial accounts (identified as Other Industrial). This portion of the NIPSCO electric forecast is based primarily on historical data (billed volume) from the past six years with greater consideration given to use for the most recent year. Annual and monthly volumes were analyzed - min, max, and averages were calculated. Historical trends, if any, were identified and are reflected in the forecast.

Table 3-5: Industrial Energy Sales

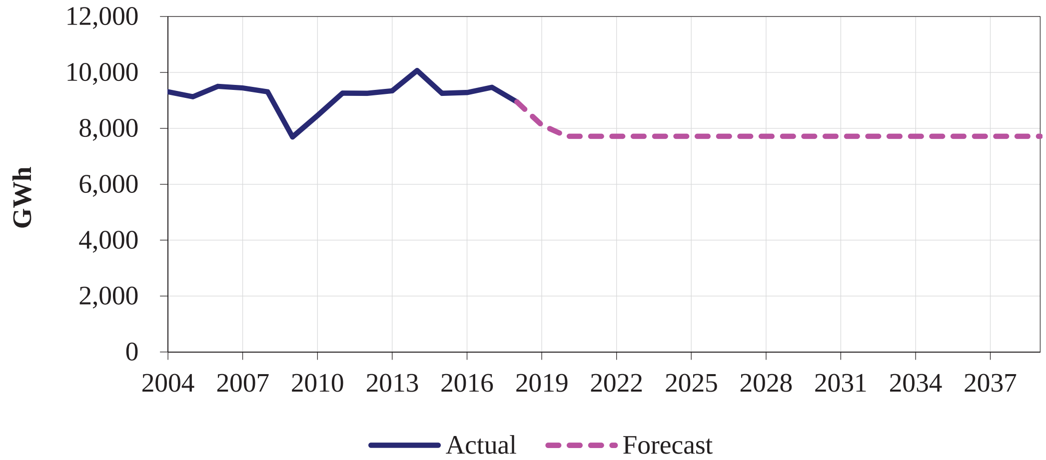


Table 3-6: Total Customers

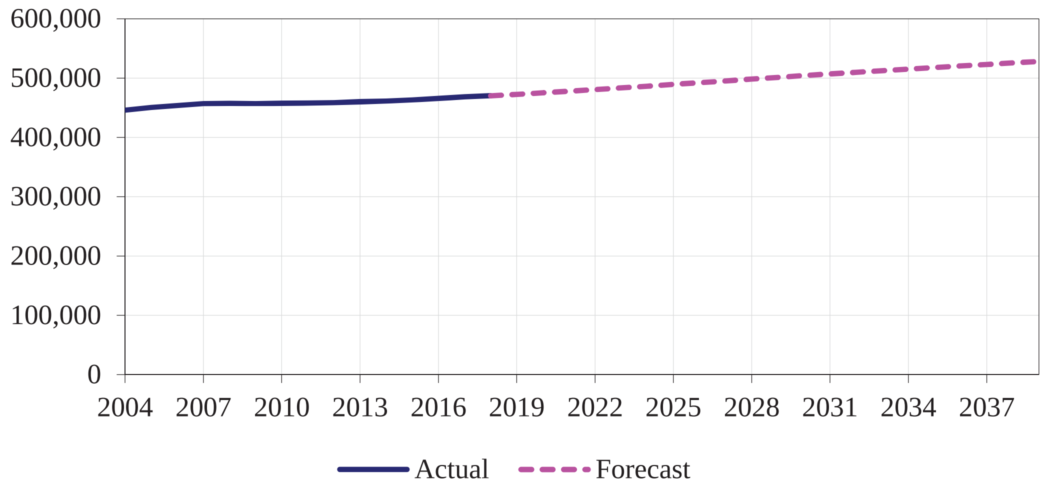
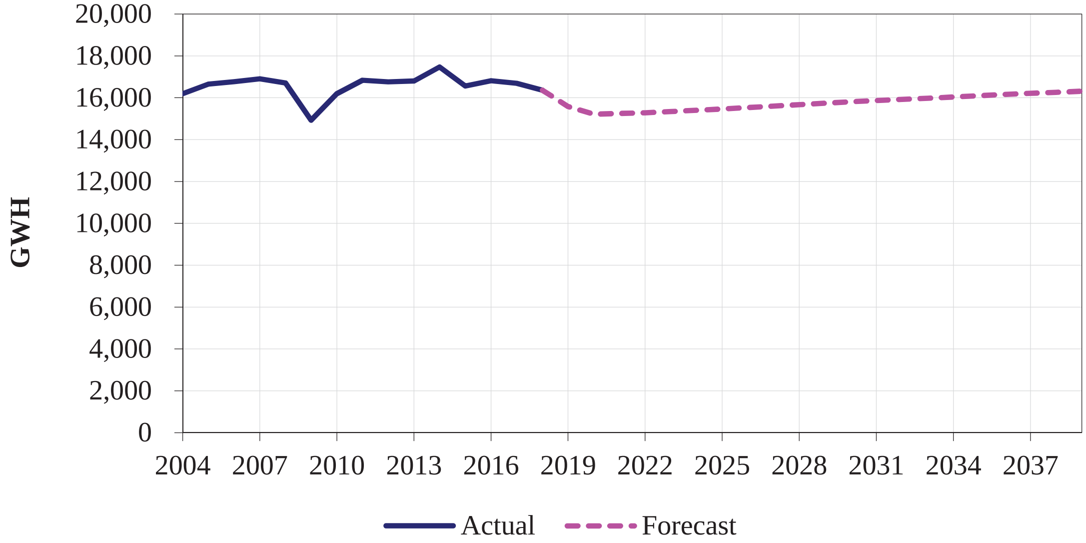


Table 3-7: Total Energy Sales



3.6 Street Lighting, Public Authority, Railroads, Company Use, Losses

The Public Authority, Railroads, Company use and losses forecasts are based on both current usage levels and anticipated future trends. The street lighting model utilizes an econometric model that accounts for the number of hours of dark and anticipated future trends. Nine years of historical data were used in the development of the street lighting long-term outlook. The model yielded an R-Square of 0.9154 and confirms statistically strong relationships between the independent and dependent variables.

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

3.7 Peak

NIPSCO uses an econometric model to project future peak demand on its system. The model incorporates Residential, Commercial, and Industrial energy levels, cooling degrees (summer) and heating degrees (winter) at peak hour, and the level of relative humidity at peak hour. The model also accounts for recent historical load factor levels and patterns associated with NIPSCO's large industrial customers. Using 32 years of data, the peak forecast is derived with a two-step approach accounting for the large influence of the Industrial class and the contribution of smaller customers.

The first step of the peak model accounts for the impact of Residential, Commercial, and Small Industrial energy levels and patterns. The model also takes into account the influence of weather at the time of the peak. Utilizing 32 years of historical data, the model yielded an R-

Square of 0.9428 and confirms a statistically strong relationships between the independent and dependent variables

The second step of the peak model accounts for the contribution of NIPSCO's large industrial customers to the NIPSCO peak. The model estimates the load factor associated with large customers and utilizes this to project peak. The load factor is estimated using a polynomial model that employs recent monthly load factory data to identify a monthly pattern. Once the load factor is estimated, it is combined with the large customer energy forecast to calculate this portion of the peak forecast. The large customer peak is then added to the initial peak generated from the first step to yield the total company peak outlook.

Peak Model

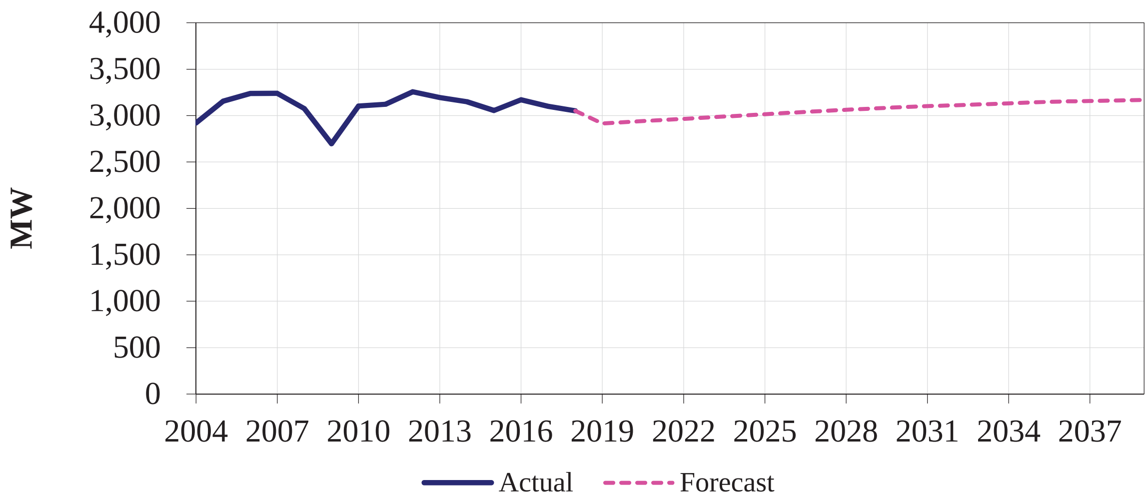
Peak_Step1 = f(Residential Energy, Commercial Energy, Small Industrial Energy, Cooling Degree Hours(Summer), Heating Degree Hours(Winter), Summer Humidity,)

Large Company Load Factor = f(Time, Time²)

Peak_Step2 = f(Large Company Load Factor, Large Company Energy, Monthly Hours)

NIPSCO Peak=Peak_Step1 + Peak_Step2

Table 3-8: Peak Hour



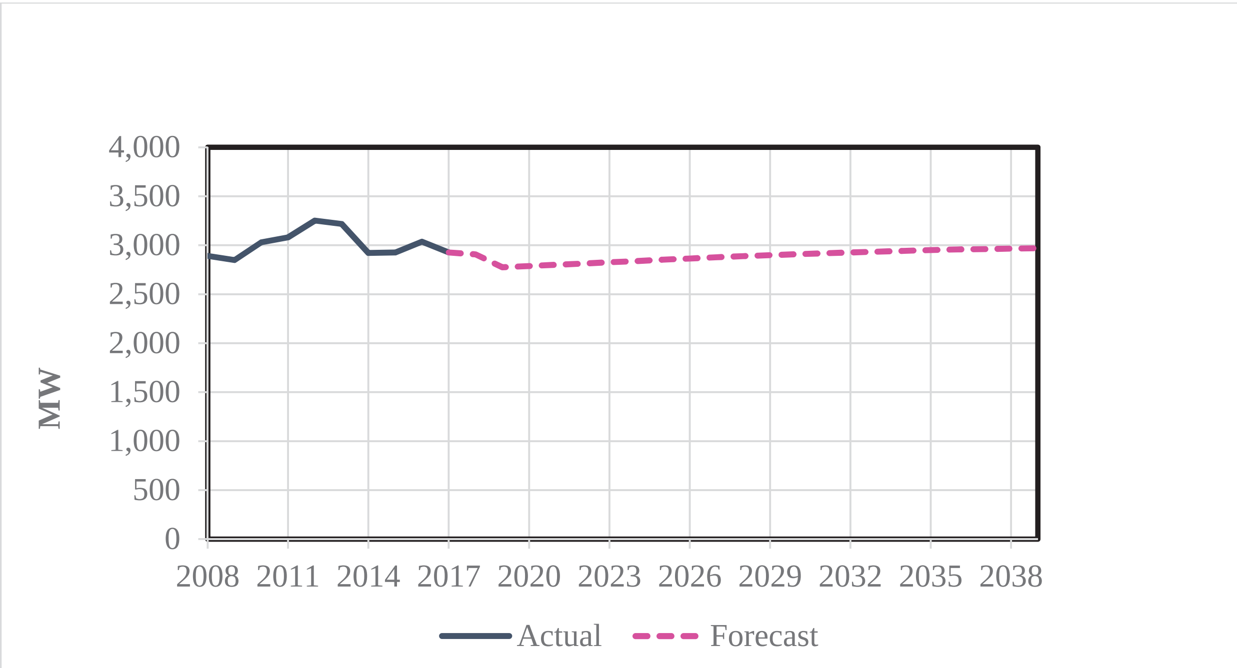
3.8 MISO Coincident Peak

MISO Coincident Peak is NIPSCO's monthly system peak at the time of MISO's system peak. NIPSCO uses an econometric model to project future demand on its system at the time of

MISO's system peak. The model incorporates NIPSCO's monthly peak demand levels and Cooling Degree Hours at the time of MISO's system peak. On average the MISO coincident peak level forecast is about 95% of NIPSCO internal peak level.

MISO Coincident Peak = f(NIPSCO Internal Peak, Cooling Degree Hours)

Table 3-9: MISO Coincident Peak



3.9 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. Although it is difficult to dispatch or coordinate, NIPSCO does have a currently-effective tariff rider available to such customers that enables the purchase from qualifying cogeneration facilities in the situation where the customer's generation exceeds load. Any such purchases are made pursuant to Rider 778 - Purchases from Cogeneration Facilities and Small Power Production Facilities - and this Rider allows for the purchases pursuant to a contract between NIPSCO and the customer. To the extent qualified and provided, Rider 778 also provides the ability to purchase capacity from such qualifying facilities.

3.10 Weather Normalization

NIPSCO produces estimates of weather-normalized energy for prior annual periods. Because industrial class energy consumption varies little with weather, NIPSCO weather-normalizes kWh sales for the Residential and Commercial classes only.

The normalization procedure uses the daily baseload, temperature sensitive load (TS) per CDD, TS per HDD, the daily non-temperature sensitive use per customer (NTSUPC), and the daily temperature sensitive use per customer per customer (TSUPC). Several assumptions are made in the normalization procedure. They are:

- May is the base load month and is not normalized for weather
- Heating energy volumes accounted for October through April
- Cooling energy volumes accounted for June through October
- October is accounted for both heating and cooling energy volumes

The general normalization equation is specified on a monthly per day basis and then scaled to a monthly concept by multiplying by days:

*Normal KWH/Customer = NTSUPC + ((TSUPC/HDD) * NHDD) + ((TSUPC/CDD) * NCDD))*

Where

NHDD: Normal Heating Degree Day, NCDD: Normal Cooling Degree Day
NTS UPC factor = May UPC /day
*NTSUPC = NTS UPC factor * billing days*
TSUPC = Total UPC – NTSUPC
TSUPC/HDD for heating months except October
TSUPC/CDD for cooling months except October
TSUPC/HDD for Oct = TSUPC/HDD from previous September
TSUPC/CDD for Oct = Average of TSUPC/CDD June-September of current season

The actual and normal energy sales for Residential and Commercial customers are shown in Figure 3-1 and Figure 3-2, respectively.

Figure 3-1: NIPSCO Residential GWh

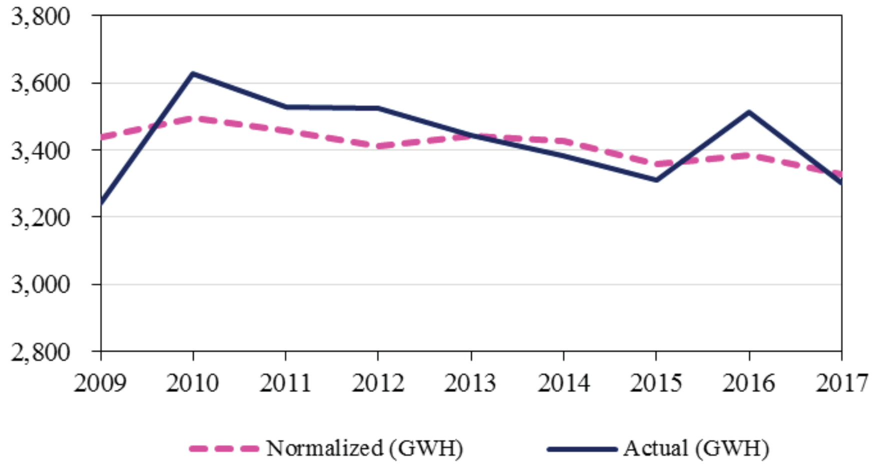
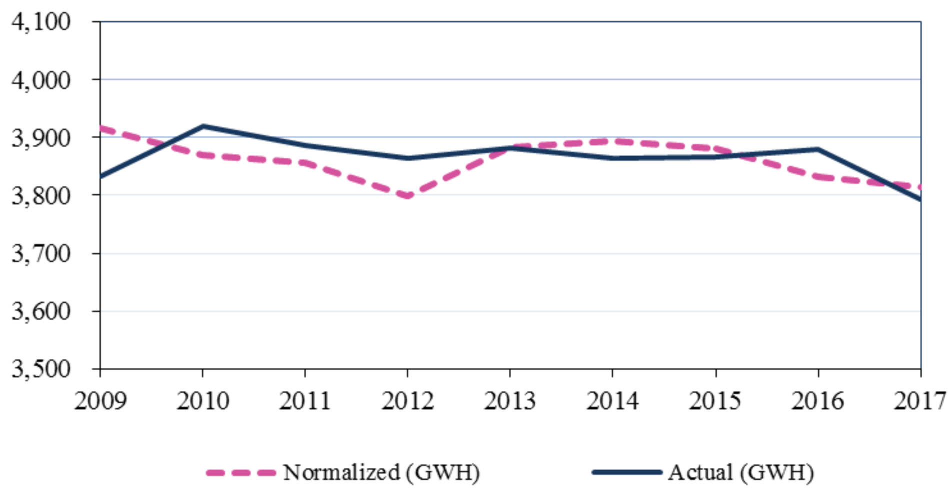


Figure 3-2: NIPSCO Commercial GWh



3.11 Forecast Results – Base Case

Over the forecast period, total energy is projected to remain flat and peak hour demand is projected to grow at 0.2%. NIPSCO expects overall customer growth to increase about 0.6% annually. Table 3-10 illustrates NIPSCO's electric energy and demand forecast.

Table 3-10: Electric Energy and Demand Forecast

	Energies (Gigawatt hour or "GWh")						Internal Peak Hour		MISO Coincident Peak Level	
Year	**Total Retail ***	**% Change**	**Losses**	**Total Output**	**% Change**	**Load Factor**	**MW**	**% Change**	**MW**	**% Change**
2008	16,705		897	17,602		65.3%	3,076		2,891	
2009	14,925	-10.7%	858	15,783	-10.3%	66.8%	2,696	-12.4%	2,848	-1.5%
2010	16,191	8.5%	915	17,106	8.4%	62.9%	3,103	15.1%	3,029	6.4%
2011	16,836	4.0%	892	17,728	3.6%	64.8%	3,122	0.6%	3,081	1.7%
2012	16,756	-0.5%	925	17,681	-0.3%	62.0%	3,257	4.3%	3,252	5.6%
2013	16,798	0.2%	839	17,638	-0.2%	63.0%	3,194	-1.9%	3,218	-1.0%
2014	17,467	4.0%	940	18,407	4.4%	66.7%	3,149	-1.4%	2,921	-9.2%
2015	16,563	-5.2%	886	17,449	-5.2%	65.2%	3,055	-3.0%	2,926	0.2%
2016	16,813	1.5%	913	17,726	1.6%	63.8%	3,173	3.9%	3,037	3.8%
2017	16,693	-0.7%	844	17,537	-1.1%	64.8%	3,087	-2.7%	2,927	-3.6%
2018	16,362	-2.0%	889	17,251	-1.6%	64.5%	3,051	-1.2%	2,907	-0.7%
2019	15,582	-4.8%	847	16,429	-4.8%	64.3%	2,916	-4.4%	2,776	-4.5%
2020	15,216	-2.4%	827	16,042	-2.4%	62.5%	2,932	0.6%	2,788	0.4%
2021	15,255	0.3%	829	16,084	0.3%	62.3%	2,949	0.6%	2,801	0.5%
2022	15,287	0.2%	831	16,118	0.2%	62.1%	2,965	0.5%	2,813	0.4%
2023	15,344	0.4%	834	16,178	0.4%	61.9%	2,982	0.6%	2,827	0.5%
2024	15,405	0.4%	837	16,242	0.4%	61.8%	2,999	0.5%	2,839	0.4%
2025	15,471	0.4%	841	16,311	0.4%	61.7%	3,016	0.6%	2,853	0.5%
2026	15,535	0.4%	844	16,379	0.4%	61.7%	3,033	0.6%	2,866	0.5%
2027	15,603	0.4%	848	16,451	0.4%	61.6%	3,048	0.5%	2,877	0.4%
2028	15,677	0.5%	852	16,529	0.5%	61.6%	3,064	0.5%	2,890	0.4%
2029	15,744	0.4%	856	16,600	0.4%	61.6%	3,077	0.4%	2,899	0.3%
2030	15,815	0.4%	859	16,674	0.4%	61.6%	3,091	0.5%	2,910	0.4%
2031	15,870	0.4%	862	16,733	0.4%	61.6%	3,103	0.4%	2,919	0.3%
2032	15,923	0.3%	865	16,788	0.3%	61.6%	3,113	0.3%	2,927	0.3%
2033	15,977	0.3%	868	16,845	0.3%	61.6%	3,123	0.3%	2,934	0.3%
2034	16,037	0.4%	871	16,909	0.4%	61.6%	3,133	0.3%	2,943	0.3%
2035	16,105	0.4%	875	16,981	0.4%	61.6%	3,145	0.4%	2,951	0.3%
2036	16,163	0.4%	878	17,042	0.4%	61.7%	3,152	0.2%	2,957	0.2%
2037	16,213	0.3%	881	17,094	0.3%	61.8%	3,158	0.2%	2,961	0.1%
2038	16,265	0.3%	884	17,148	0.3%	61.9%	3,164	0.2%	2,966	0.2%
2039	16,314	0.3%	887	17,201	0.3%	62.0%	3,169	0.2%	2,970	0.1%
Compound Average Growth Rate 2018-2039										
	0.0%			**0.0%**			**0.2%**		**0.1%**	
** Retail does not include bulk sales*										

Table 3-11 illustrates NIPSCO's electric energy by customer class.

Table 3-11: Energies by Customer Class

Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Other (GWh)	Total * (GWh)	Percent Change
2008	3,346	3,916	9,305	138	17,602	
2009	3,241	3,834	7,691	159	15,783	-10.3%
2010	3,626	3,920	8,459	186	17,106	8.4%
2011	3,527	3,886	9,257	166	17,728	3.6%
2012	3,524	3,863	9,250	119	17,681	-0.3%
2013	3,445	3,882	9,340	132	17,638	-0.2%
2014	3,384	3,864	10,071	148	18,407	4.4%
2015	3,310	3,867	9,249	138	17,449	-5.2%
2016	3,514	3,879	9,282	138	17,726	1.6%
2017	3,302	3,793	9,470	128	17,537	-1.1%
2018	3,411	3,871	8,947	134	17,251	-1.6%
2019	3,420	3,910	8,120	131	16,429	-4.8%
2020	3,418	3,949	7,718	129	16,042	-2.4%
2021	3,418	3,992	7,718	127	16,084	0.3%
2022	3,413	4,031	7,718	125	16,118	0.2%
2023	3,430	4,072	7,718	125	16,178	0.4%
2024	3,452	4,109	7,718	125	16,242	0.4%
2025	3,480	4,148	7,718	125	16,311	0.4%
2026	3,507	4,186	7,718	125	16,379	0.4%
2027	3,541	4,219	7,718	125	16,451	0.4%
2028	3,581	4,252	7,718	125	16,529	0.5%
2029	3,624	4,277	7,718	125	16,600	0.4%
2030	3,667	4,305	7,718	125	16,674	0.4%
2031	3,696	4,331	7,718	125	16,733	0.4%
2032	3,728	4,351	7,718	125	16,788	0.3%
2033	3,763	4,371	7,718	125	16,845	0.3%
2034	3,803	4,391	7,718	125	16,909	0.4%
2035	3,849	4,413	7,718	125	16,981	0.4%
2036	3,893	4,426	7,718	125	17,042	0.4%
2037	3,936	4,434	7,718	125	17,094	0.3%
2038	3,979	4,443	7,718	125	17,148	0.3%
2039	4,022	4,450	7,718	125	17,201	0.3%
Compound Average Growth Rate 2018-2039						
	0.8%	**0.7%**	**-0.7%**	**-0.3%**	**0.0%**	

**Includes Total Retail and Losses*

Table 3-12 displays the NIPSCO forecast by customer counts by class.

Table 3-12: Customer Counts by Class

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Total Customers
2008	400,640	53,438	2,484	754	457,316
2009	400,016	53,617	2,441	746	456,820
2010	400,522	53,877	2,432	740	457,571
2011	400,567	54,029	2,405	737	457,738
2012	401,177	53,969	2,445	758	458,349
2013	402,638	54,452	2,374	799	460,263
2014	403,272	54,635	2,338	751	460,996
2015	404,889	55,053	2,327	743	463,012
2016	407,268	55,605	2,313	744	465,930
2017	409,401	56,134	2,302	459	468,296
2018	411,114	56,325	2,302	459	470,199
2019	413,090	56,869	2,302	459	472,720
2020	415,157	57,351	2,302	459	475,269
2021	417,318	57,992	2,302	459	478,072
2022	419,577	58,465	2,302	459	480,803
2023	421,883	59,081	2,302	459	483,725
2024	424,236	59,519	2,302	459	486,517
2025	426,636	60,128	2,302	459	489,525
2026	429,083	60,589	2,302	459	492,433
2027	431,569	61,061	2,302	459	495,391
2028	434,147	61,535	2,302	459	498,443
2029	436,719	61,833	2,302	459	501,313
2030	439,303	62,304	2,302	459	504,368
2031	441,836	62,609	2,302	459	507,206
2032	444,249	62,905	2,302	459	509,915
2033	446,620	63,203	2,302	459	512,584
2034	449,029	63,513	2,302	459	515,303
2035	451,458	63,825	2,302	459	518,044
2036	453,890	63,956	2,302	459	520,606
2037	456,306	64,079	2,302	459	523,146
2038	458,698	64,210	2,302	459	525,669
2039	461,083	64,330	2,302	459	528,174
Compound Average Growth Rate 2018-2039					
	0.5%	**0.6%**	**0.0%**	**0.0%**	**0.6%**

3.12 Discussion of Forecast and Alternative Cases

3.12.1 High/Low Growth Cases

The high and low load growth cases were constructed from the base case forecast models and employed optimistic and pessimistic economic and demographic data from IHS Global Insight. 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. The high load growth scenario is created by looking at the customer's previous five years of history and using the peak usage and demand, as well as taking into account current business practices and any other potential growth. The low load growth scenario takes each individual customer's "worst case" scenario, whereas customer's minimum operating levels with major loads are idled, and using Rate limitations and other business protocols as guiding factors. Table 3-13 reflects NIPSCO's base, high and low load forecast scenarios for selected years.

Table 3-13: NIPSCO IRP Scenarios – Selected Year

NIPSCO IRP Scenarios - Selected Year											
	Energy Sales - GWh				Internal Demand - MW				MISO Coincident Peak - MW		
	Base	High	Low		Base	High	Low		Base	High	Low
Year	GWh	GWh	GWh		MW	MW	MW		MW	MW	MW
2018	17,251	17,587	16,909		3,051	3,119	2,982		2,907	2,972	2,842
2023	16,178	17,271	11,568		2,982	3,178	2,446		2,827	3,012	2,319
2028	16,529	18,134	11,770		3,064	3,358	2,500		2,890	3,167	2,358
2033	16,845	18,850	11,869		3,123	3,510	2,513		2,934	3,298	2,362
2038	17,148	19,639	11,960		3,164	3,666	2,509		2,966	3,437	2,352
		v Base				v Base				v Base	
		High	Low			High	Low			High	Low
		GWh	GWh			MW	MW			MW	MW
2018	-	1.95%	-1.98%		-	2.2%	-2.3%			2.2%	-2.3%
2023	-	6.76%	-28.50%		-	6.6%	-18.0%			6.6%	-18.0%
2028	-	9.71%	-28.79%		-	9.6%	-18.4%			9.6%	-18.4%
2033	-	11.90%	-29.54%		-	12.4%	-19.5%			12.4%	-19.5%
2038	-	14.53%	-30.25%		-	15.9%	-20.7%			15.9%	-20.7%

3.13 Evaluation of Model Performance and Accuracy

NIPSCO tracks its forecast in terms of mean absolute error ("MAE"). Data for 2006-2017 show that the MAE of the one-year-ahead peak hour demand forecast is 3.3% (MAE of the one-year-ahead MISO coincident peak hour demand forecast is 0.2%); the two-year-ahead forecast has a 4.2% MAE; and the MAE for the five-year-ahead forecast is 5.9%. These represent total forecast error including the effect of abnormal weather at peak. The comparable MAE GWh sales is 3.2% for the one-year-ahead forecast; 4.7% for the two-year-ahead forecast; and 3.8% for the five-year-ahead forecast. Class comparisons to weather-normalized actual data show variances with residential and commercial of 2.0% and 3.3% MAE for the one-and two-year ahead forecasts. Industrial GWh are not weather normalized because historically they have not fluctuated with weather and show 5.7% and 8.3% MAE for the one-year-ahead and the two-year-ahead forecast. NIPSCO does not have any firm wholesale power sales.

Table 3-14 and Table 3-15 show data for 2006-2017 for total GWh sales and peak hour MW and compare forecasts to actual data not normalized for weather. Table 3-16 and 3-17 show GWh sales by class. GWh are compared to actual data normalized for weather. Table 3-18 shows the performance of the MISO coincident peak model performance since 2012.

Table 3-14: Internal Peak Hour Demand (MW)

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
2006	3,238	3,099	4.3%	3,077	5.0%	3,064	5.4%
2007	3,239	3,154	2.6%	3,134	3.2%	3,146	2.9%
2008	3,076	3,224	4.8%	3,188	3.6%	3,201	4.1%
2009	2,696	3,024	12.2%	3,248	20.5%	3,170	17.6%
2010	3,103	2,965	4.5%	3,088	0.5%	3,232	4.2%
2011	3,122	3,134	0.4%	3,093	0.9%	3,282	5.1%
2012	3,257	3,183	2.3%	3,195	1.9%	3,323	2.0%
2013	3,194	3,172	0.7%	3,306	3.5%	3,233	1.2%
2014	3,149	3,209	1.9%	3,243	3.0%	3,287	4.4%
2015	3,055	3,173	3.9%	3,259	6.7%	3,300	8.0%
2016	3,170	3,118	1.6%	3,187	0.5%	3,419	7.8%
2017	3,100	3,113	0.4%	3,146	1.5%	3,349	8.0%
Average			**3.3%**		**4.2%**		**5.9%**

**Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance includes weather effect.*

Table 3-15: Total GWh including Losses

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
2006	17,500	16,750	4.3%	17,235	1.5%	17,544	0.3%
2007	17,655	17,725	0.4%	16,916	4.2%	17,928	1.5%
2008	17,602	18,355	4.3%	17,938	1.9%	18,374	4.4%
2009	15,783	16,898	7.1%	18,446	16.9%	17,716	12.2%
2010	17,106	15,910	7.0%	17,340	1.4%	17,373	1.6%
2011	17,728	16,715	5.7%	16,931	4.5%	18,389	3.7%
2012	17,681	17,754	0.4%	17,220	2.6%	18,804	6.3%
2013	17,638	17,591	0.3%	18,622	5.6%	18,258	3.5%
2014	18,407	18,275	0.7%	17,786	3.4%	18,367	0.2%
2015	17,449	18,417	5.5%	18,611	6.7%	17,747	1.7%
2016	17,726	18,103	2.1%	18,537	4.6%	18,995	7.2%
2017	17,537	17,647	0.6%	18,175	3.6%	18,118	3.3%
Average			**3.2%**		**4.7%**		**3.8%**

** Actual GWh not adjusted for weather. Forecasted GWh assumes normal weather, therefore, variance includes weather effect.*

Table 3-16: Residential and Commercial GWh

		1-Year Ahead		2-Year Ahead	
	Normal *	**Forecast**	**% Var.**	**Forecast**	**% Var.**
2008	7,328	7,641	4.3%	7,600	3.7%
2009	7,357	7,534	2.4%	7,757	5.4%
2010	7,366	7,431	0.9%	7,659	4.0%
2011	7,313	7,428	1.6%	7,474	2.2%
2012	7,213	7,382	2.3%	7,492	3.9%
2013	7,323	7,414	1.2%	7,427	1.4%
2014	7,320	7,398	1.1%	7,466	2.0%
2015	7,241	7,409	2.3%	7,461	3.0%
2016	7,216	7,323	1.5%	7,476	3.6%
2017	7,140	7,322	2.6%	7,384	3.4%
Average			**2.0%**		**3.3%**

** Adjusted for weather*

Table 3-17: Industrial GWh

		1-Year Ahead		2-Year Ahead	
	Actual *	**Forecast**	**% Var.**	**Forecast**	**% Var.**
2008	9,305	9,861	6.0%	9,523	2.3%
2009	7,691	8,579	11.6%	9,833	27.8%
2010	8,459	7,692	9.1%	8,879	5.0%
2011	9,257	8,220	11.2%	8,629	6.8%
2012	9,250	9,243	0.1%	8,632	6.7%
2013	9,340	9,111	2.4%	10,020	7.3%
2014	10,071	9,799	2.7%	9,245	8.2%
2015	9,249	9,923	7.3%	10,055	8.7%
2016	9,282	9,713	4.6%	9,969	7.4%
2017	9,470	9,288	1.9%	9,720	2.6%
Average			**5.7%**		**8.3%**

** No weather effect measured for industrial load*

Table 3-18: MISO Coincident Peak Demand

MISO Coincident Peak Demand - MW
Absolute % Variance of Forecast v Actual

		1-Year Ahead	
Year	Actual *	Forecast	% Var.
2012	2.0%	1.6%	0.4%
2013	3.6%	3.8%	0.2%
2014	2.8%	2.8%	0.0%
2015	2.3%	2.5%	0.2%
Average			**0.2%**

*Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance include weather effect. Please note: MISO coincident Peak model performance is filed with MISO annually on November 1st.

Section 4. Supply-Side Resources

4.1 Fuel Procurement Strategy

4.1.1 Coal Procurement and Inventory Management Practices

4.1.1.1 Coal Supply Strategy

NIPSCO employs a multifaceted strategy to guide coal procurement activities associated with the fuel supply requirements for its coal-fired units. The goal of this strategy is to maximize reliability while maintaining customer affordability. Key elements include: (1) procuring coal supply from sources that minimize the total cost of fuel, O&M costs, environmental costs, inventory costs and other cost impacts ("total cost of ownership"); (2) hedging customers' price exposure with forward purchases to protect against price volatility; (3) supporting environmental compliance; (4) maintaining reliable inventory levels; (5) ensuring reliability of coal supply and delivery; and (6) maximizing operational flexibility and reliability by procuring coal types that can be used in more than one unit whenever possible.

4.1.1.2 Coal Procurement

NIPSCO maintains a five-year baseline coal forecast that is used to create a strategy that drives its fuel procurement plan. It estimates coal and related coal transportation procurement requirements needed to maintain reliable and economic coal inventory levels. The strategy and fuel procurement plan are highly dynamic and are updated on a periodic basis in response to energy market conditions. Over the past several years, environmental regulations, a significant influx of highly variable renewable generation (e.g. wind and solar), low natural gas prices, and energy efficiency and other demand side initiatives have made coal-fired generation the marginal supply source. Consequently, this has created an environment with highly variable and nearly unpredictable coal purchase requirements. Therefore, NIPSCO's fuel procurement plans must remain as flexible as possible while still maintaining reliable supply. Obtaining volume flexibility can be challenging since coal suppliers and transportation providers typically require firm volume commitments.

4.1.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance of coal in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower production costs and highly efficient natural gas extraction processes (horizontal drilling and fracking) have kept natural gas a competitive fuel when used in high efficiency, CCGT units. In addition, increases in wet gas production to gather petroleum liquids further increase natural gas supply when oil prices rise. Oil prices have risen steadily over the last year helping to spur wet gas production. These dynamics are expected to keep natural gas pricing low in the near term. Longer term natural gas prices are expected to recover somewhat with the addition of new CCGTs and increased natural gas export capacity. These market dynamics continue to displace a significant amount of coal-fired electric generation and are keeping coal prices relatively low. Decreased coal demand and higher mining costs driven by government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies over the last few years. The restructuring of coal companies' debt and other costs through the bankruptcy process should allow them to produce coal in this competitive environment. Supply has been rationalized and any significant increase in demand could result in coal price volatility. However, several factors may limit the upside for coal prices. The first factor is the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal-fired electric generation. A second factor is utilities continue to retire older, higher cost coal-fired generation and this has reduced demand. Lastly, low energy prices driven by natural gas pricing and renewables will also limit demand for coal if coal prices spike.

The competitive energy market has also driven a shift in coal supply regions. Specifically, the cost to produce coal in the Appalachian regions and low coal prices have resulted in declining coal production and this has increased market share of the lower cost Illinois Basin ("ILB") region. Even with its higher sulfur content, ILB coal has become an export resource, and its use has increased domestically as utilities have installed flue gas desulfurization systems ("FGDs") to meet tighter sulfur dioxide limits and other emission standards. Southeast utilities have started using ILB coal to replace higher cost Columbian and Central Appalachia coal.

The use of Powder River Basin ("PRB") coal from Wyoming and Montana has increased significantly over the last decade. Although PRB coal has a lower heat content than coals mined in other regions, utilities typically blend PRB coal with Central Appalachian, ILB, or Northern Appalachian ("NAPP") coals to reduce their overall fuel costs. Asian demand for PRB coal has also grown as Japan and China have built new, high efficiency coal units and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand. Historically, Central Appalachian and NAPP coal have been exported into metallurgical coal and some steam coal markets abroad. Since the end of 2016, demand for seaborne coal has increased. It appears that exports will remain resilient with export volumes over the last year at or near the top of the five year range. Coal suppliers need this to continue in order to offset losses in domestic markets.

Overall, these fundamentals are bearish for coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices and incorporate in its procurement strategies.

4.1.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Domestic demand for coal has continued to trend lower over the last two years; therefore, prices have remained relatively low and stable. NAPP coal, used by NIPSCO as a blend fuel in one of its cyclone units, and ILB coal have had relatively strong price increases off of 2016 lows as export demand and prices have trended higher over the last two years.

Pricing for PRB coal has remained low over the last two years and is close to the marginal cost of production.

The export dynamic will likely keep upward pressure on the market in the near term and this would likely lower domestic demand for coal unless domestic energy prices rise. All domestic coal pricing is expected to remain soft as long as energy prices stay low, and will likely keep coal prices flat for the balance of 2018 into 2019.

4.1.1.5 Coal and Issues of Environmental Compliance

Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to evolve in a manner that meets current and future environmental requirements.

4.1.1.6 Maintenance of Coal Inventory Levels

NIPSCO has an ongoing strategy to maintain stable coal inventories and reviews inventory target levels annually and may make adjustments in anticipation of changes in supply availability relative to demand, transportation constraints and unit consumption. NIPSCO may modify target inventory levels on a unit-by-unit basis depending on the unit consumption, delivery rates, reliability of coal supply and station coal handling operations. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates and variability in delivery performance generally require higher levels of inventory to insure reasonably adequate reliability.

4.1.1.7 Forecast of Coal Delivery and Transportation Pricing

To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts that consider current and future coal supply commitments. All fuel procurement options are compared on a delivered cost basis, which includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have been somewhat stable from the various supply regions, particularly shipments originating in the PRB region due to infrastructure improvements. Railroads typically make investment in infrastructure and equipment to support anticipated shipment rates. The cyclical nature of the railroad business can create short term transportation constraints and can impact NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years.

Transportation rates have declined somewhat given the competition in the energy markets. Railroads have been willing to rationalize rail rates, as shown in the market assessment plots below, to keep market share.

Figure 4-1: PRB Customer Rates

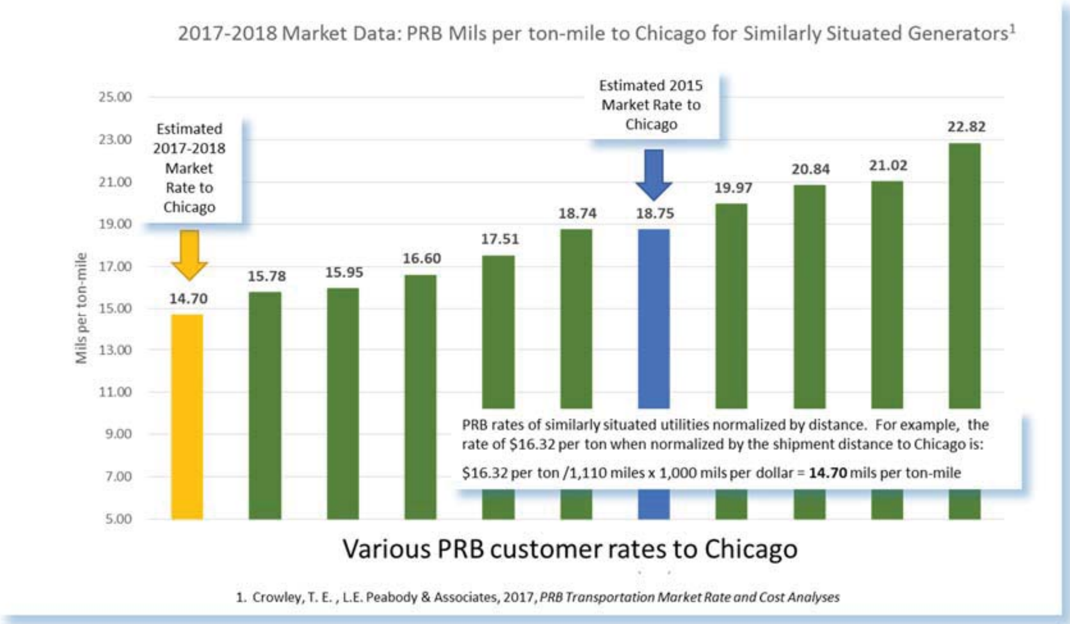
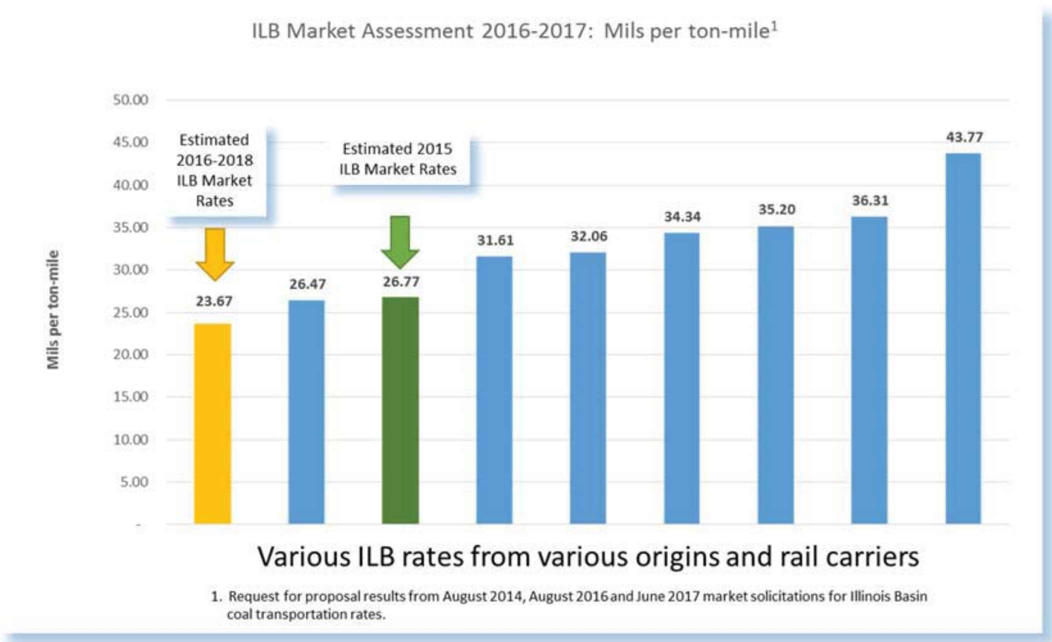


Figure 4-2: ILB Customer Rates



This pricing trend has improved the competitiveness of NIPSCO's coal-fired generation to a certain extent.

4.1.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options from various supply regions and destination for most of its coal transportation moves, and is further disadvantaged due to its geographical location. Not only are rail transportation options limited, other transport modes (trucking, barging and lake vessels) are not economically or logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one railroad. All coal deliveries by this railroad to Schahfer have been transported under agreements that historically escalated transportation rates that also included fuel surcharges indexed to oil prices. However, under this structure, lower power prices lead to a reduction in coal demand. Therefore, NIPSCO and this railroad worked to develop an agreement that lowered rates to improve the station's competitiveness in the market. As stated above, energy markets have forced a rationalization of coal pricing and associated transportation costs. NIPSCO expects this dynamic to continue for the foreseeable future.

As a result, PRB and ILB coal transportation rates have been reduced by nearly 50%. Fuel surcharges continue to fluctuate with the changes in oil prices. The expectation for transportation pricing is also expected to remain soft as long as energy prices stay low, and expect rates to be flat for the balance of 2018 into 2019. Increases in fuel charges could lead to modest transportation cost increases as oil prices trend higher.

4.1.1.9 Coal Contractual Flexibility, Deliverability and Procurement

Contract terms for coal and coal transportation agreements are typically one to five years in duration. Spot purchases are made on an as-needed basis to manage inventory fluctuations. In an effort to minimize variations in inventory levels and accommodate unit maintenance outages, most coal types under contract can be used in more than one unit. The fuel blending strategy can also be adjusted to conserve a particular type of coal if supply problems are experienced. In addition, coal suppliers have been more amenable to providing some volume flexibility. This has supported NIPSCO's inventory management efforts.

4.1.2 Natural Gas Procurement and Management

NIPSCO currently procures natural gas for its CCGT generating station using a natural gas supply contract with an energy manager that delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on the interstate pipeline, Midwestern Gas Transmission Company, and releases the capacity to the energy manager. The contract has provisions to purchase next day and intraday firm gas supplies to serve the daily needs of the facility. NIPSCO nominates and balances the gas supply needs of the CCGT generating station. A portion of the gas supply for the Sugar Creek Generating Station ("Sugar Creek") is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

The coal units and combustion turbines ("CTs") at NIPSCO are located within the NIPSCO natural gas local distribution company service territory. NIPSCO maintains a separate contract for firm delivered natural gas supply and energy management for these units. The contract has provisions to nominate next-day usage based on the expected usage of each generating station. The actual usage is balanced daily and balancing is the responsibility of the energy manager.

4.2 Electric Generation Gas Supply Request for Proposal Process

NIPSCO conducts two separate RFPs for the electric generation firm natural gas supply, one for the Sugar Creek facility and a separate one for the coal units and CTs. The RFP process may be done on a seasonal or annual basis depending on the current contract length and supplier agreement. The process includes qualifying potential suppliers, customizing the RFP based on near-term system needs, and gas supply trends. Suppliers are chosen based on the overall value of the package and ability to serve the needs of the facility. To date, NIPSCO has entered into electric generation gas supply agreements that extend no longer than one year, but is always evaluating the value and benefits of longer term agreements.

4.3 Existing Resources

NIPSCO has a variety of generation resources to meet its customers' forecast capacity and energy needs. Not only do these resources need to meet the principles set out in Section 1, they must operate within MISO, the Regional Transmission Organization, and subject to NERC standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization, ReliabilityFirst, standards approved by the Federal Energy Regulatory Commission ("FERC").

4.4 Supply Resources

NIPSCO owned generating resources consist of coal, natural gas and hydro units. Additionally NIPSCO meets it customer needs with 2 wind purchase power agreements and has an extensive demand response ("DR") program via its large industrial customers. The total Net Demonstrated Capacity ("NDC") of the existing resources is 2,925 MW across multiple generation sites, including the Schahfer (Units 14, 15, 16A, 16B, 17 and 18), Michigan City (Unit 12), Bailly (Units 10), Sugar Creek and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). Of the total capacity, 61% is from coal-fired units, 21% is from natural gas-fired units and 18% is from industrial interruptible DR program. Consistent with the 2016 IRP preferred plan NIPSCO retired 2 coal fired units (Units 7 and 8) at the Bailly in May 2018.

Table 4-1 provides a summary of the current generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity

Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	14	Coal	431
	15	Coal	472
	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	1,780
Sugar Creek		NG	535
Bailly	10	NG	31
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	100
NIPSCO			2,925

NG=Natural Gas

4.4.1 Michigan City Generating Station

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. It has one base-load unit, Unit 12 and is equipped with selective catalytic reduction ("SCR") and over-fire air ("OFA") systems to reduce nitrogen oxide ("NO_x") emissions. A new FGD ("") system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-2.

Table 4-2: Michigan City Generating Station

	Unit 12
NET Output	
Min (MW)	315
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	Coal
Turbine	General Electric
Frame	G2
In-Service	1974
Environmental Controls	FGD, SCR, OFA

4.4.2 R.M. Schahfer Generating Station

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. It is the largest of NIPSCO's generating stations. There are four coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce sulfur dioxide ("SO_2") emissions and SCR, SNCR, low NO_x burners ("LNB"), and OFA systems to reduce NO_x emissions. Unit 14 burns low and medium sulfur coal blends and Unit 15 burns low-sulfur coals to minimize SO_2 emissions. As part of the Company's Clean Air Interstate Rule (CAIR) Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. Installation of a new LNB with OFA system was completed on Unit 15 in 2009. A new FGD plant on Unit 14 was placed in service in 2013. FGD installation on Unit 15 was completed in 2014. The individual unit characteristics of Schahfer are provided in Table 4-3.

Table 4-3: R.M. Schahfer Generating Station

	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	290	250	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	1976	1979	1983	1986	1979	1979
Environmental Controls	FGD, SCR, OFA	FGD, SNCR, LNB, OFA	FGD, LNB, OFA	FGD, LNB, OFA	----	----

4.4.3 Sugar Creek Generating Station

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired CTs and CCGTs were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is its newest electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two generators and one steam turbine generator are operated in the CCGT mode and environmental control technologies include SCR to reduce NO_x, and dry low NO_x ("DLN") combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 4-4.

Table 4-4: Sugar Creek Generating Station

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	120	120	120
Max (MW)	156	157	222
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA	7FA	D11
In-Service	2002	2002	2003
Environmental Controls	SCR, DLN	SCR, DLN	---

4.4.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources)

Norway Hydro is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has four generating units capable of producing up to 7.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 4-5.

Table 4-5: Norway Hydro

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydro is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has three generating units capable of producing up to 9.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 4-6.

Table 4-6: Oakdale Hydro

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

4.4.5 Barton and Buffalo Ridge Wind (NIPSCO Purchase Power Agreements)

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 4-7.

Table 4-7: Barton Wind PPA

	Barton PPA
NET Output	
Per Unit (MW)	2
Number of Units	25
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County, South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 4-8.

Table 4-8: Buffalo Ridge Wind PPA

	Buffalo Ridge PPA
NET Output	
Per Unit (MW)	2
Number of Units	24
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

4.5 Total Resource Summary

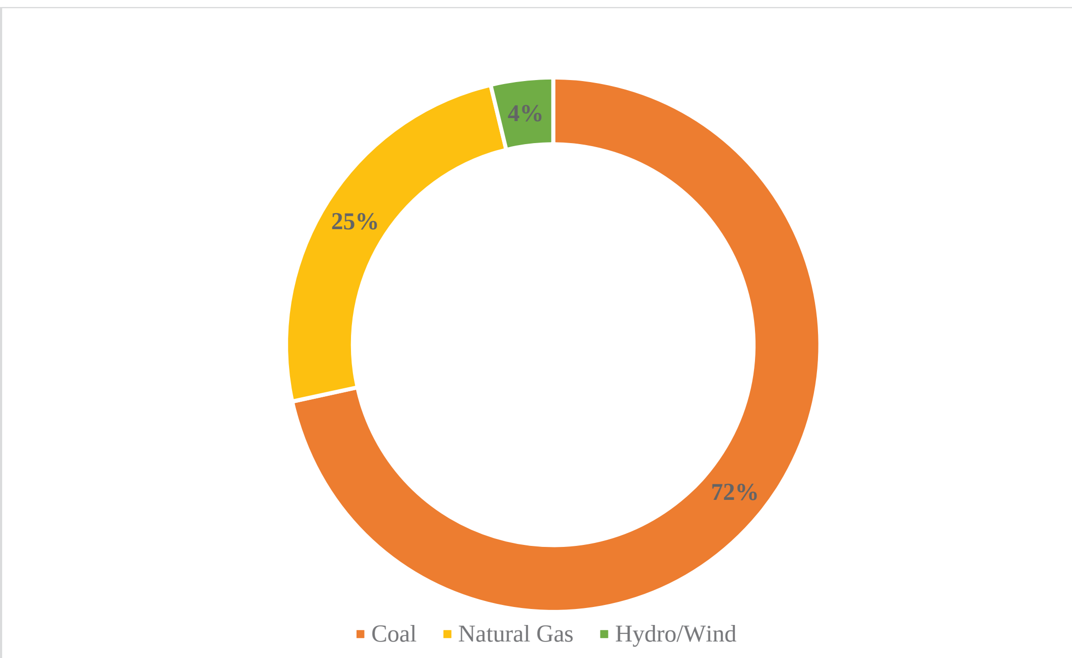
Table 4-9 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-3 illustrates NIPSCO's existing resources by fuel type.

Table 4-9: Existing Generating Units

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	14	Coal	431	1976
	15	Coal	472	1979
	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
		Subtotal	1,780	
Sugar Creek		NG	535	2002
Bailly	10	NG	31	1968
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind		Wind	100	2009
NIPSCO			2,925	

NG=Natural Gas

Figure 4-3: Existing Resources Net Demonstrated Capacity



4.6 Operations Management and Dispatch Implications

The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, environmental considerations and the overall generation mix within MISO may affect the level of future dispatch.

4.7 MISO Wholesale Electricity Market

MISO supplies an important element to NIPSCO's long term plans – ongoing liquidity. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. In 2018, MISO has members from 15 states and one Canadian province with a generation capacity of 200,000 MW and 65,800 miles of high-voltage transmission. MISO manages one of the world's largest energy and operating markets that includes a Day-Ahead Market, Real-Time Market and Financial Transmission Rights Market.

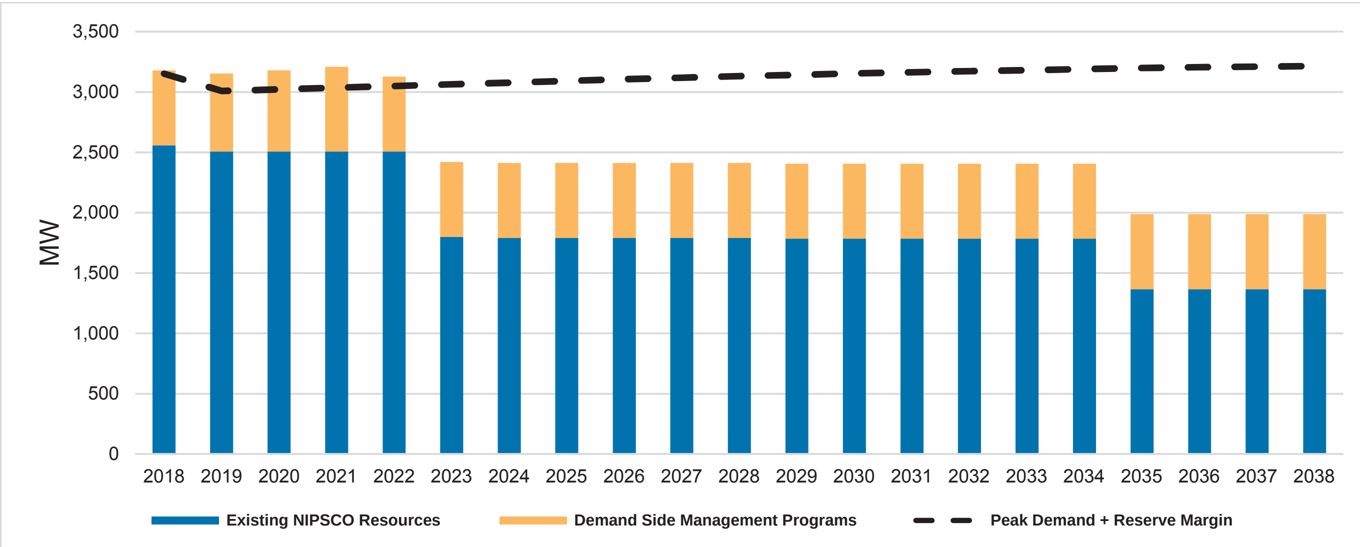
4.8 Resource Adequacy

Consistent with the principles set out in Section 1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse and affordable supply. As part of the Resource Adequacy planning process, NIPSCO is now utilizing the peak demand forecast coincident with the MISO peak demand to determine its capacity requirements. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks, which is typically in the summer. The methodology for calculating the coincident peak demand is described in detail in Section 3. NIPSCO's assessment of its existing resources against the future needs of its customers is shown in Table 4-10.

Table 4-10: Assessment of Existing Resources v. Demand Forecast (Base)

	(a)	(b)	(c)	(d)	(e)
Year	**MISO Coincident Peak Demand**	**Peak Demand + Reserve Margin**	**Demand Side Management Programs**	**Existing NIPSCO Resources**	**Capacity Position/Long Short (c+d-b)**
2018	2,907	3,152	621	2,557	26
2019	2,776	3,009	646	2,507	144
2020	2,788	3,022	673	2,507	158
2021	2,801	3,036	702	2,507	173
2022	2,813	3,050	621	2,507	78
2023	2,827	3,064	621	1,799	(644)
2024	2,839	3,078	621	1,791	(666)
2025	2,853	3,092	621	1,791	(680)
2026	2,866	3,106	621	1,791	(694)
2027	2,877	3,119	621	1,791	(707)
2028	2,890	3,132	621	1,791	(721)
2029	2,899	3,143	621	1,785	(737)
2030	2,910	3,154	621	1,785	(748)
2031	2,919	3,164	621	1,785	(758)
2032	2,927	3,173	621	1,785	(767)
2033	2,934	3,181	621	1,785	(775)
2034	2,943	3,190	621	1,785	(784)
2035	2,951	3,199	621	1,367	(1,212)
2036	2,957	3,206	621	1,367	(1,218)
2037	2,961	3,210	621	1,367	(1,222)
2038	2,966	3,215	621	1,367	(1,227)
Notes:					
Reserve Margin Assumption = 8.4%					
Existing Resource Capacity based on NIPSCO UCAP calculation and reflects retirements in 2023 and 2035 *Demand Side Management Programs include Demand Response and Energy Efficiency Programs*					

Figure 4-4: Resource Adequacy Assessment (MW)



Based on the 2016 IRP preferred plan, NIPSCO would need additional capacity resources to meets its customer demand starting in 2023 after the retirements of Schahfer Units 17 and 18. NIPSCO has evaluated a range of resource options to meet that need.

4.9 Future Resource Options

New resources may be needed to meet the future electricity requirements of NIPSCO's customers over time, so it is critical that valid cost and operational estimates are developed for such future resource options in the IRP modeling. In the 2018 IRP, NIPSCO developed a two-step process to improve the new resource evaluation process and to respond to feedback received in the 2016 IRP.[2] This process entailed:

- A review of multiple third-party data sources to assess current and future estimates of resource technology cost, as well as plausible cost ranges, and performance characteristics

- Development of final inputs for IRP modeling based on real bid data that was received from the All-Source RFP.

4.9.1 Third-Party Data Source Review

NIPSCO worked with CRA to perform a screen of third-party sources for new resource cost and operational parameter estimates. The screen included the study NIPSCO commissioned for its 2016 IRP, public sources that develop estimates, such as government forecasts and other

[2] Note that a discussion of future demand-side resource options is included in Section 5.

utility IRPs, and subscription services which provide data and capital cost estimates over time. Figure 4-5 provides a list of the sources that were relied upon for the third-party screen.

Based on the source review, NIPSCO identified a list of feasible technology options to be assessed in the initial round of review. These included:

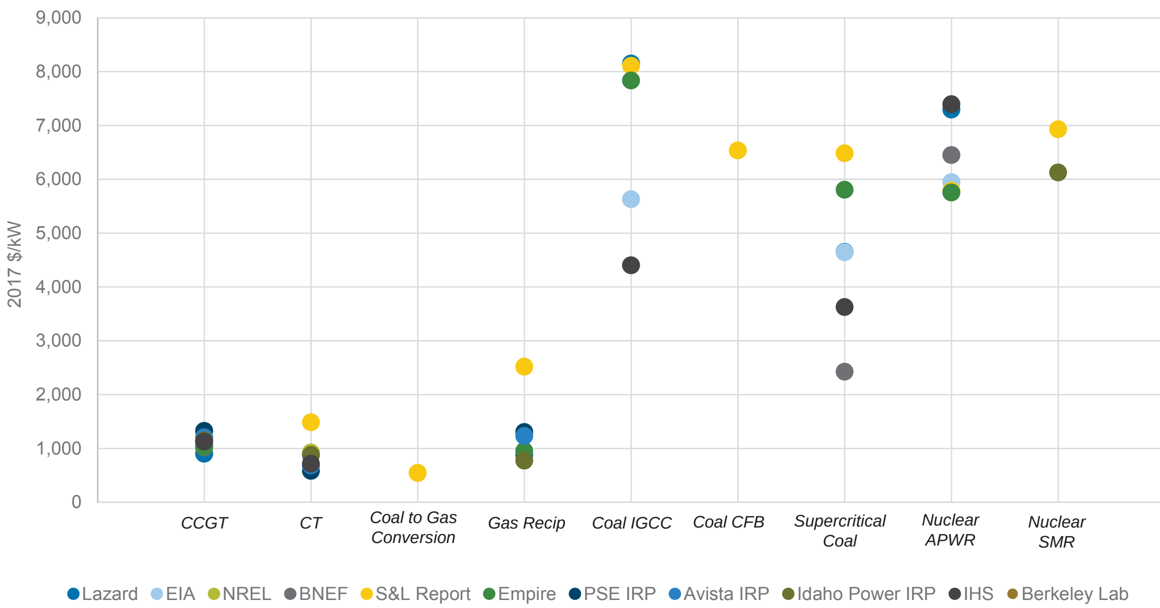
- Coal technologies – integrated gasification combined cycle, circulating fluidized bed, and supercritical pulverized coal
- Natural gas technologies – CTs, CCGTs, reciprocating engines, and coal-to-gas conversion
- Nuclear technologies – small module reactors and advanced pressurized water reactions
- Renewable technologies – onshore wind, offshore wind, distributed wind, utility-scale photovoltaic ("PV") solar, and distributed PV solar
- Other technologies – combined heat and power, battery storage, microturbines, and biomass

Figure 4-5: Data Sources for Third-Party Resource Review

Data Source	Description
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 Annual Energy Outlook)
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)
	Lazard Levelized Cost of Storage Version 3.0 (2017)
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook
	US Wind Capital Cost and Required Price Outlook
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region
	Key cost input in LCOE Scenarios, 1H 2017
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)
National Renewable Energy Technology Laboratory (NREL)	Annual Technology Baseline 2017

NIPSCO then aggregated the cost estimates from all sources by technology type to evaluate current costs on a $/kilowatt ("kW") basis. As part of this assessment, average, median, minimum, and maximum costs were recorded. A summary of the results of the survey is presented in Figure 4-6 and Figure 4-7.

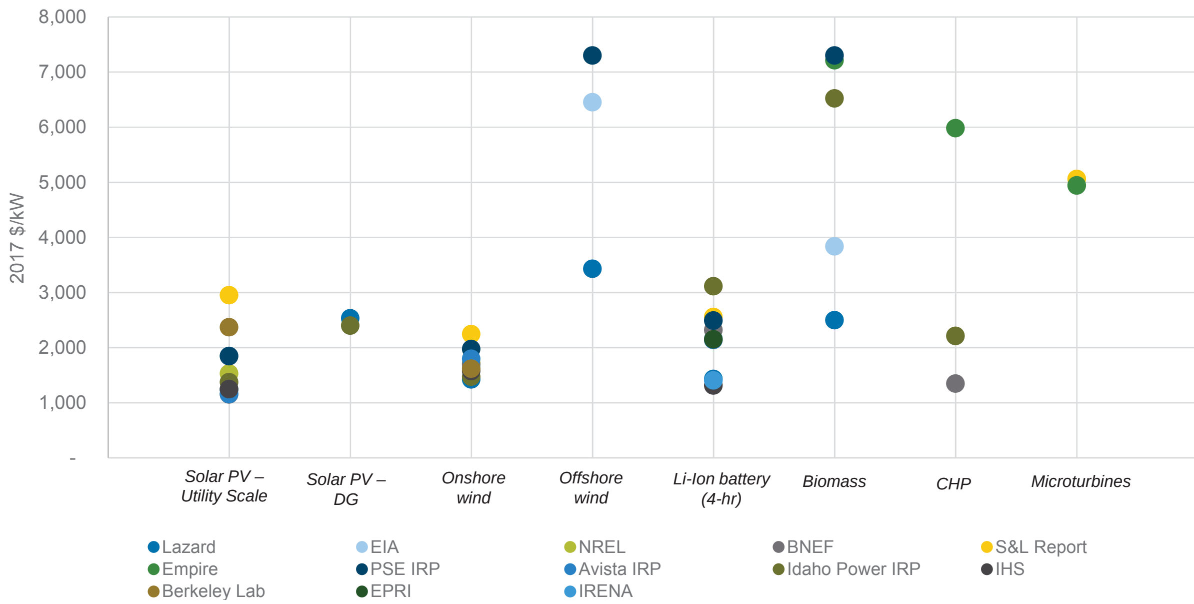
Figure 4-6: Current Capital Cost Summary for Coal, Gas, and Nuclear Technologies (2017$/kW)



2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,276	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927

Gas Recip – Gas Reciprocating Engine
IGCC – Integrated Gasification Combined Cycle
CFB – Circulating Fluidized Bed
APWR – Advanced Pressurized Water Reactor
SMR – Small Modular Reactor

Figure 4-7: Current Capital Cost Summary for Renewable, Storage, and Other Technologies (2017$/kW)[3]



2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

Given relatively large uncertainty ranges for certain technologies and given even larger uncertainty regarding future cost trends, NIPSCO determined that it was necessary to conduct an RFP process to collapse the uncertainty and identify transactable projects that could be available for future capacity needs, especially by 2023. In the 2016 IRP, NIPSCO identified several screening criteria to confirm project viability, including technical feasibility, commercial availability, economic attractiveness, and environmental compatibility. In the 2018 IRP, each of these criteria could be tested with actionable data from the RFP process as opposed to solely relying on engineering advice.

4.9.2 All Source Request for Proposals

NIPSCO worked with CRA's Auctions and Competitive Bidding practice to conduct an All-Source RFP during the spring and early summer of 2018. During NIPSCO's first Public Advisory meeting, an overview of the All-Source RFP design was provided to stakeholders and comments were solicited and accepted through April 2018. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the All-Source RFP on May 14, 2018 and closed the window for proposals on June 29, 2018.

[3] Note that renewable cost data from the S&L summary was excluded in the summaries due to vintage concerns. Old solar PV – Utility Scale data was also excluded from the Berkeley Lab source.

The All-Source RFP provided several guidelines to bidders, which are summarized below:

- Technology: The All-Source RFP requested all solutions regardless of technology, including demand-side options and storage

- Size: The All-Source RFP defined a minimum total need of 600 MW for the portfolio, but placed no size restrictions on the potential bidders. The All-Source RFP explicitly allowed for resources below 600 MW to offer their solution as a piece of a potential total need. The All-Source RFP also encouraged larger resources offer their solution for consideration.

- Ownership Arrangements: The All-Source RFP was open to asset purchases (new or existing) and PPAs. However, it required that resources qualify as MISO internal generation (not pseudo-tied) or load in the form of DR.

- Duration: The All-Source RFP requested delivery beginning June 1, 2023, but indicated that it would evaluate deliveries as early as June 1, 2020. The minimum contractual term and/or estimated useful life was requested to be five years, except for DR, which was allowed to offer for a one-year term.

- Deliverability: The All-Source RFP required that bidders have firm transmission delivery to MISO Local Resource Zone 6 ("LRZ6").

- Participants & Pre-Qualification: The All-Source RFP required counterparties be credit-worthy to ensure an ability to fulfill future resource obligations.

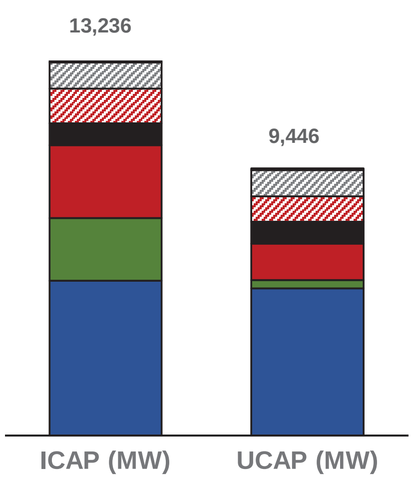
Overall, the All-Source RFP generated a large amount of bidder interest, with 90 total proposals received across a range of deal structures. NIPSCO received bids for 59 individual projects across five states with over 13 GW of installed capacity ("ICAP") represented. Many of the proposals offered variations on pricing structure and term length, and the majority of the projects were in various stages of development. A summary of the total number of proposals received by technology type is shown in Figure 4-8.

Figure 4-8: Summary of Number of Proposals Received by Technology Type

Technology	CCGT	CT	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
Asset Sale	4	-	-	1	-	1	-	-	-	6
PPA	8	-	3	6	-	26	7	8	1	59
Option	3	1	-	7	1	8	4	1	-	25
Total	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

On a total MW basis, the 13 GW of ICAP offered represented just under 10 GW of UCAP, providing a sufficiently large set of candidate options for NIPSCO to evaluate for any capacity need during the All-Source RFP delivery window. Over half of the offered UCAP was in the form of natural gas-fired projects, primarily CCGTs. However, a significant amount of renewable, coal-based, and storage resources were also offered. Figure 4-9 shows a summary of total MW offered in response to the All-Source RFP by type.

Figure 4-9: Summary of Total MW of Proposals Received by Type

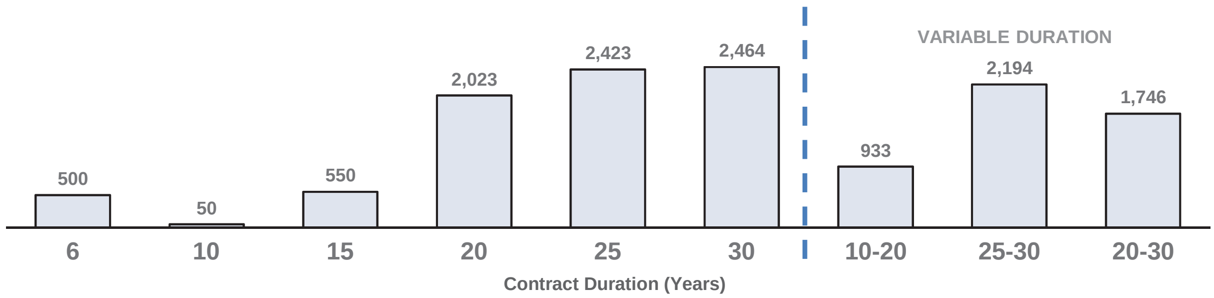


	ICAP (MW)	UCAP (est. MW)
Demand Response	70	70
Storage	925	925
Solar + Storage	1,220	902
Wind + Solar + Storage	0	0
Coal	772	772
Solar	2,580	1,291
Wind	2,209	287
Natural Gas (CT)	0	0
Natural Gas (CCGT)	5,470	5,199
	13,236	9,446

*Note that totals are on a project basis, which eliminates double counting of multiple proposals for the same facility.

Most PPA offers were relatively long in duration, with the majority of proposals offering contracts for 20 year terms or longer. Several bidders offered shorter-term options, including a number that provided NIPSCO with options to select from multiple duration possibilities. Figure 4-10 provides a summary of the total UCAP MW offered by duration.

Figure 4-10: Summary of Proposals Received by Duration (UCAP MW)



Most importantly, the All-Source RFP responses provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was relatively consistent with the third-party data review, but renewable offers were at the low end of the estimates observed in the public literature. This indicated that technology change and developer activity in a competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future. A summary of the various proposals by type and by price is provided in Figure 4-11. Note that due to confidentiality considerations, individual project prices cannot be disclosed.

Figure 4-11: Summary of Proposals by Price

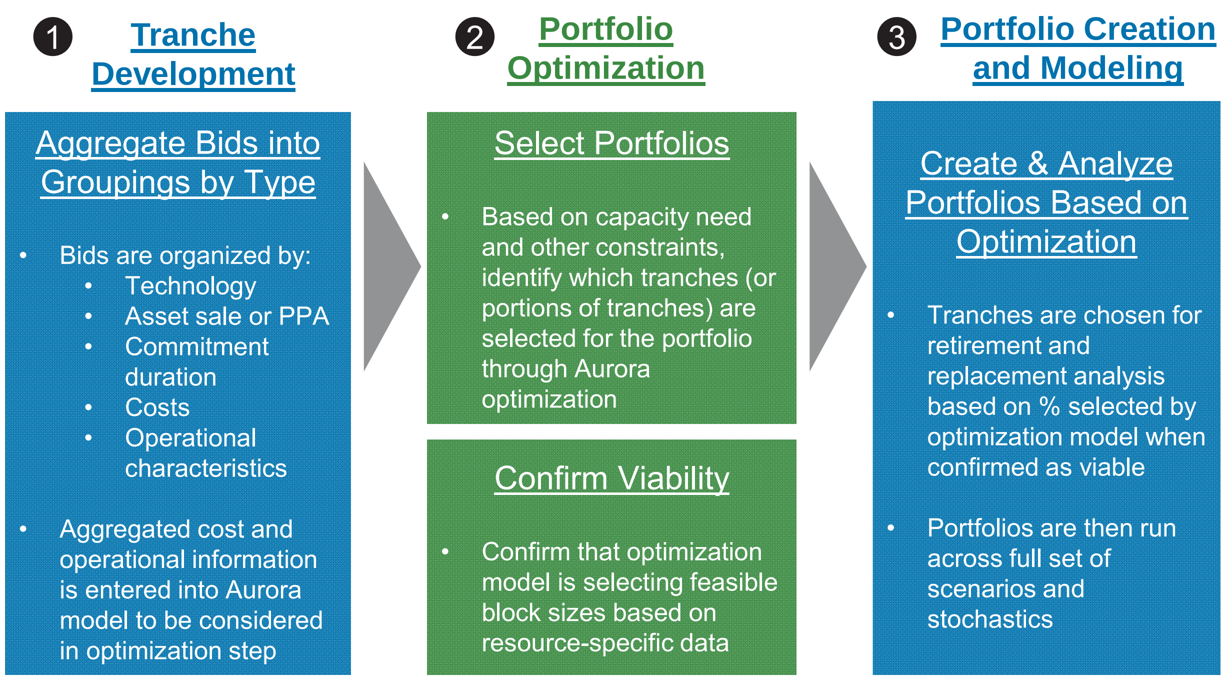
	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

4.10 Incorporation of the All-Source RFP Results into the IRP

After gathering the All-Source RFP bidder data, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for All-Source RFP-IRP integration, which is outlined in Figure 4-12:

1. Organize the various bids into groupings or tranches according to technology, whether the bid offered a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics.
2. Perform portfolio optimization analysis based on NIPSCO's potential capacity need and other portfolio design constraints, confirming option viability based on feasible block sizes of All-Source RFP tranche data.
3. Develop comprehensive portfolios with selected tranches from the portfolio optimization step and analyze them across the full set of scenarios and stochastics.

Figure 4-12: Summary of Proposals by Price



4.10.1 Tranche Development

It was determined that a tranche approach would be most effective in aggregating the numerous data points from the All-Source RFP into useable IRP information for three main reasons:

- The IRP is intended to select the best resource mix and future portfolio concept rather than select specific assets or projects. While the IRP analysis can now be highly informed by actionable All-Source RFP data, it is only meant to develop a planning-level recommended resource strategy. NIPSCO determined that asset-specific selection would require an additional level of diligence, including assessment of development risk, evaluation of locational advantages or disadvantages for specific projects, and review of transmission system impacts, to be conducted outside of the standard IRP process.

- The IRP is a highly transparent and public process that requires sharing of major inputs with stakeholders and the public. There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data.

- The IRP modeling is complex, and resource grouping improves the efficiency of the process. Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set would improve the efficiency of setup and run time.

When developing tranches, the CRA All-Source RFP team first organized resources by technology and then sorted them into categories according to whether they were offered as asset sales or PPAs. Projects were screened by the All-Source RFP team to determine conformity with bid requirements, and any non-conforming bids were eliminated. Duplicate projects that were offered multiple times under different structures were consolidated into the lowest-cost option to avoid double-counting. Beyond the initial organization and screening, the bids were then arranged by commitment duration and finally costs and operational characteristics.

For example, the All-Source RFP received multiple CCGT bids, with some being based on the same project. In developing the tranches, the team first separated the PPAs from the asset sales and then sub-divided PPA bids into short and long duration options for evaluation. The sale bids were all long duration, but had meaningfully different costs, so they were organized into two separate tranches for evaluation. This illustrative example is shown in Figure 4-13.

Figure 4-13: CCGT Tranche Development Example

PPA

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year	PPA Term (years)
PPA Bid 1	CCGT	250	250	2023	6
PPA Bid 2	CCGT	625	575	2023	30
PPA Bid 3	CCGT	625	625	2023	30
PPA Bid 4	CCGT	725	700	2023	20
PPA Bid 5	CCGT	600	600	2023	30

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (years)	Cost range** ($/kW-mo)
PPA CCGT #1	1	250	250	2023	6	
PPA CCGT #2	4	2,575	2,500	2023	27	

Sale

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year
Sale Bid 1	CCGT	625	625	2023
Sale Bid 2	CCGT	625	625	2023
Sale Bid 3	CCGT	1,025	925	2023
Sale Bid 4	CCGT	725	700	2023

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	Price Range** ($/kW)
Sale CCGT #1	2	1,250	1,250	2023	
Sale CCGT #2	2	1,750	1,750	2023	

*Capacity is rounded to the nearest 25 MW.
**Given the small number of projects within each CCGT tranche, PPA costs and asset sale prices are not being shown to preserve confidentiality. Note that PPAs were structured as tolling arrangements with fixed cost capacity payments (in $/kW-mo) plus certain variable charges (in $/MWh).

As another example, the All-Source RFP received 26 solar PPA bids. These bids generally all had similar contract structures, duration commitments, and capacity factors. Therefore, PPA price was the major factor that drove development of the tranches. In this instance, five solar PPA tranches were developed, organizing individual bids into groupings with similar pricing. Figure 4-14 provides an illustrative example of how these bids could be grouped together for evaluation.

Figure 4-14: Solar PPA Tranche Development Example

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)		Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	-	•••	2023	20	$27.xx	-
Bid 9	Solar	275	138		2023	20	$32.00	24%
Bid 10	Solar	100	50		2023	20	$34.00	24%
Bid 11	Solar	75	38		2023	20	$34.00	23%
Bid 12	Solar	25	13	•••	2023	20	$35.00	24%
Bid 13	Solar	500	250		2023	25	$35.00	25%
Bid 26	Solar	-	-		2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	488	2023	23	$33.93	24.2%

Ultimately, the tranche development process resulted in the production of 17 PPA tranches and 11 asset sale tranches. These are summarized by resource type, size, term, and costs in Figure 4-15 and Figure 4-16 for PPAs and asset sales, respectively.

Figure 4-15: Summary of PPA Tranches Used in Modeling

Tranche	Resource Type	Nameplate Capacity (MW)	UCAP (MW)	Storage Capacity (MW)	PPA Start	PPA Term (yrs)	Pricing ($/MWh)	Pricing ($/kW-mo)	Pricing ($/MW-d)
1	CCGT	250	250	-	2023	6		8.71	
2	CCGT	2,570	2,487	-	2023	27		8.58	
3	CT	685	678	-	2023	30		5.17	
4	Demand Response	70	70	-	2023	1			115.00
5	Solar	500	250	-	2023	20	28.45		
6	Solar	975	488	-	2023	23	33.93		
7	Solar	1,352	676	-	2023	26	37.62		
8	Solar	308	154	-	2022	21	62.87		
9	Solar + Storage	175	92	5	2023	20	24.80		
10	Solar + Storage	295	200	52	2023	20	28.24		
11	Solar + Storage	1,525	1,158	395	2023	22	34.54	2.27	
12	Solar + Storage	25	23	10	2024	20	61.41		
13	Storage	510	510	510	2023	16	12.58	4.31	
14	Storage	400	400	400	2023	20			323.14
15	Wind	945	128	-	2021	19	25.54		
16	Wind	479	72	-	2022	22	38.11		
17	Wind + Solar + Storage	300	95	30	2021	20	28.68		

Figure 4-16: Summary of Asset Sale Tranches Used in Modeling

Tranche	Resource Type	Nameplate	UCAP	Transfer Date	Pricing ($/kW)
1	CCGT	1,255	1,242	2023	962
2	CCGT	1,750	1,633	2023	1,084
3	CT	685	678	2023	615
4	Solar	265	133	2023	951
5	Solar	639	320	2023	1,125
6	Solar	400	200	2023	1,287
7	Solar + Storage	265	183	2023	1,067
8	Solar + Storage	440	330	2023	1,253
9	Storage	100	100	2023	932
10	Wind	1,099	165	2020	1,486
11	Wind + Solar + Storage	300	95	2021	1,406

4.10.2 Renewable Resource Tax Incentives and Tax Equity Partnership

Federal tax incentives are currently in place for renewable and paired renewable/storage resources. Resources are eligible for a production tax credit ("PTC") or an investment tax credit

("ITC"). The PTC provides a credit of $24/megawatt hour ("MWh")[4] for all generation produced by the facility, and the ITC provides a credit as a portion of the total cost of the facility. It is generally advantageous for wind resources to take the PTC, due to their high capacity factors, and solar resources to take the ITC.

The tax incentives are currently in the midst of a phase-out, as summarized in Figure 4-17. In order to qualify for the credits, projects need to begin construction by a certain date and be put into service by a certain date. The start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities. The safe harbor for beginning of construction is investment of at least 5% of the total project cost on or before the specified date.

Figure 4-17: PTC (Wind) and ITC (Solar) Phase-Out Schedule

Wind

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Qualify for Continuity Safe Harbor	Credit Percentage
2016	2020	100
2017	2021	80
2018	2022	60
2019	2023	40
2020	n/a	

Solar

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Maximize ITC	ITC Rate
2016	2020	30
2017	2021	30
2018	2022	30
2019	2023	30
2020	2023	26
2021	2023	22
2022	n/a	n/a

Given the importance of these tax incentives, NIPSCO preformed a review of their impact on All-Source RFP bids prior to developing final costs for the portfolio modeling. The impact of the tax incentives needed to be treated differently for the different types of All-Source RFP bids:

- For PPAs, no adjustments were needed, since tax incentives flow to the developer and are theoretically reflected in PPA pricing; and

[4] This value is indexed to inflation.

- For asset ownership, tax benefits flow to the utility and ultimately to the customer in rates, so adjustments needed to be made.

Without proper structuring, the Internal Revenue Code normalization rules stretch the flow of tax benefits to the customers over the regulatory life of the asset, but an alternative tax equity ownership structure can adjust the flow of benefits. In this arrangement, NIPSCO and a tax equity investor would form a partnership to develop a renewable energy project. The tax equity investor would invest to obtain a specified internal rate of return through the receipt of tax benefits in the form of depreciation, tax credits, and cash for a specified timeframe. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.

In order to properly account for the rate base reduction impact of partnering with a tax equity investor, CRA worked with NIPSCO's tax team to develop relevant financial models to estimate the breakdown of capital expenditures. For solar and solar-storage paired projects, the tax equity contribution is estimated to be around 35% of total capital costs, meaning NIPSCO would cover the remaining 65%. For wind assets, the range of tax equity contributions would be between 33 and 60%, depending on the asset's online date and expected capacity factor. Wind assets are assumed to utilize the PTC, while solar assets are assumed to take advantage of the ITC. The expected range of tax equity partner contributions for renewable resources is summarized in Figure 4-18.

Figure 4-18: Capital Cost Adjustments due to Tax Equity Partnership

Resource Type	Tax Equity Capital Cost Contribution
Solar	35%
Wind	33-60%
Solar + Storage	35%
Wind + Solar + Storage	35%

4.10.3 Self-build

As part of the process of evaluating its resource alternatives, NIPSCO investigated the feasibility of building a CCGT facility to meet its resource needs. The study considered an 800MW combine cycle F class 2x1 configuration and a 635MW advance class 1x1 consideration to be located on land at Schahfer.

For the study, NIPSCO developed conceptual site plans, conducted geotechnical studies, established the design criteria, developed single line studies and cost estimates for the two technologies. The study also considered the electric, natural gas and water interconnection requirements.

From the feasibility study results, NIPSCO determined that a self-build option was a more expensive alternative as compared to the All-Source RFP bid results for similar technology. Consequently, NIPSCO believes that a self-build CCGT is not the best resource alternative to meet customers need at this time.

4.10.4 CCGT Breakeven Analysis

NIPSCO's replacement analysis, as discussed in Section 9.2, found that replacement portfolios with renewable resources from the all source RFP are more cost effective than portfolios without. Furthermore, portfolios with CCGT are higher cost and carry increased risk due to exposure to natural gas prices and dispatch cost volatility. Selection of resource portfolios with new-build CCGT would require criteria other than economics and cost risk to justify.

NIPSCO explored the conditions that could support the inclusion of an additional CCGT into its supply portfolio. A CCGT could be part of a transmission/reliability solution to support renewables but analysis using new-build CCGT costs concludes that other reliability solutions are more cost effective. NIPSCO performed an analysis to identify the purchase price at which CCGT would be economically competitive with renewable resources. NIPSCO's analysis shows that, to be economically competitive with its preferred resource portfolio, CCGT costs would need to be approximately $284/kW or lower in the Base Scenario. This breakeven price does not appear to be likely for new-builds, but may be a possibility for re-sale of existing CCGT. A breakeven price was not achievable in the Aggressive Environmental Regulation Scenario, was $589/kW or lower in the Challenged Economy Scenario, $637/kW or lower in the Booming Economy / Abundant Natural Gas Scenario. Additional details are in Confidential Appendix D.

4.10.5 Coal to Gas Conversion

NIPSCO evaluated the potential to convert one or two units at Schahfer from coal-fired units to natural gas-fired units. As part of this analysis, NIPSCO developed operational assumptions for the potentially converted units as well as cost estimates associated with the conversion. In evaluating the operational parameters for a converted unit, NIPSCO relied on the Sargent & Lundy ("S&L") study conducted as part of the 2016 IRP process. The study concluded that a conversion would result in a 15% capacity de-rate for either Schahfer 17 or 18 when fired by gas instead of coal, as well as a slight efficiency penalty for the plant's heat rate. The key operational parameters for the conversion option are shown on a per-unit basis in Figure 4-19.

Figure 4-19: Coal-to-Gas Conversion Operational Parameters

	Category	NIPSCO Assumption
Operating Parameters	Conversion Capacity(MW) per unit	309.2
	Heat Rate (Btu/kWh)	11,106
	Forced Outage Rate	10%

Separately, NIPSCO developed capital and ongoing maintenance cost assumptions associated with a potential conversion. These costs were developed from the S&L study from 2016, as well as NIPSCO's internal experts in generation, plant operations, and major projects. The key assumptions included:

- The capital cost for conversion, which includes materials, construction labor, contingency, and owners and indirect costs were estimated by S&L .

- Gas interconnection costs were reviewed by S&L and NIPSCO's operational teams. Based on the data from the S&L study and a preliminary review with NIPSCO Gas Systems Engineering, it would be possible to convert Unit 17 or Unit 18 to natural gas without installing an additional pipeline as long as both Units 14 and 15 are retired. Leaving Units 14 and 15 in operation would likely create operational limitations related to when the units would be available to start up. Conversion of Units 17 and 18 to run simultaneously would require an additional pipeline. The size of the additional line could be smaller than the 30" used in the engineering study, but further detailed engineering analysis would be required to determine the appropriate size. Therefore, to be conservative and to evaluate whether conversion would be economic in the event that gas interconnection costs were minimal, NIPSCO assumed zero cost in its analysis.

- Environmental compliance costs were assumed to be zero.

- Maintenance capital needs were assumed to be 25% lower than current coal operations. This assumption was based on a review of NIPSCO's last three years of capital expenditures for Schahfer Units 17/18 that showed 25% of maintenance capital expenditures were for coal-specific components.

- Fixed O&M costs were estimated by S&L in the engineering study.

A summary of the assumptions for each of these cost categories is shown in Figure 4-20.

Figure 4-20: Coal-to-Gas Conversion Capital and Maintenance Cost Estimates

	Category	Estimated Cost
Conversion Investment Costs	Conversion (2015$)	$43M for 17 $87M for 17/18
	Gas Interconnection	$0M
	Environmental Compliance	$0M
Maintenance Capital	Maintenance Capital (Total 2024-2038) Nominal $	$122M for U17 $298M for 17/18
Ongoing Costs	Fixed O&M Costs (2015$/KW-yr)	$39

Ultimately, the analysis showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the All-Source RFP results and replacing both units would cost customers at least $540 million more. Based on this, it is not economically feasible to complete the conversion of either unit. This is discussed more in depth in Section 9.1.7.

Section 5. Demand-Side Resources

5.1 Existing Resources

5.1.1 Existing Energy Efficiency Resources

NIPSCO actively promotes energy conservation and efficiency to customers and works with its third party vendors to offer cost-effective energy efficiency programs. To support the continuance of its program offerings for the period 2019 through 2021, NIPSCO worked with its Oversight Board ("OSB") to develop two DSM RFPs – one for residential programs and one for commercial and industrial ("C&I") programs. Upon review of the bids and materials presented by the invited bidders, NIPSCO recommended, and its OSB approved, the selection of Lockheed Martin as the vendor to continue implementing both its residential and C&I programs. The OSB also issued a DSMRFP for an evaluation, measurement and verification ("EM&V") vendor and selected ILLUME Advising, LLC to provide an evaluation of both the residential and C&I vendors for all three program years. On November 22, 2017, NIPSCO filed its request with the IURC for approval of the following energy efficiency programs to become effective for the period January 1, 2019 through December 31, 2021 (the "2019-2021 Plan"):[5]

2019-2021 Residential Programs

Residential Heating, Ventilation and Air Conditioning ("HVAC") Energy Efficient Rebates Program

The HVAC Energy Efficient Rebates Program is designed to provide incentives to residential customers to replace inefficient HVAC equipment with energy-efficient alternatives. These measures will be paid per-unit installed, reimbursing customers for a portion of their cost. The program's intent is to help remove the financial barrier associated with the initial cost of these energy-efficient alternatives. The program will promote premium efficiency air conditioners, heat pumps that have high-efficiency, electronically commutated motors, and smart Wi-Fi thermostats.

Residential Lighting Program

The Residential Lighting Program is designed to increase the purchase and use of energy-efficient lighting products among NIPSCO's residential electric customers. The program will provide instant discounts on lighting products that meet the energy efficiency standards set by the United States Department of Energy's ENERGY STAR® Program. ENERGY STAR specifications are an important external factor to certify the quality and efficiency of program measures. As the ENERGY STAR specifications change, the program offerings will be adjusted accordingly. These adjustments ensure that the program offers incentives for lighting products that meet the latest standards and highest quality of efficiency.

5 The 2019-2021 Plan reflected herein reflects the parties' agreements set forth in the Stipulation and Settlement Agreement reached among NIPSCO, the Indiana Office of Utility Consumer Counselor, and Citizens Action Coalition of Indiana, Inc. (the "Settling Parties"), was approved in Cause No. 45011 on September 12, 2018.

Residential Home Energy Assessment Program

The Home Energy Assessment Program is designed to help eligible customers improve the efficiency and comfort of their homes, as well as deliver an immediate reduction in electricity (kWh) consumption and promote additional efficiency work. This program will provide homeowners with the direct installation of low-cost, energy-efficient measures followed by the delivery of a Comprehensive Home Assessment report.

Residential Appliance Recycling Program

The Appliance Recycling Program is designed to provide an incentive to residential customers who choose to recycle a qualifying primary or secondary working refrigerator and/or freezer. Lockheed Martin will utilize a qualified subcontractor for the implementation of this program.

School Education Program

The School Education Program is designed to produce cost-effective electric savings by influencing fifth grade students and their families to focus on the efficient use of electricity. It will provide classroom instruction, posters, and activities aligned with national and state learning standards and energy education kits filled with energy-saving products and advice. Students will participate in an energy education presentation at school, learning about basic energy concepts through class lessons and activities. Students will also receive an energy education kit of quality, high-efficiency products and are instructed to install the energy-efficient products at home with their families as well as complete a worksheet. The experience at home will complete the learning cycle started at school.

Residential Multifamily Direct Install ("MFDI") Program

The MFDI Program is designed to provide a "one-stop shop" to multifamily building owners, managers, and tenants of multifamily units containing three or more residences. With flexible and affordable options, the program will generate immediate energy savings and improvements in two distinct program phases. Phase I is a walkthrough assessment of each property, which is conducted to determine eligibility for direct installation services provided by the MFDI Program, along with complementary incentive offers available through other NIPSCO programs. Property managers will be presented with an Energy Improvement Plan that prioritizes recommendations along with a proposal to provide the direct installation services outlined in Phase II. Phase II is an in-unit direct installation of energy-efficient devices at no-cost or low-cost to the tenant or landlord, such as light emitting diode ("LED") light bulbs, low-flow showerheads, faucet aerators, pipe wrap, and Wi-Fi or smart thermostats. Educational materials about home operation, maintenance, and behavior factors that may reduce energy consumption, will be provided to tenants in each living unit.

Residential Home Energy Report Program

The Home Energy Report Program is designed to encourage energy savings through behavioral modification. The program will provide customers with home energy reports that contain personalized information about their energy use and provide ongoing recommendations to make their homes more efficient. Customers will be randomly chosen to participate in the program and may opt-out if they do not wish to participate. The reports engage customers and drive them to take action to bring their energy usage in line with similar homes. The program will empower customers to understand their energy usage better and uses competition through neighbor comparisons to influence customers to act on this knowledge, resulting in changed behavior.

Residential New Construction Program

The Residential New Construction Program is designed to increase awareness and understanding by home builders of the benefits of energy-efficient building practices, with a focus on capturing energy efficiency opportunities during the design and construction of single family homes. This program is designed to produce long-term, cost-effective savings as a result of the training they have received to achieve the various Home Energy Rating System tiers, along with strategies for incorporating the Silver, Gold, and Platinum designations into their marketing efforts to attract home buyers.

Residential HomeLife Energy Efficiency EE Calculator Program

The HomeLife Energy Efficiency Calculator Program is designed to offer NIPSCO's residential customers an online "do-it-yourself" audit and an energy savings kit for carrying out this audit, at no cost to the customer. The goal of the audit tool is to effectively: (1) identify low-cost/no-cost measures that a NIPSCO residential customer can easily implement to manage electric consumption; (2) allow eligible customers to request a free home energy kit; (3) educate customers about the variety of programs available to them through the residential energy efficiency portfolio; and (4) assist customers in finding qualified and experienced contractors through a network of trade allies.

Employee Education Program

The Employee Education Program is designed to offer valuable information to employees of NIPSCO's C&I customers by providing residential energy efficiency training seminars at the place of employment. At these seminars, educational materials will be provided to inform residential customers of energy savings opportunities and methods to proactively manage their energy consumption. These materials will also direct NIPSCO's customers to navigate to a web portal to request a free energy efficiency kit by entering their account information to confirm eligibility.

Residential Income Qualified Weatherization ("IQW") Program

The IQW Program is designed to provide energy efficiency services to qualifying low-income households. In order for a household to be eligible to participate in the IQW Program, the customer will need to be a NIPSCO residential customer with active service and must not have received weatherization services in the past 10 years from the date of application. If the household meets this initial criteria, they will automatically qualify for services regardless of income if the household receives Low-Income Home Energy Assistance (LIHEAP), Temporary Assistance for Needy Families (TANF), Supplemental Security Income (SSI) or Supplemental Security Disability Income (SSDI). Qualifying participants will receive the direct installation of no-cost energy efficiency measures and a Comprehensive Home Assessment to identify areas of the home where additional energy savings can be achieved to make the home more comfortable and reduce energy costs.

Table 5-1 shows the projected energy savings (MWh) by year for each of the Residential programs.

Table 5-1: 2019-2021 Projected Residential Energy Savings (MWh)

Residential Programs	2019	2020	2021	Total
HVAC	2,396	2,393	2,389	7,178
Lighting	26,172	26,172	26,172	78,516
Home Energy Assessment	2,145	2,143	2,140	6,428
Appliance Recycling	1,647	1,645	1,643	4,935
School Education	2,580	2,577	2,574	7,731
MFDI	1,127	1,126	1,125	3,378
Home Energy Report	9,786	9,774	9,763	29,323
New Construction	854	854	854	2,562
HomeLife Energy Efficiency Calculator	2,064	2,062	2,059	6,185
Employee Education	1,006	1,005	1,004	3,015
IQW	1,197	1,196	1,195	3,588
Total Residential Programs	**50,974**	**50,947**	**50,918**	**152,839**

Table 5-2 shows the annual total program budget for each of the Residential programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[6]

6 In the Settlement, the Settling Parties agree that NIPSCO (with Oversight Board ("OSB") approval) should be authorized to increase any individual program funding by up to 10% of the total program budget, even if this exceeds the overall 2019-2021 DSM Plan budget approved by the Commission.

Table 5-2: 2019-2021 Residential Program Budget

Residential Programs	2019	2020	2021	Total
HVAC	$531,302	$530,558	$529,843	$1,591,703
Lighting	$4,919,279	$4,919,279	$4,919,279	$14,757,837
Home Energy Assessment	$852,009	$851,003	$850,040	$2,553,052
Appliance Recycling	$431,926	$431,417	$430,928	$1,294,271
School Education	$638,243	$637,491	$636,741	$1,912,475
MFDI	$374,314	$377,243	$376,817	$1,128,374
Home Energy Report	$566,969	$566,298	$565,630	$1,698,897
New Construction	$312,095	$312,095	$312,095	$936,285
HomeLife Energy Efficiency Calculator	$487,374	$486,798	$486,225	$1,460,397
Employee Education	$279,497	$279,167	$278,838	$837,502
IQW	$424,502	$424,003	$423,520	$1,272,025
Total Residential Programs	**$9,817,510**	**$9,815,352**	**$9,809,956**	**$29,442,818**

2019-2021 C&I Programs

C&I Prescriptive Program

The Prescriptive Program is designed to provide incentives for a set list of energy efficient measures and will be paid based on per unit installed, reimbursing the customer for a portion of the cost. The Prescriptive Program will offer incentives to NIPSCO's C&I customers that are making electric energy efficiency improvements in existing buildings.

C&I Custom Program

The Custom Program will be available to C&I customers for installing new energy-saving equipment. Custom incentives are designed for more complicated projects, or those that incorporate alternative technologies. Project pre-approval will be required for all Custom incentives to ensure that only cost-effective projects are approved. Qualifying measures will be required to have a Total Resource Cost ("TRC") test score greater than 1.0, have a simple payback greater than 12 months and not be included as an energy efficiency measure in the Prescriptive Program.

C&I New Construction Program

The C&I New Construction Program is designed to encourage construction of energy efficient C&I facilities within the NIPSCO service territory. This program will offer financial incentives to encourage building owners, designers and architects to exceed standard building practices and achieve efficiency, above and beyond the 2010 Indiana Energy Conservation Code. The goal of the New Construction Program is to produce newly constructed and expanded buildings that are efficient from the start. New construction projects that may be eligible for incentives under the New Construction Program may include any of the following: (1) new building projects wherein no structure or site footprint presently exists; (2) addition to or expansion of an existing building or site footprint; and (3) a gut rehabilitation for a change of purpose requiring replacement of all electrical and mechanical systems/equipment.

Small Business Direct Install ("SBDI") Program

The SBDI Program is designed to facilitate participation in the NIPSCO business energy efficiency program of small C&I customers that do not possess the in-house expertise or capital budget to develop and implement an energy efficiency plan. The SBDI Program will offer a variety of ways for small businesses, with billing demands not exceeding 200 kW, to improve the efficiency of their existing facilities. Measures will be paid out on a per unit basis, much the same way as the Prescriptive Program, but with slightly higher incentive rates in an effort to encourage energy efficient investment from these smaller business customers. Incentive payments to the approved trade allies will occur following measure implementation and submission of all required paperwork. If additional incentives are available through other programs, customers will be directed to the appropriate application.

Retro-Commissioning ("RCx") Program

The RCx Program is designed to help NIPSCO C&I customers determine the energy performance of their facilities and identify energy-saving opportunities by optimizing their existing systems. Projects in the program will examine energy consuming systems for cost-effective savings opportunities. The RCx process will identify operational inefficiencies that can be removed or reduced to yield energy savings. Qualifying measures will be required to have a TRC test score greater than 1.0, have a simple payback of less than 12 months and not be included as an energy efficiency measure in the Prescriptive Program.

Table 5-3 shows the projected energy savings (MWh) by year for each of the C&I programs.

Table 5-3: 2019-2021 Projected C&I Energy Savings (MWh)

C&I Programs	2019	2020	2021	Total
Prescriptive	20,880	23,200	25,520	69,600
Custom	30,240	33,600	36,960	100,800
New Construction	9,360	10,400	11,440	31,200
SBDI	7,920	8,800	9,680	26,400
RCx	3,600	4,000	4,400	12,000
Total C&I Programs	**72,000**	**80,000**	**88,000**	**240,000**

Table 5-4 shows the total annual program budget for each of the C&I programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[7]

Table 5-4: 2019-2021 C&I Program Budget

C&I Programs	2019	2020	2021	Total
Prescriptive	$2,454,485	$2,727,206	$2,999,926	$8,181,617
Custom	$3,814,322	$4,238,137	$4,661,950	$12,714,409
New Construction	$1,155,142	$1,283,490	$1,411,838	$3,850,470
SBDI	$1,138,860	$1,265,400	$1,391,940	$3,796,200
RCx	$484,380	$538,200	$592,020	$1,614,600
Total C&I Programs	**$9,047,189**	**$10,052,433**	**$11,057,674**	**$30,157,296**

Table 5-5 shows the projected energy savings (MWh) by year for all Residential and C&I programs included in the 2019-2021 Plan.

Table 5-5: 2019-2021 Projected Combined Energy Savings (MWh)

	2019	2020	2021	Total
Total Residential Programs	50,974	50,947	50,918	152,839
Total C&I Programs	72,000	80,000	88,000	240,000
Total 2019-2021 Plan	**122,974**	**130,947**	**138,918**	**392,839**

Table 5-6 shows the annual total program budget for all Residential and C&I programs included in the 2019-2021 Plan.

Table 5-6: 2019-2021 Combined Program Budget

	2019	2020	2021	Total
Total Residential Programs	$9,817,510	$9,815,352	$9,809,956	$29,442,818
Total C&I Programs	$9,047,189	$10,052,433	$11,057,674	$30,157,296
Total 2019-2021 Plan Budget	**$18,864,699**	**$19,867,785**	**$20,867,630**	**$59,600,114**

Table 5-7 shows the eligible customer classes and rate schedules for each of the Residential and C&I programs included in the 2019-2021 Plan.

[7] In the Settlement, the Settling Parties agree that NIPSCO (with Oversight Board ("OSB") approval) should be authorized to increase any individual program funding by up to 10% of the total program budget, even if this exceeds the overall 2019-2021 DSM Plan budget approved by the Commission.

Table 5-7: Customers

Program	Customer Class	Electric Rate Schedule
Residential HVAC Rebates	Residential	711
Residential Lighting	Residential	711
Residential Home Energy Assessment	Residential	711
Residential Appliance Recycling	Residential	711
School Education	Residential	711
Residential MFDI	Residential	711
Residential Home Energy Report	Residential	711
Residential New Construction	Residential	711
Residential HomeLife Energy Efficiency Calculator	Residential	711
Employee Education	Residential	711
IQW	Residential	711
C&I Prescriptive	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
C&I Custom	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
C&I New Construction	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
SBDI	C&I	720, 721, 722, or 723 who have not had a billing demand of 200 kW or greater in any month during the previous 12 months
RCx	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744

5.1.2 Existing Demand Response Resources

5.1.2.1 Capacity Resources

The Commission approved Rider 775 – Interruptible Industrial Service Rider in its Rate Case Order in Cause No. 44688, issued July 18, 2016 ("Rate Case Order"). Rider 775 is available to customers taking service under Rates 732, 733 or 734. Rider 775 balances the needs of all customer groups by securing the ability and willingness of participating customers to curtail or interrupt service upon demand. NIPSCO's participating industrial customers provide a benefit to all customers, and are accordingly compensated through demand credits that are funded by all other customers. The interruptible credits are provided for two reasons, reliability and economic, each of which provides short- and long-term value to all customers.

The Interruptible Contract Demand is the demand that the customer intends to make available for interruptions and/or curtailments from one or more of customers' premises taking service under Rates 732, 733 or 734. Customers electing service under Rider 775 specify a Firm Contract Demand for each affected premise or facility that the Customer intends to exclude from interruptions or curtailments. Customers who contract for this service are required to interrupt or curtail at the stated notice by NIPSCO and the provisions of service under the Rider. Customers are also required to meet the applicable Load Modifying Resource ("LMR") requirements pursuant to MISO Tariff Module E, or any successor. NIPSCO will register all subscribed 527.776 MW of Rider 775 capacity with MISO. The LMR value is grossed-up by the Planning Reserve Margin and the Transmission Losses, since such resources have neither transmission losses, nor forced outages. As such, the 527.776 MW of LMR becomes 586.984 MW of Capacity Resources that NIPSCO can utilize to meet its MISO resource adequacy requirements.

In addition to NIPSCO's Rider 775 – Interruptible Industrial Service Rider, Rate 734 – Industrial Power Service for Air Separation & Hydrogen Production Market Customers, makes available interruptions and/or curtailments of electric demands greater than 276 MW to customers taking service under this Rate. Provisions for interruptions and/or curtailments are similar to that of Rider 775 and thus qualify as a LMR. As such, NIPSCO has registered 31.000 MW of LMRs under Rate 734. The Capacity Resource realized from the registration is 34.477 MW that NIPSCO can utilize to meet its MISO resource adequacy requirements.

On October 31, 2018, NIPSCO filed an electric rate case that revises its industrial service structure by replacing Rider 775 and Rates 732, 733, and 734 with Rates 830 and 831. The new industrial service structure requires NIPSCO's largest industrial customers on Rate 831 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR which is by definition curtailable. NIPSCO expects an increase in registered LMRs as a result of this new industrial service structure unless those Rate 831 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, the large industrial customers will continue to be eligible to participate in MISO's Demand Response Resource program discussed below.

5.1.2.2 Energy-Only Resources

NIPSCO offers Demand Response Resource Type 1 ("DRR1") and Emergency Demand Response Resource ("EDR") through Riders 781 and 782, respectively. These Riders are available to a Customer on Rates 723, 724, 725, 726, 732, 733 and 734 that has a sustainable ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as dispatched by MISO. Through these Riders, the Customer or Aggregator of Retail Customer (ARC) curtails a portion of its electric load through participation with the Company acting as the Market Participant (MP) with MISO. These Riders are available to any load that is participating in the Company's other interruptible or curtailment Riders, unless MISO rules change and do not permit load used by the Company as a LMR to also participate as a DRR1 or EDR. Although the DRR1 and EDR offered under Riders 781 and 782, respectively, do not qualify as a Capacity Resource, they do offer a means for Customers to offer into the MISO market and to be paid for the portion of their electric load curtailed. This provides economic benefit to the Customers participating in these Riders and for other NIPSCO Customers through an overall lower electric system demand, which can avoid purchased power or the need for higher cost generation resources to be committed through the MISO market. Currently, NIPSCO has two Customers participating in Rider 781 as DRR1. No Customers are participating in Rider 782 as EDR.

5.2 DSM Electric Savings Update

5.2.1 DSM Electric Savings Update – Purpose and Key Objectives

To update the electric DSM resource potential for the 2018 IRP, NIPSCO contracted with GDS to conduct a DSM Savings Update Report (the "DSM Savings Update") (a copy of which is included in Appendix B, Demand Side Management Savings Update and the 2016 Market Potential Study ("MPS"), and Action Plan.[8] GDS participated in Public Advisory Meeting 2 and provided details of its engagement with the DSM Savings Update. *See* Appendix A, Exhibit 2 (Presentation), Slides 24 through 43.

The DSM Savings Update provides an update of DSM program costs and savings for a 30-year time horizon (2019-2048). The report captures the insights from NIPSCO's prior MPS that was completed in August 2016 as well as NIPSCO's current and planned program offerings for the period 2019 to 2021 described in NIPSCO's testimony filed in Cause No. 45011. The objectives of NIPSCO's DSM Savings Update included:

- Develop a detailed plan identifying recommended cost-effective DSM savings measures and programs, as well as any possible market barriers for each recommended program. Identify best practices and programs and explain how the recommended practices and programs will achieve the desired results in NIPSCO's service territory.
- Place emphasis on innovative energy efficiency and DR programs and technologies.
- Provide detailed budgets for each program and related expenditures.
- Provide a lifetime cost analysis.

[8] A new MPS and Action Plan will be completed in 2019.

- Provide a cost-effectiveness[9] comparison or ranking for all technologies (measures) reviewed.

- Complete cost-effectiveness evaluations for each proposed program.

5.2.2 Impact of Opt-out Customers

GDS reviewed the latest information available from NIPSCO related to energy efficiency program participation, measure and program savings data, results of NIPSCO's 2016 MPS, NIPSCO's electric load and customer forecasts, NIPSCO load research data, electric avoided costs, program evaluation reports and NIPSCO's 2019-2021 Plan. NIPSCO requested that GDS prepare its base case DSM Plan update assuming that C&I electric customers that had opted out of NIPSCO's energy efficiency programs prior to January 1, 2017 would be excluded from the DSM Plan Update. These "opt-out" C&I customers represent over 60 percent of NIPSCO's 2017 non-residential kWh sales. It is important to note that the base case energy efficiency forecast for the DSM Savings Update does not include any energy efficiency savings for these opt-out C&I customers.

5.2.3 Modeling Framework

GDS used its Excel-based energy efficiency and DR planning models to prepare the DSM Savings Update. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, savings of other fuels, and benefit/cost ratios for planning periods ranging from one to thirty years. These GDS models are transparent and all formulas, model inputs and model outputs can be viewed by the model user. The GDS energy efficiency and DR planning models come with a user guide that explains where to input program data, measure data and assumptions relating to the general rate of inflation, the discount rate for financial analysis, avoided costs, line losses, planning reserve margin and other key input assumptions.

5.3 Energy Efficiency and Demand Response Bundles

For purposes of modeling energy efficiency programs in NIPSCO's 2018 IRP, GDS grouped DSM Plan energy efficiency measures into bundles according to each measure's cost of saved energy over its measure life. For energy efficiency measures, the following three bundle categories were created:

Bundle 1	Measures with a utility incentive cost ranging from \$.00 to \$.01 per lifetime kWh saved
Bundle 2	Measures with a utility incentive cost ranging from \$.011 to \$.05 per lifetime kWh saved

[9] GDS calculated the TRC Test, the Utility Cost Test ("UCT") , the Participant Test and the Ratepayer Impact Measure Test ("RIM") for each measure. GDS used the UCT test to determine measure, program and portfolio cost effectiveness. All of the results may be found in Appendices E and F.

Bundle 3	Measures with a utility incentive cost over $.05 per lifetime kWh saved

For purposes of modeling DR programs in NIPSCO's 2018 IRP, GDS grouped DR programs into three bundles by calculating the levelized cost per cumulative kW over the 30-year lifetime of the program. For DR programs, the following three bundles were created:

Bundle 1	$40/kW-year to $60/kW-year: includes C&I Direct Load Control ("DLC") of Air Conditioning ("AC") and DLC of Electric Water Heating Equipment
Bundle 2	$60/kW to $80/kW-year: includes Residential DLC of Water Heating Equipment and the C&I Third-Party Aggregator program
Bundle 3	Over $100/kW-year: includes Residential DLC of AC and Interruptible Rider

Both Residential and C&I DLC of space heating programs were found to be not cost-effective and, therefore, were not included in any DR bundles.

5.4 Energy Efficiency Potential Impacts

5.4.1 Changes That Impacted Energy Efficiency Potential

GDS updated several input assumptions during the process of preparing the DSM Savings Update. The changes made for a few of these input assumptions are discussed below.

5.4.1.1 Updated NIPSCO Load Forecast, Avoided Cost Forecast and General Planning Assumptions

In March 2018, NIPSCO sent GDS the latest electric load forecast for 2018 through 2039. CRA then extended the NIPSCO load forecast through the year 2048. GDS used this new load forecast to calculate the percent of electric MWH sales and peak demand saved each year by DSM programs. NIPSCO's new load forecast projects that total MWH sales to ultimate customers will only increase 0.3% a year on average through the year 2048. NIPSCO also provided GDS with updated planning assumptions for the general inflation rate, escalation rates for NIPSCO electric rates, the utility discount rate, line losses by class of service and the planning reserve margin. GDS used these assumptions to develop the DSM Savings Update.

5.4.1.2 NIPSCO DSM Plan Assumptions for Measure Costs, Savings, Useful Lives

GDS reviewed the assumptions for measure costs, savings and useful lives included in the 2019 to 2021 NIPSCO DSM plan and updated these assumptions where appropriate. GDS revised costs and/or savings assumptions for some energy efficiency measures if more recent data was available from NIPSCO evaluation reports or recently published technical resource/reference manuals from Michigan and Illinois.

The largest change for a measure assumption was to the baseline energy efficiency level for residential light bulbs. The NIPSCO 2019 to 2021 DSM plan assumed that the baseline technology for a residential light bulb was a 60-Watt incandescent bulb.

GDS collected information from industry experts and program implementation contractors, showing uncertainty about when the new Energy Independence and Security Act ("EISA") backstop provisions for lighting efficiency will take effect. The EISA lighting backstop provisions specify 45 lumens per Watt efficacy starting January 1, 2020. Efficiency Vermont, however, decided for planning purposes that LEDs would be the baseline standard in 2020. Efficiency Vermont assumed a one-year phase-in period for this efficacy standard. Other experts recommend allowing a sell-through period to the year 2022, or 2023 at the latest. Another recommendation GDS received was to shorten the useful life of LEDs. GDS previously used a useful life of 15 years for LEDs.

The new efficacy standard for lighting is scheduled by law to go into effect on January 1, 2020. Energy industry news articles have indicated a potential for the delay or cancelation of these new lighting efficacy standards. As of August 2018, there is uncertainty about whether these efficacy standards will go into effect on January 1, 2020. The EISA standard will not allow bulbs to be sold that do not meet the new efficacy requirements. Therefore, the new EISA standard will decrease the achievable potential for lighting savings because the baseline efficiency for most light bulbs will be significantly increased. Based on this, for planning purposes, NIPSCO assumed that the baseline technology after 2021 for general service bulbs would be a compact fluorescent light (CFL) or equivalent bulb that meets the EISA backstop provision efficacy level of 45 lumens per Watt.

5.4.1.3 Federal Appliance and Equipment Efficiency Standards

The U.S. Department of Energy ("DOE") develops and implements federal appliance and equipment standards to improve energy efficiency that will save consumers energy and money. This DOE program was initially authorized to develop, revise, and implement minimum energy efficiency standards by the federal Energy Policy and Conservation Act ("EPCA") in 1975. Several subsequent legislative amendments have required regular updates these standards and has expanded the list of products covered by the standards. The DOE is currently required to periodically review standards and test procedures for more than 60 products, representing about 90% of home energy use, 60% of commercial building energy use, and 30% of industrial energy use.

The standards program's predictable rulemaking schedule is driven by statutory deadlines the DOE must meet to comply with EPCA. These are amended by subsequent energy legislation and reflect the program's obligation to review all standards every six years and test procedures every seven years. The DOE encourages all stakeholders, including consumers, manufacturers, trade associations, utilities, energy efficiency advocates, and the general public, to participate in the rulemaking process. The standards program established the Appliance Standards and Rulemaking Federal Advisory Committee ("ASRAC") to facilitate deeper stakeholder engagement by allowing for negotiated rulemakings under the guidelines set forth in the Federal Advisory Committee Act (FACA). The process culminates in a final rule in which the DOE is required to set efficiency standards that maximize energy savings that are technologically feasible and economically justified.

The DOE considers the impact on consumers, manufacturers, and small C&I businesses when determining whether any new or amended standard is economically justified. The DSM Savings Update takes into account the impacts of federal appliance and equipment efficiency standards for those standards that are currently in place or expected to be implemented by the DOE after 2021, including the EISA backstop provisions for general service, reflector and specialty light bulbs discussed above.

5.5 Energy Efficiency Measures & Potential

5.5.1 Residential Energy Efficiency Measures

For the residential sector, there were 249 unique electric energy efficiency measures included in the energy efficiency potential analysis update. Table 5.8 provides a summary of the types of measures included for each end use in the residential sector. The measures included in this analysis are based on 2019-2021 Plan with several new measures added by GDS or suggested by NIPSCO's stakeholders. These new measures were included in the NIPSCO 2016 MPS that were not already included in the 2019-2021 Plan. GDS obtained the majority of data on residential energy efficiency measure costs, kWh and kW savings and costs from the 2019-2021 Plan. GDS reviewed this data and updated these measure assumptions for years after 2021 where necessary.

Table 5-8: Types of Electric Energy Efficiency Measures included in the Residential Sector Analysis

End Use	Measure Types Included
Electronic Equipment	ENERGY STAR Desktop and Laptop Computers, Monitors, Printer/Fax/Copier/Scanner, and Sound Bars ENERGY STAR Smart Power Strips ENERGY STAR Televisions
Appliances	ENERGY STAR Refrigerators ENERGY STAR Freezers ENERGY STAR Washing Machines ENERGY STAR Clothes Dryers ENERGY STAR Dehumidifier Refrigerator Pick-up and Recycling Freezer Pick-up and Recycling Refrigerator Replacement in Low Income Homes
Envelope	Building Insulation Improvements (Attic, Wall, Floor, Etc.) Air sealing (Weatherization) High Efficiency Windows Cool Roofing
HVAC Equipment	High Efficiency Heating Equipment (e.g., Heat Pump with electronically commutated motor) HVAC Filter Whistle Heating & Cooling Duct Sealing and Repair High Efficiency Natural Gas Furnace High Efficiency Natural Gas Boiler Wi-Fi Smart Thermostat
Lighting	Interior LED Bulbs and Fixtures Exterior LED Bulbs and Fixtures LED Nightlights
Pools	Pool Pump Controls High Efficiency Pool Pumps High Efficiency Pool Pump Heaters
Space Cooling	High Efficiency Central Air Conditioning System Air Source Heat Pump ENERGY STAR Room Air Conditioner
Water Heating	High Efficiency Water Heater Heat Pump Water Heater Faucet Aerators & Low Flow Showerheads Hot Water Pipe and Tank Insulation Solar Water Heating System
Other	Home Energy Reports and Other Types of Behavioral Programs Energy Efficiency Education Kits for Employees of NIPSCO's Customers High Efficiency Well Pump High Efficiency Hot Tub Dryer Vent Cleaning Refrigerator Coil Cleaning

5.5.2 Achievable Electric Energy Efficiency Potential

The achievable electric energy efficiency potential for the residential sector includes savings associated with measures that are:

- Included in the 2019-2021 Plan.
- Added to the plan by GDS (included in NIPSCO's 2016 MPS or that were suggested by NIPSCO's stakeholders).

Table 5-9 shows the cumulative annual achievable residential sector energy efficiency potential for the years 2019 to 2048 and estimates of the annual NIPSCO energy efficiency budgets for residential sector programs.

Table 5-9: Achievable Residential Sector Incremental Annual Energy Efficiency Potential and Annual Utility Budgets (Base Case)

Year	Incremental Annual Energy Savings (MWh)	Incremental Annual Demand Savings (MW)	Annual Utility Cost ($)
2019	50,974	10	$9,817,510
2020	50,947	17	$9,815,352
2021	50,918	24	$9,809,956
2022	46,240	42	$20,822,174
2023	46,887	61	$21,039,511
2024	47,503	79	$21,266,204
2025	48,178	98	$21,494,687
2026	48,716	117	$21,714,354
2027	49,287	137	$21,941,024
2028	49,744	156	$22,134,851
2029	50,231	175	$22,347,479
2030	50,686	195	$22,551,800
2031	51,166	215	$22,763,349
2032	51,645	234	$22,980,009
2033	52,173	254	$23,222,465
2034	52,411	268	$23,417,367
2035	52,659	281	$23,617,690
2036	53,050	294	$23,829,888
2037	53,050	298	$23,975,771
2038	53,050	301	$24,124,717
2039	53,050	304	$24,276,791
2040	53,050	307	$24,432,059
2041	53,050	310	$24,590,588

Year	Incremental Annual Energy Savings (MWh)	Incremental Annual Demand Savings (MW)	Annual Utility Cost ($)
2042	53,050	311	$24,752,445
2043	53,050	313	$24,917,702
2044	53,050	314	$25,086,429
2045	53,050	315	$25,258,699
2046	53,050	316	$25,434,587
2047	53,050	317	$25,614,169
2048	53,050	318	$25,797,522

5.5.3 Recommended Residential programs

GDS recommends that NIPSCO retain the residential energy efficiency programs that are included in its 2019-2021 Plan, but consider adding a new program such as whole-house retrofit program for qualifying low-income households if such a program can be designed to be administered in an efficient and effective manner. In addition, GDS recommends that NIPSCO add several new energy efficiency measures to its existing programs, including such measures as solar water heating, heat pump water heating, refrigerator coil cleaning brushes, dryer ductwork and vent cleaning, high efficiency clothes washers and other measures that GDS added that were cost effective.

Table 5-10 below provides the UCT benefit/cost ratios for the period 2019 to 2048 for residential programs[10]. All twelve residential energy efficiency programs included in the DSM Savings Update have a UCT ratio greater than or equal to 1.0. The overall UCT benefit/cost ratio for the residential portfolio of energy efficiency programs is 2.1. The NPV savings to NIPSCO's residential customers is $277.1 million for the thirty-year planning horizon.

10 NIPSCO utilized the UCT as the test for screening measures for inclusion. This is different from prior years when the TRC was utilized.

Table 5-10: Utility Cost Test Benefit/Cost Ratios for Residential Programs (2019 to 2048 Period)

Residential Sector Program	NPV Benefits	NPV Utility Costs	Net Benefits	BC Ratio
HVAC Energy Efficient Rebates	$20,240,111	$7,423,449	$12,816,661	2.7
Residential Lighting	$38,182,714	$13,738,788	$24,443,926	2.8[11]
Home Energy Assessment	$7,720,421	$5,194,212	$2,526,210	1.5
Appliance Recycling	$7,481,400	$4,676,459	$2,804,941	1.6
School Education	$20,025,721	$7,765,296	$12,260,425	2.6
Multifamily Direct Install	$11,325,004	$4,749,094	$6,575,911	2.4
Home Energy Report	$15,204,076	$12,735,292	$2,468,784	1.2
Residential New Construction	$18,270,532	$5,017,439	$13,253,094	3.6
HomeLife Energy Efficiency Calculator	$18,414,941	$6,111,400	$12,303,541	3.0
Employee Education	$6,151,825	$2,864,091	$3,287,734	2.1
IQW	$7,149,749	$4,261,258	$2,888,490	1.7
New Measures	$332,828,064	$174,474,645	$158,353,418	1.9
Total	**$502,994,559**	**$249,011,424**	**$253,983,135**	**2.0**

5.5.4 C&I Energy Efficiency Measures

For the C&I sector, there were 340 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-11 provides a summary of the types of measures included for each end use in the C&I sector. The measures included in this analysis are based on the 2019-2021 Plan with some new measures added by GDS. These new measures are based on a review of measures included in the 2016 MPS and discussions with stakeholders. A total of 167 additional measures were considered. Although NIPSCO's current Custom Program may technically be able to accommodate many of these measures, most would typically be considered to be prescriptive measures.

[11] The NIPSCO 2017 Portfolio Evaluation Reports lists a UCT ratio of 3.4 for the NIPSCO Residential Lighting Program and 2.9 for the Home Energy Analysis Program for calendar year 2017. It is important to note that the 2017 Portfolio Evaluation Report used a nominal discount rate of 6.53%. The DSM Savings Plan Update used a nominal discount rate of 7.65% to be consistent with the IRP modeling.

Table 5-11: Types of Electric Energy Efficiency Measures included in the C&I Sector Analysis

End Use	Measure Types Included
Office Equipment	High Efficiency Servers, Computers and Office Equipment Plug Load Sensors and Smart Power Strips
Compressed Air	Air System Maintenance Variable Frequency Drive Compressed Air Engineered Nozzle Custom Compressed Air Measures Retro-Commissioning
Cooking	Efficient Cooking Equipment Custom Kitchen
Envelope	Building Insulation Improvements High Efficiency Windows Cool Roofing
HVAC Controls	Programmable and Smart Thermostats Custom Energy Management System Installation/Optimization Occupancy Control System Retro-Commissioning
Lighting	Fixture Retrofits Premium Efficiency T8 and T5 lightbulbs High Bay Lighting Equipment LED Bulbs and Fixtures Light Tube Lighting Occupancy Sensors Custom Interior and Exterior Lighting Retro-Commissioning
Pools	Pool Pump Controls High Efficiency Pool Pump Heaters
Refrigeration	Vending Machine Misers Strip Curtains and Auto Door Closers Efficient Refrigerators/Freezers/Ice Machines High Efficiency/Variable Speed Compressors Electronically Commutated Motors Cooler Motors Door Heater Controls Efficient Compressors and Controls Door Gaskets Floating Head Pressure Controls Display Case Lighting and Controls Custom Refrigeration Retro–Commissioning
Space Cooling	Efficient Cooling Equipment Evaporative Pre-Cooler Economizer Air Source Heat Pump Geothermal Heat Pump Chiller/HVAC Maintenance Chilled Water Reset

End Use	Measure Types Included
	Room AC Custom HVAC/Chillers Retro-Commissioning
Ventilation	Enthalpy Economizer Variable Speed Drive Duct Repair and Sealing Controlled Ventilation Optimization Demand Controlled Ventilation Custom Ventilation
Water Heating	Efficient Equipment High Efficiency Hot Water Appliances Faucet Aerator/Low Flow Nozzles Pipe and Tank Insulation Heat Recovery Systems Efficient Hot Water Pump and Controls Solar Water Heating System Pre-Rinse Spray Valves Desuperheater Custom Water Heating
Other	Efficient Point of Sale Terminal Efficient Transformers Custom Motors and Drives Custom Process Custom Pumps/Fans Retro-Commissioning Process Retro-Commissioning Motors and Drives
Agriculture	Engine Block Heater Timer Energy Efficient/Energy Free Livestock Waterer High Volume Low Speed Fans High Efficiency Exhaust Fans Dairy Refrigeration Tune-up

5.5.5 Achievable Electric Energy Efficiency Savings

The achievable electric energy efficiency savings for the C&I sector includes savings associated with measures that are:

- Included in the 2019-2021 Plan
- New energy efficiency measures added to the plan by GDS that pass the UCT.

Table 5-12 shows the cumulative annual achievable energy efficiency savings for the years 2019 – 2048 and estimates of the annual energy efficiency budgets.

Table 5-12: Achievable C&I Sector Energy Efficiency Potential and Annual Budgets

Year	Cumulative Annual Energy Savings (MWh)	Cumulative Annual Demand Savings (MW)	Annual Cost ($)
2019	72,000	9.4	$9,047,188
2020	152,000	19.8	$10,052,432
2021	240,000	31.3	$11,057,675
2022	325,796	43.1	$11,839,493
2023	419,550	55.1	$12,140,734
2024	510,798	66.9	$12,444,981
2025	602,907	78.9	$12,775,475
2026	696,948	91.0	$13,163,727
2027	786,971	102.8	$13,478,238
2028	873,445	114.6	$13,798,511
2029	959,682	126.5	$14,119,573
2030	1,046,587	138.5	$14,432,594
2031	1,127,019	149.8	$14,849,184
2032	1,206,636	161.1	$15,187,942
2033	1,286,733	172.5	$15,544,398
2034	1,317,466	176.5	$15,824,693
2035	1,342,307	179.7	$16,074,726
2036	1,361,070	182.1	$16,307,510
2037	1,379,659	184.6	$16,544,828
2038	1,397,364	187.0	$16,786,479
2039	1,412,165	189.1	$16,943,342
2040	1,425,373	190.9	$17,103,500
2041	1,437,179	192.6	$17,267,020
2042	1,447,692	194.1	$17,433,974
2043	1,456,960	195.5	$17,604,435
2044	1,465,211	196.7	$17,778,475
2045	1,472,341	197.7	$17,956,170
2046	1,477,839	198.5	$18,137,597
2047	1,482,283	199.2	$18,322,833
2048	1,485,725	199.7	$18,511,960

Table 5-13 shows the cumulative annual energy efficiency savings as a percent of total C&I sector sales, excluding C&I customers that have opted out of NIPSCO's energy efficiency programs.

Table 5-13: Achievable C&I Sector Energy Efficiency Savings as a Percent of Sales (Base Case)

Year	Cumulative Energy Savings (MWh)	C&I Sector Sales Forecast (Excl. Opt-Out) (MWh)	Cumulative Savings Percent of Sales
2019	72,000	4,652,224	1.5%
2020	152,000	4,697,257	3.2%
2021	240,000	4,739,576	5.1%
2022	325,796	4,778,968	6.8%
2023	419,550	4,819,735	8.7%
2024	510,798	4,856,840	10.5%
2025	602,907	4,895,604	12.3%
2026	696,948	4,933,514	14.1%
2027	786,971	4,966,699	15.8%
2028	873,445	5,000,237	17.5%
2029	959,682	5,025,190	19.1%
2030	1,046,587	5,052,855	20.7%
2031	1,127,019	5,078,996	22.2%
2032	1,206,636	5,099,000	23.7%
2033	1,286,733	5,118,796	25.1%
2034	1,317,466	5,139,223	25.6%
2035	1,342,307	5,161,284	26.0%
2036	1,361,070	5,174,258	26.3%
2037	1,379,659	5,181,773	26.6%
2038	1,397,364	5,190,437	26.9%
2039	1,412,165	5,197,508	27.2%
2040	1,425,373	5,209,258	27.4%
2041	1,437,179	5,221,038	27.5%
2042	1,447,692	5,232,850	27.7%
2043	1,456,960	5,244,693	27.8%
2044	1,465,211	5,256,567	27.9%
2045	1,472,341	5,268,473	27.9%
2046	1,477,839	5,280,410	28.0%
2047	1,482,283	5,292,379	28.0%
2048	1,485,725	5,304,379	28.0%

Table 5-14 shows the NPV of benefits, costs, net benefits and the benefit-cost ratio for each program and for the portfolio as a whole.

Table 5-14: Benefit Cost Analysis Results – UCT

Program	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
Custom	$340,264,393	$60,474,877	$279,789,516	5.6
New Construction	$98,374,129	$18,786,751	$79,587,378	5.2
Prescriptive	$396,617,207	$38,748,919	$357,868,288	10.2
Retro-Commissioning	$16,901,754	$7,739,152	$9,162,602	2.2
Small Business Direct Install	$87,942,866	$16,596,204	$71,346,663	5.3
New Measures Prescriptive	$23,743,405	$5,029,889	$18,713,516	4.7
New Measures Custom	$9,439,944	$1,990,940	$7,449,004	4.7
New Prescriptive Ag Measures	$2,859,702	$523,495	$2,336,207	5.5
New Measures New Construction	$15,594,391	$3,778,988	$11,815,403	4.1
Total	$991,737,791	$153,669,216	$838,068,576	6.5

5.6 Future Resource Options

5.6.1 Energy Efficiency Bundles[12]

GDS converted the measure incentive costs into an equivalent annual payment spread over the life of the measure and divided the equivalent annual payment by the measure's first-year kWh savings to calculate the incentive cost per lifetime kWh saved for each measure. According to the November 2008 National Action Plan for Energy Efficiency guide titled "Understanding Cost Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy-Makers," program administrative costs are typically not included when calculating cost effectiveness at the measure level. Based on this recommendation, program administrative costs were not included in this cost calculation. Tables 5-15 and 5-16 show the cumulative annual MWh savings, MW savings and annual utility budgets for these three bundles for the energy efficiency base case scenario for residential and C&I customers, respectively. Table 5-17 summarizes the total. The cumulative MWh and budget costs are additive for residential and C&I to arrive at the total, but the peaks are not, due to the fact that different programs are not coincident. The total bundles were used in the IRP modeling.

12 Please note, the MWh, MW and budgets utilized in the IRP were from an earlier draft of the Energy Efficiency Savings Update and may differ slightly from the numbers in the final report included in Appendix B. This was due to the timing of the final report compared to when numbers were required for the model runs. However, the differences are not significant. The tables in this section reflect the numbers utilized by CRA in the IRP modeling efforts.

Table 5-15: Residential Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	23,198	9.8	$3,120,947	27,435	6.6	$6,363,684	341	0.2	$332,842
2020	36,732	12.0	$3,118,788	55,160	13.1	$6,363,871	599	0.3	$332,467
2021	50,064	14.5	$3,115,234	82,515	19.5	$6,362,402	856	0.5	$332,085
2022	70,676	18.9	$4,169,756	86,004	20.4	$1,216,278	13,208	3.5	$15,436,140
2023	91,166	23.8	$4,300,842	89,310	22.2	$1,256,494	24,414	6.8	$15,482,175
2024	112,679	28.3	$4,429,560	93,419	23.3	$1,306,866	35,635	9.7	$15,529,778
2025	133,822	32.8	$4,569,988	96,910	24.5	$1,350,188	46,866	12.6	$15,574,511
2026	155,209	37.4	$4,699,753	100,720	25.8	$1,393,143	58,108	15.5	$15,621,458
2027	176,419	41.8	$4,836,631	104,348	26.8	$1,433,990	69,363	18.1	$15,670,403
2028	199,234	46.6	$4,970,286	108,790	28.1	$1,446,694	80,604	21.0	$15,717,871
2029	217,904	50.9	$5,106,871	112,422	29.6	$1,474,239	91,853	24.2	$15,766,369
2030	237,319	55.2	$5,247,332	116,343	31.1	$1,486,926	103,112	27.4	$15,817,541
2031	254,732	59.2	$5,394,368	119,996	32.5	$1,497,348	114,383	30.5	$15,871,633
2032	274,152	63.3	$5,544,922	124,489	34.0	$1,509,677	125,665	33.7	$15,925,409
2033	290,429	67.5	$5,698,959	127,935	35.4	$1,545,193	136,952	36.9	$15,978,312
2034	300,194	69.8	$5,823,060	104,480	30.4	$1,561,017	148,249	40.3	$16,033,291
2035	309,001	71.9	$5,952,395	80,860	25.9	$1,574,207	152,798	42.1	$16,091,088
2036	320,400	74.4	$6,099,762	57,323	22.7	$1,584,608	157,352	44.0	$16,145,518
2037	323,194	75.3	$6,198,431	58,462	23.3	$1,596,027	159,923	44.8	$16,181,313
2038	326,486	76.2	$6,299,172	59,653	23.9	$1,607,685	162,493	45.6	$16,217,860
2039	328,471	76.6	$6,402,029	60,152	24.1	$1,619,588	164,753	46.0	$16,255,174
2040	332,568	75.3	$6,507,046	60,938	18.7	$1,631,741	166,995	42.1	$16,293,272
2041	333,792	75.9	$6,614,269	61,276	19.1	$1,644,149	169,223	43.0	$16,332,170
2042	335,604	76.4	$6,723,743	61,617	19.6	$1,656,818	169,385	43.5	$16,371,885
2043	336,350	76.8	$6,835,516	61,761	20.1	$1,669,753	169,537	44.2	$16,412,433
2044	338,661	77.1	$6,949,636	62,046	20.2	$1,682,960	169,620	44.2	$16,453,834
2045	338,978	77.4	$7,066,152	62,014	20.2	$1,696,443	169,698	44.2	$16,496,103
2046	340,018	77.6	$7,185,116	62,077	20.2	$1,710,210	169,770	44.3	$16,539,261
2047	340,876	77.8	$7,306,578	62,112	20.3	$1,724,267	169,832	44.3	$16,583,324
2048	342,462	78.0	$7,430,590	62,240	20.3	$1,738,618	169,882	44.3	$16,628,313

Table 5-16: C&I Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	57,477	13.7	$7,093,091	14,523	2.9	$1,954,097	0	0.0	$0
2020	121,341	28.9	$7,881,212	30,797	6.1	$2,171,219	0	0.0	$0
2021	191,591	45.6	$8,669,334	48,518	9.7	$2,388,341	0	0.0	$0
2022	258,294	62.0	$9,025,573	67,461	13.5	$2,703,163	193	0.0	$110,756
2023	332,676	78.7	$9,252,548	86,486	17.4	$2,770,426	387	0.1	$117,760
2024	408,406	95.7	$9,484,921	102,260	20.4	$2,835,287	592	0.1	$124,773
2025	485,669	113.0	$9,752,695	116,719	23.3	$2,890,234	784	0.2	$132,546
2026	564,928	130.5	$10,033,029	131,295	26.1	$2,979,807	1,025	0.2	$150,891
2027	645,287	148.4	$10,273,287	140,436	28.0	$3,046,937	1,249	0.3	$158,013
2028	722,917	166.1	$10,524,231	149,709	29.8	$3,107,737	1,497	0.3	$166,543
2029	801,264	184.1	$10,777,543	157,031	31.3	$3,168,288	1,744	0.4	$173,742
2030	880,358	202.4	$11,027,368	164,628	32.9	$3,224,944	1,975	0.4	$180,283
2031	953,821	219.3	$11,348,675	170,945	34.2	$3,311,363	2,254	0.5	$189,145
2032	1,026,654	236.3	$11,619,566	178,316	35.6	$3,372,494	2,470	0.5	$195,882
2033	1,099,943	253.4	$11,900,715	184,506	37.0	$3,440,787	2,701	0.6	$202,895
2034	1,126,736	258.8	$12,151,635	188,173	37.8	$3,482,137	2,981	0.6	$190,921
2035	1,148,291	262.9	$12,362,496	190,812	38.4	$3,520,890	3,203	0.7	$191,340
2036	1,164,268	265.7	$12,559,119	194,251	39.0	$3,556,600	3,421	0.7	$191,791
2037	1,180,955	269.5	$12,759,892	195,605	39.4	$3,592,662	3,539	0.8	$192,274
2038	1,196,990	273.1	$12,964,294	197,155	39.7	$3,629,416	3,663	0.8	$192,769
2039	1,210,329	276.2	$13,090,516	198,060	39.9	$3,659,638	3,777	0.8	$193,188
2040	1,222,254	279.1	$13,219,389	200,104	40.2	$3,690,495	3,912	0.8	$193,616
2041	1,232,984	281.7	$13,350,967	200,623	40.4	$3,722,000	4,022	0.8	$194,052
2042	1,242,596	284.0	$13,485,309	201,428	40.6	$3,754,167	4,119	0.9	$194,498
2043	1,251,057	286.0	$13,622,472	201,699	40.7	$3,787,009	4,205	0.9	$194,953
2044	1,258,590	287.8	$13,762,516	202,762	40.8	$3,820,541	4,313	0.9	$195,418
2045	1,265,087	289.4	$13,905,500	202,854	40.9	$3,854,778	4,400	0.9	$195,892
2046	1,270,045	290.7	$14,051,487	203,301	41.0	$3,889,733	4,495	0.9	$196,377
2047	1,274,014	291.7	$14,200,540	203,681	41.0	$3,925,422	4,588	0.9	$196,871
2048	1,277,052	292.5	$14,352,723	204,442	41.1	$3,961,861	4,690	1.0	$197,376

Table 5-17: Total Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	80,676	20.5	$10,214,038	41,958	8.4	$8,317,781	341	0.2	$332,842
2020	158,073	35.8	$11,000,000	85,957	16.8	$8,535,090	599	0.3	$332,467
2021	241,655	53.2	$11,784,567	131,033	25.4	$8,750,744	856	0.5	$332,085
2022	328,971	71.9	$13,195,329	153,465	28.9	$3,919,442	13,401	3.5	$15,546,896
2023	423,842	91.1	$13,553,390	175,796	33.5	$4,026,920	24,801	6.9	$15,599,935
2024	521,084	110.3	$13,914,481	195,680	37.1	$4,142,153	36,228	9.8	$15,654,551
2025	619,491	129.9	$14,322,683	213,629	40.5	$4,240,422	47,650	12.7	$15,707,057
2026	720,137	149.7	$14,732,782	232,015	43.9	$4,372,950	59,132	15.7	$15,772,349
2027	821,705	169.6	$15,109,918	244,784	46.3	$4,480,928	70,612	18.4	$15,828,416
2028	922,151	189.7	$15,494,517	258,499	49.0	$4,554,431	82,101	21.4	$15,884,414
2029	1,019,167	209.7	$15,884,414	269,453	51.9	$4,642,527	93,596	24.5	$15,940,111
2030	1,117,676	230.0	$16,274,700	280,971	55.0	$4,711,870	105,087	27.8	$15,997,824
2031	1,208,553	248.7	$16,743,044	290,941	57.8	$4,808,711	116,638	30.9	$16,060,778
2032	1,300,805	267.6	$17,164,488	302,805	60.7	$4,882,171	128,134	34.2	$16,121,291
2033	1,390,371	286.6	$17,599,674	312,441	63.6	$4,985,981	139,653	37.5	$16,181,207
2034	1,426,931	293.0	$17,974,695	292,653	61.6	$5,043,153	151,229	40.9	$16,224,212
2035	1,457,292	298.1	$18,314,890	271,672	59.5	$5,095,098	156,000	42.7	$16,282,428
2036	1,484,668	302.1	$18,658,881	251,574	58.1	$5,141,208	160,773	44.7	$16,337,309
2037	1,504,149	306.3	$18,958,323	254,067	59.0	$5,188,689	163,461	45.5	$16,373,587
2038	1,523,475	310.3	$19,263,467	256,808	59.9	$5,237,101	166,155	46.3	$16,410,629
2039	1,538,800	313.7	$19,492,545	258,212	60.2	$5,279,226	168,530	46.8	$16,448,362
2040	1,554,823	315.6	$19,726,435	261,042	55.2	$5,322,236	170,907	42.8	$16,486,888
2041	1,566,776	318.5	$19,965,236	261,899	55.9	$5,366,150	173,245	43.8	$16,526,222
2042	1,578,200	321.0	$20,209,052	263,046	56.5	$5,410,985	17,504	44.3	$16,566,383
2043	1,587,407	323.3	$20,457,988	263,459	57.2	$5,456,763	173,742	45.0	$16,607,387
2044	1,597,250	325.2	$20,712,151	264,809	57.4	$5,503,501	173,933	45.0	$16,649,251
2045	1,604,065	326.9	$20,971,653	264,868	57.5	$5,551,221	174,098	45.1	$16,691,996
2046	1,610,063	328.3	$21,236,603	265,378	57.6	$5,599,943	174,265	45.1	$16,735,637

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2047	1,614,891	329.4	$21,507,118	265,793	57.7	$5,649,688	174,420	45.1	$16,780,196
2048	1,619,514	330.2	$21,783,313	266,682	57.8	$5,700,478	174,572	45.2	$16,825,690

5.6.2 Demand Response Program Options

Five DR options were considered, including two options for NIPSCO's Interruptible Tariff. The objective of these options is to realize demand reductions from eligible customers during the highest load hours of the summer or winter as defined by the utility. Each program type provides DR using different load reduction and incentive strategies designed to target different types of customers. From the utility perspective, load reduction events for each of the different program types can be called with different notification time. Using a mix of programs provides load reduction resources that can be called under many different conditions. Table 5-18 lists the DR programs included in this DSM Savings Update.

Table 5-18: Demand Response Program Options

DR Program Option	Eligible Customer Classes	Mechanism	Season
DLC Central Air Conditioner Cycling	Residential, Small and Medium C&I	DLC Switch for Central Cooling Equipment	Summer
DLC Space Heating	Residential, Small and Medium C&I	DLC Switch for Space Heating Equipment	Winter
DLC Water Heater Cycling	Residential, Small and Medium C&I	DLC Switch for Water Heating Equipment	Summer and Winter
Interruptible Load Tariffs	Large C&I	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance.	Summer
Interruptible Load Tariffs with Third Party Aggregator	Large C&I	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance. Typically managed as a portfolio by third party contractor.	Summer

5.6.3 Demand Response Load Reduction Assumptions

The per-customer kW electric peak load reduction, multiplied by the total number of participating customers, provides the potential demand savings estimate. Load reduction impact assumptions are based on program performance for current or past NIPSCO programs and on secondary research for new programs. The Interruptible Rider impact was sourced from actual program performance. The percentage was scaled to match current program performance. The remaining program impacts were developed by taking an average of existing/past program performance from programs in states within the region. Table 5-19 shows the per-customer load reductions used for estimating the potential, along with sources. The majority of load reductions were obtained from the 2016 MPS, with the exceptions noted in the table.

Table 5-19: Demand Response Program Load Reduction Assumptions

Sector	DR Program Option	Load Reduction	Source
Residential	DLC AC	0.972 kW	FERC 2012 Survey adjusted to IN using National Oceanic and Atmospheric Administration temperatures
	DLC Space Heating	0.62 kW	2016 MPS
	DLC Water Heating	0.9 kW	2016 MPS
Business	DLC AC	3.1 kW	2016 MPS
	DLC Space Heating	1.5 kW	PGE Brattle Group 2016 Study
	DLC Water Heating	2.7 kW	2016 MPS
	Interruptible Rider	18% of Coincident Peak Load	2016 MPS
	Third Party Aggregator	18% of Coincident Peak Load	2016 MPS

The DR options for large C&I customers included in the Savings Update are described below:

5.6.4 Interruptible Rider

As described above and under Rider 775, large commercial customers enroll directly with NIPSCO in an agreement to curtail their load during system contingencies.

5.7 Consistency between IRP and Energy Efficiency Plans

Ind. Code § 8-1-8.5-10 ("Section 10"), which became law on May 6, 2015, requires, among other things, that a utility's energy efficiency goals are (1) reasonably achievable; (2) consistent with the utility's IRP, and (3) designed to achieve an optimal balance of energy resources in the utility's service territory. A utility is required to petition the Commission for approval of an energy efficiency plan under Section 10 beginning not later than calendar year 2017, and not less than once every three years.

To remain consistent with the requirements of Section 10, NIPSCO carried out a lengthy analysis of the DSM resources included in its IRP process. As noted above, NIPSCO completed an update to its 2016 MPS to determine the achievable amount of savings. *See Appendix B.* NIPSCO, through the MPS and the DSM Electric Savings Update process discussed above, then conducted an in-depth review of the amount of savings that would be achievable in its service territory with its current customer base. Following that in-depth review process, 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.

NIPSCO allowed DSM and energy efficiency measures, broadly referred to as DSM resources, to be selected across all six portfolio concepts. As discussed further in this section, three separate DSM bundles were developed by GDS for potential selection in the portfolio optimization model. The bundles were organized according to cost, and all of the resources in the first two bundles were selected by the optimization model across all portfolios.

In accordance with Section 10, NIPSCO intends to request approval in 2020 of an energy efficiency plan for implementation in 2022 ("2020 Filing") that includes:

- energy efficiency goals that are (1) reasonably achievable; (2) consistent with NIPSCO's 2018 IRP, and (3) designed to achieve an optimal balance of energy resources in its service territory;

- energy efficiency programs that are (1) sponsored by an electricity supplier and (2) designed to implement energy efficiency improvements;

- program budgets;

- program costs that include (1) direct and indirect costs of energy efficiency programs, (2) costs associated with the EM&V of program results, (3) recovery of lost revenues and performance incentives. For purposes of this filing, the "direct costs" are those associated with implementing the programs, including any costs associated with program start up, while "indirect costs" are the NIPSCO administrative costs; and

- EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Action Plan prior to its 2020 Filing based on the energy efficiency selected by the IRP model. This may be updated depending on the results of the 2019 MPS and/or another mechanism (i.e. DSM RFP results). The DSM Action Plan will take into account the results of the IRP for implementation and evaluation of the Energy Efficiency Plan.

It is important to note that the final program design is determined by the bidder(s) selected by NIPSCO, with consideration of input from its OSB. The selected bidder's(s') predictions of the market into the program design as they determine what may or may not work in the NIPSCO's service territory is important for designing an energy efficiency program. That means that the programs included in the MPS/DSM Savings Update typically change. NIPSCO uses the MPS/DSM Savings Update as a feed into the IRP to develop the Action Plan. This Action Plan allows NIPSCO to take into account not just the results of the IRP, but also the experience of NIPSCO and its vendors with a particular program or measure. For example, electric hot water heating has a great deal of potential, but NIPSCO has not found there to be much interest from customers in the program. Knowing this means that NIPSCO will either (a) not structure a large amount of savings around a measure which has historically shown little participation or (b) need to increase the incentive to increase participation, which may impact the cost effectiveness of the program.

The benefit of an Action Plan is that it uses various forms of information, including the IRP, to develop the best strategy for an energy efficiency plan. The Action Plan will then be used to develop the DSM RFPs. The results of the winning bids will be utilized to develop the filing, with support from the MPS/DSM Savings Update, IRP and Action Plan. This is the most effective way to ensure NIPSCO has an Energy Efficiency Plan that is based on real-world, achievable results from vendors who are committed to those results. Bidders' responses to the groupings identified in NIPSCO's DSM RFP will vary based on the individual bidder's perception of NIPSCO's customer base and their previous experiences within other service territories, etc. This unique process for development of the DSM RFPs and creation of the Energy Efficiency Plan allows NIPSCO to compensate for the long lead time between the completion of a market potential study and the actual implementation of a program.

That does not mean that the Energy Efficiency Plan will be without change. Until the programs are administered to the customer base and the first-hand experiences with energy efficiency occur, informed judgments must be used to establish the initial estimates of program impacts in NIPSCO's service territory. That is the benefit of utilizing an OSB. It provides an on-going mechanism to adjust to changing market conditions, including codes and standards and new technologies, and to ensure NIPSCO is capturing as much energy efficiency savings as possible for the amount of funding available.

Section 6. Transmission and Distribution System

Consistent with the principles set out in Section 1, NIPSCO continues to invest in its existing Transmission and Distribution ("T&D") resources to ensure reliable, compliant, flexible, diverse and affordable service to its customers. NIPSCO continually assesses the current physical T&D system resources for necessary improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at the state, regional, and federal levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. The goals of the planning process include:

- Adequately serve native customer load and maintain continuity of service to customers under various system contingencies.
- Proactively maintain and increase availability and reliability of the electric delivery system.
- Minimize capital and operating costs while being consistent with the above guidelines

6.1 Transmission System Planning

6.1.1 Transmission System Planning Criteria and Guidelines

NIPSCO Transmission System Planning Criteria requires performance analysis of the transmission system for the outage of various system components including but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy of transmission system performance is measured in terms of NIPSCO planning voltage criteria, facility thermal ratings, fault interrupting capability, voltage stability, and generator rotor angle stability as documented in the NIPSCO 2018 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix F). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

6.1.2 North American Electric Reliability Corporation

NIPSCO is subject to the NERC, which is certified by the FERC to establish and enforce reliability standards for the bulk-electric system and whose mission is to ensure the reliability of the North American bulk electric system. NIPSCO is registered with NERC as a Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Resource Planner, Transmission Owner, Transmission Operator, and Transmission Planner. Together with MISO, in a Coordinated Functional Registration, NIPSCO is registered as a Balancing Authority, Transmission Owner, and Transmission Operator. Each Registered Entity is subject to compliance with applicable NERC standards, and ReliabilityFirst Regional Reliability Organization standards approved by FERC. Non-compliance with these standards can result in potential fines or penalties.

6.1.3 Midcontinent Independent System Operator, Inc.

NIPSCO participates in the larger regional transmission reliability planning process through participation in the MISO, which annually performs a planning analysis of the larger regional transmission system through the MISO Transmission Expansion Plan ("MTEP"). The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies. It should be noted that while any transmission project NIPSCO wishes to build must generally be timely submitted for planning review by MISO to ensure that there is no harm to other systems in MISO, so long as NIPSCO does not request cost sharing of the project with other MISO members, NIPSCO does not have to obtain MISO Board approval to proceed with a transmission project if NIPSCO deems it necessary. Additionally, under extenuating circumstances, NIPSCO can request expedited review of those cost-shared projects that do require MISO Board approval.

Requests by generation owners to connect new generators to the NIPSCO transmission system, to change the capacity of existing generators connected to the NIPSCO transmission system, or otherwise modify existing generators connected to the NIPSCO transmission system are handled through the MISO Generation Interconnection Process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests. Requests by generation owners connecting to the PJM Interconnection LLC ("PJM") transmission system are to be coordinated with NIPSCO by PJM through MISO.

Requests by generation owners in the MISO footprint to retire existing generators are handled through the MISO Attachment Y process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify either operating procedures or improvements and upgrades necessary to accommodate these requests. Requests by generation owners in the PJM footprint to retire existing generators may be reviewed by MISO for impacts on the NIPSCO transmission system, but the generation owners in the PJM footprint are under no obligation to mitigate any resulting constraints on the NIPSCO transmission system.

Requests by generation owners to secure transmission service are handled through the MISO Transmission Service Request process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

Because NIPSCO is situated on a very significant boundary (seam) between MISO and PJM, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM under the MISO-PJM Joint Operating Agreement.

In addition, MISO may propose transmission system projects or other upgrades that are not reliability based, but are economically based and should relieve congestion. These projects must pass the Benefit Cost Ratio test established by MISO before approval. NIPSCO participates in this effort through the MISO Market Efficiency Planning Study, and the MISO-PJM Interregional Planning Stakeholder Advisory Committee which performs a coordinated system planning study with PJM.

NIPSCO is also an active participant in the Market Efficiency Project ("MEP") planning processes in both MISO and PJM. The MEP processes focus on evaluating potential future transmission projects to lower the overall production cost and lower delivered energy costs to the end use customer for the MISO and/or PJM footprint. These planning efforts require the benefits of proposed projects to exceed the costs (usually 1.25 or greater benefit to cost ratio) before the RTOs will consider it a viable solution.

6.1.4 Market Participants

MISO has developed a process through which market participants can request voluntary upgrades on the NIPSCO transmission system to better accommodate generation outlet capacity, increases in transmission rights, reduce congestion, address reliability considerations, or other market driven needs. If the Market Participant wishes to pursue these types of upgrades, they must submit their proposal to MISO, and NIPSCO and the Market Participant must negotiate payments for these upgrades as defined in the MISO tariff and corresponding Business Practice Manuals. Market Participant-Funded Projects must be filed in a timely manner with MISO for review in its transmission planning process.

6.1.5 Customer Driven Development Projects

NIPSCO may be contacted to undertake transmission upgrades by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts and NIPSCO Economic Development, will determine if identified transmission upgrades are identified necessary to meet the customer's development or expansion plans.

6.1.6 Transmission System Performance Assessment

In NIPSCO's 2018 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix F), Confidential Part 2 contains the regional power flow cases. The cases include solved real and reactive flows, voltages, detailed assumptions, sensitivity analyses, and model description. Confidential Part 3 contains applicable transmission maps. Part 4 describes the reliability criteria used for transmission planning. Confidential Part 5 presents the assessment practice used.

Confidential Part 6 contains an evaluation of the reliability criteria in relation to the present performance and the expected performance of the NIPSCO transmission system. Performance assessments are conducted annually for the near-term (5 year) and long-term (10 year) planning horizons, for both peak and off-peak load conditions, assuming known or forecasted changes in generation resources and load demand. Sensitivities to baseline forecasts or assumptions may also be considered for performance analysis of the transmission system.

NIPSCO also participates in the MISO and PJM Market Efficiency Project planning processes as discussed in Section 6.1.3: Midcontinent Independent System Operator, Inc. The MISO process includes multiple future scenarios to test future sensitivities against baseline assumptions.

6.1.7 NIPSCO Transmission System Capital Projects

NIPSCO's portfolio of transmission system projects has been identified through its annual transmission system performance assessment to establish base line reliability projects. This portfolio has been expanded to include transmission projects initiated by market participants, by customer driven development projects, and to include regional transmission projects designated through the MISO MTEP planning effort, with the most recent iteration approved by the MISO Board of Directors (MTEP 17) in 2017. NIPSCO's current portfolio includes:

- Multi-Value Project 11: Sugar Creek Substation upgrades to accommodate the new 345 kV circuit from Ameren's Kansas West substation to the NIPSCO/Duke Energy Indiana jointly-owned Sugar Creek substation
- Circuit 13812 Maple Substation upgrade
- Circuit 13854 Aetna Substation line drop upgrade
- LaGrange Substation 138kV Ring bus conversion

In addition to current portfolio, NIPSCO recently completed all transmission system projects approved by MISO (MTEP 11) as part of Multi-Value Project 12. Projects included:

- Reynolds to Burr Oak to Hiple 345kV Lines
- Reynolds to Greentown 765kV Line

6.1.8 Electric Infrastructure Modernization Plan

The Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") is an initiative to modernize infrastructure through upgrades to the NIPSCO electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year Electric TDSIC Plan (2016-2022). NIPSCO's 7-Year Electric TDSIC Plan is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time.

NIPSCO's 7-Year Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of two main segments: (1) investments that target replacement of aging assets (Aging Infrastructure) and (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability). In developing its Plan, NIPSCO considered the need to maintain a safe and reliable system. The approximate cost of the transmission portion of the TDSIC plan is $453M over the seven-year period.

6.1.9 Evolving Technologies and System Capabilities

NIPSCO Transmission Planning has provided for the installation of two variable shunt reactors ("VSRs") at the Hiple 345kV substation as part of the Multi-Value Projects. The VSRs, which will enable better and more precise control of transmission system voltage, are a relatively recent development in the industry.

6.2 Distribution System Planning

As part of the long term view, NIPSCO continues to evaluate the benefits of smart grid and distribution automation ("DA") technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure.

NIPSCO's distribution system is periodically reviewed for local circuit, substation and source feed adequacy. Normal operating status as well as single element or contingency failure loading and voltage operating characteristics are evaluated along with circuit and system wide reliability metrics (i.e., CAIDI, SAIDI, SAIFI).[13] Distribution operating and design criteria rely on NIPSCO design maximums in accordance with Company Standards and equipment manufacturer ratings. Voltage operating criteria are based on American National Standards Institute (ANSI) C84.1 and Indiana Administrative Code 170 IAC 4-1-20.

System improvement plans are developed and applied based upon mitigation of identified deficiencies associated with service capacity, service voltage, reliability levels, and load growth patterns. Specific and trending distribution component failures are mitigated through capital and infrastructure improvement processes. Infrastructure upgrade and replacement activities consider system characteristics that include severity of operating deficiencies, likelihood of failure, potential customer impact, current substation and line topology, equipment age and condition. Available new technologies are integrated into improvement and replacement activities where appropriate.

Net metering is an electricity policy for consumers who own renewable (solar, wind, biomass) energy facilities. Its application provides an incentive for customers to install renewable energy systems by reimbursing them for their generation output, at utility retail rates, for energy in excess of their service's base load electricity purchase from the utility. Typically this represents the aggregate excess power produced that is not utilized internally by the customer but is instead delivered into the utility's local electric system.

Feed-in tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources and to help accelerate the move toward renewable energy sources. This tariff provides power developers with a predictable purchase price for self-generation under a long-term power purchase arrangement, which helps support financing opportunities for these types of projects.

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[13] CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year.

NIPSCO implemented its renewable feed-n tariff in July 2011 along with its existing net metering program. These programs introduced customer-owned renewable resource based generation onto NIPSCO's electric distribution system. A relatively significant amount of renewable generation projects began coming "on line" in 2012 and that amount has continued to grow. NIPSCO's net metering and feed-in tariff generation interconnection programs provide an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's electric distribution systems. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts across the service territory.

At the end of 2017, the renewable generation data identified 10.7 MWs associated with the net metering program and 33.4 MWs of generation associated with the feed-in Tariff program. An aggregate breakdown by renewable fuel type is provided below. These values represent generation resources that include landfill gas combustion engines, animal waste gas combustion engines, PV solar array farms, small roof mounted and ground mounted residential solar arrays, intermediate sized commercial wind turbines, and small commercial and residential wind turbines.

Net Metering Generation:

- 8.64 MWs - Solar Generation
- 1.92 MWs - Wind Generation
- 0.132 MWs - Solar/Wind Combination Generation

Feed-In Tariff Generation:

- 18.87 MWs - Solar Generation
- 0.16 MWs - Wind Generation
- 14.35 MWs - Biomass Generation

The above biomass related generation value excludes 13.6 MWs of existing landfill based generation interconnected to NIPSCO's distribution system. Although these renewable generation sources feed into NIPSCO's network, the power deliveries are associated with customer PPAs with parties other than NIPSCO. These customers do not participate in NIPSCO's net metering or feed-in tariff programs. In total, approximately 55 MWs of generation is interconnected to NIPSCO's distribution system.

Based on the implementation of the net metering and feed-in tariff programs, Distribution Planning has observed voltage related operating impacts on its electric system due to larger customer-owned generation. Impacts on system operations has yet to be fully determined and will depend upon the demonstrated long term performance and reliability of various installed generating resources including solar, wind, and biomass based generation fueled resources. Differences in operational characteristics, generation penetration, power delivery timing, and location all affect the relative impact on local distribution system operations at any given time. The diverse types of customer-owned generation also have varying effects on the electric system.

NIPSCO has observed that local generation most often varies substantially depending upon individual customer equipment and generation input resources. Fuel resource type affects power delivery in various ways depending upon owner controlled resources as is the case of landfill and animal by-product gas inputs, or external environmental conditions such as wind velocity and solar irradiance. Highly variable outputs have been observed to occur on both solar and wind turbine installations. For instance, rapid changes in solar generation have exhibited swings of 85% of full rated output, within seconds. These conditions represent sizable down-up-down shifts in system operating characteristic on local circuits associated with some of the larger half MW or greater rated customer owned solar fields. These swings can present challenges to maintaining appropriate service voltage stability on distribution circuits. In addition to these more rapid changes relating to industry recognized "cloud affect," NIPSCO has also observed that more widespread weather patterns such as seasonal rain or snow storms also dramatically influence individual daily peak PV generation outputs on a longer term scale. Longer duration output reductions of 75% to 92% of rated equipment output are observed during seasonal inclement weather conditions. Significantly reduced output levels can be seen extending over several or more days, especially during winter season months. Wind powered generation was also observed to be as much, if not more, unpredictable and variable in power delivered to the distribution system. On the other hand, large biomass fueled combustion turbines appear to be less volatile in generated outputs in comparison to solar and wind associated generation. Landfill based biomass generation facilities tend to be the most predictable followed by animal waste gas associated generation. However, even though biomass fueled resources exhibit a steadier dispatch of power, there were experiences of random events where customer generation dropped completely off line. The impact of lost generation becomes more significant as the generation level increases since the local distribution system needs to adjust and compensate for fast change in power sources.

Based upon several years of operating data for currently installed renewable generation resources, these technologies present a recognized energy resource that can be utilized in supplementing customer electric energy needs. However, at this time, the impact on local electric distribution service infrastructure has not demonstrated to be sufficiently available or stable to be considered an adequate 24 hours a day/seven days a week/365 days a year substitute for NIPSCO's local electric sources in reliably meeting electric capacity and service needs. Considering that these distributed generation resources have no guarantee of power dispatch, operate in a "take it as we make it" mode, and can permanently cease operations at any time, results in a lower confidence level regarding the availability of power supply at all times, especially during periods of system stress or problems. Consequently, continued traditional capital investment into local distribution infrastructure is necessary to insure that the utility can meet all of its service obligations to its customers.

6.2.1 Evolving Technologies and System Capabilities

NIPSCO Distribution Planning continues the expansion of DA. This can be defined as the coordinated automatic control of substation breakers and interrupting-type line switches within an electric distribution system, along with the centralized retrieval of associated operating data for control and monitoring purposes.

NIPSCO's DA System enables control and automatic isolation of electric distribution line faults and the restoration of customer services during various system outage conditions. This action is accomplished through independent sectionalizing of specific circuits through the use of automatic line switches and computer-controlled substation breakers. Built-in algorithms are utilized to analyze operating conditions such as line and substation loading, to determine best response to system disturbances. Automatic restoration increases distribution system reliability by reducing the number of customers experiencing a sustained outage. In addition to the quick restoration of electric service, real-time operating data can also be retrieved and stored on the electric management system. DA Systems provide timely and accurate outage-related information to restoration teams, speeding up problem identification. This action supports quicker overall response time to identify system problems and develop repair procedures. These factors result in further improvements in customer service and system reliability. An added benefit of real-time data retrieval and device remote control is the more effective use of labor resources for operation and maintenance of the electric distribution system.

NIPSCO currently utilizes DA (communications and remote switching) on approximately 25% of its distribution substations and 30% of its distribution circuit population. Approximately two-thirds of all DA associated circuits utilize autonomous contingency switching equipment in their operations. All new and rebuilt distribution substations, and associated circuits, are assessed for need of distribution automation as part of their infrastructure projects. As part of annual system capital investment programs, new and/or rebuilt substation projects are being implemented at an approximate rate of one to two stations per year.

NIPSCO continues to evaluate the benefits of smart grid and DA technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure as part of its long term approach.

Section 7. Environmental Considerations

7.1 Environmental Sustainability

NIPSCO is committed to compliance, stewardship, and continuing to provide energy in an environmentally responsible way. NIPSCO's current electric generation portfolio consists of assets that includes coal and natural gas plants, wind contracts, and hydroelectric power plants. Environmental improvement targets were announced in 2017, and this resource plan contemplates a transition of coal generation assets to renewable energy that would result in enhanced environmental improvements in electric generation by 2028 (from 2005 levels), as follows:

- 90% Reduction in Greenhouse Gas ("GHG") Emissions
- 99% Reduction in Water Withdrawal and Wastewater Discharge
- 99% Reduction in NO_x Emissions
- 99+% Reduction in SO_2 and Mercury Emissions
- 100% Reduction in Coal Ash Generated

7.2 Environmental Compliance Plan Development

NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste, and solid waste that protect health and the environment. NIPSCO is committed to complying with all regulatory requirements. This commitment is embodied in the NiSource Environmental, Health & Safety and Climate Change Policies and is implemented through a comprehensive environmental management system. Compliance plans are developed, reviewed, and evaluated for implementation to meet new and changing legislative and regulatory developments.

NIPSCO uses a combination of external and internal resources to develop and adapt environmental compliance plans. Consultants and engineering firms are utilized to assist NIPSCO in developing cost estimates and performing modeling. Compliance plans are drafted to address proposed and final EPA and Indiana Department of Environmental Management ("IDEM") rules. As rules change, compliance plans are modified to comply with new requirements.

7.3 Environmental Regulations

7.3.1 Solid Waste Management

The EPA finalized a rule regulating the management and disposal of Coal Combustion Residuals ("CCR") which became effective on October 19, 2015. The CCR rule regulates CCRs under the Resource, Conservation, and Recovery Act (RCRA) Subtitle D as nonhazardous. The CCR rule is implemented in phases establishing requirements related to groundwater monitoring, CCR management and disposal, reporting, recordkeeping, and document management.[14] The rule allows NIPSCO to continue its byproduct beneficial use program, significantly reducing CCR that must be disposed.

To comply with the rule, NIPSCO is required to incur capital expenditures to modify its infrastructure and manage CCRs. Capital compliance costs for Schahfer Units 14 and 15 and Michigan City Unit 12 are expected to total approximately $193 million. Schahfer Units 17 and 18 will not incur any capital costs related to the CCR rule. On December 13, 2017, the IURC approved a set of projects related to CCR compliance in Cause No. 44872. NIPSCO continues to assess and monitor groundwater quality at Bailly, Michigan City, and Schahfer to comply with CCR rule requirements and to determine if historic CCR management and disposal practices will require corrective measures.

7.3.2 Clean Water Act

The CWA establishes water quality standards for surface waters as well as a permit program for regulating discharges into the waters of the United States. Under the CWA, EPA created a program to establish wastewater discharge standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge from a point source into navigable waters without a permit. The National Pollutant Discharge Elimination System ("NPDES") permit program implements the CWA's provisions.

7.3.3 Effluent Limitations Guidelines

EPA first promulgated the Steam Electric Power Generating Effluent Guidelines and Standards ("ELG Rule") in 1974, and has amended the regulation many times, with the latest revision finalized on November 3, 2015, with an effective date of January 4, 2016. The ELG rule regulates wastewater discharges from power plants operating as utilities. The implementing requirements are incorporated into NPDES permits. The ELG Rule imposes new wastewater treatment and discharge requirements on NIPSCO's electric generating facilities to be applied between 2018 and 2023. For example, the Michigan City NPDES permit was renewed in April 2016, and ELG requirements were incorporated effective November 1, 2018. On April 25, 2017, the EPA published notice in the Federal Register stating that the EPA is reconsidering portions of the ELG Rule in response to several petitions for reconsideration. On September 18, 2017, the EPA postponed the earliest compliance dates for FGD wastewater and bottom ash transport water requirements from 2018 to 2020 to potentially consider revisions to technology and numeric limits achievable.

Michigan City Unit 12 is equipped with a dry FGD, which does not require any capital expenditure for ELG rule compliance. The CCR-related infrastructure investment will allow Michigan City to comply with other aspects of the ELG Rule by the November 2018, NPDES permit compliance date. Furthermore, no capital expenditure is expected for ELG compliance on Schahfer Units 14, 15, 17, and 18, which, based on this resource plan, NIPSCO anticipates retiring by 2023.

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[14] https://www.nipsco.com/about-us/ccr-rule-compliance-data-information

7.3.4 Clean Air Act and Climate Strategy Assessment

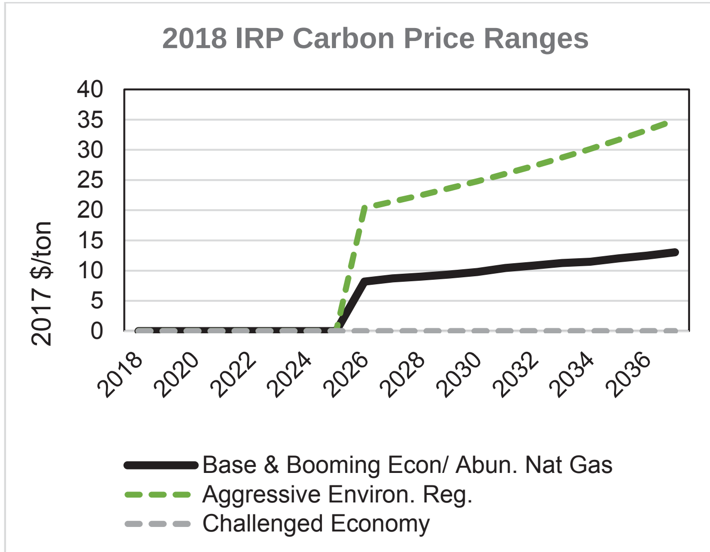
Over the last decade, NIPSCO has invested more than $800 million in new technologies to reduce emissions at its electric generating stations, improve air quality, and comply with CAA requirements. Emissions of NO_x, SO_2, and mercury have been reduced by more than 80% since 2005. All Northern Indiana counties are in attainment of the National Ambient Air Quality Standards with the exception of the ozone standards in Lake and Porter Counties, which are included in Chicago metropolitan area nonattainment.

NIPSCO has reduced GHG emissions by more than 40% since 2005, and emissions reductions are expected to continue with the anticipated retirement of coal generation and transition to renewable energy. Still, climate-related environmental laws and regulations may be developed that could result in significant cost or restrictions on NIPSCO's operations.

On October 23, 2015, the EPA issued a final rule, the CPP, to regulate CO_2 emissions from existing fossil-fuel electric generating units ("EGUs") under authority of the CAA. The CPP establishes national CO_2 emission standards that are applied to each state's mix of affected EGUs to establish either state-specific rate-based or mass-based emission limits. The U.S. Supreme Court has stayed implementation of the CPP until litigation is decided on its merits, and the EPA has proposed to repeal the CPP. On August 31, 2018, the EPA proposed to replace the CPP with the Affordable Clean Energy ("ACE") rule. The timing and cost of compliance with the ACE rule are unknown at this time and are likely dependent on future state rulemaking.

Although the timing and magnitude of required GHG reductions are uncertain, it does not appear likely that a price on carbon emissions will be required by regulation or legislation until the year 2026 or later. In the IRP modeling, NIPSCO assumed three carbon price scenarios as shown in the figure below. The base scenario assumes a new federal rule or legislative action effective by the mid-2020s, the second scenario does not assume any price on carbon, and the Aggressive Environmental Regulation scenario assumes a new stricter federal rule or legislative action effective by the mid-2020s. In the Aggressive Environmental Regulation scenario, price levels are generally consistent with a 50-60% reduction in electric sector CO_2 emissions relative to 2005 by the 2030s.

Figure 7-1: 2018 IRP Carbon Price Ranges



This resource plan considered the framework by Ceres and M.J. Bradley & Associates, *Climate Strategy Assessments for the U.S. Electric Power Industry: Assessing Risks and Opportunities Associated with a 2-Degree Transition and the Physical Impacts of Climate Change*. NIPSCO used scenario analysis to assess the potential implications of climate change and inform its strategy. The plan to transition coal generation assets to renewable energy would reduce NIPSCO greenhouse gas emissions by more than 90% by 2028 compared with 2005 levels.

Retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures to reduce NOx emissions in addition to expenditures for CCR, ELG, and GHG compliance. The IRP modeling assumed compliance with updates to the Cross-State Air Pollution Rule ("CSAPR") and ozone regulations that have not yet been proposed. Although both Schahfer Units 17 and 18 are already equipped with low-NO_x burners and OFA systems for NO_x reduction, SCR or selective non-catalytic reduction ("SNCR") could be installed for post-combustion NO_x control. SCR technology allows for greater NO_x reduction rates which leads to better operational flexibility. Therefore, SCR technology was assumed for compliance with the anticipated regulation. Conceptual cost estimates were used in the modeling.

7.4 Emission Allowance Inventory and Procurement

7.4.1 Title IV Acid Rain - SO_2 Emission Allowance Inventory

In conjunction with CSAPR, the Title IV Acid Rain Program will continue to regulate SO_2 emissions. Table 7-1 lists the actual number of SO_2 Acid Rain Program emission allowances held in inventory by NIPSCO as of September 2018 for the period 2018 through 2048. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the Acid Rain Program.

Table 7-1: SO_2 Acid Rain Program Emission Allowances

Acid Rain Program SO_2 Allowance Inventory*	
Year	**Allowances**
Bank**	264,764
2018-2048 Annual Allocation	50,706
Total* **	**1,836,650**

* Allowance inventory available in September 2018
** Reflects emission allowances from 2017 and earlier
***To obtain the total, multiply the annual allocation by 31 and add the bank.

7.4.2 CSAPR Emission Allowance Inventory

Under CSAPR, allowances are allocated to NIPSCO and managed separately from the Acid Rain Program. Table 7-2 lists the annual SO_2, annual NO_x, and ozone season NO_x allowance inventory issued to NIPSCO. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the CSAPR rule.

Table 7-2: CSAPR Allowance Inventory

CSAPR Allowance Inventory*			
Year	**Annual SO_2**	**Annual NO_x**	**Ozone Season NO_x**
Bank**	81,347	2,402	444
2018 – 2020 Annual Allocation	23,522	13,178	3,321
Total* **	**151,913**	**41,936**	**10,407**

** Allowance inventory available in September 2018.*
*** Reflects emission allowances from 2017 and earlier.*
****To obtain the total, take the annual allocation and multiply by three and add to the bank.*

Section 8. Managing Risk and Uncertainty

8.1 Introduction & Process Overview

In the 2018 IRP, NIPSCO has deployed an approach that involved the development of a fundamentals-based set of key Base Case market drivers and assumptions and the use of both scenarios and stochastics to assess risk and uncertainty. NIPSCO developed the major inputs and associated uncertainty ranges for the 2018 IRP through the following process:

- Development of the Base Case set of assumptions through fundamental energy sector and commodity price models and NIPSCO's internal load forecasting models.
- Identification of the key drivers of uncertainty and whether they can be evaluated through scenarios or stochastics.
- Development of distinct scenario themes with accompanying model-based forecast assumptions.
- Development of stochastic distributions for relevant variables.

The major market assumptions for the base case and the scenarios were developed using a set of fundamental market models deployed by CRA and discussed in more detail in Section 2.3. These models include the 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.

The following sections provide an overview of the fundamental drivers that underpin the NIPSCO Base Case for gas prices, coal prices, carbon prices, and power market prices, while the remainder of the chapter discusses the scenarios and associated assumptions and the stochastic distributions that have been developed.

8.2 Base Case Market Drivers and Assumptions

8.2.1 Natural Gas Prices

NIPSCO's 2018 Base Case natural gas price forecast is driven by a number of key market assumptions regarding the major supply and demand dynamics in the North American natural gas market. Figure 8-1 summarizes the major drivers, along with CRA's approach and assumptions for each driver, as well as supporting explanations. The remainder of this section provides additional detail related to each driver.

Figure 8-1: Natural Gas Price Drivers – Base Case

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) 2016 "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2016 "Minimum" resource, and grows the resource base to achieved PGC 2016 "Most Likely" volumes by 2050
Well Productivity	• IP rates based on historic data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data for initial mode year, IP rates improve annually in line with EIA assumptions The "Poor Heavy" resource base is conservative, and reflects the fact that sampled data reflects only geology expected to be productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA based individual well productivity on available historic data, adopted EIA assumptions for cost improvements over time
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2017 Reference Case (with CPP)	The AURORA case assumes "base case" carbon pressure and AEO 2017 Reference assumes CPP, meaning demand estimates are consistent
LNG Exports	• Under-construction projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031	Current advanced-stage projects expected to come online and be highly utilized driving 2019 view Low domestic prices drive further international interest for US gas, but no other projects able to complete before 2021
Pipeline Exports	• Mexican export increase to ~8bcf/d by 2021, 10.5bcf/d by 2030	CRA expects pipeline export capacity to meet growing gas demand in Mexico will be ~60% utilized by 2021, and 75% utilized by 2031
NGL & Condensate Value	• Liquids valued at 70% of AEO 2017 Reference Oil Price	AEO17 for long-term oil price forecast; 70% value for NGLs is consistent with last 5 years of price history

*IP = Initial Production

Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on the Potential Gas Committee ("PGC") 2016 "minimum" value as the starting value for recoverable shale reserves, with the resource base growing over time at a steady rate until the PGC "most likely" value is reached in 2050. The assumed values and ranges are shown in Figure 8-2.

PGC evaluates three categories of potential resource:

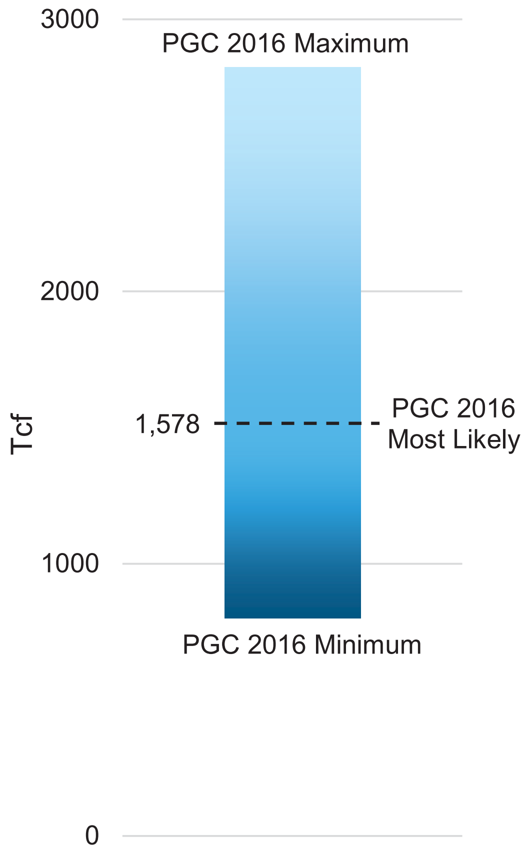
- Probable – gas associated with known fields
- Possible – gas outside of known fields, but within a productive formation in a productive province
- Speculative – gas in formations and provinces not yet proven productive

PGC assigns resource to three probability categories:

- Minimum – 100% probability that resource is recoverable
- Most Likely – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions

- Maximum – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present

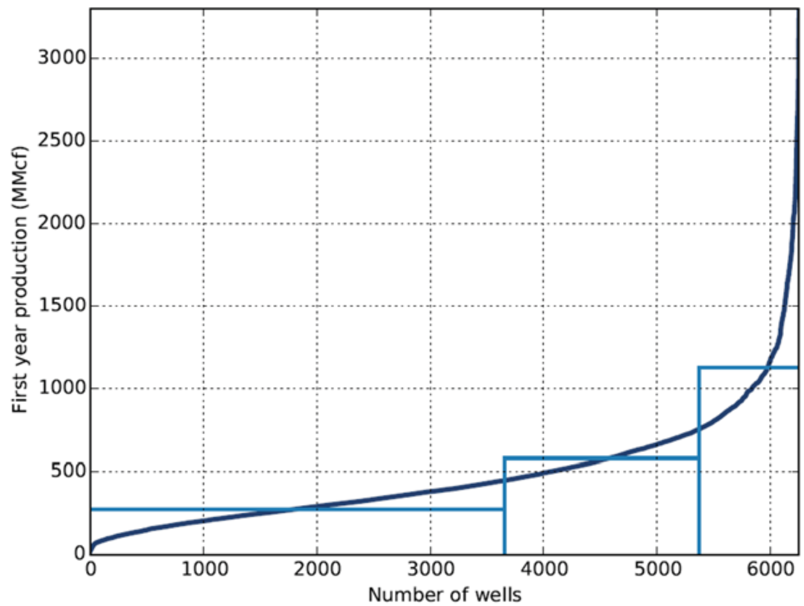
Figure 8-2: Uncertainty Range for Shale Resources in PGC 2016



Well Productivity

Natural gas well productivity assumptions are important drivers of ultimate production efficiency, especially since the bulk of gas resource is currently unproven, meaning that the geology of that resource is currently unknown. In developing assumptions for this variable, CRA generated productivity distributions for each production basin based on 2010-2016 drilling data in regions that producers expected to have favorable geology. An example of this distribution is shown in Figure 8-3, with the number of wells shown on the x-axis and the level of first-year production shown on the y-axis. In the Base Case, CRA assumed a "Poor Heavy" productivity distribution (50% poor, 20% prime, 30% average) for future undiscovered resource, as summarized in the graphic.

Figure 8-3: Well Productivity Illustration

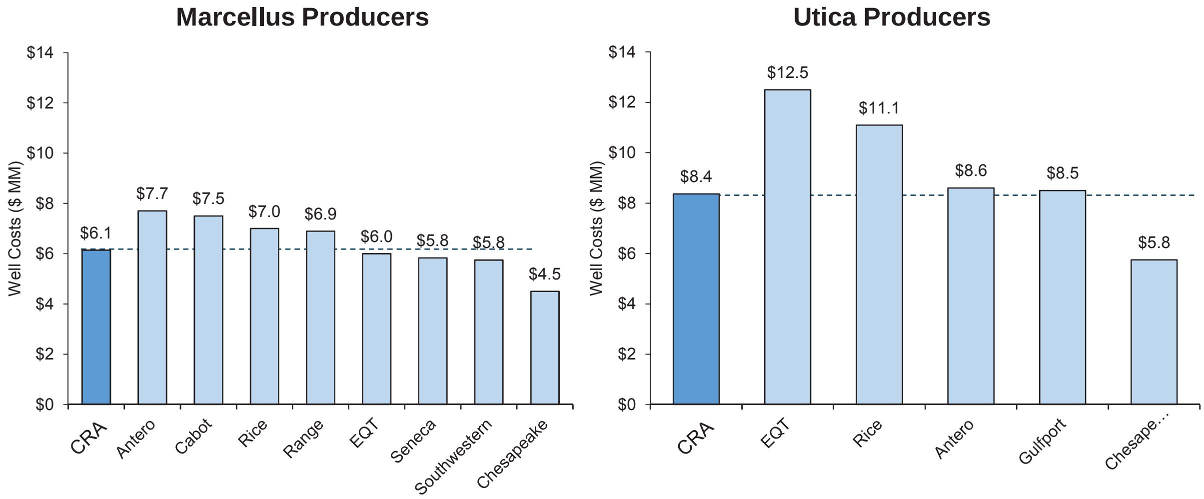


Well Costs

CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region. Figure 8-4 illustrates 2016-2017 reported costs in the Marcellus and Utica basins across major producers. Producers in these regions have been reporting declining costs over the last several years, with some producers (Antero, Seneca, Chesapeake) reporting cost reductions up to 35-37% since 2014.

For going forward costs, CRA relies on the EIA's Annual Energy Outlook ("AEO") projections for productivity improvements, fixed costs, and operations and maintenance costs. EIA's approach incorporates annual improvements to key well inputs that account for ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources from historical time periods.

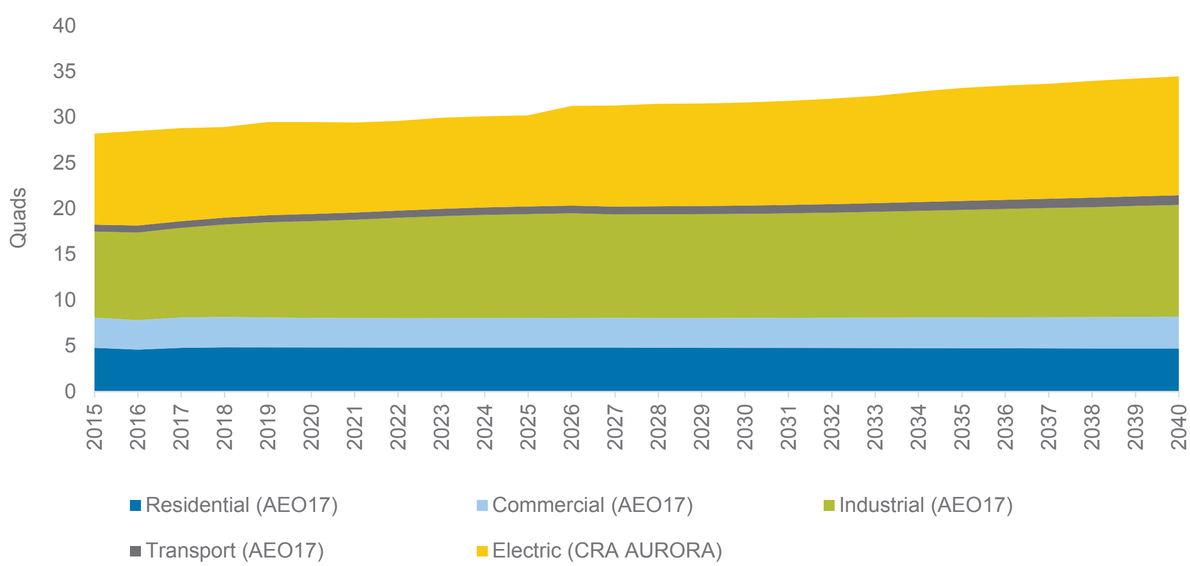
Figure 8-4: Well Costs by Producer with CRA Average



Domestic Demand

In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for residential, commercial, industrial, and transport demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-5 presents historical and forecast domestic demand assumptions through 2040 from these sources. Electric sector demand is expected to be relatively flat in the near-term, but increase substantially after the potential introduction of a carbon price, such that the demand by 2040 is 30% higher than current levels. The AEO's growth expectations for other sectors are more modest, with some growth expected in the industrial and transportation sectors over time.

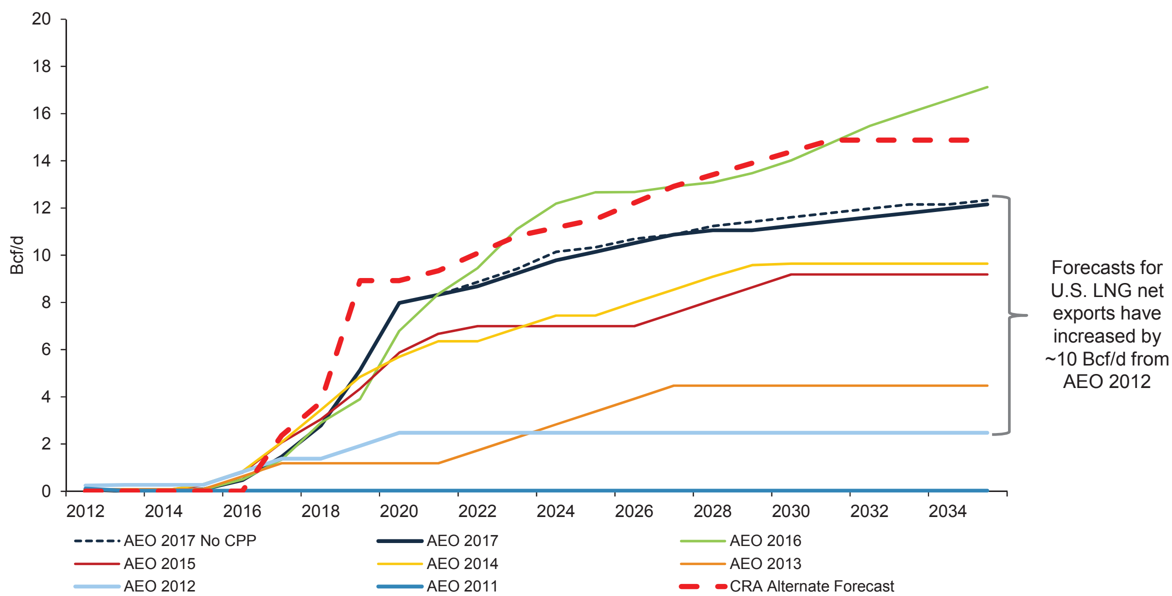
Figure 8-5: Domestic Natural Gas Demand Assumptions



Exports – LNG and to Mexico

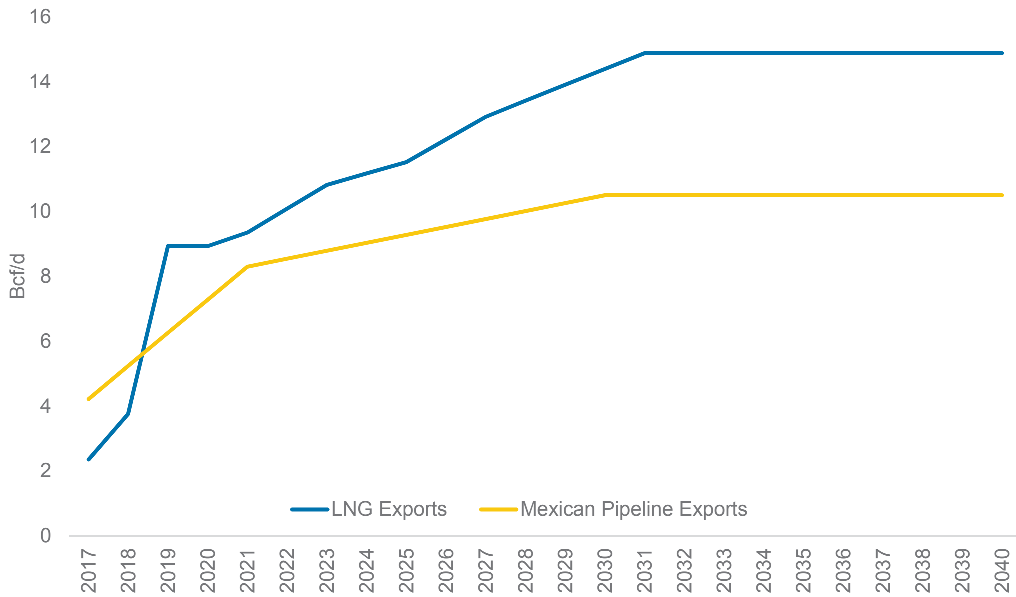
CRA develops projections for natural gas exports to Mexico via pipeline and to other international markets through LNG by reviewing estimates published by sources like the AEO and conducting analysis of specific export projects under development. The AEO has generally increased its outlook in recent years, as LNG exports in the AEO 2017 Reference Case are between 25%-35% higher than those in the AEO 2015, although lower than the more bullish long-term outlook produced in AEO 2016. CRA's review of current LNG export projects suggests that export levels will be slightly higher than AEO 2017 projects. The Base Case forecast projects about 9 billion of standard cubic feet ("bcf")/day of LNG exports by 2020, rising to nearly 15 bcf/day by 2030. CRA's Base Case projection is shown with recent AEO projections in Figure 8-6.

Figure 8-6: LNG Export Volume Projections



In addition, CRA expects that exports to Mexico will also increase, as U.S. production grows and as Mexican demand increases, primarily due to additional demand from the power sector. Mexican exports are projected to increase to around 8 bcf/day by 2021 and 10.5 bcf/day by 2030. These Base Case projections are shown along with the LNG export projections in Figure 8-7.

Figure 8-7: LNG and Mexican Pipeline Export Projections



Base Case Price Forecast

CRA's Base Case price forecast was developed based on each of the supply-demand inputs discussed above and is shown in Figure 8-8. The Base Case projects prices at Henry Hub to increase to around $3.50/ million per British thermal unit ("MMBtu") in real 2017$ by the early 2020s and approach $4/MMBtu by 2030. Recent AEO forecasts are shown with CRA's Base Case for comparison.

8.2.2 Coal Prices

NIPSCO's 2018 Base Case coal price forecast was driven by a fundamental view of the major supply and demand dynamics for each of the four major coal basins in the United States. The forecast was developed through CRA's NEEM model in an integrated fashion with other Base Case assumptions for natural gas prices (discussed above), carbon prices (discussed below), and the expected evolution of the power sector over time.

Overall, U.S. coal prices are expected to be mostly flat in real terms over the study period. The forward prices as of the time of forecast production were generally either flat or slightly backward-dated, indicating that many market participants expected relatively weak coal demand during 2018-2021, consistent with CRA's expectations. Beyond the near-term, CRA's fundamental analysis expects U.S. steam coal demand to fall significantly (~25%) over the next decade as a result of increased renewable generation and the retirement of about 33 GW of coal-fired capacity over the next five years. Increasing production costs offset the impact of declining demand in the Base Case forecast, resulting in a relatively flat price outlook.

Coal Supply and Demand Trends

Figure 8-9 summarizes historical and projected supply and demand for U.S. coals over the period from 2006 through 2037, which shows that coal demand has generally been in decline over the last ten years. Over the last three years, total coal production declined from 897 million tons to about 728 million tons (or 19%) between 2015 and 2016, but then increased 6.5% (to about 775 million tons) in 2017 as natural gas prices recovered from low levels in 2016. Modest additional declines are expected in the next five years, with more substantial declines expected by 2027 if carbon pricing is implemented, as is projected in the Base Case.

Figure 8-8: Base Case Henry Hub Natural Gas Price Forecast

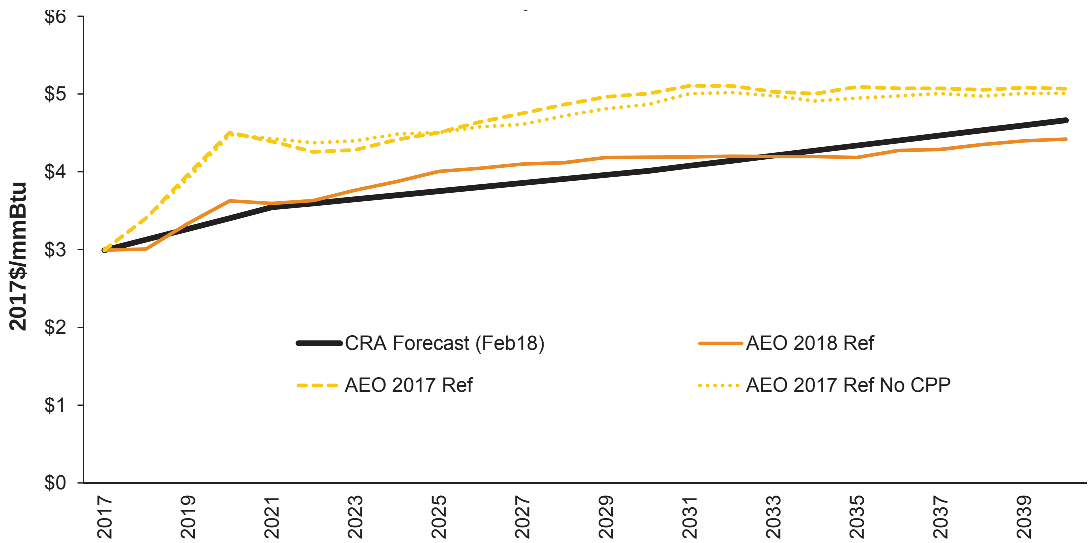
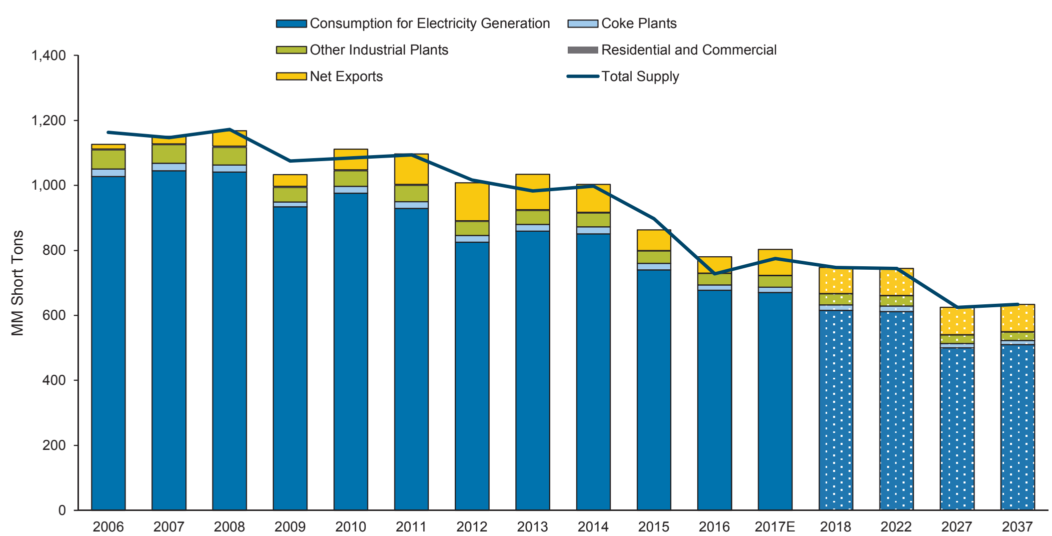


Figure 8-9: Supply-Demand Balance for U.S. Coal – 2006-2037



Regional Coal Production Expectations

While coal demand is broadly expected to decline across the U.S., each of the four major basins faces different dynamics based on regional demand from coal-fired power plants as well as international export demand. Figure 8-10 presents CRA's Base Case production estimates over the next ten years for each of the four major production basins.

Figure 8-10: Ten-Year Coal Production Expectations by Basin

Coal Type	Current to 2027 Production Forecast (% decline)	Comments
CAPP	-21%	High cost drives decline in electric sector demand; met coal demand sustained
NAPP	-13%	Increased int'l demand and some replacement of CAPP demand
ILB	-9%	Increased int'l demand and some replacement of CAPP demand
PRB	-22%	Domestic steam coal demand declines, especially after CO_2 pressure

CAPP = Central Appalachian

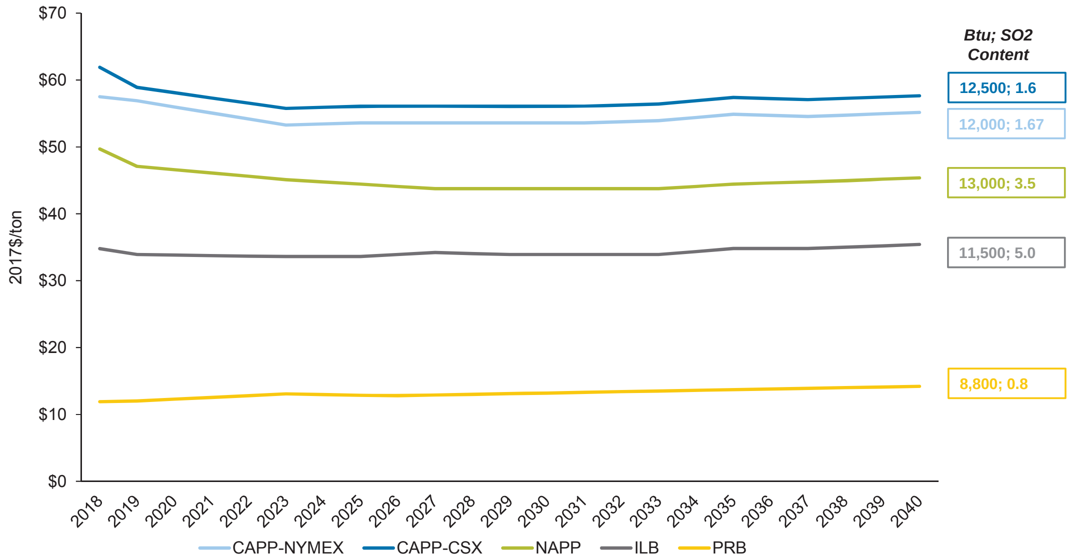
Base Case Price Forecast

CRA's Base Case price forecast is driven by both the regional production outlook and an assessment of production costs at various demand levels, which are represented as coal supply curves within the NEEM model. Figure 8-11 presents the Base Case price outlook by coal supply region, with additional basin-level commentary provided below:

- Central Appalachia ("CAPP"): Lower demand is expected to drive a price decline (in real dollars per ton) for Appalachian coal through the early-to-mid-2020s. Thereafter, reserve depletion is expected to drive modest increase in real coal price for Appalachian coals.
- NAPP: Prices for NAPP coals trend with CAPP, but reflect the lower production costs in Northern Appalachia. NAPP's lower cost profile, due to larger longwall mines, allows highly efficient mining of large-block coal reserves.
- ILB: Abundant reserves of ILB coal and low production costs (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth.

PRB: Prices are expected to increase modestly (in real dollars per ton) at an average rate of 0.8%/year through the forecast period. This price growth is driven by higher production costs due to downward-sloping coal seams and reserve depletion, even as demand is expected to decline.

Figure 8-11: Base Case Coal Price Forecast

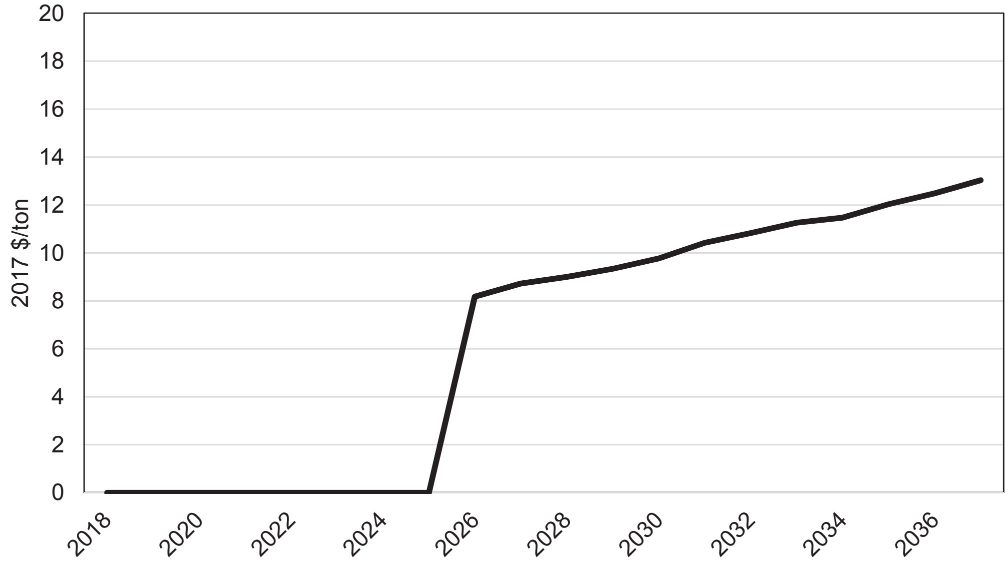


8.2.3 Carbon Policy and Prices

Although several legislative and executive actions related to carbon emissions have been attempted over the last decade, there is currently no price on carbon and no binding emission limits at the federal level. While the EPA has been given the authority to regulate carbon emissions, the Obama administration's CPP was held up in the federal courts and eventually withdrawn by the Trump administration. Although regulation that would implement a carbon price does not currently exist, NIPSCO believes that it needs to plan for the potential of such federal regulation to be implemented over the next decade.

As a result, the Base Case forecast includes a price on carbon, premised on a new federal rule or legislative action coming into force by 2026. The Base Case timing implies that a new federal administration after 2020 would need to re-promulgate a rule through the EPA or pursue a legislative solution with a newly constructed Congress. The Base Case expectation is that a new carbon regulation would be in line with the CPP and would aim to achieve 30-40% reductions in emissions from the electric sector versus an historical baseline likely to be set around the time of rule passage. CRA's analysis suggests that pricing between $8-14/ton between 2026 and 2037 would achieve such reductions and result in a 20% reduction in U.S. coal demand. The pricing outlook assumed in the Base Case is shown in Figure 8-12 in real dollars per short ton.

Figure 8-12: Base Case Carbon Price Forecast



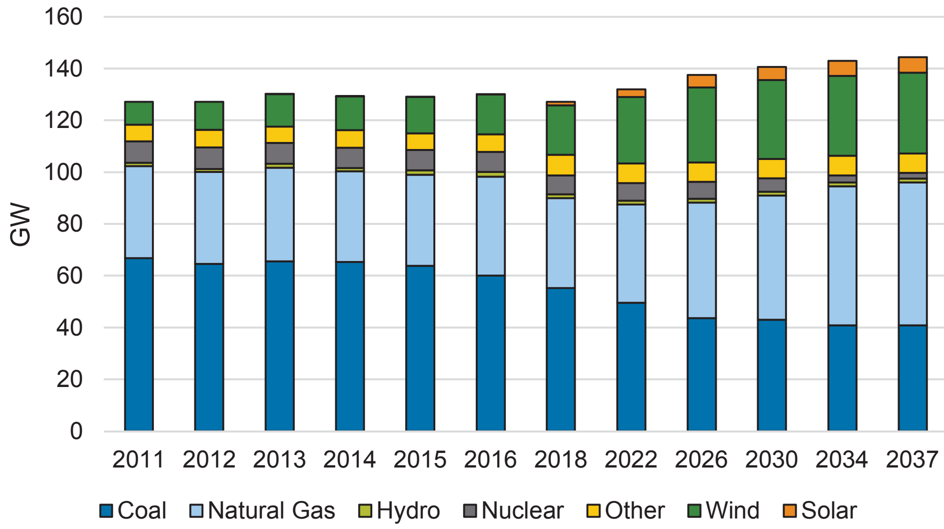
8.2.4 MISO Energy and Capacity Prices

NIPSCO operates within the MISO region, which includes parts of fifteen states throughout the Midwest and South. The traditional MISO North footprint covers parts of Indiana, Michigan, Illinois, Missouri, Kentucky, Iowa, Wisconsin, Minnesota, North Dakota, South Dakota, and Montana. NIPSCO territory and resources fall within LRZ6, covering Indiana and northern Kentucky. In developing the Base Case market price forecasts for energy and capacity, CRA deployed its Aurora market model to represent the entire MISO footprint and produce fundamental, hourly price projections that are internally consistent with the fundamental outlook for natural gas prices, carbon prices, and the future capacity mix in the region.

MISO Capacity Mix

Based on the market inputs from fuel and carbon prices, the Base Case analysis expects a continued shift from coal capacity to natural gas-fired capacity and renewables throughout MISO. Between 2011 and 2016, 7.5 GW of coal capacity retired in the MISO North region, with a net decline of 6.3 GW, due to some additions that came online prior to 2013. The Base Case forecast expects that an additional 10.5 GW of MISO North coal capacity will retire by 2023. Over half of the coal fleet is at least sixty years old, and pressure from potential carbon prices and competition from natural gas-fired and renewable resources, which are realizing lower costs, is likely to result in further retirements over time. CRA's projection of the evolution of the MISO North capacity mix is presented in Figure 8-13.

Figure 8-13: MISO North Net Winter Capacity by Fuel Type – History and Forecast



MISO Electricity Demand Growth

Electricity demand growth in MISO has been relatively modest in recent years, with total net energy for load growing at a compound annual growth rate of 0.4% between 2010 and 2016. While energy demand within the Indiana zone has grown at a rate of around 1% per year since 2010, peak load has been quite flat over the same time period. Going forward, CRA's Base Case expects MISO peak loads to grow at a 0.24% compound annual growth rate over the next ten years. This outlook is based on MISO Module E filings rather than the Independent Load Forecast, which historically has projected higher growth rates.

Base Case Energy Price Forecast

CRA's Base Case MISO market analysis uses the load growth projections, expectations for supply mix changes, and fuel and emission price forecasts to develop forecasts for power prices on an hourly basis. Overall, power prices are projected to be relatively flat in real dollars in the near-term, due to flat gas and coal prices and relatively modest load growth. Some upward pressure is expected into the 2020s as a result of higher natural gas price projections, although growing renewable quantities are likely to lower the market heat rate over time. The expectation for a national carbon price, starting in 2026, drives a noticeable price increase in that year. On a seasonal basis, market prices are expected to be highest in the summer months when load is highest, but also to display increases during the winter months when load is elevated and when gas prices are likely to be high as a result of winter heating demand. Figure 8-14 presents the annual Base Case power price projections for the Indiana region, which is LRZ6, while Figure 8-15 presents the same projections on a monthly basis.

Figure 8-14: LRZ6 (Indiana) Base Case Annual Price Projections

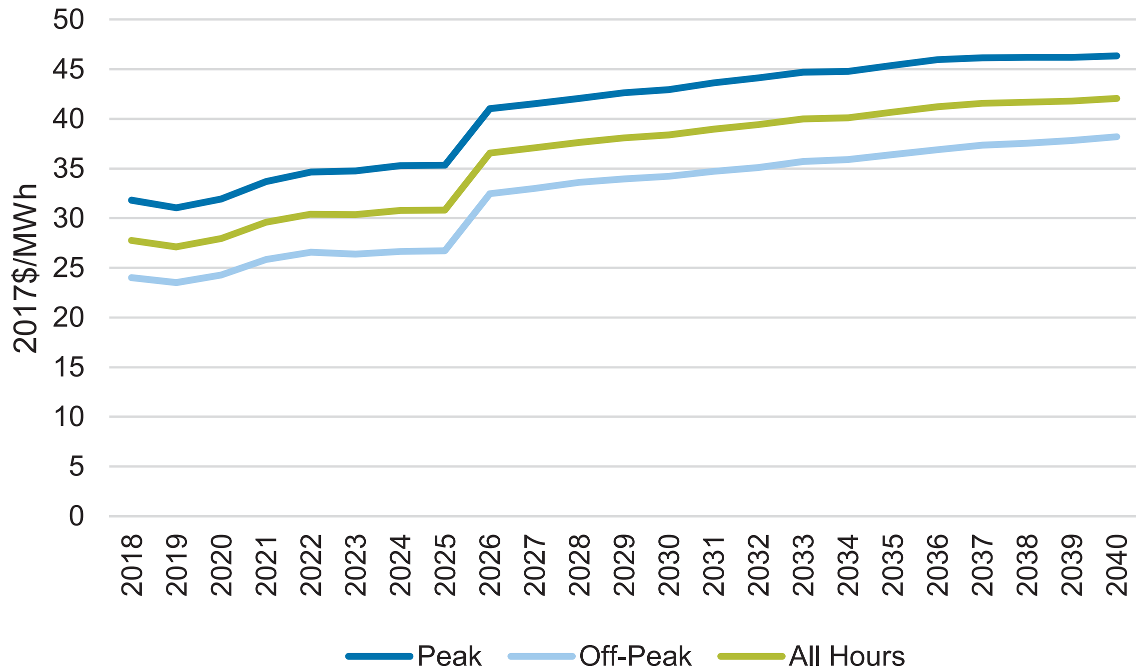
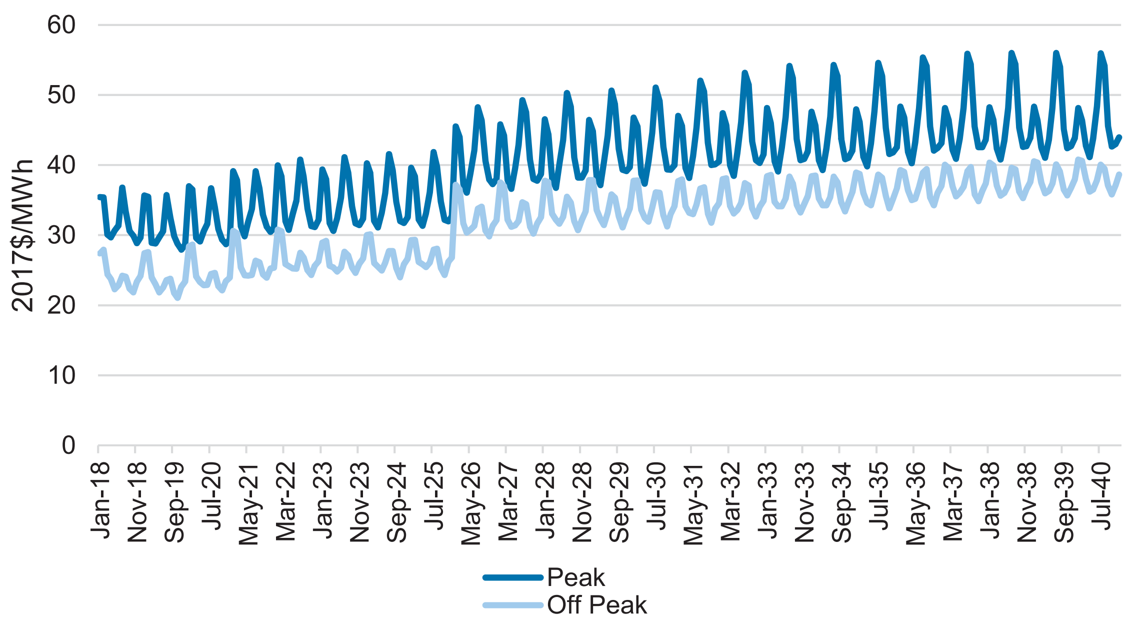


Figure 8-15: LRZ6 (Indiana) Base Case Monthly Price Projections

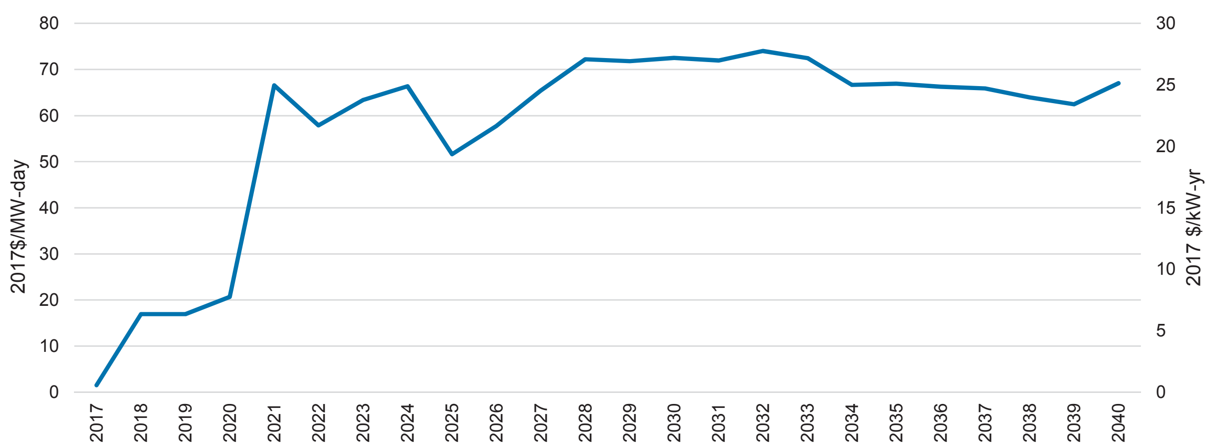


Base Case Capacity Price Forecast

In addition to the energy market, MISO also operates a capacity market which procures capacity in an annual auction. The capacity market is based on an administratively-set demand requirement and supply offers from market participants that are willing to sell capacity. Recent market prices have been relatively low even as coal capacity retires as a result of flat load, increases in renewable capacity, and increases in behind-the-meter, demand response, and energy efficiency supply. Furthermore, recent tariff revisions have impacted reduced supply offer thresholds, resulting in clearing prices around or below $10/MW-day in recent auctions.

CRA's capacity price forecast includes a fundamental evaluation of supply and demand in the market, as well as the expected offer prices for generators throughout the market. CRA expects low market prices to persist through 2021, when coal and nuclear retirements may drive prices up towards the going-forward costs of existing units. The Base Case does not expect increases in price towards MISO's cost of new entry (CONE) benchmark even as new capacity is needed, since it is likely that electric utility builds, under cost-of-service ratemaking, will enter the market and keep reserve margins in the 17-19% range. Figure 8-16 presents the Base Case capacity price projections over time.

Figure 8-16: MISO Capacity Price Projections



8.2.5 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment

After defining the Base Case market drivers and conditions, NIPSCO worked to identify the key uncertainties and drivers that could impact its business environment and future portfolio performance over the long-term. Drawing on its work from the 2016 IRP, NIPSCO identified five major drivers of uncertainty, as shown in Figure 8-17. These include commodity prices, especially for natural gas, power, and coal; environmental policy, particularly with regard to carbon pricing; economic growth, including its impact on electric sector load growth and commodity prices; NIPSCO load growth, and technology costs for new resources.

Figure 8-17: Major Drivers of Uncertainty

After identifying the major drivers of uncertainty, NIPSCO then assessed whether they should be addressed through scenario or stochastic analysis. In the 2018 IRP, NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across both scenarios and stochastics since the two approaches answer different questions and quantify risk in different fashions. Scenarios can be structured to assess major changes to specific market driver assumptions, along with related feedbacks, while stochastics can evaluate volatility and tail risk, based on observed historical data, particularly in the commodity price markets. Figure 8-18 provides a summary of the primary purposes and benefits of using deploying each approach. Based on NIPSCO's review of the different uncertainty approaches, it was determined that stochastic distributions would be developed for natural gas and power commodity prices and evaluated in concert with the ranges established through a fundamental scenario development process.

Figure 8-18: Scenario and Stochastic Uncertainty Approaches

Scenarios
Integrated Set of Assumptions

- **Can be used to answer "What if…"**
- Major events can change fundamental outlook for key drivers, altering portfolio performance
  - New policy or regulation (carbon regulation)
  - Fundamental gas price change (change in resource base, production costs, large shifts in demand)
  - Loss of a major load
- **Can tie portfolio performance directly to a "storyline"**
  - Easier to explain a specific reasoning why Portfolio A performs differently than Portfolio B

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate volatility and "tail risk"**
  - Short-term price volatility impacts portfolio performance
    - Value of certain portfolio assets is dependent on market price volatility
    - Commodity price exposure risk is broader than single scenario ranges
- **Develops a dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
  - Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes

In the scenario development process, NIPSCO developed narratives to describe possible futures, which were organized around "themes" or "states-of-the-world." The first step in developing the themes was to construct assumptions for key macro drivers, which would ultimately translate into changes for the more detailed drivers impacting NIPSCO's portfolio costs. Ultimately, NIPSCO developed three scenarios to supplement the Base Case, relying on the foundation that was built in the 2016 IRP process, but incorporating recent trends and specific risks related to the 2018 IRP Base Case assumptions. A summary of the scenario themes is shown in Figure 8-19.

Figure 8-19: Scenario Theme Overview

Theme	Drivers			
	Technology	Policy	Load	Economy
Base Case	Expected continued declines in solar/storage costs; base case nat. gas production costs	National carbon price expected in 2026 with new federal policy; current regulations on CCR/ELG	Base load forecast	Long-term growth trends in line with historical averages
Aggressive Environmental Regulation	**Renewable (wind and solar) and storage costs decline significantly, supported by policy push**	**Policy forces drive stricter carbon controls and stronger renewable targets**	Base load forecast	Reference case macroeconomic factors persist
Challenged Economy	Base technology assumptions	**No national carbon policy**	**Loss of industrial load; remaining customer load growth stagnates**	**Economic downturn with growth stalling**
Booming Economy & Abundant Natural Gas	**Continued efficiency gains in NG extraction drive lower operations costs and focus on most productive plays**	Base environmental policy; strong support for gas extraction	**Greater load growth, maintenance of industrial customers**	**Low-cost energy paradigm prevails and economic growth greater than expected**

NIPSCO then assessed the themes for diversity and robustness and translated the scenario themes into specific assumptions for the key inputs of load, carbon price, natural gas price, coal price, and power price based on additional rounds of modeling with CRA's fundamental market tools. Given that NIPSCO's All-Source RFP resulted in a range of resource technology costs to use in the IRP analysis, this variable was not specifically evaluated in the scenario development phase. Figure 8-20 summarizes the directional movement of the key input assumptions relative to the Base Case, while the subsequent section of this chapter outlines the detailed inputs that were developed as part of the scenario analysis process.

Figure 8-20: Summary of Four Major Scenarios

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**

8.3 IRP Scenarios

8.3.1 Aggressive Environmental Regulation Scenario

Description

The Aggressive Environmental Regulation Scenario represents a future in which environmental regulations will be more stringent than currently anticipated for power sector emissions, particularly related to carbon dioxide. As a result, carbon environmental compliance costs will be greater for NIPSCO than in the Base Scenario, starting at about $20/ton in real dollars in 2026, escalating to about $35/ton (real dollars) by 2037. Natural gas prices will be greater as a result of greater demand from gas in the power sector as coal generation declines. In the scenario, natural gas prices are projected to trend towards $5.50/MMBtu in real dollars over time. Coal prices are expected to be lower due to reduced coal demand. Power prices will be greater as a result of both higher carbon prices and higher natural gas prices, even though there is a faster shift in the MISO supply mix from coal to natural gas and renewables. The key directional assumptions changes are summarized in Figure 8-21.

Figure 8-21: Summary of Aggressive Environmental Regulation Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**

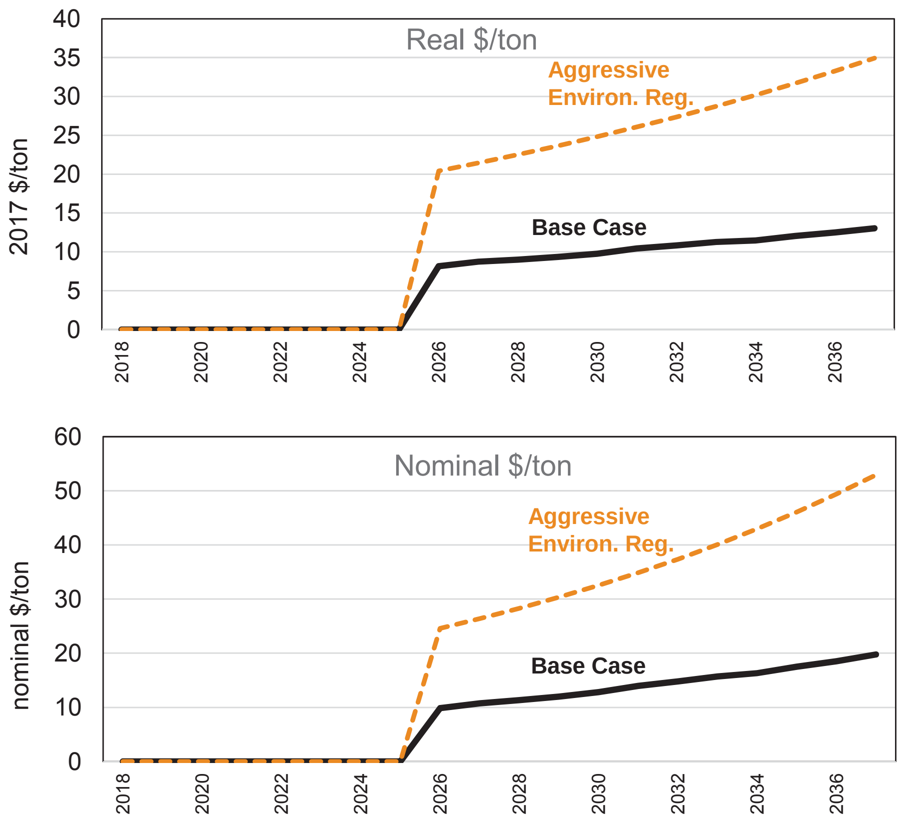
Risks Addressed

The Aggressive Environmental Regulation Scenario addresses the risk that carbon environmental regulations will be more stringent than expected in the Base Scenario. This scenario addresses the risk of higher carbon prices after 2026, which will tend to favor renewable generation and, to a lesser extent, natural gas-fired generation over coal capacity. The scenario also addresses the risk of higher prices for natural gas and power, which are correlated. Assumptions regarding load growth remain unchanged from the Base Scenario.

Detailed Scenario Assumptions

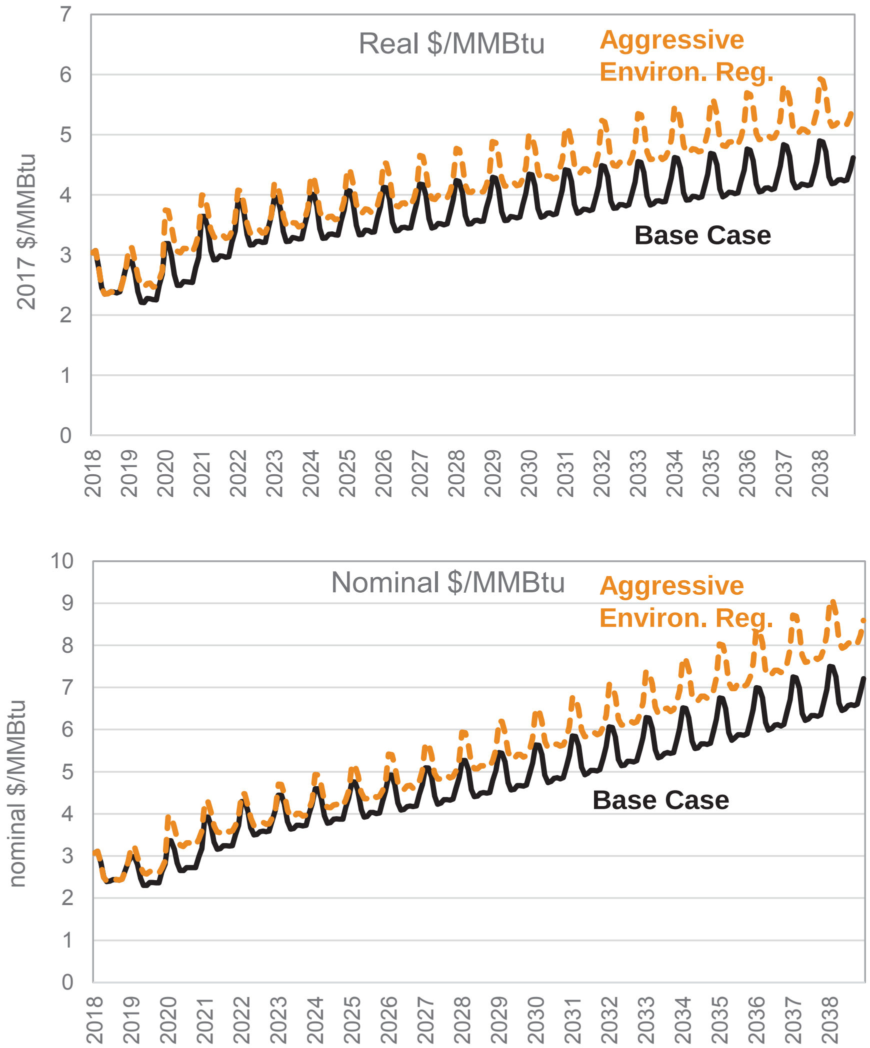
The Aggressive Environmental Regulation Scenario assumes a stricter new federal rule or legislative action on carbon dioxide emissions coming into force by the mid-2020s. Based on CRA's analysis, price levels are generally consistent with a 50-60% reduction in electric sector carbon emissions relative to 2005 by the 2030s. The scenario's timing is the same as the Base Case's, based on the fact that program implementation prior to 2026 is unlikely, given the required changes in executive administration or Congressional control, as well as the potential for legal challenges. This type of policy, however, would represent an initial pathway towards aggressive carbon reduction goals. The carbon prices over time are shown in both real and nominal dollars per ton in Figure 8-22.

Figure 8-22: Carbon Prices in Aggressive Environmental Regulation Scenario



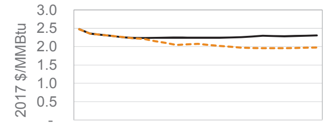
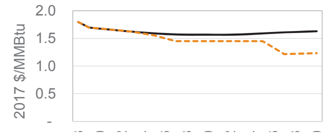
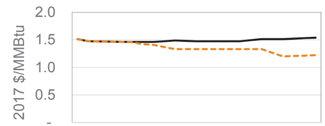
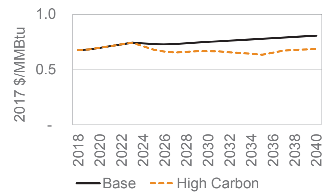
Such high carbon prices are likely to result in additional coal retirements and less coal generation in the electric power sector. Over the long-term, this is projected to result in higher demand for natural gas, even as renewable generation also expands significantly. The long-term increase in natural gas demand in the power sector is projected to be around 15%. CRA's NGF modeling projects that such an increase in gas demand will result in upward pressure on long-term gas prices on the order of about $1/MMBtu (real). The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-23.

Figure 8-23: Natural Gas Prices in Aggressive Environmental Regulation Scenario



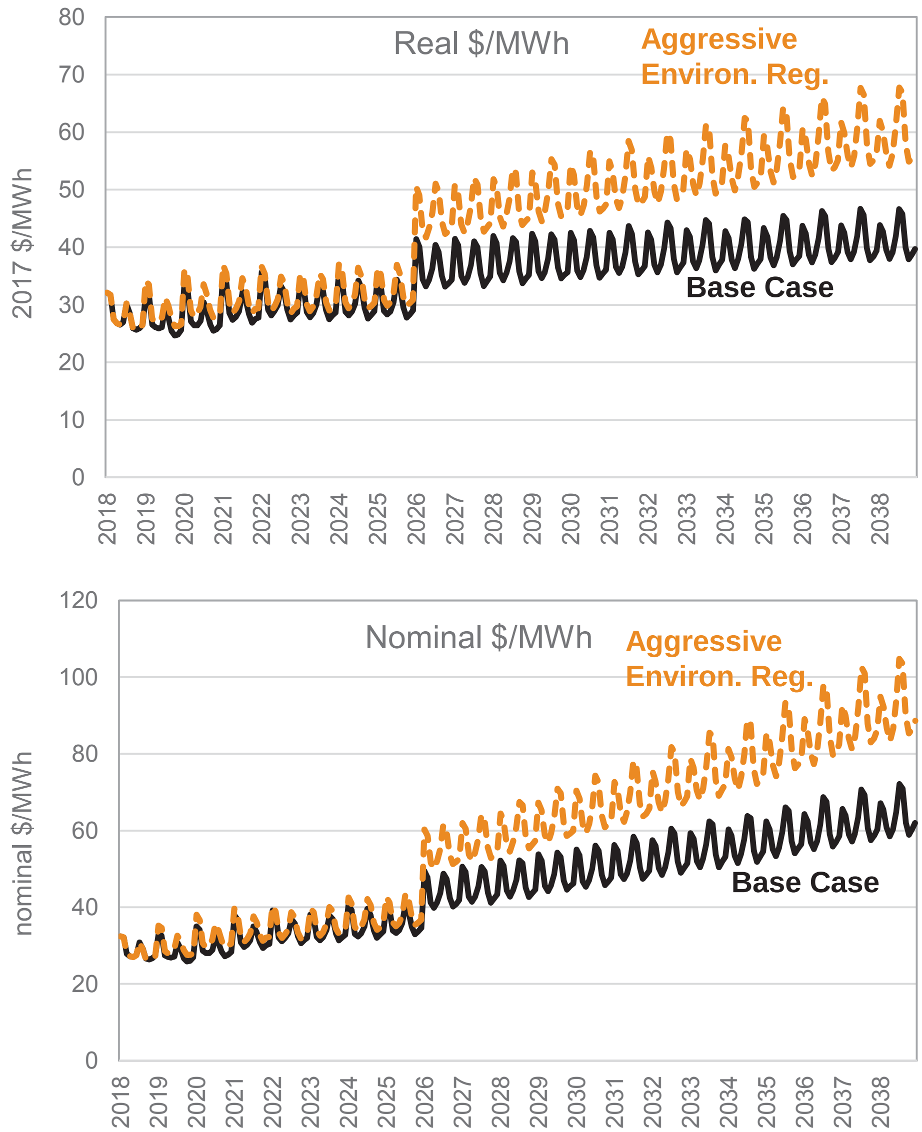
While demand for natural gas is projected to increase, demand for coal is likely to decline in the Aggressive Environmental Regulation Scenario due to reduced coal plant dispatch and additional coal retirements. In this scenario, coal demand is broadly expected to be around 10-20% lower than the Base Case in 2026 (the first year of the carbon price) and 30-50% lower over the long-term. The impacts vary based on coal production basin, but such demand declines are projected to result in price that are $0.10-$0.40/MMBtu lower than those in the Base Case. Figure 8-24 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Aggressive Environmental Regulation Scenario in real 2017 dollars.

Figure 8-24: Coal Demand and Prices in Aggressive Environmental Regulation Scenario

Coal	Base Case	High Carbon Case	
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	**-10%** in demand in 2026 with nearly **50%** reduction by 2037 keeps long-term prices declining, down $8-10/ton ($0.30/MMBtu) vs. base	
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**-10%** in demand in 2026 with nearly **50%** reduction by 2037 drives long-term prices down $10/ton ($0.40/MMBtu)	
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**-10%** in demand in 2026 and **-30 -35%** by 2037 drives prices down steadily, $3-7/ton (~$0.15-0.30/MMBtu) less than base	
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	**-20%** in demand in 2026 and **50%+** decreases thereafter drives prices down $2/ton (~$0.10/MMBtu)	

The projected changes in fuel prices and carbon prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Aggressive Environmental Regulation Scenario. Over a twenty-year period, coal generation in MISO is expected to decline by nearly 70% in this scenario, while natural gas and renewable generation are expected to make up the difference. Although renewable generation is significantly higher than in the base case, higher gas and carbon prices result in higher variable costs for the type of plant most often setting the market price in MISO. Over time, this drives average, around-the-clock ("ATC") LRZ6 power prices up by about $20/MWh (in real dollars) by the late 2030s. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-25.

Figure 8-25: LRZ6 Power Prices in Aggressive Environmental Regulation Scenario



8.3.2 Challenged Economy Scenario

Description

The Challenged Economy Scenario represents a future where economic growth is stagnant and environmental policy is focused on maintaining low energy prices through limited federal regulation of carbon emissions from the power sector. The scenario is premised on the assumption that federal regulation that would result in increased energy costs would be unlikely if economic growth is low. Thus, this scenario has no price on carbon and assumes that any future emission regulation is based on plant-specific efficiency measures or other rules without a specific cap or tax on emissions. As a result of weaker economic growth and no price on carbon, demand for natural gas is expected to fall over time, keeping natural gas prices stable at around $3.50/MMBtu (real dollars) over time. Stronger coal demand is expected to result in modestly increasing coal prices versus the Base Case. Under these scenario assumptions, fewer coal retirements and fewer renewable additions are expected when compared to the Base Case. Natural gas resources are expected to remain marginal during most hours, and lower gas prices and no carbon price result in a relatively flat power price forecast in real terms over time. Finally, under the assumption that economic growth impacts demand for electricity, including industrial demand, the Challenged Economy Scenario includes a lower load growth outlook for NIPSCO. The key directional assumptions changes are summarized in Figure 8-26.

Figure 8-26: Summary of Challenged Economy Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**

Risks Addressed

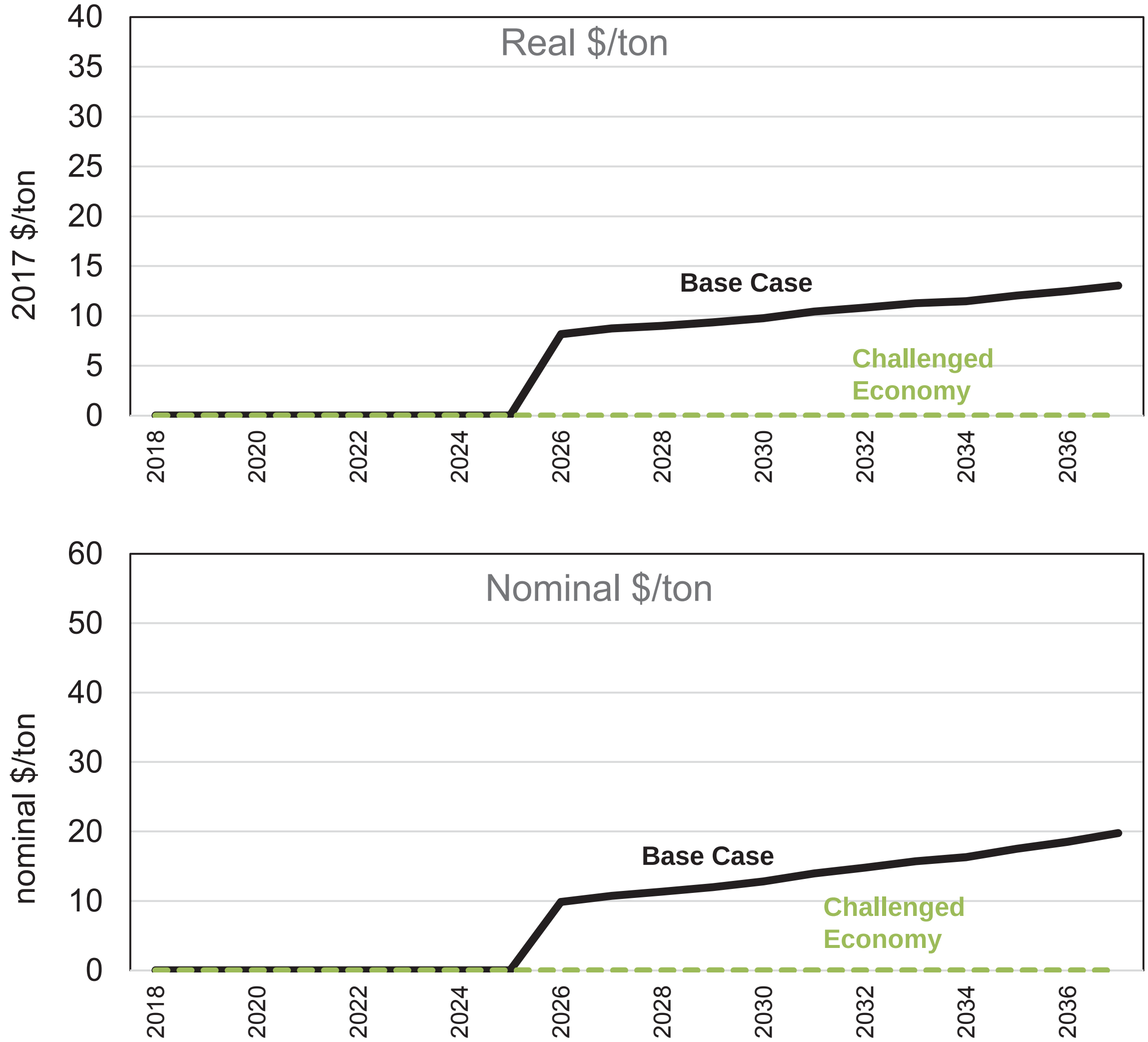
The Challenged Economy Scenario addresses the risk of an economic downturn as well as the risk of no carbon price coming into effect over the study horizon. The scenario addresses the combined risks of very low load growth, no carbon price, and low commodity prices for gas and power. Given the large amount of uncertainty related to federal action to control carbon emissions, the scenario specifically develops a future where carbon emissions are never priced, testing the robustness of portfolios against this important risk.

Detailed Scenario Assumptions

The Challenged Economy Scenario assumes no federal price on carbon, as shown in

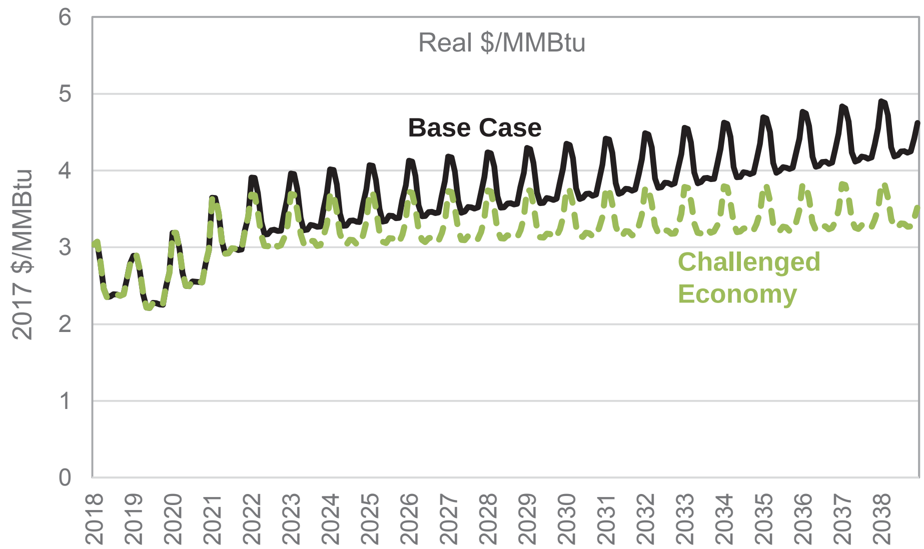
Figure **8-27** versus the Base Case. This scenario assumes that EPA regulation is broadly consistent with the recently proposed ACE rule, which focuses on heat rate efficiency improvements for existing coal plants. This proposed rule and other future regulations under this scenario would avoid specific tax-based costs or an emission cap requirement.

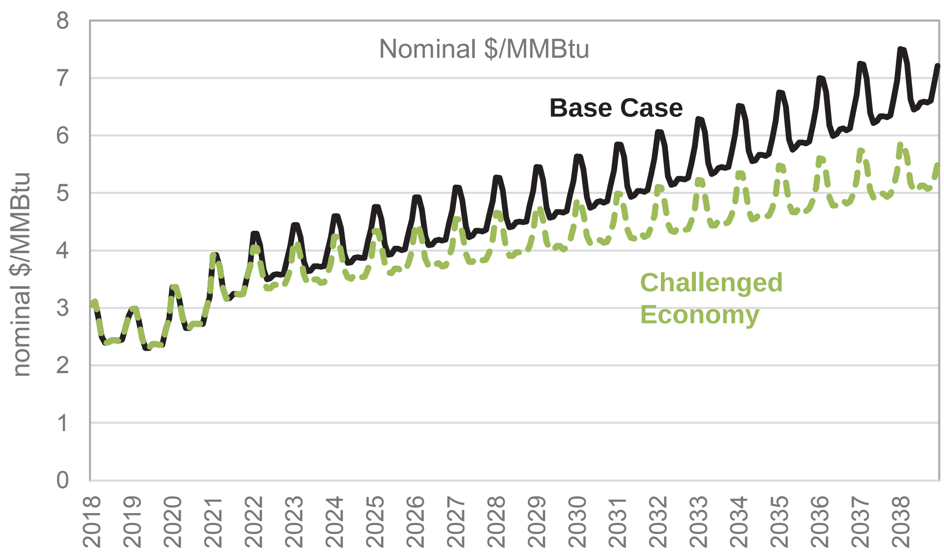
Figure 8-27: Carbon Prices in Challenged Economy Scenario



Lower carbon prices and lower overall electric demand growth are expected to reduce natural gas demand over time. CRA's modeling has found that, rather than increasing like in the Base Case, power sector natural gas demand is projected to be relatively flat over the next twenty years in the Challenged Economy Scenario. This is due to higher levels of coal generation, as well as continued renewable additions, driven by state-level policy. These expected power sector dynamics result in 15-20% lower natural gas demand than in the Base Case, flattening the natural gas price outlook at around $3.50/MMBtu (real dollars). This results in long-term prices that are about $0.90/MMBtu (real dollars) lower than those in the Base Case. The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-28.

Figure 8-28: Natural Gas Prices in Challenged Economy Scenario

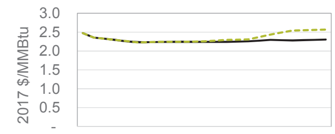


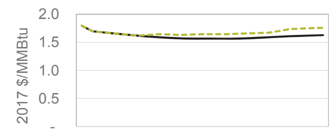


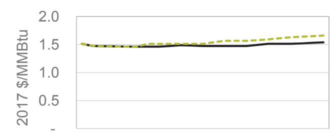
While demand for natural gas is projected to decrease, demand for coal is likely to increase in the Challenged Economy Scenario due to increased coal plant dispatch and fewer coal retirements without the influence of a carbon price. In this scenario, coal demand is broadly expected to be around 10% higher than the Base Case in 2026 (the first year of the carbon price in the Base Case) and 0%-30% higher over the long-term. The impacts vary based on coal production basin, but such demand increases are projected to result in price that are $0.10-$0.25/MMBtu higher than those in the Base Case. Figure 8-29 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Challenged Economy Scenario in real 2017 dollars.

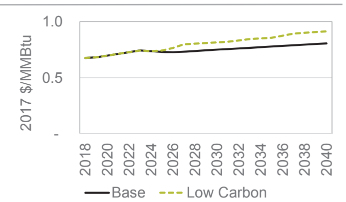
Figure 8-29: Coal Demand and Prices in Challenged Economy Scenario

Coal	Base Case	Low Carbon Case
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	Initial **+10-20%** impact in demand, but long-term demand similar to base case; prices initially stable, but increase ~$5/ton ($0.25/MMBtu) due to reserve depletion
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**+10%** in demand in 2026 and **+20%** by 2037 drives prices up $2-3/ton (~$0.10/MMBtu)
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**+6%** in demand in 2026 and **+20%** by 2037 drives prices up $2-3/ton(~$0.10/MMBtu)
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	**+13%** in demand in 2026 and **+33%** by 2037 drives prices up $2/ton (~$0.10/MMBtu)



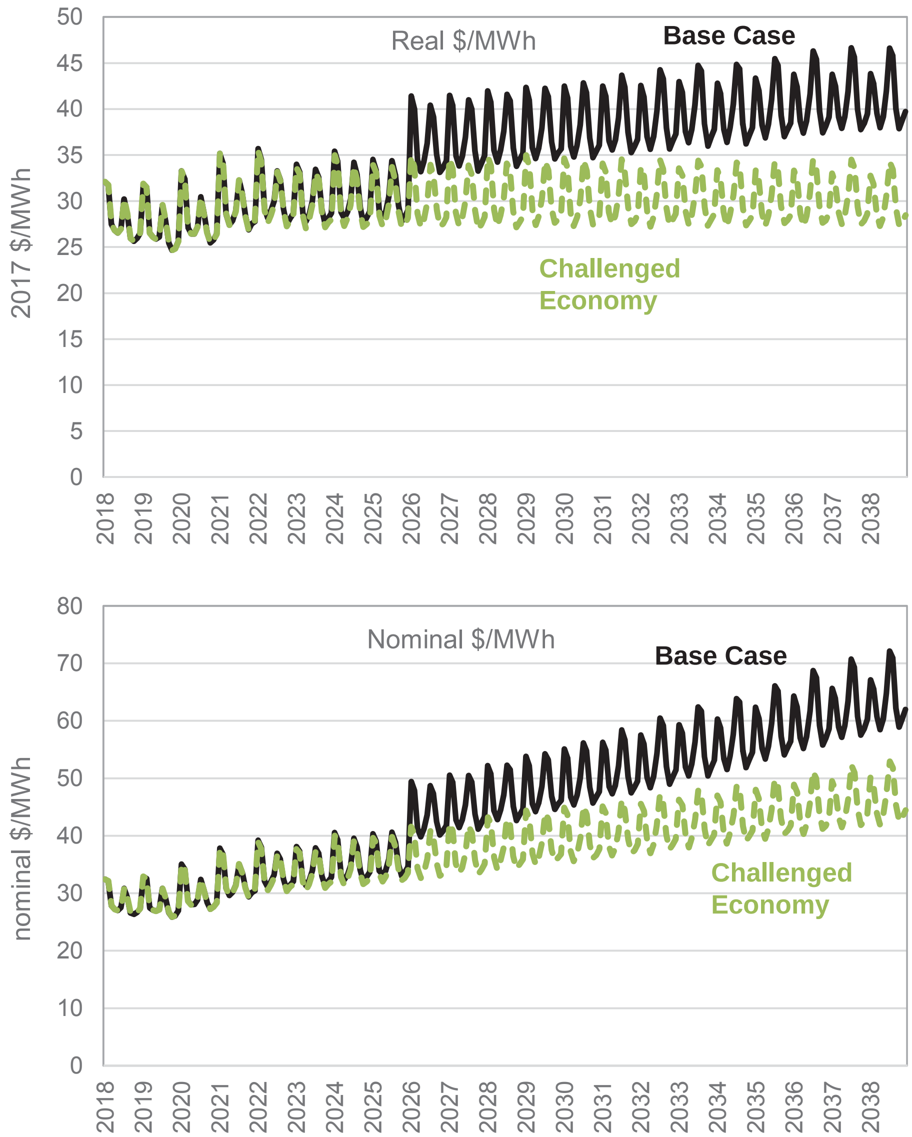






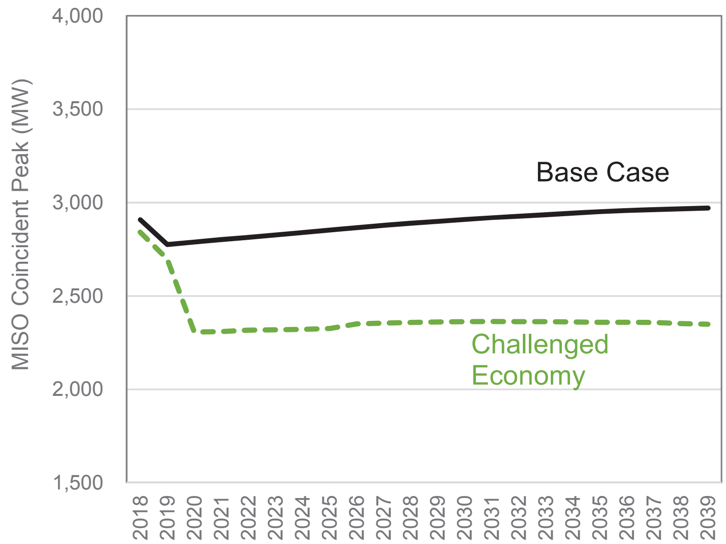
The projected changes in fuel prices and carbon prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Challenged Economy Scenario. In this scenario, coal generation is expected to stabilize after 2026, especially as coal retirements are reduced and as variable costs of operation for coal-fired plants are lower without the presence of a carbon price. The lack of a carbon price and the flatter natural gas price forecast drive power prices down, such that average, ATC prices remain around $30/MWh (in real dollars) over the long-term. This is represents a decrease of about $10-15/MWh (real dollars) versus the Base Case. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-30.

Figure 8-30: LRZ6 Power Prices in Challenged Economy Scenario



As part of the Challenged Economy Scenario, NIPSCO developed a lower load forecast that included the loss of significant industrial demand and lower load growth that is associated with lower regional economic growth. The load forecast chapter includes additional information on the detailed assumptions and methodology, while Figure 8-31 summarizes the peak load forecasts for the Base Case and the Challenged Economy Scenario. The compound annual growth rate for the high load trajectory is -0.9% versus 0.10% in the Base Case, primarily due to the significant loss of load assumed by 2020. Note that these forecasts are shown for MISO coincident peak and not NIPSCO's internal peak.

Figure 8-31: NIPSCO Peak Load Growth Forecast in Challenged Economy Scenario



8.3.3 Booming Economy/ Abundant Natural Gas Scenario

Description

The Booming Economy & Abundant Natural Gas Scenario represents a future where natural gas production costs remain low and the resource base remains highly productive, keeping natural gas prices low and flat in real terms over the next decade. Low natural gas costs are a contributing factor to higher economic growth, as low energy prices contribute to higher levels of industrial and commercial economic activity. As a result of the flat forecast for natural gas prices, coal demand is projected to erode, which leads to lower coal prices over time. Power prices remain correlated to natural gas and carbon prices and remain relatively flatter for longer in real terms in this scenario when compared to the Base Case. A spike in power prices is still projected to occur in 2026 with the introduction of a carbon price, which is the same as in the Base Case. Fewer renewables and significantly more coal retirements are projected in the MISO supply mix as a result of very cheap gas over the next ten years. Finally, under the assumption that economic growth remains robust, the Booming Economy/ Abundant Natural Gas Scenario includes a higher load growth outlook for NIPSCO. The key directional assumptions changes are summarized in Figure 8-32.

Figure 8-32: Summary of Booming Economy/ Abundant Nat. Gas Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**

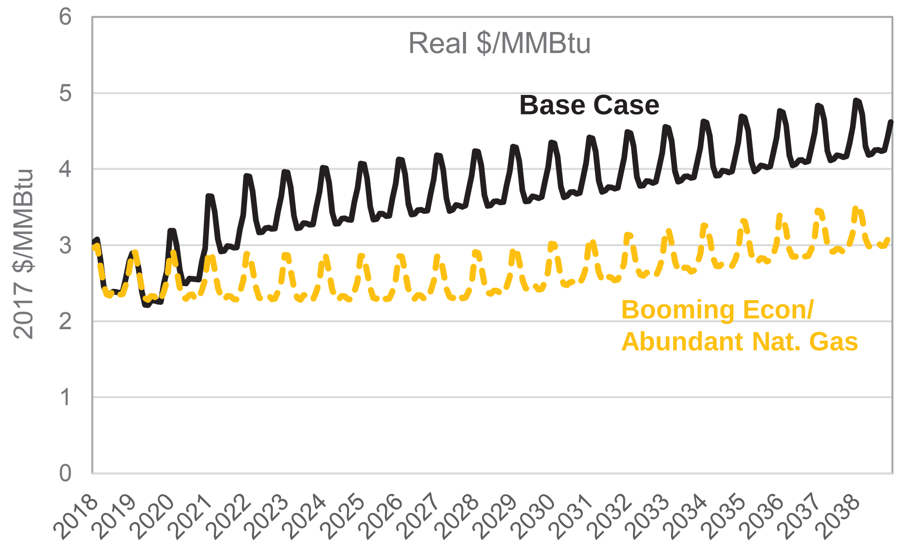
Risks Addressed

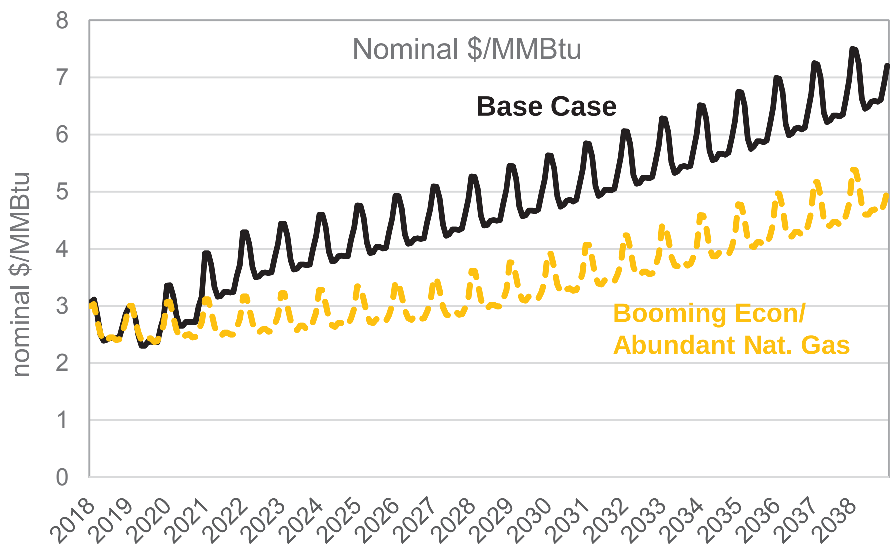
The Booming Economy/ Abundant Natural Gas Scenario addresses the risk of higher load growth for NIPSCO versus the Base Case. Higher load growth could result in higher exposure to the MISO market for NIPSCO depending on its portfolio selection. In addition, this scenario addresses the risk of persistently low natural gas prices, which would generally have the impact of favoring the economics of natural gas capacity and harming the economics of coal-fired and renewable generation. Assumptions regarding carbon prices remain unchanged from the Base Scenario.

Detailed Scenario Assumptions

The Booming Economy/ Abundant Natural Gas Scenario assumes that natural gas prices stay relatively low for a longer period of time, primarily as a result of lower production costs. This could be the result of continued expansion of the resource base, producers continuing to effectively hold operations costs down, and producers focusing on the most productive plays for a longer period of time. In order to develop natural gas price projections for this scenario, CRA adopted the long-term forward strip for natural gas for a ten-year period. As of the time of the development of the 2018 IRP assumptions, natural gas forwards at Henry Hub were relatively flat in real dollars at around $2.60/MMBtu for the next ten years. In 2028 and beyond, CRA's fundamental modeling suggested that modest increases in real prices to above $3/MMBtu by the late 2030s were likely in this case. The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-32.

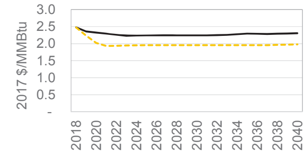
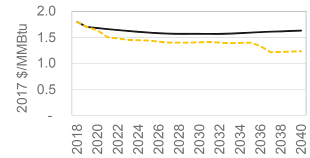
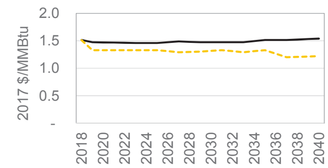
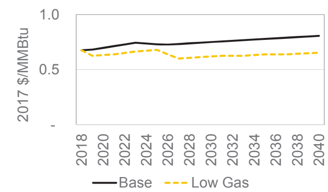
Figure 8-33: Natural Gas Prices in Booming Economy/ Abundant Nat. Gas Scenario





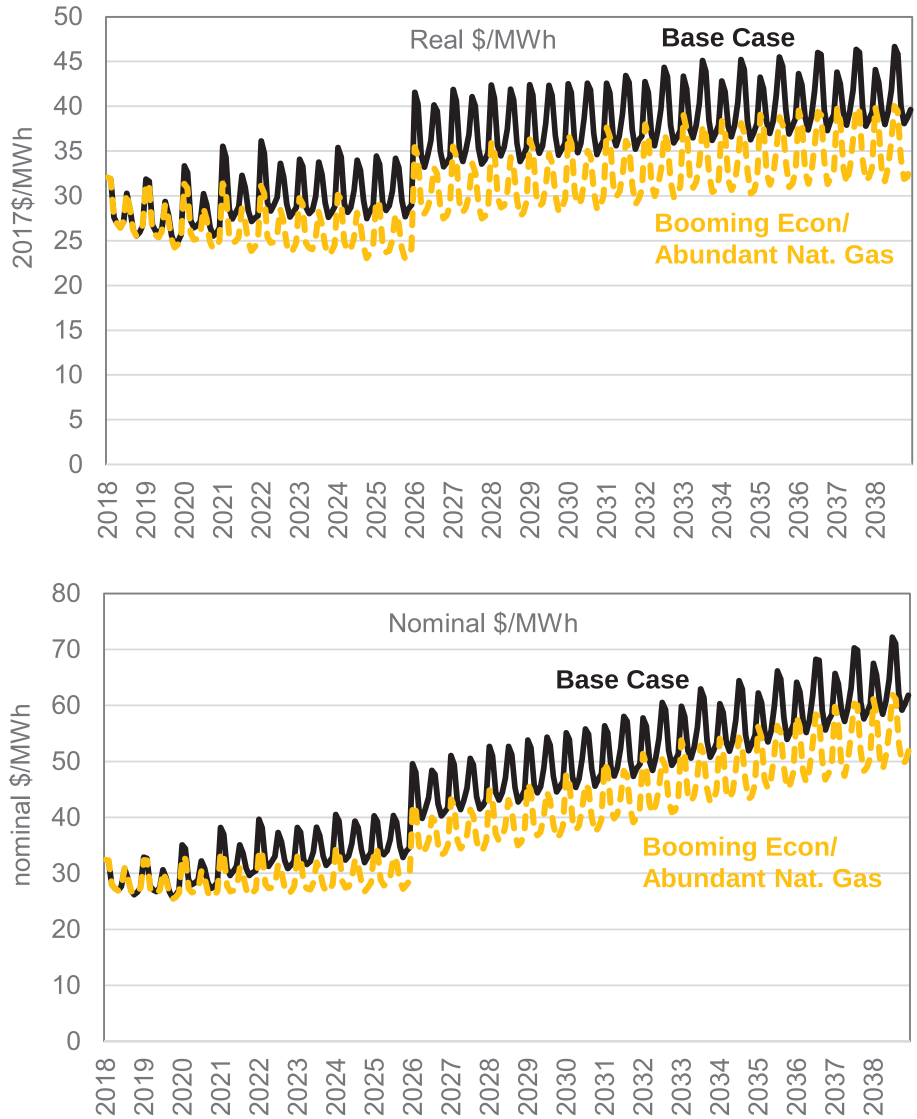
With significantly lower natural gas prices in the Booming Economy/ Abundant Natural Gas Scenario, coal demand is expected to decrease significantly as the variable costs of coal generators remain higher than those of gas plants. In this scenario, coal demand is expected to be significantly lower than the Base Case, with 30-50% lower coal demand expected across most basins, especially with the implementation of a carbon price in 2026. The impacts vary based on coal production basin, but such demand declines are projected to result in price that are $0.15-$0.40/MMBtu lower than those in the Base Case. All coal price forecasts in this scenario are flat or declining in real dollars versus currently market prices. Figure 8-34 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Booming Economy/ Abundant Natural Gas Scenario in real 2017 dollars.

Figure 8-34: Coal Demand and Prices in Booming Economy/ Abundant Nat. Gas Scenario

Coal	Base Case	Low Gas Case	
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	**-30%** in demand by early to mid-2030s, with flat demand thereafter; long-term prices down $8-10/ton ($0.30/MMBtu) vs. base	
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**-30%** in demand by mid-2020s, with nearly **50%** reduction by 2037 drives long-term prices down $10/ton ($0.40/MMBtu)	
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**-10%** in demand in early 2020s and **-30-35%** by 2037 drives prices down steadily, $3-7/ton (~$0.15-0.30/MMBtu) less than base	
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	Immediate demand erosion, growing to **50% decline** in demand in 2026 and more thereafter; drives prices down $3/ton (~$0.15/MMBtu)	

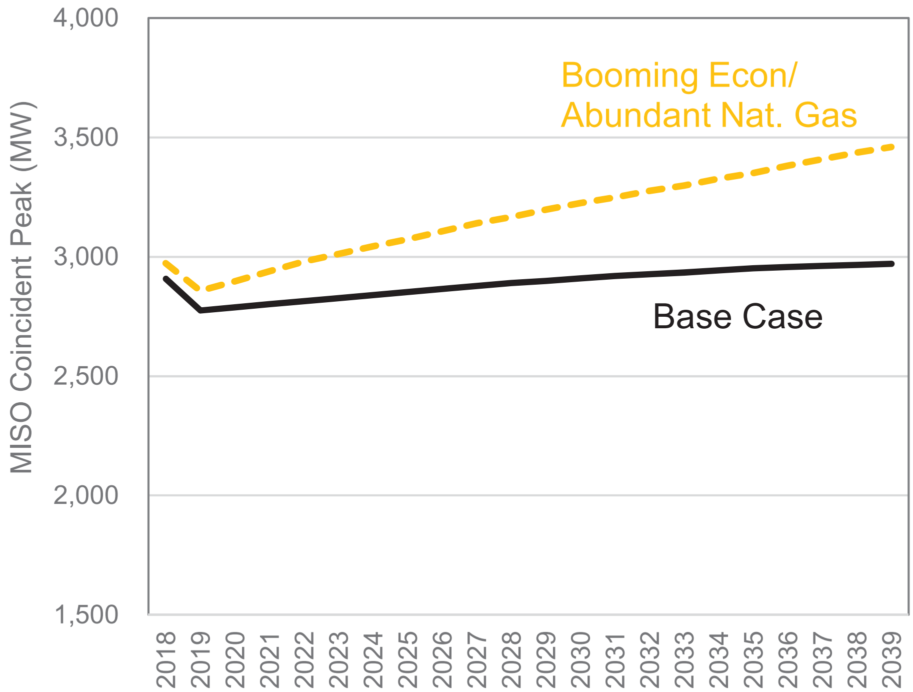
The projected changes in fuel prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Booming Economy/ Abundant Natural Gas Scenario. Similar to the Aggressive Environmental Regulation Scenario, coal generation in MISO is expected to decline by nearly 70% in this scenario over a twenty-year period. The decline in coal generation, however, is more significant in the early years in the Booming Economy/ Abundant Natural Gas Scenario. With gas generation being marginal during more hours with lower gas prices and more coal retirements, the low gas price projections result in power prices remaining very flat in real dollars and below $30/MWh on average through 2025. Although a carbon price is still incorporated in 2026, lower gas prices drive MISO power prices about $5-6/MWh lower than prices in the Base Case after 2030. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-35.

Figure 8-35: LRZ6 Power Prices in Booming Econ/ Abundant Nat. Gas Scenario



As part of the Booming Economy/ Abundant Natural Gas Scenario, NIPSCO developed a higher load forecast that is associated higher lower regional economic growth. The load forecast chapter includes additional information on the detailed assumptions and methodology, while Figure 8-36 summarizes the peak load forecasts for the Base Case and the Booming Economy/ Abundant Nat. Gas Scenario. The compound annual growth rate for the high load trajectory is 0.73% versus 0.10% in the Base Case. Note that these forecasts are shown for MISO coincident peak and not NIPSCO's internal peak.

Figure 8-36: NIPSCO Peak Load Growth Forecast in Booming Economy/ Abundant Nat. Gas Scenario



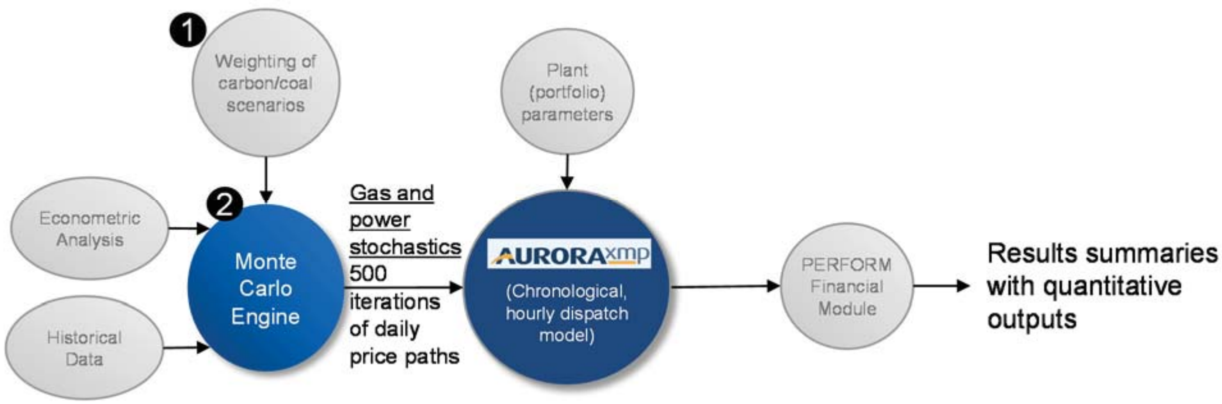
8.4 IRP Stochastics Development

The development of stochastic inputs was a separate, but complementary part of NIPSCO's assessment of risk and uncertainty. As discussed above, NIPSCO determined that stochastic analyses would be performed for key commodity prices with sufficient price history, with the full stochastic distribution of outcomes also including probability weightings for other relevant drivers like carbon prices. Overall, scenario development supported the stochastic parameter definition, with granular distributions of major commodity price inputs developed with CRA's Monte Carlo engine. The major elements of the stochastic input distribution development process included:

1. Establishment of probability weightings for major discrete variables like carbon prices and coal prices, based on the scenario assumptions.
2. Deployment of CRA's Monte Carlo engine to produce daily and hourly price paths for natural gas and power prices for each weighted scenario, based on historical data analysis, which incorporated:
   - Daily price spikes for gas; and
   - Power price volatility on a daily and hourly level, implicitly based on historical data observations that include market load shocks, fuel price changes, and plant outages.

Figure 8-37 summarizes the stochastic input development process and how the stochastic inputs were deployed in the IRP models to assess risk and uncertainty for potential portfolio options. As is shown, CRA's Monte Carlo engine relies on econometric analysis of historical price data, as well as weightings for major discrete variables based on the scenario development process. The Monte Carlo engine itself develops 500 iterations of daily and hourly price paths for gas and power prices which are fed into the Aurora model. The Aurora model is then run 500 times, incorporating each set of price paths, along with other market assumptions and portfolio parameters for NIPSCO. The 500 runs are then each analyzed within CRA's PERFORM financial model to estimate revenue requirements and total portfolio costs.

Figure 8-37: Overview of Stochastic Input Development Process



Stochastic Input Development Methodology

The development of stochastic inputs within the Monte Carlo engine incorporated several steps, which are described in more detail below:

- Step 1: Historical Data Analysis – CRA first analyzed historical commodity prices at the liquid commodity price points most relevant to NIPSCO, which included Chicago Citygate for natural gas prices and the Indiana Hub, representative of LRZ6, for power prices. The historical data analysis was performed to find a stochastic (or econometric) model that best captured the observed behavior of prices in the modeled regions. Key statistical parameters were developed from the data analysis in order to define the stochastic price processes. These included:
  - volatility levels (a measure of the price randomness);
  - mean-reversion rate (a measure of the convergence to long-term price trends and forecasts); and
  - the correlation between power and natural gas prices in the regions.
- Step 2: Parameter Estimation – Based on this analysis, CRA then fit the historical data to an econometric model by running regressions and estimating stochastic process parameters.
- Step 3: Monte Carlo Simulations – Based on the parameter estimation, CRA then deployed its Monte Carlo engine to simulate future spot prices for both natural gas and

power. The simulation included the development of 10,000 price paths for each commodity, using antithetic draw techniques to ensure fast convergence and a balanced and risk-adjusted coverage of the full spectra of positive and negative price jumps in the simulated price time series.

- Step 4: Final Probability Distributions for Each Scenario – Given the range of scenario-based inputs for key discrete variables (such as carbon prices), CRA performed the Monte Carlo simulations across multiple fundamental market scenarios and probability-weighted them to develop the full set of stochastics that preserve internal consistency with the fundamentals-based carbon and coal price inputs. In order to develop a set of inputs that could feasibly be run through the Aurora and PERFORM IRP models, 500 draws were sampled for the full portfolio dispatch analysis.

Stochastic Input Distributions

The stochastic input development process results in 500 daily or hourly price paths for the major commodities, which can be summarized with distribution plots showing monthly confidence intervals over time. Probability distribution plots for the twenty-year forecast period for natural gas prices, including historical price data, and power prices are shown in Figure 8-38 and Figure 8-39, respectively. These graphics show, on a monthly level, the broad range of the individual price paths (in gray) along with representations of the monthly confidence intervals at the 5th, 25th, 50th, 75th, and 95th percentiles.

The confidence intervals do not represent specific price trajectories, but instead indicate the probability of the price being at or below the specified level at any given point in time. For example, the top orange line in Figure 8-38 represents the monthly 95th percentile for natural gas prices, which means that 95 percent of the data set is below this price at any given point in time. In other words, five percent of the price observations in any given month across the full distribution would be expected to be above this value. These observations can come from different price paths over time, since each path is likely to be relatively volatile, moving up and down. In fact, it is highly unlikely that a single path would be at the 95th percentile for a sustained period of time. Overall, the stochastic inputs allow for evaluation of portfolio performance against extreme price outcomes on the high side and on the downside, including at the daily and hourly price levels, which are not shown in these graphics.

Figure 8-38: Stochastic Distribution for Natural Gas Prices

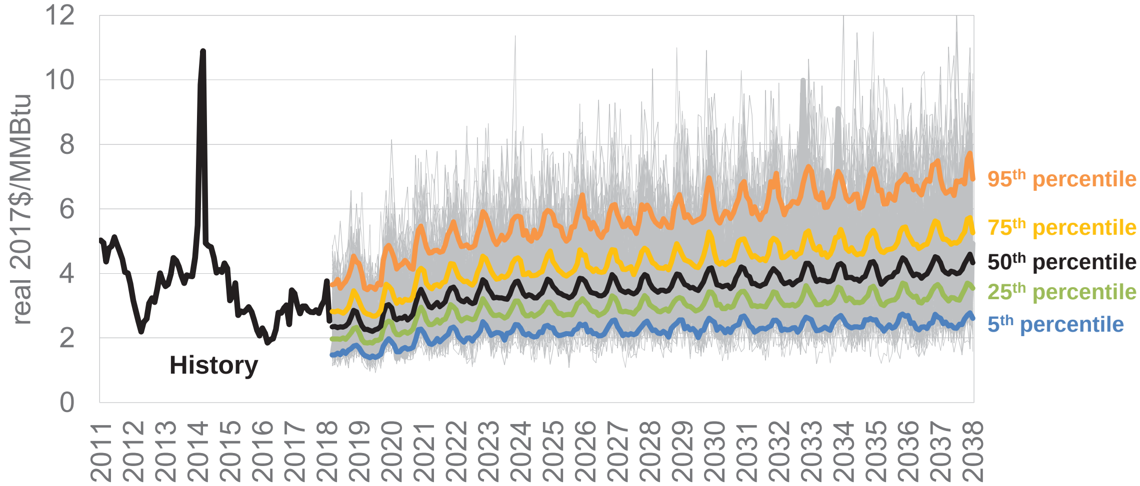
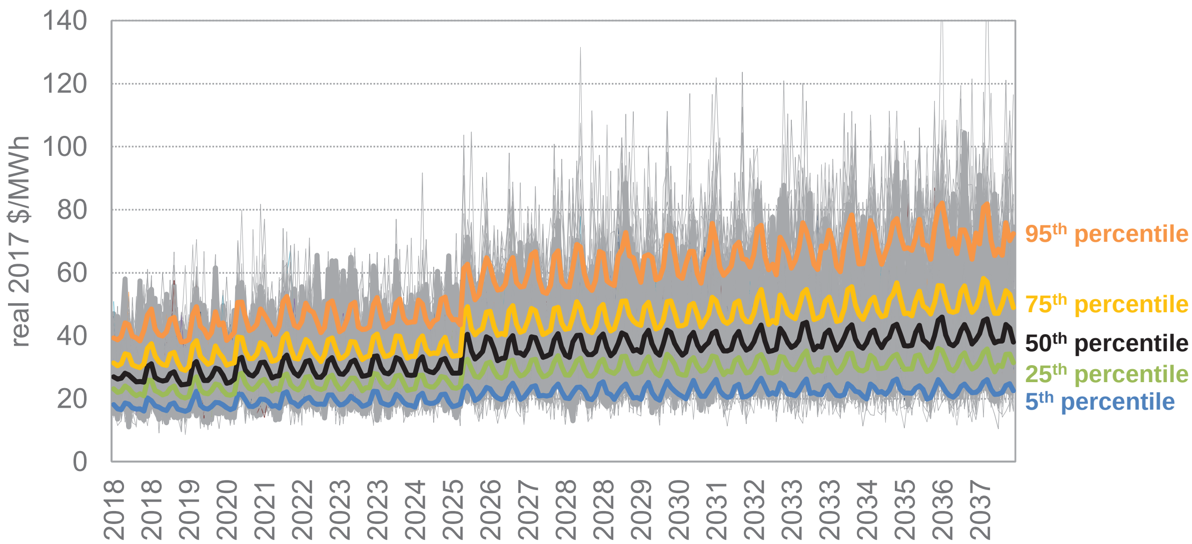


Figure 8-39: Stochastic Distribution for Power Prices



Section 9. Portfolio Analysis

9.1 Retirement Analysis

9.1.1 Process Overview

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.

9.1.2 Retirement Analysis Methodology and Results

The retirement analysis has been conducted according to the following steps:

- Identify plausible retirement plans and specify individual retirement combinations or "portfolios"

- Identify the least-cost replacement capacity to fill the resulting capacity gap for each retirement portfolio based on the results from the All-Source RFP conducted by NIPSCO (*See* Section 4.9.2 for additional information on the details of the All-Source RFP.).

- Evaluate each retirement portfolio, including its associated least-cost capacity replacement, in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed earlier in this section). The evaluation includes a full accounting of the ongoing operations of each existing plant (including any additional environmental compliance requirements) and the costs of alternatives.

- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred retirement portfolio.

9.1.3 Identification of Retirement Portfolios

All five of NIPSCO's coal-fired units were evaluated for retirement. This includes Michigan City Unit 12 and Schahfer Units 14, 15, 17 and 18. The operational dependency as well as technology and vintage similarity of the Units at Schahfer would make Unit-level retirement impractical. As a result, the analysis created Unit pairs (14&15, and 17&18) that would be jointly considered for retention or retirement. NIPSCO identified eight retirement portfolios for analysis based on different combinations of unit retirements at different points in time. The plans range from one that keeps all existing coal units in service through end-of-life to one that retires all coal in 2023. In between, the portfolios evaluate different levels of retirement at different dates over time. Figure 9-1 provides a summary of the eight portfolios, including the timing of the various retirement permutations and the assumed environmental compliance investments.

Figure 9-1: Overview of Retirement Combination Portfolios

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City in 2035)	**15% Coal in 2023** (Mich. City in 2028)	**15% Coal by 2023** (Schfr. 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR* ELG**: non-ZLD***	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	→	**Retire 2028** CCR ELG: N/A	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement

Currently NOT a viable path for ELG compliance

Note: Retirement Combination 4, 15% Coal in 2028 without ELG, is not currently a viable from an ELG compliance standpoint and is shown for discussion purposes..

*CCR: Coal Combustion Residuals
**ELG: Effluent Limitation Guidelines
***ZLD: Zero-Liquid discharge

9.1.4 Identification of Least-Cost Replacement Capacity

While NIPSCO's 2016 IRP relied on market price benchmarks for replacement capacity and energy, the All-Source RFP conducted in 2018 provided insight into the supply and pricing of alternatives available to NIPSCO. Thus, for the 2018 IRP, data from this process was used to develop detailed cost and operational estimates for the least-cost replacement capacity that was available for each of the eight retirement portfolios.

As discussed further in Section 4, representative replacement resource tranches were constructed from the All-Source RFP results based on technology, ownership structure, cost, and other operational characteristics. Then, all of the resource tranches, along with the bundles developed in the DSM assessment (*See* Section 5.), were available to the portfolio optimization model in Aurora. A portfolio optimization was then performed under each of the eight retirement portfolios to identify a least-cost set of replacement resources for each. The portfolio optimization modeling was performed to minimize the net present value of revenue requirements, with certain constraints for minimum and maximum reserve margins and maximum off-system energy sales.

Overall, the economic optimization model selected a combination of DSM and renewable resources across all retirement portfolios. Along with a small amount of flexible MISO capacity market purchases, the optimization model selected 125 MW of total DSM by 2023, approximately 150 MW of wind (UCAP), and a combination of solar and solar plus storage resources, depending on the capacity gap that was required to be filled. Figure 9-2 provides a summary of the type of capacity that was selected under the various retirement portfolios. Note that this does not represent NIPSCO's preferred replacement strategy, but only a least-cost optimization that is used to evaluate retirement implications.

Figure 9-2: Summary of Least-Cost Replacement Capacity by Retirement Portfolio

COST-EFFECTIVENESS	2 3 4 **Schahfer 17/18 Retirement** **~600MW UCAP need**		5 6 7 **Schahfer 14/15/17/18 Retirement** **~1,350MW UCAP need**		8 **All Coal Retirement** **~1,750MW UCAP Need**	
Higher	TECHNOLOGY	MW	TECHNOLOGY	MW	TECHNOLOGY	MW
	MISO Market Purchase	50	MISO Market Purchase	50	MISO Market Purchase	50
	DSM	125	DSM	125	DSM	125
	Wind	150	Wind	150	Wind	150
	Solar, Solar + Storage	390	Solar, Solar + Storage	1,070	Solar, Solar + Storage	1,500
Lower		**715**		**1,395**		**1,825**

9.1.5 Evaluation of Each Retirement Portfolio - Assumptions

Analyses were performed for each of NIPSCO's coal-fired units that evaluated the ongoing operations versus retirement and replacement of the units with an alternative under various potential future states of the world. NIPSCO used a number of factors in analyzing the retirement timing of the coal units including economics, cost risk, reliability risk and impacts to NIPSCO's employees, and the local economy. The evaluation of each retirement portfolio was performed through a full portfolio analysis that included dispatch in Aurora and financial accounting in PERFORM. Market assumptions were consistent with those outlined earlier in Section 8 for the Base Case, the three deterministic scenarios, and the full range of stochastic inputs. In addition to the major market inputs and the costs of replacement resources from the All-Source RFP results, several relevant assumptions were made regarding the ongoing costs of the existing coal fleet.

Ongoing costs include fuel, fixed O&M costs, maintenance capital, costs associated with future environmental controls, as well as the recovery of remaining book value associated with each plant as of December, 2017. This recovery includes return of (depreciation), return on, and income and property taxes associated with the remaining net book value of NIPSCO's existing fleet.

Fixed O&M costs included all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. For all units, nine-year projections of incremental O&M budgets were obtained. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix D.

Maintenance capital costs included the projected capital expenditures necessary to keep the units running through the analysis period at the projected level of operations.
For all units, nine-year projections of incremental O&M budgets were obtained. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix D. As coal units' projected retirement dates move up, the relative capital spend decreases during the years leading up to retirement. This is different than expected fixed O&M costs leading up to a retirement, which stay relatively constant over time, regardless of retirement expectation.

Capital for environmental controls and the associated O&M expenditures that are projected to be required for future environmental compliance are additive to the ongoing capital and O&M expenditures. These incremental capital estimates were provided by NIPSCO's Major Projects department based on outside engineering studies. The most recently available capital estimates, escalated by 2% for inflation, were used in the analyses as specified in the unit retirement studies. For each of the units analyzed, environmental control requirements and dates included in the analyses were based on the expected compliance requirements of final, proposed, and/or expected environmental rules and regulations.

A unique environmental capital and O&M spending schedule was developed for each retirement portfolio, with compliance retrofits required for the coal combustion residuals (CCR) and ELG rules. In Retirement Portfolio 1, NIPSCO also assumed that Schahfer Units 17 and 18 would require additional environmental upgrades associated with a selective catalytic reduction system, a de-watering system, and stack lining. NIPSCO also developed a hypothetical portfolio (Retirement Portfolio 4) that retains Schahfer 14 and 15 through 2028 with no ELG compliance spending, though this is not currently a viable ELG compliance pathway.

NIPSCO also included estimated costs to mitigate transmission related issues that would arise as a result of the various retirement combinations at Schahfer. An additional $79.8 million of capital expenditures was incorporated for transmission upgrades at the time of the Schahfer 17 and 18 retirement in any retirement portfolio. When all of Schahfer is retired, a total of $147 million in additional capital expenditures related to transmission upgrades has been incorporated. These estimates developed by NIPSCO transmission planning group are based on NERC transmission planning standards and incorporate the impact of the MISO retirement study process (Attachment Y)

Recovery of remaining depreciation expenses by 2030 has also been incorporated in the retirement analysis. NIPSCO has prudently ensured that each of its facilities has been ready and available to meet customer needs over the past several decades through appropriate capital investment and O&M expenditures. Upon retirement, due to this continued capital investment, there will be a remaining net book value associated with the generation assets. The retirement analysis assumes that when a unit is retired prior to end of life, it still recovers the return on and return of its net book value.

NIPSCO assumes that each unit continues to depreciate at the same blended rate of 4.60%, regardless of whether the unit has been retired or not. The unit continues to depreciate until its book value is equal to the negative "cost of removal" for each asset. The cost of removal was estimated by John J. Spanos, an expert witness supporting NIPSCO electric depreciation studies. In addition to the "return of" (depreciation) the existing net book value, NIPSCO continues to earn a "return on" the net book value equal to NIPSCO's assumed weighted average cost of capital, or "WACC.". Additionally, NIPSCO assumes that property and income tax will *not* be collected on the remaining net book value of the plant if it is retired.

9.1.6 Evaluation of Each Retirement Portfolio – Scorecard Metrics

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

- Cost to Customer is measured by the overall net present value of revenue requirements ("NPVRR").
- Cost Certainty measures the certainty that the net present value of revenue requirements falls within the most likely range of the distribution of outcomes. It is quantified by the 75th percentile of cost to customer in the stochastic analysis.
- Cost Risk measures the risk of unacceptable, high-cost outcomes and is quantified by the by 95th percentile of cost to customer in the stochastic analysis.
- Reliability Risk assess NIPSCO's ability to confidently transition its portfolio of resources and maintain customer and system reliability. Reliability Risk considers the activities, 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 once. Reliability risk is a qualitative assessment made by NIPSCO of how orderly the transition would be from its current portfolio. It considers NIPSCO's ability to analyze, plan for and execute any transmission system upgrades and/or other equipment needed to ensure that customers' needs for reliability met.
- Other factors, such as the loss of work for employees, and the reduction of property tax base for surrounding communities also factored into NIPSCO's decision

making process. While these do not directly impact power supply costs to customers, they are factors that should be included in the analyses. The employee metric is represented by the net impact on NiSource jobs at existing facilities, and the local economy metric is represented by the expected impact on local property taxes as compared to NIPSCO's 2016 IRP.

A summary of the decision criteria metrics is provided in Figure 9-3.

Figure 9-3: Scorecard Metrics for Retirement Analysis

2018 Retirement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year net present value ("NPV") of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

9.1.7 Evaluation of Each Retirement Portfolio – Results

Base Case Cost Results

The eight retirement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail.) to estimate revenue requirements for each over time. The assessment was first performed across the Base Case set of market assumptions and inputs in order to calculate baseline projections of the NPVRR over the thirty-year planning horizon. Under the Base Case market conditions, Retirement Portfolio 8 (retiring all coal in 2023) was the least cost option, with a thirty-year NPVRR of just over $11 billion, while Retirement Portfolio 1 (keeping all existing coal units until 2035) had the highest costs, with an NPVRR of nearly $15.4 billion. Generally speaking, retiring more coal earlier resulted in a lower NPVRR. Figure 9-4 summarizes the cost results for each retirement portfolio under the Base Case, along with a summary of the cost premium for each option relative to Portfolio 8, which is least cost.

Figure 9-4: Cost to Customer Impacts – Retirement Portfolios

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Least Cost:	$4,426M 40%	$1,937M 18%	$1,481M 13%	$1,361M 12%	$479M 4%	$369M 3%	$213M 2%	$0M

Scenario Cost Results

In addition to the analysis under Base Case conditions, NIPSCO also evaluated each retirement portfolio against each scenario described earlier in Section 8. The NPVRR for each retirement portfolio across each scenario is summarized in 9-5, with additional details regarding the scenario results described below.

Figure 9-5: Cost to Customer across All Scenarios – Retirement Portfolios (30-year NPVRR – millions of $)

Retirement Portfolio	Base	Aggressive Env Reg	Challenged Econ	Booming Econ/ Abund Nat Gas
1	15,400	17,557	11,598	15,030
2	12,911	14,271	9,642	12,758
3	12,455	13,304	9,479	12,291
4	12,336	13,184	9,359	12,171
5	11,454	12,298	8,474	11,245
6	11,343	12,084	8,428	11,125
7	11,187	11,820	8,351	11,023
8	10,974	11,688	8,079	10,745

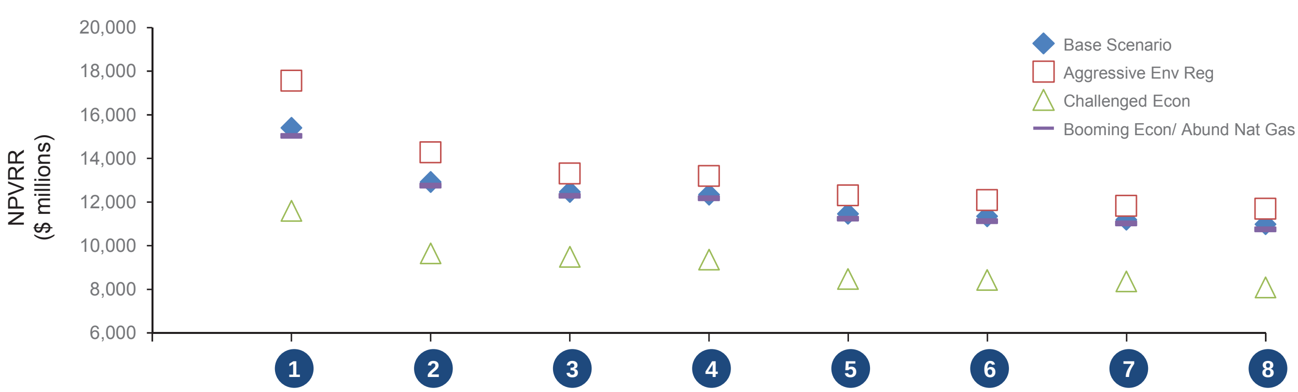
Under the Aggressive Environmental Regulation scenario, higher carbon prices drive higher portfolio costs, especially for those retirement portfolios that retain more coal capacity. The NPVRR of Retirement Portfolio 1 increases to about $17.5 billion, and the difference in cost between retaining all coal and retiring all coal in 2023 grows to about $6 billion. In addition, the costs associated with keeping Schahfer Units 14/15 beyond 2023 (Retirement Portfolio 2) rise considerably relative to the other options.

Under the Challenged Economy scenario, all portfolio costs decline due to no carbon price and lower gas and power prices. Larger NPVRR declines are observed for the portfolios that retain more coal, but the overall costs are still lowest for Retirement Portfolio 8 (retiring all coal in 2023). While the savings associated with retiring coal are lower than those in the Base Case, the difference in cost between retaining all coal and retiring all coal in 2023 is still around $3.4 billion.

Under the Booming Economy & Abundant Natural Gas scenario, cost savings associated with coal retirements are similar to those under Base Case conditions, as low natural gas prices impact the coal units and the replacement renewable options similarly. The difference in cost between retaining all coal (Retirement Portfolio 1) and retiring all coal in 2023 (Retirement Portfolio 8) is about $4.2 billion, which is similar to the difference in the Base Case.

Overall, while coal retirement economics are relatively sensitive to carbon prices, the performance of the different retirement portfolios is less impacted by changes in natural gas prices, since the lowest-cost replacement option primarily comprises renewable resources. Thus, the relative savings associated with retiring coal grow under high carbon price conditions and fall when there is no price on carbon. However, under all market scenarios that were evaluated, there is significant savings associated with retiring more coal capacity. These results are summarized for each portfolio and each scenario in Figure 9-6.

Figure 9-6: NPVRR Summary across All Scenarios – Retirement Portfolios

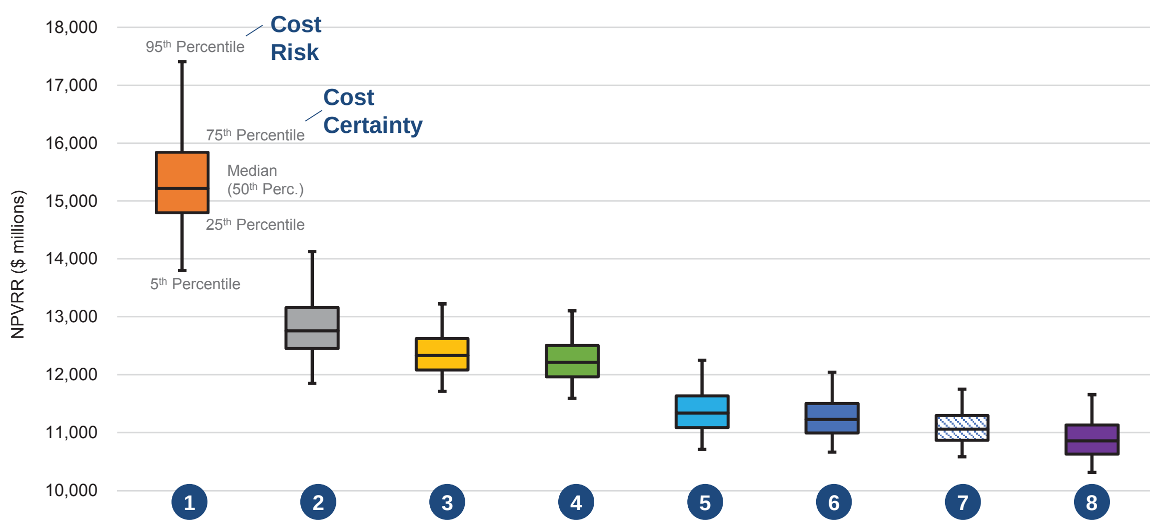


Stochastic Analysis Results

In addition to assessing each retirement portfolio against each market scenario, NIPSCO has also evaluated the retirement options against the full stochastic distribution of potential market outcomes, as described earlier in this Section. The stochastic analysis is used to further evaluate the risk of each of the retirement portfolios against a broad range of commodity price conditions for natural gas and power prices and against the potential for market price volatility on a granular daily or hourly basis. Overall, the results of the stochastic analysis suggest that retaining more coal in the portfolio increases risk, given that portfolios with more coal generally have a higher range of cost outcomes and higher NPVRR costs at the 75th percentile and the 95th percentile of the stochastic distribution.

Figure 9-7 presents a summary of the stochastic results for each of the retirement portfolios. This plot displays the distribution of outcomes for each retirement portfolio across the full 500 iterations that were analyzed in the stochastic analysis. The median value (or 50th percentile) is represented by the center line of each box, with the top and bottom of the box indicating the 75th and 25th percentiles, respectively. The lines above and below each box end at the 95th and 5th percentiles, respectively. NIPSCO's cost certainty metric is represented by the 75th percentile NPVRR value, while the cost risk metric is represented by the 95th percentile NPVRR value.

Figure 9-7: Summary of Stochastic Results – Retirement Portfolios

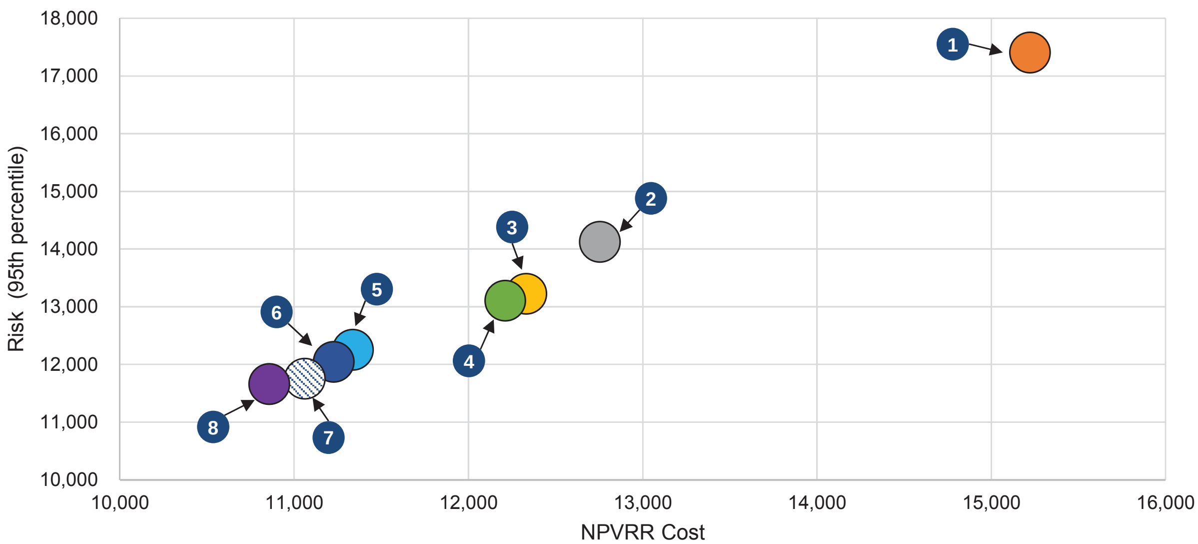


Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Lowest Cost Certainty	+$4,708 42.3%	+$2,026 18.2%	+$1,490 13.4%	+$1,370 12.3%	+$502 4.5%	+$372 3.3%	+$163 1.5%	- $ - %
Delta from Lowest Cost Risk	+$5,750 49.3%	+$2,467 21.2%	+$1,569 13.5%	+$1,449 12.4%	+$596 5.1%	+$389 3.3%	+$93 0.8%	- $ - %

Overall, portfolios that hold more coal not only tend to be higher in median cost, but also have a broader range of outcomes due to uncertainties associated with future coal plant dispatch and relatively significant carbon and commodity price uncertainty. Meanwhile, the portfolios that retire more coal and replace that capacity with fixed-price renewable resources are less subject to market price and dispatch uncertainties. Retirement Portfolio 1 (keeping all existing coal units until 2035) has a cost certainty value that is around $4.6 billion higher than that of Portfolio 8 (retiring all coal in 2023), and a cost risk value that is around $5.7 billion higher. Generally speaking the portfolios that replace more coal with more DSM and renewables result in lower NPVRR for both risk metrics.

Another way to examine the cost and risk performance of the various retirement portfolio options is to plot the median cost expectation against the cost projection at the 95th percentile. This is done in Figure 9-8, which shows that higher costs are generally associated with higher risks, as measured through the 95th percentile outcome. At the 95th percentile, portfolios that hold more coal are exposed to the risk of higher carbon prices, as well as potentially low power prices and reduced dispatch in the market. Thus, they are considered riskier than the retirement portfolios that limit such exposure with resources that have more certain dispatch and no variable costs (renewables) over the long-term.

Figure 9-8: Summary Cost and Tail Risk – Retirement Portfolios



Scorecard Summary

Figure 9-9 presents a summary of all scorecard metrics for each of the eight retirement portfolios. This includes the cost metrics associated with the Base Case NPVRR and the risk metrics associated with the stochastic analysis, as well as the impacts of each option on portfolio flexibility, NIPSCO employees, and the local economy, as described above.

Figure 9-9: Retirement Portfolio Scorecard

Preferred Retirement Path

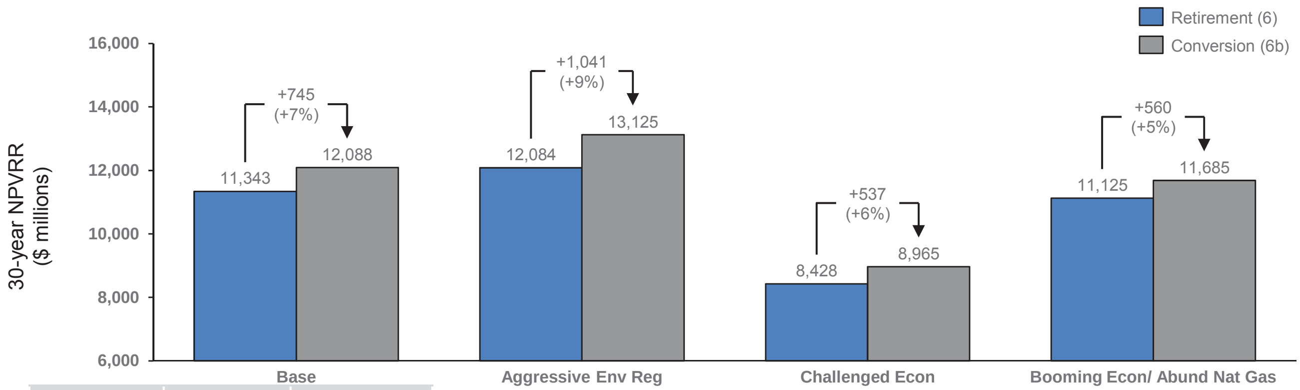
	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,400 +$4,426 40.3%	$12,911 +$1,937 17.7%	$12,455 +$1,481 13.5%	$12,336 +$1,361 12.4%	$11,454 +$479 4.4%	$11,343 +$369 3.4%	$11,187 +$213 1.9%	$10,974 - $ - %
Cost Certainty	$15,840 +$4,708 42.3%	$13,158 +$2,026 18.2%	$12,622 +$1,490 13.4%	$12,502 +$1,370 12.3%	$11,634 +$502 4.5%	$11,504 +$372 3.3%	$11,295 +$163 1.5%	$11,132 - $ - %
Cost Risk	$17,406 +$5,750 49.3%	$14,123 +$2,467 21.2%	$13,225 +$1,569 13.5%	$13,105 +$1,449 12.4%	$12,252 +$596 5.1%	$12,045 +$389 3.3%	$11,750 +$93 0.8%	$11,656 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +47%	$0M -%	($23M) (9%)	($31M) (12%)	($65M) (26%)	($74M) (29%)	($74M) (29%)	($94M) (37%)

Coal-to-Gas Conversion

As part of the retirement analysis, NIPSCO also evaluated the cost-effectiveness of converting one or two units at Schahfer to natural gas. The key assumptions for this analysis, including the operational parameters for the converted units and the costs associated with conversion and ongoing operations, are documented in Section 4. In developing this analysis, NIPSCO started with the Retirement Portfolio 6 and evaluated whether converting Schahfer 17/18 instead of replacing the capacity with the lowest-cost resources from the optimized All-Source RFP analysis was higher or lower cost. This analysis was performed for the conversion of both Units 17 and 18 and for just Unit 17 across all four market scenarios.

Across all scenarios coal to gas conversion is not a viable capacity alternative., Converting both Units 17 and 18 was projected to cost customers between $540 million to $1.04 billion more on a 30-year NPVRR basis than retirement and replacement of the units with economically optimized selections from the All-Source RFP results. This is shown in Figure 9-10. Converting a single unit was projected to cost customers between $230 million and $450 million more than retirement and replacement with economically optimized selections from the All-Source RFP results, as shown in Figure 9-11. While the conversion portfolio's economics improved under lower natural gas price and CO2 price conditions (the Challenged Economy and Booming Economy/ Abundant Natural Gas scenarios), it was still significantly higher cost across all scenarios.

Figure 9-10: Coal-to-Gas Conversion Analysis Results – Two Units



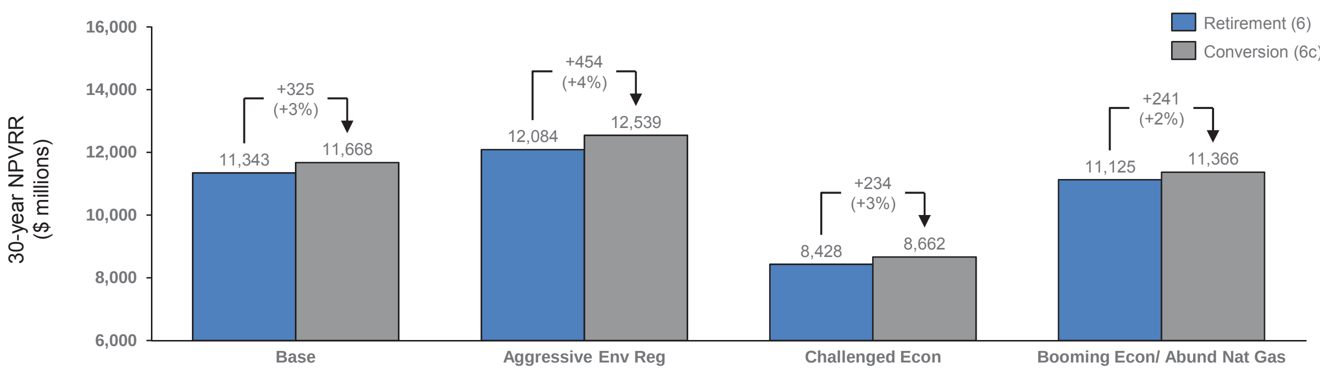
Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (17/18 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17,18 (gas) Mich. City: 12 (2028)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

Figure 9-11: Coal-to-Gas Conversion Analysis Results – One Unit (Schahfer 17)



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (17 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17(gas) Mich. City: 12 (2028)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

9.1.8 Preferred Retirement Portfolio

Retirement Portfolio 6 has been determined to be the most viable retirement pathway for NIPSCO, providing significant cost savings versus the status quo and offering an acceptable outcome for portfolio flexibility and with regard to the impact on employees and the local economy. This retirement portfolio retires all four units at Schahfer in 2023 and retires Michigan City in 2028.

Combination 6 was selected because it was the lowest cost option that held acceptable reliability risk for customers and the system. The analysis shows that Combination 6 saves customers over $1.5 billion relative to NIPSCO's 2016 IRP preferred plan. From a reliability risk standpoint, it provides enough time to reasonably erect the necessary transmission upgrades that are critical for system and customer reliability. Additionally, the replacement resources can be reasonably secured and constructed by 2023. While the transition still encompasses roughly 60% of NIPSCO's physical generation, it maintains Michigan City through 2028 and Sugar Creek, a CCGT, even longer. Both are dispatchable units that can be used to support the transition while we implement the replacement path. Another benefit of staggering the retirements is that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade and adjust as appropriate versus locking the entire transition in at once.

It is anticipated that NIPSCO's 2018 IRP preferred retirement path will require certain upgrades to the transmission system in order to maintain system reliability and remain compliant with NERC TPL standards, NIPSCO Planning criteria, and MISO requirements. This assumption will be validated once NIPSCO proceeds with filing the required forms with MISO (Attachment Y). As part of the retirement analysis, NIPSCO transmission planning group performed preliminary studies to evaluate the impact of the 2018 IRP preferred retirement path that calls for the retirements of Schahfer units 14,15,17,18 and replacement with primarily wind and solar/storage resources in central and southern Indiana by 2023. The studies identified a number of circuits on the NIPSCO transmission system that will likely violate NERC planning standards requirements. Once NIPSCO files its Attachment Y, making the retirement of Schahfer's units 14, 15, 17, 18 official with MISO, any violations found in MISO's analyses in the Attachment Y process and in NIPSCO's subsequent annual transmission planning analyses would need to be mitigated prior to the units' retirement in 2023. The mitigation of those issues consist of 5 separate projects to rebuild over 47 miles of transmission lines and to add a reactive power source to support system voltage. The initial high level estimated cost of the projects is $150 million, which is included in the retirement analysis.

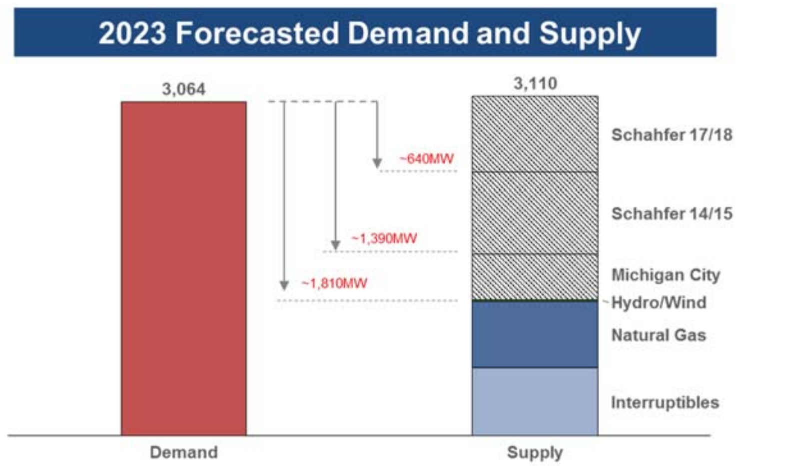
Initial estimates indicated that construction of these projects is anticipated to take until late 2022, early 2023 to complete. The projects are complex to engineer and construct because they require planned outages that need to be coordinated with MISO and PJM, as all of the projects impact PJM's system operation (reliability and markets). Furthermore, some of the rebuild projects are in urban areas or environmentally sensitive terrain like wetlands which carry additional environmental and other risks. There could also be potential outage conflicts with previously planned infrastructure improvement projects not associated with retirements.

Starting in early 2019, NIPSCO will begin engineering the projects and will begin initial construction and outage planning activities. Construction is expected to begin in early 2020. All of the projects are anticipated to be placed in service prior to the units being retired.

With its preferred retirement combination, NIPSCO has balanced customer cost and cost risk, with portfolio flexibility and the ability to successfully and reliability transform its supply resources to meet its customers' needs. Although not the least expensive solution, in all modeling analyses, the preferred portfolio results in savings to customers, greater cost certainty and lower cost risk over alternatives that hold more coal capacity. This option balances other non-economic considerations such as portfolio flexibility, employee and property tax impacts.

Under such a portfolio, a capacity gap of around 1,300 MW will open up in 2023, as shown in Figure 9-12, which summarizes current capacity resources against NIPSCO's Base Case load forecast, inclusive of reserve margin requirements. This capacity gap is the subject of the replacement analysis that is described next.

Figure 9-12: Future Capacity Need under Preferred Retirement Portfolio



2023 Estimated Capacity Excess/(Need) in MWs

As-Is	50
Retire Schahfer 17/18	(640)
Retire Schahfer 14/15/17/18	(1,390)
Retire Schahfer and Michigan City	(1,810)

9.2 Replacement Analysis

9.2.1 Process Overview

NIPSCO has evaluated a range of potential resource replacement options to fill the capacity gap that would develop under Retirement Portfolio 6. The replacement analysis was performed in a similar manner to the retirement analysis, with the following major steps:

- Identify replacement resource concepts for NIPSCO, primarily around considerations for ownership and commitment duration and portfolio diversity captured via the emissions profile of resources.

- Develop specific replacement portfolios within each concept using IRP optimization tools and data from the All-Source RFP.

- Evaluate each replacement portfolio in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed earlier in this Section).

- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred replacement portfolio.

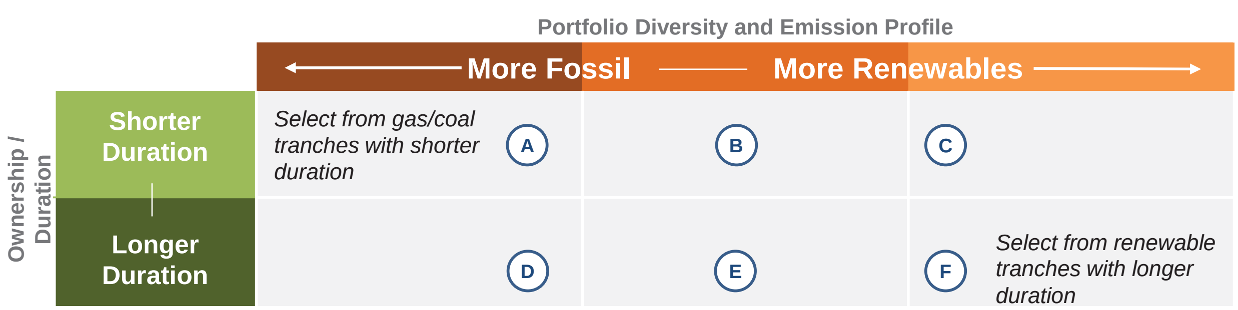
9.2.2 Identification of Replacement Resource Concepts

NIPSCO developed a matrix of replacement resource concepts based on several key planning considerations. The first consideration was structured around the commitment duration being assumed by NIPSCO under each potential portfolio option. Duration is defined as the length of time commitment to a specific resource; shorter duration resources, generally in the form of short-term PPAs, can partially mitigate industrial risk since they do not lock-in a commitment over the very long term. Longer duration resources, on the other hand, generally in the form of longer-duration PPAs or owned assets, tend to have commitments of twenty years or more. By developing portfolios across a range of duration commitments, NIPSCO was able to evaluate the costs and risks associated with different resource procurement strategies.

The second consideration was structured around the potential portfolio's diversity, specifically related to carbon dioxide emission intensity. NIPSCO currently has a portfolio with a high concentration of coal generation, and portfolio concepts were developed with varying levels of fossil and renewable resource replacements in order to evaluate the costs and risks associated with strategies that align with NIPSCO's environmental targets and various stakeholder interests.

After reviewing the type of replacement resources available from the All-Source RFP (*See* Section 4.9.2 for more detail.), NIPSCO determined that portfolio concepts could feasibly be developed across two duration levels (shorter and longer) and three diversity levels (all fossil replacements, a mix of fossil and renewable replacements, and all renewable replacements). Thus six difference concepts were identified for more detailed portfolio development, as shown in Figure 9-13. These portfolios are referred to as Portfolios A-F throughout the rest of this Section.

Figure 9-13: Replacement Consideration Matrix



9.2.3 Development of Specific Replacement Portfolios

Based on the six replacement concepts, NIPSCO then developed specific portfolios that met the desired considerations. This was done through the Aurora model's portfolio optimization capability, which allows the user to specify a set of options and portfolio constraints that drive towards a least cost revenue requirement solution.

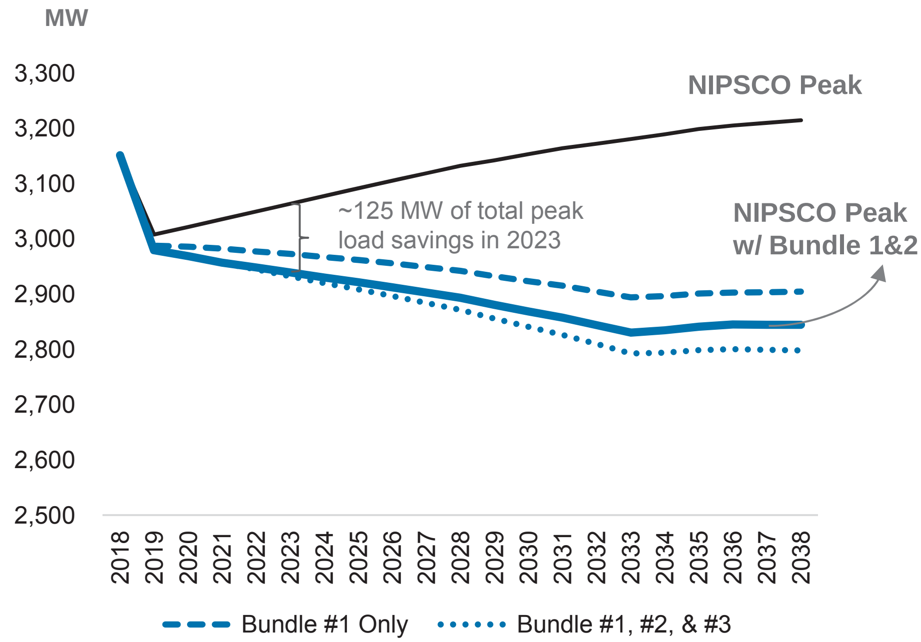
DSM Portfolio Selection

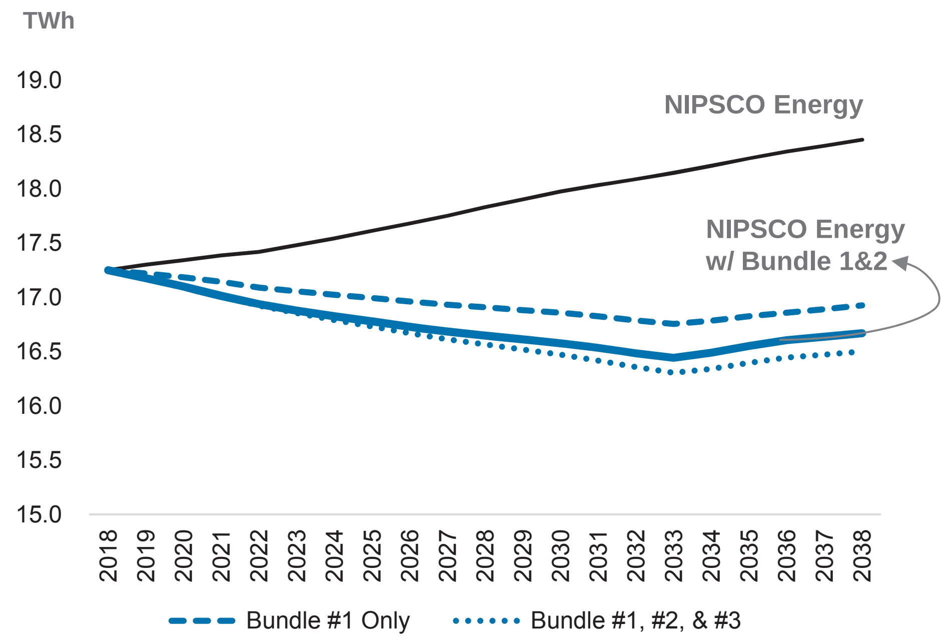
NIPSCO allowed demand side management (DSM) and energy efficiency measures, broadly referred to as DSM resources, to be selected across all six portfolio concepts. As discussed further in Section 5, three separate DSM bundles were developed by GDS Associates for potential selection in the portfolio optimization model. The bundles were organized according to cost, and all of the resources in the first two bundles were selected by the optimization model across all portfolios. Figure 9-14 summarizes the peak and average DSM MW that were selected by bundles in 2023 (the year of the capacity gap under Retirement Portfolio 6) and in 2038 (the final year of the fundamental modeling horizon). Figure 9-15 summarizes the impacts of the various DSM bundles over time, indicating the expected savings for peak load and total energy sales with Bundles 1 and 2 selected.

Figure 9-14: DSM Selection in 2023 and by 2038

DSM Bundle #	Weighted Avg. Cost ($/MWh)	MW Selected by 2023 (Peak / Average)	MW Selected by 2038 (Peak / Average)
1	17	91 / 48	310 / 174
2	23	34 / 20	60 / 29
3	159	0 / 0	0 / 0

Figure 9-15: Selected DSM Resources across Replacement Portfolios (Peak and Energy)





All-Source RFP Resource Selection

Beyond DSM selection, NIPSCO then evaluated the candidate resource options from the All-Source RFP to be selected for each of the six replacement portfolio concepts. In performing this analysis, the Aurora optimization model was constrained differently for each portfolio in order to meet the duration and diversity targets. Along the duration axis, for Portfolios A, B, and C, 400 MW of short-term MISO market purchases were assumed for each portfolio to offer a minimal duration commitment that could protect against industrial load loss. After that, short-term contract options were available first, followed by longer-term contracts when shorter-term resources were exhausted. For Portfolios D, E, and F, long-term contracts and asset ownership options were available, with no short-term PPAs eligible to be selected. Along the diversity axis, Portfolios A and D only had access to fossil-fired resources, while Portfolios C and F only had access to renewable and storage resources. Portfolios B and E were allowed to select a portion of the lowest cost fossil resources within the relevant duration concept, with the remaining capacity gap filled with renewables.

Figure 9-16 summarizes the UCAP MW selected by All-Source RFP tranche (*See* Section 4 for more detail on All-Source RFP tranche development.) across all six portfolio concepts, and Figure 9-17 summarizes the total incremental resource replacement additions in 2023 by type. The preferred fossil resources were CCGT, along with a small, fossil-based system power contract, while the preferred renewable resources were wind projects, followed by solar and solar plus storage options. Although the replacement portfolio selection process is not reflective of a specific, preferred action plan, it was able to construct a range of portfolio strategy concepts to be fully evaluated with the IRP analysis tools and against the full scorecard of key criteria metrics. A summary of NIPSCO's potential capacity position by fuel type across all of the six replacement portfolios is shown in Figure 9-18.

Figure 9-16: Selected Resource Tranches by Replacement Portfolio

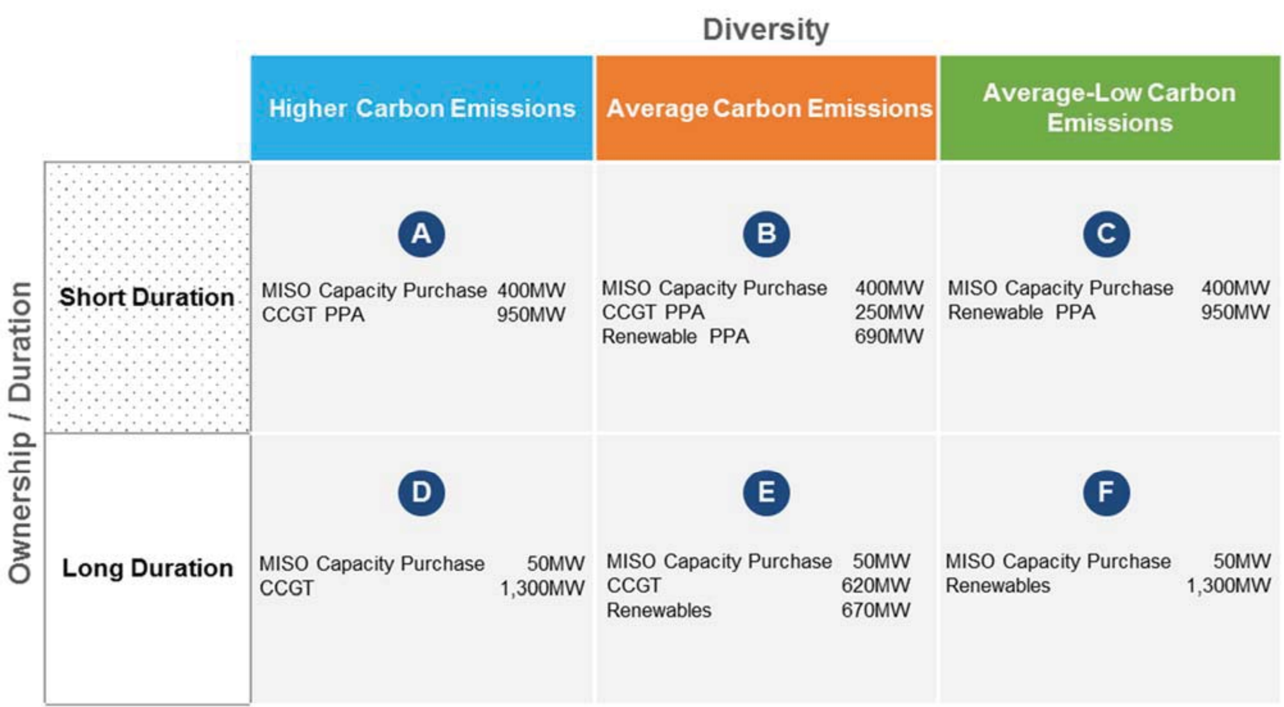


Figure 9-17: 2023 Incremental Replacement Resources by Portfolio (UCAP MW)

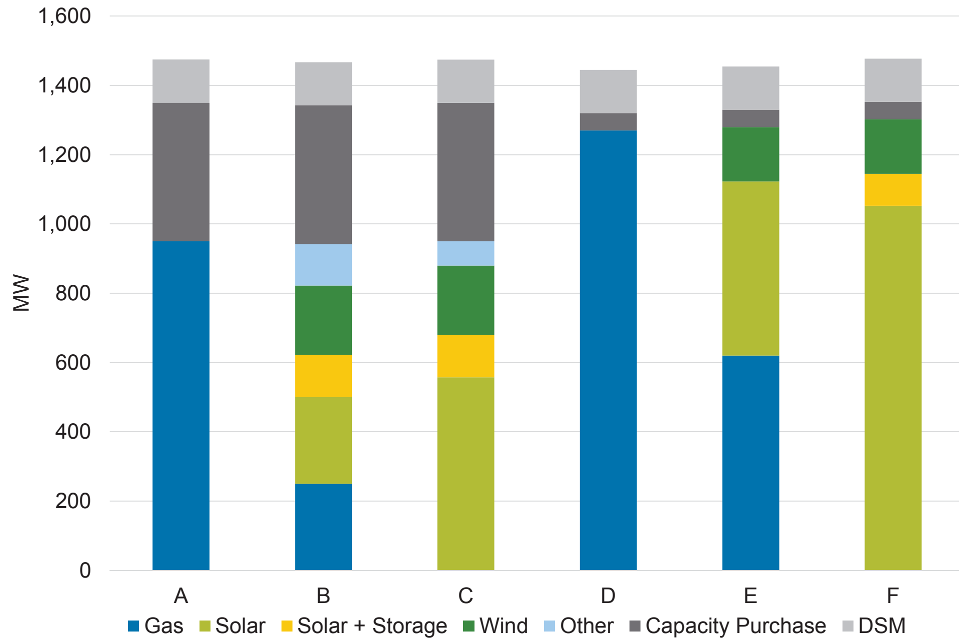
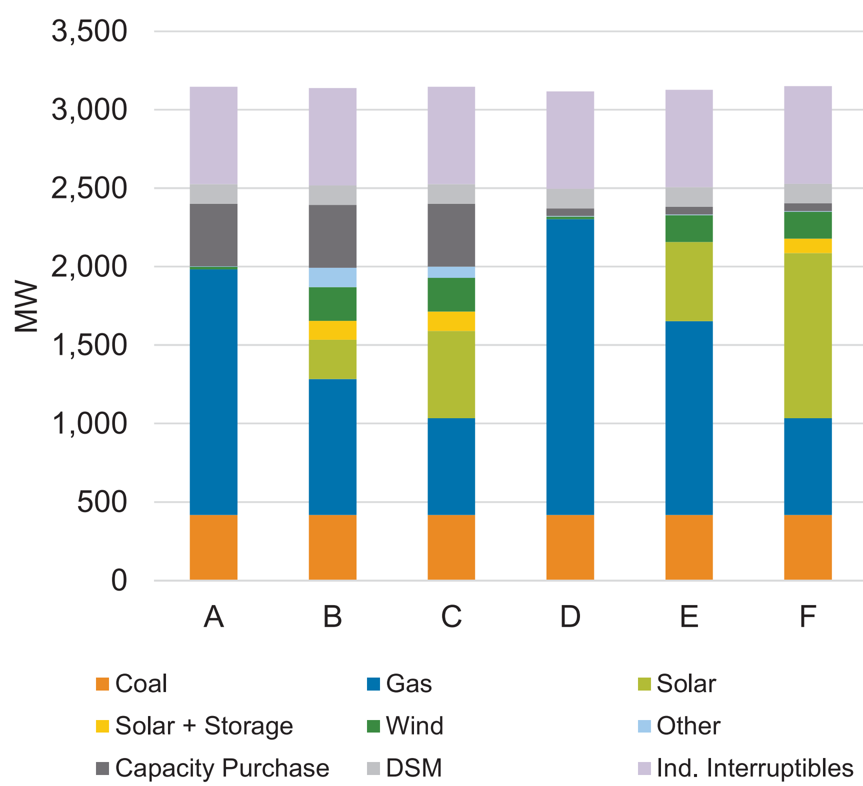


Figure 9-18: 2023 Total Projected Capacity Mix by Portfolio (UCAP MW)



9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics

Similar to the scorecard developed for the retirement analysis, NIPSCO developed a scorecard of criteria and key metrics associated with the replacement analysis. Many of the metrics are the same, with two additions: fuel security, defined as the percentage of capacity sourced from resources other than natural gas, and environmental emission intensity, defined as the total carbon emissions in 2030 from the full generation portfolio. A summary of the decision criteria metrics for the replacement analysis is provided in Figure 9-19.

Figure 9-19: Scorecard Metrics for Replacement Analysis

2018 Replacement Scorecard

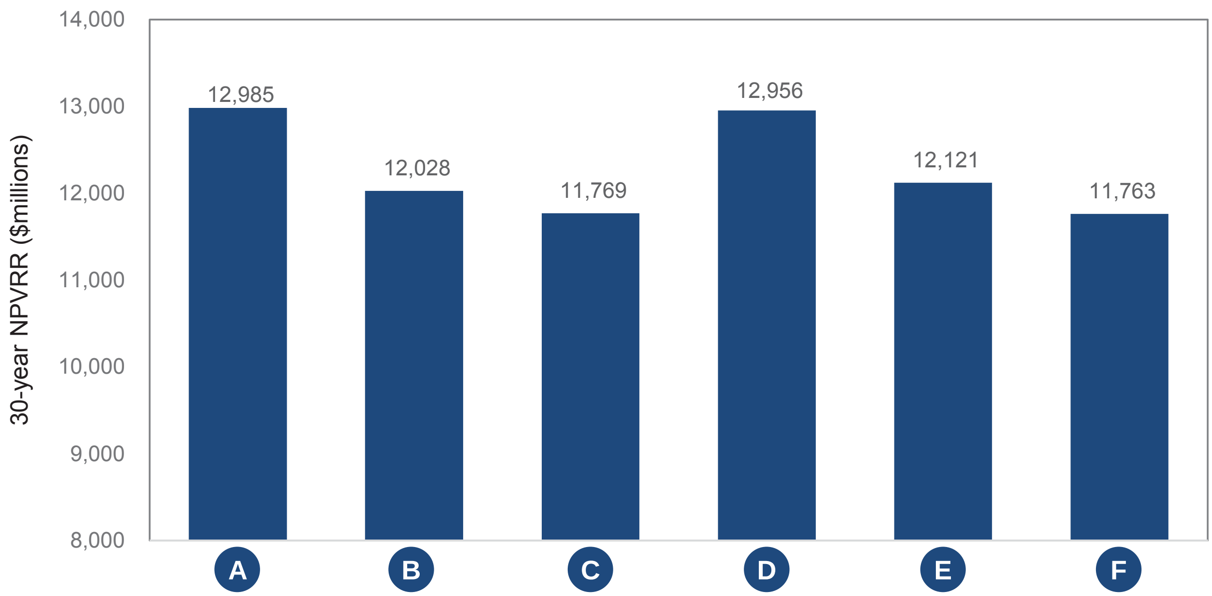
Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 ICAP MW sourced from non-gas resources)
Environmental	• Annual carbon emissions from the generation portfolio • Metric: Total annual carbon emissions (2030 metric tons of CO_2) from the generation portfolio
Employees	• Net impact on NiSource jobs • Metric: Approximate number of permanent NiSource jobs added
Local Economy	• Property tax amount from entire portfolio • Metric: 30-year NPV of estimated modeled property taxes from the entire portfolio

9.2.5 Evaluation of Replacement Portfolios – Results

Base Case Cost Results

The six replacement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail.) to estimate revenue requirements for each over time. The assessment was first performed across the Base Case set of market assumptions and inputs in order to calculate baseline projections of the NPVRR over the thirty-year planning horizon. Under the Base Case market conditions, Replacement Portfolio F (long-duration renewables) was the least cost option, with Replacement Portfolio C (short-duration renewables) only $6 million higher on an NPVRR basis. The portfolios with only natural gas and other fossil resource additions (Replacement Portfolios A and D) are highest cost, while portfolios with a mix of gas and renewable additions (Replacement Portfolios B and E) have a cost premium of between $250 and $350 million when compared to Portfolio F. Figure 9-20 summarizes the results for the each replacement portfolio under Base Case conditions.

Figure 9-20: Cost to Customer Impacts – Replacement Portfolios



Scenario Cost Results

In addition to the analysis under Base Case conditions, NIPSCO also evaluated each replacement portfolio against each scenario described earlier in Section 8. The NPVRR for each replacement portfolio across each scenario is summarized in Figure 9-21, with additional details regarding the scenario results described below.

Figure 9-21: Cost to Customer across All Scenarios – Replacement Portfolios (30-year NPVRR – millions of $)

Retirement Portfolio	Base	Aggressive Env Reg	Challenged Econ	Booming Econ/ Abund Nat Gas
A	12,985	14,476	9,496	12,167
B	12,028	12,948	8,985	11,699
C	11,769	12,675	8,740	11,475
D	12,956	14,426	9,463	12,097
E	12,121	12,970	9,102	11,756
F	11,763	12,424	8,905	11,585

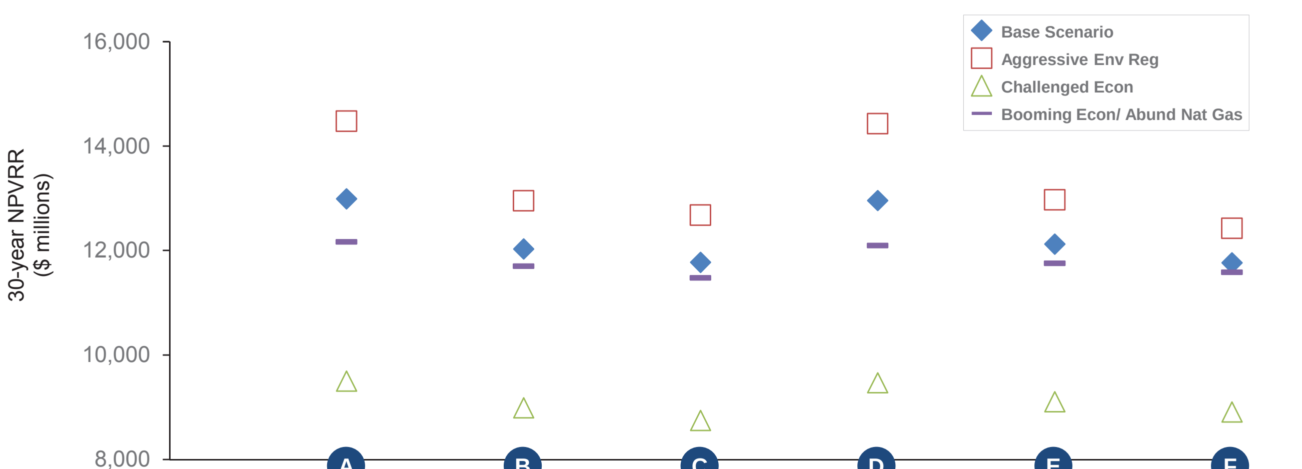
Under the Aggressive Environmental Regulation scenario, higher carbon prices and higher natural gas prices drive higher portfolio costs overall, but more so for the portfolios with significant natural gas capacity additions (Portfolios A and D). Meanwhile, the renewable dominant portfolios (Portfolios C and F) see change in costs to a lesser degree, given that most costs associated with the renewable resource additions are fixed in nature. For example, the NPVRR for Portfolio D increases by nearly $1.5 billion versus the Base Case, while the NPVRR for Portfolio F increases by less than $700 million. In addition, the shorter-duration portfolios with more exposure to the market perform relatively worse under the Aggressive Environmental Regulation scenario due to the fact that market prices are significantly higher. While Portfolios F and C are nearly identical in cost in the Base Case, Portfolio F has an NPVRR that is $250 million lower than Portfolio C's in this scenario.

Under the Challenged Economy scenario, all portfolio costs decline due to no carbon price and lower gas and power prices. Larger NPVRR declines are observed for the portfolios that include more natural gas capacity, but the renewable-only portfolios are still lowest cost. Furthermore, given that market prices are low and given that NIPSCO load is lower, the short-duration renewable concept (Portfolio C) performs best in this scenario, since its market exposure is significantly reduced. In fact, Portfolio C has a lower NPVRR than Portfolio F by about $160 million.

Under the Booming Economy & Abundant Natural Gas scenario, low natural gas prices improve the relative position of the portfolios with more natural gas capacity, as fuel costs are lower and natural gas combined cycle dispatch is higher. For example, the NPVRR of Portfolio D (long-duration natural gas) declines by about $860 million relative to the Base Case in this scenario, while the NPVRR of Portfolio F (long-duration renewables) declines by only about $180 million. However, although Portfolios D and E are much closer in Cost to Portfolio F, the all-renewables options are still the least expensive alternative. Portfolio C is slightly lower cost overall, due to lower market prices reducing its MISO market exposure relative to Portfolio F.

Overall, while the relative economics of fossil and renewable resource replacement options are impacted by changes in carbon prices, natural gas prices, and MISO market power prices, the lowest-cost replacement option is always dominated by renewable resources. When market prices are low and when NIPSCO load is low, a shorter-duration renewable strategy is lower cost, while a longer-duration renewable portfolio performs best in the Base Case and when market prices are higher. These results are summarized for each portfolio and each scenario in Figure 9-22.

Figure 9-22: NPVRR Summary across All Scenarios – Replacement Portfolios



Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon

Stochastic Analysis Results

In addition to assessing each retirement portfolio against each market scenario, NIPSCO has also evaluated the replacement options against the full stochastic distribution of potential market outcomes, as described earlier in this Section. As in the retirement analysis, the stochastic assessment is used to further evaluate the risk of each of the portfolios against a broad range of commodity price conditions for natural gas and power prices and against the potential for market price volatility on a granular daily or hourly basis.

Figure 9-23 presents a summary of the stochastic results for each of the replacement portfolios. Overall, although the introduction of stochastic price volatility impacts the natural gas and renewable resource elements in each portfolio differently, Portfolio F (long-duration renewables) has the lowest median cost, and also the lowest cost at the 75th and 95th percentiles.

Figure 9-23: Summary of Stochastic Results – Replacement Portfolios

	A	B	C	D	E	F
Ownership / Duration	**Short Duration**	**Short Duration**	**Short Duration**	**Long Duration**	**Long Duration**	**Long Duration**
Diversity:	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**
Delta from Lowest Median Cost	$1,147 9.8%	$254 2.2%	$6 0.1%	$1,044 9.0%	$271 2.3%	**$0 0.0%**
Delta from Lowest Cost Certainty	$1,477 12.4%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.0%	**$0 0.0%**
Delta from Lowest Cost Risk	$2,067 16.7%	$558 4.5%	$297 2.4%	$1,920 15.5%	$452 3.7%	**$0 0.0%**

On average, the median difference in NPVRR between the renewable-only portfolios and those that have some natural gas capacity goes down, meaning that natural gas options look relatively better in the stochastics when compared to their performance in deterministic Base Case.

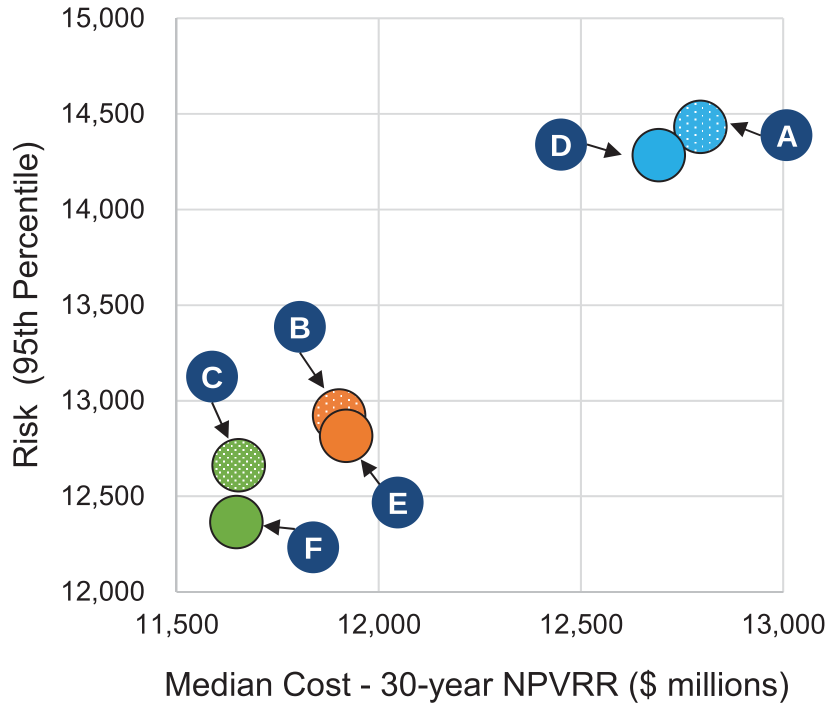
This is because natural gas plants can take advantage of potential low gas price outcomes and can flexibly dispatch in response to changing prices in a volatile market, while renewable costs and dispatch are generally fixed. However, this small improvement in NPVRR for natural gas portfolios across the stochastic distribution does not outweigh the overall cost benefits associated with incorporating fixed price renewable assets into the portfolio.

Although more favorable market conditions for gas resources are incorporated into the stochastic assessment, as more natural gas capacity is added to the portfolio, costs and risks increase. This is due to the fact that natural gas capacity is more exposed to gas price volatility on the upside, which impacts both dispatch and the costs of operation. Although gas-dominant portfolios perform better when gas prices are low, they become heavily exposed to conditions with higher gas and carbon prices, resulting in significantly higher portfolio costs than those options that include more renewables. Portfolio F (long-duration renewables) has a cost certainty value that is around $1.4 billion lower than that of Portfolio D (long-duration CCGT) and $360 million lower than that of Portfolio E (long-duration mix), and a cost risk value that is around $1.9 billion lower than Portfolio D and $450 million lower than Portfolio E.

The longer-duration renewable portfolio (F) also performs better on the risk metrics than the shorter-duration renewable portfolio (C). This is due to the fact that Portfolio C includes 400 MW of MISO market purchases, resulting in higher costs under conditions with higher carbon, fuel, and power prices. This drives the width of Portfolio C’s distribution higher. Although Portfolio F and Portfolio C have nearly identical NPVRRs at the median cost level, Portfolio F is about $125 million lower in cost at the 75th percentile and nearly $300 million lower in cost at the 95th percentile.

Another way to examine the cost and risk performance is to plot the median cost expectation against the cost projection at the 95th percentile. This is done in Figure 9-24, which shows that higher costs are generally associated with higher risks, as measured through the 95th percentile outcome. At the 95th percentile, portfolios with more natural gas capacity are exposed to the risk of higher gas prices and higher carbon prices, as well as potentially reduced dispatch in the market. More fixed-price renewable resources generally result in lower tail risk overall. The difference in risk profile between Portfolios C and F is also evident in this figure. Although both portfolios have nearly the same median cost (x-axis), F has significantly lower 95th percentile risk (y-axis).

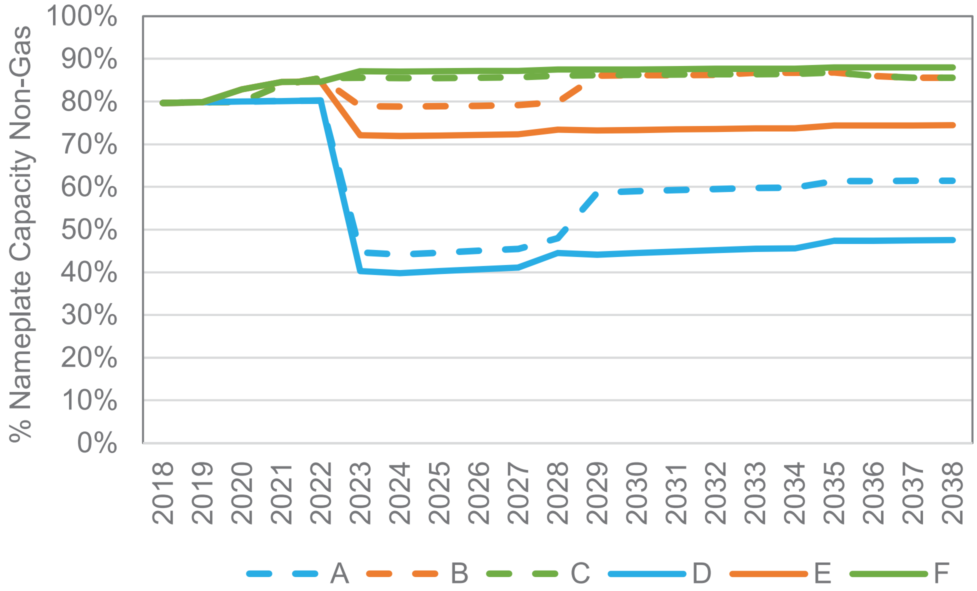
Figure 9-24: Summary Cost and Tail Risk – Replacement Portfolios



Additional Scorecard Metric Results

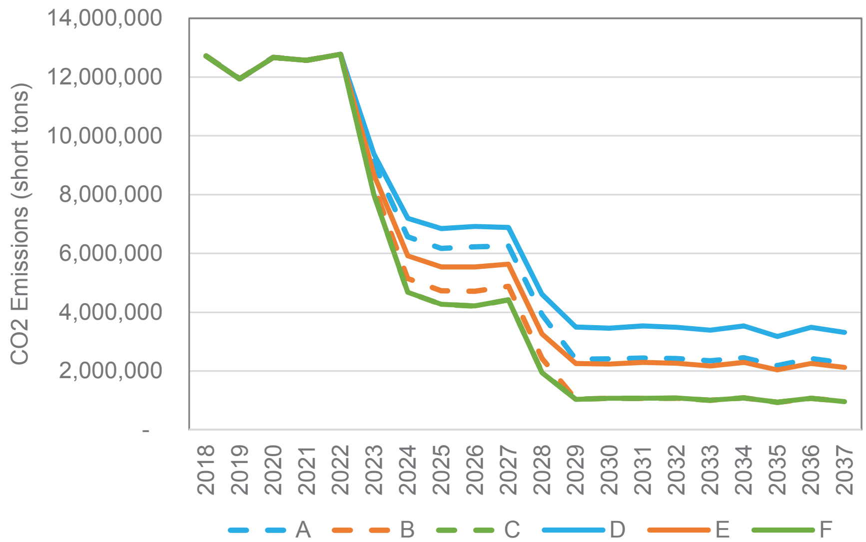
NIPSCO has identified fuel security as an important metric in its integrated scorecard assessment. Fuel security has been defined as the percentage of total nameplate capacity that is sourced from non-natural gas resources. A summary projection of this metric over time for each of the six replacement portfolios is shown in Figure 9-25. As is shown, after the potential retirement of coal capacity in 2023, Portfolios A and D would have less than 50% of their capacity comprised of non-gas resources, while Portfolios C and F would be closer to 90% for this metric. For purposes of the scorecard, 2025 is used as the benchmark year.

Figure 9-25: Percent of Nameplate Capacity that is Non-Gas for Replacement Portfolios



As an environmental stewardship benchmark, NIPSCO has identified CO2 emissions has an important scorecard metric. While all replacement portfolios would expect to realize significant CO2 emission reductions with the retirement of coal capacity in 2023 and 2028, differences in long term emissions are dependent on whether the resource replacements are renewable or natural gas-fired. Figure 9-26 summarizes the projected CO2 emissions over time for all six replacement portfolios, showing that the renewable-only options are lower over the long-term.

Figure 9-26: Projected CO2 Emissions over Time for Replacement Portfolios



Scorecard Summary

Figure 9-27 presents a summary of all scorecard metrics for each of the six replacement portfolios. This includes the cost metrics associated with the Base Case NPVRR and the risk metrics associated with the stochastic analysis, as well as the impacts of each option on fuel security, carbon emissions, NIPSCO employees, and the local economy.

Figure 9-27: Replacement Portfolio Scorecard

Preferred Replacement Path

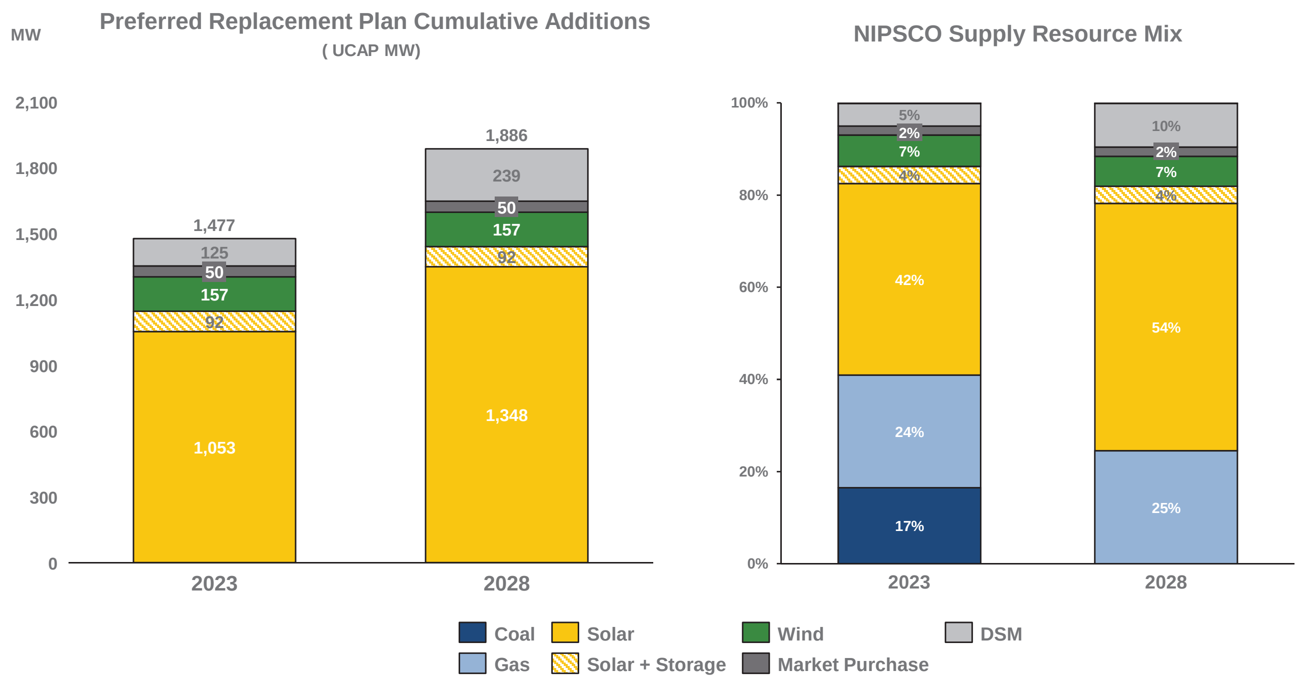
	A	B	C	D	E	F
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Cost to Customer delta from least	$12,985 $1,222 10.4%	$12,028 $265 2.2%	$11,769 $6 0.1%	$12,956 $1,192 10.1%	$12,121 $357 3.0%	$11,763 $0 0.0%
Cost Certainty delta from least	$13,360 $1,477 12.4%	$12,254 $371 3.1%	$12,007 $124 1.0%	$13,286 $1,403 11.8%	$12,245 $362 3.0%	$11,883 $0 0.0%
Cost Risk delta from least	$14,431 $2,067 16.7%	$12,922 $558 4.5%	$12,661 $297 2.4%	$14,284 $1,920 15.5%	$12,815 $452 3.7%	$12,364 $0 0.0%
Fuel Security % non-gas capacity	45%	79%	86%	40%	72%	87%
Environmental 2030 CO_2 emissions 2005 baseline = 18.2M	2.18M	0.97M	0.97M	3.13M	2.03M	0.97M
Employees	0	0	0	<30	<30	<30
Local Economy	Dependent on project selection and location; currently under evaluation					

9.3 Preferred Replacement Portfolio

The replacement scorecard shown in Figure 9-27 shows that replacement portfolios with renewables are more cost effective than portfolios without renewables. Additionally, portfolios with more renewables provide greater amounts of CO2 emissions reduction and provide the greatest amount of fuel security.

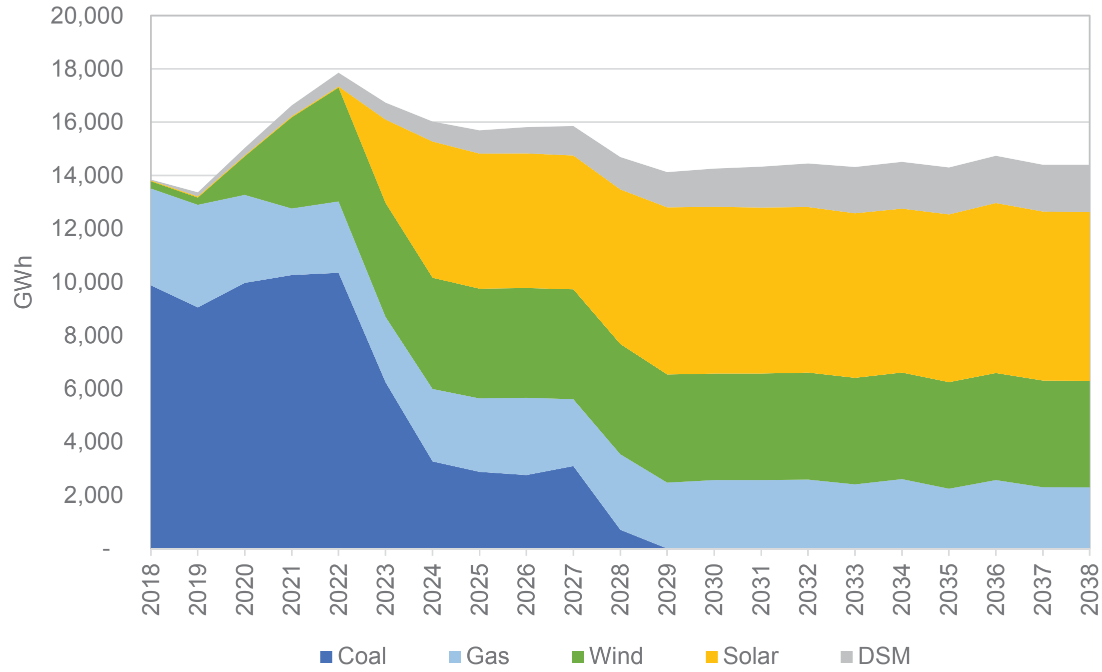
NIPSCO has selected replacement Portfolio F as the preferred plan. This portfolio calls for the addition of a mix of wind, solar, battery storage, market purchases and DSM resources over time. Figure 9-29 shows the NIPSCO preferred plan *incremental* additions and NIPSCO's overall projected capacity supply mix at the end of 2023 and 2028.

Figure 9-28: Preferred Plan Capacity Mix over Time



Over the twenty-year planning horizon, NIPSCO's generation mix is projected to shift significantly from coal to renewables. As shown in Figure 9-29, renewable generation is expected to increase with the acquisition of wind resources between 2020 and 2022 and solar resources thereafter. During this time period, coal generation is expected to decline to zero, while gas generation is projected to be relatively stable. Under this portfolio, NIPSCO will be supplied primarily by renewable resources (wind and solar) over the long-term, with meaningful natural gas and DSM contributions. Market purchases would be expected to meet the remainder of the requirements, but are dependent on renewable operations and the details of future resource decisions that are be made by NIPSCO in the coming years.

Figure 9-29: Preferred Portfolio Energy Mix

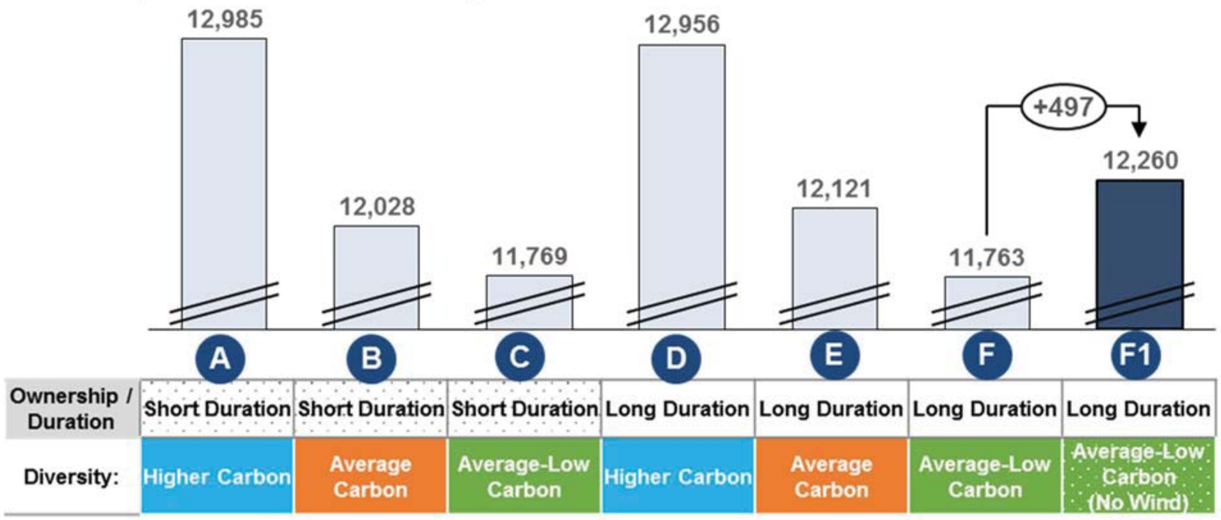


9.3.1 Procuring Wind in 2020

As discussed in Section 4.10.2, tax incentives currently available for renewable energy resources are currently in the midst of a phase out, and projects need to begin construction by a certain date and be in service by a certain date in order to receive the benefits. For wind resources to qualify for 100% of the production tax credit (PTC), projects need to be placed in service by the end of 2020. Solar resources are eligible to receive the investment tax credit (ITC), but do not need to enter into service until the end of 2023 to qualify.

NIPSCO has found that wind resources provide significant value to the portfolio from a cost perspective, and that procuring wind resources in 2020 to realize the full benefits of tax credits is important to achieve the lowest portfolio costs for customers. In order to evaluate the impact of the best-performing All-Source RFP wind resources on the costs of the portfolio, NIPSCO evaluated a variation of Portfolio F that relies solely on solar and solar plus storage resources in place of wind. This portfolio is nearly $500 million more expensive than Portfolio F on a 30-year NPVRR basis, as shown in Figure 9-30. This is due to the fact that the alternative portfolio removes the lowest-cost resources (wind) and replaces them with higher-cost solar resources and a larger amount of higher-cost market purchases.

Figure 9-30: Base Case Replacement Cost NPVRR with No Wind Portfolio



9.3.2 Preferred Plan Summary

From a customer perspective, NIPSCO's preferred plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply is available to meet future customer needs. NIPSCO also carefully planned and considered the impacts to its employees, the environment, system reliability and impacts on the local economy as the plans were developed. It is important to remember that the integrated resource plan is a snapshot in time and while it establishes a direction for NIPSCO, it is subject to change as the operating environment changes. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

The major components of the NIPSCO supply strategy for the next 20 years are expected to:

- Lead to a lower cost, cleaner, diverse and flexible portfolio by accelerating the retirement of over 75% of NIPSCO's current coal capacity by the end of 2023 and 100% by 2028
- Continue the Company's commitment to energy efficiency and demand response by executing the current filed DSM plan
- Replace retired coal generation resources with lower cost renewables, including wind, solar and battery storage
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units

- Reduce customer and Company exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply;

- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape

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

- Continue to comply with NERC and EPA standards and regulations

9.3.3 Financial Impact

Figure 9-31 shows NIPSCO's financial impact of the preferred plan over the planning period. The 30-year NPVRR is broken down into operating and capital costs. The operating costs include the fixed and variable costs associated with both existing units and future resources, as well as contract costs and net market purchases. The capital costs include all capital related costs for existing units and costs related to the acquisition of new resources in the preferred portfolio. These costs include depreciation expenses, capital charge, and taxes. In order to present a levelized net present value rate summary, the total energy forecast for NIPSCO is also discounted over the 30-year period at the same rate.

Figure 9-31: Financial Impact Summary

Financial Impact Summary	
Operating Costs ($000)	7,357,588
Capital Costs ($000)	4,405,775
Total Revenue Requirement ($000)	11,763,363
Total Energy Requirement (GWh)	203,994
Cents/kWh	5.77

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

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

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from a number of sources including: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; (v) new equity capital and (vi) tax equity financing. NiSource, Inc. procures external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB at Fitch and Baa2 at Moody's. NIPSCO intends to fulfill its commitment in Cause No. 44688, in regard to electric related projects, to "finance, in aggregate, any project, or set of projects in an approved plan, estimated to cost more than $100 million for which it receives a Certificate of Public Convenience and Necessity pursuant to Ind. Code Chapters 8-1-8.4, 8-1-8.5, 8-1-8.7, 8-1-8.8, or 8-1-39 with at least 60% debt capital.

9.3.4 Capacity Resource Planning With Non Dispatchable Resources

Reliable system planning fundamentally requires having enough resources available to meet customer needs at all times. As discussed in Section 4.8, the NIPSCO plans supply resources to meet its peak demand coincident with MISO system peak demand plus the required reserve margin. NIPSCO recognizes 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 plan outlined in the IRP is a 'low regrets' path that provides flexibility to adjust to these potential changes while managing customer cost.

Renewable resource capacity credit assumptions used in the IRP depend on the resource. The 2018 IRP modeling uses resource capacity credit roughly based on current MISO rules and are fixed over the planning horizon. For new MISO Load Resource Zone ("LRZ") 6 wind resources, the IRP modeling uses a fixed 15.6% capacity credit which is based on MISO effective load-carrying capability ("ELCC") from Planning Year 2017. ELCC is a measure of the additional load that the system can supply with an additional generator; it is ultimately a derating factor applied to the nameplate capacity of a resource in order to determine how many megawatts can be counted towards meeting a the local resource adequacy requirements of a load serving entity like NIPSCO.

For new LRZ 6 solar resources, the IRP modeling uses a fixed 50% capacity credit assumption. This assumption is based in part on current MISO methodology which sets annual UCAP based on the 3-year historical output for hours ending 15, 16, and 17 EST. Solar resources without historical data currently receive the 50% class average. NIPSCO uses this placeholder value set by MISO for 1st year operations throughout the entire modeling horizon. NIPSCO understands that MISO intends to move to an ELCC methodology for solar similar to the one used for wind when sufficient data is available.

For new LRZ 6 storage resources, the IRP modeling assumes 4 hour storage required to firm renewables (i.e. 4MWh storage creates 1MW capacity). NIPSCO understands that MISO is currently working through the stakeholder process for storage credit in response to FERC Order 841. Recent work points towards a 5% EFORd assumption and capacity credit based on 4-hour duration.

Although not modeled, renewable capacity credit is likely to change over time. NIPSCO's IRP modeling uses a UCAP assumption and renewable project size is "grossed up" to account for capacity credit. A renewable generator's contribution to meeting peak load is dynamic and depends on multiple factors including:

- Renewable generation profile –when is the unit producing energy?
- Load profile –when do customers demand energy?

- Renewable penetration levels –how much of the system is comprised of renewables?

- ISO-specific policies / methodologies

Capacity credit value and methodology is not fixed and may change. Current capacity credit methodology in MISO matches unit availability with peak load hours during the summer to arrive at a capacity credit.

However, MISO is exploring a Resource Availability and Need ("RAN") methodology that expands resource adequacy from a single summer peak view to look at seasonal needs with greater emphasis on the ability of resources to provide energy all year around. Initial solar capacity credit of 50% will likely change with Effective Load Carrying Capability analysis; both wind and solar capacity credit will change over time with increased renewable penetration levels. MISO has identified a number of available levers to mitigate reductions in resource availability including: resource diversity; geographic diversity; southwest-facing solar; solar tracking; energy storage; demand control and energy efficiency[15].

Notably, the 2018 NIPSCO IRP Preferred Plan portfolio includes many of these mitigation levers, including resource diversity through coal, natural gas, wind, solar and energy storage; geographic diversity with current and planned resources spread across and beyond NIPSCO's electric footprint; demand control; energy efficiency. Furthermore, NIPSCO will consider southwest facing solar and solar tracking in its planned procurement. NIPSCO will continue to monitor how the market evolves and incorporate it into future planning

If capacity credit rules or methodologies change, NIPSCO's IRP path can be cost-effectively scaled to adjust. If additional capacity is required, NIPSCO's modeling, based on RFP data, shows that procuring additional renewable resources is the lowest cost option. As discussed in Section 9.2, the optimization model economically selects a renewable (or renewable + storage) resource over alternatives. By not committing to any single, large asset for the majority of UCAP needs, NIPSCO can flexibly adapt as rules and technologies change.

Preferred Plan Provides Opportunities to Track Drivers that are Difficult to Quantify Today

Congestion and nodal price risk is one such driver. Energy delivery to the grid is critical to realize benefits from renewables. As part of the selection process for replacement resources identified through the RFP, NIPSCO plans to evaluate system delivery risks (market congestion impacts) associated with each project. For projects shortlisted, NIPSCO will conduct economic planning studies based on transmission congestion and variable fuel cost adjusted for purchase costs and sales revenues using the MISO Transmission Expansion Plan (MTEP) model under the Accelerated Fleet Change planning future.[16] This future assumes 26 GW of coal and natural gas retirements, 22 GW of new wind, and 14 GW of new solar in MISO by 2027. The studies will help

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[15] MISO "Renewable Integration Impact Assessment". June 5, 2018. Available at https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

[16] MISO MTEP18 Futures Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results. Available at https://cdn.misoenergy.org/MTEP18%20Futures%20Summary111488.pdf

identify potential system issues with delivering the energy from multiple wind and solar installations throughout Indiana under normal and contingent operating conditions.

Forecasting is not an exact science and NIPSCO recognizes that the current analysis may not capture all potential future states of the world and is committed to tracking market evolutions and will update and incorporate into future IRPs as appropriate. Examples of potential changes include MISO evolution on ancillary services, renewable resource availability/ capacity credit forecasts, seasonal constructs, etc.

As discussed in Section 9.4, NIPSCO's short-term action plan does not commit to immediately filling the entire 2023 capacity gap but leaves room to evaluate market and technology changes on a dynamic basis.

9.4 Short-Term Action Plan

NIPSCO's short term action plan covering the period 2019 to 2022 is focused mainly on initiating the planning process for the retirement of the Schahfer 14,15,17,18 units and beginning the procurement of replacement resources. In this period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire the Schahfer coal units by the end of 2023. NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements of the units.

NIPSCO will select replacement resources identified through the 2018 All-Source RFP evaluation process, prioritizing resources with expiring federal tax incentives to achieve lowest customer cost. For the projects selected, NIPSCO will pursue the required approvals from the commission to acquire those projects. To fill any short term capacity needs during this period, NIPSCO will rely on MISO market purchases or short term PPA(s). NIPSCO will also continue to implement the filed DSM plan for 2019 to 2021

Lastly, NIPSCO will conduct a subsequent All-Source RFP solicitation to identify preferred resources to fill the remainder of the 2023 capacity need. Figure 9-32 summarizes the short term actions for the 2018 NIPSCO IRP.

Figure 9-32: Short-Term Action Plan Summary

Initiate retirement of Schahfer units 14,15,17,18 by making required notifications to MISO, NERC and other organizations
Identify and implement required reliability and transmission upgrades resulting from retirement of the units
Select replacement projects identified from the 2018 All-Source RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost
File CPCN(s) and other necessary approvals for selected replacement projects
Procure short-term capacity as needed from the MISO market or through short-term PPA
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)
Continue implementation of filed DSM Plan for 2019 to 2021
Comply with NERC, EPA and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

9.4.1 Procurement of Preferred Resources

NIPSCO recognizes that the amount of projects that need to be acquired to support its preferred replacement plan will require much time, effort and planning. NIPSCO will utilize a multi-phase approach for acquiring those resources. As discussed in the Short Term Action Plan, in the early phases, NIPSCO will look to primarily acquire tax advantaged wind projects, with solar and solar plus storage targeted for later phases. NIPSCO will use the early phases to build the organization capabilities, repeatable processes and procedures to support later procurement phases for the need identified. NIPSCO will also seek to engage with counterparties from the 2018 all source RFP that have extensive demonstrated development, construction and operational experience with wind, solar and storage projects. Lastly, NIPSCO will look to find process efficiencies by standardizing terms and conditions in agreements with counterparties and standardizing construction oversight procedures across all projects.

9.5 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This IRP quantifies changes associated with the emerging energy market place to best accommodate risks associated with customer cost and service. No longer is it possible to view the world in terms of choosing a simple least cost option; it is now necessary to think it terms of minimizing future environmental impacts and maximizing resource diversification all the while ensuring affordable service to customers.

The IRP process and document are ever evolving and no filed document is ever up-to-date with the world as it stands the day after filing. Rather than trying to model our future world with exact precision, this IRP seeks to utilize a broad set of scenarios assumptions in combination with advanced risk treatment using stochastics to understand and develop resource plans and portfolios that perform best under multiple potential futures.

Section 10. Customer Engagement

10.1 Enhancing Customer Engagement

NIPSCO is focused on enhancing how it serves and interacts with its customers. Whether upgrading the energy infrastructure to make sure it's prepared to meet future needs, providing more convenient options to connect with the Company in-person, online or via telephone or expanding energy efficiency programs, customers are the central focus.

10.1.1 Leveraging Stakeholder Feedback

NIPSCO relies on customer feedback to uncover service improvement opportunities. Those feedback mechanisms include the J.D. Power Customer Satisfaction Surveys, MSR Group Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's call center, as well as the IURC's Consumer Affairs Division. The Company also researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the industry. This data is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and added programs and other offerings that have been instituted in recent years.

For example, recent J.D. Power Electric Customer Satisfaction survey results have highlighted the need to expand how NIPSCO communicates with customers during power outages. As a result, the Company launched NIPSCO Alerts, which enables customers to receive updates regarding power outages, including estimated restoration time via text, email, or telephone. As part of this, NIPSCO also added the option for customers to text to report a power outage. With this new offering, NIPSCO customers can now choose the option that is most convenient for them – telephone, online (desktop and mobile) and text. These enhancements were part of why NIPSCO was recently awarded with Chartwell's top award for 2018 Outage Communications Best Practices among all utilities nationally.

10.1.2 NIPSCO's Customer Workshop Series

NIPSCO recently kicked off the 7th season of its Customer Workshop Series in partnership with Purdue University. Since 2011, hundreds of NIPSCO Transmission and C&I customers from all over northern Indiana have attended the various workshops. With topics ranging from technical (Understanding HVAC, Fundamentals of Compressed Air, Energy Savings 101, etc.) to interpersonal (Six Sigma, Managing Time & Stress, Becoming a Leader, etc.), customers are able to pick which workshops are valuable to their business and reserve openings for themselves and/or their colleagues.

Attendees are able to interact with industry experts, representatives from the NIPSCO Major Account team, as well as their peers at other companies, learning best practices and voicing their current challenges and solutions in an open, classroom setting. Each season, customers are surveyed and feedback is used to improve the subsequent season. Changes for the 2018 season included additional workshops in the South Bend area, as well as a class geared towards navigating generational changes in the workplace.

10.1.3 New Business Department

The New Business Department was formed in July of 2015 to add value for customers and stakeholders by providing a focus on new business activities for all customers (residential, and C&I). The goals include:

- Continuous improvement of the new business process “from first call to install”
- Single source accountability for policy maintenance
- Enhancing relationships with builder/developer community
- Improving metrics to inform on efficiency and effectiveness
- Supporting capital budget methodology to increase clarity
- Managing growth programs including Electric Vehicle, Feed-In Tariff, Green Power, Compressed Natural Gas

The New Business Department has responsibility for any customer that requests new service, upgrade of service, retirement of service, or relocation of service. NIPSCO’s new business representatives are specifically trained in the details of these transactions and provide a resource for customer issues. Since its inception, the New Business Department has undertaken initiatives to:

- Create a single Site Readiness policy for NIPSCO
- Provide automated emails to customers with project status updates
- Revise key performance indicators to better inform on execution levels
- Simplify agreements for all customer classes
- Establish new accounting codes to provide clarity into new service costs

The New Business Department expanded in 2016 and now includes external, customer facing representatives and internal support to assist customers with their new service connections. The New Business Department continues its efforts to evaluate the new business process to determine opportunities for increased efficiency and improved customer service. An end-to-end process map has been completed, which has helped to identify additional areas of opportunity.

10.1.4 Customer Feedback

Customer feedback is essential in NIPSCO’s development of customer support and service offerings to provide for an exceptional customer experience. NIPSCO utilizes an on-line group of customers to provide feedback on project offerings and channel options. NIPSCO utilized this on-line group, along with an additional in-person focus group, in the redesign of its customer bill that launched in the spring of 2016. NIPSCO also surveys customers to determine customer satisfaction with the call center and interactions with field personnel, as well as with on-line experiences such as mobile, integrated voice response and web. Customer surveys are also used to capture specific customer issues and to gain immediate feedback on the quality of NIPSCO's customer service. NIPSCO uses the results of these surveys, as well as the information obtained through the J.D. Power Customer Satisfaction Surveys, to identify potential ways to improve the overall customer experience including training and development for customer service representatives and field personnel.

In addition to the J.D. Power Customer Satisfaction Surveys, NIPSCO also relies on customer feedback obtained through MSR Group Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's call center, as well as the Commission's Consumer Affairs Division to discover service improvement opportunities. NIPSCO also researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the utility industry. Customer feedback is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and additional programs and other offerings that have been instituted in recent years.

10.1.5 Community Partnerships - Community Advisory Panels

Another avenue used by NIPSCO to engage with its customers and stakeholders is the use of Community Advisory Panels ("CAPs"), which serve as a forum to discuss new company initiatives and programs as well as to educate and facilitate feedback regarding service and other NIPSCO-related matters in their communities. NIPSCO has five regions across the Company's footprint for the CAPs. CAPs are comprised of individual customers as well as local government and community leaders representing a diverse, broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues. This year, as part of the development of the IRP, the CAPs were asked to design a portfolio to meet NIPSCO's electricity needs. The activity led to a great deal of discussion around the best portfolio and provided insight for NIPSCO and CAP members.

10.2 Customer Programs

10.2.1 Feed-in Tariff – Rate 765

NIPSCO's Renewable Feed-in Tariff ("FIT") Phase I was approved on July 13, 2011 in Cause No. 43922. Implementation began immediately as a three-year pilot program with a 30 MW capacity cap. Phase I offered a rate greater to participants selling electricity than the retail electric rate in the current approved sales tariffs and provided an incentive to encourage development of renewable generating resources. The pilot program was designed to help maximize the development of renewable energy in Indiana, which welcomed biomass, wind, hydro and solar resources. The FIT provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a Renewable Power Purchase Agreement ("RPPA"). Participating customers receive payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- An Interconnection Agreement ("IA") and RPPA are required to reserve capacity or enter the queue.
- The customer is responsible for interconnection fees and installation costs in accordance with the Indiana Administrative Code.
- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with the IA.

Phase I concluded in March of 2015 with a total subscription of 29.7 MW and is summarized in the Table 10-1.

Table 10-1: FIT Phase I In-Service

Technology	Total FIT (kW)
Biomass	14,348
Solar (large)	14,500
Solar (small)	690
Wind (large)	150
Wind (small)	10
New Hydro	0
Total	**29,698**

NIPSCO's FIT Phase II was approved on February 4, 2015 in Cause No. 44393. NIPSCO released Phase II, Allocation I of the FIT program in March of 2015 and Phase II, Allocation II in March of 2017. Phase II allows for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW. Table 10-2 shows the subscription for Phase II as of July, 2018.

Table 10-2: FIT Phase II Project Totals

Technology	In-service (kW)	Queue (kW)	Total FIT (kW)
Micro Solar	110	74	184
Intermediate Solar	3,576	4,380	7,956
Micro Wind	20	0	20
Intermediate Wind	0	1,000	1,000
Biomass	0	0	0
Total	3,706	5,454	9,160

With over 37 MW currently interconnected in the FIT program, as of December 31, 2017, NIPSCO has a total metered generation from customers selling electricity of 473,379,090 kWh.

Table 10-3 shows the annual production and growth by technology segment.

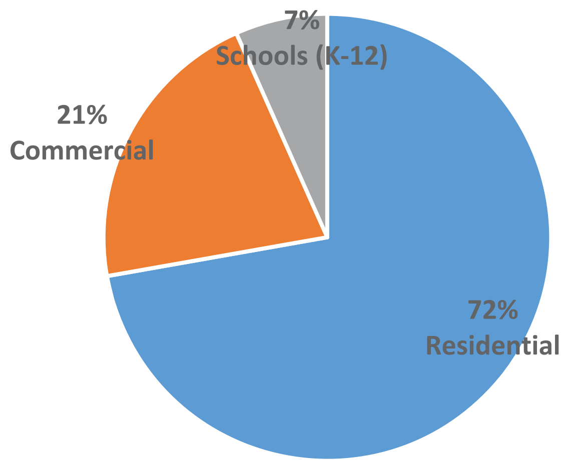
Table 10-3: Annual Production by Technology – Generation (kWh)

Technology	2011	2012	2013	2014	2015	2016	2017	*Total*
Biomass	6,219,791	19,152,432	31,602,728	49,916,700	81,369,723	83,552,339	89,486,440	**361,300,153**
Large Solar	-	433,758	15,789,457	21,665,115	22,436,103	22,696,839	24,391,349	**107,412,621**
Small Solar	-	118,895	471,806	718,758	818,332	825,066	848,789	**3,801,646**
Large Wind	-	-	90,113	165,880	217,949	165,593	167,807	**807,342**
Small Wind	-	3,588	15,721	12,051	9,462	8,019	8,487	**57,328**
Total	**6,219,791**	**19,708,673**	**47,969,825**	**72,478,504**	**104,851,569**	**107,247,856**	**114,902,872**	**473,379,090**

10.2.2 Net Metering – Rider 780

NIPSCO's Net Metering Rider allows customers to install renewable energy generation to offset all or part of their own electricity requirements. Net metering is the measurement of the difference between the electricity that is supplied by NIPSCO and the electricity that is supplied back to NIPSCO by an eligible net metering customer. Production is measured on a kWh basis. To be eligible, a customer must be in good standing and operating a solar, wind, biomass or hydro generating facility that has a nameplate capacity less than or equal to 1 MW. NIPSCO follows the rules and guidelines set forth in the Indiana Administrative Code with respect to Net Metering and the interconnection process. Customers with a fully executed Net Metering Agreement and Interconnection Agreement receive a credit for each kWh provided to NIPSCO above their own usage requirement. NIPSCO's Net Metering program capacity cap is limited to 45 MW and total subscription is as of December 31, 2017 was 10.69 MW. The total measured generation by the Net Metering customers for 2017 was 3,667,721 kWh. The current classification of NIPSCO's 270 Net Metering customers is shown in Figure 10-1.

Figure 10-1: Classification of Net Metering Customers



10.2.3 Electric Vehicle Programs (Phase I and Phase II) – Rider 785

10.2.3.1 NIPSCO IN-Charge Electric Vehicle Program – At Home (Phase I)

NIPSCO's IN-Charge Electric Vehicle ("EV") Pilot Program was approved on February 1, 2012 in Cause No. 44016 through January 31, 2016. NIPSCO launched its IN-Charge Electric Vehicle Program - At Home on April 2, 2012. On October 29, 2014, the Commission approved NIPSCO's 30-day filing to extend its EV Program an additional two years through January 31, 2017. Under the extended EV Program, the incentive of up to $1,650 per customer continued for a period through January 31, 2017 or until such time as the funds were depleted, which occurred earlier. As of June 30, 2016, 250 customers had received program incentives, exhausting the funds available for customer incentives. On January 11, 2017, in Cause No 44828, the Commission approved NIPSCO's request for a modification of its EV Program to provide that participants of record as of January 31, 2017 would be subject to an energy charge of $070894 per kilowatt hour for all kilowatt hours used per month in the PEV Off-Peak Hours, plus all applicable Riders for a period of 23 months. This program expires on December 31, 2018.

As of January 31, 2018, NIPSCO had received 382 customer enrollment requests. Estimates for installation costs, including the cost of a home EV charger, ranged from $667 to $6,325 with an average of $2,062. The average incentive amount used by customers with completed installations was $1,629.

The Bureau of Motor Vehicle registrations that show registrations in counties that NIPSCO has electric service in are as follows:

Table 10-4: NIPSCO's Electric Vehicle Customer Request Breakdown

Row Labels	2014	2015	2016	2017
BENTON	1	1	1	3
DEKALB	1	4	18	18
ELKHART	33	45	63	78
FULTON	4	5	5	4
JASPER	4	7	11	18
KOSCIUSKO	12	17	22	32
LAKE	116	154	185	250
LAPORTE	17	30	40	62
MARSHALL	7	8	9	14
NEWTON	2	2	2	7
PORTER	68	84	107	140
PULASKI		1	2	4
SAINT JOSEPH	50	71	87	148
STARKE	1	3	3	5
STEUBEN	3	6	10	18
WHITE	2	5	5	7
Grand Total	**321**	**443**	**570**	**808**

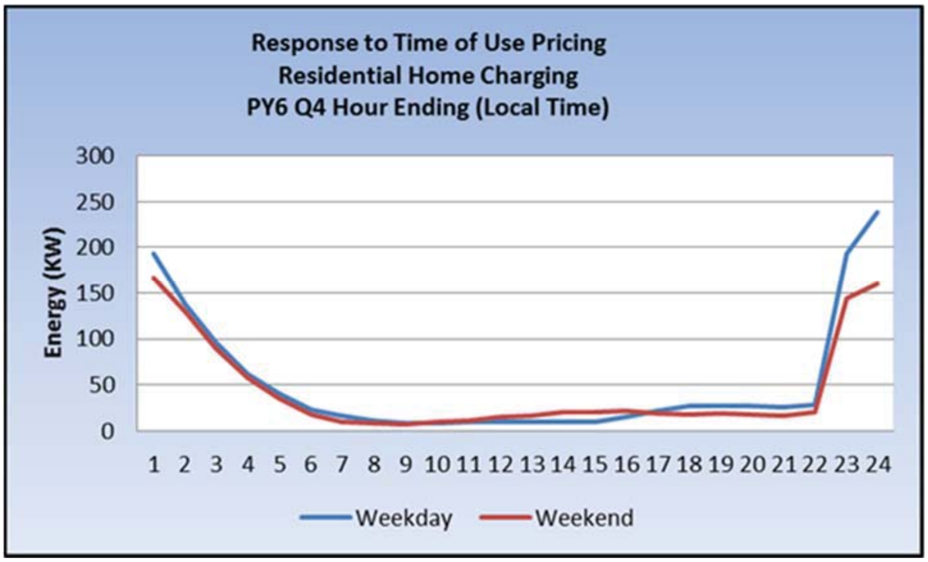
On average, EV customers that were a part of NIPSCO's pilot program used approximately 220 kWh per month to charge their electric vehicle. The actual amount of consumption will vary by individual customer. Customer vehicle type will impact the consumption significantly as well as the demand on the grid. A Tesla Model S charging demand is 10 kW, while a Chevrolet Volt charging demand is only 3.3 kW. The Nissan Leaf charging demand ranges from 3.3 kW to 6.6 kW depending on the options installed in the car. To put demand in perspective, an average size residential home has approximately 33 kW in connected load of which, on average, 18 kW might be on during coincidental peak time. For comparison, typical residential demand breakdown by appliance is listed below:

- Water Heater – 4.5 kW
- Range / Oven – 8.0 kW
- Central Air Conditioner – 6.0 kW
- Clothes Dryer – 5.0 kW
- Dishwasher – 2.0 kW
- Lighting, Fans, Appliances, Other – 7.5 kW

NIPSCO's Rate Case Order indicates that its typical residential electric customer used 698 kWh per month on average during the weather normalized test year. The average EV consumption during the pilot period was approximately 220 kWh or approximately 31 percent of the average home consumption. The type of vehicle purchased and the number of miles driven by the customer will directly impact the average consumption of the vehicle for each individual customer.

NIPSCO found that the "free" energy and discounted energy during the off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior during the pilot. The typical usage by hour over the recent three month period analyzed (November 2017 through January 2018) is shown in Figure 10-2. The vast majority of the time, EV residential customers began their charging session at 10 p.m. when the energy discounted period began and their vehicles were fully charged by 6 a.m. when the energy discounted period ended. As predicted, the total energy consumption was higher during the work week, when owners typically drove their vehicles more than they did on weekends. The analysis indicates that time of use rates do have an impact on pushing 80% of EV loads to more preferred off-peak time for utilities.

Figure 10-2: Response to Time of Use Pricing



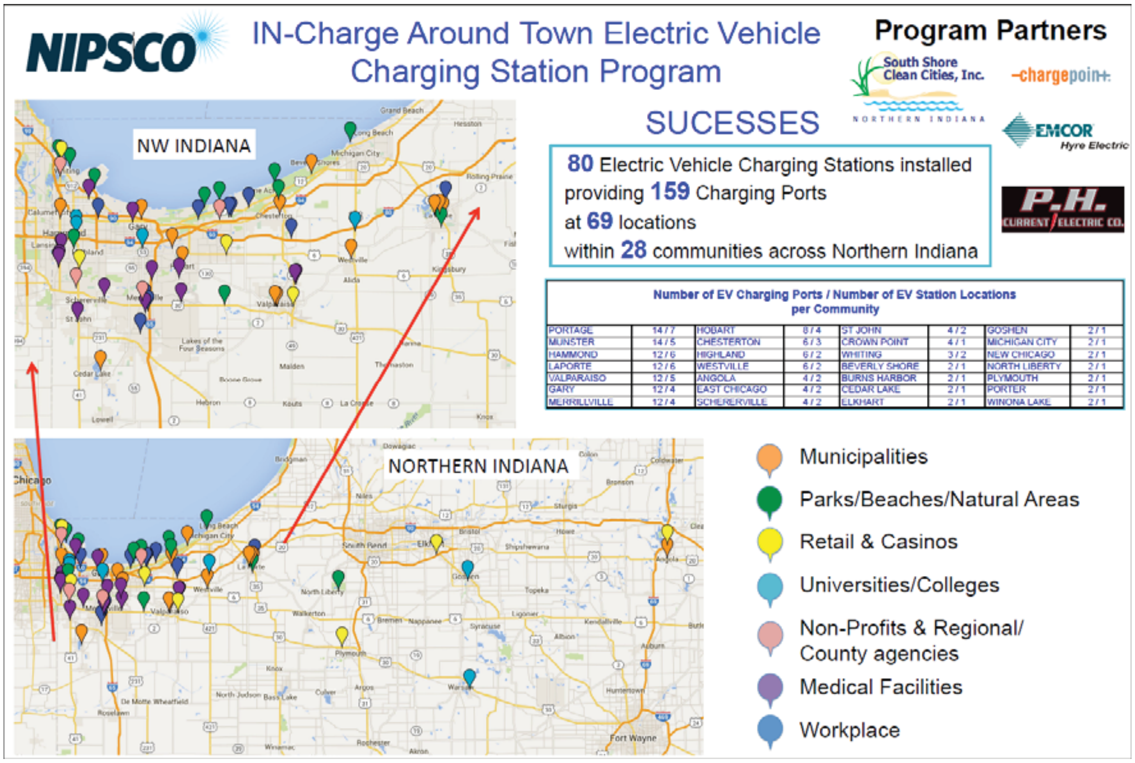
10.2.4 NIPSCO IN-Charge EV Program – Around Town (Phase II)

NIPSCO partnered with South Shore Clean Cities to expand opportunities for alternative fuel, through the launch of a public charging station incentive program in February 2014. The NIPSCO IN-Charge EV Program – Around Town made it easier and more affordable for businesses and organizations to install public charging infrastructure. The In-Charge – Around Town program was available to commercial / industrial electric customers across northern Indiana and was offered until program funds were exhausted in June 2016.

For every unit of electricity used by IN-Charge Around Town charging stations during the program, NIPSCO bought an equivalent amount of renewable energy certificates ("RECs") – the environmental attributes associated with electricity that is generated from renewable sources, such as wind power.

As of June 30, 2016, NIPSCO had installed 80 public charging stations providing 159 charging ports at 69 locations. Figure 10-3 shows a map of the station locations and application status:

Figure 10-3: Station Locations and Application Status



Number of EV Charging Ports / Number of EV Station Locations per Community

PORTAGE	14 / 7	HOBART	8 / 4	ST JOHN	4 / 2	GOSHEN	2 / 1
MUNSTER	14 / 5	CHESTERTON	6 / 3	CROWN POINT	4 / 1	MICHIGAN CITY	2 / 1
HAMMOND	12 / 6	HIGHLAND	6 / 2	WHITING	3 / 2	NEW CHICAGO	2 / 1
LAPORTE	12 / 6	WESTVILLE	6 / 2	BEVERLY SHORE	2 / 1	NORTH LIBERTY	2 / 1
VALPARAISO	12 / 5	ANGOLA	4 / 2	BURNS HARBOR	2 / 1	PLYMOUTH	2 / 1
GARY	12 / 4	EAST CHICAGO	4 / 2	CEDAR LAKE	2 / 1	PORTER	2 / 1
MERRILLVILLE	12 / 4	SCHERERVILLE	4 / 2	ELKHART	2 / 1	WINONA LAKE	2 / 1

10.2.5 Green Power Program – Rate 760

NIPSCO's Green Power Rider ("GPR") program was approved on December 19, 2012 in Cause No. 44198 through December 31, 2014. NIPSCO's request for extension of its GPR Program, with certain modifications, and as a component of NIPSCO's approved tariff on a non-pilot basis, was approved on December 30, 2014 in Cause No. 44520. The GPR Program is a voluntary program that allows customers to designate a portion or all of their monthly electric usage to be attributable to power generated by renewable energy sources. Customers can enroll online or by calling NIPSCO. .

Green Power is energy generated from renewable and/or environmentally-friendly sources or a combination of both, which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of Green Power include: solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green Power includes the purchase of RECs from the sources described above. For the GPR Program, NIPSCO's residential electric customers can designate 25%, 50% or 100% of their total electricity usage to be attributable to Green Power. In addition to those options, NIPSCO's C&I customers also have the option to designate 5% or 10% of their total electricity usage to be attributable to Green Power. As of December 31, 2017, 1,191 customers were participating in the GPR Program. Figure 10-4 shows the breakdown among residential customers as of December 31, 2017.

Figure 10-4: Residential Customer Count

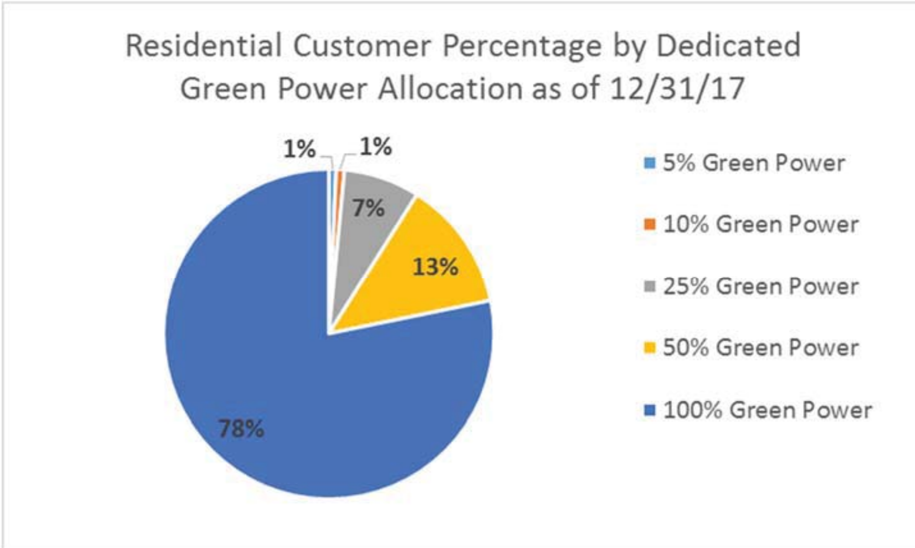
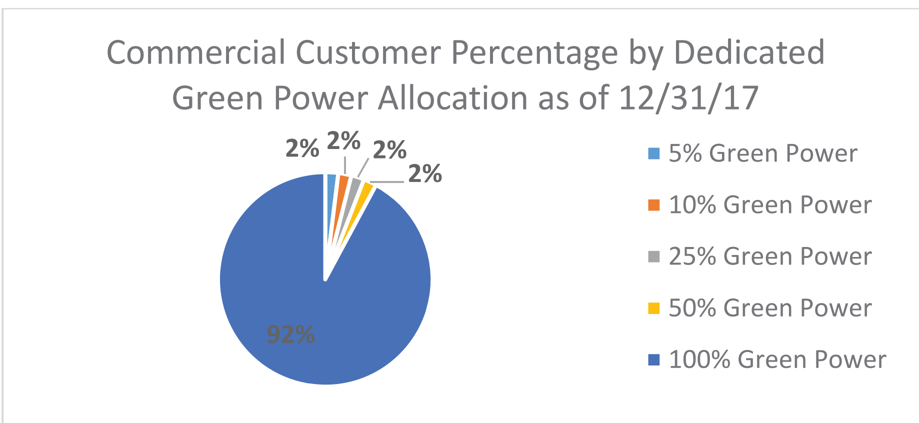


Figure 10-5 shows the breakdown of commercial and industrial customers as of December 31, 2017.

Figure 10-5: Commercial Customer Count



NIPSCO's GPR Program for the period of January 1 through December 31, 2017 accounted for 18,274,702 kWh energy consumption designated as Green Power. Residential customers accounted for 6,973,682 kWh of energy consumption and commercial and industrial customers accounted for 11,301,020 kWh of energy consumption of designated Green Power. For both residential and commercial customers, the majority of the GPR Program enrollments designate 100% of their energy as Green Power. Table 10-5 shows the energy consumption designated as Green Power for participating customers by rate for the period January 1 through December 31, 2017.

Table 10-5: 2017 Green Power Customers by Rate (kWh)

Rate	Participation %	17-Jan	17-Feb	17-Mar	17-Apr	17-May	17-Jun	17-Jul	17-Aug	17-Sep	17-Oct	17-Nov	17-Dec	TOTAL
760	100%	986	856	796	808	644	669	639	620	770	771	904	722	9,185
711	5%	455	364	294	256	219	305	387	390	320	293	241	267	3791
	10%	833	689	594	581	616	886	986	941	745	665	625	600	8,761
	25%	13,075	12,096	11,807	10,064	9,510	14,579	17,815	17,464	14,349	12,998	10,762	11,936	156,455
	50%	48,352	39,945	37,771	37,629	33,844	51,781	62,997	61,220	49,347	44,746	38,478	41,564	547,674
	100%	574,872	483,575	431,576	427,760	372,190	540,691	677,110	673,250	570,611	519,354	465,081	520,931	6,257,001
721	5%	-	-	-	-	-	173	183	174	143	149	115	109	1,046
	10%	1,959	1,515	1,651	1,667	1,681	1,968	1,720	1,888	1,696	1,728	1,496	1,408	20,377
	25%	182	126	169	213	146	223	264	275	177	116	88	96	2,075
	50%	718	569	629	639	961	1,013	1,413	1,451	960	602	382	470	9,807
	100%	91,908	80,847	73,865	65,371	59,997	58,862	65,804	72,766	72,342	72,219	70,681	78,300	862,962
723	5%	3,360	-	-	-	-	-	-	-	-	-	-	-	3,360
	100%	50,800	54,040	52,280	40,640	47,320	46,000	42,280	49,520	49,280	43,960	48,600	44,640	569,360
724	100%	363,168	408,176	465,600	450,080	471,808	530,784	523,024	532,336	412,832	445,424	394,208	388,000	5,385,440
726	100%	337,152	341,632	354,160	356,064	397,232	453,792	421,904	418,400	398,128	370,656	299,568	288,720	4,437,408
TOTAL		1,487,820	1,424,430	1,431,192	1,391,772	1,396,168	1,701,726	1,816,526	1,830,695	1,571,700	1,513,681	1,331,229	1,377,763	18,274,702

Participating customers are billed under their current applicable rate, with a separate line item showing the premium to participate in the GPR Program. This premium is calculated by multiplying the GPR Rate by the kWhs the customer specifies to be subject to the GPR. Table 10-6 shows the Green Power premiums applicable during the period January 1, 2017 through December 31, 2018.

Table 10-6: Green Power Premiums

January 2017 through December 2017	January 2018 through June 2018	July 2018 through June 2019
$0.001640	$0.002940	$0.001805

10.3 Corporate Development and Community Support

10.3.1 Supporting Economic Growth

NIPSCO partners with community leaders and state, regional, and local economic development organizations to attract and support the expansion of new and existing businesses and to help create more jobs across the NIPSCO's service territory. In addition to being one of the largest employers in the region, NIPSCO spends $1.1 million in economic development efforts each year, which has resulted in 67 new businesses or expansions and 7,500 local jobs in the last 10 years.

NIPSCO's Rider 777 – Economic Development Rider ("EDR") offers discounts on existing tariff services for qualifying projects that bring new jobs and investment from outside its service territory. When coupled with local and state incentives, a powerful package is created with often positive results.

Even with the continued growth, NIPSCO's transmission and distribution system is designed to provide all customers with reliable energy services, and NIPSCO's resource plans focus on maintaining and developing resources in NIPSCO's service territory. Additionally, the investments NIPSCO is making to modernize and upgrade its energy infrastructure continue to have a positive, direct impact on local businesses.

10.3.2 Supplier Diversity

Cultivating a diverse pipeline of suppliers helps innovate ideas and processes, gain a competitive advantage and benefit NIPSCO's communities. NIPSCO has created a supplier diversity program that strengthens and widens the playing field for qualified suppliers that are typically underutilized in the supply chain of a large corporation.

In 2017, NIPSCO's direct supplier spend in Indiana was $155 million, and the direct supplier spend with diverse Indiana businesses was $40 million.

10.3.3 Workforce Development

NIPSCO continues to lead efforts and partnerships focused on workforce development – both for the current and future workforce generations. Some of the highlights include:

- **Ivy Tech Partnership for Energy Industry Training Program:** Program began in 2009 and provides training in electric-line, power plant technology and gas technology areas. NIPSCO has hired more than 50 students from the program and graduates are guaranteed an interview opportunity. Additionally, NIPSCO provides instructors for these training classes and recently provided a full-scale electric distribution system for training purposes built within the Ivy Tech Valparaiso campus energy technology lab – the only such facility in an educational setting in Indiana.

- **NIPSCO Energy Academy:** Started in 2014, the NIPSCO Energy Academy program is a partnership designed to prepare area students for high-demand jobs in the electronics, energy and utility industries. It is the first initiative of its kind in Indiana, and it will serve students from Michigan City High School, LaPorte High School, New Prairie High School, South Central High School, LaCrosse High School and Westville High School. Participants have entered the Ivy Tech program and are in the Apprentice Program at the International Brotherhood of Electrical Workers (IBEW), with more than 100 students that have gone through the program.

- **IN-Power Youth Mentoring Program:** IN 2010, NIPSCO introduced the IN-POWER Youth Mentoring Program – a unique mentoring program for local high school students that takes a holistic approach to developing a more highly skilled future workforce in the energy sector. The program was expanded with IN-

POWER STEM PLUS, designed to give 7th and 8th grade students a firsthand experience on gas and electric safety, while teaching them about the various aspects of science, technology, engineering and math needed in the energy sector. NIPSCO employees and American Association of Blacks in Energy (AABE) Indiana members serve as mentors and instructors. Participants receive college credits, unique mentoring and internships among other opportunities.

- **Junior Achievement Support:** NIPSCO provides annual support for classroom business education programs through both contributions and volunteer instructors across NIPSCO's service area. For the last several years, NIPSCO has supported a "JA Day" in a local Hammond school.

- **City of Gary Summer of Opportunity Job Program:** The Summer of Opportunity places youth in meaningful work opportunities throughout the City of Gary, with Lunch & Learn workshops featuring local professionals with every other session focusing on financial literacy. Local youth staff six summer program sites that offer summer meals and learning. Mayor Karen Freeman-Wilson, NIPSCO, Gary Youth Services Bureau, Urban League of NWI and the Gary Chamber of Commerce have partnered to create a set of supports that enable strong transitions from school year to school year and from high school to college and career.

- **Girl Scouts Engineering Day:** For more than 5 years, NIPSCO has hosted more than 125 girls from kindergarten to fourth grade for the annual Introduce a Girl to Engineering Day. The girls come from local Girl Scout troops along with some young relatives of NIPSCO and NiSource employees. The four hour event is part of the company’s efforts to help build the next generation of female leaders, support local communities and provide opportunities for local students interested in Stem related careers. The event was organized by the employee resource group Developing and Advancing Women at NiSource (DAWN).

10.3.4 Corporate Citizenship

NIPSCO believes that reinvesting in the communities where its employees live and work will enhance the quality of life for everyone. Each year, NIPSCO and its employees donate time, money, and other resources to hundreds of local philanthropic programs and organizations across its 30-county service area, focusing on:

- Basic Human Needs
- Education
- Public Safety & Emergency Response
- Environmental Stewardship

- Economic Development

Through these programs and partnerships, NIPSCO is working hard with its communities to build a brighter future for years to come. In 2017, NIPSCO and the NiSource Charitable Foundation contributed more than $1.78 million to local organizations throughout its service territory.

A highlight of those effort is NIPSCO's annual Charity of Choice campaign, where employees select one nonprofit organization or an area of need to support. Fundraisers, volunteerism and other activities are planned throughout a summer-long, employee-led campaign. Recent benefactors and causes selected by employees have included autism, veterans, Boys and Girls Clubs, the American Heart Association, the American Red Cross and more.

10.3.5 Volunteerism

NIPSCO employees have a passion for volunteering and giving back to their local communities. Through a program called "Dollars for Doers," cultivated by NiSource, employees translate their community service into financial support for organizations they care about most. The program contributes up to $500 per employee to an organization in return for volunteer time. In 2017, NIPSCO employees contributed 5,535 volunteer hours, equating to $110,700 donated to charities of their choice. Additionally, NIPSCO employees volunteer their personal time and resources with more than 100 local nonprofit boards, associations and other local community efforts each year.

List of Appendices

Section 11. Compliance with Proposed Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(d) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents: (1) The integrated resource plan.	Submitted via email and hand delivery on October 31, 2018
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.	Confidential Appendix D
(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) the IRP public advisory process; and (vi) any additional details the commission staff may request. (B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	Executive Summary
(e) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following: (1) The name and address of each known entity considered by the utility to be an interested party. (2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information: (A) A general description of the subject matter of the submitted IRP. (B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 90 days of the IRP submittal.	Transmittal Letter

Rule	Section(s)
An interested party includes any business, organization, or customer that participated in the utility's previous public advisory process. A utility is not required to separately notify all of its customers. (3) A statement that the utility has served a copy of the documents submitted under subsection (d) above on the office of the consumer counselor.	
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) A municipally owned utility; (2) A cooperatively owned utility; and (3) A utility submitting an IRP under subsection 2(b) of this rule. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the commission, and its staff. (d) The utility retains full responsibility for the content of its IRP.	N/A
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable energy and non-energy benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and its rationale. (2) The utility is encouraged to hold additional meetings as appropriate. (3) The schedule for meetings shall be determined by the utility and shall:	Section 2.1, Appendix A

Rule	Section(s)
(A) be consistent with its internal IRP development schedule; and (B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP. (4) The utility or its designee shall: (A) chair the participation process (B) schedule meetings; and (C) develop and publish to its website agendas and relevant material for those meetings at least seven calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen calendar days following each meeting; (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility. (6) The utility shall take reasonable steps to notify its customers; the commission; and interested parties of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	
(a) The commission or its staff may host an annual technical conference to facilitate: (1) identifying contemporary issues; (2) identifying best practices to manage contemporary issues; and (3) instituting a standardized IRP format. (b) The agenda of the technical conference shall be set by the commission staff. Utilities and interested parties may request commission staff include specific contemporary issues and presenters. (c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed. The utility shall address the designated contemporary issues in its next IRP. In addition, prior to its next IRP the utility shall provide to interested parties either a discussion of the impacts of such issues on its IRP or describe how it has taken the contemporary issues into account.	N/A
(d) A utility shall address new issues raised in a contemporary issues technical conference if the contemporary issues technical conference occurred at least one (1) year prior to the submittal date of a utility's IRP.	Section 2.2.1
170 IAC 4-7-4: Integrated Resource Plan Contents	
An IRP must include the following:	

Rule	Section(s)
(1) At least a 20 year future period for a predicted or forecasted analysis.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.	Section 3.2 Section 3.3 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.8 Section 3.8 Section 3.9 Section 3.10 Section 3.11
(3) At least three alternative forecast scenarios of peak demand and energy usage in compliance with subsection 5(b) of this rule.	Section 3.11 Section 3.12
(4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.	Section 4.3 Section 4.4 Section 4.5 Section 5.1
(5) A description of possible alternative methods of meeting future demand for electric service in compliance with subsection 6(b) of this rule.	Section 5.1 Section 5.4
(6) The resource screening analysis and resource summary table required in subsection 7(a) of this rule.	Section 4.9 Confidential Appendix F
(7) The information and calculation of tests required for potential resources in compliance with subsections 7(b)-7(e) of this rule.	Confidential Appendix B
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.	Section 8.1 Section 8.3 Section 8.4 Section 8.5 Section 9.2 Section 9.3Appendix F
(9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(b) of this rule.	Section 9.2 Section 9.3
(10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.	Section 1.1 Section 9.4
(11) A discussion of the inputs; methods; and definitions used by the utility in the IRP.	Section 2 Section 3.2 Section 4.4 Section 4.9

Rule	Section(s)
	Section 5.1 Section 5.2 Section 5.5 Section 5.6 Section 7.3 Section 8.1 Section 8.2 Section 8.4 Section 9.2 Section 9.3Appendices A through D and Confidential Appendices J
(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 9(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of any adjustments made to the data. The data must be submitted with the IRP in a manipulable format.	Appendix D
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Section 3.2.1 See Note 1
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Section 3.2
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	See Note 2

Rule	Section(s)
(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 3.2 Section 5.2
(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.	Section 9 Section 6.2 Section 10.2.1 Section 10.2.2
(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Appendix A Appendix C
(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 4.1
(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.	Section 7.4
(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 7.3 Section 8.2.3
(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan.	Section 9.3 Section .2.3
(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources that are certain. Existing laws or policies continuing throughout at least some portion of the planning horizon with a high	Section 9.3

Rule	Section(s)
probability of expiration or repeal must be eliminated or altered when applicable. (C) Not include future resources, laws, or policies unless the utility receives stakeholder input on the inclusion and it meets the following conditions: (i) Future resources have obtained regulatory approvals. (ii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	
(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 9.3
(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) the limits of the utility's transmission use; (ii) the utility's assessment practices developed through experience and study; and (iii) operating restrictions and limitations particular to the utility.	Confidential Appendix F
(27) A list and description of the contemporary methods utilized by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	Section 2.2 Section 3.2 Section 8.1 Section 8.3 Section 8.4 Section 9.3 Appendix B Appendix C

Rule	Section(s)
(28) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Section 5.2 Appendix B
(29) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically in a manipulable format. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Section 3.1 Appendix C
(30) A summary of the utility's most recent public advisory process, including: (A) Key issues discussed. (B) How the utility responded to the issues (C) A description of how stakeholder input was used in developing the IRP.	Section 2.1 Appendix A
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 4.9 Section 5 Appendix B Confidential Appendix E
170 IAC 4-7-5: Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Section 3 Appendix C,
(2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.	Section 3.3 Section 3.4 Section 3.5

Rule	Section(s)
	Section 3.6 Section 3.7 Section 3.11
(3) Actual and weather normalized energy and demand levels.	Section 3.11
(4) A discussion of methods and processes used to weather normalize.	Section 3.10
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Section 3.11 Section 3.12
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes, rate classes, or both. (C) Firm wholesale power sales.	Section 3.13
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2
(8) Justification for the selected forecasting methodology.	Section 3
(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data, such as described in subdivision 4(10) of this rule.	No Response Needed
(b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices, including competition. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 3.12
(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process.	Section 3.2
170 IAC 4-7-6: Resource Assessment	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information:	Section **Error! Reference source not found.** Section 4.5

Rule	Section(s)
(1) The net dependable generating capacity of the system and each generating unit.	
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.9 Section 4.10 Section 9.1
(3) A fuel price forecast by generating unit.	Section 8.1.2
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	Section 4.4.1 Section 4.4.2 Section 4.4.3
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	Section 5.4 Section 6.1.6 Section 6.1.7 Section 6.1.8
(6) A discussion of DSM programs and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Section 3.2 Section 5.1 Section 5.6 Appendix B
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Innovative rate design as a resource in meeting future electric service requirements.	Section 5.2
(2) Demand-side resources, including Demand response programs, and Energy efficiency programs. For a demand-side resource identified in the IRP, the utility shall, include the following:	Section 5.2 Section 5.5 Appendix B

Rule	Section(s)
(A) A description of the program considered. (B) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to programs under consideration such as project life and seasonal operation. (C) The customer class or end-use, or both, affected by the program. (D) A participant bill impact projection and participation incentive to be provided in the program. (E) A projection of the program costs to be borne by the participant. (F) Estimated annual and lifetime energy (kWh) and demand (kW) savings per participant for each program. (G) The estimated program penetration rate and the basis of the estimate. (H) The estimated impact of a DSM program on the utility's load, generating capacity, and transmission and distribution requirements. (I) whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	See Note 3
(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including: (i) Size (MW). (ii) Utilized technology and fuel type. (iii) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Section 4.4 Section 4.5 Section 4.9
(4) transmission facilities as a resource including new projects, upgrades to transmission facilities, efficiency improvements, and smart grid technology.	Section 6.1.7 Section 6.1.8 Section 6.2
In analyzing transmission resources, the utility shall include the following: (A) A description of the timing, types of expansion, and alternative options considered.	Section 6.1.7 Section 6.1.8 Section 6.2
(B) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.7 Section 6.1.8

Rule	Section(s)
(C) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 6.1.3
(D) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Section 6.1.3
170 IAC 4-7-7: Selection of Resources	
(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 4.9 Section 5.3 Section 5.4
(b) The following information must be provided for a resource selected for further analysis: (1) A description of significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge. (2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan and the commission analysis to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	Confidential Appendix E
(c) For each DSM program analyzed under this section, the IRP must include one (1) or more of the following tests to evaluate the cost-effectiveness of the program. (1) Participant cost test. (2) Ratepayer impact measure. (3) Utility cost test. (4) Total resource cost test. (5) Other reasonable tests accepted by the commission.	Section 5.5 Appendix B
(d) A utility is not required to calculate a test result in a specific format.	N/A

Rule	Section(s)
(e) For each program in subsection (c), a utility must calculate the net present value of the program's impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the interest rate used in the net present value calculation.	Section 5.5 Appendix B
(f) For a test performed under subsection (c), an IRP must: (1) specify the components of the benefit and the cost for the test; and (2) identify the equation used to calculate the result.	Appendix B
(g) If a reasonable cost-effectiveness analysis for a program cannot be performed using the tests in subsection (c), because it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	N/A
(h) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios. In selecting the candidate resource portfolios, the utility shall consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Section 8.3
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential futures. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s). (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2 Appendix D
(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Section 9.3
(2) Identification of the variables used.	Section 9.3

Rule	Section(s)
(3) Identification of the standards of reliability.	Section 9.3
(4) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.3
(5) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 9.2.3
(6) An analysis showing the preferred resource portfolio utilizes, to the extent practical, all economical supply-side resources and demand-side resources as sources of new supply.	Section 9.3
(7) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten years of the planning period.	Section 5.3 Appendix B
(8) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Section 9.3.3 Confidential Appendix E
(9) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (x) operating costs; (v) construction costs; (vi) resource performance;	Section 9.3

Rule	Section(s)
(vii) load requirements; (viii) wholesale electricity and transmission prices; (ix) RTO requirements; and (x) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(10) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including the following changes: (A) The demand for electric service. (B) The cost of a new supply-side resources or demand-side resources.. (C) Regulatory compliance requirements and costs. (D) Changes in wholesale market conditions. (E) Changes in fuel costs. (F) Changes in environmental compliance costs. (G) Changes in technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Section 9.3
(11) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 2.2
170 IAC 4-7-9: Short Term Action Plan	
(a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. (b) The short term action plan must include, but is not limited to, the following: (1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio.	Section 1.1 Section 9.4

Rule	Section(s)
(B) The criteria for measuring progress toward the objective. (2) Identification of energy efficiency goals for implementation of energy efficiency that can be produced by reasonably achievable, cost effective plans developed in accordance with 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives. (3) The implementation schedule for the preferred resource portfolio. (4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	

Note 1: NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumption patterns by DSM program. The savings associated with DSM programs are gauged and claimed based on various technical resource manuals ("TRMs"), including the Indiana TRM, and the DSM programs are evaluated by program year by a third party EM&V administrator. NIPSCO will continue to consider its options. NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumptions patterns by end use.

Note 2: As part of its DSM functions, DSM programs are evaluated by program year by a third party EM&V administrator. As part of the EM&V process, the administrator surveys a sample of customers who have and have not participated in NIPSCO's DSM program. NIPSCO is currently conducting a MPS that will include primary data. In addition, NIPSCO has previously completed lighting and market effect studies. NIPSCO is considering using customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns as part of its updated MPS.

Note 3: Customer bill impacts are calculated directly utilizing the customer rate and the savings of each measure/participant. Appropriate escalators and discount rates are used to determine the NPV of these savings and then Aggregated across all measures/participants. Incentives are also included in the cost benefit analysis as an input on a per participant/measure basis. Appropriate escalators and discount rates are applied and the NPV calculated.

Appendix A

Exhibit 1

NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting One

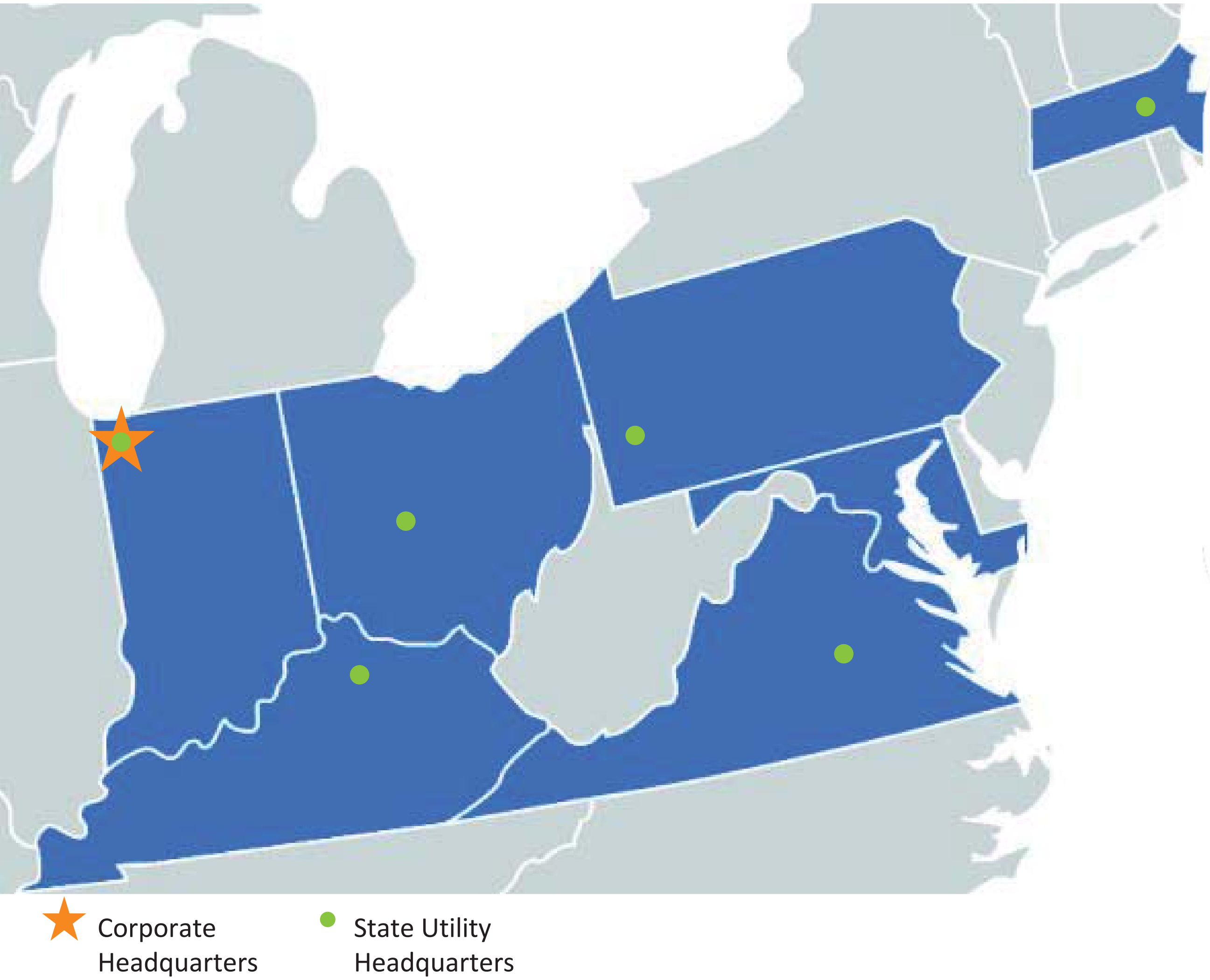
March 23, 2018

- **Welcome**
- **Introductions**
- **Safety Moment**
- **Purpose of Today**
  - Why is NIPSCO doing an update to its Integrated Resource Plan?
  - How has the process improved since 2016?
  - Provide key drivers, data
  - Provide information regarding a request for proposal for new capacity
  - Discuss the Public Advisory Process and start to get your input and feedback

Agenda

Time	Topic
9:00-9:30	Welcome and Introductions
9:30-10:15	Why a 2018 IRP Update/Improvements from 2016 Plan
10:15-10:30	Break
10:30-11:15	Modeling Approach for 2018 IRP
11:15-12:00	Key Assumptions in the 2018 IRP-Part 1
12:00-12:45	Lunch
12:45-1:15	Key Assumptions in the 2018 IRP-Part 2
1:15-1:30	Demand Side Management and the 2018 IRP
1:30-1:45	Break
1:45-2:00	Request for Proposal for Capacity
2:00-2:20	Stakeholder Presentations
2:20-2:25	2018 Public Advisory Process
2:25-2:30	Wrap Up

One of the Nation's Largest Natural Gas Distribution Companies



- 7-state footprint
- ~7,500 employees
- ~3.5M natural gas utility customers
- ~500K electric utility customers

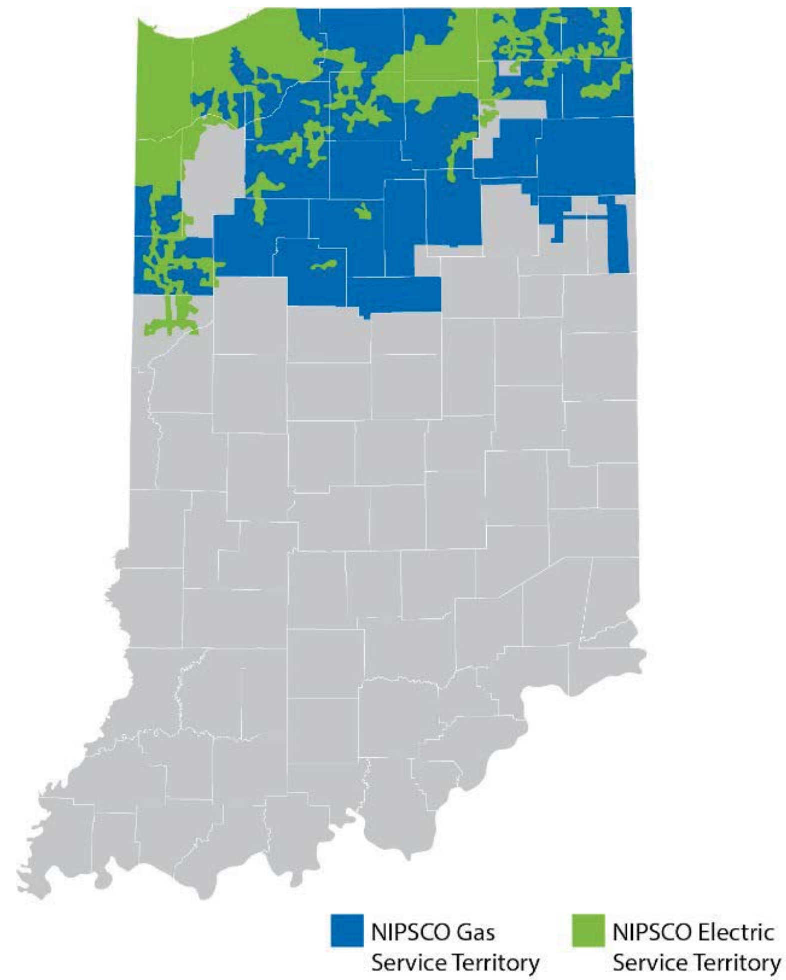
Columbia Gas
NIPSCO

Electric

- 468,000 electric customers in 20 counties
- ~3,400 MW generating capacity*
  - Operates 6 electric generating facilities (3 coal, 1 natural gas, 2 hydro)
  - Additional 100 MW of wind purchased power
- 12,800 miles of transmission and distribution
  - Interconnect with 5 major utilities (3 MISO; 2 PJM)
  - Serves 2 network customers and other independent power producers

Gas

- 819,000 natural gas customers in 32 counties
- 17,000 miles of transmission and distribution lines
- Interconnections with 7 major interstate pipelines
- 2 on-system storage facilities



2,900
Employees

Merrillville, Ind.
Headquarters

*Post Bailly retirements in May 2018, NIPSCO will have ~2900 MW of generating capacity and two coal generating facilities

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3* (July 24th)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	-Why has NIPSCO decided to file an IRP update in 2018? -What has changed from the 2016 IRP? -What are the key assumptions driving the 2018 IRP update? -How is the 2018 IRP process different from 2016?	-What is NIPSCO existing generation portfolio and what are the future supply needs? -Are there any new developments on retirements? -What are the key environmental considerations for the IRP? -How are DSM resources considered in the IRP?	-What are the preliminary results from the all source RFP Solicitation?	-What are the preliminary findings from the modeling?	-What is NIPSCO's preferred plan? -What is the short term action plan?
Meeting Goals	-Communicate and explain the rationale and decision to file in 2018 -Articulate the key assumptions that will be used in the IRP -Explain the major changes from the 2016 IRP -Communicate the 2018 process, timing and input sought from stakeholders	-Common understanding of DSM resources as a component of the IRP -Common understanding of DSM modeling methodology -Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap -Key environmental issues in the IRP	-Communicate the preliminary results of the RFP and next steps	-Stakeholder feedback and shared understanding of the modeling and preliminary results -Review stakeholder modeling and analysis requests	-Communicate NIPSCO's preferred resource plan and short term action plan -Obtain feedback from stakeholders on preferred plan

**Webinar*

- **Your input is critical to the process**
- **Today's meeting is the first of five meetings**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data and helps inform the modeling process**
  - It also serves as a "check" on the modeling process as results are received
- **This improves the Integrated Resource Plan and its results**
- **Your candid and on-going feedback is key**
  - Please ask questions and make comments!
  - Ability to make presentations as part of each Public Advisory Meeting
    - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch
- **Please provide feedback on the process itself as NIPSCO wants to continue to make this valuable for you as well as the Company**

Dan Douglas

Vice President Corporate Strategy & Development

2016 NIPSCO IRP Preferred Plan

Current Resources

Retire
- Bailly Unit 7 and 8 by May 2018
- Schahfer Units 17 and 18 by 2023

Comply
- Invest in environmental compliance (CCR and ELG) for Schahfer Units 14,15 and Michigan City 12

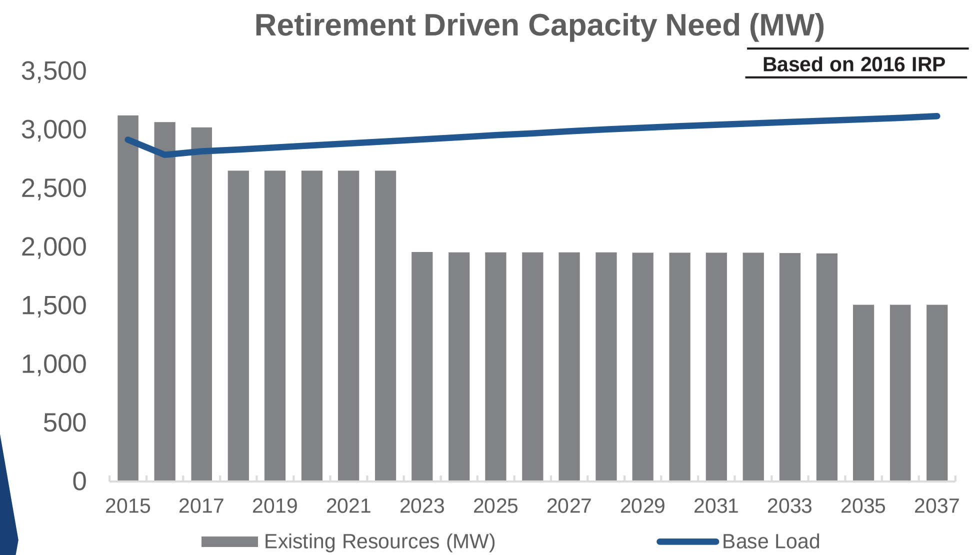
Maintain
- All gas fired units; Sugar Creek CCGT, Schahfer Units 16A&B and Bailly 10 Combustion Turbines
- Industrial interruptibles program
- Wind Power Purchase Agreements

Future Resource Need

Short-Term (2018-2022)
- Rely on existing resources
- File DSM/EE program action plans
- Fill capacity gaps with MISO procurement and or PPA

Long-Term (2023+)
- Combined Cycle Gas Turbine (CCGT) as a long term generation solution in 2023 and 2035
- Monitor MISO market fundamentals, capacity pricing and contract resource pricing

2018 NIPSCO IRP Update



Driver and Rationale for 2018 Update

- Preserve NIPSCO's ability to fully consider all resource options to address the capacity need
- Examine the remaining coal units (Schahfer 14,15,17,18 and Michigan City 12) in light of upcoming ELG compliance expenditures

Subject	2016 IRP Feedback	2018 Improvement Plan
Commodity Price Forecasts	• "NIPSCO's assumption doesn't capture the nuanced and dynamic relationships between oil and natural gas markets or whether the historic correlations between natural gas and coal markets are changing" • "Given the importance of fuel forecasts in retirement decisions that are a focal point of this IRP, it is surprising that NIPSCO only relied on one projection for fuel prices" • No transparency and availability of underlying assumptions for fuel forecasts	• Utilizing independently generated commodity price forecasts using an integrated market model • Providing transparent assumptions related to key inputs and outputs • Benchmarking against publicly available forecasts
Scenarios and Sensitivities	• "NIPSCO's construction of scenarios and sensitivities in the 2016-2017 IRP is a significant advancement over the 2014 IRP. The clarity of the narratives was commendable and transparency was exceptional"	• Building upon the progress made in the 2016 IRP with the same scenarios or thematic "states of the world" to develop portfolios and inform risk analysis
Risk Modeling	• "NIPSCO's planning model is not capable of stochastic analyses so it relied on scenario analyses and sensitivity analyses in preparing its IRP"	• Implementing efficient risk informed (stochastics) analysis with the ability to flex key variables

Source: Final DIRECTOR'S REPORT for the 2016 Integrated Resource Plans, November 2, 2017

Subject	2016 IRP Feedback	2018 Improvement Plan
Capital Cost Assumptions	• Capital cost estimates for new capacity resources were based on proprietary consultant information • "…No scenario or sensitivity covered uncertainties of resource technology cost"	• Leveraging 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources • Conducting an "all-source" Request for Proposal solicitation for replacement capacity resources
DSM Modeling	• DSM groupings are not getting quite the same treatment as the supply side resources	• Utilizing new modeling capabilities will enable DSM to be treated equally with other supply side resources
Preferred Plan and Scorecard	• "The lack of basic information about the Preferred Plan, combined with the poor discussion relating the Preferred Plan to the IRP's analyses and metrics, makes any evaluation of the Preferred Portfolio problematic at best" • "The score card would benefit from a more detailed narrative to detail those metrics that can be quantified as well as those metrics that do not lend themselves to quantification"	• Providing detailed analysis on selection of the Preferred Plan driven by need for it to be actionable • Developing enhanced scorecard methodology to include more quantifiable metrics that better evaluate tradeoffs • Incorporating rate impact analysis as part of preferred plan metrics

Source: Final DIRECTOR'S REPORT for the 2016 Integrated Resource Plans, November 2, 2017

Jim McMahon & Pat Augustine
Charles River Associates (CRA)

Fundamental Commodity Price Forecasting

- Fundamentally driven, transparent long-term price forecasts
- Forecasts for the following products:
  - Power & fuels: natural gas and coal, including fuel basis and transport
  - MISO energy and capacity prices

Integrated Resource Planning

- Scorecard development
- Portfolio development
- Risk informed portfolio analysis (stochastics)
- Retail rate forecasting
- Tradeoff analysis
- Stakeholder engagement

Overview Of Resource Planning Approach

1 Identify key objectives and metrics

2 Develop market perspectives (planning reference case and scenarios)

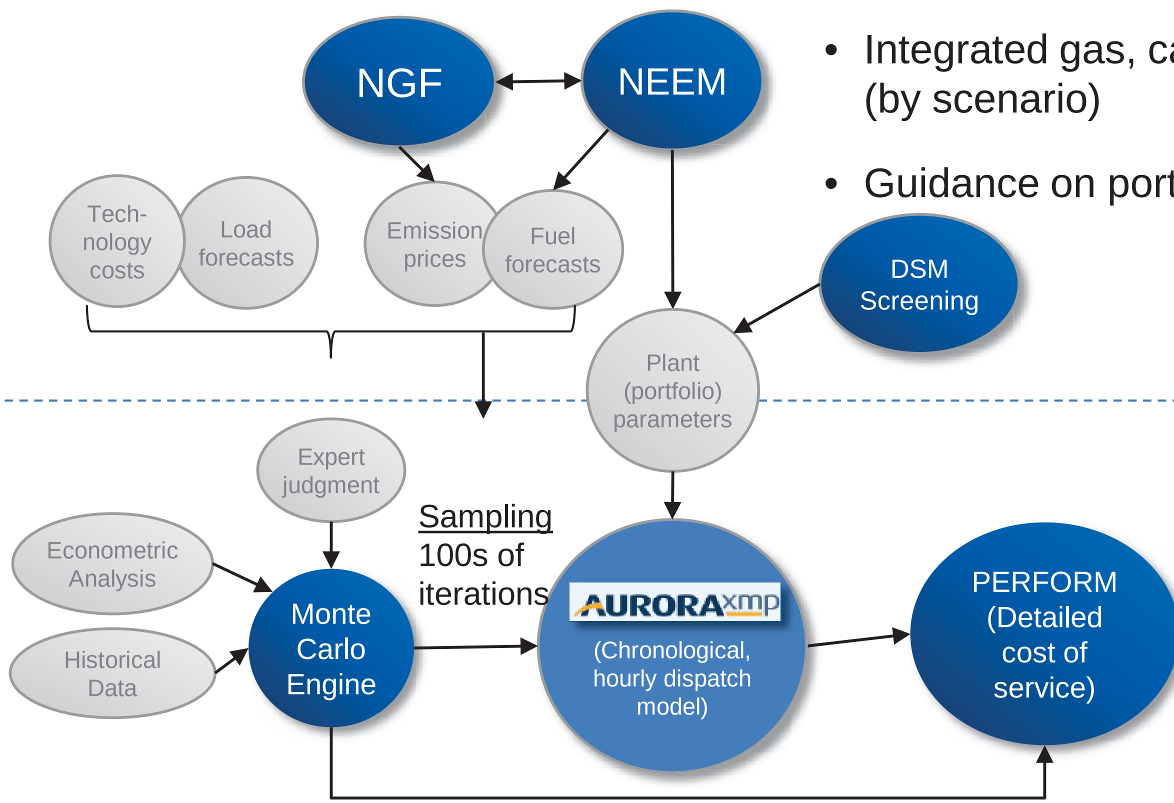
3 Develop integrated resource strategies for NIPSCO (portfolios)

4 Portfolio modeling
- Detailed scenario dispatch
- Stochastic simulations

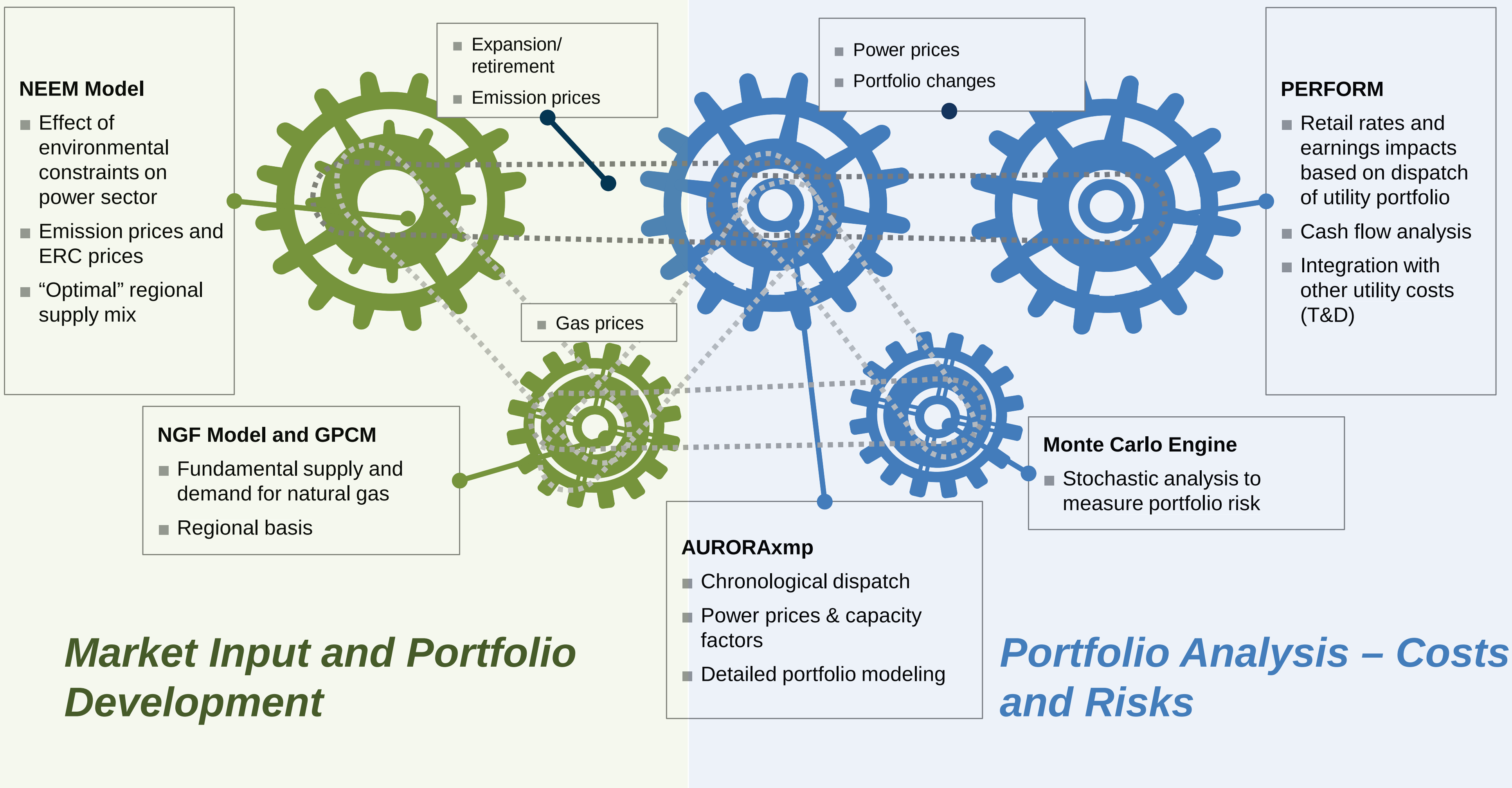
5 Evaluate tradeoffs and produce recommendation

This year's process will be structurally similar to NIPSCO's 2016 IRP process, but with changes and enhancements to respond to stakeholder feedback.

- Integrated gas, carbon forecasts (by scenario)
- Guidance on portfolio options



Environmental, Power Market and Financial Models



- **NGF optimizes production at natural gas basins throughout the US, providing the lowest cost solution based on the costs and performance characteristics of shale and other production basins, for meeting future gas demand**
- **NGF is integrated with NEEM, which provides electric and non-electric sector gas demand for a given price**

Gas Supply

- Total resource in place, proved and unproven
- Resource growth over time
- Wet / dry product distribution
- Historic wells drilled and ongoing production
- Conventional & associated production
- Existing tight and CBM
- Existing offshore production

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- First year initial production rate
- Changing drilling and production efficiencies
- Productivity decline curve
- Well lifetime
- Distribution of performance

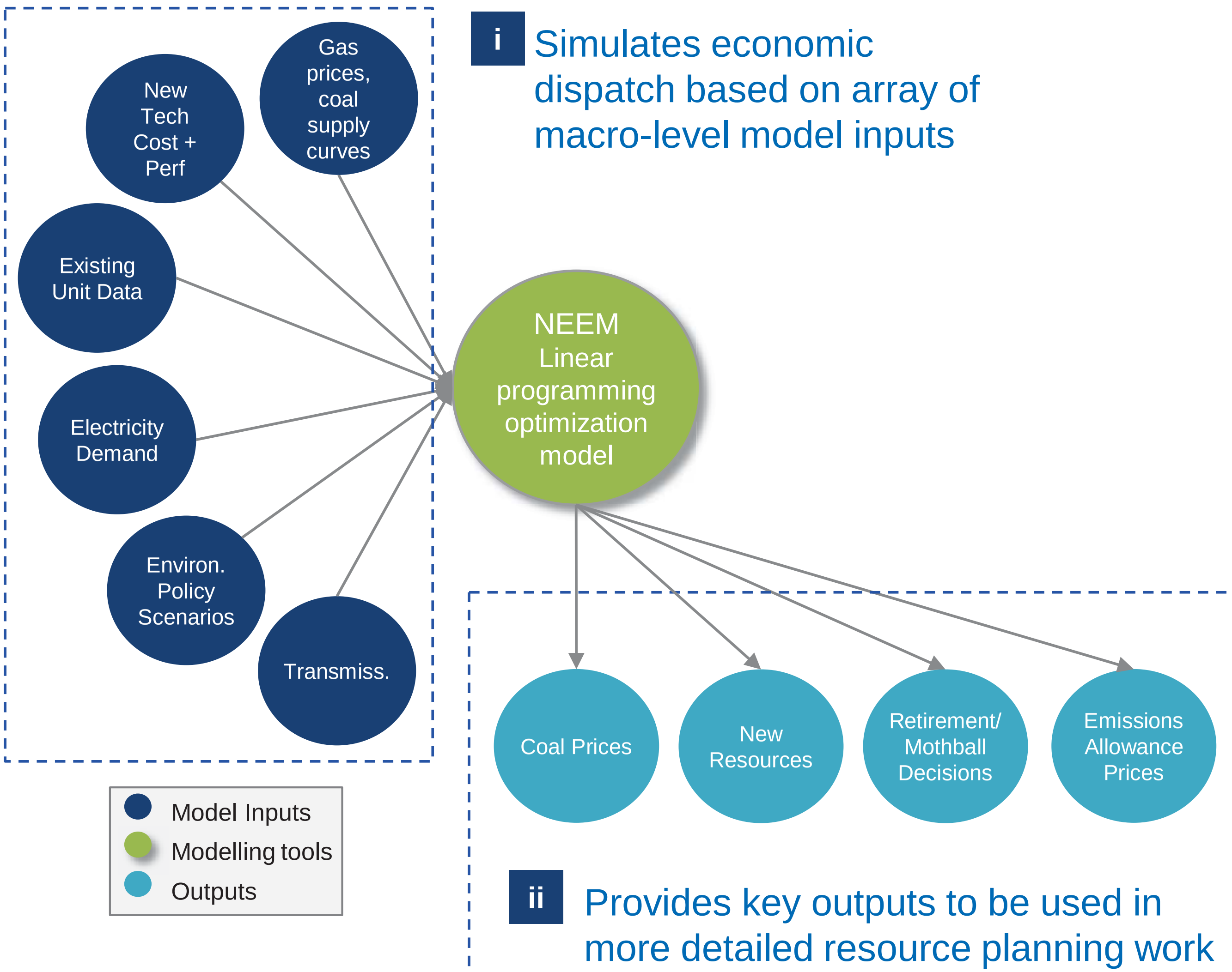
Gas Demand

- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)

Other Market Drivers

- Value of NGL / condensates
- Natural gas storage

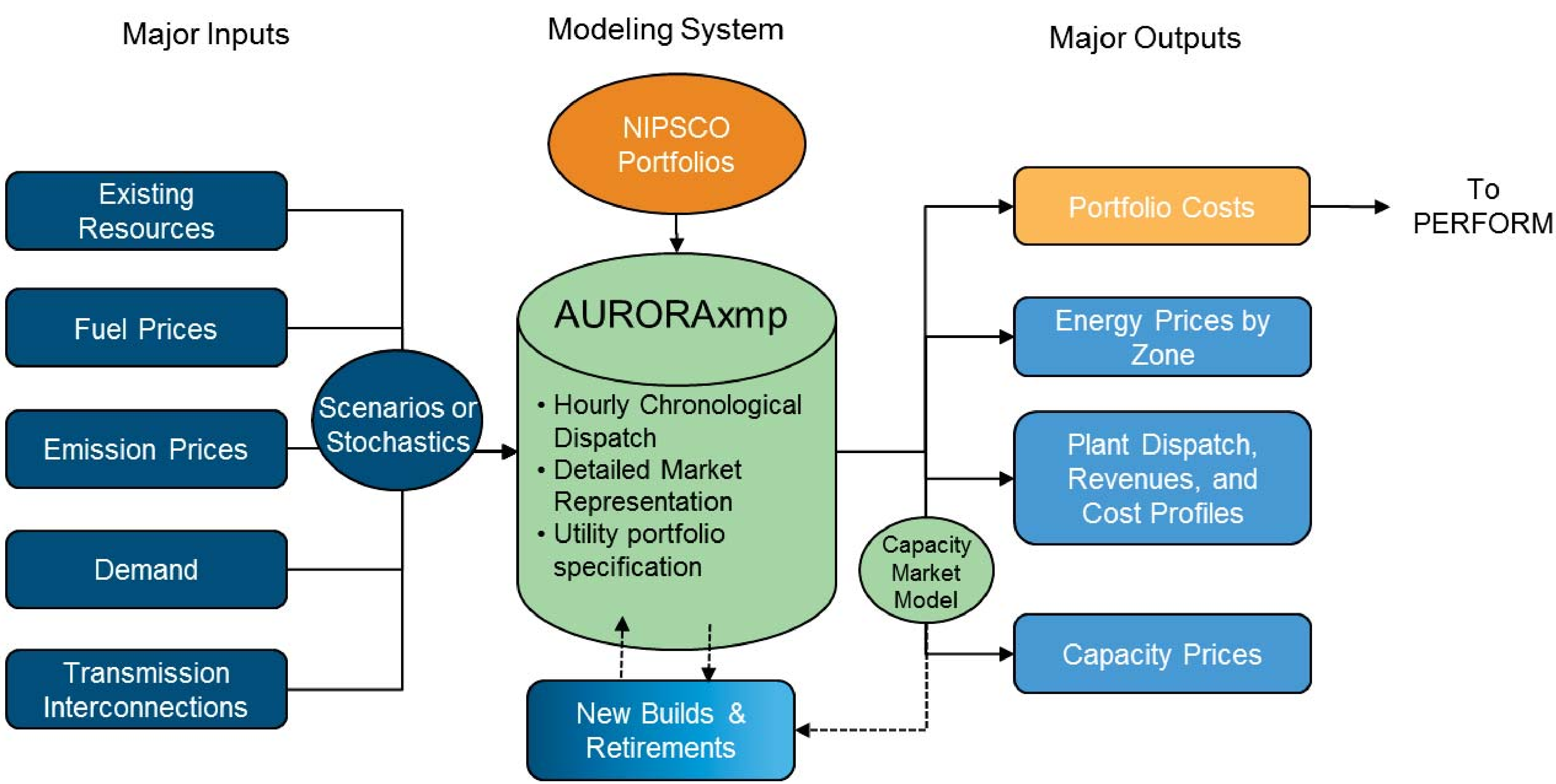
CRA continuously enhances NGF to reflect changes in key gas market drivers



CRA's NEEM Market Model:

- Minimizes the present value of incremental costs to the electric sector, while meeting demand and complying with environmental limits
- Its inputs include:
  - Technology cost assumptions
  - Operational parameters
  - Fuel prices
  - Electricity demand
  - Emission caps
  - Renewable portfolio standards
- Provides output such as coal prices by basin, new electric resource build pattern, retirement and mothball decisions, emissions and allowance prices

CRA Power Market Modeling Process



Data Collection

Portfolio Fixed Costs
- New additions / retirements (by portfolio)
- Technology costs
- Capital forecasts
- OpEx forecasts
- Load growth forecasts
- Specific investments
- Financial assumptions (WACC)

Portfolio Variable Costs
- Portfolio dispatch and associated power supply costs from Aurora analysis

Scenario/ Stochastic Analysis
- Flexibility to run scenarios/stochastics on capital, fuel, power, dispatch, etc.
- Rapid analysis of multiple portfolio options

PERFORM Model

Financial Module
- Cost of service calculation
- Detailed treatment of tax depreciation
- Asset-specific summaries

Outputs

NPVRR
- Summaries of net present value of revenue requirements
- NPV summaries by component

Retail Rate Forecast
- Forecast of generation rate (average) is possible
- Rate forecast based on perfect ratemaking assumptions (not intended to forecast specific rates by year or class)

Risk Analysis
- Scenarios or stochastic illustrate potential risk around retail rate forecast or NPVRR

Scenario and stochastic approaches often address different questions, but can be used together to perform a robust assessment of risk

Scenarios
Single, Integrated Set of Assumptions

- **Can be used to answer the "What if…" questions**
  - Major events can change fundamental outlook for key drivers, altering portfolio performance
    - New policy or regulation (carbon regulation)
    - Fundamental gas price change (change in resource base, production costs, large shifts in demand)
    - Loss of a major industrial load
    - Technology cost breakthrough (storage)
- **Can tie portfolio performance directly to a "storyline"**
  - Easier to explain a specific reasoning why Portfolio A performs differently than Portfolio B

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate "tail risk" impacts**
  - Short-term price volatility impacts portfolio performance
    - Value of certain portfolio assets is dependent on market price volatility
    - Commodity price exposure risk is broader than single scenario ranges
- **Develops a rich dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
  - Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes
  - Can robustly calculate statistical metrics to evaluate 95^{th} percentile outcomes

- **As in the 2016 IRP* process, the first step is to identify major drivers of potential uncertainty which could influence IRP outcomes**
- **Then, develop future perspectives regarding major drivers**
- **Next, assess whether scenario or stochastic (or both) treatment is appropriate**

Uncertainty Driver	Stochastics	Scenarios	Comments
Fuel Prices	✓	✓	Robust sets of historical data can support statistical analysis on top of fundamental forecasts
Carbon Prices	✓	✓	Discrete scenarios can be probability-weighted and integrated with fuel/power forecasts
Power Prices	✓	✓	Robust sets of historical data can support statistical analysis on top of fundamental forecasts
Capital Costs	✓	✓	Broad uncertainty around technology change and future cost drivers can be parameterized through review of source data and expert opinion
Load		✓	Large risks relate to loss of major industrial load, which is a discrete event
Other Environ. Policy		✓	Policy shifts (ie, with ELG compliance) are best evaluated in discrete scenario fashion

***2016 IRP Drivers*: Load, Regulations, Environmental Compliance, Economy, Technology, Commodity Prices**

2018 Scenario Theme Development

As in the 2016 IRP, the 2018 IRP is using the same "scenarios" or thematic "states-of-the-world" under which to develop portfolios and to inform stochastic distributions

Base	Aggressive Environmental Regulation	Challenged Economy	Booming Economy & Abundant Natural Gas
• Reference case commodity price outlook, with 2026 carbon price • Reference case capital cost projections • Non-carbon environ. costs reflect only current and proposed regulations (ELG, CCR)	• High carbon price • Feedbacks to gas, coal, and power prices • Non-carbon environmental compliance costs are stricter • Tech. breakthrough for renewable /storage costs	• Low load, including loss of industrial load • No carbon price • Feedbacks to gas, coal, and power prices	• Low natural gas prices as a result of larger resource base • Feedbacks to coal and power prices • Cheap energy costs drive stronger economic growth and higher load
Likely implications for NIPSCO Portfolios	***More renewables, storage, and DSM; more coal retirements***	***Fewer renewables and DSM; better coal economics; fewer self-builds and more reliance on market***	***More gas CCGT, fewer renewables and DSM***

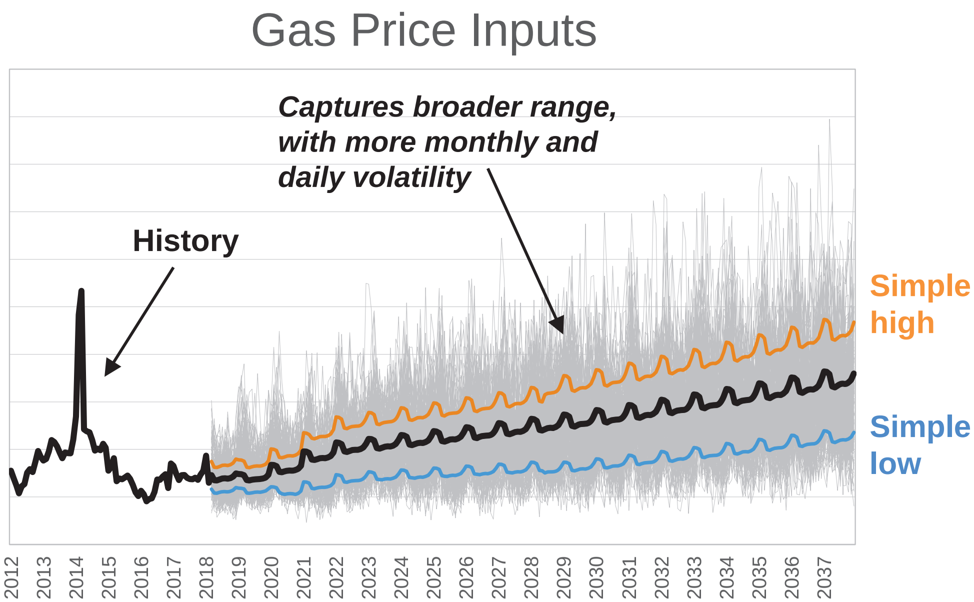
Each scenario will have a unique combination of key input variables and a fully integrated set of commodity market price forecasts

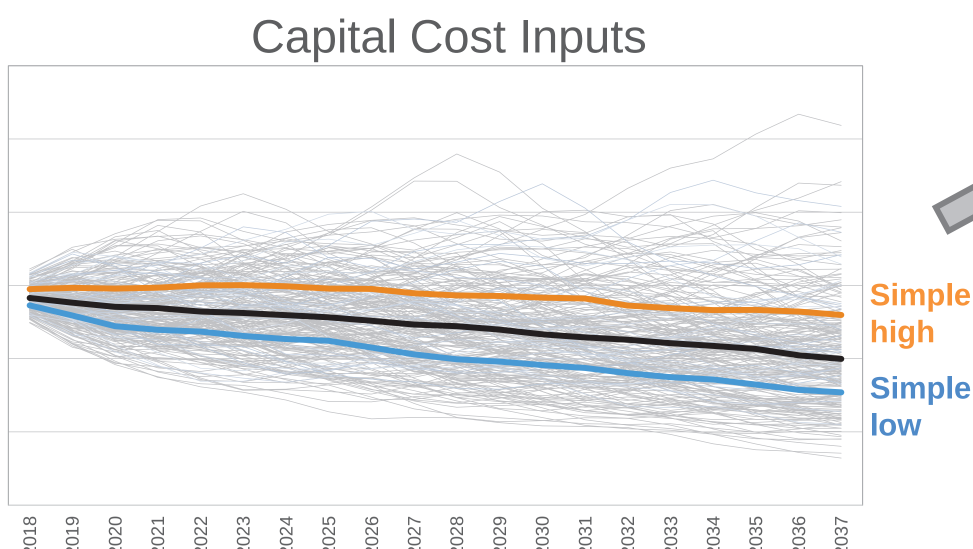
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Base	Base	Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High**	**Low**	**High**	**Low** renew./ sto.	**High**
Challenged Economy	**Low**	**Low**	**Low**	**High**	**Low**	Base	Base
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low**	**Low**	Base	Base

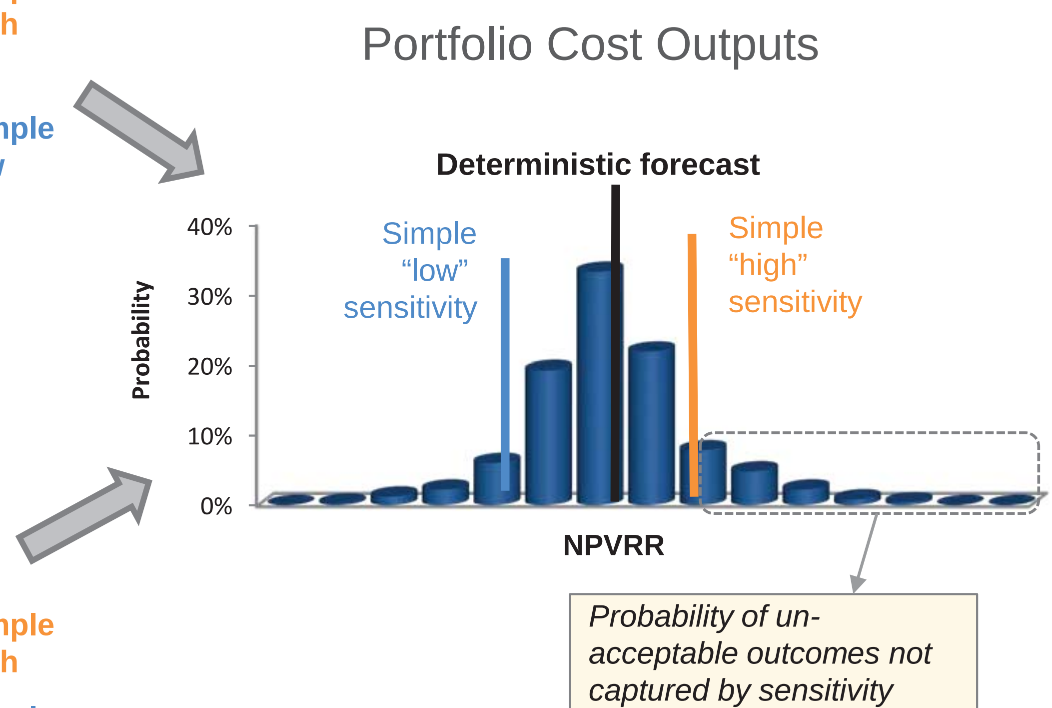
Develop All Scenario Details	• Specify key input parameters • Run models to develop integrated set of commodity price inputs and other major variables
Evaluate Favorable NIPSCO Portfolio Concepts for Each Scenario	• Run portfolio models to assess potential preferred plans under each scenario • Use expert judgment, where necessary, to establish reasonable portfolio strategies within the identified theme
Develop Stochastic Distributions	• Use scenario ranges to complement the statistically-based stochastic input development process (for example, to cover full range of fuel and power outcomes across carbon regimes)
Run All Portfolios across All Scenarios and Stochastics	• Evaluate *each* portfolio against all scenarios *and* against stochastic distributions for a rigorous review of risk profile

Stochastic Analysis Provides Improved Coverage Of Uncertainty

Stochastic distributions based on historical volatility, underlying correlations between inputs, and expert assessment of future ranges

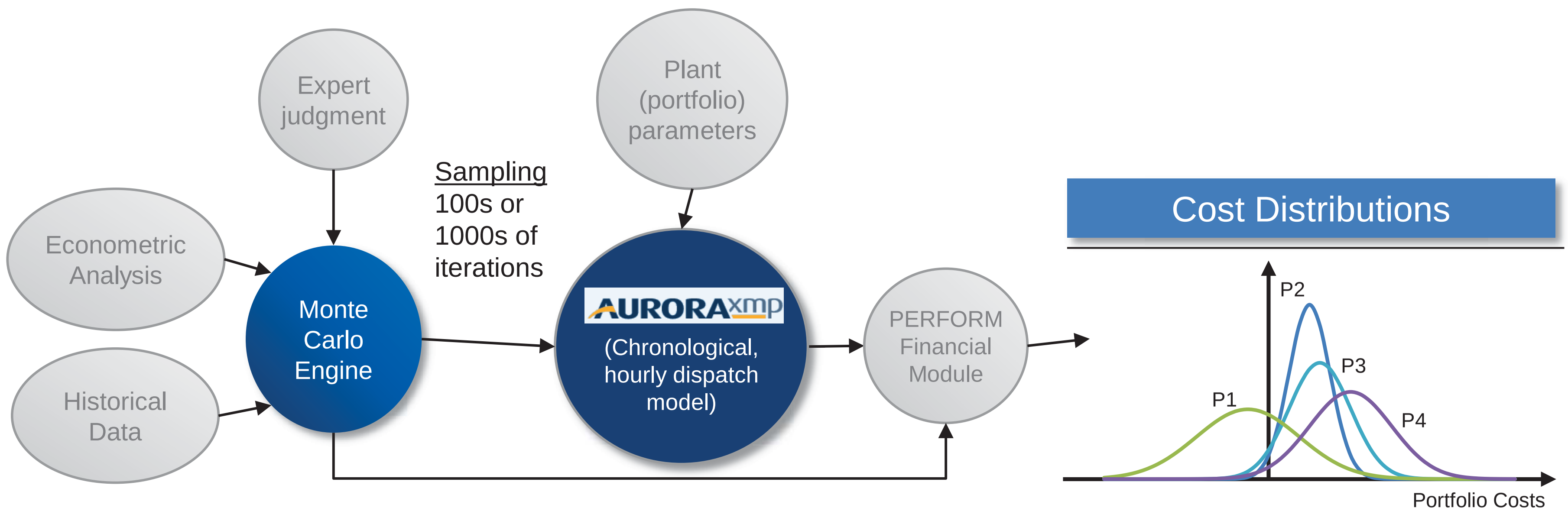






ILLUSTRATIVE

Scenario development exercise and historical data analysis support input development



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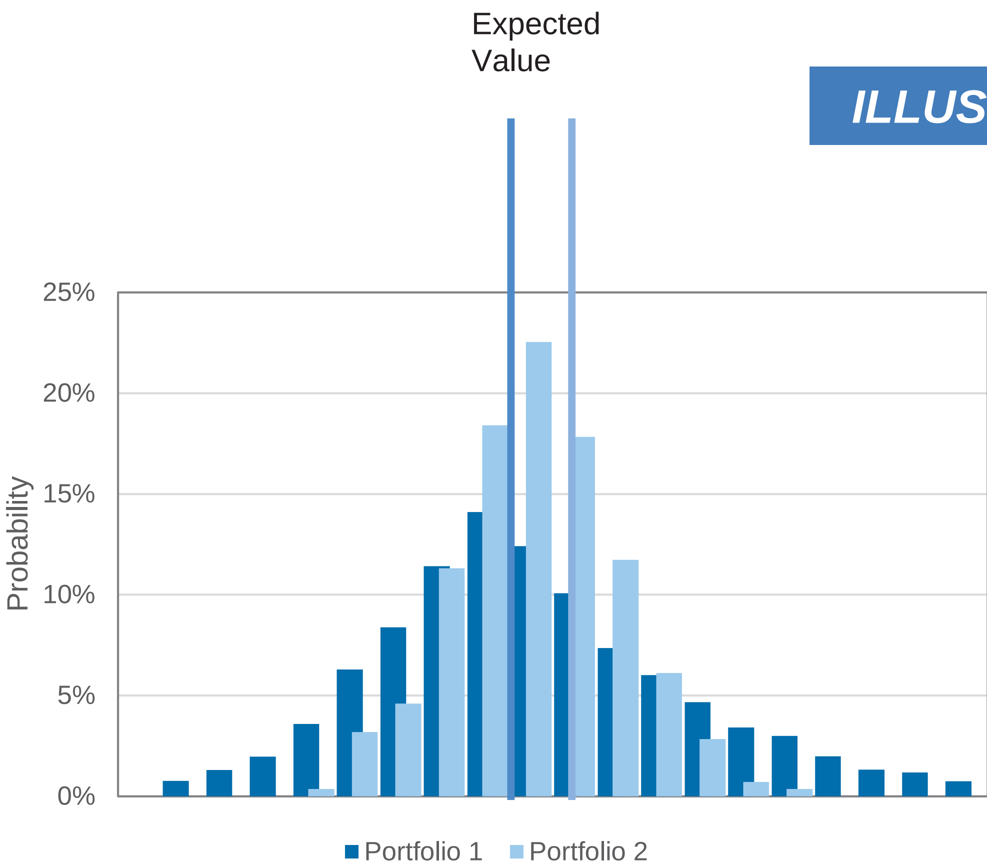

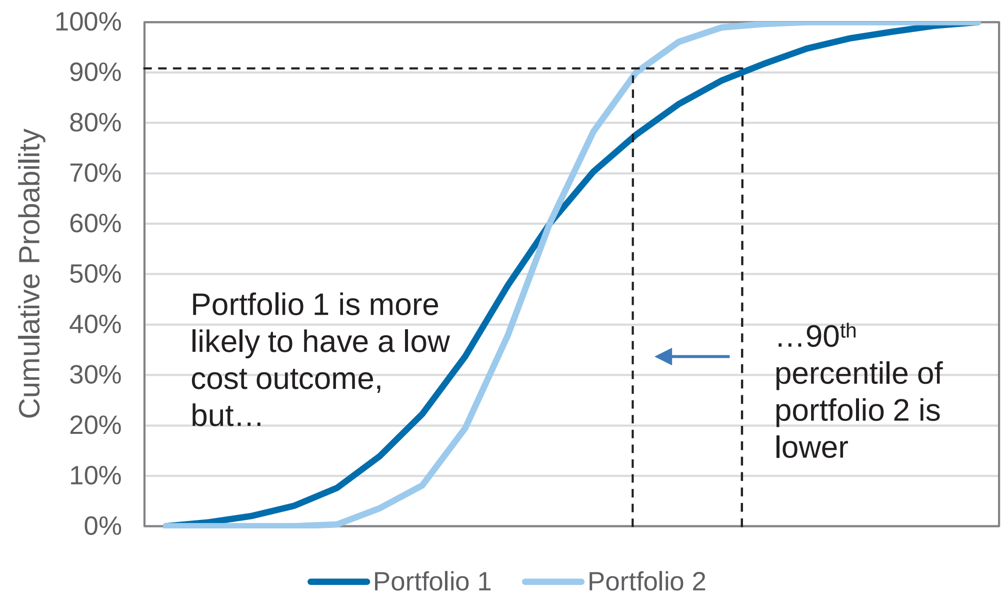

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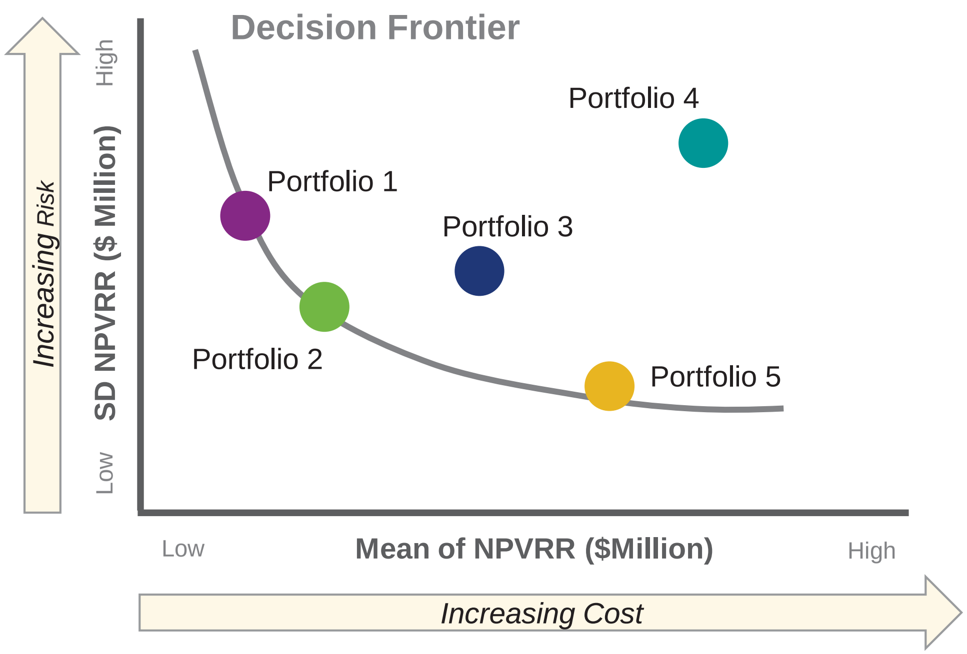
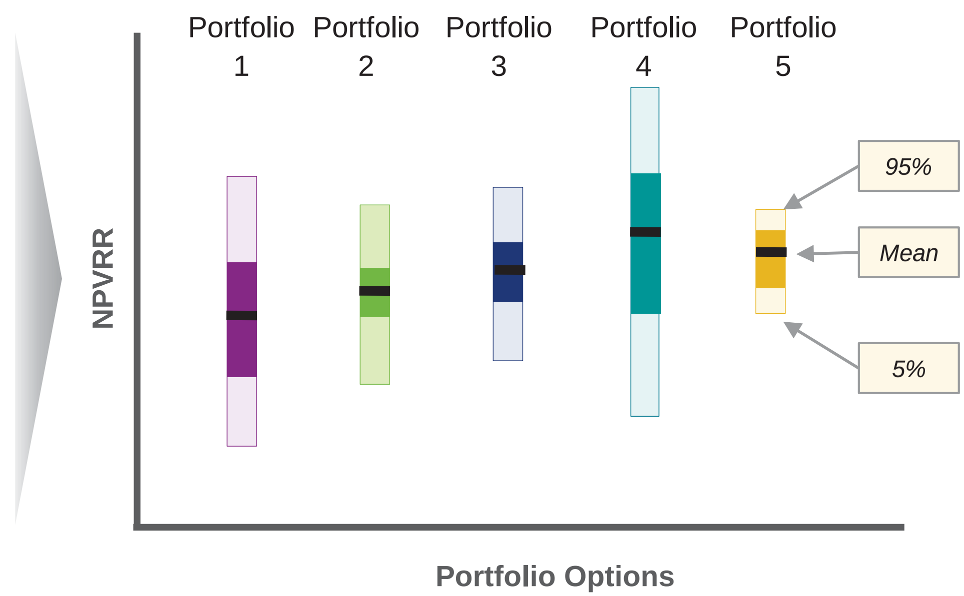
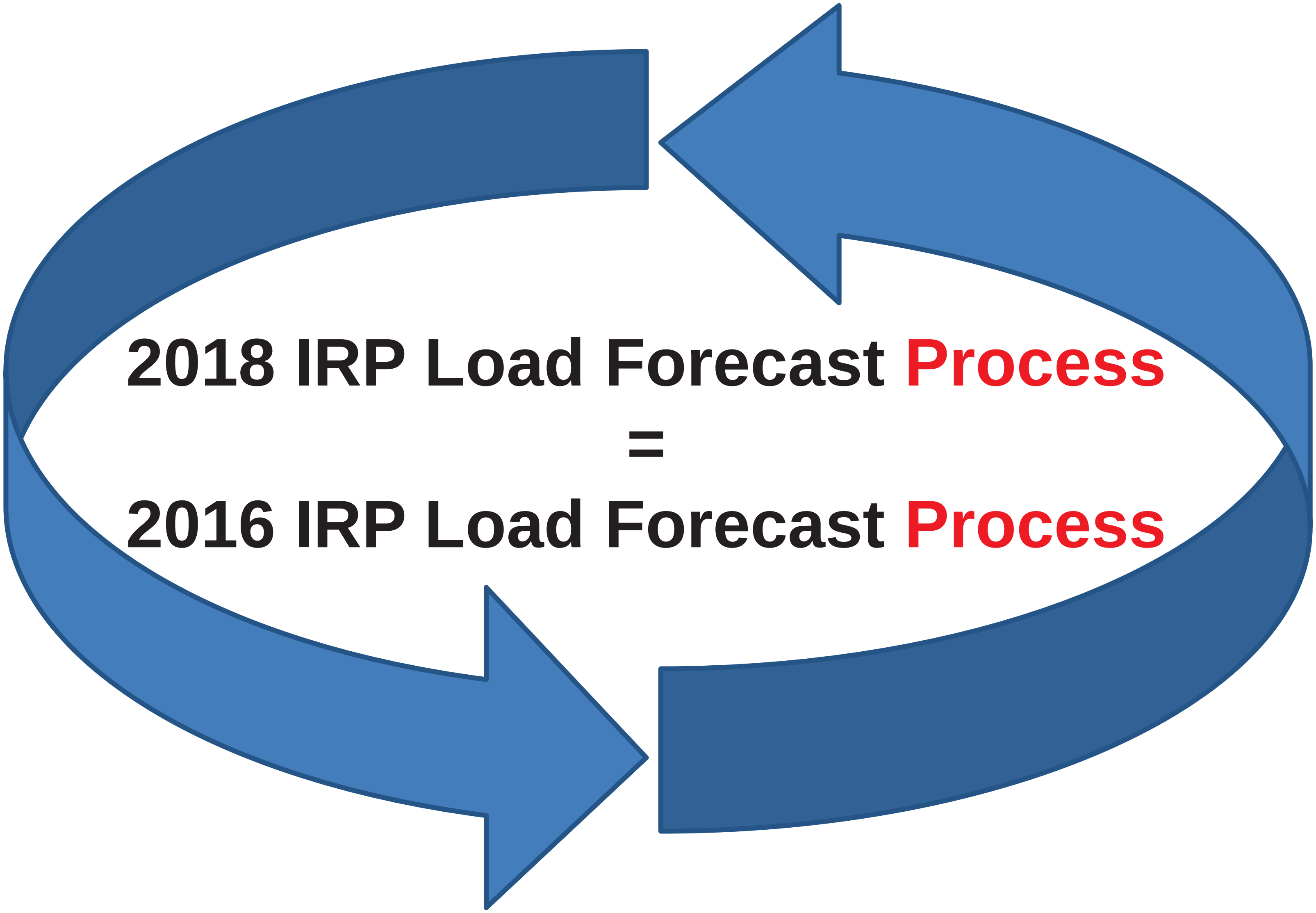


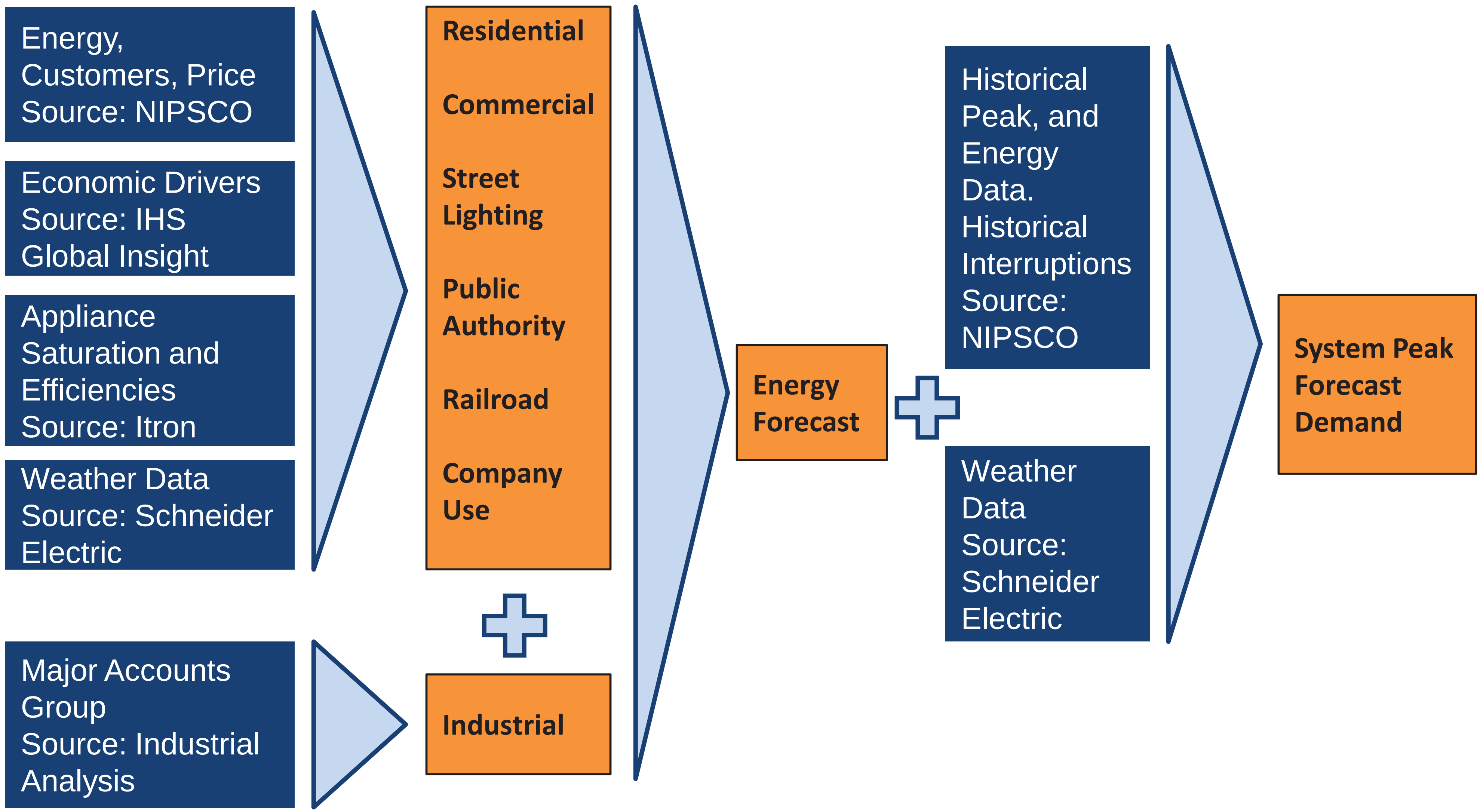


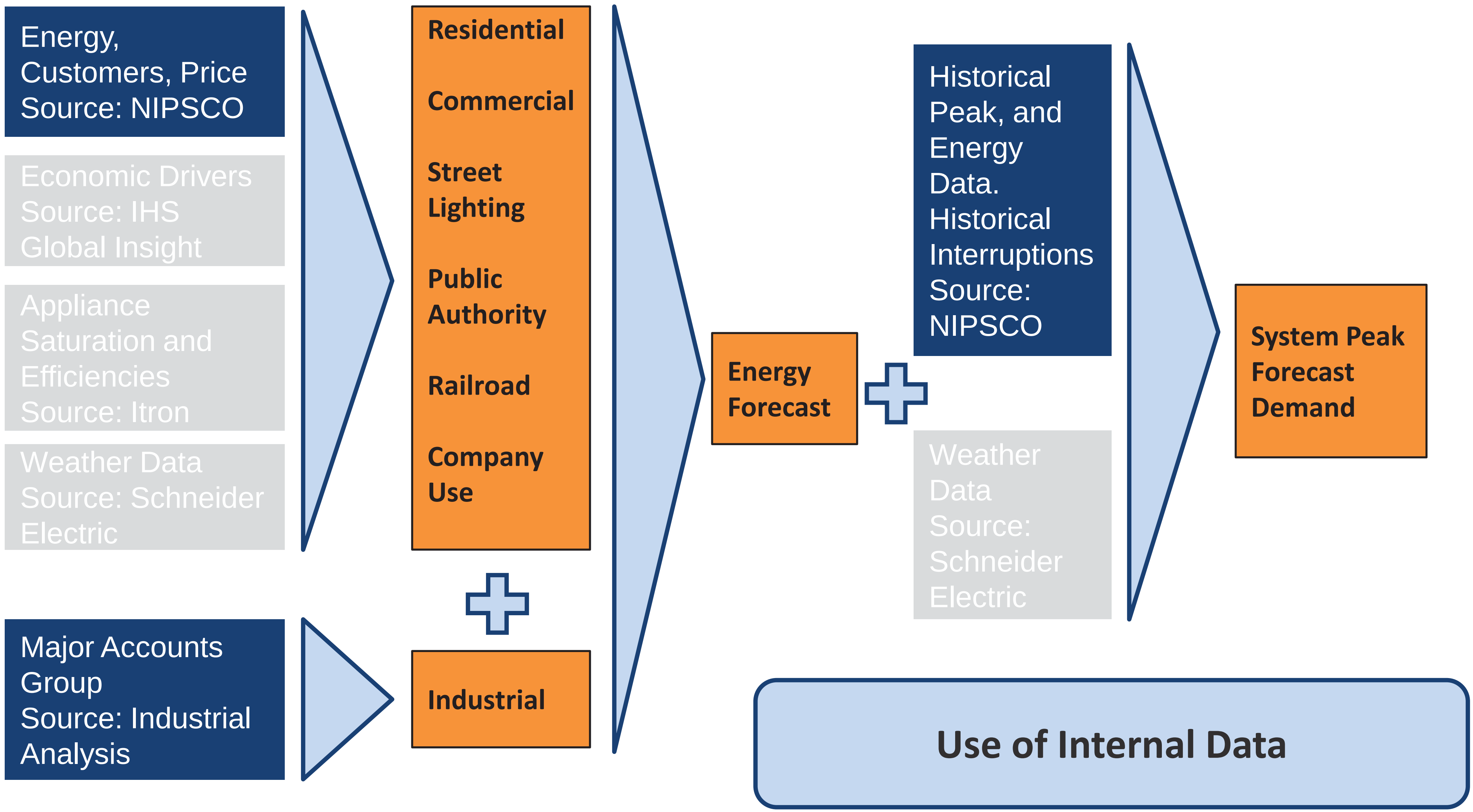
Long-Term Energy and Demand Forecast

Mahamadou Bikienga
Lead Forecasting Analyst

- Load Forecasting Process
- Residential Customer and Energy Forecast
- Commercial Customer and Energy Forecast
- Industrial Energy Forecast
- Other Energy Forecast
- Peak Forecast
- Load Forecast Outlook


2018 IRP Load Forecast Process
=
2016 IRP Load Forecast Process


Energy, Customers, Price Source: NIPSCO
Economic Drivers Source: IHS Global Insight
Appliance Saturation and Efficiencies Source: Itron
Weather Data Source: Schneider Electric
Major Accounts Group Source: Industrial Analysis
Residential
Commercial
Street Lighting
Public Authority
Railroad
Company Use
Industrial
Energy Forecast
Historical Peak, and Energy Data. Historical Interruptions Source: NIPSCO
Weather Data Source: Schneider Electric
System Peak Forecast Demand


Energy, Customers, Price Source: NIPSCO
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Historical Peak, and Energy Data. Historical Interruptions Source: NIPSCO
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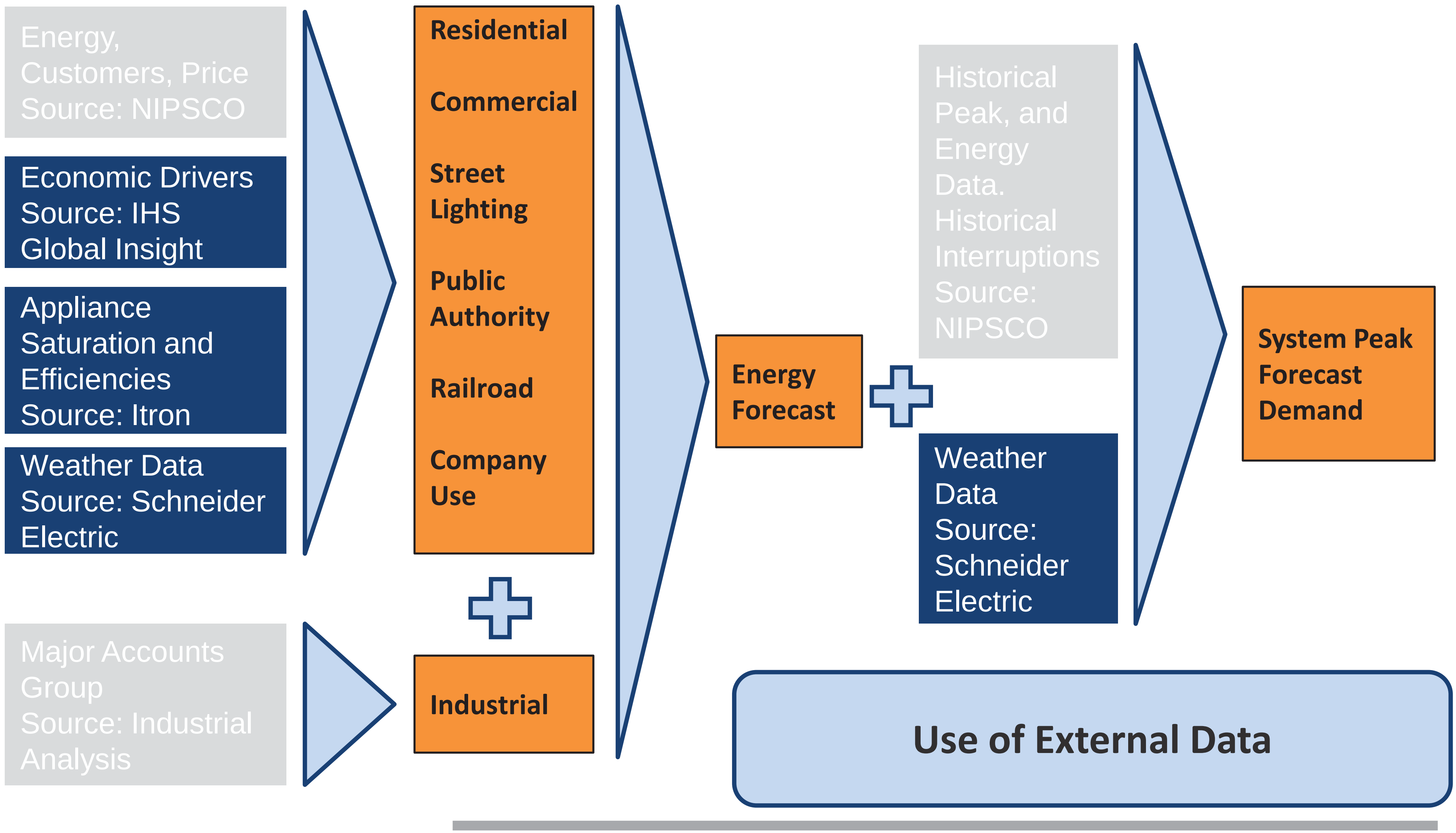
System Peak Forecast Demand
Use of Internal Data


Energy, Customers, Price Source: NIPSCO
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Residential
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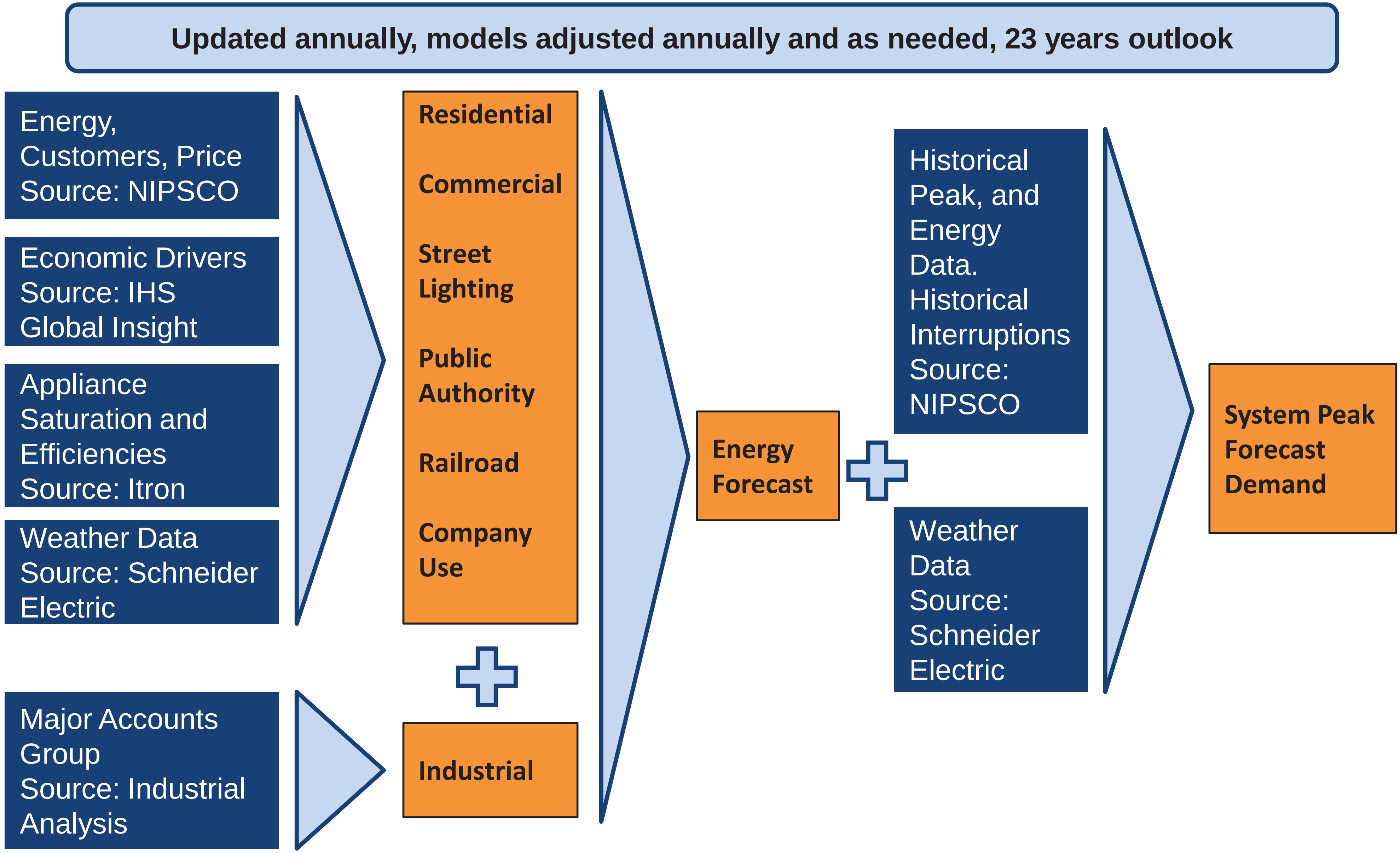
Energy Forecast
Historical Peak, and Energy Data. Historical Interruptions Source: NIPSCO
Weather Data Source: Schneider Electric
System Peak Forecast Demand
Use of External Data


Updated annually, models adjusted annually and as needed, 23 years outlook
Energy, Customers, Price Source: NIPSCO
Economic Drivers Source: IHS Global Insight
Appliance Saturation and Efficiencies Source: Itron
Weather Data Source: Schneider Electric
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Historical Peak, and Energy Data. Historical Interruptions Source: NIPSCO
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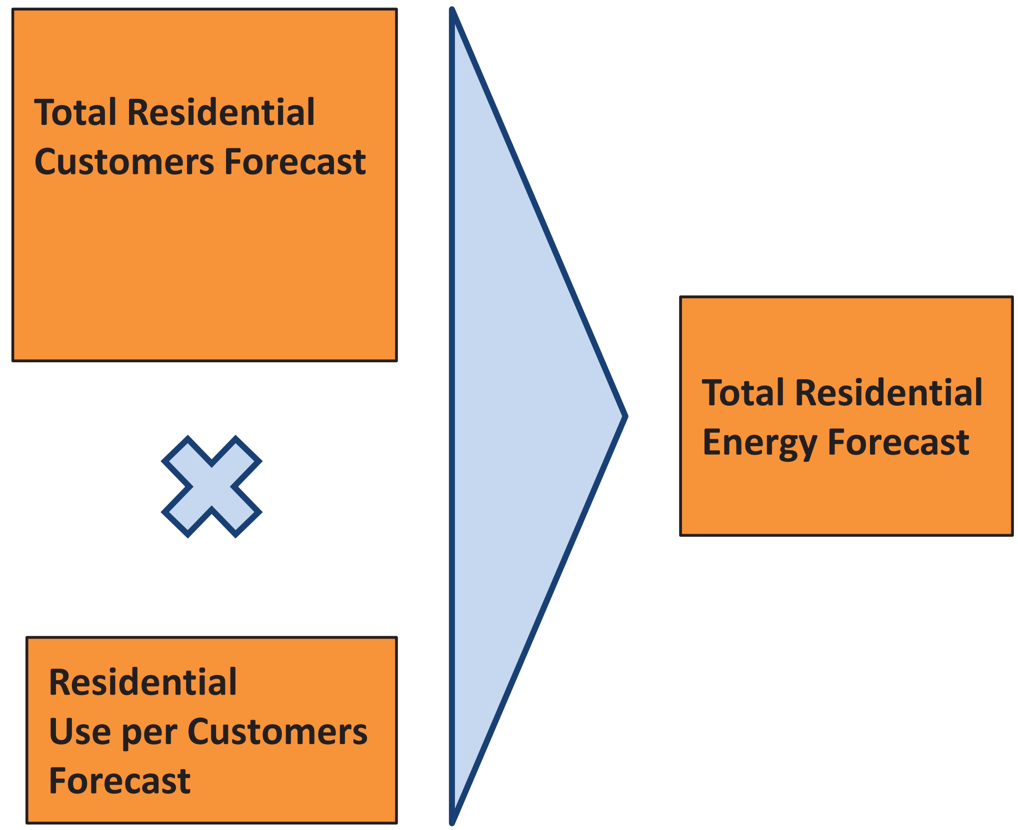
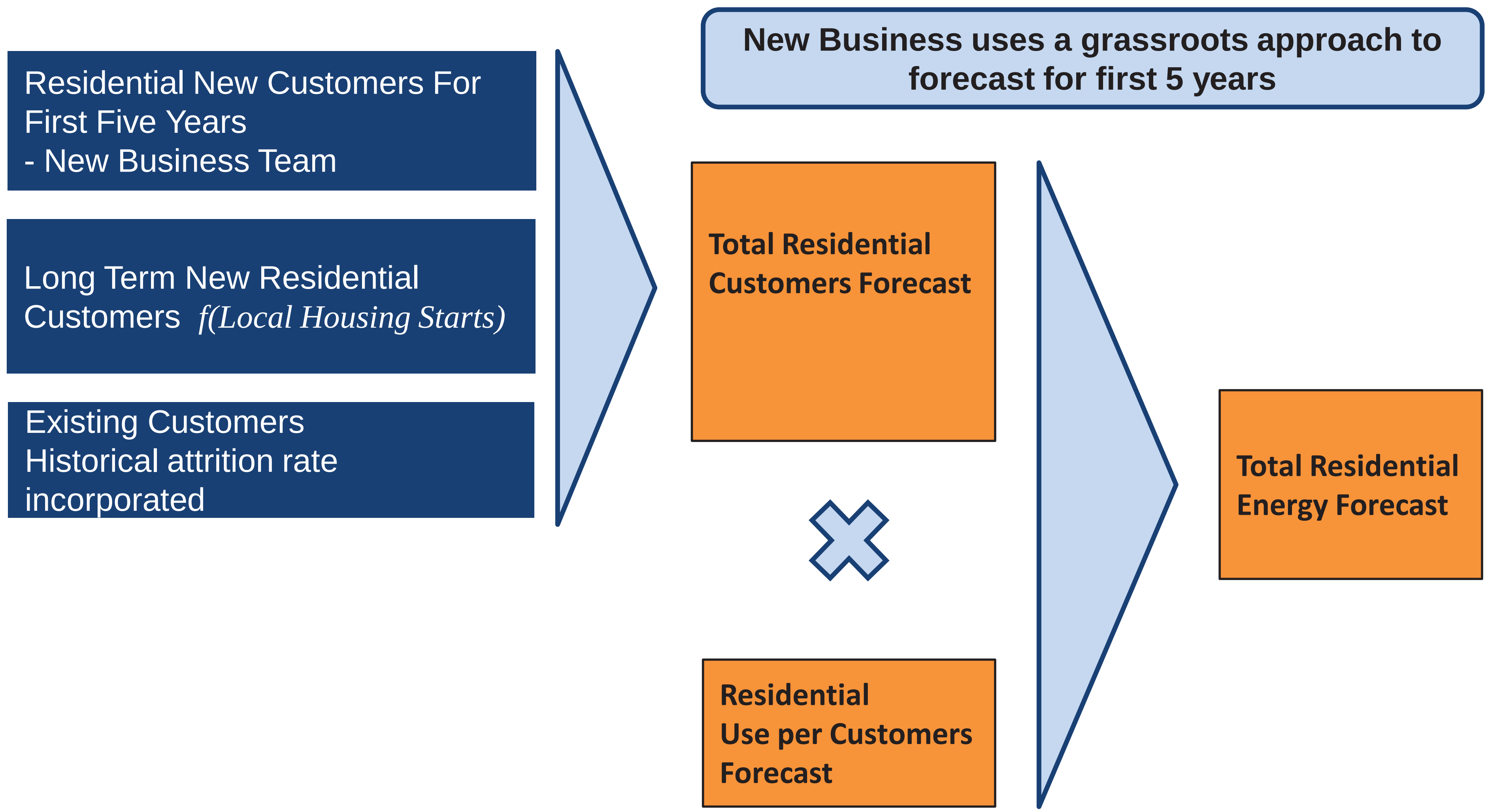
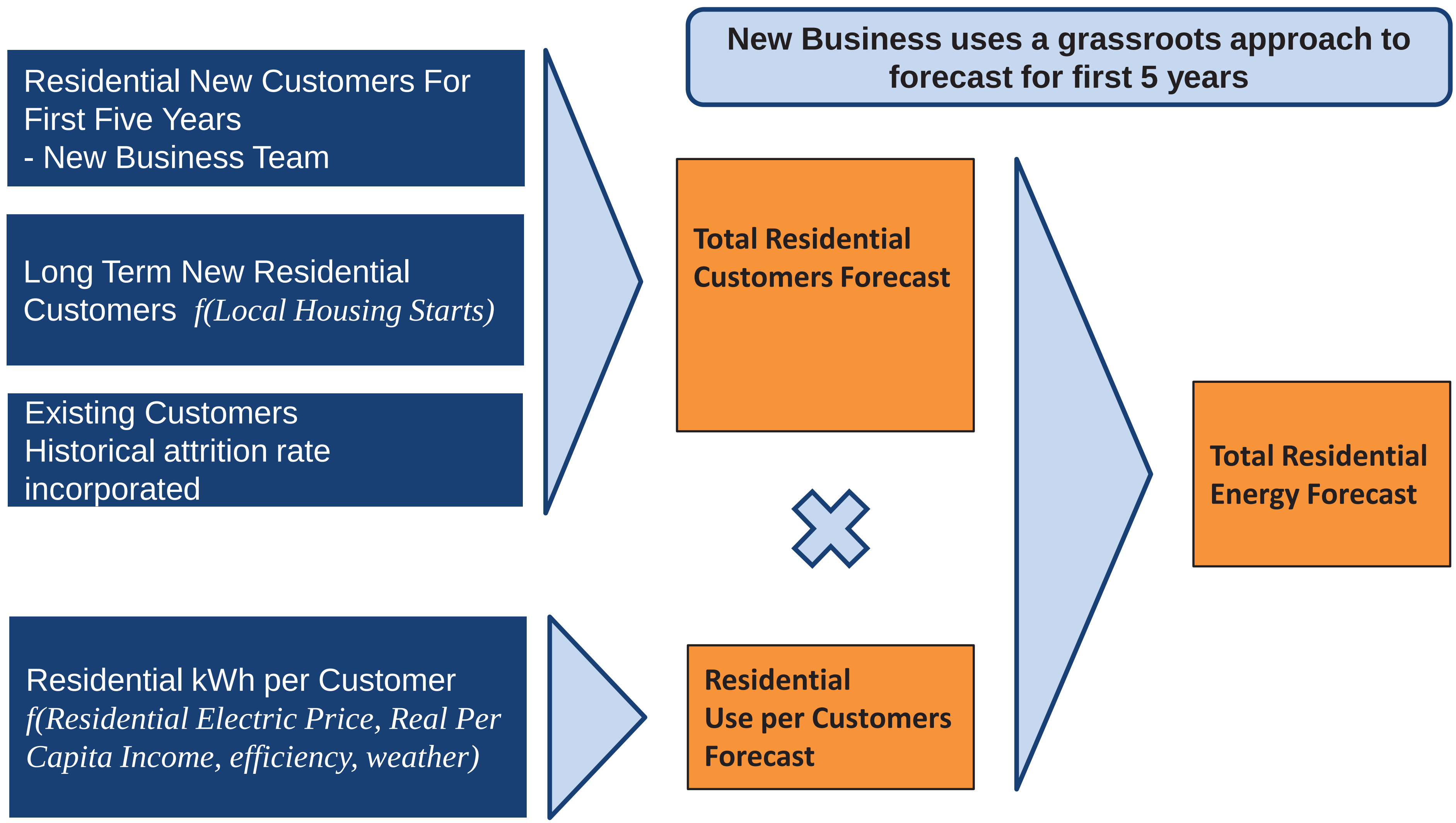
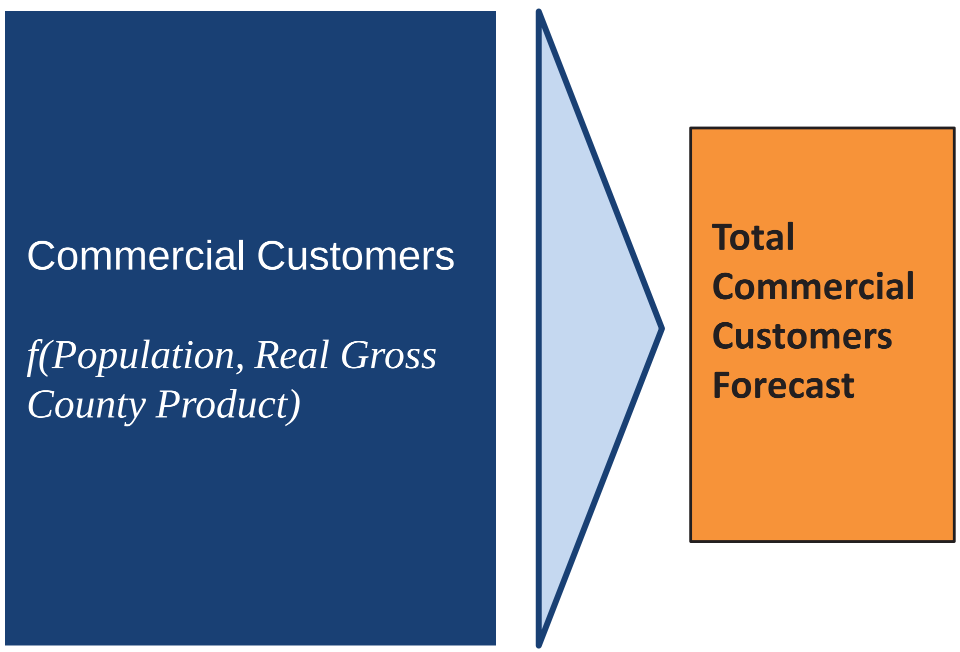
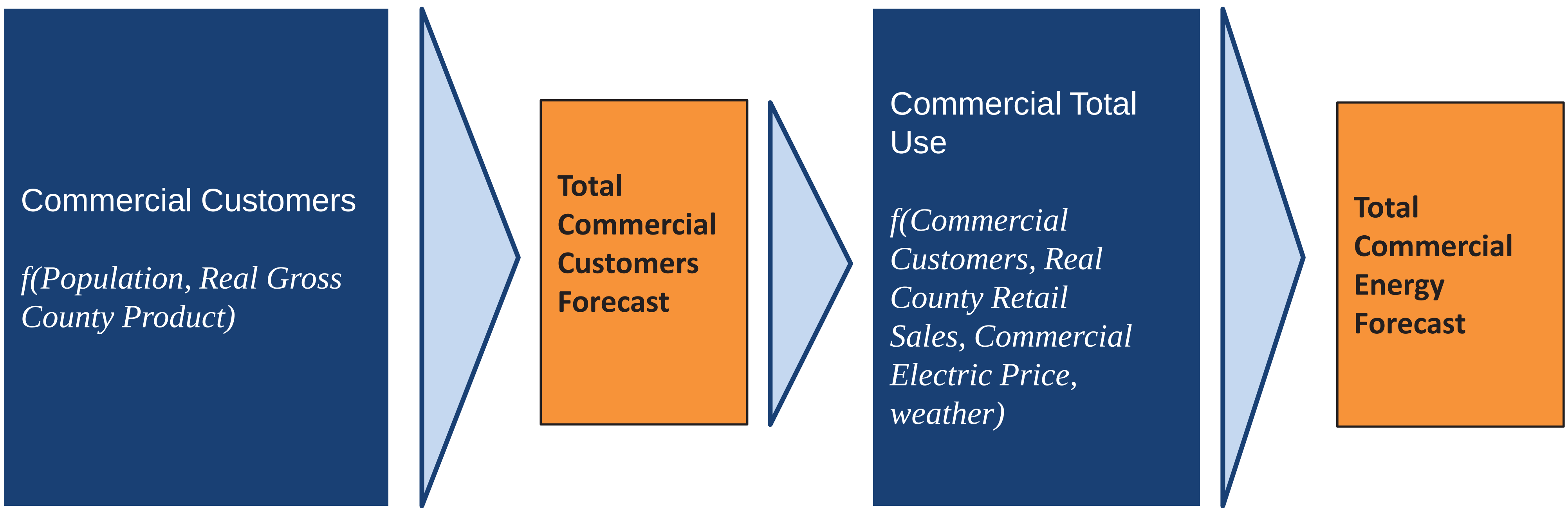
System Peak Forecast Demand

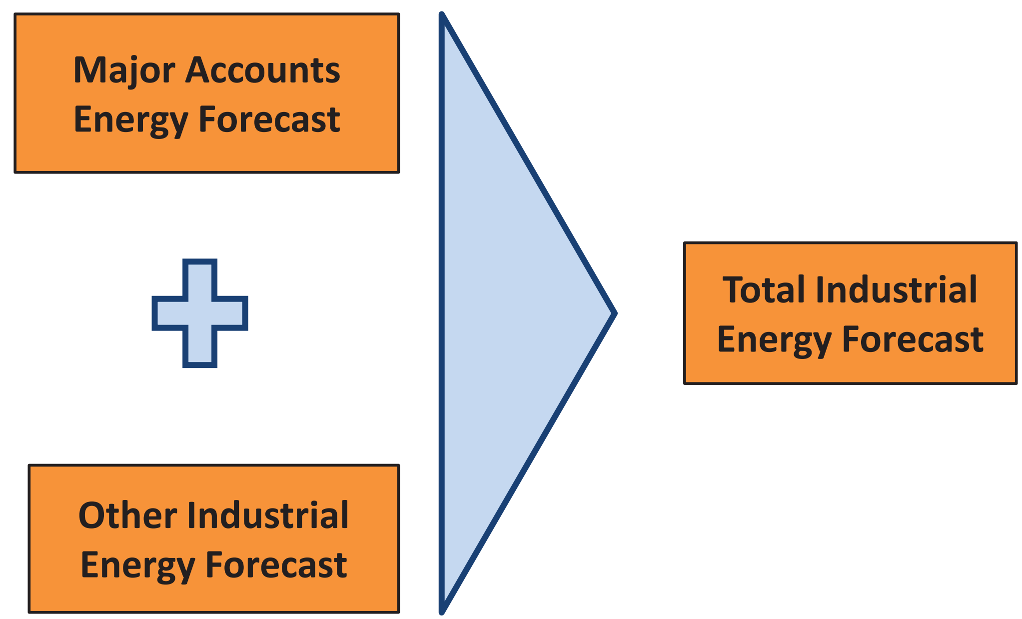

Total Residential
Customers Forecast
Residential
Use per Customers
Forecast
Total Residential
Energy Forecast

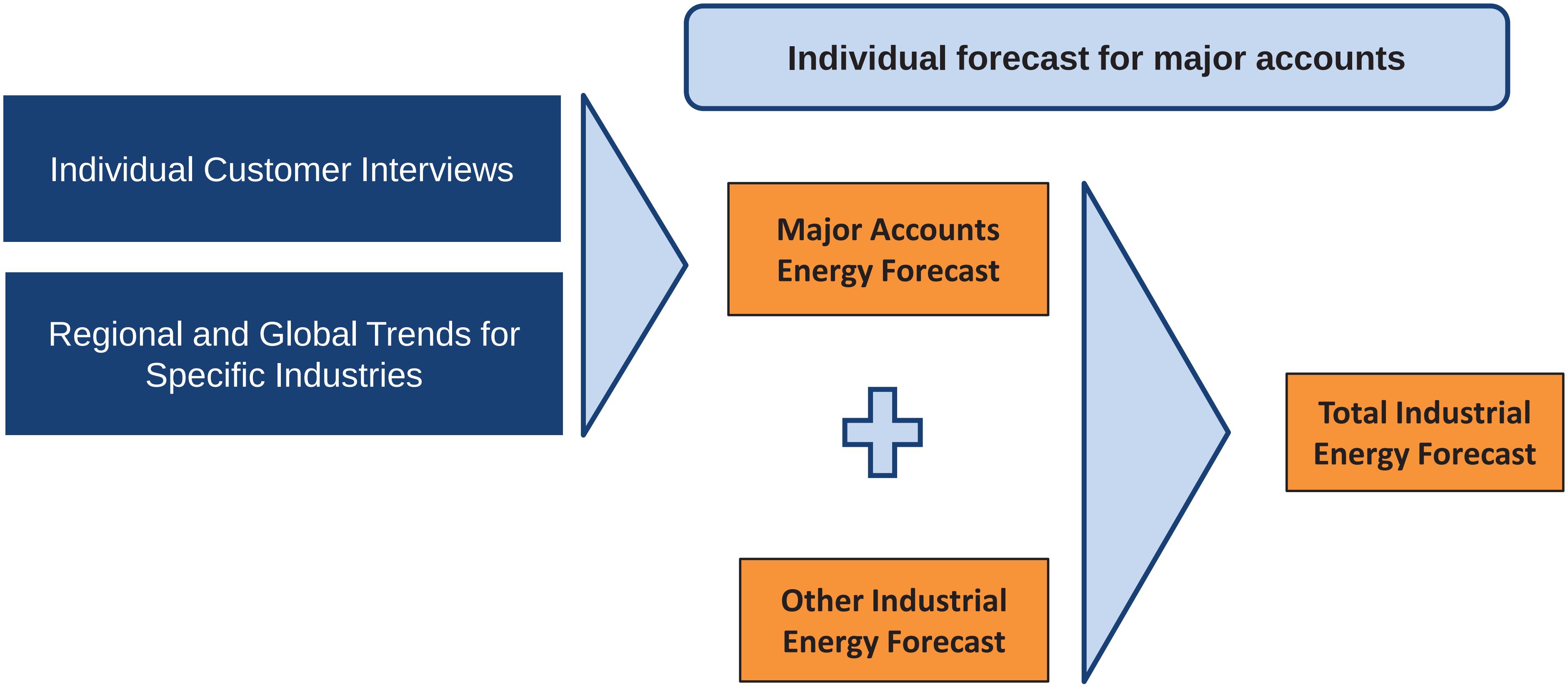

Residential New Customers For First Five Years
- New Business Team
Long Term New Residential Customers f(Local Housing Starts)
Existing Customers
Historical attrition rate incorporated
New Business uses a grassroots approach to forecast for first 5 years
Total Residential Customers Forecast
Residential Use per Customers Forecast
Total Residential Energy Forecast

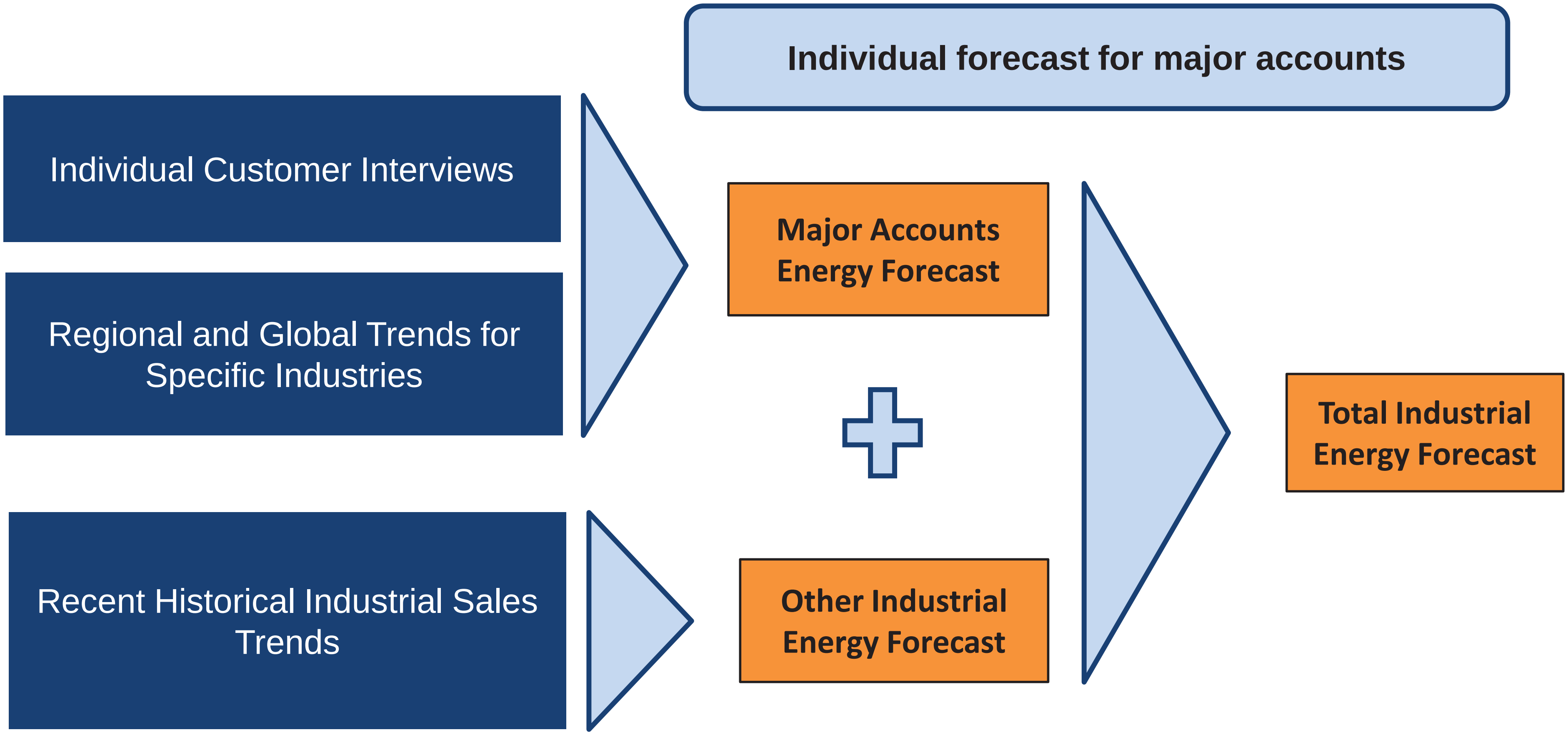

New Business uses a grassroots approach to forecast for first 5 years
Residential New Customers For First Five Years
- New Business Team
Long Term New Residential Customers *f(Local Housing Starts)*
Existing Customers
Historical attrition rate incorporated
Residential kWh per Customer
f(Residential Electric Price, Real Per Capita Income, efficiency, weather)
Total Residential Customers Forecast
Residential Use per Customers Forecast
Total Residential Energy Forecast

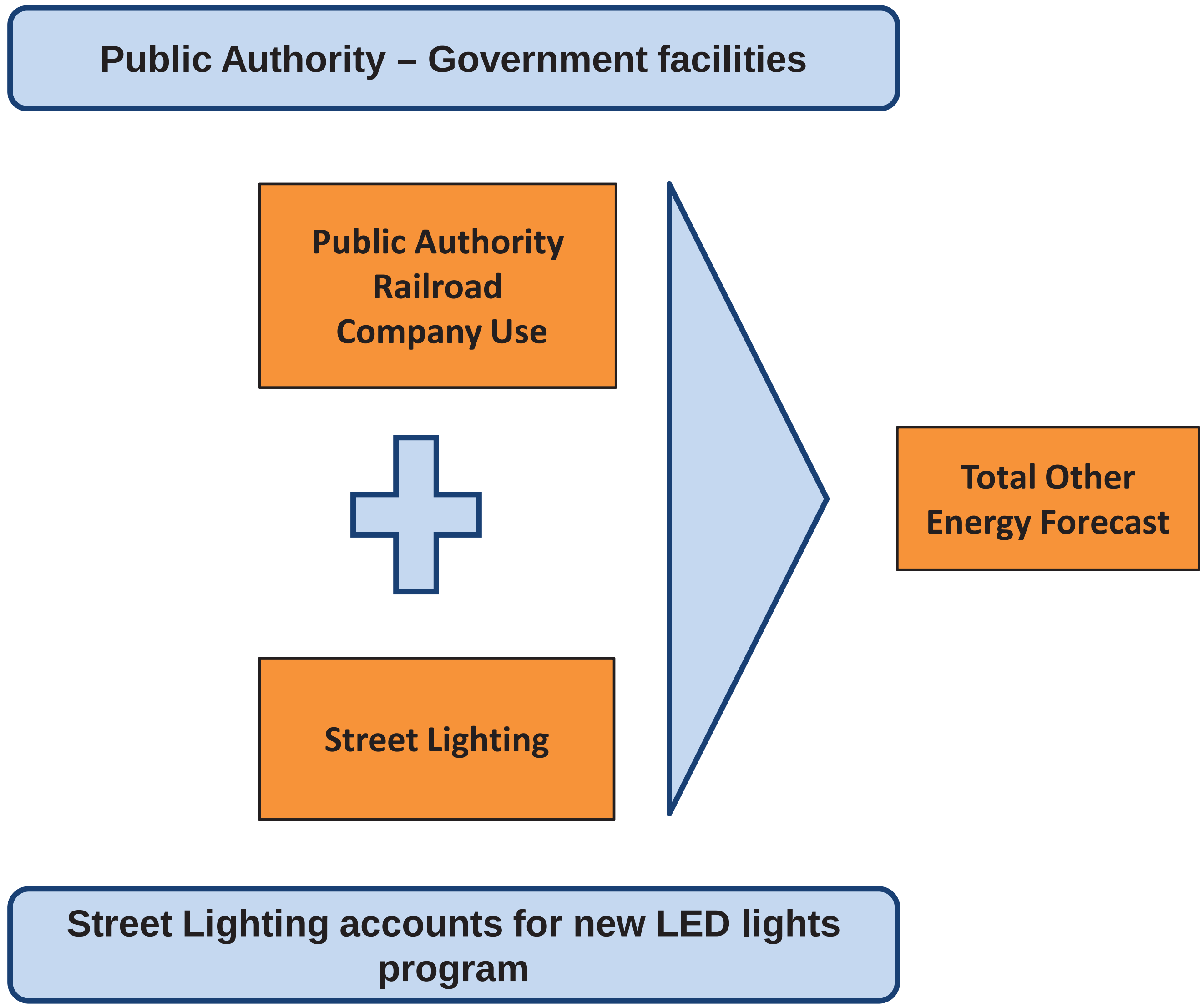

Commercial Customers
f(Population, Real Gross County Product)
Total Commercial Customers Forecast

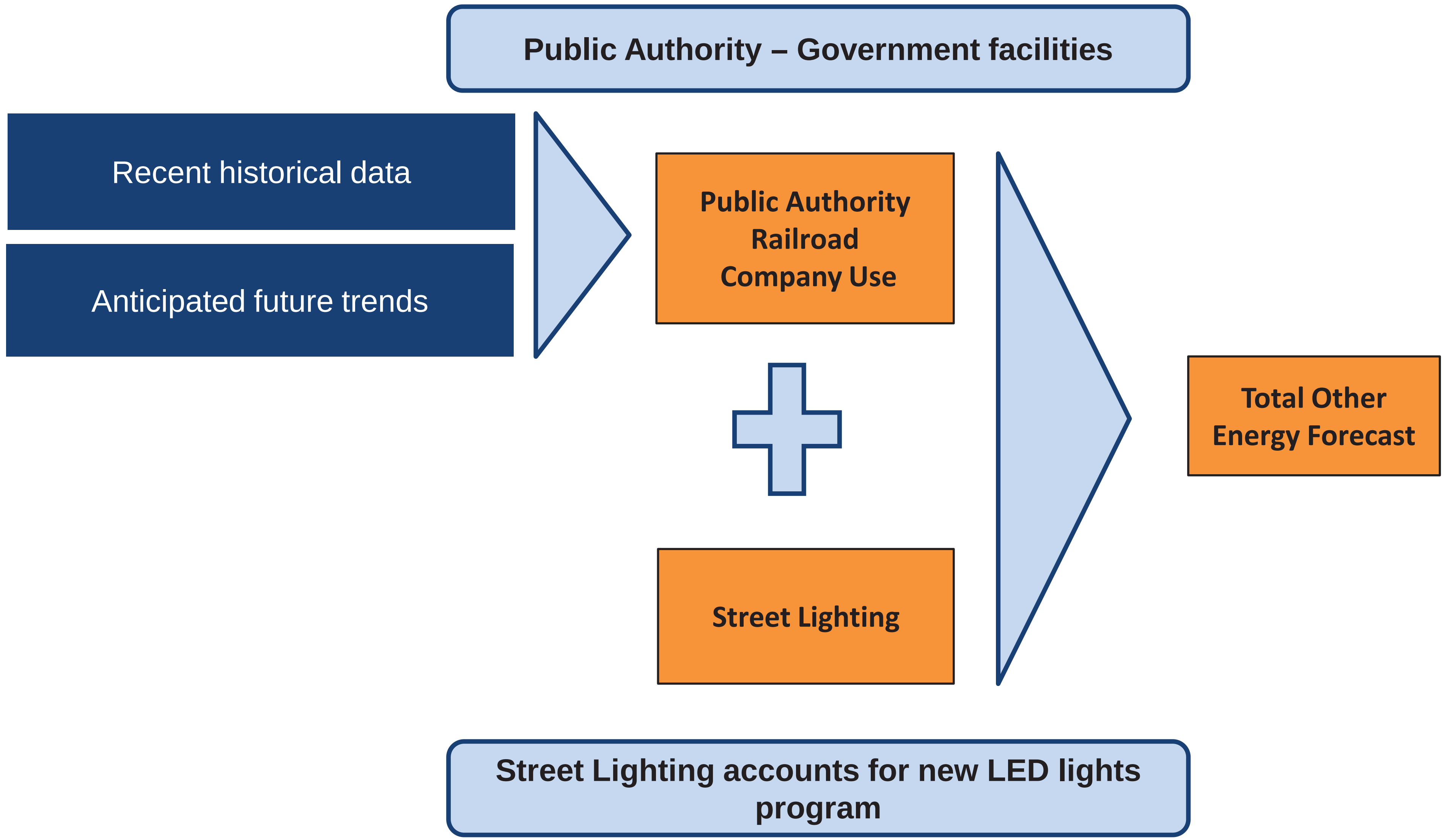

Commercial Customers
f(Population, Real Gross County Product)
Total Commercial Customers Forecast
Commercial Total Use
f(Commercial Customers, Real County Retail Sales, Commercial Electric Price, weather)
Total Commercial Energy Forecast

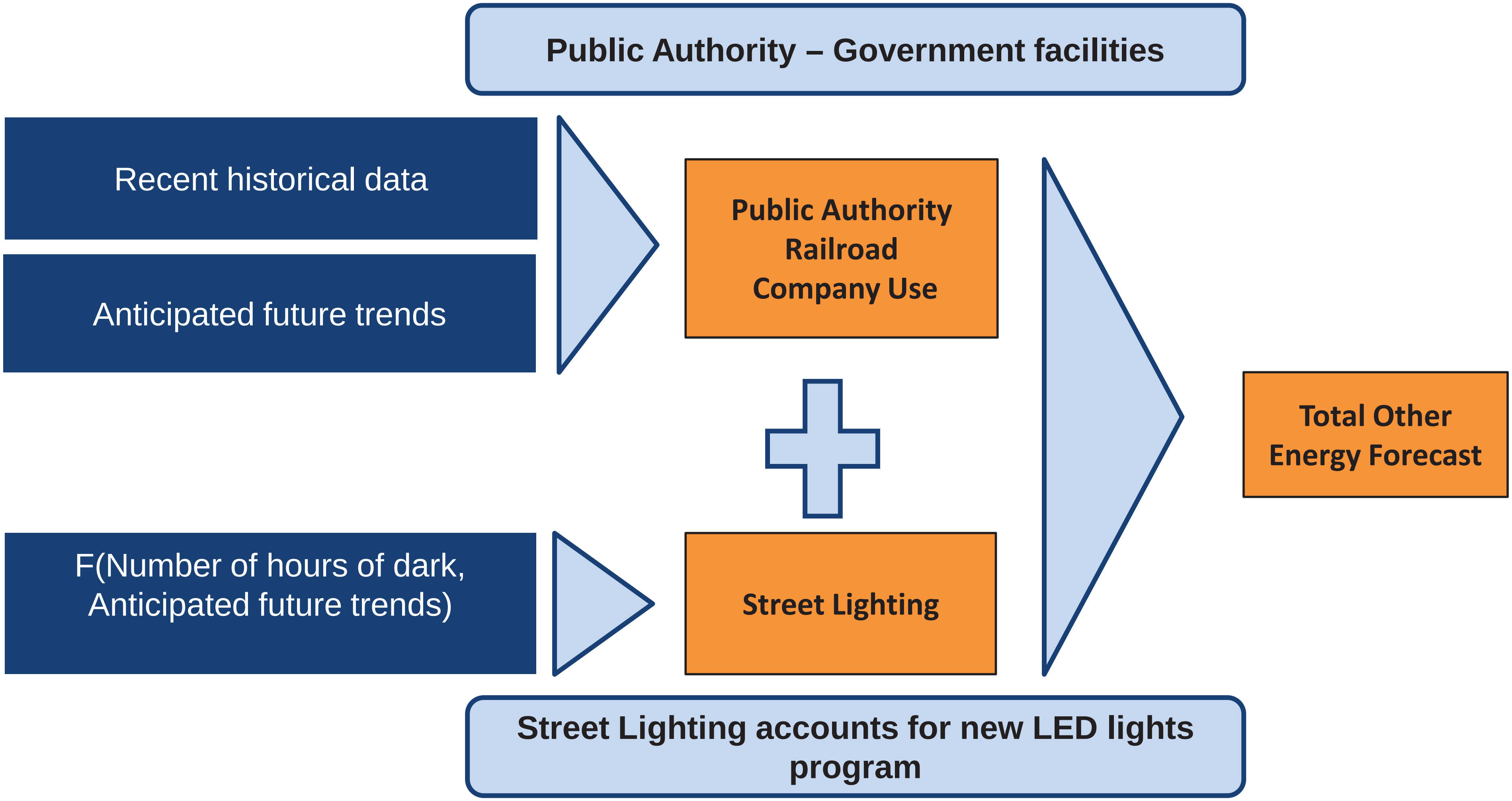

Major Accounts Energy Forecast
Other Industrial Energy Forecast
Total Industrial Energy Forecast

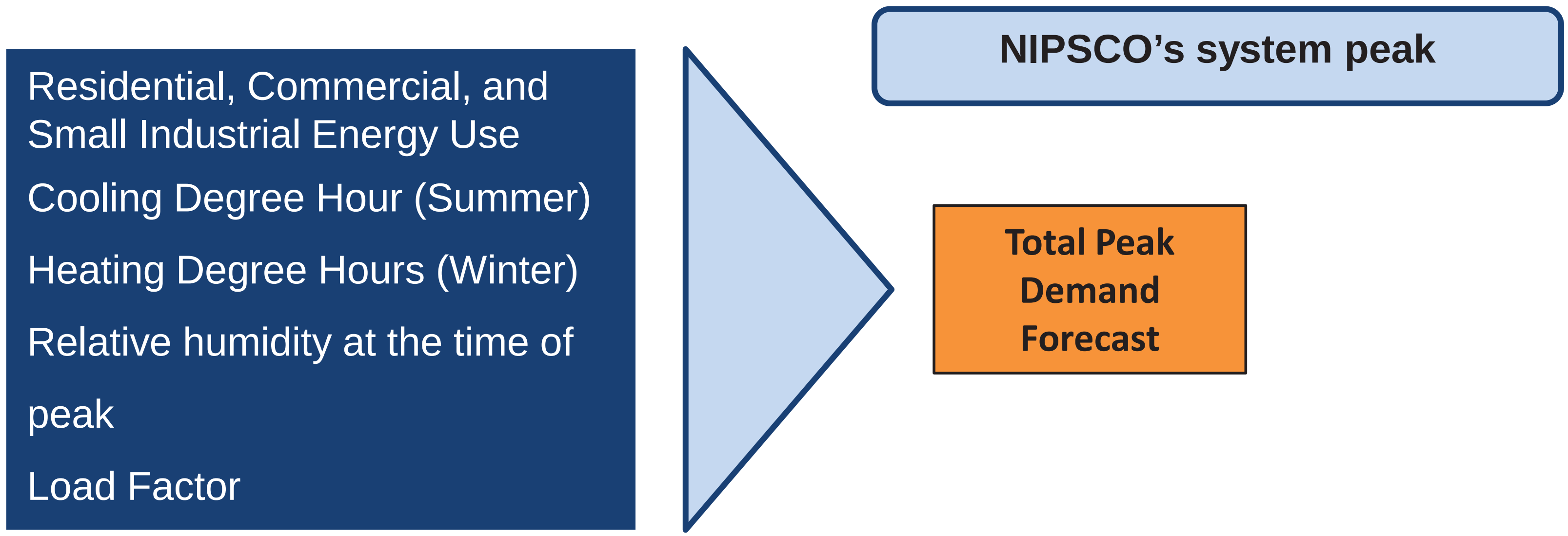

Individual forecast for major accounts
Individual Customer Interviews
Regional and Global Trends for Specific Industries
Major Accounts Energy Forecast
Other Industrial Energy Forecast
Total Industrial Energy Forecast


Individual forecast for major accounts
Individual Customer Interviews
Regional and Global Trends for Specific Industries
Recent Historical Industrial Sales Trends
Major Accounts Energy Forecast
Other Industrial Energy Forecast
Total Industrial Energy Forecast


Public Authority – Government facilities
Public Authority
Railroad
Company Use
Street Lighting
Total Other
Energy Forecast
Street Lighting accounts for new LED lights program


Public Authority – Government facilities
Recent historical data
Anticipated future trends
Public Authority Railroad Company Use
Street Lighting
Total Other Energy Forecast
Street Lighting accounts for new LED lights program


Public Authority – Government facilities
Recent historical data
Anticipated future trends
Public Authority Railroad Company Use
F(Number of hours of dark, Anticipated future trends)
Street Lighting
Total Other Energy Forecast
Street Lighting accounts for new LED lights program


Residential, Commercial, and Small Industrial Energy Use
Cooling Degree Hour (Summer)
Heating Degree Hours (Winter)
Relative humidity at the time of peak
Load Factor
NIPSCO's system peak
Total Peak Demand Forecast

Residential, Commercial, and Small Industrial Energy Use

Cooling Degree Hour (Summer)

Heating Degree Hours (Winter)

Relative humidity at the time of peak

Load Factor

NIPSCO's system peak

Total Peak Demand Forecast

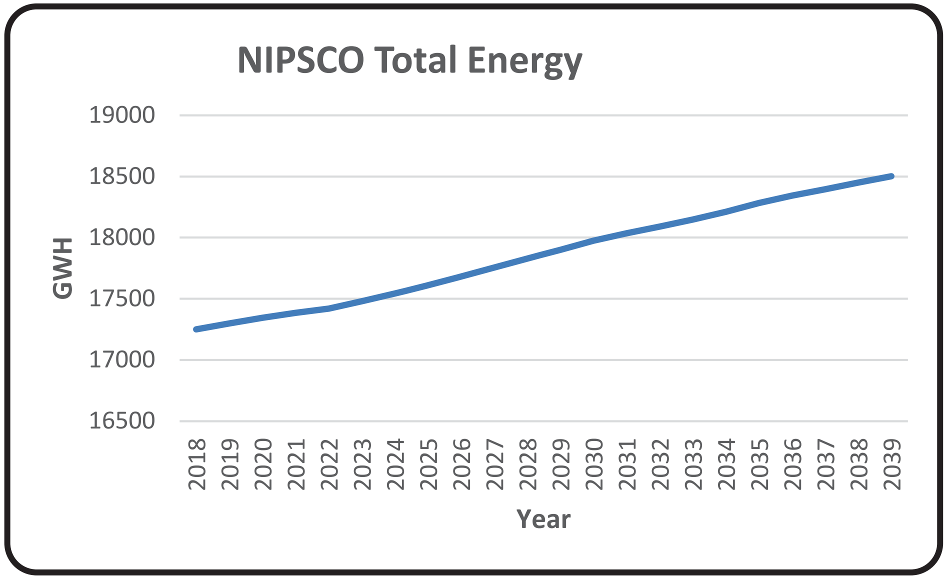
MISO Coincident Peak – NIPSCO's system peak at time of MISO's system peak

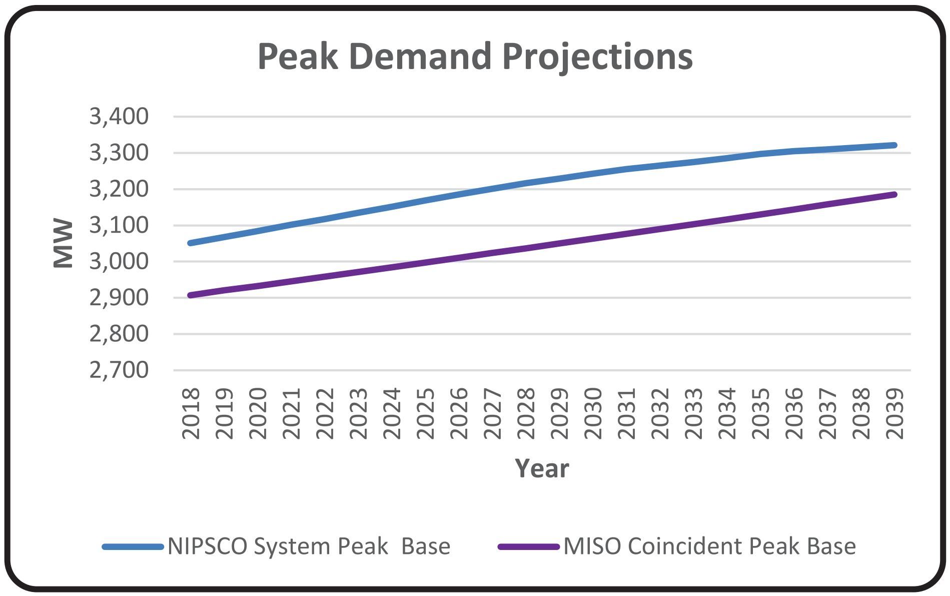
NIPSCO monthly peak

NIPSCO Cooling Degree Hours at the time of the MISO system peak

MISO Coincident Peak Forecast

Load Forecasts





Energy Requirement Projections	2018-2039 CAGR
NIPSCO Total Energy	0.33%
NIPSCO System Peak	0.41%
MISO Coincident Peak	0.44%

$$\frac{\textbf{\textit{MISO Coincident Peak}}}{\textbf{\textit{NIPSCO System Peak}}} = \sim 95\%$$

Fred Gomos
Manager Corporate Strategy & Development

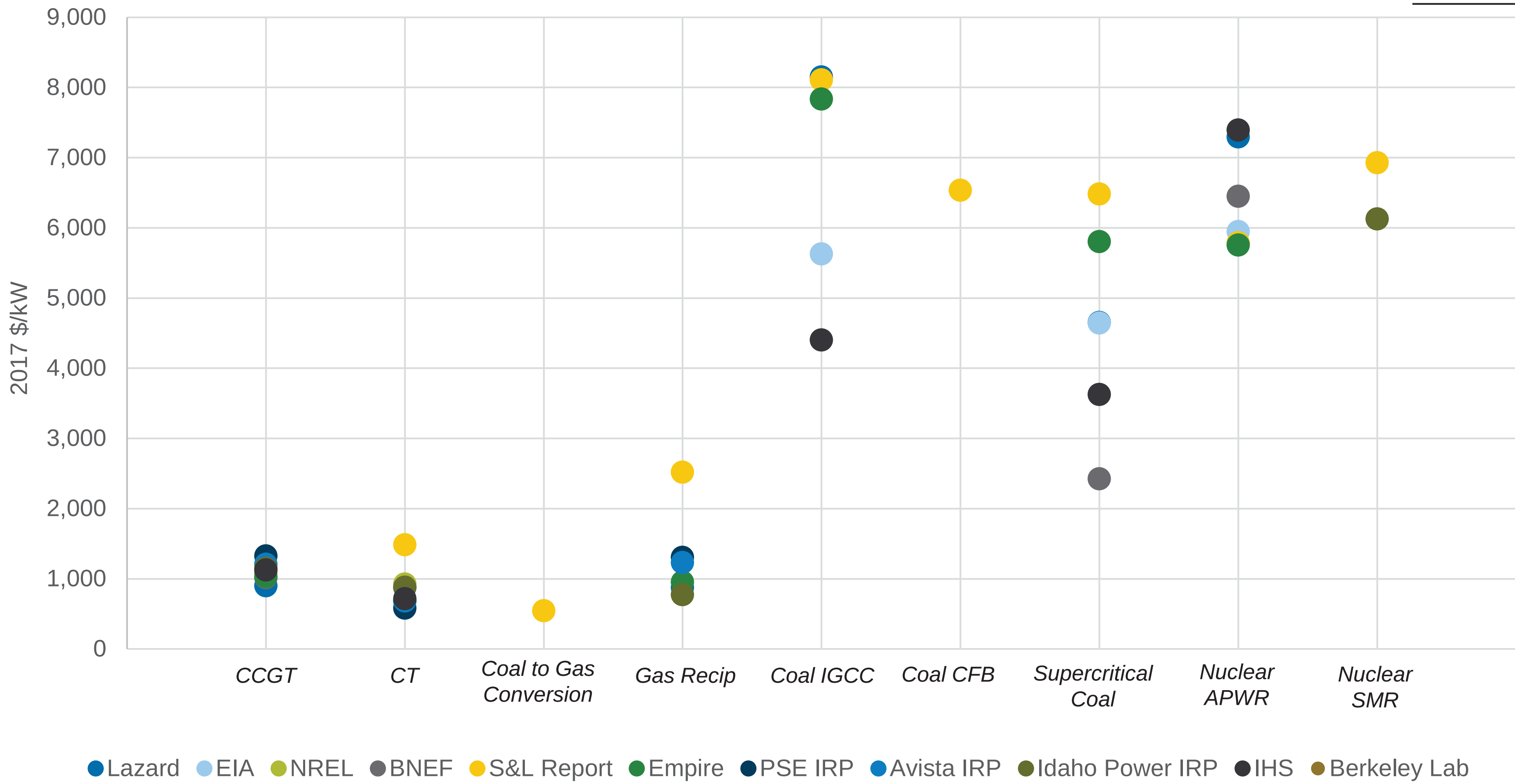
Pat Augustine
Charles River Associates (CRA)

Step 1	Develop initial NIPSCO portfolios	• Review technologies based on costs, feasibility, and regulatory constraints • Obtain current and future capital cost estimates from multiple 3rd party data sources
Step 2	Evaluate portfolios across Scenarios and Stochastics (including capital costs)	• Assess relative costs and risks of portfolio options • Perform preliminary assessment of portfolio costs, risks, and other metrics (pre-RFP)
Step 3	Integrate RFP results	• Based on RFP process, incorporate specific capacity offers that align with preliminary assessment of portfolio performance • Evaluate portfolios using more certain capital cost information from RFP bids

3rd Party Data Sources

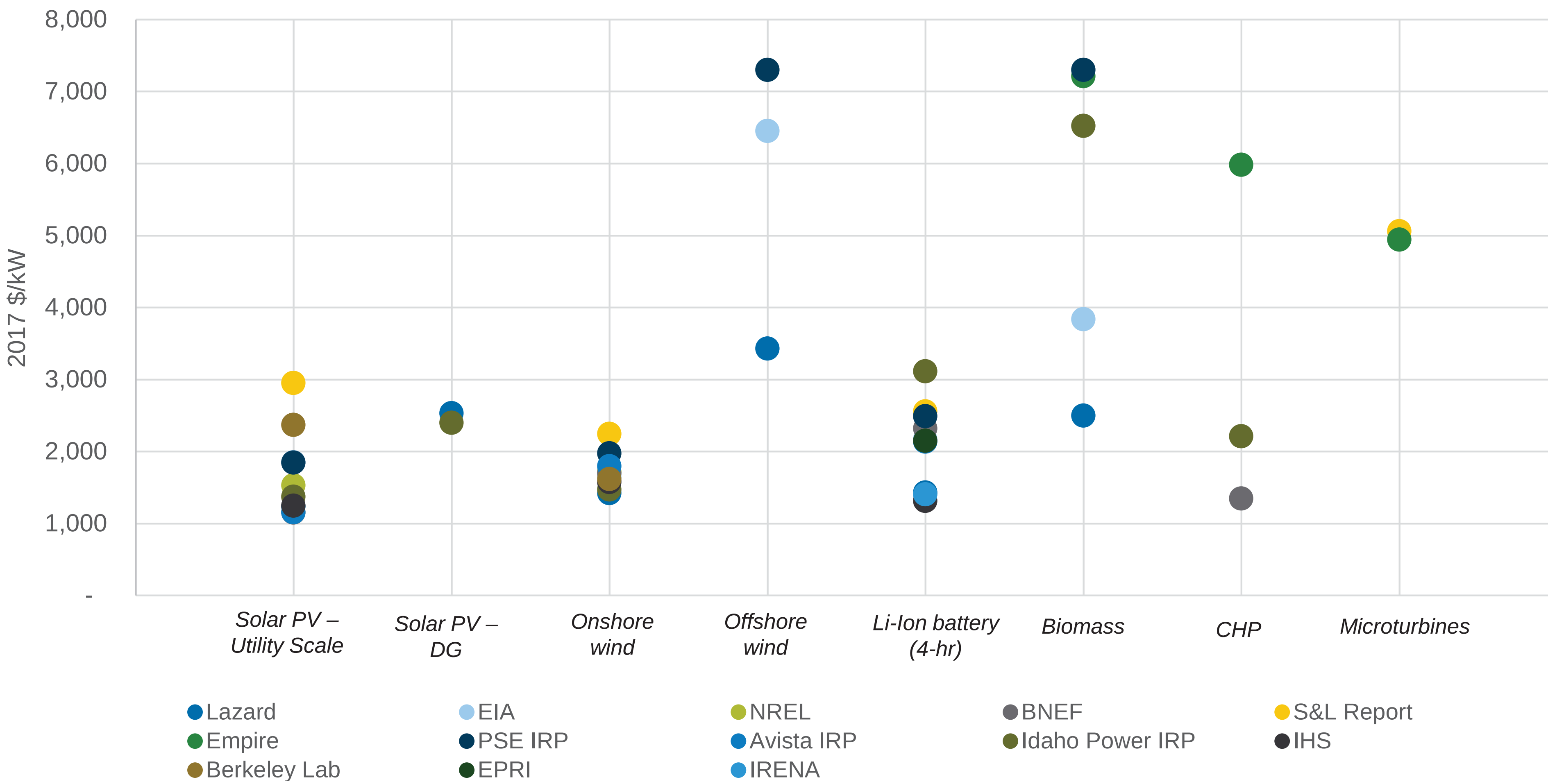
Data Source	Description	Link
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)	N/A
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 AEO)	EIA Capital Cost Estimates
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)	Empire District Avista Puget Sound Energy Idaho Power
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)	Lazard LCOE V. 11.0
	Lazard Levelized Cost of Storage Version 3.0 (2017)	Lazard LCOS V.3.0
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook	IHSMarkit (subscription required)
	US Wind Capital Cost and Required Price Outlook	
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)	
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs	
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region	Bloomberg New Energy Finance (subscription required)
	Key cost input in LCOE Scenarios, 1H 2017	
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)	
National Renewable Energy Technology Laboratory	NREL Annual Technology Baseline 2017	NREL ATB 2017

Not Exhaustive



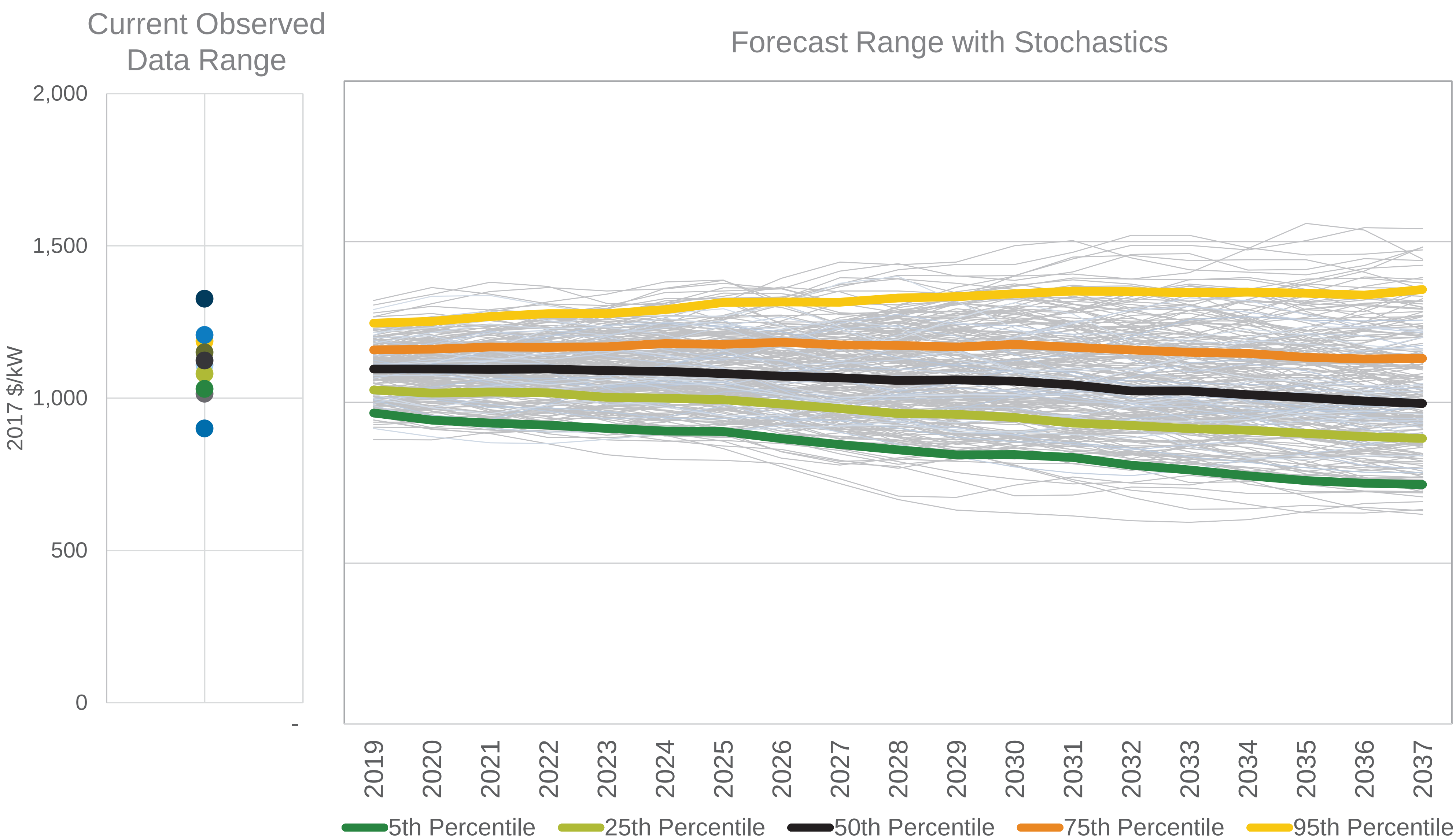
2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,276	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927

Not Exhaustive



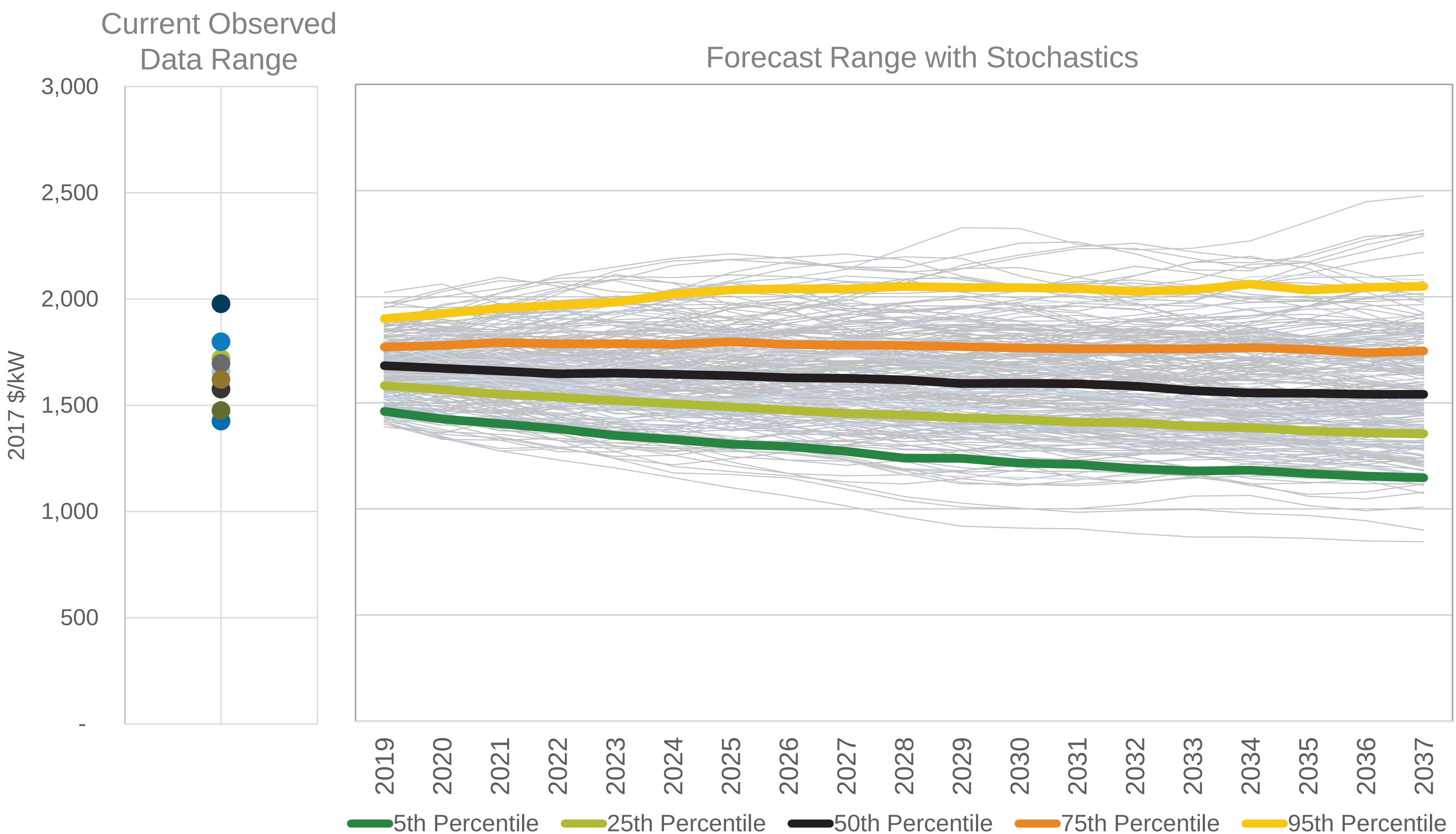
2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

- **The team used the range of data sources to develop forecasts for capital costs over time that include uncertainty bands**
- **Methodology for developing forecasts for a given technology consisted of several steps:**
  - Identify expected range of capital costs over time from data sources (starting point ranges and long-term forecasts, where they exist)
  - Using an interactive expert opinion approach based on the source data, elicit distributions for capital costs in three time periods (near-term, mid-term, and long-term)
  - Simulate 500 paths for capital costs based on random sampling from distributions



How to interpret the probability distributions and diagnostic statistics:

- 50th percentile is the middle value – half the observations are above this value and half are below
- Generally, percentiles represent thresholds below which a given percentage of observations is expected to fall (i.e., the 95th percentile indicates that 95% of the cost observations in that year are at or below this level)



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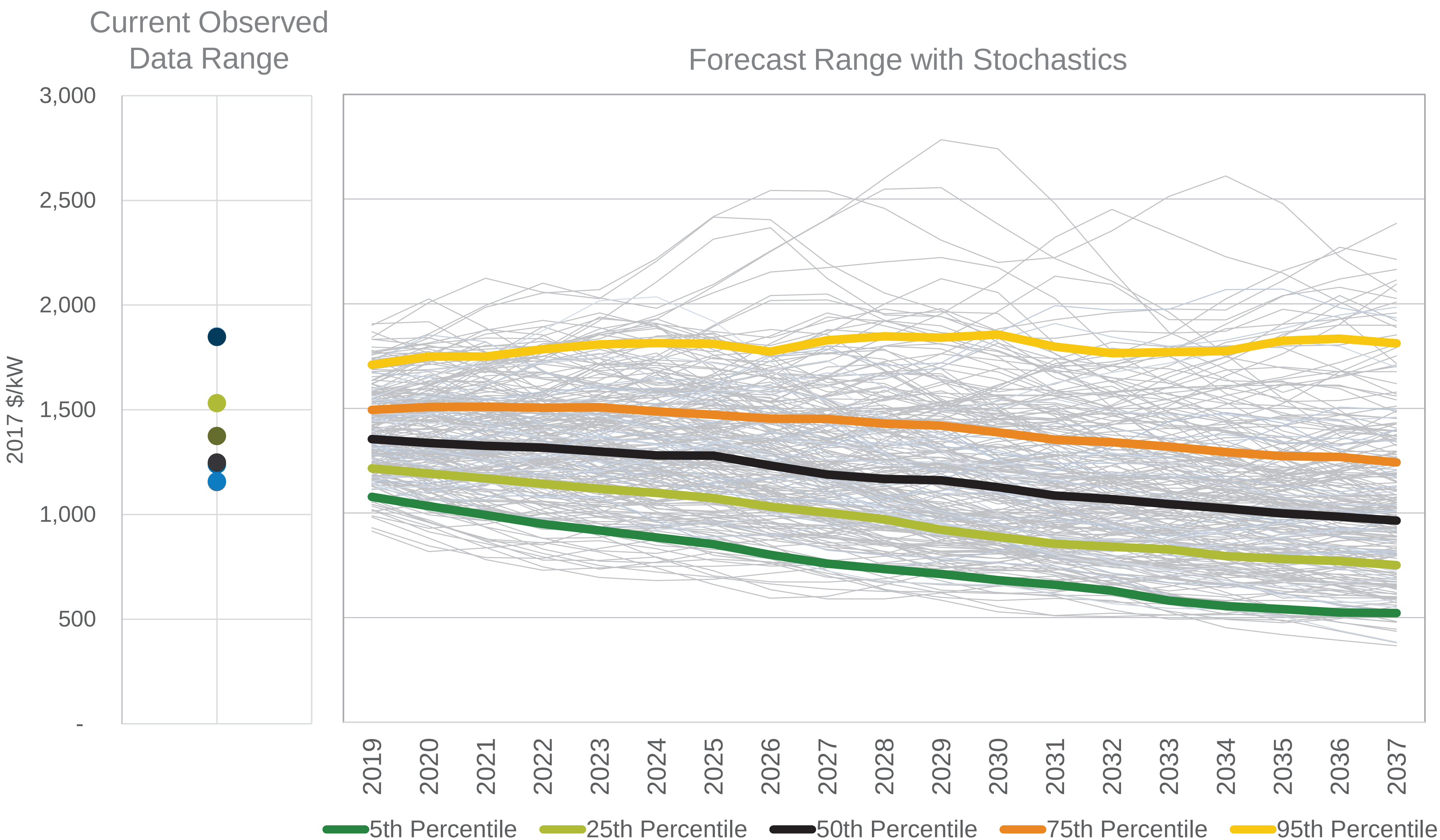

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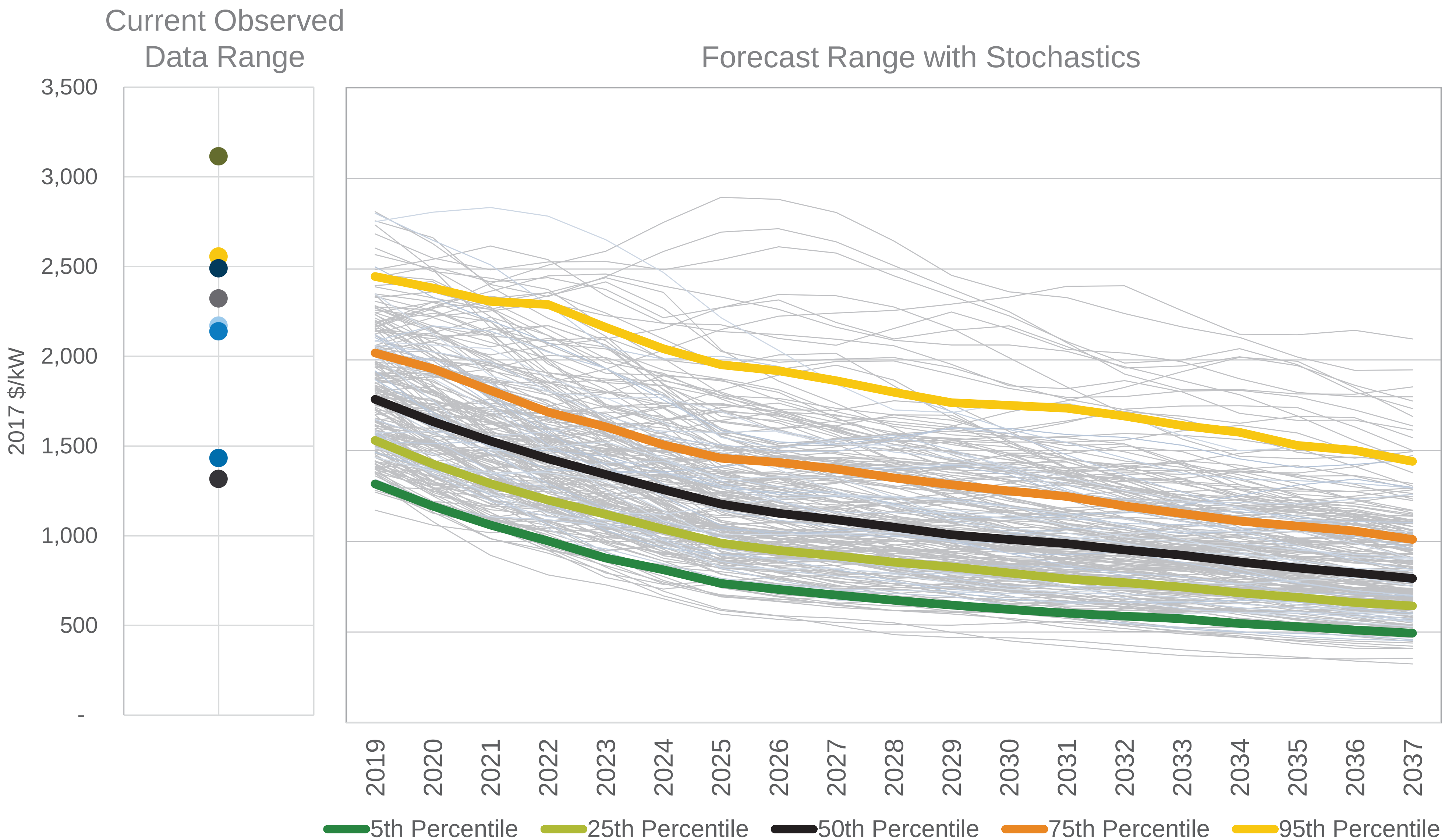

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2018 COMMODITY PRICE FORECASTING

NIPSCO IRP Stakeholder Meeting

Robert Kaineg & Pat Augustine

March 23, 2018

Outline

- Natural Gas
- Coal
- Power

CRA Natural Gas Outlook

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Natural Gas Market Overview

- The industry has undergone a considerable transformation over the last decade
- Low cost shale gas has reduced domestic prices, and the Mid-Atlantic has transformed from a gas importer into a major production region, bottlenecked by existing midstream infrastructure

Trailing Trends

Regional Gas Supply Growth

Changing Pipeline Flows

- Northeast and Mid-Atlantic transformed from a major importer to a net supplier despite significant demand growth driven by coal switching
- Sizable gas infrastructure investments made in midstream to address flow issues
- Changing supply dynamics due to generation, industrial, and Mexico exports are starting to reverse flows of the major US gas transport backbone

Leading Trends

Supply & Pricing Dynamics

- Low cost North American supply still has significant growth upside (improved drilling economics and a large resource base)
- A sustained low gas price environment starting to incent additional power generation demand for gas (new capacity + further coal and nuke to gas substitution)
- Techniques developed in the Marcellus moving back into traditional regions (e.g. Haynesville) likely to improve productivity of these regions

Demand Growth Potential

- The electric sector increasingly relies on gas generation to meet energy needs, IRPs tend to rely on new gas and renewables meet growing load
- Short term LNG outlook firming ~10bcf/d of firm projects coming online in the next 2-4 years, another 8-10 bcf/d of potential in the following decade
- Sustained low gas prices driving interest in petrochemical investments

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NGF Model – Natural Gas Price Forecasting

Gas Supply

- Total resource in place, proved and unproven
- Resource growth over time
- Wet / dry product distribution
- Historic wells drilled and ongoing production
- Conventional & associated production
- Existing tight and CBM
- Existing offshore production

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- First year initial production rate
- Changing drilling and production efficiencies
- Productivity decline curve
- Well lifetime
- Distribution of performance

Gas Demand

- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)

Other Market Drivers

- Value of NGL / condensates
- Natural gas storage

CRA continuously enhances NGF to reflect changes in key gas market drivers

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Key Modeling Inputs and Drivers of CRA's Gas Price Forecast

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) 2016 "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2016 "Minimum" resource, and grows the resource base to achieved PGC 2016 "Most Likely" volumes by 2050
Well Productivity	• IP rates based on historic data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data for initial mode year, IP rates improve annually in line with EIA assumptions The "Poor Heavy" resource base is conservative, and reflects the fact that sampled data reflects only geology expected to be productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA based individual well productivity on available historic data, adopted EIA assumptions for cost improvements over time
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2017 Reference Case (with CPP)	The AURORA case assumes "base case" carbon pressure and AEO 2017 Reference assumes CPP, meaning demand estimates are consistent
LNG Exports	• Under-construction projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031	Current advanced-stage projects expected to come online and be highly utilized driving 2019 view Low domestic prices drive further international interest for US gas, but no other projects able to complete before 2021
Pipeline Exports	• Mexican export increase to ~8bcf/d by 2021, 10.5bcf/d by 2030	CRA expects pipeline export capacity to meet growing gas demand in Mexico will be ~60% utilized by 2021, and 75% utilized by 2031
NGL & Condensate Value	• Liquids valued at 70% of AEO 2017 Reference Oil Price	AEO17 for long-term oil price forecast; 70% value for NGLs is consistent with last 5 years of price history

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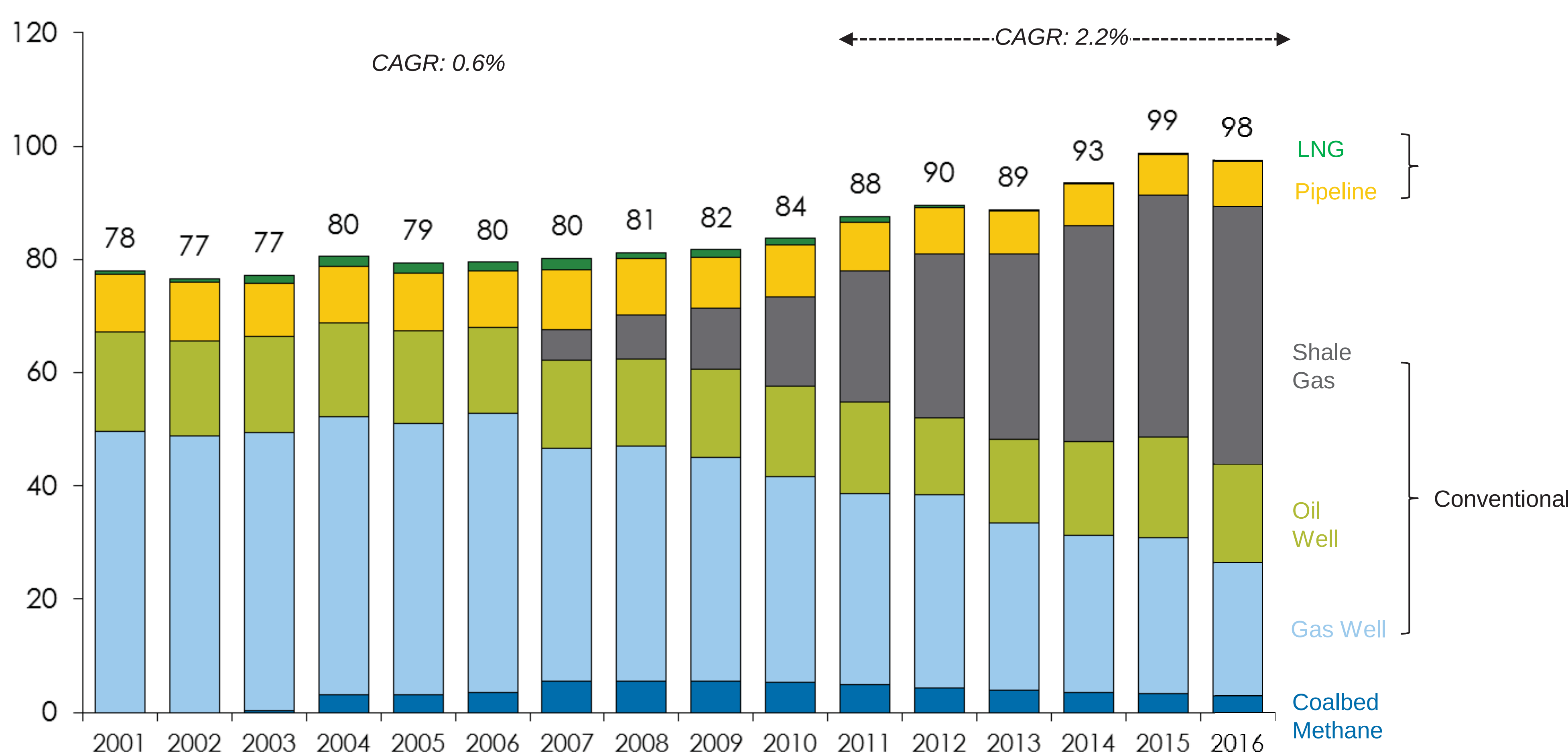
Key Natural Gas Market Trends – Shale Gas

- US Gas production was relatively flat from 2000-2010 until growth accelerated due to rapidly expanding shale gas production

Gas Withdrawals and Imports

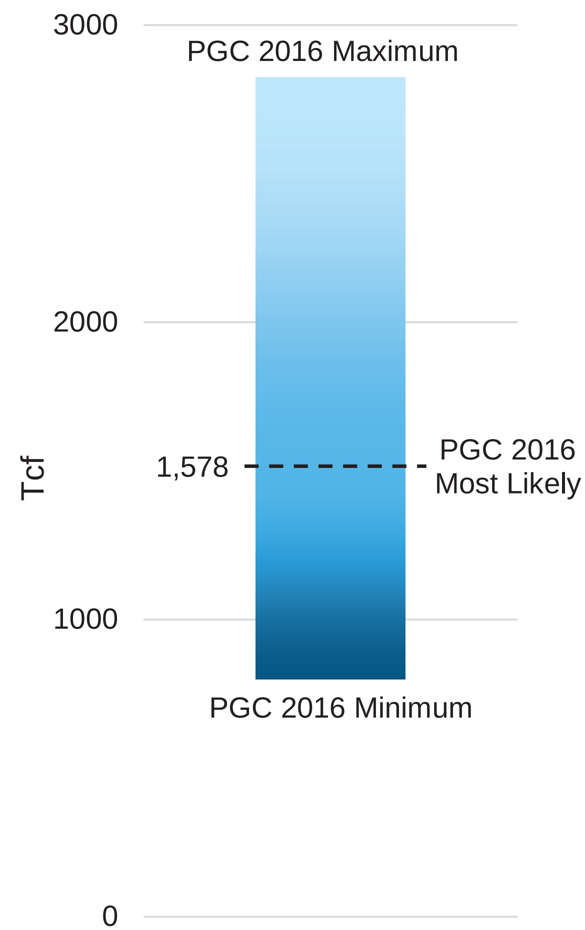


CRA relies on the PGC 2016 “Minimum” value as the starting value for recoverable shale reserves, resource grows at a steady rate until the PGC “Most Likely” value is reached in 2050

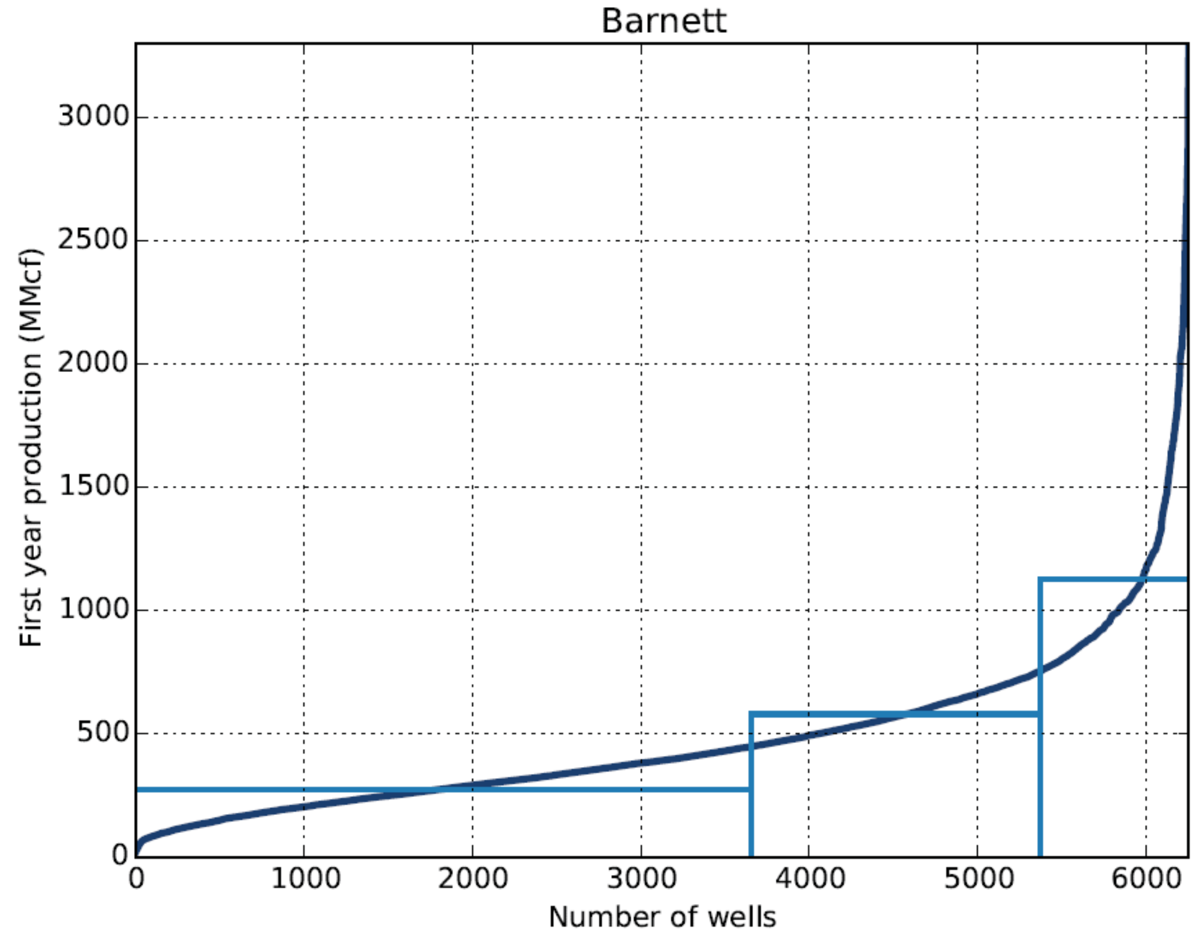
- **Probable** – gas associated with known fields
- **Possible** – gas outside of known fields, but within a productive formation in a productive province
- **Speculative** – gas in formations and provinces not yet proven productive

- **Minimum** – 100% probability that state resource is recoverable
- **Most Likely** – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions
- **Maximum** – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present

Uncertainty Range for Shale Resource in PGC 2016



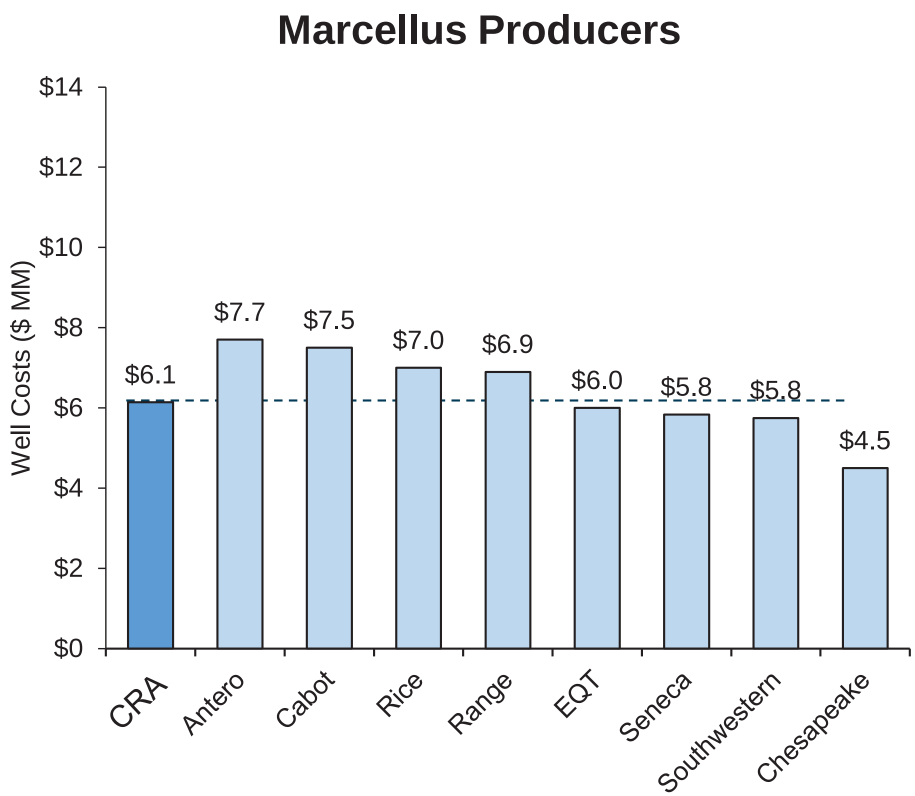
CRA assumed "Poor Heavy" productivity distribution (50% poor, 20% prime, 30% average) for future undiscovered resource

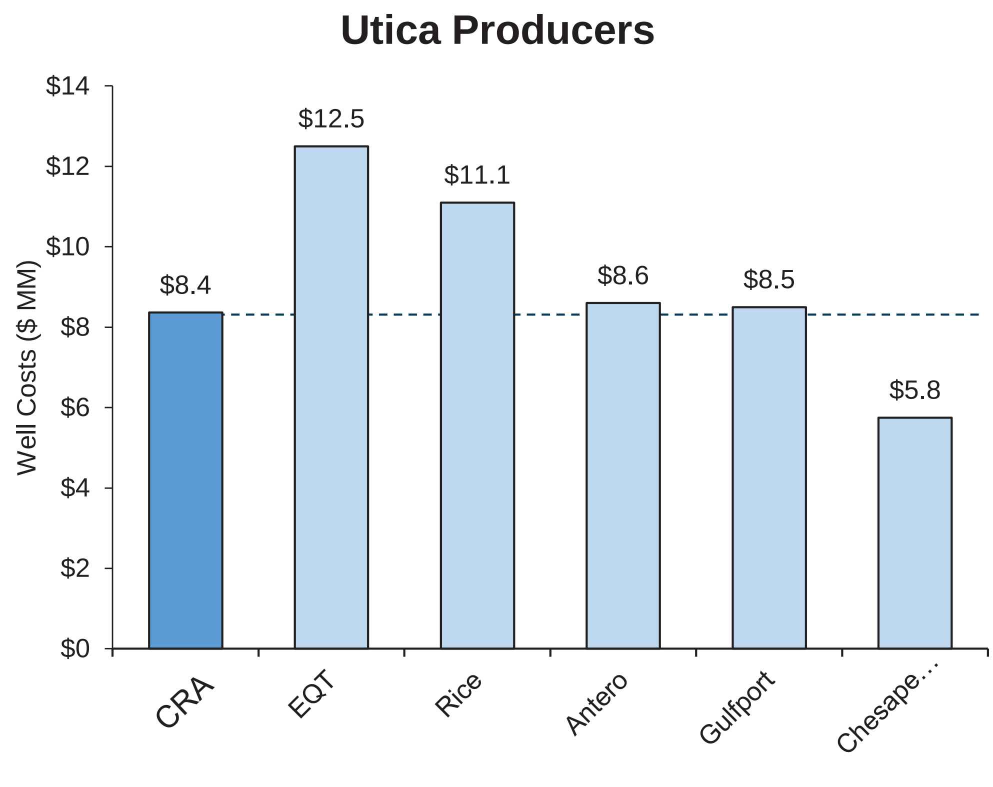


This productivity analysis was performed for all basins in CRA's model with sufficient recent drilling data

Gas Price Drivers – Drilling Costs

- CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region





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Well productivity & cost structure improves in CRA's base case consistent with EIA Tier 1 rate of EUR growth

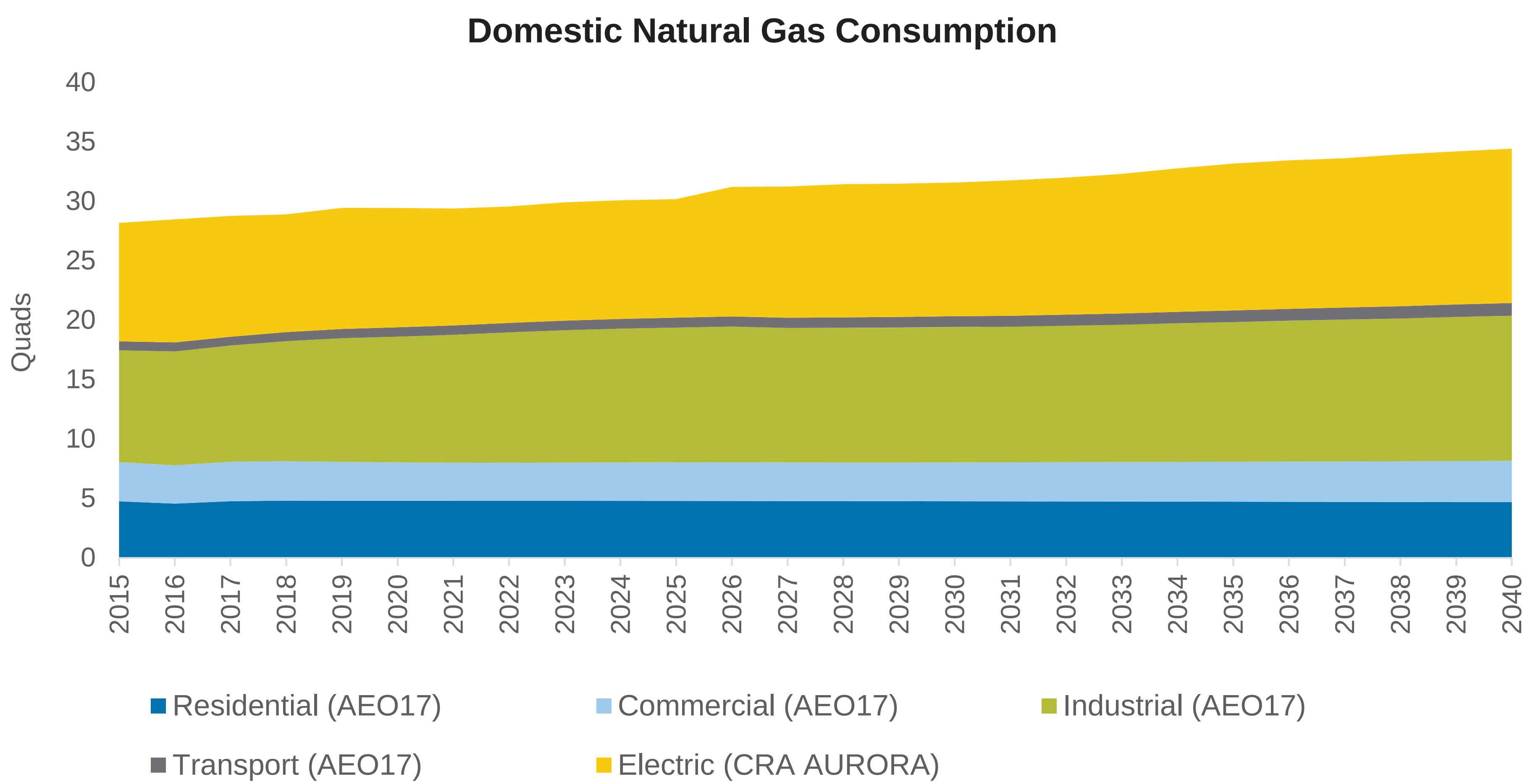
Table 9.6. Onshore lower 48 technology assumptions

Crude Oil and Natural Gas Resource Type	Drilling Cost	Lease Equipment & Operating Cost	EUR-Tier 1	EUR-Tier 2
Tight oil	-1.00%	-0.50%	1.00%	3.00%
Tight gas	-1.00%	-0.50%	1.00%	3.00%
Shale gas	-1.00%	-0.50%	1.00%	3.00%
All other	-0.25%	-0.25%	0.25%	0.25%

Source: U.S. Energy Information Administration, Office of Energy Analysis.

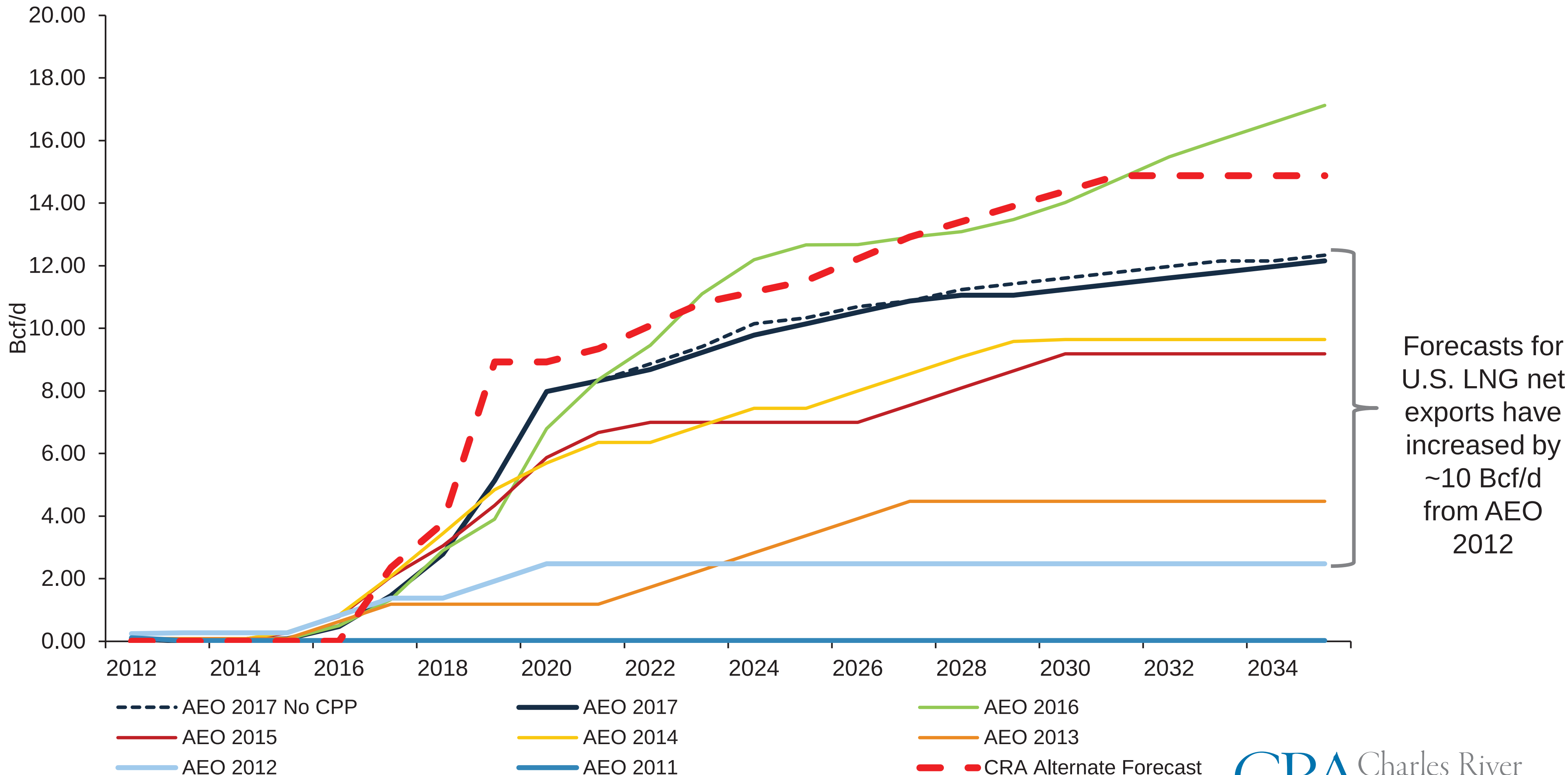
– Based values for IP rates and well costs are based on producer-reported values

CRA modeled electric gas demand in AURORA under base case CO2 assumptions, Residential, Commercial, Industrial and Transportation sector demand taken from AEO2017



Gas Price Drivers – LNG

- Forecast of LNG Exports: AEO 2017 Reference Case LNG exports are between 25%-35% higher than AEO 2015, but lower than AEO 2016
- BP forecasts higher LNG exports than AEO, with ~15 Bcf/d of exports by 2030 and ~22 Bcf/d by 2035
- LNG exports could potentially be higher than AEO 2017 projects, given current planned builds



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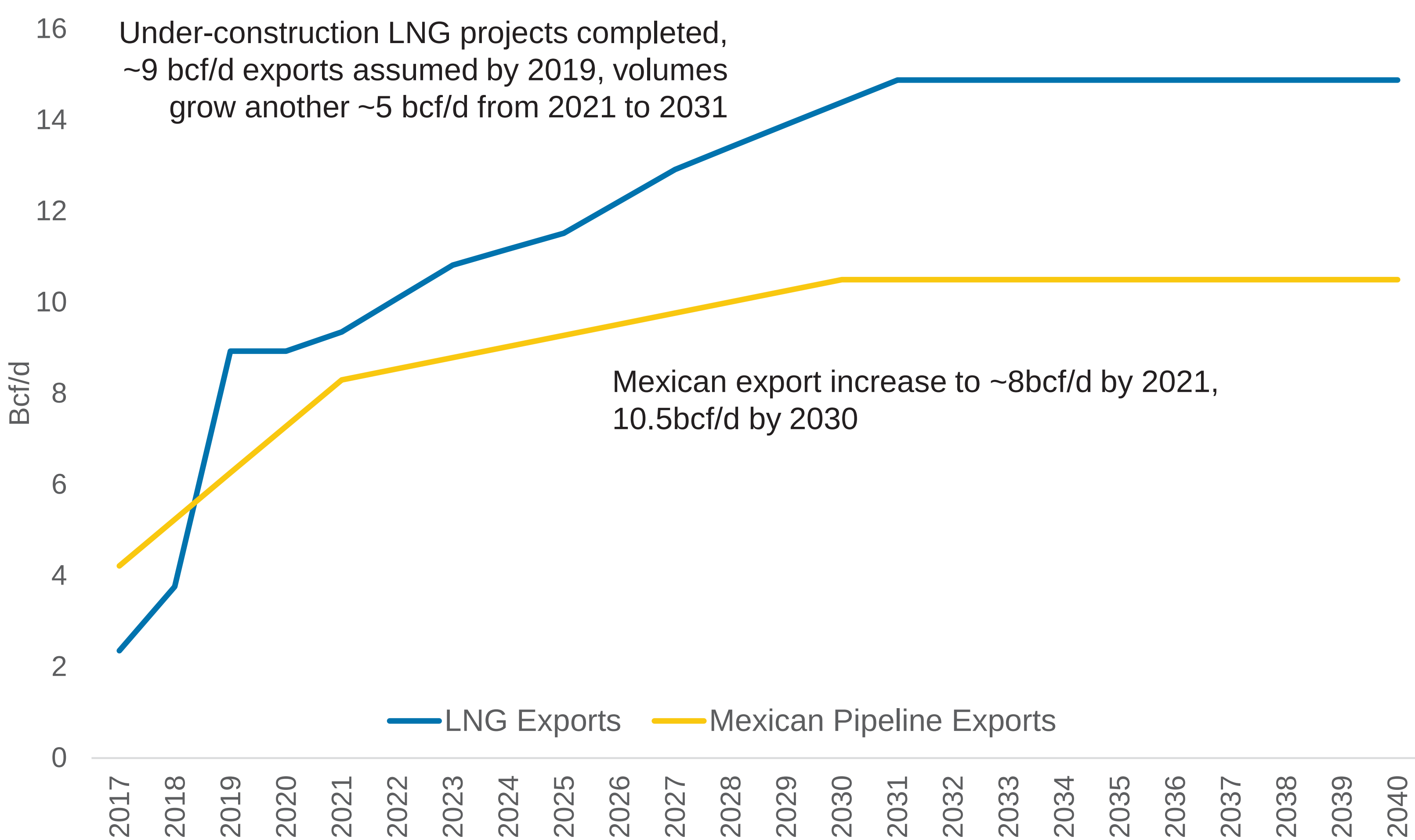
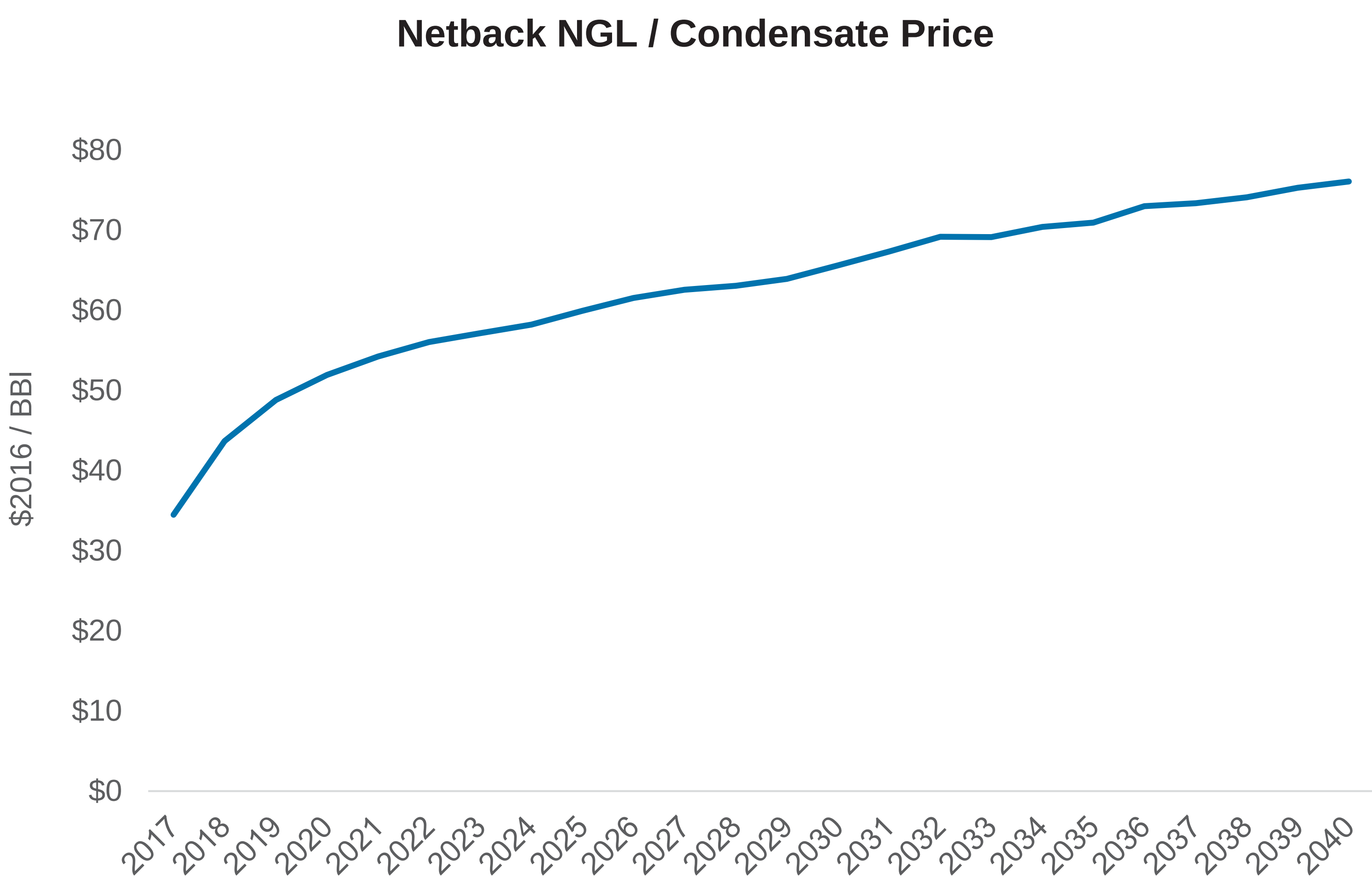
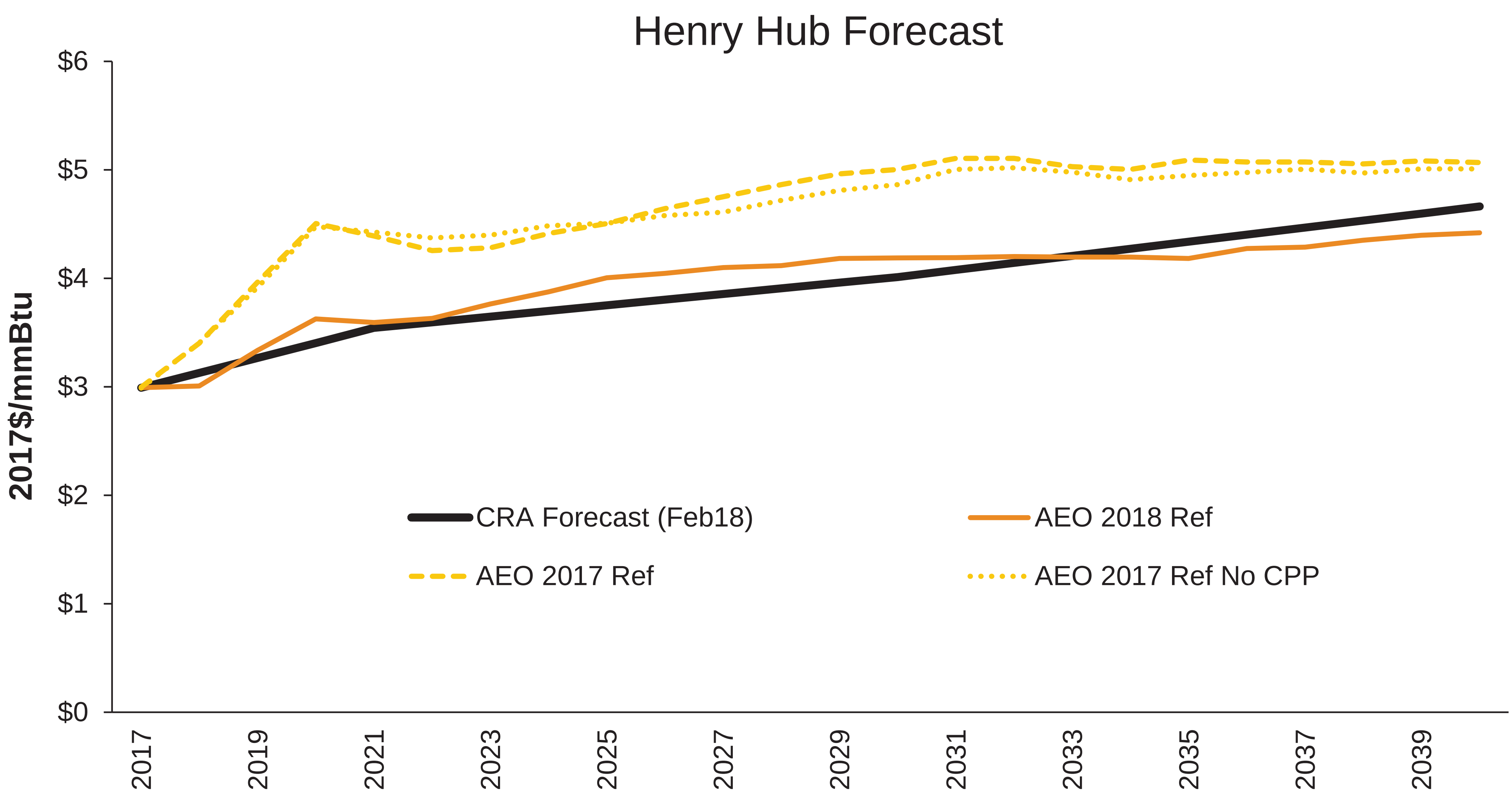
CRA assumes that LNG & Mexican gas exports grow through the 2030s



CRA assumes NGL & condensates valued at 70% of AEO reference case oil price forecast



CRA Natural Gas Price View



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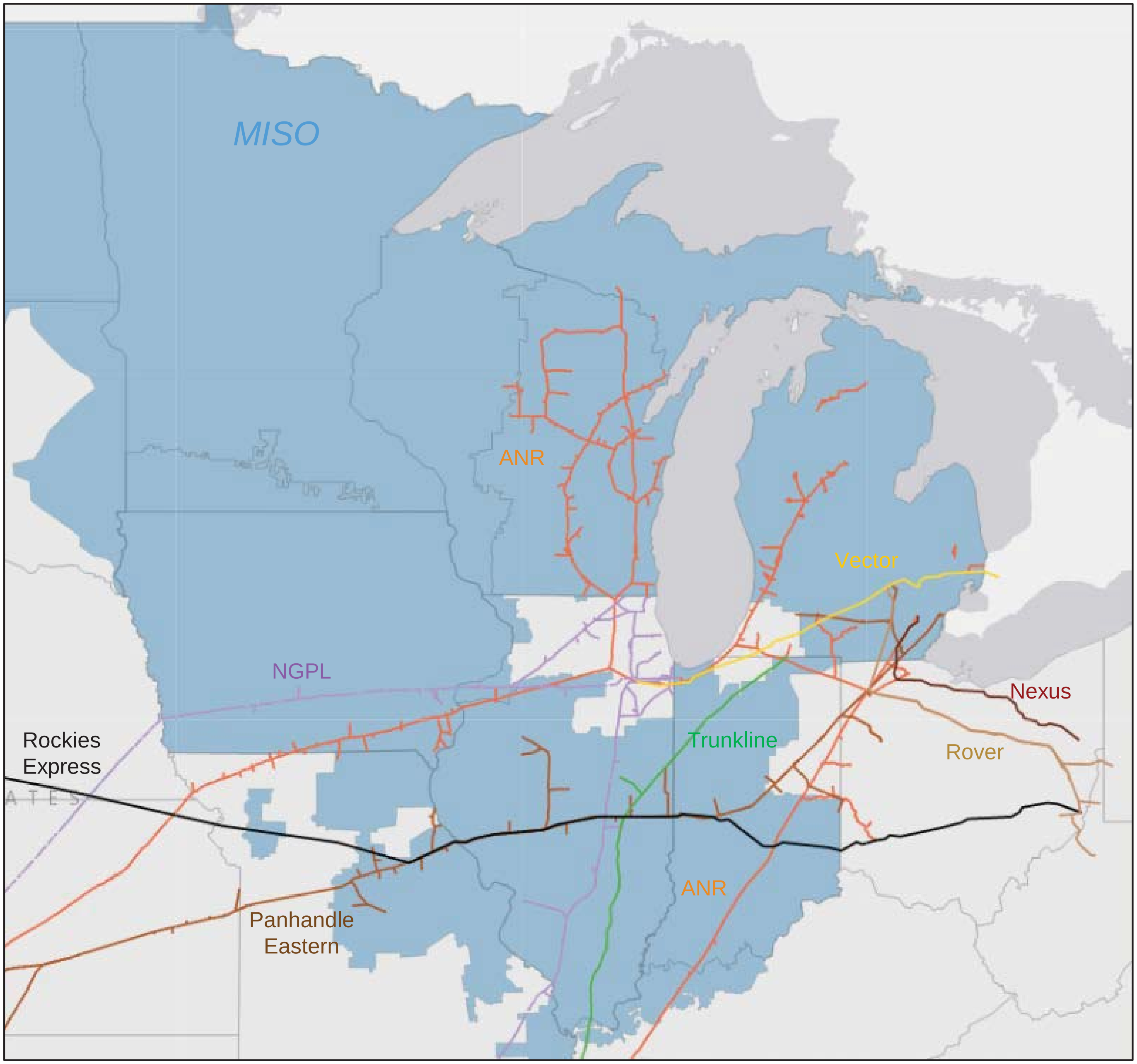
Local Gas Dynamics in MISO



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Coal Market Outlook

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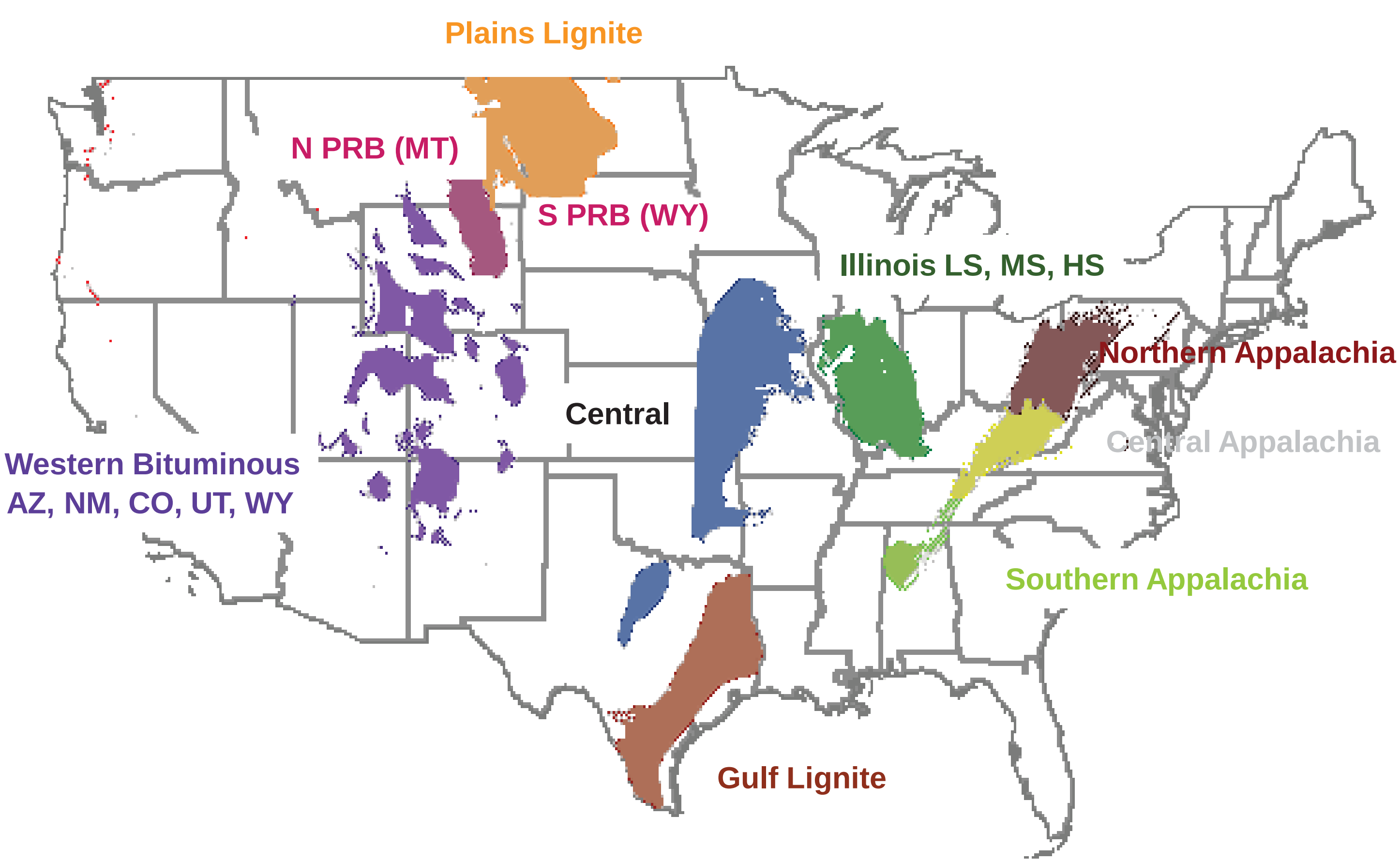
Coal

- Coal forecasting process assesses future supply/demand balance for the U.S. coal market:
  - Macroeconomic drivers, including domestic and international demand
  - Microeconomic drivers, including trends in mining costs and production trends
- The CRA NEEM model has coal supply curves, which are calibrated to reflect market analysis
- NEEM and AURORA are run in iterative fashion under various market views to develop coal price forecast



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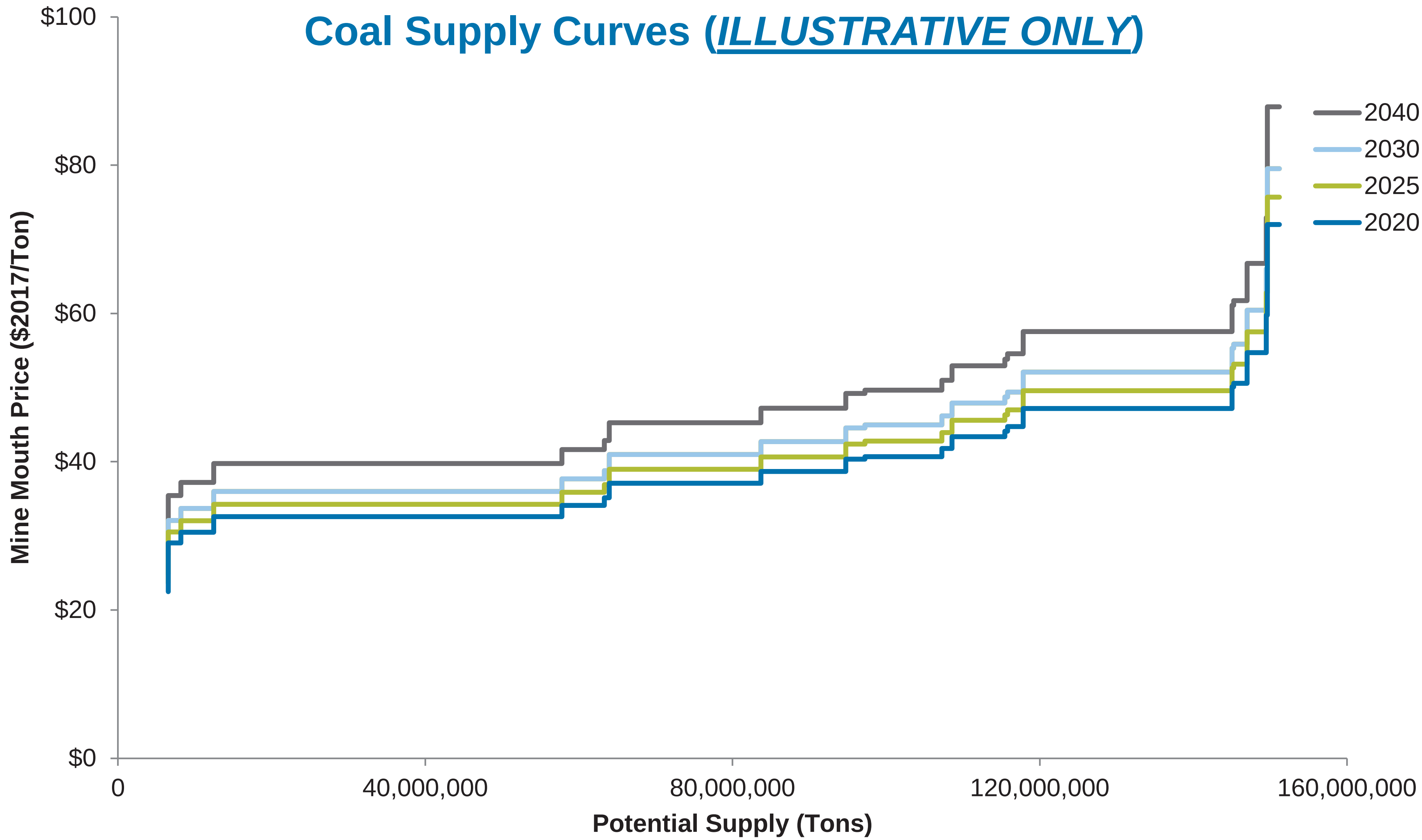
Each basin in NEEM is represented by a set of annual supply curves, which change over time to reflect cost developments & depletion (if applicable)

Coal Supply Curves (*ILLUSTRATIVE ONLY*)



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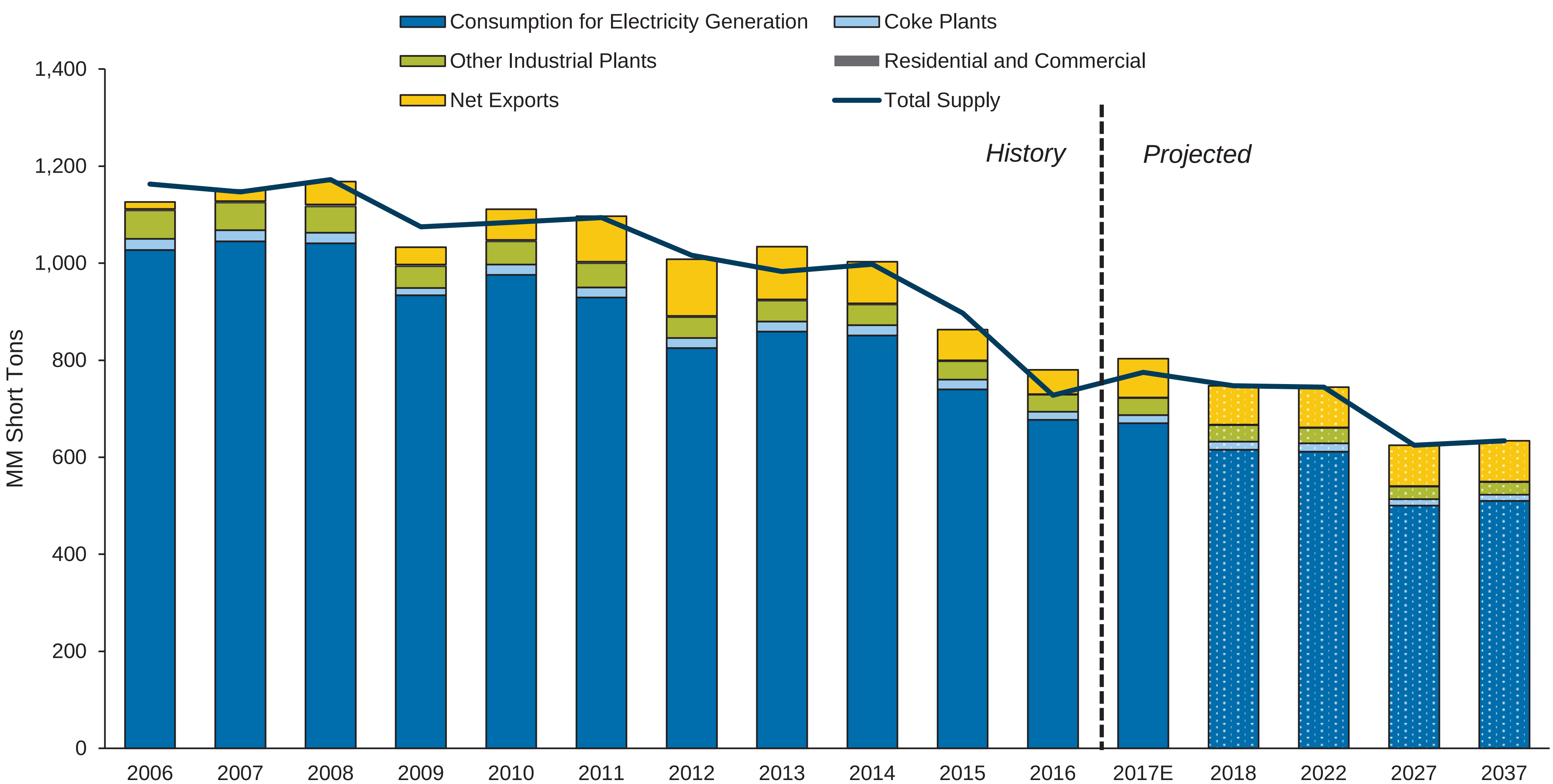
U.S. Coal Prices expected to be mostly flat over the study period

- This indicates that many market participants expect relatively weak coal demand during 2018-2021, with little appreciation or decline in real dollar pricing from current levels

- Initial results show a net decline in coal-fired demand over the study period
- CRA expects U.S. steam coal demand to fall significantly (~25%) over the next decade
- Increased renewable generation and the retirement of about 33 GW of coal-fired capacity is expected in the first 5 years of the forecast

Supply Demand Balance for U.S. Coal - 2006-2037



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Trends in Regional U.S. Coal Production

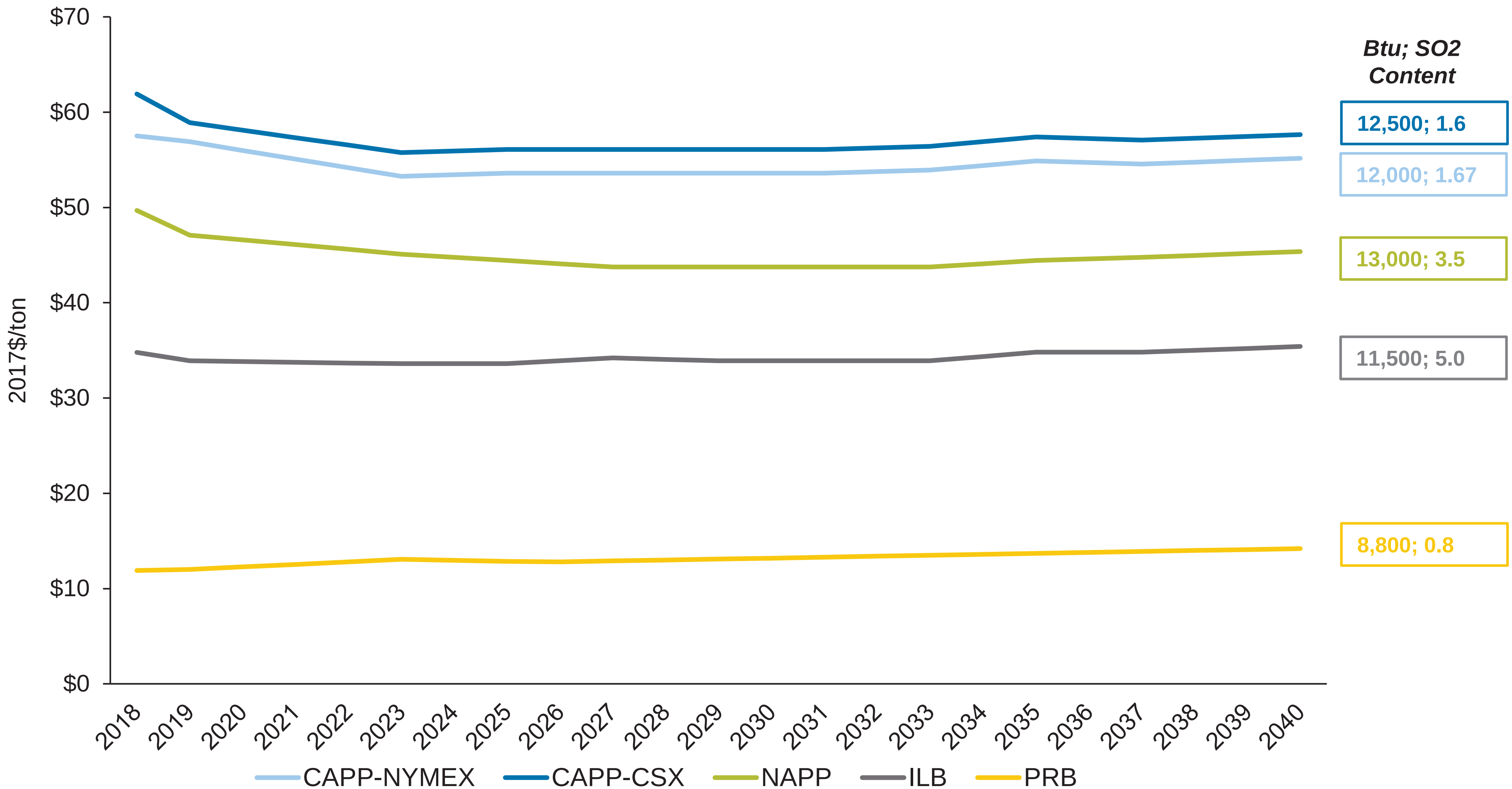
Coal Type	Current to 2027 Production Forecast (% decline)	Comments
CAPP	-21%	High cost drives decline in electric sector demand; met coal demand sustained
NAPP	-13%	Increased int'l demand and some replacement of CAPP demand
ILB	-9%	Increased int'l demand and some replacement of CAPP demand
PRB	-22%	Domestic steam coal demand declines, especially after CO_2 pressure

Summary of Price Trends by Coal

Coal	Market Trend
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton) for Appalachian coal through the early-to-mid-2020s • Thereafter, reserve depletion expected to drive modest increase in real coal price for Appalachian coals
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia • NAPP's lower cost profile, due to larger longwall mines, allows highly efficient mining of large-block coal reserves
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth
PRB	• PRB prices increase modestly (in real dollars per ton) at an average rate of 0.8%/year through the forecast period • Price growth over time driven by higher production costs due to downward-sloping coal seams/reserve depletion.

Forecast of Commodity Prices for Key U.S. Coal Types

Over the long-term, coal price projections are generally flat in real terms



Carbon Price Outlook

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Carbon Policy and Emission Pricing

- Assumes a new federal rule or legislative action coming into force by the mid-2020s. Analysis suggests a ~20% reduction in U.S. coal demand post-2026 vs. a $0 carbon price scenario.
- Rationale
  - Timing: New administration post-2020 would need to re-develop rule through EPA or pursue a legislative fix with a newly constructed Congress. Earliest likely implementation around 2026.
  - Stringency: In line with CPP-type stringency (ie, 30-40% reductions in emissions vs. historical baseline)

- Assumes a modified EPA plan to control carbon, with focus on “Building Block 1” coal plant heat rate efficiency improvements. No specific tax or emission cap requirement would be present under such regulations.
- Rationale
  - Trump Administration has withdrawn CPP with a focus on modest replacement to meet requirements of the endangerment finding. Thus, the base case would follow current rule revision expectations, with long-term potential of a continued divided Congress/Executive Branch and/or prolonged legal challenges for any future EPA regulation.

- Assumes a stricter new federal rule or legislative action coming into force by the mid-2020s. Price levels are generally consistent with a 50-60% reduction in electric sector CO_2 emissions relative to 2005 by the 2030s.
- Rationale
  - Timing: Same as Base Case
  - Stringency: Would represent an initial pathway towards aggressive carbon reduction goals (ie, 80% by 2050 target under the “2 degree” scenario). *Note that economy-wide reduction scenario has not been evaluated to date.*

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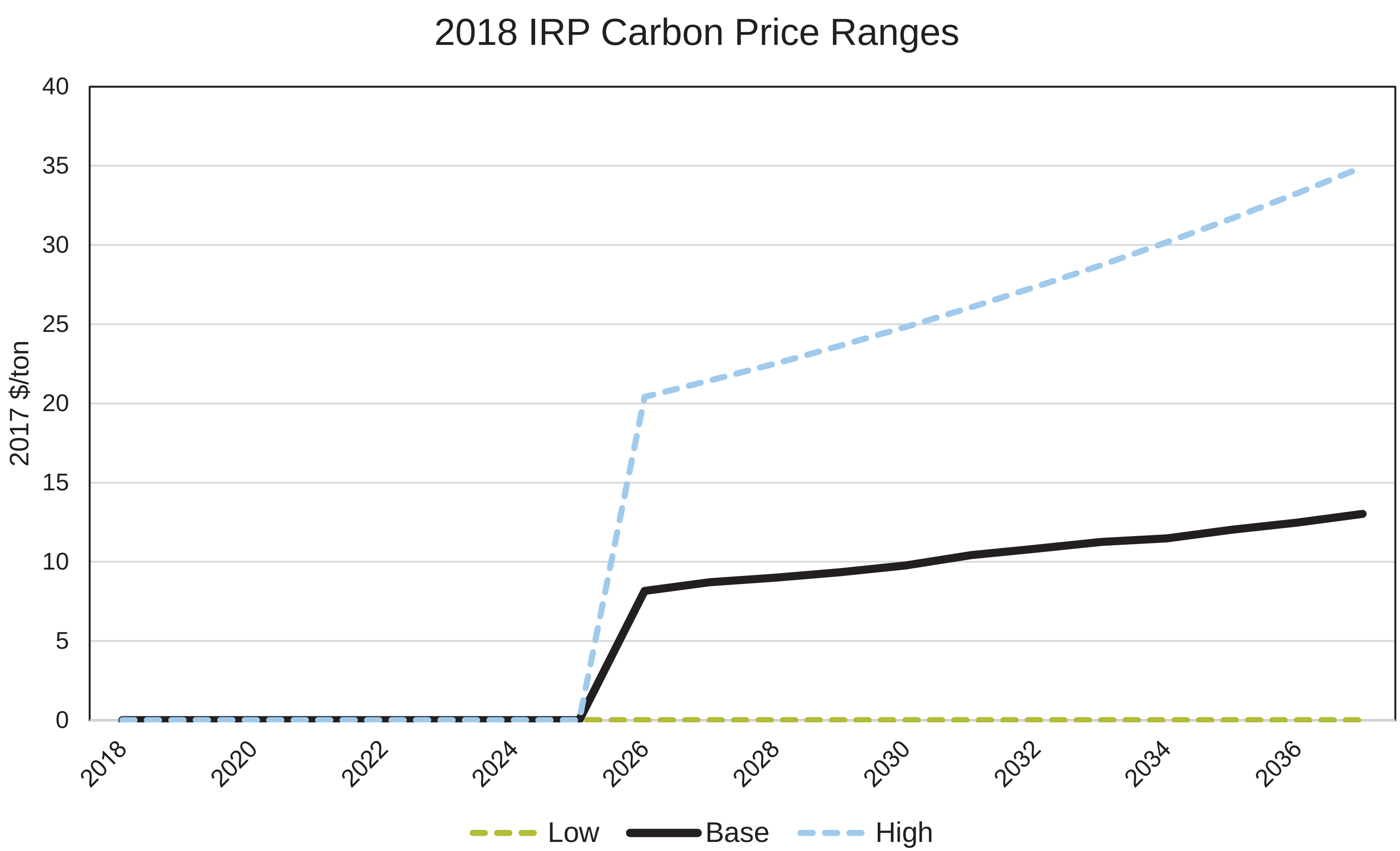
Carbon Policy and Emission Pricing



**Note that high case represents a potential initial pathway for an 80% power sector CO2 emission reduction by 2050. An additional scenario with broader economic impacts may be assessed at a later time as a separate scenario.*

MISO Power Market Outlook

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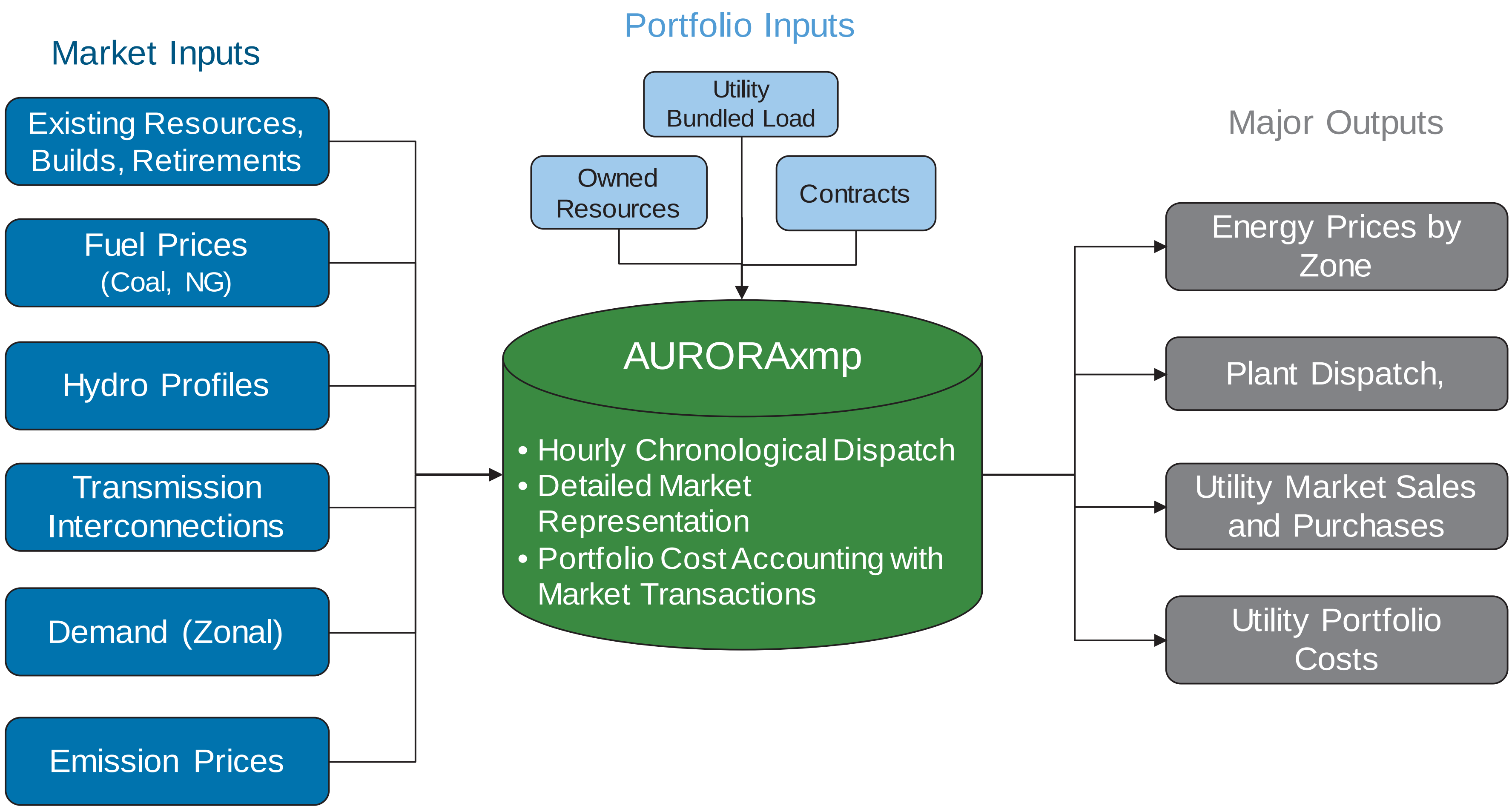
AURORA – Power Price Forecasting



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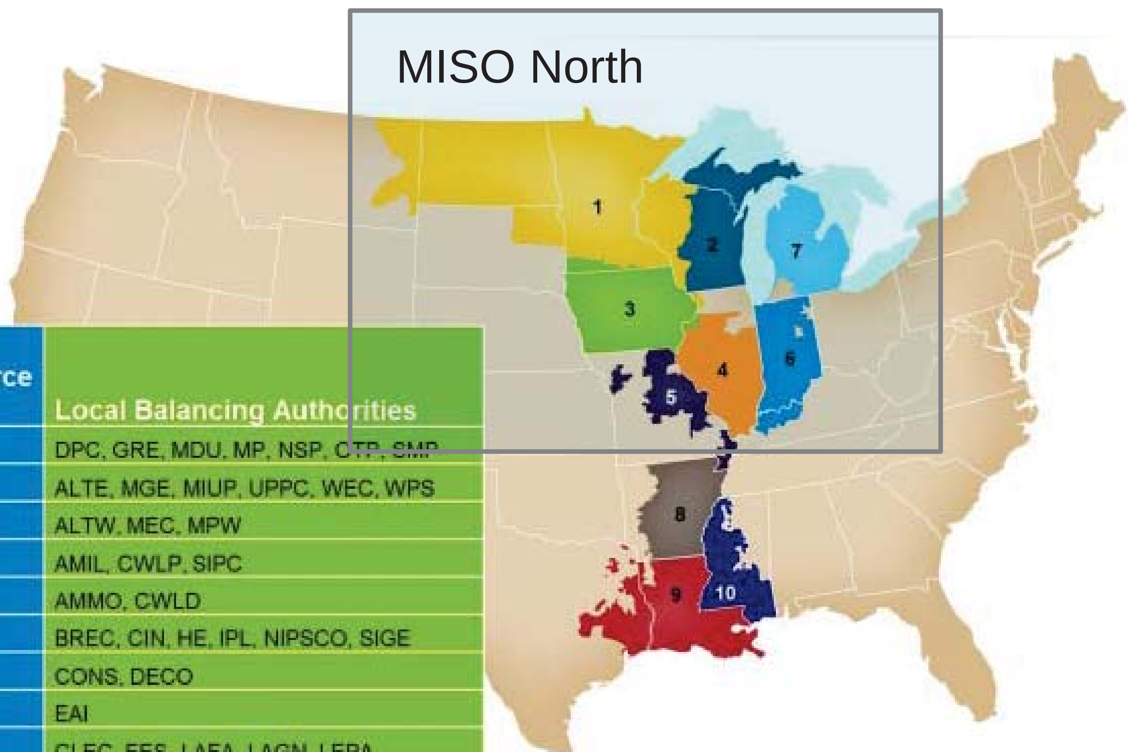
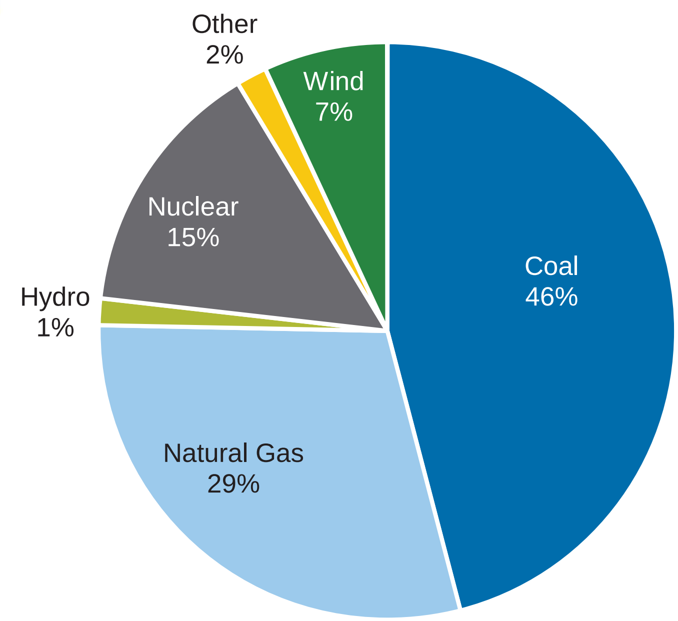
MISO – Overview



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

MISO Historical Generation by Fuel Type
Total: 686 GWh



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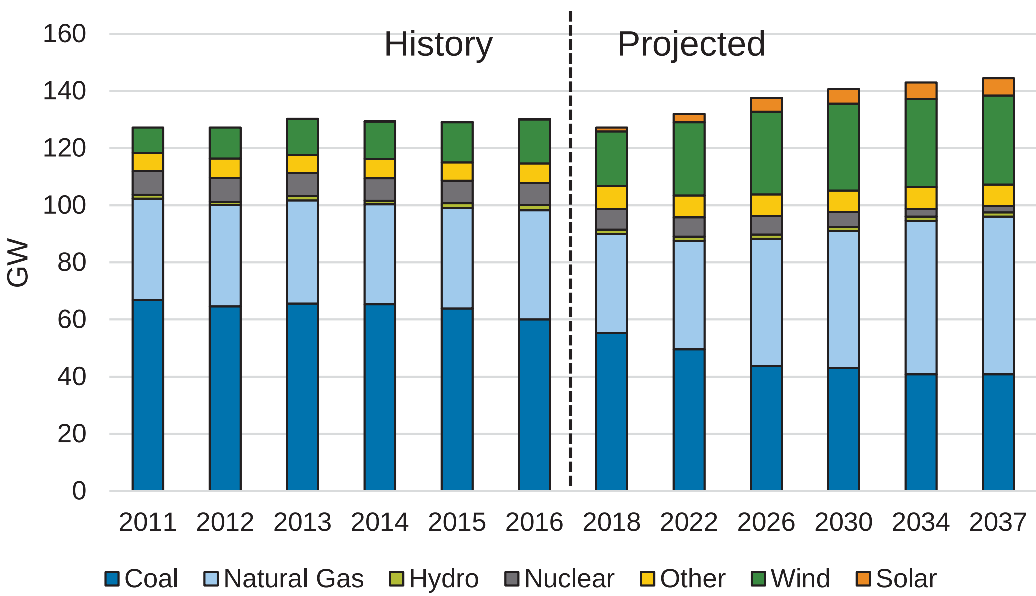
Expected continued shift from coal to gas and renewables in MISO

– 6.3 GW decline in net coal capacity; no new coal plants since 2013

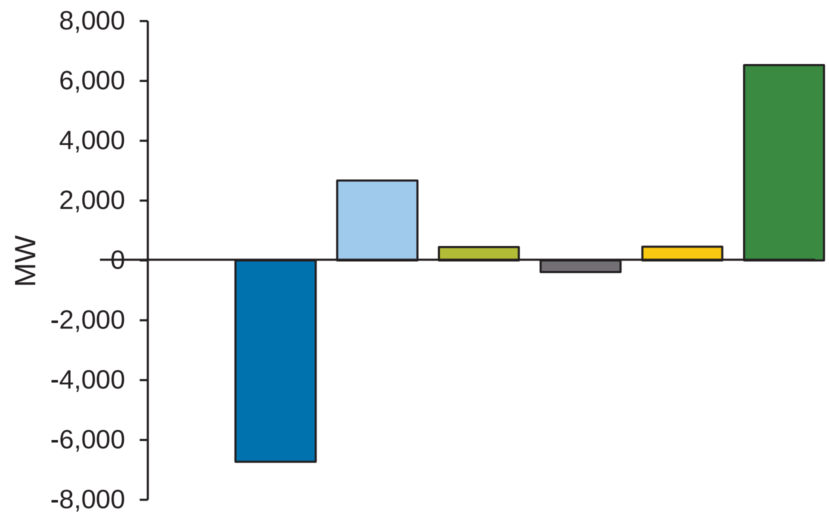
– Indiana Zone: Bailly 7 and 8, Schahfer 17 and 18, and Vectren AB Brown plant

MISO North* Net Winter Capacity by Fuel Type



*MISO North includes LRZ 1-7

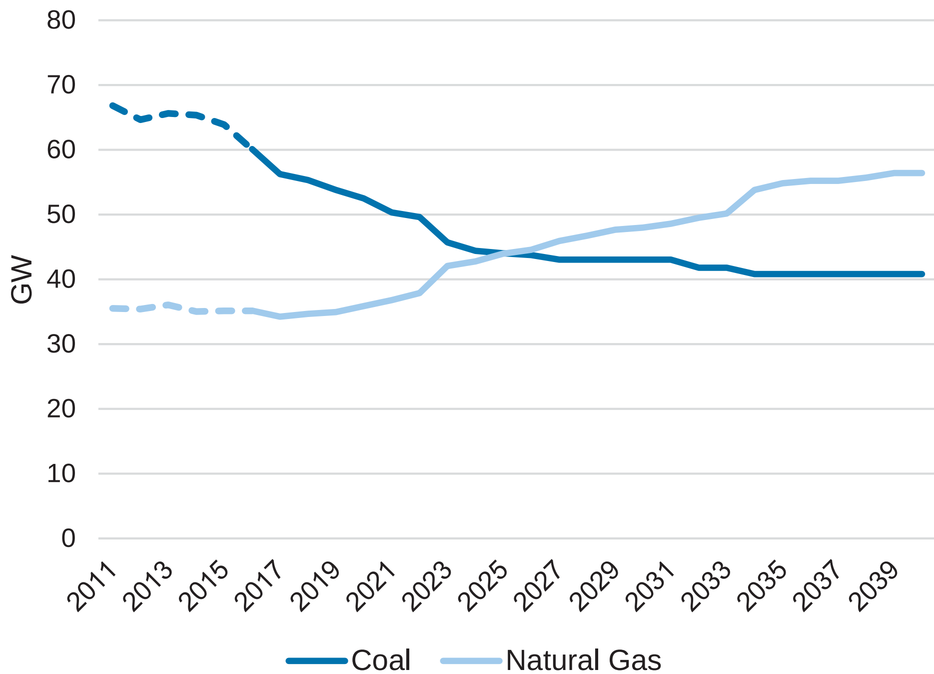
Net Change in Capacity, 2011-2016

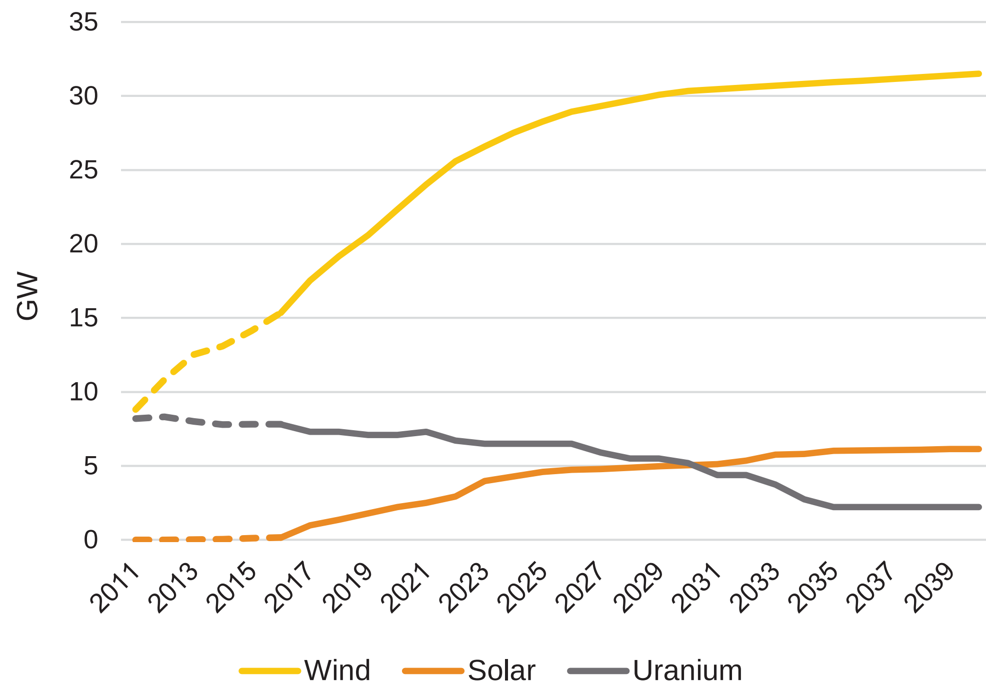


CRA expects broad trends to continue across MISO

- Coal comprised 46% of total energy produced in MISO-North in 2016, compared with 61% of energy in 2011
- Retiring coal and nuclear capacity is expected to be replaced by a mix of gas and renewables

MISO North Capacity by Fuel Type





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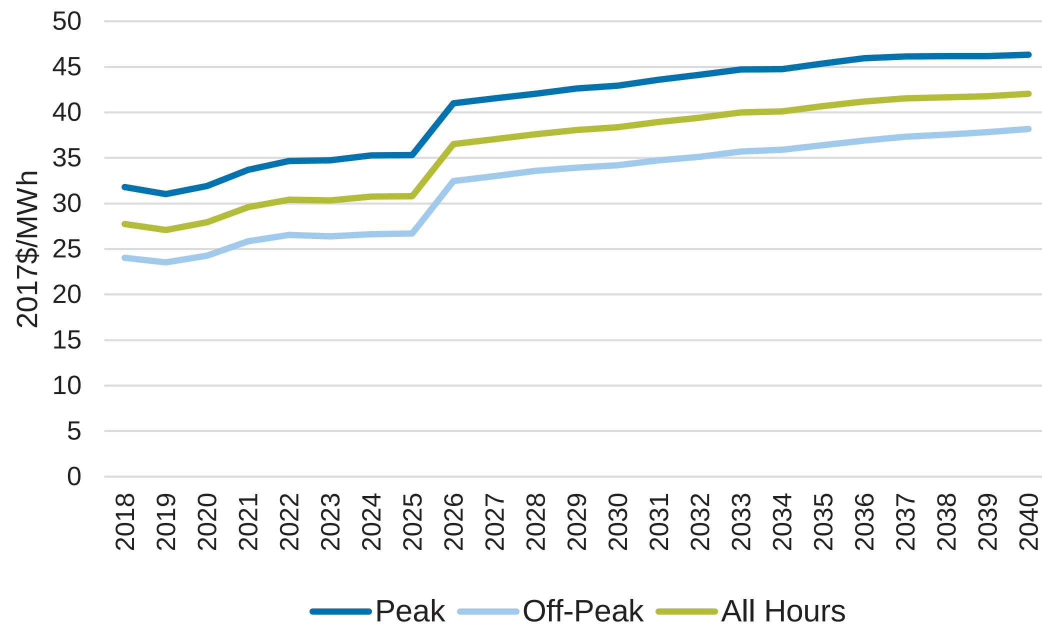
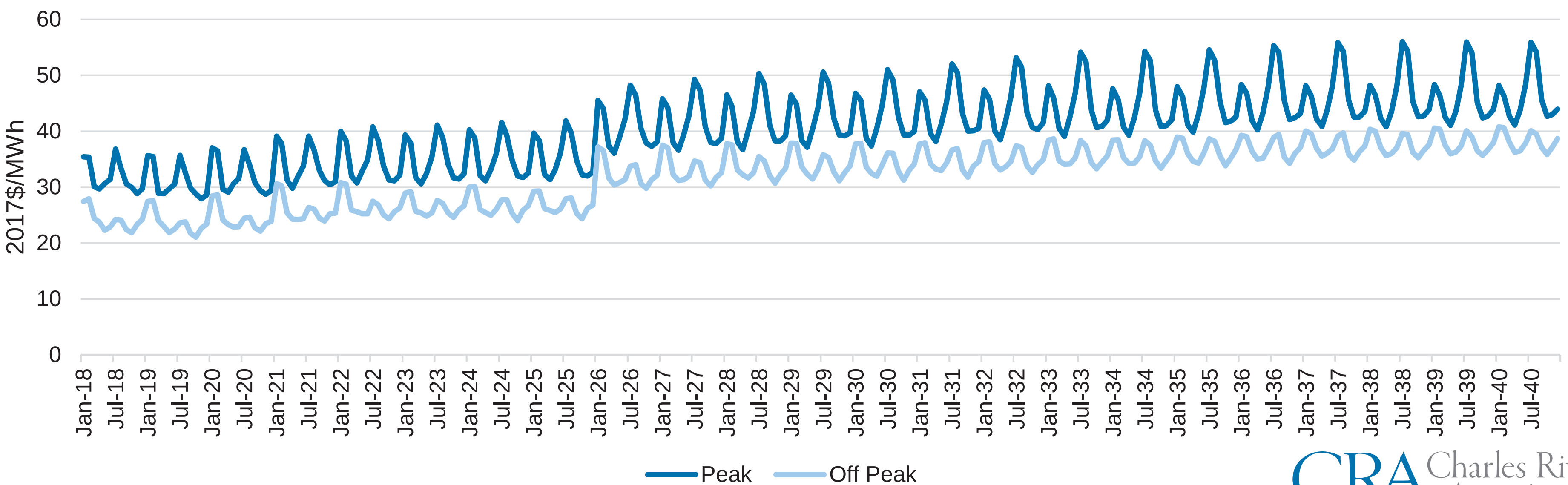
CRA Power Price Forecast – MISO Zone 6

- Power prices are relatively flat in the near-term, due to flat gas and coal prices and relatively modest load growth
- Some upward pressure expected into the 2020s as a result of higher natural gas prices, although growing renewables lower the market heat rate over time
- National carbon price, starting in 2026, drives price increase





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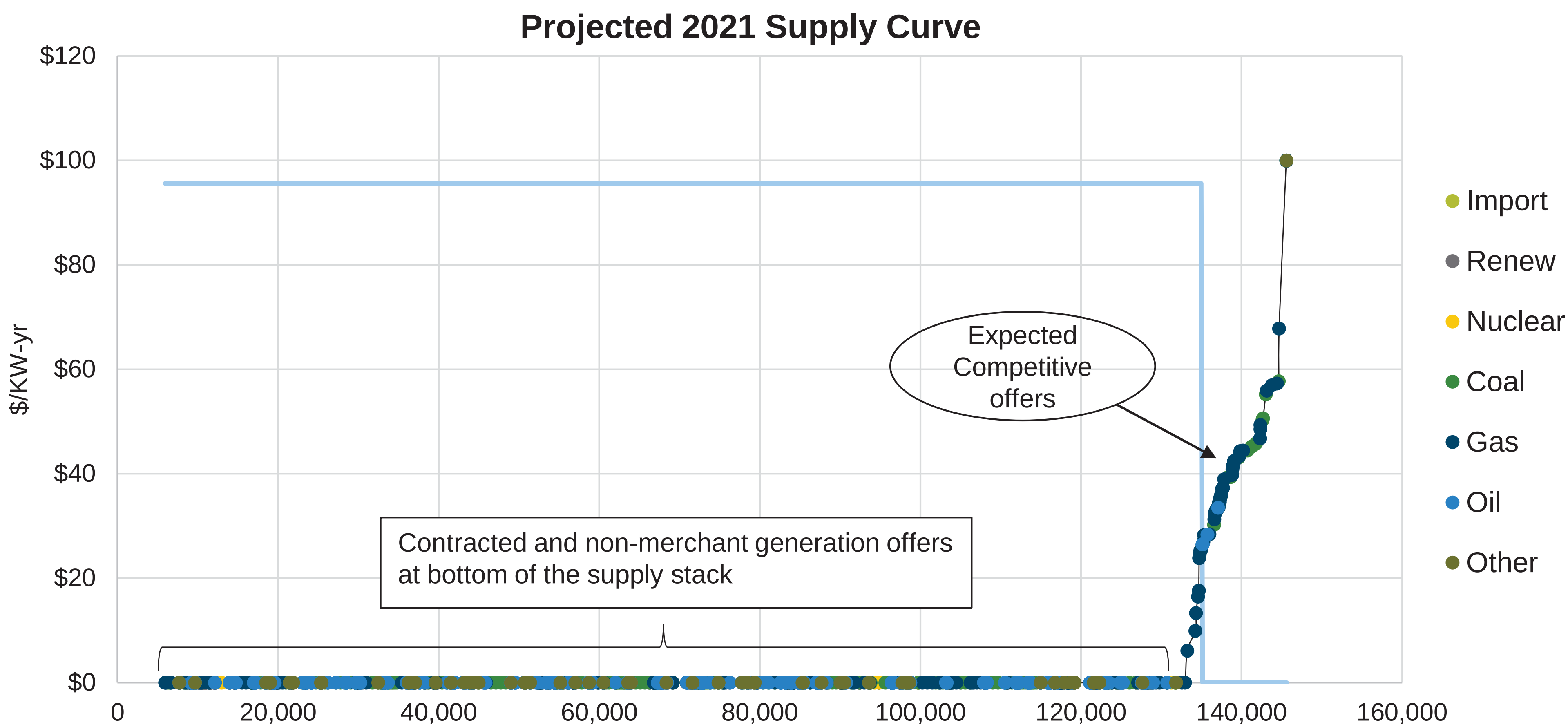
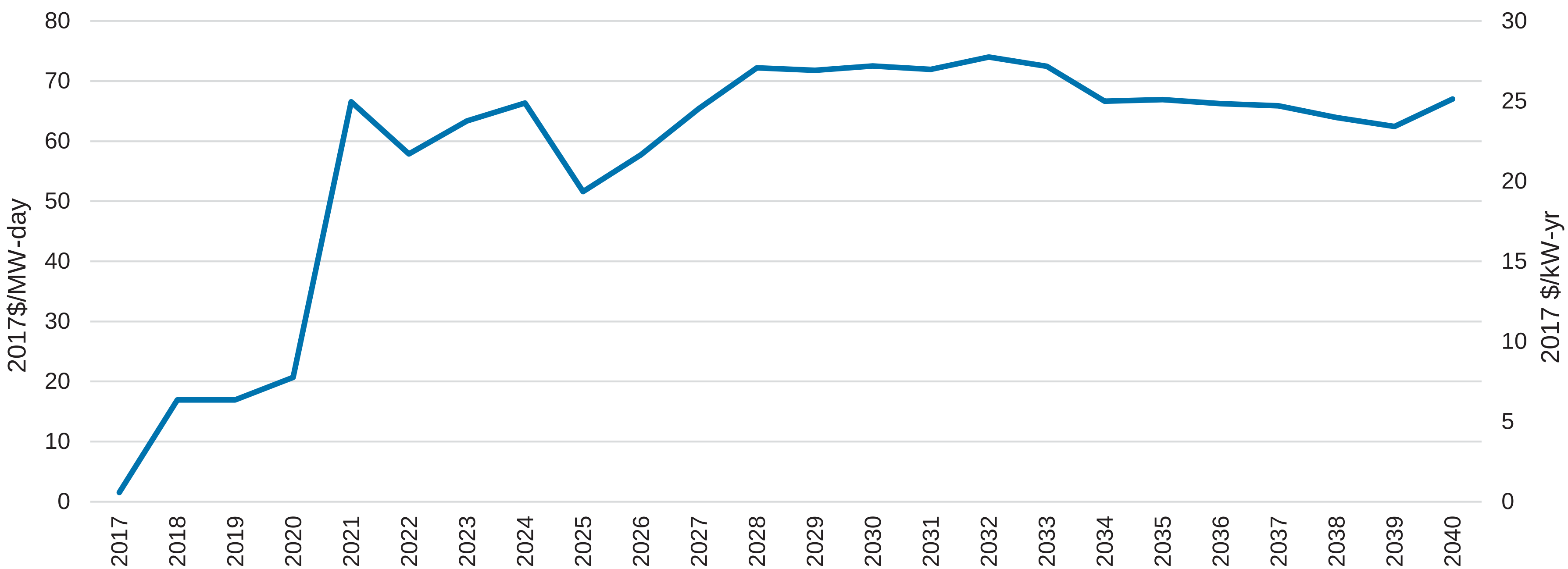
Capacity prices are influenced by market design



CRA MISO Capacity Price Forecast

- Flat load and increases in renewable, behind-the-meter, and DR/EE supply
- Tariff revisions impacted offer thresholds on the low end
- Import constraints between North and South relaxed



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Demand Side Management Update

Alison Becker
Manager Regulatory Policy

Richard Spellman
GDS Associates (GDS)

2018 Electric DSM Savings Update

- The Electric DSM Savings Update report will focus on a 20-year time horizon (2019-2038).
- For years 2019-2021, data will be gathered from NIPSCO's recent filing in Cause No. 45011 pending before the Indiana Utility Regulatory Commission ("IURC").
- GDS will update measure costs, kWh and kW savings, useful lives, saturation data, etc.

2018 Electric DSM Savings update (continued)

- The savings update will consider new sources of secondary data that are now available.
- The final Electric DSM Savings Update report will be completed by June 1, 2018
  - GDS will present draft results to the Oversight Board during the April meeting

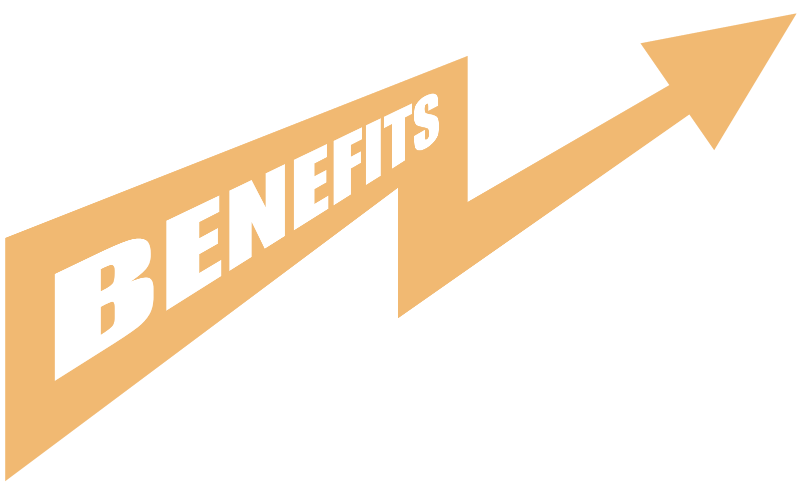
2018 Electric DSM Savings Update Report Contents

- Recommended cost-effective DSM savings measures and programs.
- Information on innovative programs and technologies.
- Budgets for each program.
- A cost-effectiveness ranking for all technologies (measures) reviewed.
- Cost-effectiveness evaluations for each proposed program.
- GDS will calculate the Total Resource Cost ("TRC") test, the Utility Cost test, the Participant test and the Rate Impact Measure ("RIM") test.
- The TRC test will be used to determine measure, program and portfolio cost effectiveness.

Technical Approach for Electric Baseline Development

FOUR-STEP PROCESS TO COMPLETING BASELINE DEVELOPMENT

1) Review Existing Market Data
2) Conduct Additional Primary Market Research
3) Market Characterization/Segmentation
4) Energy Usage (8760) Modeling / Forecast Calibration



BENEFITS OF APPROACH

~ Identify Data Gaps

~ Collection of Updated Market Data

~ Development of Updated and Detailed Market Segmentation

~ Alignment of Baseline End Use / Technology Consumption Estimates with Overall Energy Consumption Forecasts

Development of DSM Assumptions

- GDS will develop appropriate base case and energy efficient case assumptions at the measure level to inform the measure characterization.
- Updates will include:
  - Measure costs
  - Measure kWh and kW savings
  - Measure lives
  - Measure and equipment saturation data

Technical Approach-Measure Assumptions

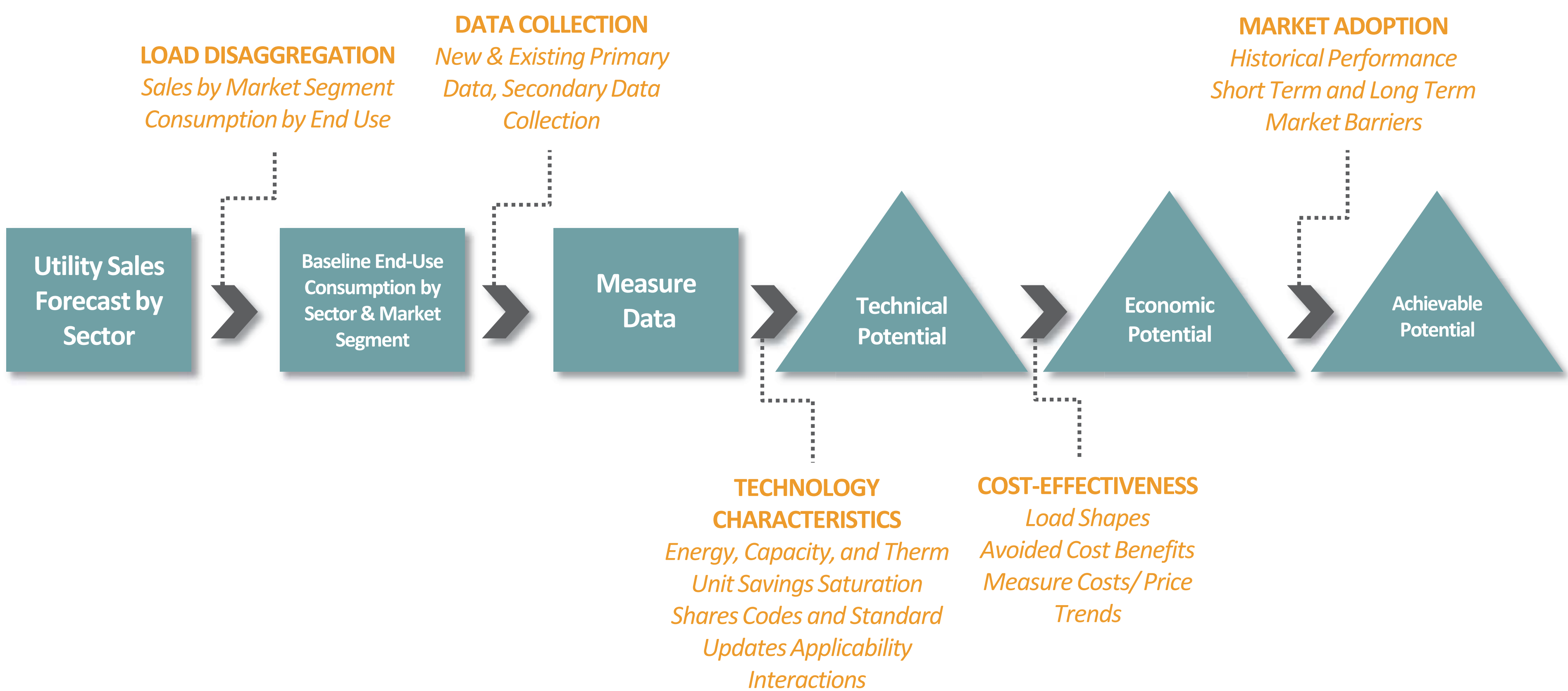
ASSUMPTION DEVELOPMENT

- **Develop measure database with detailed sourcing**
- **Account for codes and standards**
- **Coordinate with NIPSCO/OSB on critical methodological decisions**
  - Future potential of currently installed efficient technologies
  - Applicable replacement strategies (e.g. Replace on burnout, retrofit, early replacement)
  - Achievable potential scenario development
- **Develop appropriate funding levels and market adoption rates**
- **Quality control of model inputs/outputs**

METHODS & SOURCES

- **Review of existing market data (Subtask 1.1)**
- **Primary market research (Subtask 1.2); surveys, interviews, on-site inspections**
- **Indiana Technical Resource Manual version 2.2 for measure data**
- **NIPSCO program planning and evaluation data, other industry sources**
- **Energy modeling software**

Assessment of Potential Savings



Development of Funding Levels

GDS will recommend the appropriate and necessary funding levels that will support achieving specific levels of program penetration and delivery over various time periods.

Paul Kelly

Director of Federal Regulatory Policy

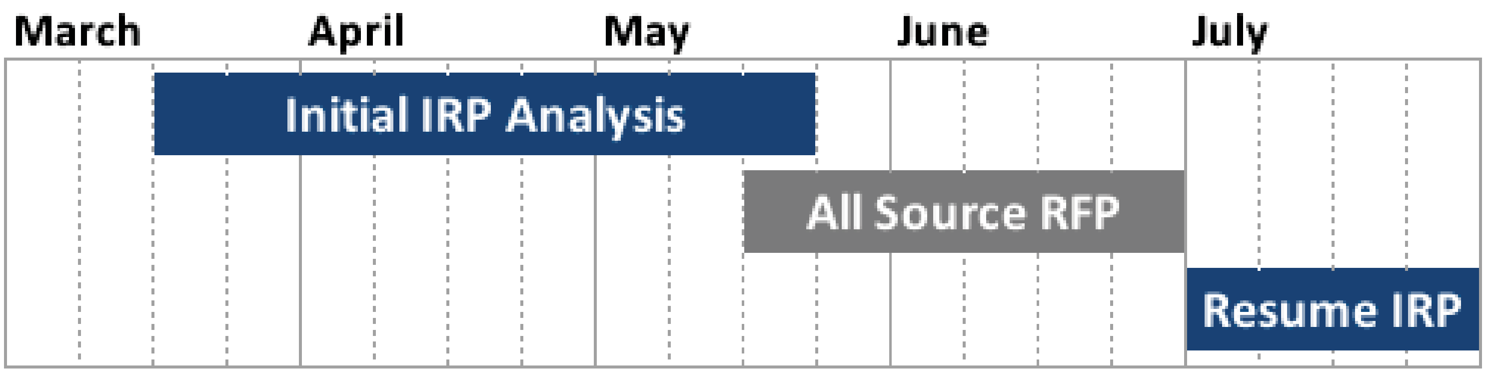
Goal | **Identify every viable resource in the market that can best meet our customers' needs**

- **Expert Assistance**
  - Retained Charles River Associates (CRA) to develop and administer RFP
  - Utilizing a separate division within CRA to ensure independence from the IRP process
- **Stakeholder Input**
  - Seeking feedback on approach/design to ensure a robust, transparent process and result
- **Resource Evaluation Criteria**

  Complementary to the IRP portfolio analysis:
  - Cost to our customers
  - Reliability
  - Deliverability
  - Duration
  - Environmental impact
  - Employee and operational impact
  - Local community impact

- **Technology**
  - Requesting all solutions regardless of technology, including demand-side options and storage
- **Size**
  - Defining a minimum total need of 600 MW for the portfolio but without a cap
  - Allows smaller resources <600 MW to offer their solution as a piece of the total need
  - Also encourages larger resources >600 MW to offer their solution for consideration
- **Acceptable Arrangements**
  - Seeking bids for asset purchases and purchase power agreements for new and existing resources
- **Duration**
  - First year of need begins June 1, 2023
  - Minimum contractual term and/or estimated useful life of 5 years
- **Deliverability**
  - Solutions must have firm transmission delivery to MISO Local Resource Zone 6
- **Participants & Pre-Qualification**
  - Intending to leverage CRA's network of contacts and recommendations from stakeholders
  - Requiring utility-grade counterparties to ensure credit quality and ability to fulfill resource obligation

Timeline for the RFP



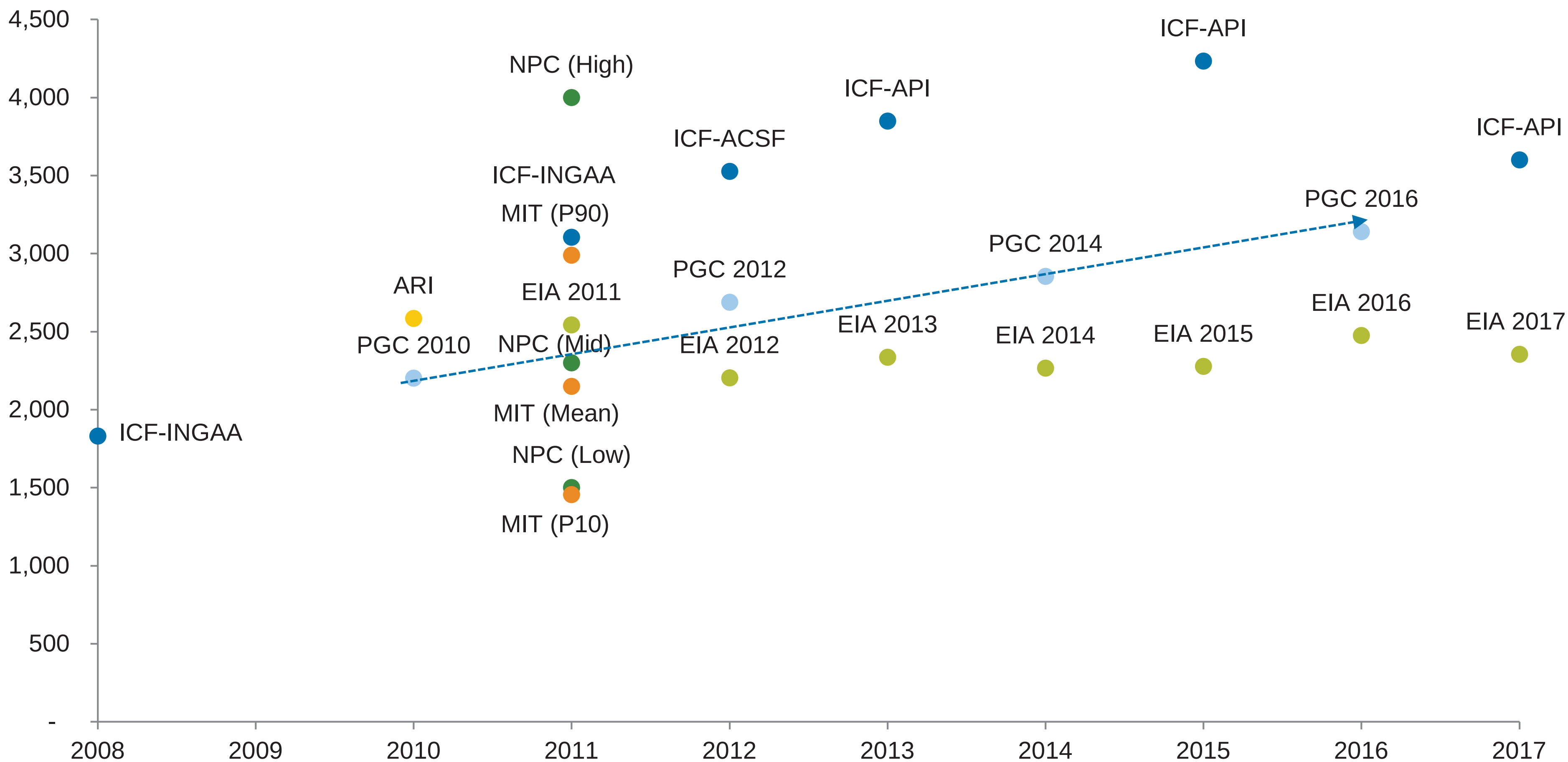
Date	Event
March 23rd	Overview RFP design with stakeholders
April 6th	RFP Design Summary document shared with stakeholders to request feedback
April 20th	Stakeholder feedback on Design Summary due back to NIPSCO
May 14th	**RFP initiated**
May 28th	Notice of Intent and Pre-qualifications due from potential bidders
June 29th	**RFP closes**
July 24th	Summary of RFP bids presented at Public Advisory Meeting webinar; IRP resumes analysis incorporating results of RFP

Similar to the 2016 IRP, NIPSCO plans to conduct a robust stakeholder engagement process for the 2018 IRP, including five formal stakeholder engagement meetings and one on one meetings with interested parties

	Meeting 1 – March 23- Avalon Manor	Meeting 2 – May 11 Avalon Manor	Meeting 3 – July 24 Webinar, SouthLake	Meeting 4 – September 19 Fair Oaks Farms	Meeting 5 – October 18 Fair Oaks Farms
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source RFP Solicitation?	- What are the preliminary findings from the modeling ?	- What is NIPSCO's preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP - Common understanding of DSM modeling methodology - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Stakeholder feedback and shared understanding of the modeling and preliminary results - Review stakeholder modeling and analysis requests	- Communicate NIPSCO's preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

Gas Price Drivers – Resource Size

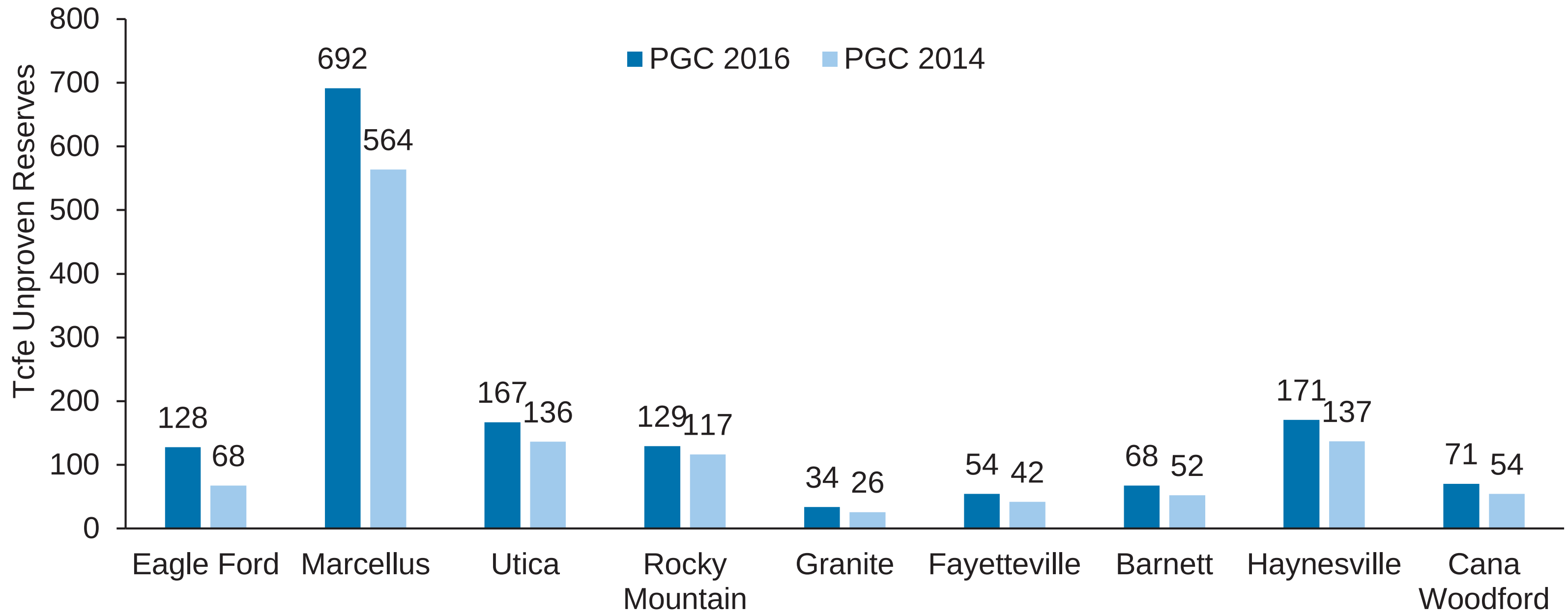
Estimates of resource in place have grown steadily as additional gas and oil continue to be discovered and extraction technology improves



* Note that CRA relies on the Potential Gas Committee (PGC) biennial report as the basis for our NGF resource estimate

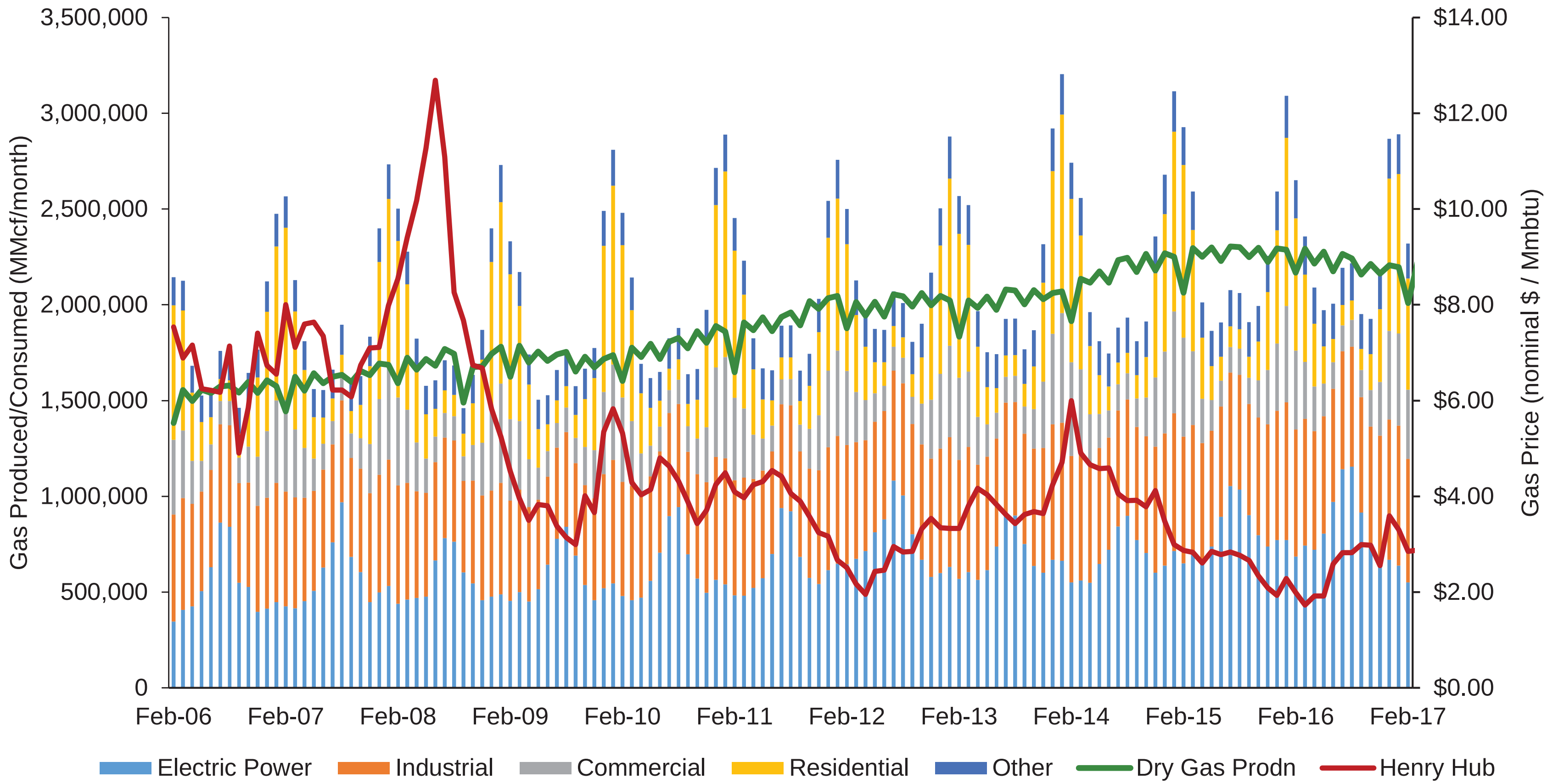
Gas Price Drivers – Resource Size

- Shale resource drives the increase in total U.S. gas resource estimates in the PGC 2016 Natural Gas Supply Study
  - PGC 2016, released in July of 2017, estimates a “Traditional” unproved gas resource of 2,658 Tcf, a 12% increase from PGC 2014
  - The increase in total resource growth is driven primarily by shale gas resource, PGC 2016 estimates a total of 1,578 Tcf of shale resource, up from 1,253 Tcf in PGC 2014
- This is PGC’s fifth consecutive publication showing an increase in resource estimates



Gas Price Drivers – Well Productivity

Natural Gas Dry Production and Consumption



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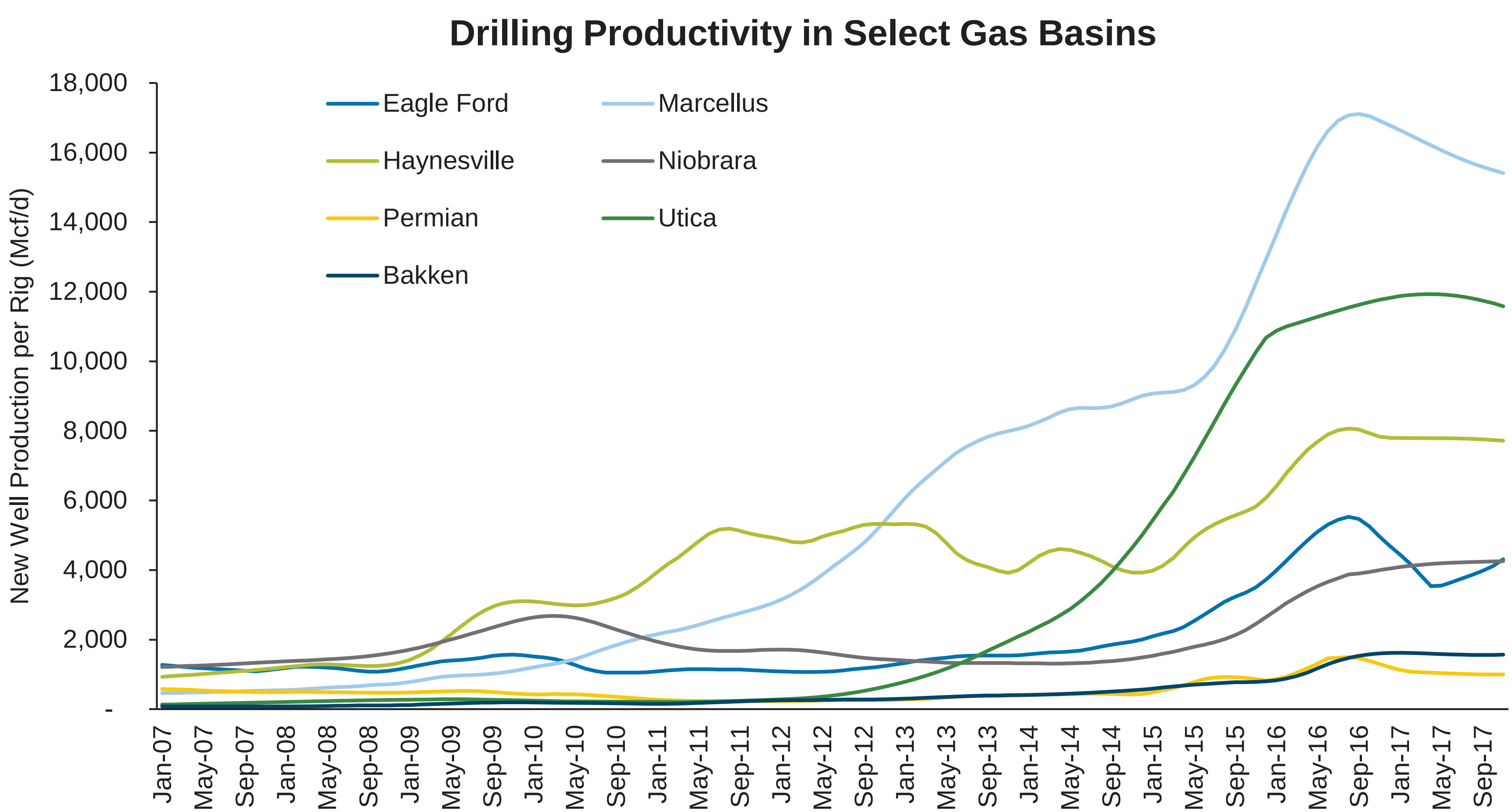
Gas Price Drivers – Productivity Trends



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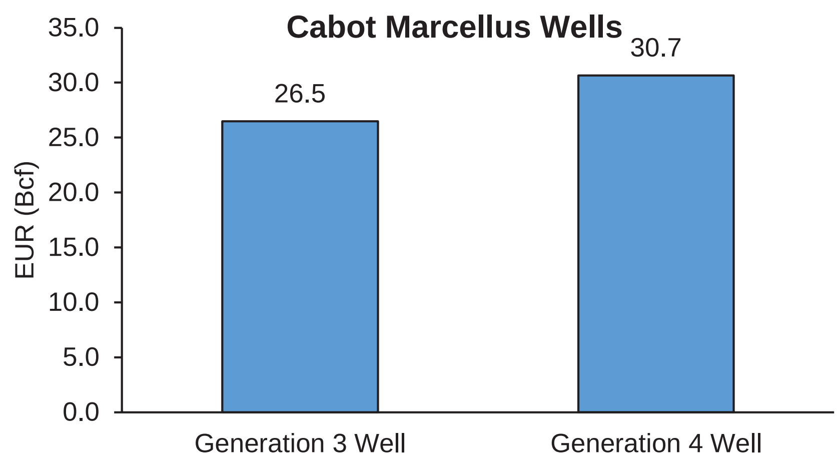
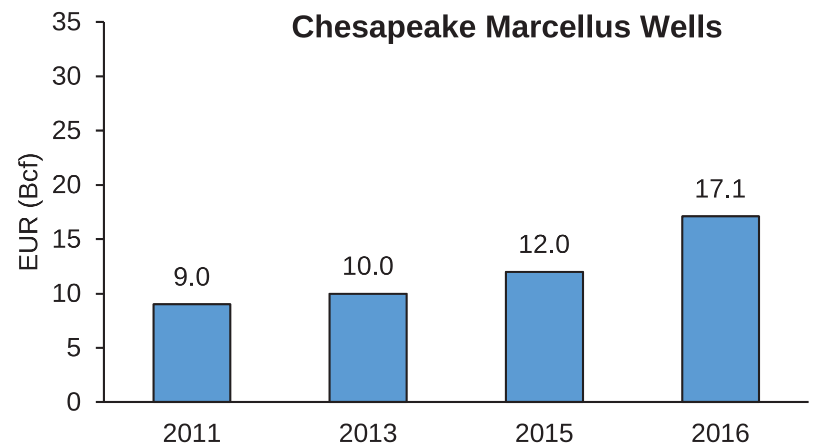
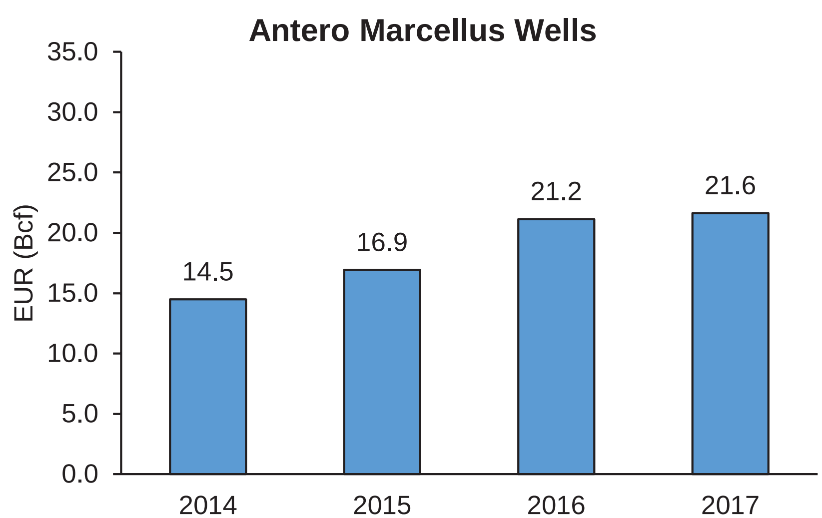
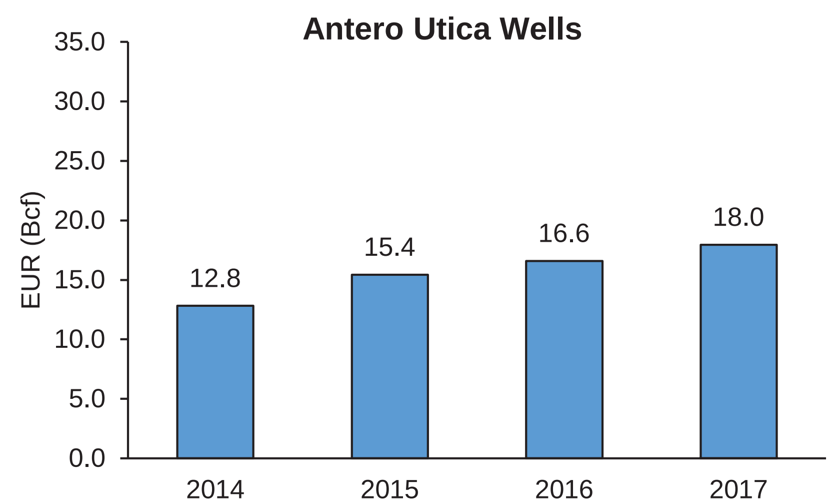
Appendix – Natural Gas - Productivity

Well productivity on a per well basis has been consistently improving, even as longer laterals and multi pad drilling improve per rig performance









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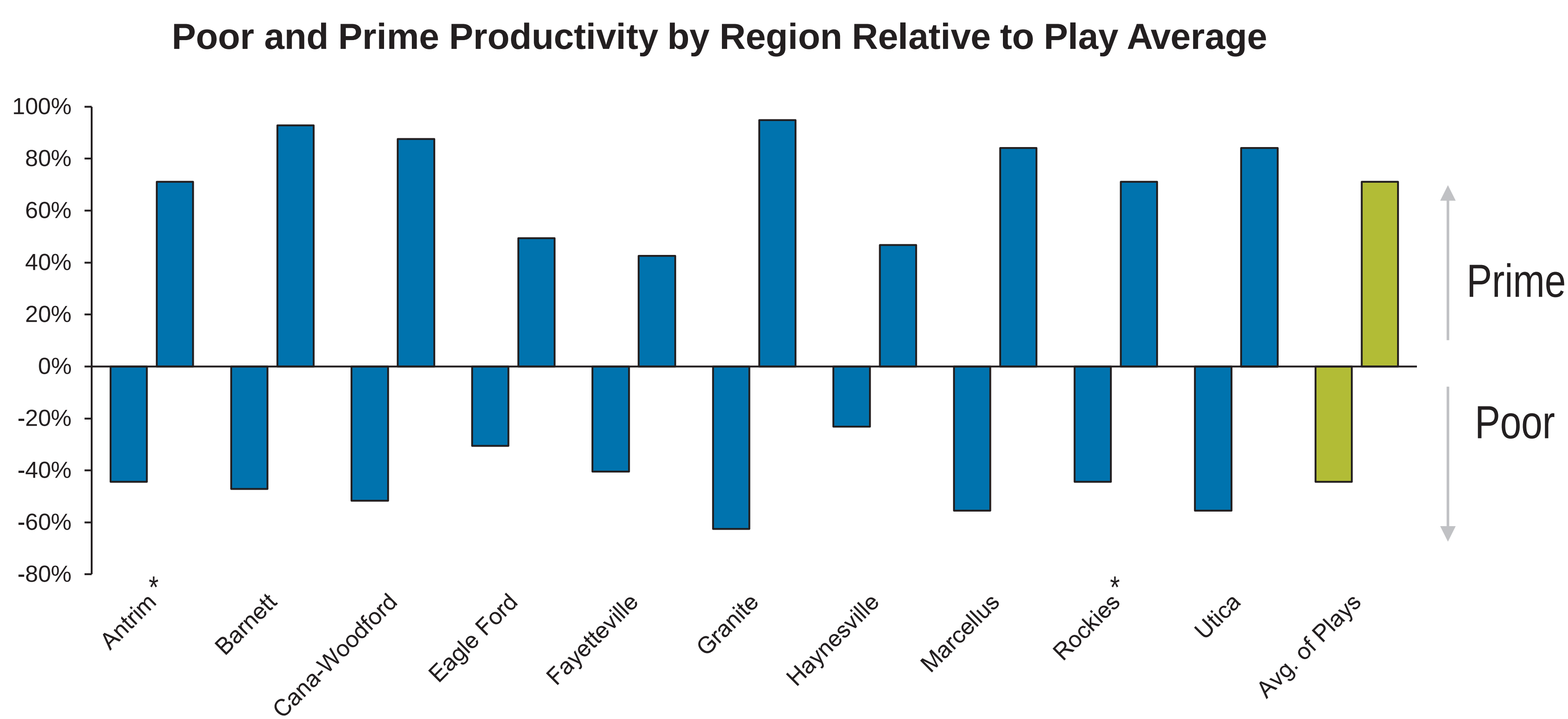
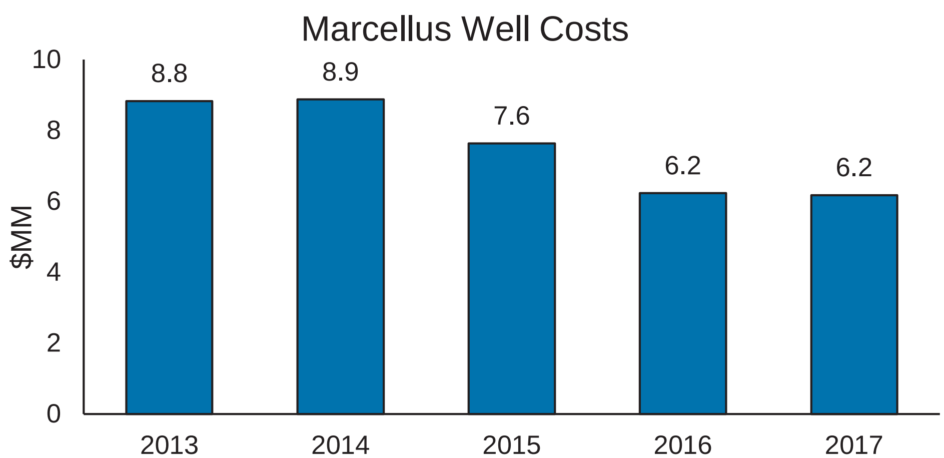
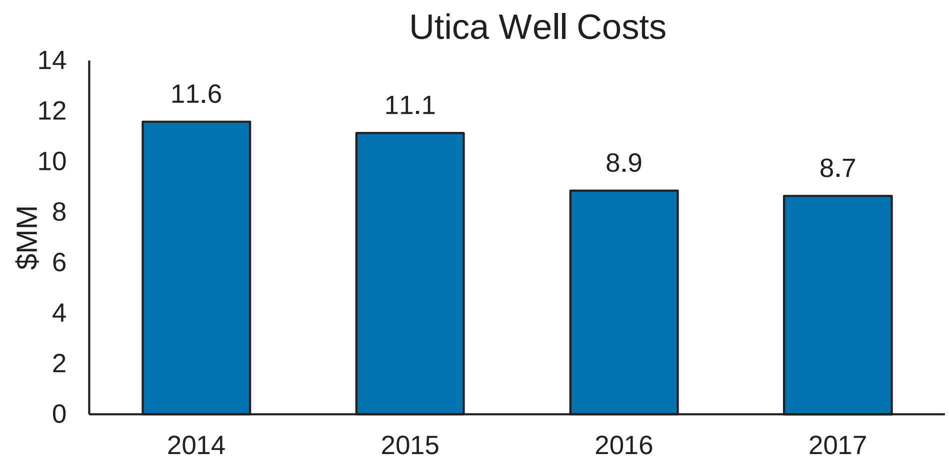
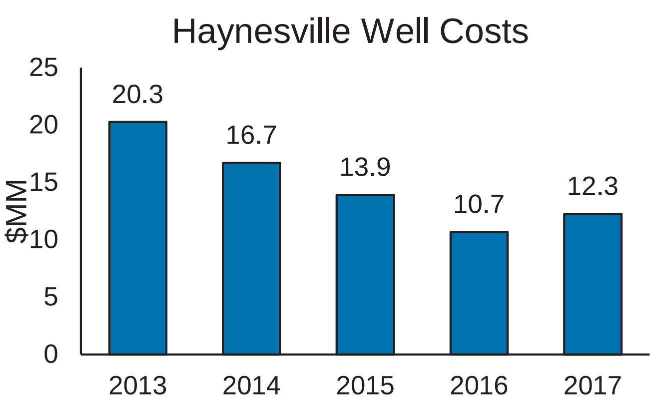
Productivity Distribution by Major Shale Basin

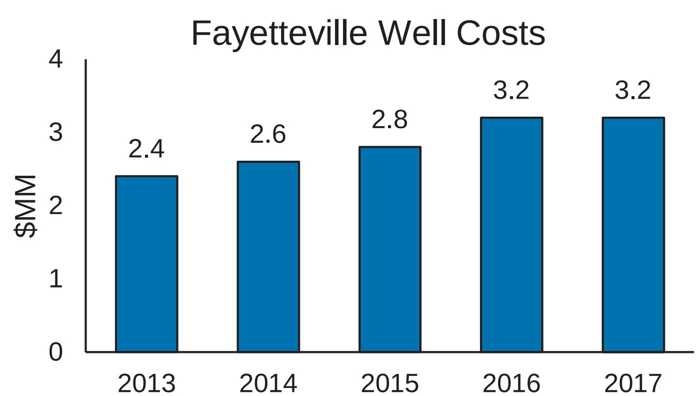


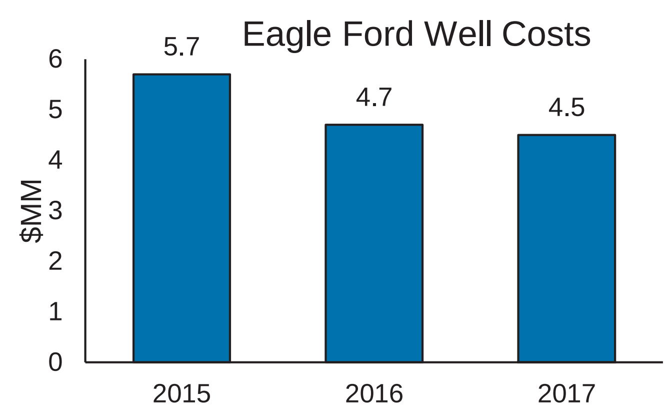
Gas Price Drivers – Drilling Costs











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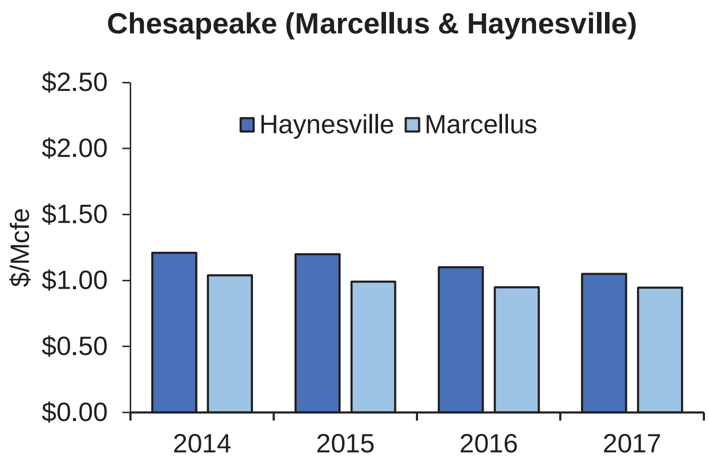
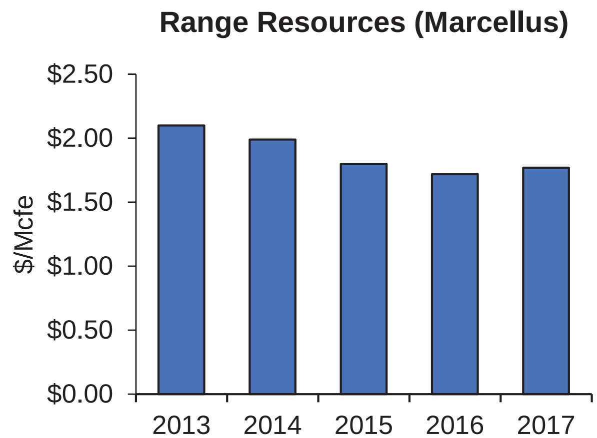
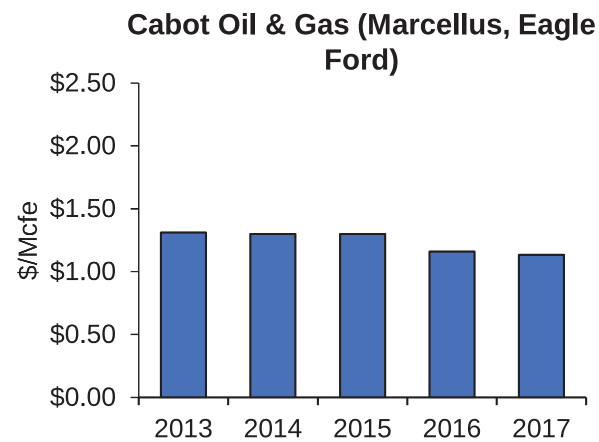
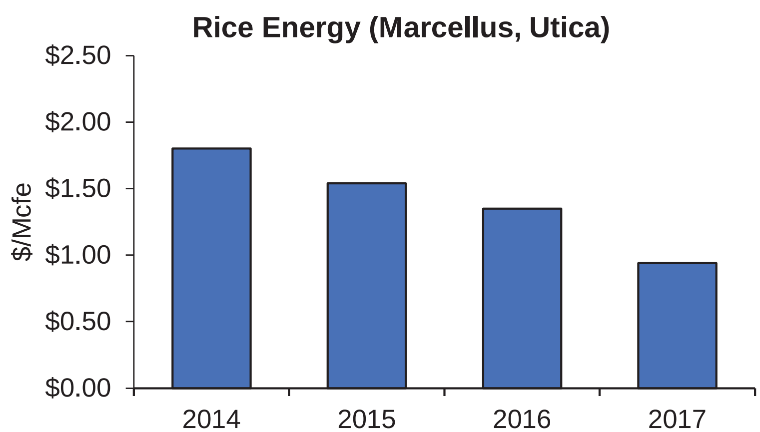
Gas Price Drivers – O&M Costs

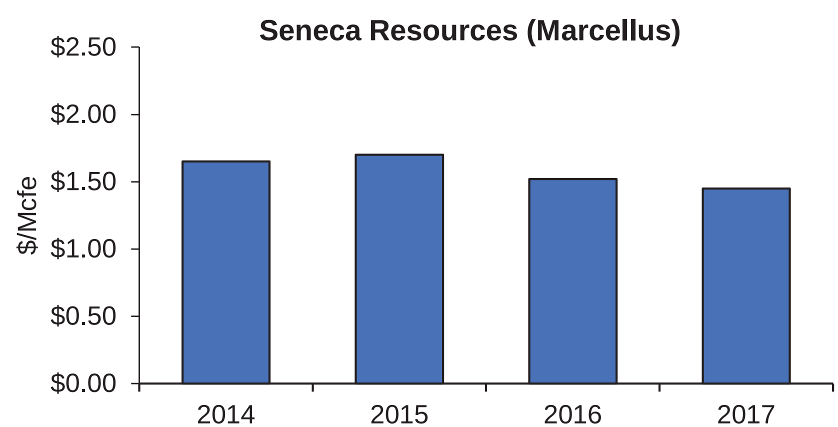
O&M Cost by Producer











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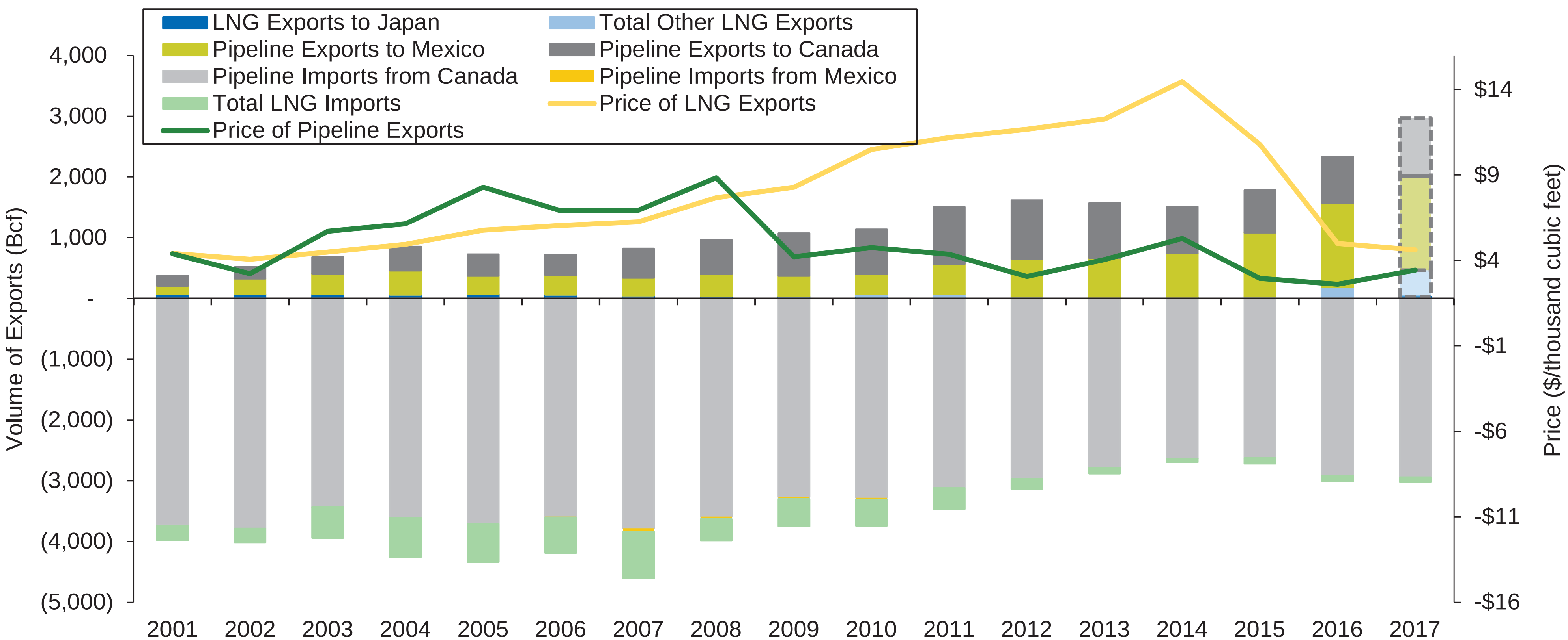
Gas Price Drivers – LNG

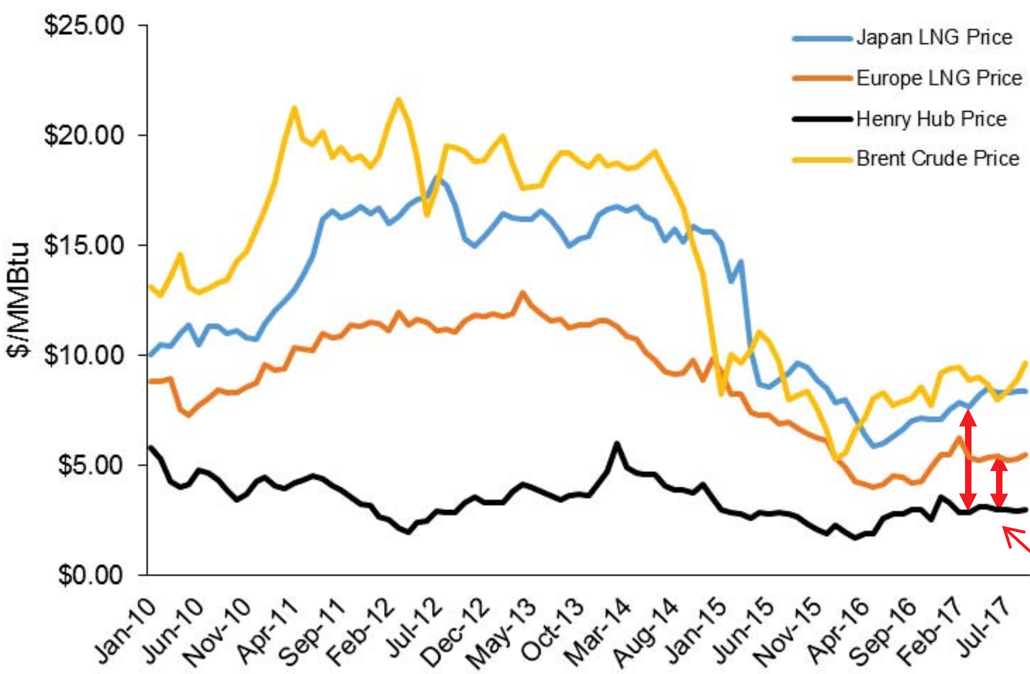
- US gas exports continue to grow, driven by export capacity additions and stabilized international market prices

U.S. Exports (LNG and Pipeline: 2001-2017 (Projected))

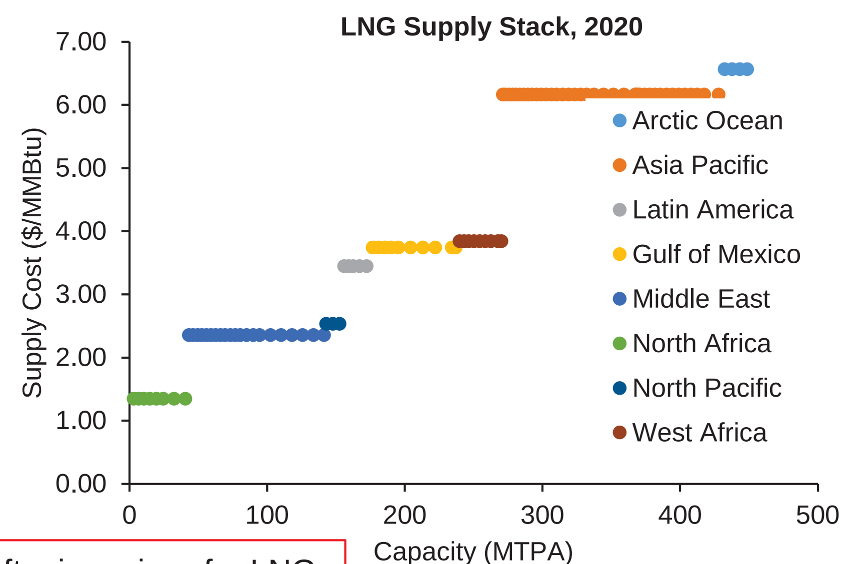


* 2017 data includes monthly average pricing data up to September 2017 and annualized projected volumes based on daily averages up to September

Gas Price Drivers – LNG



Softening prices for LNG exports threatens many potential projects



Gas Price Drivers – LNG

US LNG terminal forecast largely unchanged in the past year, approximately 10 Bcf/d is now under construction or already completed

	Project	Status	FTA / Non FTA	Expected In Service	Capacity (Bcf/d)
In Service / Under Construction	Sabine (T1-T3)	Operating	Non-FTA		1.8 Bcf/d
	Sabine (T4)	Commissioning	Non-FTA	2018	0.6 Bcf/d
	Cove Point (Full Terminal)	Commissioning	Non-FTA	2017	0.82 Bcf/d
	Sempra Cameron (T1-T3)	Under Const.	Non-FTA	2019	1.8 Bcf/d
	Elba/Southern LNG (T1-T5)	Under Const.	Non-FTA	2018	0.36 Bcf/d
	Freeport (T1-T3)	Under Const.	Non-FTA	2018-19	1.8 Bcf/d
	Sabine (T5)	Under Const.	Non-FTA	2018	0.6 Bcf/d
	Corpus Christi (T1-T2)	Under Const.	Non-FTA	2018-19	2.14 Bcf/d
	Sub-total				**9.92 Bcf/d**
Awaiting FID	Sabine (T6)	Approved	Non-FTA	2021 +	0.6 Bcf/d
	Lake Charles (T1-T3)	Approved	Non-FTA	2021 +	2.1 Bcf/d
	Magnolia (T1-T4)	Approved	FTA	2021 +	1.0 Bcf/d
	Golden Pass	Approved	Non-FTA	2021 +	2.0 Bcf/d
	Sempra-Cameron (T4-T5)	Approved	Non-FTA	2021 +	1.4 Bcf/d
	Corpus Christi (T3)	Approved	Non-FTA	2021 +	1.4 Bcf/d
	Sub-total				**8.5 Bcf/d**
	Terminals (Proposed)				**19 Bcf/d**
	Terminals (Pre-Filing)				**4.75 Bcf/d**
	Grand Total				**42.17 Bcf/d**

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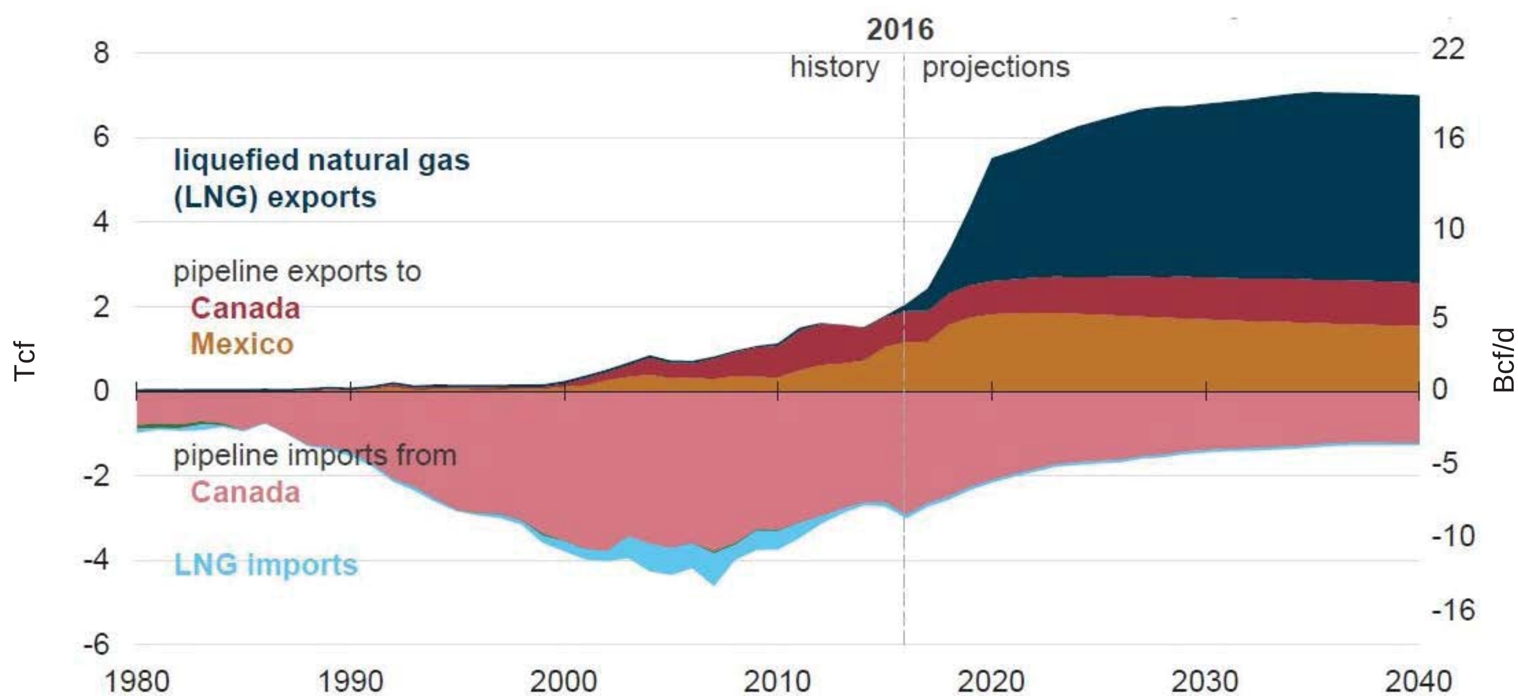
Gas Price Drivers – Net Pipeline Exports

- EIA projects that US transitions to net exporter of natural gas by 2020

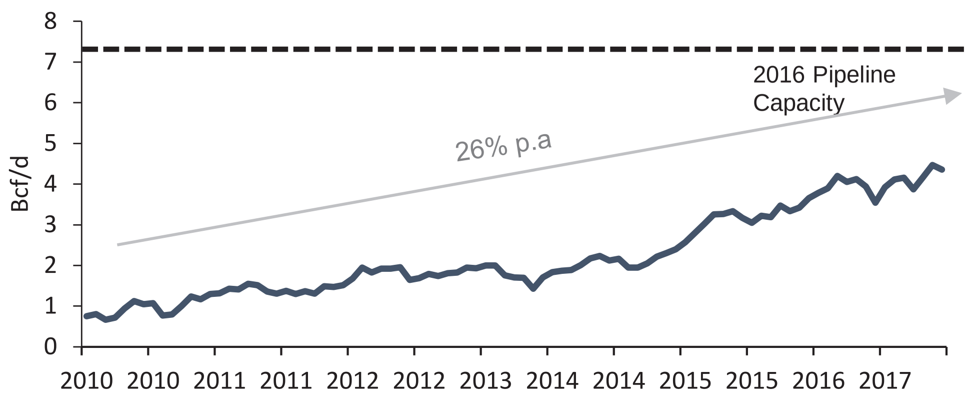
Net Exports from USA (AEO 2017)

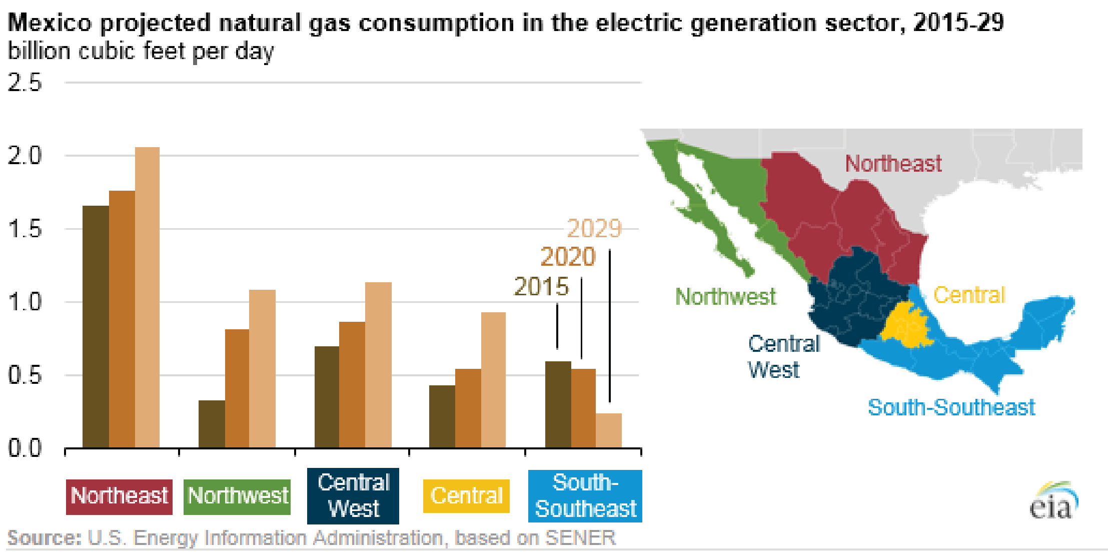


Gas Price Drivers – Net Pipeline Exports

Mexican exports have steadily risen over the last five years, and are expected to rise as electric sector demand grows while domestic production remains flat/declines

Net Exports to Mexico (2009 – 2017)





Pipeline	Online Year	Capacity (Bcf/d)
Tula - Villa de Reyes	2017	0.6
Sur de Texas - Tuxpan	2018	2.6
Tuxpan - Tula	2017	0.7
San Isidros - Samalayuca	2017	1.13
Comanche Trail Pipeline	2017	1.1
Trans-Pecos Pipeline	2017	1.3
Samalayuca - Sásabe	2018	0.5
La Laguna – Aguascalientes	2018	1.1
Nueces – Brownsville	2018	2.6

- Mexico's 2015-2019 gas development plan includes 12 new gas infrastructure projects, totaling over 3,200 miles of pipeline and 9 Bcf/d – as of July, 7 of the 12 projects have been awarded contracts
- Pipeline export capacity to Mexico is expected to double from current levels, to 14 Bcf/d, by 2018

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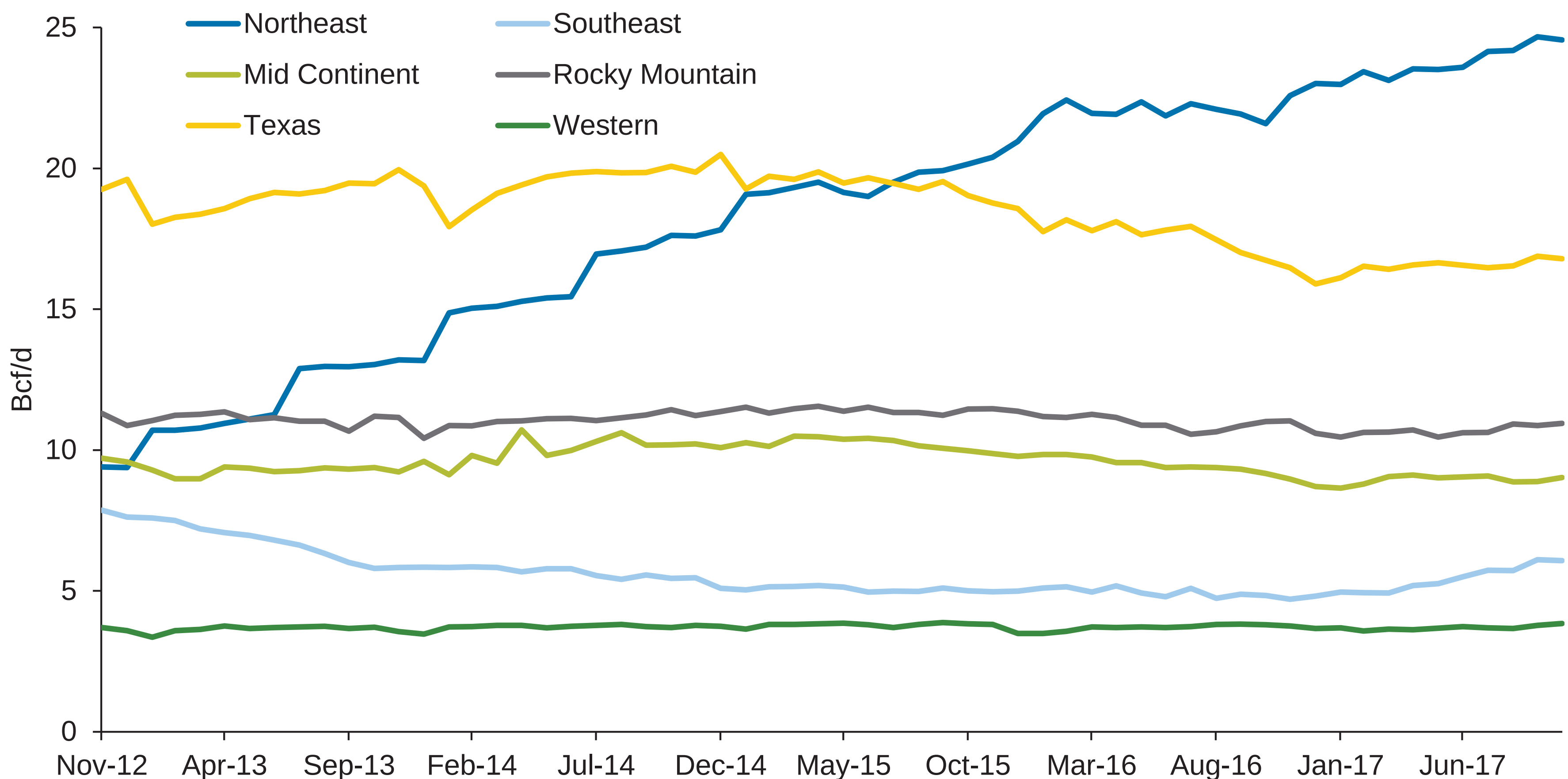
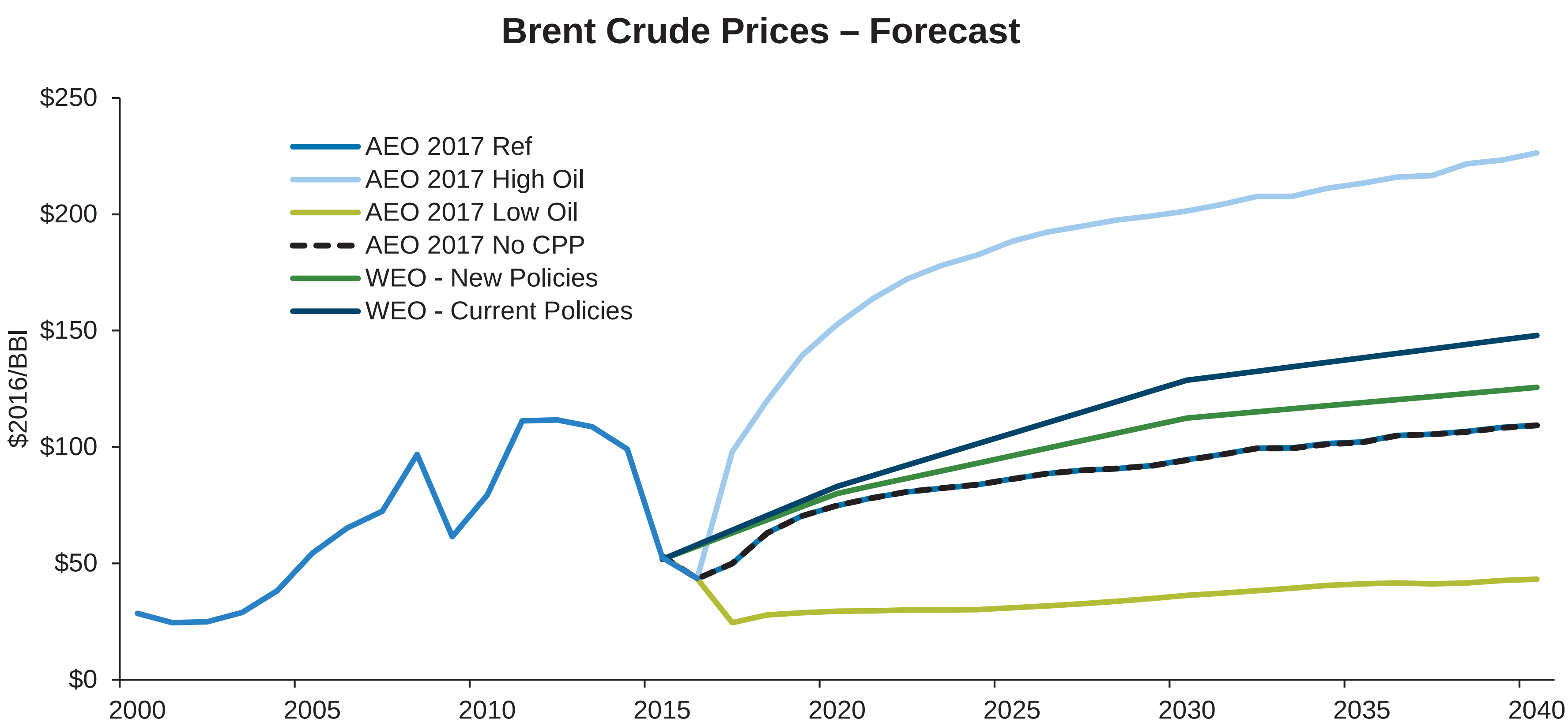
Key Natural Gas Market Trends – Changes in Flows

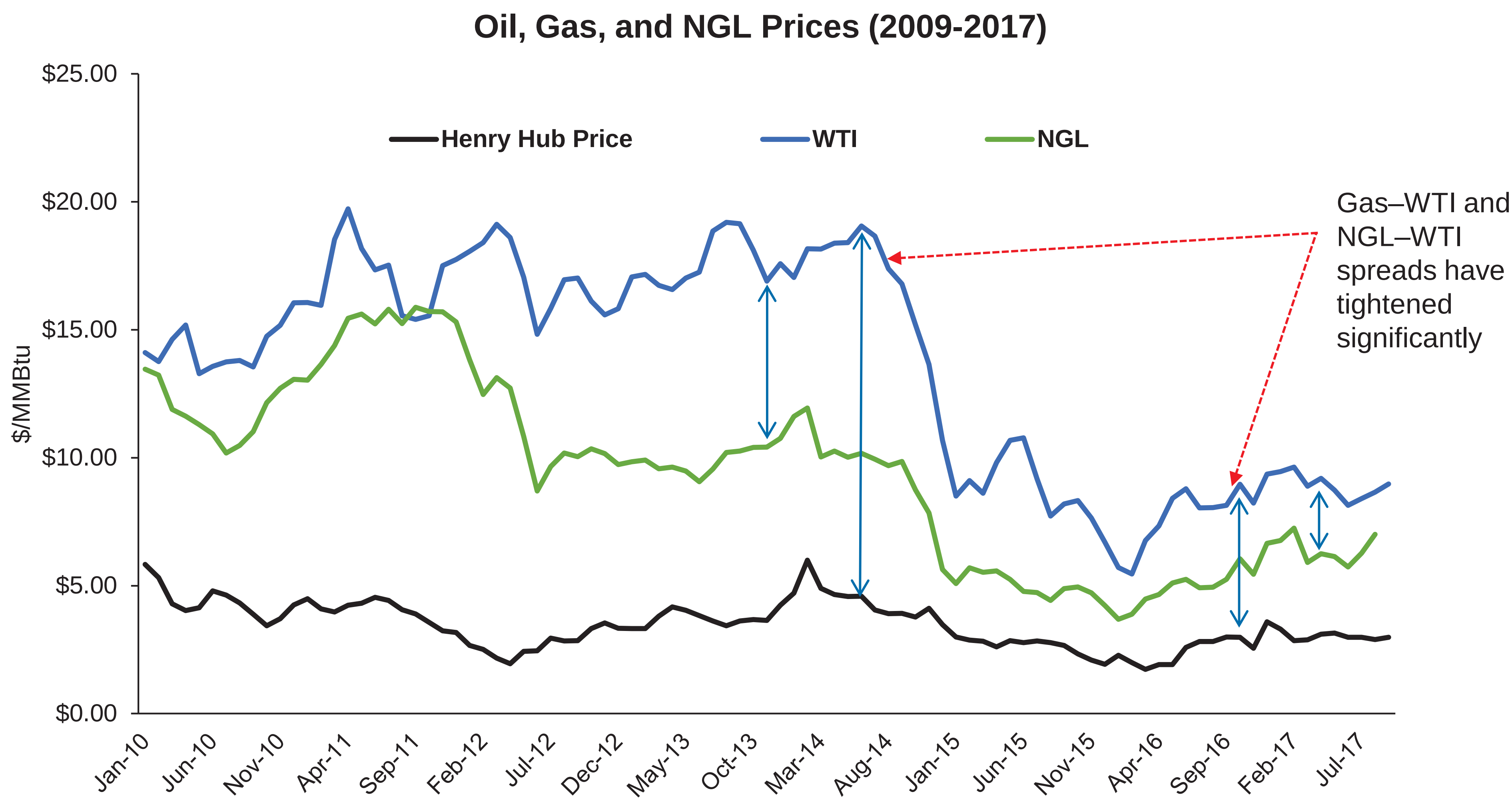
- The Northeast region has shifted from a net importer to a net exporter of natural gas, impacting regional prices and direction of gas flow across major pipelines
- These trends should continue as new large pipeline projects (Rover, Nexus, MVP and ACP) will provide long term export capacity for Marcellus/Utica production



Gas Price Drivers – Oil / NGL Prices

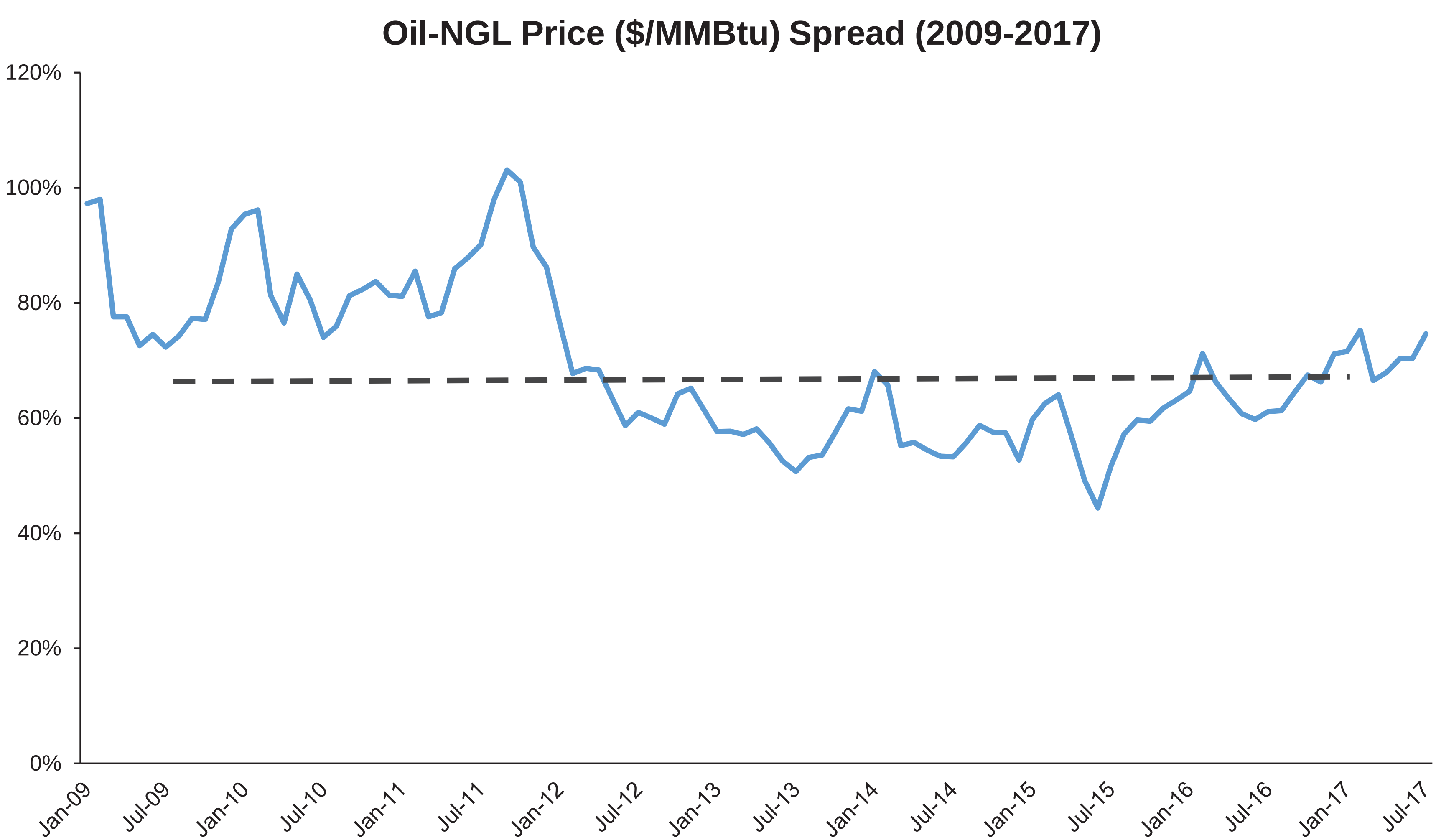


Gas Price Drivers – Oil / NGL Prices



Note: NGL Composite price encompasses NGL spot prices at Mont Belvieu with monthly volumes used to calculate weight.

Gas Price Drivers – Oil / NGL Prices



Source: EIA

Methodology for Forecasting U.S. Steam Coal Prices

- Macroeconomic drivers:
  - U.S. market: Electric demand growth expected to be met through natural gas generation under expected gas prices and environmental requirements
  - International market: International demand for exports of steam and metallurgical coals from the U.S. grow modestly
- Microeconomic drivers:
  - Trends in coal mining costs for key supply regions
  - Production trends for key coal supply regions, incl. mine expansions and closures

Coal units in the model see a delivered coal price that incorporates commodity and transport costs

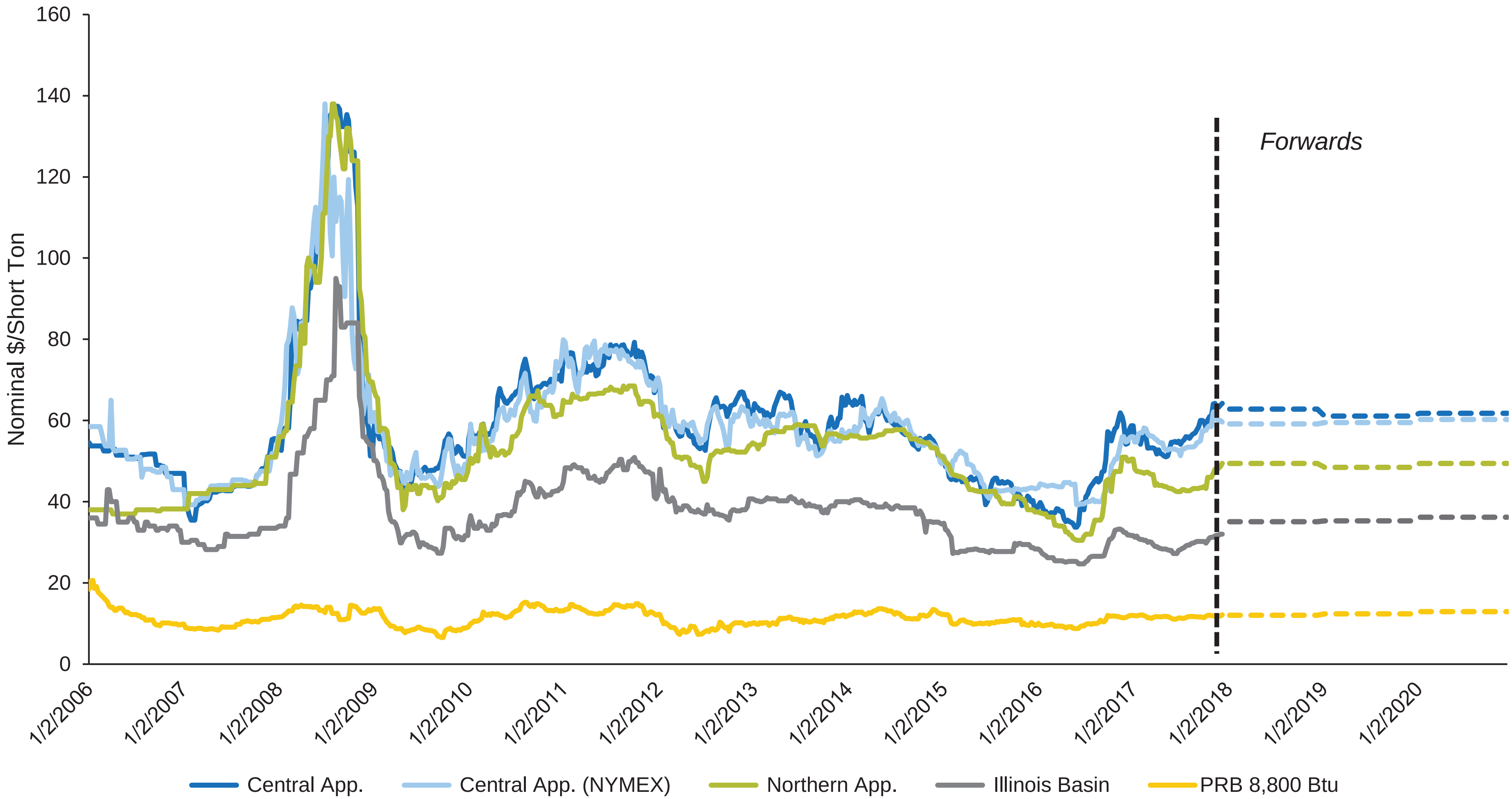
Delivered Unit Fuel Cost ($/ton) = Transportation Cost ($/ton) + Solved Mine Mouth Price ($/ton)

- CRA calibrates these inputs to reflect market developments that affect coal supply and transport costs

Coal Outlook Overview

- The price downturn from 2011-2016 reflects the 27% decline in U.S. coal production from 2014-2016
- Price increase caused by increased demand for U.S. coals exports, and a reduction in U.S. coal stockpiles
- 8-10% decline from 2017 levels by 2022, and a 25% decline by 2027, driven by CO_2 pricing from 2026
- In real terms, CRA projects prices to generally remain near current levels over the 2020-2040 period
- Due to high mining costs, Central Appalachian coal production is primarily targeted at the metallurgical coal market, and less than 30 million tons/year of this coal is currently used for electric generation within the U.S.

Historical Coal Prices vs. Forwards



Source: Coaldesk LLC broker sheet, 12/8/2017. Price for NAPP 3.5# coal is estimated based on published Coaldesk data.

The U.S. electric sector makes up the bulk of domestic demand, and is expected to decrease its reliance on coal over the forecast period

- Coal's share of 2017 U.S. electric generation was about 32%
- Carbon pressure and sustained low gas prices are likely to drive a decline in coal's market share
- CRA's base case shows that coal generation accounts for approximately 24% of total generation from 2027-2035

- Low gas prices and growing renewable generation are expected to drive 30+ GW of coal-fired retirements over the 2018-2022 period
- After 2022, tightening environmental targets and new, highly efficient NGCC entry continue this trend; CRA expects 23-24% of electric demand to be met by coal-fired units by the late 2030s

International demand for U.S. coal expected to grow modestly, driven by emerging Asian economies and decommissioning of EU nuclear units

- CRA projects 52 million tons of metallurgical coal and 40 million tons of steam coal in 2017

- Europe is the primary market for U.S. exports of both metallurgical and steam coal. However, Asia is an important secondary market, especially for metallurgical coal.
- The global scarcity of metallurgical coal reserves may allow the U.S. to maintain its 2017-2018 production levels for these coals, despite being a relatively high-cost producer.

- Several coal terminals have been proposed in the Pacific Northwest, Millennium Bulk Terminal (MBT), the last currently active project of this type, was denied its water quality certification in September 2017
- CRA's preliminary case assumes that the MBT is not completed

U.S. Mining Costs by Coal Supply Region, 2015-2017

– Smaller average size of the coal mines and greater reserve depletion in CAPP leads to an increase in expected production costs, relative to other major U.S. coal supply regions

Cash Operating Costs Per Ton of Coal

(averages for 1Q-3Q of each year unless otherwise noted)

	YTD 2015	YTD 2016	YTD 2017	Nominal % Change 2015-2017
Central App				
Arch Coal (CAPP)	$54.25	$51.30	$61.11	**NM[2]**
Contura Energy (East)[1]	$66.45	N/A	$72.35	**NM[2]**
Northern App				
Consol Coal Resources	$34.47	$30.03	$29.57	**-14.2%**
Illinois Basin				
Alliance Resource Partners (ILB EBITDA expense)	$31.67	$30.03	$25.67	**-18.9%**
Peabody Energy (Midwestern U.S.)	$33.46	$30.96	$32.23	**-3.7%**
Powder River Basin ("PRB")				
Arch Coal (PRB)	$10.69	$10.95	$10.45	**-2.2%**
Cloud Peak Energy	$9.81	$10.07	$9.68	**-1.3%**
Contura Energy (PRB)[1]	$10.38	N/A	$10.02	**-3.5%**
Peabody Energy (PRB)	$9.97	$9.80	$9.57	**-4.0%**

Source: Company financial reports.

Notes:

1. 2015 data is 1Q2015 only.

2. 2015-2017 mining cost comparisons for Central Appalachia are not meaningful due to increasing concentration on metallurgical coal production during this period.

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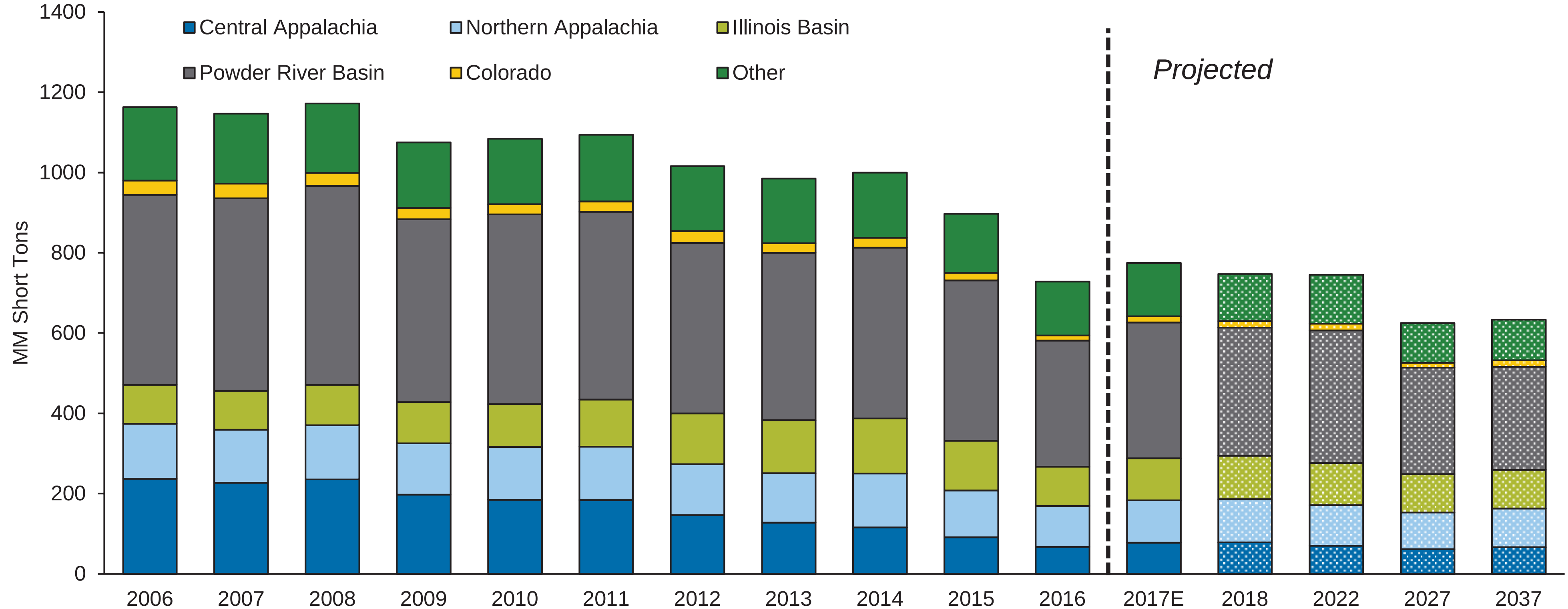
U.S. Coal Production by Supply Region - 2006-2037



Net Change in Coal Production (MM Tons)	2006-2017	2017-2022	2022-2037
Central Appalachia	(159)	(8)	(3)
Northern Appalachia	(32)	(4)	(5)
Illinois Basin	8	0	(9)
Powder River Basin	(135)	(8)	(73)
Colorado	(20)	1	(1)
Other	(50)	(11)	(20)
Total	**(388)**	**(30)**	**(112)**

Sources: 2006-2016 data from U.S. Mine Safety and Health Administration (MSHA) and Energy Information Administration (EIA). 2017 and later data is estimated.

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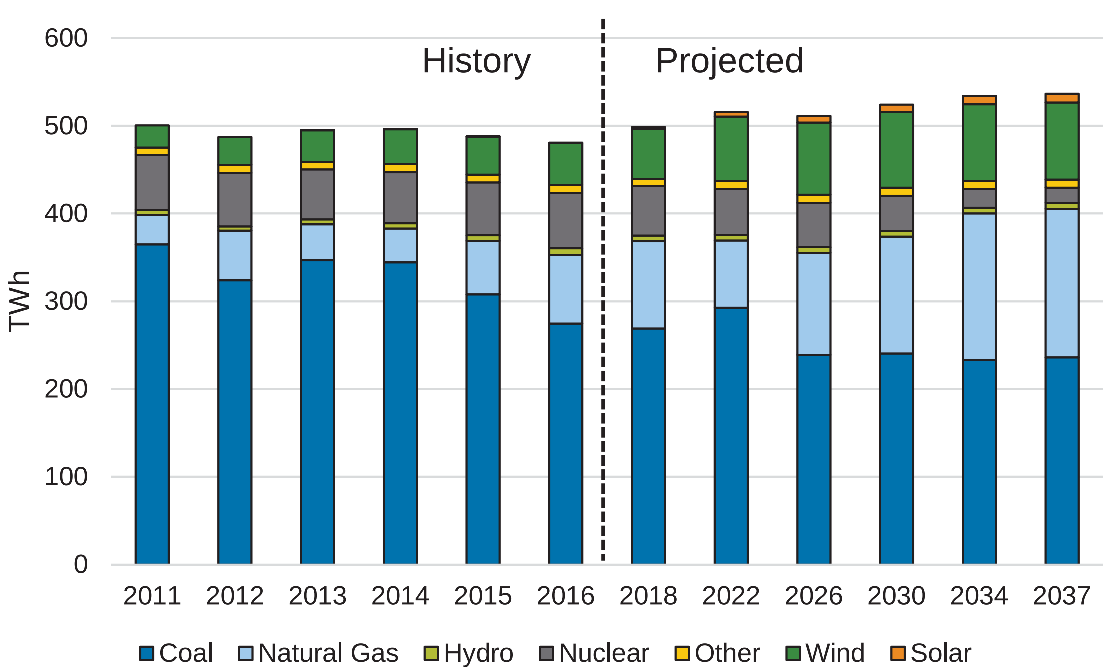
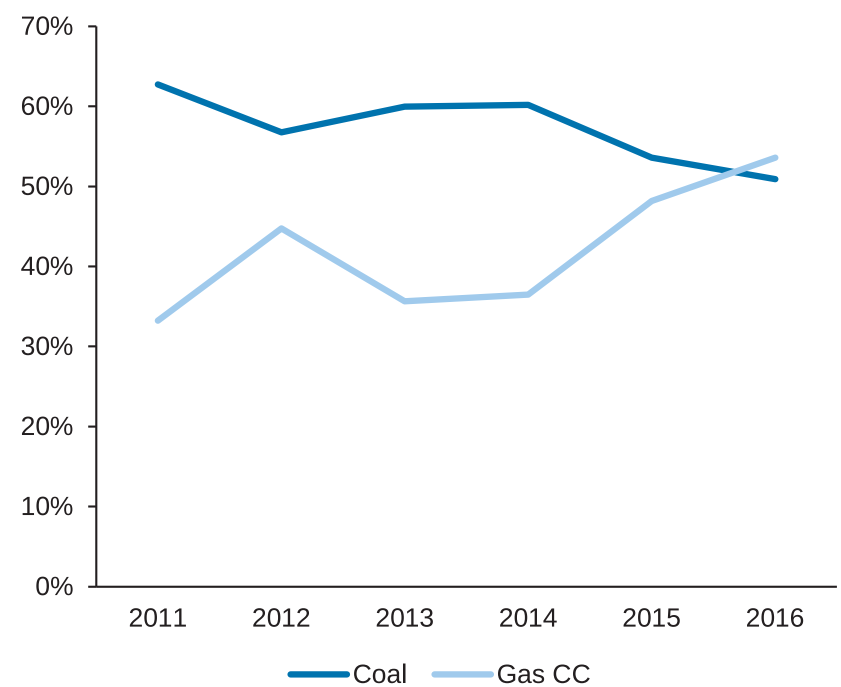
Generation has shifted from coal to gas and wind in recent years

MISO North* Generation by Fuel Type



*MISO North includes LRZ 1-7

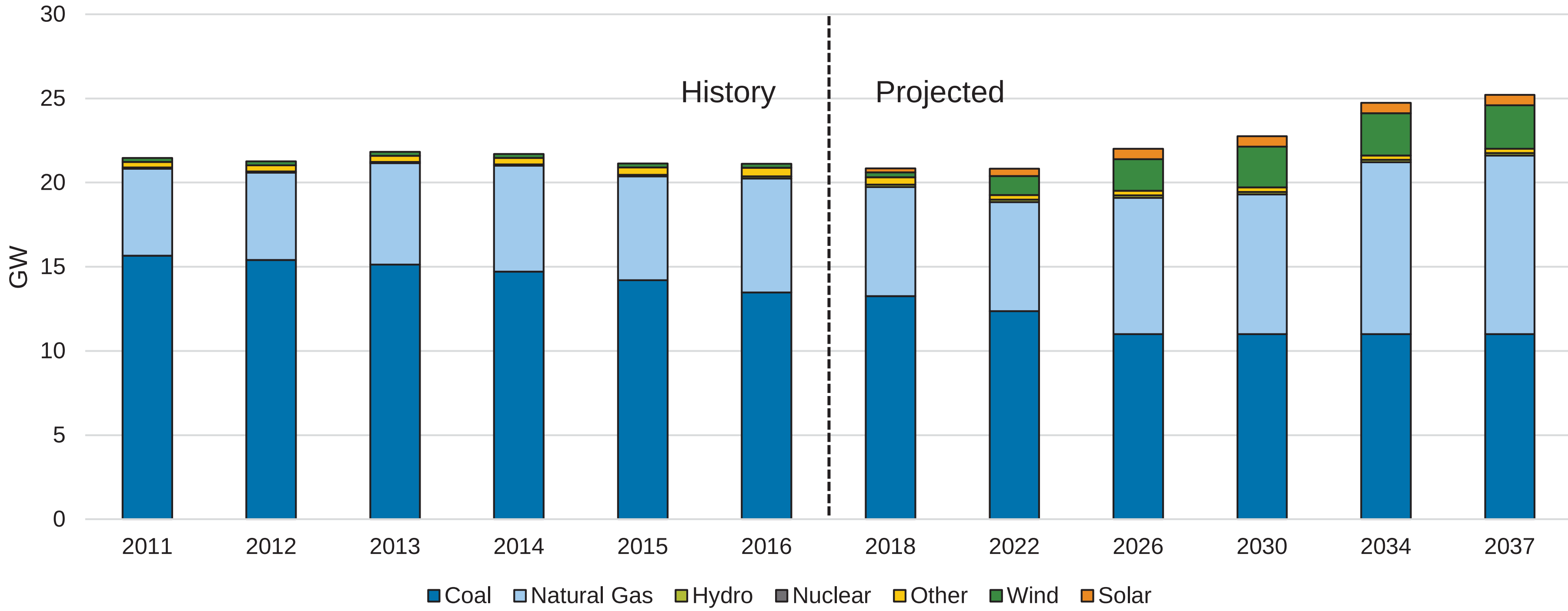
Capacity Factor by Plant Type



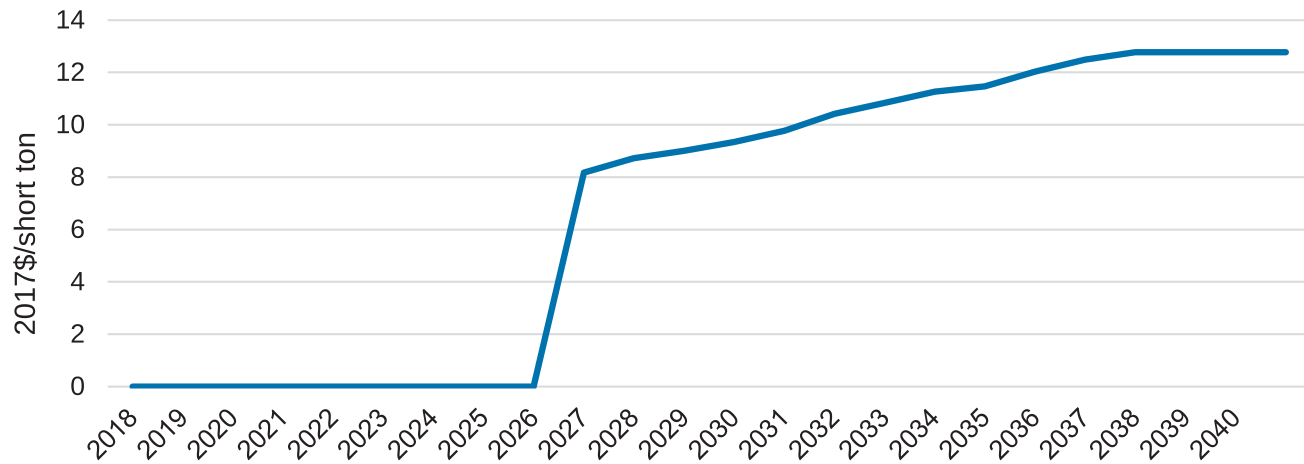
MISO-Indiana Zone

– For example: IPL Eagle Valley gas CC expected online in June 2018

MISO-Indiana Capacity by Fuel Type



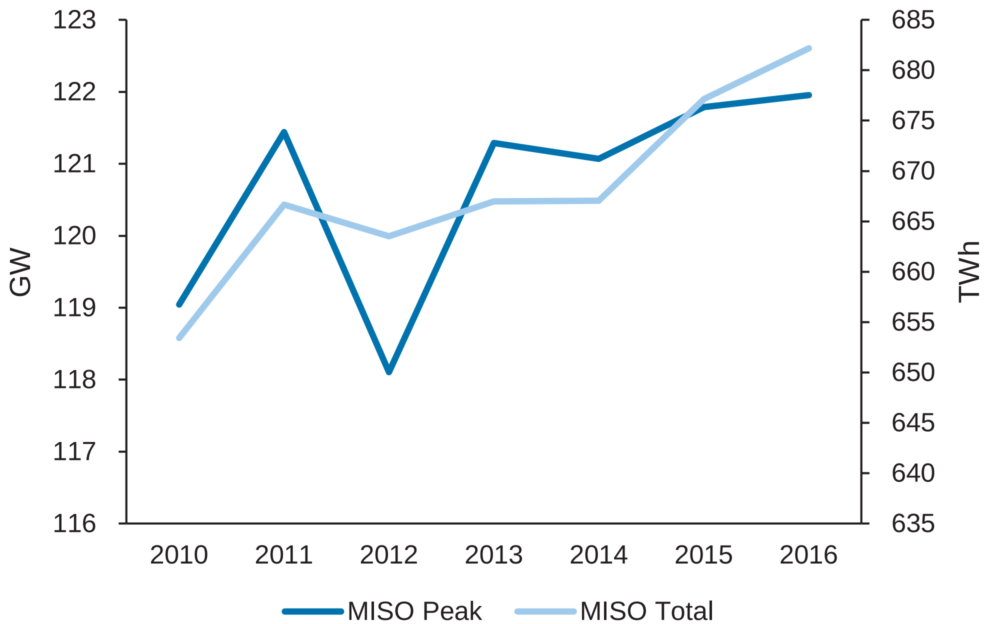
Environmental policy drivers influence shift in generation mix and power price forecast

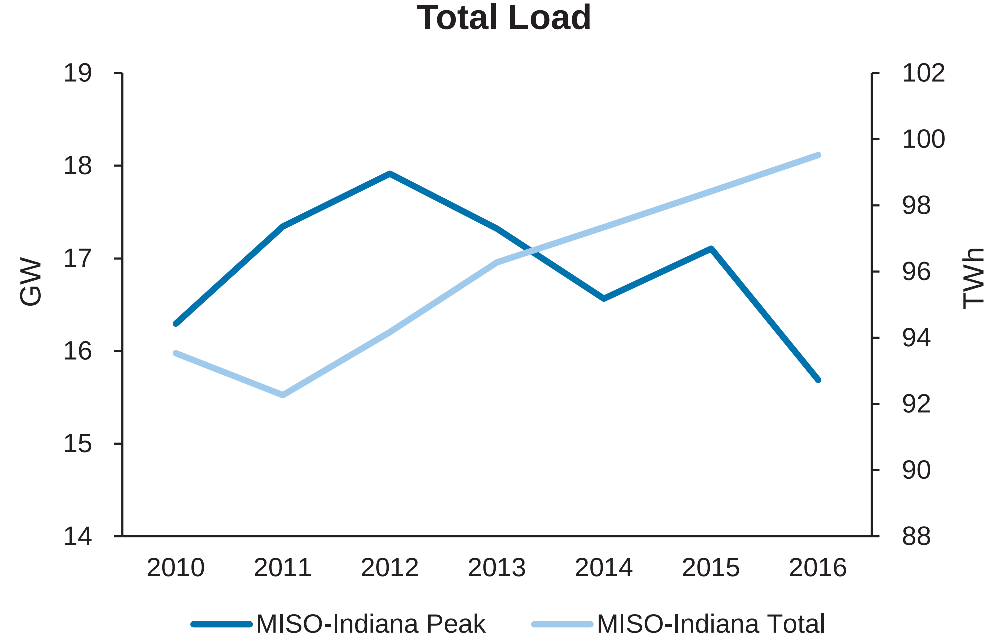


MISO RPS Targets

25% (IL, MN), 15% (MI, MO), 10% (IN, ND, WI), *None* (AR, MS, LA, IA)

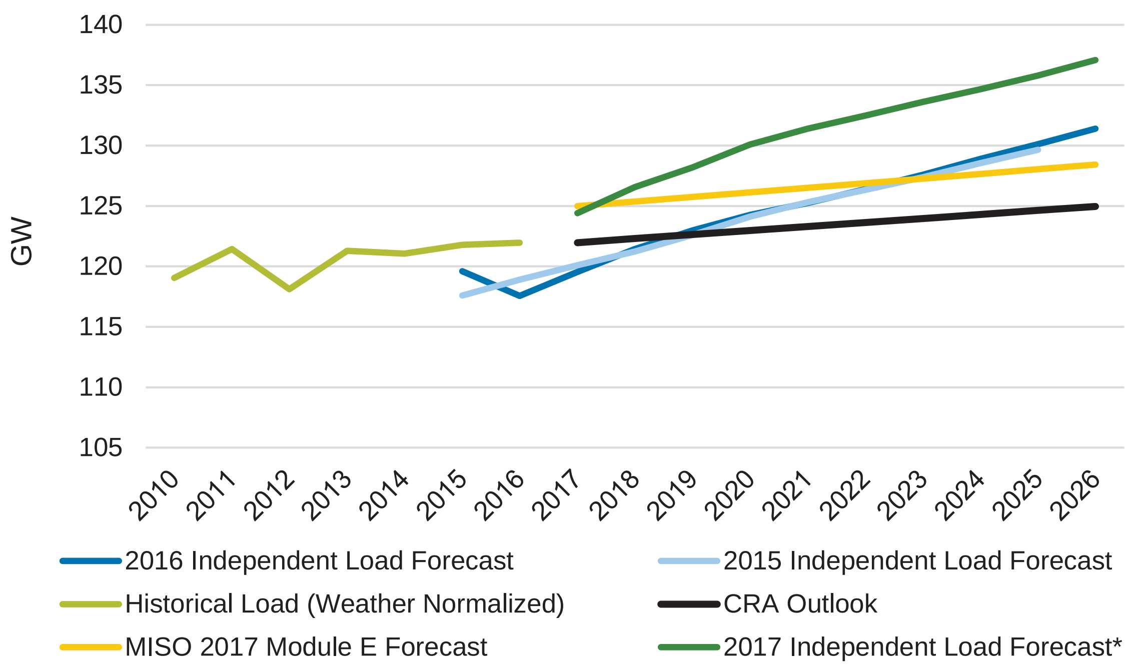
Electricity demand growth in MISO has been relatively modest





CRA expects modest growth in annual, peak demand

MISO Peak Demand Projections with Historical Load



Peak Load Forecast	10-Year Summer Peak CAGR
2010-2016 Weather-Normalized	*0.40%*
2015 Independent Load Forecast	0.98%
2016 Independent Load Forecast	1.12%
2017 MISO Module E	0.27%
CRA Outlook	**0.24%**

*Note 2017 ILF Forecast does not include impact of DR and DG

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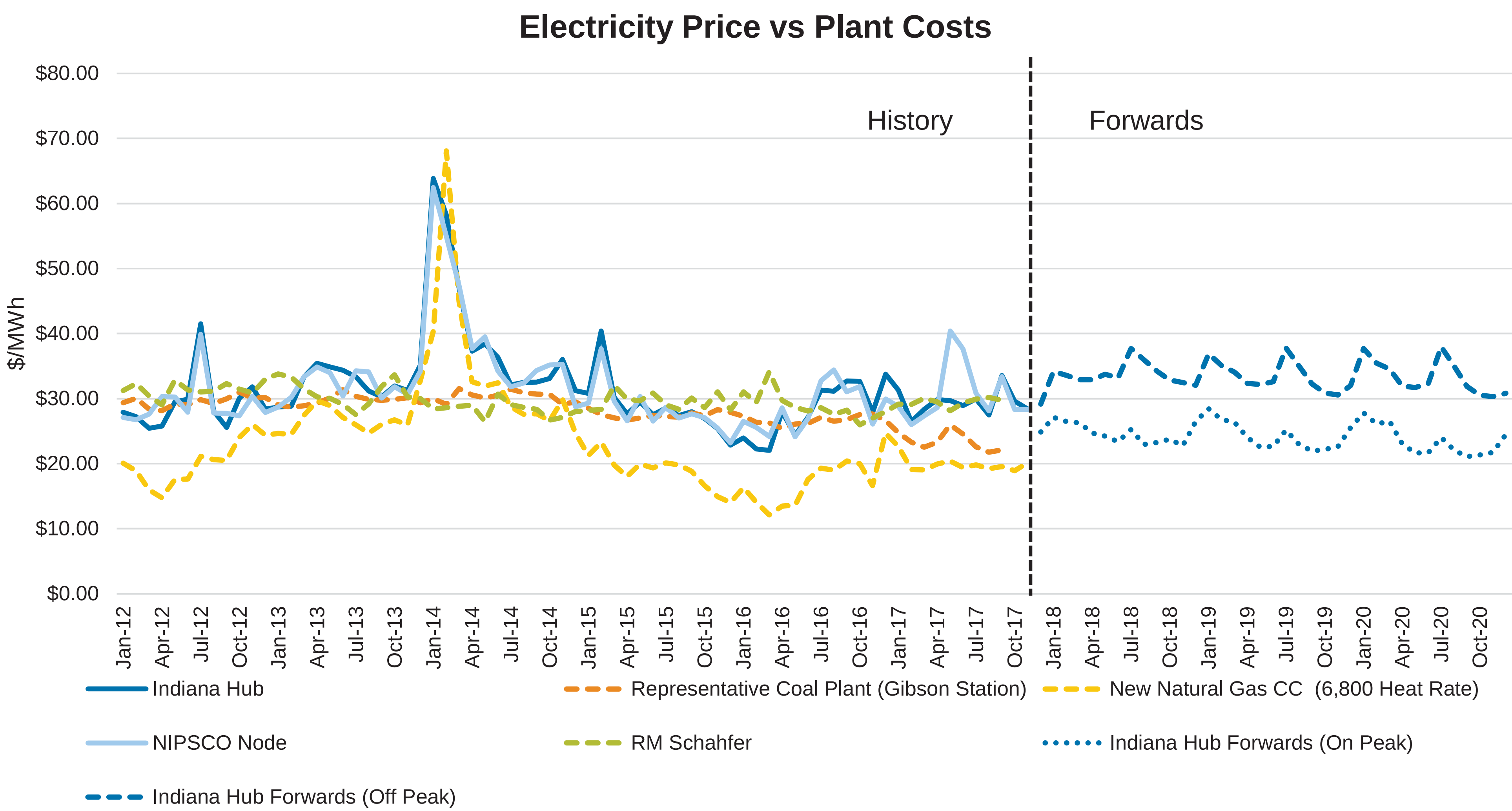
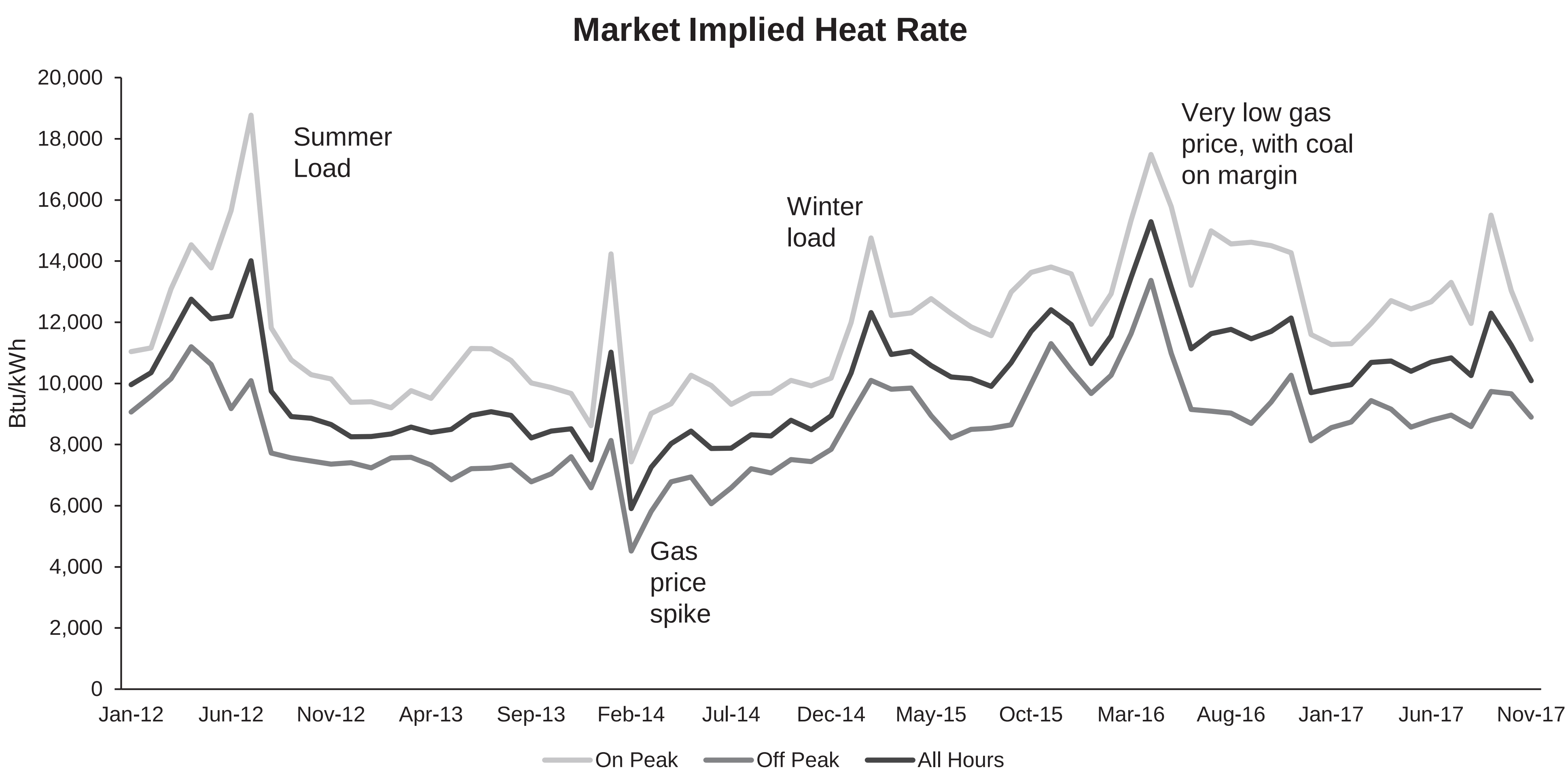
MISO Energy Market Dynamics



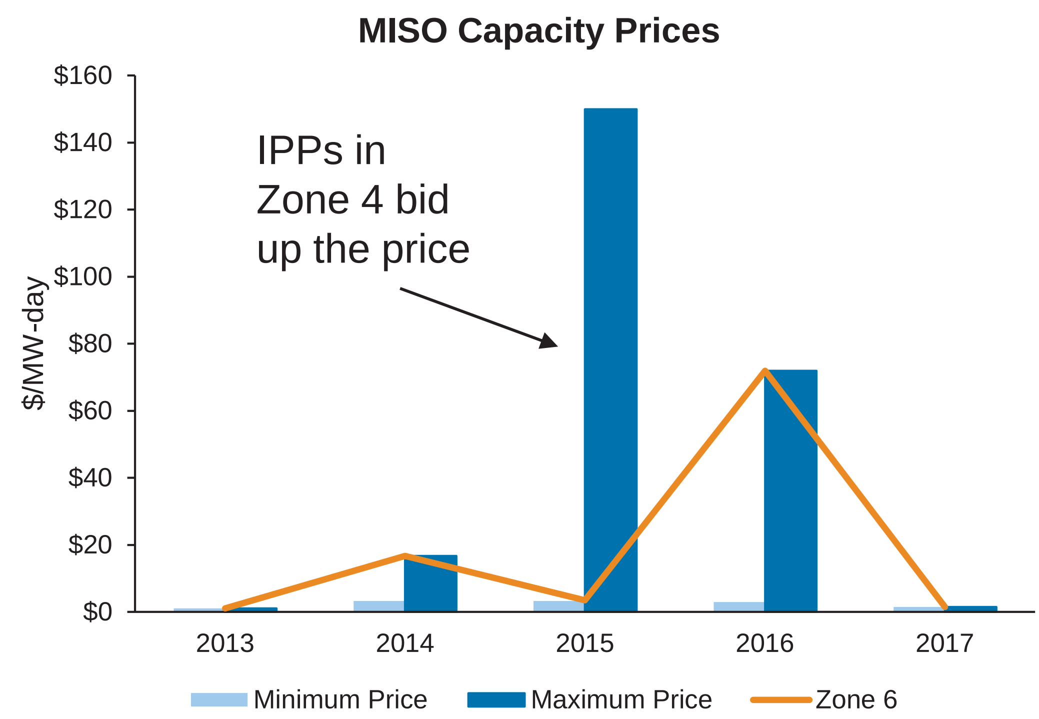
Market heat rate is seasonal, with increases in recent years



*Using Indiana Hub and RexEast Gas Price Index

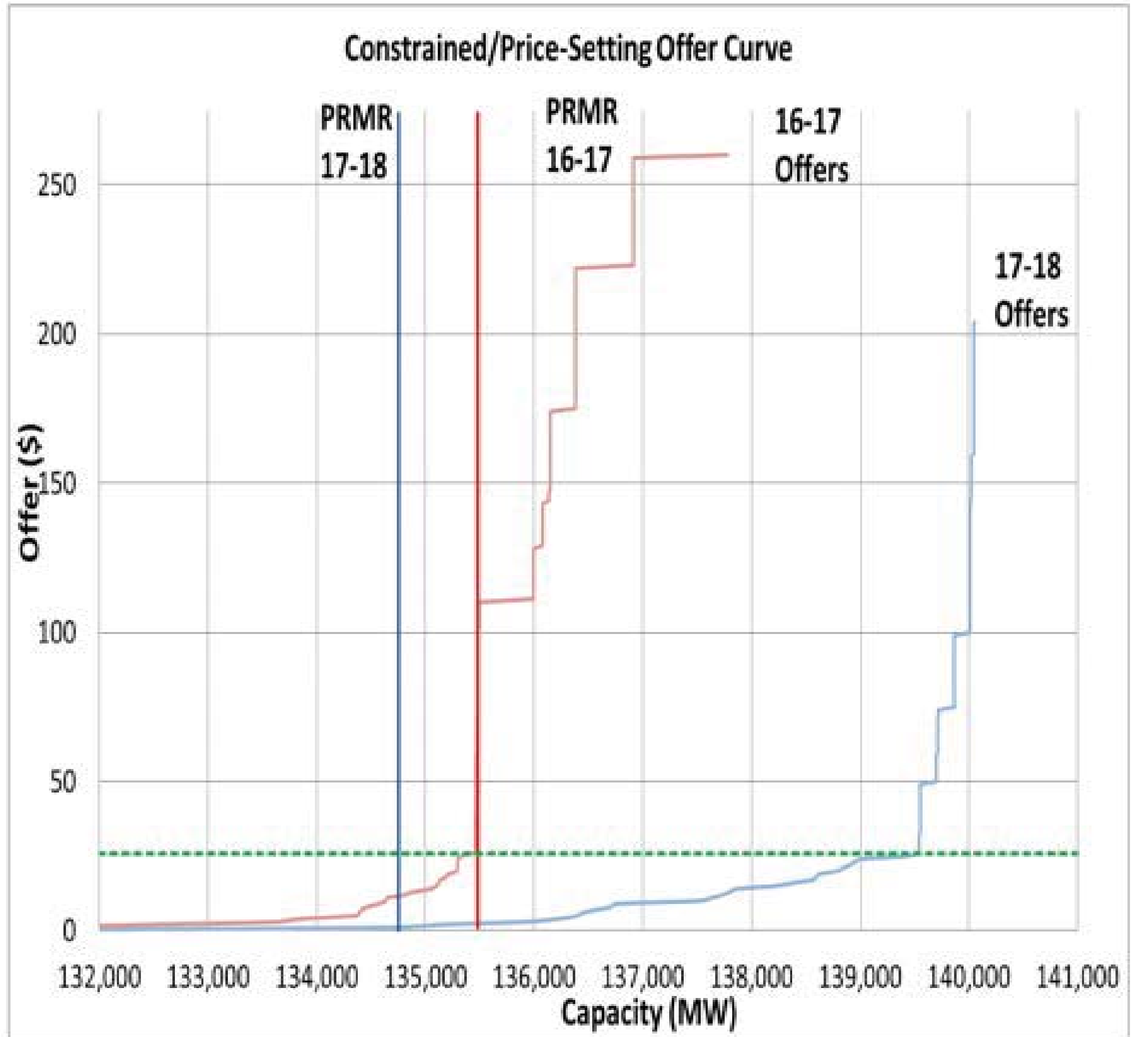
MISO Resource Adequacy and Capacity Market

- Vertical demand curve
- Prompt, rather than forward, market



Explaining the downward trend between 2016/17 and 2017/18 auctions

- More renewables
- More behind-the-meter
- More DR/EE



Source: MISO

Acronym	Definition
CRA	Charles River Associates (IRP Consultant)
NEEM	North American Electricity and Environment Model
NGF	Natural gas sector market model
ELG	Effluent Limitation Guidelines
CCR	Coal Combustion Residuals
NPVRR	Net Present Value of Revenue Requirement
LNG	Liquefied Natural Gas
MISO	Midcontinent Independent System Operator
CONE	Cost of New Entry
EIA	Energy Information Administration
AEO	Annual Energy Outlook (from EIA)

INTEGRATED RESOURCE PLANNING

ACRONYMS

ACRONYMS

A

AC	Alternating Current
ACEEE	American Council for an Energy Efficient Economy
ACESA	American Clean Energy and Security Act of 2009
ACI	Activated Carbon Injection
ACLM	Air Conditioning Load Management
	Annual Energy Outlook (from EIA)
AFUDC	Allowance for Funds used During Construction
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ARRA	American Recovery and Reinvestment Act of 2009
ASM	Ancillary Services Market
ATC	Available Transfer Capability or Capacity

B

BA	Balancing Authority or Balancing Area
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BESS	Battery Energy Storage System

C

C&I	Commercial and Industrial
CAA	Clean Air Act – EPA issued initial rules in 1970
CAAA	Clean Air Act Amendments – 1990
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCT	Clean Coal Technology
CDD	Cooling Degree Days
CFL	Compact Fluorescent Lighting
CHP	Combined Heat & Power
CIP	Critical Infrastructure Protection
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity

CPP	Clean Power Plan
CPW	Cumulative Present Worth
CRA	Charles River Associates (IRP Consultant)
CVR	Conservation Voltage Reduction
CSPAR	Cross State Air Pollution Rule – EPA issued rules July 2011
CT	Combustion Turbine

D

DA	Distribution Automation, or Day Ahead Scheduling
DG	Distributed Generation
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand-Side Management

E

ECS	Energy Control System
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFORd	Equivalent Forced Outage Rate demand
EIA	Energy Information Administration of the U.S. Department of Energy
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicles

F

FAC	Fuel Adjustment Clause
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

G

GDP	Gross Domestic Product
GHG	Green House Gas

H

HAP	Hazardous Air Pollutant
HDD	Heating Degree Days

Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning

I

ICAP	Installed Capacity
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gas Combined Cycle
IMM	Independent Market Monitor
IRP	Integrated Resource Planning
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission

K

kWh	Kilowatt hour

J

JCSP	Joint Coordinated System Planning

L

LAER	Lowest Achievable Emission Rate
LMR	Load Modifying Resource
LMP	Locational Marginal Pricing
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load Serving Entity

M

MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MFDI	Multi Family Direct Install
MISO	Midcontinent Independent System Operator
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	Midcontinent ISO Transmission Expansion Planning
MVA	Mega Volt Ampere, Mega Volt Amplifier, or Multivariate Analysis
MVP	Multi-Value Projects (transmission for both reliability and economic benefits)

MW	Megawatt

N

NAAQS	National Ambient Air Quality Standard – EPA issued rules January 2013
NEEM	North American Electricity and Environmental Model
NERC	North American Electric Reliability Corporation (formerly Council)
NG	Natural Gas
NGF	Natural Gas Sector Market Model
NID	Net Internal Demand
NIST	National Institute of Standards and Technology
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value of Revenue Requirements
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance

P

PC	Pulverized Coal
PCT	Participant Cost Test (see EM&V)
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM LLC (Regional Transmission Organization)
$PM_{2.5}$	Particulate Matter that is 2.5 micrometers in diameter or smaller
PPA	Purchase Power Agreement
PRMucap	Planning Reserve Margin on UCAP (Unforced Capacity)
PV	Photovoltaic
PVRR	Present Value Revenue Requirement

R

RCRA	Resource Conservation and Recovery Act (coal ash disposal regulations)
REC	Renewable Energy Credit
REP	Renewable Energy Production
RES	Renewable Energy Standards
RFC	Reliability First Corporation
RFP	Request for Proposals
RIM	Rate Payer Impact Measure (see EM&V)

RRaR	Revenue Requirement at Risk
RTO	Regional Transmission Organization (Independent System Operator)

S

SAIFI	System Average Interruption Frequency Index (Reliability-see also SAIDI and CAIDI)
SCADA	Supervisory Control and Data Acquisition
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction (pollution control)
SIP	State Implementation Plan (environmental)
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SREC	Solar Renewable Energy Credit

T

TBEL	Technology Based Effluent Limits
TOU	Time of Use
TRC	Total Resource Cost Test (see EM&V)
TW	Terawatt

U

UCAP	Unforced Capacity (the amount of Installed Capacity that is actually available)
UCT	Utility Cost Test (see EM&V)
Ultra SCPC	Ultra Super Critical Pulverized Coal

V

VAR	Volt Ampere Reactive, Variance, or Value at Risk

W

WQBEL	Water Quality Based Effluent Limits

Northern Indiana Public Service Company
2018 Integrated Resource Planning
Public Advisory Meeting #1
SUMMARY

March 23, 2018

Welcome and Introductions

Alison Becker opened the meeting by asking participants in the room and on the telephone to introduce themselves. She then introduced Violet Sistovaris.

Overview of Public Advisory Process
Violet Sistovaris, Executive Vice President, NiSource and President, NIPSCO

Ms. Sistovaris began by welcoming participants and explaining NIPSCO's decision to update its Integrated Resource Plan ("IRP") and the importance of stakeholders to that process. She continued with a safety message about severe weather preparedness and discussed the purposes of the meeting and reviewed the agenda. Ms. Sistovaris then provided an overview of NiSource and NIPSCO and a roadmap for the Stakeholder Engagement process and an overview of the public advisory process. She noted that NIPSCO will have a total of five public advisory meetings, with four of them being in person and the fifth as a webinar.

Why a 2018 IRP Update and Improvements from 2016
Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained the need for an update to NIPSCO's 2016 IRP, noting that the 2016 IRP Preferred Plan created a need for additional capacity. He provided an overview of the 2016 Preferred Plan and discussed the drivers and rationale for the 2018 update. Specifically, NIPSCO is doing the update now to preserve its ability to fully consider all resource options to address the capacity need. For example, a combined cycle gas turbine ("CCGT") takes several years to build. In order to have it online by the time the capacity is required in 2023, NIPSCO needs to make decisions this year. The IRP update is crucial to that process.

After providing information on why the 2018 update is required, Mr. Douglas reviewed the lessons learned from the 2016 IRP process. He provided information on NIPSCO's improvement plan in several areas, including commodity price forecasts, scenarios and sensitivities, risk modeling, capital costs assumptions, demand side management ("DSM") modeling and the Preferred Plan and scorecard.

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

- What do you think of recent tariffs that will affect solar equipment coming from other countries?
  - o Solar costs have been volatile and are difficult to plan for. We have tried to take into account all known factors including tax incentives, expert cost forecasts and supply and demand forecasts.
- There are a number of concerns related to the resource(s) that may be selected as well as the short notice related to this update. It will be important to have access to the modeling early in the process. Generally, there is a concern with the timing of the update.
  - o NIPSCO recognizes the extra work the update creates for stakeholders and apologizes for that. However, the Company finds it to be the right thing for the customers. Mr. Douglas also noted that it was encouraging to see so many stakeholders in attendance and that NIPSCO is pleased with the level of engagement in the process. Finally, he noted that NIPSCO has started the Public Advisory process earlier than in 2016 and will continue to look for ways to engage stakeholders.
- There was discussion about the request for proposal ("RFP") process that will be upcoming related to the additional capacity. There was a question about if the process would be opened up for stakeholder input. In addition, there was a question about the formal process related to the IRP. When will NIPSCO submit, when will comments be due, etc.?
  - o The intention is to facilitate the processes for stakeholder input, both formal and informal. There was discussion on how this process would fit with a filing related to a certificate of public convenience and necessity ("CPCN") if a CCGT were selected and Mr. Douglas noted that a CCGT is an example of a technology that has the longest lead time. There is no bias for any specific technology and the data in the IRP (and received from the RFP) will be the driver of the decision making.
- Expression of appreciation for five meetings, but request for other ways to solicit feedback. This could include online comments, etc.
  - o NIPSCO is happy to discuss alternative ways of soliciting feedback.
- The evaluation will be on a unit-by-unit basis?
  - o Yes. NIPSCO is grouping Units 14 and 15 and Units 17 and 18 together.
- Sounds as though NIPSCO is committing to reevaluating the retirement of Units 17 and 18?
  - o Yes.
- How will the metrics gathered be used and weighted? If they are not weighted, are they not all treated as equal?
  - o It will be important to have a discussion around metrics, but it is difficult to make those determinations without the data. It is important to look at environmental attributes, costs to customers, etc. Ultimately, NIPSCO

owns the Preferred Plan decision and will base that decision on stakeholder feedback and the scorecard criteria, not a formulaic answer given by weightings of the criteria. Once the decision has been made, NIPSCO understands the need to discuss it with stakeholders.

- At a high level, the IRP should inform the RFP, which should then inform a CPCN. It would be good to understand this process.
  - o NIPSCO recognizes this process is unique, but given the need for capacity, NIPSCO's IRP will be enhanced by the real data that comes from an RFP. The decision was made to go through an RFP as quickly as possible and use those cost results to inform the IRP. Once again, although the timing is built on the long lead-time for a CCGT, no decisions have been made.
- The Xcel Energy RFP was renewable focused. Need to have sufficient time to discuss the RFP.
  - o Today's discussion is meant to introduce the RFP and NIPSCO's planned process. However, there will be additional time for input as part of that process. The goal of the RFP is to make sure it is broad enough to capture a variety of resources without being overly complex. NIPSCO is open to ideas for how to make sure it is an "all source" RFP.

Modeling Approach
Jim McMahon and Pat Augustine, Charles River Associates ("CRA")

Messrs. McMahon and Augustine provided information related to NIPSCO's modeling approach for the IRP. The discussion started by reviewing the key areas where CRA is providing support for the 2018 IRP Update: fundamental commodity price forecasting and integrated resource planning. Mr. McMahon then reviewed the resource planning approach and models and tools to be used in the 2018 IRP Update. Regarding forecasting, CRA noted it has a Natural Gas Price Fundamentals Model ("NGF Model") and provided an overview of that as well as a discussion related to macro-level market analysis using CRA's North American Electricity and Environment Market ("NEEM") Model. There was also discussion around the use of Aurora to provide regional power market and portfolio analysis and how the PERFORM model will be utilized to perform net present value revenue requirement ("NPVRR") calculations. Charles River Associates discussed the modeling of uncertainty and also how it identifies risks and uncertainties.

NIPSCO is using the same "scenarios" for the 2018 IRP Update: Base, Aggressive Environmental Regulation, Challenged Economy, and Booming Economy & Abundant Natural Gas. In addition to discussing the scenario framework, CRA provided a table detailing the key input variables for each of the scenarios. As the next step, CRA explained how stochastics will be used in the analysis and how the use of stochastics provides improved coverage of uncertainty. Mr. Augustine finished with a discussion on the distribution of outcomes and how portfolios can be compared on a cost and risk basis.

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

- DSM is included on Slide 15, but not on Slide 16. What will be the basis of the DSM screening?
    - The basic information will come from GDS Associates, the company selected by NIPSCO to perform the update to the projected DSM savings. Slide 16 shows how CRA will incorporate that projected savings, as DSM is an input to the Aurora model.
- The extraction of natural gas produces more greenhouse gas. Does the model capture that?
    - The model does not explicitly capture greenhouse gas emissions from natural gas extraction. A final greenhouse gas emission number associated with gas consumption can be determined through reverse engineering, but it is not an input into the IRP modeling.
- Does the model incorporate the idea of an option value in terms of uncertain technologies?
    - Yes, it is represented explicitly in the modeling and that will become clearer when the results are released.
- Do you have a technique to determine historical accuracy?
    - There are ways. CRA did a validation process against the 2016 IRP, but it is not truly back-casting. There is a regular exercise in the Aurora model for back-casting capacity factors, market prices, and generation by fuel type, which is based on history. Stochastics also assist with incorporating the randomness inherent in the market.
- Will stakeholders be able to suggest scenarios?
    - Yes, it is encouraged. Stakeholder scenarios will help NIPSCO fine tune its analysis.
- Extraction emissions will not be included, correct?
    - That is correct. It may be something NIPSCO and CRA could have together by the September meeting. Right now, NIPSCO only looks at things as the United States Environmental Protection Agency does. In other words, emissions on the customer-side are included, but nothing is accounted for prior to its use by NIPSCO.
- Who determines the base case?
    - NIPSCO noted there would be additional discussion in the afternoon and that NIPSCO is looking at CRA for input as well as from the stakeholders. However, the ultimate decision is NIPSCO's.
- Is NIPSCO continuing to assume an effluent limitation guidelines ("ELG") requirement?
    - Yes, one of the scenarios will consider a less stringent ELG requirement, but the Base Case will be with the ELG requirement as it stands today.
- There does not appear to be a Base Case run with different fuel price scenarios?
    - This is an example of how the use of stochastics provides a wide range of information. NIPSCO is willing to discuss scenarios more in-depth to ensure thoughts are being captured.

- The point is that scenarios are a set of integrated and interrelated assumptions. How do you tease out and get at low and high gas prices? Can you get at that through the stochastic modeling process?
    - Scenarios establish potential states-of-the-world for high and low gas prices based on fundamental factors. In addition, stochastic modeling incorporates a broader range of potential outcomes, but it is still difficult to tease out the underlying reasons for specific price movements in certain variables such as gas prices. The scenario process is looking to capture themes NIPSCO finds to be reasonable, while the stochastics add a broader range of uncertainty.
- Regarding Base Case question in carbon pricing, there is a concern of the definition of the scenario. Want to have a discussion before locked in.
    - NIPSCO welcomes the feedback.
- One of your options is purchasing capacity for a period of time. Will you get into the level of detail of considering what you see with other Midwest generating units?
    - Yes. (It was noted NIPSCO hoped to address that more in depth in the afternoon session.)

Long-Term Energy and Demand Forecast
Mahamadou Bikienga, Lead Forecasting Analyst

Mr. Bikienga provided an overview of the load forecasting process noting that it was much the same as the 2016 process. The forecast is updated annually and the models are updated annually, or as needed. The forecast provides a 23 year outlook. There is a residential, commercial, and industrial process. In addition, for "other energy" (public authority, railroad, company use and street lighting), NIPSCO has a specific process. Mr. Bikienga outlined the peak demand forecast process and then provided NIPSCO's Total Energy and Peak Demand projections for the period of 2018-2039. The compound annual growth rate ("CAGR") for the period is 0.33% for NIPSCO total energy; 0.41% for NIPSCO System Peak; and 0.44% for Midcontinent Independent System Operator ("MISO") Coincident Peak.

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

- What is the relationship between income and the customer forecast? Is the assumption that the higher the income, the higher the usage?
    - A higher income level may mean more appliances, more usage in the household, and less sensitivity to the thermostat setting. The core assumption is higher income, higher usage.
- Total energy use per customer is declining, but the charts indicate load growth is increasing?
    - Overall, it is a very small difference. There is slow growth, with rates similar to the last IRP. Industrial growth is actually projected to be flat. This data is available, and, with the appropriate non-disclosure agreement in place, this information can be shared.

- Should there be scenarios for the load forecast? How can electric vehicles be incorporated into the forecast?
  - NIPSCO has considered electric vehicles in the past, but they have very little impact. To the extent the IRP team needs additional information for scenarios, Load Forecasting can supply that.
- Do the models take into account the increase in solar usage? For example, Arcelor might go to all solar. Do you have contractual agreements with companies to make sure they will do what they say they will do?
  - When forecasting for industrial usage, information is provided by the largest customers and that assists with the forecasting process.
  - NIPSCO considers the loss of industrial load as part of the IRP process. The Company is taking into account scenarios of high and low industrial energy usages in forecasting the industrial energy volumes.

Capital Costs Assumptions for Future Resources
Fred Gomos, Manager, Corporate Strategy and Pat Augustine, CRA

Mr. Gomos provided an overview of NIPSCO's approach for capital costs assumptions in the 2018 IRP. He cited 3 important aspects of developing capital costs in the 2018 IRP, namely, moving away from proprietary, single point estimates, and utilizing publicly available data sources and using data from the RFP to collapse the uncertainty in developing capital cost estimates. Mr. Gomos noted that step one is the development of initial portfolios; step two is the evaluation of those portfolios across scenarios and stochastics; and the final step is integrating the portfolios into the IRP. He then provided an update on the data sources to be used in the 2018 update, which are based on more publicly available data than in previous IRP processes. The current capital costs estimates for gas, coal, and nuclear technologies and for renewables, storage, and other technologies were reviewed, with a note that these would continue to be refined.

The capital cost projections for CCGT, wind, solar photovoltaics, and storage (lithium-ion 4 hour) were reviewed, with the forecast range with stochastics discussed. It was noted that the team used a range of data sources to develop the forecasts and went through several steps: identifying the range of capital costs over time, using interactive expert opinion approach based on the source data, and simulating 500 paths for capital costs based on random sampling from distributions.

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

- Are you considering retrofits of any of the existing plants?
  - A range of compliance cost options are included, including ELG compliance costs.
- When there is only one input, how does that impact the modeling?
  - There will be an initial process to evaluate the expected costs and then, from that, a shorter list of feasible technologies will be developed. For the

feasible technologies, NIPSCO will have more data to allow for a full range of options to be considered.

- Regarding the solar and battery graphs, it seems the common understanding is that battery costs are going down. But, based on the graph, surprised at the high band in a short amount of time when prices are expected to go down.
  - o There is a great deal of uncertainty where the price really is. NIPSCO expects the RFP to give better price information. However, the current slide is based on existing data, which incorporates a wide band of uncertainty, but a generally declining cost trajectory over time.
- Will the Xcel Energy information from its latest RFP be utilized among the data sources?
  - o No, as they did not publish capital costs.
- Looking at the solar and storage information, do you combine it?
  - o For purposes of the capital cost assumptions, no. That will be considered as part of another process.
- How do you anticipate including other third party studies for solar, wind and storage?
  - o Slide 56 refers to the various studies that have been utilized.
- Will NIPSCO consider other forecasts, and, if so, what is the timeframe for providing that information?
  - o NIPSCO will ultimately place more emphasis on the information contained in the responses to the RFP, but is interested in other forecasts as well, which are hopefully within the bands of the current projections. The goal is to get data from third party developers, as that is the best idea of what is executable in the market.
- How will the RFP data be integrated?
  - o The data on the slides in this section will be updated with information from the RFP. NIPSCO will continue to discuss how best to do this.

2018 Commodity Price Forecasting
Robert Kaineg and Pat Augustine, CRA

Charles River Associates provided information regarding how commodity prices would be forecasted as part of the 2018 IRP. Robert Kaineg started by providing CRA's natural gas outlook, which included an overview of the market, price forecasting, key modeling inputs, market trends, and price drivers. He then provided information regarding the local gas dynamics in MISO. Next, he provided the same type of overview for the coal market, including a discussion of trends in regional coal production in the United States and a summary of the price trends by coal. Pat Augustine provided information on carbon dioxide ("CO_2") pricing, with information on the base case, low case and high case. He then gave an update on the MISO market outlook. He started by providing an overview of how AURORA does power price forecasting and provided information regarding the MISO footprint. Mr. Augustine noted that it is expected that there will be a continued shift from coal to gas and renewables and provided CRA's Power Price Forecast for MISO Zone 6. He then provided information regarding capacity prices and how they are influenced by market design and ended by providing CRA's MISO capacity forecast.

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

- Is the price reflective of the cost of capacity (what capacity in the market is going to cost)? The prices look low.
    - o The model is not anchored to the cost of new entry. Instead, given the structure of the MISO capacity market, there will be entities that will build to native load, meaning that the existing units are going to set prices closer to the cost to stay in the market. In the Base Case, the assumptions will not necessarily reflect new cost because of the design and participation of the region.
- Would appreciate the ability to have as much information regarding what you have come up with so far in advance of the May meeting.
    - o NIPSCO will work to provide that.

Demand Side Management Update
Alison Becker, Manager, Regulatory Policy
Richard Spellman, GDS Associates, Inc.

Ms. Becker provided a brief overview regarding how NIPSCO is updating its DSM forecast for the 2018 IRP. She explained that while NIPSCO is working with its Oversight Board ("OSB") on a full market potential study ("MPS"), the timing of the 2018 IRP update did not make completing that practical in order to have the data in time for the modeling in the IRP. Therefore, NIPSCO has elected to do a 2018 Electric DSM Savings Update, with a full MPS being completed after that process is complete. She then introduced Mr. Spellman, who is the president of GDS Associates, the firm selected by NIPSCO and the OSB to perform this work, to provide an overview of the Savings Update process. Mr. Spellman explained the types of information that will be included in the Savings Update and noted that it will cover the same years included in the IRP Update (2019 to 2038). He noted this will be completed by June 1, 2018 and that GDS will work with NIPSCO and the OSB on finalizing the data.

Mr. Spellman reviewed the report contents and stated that, while the intention was to use the Total Resource Cost test as the main screening of cost effectiveness, stakeholders had requested NIPSCO to use the Utility Cost Test and that was being considered by NIPSCO. He explained that for the DSM Savings Update Report due on June 1, GDS will update assumptions relating to measure costs, kilowatt hour ("kWh") and kilowatt savings and useful lives. Mr. Spellman then reviewed the technical approach for baseline development that will be completed for the development of the full energy efficiency potential study to be completed in 2019. Finally, he went through the process related to the assessment of potential savings for the full potential study to be completed in 2019 and discussed how GDS will recommend appropriate funding levels based on the projected savings.

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

- Assuming the load forecast essentially incorporates the continuation of DSM programs as they have been in the past, how does this analysis impact that? Can past levels be accommodated or increased in the future?
    - A NIPSCO representative explained that the impacts of NIPSCO's existing DSM programs are captured in the consumption piece of load forecasting. .GDS will work closely with NIPSCO to remove the impacts of NIPSCO's existing energy efficiency programs from the NIPSCO load forecast. Typically, a calculation is performed to determine the percentage of forecast annual kWh sales that are expected to be saved in the future with energy efficiency programs, which is based on the impacts of DSM programs being removed from NIPSCO's load forecast.

RFP for Capacity
Paul Kelly, Director of Federal Regulatory Policy

Mr. Kelly provided an overview of NIPSCO's "all-source" RFP, which was still in the development at the time of the meeting. He noted that a different division of CRA had been retained to assist in the development and administration of the RFP process and that NIPSCO would be seeking stakeholder feedback on the approach/design to ensure a robust, transparent process and result. He also provided an outline of the resource evaluation criteria being considered. Mr. Kelly gave detail around the key design elements of the all-source RFP, noting that all solutions, regardless of technology would be considered. NIPSCO is open to asset purchases and purchase power agreements for new and existing resources. He then explained the timeline for the IRP, indicating a Design Summary would be shared with stakeholders on April 6 to request feedback. Ultimately, the RFP is scheduled to be initiated May 14, with a close date of June 29. At the July 24 IRP Public Advisory Meeting, a summary of the results will be presented.

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

- The schedule only allows 14 days for feedback, which is overly ambitious. Would request the opportunity to sign a non-disclosure agreement to have an opportunity to view the entire RFP.
    - That is something NIPSCO is happy to work through.
- Demand response is not typically contracted for more than one year. That should be considered in the design elements.
    - Great example of helpful feedback. This is something NIPSCO will take into account.
- How much of the IRP will already be completed when the proposals are received? How do you take the information from the RFP and weave it into the IRP?
    - The intent is to summarize by technology, size, range, etc. and put information into IRP for those technologies. The portfolio design can then be run on those numbers and replace the forecast information that was used.
- What are you looking for with the RFP? Actually contracting with vendors?

- NIPSCO wants to understand the price of a resource instead of relying on a forecast. It is important to know what is real and available within the MISO footprint and deliverable to NIPSCO's customer load. The RFP will be binding and, once the Preferred Plan is in place, the Company can begin the process of contracting with individual bidders based on the solutions selected within the Preferred Plan.

- Glad all resources are included. There are parties interested in participating and hope the RFP will allow for those bidders.
  - That is something NIPSCO wants as well.
- Will you piece together resources to get to the 600 MW or must it all be in one proposal?
  - The intent is to get whatever size resources bidders want to propose and then NIPSCO can solve for meeting the 600 MW needed by combining bidder(s) as needed.
- Is there flexibility on the length of the contract? Must it only be for five years?
  - Five years is defined as the minimum term.
- The capacity need not be within NIPSCO's service territory, just within the MISO footprint?
  - Correct. NIPSCO is required to meet its planning reserve obligation in MISO with Zonal Resource Credits for its Local Resource Zone 6. Therefore, all resources considered will need to have firm delivery to Zone 6 in order to qualify for the required capacity accreditation.
- Is the MISO region the same as the Zone?
  - No. MISO covers 15 states and a portion of Canada. While transmission from the far western part of MISO could be expensive, it is possible that a resource that is electrically distant from NIPSCO's load could bid into this RFP if it can establish the firm transmission delivery to Zone 6.
- How is the local community impact being considered? Are you considering the health and environmental impacts (for example, Michigan City with 28% of the population below the poverty level)?
  - NIPSCO plans to evaluate environmental impact as an evaluation criteria in the RFP in a way that is similar to the IRP's coal retirement analysis The Company is open to considering additional ideas and perspectives from its stakeholders on how to further assess environmental/emissions impact as well as the local community impact.
- Does NIPSCO intend to have a carbon price as part of the RFP?
  - NIPSCO is simply requesting a price for the capacity, not something specifically for carbon. The Company expects it will be an integrated price to evaluate on the cost component. Would be interested in perspectives from stakeholders on how to consider carbon in the evaluation.
- Will NIPSCO be considering self-build options in the RFP?
  - No, NIPSCO is not evaluating a self-bid option in the RFP. While NIPSCO has continued to evaluate the CCGT solution that was identified at the time of the 2016 IRP, the focus of this RFP is looking more broadly at all viable solutions to address its needs.
- When do you expect to see the execution of contracts?

- o NIPSCO does not look to transact any earlier than the close of the IRP process. Once NIPSCO is through the stakeholder process and has developed its Preferred Plan, the Company will consider negotiating definitive agreement(s) in the fourth quarter of 2018.

Stakeholder Presentations

David Repp from Jet provided a presentation "Technology Introduction and Adaptability to Indiana Power Facilities," which provided information on an alternative to existing desulfurization technology. He walked through an overview of the technology, the technical features, and the benefits that could be provided.

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

- The Indiana Coal Council favors this technology. With what type of coal can this technology be utilized?
  - o Can adapt on a wide range of low and high sulfur coals. You need to look at the economics-the higher the sulfur, the more economical the process is. That is the type of coal in Indiana.
- Is this a replacement of a scrubber?
  - o That is a site-specific answer. The absorber is similar to what you would expect for a limestone absorber. You can retrofit a limestone scrubber into this technology and it will not cost much in capital.
- Have you qualified for any Department of Energy funding for this?
  - o In discussions. The concept is ammonia based and not new. The Department of Energy has paid for new absorbers with this technology and a cost-share to retrofit, both were successful. In total, 300 units have been installed.

2018 Public Advisory Process and Closing

Ms. Becker outlined the remainder of the Public Advisory Process, with the following meetings scheduled:

Date	Location	Main Topic(s)
May 11, 2018	Avalon Manor, Merrillville, IN	• Existing Generation • Environmental Considerations • Retirements Update • DSM in the IRP
July 24, 2018	Webinar	• Preliminary Results from the RFP
September 19, 2018	Fair Oaks Farms, Fair Oaks, IN	• Preliminary Findings from the Modeling
October 18, 2018	Fair Oaks Farms, Fair Oaks, IN	• NIPSCO's Preferred Plan • Short Term Action Plan

Timothy Caister, Vice President, Regulatory Policy closed the meeting by thanking the attendees for their attendance and active participation.

Jiangnan Environmental Technology

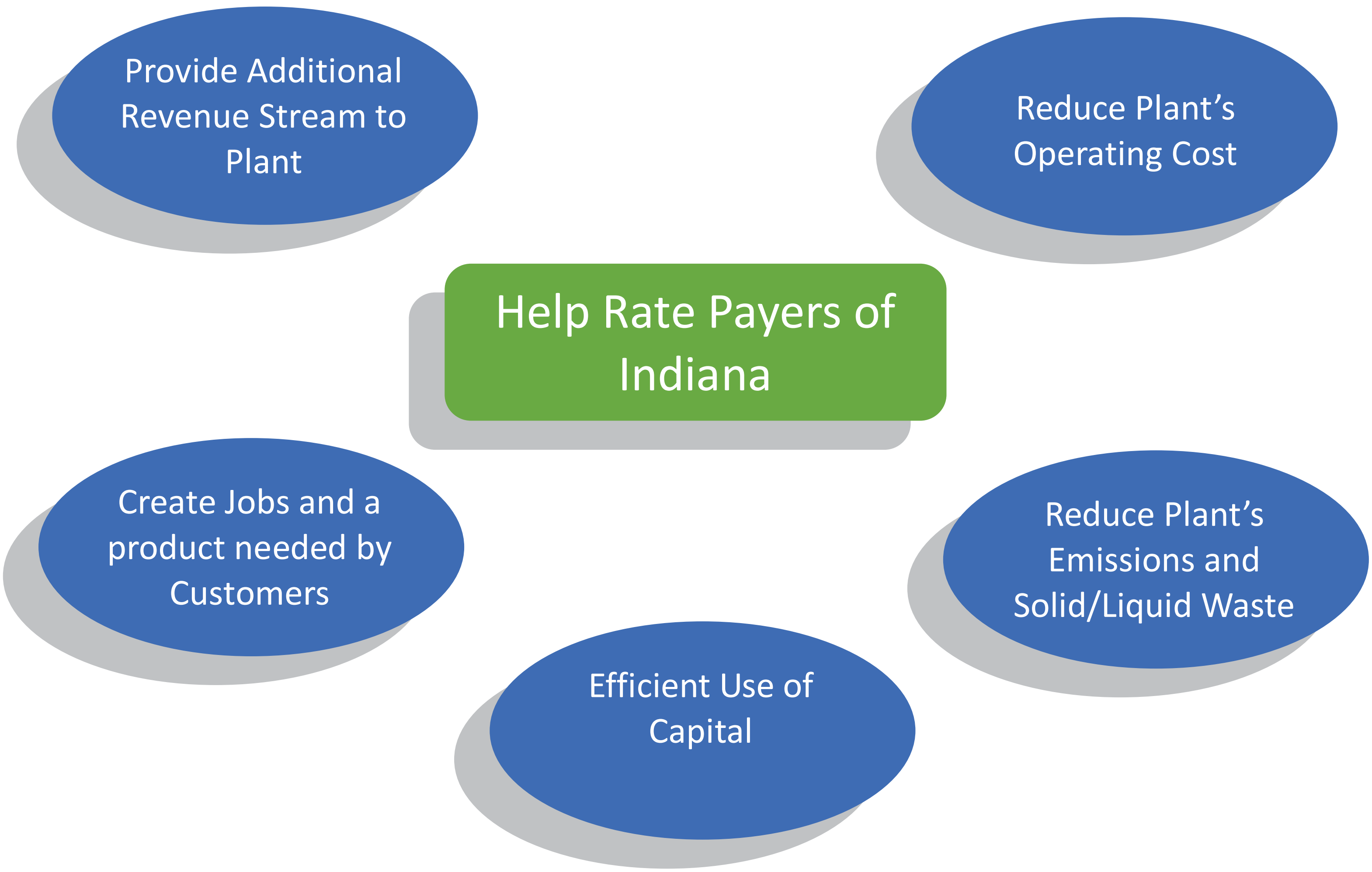
Technology Introduction and Adaptability to Indiana Power Facilities

Prepared Personally For:

NIPSCO

March 23rd, 2018

An Alternative to Existing Desulfurization Technology



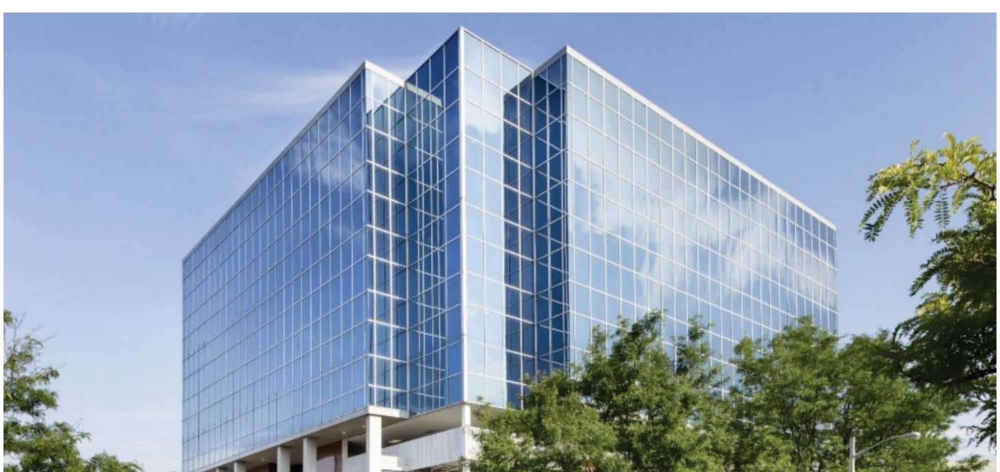
Help Keep Plants Viable

About JET

JET provides customized solutions in Engineering, Construction and Operations Services for Power Plant Desulfurization. In 1998 JET established the first ammonia desulfurization technology research institute in China, and launched the first recovery type ammonia desulfurization unit in 2004. With a global vision, and a strong organizational culture heavily focused on R&D, JET is dedicated towards providing cost effective solutions towards eliminating air pollution, improving living conditions, and helping our customers meet increasingly stringent emission standards.

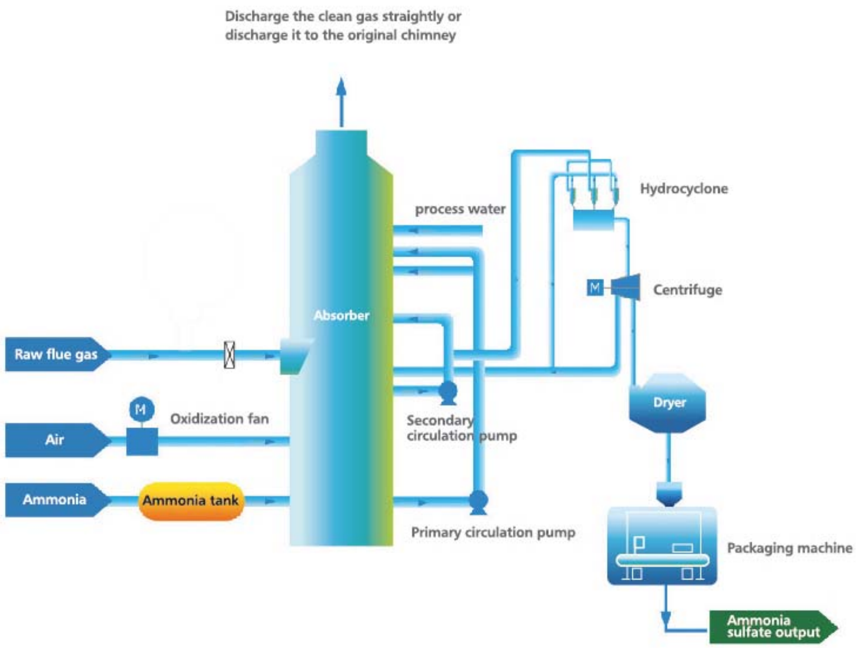
- **Global leader with 80% market share in Ammonia-Based Desulfurization**
- **65 patents and patent applications**
- **150+ projects with more than 300 installed units**
- **20+ installations with capacity bigger than 700,000 SCFM**

JNEP (China Office)



JET Global Headquarters (Ridgefield Park, NJ)

Technology



	Year	Features	NH_3 recovery	SO_2 emission ppm	Total dust lb/MMSCF	Performance
1st Gen	1998	Basic NH_3 based deSOx	not controlled	~ 70		Meets SO_2 emission limit
2nd Gen	2010	NH_3 based deSOx with NH_3 recovery control	≥ 97%	< 35		Meets HG2001-2010 standard
3rd Gen	2013	Fine PM control	≥ 98%	< 17.5	≤ 4.72	Meets GB13223-2011 special emission limit
4th Gen	**2015**	**Ultrasound-enhanced deSOx and PM-removal integration**	**≥ 99%**	**< 12**	**≤ 1.18**	**Meets ultra-low emission limit***

Performance:

- SO_2 emission ≤ 12 ppm
- Particulate Matter Emissions ≤ 1.18 lb/MMSCF
- Ammonia Slip ≤ 3 ppm
- Ammonia Recovery Rate ≥ 99%

Attachment 2-A
Page 17

Technical **Features**

Advantages of EADS compared to Limestone Process

	EADS	LIMESTONE
Process	Turn waste (SO_2) to high value fertilizer	Consume 1.6 ton limestone & generate 0.7 ton CO_2 per ton SO_2 removed
Capital Cost	0.8 Base	Base
Operating Cost	<100% Base or even make profit	Base
SO_2 Removal Efficiency	>99.5%	<97%
SO_2 Emission	12 PPM	35 to 70 PPM
Waste Water Generation	No	Yes
Solid Waste Generation	No	Yes
Synergy with Carbon Capture System	Yes	No

1

Low Operating Cost

The liquid-to-gas ratio of the ammonia process is only 1/6 to 1/3 of the limestone-gypsum process. Therefore, the power consumption of the ammonia-based process is about 50% less than that of the limestone-gypsum process.

The byproduct of the ammonia-based process is ammonium sulfate, which can be sold as fertilizer. The sales revenue from ammonium sulfate can offset the total cost of ammonia, and lower the overall operating cost.

2

No Secondary Pollution and High-value Byproduct

The EADS technology is environmentally friendly. Unlike other FGD processes such as limestone-gypsum process, it recovers SO_2 efficiently without generating any waste water, solid waste, or CO_2.

The byproduct of the ammonia-based process is saleable fertilizer, whereas the by-product of the limestone-gypsum process is gypsum and its sales value is significantly lower than that of ammonium sulfate. In some cases, the gypsum need to be disposed of as solid waste

3

High SO2 Removal Efficiency

Ammonia is a substance with much higher alkalinity and reactivity with SO_2, making it a more efficient absorbent than limestone. Therefore, the absorption of ammonia-based absorbent is faster than the limestone slurry. As a result, SO_2 removal up to 99% and SO_2 emission as low as 12 ppmv can be achieved by the ammonia-based process.

4

Excellent Adaptability and System Reliability

EADS technology can be applied to coal with sulfur content from 0.2% to 8% and flue gas with SO_2 content from 100 to 10,000 ppmv or higher.

5

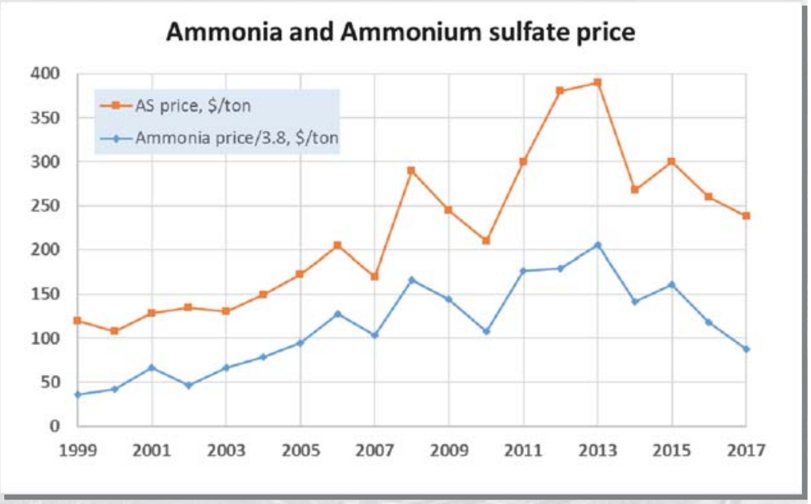
Proven Technology

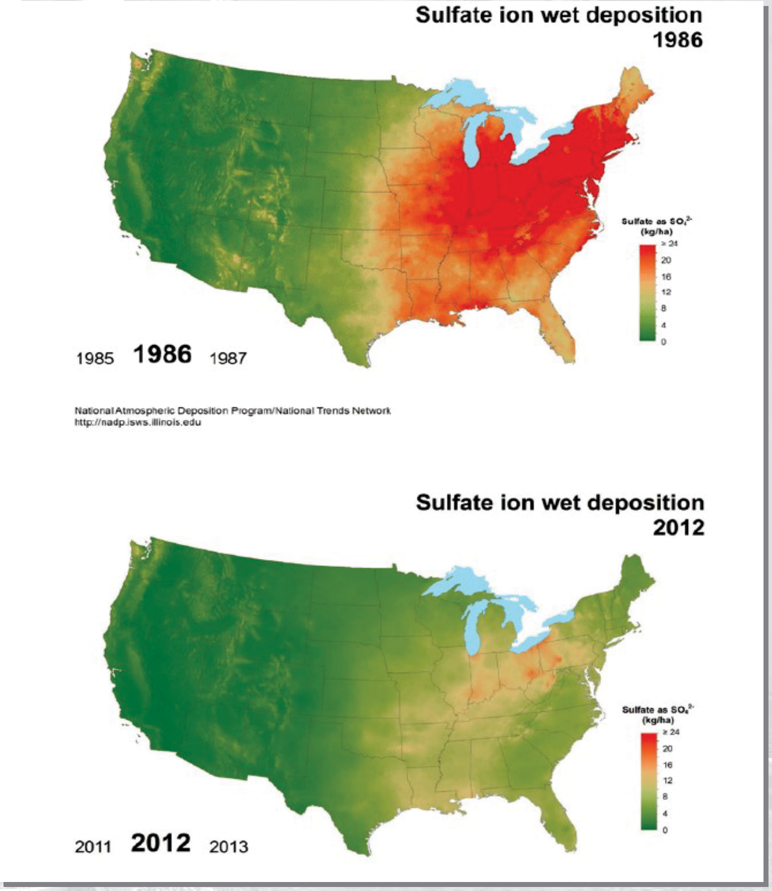
The technology proposed in this proposal is reliable and commercially proven. To date, more than 150 EADS projects have been put into operation or under construction.

Ammonia/Ammonium Sulfate

The EADS technology uses “ammonia” as the desulfurization absorbent, and anhydrous ammonia, aqueous ammonia, or gaseous ammonia can be used as the desulfurization agent. We are currently in talks with the following ammonia suppliers. Ammonia can also be synthesized from coal or natural gas.

Ammonium sulfate product will be sold to fertilizer produces as a feedstock for producing compound fertilizers or directly sold to fertilizer retailers. Ammonium sulfate is widely used in the US and Latin America, where about 70% of the fertilizers is imported. **Nitrogen based Fertilizer is a growing market with a 2016 demand of 121 Million Tons!**





Comments from our Clients

“The newly-built ammonia-based FGD project, Tower #5, has been successfully completed and no malfunction occurs since the operation. We want to thank you for the remarkable contribution to our project…” -------- Wanhua Chemical Group Co.,Ltd

“The retrofit project for our Boiler #1 within 3 months meets the emission regulations as planned, while the cost and power consumption are much lower. We much appreciate your efforts in overcoming difficulties during the retrofit, such as the limited space of the site...” -------- Sinopec Qilu Petrochemical Company

“We sincerely thank JET’s efforts and contributions in our coal-to-olefin retrofit project. The project is a highly difficult and challenging project, where the sites are small and the construction and operation run at the same time. Despite the difficulties, JET has successfully completed the construction, and the flue gas is much cleaner than before when the Limestone-gypsum process was applied…” -------- Shenhua Ningxia Coal Industry Group Co., Ltd.

Flexible Business Models – Low/No capital investment required from plant

- EPC
- BOT (Build – Operate – Transfer)
- BOO (Build – Operate – Own)

Thank you for your interests in our technologies

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JET
Jiangnan Environmental Technology

All Source Request for Proposals – Interim Summary

Introduction and Request for Proposal Overview

Northern Indiana Public Service Company ("NIPSCO") does business in the State of Indiana as a regulated public utility. NIPSCO generates, transmits and distributes electricity for sale in Indiana and the broader Midcontinent Independent System Operator, Inc. ("MISO") regional electricity market.

NIPSCO is committed to meeting the energy needs of its customers today and in the future. Through the Integrated Resource Planning ("IRP") process, NIPSCO identifies its long term capacity needs and charts a path on how best to meet those needs. The IRP process seeks to identify preferred resource portfolios that are reliable, compliant, flexible, diverse and affordable, all of which are guiding principles of NIPSCO. Long term resource planning requires addressing risks and uncertainties created by a number of factors including the costs associated with new resources.

In its 2016 IRP, NIPSCO identified a minimum capacity need of 600 megawatts ("MW") by 2023. To address that projected resource need, NIPSCO has concluded that it is in the best interest of its customers to seek to acquire, construct or contract for additional generating capacity located within the MISO market. NIPSCO is releasing an "all source" Request for Proposals ("RFP") for supply and demand side capacity ("DSM") resources. An RFP solicitation is the best opportunity to mitigate the uncertainty associated with the cost of new resources. The purpose of the RFP is to identify the most viable resource(s) available to NIPSCO in the marketplace to meet the needs of its customers. NIPSCO is currently in the initial phases of the RFP process designed to both inform the IRP and identify specific assets, resources, projects or contractual options that best meet the Company's resource requirements.

A key aspect of NIPSCO's proposed process is the integration of the IRP and RFP processes which will be conducted in parallel. The parallel design is intended to ensure that the resource requirements identified through the IRP process were informed by the most current and accurate market information and that the RFP asset selection is consistent with the NIPSCO IRP. NIPSCO will first identify its preferred resource portfolio by aggregating data from the RFP responses and inputting such data into its IRP modeling. The RFP bid evaluation and selection process will be based upon the specific resource needs identified through this IRP modeling as well as the bid evaluation criteria.

NIPSCO is committed to a collaborative process considering the needs of all stakeholders throughout the design of the RFP. **The following memorandum represents a current outline of the proposed process and is seeking stakeholder feedback and comments by Friday, April 20th, 2018 to *nipsco_irp@nisource.com.*** NIPSCO will take stakeholder comments under advisement and reserves the right to update the process documents, timeline, bidding requirements or evaluation criteria prior to the official launch of the RFP.

The NIPSCO RFP is being designed to consider all sources of capacity and the company has no stated or unstated preference for the fuel source or deal structure related to the potential resource options available through the market. Consistent with that, the RFP will be issued as an all source procurement process that will consider a range of existing and in-development fossil and non-fossil fuel sources, purchase power agreements (including capacity-purchase agreements) ("PPA"), and DSM proposals in order to identify the mix of resources that best serves customer needs.

NIPSCO has retained Charles River Associates ("CRA") to support the IRP, RFP and stakeholder processes. CRA has a long track record of executing structured procurement processes on behalf of its utility clients and will support NIPSCO throughout the RFP design and execution.

Requesting Stakeholder Feedback – Design Subject to Change

NIPSCO is providing this interim summary of the All Source RFP to stakeholders to request their feedback on the proposed design. As such, it is currently in a "draft" state and will not be finalized until NIPSCO has considered all feedback received from our stakeholders and completed additional internal review.

Information and Schedule

The RFP is scheduled to launch on May 14th, 2018. At or before the 14th of May, CRA will initiate a marketing process in association with the launch. The marketing process will include the release of a public Information Website; one or more bidder information sessions; advertising in trade publications and direct outreach to potential process participants. The goal of the marketing process is to create bidder interest in the process and to educate potential bidders about the objectives of the integrated IRP and RFP work streams. Tentative key dates for the RFP include the following:

- May 14, 2018: RFP Issued
- May 16, 2018: Bidder Information Session
- May 28, 2018: Bidder Notice of Intent and Prequalification Due
- June 4, 2018: Prequalification Notices Sent to Approved Bidders
- June 29, 2018: Bidder Proposals Due
- July 2, 2018: Start of Bid Evaluation Period
- September 15, 2018: Bid Evaluation Completed
- Quarter 4 2018: Definitive Agreements Signed with Winning Bidders

It is anticipated that any asset purchase agreements, DSM agreements or PPA that may arise as a result of the RFP process would go into effect at or around 2023. However, the timing of any individual agreement may be an element of the proposal details submitted in response to the RFP. As such, NIPSCO is willing to entertain proposals with delivery prior to 2023 in the event such agreement is advantageous for NIPSCO's customers.

Certain information will be made available to bidders in advance of the proposal due date. The public Information Website will be the central source of information for the process. All bidders will have equal access to information to ensure a fair, equitable and non-discriminatory RFP.

Capacity Assets Considered in the RFP

As noted above, NIPSCO intends to issue an all-source RFP and will consider a wide range of options to meet customer needs. NIPSCO is anticipating the receipt of bids from any of the following categories of capacity assets:

- Asset purchases for new or existing resources including dispatchable, intermittent / renewables, stand-alone storage or resources paired with storage (semi-dispatchable)
- PPA
- DSM options

While the draft RFP makes specific reference to the above categories, NIPSCO will consider bids from non-traditional resource options outside the above set to the extent that they meet the basic bid requirements for the RFP. Additionally, there is no minimum offer or offer cap associated with this RFP. NIPSCO will consider bids from resources smaller or larger than the 600 MW need identified.

Key Qualification Requirements

NIPSCO is considering all sources to meet their resource requirements, however, there will be certain minimum qualification requirements associated with participation in the RFP process and certain threshold requirements on assets supporting the bids evaluated. These requirements fall into four general categories:

1. **Counterparty credit requirements**: NIPSCO will require that PPA counterparties and developers meet certain minimum credit and financial standing requirements. Potential counterparties that do not meet the minimum requirements may need to post additional performance collateral or be supported by parental guarantees.

2. **Asset reliability and deliverability requirements**: NIPSCO requires operational control of any physical asset bid into the RFP. Physical assets must also be interconnected at the transmission voltage (under MISO's functional control). Physical assets bid or that support a PPA bid into the RFP must have firm delivery capability into MISO Load Resource Zone 6 ("LRZ6"). In addition, bidders must demonstrate that resources currently meet MISO's (n-1) contingency criteria and either demonstrate that they meet (n-1-1) transmission criteria or provide cost estimates for the upgrades required to do so.

3. **Key development milestones:** New or planned generation facilities or PPA supported by new or planned generation facilities that have a development timeline greater than {*X*} months must have executed a pro-forma MISO Interconnection Service Agreement, Interconnection Construction Services Agreement and completed a MISO System Impact Study for the project for the proposed delivery point. New or planned generation facilities or PPA supported by new or planned generation facilities that have a development timeline less than or equal to {*X*} months must provide a timeline showing ability to complete key development milestone prior to June 1, 2023 including the above referenced items for the MISO generator interconnection queue.

4. **Remaining useful life:** Assets bid into the RFP must have an expected remaining useful life of at least five (5) years. NIPSCO will also not consider PPA with contract terms of less than five (5) years unless for DSM which NIPSCO will allow a minimum term of one (1) year.

Proposals supported by assets that do not meet the threshold criteria will not be evaluated further and will not be selected as a winning bidder through this process. Facilities not meeting the threshold criteria could be considered outside this process on a case by case basis or as NIPSCO needs dictate.

Proposal Content Requirements

As part of this RFP, NIPSCO will request information from bidders in order to inform the IRP process and to evaluate the bids received. Certain required information is commercially sensitive and proprietary. As a result, access to information will be restricted consistent with the terms and conditions of the non-disclosure agreement associated with the RFP. The information requested from bidders in association with the RFP process include the following:

- Counterparty corporate and financial information
- Experience of the facility operator or the project developer
- Facility name, location, interconnection points and commercial operating node
- Facility capacity availability and deliverability information
- Generation technology including dispatch and emissions characteristics
- Facility revenues and operating costs
- Generation facility operating data
- Generation facility operating and maintenance plan including information on long term service agreements ("LTSA")
- Detailed fuel supply information including fuel supply contract information
- Emissions and waste disposal compliance information
- Water supply and permitting information
- Capital expenditure plan including the cost of compliance with certain pending or proposed environmental restrictions or action
- Pending legal action or material contingencies
- Development milestones, interconnection and permitting information
- Offer price including any transferred liabilities
- Asset purchase agreement ("APA") and/or PPA markups

Because NIPSCO is conducting this RFP as part of its IRP public advisory process, NIPSCO will summarize bids by size and technology for presentation to stakeholders unless fewer than 3 bids are received for any given category. Bidder names will also be shared in the form of an aggregate list. The individual bids will be considered highly confidential.

Modeling Scenarios and Key Assumptions

NIPSCO's IRP team is tasked with analyzing near and long-term power market performance under a range of commodity, demand and environmental scenarios. Modeling conducted in support of the IRP includes a Base Case set of parameters reflecting NIPSCO's outlook for key drivers of power market performance and operations. The IRP process will also perform scenario analysis on certain parameters including natural gas prices, coal prices, carbon prices, power prices, NIPSCO load and costs of new resources.

In association with the 2018 IRP, NIPSCO is also developing a stochastic analysis to analyze the cost and risk-related tradeoffs between different resource and retirement combinations for the NIPSCO portfolio. The preliminary stochastic analysis relies on replacement cost estimates of different types of generating capacity. These estimates will be updated consistent with information derived from the all source RFP.

IRP modeling will be used to generate an optimal acquisition portfolio for NIPSCO reflecting the Base Case, scenarios, the stochastic analysis and supported by the updated resource costs generated through the RFP process. The optimal portfolio will be used in the RFP process to determine the amount of capacity from each resource category to select as winning bidders.

RFP Evaluation Criteria

The RFP team will begin the evaluation of RFP bids concurrent with the IRP scenario modeling and stochastic analysis.

Certain bids may be disqualified from consideration to the extent that they do not meet the threshold requirements for the RFP or if the bids are otherwise non-conforming.

Bids that survive the initial screening will be subject to further analysis and ranking. RFP bids will be grouped consistent with the asset categories used for the IRP and will be reviewed using a multi-dimensional evaluation framework. The framework considers reliability and deliverability, cost, asset-specific environmental considerations, development risk and asset specific risk factors. NIPSCO intends to weight evaluation criteria as part of the framework.

1. **Facility Reliability and Deliverability**: Bidders will be requested to provide power flow analyses under the MISO (*n-1*) reliability guidelines. Bidders will also be required to provide power flow analysis under NIPSCO's (*n-1-1*) reliability criteria or the cost to mitigate the difference between (*n-1*) and (*n-1-1*). Bidders will also be required to provide operating history and projected facility loadings over recent and near-term planning years. Assets that can demonstrate they currently meet NIPSCO reliability guidelines will receive full credit under the reliability category.

2. **Facility Cost**: NIPSCO will perform an evaluation of the cash cost of each bid. The cost analysis will examine the asset bid price, asset specific estimates of fixed and operating costs, capital expenditures, taxes, congestion costs and other cash considerations. Results will be adjusted for offsetting market revenues and presented on a net $/MW-day basis.

3. **Environmental Considerations:** NIPSCO will consider the specific environmental profile of individual assets. The evaluation will consider both criteria pollutants and asset carbon intensity in order to evaluate the asset specific exposure to scenarios or regulations not explicitly considered in the IRP modeling and to differentiate among the bids for assets within a given category.

4. **Development Risk:** Existing resources will receive full credit under this evaluation category. Plants in development will be awarded points based on the developer experience in MISO and development milestones achieved. Proposals will receive points based on the

demonstrated ability of the bidder to meet the key milestones in the development timeline as measured by the MW placed into service in MISO to date by the developer. Points will also be awarded in pro-rata fashion based on the development progress of the proposed project itself. In all cases, development projects must provide development collateral in support of meeting the target commercial operation date.

5. **Asset Specific Risk Factors:** Considerations may include, but not be limited to, fuel supply security and reliability, pending litigation or material contingencies associated with the facility or operator, and uncertainty related to transmission infrastructure or upgrades that may affect the facility operations. Proposals with no additional risks, or with risks for which the Respondent has described full mitigation measures, will receive the full credit.

Post RFP Timeline

Bidder proposals are due to NIPSCO by 5:00 PM EDT Central Prevailing Time on June 29th, 2018. The bid evaluation process will begin immediately upon receipt of the bids. It is expected that the bid evaluation will be completed by mid-September 2018 and a list of finalists will be submitted to NIPSCO by CRA for modeling within the IRP. Once the Preferred Plan is determined, it is expected that NIPSCO will enter into final negotiation with selected finalists and work towards definitive agreement(s) to be executed during the fourth quarter of 2018.

During the final negotiation period, NIPSCO will conduct site visits, if applicable, and execute a detailed engineering review of each asset in consideration of a definitive agreement. In addition, NIPSCO may perform additional dispatch modeling of each finalist as part of a broader due diligence effort designed to ensure that all stakeholder interests are protected and the selected asset(s) meet(s) NIPSCO's reliability and deliverability requirements.

All definitive agreement(s) would be subject to the granting of a Certificate of Public Convenience and Necessity ("CPCN") by the Indiana Utility Regulatory Commission. Agreements may require approval in other jurisdictions or at the Federal Energy Regulatory Commission, depending on the nature of the agreement or the asset(s) selected. Any regulatory filing(s) would begin after the conclusion of NIPSCO's due diligence and the execution of definitive agreements. As such, any definitive agreements are subject to regulatory approval.

NIPSCO Public Advisory Meeting 1 Registered Participants		
First Name:	**Last Name:**	**Company:**
Lauren	Aguilar	OUCC
Linda	Anguiano	Progressive Democrats of America - Calumet Region
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Russ	Atkins	NIPSCO
Pat	Augustine	Charles River Associates
Greg	Baacke	NIPSCO
Lisa	Beck	
Vernon	Beck	NIPSCO
Alison	Becker	NIPSCO
Anne	Becker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Marc	Blanchard	BP
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Tim	Caister	NIPSCO
Andy	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Mary	Chambers	NIPSCO
Daniel	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Claudia	Earls	NiSource
Amy	Efland	NiSource/NIPSCO
Greg	Ehrendreich	MEEA
Steve	Francis	Sierra Club - Hoosier Chapter
Thomas	Frank	Commuity Strategy Group
Fred	Gomos	NiSource
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Corey	Hagelberg	Beyond Coal
Barry	Halgrimson	Retired
John	Halstead	350 IN-Calumet
Rina	Harris	Vectren
John	Henderson	Stoll Keenon Ogden PLLC
David	Hicks	Indeck Energy Services, Inc.
Stephen	Holcomb	NIPSCO
Shelby	Houston	IPL/AES
Jim	Huston	Indiana Utility Regulatory Commission
Robert	Kaineg	Charles River Associates
Pauline	Katsouros	NIPSCO
Paul	Kelly	NIPSCO
Bryan	Little	NIPSCO
Jonathan	Mack	NIPSCO
Debi	McCall	NIPSCO
Jim	McMahon	CRA

NIPSCO Public Advisory Meeting 1 Registered Participants		
First Name:	**Last Name:**	**Company:**
Emily	Medine	EVA
Tony	Mendoza	Sierra Club
Nancy	Moldenhauer	none
Richard	Nelson	Praxair, Inc.
Adam	Newcomer	NIPSCO
Elizabeth	Palacio	Ms.
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Jodi	Perras	Sierra Club
Carmen	Pippenger	IURC
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
David	Repp	JET Inc
Matt	Rice	Vectren
Joe	Rompala	Lewis Kappes
Edward	Rutter	Indiana Office of Consumer Counselor
Anthony	Salcedo	Sal-tec Service
Cliff	Scott	NIPSCO
Brent	Selvidge	IPL
Robert	Seren	NIPSCO
Frank	Shambo	NIPSCO
Violet	Sistovaris	NIPSCO
Matt	Smith	Carmeuse Lime and Stone
Joan	Soller	MISO
Dick	Spellman	GDS Associates, Inc.
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Kathleen	Szot	NIPSCO
Maureen	Turman	NiSource
Bob	Veneck	Indiana Utility Regulatory Commission
Victoria	Vrab	NIPSCO
Jennifer	Washburn	CAC
Michael	Whitmore	NIPSCO
Ashley	Williams	Sierra Club
Fang	Wu	SUFG
James	Zucal	NIPSCO

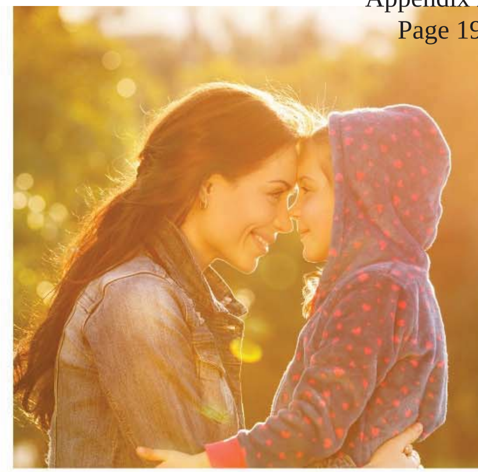
Appendix A

Exhibit 2

NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting Two

May 11, 2018



NiSource

NIPSCO

Agenda

Time	Topic
9:00-9:15	Welcome and Introductions • Safety Moment
9:15-9:30	How Does NIPSCO Plan For The Future? • Public Advisory Process
9:30-10:15	Modeling Uncertainty: Scenarios and Stochastics for 2018 Integrated Resource Plan
10:15-10:30	Break
10:30-11:00	DSM Modeling Methodology
11:00-11:45	NIPSCO Generation Overview • Operating Costs • Environmental Considerations
11:45-12:30	Lunch
12:30-12:45	2018 Scorecard
12:45 -1:15	Retirement Analysis
1:15 -1:30	Break
1:30-2:00	Replacement Analysis
2:00-2:15	Request for Proposals Update
2:15-2:45	Stakeholder Presentations
2:45-3:00	Next Steps and Wrap Up

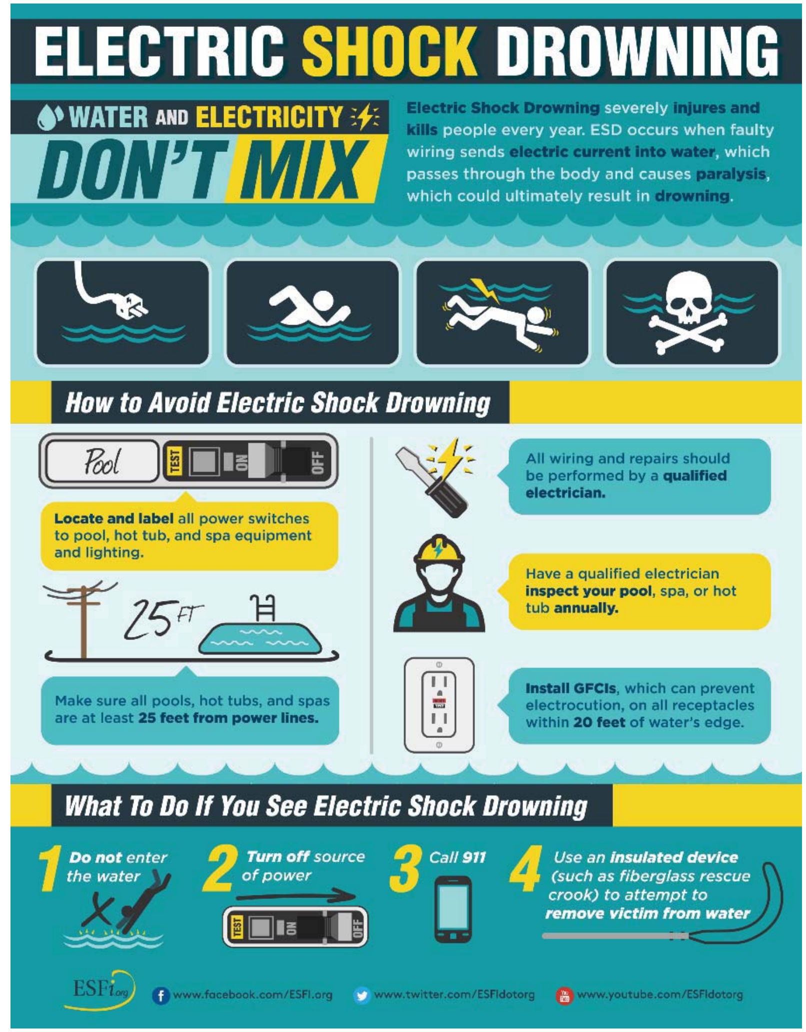
Welcome and Introductions

- Introductions
- Welcome from Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource

Wi-Fi Password: guest1234

Safety Moment: May is National Electric Safety Month

- An estimated annual average of 70 electrocution fatalities are associated with consumer products
- There are reported cases of electric shock drowning that occur at marinas or in swimming pools each year
- National and State Electric Codes seek to reduce fatalities, injuries and fires
- The Electrical Safety Foundation International has additional resources available at www.esfi.org



NIPSCO's Planning and the Public Advisory Process

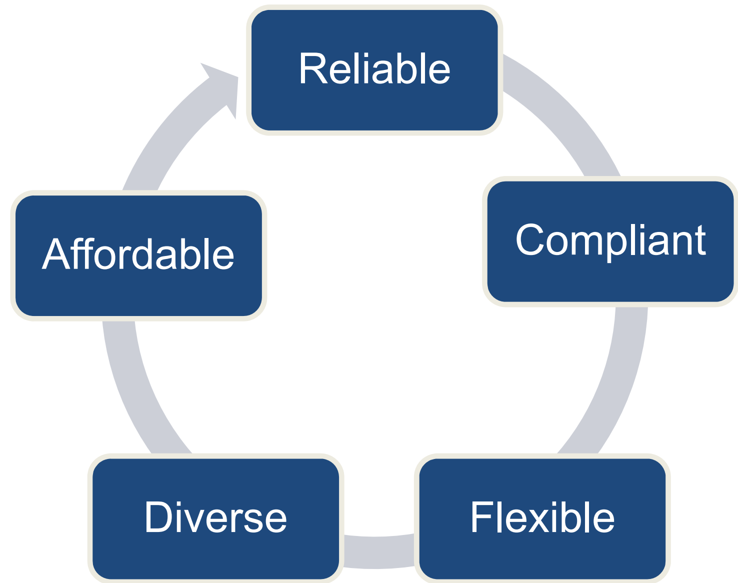
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan (IRP) – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires Careful Planning and Consideration for:
- NIPSCO's employees
- Environmental regulations
- Changes in the local economy (property tax, supplier spend, employee base)

Overview of the Public Advisory Process

- **Today's meeting is the second of five meetings**
  - Four in person meetings and one webinar
- **Your participation and candid feedback is key to the process**
  - Please ask questions and provide comments on the material being presented and the process itself to ensure this is a valuable exercise for you and NIPSCO
- **The Public Advisory process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and the overall IRP results**
  - It also serves as a "check" on the modeling process as results are received
- **Ability to make presentations as part of each Public Advisory meeting**
  - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch
- **Public Advisory Meeting Materials**
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.nipsco.com/irp

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3* (July 24th)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	-Why has NIPSCO decided to file an IRP update in 2018? -What has changed from the 2016 IRP? -What are the key assumptions driving the 2018 IRP update? -How is the 2018 IRP process different from 2016?	-What is NIPSCO existing generation portfolio and what are the future supply needs? -Are there any new developments on retirements? -What are the key environmental considerations for the IRP? -How are DSM resources considered in the IRP?	-What are the preliminary results from the all source RFP Solicitation?	-What are the preliminary findings from the modeling?	-What is NIPSCO's preferred plan? -What is the short term action plan?
Meeting Goals	-Communicate and explain the rationale and decision to file in 2018 -Articulate the key assumptions that will be used in the IRP -Explain the major changes from the 2016 IRP -Communicate the 2018 process, timing and input sought from stakeholders	-Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM -Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap -Key environmental issues in the IRP	-Communicate the preliminary results of the RFP and next steps	-Stakeholder feedback and shared understanding of the modeling and preliminary results -Review stakeholder modeling and analysis requests	-Communicate NIPSCO's preferred resource plan and short term action plan -Obtain feedback from stakeholders on preferred plan

*Webinar

Stakeholder Interactions

- Since the March 23rd Public Advisory meeting, NIPSCO has met with stakeholder groups

Stakeholder	Subject Area/Discussion Topic
Sierra Club	All-Source Request for Proposals (RFP) and integration with IRP
OUCC	All-Source RFP and integration with IRP

Modeling of Uncertainty

Jim McMahon & Pat Augustine
Charles River Associates (CRA)

Modeling of Uncertainty

- **Generation decisions are generally capital intensive and long-lived, understanding and incorporating future risk and uncertainty is important**
- **NIPSCO analysis uses both scenarios and stochastics to assess risk**

Scenarios
Integrated Set of Assumptions

- **Can be used to answer "What if…"**
- Major events can change fundamental outlook for key drivers, altering portfolio performance
    - New policy or regulation (carbon regulation)
    - Fundamental gas price change (change in resource base, production costs, large shifts in demand)
    - Loss of a major industrial load
    - Technology cost breakthrough (storage)
- **Can tie portfolio performance directly to a "storyline"**
    – Easier to explain a specific reasoning why Portfolio A performs differently than Portfolio B

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate volatility and "tail risk"**
    – Short-term price volatility impacts portfolio performance
        - Value of certain portfolio assets is dependent on market price volatility
        - Commodity price exposure risk is broader than single scenario ranges
- **Develops a dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
    – Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes
    – Can calculate statistical metrics to evaluate 95^{th} percentile outcomes

Identifying Risks and Uncertainties

- **As in the 2016 IRP process, the first step is to identify major drivers of potential uncertainty which could influence IRP outcomes**
  - Then develop future perspectives regarding major drivers
  - Next assess whether scenario or stochastic (or both) treatment is appropriate

	2018 IRP		
2016 IRP Drivers	**IRP Drivers**	**Scenarios**	**Stochastics**
Load	Load	✓	
Regulation Environmental Compliance	Policy *(Inc. Environmental)*	✓	
Economy	Economy	✓	
Technology	Technology	✓	✓
Commodity Prices	Commodity Prices	✓	✓

Integrated Scenarios

- Represent Distinct Thematic Views of the future operating environments for NIPSCO
- The 2018 IRP will use "scenarios" or thematic "states-of-the-world" under which to develop portfolios and to inform stochastic distributions
- The scenarios are used to establish reasonable ranges of key variables, which guide portfolio development and stochastic development

Theme	Drivers			
	Load	**Policy**	**Economy**	**Technology**
Base Case	Base load forecast	National carbon price expected in 2026 with new federal policy; current regulations on CCR/ELG	Long-term growth trends in line with historical averages	Expected continued declines in solar/storage costs; base case nat. gas production costs
Aggressive Environmental Regulation	Base load forecast	**Policy forces drive stricter carbon controls and stronger renewable targets**	Reference case macroeconomic factors persist	**Renewable (wind and solar) and storage costs decline significantly, supported by policy push**
Challenged Economy	**Loss of industrial load; remaining customer load growth stagnates**	No national carbon policy	**Economic downturn with growth stalling**	Base technology assumptions
Booming Economy & Abundant Natural Gas	**Greater load growth, maintenance of industrial customers**	Base environmental policy; strong support for gas extraction	**Low-cost energy paradigm prevails and economic growth greater than expected**	**Continued efficiency gains in NG extraction drive lower operations costs and focus on most productive plays**

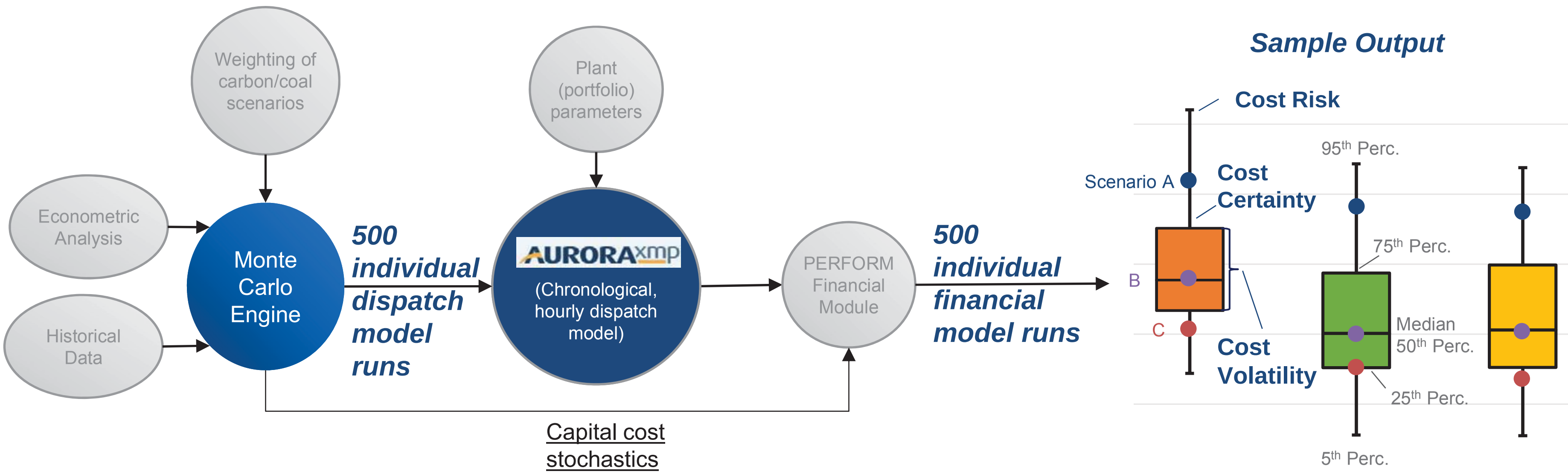
Scenario Considerations Inform Combinations of Input Variables

- Based on technology, policy, consumer and economic considerations, each scenario has a unique combination of key input variables and a fully integrated set of commodity market price forecasts

Scenario Theme	NIPSCO Load*	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs
Base	Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**	**Low** renew./ sto.
Challenged Economy	Low	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**	Base
Booming Economy & Abundant Natural Gas	High	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**	Base

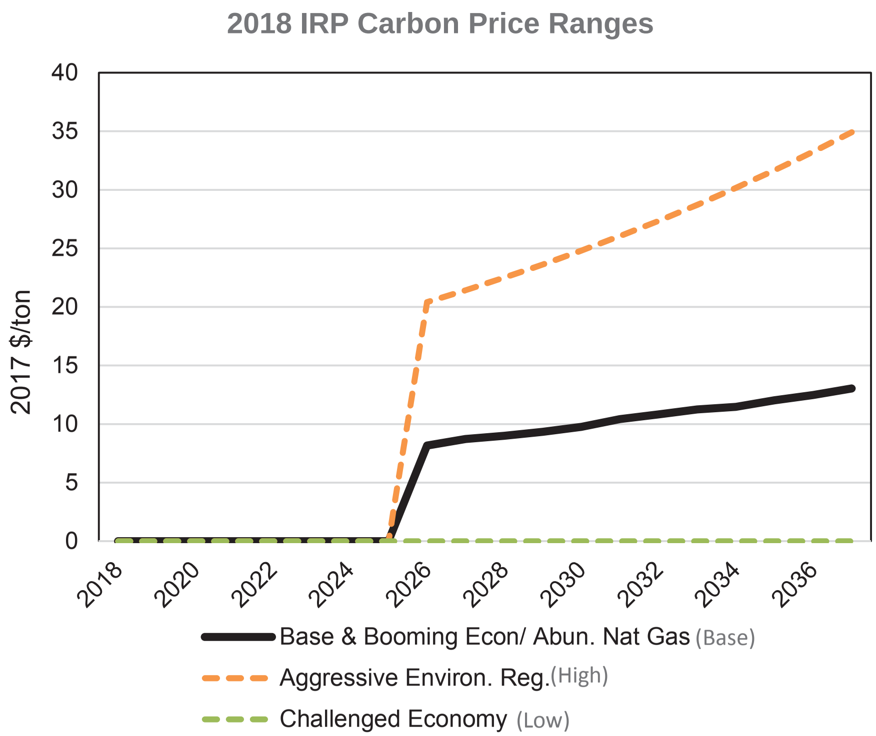
**Currently all scenarios assume NIPSCO Base load forecasts shown in March 23rd meeting, final modeling will integrate high and low load forecasts*

Stochastic Analysis Process and Benefits



- **Stochastic analysis provides a complementary, but extensive assessment of relative portfolio performance, as compared to scenarios:**
  - Captures random outcomes that are unanticipated in scenarios. For example:
    - Power price spikes that are driven by weather and outages rather than fuel prices
    - Market conditions where expected fuel and power correlations break down
    - Combinations of outcomes for key variables (capital costs, commodity costs, carbon prices) that wouldn't be contemplated through scenario construction
  - Ability to quantify costs at the 75th and 95th percentiles and measure cost volatility and risk
    - Captures tail risk outcomes not picked up in scenario trajectories
    - Measures risk over a broad range of outcomes, rather than being limited to the range of scenarios developed

Scenario Ranges of Discrete Variables – Carbon Price



25% weighting: High Case

- Assumes a stricter new federal rule or legislative action coming into force by the mid-2020s. Price levels are generally consistent with a 50-60% reduction in electric sector carbon dioxide (CO_2) emissions relative to 2005 by the 2030s

50% weighting: Base Case

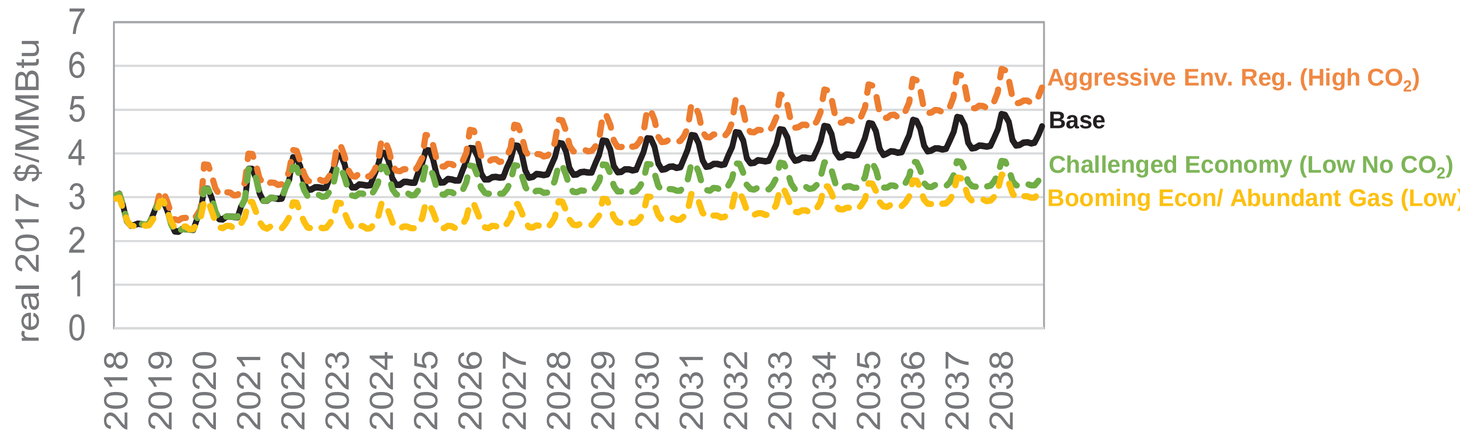
- Assumes a new federal rule or legislative action coming into force by the mid-2020s. Analysis suggests a ~20% reduction in U.S. coal demand post-2026 vs. a $0 carbon price scenario

25% weighting: Low Case

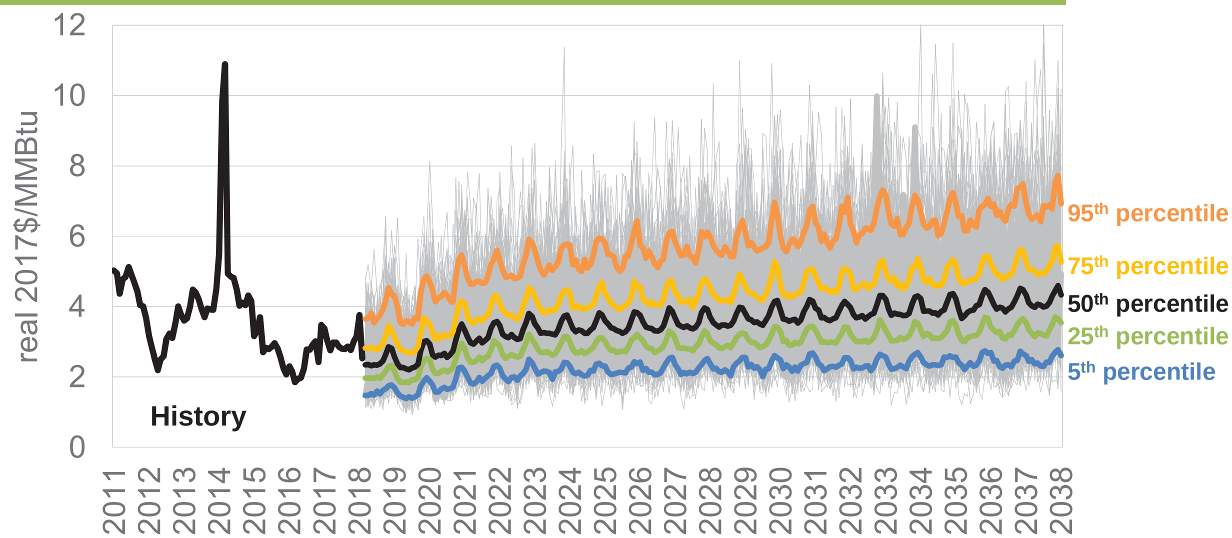
- Assumes a modified Environmental Protection Agency plan to control carbon, with focus on "Building Block 1" coal plant heat rate efficiency improvements. No specific tax or emission cap requirement would be present under such regulations

Scenario and Stochastic Ranges of Key Variables – Natural Gas

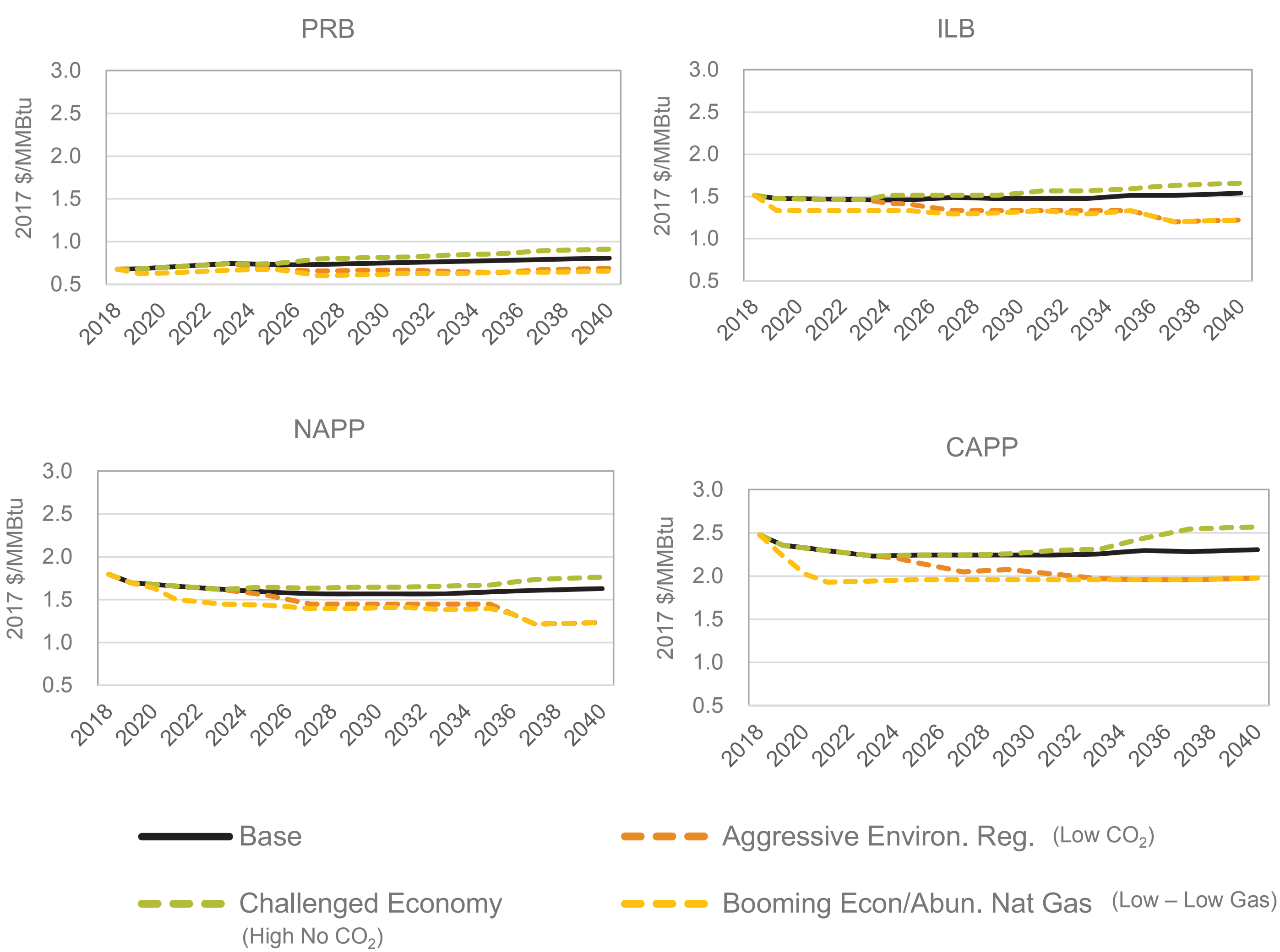
Scenario Range
(Chicago City gates)



Stochastic Distribution



Scenario Ranges of Discrete Variables - Coal



25% weighting: Challenged Economy (High Coal Price)

- Long-term demand generally up 10-35% without a carbon price, depending on coal basin

50% weighting: Base Case

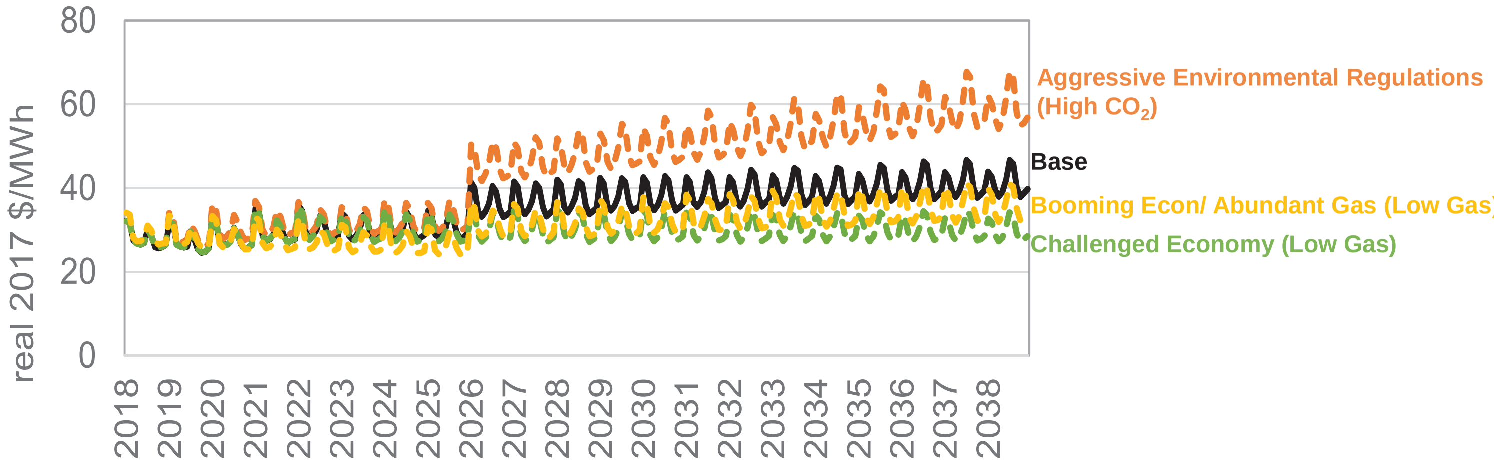
25% weighting: Aggressive Environ. Reg. & Booming Econ/Abundant Natural Gas (Low Coal Price)

- Long-term demand down 10-50% with both high carbon and persistently low natural gas prices, depending on coal basin
- Short-term demand eroded under Abundant Natural Gas scenario

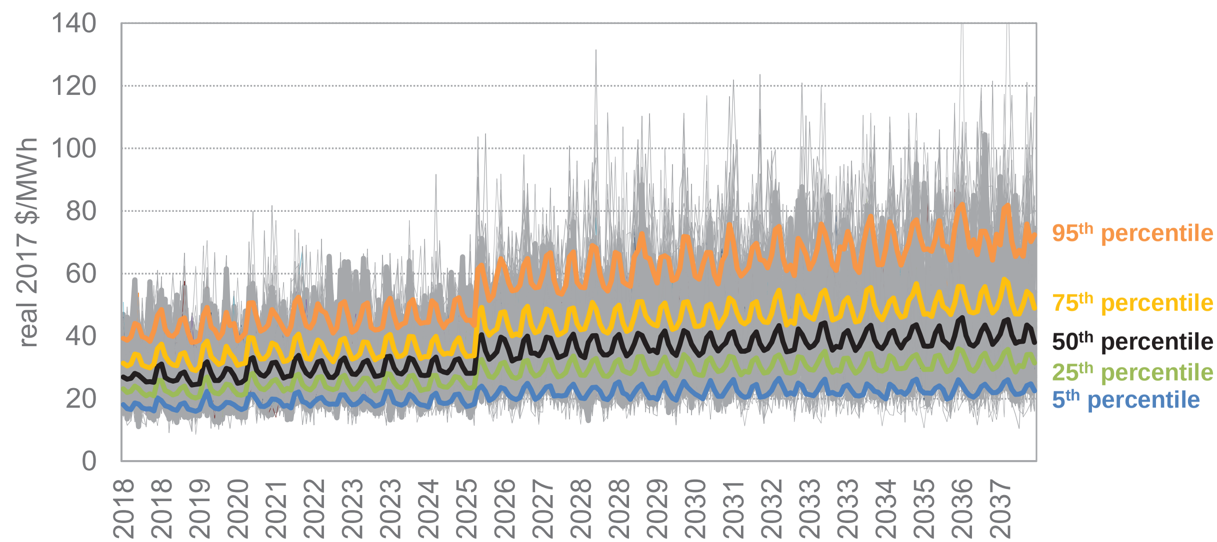
Scenario and Stochastic Ranges of Key Variables – Power Prices

Scenario Range

(MISO Indiana Zone)

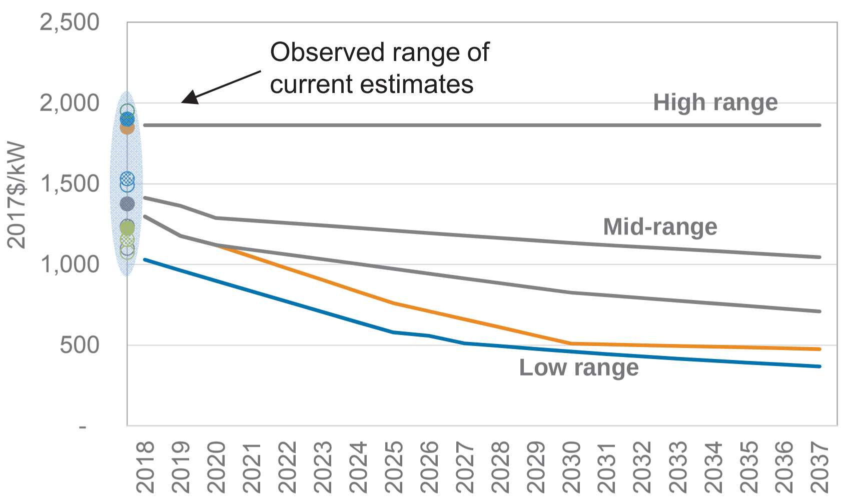


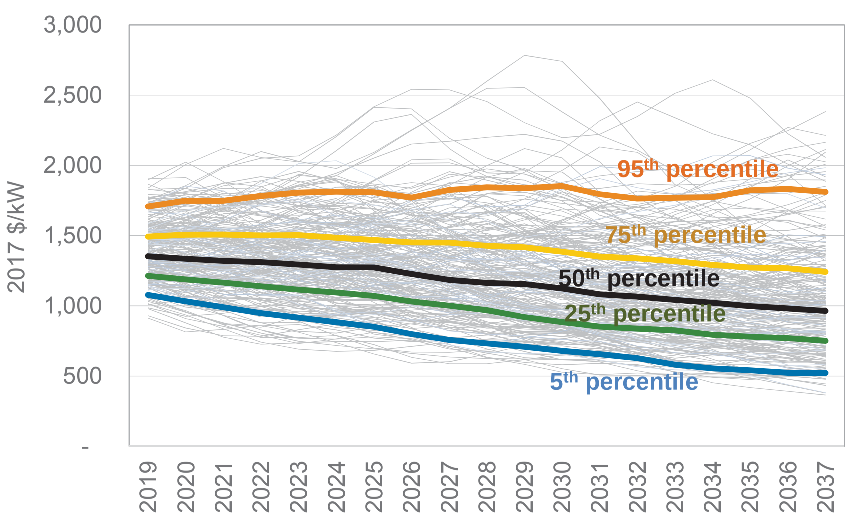
Stochastic Distribution



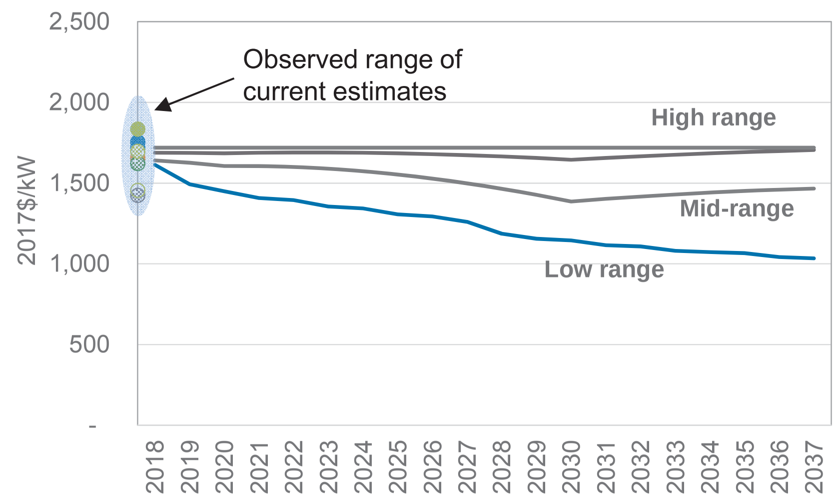
Scenario and Stochastic Ranges of Key Variables – Capital Costs

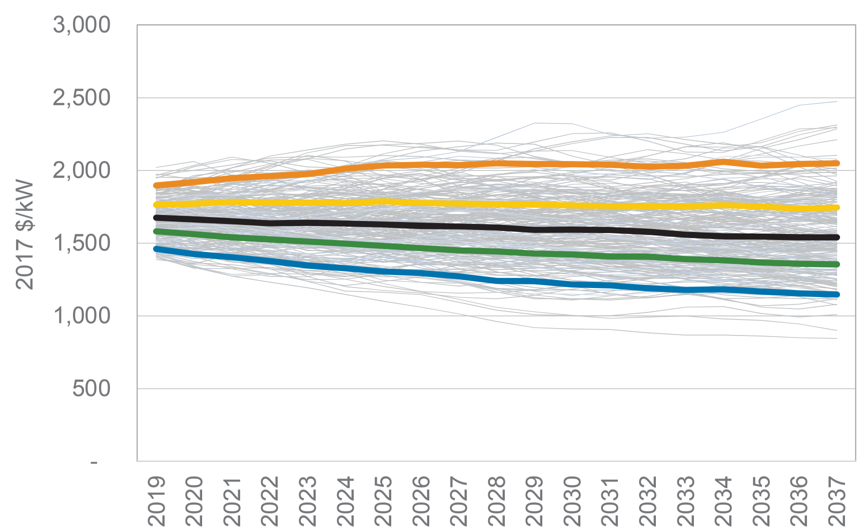
Solar Capital Costs





Wind Capital Costs





Break

DSM Modeling Methodology

Dick Spellman
GDS Associates, Inc.

Pat Augustine
Charles River Associates (CRA)

DSM Modeling Steps

Step 1	Step 2	Step 3
DSM Analysis	Identify DSM "bundles" or decrements	Analyze *each* "bundle" across *all* scenarios and full stochastic range
• Evaluate detailed program-level opportunities in service territory (DSM Savings Update) • Identify program impacts and associated costs	• Aggregate detailed DSM measures into "bundles" of measures that reflect energy savings potential at varying levels of measure costs per lifetime kWh saved • Produce bundles with detailed energy savings characteristics and costs	• Run each DSM "bundle" or decrement in IRP models against other resource options • Record savings, risks, environmental metrics • Assess vs. costs to identify the preferred DSM plan to be integrated into portfolio

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

NIPSCO Electric DSM Savings Update
Presentation to IRP Public Advisory Meeting

May 11, 2018

NIPSCO DSM SAVINGS UPDATE –STATUS REPORT

DSM Modeling Step 1

- NIPSCO’s 2019 to 2021 DSM Goals
- Screening Uses Utility Cost Test
- Energy Efficiency MWH and MW Savings
  - 2019 to 2038
- Analysis of Demand Response

DSM SAVINGS UPDATE METHODOLOGY – ALL SECTORS

DSM Modeling Step 1

- DSM potential and costs (2019 -2021) match NIPSCO Program Plan filed with the Indiana Utility Regulatory Commission in Cause No. 45011
  - 2019 to 2021 projections developed by NIPSCO and Lockheed Martin
- Program participation for 2022+ based on participation trends from NIPSCO's August 2016 potential study (except residential lighting)
- For years after 2021, GDS added new measures from the NIPSCO 2016 potential study but not explicitly listed in the 2019 -2021 DSM plan
  - Measure incentive levels after 2021 are based on NIPSCO paying a percentage of measure incremental costs
- Program non-incentive costs include NIPSCO and vendor administration; evaluation, measurement and verification; and NIPSCO marketing
  - 2019 to 2021 non-incentive costs obtained from NIPSCO
- Program non-incentive costs per first-year kWh saved from program plan year 2021 escalated at half the rate of inflation

NIPSCO DSM BUDGETS – 2019 TO 2021

DSM Modeling Step 1

NIPSCO 2019 TO 2021 ENERGY EFFICIENCY PROGRAM BUDGETS				
Sector	2019	2020	2021	Total
Residential	$9,817,510	$9,815,352	$9,809,956	$29,442,818
Commercial/Industrial	$9,047,189	$10,052,433	$11,057,674	$30,157,296
Total	$18,864,699	$19,867,785	$20,867,630	$59,600,114
INCREMENTAL ANNUAL MWH SAVINGS	122,974	130,947	138,918	392,839
$ Per First Year kWh Saved	$0.153	$0.152	$0.150	$0.152

2018 ELECTRIC DSM SAVINGS UPDATE – METHODOLOGY

DSM Modeling Step 1

- The Electric DSM Savings Update covers a 30-year time horizon (2019-2048).
- DSM savings update “base case” excludes savings for commercial and industrial (“C&I”) customers who opted out of NIPSCO programs prior to 2017.
  - Final Update report will include potential savings for opted out customers.
- Impacts of Energy Independence and Security Act (“EISA”) standards for efficacy of lighting measures reflected in the Update.
  - New standards will reduce lighting savings potential.
- NIPSCO’s latest electric and natural gas avoided costs used in calculations of the Utility Cost Test.
  - This test is used to determine measure, program and portfolio cost effectiveness

NIPSCO RESIDENTIAL PROGRAMS 2019 -2021

DSM Modeling Step 1

- Heating, Ventilation and Air Conditioning Energy Efficient Equipment Rebates
- Residential Lighting
- Home Energy Assessment
- Appliance Recycling
- School Education
- Multifamily Direct Install
- Home Energy Report
- Multifamily Direct Install
- Home Energy Report
- Residential New Construction
- HomeLife Energy Efficiency Calculator
- Employee Education
- Income Qualified Weatherization

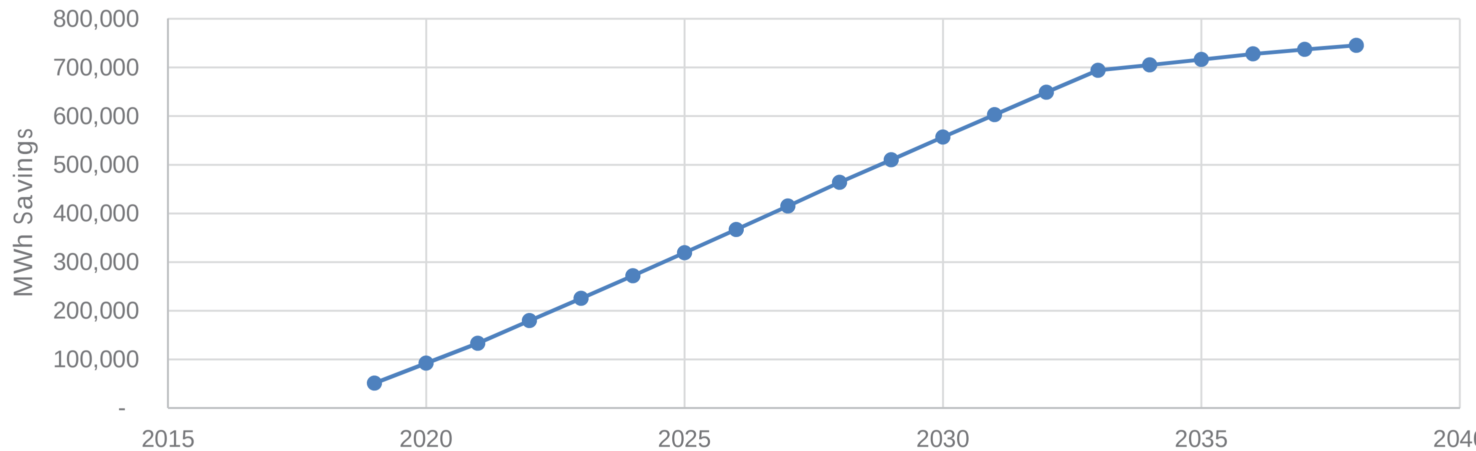
RESIDENTIAL MEASURES ADDED BY GDS AFTER 2021

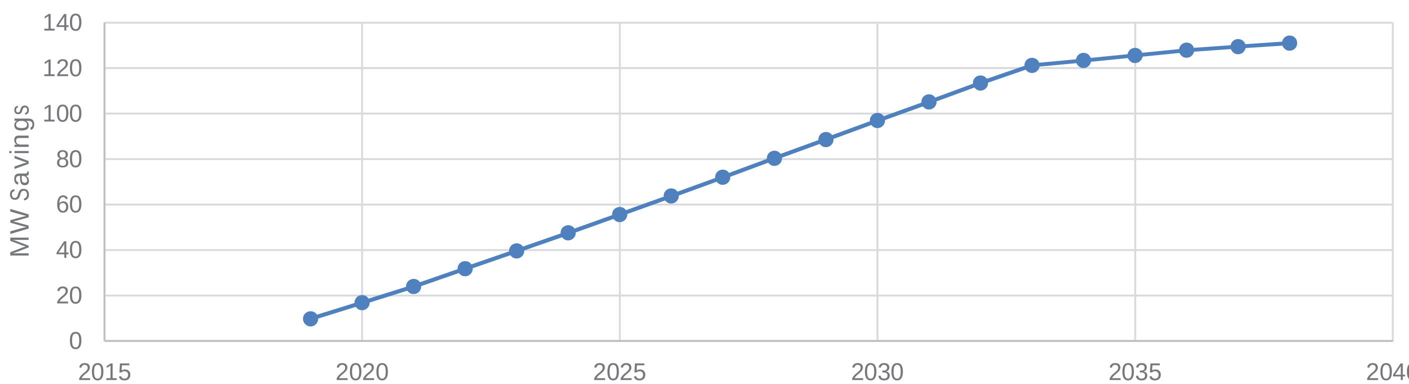
DSM Modeling Step 1

- Low Income Whole- House Program
- Dryer Vent Cleaning
- Refrigerator Coil Cleaning
- High Efficiency Clothes Washer
- High Efficiency Refrigerator
- High Efficiency Freezer
- High Efficiency Dehumidifier
- High Efficiency TV
- Energy Star ® PCs
- Energy Star Printer/Fax/Copier
- Energy Star Monitor
- High Efficiency Well Pump
- High Efficiency Clothes Dryer
- High Efficiency Hot Tub/Spa

RESIDENTIAL CUMULATIVE ANNUAL MWH AND MW SAVINGS

DSM Modeling Step 1





These are preliminary results.

C&I PROGRAMS 2019 -2021

DSM Modeling Step 1

- Prescriptive
- Custom
- C&I New Construction
- Small Business Direct Install
- Retro Commissioning

C&I MEASURES ADDED AFTER 2021

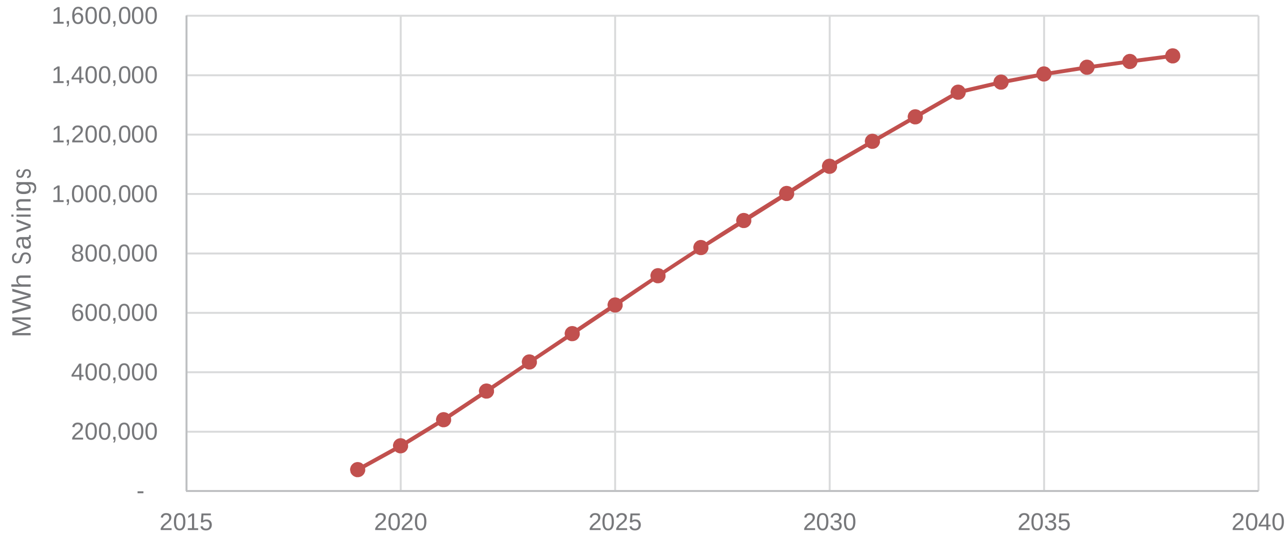
DSM Modeling Step 1

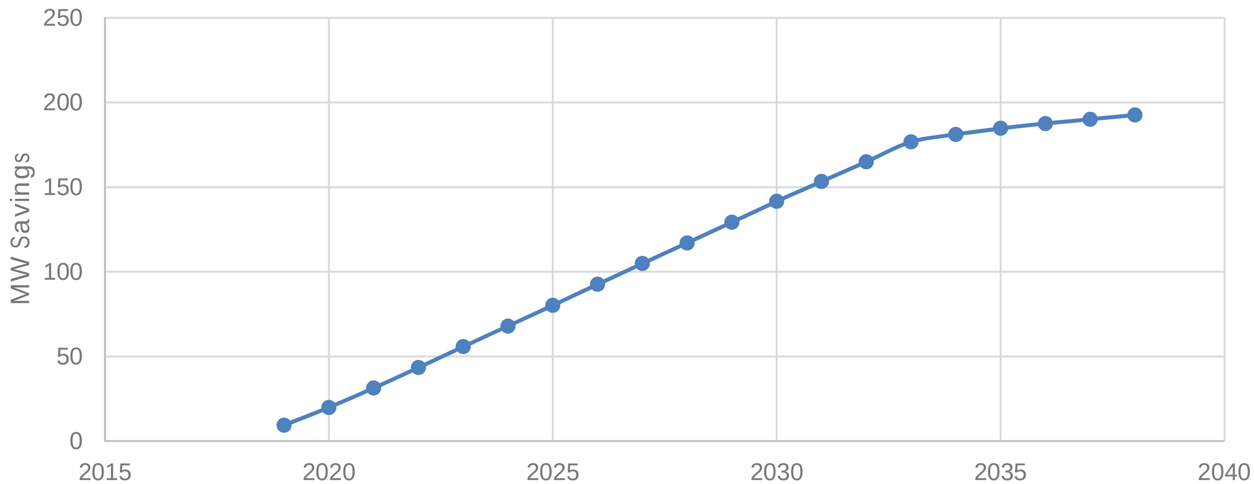
- Chiller, Rooftop Unit (“RTU”), Compressed Air, Fan System, Pumping System Maintenance
- Energy Star Office Equipment/Point-of-Sale Terminal
- HVAC Duct Repair and Sealing, Economizer
- Building Shell – Increased Insulation (R-value)
- Pool Pump Timer
- Pre-Rinse Spray Valve
- High Efficiency/Variable Speed Refrigeration Compressor, Floating Head Pressure Controls
- Room Air Conditioner
- RTU – Evaporative Precooler
- Water Heating – Desuperheater, Drainwater Heat Recovery, Faucet Aerator, Pipe Insulation, Solar
- Chilled Water Reset
- Geothermal Heat Pump
- Compressed Air Variable Frequency Drives
- Efficient Motor Rewind
- High Efficiency Transformers
- Agricultural Energy Efficiency Measures

NOTE: These measures may currently be available through the Custom program, but were added as specific measures for analysis and energy efficiency potential modeling purposes.

C&I CUMULATIVE ANNUAL MWH AND MW SAVINGS

DSM Modeling Step 1

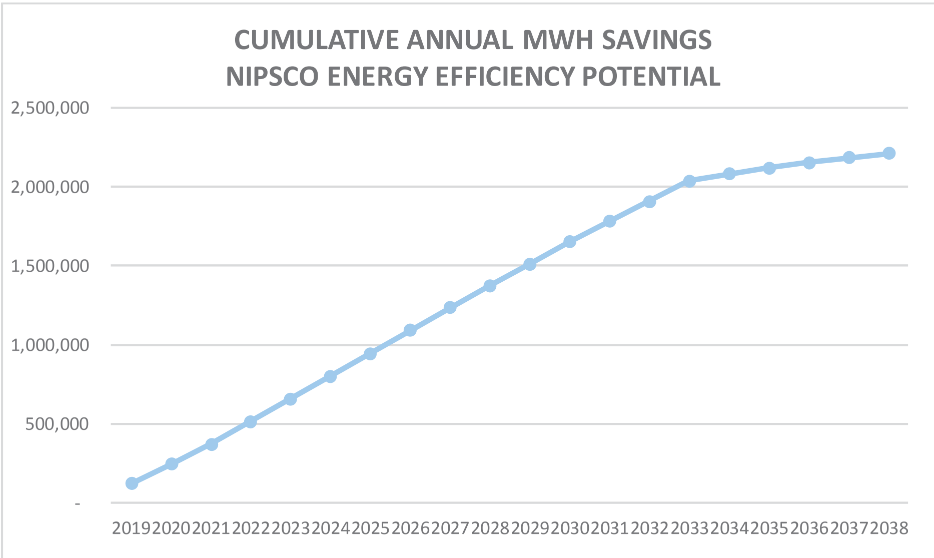


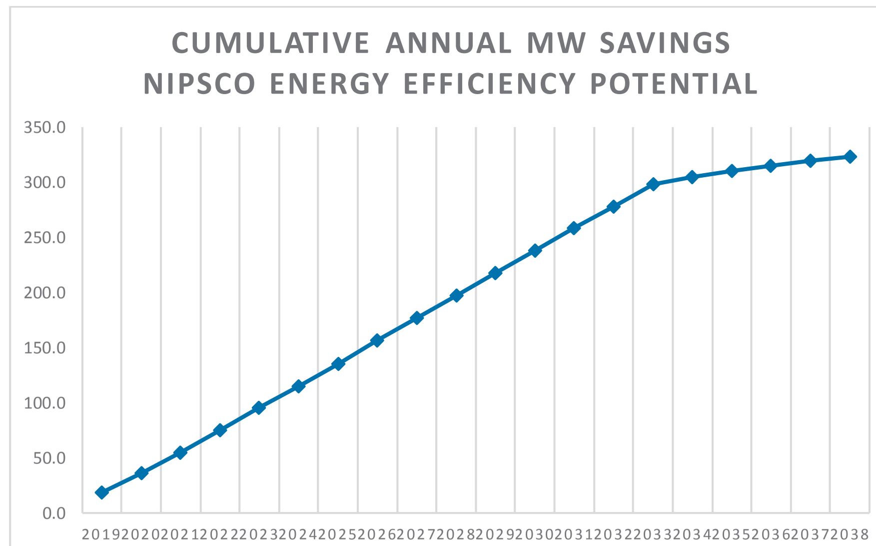


These are preliminary results.

TOTAL (ALL SECTORS) ANNUAL MWH AND MW SAVINGS

DSM Modeling Step 1

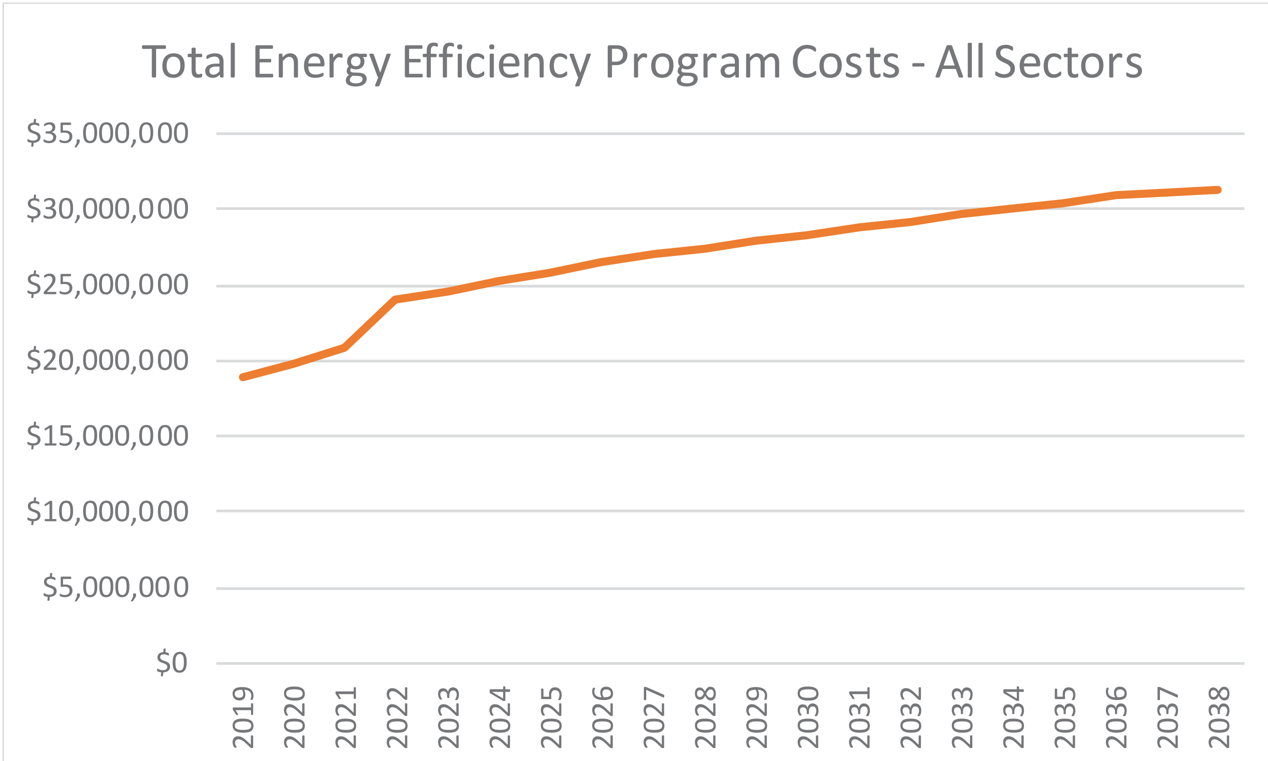




These are preliminary results.

TOTAL ENERGY EFFICIENCY PROGRAM COSTS

DSM Modeling Step 1



These are preliminary results.

DEMAND RESPONSE MEASURES FOR THE DSM SAVINGS UPDATE (RESIDENTIAL AND C&I)

- Direct load control – Central Air Conditioning
- Direct load control – Electric Water Heating
- Interruptible load tariffs
- Third Party Aggregator

NEXT STEPS FOR DSM UPDATE REPORT

DSM Modeling Step 1

- DSM Electric Savings Update report and achievable potential data inputs for the IRP are due June 1, 2018.
- In May will develop “low,” “medium,” and “high” DSM scenarios for input into IRP models and refine estimates of program costs and savings.

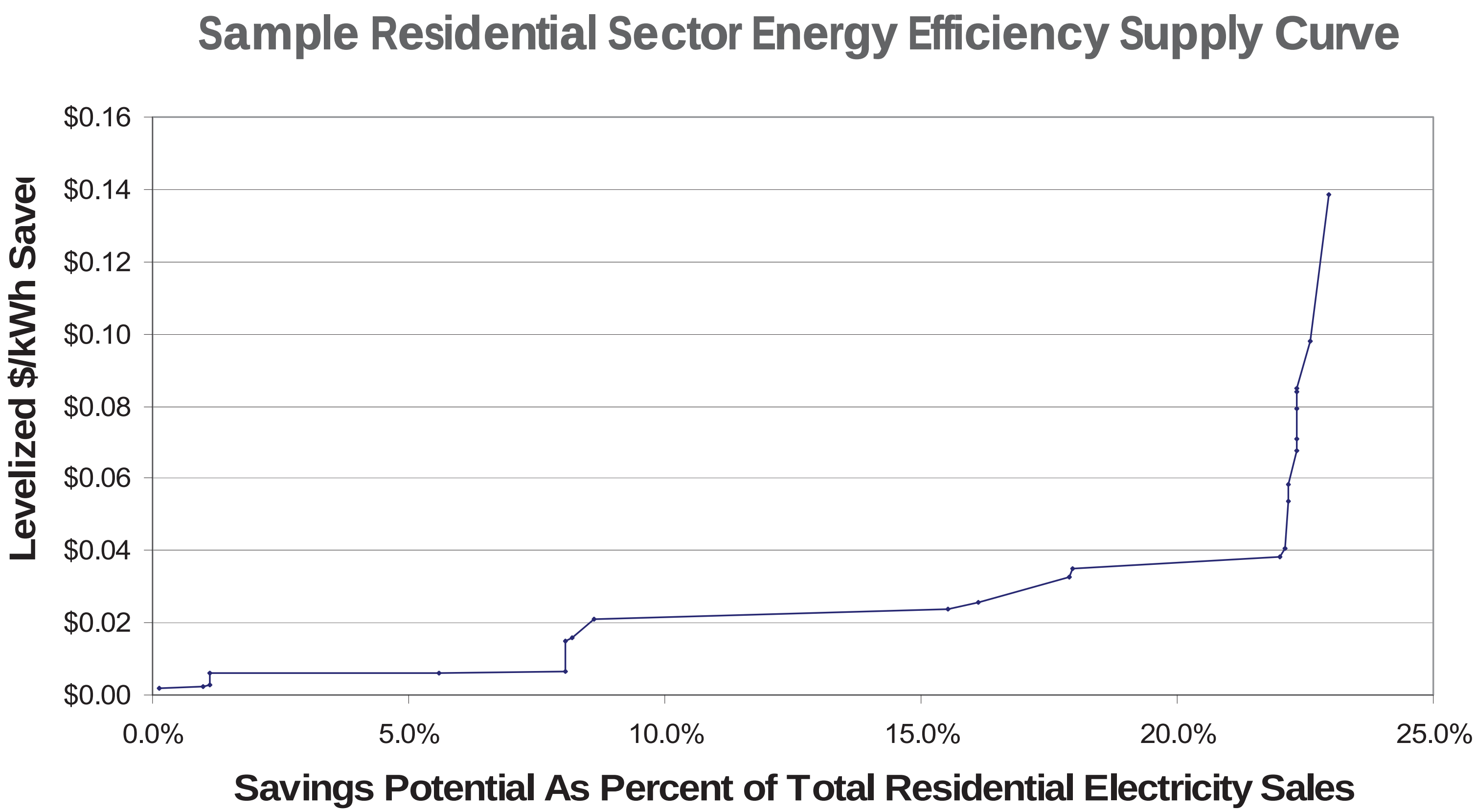
IDENTIFY DSM "BUNDLES"

DSM Modeling Step 2

- For the "low", "medium" and "high" DSM scenarios, GDS sorted energy efficiency measures into categories based on the measure cost per lifetime kWh saved.
- For example, all energy efficiency measures costing less than $.01 per lifetime kWh saved were included in bundle #1.
- Measures costing from $.01 to $.02 were included in bundle #2, and so forth.
- This creates an energy efficiency supply curve.

EXAMPLE ENERGY EFFICIENCY SUPPLY CURVE

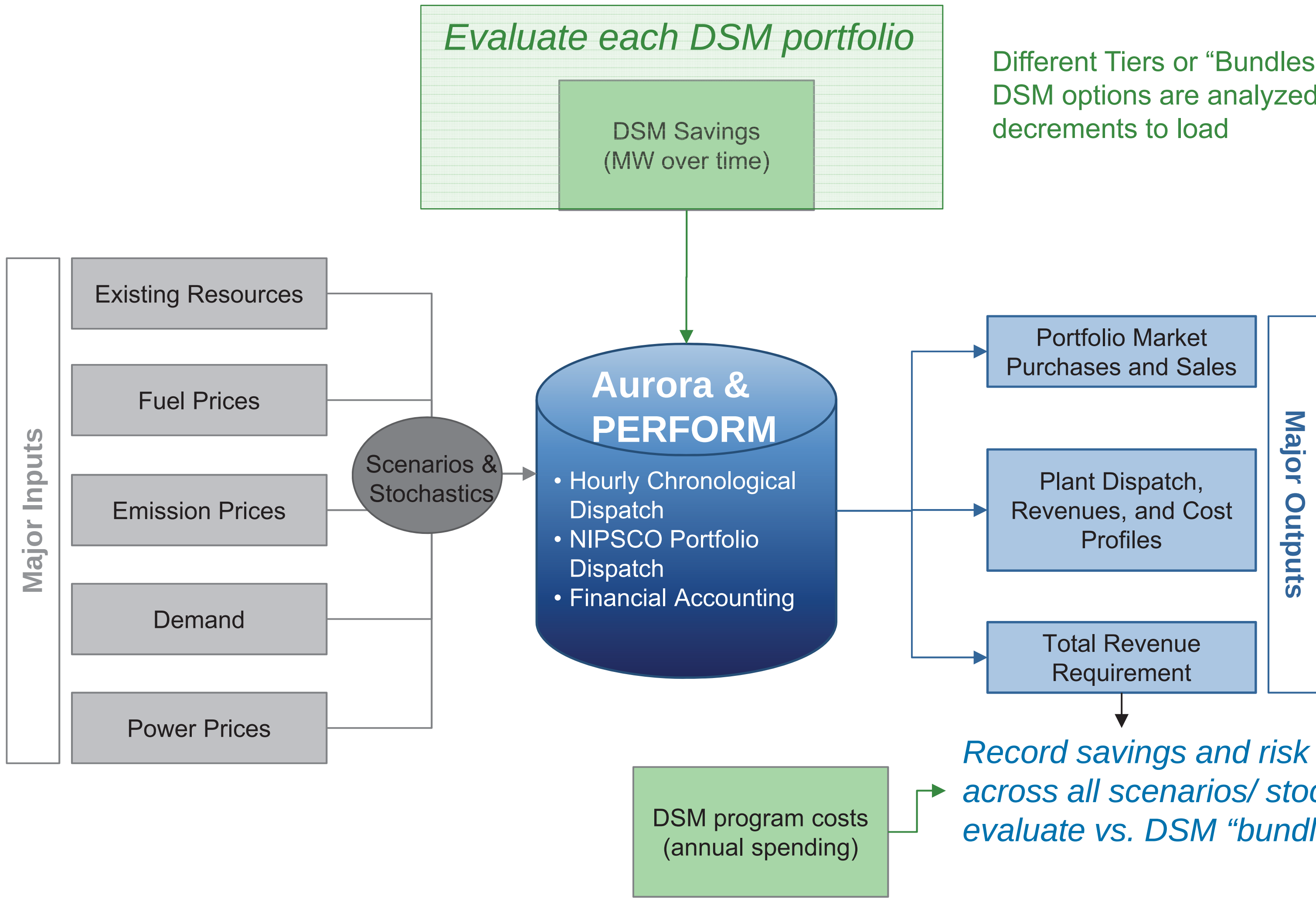
DSM Modeling Step 2



DSM Modeling Steps

Step 1	Step 2	Step 3
DSM Analysis	Identify DSM "bundles" or decrements	Analyze *each* "bundle" across *all* scenarios and full stochastic range
• Evaluate detailed program-level opportunities in service territory (DSM Savings Update) • Identify program impacts and associated costs	• Aggregate detailed DSM measures into "bundles" of measures that reflect energy savings potential at varying levels of measure costs per lifetime kWh saved • Produce bundles with detailed energy savings characteristics and costs	• Run each DSM "bundle" or decrement in IRP models against other resource options • Record savings, risks, environmental metrics • Assess vs. costs to identify the preferred DSM plan to be integrated into portfolio

DSM Modeling in IRP



Different Tiers or "Bundles" of DSM options are analyzed as decrements to load

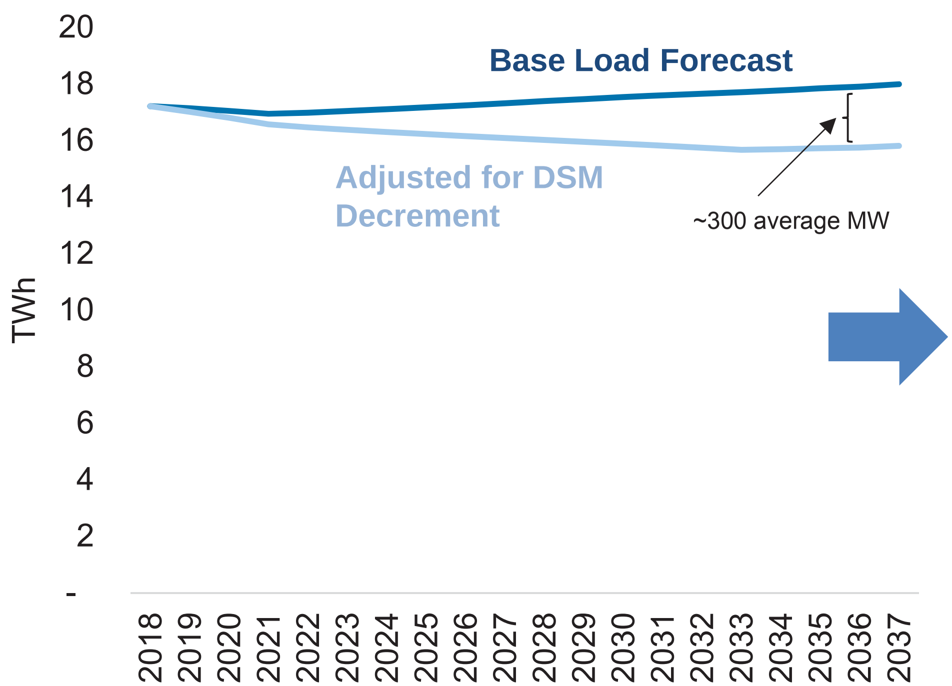
Record savings and risk metrics across all scenarios/ stochastics to evaluate vs. DSM "bundle" costs

DSM Modeling in IRP

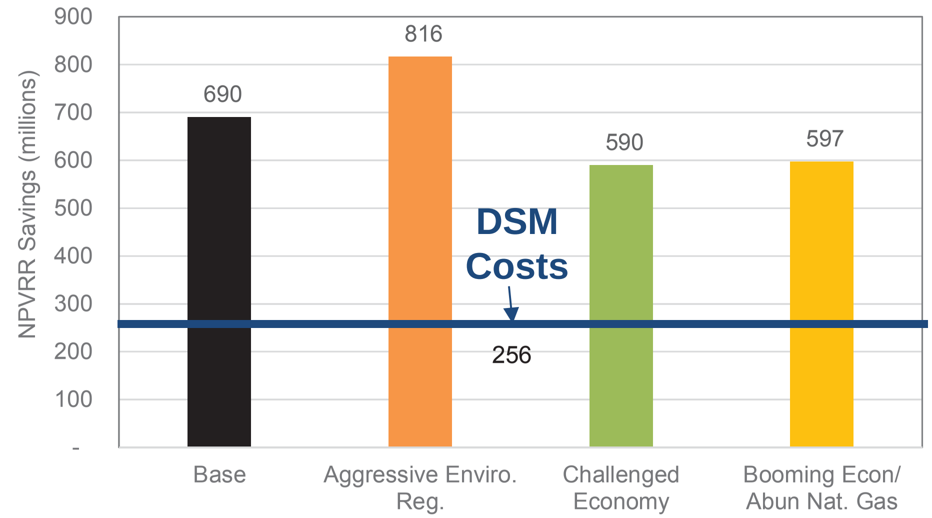
- **Once DSM decrements are identified, they will be run through IRP models to evaluate savings under scenarios and stochastics, accounting for all major uncertainties**
  – Uncertainties will include DSM costs and DSM savings volumes over time

Illustrative

Load Impact



Savings Summary



Analysis to be performed for each bundle to evaluate preferred DSM plan

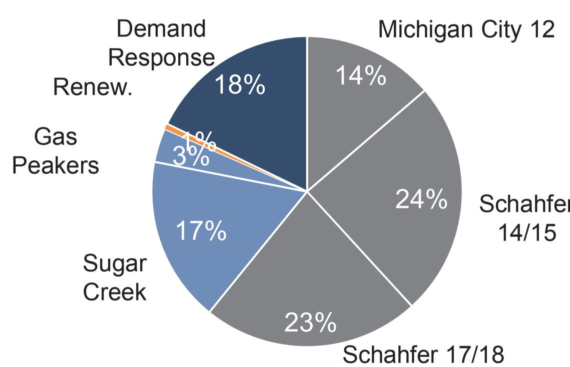
*Note: Indicative analysis has been performed for "mid-case" DSM bundle under initial cost and savings estimates. As the IRP proceeds, more detailed analysis for all bundles, inclusive of hourly savings profiles, for all scenarios and stochastics will be performed.

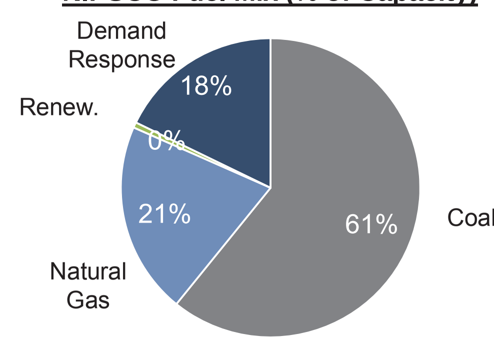
Generation Overview

Fred Gomos
Manager, Corporate Strategy & Development

NIPSCO 2018 Supply Resource Overview

Resource	Unit	Fuel	Capacity NDC (MW)	Capacity UCAP (MW)	% of Capacity (UCAP)
Michigan City	12	Coal	469	418	14%
Schahfer	14	Coal	431	320	10%
	15	Coal	472	428	14%
	16A	NG	78	64	2%
	16B	NG	77	25	1%
	17	Coal	361	344	11%
	18	Coal	361	346	11%
		Subtotal	1,780	1,527	50%
Sugar Creek		NG	535	526	17%
Bailly	10	NG	31	18	1%
Hydro	Norway	Water	4	2	0%
	Oakdale	Water	6	2	0%
		Subtotal	10	3	0%
Wind		Wind	100	14	0%
Demand Response		DSM / Interrupt.	559	559	18%
NIPSCO			3,484	**3,066**	100%

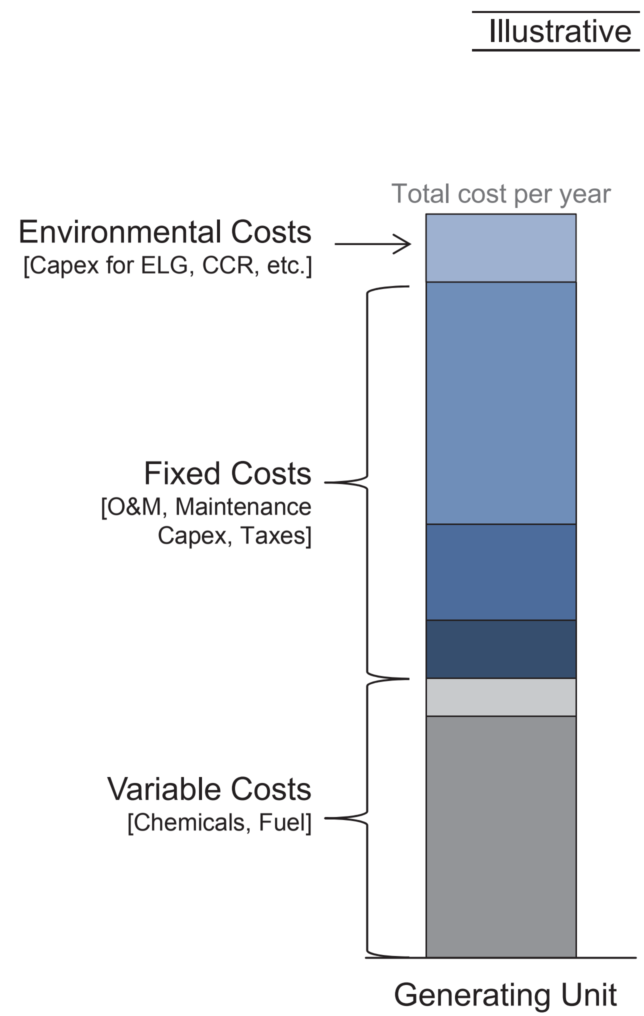




NDC: Net Demonstrated Capacity

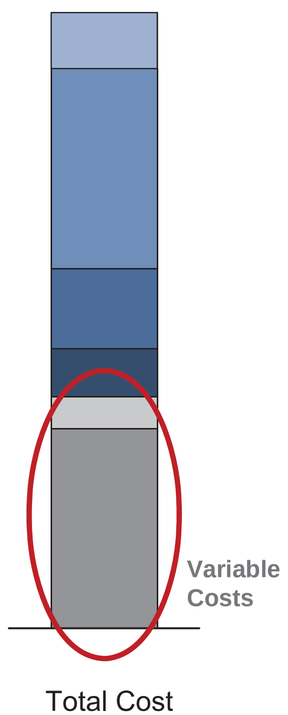
Generation Costs

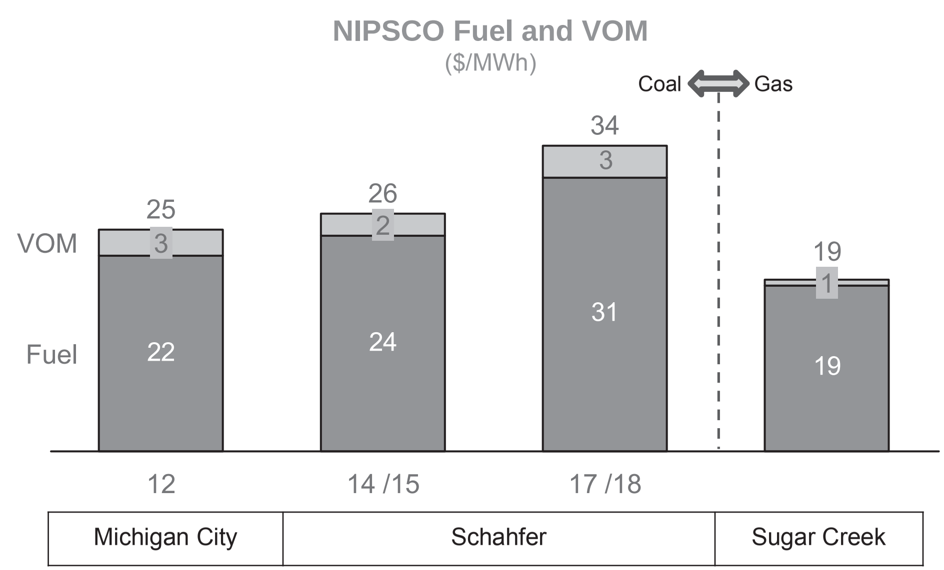
- **Generation costs vary for each NIPSCO unit**
- **Key cost components are:**
  - Environmental costs for controls required to be compliant with future regulations like effluent limitations guidelines (ELG) and coal combustion residuals (CCR)
  - Fixed costs including operations and maintenance (O&M), labor, capital recovery, allowed return, any necessary maintenance capital expenses (Maintenance Capex), and taxes
  - Variable costs including fuel and environmental chemicals
- **The sum of these costs over time and is expressed as net present value of revenue requirement (NPVRR)**



Variable Costs

- Fuel (coal or natural gas) is the largest variable cost for NIPSCO units
- Variable Operation and Maintenance (VOM) costs include chemicals for environmental controls and are generally higher for coal versus natural gas fuel generators

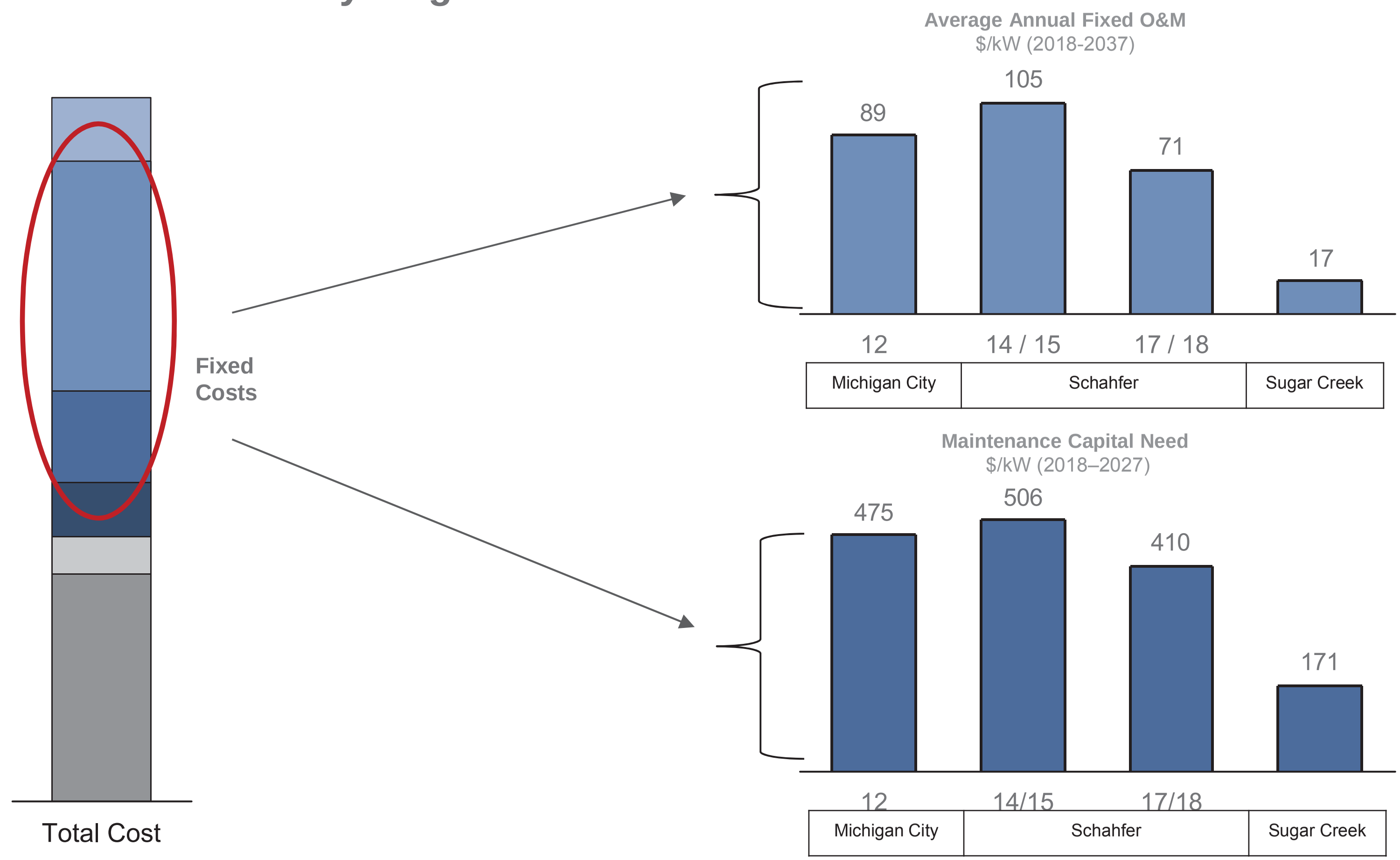




Notes: Cost shown here represent 2018 forecasts based on average annual heat rates, NIPSCO coal and natural gas prices based on 2018 contract prices; coal range from $2.06 - $2.54 $/MMBtu, Natural gas $2.61 $/MMBtu all in real 2017 $. Variable costs can vary based on market conditions.

Operating and Maintenance Costs for NIPSCO Units

- Coal units have sizeable ongoing maintenance capital needs to relative to alternatives
- NIPSCO coal units have ~4 to 5x higher fixed operating and maintenance costs than combined cycle gas turbines



Notes: Fixed O&M is based on 20 year average assuming units are retained until age based retirement date. Maintenance capital is based on a 10 year forecast divided by unit UCAP

Environmental Considerations

Kelly Carmichael
Vice President Environmental

Stakeholder Request: NiSource Environmental Targets Announced In 2017 – On Track

Reduction by 2025

Air Emissions Nitrogen Oxides Sulfur Dioxide Mercury	90%
Water Withdrawal	90%
Wastewater Discharge	90%
Coal Ash Generated	60%
Greenhouse Gas (Electric Generation & Methane)	50%

* Reductions from 2005 Levels

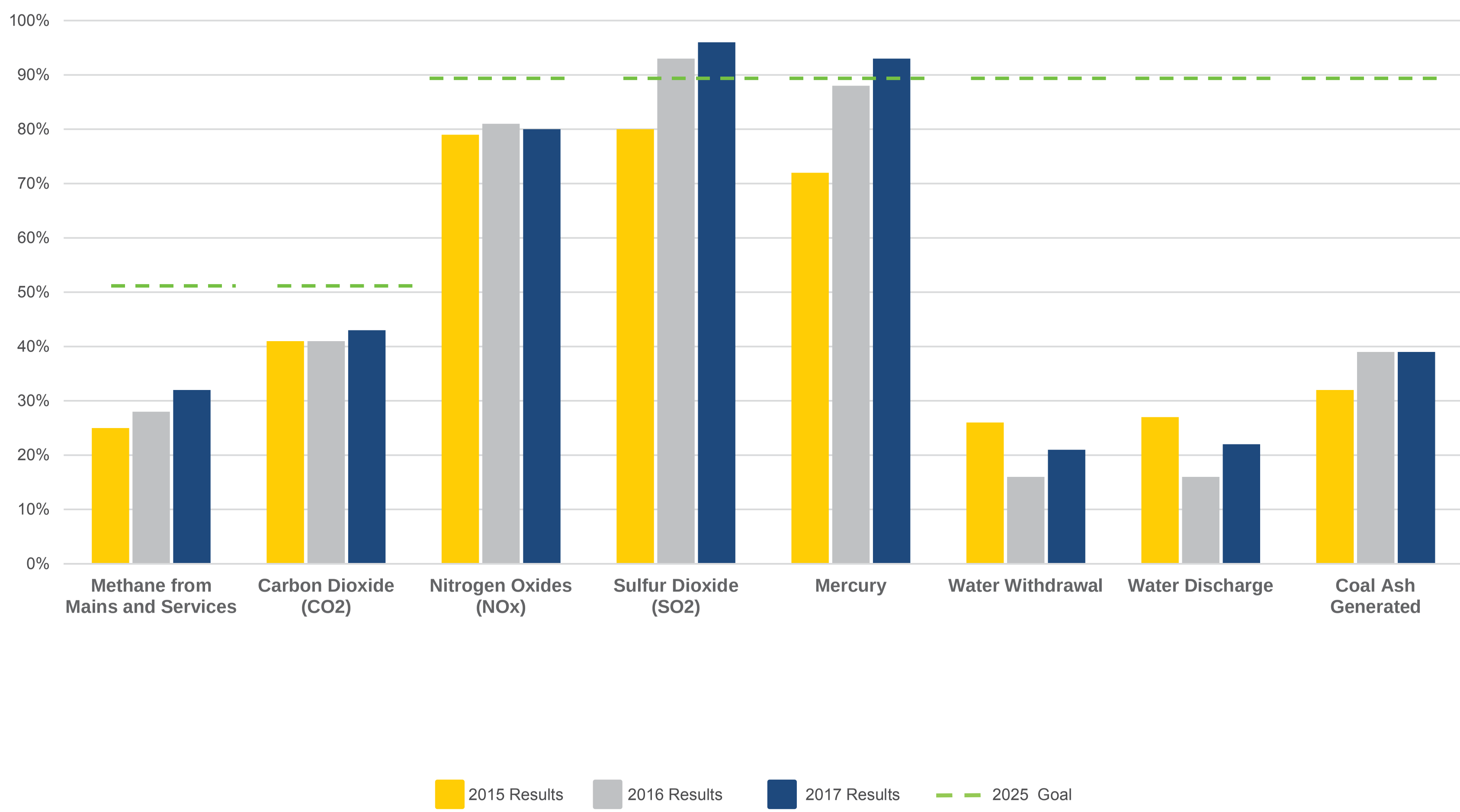
Greenhouse Gas Targets

Paris Accord U.S. Target
26-28% by 2025 from 2005 Levels

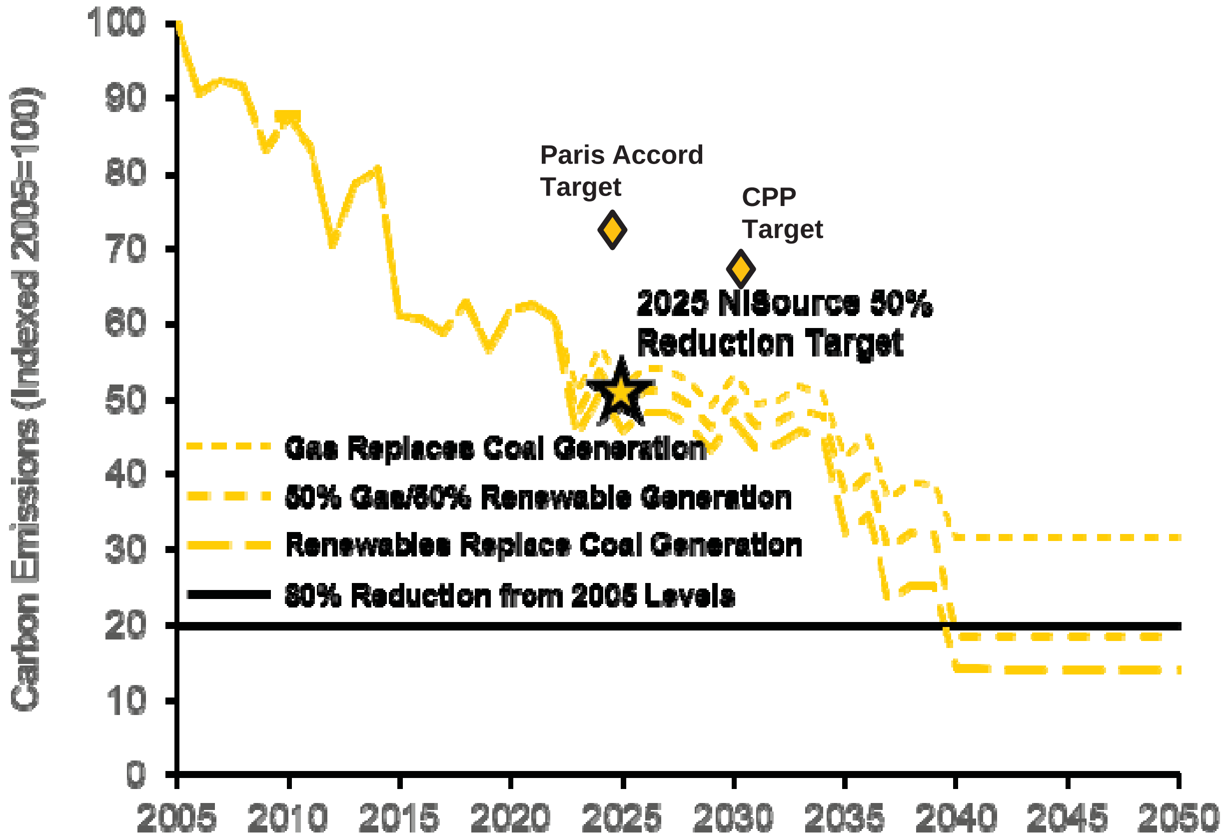
Clean Power Plan (CPP) Target
32% by 2030 from 2005 Levels

NiSource Target
50% by 2025 from 2005 Levels
(Paris and CPP Achieved 10+ Years Early)

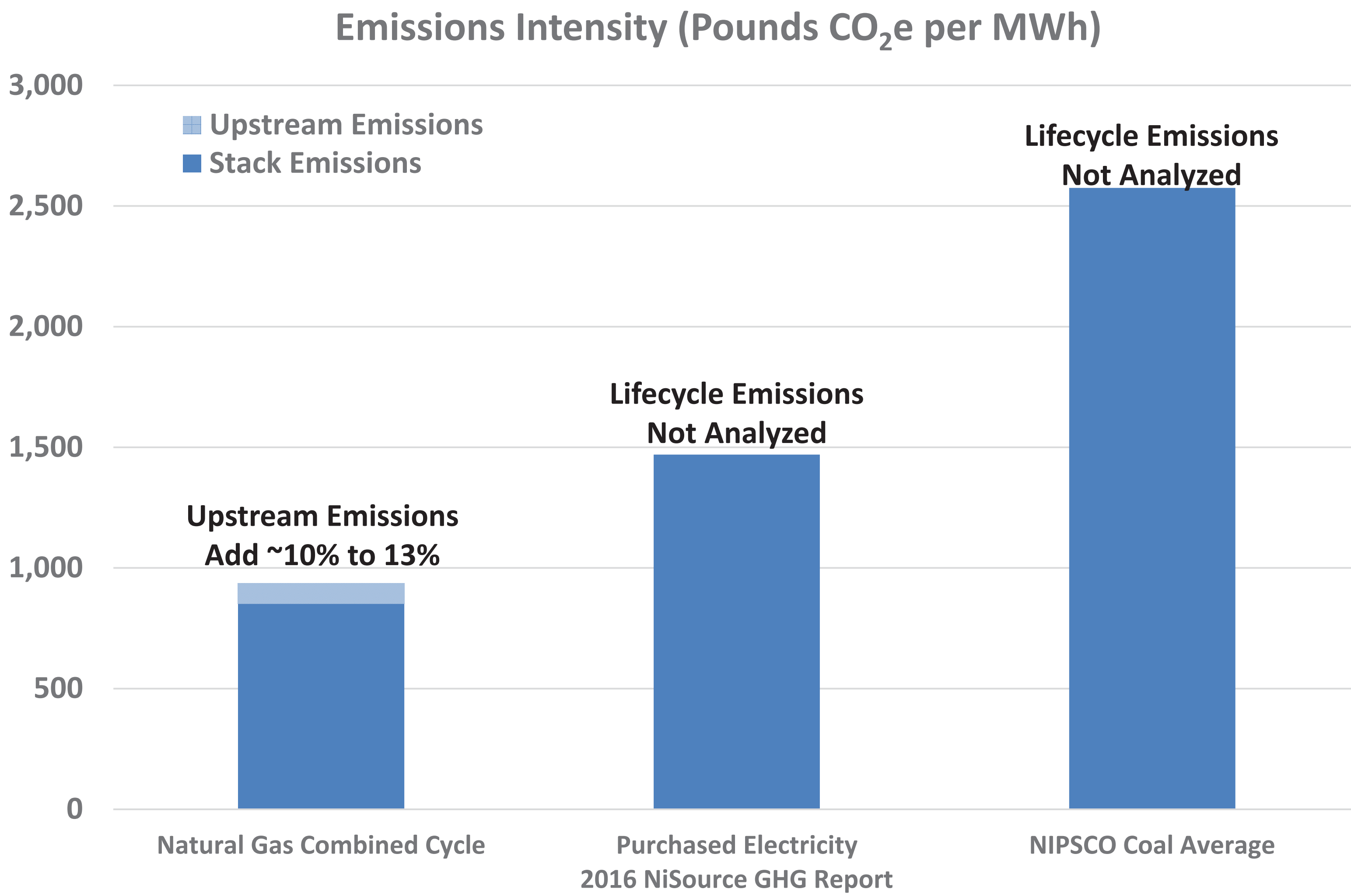
Stakeholder Request: NiSource Environmental Targets Announced In 2017 – On Track



Stakeholder Request: NiSource Carbon Emissions Trajectories



Stakeholder Request: Carbon Emissions Comparison



Natural Gas Combined Cycle lifecycle data derived from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016 and 1.2% methane leakage as found in https://www.epa.gov/sites/production/files/2017-08/documents/lacey_aga_-_ghgi_webinar_comments_on_uncertainty_analysis_aug_24_2017.pdf

Stakeholder Request: Northwest Indiana Achieves Environment Protection Agency (EPA) Health-Based Air Quality Standards

	# of IDEM* Monitors	NW Indiana** Data
Ozone	6	Achieves Standard***
Particulate Matter	12	Achieves Standard
Nitrogen Oxides (NOx)	1	Achieves Standard
Sulfur Dioxide (SO_2)	2	Achieves Standard
Carbon Monoxide	1	Achieves Standard
Lead	4	Achieves Standard

** Indiana Department of Environmental Management*
** Lake, Porter, LaPorte, Newton, & Jasper Counties*
****** Lake & Porter Counties are nonattainment for ozone due to their inclusion in the Chicago metropolitan statistical area (MSA). One monitor near the IL-WI border exceeded the standard.*

Key Environmental Rules Create Near Term Compliance Requirement

ELG and CCR Rule Summary

Coal Combustion Residuals (CCR)

- Regulates New and Existing Coal Ash Landfills and Surface Impoundments
- Phased Compliance 2015 - 2053
  - Phase I: Separate Ponds from Generation
  - Phase II: Close CCR Ponds
  - Phase III: Implement Groundwater Remedy and Monitoring
- EPA Reconsidering Portions of Rule
  - EPA Proposals in 2018; Final in 2019
  - May Add Flexibility into Compliance Plans
  - Overall Do Not Anticipate Significant Changes to NIPSCO Compliance Plan

Effluent Limitation Guidelines (ELG)

- National Standards for Treatment of Wastewater Streams
- Rule ‘Finalized’ in 2015
- Compliance Plan 2018 - 2023
  - Zero Liquid Discharge
    - Michigan City Unit 12
    - RM Schahfer Units 14 & 15
  - Retirements
    - Bailly Units 7 & 8
    - RM Schahfer Units 17 & 18
- EPA Reconsidering Portions of Rule
  - EPA Proposal in 2019; Final in 2020
  - Initial Compliance May Be Postponed
  - Revisiting Treatment Requirements
  - $170M Capital Recovery Filing Paused

Coal Combustion Residual (CCR) Compliance

- **Order granted by the Indiana Utility Regulatory Commission in December 2017 for CCR compliance on Units 12,14,15**
- **CCR compliance work is underway and largely complete; 90% of CCR spending expected by the end of 2018**
  - Because capital is largely spent, unit retirement analysis does not include any CCR savings when contemplating early retirement for units 12, 14 and 15
- **CCR compliance capital for Units 17/18 was not included in petition**
- **Cost for maintaining the option to retain Units 17/18 has increased**
  - Joint Units 14/15/17/18 CCR compliance solution is no longer available
  - CCR compliance on Units 17/18 would require a stand-alone project with cost estimate of ~$85M (direct costs only, does not include indirect costs or allowance for funds used during construction)
    - Approximately equivalent to the Units 14/15 remote ash conveying cost since units are similar

CCR costs are no longer incremental for Units 12/14/15 and have increased for Units 17/18

Effluent Limitation Guidelines Compliance

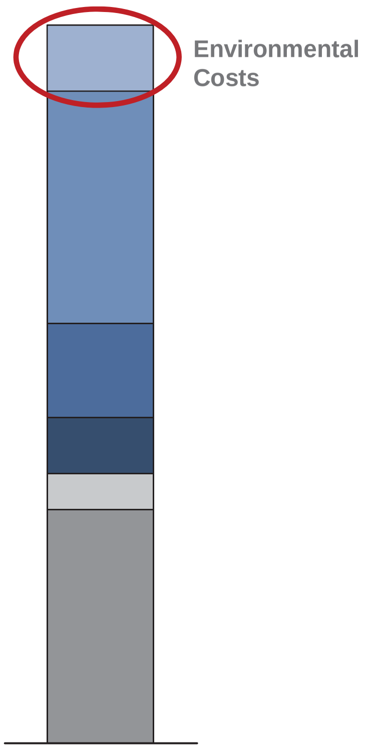
Compliance Path	Description	Cost Estimate
Zero Liquid Discharge (ZLD)	• Most stringent; no wastewater • Units 14/15 <150gpm required treatment • Units 17/18 800gpm requires treatment; more volume equals higher cost • Unit 12: dry FGD requires no capital for ELG compliance	Units / Capital Cost / O&M cost 14/15 / $170M / $3M/y 17/18 / $375M / $7M/y 12 / $0M / $0M/y
Non-ZLD Option	• Less expensive; treatment of heavy metals • Units 14/15 <150gpm required treatment • Units 17/18 800gpm requires treatment • Unit 12: dry FGD requires no capital for ELG compliance	Units / Capital Cost / O&M cost 14/15 / $134M / $0.8M/y 17/18 / $310M / $3.9M/y 12 / $0M / $0M/y
Retirement	• Retirement by rule ELG implementation date (assumed to be 2023) is a compliance pathway	• No cost
Extended Compliance Date	• EPA may provide an extended compliance date beyond 2023	• TBD based on EPA rulemaking

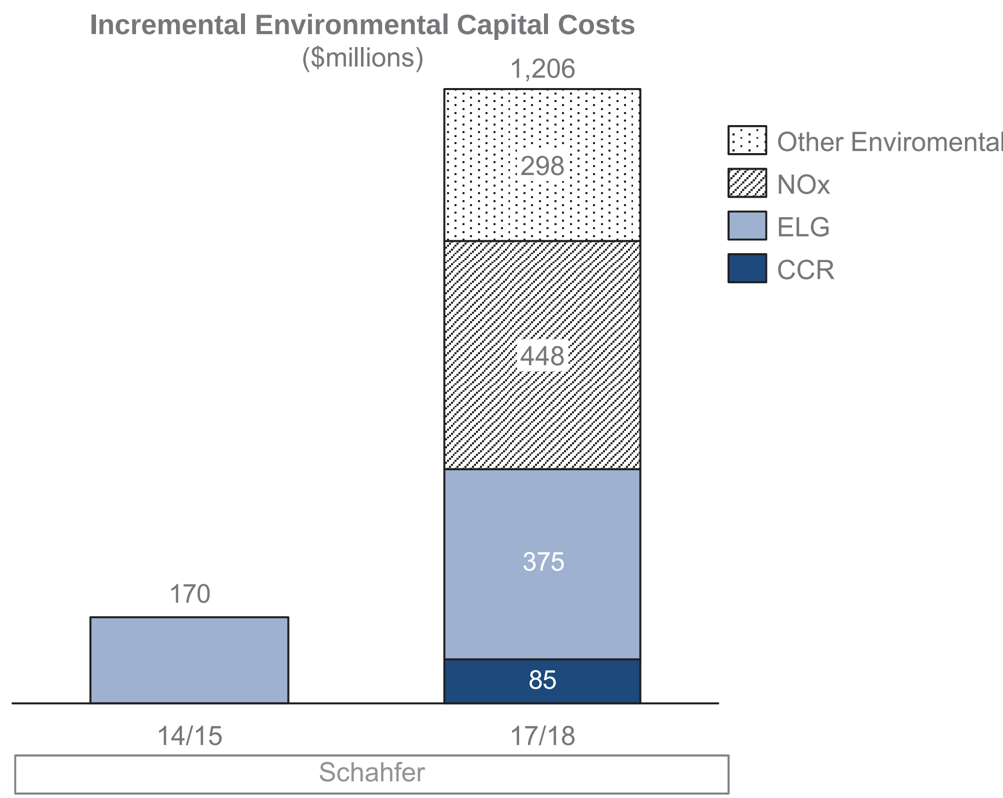
ELG compliance path not contemplated in 2016 IRP

Currently not part of the ELG Rule

Incremental Environmental Compliance Capital Costs By Unit

- NIPSCO coal units have varying levels of capital needs in order to comply with environmental rules
- Retaining Schahfer Units 17/18 beyond 2023 requires additional capital investment beyond ELG and CCR compliance





Sources and Notes: CCR costs not considered incremental for units 12,14,15; ELG cost based on ZLD compliance option assuming no retirement, retirement as a compliance option would lower compliance costs. NOx cost based on a 2024 in service date and assumes more stringent compliance standards by 2025. Other environmental include absorber vessels, dewatering system and stack lining replacement. NOx and Other Environmental costs reflect upper range of accuracy and includes directs, indirects and escalation

Lunch

2018 IRP Scorecard

Dan Douglas
Vice President Corporate Strategy & Development

The Proposed 2018 Scorecard Will Inform the NIPSCO Preferred Plan

2016 Scorecard
Cost to Customer
Portfolio Diversity
Environmental Compliance
Employees
Communities and Local Economy

2018 Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30 year net present value (NPV) of revenue requirement
Cost Certainty	• Certainty that revenue requirement within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: 95th percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas
Environmental	• Reaching 80% Carbon reduction by 2050 • Metric: Total annual carbon emissions
Short Term Optionality	• Ability to adjust the portfolio to react to changes in Large Industrial load • Metric: Quantity of Industrial coincident demand matched to flexible resources
Long Term Optionality	• Flexibility resulting from combinations of ownership, duration, and diversity • Metric: Duration of generation commitments
Employees	• Net impact on NiSource jobs • Metric: Number of permanent NiSource jobs created / retained
Local Economy	• Affect on the local economy from property taxes and jobs • Metric: Charles River Associates developed economic multiplier

Retirement Analysis

Fred Gomos
Manager, Corporate Strategy & Development

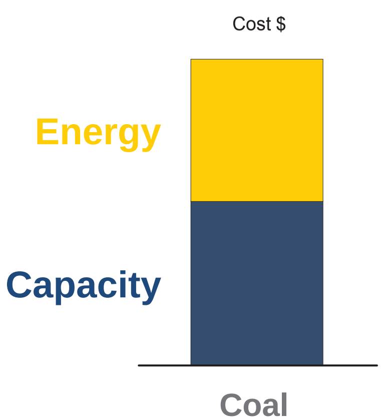
Pat Augustine
Charles River Associates (CRA)

The Retirement Analysis

- Framework evaluates the cost to keep a Unit versus the cost of retirement and replacement with an alternative
- Is the ongoing cost of operating an existing NIPSCO unit, including all required environmental compliance controls, greater than the cost of retiring the unit and replacing with an alternative?

Cost to Keep

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs

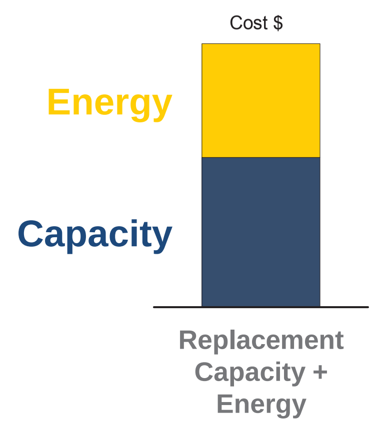


< (Maintain Unit)

> (Consider Retirement)

Cost of Alternative

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs
- Cost to retire existing unit (transmission and distribution upgrades, remaining asset value)



Replacement assumed capacity priced at the highest possible capacity price (MISO cost of new entry, CONE) plus energy priced at market

A Projection of MISO's Cost of New Entry (CONE) Plus Energy is Used in the Retirement Analysis as a Proxy for Viable Alternative

Retirement Analysis

- MISO CONE + Market Energy

Step 1

Replacement Analysis

- Complete analysis and evaluation of all Supply-side and Demand-side Resources from RFP

Step 2

Cost of Alternative

- Ongoing variable costs
- Ongoing fixed costs
- Future environmental controls costs
- Cost to retire existing unit (T&D upgrades, remaining asset value)

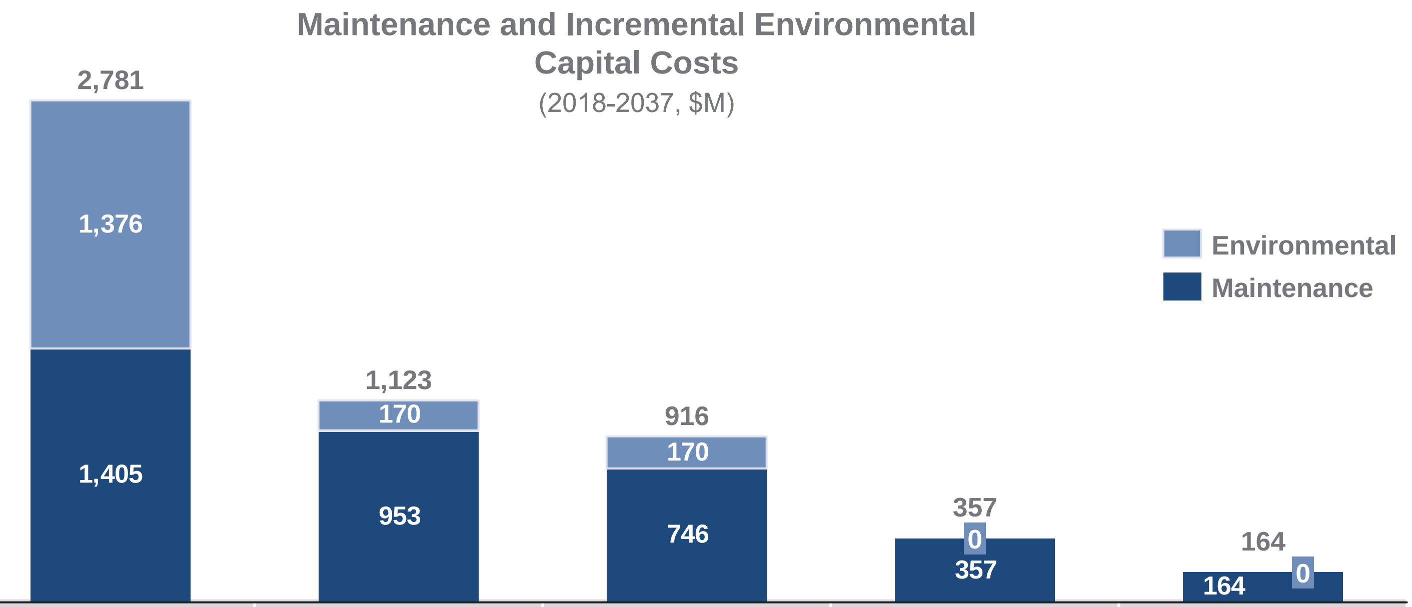
- **<u>MISO's CONE + Energy is for retirement analysis only and is not NIPSCO's selection</u>**
  - NIPSCO will optimize for other supply- and demand-side resources
- **MISO's CONE is a reasonable, conservative proxy because it represents the cost of new entry for MISO capacity**
  - The replacement analysis, supported by the RFP, will provide viable market alternatives
- **Retirement methodology is consistent NIPSCO's 2016 IRP analysis and with others in the industry**

Various Retirement Combinations Were Constructed

Portfolio Transition Target:	1a 65% Coal through 2035	2a 40% Coal in 2023	3a 15% Coal in 2030 w/ ELG	4 15% Coal in 2023	5 0% Coal in 2023
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Env. Compliance	CCR ELG: ZLD	CCR ELG: ZLD	CCR ELG: ZLD	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: ZLD	→	**Retire 2030** CCR ELG: ZLD	**Retire 2023** CCR ELG: Retirement	→
Schahfer 15	**Retain** CCR ELG: ZLD	→	**Retire 2030** CCR ELG: ZLD	**Retire 2023** CCR ELG: Retirement	→
Schahfer 17	**Retain** CCR ELG: ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→
Schahfer 18	**Retain** CCR ELG: ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→

Capital Cost By Retirement Combination

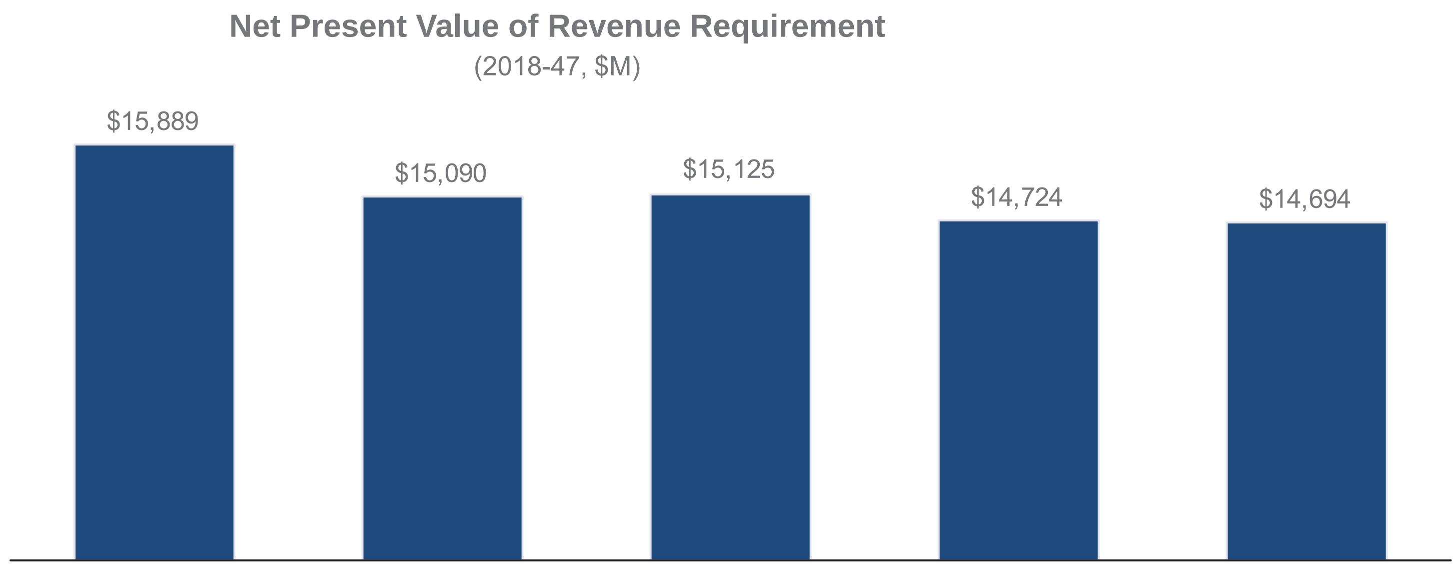
- Although there are some environmental cost savings, cost reduction from earlier retirement of coal units is primarily from avoided maintenance costs



Portfolio Transition Target:	65% Coal through 2035 (1a)	40% Coal in 2023 (2a)	15% Coal in 2030 (3a)	15% Coal in 2023 (4)	0% Coal in 2023 (5)
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None

Notes: CCR costs not considered incremental for units 12,14,15

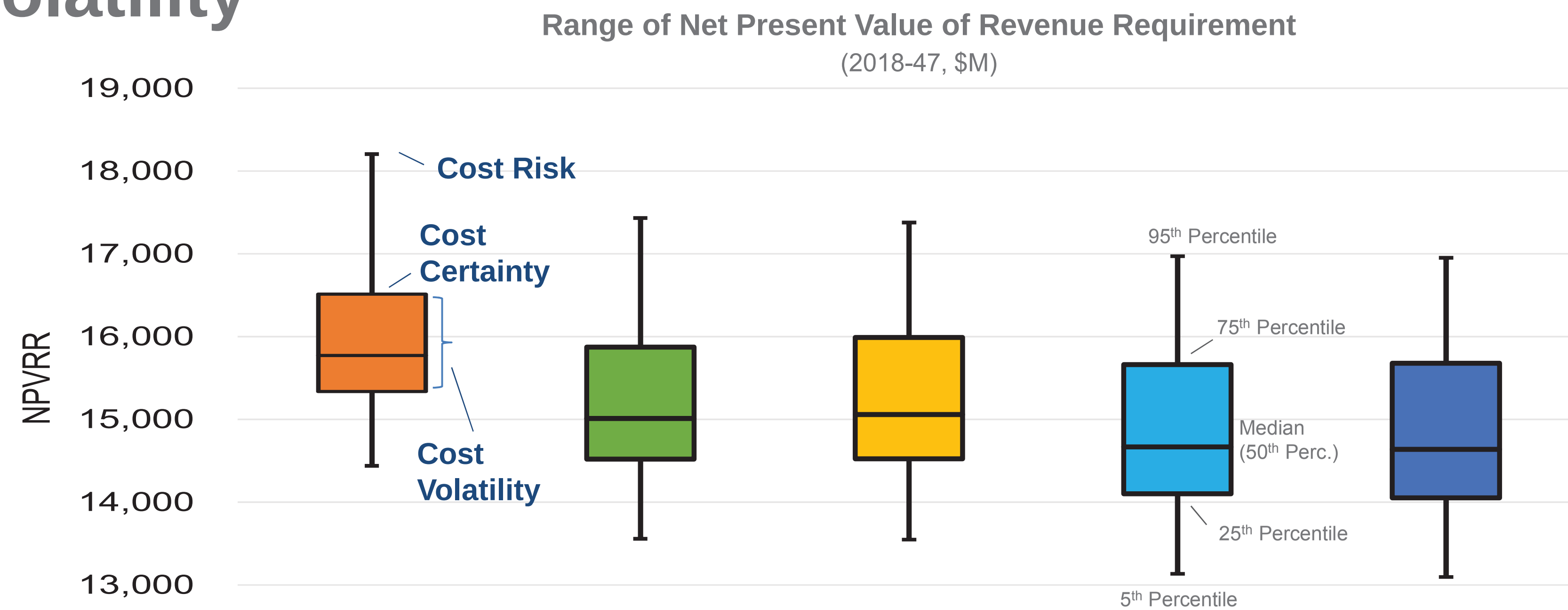
Results: Deterministic Cost to Customers



Portfolio Transition Target:	65% Coal through 2035 (1a)	40% Coal in 2023 (2a)	15% Coal in 2030 (3a)	15% Coal in 2023 (4)	0% Coal in 2023 (5)
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Delta from Least Cost	$1,195M 8.1%	$397M 2.7%	$431M 2.9%	$30M 0.2%	--

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

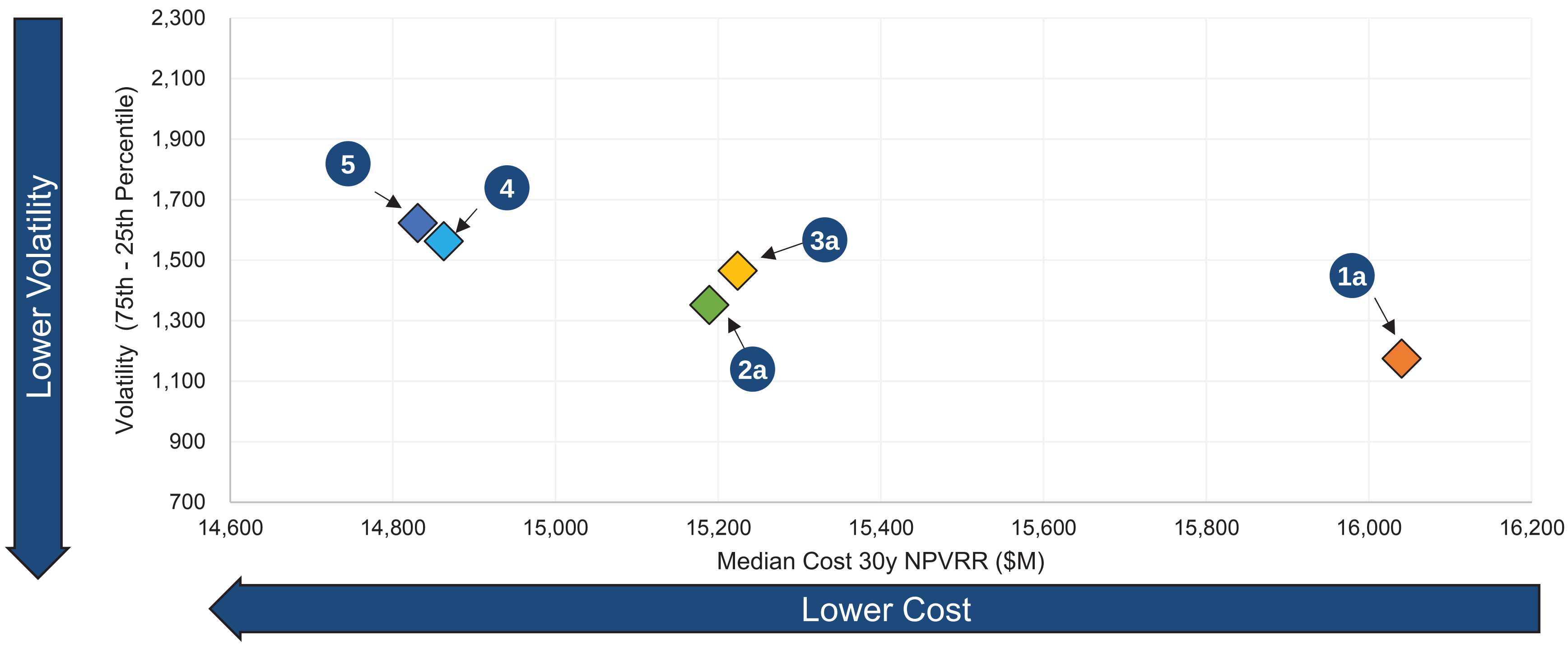
Results: Stochastic Cost Certainty, Risk, and Volatility



Portfolio Transition Target:	65% Coal through 2035 1a	40% Coal in 2023 2a	15% Coal in 2030 3a	15% Coal in 2023 4	0% Coal in 2023 5
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Delta from Lowest Cost Certain (75th%)	+$849M 5.4%	+$211M 1.3%	+$326M 2.1%	+$0M 0%	+$14M 0.1%
Delta from Least Risk (95th%)	+$1,254M 7.4%	+$481M 2.8%	+$427M 2.5%	+$21M 0.1%	+$0M 0%

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

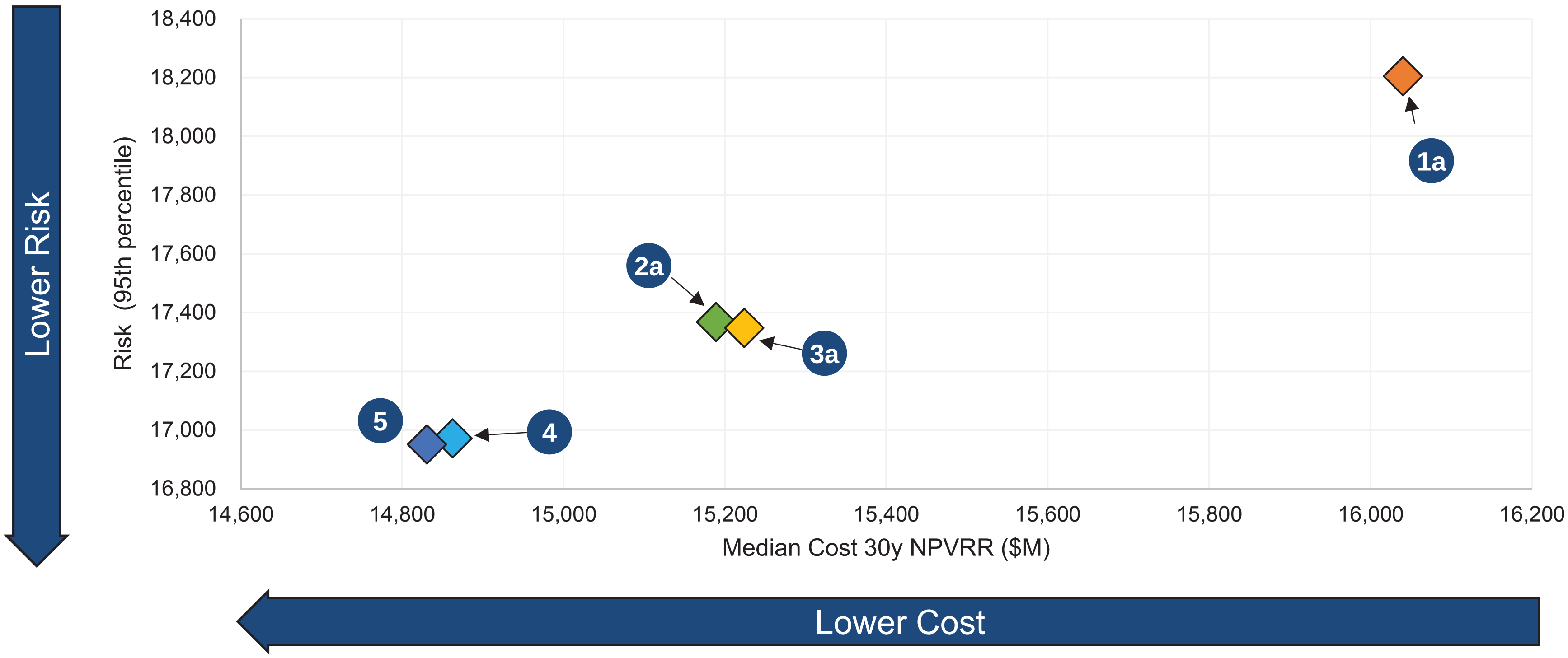
Results: Stochastic Cost Volatility



Portfolio Transition Target:	65% Coal through 2035 (1a)	40% Coal in 2023 (2a)	15% Coal in 2030 (3a)	15% Coal in 2023 (4)	0% Coal in 2023 (5)
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Incremental Volatility ($M)	0	177	291	388	448
Incremental Cost ($M)	1,210	359	394	32	0

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

Results: Stochastic Cost Risk



Portfolio Transition Target:	65% Coal through 2035 (1a)	40% Coal in 2023 (2a)	15% Coal in 2030 (3a)	15% Coal in 2023 (4)	0% Coal in 2023 (5)
Retire:	None	Schahfer:17,18 (2023)	Schahfer:17,18 (2023) Schahfer:14,15 (2030)	Schahfer:17,18 (2023) Schahfer:14,15 (2023)	Michigan City:12 (2023) Schahfer:17,18 (2023) Schahfer:14,15 (2023)
Retain:	Michigan City: 12 Schahfer:14,15,17,18	Michigan City: 12 Schahfer:14,15	Michigan City: 12 Schahfer:14,15	Michigan City: 12	None
Cost + Risk	18,205	17,432	17,378	16,972	16,951
Rank (1=lowest)	5	4	3	2	1

Note: ZLD results shown here, Non-ZLD results are not materially different and are in the appendix.

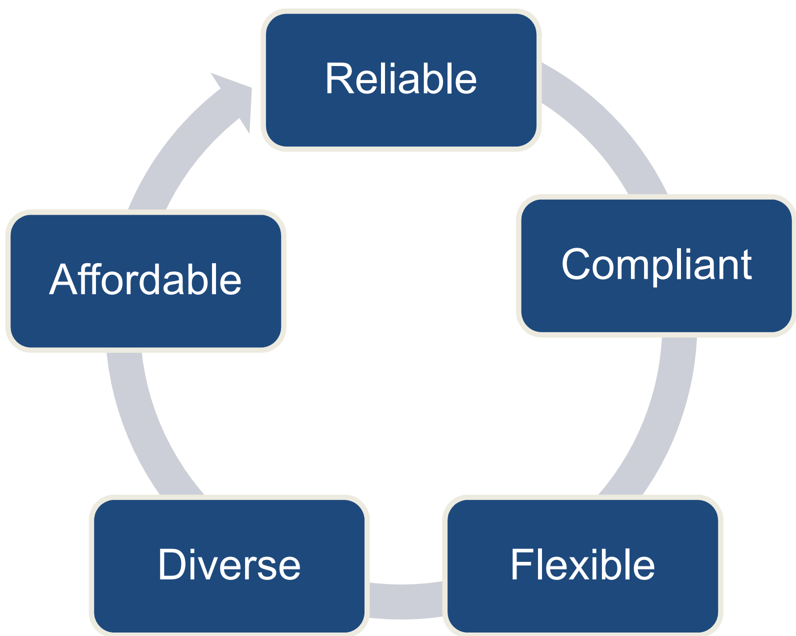
Replacement Analysis

Dan Douglas
Vice President Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course For Electric Generation

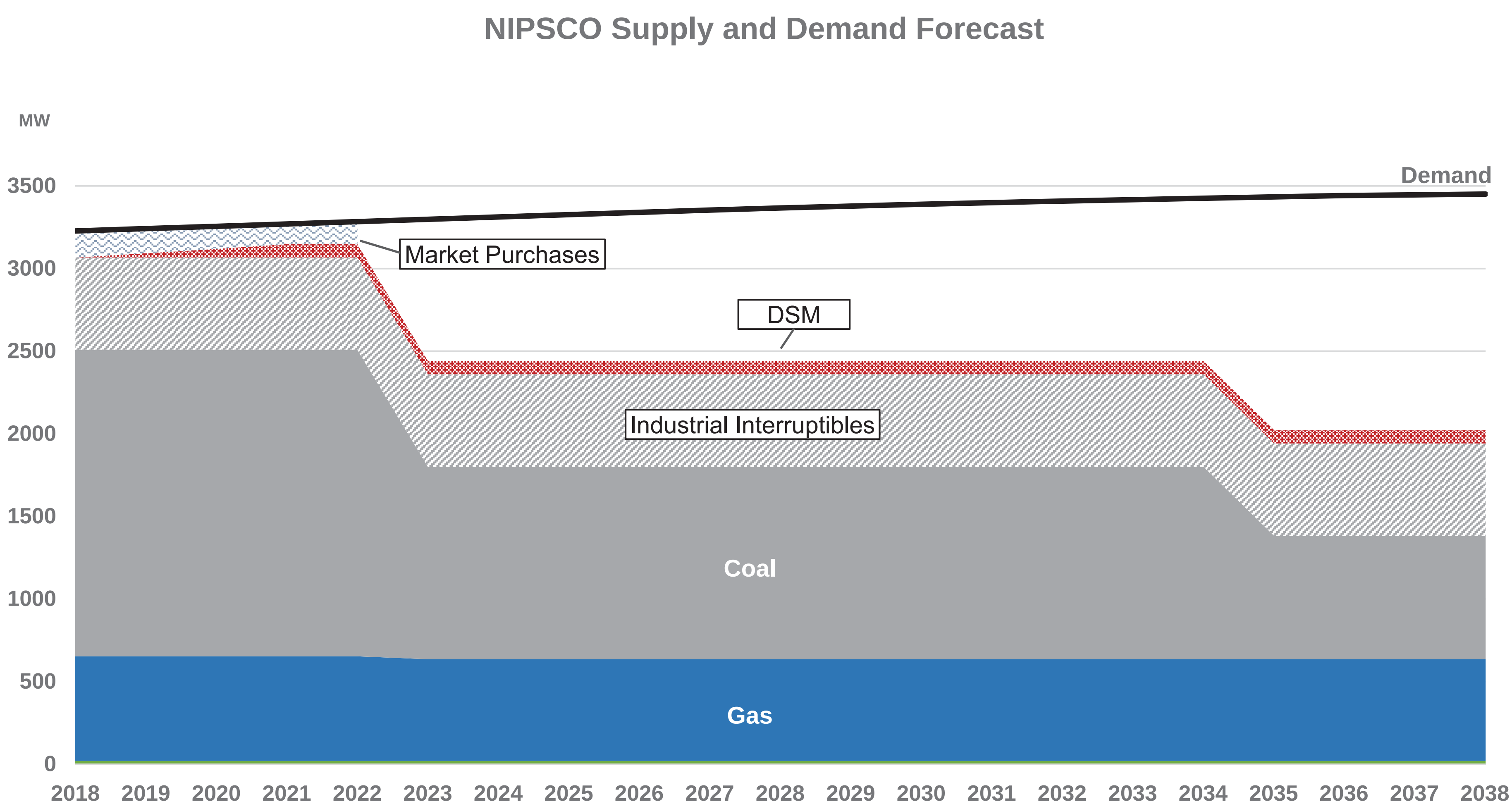


Requires Careful Planning and Consideration for:

- Our employees
- Environmental regulations
- Changes in the local economy (property tax, supplier spending, employee base)

Retiring Schahfer 17/18 Will Create a Need for New Resources

Based on 2018 Initial IRP Modeling



Replacement Resource Combinations Will Consider Ownership, Duration and Diversity

1 / 2 Ownership / Duration

- Generation can be owned by buying or building a facility, or can be secured through a financial contract
- Duration is the length of time commitment to a specific resource; shorter duration can partially mitigate industrial risk
- Ownership and duration are correlated: financial contracts are best suited for shorter duration and facility/asset ownership is best suited for longer duration resources

Considerations

- What is the right level of duration risk for the customer & NIPSCO?
- What ownership structures are best suited for each resource opportunity?

Ownership

Financial/ Contract ↔ Asset/ Facility

Duration

Industrial	Short Term	Long Term
≤ 1 yr	1–10 yrs	10+ yrs

3 Diversity

- Diversity is the mix of fossil, renewable and efficiency resources in the entire NiSource portfolio
- Diversity is measured by carbon dioxide emission rate intensity (carbon dioxide emissions per megawatt hour)

- What is the right mix of supply resources that aligns with NiSource environmental targets and satisfies customer and stakeholder interests?
- How does the updated NiSource generation portfolio compare to industry peers?

Diversity

Higher CO_2 Emissions per MWh	Lower CO_2 Emissions per MWh
4th Quartile	1st Quartile
Fewer Renewables	More Renewables

Sources & Notes: Represents average quartile CO_2 lbs/MWh; Benchmarking Air Emissions of the 100 Largest Electric Power Producers *https://www.nrdc.org/sites/default/files/benchmarking-air-emissions-2016.pdf*

Resource Combinations

Nine combinations are constructed exploring the full range of ownership, duration, and diversity possibilities

Ownership / Duration:

- **All portfolios will include ≤1 year purchases**
- **Three options:**
  - Short duration
  - Mix of Short and Long durations
  - Long duration

Short Duration	Mix of Short and Long	Long Duration
25%: ≤1yr 75%: 1-10yr	25%: ≤1yr 37.5%: 1-10yr 37.5%: 10+yrs	25%: ≤1yr 75%: 10+yrs

Diversity:

- **Three options:**
  - Higher carbon emissions
  - Average carbon emissions
  - Average-Low carbon emissions

Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
4th Quartile avg. rate 1,999	3rd Quartile avg. rate 1,515	2nd Quartile avg. rate 1,013

Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A 1-yr Market Capacity: 216 MW Purchase Power Agreement (PPA) (gas): 1,100 MW	B 1-yr Market Capacity: 216 MW PPA (gas): 600 MW PPA (renew): 1,500 MW	C 1-yr Market Capacity: 216 MW PPA (renew): 3,200 MW
Mix of Short and Long	D 1-yr Market Capacity: 216 MW PPA (gas): 550 MW CCGT: 550 MW	E 1-yr Market Capacity: 216 MW PPA (gas): 300 MW PPA (renew): 750 MW CCGT: 300 MW Renewables: 750 MW	F 1-yr Market Capacity: 216 MW PPA (renew): 1,600 MW Renewables: 1,600 MW
Long Duration	G 1-yr Market Capacity: 216 MW CCGT: 1,100 MW	H 1-yr Market Capacity: 216 MW CCGT: 600 MW Renewables: 1,500 MW	I 1-yr Market Capacity: 216 MW Renewables: 3,200 MW

Notes: nameplate capacity values are shown in the table; emission rates shown in CO_2 lbs/MWh

Replacement Resource Framework

- **Leveraging 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources**

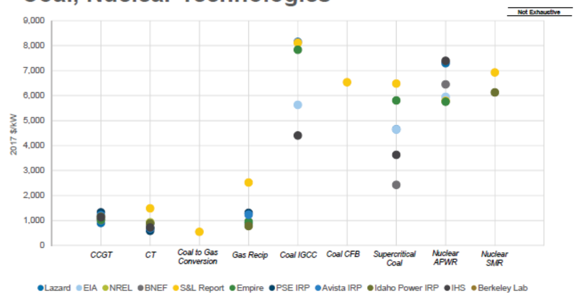
1) Use multiple data sources

3rd Party Data Sources

Data Source	Description	Link
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)	N/A
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 AEO)	EIA Capital Cost Estimates
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)	Empire District Avista Puget Sound Energy Idaho Power
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)	Lazard LCOE V. 11.0
	Lazard Levelized Cost of Storage Version 3.0 (2017)	Lazard LCOS V.3.0
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook	IHSMarkit (subscription required)
	US Wind Capital Cost and Required Price Outlook	
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)	
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs	
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region	Bloomberg New Energy Finance (subscription required)
	Key cost input in LCOE Scenarios, 1H 2017	
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)	
National Renewable Energy Technology Laboratory	NREL Annual Technology Baseline 2017	NREL ATB 2017

2) Compile current costs

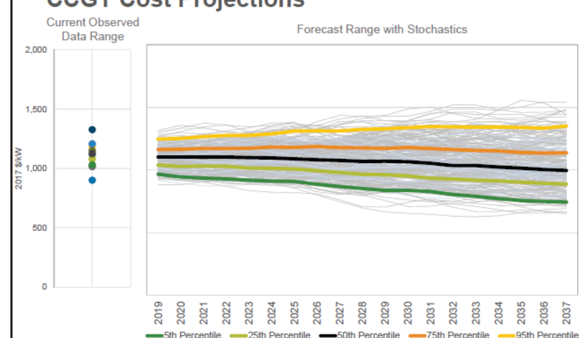
Current Capital Cost Estimates ($/kW) – Gas, Coal, Nuclear Technologies



2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,276	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927

3) Project future costs & capture uncertainty with stochastics

CCGT Cost Projections



How to interpret the probability distributions and diagnostic statistics:
- 50th percentile is the middle value – half the observations are above this value and half are below
- Generally, percentiles represent thresholds below which a given percentage of observations is expected to fall (i.e., the 95th percentile indicates that 95% of the cost observations in that year are at or below this level)

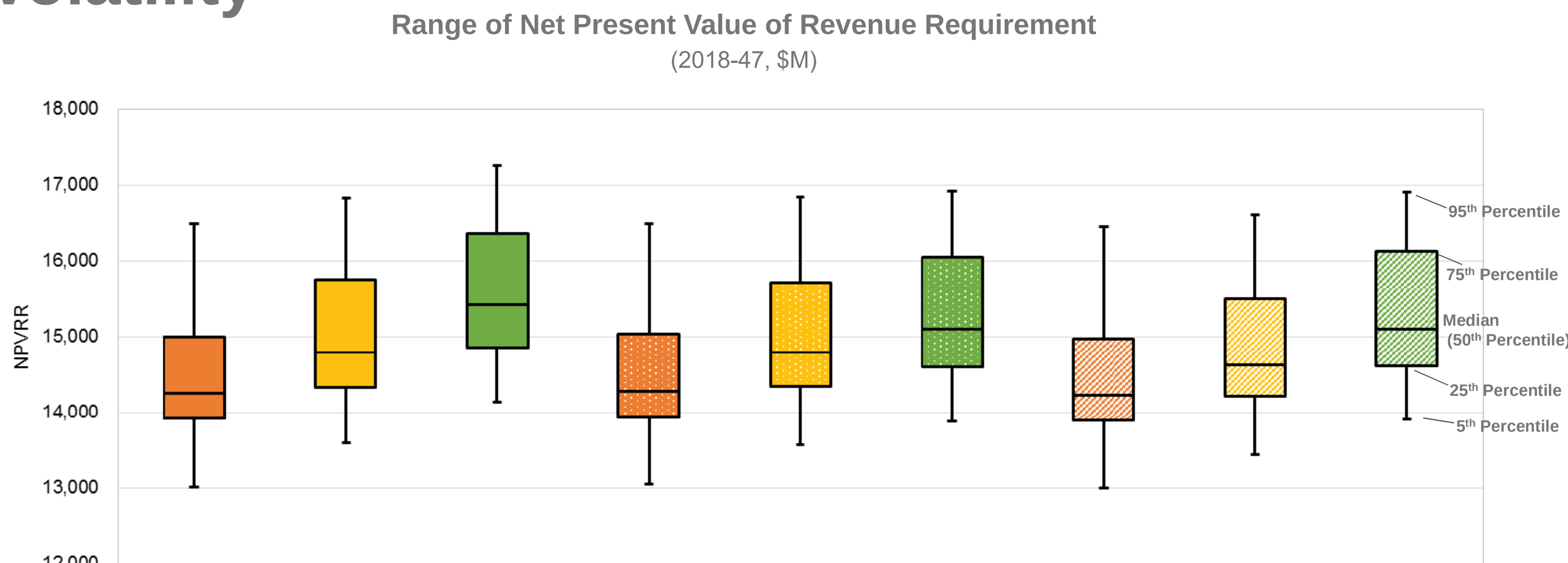
- **Conducting an all-source request for proposal (RFP) solicitation for replacement capacity resources**
  - RFP results collapse uncertainty for 2023 costs
  - Insert 2023 projects from RFP into the analysis and re-run

Results: Deterministic Cost to Customer

Diversity

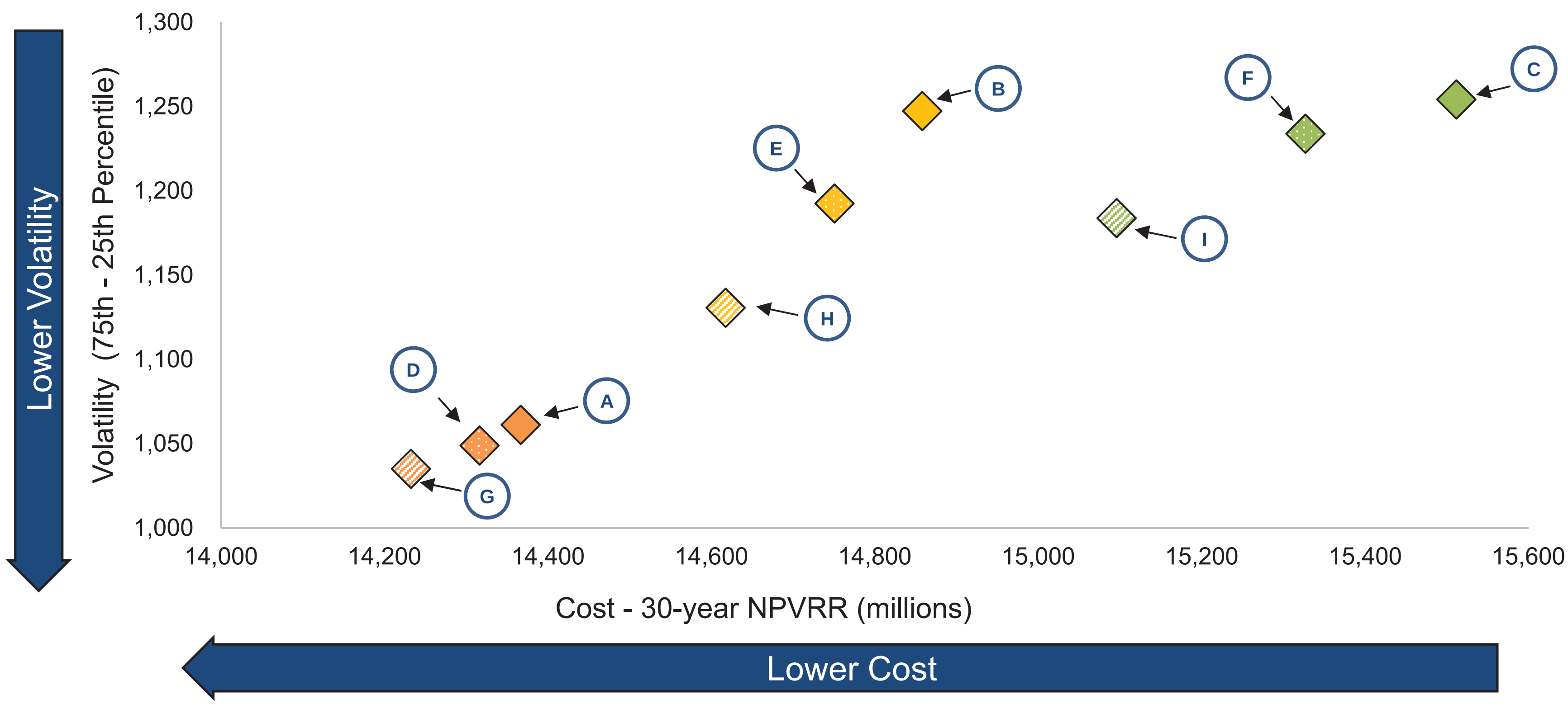
Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A Δ from Least Cost: +$140M / 1.0%	B Δ from Least Cost: +$553M / 3.8%	C Δ from Least Cost: +$1,081M / 7.5%
Mix of Short and Long	D Δ from Least Cost: +$86M / 0.6%	E Δ from Least Cost: +$449M / 3.1%	F Δ from Least Cost: +$915M / 6.3%
Long Duration	G Δ from Least Cost: +$0 / 0%	H Δ from Least Cost: +$318M / 2.2%	I Δ from Least Cost: +$721M / 5.0%

Results: Stochastic Cost Certainty, Risk, and Volatility



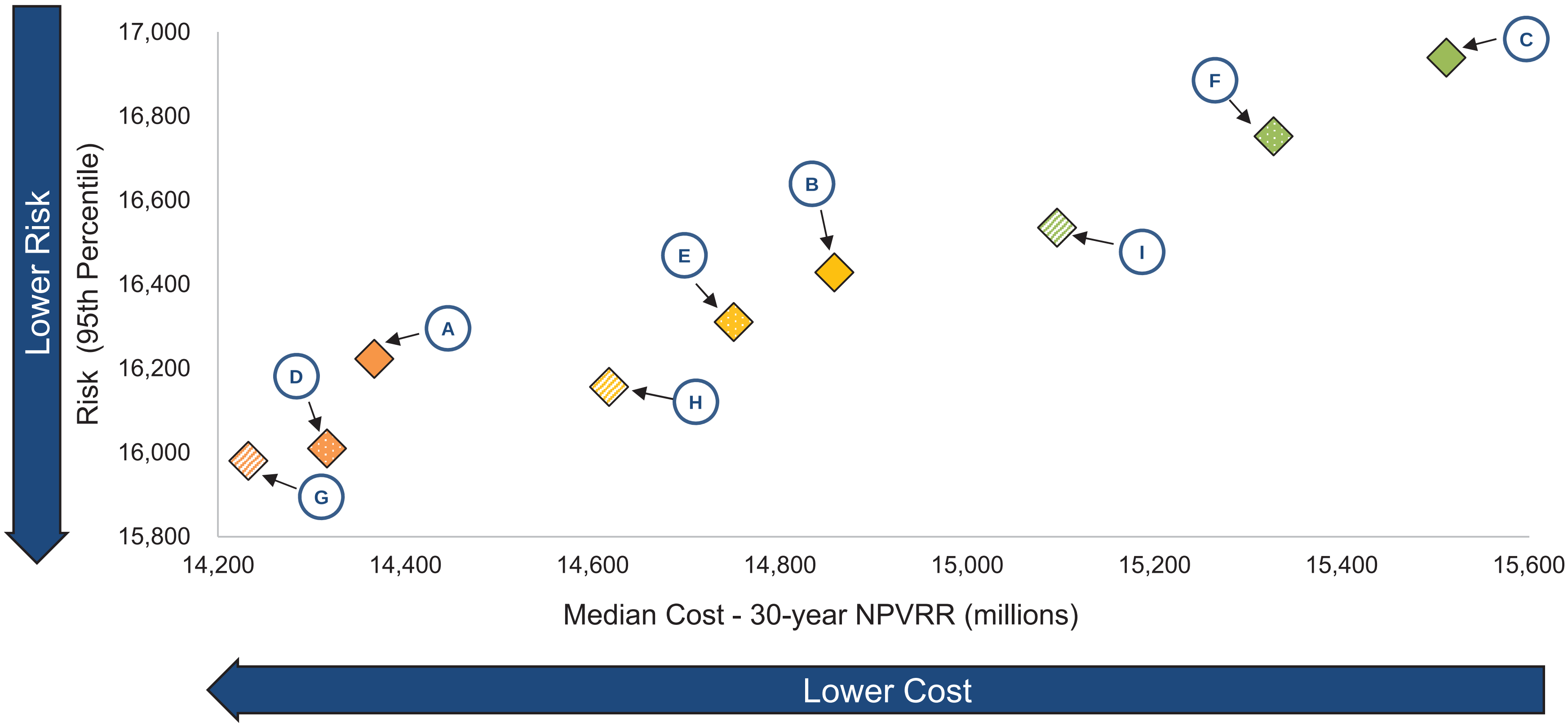
	Short Duration, Higher Carbon Emissions (A)	Short Duration, Avg. Carbon Emissions (B)	Short Duration, Avg.-Low Carbon Emissions (C)	Short & Long Duration, Higher Carbon Emissions (D)	Short & Long Duration, Avg. Carbon Emissions (E)	Short & Long Duration, Avg.-Low Carbon Emissions (F)	Long Duration, Higher Carbon Emissions (G)	Long Duration, Avg. Carbon Emissions (H)	Long Duration, Avg.-Low Carbon Emissions (I)
Delta from Lowest Cost Certain (75th%)	+$157M 1.1%	+$848M 5.7%	+$1,383M 9.3%	+$95M 0.6%	+$701M 4.7%	+$1,211M 8.2%	+$0M 0%	+$525M 3.5%	+$982M 6.6%
Delta from Least Risk (95th%)	+$243M 1.5%	+$448M 2.8%	+$959M 6.0%	+$29M 0.2%	+330M 2.1%	+$772M 4.8%	+$0M 0%	+$176M 1.1%	+$555M 3.5%

Results: Stochastic Cost Volatility



	A	B	C	D	E	F	G	H	I
	Short Duration, Higher Carbon Emissions	Short Duration, Avg. Carbon Emissions	Short Duration, Avg.-Low Carbon Emissions	Short & Long Duration, Higher Carbon Emissions	Short & Long Duration, Avg. Carbon Emissions	Short & Long Duration, Avg.-Low Carbon Emissions	Long Duration, Higher Carbon Emissions	Long Duration, Avg. Carbon Emissions	Long Duration, Avg.-Low Carbon Emissions
75th Percentile (Cost + Upside Volatility)	15,015	15,705	16,240	14,953	15,558	16,068	14,857	15,383	15,839

Results: Stochastic Cost Risk



	Short Duration, Higher Carbon Emissions	Short Duration, Avg. Carbon Emissions	Short Duration, Avg.-Low Carbon Emissions	Short & Long Duration, Higher Carbon Emissions	Short & Long Duration, Avg. Carbon Emissions	Short & Long Duration, Avg.-Low Carbon Emissions	Long Duration, Higher Carbon Emissions	Long Duration, Avg. Carbon Emissions	Long Duration, Avg.-Low Carbon Emissions
	A	B	C	D	E	F	G	H	I
Cost + Risk	16,223	16,429	16,940	16,010	16,311	16,753	15,981	16,157	16,535

RFP for Capacity

Paul Kelly
Director of Federal Regulatory Policy

Bob Lee
Charles River & Associates

Stakeholders Providing Feedback on the RFP

		Letter to NIPSCO	Interim Design Summary	Draft RFP Document (with non-disclosure agreement)
	Indiana Coal Council	✓	✓	
	Sierra Club		✓	
	Indiana Distributed Energy Alliance		✓	
	Citizens Action Coalition of Indiana, Inc.			✓
	Indiana Office of Utility Consumer Counselor			✓
Developers	Martin Banks		✓	
Developers	Jiagnan Environmental Technology (JET)		✓	
Developers	First Solar		✓	
Developers	Orion Renewable Energy Group LLC		✓	

Summary of Feedback Received and Incorporated

Stated Goal

Identify viable resources that can best meet our customers' needs

- Ensure RFP is truly all-source
- Clarify bidder qualifications, evaluation criteria and weightings
- Ensure transparency by sharing RFP results as much as possible
- Clarify scope of non-disclosure agreement and confidential information
- Allow demand response (DR) contracts with a term of 1 year and clarify DR rules
- Clarify need is based on 2016 IRP conclusion of Units 17/U18 retirements
- Market RFP to bidder audience including potential Units 17/U18 buyers
- Note no obligation to contract as a result of the RFP
- Clarify timeline to show completion of IRP and expectations as to when the review process will be completed
- Include bid requirements to filter out high risk, speculative projects; recognize MISO has specific development milestones in the queue
- Consider other recent RFPs across the United States (Xcel, AEP, Denton,TX, etc.)
- Added May 16, 2018 webinar for potential bidders to introduce RFP and answer questions at front end of timeline
- Lower credit and pre-qualification requirements

Summary of Feedback Received but Not Incorporated

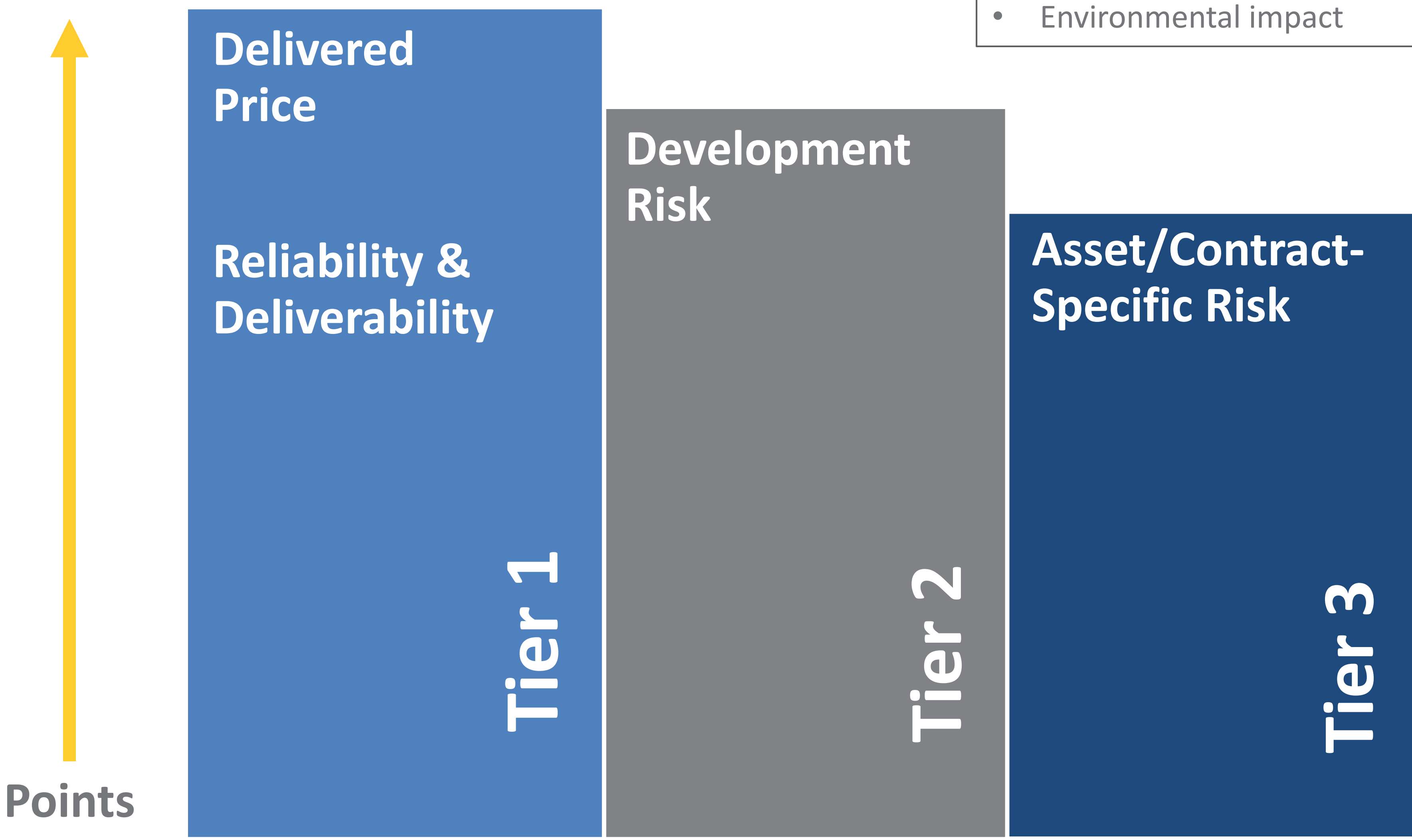
- Provide more than 45 days and/or adjust pre-bid conference timing
- Share individual bid responses
- Retain consultant to develop Units 17/U18 bid package
- Do not negotiate until IRP is submitted and accepted by Indiana Utility Regulatory Commission
- Include flexibility (frequency, time and size of irreversible decision) as an evaluation criteria
- Include full life cycle assessments (LCA) and annual carbon intensity
- Require assets to demonstrate advanced dispatch capabilities
- Require bidder and their suppliers to prove financial performance
- Require solar PV resources to meet certain industry standards
- Eliminate potential for fossil resources
- Remove MISO Zone 6 firm delivery requirement or allow financial solution
- Allow under/over-delivery for renewable energy

* NIPSCO received comments relating to scope and process of the IRP not reflected here; also multiple questions about the RFP were received that will be answered in the RFP release

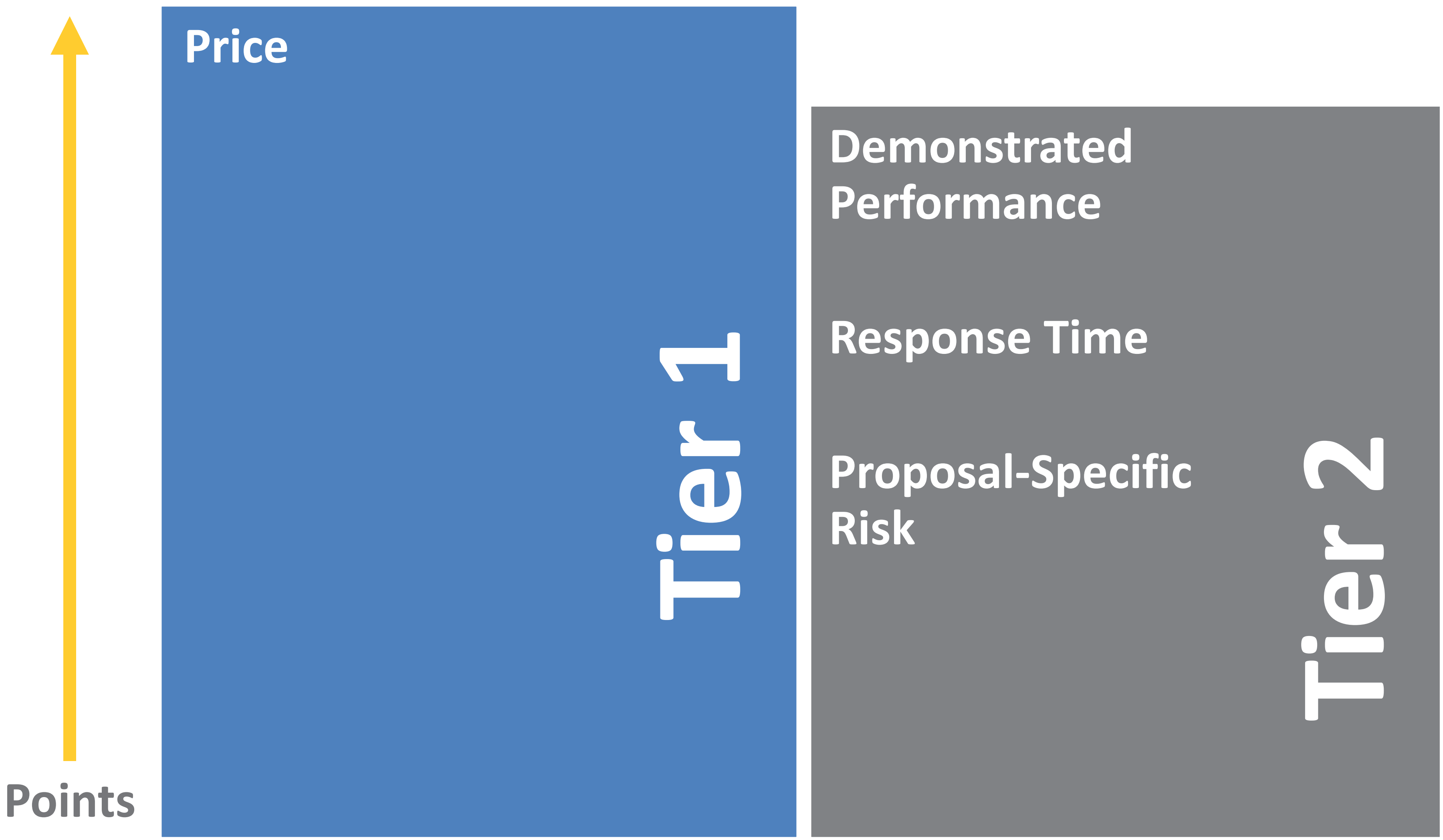
Final Evaluation Criteria (non-DR)

Other 3/23 Criteria not included:

- Portfolio diversity
- Employee impact
- Community impact
- Environmental impact



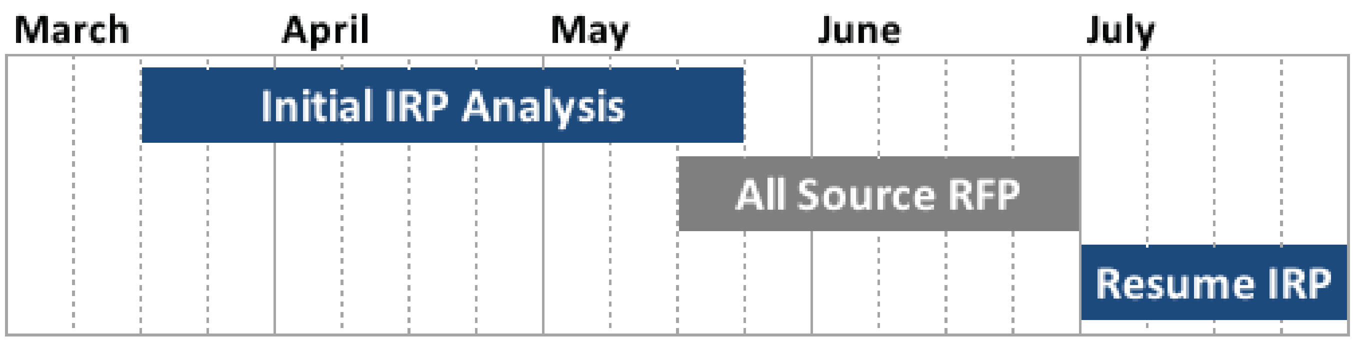
Final Evaluation Criteria (DR)



Key Design Elements of the All-Source RFP

- **Technology**
  - Requesting all solutions regardless of technology, including demand-side options and storage
- **Size**
  - Defining a minimum total need of 600 MW for the portfolio but without a cap
  - Allows smaller resources <600 MW to offer their solution as a piece of the total need
  - Also encourages larger resources >600 MW to offer their solution for consideration
- **Ownership Arrangements**
  - Seeking bids for asset purchases (new or existing) and purchase power agreements
  - Resource must qualify as MISO internal generation (not pseudo-tied) or load (DR)
- **Duration**
  - Requesting delivery beginning 6/1/2023 but will evaluate deliveries as early as 6/1/2020
  - Minimum contractual term and/or estimated useful life of 5 years (except for DR, which is 1 year)
- **Deliverability**
  - Must have firm transmission delivery to MISO Zone 6
  - Must meet N-1-1 reliability criteria or show cost estimate to achieve that quality
- **Participants & Pre-Qualification**
  - Marketing RFP to broad bidder audience which began last month to provide plenty of notice
  - Requiring credit-worthy counterparties to ensure ability to fulfill resource obligation

Revised Timeline for the RFP



Date	Event
March 23rd	Overview RFP design with stakeholders
April 6th	RFP Design Summary document shared with stakeholders to request feedback
April 20th	Stakeholder feedback on Design Summary due back to NIPSCO
May 14th	**RFP initiated**
May 16th	**RFP Webinar for bidders (includes Q&A session)**
May 28th	Notice of Intent and pre-qualifications due from potential bidders
June 29th	**RFP closes**
July 24th	Summary of RFP bids presented at Public Advisory webinar; IRP analysis incorporates results of RFP

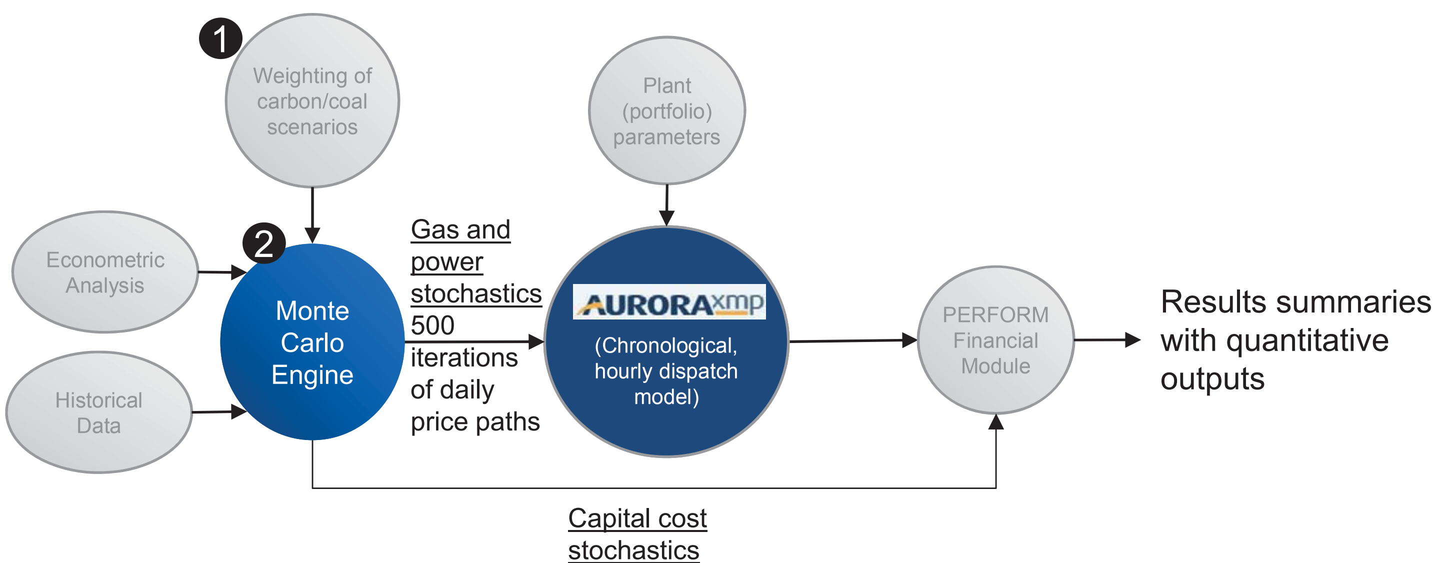
Stakeholder Presentations/Comments

Wrap Up

Appendix

Developing Stochastic Inputs

- **Scenario development supports stochastic development process**
  1. **Scenarios are probability-weighted for discrete variables (carbon/coal)**
  2. **Monte Carlo Engine is run for natural gas and power prices for each weighted scenario, based on historical data analysis, which incorporates:**
     - Daily price spikes for gas
     - Power price volatility on a daily and hourly level, implicitly based on observations like market load shocks, fuel price changes, and plant outages



Stochastics Development Details

1. **Historical Data Analysis**
   - Analyze historical commodity prices to find a stochastic (econometric) model that best captures the observed behavior of prices in the modeled region.
   - Key parameters, which define the stochastic price processes, include:
     - volatility levels (randomness),
     - mean-reversion rate (convergence to long-term price trends and forecasts)
     - correlation between with power and gas prices in the regions
2. **Parameter Estimation**
   - Fit historical data to an econometric model by running regressions and estimating stochastic process parameters
3. **Monte Carlo Simulations**
   - Simulate future spot prices using a Monte Carlo simulation model based on the estimated stochastic price processes (for gas and power prices)
   - Run 10,000 paths per commodity using antithetic draw techniques to ensure fast convergence and a balanced and risk-adjusted coverage of the full spectra of positive and negative price jumps in simulated price time series
4. **Cost Probability Distributions for Each Scenario**
   - CRA performed Monte Carlo simulations for each fundamental market scenario and probability-weighted them to develop the full set of stochastics
   - 500 draws were sampled for the full Aurora-PERFORM runs

Base Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Base	Base	Base	Base	Base	Base	Base	Base

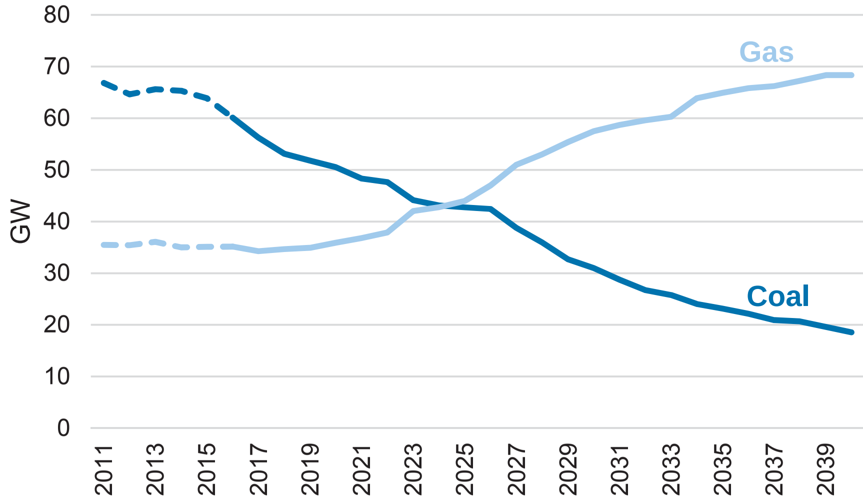
- **The scenario NIPSCO considers most likely to occur**
- **Detailed assumptions were provided during March 23 stakeholder meeting**
  - NIPSCO total energy growing at 0.33% per year and peak at 0.41% per year
  - Carbon price starting at $8/ton (real) in 2026, escalating to $13/ton (real) by 2037
  - Natural gas prices trending from current levels to $4/MMBtu (real) by 2030 and $4.50/MMBtu (real) by 2037
  - Coal prices generally flat to declining in most basins; real growth expected in PRB prices
  - Power prices correlated to gas and carbon prices; shift in MISO supply mix from coal to gas and renewables
  - Capital cost declines expected for solar and battery storage
  - Non-carbon environmental compliance costs reflect current regulations, including CSAPR, ELG, CCR, and 316(b)

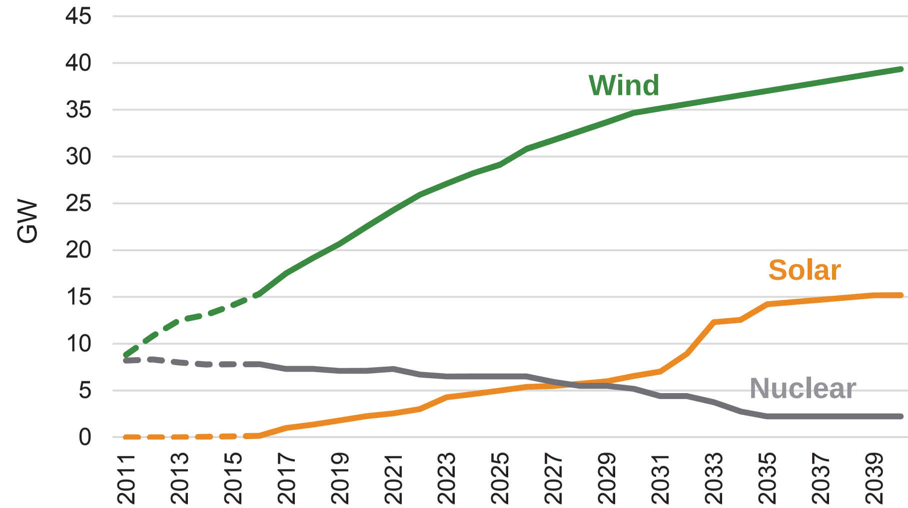
Aggressive Environmental Regulation Scenario

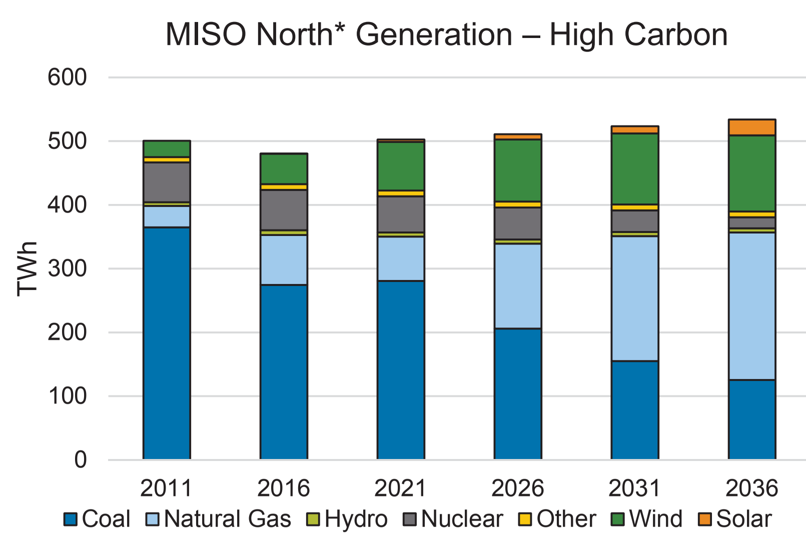
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**	**Low** renew./ sto.	Base

- Carbon price starting at ~$20/ton (real) in 2026, escalating to ~$13/ton (real) by 2037
- Natural gas prices trend up towards $5.50/MMBtu (real) over time
- Coal prices decline vs. base case as a result of declining demand
- Power prices correlated to gas and carbon prices and rise significantly higher than base case; faster shift in MISO supply mix from coal to gas and renewables
- More significant cost declines for solar and battery storage

MISO Market Changes: Aggressive Environmental Regulation







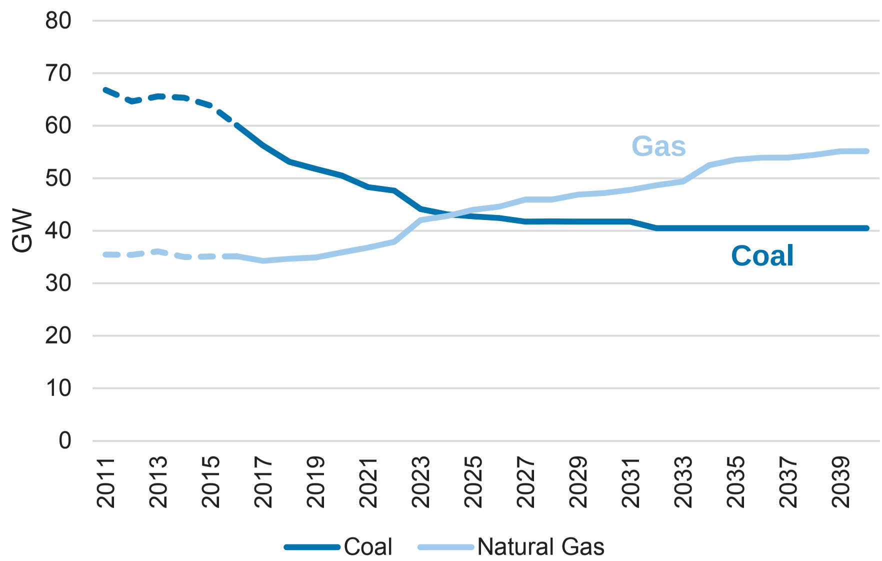
MISO North includes LRZ 1-7

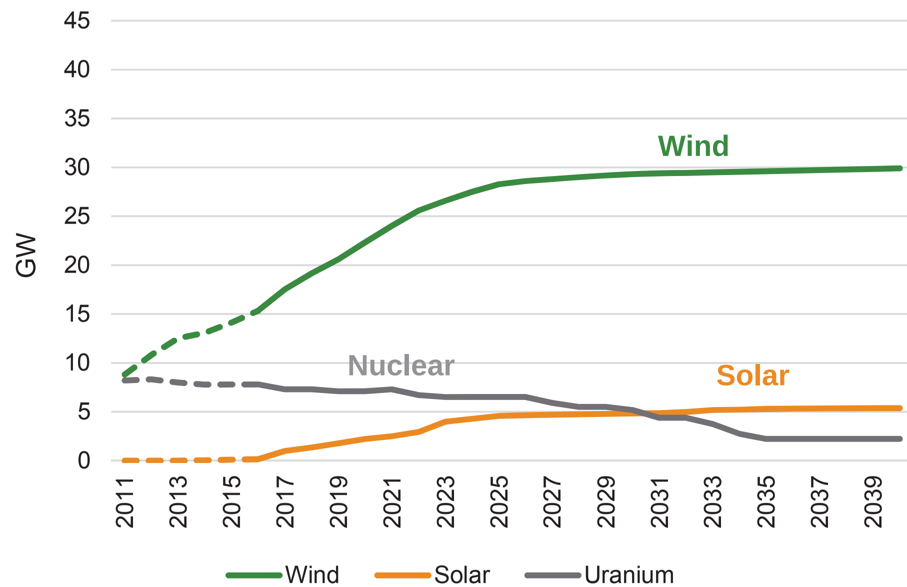
Challenged Economy Scenario

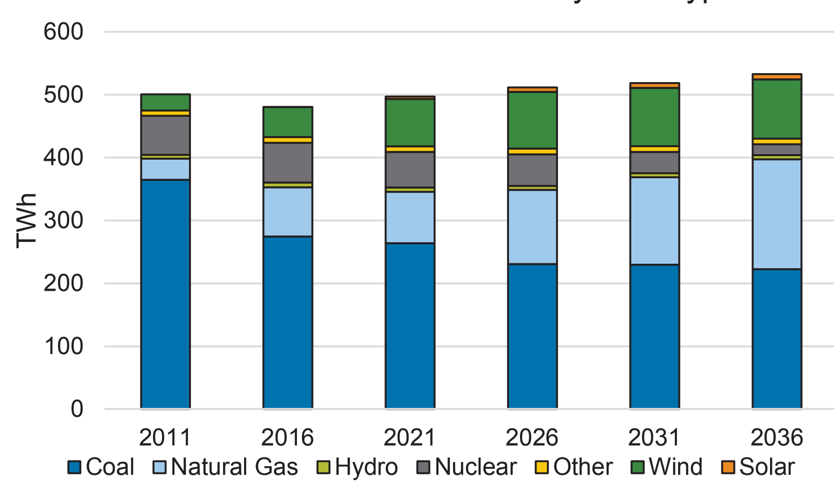
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**	Base	**Low**

- No price on carbon
- Natural gas prices stabilize around $3.50/MMBtu (real) over the long-term
- Coal prices modestly increase vs. base case as a result of increase long-term demand
- Power prices correlated to gas and carbon prices and remain relatively flat in real terms over time; slightly fewer renewables and coal retirements in MISO supply mix
- Lower NIPSCO load as a result of a loss in industrial demand

MISO Market Changes: Challenged Economy







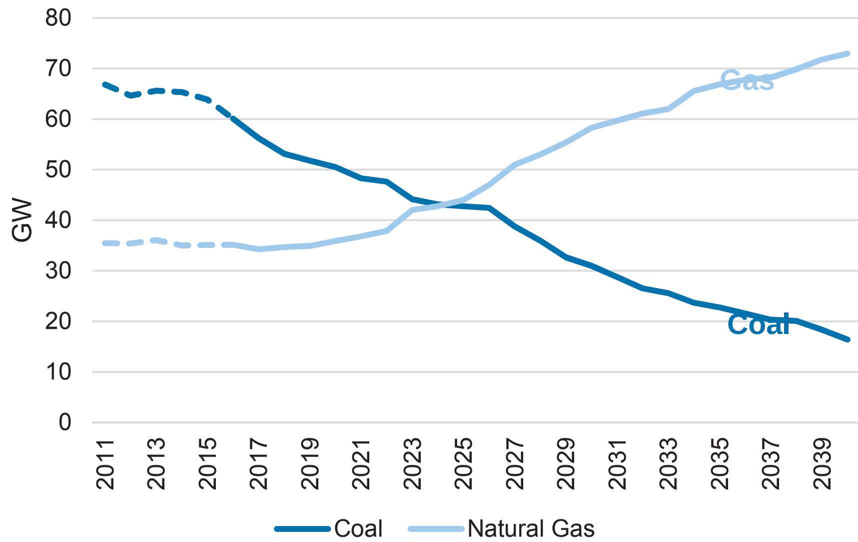
*MISO North includes LRZ 1-7

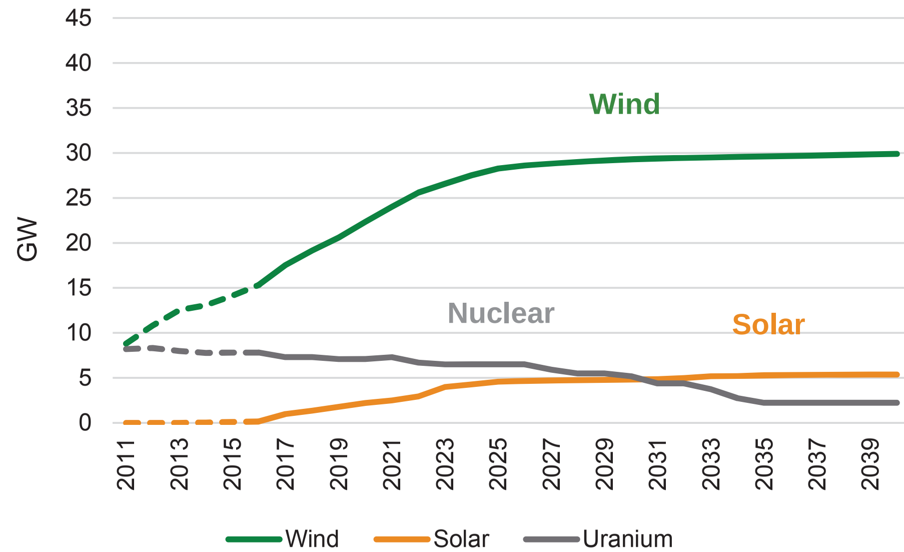
Booming Economy and Abundant Natural Gas Scenario

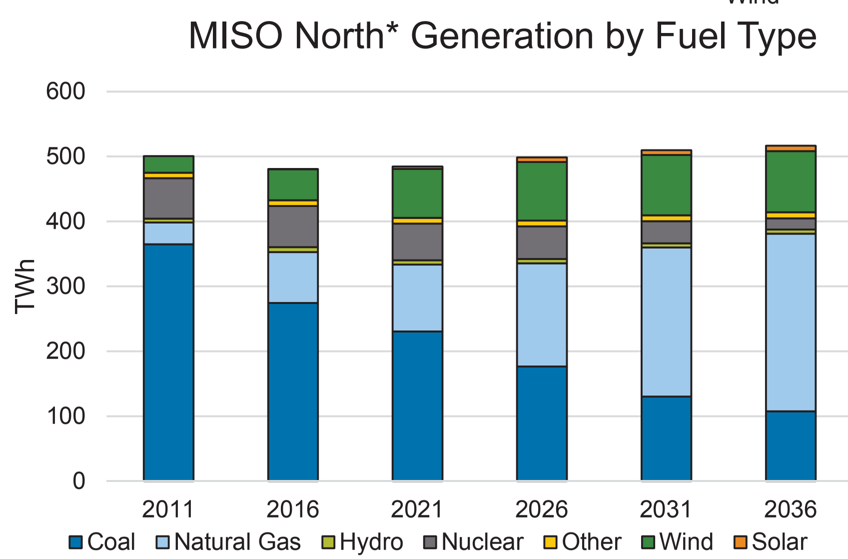
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price	Capital Costs	Other Enviro. Costs
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**	Base	**High**

- Natural gas prices are expected to stay lower for longer, primarily as a result of lower production costs
- Coal demand is likely to erode with sustained low gas prices, driving coal prices down
- Power prices correlated to gas and carbon prices and remain relatively flatter for longer in real terms, although a spike still occurs in 2026 with the carbon price; fewer renewables and significantly more coal retirements in MISO supply mix as a result of very cheap gas over the next ten years

MISO Market Changes: Booming Economy and Abundant Natural Gas







*MISO North includes LRZ 1-7

Northern Indiana Public Service Company
2018 Integrated Resource Planning ("IRP")
Public Advisory Meeting #2
SUMMARY

May 11, 2018

Welcome and Introductions

Alison Becker opened the meeting by asking participants in the room and on the telephone to introduce themselves and reviewing the agenda for the day. She then introduced Violet Sistovaris. Violet Sistovaris, Executive Vice President, NiSource and President, NIPSCO provided an introduction and thanked participants for being there. She expressed NIPSCO's commitment to the process and to obtaining stakeholder input. Ms. Becker then presented a safety moment.

NIPSCO's Planning and the Public Advisory Process

Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained how NIPSCO plans for the future and provided an overview of the public advisory process, including reviewing the current point in the stakeholder engagement process. Mr. Douglas also provided an update on stakeholder interactions to date.

Modeling of Uncertainty

Pat Augustine, Charles River Associates ("CRA")

Mr. Augustine provided information related to NIPSCO's modeling of uncertainty in the IRP. He noted that NIPSCO's process will utilize both scenarios and stochastics to assess risk. The 2018 IRP will employ the same scenario-development process as the 2016 IRP, which is to identify drivers of potential uncertainty which could influence IRP outcomes. As an additional step in the 2018 IRP, the process will also assess whether scenario or stochastic treatment (or both) for the underlying drivers is appropriate. Mr. Augustine then discussed the details of the scenario concepts, which drive the development of integrated combinations of input variables and inform the stochastic ranges. Because NIPSCO is utilizing stochastics for the first time, Mr. Augustine provided an overview of the process and the benefits of stochastic analysis. He also provided the scenario ranges of discrete variables for carbon price and coal price and stochastic ranges for natural gas prices, power prices, and capital costs.

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

- Is NIPSCO also doing some teasing out of some of the drivers in relation to risk? For example booming economy and natural gas prices don't necessarily go together. Would NIPSCO be willing to do some teasing out with the drivers within each of the scenarios?
  - Yes, NIPSCO is open to incorporating stakeholder input on the combinations of key drivers and how they are related. Under the Booming Economy scenario, natural gas prices are low due to high-levels of low-cost natural gas production, which supports strong economic growth. However, one could envision an alternative state-of-the-world where high load growth drives higher gas prices. Overall, the scenario development process intends to develop an initial range of plausible outcomes, while the full stochastics will capture a wider range of combinations of factors not contemplated in any one specific scenario. If you have a specific set of assumptions, the team would be willing to talk through that.
- In looking at key drivers for environmental and seeing carbon controls, is NIPSCO also considering any other stricter policies for wastewater treatment, etc.? That issue can be and has been an issue with plant closures.
  - Kelly Carmichael will discuss environmental policy further. However, if there is something you think is missing, NIPSCO can address that if appropriate. All of the environmental policy expected to affect the NIPSCO fleet is being considered.
- Regarding the drivers on the technology side, is there anything on the horizon where NIPSCO can keep some of its generators that are retiring or is the Company looking at some technology developments to keep some of the generators?
  - That is the purpose of the process. The IRP will consider the environmental costs and impacts and what it means for potential retirements. Kelly will discuss environmental control options further, and ifIf there are uncertainties, the retirements can be considered again.
- There is a discussion of a correlation between booming economy and low gas prices, but it is not clear if there is a correlation. The bigger issue is that there are not more scenarios.
  - It is probably possible to come up with dozens of scenarios that evaluate different potential outcomes in the market. The scenarios being discussed are the starting point, with the stochastics providing a fuller treatment of uncertainty around a broader range of combinations. If there are specific scenarios that stakeholders believe are missing, NIPSCO is happy to talk through the issue and decide whether additional modeling would be useful.
- There is a concern with how Aurora works. The impression is, when you do portfolio optimization, given the way the portfolio outputs occur, it seems there is no way to operate without stochastics.
  - While the comment generally characterizes one capability of Aurora modeling correctly, the description of how Aurora works and how it is being used in the

process is not complete. In Aurora you can optimize portfolios under a base case and across different scenarios, but you can also pre-define a portfolio and evaluate it across scenarios and stochastics. It is important to note that the process does not restrict Aurora to be only an optimizer model. While we plan to evaluate portfolio optimization, the entire scenario and stochastic risk analysis is based on using the model not to optimize, but as a comprehensive dispatch tool. In this way, the user can input different portfolios and then run through all scenarios and stochastics along with a full scorecard assessment.

- Aurora evaluates portfolios in a rigorous framework through stochastics. NIPSCO is asking stakeholders for input but there is not a lot of transparency for stakeholders in terms of what types of resources would make up costs of the portfolio. There is not really a good way for us to understand the resource needs. It is hard to say we want NIPSCO to run a specific portfolio.
    - o All of the inputs will be made available, including gas prices, coal prices, power prices, etc. for the scenarios and stochastics. These are available in spreadsheet format, so Aurora is not needed to see what is going in to the modeling process. In addition, NIPSCO will provide portfolio output details and if different portfolios are desired, within reason, those can be run.
- There is also a concern related to correlations.
    - o NIPSCO will continue to review this and is open to more specific stakeholder input on input scenarios.
- Why have the load forecasts on slide 14 not been developed yet? How does this fit into the schedule for the request for proposals for capacity (“RFP”)?
    - o The team continues to work on the scenarios and they are expected to be finished in the next month, so that they are ready prior to RFP results being received.. The IRP process includes some initial modeling to identify preliminary themes and results, some of which will be shared today, and then have final model results with all scenario and stochastics details for presentation in September.
- Very concerned about the use of stochastics rather than a binary consideration, particularly as it relates to carbon. There needs to be a base case without carbon and coal and gas pricing and stochastics do not provide that.
    - o It is important to note that stochastics are not replacing scenarios. The four individual scenarios are still being run, including the one with no carbon price. If there are other scenarios that are needed, NIPSCO will evaluate them. Ultimately, NIPSCO is keeping the scenario framework to complement to stochastics.
- How are capital cost stochastics being treated with the RFP?
    - o Thus far, NIPSCO is using a range of capital costs to obtain insight on portfolio performance. As the RFP results are received, NIPSCO will refine all capital cost (or PPA price) estimates with better data.
- On slide 17, there is a spike in natural gas prices in 2014, what is that? How is that spike included in the forecast going forward?
    - o The spike was from the very cold “polar vortex” weather event in January and February of that year. That behavior and other randomness is picked up to

some extent going forward. The volatility metric is captured in the prices going forward.

- On slide 16, is the dashed line the highest carbon prices?
    - o The orange dashed line is the high carbon price scenario. Carbon prices are not a stochastic variable, but are treated as three discrete scenarios with probability weighting. 25% of the iterations will be at high level, 50% at the middle level, and 25% at the bottom level. Fuller natural gas and power price stochastics are built around the corresponding carbon price trajectories in the three scenarios.
- Where are these stochastics being used?
    - o They are being used in the analysis of the portfolio options. So when portfolio economics are considered, all stochastics are utilized to evaluate the portfolios across hundreds of potential market outcomes.
- Will NIPSCO provide supporting data on the gas and coal forecast?
    - o Yes.
- Regarding the power pricing distributions, are they results or forecasts?
    - o Looking at slide 19, this shows the price forecasts from the Aurora model output for each individual scenario and the full stochastic distribution that is developed based on these price forecasts and the historical data analysis.
- Following up on the spike in 2014, does the forecast incorporate the likelihood of increasing extreme weather?
    - o No. The data relies on the historical data as it is.
- How far back in history does NIPSCO consider? The graphs go back to 2011.
    - o Yes, that is the approximate eight-year period of historical data that is used as representative of current and expected market conditions when developing the stochastic distributions.
- Will NIPSCO use fixed operations and maintenance (“O&M”) costs?
    - o Yes, those are evaluated as plant-level costs in the portfolio analysis.
- Assume there is a similar chart for battery costs. Does NIPSCO’s modeling incorporate the improvements in solar/wind capacity value? Is that captured?
    - o To the extent a battery option is being evaluated, it is included. To date, the initial portfolios have just looked at stand-alone solar and wind options, but batteries paired with intermittent resources would improve their capacity value. We expect such offers may be provided in the RFP.
- Regarding the notion of option value, there is uncertainty in variables, costs, load, technology, etc. To what extent does NIPSCO’s model capture this?
    - o It depends on the portfolio construction, but the modeling and scorecard development is intended to try to capture this. For example, a contract with a shorter duration can be evaluated, and it will have a different market exposure and potentially show a benefit of waiting until a lower-cost resource is available in the future. Furthermore, portfolio optionality is a separate scoring metric in the scorecard process.
- Will the model be used to select resources? Can Aurora do that?
    - o Yes, it can optimize for the lowest cost resource. However, this is not the only way that we will be using the model. The full stochastic analysis will evaluate a series of portfolios with different risk and cost metrics.

- Does any scenario explore electric vehicles?
    - o Not explicitly to date. NIPSCO continues to evaluate if there is sufficient demand to include this is the forecast, but, to date, there has not been enough demand from electric vehicles to include them in the forecast. It is, however, reviewed on an annual basis.
- The capital costs are based totally on renewables. Why they are not compared to coal and gas?
    - o Slide 20 shows just two examples. There are a whole list of technologies included in the modeling, including fossil options. This was shared in the March Stakeholder meeting
- Is there anywhere that summarizes what is included in load, such as residential community solar or rooftop solar, used to decrease demand or the projections of the ramp up of those projects?
    - o There is nothing specific included for distributed solar at this time.

Demand Side Management ("DSM") SM Modeling Methodology
Alison Becker, Manager, Regulatory Policy, Dick Spellman, GDS Associates, Inc., and Pat Augustine, CRA

Ms. Becker provided an overview of the DSM modeling steps. Mr. Spellman then provided an overview of GDS Associates' work on the DSM Savings Update Report including the methodology being utilized to conduct the update. He discussed how the NIPSCO 2019-2021 program request is the basis for the first three years of the Update Report and then provided information on measures to be added after 2021. Mr. Spellman provided preliminary projections for cumulative annual megawatt ("MWh") and megawatt ("MW") savings for both the residential and the commercial and industrial ("C&I") sectors, as well as the associated projected budgets. He also provided the combined total MWh and MW savings and costs. Mr. Spellman provided information on the demand response measures to be included in the Update Report and information regarding the next steps. This included a discussion of how the DSM "bundles" will be identified (through three scenarios and based on a $/kilowatt hour ("kWh") saved and finished by showing an example of an energy efficiency supply curve.

Mr. Augustine then reviewed Step 3 of the process, which is modeling the DSM bundles across all scenarios and the full stochastic range. He showed how this will be completed in steps with Aurora and PERFORM and how the uncertainties will be accounted for.

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

- On slide 34, are the numbers cumulative? Would 2015 results be added to 2020?
    - o No. The cumulative results only include 2019 through 2038. It excludes installations before 2019.
- Each data point stands on its own?

- Yes. For example, if a pump has a useful life of 20 years and one pump is installed each year, at the end of 20 years, the incremental annual number of pumps installed would be one pump per year, and the cumulative annual number of pumps installed after 20 years would be 20 pumps.

- Does the cost per kWh saves in the first year include NIPSCO administrative costs and evaluation, measurement and verification?
  - Yes.
- Does it include the costs to the customer?
  - NIPSCO elected, at the behest of the stakeholders, to use the Utility Cost Test for cost effectiveness screening of measures and programs. The Utility Cost test does not include costs incurred by customers.. However, the DSM Savings Update analysis and report will also include the Participant Cost Test, which does include the cost to the participant.
- If a customer has to pay incentives or lost revenues, that should be considered.
  - Lost revenues are included in the Ratepayer Impact Measure ("RIM") test, which will also be included in the analysis. But, again, in determining which measures to include in the IRP, the stakeholders requested NIPSCO to utilize the Utility Cost Test and NIPSCO agreed to that request.
- Slide 43, regarding the blue line for DSM costs, is the present value of DSM costs being captured in each bar?
  - The blue line is the present value of DSM costs. Each bar shows the present value of portfolio savings under the different scenarios.
- Slide 43, the bars are not revenue requirements?
  - Correct, they represent savings estimates.
- How is NIPSCO determining available savings if the plan is to not allow Aurora to do the optimization?
  - Aurora can be run with the existing portfolio and load forecast to arrive at a net present value of revenue requirements. Another model simulation can then be run with lower load requirements as a result of DSM savings. In the second simulation, the costs to serve the system will go down. Savings are associated with lower energy and capacity costs.
- Not allowing Aurora to make the election means it is only considering dispatch. Not understanding whether DSM is being considered to delay capacity additions.
  - It is accurate to say that Aurora only considers dispatch costs, but the full Aurora-PERFORM model incorporates savings associated with delaying capacity additions. So when a DSM bundle is evaluated, lower capacity costs will also be included. This is accounted for in the illustrative example shown on Slide 43.
- This process seems to underestimate the amount of DSM available.
  - There will be a base, high and low case for DSM. The base case is about 1% and GDS is working with NIPSCO and stakeholders on the low and high cases. Will gladly provide details.
- Has NIPSCO accounted for how catastrophic storms may impact the grid or how more people generating their own power may impact DSM?

- o Not for these purposes. For these purposes, NIPSCO only considered opportunities to reduce load. NIPSCO does not consider distributed generation in its DSM analysis.

Generation Overview
Fred Gomos, Manager, Corporate Strategy

Mr. Gomos provided an overview of NIPSCO's supply resources as of 2018. Bailly is no longer part of the supply mix as the unit is retired. He also discussed generation costs and how they vary for each unit. He then provided information related to variable costs as well as O&M costs for NIPSCO units.

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

- Regarding Schahfer Unit 14, why is unforced capacity ("UCAP") so low in comparison to nameplate capacity?
  - o It is related to the operational profile. Those units have a lower UCAP because of performance issues, but should improve over time.

UCAP is assigned by MISO based on the units historical Equivalent Forced Outage Rate ("EFORd" therefore if a unit has had performance or operation issues in the past it will get a lower UCAP rating relative to its nameplate capacity until it can demonstrate it can consistently perform at a level close to its nameplate rating

Environmental Considerations
Kelly Carmichael, Vice President, Environmental

Mr. Carmichael provided answers to various stakeholder requests from the first meeting, including NiSource environmental targets announced in 2017 (the Company is on track), NiSource's carbon emissions trajectories, a carbon emissions comparison, and health-based air quality standards in Northwest Indiana (the region has achieved Environment Protection Agency ("EPA") standards). He then provided an overview of key environmental rules and near term compliance requirements and discussed the costs of such compliance by generation unit for coal combustion residual ("CCR") and effluent limitation guidelines ("ELG") compliance.

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

- Regarding the presentation by JET at the last Public Advisory meeting, has NIPSCO considered that?
  - o The presentation was around ammonia based scrubbing and it was considered a few years ago. Must balance that NIPSCO is not a large utility and not in a position to develop technologies. Based on research at the time, it was determined NIPSCO should go with proven technologies. With ELG where they are now, NIPSCO is open to new technologies.
- Will NIPSCO be considering other technologies such as those that can be obtained on a contracted basis to reach ELG compliance?
  - o Once a rule is issued, NIPSCO will evaluate the various options.
- Nothing will be done as part of the IRP process?

  - NIPSCO has already received a request to consider ELG at zero cost and that will be examined. From a policy perspective, it is important to note that environmental rules are constantly evolving and the currently-proposed environmental control regulations may be revised.
- Do you know the percentage reduction for a 1.5 limit as opposed to 2 as it relates to the climate targets?
  - This is unknown. NIPSCO is guided based on the Ceres 2 Degree framework for the electric sector, and a number of groups are also considering the broader 80%.
- Regarding ELG, what is the best guess on when the process will begin after the rule is finalized?
  - The process has already begun with pilot studies for other technologies that would reduce costs and meet the standards. However, the process will begin in earnest as soon as the revised draft rule is received.
- Was there an increase from the last IRP?
  - Slide 57 reflects current understanding of the costs. NIPSCO will go back and review the previous costs.
- Has NIPSCO considered algae treatment for wastewater in Michigan City for example?
  - When NIPSCO has completed its CCR compliance, both the flue gas desulfurization (“FGD”) and CCR wastewater streams will be eliminated, and NIPSCO will be at zero discharge. However, it has been considered for carbon, but it is still an emerging technology.
- The Paris Climate Accord is inadequate and the less we do now, the more urgent it becomes. Have you considered that burning fossil fuels increases client negligence?
  - Must balance with reliability and costs to customers. We are working to get replacement generation online and are being transparent about our targets and are on a trajectory to outpace the Paris Accord.
- We strongly reject the move to natural gas.
- With high levels in ground water, what is being done so it is not migrating?
  - NIPSCO is in compliance with CCR and deploying capital that will allow closure of all the ponds. In addition, NIPSCO has deployed a network to monitor and sample wells. At this point, there is no indication that there are or will be off-site groundwater impacts. However, NIPSCO will deploy more wells, close coal ash ponds and consider groundwater remediation based on sampling data that is publicly available.
- Regarding slides 51 and 52: On slide 51, the percentage reduction is based on a baseline of 2005. On slide 52, looking at that alternative, it would be phased in.
  - It is difficult to look that far in the future. The graph on slide 52 assumes all coal would be replaced.
- Regarding the air quality, although the slide indicates Northwest Indiana met all EPA standards, is that an aggregate of all of the various counties in the NIPSCO footprint? If American Lung Association data is considered the results are different.

  - These are monitors deployed by the State of Indiana, which is compared to the EPA National Ambient Air Standards. All of the monitors meet the EPA standards, it is not aggregate data.
- How does NIPSCO feel about exceeding the EPA standards?
  - For clarity "achieve" means that the standards are not being exceeded. Ten years ago, regional air quality measures did not achieve the standards. Today all the measures achieve the air quality standards.
- Perhaps NIPSCO could look at a different model that looks at EPA as well as other organizations such as the American Lung Association so there isn't such a big change.
  - It is highly likely that the American Lung Association is an active participant in determining the EPA standards.
- Investing in gas and fossil fuels: why is NIPSCO continuing to invest in fossil fuels? Would it not be better to go to other sources of energy?
  - That is part of the process in the IRP as well as the RFP.
- Is there a consideration of running a model without natural gas? A model with all renewable energy and recouping losses later?
  - Yes, there are many factors being considered.
- It is clear that it is not just a carbon issue, so would like to sit down and discuss how the modeling could be adjusted. For example, the ELG requirements will likely be revisited. There is also potential for water contamination due to CCR ponds, which could lead to another cost.
  - NIPSCO is happy to meet to talk about issues and how to address environmental modeling and other items with the IRP. On the technical side, for ELG, NIPSCO is showing Zero Liquid Discharge ("ZLD") because it is clear EPA is going to revisit the rule and will likely get more stringent. Utilizing ZLD eliminates those risks. As stated before, we continue to close ponds and assess groundwater.
- Regarding the air quality standards, how close to your plants are the three monitors located? The Indiana Department of Environmental Management is not as protective of the environment as it could be. Does NIPSCO do its own monitoring in neighborhoods around the plants?
  - Some of the monitors are actually inside the plants. NIPSCO has turned its monitors over to the State for an unbiased assessment of air quality and the network is specifically designed to be representative of the air quality near NIPSCO's plants and other industrial facilities in Northwest Indiana.

2018 Scorecard
Daniel Douglas, VP, Corporate Strategy and Development

Mr. Douglas reviewed the proposed scorecard and noted that it will inform the NIPSCO Preferred Plan. He reviewed the various criteria from the 2016 scorecard and noted how it has been expanded for the 2018 version. He then reviewed each of the criteria and provided an overview of the descriptions and metrics.

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

- Was there explicit weighting of the last IRP?
    - No, and NIPSCO does not intend to in this IRP, either. The Company does not want it to be formulaic.
- Can you talk more about the cost certainty and cost risk area?
    - This gets back to the stochastic work. Back on slide 15, the right side shows how NIPSCO tries to illustrate the cost certainty and cost risk metrics. On the orange bar, Point B is the median, which is the expected cost to customers. The 75th percentile is the cost certainty and the 95th percentile is the cost risk.
- What is NIPSCO using as the metric?
    - The cost certainty is the 75th percentile. The cost risk metric is the 95th percentile. The result is a revenue requirement which allows comparing of the retirement combinations at the 95th percentile for each one.
- Has NIPSCO considered the correlation between those measures and the overall scoring?
    - They will be somewhat correlated as NIPSCO goes through the process if cost certainty is viewed as the more likely high end. However, NIPSCO will take the correlation into account as the criteria are scored.
- How will the results be presented? Color coded?
    - The intention is to be quantitative as the process moves forward. NIPSCO will clearly outline the scoring metrics and the underlying metric and scoring will be available.
- How is NIPSCO going to put them all together? How will the information be shown on the scorecard? Only by color?
    - The plan is to not show a final combined score for each one of the combinations, but will share the rationale for selecting Preferred Plan.
- Regarding environmental, is NIPSCO open to other measurements as well?
    - Yes.

Retirement Analysis
Fred Gomos, Manager, Corporate Strategy and Pat Augustine, CRA

Mr. Gomos provided an overview of how the retirement analysis is being conducted, including how the framework evaluates the all the cost to keep an existing NIPSCO nit versus the cost of retirement and replacement with an alternative. He then discussed how NIPSCO is utilizing the Midcontinent Independent System Operator (“MISO”) Cost of New Entry (“CONE”) plus energy is used in the analysis as a proxy for a viable alternative. He then reviewed the various retirement combinations that were constructed and the capital costs by retirement combination. Mr. Augustine then reviewed the results of the deterministic cost to customers; stochastic costs certainty, risk, and volatility; stochastic cost volatility; and stochastic cost risk.

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

- Although I understand using MISCO CONE, it might make sense to look at as a range. NIPSCO is using the highest end, which raises the cost of new generation.
  - o Using CONE is a good proxy because it is the worst possible case. At this point, NIPSCO does not know if it is going into the market, building or buying something. Since combined cycle gas turbine, wind and solar costs are likely close to or lower than MISO's CONE estimate on an all-in basis, CONE provides a good proxy and is conservative for analysis.
- Slide 65 seems to break out the decision into a separate retirement methodology. It is unclear why NIPSCO needs this as opposed to running the model with and without the units. It appears that NIPSCO is missing how each unit is dispatched.
  - o In 2016, NIPSCO did not have the modelling tools to do it through the model so we ran them as separate analyses. While we have the modelling tools today, the Company is still maintaining the same format for the 2018 update. If the issues are considered together, the focus on retirements is lost. NIPSCO needs a process to look at retirements decisions separately from the replacement decision.
- Slide 65, how does NIPSCO propose to accommodate if the 2023 date for ELG is not relevant? These numbers are based on what rules are today, and those rules may change. Would it be better to consider when the rule changes?
  - o NIPSCO does not know how the rule might be updated, it is necessary to use the current versions of the rules as we understand them today
- Slide 66, is this only coal, not the entire system?
  - o Correct, these costs are only for the coal fleet.
- Slide 67, is that the entire system?
  - o Yes, this is a different presentation than slide 66. Slide 67 summarizes the full cost of service.
- Is it possible that Scenario 1a would look different if carbon costs were not included?
  - o Yes, this slide only considers the Base Case assumptions.
- Slide 69, the lower left corner is where NIPSCO wants to be, correct?
  - o Yes.
- Based on this, other factors are overwhelming the costs and risks. Is NIPSCO not weighting?
  - o There are no conclusions being made at this point. NIPSCO could select portfolios based on a combination of criteria. The ultimate goal is to serve the customers in a safe, reliable and cost effective way. Stochastics help in providing new ways to do that and the scorecard will assist in showing the tradeoffs in the decision that NIPSCO is trying to make.
- It will be key to understand the scorecard.

- Encouraged to see Portfolio 5 as far to the lower left as any other option. If NIPSCO had included the risks posed by burning fossil fuels, such as a destabilized climate, would it move Portfolio 5 even more to the lower left corner?
    - In this part of the analysis, NIPSCO is quantifying the cost to serve load within the MISO market, along with an associated risk metric that is quantified through analysis of the stochastic variables discussed this morning. Other environmental considerations might be included in other elements of the scorecard.

Replacement Analysis
Dan Douglas, VP, Corporate Strategy and Development and Pat Augustine, CRA

Mr. Douglas discussed how NIPSCO plans for the future and noted that retiring Schahfer Units 17/18 will create a need for new resources. He stated that as replacements are considered, replacement resource combinations will take into account ownership, duration and diversity and he reviewed the considerations as part of this process. Mr. Augustine then provided an overview of the results of the resource combinations, including a discussion of the replacement resource framework. The results presented included the deterministic cost to customer; stochastic cost certainty, risk, and volatility; stochastic cost volatility; and stochastic cost risk.

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

- A short-term power purchase agreement ("PPA") versus company owned asset is missing from the scorecard How does NIPSCO view a PPA vs a Company owned asset NIPSCO is about the customer first and the decision will be made on that basis. The goal is to do what is best for customers, even if it means forgoing an opportunity for asset ownership. When NIPSCO calculates carbon emissions, are they only direct from power generation, or do they include transportation, mining and waste?
    - The calculation only includes direct emissions.
- What are renewables for NIPSCO? Does the Company have plans to use anything other than solar and wind?
    - NIPSCO currently has renewables that are not solar and wind including biomass projects. Other renewable resources will be evaluated if offered in the RFP.
- Slide 75 is unclear how it will be used. On diversity, it is not clear which of those is cost diverse. Is the middle or right column more diverse? Is "diversity" a code word for carbon emissions? The farther to the right, the lower the emissions are.
    - Thank you for the suggestion to change the title. Diversity is related to portfolio diversity, specifically around carbon emission intensity.
- Slide 75, if trying to map out, how does a PPA including coal fit into the boundary?

  - It could fit in the top left hand side, which is the reason to go through the RFP process. Although NIPSCO is unaware of any coal PPAs, if they exist, it will become apparent through the RFP process.
- Slide 80, was this done in spreadsheet or the model?
  - It was done through a full run of the Aurora-PERFORM stochastic modeling
- If NIPSCO ran the model with industry estimates, will the Company rerun the existing model with RFP results?
  - Yes. This current process was intended to show some of the potential tradeoffs. There will be a few phases of the analysis, with an update that incorporates RFP results.

Request for Proposals ("RFP") for Capacity
Paul Kelly, Director, Federal Regulatory Policy and Bob Lee, CRA

Mr. Kelly reviewed the stakeholders who had provided feedback on the RFP, though a letter to NIPSCO, comments on the Interim Design Study or by commenting on the draft RFP document after completing a non-disclosure agreement ("NDA"). He provided a summary of the feedback received and noted what had been incorporated and what had not been incorporated. Mr. Lee then reviewed the final evaluation criteria for non-demand response resources and demand response resources and reviewed the key design elements of the RFP. He finished by presenting the revised timeline for the RFP.

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

- Slide 84, the second bullet, it is contradictory to slide 83. Entities have been able to access through NDAs.
  - That was the RFP document prior to issuing. The results will be shared in the aggregate to parties. With certain limitations, parties who have executed an NDA will be able to view the bids.
- Please clarify if in the RFP NIPSCO is considering each technology in and of itself? NIPSCO is not comparing between technologies.
  - That is correct. The information will be provided to the IRP team, which will conduct the modeling as discussed and come back with the optimum portfolio.
- NIPSCO should consider expanding cost to customer to include cost to customer health, etc.
- Will NIPSCO be bidding?
  - No.
- Is NIPSCO eliminating a self-build option?
  - It does not mean that.
- Please clarify the results of the bidding. NIPSCO will not release the individual bids, but distribution and information on the costs without specific bidder information will be made available?
  - Correct. NIPSCO will release the average price.

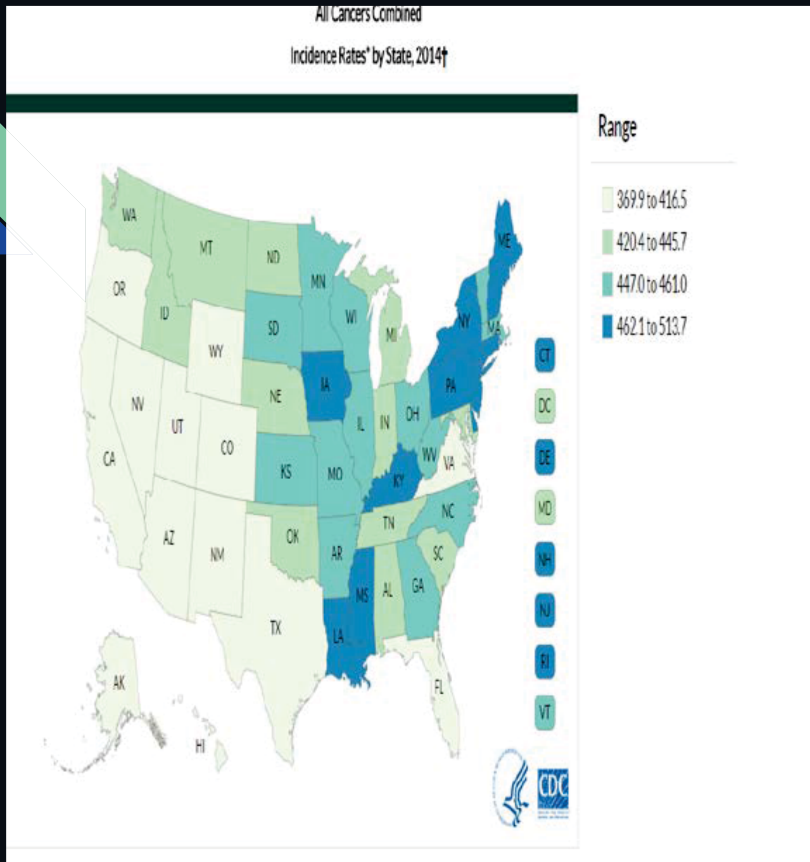
Stakeholder Presentations

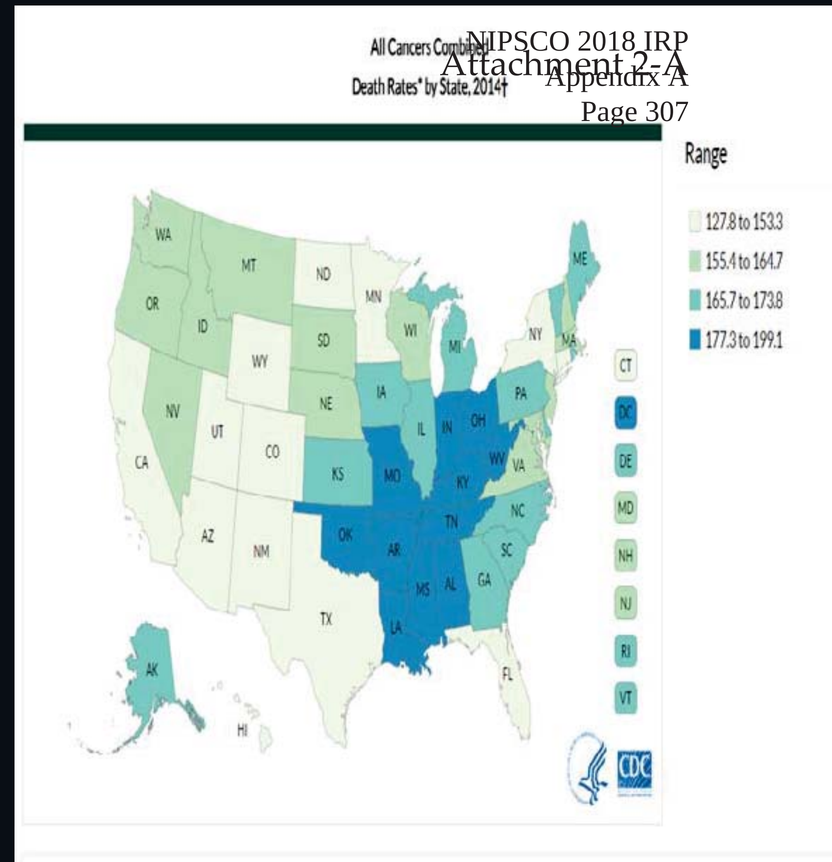
Dany Brooks; David Chiesa of S&C Electric Company; and Scott Houldieson (United Auto Workers), Barry Halgrimson, and Sam Henderson (Hoosier Environmental Council) provided stakeholder presentations.

Ms. Becker closed the meeting by thanking the attendees for their attendance and active participation.

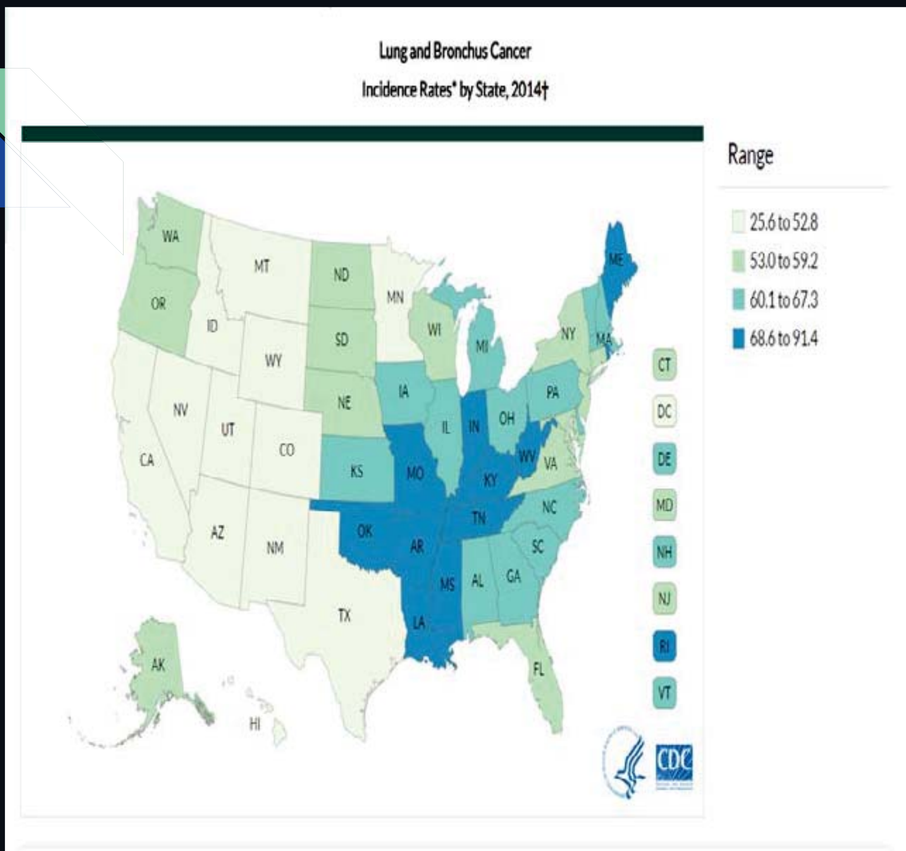
The Health Ramifications of Coal in Indiana

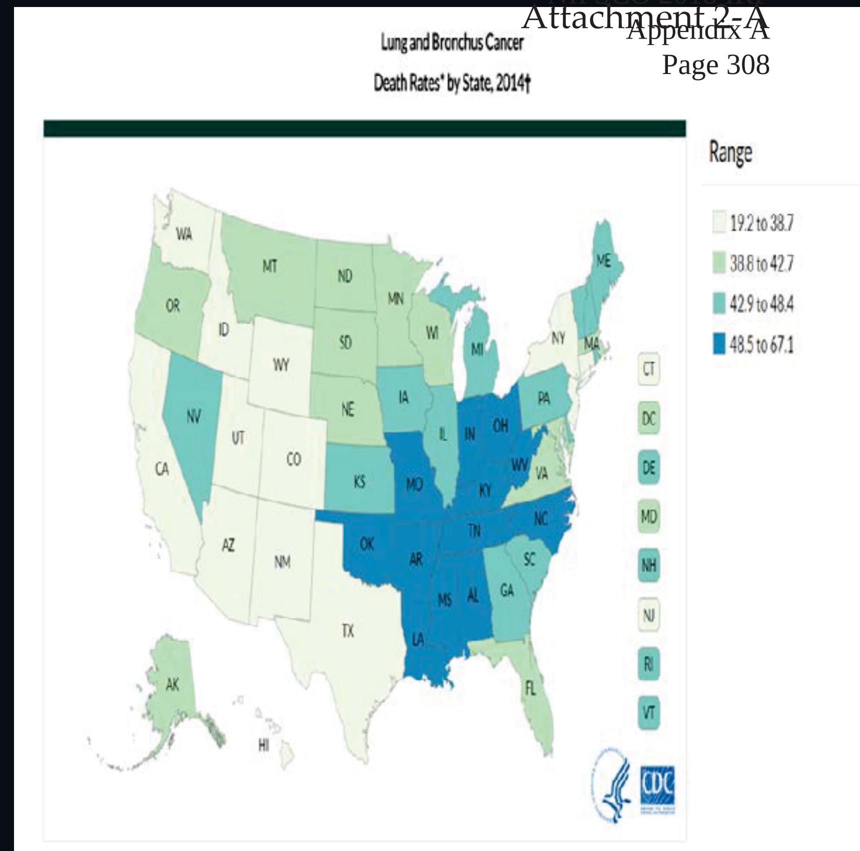
By Dany Brooks
With Supervision of PhD Candidate Jamie Hough



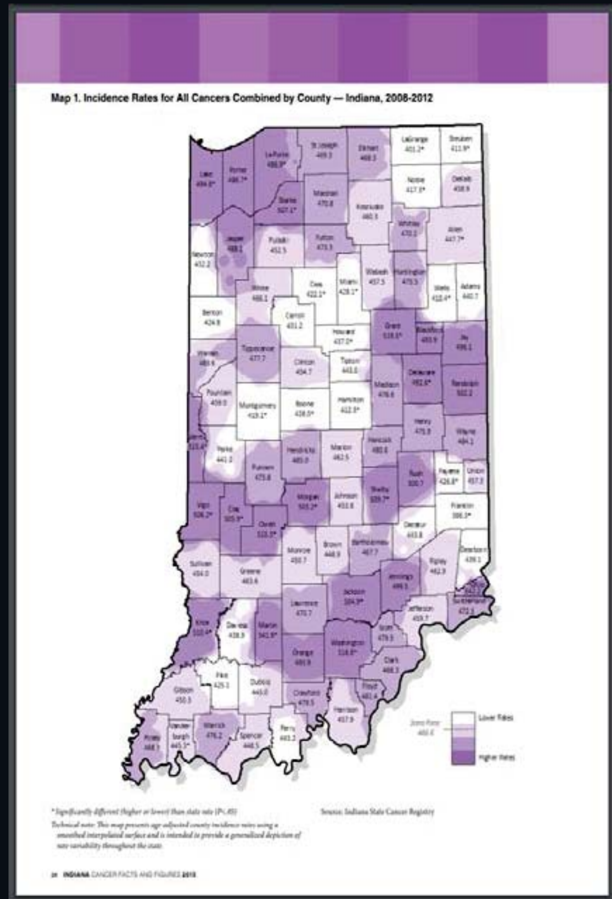


Combined Cancers Rate Maps from CDC.
https://www.cdc.gov/cancer/dcpc/data/state.htm

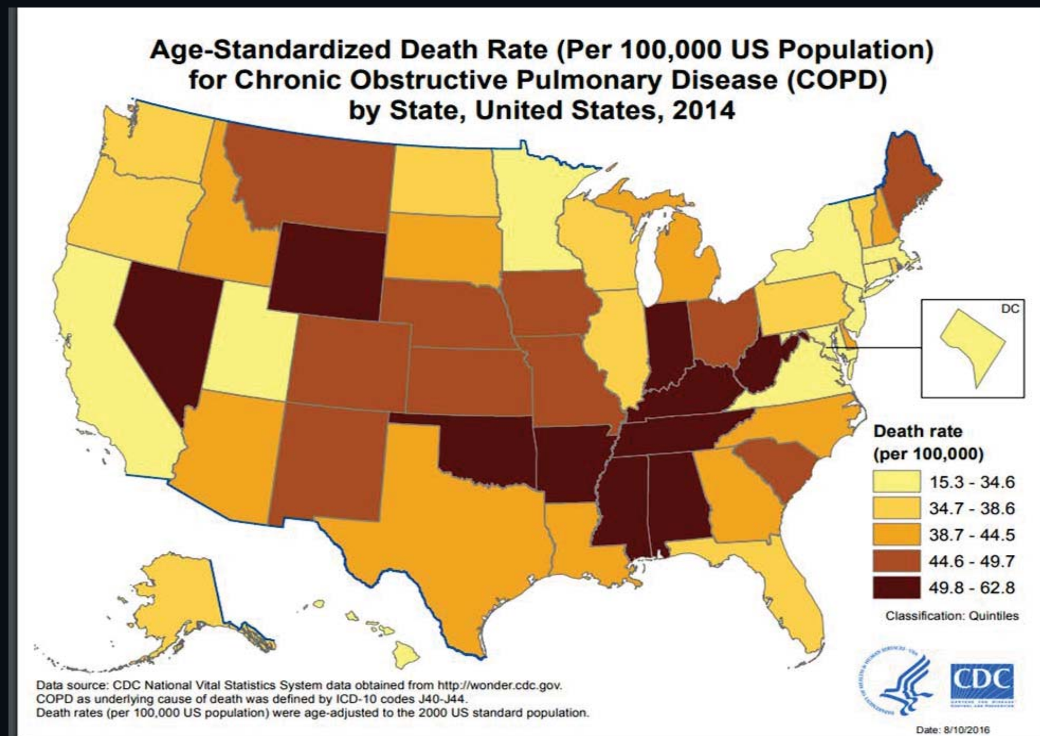




Lung Cancer Rate Maps from CDC. https://www.cdc.gov/cancer/lung/statistics/state.htm



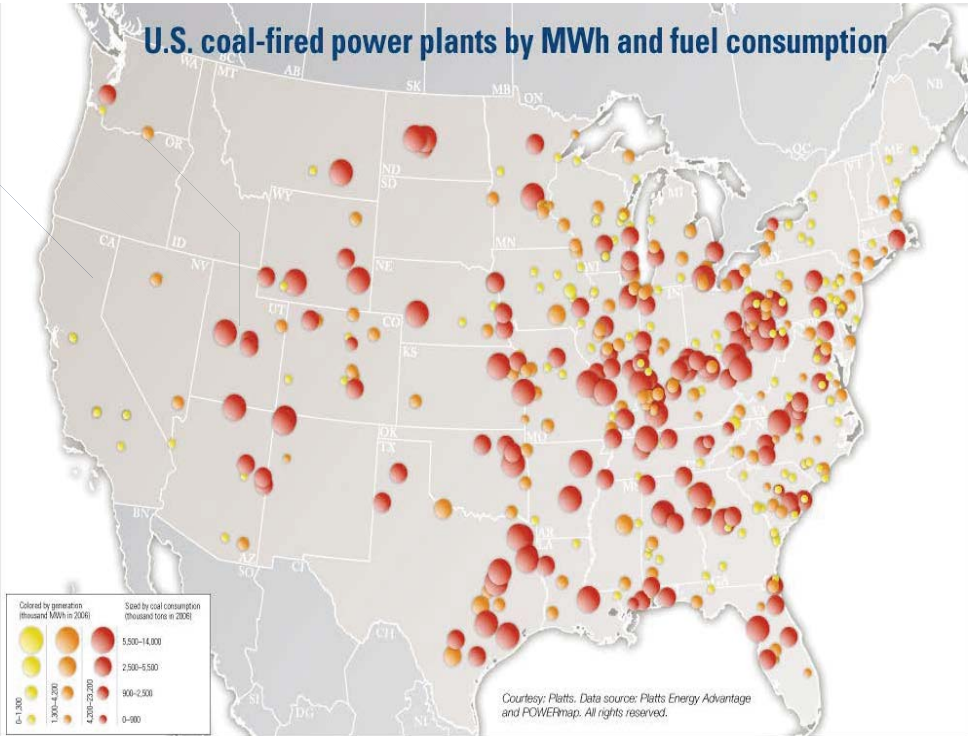
All Cancers Combined by County Map by IN Gov.

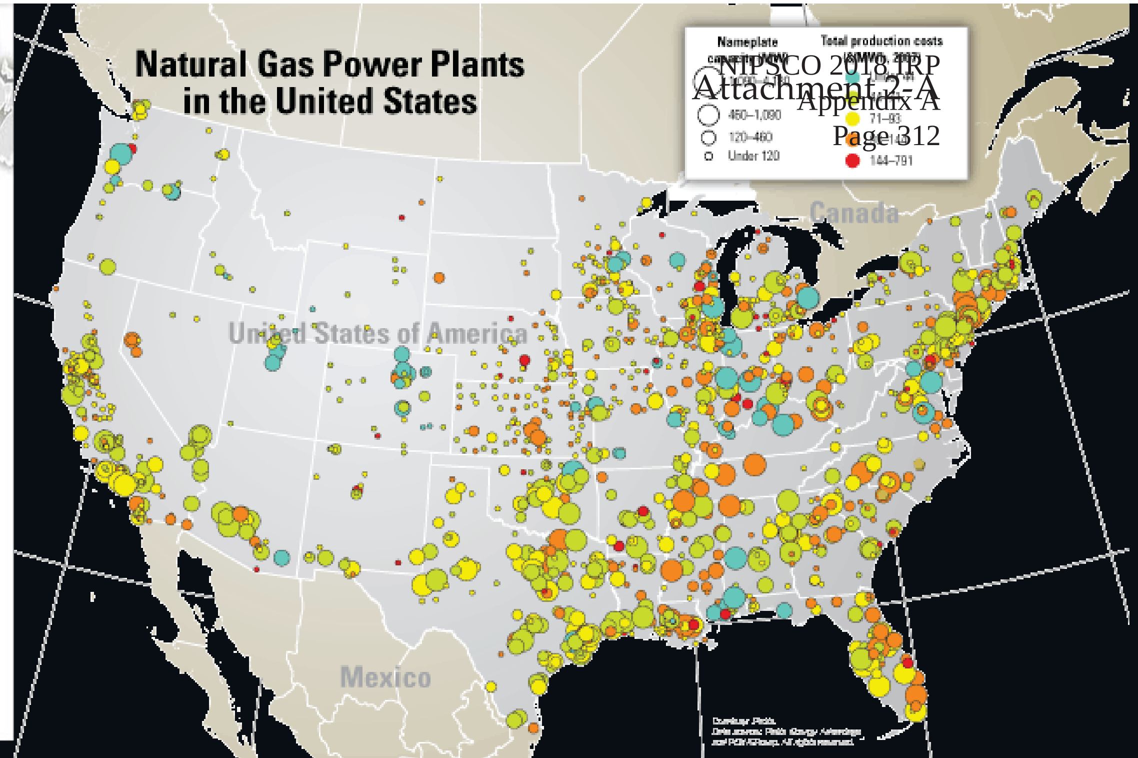


COPD Death Rate Map from CDC.
https://www.cdc.gov/copd/data.html

Confounding Health Data

- With this health data, there are many questions which must be answered
- Health problems never can be simplified to a single factors ***yet the weight of any of these contributing factors cannot be dismissed on the premise that there are other serious causes.***
- Proximity to coal fired power plants is one of the greatest of these factors



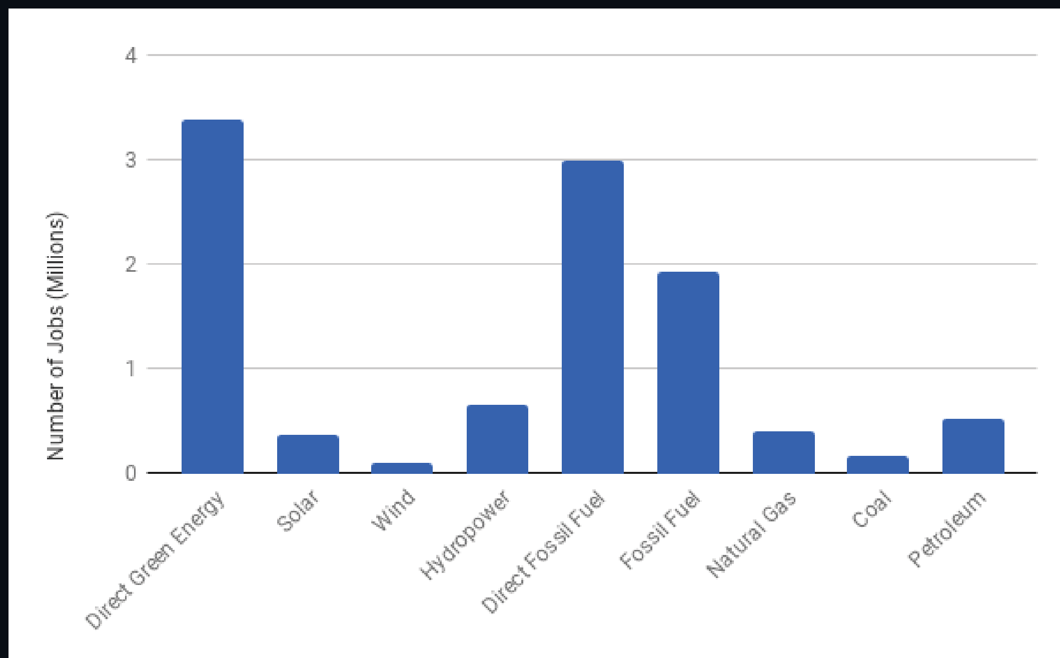


Natural Gas and Coal Power Plant Location Map by Power Magazine.

Without fossil fuels, Where do We go?

- Green energy acts restorative and regenerative for economy, health and the climate, it has become the perfect solution
- T.H. Chan School of Public Health at Harvard estimates through various studies monetary benefits of **$33 billion** dollars surpassing initial costs of **$17 billion.**
- Estimates in the same study sub-benefits of **$29 billion** in health care effects and **$21 billion** in climate benefits.
- Estimates also with investments into wind turbines with a capacity of **3000 MW** benefits of **$690 million**

A Green Future



Data from Environmental and energy Study Institute. http://www.eesi.org/papers/view/fact-sheet-jobs-in-renewable-energy-and-energy-efficiency-2017

Green Myths

- Duke energy estimates construction cost of 600 MW coal power plant at $2 Billion therefore has an estimated $3.3 million per MW
- Green energy provides cheap alternatives
  - Solar estimated $1 million per MW
  - Wind estimated $1-$2 million per MW
  - Hydro estimated $3 million per MW

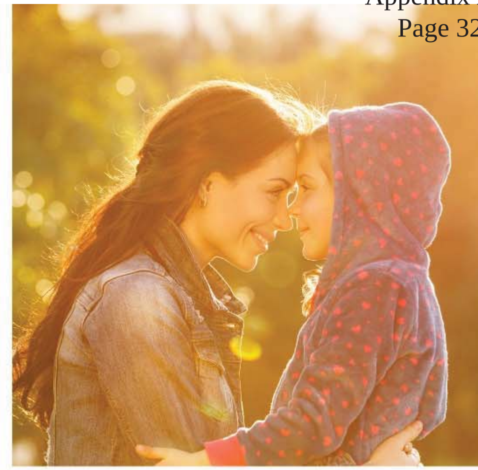
Invest in Our Future

NIPSCO Public Advisory Meeting 2 Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Lauren	Aguilar	OUCC
Jake	Allen	IPL
Linda	Anguiano	Progressive Democrats of America - Calumet Region
Russ	Atkins	NIPSCO
Pat	Augustine	Charles River Associates
Alison	Becker	NIPSCO
Anne	Becker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Michael	Blank	Peabody
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Dany	Brooks	Purdue University
Wade	Cameron	Wade Cameron
Andrew	Campbell	NIPSCO
Becky	Campbell	First Solar
Kelly	Carmichael	NiSource
Michael	Cella	Toyota Tsusho
Gilles	Charriere	Sierra Club/ NIPSCO customer
David	Chiesa	S&C Electric Company
Thomas	Cmar	Earthjustice
Jeffrey	Corder	St. Joseph Phase II, LLC
Elena	DeLaunay	Rockland Capital, LLC
Dan	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Claudia	Earls	NiSource
Amy	Efland	NiSource/NIPSCO
Steve	Francis	Sierra Club - Hoosier Chapter
Julia	Friedman	Oracle
Fred	Gomos	NiSource
Isabelle	Gordon	Office of Utility Consumer Counselor
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Corey	Hagelberg	Beyond Coal
Barry	Halgrimson	Retired
Rina	Harris	Vectren
Samuel	Henderson	Hoosier Environmental Council
Stephen	Holcomb	NIPSCO
Allison	Holly	GE
Scott	Houldieson	UAW
Shelby	Houston	IPL/AES
Robert	Kaineg	Charles River Associates
Pauline	Katsouros	NIPSCO
Sam	Kliewer	Cypress Creek Renewables
Tim	Lasocki	Orion Renewable Energy Group LLC

NIPSCO Public Advisory Meeting 2 Registered Participants		
First Name:	Last Name:	Company:
Jonathan	Mack	NIPSCO
Cyril	Martinand	ArcelorMittal
Debi	McCall	NIPSCO
Karen	McCoy	Nipsco
Jim	McMahon	CRA
Emily	Medine	EVA
Nick	Meyer	NIPSCO
Kevin	Moore	MIDWEST WIND & SOLAR LLC
Adam	Newcomer	NIPSCO
Kerwin	Olson	Citizens Action Coalition of IN
Elizabeth	Palacio-Vargas	Ms.
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Rom	Poplawski	U.S. Global Energy LLC
Dennis	Rackers	Energy & Environmental Prosperity Works!
Dennis	Rackers	NIPSCO
Thom	Rainwater	Development Partners Group
David	Repp	JET Inc
Matt	Rice	Vectren
Edward	Rutter	Indiana Office of Consumer Counselor
Carter	Scott	Ranger Power LLC
Cliff	Scott	NIPSCO
Brent	Selvidge	IPL
Frank	Shambo	NIPSCO
Violet	Sistovaris	NIPSCO
Matt	Smith	Carmeuse Lime and Stone
Anna	Sommer	Sommer Energy, LLC
Dick	Spellman	GDS Associates, Inc.
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource
Liz	Stanton	Applied Economics Clinic
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Alice	Tharenos	peabody
Michael	Therrian	midwest wind and solar
Will	Vance	Indianapolis Power & Light
Victoria	Vrab	NIPSCO
Jennifer	Washburn	CAC
Ashley	Williams	Sierra Club
John	Williams	Arcelor Mittal
Victoria	Wittig	Save the Dunes
David	Woronecki-Ellis	Sierra Club Dunelands Group
Jen	Woronecki-Ellis	Sierra Club Dunelands Group
Fang	Wu	SUFG

Appendix A

Exhibit 3



NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting Three

July 24, 2018

Welcome and Introductions

Process for Today's Webinar

- In order to best facilitate today's discussion, we are asking that you use the "chat" feature on the webinar to ask questions.
- Please type your question at any point and it will be read to the audience by the facilitator.
- When entering your question, please include your name and organization you are representing (if applicable).
- If time permits, we will have an open discussion after the material has been presented.
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received.
- We look forward to your thoughts and questions!

Agenda

Time	Topic
12:30 – 12:45	Welcome, Introductions, and Safety Moment
12:45 – 1:00	Update on the Integrated Resource Plan (“IRP”) Process
1:00 – 1:30	All-Source Request for Proposals (“RFP”) Results Overview
1:30 – 1:45	Incorporating the RFP Results
1:45 – 2:25	Stakeholder Presentations / Contingency
2:25 – 2:30	Next Meeting / Wrap Up

Safety Moment:

- **Slips, trips, and falls are the most common form of injury to office workers, and is also a common injury among non-office workers.**
- **Across all of private industry, there were 229,240 injuries involving days away from work in 2016 due to slips, trips, and falls.**
- **Several practices can help reduce or avoid slips, trips, and falls:**
  - Stay Clutter Free: Look for boxes or other impediments in walkways.
  - Step on Up: Standing on office chairs is a common source of falls. Be especially careful of office chairs with casters or rollers. Use a specifically designed step-stool or ladder instead.
  - Maintain a Clear Line of Vision: workers can run into each other around blind corners.
  - Slippery Flooring: Skid resistant flooring or carpeting can help prevent slips, trips, and falls. Be especially careful of liquid spills or runoff from rain and snow on flooring.

NIPSCO's Planning and the Public Advisory Process

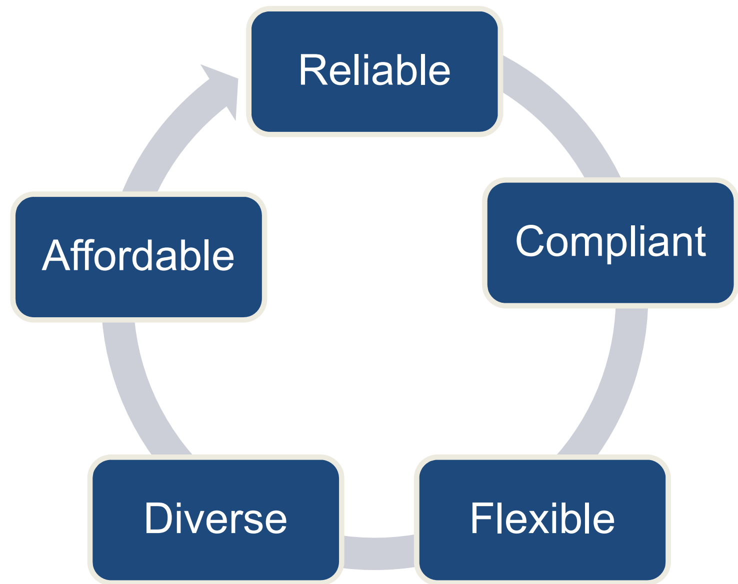
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan (IRP) – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires Careful Planning and Consideration for:

- All NIPSCO's stakeholders
- Environmental regulations
- Changes in the local economy (property tax, supplier spend, employee base)

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3* (July 24th)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	-Why has NIPSCO decided to file an IRP update in 2018? -What has changed from the 2016 IRP? -What are the key assumptions driving the 2018 IRP update? -How is the 2018 IRP process different from 2016?	-What is NIPSCO existing generation portfolio and what are the future supply needs? -Are there any new developments on retirements? -What are the key environmental considerations for the IRP? -How are DSM resources considered in the IRP?	-What are the preliminary results from the all source RFP Solicitation?	-What are the preliminary findings from the modeling?	-What is NIPSCO's preferred plan? -What is the short term action plan?
Meeting Goals	-Communicate and explain the rationale and decision to file in 2018 -Articulate the key assumptions that will be used in the IRP -Explain the major changes from the 2016 IRP -Communicate the 2018 process, timing and input sought from stakeholders	-Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM -Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap -Key environmental issues in the IRP	-Communicate the preliminary results of the RFP and next steps	-Stakeholder feedback and shared understanding of the modeling and preliminary results -Review stakeholder modeling and analysis requests	-Communicate NIPSCO's preferred resource plan and short term action plan -Obtain feedback from stakeholders on preferred plan

*Webinar

Stakeholder Interactions

- Since the May 11 Public Advisory meeting, NIPSCO has met with stakeholder groups

Stakeholder	Subject Area/Discussion Topic
Sierra Club	IRP Modelling and Scenarios
OUCC	All-Source RFP, IRP Modelling and Scenarios, Load Forecasting
CAC	IRP Modelling and Demand Side Management (DSM)
IURC	All-Source RFP and IRP Modelling

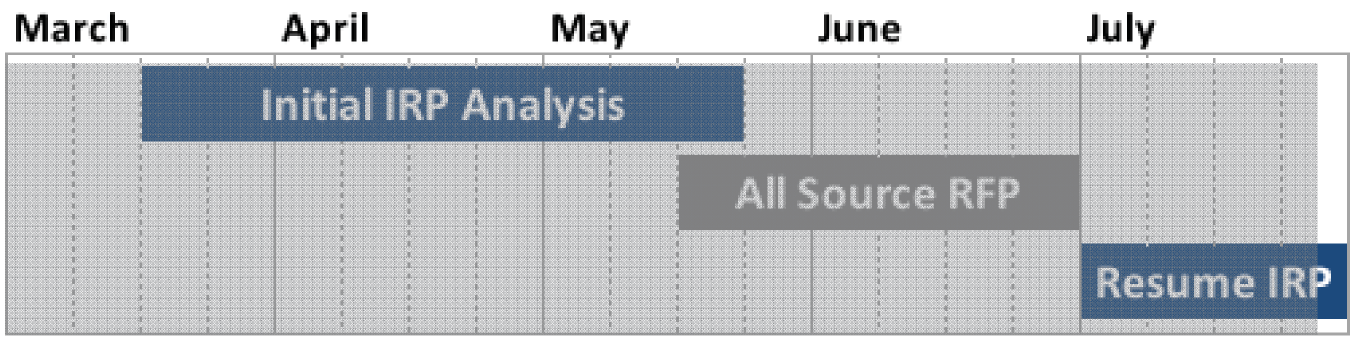
All-Source RFP Results Summary

Paul Kelly
Director, Federal Regulatory Policy

Andy Campbell
Director, Regulatory Support and Planning

Bob Lee
Charles River Associates

Timeline for the RFP



Date	Event
March 23rd	Overview RFP design with stakeholders
April 6th	RFP Design Summary document shared with stakeholders to request feedback
April 20th	Stakeholder feedback on Design Summary due back to NIPSCO
May 14th	RFP initiated
May 28th	Notice of Intent and Pre-qualifications due from potential bidders
June 29th	RFP closes
July 24th	Summary of RFP bids presented at Public Advisory Meeting webinar; IRP resumes analysis incorporating results of RFP

Key Design Elements of the All-Source RFP

- **Technology - All solutions regardless of technology**
- **Size**
  - Minimum total need of 600 megawatts ("MW") for the portfolio but without a cap
  - Allows smaller resources to offer their solution as a piece of the total need
  - Also encourages larger resources to offer their solution for consideration
- **Ownership Arrangements**
  - Seeking bids for asset purchases (new or existing) and purchase power agreements
  - Resource must qualify as Midcontinent Independent System Operator ("MISO") internal generation (not pseudo-tied) or load (demand response or "DR")
- **Duration**
  - Requesting delivery beginning June 1, 2023 but will evaluate deliveries before 2023
  - Minimum contractual term and/or estimated useful life of 5 years (except for DR, which is 1 year)
- **Deliverability**
  - Must have firm transmission delivery to MISO Zone 6
  - Must meet N-1-1 reliability criteria or show cost estimate to achieve that quality
- **Participants & Pre-Qualification**
  - Marketed RFP to broad bidder audience and Bidder Conference
    - Platts Megawatt Daily, North American Energy Marketers Association (NAEMA), NIPSCO Press Release
  - Required credit-worthy counterparties to ensure ability to fulfill resource obligation

Participating Bidders – Thank you!

Inovateus SOLAR
Development Partners
APEX CLEAN ENERGY
edp renováveis
Big Rivers ELECTRIC CORPORATION
CYPRESS CREEK RENEWABLES
EDF renewables
enel Green Power
NEXTera ENERGY
ALLETE clean energy
e.on
CALPINE ENERGY SOLUTIONS
EmberClear An Innovative Project Development Company
ibV energy partners an ib vogt company
Invenergy
Hecate Energy
J. RANCK ELECTRIC, INC.
juwi
ROCKLAND CAPITAL
Origis Energy POWERING THE SOLAR REVOLUTION
res
RANGER POWER
bp
SOUTHERN CURRENT
JET JNG US
voltus LESS ENERGY · MORE CASH
ARES
PSG ENERGY GROUP
TENASKA
EDF ENERGY
GLIDEPATH Advanced Energy Solutions

Overview of Proposals Received

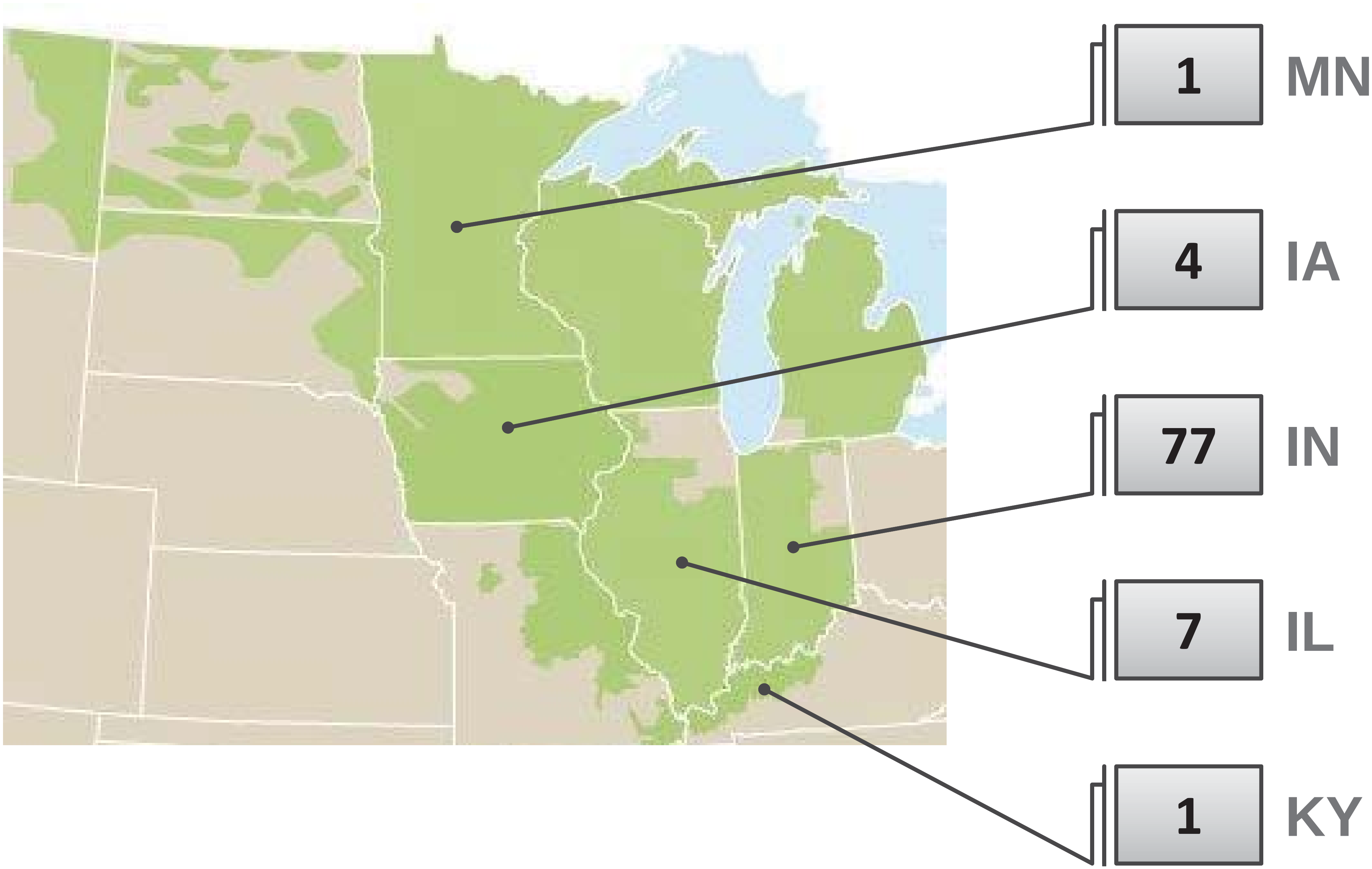
Count of Proposals

Technology	CCGT*	CT**	Other Fossil	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Response	Total
Asset Sale	4	-	-	1	-	1	-	-	-	6
PPA* **	8	-	3	6	-	26	7	8	1	59
Option	3	1	-	7	1	8	4	1	-	25
Total	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

- **The RFP generated a tremendous amount of bidder interest**
- **90 total proposals were received across a range of deal structures**
  - ❖ **59 individual projects across five states with ~13.3 gigawatts ("GW") (installed capacity or "ICAP") represented**
  - ❖ Many of the proposals offering variations on pricing structure and term length
  - ❖ Several instances of renewables paired with storage
  - ❖ Majority of the projects are in various stages of development

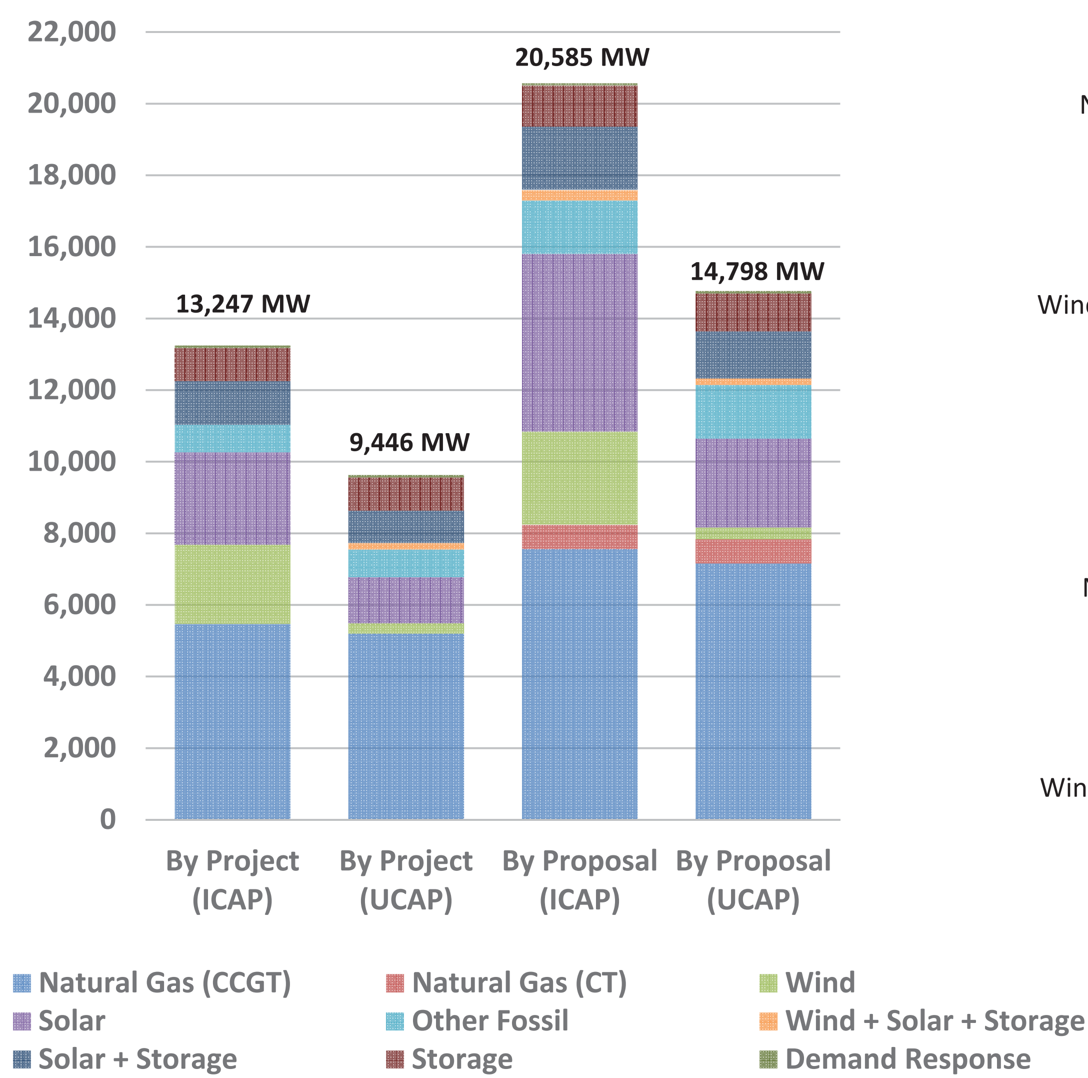
*Combined Cycle Gas Turbine **Combustion Turbine ***Purchase Power Agreement

Distribution of Proposals Received



Proposals Received by Technology (MW)

Note: Unforced capacity ("UCAP") MW are estimated using MISO class averages by technology



	ICAP by Project		ICAP by Proposal	
	(MW)	%	(MW)	%
Natural Gas (CCGT)	5,470	40%	7,561	37%
Natural Gas (CT)	-	0%	685	3%
Wind	2,209	16%	2,594	13%
Solar	2,580	19%	4,965	24%
Other Fossil / Coal	772	6%	1,494	7%
Wind + Solar + Storage	-	0%	300	1%
Solar + Storage	1,220	9%	1,760	9%
Storage	925	7%	1,155	6%
Demand Response	70	1%	70	0.3%

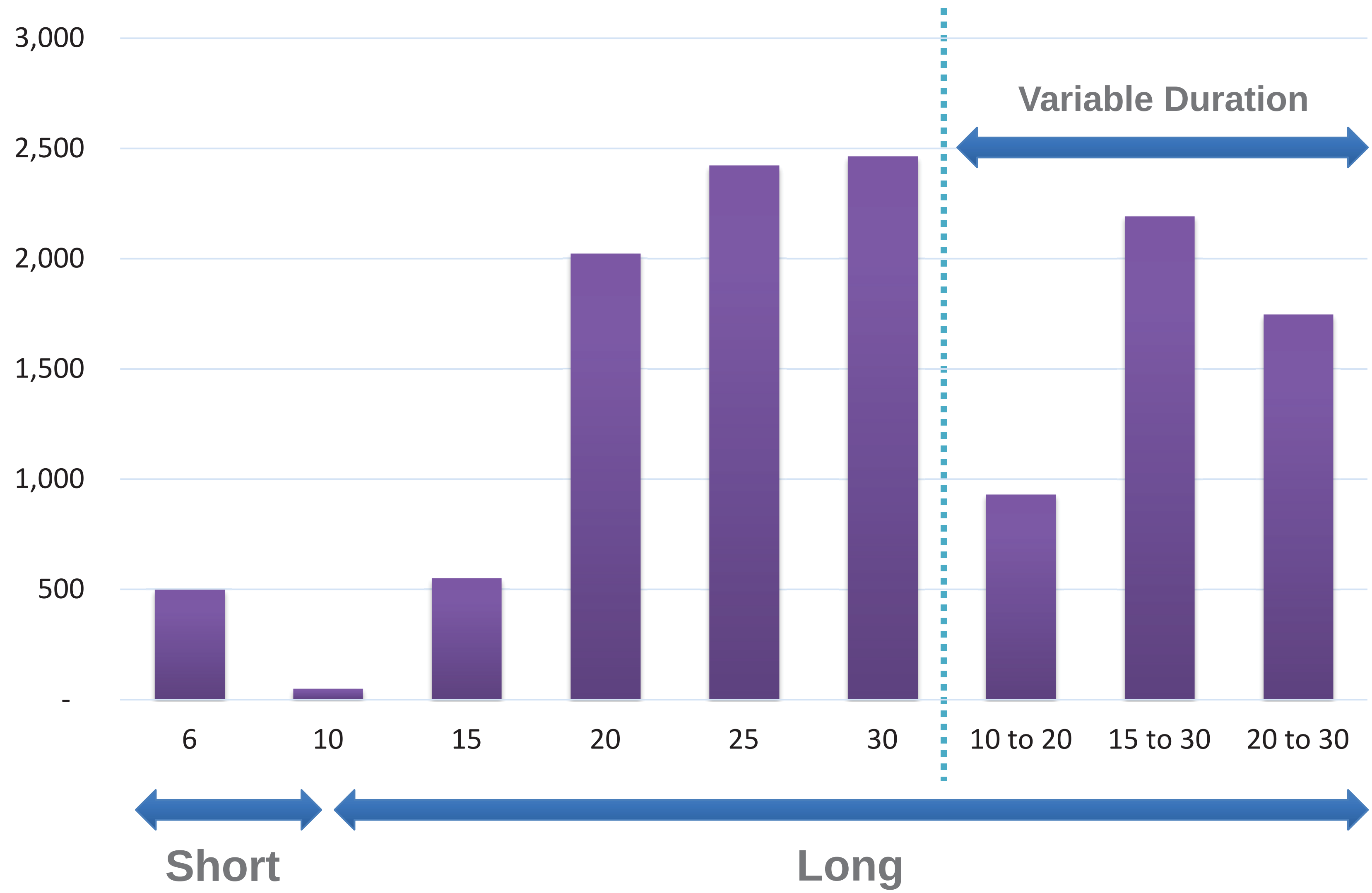
	UCAP by Project		UCAP by Proposal	
	(MW)	%	(MW)	%
Natural Gas (CCGT)	5,199	55%	7,157	48%
Natural Gas (CT)	-	0%	678	5%
Wind	287	3%	329	2%
Solar	1,291	14%	2,483	17%
Other Fossil / Coal	772	8%	1,494	10%
Wind + Solar + Storage	-	0%	110	1%
Solar + Storage	902	10%	1,322	9%
Storage	925	10%	1,155	8%
Demand Response	70	1%	70	0.5%

Proposals Received by Technology (MW) “UCAP”

Note: UCAP MW are estimated using MISO class averages by technology

Technology	CCGT	CT	Other Fossil	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Response	Total
Asset Sale	2,020	-	-	30	-	25	-	-	-	2,075
PPA	2,574	-	1,494	119	-	1,796	810	1,055	70	7,917
Option	2,563	678	-	180	110	662	513	100	-	4,806
Total	7,157	678	1,494	329	110	2,483	1,322	1,155	70	14,798
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

PPA Range of Durations (MW) “UCAP”



Overall Summary and Pricing Received

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

Preliminary – Subject to Due Diligence

RFP Evaluation Process

Determining a list of finalists by technology

- **Representative cost and performance characteristics by technology were developed based on RFP bids and provided to the IRP team for portfolio optimization modeling**
  - ❖ IRP to determine the preferred portfolio for execution
- **Bid evaluation considered both cost and non-cost factors (non-DR)**
  - ❖ Tier 1 factors – Asset Cost and Facility Reliability & Deliverability
  - ❖ Tier 2 factors – Development Risk
  - ❖ Tier 3 factors – Asset Specific Risk
- **List of finalists by technology for possible definitive agreement(s)**

Incorporating the RFP Results into the IRP

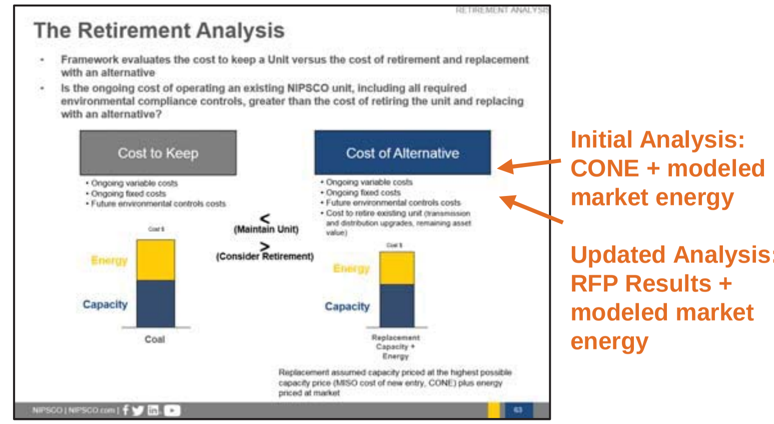
Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

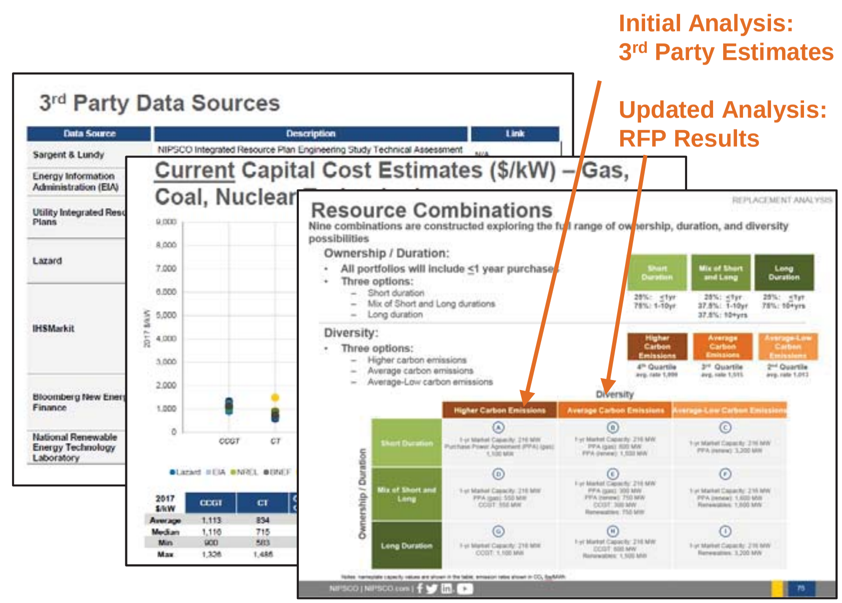
How Will The RFP Feed Into The IRP?

The results of the RFP will feed back into the IRP to inform both the retirement analysis and the replacement analysis

- **Retirement Analysis**
  - MISO Cost of New Entry ("CONE") plus market energy was used in the initial IRP analysis as a proxy for replacement costs
  - RFP results provide known and visible replacement costs and volumes
  - Representative project groups will be constructed from RFP results, assembled by technology and ownership, for use in the updated IRP analysis
  - Retirement analysis will be re-run using the representative RFP projects as selected by the optimization model



- **Replacement Analysis**
  - Initial IRP replacement costs used estimates from multiple third-party data sources; no visibility into actual replacement costs for projects available to NIPSCO
  - RFP results provide visibility into executable alternatives for NIPSCO
  - Replacement analysis will be run using somewhat simplified and anonymized RFP results



How Will The RFP Feed Into The IRP?

- The RFP responses provide key input data for supply-side portfolio costs
- A three-step process to update and run the IRP models will be carried out over the next two months

1 Develop Model Inputs

- Specify input assumptions by resource type "tranche" based on RFP results
- Develop specific resource options (supply and demand) in Aurora model format

2 Run Aurora Portfolio Optimization

- Evaluate least-cost portfolios for retirement and replacement analyses
  - Portfolios to fill each potential retirement capacity gap
  - Replacement portfolios for various levels of diversity and ownership (renewables vs. fossil, owned vs. PPA)

3 Run Full IRP Analysis

- Evaluate each portfolio against all scenarios *and* stochastics in Aurora and PERFORM models
- Complete scorecard with metrics across all objectives

Stakeholder Presentations/Comments

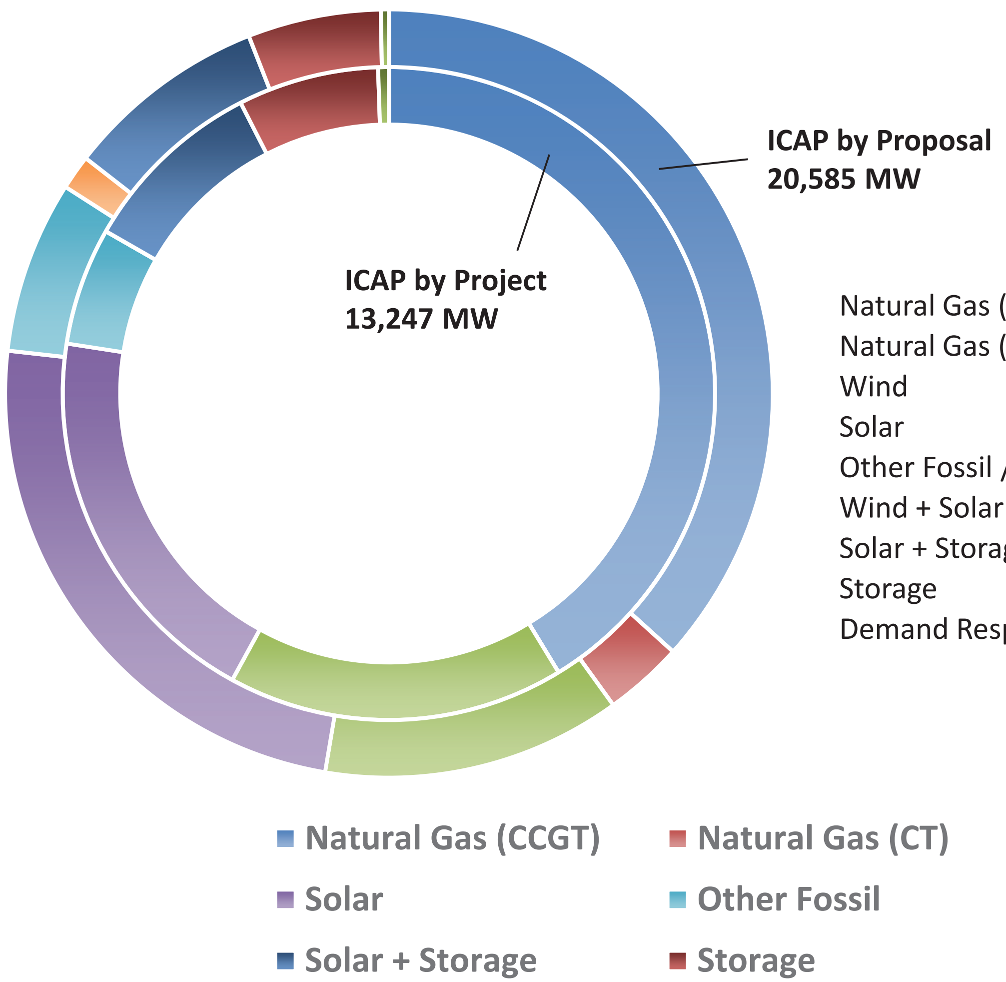
Next Steps / Wrap Up

Next Steps for RFP and IRP

RFP	IRP
• Continue to vet and evaluate the proposals received in accordance with the evaluation criteria • Determine a list of finalists by technology for possible definitive agreements once the preferred replacement path is determined	• Integrate results from the RFP into the IRP for the retirement and replacement analysis to be presented at the September 19th meeting • Setup and run stakeholder requested scenarios

Appendix

Proposals Received by Technology (MW) "ICAP"



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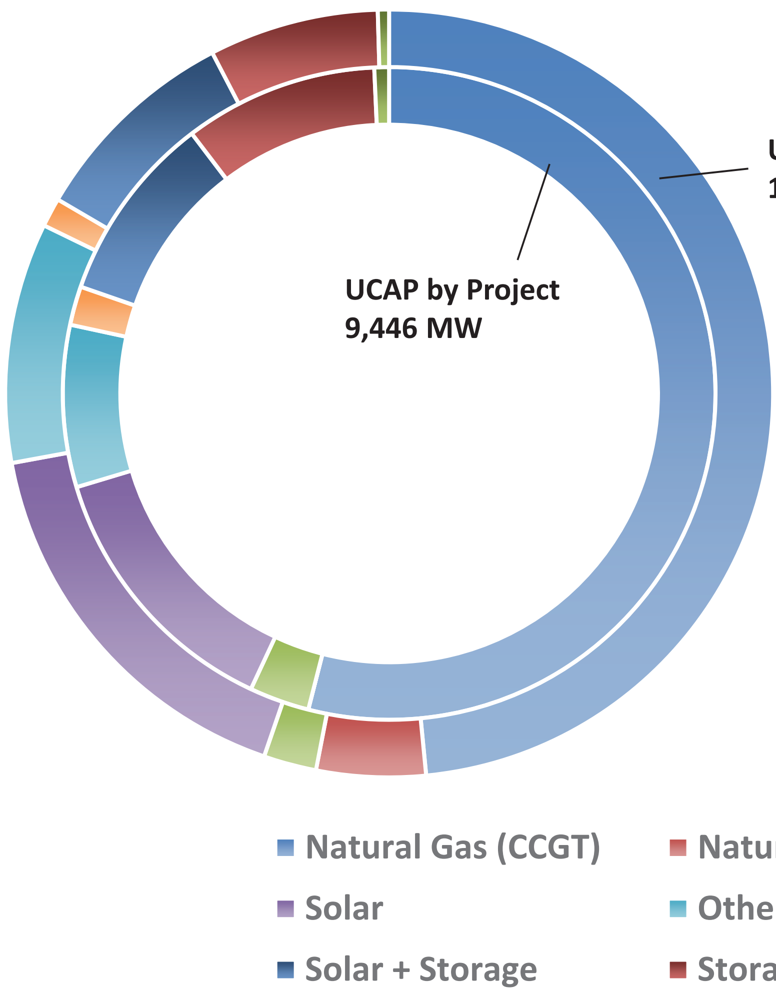

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Northern Indiana Public Service Company
2018 Integrated Resource Planning (“IRP”)
Public Advisory Meeting #3 (Webinar)
SUMMARY

July 24, 2018

Welcome and Introductions
Alison Becker, Manager, Regulatory Policy

Alison Becker opened the meeting by explaining the process for the webinar and introducing those who would be speaking. She then reviewed the agenda and did a safety moment.

NIPSCO’s Planning and the Public Advisory Process
Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained how NIPSCO plans for the future and provided an overview of the public advisory process, including reviewing the current point in the stakeholder engagement process. Mr. Douglas also provided an update on stakeholder interactions to date. He noted that the NAACP of Indiana had provided documents to NIPSCO regarding on-bill financing for energy efficiency and indicated NIPSCO would post the documents on the IRP website (nipsco.com/irp)

All-Source Request for Proposals (“RFP”) Results Summary
Paul Kelly, Director, Federal Regulatory Policy, Andy Campbell, Director, Regulatory Support and Planning and Bob Lee, Charles River Associates (“CRA”)

Paul Kelly provided an overview of where NIPSCO is in the RFP process, and Andy Campbell provided an overview of the key design elements of the RFP. He then presented a slide with the participating bidders. Bob Lee with CRA provided more in-depth information regarding the bids received. He provided an overview of the proposals received, which totaled 90 across a range of deal structures. He noted that most of the proposals were in Indiana, but there were bids received from throughout the Midwest. He then provided an overview of the proposals received by technology breaking them down by unforced capacity (“UCAP”) and installed capacity (“ICAP”). The greatest amount of megawatts was for combined cycle gas turbines (“CCGTs”), but there were proposals for a variety of renewables, including storage, as well as demand response. For purchase power agreements ("PPAs"), he provided an analysis of the range of durations by UCAP. Mr. Lee then provided an overall summary and the pricing received. He noted that for any technology where there was only one bid, for confidentiality reasons, the pricing was not provided. For asset sales, the range was a low of $959.61 for a CCGT to a high of $1,457.07 per kilowatt for those technologies where an average could be provided. For PPAs, the pricing units were different, so a range was unable to be provided. It is important to note that this information is all preliminary and subject to further due diligence.

The RFP evaluation process was reviewed, which will determine the list of finalist by technology. It was noted that the representative cost and performance characteristics by technology were developed based on the bids and provided to the IRP team for portfolio optimization and modeling. The IRP will determine the preferred portfolio for execution. The bid evaluation is made up of three tiers: a) asset cost and facility reliability and deliverability; b) development risk; and c) asset specific risk. The list of finalist by technology will be determined for possible definitive agreement(s).

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

- The slides indicate NIPSCO received 90 bids but only 31 participating bidders are listed on Slide 13. Can NIPSCO provide more information and clarification on now many bids each participant submitted?
  - This was addressed as the presentation progressed.
- Will all 90 bids summated on slide 14 be passed through to cost-effectiveness analysis (i.e., they've passed pre-screening qualifications, etc.)?
  - At this point, not every bid has been reviewed to determine whether it is a conforming bid. There has been no bid analysis for conformance or elimination at this point. Each bid is being reviewed, and qualifying bids will be incorporated in the IRP modeling process, which will use summarized bid data.
- What is "other fossil"?
  - It includes a few different bids. Some of the bids relate to the Schaefer units and another is a system power bid not tied to any other fossil bid.
- Will this presentation be sent to participants?
  - Yes, it is available at www.nipsco.com/irp
- Can you provide low-high range?
  - NIPSCO does not want to provide any individual bidder information at this point and using a range beyond what is on the slide may inadvertently disclose that information
  - NOTE: A graph with the range of the proposals in megawatts and by technology is being provided with the notes of this meeting for additional information.
- For energy storage, is there any variable operations and maintenance payment or just a capacity payment?

- For the most part it is a straight capacity payment, but there may be certain instances where there is a variable payment included in the proposal.
- Will the bidders get to see how their bids are characterized in the IRP modeling?
  - Most of the bids are straight forward, but CRA will work with any bidder where additional information is needed. It is important to note that the IRP is not necessarily modeling individual facilities but rather technologies
- Can you indicate any more information on the size of the projects bid? For example, what was the proposed size of the solar and wind projects? When will you reveal a list of finalists?
  - NIPSCO and CRA cannot provide a specific answer on size at this point. Some were as low as 5 megawatts for an individual project and others upwards of several hundred megawatts. CRA's recommendations to NIPSCO are due mid-September, but there is no date certain for public disclosure at this point.
- How will you determine UCAP?
  - For facilities currently in development, the Midcontinent Independent System Operator ("MISO") rules were generally utilized. In some cases, the bidders provided information about the UCAP.
- Can you clarify what is being modeled by the IRP team? If not individual bids, then what?
  - The individual bid data were aggregated into representative tranches. Each tranche represents a number of similar facilities of the same technology type with similar costs and operational profiles. NIPSCO is not modeling each individual project that was bid into the IRP. Rather, the process will model various technologies because NIPSCO does not want the model to select the winning proposals, but rather to use the information to improve the estimates of retirement economics and to develop thematic replacement resource options for the IRP. The RFP team will then perform detailed analysis to select specific projects based on the project portfolio themes selected through the IRP process.
- Are any of the bids from minority business enterprises, then women business enterprises and can you disclose how many are accepted?
  - This was not included in the RFP criteria, but NIPSCO will take it as an action item to ask the bidders and report in a future meeting.

Incorporating the RFP Results into the IRP
Dan Douglas, and Pat Augustine, CRA

Mr. Douglas provided an overview of how the RFP will feed into the IRP. He noted that the RFP will inform both the retirement analysis and the replacement analysis and provided additional details on both. For the initial retirement analysis, the MISO cost of new entry ("CONE") was used as a proxy for replacement costs and now, the RFP results will provide known replacement costs and volumes. Once the RFP projects are selected through an optimization model analysis, the retirement analysis will be re-run using those projects. He then explained that, for the replacement analysis, the initial

IRP replacement costs used estimates from multiple third-party sources. The RFP results will be utilized and will provide visibility into executable alternatives for NIPSCO. He noted that, ultimately, the replacement analysis will be run using somewhat simplified and anonymized RFP results.

Pat Augustine then reviewed the process for feeding the results into the IRP. He stated that step one is to develop the model inputs, which includes specifying inputs by resource type "tranche" based on the RFP results. This results in the development of specific resource options for the Aurora model. He then said that step two is to run the Aurora Portfolio optimization to evaluate the least-cost portfolios for retirement and replacement analysis. Finally, Mr. Augustine noted that a full IRP analysis will be run which will evaluate each portfolio against all scenarios and stochastics in the models and complete the scorecard with metrics across all objectives.

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

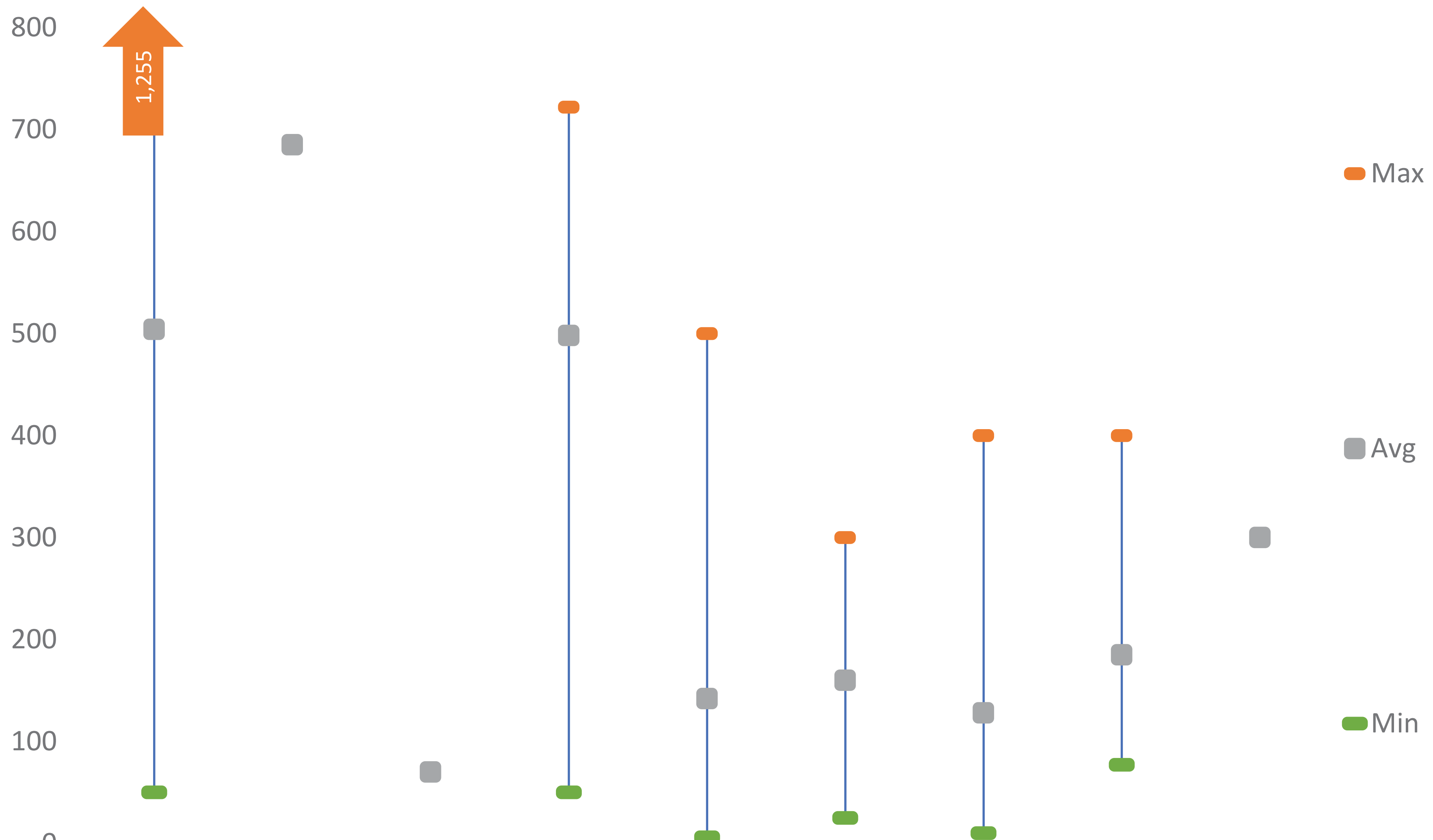
- To follow up on a previous question, there are 5 bids of 1,055 MW for energy storage. Are all 5 projects similar size, or is there a wide range in sizes for these units?
    - NIPSCO will need to review the data and follow up.
- Will all of the individual bids will be modeled in Aurora and allowed to be selected on an economic basis?
    - Each individual bid is not going to be evaluated as an individual option. Rather, multiple bids with similar characteristics will be combined into tranches. Thus, the IRP modeling will be done with average cost and operational parameter estimates, while still preserving sufficient detail from the RFP bids.
- Will there be sensitivity analysis that includes the range of bid prices instead of just average cost?
    - Multiple tranches will exist, which will implicitly include a range of bid prices. The averages presented today are only a high-level summary, while the tranches will effectively incorporate lower and higher cost levels. NIPSCO understands that there is a desire to have individual bid-based modeling as we go through the IRP. However, the goal is to not pick asset-specific winners and losers as part of the IRP analysis. There may be some confusion regarding the tranche process and NIPSCO is happy to walk through that a little more (NOTE: as a follow up to the meeting, a "technical webinar" has been scheduled for August 28 from 2:00-4:00 ET/1:00-3:00 CT. Additional information will be available at www.nipsco.com/irp).
- Will the UCAP determinations and calculations be disclosed?
    - UCAP has been disclosed in summary level across the portfolio of projects that have come back. There is no intention of sharing UCAP by proposal given the sensitives of the proposals.

Stakeholder Presentations

There were no stakeholder presentations.

Mr. Kelly and Ms. Becker closed the meeting by thanking the attendees for their attendance and active participation.

MW Range of RFP Proposals



	CCGT	CT	DR	Other Fossil	Solar	Solar + Storage	Storage	Wind	Wind + Solar + Storage
Max	1255			722	500	300	400	400	
Avg	504	685	70	498	142	160	128	185	300
Min	50			50	6	25	10	77	

March 2017

LIGHTS OUT IN THE COLD

Reforming Utility Shut-Off Policies as If Human Rights Matter

Environmental and Climate Justice Program, NAACP

LIGHTS OUT IN THE COLD: Reforming Utility Shut-Off Policies as If Human Rights Matter

March 2017

Created by the NAACP Environmental and Climate Justice Program
National Association for the Advancement of Colored People
4805 Mt. Hope Drive, Baltimore, MD 21215
(410) 580-5777
ecjp@naacpnet.org
www.naacp.org

Foreword by: Jacqueline Patterson, Environment and Climate Justice Program Director, NAACP

Primary Authors: Marcus Franklin, NAACP
Caroline Kurtz, Georgetown University Law Center

Contributing Authors: Mike Alksnis, NAACP
Lorah Steichen, NAACP
Chiquita Younger, NAACP

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David Pomerantz, Executive Director, Energy and Policy Institute

The National Consumer Law Center

The Michigan Welfare Rights Organization

The Committee to End Utility Shut Offs

Public Utility Law Center

EXECUTIVE SUMMARY

As a part of a broader consumer protection arrangement, the adoption of utility disconnection policies acknowledges the problems faced by customers who are vulnerable to having their utilities disconnected. Unfortunately, the interests of these customers often compete with the interests of utility companies, regulators, and other utility customers. This poses an obstacle to the design of appropriate disconnection policies that recognize the necessity of utility services and the rights of utility customers. A "disconnection policy" describes the justifications, procedures, and consumer protections with which a utility must comply before terminating service to a customer. Although a utility typically maintains the right to disconnect a customer for a variety of reasons, there are more problematic issues with disconnection because of nonpayment.[1]

Aftermath of a space heater fire in Prince George's County, MD
Source: http://patch.com/maryland/bowie/space-heaters-cause-bedroom-fires-twice-week-0

This report provides a comprehensive overview of common disconnection protections and policies employed by utilities nationwide, explores critical issues that should be considered in the development of disconnection policies, and calls for concrete action toward establishing policies that protect the well-being of all utility customers and the eventual **ELIMINATION OF UTILITY DISCONNECTIONS**. The need to incorporate human rights into the utility business model is a key component of the larger reform of the extractive energy economy and movement toward energy justice. The energy justice movement upholds that all individuals have the right to: safe, sustainable energy production; resilient and updated energy infrastructure; affordable energy; and uninterrupted energy service.[2]

This report discusses common disconnection protections across all types of utilities, but focuses on those set for Investor-Owned Utilities (IOU's). Issues with existing disconnection practices and state level model policies are explored. Recommendations for the establishment of a right to utility service are put forward to ensure the future protection of utility customers.

EXISTING STATE POLICIES

PROCEDURAL PROTECTIONS AND CONSIDERATIONS:

- All states require utility companies to provide a written, phone, or personally delivered notice before a disconnection.

- There is a wide range of disconnection limitations. Some states will not disconnect during certain hours of days of the week, while other states will not disconnect before or during a holiday.
- Fifteen states do not specify policies for utility reconnection fees.

SEASONAL PROTECTIONS:

- Date-based protections take place during the colder months, usually between the months of November and March or April. Temperature protections are based on various ranges of hot and cold temperatures that could place residents in danger. Most of the states will not disconnect when temperatures are below 32°F or above 95°F, but the offering of this protection varies by state.
- Nine states do not provide any state regulated seasonal protections for utility customers. These states include: Alaska, California, Colorado, Connecticut, Florida, North Dakota, Oregon, Tennessee, and Virginia.

PAYMENT ASSISTANCE

- Most states offer a payment plan option to avoid disconnections and charge a fee to reconnect to utility services.

PROTECTIONS FOR SOCIALLY VULNERABLE GROUPS

- Medical protections are generally offered for disabled or elderly customers. Generally, a medical certificate is required to postpone a disconnection for various amounts of time.
- Eight states do not have regulations establishing standard protections for socially vulnerable groups. Among these states are: Alaska, Arkansas, Colorado, Florida, Kentucky, North Carolina, North Dakota, and Rhode Island.

THE RIGHT TO UNINTERUPTED ENERGY SERVICE

The establishment of a universal **right to uninterrupted energy service** would ensure that provisions are in place to prevent utility disconnection due to non-payment and arrearages.[3] Toward establishing such a right, we call for all utility companies to advocate for and incorporate the following foundational principles into their models, operations, and policies:

1. Secure **ACCESS** to utility services for all households;
2. Ensure **INCLUSION** of all customers in the development of utility policies and regulations;
3. Create full **TRANSPARENCY** of the information and actions of utility companies, regulating bodies, legislatures, and utility affiliated organizations;
4. Guarantee the **PROTECTION** of the human and civil rights of all customers; and
5. Advance programs that help **ELIMINATE POVERTY**, so that all customers can pay utility bills.

While the end goal is clear—**to prioritize utility policies that place a moratorium on utility service disconnections**—these principles can be furthered through the following practices:

PROCEDURAL PROTECTIONS

1. Require multiple attempts at both written and telephonic or in-person contact before disconnection;
2. Secure notification of disconnection by mail;
3. Require a post-disconnection notice to all customers;
4. Provide additional notice provisions for customers who can be disconnected remotely;
5. Restrict disconnections to times between 8:00am-2:00pm on days when the utility has employees available to reconnect utility services;
6. Provide notice and utility disconnection policies in multiple languages;
7. Remove all policies allowing utilities to charge disconnection and reconnection fees;
8. Cease the collection of deposits for utility service activation and/or reconnection;

SEASONAL PROTECTIONS

9. Include seasonal protections with both temperature and date-based solutions;
10. Set disconnection arrearage minimums for customers who use utility services as the primary source of heating or cooling during periods of seasonal protection;
11. Provide utility services during extreme weather events that fall outside of seasonal protection periods;

PAYMENT ASSISTANCE

12. Allow budget payment plans to distribute utility costs throughout the year;
13. Allow partial payment plans to customers to prevent disconnections;
14. Provide connections to social services and case management resources for households with arrearages;

PROTECTIONS FOR THE SOCIALLY VULNERABLE

15. Establish simple procedures for socially vulnerable groups to apply and be registered for protection from disconnection;
16. Implement customer surveys in advance of extreme weather seasons to screen for socially vulnerable individuals;
17. Ensure active outreach to socially vulnerable customers and households for inclusion in protection programs; and
18. Registration into these programs should be complimented with a notification to local and/or state emergency relief agencies and safety responders.

The policies and protections detailed in this report represent stop-gap measures to lessen harms on utility customer wellbeing. In advancing energy justice, all individuals have the right to: safe, sustainable energy production; resilient and updated energy infrastructure; affordable energy; and uninterrupted energy service.[4] The NAACP calls for the development of policies and utility structures that improve energy efficiency throughout the energy continuum, advance clean and renewable energy production, encourage and enable the development of distributed generation, and protect human life and wellbeing. These aspects are components of the larger utility system change that we must build.

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FOREWORD: A CALL TO MORALITY—*BY JACQUELINE PATTERSON, NAACP ENVIRONMENTAL AND CLIMATE JUSTICE PROGRAM DIRECTOR*

I will never forget the sound of fear in my father's voice on the phone or the look of desperation in his eyes when I walked through the door. I was home to take care of my Dad in what turned out to be his last days on earth. I had gone out to get some items that he needed. My cell phone rang and it was him on the other end saying that the power had gone out and he didn't know how long his respirator would run without it. I raced home and as I opened the door, my Dad was just standing in the middle of the living room, attached to his respirator, looking desperate. It turned out to just be that I needed to flip the switch on the circuit breaker. But it brings home the reliance that so many have on electricity to sustain life.

As many of us were enjoying turkey, ham, or tofurkey with loved ones, exchanging presents, and engaging in holiday festivities, for some of us, all was not merry and bright. Too many are shivering in the deep freeze that had assailed a large swath of the nation, huddled around space heaters or open oven doors in homes lit by candles or kerosene lamps, because they could not pay their electricity/heating bills and were thus without this vital resource. The stories over the years are too many to list, but each one alone represents a moral imperative for systems reform of the utility business model because no life should be lost for lack of the basic human right to safe shelter, in a land of plenty:

- A Maryland man in dire straits after having his electricity disconnected, resorted to using a generator to power the home where he was raising his seven children.[5] Carbon monoxide released by the generator killed the entire family as they slept.[6] Also in MD, a fire swept through a row house killing 10 people, including 7 children aged 7 months, 5 , 7 , 11 and 12 years, and two 3 year olds, as well as 3 adults, after the termination of the electricity caused residents to begin using candles and a kerosene lamp for electricity.[7]
- In Michigan, John Skelley, a 69-year-old man, passed away in his home from hypothermia and other causes, several days after his gas service was disconnected.[8] Also in Michigan, a fire sparked by a space heater being used to heat the home after utilities had been shut off took the lives of three people.[9]
- In New York, three young boys, ages 4 months, 2 years, and 5 years died in a fire caused by a candle used for light after the utility company disconnected service for non-payment.[10]In another New York incident, a child died in a fire started by a candle, in a home where service was scheduled to be reconnected 24 hours after the desperate measures took his life.[11]
- In California, five children, ages 4, 1 and two 2 year olds, lost their lives when their electricity had been disconnected and their mothers, who were sisters living together, used candlelight to light their home, resulting in a fire. [12]

Too often these tragedies are chalked up to the inevitable consequences of poverty and implicitly relegated to being sad, but acceptable losses, with an unspoken notion that "We can't save them all!" However, every one of these losses was preventable and we cannot, in good conscience, stand by and watch more when we have the means to ensure access for all.

The cost of extreme poverty should not be a death sentence.

Whether it is extremes in heat, extremes in cold, or the need for electricity to power life saving devices like respirators or medicines requiring refrigeration not to mention just providing light, electricity/heating/cooling is essential, not just for quality of life, but also for maintenance of life!

We've shared a small sampling of illustrative stories of the consequences of inaction on utility shut-offs that have spanned decades. Yet, with relative inaction, in terms of system reform, so many more are in harm's way now, with the potential for dire circumstances resulting in desperate and possibly deadly actions. As of December 15, 2015, in Pennsylvania alone, at least 9,169 households had no central heating and 414 households were using potentially unsafe heating sources.[13] In Michigan, ravaged by the post-industrial economic downturn, from January to September 2013, DTE Energy--a utility company formerly known as Detroit Edison--reported 169,407 shut-offs, while another utility company, Consumers Energy (CMS), reported 118,203 shutoffs. Disconnections in Michigan have increased dramatically since the crash of 2008, with DTE completing two and half times as many shutoffs in 2011 than in 2007.[14] This trend is observable on a national scale.

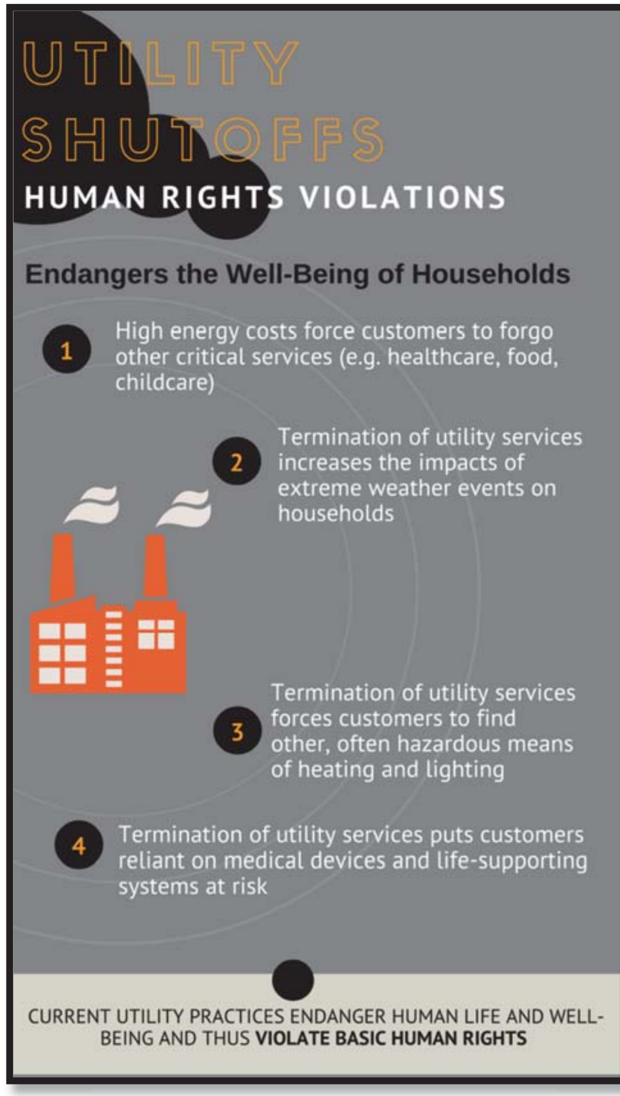
The headlines today heralding the "winter weather blast" with 99 million people in the US under a winter weather advisory[15] highlight the proven fatal cocktail being mixed with the ingredients being harsh weather and lack of protection for thousands of vulnerable households who are struggling with making ends meet, placing them in a vice that can result in resorting to hazardous means of lighting and heating.

Science has spoken and so has Mother Nature as she continues respond to our abuse in the form of the polluting ways we employ to generate energy. Climate change is already resulting in weather extremes from extreme heat to extreme cold to extreme storms.[16] As such, we are seeing more days where air conditioning or at least a fan is required and days of extreme cold requiring heat, and greater amounts of snow to such an extent that even if someone wanted to leave an unheated home in search of warmth elsewhere, this may not be an option. Besides which, the ongoing crisis of homelessness finds the most vulnerable communities without available shelter space, or any alternatives if their homes are unsafe.[17]

Nationwide, annual temperatures have been rising over the past 50 years.[18] The hottest parts of the country, including Texas, the Southwest, and Florida have already experienced large increases in extreme heat days, including days over 90°F, 95°F, and 100°F. Extreme heat when paired with rising humidity levels, make blistering hot days more dangerous. Cities in these states are facing the greatest projected increases in dangerous heat over the next several decades.[19] With more than 80 percent of Americans living in cities, urban heat islands, combined with greenhouse gas heat trapping, can have serious health effects for hundreds of millions of people during the hottest months of the year. Heat is already the number one weather-related killer in the U.S., triggering asthma attacks, heart attacks, and other serious health impacts.[20] The National Center for Disaster Preparedness of Columbia University in New York, projects that about 3,000 people in the U.S. could die each year from heat waves under current climate warming patterns. This estimate is a combination of various factors, including exposure to the higher greenhouse gas emissions, higher urban-based populations, and impeded climate adaptation and mitigation efforts.[21]

Winter storms have also increased in frequency and intensity since the 1950s, and their tracks have shifted and power intensified in the U.S. Other trends in severe storms, including the intensity and frequency of tornadoes, hail, and damaging thunderstorm winds, are being studied intensively for their relationship to climate change.[22] Loss of internal temperature control, due to extreme heat and cold, can result in a variety of illnesses, including heat cramps, heat exhaustion, heatstroke, and hyperthermia when exposed to extreme heat, and hypothermia and frostbite when exposed to extreme cold. Exposure to temperature extremes can worsen chronic health conditions.[23]

There are utilities, such as the Roanoke Rural Electric Co-Op in North Carolina, that are being intentional about designing a business model that is human rights based, protective of the environment, yet financially sound. At the same time, other utilities are driving our continued slide towards catastrophic climate change by denying science, and in some cases, intentionally obscuring science as well as by their refusal to aggressively pursue energy efficiency, embrace the transition to clean energy, and/or allow/facilitate distributed generation of clean energy.[24] [25] [26] And some of the most aggressive utilities are the ones behind the highest numbers of shutoffs where there is record keeping. These utilities obstinately defend the practices of fossil fuel based energy production, disproportionately polluting the very same communities, with the highest rates of shut-offs, to produce the very electricity to which they do not have access.



> *In Dayton Texas, Sam Houston Electric Cooperative has disconnected the utilities of vulnerable households in areas impacted by the Cedar Power Project, which operated three trash burning incinerators until 2008.*[27] *The air pollution produced by incinerators is known to contribute to the development of chronic diseases like chronic obstructive pulmonary disease (COPD) as well as many other serious health problems.*[28]

Given that low-income communities, communities of color, and vulnerable persons, including people who are elderly, pay the highest proportion of their incomes to energy and they are most vulnerable to shut off and most likely to suffer from the pollution from energy production, this is a prime example of the deep injustices in the extractive economy.

As detailed in this report, there are utilities that have managed to reform in such a way that provides protections for low-income customers. Yet too many companies and their trade associations use their influence on the Public Utilities Commissions and Public Service Commissions[29] to push back on the protections communities need.[30] We must put pressure on utility companies that have refused to innovate despite the models being out there for operating utilities in a humane way that maintains operations and uphold human rights. Not only do we need pro-people policies to reform utility company practices in the short term, but in the long term we need a people led movement to seize the reins of our utilities sector, including water, another essential resource that befalls a similar fate of being withheld from those suffering from extreme poverty.

The NAACP is a part of building the new economy that puts power in the hands of the people, literally and figuratively. However, in the meantime, we have developed this study that chronicles the best and worst of utility policies and practices with the aim of uplifting examples of the most humane policies, and providing a blueprint for reform for those who continue to sacrifice the lives of vulnerable communities for profit. We are issuing a call to legislators, regulators, utility companies, researchers, and advocates for us all to step up our efforts in reforming what we have now, even while we as people's advocates push for total-systems change. Until we have transformed to the new, people led, economy, we must all take responsibility for pushing for the reforms that protect the lives of those who are most vulnerable. We particularly issue a call to conscience to the legislators, regulators, and the companies that have used the profits from the electricity and heating bills that we pay every day, to suppress human rights through anti-customer protection, anti-regulatory, anti-clean energy, anti-energy efficiency, anti-distributed generation lobbying while staunchly maintaining practices that have taken lives.

While we build a new economy with foundational principles of human rights, community ownership and control, participatory democracy, and shared wealth and wellness, through this effort, the NAACP, its units, and its partners and allies will work to ensure that utilities, regulators, and legislators are held accountable to executing policies and practices that ensure that right to the commons, resources essential for life, are upheld for all!

LIGHTS OUT IN THE COLD:

REFORMING UTILITY SHUT-OFF POLICIES AS IF HUMAN RIGHTS MATTER

INTRODUCTION

Disconnection policies consist of the justifications, procedures, and consumer protections with which a utility must comply before terminating service to a customer. Unfortunately, the interests of these customers often compete with the interests of other stakeholders. This poses an obstacle for the design of appropriate disconnection policies that recognize the necessity of utility services and the rights of vulnerable customers. The need to incorporate human rights into the utility business model is apparent.

Disconnection policies are implemented by legislatures and regulators, and vary widely from state to state. Some policies are protective of consumers, while others lack safeguards. The right to uninterrupted energy service must be established and upheld for the protection of human life. In the long term, the termination of households from utility services must be eliminated, in the interim, it is critical to ensure the absolute highest level of protections for vulnerable households facing disconnection.

This report discusses common disconnection protections across all types of utilities, but focuses on those set for Investor-Owned Utilities (IOU's). Issues with existing disconnection practices and state level model policies are also explored. Financial options are presented as a short-term solution to reduce a household's risk of disconnection, however, the report sets forth broad principles and specific recommendations for stakeholders as we move towards a shared vision of an energy democracy. While the report highlights disconnection practices mandated by state legislatures and authorized regulatory bodies, the issues and impacts outlined can, and have, applied to Publicly-Owned Utilities (POU's) as well.

TYPES OF UTILITY COMPANIES

Investor Owned Utilities (IOUs)

Investor-owned utilities are privately-owned, for-profit electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return. Traditionally, the investor-owned utilities own generation, transmission, and distribution assets. These utilities are regulated by state legislatures and the regulatory bodies to which they delegate authority. Customer rates are set and regulated by the Public Utility Commission through public process that includes some customer participation.

Publicly Owned Utilities (POUs)/Consumer owned utilities (COUs)

Publicly owned utilities are under public control and regulation. These utilities are organized in various forms, such as municipal owned, rural cooperatives, public utility districts. COUs have varied regulatory structures. Customer rates are set by each utility's governing body-board or city council in a public forum.

Municipally owned: A municipally or city-owned utility is a non-profit electricity provider that is owned and operated by the municipality it serves. Municipals may or may not have their own generation facilities. For municipals without their own generation often develop a contract with another company to generate electricity. Since the customers are local, the municipals do not need to transmit electricity over high-voltage power lines. Generally, municipal-owned utilities are controlled by the City Council or a special board or committee.

Rural Electric Co-ops: Rural Electric Cooperatives are operated by and for the people of the community. The Electric Co-ops were formed to bring electricity to rural households that investor-owned utilities do not serve. They are divided into distribution cooperatives or generation and transmission cooperatives. Distribution co-ops provide end-users with electricity. Generation and transmission co-ops are usually owned and managed by several distribution co-ops to sell wholesale power to distribution co-ops. The consumers of the utility elect a board to manage and make decisions for the Cooperative.

Public Utility Districts (PUDs): Public Utility Districts are utility-only government agencies that provide things like electricity, natural gas, sewage treatment, waste collection/management, telecommunications, or water. The utility districts are created by the local government bodies. PUDs are regulated by a board or commission that is elected by the voters of that district.

No longer should the narrative be, poor people making bad choices and paying the consequences for their bad choices. The principles and actions promoted by this report apply to all utilities. It is time that utility companies are held accountable for the lives and families that they endanger, and that we all transition to the mindset that access to energy and utility services is a human right. The right to uninterrupted energy service must be established and upheld for the protection of human life. In the long term, the termination of households from utility services must be eliminated, in the interim, it is critical to ensure the absolute highest level of protections for vulnerable households facing disconnection.

THE HUMAN COST OF UTILITY DISCONNECTION

"These companies are getting rich while we freeze to death."

-Bernard, resident of Detroit, MI

The following is a collection of true stories about real people whose lives were cut short, or nearly cut short, by utility companies who were willing to pull the plug to protect profits.

THE PEOPLE OF DETROIT, MICHIGAN

"DTE [Energy] changes my rates practically every month. They're constantly trying to squeeze every penny out of us. I keep my gas nearly at zero and they are still charging me an arm and a leg."

-Daryl, resident of Detroit, MI

In 2010, utility shutoffs by DTE Energy resulted in several deadly house fires in Detroit that caused several deaths, including the deaths of two wheelchair-using brothers on Dexter Avenue and three children on Bangor Street. In response, DTE tried to preserve a favorable image by misdirecting attention away from its responsibility for the tragedies, making an outcry to bring "energy thieves" to justice—unidentified people who the company accused of illegally connecting houses to DTE power lines. With the support of the Michigan state government, DTE called for the arrest of "energy thieves" and launched a spying campaign against Detroit residents, which included the use of invasive aerial infrared photography to determine which households still had heat after having their power disconnected for nonpayment.

Meanwhile, DTE also launched a publicity campaign to promote its charity, the Heat and Warmth Fund (THAW), as well as its Winter Protection Plan (WPP) program. Not only do these programs protect only seniors from utility shutoffs during the winter, but they also place families into payment plans that essentially keep them in a state of permanent debt to the company. In many cases, families cannot afford to stay on track with the payment plans that are offered and end up having their power disconnected anyway.

After visiting a DTE office to make a payment, a Detroit resident named Bernard commented, "I came in here to pay $236. That was the minimum amount they said would stop them from shutting off our utilities. They wanted me to pay $560, but I just don't have the money. People on my block are using whatever they have—space heaters, stovetops, anything they can think of. Finding an alternative way to keep warm has become necessary to survive. And you know the company is making good money. These companies are getting rich while we freeze to death."

At the same DTE office, a Detroit resident and mother of three named Tametria said, "They set me up on a payment plan, where I was supposed to pay $300 every month. I kept up with most of the payments, but when I lost my job, they still shut us off. I have three kids, and now we've had to move in with a friend. I came in today and they said I have to pay $2,600 to get my house turned back on. It's unbelievable. We can't move back into our house because we can't afford those thousands of dollars."[31]

ROBERT ROBERTS – OVERLAND PARK, KANSAS

In 2016, a senior living in Overland Park, KS had his electricity shut off by his utility company even though he needed a nebulizer and oxygen to breathe. Robert A. Roberts, Sr. was already struggling to pay medical bills that piled up because of his health problems, including multiple sclerosis and chronic obstructive pulmonary disease (COPD).

A concerned neighbor, Randen Smith, decided to help Mr. Roberts by powering his medical equipment with an extension cord that was connected to Mr. Smith's home. Kansas City Power & Light (KCP&L) said it was "unsafe" to provide electricity to Mr. Roberts through the extension cord and ordered Mr. Smith to pull the plug, threatening to also shut off his power if he refused. Mr. Smith refused to stop helping Mr. Roberts. "I don't want someone dying on my hands," Smith said. "Maybe KCP&L doesn't mind, but it bothers me that someone needs help and electricity and oxygen to live, so I'm going to help."

Mr. Roberts had been living with his son and grandchildren in Overland Park since 1989.[32] The family lives less than one mile away from an incinerator used to burn medical waste, which has been operated by Shawnee Mission Medical Center since 2008.[33] The air pollution produced by incinerators is known to contribute to the development of chronic diseases like COPD, as well as many other serious health problems.

MARVIN SCHUR – BAY CITY, MICHIGAN

In 2009, a 93-year-old man named Marvin Schur froze to death in his home after his utility company restricted his electricity because of an unpaid bill. The official cause of his death was hypothermia, which was determined by a medical examiner who called it "a slow, painful death." Mr. Schur owed more than $1,000 and, as a penalty, the utility company installed a "limiter" to restrict his use of electricity, resulting in his death.

A utility bill was found on Mr. Schur's kitchen table with a large amount of money attached to it—a sign that he was trying to save up to pay his bill. The utility company was owned by Bay City, Michigan. Bay City manager Robert Bellerman stated that he did not believe the company did anything wrong.[34]

JESSE WYANT – EUDORA, KANSAS

"That's premeditated murder—if you know a person is on life-sustaining oxygen, and you pull the plug and you kill them."*-Ms. Wyant, resident of Eudora, KS*

In Eudora, KS in 2011, Beverly and Jesse Wyant were notified by the city that their electricity would be shut off if they did not pay their bill, even though Jesse, age 86, was terminally ill and needed an oxygen concentrator to survive. The couple was having difficulty making ends meet after a fire destroyed much of their home. Since then, they struggled to pay for refurbishments and other expenses so they could cope with the damage. The city refused to wait a mere five days for Beverly's state pension payment to come in; instead, they set up a turnoff time. Luckily, their daughter could pay the bill for them to keep the electricity on, but many families are not fortunate enough to have the resources to do this.[35]

LESTER BERRY – DAYTON, TEXAS

Although Lester Berry, a 70-year-old resident of Liberty County, TX, was only $129.62 behind on his electricity bill, his utility company cut off his power, resulting in his death. Mr. Berry had congestive heart failure and COPD, which meant that he needed constant power to his oxygen concentrator to survive. When Sam Houston Electric Cooperative disconnected his electricity, Mr. Berry very painfully suffocated to death.

Mr. Berry was found with his hand inches away from his phone, which needed electricity to work, leading his son to believe that he tried to call for help just before he died. Mr. Berry's family said the electric power provider was well informed about his need for electricity to power his life-sustaining medical equipment, so they had no reason to assume his power would be disconnected for nonpayment of a mere $129.62.[36]

Dayton, TX, where Lester Berry died, was home to the Cedar Power Project, which operated three trash burning incinerators until 2008.[37] The air pollution produced by incinerators is known to contribute to the development of chronic diseases like COPD, as well as many other serious health problems.

The instances of customer endangerment illustrated in the above stories highlight the need for change. With the myriad of protections, programs, and policies that exist for utility customers at risk of disconnection due to nonpayment there is no reason for undue suffering. In the interest of protecting the rights of utility customers, it is necessary to understand how utilities protect against disconnections due to nonpayment, and where there is opportunity for improvement.

DISCONNECTION POLICIES AND THEIR REGULATION

WHAT IS A DISCONNECTION POLICY?

A "disconnection policy" describes the justifications, procedures, and consumer protections with which a utility must comply before terminating service to a customer. Although a utility typically maintains the right to disconnect a customer for a variety of reasons, there are particular considerations with disconnection as a result of nonpayment.[38] Disconnection policies may be found in whole or in part in state statutes, regulations, public utility commission orders, and utility tariffs, but are most frequently established in regulations.[39] Regulators and other policymakers determine which elements to include or omit in disconnection polices, leading some disconnection policies to be more protective of consumers than others.[40] Some components that are commonly found in disconnection policies include:

1. Required notice to the customer that the utility intends to disconnect service;
2. Limitations on disconnections during certain times of year or in extreme weather;
3. Limitations on the day or time of day when a disconnection may occur;
4. Protections for customers who have disabilities, are elderly, or seriously ill; and
5. The availability of payment plans for customers who have trouble affording their bills.[41]

A disconnection notice
Source: Benefits Learning Network

HOW ARE DISCONNECTION POLICIES REGULATED?

Unlike other businesses, public utilities are bound by the public's interest because they are "of public consequence, and affect the community at large."[42] Many public utilities are even granted monopolies in exchange for what is supposed to be tight regulation in the public's interest. It is within the powers of legislatures to both regulate public utilities and define what it means for that utility to act in the public interest.[43] Traditionally, this has meant the protection of the health, safety, and general welfare of the public.[44]

Legislatures delegate their authority to directly oversee public utilities to officials who serve in public utility commissions or other regulatory agencies.[45] Despite this delegation of regulatory authority, the legislatures retain the right and the duty to define the "public interest" which utilities must adhere to and which utility regulators must protect.[46] Legislatures and regulators exercise broad power over public utilities, but the role of regulators is limited by the legislature's definition of the public interest.

Public utility commissions and legislatures are able to control market entry for new utility providers, set rates, set standards for the quality and safety of service, and prevent the utility from taking undue financial risks.[47] While public utility commissions are free to regulate utilities in accordance to the public interest, they may be limited in their ability to confront new challenges that fall outside of the scope of the traditional public interest goals.[48] Among these challenges include climate change, rising energy costs, air pollution, new technologies, and racial discrimination.[49]

Absent a clear public interest basis to tackle these challenges, commissions may enact regulations that go against the interests of customers.[50] Alternatively, this lack of clarity could cause commissions to be leery of taking action, or leave them unwilling to take on challenges, even if they would be permitted to do so.[51] Thus, it is important for legislatures to provide utility commissions with a clear public interest mandate to authorize and encourage the commission to regulate on emergent challenges or topics. This lack of clarity allows for continued violations of customers' rights by public utilities.

How Utility Companies are Regulated

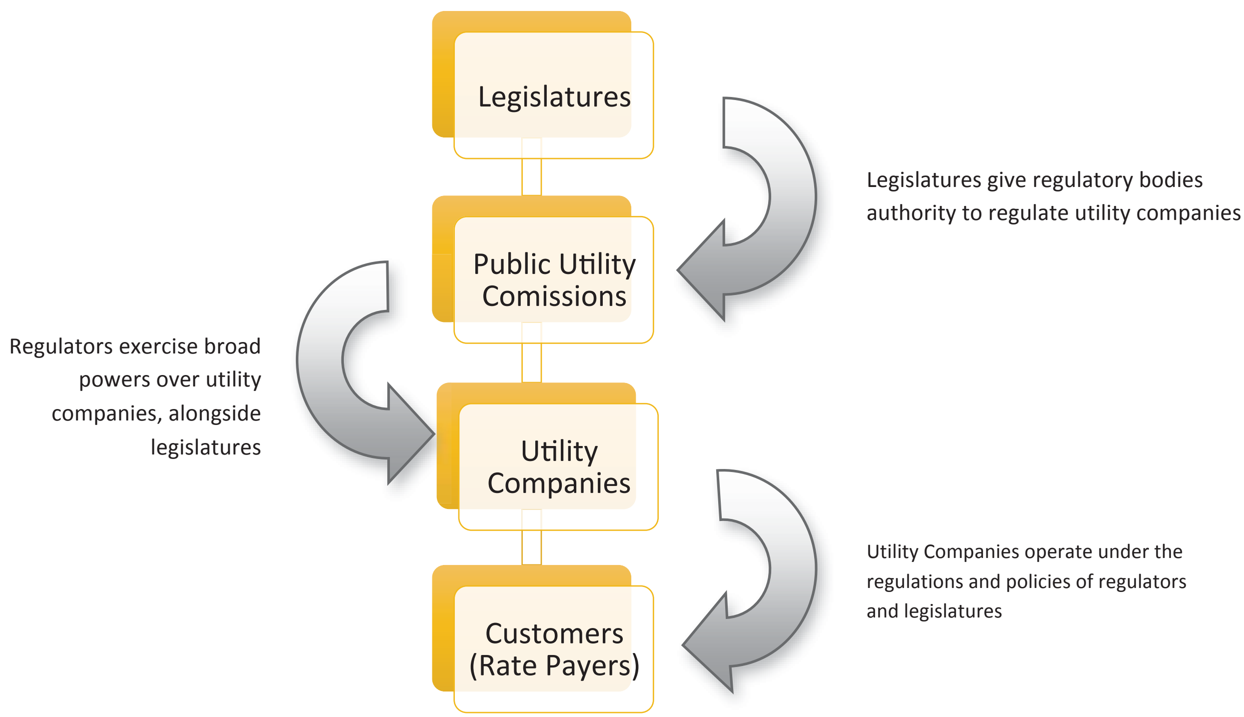


Figure 1. How Utility Models are Regulated: The Traditional Model

COMPETING INTERESTS

There are multiple stakeholders who may have competing interests regarding disconnection policies that must be considered when endeavoring to reform the utility system to solve the problems faced by those who experience utility disconnections. Figure 2 depicts some of the stakeholders who may have an interest in disconnection policies.[52] The interest of the following groups typically come into play: utility customers, those at risk and not at risk of disconnection; utility companies; and legislators and regulators. Within each of these groups are individuals that are directly and indirectly impacted by utility disconnections and other actions.

CUSTOMERS

Consumers who are at risk of being disconnected have an interest in maintaining their service under protective disconnection policies. In contrast, consumers who are not at risk of being disconnected may be asked to subsidize those customers who are unable to pay; therefore, they may want less protective policies to keep their own rates lower. This additional burden on customers in-good-standing is a form of cost shifting—when a utility charge higher rates or other fees for services to one group than another less reliable group. Such cost shifting practices undermine the ability of more customers to pay their utility bills. Too often cost shifting is practiced in instances where a utility has the ability and capacity to absorb the costs of customers at risk of nonpayment.[53]

All utility customers have an interest in disconnection policies, as disconnection from utility services for any reason directly impacts customer wellbeing and security. Often families are put at risk when utility services are denied. In most states, lack of proper and safe heating and lighting sources can be a catalyst for social service and child protective services investigations. Lack of proper heating and lighting can be designated as housing safety and physical environment hazards for children.[54] This potential of the separation of families due to utility service disconnections is not only traumatic, but frequently hinders households from seeking help when in already vulnerable positions.[55]

UTILITIES

Utilities have an interest in earning a profit, so they may prefer a less protective disconnection policy that allows them to disconnect customers more quickly once an account becomes delinquent;[56] however, utilities likely also wish to avoid putting their customers at risk, out of humanitarian concern, or, in some cases, if only to save themselves from negative press and public perception.[57]

Stakeholders in Public Utility Disconnections

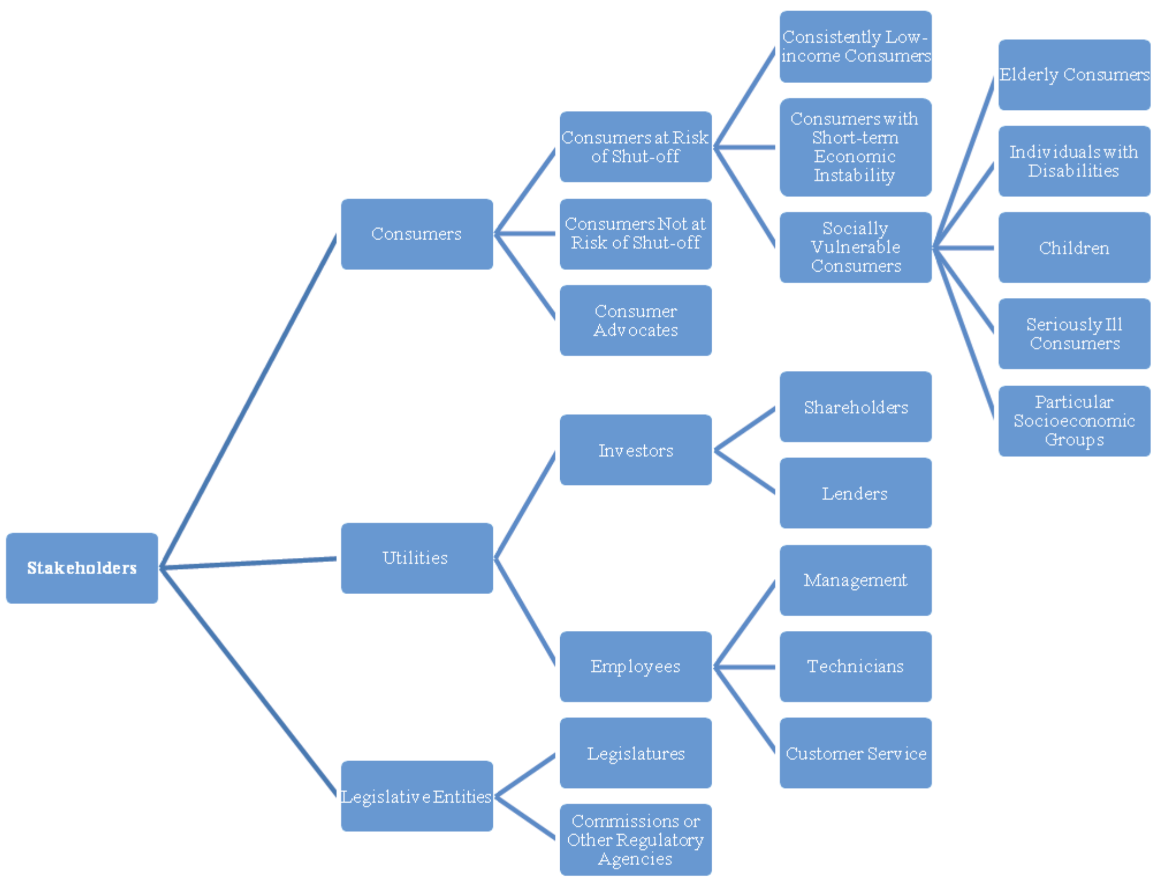


Figure 2. Stakeholders in utility disconnections

LEGISLATORS AND REGULATORS

Legislators and regulators share in the interests of both the utilities and the consumers, and they may have their own political or professional interests, but they ultimately must select a disconnection policy that will work best for the people in their state or jurisdiction.[58] In the face of these potentially competing interests, it is critical that regulators are engaged in determining how they can align the views of different stakeholders to create effective and socially-conscious disconnection policy.

DISPROPORTIONATE ENERGY BURDENS

"Something like electricity, that's really just an essential of living a normal life."

-Rudy Sylvan[59]

There are many issues with the way utilities construct and apply disconnection policies in the United States. Utility disconnections can have a discriminatory impact on low income people, people of color, elderly people, people with special health needs, and other socially vulnerable utility customers who disproportionately face potential violations of human rights. Utility companies, regulators, and legislatures have developed suites of protections, which if implemented appropriately can remediate several critical concerns for vulnerable populations. These concerns include:

1. Customers with limited income bear a disproportionate burden of energy bills;
2. Disconnections have a disparate impact on low income communities and communities of color;
3. Customers may be reliant on utility services for medical devices and life-supporting systems; and
4. Vulnerable customers' use of hazardous heating, cooling, and lighting measures can have harmful and even fatal results.

ENERGY BURDEN ON LOW-INCOME HOUSEHOLDS

About 48% of American families (approximately 59 million households) have pre-tax annual incomes of $50,000 or less, with an average after-tax income among these households of $22,732—less than $1,900 per month. Since families of color and seniors have comparatively lower median incomes, these groups are among the people who are most vulnerable to rising

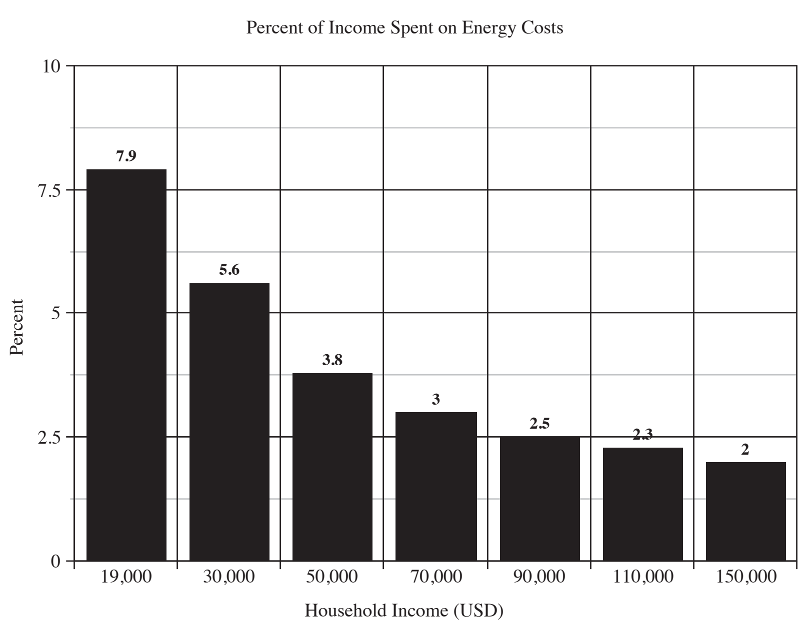


Figure3. Household Energy Burdens by household income

energy costs. "Median income" can be considered the midpoint, where one-half of households have incomes above this amount, and one-half have incomes below it. In 2015, the U.S. median household income was about $51,939. Table1 provides a summary of the median incomes of especially vulnerable households compared to the U.S median.[60]

Utility customers with limited income are at a higher risk of having their utilities disconnected due to nonpayment. This is due, in part, to the nature of utility payments. Utility costs often make up a larger portion of expenses for households with limited extra income (Figure 3,[61] and these costs can change throughout the year as increased heating or cooling is needed.[62] Energy costs are consuming as much of the incomes of America's lower- and middle-income families as the cost of other basic needs, such as housing, food and health care. Additionally, households with limited extra income may live in older homes that are less energy efficient, and they may not have the financial ability to pay for efficiency upgrades.[63] Customers having trouble affording electric service may also be struggling to maintain cell phone or internet service. Many existing policies around disconnection procedures ignore this and provide notice solely through electronic means.

Table 1. Mean Income for Vulnerable Groups in the United States vs. the National Median Income

Household Type	Percentage of U.S. Households	Median Income	Amount Lower than U.S. Median Income
African-American	13%	$45,186.93	-$6,752.07
Latino/Hispanic	13%	$45,186.93	-$6,752.07
Age 65+	23%	$39,993.03	-$11,945.97

Table 2. Utility disconnections in Cleveland, OH 2014-2015

Total Service Disconnections for Nonpayment Jun 2014 – May 2015	
Cleveland Electric Illuminating Company	14,594
Columbia Gas of Ohio	92,313
Dominion East Ohio	62,398
Orwell Natural Gas	$216
Total	**169,521**

Table 3. Unpaid bills for disconnections in Cleveland, OH 2014-2015

Total Number of Unpaid Bills for Disconnections Jun 2014 – May 2015	
Cleveland Electric Illuminating Company	12,306,545
Columbia Gas of Ohio	62,593,567
Dominion East Ohio	63,585,403
Orwell Natural Gas	86,447
Total	**138,571,962**

The cost of energy is not dramatically different for households that have significantly different incomes, which increases the likelihood that customers with little extra income will fall behind on utility payments and risk disconnection due to nonpayment. Utility cost remain significantly unchanged over all income groups is because: [64]

1. Electricity and other utility services are a basic human need, not a luxury, making it relatively inelastic to income compared to consumer goods;

2. Even if low-income families do use less electricity, there is an energy efficiency gap, in terms of housing and access to the proper technology; and
3. A significant portion of electricity bills are paid via fixed costs, which means it doesn't matter how much electricity you use or don't.

In 2009, households with incomes of less than $20,000 spent an average of $1,571 on utilities while households with incomes of $100,000–$119,999 spent an average of $2,572.[65] While these customers' relative incomes increased by more than 500%, the price they pay for utilities increases by only 163.7%. The reasons listed above have contributed to this pattern.

Disconnections due to nonpayment occur in significant amounts, and are on the rise in some areas.[66] In Ohio, four gas and electric companies serving the Cleveland area reported 169,521 service disconnections due to nonpayment during the twelve months between June of 2014 and May of 2015 (Table 2).[67] These disconnections equate to approximately $138,571,962 in unpaid utility bills, which averages to just over $800 per disconnection (Table 3).[68]

> **"The cost benefit analysis of how the utility business model is structured around utility shut offs in the face of such wealth building focus means a choice of life and death for some and the choice between a Porsche and an Audi for others.''**
>
> *-Jacqueline Patterson, Director, NAACP Environmental and Climate Justice Program*

PROFITEERING OF UTILITY COMPANIES

When considering that utility company executives make millions of dollars in bonuses and pay increases, annually, that exceed the amount of revenue lost to nonpayment is a further sign of injustice. First Energy, the parent company of Cleveland Electric Illuminating Company, made over $16 million *in performance bonuses alone* at the end of 2016, more than enough to cover the debt of disconnected customers from the previous year (Table 4). Disparities such as this are common, and even more drastic in other regions of the U.S. As shown in Appendix A, Ohio, as well as many other states, have electric affordability indexes above the national average (2.5%). Tennessee, South Carolina, Mississippi, Alabama, and Hawaii all have energy affordability indexes equal to or more than 3.5%. In these states, the average customer faces a higher energy burden. A burden that is deeply felt by low income and socially vulnerable populations. The stark contrast between the amount of money utility companies spend on executive bonuses and unnecessary infrastructure, illuminates the larger issue of profiteering within the energy industry.

DTE Headquarters in Detroit, MI
Source: U.S. Department of Energy

Detroit, MI Residences in the DTE Service Territory
Source: Fireplace Chats

Table 4. First Energy Executive Compensation FY 2015-2016

Cleveland Electric Illuminating Company (First Energy) 2015-2016			
Executive	Base Salary	Total Compensation	Pay Increase
1	$ 1,118,558.00	$ 4,238,701.00	$ 3,120,143.00
2	$ 636,154.00	$ 2,339,431.00	$ 1,703,277.00
3	$ 510,231.00	$ 7,054,125.00	$ 6,543,894.00
4	$ 752,789.00	$ 3,004,793.00	$ 2,252,004.00
5	$ 599,176.00	$ 2,135,552.00	$ 1,536,376.00
6	$ 552,404.00	$ 2,017,272.00	$ 1,464,868.00
Total	$ 4,169,312.00	$ 20,789,874.00	$ 16,620,562.00

DISPARATE IMPACT ON LOW INCOME COMMUNITIES AND COMMUNITIES OF COLOR

African Americans spend a significantly higher amount of their total incomes on energy—including electricity, heating, fuel, and the energy used to produce, package, transport and sell goods—than the general U.S. population, except in higher income groups. The American Association of Blacks in Energy argues that this occurs for two reasons:[69]

1. African Americans are more than twice as likely to live in poverty as non-African Americans. Low income households pay similar amounts for electricity and heating as high income households; and
2. African Americans spend a significantly higher fraction of their household income on electricity and heating than non-African Americans who spend more on energy used in the production and consumption of goods.

In general, low income populations spend a significantly higher fraction of expenditures on energy purchases than the middle-class and the wealthy: 13% of expenditures in the lowest income groups as opposed to just 5% of household income in the highest income groups.[70] The higher percentage of low income African Americans exacerbates the vulnerability of African Americans to high energy prices and in turn utility disconnections. This helps explain why increases in energy prices are likely to negatively impact African Americans more significantly than the general population.[71] In addition to the economic burden of high prices, to the extent that low income customers, low income African Americans customers in particular, choose to forgo or trade-off energy use with other necessities such as food and health care, high energy prices can represent a significant health hazard.[72] The choice between utility services and other necessities is not an easy choice. In a 2011 survey, lower-income households reported the following reactions to high energy bills:

- 24% went without food for at least one day;
- 37% went without medical or dental care;
- 34% did not fill a prescription or took less than the full dose; and.
- 19% had someone become sick because their home was too cold.[73]

While having limited extra income puts individuals at higher risk for being disconnected due to nonpayment, a customer's race may also influence how likely an individual is to be disconnected from utility service. Data from the 2009 United States Energy Information Administration's Residential Energy Consumption Survey indicates that even among financially similar customers, African Americans experienced disconnections more frequently.[74] Among all households at or below 150% of the federal poverty level, 11.3% of African American headed households were shut off in contrast to 5.5% of Caucasian headed households.[75] While every region of the United States reflected this disparity, it was most prominent in the southern region, where 16% of African American headed households at or below 150% of the poverty level were disconnected compared to approximately 6% of Caucasian headed households.[76] In this case, intentional discrimination can be difficult to prove without concrete data and research of the differences between groups in the prioritization of energy bills over other expenses. These disparities may be the result of institutional racism; uneven levels of consumer education; differences in savings, available income, or outside assistance; and geographic density of customers based on race.[77]

"Regardless of whether it's shut off or simply that bills are so high that people voluntarily limit usage, several things happen. People use space heaters, kerosene heaters, that increase risk of fire and carbon monoxide poisoning. And people limit use of electricity. They light the home with candles, which are often too close to something combustible."

-David Fox of the National Low-Income Energy Consortium (NLIEC)

USE OF HAZARDOUS HEATING METHODS

Despite the significant costs of utilities on customers with limited extra income, the use of utility services remains necessary. Heating and cooling homes accounts for 47.7% of all residential energy consumption, with 41.5% of all residential consumption going solely to heating.[78] Customers use more energy in months when heating is necessary, and customers with little extra income may be especially vulnerable to disconnection during these more costly months.[79] For customers who live in colder climates, or who experience unusually extreme weather, the consequences of being disconnected throughout the winter months are potentially severe.

A family sits and waits as emergency respondents extinguish the flames
Source: Denver Post

Customers take risks when they turn to alternative heating or light sources, such as space heaters, candles or generators, which can cause fires or emit toxic carbon monoxide.[80] As noted, there have been publicized deaths that resulted from the disconnection of a heat-utility during the winter months. ***According to the National Fire Protection Association, while only 32 percent of home heating fires involve space heaters, heaters are involved in 79 percent of home heating fire deaths.***[81] Customers face additional health hazards throughout the year particularly when they are left without air conditioning in extreme heat, and when electricity is disconnected from customers who rely on the service to power their medical devices.[82]

TYPES OF DISCONNECTION POLICIES

The policies and protections outlined in this section are common among all types of utility companies. But these are particularly measures outlined by state legislatures and authorized regulatory bodies (i.e. Public Utility Commissions, Public Service Commissions, and other bodies) for the regulation of IOUs. Many of these protections are also used by Publically-Owned Utilities (POUS) and Customer Owned Utilities (COUs).

PROCEDURAL PROTECTIONS AND CONSIDERATIONS

Procedural protections that are commonly included in disconnection policies include adequate notice prior to disconnection of the utility service and limitations on when disconnections may occur. An additional procedural option often used by states is the imposition of fees for disconnecting or reconnecting a utility service to a customer. Utility services can be disconnected and reconnected in person and remotely, depending on the type of meter or infrastructure onsite. Producers for in person or automated disconnection and reconnections have varying policies in several states. This includes differences in notice and associated fees.

Louisville, KY November 15, 2016: House Fire caused using space heater
Source: WLKY, Kentucky

Notice: Is a constitutionally assured procedural right that must be given to all customers before termination of utility service.[83] In addition to being constitutionally required, providing a robust notice to customers ensures that customers are aware that they are delinquent in their payments. This not only protects the customer from being disconnected, but it alerts customers of their duty to pay for the utility service. Though a minimum level of notice is required before any utility may be disconnected for nonpayment, the length of notice and notice procedures vary widely in different states. Typically, notice is given by mail, by posting of the notice at the customer's home, by delivery to the customer, by phone, or, in limited states, by email.[84] Some states require that notice be provided in multiple languages.[85]

Limitations on Disconnection: Many states choose to limit the days and times when utilities may disconnect a customer from service. Enacting these limitations often protects customers from being disconnected at a time when they would be unable to quickly remedy the disconnection. Most states will, at minimum, limit disconnections to business hours on days when the utility is open and available to receive a customer's payment.[86] Some states offer more customer protection by allowing disconnection only during limited hours of the business day. If a state requires personal notice before a disconnection, the state may be more lenient with the hours and days on which a disconnection may take place.

Disconnection and Reconnection Fees: Almost every state explicitly authorizes reconnection fees.[87] Reconnection fees are authorized to allow a utility to collect additional payment for the acts of disconnection and reconnection, and the provision of other customer service interactions with the customer prior to the disconnection. Reconnection fees are often adopted as a deterrent for customer to reach disconnected status.[88] Other states are more protective of certain customers, such as the elderly or low-income customers for whom a fee would prevent reconnection.[89] Some states also authorize the collection of a fee for disconnection.[90] The fee amounts and procedures for disconnection and reconnection vary among states. The Public Utility Commission, of Ohio provides a Winter Reconnect Order for residential customers under the threat of disconnection or who have been disconnected to file for have their service reconnected or maintained for the winter months. Customers filing an order must pay a $175 fee to retain service and an additional reconnection fee of $36 to reconnect service.[91] Some states, including Arkansas, do not charge disconnection fees, but may still allow for utilities to charge reconnection fees.[92]

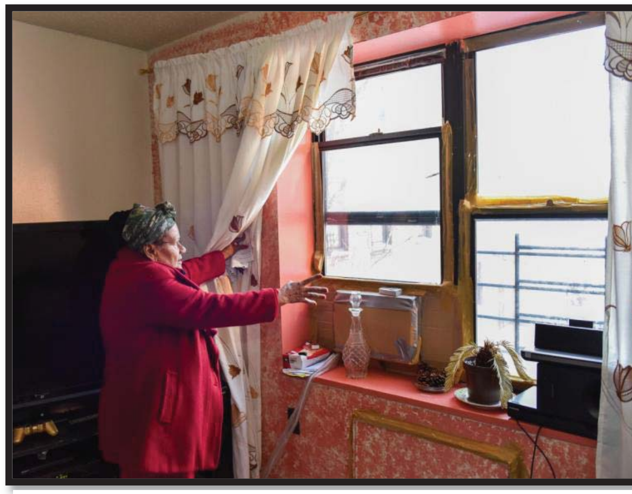
House fires can start from even a lit candle when used for heating and light in a home

In most cases disconnection and reconnection fees are still applied for remote disconnections and reconnections—remote connections can be made simply by flipping a switch. Disconnection and reconnection fees are another obstacle for customers at risk of disconnection, as well as those who have already been disconnected. Utility companies that offer these fees as disincentives for customers do not recognize that disconnections themselves are disincentives for most customers. These administrative polices do not help any customer, but further endanger customer well-being.

Deposits and Guarantees: In some states, new utility customers or customers with poor payment history, utility companies can require payment of a deposit or the submission of a letter of guarantee from a third party able to pay in lieu of the customer. Many PCU's and other utility regulatory bodies set minimums and maximums on deposit amounts and prescribe payment installment programs for paying deposits more than a set amount.[93] Deposits are often required on top of reconnection fees and arrears.[94] Deposit amounts vary from state to state and have been reported in excess of $150.[95]

SEASONAL PROTECTIONS

Seasonal protections are included in the disconnection policies of many states. Seasonal protections are generally date-based, temperature-based, or include a combination of both protections. Most seasonal protection policies apply to winter months or cold temperatures, but some also apply to summer months and extreme heat. Seasonal protections are usually implemented to protect customers from the health risks associated with having a utility disconnected during periods that could be especially dangerous to health.



Resident reveals the duct taped windows in her Claremont Houses apartment in the Bronx, NY.
Source: [David Wexler, New York Daily News]

Date-Based Protections: These protections set specific dates of when customers cannot, without due diligence, be disconnected from a utility service. Dates typically span the late fall to early spring months, when temperatures are at their lowest. Though less common, some states implement date-based protection periods for the summer months as well.[96]

Temperature-Based Protections: Many states have a temperature-based protection plan to protect customers from extreme cold weather. These protections acknowledge the dangers that customers face when they are disconnected from a utility that may be providing them with heat during periods of cold weather.

PAYMENT ASSISTANCE

> **"[S]ome energy companies will offer the bare minimum in assistance. Many application assistance locations are inaccessible to disadvantaged populations... [P]rogram applications require multiple sources of documents and are so lengthy, complex and intrusive that needy applicants are discouraged from completing them. The process of applying for energy bill payment assistance should not cause added humiliation."**
>
> *-Katherine Egland, Member, National NAACP Board of Directors*

Many states require utilities to offer payment plans that may allow a customer to avoid disconnection or to more easily afford their bills throughout the course of the year. These plans can take many forms. One common option allows for all customers to enter a "budget billing" or "leveled plan." These plans are typically available to any eligible customer, and it allows a customer to divide a yearly bill evenly over twelve months.[97] A second common option is offered only to customers who are at risk of having their utility disconnected. These customers are given a chance to pay the amount due in portions rather than all at once, which allows a customer to expedite reconnection to the utility service.[98] Payment plans are also frequently required to avoid disconnection during seasonal protective periods.[99]

PROTECTIONS FOR SOCIALLY VULNERABLE GROUPS

Most states offer protection for groups that may be considered especially vulnerable to the risks and hazards associated with utility disconnections. Traditionally, this category includes protection for people who are elderly, people with special health conditions, and individuals with disabilities. Most states only require utilities to offer protections to socially vulnerable customers who register with the utility; however, for some of these groups, registration may be a barrier that prevents them from being protected under the applicable laws.

STATE DISCONNECTION PROTECTION POLICIES

Disconnection protections vary significantly by state. The combination of protections provided by utilities is ideally fit to the context of that state and its definition of public interest, however, these considerations do not result in adequate protections in all cases. To truly uphold human rights, in the public interest, the ultimate aim is to eliminate disconnections altogether and, pending broader system reform, ensure the absolute highest level of protection for vulnerable households facing disconnection. Table 5 illustrates how different protection policies and prescriptions are state by state.

Table 6 indicates the general utility disconnection policies for each state. Most states require utility companies to provide a written, phone, or personally delivered notice before a disconnection. Date based protections take place during the colder months, usually between the months of November and March or April. Temperature protections are based on various ranges of hot and cold temperatures that could place residents in danger. Most of the states will not disconnect when temperatures below 32°F or above 95°F, but the offering of this protection varies by state. Most the states offer a payment plan option to avoid disconnections and charge a fee to reconnect to utility services. Medical protections are generally offered for disabled or elderly customers. Generally, a medical certificate is required to postpone a disconnection for various amounts of time. There is a wide range of disconnection limitations. Some states will not disconnect during certain hours of days of the week, while other states will not disconnect before or during a holiday. A detailed compilation of utility disconnection protections can be found in Appendix B.

MODEL STATE POLICIES

The following polices are key examples of what utilities can do to provide more protective disconnection polices. These policies represent a step toward a more human rights based utility structure.

NOTICE

- In Oregon, a utility must provide a written notice by mail or delivery at least fifteen days before the scheduled disconnection.[100] A second notice must then be mailed or delivered five days before the scheduled disconnection.[101] The utility must attempt to make personal contact with the customer immediately before the disconnection, and if this attempt is unsuccessful, the utility must post a notice at the customer's residence.[102] Additionally, Oregon requires special notice protections following a disconnection when a utility is able to disconnect a customer remotely without making personal contact.[103]
- Some states require that notice be provided in multiple languages, as in Colorado where a utility must provide notice in English and "languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information."[104]

LIMITATIONS ON DISCONNECTION

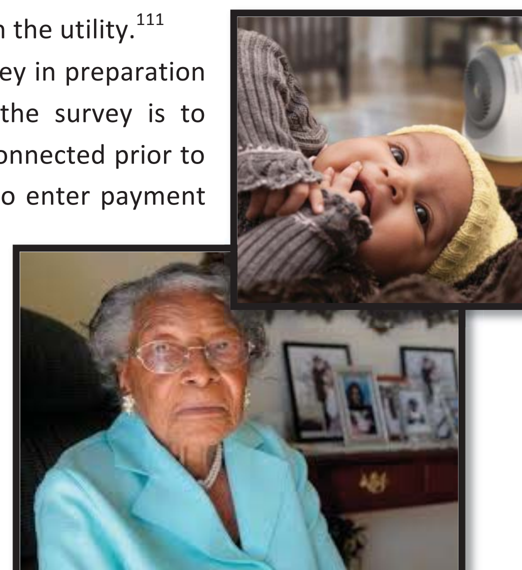
- In Iowa, a customer may only be disconnected between the hours of 6:00am and 2:00pm, which ensures that a customer has an opportunity to be reconnected the same day that the disconnection takes place.[105]
- Most states provide avenues for renters to address situations where landlords fail to pay utility bills. In these instances, if a landlord fails to provide a utility, they can be held in violation of state and local housing codes and penalized. Many states have provisions which provide tenants with remedies against utility disconnections including: transferring of rental properties to tenant control; paying utility bills in place of landlords and deducting the amount from rent payments; and/or avenues for legal action and court involvement. [106]

DISCONNECTION AND RECONNECTION FEES

- Arkansas does not charge disconnection fees for water, gas, or electric utilities.[107]

SEASONAL PROTECTIONS

- Rhode Island has one of the most protective date-based winter seasonal protection plans. The regulation was recently passed, and became effective on November 2, 2016.[108] During the period from November 1–April 15, utilities are severely restricted in their ability to disconnect a customer for nonpayment. Customers who use a utility for their primary heating service may not be terminated unless they have arrearages greater than $500.[109] While customers who have delinquencies greater than this amount may be disconnected, the utility must first file an affidavit with the state's Division of Public Utilities and Carriers at least forty-eight hours before the scheduled disconnection.[110] Additionally, there are no disconnections allowed for any customer who has a protected status with the utility.[111]
- In Pennsylvania, utilities are required to distribute a survey in preparation for the winter protection period.[112] The purpose of the survey is to connect utilities with the customers who have been disconnected prior to the winter protection period. Utilities are encouraged to enter payment agreements with these customers so that they may be reconnected before the winter period begins.[113]



Small children, the elderly, and those with medical conditions and disabilities are particularly vulnerable to exposure to extreme weather
(Child) Source: [Olkbridge Family]
(Woman) Source: [Persimmon Hollow]

PAYMENT ASSISTANCE

- Rhode Island's Henry Shelton Act of 2011 (amended in 2016) establishes an arrearage forgiveness program for customers eligible for Low Income Home Energy Assistance Program (LIHEAP) who have had their utility services disconnected for non-payment or who have been scheduled for disconnection. Participating customers have one-twelfth of their arrearage forgiven for every month of successful payment, for up to $1,500 of forgiveness in a year.[114] This system is based on a similar model in Massachusetts.[115]

PROTECTIONS FOR SOCIALLY VULNERABLE GROUPS

- Massachusetts offers expansive protection for individuals who are seriously ill, elderly, and have disabilities, but the state also requires that utilities take steps to protect young children.[116] No disconnections are allowed for households with children under twelve-months, or for households where the only residents are aged sixty-five or older and minor children.[117]
- To combat barriers to registration for protection programs, North Dakota implemented a utility survey that must be distributed to all new customers and all current customers on an annual basis. This survey questions all customers about any members of the household who qualify for protection due to age, illness, or disability.[118]

Table 5. Survey of State utility customer disconnection protections

State	Procedural Protections	Seasonal Protections	Payment Assistance	Protections for Vulnerable Groups
Alabama	Provide customers with a written notice five days before scheduled disconnection Requires a reconnection charge	When the temperature is forecasted to be 32°F or below for that calendar day, the utility cannot be disconnected	The utility does not have a payment plan option and	Special consideration based on age, disability, medical conditions or other circumstances is granted, but not required
Alaska	Customers receive an initial notice fifteen days before scheduled disconnection, and a second notice is provided in person, by telephone or by posting three days before a disconnection Disconnections can occur Monday-Thursday between 8:00am-5:00pm	Does not require seasonal protections	Deferred payment agreement with the utility to pay their outstanding balance in installments over a period not to exceed 12 months	A customer, who is elderly, ill, dependent on life support systems, or disabled, can have their disconnection postponed for fifteen days
Arkansas	Initial notice to be mailed eight days or delivered five days before the disconnection, Disconnections can only occur during normal business hours No reconnection charges	Disconnections are not permitted between November 1-March 31 Gas utilities may not disconnect for low-income customers When the temperature is 95°f or above, disconnections are not allowed for elderly or disabled customers	Offer payment plans for customers, who qualify as low-income, during winter protection period	Customers, who are elderly or have disabilities, must have two notice attempts at least 72 hours before shut off
Kansas	Written notice to be sent ten days before scheduled disconnection and the utility must call two times at least two days before disconnection	Disconnections are not permitted between November 1-March 31 If temperature drops below 35°F in the following 48-hour period, disconnections are not permitted	Customers must enter into negotiated payment plan, pay 1/12 of arrearage, 1/12 of current bill and disconnection, reconnection and deposit if applicable and apply for energy assistance funds to avoid disconnection	Customers with a medical certification must also provide proof of inability to pay the bill in full
Tennessee	Requires only a reasonable notice to be provided Does not specify a period for disconnections	Does not offer date based or temperature based protection	Offers payment plans for customers	A thirty day disconnect delay can be granted if physician, public health official or social service official certifies that a household member's health would be adversely affected

Table 6. Disconnection Protection Polices in the United States

State	Notice	Date Based Protection	Temp. Based Protection	Payment Plans	Reconnection Fee	Medical Protections	Disconnection Limitations
Alabama	X		X		X	X	
Alaska	X			X	X		X
Arizona	X		X		X		
Arkansas	X	X	X	X			X
California	X					X	
Colorado	X						
Connecticut	X			X	X	X	
Delaware	X	X	X	X		X	X
D.C.	X		X		X	X	X
Florida	X				X		X
Georgia	X	X	X	X	X	X	X
Hawaii	X					X	X
Idaho	X	X		X		X	X
Illinois	X	X	X	X		X	X
Indiana	X	X		X	X	X	
Iowa	X	X		X	X	X	X
Kansas	X	X	X	X	X	X	
Kentucky	X	X		X			X
Louisiana	X	X	X	X	X	X	X
Maine	X	X		X	X	X	X
Maryland	X	X	X	X		X	X
Massachusetts	X	X		X		X	X
Michigan	X	X		X	X	X	X
Minnesota	X	X	X	X	X	X	X
Mississippi	X	X	X	X	X	X	
Missouri	X	X	X	X	X	X	
Montana	X	X	X	X		X	X
Nebraska	X	X		X	X	X	X
Nevada	X		X	X	X	X	X
New Hampshire	X	X		X	X	X	X
New Jersey	X	X	X	X		X	
New Mexico	X	X		X	X	X	X
New York	X	X		X		X	X
North Carolina	X	X		X	X		X
North Dakota	X			X	X		X
Ohio	X	X		X	X	X	X
Oklahoma	X	X	X	X	X	X	X
Oregon	X			X	X	X	
Pennsylvania	X	X		X	X	X	X
Rhode Island	X	X	X	X	X		X
South Carolina	X	X		X	X	X	X
South Dakota	X	X		X		X	X
Tennessee	X			X		X	
Texas	X		X	X	X	X	X
Utah	X	X		X	X	X	X
Vermont	X	X	X	X	X	X	X
Virginia	X				X	X	X
Washington	X	X		X	X	X	X
West Virginia	X	X		X	X	X	X
Wisconsin	X	X	X	X	X	X	X
Wyoming	X	X	X	X	X	X	X

FINANCING TO REDUCE AND ELIMINATE DISCONNECTIONS

There are financing models that can help reduce the burden of utility costs on at-risk customers. These options are only steps toward a broader vision. It bares emphasis that the injustices of many utility practices are fundamental wrongdoings that contribute to the creation and continuation of poverty. The big picture is economic justice and equity, virtues that are thwarted by current utility business models regardless of strategies to reduce household energy burdens. Bill assistance programs, energy efficiency and weatherization programs, and inclusive financing models are resources that can and should be used in the short term to prevent and reduce the risk of utility disconnection. These approaches are band-aids applied to the symptoms of deep systemic roots of poverty. While they are positive and useful models and resources, they are merely a step toward the ideal.

BILL ASSISTANCE PROGRAMS

Bill assistance programs provide financial assistance for households to pay their immediate home energy bills. There are many federally funded bill assistance programs, the main programs include the: Low Income Home Energy Assistance Program (LIHEAP), the primary federal bill assistance program; Emergency Food and Shelter Program (EFSP), funded by the Federal Emergency Management Agency; and Residential Assistance for Families in Transition (RAFT), provided by the U.S. Department of Housing and Community Development. Federal Bill assistance programs, as well as those operated by non-profits, often have social service and case management resources for households.

Bill assistance programs are often the first solution at risk customers use to avoid utility disconnections
Source: La Casa De Don Pedro

LIHEAP provides funding to states, which is then distributed to qualified households. The funds dispersed by states can be direct bill assistance (the majority of funds), crisis assistance, support for weatherization programs, or other forms of aid to reduce household energy needs. Across most states, household eligibility is established between 150% and 110% of the federal poverty line, or 60% of the state median income.[119] The program also provides direct payments to tenants, who meet income eligibility requirement for fuel assistance, whose heat is included in the rent.[120]

EFSP grants are allocated at the county and regional levels. EFSP tends to pays for only one month's utility bill and requires that the household has received a shut-off notice. In many states, the same agency that processes LIHEAP applications also administers EFSP funds. The Department of Housing and Community Development's RAFT program provides substantial help with utility and heating bills. Unlike other federal bill assistance programs, RAFT's requirements and regulations tend to change with each fiscal year. Often to qualify for RAFT assistance, households must have at least one dependent child under the age of 21 and at risk of homelessness. Utility bill payments will be made only as part of family re-housing or stabilization plans. RAFT funds are administered by regional non-profit agencies.[121]

Although many bill assistance programs exist, there is still limited federal funding available in most states for low-income residents, and some funding is available from utilities in some states. Many state programs also have trouble reaching their target populations. Even in states with more successful bill assistance programs (e.g. California, New York, Illinois, etc.), only about 1% of the eligible population are reached annually.[122] Although many households receive assistance and can avoid disconnection through bill assistance programs, they are not an effective long term solution.

WEATHERIZATION AND ENERGY EFFICIENCY PROGRAMS

Through upgrading the efficiency of homes, households can reduce the burden of their energy bills. Programs that focus on weatherization and energy efficiency fund longer term solutions to household energy burdens by cutting wasted energy, improving comfort, and lowering costs.[123] Weatherization and energy efficiency retrofits are multi-benefit approaches to alleviating many consequences of living in poverty. When done holistically, the infrastructure and ventilation improvements and use energy efficient appliances that characterize these programs can save a household from undue energy burdens and environmental health hazards.[124] Low income households, the same that are most at risk of utility disconnections, are more often living in sick buildings, homes, and communities with poor environmental health conditions.[125]

Weatherization programs install energy efficiency upgrades aimed at improving the physical space between the interior and exterior of a building, such as weather-stripping doors and windows, air sealing (as seen in the picture above), and installing insulation. Weatherization programs also fund upgrades or repairs to heating and cooling systems.[126] The most effective weatherization and energy efficiency programs address the largest household energy uses with the longest sustained savings (e.g. heating and cooling), which often have the greatest impact on reducing energy burdens.[127]

Weatherization of homes is easy and effective way to reduce energy use
Source: [Habitat for Humanity, Prince William County, VA]

Unlike bill assistance and most weatherization programs, utility energy efficiency programs can include a variety of program strategies. Some utility energy efficiency programs operate in tandem with local or statewide weatherization efforts, using similar channels to reach customers. The most common low-income energy efficiency approaches are whole-building weatherization, and the installation of low-cost energy efficiency measures (e.g., efficient lighting, high-efficiency showerheads and faucet aerators, and air infiltration reductions). Some utilities operate direct-install programs targeting multifamily rental buildings as part of their low-income program offerings.[128] Building upgrades through weatherization and energy efficiency programs are the primary way of reducing the likelihood of non-payment that most households can employ.

Reductions in energy bills often equal reductions in the risk of disconnection. Even still, investment in energy efficiency and weatherization programs is an underutilized strategy.[129]

INCLUSIVE FINANCING MODELS

Programs that help utility customers pursue home improvements can reduce monthly utility bills. With energy efficiency measures alone, customers are predicted to save $2 trillion by 2030. Inclusive financing programs use a utility tariff rather than a loan to finance cost effective energy upgrades, and they break down the barriers to access so that these savings can be realized. [130] These models are providing an avenue for access for utility customers who may not qualify for direct install programs for low-income customers yet still struggle to make ends meet and keep the lights on.

Utilities that offer inclusive financing can remove major barriers to energy efficiency and renewable energy development by allowing customers to opt into a tariff that authorizes the utility (1) to make site-specific investments in cost effective energy upgrades and (2) to recover its costs with a charge on the bill that is significantly less than the estimated savings. Where inclusive financing programs exists, they are open to all utility customers regardless of their income, credit score, or renter status.[131] Figures 4 and 5, from the Institute for Local Self-Reliance's Energy Democracy Initiative, illustrates the how inclusive financing works in the utility space. Utilities provide contractors with the upfront funding for onsite energy efficiency, weatherization, and renewable energy projects. The resulting savings from those projects is more than the costs added to the utility bill as payment for the project installation and infrastructure. The result is lower monthly utility bills. No utility offering inclusive financing based on the Pays As You Save®(PAYS®) system has reported a single disconnection for non-payment among program participants.

Many utility cooperatives have seen inclusive financing models work. At Roanoke Electric, a utility cooperative in a persistent poverty area of North Carolina, the Upgrade to $ave program has invested in upgrades at more than 300 homes. The estimated average monthly net savings for participating customers

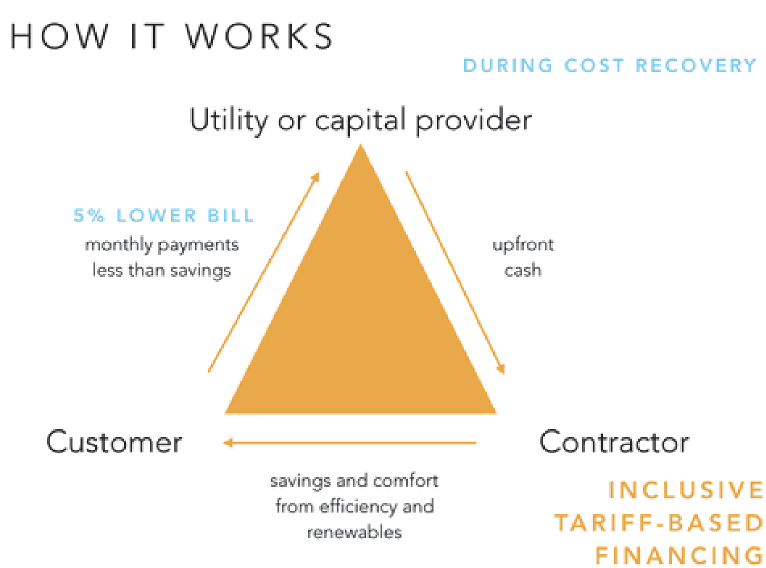


Figure4. Inclusive Financing Model, Source: Local Self-Resilience Energy Democracy Initiative

is around $50, as they pay the monthly program service charge that is capped at 75% of the estimated savings - so the customer net savings from the beginning. [132] With these savings, inclusive financing models have the express potential to reduce and eliminate utility disconnections and provide critical services to vulnerable populations.

Figure 5. Simple overview of how inclusive financing works

THE NEED FOR UNITERRUPTED SERVICE

"What kind of world do we live in where children can die a fiery death and there is no massive outcry?...We call on everyone opposed to this constant inhumanity against poor people to join us...and demand an immediate moratorium on gas and light shutoffs,"

-Maureen Taylor, State Chairperson, Michigan Welfare Rights Organization

The establishment of a universal **right to uninterrupted energy service** would ensure that provisions are in place to prevent utility disconnection due to non-payment and arrearages.[133] Toward establishing such a right, we call for all utility companies to advocate for and incorporate the following foundational principles into their models, operations, and policies:

1. Secure **ACCESS** to utility services for all households;
2. **INCLUSION** of all customers in the development of utility policies and regulations;
3. **TRANSPARENCY** of the actions of and information held by utility companies, regulating bodies, legislatures, and utility affiliated organizations;
4. **PROTECTION** of the human and civil rights of all customers; and
5. Advance programs that help **ELIMINATE POVERTY**, so that all customers can pay utility bills.

Maureen Taylor of the Michigan Welfare Right Organization
Source: Wiley Price

The policies and protections detailed in this report represent stop-gap measures to lessen harms wrought by a system that is predicated on amassing profits without regard to the impacts on people. In advancing energy justice, all individuals have the right to: safe, sustainable energy production; the resilient and updated energy infrastructure; affordable energy; and uninterrupted energy service.[134] The NAACP calls for the development of policies and utility structures that improve energy efficiency throughout the energy continuum, advance clean and renewable energy production, encourage and enable the development of distributed generation, and protect human life and wellbeing. We further call for a system that puts power in the hands of the people, literally and figuratively. These aspects are components of the larger utility system change that we must build.

Source: [People over Profit, twitter.com]

There are proven pathways for change. As demonstrated, improved energy efficiency would lower energy bills and make it less likely for utility customers to fall into arrears.[135] The same is true of distributed generation, particularly when paired with Pay As You Save (PAYS) models that would allow households to pay very little for electricity.[136] With greater energy independence and reliance on renewable sources, the entire energy system would be less vulnerable to market fluctuations, which would stabilize costs.[137] Through reducing emissions from fossil fuel based energy production, climate change mitigation goals would also benefit from these shifts. Therefore, the tremendous expense of disaster related outages, which are increasing and have real impacts on utilities' budgets,[138] would be reduced—protecting customers from yet another hazardous outage that is outside of their control.

Utility customers who are disconnected due to non-payment should not face the potential of death and suffering when viable solutions exist. Much action is needed to cease this needless endangerment. Now is the time to expand the research and evidence surrounding the impacts and issues of utility disconnections, as well as reform how we manage and operate the entities that supply these critical services.

IMPROVED DATA COLLECTION, RESEARCH, AND TRANSPARENCY

"For some customers, there is "a permanent level of unaffordability built into the rates."

-William Yates, Senior Financial Analyst, Public Utility Law Project of New York.

There is a need for more extensive and transparent data and research concerning utility disconnections, nationwide. Until this information is more readily documented, shared, and analyzed our message will be more easily ignored. Where this information does exist, it needs to be made publicly available, especially to customers of utilities.

RECCOMENDATIONS FOR UTILITY COMMISSIONS, REGULATORS, AND UTILITIES

It is the responsibility of utility companies and those who regulate them to ensure that records and data of disconnections are documented and made publicly available, at minimum, to its customer base. In accordance with the rights, principles, and actions previously discussed, we advise public utility commissions, regulators, and utility companies to:

1. Set strict record keeping standards of the entire disconnection/ termination of service process;
2. Conduct studies on the financial and human costs of utility disconnections;
3. Make records of disconnection publicly available on commission, utility, or government websites; and
4. Use this information to evaluate and improve disconnection protection policies and safeguards.

Members of the Committee Against Utility Shutoffs (CAUS) speaking at a community event
Source: CAUS

RECCOMENDATIONS FOR GOVERNMENT AGENCIES AND ORGANIZATIONS

Several federal and state agencies and organizations collect, analyze, and release data and reports regarding the U.S. energy industry at multiple scales (e.g. U.S. Energy Information Administration). To the extent that utility disconnections are a part of these analyses is currently unknown, however, moving forward, it is imperative that this information be included and made publicly available. In accordance with the rights, principles and actions previously discussed, we advise these government agencies and organizations to:

1. Maintain extensive and up to date databases containing disconnection data provided by utility companies and regulatory sources;
2. Obtain, analyze, and make transparent aggregate utility disconnection data in U.S. energy sector reports; and
3. Hold public utility commissions, regulators, and utility companies accountable for providing complete datasets for assessment and dissemination.

RECCOMENDATIONS FOR UNIVERSITY AND NON-PROFIT RESEARCHERS

As a society, we rely on academic and professional research for input into policy development. Thus, researchers from universities and organizations with research capacity (e.g. National Consumer Law Center and the Consumer Federation of America) must also be aware of these issues and conduct studies that foster better understanding of the connections between utility disconnections, their impacts on households, and other industries and sectors. We are asking researchers from colleges, universities, and capable non-profit organizations, particularly those with strong environmental and energy justice programs, to:

1. Expand research on socially conscious utility and energy models;

2. Advance research that impacts all parts of society, particularly vulnerable populations;
3. Partner with communities in and promote community participatory research models; and
4. Use expanded data in accordance with the principles and rights outlined.

UPHOLDING HUMAN RIGHTS IN THE SHORT TERM

"**Utilities are a social right. People have a right not to freeze to death! They have the right not to live on the bare edge of survival. To realize this right, however, we must fight for it. And this demonstration is an initial stage in this fight.**"

-Lawrence Porter, CAUS chairman and SEP Assistant National Secretary[139]

While the end goal is clear—**to prioritize utility policies that place a moratorium on utility service disconnections**— these principles can be furthered through the following practices:

PROCEDURAL PROTECTIONS

1. Require multiple attempts by phone, in writing, and, in person contact before disconnection;
2. Secure notification of disconnection by mail;
3. Require a post-disconnection notice to all customers;
4. Provide additional notice provisions for customers who can be disconnected remotely;
5. Restrict disconnections between 8:00am-2:00pm (or during hours of operations, and not later than 2 hours before close of business) on days when utilities have employees available for reconnections;
6. Provide notice and utility disconnection policies in multiple languages;
7. End policies surrounding disconnection and reconnection fees;
8. Cease the collection of deposits for utility service activation and/or reconnection;
9. Ensure that renters retain access to energy services when nonpayment is the fault of the landlord or other third party;

SEASONAL PROTECTIONS

10. Include seasonal protections with both temperature and date-based solutions;
11. Set disconnection arrearage minimums for customers who use utility services as the primary source of heating or cooling during periods of seasonal protection;
12. Provide utility services during extreme weather events that fall outside of seasonal protection periods;

Committee Against Utility Shutoffs (CAUS) Utility Shut-off Demonstration in Detroit, MI
Source: CAUS

PAYMENT ASSISTANCE

13. Allow budget payment plans to distribute utility costs throughout the year;

14. Allow partial payment plans to customers to prevent disconnections;
15. Provide connections to social services and case management resources for households with delinquent bills (i.e. budgeting, food assistance, and other social services);

PROTECTIONS FOR HOUSEHOLDS THAT ARE SOCIALLY VULNERABLE

16. Establish simple procedures for socially vulnerable groups to apply and be registered for protection from disconnection;
17. Implement customer surveys in advance of extreme weather seasons to screen for socially vulnerable individuals;
18. Ensure active outreach to socially vulnerable customers and households for inclusion in protection programs; and
19. Registration into these programs should be complimented with a notification to local and/or state emergency relief agencies and safety responders.

RECCOMENDATIONS FOR UTILITY COMPANIES

With the intent to incorporate human rights into existing utility business models, we advise Utility Companies and affiliate organizations to:

1. Operate according to the principles and practices of human rights; and
2. Cease investments and lobbying practices that undermine the right to uninterrupted utility services.

INVESTOR-OWNED UTILITY ENGAGEMENT

While every state has different regulation rules, it is a common practice to contact the utility as the first step to engagement. Investor-owned utilities are regulated by the Public Service Commission (PSC)/Public Utility Commission (PUC). Generally, PSC/PUC deal with problems or issues that the consumer feels were not solved by the utility, such as,

- Service installation and line extensions
- High bills
- Quality of service
- Meter tests
- Reasonable payment arrangements
- Outages
- Incorrect rates or tariffs
- Unauthorized switching of utility service from one

RECCOMENDATIONS FORPUBLIC UTILITY COMMISSIONS AND REGULATORS

With the intent to incorporate human rights into existing utility business models, we advise Public Utility Commissions, and regulators to:

1. Enforce and adhere to the principles and practices of a human rights based utility model;
2. Hold public hearings to investigate the extent and nature of disconnections in services areas;
3. Mandate exploration and implementation of energy efficiency, clean energy, and distributed generation programs and technologies;
4. Ensure that regulatory processes, meetings, and proceedings are accessible to all customers; and
5. Hold themselves and utility companies accountable to the concerns of customers.

RECCOMENDATIONS FOR LEGISLATURES

With the intent to incorporate human rights into existing utility business models, it is critical that legislatures:

1. Amend legal definitions of "public interest" to incorporate additional aspects of human rights;
2. Establish policies mandating the principles and practices of the right to uninterrupted utility service;
3. Pass legislation that enables the advancement of energy efficiency and clean energy programs and technology;
4. Pass legislation that enables the advancement of energy independence;
5. Provide utility commissions with a clear public interest mandate to authorize and encourage commissions to regulate on new challenges and topics including climate change, rising energy costs, air pollution, new technologies, and racial discrimination.

Traditional and innovative public interests related to disconnection policies could include: the health, safety, and welfare of the public; consumer protection from monopoly market power; protection of low-income members of society; protection of socially vulnerable groups; protection of socioeconomic group who are disproportionately impacted by utility disconnections; enabling consumers to pay for utilities.

RECCOMENDATIONS FOR UTILITY CUSTOMERS AND CONSUMER ADVOCATES

As customers and advocates, our goal in the short term is to stop the suffering of vulnerable communities and those who face utility disconnection now. We as advocates who seek to secure disconnection policies that fall outside of traditional regulations and protect the right to uninterrupted utility services must:

1. Directly engage state and local legislatures before a commission will pass regulations;
2. Demand legislatures pass specific authorizations for these regulations;
3. Petition utilities and public utility commissions to adopt these principles;
4. Hold utilities accountable for supporting the human rights of customers by documenting and building the evidence of how human and civil rights are violated;
5. Partner with research institutions to conduct community participatory research;
6. Demand improved access to Public Utility Commission and regulatory meetings and proceedings;
7. Demand increased transparency of the operations of utility companies and their affiliates; and
8. Enforce the demand for policies and practices that protect human life through grassroots advocacy (e.g. consumer education, direct negotiations, lobbying, direct action, media campaigns, and litigation where necessary, etc.)

By recognizing energy as a basic need and human right, households would ideally be protected by moratoriums whereby energy services would remain available indefinitely, particularly for vulnerable households and customers. However, right now the goal is to end the current suffering of households that are energy insecure by adopting these principles. In advancing more humane disconnection practices, we must recognize that protections do not curb utility debt accumulation or provide indefinite protections from suffering. Households who experience chronic energy insecurity are not only subjected to shut-offs, but also face increased financial liabilities, exposure to additional health risks, and residential and economic instability.[140] The policies and strategies outlined here represent a movement toward a more humanistic utility model, however, we must exemplify the change we want to see. We must develop community solar gardens and engage in community aggregated choice, while advocating for policies that move communities toward energy sovereignty (e.g. energy efficiency, clean energy, distributed generation, local hire provisions, disadvantaged business enterprise, etc.).

Advocates of the George Wiley Center, RI
Source: George Wiley Center

BUILDING ON THE LEGACY OF CHANGE

In solidarity with organizations and initiatives nationwide, we seek to advance the conversation and action around the creation of utility models that work for consumers and the environment. We stand with those who have worked for decades before us to remove the ills of utility disconnections, including TURN: The Utility Reform Network in California, the George Wiley Center in Rhode Island, the Utility Reform Project in Oregon, New York's Utility Project in New York, the Committee Against Utility Shutoffs (CAUS) and Michigan Welfare Rights Organization (MWRO) in Michigan, and national organizations like the National Consumer Law Center, and the Consumer Federation of America, among others. The work of these and other organizations have saved lives and secured the safety of so many in the states and regions in which they advocate and beyond.

Members of the George Wiley Center have successfully secured the strongest child protection in the country. In Rhode Island, there are guaranteed utility service protections for households in financial hardship with children under two years old. The Center has also challenged the State's Division of Public directly through collective community action to institute Emergency Restoration of utility service to medically vulnerable

LEADING DISCONNECTION PROTECTION WORK NATIONWIDE

TURN-: The Utility Reform Network [CA]advocates for customers and assists them with understanding their bills and utility practices. The group holds utility corporations accountable by demanding fair rates, cleaner energy and strong consumer protections.

http://www.turn.org/

George Wiley Center [RI] organizes people from low-income communities to advocate for systematic change. One of the major campaigns is based on utility justice. The "Know Your Utility Rights" clinics educate consumers on their rights and how to challenge the Division of Public Utilities.

http://www.georgewileycenter.org/utilities

Utility Reform Project [OR]is asking for a reform of the entire utility system. The group wants the control of electric utilities to be in the hands of customers and their elected officials. They want just utility rates and fair billing practices.

http://utilityreform.org/index.htm

New York Utility Project [NY] is advocating for universal service, affordability, and customer protection for New York State utility consumers.

http://utilityproject.org/

Committee Against Utility Shutoffs (CAUS) [MI] is asking for the stop to utility shut offs and for DTE Energy's top executives and government regulators to be held accountable for utility related fires.

https://www.facebook.com/stopshutoffs/

households. These are protections all states should have in place.

In December 2015, New York's Utility Project filed an amicus brief in the United States Supreme Court in Hughes v. PPL EnergyPlus, LLC. The organization sought answers to the following:

> *Whether, when a seller offers to build generation and sell wholesale power on a fixed-rate contract basis, the Federal Power Act field-preempts a state order directing retail utilities to enter into the contract; and whether the Federal Energy Regulatory Commission's (FERC's) acceptance of an annual regional capacity auction preempts states from requiring retail utilities to contract at fixed rates with sellers who are willing to commit to sell into the auction on a long-term basis.*[141]

The Utility Project frequently engages in such legal action to ensure that utility action is in accordance with customer interests and rights.

The NAACP stands with these organizations in the pursuit of the elimination of the practice of utility service disconnection. While establishing and expanding protections is pressing, advocates must remember that the goal is much larger. Utility companies and their associates must be held accountable and be leaders in the transformation of the energy sector. Equity will not be achieved overnight. It will only be achieved through hard work on the part of us all.

LONG TERM VISION

It is crucial to remember that the reforms we are calling for and the tactics we use to achieve them are in the short term to address the emergency circumstances in which all too many households find themselves. In the long term, we must continue to push for systems change, including distributed generation and people owned, human rights centered utilities. It is time to not only eliminate the harmful utility practices, but to correct the extractive economy that we currently face.

Each of the deaths and suffering detailed in this report is an indictment against the companies who wielded power and ignored the cries for mercy in the heartless pursuit of profits, and against the legislators and regulators who failed to provide adequate leadership. In the short term, we can push for the reforms as detailed above. But they've had their chance and it's time for a total system revolution.

The fight against the extractive economy is not about making things better for people who are poor; it is about eliminating poverty, racism, and other social and structural inequities that render households vulnerable. In 2015, the U.S. energy sector made $178 billion from residential energy use alone. As we focus on eliminating poverty while ensuring energy security, one way of doing this is to reform the energy sector, a $6 trillion sector, by transitioning power to the people and anchoring the change in increased energy efficiency distributed generation of clean energy.

There is an opportunity to reinvent this sector, to create a shared economy and keep this money in the hands of citizens. Some individuals, households, and communities have begun to move toward energy sovereignty. Stories such as Amy Mays, (see story on Page 33, *From Persecuted by My Utility to Powered and Empowered by the SUN!)*, provide an example of what can be. It is time for a Just Transition to localized economies, grounded in ecological stewardship, community wellbeing, democratic decision-making, and locally control resources (Figure 6). [142]

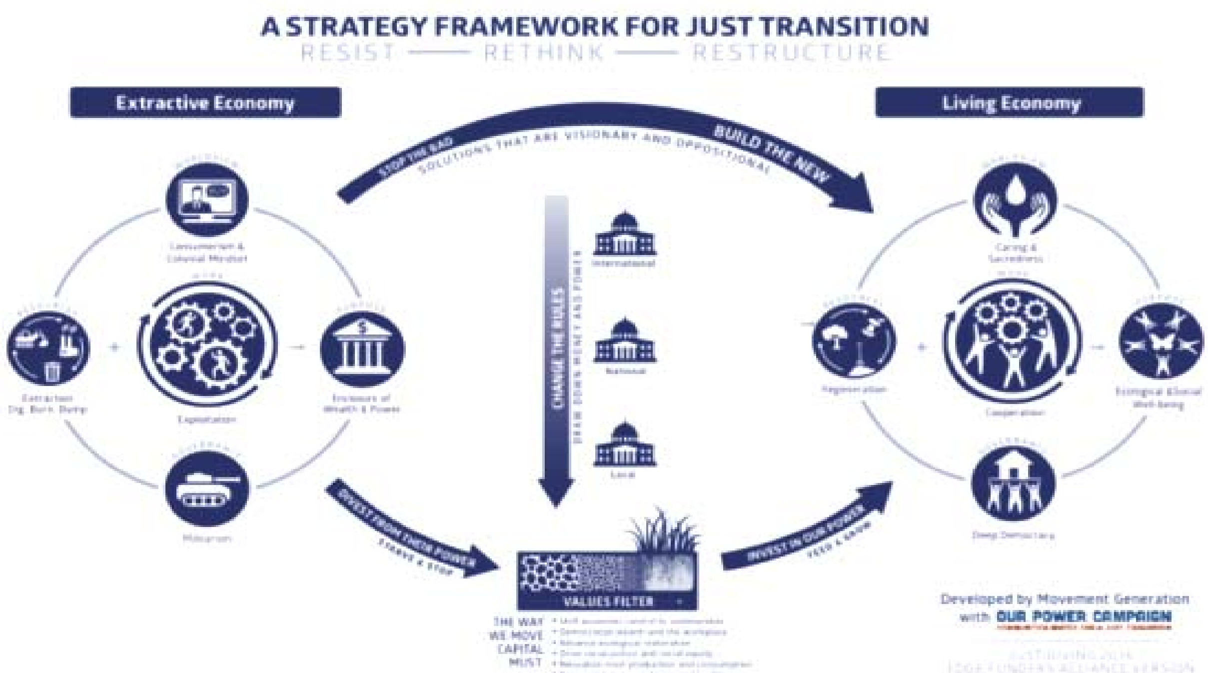


Figure 6. A Just Transition, Source: Our Power Campaign, Climate Justice Alliance

VISION IN ACTION

Amy Mays telling her story at an NAACP Energy Justice Training in 2016

FROM PERSECUTED BY MY UTILITY TO POWERED AND EMPOWERED BY THE SUN! - AMY MAYS, ARIZONA

My story began in 1994 when I opened a beauty shop for my daughter. After we had been in business for four years, my troubles began with the local utility company, Salt River Project (SRP), when they required that I pay an additional deposit to continue to receive electricity services. I fought, but eventually ended up paying the additional deposit. Then, in June 2003, the utility company demanded a further deposit, even though I was current on all payments.

I contacted the Arizona State NAACP office and they convinced the utility company to reconnect the electricity if I paid a portion of the deposit. However, in August 2003, SRP again disconnected the electricity requesting the remainder of the deposit. We did not have the money so they turned off the electricity, which resulted in the closing of our nearly ten-year old business. Even though our service was terminated, with all payments up to date, the utility company inexplicably continued to demand payment for this completely illegitimate "bill."

Since that bill from my closed business went "unpaid," to add insult to injury, the utility company disconnected the electrical power to my home on April 8, 2004.From 2004 to 2006 I suffered without electricity, living out of my ice chest.

When I first heard about solar panels in 2006 I began reading everything I could about them. I searched online until I located a solar system designed for off-grid cabins. I ordered my first solar system for $5,000. As a trained electrician, I had the skills to install the panels myself. I purchased additional solar panels one or two panels at a time, and the necessary equipment for installation, until I had accumulated enough for an additional system, which I also installed myself. As I've gotten older, I've trained another electrician to help maintain my solar panel system.

Ten years later, now in 2016, my home is still not connected to the utility-operated grid. I haven't paid an electricity bill since 2004, and the savings I have experienced as a result have been tremendous. Without an electricity bill to pay every month, my solar panels paid for themselves and I've been saving money ever since. I will never go back to the utility connection. Through my own rooftop solar panels, I have been liberated from the high rates the utility companies demand and the control they held over me!

With life threatening, high heat temperatures in Arizona, solar has literally saved my life!

I share my story with everyone I meet. In fact, my doctor was so inspired by my story that he recently had solar panels installed on his home. He, too, has been thrilled with his experience going solar and told me that last month his electricity bill has gone down to a mere $30.

It feels good to control my own power and not have to rely on the utility company for anything. I want people to know that if I can find independence through solar, then other people can do the same. The power from the sun is already there and always will be. Now people just need to find ways to use it!


NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE
NAACP
FOUNDED
1909

Boosting Energy Efficiency through On-Bill Financing

The Environmental and Energy Study Institute's (EESI) on-bill financing initiative is a nationwide effort to help implement programs that cost-effectively cut energy use and expand clean energy access to more home homes and businesses. EESI has assembled a team that will assist utilities to design, implement, and evaluate residential meter-based on-bill financing programs. EESI will also assist rural utilities with applications to two U.S. Department of Agriculture loan programs – the Energy Efficiency Conservation Loan Program (EECLP), and the Rural Energy Savings Program (RESP) – to capitalize their projects.

EESI provides assistance to utilities looking to implement on-bill financing (OBF) projects. EESI's project team is available to:

- Share firsthand experience and lessons learned from developing utility OBF programs
- Conduct a needs assessment to determine if OBF is a good fit for the utility and its member-customers
- Identify resources and coordinate with stakeholders to overcome barriers to implementation
- Help utilities design a project and access capital for financing
- Help utilities navigate the EECLP and RESP application processes
- Assist utilities to implement and troubleshoot their projects

On-bill financing programs can vary wildly in their design. EESI's model for a successful on-bill financing program incorporates flexibility to meet local needs while maintaining the following design principles:

- Loan rates need to be set at or below five percent, with extended payback times, in order to increase the likelihood that the loans will be cash-flow positive participants
- Participants should not be required to make upfront payments for home improvements
- Programs need strong quality assurance plans that keep contractors accountable
- Programs should finance "whole house" sets of energy efficiency improvement measures to maximize cost-effective savings, with a utility advisor or other 3rd party providing guidance to participants on the package that best fits their needs
- In order to be better accessible to low-income households, programs have to offer alternative methods of loan underwriting (i.e., good bill payment history in lieu of a credit check)
- Loans should be affixed to the meter, not the individual

EESI is a nonprofit that currently has grant funding to provide technical assistance to utilities to design innovative and inclusive on-bill financing programs for their customers. EESI has helped more than 15 utilities to develop or improve their customized on-bill programs. Learn more at www.eesi.org/OBF or contact us directly.

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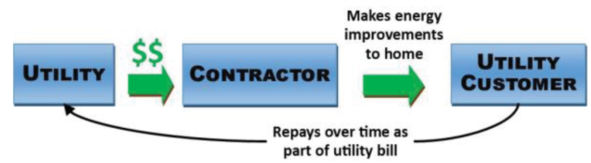
What is On-Bill Financing?

Simplified Example of On-Bill Financing Program



“On-bill financing” programs, in which utilities issue loans for energy improvements that are repaid as part of the utility bill, are an exciting opportunity to expand residential energy efficiency efforts around the country. Successful pilot models have shown that utilities of all types can use on-bill financing programs to significantly reduce peak demand, carbon emissions and fossil fuel use. By driving down the need for additional power generation, these programs can be a winning business strategy for utilities. On-bill financing programs can help alleviate poverty by reducing families’ energy bills, while creating community-based jobs and economic growth by keeping energy dollars local and building demand for energy efficient products.

Help My House **Pilot Program**

The “Help My House” pilot, implemented in 2011 and early 2012, produced very encouraging results among its 125 participating homes. Participants' energy bills were cut by 34 percent, saving an average of $288 per home per year after loan payments. “Help My House” was designed to address the special challenges and opportunities facing rural communities to save energy, cut household utility bills, and reduce greenhouse gas emissions, all while supporting high-skilled jobs and keeping more dollars in the local economy.

The pilot’s innovative approach provided low-cost financing to co-op members for “whole house” efficiency upgrades, without upfront costs or traditional credit checks. Loans are attached to the meter and repaid over 10 years through charges on each participant’s monthly bill. In most cases, monthly energy savings exceed the cost of loan payments. This improves participants’ quality of life by increasing discretionary income and improving home comfort.

The comprehensive "whole house" approach, in which all of the energy efficiency measures were evaluated as part of the same system. Participating homes received a combination of air sealing, duct repair, HVAC upgrades, and insulation improvements. More than 95 percent of participants reported that they were more satisfied with their co-op after participating in the pilot.

Average “Help My House” Pilot Results	
Project Costs	$7,684
Annual kWh Savings	10,809 kWh
kWh % Savings	34%
Annual $ Savings	$1,157
Annual Loan Repayment	$869
Annual Net $ Savings	$288
Project Simple Payback	6.6 years
kWh Savings over 15 years	162,135 kWh
Net $ Savings over 15 years	$8,665

Loan capital for the pilot came primarily from a U.S. Department of Agriculture loan, supplemented by South Carolina co-op funds. Thanks in part to the success of the pilot, federal programs have been created to help co-ops around the country to develop similar programs. EESI assisted with the design and implementation of the pilot project, working in cooperation with The Electric Cooperatives of South Carolina (ECSC), the association representing the state’s 20 distribution co-ops; and Central Electric Power Cooperative, the state’s generation and transmission co-op. EESI participated in the "Help My House" pilot program in part to help develop a model that could be replicated by co-ops and other utilities across the country.

The value of lost energy sales to the electricity supplier and power provider depends on a number of factors. If the load shape improves and load factor increases, this could help offset the financial impact of reduced revenue on the co-op. The timing of new generation is another factor. Central's power providers are currently projected to have surplus generation capacity for the next 15 years, an unforeseen result of the drop in electricity demand growth that has occurred as a result of the economic downturn of the last several years. Unless there are significant rate, regulatory or other changes, reducing energy sales will not have the effect of deferring new generation resources for many years.

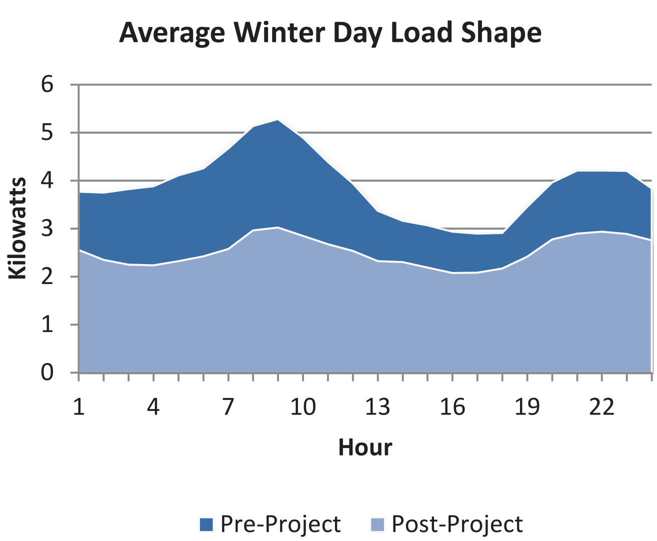
Demand Savings

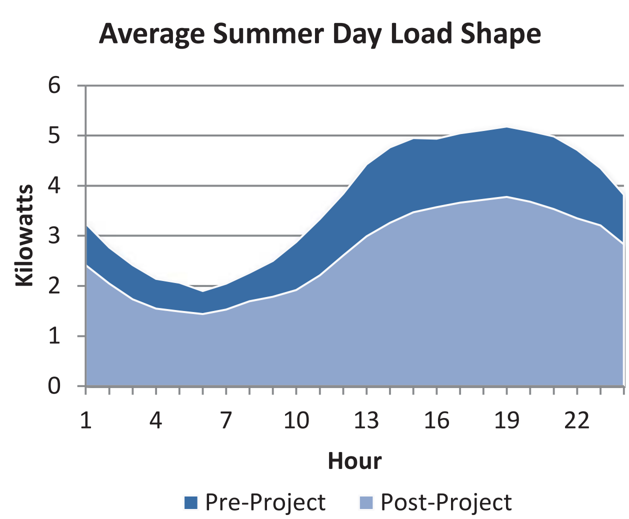
Residential users typically pay the same price per kWh regardless of when it is consumed, but the wholesale power that Central Electric purchases for its member co-ops consists of two components: an essentially flat energy charge across all hours and significant demand charges on monthly and annual peaks. The HMH pilot was designed, in part, to determine the effect of energy efficiency retrofits on peak consumption.

In the last several years, many of the homes served by co-ops in South Carolina have been equipped with advanced metering systems, which collect energy use data in hourly increments or even more frequently. Integral Analytics conducted an hourly billing data analysis on 48 of the 125 homes for which hourly use data was available in order to determine hourly savings during periods when the system was at peak demand.

The analysis models hourly use with hourly weather data, which enabled Integral Analytics to determine how the retrofits reduced energy use on the warmest summer days and the coldest winter days when the system was at peak demand. This model predicts how the retrofitted homes would perform during a typical meteorological day. The graphs below show the average hourly demand for each peak season. The difference between the pre-project line and the post-project line is the average hourly demand savings per home. The difference between the two lines over the entire year is the annual energy saved.

Figure 6 - Average Daily Load Shape by Season (kW)





The load shapes illustrate a substantial reduction in average use during peak hours. The reduced summer and winter loads make more efficient use of the distribution system, but the financial impact on the co-ops and the Central Electric system is determined by the load factor. Calculating load factor is a matter of dividing average energy by peak hourly demand. A higher load factor is desirable because it means the load is more constant. A more constant load is less expensive to serve because less money is needed to build or buy peak generation, transmission and distribution resources.

Integral Analytics conducted a billing data analysis on the homes with hourly data to calculate pre-project use during system peaks in a TMY. The table below shows what this model estimates the load factor to be before and after a HMH retrofit.

Table 9 - TMY Average Participant Load Factor Change (System Peak)

	Pre-Project (TMY weather normalized)			Post-project (TMY weather normalized)			Change in Load Fct
Month	**Avg kW**	**Peak kW**	**Load Fct**	**Avg kW**	**Peak kW**	**Load Fct**	
January	5.53	7.22	0.77	3.16	3.92	0.81	5%
February	4.74	6.74	0.70	2.82	3.75	0.75	7%
March	2.93	3.13	0.94	1.89	2.13	0.88	-5%
April	2.95	3.19	0.92	1.99	2.06	0.97	4%
May	2.87	3.99	0.72	2.01	3.04	0.66	-9%
June	3.52	5.08	0.69	2.48	3.70	0.67	-3%
July	3.76	5.03	0.75	2.69	3.66	0.73	-2%
August	3.52	4.54	0.78	2.48	3.12	0.79	2%
September	3.22	4.75	0.68	2.23	3.42	0.65	-4%
October	2.78	3.61	0.77	2.25	2.99	0.75	-2%
November	2.80	3.40	0.82	2.29	2.79	0.82	-1%
December	5.22	5.85	0.89	3.02	3.30	0.91	3%
Total			**0.78**			**0.78**	**0%**

Table 9 shows a reduction in average kW and peak kW occurring in all 12 months. Load factor, however, is a function of the relationship between average use and use during system peak. Use drops every month during the coincident peak, but the load factor increases in some months and decreases in other months. The net impact on load factor over the year is 0 percent. According to this analysis, homes that have undergone HMH retrofits would have no effect on system load factor.

The HMH pilot did not include any load management measures because doing so would have introduced additional variables into the analysis and weakened the co-ops' ability to draw conclusions on cost-effectiveness of the efficiency measures. The South Carolina co-ops have an existing demand reduction program which includes the installation of over 120,000 water heater switches and air conditioner control devices. To bring more value to the cooperatives and their members, demand reduction devices could be installed on homes receiving energy efficiency retrofits. A water heater switch reduces demand by 0.7kW in the winter time and 0.3kW in the summer. An air conditioner switch reduces the summer time peak an additional 1.0kW. Any combination of load reduction devices brings additional value to an efficiency retrofit program.

Value of Demand Savings

The residential member does not benefit directly from demand savings because the residential kWh rate is the same no matter when the electricity is used, and there is no demand charge. Several co-ops have time-of-use rates in the residential rate class, but they are rarely used by co-op members.

The distribution co-op, however, can benefit from demand savings. The value of demand savings to the co-ops is driven by wholesale power contracts that have significant demand components and can be as much as $15/kW per month. The price is higher for the power purchased during system peaks because Central pays more to suppliers during system peaks. Central buys most of its power from two generators: Santee Cooper and Duke Energy. The power they purchase consists of both monthly and annual demand charges on peak hours.

The analysis by Integral Analytics looked at demand during system peak hours each month and calculated a load factor, which is simply the average demand divided by peak demand. For a home to have a 100 percent load factor, it would use the same amount of energy for each hour of the year. The load factor for all South Carolina co-ops is 45 percent, which is below average compared to systems around the country.

For the distribution utility, reducing demand during coincident peak hours reduces expenditures for power purchase, and one to two kW per month in load management switches provide a counterbalance for some of the lost revenue that is caused by energy efficiency.

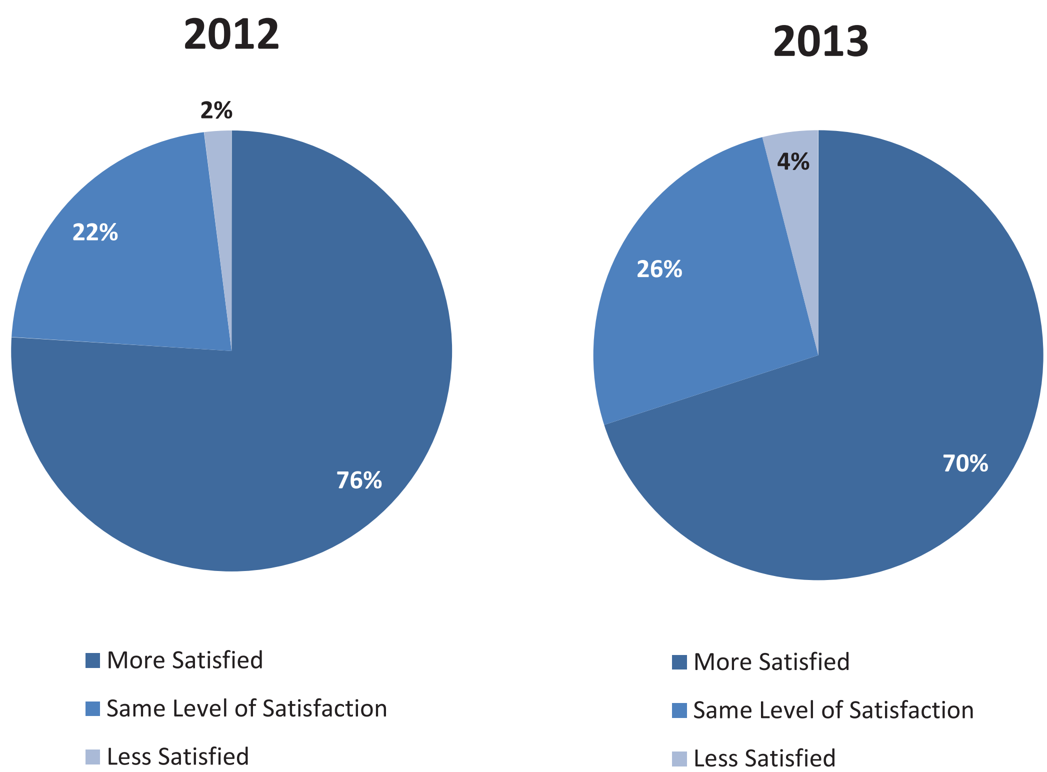
Member Satisfaction with the Pilot

Carton Donofrio Partners conducted two surveys after the HMH retrofits were complete. The first survey was conducted in early 2012, shortly after energy efficiency measures were installed but before participants had a good sense of how their homes were performing. This survey included participants as well as co-op members who knew of the pilot but did not participate. The second survey was conducted in March and April of 2013, a full year after the HMH homes had been retrofitted, and included only those consumers who participated in and completed the program.

The first survey provides a view into the opinions of both the participants and those who had been contacted about the pilot but did not participate. The vast majority (92 percent) of co-op members contacted about the pilot had the same or higher satisfaction with their co-op as a result of being contacted. Seventy-four percent of non-participants felt the same or higher satisfaction as a result of the program. This number is surprisingly high considering the fact that many of the members contacted about the program were on a high bill complaint list. The few non-participants who were less satisfied were disappointed that their homes did not qualify for the pilot despite high energy bills.

Both surveys asked participants about the level of satisfaction with the co-op compared to one year prior. Ninety-eight percent of the participants surveyed in 2012 had the same or higher level of satisfaction with the co-op compared to the previous year. In the 2013 survey, this number dropped slightly to 96 percent.

Figure 7 - HMH Participants Overall Co-op Satisfaction Compared to Year Before



Nearly all participants (96 percent) in the 2012 survey were satisfied with the installation of the efficiency measures. The same percentage of participants (96 percent) responded that they felt their homes were more comfortable after the improvements. The second survey reaffirmed the findings of a year earlier. In fact, 70 percent of program participants showed they are even more satisfied one year later.

Comfort is likely an important reason for this high level of satisfaction. After living in their newly efficient homes for a full year, 76 percent of program participants say their homes are a lot more comfortable, while an additional 13 percent say their homes are somewhat more comfortable.

In addition, participants are generally happy about their energy bills. Specifically, 89 percent of participants are either somewhat satisfied or very satisfied with post-retrofit electricity bills.

NIPSCO Public Advisory Meeting 3 Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Robert	Adams	AES-IPL
Lauren	Aguilar	OUCC
Anthony	Alvarez	OUCC
Mark	Anderson	Anderson & Anderson, PC
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Heidi	Aschbacher	Invenergy
Pat	Augustine	Charles River Associates
Kim	Ballard	IURC
Mike	Banas	NiSource
Alison	Becker	NIPSCO
Anne	Becker	Lewis Kappes
Richard	Benedict	Self
Mahamadou	Bikienga	NiSource
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Jeffrey	Brooks-Gillies	Freelance reporter
Kelly	Carmichael	NiSource
Kathleen	Castilloux	Beckwith Electric Co, Inc
Peter	Cavan	Centrica
Michael	Cella	Toyota Tsusho
Richard	Ciciarelli	Guggenheim
Paul	Ciesielski	ArcelorMittal USA LLC
Jeffrey	Corder	St. Joseph Phase II, LLC
Nicklaus	Corder	EnFocus Development
Bette	Dodd	Lewis Kappes
Jeffery	Earl	Indiana Coal Council
Claudia	Earls	NiSource
Amy	Efland	NiSource/NIPSCO
Gregory	Ehrendreich	MEEA
Andrew	Fay	First Solar
Steve	Francis	Sierra Club - Hoosier Chapter
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Barry	Halgrimson	Retired
Allison	Holly	GE
Shelby	Houston	IPL/AES
James	Huston	Indiana Utility Regulatory Commission
Ben	Inskeep	EQ Research
Francisco	Itriago	IPL
Lynn	Jensen	Marathon Petroleum Company LP
Alex	Jorck	Whole Sun Designs Inc
Sam	Kliewer	Cypress Creek Renewables
Corey	Kupersmith	Sun2O Partners

NIPSCO Public Advisory Meeting 3 Registered Participants		
First Name:	Last Name:	Company:
Willard	Ladd	Development Partners
Tim	Lasocki	Orion Renewable Energy Group LLC
Joe	Lesches	Stone Capital
Jonathan	Mack	NIPSCO
Patrick	Maguire	Indianapolis Power and Light
James	Mangrum	Arcelor Mittal
Cyril	Martinand	ArcelorMittal
Christian	Martinez	First Solar
Karen	McCoy	Nipsco
Cassandra	McCrae	Earthjustice
Jim	McMahon	CRA
Emily	Medine	EVA
Zachary	Melda	NextEra Energy Resources
Nick	Meyer	NIPSCO
Ana	Mileva	Blue Marble Analytics
Troy	Miller	GE Power
Kevin	Moore	MIDWEST WIND & SOLAR LLC
David	Nderitu	State Utility Forecasting Group
Adam	Newcomer	NIPSCO
Mark	Noll	Charles River Associates
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Pamela	Paultre	NextEra Energy Resources
Jodi	Perras	Sierra Club
Carmen	Pippenger	IURC
Geof	Potter	None
Mark	Pruitt	The Power Bureau
Dennis	Rackers	Energy & Environmental Prosperity Works!
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
Emily	Rhodes	Delta Institute
Matt	Rice	Vectren
Adam	Rickel	NextEra Energy Resources LLC
Tonya	Rine	Vectren Corporation
Woody	Saylor	St Joseph Energy Center
Carter	Scott	Ranger Power LLC
Cliff	Scott	NIPSCO
Rob	Seren	NIPSCO
Julie	Shea	NiSource
Regiana	Sistevaris	Indiana Michigan Power Company
Violet	Sistovaris	NIPSCO
Anna	Sommer	Sommer Energy, LLC
Dick	Spellman	GDS Associates, Inc.
Jennifer	Staciwa	NIPSCO
Karl	Stanley	NiSource

NIPSCO Public Advisory Meeting 3 Registered Participants		
First Name:	Last Name:	Company:
Liz	Stanton	Applied Economics Clinic
Brian	Steinkamp	PSG Energy Group
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Alice	Thare	peabody
Dale	Thomas	IURC
Bob	Veneck	Indiana Utility Regulatory Commission
Victoria	Vrab	NIPSCO
Victoria	Vrab	NIPSCO
John	Wagner	NIPSCO
Jennifer	Washburn	CAC
Keith	Weber	NiSource
Tyler	Welsh	PSG ENERGY GROUP, LLC
Ashley	Williams	Sierra Club
Bryndis	Woods	Applied Economics Clinic
Fang	Wu	SUFG
Rex	Young	Cooperative Solar LLC

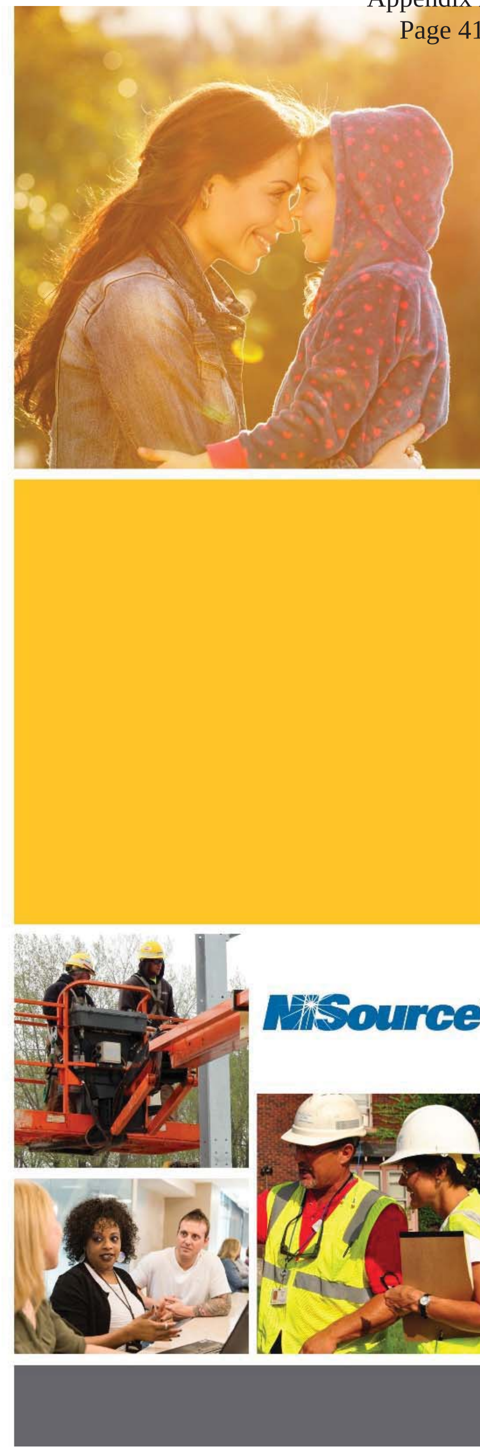
Appendix A

Exhibit 4

NIPSCO Integrated Resource Plan 2018 Update

Technical Webinar

August 28, 2018



Welcome and Introductions

Process for Today's Webinar

- In order to best facilitate today's discussion, we are asking that you use the "chat" feature on the webinar to ask questions.
- Please type your question at any point and it will be read to the audience by the facilitator.
- When entering your question, please include your name and organization you are representing (if applicable).
- After the material has been presented, we will allow for additional discussion as time permits.
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received.
- We look forward to your thoughts and questions!

Agenda

Time (CENTRAL TIME)	Topic
1:00 – 1:15	Welcome, Introductions, and Safety Moment
1:15 – 2:15	Incorporating the RFP Results into the IRP
2:15 – 2:30	Next Meeting / Wrap Up

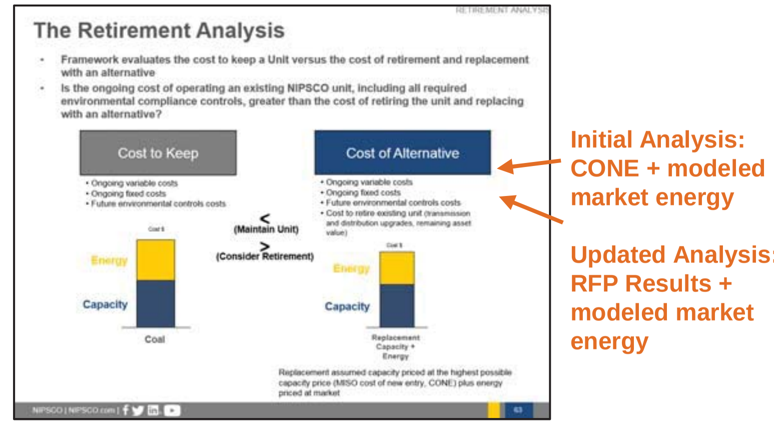
Incorporating the RFP Results into the IRP

Pat Augustine
Charles River Associates (CRA)

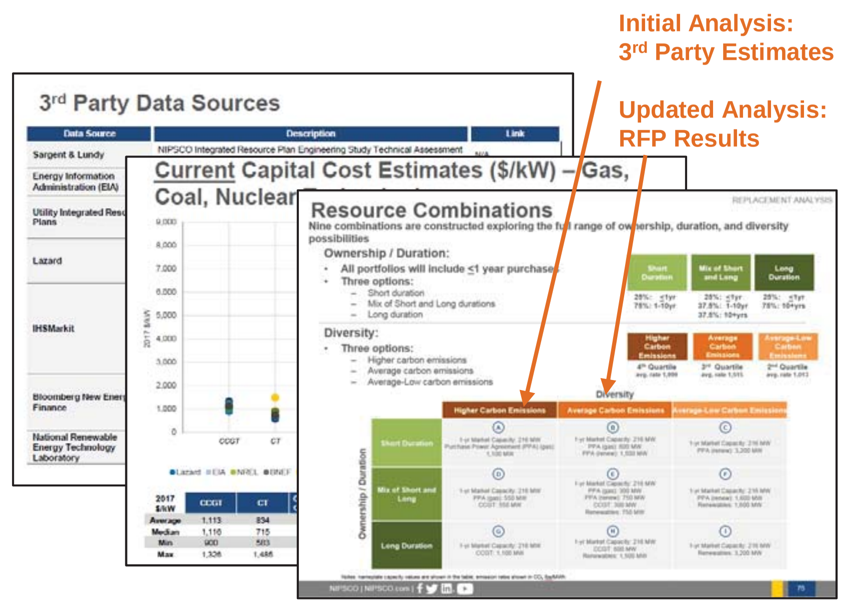
Recap: How Will The RFP Feed Into The IRP?

The results of the RFP will feed back into the IRP to inform both the retirement analysis and the replacement analysis

- **Retirement Analysis**
  - MISO Cost of New Entry ("CONE") plus market energy was used in the initial IRP analysis as a proxy for replacement costs
  - RFP results provide known and visible replacement costs and volumes
  - Representative project groups will be constructed from RFP results, assembled by technology and ownership, for use in the updated IRP analysis
  - Retirement analysis will be re-run using the representative RFP projects as selected by the optimization model



- **Replacement Analysis**
  - Initial IRP replacement costs used estimates from multiple third-party data sources; no visibility into actual replacement costs for projects available to NIPSCO
  - RFP results provide visibility into executable alternatives for NIPSCO
  - Replacement analysis will be run using somewhat simplified and anonymized RFP results



Why Organize Bids into Representative Groups or Tranches?

- **The IRP is intended to evaluate and select the best resource mix (technology) and future portfolio constructs, and *not* to select specific assets or projects**
  - While now highly informed by current and actionable RFP data, the IRP is meant to develop a planning-level recommended resource strategy (Preferred Plan)
  - Asset-specific selection requires an additional level of diligence (assessment of development risk, locational advantages or disadvantages, transmission system impacts, etc.)
- **The IRP is a highly transparent and public process that requires sharing of major inputs with all stakeholders**
  - Evaluating asset specific options from the RFP raises confidentiality concerns as that could reveal bid specific cost and technology data which bidders typical consider as proprietary and confidential information
- **The IRP modeling is complex, and resource grouping improves the efficiency of the process**
  - Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller aggregate data set improves the efficiency of setup and run time

IRP Analysis: Tranche Development and Assessment

- **A three-step process to update and run the IRP models is currently in process**

1 Tranche Development

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Operational characteristics
- Aggregated cost and operational information is entered into Aurora model to be considered in optimization step

2 Portfolio Optimization

Select Portfolios

- Based on capacity need and other constraints, identify which tranches (or portions of tranches) are selected for the portfolio through Aurora optimization

Confirm Viability

- Confirm that optimization model is selecting feasible block sizes based on resource-specific data

3 Portfolio Creation and Modeling

Create & Analyze Portfolios Based on Optimization

- Tranches are chosen for retirement and replacement analysis based on % selected by optimization model when confirmed as viable
- Portfolios are then run across full set of scenarios and stochastics

❶ Tranche Development

- **Bids are aggregated and similar resources are combined into representative tranches**
  - Bids are sorted by bid type (PPA or asset sale), technology type, duration, online year, and cost
  - Price and operational characteristics for the tranche are calculated using weighted average of individual bids within the tranche
  - Certain tranches contain only one bid, if the bid had unique characteristics that make it difficult to aggregate

Representative and Illustrative

PPA Solar Tranche Example

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)	Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	-	2023	20	$27.xx	-
•••							
Bid 9	Solar	275	138	2023	20	$32.00	24%
Bid 10	Solar	100	50	2023	20	$34.00	24%
Bid 11	Solar	75	38	2023	20	$34.00	23%
Bid 12	Solar	25	13	2023	20	$35.00	24%
Bid 13	Solar	500	250	2023	25	$35.00	25%
•••							
Bid 26	Solar	-	-	2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	488	2023	23	$33.93	24.2%

*Capacity and bid prices are rounded to the nearest 25 MW and dollar respectively to preserve confidentiality.

❶ Tranche Development

- Some technology types have multiple bids with the same project, requiring tranches to be developed for PPA and asset sale options and for different durations, as necessary

Representative and Illustrative

CCGT Tranche Example

PPA

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year	PPA Term (years)
PPA Bid 1	CCGT	250	250	2023	6
PPA Bid 2	CCGT	625	575	2023	30
PPA Bid 3	CCGT	625	625	2023	30
PPA Bid 4	CCGT	725	700	2023	20
PPA Bid 5	CCGT	600	600	2023	30

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (years)	Cost range** ($/kW-mo)
PPA CCGT #1	1	250	250	2023	6	
PPA CCGT #2	4	2,575	2,500	2023	27	

Sale

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year
Sale Bid 1	CCGT	625	625	2023
Sale Bid 2	CCGT	625	625	2023
Sale Bid 3	CCGT	1,025	925	2023
Sale Bid 4	CCGT	725	700	2023

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	Price Range** ($/kW)
Sale CCGT #1	2	1,250	1,250	2023	
Sale CCGT #2	2	1,750	1,750	2023	

*Capacity is rounded to the nearest 25 MW.
**Given the small number of projects within each CCGT tranche, PPA costs and asset sale prices are not being shown to preserve confidentiality. Note that PPAs were structured as tolling arrangements with fixed cost capacity payments (in $/kW-mo) plus certain variable charges (in $/MWh).

❷ Portfolio Optimization and Selection

- **Optimization modeling allows for portions of tranches containing multiple resources to be selected**
  - After the optimization step, CRA confirms that resource selection is reasonable given available resources in tranche

Representative and Illustrative

Sample Optimization Model Output (Percentage Selected)				
Tranche Name	**Illustrative 2023 Retirement Portfolio**			
	No Retirements	**Schahfer 17/18 Retires**	**All Schahfer Retires**	**All Schahfer + Michigan City Retire**
Indiana Solar + Storage #2 (PPA)		100%	100%	100%
Indiana Solar + Storage #3 (PPA)			100%	100%
Indiana Solar #2 (PPA)		96%	100%	100%
Indiana Solar #3 (PPA)			100%	100%
Indiana Solar #4 (PPA)			8%	70%
Indiana Wind #1 (PPA)		83%	83%	83%
Indiana Wind #2 (PPA)		57%	57%	57%

Confirm viability based on resources in tranche when portions are selected*

- Indiana Solar #4:
  - 8% of Indiana Solar #4 tranche is ~100 MW of nameplate solar, a reasonable block size for this technology and tranche based on the bids within it
- Indiana Wind #1:
  - 5 unique resources in tranche, 4 least expensive bids make up 89% of tranche, close to optimization model selection of 83%

*The optimization model may select only portions of a tranche, due to capacity need, reserve margin constraints, and other economic factors.

❸ Detailed Portfolio Creation

- **Portfolio optimization, using the tranches as resource options, is now being performed for both the retirement and replacement analyses to:**
  - Fill retirement gaps (MW) across different retirement portfolios (as shown in the illustrative example in the previous slide)
  - Build out replacement options across duration and diversity (emissions) matrix to test full range of portfolio alternatives, as shown below)

Diversity

Ownership / Duration	More Fossil	⟵ ⟶	More Renewables
Shorter Duration	*Select from gas/coal tranches with shorter duration*		
Longer Duration		**Portfolios being developed for combinations across both dimensions**	*Select from renewable tranches with longer duration*

- **IRP will evaluate performance of each portfolio across *all* scorecard metrics**
- **Further narrowing down and modeling of bid-specific costs and parameters at the asset-level to be completed <u>in later RFP selection process</u>**

How UCAP Was Determined From RFP Bid Data

MISO UCAP Determination By Resource Type

- **UCAP is based on historical unit availability**
  - This accounts for forced outages and derates on most resource types
  - Renewables and other types of intermittent resources are awarded UCAP based on historical average output during the summer for hours ending 15, 16, and 17 EST
  - New resources are awarded UCAP based on class averages by resource type until historical information is available

UCAP Calculation Methodology For IRP

- **For projects with operating history, actual UCAP data was used if provided**
- **For new projects, CRA and NIPSCO have used MISO rules based on unit type:**
  - Fossil units are de-rated based on a forced outage rate provided
  - Intermittent renewables are applied class-specific de-rates for generic technologies
  - Storage resources are assumed to provide full capacity credit if they can meet 4-hour peak

MISO Planning Year 2018-2019 Pooled EFORd Class	
Resource Type	**Average UCAP (%)**
Combined Cycle (CCGT)	95
Combustion Turbine	71 - 94
Nuclear	91
Pumped Storage	91
Steam - Coal	92
Steam - Gas	88
Steam - Oil	91
Steam - Waste Heat	91
Steam - Wood	91
Hydro	91
Wind	15
Solar	50 - ?

Illustrative Example For New Projects					
Resource Type	**Capacity Offered (ICAP)**			**Calculation Example**	**Resulting UCAP**
CCGT	100 MW			100 * (1 – .05)	95 MW
Wind	100 MW			100 * (0.15)	15 MW
Solar	100 MW			100 * (0.5)	50 MW
Solar + Storage	100 MW solar		30 MW storage	100 * (0.5) + 30	80 MW
Wind + Storage	100 MW wind		30 MW storage	100 * (0.15) + 30	45 MW
Wind + Solar + Storage	100 wind	100 solar	30 MW storage	100 * (0.15) + 100 * (0.5) + 30	95 MW

Next Steps / Wrap Up

NIPSCO Public Advisory Technical Webinar Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Robert	Adams	AES-IPL
Anthony	Alvarez	OUCC
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Jeffrey	Corder	St. Joseph Phase II, LLC
Nicklaus	Corder	EnFocus Development
Jeffery	Earl	Indiana Coal Council
Amy	Efland	NiSource/NIPSCO
Steve	Francis	Sierra Club - Hoosier Chapter
Richard	Gillingham	Hoosier Energy
Doug	Gotham	State Utility Forecasting Group
Robert	Greskowiak	Invenergy LLC
Barry	Halgrimson	Retired
Jeffrey	Hammmons	Environmental Law & Policy Center
Rina	Harris	Vectren
John	Haselden	OUCC
Shelby	Houston	IPL/AES
Jim	Huston	Indiana Utility Regulatory Commission
Ben	Inskeep	EQ Research
Dave	Johnston	Indiana Utility Regulatory Commission
Alex	Jorck	Whole Sun Designs Inc
Will	Kenworthy	Vote Solar
Mark	Kornhaus	NextEra Energy
Stefanie	Krevda	Indiana Utility Regulatory Commission
Tim	Lasocki	Orion Renewable Energy Group LLC
Tracy	Leslie	EPRI
Patrick	Maguire	Indianapolis Power and Light
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Emily	Medine	EVA
Zachary	Melda	NextEra Energy Resources
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Bob	Pauley	IURC
Timothy	Powers	Inovateus Solar LLC
Dennis	Rackers	Energy & Environmental Prosperity Works!

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Tonya	Rine	Vectren Corporation
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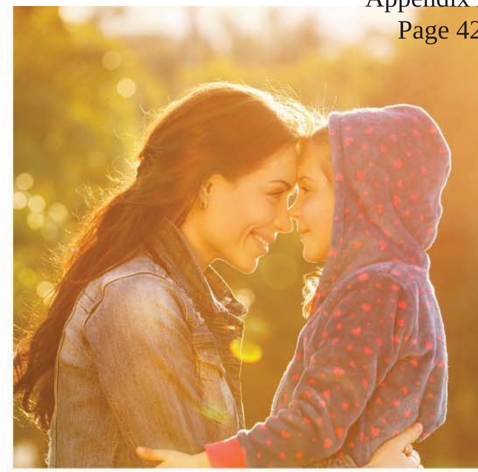
Zachary	Scott	PSG Energy Group
Julie	Shea	NiSource
Isabella	Solari	PSG Energy Group
Jennifer	Staciwa	NIPSCO
Brian	Steinkamp	PSG Energy Group
Bruce	Stevens	Indiana Coal Council
Alice	Tharenos	peabody
William	Vance	Indianapolis Power & Light
Nathan	Vogel	Inovateus Solar
Jennifer	Washburn	CAC
Tyler	Welsh	PSG ENERGY GROUP, LLC
Rex	Young	Cooperative Solar LLC
Jim	Zucal	NIPSCO

Appendix A

Exhibit 5



NIPSCO Integrated Resource Plan - 2018 Update

Public Advisory Meeting Four

September 19, 2018

NISource

NIPSCO

Welcome and Introductions

- Introductions
- Welcome from Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource

Process for Participating Via Webinar

- In order to best facilitate today's discussion, we are asking that you use the "chat" feature on the webinar to ask questions
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- We look forward to your thoughts and questions

Agenda

Time	Topics
9:30-9:45	Welcome and Introductions • Safety Moment
9:45-10:15	How Does NIPSCO Plan For The Future? • Public Advisory Process
10:15-10:30	Energy and Demand Forecast Update
10:30-10:45	Break
10:45-11:45	Modeling Uncertainty: 2018 Integrated Resource Plan Scenarios and Risk Analysis (Stochastics)
11:45- 12:30	Lunch
12:30-1:15	Retirement Analysis • Retirement Framework • Scenario Results • Risk Analysis (Stochastics) Results • Retirement Scorecard
1:15-2:00	Replacement Analysis • Incorporating Demand-Side Management • Incorporating the Results from the Request for Proposals (“RFP”) • Scenario Results • Risk Analysis (Stochastics) Results • Replacement Scorecard
2:00-2:15	Break
2:15-2:30	Stakeholder Requested Scenario Results
2:30-3:00	Stakeholder Presentations and Wrap Up

Safety Moment

Safe Driving

- **Each year there are more than 40,000 deaths nationwide related to motor vehicle crashes**

- **Top three causes of motor vehicle accidents**
  - Distracted or inattentive driving
  - Speeding
  - Impairment (drugs or alcohol)

- **Other Rules to Follow**
  - Pull through or back into parking spaces
  - Perform a 360 walk-around
  - Adjust your driving based on weather conditions

NIPSCO's Planning and the Public Advisory Process

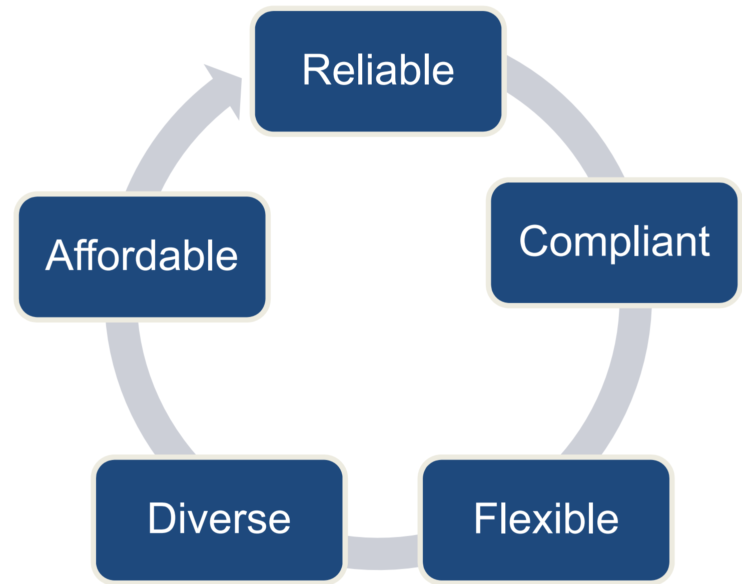
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan ("IRP") – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires careful planning and consideration for all of NIPSCO's stakeholders including the communities we serve and our employees

Overview of the Public Advisory Process

- **Today's meeting is the fourth out of five meetings**
  - Two in-person meetings and one webinar so far
  - Additional technical webinar added at stakeholder request
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.nipsco.com/irp
- **The Public Advisory process provides NIPSCO with feedback on our process, assumptions and conclusions. This helps inform the modeling and the overall IRP results**
- **Your participation and candid feedback is key to the process**
  - Please ask questions and provide comments on the material being presented and the process itself to ensure this is a valuable exercise for NIPSCO and its customers
- **Ability to make presentations as part of each Public Advisory meeting**
  - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3 (July 24)	Technical Webinar (August 28)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	- Why has NIPSCO decided to file an IRP update in 2018? - What has changed from the 2016 IRP? - What are the key assumptions driving the 2018 IRP update? - How is the 2018 IRP process different from 2016?	- What is NIPSCO existing generation portfolio and what are the future supply needs? - Are there any new developments on retirements? - What are the key environmental considerations for the IRP? - How are DSM resources considered in the IRP?	- What are the preliminary results from the all source RFP Solicitation?	- How are the RFP results integrated into the IRP modeling?	- What are the preliminary results from the modeling and how do they inform the retirement and replacement decisions? - What is the "most viable" retirement and replacement path? - What is NIPSCO's forecasted customer demand? - How is NIPSCO modeling risk and uncertainty in the IRP?	- What is NIPSCO's preferred plan? - What is the short term action plan?
Meeting Goals	- Communicate and explain the rationale and decision to file in 2018 - Articulate the key assumptions that will be used in the IRP - Explain the major changes from the 2016 IRP - Communicate the 2018 process, timing and input sought from stakeholders	- Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM - Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap - Key environmental issues in the IRP	- Communicate the preliminary results of the RFP and next steps	- Explain the process for integrating the results from the RFP into the IRP modeling for both the retirement and replacement analysis?	- Share with stakeholders most viable retirement path and most viable replacement portfolios - Explain how NIPSCO is modeling risk and uncertainty in the IRP - Communicate NIPSCO forecasts for customer demand	- Communicate NIPSCO's preferred resource plan and short term action plan - Obtain feedback from stakeholders on preferred plan

Stakeholder Interactions

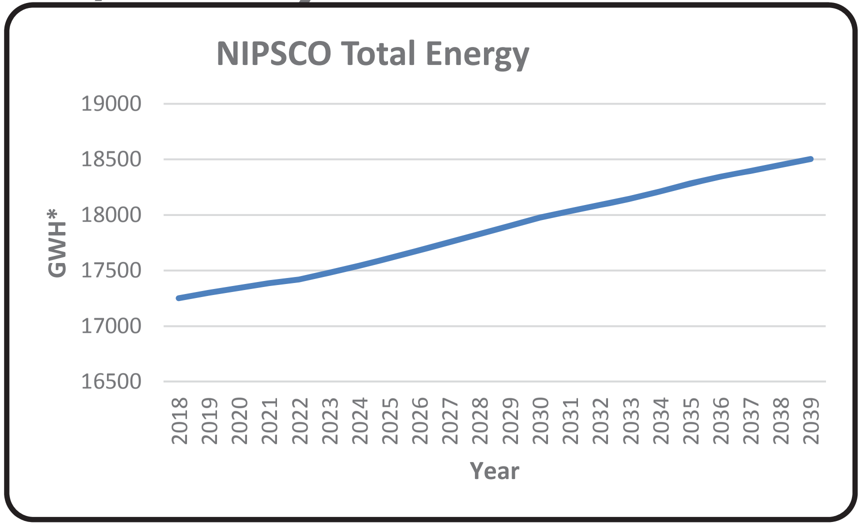
- So far during the IRP process, NIPSCO has met with and responded to requests from stakeholder groups

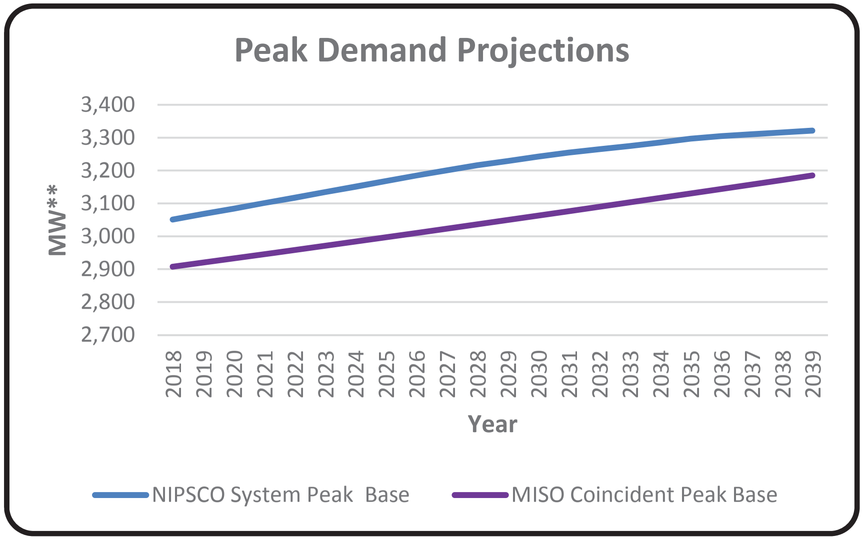
Stakeholder	Subject Area/Discussion Topic
Sierra Club	IRP Modeling and Scenarios
Office of Utility Consumer Counselor ("OUCC")	All-Source RFP, IRP Modeling and Scenarios, Load Forecasting
Citizens Action Coalition of Indiana, Inc. ("CAC")	IRP Modeling and Demand Side Management ("DSM")
Indiana Utility Regulatory Commission ("IURC")	All-Source RFP and IRP Modeling
NIPSCO Industrial Group	All-Source RFP and IRP Modeling
Indiana Coal Council	Scenario/Portfolio Requests
NAACP of Indiana	DSM and On-Bill financing

Energy and Demand Forecast Update

Amy Efland
Manager, Demand Forecasting

Load Forecasts (Originally Presented March 23, 2018)



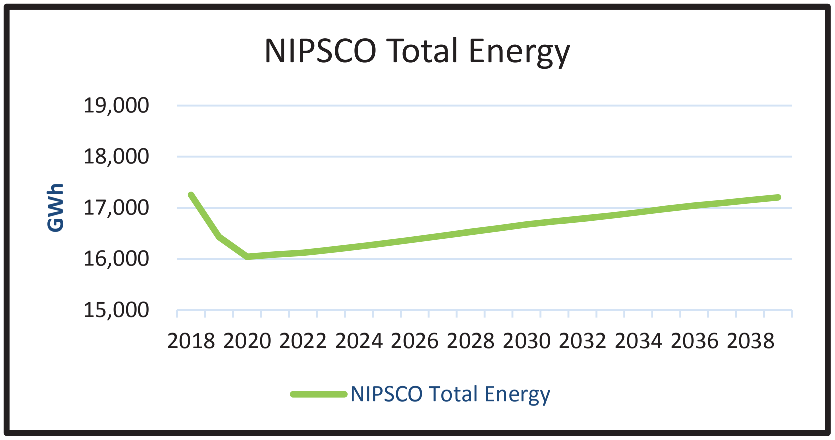


Energy Requirement Projections	2018-2039 CAGR***
NIPSCO Total Energy	0.33%
NIPSCO System Peak	0.41%
MISO Coincident Peak	0.44%

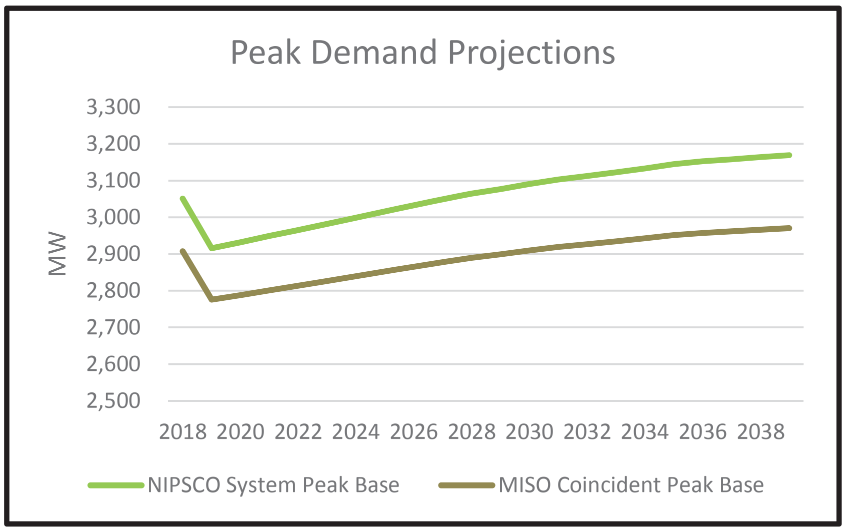
*GWH: Gigawatt hour
**MW: Megawatt
***GAGR: Compound Annual Growth Rate

$$\frac{\textit{MISO Coincident Peak}}{\textit{NIPSCO System Peak}} = \sim 95\%$$

Base Case Update: Change In Large Industrial Customer Demand



Energy Requirement Projections	2018-2039 CAGR*
NIPSCO Total Energy	0%
NIPSCO System Peak	0.2%
MISO Coincident Peak	0.1%

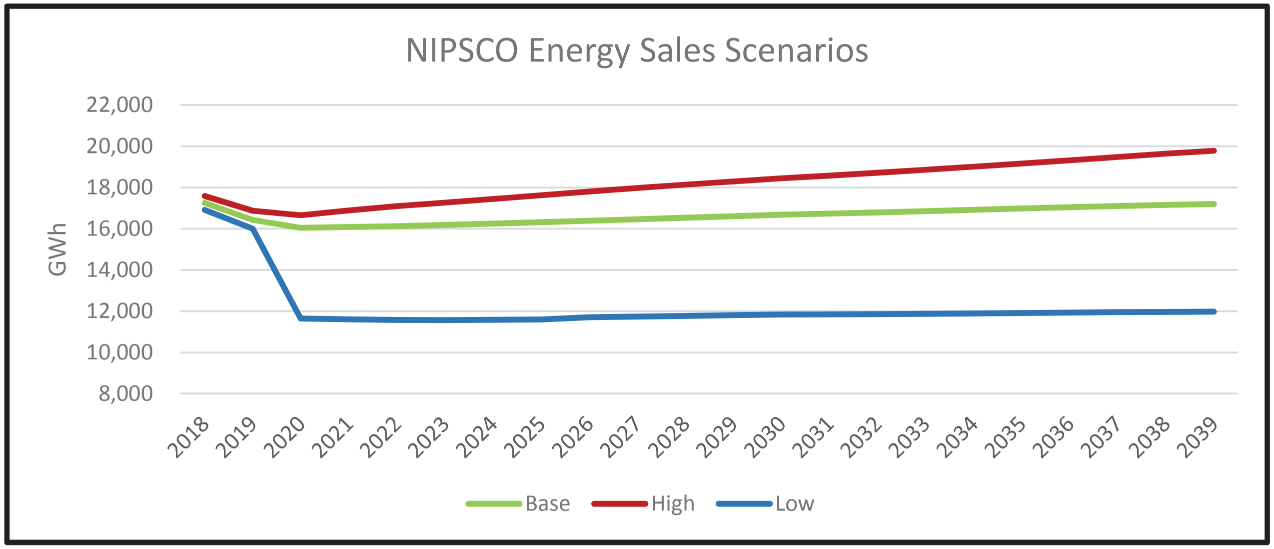


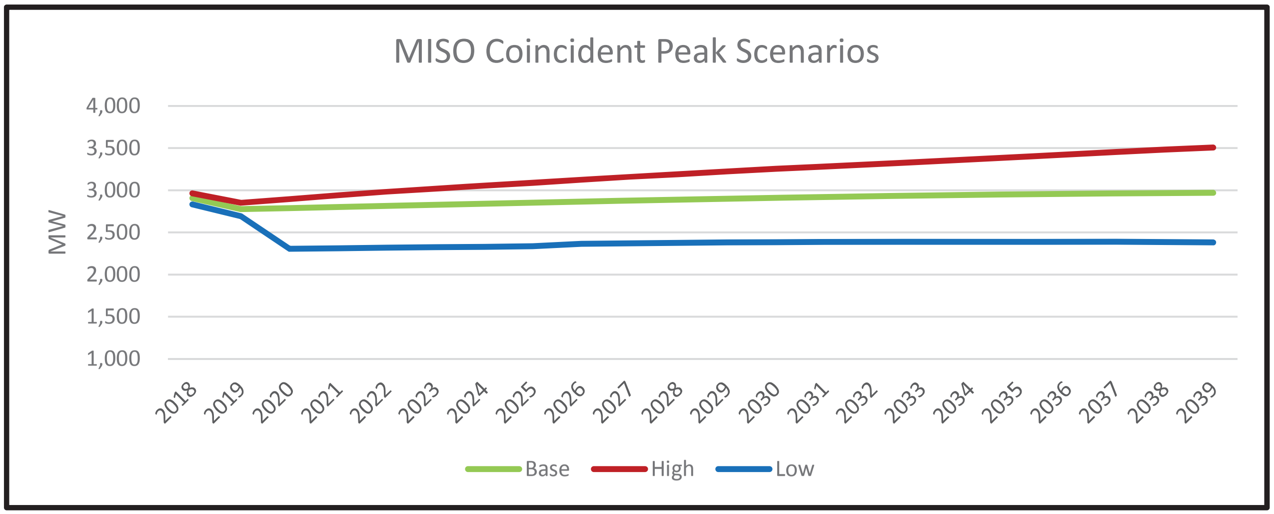
$$\frac{\boldsymbol{MISO\ Coincident\ Peak}}{\boldsymbol{NIPSCO\ System\ Peak}} = \sim 95\%$$

Energy And Load Scenarios

- High and low scenarios are constructed from the base case forecast models.
- Optimistic and Pessimistic economic and demographic data are from IHS Global Insight.
- The Industrial scenario forecasts are constructed using recent historical levels and trends for each large customer.
- The Industrial high load growth scenario is created by looking at the customer's previous five years of history giving consideration to peak usage and demand. Current business practices and other potential growth are also considered.
- The low load growth scenario accounts for the "worst case" scenario for each large customer and assumes the customer's minimum operating levels.

Energy And Load Scenarios (Continued)





Modeling of Uncertainty

Pat Augustine
Charles River Associates (CRA)

Modeling of Uncertainty

- **Generation decisions are generally capital intensive and long-lived, understanding and incorporating future risk and uncertainty is important**
- **NIPSCO analysis uses both scenarios and stochastics to assess risk**

Scenarios
Integrated Set of Assumptions

- **Can be used to answer "What if…"**
- Major events can change fundamental outlook for key drivers, altering portfolio performance
    - New policy or regulation (carbon regulation)
    - Fundamental gas price change (change in resource base, production costs, large shifts in demand)
    - Loss of a major industrial load
    - Technology cost breakthrough (storage)
- **Can tie portfolio performance directly to a "storyline"**
    – Easier to explain a specific reasoning why Portfolio A performs differently than Portfolio B

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate volatility and "tail risk"**
    – Short-term price volatility impacts portfolio performance
        - Value of certain portfolio assets is dependent on market price volatility
        - Commodity price exposure risk is broader than single scenario ranges
- **Develops a dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
    – Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes
    – Can calculate statistical metrics to evaluate 95^{th} percentile outcomes

Scenario Considerations Inform Combinations of Input Variables

- Based on technology, policy, consumer and economic considerations, each scenario has a unique combination of key input variables and a fully integrated set of commodity market price forecasts

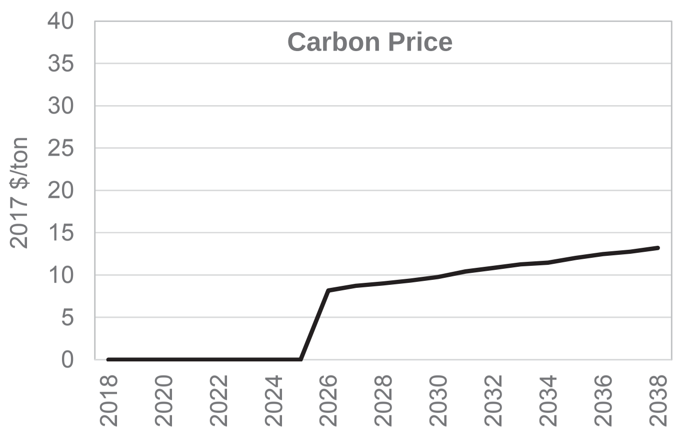
Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High (CO_2*)**	**Low (CO_2)**	**High (CO_2)**
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**

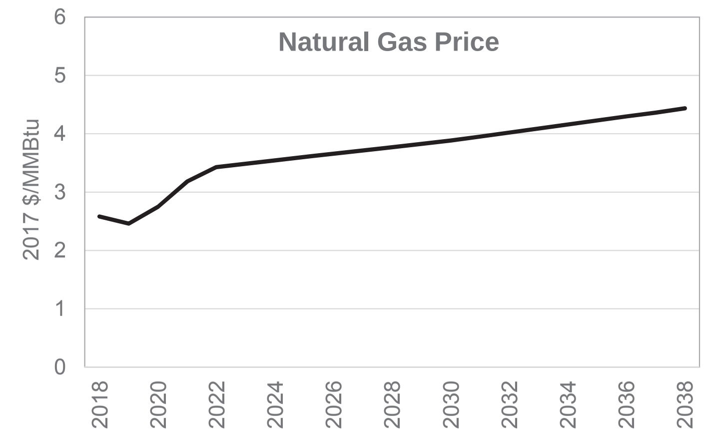
*Carbon dioxide

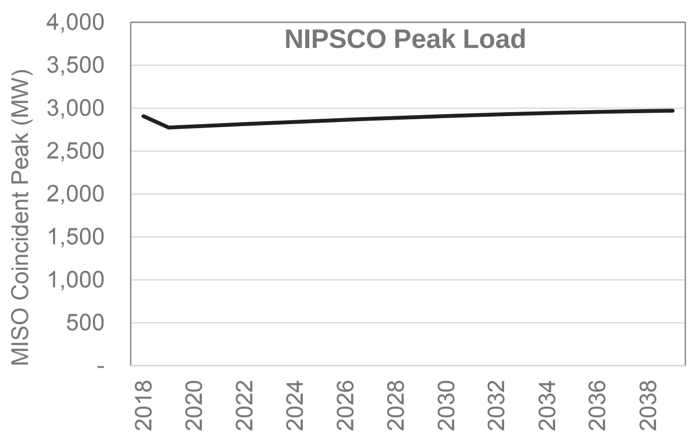
Base Case

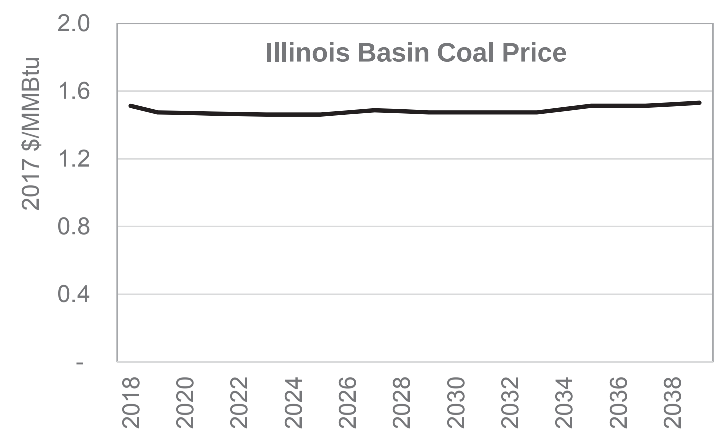
Description

- Fundamentals-based assessment of key drivers that influence NIPSCO's portfolio costs
- CO_2 price in 2026, based on a new potential federal rule or legislative action initiated after 2020
- Natural gas resource base is in line with "most-likely" expectations, but demand pressures push natural gas prices up over time
- Coal demand is expected to erode over time, especially after 2026, keeping coal prices generally flat in real terms
- NIPSCO load forecast includes near-term loss of industrial load, but modest long-term growth



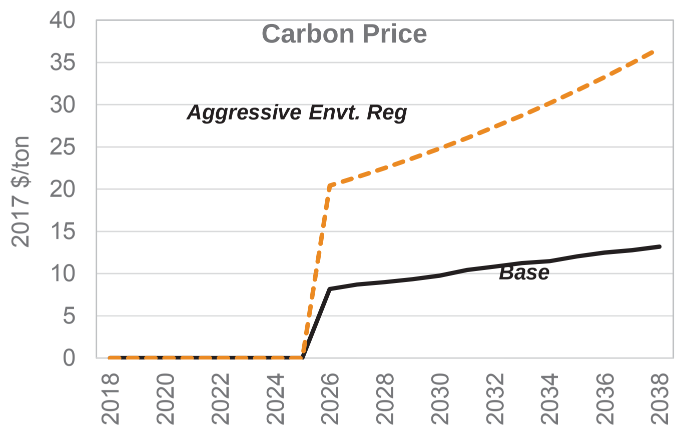


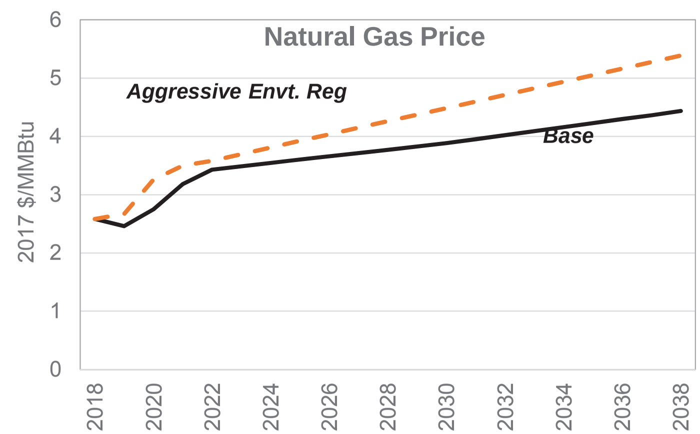


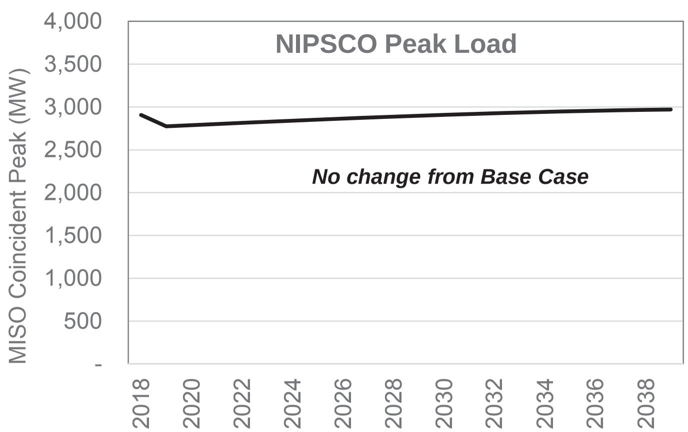


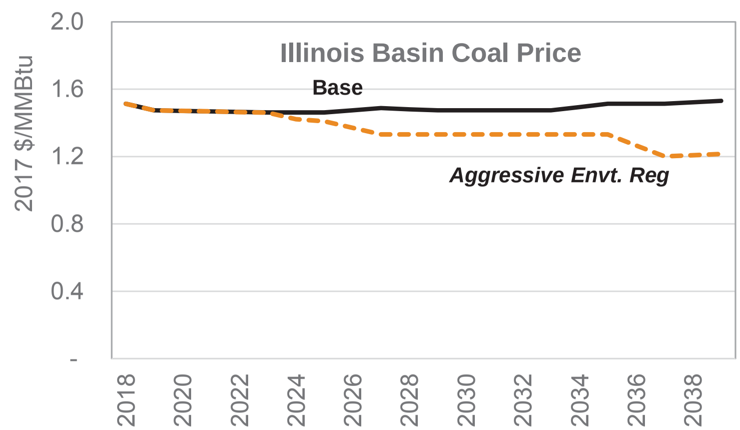
Aggressive Environmental Regulation Scenario Theme

Description	Risks Addressed
• A future in which power sector CO_2 regulations will be more stringent than currently anticipated • Higher CO_2 prices, with feedbacks driving higher gas prices and lower coal prices • Higher power prices and a faster shift in the Midcontinent Independent System Operator ("MISO") supply mix from coal to natural gas and renewables	• The risk that carbon regulations will be more stringent than expected • The risk of higher prices for natural gas and power, which are correlated



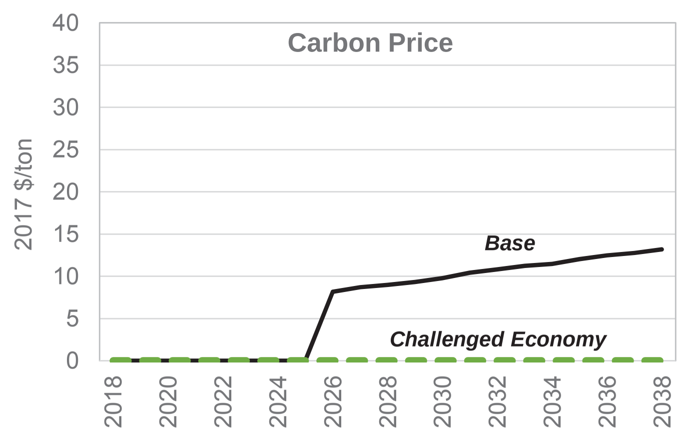


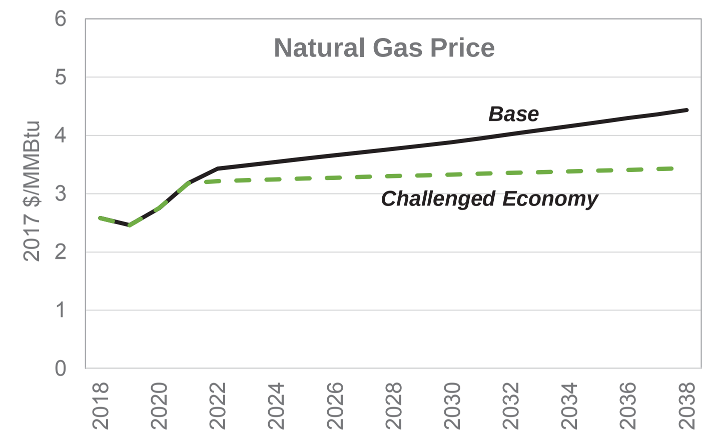


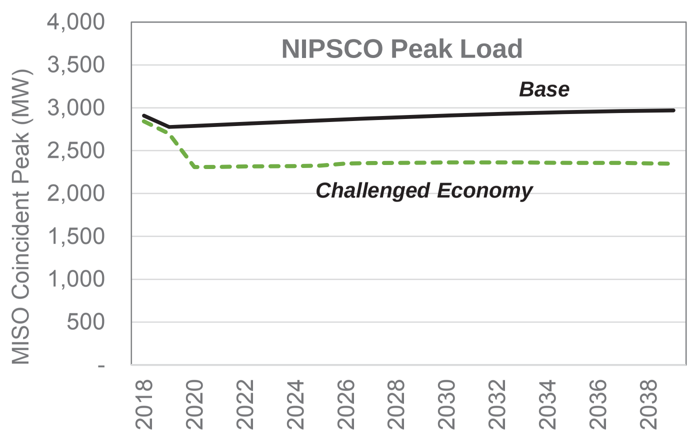


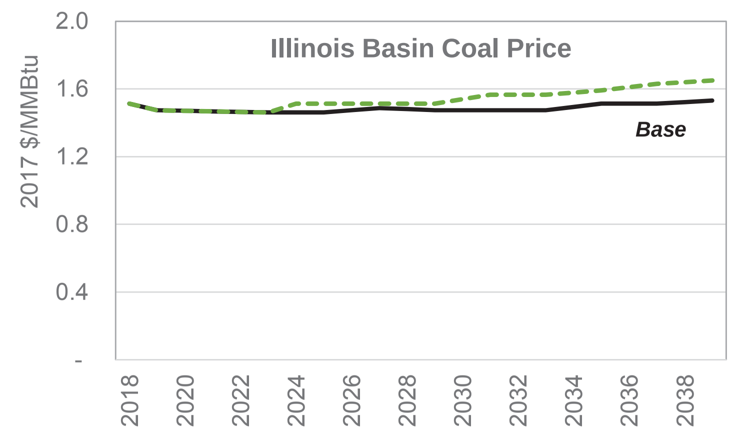
Challenged Economy Scenario Theme

Description	Risks Addressed
• A future where economic growth is stagnant and environmental regulation is limited, with no price on CO_2. • Demand feedbacks drive gas and power prices lower and coal prices higher • Load declines including the loss of large industrial load	• The risk of an economic downturn that could negatively impact NIPSCO load • The risk of no price on carbon over the forecast horizon and its expected influence on other commodity prices • The loss of large industrial customer load



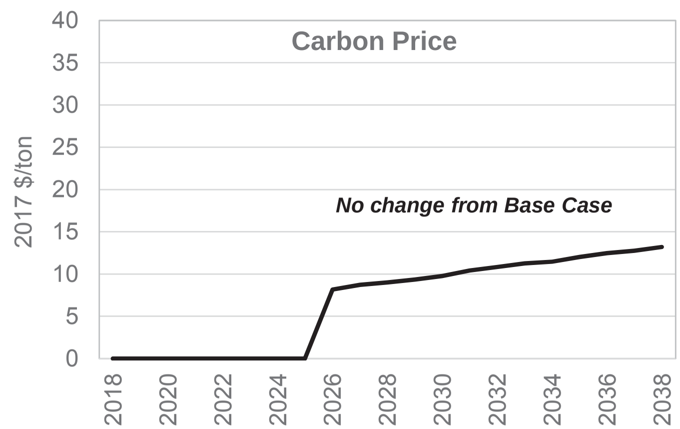


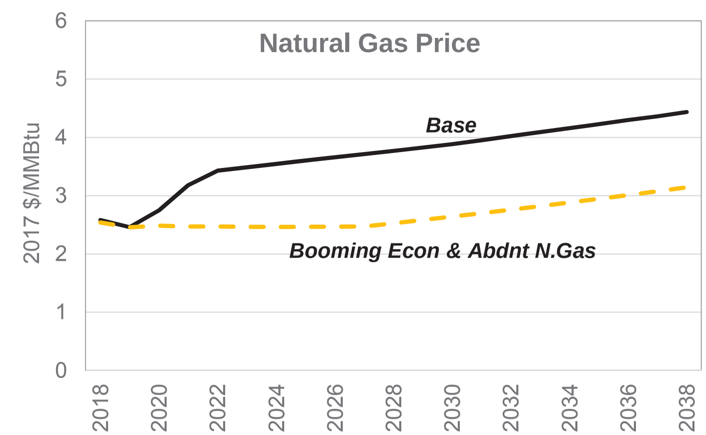


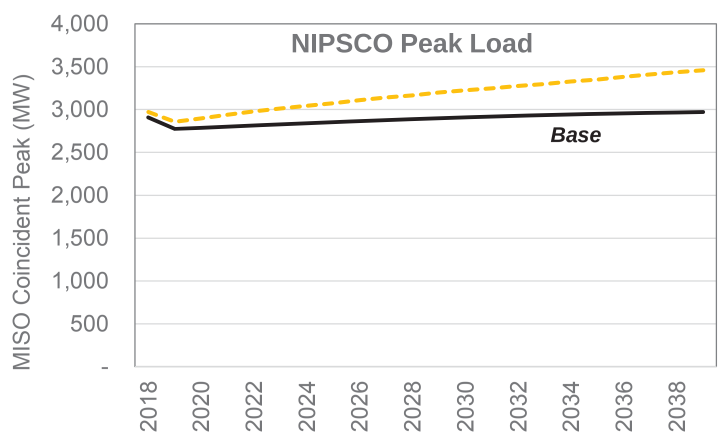


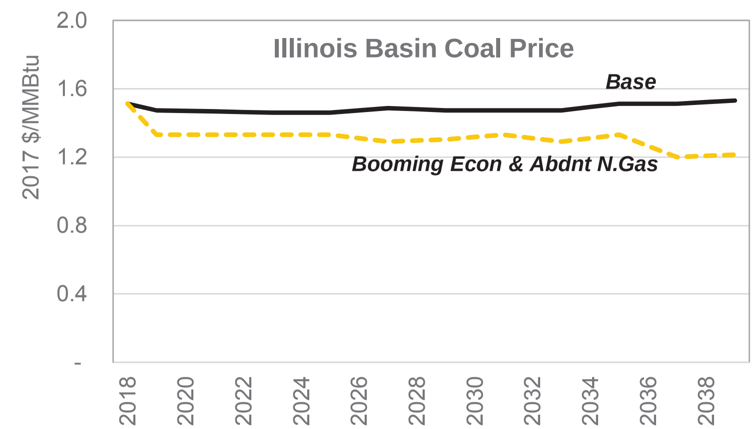
Booming Economy And Abundant Natural Gas Scenario Theme

Description	Risks Addressed
• A future where natural gas production costs remain low and the resource base remains highly productive, keeping natural gas prices low and flat in real terms over the next decade. • Feedbacks driving coal and power prices lower • Lower energy prices drive economic growth and increases to NIPSCO load	• The risk of persistently low natural gas prices • The risk of higher load growth for NIPSCO, which could result in higher exposure to the MISO market

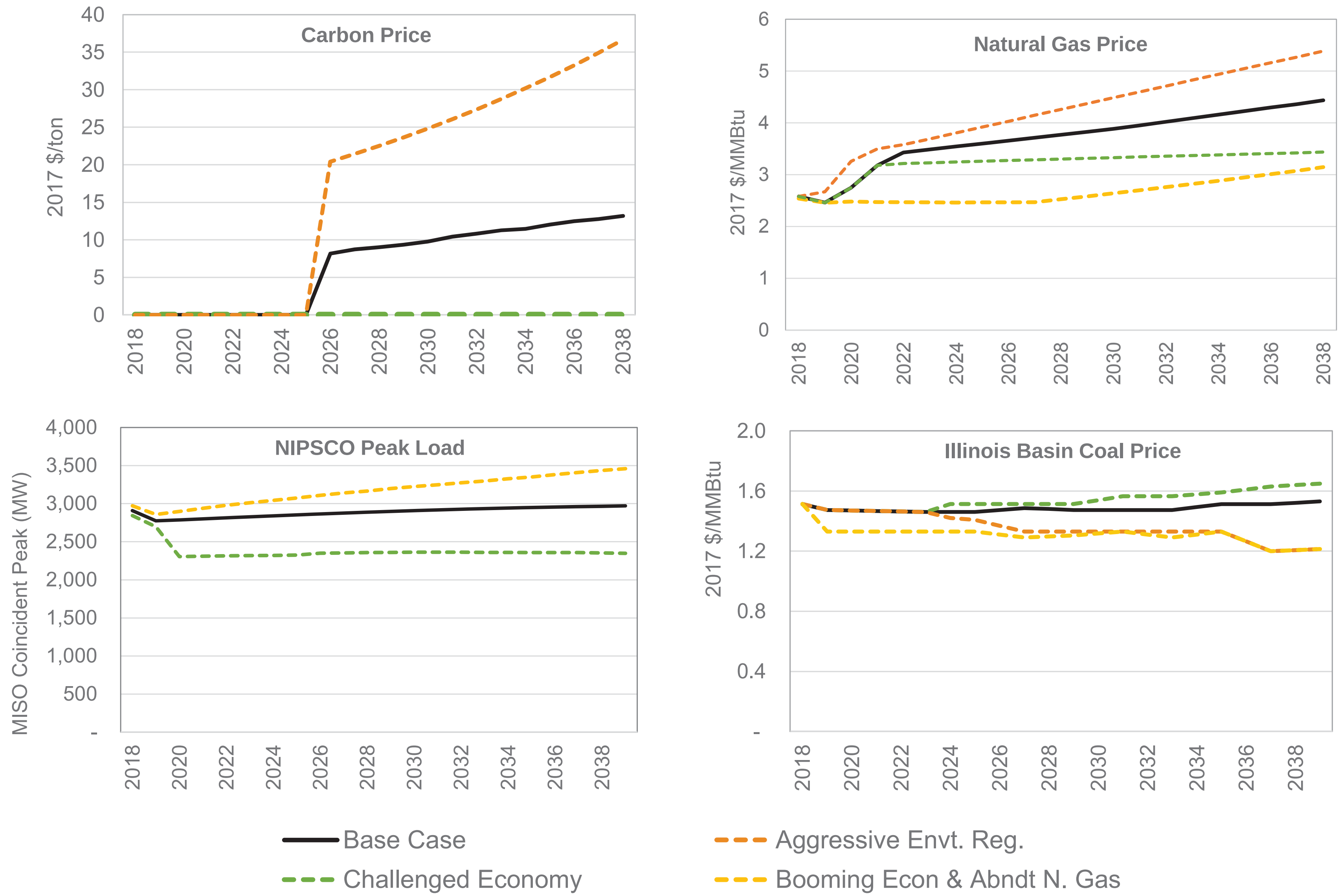








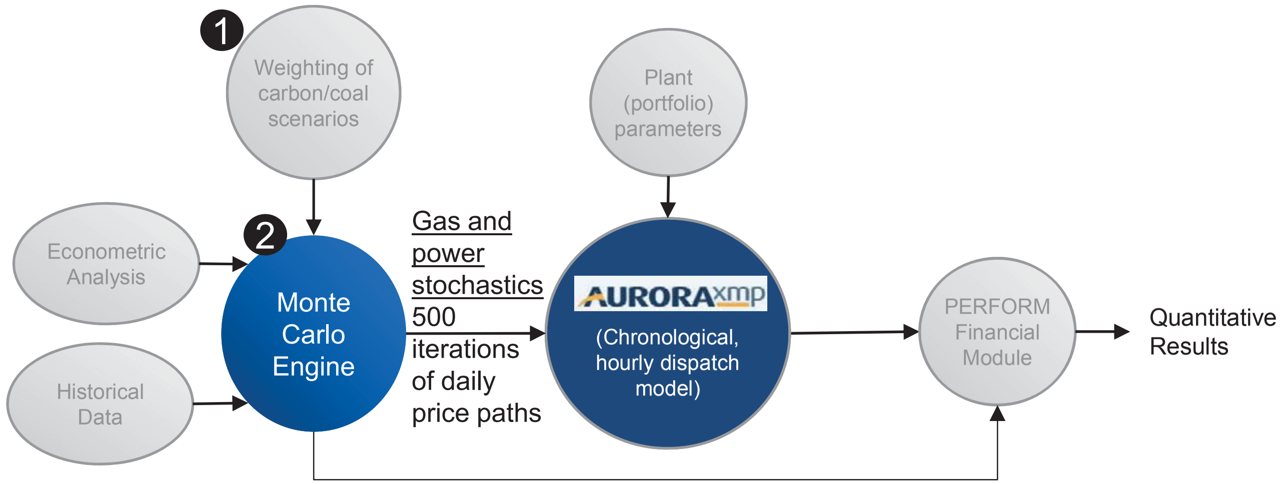
Scenario Summary

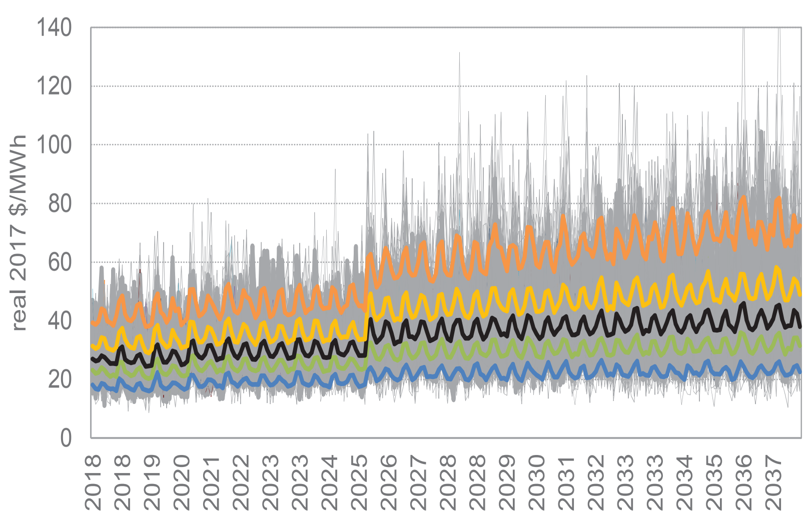


Stochastics Development

Scenario development is one component of stochastic development process

1. Scenarios are probability-weighted for discrete variables (carbon/coal)
2. Monte Carlo Engine is run for natural gas and power prices for each weighted scenario, based on historical data analysis, which incorporates daily and hourly volatility





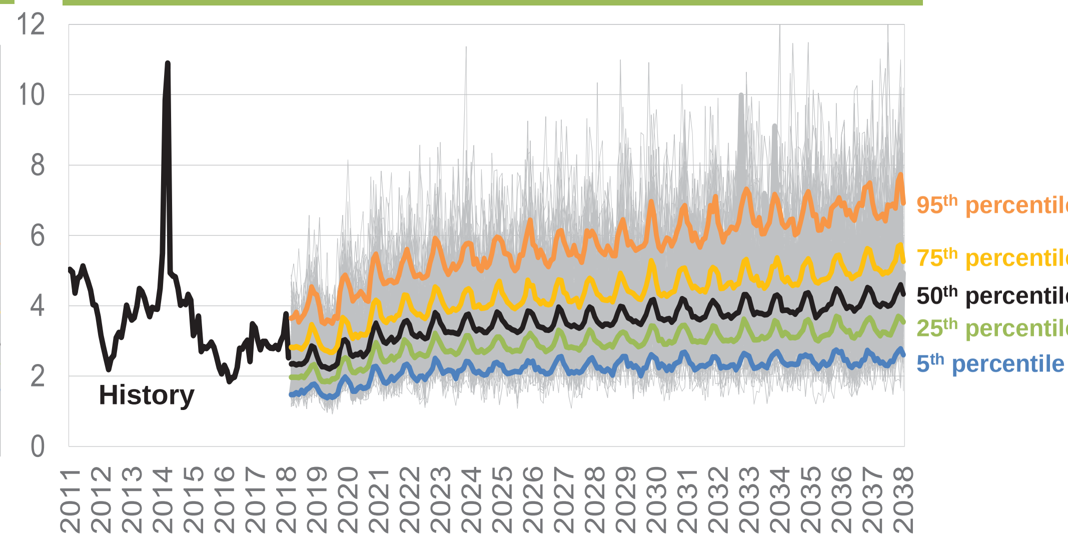
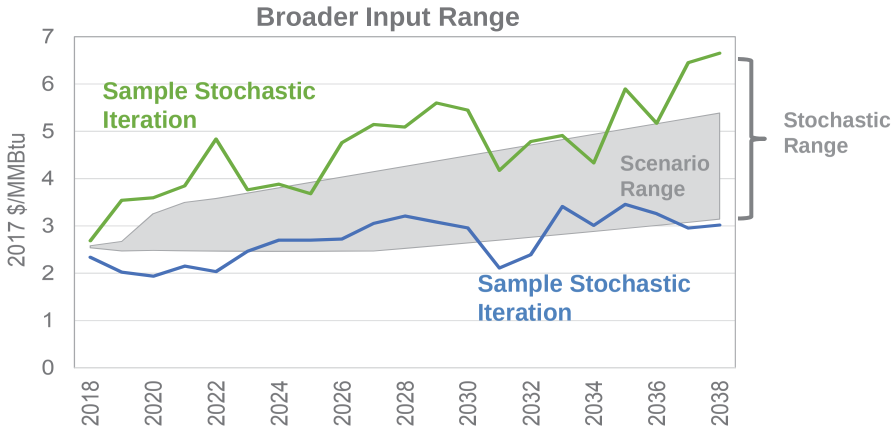
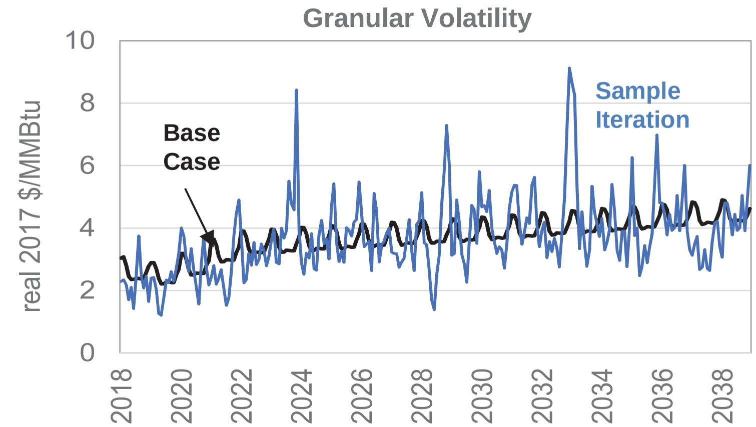
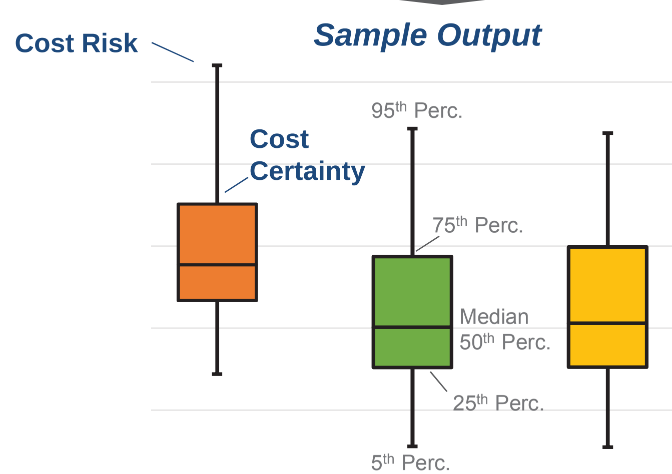


Illustration Of Stochastic Details

- The use of stochastic inputs for commodity prices broadens the range of inputs evaluated and allows for the assessment of the impact of volatility (daily, hourly, monthly over time







Outputs can be quantified across a probability distribution rather than discrete outcomes

Retirement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Retirement Analysis Framework

- The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and were fed into the retirement and replacement analysis
- Representative project groups were constructed from RFP results, assembled by technology and ownership structure, for use in the updated retirement analysis

	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO Cost of New Entry ("CONE") + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

Retirement analysis uses representative RFP projects *as selected by the optimization model* – selection driven by economics

Various Retirement Combinations Were Constructed

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City in 2035)	**15% Coal in 2023** (Mich. City in 2028)	**15% Coal by 2023** (Schfr. 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR[1] ELG[2]: non-ZLD[3]	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A					**Retire 2028** CCR ELG: N/A		**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: non-ZLD		**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement			**Retire 2023** CCR ELG: Retirement
Schahfer 15	**Retain** CCR ELG: non-ZLD		**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement			**Retire 2023** CCR ELG: Retirement
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement					**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx[4]: SCR[5]	**Retire 2023** CCR/ELG: Retirement					**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement

Currently NOT a viable path for ELG compliance

Note: Retirement Combination 4, 15% Coal in 2028 without ELG, is not currently a viable from an ELG compliance standpoint and is shown for discussion purposes..

[1]CCR: Coal Combustion Residuals
[2]ELG: Effluent Limitation Guidelines
[3]ZLD: Zero-Liquid discharge
[4]NOx: Nitrogen oxides
[5]SCR: Selective Catalytic Reduction

What Technology Is the Model Selecting From RFP Results?

- **Economic optimization model is selecting DSM and renewables as the replacement resources in all retirement cases**
- **While the model selected resources were used for the retirement analysis, a separate replacement analysis will be performed**

2 3 4 **Schahfer 17/18 Retirement** ~600MW UCAP need		5 6 7 **Schahfer 14/15/17/18 Retirement** ~1,350MW UCAP need		8 **All Coal Retirement** ~1,750MW UCAP Need	
TECHNOLOGY	MW	TECHNOLOGY	MW	TECHNOLOGY	MW
MISO Market Purchase	50	MISO Market Purchase	50	MISO Market Purchase	50
DSM	125	DSM	125	DSM	125
Wind	150	Wind	150	Wind	150
Solar, Solar + Storage	390	Solar, Solar + Storage	1,070	Solar, Solar + Storage	1,500
	715		**1,395**		**1,825**

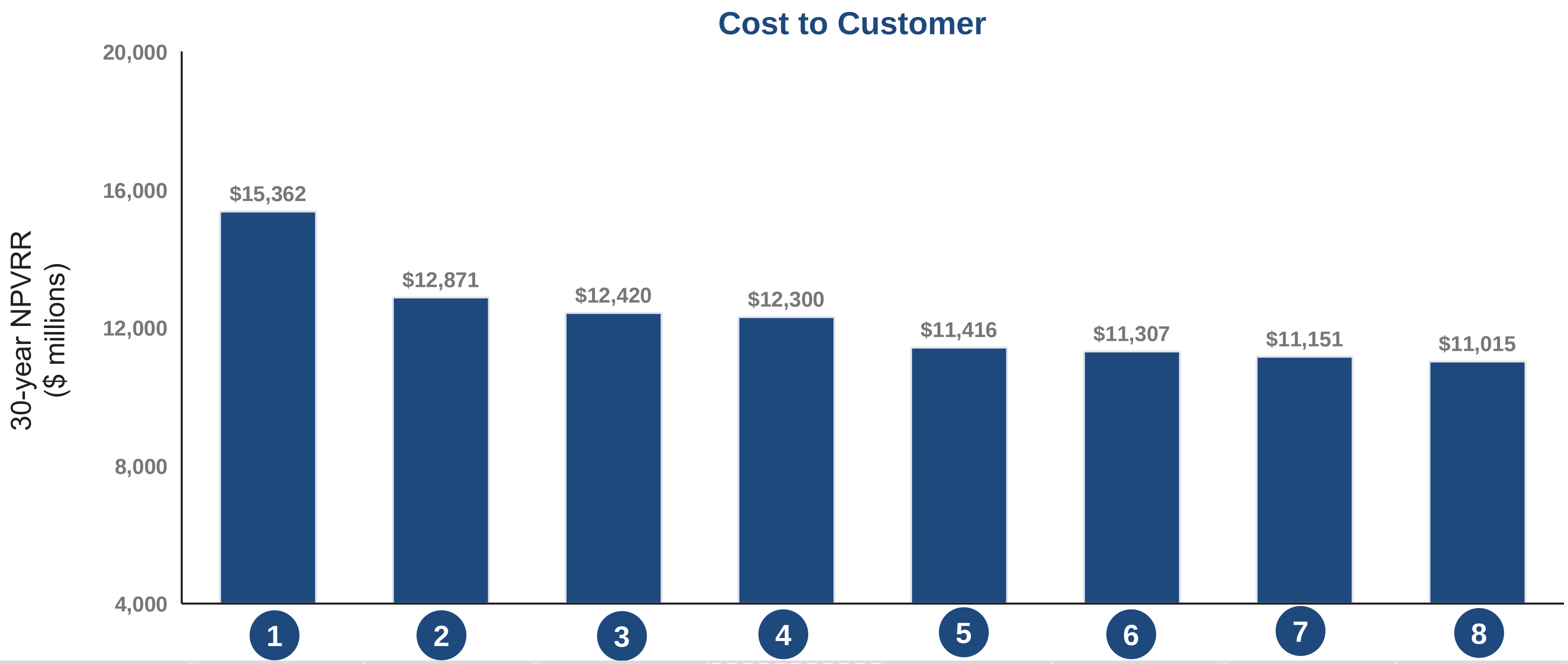
Higher
COST-EFFECTIVENESS
Lower

This is ***not*** NIPSCO's replacement resource selection or plan

Retirement Results – Base Case

- Retaining more coal in the NIPSCO portfolio results in higher costs to customers

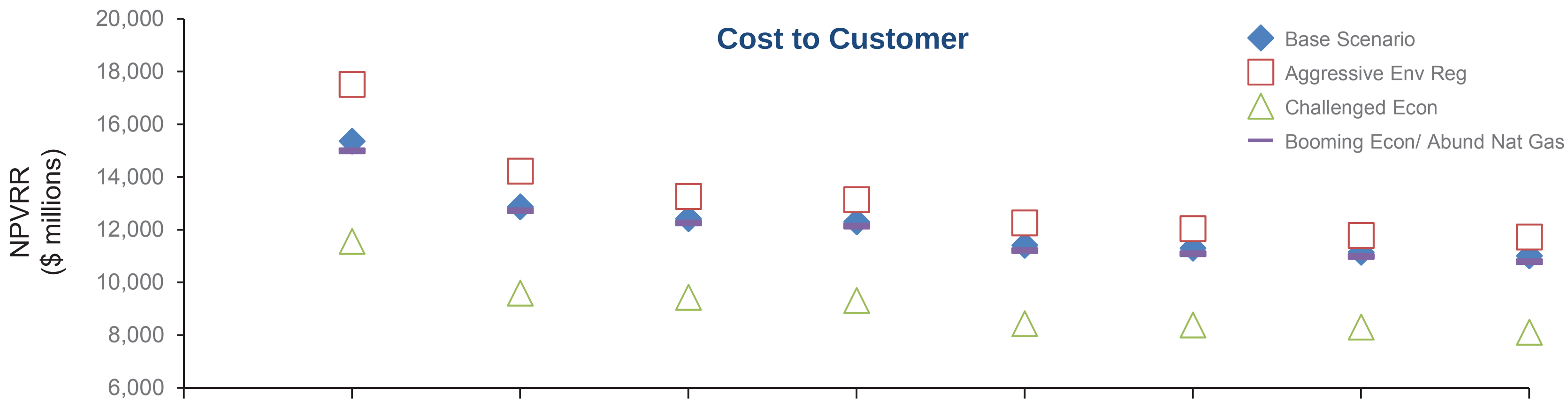
Preliminary, Subject to Change



	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Least Cost:	$4,347M 39%	$1,856M 17%	$1,405M 13%	$1,285M 12%	$401M 4%	$292M 3%	$137M 1%	$0M

Retirement Analysis: Scenarios

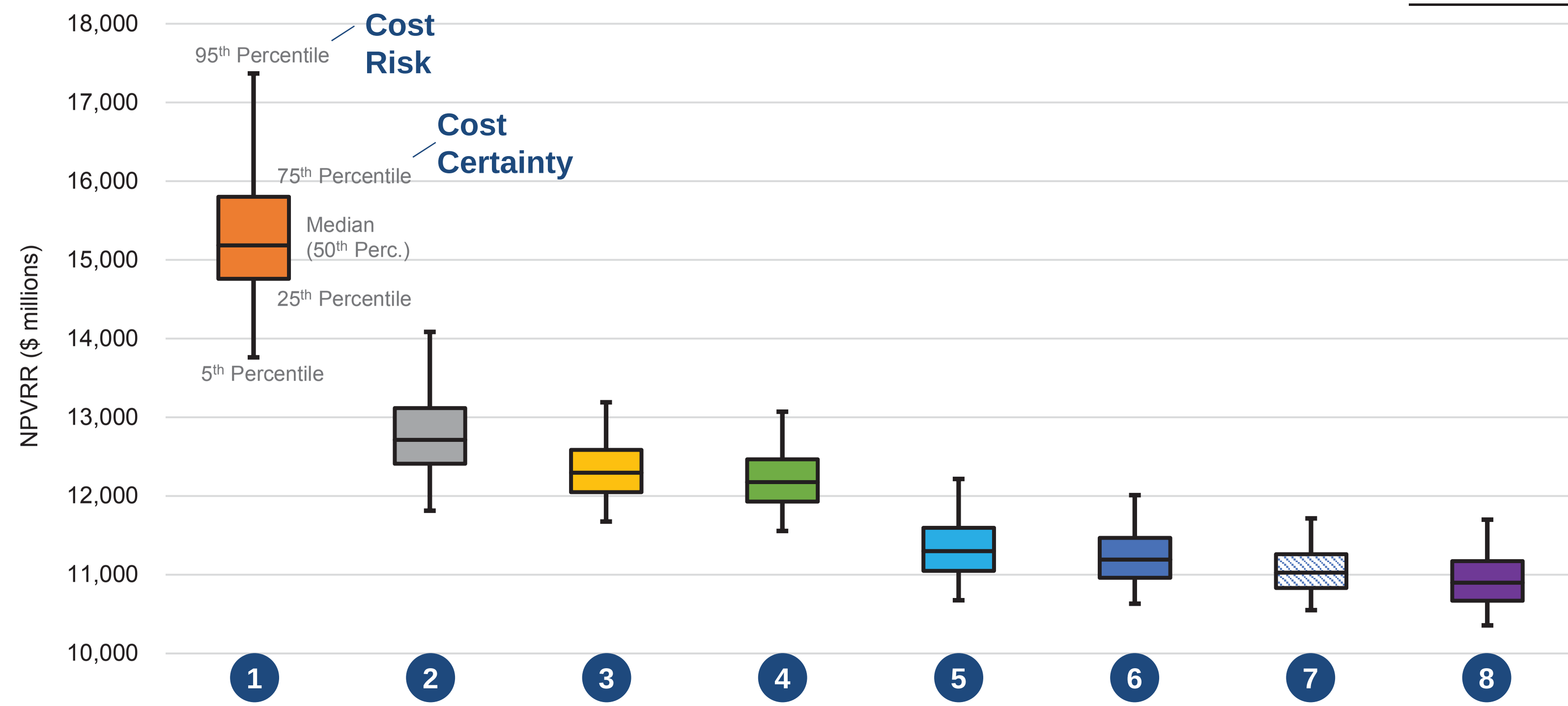
Preliminary, Subject to Change



		1	2	3	4	5	6	7	8
	Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
	Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
	Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Base Scenario	**Delta from Lowest Cost to Customer**	$4,347M 39.5%	$1,856M 16.9%	$1,405M 12.8%	$1,285M 11.7%	$401M 3.6%	$292M 2.7%	$137M 1.2%	$0M 0.0%
Aggressive Env Reg	**Delta from Lowest Cost to Customer**	$5,790M 49.4%	$2,502M 21.3%	$1,539M 13.1%	$1,419M 12.1%	$532M 4.5%	$320M 2.7%	$56M 0.5%	$0M 0.0%
Challenged Econ	**Delta from Lowest Cost to Customer**	$3,440M 42.4%	$1,482M 18.3%	$1,324M 16.3%	$1,204M 14.8%	$316M 3.9%	$272M 3.4%	$196M 2.4%	$0M 0.0%
Booming Econ/ Abund Nat Gas	**Delta from Lowest Cost to Customer**	$4,206M 39.0%	$1,931M 17.9%	$1,470M 13.6%	$1,350M 12.5%	$421M 3.9%	$303M 2.8%	$202M 1.9%	$0M 0.0%

Retirement Analysis: Risk (Stochastics)

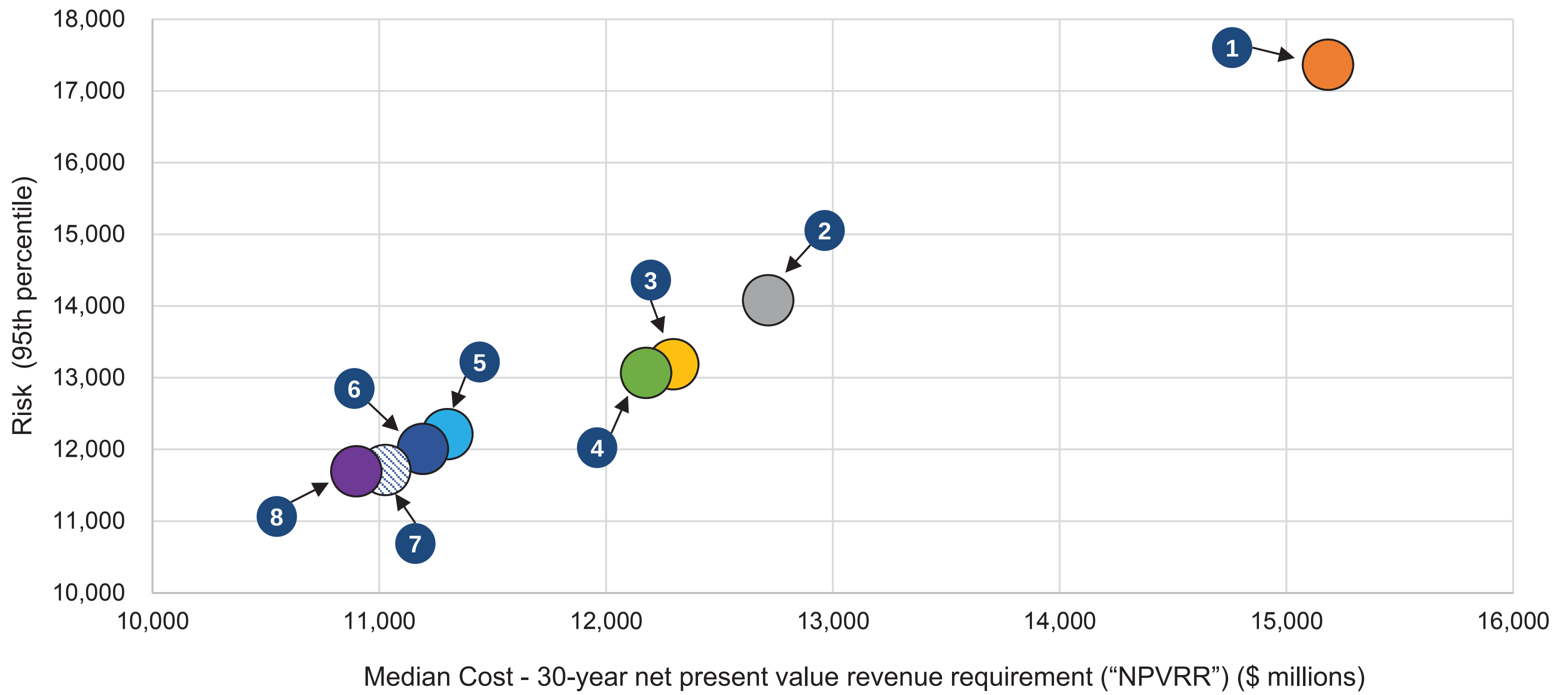
Preliminary, Subject to Change



Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Lowest Cost Certainty	+$4,629 41.4%	+$1,944 17.4%	+$1,414 12.7%	+$1,294 11.6%	+$424 3.8%	+$295 2.6%	+$87 0.8%	- $ - %
Delta from Lowest Cost Risk	+$5,671 48.5%	+$2,386 20.4%	+$1,492 12.8%	+$1,372 11.7%	+$517 4.4%	+$313 2.7%	+$17 0.1%	- $ - %

Retirement Analysis: Cost Risk

Preliminary, Subject to Change



	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement

Retirement Scorecard

2018 Retirement Scorecard

Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year net present value (“NPV”) of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75^{th} percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95^{th} percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO’s 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

Retirement Scorecard

Preliminary, Subject to Change

- Analysis indicates that most viable option is the full retirement of Schahfer coal units by 2023 and Michigan city by 2028
- A final retirement decision has not been made; alternatives are still being evaluated with stakeholders. Finalized plan will be communicated in October

	1	2	3	4	5	6 (Most Viable)	7	8
Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal by 2028 w/ ELG	15% Coal by 2028 w/o ELG	15% Coal in 2023 (Mich. City 2035)	15% Coal in 2023 (Mich. City 2028)	15% Coal by 2023 (Schfr 17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,362 +$4,347 39.5%	$12,871 +$1,856 16.9%	$12,420 +$1,405 12.8%	$12,300 +$1,285 11.7%	$11,416 +$401 3.6%	$11,307 +$292 2.7%	$11,151 +$137 1.2%	$11,015 - $ - %
Cost Certainty	$15,801 +$4,629 41.4%	$13,117 +$1,944 17.4%	$12,586 +$1,414 12.7%	$12,466 +$1,294 11.6%	$11,597 +$424 3.8%	$11,468 +$295 2.6%	$11,260 +$87 0.8%	$11,173 - $ - %
Cost Risk	$17,368 +$5,671 48.5%	$14,082 +$2,386 20.4%	$13,189 +$1,492 12.8%	$13,069 +$1,372 11.7%	$12,214 +$517 4.4%	$12,009 +$313 2.7%	$11,714 +$17 0.1%	$11,697 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +51%	$0M -%	($19M) (8%)	($27M) (12%)	($60M) (26%)	($66M) (29%)	($65M) (28%)	($85M) (37%)

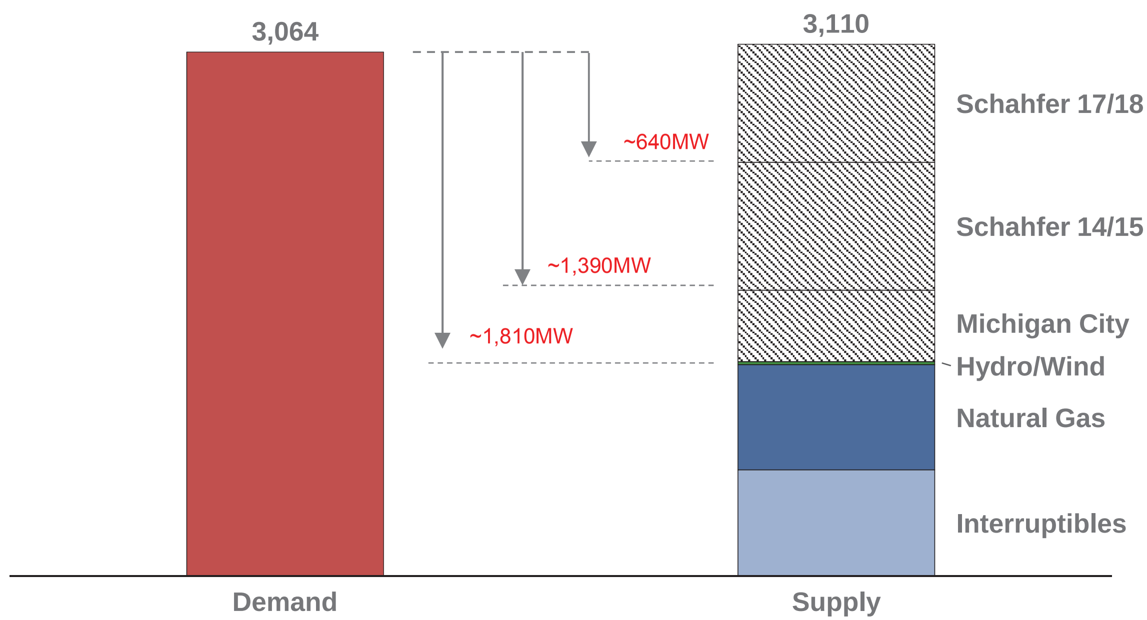
Replacement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Retirements Will Create A Need For New Resources

2023 Forecasted Demand and Supply



2023 Estimated Capacity Excess/(Need) in MWs

As-Is	50
Retire Schahfer 17/18	(640)
Retire Schahfer 14/15/17/18	(1,390)
Retire Schahfer and Michigan City	(1,810)

Notes: Demand reflects loss of BP load

Replacement Analysis Framework

- **The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and fed into the retirement and replacement analysis**
- **These RFP projects are used to construct resource combinations that explore the range of Ownership / Duration and Diversity possibilities**

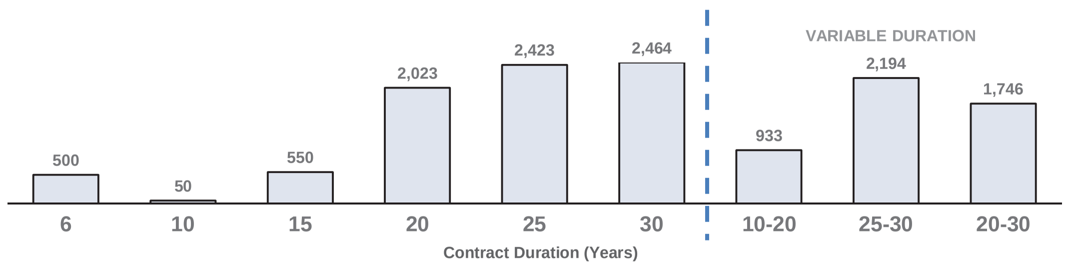
	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO CONE + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

RFP Generated Significant Amount Of Responses

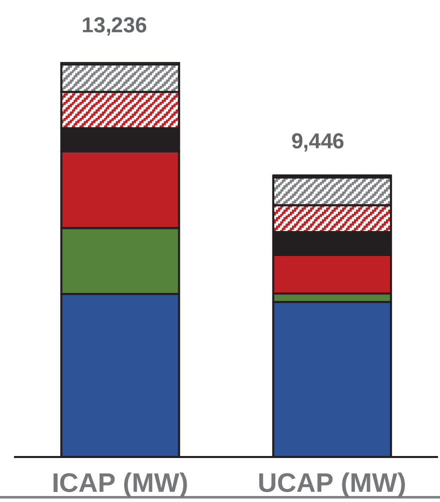
Technology & Ownership
(Overview Of Proposals)

Technology	CCGT*	CT**	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
Asset Sale	4	-	-	1	-	1	-	-	-	6
PPA	8	-	3	6	-	26	7	8	1	59
Option	3	1	-	7	1	8	4	1	-	25
Total	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

Duration
(UCAP MW by duration)



Quantity & Technology & Ownership
(RFP Projects By Technology)



	ICAP*** (MW)	UCAP (est. MW)
Demand Response	70	70
Storage	925	925
Solar + Storage	1,220	902
Wind + Solar + Storage	0	0
Coal	772	772
Solar	2,580	1,291
Wind	2,209	287
Natural Gas (CT)	0	0
Natural Gas (CCGT)	5,470	5,199
	13,236	9,446

Note that totals are on a project basis, which eliminates double counting of multiple proposals for the same facility.

- Nearly 10,000 MW of MISO-recognized capacity (UCAP) was offered into the RFP
- A broad set of technologies and fuels, both fossil and renewable, are available
- Ownership and PPA options are available
- Most contract durations skew to 20+ years; several bidders did offer shorter 10-year and 15-year options
- NIPSCO has begun outreach to respondents and will not be releasing a shortlist of RFP finalists

*Combined cycle gas turbine
**Combustion turbine
***Installed Capacity

There are more than enough capacity resources bid in to RFP to meet NIPSCO's needs

Incorporating DSM In IRP Modeling

- **DSM summary analysis was presented during the May public advisory meeting and the analysis approach has been refined in consultation with stakeholders**
- **DSM programs were evaluated and aggregated into three bundles that are available to be selected by optimization model**

DSM Analysis	Identify DSM "bundles" or decrements	Analyze *each* "bundle" for portfolio selection on equal footing with other resources
• Evaluate detailed program-level opportunities in service territory • Identify program impacts and associated costs	• Aggregate detailed DSM options into "bundles" of programs to reflect varying levels of energy savings and associated costs • Produce bundles with detailed energy savings characteristics and costs	• Use Aurora portfolio optimization with DSM costs and hourly savings profiles • Assess mix of bundles to be integrated into portfolio

DSM Bundle	Weighted Avg. Cost ($/MWh*)	MW Selected by 2023 (Peak / Average)	MW Selected by 2038 (Peak / Average)
1	16.98	91 / 48	310 / 174
2	23.27	34 / 20	60 / 29
3	159	0 / 0	0 / 0

Bundles #1 & #2 were selected by optimization model

*Megawatt hour

Recap from Aug. 28 Technical Webinar: Tranche Development and Assessment

1 Tranche Development

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Operational characteristics
- Aggregated cost and operational information is entered into Aurora model to be considered in optimization step

2 Portfolio Optimization

Select Portfolios

- Based on capacity need and other constraints, identify which tranches (or portions of tranches) are selected for the portfolio through Aurora optimization

Confirm Viability

- Confirm that optimization model is selecting feasible block sizes based on resource-specific data

3 Portfolio Creation and Modeling

Create & Analyze Portfolios Based on Optimization

- Tranches are chosen for retirement and replacement analysis based on % selected by optimization model when confirmed as viable
- Portfolios are then run across full set of scenarios and stochastics

Replacement Analysis: Resource Combinations Were Created That Explore The Range Of Ownership / Duration And Diversity Possibilities

- **RFP projects provide good coverage to construct resource combinations that cover the spectrum of Ownership / Duration and Diversity**

Preliminary, Subject to Change

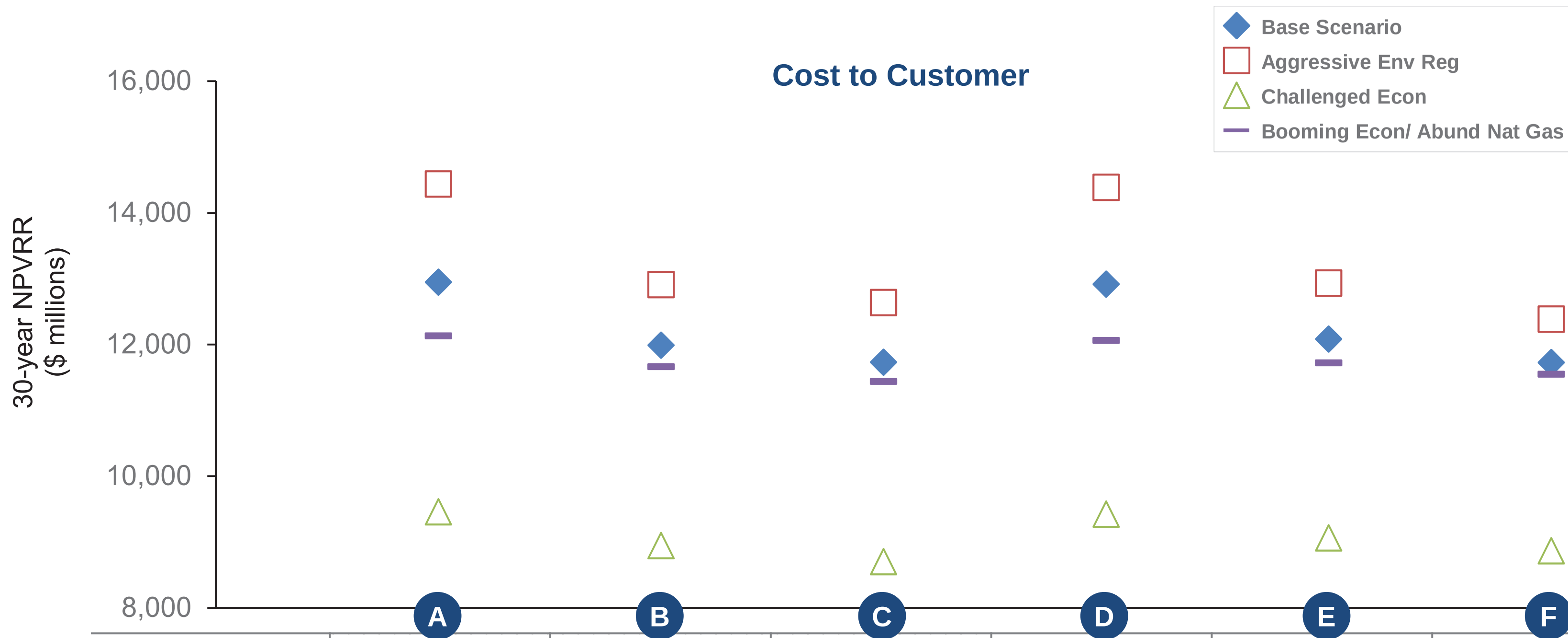
Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	**A** MISO Capacity Purchase 400MW CCGT PPA 950MW	**B** MISO Capacity Purchase 400MW CCGT PPA 250MW Renewable PPA 690MW	**C** MISO Capacity Purchase 400MW Renewable PPA 950MW
Long Duration	**D** MISO Capacity Purchase 50MW CCGT 1,300MW	**E** MISO Capacity Purchase 50MW CCGT 620MW Renewables 670MW	**F** MISO Capacity Purchase 50MW Renewables 1,300MW

Notes: Values above reflect 2023 additions shown in UCAP; additional generic solar additions are included in all portfolios starting in 2028.
All portfolios include a total of 125 MW (peak) DSM by 2023 and 370 MW (peak) DSM by 2038.

Replacement Analysis: Scenarios

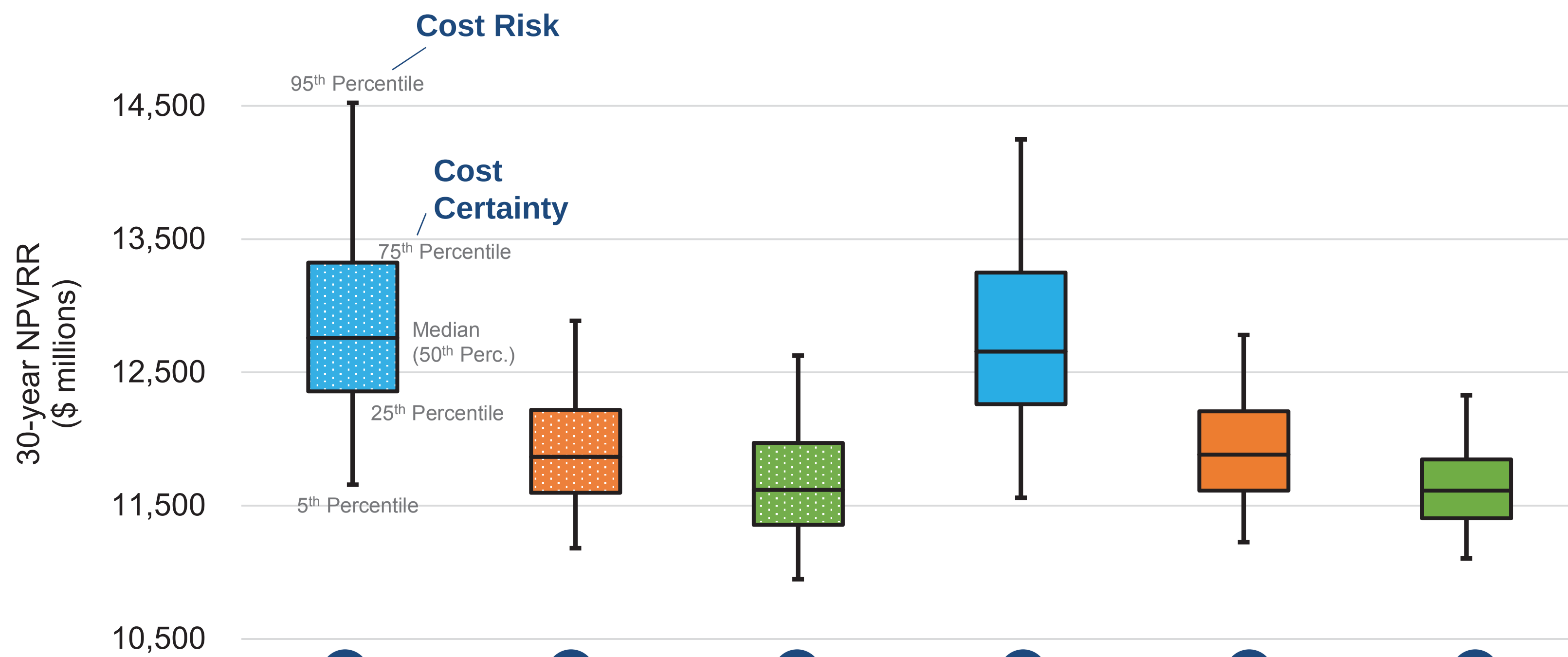
Preliminary, Subject to Change



		A	B	C	D	E	F
	Ownership / Duration	**Short Duration**	**Short Duration**	**Short Duration**	**Long Duration**	**Long Duration**	**Long Duration**
	Diversity:	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**	**Higher Carbon**	**Average Carbon**	**Average-Low Carbon**
Base Scenario	**Delta from Lowest Cost to Customer**	$1,222 10.4%	$265 2.3%	$6 0.1%	$1,192 10.2%	$357 3.0%	**$0 0.0%**
Aggressive Env Reg	**Delta from Lowest Cost to Customer**	$2,052 16.6%	$524 4.2%	$250 2.0%	$2,002 16.2%	$546 4.4%	**$0 0.0%**
Challenged Econ	**Delta from Lowest Cost to Customer**	$756 8.7%	$244 2.8%	**$0 0.0%**	$722 8.3%	$361 4.2%	$165 1.9%
Booming Econ/ Abund Nat Gas	**Delta from Lowest Cost to Customer**	$692 6.0%	$224 2.0%	**$0 0.0%**	$622 5.4%	$281 2.5%	$109 1.0%

Replacement Analysis: Stochastics

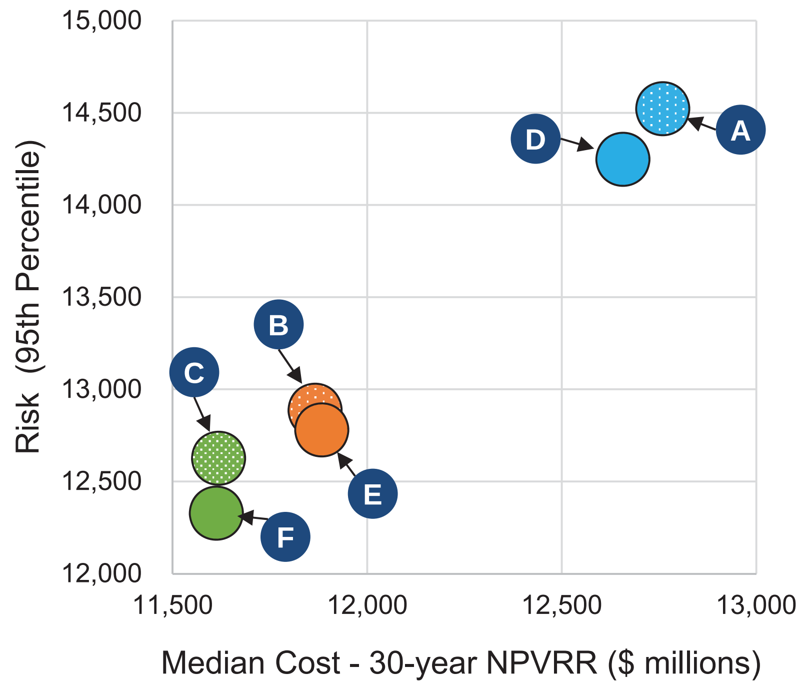
Preliminary, Subject to Change



Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Delta from Lowest Median Cost	$1,147 9.9%	$254 2.2%	$6 0.1%	$1,044 9.0%	$271 2.3%	**$0 0.0%**
Delta from Lowest **Cost Certainty**	$1,477 12.5%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.1%	**$0 0.0%**
Delta from Lowest **Cost Risk**	$2,194 17.8%	$558 4.5%	$297 2.4%	$1,920 15.6%	$452 3.7%	**$0 0.0%**

Replacement Analysis: Stochastics

Preliminary, Subject to Change



Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A	B	C
Long Duration	D	E	F

Replacement Scorecard

2018 Replacement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 ICAP MW sourced from non-gas resources)
Environmental	• Annual carbon emissions from the generation portfolio • Metric: Total annual carbon emissions (2030 metric tons of CO_2) from the generation portfolio
Employees	• Net impact on NiSource jobs • Metric: Approximate number of permanent NiSource jobs added
Local Economy	• Property tax amount from entire portfolio • Metric: 30-year NPV of estimated modeled property taxes from the entire portfolio

Replacement Scorecard

Preliminary, Subject to Change

Most Viable

	A	B	C	D	E	F
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Cost to Customer delta from least	$12,949 $1,222 10.4%	$11,992 $265 2.3%	$11,733 $6 0.1%	$12,920 $1,192 10.2%	$12,085 $357 3.0%	$11,727 $0 0.0%
Cost Certainty delta from least	$13,325 $1,477 12.5%	$12,218 $371 3.1%	$11,971 $124 1.0%	$13,250 $1,403 11.8%	$12,209 $362 3.1%	$11,847 $0 0.0%
Cost Risk delta from least	$14,522 $2,194 17.8%	$12,886 $558 4.5%	$12,625 $297 2.4%	$14,248 $1,920 15.6%	$12,780 $452 3.7%	$12,328 $0 0.0%
Fuel Security % non-gas capacity	45%	79%	86%	40%	72%	87%
Environmental 2030 CO_2 emissions 2005 baseline = 18.2M	2.18M	0.97M	0.97M	3.13M	2.03M	0.97M
Employees	0	0	0	<30	<30	<30
Local Economy	Under evaluation					

Stakeholder Requested Scenarios

Fred Gomos
Manager, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

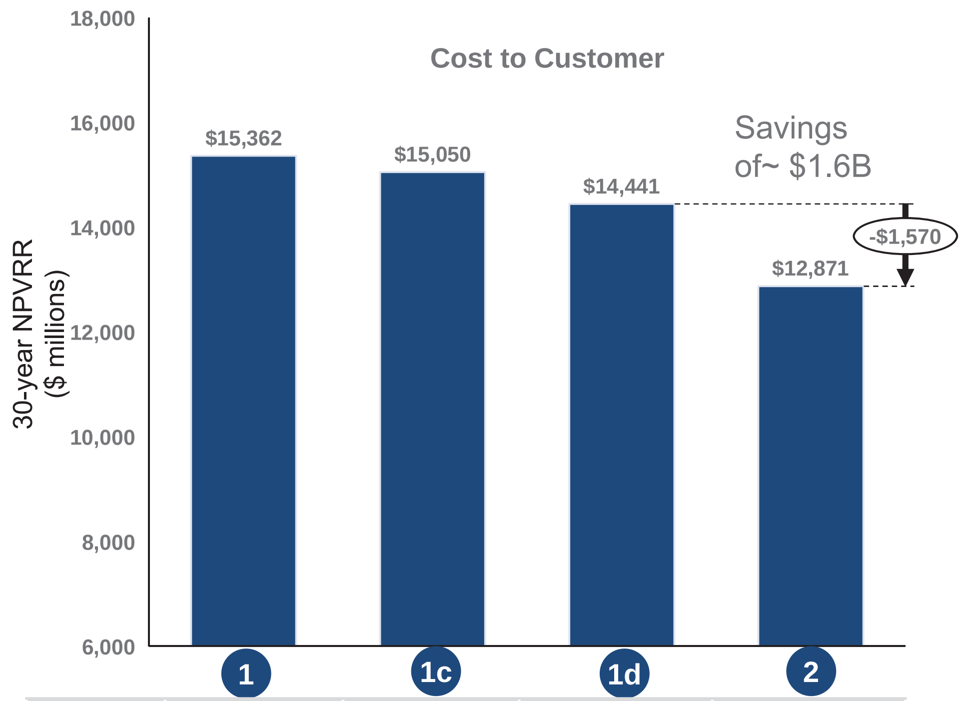
Stakeholder Request – Indiana Coal Council Portfolios for Schahfer Units 17/18

- Indiana Coal Council requested we look at retirement combinations with less costly ELG-related compliance for Schahfer 17/18 and an alternative market case

	1	1c	1d	2
Portfolio Transition Target:	**65% Coal through 2035**	**65% Coal through 2035**	**65% Coal through 2035**	**40% Coal in 2023**
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Environmental Compliance	CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	→	→
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	→	→
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement

Stakeholder Request - Coal Council Scenarios

Base Case

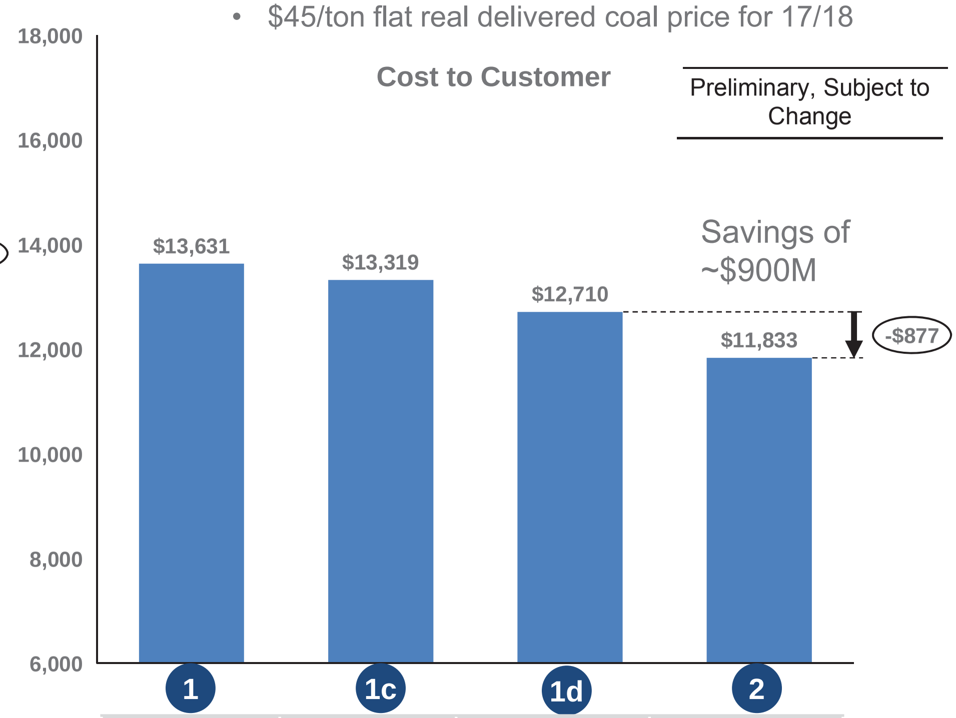


Portfolio Transition Target:	65% Coal through 2035	65% Coal through 2035	65% Coal through 2035	40% Coal in 2023
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Alternative Case – Coal Council

- No carbon price
- High natural gas price
- $45/ton flat real delivered coal price for 17/18

Preliminary, Subject to Change



65% Coal through 2035	65% Coal through 2035	65% Coal through 2035	40% Coal in 2023
None	None	None	Schfr:17,18 (2023)
Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Stakeholder Request – Evaluate Coal to Gas Conversion for Schahfer Units 17/18

- OUCC requested that NIPSCO further evaluate a coal to gas conversion for Schahfer 17/18 as a potential replacement alternative on 2023

	6	6b
Portfolio Transition Target:	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (MC 2028) (17/18 Conv.)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Mich. City: 12 (2028) CONVERT Schfr: 17,18 (2023)
Env. Compliance	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retire 2028** CCR ELG: N/A	→
Schahfer 14	**Retire 2023** CCR ELG: Retirement	→
Schahfer 15	**Retire 2023** CCR ELG: Retirement	→
Schahfer 17	**Retire 2023** CCR/ELG: Retirement	**Convert to Gas 2023**
Schahfer 18	**Retire 2023** CCR/ELG: Retirement	**Convert to Gas 2023**

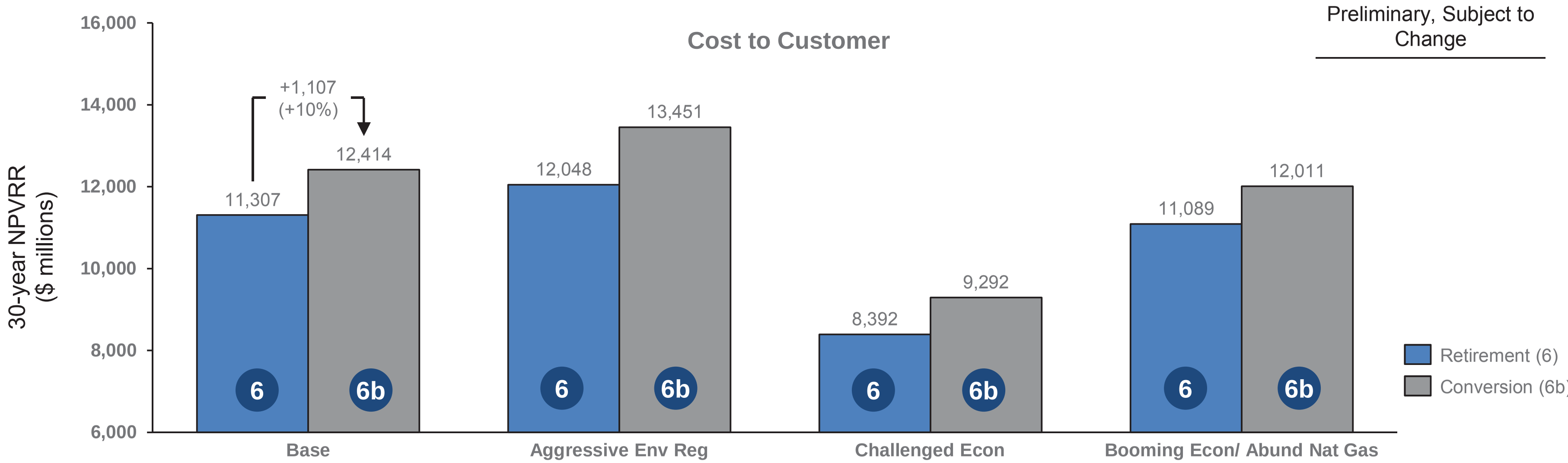
Key Assumptions

	Category	Estimated Cost	Cost Notes
Conversion Investment Costs	**Conversion**	$87M	• Equipment, materials and construction labor, contingency, owners and indirect costs • Based on S&L Study cost estimates of $121/kW
	Gas Interconnection	$68M	• Incremental cost for 30” gas pipeline interconnection
	Environmental Compliance	TBD	
Maintenance Capital	**Maintenance Capital (Total 2023-2037)**	$438M	• Assumes same maintenance capital needs as current coal operations from 2023 through 2037
Ongoing Costs	**Fixed O&M Costs ($KW-yr)**	$39	• Based on S&L Study cost estimates for expected O&M post conversion

Stakeholder Request – Evaluate Coal to Gas Conversion for Schahfer 17/18

- Conversion is an expensive replacement alternative across all scenarios as compared to the retirement of Schahfer 17/18 and replacing with alternative selections from the RFP results

Preliminary, Subject to Change



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (17/18 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17,18 (gas) Mich. City: 12 (2028)

Aggressive Env Reg	
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

Challenged Econ	
15% Coal in 2023	15% Coal in 2023 (Schfr. 17/18 gas)

Booming Econ/ Abund Nat Gas	
15% Coal in 2023	15% Coal in 2023 (Schfr. 17/18 gas)

Michigan City 12	Retire 2028	Retire 2028
Schahfer 14	Retire 2023	Retire 2023
Schahfer 15	Retire 2023	Retire 2023
Schahfer 17	Retire 2023	Convert to Gas 2023
Schahfer 18	Retire 2023	Convert to Gas 2023

Conversion economics are improved when gas prices are low, but is still uncompetitive with RFP alternatives

Stakeholder Presentations

Wrap Up

Northern Indiana Public Service Company
2018 Integrated Resource Planning ("IRP")
Public Advisory Meeting #4
SUMMARY

September 19, 2018

Welcome and Introductions

Alison Becker opened the meeting by having those in the room introduce themselves. She then introduced Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource. Ms. Sistovaris welcomed the participants and discussed NIPSCO's planning process and the balance the Company strives to achieve related to meeting customer needs through generation. She thanked the stakeholders for their participation in the process and encouraged on-going dialog. Ms. Becker then reviewed the process for those participating by telephone and the agenda for the day and did a safety moment.

NIPSCO's Planning and the Public Advisory Process

Dan Douglas, Vice President, Corporate Strategy and Development

Mr. Douglas thanked participants for attending. He explained how NIPSCO plans for the future and provided an overview of the public advisory process, including reviewing the current point in the stakeholder engagement process. He apologized to participants that the full presentation was not made available prior to the meeting, but noted that what NIPSCO was presenting from both a retirement and replacement perspective was substantially different than what has been shown in the past, and, therefore, the details needed to be communicated in an orderly manner. He reiterated that the decisions are not final and that feedback is appreciated in both the meeting and the weeks to come. Mr. Douglas noted that NIPSCO has a deep commitment to its employees and that the Company wants to ensure those employees are notified of possible outcomes in a thoughtful way. He then reviewed where NIPSCO is in the Public Advisory process and noted this meeting was the fourth Public Advisory meeting, with the addition of a technical webinar, for a total of five stakeholder participation opportunities. He then reviewed the stakeholder interactions that have taken place outside of the Public Advisory process, noting that seven groups have met with NIPSCO one-on-one and he encouraged stakeholders to continue to engage NIPSCO one-on-one as desired.

Energy and Demand Forecast Update
Amy Efland, Manager, Demand Forecasting

Amy Efland provided an update on the energy and demand forecasts that had previously been presented during the March Public Advisory meeting. She provided information regarding the NIPSCO energy and peak demand projections and provided an updated energy requirements projections. Ms. Efland then discussed an update to the base case related to a change in large industrial customer demand. She noted that Industrial scenario forecasts are constructed using recent historical levels and trends for each large customer. She also reviewed how the Industrial high load growth and low load growth scenarios are developed. Finally, she provided updated energy sales and coincident peak curves for the base, high and low scenarios.

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

- On Slide 13, it looks like it is showing significant drop in peak demand projections but on Slide 15 you only see that drop in the lowest scenario rather than base scenario?
    - This view has more to do with scale of the chart. Each scenario has a pretty significant drop. Looking at Slide 13, this is the base forecast and this magnifies it. You can see the same pattern.
- Given that difference in scale, there appears to be a much larger drop in load forecast. What is that getting at?
    - The Industrial portion is driving that. More equal distance for Residential and more of a downswing in the Industrial piece. The pessimistic scenario for industrial is much greater than optimistic.
- The drop in Slide 13 is significant and is reflected in Slide 15. The only difference is the scale in the chart. There is a very large drop in the low case. Please provide more discussion on that.
    - On the pessimistic side, for NIPSCO Industrial load is about 50% of total load, and the Industrial forecast through 2019 drops a half from that, which is a significant dip. The optimistic side stays consistent with the base case, which is only being driven by Residential and Commercial which is only 50% of NIPSCO's total load.
- Slide 15 is presenting Midcontinent Independent System Operator ("MISO") coincident peak scenario, not NIPSCO's?
    - The relationship and patterns are very similar. It is 95% relationship with NIPSCO base.
- Is the MISO coincident peak what you need to plan for?
    - Yes. Both are presented in the IRP, but NIPSCO plans for the MISO coincident peak.
- Is the expected baseline drop in Industrial load based on known changes from industrial customers?
    - It is based on an expected drop based on economic information and conversations with Industrial customers.

- Why showing a return to growth?
  - This is based on the number of customers and potential patterns the Company sees occurring in the future.

Modeling of Uncertainty
Pat Augustine, Charles River Associates

Pat Augustine began by discussing how generation decisions are generally capital intensive and long-lived, so it is important to understand and incorporate future risk and uncertainty. He reviewed the process for using scenarios and stochastics to assess risk. First, he explained that scenarios are used to answer "what if. . .." scenarios He then explained that stochastics evaluate more granular volatility as well as "tail risk." After providing this background, Mr. Augustine reviewed the scenarios and combinations of input variables that go into the scenarios. He noted that each scenario had a unique combination of key input variables and a fully integrated set of commodity market price forecasts. Mr. Augustine then reviewed each of the scenarios and provided a brief description. For each scenario, he reviewed the curves related to carbon, natural gas and Illinois Basin coal prices for each scenario, as well as the NIPSCO peak load. After providing each individually, he showed a slide with the scenario summary.

After presenting the various scenarios, Mr. Augustine reviewed the development of stochastics, showing power price and natural gas price stochastic distributions as two examples. He finished by noting that the use of stochastic inputs for commodity prices broadens the range of inputs evaluated and allows for the assessment of the impacts of volatility (daily, hourly, and monthly over time).

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

- Are all figures being shown in nominal dollars?
  - No. All figures are in 2017 real dollars.
- Trying to understand market based approach and want to confirm that in fact NIPSCO is looking to sell carbon dioxide ("CO_2") on the market whereas this approach would not prioritize people on the front line, especially people of color, who would be impacted by pollution elsewhere. There is a summary report out of Germany saying that carbon pricing actually does not reduce the emissions because of the profitability – entities are making profit from selling CO_2. Can you clarify-is air being sold as a commodity?
  - Broadly speaking, it is difficult to predict what a future regulation on carbon emissions will look like. However, for modeling purposes, a price on carbon is incorporated to reflect the potential costs associated with emitting CO_2 that NIPSCO would absorb. NIPSCO is not modeling any situation where NIPSCO would profit through the sale of CO_2 allowances. All prices on carbon add costs for any ton of CO_2 that is emitted. While

the Company is not modeling any policies that would directly force retirements, NIPSCO is applying costs to CO_2 emissions to assess how different portfolios perform.

- Explain in more layman's terms – is the CO_2 being traded across the market for a profit to NIPSCO or another utility to MISO?
  - No. The CO_2 price here is a cost. Any ton of CO_2 emitted by NIPSCO would be associated with a cost which is absorbed in the portfolio calculations. There is no assumption that there would be a profit from selling a potential future CO_2 allowance.
- There is an incentive to reduce, but there is a market right? Indiana could continue to host more CO_2 that would be emitted?
  - Currently there is no operating market in Indiana. The analysis assumes a future potential tax or carbon market to increase the costs associated with emitting CO_2. Structurally, a cap-and-trade regime would be designed to bring CO_2 emissions down. There is currently none in place for Indiana. The intent of a future potential policy, however, would be to drive emissions down, not establish something that NIPSCO would profit from.
- In the challenged economy, slow economic growth is paired with lack of carbon price. However, those are not really related. It would not be dynamic on its own but a combination?
  - The comments are fair. There are plenty of variations for the different variables that could theoretically be developed. However, in this case, the reason for pairing low load and no carbon price was to stress a low portfolio cost outcome. This is certainly not the only way a no carbon scenario could play out, but it was a plausible outcome that helps bracket the range of future states-of-the-world.
- These look like delivered natural gas prices. Could not some of this variability be controlled by having firm transportation at NIPSCO, and thus just looking at commodity price variability?
  - This graphic is actually only showing the underlying commodity price and is not representing the delivered price to a certain plant. The right side graphic is showing the most proximate hub point, Chicago Citygate, for natural gas. Thus, NIPSCO is only evaluating the liquid market benchmark when the Company is assessing market shocks and uncertainties in the stochastic process.

Retirement Analysis
Pat Augustine and Dan Douglas

Mr. Augustine reviewed the retirement analysis framework, noting that the responses to NIPSCO's all-source request for proposals ("RFP") were fundamental to indicating the actual projects available to NIPSCO. He noted that the key decision was what units to retire and when. He then reviewed the various retirement combinations that were constructed and went through each of the eight options. After providing the overview, he revealed the technologies being selected by the model based on the RFP results for the various retirement combinations and reviewed the results for the base case, which included an analysis of the preliminary expected cost to customer over the next 30 years. He then reviewed the preliminary results of the cost to customers over the next 30 years for each retirement combination and each of the scenarios. Then he provided a preliminary review of the stochastics for each of the retirement combinations. Finally, Mr. Augustine provided information related to the cost risk for each of the retirement combinations.

Mr. Douglas then provided an overview of the Retirement Scorecard. He explained that NIPSCO is using a scorecard to navigate the “most viable” retirement and replacement paths, noting that NIPSCO elected to remove the “red-yellow-green” color-coding in an effort to be more quantitative in the scoring. He then reviewed the Reliability Risk, Employees and Local Economy portions of the scorecard, noting that Mr. Augustine had already covered the Cost to Customer, Cost Certainty and Cost Risk components. For Reliability Risk, he noted that activities, timelines and risk of the MISO retirement process, transmission system upgrades, remaining unit dependencies, fuel and maintenance contracts, future resource procurement and the percentage of the system turning over at once were factors that were considered, but did not rise to the level of driving risk acceptability.

Regarding the impact on NIPSCO employees, he noted that there are over 400 employees at coal units that are focused on reliably and safely generating electricity for NIPSCO’s customers. This was an important consideration in the retirement analysis, with the criteria utilized being the number of employees that are impacted by retirement plans prior to 2023. His final criterion was the local economy, specifically the property tax payments made by the generation facilities to local communities. This was quantified by estimating the present value of future property taxes relative to the 2016 IRP. Mr. Douglas finished by noting these criteria are important to be considered in concert with the financial metrics to provide a comprehensive perspective on retirement considerations.

Mr. Douglas explained to participants that a number of slides were marked “preliminary, subject to change.” He further explained that this is not because NIPSCO expects the underlying analysis to change, but that the Company continues to review and ensure there are no refinements needed, including any stakeholder feedback received. He then reviewed the Retirement Scorecard, noting that the criteria discussed are along the left side. He then explained that retiring coal earlier is the most cost effective option as well as the highest cost certainty and lowest cost risk. He noted that Combination 8, which is 0% coal in 2023 has the lowest net present value requirement (“NPVRR”), with Combination 1, which is 65% coal through 2035 having the highest cost.

Mr. Douglas then noted that Combinations 1-6 are acceptable from a Reliability Risk perspective, but 7 and 8 are unacceptable. He explained that Combination 7, 15% coal by 2023 is not executable in the time allotted due to required transmission upgrades to maintain system reliability. These upgrades require coordination with MISO as well as having environmental wetland management issues, meaning they will not be complete until 2022 under the best case scenario. Combination 8 would require NIPSCO to retire and replace 1,800 megawatts (“MW”) at one time. And, while the RFP indicated sufficient capacity, that much transition at one time could create reliability and execution risk for customers that the Company is not willing to accept. Furthermore, he noted, there are benefits to staggering the transition to allow for better views of technology.

After reviewing the impact to employees and the local economy (which is measured relative to the 2016 IRP retirement plan), he noted that, as indicated by the red dashed box, NIPSCO selected Combination 6, 15% coal in 2023 as the “most viable” retirement path. This Combination was selected at a high level because it is the lowest cost option that held acceptable reliability risk for customers and the system. He then provided additional details about Combination 6, including that it is preliminarily projected to save customers $1.5 billion relative to NIPSCO’s 2016 preferred plan, it provides enough time to complete the necessary transmission upgrades, replacement resources can be reasonably secured by 2023, and it allows NIPSCO to continue to assess customer, technology and market changes over the next decade. Mr. Douglas also noted that Michigan City Unit 12 will be maintained through 2028 and there are no plans to retire the combined cycle gas turbine (“CCGT”) at Sugar Creek at this time. He then reiterated that these decisions are not final.

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

- Slide 27: So the retirement analysis compares the cost of keeping a unit to replacing it with the most economic resource. It seems like that optimization does not actually take place in that retirement analysis, only replacement analysis?
    - It is taking place here, as the Company develops the least-cost optimized alternative set of resources for each retirement portfolio. In the full replacement analysis NIPSCO also incorporates environmental and risk metrics, so there are more considerations against which to develop replacement portfolio. Here the Company is putting all RFP results into the optimization model to find a least cost benchmark vs. coal retirements. The extra layer for replacements will be added later.
- So the retirement analysis is pitting existing resources against the most economically optimal resources from the RFP?
    - Yes.
- Regarding the treatment of stranded costs of existing resources, could you address that directly and specifically for the scenario in which the existing resources are retained? You have a set of cash flows – and then in scenarios where replaced, do you continue to reflect the ongoing capital costs of those resources after retirement?
    - All existing resource capital is recovered over time with the same depreciation rates used across all portfolios. There are some small credit backs after a unit is retired – property taxes, for example. However, in terms of current invested capital, all costs are assumed to be recovered over time, regardless of whether a plant is retired or not. Depreciation is assumed to occur through 2030.
- Through 2030? What is that date?

- o This is an assumption that the Company is using to be consistent with NIPSCO's internal depreciation rate. The coal plants were scheduled to generally operate through the 2030s. Based on the initial retirement analysis results, the Company tried to move to a depreciation assumption that accelerates recovery slightly, but does not put all of the costs immediately back on customers.
- Does that mean that you take full amount of stranded costs and those costs get recovered through 2030, meaning the depreciation rate would increase?
  - o Yes – the remaining net book value of the facility is recovered, including a return on the investment, through 2030. The depreciation rate has been adjusted accordingly.
- By doing that, you are essentially burdening the replacement assets with an additional amount of depreciation in those years?
  - o Yes, the Company is putting an additional cost into the portfolios with replacement assets that would not have otherwise been there. The best way to think about is that NIPSCO tried to build in what it believes can be recovered going forward. The assumption is that the Company is going to be able to recover the deprecation going forward to a certain date. It is not viable to go out past 2030, which would drag recovery way past the date of retirement.
- For the record, the last IRP update in 2016 – the Plan called for the retirement of Michigan City in 2018. There are many people with asthma. Questions: 1. ELG – is that natural gas plant and once that coal retires you are not going to replace with natural gas? 2. Have you calculated the resistance to natural gas plants that is progressively growing with people who are opposed to fossil fuels?
  - o 1. "ELG" stands for effluent limitation guidelines. This has nothing to do with natural gas, but rather a capital expenditure associated with environmental compliance at the coal plants. 2. The Company will get to the replacement options, including natural gas and renewables later. Those will be presented in a similar scorecard.
- Demand Side Management ("DSM") referred on Slide 29 – is that peak load and energy efficiency?
  - o Yes, it is a combination and based on the program bundles developed from the study conducted by GDS Associates. That study aggregated programs and not a single peak demand response options. The peak impact is shown here.
- Slide 29 – scenario 8 – so the all coal replacement shows 715, 1395, 1825 MW but the RFP was only for 600 MW. How do you reconcile that? Will NIPSCO need to do a new RFP?
  - o The RFP asked for an approximate 600 MW but around 10,000 MW of resources were offered. The capacity shown here is all from the RFP.
- If you have an aggressive energy regulatory environment – the savings of going to scenario would be $5.8 billion, right?
  - o Yes, that number is the net present value ("NPV") over the 30-year period.
- Retirement scenario 7 – how much ELG compliance is required? What needs to be done if you followed scenario 7?

  - The short answer is that the Company would not need to do anything from an ELG compliance position under retirement portfolio 7.
- Just to be clear, on Slide 32, this assumes the resource plans shown on Slide 29?
  - Yes, the numberings are the same. The portfolio number labels refer back to slide 28, which is the overall legend for the 8 plans. However, please note that none of these represent a final resource plan at this point.
- Where you have portfolio transmission targets what are those? We (the NAACP) have also called for a reduction of CO_2 based on location, is that reflected somewhere?
  - In terms of location, there is no separate location metric.
- Only based on retirement? No additional efforts or ability to reduce CO_2 even if not retired?
  - Yes, all results are based on the various portfolios established in this retirement analysis.
- On the scorecard – when looking at local economic impact of retiring – where would you put in analysis any potential property tax revenue to for example Jasper County – from the renewables? Solar, wind, it looks like only looking at negative but not taking into account future property tax revenues from those?
  - NIPSCO is considering and thinking about the economic impact of replacement resources. This scorecard feels a bit like negative impacts are shown. There are positives on the Replacement Scorecard.
- On the employee side – we (the NAACP) do a lot of narrative regarding the just transition and preparing folks for the clean renewable energy sector. For example, the organization is a big proponent of an apprenticeship program – NIPSCO have anywhere envision that?
  - NIPSCO is absolutely open to that. The Company is engaged with Ivy Tech now on that type of program today to prepare employees. NIPSCO is more than willing to broaden in future – some ongoing dialogue or thoughts are welcome. There will be a need for that. There will be a switch for NIPSCO's employees and fewer employees will be required.
- The present value is basically the amount of money you have now?
  - Yes, it discounts future value back to today
- What time period are you looking at for the property tax metric?
  - Schahfer 14, 15, 17, and 18 and Michigan City unit 12 all have different lives associated with them. Generally coal plants are scheduled to retire at an age of about 60 years. Schahfer would be scheduled to operate until almost 2040 and Michigan City until 2035. So if a unit is now scheduled to retire in 2023, the loss of property tax income would be calculated over the time between the new retirement date and the original end-of-life assumption.
- Reliability risk is the only one not quantified. Is there any other Quantitative assessment?
  - The Company tried to assess all activities associated with a potential retirement. This includes transmission upgrades. For example, the plan requires three lines to rebuild or build stronger. The MISO retirement

process, remaining unit dependencies at Schahfer, and future resource procurement are also factors. For example, on future resource procurement, NIPSCO will need to execute on multiple bids from the RFP and this does not happen overnight. Also, the analysis considered the percentage of NIPSCO's system turning over at once. When you think about retirement portfolios 6, 7 and 8, you are in the neighborhood of 60%-75% of the system changing at same time.

- Please confirm that the analysis includes some of the spending that currently goes from NiSource through the plants rather than employee spend. Does this include contractor, indirect employment and impact both locally and broader scale, including that given to suppliers? Is this a comparison between current spending and that going forward?
    - Yes. This looks pretty narrowly at the property tax portion. There are obviously economic multiplier effects, but the Company has not taken all of that into account at this time. NIPSCO is cognizant of the impact on communities and is in discussions with them. On the upside, there is potential to build and own resources in some of these communities. That could offset some of the number.
- The geographic distribution of the renewable resources and how you look at that for location – and how meshes up with existing transmission distribution network
    - The Company has been looking at specific sites, but do not currently have a map to share. However, all are within MISO Zone 6, which means that the majority are in Indiana, and there are a good amount that are in the service territory today. That is a positive sign. The Company is working through the specific economics, but right now the alternatives are primarily Indiana-based.
- Remind me have you presented data as to the capital expenditures for maintenance and replacement of existing projects related to your existing fleet – or are those expenditures just embedded?
    - All of those estimates are embedded in the model. NIPSCO's Major Projects group estimates the costs to maintain the units into the future, as well as the costs to potentially wind down the operations at each facility. Those estimated costs are built into this analysis.
- If presented, where is it?
    - The numbers can be shared. The high level numbers were shown during a previous meeting and were directional and aggregated.
- What impact for Terre Haute facility?
    - The Company intends to continue to operate Sugar Creek, which is a 550 MW natural gas CCGT. The plant is economic and has a high capacity factor today.
- Can you talk about how the solar tax credit expiration affects this and the end of the wind production tax credit ("PTC")?
    - Ultimately it is assumed that the projects would take advantage of both. The PTC for wind begins to sunset in 2020. The investment tax credit for solar goes until 2023. The plan is to take advantage of both.

- Has NIPSCO analyzed a retirement scenario that starts in 2021 and then staggers the retirements over the next few years?
  - Yes, Retirement Portfolio 7 does exactly that. As part of reviewing the potential plan, it was discovered that it requires fairly significant transmission line upgrades, which would require environmental permitting associated with wetlands and rights-of-way. Secondly, that portfolio requires MISO coordination, and it would be into 2022 for all of that to occur. It was better to package the retirements together in 2023 to allow for some contingency in the schedule for potential environment and permitting issues.
- NIPSCO's IRP is off schedule. When will the next one be submitted? In 2021 or sooner?
  - The Indiana Energy Association submitted comments to the proposed rule suggesting an addition to allow for a utility to take its IRP out of the normal schedule. NIPSCO will work with the Indiana Utility Regulatory Commission ("IURC") on the date for the next submission.
- Can you quickly summarize the key stakeholders? Also, who makes final decision – the chief executive officer, the board of directors, who?
  - Related to stakeholders – they are vast – customers, and most of the groups represented in this room. NIPSCO takes seriously the involvement of people from this room. NiSource owns the ultimate decision. A management team and a steering team has met on a bi-weekly basis to walk through options. Given the potential significance of changes, the NiSource board of directors is aware, but does not approve formally. However, since the replacement plan will likely require large capital expenditures, board level approval will be required going forward.
- What do you anticipate as the challenges of the MISO process through the retirements? Do you anticipate any significant challenges?
  - The Company has run its own analysis to evaluate transmission upgrades that are needed from reliability standpoint. A similar analysis was completed for the Bailly retirement in May. MISO said NIPSCO needed to only do synchronous upgrades, which were completed.
- The reduction in employees – scenarios 7 and 8 – is it calculated as the dollar amount of operations or by personnel? Is that calculated in there as part of the savings to the company, or the bottom line cost to customers?
  - The analysis assumes that fixed operations and maintenance costs, which include labor, would no longer need to be expended after a retirement. Does that mean the employees will not still be with the Company? Not necessarily, since just like with Bailly, NIPSCO could keep employees in other areas of the company. However, expenses associated with those employees are going away in relation to retired facilities.
- Concerned about those jobs in the "clean energy economy." In looking at scenarios 6 and 8, what would ramp you up to 0% coal and 2023? What is the $20 million included on the scorecard?
  - That would be the local economy number.

- Regarding the cost to customers ($11,151 million for scenario 7 $11,307 million for scenario 8). How do you get the costs for scenario 8 – seems negligible?
    - o The difference between scenarios 6 and 8 is the retirement of Michigan City. However, the early retirement would shift 75% of NIPSCO's physical generation assets at one time, so keeping some capacity for a slightly longer period is the Company's most viable plan right now. The management team views the difference as a negligible cost as well, but the reliability that the plan gives us is valuable.
- Is it not true that if the Company wishes to recover its undepreciated capital in the coal plants, it will require IURC approval?
    - o Yes, that is correct.
- Babcock and Wilcox – is that study available?
    - o That is only used as an example of an engineering firm. There is no study produced by that firm

Replacement Analysis
Pat Augustine and Dan Douglas

Mr. Douglas started the review of the section by reminding participants that NIPSCO has forecasted a 2023 peak demand of just over 3,000 MWs. He stated that retiring the units at Schahfer and Michigan City will lead to a combined 1,820 MWs required. Based on this, NIPSCO completed its replacement analysis, which, like the Retirement Analysis, is still preliminary. He reviewed the replacement analysis framework, noting that the RFP was a main source of information for determining replacement options. Mr. Douglas noted that nearly 10,000 MWs of unforced capacity ("UCAP") was offered through 90 different proposals covering a broad range of technologies. These included both power purchase agreements ("PPA") and ownership options. He told the stakeholders that NIPSCO will not be releasing a short list of finalists; rather that information will be part of any certificate of public convenience and necessity process. He also informed the group that NIPSCO has begun to reach out to several bidders and is working through the list. That process is being facilitated be a separate department within Charles River Associates.

Mr. Augustine reviewed how DSM would be incorporated into the IRP modeling process. Specifically, three bundles were determined and run through the optimization model, with the model selecting bundles 1 and 2. He then provided a recap of the August 28 Technical Webinar with a reminder on tranche development and assessment. He then provided an overview of the replacement analysis, explaining that different replacement combinations were created to explore the range of ownership/duration and diversity possibilities. This created six replacement portfolios, which were categorized as high, average, and average-low carbon emissions and then short- or long-term duration. Mr. Augustine then went through the replacement analysis for the various scenarios and then the stochastics. Finally, based on the stochastics, he showed the cost risk for each of the replacement scenarios being considered and noted this was all still preliminary.

Mr. Douglas then reviewed the Replacement Scorecard. As with the Retirement Scorecard, the Replacement Scorecard is being used to help navigate the various paths and NIPSCO has done away with the “red-yellow-green” color coding in favor of more quantitative scoring. He noted that there are some nuances from the Retirement Scorecard. As with the Retirement Scorecard, Mr. Douglas explained how fuel security, environmental, employees and local economy were considered in the Replacement Scorecard. Regarding fuel security, he noted that the criterion assesses NIPSCO’s ability to reduce exposure to short-term fuel supply and/or deliverability issues, which is expressed as a percentage of capacity sourced from resources other than natural gas in 2025. Mr. Douglas explained that the environmental criterion considered the annual carbon emissions from the resource portfolio in 2030 by metric tons of CO_2. For employees, he explained that the number of NIPSCO jobs added for the resource portfolio was considered. And, finally, for the local economy, NIPSCO considered the property taxes for the portfolio, without making a determination of where the facilities would be, only considering assets that would pay property taxes.

After providing this background into the scorecard, Mr. Douglas provided the preliminary results of the analysis. He noted that NIPSCO does not expect the results to change directionally, but the analysis will continue to be reviewed, including taking stakeholder feedback into account. Mr. Douglas stated that the left side includes the criteria included in the scorecard and the various scenarios are laid out across the top. He said that including renewables is the least cost option as well as the highest cost certainty and lowest cost risk. He noted that, by comparison, portfolios with natural gas technologies have a cost over 10% higher than renewable—only portfolios. Portfolio F, which is long duration and average-low carbon pricing, which is predominately long-term renewable PPA, DSM, and a small amount of market purchases, is the lowest cost option and the strongest portfolio from a fuel security standpoint. In addition, he said, it provides the lowest emissions for customers.

Mr. Douglas pointed out that, in order to be competitive, a natural gas turbine would need to be $300/kilowatt (“kw”). However, new plants are roughly $1,000/kw and that no CCGT was included in a response to the RFP at that price. He once again stressed that the decision is not final and that the Company is open to feedback over the coming weeks to adjust this direction.

In summarizing this section, Mr. Douglas stated that NIPSCO believes the retirement and replacement path will provide reliable power, enable lower costs and provide significant environmental benefit. He noted that the scorecards demonstrate that retiring coal and replacing with renewables will create significant savings. Finally, from a reliability perspective, he committed the Company to making sure the plan keeps the lights on for its customers. He stated that transitioning from coal to renewables is a significant move and NIPSCO is approaching the shift with an appropriate level of caution and analysis.

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

- What is the MW of interruptibles on Slide 37?
    - o About 600 MW
- Slide 38: Regarding hydro. Please explain the hydro-where is it located, is it water, what will be impacted?
    - o The hydro plants are powered by water. They are fairly small – less than 20 MW of nameplate capacity. Ultimately NIPSCO only gets capacity value of 5 to 7 MW.
- Confirm that all projects considered are in the MISO queue on slide 39.
    - o They are at various stages in the MISO queue, and some are not formally in the queue yet. Currently NIPSCO is looking for 2023 assets, so this is not surprising.
- What are the locations for the technology ownership? I am struggling with carbon markets and trading. Is this where the wind turbines are located or where the PPA is coming from? If located in other states, is this where the Company will get credit for purchasing clean energy?
    - o The RFP asked that all assets be deliverable into MISO Zone 6. Environmental credits would flow to the owner of the facility. It is important to note that there is no carbon market, so with respect to CO_2 credits, the input assumptions introduce costs associated with operating plants that emit carbon.
- Regarding "cap and trade," some states will still pollute with coal fired power plant and then be able to purchase clean energy from another states and that considered acceptable with federal guidelines with cap and trade system. Did NIPSCO consider this?
    - o It is hard to speculate now because there is no-cap-and trade program in place. The latest Affordable Clean Energy rule from the U.S. Environmental Protection Agency ('EPA") does not create a tradable commodity. Again, any CO_2 costs in the assumptions are costs only.
- Why would NIPSCO purchase clean energy out of state as opposed to producing in Indiana and phase out coal retirements – why would build in another state?
    - o It would be based on economics. For example, Oklahoma has great wind resources, although you have to pay for the transmission path. For example, NIPSCO may be able to produce at $25/MWh here in Indiana but it could be more cost effective to get from Oklahoma if it can be obtained for $20/MWh, including transmission. If the resources are cost neutral, the Company certainly would have a bias in terms of service territory, but again, NIPSCO is letting economics lead. The vast majority of RFP responses are in Indiana, so it is unlikely that we will pursue significant out-of-state resources.
- The "installed capacity" – does that mean there are already facilities?
    - o Installed Capacity ("ICAP") is the total capacity that a plant could output at any given time. UCAP is the capacity available when the MISO market is at its peak. For example, solar output is fairly well aligned when load

peaks in the mid-to-late afternoon, so MISO discounts the UCAP to 50%. Wind, however, is much lower – around 15%. This is because the wind does not typically blow in the summer afternoons when you have the MISO peak.

- For DSM that was the achievable level from the MPS?
  - Yes, bundled together by cost.
- Was there an amount higher than that bundled in?
  - There was a high case, but only the achievable base case went in.
- To clarify, NIPSCO chose not to use the decrement model sent by the Citizens Action Coalition of Indiana, Inc. ("CAC")?
  - Correct, the decrements have not been isolated individually. The analysis would likely find a similar set of results if the decrements were used since it is just a different way of organizing the data. The goal here was to put DSM on equal footing with the supply side options.
- Is NIPSCO willing to sit down with the CAC to see how using the decrement model would impact the analysis?
  - Yes.
- Is a "MISO Capacity Purchase" different from a PPA? How?
  - Yes, the decision was made to carve out 400 MW of MISO short-term market purchases in the short-duration portfolio concepts. This is separate from any PPAs offered in the RFP.
- What is the cutoff (in years) between short and long term duration PPAs?
  - Short term is generally defined as 15 years or less. In concepts A & B, a 6-year CCGT option was included. In concepts B & C, the shortest renewable PPA was 15 years.
- Overview of all the responses tabulated, if technology gave you an option, how is that being categorized? As PPA, long term duration, etc.?
  - An initial level of screening was performed to see whether an asset sale or PPA was more economic and then kept it in one tranche to avoid double counting. Overall, PPA and asset sale costs for the same asset were similar. Project-level pricing analysis is being done on the RFP team and not as part of this IRP.
- Is this analysis neutral on whether the asset would be secured by PPA or through NIPSCO self-build?
  - Yes. NIPSCO has completed a self-build CCGT analysis and compared it to the RFP results. The internal build cost is higher than what can be obtained from the market, and the Company is no longer evaluating or considering a self-build CCGT option.
- Why do bundles A through F add up to 1,720 MW when earlier it was noted that 1,810MW was needed?
  - Note that DSM is not shown in each individual box, but is included for each portfolio.
- Point of Clarity, when doing the calculation we included DSM in the 1,720 number.
  - The number that is being targeted for 2023 is 1,400MW, which would allow for all of the Schahfer capacity to be replaced. The question might

be referring to the additional capacity associated with the Michigan City retirement in 2028. You should note that the replacement capacity here is only showing RFP capacity that is selected in the 2023 time period. Beyond that, there are generic solar additions that fill future gaps associated with Michigan City.

- Is the cost to customer based upon on the levelized cost of entry (LCOE)? If yes, has there been any analysis of the impact of the scenarios on year-by-year rates?
  - The cost is based on a full build-up of an all-in revenue requirement, baking in all costs associated with new resource options and annual spend associated with maintenance, capital, fuel, and other costs associated with the current fleet.
- The question is actually whether the costs are levelized?
  - All inputs are annual numbers reflecting when the various costs would be faced over time. The results summaries are presented as an NPV, but there are year-by-year results which can be provided.
- And does the "Cost to Customer" include recovery of the undepreciated capital of the retired plants?
  - Yes.
- Slide 44- visually if I am looking at the lowest point on portfolio C, it appears to be lower cost than portfolio F, is there a measure between the delta?
  - No there is not a metric for that, since the analysis focused on upside cost risk. You are making a good point, since there are outcomes where C is lower cost than F. This tends to occur when there is no carbon price and power market prices are low. However, on the flipside, the opposite is true. If the market is higher, having that exposure in portfolio C will bring the cost up on the high end.
- For short duration project, what you assume comes after is that you are choosing generic projects for the remaining 30 years?
  - The Company is assuming that a generic set of resources, which tend to be solar, are included after the expiry of short-duration projects
- Just to be clear, portfolio F is in UCAP. So the ICAP value is going to be closer to 2,600MW in round numbers, correct (assuming that it is mostly solar)?
  - That is generally fair, yes. Portfolio F has around 150-200 MW of wind UCAP, which translates to around 1,000 MW of ICAP. The remainder is solar or solar plus storage, so it is fair to say that the total ICAP of the renewables would be in that range.
- Regarding the environmental metric, can you clarify what is meant by "inside the fence line" and is this in line with what you are developing/retiring to this metric? Also, discussion on measuring out co-pollutants on CO_2.
  - Yes, co-pollutants are being discussed with the Environmental team. “Inside the fence” means owned by NIPSCO, although not necessarily physically in its service territory. Assets such as Sugar Creek are outside of the territory, but owned by the Company. The policy is to record emissions only for units owned by the Company.
- Do the PPA agreements presume NIPSCO liability for CO_2 emissions?

  - For reporting purposes, NIPSCO is following EPA rules - if it is accounted for it but if another entity owns it, the owner will count it too, so that double counts.
- Is it appropriate to assume all portfolios A-F meet all criteria in reliability scorecard?
  - Yes.
- Just to clarify, how is the carbon price applied to PPAs?
  - The carbon price is added to the variable cost component of gas-based PPA bids. Bidders did not explicitly assume a cost for carbon, so it was assumed that NIPSCO would pay for any future carbon costs as a pass-through in the same way as the cost of natural gas. The CCGT PPAs tend to be structured around a fixed capacity price plus variable costs, and carbon would be included in variable.
- The CO_2 emissions should be reflected in scorecard.
  - NIPSCO Understands the concern and a one-on-one follow up is welcomed.
- What is the sense of solar or wind or some other unknown resource?
  - If NIPSCO had to make an assessment from a UCAP perspective it would be solar because wind UCAP ratings are lower. But ICAP may be larger for solar as well.
- Are you talking about familiar fields of solar panels?
  - The IRP team has not looked at RFP responses, but these projects are large scale wind and solar photovoltaics.
- Are you trying to normalize this to NIPSCO customers, what will this do to my bill and how are you going to communicate that?
  - Hard to answer. Cost savings will be realized from the retirement/replacement plan. The analysis indicates this path would be lower than if the Company continued with coal assets. Does that mean, lower bills? That cannot be answered at this time, but it is clear bills will be lower than the alternative.
- Are you assuming solar plus storage or bids for both?
  - The Company did receive bids for solar plus storage.

Stakeholder Requested Scenarios
Pat Augustine

Mr. Augustine provided an overview of scenarios requested by the Indiana Coal Council and the Office of Utility Consumer Counselor (“OUCC”). He said that the Indiana Coal Council requested NIPSCO look at retirement combinations with less costly environmental compliance for Schahfer Units 17/18 and an alternative market case. He then provided the results of that scenario. Mr. Augustine then reviewed the OUCC’s request that NIPSCO consider converting Schahfer Units 17/18 from coal to gas and provided the results of that request.

- Why would you need to kick water out to convert?
    - After discussions with OUCC, it was determined NIPSCO should update the environmental compliance assumptions. Some of the original cost assumptions included would not be needed on a coal-to-gas conversion. Under this scenario, some stack to re-work would be required, but not the de-watering.
- Confirm, if converted to gas, would or would not need water?
    - Would not need water.
- Why not compare the lower environmental capital expenditures to scenario 6?
    - Those results are available. However, the point here is to provide an apples-to-apples comparison of keeping Units 17/18 vs. the RFP alternative. Thus, the intent of showing retirement portfolio 2 is to isolate the impact of the Unit 17/18 economics, without also incorporating all of the other impacts of retiring 14/15 and Michigan City. The results for other portfolios are available for those who have interest.
- Slide 51, the $438 million assumes same capital needs as current coal needs - would like to understand why that assumption is reasonable?
    - Because of other communication commitments, no operations staff were available. However, the costs are boiler costs, so they would be the same, whether the unit(s) is/are fired by coal or gas. NIPSCO is committed to working with the OUCC on this issue.
- Is it fair to put “TBD” on the environmental compliance number?
    - That is fair since there may be updates to be made. NIPSCO will work with OUCC to refine the analysis.
- OUCC would agree but would want best numbers possible and sure that scenario is still best, but would like actual numbers. OUCC not coming across that they prefer the conversion but just want to see numbers, not advocating for that.

Stakeholder Presentations

The Sierra Club/Beyond Coal Campaign provided a presentation that consisted of a speech, a video including interviews of NIPSCO customers and a PowerPoint presentation showing the results of a mural made by children in NIPSCO’s service territory.

Ms. Becker closed the meeting by thanking the attendees for their attendance and active participation and noted the next meeting is scheduled for October 18, 2018.

NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Denise	Abdul-Rahman	Indiana State Conference of the NAACP
Robert	Adams	AES-IPL
Lauren	Aguilar	OUCC
Jake	Allen	IPL
Anthony	Alvarez	OUCC
Laura	Arnold	Indiana Distributed Energy Alliance (IndianaDG)
Pat	Augustine	Charles River Associates
Kim	Ballard	IURC
Richard	Benedict	Self
Anne	BEcker	Lewis Kappes
Mahamadou	Bikienga	NiSource
Marc	Blanchard	BP
Peter	Boerger	Indiana Office of Utility Consumer Counselor
Bradley	Borum	IURC
Wendy	Bredhold	Sierra Club
Andy	Campbell	NIPSCO
Kelly	Carmichael	NiSource
Joseph	Conn	NWI Beyond Coal Campaign
Jeffrey	Corder	St. Joseph Phase II, LLC
Nick	Corder	EnFocus Development
Dan	Douglas	NIPSCO
Jeffery	Earl	Indiana Coal Council
Michael	Eckert	Office of Utility Consumer Counselor
Amy	Efland	NiSource/NIPSCO
Gregory	Ehrendreich	MEEA
Clare	Everts	Charles River Associates
Steve	Francis	Sierra Club - Hoosier Chapter
John	Garvey	CRA
Fred	Gomos	NiSource
Doug	Gotham	State Utility Forecasting Group
Abby	Gray	OUCC
Stacie	Gruca	OUCC
Corey	Hagelberg	Beyond Coal
Jeffrey	Hammons	Environmental Law & Policy Center
John	Haselden	OUCC
Shelby	Houston	IPL/AES
Paul	Kelly	NIPSCO
Will	Kenworthy	Vote Solar
Sam	Kliewer	Cypress Creek Renewables
Mark	Kornhaus	NextEra Energy
Kim	Krupsaw	Vectren Corp
Tim	Lasocki	Orion Renewable Energy Group LLC
Jonathan	Mack	NIPSCO
Patrick	Maguire	Indianapolis Power and Light
Finnian	McCabe	Ground Star Energy llc

NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Debi	McCall	NIPSCO
Cassandra	McCrae	Earthjustice
James	McMahon	CRA
Emily	Medine	EVA
Zachary	Melda	NextEra Energy Resources
Nick	Meyer	NIPSCO
Ana	Mileva	Blue Marble Analytics
Adam	Newcomer	NIPSCO
David	Ober	Indiana Utility Regulatory Commission
Kerwin	Olson	Citizens Action Coalition of IN
April	Paronish	Indiana Office of Utility Consumer Counselor
Bob	Pauley	IURC
Jodi	Perras	Sierra Club
Timothy	Powers	Inovateus Solar LLC
Mark	Pruitt	The Power Bureau
Dennis	Rackers	Energy & Environmental Prosperity Works!
Thom	Rainwater	Development Partners Group
Jeff	Reed	OUCC
David	Repp	JET Inc
Adam	Rickel	NextEra Energy Resources LLC
Chad	Ritchie	Lockheed Martin
Edward	Rutter	Indiana Office of Consumer Counselor
Carter	Scott	Ranger Power LLC
Cliff	Scott	NIPSCO
Zachary	Scott	PSG Energy Group
Rob	Seren	NIPSCO
Frank	Shambo	NIPSCO
Regiana	Sistevaris	Indiana Michigan Power Company
Violet	Sistovaris	NIPSCO
Barbara	Smith	OUCC
Jennifer	Staciwa	NIPSCO
Bruce	Stevens	Indiana Coal Council
George	Stevens	I U R C
Emily	Straka	Ranger Power
Alice	Tharenos	peabody
Dale	Thomas	IURC
Maureen	Turman	NiSource
William	Vance	Indianapolis Power & Light
Bob	Veneck	Indiana Utility Regulatory Commission
Nathan	Vogel	Inovateus Solar
Victoria	Vrab	NIPSCO
John	Wagner	NIPSCO
Jennifer	Washburn	CAC
Adam	Watson	NiSource Inc.
Rev. Curtis	Whittaker, Sr.	Progressive Community Church

NIPSCO Public Advisory Meeting 4 Registered Participants		
First Name:	Last Name:	Company:
Ryan	Wilhelmus	Vectren
Ashley	Williams	Sierra Club
Bryndis	Woods	Applied Economics Clinic
David	Woronecki-Ellis	Sierra Club Dunelands Group
Jen	Woronecki-Ellis	Sierra Club Dunelands Group
Fang	Wu	SUFG
Jim	Zucal	NIPSCO

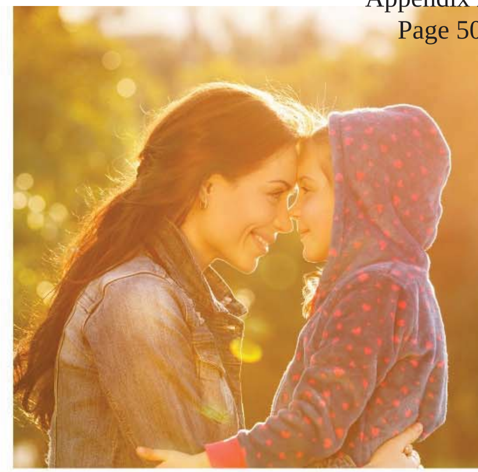
Appendix A

Exhibit 6

NIPSCO Integrated Resource Plan - 2018 Update

Public Advisory Meeting Five

October 18, 2018



Welcome and Introductions

Process for Participating Via Webinar

- In order to best facilitate today's discussion, we are asking that you use the "chat" feature on the webinar to ask questions
- Please type your question at any point and it will be read to the audience by the facilitator
- When entering your question, please include your name and organization you are representing (if applicable)
- You may also email questions to nipsco_irp@nisource.com and those questions will be answered as they are received
- We look forward to your thoughts and questions

Agenda

Time (Central Time)	Topics
9:30-9:45	Welcome and Introductions • Safety Moment
9:45-10:30	Public Advisory Process, Review of Prior Meetings and Update on Stakeholder One-on-One Meetings
10:30-10:45	Break
10:45-11:15	Stakeholder Requested Analysis
11:15-11:45	Updated Retirement and Replacement Analysis
11:45- 12:30	Lunch
12:30-1:30	Preferred Resource Plan and Short Term Action Plan
1:30-1:45	Break
1:45-2:15	Stakeholder Presentations
2:15-2:30	Public Advisory Feedback/Next Steps/Wrap Up

Safety Moment:

Fire Extinguisher Use and Limitations

- **Fire Extinguishers are used to prevent small fires from becoming larger.**
  - Do not use them to combat large or rapidly moving fires.
  - Always be aware of your safety and always call the appropriate authorities to combat the fire.
- **P.A.S.S. Method to using a fire extinguisher.**
  - **P- Pull.** Pull the pin. Hold the extinguisher away and release the locking mechanism.
  - **A- Aim.** Aim the stream towards the base of the fire.
  - **S- Squeeze.** Squeeze the lever slowly and evenly
  - **S- Sweep.** Sweep the nozzle side to side to combat the fire.
- **Limitations**
  - A dry chemical fire extinguisher such as the common red "ABC" extinguishers will reach a distance of 5 to 20 feet.
  - A 10lb to 20lb dry chemical fire extinguisher will most likely last only 10 to 25 seconds.
  - Fire extinguishers are to fight small fires only – a good rule of thumb is to use one only if the fire is the size of a small trash can or smaller.
  - Must be inspected to maintain operating order.

NIPSCO's Planning and the Public Advisory Process

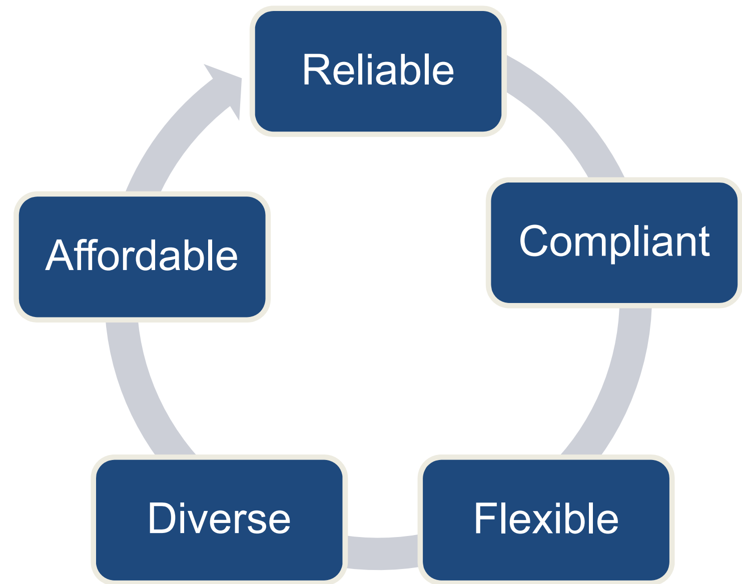
Dan Douglas
Vice President, Corporate Strategy & Development

How Does NIPSCO Plan for the Future?

Charting The Long-Term Course for Electric Generation

About the IRP Process

- Every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan ("IRP") – is required of all electric utilities in Indiana
- IRP process includes extensive analysis of a range of generation scenarios, with criteria such as reliable, affordable, compliant, diverse and flexible



Requires careful planning and consideration for all of NIPSCO's stakeholders including the communities we serve and our employees

Overview of the Public Advisory Process

- **Today's meeting is the fifth out of five meetings**
  - Three in-person meetings and one webinar so far
  - Additional technical webinar added at stakeholder request
  - Presentation materials and summary meeting notes are posted on NIPSCO's IRP webpage: www.nipsco.com/irp
- **The Public Advisory process provides NIPSCO with feedback on our process, assumptions and conclusions. This helps inform the modeling and the overall IRP results**
- **Your participation and candid feedback is key to the process**
  - Please ask questions and provide comments on the material being presented and the process itself to ensure this is a valuable exercise for NIPSCO and its customers
- **Ability to make presentations as part of each Public Advisory meeting**
  - If you wish to make a presentation today and have not already indicated so, please see Alison Becker during break or at lunch

Stakeholder Engagement Roadmap

	Meeting 1 (March 23)	Meeting 2 (May 11)	Meeting 3 (July 24)	Technical Webinar (August 28)	Meeting 4 (September 19)	Meeting 5 (October 18)
Key Questions	-Why has NIPSCO decided to file an IRP update in 2018? -What has changed from the 2016 IRP? -What are the key assumptions driving the 2018 IRP update? -How is the 2018 IRP process different from 2016?	-What is NIPSCO existing generation portfolio and what are the future supply needs? -Are there any new developments on retirements? -What are the key environmental considerations for the IRP? -How are DSM resources considered in the IRP?	-What are the preliminary results from the all source request for proposals ("RFP") Solicitation?	-How are the RFP results integrated into the IRP modeling?	-What are the preliminary results from the modeling and how do they inform the retirement and replacement decisions? -What is the "most viable" retirement and replacement path? -What is NIPSCO's forecasted customer demand? -How is NIPSCO modeling risk and uncertainty in the IRP?	-What is NIPSCO's preferred plan? -What is the short term action plan?
Meeting Goals	-Communicate and explain the rationale and decision to file in 2018 -Articulate the key assumptions that will be used in the IRP -Explain the major changes from the 2016 IRP -Communicate the 2018 process, timing and input sought from stakeholders	-Common understanding of DSM resources as a component of the IRP and the methodology that will be used to model DSM -Understanding of the NIPSCO resources, the supply gap and alternatives to fill the gap -Key environmental issues in the IRP	-Communicate the preliminary results of the RFP and next steps	-Explain the process for integrating the results from the RFP into the IRP modeling for both the retirement and replacement analysis	-Share with stakeholders most viable retirement path and most viable replacement portfolios -Explain how NIPSCO is modeling risk and uncertainty in the IRP -Communicate NIPSCO forecasts for customer demand	-Communicate NIPSCO's preferred resource plan and short term action plan -Obtain feedback from stakeholders on preferred plan

Stakeholder Interactions

- During the IRP process, NIPSCO has met with and responded to requests from stakeholder groups
- Also received written comments from stakeholders

Stakeholder	Subject Area/Discussion Topic
Sierra Club	IRP Modeling and Scenarios
Office of Utility Consumer Counselor (“OUCC”)	All-Source RFP, IRP Modeling and Scenarios, Load Forecasting
Citizens Action Coalition of Indiana, Inc. (“CAC”)	IRP Modeling and Demand Side Management (“DSM”), DSM Decrement Approach
Indiana Utility Regulatory Commission (“IURC”)	All-Source RFP and IRP Modeling
NIPSCO Industrial Group	All-Source RFP and IRP Modeling
Indiana Coal Council	Scenario/Portfolio Requests
NAACP of Indiana	DSM, On-Bill financing, Retirement Dates
St. Joseph Energy Center	All-Source RFP and IRP Modeling

Stakeholder Requested Analysis Results

Pat Augustine
Charles River Associates

Stakeholder Requested Analysis

- **As part of the 2018 IRP Public Advisory Process, Stakeholders have requested that NIPSCO run the following analyses:**

Stakeholder		Requested Analysis
	OUCC	Evaluate the conversion of Schahfer Units 17 and 18 to burn natural gas
	CAC	Decrements Approach for Energy Efficiency and DSM Modeling
	Indiana Coal Council	Lower Cost ELG Compliance Scenarios Alternative Market Scenario • No carbon price • High natural gas price • $45/ton flat real delivered coal price for 17/18

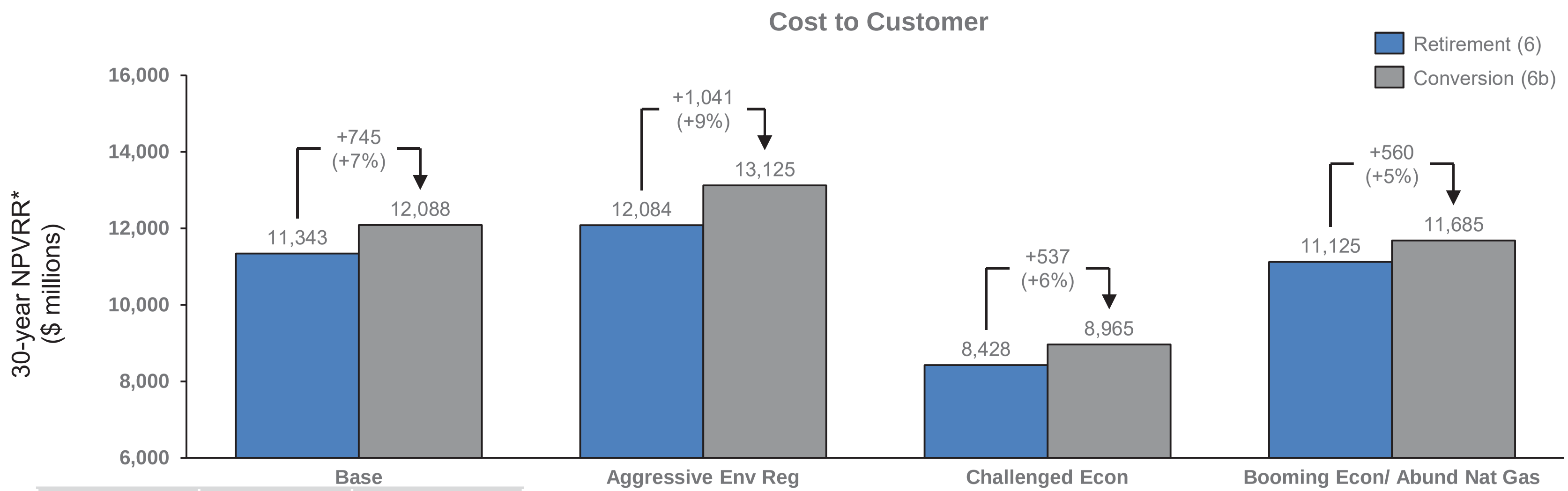
Coal to Gas Conversion Analysis Assumptions (Converting Either 17/18 or Unit 17 only)

	Category	NIPSCO Assumption	Notes
Operating Parameters	**Conversion Capacity(megawatts, or "MW") per unit**	302	15% de-rate from current unforced capacity rating ("UCAP") of 355 MW
	Heat Rate (Btu/kWh)	11,106	
	Forced Outage Rate	10%	

	Category	Estimated Cost	Notes
Conversion Investment Costs	**Conversion (2015$)**	$43M for 17 $87M for 17/18	• Equipment, materials and construction labor, contingency, owners and indirect costs from Sargent and Lundy ("S&L") November 2015 Engineering Study Technical Assessment for the 2016 NIPSCO IRP. Estimated cost of $121/kW
	Gas Interconnection	$0M	• Based on the data from the S&L November 2015 Engineering Study Technical Assessment for the 2016 NIPSCO Integrated Resource Plan and a preliminary review with NIPSCO Gas Systems Engineering, it would be possible to convert Unit 17 or Unit 18 to natural gas without installing an additional pipeline as long as both Units 14 and 15 are retired. Leaving Units 14 and 15 in operation would likely create operational limitations related to when the units would be available to start up. Conversion of Units 17 and 18 to run simultaneously would require an additional pipeline. The size of the additional line could be smaller than the 30" referenced it the S&L study but further detailed engineering analysis would be required to determine the appropriate size. Assumed zero cost in analysis
	Environmental Compliance	$0M	• The revised analysis assumes no environmental compliance capital costs if the units are converted to natural gas
Maintenance Capital	**Maintenance Capital (Total 2024-2038) Nominal $**	$122M for U17 $298M for 17/18	• Assumes maintenance capital needs will be 25% lower than current coal operations. Derived from review of last 3 years of capital expenditures for 17/18 that showed 25% of maintenance capital expenditures was for coal specific components
Ongoing Costs	**Fixed Operations and Maintenance ("O&M") Costs (2015$/kW-yr)**	$39	• Based on S&L Study cost estimates for expected O&M post conversion

Coal to Gas Conversion Results (Units 17 and 18): Cost To Customer

- Across all scenarios, converting both Unit 17 and 18 would cost NIPSCO customers between $540M to $1.04B more than retirement and replacement with economically optimized resource selections from the RFP results



	Base: Retirement (6)	Base: Conversion (6b)
Portfolio Transition Target:	**15% Coal in 2023**	**15% Coal in 2023** (Schfr.17/18 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17,18 (gas) Mich. City: 12 (2028)

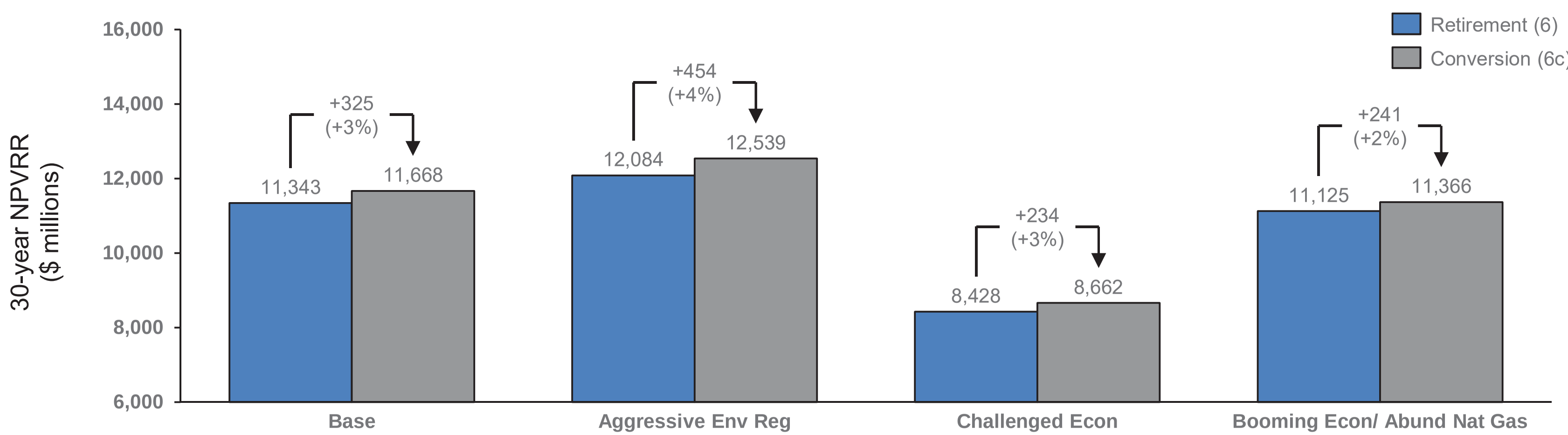
Scenario	Retirement (6)	Conversion (6b)
Aggressive Env Reg	**15% Coal in 2023**	**15% Coal in 2023** (Schfr.17/18 gas)
Challenged Econ	**15% Coal in 2023**	**15% Coal in 2023** (Schfr.17/18 gas)
Booming Econ/ Abund Nat Gas	**15% Coal in 2023**	**15% Coal in 2023** (Schfr.17/18 gas)

Michigan City 12	**Retire 2028**	**Retire 2028**
Schahfer 14	**Retire 2023**	**Retire 2023**
Schahfer 15	**Retire 2023**	**Retire 2023**
Schahfer 17	**Retire 2023**	**Convert to Gas 2023**
Schahfer 18	**Retire 2023**	**Convert to Gas 2023**

*NPVRR: Net present value of revenue requirements

Coal to Gas Conversion Results (Unit 17 Only): Cost To Customer

- Across all scenarios, converting a single Unit (17) would cost NIPSCO customers between $230M and $450M more than retirement and replacement with economically optimized resource selections from the RFP results



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (Schfr. 17 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17(gas) Mich. City: 12 (2028)

Aggressive Env Reg	
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

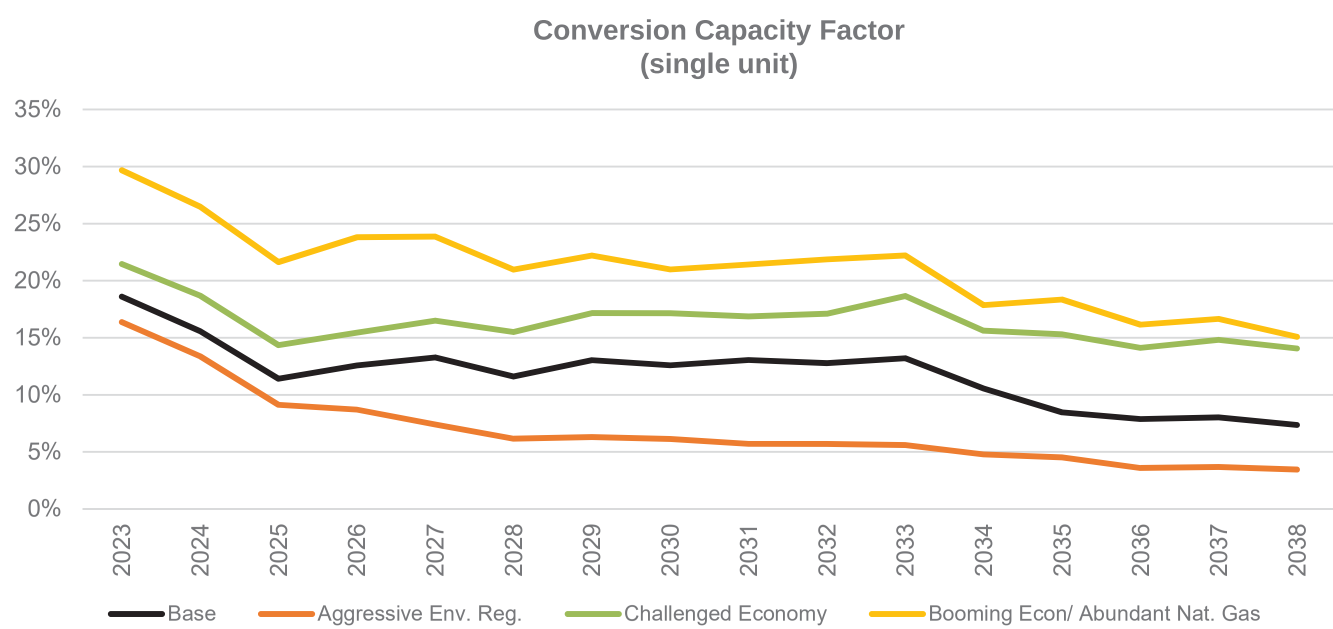
Challenged Econ	
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

Booming Econ/ Abund Nat Gas	
15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)

Michigan City 12	Retire 2028	Retire 2028
Schahfer 14	Retire 2023	Retire 2023
Schahfer 15	Retire 2023	Retire 2023
Schahfer 17	Retire 2023	Convert to Gas 2023
Schahfer 18	Retire 2023	Retire 2023

Coal to Gas Conversion Results: Capacity Factors

- **The Base Case capacity factors are in the 7-16% range, while the full range across all scenarios is about 3-25%**
- **Capacity Factors tend to fall over time, as gas prices generally increase and as the Midcontinent Independent System Operator ("MISO") market evolves towards having more lower variable cost capacity.**
- **Under all scenarios, conversion leads to higher MISO market purchases, potentially increasing NIPSCO customer's exposure to market risk**



Notes: 2023 is a partial year, since the converted unit is assumed to begin operating in June. The 2023 annual capacity factor is thus slightly weighted towards the higher summer months.

Decrements Approach for Energy Efficiency and DSM Modeling

- CAC proposed that NIPSCO consider evaluating energy efficiency and DSM programs with an avoided cost decrements approach.
- As per CAC guidance, this approach should do the following:

  When modeled as "decrements," energy efficiency savings are assumed to be fixed in any given modeling run. That is, they are embedded as reductions to the load forecast and are not selectable resources.

  – ***The blocks are modeled without any assumption as to their cost.***

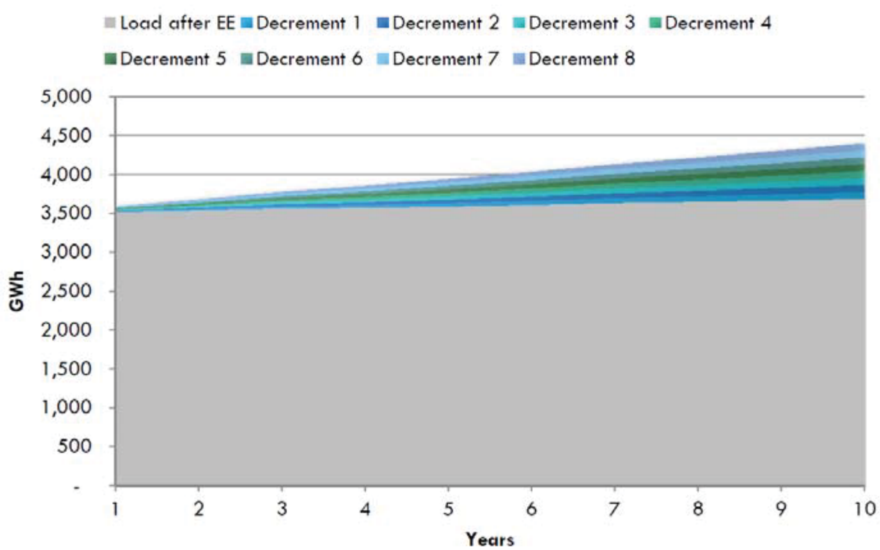
  – ***The supply-side plan is allowed to simultaneously change with each decrement of efficiency, meaning that it is possible that future supply-side additions could be avoided as levels of energy efficiency increase.***
- ***The key output is the net present value ("NPV") of each scenario, which represents the total capacity and energy costs over the study period, discounted to the present year's dollars.***

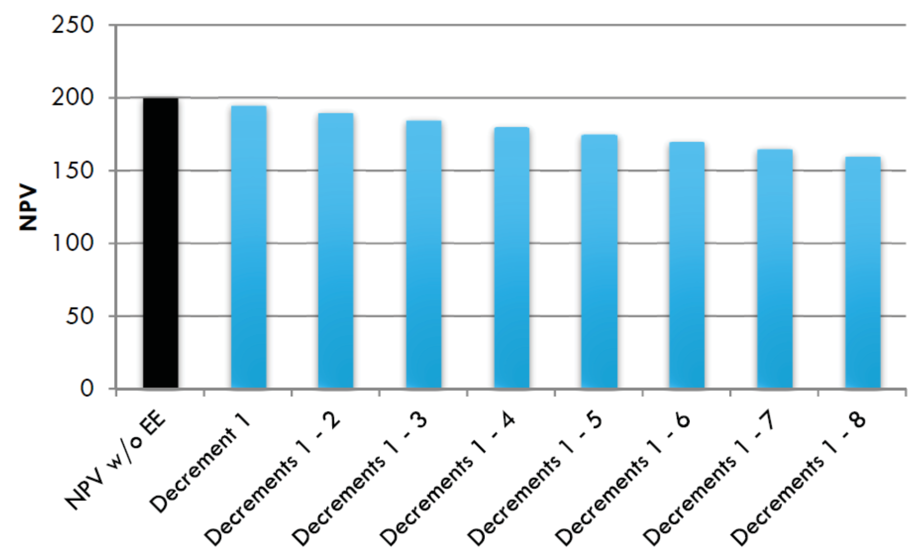
Source: Sommer, Anna, "An Avoided Cost Decrement Approach to Energy Efficiency in IRPs," April 10, 2018

Decrements Approach

- The approach is designed to identify potential decrements (or savings) from the load forecast and evaluate the impacts of such savings on portfolio NPV, without accounting for any costs

Illustrative Load after 8 Decrements → **Illustrative NPV for 8 Decrements**





Source: Sommer, Anna, "An Avoided Cost Decrement Approach to Energy Efficiency in IRPs," April 10, 2018

Comparison to NIPSCO IRP Approach

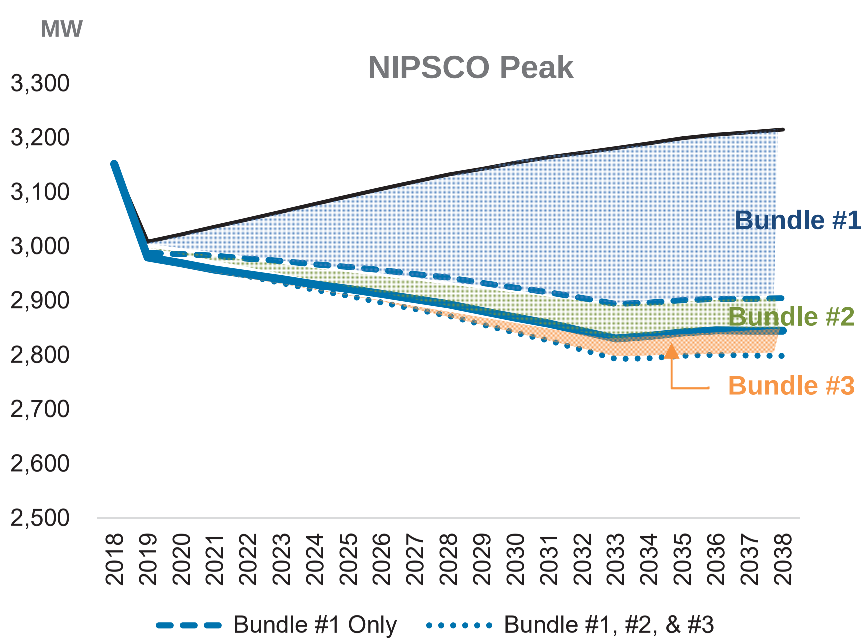
	NIPSCO 2018 IRP	Decrements Approach
EE/DSM input development – energy savings	GDS Associates, Inc. ("GDS") study identified 3 bundles based on a bottom-up program review, organized by cost	Could use decrements of any size (but NIPSCO preserved 3 bundles for hourly shape integrity in its decrements evaluation)
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

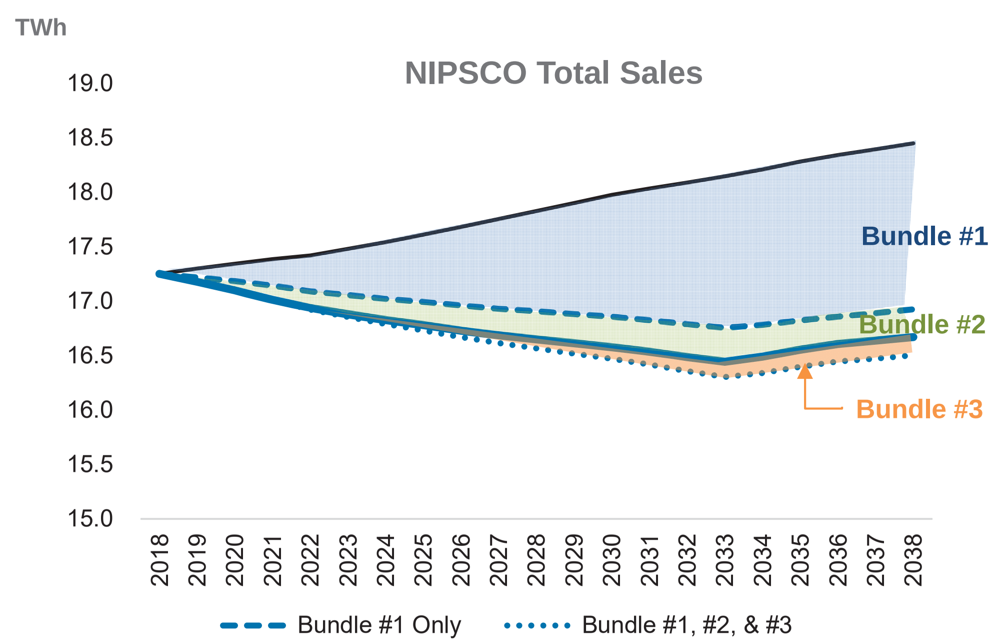
Decrement Definition for NIPSCO IRP

- **In performing a decrements analysis, NIPSCO utilized the same bundles that were established by GDS in its Energy Efficiency Savings Update.**

DSM Bundle #	Weighted Avg. Cost ($/MWh)
1	16.98
2	23.27
3	159.00

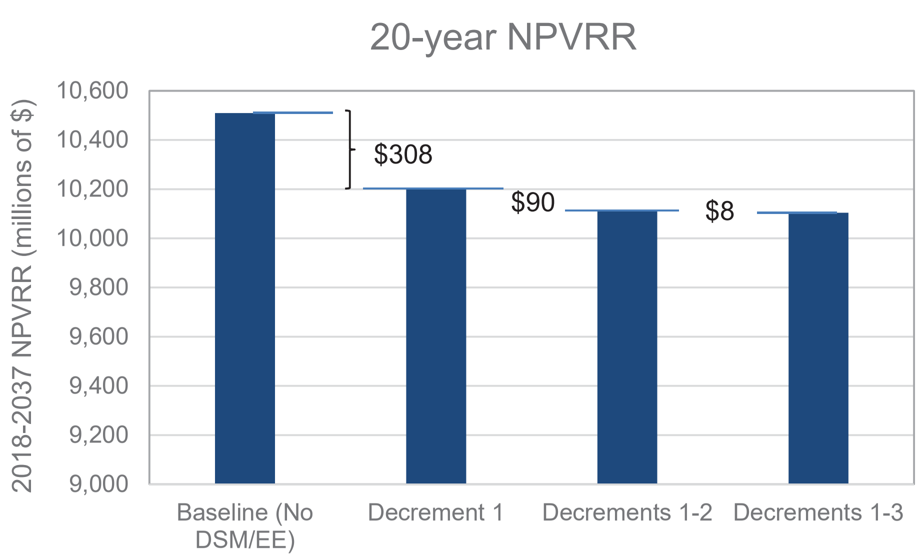
Impact of Selected DSM on NIPSCO Peak and Average Load





Decrement Portfolio Results

- **Decrement portfolio runs result in lower portfolio costs due to <u>less energy to serve,</u> which results in fewer fuel and energy market purchases, and <u>avoided solar capacity additions,</u> either from RFP resources or generic builds**
  – Bundle #1 avoids 298 MW, Bundle #2 avoids 60 MW, and Bundle #3 avoids 43 MW of **UCAP** additions over the forecast horizon



Summary of NPV of Savings and Costs

	NPV of Savings	NPV of Costs	Net Benefit
Bundle #1	307,639,744	131,461,432	176,178,312
Bundle #2	89,685,940	51,063,023	38,622,917
Bundle #3	7,804,359	108,310,129	(100,505,770)

- **Bundles 1 and 2 are cost-effective in this approach, while Bundle 3 is not**
- **This is consistent with the analysis performed in the IRP**

Stakeholder Request – Indiana Coal Council Portfolios for Schahfer Units 17/18

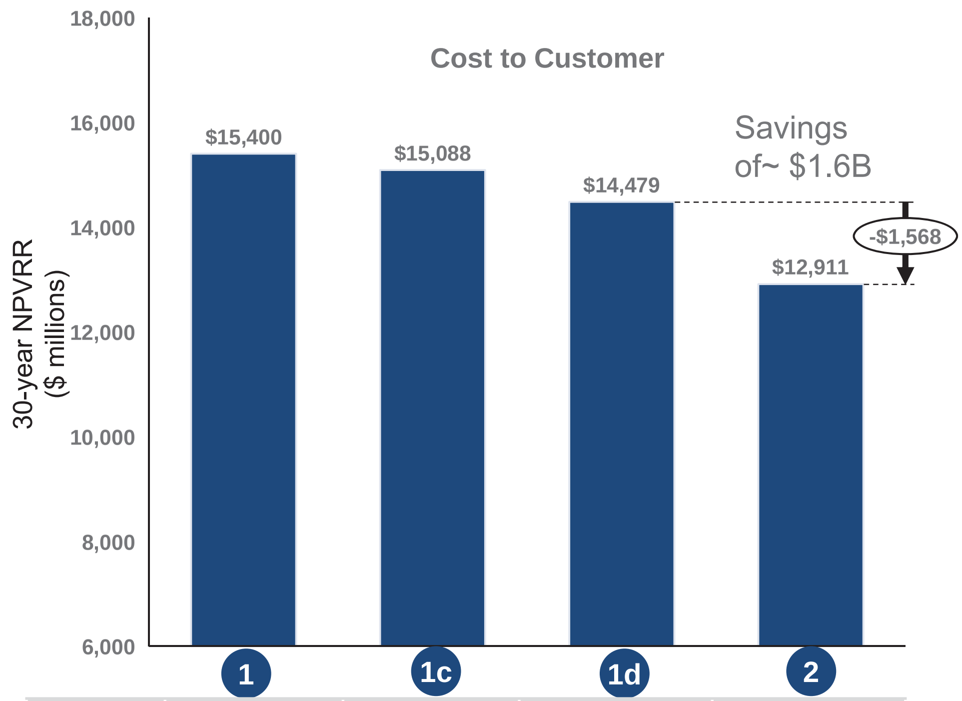
- **Indiana Coal Council requested NIPSCO evaluate retirement combinations with less costly ELG-related compliance for Schahfer 17/18 and an alternative market case**

Portfolio Transition Target:	1 65% Coal through 2035	1c 65% Coal through 2035	1d 65% Coal through 2035	2 40% Coal in 2023
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Environmental Compliance	CCR[1] ELG[2]: non-ZLD[3]	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	→	→
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	→	→
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx[4]: SCR[5]	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retain** CCR **ELG: None** NOx: SCR	**Retain** CCR **ELG: None** **NOx: None**	**Retire 2023** CCR/ELG: Retirement

[1]Coal Combustion Residuals
[2]Effluent Limitation Guidelines
[3]Zero Liquid Discharge
[4]Nitrogen Oxides
[5]Selective Catalytic Reduction System

Stakeholder Request – Indiana Coal Council Scenarios

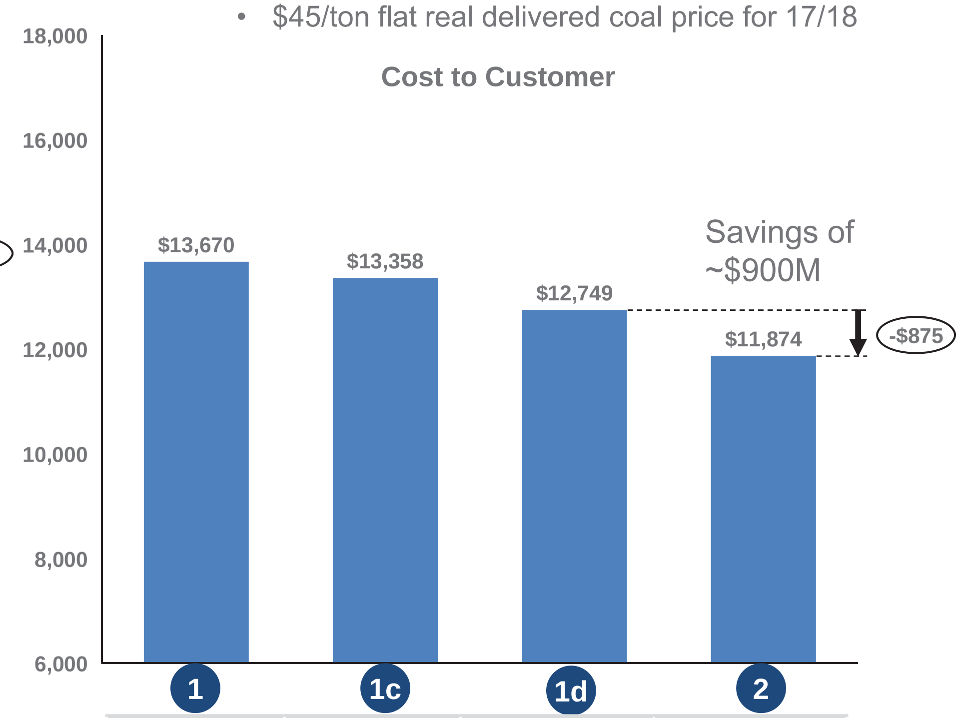
Base Case



Portfolio Transition Target:	65% Coal through 2035	65% Coal through 2035	65% Coal through 2035	40% Coal in 2023
Retire:	None	None	None	Schfr:17,18 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Alternative Case – Coal Council

- No carbon price
- High natural gas price
- $45/ton flat real delivered coal price for 17/18



65% Coal through 2035	65% Coal through 2035	65% Coal through 2035	40% Coal in 2023
None	None	None	Schfr:17,18 (2023)
Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15
CCR ELG: non-ZLD	CCR ELG: NONE	No Environmental Capital	CCR ELG: non-ZLD

Retirement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Recap: Retirement Analysis Framework

- **The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and were fed into the retirement and replacement analysis**
- **Representative project groups were constructed from RFP results, assembled by technology and ownership structure, for use in the updated retirement analysis**

	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO Cost of New Entry (“CONE”) + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers’ needs?

Retirement analysis based on most recent data and representative RFP projects *as selected by the optimization model* – selection driven by economics

Recap: Various Retirement Combinations Were Constructed

Portfolio Transition Target:	1 65% Coal through 2035	2 40% Coal in 2023	3 15% Coal by 2028 w/ ELG	4 15% Coal by 2028 w/o ELG	5 15% Coal in 2023 (Mich. City in 2035)	6 15% Coal in 2023 (Mich. City in 2028)	7 15% Coal by 2023 (Schfr. 17/18 2021)	8 0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR[1] ELG[2]: non-ZLD[3]	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	→	**Retire 2028** CCR ELG: N/A	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx[4]: SCR[5]	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement

Currently NOT a viable path for ELG compliance

Note: Retirement Combination 4, 15% Coal in 2028 without ELG, is not currently a viable from an ELG compliance standpoint and is shown for discussion purposes.

[1]CCR: Coal Combustion Residuals
[2]ELG: Effluent Limitation Guidelines
[3]ZLD: Zero-Liquid discharge
[4]NOx: Nitrogen oxides
[5]SCR: Selective Catalytic Reduction

Recap: What Technology Is the Model Selecting From RFP Results?

- Economic optimization model is selecting DSM and renewables as the replacement resources in all retirement cases
- While the model selected resources were used for the retirement analysis, a separate replacement analysis was performed

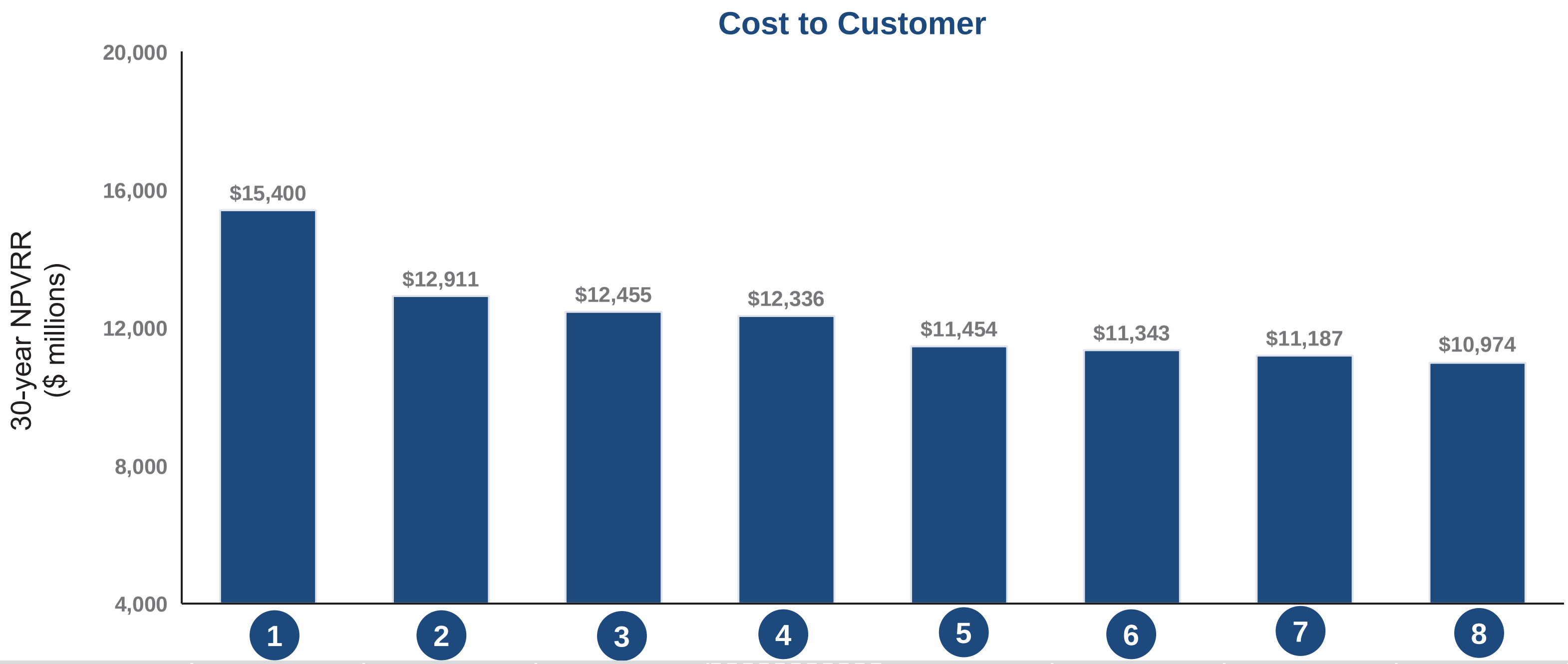
Higher — COST-EFFECTIVENESS — Lower

2 3 4 Schahfer 17/18 Retirement ~600MW UCAP need		5 6 7 Schahfer 14/15/17/18 Retirement ~1,350MW UCAP need		8 All Coal Retirement ~1,750MW UCAP Need	
TECHNOLOGY	MW	TECHNOLOGY	MW	TECHNOLOGY	MW
MISO Market Purchase	50	MISO Market Purchase	50	MISO Market Purchase	50
DSM	125	DSM	125	DSM	125
Wind	150	Wind	150	Wind	150
Solar, Solar + Storage	390	Solar, Solar + Storage	1,070	Solar, Solar + Storage	1,500
	715		**1,395**		**1,825**

This is ***not*** NIPSCO's replacement resource selection or plan

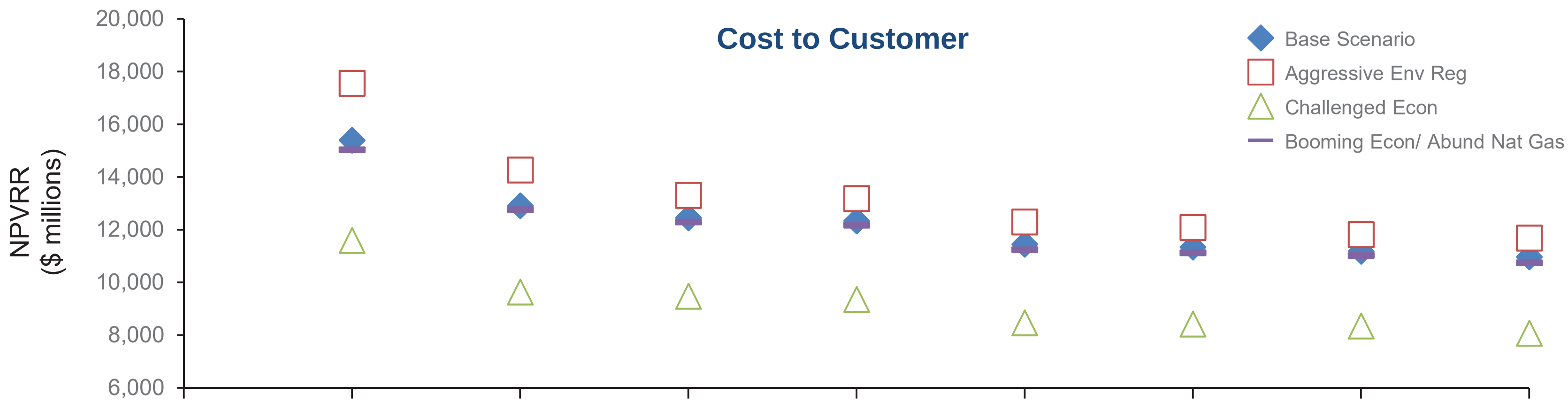
Retirement Results – Base Case

- Retaining more coal in the NIPSCO portfolio results in higher costs to customers



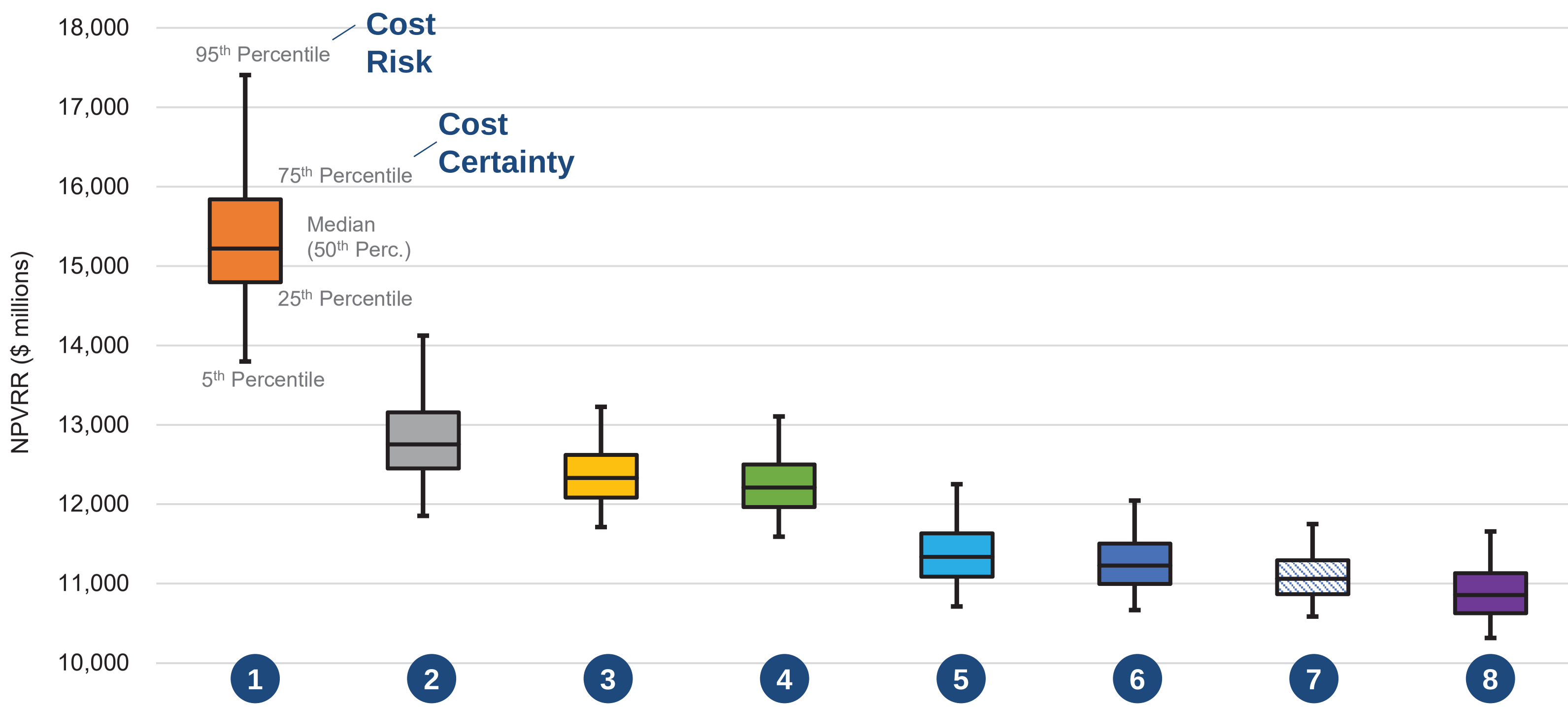
Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Least Cost:	$4,426M 40%	$1,937M 18%	$1,481M 13%	$1,361M 12%	$479M 4%	$369M 3%	$213M 2%	$0M

Retirement Analysis: Scenarios



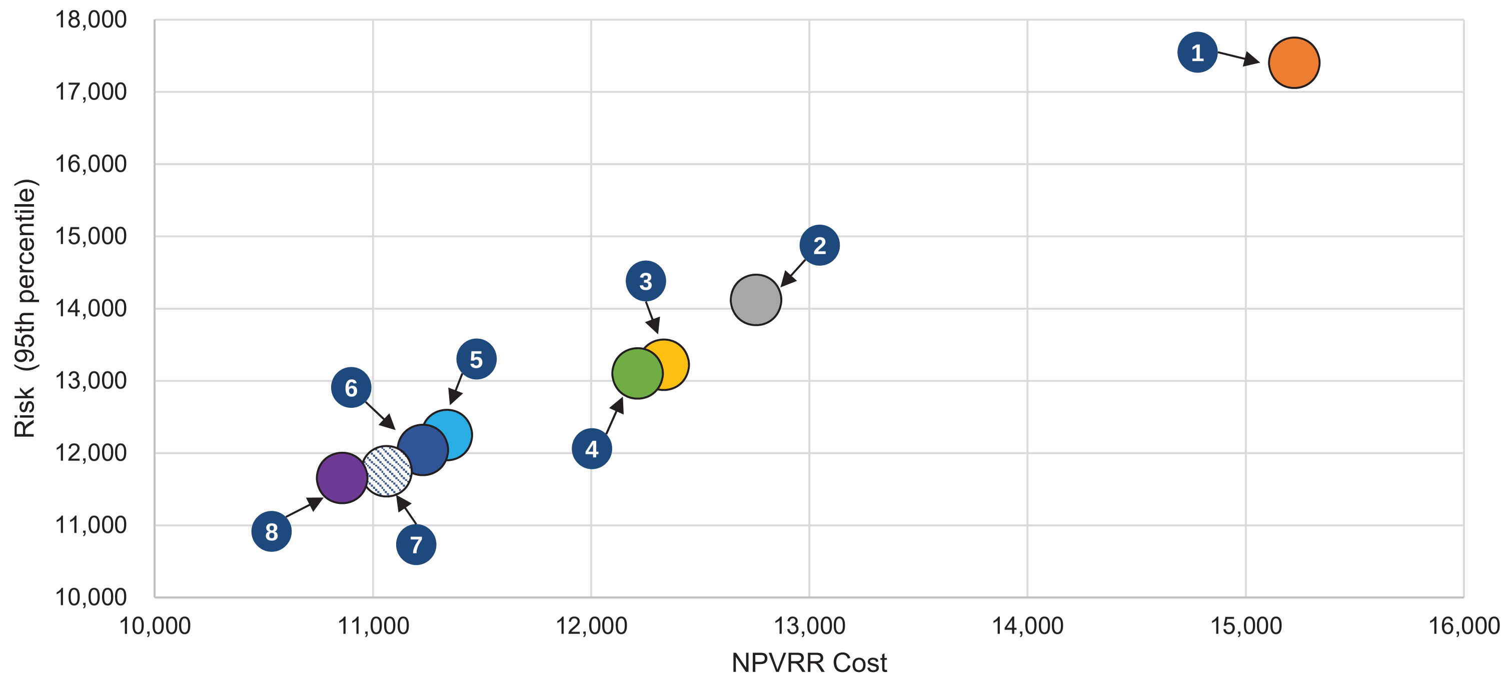
		1	2	3	4	5	6	7	8
	Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal in 2028 w/ ELG**	**15% Coal in 2028 w/o ELG**	**15% Coal in 2023** (MC 2035)	**15% Coal in 2023** (MC 2028)	**15% Coal in 2023** (17/18 2021)	**0% Coal in 2023**
	Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
	Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Base Scenario	**Delta from Lowest Cost to Customer**	$4,426M 40.3%	$1,937M 17.7%	$1,481M 13.5%	$1,361M 12.4%	$479M 4.4%	$369M 3.4%	$213M 1.9%	$0M 0.0%
Aggressive Env Reg	**Delta from Lowest Cost to Customer**	$5,869M 50.2%	$2,584M 22.1%	$1,616M 13.8%	$1,496M 12.8%	$610M 5.2%	$396M 3.4%	$132M 1.1%	$0M 0.0%
Challenged Econ	**Delta from Lowest Cost to Customer**	$3,519M 43.6%	$1,563M 19.3%	$1,400M 17.3%	$1,280M 15.8%	$395M 4.9%	$349M 4.3%	$272M 3.4%	$0M 0.0%
Booming Econ/ Abund Nat Gas	**Delta from Lowest Cost to Customer**	$4,285M 39.9%	$2,013M 18.7%	$1,546M 14.4%	$1,426M 13.3%	$499M 4.6%	$380M 3.5%	$278M 2.6%	$0M 0.0%

Retirement Analysis: Risk (Stochastics)



Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Lowest Cost Certainty	+$4,708 42.3%	+$2,026 18.2%	+$1,490 13.4%	+$1,370 12.3%	+$502 4.5%	+$372 3.3%	+$163 1.5%	- $ - %
Delta from Lowest Cost Risk	+$5,750 49.3%	+$2,467 21.2%	+$1,569 13.5%	+$1,449 12.4%	+$596 5.1%	+$389 3.3%	+$93 0.8%	- $ - %

Retirement Analysis: Cost Risk



	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement

Retirement Scorecard

2018 Retirement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75^{th} percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95^{th} percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

Retirement Scorecard and Preferred Retirement Path

- The most viable option for NIPSCO is the full retirement of Schahfer coal units by 2023 and Michigan City by 2028
- While retiring more coal earlier is less expensive to customers, the reliability risk of those portfolio is unacceptable to NIPSCO

Preferred Retirement Path

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,400 +$4,426 40.3%	$12,911 +$1,937 17.7%	$12,455 +$1,481 13.5%	$12,336 +$1,361 12.4%	$11,454 +$479 4.4%	$11,343 +$369 3.4%	$11,187 +$213 1.9%	$10,974 - $ - %
Cost Certainty	$15,840 +$4,708 42.3%	$13,158 +$2,026 18.2%	$12,622 +$1,490 13.4%	$12,502 +$1,370 12.3%	$11,634 +$502 4.5%	$11,504 +$372 3.3%	$11,295 +$163 1.5%	$11,132 - $ - %
Cost Risk	$17,406 +$5,750 49.3%	$14,123 +$2,467 21.2%	$13,225 +$1,569 13.5%	$13,105 +$1,449 12.4%	$12,252 +$596 5.1%	$12,045 +$389 3.3%	$11,750 +$93 0.8%	$11,656 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +47%	$0M -%	($23M) (9%)	($31M) (12%)	($65M) (26%)	($74M) (29%)	($74M) (29%)	($94M) (37%)

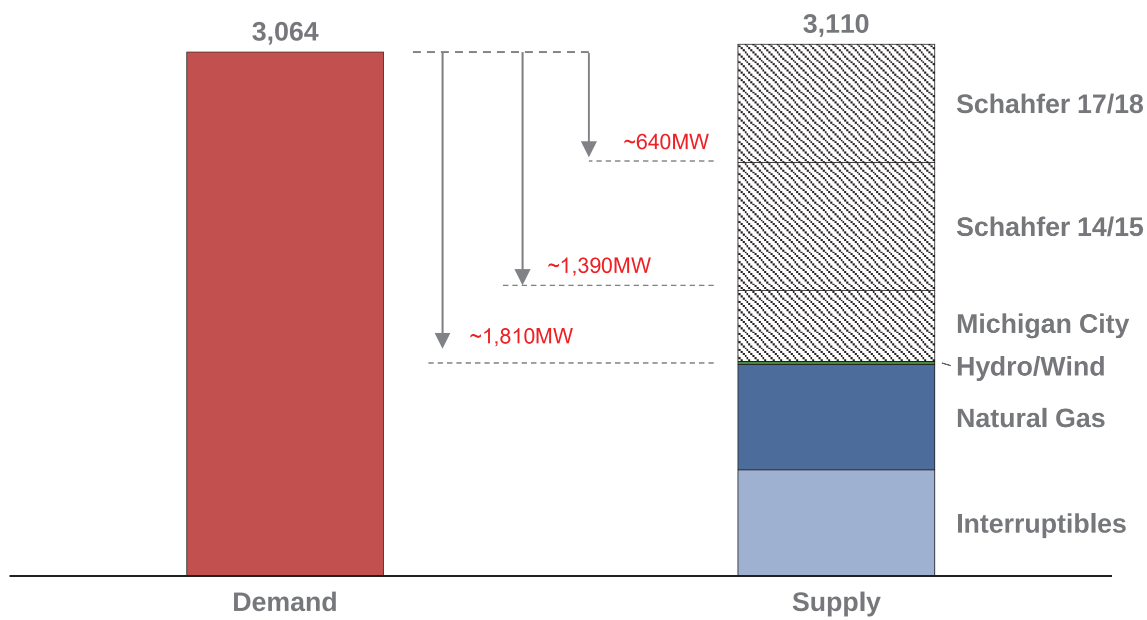
Replacement Analysis

Dan Douglas
Vice President, Corporate Strategy & Development

Pat Augustine
Charles River Associates (CRA)

Retirements Will Create A Need For New Resources

2023 Forecasted Demand and Supply



2023 Estimated Capacity Excess/(Need) in MWs

As-Is	50
Retire Schahfer Units 17/18	(640)
Retire Schahfer Units 14/15/17/18	(1,390)
Retire Schahfer and Michigan City	(1,810)

Notes: Demand reflects loss of BP load

Replacement Analysis Framework

- **The responses to the all-source RFP provided insight into the supply and pricing of alternatives available to NIPSCO and fed into the retirement and replacement analysis**
- **These RFP projects are used to construct resource combinations that explore the range of Ownership / Duration and Diversity possibilities**

	Retirement Analysis	Replacement Analysis
Core question	*How does the cost to keep a unit compare to the cost to replace with economically optimized resources?*	*What are the replacement resource portfolios?*
Initial analysis	MISO CONE + market energy	3rd party cost and performance estimates
All-Source RFP	**Actual projects available to NIPSCO**	**Actual projects available to NIPSCO**
Key Decision	What units should retire, and when?	What new resources should be added to meet customers' needs?

Replacement Analysis: Resource Combinations Were Created That Explore The Range Of Ownership / Duration And Diversity Possibilities

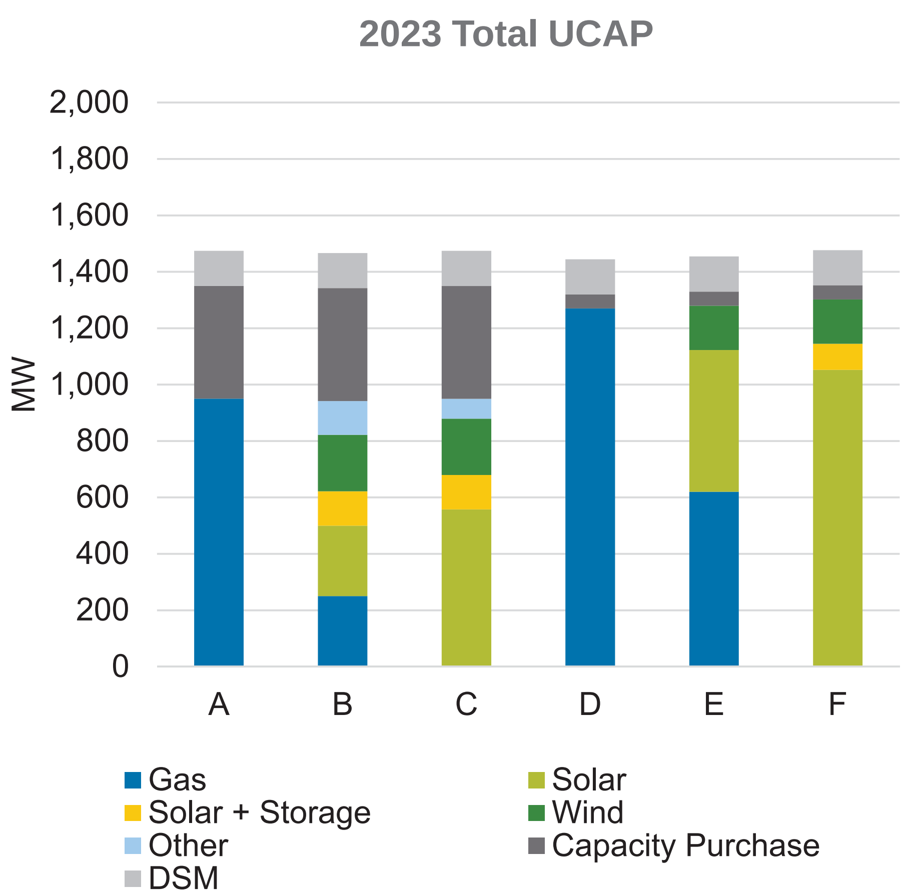
- RFP projects provide good coverage to construct resource combinations that cover the spectrum of Ownership / Duration and Diversity

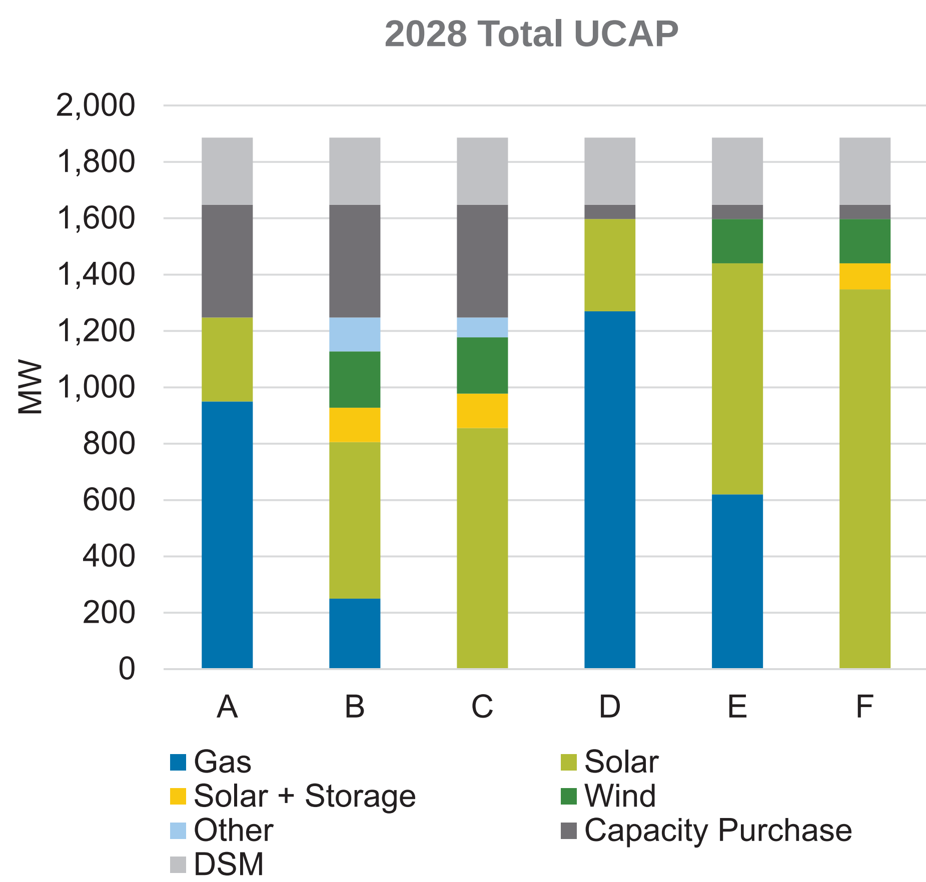
Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A MISO Capacity Purchase 400MW Combined Cycle Gas Turbine ("CCGT") Purchase Power Agreement ("PPA") 950MW	B MISO Capacity Purchase 400MW CCGT PPA 250MW Renewable PPA 690MW	C MISO Capacity Purchase 400MW Renewable PPA 950MW
Long Duration	D MISO Capacity Purchase 50MW CCGT 1,300MW	E MISO Capacity Purchase 50MW CCGT 620MW Renewables 670MW	F MISO Capacity Purchase 50MW Renewables 1,300MW

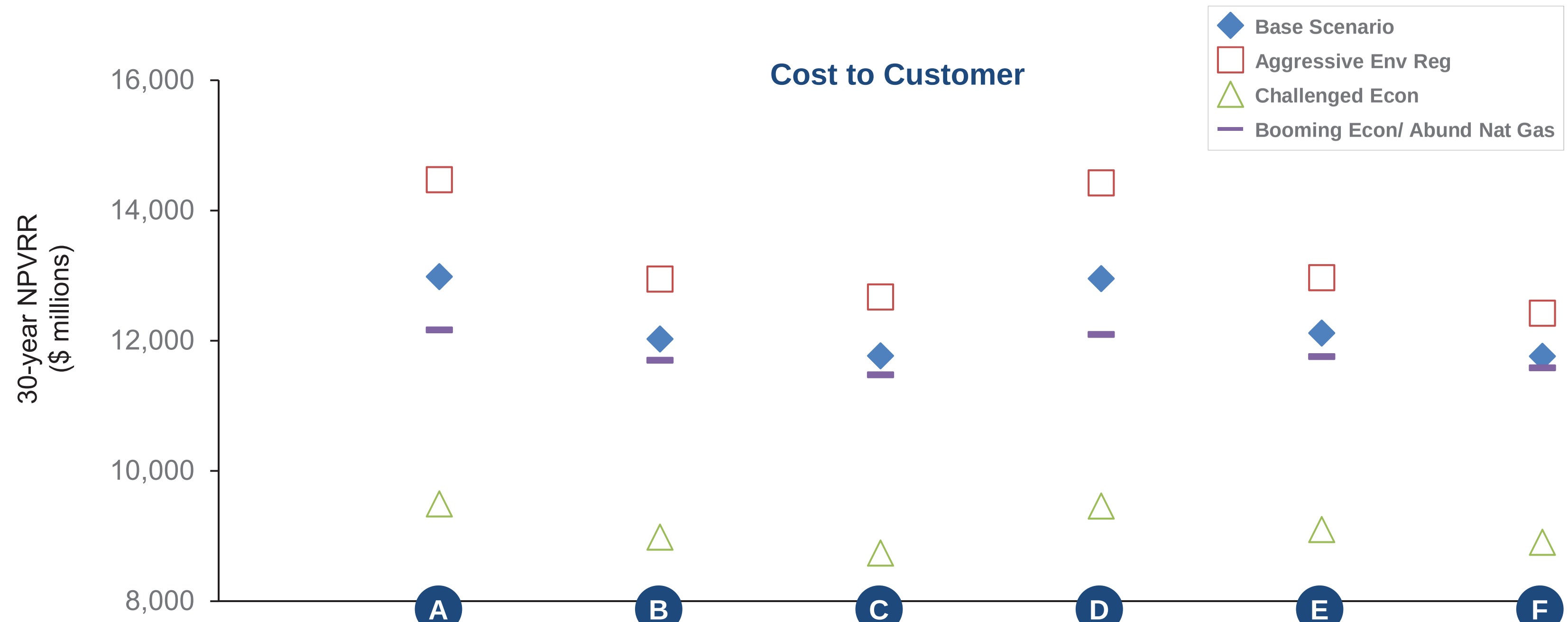
Notes: Values above reflect 2023 additions shown in UCAP; additional generic solar additions are included in all portfolios starting in 2028.
All portfolios include a total of 125 MW (peak) DSM by 2023 and 370 MW (peak) DSM by 2038.

2023 And 2028 New Resources Additions By Portfolio (UCAP MW)



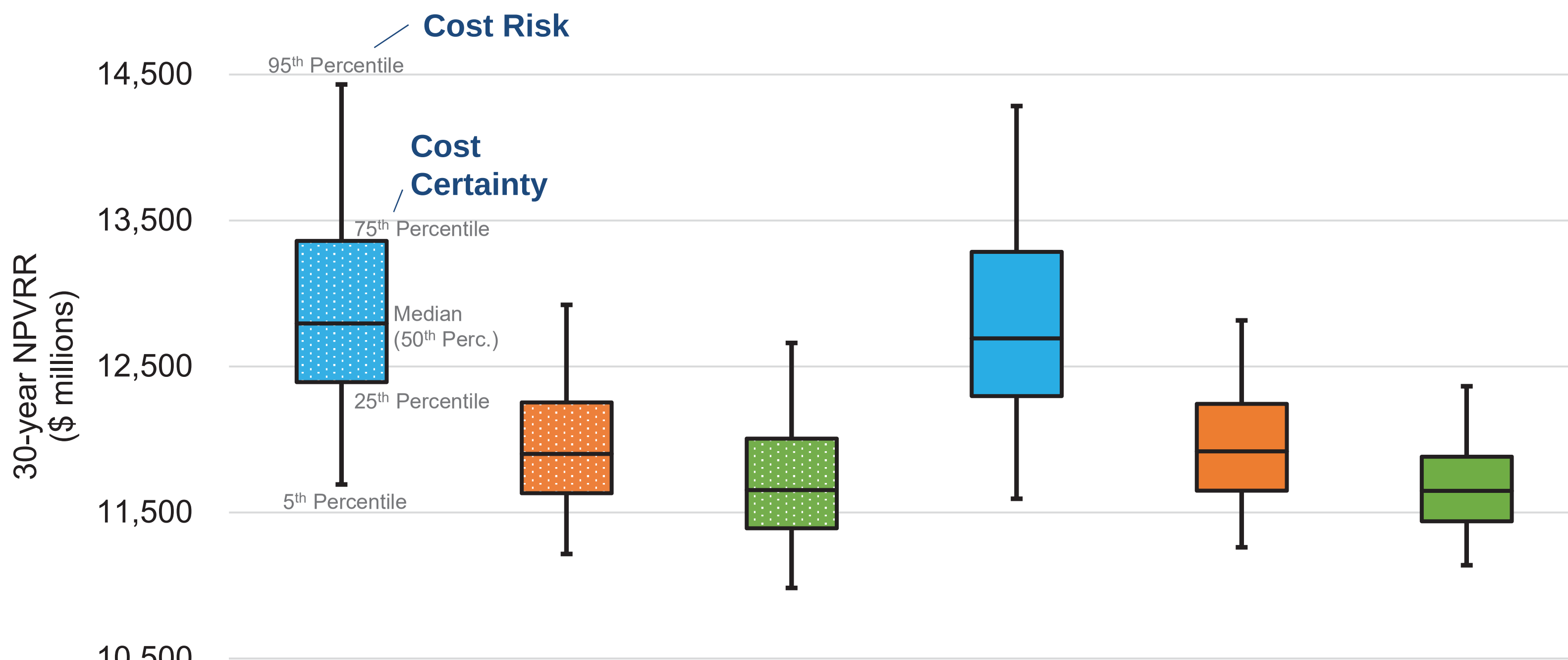


Replacement Analysis: Scenarios



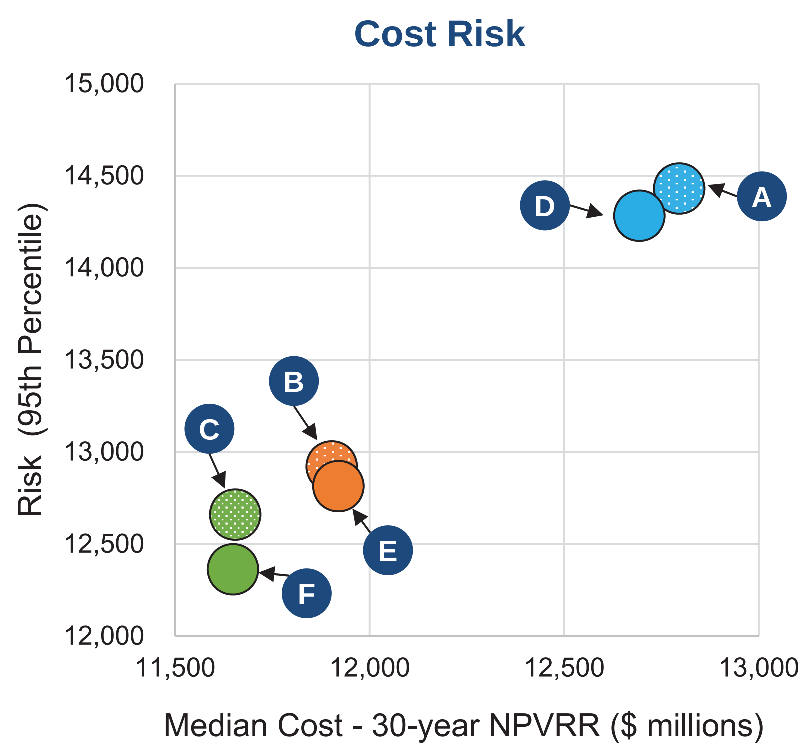
		A	B	C	D	E	F
	Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
	Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Base Scenario	**Delta from Lowest Cost to Customer**	$1,222 10.4%	$265 2.2%	$6 0.1%	$1,192 10.1%	$357 3.0%	**$0 0.0%**
Aggressive Env Reg	**Delta from Lowest Cost to Customer**	$2,052 16.5%	$524 4.2%	$250 2.0%	$2,002 16.1%	$546 4.4%	**$0 0.0%**
Challenged Econ	**Delta from Lowest Cost to Customer**	$756 8.6%	$244 2.8%	**$0 0.0%**	$722 8.3%	$361 4.1%	$165 1.9%
Booming Econ/ Abund Nat Gas	**Delta from Lowest Cost to Customer**	$692 6.0%	$224 2.0%	**$0 0.0%**	$622 5.4%	$281 2.4%	$109 1.0%

Replacement Analysis: Stochastics



Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Delta from Lowest Median Cost	$1,147 9.8%	$254 2.2%	$6 0.1%	$1,044 9.0%	$271 2.3%	**$0 0.0%**
Delta from Lowest Cost Certainty	$1,477 12.4%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.0%	**$0 0.0%**
Delta from Lowest Cost Risk	$2,067 16.7%	$558 4.5%	$297 2.4%	$1,920 15.5%	$452 3.7%	**$0 0.0%**

Replacement Analysis: Stochastics



Diversity

Ownership / Duration	Higher Carbon Emissions	Average Carbon Emissions	Average-Low Carbon Emissions
Short Duration	A	B	C
Long Duration	D	E	F

Replacement Scorecard

2018 Replacement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75^{th} percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95^{th} percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 installed capacity MW sourced from non-gas resources)
Environmental	• Annual carbon emissions from the generation portfolio • Metric: Total annual carbon emissions (2030 metric tons of carbon dioxide, or "CO_2") from the generation portfolio
Employees	• Net impact on NiSource jobs • Metric: Approximate number of permanent NiSource jobs added
Local Economy	• Property tax amount from entire portfolio • Metric: 30-year NPV of estimated modeled property taxes from the entire portfolio

Replacement Scorecard and Preferred Replacement Portfolio

- Replacement portfolios with renewables are more cost effective than portfolios without renewables
- Portfolio F is the preferred replacement portfolio for NIPSCO as it performs well across cost and risk metrics: Cost to Customer; Cost Certainty, and Cost Risk while lowering emissions and fuel security risk

Preferred Replacement Path

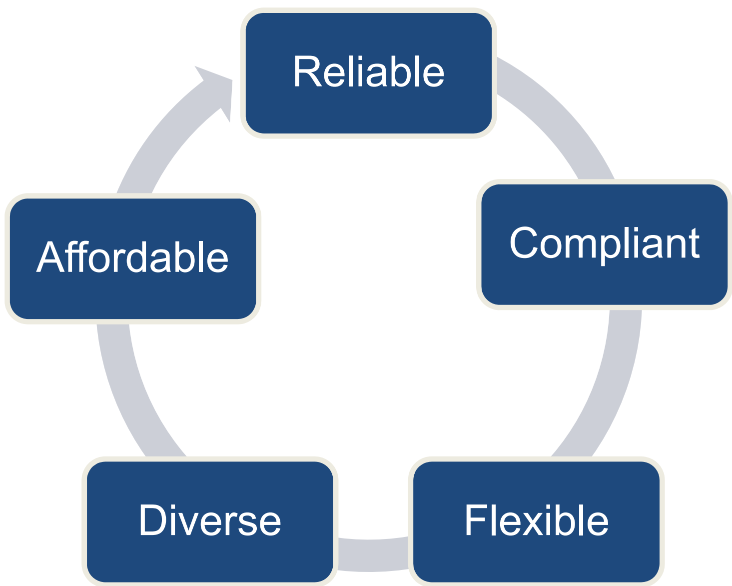
	A	B	C	D	E	F
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Cost to Customer delta from least	$12,985 $1,222 10.4%	$12,028 $265 2.2%	$11,769 $6 0.1%	$12,956 $1,192 10.1%	$12,121 $357 3.0%	$11,763 $0 0.0%
Cost Certainty delta from least	$13,360 $1,477 12.4%	$12,254 $371 3.1%	$12,007 $124 1.0%	$13,286 $1,403 11.8%	$12,245 $362 3.0%	$11,883 $0 0.0%
Cost Risk delta from least	$14,431 $2,067 16.7%	$12,922 $558 4.5%	$12,661 $297 2.4%	$14,284 $1,920 15.5%	$12,815 $452 3.7%	$12,364 $0 0.0%
Fuel Security % non-gas capacity	45%	79%	86%	40%	72%	87%
Environmental 2030 CO_2 emissions 2005 baseline = 18.2M	2.18M	0.97M	0.97M	3.13M	2.03M	0.97M
Employees	0	0	0	<30	<30	<30
Local Economy	Dependent on project selection and location; currently under evaluation					

Lunch

Preferred Resource Plan

Dan Douglas
Vice President, Corporate Strategy & Development

NIPSCO Preferred Supply Portfolio Criteria



Requires careful planning and consideration for all of NIPSCO's stakeholders including the communities we serve and our employees

The IRP is an informative submission to the IURC; NIPSCO intends to remain engaged with interested stakeholders

Action Plan For Current Supply Resources

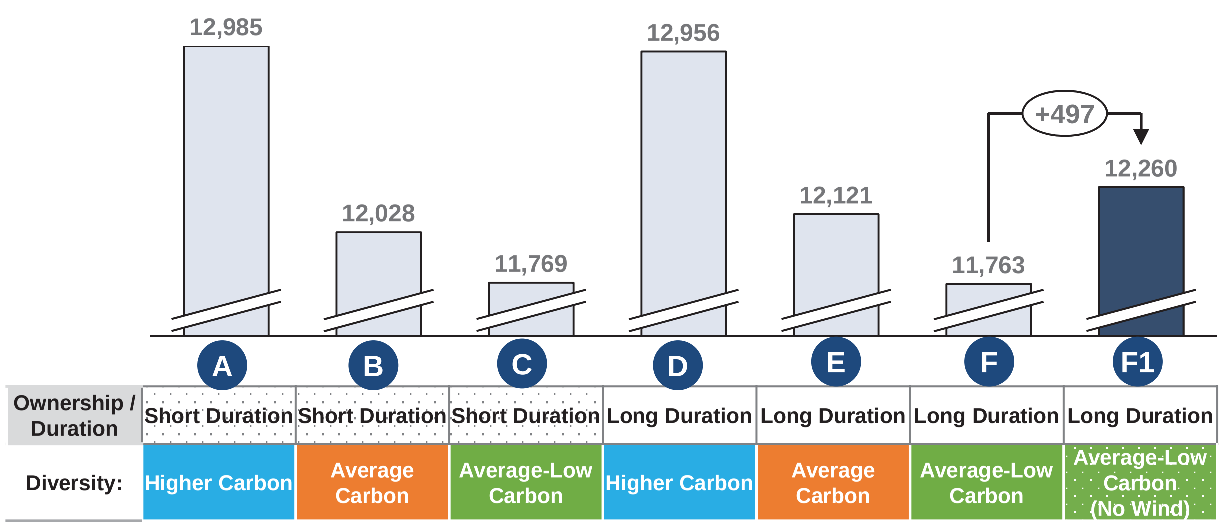
- **Retire all of NIPSCO's coal capacity by the end of 2028**
  - Pursue most viable path, consisting of the retirement of Schahfer 14,15,17,18 by the end of 2023 and Michigan City 12 by the end of 2028, subject to MISO and other considerations
- **Maintain current gas fueled generation**
- **Maintain current wind Purchase Power Agreements**
- **Implement filed 3 year Demand Side Management plan for 2019 to 2021**

NIPSCO Supply Resource Plan And Timing

Timing	Near Term 2018 – 2020	Mid Term 2021 – 2023	Long Term 2024 – 2037
NIPSCO Activity Description	• Initiate retirement process of Schahfer Units 14,15,17,18 • Identify and begin implementation of required reliability and transmission upgrades • Select initial replacement projects identified from the 2018 RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve customer savings • Actively monitor technology and market trends and evolution	• Fully implement required reliability upgrades • Actively monitor technology and market trends, and continue engagement with project developers and asset owners to understand landscape • Conduct subsequent RFP to identify preferred resources to fill the remainder of the 2023 capacity need; procure replacement resources • Implement Schahfer coal retirement with a focus on interests of customers, employees and local communities	• Monitor market and industry development and refine future IRPs
Retirements	• None	• Schahfer Units14/15/17/18 (2023)	• Michigan City Unit 12 (2028)
Expected Capacity Additions	~150-200MW (UCAP)	~1,100-1,150MW (UCAP)	~400MW (UCAP)
NIPSCO's Preferred Replacement Plan	• Demand Side Management • PPA / Market purchases • Primarily Wind	• Demand Side Management • Wind/Solar/Storage • Market Purchases	• Demand Side Management • Wind/Solar/Storage • Market Purchases
Expected Regulatory Filings	• Approvals for replacement capacity projects	• Approvals for replacement capacity projects • DSM Plan for 2022- 2025 (file in late 2020)	• Approvals for replacement capacity projects

Procuring Wind In 2020 To Realize Tax Benefits Leads To Lower Customer Cost

- **Indiana wind resources bid into the All-Source RFP are attractive replacement options that have increasing demand and are subject to near-term phase out of tax incentives**
- **NIPSCO would need to procure these wind resources in 2020 to realize Production Tax Credit benefits and lower customer cost**
- **What is the value of these wind resources (or alternatively, if we elect not to procure, what is the incremental cost)?**
  - A new “No Wind” portfolio F1 was constructed from Portfolio F with no wind and instead relying on the next set of most attractive solar tranches
  - **Excluding wind would raise the 30-year NPV by about $500 million**, resulting in a higher cost than the optimized wind/solar/CCGT option (Portfolio E)



- Portfolio F with no wind removes the lowest-cost energy resources (which tend to have an LCOE in the $25-35/MWh *nominal* range) and replaces with slightly higher cost solar resources that produce far less energy
- The impact is that the “No Wind” portfolio relies much more heavily on market purchases over the forecast horizon (up to ~35-40% in 2030 verses ~15% when wind is in the portfolio)

2019 to 2021 DSM Plan Summary

Eleven Residential and five Commercial and Industrial ("C&I") programs with a total 392,839 MWh Gross Energy Efficiency Goals over the three year period.

Residential Programs

- Heating, Ventilation and Air Conditioning Energy Efficient Equipment Rebates
- Residential Lighting
- Home Energy Assessment
- Appliance Recycling
- School Education
- Multifamily Direct Install
- Home Energy Report
- Residential New Construction
- HomeLife Energy Efficiency Calculator
- Employee Education
- Income Qualified Weatherization

C&I Programs

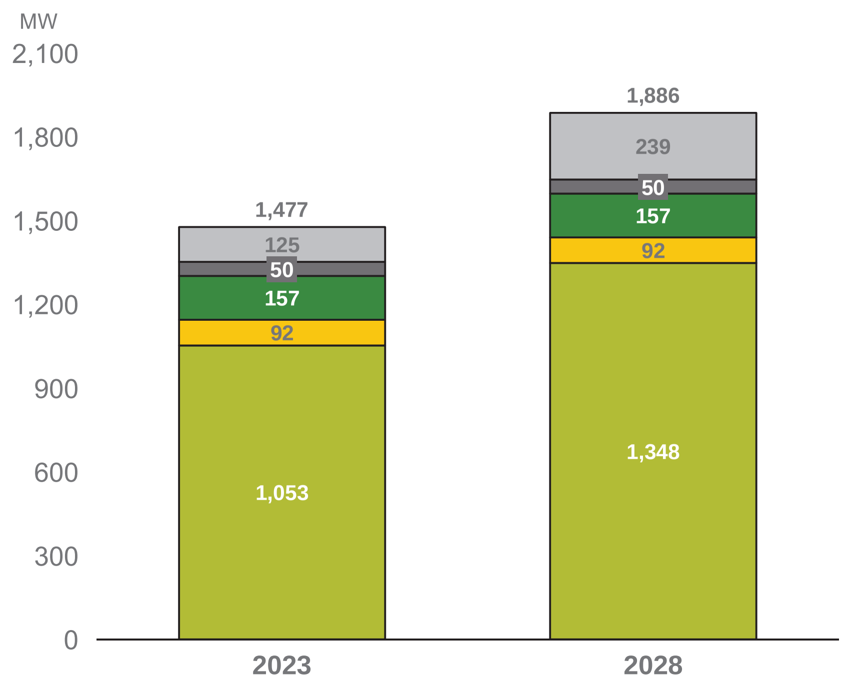
- Prescriptive
- Custom
- C&I New Construction
- Small Business Direct Install
- Retro Commissioning

2019 – 2021 NIPSCO Electric DSM Plan was approved by the IURC on September 12, 2018

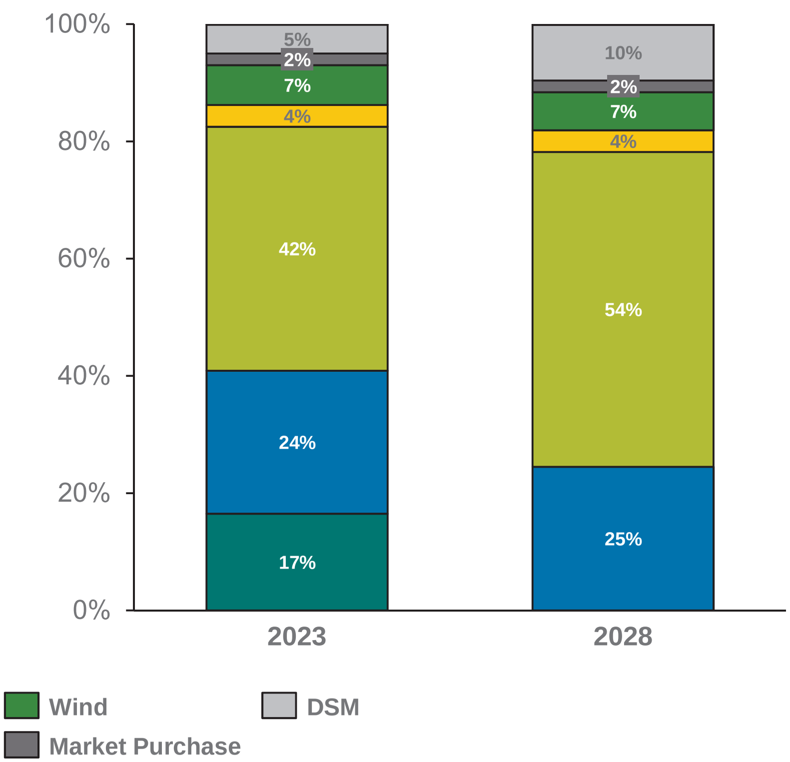
NIPSCO Cumulative Replacement Resource Mix

- By 2023, the IRP preferred plan calls for adding approximately 1,150 MW of solar and solar+ storage, 160 MW of wind, 125 MW of DSM and 50 MW of market purchases to the NIPSCO supply portfolio
- In 2028, an additional 300 MW of solar and 114 MW of DSM resources is expected to be added

Preferred Replacement Plan Cumulative Additions
(UCAP MW)



NIPSCO Supply Resource Mix



Preferred Resource Plan

NIPSCO Preferred Plan

Short-Term (2019-2022)

- Initiate retirement of Schahfer Units 14,15,17,18
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units
- Select replacement projects identified from the 2018 RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost
- File for Certificate(s) of Public Convenience and Necessity and other necessary approvals for selected replacement projects
- Procure short-term capacity as needed from the MISO market or through short-term PPA(s)
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
- Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)
- Continue implementation of filed DSM Plan for 2019 to 2021
- Comply with North American Electric Reliability Corporation, U.S. Environmental Protection Agency, and other regulations
- Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

Long-Term (2023+)

- Retire Schahfer Units 14,15,17,18 by the end of 2023 and Michigan City Unit 12 by the end of 2028
- Monitor market and industry evolution and refine future IRP plans

Stakeholder Presentations

Public Advisory Feedback/ Next Steps/ Wrap Up

Next Steps

IRP	RFP
• Submit IRP by October 31st 2018 • Meeting summary available November 2, 2018 • NIPSCO IRP website: www.nipsco.com/irp • NIPSCO IRP email: nipsco_irp@nisource.com	• Counterparty outreach indicating if NIPSCO is intending to move forward with their proposal in the fourth quarter of 2018 • Begin commercial negotiations that aligns with IRP preferred plan • Future RFP event(s) – Given the number of potential transactions there will likely be a need for at least one additional RFP

Closing Remarks

Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource

Northern Indiana Public Service Company
2018 Integrated Resource Planning ("IRP")
Public Advisory Meeting #5
SUMMARY

October 18, 2018

Welcome and Introductions

Alison Becker opened the meeting by having those in the room introduce themselves. Ms. Becker then reviewed the agenda for the day and did a safety moment.

NIPSCO's Planning and the Public Advisory Process
Dan Douglas, Vice President, Corporate Strategy and Development

Dan Douglas thanked the participants for attending and noted that engagement continues to surpass prior years. He said this continued and deep involvement makes NIPSCO's process stronger, more transparent and hopefully better understood. He then provided a review of how NIPSCO plans for the future and how NIPSCO considers the perspectives of each of the stakeholders in the room as well as the communities NIPSCO serves and the employees that serve the customers. He noted that the IRP is an important part of the internal strategic process and a strong indicator of NIPSCO's future resource actions. He provided an update on the Public Advisory process and reminded the group that NIPSCO looks forward to further feedback. He stated that, for this meeting, the focus will be on two questions: what is NIPSCO's preferred plan and what is the short term action plan? He then provided an update on the one-on-ones that have taken place with stakeholders throughout the process stating that these meetings have largely focused on modeling, the all source request for proposals ("RFP") and demand side management ("DSM"), along with specific modelling runs and stated information about those runs will be provided today. He finished the section by again thanking the participants, particularly those who have taken the time to participate in individual meetings.

Stakeholder Requested Analysis
Pat Augustine, Charles River Associates

Pat Augustine began by providing an update to the stakeholder-requested analysis noting that the Office of Utility Consumer Counselor ("OUCC") asked for NIPSCO to evaluate the conversion of Schahfer Units 17 and 18 from coal to natural gas, the Citizens Action Coalition of Indiana, Inc. (“CAC”) requested NIPSCO to re-run the DSM modeling using its proposed decrements approach, and the Indiana Coal Council requested NIPSCO to use a lower cost for the effluent limitation guidelines (“ELG”) compliance and an alternative market scenario. Mr. Augustine reviewed the OUCC’s request and noted changes to the assumptions and estimated costs associated with the conversion since the last meeting. He noted that both the gas interconnection and environmental costs had now been assumed to be $0. He then provided an update on the costs to the customer to undertake the conversion. To convert both Units under the new assumptions, it would costs customers between $540 million to $1.04 billion more than retirement and replacement with economically optimized resource selections from the RFP results. He then provided the projected cost to convert only Unit 17 ($230 M to $450 M) and showed the capacity factors under the various scenarios.

Mr. Augustine then reviewed the request from the CAC, noting that it had asked for energy efficiency and demand side management programs to be evaluated as “fixed” blocks in the modeling runs. This allows the supply-side plan to simultaneously change with each decrement of efficiency, meaning that it is possible that future supply-side additions could be avoided as levels of energy efficiency increase. He stated that the approach is designed to identify potential decrements from the load forecast and evaluate the impacts of the savings on the portfolio net present value of revenue requirements (“NPVRR”) without accounting for costs. He provided an illustration of the load and NPV for eight decrements under an illustrative example. Mr. Augustine then showed a comparison to NIPSCO’s approach and reminded the group that NIPSCO had used three “bundles” based on the cost of the energy efficiency savings as provided through the DSM Savings Update report. Finally, Mr. Augustine showed the decrement portfolio results using these three bundles and noted that the results using the decrements analysis were similar to the results NIPSCO achieved in its IRP analysis.

Mr. Augustine then turned his attention to the Indiana Coal Council’s request and noted that the Indiana Coal Council requested that NIPSCO evaluate retirement combinations with less costly ELG-related compliance for Schahfer Units 17 and 18 and an alternative market case. He updated the results from the previous meeting based on new numbers and noted that the Indiana Coal Council’s assumptions included no cost for carbon compliance, a high natural gas price and a $45/ton flat real delivered coal price for Units 17 and 18.

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

- Why should any of this cost the consumer anything?
    - The consumer would pay for all costs of service to operate this potential converted facility and any other resources used to serve load.
- No matter what energy that a consumer receives is going to cost them - why would consumer have to pay for the conversion?

- The ultimate cost to operate the entire system is the basis of the cost to consumer metric in this modeling framework. The costs that NIPSCO is showing are the NPV of a projection of 30 years of future costs. In this particular portfolio, NIPSCO is showing that a conversion would be higher cost than the alternatives. At this point, this analysis just shows cost differences across different portfolio strategies. The coal-to-gas conversion was not selected in preferred plan.

- What is a decrement? Is it a slice versus a bundle or a collection of those slices?
  - The decrement in this case is the same as the bundle. We are using the term “bundle” here to be consistent with the analysis that GDS Associates (“GDS”), the DSM consultant, performed. GDS developed three distinct bundles, which are aggregates of savings based on a cost ordering of potential DSM programs. In this example, the decrement is the same thing. In general terms, a decrement could represent any slice (i.e., 0.5%, 1% savings, etc.) but here the analysis uses the bundles that were already developed.
- The CAC would like to thank NIPCSO for performing the analysis which captured what we asked the Company to do. The CAC appreciates it, but only one thing that we reflected on, and it ended up not mattering for NIPSCO that there were not smaller decrements, but in the future could use smaller decrements.
  - Thank you. Bundle 1 was a fairly large decrement. It was found to all be cost effective, but your point is well taken. There could be a more granular look in future analysis.

Retirement Analysis
Pat Augustine and Dan Douglas

Mr. Augustine provided a recap from the previous meeting regarding the retirement analysis, sharing updates where applicable. He reviewed the retirement analysis framework, noting that the responses to the RFP were fundamental to indicating the actual projects available to NIPSCO. He noted that the key decision was what units to retire and when. He then reviewed the various retirement combinations that were constructed and went through each of the eight options. After providing the overview, he revealed the technologies being selected by the model based on the RFP results for the various retirement combinations and reviewed the results for the base case, which included an analysis of the expected cost to customer over the next 30 years. He then reviewed the results of the cost to customer analysis over the next 30 years for each retirement combination under each of the scenarios. Then he provided a review of the stochastics analysis results for each of the retirement combinations. Finally, Mr. Augustine provided information related to the cost risk for each of the retirement combinations.

Mr. Douglas then provided an overview of the Retirement Scorecard. He explained that NIPSCO is using a scorecard to navigate the “most viable” retirement and replacement paths. He then reviewed the Reliability Risk, Employees and Local Economy portions of the scorecard, noting that Mr. Augustine had already covered the Cost to Customer, Cost Certainty and Cost Risk components. For Reliability Risk, he noted that activities, timelines and risk of the MISO retirement process, transmission system upgrades, remaining unit dependencies, fuel and maintenance contracts, future resource procurement and the percentage of the system turning over at once were factors that were considered. As with Mr. Augustine's remarks, much of this was a review of the previous meeting, with Mr. Douglas noting any changes that had taken place since the last discussion.

Regarding the impact on NIPSCO employees, he noted that there are over 400 employees at coal units that are focused on reliably and safely generating electricity for NIPSCO's customers. This was an important consideration in the retirement analysis, with the criteria utilized being the number of employees that are impacted by retirement plans prior to 2023. His final criterion was the local economy, specifically the property tax payments made by the generation facilities to local communities. This was quantified by estimating the present value of future property taxes relative to the 2016 IRP. Mr. Douglas finished by noting these criteria are important to be considered in concert with the financial metrics to provide a comprehensive perspective on retirement considerations.

He noted that the Company continued to review the scorecard findings to ensure there are no refinements needed based stakeholder feedback received. He then reviewed the Retirement Scorecard, noting that the criteria discussed are along the left side. He then explained that retiring coal earlier continued to be the most cost effective option as well as the highest cost certainty and lowest cost risk. He noted that Combination 8, which is 0% coal in 2023 has the lowest net present value requirement ("NPVRR"), with Combination 1, which is 65% coal through 2035 having the highest cost.

Mr. Douglas then noted that Combinations 1-6 are acceptable from a Reliability Risk perspective, but 7 and 8 are unacceptable. He reminded the group that Combination 7, 15% coal by 2023, with Units 17 and 18 retired by 2021, is not executable in the time allotted due to required transmission upgrades to maintain system reliability. These upgrades require coordination with the Midcontinent Independent System Operator, Inc. ("MISO") as well as having environmental wetland management issues, meaning they will not be complete until 2022 under the best case scenario. Combination 8 would require NIPSCO to retire and replace 1,800 megawatts ("MW") at one time. And, while the RFP indicated sufficient capacity, that much transition at one time could create reliability and execution risk for customers that the Company is not willing to accept. Furthermore, he noted, there are benefits to staggering the transition to allow for better views of technology.

After reviewing the impact to employees and the local economy (which is measured relative to the 2016 IRP retirement plan), he noted that, as indicated by the red dashed box, NIPSCO selected Combination 6, 15% coal in 2023 as the "most viable" retirement path. This Combination was selected at a high level because it is the lowest cost option that held acceptable reliability risk for customers and the system. He then provided additional details about Combination 6, indicating that it provides enough time to complete the necessary transmission upgrades, that replacement resources can be reasonably secured by 2023, and that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade. Mr. Douglas also noted that Michigan City Unit 12 will be maintained through 2028 and there are no plans to retire the combined cycle gas turbine ("CCGT") at Sugar Creek at this time. He concluded by noting this will be the preferred plan in NIPSCO's IRP submission.

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

- Do the coal retirement cases include costs per the recent court ruling?
    - All the coal retirement cases do include environmental compliance costs associated with the Coal Combustion Residuals rule ("CCR"). They are included in the capital schedules that were shared with the Indiana Coal Council a few weeks back. There have been no adjustments, so CCR costs are included here.
- To be clear, the cases without coal include CCR?
    - If there is a retirement, the CCR expenditures would change slightly versus the situation where all of Schahfer were to stay online beyond 2023. However, anything currently being spent on CCR is included across the board. The CCR rule refers to coal combustion residuals capital.
- Notion of selecting resources from IRP to do a retirement analysis and yet units retire are to inform resources that are optimal, so can you address that idea?
    - The initial analysis involved doing retirement analysis against the cost of new entry ("CONE") and market purchases because there was not an optimized set of real options to compare.
- Do you really need to do those (the retirement and replacement analysis) separate? Looks like you could perform a single analysis instead of two separate analyses to inform retirement and replacement at the same time.
    - The main reason for doing a separate replacement analysis is to allow for an evaluation against the multi-dimensional scorecard framework. So while the preferred retirement portfolio does have an economically optimized set of replacement resources, the IRP is also interested in testing risk, environmental benefits, and other factors. The second phase replacement analysis dives deeper and broadens the range of portfolio concepts that will be discussed later in the presentation. For example, NIPSCO is able to build out different concepts around commitment duration and portfolio diversity. Purchase power agreement(s) ("PPA(s)") versus ownership or natural gas resources versus renewables are two examples.
- On slide 30, why is number 4 highlighted?
    - The shading simply indicates that it is not a viable path for ELG compliance at the moment.
- Also on slide 30, scenario 4 highlighted in the table, but scenario 7 is also highlighted in the graph. Why is scenario 7 highlighted?
    - This is not an intentional highlight, but a shading to differentiate from the other portfolios. The graphic simply does not have enough unique colors.

- On the local economic impact, the economic impact when a coal unit is shutdown is clear. However, what about the economic impact of the resources being added, for example, whether it is a wind farm or solar facility, those would also have potential property tax impacts to the local economy? Since NIPSCO has not provided locations of the alternative resources, the Company does not have the positive impacts yet?
    - That is correct. As far as providing for any positive economic impact, NIPSCO does not know at this point where facilities will be located. However, there could be respondents to the RFP in the exact same counties that could offset these numbers. It is important to note that NIPSCO is not far along enough down that path to make such a conclusion.
- Are we correct to understand local economy as local property taxes?
    - Correct
- On reliability risk, a complicated mix of factors was reduced to a binary measurement of acceptable/unacceptable, but it does not capture variances between scenarios. It would be good in future IRPs to discuss further and different degradations of variability.
    - There are always opportunities to get sharper on this. NIPSCO took strides forward from 2016, but the Company always has opportunities to improve the process. Ultimately the analysis was challenging regarding how to capture 6, 7, 8 different factors within a single metric. Ultimately, it was decided to call it reliability risk because there were clear markers that made it possible/not possible. However, your approach shows how NIPSCO can improve in the future.
- Would Michigan City be a good source for wind? And as a follow up, that would be a good transition of jobs in that area.
    - NIPSCO continues reviewing specific bids from the RFP now, but there is not a specific answer on location right now.
- Are property taxes going up, going down or stabilizing?
    - If the plant is retired, there would no longer be a facility there and the property taxes paid by NIPSCO would go away. The Schahfer plant is in Jasper County and is the number one property taxpayer in the county. If it retires, less taxes would be paid to the county.
- Can you unpack the component parts of reliability? Is this from MISO? Do they all have weight? There is no separate scorecard?
    - The analysis starts with MISO, the independent system operator in the region. To retire an asset, NIPSCO must go through a retirement filing with MISO, which is known as an Attachment Y filing. After a potential retirement, the Company is responsible for changes to the transmission system, primarily a set of upgrades that would be identified through the MISO process. We have 5 or 6 upgrades that need to happen with the retirement of Schahfer. Beyond that process, NIPSCO considers the remaining unit dependencies at Schahfer to evaluate the feasible timing of retirements. It is also important to understand current contracts and the costs that go into operating the units. NIPSCO also considered the

challenges associated with future resource procurement. The RFP resulted in around 30 bidders and 90 different projects. These developers may be looking at other opportunities and we require time to negotiate and consider many potential projects. Finally, the Company examined the percentage of the system turning over at once. When you talk about retiring 2/3 of the portfolio and switching to intermittent power, NIPSCO wants to have something to step through over time rather than turn everything over at one point. In summary, this category was a "catch-all" bucket with miscellaneous smaller factors that drive NIPSCO to a binary decision.

- Regarding property taxes, if Schahfer is the biggest payer of property taxes in Jasper County, what entity is the largest payer in Michigan City?
  - NIPSCO is not the largest contributor of property taxes in LaPorte County, but it is one of the top three.
- On transmission upgrades, are these built into costs?
  - Yes, they are built into the costs. NIPSCO considered different retirement scenarios and the applicable permitting issues, and captured costs associated with the pretty significant amount of work needs to be done there. The project plan goes out into 2022 or 2023 even if the required projects were started immediately.
- First, going back to cost of customer, does NIPSCO have the rates by year.
  - The Company has determined the total revenue requirement but have not broken down rates to customer class. The analysis thus far assumes perfect rate making.
- Also, with respect to cost certainty around the RFP responses, did you consider tariffs?
  - The responses came through in the June timeframe and were evaluated in July. Most of the turbines would have steel as a major component and the developers were likely aware of many of the tariffs so it is NIPSCO understanding that many were procured at a price point consistent with their RFP bids.
- Does NIPSCO feel an ethical responsibility to coal miners?
  - Absolutely, but the Company is also focused on our employees and our customers. NIPSCO hopes that lower costs for customers, including large industrial customers, will help improve the local economy.
- Between scenarios 6 and 8 can you explain how both retire Michigan City, but with a difference of five years. What happens in those 5 years?
  - The employee line shows only those jobs impacted through 2023. The remaining difference in economics is for the extra five years of Michigan City operation versus RFP alternatives.
- It seems as those there are very minute differences between scenarios 5 & 6 and the only change is the Michigan City retirement date?
  - Michigan City runs fairly economic today (i.e. it is often dispatched based on price), so changing the retirement date has a relatively small impact. Most of the environmental work has been completed at the site, and NIPSCO realizes a relatively strong dispatch with a fairly good heat rate.

There are savings associated with retirement, but not as big as with the Schahfer retirement. Costs are important, so we believe accelerating the retirement from 2035 is the right thing for our customers. Reliability risk is also significant, which is why we are focused on 2028.

- The difference in dates for the retirements at the coal plants affects the amount of maintenance required. Is that true statement?
  - Yes, that is correct. The maintenance capital schedules vary based on expected retirement date. For example, if you have a 10-year old car, if you know you will keep it another 5 years, you will get a tune up, change the tires, etc. If you know you will sell it in year, you will likely wait to do maintenance work. With the coal plants, we have similarly looked at maintenance schedules and stepped those costs down accordingly.
- Would NIPSCO change the retirement date at Michigan City if the County and customer base agreed that retirement in 2023 was fine with them?
  - Reliability risk is an important factor. NIPSCO must maintain reliability and keep the lights on going forward. The retirement plan involves making moves that are directionally different than our peers and there is a bit of a comfort level with maintaining what works. It is a rare moment when you get all stakeholders to come to agreement.
- With reliability risk, is it not possible to just “flip a switch” and rely on the MISO market? Will that not be a possible situation once NIPSCO has converted to renewables?
  - At some point, something needs to generate electricity. NIPSCO’s expectation is that, given the economics, there will be more and more transition to renewables. MISO is not in the room, but it would likely say that as there are more intermittent resources on the system, there will be more risk on MISO to preserve reliability.
- Regarding reliability risk, do you foresee keeping with this theme to retire Schahfer in 2023 and Michigan City will continue to bear burden of hosting coal and then retire or convert to natural gas in Michigan City? From an equity injustice lens, would be very burdensome (ongoing burden, ongoing inequity) if this community continues to bear the burden of environmental burden. This is particularly true for communities of color, low income, etc. The Indiana Conference of the NAACP would adamantly appeal that whenever you retire, that the community does not get the burden of methane or other environment impacts. There have been health impacts to communities that have born the burden all of these years.
  - Although the replacement plan has not be discussed yet in this presentation, as of now, NIPSCO will not transition coal to gas at Michigan City based on current economics.
- Did NIPSCO take into consideration the communities? Did the Company take into consideration the fact that the Michigan City population is minority and environmental justice and where in the matrix is that considered or exercised?
  - NIPSCO’s wants to be compliant with all United States Environmental Protection Agency (“EPA”) rules, so any plan selected by NIPSCO needs

to be compliant with those rules. NIPSCO does take that into account and the Company wants to take care of the customers in that territory.

Replacement Analysis
Pat Augustine and Dan Douglas

Mr. Augustine reviewed and updated the replacement analysis. He started the review of the section by reminding participants that NIPSCO has forecasted a 2023 peak demand of just over 3,000 MWs. He stated that retiring the units at Schahfer and Michigan City will lead to a combined 1,810 MWs required. Based on this, NIPSCO completed its replacement analysis. He reviewed the replacement analysis framework, noting that the RFP was a main source of information for determining replacement options. Mr. Augustine noted that various resource combinations were created to explore the range of ownership/duration and diversity possibilities. He then reviewed the possible resource additions based on unforced capacity ("UCAP") in 2023 and 2028. After this explanation, he showed the various replacement scenarios and the stochastics for those scenarios.

Mr. Douglas then reviewed the Replacement Scorecard. As with the Retirement Scorecard, the Replacement Scorecard is being used to help navigate the various paths and NIPSCO has done away with the "red-yellow-green" color coding in favor of more quantitative scoring. He noted that there are some nuances from the Retirement Scorecard. As with the Retirement Scorecard, Mr. Douglas explained how fuel security, environmental, employees and local economy were considered in the Replacement Scorecard. Regarding fuel security, he noted that the criterion assesses NIPSCO's ability to reduce exposure to short-term fuel supply and/or deliverability issues, which is expressed as a percentage of capacity sourced from resources other than natural gas in 2025. Mr. Douglas explained that the environmental criterion considered the annual carbon emissions from the resource portfolio in 2030 by metric tons of CO_2. For employees, he explained that the number of NIPSCO jobs added for the resource portfolio was considered. And, finally, for the local economy, NIPSCO considered the property taxes for the portfolio, without making a determination of where the facilities would be, only considering assets that would pay property taxes.

After providing this background into the scorecard, Mr. Douglas provided the results of the analysis. He said that including renewables is the least cost option as well as the lowest cost certainty and lowest cost risk. He noted that, by comparison, portfolios with natural gas technologies have a cost over 10% higher than renewable-only portfolios. Portfolio F, which is long duration and average-low carbon pricing, which is predominately long-term renewable PPA or renewable ownership, DSM, and a small amount of market purchases, is the lowest cost option and the strongest portfolio from a fuel security standpoint. In addition, he said, it provides the lowest emissions for customers.

In summarizing this section, Mr. Douglas stated that NIPSCO believes the retirement and replacement path will provide reliable power, enable lower costs and provide significant environmental benefit. He noted that the scorecards demonstrate that retiring coal and replacing with renewables will create significant savings. Finally, from a reliability perspective, he committed the Company to making sure the plan keeps the lights on for its customers. He stated that transitioning from coal to renewables is a significant move and NIPSCO is approaching the shift with an appropriate level of caution and analysis.

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

- For scenario E, how did you come up with mix of resources as opposed to 300 CCGT and 1070 renewables? How did that mix come about?
    - This was primarily due to the nature of the bids that came in. NIPSCO was broadly looking to split the renewable and natural gas capacity fairly evenly on a UCAP basis. All long-term combined cycle gas turbine ("CCGT") bids included projects in the 600-700 MW range, so that naturally fit into the portfolio concept, with the remainder being renewables.
- Are you performing life cycle analysis of carbon emissions?
    - No, we are focused on the point of emissions for generating capacity.
- On slide 38, what is included in the "other" category?
    - "Other" incorporates a system power bid and a small demand response offer. The system power bid was short-term and the demand response bid was one year in duration.
- Is any gas self-build?
    - No, a self-build was evaluated and compared to the RFP bids, but all of the portfolios analyzed were with resources from the RFP.
- Throughout the analysis, it is either 2023 or 2028 for the retirements. 2028 is unacceptable for Michigan City. And what is going to keep you from reneging on all of this? 2028 is 10 years from now and asthma, cancer, and everything else wrong with these scenarios and how can you re assure the people? Is there a way to move all this up?
    - Please look back at the retirement scorecard. NIPSCO has to provide an affordable, compliant, and diverse portfolio. This is all really complicated, but please look at the transmission that needs to be built before the Units can be retired. Your concerns are heard, but it is important to note the NIPSCO is pulling retirements earlier by 10-20 years (or more) and trying to make significant strides for better costs for customers while being environmentally friendly.
- Can you clarify what is meant by "inside the fence line"?
    - This means at the point of generation, not taking into account any emissions that may have happened during the production or transmission of natural gas. We only count emissions created at the generation site, which is aligned with EPA metrics.

- Fewer than 30 jobs are created in scenario F, where does that compute with the 276 employees lost with optimal retirement scorecard? This could be net reduction from 276 to 30?
  - o The 276 is related to those who are working at the Schahfer facility now. They may not all necessarily lose jobs but they would not be working at Schahfer. In the replacement analysis, NIPSCO is demonstrating the "steady state" number of jobs for a solar or wind facility. There would also be an influx of construction jobs to get things up and running. So overall, NIPSCO would offset some of the jobs lost at Schahfer.
- Does NIPSCO plan to report on indirect emissions in the future?
  - o In a previous meeting, there was a discussion on this. For NIPSCO and NiSource, you can go to the annual report or greenhouse gas report where greenhouse gas emissions inside the fence line are calculated as well as "scope 2" (associated with transport) and "scope 3" (vendors, etc). This is available on the website.
- What is the nameplate capacity of solar, as well as energy storage, selected in the preferred plan?
  - o The UCAP is available on Slide 38.
- Slide 38 is unclear as to what amount of energy storage is selected (conflated with solar).
  - o The solar plus storage project is about 180 MW of nameplate capacity. 175 MW of the capacity is solar, with 4.9 MW of battery storage.
- When is the next IRP?
  - o Based on the proposed rule, the IRP is required every 3 years. We were on schedule to do it in 2019, but moved it up. We will continue to work with the Indiana Utility Regulatory Commission on the next date, but it is assumed the next IRP will be submitted in 2021 (based on a 2018 date) or 2022 (based on the original 2019 date).
- I appreciate that NIPSCO is acknowledging that clean energy is the most affordable and viable option that distinguishes you from Indiana's other investor owned utilities ("IOUs"). What differentiates and allows you to acknowledge it?
  - o NIPSCO cannot speak to other utilities and their decisions. The Company is making decisions based on its customers and based on its assets. The retirement and replacement plans are the right decisions from cost, local economy, and fuel security perspectives. NIPSCO considered what is available to customers through the RFP, and the Company evaluated the tradeoffs, and feels it's the right decision for customers.
- Through preferred plan, how much weight is given to local resources? How are they ultimately the beneficiaries of this?
  - o NIPSCO required the resources to be within MISO and within Zone 6 of MISO. NIPSCO supports resources within the service territory for taxes and to benefit the local economy.
- Is NIPSCO going to limit choice to existing RFP library or will the Company consider other competitive bids once the technology has been selected?
  - o Right now NIPSCO is focused on the responses to the recent RFP.

- Was there any kind of notice taken regarding if the equipment was made in the United States versus overseas?
  - No, the Company did not consider that.
- Will there be a regulatory filing for undepreciated coal plants?
  - Yes, inside the rate case NIPSCO will be filing on October 31, 2018.
- Can you give any more definition to timing of RFP? And amount of RFP? At that point, after the replacement of Schahfer Units, right?
  - Right now, NIPSCO is focusing on projects with expiring wind production tax credits. Our intention is to take advantage of those before they phase out, although wind will provide a limited amount of firm UCAP. The Company also sees some solar projects are well priced that it can take advantage of through the recent RFP. NIPSCO is negotiating those as well. However, since the Company does not plan to fill the full retirement gap right away, another RFP will likely be required in the 2019-2021 timeframe. At this point, there are not more specifics.
- How will Schahfer retirement impact Georgia Pacific Gypsum?
  - While it is expected there will be an impact, it is not known. The facility was built with the idea that it would take gypsum from Schahfer. Georgia Pacific has known since the last IRP that a retirement was possible, so this is not truly a new issue for it.
- Thank you for your extensive work on the IRP. The NIPSCO Industrial Group appreciates it. We understand and appreciate it is a complex and very nuanced undertaking. While we are still reviewing your findings, we generally support the direction of your resource planning efforts. We look forward to working together as we move forward; specifically in the certificate of public convenience and necessity ("CPCN") proceedings coming down the road.
  - Thank you.
- A statement in medicine, "you can't improve what you can't measure." So did NIPSCO take into consideration the international concern with the climate crisis and how fast to move, where to move, how to move? There has been no secret that a lot of concern with climate change and damage caused by smaller increase in global temperatures. If you did, how you metricize that and if you did, where did it appear? As a follow up statement, latest report, 100% by 2030
  - On Slide 43, we have a specific line for environmental impact related to CO_2 emissions. NIPSCO is reducing emissions by 90% by 2030, so I think you'll find that we have been aggressive on that front and more aggressive than the Paris Climate Agreement. The latest report calls for a 45% reduction by 2030 under the 1.5 degree scenario. The Company will beat that by twice the magnitude and more quickly.

Preferred Resource Plan
Dan Douglas

Mr. Douglas started by reviewing NIPSCO's preferred supply portfolio criteria, nothing that NIPSCO comes back to five key principles: reliable, compliant, flexible, diverse and affordable which are first and foremost focused on NIPSCO's customers. He noted that the Company also carefully considered the perspectives of each of the stakeholders in the room as well as the communities served and the employees that serve customers. He reminded the group that the submission of the IRP is not the end of NIPSCO's engagement in this process. As always, the Company will remain engaged with all interested stakeholders. He then provided an overview of the action plan for NIPSCO's current supply resources, noting the NIPSCO will maintain current gas generation and current wind PPAs. The recently approved DSM Plan will be implemented from 2019-2021. Mr. Douglas then walked the group through the components of the Company's preferred supply plan in the short-, medium-, and long-term. In the short term, so from now to 2020 NIPSCO's activities will center on: Initiating the retirement process for the units slated for retirement at Schahfer; identifying and implementing required reliability and transmission upgrades; selecting projects from the 2018 RFP evaluation process prioritizing resources that have expiring tax credits; and continuing to monitor market trends and how technology continues to evolve.

Mr. Douglas noted that, during this time period, NIPSCO expects to add about 150 to 200 MW of UCAP capacity, with the expected source to be primarily from wind. However, all sources in the RFP will be considered, in addition to DSM and market purchases or short term PPAs as needed. He noted that, once the projects have been selected, NIPSCO will make the necessary regulatory filings.

Regarding the midterm period from 2021, NIPSCO's activities will primarily consist of: implementing the reliability upgrades; continuing to actively monitor technology and market trends and engaging with developers and asset owners to understand the landscape for generation; conducting a subsequent RFP to identify resources to fill the remainder of the 2023 capacity gap. In addition, NIPSCO will implement the Schahfer retirement focusing on customers, employees and the impact to local communities. Mr. Douglas stated that, during this time period, NIPSCO expects to add about between 1,100 and 1,150 MW of UCAP capacity identified from the next RFP, likely solar/storage, DSM and market purchases. NIPSCO will file the next DSM plan for 2022 to 2025 in late 2020 as well as for any required regulatory approvals for replacement resources.

Finally, he discussed plans for the long term starting in 2024. NIPSCO will be focused on monitoring the market and industry developments and refining its future resource plans. In 2028 the last remaining coal Unit, Michigan City 12, will retire and NIPSCO will have a 400 MW UCAP need which will be filled with DSM, wind/solar/storage and market purchases.

Mr. Douglas then discussed the procurement of wind resources in 2020 to realize tax benefits, which lead to lower customer costs. He noted that NIPSCO's analysis shows that acquiring wind in 2020, while still eligible for the full tax credits, provides a 30-year NPV benefit of almost $500M to customers if those purchases are included in the preferred portfolio. He also provided information regarding NIPSCO's current DSM plan, noting that the plan projects savings of over 392,000 MWh over the three year period.

He then turned to a discussion of NIPSCO's cumulative replacement resource mix, noting that, by 2028, 75% of the NIPSCO supply will come from renewables and DSM resources. In summary, he provided an overview of NIPSCO's preferred plan for the 2018 IRP, noting the plan is broken out into the short-term (2019-2022) and the long-term (2023 and beyond). He concluded by saying that the actions coming out of this IRP will place NIPSCO on a course to continue providing reliable power while enabling lower costs and providing significant environmental benefit.

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

- On slide 51, can you confirm that it is in UCAP rather than nameplate capacity? It shows 1,348 MW of solar by 2028. Does that really mean 2,676 MW of nameplate capacity, since you multiply by 2 to get from solar UCAP to solar nameplate capacity?
    - Yes, can confirm the slide is denominated in UCAP.
- Can you confirm NIPSCO is planning to file a new rate case on Oct 31?
    - Yes.
- Do you intend to charge more for electricity through renewables than other resources?
    - No, renewables will be baked into the cost of the total portfolio. The plan is not for renewable resources to cost more for customers than other resources.
- Regarding the carbon market: NIPSCO is getting some form of revenue from carbon. Is that revenue passed onto customer to reduce rates, maybe? Is there a scenario around revenue and put into basket to help with solar/wind equity?
    - There is no carbon market and no revenue coming from it. If that became available, further discussions would take place.
- Are you doing it because of good corporate reason or because you're projecting to sell?
    - There is no projection of revenue from a future carbon market in this analysis. In the scenarios with a carbon tax, we assume that a carbon tax is being paid by NIPSCO, rolling through customer costs.
- Are you being incentivized to reduce carbon in those scenarios?
    - Yes
- There is a market for renewable energy credits ("RECS") from other states. In the RFP is that REC owned by the installer, and, therefore, probably baked into their bids?
    - That is correct. NIPSCO used the renewable costs, whether it is PPA or asset sales, as per the RFP bids that came through. There is no separate REC price stream that is isolated out or credited back to NIPSCO. Customers would pay for the REC attribute, so it would be in their interest if we were to sell any in the future.

- On Slide 38, please clarify, nameplate capacity of solar in the plan.
    - That slide is unclear as to what is selected. The solar plus storage project is about 180 MW of nameplate capacity. 175 MW of the capacity is solar, with 4.9 MW of battery storage.
- Once these bids are accepted, are the receivers transparent to all?
    - The process is ongoing and NIPSCO is in the middle of a negotiation and commitment process now. There will be clarity in the CPCN process, which will document the selected projects.
- Will the CPCN process show who was accepted?
    - Yes
- The RFP had asked them to commit to offering process and ability through December of 2018. Did that get changed?
    - The RFP specifically asked them to hold the price through the end of year. However, there is no mutually exclusive arrangement, so developers can also negotiate with others if they wish.
- Just to correct the record - Kelly is correct, the reduction is 45% by 2030 and 100% by 2050 and reducing from 2010 CO_2 levels. It is still if you make the targets, you will not be contributing to Armageddon, but not necessarily reducing to where we need to go long term. Still behoove you to get out as fast as possible.
    - Your point is understood.

Stakeholder Presentations

Laura Arnold of Indiana DG provided a presentation regarding net metering and where NIPSCO is in reaching 1.5% of the summer peak and the amount of net metering related to commercial customers. Denise Abdul-Rahman of the Indiana State Conference of the NAACP provided a presentation regarding the efforts the Indiana State Conference of the NAACP has undertaken related to environmental and climate justice and discussed its concerns with NIPSCO's preferred plan.

Violet Sistovaris, President, NIPSCO and Executive Vice President, NiSource, provided participants with an update on the recent incident involving Columbia Gas of Massachusetts and NiSource's response. She the closed the meeting by thanking the attendees for their attendance and active participation throughout the process.

Stakeholder Presentation on
Non-residential Net Metering Problem

by Laura Ann Arnold, President
Indiana Distributed Energy

October 18, 2018

Impact of non-residential net metering on NIPSCO IRP

IndianaDG Mission Statement

- To be the voice of the renewable energy (RE) and distributed generation (DG) business, educational and public sectors in Indiana to advocate public policies and to foster economic growth which fosters this business sector, creates jobs, promotes national security, provides stabilized energy resources and improves the quality of the environment.

IndianaDG Members

- Developers of renewable energy and distributed generation (RE&DG) both located in Indiana doing projects here and elsewhere across the country
- Manufacturers of RE/DG systems
- Supporting non-profits and individuals wanting to develop RE/DG projects

Problem: What happens when 1 of 3 groups of customers reaches 1.5% cap?

- NIPSCO is on the verge of reaching its 1.5% cap for 1 of the 3 groups of net metering customers.
- An 890 kW proposed project was told there was insufficient capacity for a non-residential net metering agreement.
- Customer downsized project to 500 kW.
- Most recently 84 kW left for non-residential net metering.

What does SEA 309-2017 tell us should happen now?

- Let's look at the relevant sections of SEA 309-2017 for some guidance.
- Unfortunately, SEA 309 is somewhat ambiguous and creates uncertainty about next step.
- Some guidance from revised net metering rule.

SEA 309-2017
Chapter 40. Distributed Generation

- Sec. 10. Subject to sections 13 and 14 of this chapter, a net metering tariff of an electricity supplier must remain available to the electricity supplier's customers until the earlier of the following:

Chapter 40. Distributed Generation; Sec. 10 con't

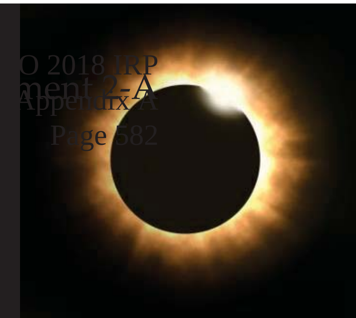
- (1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.
- (2) July 1, 2022.

Chapter 40. Distributed Generation Sec. 10 con't

- Before July 1, 2022, if an electricity supplier reasonably anticipates, at any point in a calendar year, that the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff will equal at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier, the electricity supplier shall, in accordance with section 16 of this chapter, petition the commission for approval of a rate for the procurement of excess distributed generation.

Sec. 10 con’t

- Sec. 12. (a) Before January 1, 2018, the commission shall amend 170 IAC 4-4.2-4, and an electricity supplier shall amend the electricity supplier's net metering tariff, to do the following:
- Increase the allowed limit on the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier.



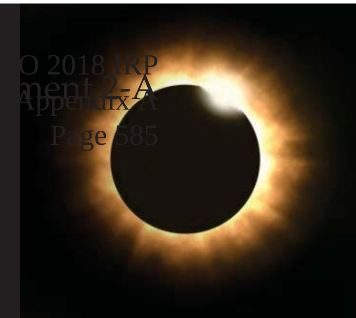
- Modify the required reservation of capacity under the limit described in subdivision (1) to require the reservation of:
  - forty percent (40%) of the capacity for participation by residential customers; and
  - fifteen percent (15%) of the capacity for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

SEA 309-Section 16

- Sec. 16. Not later than March 1, 2021, an electricity supplier shall file with the commission a petition requesting a rate for the procurement of excess distributed generation by the electricity supplier. After an electricity supplier's initial rate for excess distributed generation is approved by the commission under section 17 of this chapter, the electricity supplier shall submit on an annual basis, not later than March 1 of each year, an updated rate for excess distributed generation in accordance with the methodology set forth in section 17 of this chapter.

Section 17

- Sec. 17. The commission shall review a petition filed under section 16 of this chapter by an electricity supplier and, after notice and a public hearing, shall approve a rate to be credited to participating customers by the electricity supplier for excess distributed generation if the commission finds that the rate requested by the electricity supplier was accurately calculated and equals the product of:



SEA 309; Section 17

- (1) the average marginal price of electricity paid by the electricity supplier during the most recent calendar year;
- (2) multiplied by one and twenty-five hundredths (1.25).

- *Average marginal price = LMP or locational marginal price*

What does revised net metering rule say about this?

- Can an investor-owned electric utility exceed the 1.5% of summer peak load cap for net metering?
- The answer is YES.

170 IAC 4-4.2-4 Availability

- **170 IAC 4-4.2-4 Availability**
- Authority: IC 8-1-1-3; IC 8-1-40-12
- Affected: IC 8-1-2-34.5; IC 8-1-37-4; IC 8-1-40

- Sec. 4. (a) An investor-owned electric utility shall offer net metering to a customer that installs a net metering facility prior to the earlier of the following:

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170 IAC 4-4.2-4 Availability

- (1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the investor-owned electric utility's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the investor-owned electric utility; or
- (2) July 1, 2022.

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- (b) The investor-owned electric utility **may** limit the aggregate amount of net metering facility nameplate capacity under the net metering tariff to one and one-half percent (1.5%) of the most recent summer peak load of the utility, with:

- (1) forty percent (40%) of the capacity reserved solely for participation by residential customers; and

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- (1) forty percent (40%) of the capacity reserved solely for participation by residential customers; and
- (2) fifteen percent (15%) of the capacity reser ved solely for participation by customers that install a net metering facility that uses a renewable energy resource described in IC 8-1-37-4(a)(5).

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- However, the investor-owned electric utility **<u>may</u>** increase the limit on the aggregate amount of net metering facility nameplate capacity at the investor-owned electric utility's sole discretion.

Duke Energy proposes to exceed net metering cap

- In Duke Energy Indiana Cause No. 45145, Andrew Ritch states: "The Company agreed that participants under Rider 26 would be eligible for net metering, but solar facilities installed pursuant to this program will be in addition to and will not count against the system net metering cap contained in the Company's net metering tariff, Standard Contract Rider No. 57. Therefore, this customer option would not be competing with other customer options for the net metering eligibility under the system-wide cap. The Company also agreed that Rider participation would initially be limited to a total of 12 MWs."

PURPA Implementation: federal & state public utility commission

- US Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978.
- QF = Qualifying Facility—Two categories:
  - Small power producers which are renewable energy such as solar, wind, biomass or geothermal
  - Cogeneration facilities which sequentially produce electricity & thermal energy; aka CHP

NIPSCO seems to believe customers should use PURPA

- Frank Shambo 10/15/18 email states: "....all business and home owners are allowed to add renewable resources for their own benefit. There is no cap that constrains this activity. The cap solely deals with additional incentives. I would also note that NIPSCO has also offered a Standard Contract for the purchase of capacity and energy from qualifying facilities since 1985. A copy of the Standard Contract is attached. The value of energy and capacity is updated annually. This agreement would provide benefits for the energy that is pushed back onto NIPSCO's system above the volume used by the customer."

Should NIPSCO petition IURC for new tariff?

- SEA 309-2017 appears unclear as to *<u>when</u>* NIPSCO should petition the IURC to establish the average marginal price times 1.25%.

What is the current status of net metering?

- The last formal information is contained in the 2018 Net Metering Report for the year ending 2017.
- There is a need for earlier reporting than Feb. 28, 2019 to determine if other utilities are approaching their net metering cap for any category of customers.

Table 1. Nameplate Capacity by utility and by resource type, 2017

Table 1. Nameplate Capacity by utility and by resource type, 2017

	Total (kW)	Solar (kW)	Wind (kW)[8]	Biomass (kW)
Duke Energy Indiana	17,878	15,659	2,220	0
NIPSCO	10,689	8,641	2,048	0
I&M	10,405	9,909	256	240
Vectren	7,799	7,782	16	0
IPL	2,369	2,319	50	0
Total	49,140	44,310	4,590	240

Table 3. Nameplate Capacity relative to 1.5% peak load by utility, 2017

Table 3. Nameplate Capacity relative to 1.5% peak load by utility, 2017

	2016 Summer Peak Load (kW)	2017 Net Metering Capacity (kW)	Percent of peak load	Remaining Net Metering Capacity under 1.5% cap (kW)
Vectren	1,097,700	7,799	0.71%	8,667
NIPSCO	3,142,160	10,689	0.34%	36,444
Duke Energy Indiana	5,492,000	17,878	0.33%	64,502
I&M	3,659,700	10,405	0.28%	44,491
IPL	2,716,000	2,369	0.09%	38,371
Total	16,107,560	49,140	0.31%	192,474

Table 3. Solar Nameplate Capacity Growth year over year

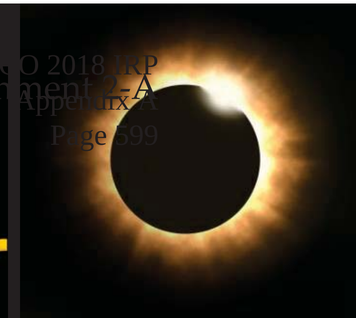


Table 7. Solar Nameplate Capacity growth year over year

	Capacity (kW)	% change from previous year	Absolute change from previous year (kW)
2005	23		
2006	66	188%	43
2007	121	83%	55
2008	167	38%	46
2009	307	84%	140
2010	529	72%	221
2011	1,119	112%	591
2012	1,789	60%	670
2013	2,657	49%	868
2014	4,346	64%	1,689
2015	8,123	87%	3,777
2016	15,476	91%	7,353
2017	44,310	186%	28,834

Table 8. Wind Nameplate Capacity growth year over year

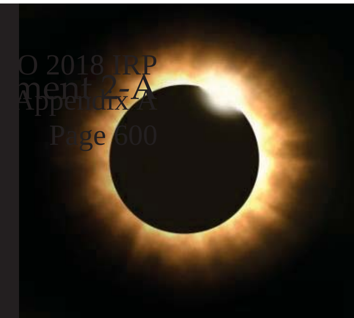
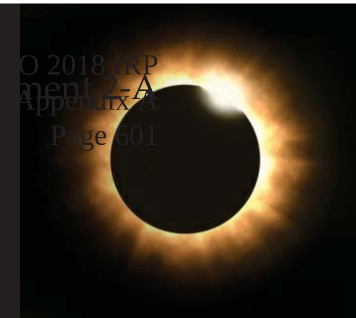


Table 8. Wind Nameplate Capacity growth year over year

	Capacity (kW)	% change from previous year	Absolute change from previous year (kW)
2005	0		
2006	0		
2007	19		19
2008	65	243%	46
2009	196	202%	131
2010	255	30%	58
2011	732	187%	477
2012	3,509	379%	2,777
2013	4,431	26%	922
2014	4,446	0%	15
2015	4,620	4%	174
2016	4,476	-3%	-144
2017	4,590	3%	114

Contact information



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  Indianapolis, IN 46202

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INDIANA STATE CONFERENCE OF THE NAACP ENVIRONMENTAL AND CLIMATE JUSTICE PROGRAM

Denise Abdul-Rahman
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History and Background

- Indiana State Conference of the NAACP is 58 years old
- 35 Branches across the State including Youth and College
- Our Indiana Environmental Climate Justice Program work is local (city), state, midwest, national and global advocacy
- National NAACP is 110 years old
- 2500 Branches

The Indiana State Conference of the NAACP Environmental and Climate Justice (ECJ) Program

Environmental injustices, including climate change, have a disproportionate impact on communities of color and low income communities in the US and around the world. Our work is implemented within the context of human and civil rights issue, advocating for three objectives:

Reduce Harmful Emissions Equitably Particularly Greenhouse Gases

Advance Equitable Energy Efficiency and Equitable Energy

and Strengthen Community Resistance and Livability.

Engage/Educate

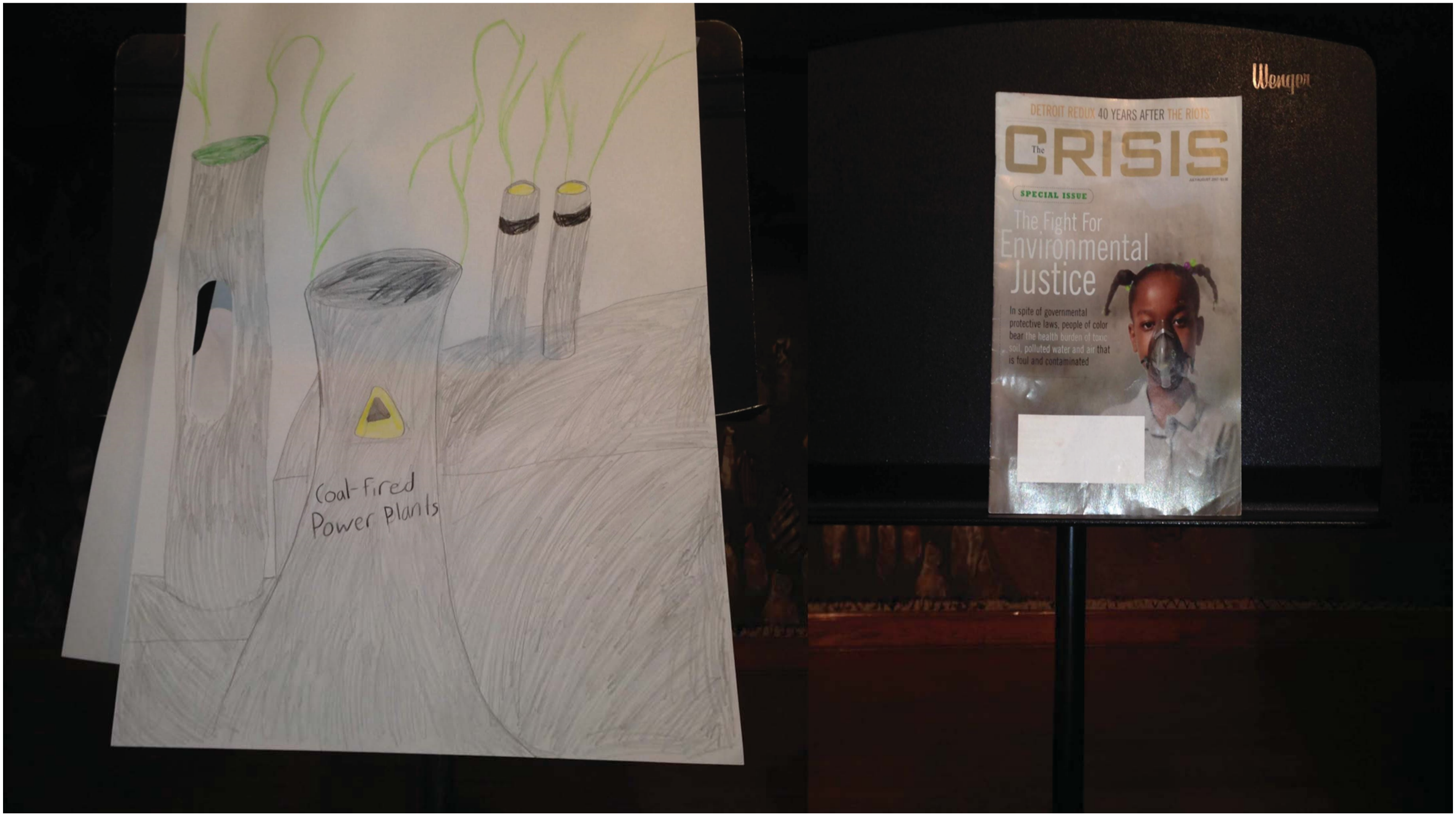
Empowerment (We support the existing power)

Advocate

***Jemez Principles**

1. ***Be Inclusive, 2. Bottom up organizing, 3. Let People Speak for themselves, 4. Work Together in solidarity and mutuality, 5. Build Just Relationships among Ourselves 6. Commitment to Self Transformation***


BREAKFAST: IMAGINE WOMEN
HIP HOP TO ENERGY DEMOCRACY
HORIZON CONVENTION CENTER, Interurban Hall, Municicie, IN
CONTACT: Denise Abdul-Rahman at darahman17@gmail.com
FREE! JOIN US OCT 26
7:30am-9:30am
Celebrating People Power,
Healthy Communities, and Make Art with
Dr. Denise Fairchild, Keynote Speaker
Janet McCabe, Special Guest Speaker
Jacqueline Patterson, Key Address
Nicole Burts, Moderator
Manon Voice, Hip Hop Artist
Stacia Moon, Trained Musician
Ess McKee, Mixed Media Creator
Denise Abdul-Rahman, Speaker, Organizer and Facilitator
CLIMATE JUSTICE ALLIANCE
COMMUNITIES UNITED FOR A JUST TRANSITION
ENERGY DEMOCRACY NATIONAL TOUR 2018
ENERGY DEMOCRACY
ADVANCING EQUITY IN CLEAN ENERGY SOLUTIONS


Coal-Fired
Power Plants
Wenger
DETROIT REDUX 40 YEARS AFTER THE RIOTS
The CRISIS
SPECIAL ISSUE
The Fight For
Environmental
Justice
In spite of governmental
protective laws, people of color
bear the health burden of toxic
soil, polluted water and air that
is foul and contaminated