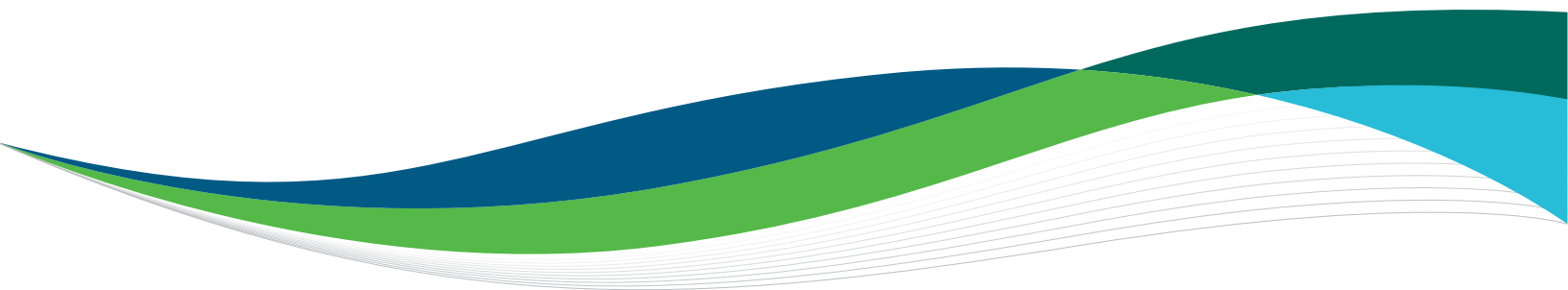


# Volume II

## Attachments



# INDIANA

**2024** | **INTEGRATED**  
DUKE ENERGY | **RESOURCE PLAN**



BUILDING A *SMARTER* ENERGY FUTURE®



## Volume II – Technical Attachments

Attachment A-1 – **Stakeholder Meeting Summaries & Slides**

Attachment A-2 – **Datasite Uploads**

Attachment C-1 – **EnCompass Modeling Inputs & Outputs**

Attachment C-2 – **Ongoing Capital & FOM Costs**

Attachment C-3 – **Projected Bill Impacts**

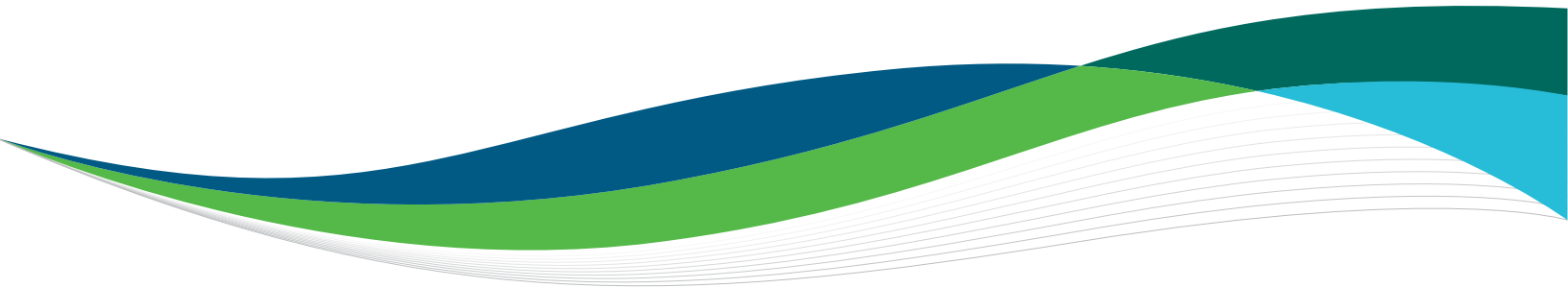
Attachment D-1 – **Additional Load Shapes**

Attachment D-2 – **Load Forecast Files**

Attachment H-1 – **Market Potential Study**

# Attachment A-1

## Stakeholder Meeting Summaries & Slides



# INDIANA

**2024** | **INTEGRATED**  
DUKE ENERGY | **RESOURCE PLAN**



BUILDING A *SMARTER* ENERGY FUTURE®



# Duke Energy Indiana's 2024 Integrated Resource Plan Engagement Session

## FEBRUARY 22, 2024 MEETING SUMMARY

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## Meeting Information

On Thursday, February 22, 2024, Duke Energy Indiana (DEI) convened the first stakeholder meeting to inform the development of the 2024 DEI Integrated Resource Plan. The meeting was held in person at Duke Energy Indiana's Regional Headquarters in Plainfield, Indiana, with the option to attend virtually. Approximately 100 external individuals representing over 50 organizations participated in this session.

## Facilitation Process

To encourage collaboration and to foster an environment where diverse perspectives could be shared, 1898 set forth the following ground rules for the session:

- **Respect each other:**  
Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.
- **Focus on today's topics:**  
Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.
- **Chatham House Rule:**  
Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

## Session Participation

This hybrid event was facilitated by 1898 & Co. and the session included presentations and robust conversations on the following topics:

- 2024 IRP engagement process and timeline
- Review of previous IRP and planned enhancements for 2024
- MISO overview
- Policy updates, including Clean Air Act (CAA) 111 and Inflation Reduction Act (IRA)
- IRP scenario development and analytical framework
- IRP planning objectives and potential scorecard metrics

Attendees who participated in person were asked to raise their hand to ask a question or make a comment. Team members from both Duke Energy and 1898 & Co. called on in-person attendees and walked through the room with microphones so all participants, both in person and online, could hear the questions or comments of participants.

Virtual attendees used the "raise hand" feature in Teams or submitted a question through the "Q&A" feature. Staff from 1898 & Co. took meeting notes, which have been included in the summary. Pursuant to the ground rules, the notes have been anonymized.

If participants had questions after the session or wanted to share feedback or additional information, they were asked to send an email to [DEIndianalRP@1898andco.com](mailto:DEIndianalRP@1898andco.com).

## Access to Meeting Materials

Meeting materials for the February 22, 2024 engagement session were posted to Duke Energy Indiana's IRP website at [duke-energy.com/IndianalRP](https://duke-energy.com/IndianalRP) on February 14, 2024. Participants were asked to visit the website to view the materials and meeting summaries. The 1898 & Co. team will continue to contact stakeholders via email as the website is updated with materials for each session.

## Meeting Notes

*This document includes a high-level summarization of the presentation material as well as the questions and comments made by participants. The questions and comments were captured throughout the meeting; however, the summary herein does not constitute a meeting transcript. Questions and commentary were edited for clarity as needed. Similar summaries will be prepared following each public engagement session throughout this process.*

## Welcome

*Stan Pinegar, Duke Energy Indiana State President*

Mr. Pinegar opened the meeting by welcoming participants and encouraging active engagement in the 2024 IRP process.

## Safety & Introductions

*Karen Hall, Duke Energy Resource Planning Director*

Ms. Hall started with a safety moment discussing heart health before introducing the Duke Energy team that will be supporting the 2024 IRP.

## Meeting Guidelines & Agenda

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk introduced the 1898 & Co. team before discussing the ground rules for the hybrid meeting. These guidelines included respecting each other, staying on topic, and the Chatham House Rule. He also reviewed guidelines for audience participation and the meeting agenda.

## 2024 IRP Engagement Process | Objectives & Commitments

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk first provided a level set of the Integrated Resource Plan (IRP). This includes the IRP having a 20-year planning horizon for serving load, being filed with the Indiana Utility Regulatory Commission (IURC) every three years, providing opportunities for stakeholder input, and resulting in a preferred resource portfolio and short-term action plan.

He then discussed the objectives and commitments of the stakeholder engagement process, including fostering an environment for meaningful conversations, leveraging participants' expertise and experience, building upon areas of agreement, clarifying areas of disagreement, and seeking opportunities for collaboration.

The commitments for this process include prioritizing a transparent environment, conducting technical meetings and timely modeling input data, sharing the process with stakeholders, considering all recommendations from participants, including a wide range of stakeholders, and selecting a preferred portfolio that is informed by proactive and robust engagement.

Mr. Burczyk also highlighted the proposed timeline for the 2024 DEI IRP stakeholder meetings, which includes five (5) total public stakeholder meetings and five (5) technical meetings.

### Q&A related to the engagement process and opening comments

1. Question: Were the materials already distributed?
  - a. Yes, slides were posted on February 14 to [duke-energy.com/IndianaIRP](https://duke-energy.com/IndianaIRP) and distributed via email to registered attendees.
2. Question: Is DEI committed to rapid build out of renewables including investments in residential energy efficiency? Will DEI stop burning coal before 2030?
  - a. We will be evaluating multiple portfolios throughout this process to understand the best path forward. We will have robust engagement to talk through the different alternatives available. We will have opportunities throughout this process to evaluate a host of portfolios related to those items.
3. Question: How have your carbon emissions changed since the 2021 IRP or before that?
  - a. Increasingly clean energy is a key objective in the planning process. While portfolios have not been modeled or determined at this point, there are several proposed scorecard metrics that highlight emissions reduction impacts, which we will share later in this presentation. Emissions reductions over time will be addressed throughout the IRP process. We are in a dynamic environment, especially regarding the impact load growth has on the IRP. We do not have carbon emissions data to present today, but we can discuss this in a future stakeholder meeting.
4. Question: If fossil fuel plants can be closed and go to totally clean energy in Maui, why can't you do it in Indiana?

- a. Every region is different, and we are planning to meet the needs of our customers here in Indiana.
5. Comment: It would be helpful if DEI provided a breakdown of the MW by type of energy changes since the last IRP, and any current RFPs and deployment.
6. Comment: DEI should focus on the goals needed in the long term and consider technological and economic feasibility. Commenter requested that DEI implement a new approach for integrated resource planning by the next planning session.
7. Comment: Commenter would like DEI to develop a community advocacy group that would be able to meet after/during this process so that we could keep our communities updated on what's going on.
8. Comment: Commenter emphasized the importance of a transparent process that puts the customers first.

## Review Previous IRP

*Matt Peterson, Duke Energy Resource Planning Manager*

Mr. Peterson discussed developments since the 2021 IRP, which includes changes to the planning reserve margin as well as supply chain and interconnection constraints. He also explained that DEI issued an RFP and switched from an annual planning to seasonal planning approach to follow MISO's seasonal accreditation construct.

Mr. Peterson discussed that DEI performed additional modeling when the Inflation Reduction Act (IRA) was passed resulting in the 2021 IRP Refresh. Mr. Peterson highlighted that this refresh confirmed DEI's need for a combined cycle and additional renewable resources. Then, DEI performed updated modeling in the fall of 2023 to reflect the impacts of the proposed Clean Air Act rules. That fall, CPCN modeling informed another RFP that was issued in December, which will be used as an input into the 2024 IRP modeling. He also displayed a chart, which showed the outcomes of the IRP refresh and fall CPCN modeling, highlighting that these results helped identify a need for a target of 2,500 MW of non-intermittent resources and 2,500 MW of intermittent resources (including solar, wind and hybrid resources). He also discussed that some coal retirements had to be pushed back to meet planning reserve margins but will still be retired by 2035.

## Q&A related to the review of the previous IRP

1. Question: Is DEI going to do the CPCN filing regardless of the new analysis being conducted now?
  - a. To meet the timeline of when these resources need to come online to replace retiring coal, we need to continue the process of going down the CPCN route.
2. Question: Will the 2024 IRP not be the justification of the CPCN?
  - a. We've completed the 2021 IRP, the IRP refresh, and the latest CPCN modeling all to support potential CPCN filings later this year.

3. Question: What are the differences between Solar, S+S (Solar) and S+S (Storage) on slide 22?
  - a. “Solar” represents any solar capacity that is not paired with storage. “S+S” is “solar plus storage,” and this slide splits out each component separately – the solar capacity that is paired with storage and the storage capacity that is paired with solar.
4. Question: Is there any wind coming online in the future?
  - a. DEI is seeking 2,500 MW of intermittent resources and, as RFP results come in, they will inform this year's IRP modeling. We are waiting on the market responses and will see results over the next couple of months.
5. Question: Regarding slide number 22, are these coal projections being proposed for the 2024 IRP?
  - a. The graph on slide 22 represents the results from previous public modeling exercises, including the IRP Refresh and CPCN modeling. Portfolios have not yet been developed for the 2024 IRP.
6. Question: What do you plan to do with distributed renewable energy sources, especially for houses of worship?
  - a. During the next stakeholder meeting, we will have subject matter experts available to address distributed energy resources.
7. Question: If you could put a number to your current generation in output through DERs, is that something you can do currently? I would also like to see a goal to DERs as well.
  - a. We can pull that data and share it in a future stakeholder meeting.
8. Comment: It would be useful to see how the CPCN modeling compared to the 2021 IRP.
9. Question: If the CPCN modeling is largely in response to new EPA regulation standards, which are stricter on fossil fuel generation, why would the model result in a greater amount of fossil fuel generation?
  - a. The Clean Air Act 111 (“CAA 111”), as the draft is written, has impacts to fossil fuel generation, including coal and natural gas. We have modeled the CAA 111 and have still identified the need for a natural gas CC to replace coal. We are also seeing an increase in load and required reserve margins. We must be able to responsibly retire coal and replace it with generation in a timely manner.

## **IRP Enhancements (What's New in 2024)**

*Matt Kalembe, Duke Energy Vice President, Integrated Resource Planning*

Mr. Kalembe discussed the Director's comments from the 2021 IRP, which included providing more detail on the load forecast, more discussion around demand-side management modeling and analysis, and more open communication with stakeholders. He also discussed what is new in the 2024 IRP, including the IN House Enrolled Act 1007 Pillars, Clean Air Act 111 impacts, Inflation Reduction Act updated assumptions, economic development activity, additional high load sensitivities, changes to planning reserve margins, adjusted unforced capacity, updated MISO Seasonal Accredited Capacity and potentially Direct Loss of Load, updated market potential study, and wind availability study.

## Q&A related to the IRP Enhancements

1. Question: What does DSM stand for?
  - a. DSM stands for demand-side management. DSM will be a selectable resource within the model.
2. Question: How is DEI trying to integrate transmission and distribution planning into the IRP?
  - a. We are actively evaluating opportunities to further integrate the many components of system planning. We will continue to work closely with transmission and distribution planners as we develop our resource plans.
3. Question: Does the Infrastructure Act play a role in the IRP?
  - a. Infrastructure Act funding for utilities is largely focused on grid resilience. There are also IRA dollars available for distributed resources, which play a role in the IRP.
4. Question: Is there a mechanism in this IRP process to evaluate emerging technologies like long-duration energy storage?
  - a. DEI is evaluating emerging technologies, and in a future session, we will discuss the resources we can allow the model to select, including types of energy storage.
5. Question: In the director's comments, what do you mean by net metering input assumptions and why is that important?
  - a. Duke Energy develops forecasts for net metering (behind-the-meter solar adoption) within each of our jurisdictions. The net metering forecast is an input into our forecast for load expectations over the next 20 years, as behind-the-meter resources impact forecasted demand and load patterns.
6. Question: What are the challenges to developing wind projects and are you looking at those as an opportunity to balance some of the intermittency issues with solar as well as battery storage as alternatives to fossil-based generation?
  - a. We are assessing this as part of our wind viability study, and we have opened the RFP for sourcing wind outside of Zone 6.
7. Question: Is Duke Energy looking at any residential energy storage for helping people be more resilient against residential outages?
  - a. Duke Energy offers various residential customer programs. We will discuss distributed resources pertaining to the IRP in a future session and recommend visiting our website to learn more about specific programs.

## MISO Overview

*Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Lind provided an overview of MISO, which is an independent member-based organization focused on the reliable operations of the high-voltage electric transmission system across its region, and of which Duke Energy Indiana is a member. He highlighted several ways in which MISO works on reliability of its system, including ancillary services to support the operational balance of supply and demand, energy markets where energy is bought and sold, and resource adequacy in which MISO works with state regulators to ensure there are enough resources to keep the lights on in all hours. He also discussed how the MISO energy mix has changed historically (with coal being replaced by other resources) and the plans moving forward (with planning projections suggesting that by 2030 an estimated 20% of production will likely come from wind and solar as more thermal units are retired).

Mr. Lind also provided a MISO capacity overview, highlighting MISO Planning Reserve Margin Requirement (PRMR) rules, Seasonal Accredited Capacity (SAC) and Effective Load Carrying Capability (ELCC) studies and MISO capacity auctions. He also discussed the generation interconnection (GI) queue, emphasizing that resources entering the GI queue increase annually and that there are currently 1,317 projects totaling 228 GW in the queue. He also highlighted that MISO continues to study and refine resource accreditation methodologies in addition to focusing on the six critical system attributes that have been identified with assistance from stakeholders (availability, long-duration energy at high output, fuel assurance, rapid startup, ramp-up capability and voltage stability).

## Q&A related to the MISO Overview

1. Question: Would Duke Energy support legislation (such as the current HB 1193) allowing third-party owned community solar projects within Indiana?
  - a. DEI is unable to discuss potential support of proposed legislation in this specific forum.
2. Question: Is capacity relative to demand? How can we minimize the requirements for increased transmission?
  - a. The capacity obligation can be met through incremental energy production and, on the demand side, through efficiency savings and load curtailments. There are going to be different costs and tradeoffs to what the profile in the IRP looks like.
3. Question: Could you discuss the NERC study that came out in December that showed MISO at a particularly high risk for capacity and to what extent are you including the backup necessary for storage with CC plants to provide the security necessary?
  - a. One option is backup fuel oil as an alternative to firm capacity. We are evaluating that and including as an option in the IRP. Additionally, DEI looks at, depending on our pipeline situation, how firm is firm transport.
4. Question: Will new CPCN include option for dual fuel?
  - a. This is still to be determined.

5. Question: Does DEI's permit for the new plant include a provision for dual fuel capability?
  - a. We have filed for a permit, which did not include dual fuel capability.
6. Question: If you are generating all the time, where does the extra end up and in what form?
  - a. In order for the grid to work, the supply and demand has to be near equal or it will result in imbalances and blackouts due to equipment failure. Individual utilities may generate higher than what their local demand is, but across the MISO footprint, utilities are interconnected, and the supply and demand must be balanced across system.
7. Comment: Commenter wants the supply of the increased demand from EVs to be clean energy.
8. Question: Can DEI include distributed resource generation as well as community solar to help with the demand of EVs?
  - a. Yes, demand-side resources are included in resource planning. We are assuming an uptick in EV adoption in our load forecast, and we are going to evaluate what resources best meet that demand. As we develop portfolios, we will see portfolios with an increasing mix of distributed generation.
9. Comment: Commenter states that Indiana Michigan Power is planning to complete an upgrade of their distribution system, and they announced a customer collaborative process to incent and educate customers to provide more resources.
10. Question: To what extent will Duke Energy be engaging in that same type of upgrade (as the Indiana Michigan Power comment above) to increase the capacity of the distribution system and inject resources to meet more load through these resources? Will DEI permit third parties to construct facilities that sell generation connected to the distribution system to Duke Energy that can be used in community solar projects?
  - a. Duke Energy is doing a lot of work on programs and technologies in this realm. Around third-party solar, we agree there are funds out there that we are working toward applying for, and there are programs Duke Energy would be interested in exploring further.
11. Question: You mentioned community solar, but the state house did not hear the bill that would allow community solar. What were you talking about when you were talking about community solar?
  - a. We were talking holistically about distributed solar as a resource option.
12. Comment: We do not have community solar in Indiana. Would Duke Energy lobby our legislators to pass legislation that supports community solar?
  - a. DEI is unable to discuss potential support of legislation in this specific forum.
13. Comment: Under PURPA, all utilities have a legally enforceable obligation to purchase renewable energy from facilities of 5 MW or less. In terms of what Duke Energy has talked with us about, the Solar for all program you're essentially doing community solar demonstration projects. You don't need additional statutory authorization.



## Clean Air Act (CAA) 111 Overview

*Taylor Meredith, Duke Energy Federal Government Affairs Director*

Ms. Meredith discussed the various components of the proposed EPA CAA Section 111, highlighting compliance pathways for coal, existing natural gas, and new natural gas resources. For coal resources, the pathways include plants retiring by the end of 2031, plants retiring by the end of 2034 with a 20% capacity factor limitation, plants retiring by the end of 2039 with an 18% emission rate reduction based on 40% gas co-firing, and plants operating beyond 2039 with installation of 90% carbon capture and sequestration by 2030. She also explained that for existing natural gas units of more than 300 MW and operating above a 50% capacity factor, there is a performance standard of 1,000 lb. CO<sub>2</sub>/MWh or current permit standard followed by reducing capacity factor, green hydrogen or CCS. For new natural gas, she discussed that units built after May 23, 2023, have a proposed standard of 770 lb./MWh for baseload units followed by reducing capacity factor, green hydrogen or CCS.

### Q&A related to the Clean Air Act (CAA) 111 Overview

1. Question: To be able to operate a plant all the way through the year, DEI would need to underuse it before the winter. Has DEI calculated what that translation is?
  - a. Presumably you would see higher usage in summer and winter and less in the shoulder months. When we model hour by hour, it will solve for that parameter and limit utilization to meet 50% on the annual basis.
2. Question: Are upstream methane releases included in the calculation of emissions for this rule?
  - a. No, the emissions are based on the performance of the individual unit.
3. Question: Is there any accounting for greenhouse gas emissions in the production of the hydrogen?
  - a. We assume the EPA will require use of green hydrogen. There are other EPA rulemakings regulating carbon emissions from upstream sources. This rule is focused on the performance of natural gas and coal units.
4. Question: Is carbon capture and sequestration ("CCS") something that is being included in your modeling? I thought Edwardsport was carbon capture ready, so how is that working?
  - a. DEI will be considering CCS in the 2024 IRP, but whether it's a base assumption or sensitivity has not been determined. There is a study going on with the DOE at Edwardsport looking at CCS.
5. Comment: Commenter identifies clean and equitable energy as including solar, wind, energy efficiency and geothermal. Commenter feels that hydrogen and CCS are rooted in false solutions.
6. Question: Where will these hydrogen sites be located?
  - a. This has not yet been determined. Siting for hydrogen production or other resources is not included in the IRP process.
7. Question: Did you all determine that this is considered the most cost-effective model?

- a. These are the technologies EPA proposed as “the best system of emission reduction” in their proposed rule.
- 8. Question: To what extent is Duke Energy looking at turbines that would be able to use green hydrogen? Is this something for the 2040s or when would you expect to look at this?
  - a. The assumption is that turbines that are selectable in the 2024 IRP are green hydrogen capable. This will be a good conversation in our future session where we plan to discuss selectable resources.

## **Incorporating the Inflation Reduction Act (IRA)**

*Jennifer Poppler, Duke Energy Principal Planning Analyst*

Ms. Poppler discussed investment tax credits (ITC) and production tax credits (PTC), emphasizing that ITCs are the only option for storage, but either ITC or PTC can be utilized for most other non-carbon emitting resources. She also highlighted that, in general, capital-intensive projects fare better under ITC and high-capacity factor projects fare better under PTC. She explained that for ITCs all that is required is building a zero-carbon emitting resource whereas PTCs are based on production of the resource. Ms. Poppler displayed a visual, which showed that there is a 50% max credit for ITCs and a \$36/MWh max credit for PTCs (illustrative as PTCs inflate over time). She also went into detail on the three types of energy communities (coal closure category, statistical area category and brownfield category) and DEI's assumption that the energy community bonus is available on 60% of solar, 60% of wind and 100% of batteries. She then displayed a chart that outlines the current IRA supply-side modeling assumptions by resource type.

## **Q&A related to Incorporating the Inflation Reduction Act (IRA)**

- 1. Question: To what extent does the modeling and load forecasting take into consideration IRA incentives for customers and the extent to which taking advantage of those incentives could impact electric demand?
  - a. That topic is squarely in the agenda of our next session, where we will do a deep dive on tax incentive assumptions for EV and rooftop solar forecasts along with other supporting programs.
- 2. Question: Has Duke Energy considered customer programs in Indiana like the “Pay to Save” energy efficiency and distributed energy production program that exists in North Carolina?
  - a. We plan to discuss EE/DSM opportunities and program assumptions related to the IRP in our upcoming session.
- 3. Question: Can you explain the difference between SMR and advanced nuclear on your chart?
  - a. SMRs are small modular reactors, which are similar to the nuclear technology utilized by today's commercial operating fleet but are smaller. Advanced nuclear on this chart represents advanced reactors that are paired with storage. We

called these out separately since IRA modeling assumptions are different for new nuclear with and without storage.

## Scenario Development

*Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning*

Mr. Kalembo provided some key definitions for scenario, reference scenario, sensitivity, and stochastics for context of how these terms will be used in the 2024 IRP process. He then explained the goal of developing scenarios that reflect vastly different future outcomes and determining how those future outcomes could impact resource plan modeling inputs. He then walked through the three proposed scenarios (aggressive policy and rapid innovation, reference, and minimum policy and lagging innovation) and how the variables change across each. Mr. Kalembo then walked through the process of utilizing worldview scenarios to analyze different generation strategies, with each generation strategy being modeled under the reference scenario to determine initial candidate portfolios, followed by modeling the generation strategies under the alternate scenarios and performing scenario analysis against each portfolio. He then walked through the overall analytical framework and what the scorecard could look like at a high level. He expressed that the goal of the scorecard is to evaluate a diverse set of portfolios using meaningful metrics for each planning objective.

## Q&A related to Scenario Development

1. Question: How will DEI be measuring resiliency?
  - a. We will discuss the proposed measures for resiliency in the next section of the presentation today.
2. Question: Is it possible that we can see DEI's modeling assumptions?
  - a. Yes, we plan to share assumptions. Certain inputs may be confidential and require a nondisclosure agreement.
3. Question: With the last IRP, wasn't there a discussion about a scenario described as deep decarbonization and rapid electrification (DDRE)? What has come of that, and will that be considered in this IRP?
  - a. Yes, we are proposing to incorporate the DDRE scenario you mentioned as part of the high distributed resource strategy portfolio. DEI is also developing multiple load forecasts including an ultra-high forecast using the DDRE inputs we received from stakeholders, and we will run each of the generation strategies through the different load forecasts. This will show how the high distributed resource generation strategy and other generation strategies perform across different levels of electrification.
4. Follow-up Question: These worldviews here all look like they are based on external factors. What happened to internal policies like corporate sustainability goals and corporate responsibility?
  - a. In the metrics, we will be able to see how different portfolios perform against our objectives and goals. The worldview scenarios serve to test each portfolio

against several variables including external policies, while the metrics allow comparison between portfolios and show how they perform with respect to our planning objectives such as environmental sustainability.

5. Question: How are you thinking about accounting for the Good Neighbor Rule, which is under contention, in your modeling?
  - a. We may not have the exact answer for you today, so we'd like to come back to you in a future meeting. To some extent it will show up in the inputs. There would be a change in allowance prices, and depending on when the rule is final, we will have to be explicit in where we are saying the rule is implemented. If it's not final, then it might be a scenario or a sensitivity analysis. We will discuss that, and it will be interesting to test what the impacts are.
6. Comment: Duke Energy should consider adding diversity, equity and inclusion to the scorecard.
7. Question: To what extent are we incorporating policy choices as opposed to real-world consequences in our alternative futures? The Europeans look at how what we're doing mitigates or aggravates real-world consequences and the extent to which you have things like the collapse of the banking system.
  - a. Each worldview scenario will drive very different outcomes by changing variables that we can control in the model. The analysis does not attempt to predict how portfolios impact the banking sector or other sectors.

## **IRP Planning Objectives & Potential Scorecard Metrics**

*Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning*

Mr. Kalembo summarized House Enrolled Act (HEA) 1007 Requirements and the five pillars: Reliability, Resiliency, Stability, Environmental Sustainability, and Affordability. Mr. Kalembo discussed how the five pillars, as well as consideration of risk and uncertainty, inform the scorecard metrics and that each plays a role in selecting the preferred portfolio.

Mr. Kalembo emphasized the desire for and importance of stakeholder feedback in determining the scorecard metrics. He also noted that no single metric can determine a preferred portfolio – that all metrics must be considered holistically to compare candidate portfolios and assess the tradeoffs amongst different resource plans. Mr. Kalembo then discussed each of the proposed scorecard metrics grouped by the planning objective categories of Environmental Sustainability, Affordability, Reliability, Resiliency, Stability, and Risk & Uncertainty, which was further broken down into Cost Risk, Market Exposure, and Execution Risk.

## **Q&A related to Planning Objectives & Potential Scorecard Metrics**

1. Comment: DEI did not post all Q&A for the past IRP engagement process.
2. Question: If DEI considers 2005 the baseline for CO<sub>2</sub> reduction, is it considering all reduction since 2005?
  - a. Yes

3. Question: Does this IRP go out to 2044?
  - a. Yes, it is 20 years to the end of 2044.
4. Comment: DEI should account for all Scope 1 and relative Scope 3 emissions.
5. Question: Do you levelize the capital costs?
  - a. The costs are levelized over the life of the asset.
6. Question: As far as these metrics are concerned, are they inputs or outputs?
  - a. These metrics would measure the outputs of the model.
7. Question: When we are talking about a metric, what is the unit (e.g., high, low, medium)?
  - a. We do not plan to weight the metrics, as in, not weighting one metric over another. The metrics are for comparative purposes across portfolios, looking at comparative numbers from modeling outputs. We are proposing quantitative metrics and trying to avoid subjective measures.
8. Question: Are these the only metrics you are considering? (asked during the first metrics slide)
  - a. No. We have four or five more slides with more proposed metrics, and we are seeking your feedback on other possible metrics DEI should consider.
9. Question: As you look at the CO<sub>2</sub> emissions reduction, will your model show where the reductions are in ethnically diverse and disadvantaged communities and give some kind of credit in the modeling that you are reducing CO<sub>2</sub> emissions in those particular areas?
  - a. That is an interesting concept we'd have to think about. The model is location agnostic, so the CO<sub>2</sub> emissions metric provided by the modeling is on a system scale.
10. Comment: Going back to environmental sustainability objectives, consider adding the percentage of carbon reduction as a measure. This would match your cumulative CO<sub>2</sub> reduction but in terms of percentages.
11. Comment: Commenter states the metrics are set up as a way that says we must have more natural gas because we can't be reliable without that. Commenter thinks there should be attention to energy efficiency, and states that 10% of households in Indiana are facing their utilities being turned off. Commenter states he/she sees nothing that addresses that in the metrics.
12. Question: Will customer rate impact look at customer classes as well as a breakdown of impacts within classes, especially between different residential usage and income levels? Is that level of detail possible?
  - a. The metric we've proposed here is the overall rate impact. I'm not sure the level of detail possible, so we can take that back and see how that would work.
13. Comment: We've had tornadoes, floods, severe windstorms before Duke Energy finally came around and started cutting trees. That has to play into your power delivery.
14. Follow-up Comment: It does seem like you need goals and say how you want to do things better. Maintenance means you have a system in place for checking things.
15. Question: With the 95th percentile metric, what year are you looking at and is that a year in the portfolio that you are worried about there being a surplus in MISO?
  - a. When looking at what year would represent the 95th percentile, the data goes back to the 1980s. We think it would be meaningful to evaluate the measure in the year after our largest coal retirement, but we are open to suggestions.

16. Comment: In regard to CO<sub>2</sub> sequestering, we have two counties concerned about the safety of it because they are on a fault line in west central Indiana. Commenter states they don't want to clean the air at the expense of the community.
17. Comment: Commenter believes it would be cost effective to do pilot programs on little things like virtual power plants and would be a cheap way to get data quickly.
18. Question: How is the maintenance and operation risk of facilities being evaluated?
  - a. We account for cost of ongoing maintenance. The risk component would be an interesting piece to review.
19. Comment: On weighting these risks, commenter states he/she is on the fence on whether they should be weighted, citing that if we don't weight them, the stakeholder biases in this process are not addressed. Commenter concludes that some biases are good, some are bad, and we need to discuss them.
20. Comment: Commenter doesn't want Duke Energy to lose money, but also doesn't want them to overcharge consumers. Commenter suggests some measurement of sustainability of the utility and indicates profitability may not be the right metric.
21. Comment: A lot of metrics, particularly nameplate capacity, seem to be putting renewable portfolios in a negative light and natural gas portfolios in a positive light. Some metrics might give bad information that would bias decisions in the transition to cleaner resources.
22. Question: When you look at risk when it comes to hydrogen, nuclear and CCS, are risks factored in as it relates to impacting disadvantaged and ethnically diverse communities, since you don't know where you are placing those right now?
  - a. The proposed metric for new technology additions is intended to capture overall risk associated with the technologies you referenced. We welcome feedback on how a metric around this issue could make its way into the IRP.

## Next Steps & Closing

*Karen Hall, Duke Energy Resource Planning Director*

Ms. Hall thanked stakeholders for their participation and feedback. She asked participants to continue the conversation by sharing feedback and comments to [DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com). She called out that the next stakeholder meeting will take place toward the end of April and asked stakeholders to look for an invitation to register.

## Q&A related to Next Steps & Closing

1. Question: Will you be publishing all of the Q&A?
  - a. Yes, a meeting summary including summarized topics and Q&A from the session will be posted to the Duke Energy Indiana IRP website [duke-energy.com/IndianaIRP](https://duke-energy.com/IndianaIRP).
2. Question: Will comments and feedback be published as well without attributions to any organizations?
  - a. Correct. There are no attributions to individuals or organizations.



# 2024 Duke Energy Indiana Integrated Resource Plan Public Stakeholder Meeting 1

*FEBRUARY 22<sup>nd</sup>, 2024*



BUILDING A **SMARTER** ENERGY FUTURE®



# Welcome





**Duke Energy Welcome**  
**Stan Pinegar**  
State President, Duke Energy Indiana



# Safety

# Location safety



## General Area Evacuation Procedures

If you hear or see evacuation alarms in your area:

- Move safely and quickly out of the building.
- Encourage others around you to evacuate.
- As appropriate, gather in the assembly area and await further instruction.

## Shelter in Place

In the event of severe weather, move away from windows to the center of the building. Stairwells, interior rooms, restrooms or similar locations will provide protection.

## Evacuation Assembly Areas

- The primary evacuation route is through the lobby where you entered. The secondary is through the side door at the stairwell at the back of this room.
- The assembly point is located inside the perimeter fence in the grassy area and/or parking lot near the East poles utilized for training.

## AED

An AED is located in the Mail/Copy/Print Room number 01105

## Location Information for Emergency Dispatchers

Floor 1 Medium Conference Room 00197 of Duke Energy's 50's Building, 1000 E. Main Street, Plainfield IN 46168

# Safety - February is American Heart Month



For additional information on  
**American Heart Month**  
and keeping your heart healthy, visit

[https://www.cdc.gov/heartdisease/american\\_heart\\_month.htm](https://www.cdc.gov/heartdisease/american_heart_month.htm)

<https://www.nhlbi.nih.gov/health-topics/education-and-awareness/heart-month/animated-gifs>



# Introductions



Integrated Resource Planning Team



**Matt Kalembe**  
*Vice President,  
Integrated Resource  
Planning*



**Nate Gagnon**  
*Managing Director,  
Midwest Integrated  
Resource Planning*



**Matt Peterson**  
*Resource  
Planning Manager*



**Emma Goodnow**  
*Market Strategy &  
Intelligence Director*



**Karen Hall**  
*Resource  
Planning Director*



**Chris Hixson**  
*Principal Engineer,  
Resource Modeling*



**Josh Paragas**  
*Engineer, Resource  
Modeling*



**Tyler Cook**  
*Engineer, Resource  
Modeling*

Indiana Regulatory and Legal Team



**Kelley Karn**  
*Vice President,  
Indiana Regulatory  
Affairs and Policy*



**Beth  
Heneghan**  
*Deputy General  
Counsel*



**Liane Steffes**  
*Associate  
General Counsel*



**Taylor Meredith**  
*Federal Government  
Affairs Director*



**Vicky  
Sullivan**  
*Climate Policy  
Director*



**Jennifer  
Poppler**  
*Principal Planning  
Analyst*

CAA 111 Overview

Incorporating the IRA

# Stakeholder Meeting Host: 1898 & Co.

**1898 & Co. is the business, technology and security consultancy part of Burns & McDonnell.**

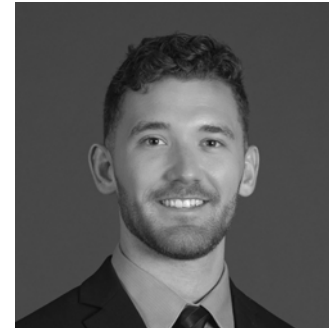
- The Resource Planning & Market Assessments group has been working on Integrated Resource Plans for over 20 Years.
  - Helping utilities in Indiana and across the US plan for the future.
- Today and throughout the IRP Process, our team will help to facilitate the stakeholder meetings.
- We look forward to working with, and hearing from you all.



**Matt Lind**  
*Director*



**Drew Burczyk**  
*Project Manager*



**Loren Carlisle**  
*Lead Analyst*



**Carinna Marling**  
*Analyst*



# Meeting Guidelines



# Meeting Ground Rules



## **Respect each other:**

Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

## **Focus on today's topics:**

Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.

## **Chatham House Rule:**

Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

# Participation



There will be several opportunities throughout the presentation for attendees to actively participate by asking questions, making comments and/or otherwise sharing information.

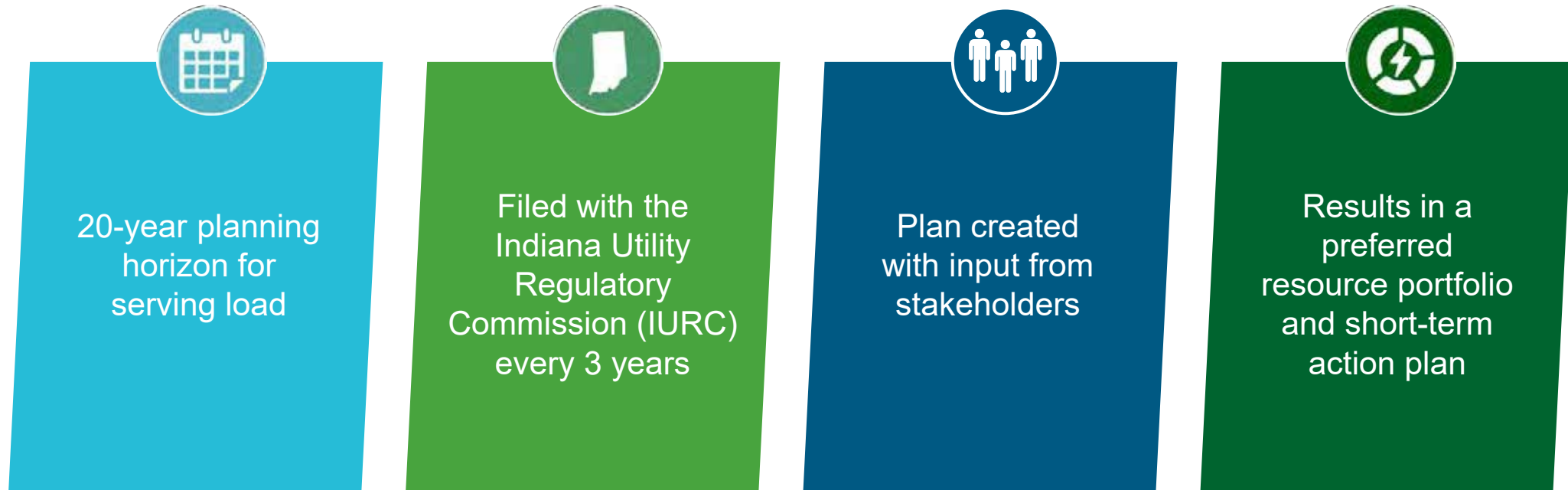
- **Q&A:** Please use the “Q&A” feature, on the menu at the bottom of your screen, to submit questions to the presenters. We will respond to as many of these as possible, time permitting, during designated time periods.
- **Raise hand:** If you wish to ask a question or make a comment orally, please use the “raise hand” feature, during designated time periods. A facilitator will call on you and invite you to unmute.
- **Chat:** The chat feature is enabled for sharing information and resources with other participants; however, it is sometimes difficult to monitor. If you would like a response from the presenters, please use the Q&A or raise hand features.

Time	Duration	Present   Discuss	Topic	Presenter
9:30	30		Sign-in & Refreshments	
10:00	5	5   0	Welcome	Stan Pinegar, Duke Energy Indiana State President
10:05	10	10   0	Safety & Introductions	Karen Hall, Duke Energy Resource Planning Director
10:15	10	10   0	Meeting Guidelines & Agenda	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:25	10	10   0	2024 IRP Engagement Process   Objectives & Commitments	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:35	15	10   5	Review Previous IRP	Matt Peterson, Duke Energy Resource Planning Manager
10:50	15	10   5	IRP Enhancements (What's new in 2024)	Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning
11:05	10	5   5	Proposed Timeline	Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning
11:15	25	15   10	MISO Overview	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
11:40	50		LUNCH	
12:30	15	10   5	Clean Air Act (CAA) 111 Overview	Taylor Meredith, Duke Energy Federal Government Affairs Director Vicky Sullivan, Duke Energy Climate Policy Director
12:45	15	10   5	Incorporating the Inflation Reduction Act (IRA)	Jennifer Poppler, Duke Energy Principal Planning Analyst
1:00	30	15   15	Scenario Development	Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning
1:30	10	5   5	IRP Planning Objectives	Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning
1:40	15	5   10	Potential Measures of Environmental Sustainability & Affordability	Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning
1:55	15	5   10	Potential Measures of Reliability, Resiliency and Stability	Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning
2:10	15	5   10	Potential Measures of Risk & Uncertainty	Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning
2:25	5	5   0	Next Steps & Closing	Drew Burczyk & Karen Hall
2:30			Adjourn	



# Engagement Process Objectives & Commitments

# Level Set | Indiana Integrated Resource Plan (IRP)



*“Preferred resource portfolio means the utility's selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration.”<sup>11</sup>*



# Stakeholder Engagement Objectives



- Foster an environment that enables meaningful conversations around resource planning that prioritizes affordability, reliability and increasingly clean energy for customers
- Leverage participants' expertise and experience which represent a wide range of perspectives
- Build upon areas of agreement, clarify areas of disagreement, and seek opportunities for collaboration

# Commitments for 2024 IRP Engagement

*In developing the 2024 IRP, Duke Energy will...*



Prioritize broad, transparent and inclusive participation through meaningful encounters



Conduct technical meetings and timely share modeling input data with interested stakeholders who sign a non-disclosure agreement



Share the process including the roadmap and engagement schedule with stakeholders



Consider all recommendations and comments offered by participants



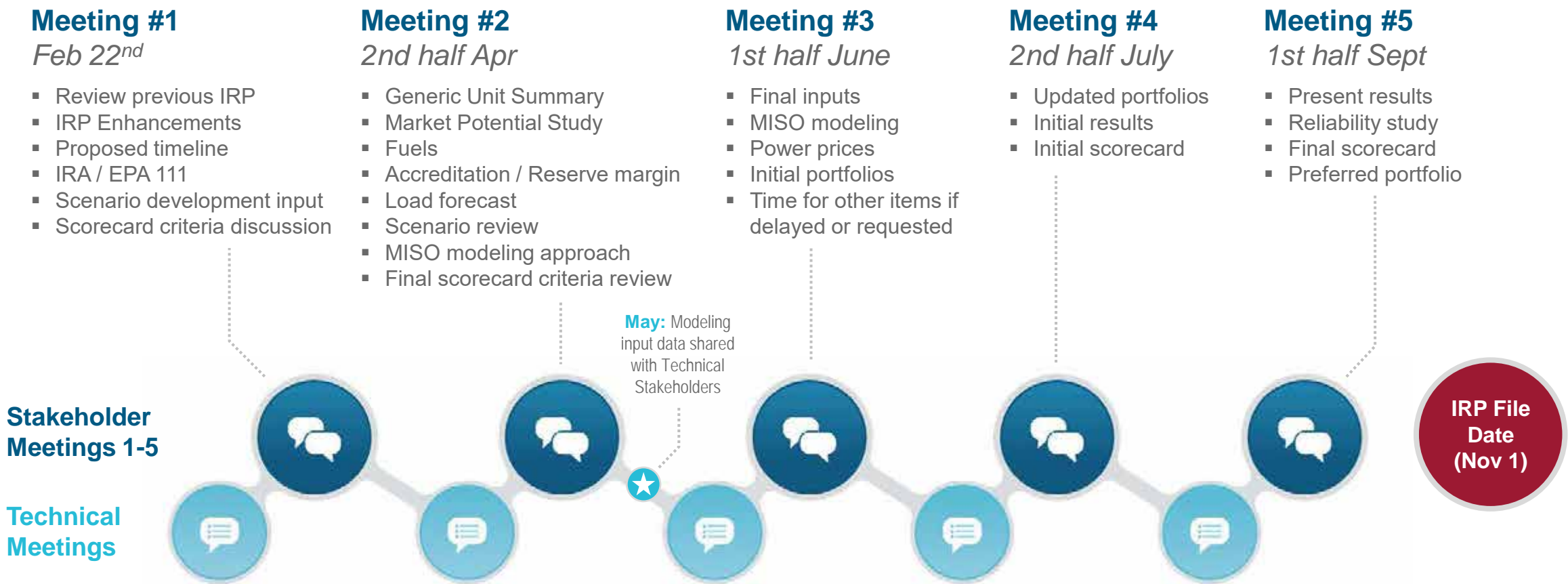
Include a wide range of stakeholders in engagement process



Select a preferred portfolio that is informed by proactive and robust engagement

# 2024 DEI IRP Stakeholder Meetings *(proposed timeline)*

*Engaging with our stakeholders in multiple sessions throughout the 2024 IRP process*





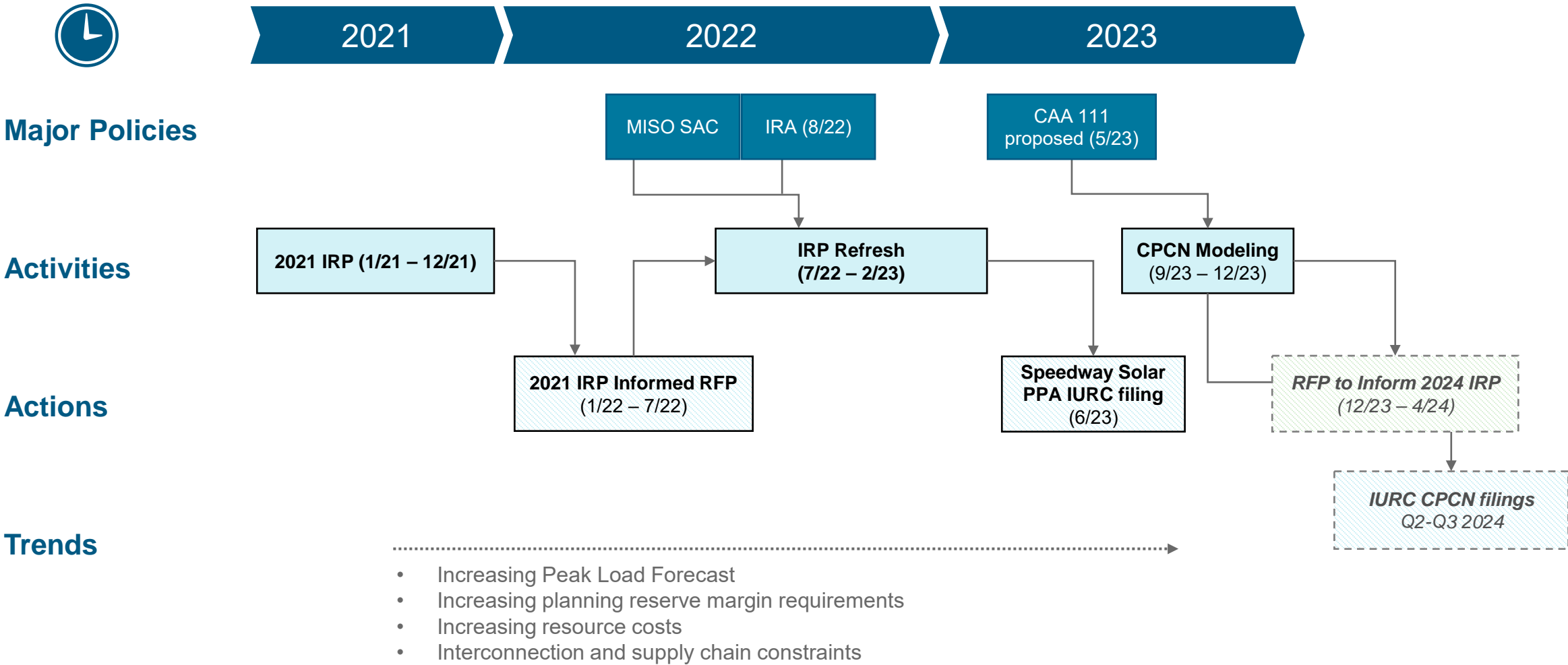


# Q&A



# Review Previous IRP

# 2021 to 2023 Timeline

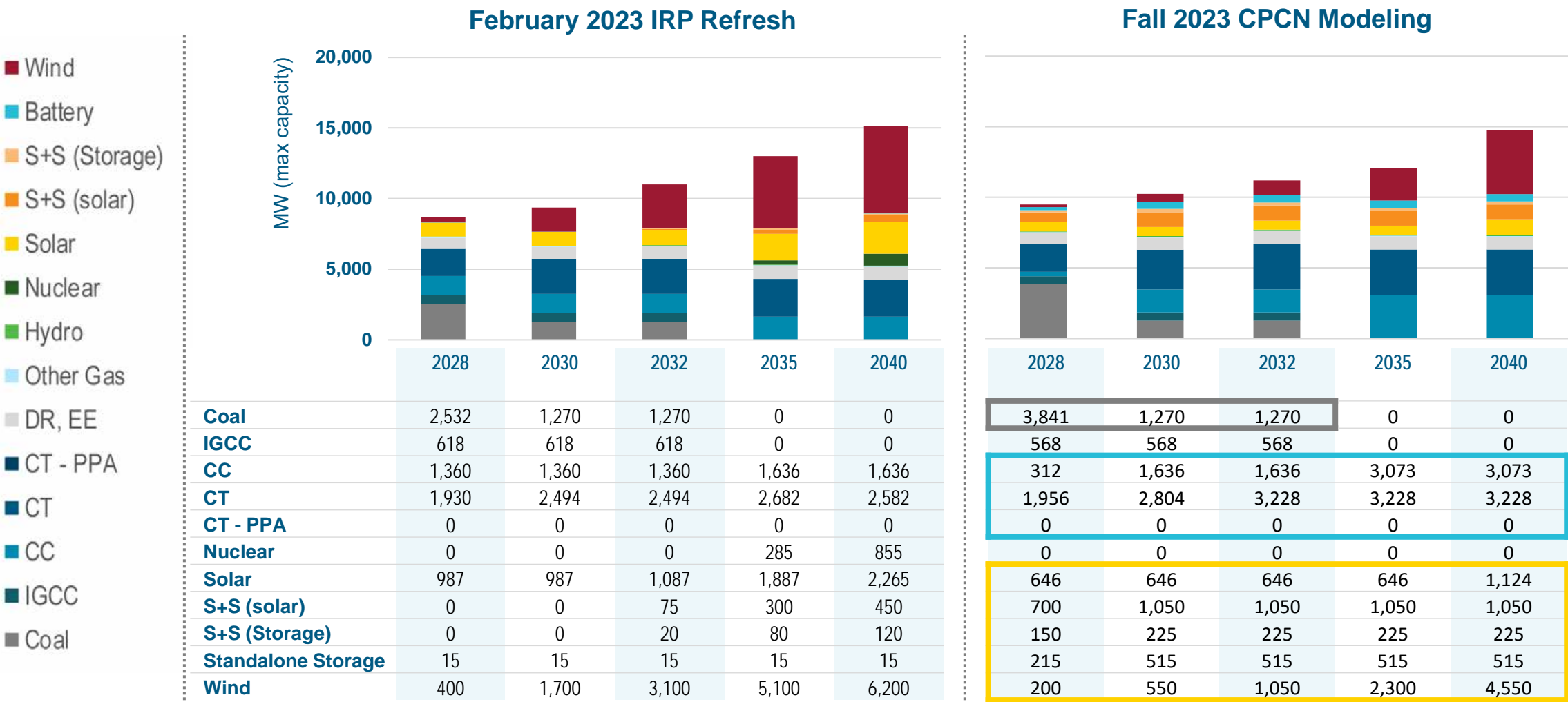


MISO: Midcontinent Independent System Operator  
SAC: Seasonal Accreditation Construct  
IRA: Inflation Reduction Act

CAA: Clean Air Act  
RFP: Request for Proposal  
CPCN: Certificate of Public Convenience and Necessity

PPA: Power Purchase Agreement

# Outcomes of February ‘23 Refresh and Fall’23 CPCN Modeling



# Outcomes from 2023 CPCN modeling



- 2023 Fall Update Modeling (presented in December 2023 to stakeholders)
  - Informed RFP issued in December 2023 for resources through 2032
    - Targeting 2,500 MW of non-intermittent resources (CC, CT, Storage)
    - Targeting 2,500 MW of intermittent resources (solar and wind, including hybrid)
- Supported plans for potential filing of CPCNs for new CC and solar generation in 2024
  - DEI applied for an air permit Jan 17th to maintain the option for adding natural gas CC generation at Cayuga station



*BUILDING A SMARTER ENERGY FUTURE®*

# Q&A





# IRP Enhancements

# Incorporating Director's Comments from 2021 IRP



## Load Forecast

*Would like more detail on how load is forecasted and increased information to evaluate the methodology & assumptions*

- Add much more of the data behind the load forecast (e.g., Itron results) to IRP document
- Deeper discussion of electric vehicle (EV) and net metering input assumptions and provide more granular output information
- Discussion of economic development opportunities



## DSM

*Limited discussion of EE and DR modeling and associated analysis*

- Full discussion of energy efficiency and demand response assumptions in stakeholder process and IRP document
- Describe how the Market Potential Study (MPS) is incorporated in the IRP document
- Add MPS report as an attachment to document



## Public Advisory Meetings & Stakeholder Engagement

*Session content lacking in substance and tone.  
Tone did not encourage open discussion.  
Must be more forthcoming about key parts of analysis.*

- Benchmarked stakeholder processes across other Indiana utilities
- Met with IURC and other stakeholders to gather direct feedback to develop stakeholder engagement plan for the 2024 IRP process
- Incorporating technical stakeholder meetings, in addition to public meetings, for deeper engagement and more frequent communication throughout the IRP process
- Providing robust content in all sessions and designating time for open discussion throughout each session's agenda

# What's New in the 2024 IRP



- IN House Enrolled Act (HEA) 1007 Pillars
  - Evaluating Stochastic Analysis to measure robustness of portfolios
  - Enhanced Reliability Verification Analysis (Resource Adequacy of portfolios)
- Including Clean Air Act (CAA) 111 impacts
- Adjustments to Inflation Reduction Act (IRA) assumptions
- Significant economic development activity
- Additional high load sensitivities
- Increase in planning reserve margins leading to winter planning vs historically summer planning
- Adjusted unforced capacity (UCAP) to reflect recent capacity accreditation
- Updates to MISO Seasonal Accredited Capacity (SAC), and potentially Direct Loss of Load (DLOL) methodologies
- Updated Market Potential Study
- Wind availability study



# Q&A

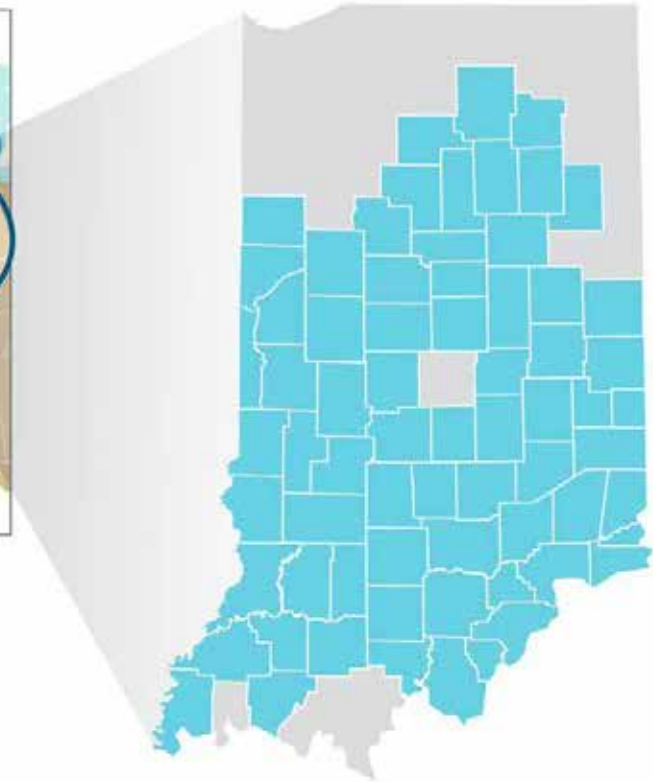


# MISO Overview



# Midcontinent Independent System Operator (MISO)

- MISO is an Independent, not-for-profit, member-based organization focused on managing the flow of high-voltage electricity across its region.
  - Duke Energy Indiana is a member of MISO.
- MISO became the nation's first FERC-approved Regional Transmission Organization (RTO) on December 20, 2001
- MISO is divided into 10 Local Resources Zones (LRZ)
  - Duke Energy Indiana operates in MISO LRZ 6.
- Several inputs, assumptions, and other parts of this IRP will reference policy changes or updates from MISO that impact Duke Energy Indiana



SERVICE TERRITORIES (counties served)  
Duke Energy Indiana



# Reliability Through Market Products

## Ancillary Services

*Services necessary to support the operational balance of energy supply and demand.*

- Synchronized Regulation
- Contingency Reserves
- Black Start Regulation
- Flexibility Reserves

## Energy Markets

*Energy is bought and sold through wholesale and retail energy markets.*

- Real Time Market
- Day Ahead Market
- Financial Transmission Rights (FTR)
- Auction Revenue Rights (ARR)

## Resource Adequacy

*MISO in concert with state regulators works to ensure there are enough resources in place to keep the lights on in all hours.*

- Seasonal Resource Adequacy
- Resource Effective Load Carrying Capability (ELCC)
- Direct Loss-Of-Load (DLOL)

**Near Term**

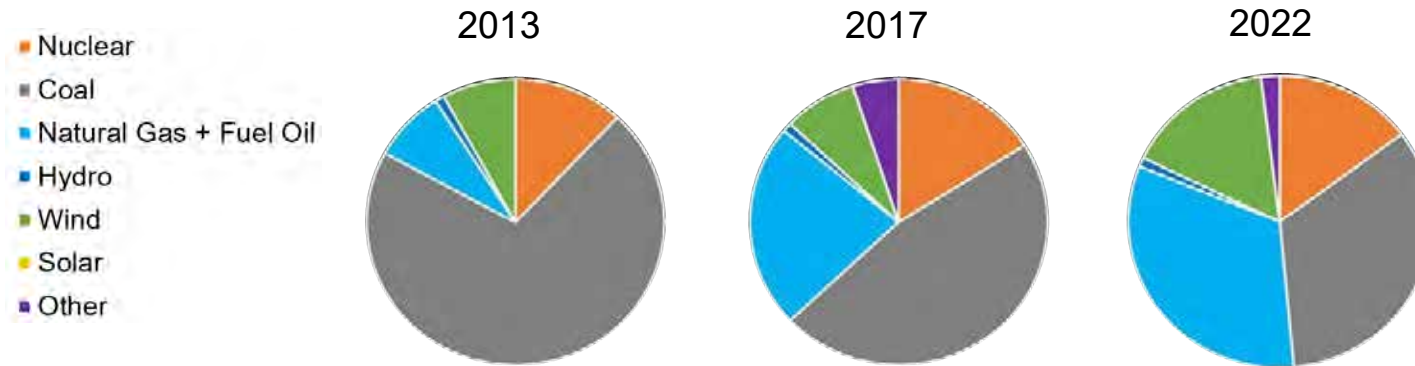
**Long Term**

[MISO Market Basics \(misoenergy.org\)](http://misoenergy.org)



*Redefined markets need to be robust for potential volumes of participating resources projected in MISO's future scenarios*

## MISO Energy Mix



## MISO Forward Planning

- Market reforms over the past decade have successfully increased efficiency and adapted markets with industry change.
- Planning projections suggest that by 2030, an estimated 20% of transmission connected production will likely come from wind and solar, and more thermal units will retire.



State Of The Market | Potomac Economics  
[Redefining Energy and Ancillary Services Markets \(misoenergy.org\)](https://misoenergy.org)

# MISO Capacity Overview

## MISO PRMR + Rules

- Load Serving Entities (LSE) are required to procure capacity to meet their Planning Reserve Margin Requirement (PRMR), which can be met with capacity provided from generating resources or purchased via Capacity Auction.

## SAC + ELCC Studies

- Seasonal Accredited Capacity (SAC) scores are evaluated by MISO to assign resource capacity values for each season.
- Effective Load Carrying Capability (ELCC) studies utilize Loss of Load Expectation (LOLE) to aid in determining the capacity values for wind and solar generation.

## Capacity Auction

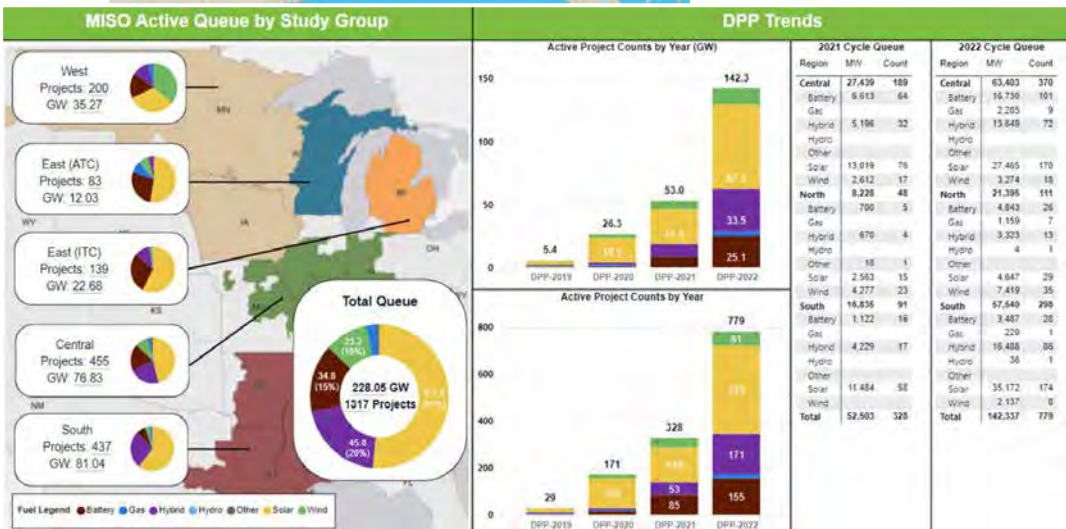
- MISO holds a seasonal Planning Resource Auction (PRA) which helps ensure resource adequacy requirements are met.
- The capacity auction is incremental.
- PRAs procure needs above and beyond what is already secured.

# MISO Generation Interconnection Queue (GI)

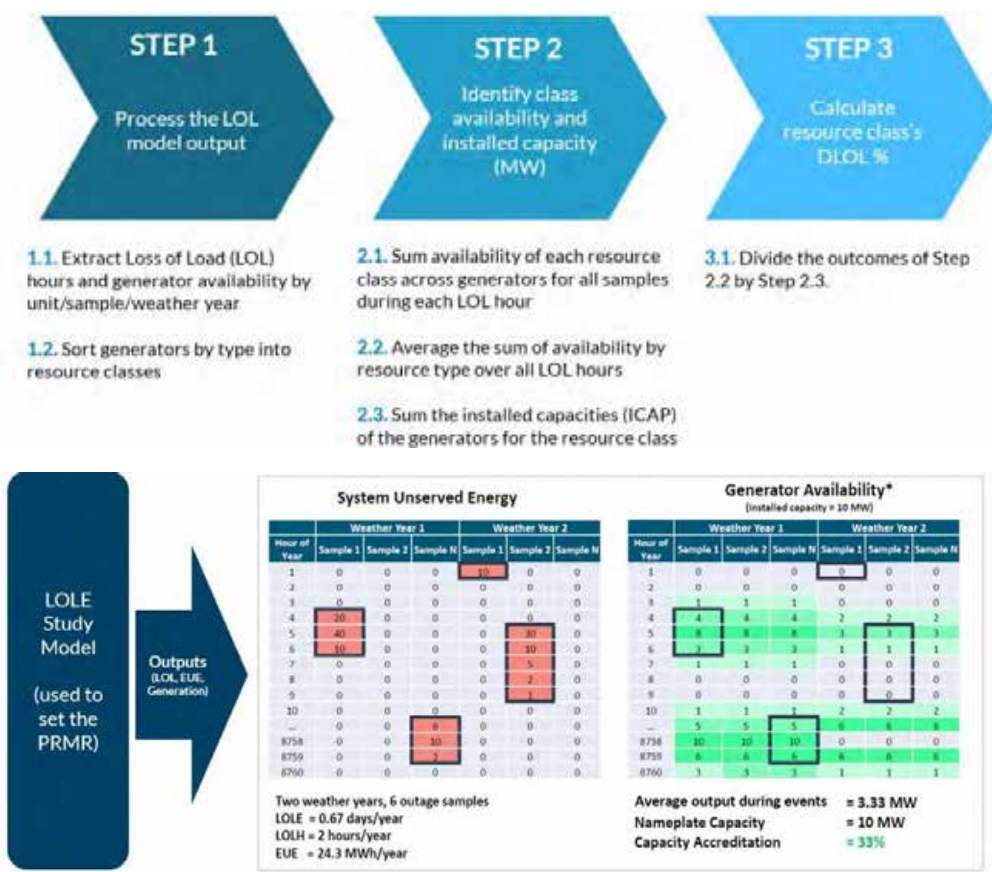
- The number of resources entering MISO GI queue has been increasing annually.
- There are currently 1317 projects totaling 228 GW currently in the MISO queue.
- Projects go through the GI process to determine the grid upgrades needed to interconnect and the associated costs.
- MISO has been working on process updates associated with the GI Queue.



[GI Queue MISO Energy](#)



# Seasonal Resource Adequacy



Summer



Fall



Winter



Spring

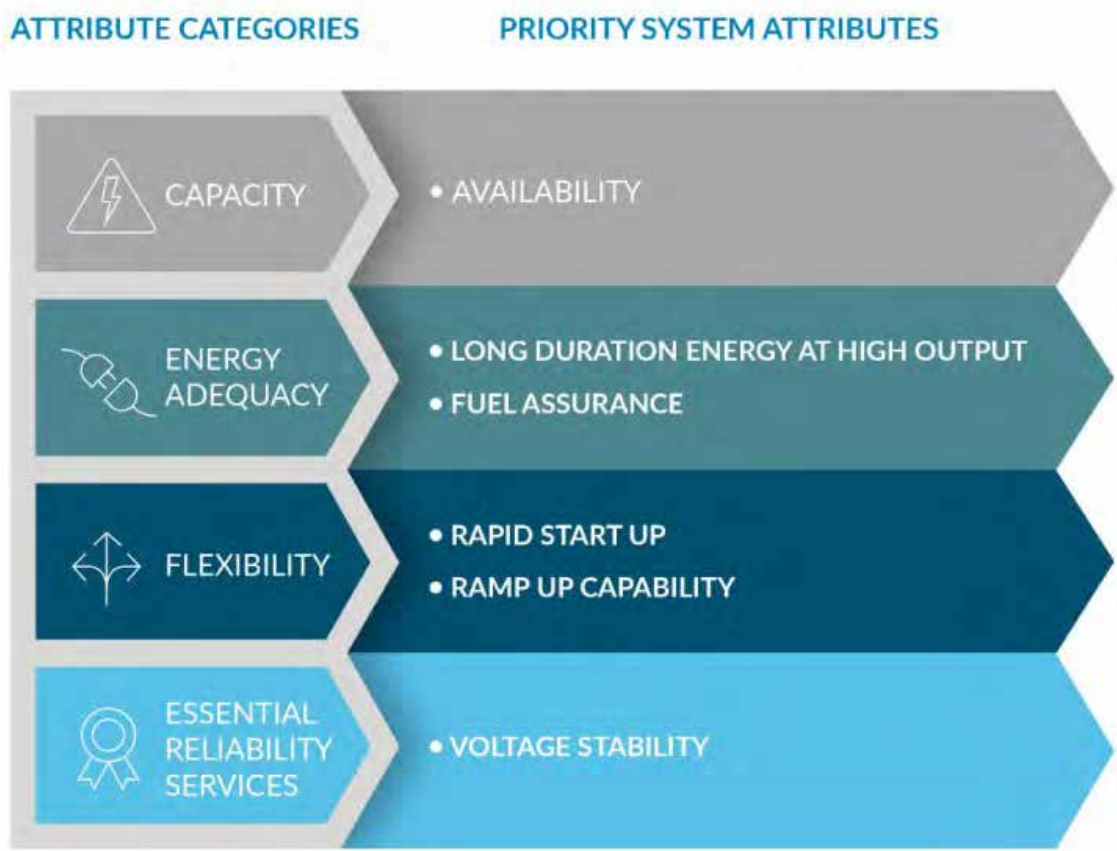
- MISO is continuing to study and refine resource accreditation methodologies.
- Discussed further during future Technical Stakeholder meetings.



# Reliability Imperative and System Attributes

## Critical System Attributes

- Fall 2022 MISO Launched an initiative in the public stakeholder process to identify which critical system attributes may become scarce due to fleet changes.
- MISO and its stakeholder seek to quantify how much of each critical attribute the system will need to continue to evolve.
- MISO has proposed six (6) “priority system attributes” in four categories.



[MISO’S Response to the reliability imperative \(misoenergy.org\)](https://misoenergy.org)





# Q&A



# Lunch



# Clean Air Act 111 (CAA 111)

# Proposed EPA CAA Section 111 rule components

Year	Coal				Year	Existing Gas			New Gas	
	Imminent	Near-term	Medium-term	Long-term						
2030	Retire without changes by 12/31/31	20% capacity factor (CF) limitation and retire by 12/31/34	Emission rate reduction (16%) based on 40% gas co-firing and retire by 12/31/39	Install 90% carbon capture and sequestration (CCS) by 2030 to operate beyond 2039	(Phase 1)	For units >300 MW and with >50% CF, performance standard of 1000 lb CO <sub>2</sub> /MWh or current permit standard, followed by reducing CF, H <sub>2</sub> , or CCS path:			Final standards apply to units built after 5/23/23. Proposed standard is 770 lb/MWh for baseload units, followed by H <sub>2</sub> or CCS path:	
2031										
2032					2032 (Phase 2)		30% green H <sub>2</sub> (12% reduction)		30% green H <sub>2</sub> (680 lbs/MWh)	
2034										
2035					2035	Impose 50% CF*		90% CCS (89% reduction)		90% CCS (90 lbs/MWh)
2038					2038 (Phase 3)		96% green H <sub>2</sub> (88.4% reduction)		96% green H <sub>2</sub> (90 lbs/MWh)	
2039										

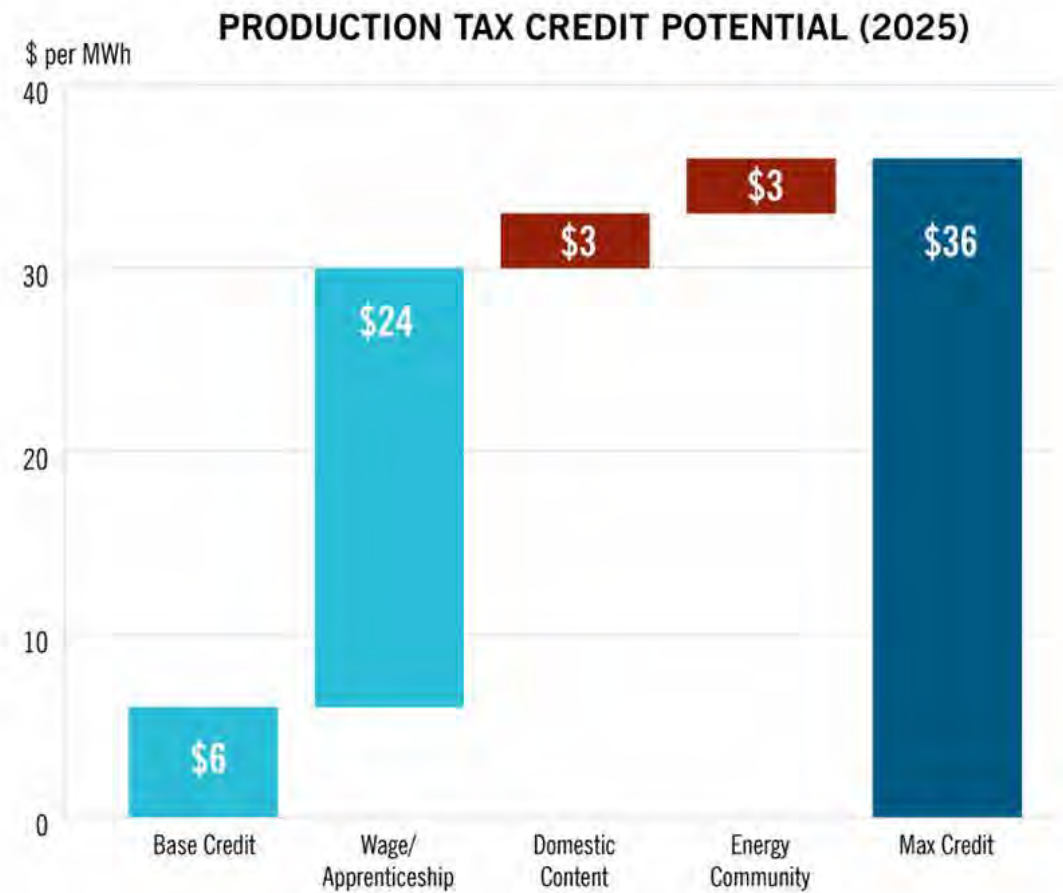
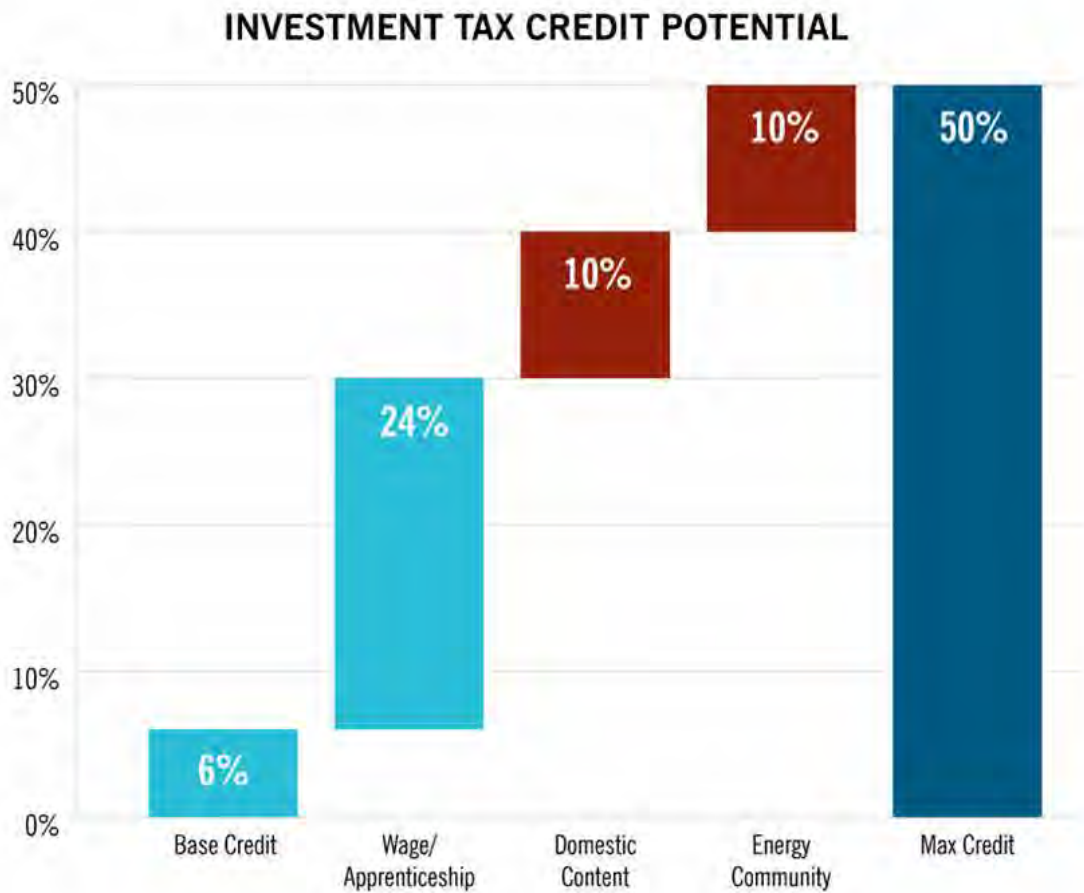
- EPA assumed existing gas units would adopt a 50% capacity factor (CF) limitation in 2035 in the analysis for the proposed rules.



# Incorporating the Inflation Reduction Act (IRA)



# Investment Tax Credit (ITC) & Production Tax Credit (PTC) Potential Ranges



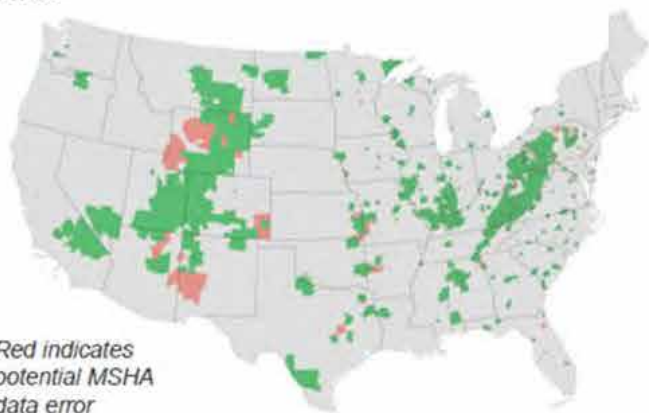
<5 MW solar, wind and associated storage can receive up to 70% ITC with statutory limits



# IRA – Energy Communities

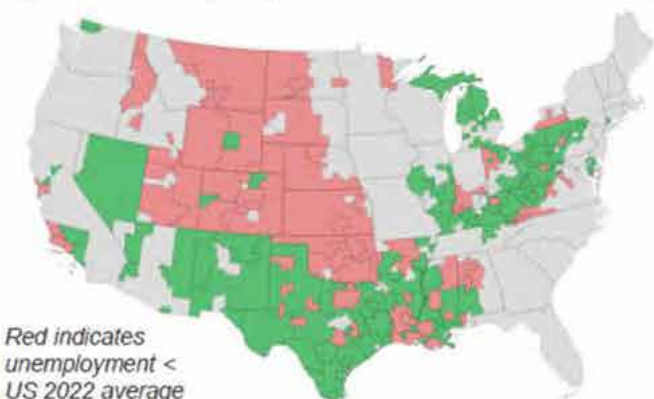
## Coal Closure Category

Census tracts neighboring retired coal mines or coal-fired electric generating units



## Statistical Area Category

Metro / sub-state areas with historical employment in fossil industries **and** higher unemployment than US average



## Brownfield Category

Properties with the potential presence of hazardous substances, pollutants, or contaminants



DEI assumes Energy Community bonus on 60% of solar, 60% of wind and 100% of batteries.

Maps from CRA, Inflation Reduction Act Energy Communities, April 13, 2023, Presentation

# Current IRA Supply Side Modeling Assumptions

	Base (PTC->45Y)	Base (ITC-> 48)	Bonus Wage&App	Bonus Energy Comm	Bonus Dom Content	PTC Modeling	ITC Modeling
<i>SMR</i>	Yes	No	Yes	No	No	W&A PTC	N/A
<i>Standalone Solar</i>	Yes	No	Yes	60%	No	1.06xW&A PTC	N/A
<i>Wind Pre-2030</i>	Yes	No	Yes	60%	No	1.06xW&A PTC	N/A
<i>Wind 2030 - 2034</i>	Yes	No	Yes	60%	Yes	1.06x1.05xW&A PTC	N/A
<i>Wind 2035+</i>	Yes	No	Yes	60%	Yes	1.06x1.1xW&A PTC	N/A
<i>Solar + Storage</i>							
<i>Solar</i>	Yes	No	Yes	60%	No	1.06xW&A PTC	N/A
<i>Storage</i>	No	Yes	Yes	60%	No	N/A	36% ITC
<i>Advanced Nuclear</i>							
<i>Nuclear</i>	Yes	No	Yes	No	No	W&A PTC	N/A
<i>Storage</i>	No	Yes	Yes	No	No	N/A	30% ITC
<i>Standalone Storage</i>	No	Yes	Yes	Yes	No	N/A	40% ITC

	Incentive	Bonus Wage&App	Tax Credit Description	Phase Out
<i>CCS</i>	45Q	Yes	12 Years of Tax Credits @ \$85/Metric Ton of CO <sub>2</sub> Captured & Sequestered	Construction Must Begin by 12/31/32; Safe Harbor available
<i>Hydrogen</i>	45V	Yes	10 Years of Tax Credits @ \$3/kg Hydrogen Produced (<.45 kg of CO <sub>2</sub> e/kg)	Construction Must Begin by 12/31/32; Safe Harbor available

Assumption of 10% discount for credit transfers prior to 1/1/29 for PTCs & ITCs; CCS credits will be transferred in Year 6+ of operation at a 10% discount.  
 Assume tax incentives do not phase out during planning period.  
 All PTCs are earned over the first 10 years of production  
 Wage & Apprenticeship (W&A): Project wages must be equal to or greater than local prevailing wages; certain percentage of work hours must be performed by qualified apprentices



# Q&A



# Scenario Development

# Key Definitions



## Scenario Analysis

### Scenario:

*“Worldview”*

- Potential futures outlining how external trends could influence **many key variables** impacting a resource plan. These potential futures enable us to test a portfolio’s performance across a diverse range of future world landscapes.
- In scenario analysis, many assumptions are changed at once to reflect a vastly different overall view of the future.

### Reference Scenario:

*“Most likely future scenario”*

- 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.<sup>[1]</sup>
- Includes existing laws and policies.



## Risk Analysis

### Sensitivity:

*Single Variable*

- Sensitivity analysis stresses a **single variable** while holding all else constant to isolate the impact of that variable. This provides insight into the risk associated with specific key variables that are difficult to know with certainty.

### Stochastics:

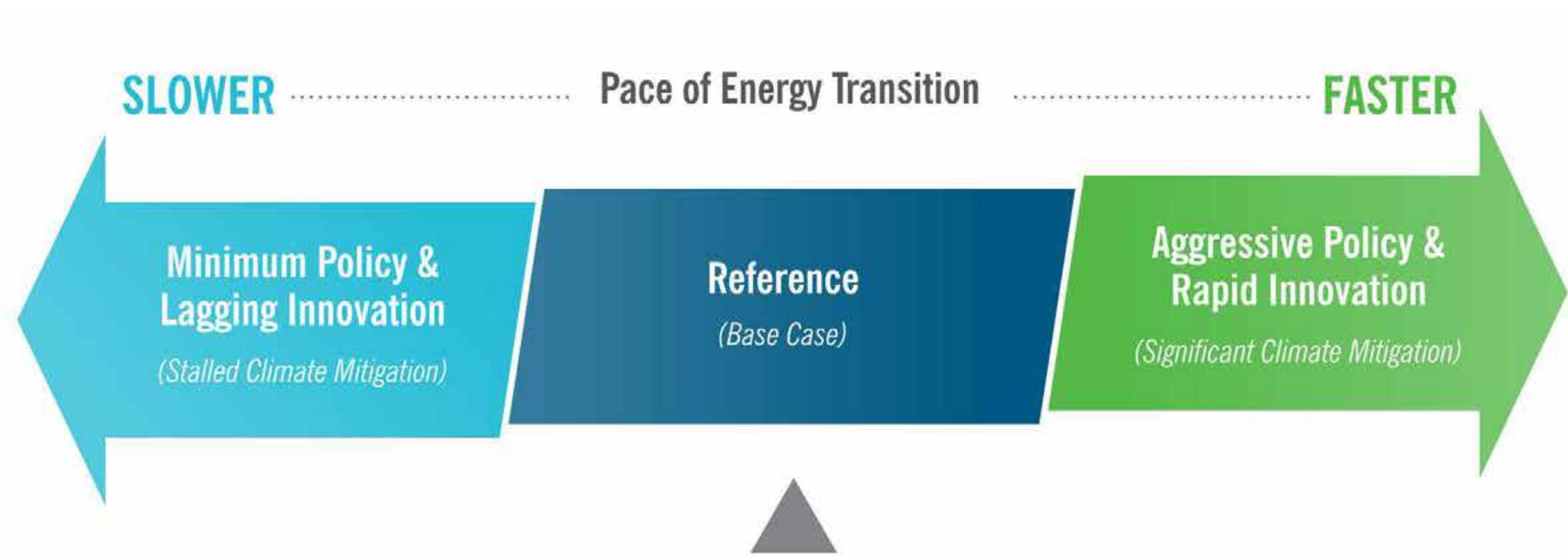
*Multivariate Risk / Probabilistic Risk Analysis*

- Tests selected candidate portfolios against a range of potential inputs such as weather, prices, and generation performance, which have elements of uncertainty that may be analyzed statistically but may not be predicted precisely.

<sup>[1]</sup>170 Ind. Admin. Code 4-7-4



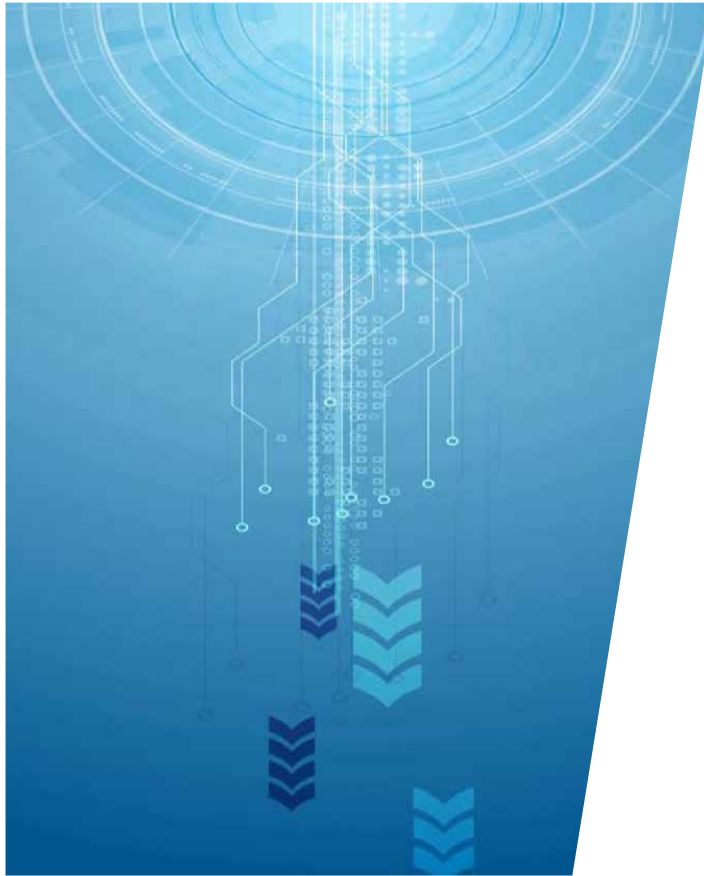
# Proposed Scenarios | “Worldviews”



Goal: Develop scenarios that (A) reflect vastly different future outcomes than the reference case and (B) where the fundamental drivers of those divergent futures could plausibly impact many resource plan modeling inputs.



# Considerations



- Scenarios and sensitivities should not be construed as policy goals.
- The Aggressive Policy & Rapid Innovation and Minimum Policy & Lagging Innovation scenarios are not predictions of the future. Instead, they are vastly varying futures developed to **intentionally push the boundaries** on what may be viewed as possible future outcomes.
- Scenarios and sensitivities serve as stressors to test how different future resource plans perform relative to each other with respect to the IRP planning objectives.

# Proposed Scenarios | Variables Across Worldviews

	CAA 111	Coal Price	Gas Price	IRA	Resource Availability (interconnection timing)	CO <sub>2</sub> Tax	Renewables & Storage Cost	Distributed Resources (incl. net metering)	Emerging Technology
Aggressive Policy & Rapid Innovation	Phases 1-3	High	High	Extend + Domestic Content	High Renew. Availability (Base in Near-Term; High in Long-Term)	High	Low	High	Earlier & More Options Available
Reference	Final Rule	Base	Base	Extend	Base	None	Base	Base	Base
Minimum Policy & Lagging Innovation	Repeal	Low	Low	Repeal	Base	None	Base	Low	Later & Less Options Available

# Scenario Narrative | Aggressive Policy & Rapid Innovation

	CAA 111	Coal Price	Gas Price	IRA	Resource Availability (interconnection timing)	CO <sub>2</sub> Tax	Renewables & Storage Cost	Distributed Resources (incl. net metering)	Emerging Technology
Aggressive Policy & Rapid Innovation	Phases 1-3	High	High	Extend + Domestic Content	High Renew. Avail. (Base in Near-Term; High in Long-Term)	High	Low	High	Earlier & More Options Avail.

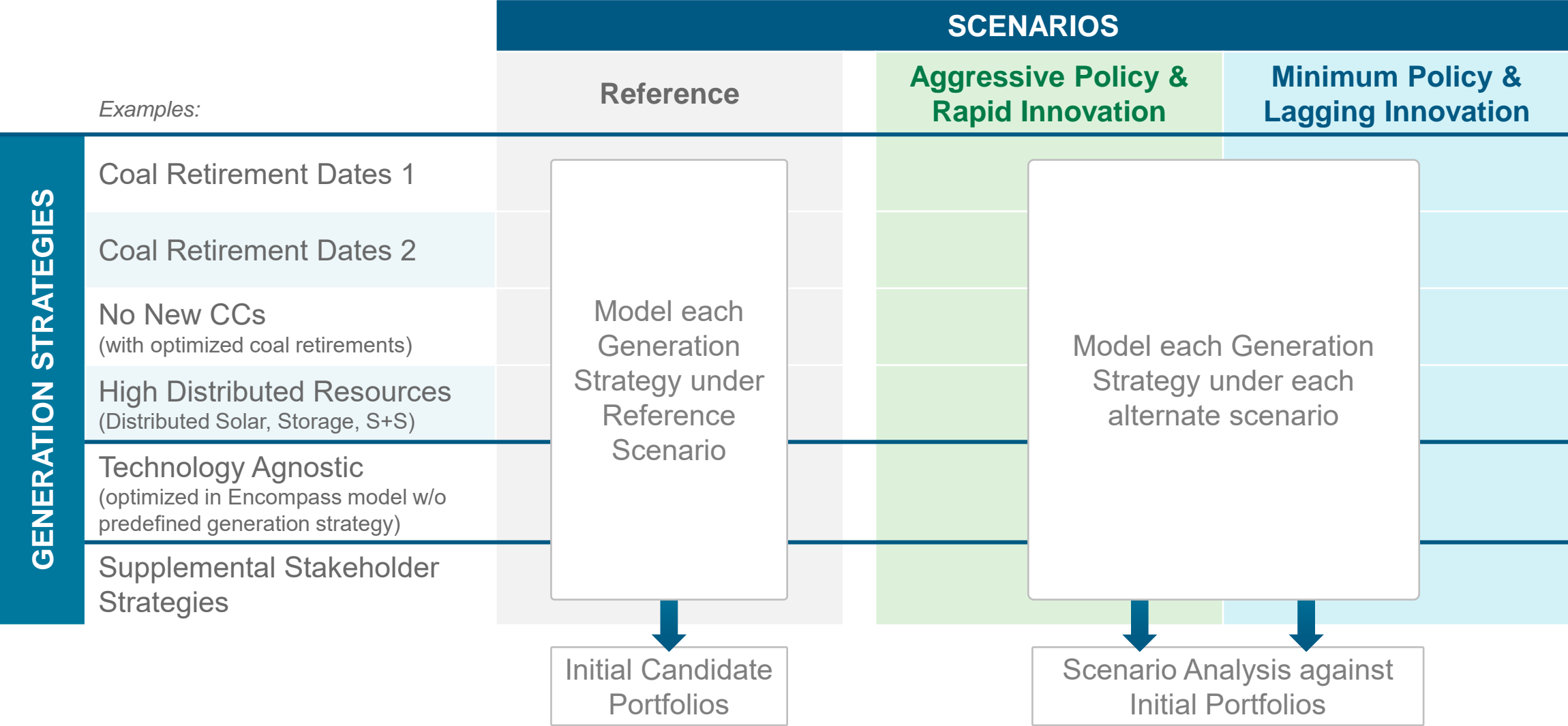
- **CAA 111:** Complete implementation.
- **Coal Prices:** Aggressive regulation limits supply, driving higher prices.
- **Gas Prices:** Aggressive regulation constrains supply, driving higher prices.
- **IRA:** Extended and enhanced IRA incentives, including additional incentives for domestic content.
- **Resource Availability:** Interconnection availability consistent with base in near-term (3-7 years). Favorable transmission and queue reform is enacted to enable higher interconnection of renewable resources in the longer-term planning horizon (8+ years).
- **CO<sub>2</sub> Tax:** Legislation passed for high CO<sub>2</sub> tax. Implemented by 2030.
- **Renewables & Storage Cost:** Extension of favorable government incentives towards renewables and storage reduces overall cost.
- **Distributed Resources (DER):** Favorable government incentives available to customers to implement distributed renewables and storage drives higher adoption.
- **Emerging Technology:** Increased incentives for emerging technology research and development will drive commercialization and increased availability of new resource options at a faster pace than reasonably expected.

# Scenario Narrative | Minimum Policy & Lagging Innovation

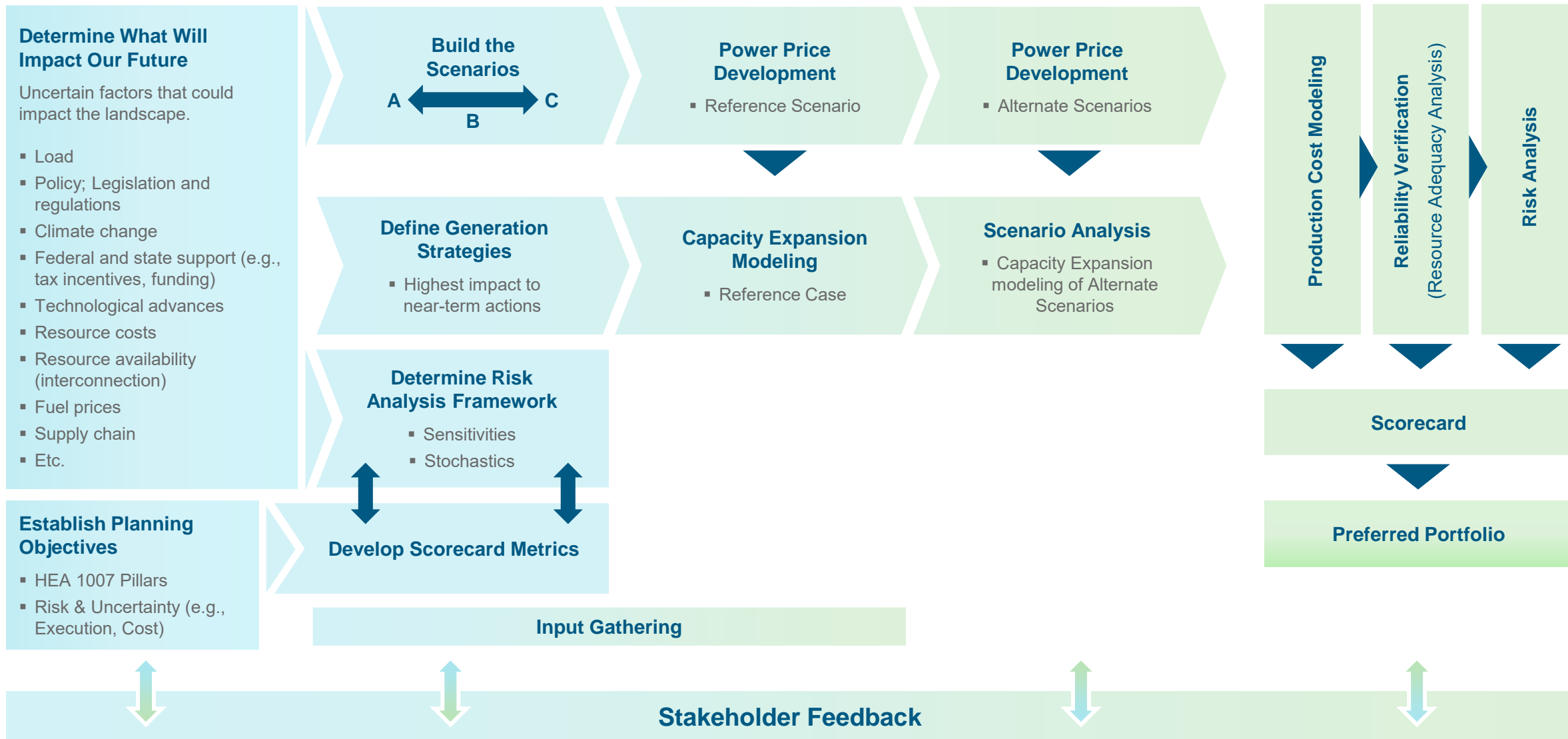
	CAA 111	Coal Price	Gas Price	IRA	Resource Availability (interconnection timing)	CO <sub>2</sub> Tax	Renewables & Storage Cost	Distributed Resources (incl. net metering)	Emerging Technology
Minimum Policy & Lagging Innovation	Repeal	Low	Low	Repeal	Base	None	Base	Low	Later & Less Options Avail.

- **CAA 111:** Stayed and repealed prior to implementation.
- **Coal Prices:** Less government regulation drives price competition amongst competing fuels.
- **Gas Prices:** Less government regulation drives price competition amongst competing fuels.
- **IRA:** Repealed by 2025.
- **Resource Availability:** Interconnection availability consistent with base case.
- **CO<sub>2</sub> Tax:** No CO<sub>2</sub> tax legislation.
- **Renewables & Storage Cost:** Reduced government incentives for renewables and storage increases overall cost but is offset by tempered demand.
- **Distributed Resources (DER):** Reduced government incentives available to implement distributed renewables and storage, driving lesser adoption.
- **Emerging Technology:** Lack of incentives for emerging technology research and development leads to delayed commercialization and insufficient infrastructure to enable new resource technology availability.

# Analytical Framework | Preliminary Run Matrix



# Analytical Framework





# What the Scorecard could look like

- Goal: evaluate diverse set of portfolios on Scorecard

		Reliability		Resiliency		Stability		Affordability		Environmental Sustainability		Risk	
Portfolios		Metric	Metric	Metric	Metric	Metric	Metric	Metric	Metric	Metric	Metric	Metric	Metric
PREDEFINED GEN. STRATEGIES	Coal Retirements 1												
	Coal Retirements 2												
	No New CCs (Optimized retirements)												
	High Distributed Resources (Distributed Solar, Storage, S+S)												
TECHNOLOGY AGNOSTIC	Technology Agnostic (Reference Scenario)												
	Technology Agnostic (Aggressive Policy & Rapid Innovation)												
	Technology Agnostic (Minimum Policy & Lagging Innovation)												
STAKE-HOLDER	Stakeholder Strategy A												
	Stakeholder Strategy B												

Diverse set of **Portfolios**

Metric(s) for each **Planning Objective**

Metrics informed by **Scenario Analysis** and **Risk Analysis** (sensitivities & stochastics)

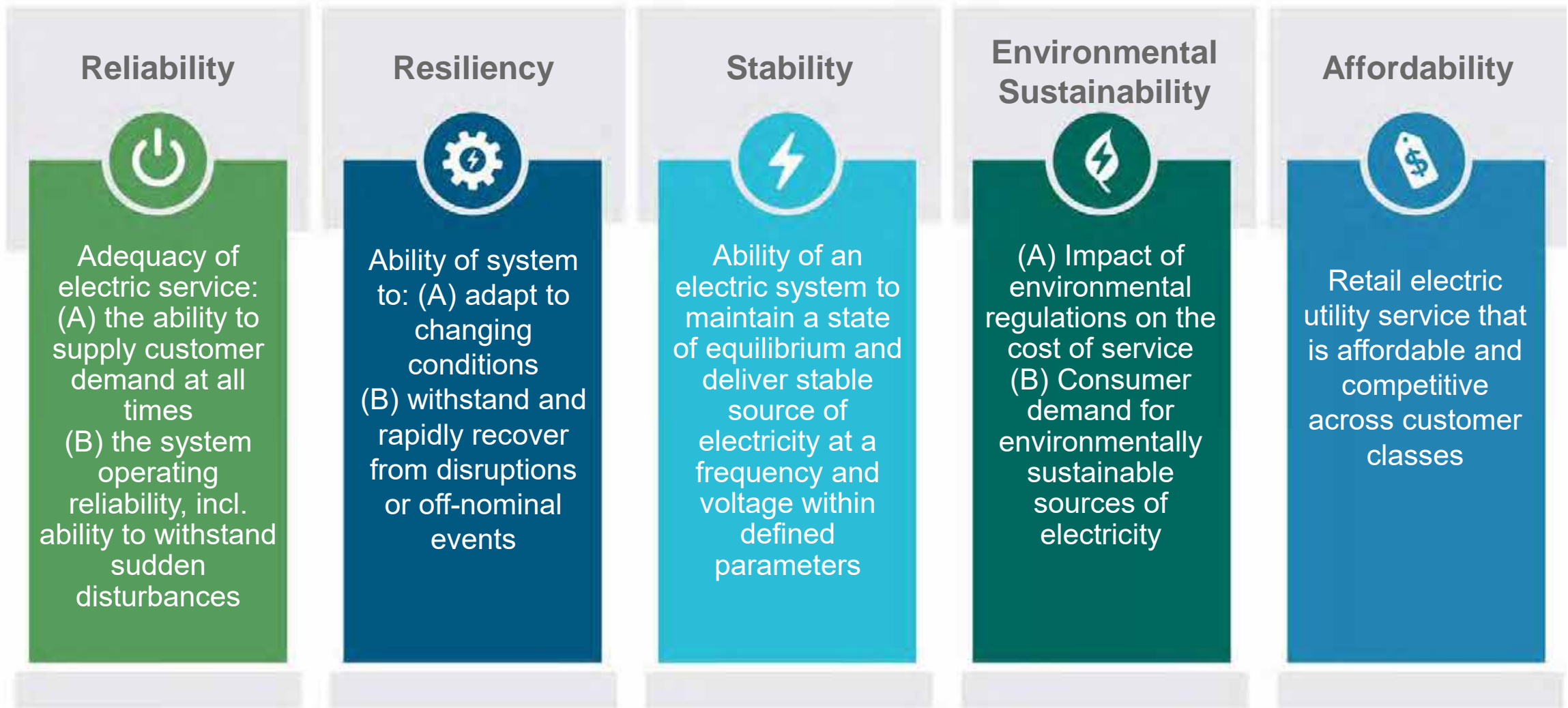


# Q&A



# Planning Objectives

# House Enrolled Act (HEA) 1007 Requirements | 5 Pillars



# Planning Objectives will guide selection of Preferred Portfolio

**“Preferred resource portfolio** means the utility’s selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration.”<sup>[1]</sup>

<sup>[1]</sup> 170 IAC 4-7-1 (cc)





# Potential Scorecard Metrics



# Potential Measures of Environmental Sustainability & Affordability

Planning Objective	Measure	Description	Purpose
<b>Environmental Sustainability</b>	CO <sub>2</sub> Emissions Reduction	Percent CO <sub>2</sub> reduction from 2005 baseline at specified years (e.g., 2030 and 2035)	Allows comparison of pace at which resource mix gets cleaner
	Cumulative CO <sub>2</sub> Reduction	Cumulative volume of CO <sub>2</sub> reduction from 2005 baseline at specified year(s)	Allows comparison of pace at which resource mix gets cleaner from a cumulative basis
	Non-CO <sub>2</sub> Emissions Ranking	Portfolio ranking across an annual average of SO <sub>2</sub> , NO <sub>x</sub> , Hg, and PM	Assesses the volume of non-CO <sub>2</sub> emissions
	CO <sub>2</sub> Intensity	Pounds of CO <sub>2</sub> emitted per megawatt-hour (MWh) of energy generated on system	Allows comparison of pace at which resource mix gets cleaner on a per unit of energy basis
<b>Affordability</b>	Present Value Revenue Requirement (PVRR)	Forecasted incremental revenue requirement over full analysis period, discounted to present	Provides estimate of total portfolio cost over analysis period in present value terms
	Customer Rate Impact (CAGR)	Average annual rate impact to customers over specified time periods (e.g., 5-yr, 10-yr)	Provides estimate of average annualized rate impact to customers, inclusive of existing unit on-going costs

# Potential Measures of Reliability

Planning Objective	Measure	Description	Purpose
Reliability	Peak Availability of On-System Resources	Percentage of on-demand MWs owned and/or contracted by Duke Energy Indiana	Ability of the portfolio's on-system generation to provide energy 'on-demand' during peak hours
	Market Reliance in Peak Seasons	Market purchases in Summer & Winter in year(s) following largest unit retirements as a proportion of energy demand	Assesses the reliance a portfolio has on the market during peak seasons following major retirements
	Market Reliance	Average market purchases over planning period as a proportion of energy demand	Assesses the reliance a portfolio has on the market throughout the planning horizon
	Energy Self-Sufficiency (Unserved Energy w/o Market Purchases)	Percent unserved energy over the planning period with market purchases turned off	Test ability of a portfolio to serve all of customers' needs without relying on market purchases
	95th Percentile Expected Net Load Ramp [MW/hr.]	95th percentile of forecasted daily maximum net load ramp (total load less intermittent gen) averaged across weather years	Indicates flexibility expected to be required of dispatchable energy resources in future years to back stand renewables and follow net load ramp needs on the system

# Potential Measures of Resiliency

Planning Objective	Measure	Description	Purpose
Resiliency	Resource Diversity	An empirically-derived diversity baseline of the system's capacity resources by technology type, as measured by the Herfindahl-Hirschman Index (HHI) – the sum of squares of technology share in the portfolio on a capacity basis	Measure diversity of capacity resource types on system as an indicator of resilience and flexibility in all time scales
	Fuel Diversity	An empirically-derived diversity baseline of the system's fuel sources, as measured by the Herfindahl-Hirschman Index (HHI) – the sum of squares of each fuel's share in the portfolio on an energy basis	Indicates extent to which a portfolio utilizes a variety of fuel sources and mitigates risk associated with fuel-related supply contingencies
	Performance in 95 <sup>th</sup> Percentile Extreme Weather Event	Percent unserved energy during an extreme weather event in summer and winter based on most extreme weather events (95 <sup>th</sup> percentile or greater) observed in Indiana with market purchases turned off	Tests portfolios performance in an off-nominal extreme (95 <sup>th</sup> percentile or greater) summer and winter weather event

# Potential Measures of Stability

Planning Objective	Measure	Description	Purpose
Stability	Rate of Change of Inertial MW	Pace of change from Inertial MW to Low/No Inertia MW in any given 1-2-year period	Indicates risk to stability via operational complexity as fleet is transitioned
	Penetration of IBRs (% capacity)	Inverter Based Resource MW as a percent of total fleet MWs	Indicates risk of stability and voltage support issues that may arise with a high penetration of IBRs

- Stability is a basic requirement in Duke Energy Indiana’s transmission planning. The Company adheres to all applicable industry standards (NERC, FERC, RFC), and to its own detailed planning criteria.
- The stability of the Duke Energy Indiana system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC and RFC Reliability Standards. Generating units, at a minimum, must maintain stability and deliver electricity at a frequency and voltage consistent with industry standards under various contingency situations.

# Potential Measures of Risk & Uncertainty

Planning Objective	Measure	Description	Purpose
Cost Risk	Cost Certainty (\$B)	Range between Min & Max PVRRs across scenarios and stochastic iterations	Indicates risk of cost variance across potential futures
	Cost Risk (\$B)	95th percentile of PVRR across stochastic iterations under varying market conditions	Indicates risk of high-cost outcomes
	IRA Exposure	Total PVRR impact of IRA tax credits (present value dollars)	Indicates both risk & opportunity of the IRA tax credits
Market Exposure	Fuel Market Exposure	Portion of energy generated by resources with exposure to coal and gas markets	Indicates cost risk associated with fuel price volatility
	Market Risk - Energy Purchases & Sales	Average energy purchases + sales as percent of load	Indicates cost risk associated with each portfolio's overall market exposure
	Market Risk - Capacity Purchases	Maximum single year capacity purchases	Indicates risk of capacity shortfall and exposure to market volatility

# Potential Measures of Risk & Uncertainty (cont.)

Planning Objective	Measure	Description	Purpose
Execution Risk	Cumulative New Technology Additions	Cumulative MW additions of CCS, new nuclear, long duration storage or other emerging technologies. <i>(CCS represented as MW capacity)</i>	Provides indication of risk associated with investment in emerging technologies and/or technologies new to the Duke Energy Indiana system
	Cumulative Resource Additions	Cumulative MW additions of all capacity resource technology types, including CCS and DSM, through 2035 and 2040	Indicates scale and pace of infrastructure siting, permitting, construction and interconnection required
	Cumulative Nameplate MW Additions as % of Current System	Nameplate MW required by year specified, as percentage of total nameplate MW serving customers today, including contracted generation	Illustrates the magnitude of infrastructure requirements in the context of the existing system





# Q&A

## Next Steps



Additional questions, comments, and feedback can be sent to [DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com)

The next technical meeting will occur in mid-April.  
The next public stakeholder meeting will occur in second half of April.

Meeting registration will be sent out 4-6 weeks in advance.



# Thank you

# APPENDIX



BUILDING A SMARTER ENERGY FUTURE®

# Acronyms

<b>AR</b>	Advanced Reactor
<b>CAA 111</b>	Clean Air Act 111
<b>CAGR</b>	Compound Annual Growth Rate
<b>CC</b>	Combined Cycle
<b>CCS</b>	Carbon Capture & Sequestration
<b>CF</b>	Capacity Factor
<b>CPCN</b>	Certificate of Public Convenience and Necessity
<b>CT</b>	Combustion Turbine
<b>DEI</b>	Duke Energy Indiana
<b>DER</b>	Distributed Energy Resources
<b>DLOL</b>	Direct Loss of Load
<b>DR</b>	Demand Response
<b>DSM</b>	Demand-side Management
<b>EE</b>	Energy Efficiency
<b>EH</b>	Expanded Hours
<b>EPA</b>	Environmental Protection Agency
<b>FERC</b>	Federal Energy Regulatory Commission
<b>HEA</b>	House Enrolled Act
<b>HHI</b>	Herfindahl-Hirschman Index
<b>IAC</b>	Indiana Administrative Code
<b>IBR</b>	Inverter-Based Resource
<b>IGCC</b>	Integrated Gasification Combined Cycle
<b>IRA</b>	Inflation Reduction Act

<b>IRP</b>	Integrated Resource Plan
<b>ITC</b>	Investment Tax Credit
<b>IURC</b>	Indiana Utility Regulatory Commission
<b>MISO</b>	Midcontinent Independent System Operator
<b>MPS</b>	Market Potential Study
<b>MSHA</b>	Mine Safety and Health Administration
<b>MTons</b>	Million Short Tons (standard metric of emissions)
<b>MW</b>	Megawatt
<b>MWh</b>	Megawatt Hour
<b>NERC</b>	North American Electric Reliability Corporation
<b>PPA</b>	Power Purchase Agreement
<b>PTC</b>	Production Tax Credit
<b>PVRR</b>	Present Value Revenue Requirement
<b>PY</b>	Planning Year
<b>RFC</b>	ReliabilityFirst Corporation
<b>RFP</b>	Request for Proposal
<b>RTO</b>	Regional Transmission Organization
<b>S+S</b>	Solar plus Storage
<b>SAC</b>	Seasonal Accreditation Construct
<b>SMR</b>	Small Modular Reactor
<b>STAP</b>	Short-Term Action Plan
<b>UCAP</b>	Unforced Capacity
<b>W&amp;A</b>	Wage & Apprenticeship



***Slides reviewed at Technical Stakeholder Session on February 6<sup>th</sup>***



# Seasonal Accreditation Adjusted UCAP



# MISO Seasonal Accreditation Capacity (SAC) Value Considerations

Considerations and observations based on Stakeholder feedback in 2023 Refresh process



## ***Question:***

What seasonal capacity accreditation values are representative for use in long-term planning?

## ***Observation:***

- By-unit by-season accreditation capacity values are too volatile year-over-year to be used as long-term assumptions
- A unit with a low individual season SAC value may indicate retirement to the model, whereas a unit with a high individual season SAC value may indicate continued operation for a long time – both results are misleading as bookends
- A diverse system should realize a relatively steady total accreditation value, but this needs to be allocated reasonably to the individual units
- It is reasonable to use unit-level unforced capacity (UCAP) values, adjusted pro-rata so the classes (coal and CC/CT) total to the system SAC

# Individual Units vs. System SAC Volatility Example

- From planning year (PY) 23-24 to PY24-25, some units experienced as much as +40% to -25% in SAC values
  - The sum of all Schedule 53 SAC only changed about 3 to 8%
- System total SAC is substantially more stable than by-unit by-season SAC

<b>Gibson 1</b>	<b>Summer</b>	<b>Fall</b>	<b>Winter</b>	<b>Spring</b>
Internal Rating, MW	630	635	635	635
PY23-24 UCAP, MW	547	600	563	564
PY23-24 SAC, MW	483	638	442	489
PY24-25 SAC, MW*	601	639	511	684
SAC Change, MW	118	1	69	195
SAC % Change	24%	0%	16%	40%

<b>Wheatland CT1</b>	<b>Summer</b>	<b>Fall</b>	<b>Winter</b>	<b>Spring</b>
Internal Rating, MW	115	119	122	119
PY23-24 UCAP, MW	107	99	130	115
PY23-24 SAC, MW	113	97	126	120
PY24-25 SAC, MW*	113	100	116	90
SAC Change, MW	0	4	(10)	(30)
SAC % Change	0%	4%	-8%	-25%

<b>All Schedule 53**</b>	<b>Summer</b>	<b>Fall</b>	<b>Winter</b>	<b>Spring</b>
Internal Rating, MW	5,675	5,813	5,904	5,813
PY23-24 UCAP, MW	4,917	4,971	5,302	5,231
PY23-24 SAC, MW	4,752	4,595	4,800	4,639
PY24-25 SAC, MW*	4,907	4,939	4,960	4,795
SAC Change, MW	155	345	160	156
Coal	179	288	197	149
CC/CT	(25)	57	(37)	7
SAC % Change	3.3%	7.5%	3.3%	3.4%
Coal	5.1%	8.2%	5.8%	4.4%
CC/CT	-2.0%	5.2%	-2.6%	0.6%

\*Draft PY24-25 SAC as of 12/15/2023; subject to change

\*\*Schedule 53 SAC only, Duke Share

# Pro-Rata Adjustment of UCAP to Sum to Total System SAC

Adjusted UCAP serves as basis for individual units

PY24-25 Auction Data		DRAFT 12/15/23 - Subject to Change				DRAFT 12/15/23 - Subject to Change				DRAFT 12/15/23 - Subject to Change			
		UCAP				SAC				UCAP-Adjusted			
		Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
Cayuga 1	Coal	473.0	451.7	496.6	496.4	354.0	461.1	560.5	318.0	445.6	440.2	463.5	439.9
Cayuga 2	Coal	491.7	459.5	464.4	488.8	439.4	502.6	449.7	478.9	463.3	447.8	433.5	433.2
Edwardsport IGCC	Coal	477.0	462.2	474.0	516.6	495.5	521.0	505.8	449.2	449.4	450.4	442.4	457.8
Gibson 1	Coal	611.9	571.3	558.1	592.0	600.9	638.8	510.6	684.4	576.5	556.7	520.9	524.7
Gibson 2	Coal	531.5	560.0	509.4	552.9	524.1	593.9	481.8	536.6	500.8	545.7	475.5	490.0
Wheatland CT1	Gas CT	104.9	100.7	122.1	87.5	113.0	100.4	116.3	89.8	108.0	91.8	104.9	87.1
Wheatland CT2	Gas CT	108.2	106.3	128.9	109.8	103.1	119.6	117.0	92.9	111.4	96.9	110.7	109.3
Wheatland CT3	Gas CT	100.4	107.9	130.0	117.9	109.8	118.2	117.6	135.2	103.3	98.4	111.7	117.4
Wheatland CT4	Gas CT	107.1	112.9	128.9	117.7	112.0	105.7	117.6	134.8	110.2	102.9	110.7	117.2
Coal		4,000	4,020	3,968	4,093	3,769	3,917	3,704	3,628	3,769	3,917	3,704	3,628
Other		1,424	1,460	1,828	1,515	1,465	1,331	1,571	1,508	1,465	1,331	1,571	1,508
Total		5,423	5,479	5,797	5,608	5,234	5,248	5,275	5,136	5,234	5,248	5,275	5,136

Note: Not all Schedule 53 unit rows are depicted in the table  
Values shown are whole unit basis

Total SAC ties by class and in total

# MISO Proposed Changes to Seasonal Accreditation

- Currently leveraging UCAP in modeling today
- Proposed changes to MISO's Seasonal Accreditation Construct from UCAP to Direct Loss of Load (DLOL) will have significant impacts on expansion plan

PY23-24	Summer			Fall			Winter			Spring		
Resource Class	UCAP <sup>†</sup>	DLOL		UCAP	DLOL		UCAP	DLOL		UCAP	DLOL	
		Base	3% EH <sup>††</sup>		Base	3% EH		Base	3% EH		Base	3% EH
Gas*	90%	88%	89%	84%	88%	88%	79%	66%	66%	84%	68%	68%
Combined Cycle	91%	90%	91%	94%	88%	89%	90%	74%	74%	92%	74%	74%
Coal	92%	91%	91%	91%	87%	89%	90%	72%	74%	89%	74%	74%
Hydro**	96%	96%	96%	94%	97%	96%	93%	92%	92%	97%	88%	87%
Nuclear	95%	90%	91%	96%	83%	87%	95%	84%	86%	92%	77%	80%
Pumped Storage	99%	98%	98%	91%	98%	98%	94%	47%	51%	89%	70%	68%
Storage	95%	94%	93%	95%	89%	93%	95%	90%	90%	95%	97%	96%
Solar MISO	45%	36%	42%	25%	28%	35%	6%	0%	2%	15%	15%	22%
Solar N/C		39%	44%		31%	38%		0%	2%		17%	24%
Solar South		31%	38%		20%	27%		0%	2%		10%	19%
Wind MISO	18%	11%	14%	23%	15%	15%	40%	13%	17%	23%	16%	16%
Wind N/C		11%	14%		15%	15%		13%	17%		16%	16%
Wind South								32%	32%		35%	35%
Run-of-River	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

\*Gas resource class has been adjusted by removing Combined Cycle Resources

\*\*Hydro resource class numbers are revised after removing diversity contracts

†UCAP = current accreditation methodology by resource type

††3% EH = 3% expanded hours (anytime generation is within 3% of load)



# Duke Energy Indiana's 2024 Integrated Resource Plan Engagement Session

## APRIL 29, 2024 MEETING SUMMARY

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## Meeting Information

On Monday, April 29, 2024, Duke Energy Indiana (DEI) convened the second stakeholder meeting to inform the development of the 2024 DEI Integrated Resource Plan. The meeting was held virtually. Approximately 75 external individuals representing over 50 organizations participated in this session.

## Facilitation Process

To encourage collaboration and to foster an environment where diverse perspectives could be shared, 1898 set forth the following ground rules for the session:

- **Respect each other:**  
Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.
- **Focus on today's topics:**  
Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.
- **Chatham House Rule:**  
Empower others to voice their perspective by respecting the Chatham House Rule: You are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

## Session Participation

This virtual event was facilitated by 1898 & Co. and the session included presentations and robust conversations on the following topics:

- Feedback from the first Public Engagement Session
- Load forecasting results and methodology
- Grid Edge customer programs
- Market Potential Study
- Power price development

Virtual attendees used the "raise hand" feature in Teams or submitted questions through the "Q&A" feature. Staff from 1898 & Co. took meeting notes, which have been included in the summary. Pursuant to the ground rules, the notes have been anonymized.

If participants had questions after the session or wanted to share feedback or additional information, they were asked to send an email to [DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com).

## Access to Meeting Materials

Meeting materials for the April 29, 2024, engagement session were posted to Duke Energy Indiana's IRP website at [duke-energy.com/IndianaIRP](https://duke-energy.com/IndianaIRP) on April 22, 2024. Participants were asked to visit the website to view the materials and meeting summaries. The 1898 & Co. team will continue to contact stakeholders as the website is updated with materials for each session.

## Meeting Notes

This document includes a high-level summarization of the presentation material as well as the questions and comments made by participants. The questions and comments were captured throughout the meeting; however, the summary herein does not constitute a meeting transcript. Questions and commentary were edited for clarity as needed. Similar summaries will be prepared following each public engagement session throughout this process.

## Welcome

*Stan Pinegar, Duke Energy Indiana State President*

Mr. Pinegar opened the meeting by welcoming participants and encouraging active engagement in the 2024 IRP process.

## Safety & Introductions

*Karen Hall, Duke Energy Resource Planning Director*

Ms. Hall provided a safety moment discussing eye wellness before introducing the Duke Energy teammates who are supporting the 2024 IRP.

## Meeting Guidelines & Agenda

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk discussed the ground rules for the virtual meeting. These guidelines included respecting each other, staying on topic, and the Chatham House Rule. He also reviewed guidelines for audience participation and the meeting agenda.

## Stakeholder Feedback and Incorporation

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk provided an overview of stakeholder feedback that was received and incorporated into the agenda for the second Public Engagement Session and when this feedback would be discussed in the meeting. He then covered additional feedback and the responses from Duke Energy, which included topics such as diversity, equity and inclusion, Scope 3 emissions reporting, rate impacts, and inclusion of wind in the IRP modeling.

## Q&A related to Stakeholder Feedback and Incorporation

1. Question: Can Duke Energy share the IRP slides in an accessible format?
  - a. Yes, we have provided an updated version of the slides on the IRP website that is more accessible and is text-searchable: [duke-energy.com/IndianaIRP](https://duke-energy.com/IndianaIRP)

2. Question: Could you share the same data for Scope 2 emissions that you have in the appendix for Scope 1 emissions?
  - a. Duke Energy provides information on Scope 2 emissions in its Impact Report available at [duke-energy.com/impact](https://www.duke-energy.com/impact).
3. Question: Is the Impact Report something that is reported at a Duke Energy-wide level or at a Duke Energy Indiana level?
  - a. The Impact Report includes emissions reporting at the enterprise level for Duke Energy, as well as additional metrics and information on various topics specific to Duke Energy jurisdictions. The IRP will focus on Scope 1 emissions.
4. You mention the IRP being a roadmap. However, there are times where retirement dates set in the previous IRP change. What takes place that leads to these changes?
  - a. The IRP is a roadmap created at a snapshot in time, so several things change between IRP cycles that can require adjustments in the plan. Things like new unit availability/timing, resource accreditation methodology, customer load needs, fuel prices, regulatory/policy changes, and several other factors could impact planning and necessitate updates between IRP cycles, including adjustment of retirement dates. It is important to adapt to market changes between IRP cycles and, when necessary, make plant-specific timing updates to the IRP to serve our customers.
5. Question: Will any future meetings be held in person?
  - a. We are open to your feedback here. We have not finalized specific dates, but we intend to hold additional in-person meetings during this IRP engagement process. We will keep you all informed as these future meetings are scheduled. Current plans are for two of the remaining three public stakeholder meetings to include hybrid, in-person and remote options.
6. Comment: Commenter thinks DEI could utilize the six-point plan they helped to draft for EV charging deployment as a metric for environmental justice (EJ) and equity such as geographic location of resources, contracts, GHG reductions that benefit disadvantaged communities (DAC), and reliability and resiliency for DAC/EJ.
  - a. DEI requested commenter to provide the plan for its review and consideration.

## IRP Fundamentals

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk explained the purpose and objectives of an IRP and provided details specific to filing an IRP in the state of Indiana, including filing every three years, planning over a 20-year horizon, developing the plan with stakeholder input, and putting forward a preferred resource portfolio. He also discussed how IRPs support planning to serve increasing energy needs by determining the supply-side and demand-side resource needs that balance costs, benefits, and risks. Lastly, he outlined the questions an IRP can help answer, as well as those which an IRP is not equipped to address.

## Community Engagement

*Dan Rhodes, Duke Energy Director, Infrastructure Engagement*

Mr. Rhodes started with a discussion of Duke Energy Indiana's deep-rooted history of community engagement, which includes Indiana community support through grants, corporate matching programs, public assistance programs, and community giving for a combined total of \$4,912,000 in 2023. He also highlighted Duke Energy's Share the Light Fund®, which provides financial support to individuals and families struggling to pay their energy bills.

Mr. Rhodes then discussed infrastructure engagement and emphasized Duke Energy Indiana's commitment to executing projects with a focus on safety, protecting the environment, managing customer costs, and creating value for local communities. This is done through direct collaboration with local communities in meetings and discussions, consultations, direct mail communications, open houses, and community advisory boards.

### Q&A related to Community Engagement

1. Question: Does Duke Energy pass on lobbying costs to ratepayers?
  - a. Indiana law prohibits us from including lobbying costs in our rates. Those costs are not passed along to ratepayers.
2. Question: What is the status of the coal ash at Gallagher?
  - a. The coal ash remediation is an ongoing process at Gallagher. We do have some things pending with IDEM and some approved plans that we are waiting on them to respond to. But we are in the process of doing work at Gallagher.
3. Question: Was the local NAACP engaged in your Gallagher outreach?
  - a. The IDEM held a public hearing, and anyone was welcome to attend. DEI engaged neighbors around the Gallagher plant and conducted ash basin site tours with legislators, the New Albany mayor, New Albany City Council and city staff. We are unaware if additional direct outreach was made to the members of the local NAACP.

## Load Forecasting Methodology

*Phil Stillman, Duke Energy Managing Director, Load Forecast*

Mr. Stillman started by discussing the Duke Energy Indiana retail customer mix, highlighting that although commercial and industrial customers make up only 11% of the customer base, they account for two-thirds of retail sales. He then emphasized that the goal of load forecasting is to predict customer energy needs well into the future.

Mr. Stillman provided insight into the data-intensive process of load forecasting, which includes reviewing inputs such as historical usage, economic forecasts and energy efficiency trends. He provided details on how the forecast is created for each customer class (residential, commercial, industrial, government, and wholesale). Mr. Stillman also provided details on load

forecast drivers for economic development and explained how these drivers influence historical trends and forecasts. He highlighted the key considerations of economic development in forecasting and referenced four major projects that have been announced in the DEI territory.

Mr. Stillman provided details on the four load forecasting scenarios that are being developed for the 2024 IRP (Low Case, Base Case, High Case, Ultra-High Case) and how assumptions around economics, electric vehicles, behind-the-meter solar, economic development, and electrification are being considered in these scenarios.

### Q&A related to Load Forecasting Methodology

1. Question: When you say "end-use forecasting," do you mean you do different econometric forecasts, one for each end use type?
  - a. For the most part, we are referring to residential and commercial forecasts. EIA and other sources are used to predict how customers will use energy in the future. This allows us to incorporate different energy trends and expectations around future efficiencies, such as energy-efficient appliance saturations.
2. Question: Is that similar to how you use IRA and IJJA in the forecast?
  - a. The IRA and IJJA are not necessarily considered an end-use, but the econometric variables are inputs for each forecast, so IRA and IJJA are incorporated into our forecasting. For example, in the industrial class, when you look at industrial production indices and forecasts, you would see things such as how IJJA, the Chips Act, and other changes are expected to impact the economy going forward.
3. Question: Is Duke Energy Indiana's electricity mix expected to be a challenge in attracting investment from companies that are targeting net zero?
  - a. The company has already had success in bringing different companies to our territory.
4. Question: To what extent does the industrial sales forecast include anticipated increased load at the LEAP District site?
  - a. That site is served by Wabash Valley Power and Boone County REMC, so that load is not a factor in our load forecast.
5. Question: Will Duke Energy identify the companies with economic development contracts that have clean energy goals?
  - a. On the slides, announcements have been made publicly with Canadian Solar, Nucor, Rolls-Royce, and Stellantis. We are not going to speak specifically about these companies' goals, but we have been working with at least two of these companies on renewables and have public filings at the IURC to help procure solar on their behalf.
6. Question: Do these companies own the solar assets or does Duke Energy Indiana?
  - a. There are certain rules that the commission regulates. We can reach contract arrangements with these customers. The commission can approve special contracts and special filings through its alternative regulatory plan or special contract agreements with larger customers.

7. Question: Does Duke Energy Indiana have targets on what ideal business attraction prospects could look like?
  - a. We have a pipeline beyond what was discussed today. We would encourage contact with our economic development team to pursue projects you have in mind.
8. Question: Have you lost companies who were considering locating here because you were not able to meet their renewable energy demand?
  - a. When prospects decide to go to a different state or service territory, there are usually multiple contributing factors to that decision.

## EV & Distributed Energy Resource Forecasts

*Bryan Wright, Duke Energy Lead Structuring Analyst*

*Bryan Dougherty, Duke Energy Principal Structuring Analyst*

Mr. Wright started with an explanation of how Duke Energy Indiana utilizes the Guidehouse Vehicle Analytics and Simulation Tool ("VAST") and the three modules (vehicle adoption, charging load impacts, and sensitivity adjustments) in their electric vehicle forecasting. He discussed some of the inputs for VAST and their sources, including fuel costs, efficiency, MSRP assumptions and more. He also provided details on EV adoption forecasts, with EVs as percentage of new vehicle sales increasing from 11% by 2030 for the 2021 Duke Energy Indiana IRP to 38% by 2030 for the 2024 IRP.

Mr. Wright then discussed the EV adoption scenarios which are designed to capture a broad range of EV adoption possibilities (low, base, high, and ultra-high) and the differences in assumptions between these scenarios. He explained that as EV adoption continues to increase, so will the EV portion of Duke Energy Indiana's total energy.

Mr. Dougherty provided insight into Duke Energy Indiana's current customer-owned behind-the-meter (BTM) solar, which accounted for 86.8 MW as of February 2024. He then went into detail on the process for forecasting BTM solar as well as historical trends and drivers such as Investment Tax Credits (ITC) and state policy changes that can impact BTM adoption. He also provided a high-level summary of how the base forecast used in this IRP compares to the forecast for the 2021 IRP, highlighting higher customer adoption, higher system costs, and system size adjustments. Mr. Dougherty also discussed the BTM scenarios (low, base, high, and ultra-high) and the key differences between these scenarios.

## Q&A related to EV and Distributed Energy Forecasts

1. Question: Are the EV adoption percentages on slide 47 national percentages?
  - a. No. All data shown is for Duke Energy Indiana territory specifically.
2. Question: Are there options to model peak EV management in VAST that reflect currently available technologies?



- a. The VAST tool does not currently have a peak management demand response program within the tool. However, it does have time-of-use rates that have been implemented in the forecast with assumed adoption rates in specific tariffs that reflect response to dynamic rates.
3. Question: Will there be an opportunity for the IRP model to manage the peak load contribution through demand response?
  - a. It is currently set up so that the hourly EV forecast is done inside the VAST tool and is then provided to the load forecast as a load modifier to capture the low, medium, high, and ultra-high scenarios, with each having different adoption levels. The managed charging element is done within the VAST model using a percent of total vehicles and existing tariff structures. The modeling of the load shifting through TOU rates is done through VAST with the different scenarios having larger peak contributions, due to adoption levels, as opposed to a demand response type of resource.
4. Question: Under what scenarios would Duke Energy model EV charging when capable (i.e., plug and charge, smart charging, V2G peak reduction)?
  - a. We model EV charging in all scenarios. Time-of-use rates are currently modeled. When V2G is more mature with higher impacts and able to be modeled in the tool, we will be working to include this in the EV forecast model.
5. Question: If there were more renewable integration, would higher EV adoption occur and is that accounted for in the model?
  - a. That is not currently accounted for in the model. We have not seen a strong correlation in our analysis between the fuel source of energy and EV adoption. Our analysis has shown total cost of ownership as the key driver of EV adoption.
6. Question: Do you have a green option for customers with EVs who might want their energy to come from renewable resources?
  - a. In the EV forecast module itself, we don't currently have an option to prescribe a particular energy source for the EV charging. However, renewable energy credits (RECs) are available to Duke Energy Indiana customers and Mr. Oliver will discuss managed charging opportunities in the next section of today's meeting.
7. Question: What do you expect to happen so long as Duke Energy Indiana is dependent on coal in terms of delinking charging stations from the Duke Energy Indiana supply? Can you have a particular source of energy supply a specific charging station?
  - a. If the charging station is connected to the grid, the portfolio and the Midwest ISO market would be a factor. Energy supply at any specific charging station will reflect the changing energy mix of the system and overall market. On-site solar at charging stations could be one option used to serve those customers when available. Additionally, customers can purchase RECs under our Go Green Power program on a voluntary basis.

## Grid Edge and Customer Programs

*Jay Oliver, Duke Energy Managing Director, Energy Storage & Grid Development*

*Zak Kuznar, Duke Energy Managing Director, Grid Solutions Development*

Mr. Oliver started with an overview of integrated system planning and its four components (generation, transmission, distribution, and customer), as well as how they are all connected. He then explained that the grid edge begins at the transmission to distribution substation where distribution lines begin, meaning that grid edge begins where the network transmission system ends.

Mr. Oliver then provided details on the four Grid Edge methodologies that Duke Energy uses today to help manage load (voltage optimization, demand response/distributed capacity, energy efficiency, and dynamic pricing). He also explained the control systems for these customer programs, which currently include the Energy Management System (EMS) and the Advanced Distribution Management System (ADMS), and additionally covered the Customer Energy Control System (CECS), which is currently under development.

Mr. Kuznar discussed the current state of demand response programs and where Duke Energy plans for these programs to be in the future. He highlighted several opportunities such as energy efficiency, distribution batteries and renewables, as well as various customer programs such as Bring Your Own Thermostat (BYOT) and Vehicle-to-Grid (V2G).

## Q&A related to Grid Edge and Customer Programs

1. How are you going to make this a win-win proposition so that customers act as partners to Duke Energy in these programs?
  - a. These are all voluntary programs, and we analyze the results to make sure the programs are mutually beneficial.
2. Comment: If programs customers want don't have the incentives they feel are deserved, then they will not participate, and you will not be able to generate the system benefits that you need.
3. Comment: I am concerned that DERMS will be a very cost-intensive program that risks losing a lot of people who might otherwise participate, and I recommend looking at other ways to control devices that rely on things like inverter programming as opposed to DERMS.
4. Question: What is the timeline for planned control systems to have a meaningful impact on your capacity?
  - a. We plan on going live with an advanced distribution planning (ADP) tool later this year. It is designed to predict local capacity problems better than we do today. We do not know exactly when we expect to start seeing the benefits, but we anticipate that it will take a bit of time. Technology in the future is likely going to drive some of these new business cases. However, we also need to be proactive in understanding how to optimize some of these resources and program

development in the most cost-effective way for the future. These are all things that we are looking at across the enterprise.

5. Question: If Duke Energy Indiana provided larger incentives for DER programs, would that increase adoption so you could see a larger impact?
  - a. As part of the IRP, we are looking at different scenarios for the future, and we are looking at the portfolio impacts of different adoption rates of distributed resources.
6. Question: How do you anticipate cost-effectively treating the customers as business partners in these programs coming from the bottom up as you look top down?
  - a. Grid Edge resources can, in certain instances, be used to resolve local capacity constraints as well as bulk power constraints. Across Duke Energy's different service territories, there are already certain programs in place, and more that we will continue looking into for the future, that can be leveraged across the integrated power system. Things like ADMS, EMS, and DERMS systems enable these programs today. Examples are air conditioning and thermostat controls. Customer-sited solar typically today is take-all and not controlled. And again, there are potential new programs that Duke Energy is looking at leveraging in the future.
7. How is Duke Energy working with municipalities and how could municipalities work with Duke Energy to prepare for the appropriate EV charging infrastructure as new housing is being built? How should communities be engaging?
  - a. The most important thing is to contact Duke Energy early in the process. It can take time to build the distribution infrastructure needed to serve EV charging. Currently, Duke Energy Indiana leverages email, phone, external publications, community relations managers, and large account managers to engage and educate municipalities regarding EV charging. We encourage our municipal customers to connect with us early in the planning process to ensure they are aware of our EV charging programs and incentives for consideration as their project develops. Our team of EV program specialists and engineers will help ensure projects are EV-ready and provide fleet electrification advisory services where needed. Duke Energy Indiana currently has a 24-month pilot, the C&I Rebate program, which offers a \$500 rebate per charger to qualifying public or private entities, apartment dwelling units, and government or workplace fleet operators. More information about this and other EV programs is available at [duke-energy.com/business/renewables-and-ev](https://duke-energy.com/business/renewables-and-ev), or send questions to [ChargerRebateIN@duke-energy.com](mailto:ChargerRebateIN@duke-energy.com).

## **Demand-Side Management Market Potential Study**

*Rush Childs, Manager, Advisory Services, Resource Innovations*

Mr. Childs started by explaining the services that Resource Innovations offers and their broad client base throughout North America. He then went into detail about the Demand-Side Management (DSM) Market Potential Study (MPS). He discussed how this Market Potential

Study is used as an input to the Duke Energy Indiana IRP and that the study will project savings opportunities and associated costs for demand-side management technologies. He explained the process of conducting the Market Potential Study, which includes evaluating the technical, economic, and achievable potential of various demand-side management technologies and considering input from stakeholders. Mr. Childs also explained the research that was used to develop estimates for energy savings and discussed sources for the assumptions in the study. He then walked through how the model applies energy-saving measures to provide outputs that can be utilized in the IRP.

## Q&A related to the Demand-Side Management Market Potential Study

1. Question: What is the status of the MPS?
  - a. Resource Innovations is coordinating with Duke Energy Indiana to get avoided cost benefits for economic potential. We plan to discuss economic and achievable potential with Duke Energy Indiana in the coming weeks.
2. Question: Is there a way that we can see the assumptions that influence savings potential?
  - a. We have provided baseline assumptions and information and the full dataset of the measure inputs, at this point, but there are additional modeling aspects that we still need to discuss with OSB. We are working on that now and will be discussing economic and achievable potential in the coming weeks.
3. Question: Can we get the full modeling inputs on the Market Potential Study similar to what we get on the IRP where we can rerun the model and produce the same portfolio?
  - a. Resource Innovations' MPS model is programmed in Analytica and is considered to be proprietary work product. We are working with the Indiana OSB to address any questions and will continue to provide modeling inputs.
4. Question: What was assumed in the MPS regarding policy changes, and what customers would be expected to participate in some of these different programs?
  - a. DEI is using the utility cost test to evaluate a measure's cost-effectiveness. The inputs to that include the incentive rate-based typical program rebate levels and program administration costs. For achievable potential, the incremental cost is reduced by the incentive, and we estimate the customer payback period.
5. Question: Are industrial customers included in the study, or does it only focus on residential and commercial customers?
  - a. The study does not only focus on residential and commercial. Achievable potential for industrial customers is included as well. We work with Duke Energy Indiana to identify which existing industrial customers have opted out from programs and should be excluded from the MPS analysis.
6. Question: To what extent will you look at customer demand for DERs? Will you be doing a MPS under the oversight boards with respect to DERs?
  - a. Running a scenario or a part of the MPS to include DERs is not meant to replace anything that DEI is already doing internally but is to see if any of that should potentially be included in future EE or DSM filings. There will still be a similar workstream to the one we did in the previous IRP process around DERs. It is

important for the IRP to look at things in two buckets: what can Duke Energy deploy versus what is up to a customer to adopt.

## Supply-Side Resources

*Kristen Cooper, Duke Energy Lead Engineer*

*Matt Kalembe, Duke Energy Vice President, Integrated Resource Planning*

Ms. Cooper started with an explanation of the Generic Unit Summary (GUS), which is a compilation of overnight and operations and maintenance (O&M) costs from various sources and tools. She then discussed the overnight capital costs for different resources, comparing costs from the 2023 CPCN to updated costs for the 2024 IRP.

Mr. Kalembe discussed the “Aggressive Policy & Rapid Innovation” scenario that was reviewed in the first public stakeholder session and Duke Energy Indiana's plan to use low renewables and storage costs for this scenario. He went on to compare both thermal and renewable resource availability across the different scenarios for the IRP (Reference Case, Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation) as well as the basis for assumptions for these resources.

## Q&A related to Supply-Side Resources

1. Question: Will you use the RFP wind, solar, and storage costs to inform these costs for your IRP?
  - a. Yes, we have used the values received as part of the RFP to inform, double check, and benchmark against other sources used in the GUS.
2. Question: Will those of us with an NDA be able to see cost estimates included in the modeling and how they were built?
  - a. As part of our data and model sharing, stakeholders with an NDA will be able to see all cost inputs to the modeling. We will follow up regarding the additional information that builds into modeling cost inputs.
3. Question: What is the basis for the nuclear SMR costs declining?
  - a. The SMR values and cost came from the 2023 INL report ([https://inldigitallibrary.inl.gov/sites/sti/sti/Sort\\_66425.pdf](https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_66425.pdf)). We assumed that there would be multiple installations which would give us quicker learning. The charts from the stakeholder meeting represent the project start year, so these are a bit different from the in-service date that the model uses when selecting new resources. When you factor in the time for developing a SMR, the cost declines are not actually seen for units that would be installed until the mid- to late 2030s and are accounting for the learning over the next decade as more of these projects are developed.
4. Question: How does GUS planning influence RFP responses?

- a. It is the other way around, where the RFP responses can help to inform the GUS. RFPs are the latest real installation specific data that we have. The GUS is derived from many different sources, including RFP responses.
5. Question: Does Duke Energy Indiana have different projections for wind and solar when paired with storage?
  - a. They are currently modeled together, but we are looking to potentially change this methodology in the future. We will share updates with stakeholders during the IRP process if we do change how these are modeled.
6. Question: Are these technology cost curves for utility-scale transmission-connected resources?
  - a. Yes.
7. Comment: Please make sure to project the cost curves associated with the distribution connected solar system as well.
  - a. Our behind-the-meter solar adoption assumptions include cost projections for distributed solar systems.
8. Question: Why are the slopes of the curves for the out-years of the aggressive cases the same as the out-years of the base case?
  - a. These are based on NREL curves which show technology cost declines going out about 10 years and then flattening out. We are using this assumption from those NREL curves.
9. Comment: I do not think that nuclear learning should be applied to the curves from the beginning because the INL curves are built upon grey literature.
10. Question: Is it correct that gas CT will not be available for the model to select until 2031?
  - a. Yes, that is the assumption we have proposed to model.
11. Comment: The assumptions on wind and storage project timing and size seem conservative. I would encourage additional thinking so we don't over-constrain the model.
12. Question: Has Duke Energy factored in recent IEA information that projects the total capital cost of battery storage to drop by 40% by 2030?
  - a. The data presented today is from before that report came out. We will review that information to see if that is something that should be factored into our cost assumptions.
13. Question: Are you considering removing some of the caps on the rate of addition with solar and storage?
  - a. We will assess if those caps should be opened further in the reference case.

## Fuels

*Tiffany Weir, Duke Energy Director, Rates & Regulatory Filings*

Ms. Weir provided an overview of how fuel price curves for both coal and gas are created, which includes looking at forward markets, long-term fundamentals, and a blend to interpolate between the two. She then explained the gas and coal curves, which showed projections for the



reference, low, and high cases and how EIA data was used to develop these curves.

Ms. Weir then discussed trends in commodity pricing, with short-term gas pricing decreasing (due to robust supply and delays in LNG export capacity) and then blending back to the long-term trend, and short-term coal also decreasing (from record highs in 2022 due to low natural gas pricing and declines in domestic coal generation) and then blending back to the long-term trend.

### Q&A related to Fuels

1. Question: What are you using in your model to reflect the cost of hydrogen when you model CTs with hydrogen capability?
  - a. We have not narrowed down what the adder will be for hydrogen in the Midwest, but that will be included in the next data share for those that have NDAs.
2. Question: Are you including anything in the CC costs for dual fuel capability to maintain reliability?
  - a. Generics beyond what is in the RFP have on-site fuel storage.
3. Question: Is that on-site storage through a mini-LNG plant or is that dual fuel capability?
  - a. It was ultra-low sulfur diesel.
4. Question: Are these coal costs based on contracted prices?
  - a. These are based on 100% observable market curves from third-party providers. We do not include coal contract supply costs in the creation of market price curves used in modeling.
5. Question: What long-term coal contracts does DEI have?
  - a. We are currently contracted through the next three-year period.
6. Question: What coal suppliers do we expect to be in business in the long term?
  - a. While there are sufficient supply reserves, there is no way for the company to know who will be in business 20 years from now.

### Accreditation/Reserve Margin & MISO Modeling

*Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Lind first explained that the purpose of a planning reserve margin is to ensure system reliability by carrying a certain amount of capacity above projected peak load. He went on to discuss how the Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study, which helps determine resource adequacy requirements. He also provided the values for the seasonal MISO 2024-2025 planning year reserve margins (9% in summer, 14.2% in fall, 27.4% in winter, and 26.7% in spring).

Mr. Lind discussed how MISO (with FERC approval) determines how to calculate accreditation for different resource types and explained that MISO has filed a direct loss of load (D-LOL) approach with FERC. He provided a table that shows the current and proposed accreditation factors for different resource types in each of the four planning seasons. He emphasized that for

new unit accreditation, the plan is to first perform MISO market runs to determine how much of each resource is installed in the MISO market, which will then be used to inform the resource accreditation inputs for the Duke Energy Indiana IRP simulations for portfolio building.

Mr. Lind also explained how power prices are developed using EnCompass. He provided details on the process of utilizing EnCompass to simulate the Horizon Energy-developed National Database, which then gets updated with IRP assumptions to develop a unique set of power prices for each scenario in the IRP.

### Q&A related to Accreditation/Reserve Margin & MISO Modeling

1. Question: Are there specific seasons that are of higher risk from the perspective of meeting the respective reserve margin?
  - a. The seasonal reserve margin accounts for the different risks in MISO throughout the year. You can have generation availability concerns that could lead to reliability risk in every season.
2. Question: How are hybrid resources accredited?
  - a. They are currently modeled as separate resources with separate accreditations. This means that if we are modeling 100 MW of solar paired with 50 MW of storage, the total accredited for the facility will be the accredited value of solar plus the accredited value of storage.
3. Question: Are you planning to back test individual assets for their capacity accreditation?
  - a. The assumptions will be built on accredited factors, and reliability performance will be reviewed after the fact.
4. Question: What are you planning to use as the individual resource accreditation for existing units?
  - a. We plan to use the specific accreditation for each of our resources.
5. Question: Is DEI concerned about some of the indicative values for existing resources? Duke Energy Indiana initially provided MISO with some feedback on these values. Is this still a concern?
  - a. There are no material concerns. A minor issue that we've identified is the classification of IGCC. Lower thermal accreditation is as expected, consistent with significantly reduced reserve margins under D-LOL. Of course, there remains uncertainty for predicting these values into the future, along with expected volatility as we have seen with the SAC accreditation values.
6. Question: Is it possible to have an iterative step to look at SERVVM results at base operation to see if things need to be adjusted for a future portfolio look, to try and find a baseline based on the portfolio today and look at results from SERVVM today and not just at the portfolios coming out of the IRP?
  - a. That is something we can look at. We are using SERVVM as a report out and are not planning on using it to adjust portfolios at this point.

## Scenario & Generation Strategies Review

*Matt Kalembo, Duke Energy Vice President, Integrated Resource Planning*

Mr. Kalembo reviewed the three modeling scenarios (Minimum Policy & Lagging Innovation, Reference, and Aggressive Policy & Rapid Innovation) and the considerations of these varying worldviews. He went on to discuss the changes to the proposed scenarios since the first Public Engagement Session, highlighting that Duke Energy Indiana plans to extend the IRA and add domestic content for both solar and wind in the aggressive case. He also noted that Duke Energy Indiana is considering incorporating a CO<sub>2</sub> tax informed by the Market Choice Act for the aggressive case. For the emerging technology scenario assumptions, he highlighted the technologies that would be available/unavailable across worldviews.

Mr. Kalembo continued with discussing the potential generation strategies, which includes looking at two different retirement dates, not building new combined cycles, and three technology agnostic cases. He also explained how Duke Energy Indiana will be utilizing the sensitivities discussed earlier in the session to conduct risk analysis.

## Q&A related to Scenario & Generation Strategies Review

1. Question: With the assumed implementation of CAA 111, does that mean you will run a case with a 40% capacity factor and another with CCS?
  - a. We are still looking at that. We want to make sure we evaluate it correctly to ensure compliance. We do not think that CCS is a viable option in the timeframe of the final rule. It is to be determined whether we will include CCS. There is more to come on this as we continue to review the final rule.
2. Comment: It would be helpful if slides that change between meetings could have something to differentiate what exactly has changed (i.e., bold, highlight, etc.).
3. Question: What can Duke Energy Indiana do to accelerate the move away from coal and fossil fuels?
  - a. We will look at portfolios that move away from coal and fossil fuels at different paces compared to others as we go through this IRP.
4. Question: Can we look at more rooftop solar adoption in the IRP?
  - a. Yes, we have a scenario that assumes 25% of residential customers install behind-the-meter solar by 2040.

## Final Scorecard Metrics Review

*Nate Gagnon, Duke Energy Managing Director, IRP & Analytics*

Mr. Gagnon reviewed the five pillars of House Enrolled Act (HEA) 1007: Reliability, Resiliency, Stability, Environmental Sustainability, and Affordability. He discussed how the five pillars, as well as consideration of risk and uncertainty, informed the scorecard metrics and that each plays a role in selecting the preferred portfolio.

Mr. Gagnon discussed how several of the draft scorecard metrics presented at the first stakeholder meeting were either consolidated, removed, or adjusted based on stakeholder feedback. Mr. Gagnon then walked through the final scorecard metrics.

### Q&A related to Final Scorecard Metrics Review

1. Question: In the sensitivity step, will you reoptimize portfolios or fix the portfolios from the scenario simulations?
  - a. We will take that on a case-by-case basis. For different sensitivities, it can be important to see how the capacity expansion reoptimizes versus trying to test out how a specific portfolio performs under a change in conditions.
2. Question: What do you intend to do regarding remapping the evolution of DG resources?
  - a. Stability is something we will address in the narrative but not something that we will specifically include on the scorecard. This change was based on stakeholder feedback that this is expected to potentially become less of a concern moving forward with the advance of technology. Stability is hard to boil down to an IRP context-relevant metric for a scorecard across 20 years. But it is critical and will be something we evaluate as part of this IRP. We will include additional narrative around stability, but it will not be shown as a scorecard metric.

# 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 2

*April 29, 2024*



BUILDING A **SMARTER** ENERGY FUTURE®





# Welcome





**Duke Energy Welcome**  
**Stan Pinegar**  
State President, Duke Energy Indiana



# Safety

# Safety - Eye Wellness



**USE THE 20-20-20 RULE:**  
every 20 minutes, take a 20-second break and look at something 20 feet away.



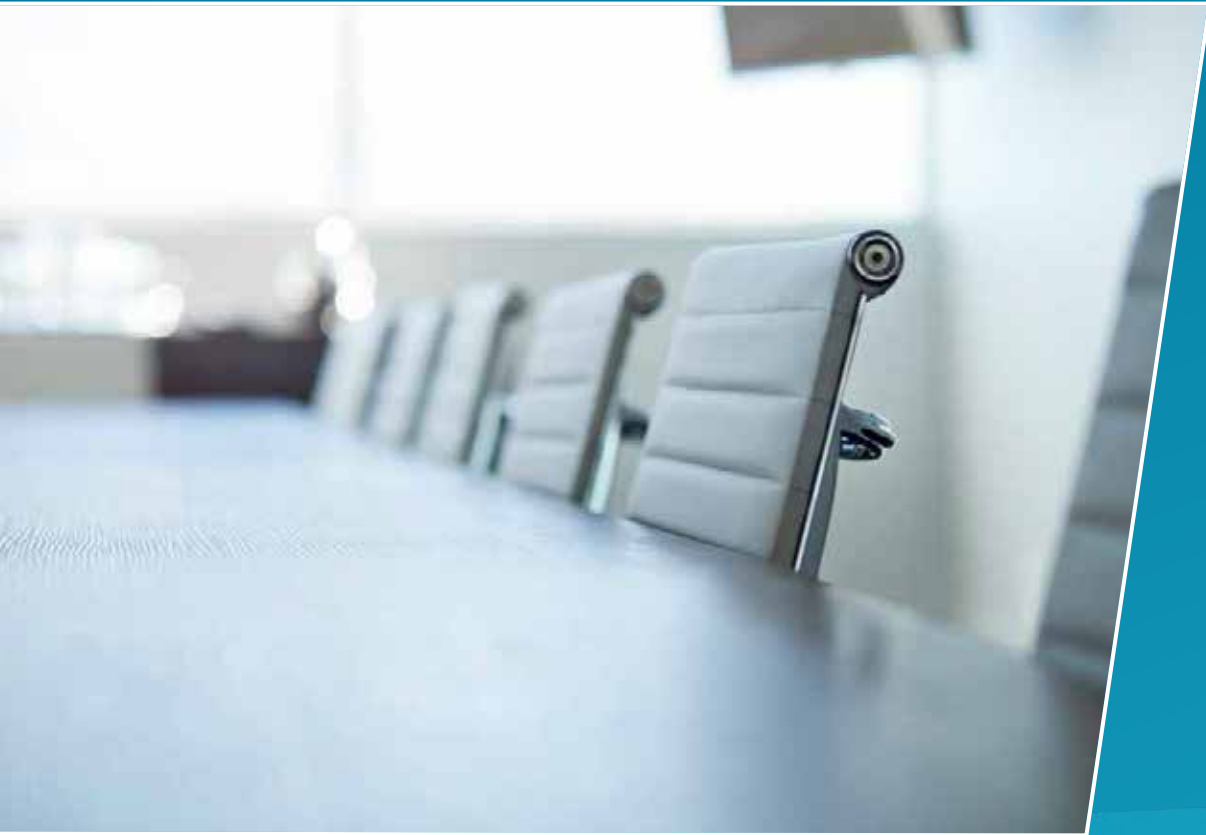
 **Prevent  
Blindness**

For more information, visit  
[PreventBlindness.org/digital-devices-and-your-eyes](https://preventblindness.org/digital-devices-and-your-eyes)

## To help avoid eye strain, Prevent Blindness recommends the following:

- Place your screen 20 to 26 inches away and a little bit below eye level.
- Use a document holder placed next to your screen. It should be close enough, so you don't have to swing your head back and forth or constantly change your eye focus.
- Change your lighting to lower glare and harsh reflections. Glare filters over your digital screens can also help.
- Get a chair you can adjust.
- Choose screens that can tilt and swivel. Adjustable keyboards are also helpful.
- Computer glasses with yellow-tinted lenses that block blue light can help ease digital eye strain by increasing contrast.
- Anti-reflective lenses reduce glare and increase contrast and also block blue light from digital devices.

<https://preventblindness.org/2024-workplace-eye-health/>



# Introductions



# Duke Energy Team

## Integrated Resource Planning Team



**Matt Kalembo**  
*Vice President,  
Integrated Resource  
Planning*



**Nate Gagnon**  
*Managing Director,  
Midwest Integrated  
Resource Planning*



**Matt Peterson**  
*Resource  
Planning Manager*



**Emma Goodnow**  
*Market Strategy &  
Intelligence Director*



**Karen Hall**  
*Resource  
Planning Director*



**Chris Hixson**  
*Principal Engineer,  
Resource Modeling*



**Josh Paragas**  
*Engineer, Resource  
Modeling*



**Tyler Cook**  
*Engineer, Resource  
Modeling*

### Community



**Dan Rhodes**  
*Director  
Infrastructure  
Engagement*

### Load Forecast



**Phil Stillman**  
*Managing  
Director Load  
Forecast*



**Joseph Phalen**  
*Principal Load  
Forecasting  
Analyst*

### EV & DER Forecast



**Bryan Wright**  
*Lead Structuring  
Analyst*



**Bryan Dougherty**  
*Principal Structuring  
Analyst*

### Grid Edge

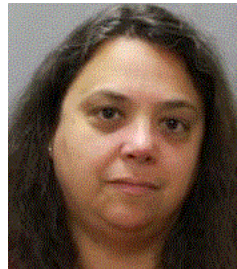


**Jay Oliver**  
*Managing Director  
Energy Storage &  
Grid Development*



**Zak Kuznar**  
*Managing Director  
Grid Solutions  
Development*

### Fuels



**Tiffany Weir**  
*Director Rates &  
Regulatory Filings*

### GUS



**Kristen Cooper**  
*Lead Engineer*



# Agenda



# Public Stakeholder Meeting #2 Agenda

Time	Duration	Present   Discuss	Topic	Presenter
9:30	5	5   0	Welcome & Safety	Stan Pinegar, Duke Energy Indiana State President Karen Hall, Duke Energy Resource Planning Director
9:35	5	5   0	Meeting Guidelines & Agenda	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:40	20	15   5	Stakeholder Feedback & Incorporation	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:00	15	10   5	IRP Fundamentals	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:15	15	10   5	Community Engagement	Dan Rhodes, Duke Energy Director, Infrastructure Engagement
10:30	30	15   15	Load Forecast	Phil Stillman, Duke Energy Managing Director Load Forecast Joseph Phalen, Duke Energy Principal Load Forecasting Analyst
11:00	10	-	BREAK	
11:10	30	15   15	EV & Distributed Energy Resource Forecasts	Bryan Wright, Duke Energy Lead Structuring Analyst Bryan Dougherty, Duke Energy Principal Structuring Analyst
11:40	25	10   15	Grid Edge & Customer Programs	Jay Oliver, Duke Energy Managing Director Energy Storage & Grid Development Zak Kuznar, Duke Energy Managing Director Grid Solutions Development
12:05	20	10   10	Demand-Side Management Market Potential Study	Rush Childs, Manager, Advisory Services, Resource Innovations
12:25	30	-	BREAK	
12:55	15	10   5	Supply-Side Resources	Kristen Cooper, Duke Energy Lead Engineer
1:10	15	10   5	Fuels	Tiffany Weir, Duke Energy Director Rates & Regulatory Filings
1:25	15	10   5	Accreditation/Reserve Margin & MISO Modeling	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
1:40	20	10   10	Scenario & Generation Strategies Review	Matt Kalembe, Duke Energy Vice President, Integrated Resource Planning
2:00	10	-	BREAK	
2:10	25	15   10	Final Scorecard Metrics Review	Nate Gagnon, Duke Energy Managing Director, IRP & Analytics
2:35	25	0   25	Open Q&A	
3:00			Adjourn	



# Meeting Guidelines

# Meeting Ground Rules



## **Respect each other:**

Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

## **Focus on today's topics:**

Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.

## **Chatham House Rule:**

Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

# Participation



There will be several opportunities throughout the presentation for attendees to actively participate by asking questions, making comments and/or otherwise sharing information.

- **Q&A:** Please use the “Q&A” feature, on the menu at the bottom of your screen, to submit questions to the presenters. We will respond to as many of these as possible, time permitting, during designated time periods.
- **Raise hand:** If you wish to ask a question or make a comment orally, please use the “raise hand” feature, during designated time periods. A facilitator will call on you and invite you to unmute.
- **Chat:** The chat feature is enabled for sharing information and resources with other participants; however, it is sometimes difficult to monitor. If you would like a response from the presenters, please use the Q&A or raise hand features.



# Stakeholder Feedback and Incorporation

# Stakeholder Feedback Received & Incorporated into Meeting #2 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
How does the IRP account for community impacts related to new resources?	IRP Fundamentals, Community Engagement
Does the IRP determine where new resources will be sited?	IRP Fundamentals, Community Engagement
How is the safety of new infrastructure considered?	Community Engagement
What opportunities exist for community advocacy?	Community Engagement
Is Duke Energy exploring pilots such as VPPs?	Grid Edge & Customer Programs
What is the role of transmission and distribution planning?	IRP Fundamentals; Grid Edge & Customer Programs
Does load forecast incorporate the IRA?	Load Forecast
Is there a mechanism in IRP process to evaluate emerging technologies such as long duration energy storage?	Supply Side Resources (Generic Unit Summary)
Is CCS included as an option in modeling?	Supply Side Resources (Generic Unit Summary)
To what extent is Duke Energy looking at turbines that are green hydrogen-capable and what is the timing?	Supply Side Resources (Generic Unit Summary)
Will modeling assume dual fuel on new natural gas units?	Supply Side Resources (Generic Unit Summary)



# Stakeholder Feedback Received & Incorporated into Meeting #2 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
Include percent CO <sub>2</sub> reduction as a scorecard metric	Final Scorecard Criteria Review
Prefer scorecard metrics are not weighted	Final Scorecard Criteria Review
Remove scorecard metrics that overlap	Final Scorecard Criteria Review
Remove inverter-based resource metrics from scorecard	Final Scorecard Criteria Review
Consider a strategy to exit coal by 2030	Scenario & Generation Strategies Review
Provide existing unit retirement date assumptions	Scenario & Generation Strategies Review
Appreciate narrative on alternate scenario assumptions and would like to review in further detail next meeting, along with narrative for generation strategies	Scenario & Generation Strategies Review
Will Deep Decarbonization & Rapid Electrification inputs be included in modeling?	Scenario & Generation Strategies Review
Provide supporting information for IRA domestic content assumptions	Scenario Development & Appendix

# Stakeholder Feedback Received & Incorporated into Meeting #2 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
Current amount of distributed energy resources on DEI system	Grid Edge & Customer Programs
What is Duke Energy's plan for distributed energy resources?	Grid Edge & Customer Programs
Better understanding of distributed energy resource programs for customers	Grid Edge & Customer Programs DEI plans to host a public webinar about distributed energy resource programs this summer. Note: Reach out to <a href="mailto:Karen.Hall2@duke-energy.com">Karen.Hall2@duke-energy.com</a> for more information.
Would like to see more attention given to energy efficiency	Market Potential Study
Does Duke Energy offer programs to support low-income customers?	Appendix
Desire to see DEI CO <sub>2</sub> emissions over time	Appendix
Resource capacity changes over time (since last IRP)	Appendix
Provide data in advance of the Technical Stakeholder sessions	Data Sharing

# Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
Creating a Diversity, Equity, and Inclusion (DE&I) and/or environmental justice metric in scorecard.	<p>This year's IRP will include a discussion of community impact highlighting our deep-rooted support for the communities where we live and work. Community engagement and impacts will be discussed further today as well.</p> <p>The 5 Pillars (Reliability, Resiliency, Stability, Environmental Sustainability, Affordability) and the metrics which will be included in the scorecard evaluation are related to aspects of DE&amp;I. Environmental Sustainability metrics will evaluate the different portfolios on their emissions. Similarly, the affordability metrics will compare total portfolio cost. Reliability, resiliency, and stability are all evaluated on a portfolio-wide basis and evaluate how the portfolio can provide all Duke Energy Indiana customers with energy during the study period.</p> <p>Learn about Duke Energy's commitment to our vibrant communities here: <a href="#">Vibrant Communities - Duke Energy</a></p> <p>Learn about Duke Energy's Just Transition, including an Indiana case study, here: <a href="#">A Just Transition Approach - Duke Energy</a></p> <p>Learn about Duke Energy's environmental justice principles: <a href="#">Environmental Justice Priority Brief - Duke Energy</a></p> <p>Information regarding Duke Energy's diverse workforce can be found here: <a href="#">Diverse Skilled Workforce - Duke Energy</a></p>

# Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
Will Duke energy provide Scope 3 reporting as part of the IRP?	Duke Energy provides information on Scope 3 emissions in its Impact Report. Annual report is available at <a href="https://www.duke-energy.com/impact">duke-energy.com/impact</a> As part of the IRP portfolio evaluation, we will be estimating each portfolios' direct CO <sub>2</sub> , SO <sub>2</sub> , NOx, Hg, and PM emissions.
When looking at the rate impact metric, is it only evaluating the costs associated with new resources? Will the rate impact be broken down by customer class in the scorecard?	For the IRP we will be looking at the annual portfolio costs out of the model and using these to estimate average annualized rate impact to all customers, inclusive of existing unit on-going variable costs. The intent of the rate impact metric is to show the relative ranking/impact on rates across the different portfolios. Additional details such as breakdown by customer class are not included in IRP analysis.
Is wind being considered as a resource option in the IRP modeling? Can wind help balance the intermittency of solar resources?	Yes, wind is being considered as part of the IRP, and we will be covering wind options being considered in the Generic Unit Summary portion of today's meeting. IRP model simulations capture the potential diversification benefits of having both wind and solar in the portfolio.



# Q&A



# IRP Fundamentals



# What is an Integrated Resource Plan (IRP)?



**An Integrated Resource Plan (IRP)** explains how an electric utility will meet the projected peak demand and energy requirements of its customers in a cost-effective, reliable manner.

IRPs balance multiple objectives including system reliability, environmental responsibility, and cost impacts.

- ▶ Least-cost planning principles
- ▶ Reliable resource portfolio
- ▶ Manage risk through diverse resource mix
- ▶ Reduce environmental impacts

# The Indiana IRP Process



IRPs are submitted **every three years**



Plan is created with **Stakeholder input**



20-year look at how utility can **cost-effectively** serve our customers



Modeling and analysis culminate in a **Preferred Resource Portfolio**

# Fundamentals of Resource Planning

## Planning to Serve Increasing Energy Needs

### Customer Demand Growth



### Resource Retirements



### Resource Need

- Load forecast changes
- Economic development driving growth
- Effects of customer programs and grid edge resources
- Power station retirement
- Power purchase contract expiration
- Supply-side and demand-side resources
- Balancing costs, benefits, and risks

## Questions the IRP can help us answer

- What is the expected resource need over the planning horizon?
- What are the tradeoffs associated with different resource decisions (retirement dates, types and quantities of new resources)?
- Ultimately, what is the resource portfolio, including timing and scale of additions and retirements, that appropriately balances the planning objectives?

### Examples of topics that the IRP process is not equipped to address:

- Siting of new resources and associated site-specific considerations
- Specifics of resource procurement, including procurement mechanisms, contract structures, etc.
- Near-term operational considerations
- Optimal policy and regulatory structures



# Q&A



# Data Sharing



# Data Sharing



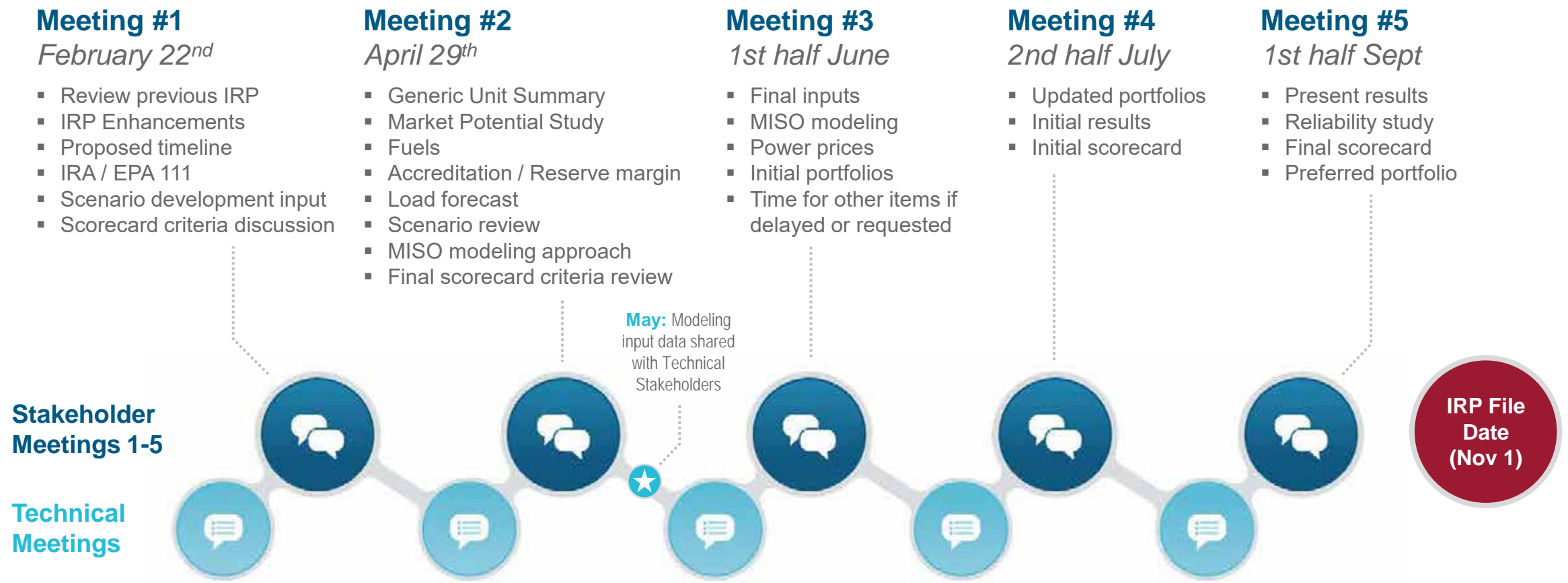
- Data related to this meeting has been provided to Technical Stakeholders who have signed a non-disclosure agreement.
- Technical Stakeholders should have received an email notification with a registration link for Datasite, the secure platform Duke Energy is leveraging to share data and modeling files.
- As files are available, they will be uploaded to Datasite so Technical Stakeholders have the opportunity to review in advance of the meetings to help facilitate robust technical discussions.
- If you have difficulty accessing Datasite or, if there are ways that we can improve data sharing or these technical meetings, please let us know.





# 2024 DEI IRP Stakeholder Meetings *(proposed timeline)*

*Engaging with our stakeholders in multiple sessions throughout the 2024 IRP process*





# Community Engagement

# History of community impact



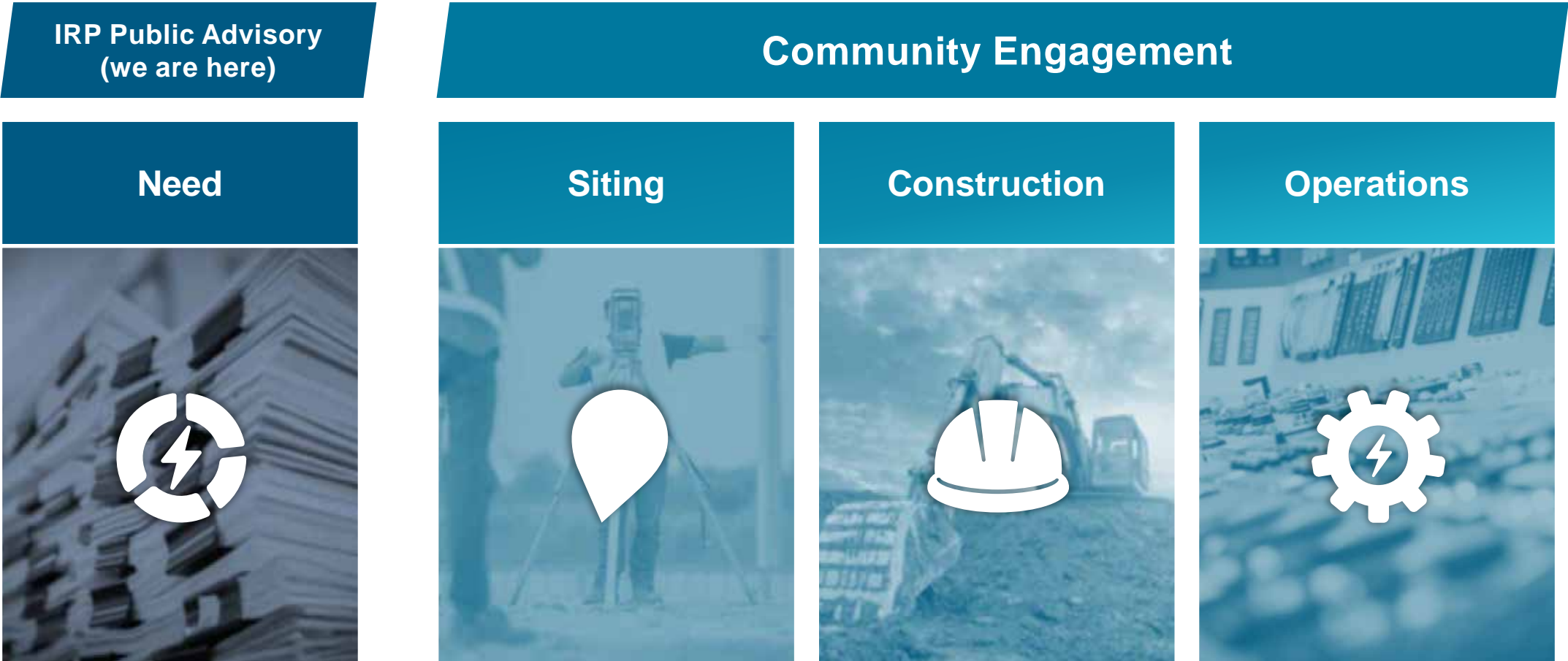
Duke Energy partners with social service agencies in 39 counties to assist low-income customers. In 2023 and 2024, Duke Energy representatives assisted about 4,000 customers in signing up for federal bill assistance, including energy assistance programs, and to provide information about energy efficiency programs

Duke Energy has a long history of deep-rooted community engagement and partnerships in Indiana. In 2023, Duke Energy employees and retirees contributed about **\$418,000** to Indiana nonprofit organizations and contributed more than **13,600 hours** in the communities where they live and work. The Duke Indiana State President’s Office has supported weatherization programs for customers through contributions to the Indiana Housing and Community Development Authority.

## 2023 Annual Indiana Community Support

	Type of Giving	2023 Amount
	Foundation Awarded Grants <i>Grants awarded through Duke Energy Foundation’s grant programs</i>	\$2,780,000
	Corporate Matching Gifts Programs <i>Corporate Campaigns, Matching Gifts Program, Volunteer Grants</i>	\$474,000
	Public Assistance Programs <i>Share the Light Fund</i>	\$500,000
	Community Giving <i>Sponsorship dollars administered by IN President and District Managers</i>	\$1,158,000
2023 Total Annual Community Support		\$4,912,000

# Infrastructure Engagement







# Q&A

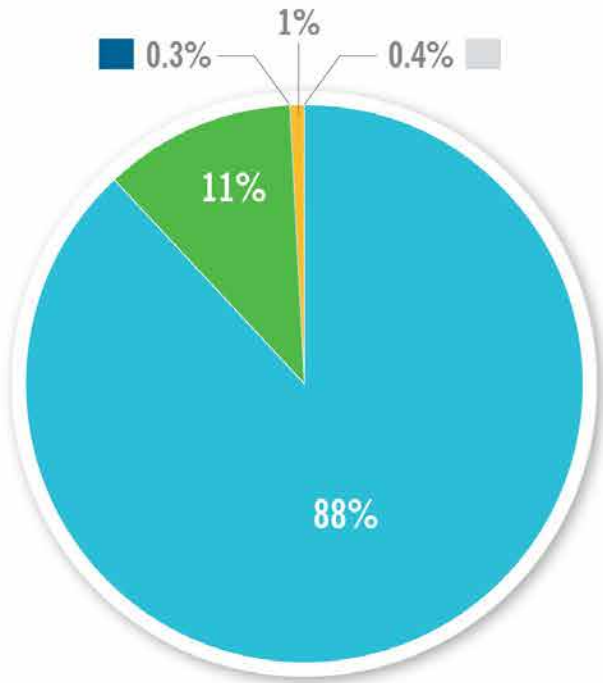


# Load Forecasting Methodology



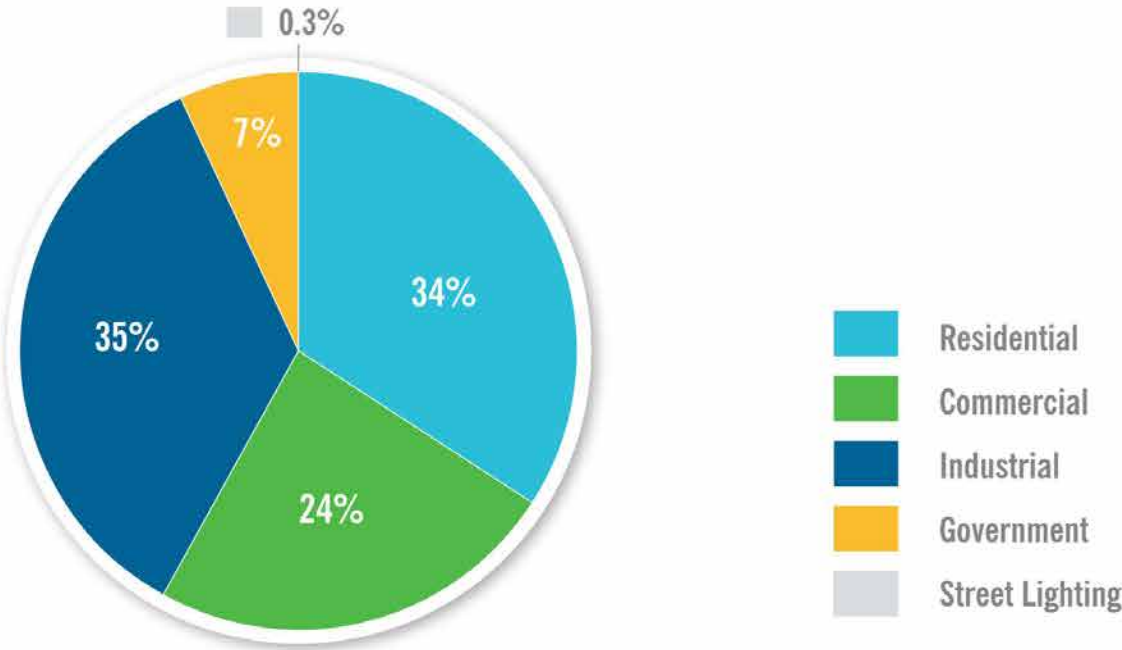
# Duke Energy Indiana Retail Customer Mix

2023 Customer Breakdown



Residential customers account for **88% of the 900,000 total** customers in Indiana.

2023 Sales Breakdown (MWh)



Although C&I make up only 11% of the customer base, they account for **two thirds of retail sales**.  
The largest 15 customers make up ~30% of C&I sales.

# Key Takeaways



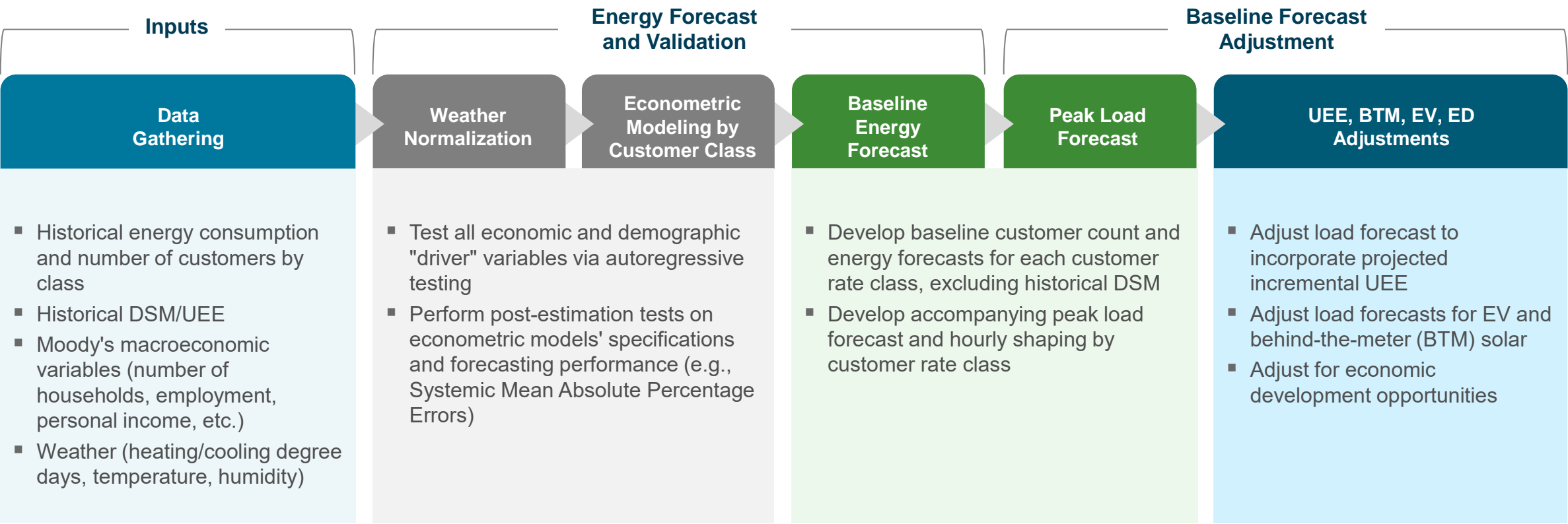
**Load forecasting is not just about a number, but about developing a coherent understanding of relationships between drivers like economics, demographics, and behavior, and future customer energy needs.**

- Allows for understanding of a wide range of possible futures.
- Allows the Company to understand potential headwinds and tailwinds to the load forecast and their potential impact on customer demand.

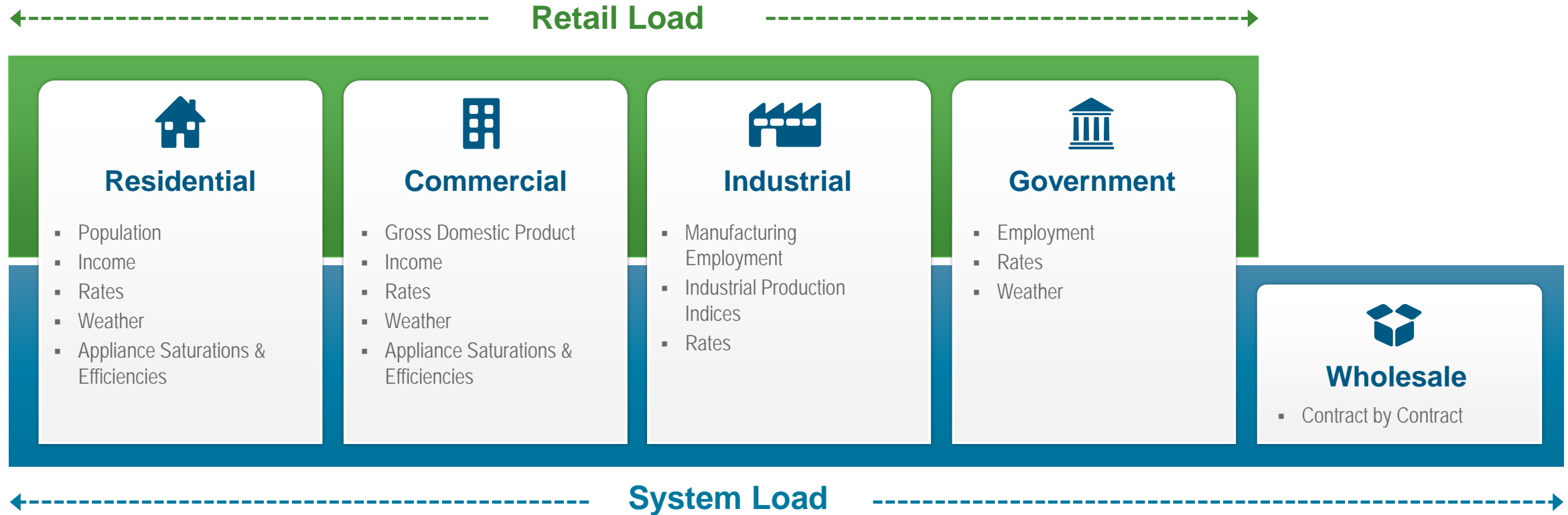
**The goal is to project customer energy needs decades into the future in terms of both annual energy consumption and peak demand.**

- The load forecast is a key input to resource planning.
- Data from multiple groups within the Company is used to produce the load forecast.

# Load forecasting methodology overview



# Primary Forecast Drivers by Customer Class



- Load forecast is based on a bottom-up approach (projections by customer class).
- For Residential and Commercial classes, the listed predictors are grouped within "End Uses"
- The relationship between the sales drivers and energy sales is constantly reexamined.

# 2024 Load Forecast Drivers



## Current State:

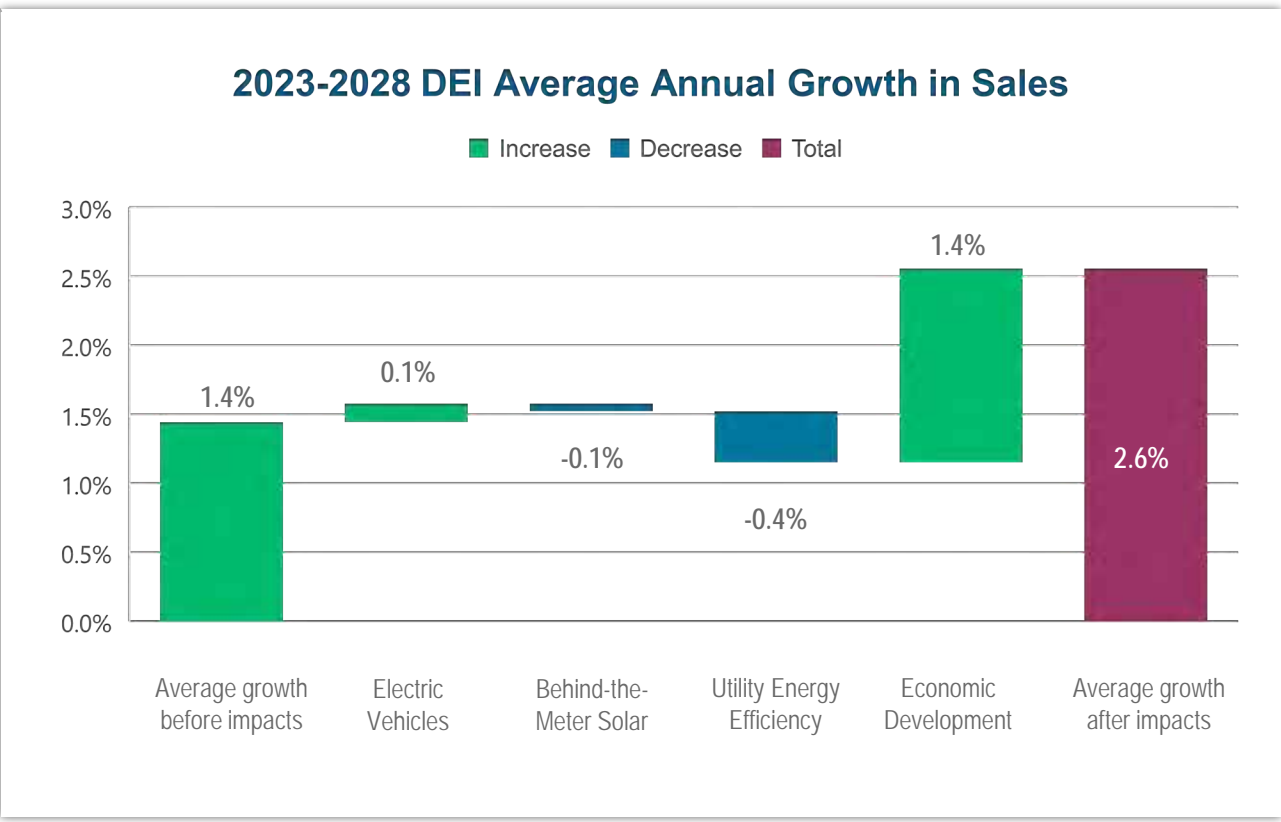
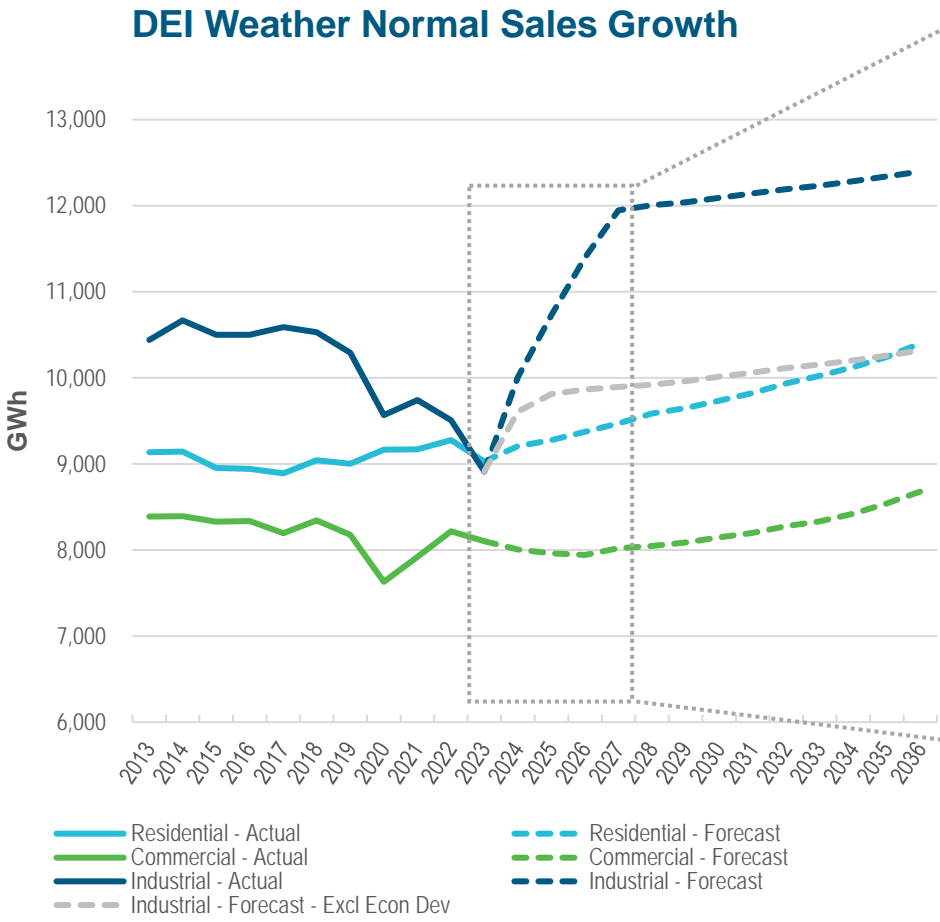
- Consistent population growth
- Economic challenges in industrial sector



## Future State:

- Population growth (natural increase and net migration) and the impact on residential customers
- Feedback cycle between commercial success and residential population
- Economic development
- Electric vehicle adoption, customer-sited generation

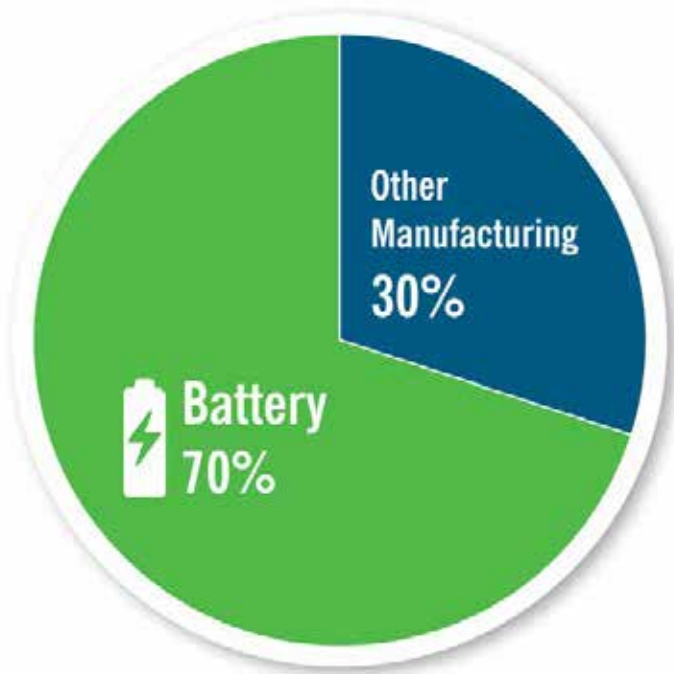
# Near-Term Sales Growth Drivers





# Economic Development

## Economic Development Pipeline grows to 300-500 MW by 2030



**Note:** Pipeline includes projects greater than 20 MW with plans sufficiently advanced such that the demand could be anticipated with a reasonable degree of certainty



### News Headlines

*IndyStar*

**New solar cell plant will bring 1,200 jobs to southern Indiana**

*Oct 2023*

*Manufacturing Dive*

**Nucor to build \$115M utility structure plant in Indiana**

*June 2023*

*Kokomo Tribune*

**Stellantis, Samsung SDI to build 2nd EV battery plant in Kokomo**






*Oct 2023*

*WLFI.com*

**Rolls-Royce launches \$204M aerospace expansion near Purdue**

*April 2022*

# Load Scenario Assumptions

	 Economics	 Electric Vehicles	 Behind-the-Meter Solar	 Economic Development	 Electrification
Low Case	90/10	Low Adoption	High Adoption	Low (25%)	Base
Base Case	50/50	Base Adoption	Base Adoption	Base (~60%)	Base
High Case	10/90	High Adoption	Low Adoption	Higher (75%)	Base
Ultra-High Case	10/90	Ultra-High Adoption	Low Adoption*	Highest (100%)	High

\*Additional BTM solar included in model with supply-side resources



# Q&A



# Break



# EV Forecast

# Electric Vehicle Modeling – Guidehouse Vehicle Analytics and Simulation Tool (“VAST”)





# EV Forecast Model Sources



The VAST model is updated biannually by Guidehouse, and the Spring 2024 forecast inputs were gathered end of year 2023

Vehicle Adoption			Charging Load Impacts		
Inputs	Description	Source	Inputs	Description	Source
Vehicle Registration Data	US vehicle registration by make, model and year at the zip code	IHS Markit	Vehicle Adoption Forecast	Number of BEVs and PHEVs forecasted by year	Vehicle Adoption Module
Vehicle Availability	Future availability of EV and ICE models	Guidehouse SME Insights	Vehicle Miles Traveled	Forecasted annual vehicle miles traveled	Federal Highway Administration
Fuel Costs	Electricity rates (\$/kwh) and gasoline and diesel prices (\$/gal)	Energy Information Administration (electricity) AAA (gasoline and diesel)	Vehicle Charging Load Shapes	Typical hourly charging behavior by vehicle type	NREL's Electric Vehicle Infrastructure – Projection tool (EVI-Pro)
Vehicle Miles Traveled	Forecasted annual vehicle miles traveled	Federal Highway Administration	Electric Tariff Rates	Electric rates and demand charges	Duke Energy
Vehicle Efficiency	kWh/mile forecast	Argonne National Lab Guidehouse SME Insights	Customer Counts on Tariffs	Proportion of customers on TOU vs non-TOU rates	Duke Energy
BEV/PHEV Ratios	Registered percentages of Battery Electric vs Plug-in Hybrid Electric	IHS Markit	Customer Price Sensitivity	Sensitivity of customers to energy and demand prices regarding electric vehicle charging	Guidehouse SMEs - Empirical literature analysis
PHEV Utilization	PHEV miles proportion using the battery	Argonne National Lab	Vehicle per Charger Ratios	Current, long-run, and interpolated ratios of chargers needed to support number of EVs	Alternative Fuel Data Center (current) NREL's EVI-Pro (long-run)
MRSP Assumptions	Total MSRP vehicle cost for vehicles	International Council on Clean Transportation (ICCT) Guidehouse SME Insights			

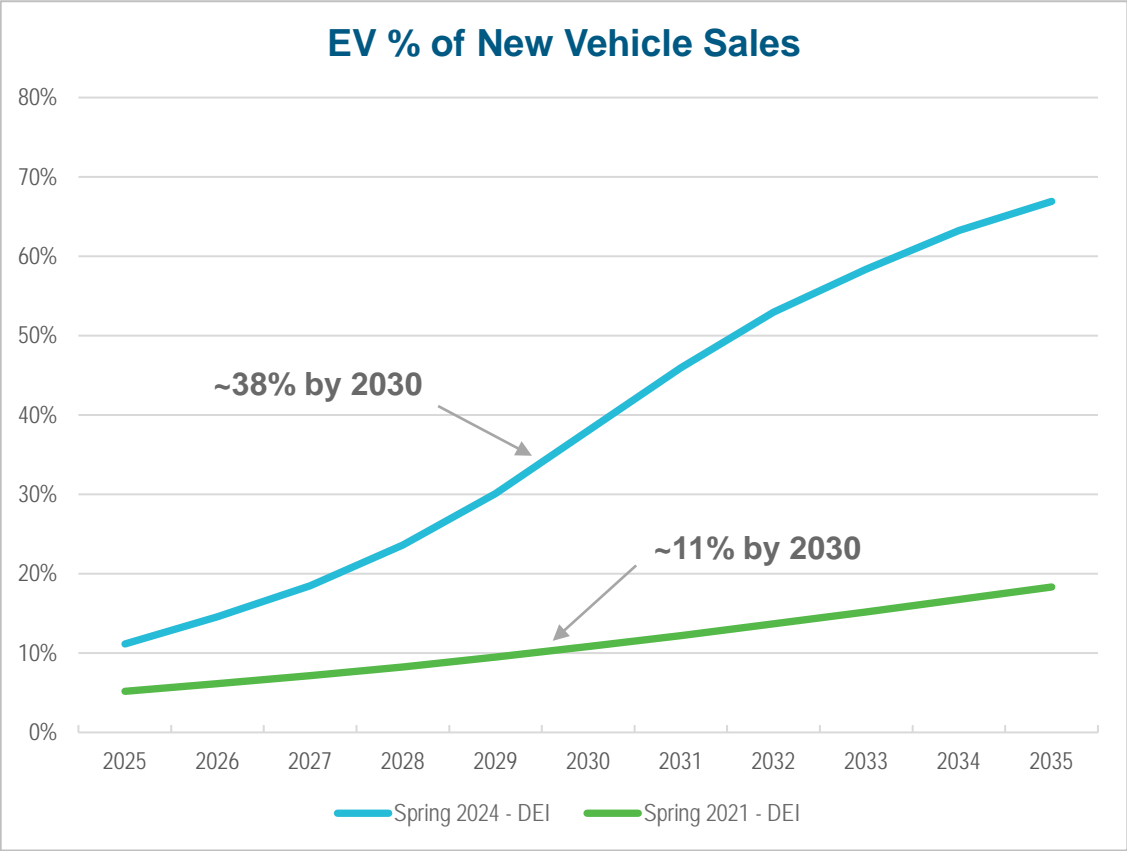
# EV Adoption Base Forecast Comparison

## Base EV Projections

- Reflects impacts of IRA incentives, IIJA, additional EV models, OEM electrification pledges, internal combustion engine (ICE) vehicle bans in CA and other states to increase vehicle availability
- Spring 2024 forecast includes projections for light duty (LD), medium duty (MD), and heavy duty (HD) EV adoption

## EV Percentage of Total Energy

Duke Energy Indiana	2021 IRP Forecast - Base	2024 IRP Forecast - Base
2025	~0.1%	~0.1%
2030	0.8%	1.3%
2040	3.7%	7.9%



Note: EV forecast includes Electric Vehicles (EV) Battery Electric Vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV)

# EV Alternate Scenarios

Multiple EV adoption scenarios were developed to capture a broad range of EV adoption possibilities

	Low	Base	High	Ultra-High
Key Assumption Differences	<ul style="list-style-type: none"> <li>Higher EV Cost (~5% increase in MSRP)</li> <li>Lower EV availability and increased ICEV availability</li> <li>Lower consumer preference for EVs</li> </ul>	Base Case	<ul style="list-style-type: none"> <li>Lower EV Cost (~5% decrease in MSRP)</li> <li>Higher EV availability and decreased ICEV availability</li> <li>Higher consumer preference for EVs</li> </ul>	EV adoption scaled to meet a stakeholder-provided scenario of EVs composing 68% of vehicles on the road by 2040
% of New Vehicle Sales – 2030	24%	38%	52%	76%
% of Vehicles on the Road – 2030	5%	7%	10%	14%
% of Vehicles on the Road – 2040	19%	33%	38%	68%
Total Energy (GWh) – 2030	330	413	659	956
Total Energy (GWh) – 2040	2,001	2,720	3,515	6,077

# Key Results/Takeaways



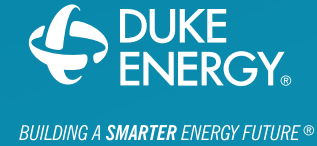
There has been a **substantial increase** in forecasted electric vehicle adoption since the 2021 DEI IRP



Currently EVs are a small portion of total electric usage (**< 0.2% of total system energy**), but as EV adoption increases over time, they contribute a larger portion of the total system energy (**1.3% by 2030**)



The forecasted scenarios (Low, Base, High, and Ultra-High) are designed to capture a broad range of **EV adoption possibilities**



# Behind-the-Meter (BTM) Distributed Resource Forecasting



# Customer-Owned BTM Solar Capacity



DEI’s current capacity from customer-owned behind-the-meter DERs through the end of February 2024.

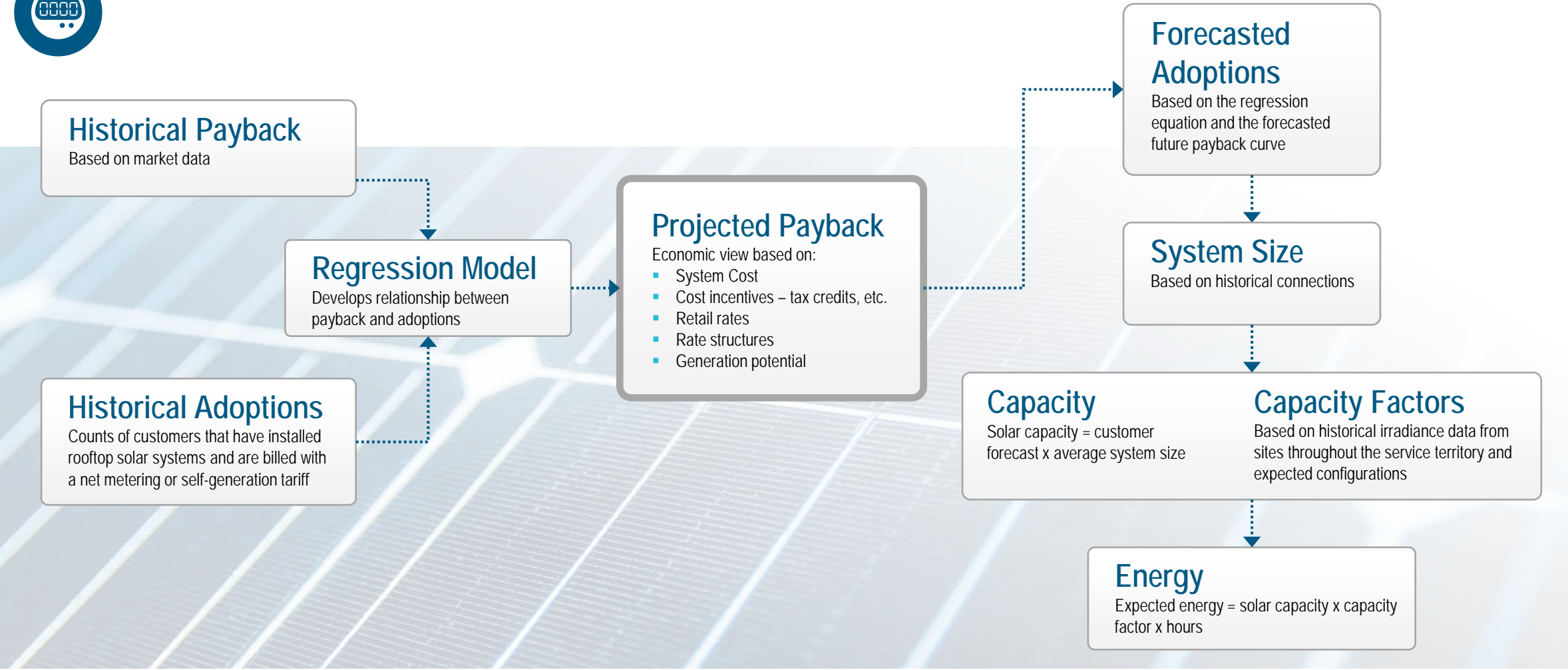
**Notes:**

- Does not include large distribution or transmission projects
- Solar paired with storage represents the solar capacity only, as customers do not provide battery size information to Duke Energy.

DEI BTM Capacity		Customers	
	Solar Only	81.0 MW	3,677
	Solar + Storage	5.8 MW	582
Total		86.8 MW	4,259

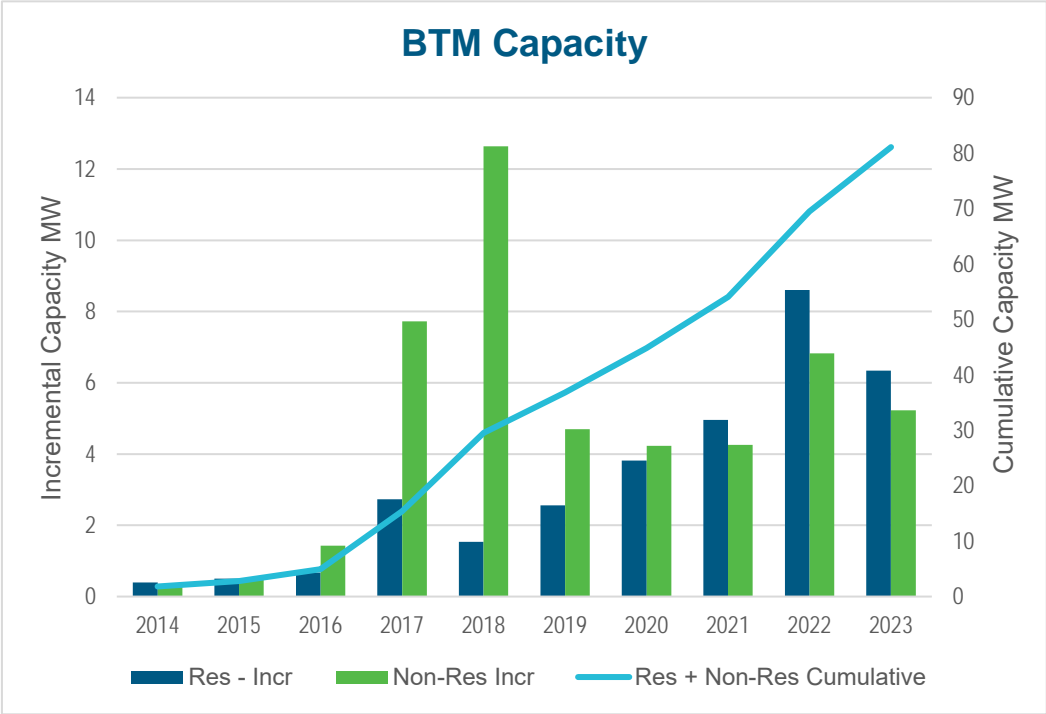
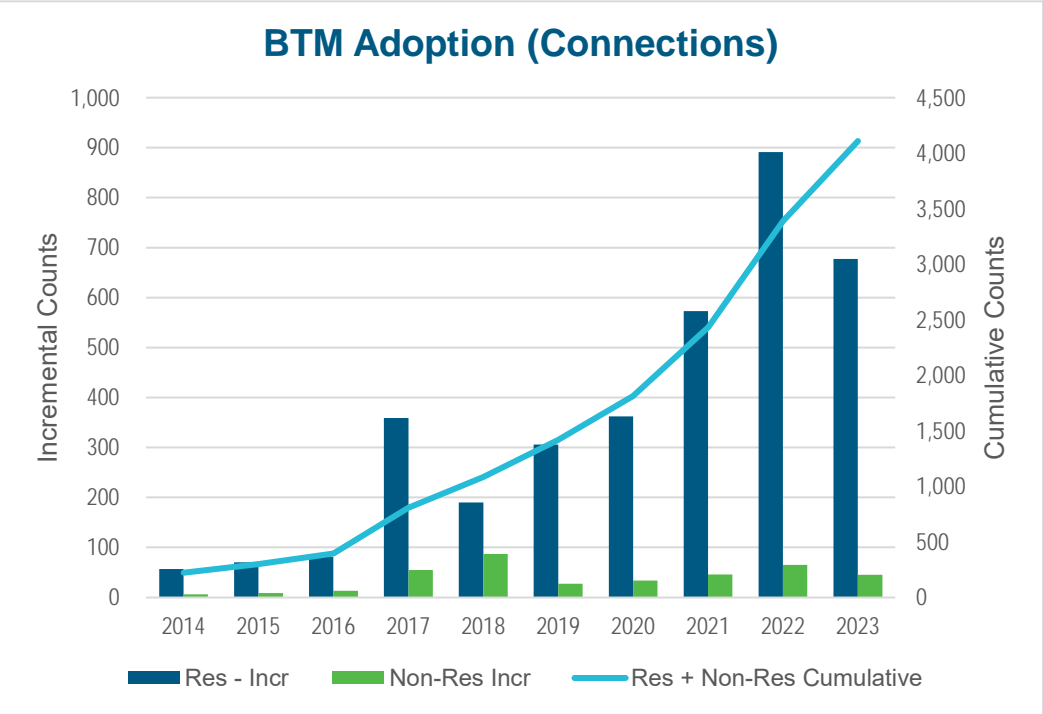


# Forecasting Behind-the-Meter (BTM) Solar

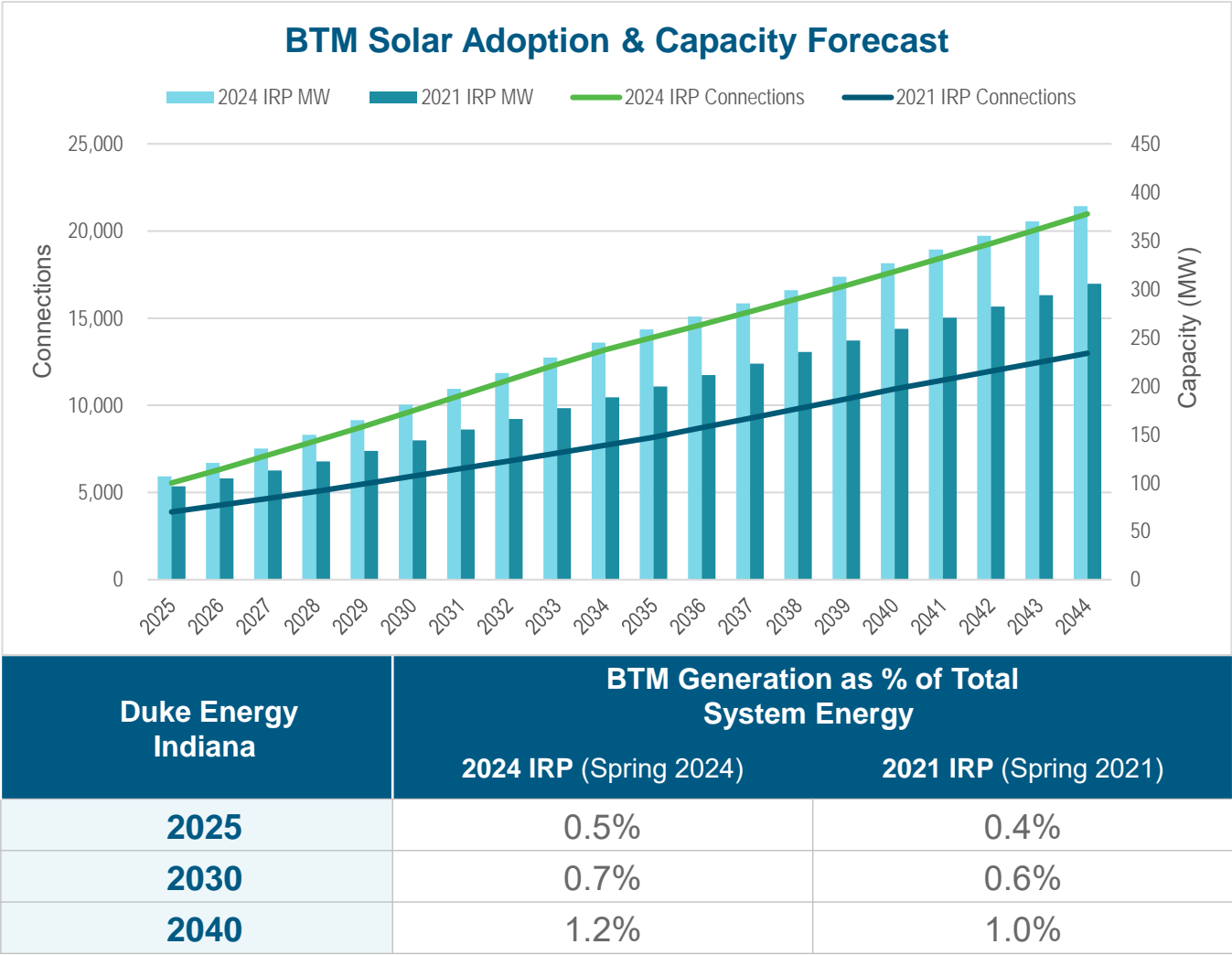


# DEI Behind-the-Meter Solar History

- BTM adoption counts peaked in 2022
- Recent trends in adoption influence future projections
- Factors influencing historical trends
  - State policy changes
  - Investment Tax Credits (ITC)
  - Solar panel prices
  - Fuel price volatility
  - Macroeconomic trends
  - Maturing market



# Behind-the-Meter Solar Base Forecast



**2024 IRP base forecast relative to previous:**

- Higher customer adoption, but only slight increase in BTM generation as percent of total system energy
- Reflects higher system costs
- Includes federal ITC through 2034 while the prior forecast assumed no extension of the federal ITC beyond 2023
- Incorporates historical data through 2023 while the prior modeling used historical data through 2020
- System size estimates have been adjusted to include the more recent historical data – residential sizes have increased from about 8 to 9 KW, while non-residential sizes have decreased from averages around 200 kW to about 120 kW

# Behind-the-Meter Solar Alternate Scenarios



	Low	Base	High	Ultra-High
<b>Key Assumption Differences</b>	<ul style="list-style-type: none"><li>▪ Payback model adjustments</li><li>▪ High system costs</li><li>▪ Removal of ITC credits</li></ul>	Base Case	<ul style="list-style-type: none"><li>▪ Payback model adjustments</li><li>▪ Low system costs</li><li>▪ Enhanced ITC credits</li></ul>	Scaled to meet a stakeholder-provided scenario of 25% adoption by year end 2040  Note: Incremental distributed solar is added as supply-side resource in model rather than load modifier
<b>% of Residential Customers – 2024</b>	0.5%	0.5%	0.6%	1.9%
<b>% of Residential Customers – 2030</b>	0.7%	1.0%	1.3%	13.0%
<b>% of Residential Customers – 2040</b>	1.3%	1.8%	2.3%	25.0%



# Q&A



# Grid Edge & Customer Programs



# Integrated System Planning and Operations



## Why integrated planning?

Value all energy resources based on their functional capabilities, regardless of location

Ability to “stack” benefits across the different systems

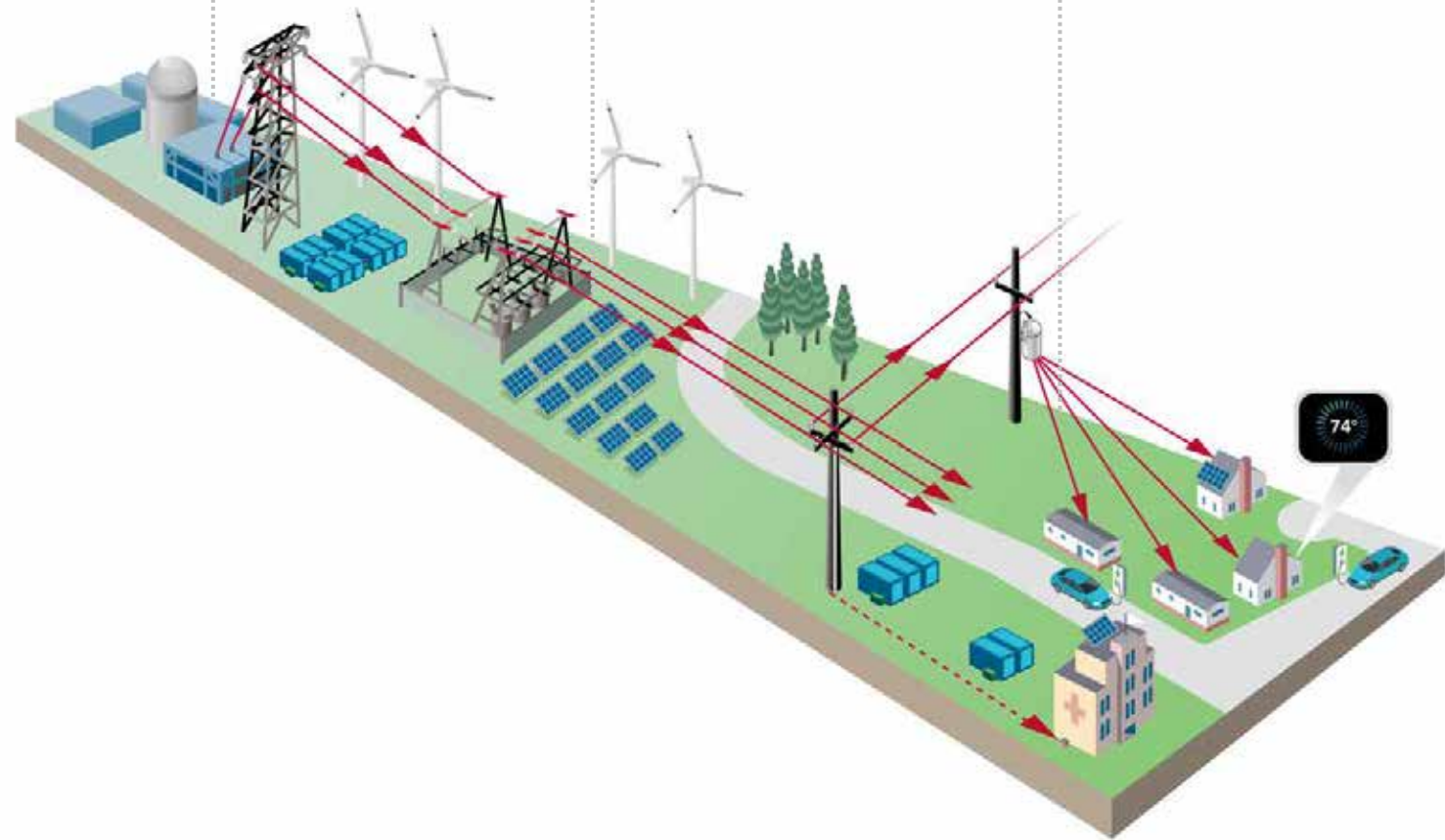
Improve reliability and resiliency

Generation: bulk energy production facilities

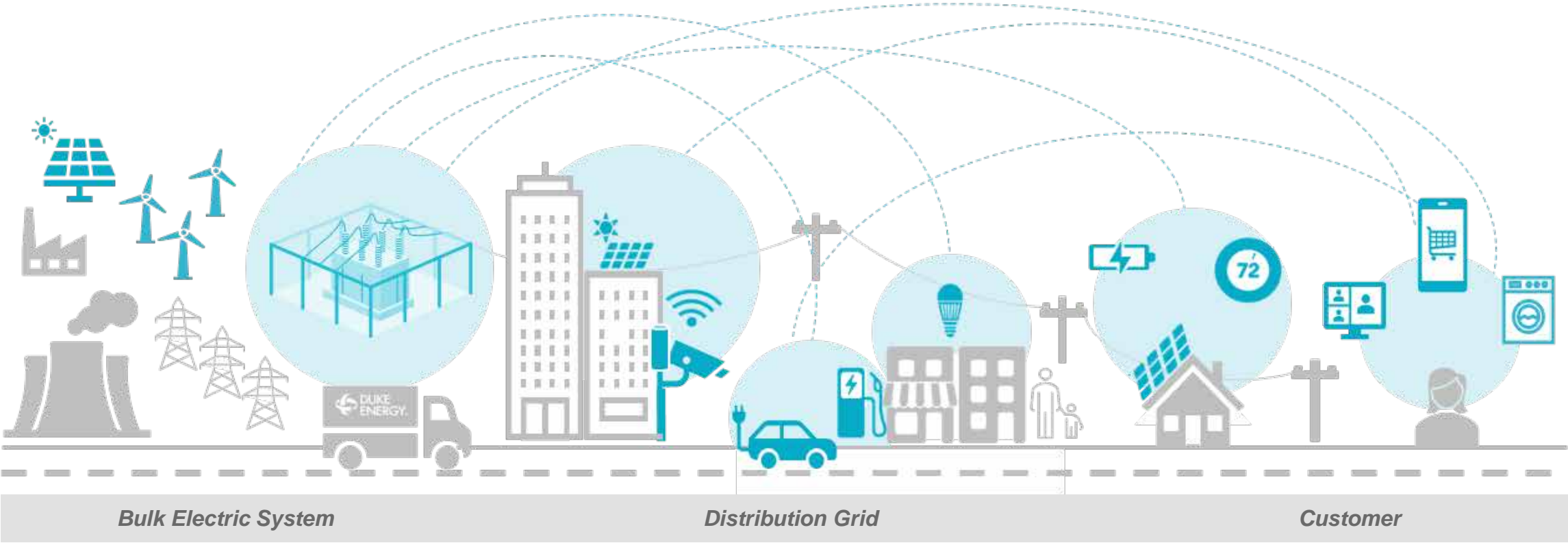
Transmission: bulk power transmission, typically at or above 100 kV

Distribution: lines that bring power to customers, typically 12 to 34 kV

Customer: DERs such as customer sited solar and demand response



# What is the Grid Edge?



? What is the value to our customers?  
Engaging with our customers to reduce and manage  
load at the Grid Edge can be cost-effective

Grid Edge

Reliable

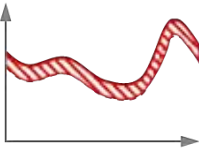

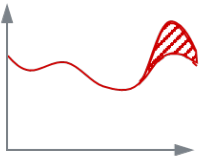


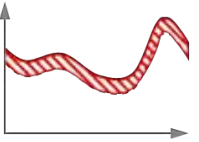


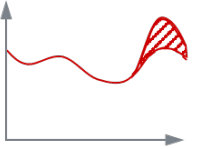


Affordable

Clean

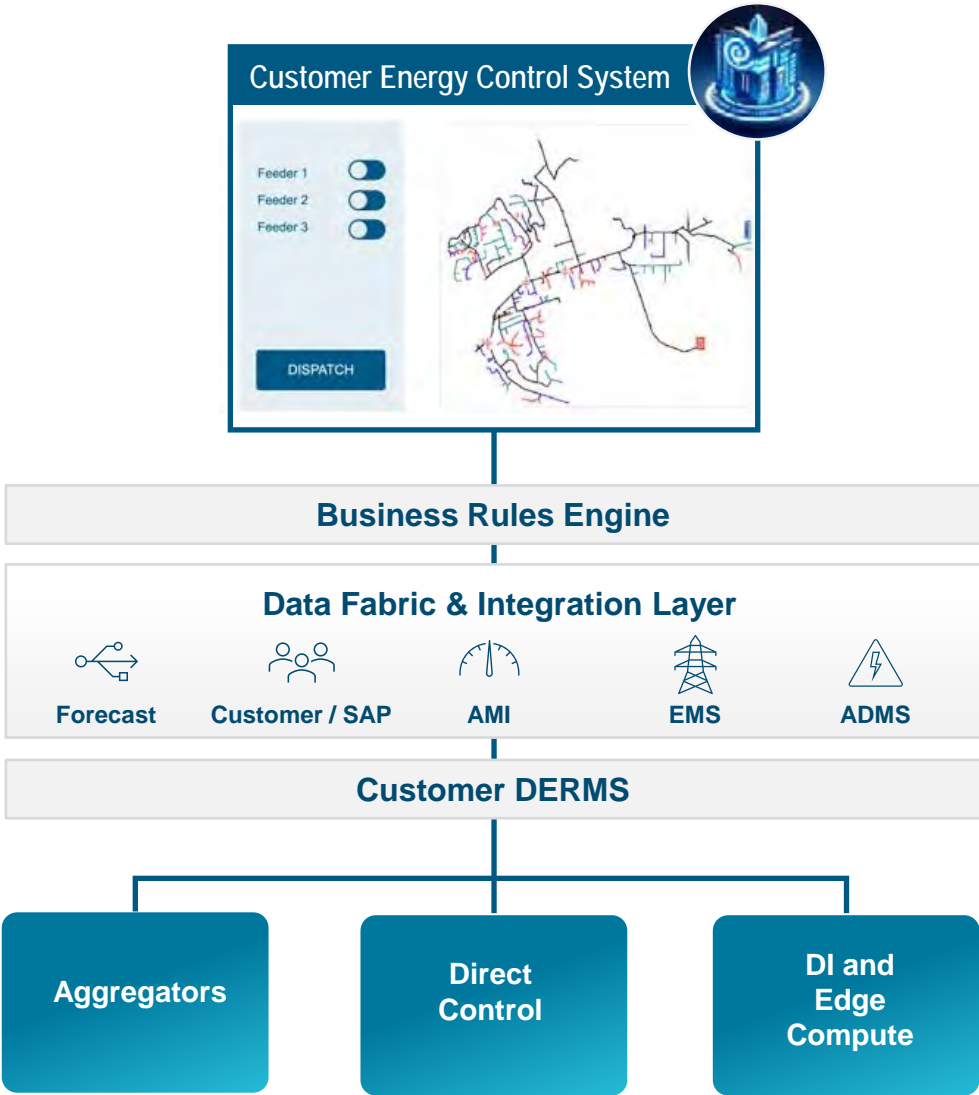
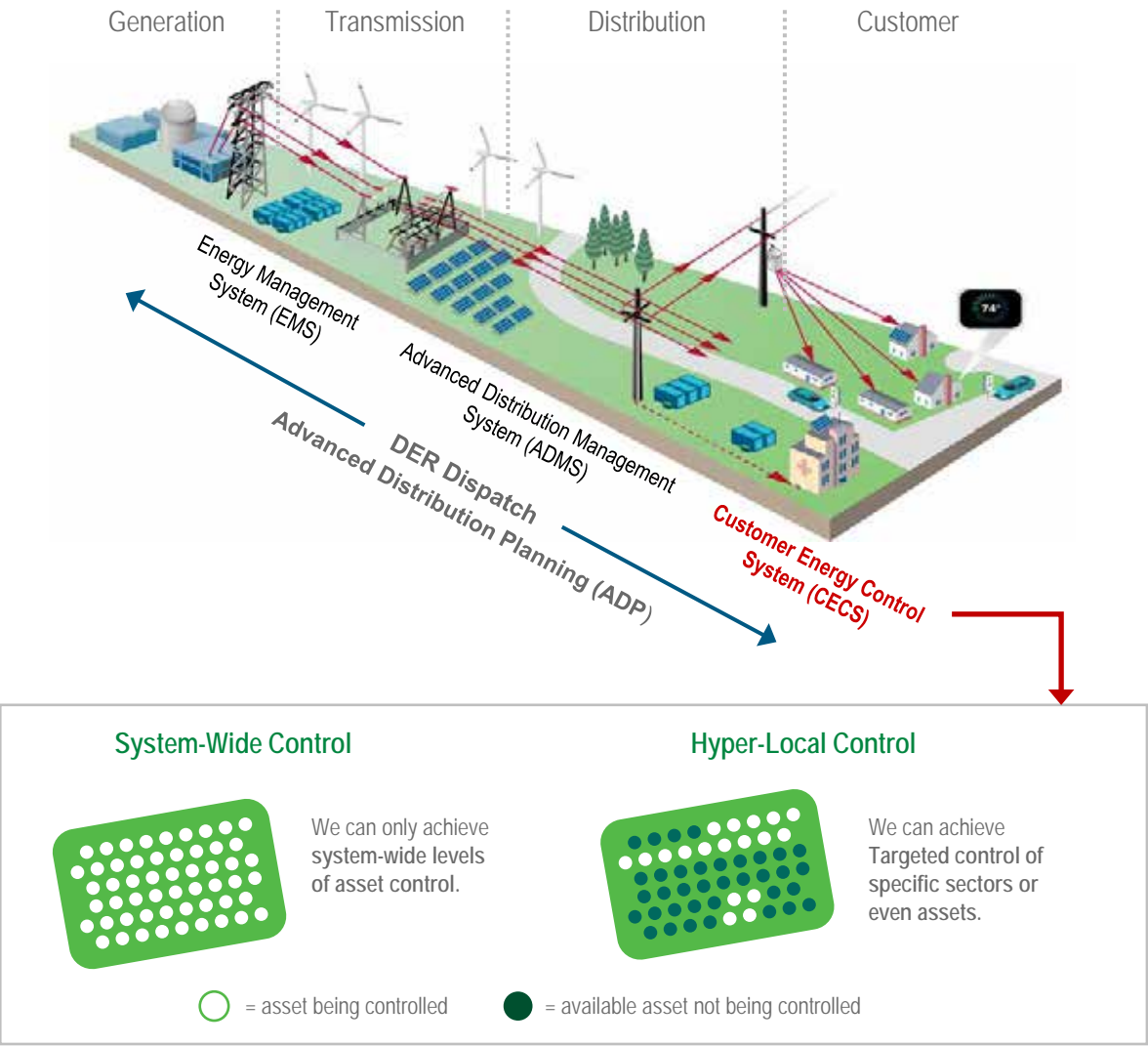
# Grid Edge Programs

Technology  Energy

## Examples of Resources and Emerging Opportunities

RESOURCES	<b>Voltage optimization</b>  <b>Baseload:</b> Eliminates demand	 Integrated Volt Var Control	
	<b>Demand response / Distributed Capacity</b>  <b>Peaker Plant / Reserves:</b> Functions like a gas CT or battery supporting peak demand	 Residential programs	 Managed Charging
	<b>Energy efficiency</b>  <b>Baseload:</b> Eliminates demand	 Behavioral programs (My Home Energy Report)	 Retrofits and appliance replacement
	<b>Dynamic pricing</b>  <b>Peaker Plant:</b> Functions like a gas CT, battery, or pumped hydro by supporting, shifting, and reducing demand	 Time differentiated rates	 Peak time messaging

# Control Systems



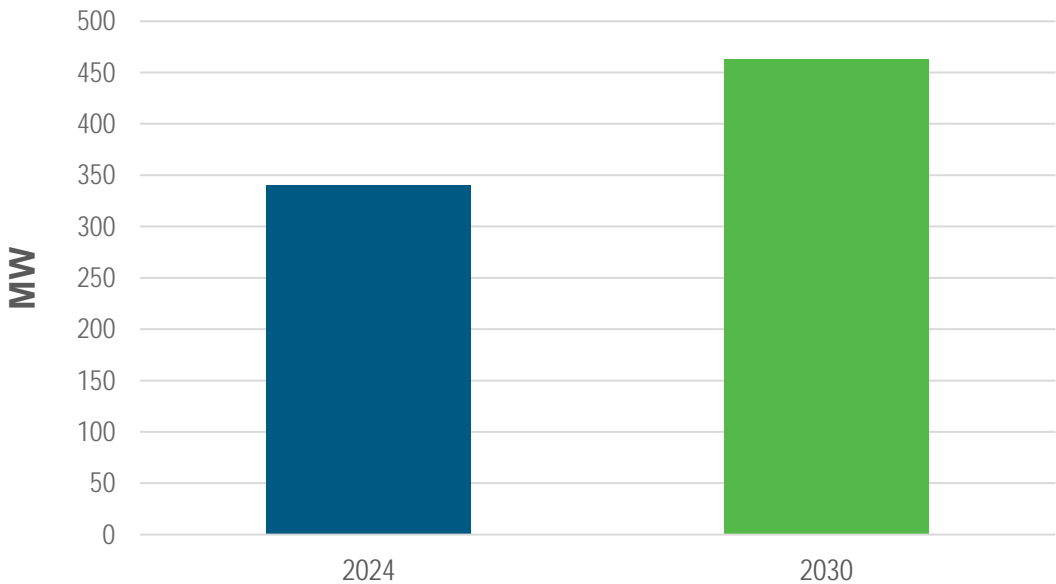
# Grid Edge | Demand Response

**Current State:** Demand Response (kW)

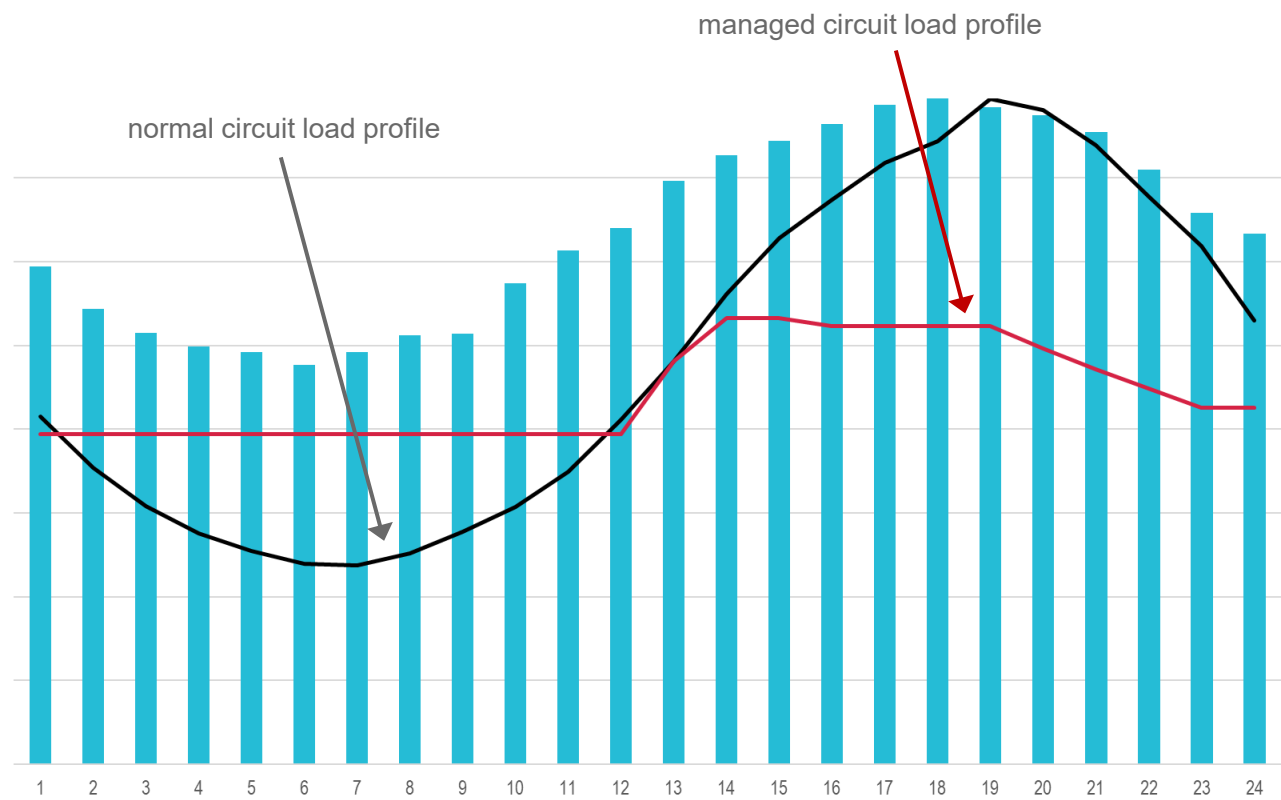
BYOT	33,535
PM Business	5,327
PM Water Heating	244
Power Manager	67,223
PowerShare / Savings on Demand	236,519
Total	342,848



**Future State:** Demand Response (MW)



# Grid Edge Opportunity



- Grid edge programs create the opportunity to directly reduce carbon emissions and enable clean energy resources to maximize their value
- Reducing load and managing load at the Grid Edge can be one of the most cost-effective means to reduce carbon

Note: illustrative circuit load profile

## Opportunities:

- Energy Efficiency
- Active Demand Response
- Distribution Batteries
- Distribution Renewables
- Voltage Optimization

## Customer Programs:

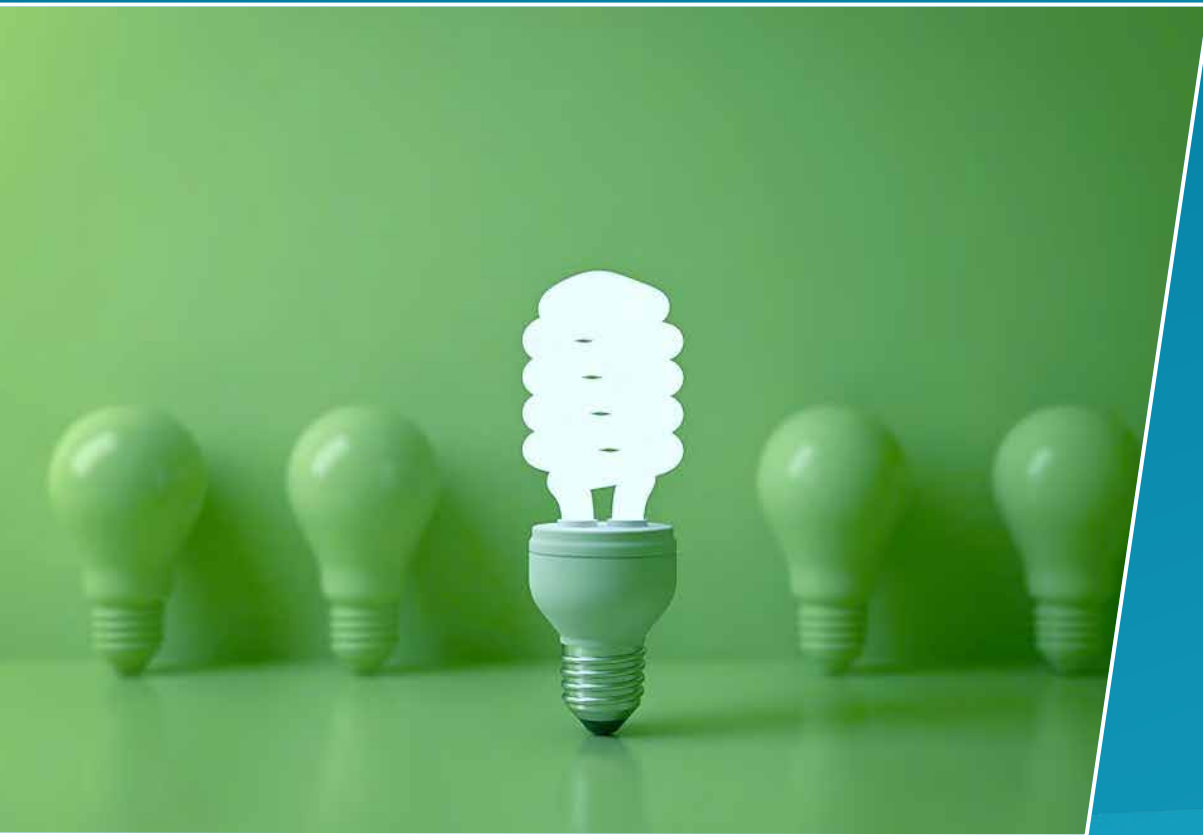
- DR (Residential, C&I)
- Bring Your Own Thermostat
- TOUs (EV, Res, etc.)
- Potential Future Programs: Residential battery, V2G







# Q&A



# Market Potential Study



# Demand-Side Management Market Potential Study

Duke Energy Indiana | April 2024





# Agenda

**1** / Introduction to Resource Innovations

**2** / DSM Market Potential and the IRP Process

**3** / Overview of MPS Concepts

**4** / Key MPS Components

**5** / Summary

# RI Services and Software

## Advisory Services

Research & Measurement  
Planning & Design  
Analytics & Strategic Consulting  
Grid Modernization

## Utility DSM

Residential & Income Qualified  
Commercial, Industrial, & Agriculture  
Flexible e-commerce  
Client Services  
Market Transformation  
Transportation Electrification  
Load Flexibility

## Government Services

Grant Management  
Program Administration  
Decarbonization

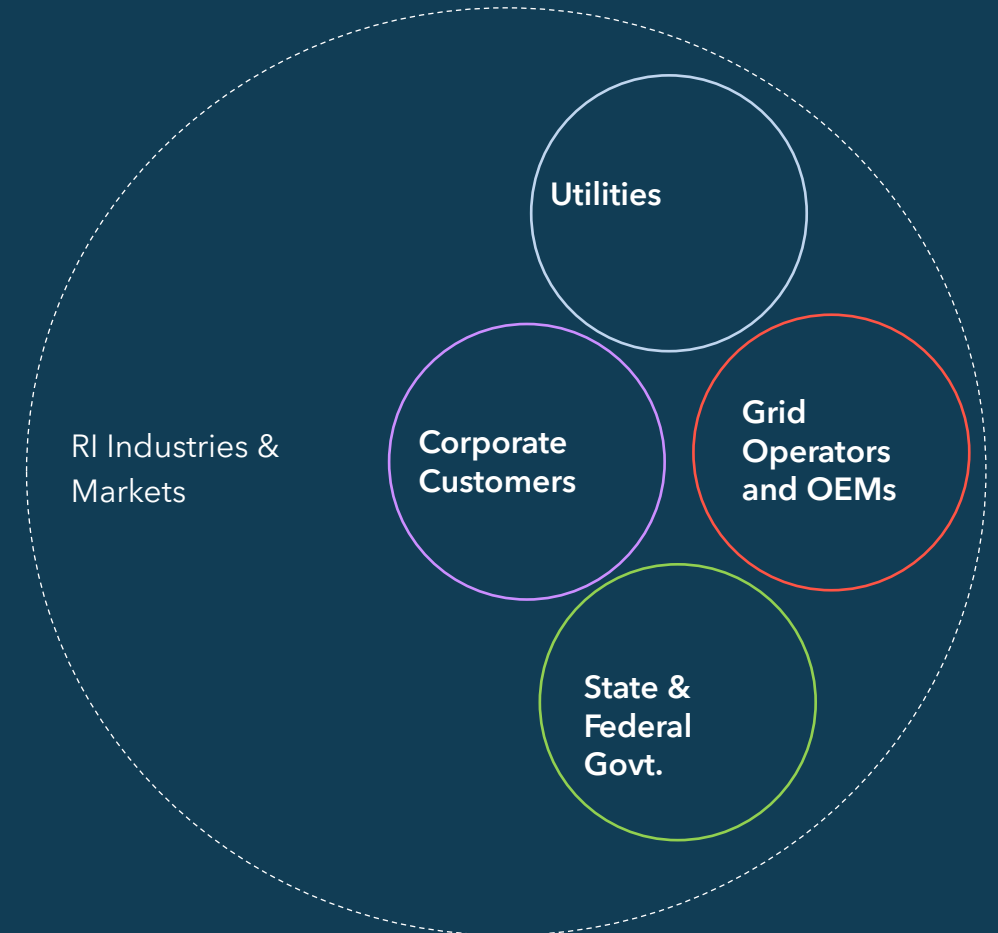
## Corporate Services

Fleet Electrification  
ESG / Decarbonization Advisory  
Energy Efficiency

## Software & Analytics

Grid Analytics Platform  
Customer Platform  
E-commerce Platform

Providing Innovative Technology-Enabled  
Software, Services, and Consulting.





# Broad geographic reach combined with deep client relationships

## Advisory Services

- 25+ US and Canada customers
- Highly skilled team of experts
- End-to-end utility services

## Utility DSM

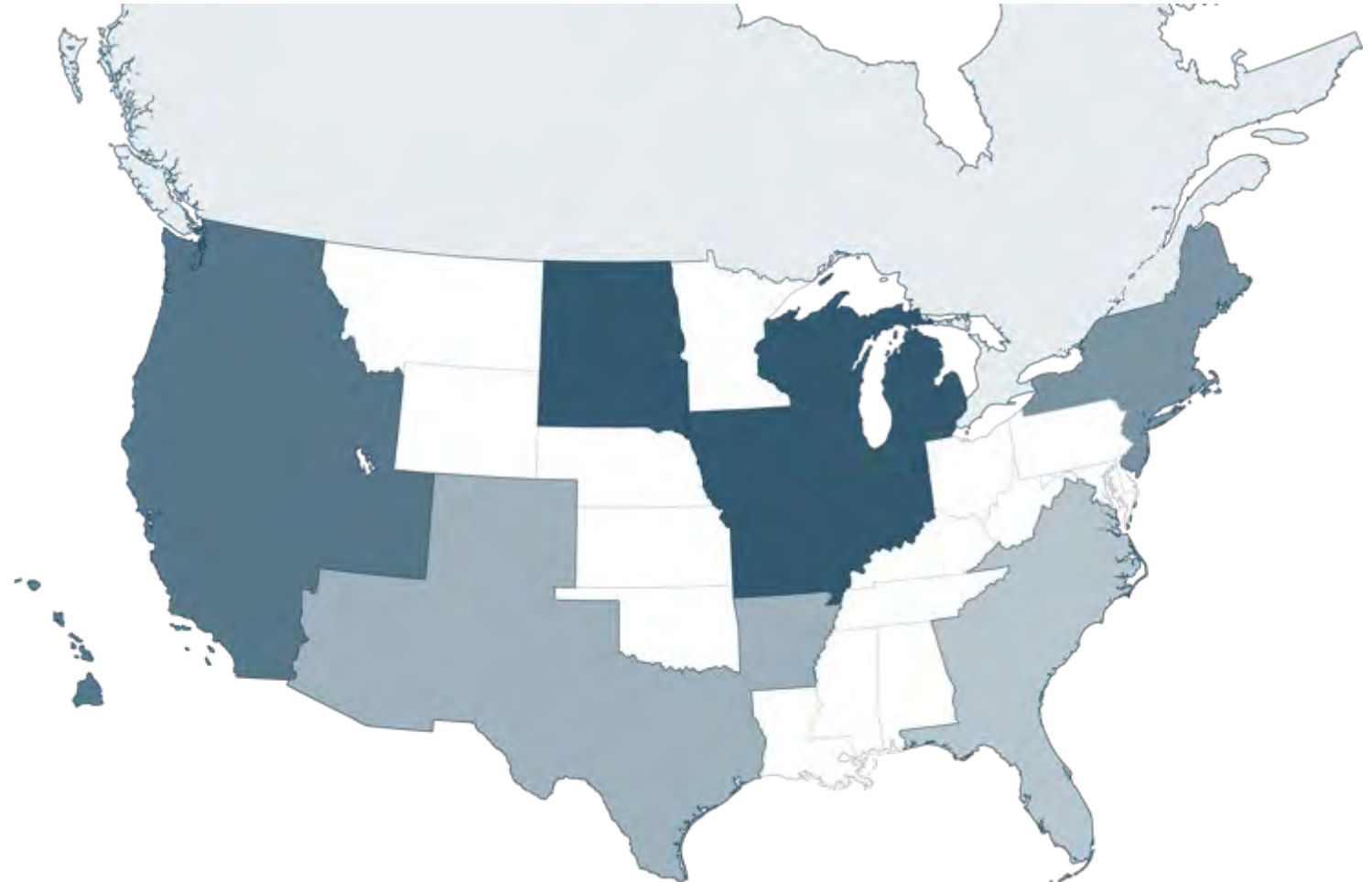
- 90+ Utility Customers
- Geographically diversified customer base
- 99% Customer retention rate

## Government Services

- Grant Management and Administration
- Demand Side Management (DSM)
- Decarbonization

## Software & Analytics

- 70+ Software Clients & Partners
- Strong Partner Channel deployed worldwide
- >95% Customer Retention







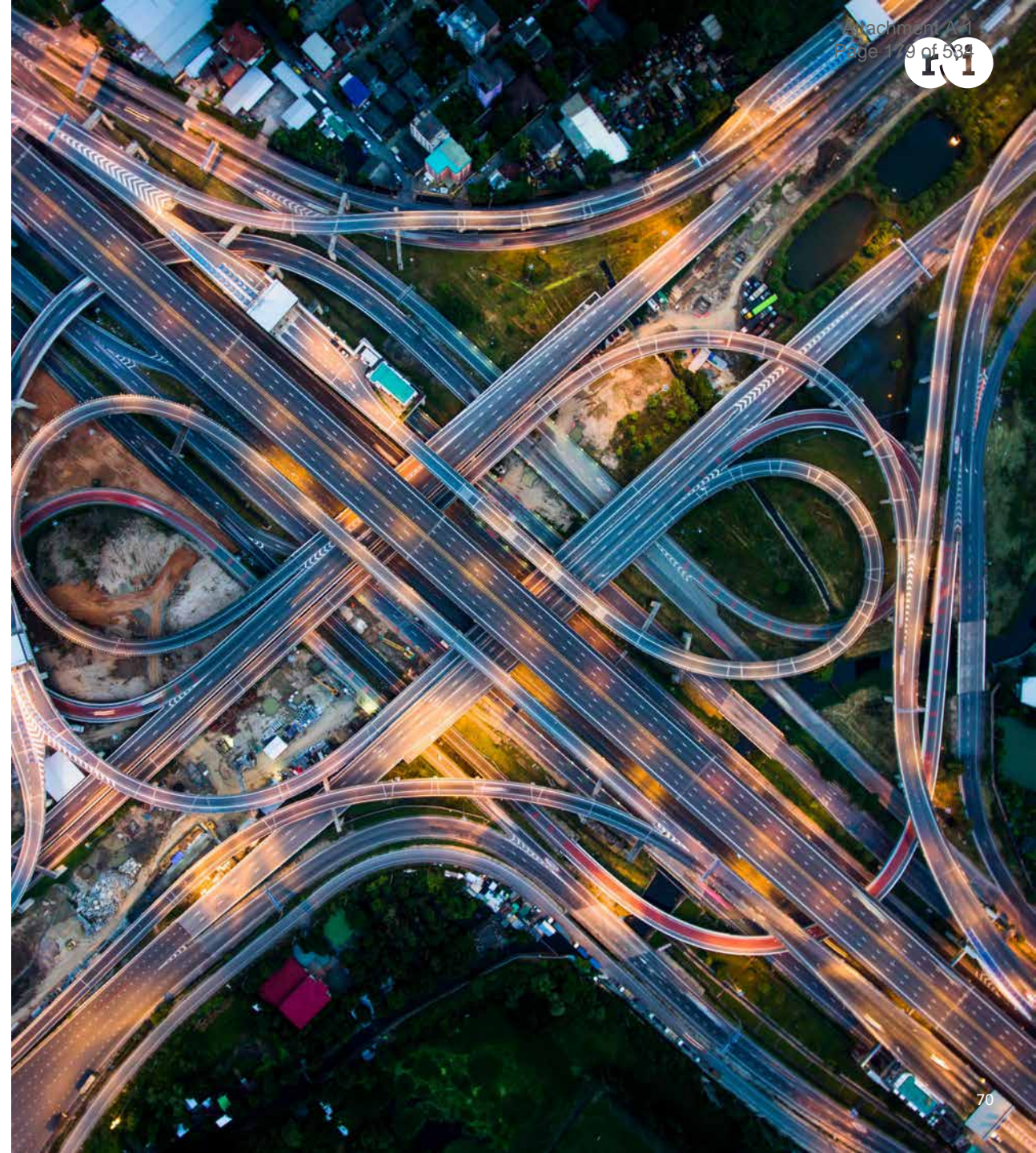
# 2/ DSM Market Potential and the IRP Process

# DSM Market Potential Analysis

Our analysis identifies opportunities for energy efficiency, demand response, and distributed energy resources. We examine all customer types and electricity end uses to find ways that utility programs can engage with customers to support energy efficiency and peak load management. We provide output data to Duke Energy for use in subsequent IRP modeling.

## Components of Market Potential Assessment

- Current levels of consumption and trends for electricity use
- Impact of individual technologies on consumption and peak load
- Costs and benefits of individual technologies
- Identify cost-effective technologies that might be incentivized by Duke Energy programs
- Calculate expected customer payback and technology adoption rates





# Project Goals

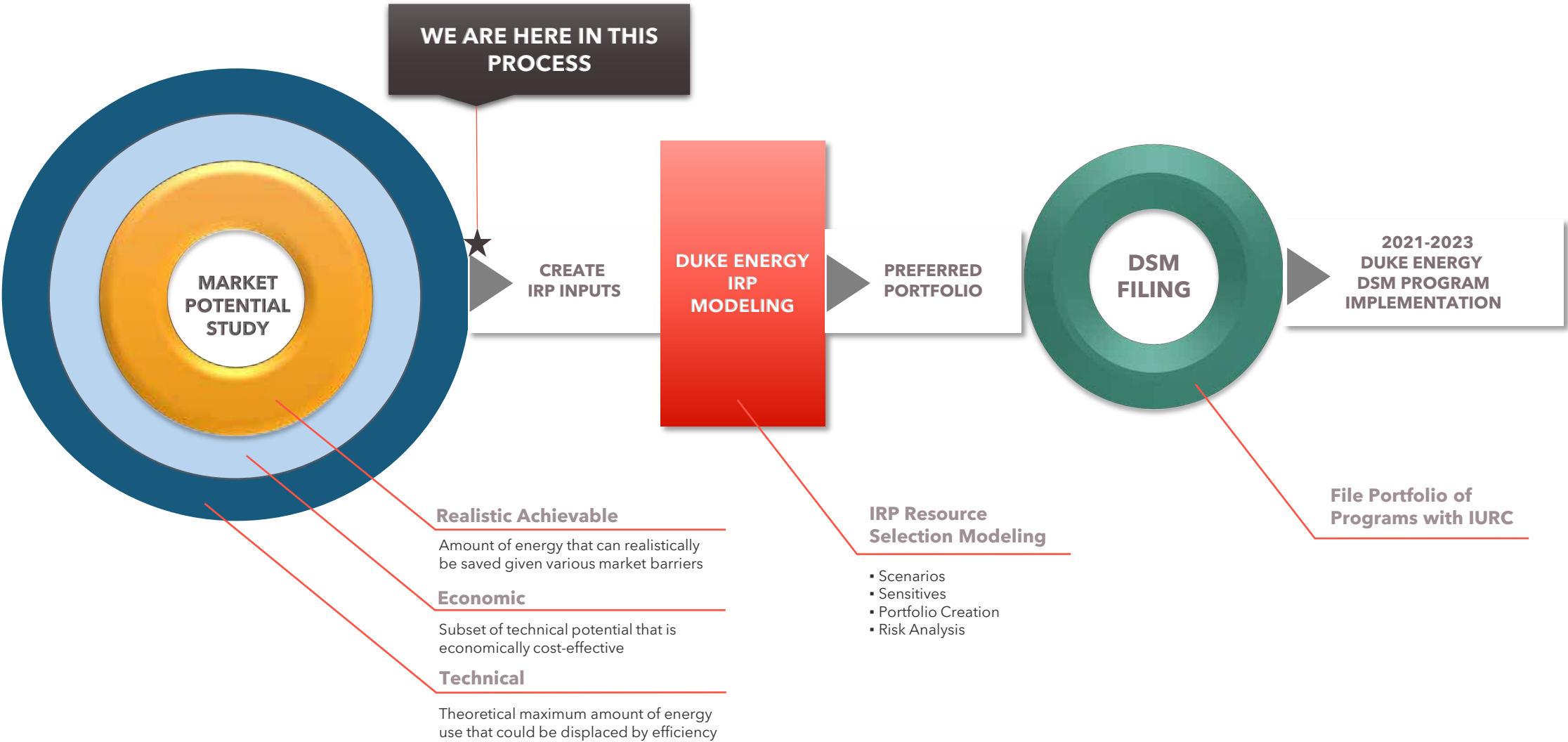
Technical, Economic, and Achievable Potential over a 25-year Study Period, with Estimates of 5-year, 10-year, and 25-year Energy and Demand Savings

## Achievable Potential Estimates for Cost-effective Program Offers:

- Energy Efficiency, Demand Response, CHP, and Solar + Storage
- Utility Cost Test (UCT) Screening
- Indiana Energy Efficiency Oversight Board (OSB) Collaboration
- Inflation Reduction Act
- Provide Input for Duke Energy IRP Models

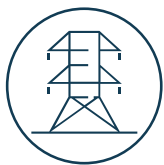


# Market Potential Studies & IRPs



# Market Potential Follows a Stepwise Workflow

The framework for analyzing market potential was established in 2007 under the National Action Plan for Energy Efficiency. The stages of market potential are designed to ensure broad consideration of measure opportunities, and firms like ours partner with utilities and DSM stakeholder groups to ensure a comprehensive analysis.



## Technical Potential

- What technologies are commercially available?
- Are there technical limits to their application?
- Which technologies apply to different customer groups?
- How much electricity/load can they save?



## Economic Potential

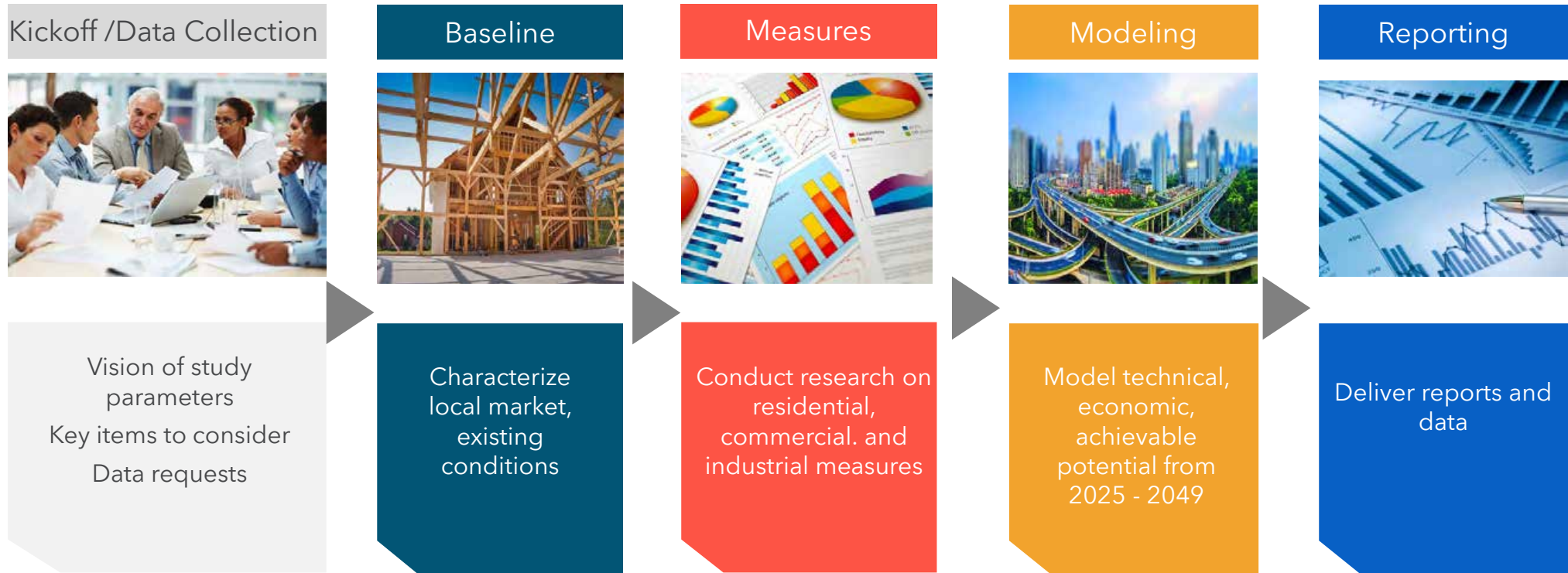
- How much do these technologies cost?
- Will it be cost-effective for Duke Energy to offer a program with incentives to reduce the customer cost?
- How do the costs and benefits of the different technologies compare?
- What is the maximum, cost-effective savings impact?



## Achievable Potential

- How much would it cost customers, after incentives?
- What is the expected payback period for each technology?
- How is payback time likely to affect customer adoption rates?
- What types of programs might be able to support customer adoption?

# Study Workflow



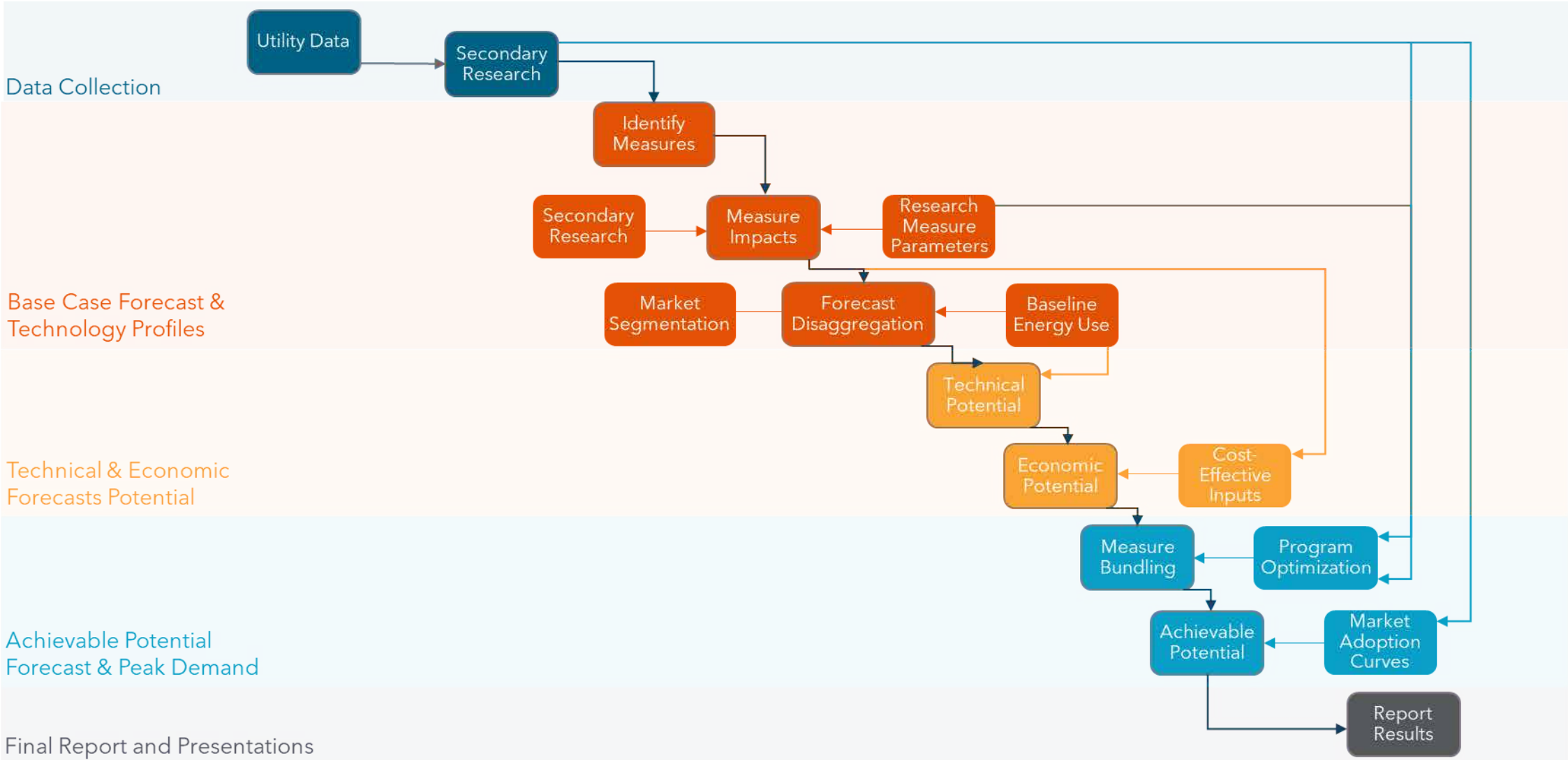




# Description of MPS Concepts



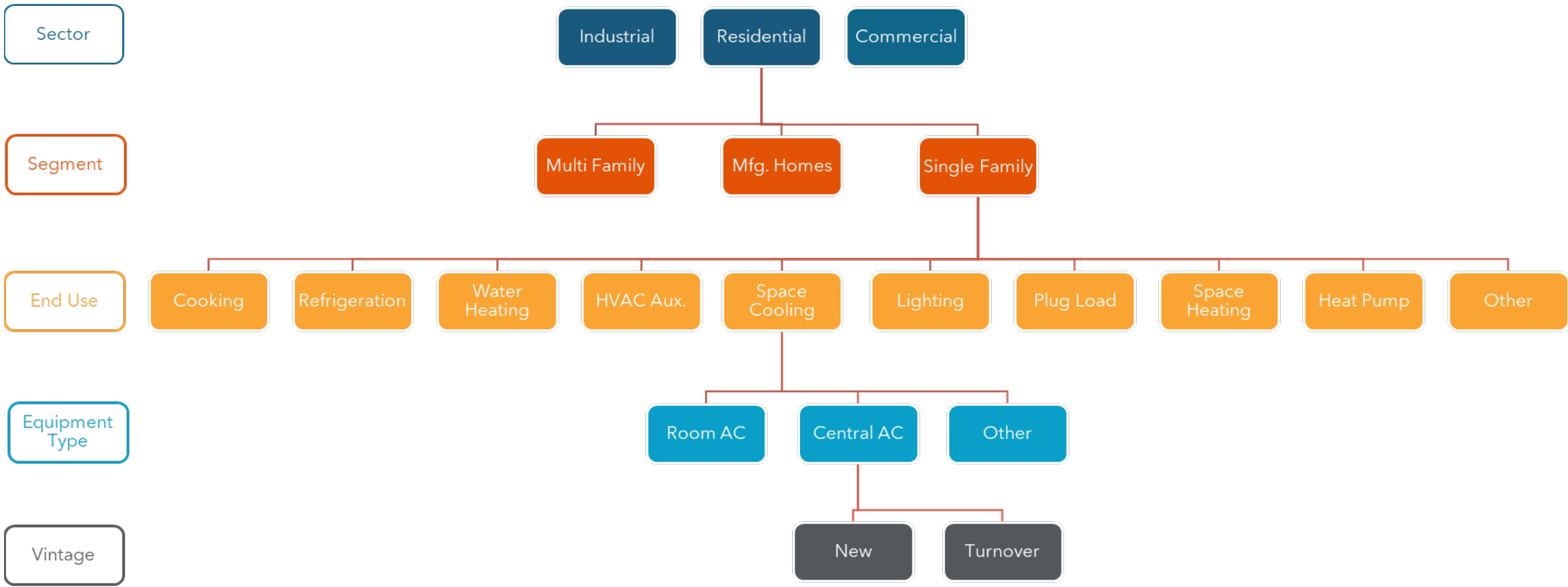
# Overall Process



# Forecast Disaggregation and DSM Potential



# Electricity Sales Forecast Decomposition

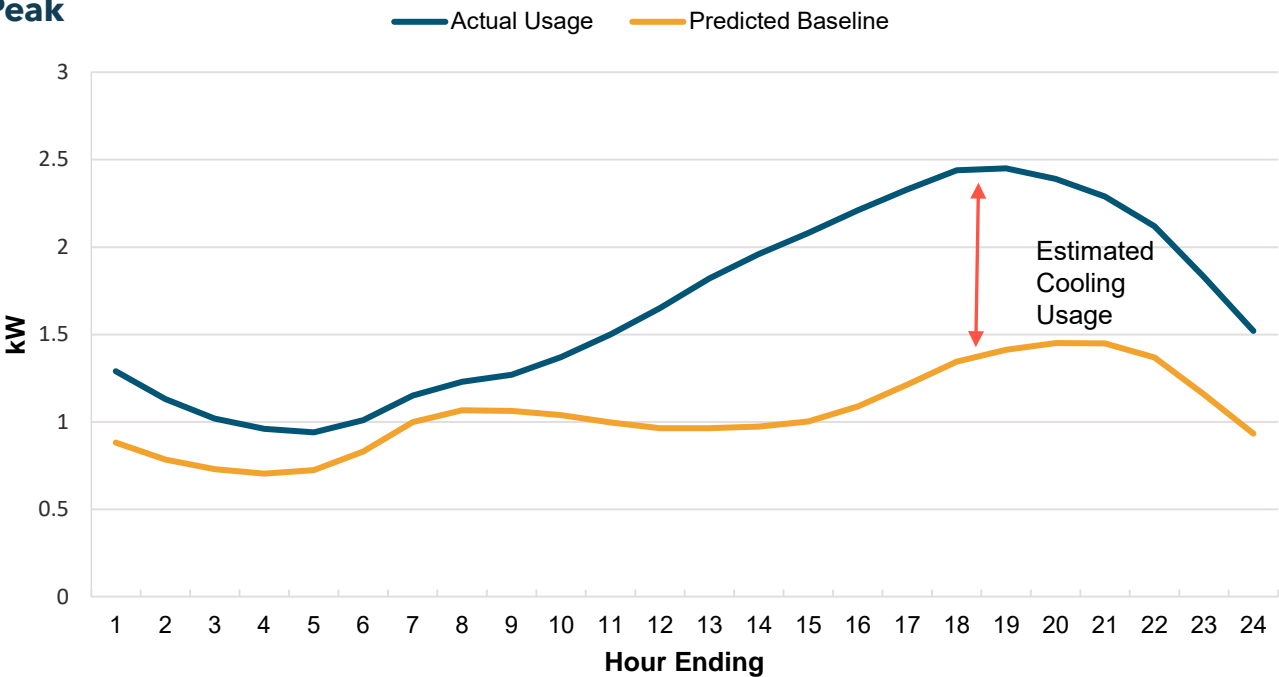


# Seasonal Load Disaggregation (Residential, SMB)

Analysis Based on Sample or Census AMI Data for Residential and Small/Medium Businesses

## Regression Analysis to Quantify Weather Responsive Load at Peak

- Cooling Degree Days, Heating Degree Days
- Weekdays, Weekends, Excluding Holidays
- Estimate Parameters and Predict for Mild Temperatures (0 Degree-days)
- Difference in Estimated Baseline and Observed Loads is Available Capacity Reduction at Peak (Technical Potential)
- Pool Pump Loads from DEI DSMore Software
- Other Loads from NREL RESTOCK and COMSTOCK for Indiana
  - Water heaters
  - End Use Load Coincidence at DEI Peak Hours

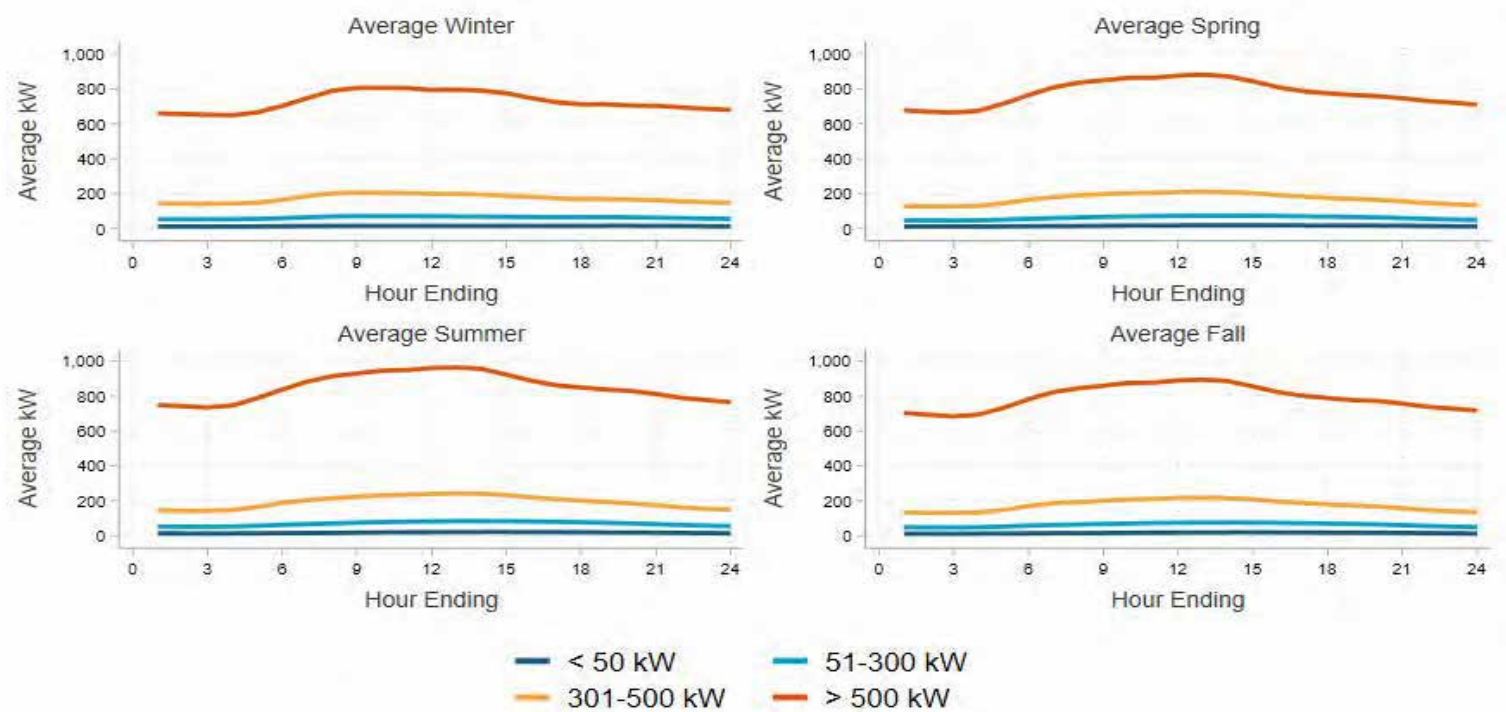


# Seasonal Load Reduction Capacity, Large Commercial

Analysis Based on Census AMI Data

## Key Assumptions of Total, Short-term Load Shed for a Suitable Price/Incentive

- Customer Loads at System Peak
- Large C&I Customers More Flexible in Scheduling, Contracting
- Individual, Anonymized Customer Loads from AMI
- Aggregated by Customer Segment
- Typical Weekdays, Weekends, Excluding Holidays





# Technology Research

We develop a robust set of all commercially-available technologies to consider in the study. Our model applies the technologies to the market baseline and accumulates savings over the study period

- We compare our measure list to current utility offerings, and incorporate any jurisdiction information and guidance on measure savings
- We share all measure data and inputs with the utility and stakeholders such as the Indiana Energy Efficiency Oversight Board
- We review stakeholder feedback, comments, and suggestions, incorporating as many as practicable
- The 2024 DEI MPS includes **474** DSM technologies, which results in over **9,083** permutations when applied to the market baseline of all economic sectors, all customer segments, all customer end uses, and all construction vintages

1

## Define the Features of the Measure

What is the baseline technology? How much energy can efficient tech. save? Which customers/end-uses are applicable?

2

## Measure Costs and Benefits

What is the cost of the measure? How much will it save over its lifetime when compared to the standard/baseline? Is it cost-effective to offer utility incentives?

3

## Customer Adoption

What is the customer payback, expected market share? Which technologies compete for market share? What is the expected timeline for market penetration?



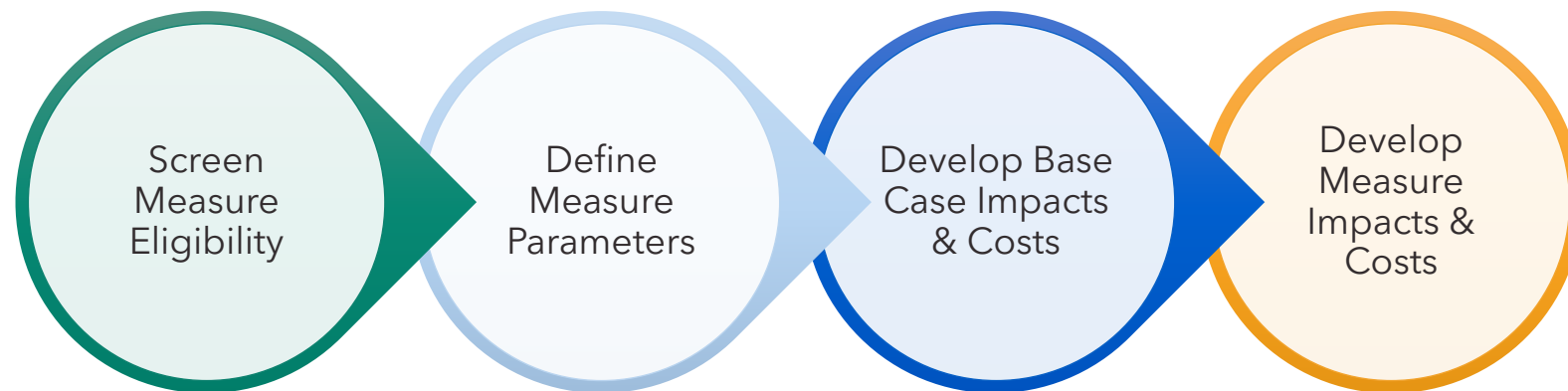
# Measure Characterization

## Measure data required:


- Efficient and baseline technology characteristics
- Equipment and labor costs
- Equipment useful life
- Energy and demand savings
- Applicability and current saturation

## Measure sources:

- Indiana TRM
- Nexant measure library platform
- Input from OSB
- Custom measures and new technologies



# Measure Library



HOMEADMINDOCS

HELPRESET PASSWORDLOG OUT

GENERALMEASURESCOMPONENTSVARIABLES

Collection-level Variables + Add Collection-level Equation Variable

Show 10 entriesSearch:

Name	Value	Short Desc.
btu_kwh (delete)	3412.00000	BTUs per kilowatt hour
btu_ton (delete)	12000.00000	BTUs per cooling ton
CF_GallontokWh (delete)	33.70000	Gallon to kWh Conversion Factor
CF_GastokWh (delete)	33.40000	Gallon of Gas to kWh Conversion Factor

Info

Name:

Duke Energy MPS Indiana

Short description:

DEI MPS - September 2020

Full description:

This is the measure library collection for the Duke Energy Indiana MPS

Utilities:

Duke Energy Indiana

Files

Duke\_Energy\_MPS\_Indiana\_MeasureEquationsAndVariables\_2020-09-19\_

Duke\_Energy\_MPS\_Indiana\_Variables\_2020-09-25\_10-11.csv

Duke\_Energy\_MPS\_Indiana\_MeasureEquationsAndVariables\_2020-09-25\_

Duke\_Energy\_MPS\_Indiana\_MeasureEquationsAndVariables\_2020-09-25\_

Duke\_Energy\_MPS\_Indiana\_Variables\_2020-10-01\_14-24.csv

Duke\_Energy\_MPS\_Indiana\_MeasureEquationsAndVariables\_2020-10-12\_

Duke\_Energy\_MPS\_Indiana\_MeasureEquationsAndVariables\_2020-10-19\_

Duke\_Energy\_MPS\_Indiana\_MeasureEquationsAndVariables\_2020-10-19\_

GENERALMEASURESCOMPONENTSVARIABLES

+ add Measure

Show 10 entriesSearch:

Name	Short Desc.	Measure Type	Unit of Measure	Measure Life	EE	Electrification	DR	DER	Sector
1.5 GPM Bathroom Faucet Aerators	Low-Flow Faucet Aerator with Flow Rate of 1.5 gpm	Non-Equipment	Per End Use Consumption	10.00000	Yes	No	No	No	Residential



# 4 Key MPS Components

# The Model

## Stock-and-Flow

- Current customers, sales, efficiency (stock).
- Changes in sales, customers, efficiency levels, equipment turnover, codes & standards (flow).
- Apply technologies to customers, end uses; retrofit and/or replace with efficient technology.
- Total savings for technical, economic, achievable potential over the study period.

**resource innovations**  
Reimagining tomorrow with *Nexant* today

### TEAPOT

Technical, Economic, & Achievable Potential

#### Key Input

Behavior Category	(variable)	Table
Start Year Stock	(fraction/year)	Table
Stock Growth Rate	(fraction/year)	Table
Sales Forecast	(kWh/yr or therms/yr)	Table
Start Year Sale Dist by Segment	(dimensionless)	Table
Start Year Sales Dist by End Use	(dimensionless)	Table
End Use Fuel Share	(dimensionless)	Table
End Use Saturation	(dimensionless)	Table
Equipment Type Saturation	(dimensionless)	Table
Energy Intensity	(variable)	Table
Energy Intensity CAGR	(fraction/year)	Table
Equipment Type EUL	(Years)	Table
Electric Rate	(\$/kWh)	Table
Retrofit Diffusion Coeff		Table
New/Turnover Diffusion Parameters		Table
B/C Threshold	(dimensionless)	Table
Avoided Cost Multiplier	(dimensionless)	Table
Program Incentive Fraction	(fraction)	Table
Minimum Adjusted Incentive Fraction	(fraction)	Table
Constrain Incentives for UCT?		<input checked="" type="checkbox"/>
Program Admin Cost	(\$/kWh or therm)	Table

#### Key Output

##### Filters

Sector Selected	Residential
Utility Selected	DEI
Customer Base	All Customers
Adoption Scen	All
Avoided Cost Scenario	Base
Incentive Scenario	Base Incentive Case

##### Summary Output

Savings by Sector	(kWh or kW)	Calc
Savings by End Use	(kWh or kW)	Calc
Savings by Equipment Type	(kWh or kW)	Calc
Svgs by Measure Name	(kWh or kW)	Calc
Svgs % Sale, Sector	(%)	Calc
Svgs % Sale, EqType	(%)	Calc
Calibrated Energy Forecast	(kWh)	Calc
Savings Output, Detailed	(kWh or kW)	Calc
Savings Cals Viewer	«Multiples»	Calc
Svgs by Meas Name & Behavioral...	(kWh or kW)	Calc



# Technical Potential (EE)



- Measures ranked by savings %
- Applied to baseline “equipment forecast”
- Dealing with representative buildings in a segment



# Economic Potential

Duke Energy and OSB Stakeholders Use the Utility Cost Test

## Features of the UCT Test

- Compares Utility Cost of a Program Offer to Avoided Energy, Capacity, and T&D
- Incorporates All Utility Costs: Incentive and Administrative
- Consistent with DSM Program Planning and Regulation

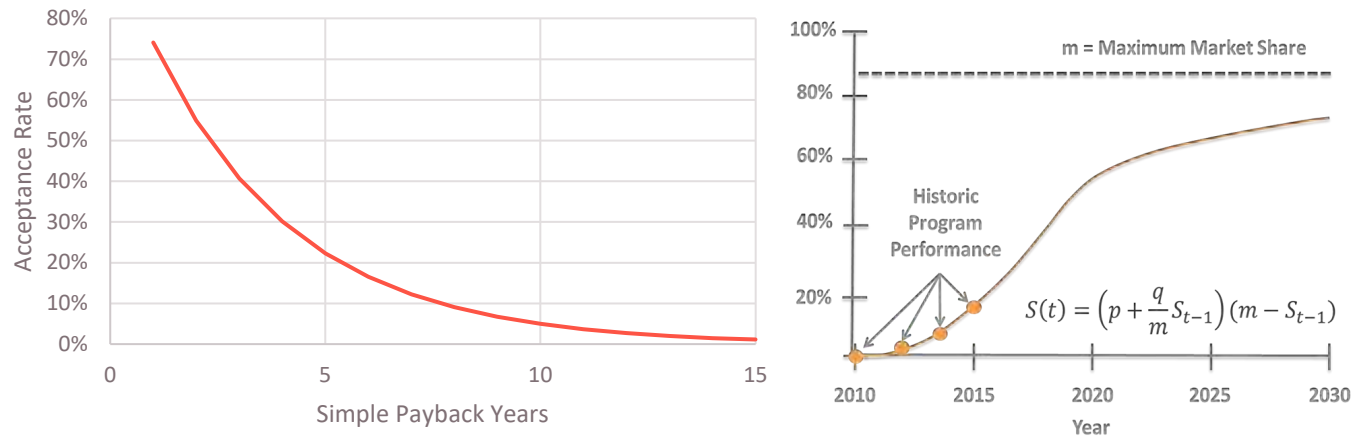
## Application of the UCT for DSM Potential

- Requires Assumptions for Incentive Rates and Administrative Costs
- Choice of Incentive Rate is Endogenous to Test Outcome
- Set an Incentive Rate Minimum at 30% of Measure Incremental Cost
- Avoided Cost Benefits Calculated by Duke Energy, with Measure Input Provided by RI





# Achievable Potential



## Incorporates Expected Market Response to Cost-Effective Offers

- Customer Payback Acceptance is Long-run Market Share
- Competing Measures are Allocated by Logit Market Share
- Adoption Rates over Time follow Bass Diffusion Model
- Year 1 Potential is Calibrated to Past Program Achievements

# Output for Integrated Resource Planning



## High-Resolution Output

- Expected Utility Costs and Benefits from Program Offerings
- Energy and Load Impacts by Economic Sector, Customer Segment, Electricity End Use, and Construction Vintage
- Anticipated Energy and Load Impacts for Each Year of the Planning Period
- Robust Modeling Tools for Scenario Analysis
- Transparent and Collaborative Process



## Holistic View of DSM Opportunities

- Assess and Compare the Vast Array of Savings Opportunities
- Identify Key Technologies for Different Customer Types
- Explore Costs and Benefits of Savings, and Timing of DSM Investment Opportunities
- Detailed, Granular Assessment that Enables Big-Picture Strategy
- Integrated View of both Utility and Customer Perspectives



Thank you!



# Q&A



# Break

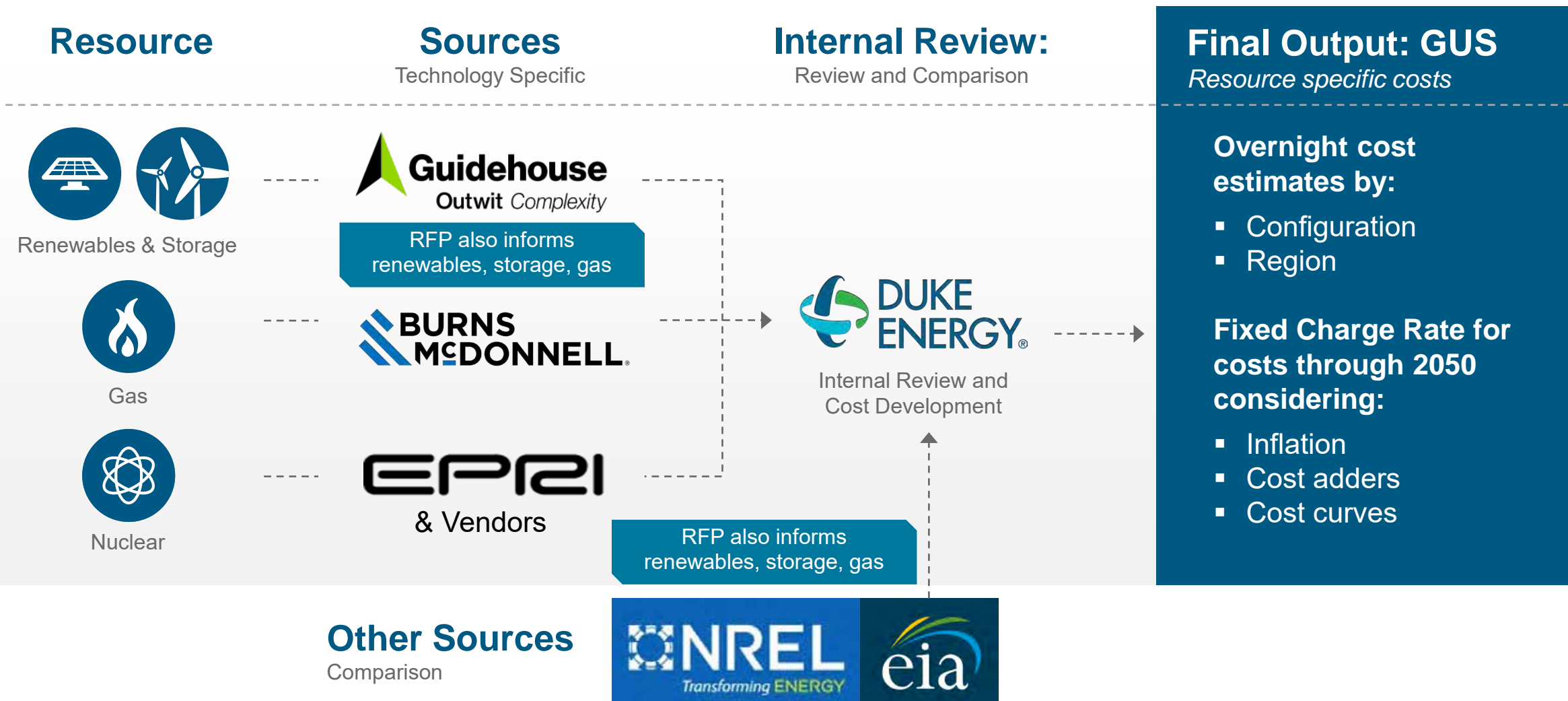




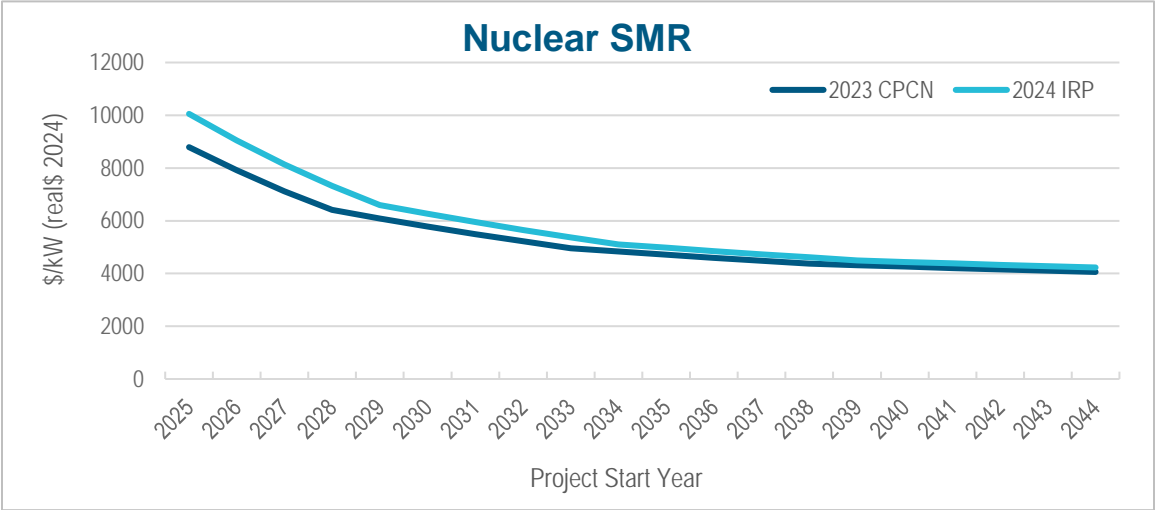
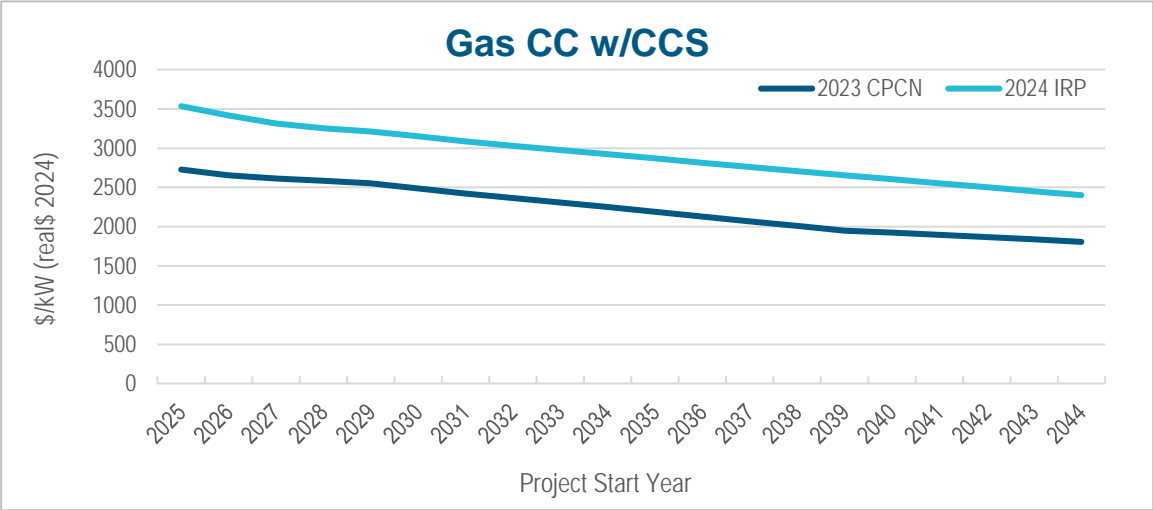
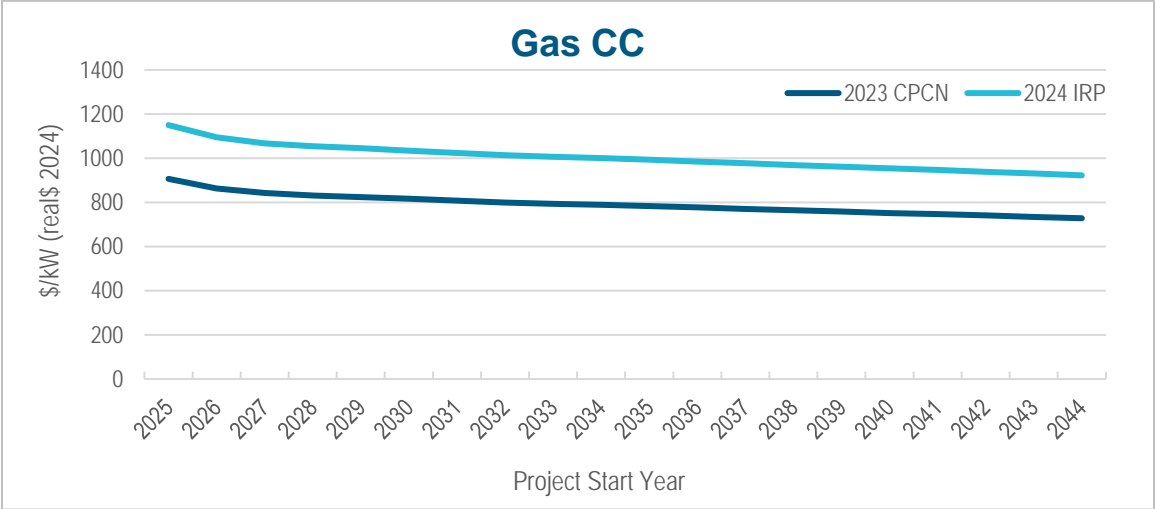
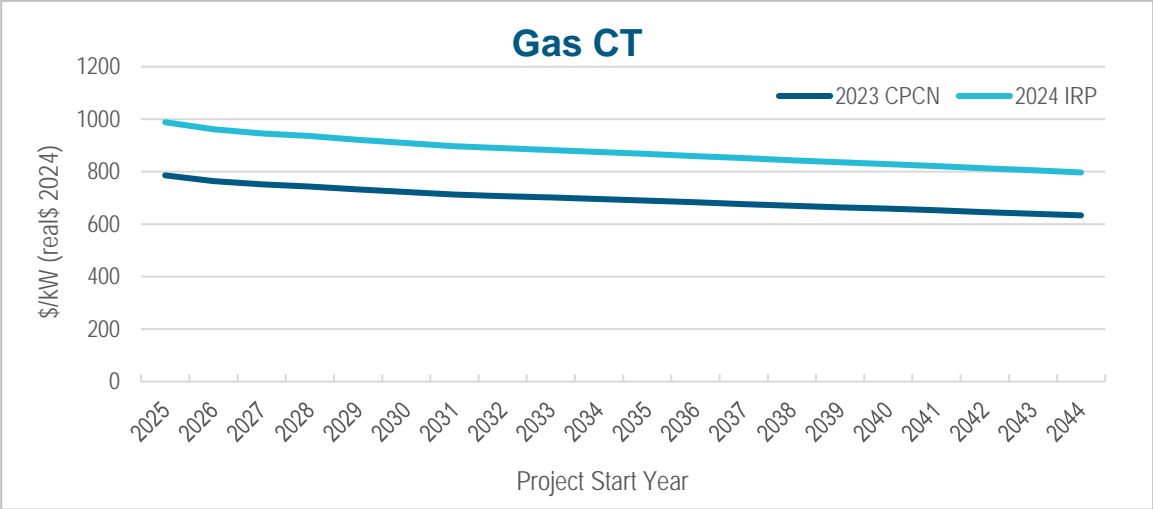
# Supply-Side Resources

## Generic Unit Summary & Resource Availability

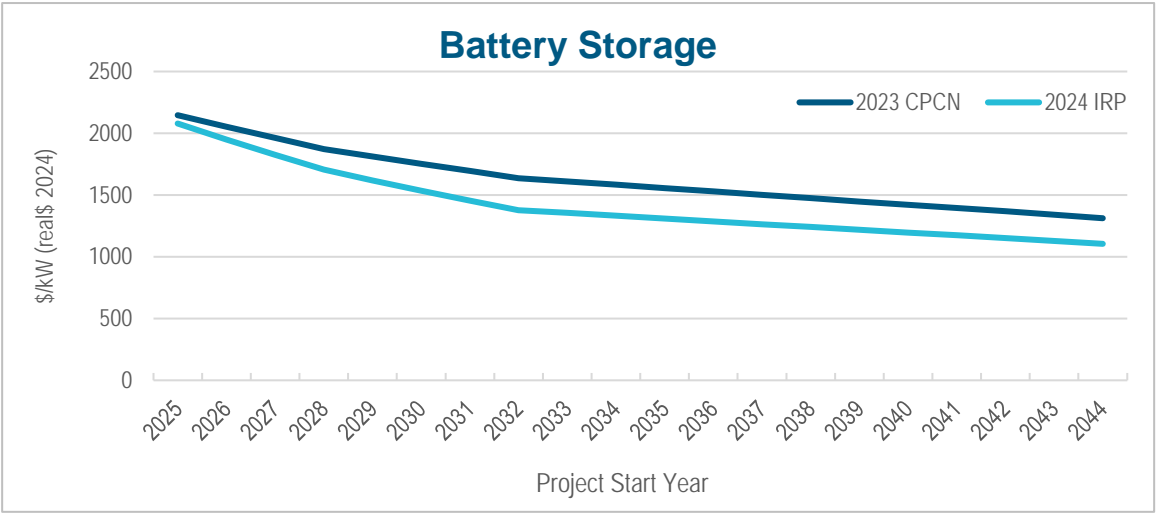
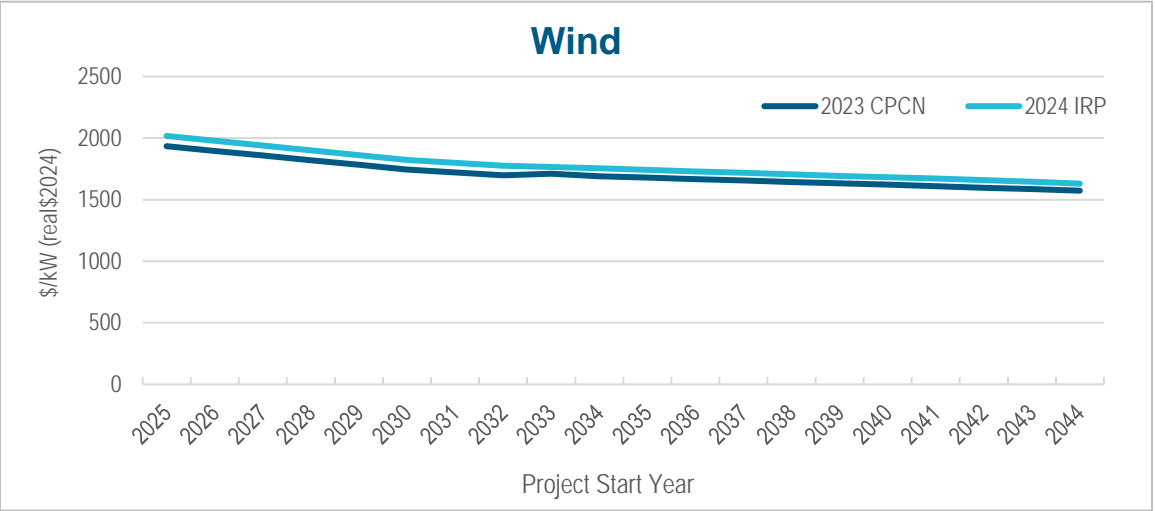
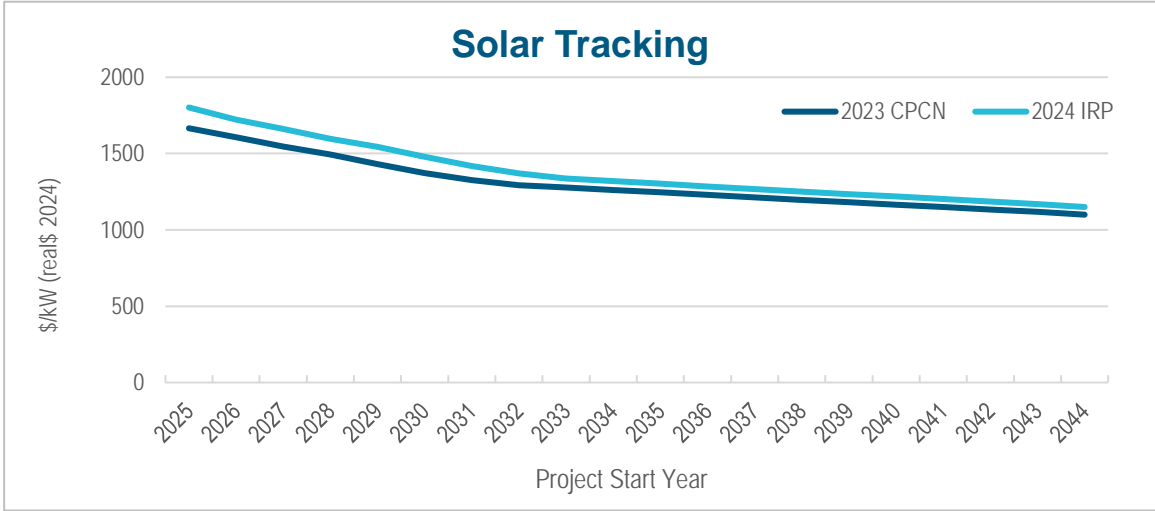
# Generic Unit Summary “GUS” Development



# Overnight Capital Costs | Thermal

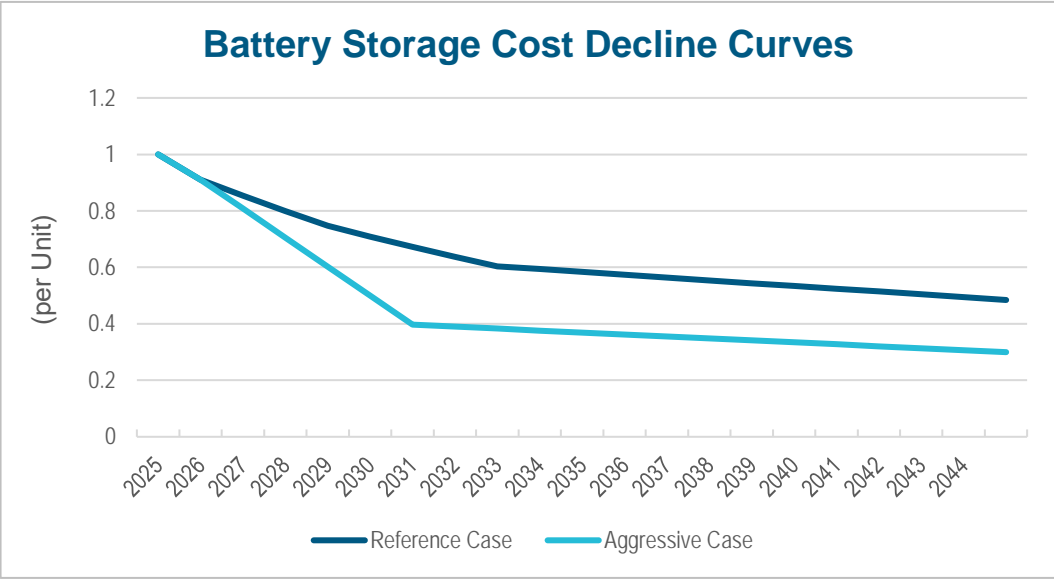
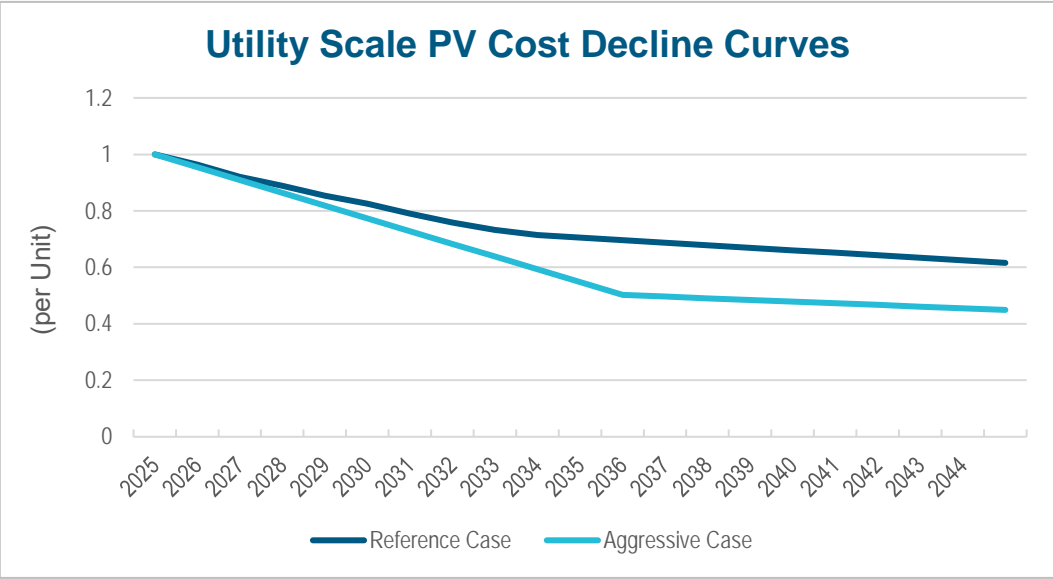


# Overnight Capital Costs | Renewables & Storage



# Low Renewables & Storage Cost in Aggressive Policy & Rapid Innovation Scenario

- The Aggressive Policy & Rapid Innovation “worldview” includes lower renewable and storage costs than the Reference Case
- Propose to use the NREL ATB 2023 Advanced case cost decline curves for future solar costs
- DEI’s cost decline curve for storage is more aggressive than NREL’s assumption. For low storage cost, propose to reach NREL’s Advanced case storage costs by 2030 and follow those costs for 2030+



# Annual Resource Availability (Interconnection Timing, BOY) | Thermal

Resource Type	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation	Basis for Assumption
CT	2031+: Two HA.03 (851 MW)	2031+: Two HA.03 (851 MW) <b>H<sub>2</sub> fuel</b>	Reference	Assessment of resource availability and suitable locations
CC	2029+: 1x1 H.03 (664 MW)	Reference	Reference	Assessment of resource availability and suitable locations
	2031+: 2x1 H.03 (1,364 MW)			
CT PPA	Thru 2028: 600 MW	Reference	Reference	MISO D-LOL implementing in 28/29
Nuclear	2037+: SMR 2039+: Advanced Reactor	Reference	N/A	Based on assumption of earliest availability

Note: Differences from reference case marked in **Bold**  
BOY: Beginning of Year. Availability begins January 1 of year listed.



# Annual Resource Availability (Interconnection Timing, BOY) | Renewables & Storage

Resource Type	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation	Basis for Assumption
Solar	2026: 199 MW	2026: 199 MW	Reference	Added capacity to 2023 & 2024 queues, accelerated study timelines, and IRA guidance supporting larger market pool
	2027: 300 MW	2027: 300 MW		
	2028: 750 MW	2028: 750 MW		
	2029+: 1,000 MW	<b>2029+: 1,500 MW</b>		
Wind	2028: 200 MW	2028: 200 MW	Reference	Assumes added capacity to 2023 and 2024 queues, accelerated study timelines and stakeholder acceptance
	2029: 200 MW	2029: 200 MW		
	2030+: 300 MW	<b>2030+: 600 MW</b>		
Storage	2028-2029: 300 MW	2028-2029: 300 MW	Reference	2028-2029: Based on RFP data 2030+: Based on MISO Queue
	2030+: 700 MW	<b>2030+: 1,200 MW</b>		
LDES	N/A	<b>2030+: 100 MW (10-hr) 2032+: 100 MW (100-hr); 500 MW (total)</b>	Reference	Technology Readiness Level score
SPS	2028-2029: 400 MW Solar; 50% (4-hr)	2028-2029: 400 MW Solar; 50% (4-hr)	Reference	Added capacity to 2023 & 2024 queues, accelerated study timelines, and IRA guidance supporting larger market pool
	2030+: 600 MW Solar; 50% (4-hr)	<b>2030+: 1,000 MW Solar; 50% (4-hr)</b>		

Note: Differences from reference case marked in **Bold**  
BOY: Beginning of Year. Availability begins January 1 of year listed.



# Q&A



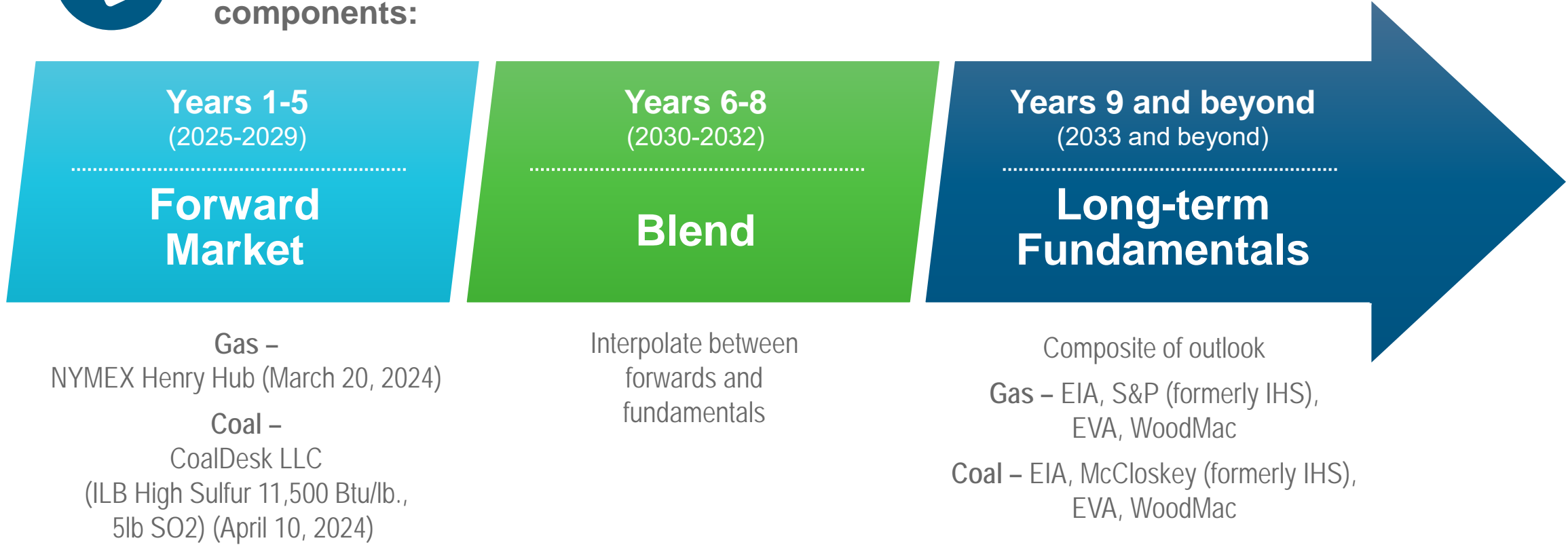
*BUILDING A SMARTER ENERGY FUTURE®*

# Fuels

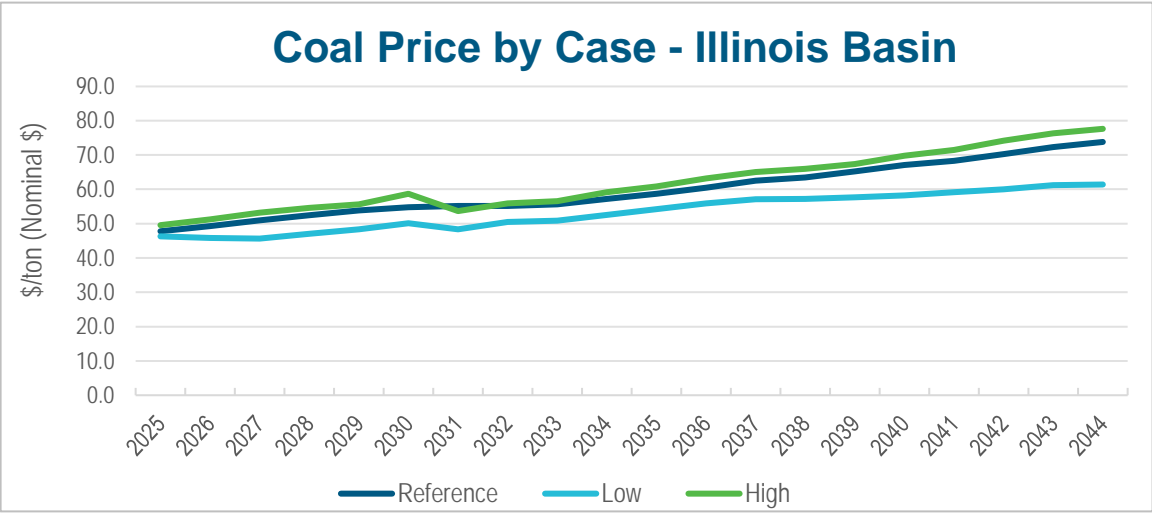
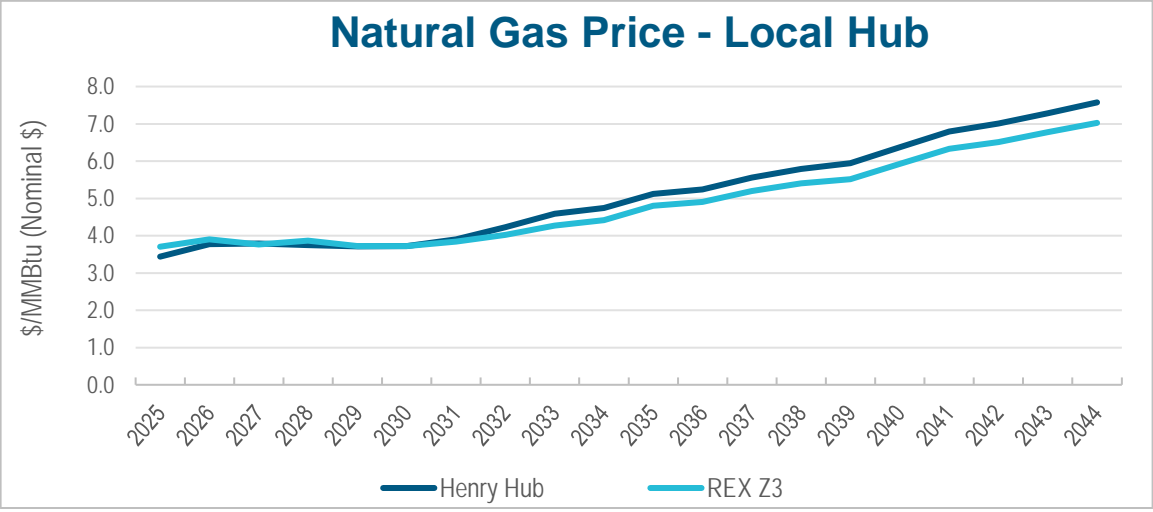
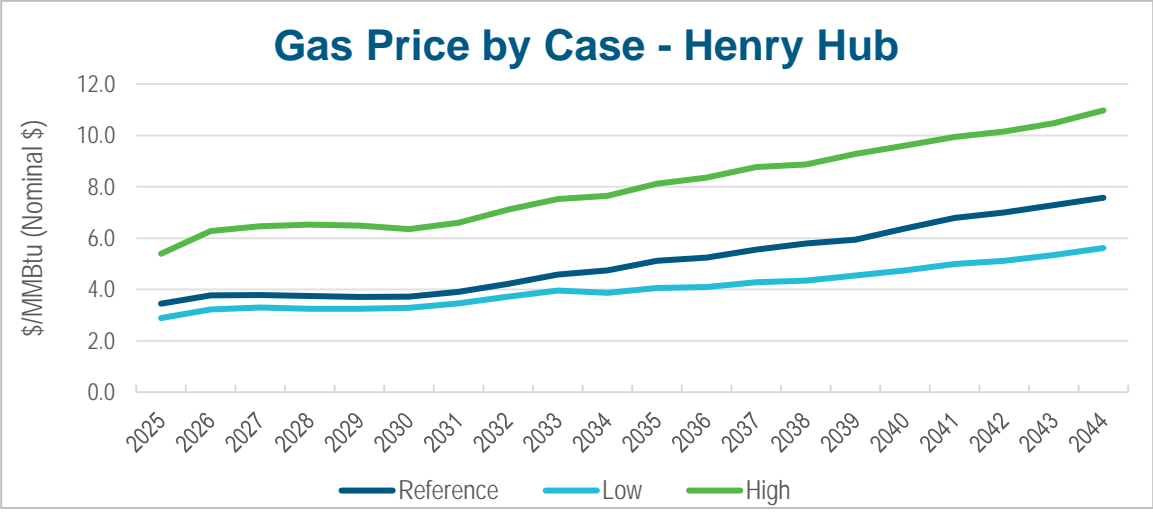
# Fuel Prices – Overview



The fuel price curves are constructed from three components:



# Fuel Prices – Natural Gas and Coal



# Commodity Price Trends



## GAS

- Short term pricing across the region has decreased considerably due to robust supply coupled with delays in new LNG export capacity.
- After the forward curve period, price blends back to the long-term trend.



## COAL

- Short term pricing for Illinois Basin has decreased considerably after the record highs seen in 2022 due to low natural gas pricing and the ensuing declines in domestic coal generation demand.
- After the forward curve period, price blends back to the long-term trend.





# Q&A



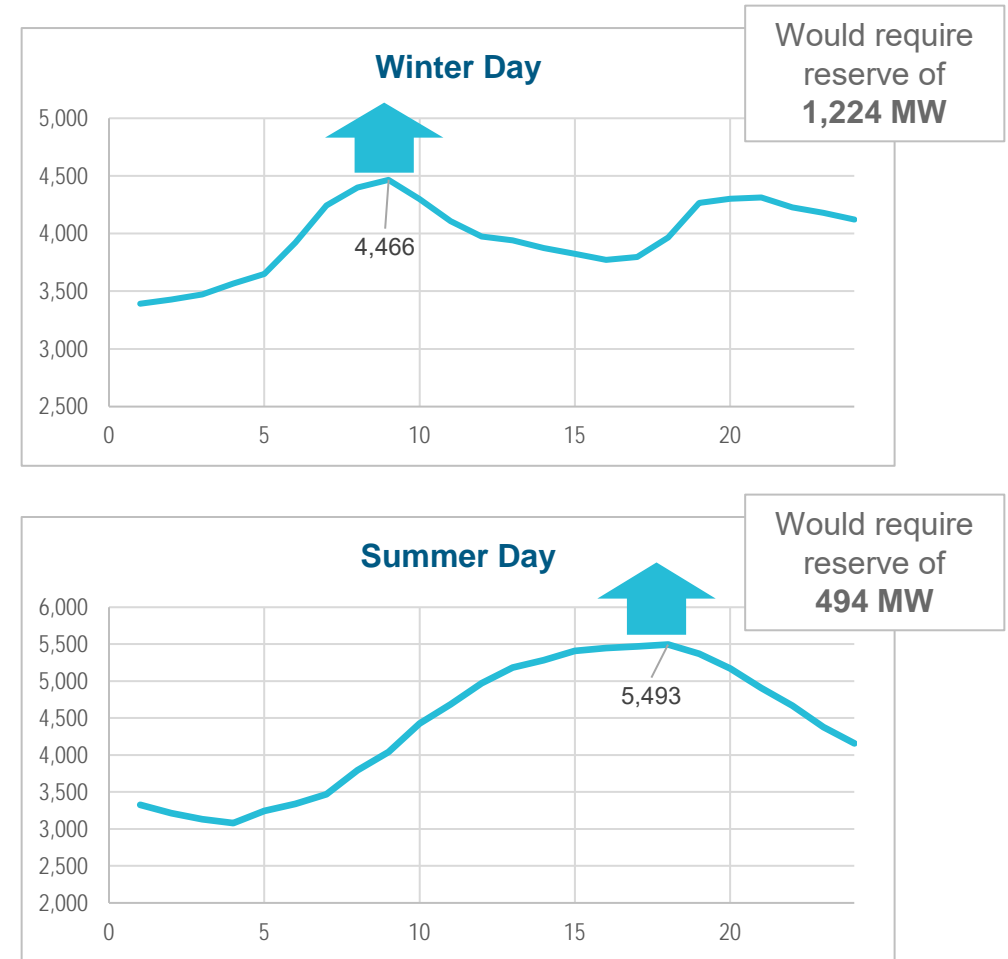
# Accreditation/ Reserve Margin

# Planning Reserve Margin

- To help ensure future system reliability in the face of forecast uncertainty, utilities carry a certain amount of capacity above projected peak load.
  - Total capacity requirement = peak load + Planning Reserve Margin Requirement (PRMR)
- MISO conducts an annual Loss of Load Expectation (LOLE) study to determine resource adequacy requirements and set the PRMR.
- MISO has moved to a seasonal methodology (Summer, Fall, Winter, Spring). No longer only planning for summer peak only.
- Up to 15% of capacity obligation may be purchased at auction
- MISO 2024-2025 Planning Year reserve margins:

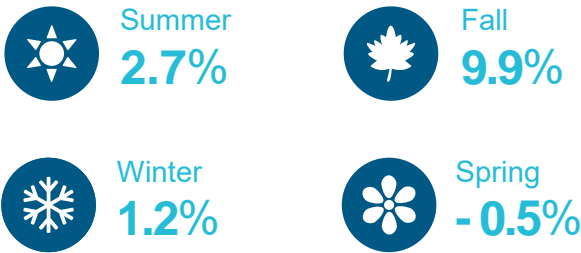


Illustrative System Demand (MW)



# Resource Accreditation

- Is the calculation of how much capacity a specific resource is accredited compared to the installed capacity.
- MISO (along with its stakeholders and approval from FERC) determines how to fairly calculate the accreditation for different resource types.
- MISO has filed with FERC a direct loss of load (D-LOL) approach to resource accreditation. The most recent assumptions based on this approach are in the following table.
  - Under D-LOL, planning reserve margins are also expected to decrease:



PY23-24 Resource Class	Summer		Fall		Winter		Spring	
	Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed
Gas	90%	88%	84%	88%	79%	66%	84%	69%
Combined Cycle	91%	90%	94%	89%	90%	74%	92%	75%
Coal	92%	91%	91%	88%	90%	73%	89%	74%
Hydro	96%	96%	94%	96%	93%	92%	97%	88%
Nuclear	95%	90%	96%	85%	95%	86%	92%	80%
Pumped Storage	99%	98%	91%	98%	94%	50%	89%	67%
Storage	95%	94%	95%	93%	95%	91%	95%	95%
Solar	45%	36%	25%	31%	6%	2%	15%	18%
Wind	18%	11%	23%	15%	40%	16%	23%	16%
Run-of-River	100%	100%	100%	100%	100%	100%	100%	100%

Note: seasonal PRMR under D-LOL was estimated based on PY23-24 load obligation data provided by MISO

# New Unit Accreditation in Modeling Overview



## Plan to monitor MISO updates (D-LOL)

- Propose using D-LOL as base case assumption in modeling.
- Consider additional sensitivity analysis around accreditation assumptions.

## For MISO Market runs

- Non-dispatchable resources
  - Start with proposed MISO seasonal D-LOL values
  - Utilize D-LOL curve and installed capacity data points from MISO stakeholder meetings
- Dispatchable resources
  - Proposed MISO seasonal D-LOL values

## For IRP runs

- Non-dispatchable
  - For each scenario, look at installed capacity out of NDB run and use corresponding D-LOL value in IRP model.
  - Tying D-LOL curves to the year and modeling as a static curve not associated with Duke Energy Indiana IRP portfolio resource selection.
- Dispatchable
  - Same as MISO Market runs

# Reliability Verification: Motivation and Modeling



- Integration into the MISO market is a fundamental component of reliability for DEI, and DEI supports MISO through reliably operating generating resources and ultimately supporting its firm load obligations to customers.
- The PRMR is influenced by the degree of forecast uncertainty related to factors including weather impacts on load and generation, economic growth, generator performance, and others. As the resource mix changes, it is important for DEI to continue to meet its reliability obligation as part of the MISO system.
- More detailed modeling is necessary to supplement the weather-normal, fixed PRMR EnCompass expansion process to verify how well potential future resource portfolios fulfill this role. The SERVM stochastic model is used to evaluate portfolio performance under real-world uncertainties:

**Weather:**  
44 years of  
weather history  
(1980-2023)

**Weather Impact on Load  
and Resources**  
(weather-driven performance  
of hydro, wind, solar, and  
thermal resources)

**Economic Load  
Forecast Error:**  
distribution of long-term  
load growth uncertainty  
with varying probabilities  
of occurrence

**Unit Outage  
Modeling**  
(frequency and  
duration of thermal  
unit forced outages)



# Reliability Verification: Measurement



Reliability verification process measures how well the DEI portfolio performs in serving DEI customer loads relative to a near-future benchmark.

- ***Not targeting 0.1 event-days/year LOLE for DEI in isolation – this reliability threshold is a property of the interconnected MISO market.***
- Instead, we model a reference internal reliability baseline for DEI (LOLE expected > .1 event-days/year) and evaluate portfolios in selected future years against this baseline
- Worse performance than baseline indicates that a resource portfolio is less aligned to DEI load than current resources, and may place greater strain on future MISO reliability
- Will quantify other reliability metrics which may include EUE, event depth and duration, etc., to further characterize reliability risk



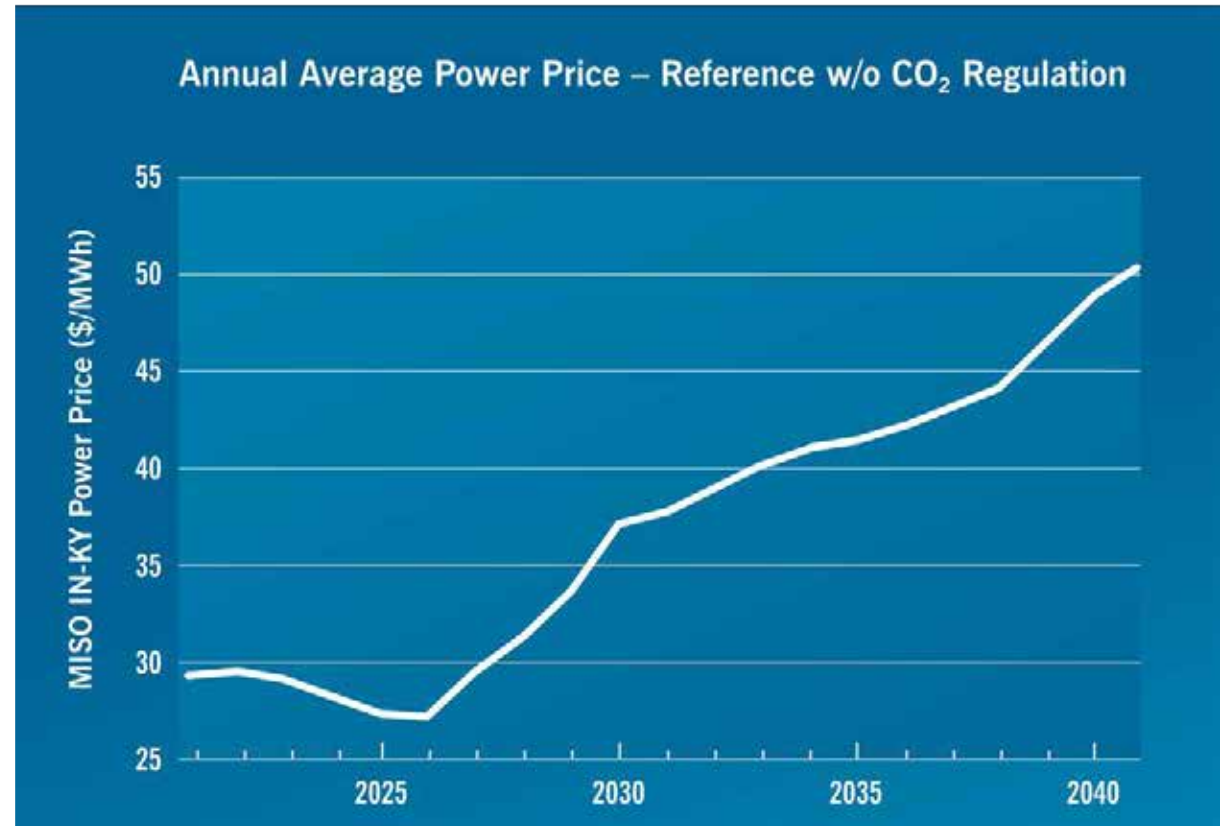
# Q&A



# Power Price Development

# Power Price Development

- Use EnCompass to simulate Horizon Energy developed National Database.
- Make updates to align with IRP assumptions
  - Natural gas forecast
  - Coal forecast
  - CO<sub>2</sub> tax
  - New resource costs
- Unique simulation performed for each IRP Scenario
- Hourly LMPs from MISO wide analysis used as an input into Duke Energy Indiana's IRP model.



Example (2021 IRP)



# Q&A

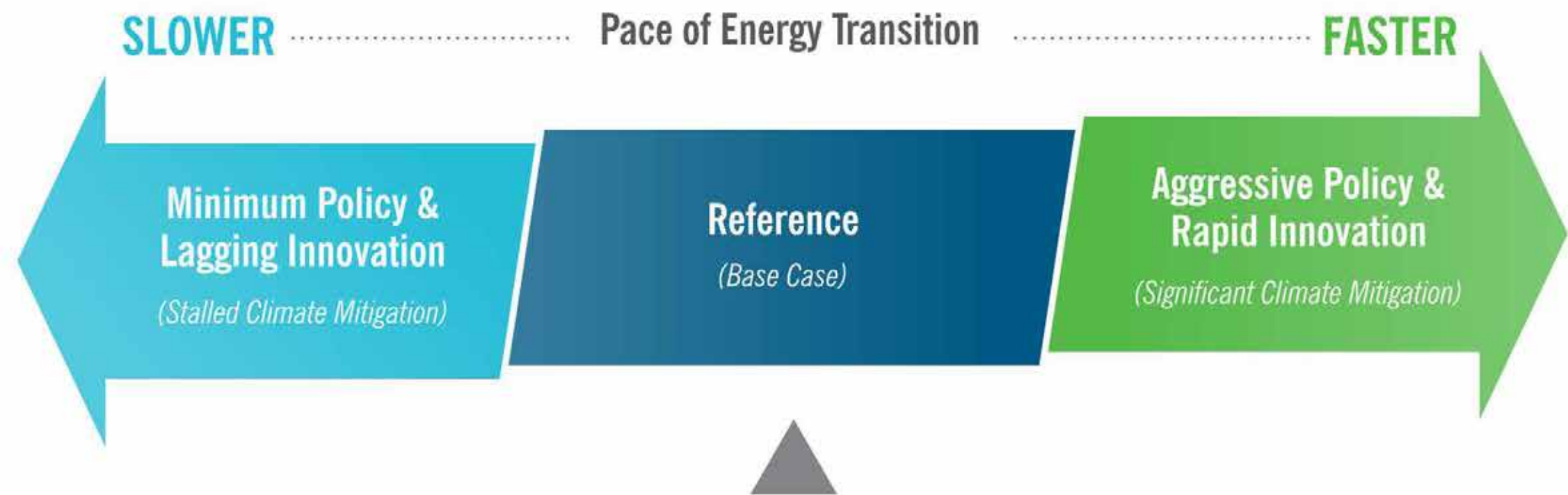




# Scenarios & Generation Strategies Review



# Modeling Scenarios | “Worldviews”



**Goal:** Develop scenarios that (A) reflect vastly different future outcomes than the reference case and (B) where the fundamental drivers of those divergent futures could plausibly impact many resource plan modeling inputs.

# Considerations



- Scenarios and sensitivities should not be construed as policy goals.
- The Aggressive Policy & Rapid Innovation and Minimum Policy & Lagging Innovation scenarios are not predictions of the future. Instead, they are vastly varying futures developed to **intentionally push the boundaries** on what may be viewed as possible future outcomes.
- Scenarios and sensitivities serve as stressors to test how different future resource plans perform under different future conditions relative to each other with respect to the IRP planning objectives.

# Proposed Scenarios | Variables Across Worldviews

	CAA 111	Coal Price	Gas Price	IRA	Resource Availability (interconnection timing)	CO <sub>2</sub> Tax	Renewables & Storage Cost	Distributed Resources (incl. net metering)	Emerging Technology
Aggressive Policy & Rapid Innovation	Phases 1-3	High	High	Extend + Domestic Content	High Renew. Avail. (Base in Near-Term; High in Long-Term)	Yes	Low	High	LDES & H2 Available
Reference	Final Rule	Base	Base	Extend	Base	No	Base	Base	Base
Minimum Policy & Lagging Innovation	Repeal	Low	Low	Repeal	Base	No	Base	Low	Advanced Nuclear not available

# Scenario Narrative | Aggressive Policy & Rapid Innovation

	CAA 111	Coal Price	Gas Price	IRA	Resource Availability (interconnection timing)	CO <sub>2</sub> Tax	Renewables & Storage Cost	Distributed Resources (incl. net metering)	Emerging Technology
Aggressive Policy & Rapid Innovation	Phases 1-3	High	High	Extend + Domestic Content	High Renew. Avail. (Base in Near-Term; High in Long-Term)	High	Low	High	LDES & H2 Available

- **CAA 111:** Complete implementation.
  - **Coal Prices:** Aggressive regulation limits supply, driving higher prices.
  - **Gas Prices:** Aggressive regulation constrains supply, driving higher prices.
  - **IRA:** Extended IRA incentives and additional capture of incentives for domestic content.
  - **Resource Availability:** Interconnection availability consistent with base in near-term (through 2028). Favorable transmission and queue reform is enacted to enable higher interconnection of renewable resources in the longer-term planning horizon (beginning 2029).
  - **CO<sub>2</sub> Tax:** Legislation passed for high CO<sub>2</sub> tax. Implemented by 2030.
- **Renewables & Storage Cost:** Extension of favorable government incentives towards renewables and storage reduces overall cost.
  - **Distributed Resources (DER):** Favorable government incentives available to customers to implement distributed renewables and storage drives higher adoption.
  - **Emerging Technology:** Increased incentives for emerging technology research and development will drive commercialization and increased availability of new resource options at a faster pace than reasonably expected.

# Scenario Narrative | Minimum Policy & Lagging Innovation

	CAA 111	Coal Price	Gas Price	IRA	Resource Availability (interconnection timing)	CO <sub>2</sub> Tax	Renewables & Storage Cost	Distributed Resources (incl. net metering)	Emerging Technology
Minimum Policy & Lagging Innovation	Repeal	Low	Low	Repeal	Base	None	Base	Low	Advanced Nuclear not available

- **CAA 111:** Stayed and repealed prior to implementation.
  - **Coal Prices:** Less government regulation drives price competition amongst competing fuels.
  - **Gas Prices:** Less government regulation drives price competition amongst competing fuels.
  - **IRA:** IRA is repealed by 2025.
  - **Resource Availability:** Interconnection availability consistent with base case.
  - **CO<sub>2</sub> Tax:** No CO<sub>2</sub> tax legislation.
  - **Renewables & Storage Cost:** Reduced government incentives for renewables and storage increases overall cost but is offset by tempered demand.
- **Distributed Resources (DER):** Reduced government incentives available to implement distributed renewables and storage, driving lesser adoption.
  - **Emerging Technology:** Lack of incentives for emerging technology research and development leads to delayed commercialization and insufficient infrastructure to enable new resource technology availability.

# Generation Strategies Summary

2024 IRP Generation Strategies							
Predefined Retirements		Optimized Retirements				Stakeholder Strategies	
						Optimized Ret.	Predefined Ret.
Coal Retirement #1	Coal Retirement #2	No New CCs	Tech Agnostic Reference	Tech Agnostic Aggressive Policy & Rapid Innovation	Tech Agnostic Minimum Policy & Lagging Innovation	Carbon Cap	Out of Coal by 2030

- **Coal Retirement #1:** Includes predefined coal retirement dates based on the Fall'23 CPCN modeling and are similar to the most recent rate case physical retirement dates.
  - **Coal Retirement #2:** The Technology Agnostic Reference case will be run first to inform the predefined coal retirement dates for this strategy.
  - **No New CCs:** This strategy will not allow any new CCs to be selected. The purpose is to see a portfolio without the ability to build new CCs in future.
  - **Technology Agnostic Reference:** Allow the model to optimize resource selection and retirement dates based on the Reference scenario.
- **Technology Agnostic Aggressive Policy & Rapid Innovation:** Allow the model to optimize resource selection and retirement dates based on the Aggressive Policy & Rapid Innovation scenario worldview.
  - **Technology Agnostic Minimum Policy & Lagging Innovation:** Allow the model to optimize resource selection and retirement dates based on the Minimum Policy & Lagging Innovation scenario worldview.
  - **Carbon Cap:** Stakeholder requested strategy focused on rapid decarbonization, including high DER adoption and a cap on carbon emissions.
  - **Out of Coal by 2030:** Stakeholder requested strategy that will force all coal units to retire by end of year 2030.



# Coal Retirements (EOY) by Generation Strategy

				2024 IRP Generation Strategies							
				Predefined Retirements		Optimized Retirements				Stakeholder Strategies	
				Coal Ret. #1	Coal Ret. #2	No New CCs	Tech Agnostic Reference	Tech Agnostic Aggressive Policy & Rapid Innovation	Tech Agnostic Minimum Policy & Lagging Innovation	Optimized Ret.	Predefined Ret.
Unit	2021 IRP	2023 IRP Refresh	CPCN Modeling							Carbon Cap	Out of Coal by 2030
Cayuga 1	2026	2027	2028	2028	TBD						2028
Cayuga 2	2026	2027	2028	2029	TBD						2029
Gibson 1	2034	2034	2034	2034	TBD						2030
Gibson 2	2034	2034	2034	2034	TBD						2030
Gibson 3	2028	2028	2028/2030	2030	TBD						2029
Gibson 4	2028	2028	2028/2030	2030	TBD						2029
Gibson 5	2024	2025	2029	2029	TBD						2029

EOY: End of Year

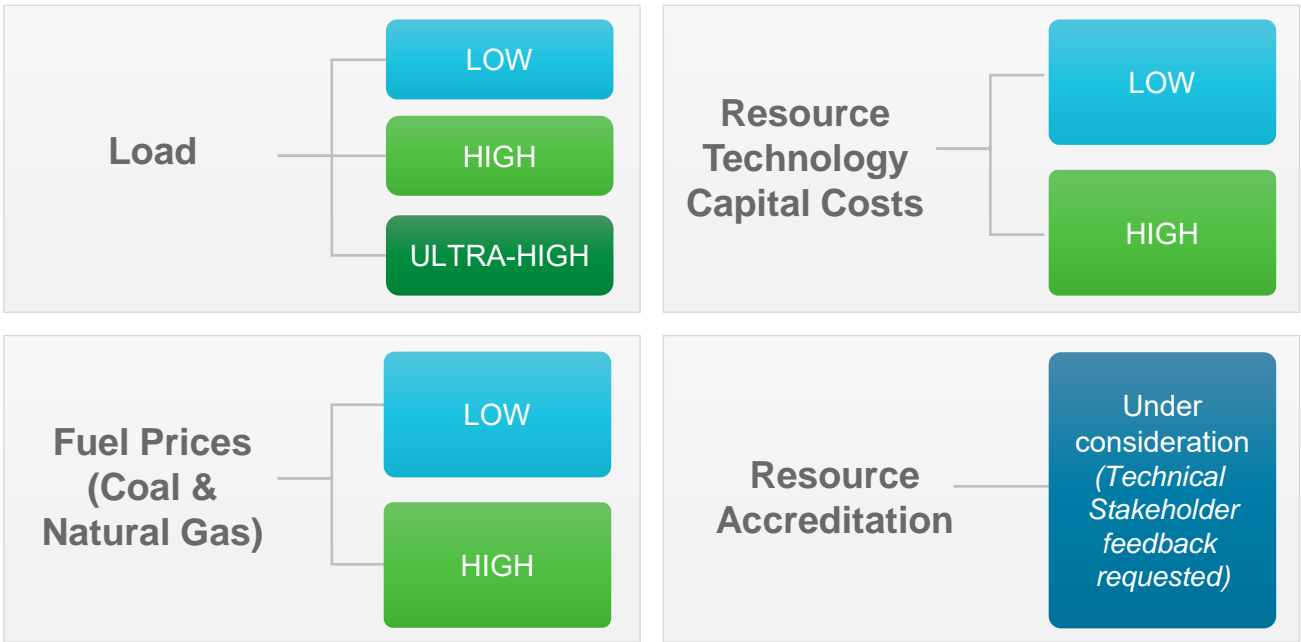
# Risk Analysis | Sensitivities

## Sensitivity: Single Variable

Sensitivity analysis stresses a **single variable** while holding all else constant to isolate the impact of that variable. This provides insight into the risk associated with specific key variables that:

- are difficult to know with certainty
- could impact future portfolio performance against planning objectives over the long-term
- may be subject to greater volatility independent of other variables

## Proposed Sensitivities for 2024 IRP Modeling:



In addition, Probabilistic Risk Analysis will be performed as part of Reliability & Performance Verification to test key sensitivities such as weather and generation performance. Additional information is included in the Reliability Verification slides.



# Q&A

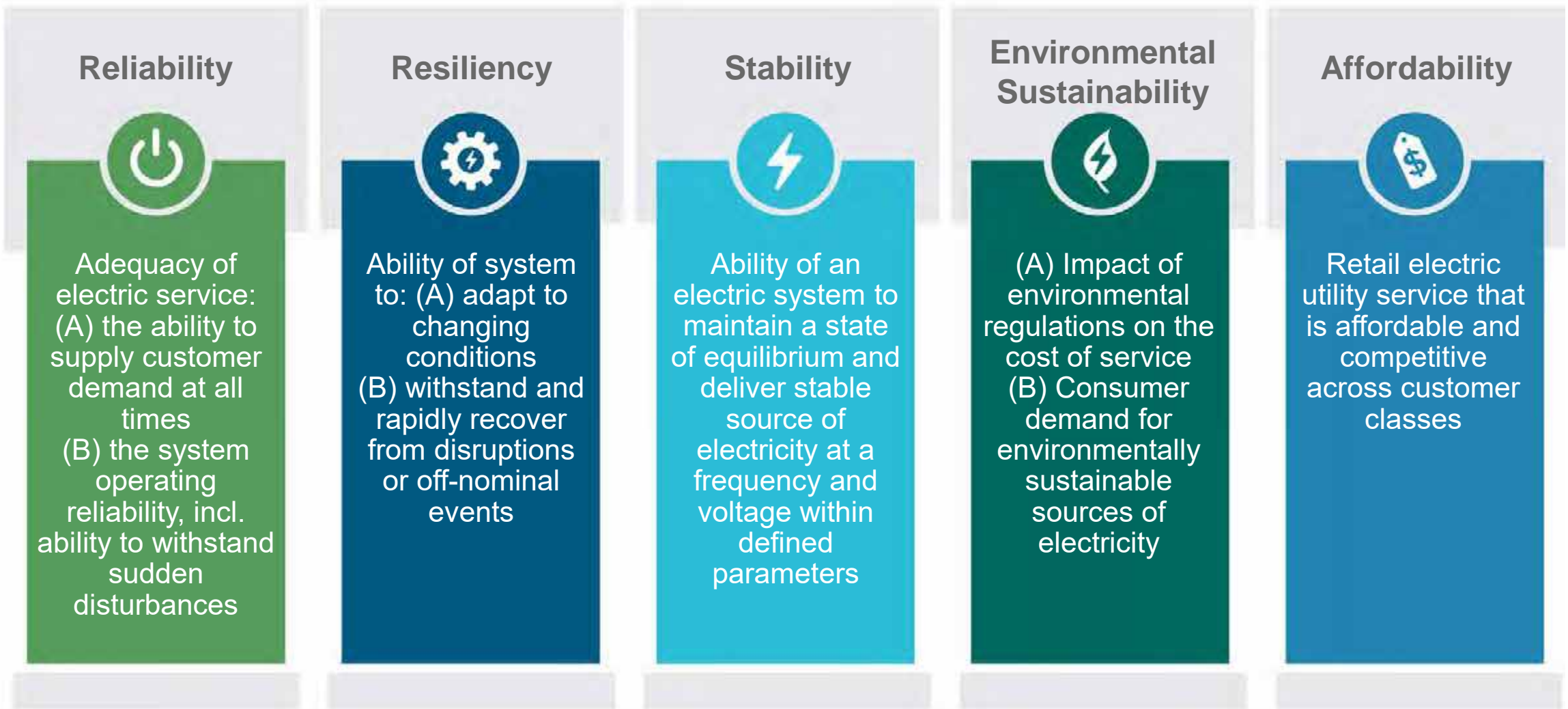


# Break



# Scorecard Metrics

# House Enrolled Act (HEA) 1007 Requirements | 5 Pillars





# Planning Objectives will guide selection of Preferred Portfolio

**“Preferred resource portfolio** means the utility’s selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration.”<sup>[1]</sup>

<sup>[1]</sup> 170 IAC 4-7-1 (cc)



# Additional Scorecard Feedback Considered/Incorporated

	Feedback	Response
<b>Overall</b>	Recommend examining both the near-term and total for each measure: <ul style="list-style-type: none"> <li>• “Near-Term” - reflect how portfolio performs over first decade of the IRP analysis period to assess near-term impacts</li> <li>• “Total” – reflect overall portfolio performance for entire IRP period</li> </ul>	Partially incorporated Will include assessment of near-term and total impacts where most meaningful
	Preference that scorecard metrics are not weighted	Incorporated Scorecard metrics will not be weighted
	Assess the potential scorecard metrics discussed for overlap and remove those that may overlap	Incorporated Redundant metrics removed to limit overlap
<b>Environmental Sustainability</b>	Remove CO <sub>2</sub> intensity metric, as CO <sub>2</sub> intensity does not indicate if overall emissions are increasing or decreasing	Incorporated Removed CO <sub>2</sub> intensity metric
	Reflect CO <sub>2</sub> emissions reduction since beginning of planning period rather than from 2005 baseline to show comparison to DEI's CO <sub>2</sub> emissions today (operationalized as 2023 total CO <sub>2</sub> emissions)	Incorporated Changed baseline to 2023 for cumulative reduction metric
	Use cumulative total (absolute) CO <sub>2</sub> -equivalent emissions over the IRP period as a measure for the Environmental Sustainability objective	Not incorporated Scorecard will focus on relative progress towards a cleaner energy future
	For Non-CO <sub>2</sub> emissions ranking, modify this to measure absolute emissions of each pollutant (SO <sub>2</sub> , NO <sub>x</sub> , Hg, PM) rather than using a ranking	Not incorporated Emissions data informing ranking will be provided

# Additional Scorecard Feedback Considered/Incorporated

	Feedback	Response
Reliability	The peak availability of on-system resources does not necessarily align with the hours in which there is a risk of resource inadequacy since Duke a small piece of the overall MISO system.	Incorporated Shifted assessment from Duke Energy peak to MISO high-risk resource adequacy hours
	Energy self-sufficiency metric is not a good measure because a utility in MISO does not have to self-supply all its own load without any assistance.	Incorporated Removed metric
	Concerned about 95th percentile expected net load ramp metric since less ramping is not necessarily the goal	Incorporated Removed metric
	Of the proposed reliability metrics, prefer the market reliance metric because it reflects a meaningful risk to ratepayers, though this is more a measure of risk exposure than it is of reliability and should be accompanied by a market sales metric.	Incorporated Market exposure included as risk metric
	Include a measure of fast start and spinning reserve capable resources capacity as a percentage of peak load or as a percentage of average load.	Incorporated Added metric

# Additional Scorecard Feedback Considered/Incorporated

	Feedback	Response
Resiliency	HHI metrics for resource diversity and fuel diversity do not get at the meaning of resilience.	Partially incorporated Removed fuel diversity metric
	Performance in a 95th percentile extreme weather event, paired with an assumption that Duke is fully isolated, is not a realistic metric. There is no credible scenario in which Duke would be unable to exchange power with neighboring systems without other material impacts to its system.	Not incorporated Duke Energy performance in isolation indicates ability to support overall MISO system
	Because over 95% of outages occur on the distribution system, rather than the transmission system, a resiliency metric needs to measure differences in outages on the distribution system, not just what might be resource adequacy-related outages from bulk level resources. Request Duke reconsider its resiliency measures and make significant adjustments or shift this objective to a narrative discussion.	Partially incorporated Reconsidered potential metrics and agree that distribution outages are largely outside of IRP scope
Stability	Remove inverter-based resource metrics from scorecard and consider stability discussion in document	Incorporated Removed metric
	Recommend a narrative approach to this metric that describes any known voltage stability issues that DEI experiences or would experience with resource retirements and options to respond to those issues with synchronous machines or IBRs.	Incorporated Stability will be addressed in the narrative rather than in scorecard

# Additional Scorecard Feedback Considered/Incorporated

	Feedback	Response
Market Exposure	Market exposure metric is similar to the proposed reliability metric (market reliance), which means if both are used, the metric is effectively double counted.	Incorporated Market exposure included only as risk metric
Execution Risk	The cumulative technology and new resource additions metrics overlap.	Incorporated Removed overlapping metrics. Including only one technology/resource addition metric
	Rather than a single point metric, it would be more helpful to have a timeline that shows when the pre-construction activities such as design would have to start, when contracting and then construction is likely to commence, and finally when the project would come online. This would give a sense of how important making a decision on any particular resource would be and also to what degree sequencing risks the projected online date.	Partially incorporated Discussion of project lead times will be included in narrative

# Measures of Environmental Sustainability & Affordability

Planning Objective	Measure	Description	Purpose
Environmental Sustainability	CO <sub>2</sub> Emissions Reduction	Percent CO <sub>2</sub> reduction from 2005 baseline at specified years (2035, 2044)	Allows comparison of pace of emissions reduction
	Cumulative CO <sub>2</sub> Reduction	Cumulative volume of CO <sub>2</sub> reduction over the planning period (tons from 2023)	Allows comparison of cumulative emissions reduction
	Non-CO <sub>2</sub> Emissions Ranking	Portfolio ranking across an annual average of SO <sub>2</sub> , NO <sub>x</sub> , Hg, and PM	Assesses the volume of non-CO <sub>2</sub> emissions
Affordability	Present Value Revenue Requirement (PVRR)	Forecasted incremental revenue requirement over full analysis period, discounted to present	Provides estimate of total portfolio cost over analysis period in present value terms
	Customer Rate Impact (CAGR)	Average annual rate impact to customers over 5-year and 10-year time periods	Provides estimate of average annualized rate impact to customers, inclusive of existing unit on-going costs



# Measures of Reliability & Resiliency

Planning Objective	Measure	Description	Purpose
Reliability	Availability of On-System Resources in High-Risk Hours	On-demand MW as percentage of peak load during MISO high-risk resource adequacy hours in 2035	Ability of the portfolio to provide energy 'on-demand' during high-risk hours
	Fast Start & Spinning Reserve Capability	Fast start and spinning reserve capable resource capacity (MW) as percentage of peak load in 2035	Portfolio's ability to compensate for unpredictable imbalances between load and generation caused by sudden outages
Resiliency	Resource Diversity	An empirically-derived diversity baseline of the system's capacity resources by technology type, as measured by the Herfindahl-Hirschman Index (HHI) – the sum of squares of technology share in the portfolio on a capacity basis in 2035	Measure diversity of capacity resource types on system as an indicator of resilience and flexibility in all time scales
	Performance in 95 <sup>th</sup> Percentile Extreme Weather Event	Percent unserved energy during an extreme weather event in summer and winter based on most extreme weather events (95 <sup>th</sup> percentile or greater) observed in Indiana with market purchases turned off	Tests portfolios performance in an off-nominal extreme (95 <sup>th</sup> percentile or greater) summer and winter weather event

# Measures of Risk & Uncertainty

Planning Objective	Measure	Description	Purpose
Cost Risk	Cost Risk & Certainty (\$B)	Maximum PVRR and the range between Min & Max PVRRs across scenario and risk analysis	Indicates risk of cost variance and high-cost outcomes across different potential futures
	IRA Exposure	Total PVRR impact of IRA tax credits (present value dollars) over planning period	Indicates both opportunity & risk of the IRA tax credits
Market Exposure	Fuel Market Exposure	Average annual energy generated by resources with exposure to coal and gas markets as percent of load, over planning period	Indicates cost risk associated with fuel price volatility
	Energy Market Exposure	Average annual energy purchases + sales as percent of load, over planning period	Indicates cost risk associated with each portfolio's overall market exposure
Execution Risk	Cumulative Resource Additions in MW and as % of Current System	Cumulative MW additions of all capacity resource technology types, including CCS and DSM, through 2030 and 2035, expressed as MW and as percent of total MW capacity serving customers today, including contracted generation	Indicates scale and pace of infrastructure siting, permitting, construction and interconnection required, and illustrates the magnitude of infrastructure requirements in the context of existing system



# Q&A



# Open Q&A



# Thank you

## Next Steps



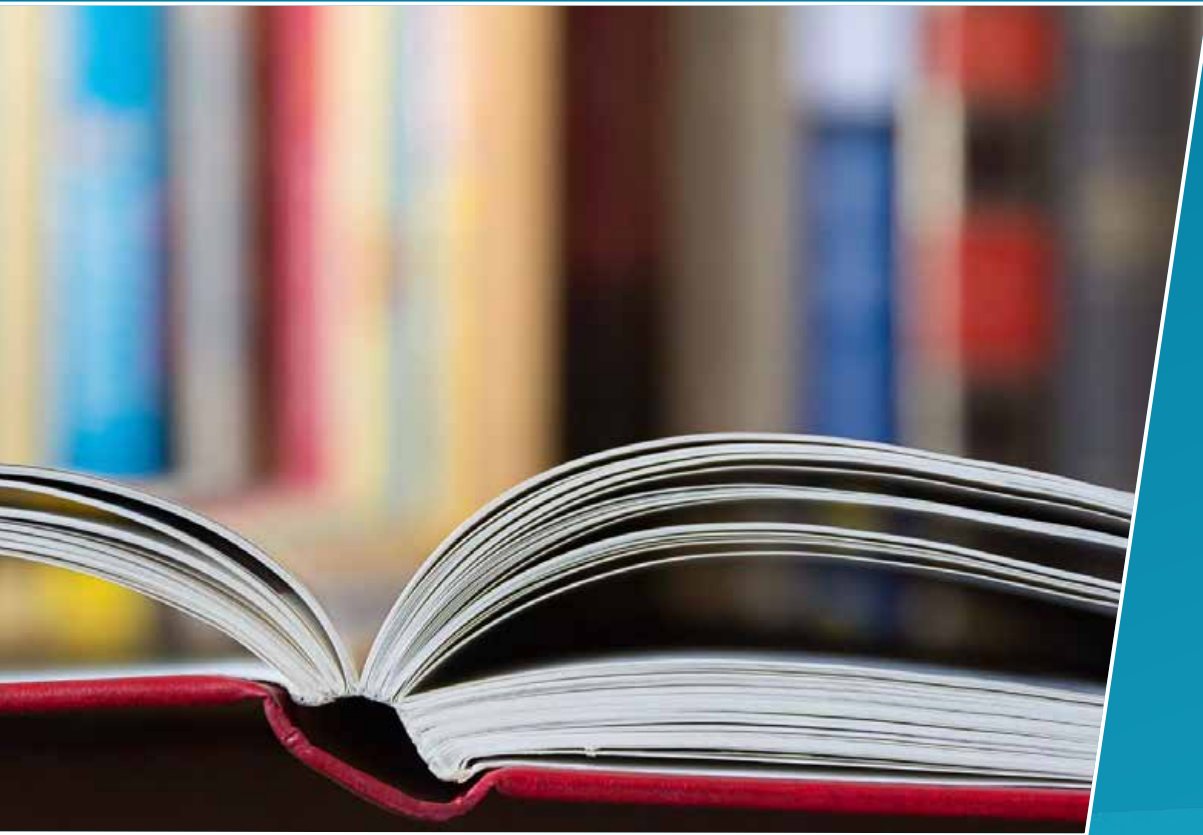
Additional questions, comments,  
and feedback can be sent to

[DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com)

The third technical meeting will occur in early June.  
The next public stakeholder meeting will occur in  
first half of June.

Meeting registration will be sent out  
4-6 weeks in advance.



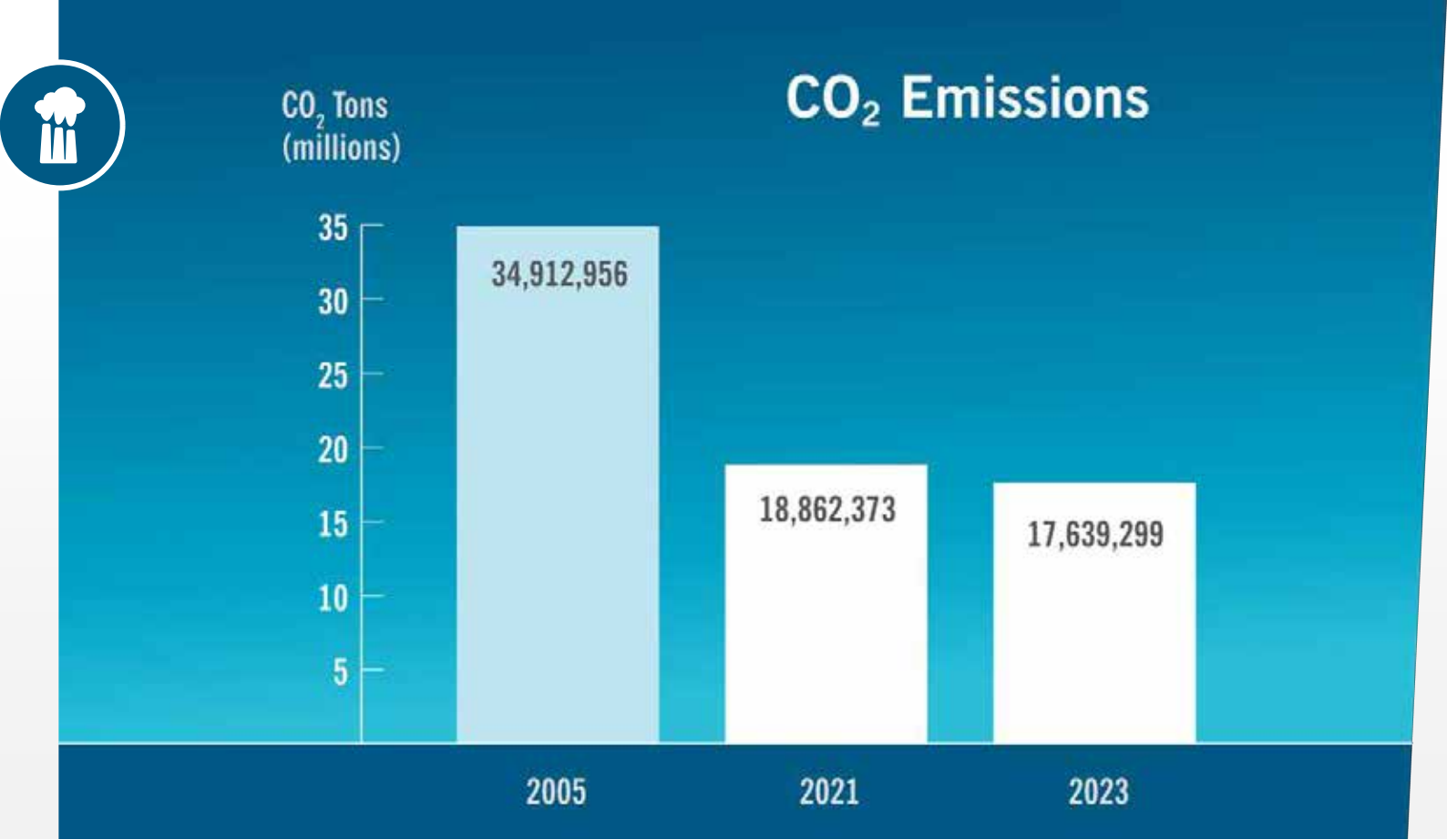


# Appendix



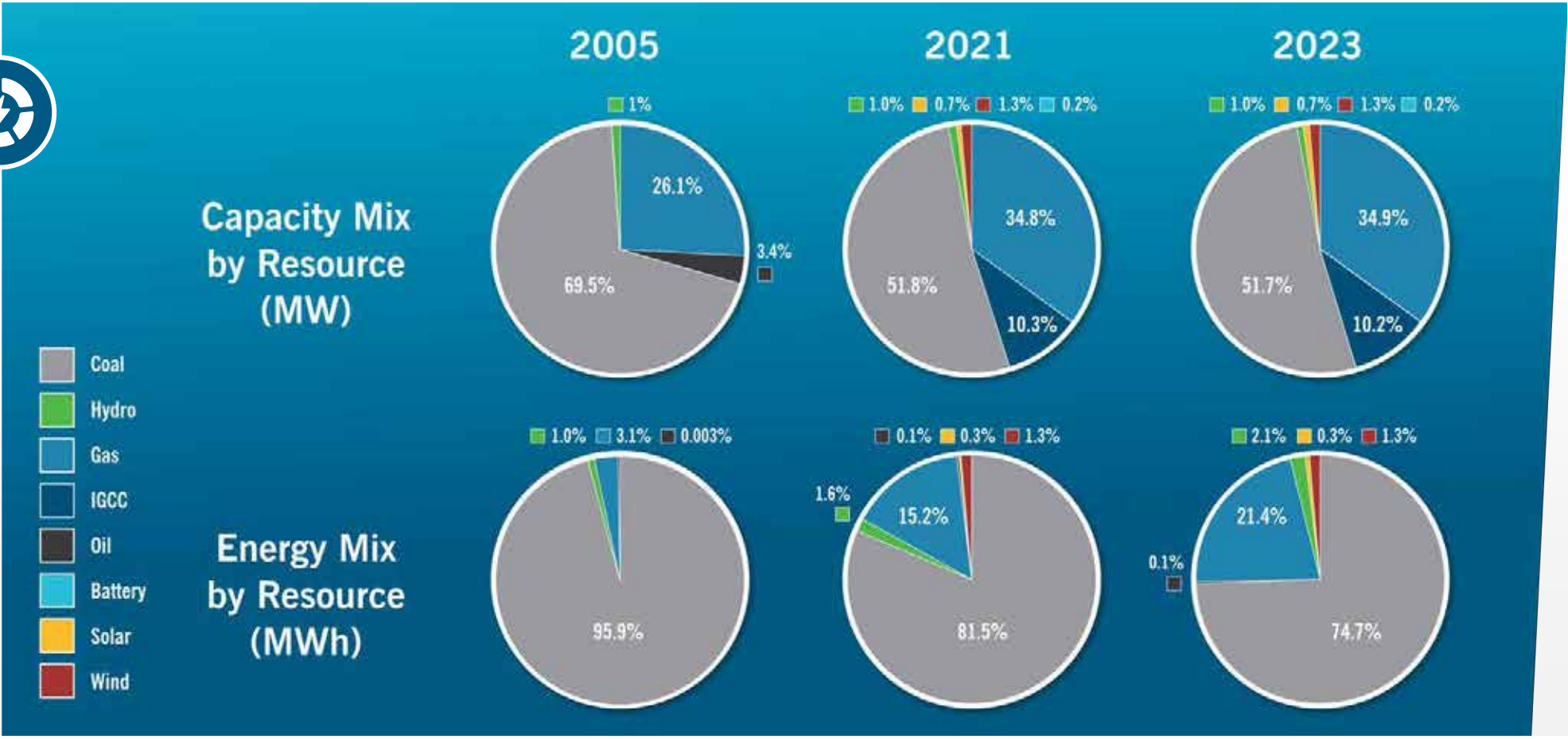
## Appendix: DEI Emissions, Energy, & Capacity Mix

# Duke Energy Indiana Carbon Emissions



Note: Scope 1

# Energy & Capacity Mix Over Time







# Appendix: DEI Customer Programs

# Special Assistance Programs



Duke Energy offers several programs and resources to assist customers in times of uncertainty, including

- Installment Plans
- Due Date Extensions
- Financial Assistance
  - Energy Assistance Program
  - Share the Light Fund
  - 211.org



For more information about Duke Energy's special assistance programs, please visit our website

<https://www.duke-energy.com/home/billing/special-assistance>



# Energy Efficiency Programs





# Appendix: Domestic Content Bonus Assumptions

# Domestic Content Bonus Considerations



- The IRA has added a bonus of +10% ITC or a 1.1x PTC for new carbon free generation built with domestic materials
- There will be a cost premium for domestic content which will offset most of the PTC bonus
- Domestic content qualification is very complicated as is seen below
  - For example, solar modules are 45% of the cost of the manufactured equipment so 100% of modules and some portion of other equipment need to be manufactured domestically to meet the manufactured products requirement below
- Domestic manufacturing is slowly developing for solar, but all supply is under contract; wind manufacturing is even slower to develop
- Final domestic content guidance will not be out until later this year

## Domestic Content Qualification Overview

### Qualified Facility

- 100% of all iron and steel components must be produced in US
- 40%-55% of all "manufactured products" must be produced in US

### Manufactured Product that is a Component of the Qualified Facility

- 100% of the manufacturing process must occur in US
- 100% of the components must be of US origin

### Component Parts of the Manufactured Product

- 100% of the manufacturing process must occur in US
- 0% of subcomponents required to be of US origin (including raw materials)

### An energy project satisfies the domestic-content requirement if it meets the two requirements below

- **Steel or Iron Requirement** - 100% of all of the steel and iron that are structural in function must be completely manufactured in the United States except for the "metallurgical processes involving refinement of steel additives."

- **Manufactured-Products Requirement** - To meet the Manufactured Product Requirement, the product must meet one of two tests:

(1) A manufactured product is produced in the US if all of the manufacturing processes take place in the United States and all of the product components are of US origin. Components include any articles, materials or supplies that are incorporated into the manufactured product and may be of US origin if manufactured in the United States regardless of the origin of subcomponents.

(2) The domestic cost percentage (cost to manufacture - need guidance) is found by dividing the domestic manufactured products and components cost by the total manufactured products cost; at least 40% of the total cost of the product must comply with the requirements. The percentage is gradually raised to 55% for projects that begin after 2026.

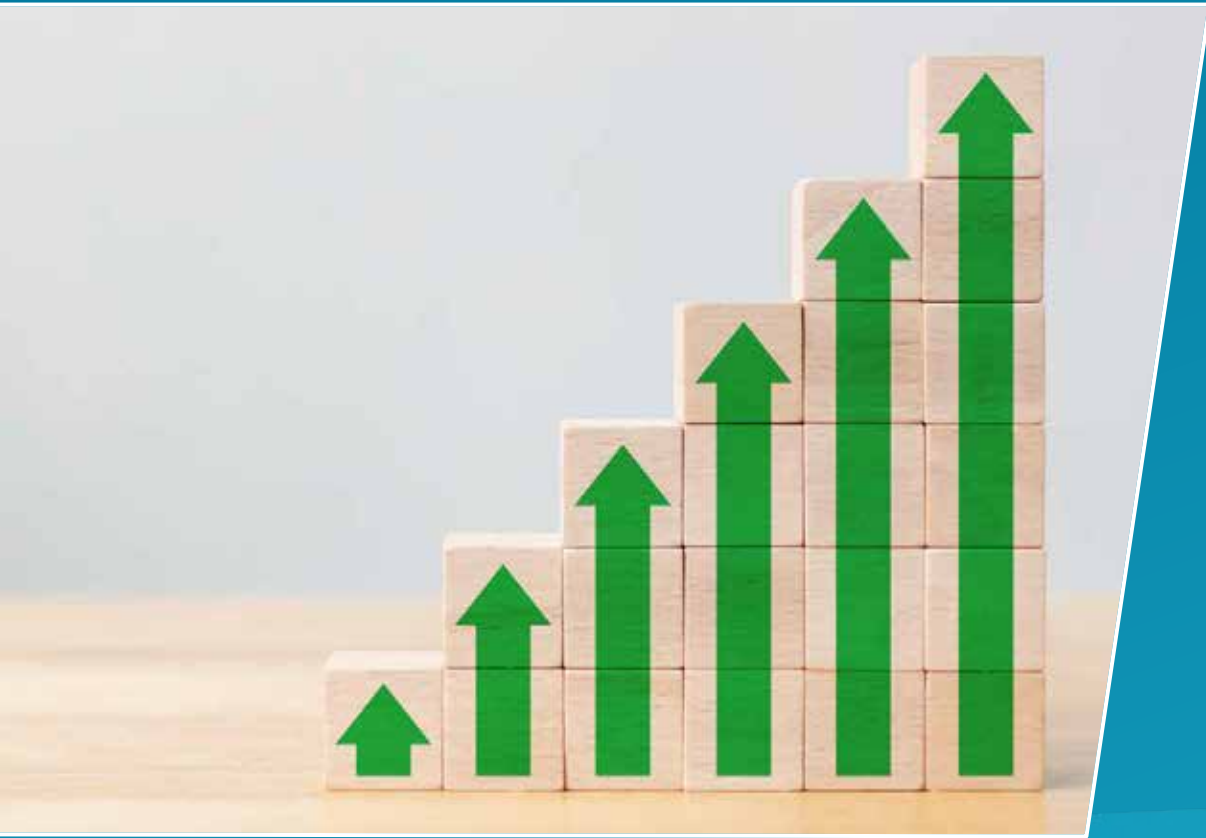
## Aggressive Policy & Rapid Innovation Scenario assumes additional capture of IRA Domestic Content Bonus for Renewables

	Base (PTC->45Y)	Base (ITC-> 48)	Reference Domestic Content Bonus	Aggressive Policy & Rapid Innovation Domestic Content Bonus
<i>Solar Pre-2030</i>	Yes	No	No	No
<i>Solar 2030-2034</i>	Yes	No	No	<b>100%</b>
<i>Solar 2035+</i>	Yes	No	50%	<b>100%</b>
<i>Wind Pre-2030</i>	Yes	No	No	No
<i>Wind 2030 - 2034</i>	Yes	No	No	<b>50%</b>
<i>Wind 2035+</i>	Yes	No	50%	<b>100%</b>
<i>Solar + Storage</i>				
<i>Solar</i>	Yes	No	No	<b>See solar above</b>
<i>Storage</i>	No	Yes (36%)	No	No
<i>Standalone Storage</i>	No	Yes (40%)	No	No

Note: Differences from reference case marked in **Bold**

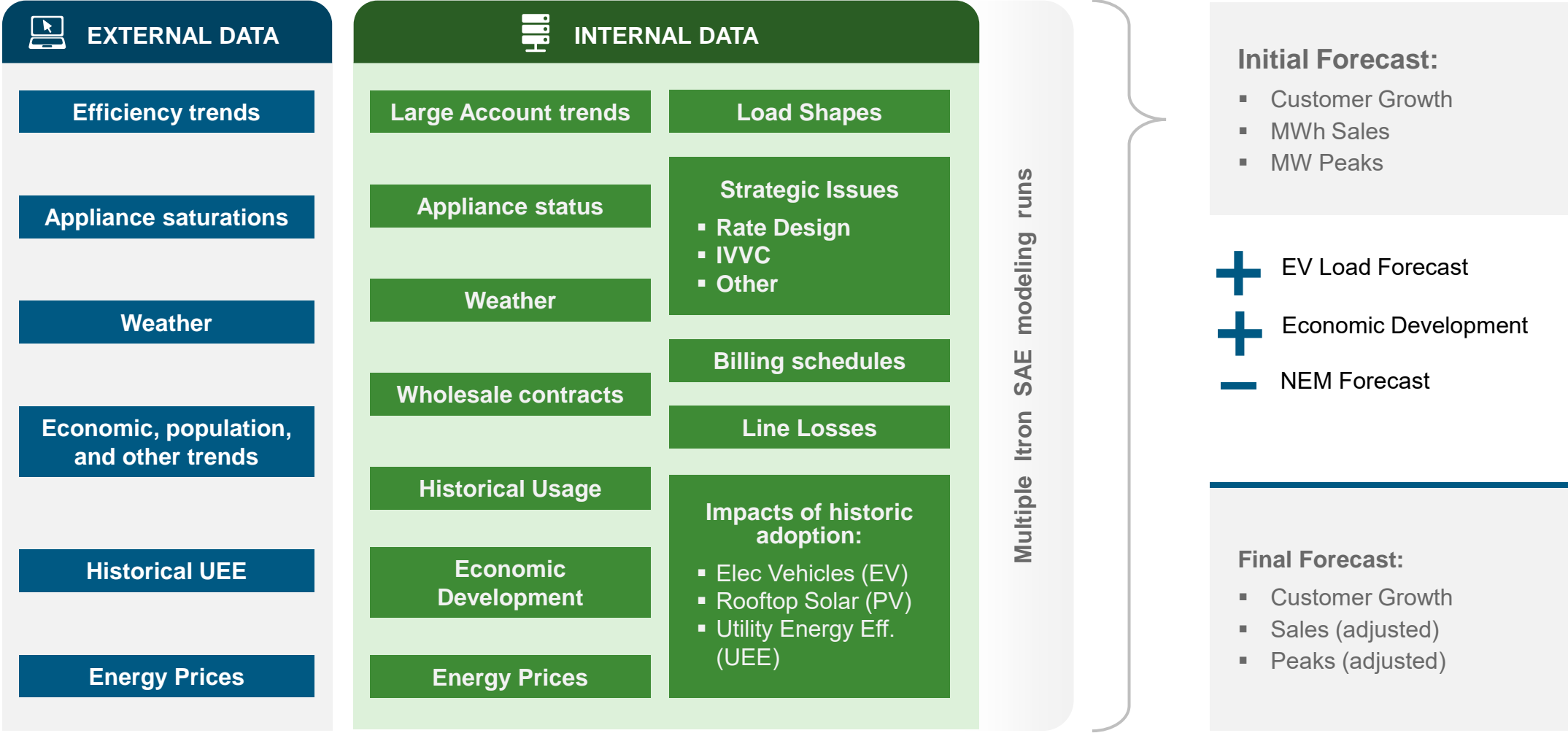
- Final guidance has not been issued related to the “cost” determination associated with domestic content. Current guidance is based on cost to manufacture. The impact is that manufacturers are reluctant to provide the appropriate documentation.
- Utilities are still required to normalize the ITC in rate recovery – therefore the PTC currently provides far more value. However, the Domestic Content benefit associated with the PTC is lower (compared to the ITC). The impact is less ability to absorb cost premiums to comply with Domestic Content.
- Underlying cost curves to meet domestic content – specific to panels – are currently at premiums of 15%. This outweighs the benefits of the PTC Domestic Content bonus.





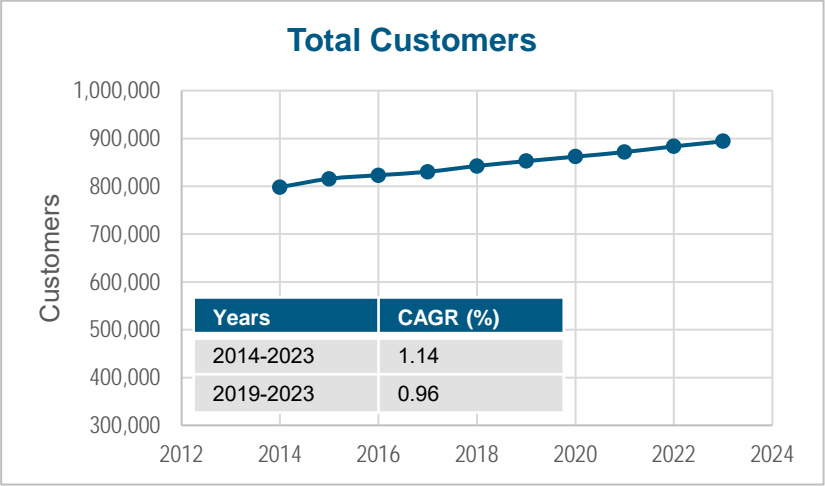
## Appendix: Load Forecasting Results

# Forecasting Process

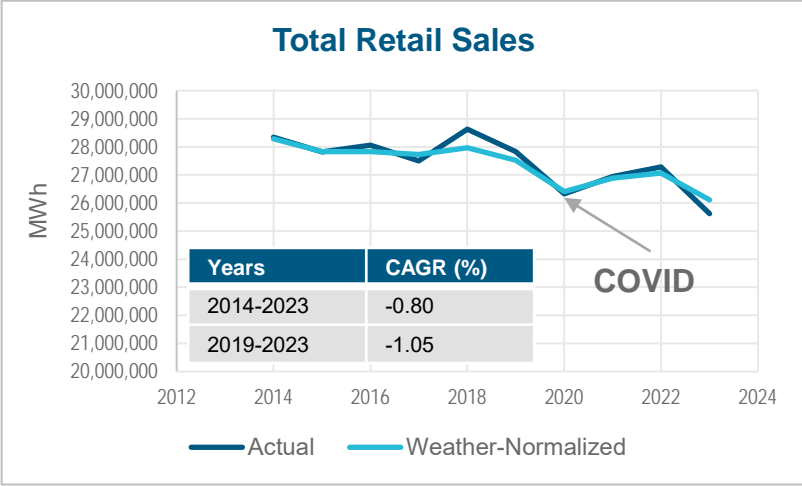




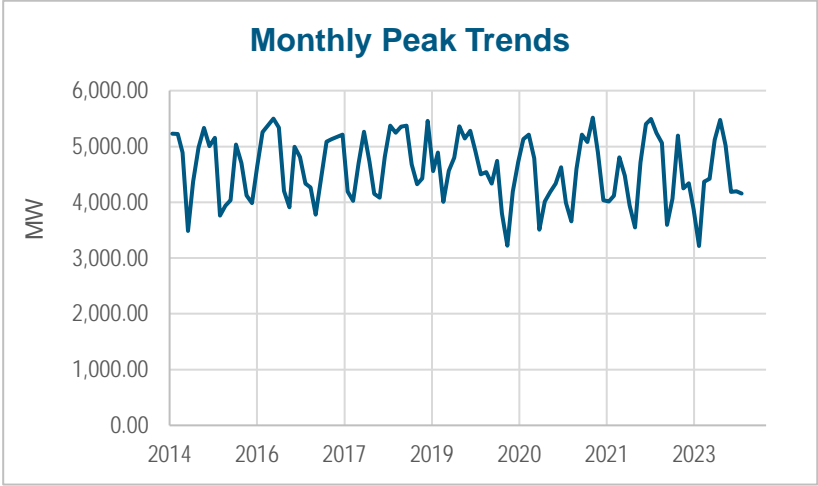
# Historical Customer and Energy Usage Trends: 2014-2023



Customer growth has been steady over the past 5-10 years (1% growth rate).

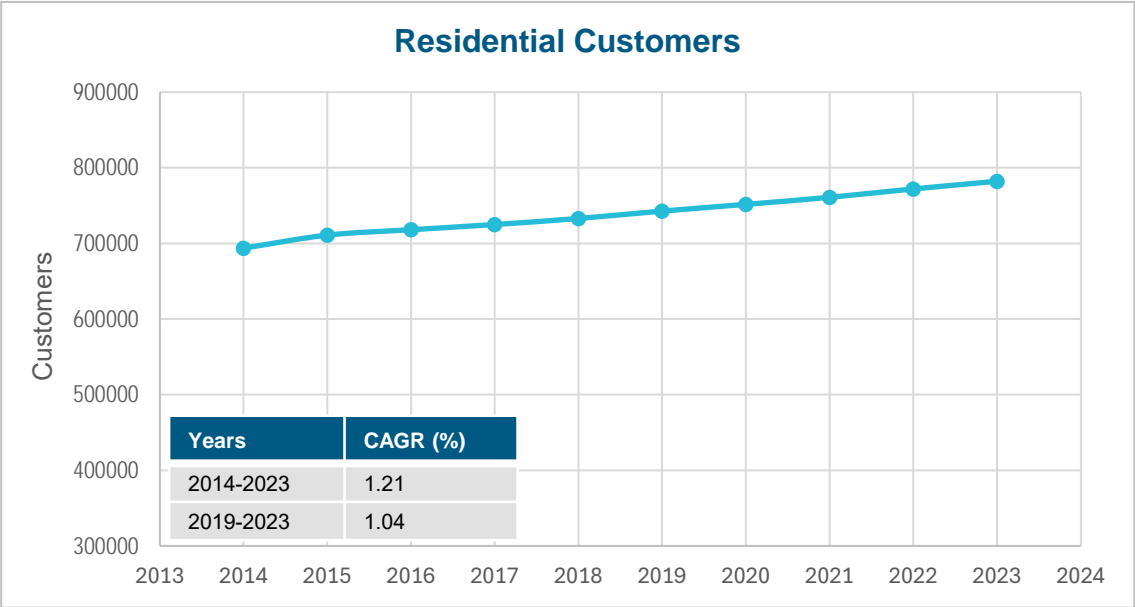


Despite customer growth, **total energy usage** has been slowly decreasing due to energy efficiency gains across customer classes, as shown in the next several slides.

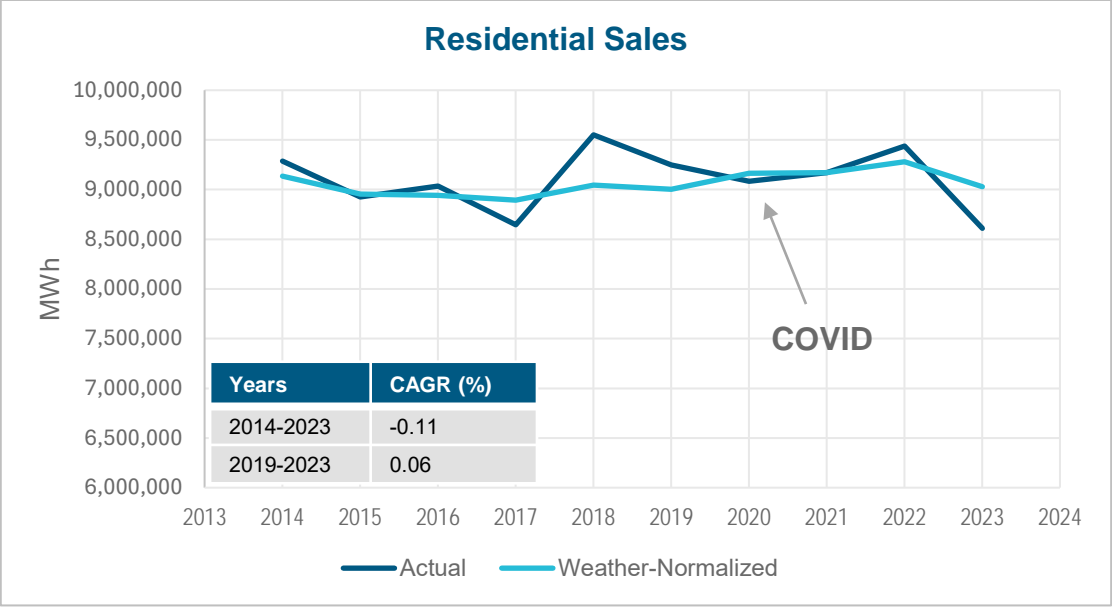


**Total system peak load** has remained relatively consistent over the past decade.

# Historical Residential Trends: 2014-2023



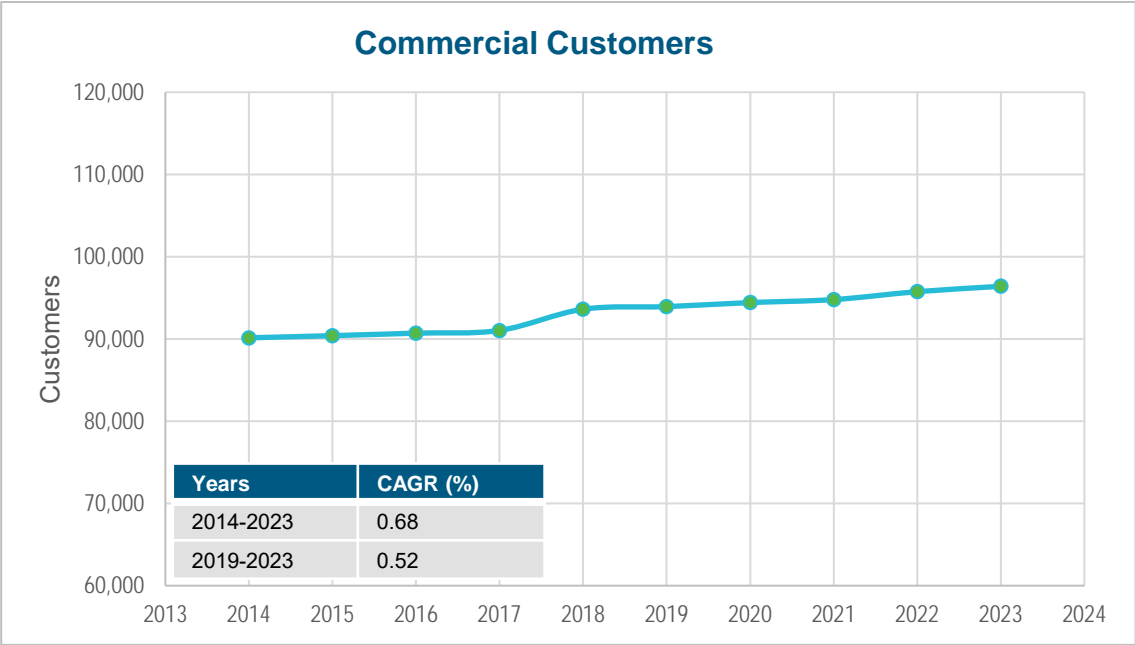
The residential class is the primary positive driver of customer growth.



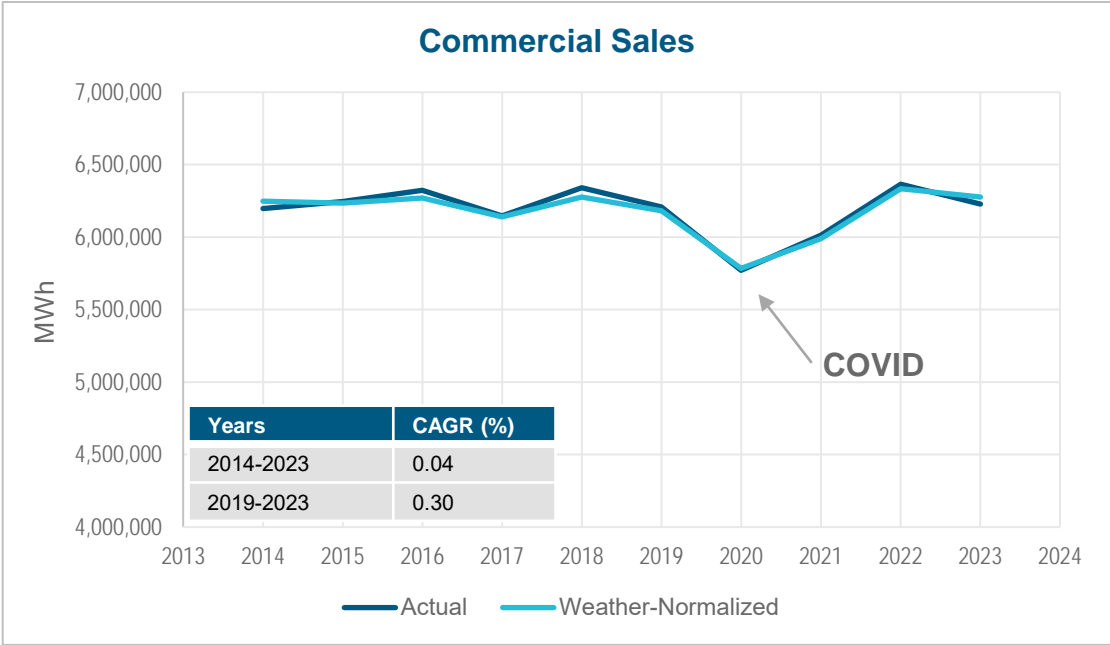
Residential sales have been relatively flat over the past decade, with increased customer growth balanced by improved energy efficiency.

More recently, the COVID pandemic led to a slight increase in residential usage, which may be starting to correct itself in 2023-2024 (see shift downward from 2022 to 2023 in normalized sales).

# Historical Commercial Trends: 2014-2023

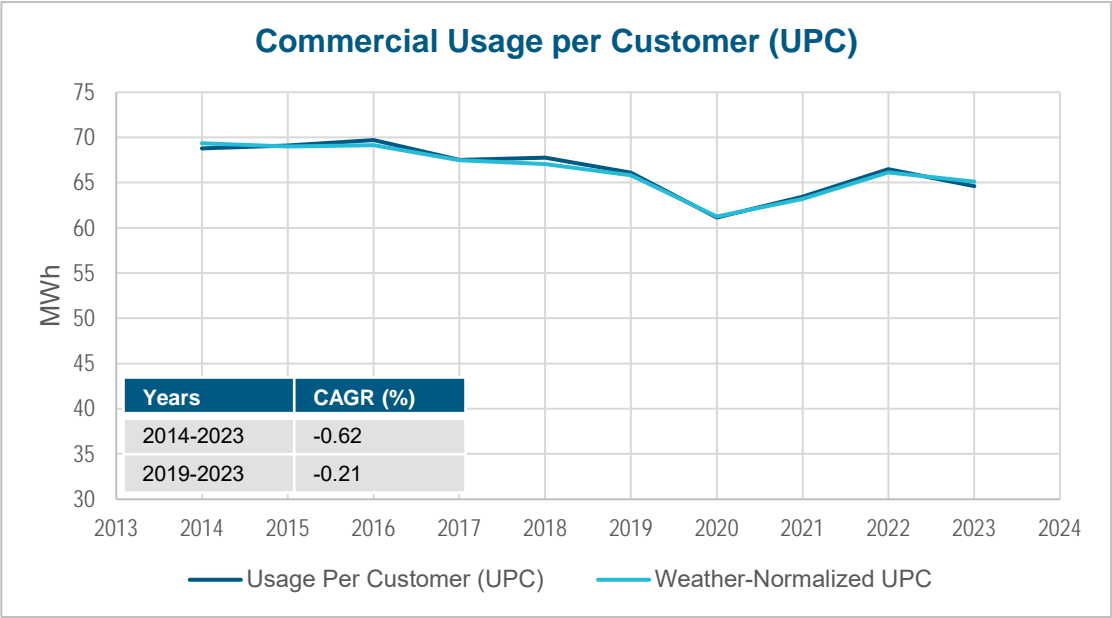
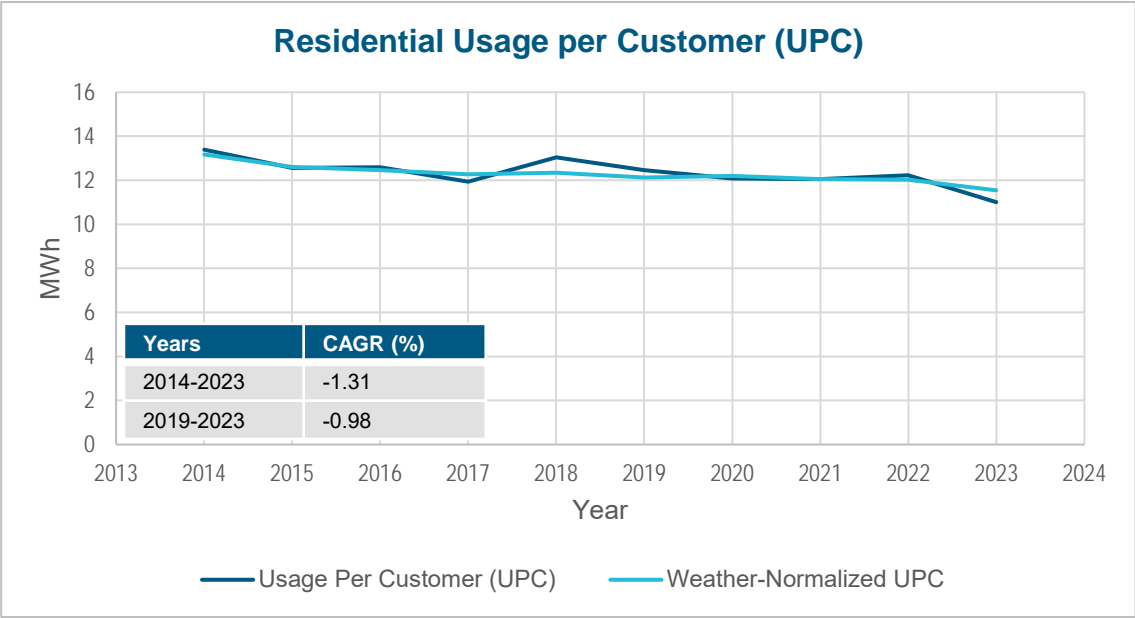


The **commercial class** has seen consistent customer growth but to a lesser extent than residential customers.



**Commercial sales** have been flat and steady over the past decade, dipping only during the pandemic. Recent energy usage suggests that commercial customers have returned to pre-pandemic usage levels.

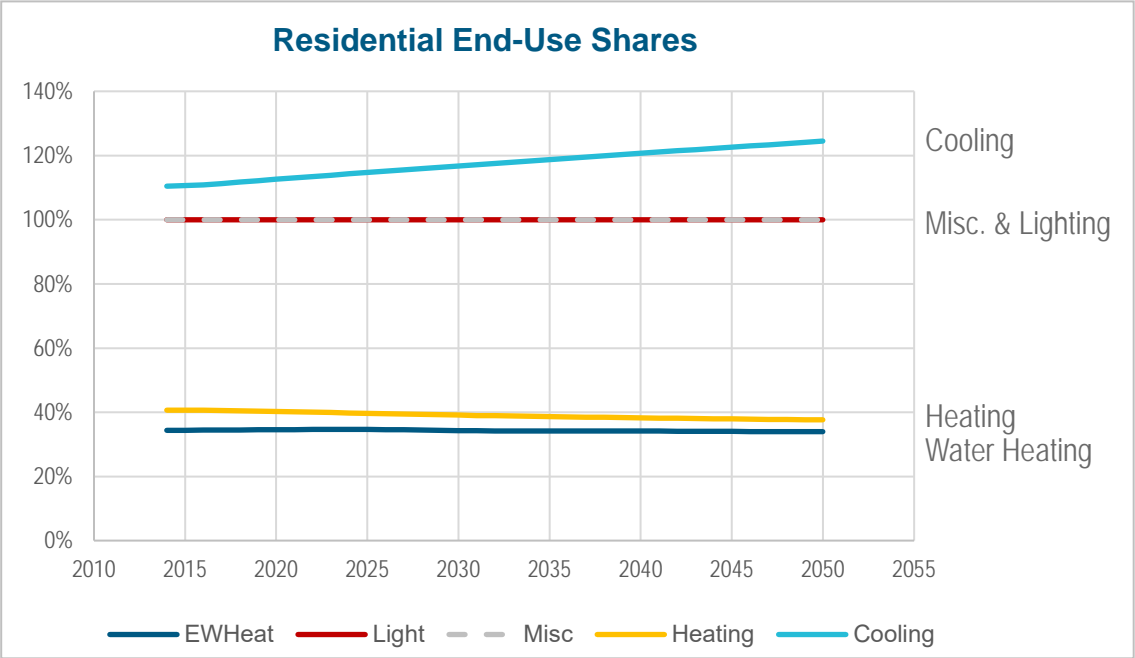
# Residential and Commercial Usage Per Customer: 2014-2023



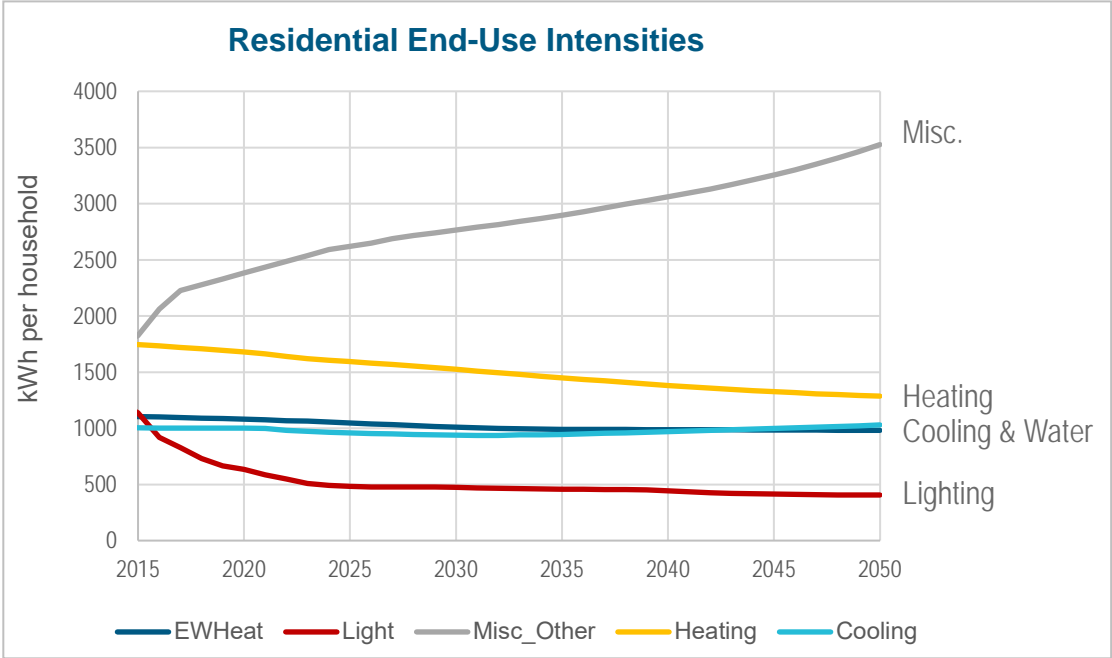
- **Residential annual usage per customer (UPC)** has steadily declined, with a –1% growth rate over the past decade. **Commercial customers** show a similar pattern to a lesser extent.
- Declining household usage is due to higher efficiency across end uses, such as heating and cooling.
- This trend is expected to reverse in the mid-2030's due to increased electrification trends, as shown in the forecast results in upcoming slides.

# End-Use Trends: History and Forecast

Residential end-use energy intensity forecast is produced by Itron.



**Electric cooling sources** are predicted to consistently increase in residential households over the next several decades.

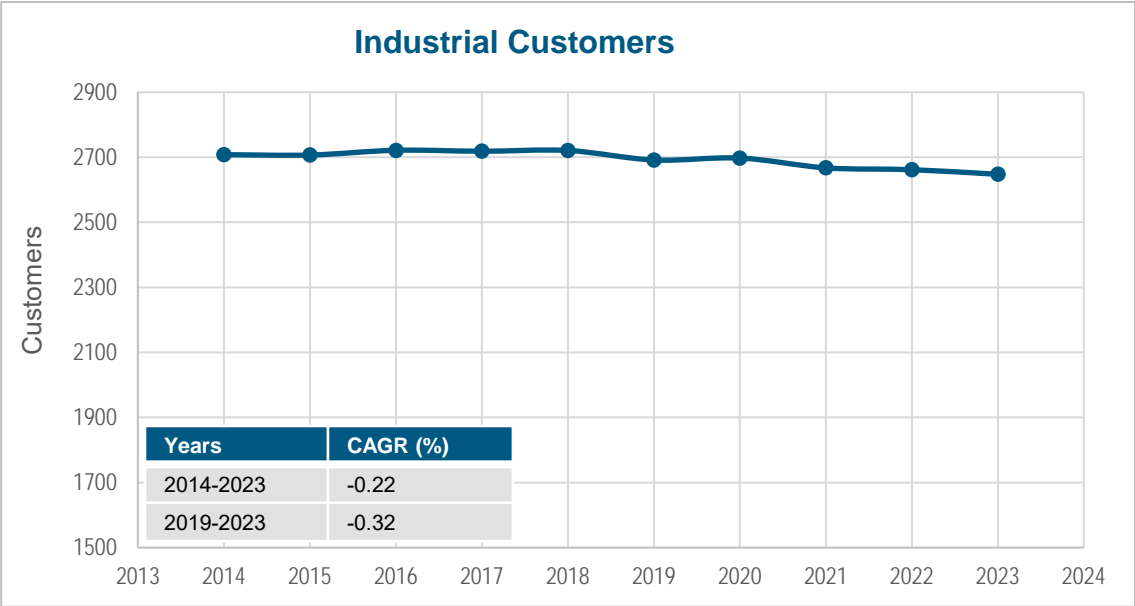


**Equipment efficiency improvements** limit energy usage from heating, cooling, and lighting.

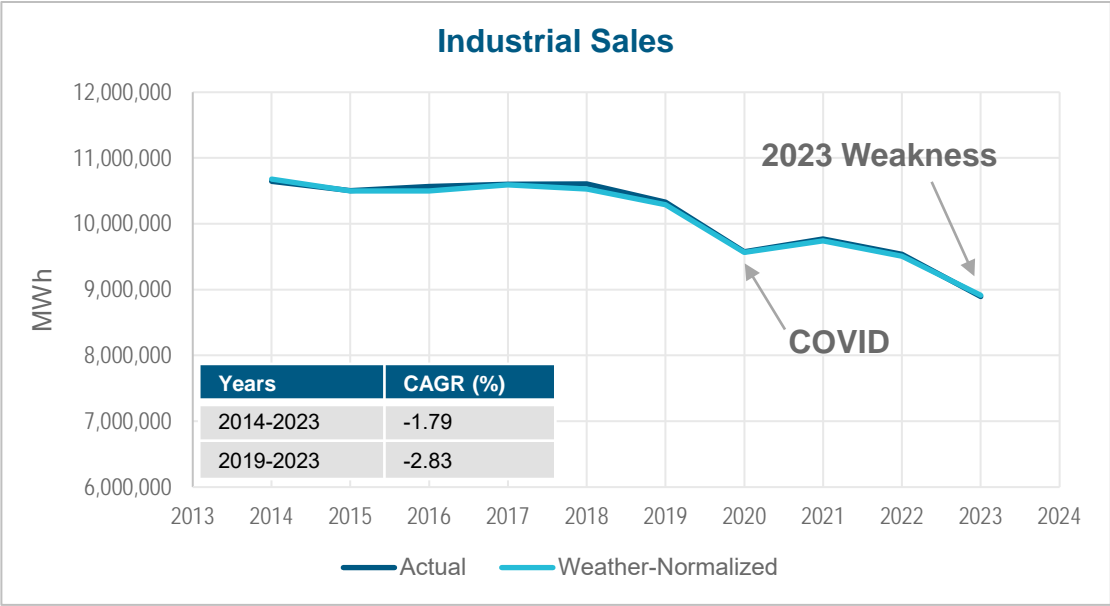
Miscellaneous electrical equipment (connected devices, chargers, gaming, pool pumps, etc.) drive increased usage at home over the next 30 years.

Source: Itron

# Historical Industrial Trends: 2014-2023



**Industrial customer growth** has been flat over the past 5-10 years.



**Industrial energy usage** fell during the pandemic and has struggled to reach pre-pandemic levels.

**Industrial weakness** in 2023 is related to general economic pressures including: difficulties in attracting and retaining workforce, weak domestic economy, increased raw material costs, and increased production costs.

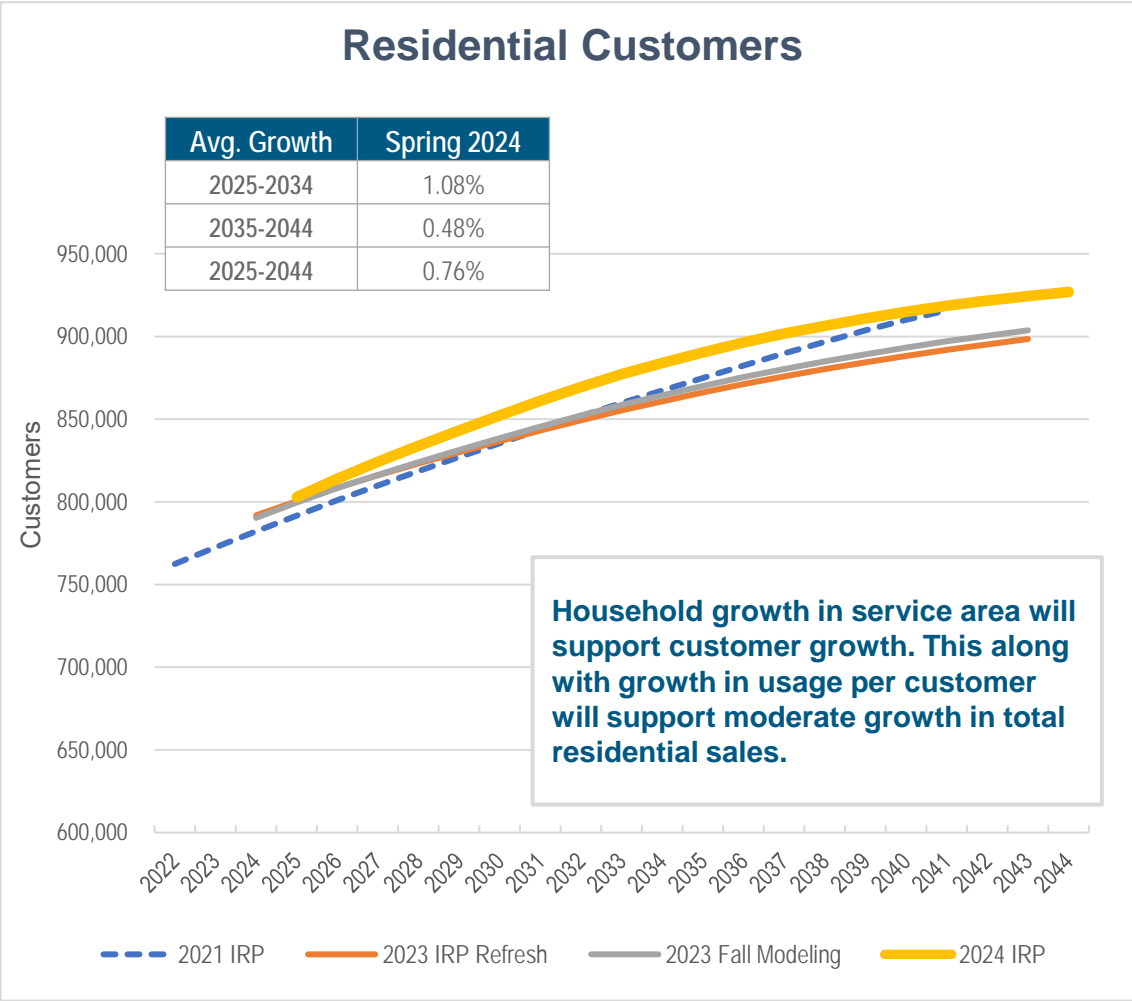
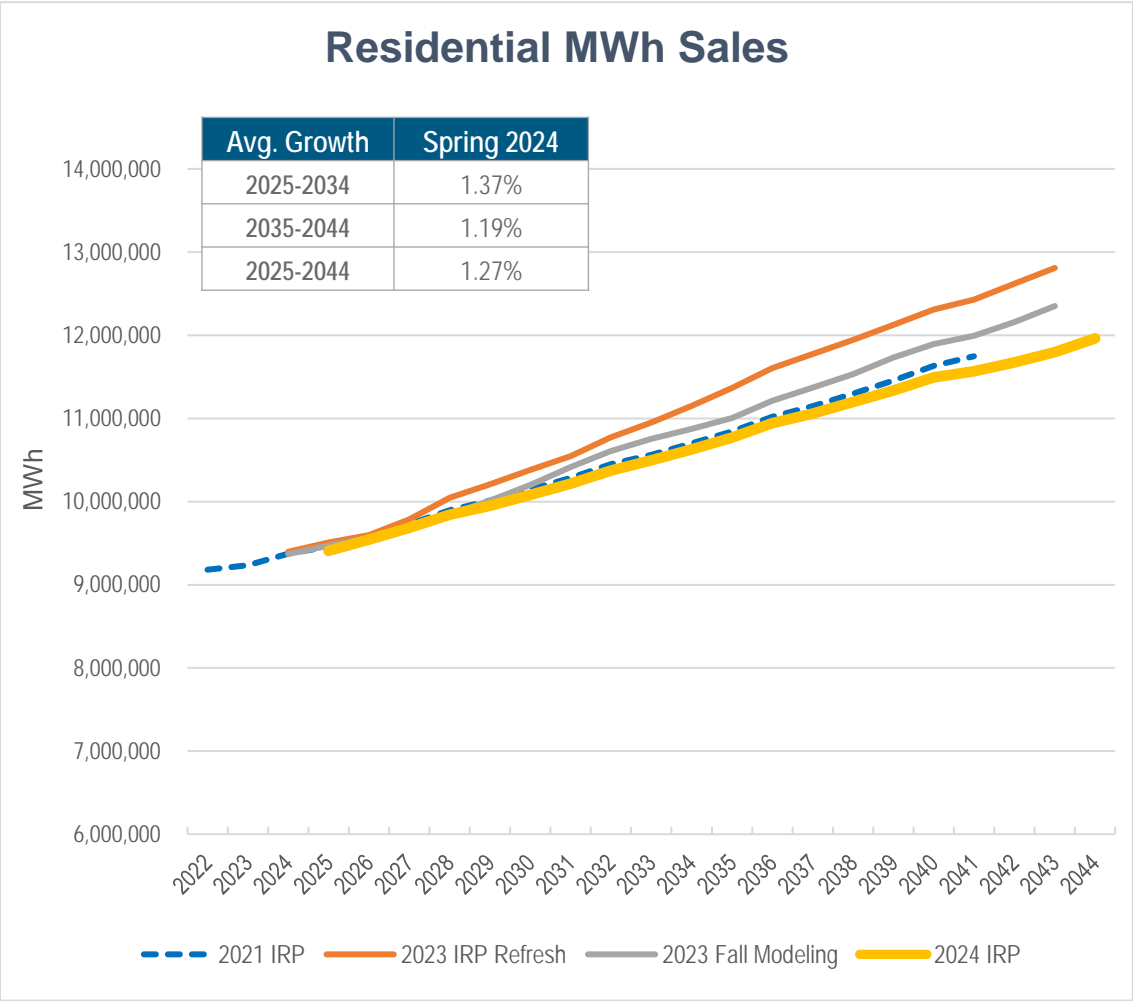


# Current Industrial Landscape

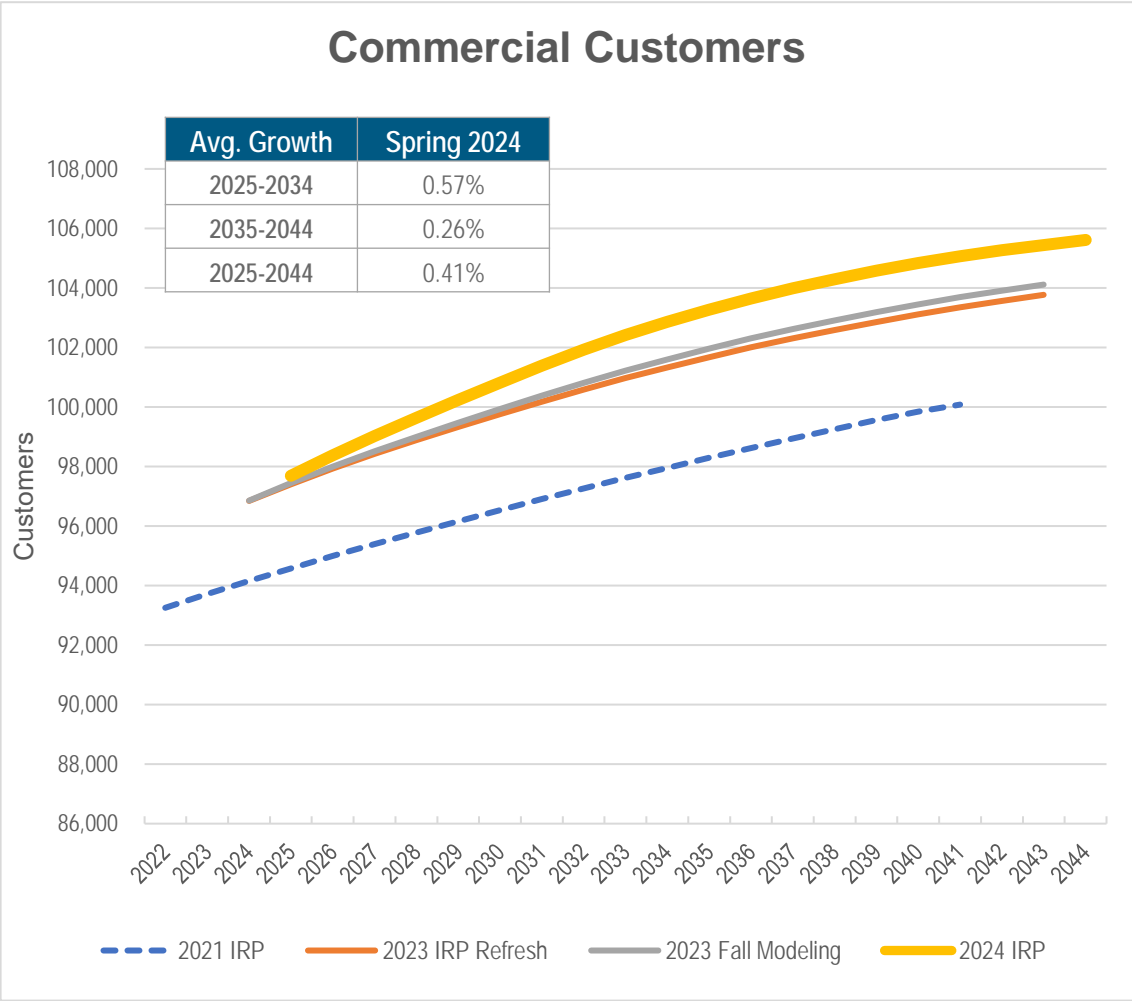
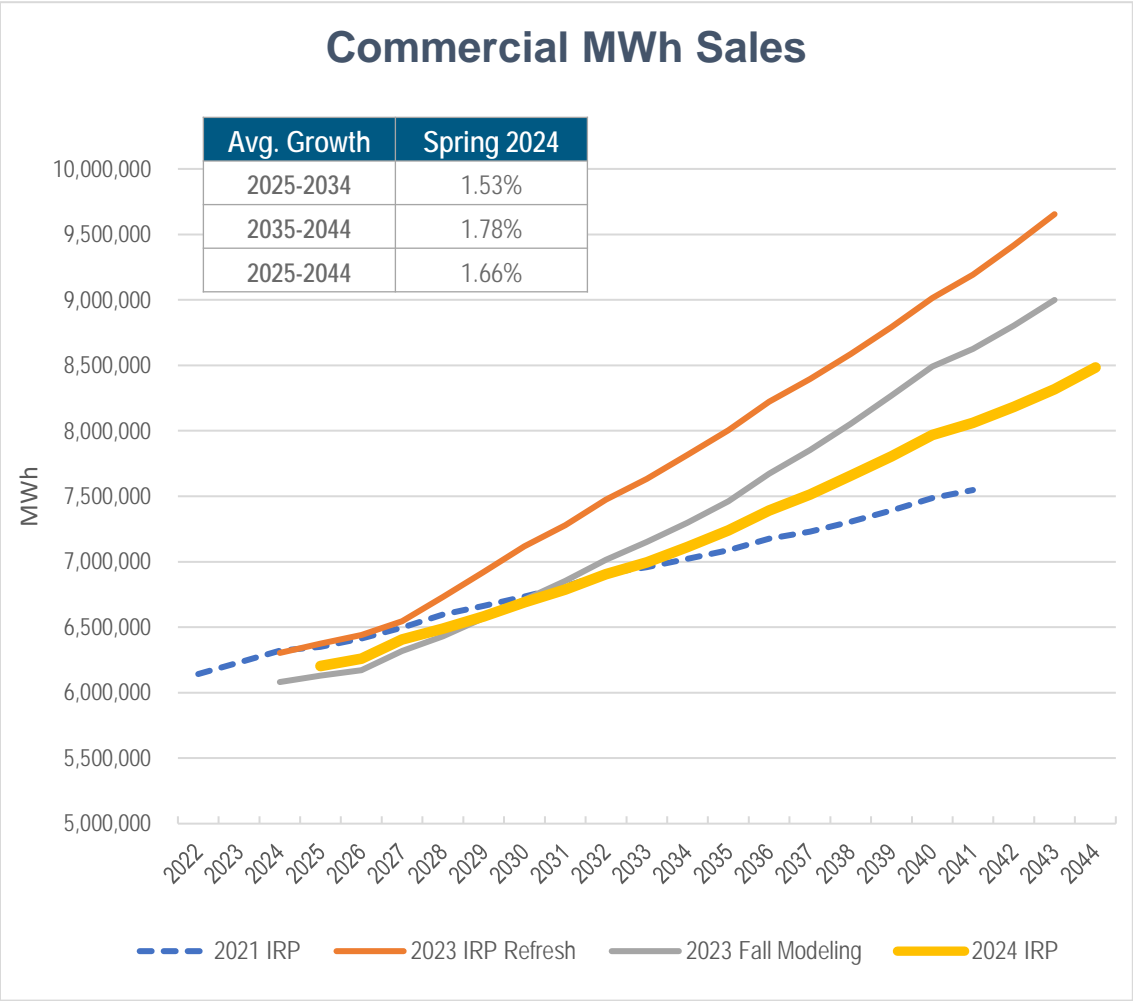
## Indiana Top Industrial Sectors



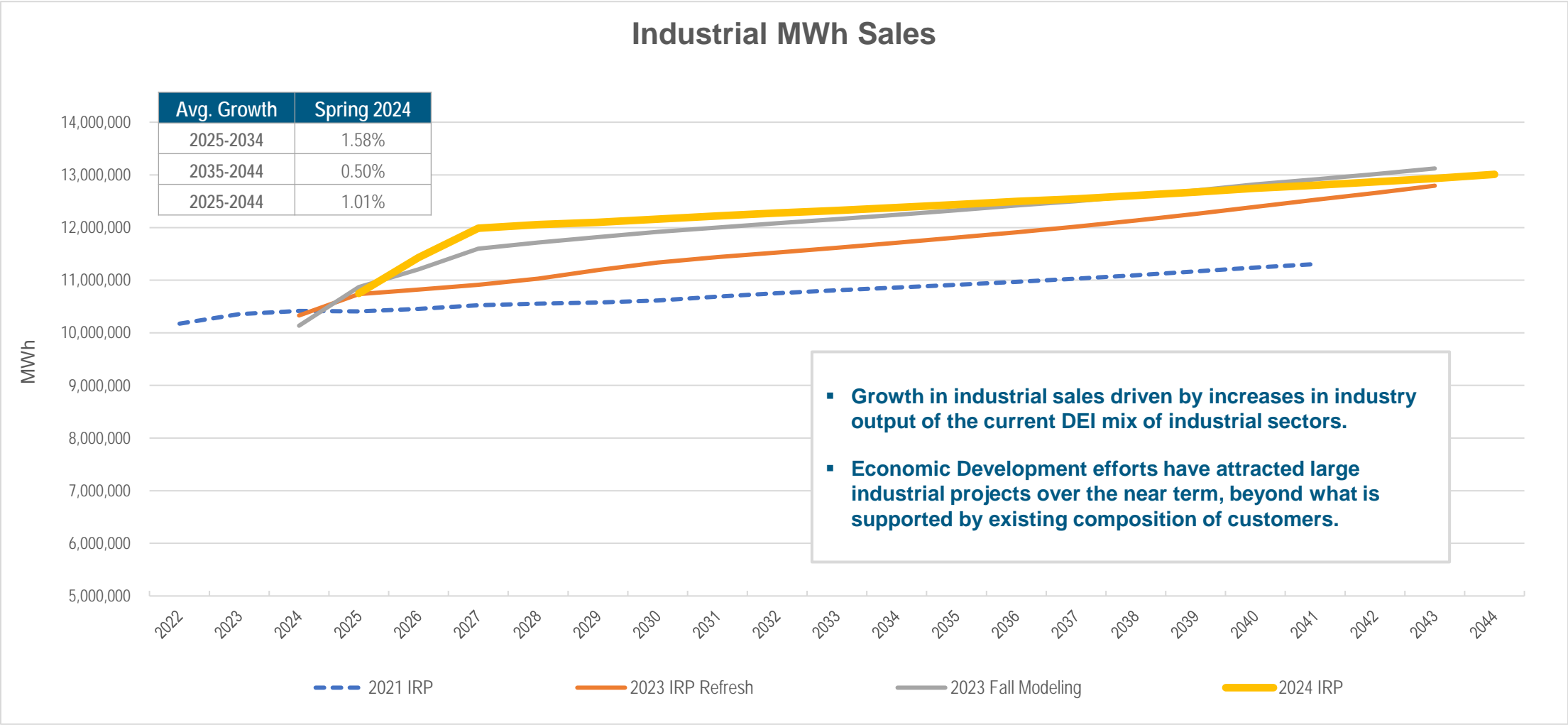
# Residential Sales Forecast



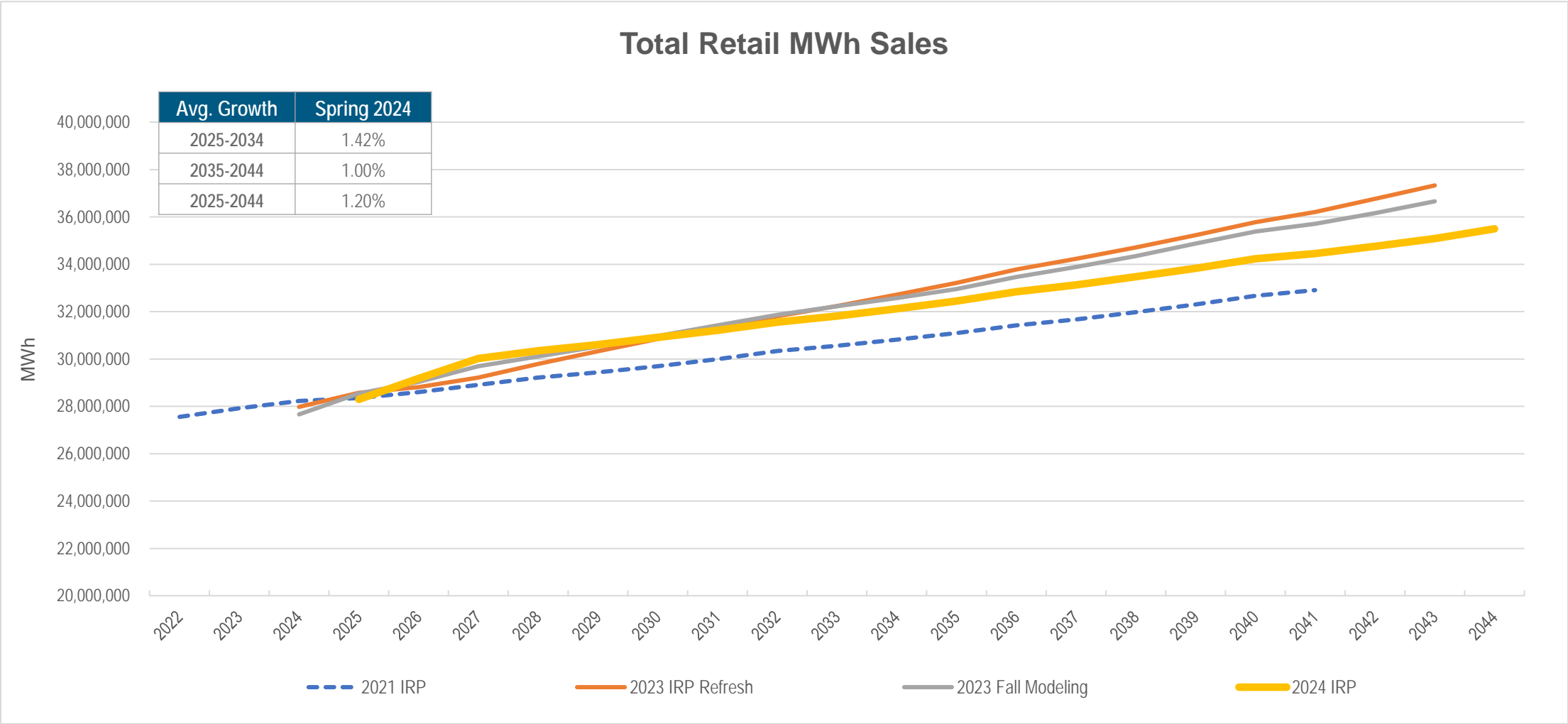
# Commercial Sales Forecast



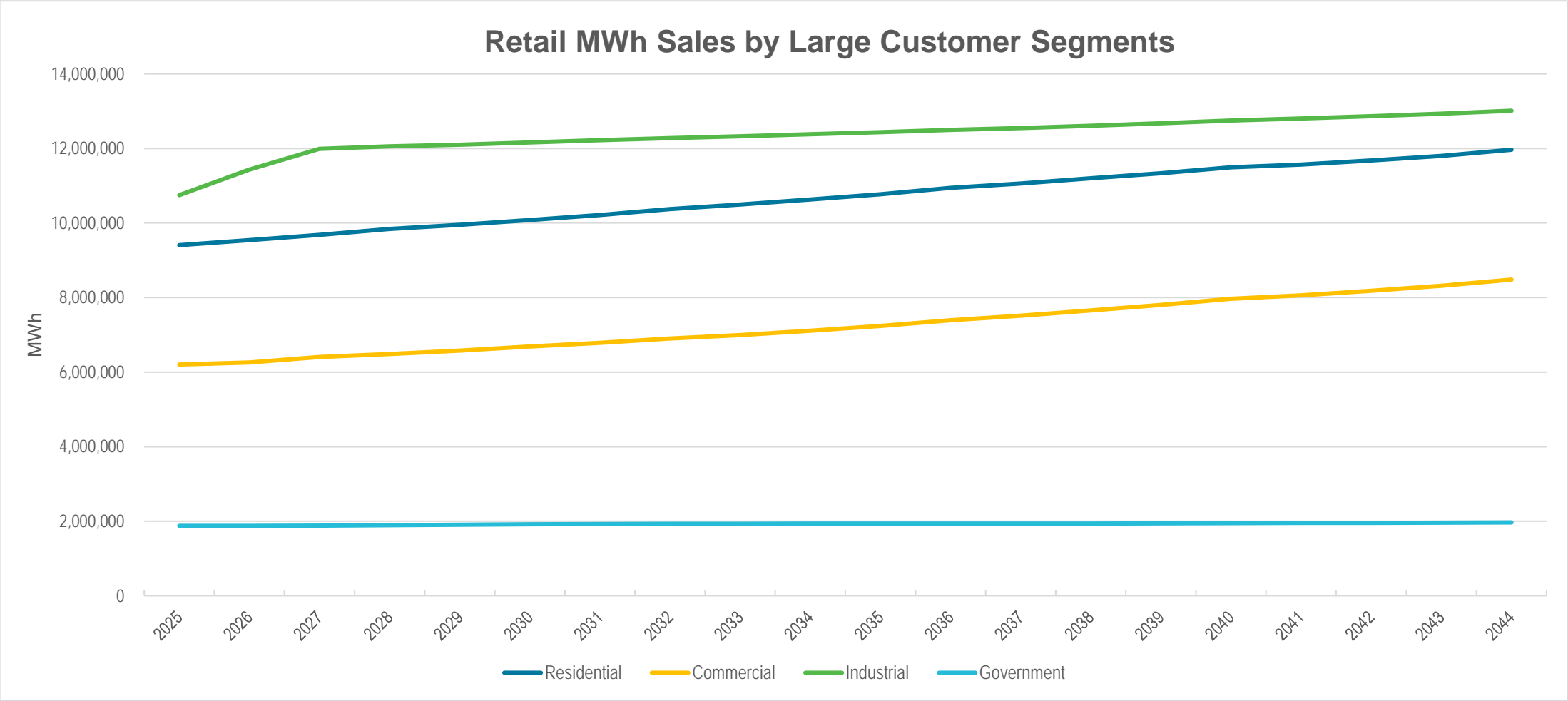
# Industrial Sales Forecast



# Total Retail Sales Forecast

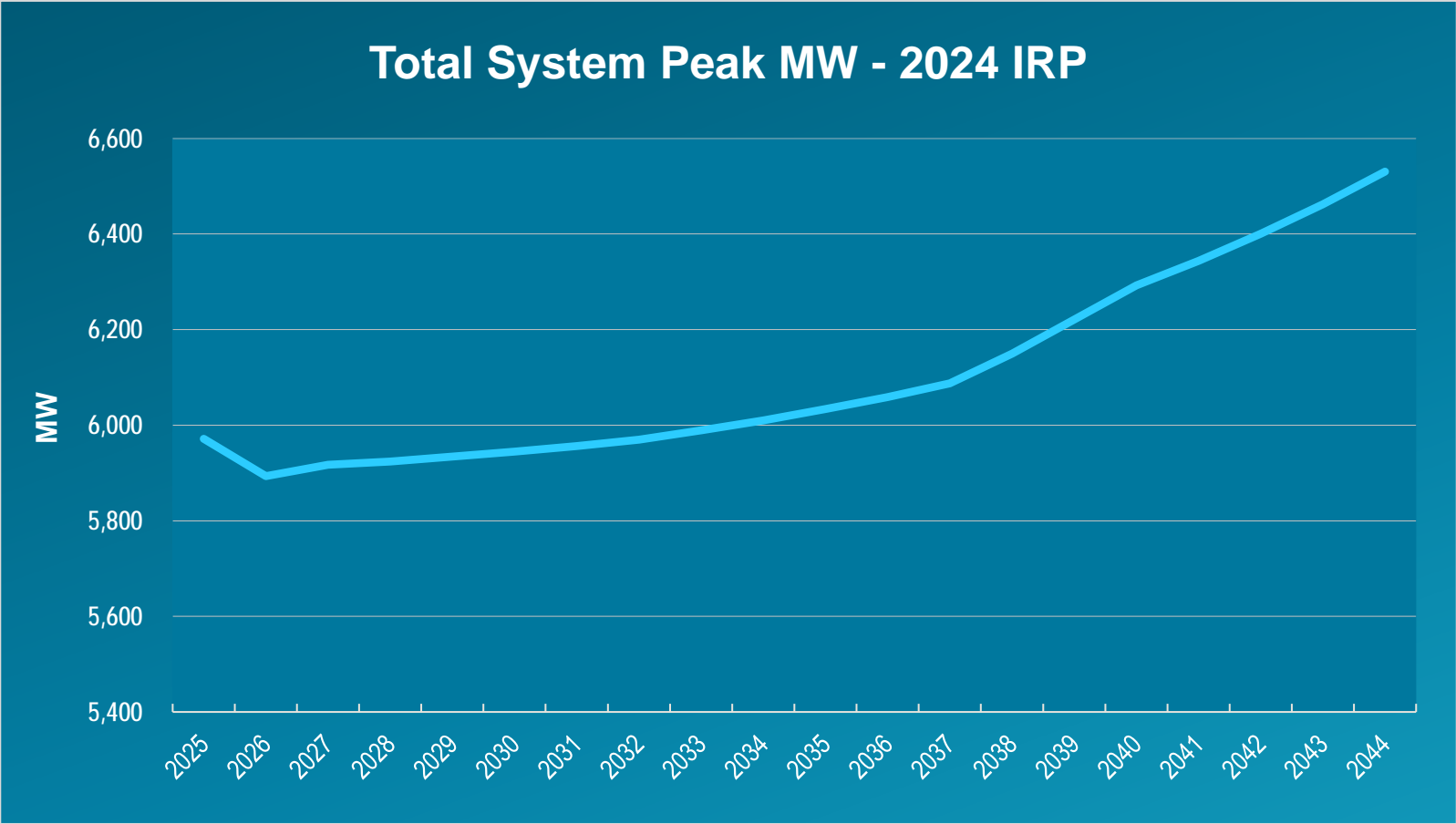


# Retail Sales by Class - Spring 2024 Forecast





# DEI Annual Retail Gen IRP Peak Load Factor Components

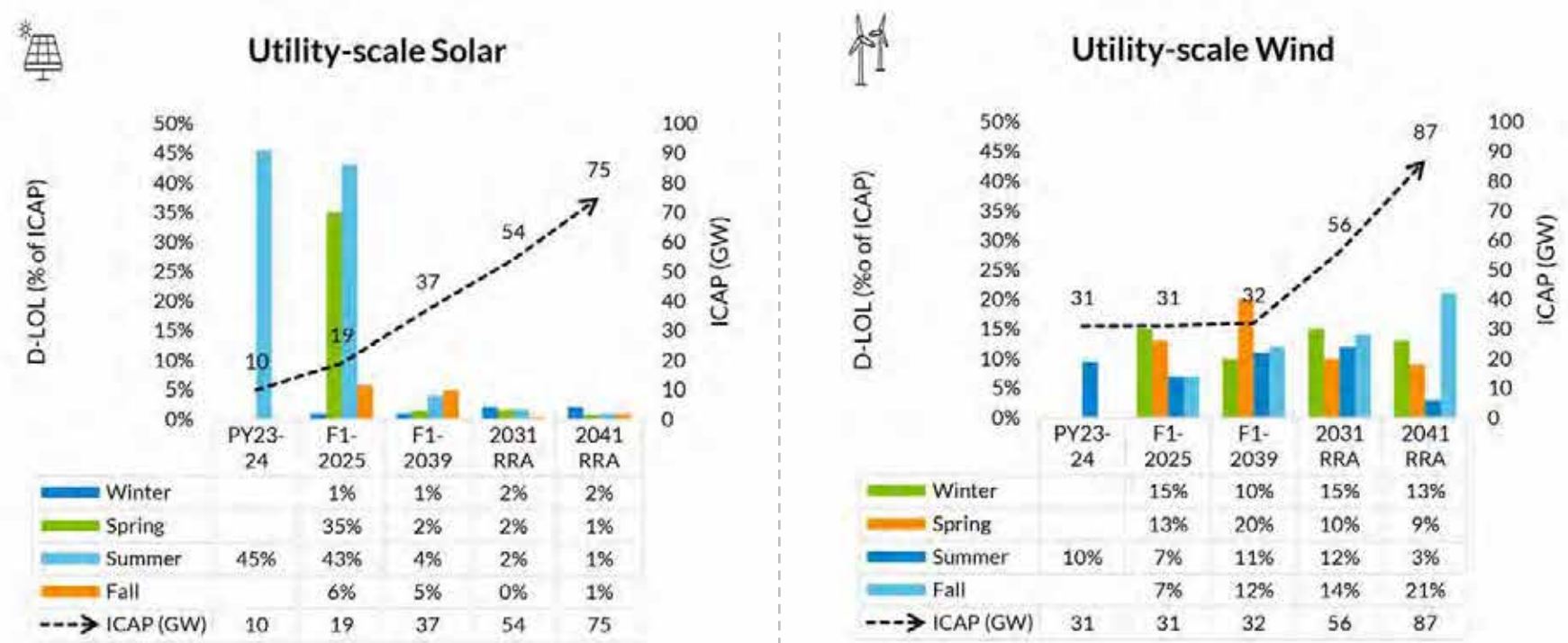




# Appendix: D-LOL Accreditation

# D-LOL Accreditation

Direct-LOL results using latest Planning Year (PY), results from the non-thermal evaluation and the 2022 Regional Resource Assessment (RRA) portfolios



PY: Planning year | F1: Future 1 | RRA: Regional Resource Assessment | ICAP: Installed Capacity | D-LOL: Direct Loss of Load

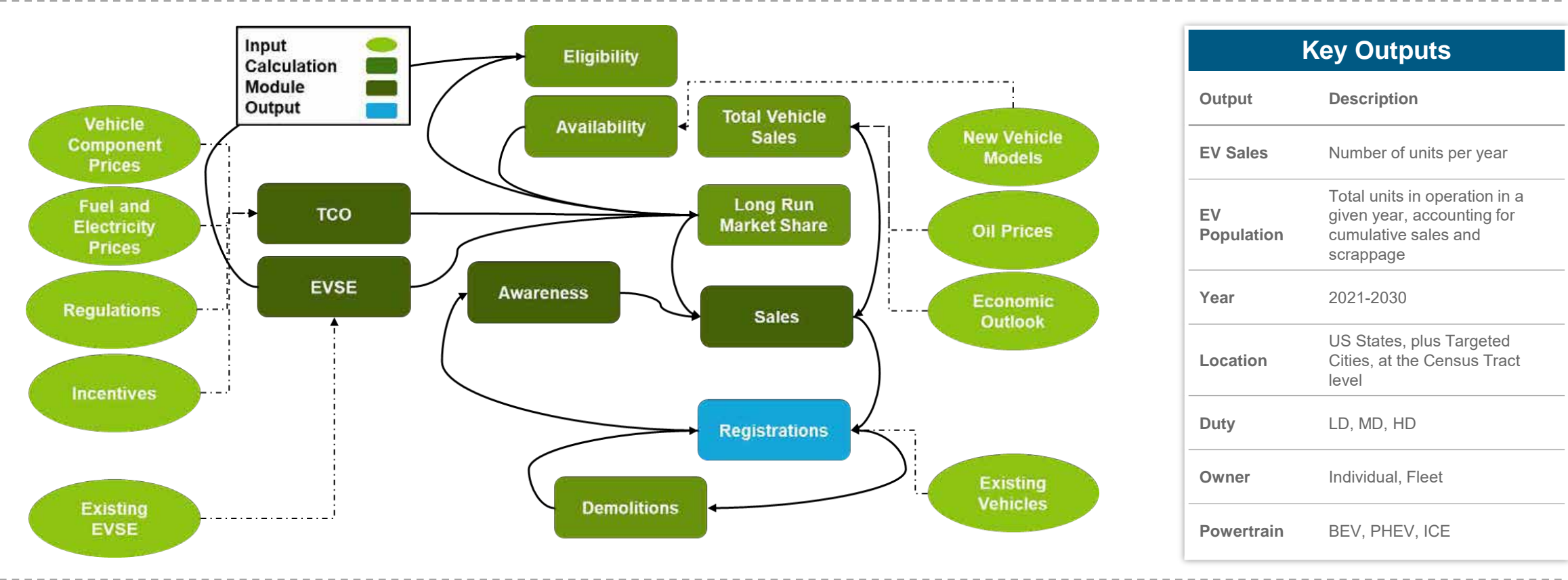
Source: MISO; Market Redefinition: Accreditation Reform, Resource Adequacy Subcommittee ([Link](#))





# Appendix: EV Forecast

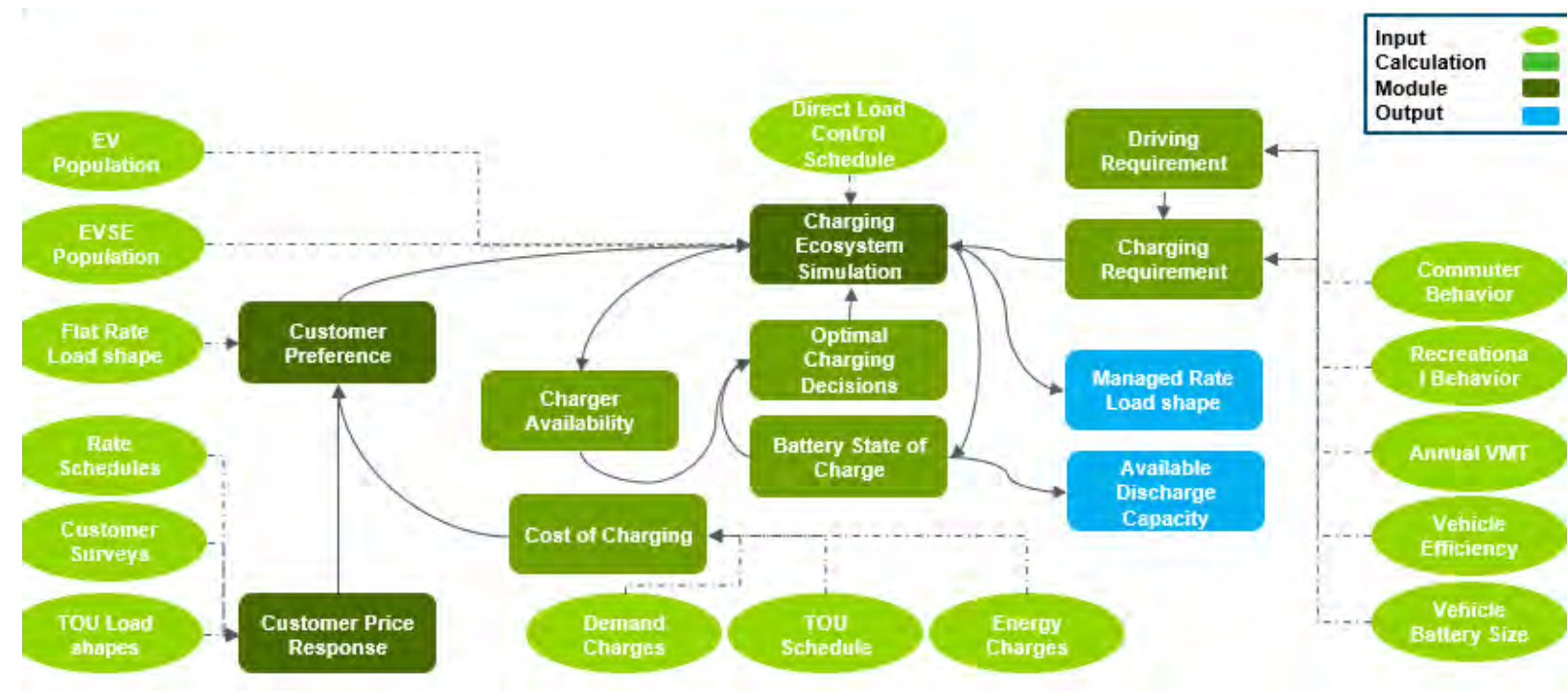
# Vehicle Analysis and Simulation Tool (“VAST”) EV adoption model



TCO: Total Cost of Ownership  
EVSE: Electric Vehicle Supply Equipment  
Source: Guidehouse Analytics



# Vehicle Analysis and Simulation Tool (“VAST”) Load Impacts Model



Key Outputs	
Output	Description
System Geography	State-Territory level
Use Case	Charging use case, examples include Public Market and Private Depot
Duty	Light, Medium, Heavy
Technology	L1, L2, DC
Year	2021-2040
Day of Week/ Time of Day	Hourly, Weekend/Weekday
kWh	Hourly energy consumption

TOU: Time of Use  
EVSE: Electric Vehicle Supply Equipment  
Source: Guidehouse Analytics





# Appendix: Acronyms

# Acronyms

<b>ADMS</b>	Advanced Distribution Management System
<b>ADP</b>	Advanced Distribution Planning
<b>AMI</b>	Advanced Metering Infrastructure
<b>ATB</b>	Annual Technology Baseline
<b>BEV</b>	Battery Electric Vehicle
<b>BOY</b>	Beginning of Year
<b>BTM</b>	Behind-the-Meter
<b>BYOT</b>	Bring Your Own Thermostat
<b>C&amp;I</b>	Commercial & Industrial
<b>CAA 111</b>	Clean Air Act 111
<b>CAGR</b>	Compound Annual Growth Rate
<b>CC</b>	Combined Cycle
<b>CCS</b>	Carbon Capture and Sequestration
<b>CECS</b>	Customer Energy Control System
<b>CHP</b>	Combined Heat and Power
<b>CPCN</b>	Certificate of Public Convenience and Necessity
<b>CT</b>	Combustion Turbine
<b>DE&amp;I</b>	Diversity, Equity, & Inclusion
<b>DEI</b>	Duke Energy Indiana
<b>DER</b>	Distributed Energy Resources
<b>D-LOL</b>	Direct Loss of Load
<b>DR</b>	Demand Response
<b>DSM</b>	Demand Side Management

<b>ED</b>	Economic Development
<b>EDG</b>	Excess Distributed Generation
<b>EE</b>	Energy Efficiency
<b>EMS</b>	Energy Management System
<b>EOY</b>	End of Year
<b>EPA</b>	Environmental Protection Agency
<b>EUE</b>	Expected Unserved Energy
<b>EV</b>	Expected Unserved Energy
<b>EVSE</b>	Electric Vehicle Supply Equipment
<b>FERC</b>	Federal Energy Regulatory Agency
<b>GUS</b>	Generic Unit Summary
<b>GW</b>	Gigawatt
<b>HD</b>	Heavy Duty
<b>HEA</b>	House Enrolled Act
<b>ICAP</b>	Installed Capacity
<b>ICCT</b>	International Council on Clean Transportation
<b>ICE</b>	Internal Combustion Engine
<b>ICEV</b>	Internal Combustion Engine Vehicle
<b>IJA</b>	Infrastructure Investment and Jobs Act
<b>IN</b>	Indiana
<b>IRA</b>	Inflation Reduction Act
<b>IRP</b>	Integrated Resource Plan
<b>ITC</b>	Investment Tax Credit

# Acronyms

<b>IURC</b>	Indiana Utility regulatory Commission
<b>IVVC</b>	Integrated Volt/VAR Control
<b>kV</b>	Kilovolt
<b>kW</b>	Kilowatt
<b>LD</b>	Light Duty
<b>LDSE</b>	Long Duration Energy Storage
<b>LMP</b>	Locational Marginal Pricing
<b>LNG</b>	Liquefied Natural Gas
<b>LOLE</b>	Loss of Load Expectation
<b>MD</b>	Medium Duty
<b>MISO</b>	Midcontinent Independent System Operator
<b>MPS</b>	Market Potential Study
<b>MSRP</b>	Manufacturer's Suggested Retail Price
<b>MW</b>	Megawatt
<b>MWh</b>	Megawatt-hour
<b>NEM</b>	Net Energy Metering
<b>NREL</b>	National Renewable Energy Laboratory
<b>NYMEX</b>	New York Mercantile Exchange
<b>OEM</b>	Original Equipment Manufacturer
<b>OSB</b>	Oversight Board
<b>PHEV</b>	Plug-In Hybrid Electric Vehicle
<b>PM</b>	Power Manager

<b>PPA</b>	Power Purchase Agreement
<b>PRMR</b>	Planning Reserve Margin Requirement
<b>PTC</b>	Production Tax Credit
<b>PV</b>	Photovoltaic
<b>PVRR</b>	Present Value Revenue Requirement
<b>PY</b>	Planning Year
<b>RFP</b>	Request for Proposal
<b>RRA</b>	Regional Resource Assessment
<b>SAE</b>	Statistically Adjusted End Use
<b>SME</b>	Subject Matter Expert
<b>SMR</b>	Small Modular Reactor
<b>T&amp;D</b>	Transmission & Distribution
<b>TCO</b>	Total Cost of Ownership
<b>TOU</b>	Time-of-Use
<b>TRM</b>	Technical Reference Manual
<b>UCT</b>	Utility Cost Test
<b>UPC</b>	Usage Per Customer
<b>UEE</b>	Utility Energy Efficiency
<b>V2G</b>	Vehicle-to-Grid
<b>VAST</b>	Vehicle Analysis and Simulation Tool
<b>VMT</b>	Vehicle-Miles Traveled
<b>VPP</b>	Virtual Power Plant



# Duke Energy Indiana's 2024 Integrated Resource Plan Engagement Session

## JUNE 20, 2024, MEETING SUMMARY

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## Meeting Information

On Thursday, June 20, 2024, Duke Energy Indiana convened the third stakeholder meeting to inform the development of the 2024 Duke Energy Indiana Integrated Resource Plan ("IRP"). The meeting was held in person at Duke Energy Indiana's Regional Headquarters in Plainfield, Indiana, with the option to attend virtually. Approximately 67 external individuals representing over 35 organizations participated in this session.

## Facilitation Process

To encourage collaboration and to foster an environment where diverse perspectives could be shared, 1898 set forth the following ground rules for the session:

- **Respect each other:**  
Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve a better understanding and develop robust solutions.
- **Focus on today's topics:**  
Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.
- **Chatham House Rule:**  
Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

## Session Participation

This hybrid event was facilitated by 1898 & Co., and the session included presentations and robust conversations on the following topics:

- Feedback from the Second Public Engagement Session
- MISO Power Price Modeling
- Incorporation of CAA 111
- Preliminary Portfolios
- Market Potential Study

Attendees who participated in person were asked to raise their hand to ask a question or make a comment. Team members from both Duke Energy and 1898 & Co. called on in-person attendees and walked through the room with microphones so all participants, both in person and online, could hear the questions or comments of participants.

Virtual attendees used the "raise hand" feature in Teams to ask a question or make a comment aloud or submitted a question through the "Q&A" feature. Virtual attendees had access to the "chat" feature in Teams to share links to information and communicate with each other. Staff

from 1898 & Co. took meeting notes, which have been included in the summary. Pursuant to the ground rules, the notes have been anonymized.

If participants had questions after the session or wanted to share feedback or additional information, they were asked to send an email to [DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com).

## Access to Meeting Materials

Meeting materials for the June 20, 2024 engagement session were posted to Duke Energy Indiana's IRP website at [duke-energy.com/IndianaIRP](https://duke-energy.com/IndianaIRP) on June 13, 2024. Participants were asked to visit the website to view the materials and meeting summaries. The 1898 & Co. team will continue to contact stakeholders via email as the website is updated with materials for each session.

## Meeting Notes

This document includes a high-level summarization of the presentation material as well as the questions and comments made by participants. The questions and comments were captured throughout the meeting; however, the summary herein does not constitute a meeting transcript. Questions and commentary were edited for clarity as needed. Similar summaries will be prepared following each public engagement session throughout this process.

## Safety

*Michael Carnagua, Duke Energy Senior Event Technician*

Mr. Carnagua outlined in person emergency and evacuation protocols. Mr. Carnagua then provided a safety moment on sun and heat safety.

## Welcome

*Stan Pinegar, Duke Energy Indiana State President*

Mr. Pinegar opened the meeting by welcoming attendees, thanking them for their participation, and encouraging active engagement in the 2024 IRP process.

## Introductions

*Karen Hall, Duke Energy Resource Planning Director*

Ms. Hall introduced the Duke Energy teammates who are supporting the 2024 IRP. Ms. Hall also instructed participants to contact her for any technical issues throughout the meeting.

## Meeting Guidelines & Agenda

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*



Mr. Burczyk discussed the ground rules for the hybrid meeting. These guidelines included respecting each other, staying on topic, and the Chatham House Rule. He also reviewed guidelines for audience participation and the meeting agenda.

## Stakeholder Feedback and Incorporation

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk provided an overview of stakeholder feedback that was received and incorporated into the agenda for the second Public Engagement Session and when this feedback would be discussed in the meeting. He then covered additional feedback and the responses from Duke Energy Indiana, which included topics such as future stakeholder meetings and modeling assumptions.

## Q&A related to Stakeholder Feedback and Incorporation

1. Question: Please explain why Duke Energy is not implementing renewables until 2030?
  - a. The model was allowed to select renewable projects before 2030, and there are initial portfolios that have renewables selected before 2030. Slide 16 highlights the changes in renewable resource availability assumptions in the early 2030s since the previous meeting. The full resource availability assumptions can be found in the appendix.
2. Question: Did Duke Energy sell one of their solar farms? I saw an article that said in October, Duke Energy announced the sale of a 3.4 MW unregulated, utility-scale commercial renewables business to Brookfield Renewable Partners.
  - a. This was not an asset of Duke Energy Indiana. Rather, this was the Duke Energy non-regulated renewable portfolio. There is strict regulation on whether the non-regulated renewables can be used on the regulated side at both the federal and state levels, so it wasn't an option for Duke Energy Indiana to serve its customers with these resources. Duke Energy Indiana has not sold any solar farms and has been moving forward with adding more renewables to the portfolio.
3. Question: There has not been mention of Duke Energy Indiana's modeling of a feedback loop for customer defection due to near term constraints with the sustainable energy transition. Is this included in the modeling?
  - a. Load sensitivity cases will be run in the modeling to account for uncertainty surrounding load.
4. Question: Can you provide feedback on any revised timeline for Duke's responses to the RFP?
  - a. The RFP and IRP will remain separate processes. The Company is using the bids received to help inform IRP modeling assumptions.
5. Question: Regarding the responses to the RFP, did the Company only benchmark costs related to battery, solar, and wind?
  - a. We are using actual costs for selectable resources in the near term for wind, solar and storage and using RFP bids for thermal resources to confirm that our generic cost forecasts are in line with what is available in the market. We use generic cost forecasts for all resources in later years. Where possible (i.e., for

resource types for which we received asset transfer bids), we benchmark our forecasts against actual bids.

6. Question: Are you trying to exactly match the RFP responses for the year in question?
  - a. Not exactly, as different tranches have different price points. Ideally, the forecast curves go through the middle of that range.
7. Question: Is there something you can provide to us that demonstrates that comparison between RFP responses and your forecast curves?
  - a. We will review with the RFP team and plan to provide an update on this comparison to technical stakeholders who have signed an NDA and made this request.
8. Question: Duke Energy Indiana indicates that the costs required to build SMRs are expected to decline after the first SMR is installed. Does this refer to the first SMR nationally?
  - a. Correct. Costs are expected to decline after the first SMR is built in the U.S.

## **MISO Modeling – IRP Energy Market Prices (Power Prices)**

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk showed the Reference Case power prices and explained how EnCompass and the Horizon Energy National database were simulated to determine the forecast for each scenario. He also discussed the updates that were made to align with IRP assumptions and mentioned that MISO-wide analysis results in LMPs which are used as inputs to the IRP model.

### **Q&A related to MISO Modeling**

1. Question: What is the basis for the projected CO<sub>2</sub> tax amount?
  - a. The CO<sub>2</sub> tax price forecast used in the Aggressive Policy & Rapid Innovation Scenario is based on proposed federal legislation in the Market Choice Act (H.R. 6665), which was introduced in December 2023.
2. Question: Do the power prices take into account different energy sources individually so that it can be used for the IRP models for different energy mixes?
  - a. Yes, under each scenario there is a unique resource buildout that is dispatched on a unit by unit basis.

## **Incorporation of 111 in Generation Strategies**

*Nate Gagnon, Managing Director Midwest IRP*

Mr. Gagnon started by summarizing the options under the EPA CAA 111 Final Rule for coal units which included modifying for natural gas co-firing, converting to 100% natural gas fuel, retiring, or adding Carbon Capture and Sequestration (CCS) for existing coal units. For new gas units, he outlined how the options are running as an intermediate unit (40% capacity factor max), running as a peaking unit (20% capacity factor max), or adding CCS. He also walked through the current IRP generation strategies that Duke Energy Indiana has modeled so far which

include Retire Coal Units, Convert Coal Units, and Blend #1 which has a combination of converting and retiring coal units. Mr. Gagnon outlined how each existing coal facility could meet CAA 111 requirements under each of the respective generation strategies. Duke Energy Indiana also modeled a strategy that assumed EPA CAA 111 was not in effect,

### Q&A related to Incorporation of 111 in Generation Strategies

1. Question: Do the power price update assumptions take into account Federal Investment Tax Credits (ITCs) for solar?
  - a. Yes, the power prices do take into account ITCs. Under both the Reference scenario and the Aggressive Policy & Rapid Innovation scenario it is assumed that the IRA, and therefore the ITCs are extended. In the Minimum Policy and Lagging Innovation scenario, the IRP modeling assumes that ITCs are repealed. These differences by scenario are included in both the National Database runs for the market price development and the DEI local IRP modeling.
2. Question: Does the Company's modeling include considerations for which resource type provides the cleanest air, least CO<sub>2</sub> emissions, least health impacts, in addition to the costs?
  - a. Yes, a generator's specific cost, performance, and emissions are all captured in the model. We have developed a scorecard that will be used to evaluate each portfolio's performance, including metrics on affordability and environmental sustainability.
3. Question: It appears Duke Energy Indiana is planning to convert Edwardsport to natural gas in these portfolios. I thought that Edwardsport already operated like a natural gas plant. Will additional capital investment be required for the natural gas conversion at Edwardsport?
  - a. The natural gas conversion being listed for Edwardsport is to indicate that, in these portfolios, Edwardsport would stop using the gasifiers that turn coal into syngas. The Company anticipates there will be some capital investment required to optimize the units to burn natural gas only.

### Initial Preliminary Portfolios

*Nate Gagnon, Managing Director Midwest IRP*

Mr. Gagnon then discussed the IRP planning period. He explained how the IRP planning period can be thought of in three main blocks: the immediate future, early 2030s, and the latter half of the planning period. Mr. Gagnon mentioned that when looking at these blocks, the near-term action plan is more focused on the immediate future and into the early 2030s, but some of the further out decisions will be re-evaluated over future IRP iterations. He also walked through preliminary model results for four preliminary portfolios. The preliminary results focused on the supply-side resource changes, energy mix, and CO<sub>2</sub> emissions over the study period for the four portfolios. He then went into more detailed results associated with the four preliminary portfolios being shared.

## Q&A related to Initial Preliminary Portfolios

1. Question: Do the emissions results of the portfolios rely on CCS in order to achieve these CO<sub>2</sub> reductions?
  - a. It does not. CCS resources were not selected by the model in the initial portfolios shown here today.
2. Question: Could you define "Market" in the Energy Mix Over Time bar graphs?
  - a. In the production cost model, the market can be thought of as the MISO energy market. The model is dispatching against the market energy price, so when Duke Energy Indiana's resources are cost-effective, they are run to serve load. When Duke Energy Indiana's resources are more expensive, it buys energy from the MISO market.
3. Question: With the amount of energy purchases seen in these portfolios, could all the portfolios support the 1,095 MW solar shown in the retire scenario?
  - a. The model is selecting resource choices based on economics. So, the other portfolios have the option to add additional solar during the capacity expansion step of the model. Those additional renewables would then generate energy and decrease the amount of energy being purchased from the market in those portfolios. However, based on the economics of the model, not every portfolio selects the additional 1,095 MW of solar resources.
4. Question: Please explain where Duke Energy considers energy efficiency in its planning. Homes in Indiana could be much more efficient.
  - a. Existing Energy Efficiency programs that are already being used by customers is included in the load forecast. Additional impacts of increased utilization of existing EE programs are forecast as resources in the model. Finally, while detailed assumptions are being finalized for the analysis as part of the Market Potential Study (MPS), energy efficiency across all new programs that are identified in the MPS are included as selectable resources in the model.
5. Comment: For battery/energy storage, please consider the equitable energy storage principles.
6. Question: Why is wind missing from the capacity mix?
  - a. There are 200 megawatts of wind selected by the beginning of 2030 and additional greater amounts of wind selected in the 2030s and 2040s in each of the 111 compliant cases. Wind does not get selected in the "no 111" case. Wind is available for selection in all years beginning 2028 and it's just a question of how the characteristics of wind generation stack up against the characteristics of other generation types and what the model opts to select.
7. Question: Are CO<sub>2</sub> emissions related to market purchases included here?
  - a. Yes, the national database runs are also used to calculate the CO<sub>2</sub> emissions that would be associated with market purchases.
8. Question: Can you confirm that upstream emissions from gas production and transport are not included?
  - a. Yes, that is correct.
9. Question: How can DEI justify not modeling alternative electric energy supply frameworks?

- a. The IRP is a fairly prescribed process in Indiana and fairly specific on what vertically integrated utilities should model.
10. Question: Is there concern that the very large amounts of market purchases indicate that the market price is too low?
- a. Finding the market price is an iterative process, and there is a practical limit to the number of iterations that can be done. The market energy prices in the model now are the best forecast that is available at this time. Additionally, the fact that converted coal units with relatively high heat rates are operating at fairly low capacity factors while CCGTs that are more efficient than converted coal units are operating at or near their capacity factor limits, is some validation that the market prices directionally make sense.
11. Question: Can you say more about which of the components of the capacity mix in later years make it so uneconomic compared to the market?
- a. MISO's energy mix has more wind and CC toward the end of the planning period. Wind has a near zero dispatch price, which is negative with tax credits, and CCs have a competitive dispatch price. When CC units are on the margin, DEI generates its own energy, and when wind is on the margin, DEI tends to buy more from the market.
12. Question: Did the model not select any SMRs?
- a. That is correct. There are plans to model portfolios which include SMRs in the back end of the period and do the same with CCS, but right now the model is not selecting SMRs.
13. Question: Where are these companies that are purchasing power purchasing their power from?
- a. For resource selection in the capacity expansion model, there is a requirement that the portfolio needs to meet at least 75% of customer's energy needs with Duke Energy Indiana resources. After the capacity expansion step, when the portfolios are run in the production cost model, there is no constraint on the amount of energy that needs to be produced by Duke Energy Indiana resources and instead can buy energy from the MISO market when it is more economic.
14. Question: Has there been a consideration for putting solar and batteries behind-the-meter and what impact that might have?
- a. Yes, different levels of distributed resources are considered in the model. Behind-the-meter programs will be discussed in detail at the Customer Programs meeting in August.
15. Question: Is the market less expensive than Duke Energy Indiana's own generators?
- a. In the portfolios showing market purchase levels 10 years from now, the one that buys more from the market is also the one with converted coal units. Converted coal units are less efficient than gas and have a higher fuel cost, leading to the market being more cost effective in the reference worldview.
16. Question: How is Duke Energy modeling projected Data Center and Transshipment Center loads? Are these special contracts with assigned costs or are they standard tariff loads with system-allocated costs?

- a. For modeling demand for the system, economic development load is reflected in the load forecast and adjusted at different levels across the worldviews. Different contract types are not modeled in the IRP.
- 17. Question: Is MISO or the grid unconstrained through the modeling horizon for energy availability?
  - a. Regarding energy purchases in the local model, it is capped in the capacity expansion model, where the portfolios being developed have to add resources to serve 75% of Duke Energy Indiana's energy. Then in the production cost stage, the portfolio from the capacity expansion step is imported and dispatched based on economics without a restriction on energy purchases.
- 18. Question: Why are the economics for wind expected to improve 10 years out?
  - a. The expectation is that the cost of renewables will decrease over time. As you go further out, the current trends are particularly favorable for wind. Wind resources have a higher capacity factor than solar. MISO's seasonal capacity construct is included in the model, so the resource accreditation in all seasons also plays a role in which resources are selected by the model.
- 19. Comment: Please think more about future demand as it relates to data centers and crypto.
  - a. Sensitivity analysis for both high and low load will be run to consider uncertainties around economic development load.
- 20. Comment: If you don't have to mitigate your carbon releases you will externalize those costs onto everyone else. You will generate more income for shareholders at the costs of others.
  - a. EnCompass is being used for IRP modeling and is a cost optimization model. The portfolios in the modeling are being developed by the model with the objective to minimize costs.
- 21. Comment: In regard to crypto, residential users who use less electricity pay more per KWh than a crypto miner, so that is something that you need to consider.
- 22. For the rapid change and innovation worldview, to what extent would you reflect some of the regulatory flexibilities from the Alternative Utility Regulatory Act in your modeling, particularly in situations with significant transportation loads and data centers?
  - a. New industrial class loads that have round-the-clock energy needs represent a different kind of challenge than, say, the residential class of customers, as you have significant fluctuation in energy need over the course of the day which has implications for different types of resources being needed to serve that round-the-clock load. The energy needs of each customer class are included in the hourly load forecast.

## **Demand-Side Management Market Potential Study**

*Rush Childs, Manager, Advisory Services, Resource Innovations*

Mr. Childs started by explaining that the goal of the Market Potential Study (MPS) was to evaluate the technical, economic, and achievable potential of various demand-side



management technologies. Mr. Childs also explained the research used to develop estimates for energy savings and discussed sources for the assumptions in the study. He explained how each of the three types of potential were evaluated, presented the results of the study, and walked through OSB feedback and responses.

### Q&A related to the Demand-Side Management Market Potential Study

1. Question: Is baseline study part of the DSM Market Potential study?
  - a. Existing baseline data from secondary sources such as EIA 2020 recs data and the Duke Energy appliance saturation survey was used. We didn't conduct primary research on the market baseline.
2. Question: Does the efficiency modeling take into account the Indiana Home Energy Rebates Program that is currently being defined?
  - a. No, assuming it is a low-income program, there already are Duke Energy low-income measures in the study, so the potential for those measures is captured; this program is presumably made up of similar measures as those assessed in the MPS.
3. Question: When you say "sales," are these sales by DEI related to private investments in energy efficiency?
  - a. They are utility energy sales, so essentially, they are the consumption of energy.
4. Question: Was a Total Resource Cost (TRC) performed as well? Were the results radically different between the UCT and TRC?
  - a. TRC results will be reported. UCT is what was used to determine cost-effectiveness and for the screening step in the study.
5. Question: It looks like your model is still showing a peak savings as a percentage of sales in 2032. Why is that if you are not accounting for IRA expiration?
  - a. This curve reflects a combination of energy efficiency retrofits and equipment turnover, so the peak reflects the adoption of retrofit measures. Those will eventually expire and return to a baseline with equipment turnover. What is shown here are incremental savings and the hump is caused by the fact there is a limited pool of potential retrofits available before associated equipment is eventually replaced.
6. Question: Is your pool of potential participants assumed to be declining over time?
  - a. The pool for retrofits is declining, not the pool of potential participants.
7. Question: Why can you provide inputs and outputs from the MPS model, but you can't provide the model itself?
  - a. Resource Innovation does not license the model for external use, it's something that is used to deliver consulting services. Resource Innovations is a third-party consulting firm and there are concerns around competition.
8. Question: Are there energy efficiency programs available in Indiana?
  - a. We mapped our measures to programs that exist in Indiana to reflect the estimated adoption of energy efficiency measures through these programs.
9. Question: Where can I learn more about these energy efficiency programs?

- a. You can find more information on our website: <https://www.duke-energy.com/home/savings>. There is a summary of the energy efficiency programs within our filings on the IURC website.
10. Question: How do you tease out what is going on with conversions from gas to electric?
- a. There is no natural gas baseline in this study. It is entirely electric to electric. Fuel conversion gets into a new realm of rules and regulations. The Duke Energy appliance saturation surveys indicated that there was still a fairly large share of electric resistance water heating in the residential market and that is why you see residential water heating being one of the highest end uses for potential savings here, because those can all be converted to heat pump water heaters.
11. Question: Did you look at a typical Indiana home for the residential? If you look at the bottom 20% instead of a typical home, you might see different results for both benefit to ratepayer and impact of cost effectiveness.
- a. Yes, this was based on the typical Indiana home. So, in a market-wide study, both homes with higher and lower savings are considered in the average.

# 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 3

*June 20, 2024*



BUILDING A **SMARTER** ENERGY FUTURE®



# Welcome

## Stan Pinegar

State President, Duke Energy Indiana





# Safety

# Location safety



## General Area Evacuation Procedures

If you hear or see evacuation alarms in your area:

- Move safely and quickly out of the building.
- Encourage others around you to evacuate.
- As appropriate, gather in the assembly area and await further instruction.

## Shelter in Place

In the event of severe weather, move away from windows to the center of the building. Stairwells, interior rooms, restrooms or similar locations will provide protection.

## Evacuation Assembly Areas

- The primary evacuation route is through the lobby where you entered. The secondary is through the side door at the stairwell at the back of this room.
- The assembly point is located inside the perimeter fence in the grassy area and/or parking lot near the East poles utilized for training.

## AED

An AED is located in the Mail/Copy/Print Room number 01105

## Location Information for Emergency Dispatchers

Floor 1 Medium Conference Room 00197 of Duke Energy's 50's Building, 1000 E. Main Street, Plainfield IN 46168



# Safety Moment – Sun and Heat

## Sun Safety

### 5 tips to protect your skin from the sun:

- Stay in the **shade**, especially from 10am-4pm
- Wear clothing with **long-sleeves** with UV protection
- Wear **hats** with brims
- Wear **sunglasses**
- Apply **sunscreen** with at least SPF 15
  - Use water-resistant, broad-spectrum (UVA/UVB)
  - Check expiration date
  - Apply 30 minutes in advance, and reapply at least every 2 hours

**Check your skin regularly for any changes and see a doctor if you have any concerns!**

## Heat Safety

### 3 things to remember about heat safety:



- **Lightweight, light-colored, loose-fitting** clothing
- Pace yourself with exercise
- Wear **sunscreen**
- **Do not leave children or pets in cars**, even with windows cracked
- Drink **fluids** regularly
- Avoid sugary or alcoholic drinks
- Replace lost salt and minerals
- Check the **forecast** for heat alerts
- **Know the signs** & symptoms of heat-related illness
- **Monitor** high-risk individuals



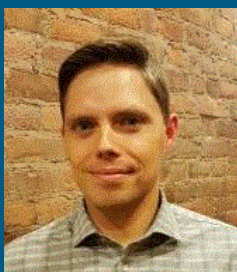
# Introductions

# Duke Energy Team

## Integrated Resource Planning Team



**Matt Kalembo**  
*Vice President,  
Integrated Resource  
Planning*



**Nate Gagnon**  
*Managing Director,  
Midwest Integrated  
Resource Planning*



**Matt Peterson**  
*Resource  
Planning Manager*



**Emma Goodnow**  
*Market Strategy &  
Intelligence Director*



**Karen Hall**  
*Resource  
Planning Director*



**Chris Hixson**  
*Principal Engineer,  
Resource Modeling*



**Josh Paragas**  
*Engineer, Resource  
Modeling*



**Tyler Cook**  
*Engineer, Resource  
Modeling*

## Indiana Regulatory and Legal Team



**Kelley Karn**  
*Vice President,  
Indiana Regulatory  
Affairs and Policy*



**Beth  
Heneghan**  
*Deputy General  
Counsel*



**Liane Steffes**  
*Associate  
General Counsel*

## EE Programs

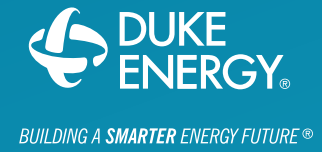


**Amy Dean**  
*Lead Strategy &  
Collaboration  
Manager*

## 1898 & Co.



**Drew Burczyk**  
*Consultant, Resource  
Planning & Market  
Assessments*



# Agenda

# Public Stakeholder Meeting #3 Agenda

Time	Duration	Present   Discuss	Topic	Presenter
9:30	30	-	Sign In & Refreshments	
10:00	5	5   0	Welcome & Safety	Stan Pinegar, Duke Energy Indiana State President Karen Hall, Duke Energy Resource Planning Director
10:05	5	5   0	Meeting Guidelines & Agenda	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:10	25	15   10	Stakeholder Feedback & Incorporation	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:35	15	5   10	MISO Modeling – IRP Energy Market Prices (Power Prices)	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:50	10	-	BREAK	
11:00	30	20   10	Incorporation of 111 in Generation Strategies	Nate Gagnon, Managing Director Midwest IRP
11:30	30	20   10	Initial Preliminary Portfolios	Nate Gagnon, Managing Director Midwest IRP
12:00	45	-	LUNCH	
12:45	60	20   40	Initial Preliminary Portfolios (continued)	Nate Gagnon, Managing Director Midwest IRP
1:45	5	-	BREAK	
1:50	40	20   20	Demand-Side Management Market Potential Study	Rush Childs, Manager, Advisory Services, Resource Innovations
2:30	30	0   30	Open Q&A	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
3:00			Adjourn	

# Technical Stakeholder Meeting #3 Agenda

Time	Duration	Present   Discuss	Topic	Presenter
9:00	5	5   0	Welcome & Safety	Karen Hall, Duke Energy Resource Planning Director
9:05	5	5   0	Meeting Guidelines & Agenda	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:10	30	20   10	Incorporation of 111 in Generation Strategies	Nate Gagnon, Duke Energy Managing Director Midwest IRP
9:40	25	15   10	Initial Preliminary Portfolios	Nate Gagnon, Duke Energy Managing Director Midwest IRP
10:05	10	-	BREAK	
10:15	30	15   15	Initial Preliminary Portfolios (continued)	Nate Gagnon, Duke Energy Managing Director Midwest IRP
10:45	30	0   30	Open Q&A	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
11:15	10	-	BREAK	
11:25	40	10   30	EnCompass Modeling Files – Q&A with Modelers	Josh Paragas, Duke Energy Engineer – Resource Modeling
12:05			Adjourn	





# Meeting Guidelines

# Meeting Ground Rules



## **Respect each other:**

Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

## **Focus on today's topics:**

Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.

## **Chatham House Rule:**

Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

# Participation



There will be several opportunities throughout the presentation for attendees to actively participate by asking questions, making comments and/or otherwise sharing information.

- **Q&A:** Please use the “Q&A” feature, on the menu at the bottom of your screen, to submit questions to the presenters. We will respond to as many of these as possible, time permitting, during designated time periods.
- **Raise hand:** If you wish to ask a question or make a comment orally, please use the “raise hand” feature, during designated time periods. A facilitator will call on you and invite you to unmute.
- **Chat:** The chat feature is enabled for sharing information and resources with other participants; however, it is sometimes difficult to monitor. If you would like a response from the presenters, please use the Q&A or raise hand features.



# Stakeholder Feedback and Incorporation

# Stakeholder Feedback Received & Incorporated into Meeting #3 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
What is the status of the Market Potential Summary?	Market Potential Study
Can the assumptions for the Market Potential Summary be shared?	Market Potential Study
When you talk about assumed implementation of Clean Air Act 111, does that mean you will be running two cases?	Incorporation of 111 in Generation Strategies
In terms of new natural gas combined cycle plants, how are you planning on modeling the final 111 rules?	Incorporation of 111 in Generation Strategies
Is there any resource that will be modeled as burning hydrogen. Or are they just assuming they are hydrogen capable?	Incorporation of 111 in Generation Strategies
With 111 and gas plants hydrogen capable, does Clean Air Act 111 essentially require burning hydrogen?	Incorporation of 111 in Generation Strategies
When is the Customer distributed Energy Resource (DER) Programs Webinar?	The webinar will be held August 6 <sup>th</sup> at 2:30 PM. Invitations will be sent in early July to all those who have attended an IRP engagement session or expressed interest in attending.

# Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
Will any future meetings be held in person?	Meeting 3 today is a hybrid meeting, with both in person and virtual options. We are currently planning to hold the 5 <sup>th</sup> meeting as a hybrid meeting as well. Please provide us additional input on what meeting format works best for you all.
The assumptions on wind, solar, and storage project timing and size seem conservative. I would encourage additional thinking, so we don't over constrain the model.	<p>Having received stakeholder questions and input, we reviewed and updated the availability assumptions for new renewable resources in the model.</p> <ul style="list-style-type: none"> <li>• Increased Solar availability in Reference Case from 1,000 MW to 1,200 MW beginning 2032.</li> <li>• Increased Wind availability in Reference Case from 300 MW to 400 MW beginning 2032.</li> <li>• Increased Wind availability in Aggressive Worldview from 600 MW to 1,000 MW beginning 2032.</li> </ul> <p>The detailed updates and basis for assumptions are highlighted in the Appendix.</p>
According to information published by IEA a few days ago, the total capital cost of battery storage are projected to drop 40% by 2030. Has Duke factored that into its analysis?	The current cost curves being used in the modeling for generic storage resources include an approximate 30% decrease in pricing from today by 2030 in the Base Case, under the Aggressive Policy Scenario storage costs decline further. Storage projects that were submitted as part of the RFP are also selectable options in the model, which include storage resources and their pricing, up until 2030.



# Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
What is the basis for Nuclear SMR costs declining?	We have included additional information in the Appendix on SMR cost curves. This includes the cost curve on an in-service year basis to better illustrate that cost declines occur only after the first SMR is installed. The slide also includes an explanation of the rationale for expected SMR cost declines while experience is gained.
Are you going to use the RFP bid information to inform cost assumptions in IRP modeling?	Yes. We have benchmarked IRP cost assumptions against the RFP bids received. Also, it is important to note that in the near-term years where RFP bids are available, we are including averaged bids as selectable resources in the IRP model.



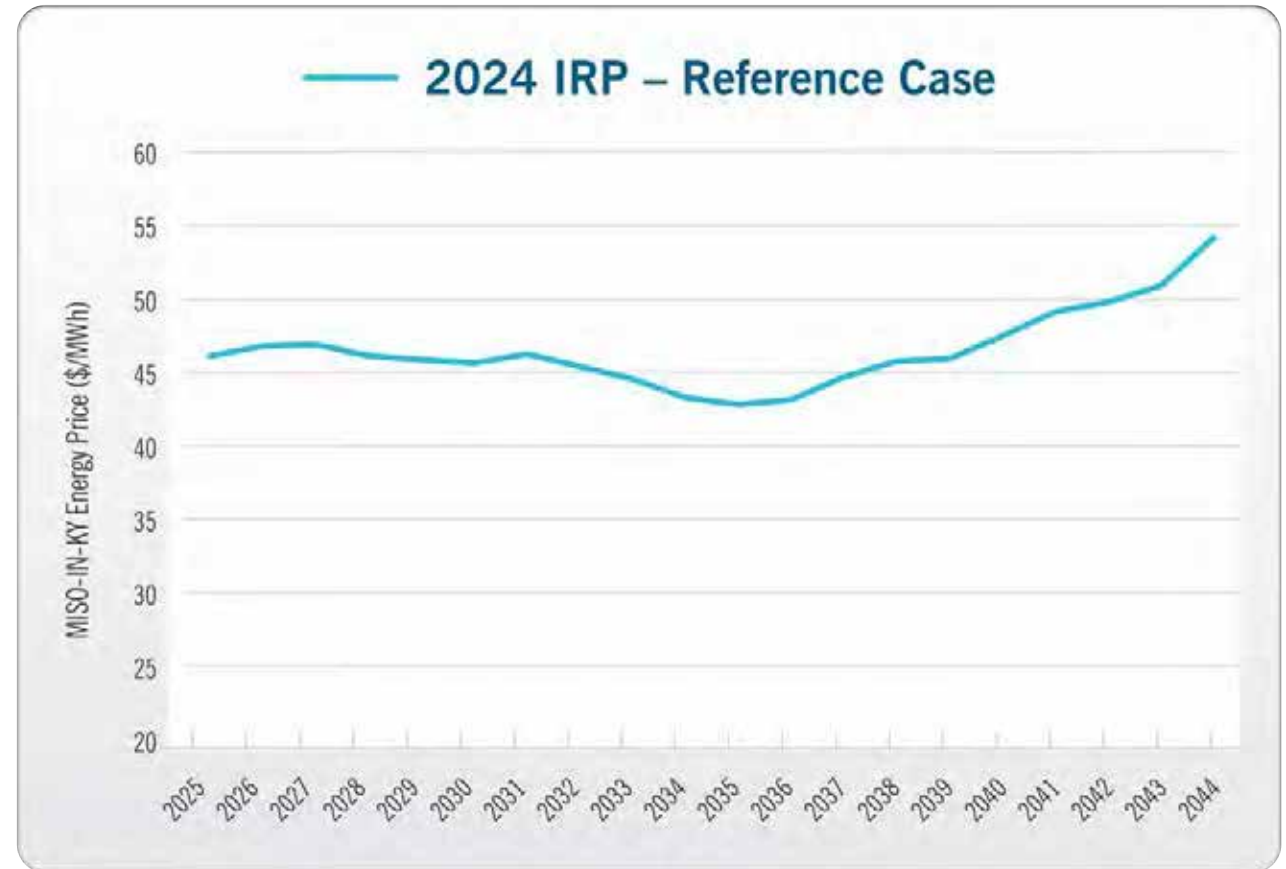
# Q&A



# MISO Modeling – IRP Energy Market Prices (Power Prices)

# Power Price Update

- Used EnCompass to simulate Horizon Energy developed National Database
- Made updates to align with IRP assumptions
  - Natural gas price forecast
  - Coal price forecast
  - CO<sub>2</sub> tax / policy constraints
  - Relative economics of new resources
- Unique simulation performed for each IRP Scenario
- Hourly locational margin prices (LMPs) from Midcontinent Independent System Operator (MISO)-wide analysis used as an input into Duke Energy Indiana's IRP model





# Q&A



# Break





# Incorporation of Clean Air Act 111 in Generation Strategies

# Summary of Options Under EPA CAA 111 Final Rule<sup>1</sup>

Resource Type	Option	Deadline	Considerations
Existing Coal Units	Modify for gas co-firing	1/1/2030	Minimum 40% gas burn (16% CO <sub>2</sub> emissions reduction from 100% coal) <sup>2</sup> Must retire by 1/1/2039
	Convert to 100% gas fuel	1/1/2030	No mandated retirement date
	Retire	1/1/2032	No modifications necessary
	Add Carbon Capture & Sequestration (CCS)	1/1/2032	No mandated retirement date Likely not possible by 2032 <sup>3</sup>
New Gas Units	Run as intermediate unit (maximum 40% capacity factor)	1/1/2032	New CCs and CTs able to meet CO <sub>2</sub> intensity standard for this pathway (1,170 lb./MWh)
	Run as peaking unit (maximum 20% capacity factor)	1/1/2032	Not included in modeling (see above)
	Add CCS	None	Likely not possible before 2035 Eliminates capacity factor constraint Assuming CCs added after 2037 have CCS

<sup>1</sup>Environmental Protection Agency (EPA) Clean Air Act (CAA) Section 111 issued April 25, 2024

<sup>2</sup>Model set to 50% minimum gas burn to ensure compliance

<sup>3</sup>Except potentially at Edwardsport

Not included as pathway in modeling

Note: Hydrogen is no longer specified as a compliance option under EPA CAA 111

# Incorporation of CAA 111 Compliance Pathways in Generation Strategies

Unit	Retirement Dates in Prior Analysis (EOY basis)			111 Compliant - 2024 IRP Generation Strategies			
	2021 IRP	2023 IRP Refresh	CPCN Modeling	<i>Retire Coal Units</i>	<i>Convert Coal Units</i>	<i>Blend #1</i>	<i>Blend #2 TBD</i>
Cayuga 1	2026	2027	2028	<i>Retire by 1/1/2031</i>	<i>NG Conversion by 1/1/2030</i>	<i>NG Conversion by 1/1/2030</i>	
Cayuga 2	2026	2027	2028	<i>Retire by 1/1/2031</i>	<i>NG Conversion by 1/1/2030</i>	<i>NG Conversion by 1/1/2030</i>	
Gibson 1	2034	2034	2034	<i>Retire by 1/1/2032</i>	<i>NG Conversion by 1/1/2030</i>	<i>Retire by 1/1/2032</i>	
Gibson 2	2034	2034	2034	<i>Retire by 1/1/2032</i>	<i>NG Conversion by 1/1/2030</i>	<i>Retire by 1/1/2032</i>	
Gibson 3	2028	2028	2028/2030	<i>Retire by 1/1/2032</i>	<i>Co-fire by 1/1/2030</i>	<i>Retire by 1/1/2032</i>	
Gibson 4	2028	2028	2028/2030	<i>Retire by 1/1/2032</i>	<i>Co-fire by 1/1/2030</i>	<i>Retire by 1/1/2032</i>	
Gibson 5	2024	2025	2029	<i>Retire by 1/1/2030</i>			
EDW	NG Conversion 2035	NG Conversion 2035	NG Conversion 2035	<i>NG Conversion by 1/1/2030</i>			

Generation Strategies include “bookend” pathways and a blended pathway. Preserving option for an additional blended strategy.

- Generation Strategies will be evaluated in Reference Case and alternate scenarios (“Worldviews”)
- IRP analysis will also include:
  - Portfolios that reflect alternate scenarios such as a “no-111” world
  - Stakeholder Strategies emphasizing aggressive carbon reduction and an earlier exit from coal
  - Additional analysis of Edwardsport options

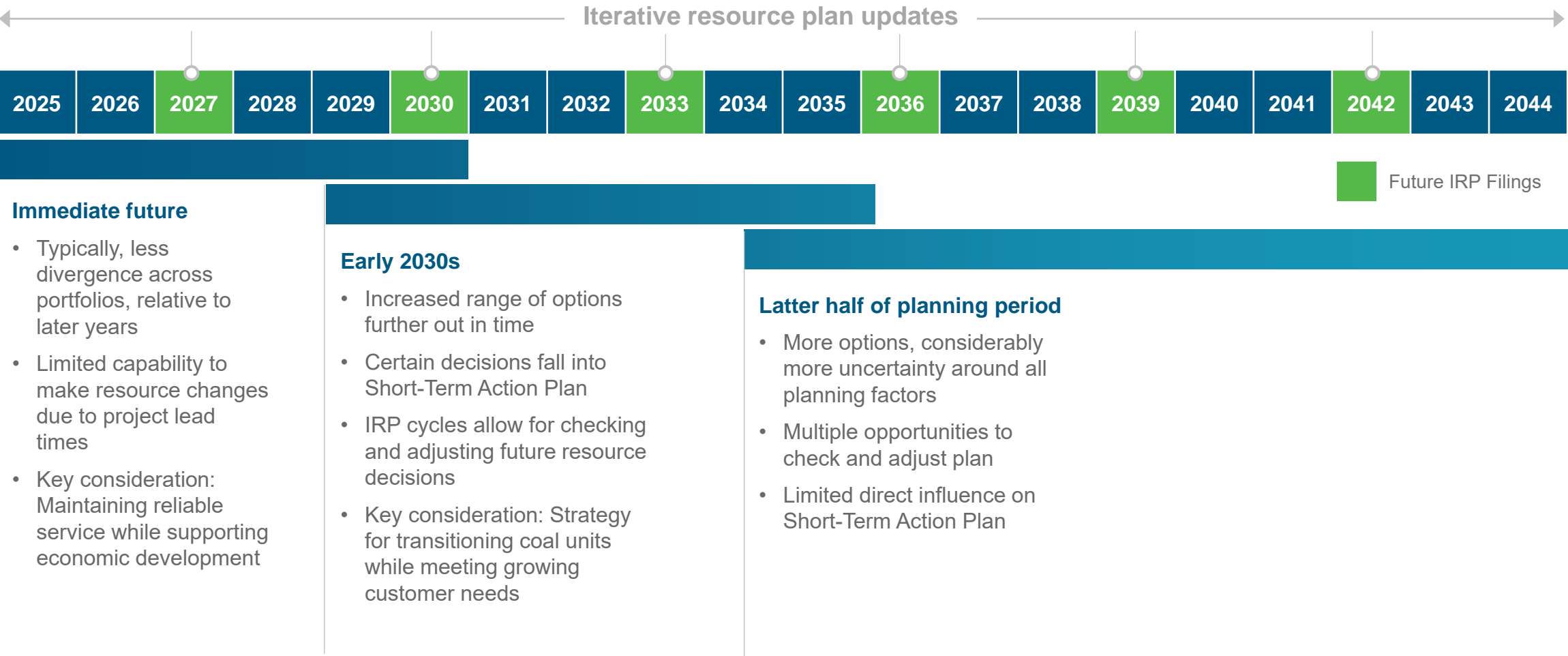


# Q&A



# Initial Preliminary Portfolios

# Thinking About the IRP Planning Period





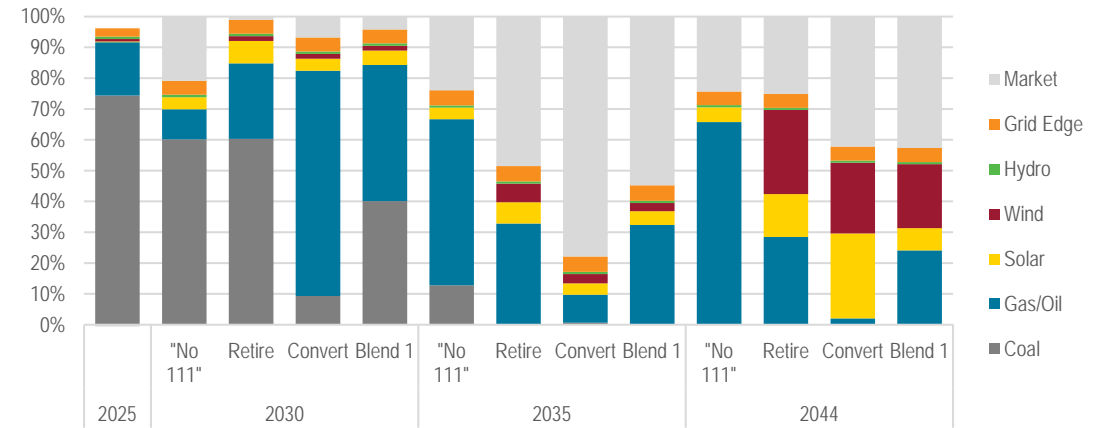
# Results Summary: Preliminary Strategies in Reference Worldview

## Cumulative Supply-Side Resource Changes (ICAP MW)

	Coal		Solar <sup>3</sup>	Wind <sup>4</sup>	Battery <sup>5</sup>	CC <sup>6</sup>	CT
	Retired <sup>1</sup>	Converted / Co-Fired <sup>2</sup>					
MW By January 1, 2030							
"No 111"	(313)	--	595	--	650	--	--
Retire	(313)	568	1,095	200	653	--	--
Convert	(313)	3,462	595	200	718	--	--
Blend 1	(313)	1,566	695	200	602	--	--
MW By January 1, 2035							
"No 111"	(2,571)	568	595	--	650	2,728	--
Retire	(3,837)	568	1,095	800	653	3,392	--
Convert	(313)	3,462	595	400	1,018	--	--
Blend 1	(2,839)	1,566	695	350	602	2,728	--

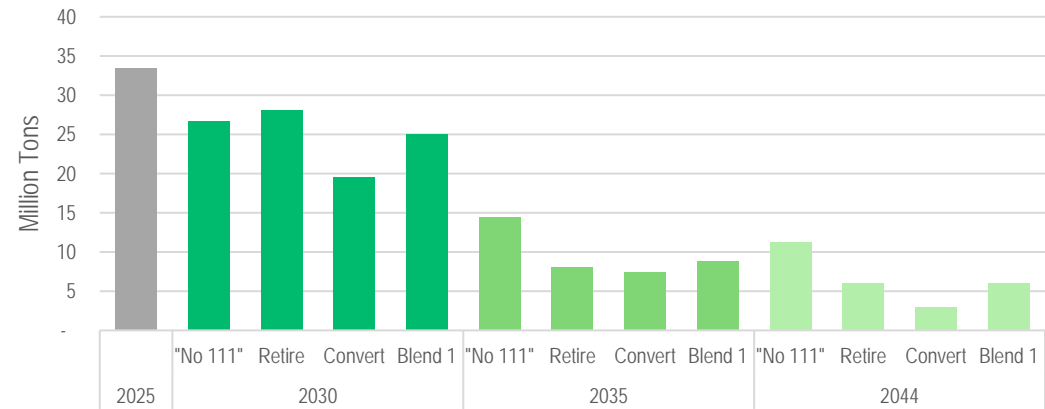
<sup>1</sup>Duke-owned portion of Gibson 5 is 313 MW  
<sup>2</sup>Co-fired at 50% of unit MW. Includes Edwardsport conversion from IGCC to CC.  
<sup>3</sup>Includes solar paired with storage.  
<sup>4</sup>Includes wind paired with storage.  
<sup>5</sup>Includes batteries paired with solar and wind.  
<sup>6</sup>Reflects CC additions only. Noblesville CC (312 MW) retires by 1/1/2035 in all cases.  
Not shown in table: all cases include short-term capacity purchases in the 2020s.

## Energy Mix Over Time



Note: Grid Edge includes DSM (EE/DR) & IVVC

## CO<sub>2</sub> Emissions Over Time



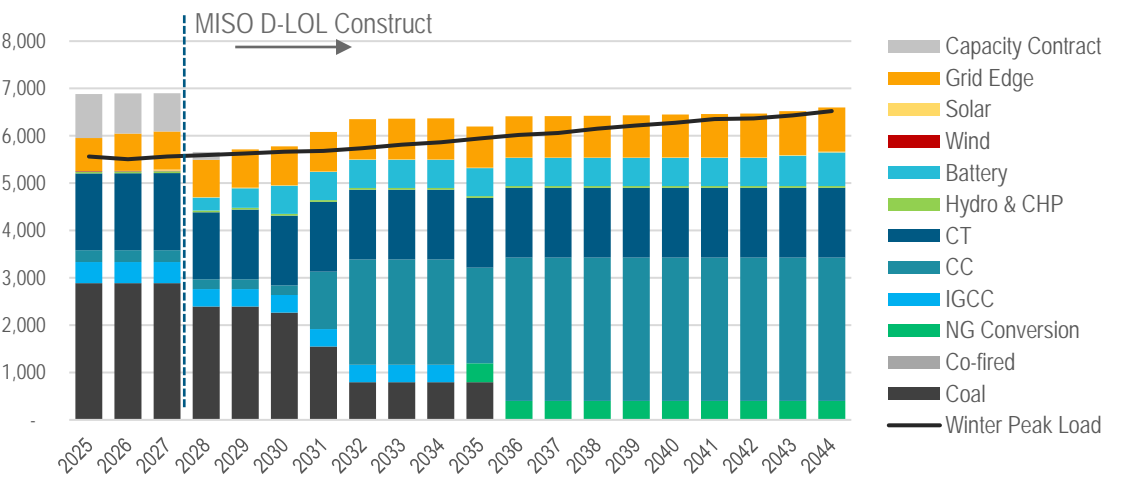
Preliminary modeling as of June 10; Subject to change

Grid Edge: energy efficiency and demand response

# No CAA 111 (Reference Worldview)

## Preliminary Modeling

### Capacity Mix (Winter UCAP MW)

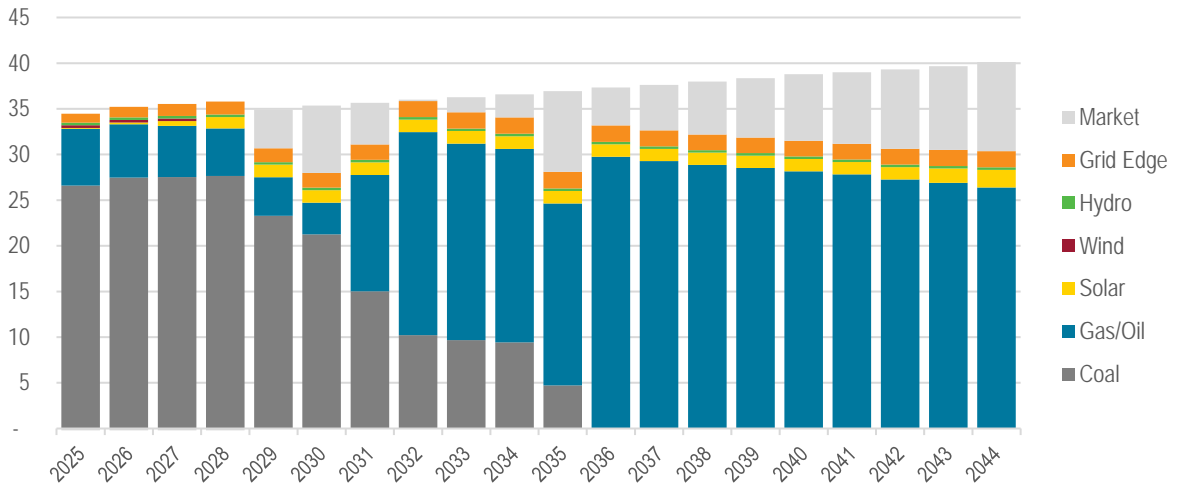


### Supply-Side Capacity Changes (ICAP MW)

	2025-26	2027-28	2029-30	2031-32	2033-34	2035-36	2037-38	2039-40	2041-42	2043-44
Coal Retire	-	-	(313)	(2,258)	-	(1,266)	-	-	-	-
NG Conv.	-	-	-	-	-	568	-	-	-	-
CC	-	-	-	2,728	-	1,052	-	-	-	-
Solar*	199	400	(4)	-	-	(11)	(11)	-	-	250
Wind*	-	-	-	-	-	-	-	-	-	-
Battery*	-	300	350	-	-	-	-	-	-	125

\*Including paired

### Annual Energy Mix (TWh)



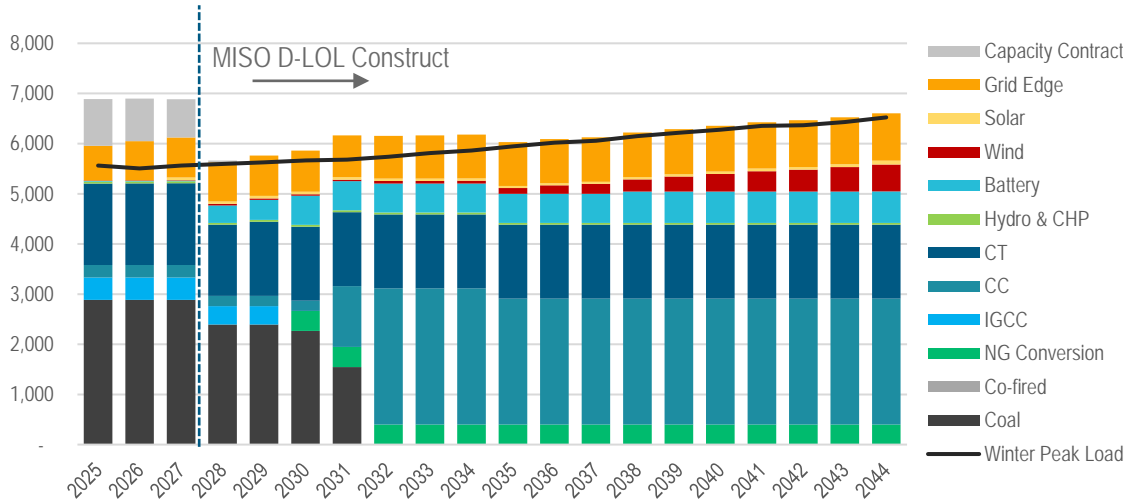
### Portfolio notes:

- Solar and battery additions in the 2020s supply incremental energy and capacity
- Measured transition out of coal through the mid-2030s while increasing total capacity
- Economically-competitive generation mix limits market energy purchases
- Coal Retirements: Gibson 5 (2030), Cayuga 1 & 2 (2031), Gibson 3 & 4 (2032), Gibson 1 & 2 (2036)

# CAA 111 Compliant Strategy: Retire Coal Units (Reference Worldview)

## Preliminary Modeling

### Capacity Mix (Winter UCAP MW)

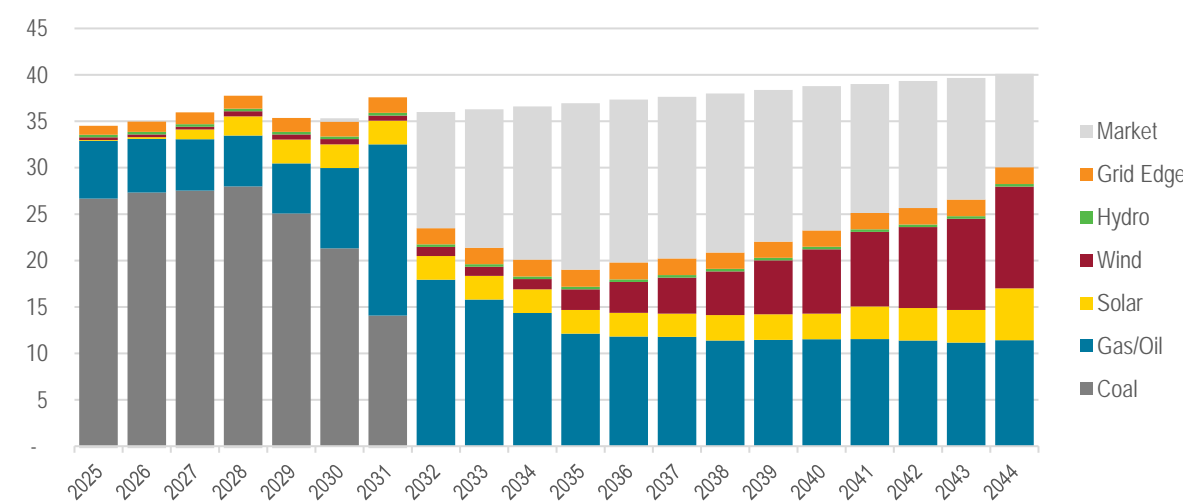


### Supply-Side Capacity Changes (ICAP MW)

	2025-26	2027-28	2029-30	2031-32	2033-34	2035-36	2037-38	2039-40	2041-42	2043-44
Coal Retire	-	-	(313)	(3,524)	-	-	-	-	-	-
NG Conv.	-	-	568	-	-	-	-	-	-	-
CC	-	-	-	3,392	-	(312)	-	-	-	-
Solar*	199	750	146	-	-	(11)	89	-	350	950
Wind*	-	200	-	150	50	800	500	800	650	800
Battery*	-	402	251	-	-	-	50	-	-	-

\*Including paired

### Annual Energy Mix (TWh)



### Portfolio notes:

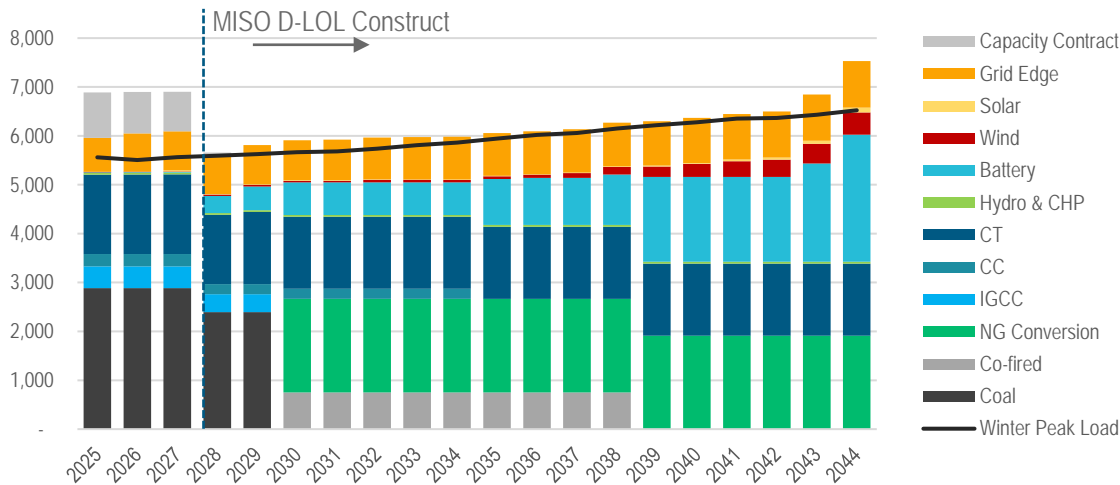
- Solar, wind, and battery additions in the 2020s supply incremental energy and capacity
- CC units added by beginning of 2031 and 2032 allow retirement of Cayuga (2029/2030) and Gibson (2032) coal units while providing incremental firm capacity
- New CCs are economically competitive, dispatching up to 40% capacity factor limit under CAA 111
- Economic market purchases account for much of remaining energy in mid-2030s, before declining as relative economics of wind improve

Preliminary modeling as of June 10; Subject to change

# CAA 111 Compliant Strategy: Convert Coal Units (Reference Worldview)

## Preliminary Modeling

Capacity Mix (Winter UCAP MW)

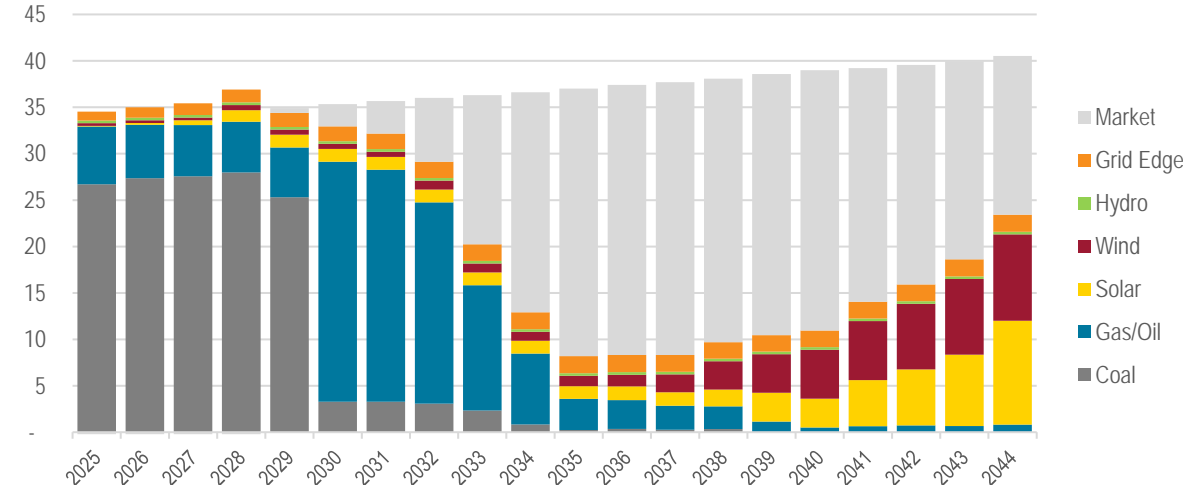


Supply-Side Capacity Changes (ICAP MW)

	2025-26	2027-28	2029-30	2031-32	2033-34	2035-36	2037-38	2039-40	2041-42	2043-44
Coal Retire	-	-	(313)	-	-	-	-	-	-	-
Conv./Co-fire	-	-	4,092 <sup>1</sup>	-	-	-	-	(1,261)	-	-
CC	-	-	-	-	-	(312)	-	-	-	-
Solar*	199	400	(4)	-	-	39	139	550	1,350	2,250
Wind*	-	200	-	150	-	100	650	800	650	800
Battery*	-	368	350	-	-	325	75	775	-	950

\*Including paired

Annual Energy Mix (TWh)



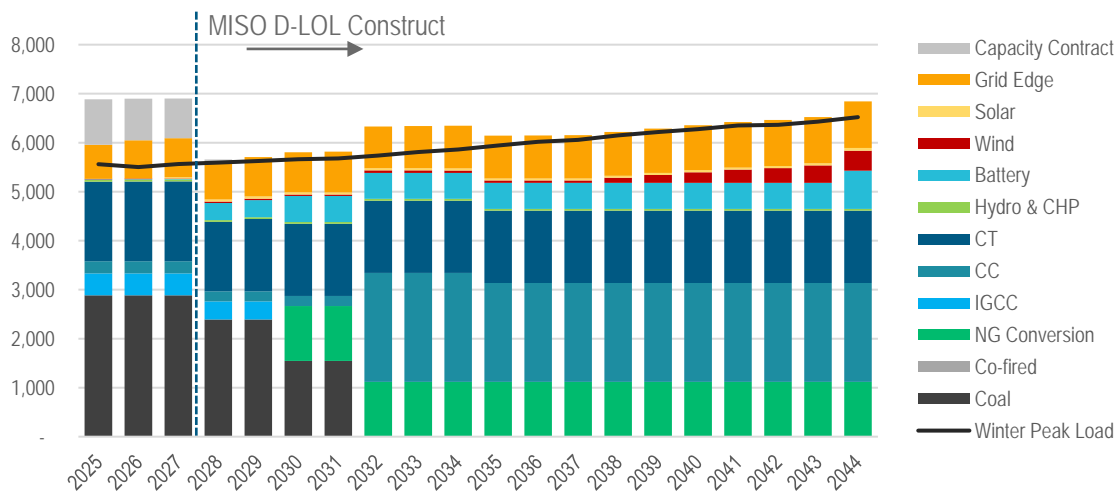
### Portfolio notes:

- Solar, wind, and battery additions in the 2020s supply incremental energy and capacity
- <sup>1</sup>Cayuga 1 & 2 and two Gibson units converted to natural gas, remaining two Gibson units co-fire 50% gas, all by Jan 1, 2030
- Dispatch economics of converted and co-fired coal units lag the market, leading to increased energy purchases in the mid-2030s (over 75% of total energy in 2035)
- Wind and solar additions later in the period reduce purchases in the 2040s

# CAA 111 Compliant Strategy: Blend 1 (Reference Worldview)

## Preliminary Modeling

### Capacity Mix (Winter UCAP MW)

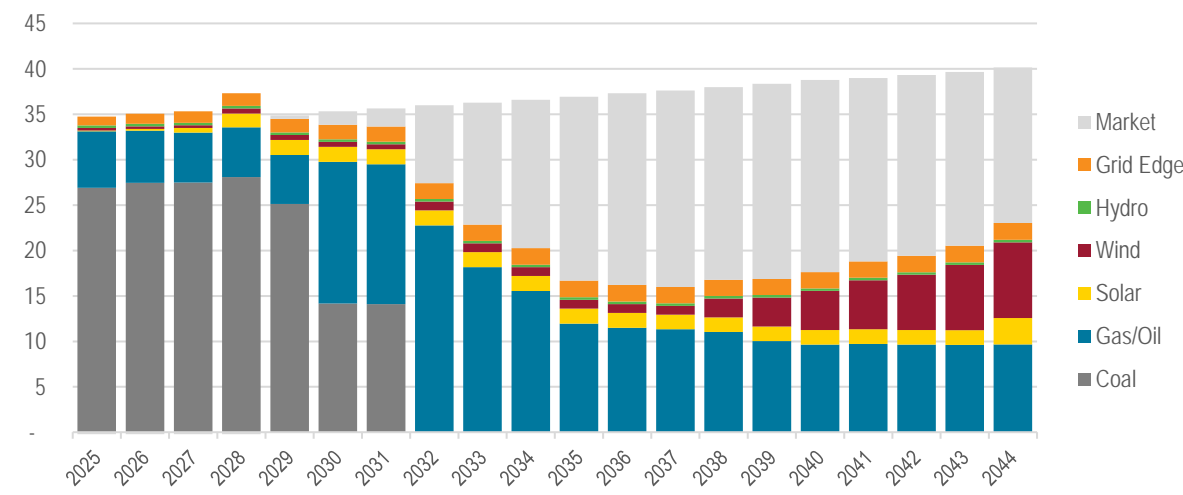


### Supply-Side Capacity Changes (ICAP MW)

	2025-26	2027-28	2029-30	2031-32	2033-34	2035-36	2037-38	2039-40	2041-42	2043-44
Coal Retire	-	-	(313)	(2,526)	-	-	-	-	-	-
NG Conv.	-	-	1,566	-	-	-	-	-	-	-
CC	-	-	-	2,728	-	(312)	-	-	-	-
Solar*	199	500	(4)	-	-	(11)	(11)	-	-	550
Wind*	-	200	-	150	-	-	400	800	650	800
Battery*	-	402	200	-	-	-	-	-	-	275

\*Including paired

### Annual Energy Mix (TWh)



### Portfolio notes:

- Solar, wind, and battery additions in the 2020s supply incremental energy and capacity
- Cayuga 1 & 2 converted to natural gas by Jan 1, 2030
- CC units added by beginning of 2032, allow retirement of Gibson coal units and provide incremental firm capacity
- Wind added later in the period as relative economics improve reduce market energy purchases in the 2040s



# Q&A





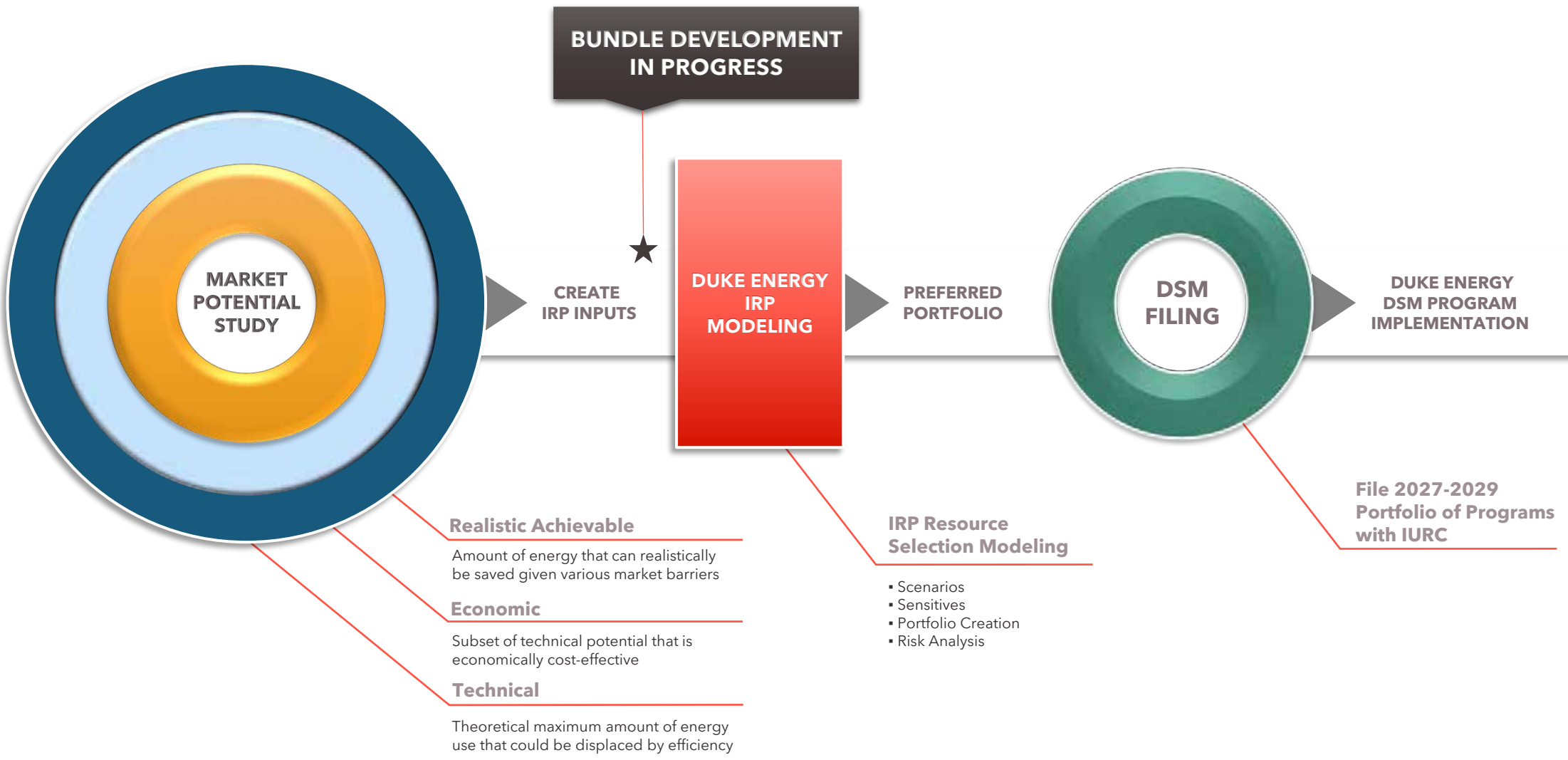
# Break



# Demand-Side Management Market Potential Study

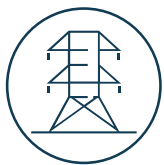
# Market Potential Studies & IRPs

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# Market Potential Follows a Stepwise Workflow

The framework for analyzing market potential was established in 2007 under the National Action Plan for Energy Efficiency. The stages of market potential are designed to ensure broad consideration of measure opportunities, and firms like ours partner with utilities and DSM stakeholder groups to ensure a comprehensive analysis.



## Technical Potential

- What technologies are commercially available?
- Are there technical limits to their application?
- Which technologies apply to different customer groups?
- How much electricity/load can they save?



## Economic Potential

- How much do these technologies cost?
- Will it be cost-effective for Duke Energy to offer a program with incentives to reduce the customer cost?
- How do the costs and benefits of the different technologies compare?
- What is the maximum, cost-effective savings impact?

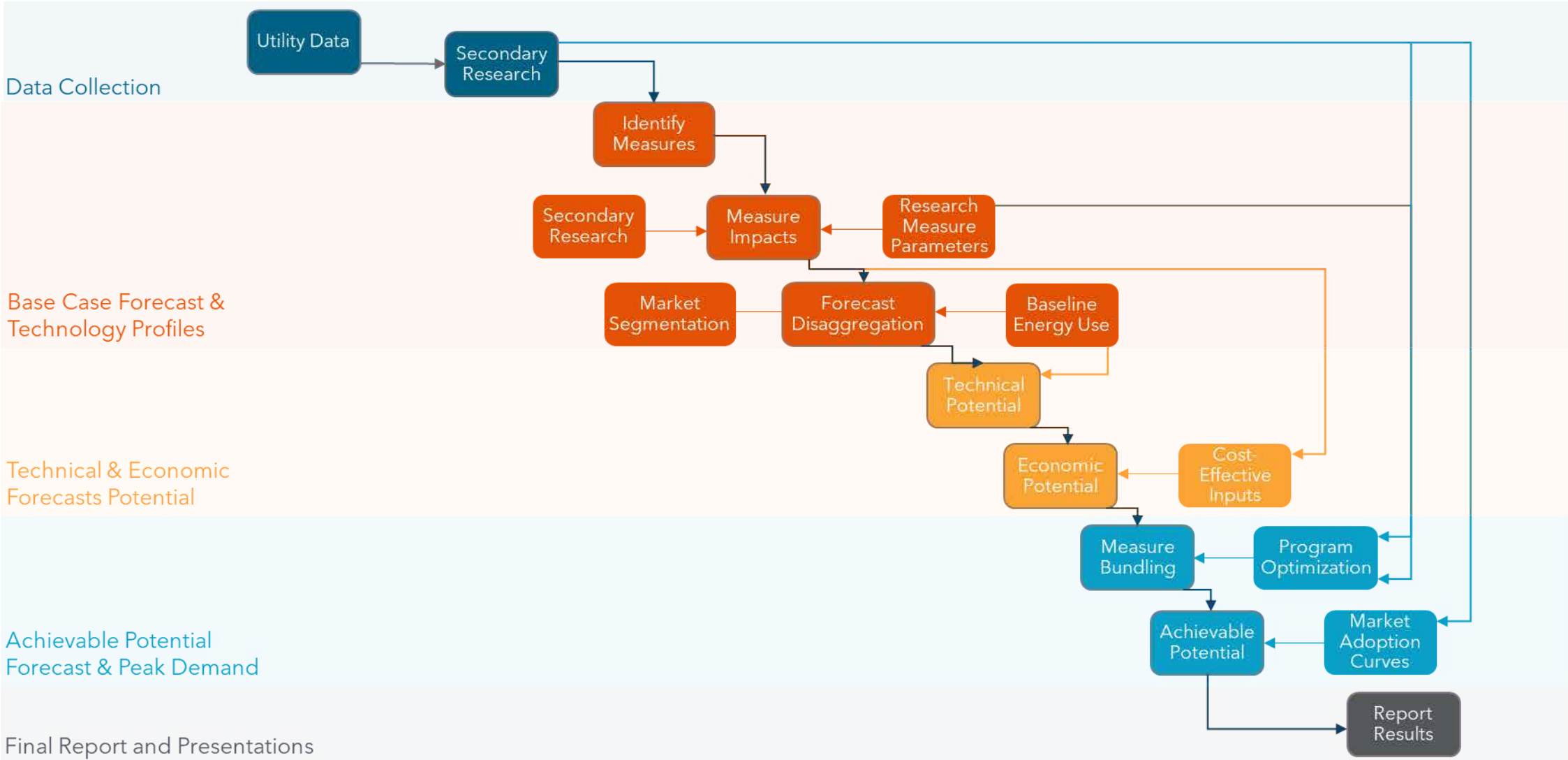


## Achievable Potential

- How much would it cost customers, after incentives?
- What is the expected payback period for each technology?
- How is payback time likely to affect customer adoption rates?
- What types of programs might be able to support customer adoption?

# Overall Process

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# Technology Research

We develop a robust set of all commercially-available technologies to consider in the study. Our model applies the technologies to the market baseline and accumulates savings over the study period

- We compare our measure list to current utility offerings, and we incorporate any jurisdiction information and guidance on measure savings
- We share all measure data and inputs with the utility and its stakeholders, in this case the Indiana Energy Efficiency Oversight Board
- We review stakeholder feedback, comment, and suggestions, incorporating as many as practicable
- The 2024 DEI MPS includes 474 DSM technologies, which results in over 9,083 permutations when applied to the market baseline of all economic sectors, all customer segments, all customer end uses, and all construction vintages

1

## Define the Features of the Measure

What is the baseline technology? How much energy can efficient tech. save? Which customers/end-uses are applicable?

2

## Measure Costs and Benefits

What is the cost of the measure? How much will it save over its lifetime when compared to the standard/baseline? Is it cost-effective to offer utility incentives?

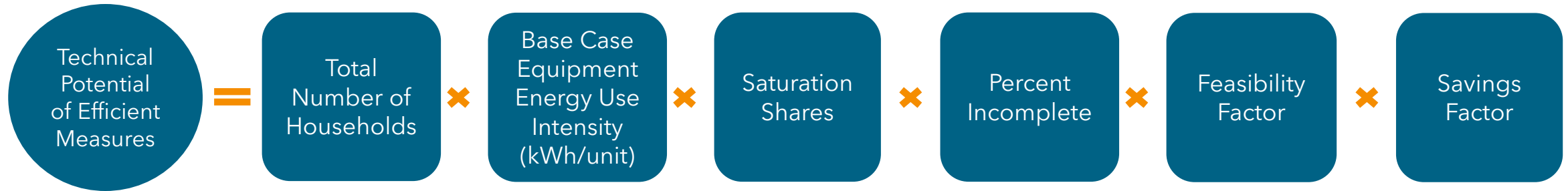
3

## Customer Adoption

What is the customer payback, expected market share? Which technologies compete for market share? What is the expected timeline for market penetration?



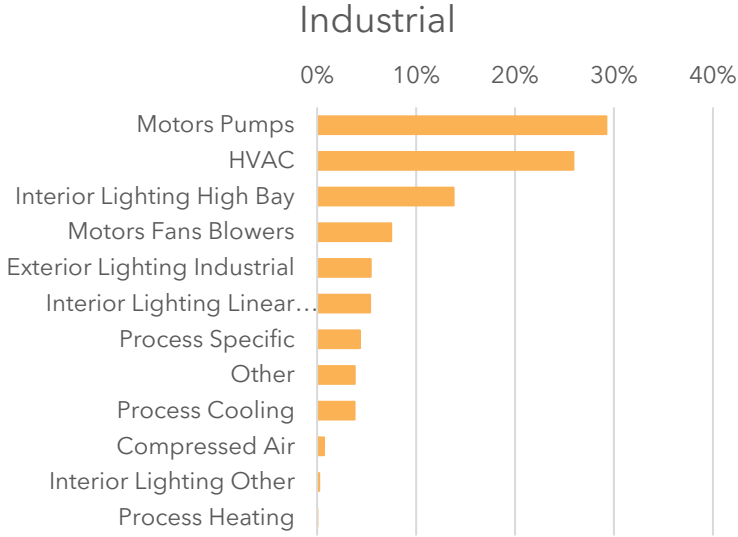
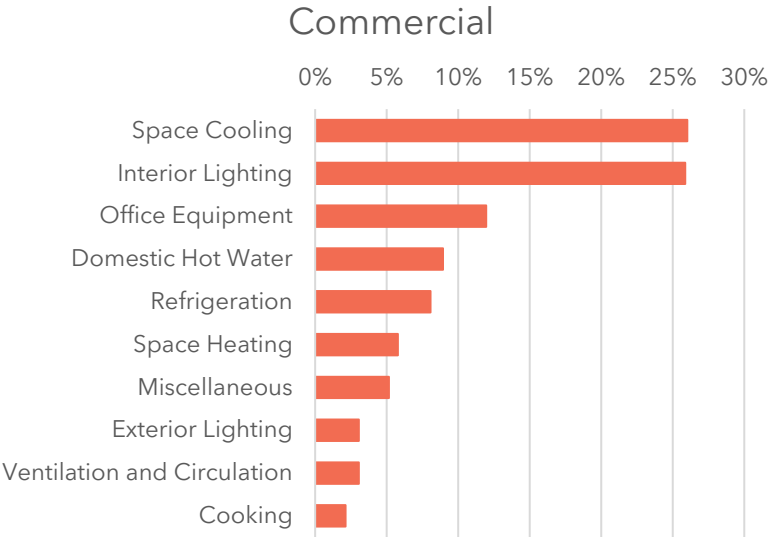
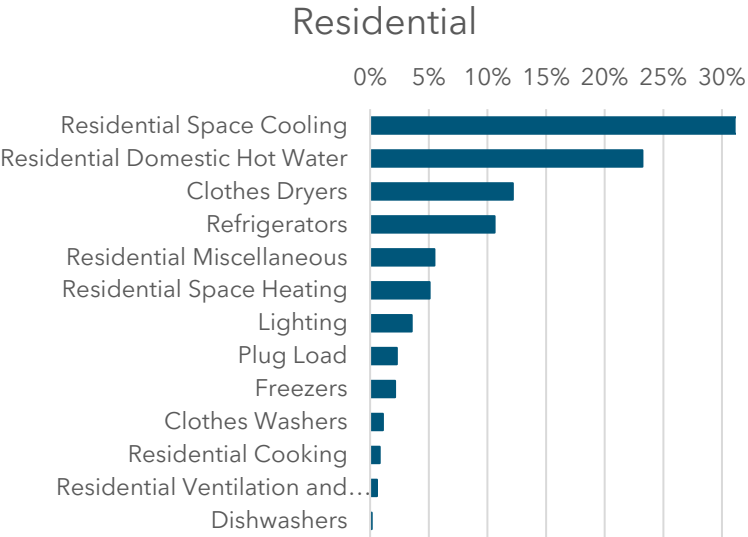
## Technical Potential (EE)



- Measures ranked by savings %
- Applied to baseline “equipment forecast”
- Dealing with representative buildings in a segment
- Includes all customers

# End Use Share of Cumulative TP by Sector

	Residential	Commercial	Industrial	System
2025 Base Load (MWh)	9,482,055	6,143,426	10,869,177	26,494,658
Sum of Annual Incremental Savings (MWh)	7,090,536	3,628,640	4,524,002	15,243,179
Cumulative Savings with Measure Rolloff (MWh)	3,080,195	1,173,495	1,624,688	5,878,378
% of 2025 Base Load	32%	19%	15%	22%



# Economic Potential

## Duke Energy and OSB Stakeholders Use the Utility Cost Test

### Features of the UCT Test

- Compares Utility Cost of a Program Offer to Avoided Energy, Capacity, and T&D
- Incorporates All Utility Costs: Incentive and Administrative
- Consistent with DSM Program Planning and Regulation

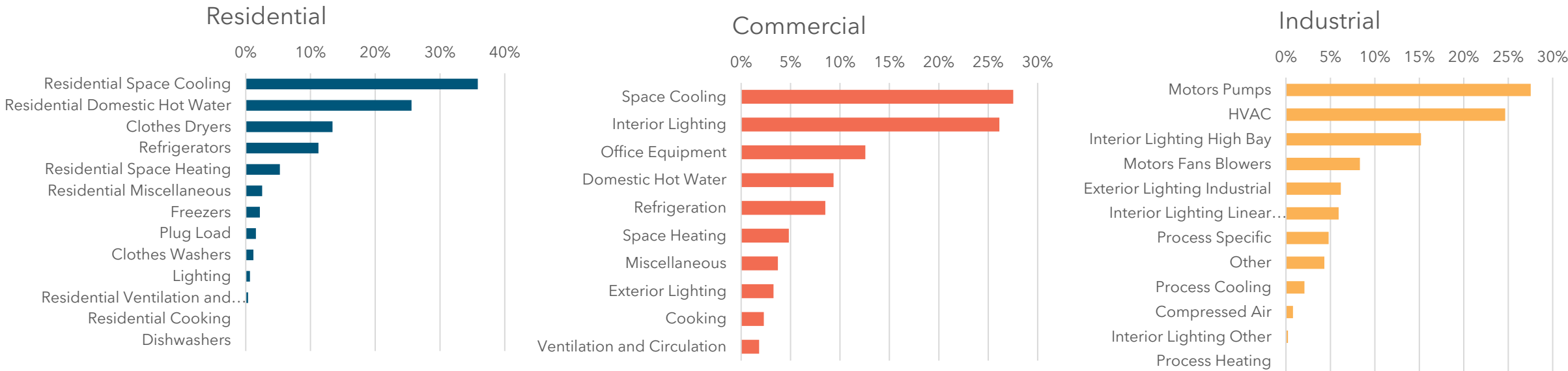
### Application of the UCT for DSM Potential

- Requires Assumptions for Incentive Rates and Administrative Costs
- Choice of Incentive Rate is Endogenous to Test Outcome
- Set an Incentive Rate Minimum at 30% of Measure Incremental Cost
- Avoided Cost Benefits Calculated by Duke Energy, with Measure Input Provided by RI



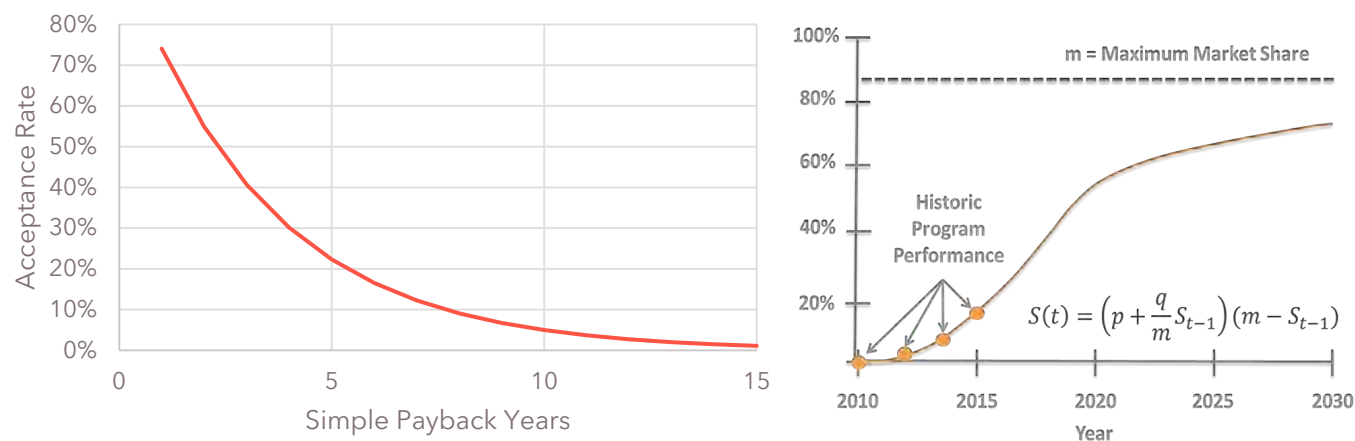
# End Use Share of Cumulative EP by Sector

	Residential	Commercial	Industrial	System
2025 Base Load (MWh)	9,482,055	6,143,426	10,869,177	26,494,658
Sum of Annual Incremental Savings (MWh)	6,468,444	3,468,270	4,226,448	14,163,162
Cumulative Savings with Measure Rolloff (MWh)	2,686,049	1,100,618	1,468,629	5,255,296
% of 2025 Base Load	28%	18%	14%	20%





# Achievable Potential

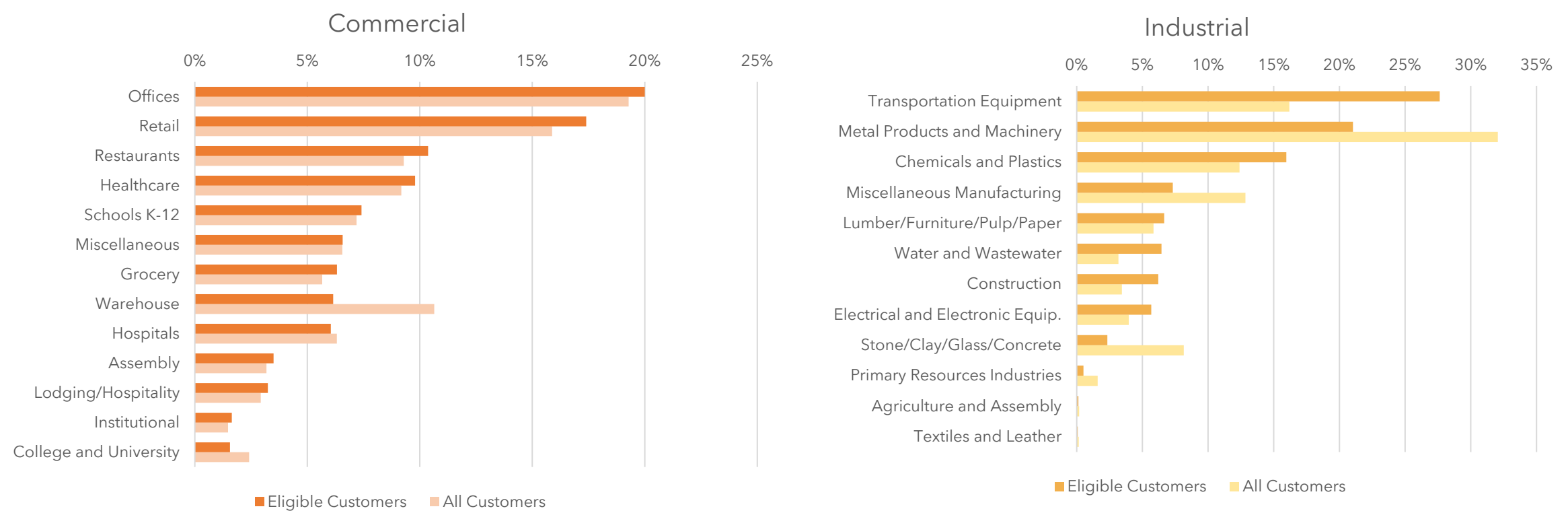


## Incorporates Expected Market Response to Cost-Effective Offers

- Customer Payback Acceptance is Long-run Market Share
- Competing Measures are Allocated by Logit Market Share
- Adoption Rates over Time follow Bass Diffusion Model
- Year 1 Potential is Calibrated to Past Program Achievements



# Start Year Sales Distribution by Segment – Eligibility





# Duke Energy Program Savings 2023

Program	Actual YTD Gross @ Meter MWH Total
<b>Duke Portfolio - Residential</b>	
Agency Assistance Portal	0
Income Qualified Neighborhood	857
Income Qualified Weatherization	255
Energy Efficiency Education Program for Schools	878
Multi-Family EE Products & Services	2,275
Residential Energy Assessments	2,765
Smart \$aver® Residential	19,455
My Home Energy Report	83,887
<b>Duke Portfolio - Residential Total</b>	<b>110,373</b>
<b>Duke Portfolio - Non-Residential</b>	
Power Manager® for Business	355
Public Efficiency Streetlighting	5,079
Business Energy Saver	12,347
Smart \$aver® Non-Residential	55,926
<b>Duke Portfolio - Non-Residential Total</b>	<b>73,707</b>
<b>Duke Portfolio - Grand Total</b>	<b>184,080</b>

# APS, IRA, Model Calibration

## APS Considerations

- Allocate Measures to DEI Programs
- Generalizations of Existing DEI Programs
  - New Smart \$aver Categories for Similar Measures
  - Some Measures not Currently Offered
- Assign Adoption Curves
- Align with Ongoing Adaptive Program Management by DEI
- Market Diffusion to Reach 100% of Long-run Market Share Estimated by Simple Payback Acceptance
- All Measures Increase Market Share over Time, Growing via Bass Diffusion, Representing Additional Program Savings over Baseline

## Inflation Reduction Act

- HOMES 20% Retrofit Performance Measure
  - Indiana funding allocation
  - Measure costs \$10,000
  - Income-qualified at <80% AMI and <150% AMI
  - <150% AMI Measure Assigned to a "Residential Construction" Program Archetypes
  - Only Modeled 20% Performance because Assumed More Customers would Benefit
- EE Tax Credit Can be Claimed for Entire Project Cost, but There's a Cap; Assumed to Reach Cap
- Smart \$aver Incentives Apply; IRA Credit Reduced by Incentive

## Model Calibration

- Measure-Program Allocation Adjustments
- Applicability Adjustments to Align Measures with Taxonomy
  - Measure Savings Modeled against Equipment-type Baseline
  - Sometimes Equipment Baseline is too Coarse and Needs Adjusting
  - E.g. Algorithms Sometimes Estimate Savings too Narrowly (ECM Motor)
- Adjustments for Observed Adoption (Pre-Pay Program)

# APS Sensitivities

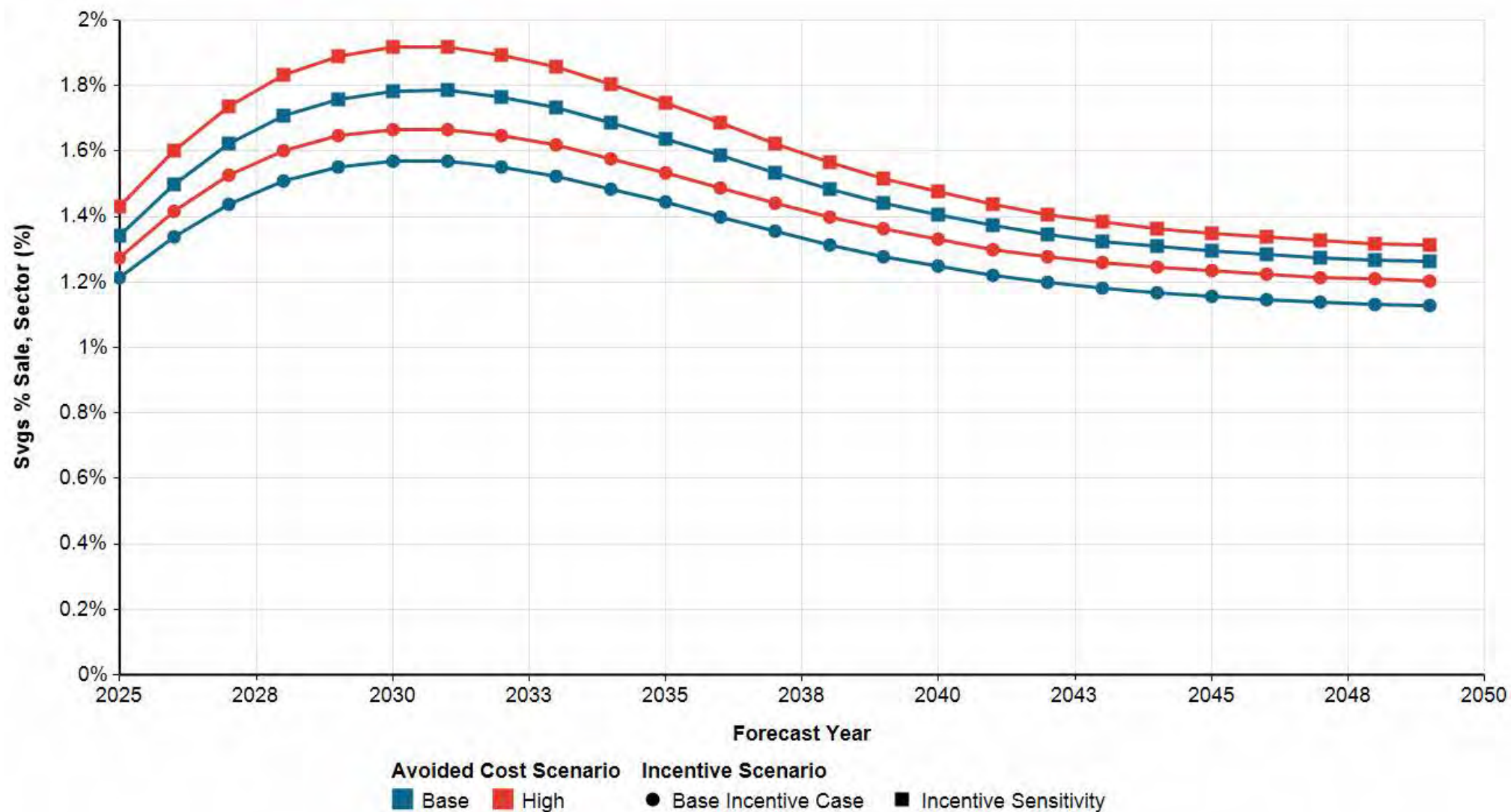
## Vary Costs and Benefits to Examine Sensitivity

- Base Case - Eligible Customers with IRA Impacts
- Incentive Sensitivity - Base with double incentive, capped at 75% or max cost-effective incentive
- Avoided Cost Sensitivity - Increase avoided costs by 50%

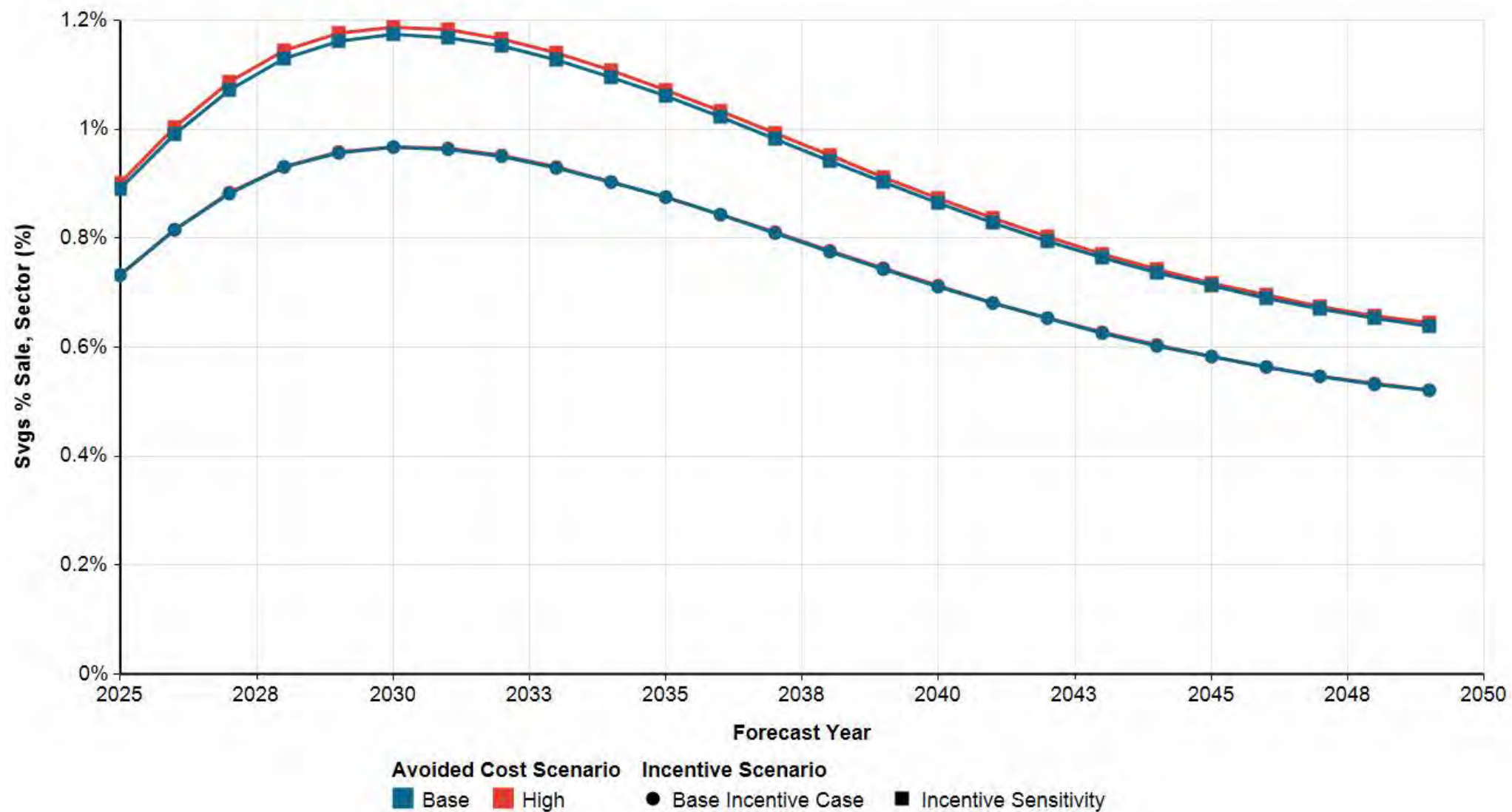


# APS Sensitivity and Share of Sales - RESIDENTIAL

\*This graph does not account for IRA

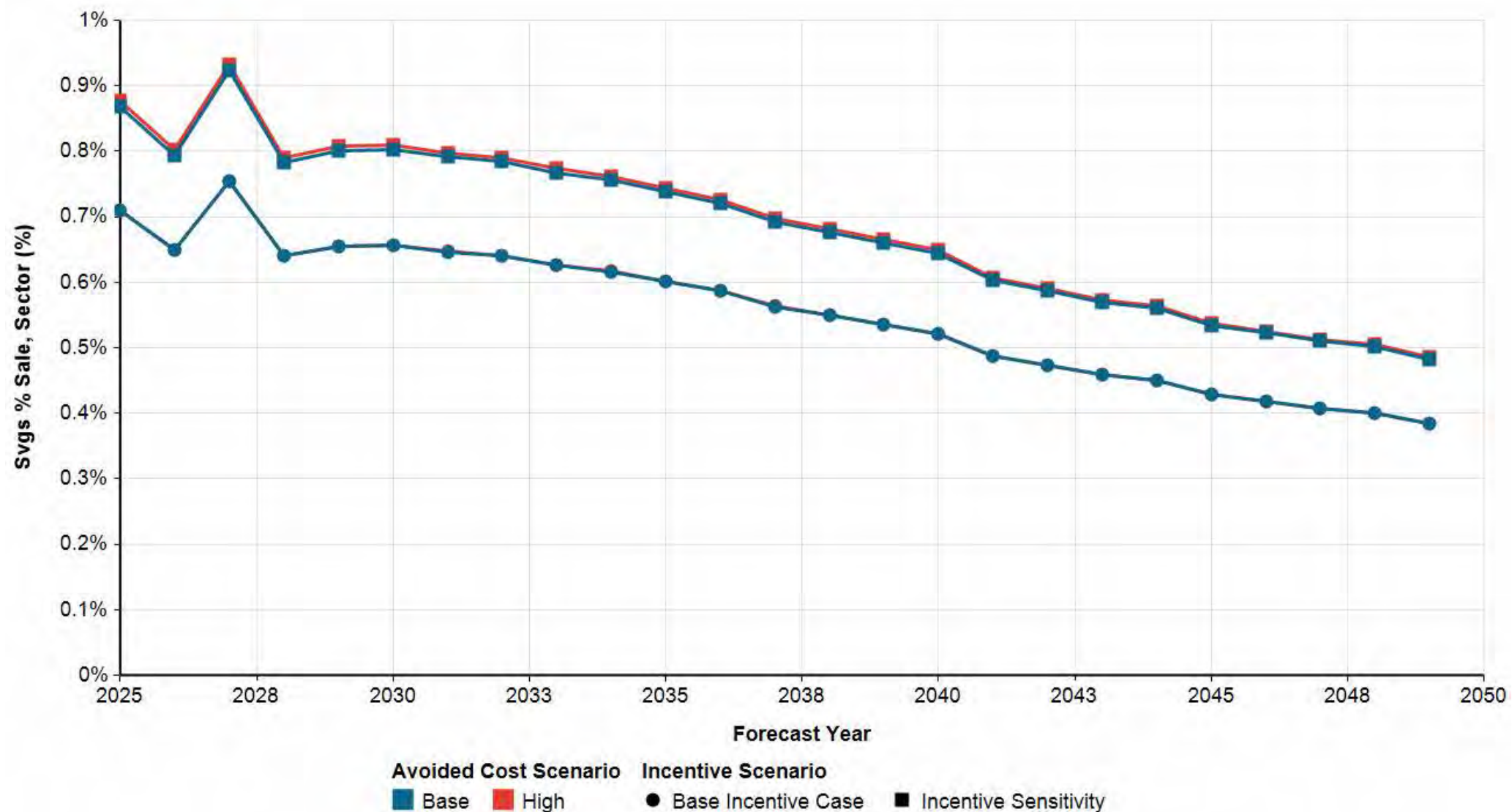


# APS Sensitivity and Share of Sales - COMMERCIAL



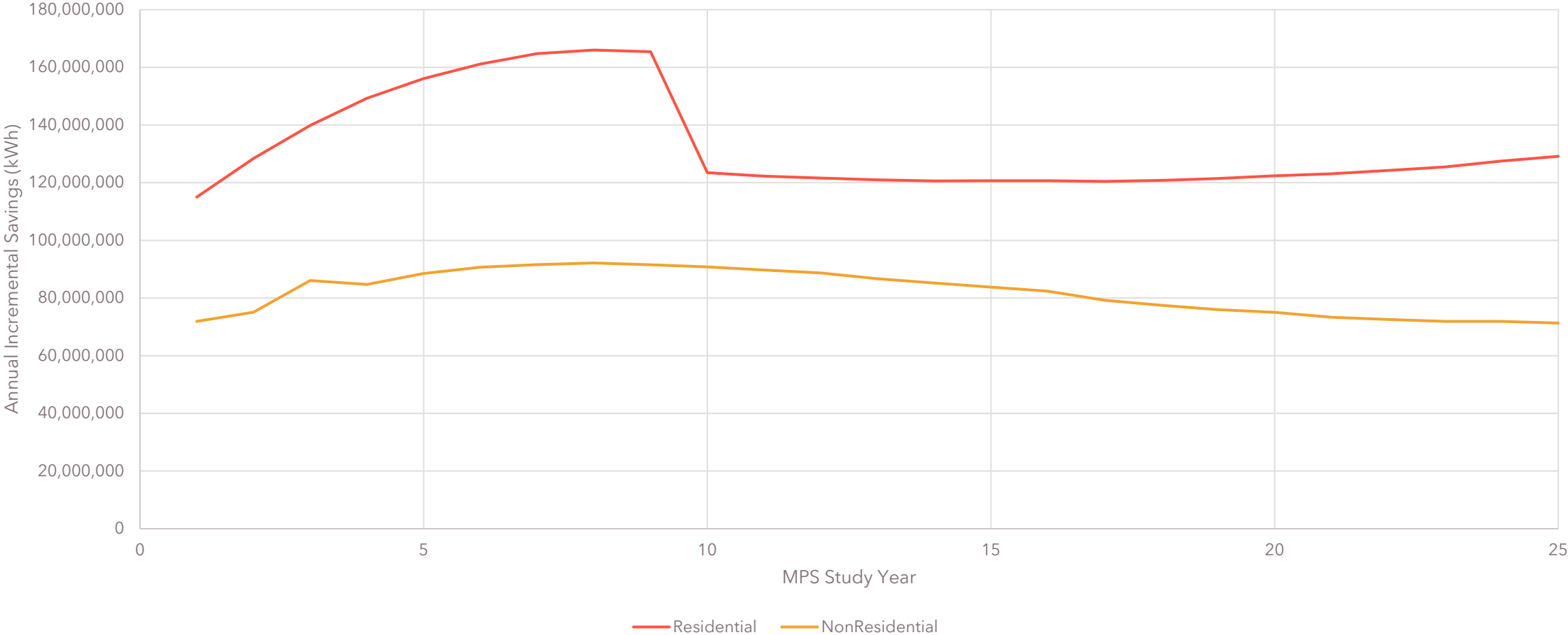


# APS Sensitivity and Share of Sales - INDUSTRIAL





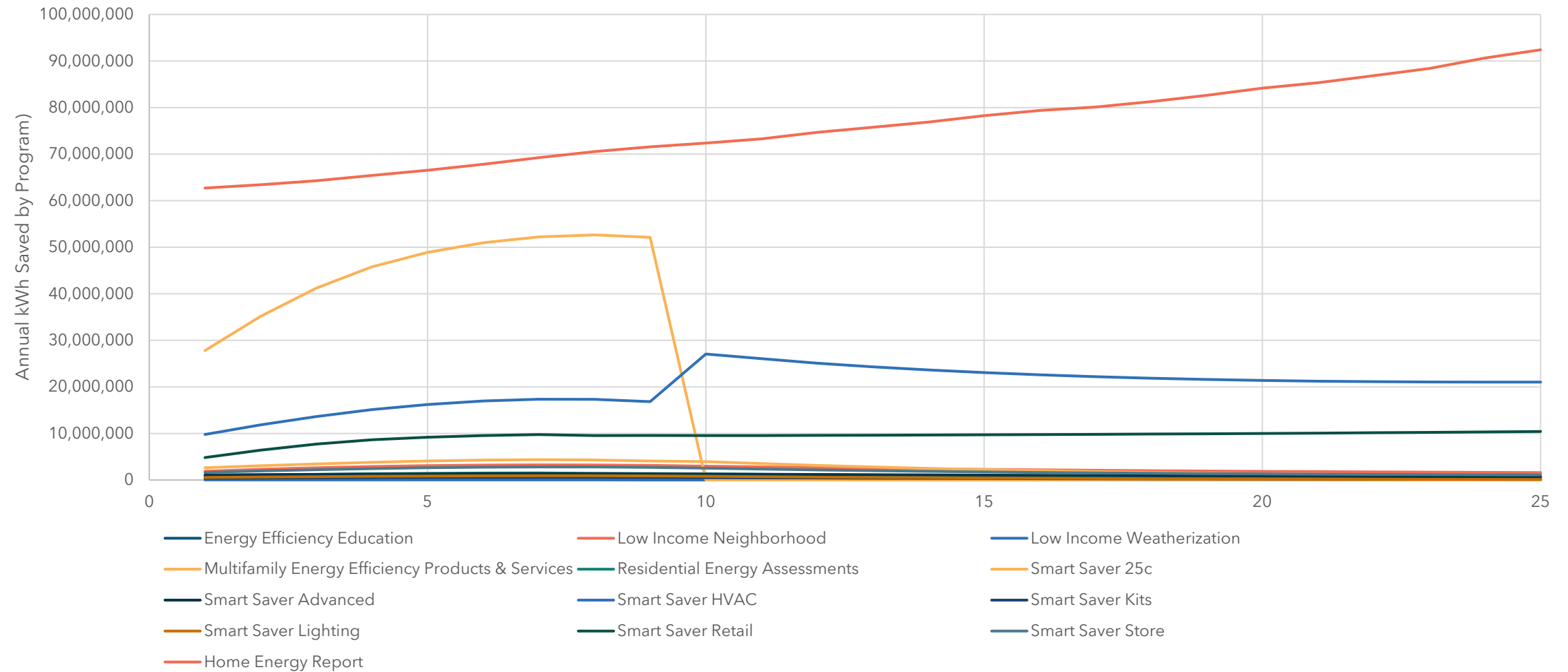
# Annual Incremental Savings – Base Case w/ IRA



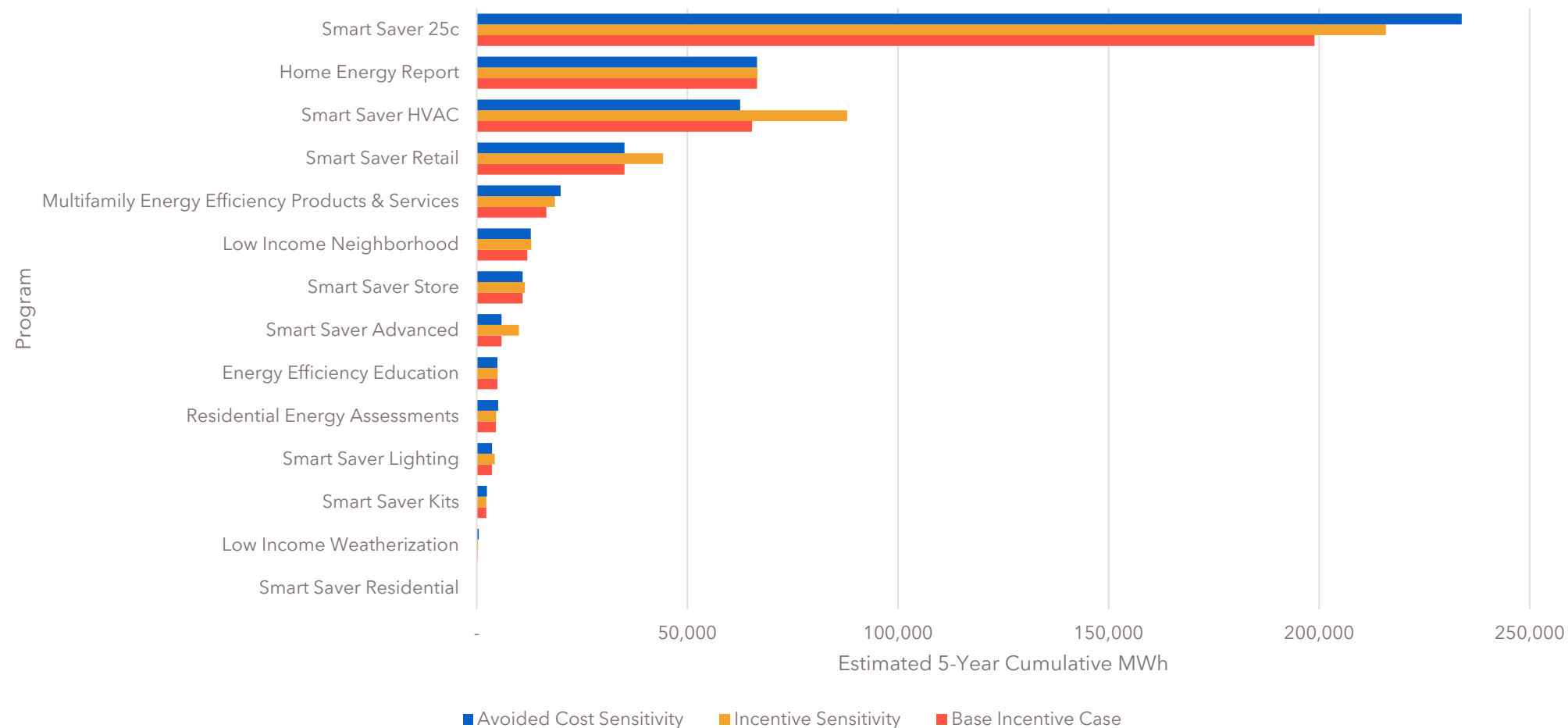
# Program Potential - Eligible Customers with IRA

Savings Perspective	Year 1	5-Year	10-Year	25-Year
Residential				
Sum of Annual Incremental Energy (MWh)	114,999	688,633	1,469,454	3,310,742
Cumulative Energy (MWh)	114,999	426,633	813,778	853,847
Non-Residential				
Sum of Annual Incremental Energy (MWh)	71,908	406,246	863,017	2,048,267
Cumulative Energy (MWh)	71,908	393,876	763,470	849,269

# Market Potential with Utility Programs – RES, IRA Sunset



# Achievable: Sensitivity to Costs and Benefits (Res)

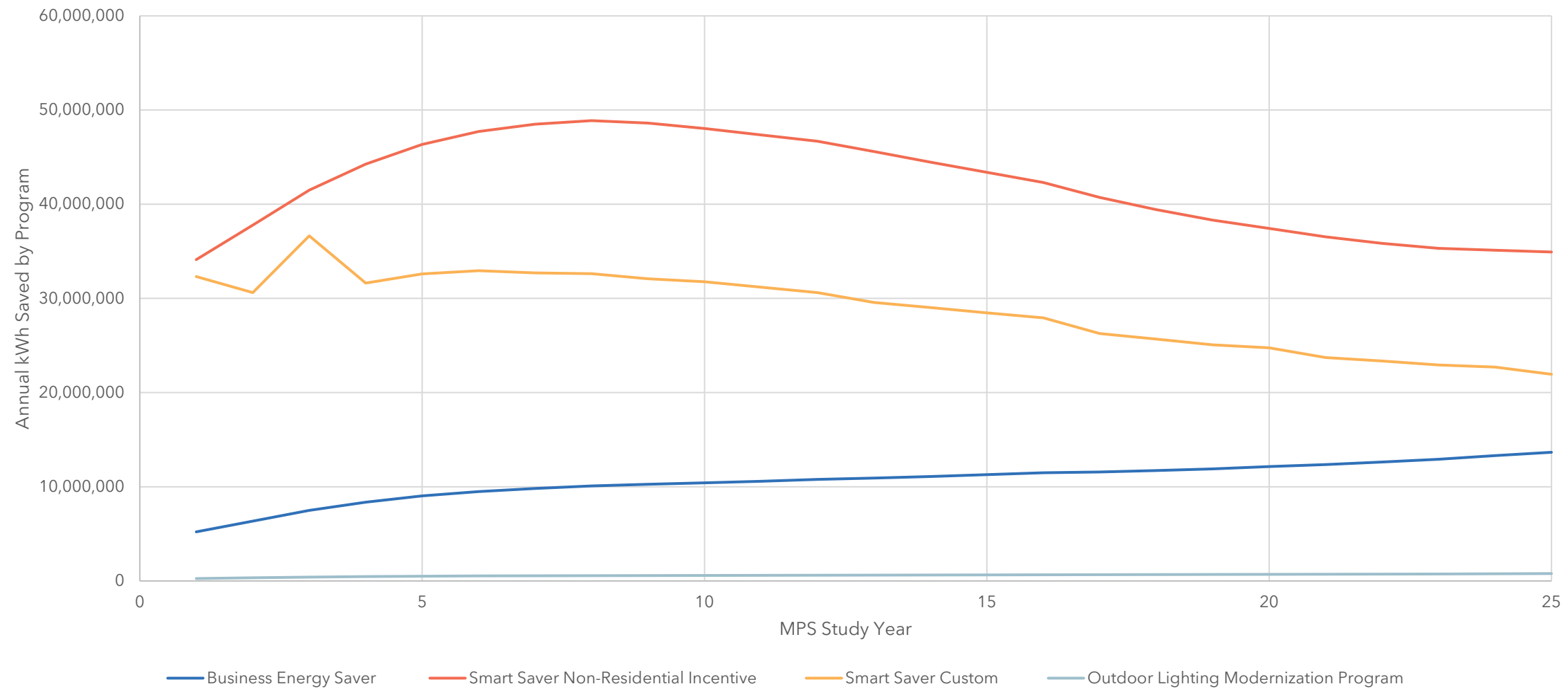


# Portfolio Costs by Scenario and Sector (Res, 5 Years)

Program Scenario	Metric	Low Income Neighborhood	Low Income Weatherization	Energy Efficiency Education	Multifamily Energy Efficiency Products & Services	Residential Energy Assessments	Smart Saver HVAC	Smart Saver Lighting	Smart Saver Store	Smart Saver Retail	Smart Saver Advanced	Smart Saver Kits	Home Energy Report	Smart Saver 25c
Base	Cumulative Energy (MWh)	11,997	192	4,889	16,536	4,548	65,360	3,611	10,891	35,057	5,873	2,250	66,540	198,888
Incentive Sensitivity	Cumulative Energy (MWh)	12,940	303	4,956	18,544	4,621	87,918	4,247	11,428	44,232	10,002	2,251	66,633	215,833
Avoided Cost Sensitivity	Cumulative Energy (MWh)	12,830	479	4,897	19,913	5,078	62,536	3,620	10,891	35,057	5,873	2,402	66,540	233,844
Base	Cumulative Spring Peak Demand (kW)	1,758	38	309	2,190	959	16,557	317	2,222	5,196	1,147	331	12,994	42,510
Incentive Sensitivity	Cumulative Spring Peak Demand (kW)	1,997	60	314	2,504	965	23,453	372	2,289	6,613	1,794	331	13,030	60,968
Avoided Cost Sensitivity	Cumulative Spring Peak Demand (kW)	1,871	92	310	2,631	1,031	16,179	317	2,222	5,196	1,147	351	12,994	48,032
Base	Cumulative Summer Peak Demand (kW)	1,513	39	231	1,931	988	17,496	272	2,261	5,111	1,171	261	13,274	42,595
Incentive Sensitivity	Cumulative Summer Peak Demand (kW)	1,769	62	235	2,260	993	25,109	320	2,322	6,528	1,807	261	13,314	62,783
Avoided Cost Sensitivity	Cumulative Summer Peak Demand (kW)	1,597	94	232	2,277	1,041	17,218	273	2,261	5,111	1,171	277	13,274	46,966
Base	Cumulative Fall Peak Demand (kW)	1,420	35	270	1,934	832	14,755	273	1,957	4,973	1,034	266	11,714	36,719
Incentive Sensitivity	Cumulative Fall Peak Demand (kW)	1,629	54	274	2,220	837	20,982	321	2,018	6,354	1,622	266	11,746	52,647
Avoided Cost Sensitivity	Cumulative Fall Peak Demand (kW)	1,509	84	271	2,315	889	14,456	274	1,957	4,973	1,034	282	11,714	41,128
Base	Cumulative Winter Peak Demand (kW)	2,836	48	2,093	4,655	1,212	19,381	750	2,994	5,643	1,530	526	17,304	62,419
Incentive Sensitivity	Cumulative Winter Peak Demand (kW)	3,139	75	2,119	5,554	1,225	26,264	881	3,072	6,994	2,434	526	17,325	53,465
Avoided Cost Sensitivity	Cumulative Winter Peak Demand (kW)	3,028	147	2,095	5,375	1,334	18,728	752	2,994	5,643	1,530	561	17,304	69,402
Base	Total Program Cost (\$T)	13,259	192	1,351	5,667	360	25,031	1,094	2,477	13,195	1,491	426	9,672	130,221
Incentive Sensitivity	Total Program Cost (\$T)	15,151	369	1,369	8,498	401	57,764	1,597	3,371	22,874	15,538	426	9,679	245,170
Avoided Cost Sensitivity	Total Program Cost (\$T)	14,705	791	1,353	6,858	457	24,071	1,116	2,477	13,195	1,492	486	9,672	184,409
Base	Levelized Cost (\$/kWh)	\$0.27	\$0.25	\$0.07	\$0.08	\$0.02	\$0.09	\$0.07	\$0.06	\$0.09	\$0.06	\$0.05	\$0.04	\$0.16
Incentive Sensitivity	Levelized Cost (\$/kWh)	\$0.29	\$0.30	\$0.07	\$0.11	\$0.02	\$0.16	\$0.09	\$0.07	\$0.13	\$0.38	\$0.05	\$0.04	\$0.28
Avoided Cost Sensitivity	Levelized Cost (\$/kWh)	\$0.28	\$0.41	\$0.07	\$0.08	\$0.02	\$0.09	\$0.08	\$0.06	\$0.09	\$0.06	\$0.05	\$0.04	\$0.19

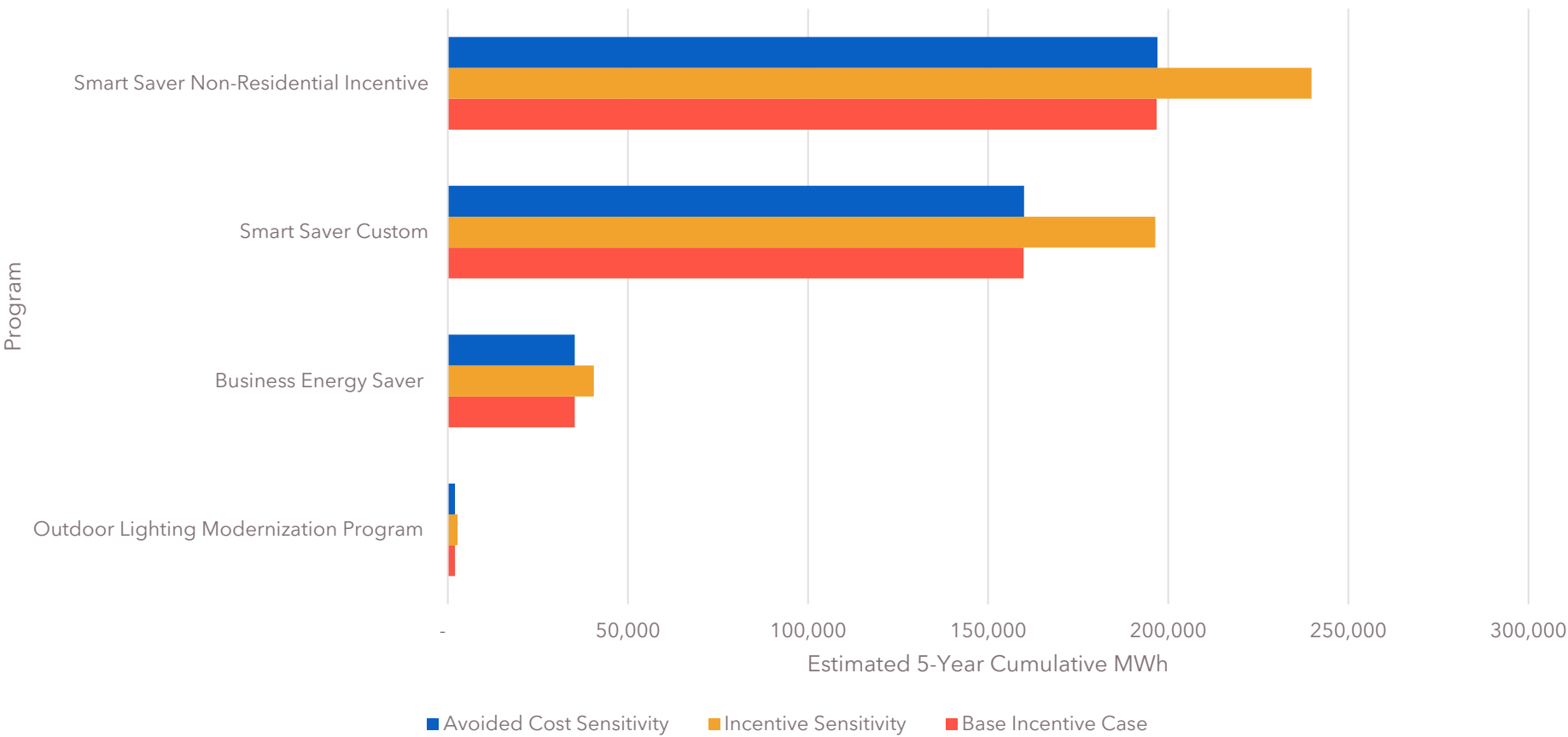


# Market Potential with Utility Programs – Non-Res





# Achievable: Sensitivity to Costs and Benefits (NonRes)



# Portfolio Costs by Scenario and Sector (NonRes, 5 Years)

Program Scenario	Metric	Smart Saver Custom	Business Energy Saver	Smart Saver Non-Residential Incentive	Outdoor Lighting Modernization Program
Base	Cumulative Energy (MWh)	159,862	35,234	196,801	1,979
Incentive Sensitivity	Cumulative Energy (MWh)	196,403	40,558	239,780	2,719
Avoided Cost Sensitivity	Cumulative Energy (MWh)	159,957	35,243	197,035	1,979
Base	Cumulative Spring Peak Demand (kW)	21,317	8,003	40,484	0
Incentive Sensitivity	Cumulative Spring Peak Demand (kW)	26,189	9,399	50,365	0
Avoided Cost Sensitivity	Cumulative Spring Peak Demand (kW)	21,331	8,005	40,518	0
Base	Cumulative Summer Peak Demand (kW)	21,308	7,573	38,711	0
Incentive Sensitivity	Cumulative Summer Peak Demand (kW)	26,176	8,930	48,354	0
Avoided Cost Sensitivity	Cumulative Summer Peak Demand (kW)	21,322	7,575	38,743	0
Base	Cumulative Fall Peak Demand (kW)	21,320	7,593	39,211	0
Incentive Sensitivity	Cumulative Fall Peak Demand (kW)	26,196	8,962	48,985	0
Avoided Cost Sensitivity	Cumulative Fall Peak Demand (kW)	21,334	7,595	39,243	0
Base	Cumulative Winter Peak Demand (kW)	19,000	5,676	29,058	456
Incentive Sensitivity	Cumulative Winter Peak Demand (kW)	23,434	6,598	36,637	626
Avoided Cost Sensitivity	Cumulative Winter Peak Demand (kW)	19,011	5,677	29,087	456
Base	Total Program Cost (\$T)	20,489	3,988	29,106	290
Incentive Sensitivity	Total Program Cost (\$T)	40,003	8,271	60,759	716
Avoided Cost Sensitivity	Total Program Cost (\$T)	20,539	3,994	29,200	290
Base	Levelized Cost (\$/kWh)	\$0.03	\$0.03	\$0.04	\$0.04
Incentive Sensitivity	Levelized Cost (\$/kWh)	\$0.05	\$0.05	\$0.06	\$0.06
Avoided Cost Sensitivity	Levelized Cost (\$/kWh)	\$0.03	\$0.03	\$0.04	\$0.04

# OSB Collaboration and Feedback

Thank you for your participation, flexibility, and engagement!

## Additional Items for OSB:

- DER wrap-up and Summary
- Demand Response Results Summary

Study Component	Delivered	Notes	Cadence (days)
Kickoff	9/21/2023	Presentation and Review of Added Scope	0
Correspondence	10/11/2023	CAC Areas of Interest to RI	15
Draft Work Plan	10/23/2023	Comments rec'd CAC	9
Draft Measure List	10/23/2023	Comments rec'd CAC	1
Measure List Memo	10/23/2023		1
Draft 2 Measure List	10/31/2023	Addressed CAC comments	7
Correspondence	10/31/2023	RI response to CAC Areas of Interest memo	1
Final MPS Workplan	11/10/2023	Updates reflecting CAC comments	9
Draft Measure Impacts	11/17/2023	Comments rec'd CAC	6
Draft 2 Measure Impacts	11/29/2023	Comments rec'd CAC	9
Draft Market Baseline	12/13/2023	Comments rec'd CAC	11
COM Impacts to DEI	12/22/2023		8
RES Impacts to DEI	1/4/2024		10
IND Impacts to DEI	1/10/2024		5
Correspondence	1/29/2024	Response to CAC comments on Measure Impacts, Market Baseline Rev.	14
Draft EE Technical Potential	2/16/2024	Comments/request CAC	15
Draft Inputs DR Technical Potential	2/21/2024		4
EE Technical Potential Levelized	2/28/2024	RI response to CAC request	6
DR Technical Potential Inputs and Baseline	3/5/2024	Comments rec'd CAC	5
DER Technical Potential and Methods	3/19/2024	Two meetings held for those interested	11
DSMore Measure Avoided Costs Rec'd	3/21/2024		3
Initial DRAFT APS to DEI	4/12/2024		17
Revised Draft to DEI	5/10/2024		21
Summary Results, Inputs, Outputs to OSB	05/15/2024		3
(Forthcoming) Response to DER, DR Comments, EE APS Comments, and FINAL Results	TBD		

# OSB Stakeholder Feedback

## OSB Comments

- Energy Efficiency Tax Credits should be applied as a reduction in equipment purchase cost, with utility incentives providing further cost reductions
- Program administrative costs should be revised downward
- Calibrate Low Income Weatherization to recent program achievements
- Update measure inputs to use a larger average square footage value of single family homes
- Requested to provide a copy of the model

## Response

- Implemented as described; qualifying EE measures receive a discount from IRA tax credits and DEI incentives
- Resource Innovations reduced program administrative costs to match average costs from the 2023 program year
- RI modeled all existing income-qualified programs under the name “Low Income Neighborhood”
  - “Low Income Weatherization” was modeled exclusively as the IRA HOMES program scenario
  - Allows DEI to identify income-qualified retrofit impacts from IRA funding as distinct from existing income-qualified programs
- RI cannot accommodate this request, as it affects measure inputs that were established early in the study; existing values are reasonable estimates and the impact from proposed changes is likely minimal
- RI has provided all model inputs and outputs (draft); final model results will be provided to the OSB; the MPS model is proprietary to Resource Innovations

# Output for Integrated Resource Planning



## High-Resolution Output

- Expected Utility Costs and Benefits from Program Offerings
- Energy and Load Impacts by Economic Sector, Customer Segment, Electricity End Use, and Construction Vintage
- Anticipated Energy and Load Impacts for Each Year of the Planning Period
- Robust Modeling Tools for Scenario Analysis
- Transparent and Collaborative Process



## Holistic View of DSM Opportunities

- Assess and Compare the Vast Array of Savings Opportunities
- Identify Key Technologies for Different Customer Types
- Explore Costs and Benefits of Savings, and Timing of DSM Investment Opportunities
- Detailed, Granular Assessment that Enables Big-Picture Strategy
- Integrated View of both Utility and Customer Perspectives



# Q&A





# EnCompass Model Review (Technical Meeting)

# Data Sharing



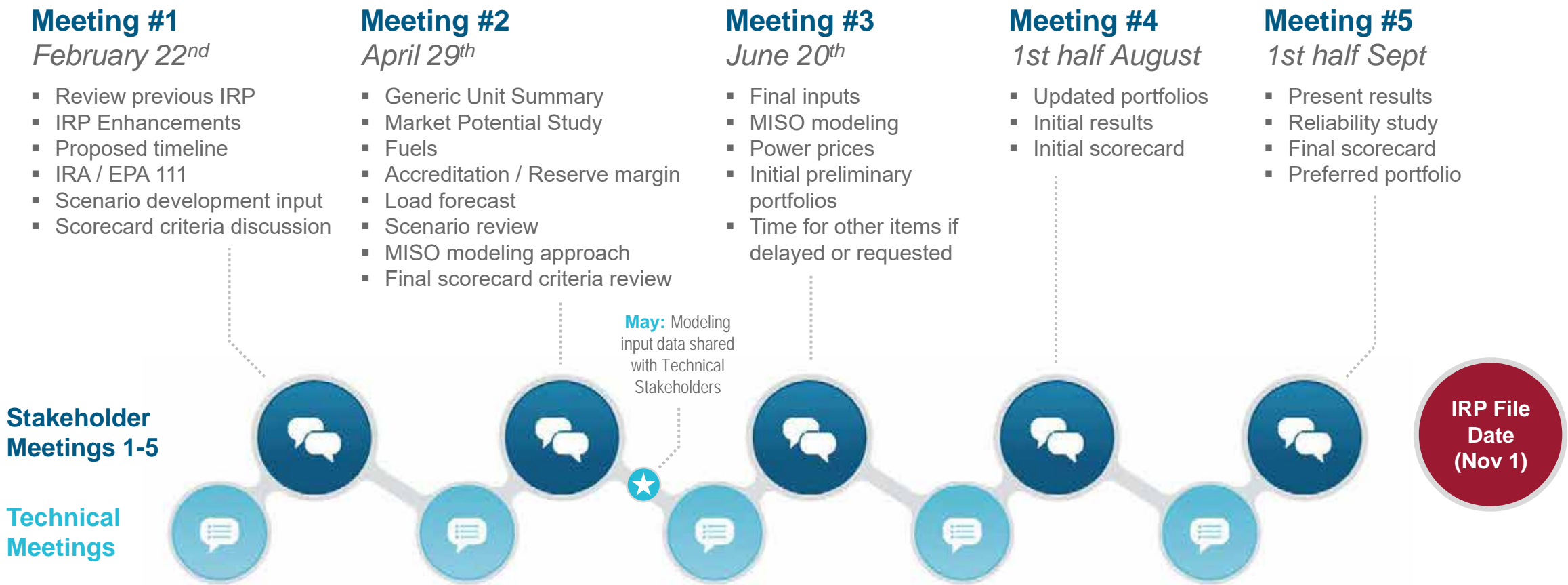
- Data related to this meeting has been provided to Technical Stakeholders who have signed a non-disclosure agreement.
- As files are available, they will be uploaded to Datasite so Technical Stakeholders have the opportunity to review in advance of the meetings to help facilitate robust technical discussions.
- Prior to this meeting we shared modeling data with Technical Stakeholders. This included the EnCompass National Database and DEI Local files on 5/31.
- Updated Local IRP modeling files were shared on 6/11, which included the preliminary portfolios discussed today.

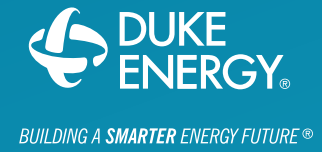


If you have difficulty accessing Datasite or, if there are ways that we can improve data sharing for these technical meetings, please let us know.

# 2024 DEI IRP Stakeholder Meetings

*Engaging with our stakeholders in multiple sessions throughout the 2024 IRP process*





# Open Q&A

## Next Steps



Additional questions, comments,  
and feedback can be sent to

[DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com)

**Please provide any written feedback by July 10, 2024**

The fourth technical and public stakeholders meeting will  
occur in early August.

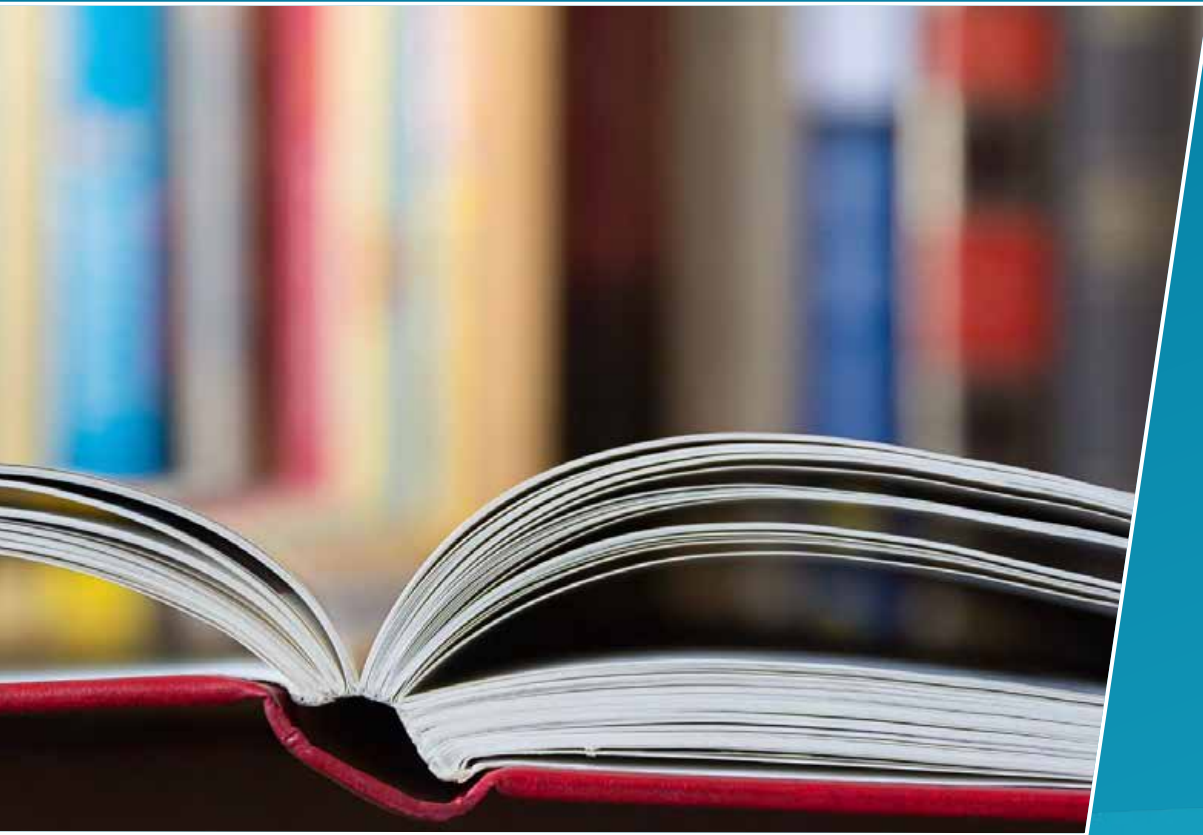
Meeting registration will be sent out  
4-6 weeks in advance.



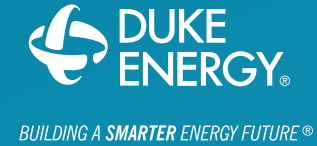


# Thank you





# Appendix



# Appendix:

## Resource Availability

### Updates since Meeting 2

# Annual Resource Availability (Interconnection Timing, BoY) | Thermal

Resource Type	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation	Basis for Assumption
CT	2031+: Two HA.03 (851 MW)	2031+: Two HA.03 (851 MW) <b>H<sub>2</sub> fuel</b>	Reference	Assessment of resource availability and suitable locations
CC	2029+: 1x1 H.03 (664 MW)	Reference	Reference	Assessment of resource availability and suitable locations
	2031+: 2x1 H.03 (1,364 MW)			
CT PPA	Thru 2028: 600 MW	Reference	Reference	MISO D-LOL implementing in 28/29
Nuclear	2037+: SMR 2039+: Advanced Reactor	Reference	N/A	Based on assumption of earliest availability

Note: Differences from reference case marked in **Bold**  
BoY: Beginning of Year – Availability begins January 1 of year listed.

No changes to Thermal Resource Availability since Meeting 2

# Annual Resource Availability (Interconnection Timing, BoY) | Renewables & Storage

Resource Type	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation	Basis for Assumption
Solar	2026: 199 MW	2026: 199 MW	Reference	Speedway PPA in-flight 2022 RFP awards 2024 RFP proposals pending evaluation
	2027: 300 MW	2027: 300 MW		
	2028: 750 MW	2028: 750 MW		Assumes added capacity in future DPP cycles & queue reforms result in expedited study processes
	2029-2031: 1,000 MW	<b>2029-2031: 1,500 MW</b>		
	2032+: 1,200 MW (↑ 200)	<b>2032+: 1,500 MW</b>		
Wind	2028: 200 MW	2028: 200 MW	Reference	2024 RFP proposals pending evaluation
	2029: 200 MW	2029: 200 MW		
	2030-2031: 300 MW	<b>2030-2031: 600 MW</b>		Assumes added capacity in future DPP cycles, queue reforms expedite study processes & procurement outside of LRZ6
	2032+: 400 MW (↑ 100)	<b>2032+: 1,000 MW (↑ 400)</b>		
Storage	2028-2029: 300 MW	2028-2029: 300 MW	Reference	2028-2029: Based on RFP data 2030+: Based on MISO Queue
	2030+: 700 MW	<b>2030+: 1,200 MW</b>		
LDES	N/A	<b>2030+: 100 MW (10-hr) 2032+: 100 MW (100-hr); 500 MW (total)</b>	Reference	Technology readiness level
SPS	2028-2029: 400 MW Solar; 50% (4-hr)	2028-2029: 400 MW Solar; 50% (4-hr)	Reference	Assumes added capacity in future DPP cycles & queue reforms result in expedited study processes
	2030+: 600 MW Solar; 50% (4-hr)	<b>2030+: 1,000 MW Solar; 50% (4-hr)</b>		

Note: Differences from reference case marked in **Bold**  
BoY: Beginning of Year – Availability begins January 1 of year listed.

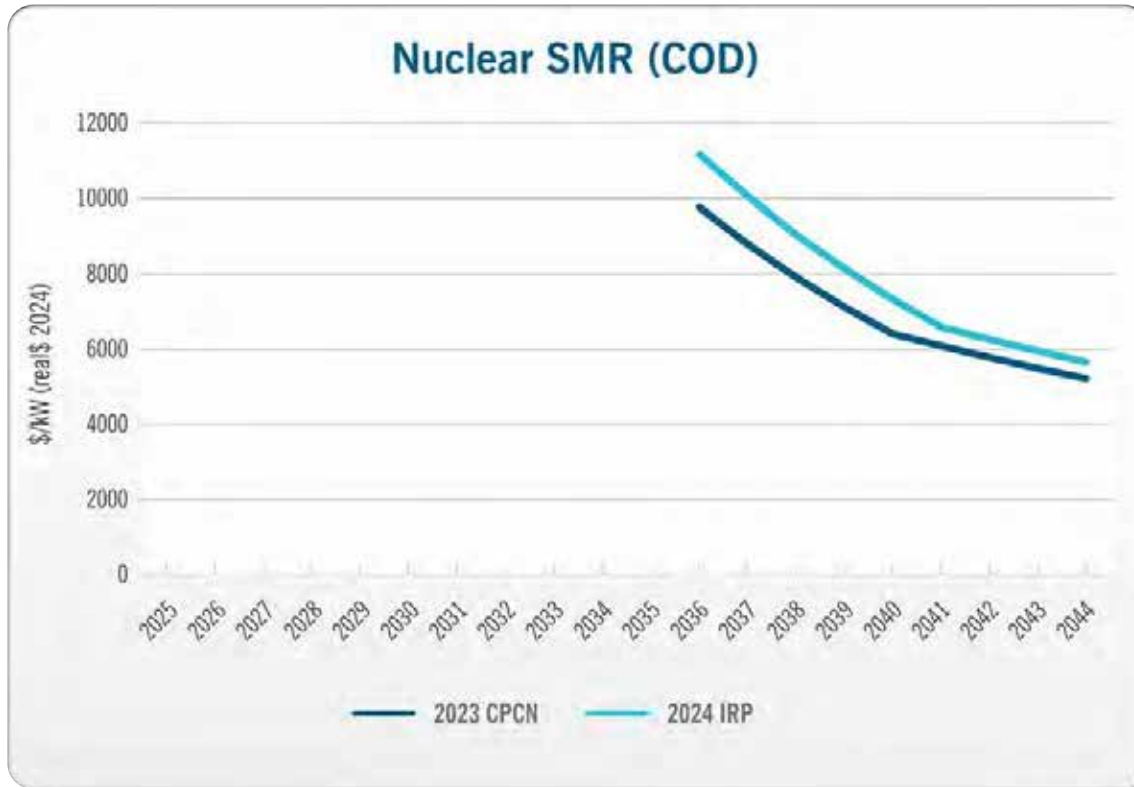
Changes since Meeting 2 are highlighted





# Appendix: Nuclear SMR Costs

# Nuclear SMR Cost Curve



## SMR Advantages Relative to Traditional Nuclear:

- Modularized section for containment fabricated offsite
  - Reduces quantity of concrete, rebar
  - Majority of welding done offsite
- Modularized equipment rooms fabricated offsite and installed in sections
- Reactor vessel below grade
  - Passive shutdown and cooling
  - Fewer moving parts (pumps, valves, motors, etc.) required
- Greater use of commercially available components
- Smaller site footprint
- Proven reactor technology should result in reduced licensing costs

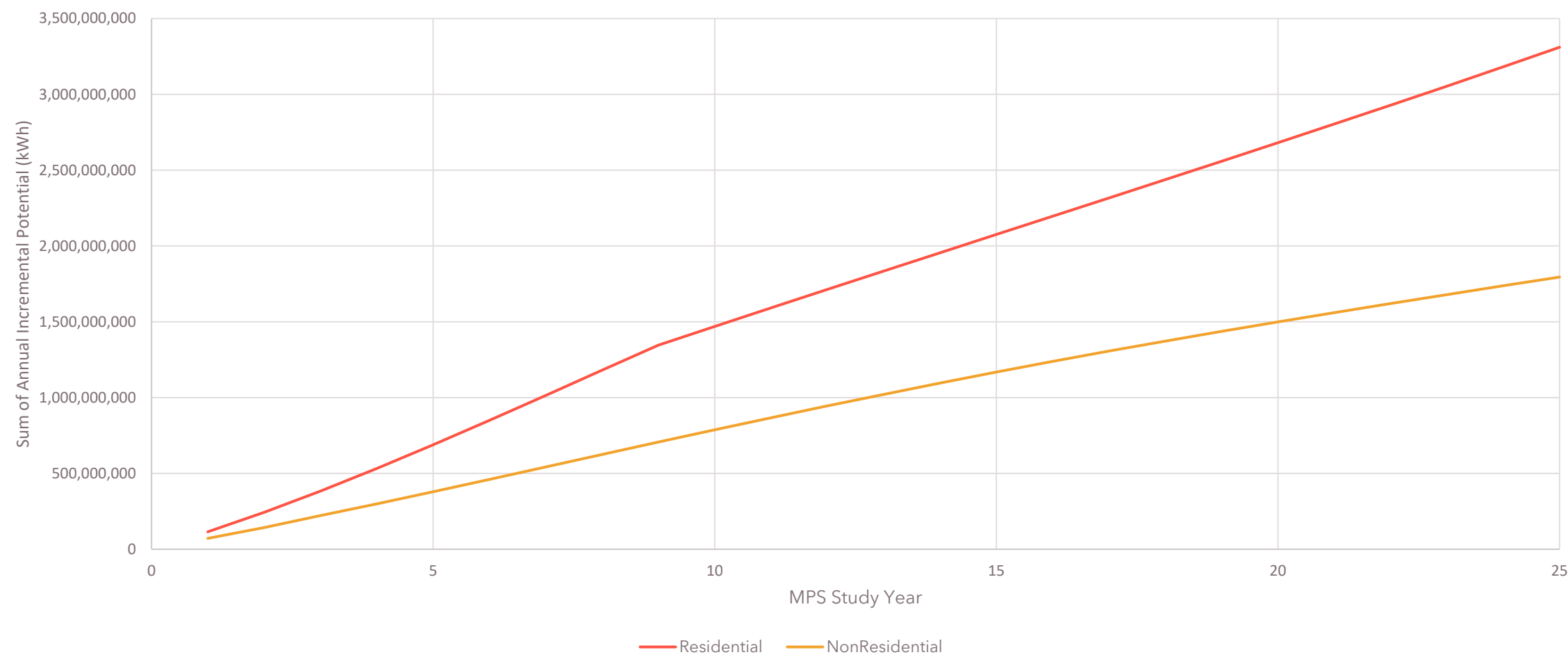
**Costs can be expected to decline as designs, manufacturing processes, and construction processes are refined and improved.**





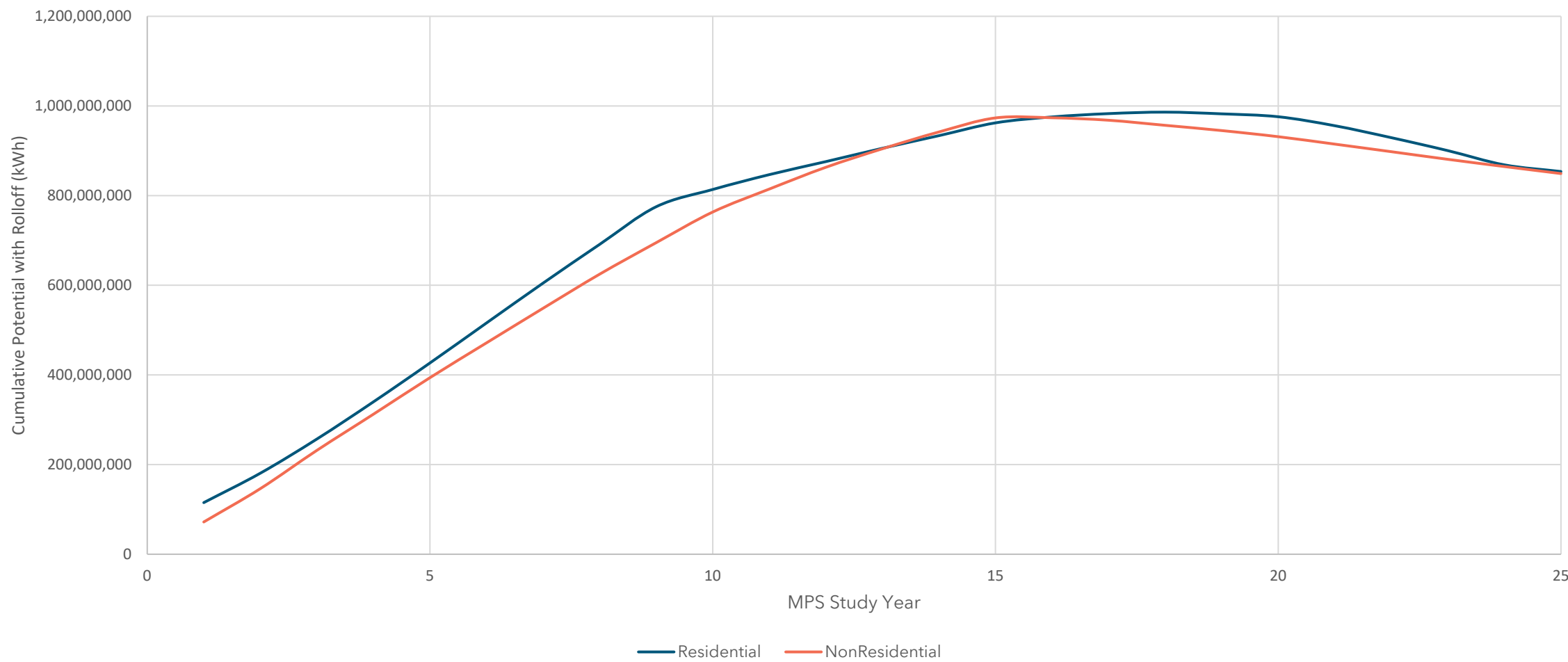
# Appendix: Demand-Side Management Market Potential Study

# Total Energy Saved (Sum of Annuals) – Base Case w/ IRA





# Cumulative Savings with Rolloff – Base Case w/ IRA



# First-Year Impacts by Measure (top 20, Ach.)

## Residential

Measure Name	Cumul Savings	% of Savings
Behavior Modification Home Energy Reports	59,196,860	51%
Air Sealing	6,936,905	6%
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	6,284,225	5%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	5,427,951	5%
Energy Star Door	3,627,491	3%
HVAC ECM Motor	3,056,869	3%
Behavior Modification Pre-pay plan	2,953,816	3%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	2,797,874	2%
Ceiling Insulation	1,759,343	2%
Low-E Storm Window	1,603,068	1%
Air Handler Filter Clean	1,602,695	1%
Energy Star Desktop Computer	1,147,601	1%
1.5 GPM Kitchen Faucet Aerators	1,128,331	1%
1.60 GPM Low-Flow Showerhead	1,115,559	1%
RealTime Information Monitoring Residential	1,010,861	1%
Energy Efficiency Education in Schools	761,950	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	754,596	1%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	715,751	1%
Programmable Thermostat Residential	656,944	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF	616,151	1%

## Non-Residential

Measure Name	Cumul Savings	% of Savings
VFD on HVAC Fan	7,352,262	10%
VFD on Cooling Tower Fans	3,992,913	6%
Air Compressor Optimization	3,294,232	5%
Time Clock Control	2,909,462	4%
SP to ECM Evaporator Fan Motor (Walk-In_ Refrigerator)	2,888,236	4%
VFD on process pump	2,777,933	4%
Demand Defrost	2,554,470	4%
LED Linear - Lamp Replacement	2,361,680	3%
Indoor daylight sensor	1,911,288	3%
Evaporator Fan Motor Control	1,538,962	2%
LED High Bay_LF Baseline	1,339,403	2%
Energy Star PCs-Desktop	1,284,783	2%
High Bay Occupancy Sensors_ Ceiling Mounted	1,233,247	2%
Refrigeration Economizer	1,167,224	2%
Energy Star Monitors	1,161,185	2%
1.5 GPM Low-Flow Showerhead	1,043,923	1%
Cogged Belt on 40hp ODP Motor	1,023,237	1%
High Volume Low Speed Fan (HVLS)	997,605	1%
Cogged Belt on 15hp ODP Motor	996,482	1%
VFD on HVAC Pump	993,656	1%

# Five-Year Cumulative Impact by Measure (Ach.)

## Residential

Measure Name	Cumul Savings	% of Savings
Behavior Modification Home Energy Reports	62,799,748	15%
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	48,660,929	11%
Air Sealing	44,430,929	10%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	40,164,710	9%
Energy Star Door	23,436,278	5%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	22,222,860	5%
HVAC ECM Motor	19,751,682	5%
Ceiling Insulation	11,364,616	3%
Low-E Storm Window	10,382,557	2%
Energy Star Desktop Computer	7,457,980	2%
1.60 GPM Low-Flow Showerhead	7,322,591	2%
1.5 GPM Kitchen Faucet Aerators	7,277,588	2%
Air Handler Filter Clean	6,949,655	2%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	5,866,852	1%
RealTime Information Monitoring Residential	5,692,702	1%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	5,574,108	1%
Energy Efficiency Education in Schools	4,888,956	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF	4,661,804	1%
CEE Tier 3 Refrigerator	4,301,277	1%
Programmable Thermostat Residential	4,269,971	1%

## Non-Residential

Measure Name	Cumul Savings	% of Savings
VFD on HVAC Fan	38,040,493	10%
VFD on Cooling Tower Fans	19,367,860	5%
LED Linear - Lamp Replacement	18,570,268	5%
SP to ECM Evaporator Fan Motor (Walk-In_Refrigerator)	15,658,092	4%
Time Clock Control	14,937,553	4%
VFD on process pump	12,821,992	3%
Demand Defrost	12,350,938	3%
Air Compressor Optimization	11,222,465	3%
Indoor daylight sensor	10,202,862	3%
Energy Star PCs-Desktop	9,103,834	2%
Evaporator Fan Motor Control	8,640,233	2%
LED High Bay_LF Baseline	8,217,258	2%
Energy Star Monitors	8,118,564	2%
Cogged Belt on 40hp ODP Motor	6,473,042	2%
High Volume Low Speed Fan (HVLS)	6,347,322	2%
Refrigeration Economizer	6,328,728	2%
Cogged Belt on 15hp ODP Motor	6,286,779	2%
LED Linear - Fixture Replacement	6,091,651	2%
1.5 GPM Low-Flow Showerhead	5,733,126	1%
High Efficiency PTHP	5,719,880	1%

# Ten-Year Cumulative Impacts by Measure (Ach.)

## Residential

Measure Name	Cumul Savings	% of Savings
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	106,826,536	13%
Air Sealing	88,571,505	11%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	86,909,606	11%
Behavior Modification Home Energy Reports	68,337,152	8%
Energy Star Door	48,473,157	6%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	47,717,581	6%
HVAC ECM Motor	28,910,574	4%
Low-E Storm Window	24,279,271	3%
Ceiling Insulation	22,478,750	3%
1.60 GPM Low-Flow Showerhead	16,033,832	2%
1.5 GPM Kitchen Faucet Aerators	16,026,965	2%
Air Handler Filter Clean	13,934,967	2%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	13,514,124	2%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	12,626,502	2%
RealTime Information Monitoring Residential	11,947,835	1%
Energy Star Desktop Computer	11,142,404	1%
CEE Tier 3 Refrigerator	10,290,267	1%
ASHP - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2 (from elect resistance)	9,542,473	1%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF	9,484,123	1%
Smart Thermostat Residential	8,416,472	1%

## Non-Residential

Measure Name	Cumul Savings	% of Savings
VFD on HVAC Fan	76,462,762	10%
LED Linear - Lamp Replacement	45,226,201	6%
VFD on Cooling Tower Fans	37,846,844	5%
SP to ECM Evaporator Fan Motor (Walk-In_ Refrigerator)	32,213,547	4%
Time Clock Control	24,275,272	3%
VFD on process pump	24,227,492	3%
Demand Defrost	23,463,931	3%
Indoor daylight sensor	21,037,384	3%
Evaporator Fan Motor Control	18,380,204	2%
LED High Bay_LF Baseline	17,949,982	2%
LED Linear - Fixture Replacement	14,708,107	2%
Cogged Belt on 40hp ODP Motor	14,223,456	2%
High Volume Low Speed Fan (HVLS)	13,994,054	2%
Cogged Belt on 15hp ODP Motor	13,800,387	2%
Heat pump water heater 50gallon	13,500,199	2%
Energy Star PCs-Desktop	13,419,513	2%
Refrigeration Economizer	12,925,657	2%
High Efficiency PTHP	12,379,547	2%
Air Compressor Optimization	11,928,408	2%
Energy Star Monitors	11,887,261	2%



# Twenty-Five-Year Cumulative Impacts by Measure (Ach.)

## Residential

Measure Name	Cumul Savings	% of Savings
Heat Pump Water Heater 50 Gallons- CEE Advanced Tier	93,082,360	11%
Behavior Modification Home Energy Reports	87,370,432	10%
Heat Pump Water Heater 50 Gallons-ENERGY STAR	75,601,752	9%
Air Sealing	46,378,643	5%
Low-E Storm Window	37,482,555	4%
Energy Star Door	35,780,120	4%
HVAC ECM Motor	33,084,255	4%
Energy Star Desktop Computer	24,499,572	3%
CEE Tier 3 Refrigerator	23,222,336	3%
Ceiling Insulation	22,831,933	3%
ASHP - CEE Advanced Tier: 17.8 SEER/17 SEER2; 10.0 HSPF (from elec resistance)	20,966,078	2%
Air Handler Filter Clean	19,761,469	2%
Energy Star Air Purifier	18,996,523	2%
ASHP - CEE Tier 2: 16.8 SEER/16 SEER2; 9.0 HSPF (from elec resistance)	16,777,552	2%
Properly Sized CAC	15,567,709	2%
ASHP - ENERGY STAR/CEE Tier 1: 16 SEER/15.2 SEER2 (from elect resistance)	15,326,162	2%
Energy Star Freezer	15,176,376	2%
Energy Star LED Directional Lamp Residential	15,037,609	2%
Central AC - CEE Tier 2: 16.8 SEER/16 SEER2	14,149,398	2%
1.60 GPM Low-Flow Showerhead	13,967,484	2%

## Non-Residential

Measure Name	Cumul Savings	% of Savings
LED Linear - Lamp Replacement	80,966,254	10%
VFD on HVAC Fan	64,366,072	8%
VFD on Cooling Tower Fans	34,517,140	4%
LED High Bay_LF Baseline	32,249,159	4%
LED Linear - Fixture Replacement	31,770,409	4%
SP to ECM Evaporator Fan Motor (Walk-In_Refrigerator)	28,392,268	3%
Heat pump water heater 50gallon	26,780,547	3%
Energy Star PCs-Desktop	24,708,748	3%
Cogged Belt on 40hp ODP Motor	23,988,820	3%
Cogged Belt on 15hp ODP Motor	23,254,687	3%
Energy Star Monitors	21,882,581	3%
VFD on process pump	20,954,691	2%
High Efficiency PTHP	18,967,808	2%
Solar Thermal Water Heating System Commercial	18,398,817	2%
Custom Measure - Non-Lighting_65	17,843,078	2%
High Volume Low Speed Fan (HVLS)	17,205,033	2%
Evaporator Fan Motor Control	14,541,982	2%
High Efficiency Welder	14,226,094	2%
Ductless Mini-Split HP	13,189,186	2%
Synchronous Belt on 75hp ODP Motor	11,874,879	1%



# Appendix: Acronyms

# Acronyms

<b>AMI</b>	Advanced Metering Infrastructure
<b>APS</b>	Achievable Potential Study
<b>ASHP</b>	Air Source Heat Pump
<b>BOY</b>	Beginning of Year
<b>CAA 111</b>	Clean Air Act 111
<b>CC</b>	Combined Cycle
<b>CCS</b>	Carbon Capture and Sequestration
<b>CEE</b>	Center for Energy and Environment
<b>CHP</b>	Combined Heat and Power
<b>CPCN</b>	Certificate of Public Convenience and Necessity
<b>CT</b>	Combustion Turbine
<b>DE&amp;I</b>	Diversity, Equity, & Inclusion
<b>DEI</b>	Duke Energy Indiana
<b>DER</b>	Distributed Energy Resources
<b>D-LOL</b>	Direct Loss of Load
<b>DR</b>	Demand Response
<b>DSM</b>	Demand Side Management

<b>ECM</b>	Electronically Commutated Motor
<b>EE</b>	Energy Efficiency
<b>EOY</b>	End of Year
<b>EPA</b>	Environmental Protection Agency
<b>GPM</b>	Gallons per Minute
<b>GW</b>	Gigawatt
<b>HSPF</b>	Heating Seasonal Performance Factor
<b>HVLS</b>	High Volume Low Speed
<b>HEA</b>	House Enrolled Act
<b>ICAP</b>	Installed Capacity
<b>ICCT</b>	International Council on Clean Transportation
<b>ICE</b>	Internal Combustion Engine
<b>ICEV</b>	Internal Combustion Engine Vehicle
<b>IEA</b>	International Energy Agency
<b>IGCC</b>	Integrated Gasification Combined Cycle
<b>IRA</b>	Inflation Reduction Act
<b>IRP</b>	Integrated Resource Plan

# Acronyms

<b>IURC</b>	Indiana Utility Regulatory Commission
<b>kV</b>	Kilovolt
<b>kW</b>	Kilowatt
<b>kWh</b>	Kilowatt-hour
<b>lb</b>	Pound
<b>LMP</b>	Locational Marginal Pricing
<b>MISO</b>	Midcontinent Independent System Operator
<b>MPS</b>	Market Potential Study
<b>MW</b>	Megawatt
<b>MWh</b>	Megawatt-hour
<b>NG</b>	Natural Gas
<b>ODP</b>	Open Drip-Proof
<b>OSB</b>	Oversight Board
<b>PTHP</b>	Packaged Terminal Heat Pump
<b>RES</b>	Residential
<b>RFP</b>	Request for Proposal
<b>SEER</b>	Seasonal Energy Efficiency Ratio

<b>SMR</b>	Small Modular Reactor
<b>T&amp;D</b>	Transmission & Distribution
<b>TWh</b>	Terawatt-hour
<b>UCAP</b>	Unforced Capacity
<b>UCT</b>	Utility Cost Test
<b>VFD</b>	Variable Frequency Drives



# Duke Energy Indiana's 2024 Integrated Resource Plan Engagement Session

## AUGUST 13, 2024, MEETING SUMMARY

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## Meeting Information

On Tuesday, August 13, 2024, Duke Energy Indiana convened the fourth stakeholder meeting to inform the development of the 2024 Duke Energy Indiana Integrated Resource Plan ("IRP"). The meeting was held virtually. Approximately 63 external individuals representing over 38 organizations participated in this session.

## Facilitation Process

To encourage collaboration and to foster an environment where diverse perspectives could be shared, 1898 set forth the following ground rules for the session:

- **Respect each other:**  
Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve a better understanding and develop robust solutions.
- **Focus on today's topics:**  
Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.
- **Chatham House Rule:**  
Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

## Session Participation

This virtual event was facilitated by 1898 & Co., and the session included presentations and robust conversations on the following topics:

- Feedback from the Third Public Engagement Session
- RFP Update
- Updated Portfolio Modeling
- Preliminary Scorecard
- Energy Market Interaction and Stochastic Modeling

Virtual attendees used the "raise hand" feature in Teams to ask a question or make a comment aloud or submitted questions through the "Q&A" feature. Virtual attendees had access to the "chat" feature in Teams to share links to information and communicate with each other. Staff from 1898 & Co. took meeting notes, which have been included in the summary. Pursuant to the ground rules, the notes have been anonymized.

If participants had questions after the session or wanted to share feedback or additional information, they were asked to send an email to [DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com).



## Access to Meeting Materials

Meeting materials for the August 13, 2024 engagement session were posted to Duke Energy Indiana's IRP website at [duke-energy.com/IndianaIRP](https://duke-energy.com/IndianaIRP) August 6, 2024. Participants were asked to visit the website to view the materials and meeting summaries. The 1898 & Co. team will continue to contact stakeholders via email as the website is updated with materials for each session.

## Meeting Notes

This document includes a high-level summarization of the presentation material as well as the questions and comments made by participants. The questions and comments were captured throughout the meeting; however, the summary herein does not constitute a meeting transcript. Questions and commentary were edited for clarity as needed. Similar summaries will be prepared following each public engagement session throughout this process.

## Safety

*Karen Hall, Duke Energy Resource Planning Director*

Ms. Hall provided a safety moment on cybersecurity attacks and the potential threats of vishing, smishing, and quishing.

## Welcome

*Stan Pinegar, Duke Energy Indiana State President*

Mr. Pinegar opened the meeting by welcoming attendees, thanking them for their participation, and encouraging active engagement in the 2024 IRP process.

## Introductions

*Karen Hall, Duke Energy Resource Planning Director*

Ms. Hall introduced the Duke Energy teammates who are supporting the 2024 IRP.

## Meeting Guidelines & Agenda

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk discussed the ground rules for the virtual meeting. These guidelines included respecting each other, staying on topic, and the Chatham House Rule. He also reviewed guidelines for audience participation and the meeting agenda.

## Stakeholder Feedback and Incorporation

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk provided an overview of stakeholder feedback that was received and incorporated into the agenda for the fourth Public Engagement Session and when this feedback would be discussed in the meeting. He then covered additional feedback and the responses from Duke Energy Indiana, which included topics such as resource availability assumptions, firm gas transportation, and other IRP modeling questions.

### Q&A related to Stakeholder Feedback and Incorporation

1. Question: Is Duke Energy Indiana planning able to provide additional details on the build-up of firm natural gas transportation costs?
  - a. The total costs for firm natural gas transportation are included in the modeling and have been provided to technical stakeholders. Some of the details of the build-up are confidential, so Duke Energy Indiana is unable to disclose them at this time.
2. Question: Is Duke Energy Indiana considering running a sensitivity that would include potential significant increases in load due to data centers?
  - a. Yes, the high load sensitivity includes economic development for data centers.
3. Question: Is the storage capacity in the model the maximum for each year or incremental?
  - a. It is the maximum for each year.

## RFP Update

*Robert Lee, Vice President, Charles River Associates*

Mr. Lee provided an overview of Duke Energy Indiana's all-source Request for Proposal (RFP). He explained that the RFP accepted bids for power purchase agreements (PPA), build transfer agreements (BTA), and existing asset sales. Mr. Lee outlined the evaluation criteria, including proposal economics, reliability and deliverability, development, and asset-specific benefits/risks. He presented the RFP results by technology type and noted that most projects were in MISO LRZ 6, which was preferred as part of the RFP. Mr. Lee then reviewed the pricing of the RFP proposals. Mr. Lee explained how the IRP and RFP studies are separate but are both parts of the asset selection process.

### Q&A related to RFP Update

1. Question: Can you provide more information on the updates to the IRP modeling regarding the RFP bids?
  - a. EnCompass was initially evaluating and selecting from a large number of very similar resources, which increases the complexity of the solution that the model must solve. So, we have updated the model to select from generic resources for the different technologies. The costs for the generic resources are still informed by the data from the RFP.

2. Question: What is the difference between RFP bids previously modeled and the resources being modeled now?
  - a. The projects modeled previously were an aggregate of RFP bids, and now the model is selecting the generic resources.
3. Question: Please explain how a single tranche by resource type is created?
  - a. Benchmarking is done to ensure that the generic curves fall in the range of the costs from the RFP bids. Additional RFP cost information, including the benchmarking of the generic curves, has been provided to technical stakeholders subject to an NDA.
4. Question: Regarding the thermal resource RFP, what types of generation bids were submitted.
  - a. There were shorter term Power Purchase Agreements for a few different resources outside of Local Resource Zone 6 and several self-build options including Combined Cycle Gas Turbines (CCGTs) with different in-service dates.
5. Question: Were all the thermal resources natural gas resources?
  - a. Yes, all the thermal resources were natural gas.
6. Question: What is the total nameplate capacity for each technology?
  - a. The total installed capacity (ICAP) for Solar projects is 5,145 MW, while proposals account for 14,308 MW. Solar + Storage projects contribute 4,612 MW, with proposals adding up to 6,954 MW. Wind projects have an installed capacity of 1,777 MW, and proposals contribute 3,507 MW. Thermal projects provide 5,105 MW, with proposals amounting to 11,116 MW. Finally, Storage projects contribute 2,001 MW, with proposals adding up to 4,400 MW. In total, the combined ICAP for all technologies is 18,602 MW by project and 40,254 MW by proposal.
7. Question: Are the MWs provided for seasonal accredited capacity?
  - a. No, those numbers represent the installed capacity.
8. Question: How is a project defined?
  - a. A project is an individual site.
9. Question: What stage are the RFP projects in?
  - a. Some RFP projects are in development, and most are already in the MISO queue, though that was not a requirement of the RFP.
10. Question: How would the passage of the Barrasso/Manchin Energy Permitting Act of 2024 affect the RFP with respect to solar and wind capacity?
  - a. The Barrasso/Manchin Energy Permitting Act of 2024 is still a bill and is not current legislation, so it would not be considered in the RFP at this stage. However, the Aggressive Policy & Rapid Innovation scenario in the IRP assumes transmission and queue reforms are enacted that enable higher annual interconnection ("resource availability") of renewable resources in the IRP modeling. The effect of permitting reform would be captured by proxy, along with other uncertainties, through the scenario analysis.
11. Question: Are the RFP asset sale prices shown in the RFP summary table on slide 23 a \$/kW basis or an LCOE basis?

- a. These are on a \$/kW basis and are calculated by dividing the costs of purchasing the asset by the capacity of the resource.
12. Question: What does the count of asset sales represent on slide 23?
- a. That count represents the number of different options available, including self-build options.

## Updated Portfolio Modeling

*Nate Gagnon, Managing Director Midwest IRP*  
*Matt Peterson, Lead Resource Planning Analyst*

Mr. Gagnon provided an overview of the analytical framework for the IRP, which includes the generation strategies and worldviews (Reference, Aggressive Policy & Rapid innovation, and Minimum Policy & Lagging Innovation), resulting in 18 scenario portfolios. He added that with additional strategy variations, portfolio sensitivities, production cost sensitivities, and a supplemental stakeholder portfolio, the total number of resource portfolios modeled exceeds 40. Mr. Gagnon then reviewed the different generation strategies—convert/co-fire coal, retire coal, convert Cayuga, co-fire Gibson, incremental generation, exit coal earlier, and “No EPA 111”—and specifically addressed how they relate to the Cayuga, Gibson, and Edwardsport units in terms of retirement, co-firing, and natural gas conversion. He emphasized that while these strategies have unit-specific assumptions in the IRP, detailed studies will be conducted before the execution phase to validate these assumptions.

Mr. Gagnon then presented preliminary results for the strategies under the reference scenario, covering unforced capacity (UCAP), energy mix, and preliminary PVRs. He highlighted that renewables make up a sizable portion of total energy across all cases, but in most portfolios, a substantial portion of the accredited capacity is thermal resources. He also discussed that in strategies involving the converted and co-fired units, these units become less competitive in the energy market, leading to the use of MISO energy market purchases to reduce costs. Additionally, he noted that the PVRs for the generation strategies are generally close, except for the “No EPA 111” strategy, which is not necessarily directly comparable to the others.

Mr. Peterson provided a summary of the individual generation strategies, focusing on the Reference, Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation worldviews. He shared results related to installed capacity, carbon emissions, and energy mix over time and offered an overview of each strategy.

Mr. Gagnon discussed the preliminary high-load sensitivity analysis and mentioned that a low-load sensitivity analysis is also underway. He pointed out that the forecasted peak load shape changes in the high load sensitivity due to assumptions around industrial load and data centers.

Mr. Gagnon then reviewed the IRP planning process, emphasizing that uncertainty increases over time within the planning period. He also discussed the key considerations and sources of uncertainty in developing the short-term action plan for the 2024 IRP, including balancing the retirement, natural gas conversion, and co-firing of existing coal units, as well as balancing the five IRP pillars when considering new resource additions. He outlined a few sources of uncertainty, including regulatory, demand, market, and supply chain assumptions.

## Q&A related to Updated Portfolio Modeling

1. Question: Is Duke Energy considering burning natural gas instead of coal at Edwardsport?
  - a. In all the EPA 111-compliant strategies, the conversion of Edwardsport to natural gas takes place in 2030, and in the “No EPA 111” strategy, that conversion takes place in 2035. Edwardsport can burn gas, but the unit is optimized to burn syngas, so its maximum unit output is lower when Edwardsport burns natural gas. With the projected load growth in zone 6, derating Edwardsport in the near term increases the need for capacity.
2. Question: Is there an expected capacity derate when converting the Cayuga and Gibson units to natural gas?
  - a. No. Derates for those units are not expected.
3. Question: Are batteries being considered in the model, and can they provide system reliability benefits similar to thermal resources?
  - a. Yes. Batteries can provide several benefits to a resource portfolio, and they increase as part of the UCAP mix over the planning period. However, batteries do not generate energy, so, while they can provide system reliability benefits, there are significant differences between batteries and thermal generators in terms of contributions to the system.
4. Question: What is the discount rate assumption for PVRR calculations?
  - a. It is assumed to be the utility's weighted average cost of capital, which is 7.07%.
5. Question: Is the rate base investment of the coal capacity included in the PVRR?
  - a. No, because depreciation of existing assets is consistent across all generation strategies and portfolios. The cost of converting units to natural gas or enabling them to co-fire is reflected in PVRR. The PVRR metric is intended to help show the differences in cost between the generation strategies.
6. Question: What is IVVC?
  - a. IVVC is Integrated Volt/VAR Control, which manages voltage and power factor on distribution circuits.
7. Question: Is a carbon capture and sequestration (CCS) investment being made and included in the analysis?
  - a. CCS will be evaluated at Edwardsport, but the generation strategies themselves do not include CCS. There are selectable combined cycle resources with CCS available for selection in the model, but the model is not currently selecting them.
8. Question: What does the negative ICAP represent in the generation strategy summaries?
  - a. The negative ICAP shows retired unit capacity.
9. Question: Why do the CO<sub>2</sub> emissions over time appear higher in the short-term and comparable in the long-term between the Retirement and Co-Fire/Conversion scenarios?
  - a. All strategies will have similar resources in the first few years of the planning period. In the late 2020's this starts to deviate across the strategies as there are changes in the existing resource assumptions. The co-fire and conversions in the EPA 111-compliant strategies will take place by 2030. Under the retire coal

strategy, the Gibson units continue to operate on coal and retire by 1/1/2032. These differences in existing resource retirement, conversion, and co-firing timing as well as the resource mix, leads to the emission results varying in the middle of the planning horizon. Later in the planning period, coal is replaced by more efficient combined cycles and/or renewables, resulting in similar reductions across all generation strategies.

10. Question: Is consideration being given to the effects of continuing cost increases as it impacts rates in the PVRR modeling?
  - a. Rate impact calculations are a metric in the scorecard. However, in those rate impact calculations, the costs will reflect the impacts within the scope of the IRP. Other system costs that are the same across strategies will not be included in the calculation.
11. Comment: Commenter is concerned that the rate-based value of existing coal units is not fully considered in this analysis.
12. Comment: Commenter does not believe that the comparison of relative NPVs provides a good indication of affordability.
13. Question: Why are CO<sub>2</sub> equivalent emissions not included for transport and methane leakage from natural gas pipes?
  - a. We do not have data specific to each potential resource portfolio, nor do we have a means of projecting upstream emissions over the planning horizon, so we've not included these metrics in the IRP
14. Question: Will Duke Energy Indiana share its assumptions around power purchase pricing?
  - a. The methodology and results for power price development were discussed at Stakeholder Meetings 2 and 3. The modeling files and data for the National Database used to develop the power price assumptions were also provided to technical stakeholders on the DataSite, subject to non-disclosure agreements.
15. Question: How much data center load is included in the high load sensitivity?
  - a. The high load sensitivity includes 507 MW of new data center load by 2031.
16. Question: How much does EV adoption impact your storage projections?
  - a. The EV forecast contains assumptions around EV charging, but there is still a lot of uncertainty around vehicle-to-grid technology at enough scale to impact storage projections so it is a bit early for that to be included in the IRP.

## Preliminary Scorecard

*Nate Gagnon, Managing Director Midwest IRP*

Mr. Gagnon started by providing an explanation of each scorecard metric and how they are calculated and emphasized that the purpose of these metrics is to assist in distinguishing between the IRP portfolios. He then requested that scorecard feedback be emailed to [DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com) for consideration. He also reviewed potential updates to the fast start, spinning reserve, and environmental metrics based on stakeholder feedback.



Mr. Gagnon then provided a detailed look at PVRR and initial observations. He emphasized that in the Aggressive Policy & Rapid Innovation worldview, variables such as increased fuel costs and implementation of a CO2 tax result in higher PVRRs for all strategies, with the opposite being true for the Minimum Policy & Lagging innovation worldview. He also pointed out that preliminary results for the Reference worldview suggest limited variability in total portfolio costs.

Mr. Gagnon reviewed preliminary results for CO2 emissions reduction for both 2035 and 2044. He also emphasized that the energy market purchases also influence the total portfolio CO2 emissions.

### Q&A related to Preliminary Scorecard

1. Question: Why do the reliability metrics drop below 100% for the Retire Coal and Exit Coal Earlier portfolios when all portfolios have market purchases?
  - a. This metric looks at MW (capacity), not the MWh (energy). It looks at the capacity of thermal and energy storage resources on the system as a percentage of the summer peak load in 2035.
2. Question: Is the Herfindahl–Hirschman index calculated using installed capacity or UCAP?
  - a. This calculation is based on installed capacity.
3. Question: Why are the reliability metrics based on installed capacity?
  - a. Installed capacity is used because both energy and capacity are needed and installed capacity provides a better sense of the total scale of the system.
4. Comment: I think the execution risk metrics should use both installed capacity and UCAP.
5. Question: Has Duke Energy Indiana considered producing a 10-year and 20-year NPV?
  - a. The Customer Bill Impact CAGR will be shown in 2030 and 2035. This should provide a sense for the portfolio costs at the midpoint of the study period. Annual revenue requirements will be included in the final IRP document as well.

### Energy Market Interaction & Stochastic Modeling

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co*  
*Ameya Deoras, Manager of Quantitative Analytics*  
*Nate Gagnon, Managing Director Midwest IRP*

Mr. Burczyk provided an overview of the MISO energy market, explaining the process of selling and purchasing energy within the market. He described the two-part simulation used in the IRP model: capacity expansion and production cost. The capacity expansion model requires Duke Energy Indiana to serve 75% of its customers' energy needs with its own generation. However, the production cost model does not impose any targets for meeting customer energy needs. The production cost step inherits the portfolio from the capacity expansion step but dispatches the portfolios more granularly, based on economics, like the real-world MISO energy market and unit dispatch.

Mr. Deoras gave an overview of the stochastic modeling methodology used in the IRP, emphasizing that the goal is to simulate quantifiable uncertainties based on historical

observations or forward-looking market data. He explained that SERVIM is used for reliability modeling, creating historical load data that is then fed into PowerSIMM to simulate hourly power prices. He presented data from these simulations, including Henry Hub and Indiana Hub hourly gas prices, as well as the market-implied heat rate. He noted that in these simulations, power price increases do not keep pace with gas price increases.

Mr. Deoras then shared the generation and net purchases results from the stochastic modeling. He pointed out that while net purchases appear high, this reflects the market's potential to offer more economic prices for customers rather than an inability to generate the necessary power.

### Q&A related to Energy market interaction & Stochastic Modeling

1. Question: Please describe, in detail, the EnCompass assumptions regarding MISO Capacity.
  - a. Technical stakeholders have received access to the National Database, which has full visibility into these assumptions. Additionally, these assumptions were discussed in the second public stakeholder meeting, and the results were shared at the third public stakeholder meeting.
2. Question: Why is data displayed in the 10<sup>th</sup> to 90<sup>th</sup> percentile range?
  - a. This range is standard for statistical graphs because of potential outliers. The mean will still include all data points.
3. Question: How are the risks of data center load considered as part of the stochastic analysis?
  - a. Higher loads typically result in higher prices, which is considered in the stochastic analysis.
4. Question: What is driving the overall shift beginning in 2028, where Duke Energy generation produces lots of energy, to the company purchasing significant amounts of energy later in the study period?
  - a. The shift from Duke Energy Indiana's units generating significant energy in 2028 to purchasing power later in the study period is driven by many factors. Power prices come out of the National Database modeling, which looks at the entire Eastern Interconnect. Over time, there is a greater saturation of renewables across the Eastern Interconnect, which drives the implied market heat rate down. Also, depending on the generation strategy, the steam units have been converted to natural gas units or co-fire in several cases. These converted units are expected to operate differently in the market than in the early years of the planning period when they operate on coal.
5. Question: Is anything from the consumer side factored into these models?
  - a. The impact is seen in the load. If customers generate more, the load that the Duke Energy Indiana system must serve decreases. Behind-the-Meter (BTM) solar is one of the considerations in the Aggressive Policy & Rapid Innovation worldview.

# 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 4

*August 13, 2024*



BUILDING A **SMARTER** ENERGY FUTURE®



# Safety



# Safety Moment: Preventing Cybersecurity Attacks

## Cyberattacks are not Limited to Email



Phishing is a social engineering attack attempting to trick you into revealing sensitive information. Voice phishing, or **vishing**, using phone calls. Text phishing, or **smishing**, leverages text messages. QR phishing, or **quishing**, involves QR codes that direct you to a bad actor's website, which may appear legitimate.

### Avoid falling victim by following these tips:

- **Don't trust caller ID.** Cybercriminals use a tactic called ID spoofing to have the call appear to be originating from a trusted source.
- If you suspect that a call is from an illegitimate source, **hang up**.
- If a text message seems suspicious, avoid replying and **block the number**.
- **Do not scan QR codes** from untrusted emails, posters, or other physical locations.
- Join the Federal Trade Commission's National Do Not Call Registry at [donotcall.gov](https://www.donotcall.gov)

Sources: <https://www.uspis.gov/news/scam-article/quishing>  
<https://www.cisecurity.org/insights/newsletter/vishing-and-smishing-what-you-need-to-know>



# Welcome

## Stan Pinegar

State President, Duke Energy Indiana





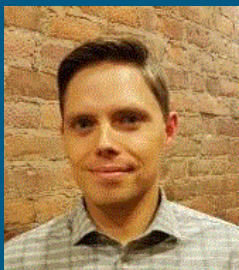
# Introductions

# Duke Energy Team

## Integrated Resource Planning Team



**Matt Kalemba**  
*Vice President,  
Integrated Resource  
Planning*



**Nate Gagnon**  
*Managing Director,  
Midwest Integrated  
Resource Planning*



**Matt Peterson**  
*Resource  
Planning Manager*



**Emma Goodnow**  
*Market Strategy &  
Intelligence Director*



**Karen Hall**  
*Resource  
Planning Director*



**Chris Hixson**  
*Principal Engineer,  
Resource Modeling*



**Josh Paragas**  
*Engineer, Resource  
Modeling*



**Tyler Cook**  
*Engineer, Resource  
Modeling*

## Indiana Regulatory and Legal Team



**Kelley Karn**  
*Vice President,  
Indiana Regulatory  
Affairs and Policy*



**Beth  
Heneghan**  
*Deputy General  
Counsel*



**Liane Steffes**  
*Associate  
General Counsel*



**Dan Symphon**  
*Generation and  
Regulatory Strategy  
Director*

## RFP



**Drew Burczyk**  
*Consultant, Resource  
Planning & Market  
Assessments*

## 1898 & Co.



# Agenda

# Public Stakeholder Meeting #4 Agenda

Time	Duration	Present   Q&A	Topic	Presenter
9:30	5	5   0	Welcome & Safety	Stan Pinegar, Duke Energy Indiana State President Karen Hall, Duke Energy Resource Planning Director
9:35	5	5   0	Meeting Guidelines & Agenda	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:40	25	15   10	Stakeholder Feedback & Incorporation	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:05	25	15   10	RFP Update	Robert Lee, Vice President, Charles River Associates (CRA)
10:30	10	-	BREAK	
10:40	60	30   30	Updated Portfolio Modeling	Nate Gagnon, Duke Energy Managing Director Midwest IRP Matt Peterson, Duke Energy Lead Resource Planning Analyst
11:40	40	-	BREAK	
12:20	30	15   15	Updated Portfolio Modeling (cont.)	Nate Gagnon, Duke Energy Managing Director Midwest IRP
12:50	30	15   15	Preliminary Scorecard	Nate Gagnon, Duke Energy Managing Director Midwest IRP
1:20	5	-	BREAK	
1:25	25	15   15	Preliminary Scorecard (cont.)	Nate Gagnon, Duke Energy Managing Director Midwest IRP
1:50	25	15   10	Energy Market Interaction & Stochastic Modeling	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co. Ameya Deoras, Duke Energy Manager Quantitative Analytics
2:15	40	0   40	Open Q&A	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
2:55	5	5   0	Next Steps	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
3:00			Adjourn	



# Meeting Guidelines



# Meeting Ground Rules



## **Respect each other:**

Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

## **Focus on today's topics:**

Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.

## **Chatham House Rule:**

Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).



# Participation



There will be several opportunities throughout the presentation for attendees to actively participate by asking questions, making comments and/or otherwise sharing information.

- **Q&A:** Please use the “Q&A” feature, on the menu at the bottom of your screen, to submit questions to the presenters. We will respond to as many of these as possible, time permitting, during designated time periods.
- **Raise hand:** If you wish to ask a question or make a comment orally, please use the “raise hand” feature, during designated time periods. A facilitator will call on you and invite you to unmute.
- **Chat:** The chat feature is enabled for sharing information and resources with other participants; however, it is sometimes difficult to monitor. If you would like a response from the presenters, please use the Q&A or raise hand features.



# Stakeholder Feedback and Incorporation

# Stakeholder Feedback Received & Incorporated into Meeting #4 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
What do market purchases in the results represent?	Market Purchases Overview
In terms of the market being less expensive than generation in house, is that the case now?	Market Purchases Overview
Can the model add more resources to the portfolio in order to decrease energy market purchases, even if the capacity is not needed in the portfolio?	Market Purchases Overview
How does the RFP inform the IRP modeling?	RFP Update
Is there a revised timeline for responses to the RFP?	RFP Update

# Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
Will any future meetings be held in person?	The third meeting was shifted to a hybrid meeting (in person and virtual options). We initially planned to hold the 5 <sup>th</sup> meeting as a hybrid meeting. Asking for your feedback given in-person attendance of meeting 3. Please provide additional input on what meeting format works best, so we can accommodate preferences on how we can make this process most successful.
What costs are included in your firm transport assumptions for natural gas?	Our FT cost assumption includes all costs associated with delivering firm gas to the site in question. This is inclusive of expected pipeline upgrades and construction or upgrading of the lateral and achieving required delivered pressures (compression and/or regulation and heating).
Are combined cycles assumed to be dual fuel capable?	Yes, generic combined cycles included in the modeling are dual fuel capable and have on-site ultra-low sulfur diesel storage on-site.
What is the first year that storage resources are allowed to be selected in the model?	Battery energy storage resources can be selected in the model beginning 2028.
Will new demand response (DR) resources be included as options in the IRP model?	Contributions from existing and forecasted demand response resources are inputs to the IRP model rather than being selectable resource options.
What is the data source for the CT and CC capital costs?	CT and CC capital costs come from the Generic Unit Summary (GUS). Several sources are used to develop the prices in the GUS, including third party vendor forecasts, which are benchmarked against public sources and data from RFPs.
What is the source for CCS O&M assumptions?	CC w/ CCS O&M costs were provided by Burns and McDonnell as part of the Generic Unit Summary process.

# Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Info	Response/Update
In addition to the increased resource availability limits for Solar & Wind shared in Meeting 3, will Storage availability be increased in model?	<p>There are no plans to increase the assumed energy storage availability at this time. Resource availability assumptions take into account interconnection, supply chain, and plan executability. Potential relief in any one of these areas alone may not justify increasing the assumed pace at which new storage resources could be added to system.</p> <p>As a reminder, energy storage, including SPS, is selectable in the following amounts:</p> <p>Reference case –</p> <ul style="list-style-type: none"> <li>• 2028-2029: 500 MW/yr</li> <li>• 2030+: 1,000 MW/yr</li> </ul> <p>Aggressive case –</p> <ul style="list-style-type: none"> <li>• 2028-2029: 500 MW/yr</li> <li>• 2030-2031: 1,700 MW/yr 4-hour and 100 MW/yr 10-hour</li> <li>• 2032+: 1,700 MW/yr 4-hour and 500 MW/yr combined total of 10-hour, 100-hour</li> </ul> <p>Also note that in modeling conducted to date, these assumptions do not constrain model selection of energy storage in any but a few years.</p>
Model EV and data center load profiles explicitly in SERVVM	It may be appropriate to consider this step in future IRPs as the temperature sensitivity of these loads becomes better understood, but the 2024 effort must remain focused on completion of the core analysis.
Will DEI provide estimated Scope 3 emissions for each case?	CO <sub>2</sub> emissions projections include estimated emissions associated with MISO energy market purchases.



# Q&A





# RFP Update

# DEI 2023/2024 Request for Proposals (RFP) Status

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## **All Source**

- Two targeted RFPs issued concurrently: Intermittent (renewable) & Non-Intermittent (thermal and storage)
- RFP bid selection compared assets within categories based on both quantitative and qualitative criteria
- Capacity targets initially informed by IRP process and finalized based on recent IRP modeling
- Accepted Structures: Purchase Power Agreements (PPA), Build Transfer Agreements (BTA), Existing Asset Sale

## **Role of CRA as the Independent Third-Party Administrator**

- Acted as RFP Manager facilitating the RFP process
- Reviewed proposals to ensure they conform with basic threshold requirements
- Independently evaluated bids according to pre-specified criteria
- Managed bidder communication and marketing
- Provided utility with a ranked list of projects by type to consider for advancement
- Duke Energy Indiana and CRA collaborate on additional due diligence for final selections and contracting

## **Schedule (Current)**

- Advanced due diligence / Contract negotiations: July / August 2024
- Internal approvals for earliest projects / Definitive agreements signed: Q3 / Q4 2024
- First round of certificates of public convenience and necessity (CPCNs) filed: Late 2024 or first half 2025

# DEI 2023/2024 RFP – Product Definition

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## **Intermittent Generation**

- Stated Need: Up to 2,500 MW (ICAP) in-service by 12/31/2032
- New or existing resources using proven technologies with technology specific minimum capacities
- Resource type examples: Solar, wind, standalone storage, hybrid with storage

## **Non-Intermittent Generation**

- Stated Need: Up to 2,500 MW (ICAP) in-service by 12/31/2032
- New or existing resources using proven technologies with no stated minimum capacity
- Resource type examples: Thermal (CT, CC, Industrial STG, no coal), standalone storage, system sales
- Firm fuel supply required

## **Definitions common to intermittent and non-intermittent generation**

- Structures: Purchase Power Agreements (PPA), Build Transfer Agreements (BTA), Existing Asset Sale;
- PPA / useful life min length 3 to 5 years
- Strong preference for MISO Zone 6 NRIS Qualified (Firm) Capacity
  - ❑ Exceptions considered for wind resources or for PPA bids if there are limited in-zone options

# DEI's 2023/2024 RFP Evaluation Criteria

## PRICE

## NON-PRICE



### Proposal Economics

(30% / 300 points)

**300 points:** The total points available under the evaluation category will be calculated using a **levelized cost of energy or levelized cost of capacity basis utilizing a 30-year period**

Other proposals will receive a percentage discount off points based on the proposal's cost premium versus the lowest cost proposal

Capital costs will include the asset purchase price, interconnection costs, and projected CAPEX requirements over asset

Operating costs will include annual fixed and variable O&M costs, fuel and emissions costs and all other costs including taxes, service agreements and fixed pipeline charges

The market value of facility output will be based on DEI's internal modeling and analysis of the Indiana and broader MISO region

If asset is not in service or under Duke Energy Indiana ("DEI") control at any point within the 30-year period, **the levelized cost will reflect market purchases of energy and capacity**



### Reliability and Deliverability

(30% / 300 points)

**300 points:** All proposals will initially be allotted full points. Points will be subtracted based on an assessment of **environmental reliability, age and outage history, and fuel reliability**

**(50) points:** preference for advance class turbines

**Facility Age and Demonstrated Reliability** will be evaluated. Reliability will be based in observed vs projected UCAP and EFORd vs standards for the MISO asset classes

**(10) points:** Each year in service beyond **technology specific benchmark**

**(100), (50) and (25) point** deductions for High, Medium and Low-risk assets respectively based on outage history.

**(100) point** deduction based on an assessment of **of fuel security and reliability** at thermal assets. The evaluation metric will consider:

- An assessment of the "firm fuel" availability, facility infrastructure and fuel access
- An assessment of potential fuel price volatility.



### Development

(20% / 200 points)

Four milestones have been selected and **15 Points** will be awarded for each:

1. MISO Queue number
2. Completed MISO System Impact Study
3. Completed MISO Facilities Study or using MISO generator interconnection agreement (GIA) Process
4. Completed a MISO GIA

All projects are required to have achieved site control and have a feasible plan for zoning

**20 points:** Completed all environmental studies / permits - impacted species, mitigation, conservation plans, etc.

**20 points:** EPC Contract awarded

**100 points:** Developers that have placed **1,000 MW ICAP or more of capacity** into service in MISO

Other developers will receive points based on the following formula: **(MW in service/1,000) \* 100 rounded to the nearest full point**



### Asset Specific Benefits / Risks

(20% / 200 points)

**100 points:** Facilities with no material risks

**100 points:** Facilities will receive points for project specific benefits including but not limited to

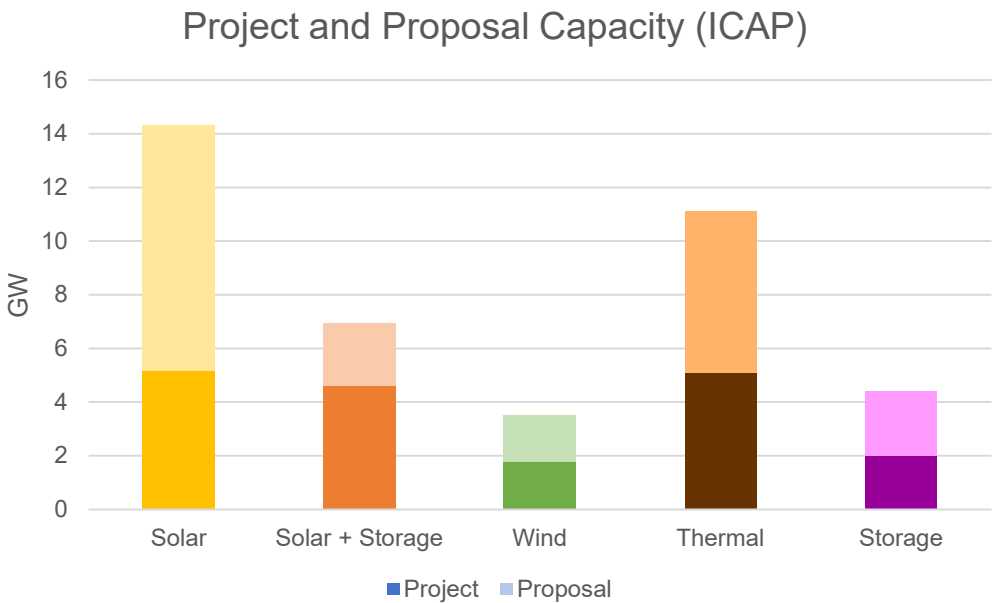
- Black start capability
- Operating flexibility and optionality provide by storage assets
- Ability to integrate with DEI's corporate and operating frameworks

**25 points:** MBE diversity and community benefits each

- MBE (Minority Business Enterprise) or a WBE (Women's Business Enterprise) or a Veteran Owned Business
- Just Transition - Replacement generation in communities that have been impacted by other generation retirements
- Environmental Justice - New generation not impacting lower income communities disproportionately
- Positive Impact on local community DEI's serves (IN business / labor, environmental)

# DEI 2023/2024 RFP – Overview of Bids

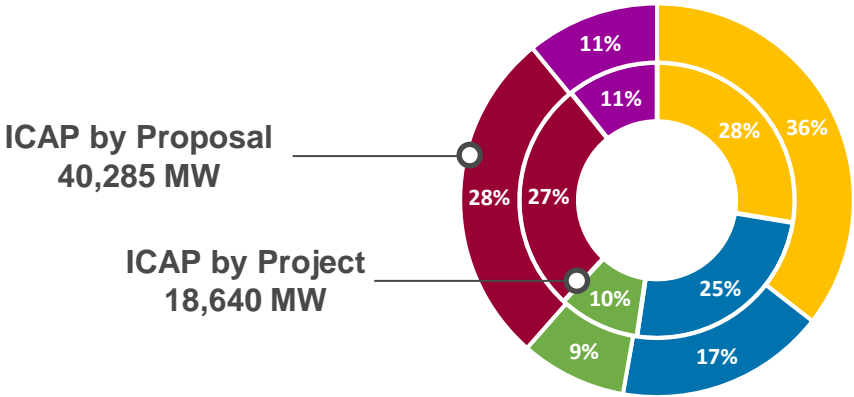
- 68 individual projects across six states with 18.6 GW (ICAP) represented
- 160+ different proposal structures between the 68 projects, totaling 40.3 GW (ICAP)



Note: Darker shade indicates Project GW, which are a subset of Proposal GW

Allocation by Technology Type (ICAP)

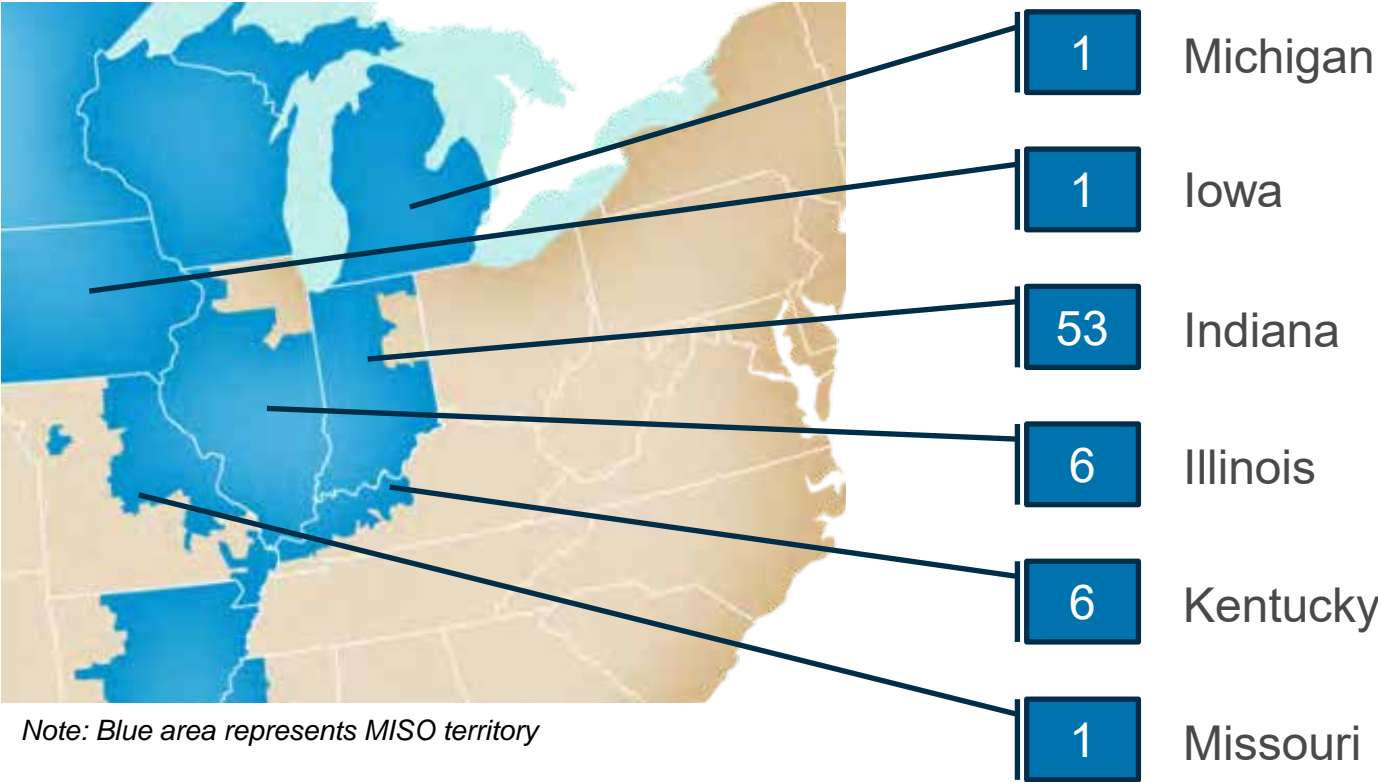
	ICAP by Project		ICAP by Proposal	
	MW	%	MW	%
Solar	5,145	28%	14,308	36%
Solar + Storage	4,612	25%	6,954	17%
Wind	1,777	10%	3,507	9%
Thermal	5,105	27%	11,116	28%
Storage	2,001	11%	4,400	11%
Total (MW)	18,602	100%	40,254	100%



# DEI 2023/2024 RFP – Distribution of Projects Received

- 68 individual projects across six states with 18.6 GW (ICAP) represented
- Sums below account for the largest MW proposal option of a given project

Project MIN of ICAP and POI (MW)						
	Solar	SPS	Wind	Thermal	Storage	Total
IL	150	0	947	537	0	1,634
IN	4,695	4,462	110	3,332	1,601	14,162
IA	0	0	230	0	0	230
KY	300	150	200	0	400	1,050
MI	0	0	0	1,236	0	1,236
MO	0	0	290	0	0	290
Total	5,145	4,612	1,777	5,067	2,001	18,602





# DEI 2023/2024 RFP – Summary of Pricing

## Average Weighted Pricing by Technology and Deal Structure

Technology	Asset Sale (BTA)		Power Purchase Agreement			
	\$/kW	Count	\$/MWh	\$/kW-mo	\$/kW-yr	Count
Solar	\$ 2,099.79	10	\$ 67.53			73
Solar + Storage	\$ 3,360.14	8	\$ 68.69			22
Wind			\$ 66.09			15
Thermal	\$ 1,665.42	8		\$ 11.64		5
Storage	\$ 1,931.26	7			\$ 158.14	20

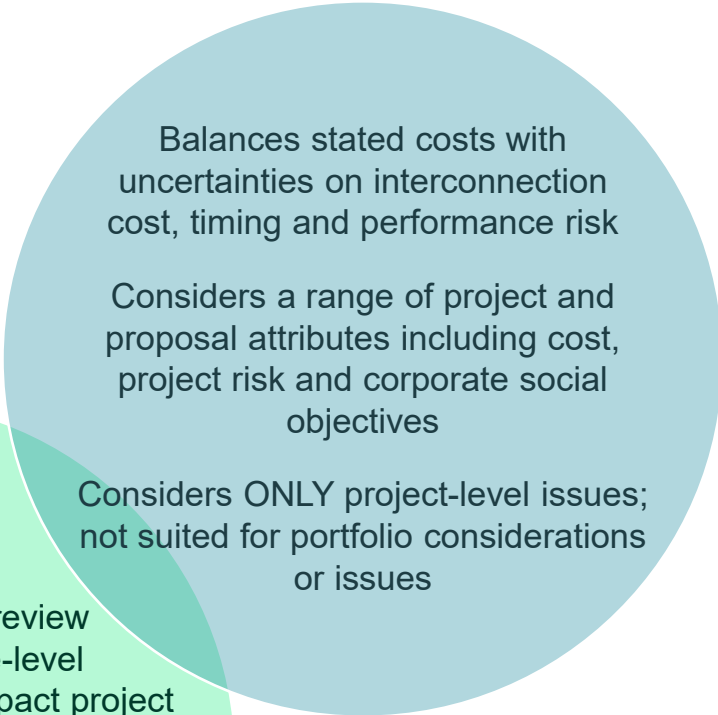
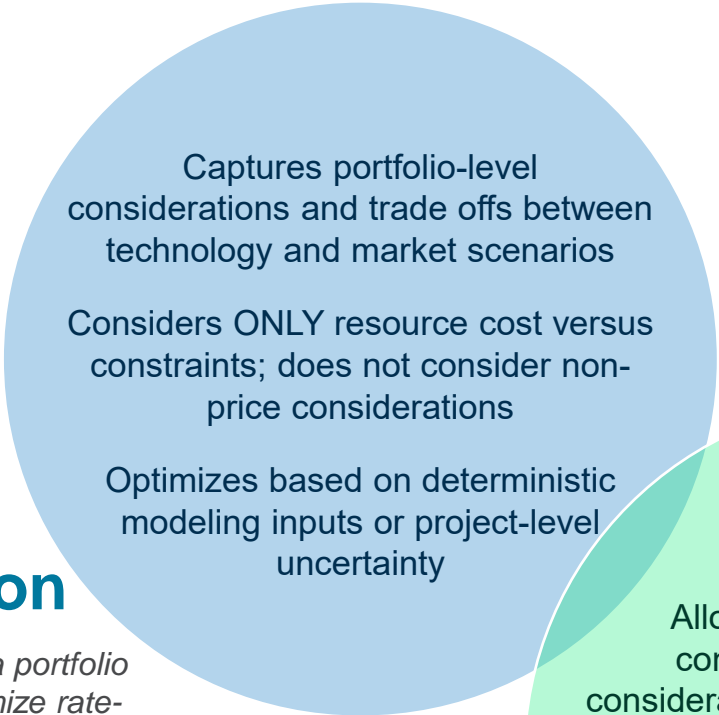
*This table reflects proposals received (not projects). Some proposals are mutually exclusive or have been bid as both Asset Sale and PPA.*

- Average bid prices shown for ‘Asset Sale’ represent capital costs and exclude on-going fuel and O&M
- Figures shown are for representation and do not purport competition between technologies; Separate short-listed assets are created for each RFP event
- All information is preliminary and subject to further review

# DEI 2023/2024 RFP – Considerations on Asset Selection

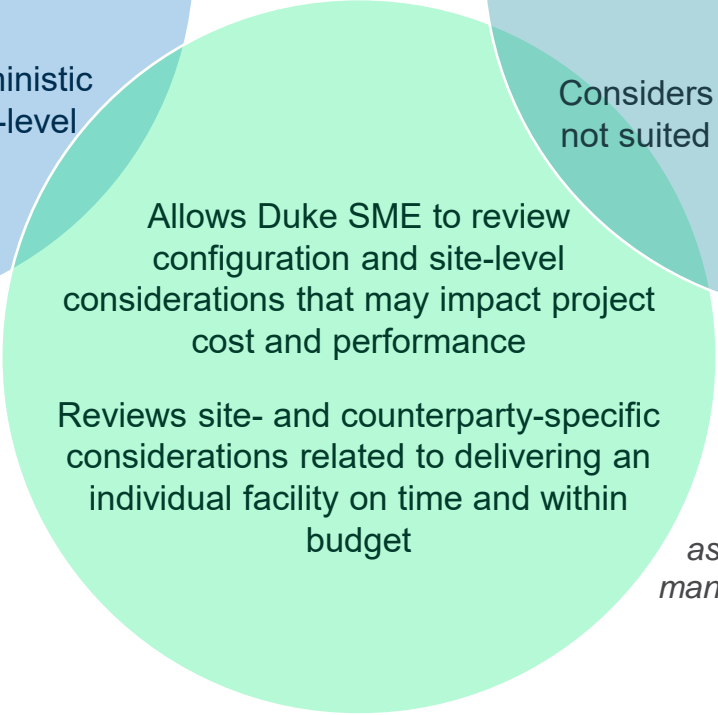
## Resource Planning Optimization

*Designed to optimize a portfolio composition and minimize rate-payer costs based on high-level market dynamics and market risk considerations*



## RFP Project Rankings

*Designed to evaluate and rank order a large number of similar projects based on a mix of objectives and subjective criteria. Process is well-suited for screening options and identifying a short-list for advancement*



## Final Due Diligence

*Provides a final, formal review of each candidate project and counterparty based on a detailed assessment of site-level considerations, equipment manufacturers, counterparty level considerations and transfer agreement / PPA language*



# Q&A

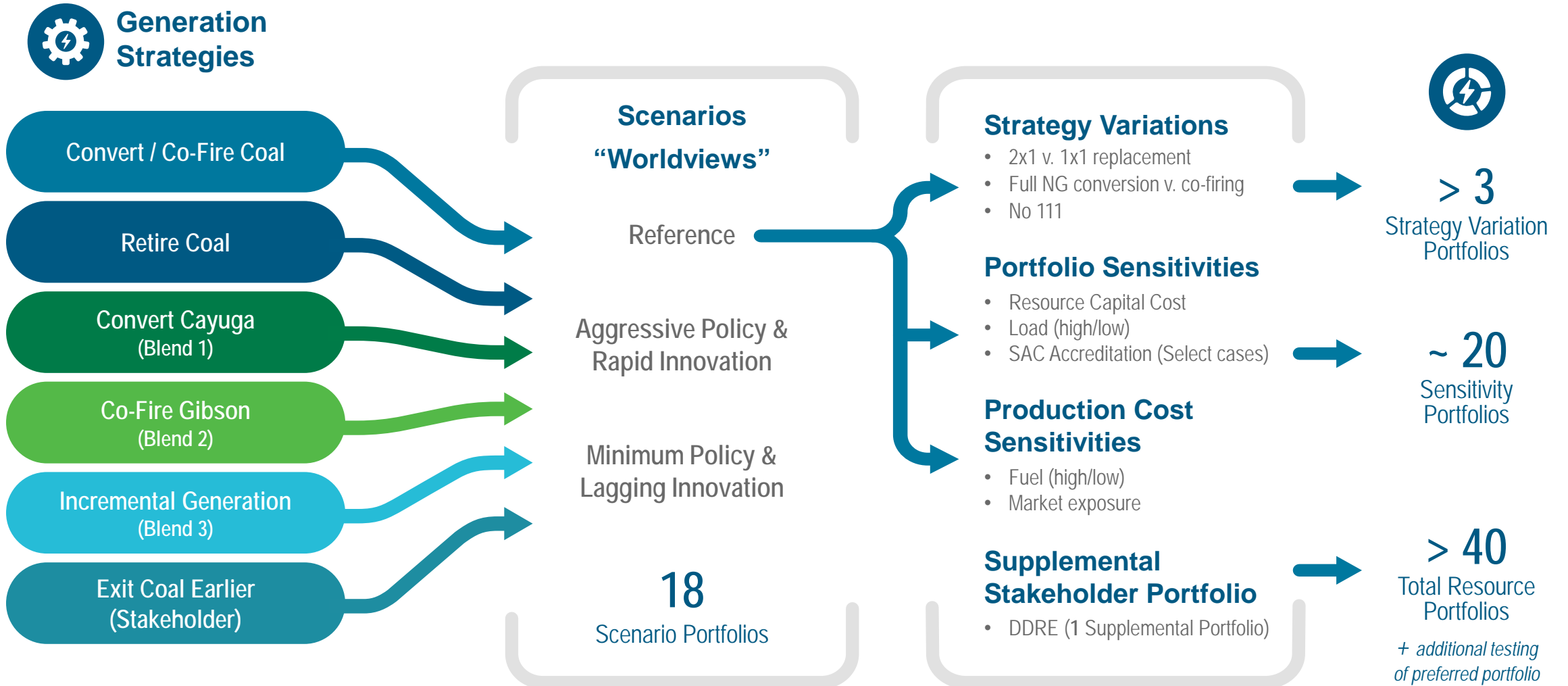


# Break



# Preliminary Portfolio Modeling Update

# Analytical Framework





# Generation Strategies Included in IRP Analysis

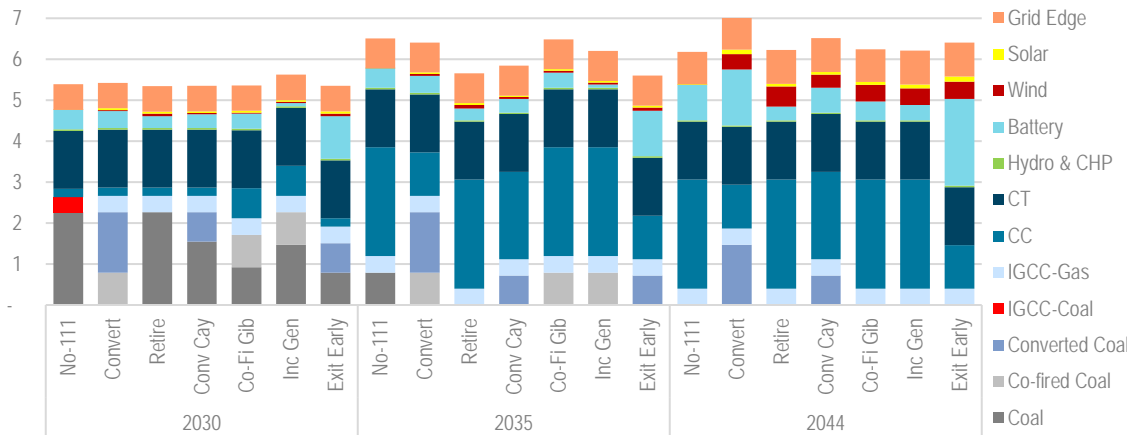
CAA Section 111-Compliant Strategies							Non-Compliant		
Unit	Convert / Co-Fire Coal	Retire Coal	Convert Cayuga (Blend 1)	Co-Fire Gibson (Blend 2)	Incremental Generation (Blend 3)*	Exit Coal Earlier (Stakeholder)	“No 111”		
Cayuga 1	NG Conversion by 1/1/2030	Retire by 1/1/2030	NG Conversion by 1/1/2030	Retire by 1/1/2030	Retire by 1/1/2032	NG Conversion by 1/1/2029	Retire by 1/1/2032		
Cayuga 2		Retire by 1/1/2031		Retire by 1/1/2031					
Gibson 1	Co-fire by 1/1/2030	Retire by 1/1/2032	Retire by 1/1/2032	Co-fire by 1/1/2030		Retire by 1/1/2032	Retire by 1/1/2036		
Gibson 2									
Gibson 3	NG Conversion by 1/1/2030					Retire by 1/1/2032		Retire by 1/1/2030	Retire by 1/1/2032
Gibson 4									
Gibson 5	Retire by 1/1/2030								
EDW	NG Conversion by 1/1/2030						NG Conversion by 1/1/2035		

\*Economic growth-oriented strategy that includes an incremental 1x1 CC by 1/1/2030 in addition to prescribed 2x1 CCs to replace Cayuga 1&2 and Gibson 3&4 by 2032

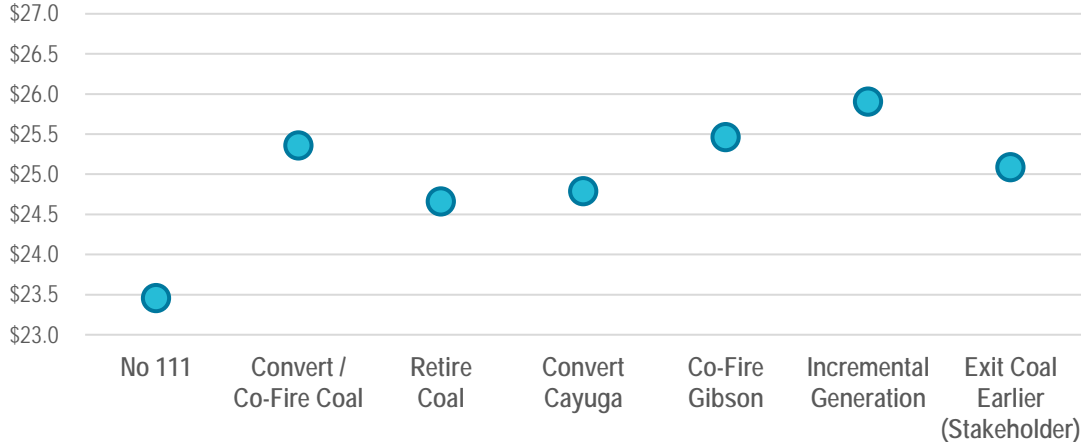
 Indicates strategies added since Meeting 3

# Preliminary Results Summary for All Strategies in Reference Scenario

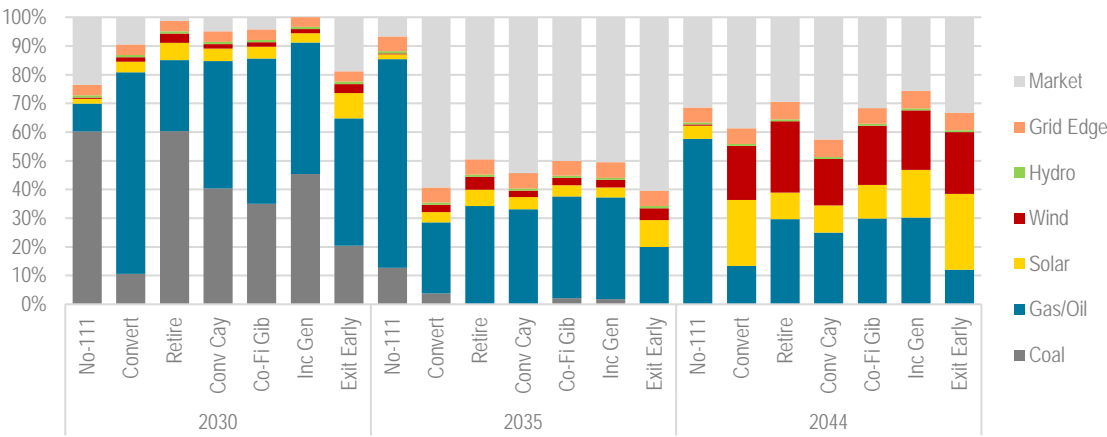
UCAP Capacity Mix Over Time (Winter GW)



Preliminary PVRs (\$B) through 2044



Energy Mix Over Time



Initial Observations

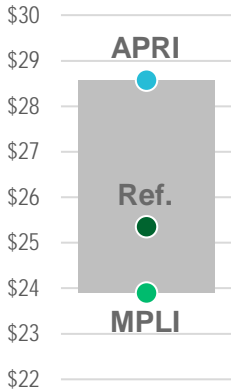
- Co-firing existing coal units or fully converting to natural gas provides capital cost savings but increases system operating costs, ultimately driving up PVRs
- Dispatchable thermal generation contributes critical UCAP MW across all strategies into the late 2030s
- Contributions from wind and solar increase over time, providing a substantial portion of total energy by the end of the planning period for all 111-compliant strategies

# Generation Strategy Results Summary: Convert / Co-Fire Coal

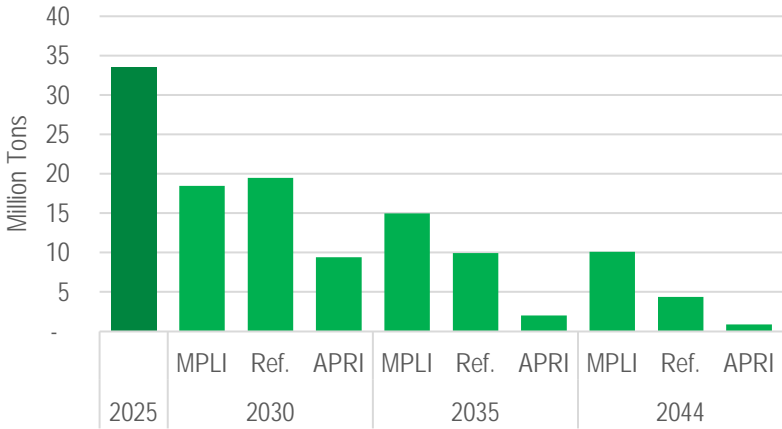
## Notes on Generation Strategy

- Converting coal units to burn 100% natural gas or co-fire coal/gas, mitigates need for new capacity in near term, but does not provide additional capacity.
- Converted and co-fired coal units provide needed capacity but struggle to compete economically in the MISO energy market, with economic energy purchases supplying a substantial portion of total energy in the mid-2030s.
- Solar, wind, and battery additions supply needed incremental energy and capacity before 2030, with new CC capacity added in the early 2030s in the Minimum Policy & Lagging Innovation (MPLI) scenario, which envisions the rollback of GHG rules under CAA Section 111.
- Co-fired coal units (Gibson 1 & 2) must retire by 2039 under CAA Section 111, necessitating investment in replacement capacity in the mid/late 2030s.

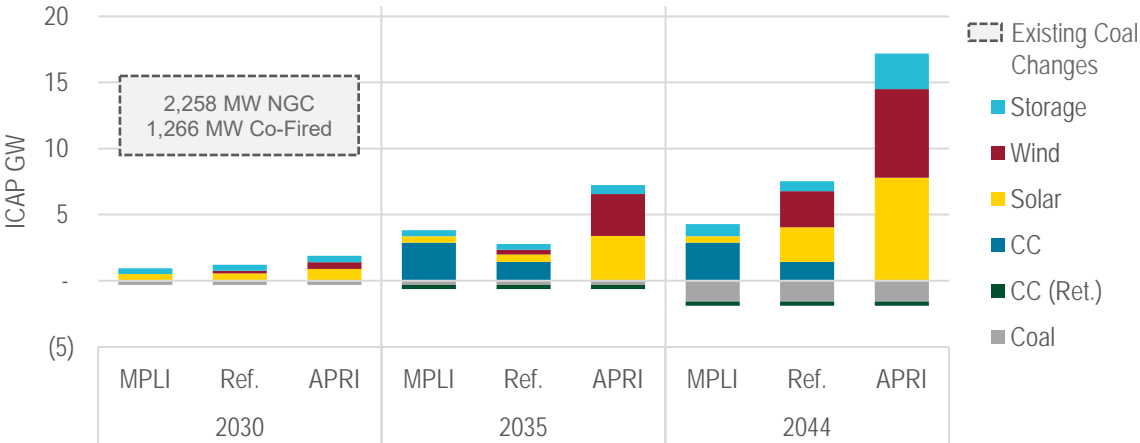
### PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

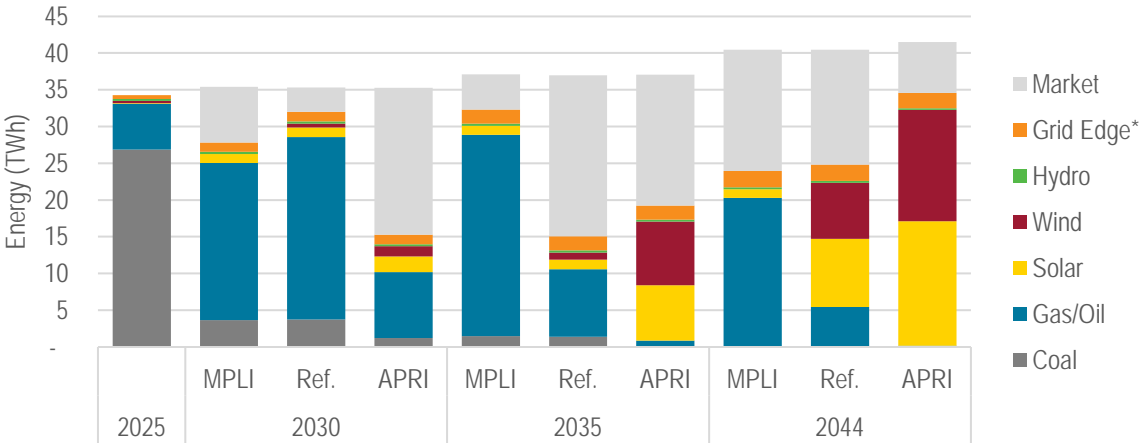


## Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



\*Grid Edge includes DSM (EE/DR) & IVVC

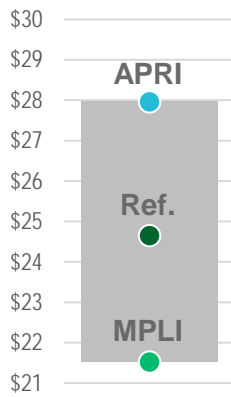
Preliminary modeling results subject to change

# Generation Strategy Results Summary: Retire Coal

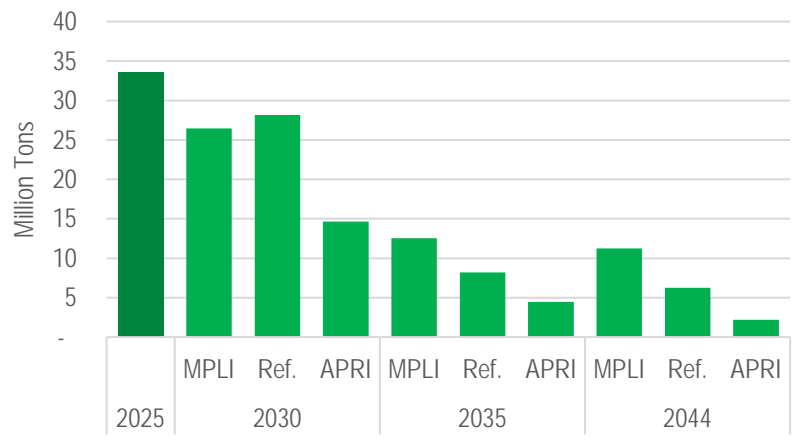
## Notes on Generation Strategy

- Significant additions of dispatchable and variable energy resources are required by the early 2030s to meet incremental load growth and replace over 3.8 GW of retiring coal.
- New gas-fired combined-cycle generators provide improved resource accreditation over retiring units and operate competitively in the MISO market, dispatching up to the 40% capacity factor limit under CAA 111.
- Energy mix varies considerably across scenarios in the mid-2030s, with the repeal of the recently adopted GHG rule under CAA Section 111 allowing CCs to operate up to their economic limits in Minimum Policy & Lagging Innovation (MPLI), while additional policy constraints and falling costs drive greater adoption of renewables in Aggressive Policy & Rapid Innovation (APRI).

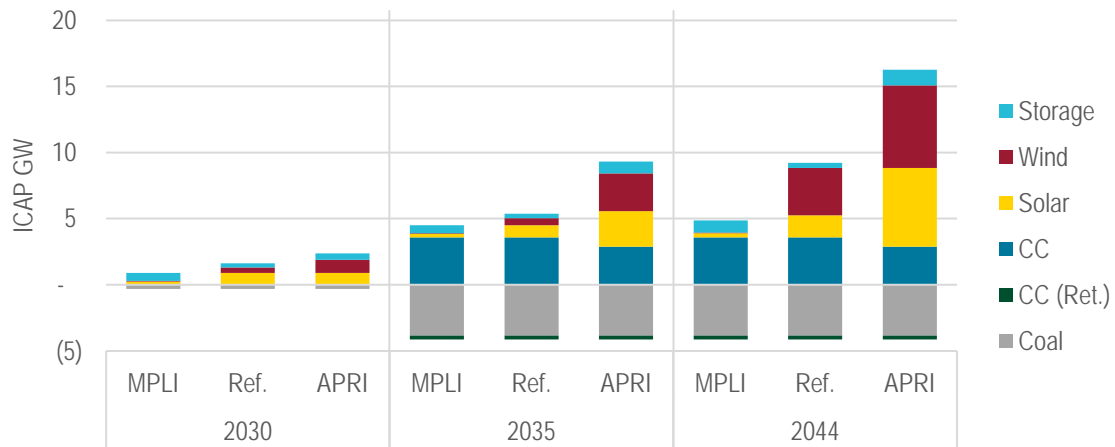
PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

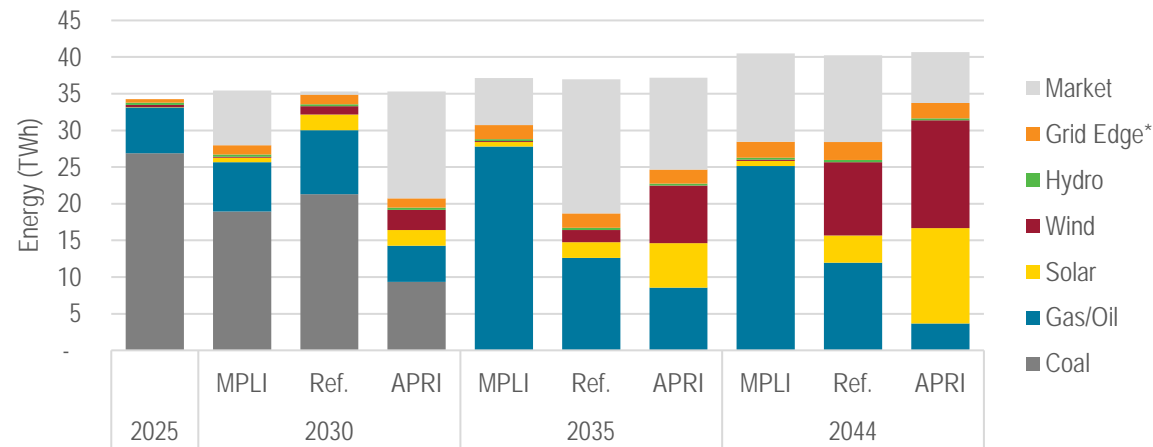


## Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



\*Grid Edge includes DSM (EE/DR) & IVVC

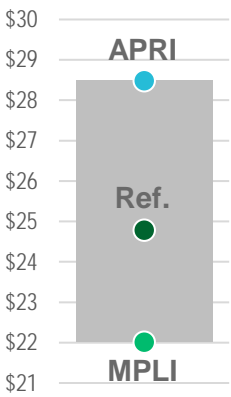
Preliminary modeling results subject to change

# Generation Strategy Results Summary: Convert Cayuga (Blend 1)

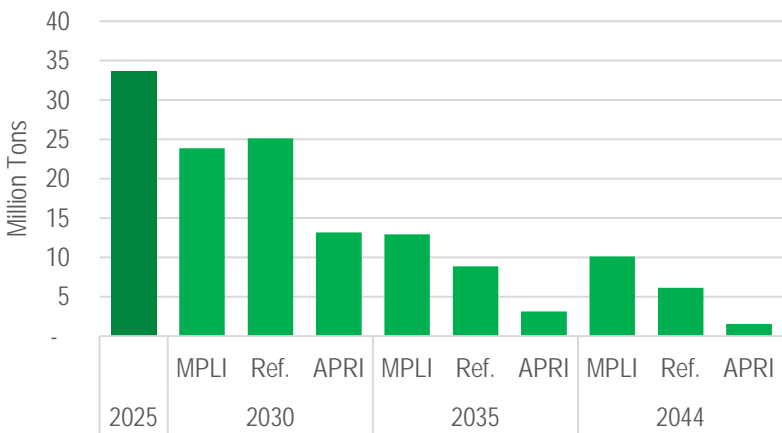
## Notes on Generation Strategy

- Cayuga units 1 and 2 are repowered to burn 100% natural gas by 2030, while Gibson units 1 through 4 are retired and replaced with new combined-cycle generation by 2032.
- Renewables and storage are favored in the Aggressive Policy & Rapid Innovation (APRI) scenario, displacing a portion of the gas capacity added in other scenarios as coal units retire, while in the Minimum Policy & Lagging Innovation (MPLI) scenario, new CCs provide substantially more energy than in other cases.
- Full gas conversion at the Cayuga units allows them to operate through the end of the planning period, consistent with the GHG rule under CAA Section 111.

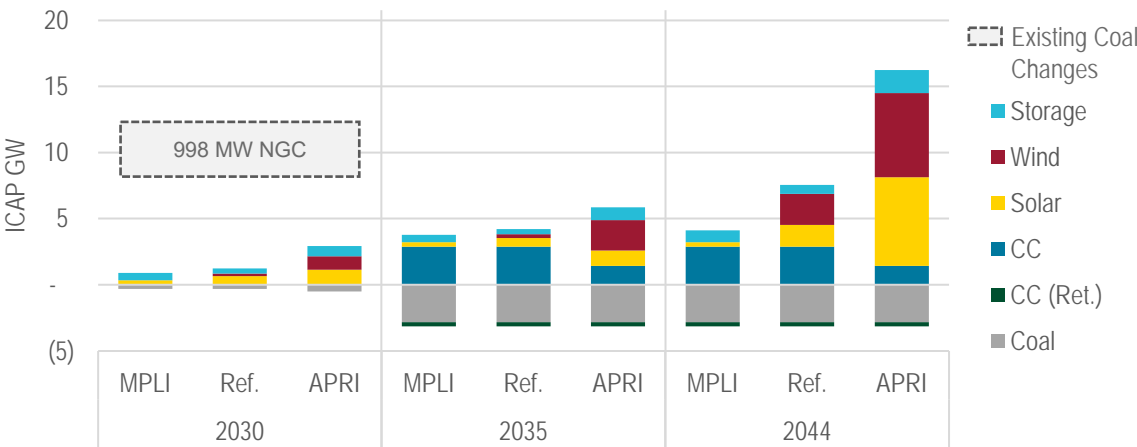
PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

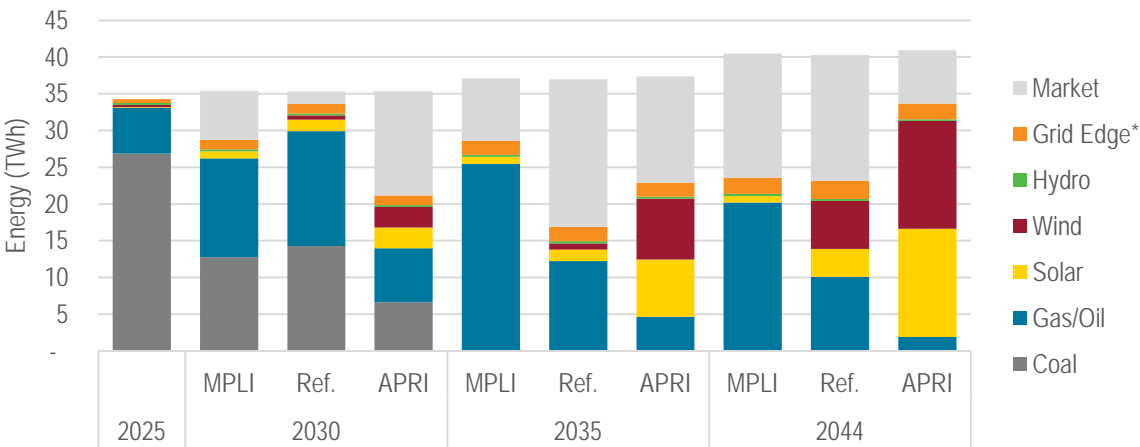


## Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



\*Grid Edge includes DSM (EE/DR) & IVVC

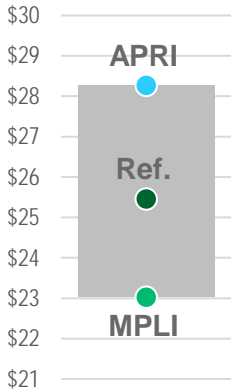
Preliminary modeling results subject to change

# Generation Strategy Results Summary: Co-Fire Gibson (Blend 2)

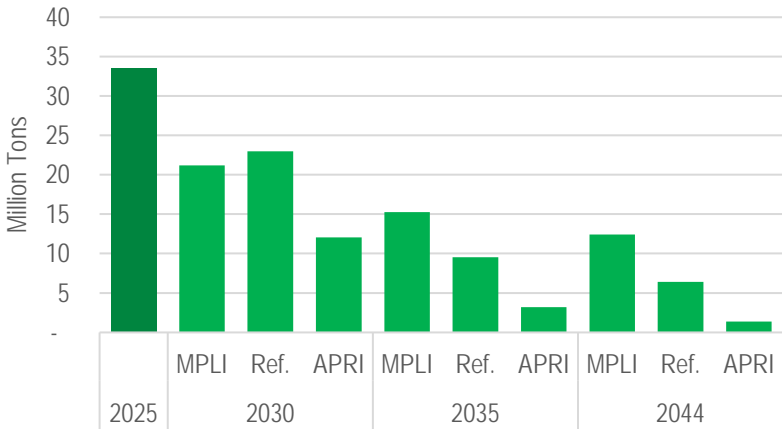
## Notes on Generation Strategy

- Cayuga units 1 and 2 retire by 2030 and 2031. Two 1x1 CCs are added at the site, replacing the retiring coal and providing incremental MW to help serve growing load.
- Gibson 1 and 2 are converted to enable co-firing natural gas with coal, allowing them to continue to operate through 2038 under CAA Section 111, at which point additional capacity is needed.
- Renewables and storage are added in the late 2020s to meet near-term needs in all scenarios, with that trend accelerating in the Aggressive Policy & Rapid Innovation (APRI) scenario, and the balance shifting towards new gas in the Minimum Policy & Lagging Innovation (MPLI) scenario.
- Energy from new CCs displaces market purchases in the MPLI scenario.

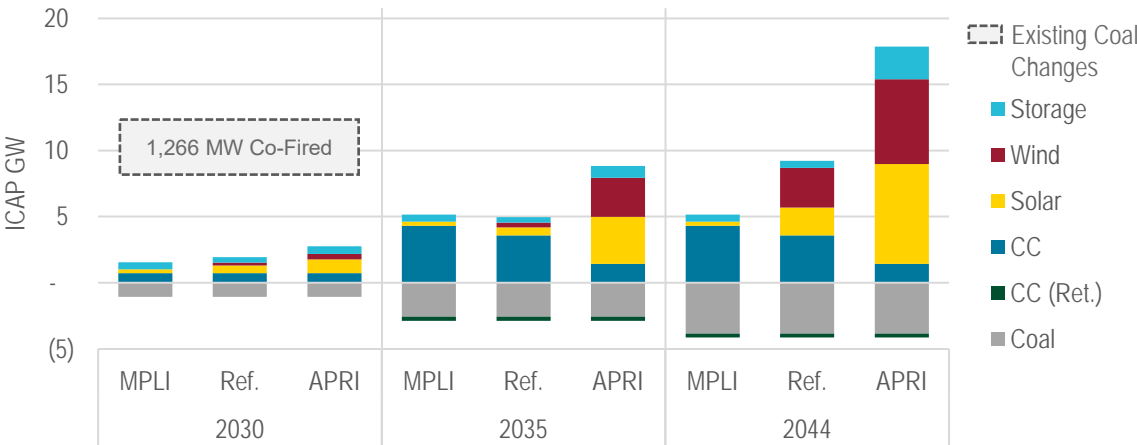
### PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

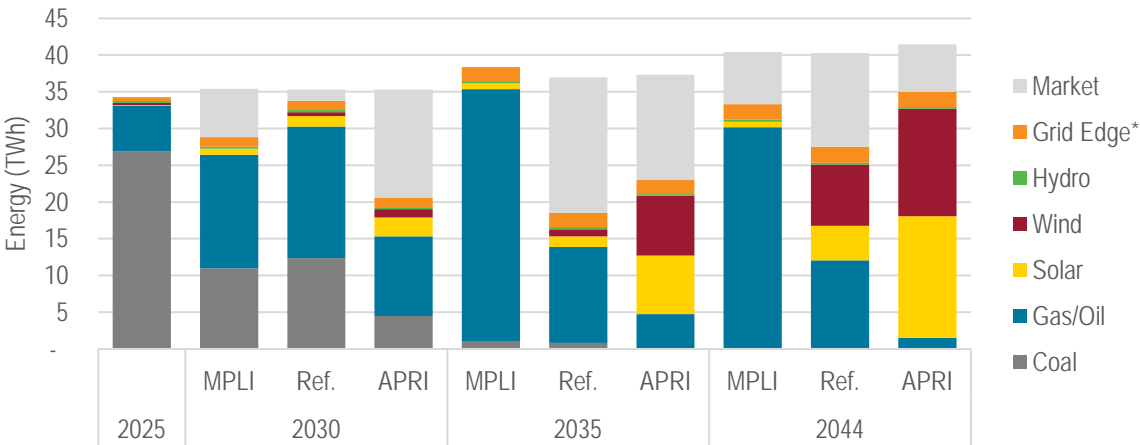


## Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



\*Grid Edge includes DSM (EE/DR) & IVVC

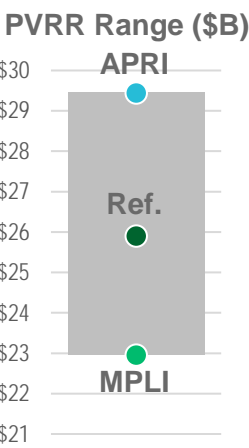
Preliminary modeling results subject to change



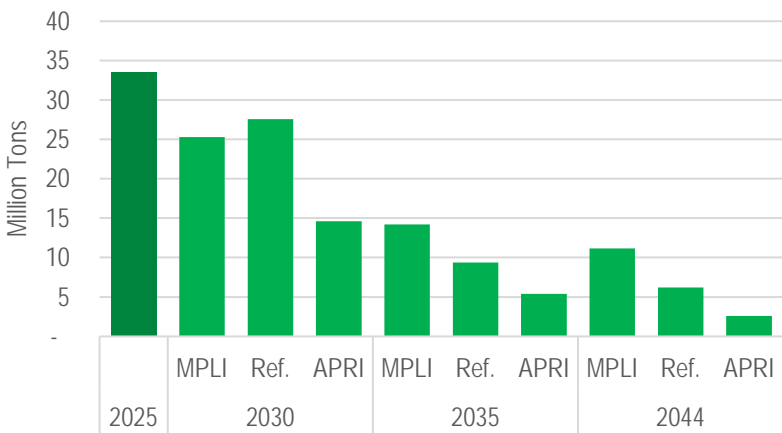
# Generation Strategy Results Summary: Incremental Generation (Blend 3)

## Notes on Generation Strategy

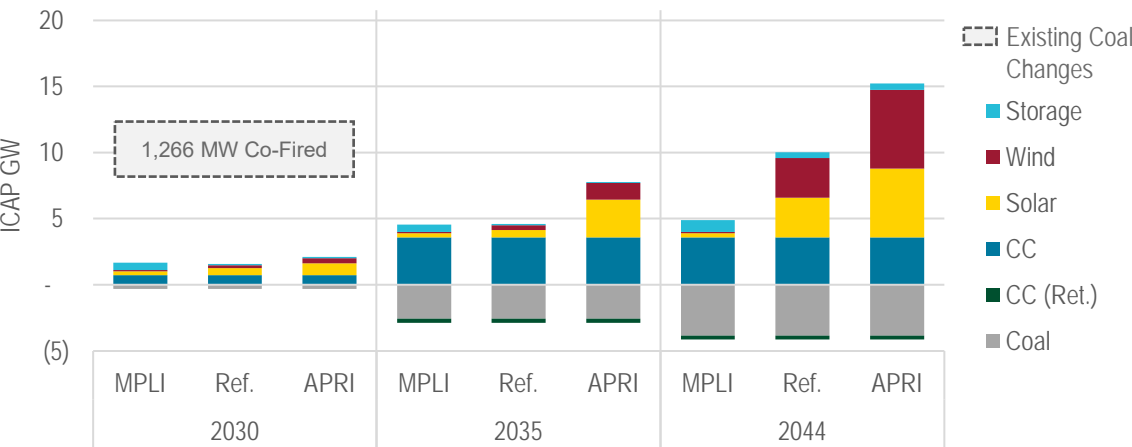
- The growth-oriented Incremental Generation (Blend 3) strategy builds on Co-Fire Gibson (Blend 2), seeking to support rapid economic development with the addition of a combined-cycle prior to the retirement of the Cayuga units.
- The inclusion of incremental capacity in the early 2030s mitigates the need for additional resources through the remainder of the decade.
- Solar, wind, and battery additions in the 2020s help meet near-term needs before incremental gas can be brought online, with further expansion of renewable capacity providing energy in the late 2030s, particularly in the Aggressive Policy & Rapid Innovation (APRI) scenario.



## CO<sub>2</sub> Emissions Over Time

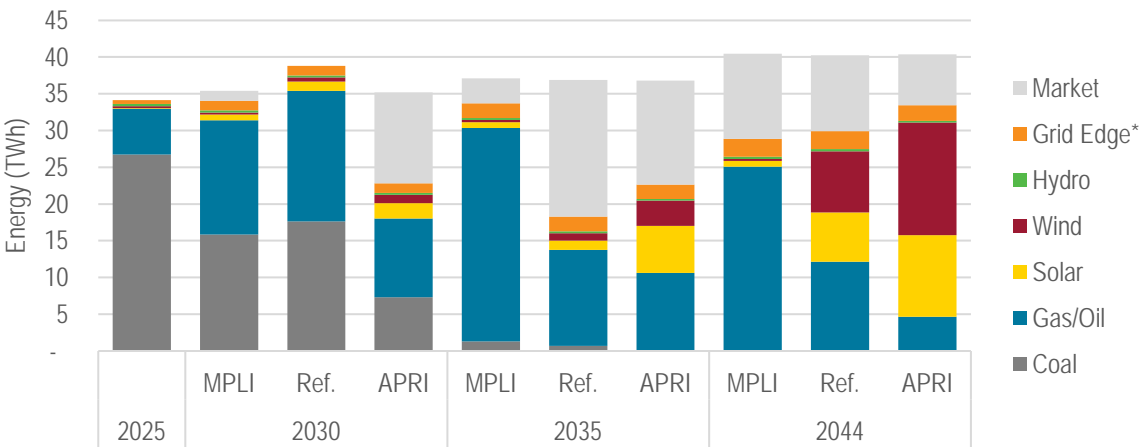


## Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



\*Grid Edge includes DSM (EE/DR) & IVVC

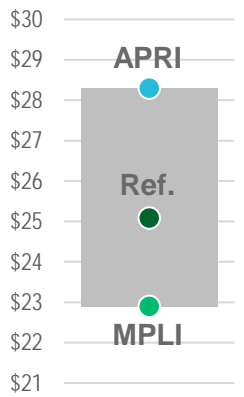
Preliminary modeling results subject to change

# Generation Strategy Results Summary: Exit Coal Earlier (Stakeholder)

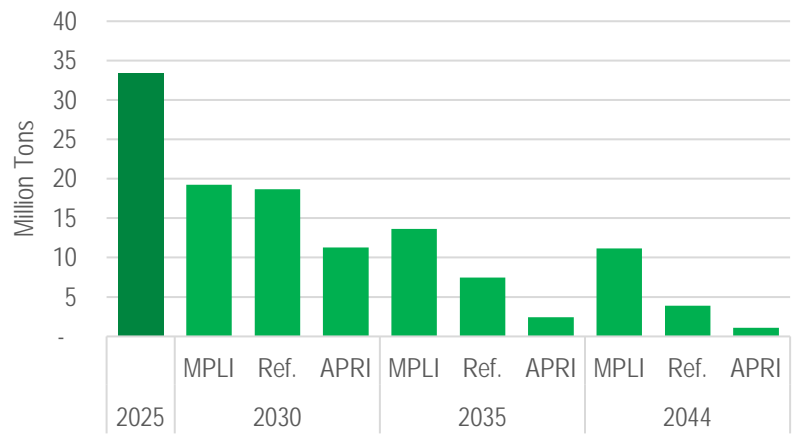
## Notes on Generation Strategy

- Accelerating the retirement of Gibson 3 and 4 to 2030 necessitates the addition of higher volumes of renewables and storage by 2030 than in other strategies, while conversion of Cayuga to 100% natural gas maintains capacity at that site.
- New CC capacity is added to offset coal retirements in all scenarios, with a 2x1 replacing Gibson units 1 and 2 when they retire by 2032, consistent with the GHG rule under CAA Section 111.
- Additional gas capacity is selected in the Minimum Policy & Lagging Innovation (MPLI) scenario in which capacity factor limits under CAA Section 111 are assumed to be repealed, whereas in the Aggressive Policy & Rapid Innovation (APRI) scenario, renewables are favored.

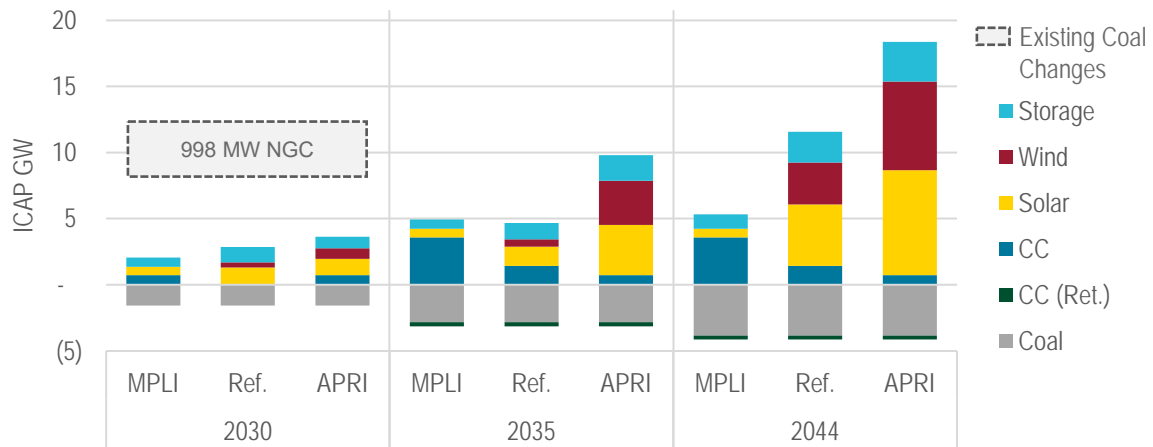
PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

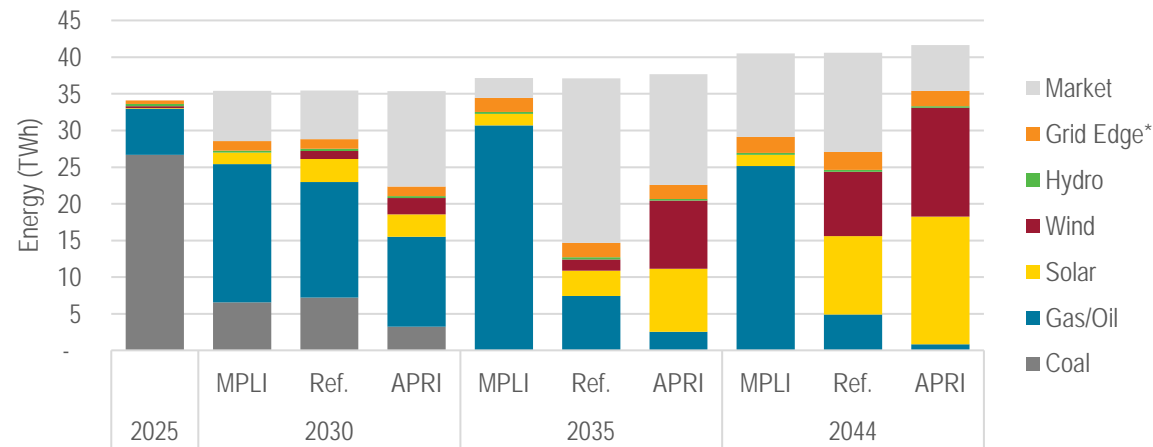


## Cumulative Resource Additions (ICAP)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



\*Grid Edge includes DSM (EE/DR) & IVVC

Preliminary modeling results subject to change



# Q&A



# Break

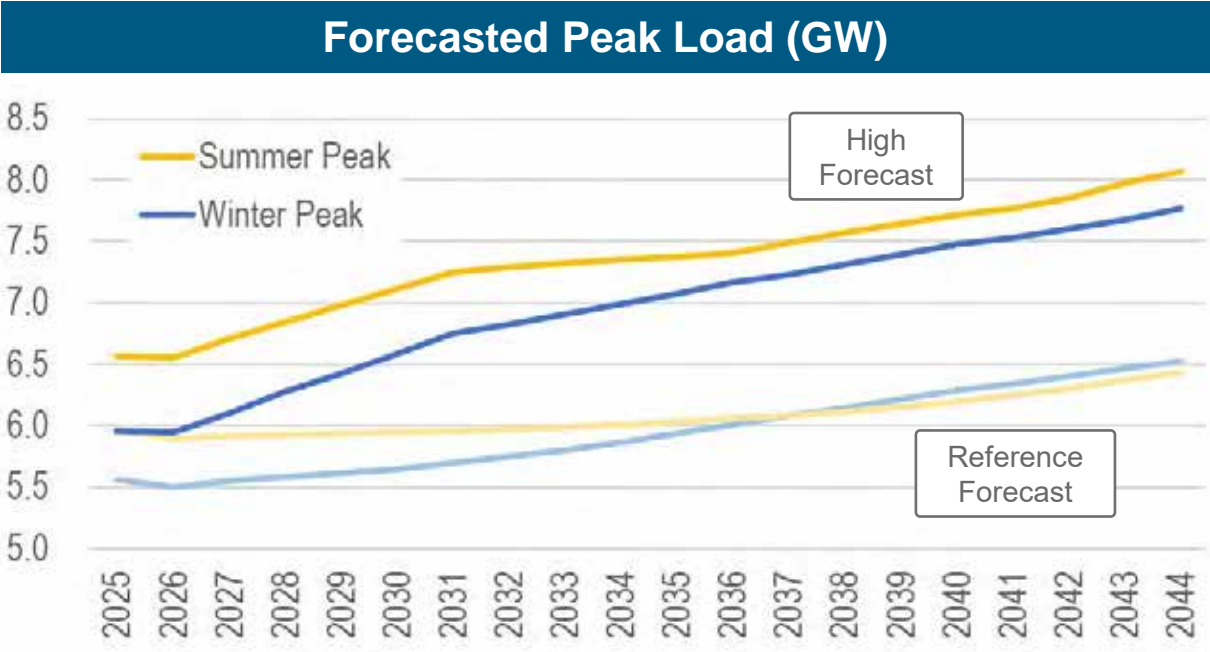


# Preliminary Portfolio Modeling Update

## *High Load Sensitivity*



# Portfolio Sensitivity Analysis: High Load (Preliminary Results)



- The greatly increased load evaluated in the “high load” forecasts necessitates a substantial increase in resource additions of all types, relative to the Reference case analysis
- PVRs across the “high load” cases are approximately 25% to 35% higher than in the Reference cases as a consequence of the additional capacity and energy needs

**Impact of High Load on Resource Selection**

**Reference Case Resource Additions Through 2044 (GW)**

Strategy	CC	Solar	Wind	Storage
Convert	1.4	2.6	2.8	0.8
Retire	3.6	1.6	3.6	0.4
Convert Cay.	2.9	1.6	2.4	0.7
Co-Fire Gib.	3.6	2.1	3.0	0.5
Incremental Gen.	3.6	3.0	3.0	0.4
Exit Coal Earlier	1.4	4.6	3.2	2.3

**Results Changes in High Load Modeling (incremental GW)**

Strategy	CC	Solar	Wind	Storage
Convert	+0.7	+4.4	+0.3	+1.3
Retire	--	+4.5	+0.9	+1.6
Convert Cay.	+0.7	+2.4	+1.6	+0.7
Co-Fire Gib.	+0.7	+3.5	+0.7	+0.9
Incremental Gen.	+1.2	+4.4	+0.8	+0.7
Exit Coal Earlier	+2.2	+0.8	+0.8	-0.3





# Q&A



# Preliminary Portfolio Modeling Update

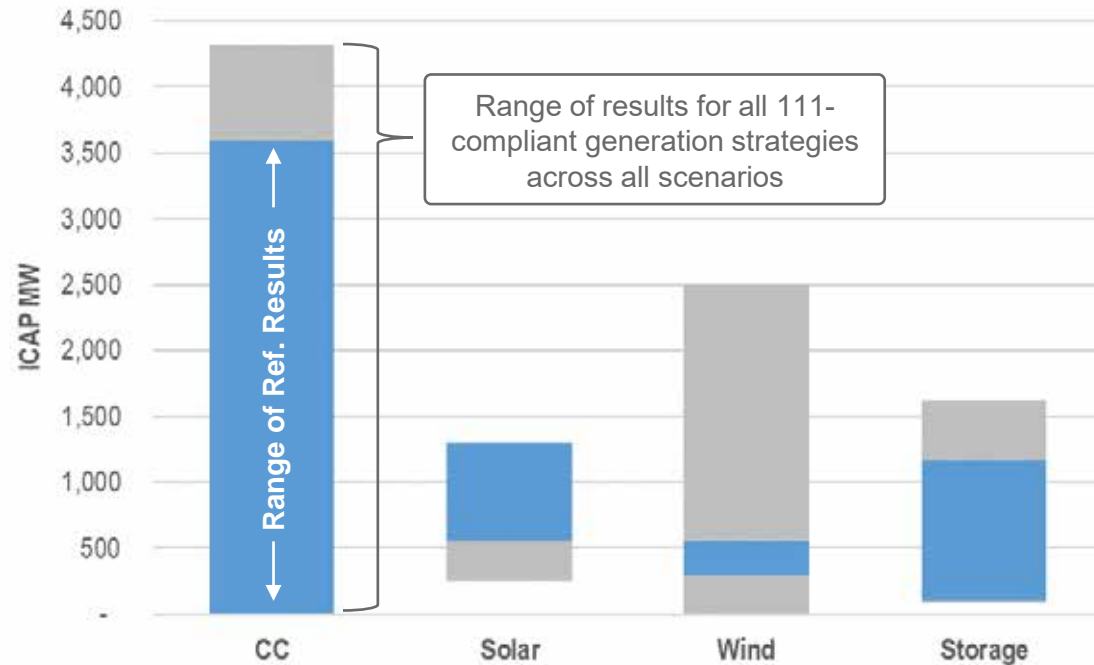
## *Considerations for Short-Term Action Plan*

# Reminder: Thinking About the IRP Planning Period



# Using Model Results to Inform a Short-Term Action Plan

## Range of Supply Side Resource Additions by 2032



In results to date, each portfolio also includes:

- 295 MW (1.5 TWh/yr) of new EE by 2032
- 548 MW of demand response by 2032, including existing programs

## Significant Considerations for Developing a Short-Term Action Plan:

- Appropriate balance of retirement / gas conversion / co-firing across eight coal units totaling ~4.4 GW of dispatchable capacity
- Mix of new resources, both incremental and replacement, that appropriately balances the five pillars and supports economic development

## Sources of Substantial Uncertainty:

- Regulatory – ultimate fate of EPA CAA Section 111 rule
- Demand – pace and scale of economic development in DEI service territory
- Market – resource adequacy and economic competitiveness dynamics by mid-2030s
- Supply chain – new resource availability and cost



# Q&A



# Preliminary Scorecard Results



# Draft Scorecard

Environmental Sustainability				Affordability			Reliability		Resiliency		Cost Risk		Market Exposure		Execution Risk					
Portfolio	CO <sub>2</sub> Emissions Reduction		Cumulative CO <sub>2</sub> Reduction Over Planning Period (MM tons)	Non-CO <sub>2</sub> Emissions Ranking	PVRR (\$B)	Customer Bill Impact (CAGR)		Availability of On-Demand Resources in High-Risk Hours	Fast Start & Spinning Reserve Capability	Resource Diversity	Performance in 95 <sup>th</sup> Percentile Extreme Weather Event	Cost Variability (\$B)	IRA Exposure		Fuel Market Exposure	Maximum Energy Market Exposure	Cumulative Resource Additions in MW		Cumulative Resource Additions as % of Current System ICAP	
	2035	2044	2044			2030	2035	2035	2035				2030	2035	2035	2035	2030	2035	2030	2035
Convert / Co-Fire Coal	-70%	-87%	355	3.8	\$25.4			123%	124%	22%		\$23.9 - \$28.6	86%	44%	67%	68%	1,410	3,135	17%	39%
Retire Coal	-75%	-81%	344	3.8	\$24.7			98%	98%	28%		\$21.5 - \$28.0	89%	32%	70%	50%	1,827	5,773	23%	71%
Convert Cayuga (Blend 1)	-74%	-82%	345	3.3	\$24.8			103%	104%	23%		\$22.0 – \$28.5	86%	29%	75%	60%	1,427	4,554	18%	56%
Co-Fire Gibson (Blend 2)	-72%	-81%	342	3.3	\$25.5			119%	120%	25%		\$23.0 – \$28.3	57%	26%	74%	53%	2,129	5,292	26%	65%
Incremental Generation (Blend 3)	-72%	-82%	333	5.5	\$25.9			114%	115%	27%		\$23.0 – \$29.4	48%	20%	74%	52%	1,762	4,939	22%	61%
Exit Coal Earlier (Stakeholder)	-78%	-88%	380	1.5	\$25.1			94%	95%	15%		\$22.9 – \$28.3	94%	64%	58%	61%	3,055	5,019	38%	62%

A description of each scorecard metric is included on the following slide

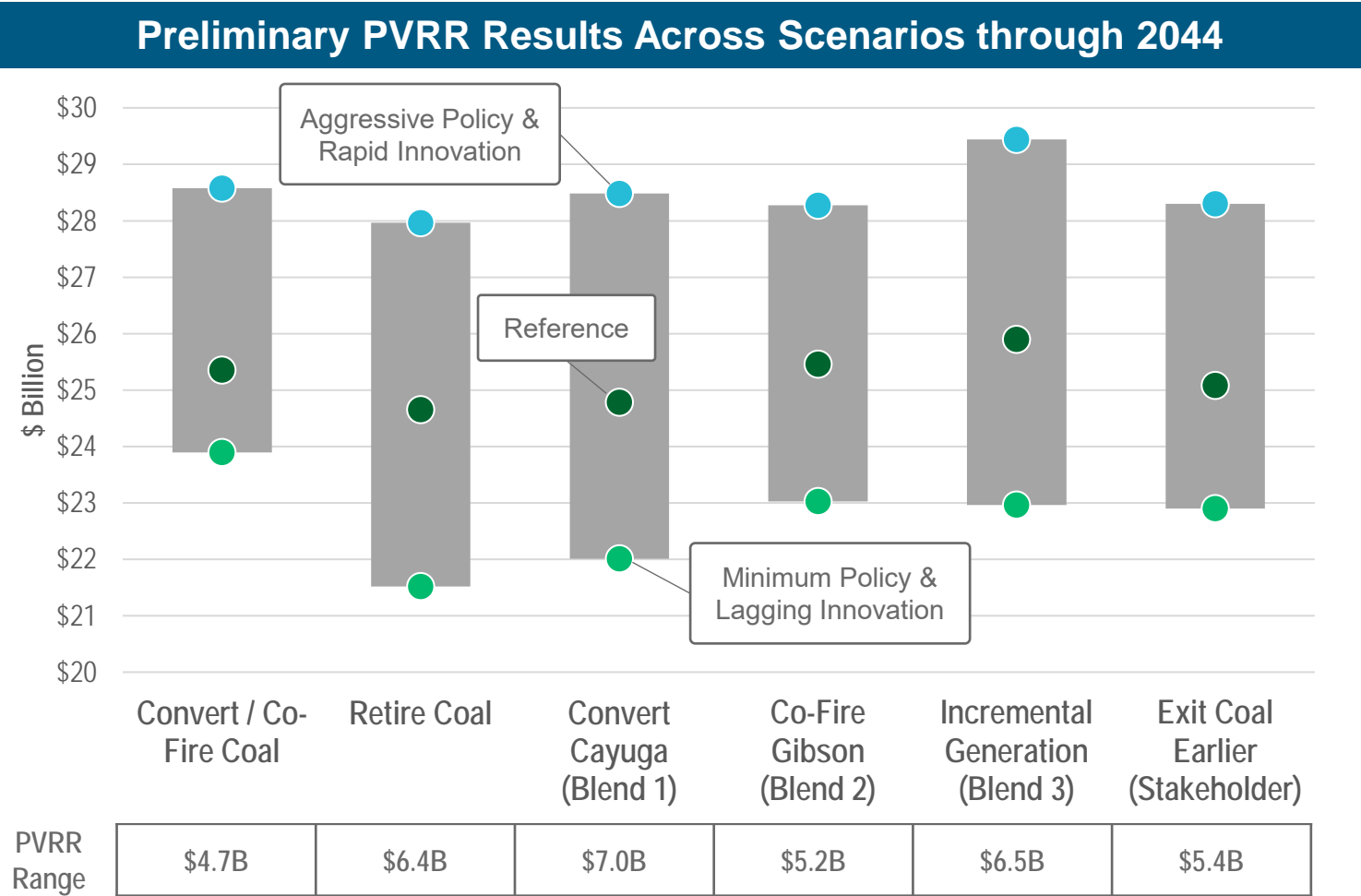
 Analytics ongoing

# Scorecard Metrics

Metric	Description
CO <sub>2</sub> Emissions Reduction	Percent CO <sub>2</sub> reduction relative to 2025
Cumulative CO <sub>2</sub> Reduction	Cumulative volume of CO <sub>2</sub> reduction over the planning period (tons from 2025)
Non-CO <sub>2</sub> Emissions Ranking	Portfolio ranking based on cumulative volume of SO <sub>2</sub> , NO <sub>x</sub> , Hg, and PM over planning period
Present Value of Revenue Requirement (PVRR)	Total revenue requirement associated with resource plan investments over the planning period, discounted to present; Provides estimate of total plan cost
Customer Bill Impact	Projected compound annual growth rate (CAGR) in customer bill associated with resource plan investments; Provides snapshot of portfolio cost impact at points in time
Availability of On-Demand Resources in High-Risk Hours	Thermal and Storage MW as percentage of peak load in June 2035
Fast Start & Spinning Reserve Capability	Fast start and spinning reserve capable installed resource capacity MW as percentage of peak load in 2035
Resource Diversity	The sum of squares of technology share on an installed MW capacity basis in 2035

Metric	Description
Performance in 95th Percentile Extreme Weather Event	Percent unserved energy during an extreme weather event in summer and winter based on most extreme weather events (95th percentile or greater) observed in Indiana with market purchases turned off
Cost Variability	Minimum and Maximum PVRR across worldview scenarios (MPLI, APRI, Reference)
IRA Exposure	Cumulative MW additions with exposure to IRA tax credits as a percentage of total MW additions
Fuel Market Exposure	Generation (MWh) with exposure to coal and gas market prices as a percent of total fleet generation averaged annually over the planning period
Maximum Energy Market Exposure	Maximum absolute value of net energy purchases/sales as a percentage of total energy demand through the study period
Cumulative Resource Additions in MW	Cumulative MW additions of capacity resources through 2030 and 2035
Cumulative Resource Additions as % of Total System ICAP	Cumulative MW additions of capacity resource technologies through 2030 and 2035 expressed as a percentage of total current system capacity

# Affordability: PVRR

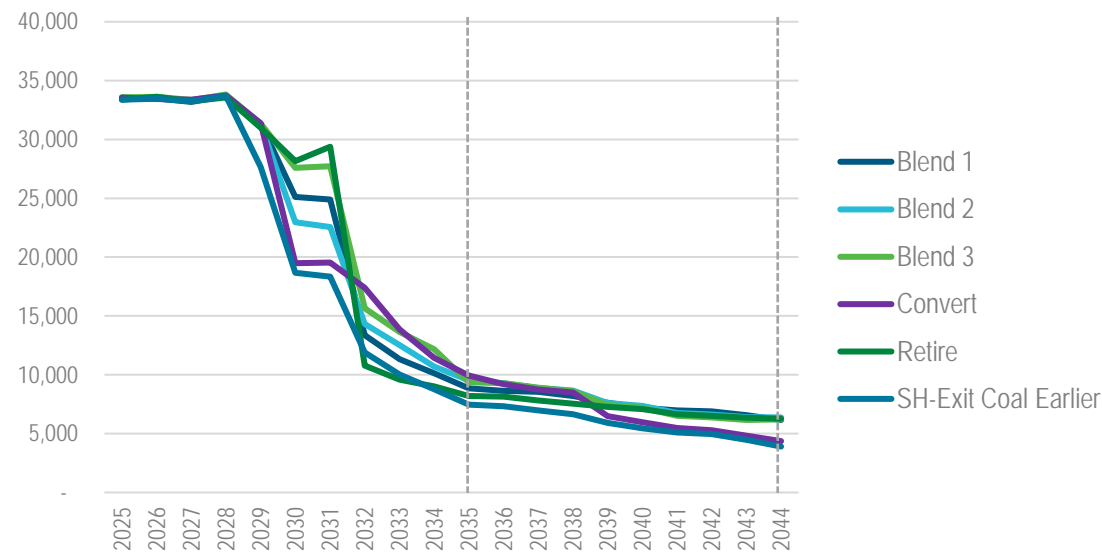


## Initial Observations:

- In the Aggressive Policy & Rapid Innovation scenario, higher fuel costs, imposition of a CO2 tax, and capacity factor restrictions on existing gas assets outweigh savings from improved IRA benefits and accelerated cost declines for renewables and storage, resulting in higher PVRRs for all strategies.
- Cost savings from low fuel prices and the repeal of the GHG rule under CAA Section 111 offset the loss of IRA tax credits in Minimum Policy & Lagging Innovation, resulting in lower PVRRs for all strategies.
- Preliminary results for the Reference scenario suggest limited variability in total portfolio costs over the planning period in that case, as represented by PVRR.

# CO<sub>2</sub> Emissions in Preliminary Results

Annual CO<sub>2</sub> Emissions Over Time (000's Tons)



- Emissions include CO<sub>2</sub> associated with market purchases
- All 111-compliant portfolios achieve 70%-78% CO<sub>2</sub> reduction in the reference case over the first 10 years of the period (2035) and 81%-88% by 2044.
- Portfolios CO<sub>2</sub> emissions reductions are greater under the Aggressive Policy & Rapid Innovation Scenario.

2035 CO<sub>2</sub> Emissions Reduction (from 2025 levels)

Strategy	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation
Convert / Co-fire Coal	-70%	-94%	-61%
Retire Coal	-75%	-88%	-63%
Convert Cay. (Blend 1)	-74%	-90%	-61%
Co-Fire Gib. (Blend 2)	-72%	-90%	-61%
Incremental Gen. (B3)	-72%	-83%	-57%
Exit Coal Earlier (SH)	-78%	-94%	-65%

2044 CO<sub>2</sub> Emissions Reduction (from 2025 levels)

Portfolio	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation
Convert / Co-fire Coal	-87%	-97%	-73%
Retire Coal	-81%	-94%	-67%
Convert Cay. (Blend 1)	-82%	-95%	-66%
Co-Fire Gib. (Blend 2)	-81%	-96%	-63%
Incremental Gen. (B3)	-82%	-92%	-63%
Exit Coal Earlier (SH)	-88%	-97%	-67%



# Q&A



# Break





# Energy Market Interaction & Modeling

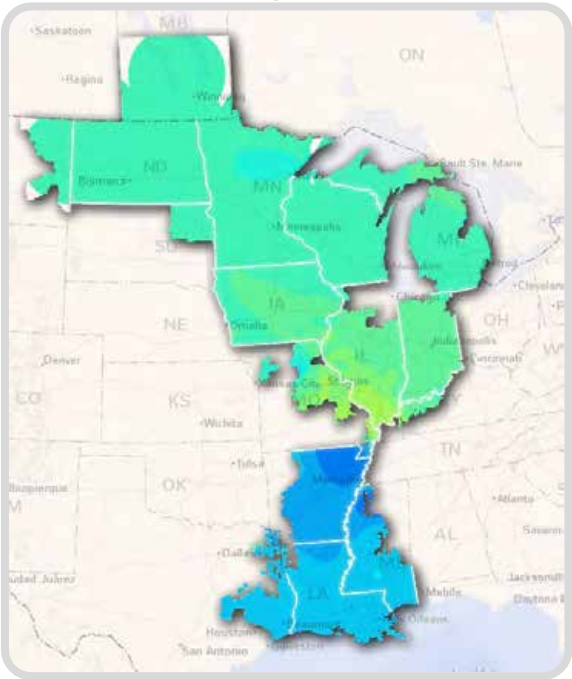
# MISO Energy Market Interaction

Duke Energy Indiana is a member of the Midcontinent Independent System Operator (MISO).

MISO dispatches the system by matching the amount of generation online in order to serve MISO's total load every hour of every day.




All energy generated by DEI resources is sold into MISO.

DEI buys energy needed to serve load from the market.



**MISO Market Participants**  
(including Duke Energy Indiana)




**Generation**





**MISO ENERGY MARKET**

**MISO Wide Energy**



**Generation****Load**



**MISO Market Participants**  
(including Duke Energy Indiana)

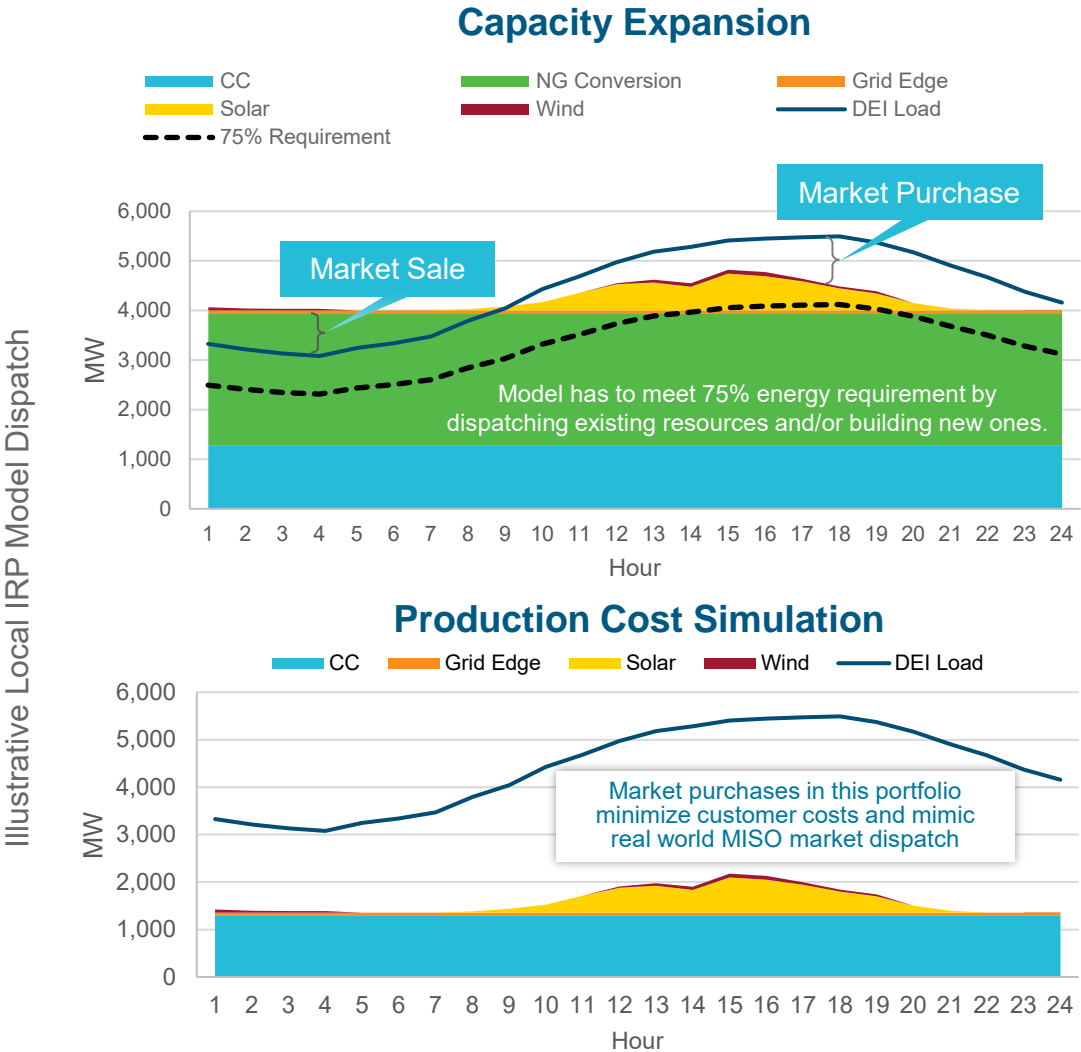
**Load**



# Market Purchases in the IRP Model

In the local IRP model, there are two parts to the simulation:

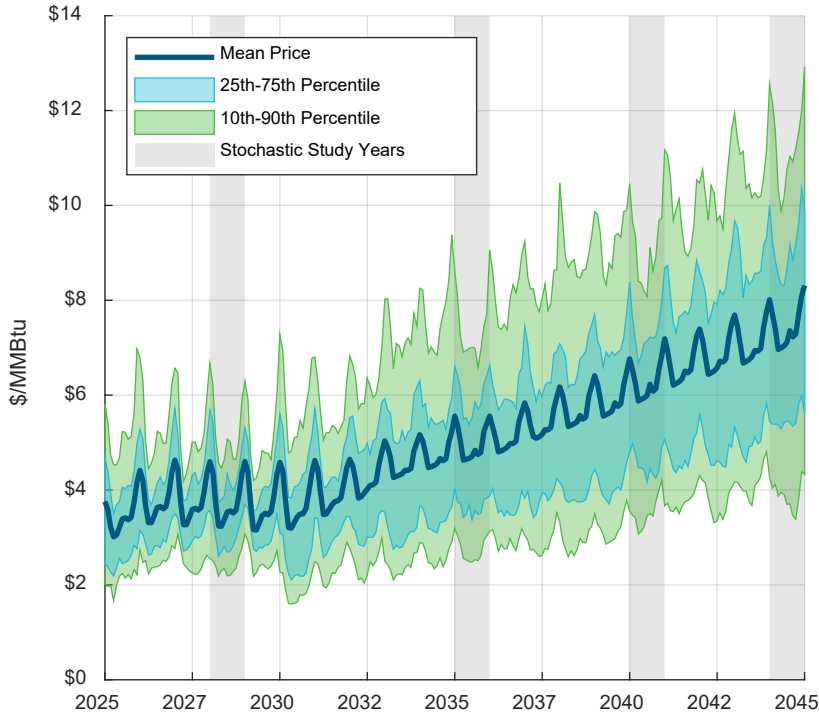
- 1. Capacity expansion** – EnCompass builds new resources in order to meet capacity need. The objective of the model is to minimize portfolio costs.
  - During this step, the portfolio build is required to serve 75% of customers' energy needs with DEI generation.
- 2. Production cost** – the portfolio developed in the capacity expansion is imported and simulated in a chronological 8760 simulation with more detailed settings.
  - DEI does not require the model to hit any customer energy need target, and generation is dispatched based on economics. This operation is more similar to the real-world MISO operations where DEI generation does not necessarily with DEI load.



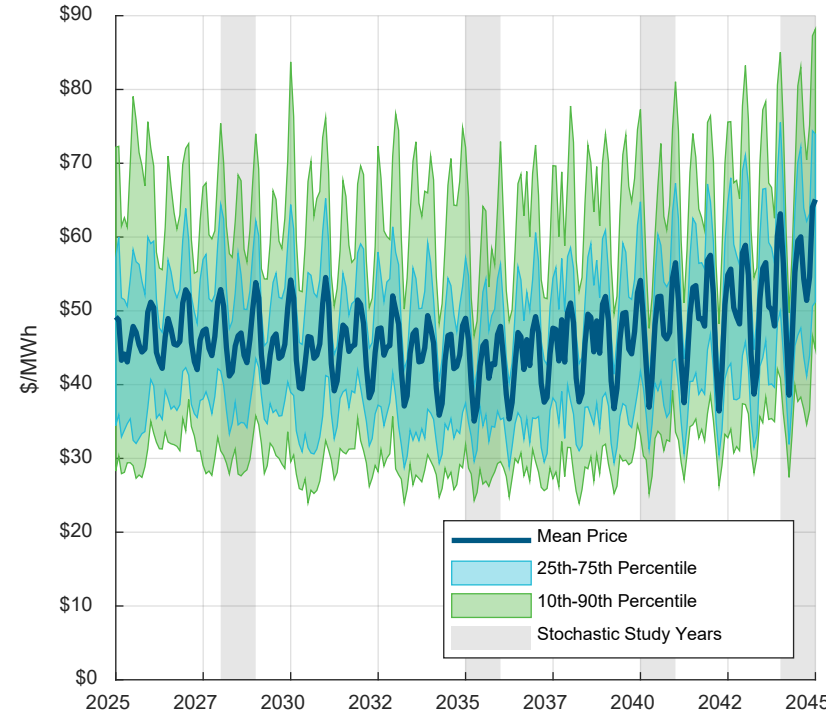
\*Charts are illustrative-only and do not reflect any one modeled portfolio

# Stochastic Modeling of Energy Market Exposure

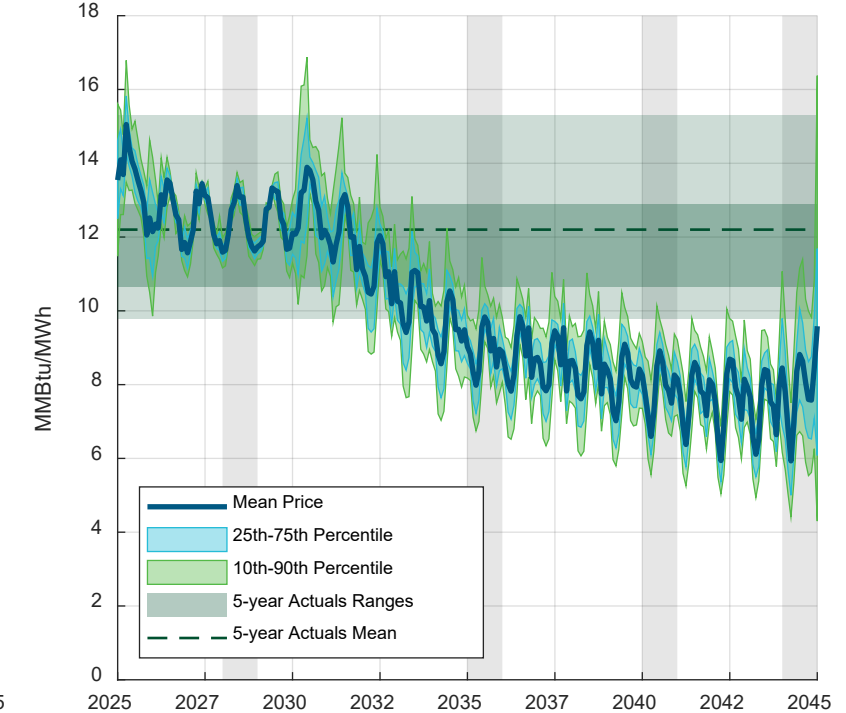
Simulated Gas Price Statistics (Henry Hub)



Simulated Power Price Statistics (IND HUB)



Market Implied Heat Rate



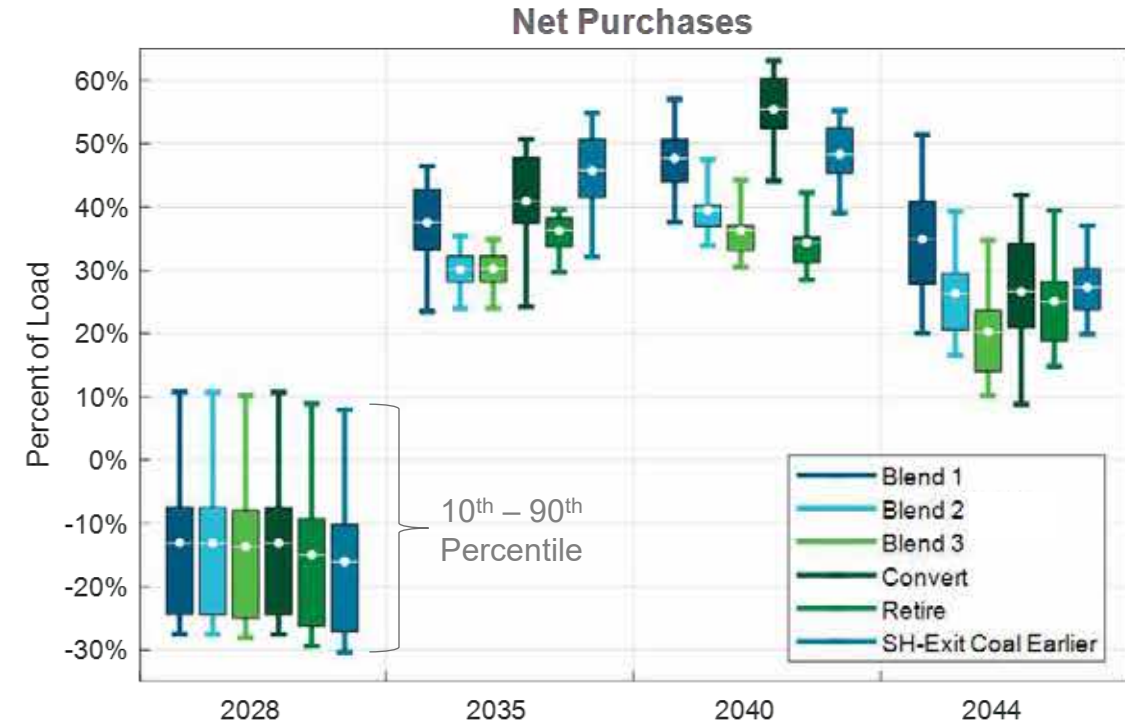
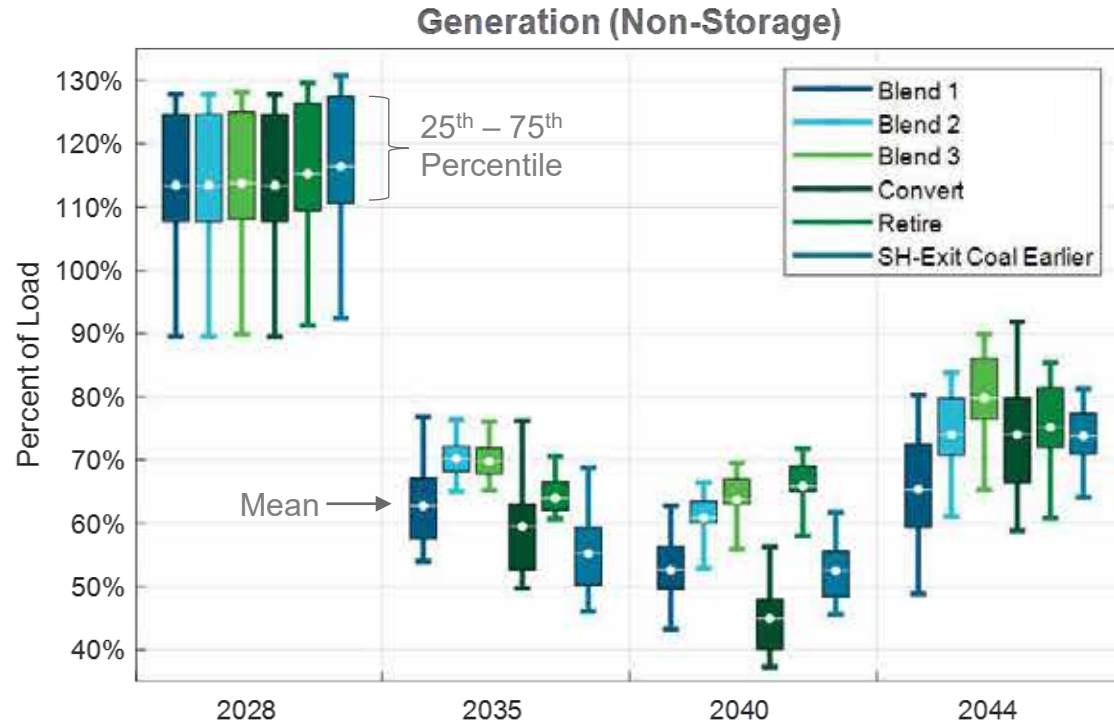
## Methodology

- Stochastic model produces simulations of correlated load, renewables, fuel prices and power prices using 43 years of weather history and market volatility
- Power price hourly shapes are driven by MISO net load projections. Monthly averages match Encompass 111 power prices

## Observations

- Market implied heat rates (ratio of power to gas prices) drop as power price growth is not projected to keep pace with gas prices. In later study years, the rates are seen to be below historical ranges affecting profitability and the resulting capacity factors of the generation fleet.
- Preliminary, directional results shown, subject to revision.

# Stochastic Modeling of Energy Market Exposure



- Stochastic model analyzes portfolios using 43 weather years, and simulations of load, fuel prices, power prices and outages
- Units dispatched based on profitability compared to simulated market prices, which are driven by MISO net load projections
- Produces ranges of energy and costs to estimate uncertainty in modeled projections

- Differences in portfolio generation and purchases driven by difference in cost competitiveness against common market prices
- Higher projected power prices & lower gas prices in 2028 drive higher generation and market sales compared to later years
- Preliminary, directional results shown, subject to revision. Model will be expanded to analyze portfolio costs and revenues





# Q&A

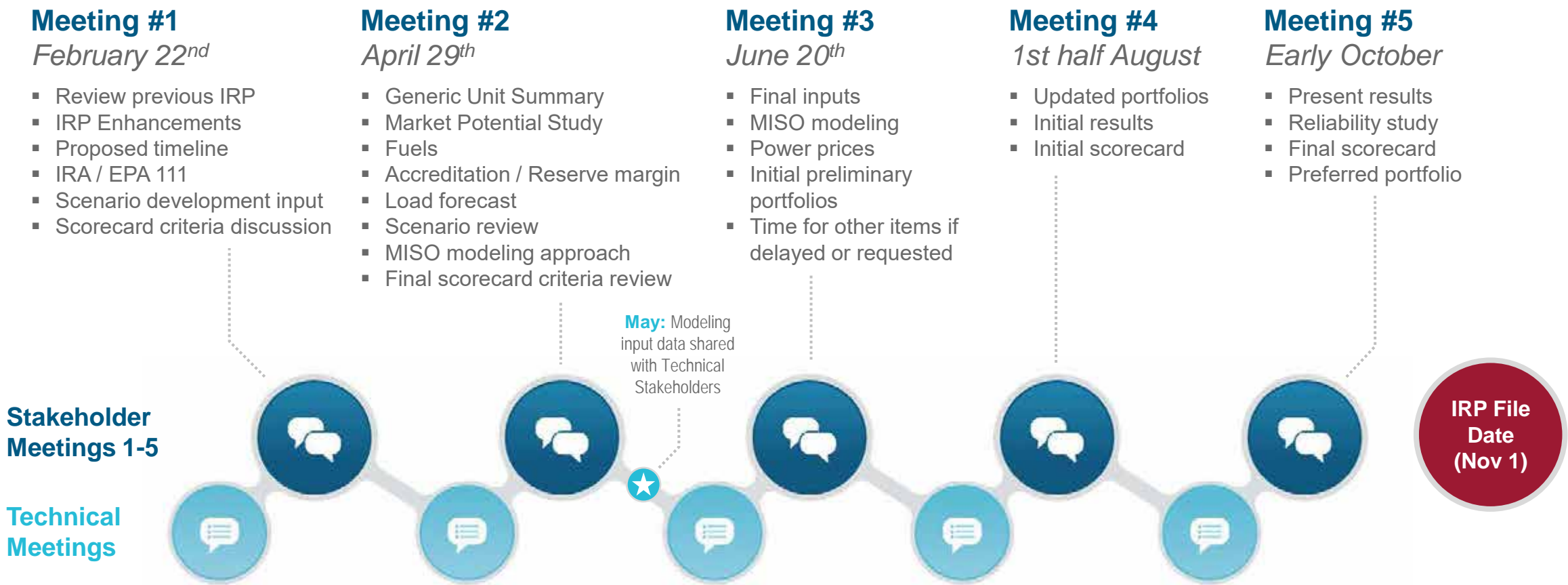




# Open Q&A

# 2024 DEI IRP Stakeholder Meetings

*Engaging with our stakeholders in multiple sessions throughout the 2024 IRP process*



# Next Steps



**Modeling and analysis  
to be performed in  
coming weeks**

- Review Stakeholder Meeting Feedback
- Perform Additional Sensitivity Modeling
- Final Base Case and Scenario Simulations
- Final Scorecard
- Select Preferred Portfolio

Jul

Aug

Sep

Oct



**Customer Programs  
Webinar**  
Aug. 6

**Technical Stakeholder #4**  
Aug. 8  
**Public Stakeholder #4**  
Aug. 13

**Public Stakeholder #5**  
**Technical Stakeholder #5**  
Early Oct.

**IRP File  
Date  
Nov 1**



**Topics  
seeking  
input**

- Scorecard calculations
- Analytical framework
- Meeting 5 format
- Data sharing

## Next Steps



Additional questions, comments,  
and feedback can be sent to

[DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com)

**Please provide any written feedback by August 20, 2024**

The fifth technical and public stakeholders meeting will occur  
in early October.

Meeting registration will be sent out  
4-6 weeks in advance.



# Thank you



# Appendix: Acronyms



# Acronyms

<b>APRI</b>	Aggressive Policy & Rapid Innovation
<b>BOY</b>	Beginning of Year
<b>BTA</b>	Build Transfer Agreements
<b>CAA 111</b>	Clean Air Act 111
<b>CAGR</b>	Compound Annual Growth Rate
<b>CAPEX</b>	Capital Expenditures
<b>CC</b>	Combined Cycle
<b>CCS</b>	Carbon Capture and Sequestration
<b>CPCN</b>	Certificate of Public Conveniency and Necessity
<b>CT</b>	Combustion Turbine
<b>DDRE</b>	Deep Decarbonization and Rapid Electrification
<b>DEI</b>	Duke Energy Indiana
<b>D-LOL</b>	Direct Loss of Load
<b>DPP</b>	Definitive Planning Process
<b>DR</b>	Demand Response
<b>DSM</b>	Demand-Side Management
<b>EE</b>	Energy Efficiency
<b>EFORd</b>	Equivalent Forced Outage Rate on Demand
<b>EPA</b>	Environmental Protection Agency
<b>EPC</b>	Engineering, Procurement, and Construction
<b>FT</b>	Firm Transport
<b>GHG</b>	Greenhouse Gas
<b>GIA</b>	Generator Interconnection Agreement
<b>GUS</b>	Generic Unit Summary

<b>GW</b>	Gigawatt
<b>ICAP</b>	Installed Capacity
<b>IRA</b>	Inflation Reduction Act
<b>IRP</b>	Integrated Resource Plan
<b>IVVC</b>	Integrated Volt/VAR Control
<b>kW</b>	Kilowatt
<b>MBE</b>	Minority Business Enterprise
<b>MISO</b>	Midcontinent Independent System Operator
<b>MPLI</b>	Minimum Policy & Lagging Innovation
<b>MW</b>	Megawatt
<b>MWh</b>	Megawatt-hour
<b>NG</b>	Natural Gas
<b>NGC</b>	Natural Gas Conversion
<b>NRIS</b>	Network Resource Interconnection Service
<b>O&amp;M</b>	Operations and Maintenance
<b>PPA</b>	Power Purchase Agreement
<b>PVRR</b>	Present Value of Revenue Requirement
<b>RFP</b>	Request for Proposal
<b>SAC</b>	Seasonal Accredited Capacity
<b>SPS</b>	Solar Plus Storage
<b>STG</b>	Steam Turbine Generator
<b>TWh</b>	Terawatt Hour
<b>UCAP</b>	Unforced Capacity
<b>WBE</b>	Women's Business Enterprise



# Duke Energy Indiana's 2024 Integrated Resource Plan Engagement Session

## OCTOBER 3, 2024, MEETING SUMMARY

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## Meeting Information

On Thursday, October 3, 2024, Duke Energy Indiana convened the fifth stakeholder meeting to inform the development of the 2024 Duke Energy Indiana Integrated Resource Plan ("IRP"). The meeting was held virtually. Approximately 65 external individuals representing over 37 organizations participated in this session.

## Facilitation Process

To encourage collaboration and to foster an environment where diverse perspectives could be shared, 1898 set forth the following ground rules for the session:

- **Respect each other:**  
Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve a better understanding and develop robust solutions.
- **Focus on today's topics:**  
Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.
- **Chatham House Rule:**  
Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

## Session Participation

This virtual event was facilitated by 1898 & Co., and the session included presentations and robust conversations on the following topics:

- Feedback from the Fourth Public Engagement Session
- Analytical Framework and Preferred Portfolio
- Scenario and Sensitivity Analysis
- Scorecard Results and Enhanced Reliability Evaluation
- Preferred Portfolio and Short-Term Action Plan Considerations

Virtual attendees used the "raise hand" feature in Teams to ask a question or make a comment aloud or submitted a question through the "Q&A" feature. Virtual attendees had access to the "chat" feature in Teams to share links to information and communicate with each other. Staff from 1898 & Co. took meeting notes, which have been included in the summary. Pursuant to the ground rules, the notes have been anonymized.

If participants had questions after the session or wanted to share feedback or additional information, they were asked to send an email to [DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com).

## Access to Meeting Materials

Meeting materials for the October 3, 2024 engagement session were posted to Duke Energy Indiana's IRP website at [duke-energy.com/home/products/indiana-integrated-resource-plan](https://duke-energy.com/home/products/indiana-integrated-resource-plan) on September 26, 2024. Participants were asked to visit the website to view the materials and meeting summaries. The 1898 & Co. team will continue to contact stakeholders via email as the website is updated with materials.

## Meeting Notes

This document includes a high-level summarization of the presentation material as well as the questions and comments made by participants. The questions and comments were captured throughout the meeting; however, the summary herein does not constitute a meeting transcript. Questions and commentary were edited for clarity as needed.

## Safety

*Karen Hall, Duke Energy Resource Planning Director*

Ms. Hall provided a safety moment on fire prevention, covering cooking fire safety, tips for handling small fires, checking fire alarms, and the importance of all family members knowing what to do if there is a fire.

## Welcome

*Stan Pinegar, Duke Energy Indiana State President*

Mr. Pinegar opened the meeting by welcoming attendees, thanking them for their participation, and encouraging active engagement in the fifth and final stakeholder meeting for the 2024 IRP.

## Introductions

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk introduced the Duke Energy teammates who are supporting the 2024 IRP.

## Meeting Guidelines & Agenda

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk discussed the ground rules for the virtual meeting. These guidelines included respecting each other, staying on topic, and the Chatham House Rule. He also reviewed guidelines for audience participation and the meeting agenda.

## Stakeholder Feedback and Incorporation

*Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.*

Mr. Burczyk provided an overview of stakeholder feedback that was received and incorporated into the agenda for the fifth Public Engagement Session and when this feedback would be discussed in the meeting. He then covered additional feedback and the responses from Duke Energy Indiana, which included topics such as heat rate inputs for the IRP modeling, data center load sensitivity clarifications, and other IRP modeling questions.

## Analytical Framework & Preferred Portfolio

*Nate Gagnon, Managing Director Midwest IRP*

Mr. Gagnon provided an overview of the different generation strategies—Convert/Co-fire Coal, Retire Coal, Convert Cayuga, Co-fire/Retire Gibson, Co-fire/Convert Gibson, Exit Coal Earlier, and "No EPA 111"—and specifically addressed how they relate to the Cayuga, Gibson, and Edwardsport units in terms of retirement, co-firing, or natural gas conversion under each strategy. He explained that Blend 3, a strategy that included incremental generation, was replaced with Blend 4, which is a Co-fire/Convert Gibson generation strategy. Blend 4 includes the retirement of Cayuga 1 by 1/1/2030, the retirement of Cayuga 2 by 1/1/2031, and then to meet the requirements of CAA Section 111, Gibson 1 and Gibson 2 are converted co-fired units by 1/1/2030 while Gibson 3 and Gibson 4 are converted to natural gas units by 1/1/2030. Mr. Gagnon then reviewed the analytical framework for the IRP, which includes the generation strategies and worldviews (Reference, Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation), resulting in 18 Scenario portfolios. He added that with additional strategy variations, portfolio sensitivities, production cost sensitivities, and a supplemental stakeholder portfolio, there is a total of 45 resource portfolios modeled.

Mr. Gagnon presented the Co-fire/Retire Gibson strategy (Blend 2) as the Preferred Portfolio, noting that it achieves an appropriate balance across the IRP planning objectives. He highlighted that Blend 2 balances cost and risk for customers, adds incremental capacity to serve economic development, and also preserves optionality to adapt to changing conditions. Mr. Gagnon also highlighted some of the short-term action plans that support Blend 2.

## Q&A related to Analytical Framework & Preferred Portfolio

1. Question: Under the non-EPA 111-compliant pathway, why do Gibson 1 and 2 retire on 1/1/2036 but, under the EPA 111 compliant pathway, there are portfolios that convert existing coal units to be co-fired units that stay online through 2038?
  - a. This is based on EPA 111 compliance deadlines. The EPA 111-compliant strategies have additional constraints for existing coal-fired units and new gas units which require many changes to be made by 2032, introducing additional challenges from an operational standpoint. In generation strategies that are EPA 111-compliant, Gibson 1 & 2 are co-fired by 1/1/2030, allowing them to run through 2038 in compliance with the rule. These co-fired units do not contribute

significantly to the total energy supply, but they provide vital capacity to maintain reliability for customers. Keeping this capacity online until the mandated retirement date under the rule defers the need for replacement resources and helps maintain affordability for customers. The “No 111” strategy variation benefits from a less restrictive regulatory environment, providing operational flexibility and allowing a more measured pace of transition out of coal through the early 2030s. In that case, all coal units retire by the end of 2035.

2. Question: What drives the differences between the retirement strategies in terms of the five Gibson units?
  - a. The Duke Energy Indiana IRP team worked with plant engineers to determine the different strategies based on the operational considerations of the Gibson units (age of emissions controls, site layout, etc.). Moving forward, more refined engineering studies could confirm or lead to adjustments to which units are selected for co-firing, conversion, or retirement.
3. Question: What are the challenges related to existing unit retirement timing and what drives the new resource selection in the IRP model?
  - a. There is a cost to retiring and replacing the existing capacity that is on the system. The IRP model is an economic optimization model that selects resources to meet energy and capacity needs, accounting for a variety of constraints. When resources are being selected over the planning period, the model is looking at the energy and capacity needs in the near and long term and the economics of these decisions drive the resource selection in order to meet the system’s needs.
4. Comment: It would be helpful to see the differences of non-CO<sub>2</sub> emissions metrics.
5. Question: Does the model assume a specific amount of coal or gas that must be used each year?
  - a. The model utilizes an economic dispatch to determine which fuel to burn on an hourly basis. Generally, the converted and co-fired units are dispatched infrequently in the modeling and have low capacity factors. These units act primarily as capacity resources. With low capacity factors after converting to natural gas or co-fired units, the total emissions from these resources are also lower.
6. Question: How does the 2024 Preferred Portfolio compare with the Preferred Portfolio from the 2021 IRP in terms of clean energy and coal retirements?
  - a. Significant changes have occurred in state and federal policies, regulatory environment and the marketplace since Duke Energy Indiana submitted its 2021 IRP that have impacted the resources this IRP. We are planning the 2024 IRP in a time of profound transformation, and many impactful changes have occurred since the 2021 IRP which are reflected in the 2024 IRP.
7. Question: Was an early switch to gas without any modifications of Edwardsport considered?
  - a. No, Edwardsport is optimized to burn syngas, so its maximum unit output is lower when Edwardsport burns natural gas. With the projected load growth, derating Edwardsport in the near term increases the need for additional new capacity.



8. Question: Are there potential technical or economic challenges associated with adding CCS at Edwardsport?
  - a. Yes, but the ongoing Front-End Engineering Design (FEED) study with the DOE will help provide additional details and input on future plans at Edwardsport.
9. Question: What are the cost savings of timing the Edwardsport conversion with the next major maintenance outage?
  - a. That is something that would be considered as part of the execution plan after the IRP analysis. Additional planning, studies, and engineering would play a role in the final conversion execution.
10. Question: When co-firing, can the unit run on 100% coal or 100% gas?
  - a. In the model, co-fired units can run up to 50% of full load on gas. Operationally, it is possible for a co-fired unit to run on 100% coal; however, the emissions standards under the 111 rule effectively require co-fired units to burn at least 40% gas on an annual average basis.

## Scenario & Sensitivity Analysis Summary

*Nate Gagnon, Managing Director Midwest IRP*  
*Matt Peterson, Lead Resource Planning Analyst*

Mr. Peterson provided a summary of the individual generation strategies, focusing on how each strategy performed in the Reference, Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation worldviews. He shared results related to cumulative supply-side changes, carbon emissions, Present Value of Revenue Requirement (PVR), firm capacity mix, and energy mix over time and offered an overview of each strategy.

Mr. Gagnon reviewed the results of the portfolio sensitivity analysis, highlighting peak load forecasts for high/low cases, resource selection changes under high and low load cases, the impact of high CC costs, changes in the capacity accreditation methods, and fuel prices. He emphasized changes in solar, wind, and storage capacity by 2035 and 2044, the sensitivity of resource selection to accreditation methods, as well as the impact of installed costs, technology advancements, and renewable energy contributions on capacity planning decisions.

## Q&A related to Scenario & Sensitivity Analysis Summary

1. Question: Several portfolios add additional solar and storage in the near term and then include significant wind, solar, and storage additions in the 2035-2044 time period. Why do we not see a steadier selection of resources in each year of the planning period?
  - a. The timing of these resource additions is based on the selections made by the EnCompass model. The model is selecting resources that most economically meet Duke Energy Indiana's energy and capacity needs to maintain reliability. The model selects some solar and storage in the near term to fill in capacity needs prior to 2030. As coal units are retired around the early 2030s, the model generally selects combined cycles to replace the retiring coal capacity in order to maintain firm capacity needs. After 2035, incremental capacity and energy needs

in the model are fulfilled by renewables and storage resources. Forcing in additional resources before they are needed would increase portfolio costs.

2. Question: This IRP shows a reduction in renewables by 2035 when compared to the 2021 IRP. Can you explain how this is consistent with environmental sustainability?
  - a. The Preferred Portfolio must balance all six planning objectives, of which environmental sustainability is one. There have been many changes since the development of the IRP that influence resource selection, including rapid increases in the cost of new resources, MISO capacity accreditation reform that emphasizes dispatchable resources, and industrial sector load growth that requires reliable, around-the-clock energy supply. All these significantly influence the timing and amount of resource additions and retirements.
3. Question: How are price changes, specifically for new generation, considered in the IRP. For example, if the Federal Reserve drops interest rates?
  - a. Each IRP is essentially a snapshot in time. Cost forecasts, for both fuels and new resources, are based on the best information currently available, including prevailing interest rates and many other factors. The Preferred Portfolio allows flexibility to adapt to changing conditions, and the entire analysis is updated every three years with each new IRP.
4. Question: Do the CO<sub>2</sub> emissions graphs on slides 23-25 include emissions from market purchases?
  - a. Yes, those graphs include emissions from market purchases.
5. Question: How does the firm capacity mix change between summer and winter?
  - a. This depends on the MISO rules for capacity value of the various resource types. For instance, certain resources, like solar, receive a higher accreditation in the summer and lower in the winter. So, for solar, that leads to a larger percentage of the firm capacity mix in the summer and lower in the winter. We have shown the winter calculation on the slides because the winter reserve margin becomes more limiting over time than the summer for our system.
6. Question: Please explain why the Minimum Policy and Lagging Innovation Scenario wasn't selected as the Preferred Portfolio?
  - a. Scenarios are not selectable generation strategies. Rather, they are intended to stress test the generation strategies under different conditions. The Reference Scenario has the assumptions that are believed to be most probable. Both the Minimum Policy and Lagging Innovation Scenario and the Aggressive Policy and Rapid Innovation Scenario consider potential futures that are less likely, but not implausible and are meant to explore the range of alternative future outcomes.
7. Question: Why are the winter peaks higher than the summer peaks starting in 2038?
  - a. The load forecast indicates that Duke Energy Indiana's growth is driven significantly by industrial customers, which have around the clock energy needs and are less temperature sensitive than residential load, which flattens out the annual load profile and leads to the shift toward winter peaks.
8. Comment: Commenter is concerned that environmental sustainability is not viewed as a "must" for the IRP.
9. Question: Are renewable capital costs constant in the model?

- a. No, renewables include cost curve assumptions that change over the planning period. Additionally, the Aggressive Policy and Rapid Innovation Scenario assumes more rapid cost declines for renewables and storage.
- 10. Question: How does Duke Energy account for behind-the-meter generation for large customers, particularly those that can handle a substantial share of their own energy and capacity needs?
  - a. The load forecast includes assumptions around customer behind-the-meter solar generation, with the effect of lowering the overall load over the forecast. A low, base, and high behind-the-meter generation forecast is included in the 2024 IRP modeling. Interruptible load, which is essentially equivalent to a demand response program is also modeled for large customers.
- 11. Question: Why do other investor-owned utilities in Indiana have more aggressive coal retirement and renewable generation additions than Duke Energy Indiana?
  - a. It is important to remember that every system is different. While other utilities in Indiana are helpful context, they are not determinative of Duke Energy's analysis and the path forward for balancing objectives specific to Duke Energy's system. Duke Energy Indiana remains committed to maintaining reliability and affordability while transitioning to an increasingly diverse and environmentally sustainable mix of resources.

## Scorecard Results & Enhanced Reliability Evaluation

*Nate Gagnon, Managing Director Midwest IRP*  
*Patrick O'Connor, Principal Quantitative Analyst*  
*Ameya Deoras, Manager Quantitative Analytics*

Mr. Gagnon reviewed the final scorecard metric updates, highlighting the incorporation of stakeholder feedback into the metrics. He discussed the separation of spinning reserve and fast start metrics, and the change in resource diversity to a firm capacity basis per stakeholder requests. He emphasized the PVRR results across Scenarios, noting that the Convert/Co-fire Coal strategy consistently yielded the highest PVRR, while the Retire strategy offered the lowest PVRR. He also highlighted the projected customer bill growth rates, with the Exit Coal Earlier strategy having a higher impact by 2030 and the Retire Coal strategy having higher rate impacts by 2035.

Mr. Gagnon then focused on environmental sustainability, detailing the CO<sub>2</sub> emissions trends across generation strategies. He noted that emissions drop steeply in 2030-2032 as coal is replaced by natural gas, renewables, and low-cost energy from the MISO market. He also discussed the CO<sub>2</sub> intensity of the Duke Energy Indiana portfolio, with the Retire Coal strategy having the lowest intensity in 2035 due to the significant contribution of advanced class CCs.

Mr. O'Connor reviewed the reliability and resiliency performance of the portfolios over a range of conditions in the stochastic analysis, including extreme cold weather scenarios. He highlighted the Expected Unserved Energy (EUE) metric, which represents periods of potential reliance on

the MISO market to meet customer demand. The study year 2035 was used as a benchmark, showing differing levels of winter risk across generation strategies.

Mr. Deoras then discussed the stochastic modeling of energy market exposure, explaining that real data from 43 weather years was used to create 300 different iterations. He noted that the results for 2028 are similar across the scenarios but that the 2044 operating costs are reduced by higher PTC/ITC credits, with narrower ranges resulting from higher renewables not subject to dispatch based on market/fuel prices. This also leads to lower net purchases in 2044. He noted that CO<sub>2</sub> emissions reductions in later years are driven by portfolio composition changes and lower market power prices. He then reviewed results for maximum generation dispatch of the Preferred Portfolio.

Mr. Gagnon also presented the scorecard results, covering various metrics such as environmental sustainability, affordability, reliability, resiliency, cost risk, market exposure, and execution risk. He detailed the cumulative resource additions by 2035 and 2044, and the performance of the generation strategies across the scorecard metrics.

#### Q&A related to Scorecard Results & Enhanced Reliability Evaluation

1. Question: Can you provide data from the non-CO<sub>2</sub> emissions metric that was previously on the scorecard?
  - a. Yes. This data will be included in the final IRP document.
2. Question: Please explain the 43-year weather factor used in the stochastic analysis?
  - a. In place of the weather profile used in the capacity expansion model, the stochastic analysis utilizes weather data from 1980 to 2022 from Indiana weather stations to determine what load would look like in each of those weather years. That is then used to run outage simulations to get 300 different probabilistically generated scenarios.
3. Question: Is there a weighting applied to the 43 weather years?
  - a. No, each of the weather years is viewed as being equally probable.
4. Comment: Commenter is concerned that the 43 years of historical weather data is not indicative of future weather patterns.
  - a. Duke Energy is open to altering this methodology if there is another generally agreed upon method that can be applied to this analysis in the future.
5. Question: Did you use the same historical weather data in the 2021 IRP?
  - a. The SERVIM enhanced reliability analysis was not performed as part of the 2021 IRP. However, this is a similar process to what MISO and others follow. This analysis aims to get a wide range of outputs as opposed to the deterministic model, which uses a single weather profile.
6. Comment: Commenter recommends looking at IPCC for future weather trends.
7. Question: Has Duke Energy Indiana looked at how other utilities are modeling weather in their stochastic analyses?
  - a. Using historical weather data is an industry standard practice as it pulls data that includes historical extreme weather years. There is no widely agreed-upon way to predict future weather patterns on an hourly basis.

8. Question: Are other Duke Energy subsidiaries using historical weather data that are relevant to their regions?
  - a. Yes. Duke Energy subsidiaries are using similar weather data specific to their respective regions in other jurisdictions. From an input and software perspective, this analysis is also consistent with similar MISO and other peers' analysis.
9. Question: Does the idea that there is more decentralized and consumer access to rooftop solar and community solar factor into the resiliency and energy needs?
  - a. The capacity expansion modeling includes a forecast for new rooftop solar, but it is not explicitly modeled in the stochastic analysis as this analysis is done to evaluate risk. The main risk factors are power prices, fuel prices, and outages.
10. Question: Are polar vortexes compelling evidence of climate change associated with overall global warming?
  - a. Events like polar vortexes represent instances of past extreme weather and are an important component of the historical data used in the stochastic analysis to evaluate what Duke Energy's load might look like under extreme conditions in the future.
11. Question: How are you incorporating projected increases in temperature ranges due to climate change, particularly in the hotter summer months?
  - a. No adjustments were made to any of the historical weather data, but the data does have extreme weather events, which helps to account for this.
12. Question: Why is the Exit Coal Earlier strategy weather risk higher?
  - a. The Exit Coal Earlier strategy is more susceptible to reliability risk in the winter as it carries less thermal generation, relying more on more solar and storage. When the system is under stress, the storage cannot charge overnight.
13. Question: Can information for the cumulative CO<sub>2</sub> emissions by year and strategy be shared?
  - a. Yes. The IRP will include the annual CO<sub>2</sub> emissions by generation strategy.
14. Question: Work has been done with Purdue Climate Change Center to develop a load forecast that considers climate change as part of the previous IRP, is that not being used as part of this IRP?
  - a. In the 2021 IRP, Duke Energy ran a sensitivity at request of stakeholders, working with Purdue data on climate change temperatures, which did not make a material difference to the load forecast. Since it did not have a significant impact, the sensitivity was not included in the 2024 IRP.
15. Question: What are some of the reasons for not transitioning away from thermal resources in the next few years?
  - a. We must reliably serve our customers while maintaining affordability. Constraints such as project lead times, interconnection process delays, and permitting are all factors that are limiting the near-term speed of transition, and cost to customers is always an important consideration. The Aggressive Policy & Rapid Innovation, and Minimum Policy & Lagging Innovation scenarios, which are based on alternate assumptions and forecasts, explore potential futures in which the transition occurs more or less rapidly. As part of the IRP, it is important to identify a Preferred Portfolio which balances all of the planning objectives.

16. Question: Why does the scorecard make a comparison for CO<sub>2</sub> emissions reduction to 2025 instead of 2005 like the 2021 IRP?
- a. This baseline year was used at the request of stakeholders. 2025 is used to provide a baseline to compare what the emissions look like at the start and the end of the planning period. Additionally, we are factoring in the emissions from MISO market purchases in this IRP, which would not have been accounted for in the 2005 values. The change to use a more recent datapoint that was more representative of Duke Energy Indiana operations today was suggested by stakeholders and something that we highlighted as a change in the second public stakeholder meeting.
17. Question: In comparing the overall environmental impact, what data is included for quality impact such as particulate matter?
- a. Those impacts are correlated to CO<sub>2</sub> emissions, and are not explicitly outlined in the scorecard, but they will be included in the IRP document.
18. Question: Can you elaborate on the Energy Market Exposure metric?
- a. The Energy Market Exposure metric measures the maximum value of net energy purchases and sales from the MISO market as a percentage of total energy demand through the study period. The Preferred Portfolio does not need to purchase from the market to meet demand but does so when it is more economical.
19. Question: What is the confidence level on the CAGR metric?
- a. As with the IRP in general, the bill impact calculation is based on estimated and forecasted costs associated with each generation strategy over time and are therefore subject to fluctuations on how those factors materialize. Generally speaking, the more quickly a generation strategy transitions, the higher the CAGR will be in the early years of the planning horizon. Forecast error can be expected to affect the generation strategies in similar ways, which makes the relative bill impact results much more robust than the absolute numbers.
20. Question: Can the full cost breakdown and relationship between portfolio costs and the rate impact be shared?
- a. Bill impact analysis and calculations for each candidate portfolio have been provided to technical stakeholders who have signed an NDA.

## **Preferred Portfolio & Short-Term Action Plan Considerations**

*Nate Gagnon, Managing Director Midwest IRP*

Mr. Gagnon provided model results for the Preferred Portfolio, highlighting cost metrics, capacity changes, and energy savings. He discussed the optionality provided by the Blend 2 portfolio for a future in which CAA Section 111 restrictions are relaxed. He highlighted the potential for tax credits associated with CCS at Edwardsport to lower the PVRR and the need to advance early studies to maintain small modular reactors (SMRs) as a viable future planning option.

Mr. Gagnon also reviewed the planning period, noting the limited capability to make resource changes in the immediate future due to project lead times, the increased range of options in the early 2030s, and the greater uncertainty in the latter half of the planning period. He emphasized



the importance of maintaining reliable service while supporting economic development and transitioning coal units to meet growing customer needs.

Mr. Gagnon discussed the considerations for the short-term action plan, emphasizing the importance of maintaining flexibility to adapt to changing conditions. He highlighted the need to install two advanced class 1x1 combined cycle (CC) units at Cayuga Station by 2030 and 2031 to replace aging coal units and gain incremental capacity. He also stressed the importance of securing gas supply to Gibson Station to support co-firing, CC, and gas conversion options, and deploying approximately 500 MW of solar and 400 MW of battery energy storage by 2030 to meet near-term energy and capacity needs with the retirement of Gibson 5. Mr. Gagnon also presented potential plan adjustments if there is a delay of compliance deadlines under the 111 final rule, such as CCS evaluation at Edwardsport, and the preparation to develop a 2x1 CC to replace Gibson 3 and 4.

### Q&A related to Preferred Portfolio & Short-Term Action plan Considerations

1. Question: Will you provide more information about the investigations, input data, and conclusions for SMRs?
  - a. One of the appendices in the IRP document will be devoted to supply-side resources and contain more information on SMRs.
2. Question: How do you weigh the indirect environmental, health, and economic costs of emitting CO<sub>2</sub> when these costs exceed the direct costs of zero or low CO<sub>2</sub> approaches such as solar?
  - a. The goal of the IRP is to select a portfolio that most appropriately balances many planning objectives, including environmental sustainability, which includes CO<sub>2</sub> emissions as one of the indicators. It is difficult to quantify indirect impacts of emissions from the Duke Energy Indiana portfolio so that is not within the scope of the IRP analysis.
3. Question: Are virtual power plants (via the aggregation of distributed energy resources) counted within demand response?
  - a. A “virtual power plant” is another term used to describe the aggregation of demand response programs and an estimate is included in Duke Energy Indiana’s IRP as a resource. Over the summer, the Company held a webinar that highlighted many of the demand response programs available to our customers.
4. Question: Why is the demand response capacity flat?
  - a. The demand response capacity is not flat, but with the scale it is difficult to see the increase. In addition, it is difficult to include new, innovative customer programs in the quantitative IRP analysis because there is not yet data on their potential effects.
5. Question: Can data on cost metrics, energy mix, CO<sub>2</sub> emissions, firm capacity, and installed capacity be shared for the other strategies like it is for the Preferred Portfolio?
  - a. The appendix section of today’s meeting contains similar data for each of the generation strategies. Annual data will be included in the IRP document.
6. Question: Why are wind and solar investments not ramping up until 2035?
  - a. Some solar and storage are selected in the near term before 2030. Wind and solar resources were available for selection over the entire planning period, but

the model did not select them in the earlier years. Forcing in these resources on top of what was economically selected by the model would increase costs to customers.

7. Question: Were wind + storage and solar + storage considered in the IRP analysis?
  - a. Solar + storage is a selectable option in the model. With the granularity of how the model operates, it is better to determine whether energy storage should be co-located with renewables in the plan execution phase. Once energy storage is on the system, the analysis factors it in and utilizes storage resources to distribute renewable energy when needed. It is important to still consider that in some ways the MISO market and energy prices will also play a role in the storage resource dispatch.
8. Question: Does the Edwardsport conversion cost include the costs to optimize Edwardsport to run on natural gas?
  - a. Yes, the conversion cost is included in the analysis.
9. Comment: Commenter believes there is a lack of diversity in the Preferred Portfolio.
10. Question: Can information on the size of rooftop solar and what Duke Energy might do to encourage more rooftop solar be provided?
  - a. Rooftop (or "behind-the-meter") solar forecast and assumptions were presented in the second stakeholder meeting. Information on the capacity and adoption of behind-the-meter solar is included on slides 52-53 of the meeting two materials. Information about the Company's behind-the-meter programs will be included in the IRP document. The aggregate capacity customer programs, including rooftop solar, that are included in IRP modeling can be found on slide 42 of the Meeting 5 material. Duke Energy Indiana continues to look for ways to educate and help make the process of considering and adopting renewable generation easier for customers. There are several resources available on the Company's website. The "Generate Your Own" webpage provides an Interconnection Overview which includes generation options and details on how to get support. Customers can also get connected with trusted solar installers that have been vetted by the Company at Find It Duke.
11. Comment: Commenter believes there is more potential to increase sustainability and resiliency with behind the meter solar programs.
12. Question: What is Duke Energy proposing for the short-term action plan in regard to SMRs?
  - a. Duke Energy Indiana and Purdue University published an interim study on the feasibility of SMR and advanced nuclear deployment. Duke Energy and Purdue continue to collaborate on these issues. Additionally, Duke Energy is performing a preliminary siting study in the Midwest. SMRs were not selected by the model in this analysis, but these studies are being done to keep SMRs as a potential option for the future to provide round-the-clock zero-carbon energy.
13. Question: Does the timeline for the Preferred Portfolio consider imminent climate tipping points?
  - a. The timelines in the IRP analysis include compliance with required environmental rules and regulations, including those related to greenhouse gas emissions.

14. Question: Should Duke receive credits from the federal government for CCS projects or any other federally incentivized projects, how will you ensure compliance with Justice 40 if applicable?
- a. The IRP aims to identify a resource plan that will reliably serve customers over the planning horizon, while siting and execution of resource additions occur after the IRP has identified resource needs for the overall system. The Company is committed to seeking feedback and input on its projects and adjusting and aligning efforts where possible to achieve the best outcomes for the communities it serves. Thoughtful consideration of how projects and resource decisions affect communities is a cornerstone of the Company's approach. Should Duke Energy Indiana receive federal funding for any such project, the Company would work with the appropriate agency on a detailed community benefits plan.
15. Question: How does Duke Energy Indiana's pace of conversion to low-CO<sub>2</sub>, low-toxin emission sources compare to Duke Energy's other non-Indiana service territories?
- a. The right path forward for Duke Energy Indiana may not be the right path forward for another Indiana utility or another jurisdiction of Duke Energy. The goal of the IRP is to balance the portfolio across the Indiana objectives.
16. Question: Is the nearest term SMR in Indiana the Purdue reactor?
- a. Duke Energy and Purdue University worked together on an interim feasibility study for SMRs and advanced nuclear. The study examined the state of technology, the challenges such a deployment would pose, and proposed policy solutions. There has been no commitment from Purdue University or Duke Energy on siting or building an SMR. However, we continue to collaborate with Purdue University regarding SMR and advanced nuclear development.
17. Question: When will Duke Energy release an RFP regarding solar and storage needs to meet their near-term action plan?
- a. The Duke Energy team is working with bidders on an RFP currently to secure that capacity. More information surrounding this RFP can be found in the Meeting 4 materials.
18. Question: In 10 years, what would change regarding wind and solar that would change the model and its demand?
- a. 10 years out is unpredictable, but a future IRP evaluation will be performed in 2027 with updated inputs that have the possibility to contribute to different resources being selected.
19. Question: In comparing Blend 4 to Blend 2, Blend 4 achieves lower emissions over time with minimal customer impact. Why was Blend 2 selected as the Preferred Portfolio over Blend 4?
- a. The key difference between these portfolios is retiring Gibson 3 and 4 or converting the units to natural gas. This will continue to be evaluated, but ultimately the decision came down to transitioning away from legacy steam units toward a more efficient, flexible, resilient resource mix faster, which adds incremental generation.
20. Question: Do any of the evaluated strategies lock in fossil fuel use beyond 2050?

- a. Nothing is locked in place. With the uncertainty of long-term planning, it is difficult to predict what the energy mix will look like that far out.
21. Question: Will more information on the FEED study at Edwardsport for carbon capture be available?
- a. This is a DOE study, so results will be public once the study is completed.
22. Question: Where can information on the modeled portfolios and how much of each resource was considered be found?
- a. Information on what the model selected for each portfolio can be found in the appendix of the meeting slides. The IRP document will contain more details on what was considered and selected in the model.
23. Question: Will the appendix of the IRP include modeling assumptions?
- a. Chapter 3 – Key Assumptions will outline the modeling assumptions used in the IRP analysis.
24. Question: Did the IRP include any results from Duke Energy's recent clean energy RFP?
- a. Indirectly, yes. Cost forecasts used in the analysis were benchmarked against RFP bids to ensure cost projections are in line with what is currently in the market. The RFP also helped to inform how much new capacity would be available in the late 20s and early 30s.

# 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 5

*October 3, 2024*



BUILDING A **SMARTER** ENERGY FUTURE®



# Safety





## October is Fire Prevention Month

### 1. Cooking fires are the leading cause of home fires and home fire injuries

- Stay in the kitchen – Unattended cooking is the leading cause of cooking fires and deaths
- Keep anything that can catch fire — oven mitts, wooden utensils, food packaging, towels or curtains — away from your stovetop
- Have a “kid-free zone” of at least 3 ft around the stove and areas where hot food or drink is prepared or carried

### 2. If you have a small (grease) cooking fire and decide to fight the fire...

- On the stovetop, smother the flames by sliding a lid over the pan and turning off the burner - Leave the pan covered until it is completely cooled

- For an oven fire, turn off the heat and keep the door closed

### 3. If you have any doubt about fighting a small fire...

- Just get out! Close the door behind you to help contain the fire
- Call 9-1-1 from outside the home

### 4. Check Alarms

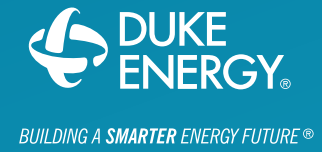
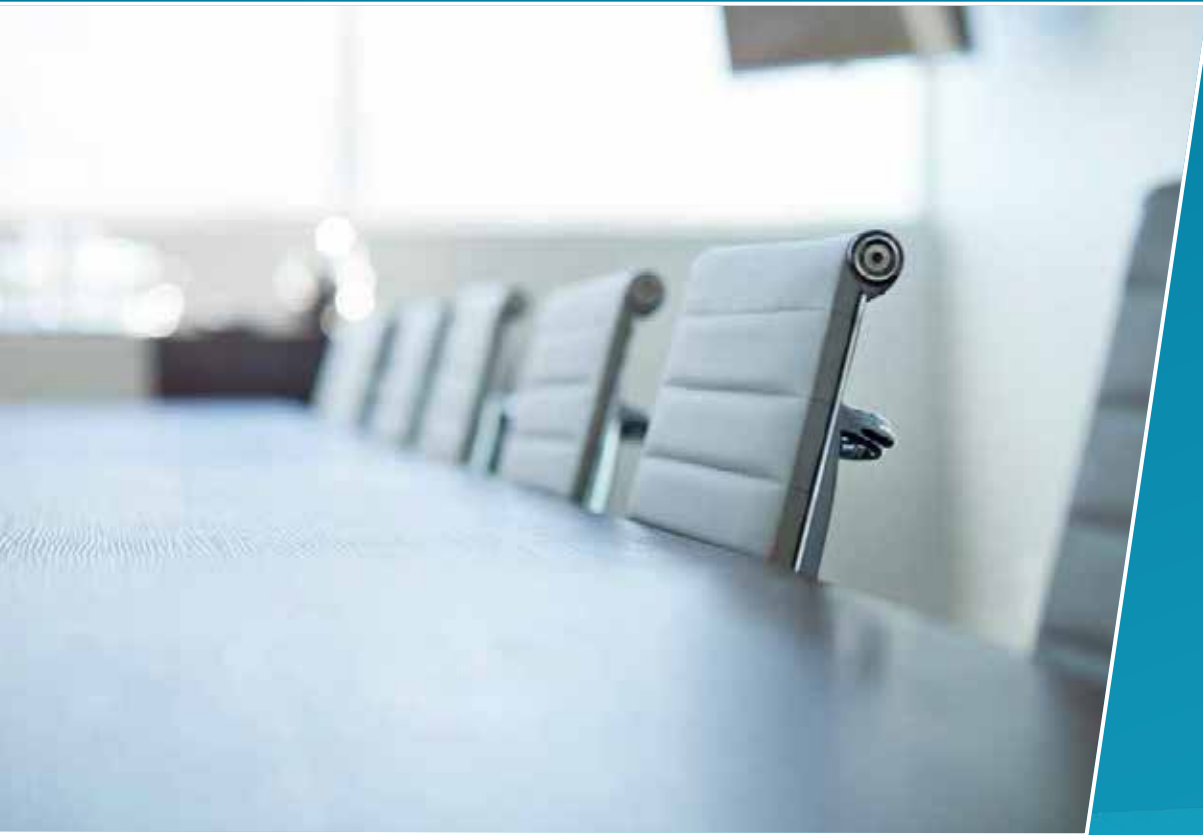
- Twice a year check batteries and replace equipment that's more than 10 years old

### 5. Know what to do if there is a fire and conduct a fire drill, including a meet-up location



# Welcome Stan Pinegar

State President, Duke Energy Indiana



# Introductions

# Duke Energy Team

## Integrated Resource Planning Team



**Matt Kalembe**  
*Vice President,  
Integrated Resource  
Planning*



**Nate Gagnon**  
*Managing Director,  
Midwest Integrated  
Resource Planning*



**Matt Peterson**  
*Resource  
Planning Manager*



**Emma Goodnow**  
*Market Strategy &  
Intelligence Director*



**Karen Hall**  
*Resource  
Planning Director*



**Chris Hixson**  
*Principal Engineer,  
Resource Modeling*



**Josh Paragas**  
*Engineer, Resource  
Modeling*



**Tyler Cook**  
*Engineer, Resource  
Modeling*

## Indiana Regulatory and Legal Team



**Kelley Karn**  
*Vice President,  
Indiana Regulatory  
Affairs and Policy*



**Beth  
Heneghan**  
*Deputy General  
Counsel*



**Liane Steffes**  
*Associate  
General Counsel*



**Ameya Deoras**  
*Manager, Quantitative  
Analytics*



**Patrick O'Connor**  
*Principal Quantitative  
Analyst*



**Drew Burczyk**  
*Consultant, Resource  
Planning & Market  
Assessments*

## Reliability Analytics

## 1898 & Co.



# Agenda



# Public Stakeholder Meeting #5 Agenda

Time	Duration	Present   Q&A	Topic	Presenter
9:30	5	5   0	Welcome & Safety	Stan Pinegar, Duke Energy Indiana State President Karen Hall, Duke Energy Resource Planning Director
9:35	5	5   0	Meeting Guidelines & Agenda	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:40	10	5   5	Stakeholder Feedback & Incorporation	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
9:50	25	15   10	Analytical Framework & Preferred Portfolio	Nate Gagnon, Duke Energy Managing Director Midwest IRP
10:15	45	25   20	Scenario & Sensitivity Analysis Summary	Nate Gagnon, Duke Energy Managing Director Midwest IRP Matt Peterson, Duke Energy Lead Resource Planning Analyst
11:00	10	-	BREAK	
11:10	60	30   30	Scorecard Results & Enhanced Reliability Evaluation	Nate Gagnon, Duke Energy Managing Director Midwest IRP Patrick O'Connor, Duke Energy Principal Quantitative Analyst Ameya Deoras, Duke Energy Manager Quantitative Analytics
12:10	40	-	BREAK	
12:50	30	15   15	Preferred Portfolio & Short-Term Action Plan Considerations	Nate Gagnon, Duke Energy Managing Director Midwest IRP
1:20	40	0   40	Open Q&A	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
2:00	5	5   0	Next Steps & Closing Remarks	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co. Nate Gagnon, Duke Energy Managing Director Midwest IRP
2:05	-	-	Adjourn	



# Technical Stakeholder Meeting #5 Agenda

Time	Duration	Present   Q&A	Topic	Presenter
9:00	5	5   0	Welcome & Safety	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co
9:05	20	10   10	Analytical Framework & Preferred Portfolio	Nate Gagnon, Duke Energy Managing Director Midwest IRP
9:25	45	25   20	Scenario & Sensitivity Analysis Summary	Nate Gagnon, Duke Energy Managing Director Midwest IRP Matt Peterson, Duke Energy Lead Resource Planning Analyst
10:10	10	-	BREAK	
10:20	65	35   30	Scorecard Results & Enhanced Reliability Evaluation	Nate Gagnon, Duke Energy Managing Director Midwest IRP Patrick O'Connor, Duke Energy Principal Quantitative Analyst Ameya Deoras, Duke Energy Manager Quantitative Analytics
11:25	15	-	BREAK	
11:40	30	0   30	Open Q&A	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
12:10	5	5   0	Next Steps & Closing Remarks	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co. Nate Gagnon, Duke Energy Managing Director Midwest IRP
12:15	-	-	Adjourn	



# Meeting Guidelines

# Meeting Ground Rules



## **Respect each other:**

Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

## **Focus on today's topics:**

Please respect the scope of today's meeting to make the most of our time. Pending legal issues are outside the scope of today's meeting.

## **Chatham House Rule:**

Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

# Participation



There will be several opportunities throughout the presentation for attendees to actively participate by asking questions, making comments and/or otherwise sharing information.

- **Q&A:** Please use the “Q&A” feature, on the menu at the bottom of your screen, to submit questions to the presenters. We will respond to as many of these as possible, time permitting, during designated time periods.
- **Raise hand:** If you wish to ask a question or make a comment orally, please use the “raise hand” feature, during designated time periods. A facilitator will call on you and invite you to unmute.
- **Chat:** The chat feature is enabled for sharing information and resources with other participants; however, it is sometimes difficult to monitor. If you would like a response from the presenters, please use the Q&A or raise hand features.



# Stakeholder Feedback and Incorporation

# Stakeholder Feedback Received & Incorporated into Meeting #5 Agenda

Feedback, Question, or Requested Information	Section of Today's Meeting
Scorecard Metric Feedback	Final Scorecard Metric Updates
How are risks of data center load captured in the IRP analysis?	Scenario and Sensitivity Analysis Summary



# Additional Feedback Received and Duke Energy Responses

Feedback, Question, or Requested Information	Response/Update
What is the basis of the heat rate inputs for the existing coal units? And why might these be higher or lower than the operational heat rate of these units in recent years?	<p>We just recently completed an evaluation of the heat rate coefficients for our Indiana coal fleet. The updated coefficients have been included in the final IRP analytics. The changes are not dramatic and reflect both increases and decreases depending on the unit, the season, and the loading level.</p> <p>There can be some differences between model inputs/outputs when compared to historical heat rate data, one main driver can be due to unit loading levels when comparing operational data over the past few years against the EnCompass production cost model, which optimizes unit dispatch with perfect foresight. Since heat rates describe a curve, with units generally operating less efficiently near min load than they do closer to max.</p>
How many MW of Data Center load is included in the high load sensitivity?	The high load sensitivity includes 500 MW of new data center load by 2031.
Please provide additional detail on the input assumptions and the results of the National Database Simulations used to determine the market energy price assumptions.	Model inputs and results summaries from the National Database were re-posted to Datasite for technical stakeholders to review.



# Q&A



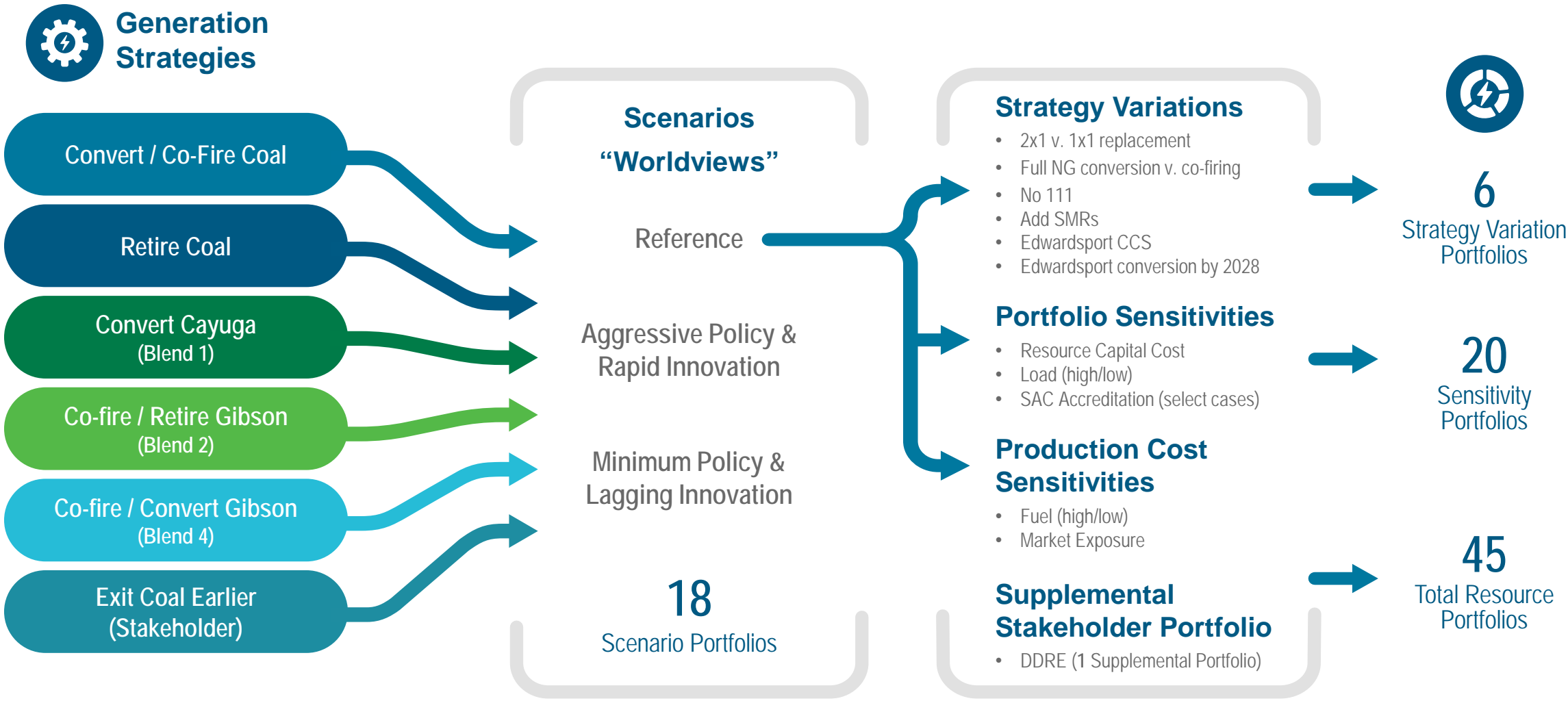
# Analytical Framework and Preferred Portfolio

# Generation Strategies Included in IRP Analysis

CAA Section 111-Compliant Strategies							Non-Compliant	
Unit	Convert / Co-Fire Coal	Retire Coal	Convert Cayuga (Blend 1)	Co-fire/Retire Gibson (Blend 2)	Co-fire/Convert Gibson (Blend 4)	Exit Coal Earlier (Stakeholder)	“No 111”	
Cayuga 1	NG Conversion by 1/1/2030	Retire by 1/1/2032	NG Conversion by 1/1/2030	Retire by 1/1/2030		NG Conversion by 1/1/2029	Retire by 1/1/2032	
Cayuga 2				Retire by 1/1/2031				
Gibson 1	Co-fire by 1/1/2030		Retire by 1/1/2032	Co-fire by 1/1/2030		Retire by 1/1/2032	Retire by 1/1/2036	
Gibson 2								
Gibson 3	NG Conversion by 1/1/2030			Retire by 1/1/2032	Retire by 1/1/2032	NG Conversion by 1/1/2030	Retire by 1/1/2030	Retire by 1/1/2032
Gibson 4								
Gibson 5	Retire by 1/1/2030							
EDW	NG Conversion by 1/1/2030						NG Conversion by 1/1/2035	

 Indicates strategies added since Meeting 4

# Analytical Framework



# 2024 Preferred Portfolio: Blend 2

<p><i>Preferred portfolio based on IRP criteria:</i></p> <p><b>Co-fire/Retire Gibson (Blend 2)</b></p>	<p>✓</p> <p><b>BALANCES COST &amp; RISK FOR CUSTOMERS</b></p>	<p>✓</p> <p><b>ADDS INCREMENTAL CAPACITY TO SUPPORT ECONOMIC DEVELOPMENT</b></p>	<p>✓</p> <p><b>PRESERVES OPTIONALITY TO ADAPT TO CHANGING CONDITIONS</b></p>
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Short-term actions supporting  
**Blend 2**

- Advance development of 1x1 CCs to replace retiring Cayuga coal units, add ~440 MW of incremental capacity by 2031
- Prepare to co-fire units Gibson 1&2 on 50% coal, 50% natural gas in compliance with the EPA CAA Section 111 Final Rule
- Commence development of 2x1 CC to replace retiring Gibson units 3&4, add ~177 MW of incremental capacity by 2032
- Prepare to retire Gibson unit 5, add ~499 MW of solar, ~400 MW of battery energy storage by 2030
- Prepare to convert Edwardsport to operate on 100% natural gas fuel by 2030 in compliance with EPA 111 Rule, while completing CCS FEED study to inform final decision
- Continue to monitor environmental regulations and market conditions, and evaluate opportunities to adjust course offered by the Blend 2 strategy

**Resource Planning Objectives**

 Reliability

 Resiliency

 Stability

 Environmental Sustainability

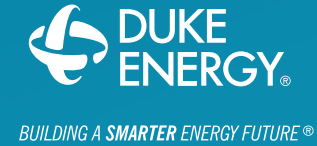
 Affordability

 Risk & Uncertainty





# Q&A

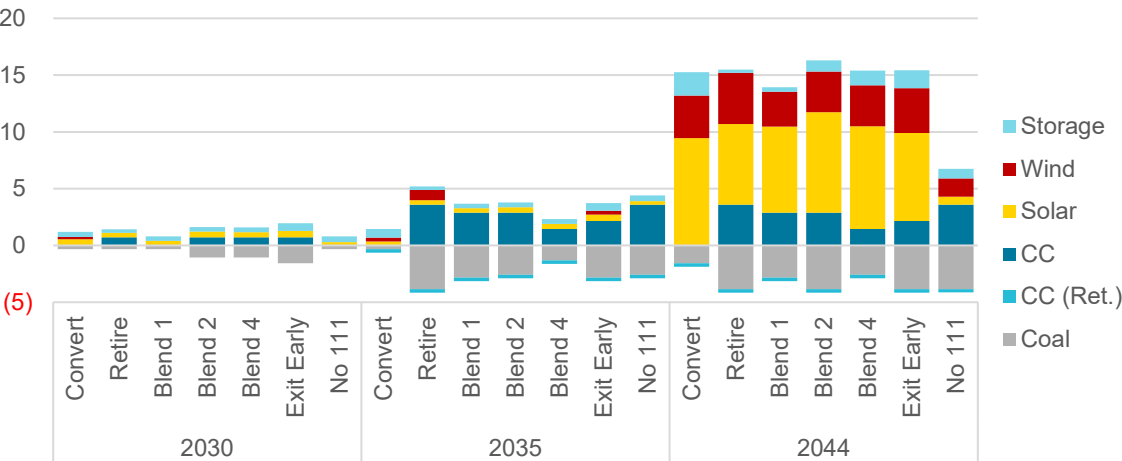


# Scenario and Sensitivity Analysis Summary

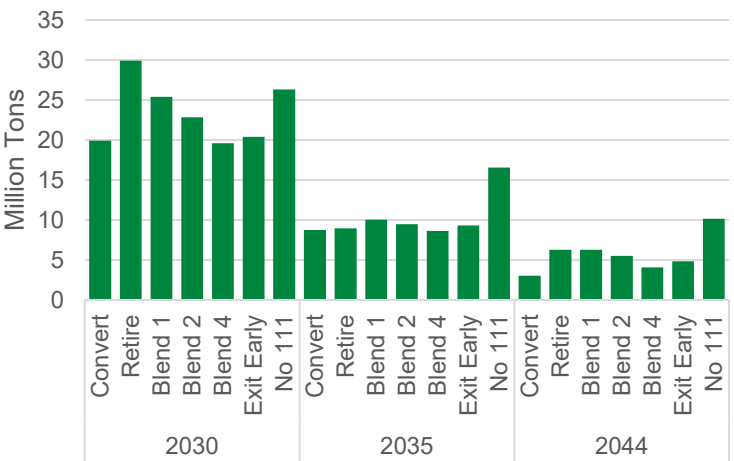
*Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.*

# Results Summary for All Strategies in Reference Scenario

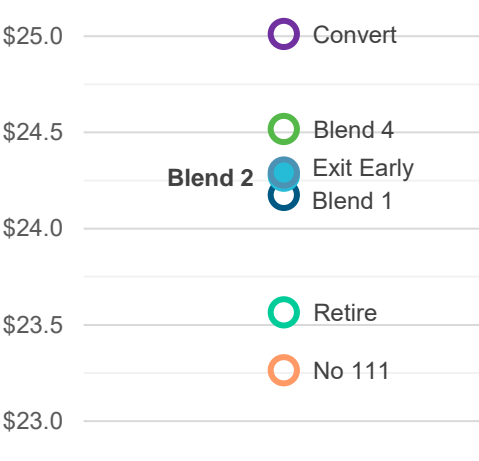
Cumulative Supply-Side Changes (Installed GW, BOY)



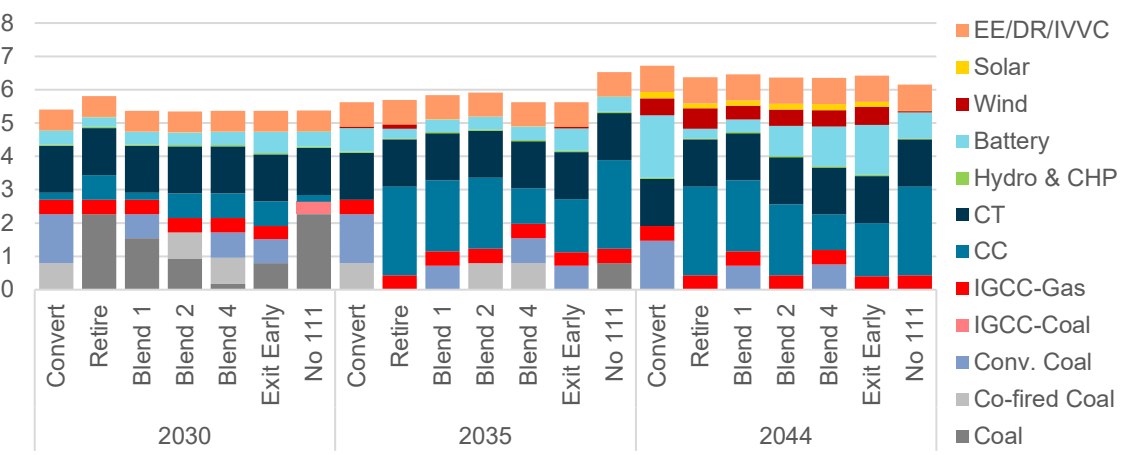
CO<sub>2</sub> Emissions (Mt)



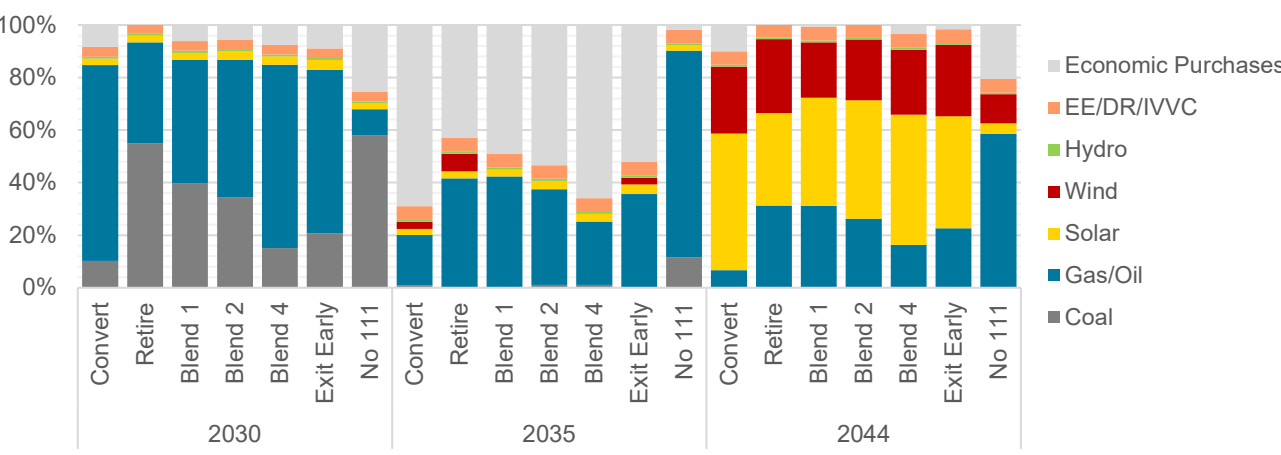
PVRR (\$B)



Firm Capacity Mix (Winter GW, BOY)

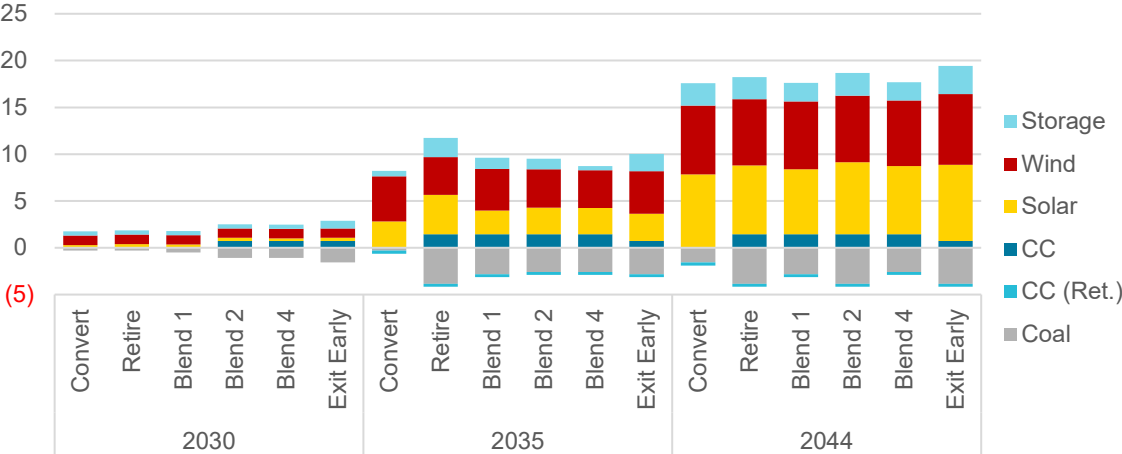


Energy Mix

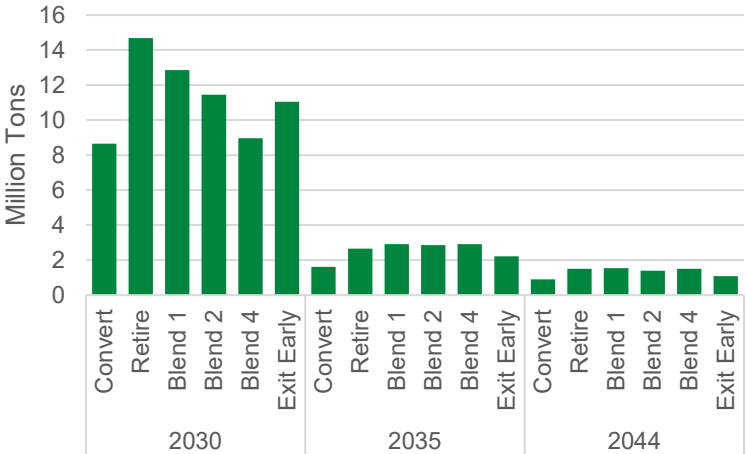


# Results Summary in Aggressive Policy & Rapid Innovation Scenario

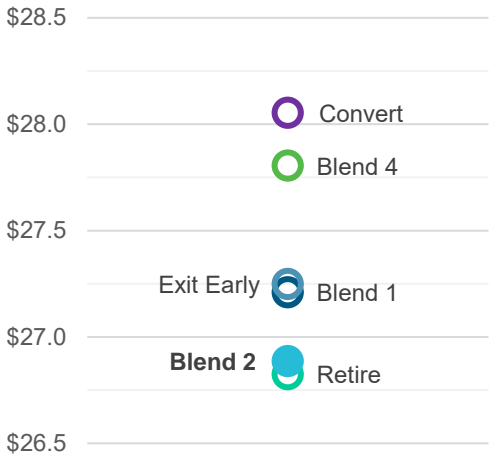
Cumulative Supply-Side Changes (Installed GW, BOY)



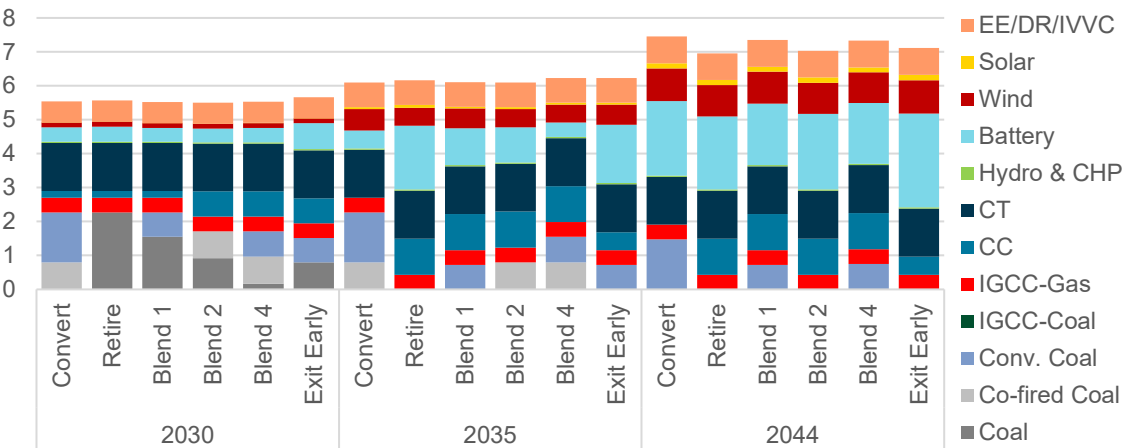
CO<sub>2</sub> Emissions (Mt)



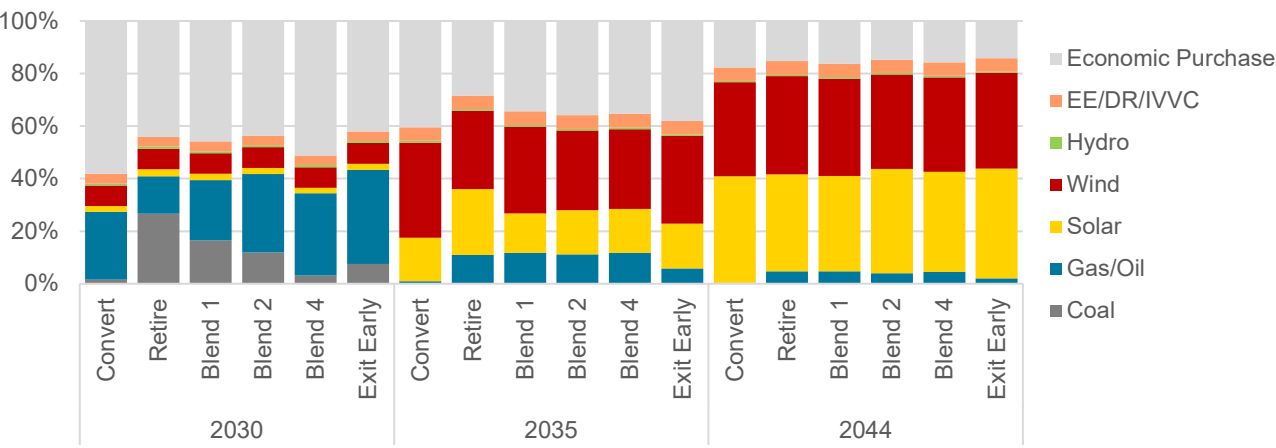
PVRR (\$B)



Firm Capacity Mix (Winter GW, BOY)



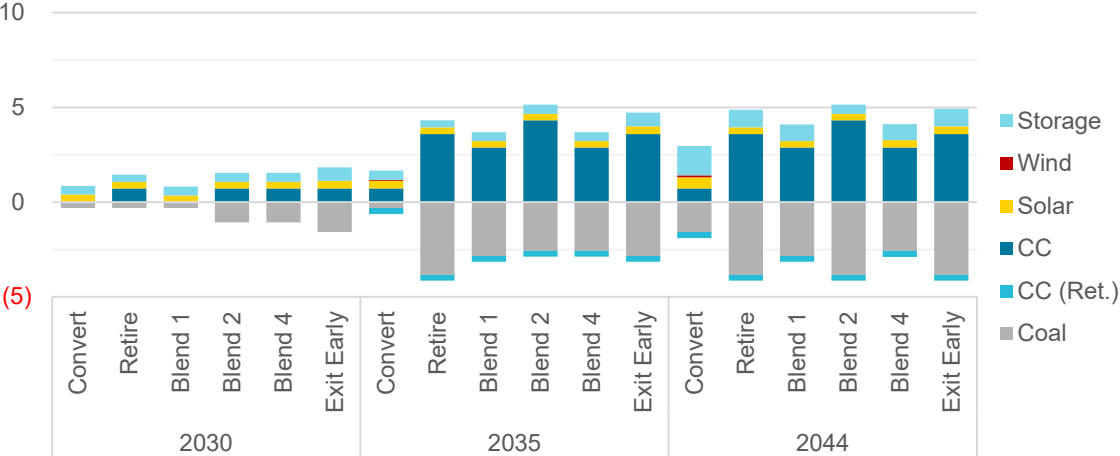
Energy Mix



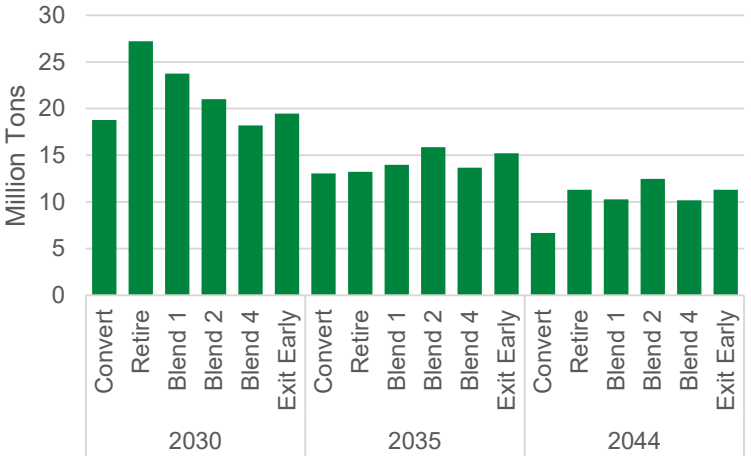
Note: The "No 111" generation strategy is modeled in the Reference scenario only

# Results Summary in Minimum Policy & Lagging Innovation Scenario

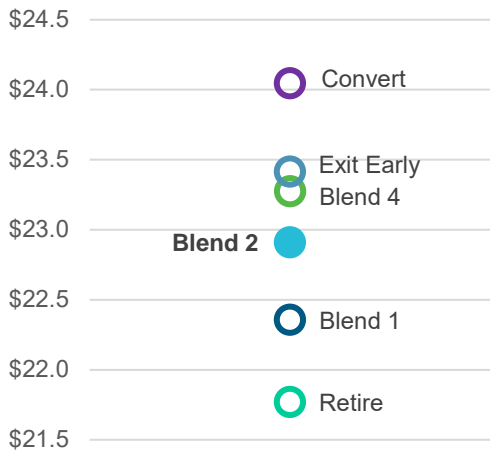
Cumulative Supply-Side Changes (Installed GW, BOY)



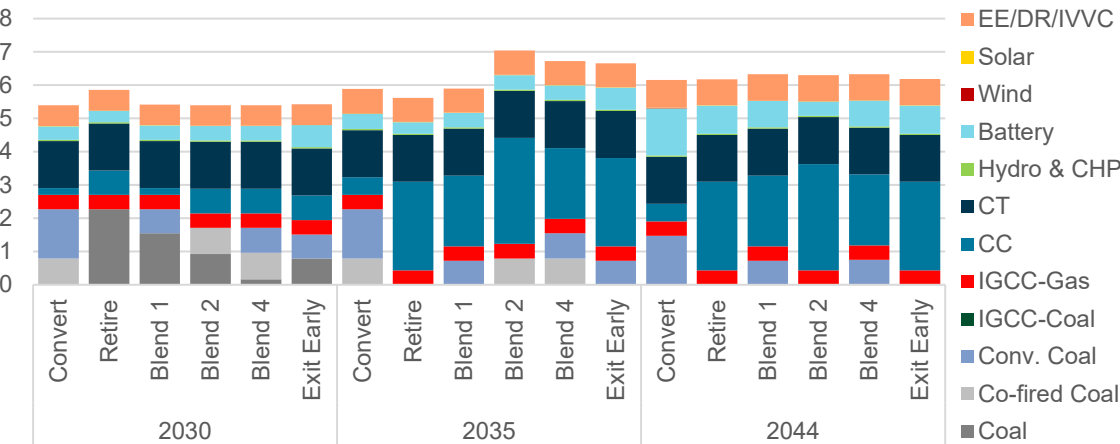
CO<sub>2</sub> Emissions (Mt)



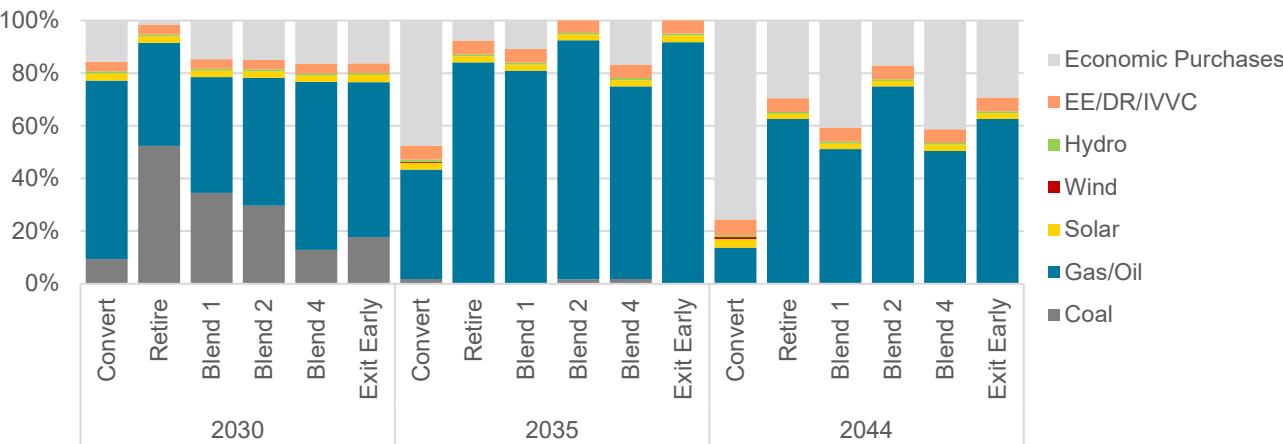
PVRR (\$B)



Firm Capacity Mix (Winter GW, BOY)



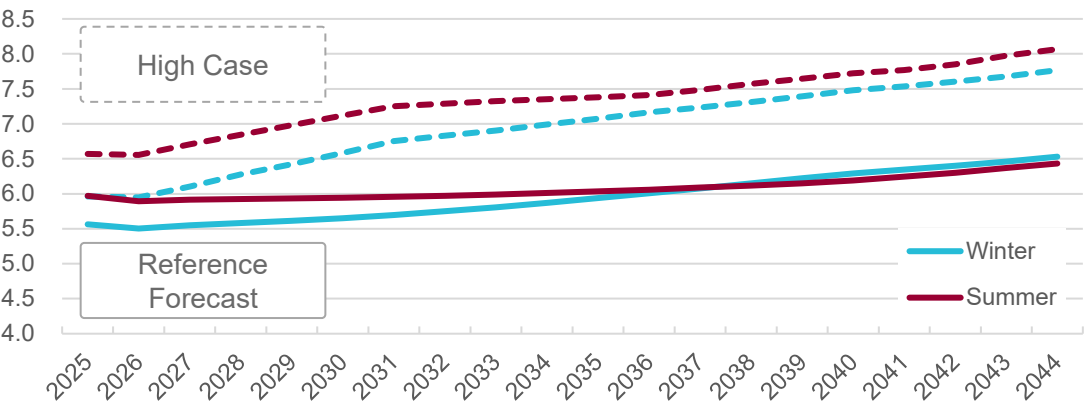
Energy Mix



Note: The "No 111" generation strategy is modeled in the Reference scenario only

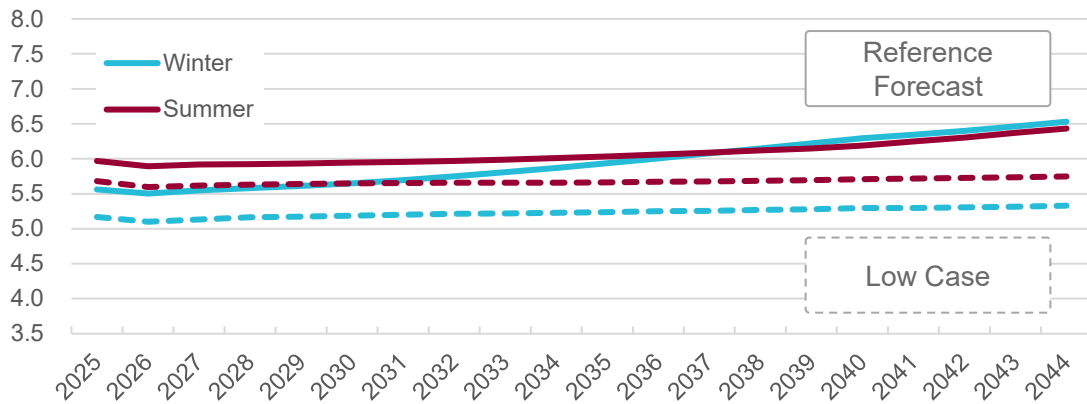
# Portfolio Sensitivity Analysis: Load Forecast

## Peak Load Forecast: Reference and High Cases (GW)



Note: High load forecast includes 500 MW of data center load in addition to assumption that 75% of economic development pipeline projects come to fruition

## Peak Load Forecast: Reference and Low Cases (GW)



## Resource Selection Changes in High Load Case (Installed MW change from Reference Case by 2035)

Generation Strategy	CC	Solar	Wind	Storage
Convert / Co-fire Coal	+719	+1,200	+400	+900
Retire Coal	+719	+1,950	+1,450	+725
Blend 1	+719	+1,000	+1,200	+650
Blend 2	+1,438	+1,000	+300	+900
Blend 4	+1,438	+1,100	+550	+875
Exit Coal Earlier (SH)	+1,438	+1,000	+1,200	+900

## Resource Selection Changes in Low Load Case (Installed MW change from Reference Case by 2035)

Generation Strategy	CC	Solar	Wind	Storage
Convert / Co-fire Coal	--	(150)	+50	(400)
Retire Coal	(719)	+500	--	--
Blend 1	+719	(150)	+650	(175)
Blend 2	--	(200)	--	(200)
Blend 4	--	--	--	(250)
Exit Coal Earlier (SH)	--	--	(250)	(500)

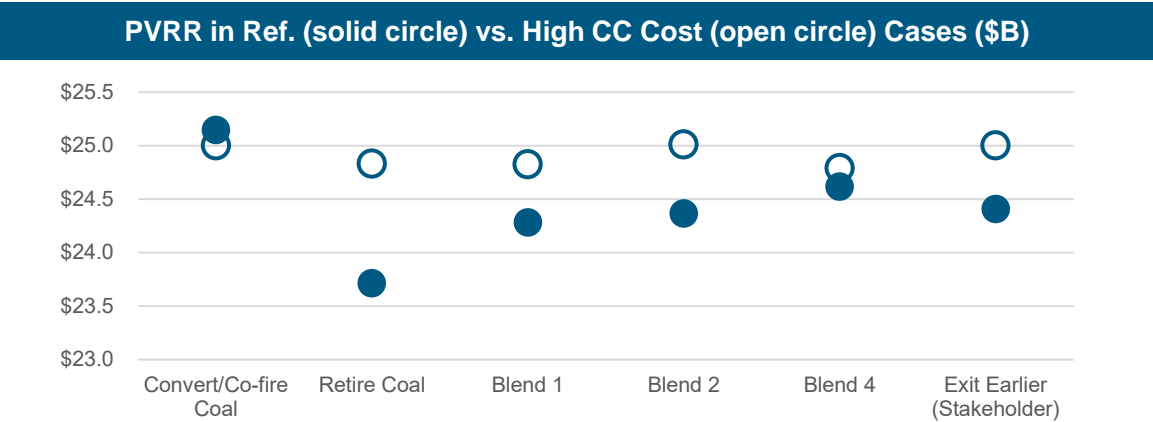


# Portfolio Sensitivity Analysis: CC Cost, Capacity Accreditation

## Impact of High (1.6x) CC Costs on Resource Selection & PVRR

- In a high CC cost future, at least 1,438 MW of new CC capacity is selected for most generation strategies (equivalent of two 1x1 CCs or one 2x1 CC)
- A high CC cost environment tightens the already narrow range of PVRR results across generation strategies, increasing total cost in proportion to CC MW in the Reference Case

CC Capacity Additions by 2035 (MW)			
Strategy	Reference Case	High CC Cost	Change from Ref
Convert/Co-fire Coal	--	--	--
Retire Coal	3,595	2,876	(719)
Blend 1	2,876	1,438	(1,438)
Blend 2	2,876	1,438	(1,438)
Blend 4	1,438	--	(1,438)
Exit Earlier	2,157	1,438	(719)



## Impact of Accreditation Method on Resource Selection

- Results show some sensitivity to capacity accreditation method, with additional selection of renewables in the bookend strategies evaluated (Convert, Retire) using Seasonal Accredited Capacity (SAC) throughout the study period in comparison to the adoption of Direct Loss of Load (D-LOL) methodology starting in 2028

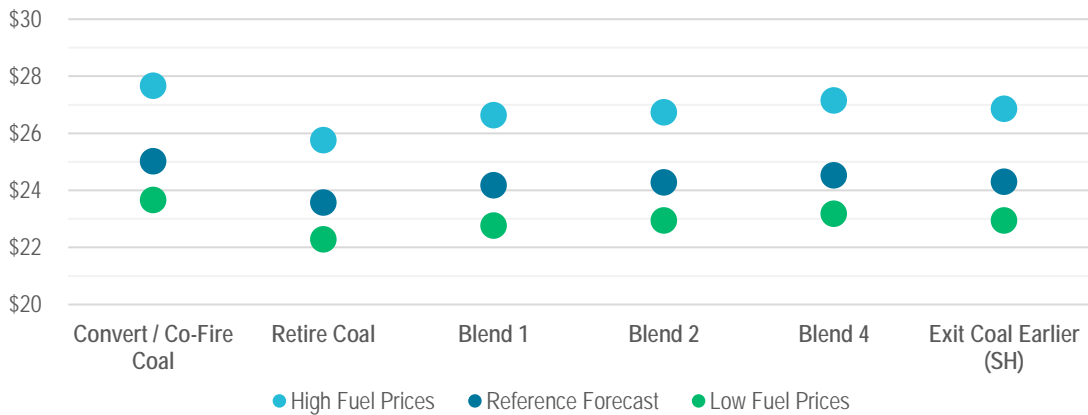
Capacity Accreditation for D-LOL & SAC Methods (Summer   Winter)				
Accreditation Method	CC	Solar	Wind	Storage
D-LOL (used in IRP 2028+)	90%   74%	36%   2%	11%   16%	94%   91%
SAC (used in IRP through 2027)	91%   90%	45%   6%	18%   40%	95%   95%

Reference Worldview Resource Additions by 2035 (Nameplate MW)				
Strategy	CC	Solar	Wind	Storage
Convert/Co-fire Coal in Ref.	--	349	350	750
► Change w/ SAC throughout	+719	+700	+500	+75
Retire Coal Reference	3,595	399	900	300
► Change w/ SAC throughout	(719)	+600	+900	+550

Reference Worldview Resource Additions by 2044 (Nameplate MW)				
Strategy	CC	Solar	Wind	Storage
Convert/Co-fire Coal in Ref.	--	9,449	3,750	2,050
► Change w/ SAC throughout	+719	+200	+700	(750)
Retire Coal Reference	3,595	7,099	4,500	300
► Change w/ SAC throughout	(719)	+50	+900	+550

# Production Cost Sensitivity Analysis: Fuel Price Forecasts

## PVRR Results for Alternate Fuel Price Forecasts (\$B)

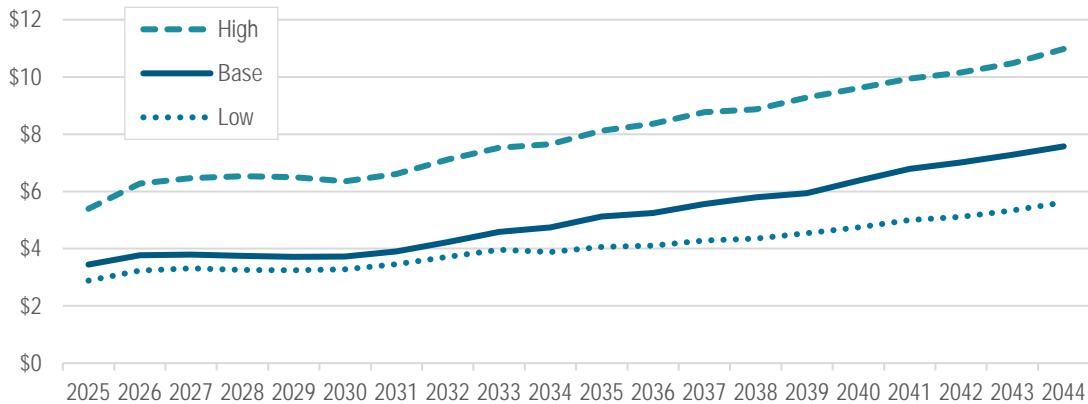


Note: Fuel price sensitivity modeled for each generation strategy in the Reference case

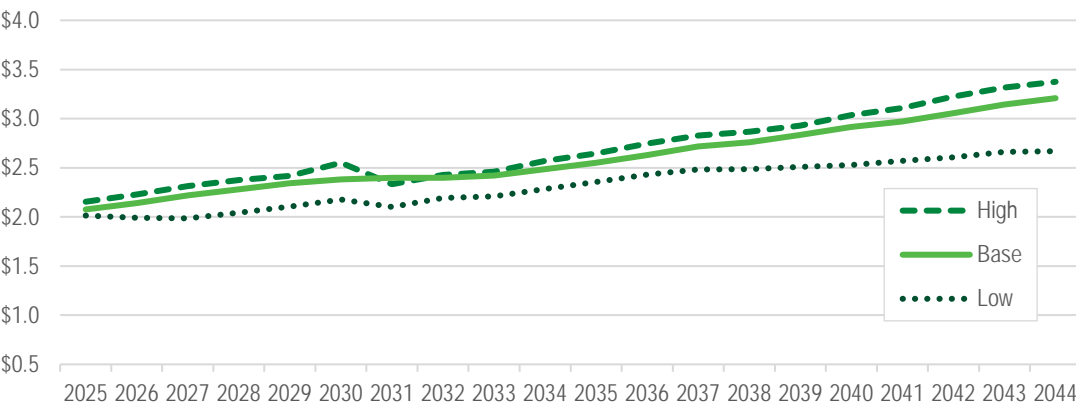
## Evaluation of Sensitivity to Fuel Price Variability

- Analysis of relative changes in portfolio operating costs under alternate fuel price forecasts, without altering the composition of the candidate portfolios
- Changes in fuel costs affect the cost of energy purchased from the MISO market as well as operating cost for the Duke Energy Indiana portfolio.
- Alternate fuel price forecasts do not capture supply shocks, the risk of which can reasonably be expected to increase over time for coal as the domestic utility industry shifts to other resources.
- PVRR changes are very similar across generation strategies, with little impact to relative ranking among the candidate portfolios.

## Natural Gas Price Forecasts (Henry Hub, \$/MMBtu)



## Coal Price Forecasts (Illinois Basin, \$/MMBtu)





# Q&A



# Scorecard Results

*Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.*

# Final Scorecard Metric Updates

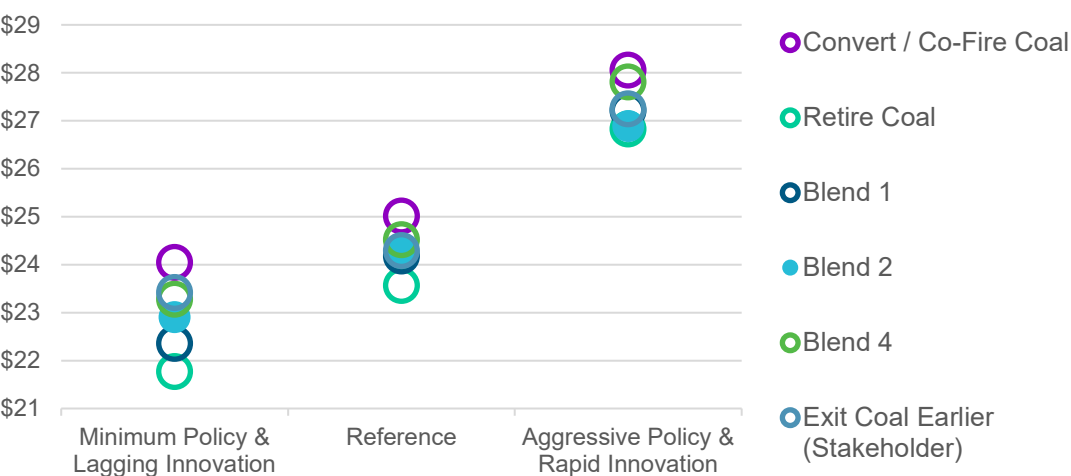


In **meeting 4** we discussed several potential changes to the final scorecard metrics and requested feedback on those updates. Following the meeting, we received feedback from several stakeholders. These are the updates made to the final scorecard.

Metric	Change	Summary
Non-CO <sub>2</sub> Emission Ranking	Removed	The non-CO <sub>2</sub> emissions ranking did not provide insight into portfolio emissions differently than the CO <sub>2</sub> metrics that were already included. Also, the magnitude and scale of differences between portfolios were not clear. There will still be commentary on non-CO <sub>2</sub> emissions in the IRP report.
CO <sub>2</sub> Intensity	Added	We have included the CO <sub>2</sub> intensity metric in the scorecard today. The CO <sub>2</sub> emissions reduction and cumulative CO <sub>2</sub> emissions both capture estimated CO <sub>2</sub> emissions associated with market purchases. The CO <sub>2</sub> intensity metric shows the emissions of DEI-specific unit generation across the different strategies.
Spinning Reserve and Fast Start	Split into 2 metrics	The spinning reserve and fast start metrics have been broken out separately in the final scorecard. This will provide more granular insights on the two metrics in isolation.
Resource Diversity from Firm Capacity	Changed	We have updated resource diversity to be shown on a firm capacity basis in the final scorecard.

# Affordability: PVRR & Customer Bill Impacts

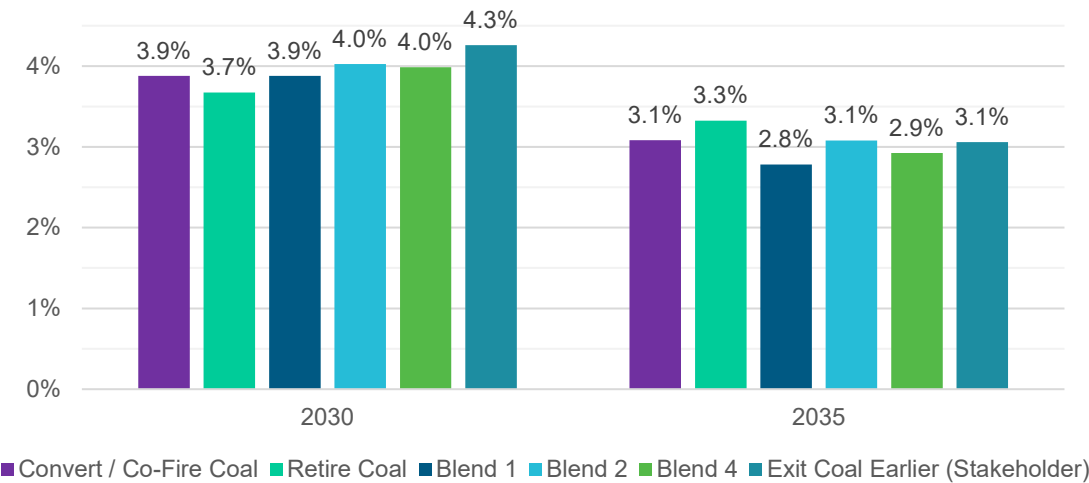
PVRR Results Across Scenarios



- PVRRs are tightly grouped in the Reference and Aggressive scenarios and exhibit more divergence in the Minimum scenario where strategies with more flexibility to maximize the value of new CC resources provide opportunities to lower total cost.
- Convert/Co-fire Coal strategy consistently yields the highest PVRR, while the Retire strategy that replaces aging coal units with highly efficient advanced class CCs offers the lowest PVRR over the planning period.

**Note:** IRP PVRR calculations do not consider depreciation of existing assets, other non-avoidable costs, costs not related to resource planning (e.g., distribution), and are useful for comparison only.

Customer Bill Compound Annual Growth Rates (Reference)

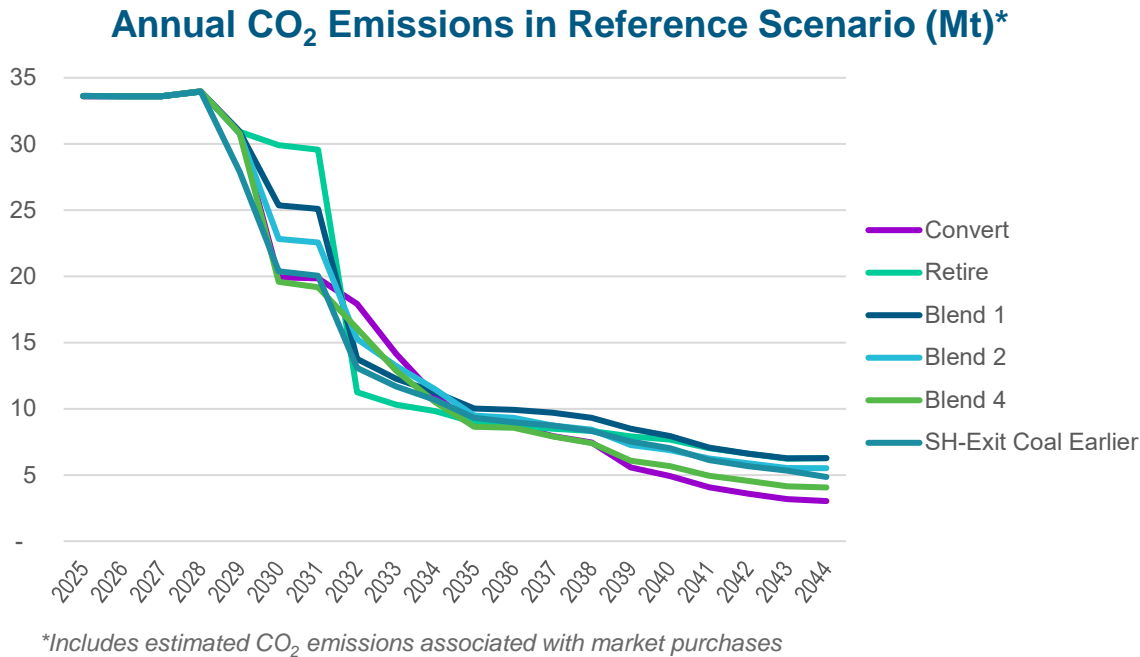


- Projected customer bill growth rates (nominal) provide an estimate of IRP-related cost to customers at a specified snapshot in time.
- The Exit Coal Earlier strategy, which calls for aggressive deployment of new resources in the 2020s, carries a relatively higher customer bill impact by 2030. Similarly, the Retire Coal strategy, which requires significant investment to replace all steam units by 2032, yields a relatively higher bill impact by 2035.

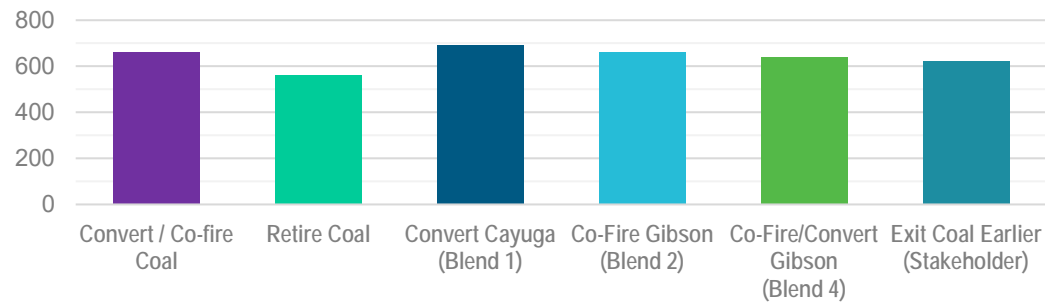
**Note:** IRP bill impacts for typical residential household using 1,000 kWh/month exclude depreciation of existing assets, other non-avoidable costs, costs not related to resource planning (e.g., distribution). IRP bill impact projections are useful only for relative comparison of portfolios.



# Environmental Sustainability: CO<sub>2</sub> Emissions & Intensity



## 2035 CO<sub>2</sub> Intensity of Duke Energy Indiana Portfolio (lbs./MWh)



- CO<sub>2</sub> emissions trends are very similar across generations strategies, with emissions dropping off steeply in 2030-2032 as coal gives way to gas, renewables, and low-cost energy from the MISO market in the energy mix.
- Emissions decline steadily through the second half of the planning period, as renewables are added to the portfolio, displacing purchased energy.
- CO<sub>2</sub> intensity of the Duke Energy Indiana portfolio varies only slightly across generation strategies. In 2035, a year in which economic energy purchases account for 50% or more of the total mix for several strategies, the Retire Coal strategy, in which advanced class CCs account for most of the Company-generated energy, has the lowest CO<sub>2</sub> intensity.

## 2044 CO<sub>2</sub> Emissions Reduction (from 2025 levels)\*

Portfolio	Reference Case	Aggressive Policy & Rapid Innovation	Minimum Policy & Lagging Innovation
Convert / Co-fire Coal	-91%	-97%	-80%
Retire Coal	-81%	-95%	-66%
Convert Cay. (Blend 1)	-81%	-95%	-69%
Co-Fire Gib. (Blend 2)	-84%	-96%	-63%
Conv. Gib. (Blend 4)	-88%	-95%	-70%
Exit Coal Earlier (SH)	-86%	-97%	-66%

*\*Includes estimated CO<sub>2</sub> emissions associated with market purchases*

# Reliability & Resiliency: Performance Over a Range of Conditions

- **Purpose:** evaluate portfolio reliability and resiliency across a wide range of conditions.
- **Approach:** simulate an islanded system across thousands of scenarios with varying weather, unit outages, and economic conditions.
- **Metric:** Expected Unserved Energy (“EUE”) represents periods of potential reliance upon the broader MISO market to meet customer demand. EUE is shown as a percentage of 2035 load, and also indexed to 2028 results to show change over time.
- **Study year:** 2035 is a benchmark year for this IRP near the middle of the planning period, far enough into the future that portfolios diverge substantially but not so far that increasing uncertainty limits the usefulness of the results

2035 EUE Relative to 2028 Baseline

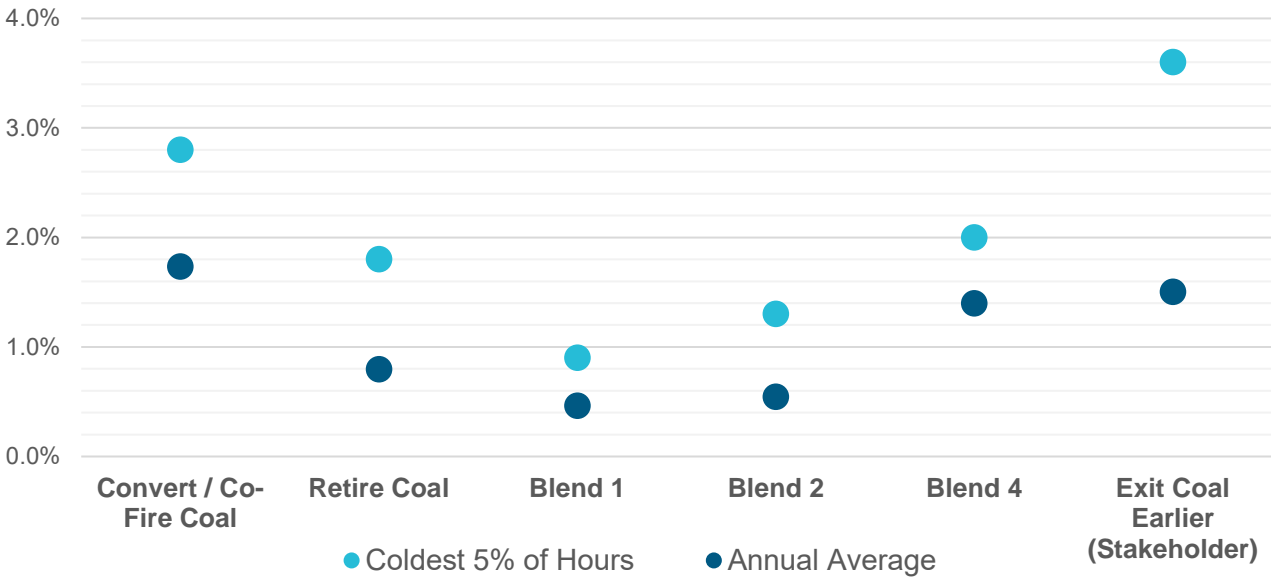
Normalized EUE	2035
Convert	3.6
Retire	1.6
Blend 1	1.0
Blend 2	1.1
Blend 4	2.9
SH – Exit Coal Earlier	3.1

- **Extreme cold:** To explore cold weather risk in more detail, simulations were run for 95th percentile or colder winter hours only. Results are presented here along with results for the full year, showing differing levels of winter risk across generation strategies.

Cold-Weather (95<sup>th</sup> Percentile) Simulated EUE as a % of Load in 2035

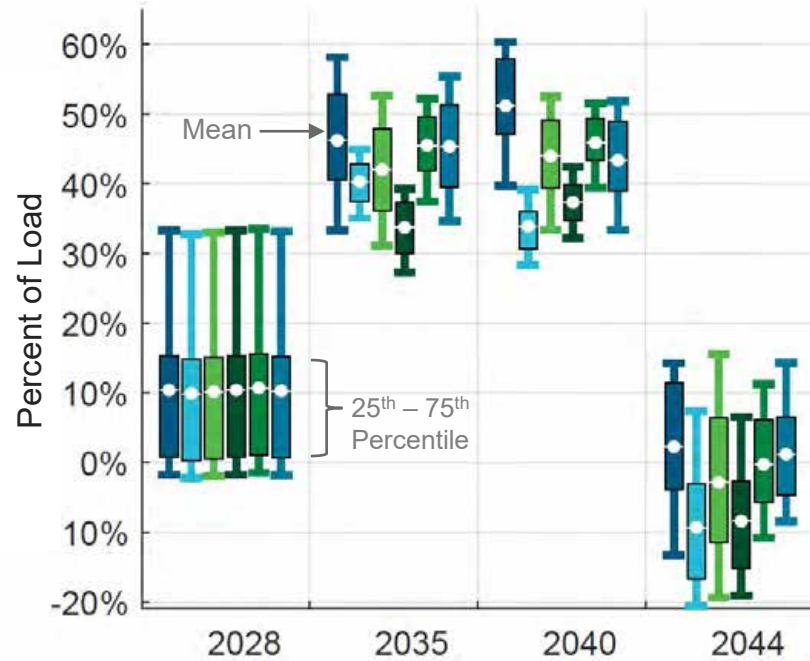
Portfolio	Convert	Retire	Blend 1	Blend 2	Blend 4	SH – Exit Earlier
Mean EUE	2.8%	1.8%	0.9%	1.3%	2.0%	3.6%

2035 Average Annual and Cold-Weather Simulated EUE as a % of Load



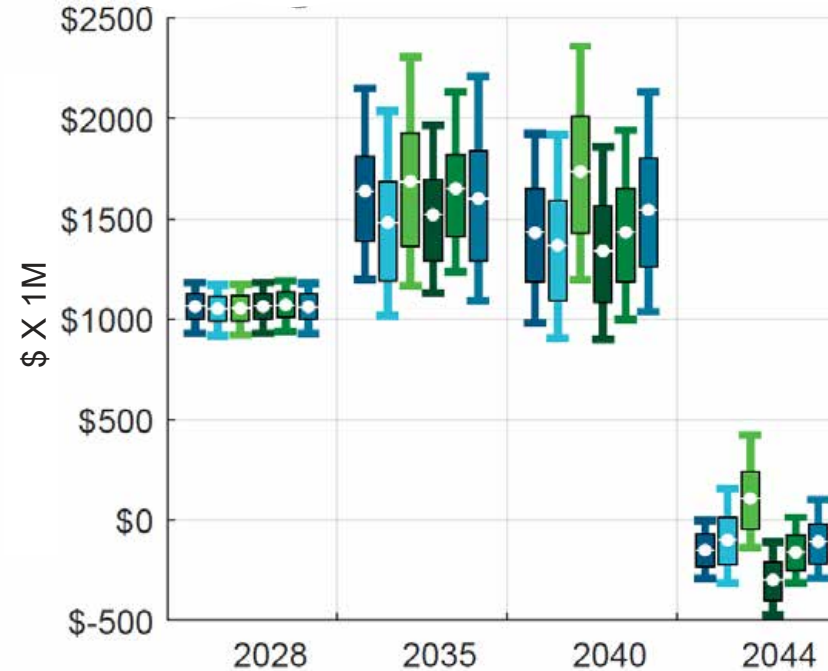
# Stochastic Modeling of Energy Market Exposure

Net Purchases with Economic Dispatch



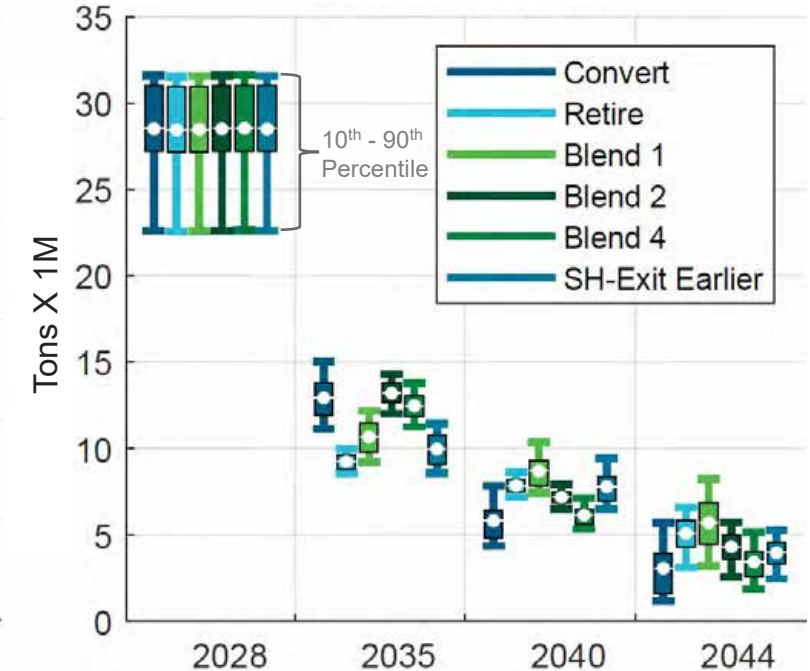
- Net purchases represent opportunities to reduce costs by transacting with the market when economic.
- 2028 lower net purchases driven by projections of higher power prices & lower gas prices.
- 2044 lower net purchases mainly due to increase in renewables.

Operating Cost Net of Purchases/Sales



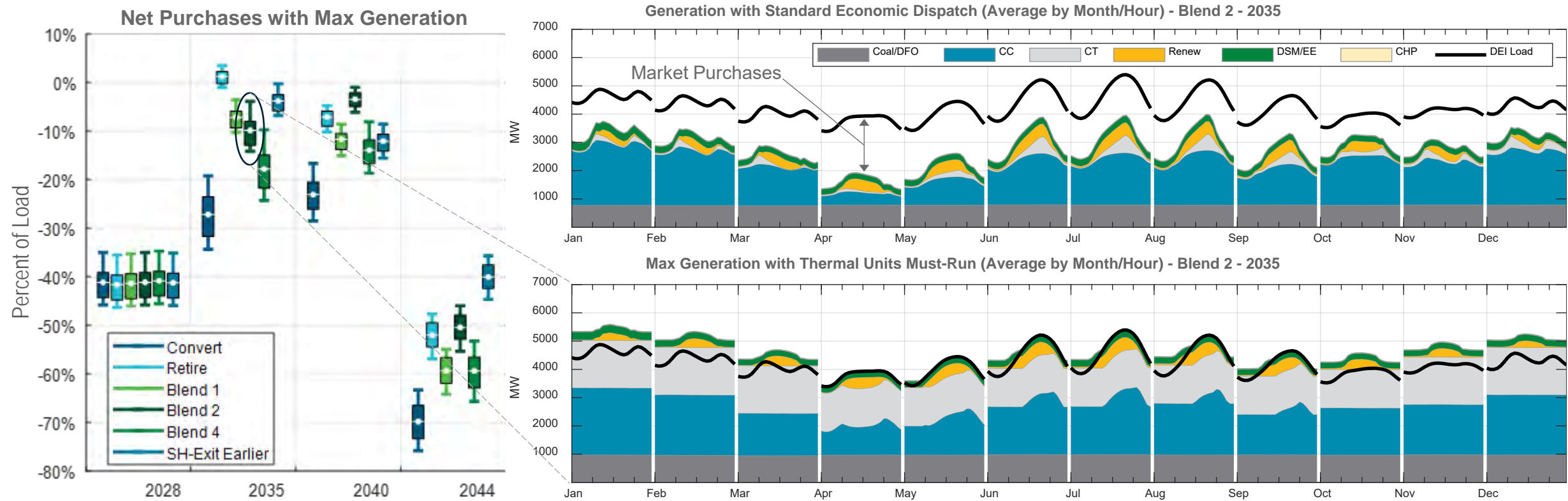
- Operating costs net of purchases and sales include fixed and variable operating costs.
- 2044 operating costs reduced by higher PTC/ITC credits. Narrower ranges in 2044 result from higher renewables that are not subject to dispatch based on market/fuel prices.

CO<sub>2</sub> Emissions



- CO<sub>2</sub> emissions reductions in later years driven by portfolio composition changes as well as lower market power prices.
- Preliminary directional results shown are subject to revision

# Stochastic Modeling of Energy Market Reliance



- Max Generation dispatch runs thermal units at max capacity subject to outages & annual EPA 111 rules.
- Annual average purchases net of sales shown. Almost all portfolios are net sellers of energy (negative purchases) under max generation dispatch.
- Average 12x24 month/hour profiles show representative (expected) asset generation mix for a single portfolio in a given dispatch year.
- Difference between total generation and load is treated as purchase or sale. MWh of excess sales net against MWh of purchases are used to produce annual averages shown in chart to left.
- Economic dispatch optimizes purchases to reduce total cost to serve load for customers thereby reducing capacity factors.
- Difference between standard (economic) dispatch and max generation dispatch demonstrates portfolio capacity available to reduce market reliance.

# Scorecard Results

	Environmental Sustainability				Affordability			Reliability		Resiliency		Cost Risk			Market Exposure		Execution Risk			
Portfolio	CO <sub>2</sub> Emissions Reduction Over Planning Period		Cumulative CO <sub>2</sub> Reduction Over Planning Period (MM tons)	CO <sub>2</sub> Intensity of Duke Energy Indiana Portfolio (lbs./MWh)	PVRR (\$B)	Customer Bill Impact (CAGR)		Fast Start Capability (as % of Coincident Peak)	Spinning Reserve Capability (as % of Coincident Peak)	Resource Diversity (Firm Capacity)	Simulated EUE in 95%+ Cold Weather (Islanded System)	Cost Variability Across Scenarios (\$B)	IRA Exposure		Fuel Market Exposure	Maximum Energy Market Exposure	Cumulative Resource Additions in MW		Cumulative Resource Additions as % of Current System Installed Capacity	
	2035	2044	2044	2035	2044	2030	2035	2035	2035	2035	2035	2044	2030	2035	Avg.	Max Year	2030	2035	2030	2035
Convert / Co-fire Coal	74%	91%	367	661	\$25.0	3.9%	3.1%	39%	93%	1766	2.8%	\$24.0 – \$28.1	81%	81%	61%	69%	992	1,779	12%	22%
Retire Coal	73%	81%	340	562	\$23.6	3.7%	3.3%	31%	93%	3853	1.8%	\$21.8 - \$26.8	43%	29%	72%	43%	1,611	5,542	20%	68%
Blend 1	70%	81%	337	691	\$24.2	3.9%	2.8%	33%	98%	2802	0.9%	\$22.4 - \$27.2	81%	20%	76%	51%	992	4,005	12%	49%
Blend 2	72%	84%	348	660	\$24.3	4.0%	3.1%	33%	102%	2739	1.3%	\$22.9 - \$26.9	50%	22%	72%	53%	1,811	4,105	22%	51%
Blend 4	74%	88%	367	641	\$24.5	4.0%	2.9%	33%	100%	1758	2.0%	\$23.3 - \$27.8	49%	33%	66%	66%	1,786	2,642	22%	33%
Exit Coal Earlier (Stakeholder)	72%	86%	362	624	\$24.3	4.3%	3.1%	38%	87%	2291	3.6%	\$23.4 - \$27.2	57%	39%	70%	52%	2,136	4,061	26%	50%

A description of each scorecard metric is included on the following slide. Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.

# Scorecard Metrics

Metric	Description
CO <sub>2</sub> Emissions Reduction	Percent CO <sub>2</sub> reduction relative to 2025
Cumulative CO <sub>2</sub> Reduction	Cumulative volume of CO <sub>2</sub> reduction over the planning period (tons from 2025)
CO <sub>2</sub> Intensity	CO <sub>2</sub> emissions from Duke Energy Indiana's generation divided by DEI resource generation
Present Value of Revenue Requirement (PVRR)	Total revenue requirement associated with resource plan investments over the planning period, discounted to present; Provides estimate of total plan cost
Customer Bill Impact	Projected compound annual growth rate (CAGR) in customer bill associated with resource plan investments; Provides snapshot of portfolio cost impact at points in time
Fast Start Capability	Fast start capable capacity (CT and battery MW) as percentage of peak load in 2035
Spinning Reserve Capability	Spinning reserve capable capacity (steam, CC, CT, CHP and hydro MW) as percentage of peak load in 2035
Resource Diversity	The sum of squares of technology share in 2035 on a firm capacity basis

Metric	Description
Simulated EUE of Islanded System in 95 <sup>th</sup> Percentile Cold Weather	Percent unserved energy during coldest weather (95th percentile or greater) observed in Indiana with market purchases turned off
Cost Variability	Minimum and Maximum PVRR across worldview scenarios
IRA Exposure	Cumulative MW additions with exposure to IRA tax credits as a percentage of total MW additions
Fuel Market Exposure	Generation (MWh) with exposure to coal and gas market prices as a percent of total fleet generation averaged annually over the planning period
Maximum Energy Market Exposure	Maximum absolute value of net energy purchases/sales as a percentage of total energy demand through the study period
Cumulative Resource Additions in MW	Cumulative MW additions of capacity resources through 2030 and 2035
Cumulative Resource Additions as % of Total System Installed Capacity	Cumulative MW additions of capacity resource technologies through 2030 and 2035 expressed as a percentage of total current system capacity





# Q&A

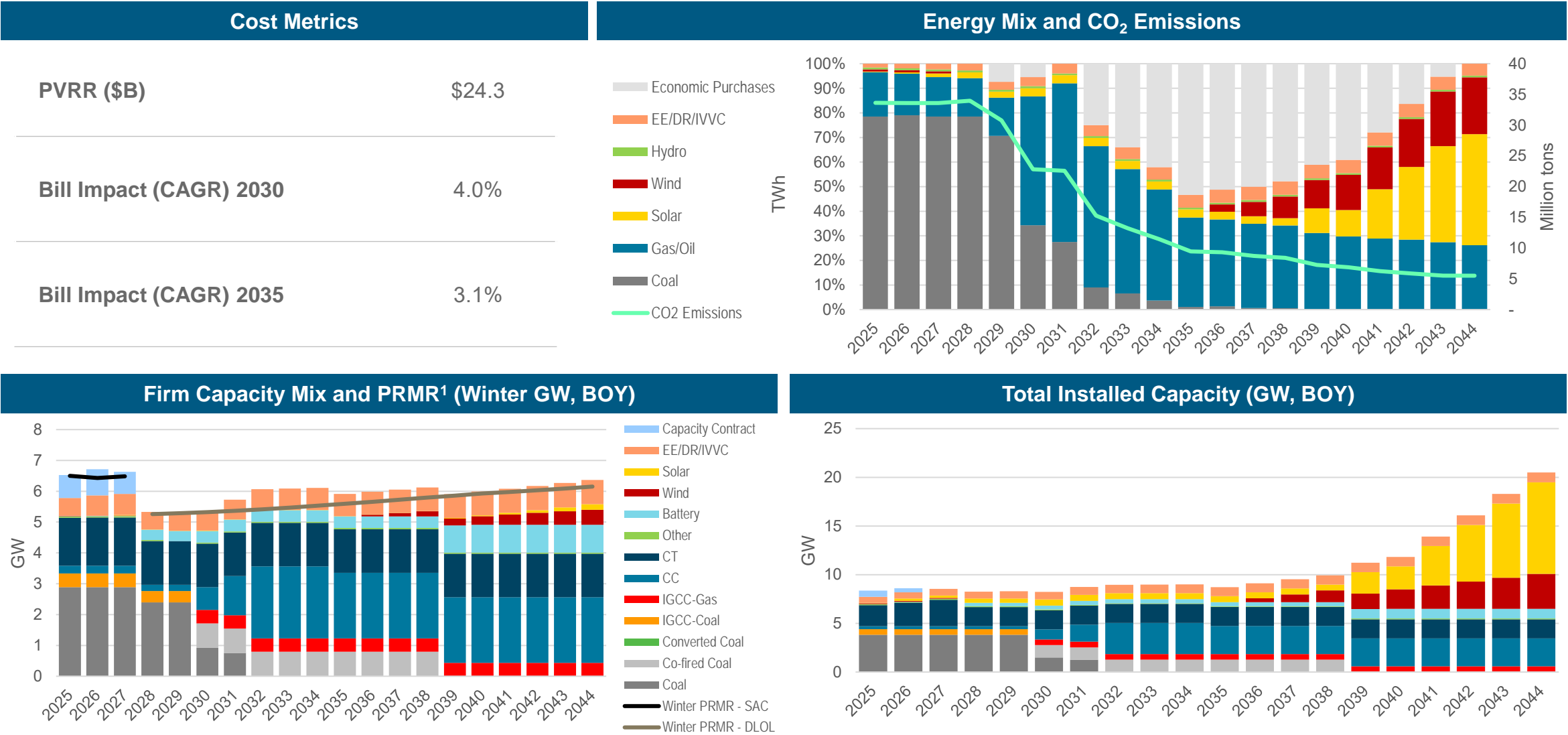


# Preferred Portfolio

## *Considerations for Short-Term Action Plan*

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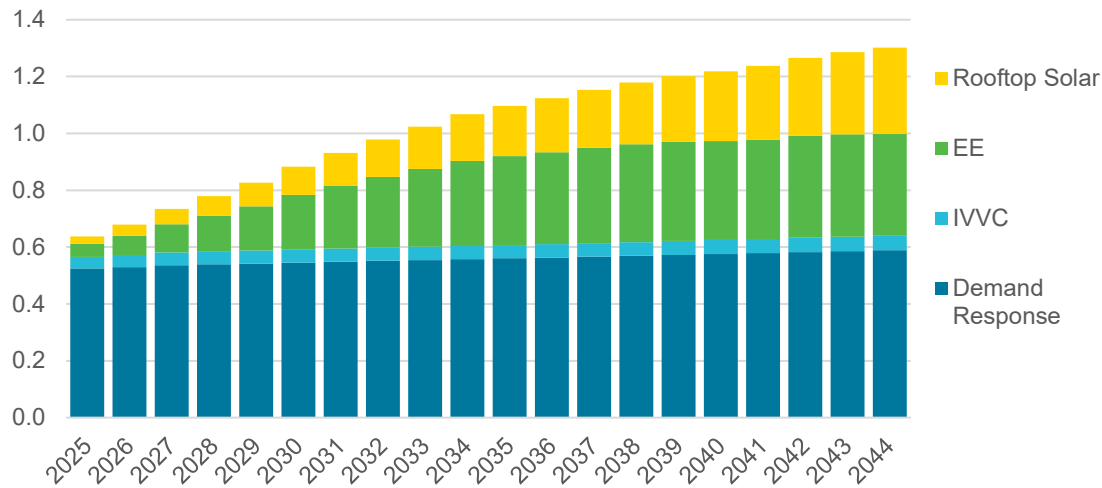
# Co-Fire / Retire Gibson (Blend 2) | Reference Scenario



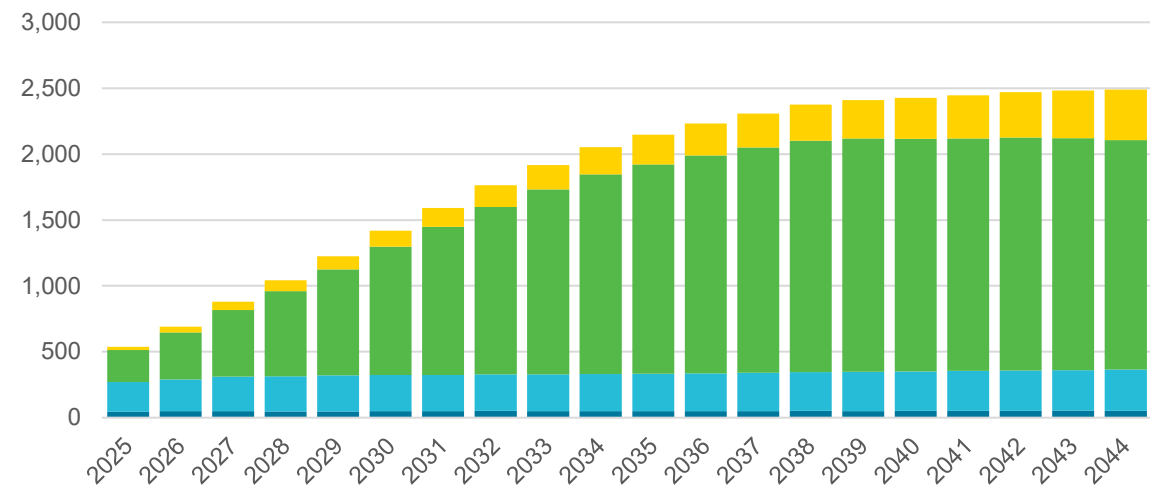
<sup>1</sup>Planning Reserve Margin Requirement (PRMR): Assumes MISO SAC 2025-2027, converts to DLOL beginning 2028

# Demand-Side Resources in the Preferred Portfolio

Max Capacity (GW, Beginning of Year)



Energy Contribution (GWh)



Bundles Available for Selection

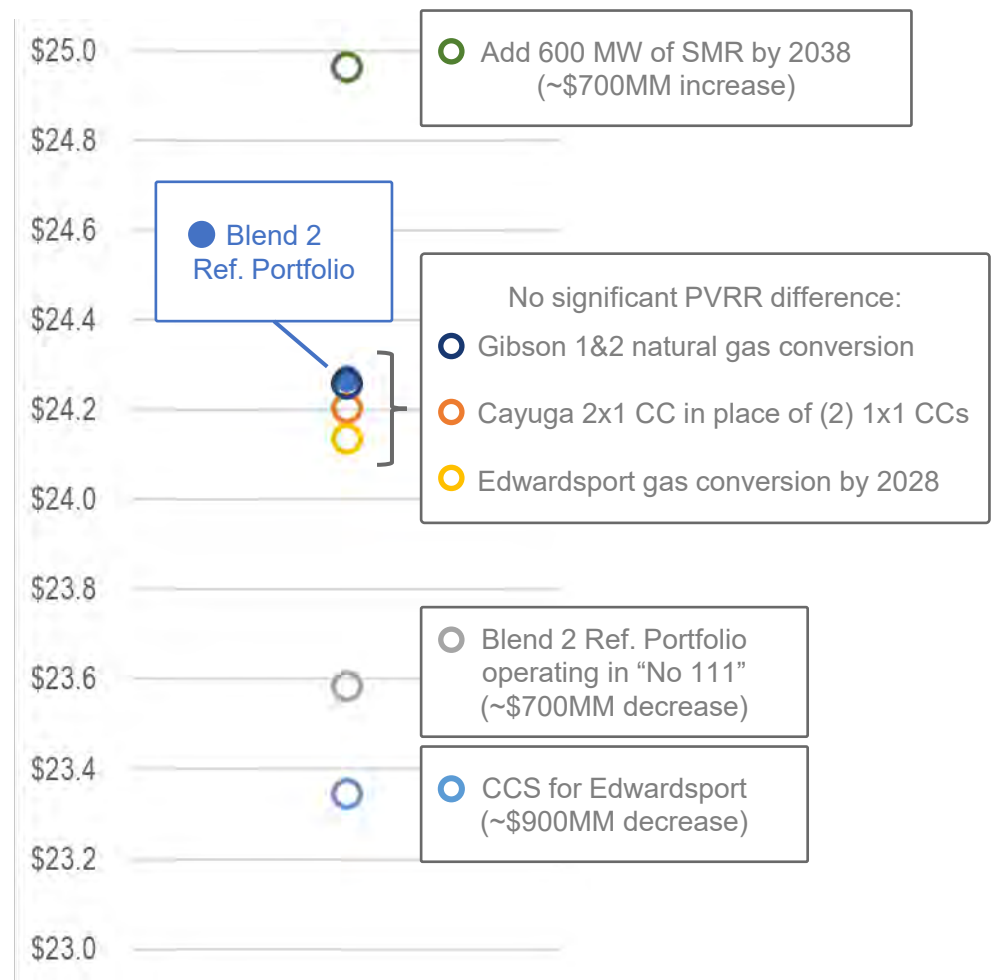
Bundle	Type	Year Avail.	Levelized Cost (\$/MWh)
EE Bundle 1	Base	2025	\$28.86
EE Bundle 2	Base	2027	\$32.46
EE Bundle 7	High	2027	\$51.22
EE Bundle 3	Base	2030	\$33.28
EE Bundle 8	High	2030	\$52.72
EE Bundle 4	Base	2034	\$27.59
EE Bundle 9	High	2034	\$43.34
EE Bundle 5	Base	2042	\$27.59
EE Bundle 10	High	2042	\$42.68

Energy Savings (GWh)

2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
242	357	346	346	345	345	344	340	332	311	277	238	207	183	135	71	24	9	8	7
0	0	159	300	459	458	447	428	405	386	370	356	333	305	276	255	241	205	149	88
0	0	176	348	538	552	540	518	492	469	450	434	409	377	344	319	304	260	191	117
0	0	0	0	0	171	331	502	667	654	632	602	571	543	521	494	457	422	387	360
0	0	0	0	0	190	384	589	788	789	763	729	693	661	635	604	562	523	482	451
0	0	0	0	0	0	0	0	0	166	310	457	597	724	839	944	1,042	977	936	885
0	0	0	0	0	0	0	0	0	187	371	557	734	896	1,044	1,180	1,307	1,252	1,206	1,147
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	156	279	403
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	175	331	488

# PVRR Changes in Response to Blend 2 Strategy Variations

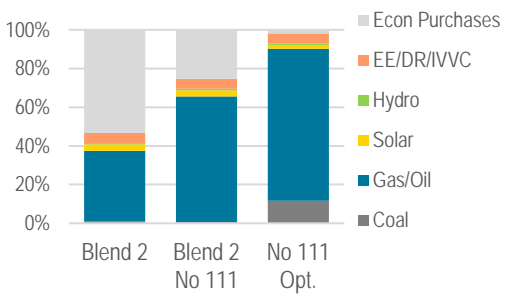
## PVRR Results Across Blend 2 Variations



## Key Insights

- Several variations on Blend 2 result in no significant changes to PVRR
  - Full gas conversion of Gibson units 1 & 2 (rather than co-firing)
  - Replacing Cayuga with a 2x1 CC (rather than two 1x1 CCs)
  - Retiring the Edwardsport gasifiers by 2028 (rather than 2030)
- Small modular reactors (SMR) were not economically selected as a resource in the preferred portfolio for the 2024 IRP. However, the considerable cost uncertainty for SMRs and the potential future value of reliable, around-the-clock, carbon-free generation make it prudent for Duke Energy Indiana to continue to advance early studies to maintain advanced nuclear as a viable option in future resource planning.
- The potential for tax credits associated with CCS at Edwardsport to lower PVRR makes it prudent to complete the ongoing FEED study. At this point, however, risk and uncertainty regarding cost, timely project execution, and long-term reliable operation of a CCS system preclude it from being part of the preferred portfolio.
- The Blend 2 portfolio is well-positioned for a future in which CAA Section 111 restrictions are relaxed, with an estimated PVRR only slightly greater than the \$23.3 billion PVRR of the optimized "No 111" portfolio and the ability to operate competitively in the MISO energy market, limiting future purchases.

### 2035 Energy Mix Across Cases



# Reminder: Thinking About the IRP Planning Period



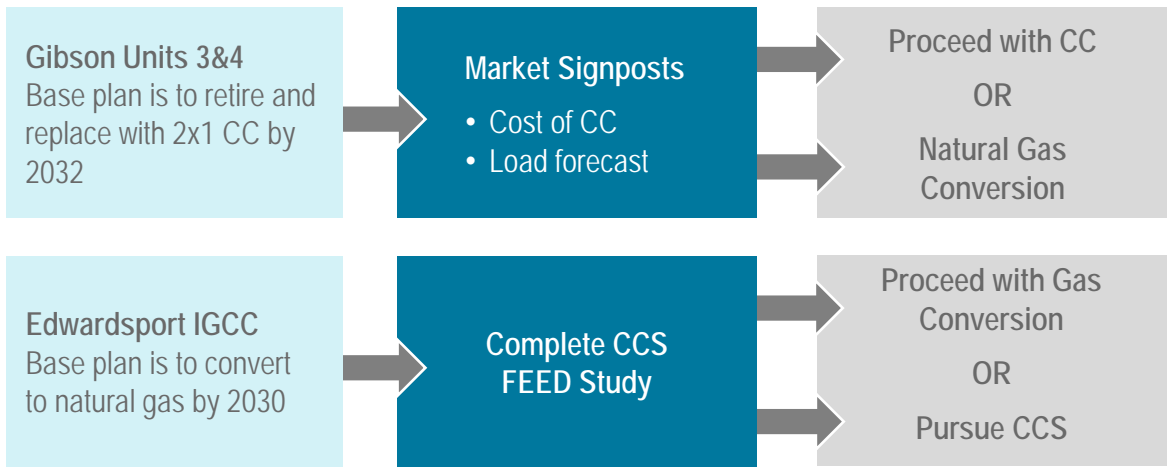


# Blend 2 Provides Optionality for “No 111” World, Other Circumstances

## Short-Term Actions Prudent Across a Range of Future Conditions

- Install two highly-efficient advanced-class 1x1 CCs at Cayuga Station by 2030, 2031 to gain incremental capacity and replace aging coal units
- Secure gas supply to Gibson Station to support co-firing, CC, and gas conversion options
- Deploy ~500 MW of solar and ~400 MW of battery energy storage by 2030 to meet near-term energy and capacity needs, retire Gibson 5
- Advance early studies to maintain SMRs as a viable future planning option
- Pursue additional cost-effective contributions from EE and DR resources

## Opportunities to Adjust Course in Response to Changing Market Conditions, Maintaining 111 Compliance



## Opportunities to Adjust Course in Response to Potential Delay of Compliance Deadlines Under EPA CAA Section 111 Final Rule

Plan for 111 Compliance	Adjustment for Delay
Edwardsport IGCC	
<ul style="list-style-type: none"><li>• Prepare to convert to 100% natural gas fuel by 2030</li><li>• Complete FEED study to inform ultimate decision on CCS</li></ul>	<ul style="list-style-type: none"><li>• Continue coal gasification and monitor regulatory developments</li><li>• Complete CCS FEED study and update evaluations of gas conversion and CCS options as appropriate</li></ul>
Gibson Station	
<ul style="list-style-type: none"><li>• Co-fire units 1 &amp; 2 with natural gas (up to 50%) by 2030</li><li>• Prepare to develop 2x1 CC to replace units 3 &amp; 4, while monitoring market conditions to inform potential pivot to gas conversion</li></ul>	<ul style="list-style-type: none"><li>• Delay action on units 1 &amp; 2 and monitor regulatory developments</li><li>• Prepare to develop 2x1 CC to replace units 3 &amp; 4, while monitoring market conditions to inform potential delay</li></ul>



# Q&A



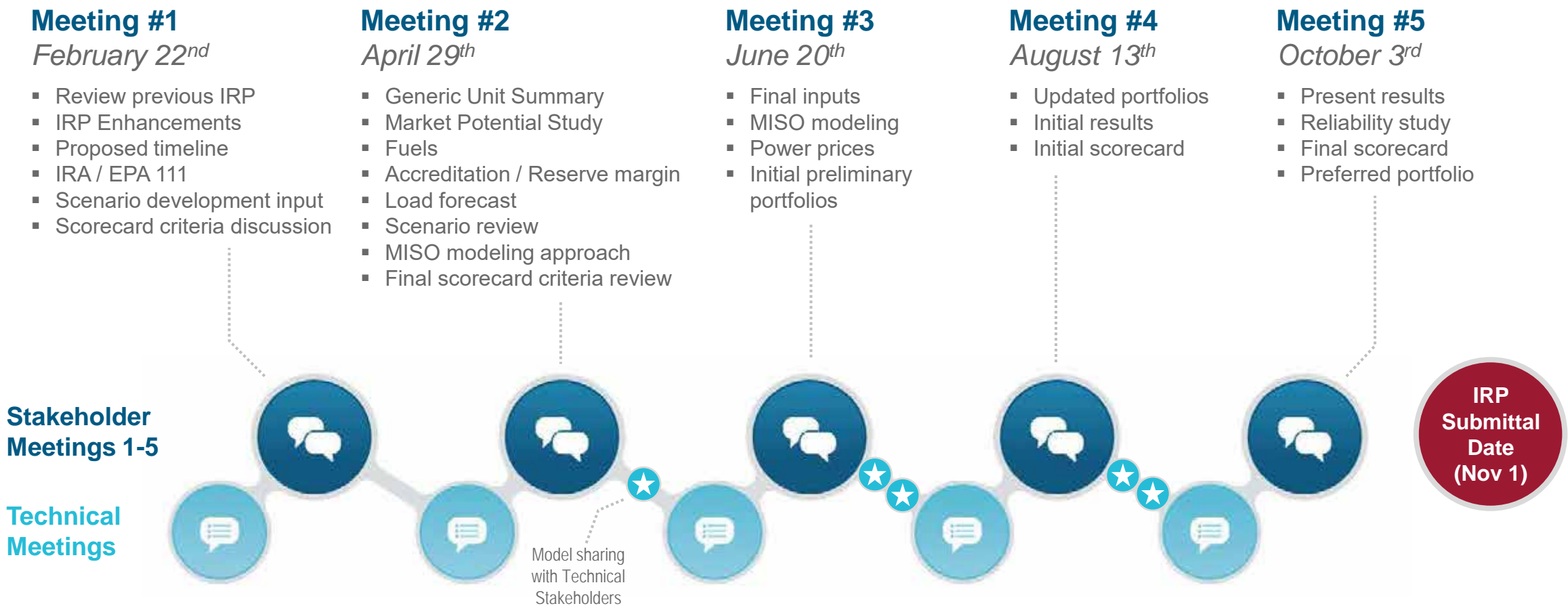
# Open Q&A



# Thank you

# 2024 DEI IRP Stakeholder Engagement

*Engaging with our stakeholders in multiple sessions throughout the 2024 IRP process*





## Next Steps



Additional questions, comments,  
and feedback can be sent to

[DEIndianaIRP@1898andco.com](mailto:DEIndianaIRP@1898andco.com)

**The IRP submittal date is November 1.**

After the IRP is submitted, the email address above will no longer be active. A Duke Energy IRP email address will be communicated to stakeholders and updated on the IRP webpage at that time.





# Appendix: Generation Strategy Results

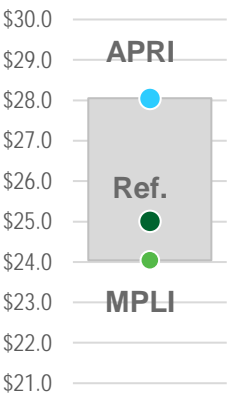
*Results are not considered final until the IRP is submitted. While Duke Energy Indiana does not expect analytics to change before the IRP is submitted, the Company will continue to review details and make adjustments as needed.*

# Generation Strategy Results Summary: Convert / Co-Fire Coal

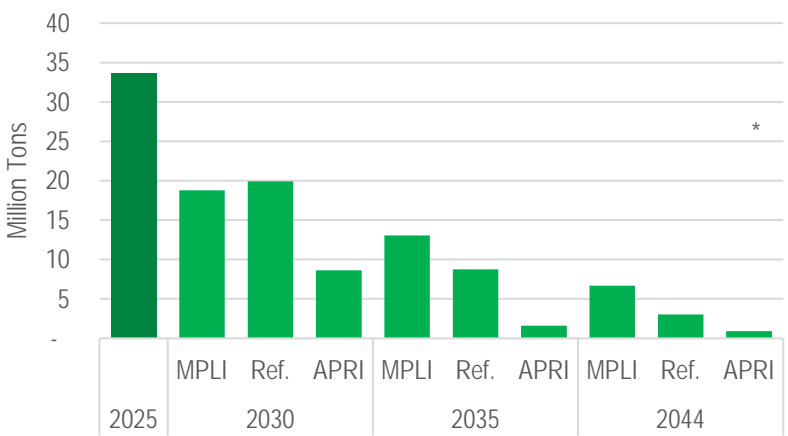
## Notes on Generation Strategy

- Converting coal units to burn 100% natural gas or co-fire coal/gas, mitigates need for new capacity in near term, but does not provide additional capacity.
- Converted and co-fired coal units provide needed capacity but struggle to compete economically in the MISO energy market, with economic energy purchases supplying a substantial portion of total energy in the mid-2030s.
- Solar, wind, and battery additions supply needed incremental energy and capacity before 2030, with new CC capacity added in the early 2030s in the Minimum Policy & Lagging Innovation (MPLI) scenario, which envisions the rollback of GHG rules under CAA Section 111.
- Co-fired coal units (Gibson 1 & 2) must retire by 2039 under CAA Section 111, necessitating investment in replacement capacity in the mid/late 2030s.

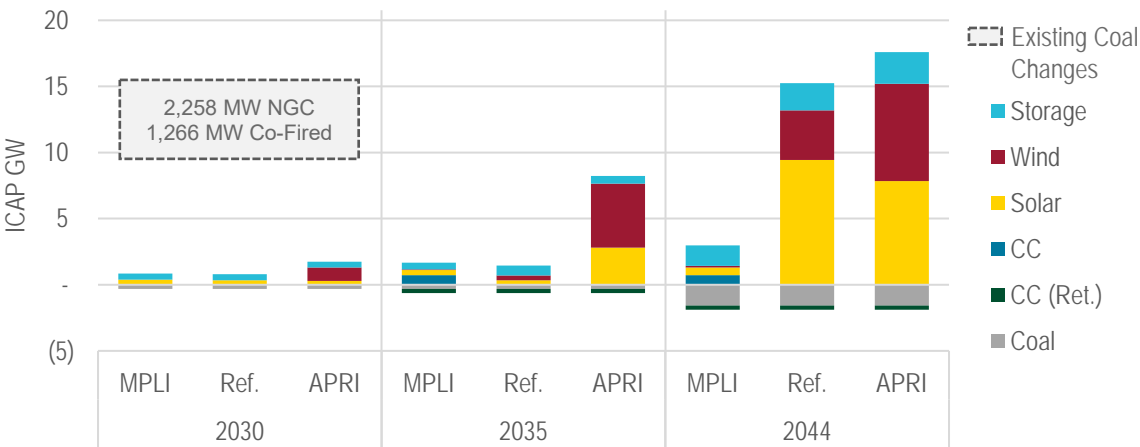
### PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

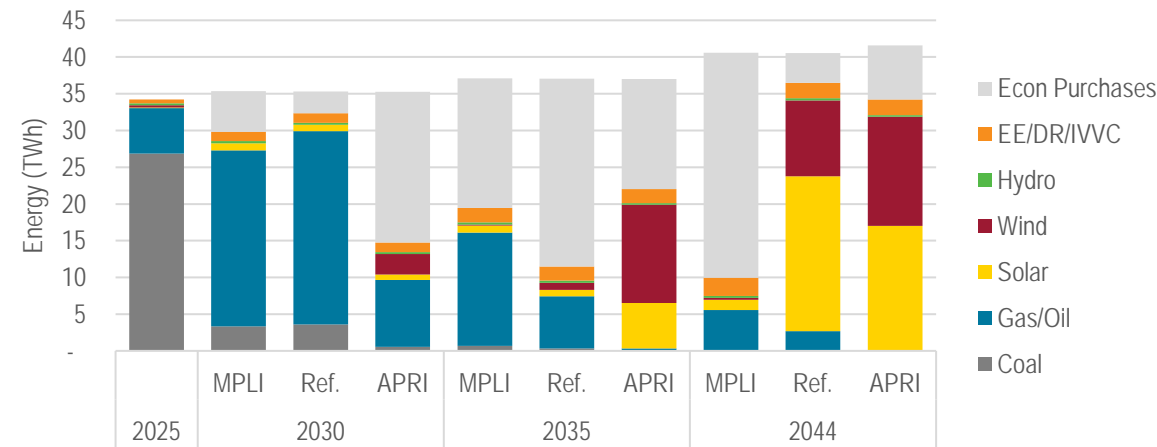


## Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



# Convert / Co-Fire Coal : Annual Resource Additions & Retirements (Beginning-of-Year)

Existing Resources																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						Conv.														
Cayuga 2						Conv.														
Gibson 1						Cofire									(632)					
Gibson 2						Cofire									(633)					
Gibson 3						Conv.														
Gibson 4						Conv.														
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC																				
2x1 CC																				
Solar <sup>1</sup>		199		150											1,800	200	1,750	1,800	1,750	1,800
Wind										250	100	200	400	400	400	400	400	400	400	400
Battery <sup>1</sup>				350		100					300				50	50				350
EE/DR <sup>2</sup>	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

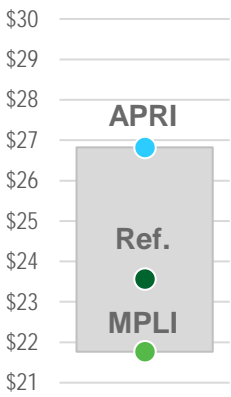
<sup>1</sup>Includes paired  
<sup>2</sup>EE/DR additions, net of annual program roll off

# Generation Strategy Results Summary: Retire Coal

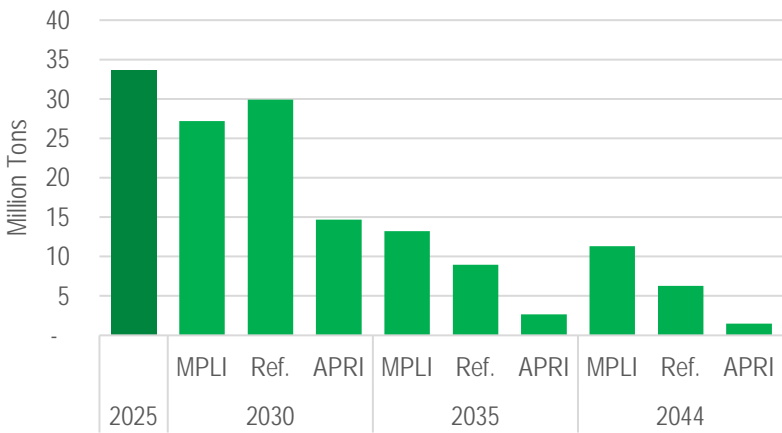
## Notes on Generation Strategy

- Significant additions of dispatchable and variable energy resources are required by the early 2030s to meet incremental load growth and replace over 3.8 GW of retiring coal.
- New gas-fired combined-cycle generators provide improved resource accreditation over retiring units and operate competitively in the MISO market, dispatching up to the 40% capacity factor limit under CAA 111.
- Energy mix varies considerably across scenarios in the mid-2030s, with the repeal of the recently adopted GHG rule under CAA Section 111 allowing CCs to operate up to their economic limits in Minimum Policy & Lagging Innovation (MPLI), while additional policy constraints and falling costs drive greater adoption of renewables in Aggressive Policy & Rapid Innovation (APRI).

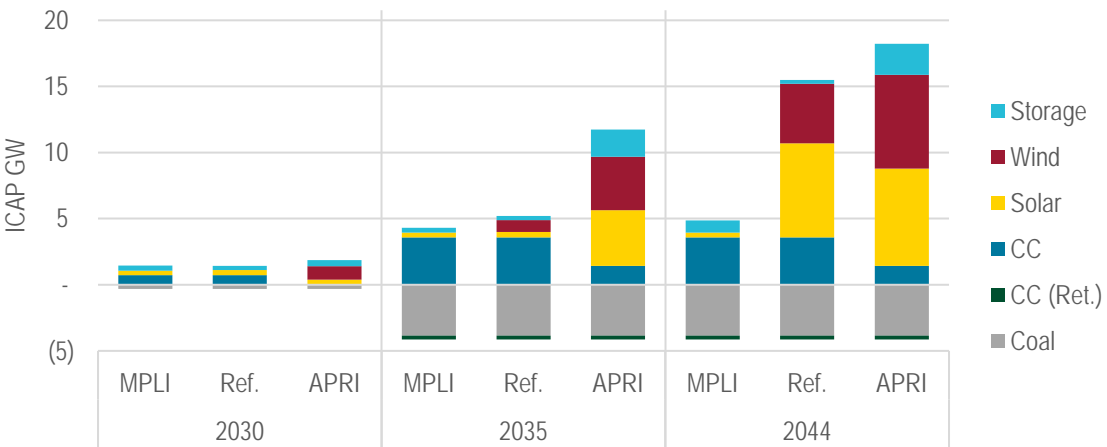
PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

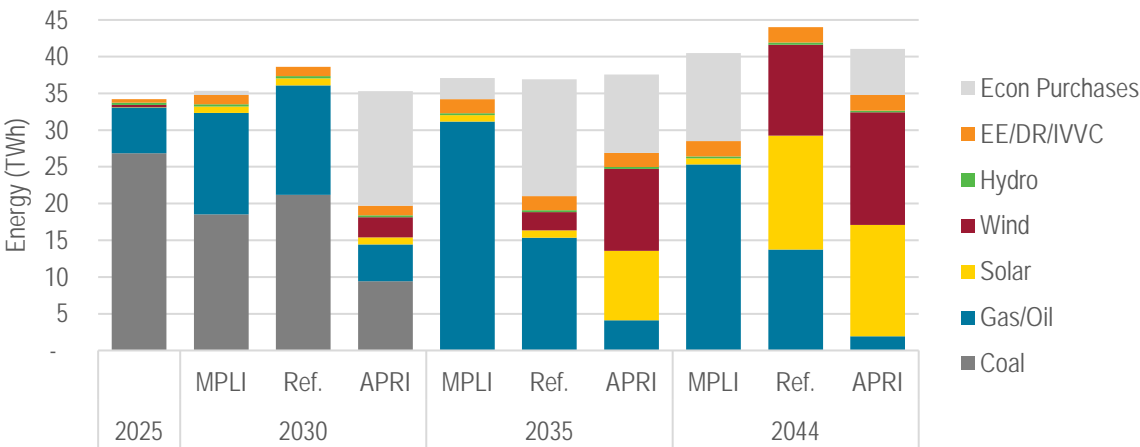


## Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



# Retire Coal: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1								(502)												
Cayuga 2								(496)												
Gibson 1								(632)												
Gibson 2								(633)												
Gibson 3								(635)												
Gibson 4								(626)												
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719														
2x1 CC								2,876												
Solar <sup>1</sup>		199		200													1,500	1,600	1,800	1,800
Wind									250	250	400	400	400	400	400	400	400	400	400	400
Battery <sup>1</sup>				300																
EE/DR <sup>2</sup>	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

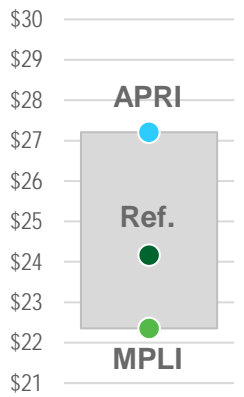
<sup>1</sup>Includes paired  
<sup>2</sup>EE/DR additions, net of annual program roll off

# Generation Strategy Results Summary: Convert Cayuga (Blend 1)

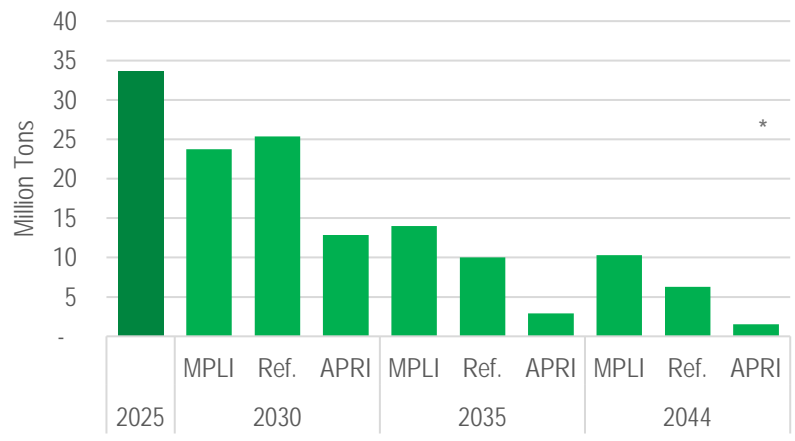
## Notes on Generation Strategy

- Cayuga units 1 and 2 are repowered to burn 100% natural gas by 2030, while Gibson units 1 through 4 are retired and replaced with new combined-cycle generation by 2032.
- Renewables and storage are favored in the Aggressive Policy & Rapid Innovation (APRI) scenario, displacing a portion of the gas capacity added in other scenarios as coal units retire, while in the Minimum Policy & Lagging Innovation (MPLI) scenario, new CCs provide substantially more energy than in other cases.
- Full gas conversion at the Cayuga units allows them to operate through the end of the planning period, consistent with the GHG rule under CAA Section 111.

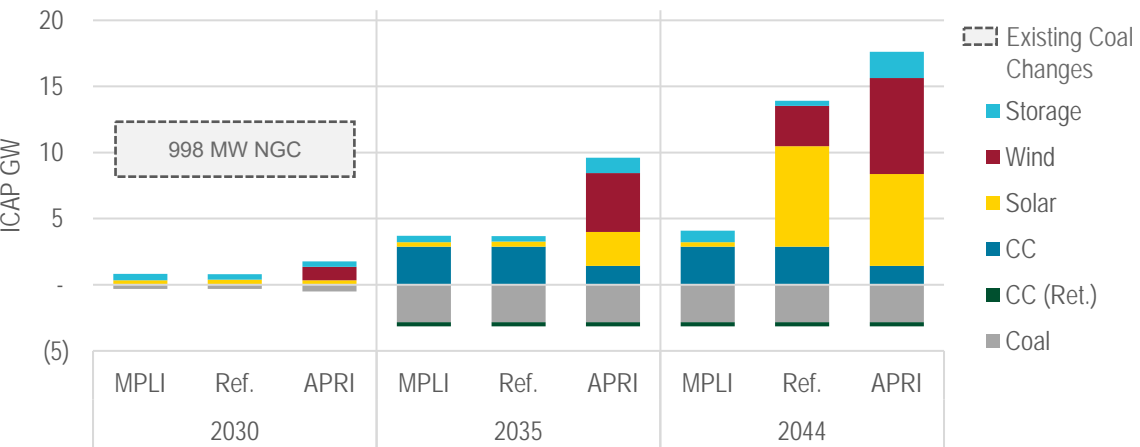
PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

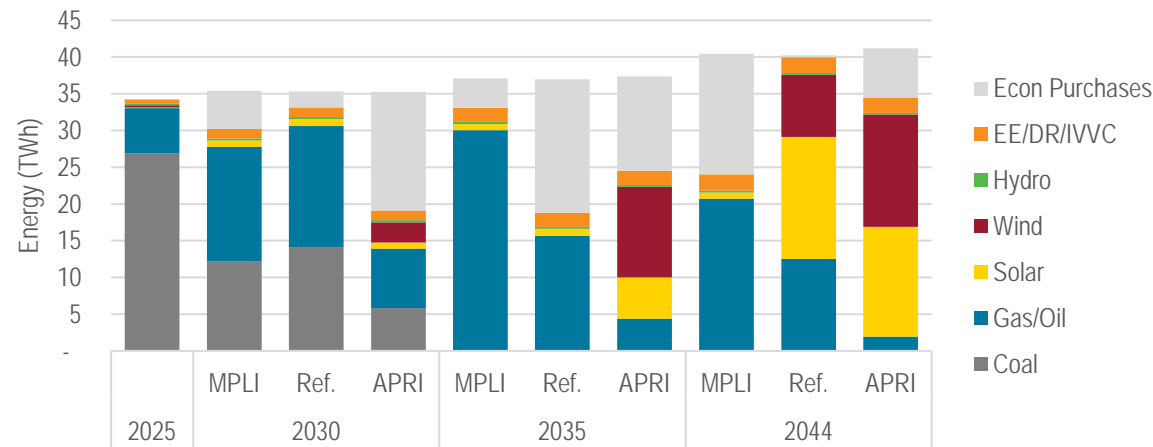


## Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time





# Blend 1: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						Conv.														
Cayuga 2						Conv.														
Gibson 1								(632)												
Gibson 2								(633)												
Gibson 3								(635)												
Gibson 4								(626)												
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC																				
2x1 CC								2,876												
Solar <sup>1</sup>		199		200													1,800	1,800	1,800	1,800
Wind													250	400	400	400	400	400	400	400
Battery <sup>1</sup>				300		100														
EE/DR <sup>2</sup>	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

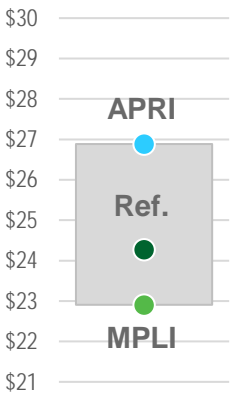
<sup>1</sup>Includes paired  
<sup>2</sup>EE/DR additions, net of annual program roll off

# Preferred Portfolio: Co-Fire Gibson (Blend 2)

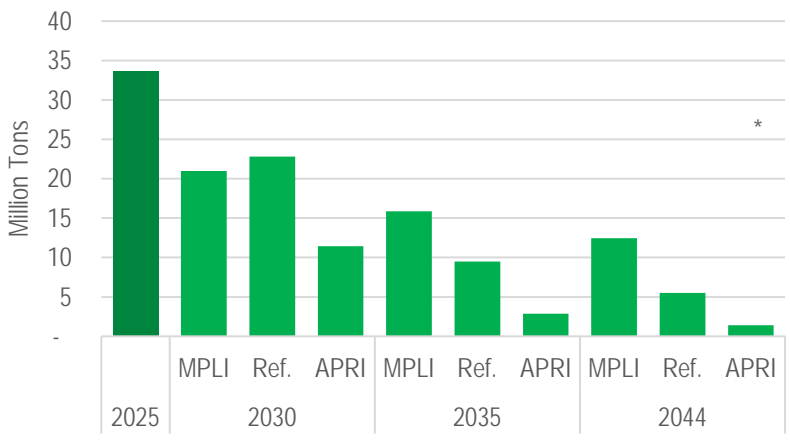
## Notes on Generation Strategy

- Cayuga units 1 and 2 retire by 2030 and 2031. Two 1x1 CCs are added at the site, replacing the retiring coal and providing incremental MW to help serve growing load. Similarly, Gibson 3 and 4 are replaced with a 2x1 CC by 2032.
- Gibson 1 and 2 are converted to enable co-firing natural gas with coal, allowing them to continue to operate through 2038 under CAA Section 111, at which point additional capacity is needed.
- Renewables and storage are added in the late 2020s to meet near-term needs in all scenarios, with that trend accelerating in the Aggressive Policy & Rapid Innovation (APRI) scenario, and the balance shifting towards new gas in the Minimum Policy & Lagging Innovation (MPLI) scenario.
- Energy from new CCs displaces market purchases in the MPLI scenario.

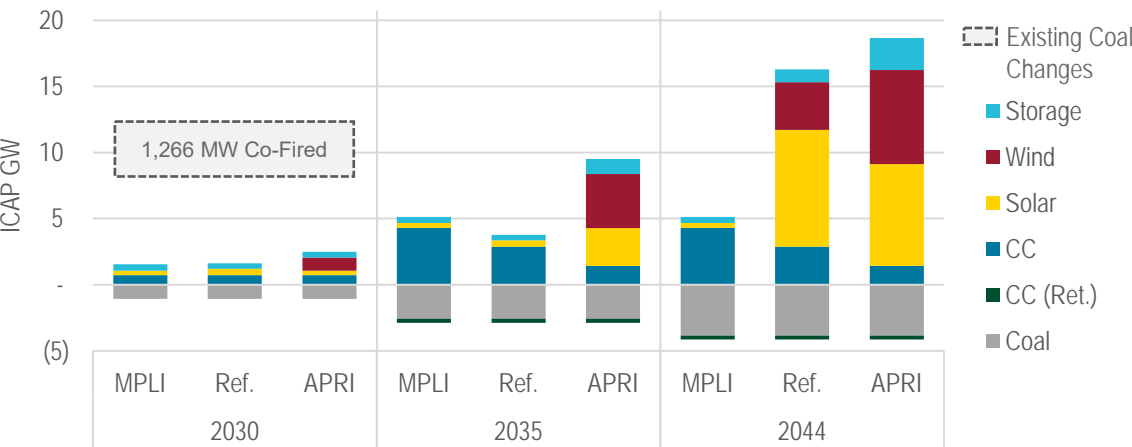
### PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

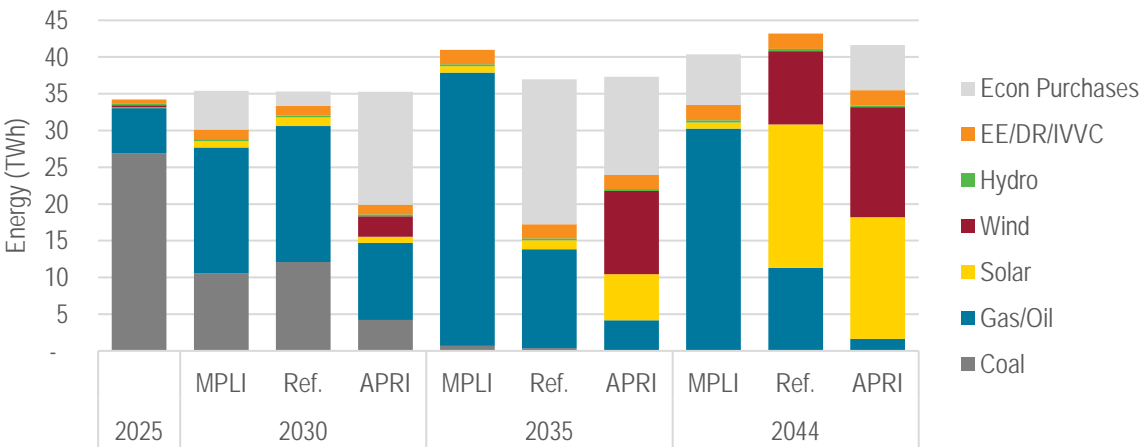


## Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



# Blend 2: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						(502)														
Cayuga 2						(256)	(240)													
Gibson 1						Cofire									(632)					
Gibson 2						Cofire									(633)					
Gibson 3								(635)												
Gibson 4								(626)												
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719	719													
2x1 CC								1,438												
Solar <sup>1</sup>		199		150		150									1,150	150	1,700	1,750	1,800	1,800
Wind												400	400	400	400	400	400	400	400	400
Battery <sup>1</sup>				350		50									550	25				
EE/DR <sup>2</sup>	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

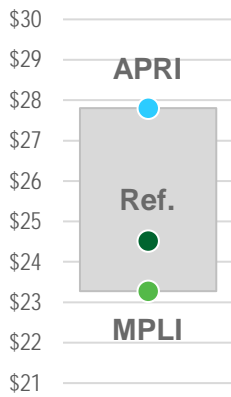
<sup>1</sup>Includes paired  
<sup>2</sup>EE/DR additions, net of annual program roll off

# Generation Strategy Results Summary: Co-fire/Convert Gibson (Blend 4)

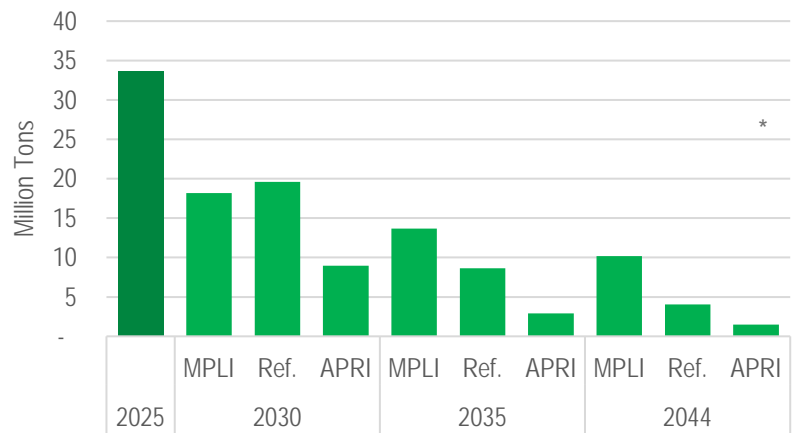
## Notes on Generation Strategy

- Cayuga units 1 and 2 retire by 2030 and 2031. Two 1x1 CCs are added at the site, replacing the retiring coal and providing incremental MW to help serve growing load.
- Gibson 1 and 2 are converted to enable co-firing natural gas with coal, allowing them to continue to operate through 2038 under CAA Section 111, at which point additional capacity is needed. Gibson 3 and 4 are converted to natural gas and operate throughout the study period.
- Renewables and storage are added in the late 2020s to meet near-term needs in all scenarios, with that trend accelerating in the Aggressive Policy & Rapid Innovation (APRI) scenario, and the balance shifting towards new gas in the Minimum Policy & Lagging Innovation (MPLI) scenario.

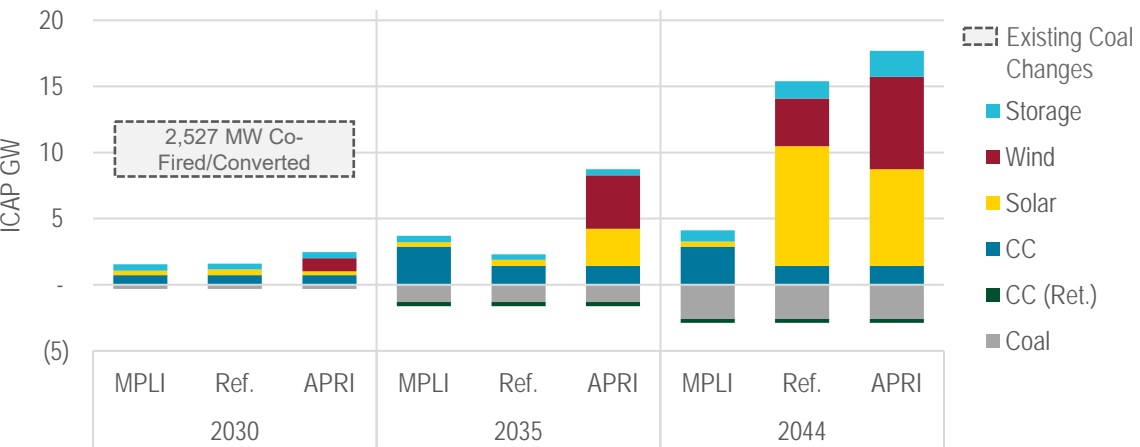
PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

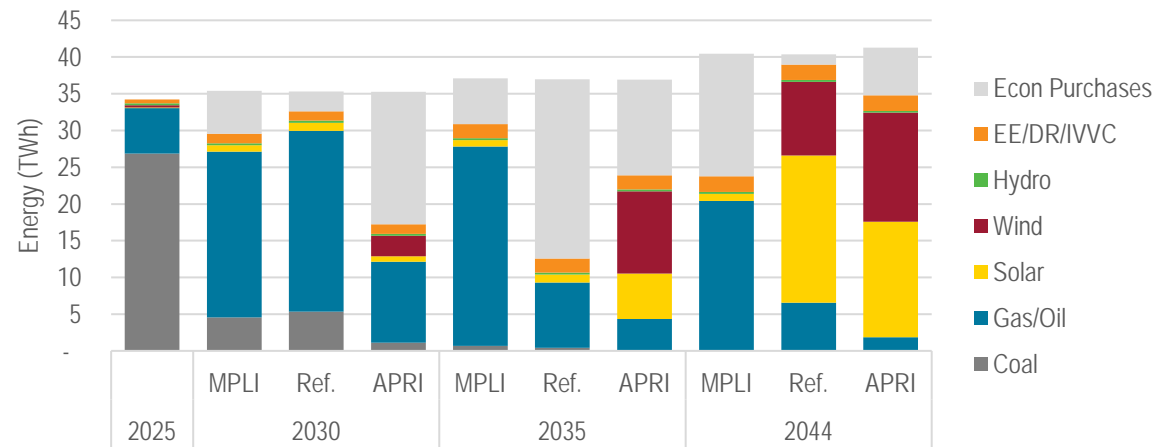


## Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time



# Blend 4: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1						(502)														
Cayuga 2						(256)	(240)													
Gibson 1						Cofire									(632)					
Gibson 2						Cofire									(633)					
Gibson 3						Conv.														
Gibson 4						Conv.														
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719	719													
2x1 CC																				
Solar <sup>1</sup>		199		100		150									1,700	50	1,800	1,500	1,750	1,800
Wind												400	400	400	400	400	400	400	400	400
Battery <sup>1</sup>				350		75									850	25				
EE/DR <sup>2</sup>	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

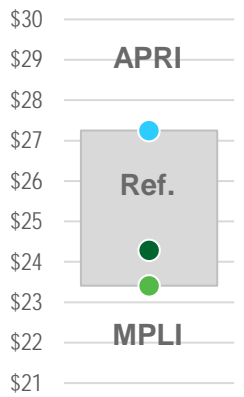
<sup>1</sup>Includes paired  
<sup>2</sup>EE/DR additions, net of annual program roll off

# Generation Strategy Results Summary: Exit Coal Earlier (Stakeholder)

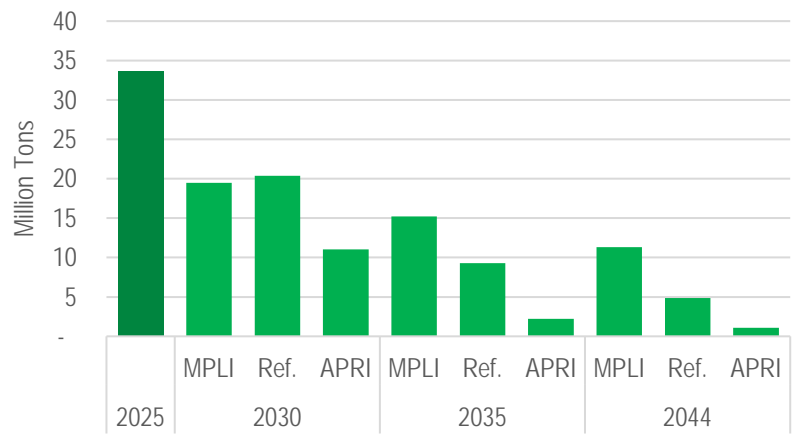
## Notes on Generation Strategy

- Accelerating the retirement of Gibson 3 and 4 to 2030 necessitates the addition of higher volumes of renewables and storage by 2030 than in other strategies, while conversion of Cayuga to 100% natural gas maintains capacity at that site.
- New CC capacity is added to offset coal retirements in all scenarios, with a 2x1 replacing Gibson units 1 and 2 when they retire by 2032, consistent with the GHG rule under CAA Section 111.
- Additional gas capacity is selected in the Minimum Policy & Lagging Innovation (MPLI) scenario in which capacity factor limits under CAA Section 111 are assumed to be repealed, whereas in the Aggressive Policy & Rapid Innovation (APRI) scenario, renewables are favored.

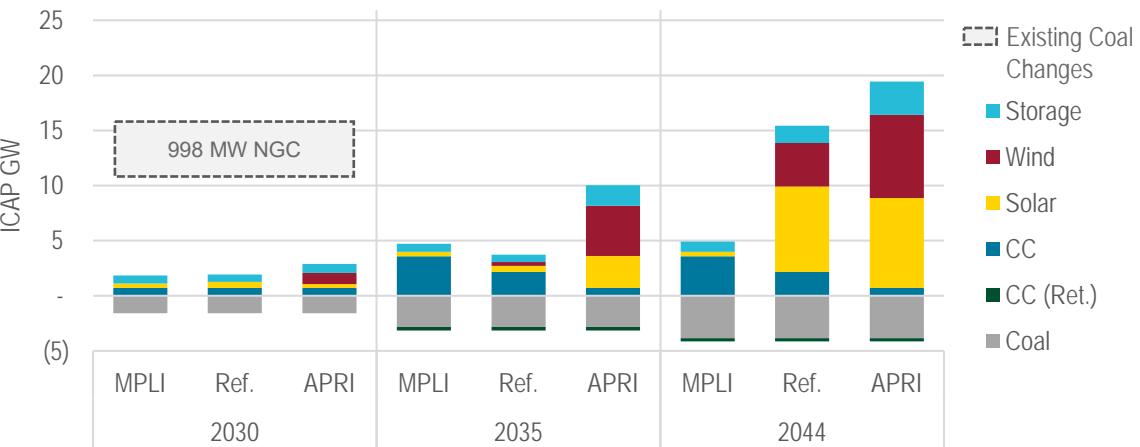
PVRR Range (\$B)



## CO<sub>2</sub> Emissions Over Time

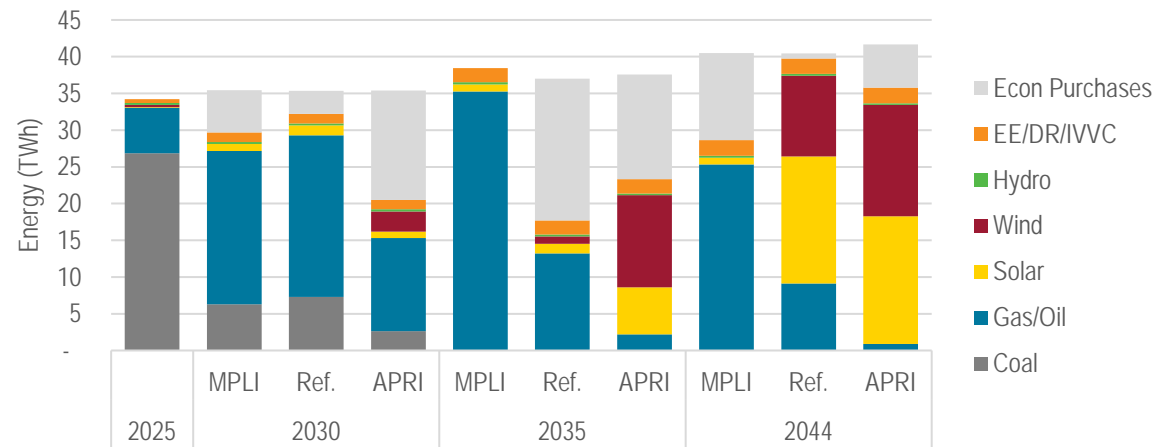


## Cumulative Supply-Side Changes (Installed GW, BOY)



APRI: Aggressive Policy & Rapid Innovation | MPLI: Minimum Policy & Lagging Innovation

## Energy Mix Over Time





# Exit Coal Earlier: Resource Additions & Retirements (Beginning-of-Year Basis)

Existing Resources																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1					Conv.															(502)
Cayuga 2					Conv.															(496)
Gibson 1								(632)												
Gibson 2								(633)												
Gibson 3						(635)														
Gibson 4						(626)														
Gibson 5						(313)														
Edwardsport						Conv.														
Noblesville CC											(312)									
Wind PPA				(100)																
Solar PPA						(4)						(11)	(11)							

Resource Additions																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC						719														
2x1 CC								1,438												
Solar <sup>1</sup>		199		150		200											1,800	1,800	1,800	1,800
Wind											350	400	400	400	400	400	400	400	400	400
Battery <sup>1</sup>				325		350														900
EE/DR <sup>2</sup>	46	21	32	26	30	38	32	30	29	28	16	13	15	12	8	2	4	13	4	0

<sup>1</sup>Includes paired  
<sup>2</sup>EE/DR additions, net of annual program roll off



# Appendix: Acronyms

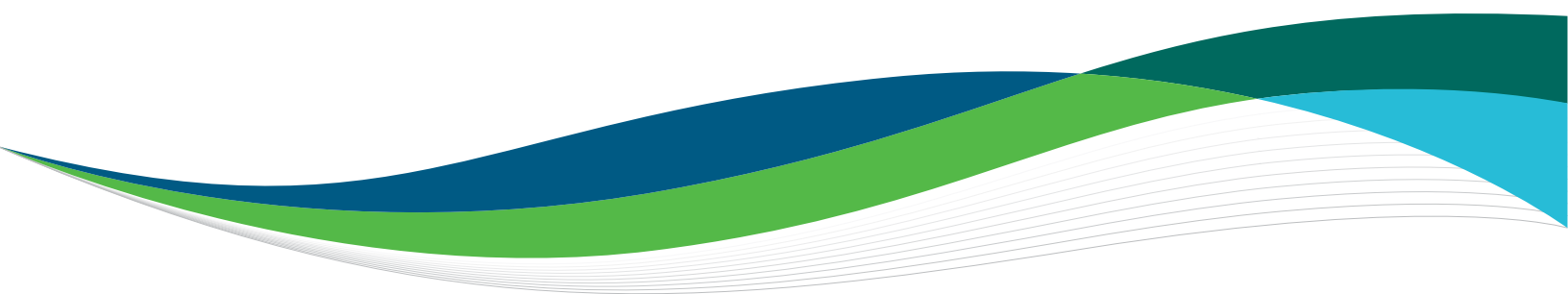
# Acronyms

<b>APRI</b>	Aggressive Policy & Rapid Innovation
<b>BOY</b>	Beginning of Year
<b>CAA 111</b>	Clean Air Act 111
<b>CAGR</b>	Compound Annual Growth Rate
<b>CC</b>	Combined Cycle
<b>CCS</b>	Carbon Capture and Sequestration
<b>DDRE</b>	Deep Decarbonization and Rapid Electrification
<b>DEI</b>	Duke Energy Indiana
<b>D-LOL</b>	Direct Loss of Load
<b>DR</b>	Demand Response
<b>DSM</b>	Demand-Side Management
<b>EE</b>	Energy Efficiency
<b>EPA</b>	Environmental Protection Agency
<b>EUE</b>	Expected Unserved Energy
<b>FEED</b>	Front-End Engineering Design
<b>GHG</b>	Greenhouse Gas
<b>GW</b>	Gigawatt
<b>GWh</b>	Gigawatt-hour
<b>ICAP</b>	Installed Capacity
<b>IGCC</b>	Integrated Gasification Combined Cycle
<b>IRA</b>	Inflation Reduction Act
<b>IRP</b>	Integrated Resource Plan

<b>ITC</b>	Investment Tax Credit
<b>IVVC</b>	Integrated Volt/VAR Control
<b>kWh</b>	Kilowatt-hour
<b>MISO</b>	Midcontinent Independent System Operator
<b>MM</b>	Million
<b>MMBtu</b>	Million British Thermal Units
<b>MPLI</b>	Minimum Policy & Lagging Innovation
<b>Mt</b>	Million Tons
<b>MW</b>	Megawatt
<b>MWh</b>	Megawatt-hour
<b>NG</b>	Natural Gas
<b>NGC</b>	Natural Gas Conversion
<b>PPA</b>	Power Purchase Agreement
<b>PRMR</b>	Planning Reserve Margin Requirement
<b>PTC</b>	Production Tax Credit
<b>PVRR</b>	Present Value of Revenue Requirement
<b>RFP</b>	Request for Proposal
<b>SAC</b>	Seasonal Accredited Capacity
<b>SMR</b>	Small Modular Reactor
<b>TWh</b>	Terawatt Hour

# Attachment A-2

Datasite Uploads



# INDIANA

**2024** | **INTEGRATED**  
DUKE ENERGY | **RESOURCE PLAN**



BUILDING A *SMARTER* ENERGY FUTURE®

Date Posted	Date Removed	File Name
4/12/2024	6/11/2024	Confidential Projected Inflation-Adjusted PTC Rates Under Sections 45 and 45Y_03.04.24_Preliminary.xlsx
4/12/2024	6/11/2024	DEI Base Load Forecast and Comparison Over Time for Spring 2024 IRP 4_11_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI Demand Response Forecast for IRP - Preliminary Draft.xlsx
4/12/2024	6/11/2024	DEI ELCC Curves_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI Fuel Curves_04_11_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI Reserve Margin Conversion from MISO_4_3_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_BTM_Forecast_Base_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_BTM_Forecast_High_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_BTM_Forecast_Low_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_BTM_Forecast_Ultra_High_4_5_2024_Solar_as_Resource_Inputs_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_EV Forecast_8760_Base_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_EV Forecast_8760_High_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_EV Forecast_8760_Low_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	DEI_EV Forecast_8760_UltraHigh_4_5_2024_Preliminary_Confidential.xlsx
4/12/2024	6/11/2024	Reallocated SAC for IRP - PY24-25 Preliminary Draft 032524 - w-DLOL.xlsm
4/12/2024	6/11/2024	Reallocated SAC for IRP - PY24-25 Preliminary Draft 032524.xlsm
5/31/2024	7/23/2024	119. NDB_OnShore_Wind_11-01-2023.xlsx
5/31/2024	7/23/2024	DEIN 23S EE Projects.xlsx
5/31/2024	6/11/2024	EnCompass Input Share - NDB Runs - 2024.05.27.zip
5/31/2024	6/11/2024	Summary of EnCompass Data Shared 05.31.2024.docx
5/31/2024	6/11/2024	_DEI IRP Local Runs.xlsx
5/31/2024	6/11/2024	24S 111 MISO Market.xlsx
5/31/2024	6/11/2024	24S 111 Z6R MISO Market.xlsx
5/31/2024	6/11/2024	DEIN 23F New CC.xlsx
5/31/2024	6/11/2024	DEIN 23S CPCN Solar.xlsx
5/31/2024	6/11/2024	DEIN 23S EE Projects.xlsx
5/31/2024	6/11/2024	DEIN 23S No Market Limit.xlsx
5/31/2024	6/11/2024	DEIN 24 IRP Thermal Tranches.xlsx
5/31/2024	6/11/2024	DEIN 24 IRP Tranches.xlsx
5/31/2024	6/11/2024	DEIN 24S Base.xlsx
5/31/2024	6/11/2024	DEIN 24S Capital.xlsx
5/31/2024	6/11/2024	DEIN 24S Cay CC Cost Inc.xlsx
5/31/2024	6/11/2024	DEIN 24S DLOL.xlsx
5/31/2024	6/11/2024	DEIN 24S Edwardsport Gas 2030.xlsx
5/31/2024	6/11/2024	DEIN 24S EE Firm Capacity.xlsx
5/31/2024	6/11/2024	DEIN 24S ELCC Curves 111.xlsx
5/31/2024	6/11/2024	DEIN 24S Emissions on Fuel.xlsx
5/31/2024	6/11/2024	DEIN 24S Existing CT Limit.xlsx
5/31/2024	6/11/2024	DEIN 24S Fuel Prices.xlsx
5/31/2024	6/11/2024	DEIN 24S Gibson Gas Cost.xlsx
5/31/2024	6/11/2024	DEIN 24S IRA.xlsx
5/31/2024	6/11/2024	DEIN 24S IRA Extended.xlsx
5/31/2024	6/11/2024	DEIN 24S Load.xlsx
5/31/2024	6/11/2024	DEIN 24S Market Limit - 25%.xlsx
5/31/2024	6/11/2024	DEIN 24S New Gas CF Limit.xlsx
5/31/2024	6/11/2024	DEIN 24S New Gas Update.xlsx
5/31/2024	6/11/2024	DEIN 24S Nuclear ITC.xlsx
5/31/2024	6/11/2024	DEIN 24S Outage Schedule.xlsx
5/31/2024	6/11/2024	DEIN 24S Project Limits.xlsx
5/31/2024	6/11/2024	DEIN 24S Split Cay Retire.xlsx
5/31/2024	6/11/2024	DEIN 24S Transmission Adder.xlsx
5/31/2024	6/11/2024	Duke Midwest Base.xlsx
5/31/2024	6/11/2024	101. NDB_Topology_11-01-2023.xlsx
5/31/2024	6/11/2024	102. NDB_Demand_RPS_11-01-2023.xlsx
5/31/2024	6/11/2024	103. NDB_Fuel_Emission_11-01-2023.xlsx
5/31/2024	6/11/2024	103a. EAST_Emissions.xlsx
5/31/2024	6/11/2024	104. NDB_Nuclear_11-01-2023.xlsx
5/31/2024	6/11/2024	105. NDB_Coal_11-01-2023.xlsx
5/31/2024	6/11/2024	106. NDB_CC_11-01-2023.xlsx
5/31/2024	6/11/2024	107. NDB_IGCC_11-01-2023.xlsx
5/31/2024	6/11/2024	108. NDB_STORAGE_11-01-2023.xlsx

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5/31/2024	6/11/2024	110. NDB_GT_11-01-2023.xlsx
5/31/2024	6/11/2024	111. NDB_IC_11-01-2023.xlsx
5/31/2024	6/11/2024	112. NDB_Hydro_11-01-2023.xlsx
5/31/2024	6/11/2024	112a. NDB_New_Hydro_11-01-2023.xlsx
5/31/2024	6/11/2024	113. NDB_PS_11-01-2023.xlsx
5/31/2024	6/11/2024	114. NDB_Biomass_11-01-2023.xlsx
5/31/2024	6/11/2024	114a. NDB_New_Biomass_11-01-2023.xlsx
5/31/2024	6/11/2024	115. NDB_FuelCell_11-01-2023.xlsx
5/31/2024	6/11/2024	116. NDB_Geothermal_11-01-2023.xlsx
5/31/2024	6/11/2024	116a. NDB_New_Geothermal_11-01-2023.xlsx
5/31/2024	6/11/2024	117. NDB_Landfill_11-01-2023.xlsx
5/31/2024	6/11/2024	117a. NDB_New_Landfill_11-01-2023.xlsx
5/31/2024	6/11/2024	118. NDB_Other_11-01-2023.xlsx
5/31/2024	6/11/2024	119. NDB_OnShore_Wind_11-01-2023.xlsx
5/31/2024	6/11/2024	120. NDB_OffShore_Wind_11-01-2023.xlsx
5/31/2024	6/11/2024	121. NDB_Solar_PV_11-01-2023.xlsx
5/31/2024	6/11/2024	122. NDB_Solar_Steam_11-01-2023.xlsx
5/31/2024	6/11/2024	123. NDB_Expansion_11-01-2023.xlsx
5/31/2024	6/11/2024	124. NDB_DR_11-01-2023.xlsx
5/31/2024	6/11/2024	125. NDB_DER_Solar_11-01-2023.xlsx
5/31/2024	6/11/2024	126. NDB_DER_Battery_11-01-2023.xlsx
5/31/2024	6/11/2024	126a. NDB_Battery_11-01-2023.xlsx
5/31/2024	6/11/2024	126b. NDB_Battery_Target_11-01-2023.xlsx
5/31/2024	6/11/2024	127. Market_Rules_11-01-2023.xlsx
5/31/2024	6/11/2024	22F H2 CT.xlsx
5/31/2024	6/11/2024	23F 111 Gas CF Limits.xlsx
5/31/2024	6/11/2024	23F CCS Projects.xlsx
5/31/2024	6/11/2024	23F Future 2A Siting.xlsx
5/31/2024	6/11/2024	23F MISO Z6 KY NUC PTC.xlsx
5/31/2024	6/11/2024	23F PJM RTEP.xlsx
5/31/2024	6/11/2024	23F PTC Swap.xlsx
5/31/2024	6/11/2024	23F PTC to IRA Projects.xlsx
5/31/2024	6/11/2024	23F Renewable ITC_PTC Input Cleared.xlsx
5/31/2024	6/11/2024	23F Schedule 53 Class Average.xlsx
5/31/2024	6/11/2024	23F Wind OS ISONE-Maine PTC.xlsx
5/31/2024	6/11/2024	23S No Zone 6 Renewables.xlsx
5/31/2024	6/11/2024	24S 111 Gas CF.xlsx
5/31/2024	6/11/2024	24S 111 ST CF.xlsx
5/31/2024	6/11/2024	24S 50% Coal DFO.xlsx
5/31/2024	6/11/2024	24S Base.xlsx
5/31/2024	6/11/2024	24S CCS Projects.xlsx
5/31/2024	6/11/2024	24S CSAPR Update.xlsx
5/31/2024	6/11/2024	24S DLOL PRM & ELCC.xlsx
5/31/2024	6/11/2024	24S Duke Adders 111.xlsx
5/31/2024	6/11/2024	24S Duke Capital Costs.xlsx
5/31/2024	6/11/2024	24S Duke Fuel Costs.xlsx
5/31/2024	6/11/2024	24S MISO SAC ELCC.xlsx
5/31/2024	6/11/2024	24S Updates.xlsx
5/31/2024	6/11/2024	24S Z6R Duke Adders 111.xlsx
5/31/2024	6/11/2024	Dataset_for_Viewing.xlsx
5/31/2024	6/11/2024	filelist.txt
5/31/2024	6/11/2024	No Coal Must Run.xlsx
5/31/2024	6/11/2024	Object Creation.xlsx
5/31/2024	6/11/2024	Reduce Zone 6 CC.xlsx
5/31/2024	6/11/2024	_DEI IRP NDB 111 Reference Runs.xlsx
5/31/2024	6/11/2024	101. NDB_Topology_11-01-2023.xlsx
5/31/2024	6/11/2024	102. NDB_Demand_RPS_11-01-2023.xlsx
5/31/2024	6/11/2024	103. NDB_Fuel_Emission_11-01-2023.xlsx
5/31/2024	6/11/2024	103a. EAST_Emissions.xlsx
5/31/2024	6/11/2024	104. NDB_Nuclear_11-01-2023.xlsx



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5/31/2024	6/11/2024	107. NDB_IGCC_11-01-2023.xlsx
5/31/2024	6/11/2024	108. NDB_STORAGE_11-01-2023.xlsx
5/31/2024	6/11/2024	109. NDB_Steam_Gas_Oil_11-01-2023.xlsx
5/31/2024	6/11/2024	110. NDB_GT_11-01-2023.xlsx
5/31/2024	6/11/2024	111. NDB_IC_11-01-2023.xlsx
5/31/2024	6/11/2024	112. NDB_Hydro_11-01-2023.xlsx
5/31/2024	6/11/2024	112a. NDB_New_Hydro_11-01-2023.xlsx
5/31/2024	6/11/2024	113. NDB_PS_11-01-2023.xlsx
5/31/2024	6/11/2024	114. NDB_Biomass_11-01-2023.xlsx
5/31/2024	6/11/2024	114a. NDB_New_Biomass_11-01-2023.xlsx
5/31/2024	6/11/2024	115. NDB_FuelCell_11-01-2023.xlsx
5/31/2024	6/11/2024	116. NDB_Geothermal_11-01-2023.xlsx
5/31/2024	6/11/2024	116a. NDB_New_Geothermal_11-01-2023.xlsx
5/31/2024	6/11/2024	117. NDB_Landfill_11-01-2023.xlsx
5/31/2024	6/11/2024	117a. NDB_New_Landfill_11-01-2023.xlsx
5/31/2024	6/11/2024	118. NDB_Other_11-01-2023.xlsx
5/31/2024	6/11/2024	119. NDB_OnShore_Wind_11-01-2023.xlsx
5/31/2024	6/11/2024	120. NDB_OffShore_Wind_11-01-2023.xlsx
5/31/2024	6/11/2024	121. NDB_Solar_PV_11-01-2023.xlsx
5/31/2024	6/11/2024	122. NDB_Solar_Steam_11-01-2023.xlsx
5/31/2024	6/11/2024	123. NDB_Expansion_11-01-2023.xlsx
5/31/2024	6/11/2024	124. NDB_DR_11-01-2023.xlsx
5/31/2024	6/11/2024	125. NDB_DER_Solar_11-01-2023.xlsx
5/31/2024	6/11/2024	126. NDB_DER_Battery_11-01-2023.xlsx
5/31/2024	6/11/2024	126a. NDB_Battery_11-01-2023.xlsx
5/31/2024	6/11/2024	126b. NDB_Battery_Target_11-01-2023.xlsx
5/31/2024	6/11/2024	127. Market_Rules_11-01-2023.xlsx
5/31/2024	6/11/2024	22F H2 CT.xlsx
5/31/2024	6/11/2024	23F 111 Gas CF Limits.xlsx
5/31/2024	6/11/2024	23F CCS Projects.xlsx
5/31/2024	6/11/2024	23F Future 2A Siting.xlsx
5/31/2024	6/11/2024	23F MISO Z6 KY NUC PTC.xlsx
5/31/2024	6/11/2024	23F PJM RTEP.xlsx
5/31/2024	6/11/2024	23F PTC Swap.xlsx
5/31/2024	6/11/2024	23F PTC to IRA Projects.xlsx
5/31/2024	6/11/2024	23F Renewable ITC_PTC Input Cleared.xlsx
5/31/2024	6/11/2024	23F Schedule 53 Class Average.xlsx
5/31/2024	6/11/2024	23F Wind OS ISONE-Maine PTC.xlsx
5/31/2024	6/11/2024	23S No Zone 6 Renewables.xlsx
5/31/2024	6/11/2024	24S 111 Gas CF.xlsx
5/31/2024	6/11/2024	24S 111 ST CF.xlsx
5/31/2024	6/11/2024	24S 50% Coal DFO.xlsx
5/31/2024	6/11/2024	24S Base.xlsx
5/31/2024	6/11/2024	24S CCS Projects.xlsx
5/31/2024	6/11/2024	24S CSAPR Update.xlsx
5/31/2024	6/11/2024	24S DLOL PRM & ELCC.xlsx
5/31/2024	6/11/2024	24S Duke Adders 111.xlsx
5/31/2024	6/11/2024	24S Duke Capital Costs.xlsx
5/31/2024	6/11/2024	24S Duke Fuel Costs.xlsx
5/31/2024	6/11/2024	24S MISO SAC ELCC.xlsx
5/31/2024	6/11/2024	24S Updates.xlsx
5/31/2024	6/11/2024	24S Z6R Duke Adders 111.xlsx
5/31/2024	6/11/2024	Dataset_for_Viewing.xlsx
5/31/2024	6/11/2024	No Coal Must Run.xlsx
5/31/2024	6/11/2024	Object Creation.xlsx
5/31/2024	6/11/2024	Reduce Zone 6 CC.xlsx
5/31/2024	6/11/2024	_DEI IRP NDB 111 Reference Runs.xlsx
6/11/2024	7/23/2024	Preliminary - No-111 portfolio
6/11/2024	7/23/2024	_DEI IRP Local Runs 2024.06.10.xlsx

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6/11/2024	7/23/2024	_EnCompass Input Share No 111 - 2024.06.11.xlsx
6/11/2024	7/23/2024	24S 111 MISO Market.xlsx
6/11/2024	7/23/2024	24S 111 Z6R MISO Market.xlsx
6/11/2024	7/23/2024	24S REF MISO Market.xlsx
6/11/2024	7/23/2024	24S REF Z6R MISO Market.xlsx
6/11/2024	7/23/2024	DEIN 23F New CC.xlsx
6/11/2024	7/23/2024	DEIN 23S CPCN Solar.xlsx
6/11/2024	7/23/2024	DEIN 23S EE Projects.zip
6/11/2024	7/23/2024	DEIN 23S No Market Limit.xlsx
6/11/2024	7/23/2024	DEIN 23S No Market Limit.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP Coal Retirements.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP REF Optimized Retirement FOM.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP Thermal Tranches.xlsx
6/11/2024	7/23/2024	DEIN 24 IRP Tranches.xlsx
6/11/2024	7/23/2024	DEIN 24S Base.xlsx
6/11/2024	7/23/2024	DEIN 24S Capital.xlsx
6/11/2024	7/23/2024	DEIN 24S Cay CC Cost Inc.xlsx
6/11/2024	7/23/2024	DEIN 24S Cayuga NGC.xlsx
6/11/2024	7/23/2024	DEIN 24S Cayuga Retire by '31.xlsx
6/11/2024	7/23/2024	DEIN 24S CC4 CT2 Avail.xlsx
6/11/2024	7/23/2024	DEIN 24S Coal to Gas Options.xlsx
6/11/2024	7/23/2024	DEIN 24S DLOL.xlsx
6/11/2024	7/23/2024	DEIN 24S Edwardsport Gas 2030.xlsx
6/11/2024	7/23/2024	DEIN 24S Edwardsport Gas 2035.xlsx
6/11/2024	7/23/2024	DEIN 24S EE Firm Capacity.xlsx
6/11/2024	7/23/2024	DEIN 24S ELCC Curves 111.xlsx
6/11/2024	7/23/2024	DEIN 24S ELCC Curves REF.xlsx
6/11/2024	7/23/2024	DEIN 24S Emissions on Fuel.xlsx
6/11/2024	7/23/2024	DEIN 24S Existing CT Limit.xlsx
6/11/2024	7/23/2024	DEIN 24S Fuel Prices.xlsx
6/11/2024	7/23/2024	DEIN 24S Gib 1-2 NGC.xlsx
6/11/2024	7/23/2024	DEIN 24S Gib 3-4 DFO.xlsx
6/11/2024	7/23/2024	DEIN 24S Gibson Gas Cost.xlsx
6/11/2024	7/23/2024	DEIN 24S Gibson Retire by '32.xlsx
6/11/2024	7/23/2024	DEIN 24S Hourly Profiles.zip
6/11/2024	7/23/2024	DEIN 24S IRA Extended.xlsx
6/11/2024	7/23/2024	DEIN 24S IRA.xlsx
6/11/2024	7/23/2024	DEIN 24S IRP Project Limits.xlsx
6/11/2024	7/23/2024	DEIN 24S Load.xlsx
6/11/2024	7/23/2024	DEIN 24S Market Limit - 25percent.xlsx
6/11/2024	7/23/2024	DEIN 24S New Gas CF Limit.xlsx
6/11/2024	7/23/2024	DEIN 24S New Gas Update.xlsx
6/11/2024	7/23/2024	DEIN 24S Nuclear ITC.xlsx
6/11/2024	7/23/2024	DEIN 24S Outage Schedule.xlsx
6/11/2024	7/23/2024	DEIN 24S Split Cay Retire.xlsx
6/11/2024	7/23/2024	DEIN 24S Transmission Adder.xlsx
6/11/2024	7/23/2024	DEIN Remove FOM - PC.xlsx
6/11/2024	7/23/2024	Duke Midwest Base.zip
7/9/2024	7/23/2024	CONFIDENTIAL_DEI Inflated Installed Calculation Example_June 2024.xlsx
7/9/2024	7/23/2024	CONFIDENTIAL_Generic Cost vs RFP Bids.xlsx
7/9/2024	7/23/2024	CONFIDENTIAL_IRP Generic Unit Summary Midwest.xlsx
7/23/2024	8/26/2024	_111 Generation Strategies.xlsx
7/23/2024	8/26/2024	24S 111 MISO Market.xlsx
7/23/2024	8/26/2024	24S 111 Z6R MISO Market.xlsx
7/23/2024	8/26/2024	DEIN 23F New CC.xlsx
7/23/2024	8/26/2024	DEIN 23S CPCN Solar.xlsx
7/23/2024	8/26/2024	DEIN 23S EE Projects.xlsx
7/23/2024	8/26/2024	DEIN 23S No Market Limit.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP Blend 3 Forced Units.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP Consolidate 2x1s.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP Thermal Tranches.xlsx

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7/23/2024	8/26/2024	DEIN 24S Base.xlsx
7/23/2024	8/26/2024	DEIN 24S Capital.xlsx
7/23/2024	8/26/2024	DEIN 24S Cay CC Cost Inc.xlsx
7/23/2024	8/26/2024	DEIN 24S Cayuga NGC 2029.xlsx
7/23/2024	8/26/2024	DEIN 24S Cayuga NGC.xlsx
7/23/2024	8/26/2024	DEIN 24S Cayuga Retire by '32.xlsx
7/23/2024	8/26/2024	DEIN 24S CC4 1x1 Avail.xlsx
7/23/2024	8/26/2024	DEIN 24S CCU Gib Fix Cost Adj.xlsx
7/23/2024	8/26/2024	DEIN 24S Coal to Gas Options.xlsx
7/23/2024	8/26/2024	DEIN 24S DLOL.xlsx
7/23/2024	8/26/2024	DEIN 24S Edwardsport Gas 2030.xlsx
7/23/2024	8/26/2024	DEIN 24S EE Projects.xlsx
7/23/2024	8/26/2024	DEIN 24S ELCC Curves 111.xlsx
7/23/2024	8/26/2024	DEIN 24S Emissions on Fuel.xlsx
7/23/2024	8/26/2024	DEIN 24S Existing CT Limit.xlsx
7/23/2024	8/26/2024	DEIN 24S Force CAY 1x1s.xlsx
7/23/2024	8/26/2024	DEIN 24S Fuel Prices.xlsx
7/23/2024	8/26/2024	DEIN 24S Gib 1-2 DFO.xlsx
7/23/2024	8/26/2024	DEIN 24S Gib 3-4 NGC.xlsx
7/23/2024	8/26/2024	DEIN 24S Gib 3-4 Retire.xlsx
7/23/2024	8/26/2024	DEIN 24S Gibson Gas Cost.xlsx
7/23/2024	8/26/2024	DEIN 24S Gibson Retire by '32.xlsx
7/23/2024	8/26/2024	DEIN 24S Gibson Retire Stakeholder 1.xlsx
7/23/2024	8/26/2024	DEIN 24S Hourly Profiles.xlsx
7/23/2024	8/26/2024	DEIN 24S IRA Extended.xlsx
7/23/2024	8/26/2024	DEIN 24S IRA.xlsx
7/23/2024	8/26/2024	DEIN 24S IRP Project Limits.xlsx
7/23/2024	8/26/2024	DEIN 24S Load.xlsx
7/23/2024	8/26/2024	DEIN 24S Market Limit - 25.xlsx
7/23/2024	8/26/2024	DEIN 24S New Gas CF Limit.xlsx
7/23/2024	8/26/2024	DEIN 24S New Gas Update.xlsx
7/23/2024	8/26/2024	DEIN 24S Nuclear ITC.xlsx
7/23/2024	8/26/2024	DEIN 24S Outage Schedule.xlsx
7/23/2024	8/26/2024	DEIN 24S Split Cay Retire.xlsx
7/23/2024	8/26/2024	DEIN 24S Transmission Adder.xlsx
7/23/2024	8/26/2024	Duke Midwest Base.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 Blend 1 PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 Blend 3 PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 CCU PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 RCU PC.xlsx
7/23/2024	8/26/2024	DEIN 24 IRP 111 SH 1 PC.xlsx
7/23/2024	8/26/2024	DEI 2024 IRP Modeling_Change Log_07.22.2024
7/25/2024	8/26/2024	_111 Generation Strategies.xlsx
7/25/2024	8/26/2024	24S No 111 MISO Market.xlsx
7/25/2024	8/26/2024	24S No 111 Z6R MISO Market.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP Coal Retirements.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP No 111 Opt Ret FOM.xlsx
7/25/2024	8/26/2024	DEIN 24S Edwardsport Gas 2035.xlsx
7/25/2024	8/26/2024	DEIN 24S ELCC Curves No 111.xlsx
7/25/2024	8/26/2024	DEIN 24S Force Gib 1x1.xlsx
7/25/2024	8/26/2024	DEIN 24S Market Limit - 25percent.xlsx
7/25/2024	8/26/2024	DEIN Remove FOM - PC.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP 111 Blend 2 - CAY 1x1s Gib 1x1 PC.xlsx
7/25/2024	8/26/2024	DEIN 24 IRP No 111 Opt Ret PC.xlsx
9/3/2024	9/20/2024	_DEIN 24 IRP Local Input Share 08.29.2024.xlsx
9/3/2024	9/20/2024	24S 111 MISO Market.xlsx
9/3/2024	9/20/2024	24S 111 Z6R MISO Market.xlsx
9/3/2024	9/20/2024	24S APRI MISO Market.xlsx
9/3/2024	9/20/2024	24S APRI Z6R MISO Market.xlsx
9/3/2024	9/20/2024	24S MPLI MISO Market.xlsx

Date Posted	Date Removed	File Name
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9/3/2024	9/20/2024	24S No 111 MISO Market.xlsx
9/3/2024	9/20/2024	24S No 111 Z6R MISO Market.xlsx
9/3/2024	9/20/2024	DEIN 23F New CC.xlsx
9/3/2024	9/20/2024	DEIN 23S CPCN Solar.xlsx
9/3/2024	9/20/2024	DEIN 23S EE Projects.xlsx
9/3/2024	9/20/2024	DEIN 23S No Market Limit.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Blend 4 Adjustments.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP CCU Gib Fix Cost Adj.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP CCU Project Limits.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Coal Retirements.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Consolidate CCs.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP High Load CT PPA.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP No 111 Opt Ret FOM.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP SH 1 Relax Battery Limit.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Thermal Tranches.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP Tranches.xlsx
9/3/2024	9/20/2024	DEIN 24S APRI Capital and FOM Costs.xlsx
9/3/2024	9/20/2024	DEIN 24S APRI Market Sale Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S APRI Project Limits.xlsx
9/3/2024	9/20/2024	DEIN 24S Base.xlsx
9/3/2024	9/20/2024	DEIN 24S Capital.xlsx
9/3/2024	9/20/2024	DEIN 24S Cay CC Cost Inc.xlsx
9/3/2024	9/20/2024	DEIN 24S Cayuga NGC 2029.xlsx
9/3/2024	9/20/2024	DEIN 24S Cayuga NGC.xlsx
9/3/2024	9/20/2024	DEIN 24S Cayuga Retire by '32.xlsx
9/3/2024	9/20/2024	DEIN 24S CC Min Up April 2035.xlsx
9/3/2024	9/20/2024	DEIN 24S CC Min Up April 2046.xlsx
9/3/2024	9/20/2024	DEIN 24S CO2 Tax.xlsx
9/3/2024	9/20/2024	DEIN 24S Coal to Gas Options.xlsx
9/3/2024	9/20/2024	DEIN 24S DL0L.xlsx
9/3/2024	9/20/2024	DEIN 24S Edwardsport Gas 2030.xlsx
9/3/2024	9/20/2024	DEIN 24S Edwardsport Gas 2035.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Firm Cap High Load.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Firm Cap High PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Firm Cap Low PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S EE Projects.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves 111.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves APRI.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves MPLI.xlsx
9/3/2024	9/20/2024	DEIN 24S ELCC Curves No 111.xlsx
9/3/2024	9/20/2024	DEIN 24S Emissions on Fuel.xlsx
9/3/2024	9/20/2024	DEIN 24S Existing CT Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S Existing Gas CF Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S Force CAY 1x1s.xlsx
9/3/2024	9/20/2024	DEIN 24S Fuel Prices.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 1-2 DFO FT.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 1-2 DFO.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 3-4 NGC.xlsx
9/3/2024	9/20/2024	DEIN 24S Gib 3-4 Retire.xlsx
9/3/2024	9/20/2024	DEIN 24S Gibson Gas Cost.xlsx
9/3/2024	9/20/2024	DEIN 24S Gibson Retire by '32.xlsx
9/3/2024	9/20/2024	DEIN 24S Gibson Retire Stakeholder 1.xlsx
9/3/2024	9/20/2024	DEIN 24S High Fuels Prices.xlsx
9/3/2024	9/20/2024	DEIN 24S High Load.xlsx
9/3/2024	9/20/2024	DEIN 24S High PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S Hourly Profiles.xlsx
9/3/2024	9/20/2024	DEIN 24S IRA 100 percent Domestic Content.xlsx
9/3/2024	9/20/2024	DEIN 24S IRA Extended.xlsx
9/3/2024	9/20/2024	DEIN 24S IRA.xlsx
9/3/2024	9/20/2024	DEIN 24S IRP LDES Set Up.xlsx

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9/3/2024	9/20/2024	DEIN 24S Limit 1x1 CC.xlsx
9/3/2024	9/20/2024	DEIN 24S Load.xlsx
9/3/2024	9/20/2024	DEIN 24S Low Fuels Price.xlsx
9/3/2024	9/20/2024	DEIN 24S Low PV Load.xlsx
9/3/2024	9/20/2024	DEIN 24S Market Limit - 25 percent.xlsx
9/3/2024	9/20/2024	DEIN 24S New Gas CF Limit.xlsx
9/3/2024	9/20/2024	DEIN 24S New Gas Update.xlsx
9/3/2024	9/20/2024	DEIN 24S No IRA.xlsx
9/3/2024	9/20/2024	DEIN 24S No Nuc.xlsx
9/3/2024	9/20/2024	DEIN 24S Nuclear ITC.xlsx
9/3/2024	9/20/2024	DEIN 24S Outage Schedule.xlsx
9/3/2024	9/20/2024	DEIN 24S Split Cay Retire.xlsx
9/3/2024	9/20/2024	DEIN 24S Transmission Adder.xlsx
9/3/2024	9/20/2024	DEIN Remove FOM - PC.xlsx
9/3/2024	9/20/2024	Duke Midwest Base.xlsx
9/3/2024	9/20/2024	_DEI 24 IRP NDB Inputs.xlsx
9/3/2024	9/20/2024	101. NDB_Topology_11-01-2023.xlsx
9/3/2024	9/20/2024	102. NDB_Demand_RPS_11-01-2023.xlsx
9/3/2024	9/20/2024	103. NDB_Fuel_Emission_11-01-2023.xlsx
9/3/2024	9/20/2024	103a. EAST_Emissions.xlsx
9/3/2024	9/20/2024	104. NDB_Nuclear_11-01-2023.xlsx
9/3/2024	9/20/2024	105. NDB_Coal_11-01-2023.xlsx
9/3/2024	9/20/2024	106. NDB_CC_11-01-2023.xlsx
9/3/2024	9/20/2024	107. NDB_IGCC_11-01-2023.xlsx
9/3/2024	9/20/2024	108. NDB_STORAGE_11-01-2023.xlsx
9/3/2024	9/20/2024	109. NDB_Steam_Gas_Oil_11-01-2023.xlsx
9/3/2024	9/20/2024	110. NDB_GT_11-01-2023.xlsx
9/3/2024	9/20/2024	111. NDB_IC_11-01-2023.xlsx
9/3/2024	9/20/2024	112. NDB_Hydro_11-01-2023.xlsx
9/3/2024	9/20/2024	112a. NDB_New_Hydro_11-01-2023.xlsx
9/3/2024	9/20/2024	113. NDB_PS_11-01-2023.xlsx
9/3/2024	9/20/2024	114. NDB_Biomass_11-01-2023.xlsx
9/3/2024	9/20/2024	114a. NDB_New_Biomass_11-01-2023.xlsx
9/3/2024	9/20/2024	115. NDB_FuelCell_11-01-2023.xlsx
9/3/2024	9/20/2024	116. NDB_Geothermal_11-01-2023.xlsx
9/3/2024	9/20/2024	116a. NDB_New_Geothermal_11-01-2023.xlsx
9/3/2024	9/20/2024	117. NDB_Landfill_11-01-2023.xlsx
9/3/2024	9/20/2024	117a. NDB_New_Landfill_11-01-2023.xlsx
9/3/2024	9/20/2024	118. NDB_Other_11-01-2023.xlsx
9/3/2024	9/20/2024	119. NDB_OnShore_Wind_11-01-2023.xlsx
9/3/2024	9/20/2024	120. NDB_OffShore_Wind_11-01-2023.xlsx
9/3/2024	9/20/2024	121. NDB_Solar_PV_11-01-2023.xlsx
9/3/2024	9/20/2024	122. NDB_Solar_Steam_11-01-2023.xlsx
9/3/2024	9/20/2024	123. NDB_Expansion_11-01-2023.xlsx
9/3/2024	9/20/2024	124. NDB_DR_11-01-2023.xlsx
9/3/2024	9/20/2024	125. NDB_DER_Solar_11-01-2023.xlsx
9/3/2024	9/20/2024	126. NDB_DER_Battery_11-01-2023.xlsx
9/3/2024	9/20/2024	126a. NDB_Battery_11-01-2023.xlsx
9/3/2024	9/20/2024	126b. NDB_Battery_Target_11-01-2023.xlsx
9/3/2024	9/20/2024	127. Market_Rules_11-01-2023.xlsx
9/3/2024	9/20/2024	22F H2 CT.xlsx
9/3/2024	9/20/2024	23F 111 Gas CF Limits.xlsx
9/3/2024	9/20/2024	23F CCS Projects.xlsx
9/3/2024	9/20/2024	23F EIA High Fuels.xlsx
9/3/2024	9/20/2024	23F EIA Low Fuels.xlsx
9/3/2024	9/20/2024	23F Future 2A Siting.xlsx
9/3/2024	9/20/2024	23F MISO Z6 KY NUC PTC.xlsx
9/3/2024	9/20/2024	23F PJM RTEP.xlsx
9/3/2024	9/20/2024	23F PTC Swap.xlsx

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9/3/2024	9/20/2024	23F Renewable ITC_PTC Input Cleared.xlsx
9/3/2024	9/20/2024	23F Schedule 53 Class Average.xlsx
9/3/2024	9/20/2024	23F Wind OS ISONE-Maine PTC.xlsx
9/3/2024	9/20/2024	23S No Zone 6 Renewables.xlsx
9/3/2024	9/20/2024	24S 111 Gas CF.xlsx
9/3/2024	9/20/2024	24S 111 Proposed Existing Gas CF.xlsx
9/3/2024	9/20/2024	24S 111 ST CF.xlsx
9/3/2024	9/20/2024	24S 50 percent Coal DFO.xlsx
9/3/2024	9/20/2024	24S AGRI Project Limits.xlsx
9/3/2024	9/20/2024	24S Base.xlsx
9/3/2024	9/20/2024	24S CCS Projects.xlsx
9/3/2024	9/20/2024	24S CO2 Tax.xlsx
9/3/2024	9/20/2024	24S CSAPR Update.xlsx
9/3/2024	9/20/2024	24S DLOL PRM & ELCC.xlsx
9/3/2024	9/20/2024	24S Duke Adders 111.xlsx
9/3/2024	9/20/2024	24S Duke Adders.xlsx
9/3/2024	9/20/2024	24S Duke AGRI Capital and FOM Costs.xlsx
9/3/2024	9/20/2024	24S Duke Capital Costs.xlsx
9/3/2024	9/20/2024	24S Duke Fuel Costs.xlsx
9/3/2024	9/20/2024	24S IRA Repealed.xlsx
9/3/2024	9/20/2024	24S LDES.xlsx
9/3/2024	9/20/2024	24S MISO SAC ELCC.xlsx
9/3/2024	9/20/2024	24S No Nuclear.xlsx
9/3/2024	9/20/2024	24S PTC with 100 percent Domestic Content.xlsx
9/3/2024	9/20/2024	24S Updates.xlsx
9/3/2024	9/20/2024	24S Z6R Duke Adders 111.xlsx
9/3/2024	9/20/2024	24S Z6R Duke Adders.xlsx
9/3/2024	9/20/2024	Dataset_for_Viewing.xlsx
9/3/2024	9/20/2024	No Coal Must Run.xlsx
9/3/2024	9/20/2024	Object Creation.xlsx
9/3/2024	9/20/2024	Reduce Zone 6 CC.xlsx
9/3/2024	9/20/2024	A DEIN 24 IRP APRI Blend 1 PC.xlsx
9/3/2024	9/20/2024	A DEIN 24 IRP APRI Blend 2 - CAY 1x1s PC.xlsx
9/3/2024	9/20/2024	A DEIN 24 IRP APRI Blend 4 PC.xlsx
9/3/2024	9/20/2024	A DEIN 24 IRP APRI CCU PC.xlsx
9/3/2024	9/20/2024	A DEIN 24 IRP APRI RCU PC.xlsx
9/3/2024	9/20/2024	A DEIN 24 IRP APRI SH 1 PC.xlsx
9/3/2024	9/20/2024	M DEIN 24 IRP MPLI Blend 1 PC.xlsx
9/3/2024	9/20/2024	M DEIN 24 IRP MPLI Blend 2 - CAY 1x1s PC.xlsx
9/3/2024	9/20/2024	M DEIN 24 IRP MPLI Blend 4 PC.xlsx
9/3/2024	9/20/2024	M DEIN 24 IRP MPLI CCU PC.xlsx
9/3/2024	9/20/2024	M DEIN 24 IRP MPLI RCU PC.xlsx
9/3/2024	9/20/2024	M DEIN 24 IRP MPLI SH 1 PC.xlsx
9/3/2024	9/20/2024	R DEIN 24 IRP 111 Blend 1 PC.xlsx
9/3/2024	9/20/2024	R DEIN 24 IRP 111 Blend 2 - CAY 1x1s PC.xlsx
9/3/2024	9/20/2024	R DEIN 24 IRP 111 Blend 4 PC.xlsx
9/3/2024	9/20/2024	R DEIN 24 IRP 111 CCU PC.xlsx
9/3/2024	9/20/2024	R DEIN 24 IRP 111 RCU PC.xlsx
9/3/2024	9/20/2024	R DEIN 24 IRP 111 SH 1 PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 Blend 1 High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 Blend 2 CAY 1x1s High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 Blend 4 High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 CCU High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 RCU High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP 111 SH 1 High Load PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP No 111 Opt Ret PC.xlsx
9/3/2024	9/20/2024	DEIN 24 IRP No 111 Opt Ret PC.xlsx
9/3/2024	9/20/2024	24S AGRI PC.xlsx
9/3/2024	9/20/2024	24S AGRI Z6R PC.xlsx
9/3/2024	9/20/2024	24S EPA 111 PC Adders.xlsx



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9/3/2024	9/20/2024	24S EPA 111 Z6R PC Adrs.xlsx
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9/3/2024	9/20/2024	24S MPLI Z6R PC.xlsx
9/3/2024	9/20/2024	24S Ref PC Adders.xlsx
9/3/2024	9/20/2024	24S Ref Z6R PC Adrs.xlsx
9/3/2024	9/20/2024	READ ME.txt
9/20/2024	10/4/2024	_DEIN 24 IRP Local Input Share 09.19.2024.xlsx
9/20/2024	10/4/2024	24S 111 High Fuel MISO Market.xlsx
9/20/2024	10/4/2024	24S 111 Low Fuel MISO Market.xlsx
9/20/2024	10/4/2024	24S 111 MISO Market.xlsx
9/20/2024	10/4/2024	24S 111 Z6R MISO Market.xlsx
9/20/2024	10/4/2024	24S APRI MISO Market.xlsx
9/20/2024	10/4/2024	24S APRI Z6R MISO Market.xlsx
9/20/2024	10/4/2024	24S MPLI MISO Market.xlsx
9/20/2024	10/4/2024	24S MPLI Z6R MISO Market.xlsx
9/20/2024	10/4/2024	24S No 111 MISO Market.xlsx
9/20/2024	10/4/2024	24S No 111 Z6R MISO Market.xlsx
9/20/2024	10/4/2024	DEIN 23F New CC.xlsx
9/20/2024	10/4/2024	DEIN 23S CPCN Solar.xlsx
9/20/2024	10/4/2024	DEIN 23S Edwardsport CCS Boiler.xlsx
9/20/2024	10/4/2024	DEIN 23S EE Projects.xlsx
9/20/2024	10/4/2024	DEIN 23S No Market Limit.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Blend 4 Adjustments.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP CCU Gib Fix Cost Adj.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP CCU Project Limits.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Coal Retirements.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Consolidate CCs.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Force Nuc.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP High CC CT Cost.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP High Load CT PPA.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP No 111 Opt Ret FOM.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP SH 1 Relax Battery Limit.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Thermal Tranches.xlsx
9/20/2024	10/4/2024	DEIN 24 IRP Tranches.xlsx
9/20/2024	10/4/2024	DEIN 24S 2032 2x1.xlsx
9/20/2024	10/4/2024	DEIN 24S APRI Capital and FOM Costs.xlsx
9/20/2024	10/4/2024	DEIN 24S APRI Market Sale Limit.xlsx
9/20/2024	10/4/2024	DEIN 24S APRI Project Limits.xlsx
9/20/2024	10/4/2024	DEIN 24S Base.xlsx
9/20/2024	10/4/2024	DEIN 24S Blend 2 Gib Fixed Cost Adj.xlsx
9/20/2024	10/4/2024	DEIN 24S Capital.xlsx
9/20/2024	10/4/2024	DEIN 24S Cay CC Cost Inc.xlsx
9/20/2024	10/4/2024	DEIN 24S Cayuga NGC 2029.xlsx
9/20/2024	10/4/2024	DEIN 24S Cayuga NGC.xlsx
9/20/2024	10/4/2024	DEIN 24S Cayuga Retire by '32.xlsx
9/20/2024	10/4/2024	DEIN 24S CO2 Tax.xlsx
9/20/2024	10/4/2024	DEIN 24S Coal to Gas Options.xlsx
9/20/2024	10/4/2024	DEIN 24S DLOL.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport CCS 2032.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport Gas 2028.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport Gas 2030.xlsx
9/20/2024	10/4/2024	DEIN 24S Edwardsport Gas 2035.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap High Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap High PV Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap Low Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Firm Cap Low PV Load.xlsx
9/20/2024	10/4/2024	DEIN 24S EE Projects.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves 111.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves APRI.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves MPLI.xlsx
9/20/2024	10/4/2024	DEIN 24S ELCC Curves No 111.xlsx

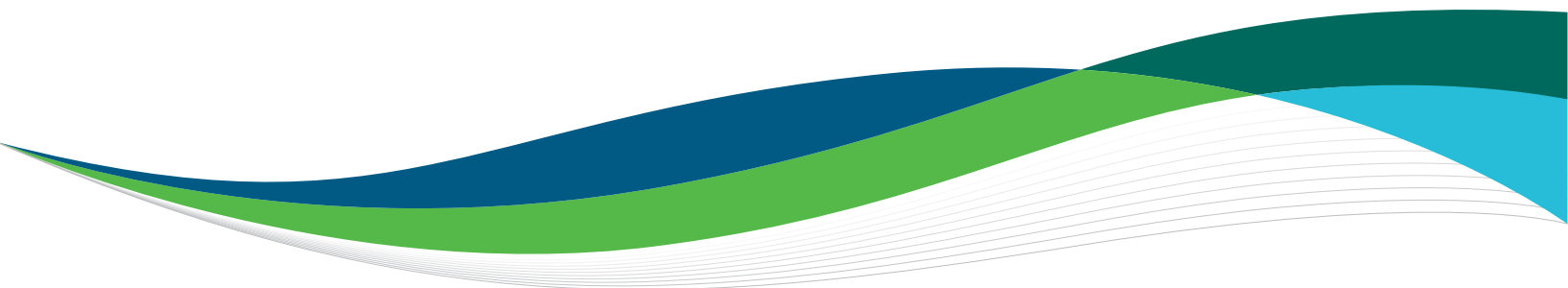
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9/20/2024	10/4/2024	DEIN 24S Emissions on Fuel.xlsx
9/20/2024	10/4/2024	DEIN 24S Existing CT Limit.xlsx
9/20/2024	10/4/2024	DEIN 24S Existing Gas CF Limit.xlsx
9/20/2024	10/4/2024	DEIN 24S Extend MISO SAC.xlsx
9/20/2024	10/4/2024	DEIN 24S Force CAY 1x1s.xlsx
9/20/2024	10/4/2024	DEIN 24S Force CAY 2x1.xlsx
9/20/2024	10/4/2024	DEIN 24S Fuel Prices.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 1-2 DFO FT.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 1-2 DFO.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 1-2 NGC.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 3-4 NGC.xlsx
9/20/2024	10/4/2024	DEIN 24S Gib 3-4 Retire.xlsx
9/20/2024	10/4/2024	DEIN 24S Gibson Gas Cost.xlsx
9/20/2024	10/4/2024	DEIN 24S Gibson Retire by '32.xlsx
9/20/2024	10/4/2024	DEIN 24S Gibson Retire Stakeholder 1.xlsx
9/20/2024	10/4/2024	DEIN 24S High Fuels Prices.xlsx
9/20/2024	10/4/2024	DEIN 24S High Load.xlsx
9/20/2024	10/4/2024	DEIN 24S High PV Load.xlsx
9/20/2024	10/4/2024	DEIN 24S Hourly Profiles.xlsx
9/20/2024	10/4/2024	DEIN 24S IRA 100percent Domestic Content.xlsx
9/20/2024	10/4/2024	DEIN 24S IRA Extended.xlsx
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# Attachment C-1

## EnCompass Modeling Inputs & Outputs

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# INDIANA

## 2024

DUKE ENERGY

## INTEGRATED

## RESOURCE PLAN

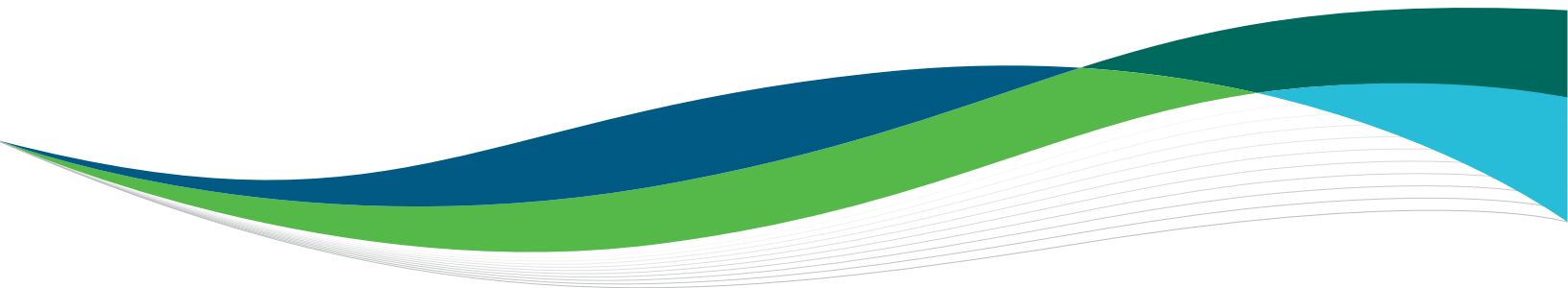


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# Attachment C-2

## Ongoing Capital & FOM Costs

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# INDIANA

**2024**  
DUKE ENERGY

**INTEGRATED  
RESOURCE PLAN**

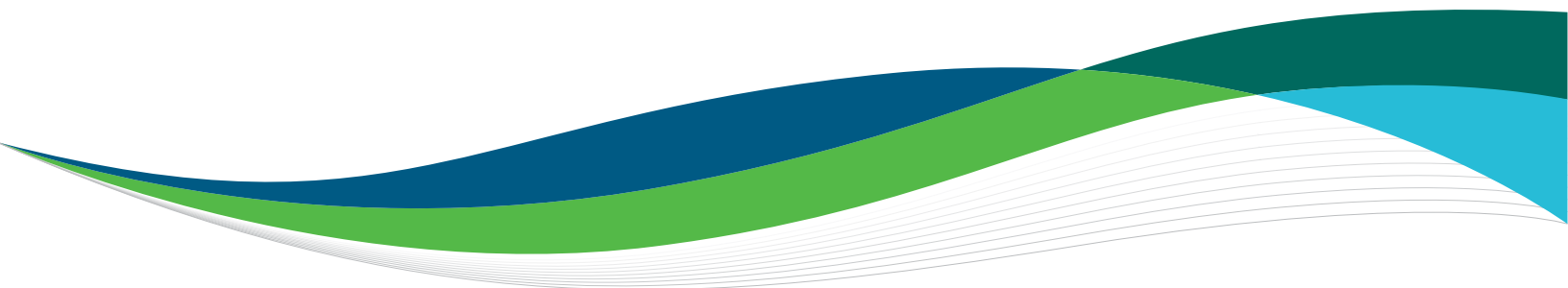


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# Attachment C-3

## Projected Bill Impact Calculations

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# INDIANA

## 2024

DUKE ENERGY

## INTEGRATED

## RESOURCE PLAN

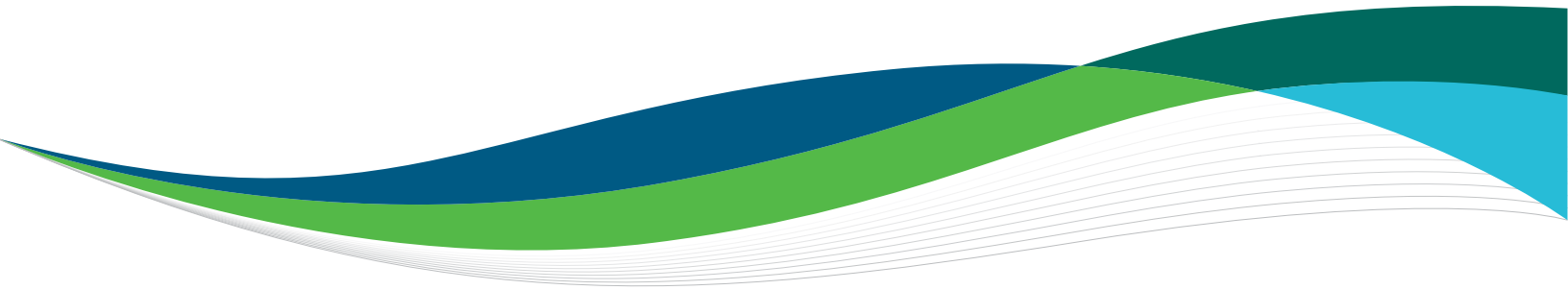


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# Attachment D-1

## Additional Load Shapes



# INDIANA

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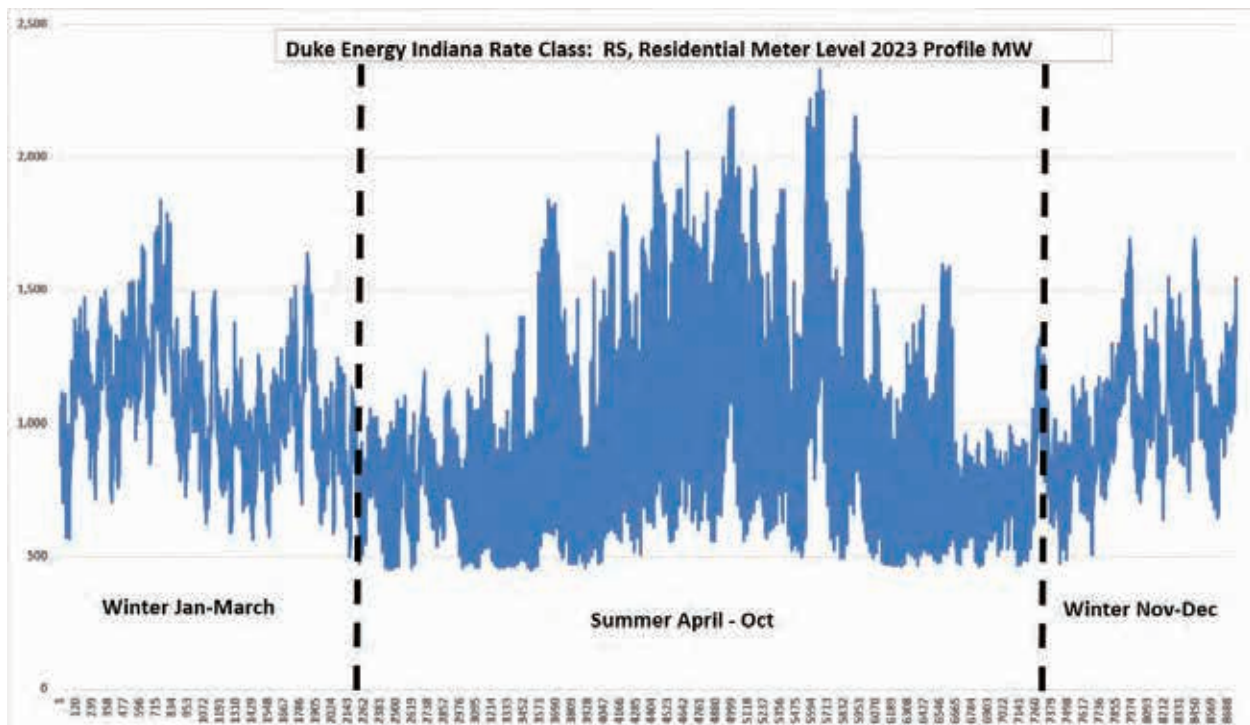
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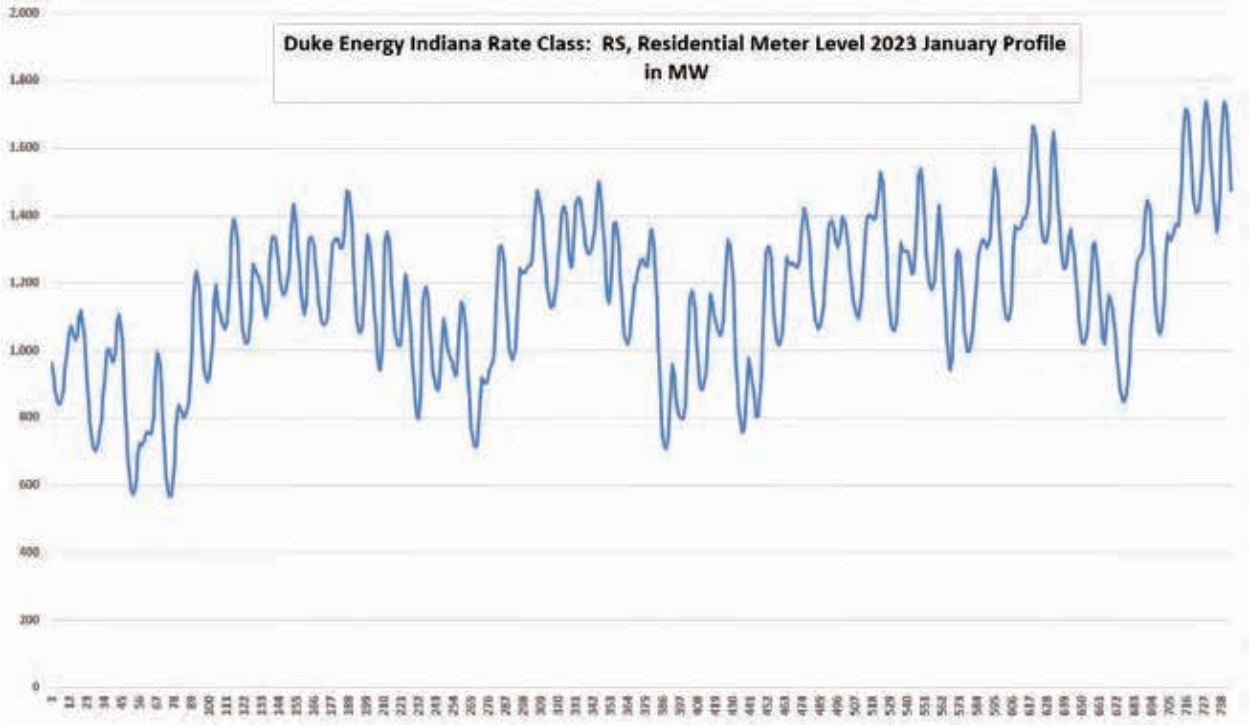
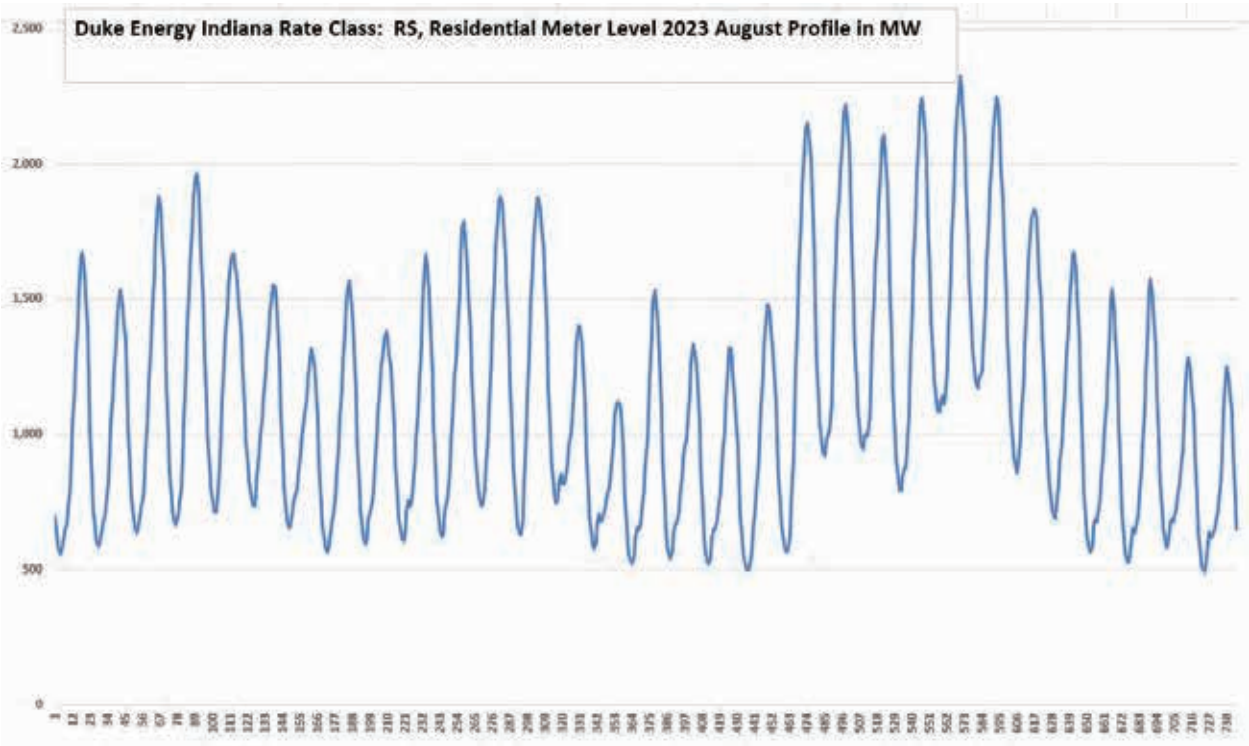
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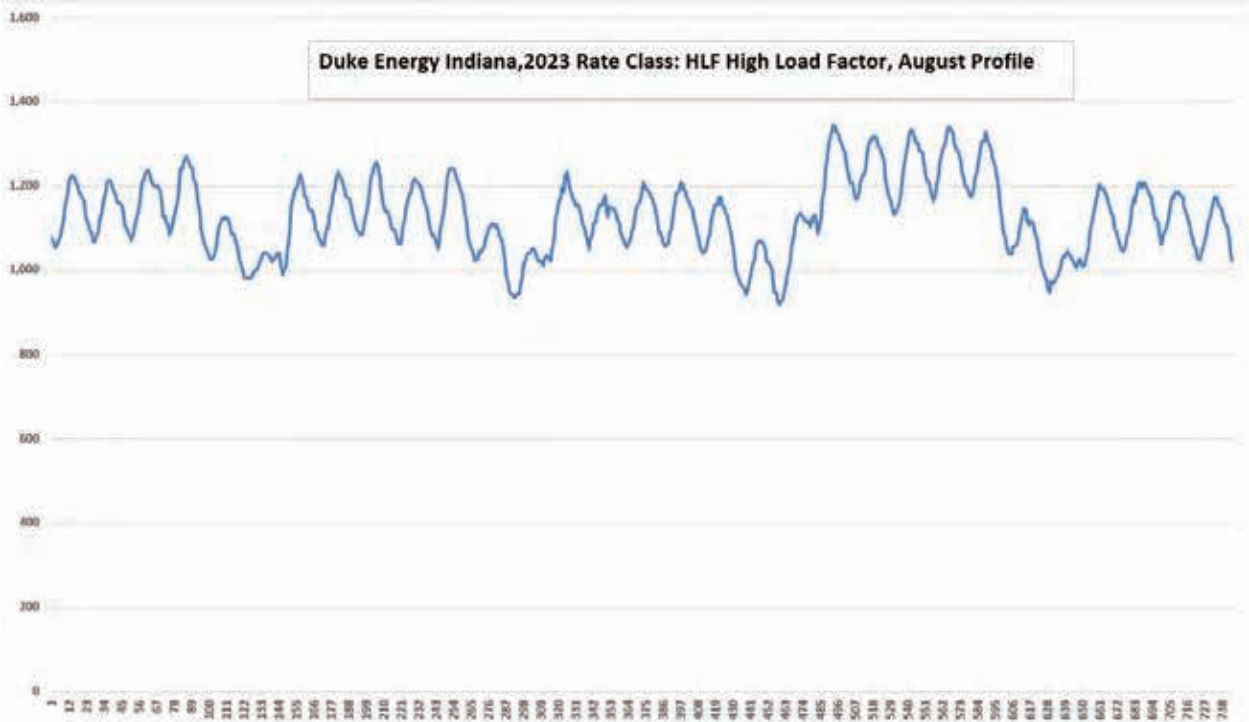
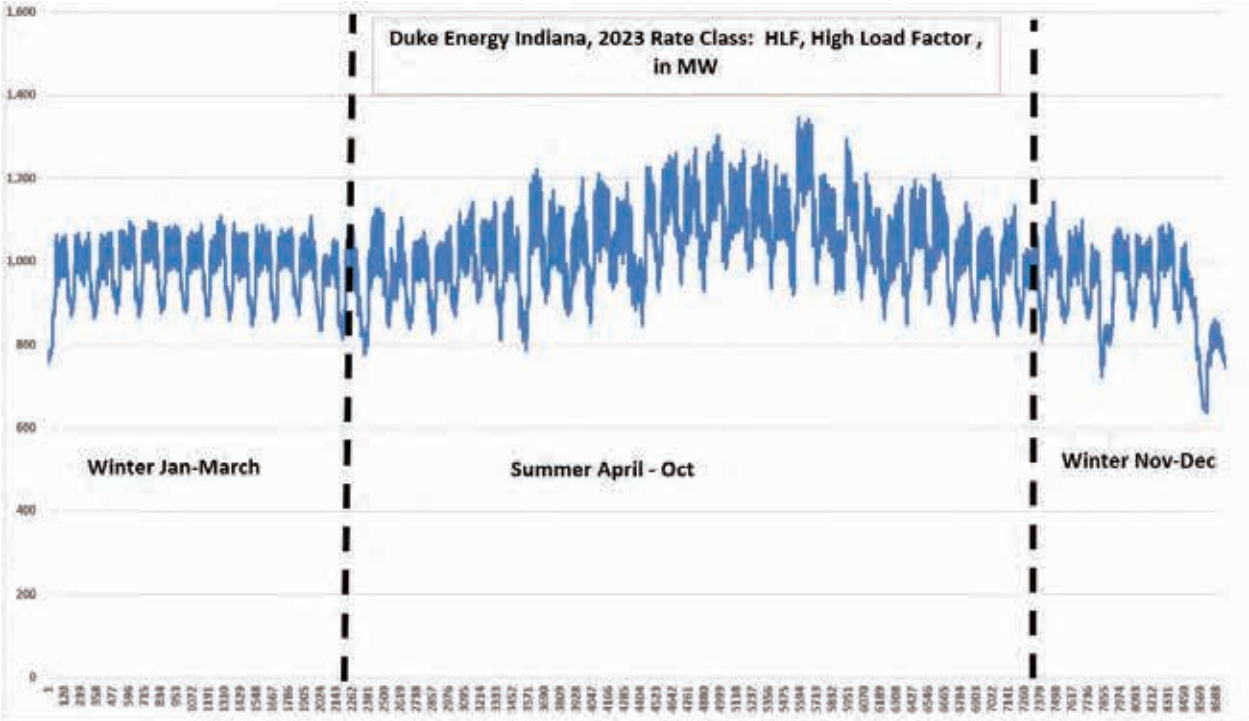
## Load Shapes

### Historical Metered Hourly Load Shapes by Rate Class & Load Factor

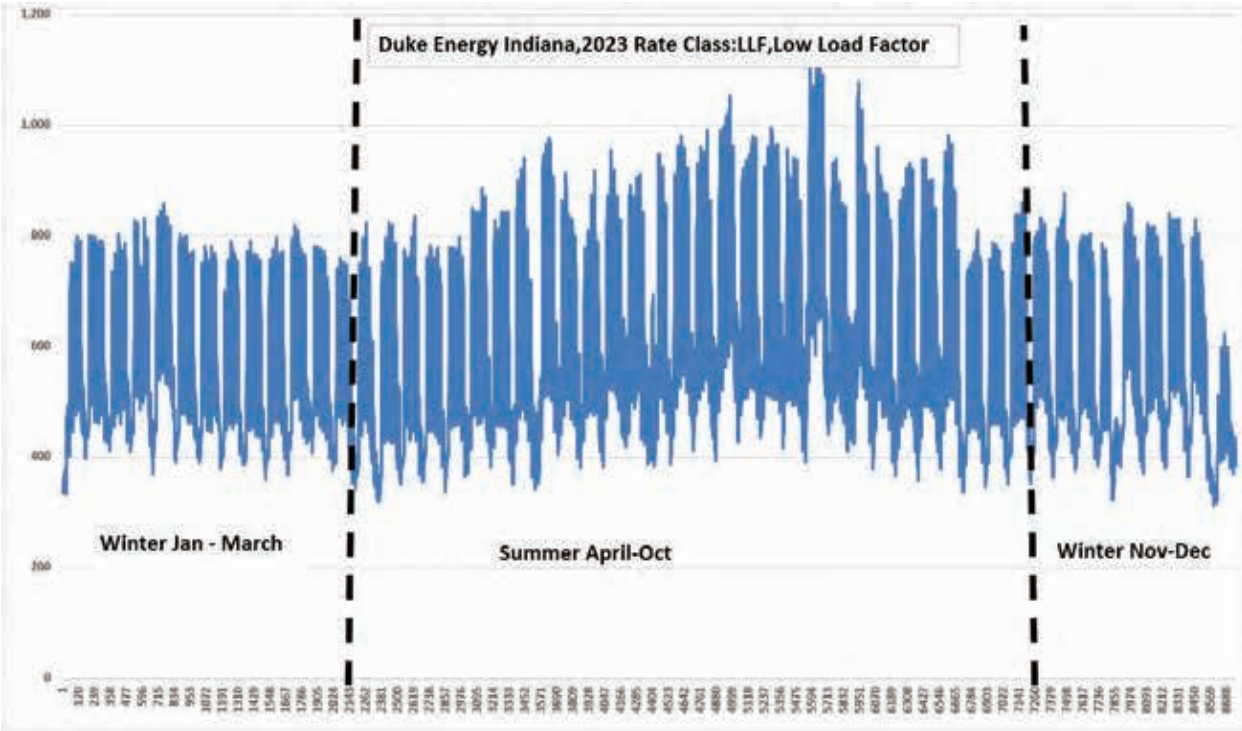
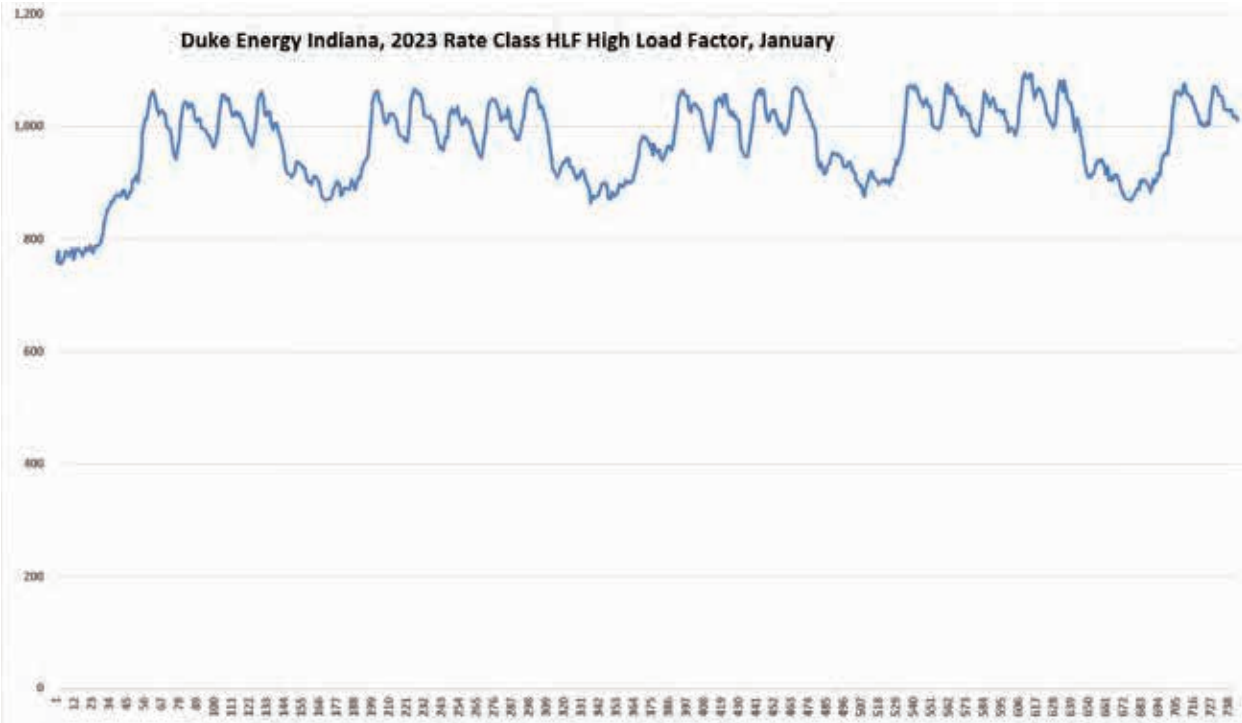
The following charts are metered hourly load shapes by rate class for 2023 using actual weather. Metered hourly load shapes from history support the hourly load shape model, Itron LT, which supports the Duke Energy Indiana hourly load forecast. Weather adjustments are applied to the hourly load shape and the historic monthly sales history for reference and for calibration of the model to generate the forecast under normal weather conditions for the 2024 IRP. Actual weather load shapes are provided to reflect history without model imputation.

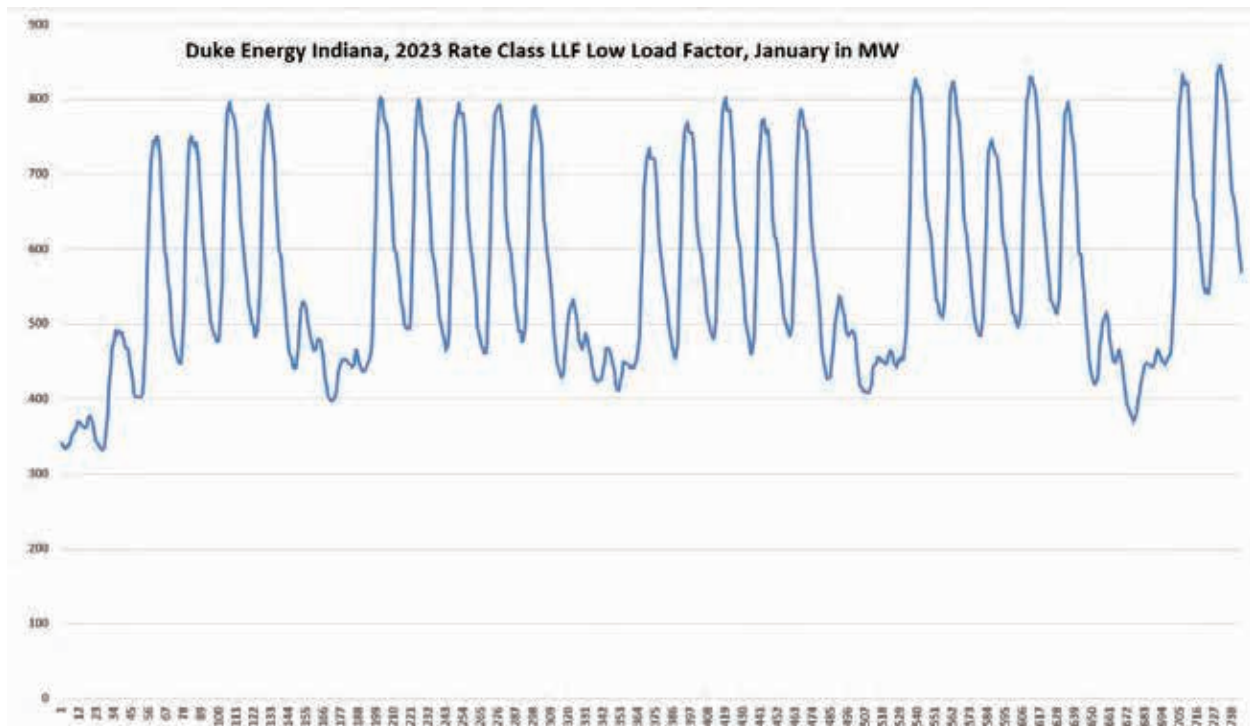
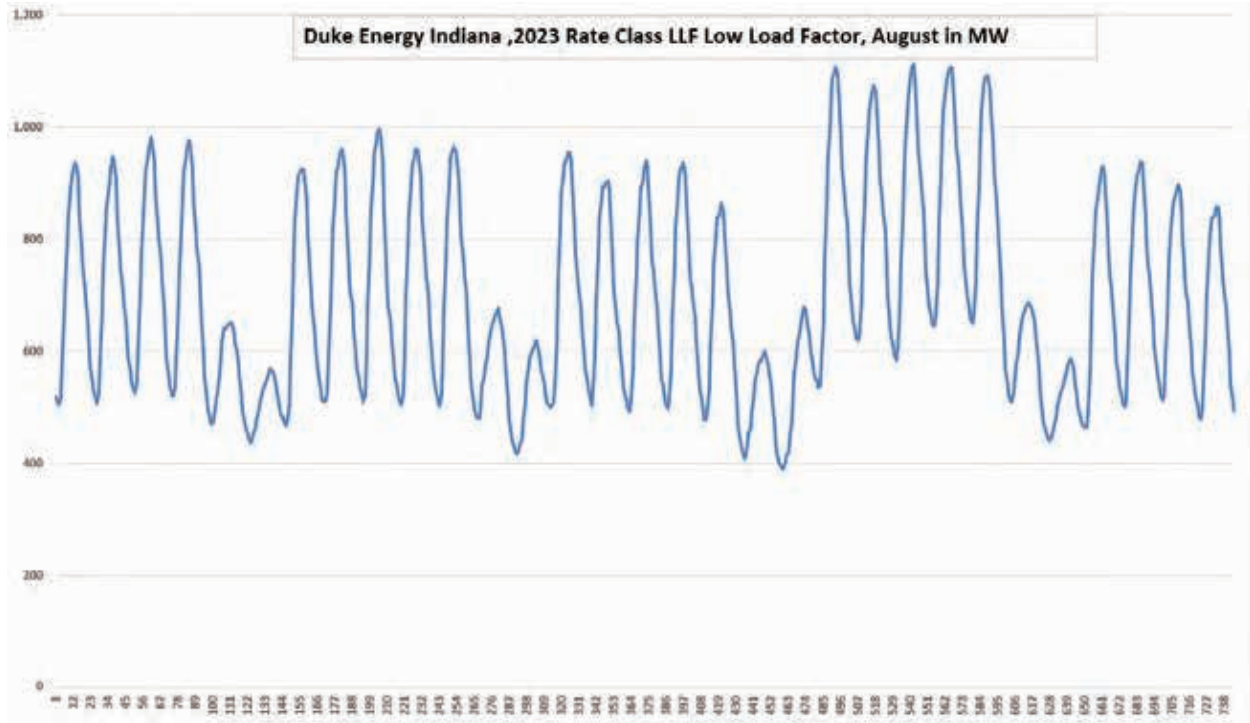






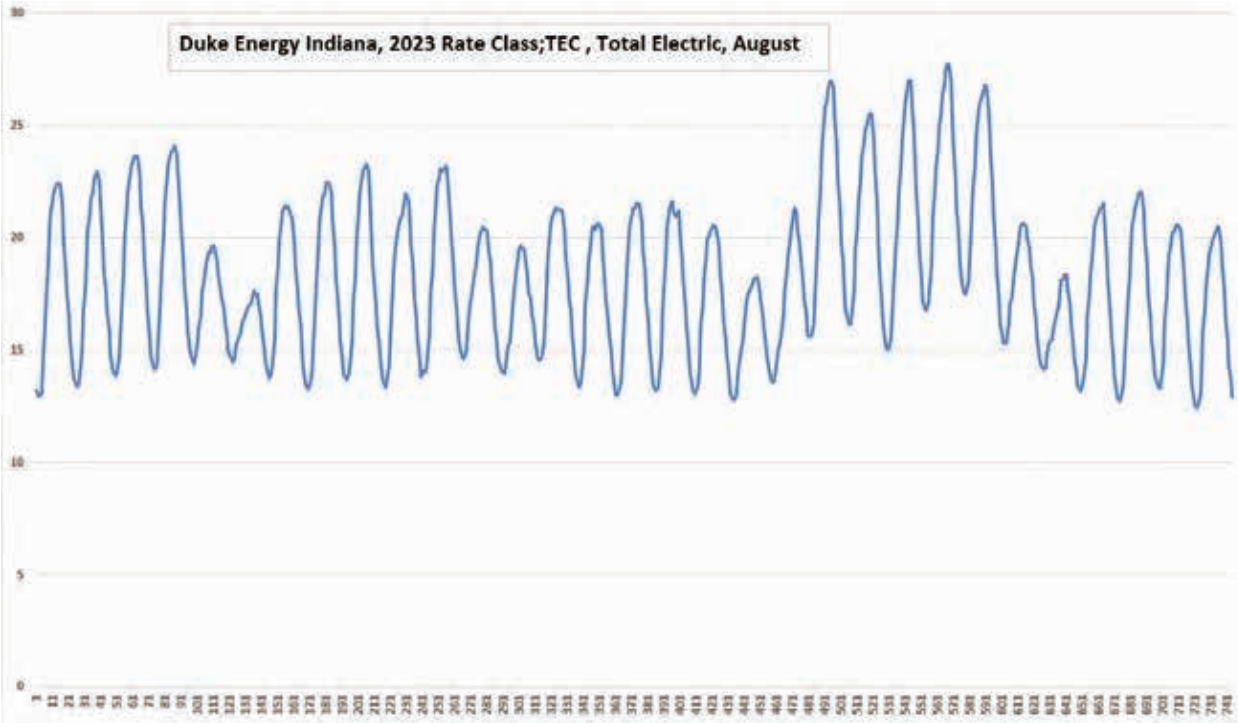
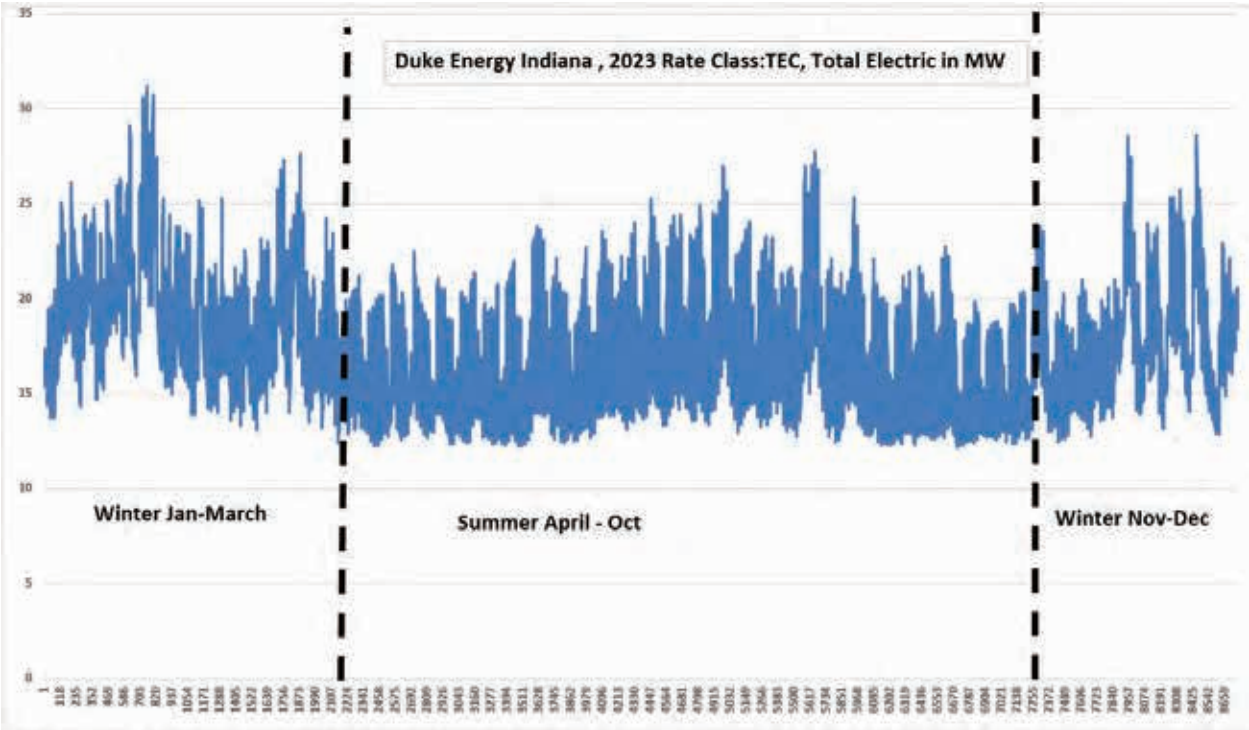


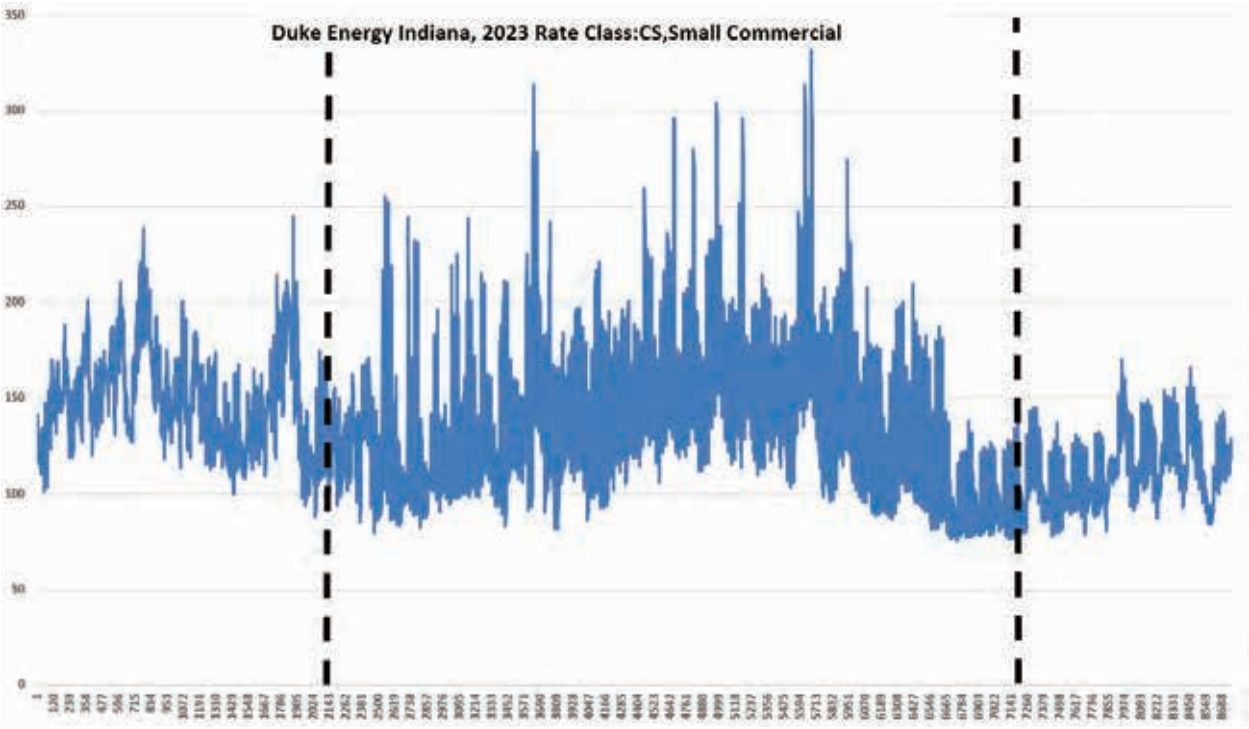
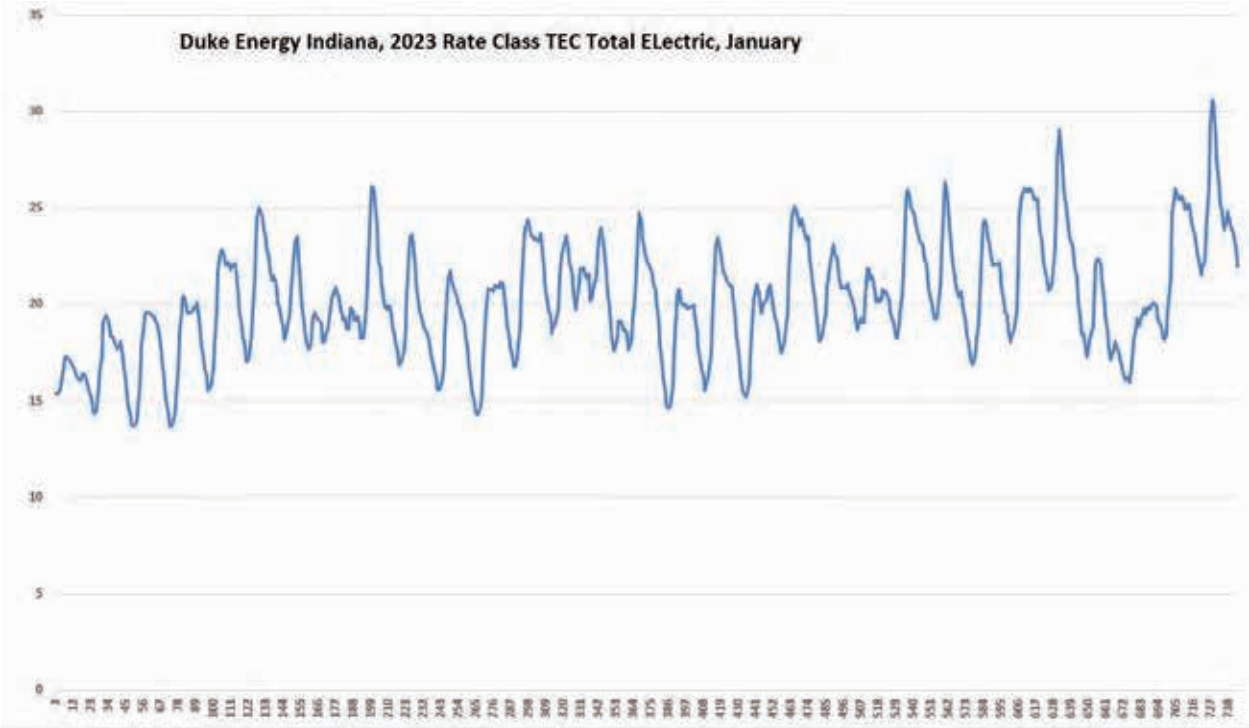


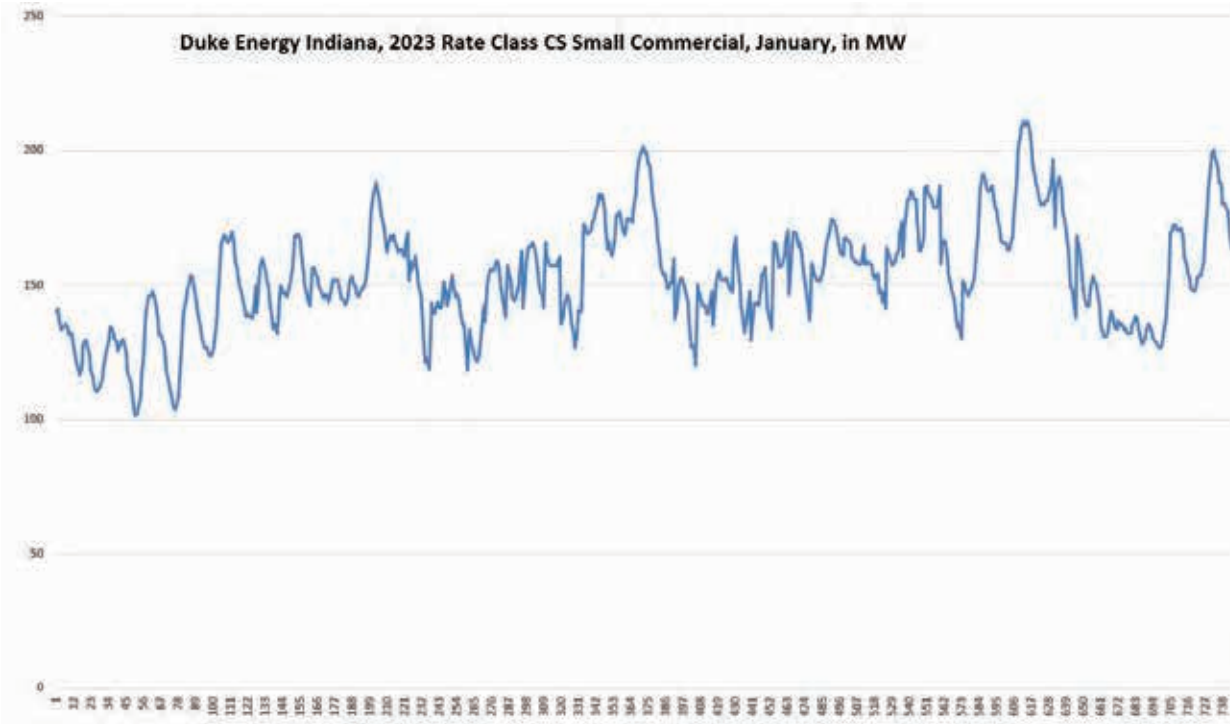
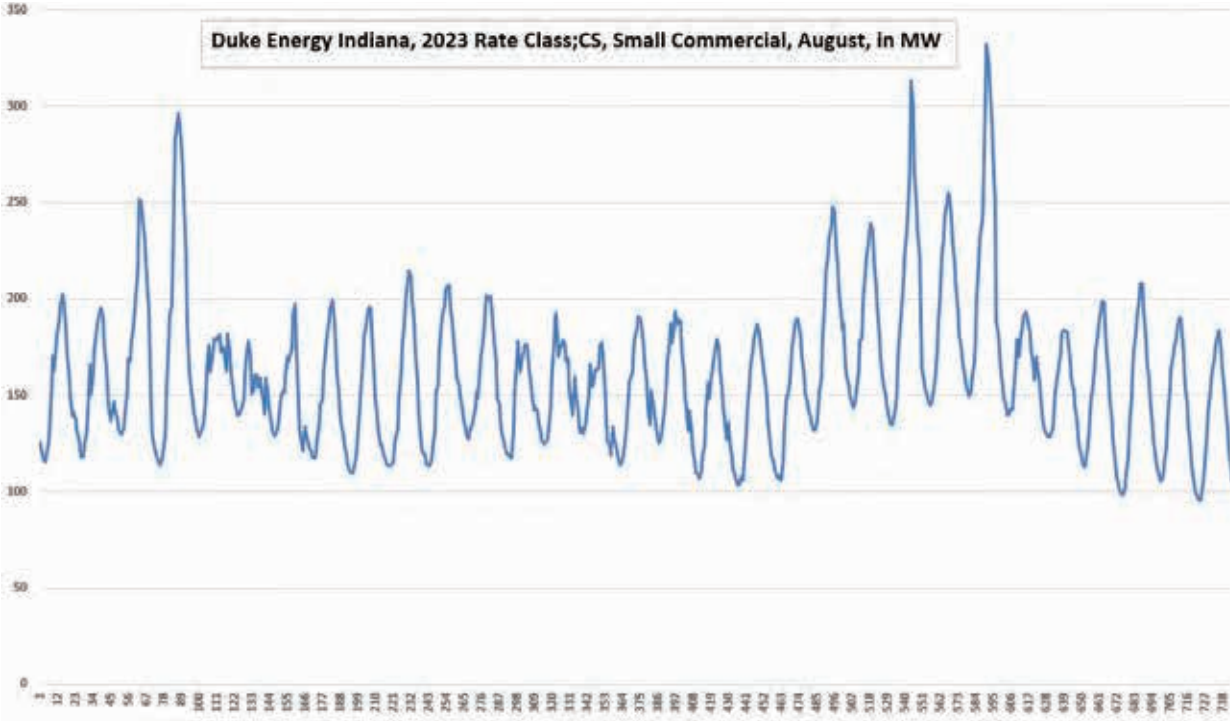




Total Electric Class (“TEC”)



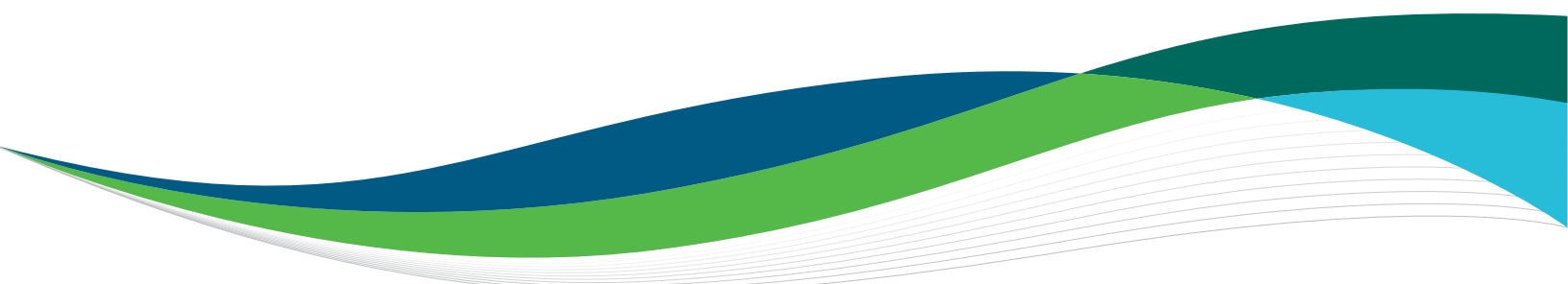




# Attachment D-2

## Load Forecast Files

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# INDIANA

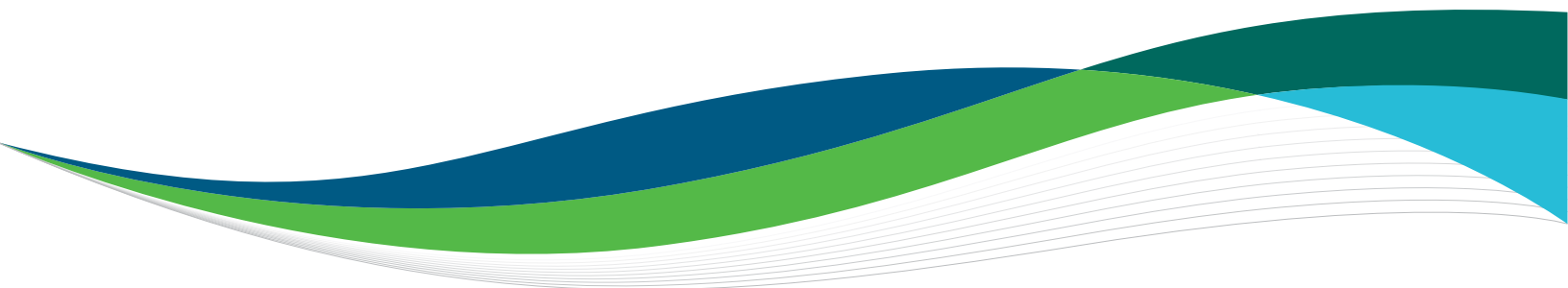
**2024** | **INTEGRATED**  
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# Attachment H-1

## Market Potential Study



# INDIANA

## 2024

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## RESOURCE PLAN



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## **Duke Energy Indiana Energy Efficiency and Demand Response Market Potential Report**

Date: August 2024



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# 1. Executive Summary

In fall of 2023, Duke Energy retained Resource Innovations, formerly Nexant Inc., to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand response (DR) programs in the Duke Energy Indiana (DEI) service territory. This report describes the potential for EE and DR savings in the service territory in Indiana. The main objectives of the study include:

- Estimating EE and DR potential over the short term (five years), medium term (ten years), and long term (twenty-five years) planning horizons
- Exploring the sensitivity of savings estimates to changes in incentive rates and avoided energy costs
- Developing customer participation estimates that are independent of historical Duke Energy program trends
- Assessing the potential impact of the 2022 Inflation Reduction Act on EE/DR savings potential
- Engaging the Indiana OSB members and offering opportunities for feedback and contribution to the market potential study (MPS)
- Providing data to Duke Energy for integrated resource planning

Technical potential indicates the theoretical upper limit on savings from EE. We estimate cumulative technical potential as a share of projected 2025 electricity sales to be 22% in DEI (regardless of customer EE/DR opt-out status). Technical potential ignores measure costs to focus on energy savings wherever technically feasible. Cumulative economic potential is 20% of all sales, regardless of EE/DR program eligibility. This estimate is based on using the utility cost test (UCT) to determine if a measure is cost-effective. The test compares the costs and benefits of offering a measure to customers through a utility-sponsored EE or DR program.

The UCT costs are for utility incentives and program administration, and UCT benefits stem from avoiding the energy, capacity, transmission, and distribution (T&D) costs of the electricity saved by the program measure. Economic potential with a UCT screening criterion does not examine customer benefits and costs; rather, it simply assumes all customers adopt a measure that is cost-effective under the UCT screening directive. As constructed, this economic potential estimate using a UCT screening indicates how utility program costs and benefits affect measures' potential savings if all customers are assumed to adopt measures that are cost-effective for the utility to offer.

For customers eligible to participate in EE/DR programs, achievable market potential (AMP) represents expected customer adoption for each AMP scenario. Using the set of cost-effective measures from the UCT Economic Potential, Resource Innovations applied customer payback acceptance curves to calculate a measure's long-run market share relative to competing EE measures, including baseline technologies (e.g., current codes and standards). With the data available for this MPS, payback acceptance is the most feasible approach for estimating customers' willingness to invest in EE/DR equipment and retrofit measures. As the payback acceptance approach considers only simple payback and the presence of utility incentives from the economic

potential scenario, the achievable potential scenario implicitly assumes programs continually identify and successfully reduce barriers to customer participation. Duke Energy has a demonstrated history of applying best practices and concepts from the EE and DR program lifecycle to accomplish this end by continually engaging in the cycle of program planning, implementation, evaluation, and adaptation.

We present results for three primary scenarios:

- **Base** – reflects current Duke Energy programs and program costs, incentive rates, and utility avoided cost benefits generated by the program; includes estimated impacts from the 2022 Inflation Reduction Act (IRA)
- **High Incentive** – doubles current incentive rates with a cap at 75% of the measure incremental cost; applies utility avoided cost benefits from the base scenario.
- **High Avoided Costs** – increases utility avoided cost benefits by 50%, uses base scenario incentive rates

### 1.1.1. Energy Efficiency Potential

The estimated technical and economic potential scenarios for DEI are summarized in [Table 1-1](#), which lists cumulative energy and demand savings for each type of potential<sup>1</sup>. Savings percentages are presented as a share of end year sales over 25 years. Technical and economic potential includes savings estimates for all DEI customers, regardless of program eligibility. Technical and economic potential also do not include impacts from the IRA since the IRA funding is irrelevant to technical potential and economic potential is based on the utility cost test.

**Table 1-1: DEI Cumulative Energy Efficiency Technical and Economic Potential (2025 – 2049)**

Scenario	Energy (GWh)	% of 2025 Sales	Demand (MW)			
			Spring	Summer	Fall	Winter
Technical Potential	5,878	22%	1,456	1,478	1,350	876
Economic Potential	5,255	20%	1,345	1,367	1,247	752

[Table 1-2](#) and [Table 1-3](#) summarize the short-term (5-year), medium term (10-year) and long-term (25-year) DEI portfolio EE achievable market potential for the base, high incentive, and high avoided cost scenarios. AMP estimates adjust the customer base to remove customers that have opted-out of EE

---

<sup>1</sup> “Cumulative” potential includes savings “roll off” for non-equipment measures or EE retrofits. Retrofit opportunities can typically only be addressed once before the associated equipment is replaced or energy savings from the retrofit decays. Cumulative potential represents impacts to the baseline utility forecast and should not be equated with the concept of “total energy saved.” The sum of annual incremental EE savings represents total energy saved.

and DR and include estimate impacts from the IRA funding; these impacts are presented over each stated time horizon (5 years, 10 years, or 25 years).

**Table 1-2: DEI Energy Efficiency Achievable Market Potential - Energy Savings**

Scenario		Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)		244,600	214,301	200,437
High Incentive	Annual Incremental Energy (MWh)		277,521	251,706	231,005
High Avoided Cost	Annual Incremental Energy (MWh)		254,363	216,096	200,812
Base	Cumulative Energy (MWh)		820,509	1,577,248	1,703,116
High Incentive	Cumulative Energy (MWh)		963,366	1,874,902	2,188,708
High Avoided Cost	Cumulative Energy (MWh)		858,177	1,653,518	1,742,073

**Table 1-3: DEI Energy Efficiency Achievable Market Potential - Demand Savings**

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	48	42	42
High Incentive	Annual Incremental Spring Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	49	42	42
Base	Annual Incremental Summer Peak Demand (MW)	47	41	42
High Incentive	Annual Incremental Summer Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	49	42	42
Base	Annual Incremental Fall Peak Demand (MW)	44	38	38
High Incentive	Annual Incremental Fall Peak Demand (MW)	53	46	45
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	45	39	39
Base	Annual Incremental Winter Peak Demand (MW)	55	44	39
High Incentive	Annual Incremental Winter Peak Demand (MW)	58	51	43
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	57	44	39
Base	Cumulative Spring Peak Demand (MW)	156	307	347
High Incentive	Cumulative Spring Peak Demand (MW)	201	401	476
High Avoided Cost	Cumulative Spring Peak Demand (MW)	162	319	353
Base	Cumulative Summer Peak Demand (MW)	155	304	344
High Incentive	Cumulative Summer Peak Demand (MW)	201	402	475
High Avoided Cost	Cumulative Summer Peak Demand (MW)	159	314	349
Base	Cumulative Fall Peak Demand (MW)	144	283	322
High Incentive	Cumulative Fall Peak Demand (MW)	185	369	440
High Avoided Cost	Cumulative Fall Peak Demand (MW)	149	293	327
Base	Cumulative Winter Peak Demand (MW)	176	335	326
High Incentive	Cumulative Winter Peak Demand (MW)	190	367	401
High Avoided Cost	Cumulative Winter Peak Demand (MW)	183	350	335

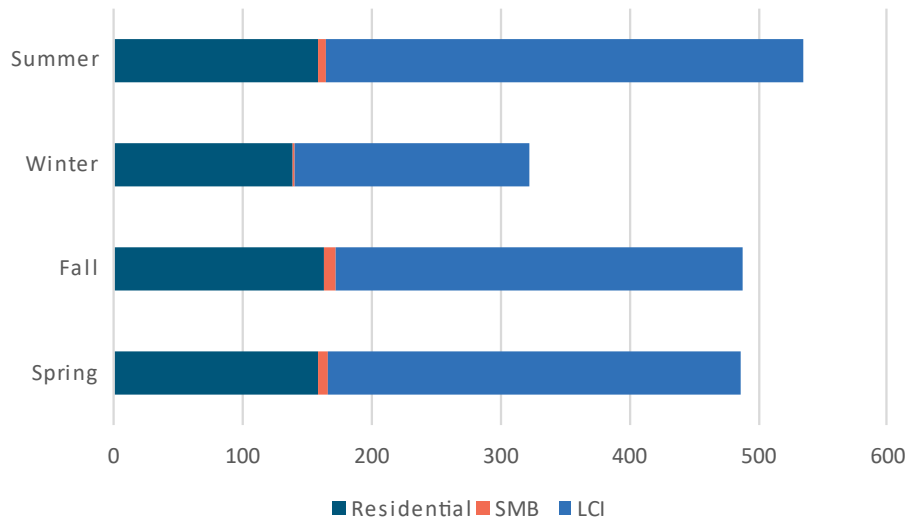
### 1.1.2. Demand Response Potential

DR opportunities were analyzed for Indiana service territories to determine the amount of seasonal peak capacity that could be reduced through DR initiatives from a technical, economic, and achievable potential perspective. While technical and economic potential are theoretical upper limits, participation rates applied to achievable potential are calculated as a function of the incentives offered to each customer group for utility-enabled DR. For a given incentive level and participation rate, the cost-effectiveness of each DR measure is evaluated to determine whether the aggregate DR potential from that measure should be included in the achievable potential.

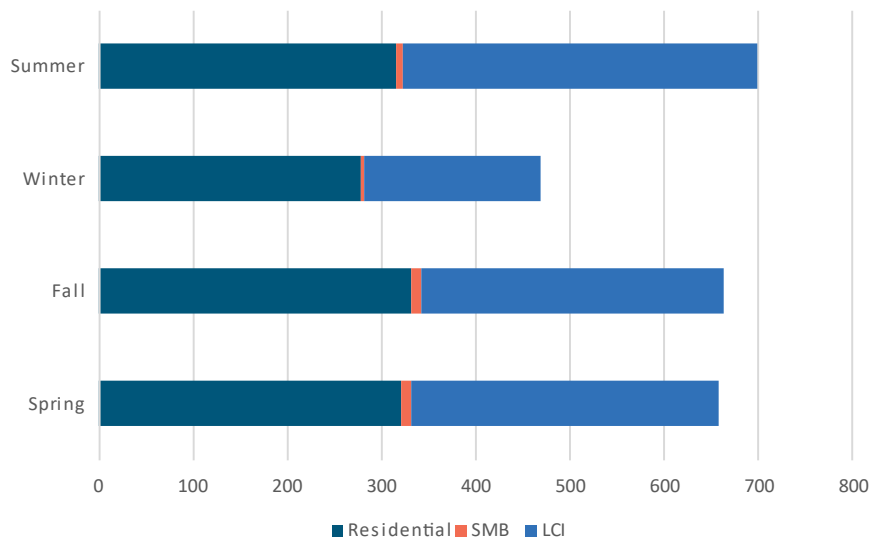


Base and Enhanced scenarios were constructed for the DR potential analysis. Base and Enhanced scenarios assume different levels of customer incentive and marketing efforts/costs. The Base Scenario aligns with current Duke Energy offerings for measures covered by existing programs, and assumes conservative incentive and marketing for new measures, while the Enhanced Scenario assumes more aggressive expansion. [Figure 1-1](#) and [Figure 1-2](#) summarizes the achievable seasonal peak DR potential estimated for DEI for the base and enhanced scenarios respectively. These results represent incremental DR potential beyond current Duke Energy program enrollments.

**Figure 1-1 DEI DR Peak Capacity Achievable Potential – Base Case**



**Figure 1-2: DEI DR Peak Capacity Achievable Potential – Enhanced Case**

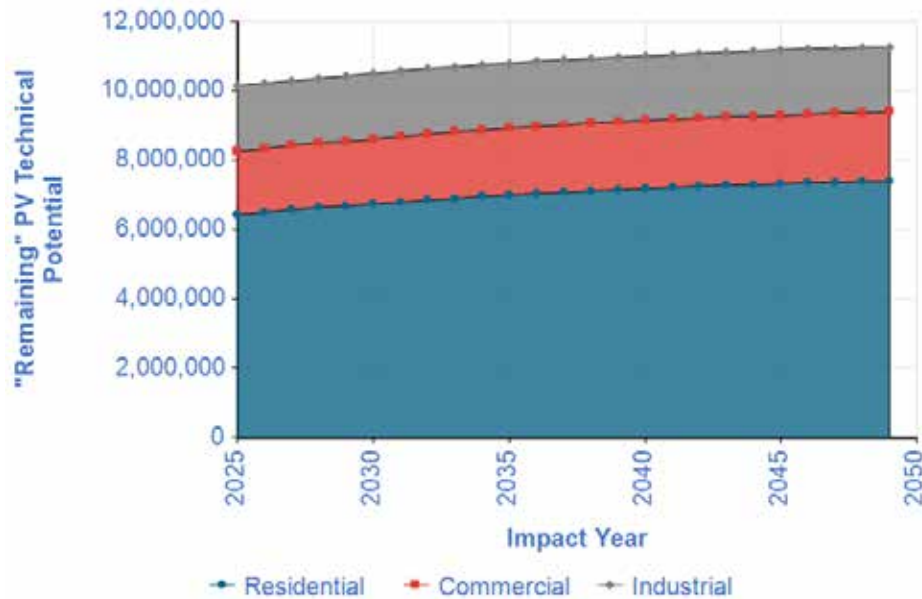


### 1.1.3. Distributed Energy Resources Potential

The Distributed Energy Resources (DERs) technologies included in this study are rooftop solar photovoltaic (PV) systems, and battery storage systems charged from customers' PV systems. The study leveraged the customer segmentation and load disaggregation data assembled for the EE and DR analyses, and applied our DER model, SPIDER™ (Spatial Penetration and Integration of Distributed Energy Resources), to analyze system economics and adoption trends for solar and battery storage. This model dynamically responds to rapidly changing technologies and accounts for all key time-varying elements such as technology costs, incentives, tax credits, and electric rates.

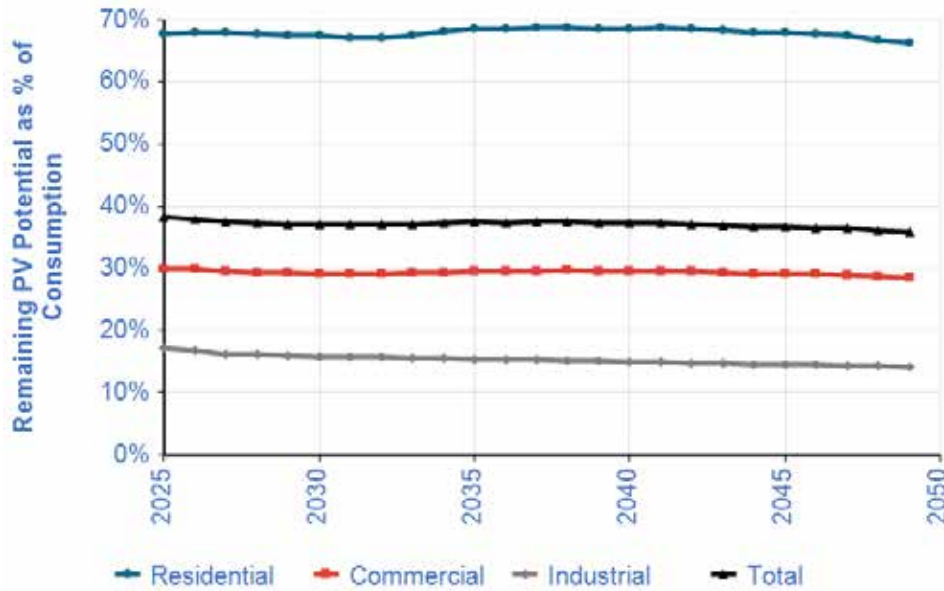
DER technical potential estimates quantify all technically feasible distributed generation opportunities from PV systems and battery storage systems charged from PV. The estimated PV technical potential results are summarized in [Figure 1-3](#).

**Figure 1-3: PV Technical Potential Remaining (MWh)**



Remaining PV can also be expressed as a share of the DEI baseline energy sale forecast, as below in [Figure 1-4](#).

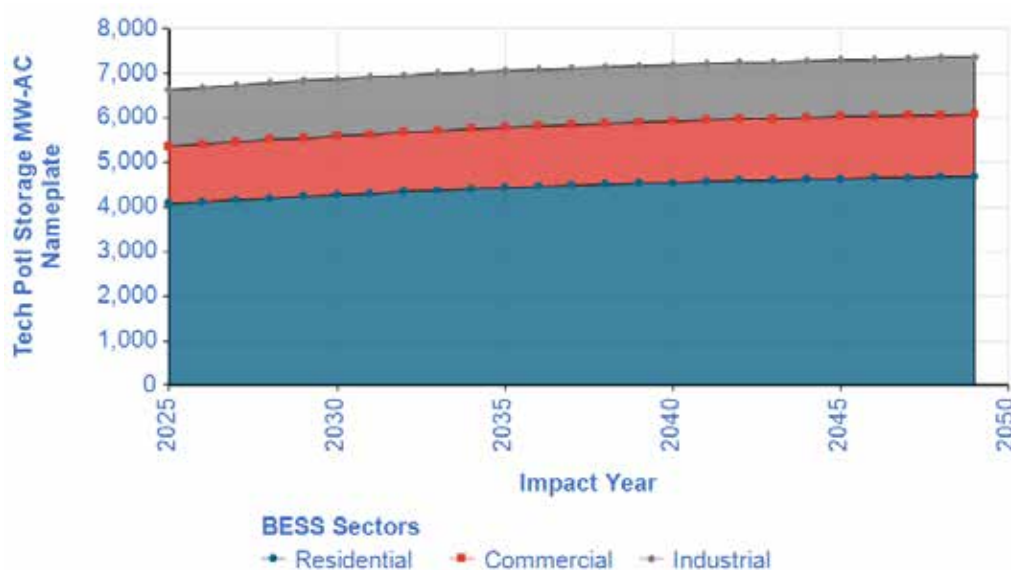
Figure 1-4: Remaining PV as a Share of the DEI Sales Forecast



RI analyzed two technical potential results for storage: one based on the nameplate rating of the storage system, and the other based on the expected grid impact of customer-sited storage dispatch under existing rates structures.

Nameplate technical potential assumes all PV calculated technical potential is paired with storage, and storage systems are sized according to maximum solar PV output. Under this assumption, nameplate MW-AC of paired storage technical potential is equivalent to nameplate MW-AC of solar PV assuming storage system sized equal to max PV capacity, and the result is presented in [Figure 1-5](#).

Figure 1-5: Nameplate Technical Potential in MW-AC of PV and Paired Storage



The technical potential of expected grid impacts is much different than physical nameplate capacity under the current DEI rate structures. The technical potential of the expected grid impact describes the system impact when an impaired storage system is dispatched optimally to maximize customer benefit, using the current (most cost-effective) electric rate for that installed system. Expected paired storage grid impact is examined in all four seasons (due to transition to MISO seasonal resources accreditation) and is mostly negative (e.g. an expected increase in load during the system peak hour), for several reasons:

- Small energy rate spread between peak and off peak.
- Solar generation peaks are coincident with system peaks, leading to customer battery charging during peak periods.
- Non-residential customers are expected to dispatch to reduce their own facility/account peaks as opposed to system peaks.

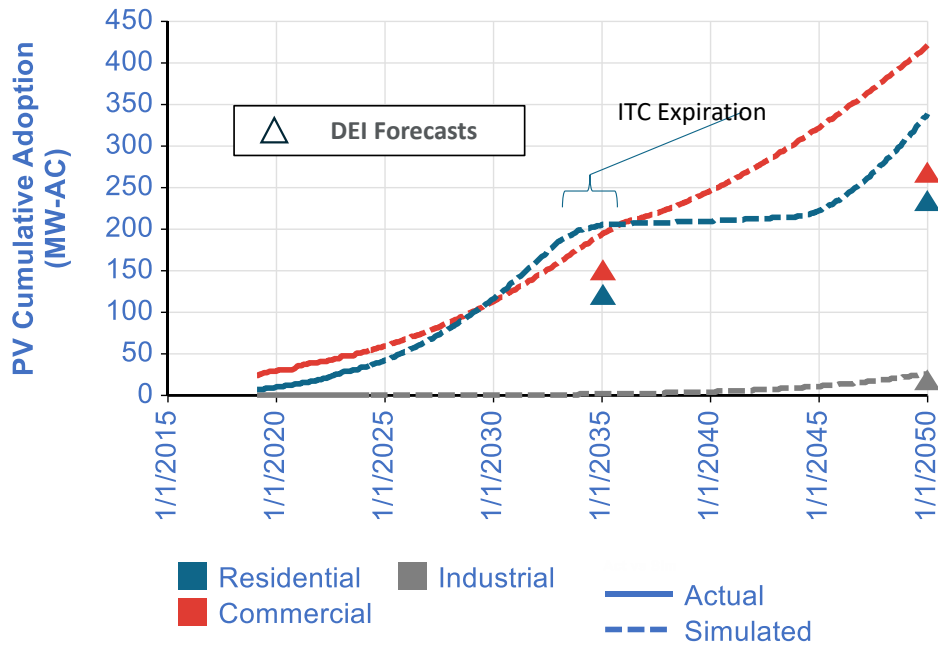
Different rate structures, or a DR program, would change the expected grid impacts. The expected seasonal grid impacts for PV and paired storage technical potential are presented in [Figure 1-6](#).

Figure 1-6: Expected Grid Impacts of PV and Paired Storage

Year	Residential				Commercial				Industrial			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2025	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.68	1.11	-23.85
2026	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.74	1.11	-23.93
2027	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.77	1.11	-23.98
2028	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.78	1.11	-23.99
2029	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.79	1.11	-24.01
2030	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2031	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2032	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2033	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2034	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2035	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2036	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2037	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2038	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2039	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2040	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2041	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2042	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2043	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2044	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2045	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2046	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2047	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2048	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2049	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02

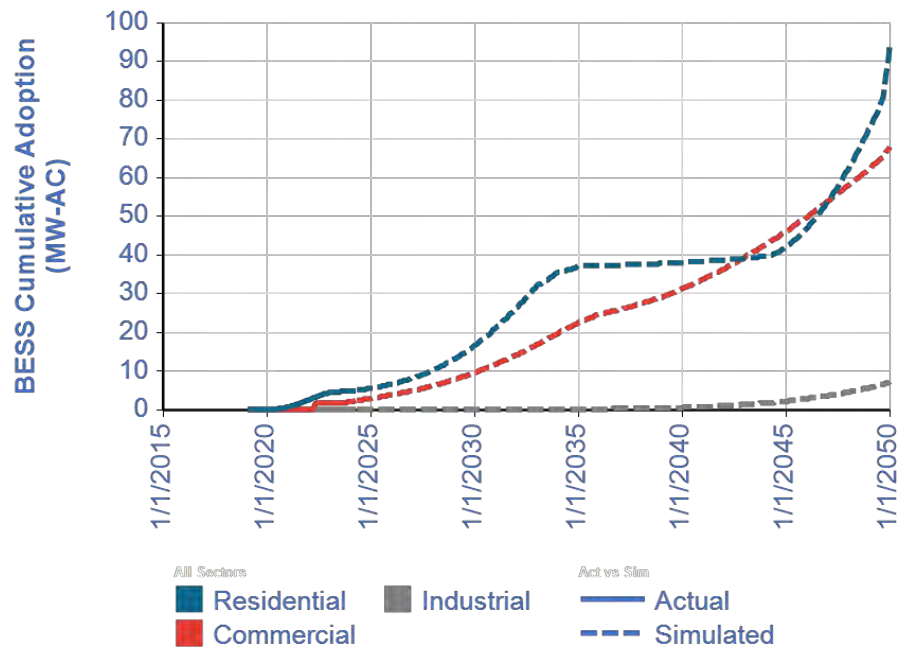
Technical potential indicates the theoretical upper limit on DER opportunities, as it ignores measure costs to focus on opportunities wherever technically feasible. Economic and achievable potential use the utility cost test (UCT) that compares the costs and benefits of offering the DER systems to customers through a utility-sponsored program. We model technology diffusion over time, with time-varying factors such as expected system costs and complex market dynamics; the resulting solar PV forecast is presented below in [Figure 1-7](#).

Figure 1-7: Baseline Solar PV Adoption Forecast, MW-AC



The forecast for Paired Battery Storage is presented below in [Figure 1-8](#).

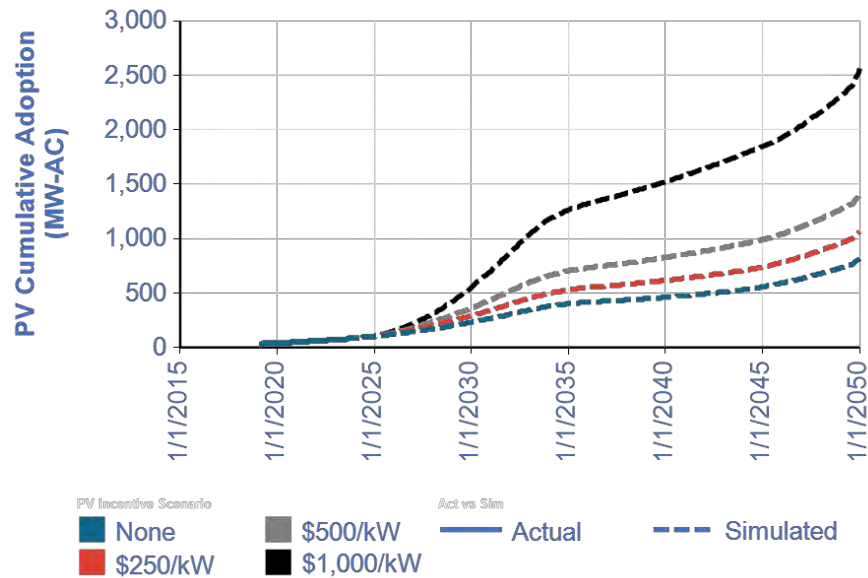
Figure 1-8: Paired Battery Storage Forecast





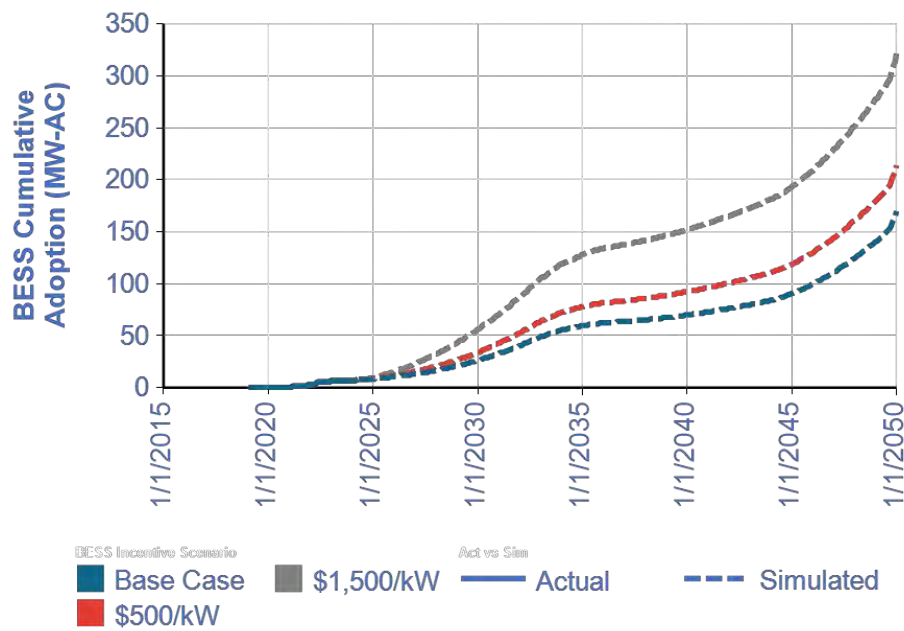
These forecasts can be influenced by utility incentives for equipment and installation. RI developed forecasts for several different incentive scenarios. The results are presented below in [Figure 1-9](#) and [Figure 1-10](#).

**Figure 1-9 Solar PV Forecast with Incentive Offers**



The battery storage forecast is similarly influenced, as below in [Figure 1-10](#).

**Figure 1-10 Paired Battery Storage Forecast with Incentive Offers**



## 2. Introduction

In fall of 2023, Duke Energy retained Resource Innovations to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand response (DR) programs in the Duke Energy Indiana (DEI) service territory. This report describes the potential for EE and DR savings in the service territory in Indiana.

### 2.1. Objectives and Deliverables

The main objectives of the study include:

- Estimating EE and DR potential over the short term (five years), medium term (ten years), and long term (twenty-five years) planning horizons
- Exploring the sensitivity of savings estimates to changes in incentive rates and avoided energy costs
- Developing customer participation estimates that are independent of historical Duke Energy program trends
- Assessing the potential impact of the 2022 Inflation Reduction Act on EE/DR savings potential
- Engaging the Indiana Energy Efficiency Oversight Board (OSB) and offering opportunities for feedback and contribution to the market potential study (MPS)
- Providing data to Duke Energy for integrated resource planning

RI developed the following deliverables for the MPS:

- Measure list and supporting memorandum describing the measure research process
- An MPS work plan
- Periodic presentations to Duke Energy and the Indiana OSB
- Responses to Indiana OSB members' feedback on interim study components
- Interim, draft results of technical and economic potential
- Presentations to Duke Energy and the OSB to solicit feedback on estimating the impacts of the 2022 Inflation Reduction Act
- Achievable potential estimates describing three APS scenarios: base, high incentive, and high avoided costs
- This report and summary of all project activities

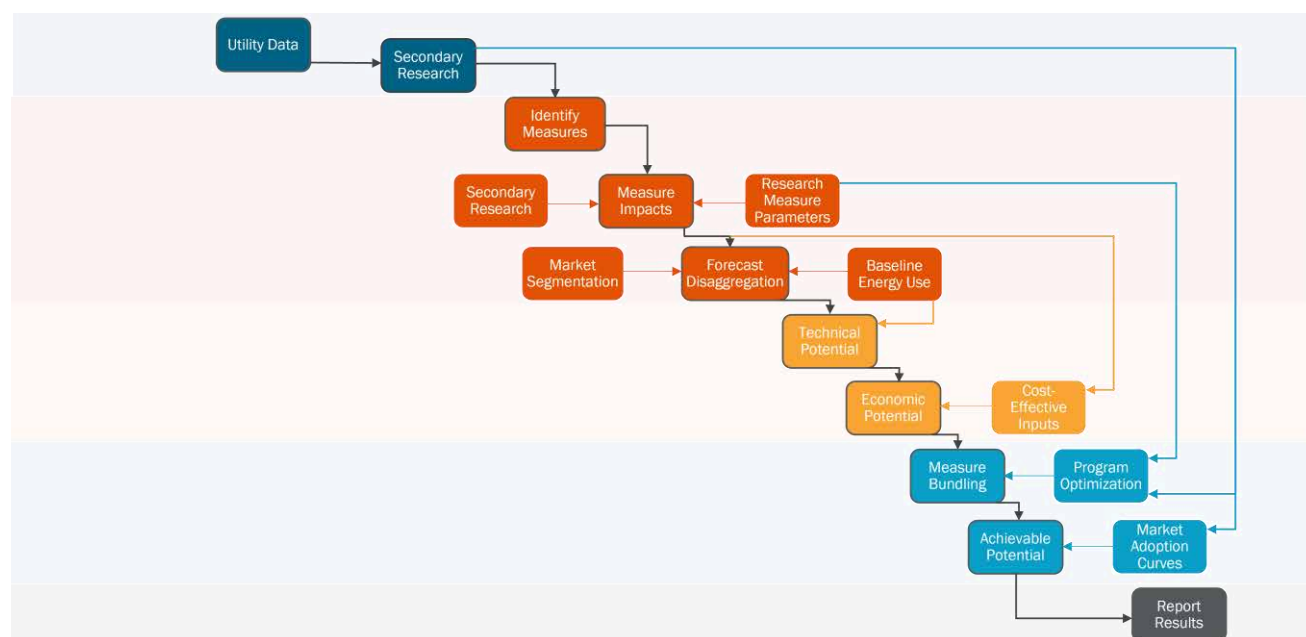
### 2.2. Study Approach

Market potential studies describe each type of energy efficiency potential: technical, economic, and achievable. These assessments should incorporate current market conditions and trends, as observed with available primary and secondary data. All components of the study, such as baseline energy consumption, expected utility sales forecasts, and available EE and DR measures, among others, are determined based on available data. A market potential study is therefore a discrete estimate of EE and DR potential based on current market conditions and savings opportunities. This study considers existing technology and market trends as observed with currently available data and

does not speculate on the potential impact of unknown, emerging technologies that are not yet commercially available.

Resource Innovations developed estimates with models, tools, and techniques developed over dozens of client engagements for EE and DR resource planning over the past two decades. We examined multiple scenarios by changing inputs related to program incentives, utility avoided cost benefits, and eligible customers. Resource Innovations used primary data provided by Duke Energy and secondary data sources to decompose DEI sales forecasts into customer-class and end use components. Resource Innovations characterized measures for all electric end uses, accounting for end use saturation, fuel shares, technical feasibility, current efficiency levels, and costs. As illustrated in [Figure 2-1](#), we used these results to assess the savings that could be captured by Duke Energy customers with the full range of commercially available energy efficiency measures and practices. We estimated EE and DR savings for each customer class, market segment, and electric end use by applying measure impacts to the service territory over time.

**Figure 2-1: Market Potential Study Flow Chart**



We aggregated measure impacts for the technical, economic, and achievable scenarios by sorting and ranking measures according to scenario criteria and modeled the application of measures to replace equipment failures or to retrofit existing buildings. Following regulatory and stakeholder direction, we estimated economic potential by applying the utility cost test (UCT) to weigh EE and DR costs against their estimated benefits, the latter provided to us by Duke Energy.

The savings potential for EE and DR in Duke Energy's Indiana territory is characterized by levels of opportunity. The ceiling or theoretical maximum savings is based on commercialized technologies and behavioral measures, whereas the realistic savings that may be achieved through DR programs reflect real world market constraints such as utility budgets, customer perspectives and energy efficiency policy. This analysis defines these levels of energy efficiency potential according to the

Environmental Protection Agency’s (EPA) National Action Plan for Energy Efficiency (NAPEE) as illustrated in [Figure 2-2](#).

**Figure 2-2: Energy Efficiency Potential**



EPA – National Guide for Resource Planning

Technical potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Economic potential is the amount of energy and capacity saved by applying efficiency measures that pass a cost-effectiveness test. The utility cost test (UCT) is used in this study, in keeping with jurisdictional practice. Achievable market potential is the energy and capacity savings that can be achieved in a market with cost-effective, utility-sponsored programs; achievable market potential is primarily driven by the influence of incentive levels on customer adoption rates and addresses market barriers associated with customer preferences and opportunity costs. Our analysis assumed Duke Energy will continue to adaptively manage programs, following the EE/DR program life cycle: market assessment, program design, implementation, evaluation, and adaptation.

RI explored technical, economic, and achievable market program potential over a 25-year period from January 2025 to December 2049. The quantification of these three levels of energy efficiency potential reflects assumptions developed from feedback by the EE and DR Collaborative, Duke Energy, and regulators. Savings opportunity follows the path from a theoretical maximum to realistic savings potential in a market with utility-sponsored programs.

Achievable potential is based on customer payback acceptance curves; this approach describes customers’ adoption decisions relative to the length of time required to recoup their investment in energy efficiency. Payback acceptance is calculated for all measures that pass the UCT cost screening.

Owing to these MPS parameters and focus, we describe our estimates as expected EE and DR potential in a market featuring utility-sponsored programs and incentives. The estimates assume adaptive program management is applied to successfully lower market and non-market barriers to

customer adoption over time; the customer payback acceptance approach addresses only the barriers of investment costs and opportunity costs.

Naturally occurring conservation and efficiency is captured in this analysis by the Duke Energy electricity sales and load forecasts. We addressed changing energy codes and equipment standards by incorporating changes to codes and standards in the development of the base-case forecasts or with adjustment to measure savings that reflect changing baselines. The Duke Energy forecasts account for known or planned future federal code changes and existing market trends towards more efficient equipment. RI estimated savings potential based on a combination of market research, analysis, and a review of Duke Energy's existing programs, all in consideration of feedback from Duke Energy and the OSB. The programs that RI examined included both energy efficiency (EE) and demand response (DR) programs; therefore, this report is organized to offer detail on both types of programs.

The remainder of the report provides describes each step in the potential analysis process, according to the following sections:

- Market Characterization
- Measure List
- Technical Potential
- Economic Potential
- Achievable Market Potential

## 3. Market Characteristics

Market potential studies estimate savings potential relative to existing market conditions. This study used base year energy use and sales forecasts provided to us by Duke Energy. We used customer segmentation and secondary data to decompose the sales forecast into its end use components and to describe customer segments in the DEI service territory. This section presents baseline market conditions, while the subsequent sections address measure opportunities and market potential scenarios.

### 3.1. Customer Segments

As electricity consumption patterns vary by customer type, RI segmented customers to better describe opportunities for energy efficiency or customers' ability to provide DR grid services. Customer segmentation provides higher resolution estimates of cost-effective EE and DR programs. Significant cost efficiency can be achieved through strategic EE and DR program designs that recognize and address the similarities of EE and DR potential that exists within each customer group.

RI segmented DEI customers by economic sector to describe how much of the Duke Energy sales and peak load forecasts are attributable to the residential, commercial, and industrial sectors. Customer segments within each economic sector are used to estimate how much electricity each customer type consumes annually and during system peaking conditions. End use disaggregation looks within a typical home or business in each segment to describe the typical equipment using electricity during periods of peak demand and to estimate annual consumption within each end use for current consumption trends.

The Technical and Economic potential estimates include all customers, but for Achievable, RI used Duke Energy customer data to identify and remove customers that have opted out of DR programs or are not eligible to participate in Duke Energy programs. [Table 3-1](#) lists study segments for each economic sector. We also segmented customers according to space heating fuel (electric vs. gas) and by annual consumption tertiles (that is, three groups of equal customer size). Segmentation allows for more accurate estimates of which customers exhibit consumption patterns that make them cost effective to recruit for EE and DR programs.



**Table 3-1: MPS Customer Segments by Economic Sector**

Residential	Commercial		Industrial	
Single Family	Assembly	Lodging/ Hospitality	Chemicals and plastics	Primary resource industries
Multifamily	College and University	Miscellaneous	Construction	Stone, clay, glass, and concrete
Mobile Home	Data Center	Offices	Electrical and electronic equipment	Textiles and leather
	Grocery	Restaurant	Lumber, furniture, pulp, and paper	Transportation equipment
	Healthcare	Retail	Metal products and machinery	Water and wastewater
	Hospitals	Schools K-12	Miscellaneous manufacturing	
	Institutional	Warehouse		

From an equipment and energy use perspective, each segment has variation within each building type or sub-sector. For example, the energy consuming equipment in a convenience store will vary significantly from the equipment found in a supermarket. To account for the resolution of available baseline consumption data, the selected end uses describe energy savings potential that are consistent with those typically studied in national or regional surveys. These end uses are listed in [Table 3-2](#).

**Table 3-2: Electricity End Uses by Economic Sector**

Residential End Uses	Commercial End Uses	Industrial End Uses
Space heating	Space heating	Process heating
Space cooling	Space cooling	Process cooling
Domestic hot water	Domestic hot water	Compressed air
Ventilation and circulation	Ventilation and circulation	Motors, pumps
Lighting	Interior lighting	Motors, fans, blowers
Cooking	Exterior lighting	Process-specific
Refrigerators	Cooking	Lighting
Freezers	Refrigeration	HVAC
Clothes washers	Office equipment	Other
Clothes dryers	Miscellaneous	
Dishwashers		
Plug load		
Miscellaneous		

For demand response potential, customers were classified into sectors based on rate class and further segmented using premise-level characteristics. A summary is presented below in [Figure 3-1](#). Residential customers were segmented using premise type; SMB customers were

segmented using annual kWh consumption bins; large C&I customers were segmented using maximum hourly load.

**Figure 3-1: Demand Response Customer Segmentation**

Sector	Residential	SMB	Large C&I
Rates Included	RS	C110 (CS) OCS	LLF HLF
Segments	Single Family Multi-family Mobile Home	0-15,000 kWh 15,001-30,000 kWh 30,001-50,000 kWh 50,001+ kWh	0-50 kW 51-300 kW 301-500 kW 501+ kW

We targeted end uses with controllable load for residential customers and small/medium business (SMB) customers. [Table 3-3](#) summarizes the control strategies analyzed for each sector. For large commercial and industrial (large C&I) customers who would potentially reduce large amounts of electricity consumption for a limited time, all load during peak hours was included. For residential and SMB customers, AC/heating loads, pool pumps and electric water heaters, as well as some DERs, were studied. For large C&I customers the analysis included automated and contractual demand response, as well as EV charging and battery storage measures.

**Table 3-3: Demand Response Measures**

Residential	SMB	LCI
<ul style="list-style-type: none"> <li>HVAC, Utility Direct Load Control</li> <li>Smart Thermostats</li> <li>Temporary Price Responsiveness</li> <li>Water Heater, Utility Direct Load Control</li> <li>Pool Pump, Utility Direct Load Control</li> <li>EV Charging, Utility Direct Load Control</li> <li>Rooftop Solar</li> <li>Battery Storage</li> </ul>	<ul style="list-style-type: none"> <li>HVAC, Utility Direct Load Control</li> <li>Smart Thermostats</li> <li>Water Heater, Utility Direct Load Control</li> <li>Pool Pump, Utility Direct Load Control</li> <li>Temporary Price Responsiveness</li> <li>EV Charging, Utility Direct Load Control</li> <li>Battery Storage</li> </ul>	<ul style="list-style-type: none"> <li>Contractual Load Curtailment</li> <li>Auto DR</li> <li>EV Load Shed</li> <li>Battery Storage</li> </ul>

## 3.2. Forecast Disaggregation

We worked with Duke Energy to establish a common understanding of the assumptions and granularity in the baseline load and sales forecasts. We reviewed the following:

- How are Duke Energy's current program offerings reflected in the energy and demand forecast?
- What are the assumed weather conditions and hour(s) of the day when the system is projected to peak?
- How much of the sales forecast is attributable to accounts that are not eligible for EE and DR programs or have opted-out of the EE and DR riders?
- How are projections of population increase, changes in appliance efficiency, and evolving distribution of end use load shares accounted for in the twenty-five-year peak sales and demand forecasts?

RI segmented the DEI electricity consumption forecasts by customer class and end use. The resulting baseline represents the Indiana electricity market by describing how electricity is consumed within the service territory. RI developed these forecasts for the years 2025–2049 and based them on data provided by Duke Energy and supporting, secondary sources. The data addressed current baseline consumption, system load, and sales forecasts.

The baseline for DR potential describes loads in the absence of existing, dispatchable DR. This baseline was necessary to assess how DR can assist in meeting specific planning and operational requirements. RI used Duke Energy's seasonal demand forecast, which was developed for system planning purposes.

RI developed a list of electricity end uses by sector ([Table 3-2](#)) and examined EE and DR measures that could potentially reduce baseline consumption for each end use. RI began with Duke Energy's estimates of average end use consumption for residential customers and shares of Duke Energy sales to non-residential customer segments. We combined these data with Duke Energy's 2022 residential appliance saturation surveys, data products from the Energy Information Agency (EIA) and estimates of manufacturing end use consumption from the Department of Energy (DOE).

### 3.3. Market Description

Customer segmentation addresses the diverse energy savings opportunities for Duke Energy's customer base. Duke Energy provided RI with data describing premises type and load characteristics for all customers. RI's approach to segmentation varied slightly for commercial and residential accounts, but the overall logic was consistent with the concept of expressing the accounts in terms that are relevant to EE and DR opportunities. The following sections describe the segmentation analysis and results for commercial and industrial C&I accounts ([Section 3.3.1](#)) and residential accounts ([Section 3.3.2](#)).

#### 3.3.1. Commercial and Industrial Accounts

RI segmented C&I accounts according to two approaches: annual energy consumption and peak energy demand.

Duke Energy provided RI with customer data containing rate codes for individual accounts. RI classified the customers in this group as *either* small and medium businesses (SMB) or large

commercial & industrial (LCI) using rate class and peak demand characteristics. SMB customers were segmented based on annual energy consumption, while large LCI customers were segmented using maximum demand.

RI segmented both the SMB and Large C&I customer segments using monthly billing records and hourly AMI data, which was provided by Duke Energy as part of the customer data request. RI aggregated the SMB segments using data available, and the resulting customer counts are shown in [Table 3-4](#) for SMB customers.

**Table 3-4: Summary of SMB Segment**

Segment	DEI Number of Accounts
0-15,000 kWh	52,858
15,001-25,000 kWh	11,595
25,001-50,000 kWh	6,298
50,000 kWh+	7,256
<b>Total</b>	<b>78,007</b>

Large C&I customers were defined for the DR potential analysis based on account size (demand). Duke Energy provided a census of AMI data to RI for estimating the DR potential capacity available from these large accounts. [Table 3-5](#) presents the resulting customer counts by customer segment.

**Table 3-5: Summary of Large C&I Segment**

Segment	DEI Number of Accounts
<100 kW	4,808
100-300 kW	2,838
300-500 kW	667
>500 kW	688
<b>Total</b>	<b>9,001</b>

### 3.3.2. Residential Accounts

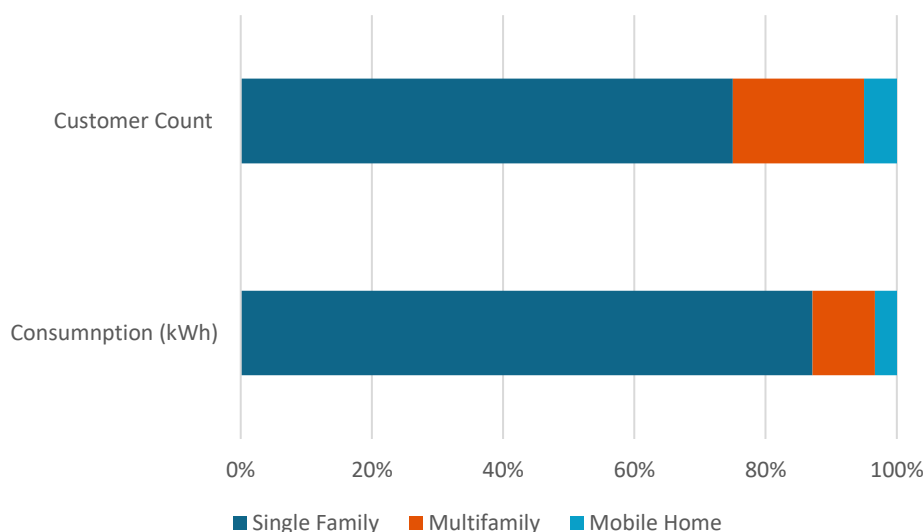
RI segmented residential accounts to align DR opportunities with appropriate DR measures. Residential segments are based on customer dwelling type (single family or multifamily). The resulting distribution of customers and total electricity consumption by each segment is presented below in [Table 3-6](#).

**Table 3-6: DEI Residential Market Characteristics by Type of Dwelling Unit**

Attribute	Single Family	Multi-Family	Mobile Home
Customer Count	599,719	159,925	39,981
Total kWh Consumption	8,261,990,781	904,383,546	315,680,288

Figure 3-2 presents a visual representation of this information. The DEI territory in Indiana consists primarily of single-family dwellings, which have the greater share of both accounts and consumption.

**Figure 3-2: DEI Residential Market Characteristics by Type of Dwelling Unit**



The DR assessment required the use of interval data to estimate the loads associated with space cooling and space heating. For this study, interval data were available from all DEI customers.

The residential sector was segmented into three different groups based on premise type (i.e., single-family, multi-family, other). Within each of these customer groups, heating and cooling load profiles were estimated using observed AML consumption data and weather data.

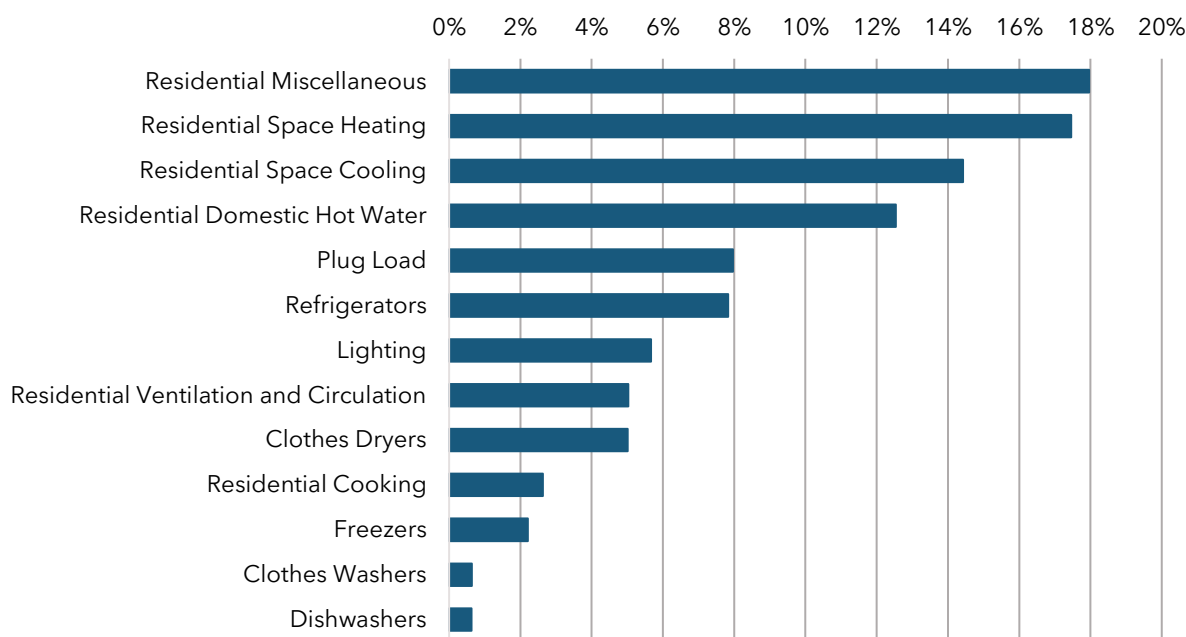
### 3.4. Start Year 2025 Disaggregated Sales

Duke Energy provided Resource Innovations with an end use forecast for residential customers and a forecast of sales by customer segment for non-residential customers. These forecasts are based in part on the Energy Information Administration (EIA) research activities in the residential, commercial, and manufacturing sectors. As of the time of this study the data provided by these products represented the best available secondary data sources for end use consumption within each economic sector. The following secondary data sources were used by RI to disaggregate each sector's loads:

- Residential load disaggregation is based on Duke Energy’s estimates of residential end use load shares; this information in turn is derived from the EIA Residential End Use Consumption Survey (RECS), vintage 2020.
- Commercial load disaggregation is based on the Commercial Building Energy Consumption Survey (CBECS) and Duke Energy estimates of sales by commercial segment, vintage 2018.
- Industrial load disaggregation is based on Manufacturers’ Energy Consumption Survey (MECS), vintage 2018.

With the details provided by Duke Energy, Resource Innovations was able to identify and categorize some miscellaneous electric loads into an end use category we labelled as “plug loads.” Nevertheless, there remains a large share of residential load classified as “residential miscellaneous – other,” and no further data are available at this time to further describe this end use. “Residential miscellaneous – other” is one subcategory of the broader residential miscellaneous. Residential miscellaneous also include pool pumps, spas, and ceiling fans as discrete loads that we could identify with available data. Residential miscellaneous loads have historically lacked detail because of the plethora of possible items that might use electricity in this category; in our experience this is not an issue specific to Duke Energy. The disaggregated loads for the start year 2025 residential end uses are summarized in [Figure 3-3](#).

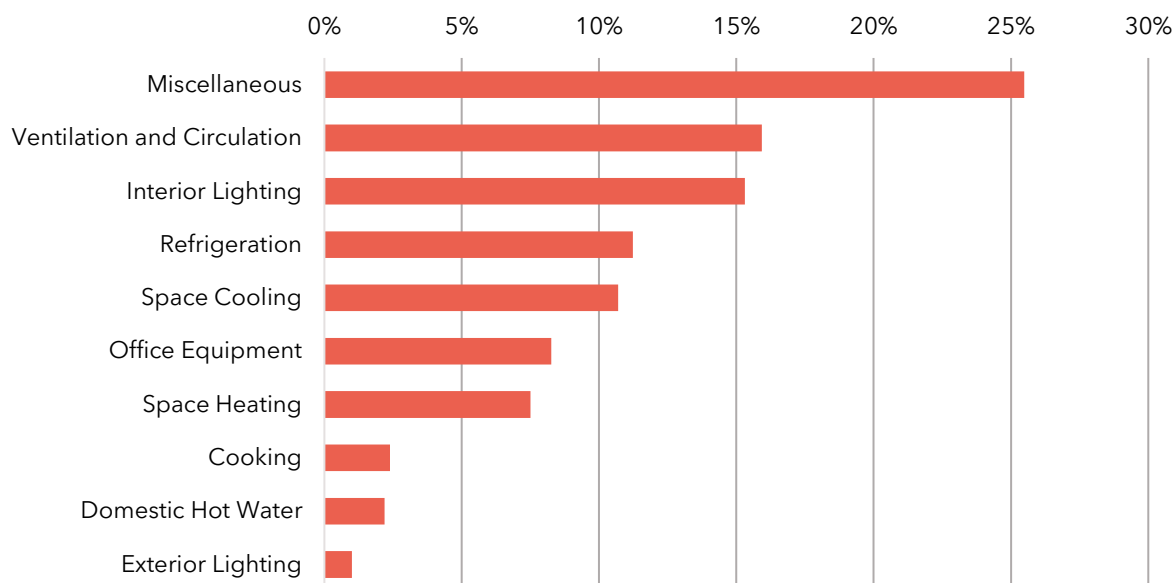
**Figure 3-3: DEI 2023 Residential End Uses, Baseline Consumption Shares**



The commercial start year load shares were constructed with a combination of end use consumption shares from CBECS data, and our estimates of 2023 annual billed consumption by commercial customer type (e.g., building type or segment). [Figure 3-4](#) presents a summary of the end use consumption data available for the commercial sector.

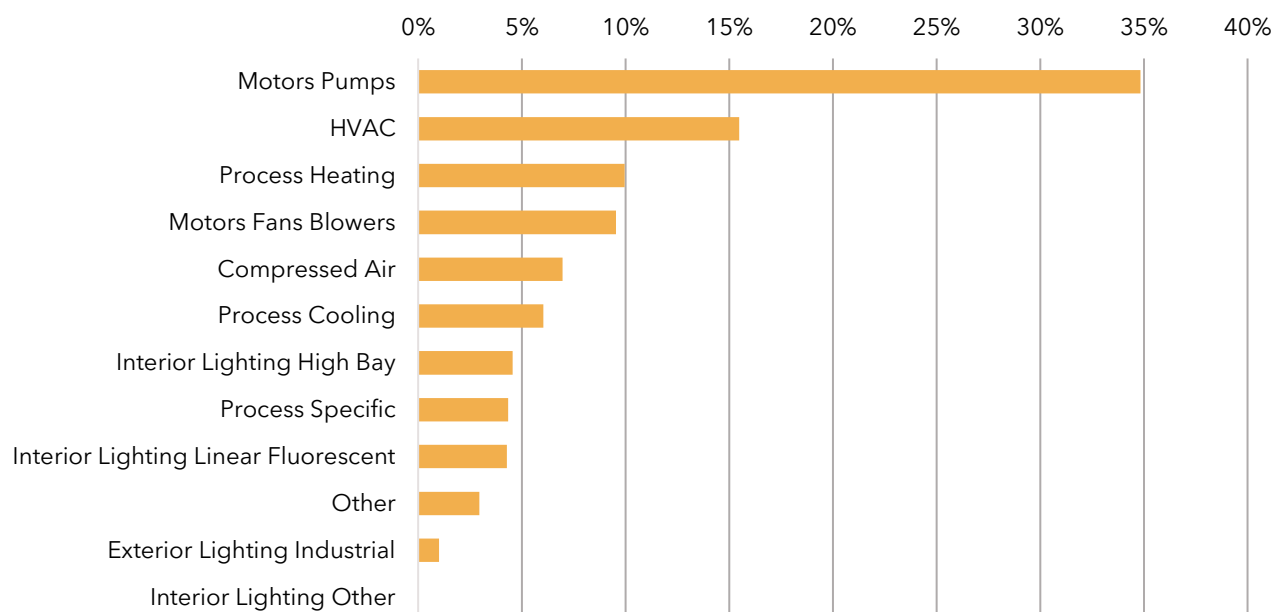


**Figure 3-4: DEI Commercial End Uses, Baseline Load Shares**



Industrial customer consumption shares are based on the 2018 EIA MECS survey and Duke Energy billed consumption in 2023. [Figure 3-5](#) presents a summary of industrial customers' end use consumption.

**Figure 3-5: DEI Industrial End Uses, Baseline Load Shares**



In the base year 2023, the top end use consumption categories for each economic sector are as follows:

- **Residential:** Miscellaneous, space heating, space cooling
- **Commercial:** Miscellaneous, ventilation and circulation, interior lighting
- **Industrial:** Motors pumps, HVAC, and process heating

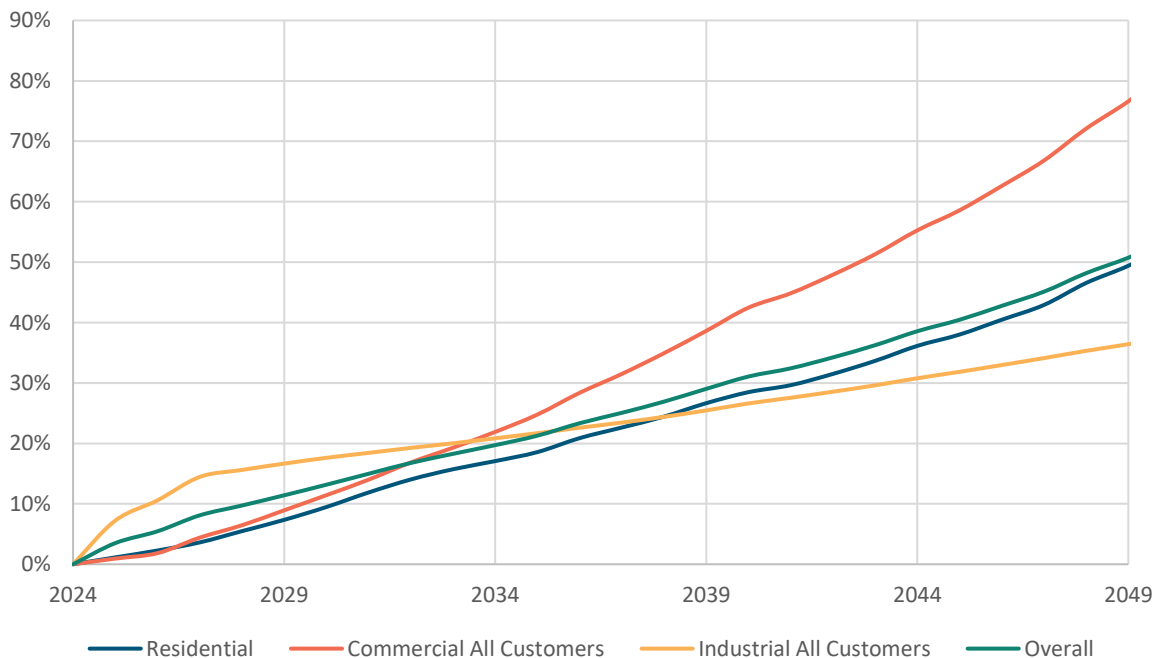
### 3.5. DEI Sales Forecast 2025 - 2049

#### 3.5.1. DEI System Energy Sales

Duke Energy provided its 2022 and 2023 vintage sales forecast data to Resource Innovations. Our estimates of energy efficiency potential present savings opportunities relative to these forecasts. The forecast of baseline sales used to estimate potential does not include savings from future utility-sponsored energy efficiency,

DEI electricity sales for 2025 are forecasted to be 26,495 GWh, increasing to 38,586 GWh in 2049. This increase of 12,091 GWh represents a change of 46% over the period, or 1.5% average annual growth. The commercial sector is expected to account for the largest share of the increase, growing by 4,606 GWh or 2.3% annually, to reach 10,749 GWh (an increase of 75%) over the 25-year period. The industrial sector is expected to increase by 2,959 GWh to reach 13,828 GWh, a change of 27% over the 25-year period (1% annually). The residential sector is forecasted to increase by 4,526 GWh (48%) at an average annual growth rate of 1.6%. [Figure 3-6](#) illustrates the growth rate of sales for each economic sector over the period of analysis. In 2049 the residential sector accounts for 36% of total electricity sales, the commercial sector 28% and the industrial sector 36%. This forecast includes the impact of adding back utility energy efficiency and solar impacts to establish an MPS baseline.

**Figure 3-6: DEI Electricity Sales Growth over Base Year, by Economic Sector, for 2025 - 2049**

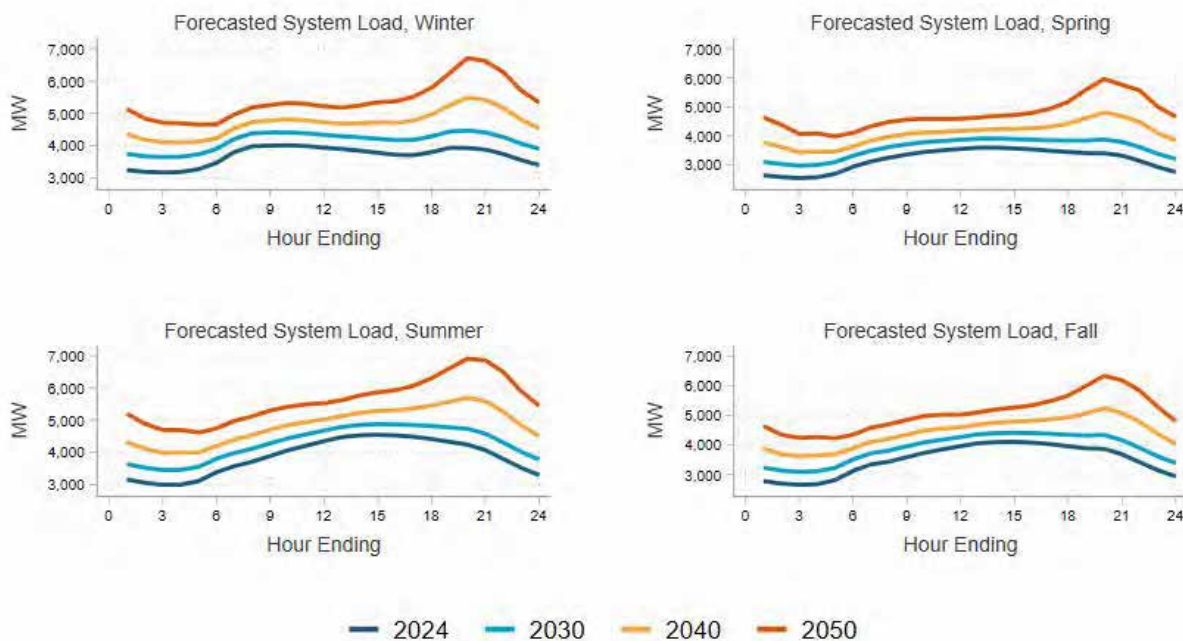


### 3.5.2. DEI System Demand

Estimating technical potential for demand response resources requires knowing how much load is available to be curtailed or shifted during system peak demand conditions. Demand response benefits accrue from avoiding costly investments to meet peak loads; load reductions have lower value if they occur outside the hours of peak system demand. Our estimates of market potential for demand response are based on when load reductions will most likely be needed throughout the year.

The primary data source used to determine when demand response resources will be needed was the DEI system load forecast. This forecast projects loads for all 8,760 hours of each forecast year available to represent the MPS study period (2025-2049). Figure 3-7 represents an initial inspection of the data. The figure shows the expected system load profiles for peak days during each season. Summer was defined as August weekdays; spring was defined as May weekdays; fall was defined as September weekdays; and winter as January weekdays.

Figure 3-7: DEI System Load Forecast by Year (2024, 2030, 2040 and 2050)

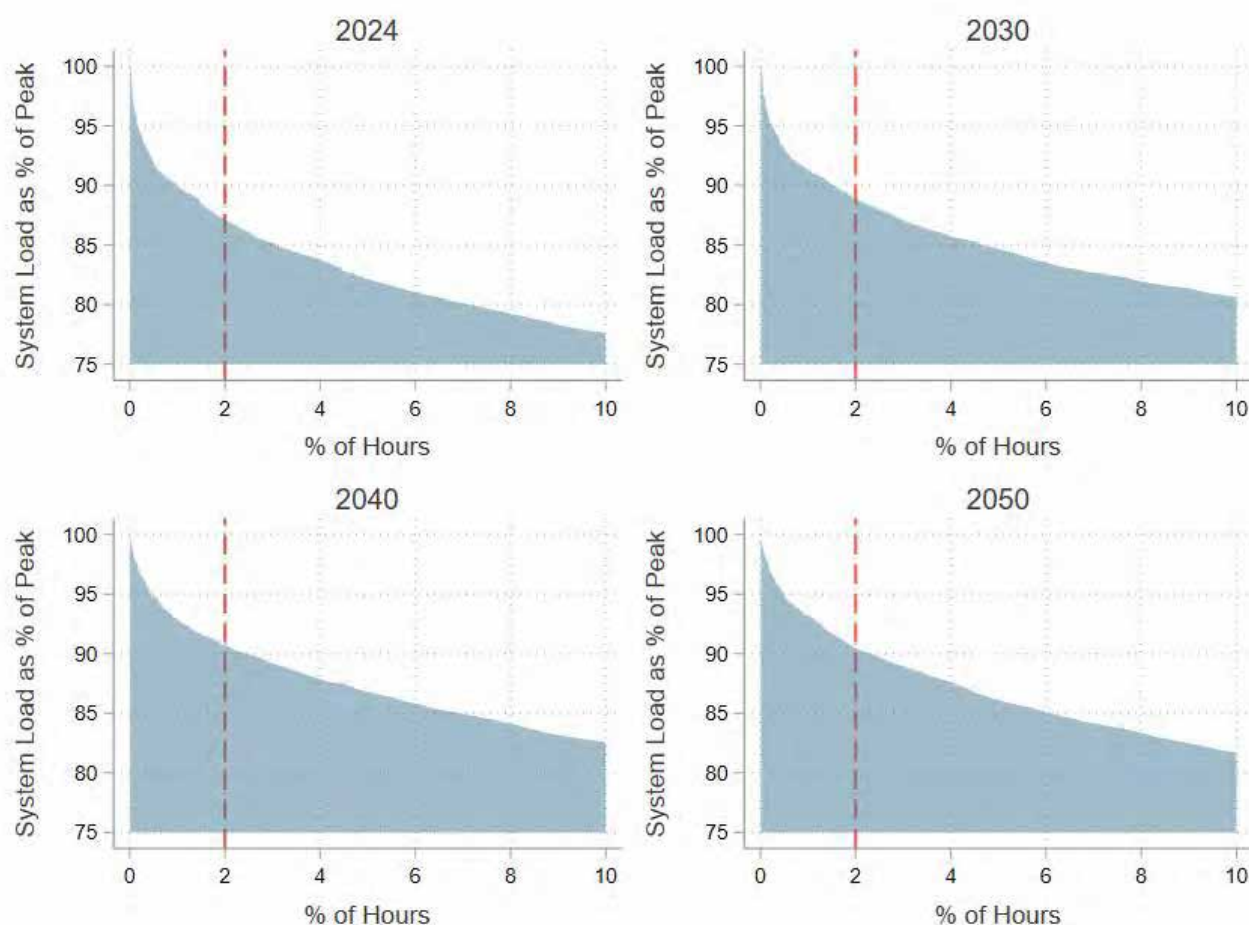


Several patterns are apparent from examining the figure above. First and foremost, forecasted peak loads are projected to increase over time. These data also indicate summer peak loads are slightly higher than winter peak loads. This potential study focuses on seasonal peak periods as defined by Duke Energy:

- Summer peak: August weekdays, hour-ending 15
- Spring peak: May weekdays, hour-ending 14
- Fall peak: September weekdays, hour-ending 15
- Winter peak: January weekdays, hour-ending 19

Though useful for assessing patterns in system loads, [Figure 3-7](#) does not provide information about the concentration of peak loads. A useful tool to examine peak load concentration is a load duration curve, which is presented for 2024, 2030, 2040 and 2050 in: [Figure 3-8](#). This curve shows the top 10% of hourly loads as a percentage of the system's peak hourly usage, sorted from highest to lowest.

**Figure 3-8: DEI Forecasted Load Duration Curve by Year**



The x-axis in [Figure 3-8](#) is depicted as the cumulative percentage of hours. The orange dotted line drawn at 2% serves as a helpful reference point for interpretation by showing the amount of peak capacity needed to serve the 2% of hours with the highest usage.<sup>2</sup> As depicted in the upper left panel of [Figure 3-8](#), approximately 87% of DEI's system peak capacity is required to serve 2% of the hours in 2024. By 2050 (depicted in the lower right panel), approximately 91% of system peak is projected to be needed to serve the top 2% of hours. This means that, while

<sup>2</sup> Another interpretation of the load duration curve data would be the amount that peak load capacity could be reduced by shaving demand during 2% of the hours throughout the year.

loads continue to grow over all hours, the number of hours of extreme usage are forecasted to be come slightly less concentrated over time.

### 3.5.3. DEI Customer Opt-Outs

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke Energy provided RI with current opt-out information for Indiana, which showed an opt-out rate of approximately 9.6% of commercial sales and 59.2% of industrial sales in the DEI service territory. We incorporated this opt-out rate into the MPS by excluding sales to non-residential customers that opted out, and we applied the applicable energy efficiency technologies and market adoption rates to the remaining customer base.

### 3.5.4. Market Description and DER-Specific Considerations

The DER analysis leveraged the customer segmentation and load disaggregation data assembled for the EE and DR analyses, and applied our DER model, SPIDER™ (Spatial Penetration and Integration of Distributed Energy Resources), to estimate system economics and adoption. This model dynamically responds to rapidly changing technologies and accounts for all key time-varying elements such as technology costs, incentives, tax credits, and electric rates. The general approach is presented in [Figure 3-9](#).

**Figure 3-9: DER Market Characteristics and Related Study Components**

Segmentation/Technologies	Key Input	Key Output
<ul style="list-style-type: none"> <li>Technologies considered <ul style="list-style-type: none"> <li>Rooftop solar PV</li> <li>Paired solar PV + battery storage systems</li> </ul> </li> <li>Customer segmentation <ul style="list-style-type: none"> <li>Residential</li> <li>Commercial</li> <li>Industrial</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>Technology costs over time</li> <li>Performance characteristics</li> <li>Rooftop area &amp; suitability</li> <li>Historical adoption</li> <li>Load and generation shapes</li> <li>Electric rate structure</li> <li>Tax credits and incentives</li> </ul>	<ul style="list-style-type: none"> <li>Cost effectiveness</li> <li>Adoption forecast (25 years)</li> <li>Hourly energy and peak demand impacts</li> <li>System level granularity</li> <li>Optimal storage dispatch</li> </ul>

Additional data on current market conditions and related suitability for PV systems is described below in [Table 3-7](#).

**Table 3-7: Technical Input Assumptions for DER Measures**

Data Item	Res	Com	Ind	Units	Source/Notes
<b>Roof Area Suitability</b>	30%	56%	82%	Suitable Area/Total Area	NREL Lidar Study (accounting for tilt, orientation, & shading)
<b>Power Density</b>	200	200	200	W/m2	Assumes 20% module efficiency
<b>Average Home Size</b>	2,017	N/A	N/A	Square Feet	EIA
<b>PV Capacity Factor</b>	15.8	14.7	14.7	(kWh AC/year) / (kW-DC*8760 hrs)	NREL PV Watts (30/10 degree tilt for res/nonres)
<b>Energy Intensity</b>	N/A	11.7	79.4	kWh / Square Foot	2018 CBECS & MECS
<b>Average # Floors</b>	1.37	2.52	2.2	Number of Floors / Building	2020 RECS, 2018 CBECS & MECS
<b>Module to Roof Area Ratio</b>	0.7	0.7	0.7	Fraction	NREL Lidar Study (racking configuration). Plus res "setback"
<b>Currently Installed PV</b>	36.5	69		MW-DC	Utility Interconnection Database (through Oct 2024)



## 4. Measure List

RI maintains a database of energy efficiency measures for MPS studies. Measure data are refined as new data or algorithms are developed for estimating measure impacts. The current list of savings opportunities, or “measures,” incorporates the measure list used in version 12 of the Illinois Technical Reference Manual, with additional supplemental measures from prior MPS studies. We added or subtracted measures at the request of project stakeholders and to follow the Indiana TRM, which in turn is linked to the Illinois TRM. At the outset of this study, RI used the Indiana TRM (tied to version 10 of the Illinois TRM) and responded to stakeholder request to incorporate updates contained in version 12 of the Illinois TRM. This section describes how the measure data is developed, maintained, and applied in the study for energy efficiency and DR services and products.

The EE measure data used in the 2023 MPS study includes a list of proposed measures that has been reviewed many times by many project stakeholders in multiple jurisdictions. Resource Innovations curates a database of EE measures that we update each time we conduct a market potential study. Updates for this project included sharing the measure list with the Indiana OSB members to solicit proposed measure additions. We requested, received, and responded to OSB input concerning measures to be included in the study. We also presented detailed information on the measure research process, and we requested feedback and comments from OSB members on the same. After conducting measure research, we provided all OSB stakeholders with data on the algorithm for estimating measure impacts for each measure in the study, as well as algorithm parameter values used to calculate the impact estimates. The OSB provided comments/responses concerning the parameter values, to which we also responded before proceeding with the subsequent tasks in the study.

Measures included in this study represent opportunities to reduce consumption across all major electricity end uses and customer types. The MPS does not include measures related to fuel switching (e.g., converting from gas space heating to electric space heating). This scope of measures is reasonable because the MPS applies the UCT to screen measures for economic potential; measures are assigned to utility-sponsored programs and screened to ensure they are cost-effective for Duke Energy to offer in a utility-sponsored program for energy efficiency.

The measures included in the study are those currently available for purchase in today’s market. The MPS does not speculate on future technologies but does include many nascent or novel savings opportunities such as smart panels, networked lighting controls, heat pump water heaters, and others. All measure impacts are modeled as a percentage reduction in baseline energy consumption. The MPS model also includes a stock and flow calculation for equipment burnouts or turnover. Future measure impacts are applied to a future baseline energy consumption estimate that reflects a continuation of historical and current trends. In this manner our estimates of savings potential are incremental to naturally occurring energy efficiency savings captured by the Duke Energy sales forecast.

The final measure list included energy efficiency technologies and products that enable DR opportunities. DR initiatives that do not rely on installing a specific technology, such as time-of-use rates and permanent load shifting, are not examined in the DR potential estimates.

## 4.1. Energy Efficiency Measures

RI's measure data represents savings opportunities for all electricity end uses and customer types. EE program measure offers are typically more specific than those required to assess EE potential. For example, Duke Energy programs have historically had multiple instances of LED lamps with varying characteristics (candelabra base, globe base, A-line, etc.). Although these distinctions are important during program delivery, this level of granularity is not necessary to identify the market potential for EE savings.

RI used a qualitative screening approach to assess emerging technologies for the Indiana service territory. The qualitative screening criteria that RI used included: difficult to quantify savings, no longer current practice, better measure available, immature, or unproven technology, limited applicability, poor customer acceptance, health and environmental concerns, and end-use service degradation. If we were able to identify specific products and generate estimates of measure savings for emerging technologies, then we added them to the measure list. RI updated its online measure database to support this study. RI's database contains the following information for each measure:

- Classification of measure by type, end use, and subsector
- Description of the base-case and the efficiency-case scenarios
- Measure life
- Savings algorithms and calculations per subsector, taking weather zones and subsectors into consideration
- Input values for variables used to calculate energy savings
- Measure costs
- Output to be used as input in RI's TEAPOT model

Detailed measure assumptions in this database were provided to Duke Energy and the Indiana OSB. As shown in [Table 4-1](#), the study included 393 unique energy efficiency measures. Expanding the measures to account for all relevant combinations of segments, end uses, and construction types resulted in 9,431 measure permutations that we modeled against the market baseline.

**Table 4-1: EE Measure Counts by Sector**

Sector	Unique Measures	Permutations
Residential	115	1,780
Commercial	168	5,113
Industrial	110	2,538

## 4.2. Inflation Reduction Act Measure Development

The 2022 Inflation Reduction Act recently made available approximately \$360 billion for investments to reduce greenhouse gas emissions and combat climate change. Major federal program included in the IRA are as follows:

- Home energy performance-based whole-house (HOMES) rebates through the Department of Energy (DOE)
- 179D Energy efficient commercial building deduction
- High-efficiency electric home rebate program (DOE)
- 25c Energy Efficient Home Improvement Credit

Resource Innovations developed an EE MPS modeling scenario around this legislation to address the potential magnitude of expected impacts the program could have on achievable market potential. Significant uncertainty remains concerning how the program will be implemented, but RI's analysis included the following procedures and assumptions, described below. We made assumptions in modeling IRA impacts, as follows:

- Develop additional, "IRA measures" to supplement the original measure list developed for the MPS.
  - HOMES includes a whole home retrofit measure that RI prepared for modeling.
  - Measure saves 20% for existing construction, incremental cost is assumed to be \$10,000.
  - Measure applies to population in a manner consistent with income distribution; two versions were applied: HOMES for customer base with <80% area median income (AMI), HOMES for customer base with 80%-150% AMI income.
  - Included \$1 per kWh in administrative costs for Duke Energy resource expenditures facilitate and support the HOMES program.
- Measures that qualify for the 25c Energy Efficiency Tax credit were modeled as a duplicate of the corresponding, existing Smart \$aver measures; Duke Energy program incentives and rebates were applied to the measures' incremental costs, and those costs were further reduced by subtracted the capped tax credit amount for each measure prior to calculating customer payback times.
- Administrative costs from relevant Duke Energy programs, on a per-kWh basis, were used to account for the potential of increased program participation volume that may result from the IRA.

After developing these measures and cost-estimates, Resource Innovations applied the measures within our model to estimate the potential impacts and included these expected impacts from the IRA in the base achievable potential case.

### 4.3. DR Services and Products

RI and Duke Energy worked together to determine which DR products and services were included in the MPS, and addressed the following:

- **Direct load control.** Customers receive incentive payments for allowing the utility a degree of control over equipment, such as air conditioners or water heaters. This includes both switch-based programs and smart thermostat programs.
- **Emergency load response.** Customers receive payments for committing to reduce load if called upon to do so by the grid operator.
- **Economic load response:** Utilities provide customers with incentives to reduce energy consumption when marginal generation costs are higher than the incentive amount required to achieve the needed energy reduction.
- **Base interruptible DR.** Customers receive a discounted rate for agreeing to reduce load to a firm service level upon request.
- **Automated DR.** Utility dispatched control of specific end-uses at customer facilities.

#### 4.4. DER Measure Input Assumptions

The DER measure list includes rooftop PV systems and battery storage systems charged from PV systems. PV systems utilize solar panels (a packaged collection of PV cells) to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter, a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted systems that face south-west, south, and/or, south-east. The potential associated with roof-mounted systems installed on residential, commercial, and industrial buildings was analyzed.

Distributed battery storage systems included in this study consist of behind-the-meter battery systems installed in conjunction with an appropriately sized PV system at residential and non-residential customer facilities. These battery systems typically consist of a DC-charged battery, a DC/AC inverter, and electrical system interconnections to a PV system. On their own battery storage systems do not generate or conserve energy but can collect and store excess PV generation to provide power during particular time periods, which for DR purposes would be to offset customer demand during the utility's system peak. The system specification is presented in [Table 4-2](#).

**Table 4-2. System Specifications**

Specification	Value
Hours of Storage at Peak Capacity	2.5
Round-Trip Efficiency	90%
Ratio of Peak Storage Power to Peak Solar Power	1.0

## 5. Technical Potential

Technical potential relates to base year load shares and reference case load forecasts for 2025 to 2049. Measure savings impacts are applied to the baseline data to estimate technical potential. The technical potential scenario estimates the savings potential when all technically feasible energy efficiency measures are fully implemented, while accounting for equipment turnover. This savings potential can be considered the maximum reduction attainable with available technology and current market conditions (e.g., currently available technology, building stock, and end uses as reflected in Duke Energy forecasted sales). EE and DR potential scenarios that account for measures' costs and benefits and market adoption are discussed in subsequent report sections for economic potential and achievable potential, respectively.

### 5.1. Approach and Context

Technical potential represents a straightforward application of EE and DR measures to the baseline market context for Duke Energy Indiana. Technical potential is determined by the energy intensity of baseline consumption and the savings opportunities represented by EE and DR measures. Baseline conditions for electricity consumption inherently reflect historic and current economic conditions, the current configuration of the power system, policy context, and customer preferences.

Current and projected sales and load are based on the current and projected numbers of accounts served by economic sector. The types of loads present at these accounts are reflective of customers' economic sector, segment, and final demand for electricity services. Final demand for electricity is reflective of numerous, complex factors such as the set of available technologies that meet electricity end uses (e.g., HVAC for heating, cooling, and ultimately: comfort); the cost of technologies that produce electricity end uses; the price of electricity and other energy sources; customer demand for electricity services; and behavioral or other contextual factors that collectively drive customer decisions about energy consumption.

#### 5.1.1. Energy Efficiency

Energy efficiency technical potential provides a theoretical maximum for electricity savings relative to the forecast baseline. Technical potential ignores all non-technical constraints on electricity savings, such as cost-effectiveness and customer willingness to adopt energy efficiency. For an EE potential study, technical potential refers to delivering less electricity to satisfy the same end uses. In other words, technical potential might be summarized as "doing the same thing with less energy, regardless of the cost."

RI applied estimated energy savings from equipment or non-equipment measures to all electricity end uses and customers. Since technical potential does not consider the costs or time required to achieve these electricity savings, the estimates provide an upper limit on savings potential. RI presents technical potential results as a single numerical value for the DEI service territory.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in [Equation 5-1](#) below, while the core equation used in

the nonresidential sector technical potential analysis for each individual efficiency measure is shown in Equation 5-2, below.

Equation 5-1: Core Equation for Residential Sector Technical Potential



Where:

**Base Case Equipment Energy Use Intensity** = the electricity used per customer per year by each base-case technology in each market segment; efficient technologies are applied to reduce this base case equipment energy use intensity.

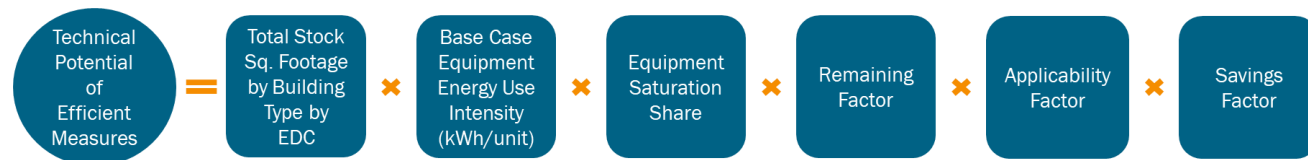
**Saturation Share** = the fraction of the electricity end use consumption that may be reduced by applying an efficient technology in each market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

**Remaining Factor** = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

**Applicability Factor** = the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (i.e., it may not be possible to install a heat pump water heater for every home due to space constraints).

**Savings Factor** = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Equation 5-2: Core Equation for Nonresidential Sector Technical Potential



Where:

**Total Stock Square Footage by Building Type** = the forecasted square footage level for a given building type (e.g., office buildings).

**Base Case Equipment Energy Use Intensity** = the electricity used per square foot per year by each base-case equipment type in each market segment. In other words, the base case equipment



energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

**Equipment Saturation Share** = the fraction of the equipment electrical energy that is applicable for the efficient technology in each market segment. For example, for room air conditioners, the saturation share would be the fraction of all space cooling kWh in each market segment that is associated with room air conditioner equipment.

**Remaining Factor** = the fraction of equipment that is not considered to already be energy efficient. For example, the fraction of electric water heaters that is not already energy efficient.

**Applicability Factor** = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (i.e., it may not be possible to install VFDs on all motors in each market segment).

**Savings Factor** = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

It is important to note that the technical potential estimate represents electricity savings potential at a specific point in time. In other words, the technical potential estimate is based on data describing *status quo* customer electricity use and technologies known to exist today. As technology and electricity consumption patterns evolve over time, the baseline electricity consumption will also change accordingly. For this reason, technical potential is a discrete estimate of a dynamic market. RI reported technical potential over a defined time period, based on currently known DR measures and observed electricity consumption patterns.

#### 5.1.1.1.1. Addressing Naturally Occurring Energy Efficiency

Duke Energy's baseline sale forecast includes the impacts of efficiency actions that are expected to occur in the absence of utility intervention. RI worked with Duke Energy's forecasting group to understand how the sales forecasts incorporated two known sources of naturally occurring efficiency:

- **Codes and Standards:** The sales forecasts incorporated the impacts of known code changes. While some code changes have relatively little impact on overall sales, others— particularly the Energy Independence and Security Act (EISA) and other federal legislation—will have noticeable influence. Given the uncertainty associated with the implementation of the EISA backstop and current market trends, RI adjusted the future lighting baseline to the EISA-compliant standard.
- **Baseline Measure Adoption:** Sales forecasts typically exclude the projected impacts of future DR efforts, but account for baseline efficiency penetration.

By properly accounting for these factors, the potential study represents the difference between the anticipated adoption of efficiency measures because of DR efforts and the “business as usual” adoption rates absent any projected future impacts of utility-sponsored programs. This is true even in the technical and economic scenarios, where adoption was assumed to be 100%, and was

particularly important in the achievable potential analysis, where RI estimated the measure adoption in a market featuring utility-sponsored programs.

### 5.1.2. Demand Response

The concept of technical potential applies differently to demand response than for energy efficiency. Technical potential for demand response is effectively the magnitude of loads that can be managed during conditions when grid operators need peak capacity, ancillary services, or when wholesale energy prices are high. Which accounts are consuming electricity at those times? What end-uses are in play? Can those end-use loads be managed? Large C&I accounts generally do not provide the utility with direct control over end-uses. However, businesses will forego virtually all electric demand temporarily if the financial incentive is large enough.

For residential and SMB accounts where DR means direct utility load control, technical potential for demand response is limited by the loads that can be controlled remotely at scale. RI produced disaggregated weather-responsive load for all 8760 hours. This approach identifies weather-responsive customer loads available at times when the different grid applications are needed can vary substantially. Instead of producing disaggregated loads for the average residential customers, the study was produced for several customer segments, thereby allowing the study to identify which customers were cost-effective to recruit and which were not.

RI used interval data for all large C&I customers; and we used interval data from Duke Energy's load research sample for SMB and residential customers. Technical potential, in the context of DR, is defined as the total amount of load available for reduction that is coincident with the period of interest. In the context of this study, DR capacity is defined as the system peak hour for the summer, winter, fall, and spring seasons. Thus, four sets of capacity values are estimated.

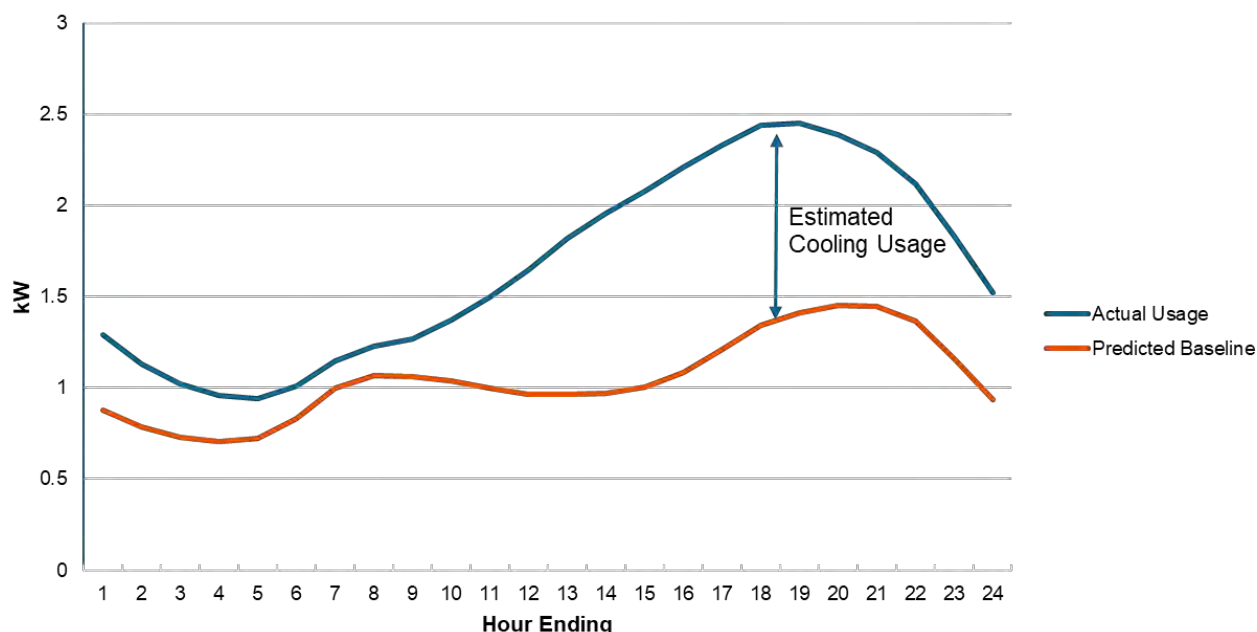
As previously mentioned, all large C&I load is considered dispatchable, while residential and SMB DR capacity is based on specific end uses. For this study, it was assumed that summer DR capacity for residential customers would be comprised of air-conditioning (AC), pool pumps, water heaters, and managed electric vehicle charging. For small C&I customers, summer capacity would be based on AC load and water heaters. For winter capacity, both residential and small C&I DR capacity would be based on electric heating and water heaters. Fall and spring DR capacity for residential customers would be comprised of air-conditioning (AC), electric heating, pool pumps, water heaters, and managed electric vehicle charging. For small C&I customers, fall and spring capacity would be based on AC load, electric heating, and water heaters.

AC and heating load profiles for residential customers and AC load profiles for SMB customers were generated with the load research sample provided by Duke Energy. This sample included a customer breakout based on housing type for residential customers. Resource Innovations then used the interval data from these customers to create an average load profile for each customer segment.

The average load profile for each customer segment was combined with historical weather data and used to estimate hourly load as a function of weather conditions. AC and heating loads were estimated by first calculating the baseline load on days when cooling degree days (CDD) and heating

degree days (HDD) were equal to zero, and then subtracting this baseline load. This methodology is illustrated by Figure 5-1 (a similar methodology was used to predict heating loads).

**Figure 5-1: Methodology for Estimating Cooling Loads**



This method was able to produce estimates for average AC/heating load profiles for the seven different customer segments within the residential and small C&I sectors.

Profiles for residential pool pump loads were estimated by utilizing utility-specific end-use load data provided by DEI. Profiles for residential water heater loads were estimated by using NREL's end-use load profile database.

For all eligible loads, the technical potential was defined as the amount that was coincident with system peak hours for each season, which are August from 2:00-3:00 PM for summer, January from 6:00-7:00 PM for winter, September from 2:00-3:00 PM for fall, and May from 1:00-2:00 PM for spring. As mentioned in [Section 4.3](#), for technical potential there was also no measure breakout needed, because all measures will target the end-uses' estimated total loads.

### 5.1.3. Solar Photovoltaic Systems

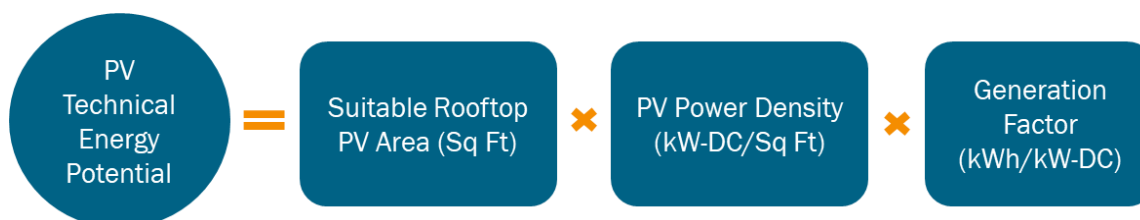
To determine technical potential for PV systems, RI estimated the percentage of rooftop square footage that is suitable for hosting PV technology. Our estimate of technical potential for PV systems in this report is based in part on the available roof area and consisted of the following steps:

- Step 1: Outcomes from the forecast disaggregation analysis were used to characterize the existing and new residential, commercial, and industrial building stocks.

- To calculate the total roof area for residential buildings, the average roof area per household is multiplied by the number of households.
- For commercial and industrial buildings, RI calculated the total roof area by first dividing the load forecast by the energy usage intensity, which provides an estimate of the total building square footage. This result is then divided by the average number of floors to derive the total roof area.
- Step 2: The total available roof area feasible for installing PV systems was calculated. Relevant parameters included unusable area due to other rooftop equipment and setback requirements, in addition to possible shading from trees and limitations of roof orientation (factored into a “technical suitability” multiplier).
- Step 3: Estimated the expected power density (kW per square foot of roof area).
- Step 4: Estimated the hourly PV generation profile using NREL’s PV Watts Calculator
- Step 5: Calculated total energy and coincident peak demand potential by applying RI’s Spatial Penetration and Integration of Distributed Energy Resources (SPIDER) Model.

The methodology presented in this report uses the following formula to estimate overall technical potential of PVs:

Equation 5-3. Core Equation for Solar Technical Energy Potential



Where:

- **Suitable Rooftop PV Area for Residential [Square Feet]:** Number of Residential Buildings times Average Roof Area Per Building times Technical Suitability Factor
- **Suitable Rooftop PV Area for Commercial [Square Feet]:** Energy Consumption [kWh] divided by Energy Intensity [kWh / Square Feet] divided by Average No. of Stories Per Building times Technical Suitability Factor
- **PV Power Density [kW-DC/Square Feet]:** Maximum power generated in Watts per square foot of solar panel.
- **Generation Factor:** Annual Energy Generation Factor for PV, from PV Watts (dependent on local solar irradiance)

#### 5.1.4. Battery Storage Systems Charged from PV Systems

Battery storage systems on their own do not generate power or create efficiency improvements, but store power for use at different times. Therefore, in analyzing the technical potential for battery storage systems, the source of the stored power and overlap with technical potential identified in other categories was considered.

Battery storage systems that are powered directly from the grid do not produce annual energy savings but may be used to shift or curtail load during specific time periods. As the DR technical potential analyzes curtailment opportunities for the summer and winter peak period, and battery storage systems can be used as a DR technology, the study concluded that no additional technical potential should be claimed for grid-powered battery systems beyond that which can be attributed to DR.

Battery storage systems that are connected to on-site PV systems also do not produce additional energy savings beyond the energy produced from the PV system<sup>3</sup>. However, PV-connected battery systems do create the opportunity to store energy during period when the PV system is generating more than the home or business is consuming and use that stored power during utility system peak periods.

To determine the additional technical potential peak demand savings for “solar plus storage” systems, our methodology consisted of the following steps:

- Assume that every PV system included in PV Technical Potential is installed with a paired storage system.
- Size the storage system assuming peak storage power is equal to peak PV generation and energy storage duration is three hours.

Apply RI’s hourly dispatch optimization module in SPIDER to create an hourly storage dispatch profile that maximizes the economic benefit from the customer perspective and accounts for a) customer hourly load profile, b) hourly PV generation profile, and c) battery peak demand, energy capacity, and roundtrip charge/discharge efficiency (illustrated in [Table 4-2](#)). This impact is different than that which might be expected if the storage were instead used for a demand response program.

## 5.2. DEI Energy Efficiency Technical Potential

This section provides the results of the DEI energy efficiency technical potential for each of the three segments.

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<sup>3</sup> PV-connected battery systems experience some efficiency loss due to storage, charging, and discharging.

## 5.2.1. Summary

Table 5-1 summarizes the cumulative energy efficiency technical potential by sector. Cumulative impacts represent persistent impacts to the base DEI energy sales forecast and is not equal to the sum of annual incremental energy. This is due to the “rolloff” of energy efficiency retrofit measures as they reach the end of their effective useful lives, and their forecast impacts are superseded by impacts from replacing associated equipment with high efficiency equipment over time. The total energy saved over the period is represented by the sum of incremental annual energy saving and represents all energy efficiency potential captured over the study period.

**Table 5-1: DEI Cumulative Energy Efficiency Technical Potential by Sector**

Sector	Energy (GWh)	% of 2025 Base Sales	Technical Potential (2025-2049)			
			Demand (MW)			
			Spring	Summer	Fall	Winter
Residential	3,080	32%	890.6	918.4	788.7	497
Commercial	1,173	19%	351.6	345.9	347.5	188.7
Industrial	1,625	15%	213.9	214	214	190.4
<b>Total</b>	<b>5,878</b>	<b>22%</b>	<b>1,456</b>	<b>1,478</b>	<b>1,350</b>	<b>876</b>

## 5.2.2. Sector Details

Figure 5-2 summarizes the DEI residential sector energy efficiency technical potential by end use and customer segment.

**Figure 5-2: DEI Residential EE Technical Potential– Cumulative 2049 by End-Use**

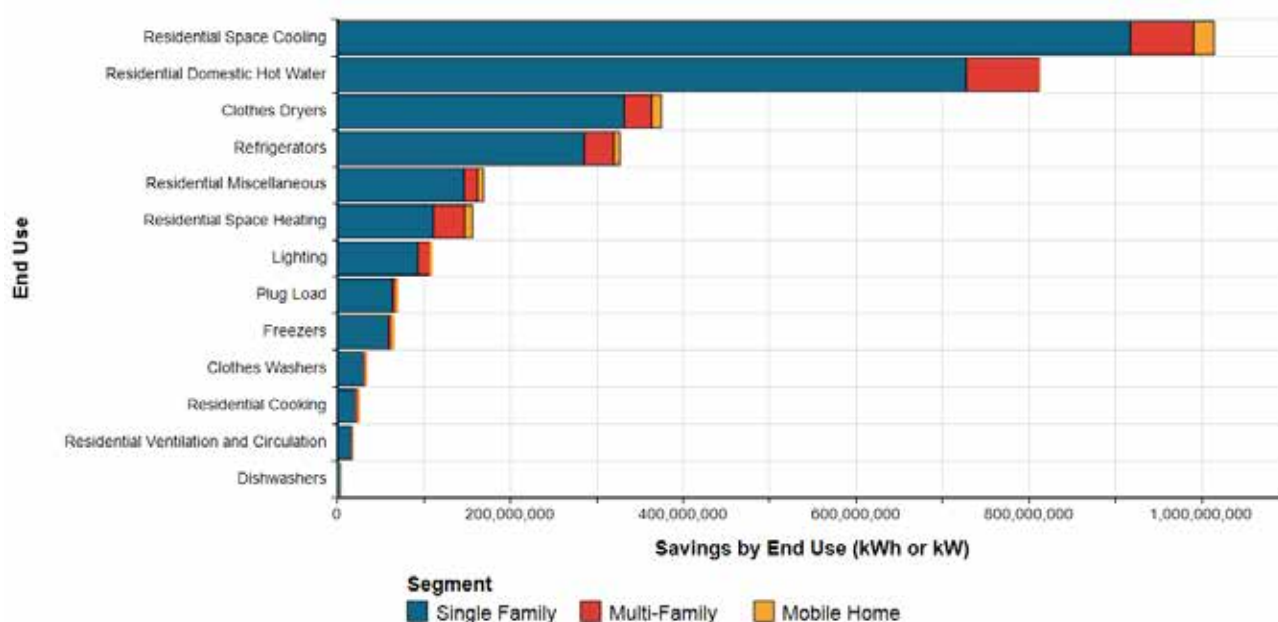




Figure 5-3 summarizes the DEI commercial sector EE technical potential by end use.

Figure 5-3: DEI Commercial EE Technical Potential – Cumulative 2049 by End-Use

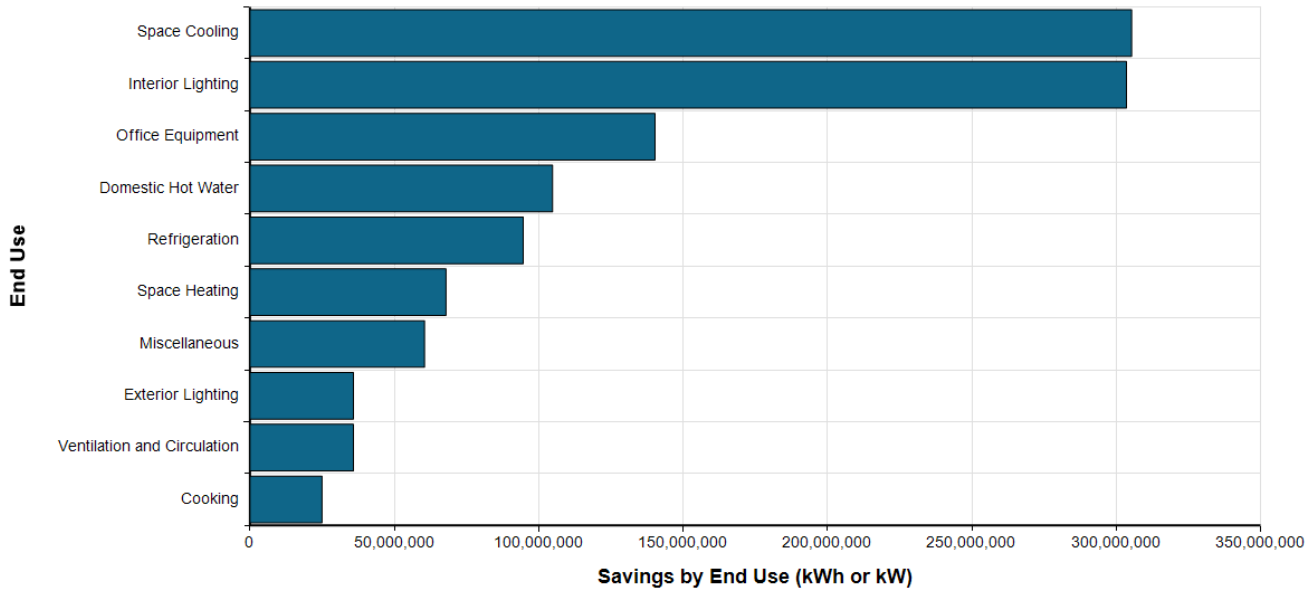


Figure 5-4 provides a summary of DEI energy efficiency technical potential contributions by commercial facility types analyzed in this study.

Figure 5-4: DEI Commercial EE Technical Potential – Cumulative 2049 by Segment

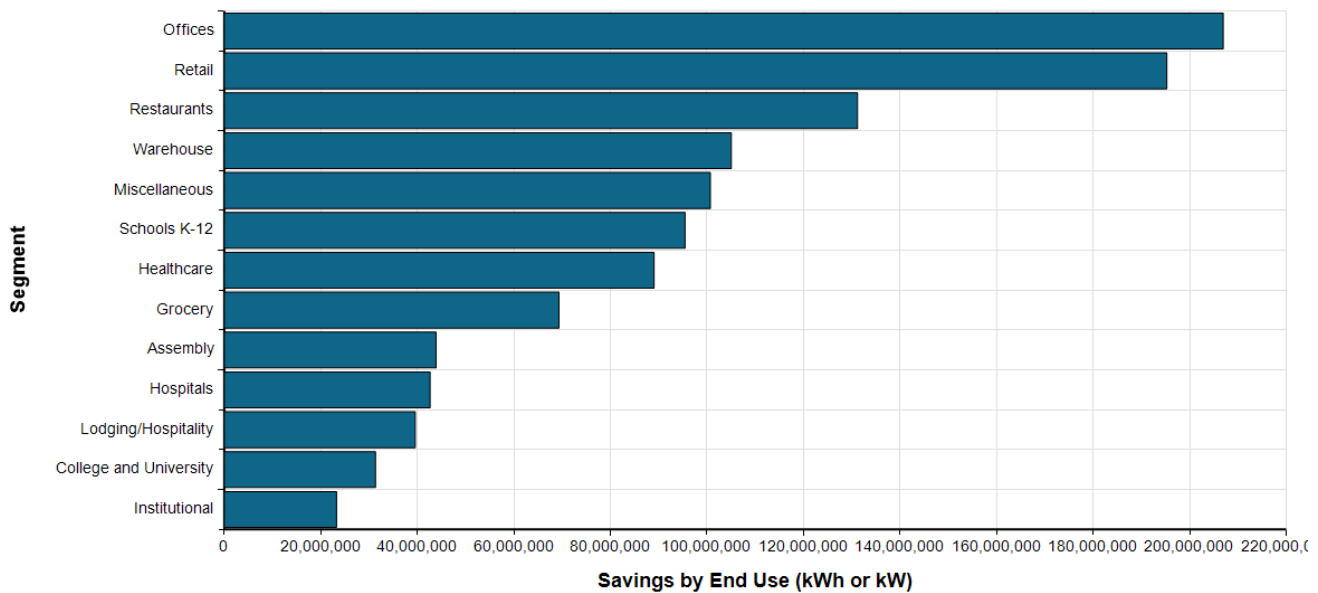


Figure 5-5 summarizes the DEI industrial sector energy efficiency technical potential by end use.

Figure 5-5: DEI Industrial EE Technical Potential – Cumulative 2049 by End-Use

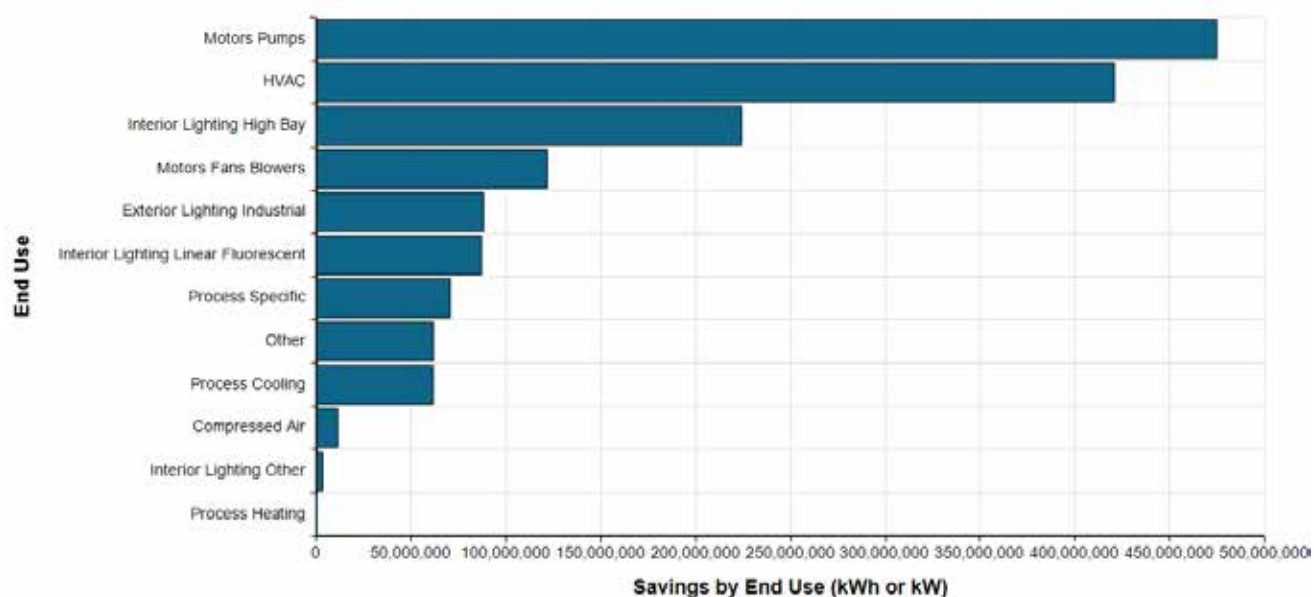
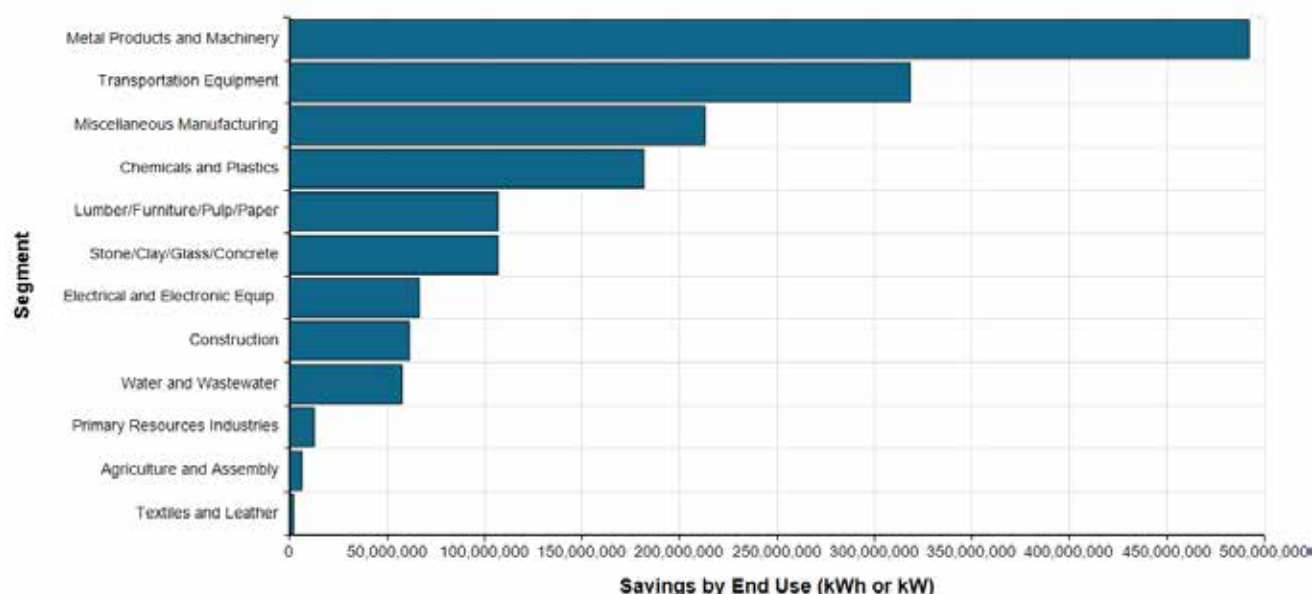


Figure 5-6 provides a summary of DEI energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 5-6: DEI Industrial EE Technical Potential – Cumulative 2049 by Segment



### 5.3. DEI Controllable Peak Load, by Customer Type

Technical potential for demand response is defined for each class of customers as follows:

- Residential & SMB customers – Technical potential is equal to the aggregate load for all end uses that can participate in Duke Energy’s current programs plus DR measures not currently offered in which the utility uses specialized devices to control loads (*i.e.*, direct load control programs). This includes cooling, heating, and electric water heating loads for residential and small C&I customers. Pool pump loads, electric vehicle charging, and paired battery storage systems are also considered for residential and SMB sectors.
- Large C&I customers – Technical potential is equal to the total amount of load for each customer segment. This reflects the contractual nature of most large C&I programs and the fact that for a large enough payment and small enough number of events, we assume large C&I customers would be willing to reduce their usage to zero; technical potential includes all customers, even though many have opted out of the DR rider and are therefore not actually eligible to participate in Duke Energy programs.

As with the EE analysis, DR technical potential includes all customers, regardless of opt-out status or current participation in DR programs. [Table 5-2](#) summarizes the seasonal DR technical potential by sector:

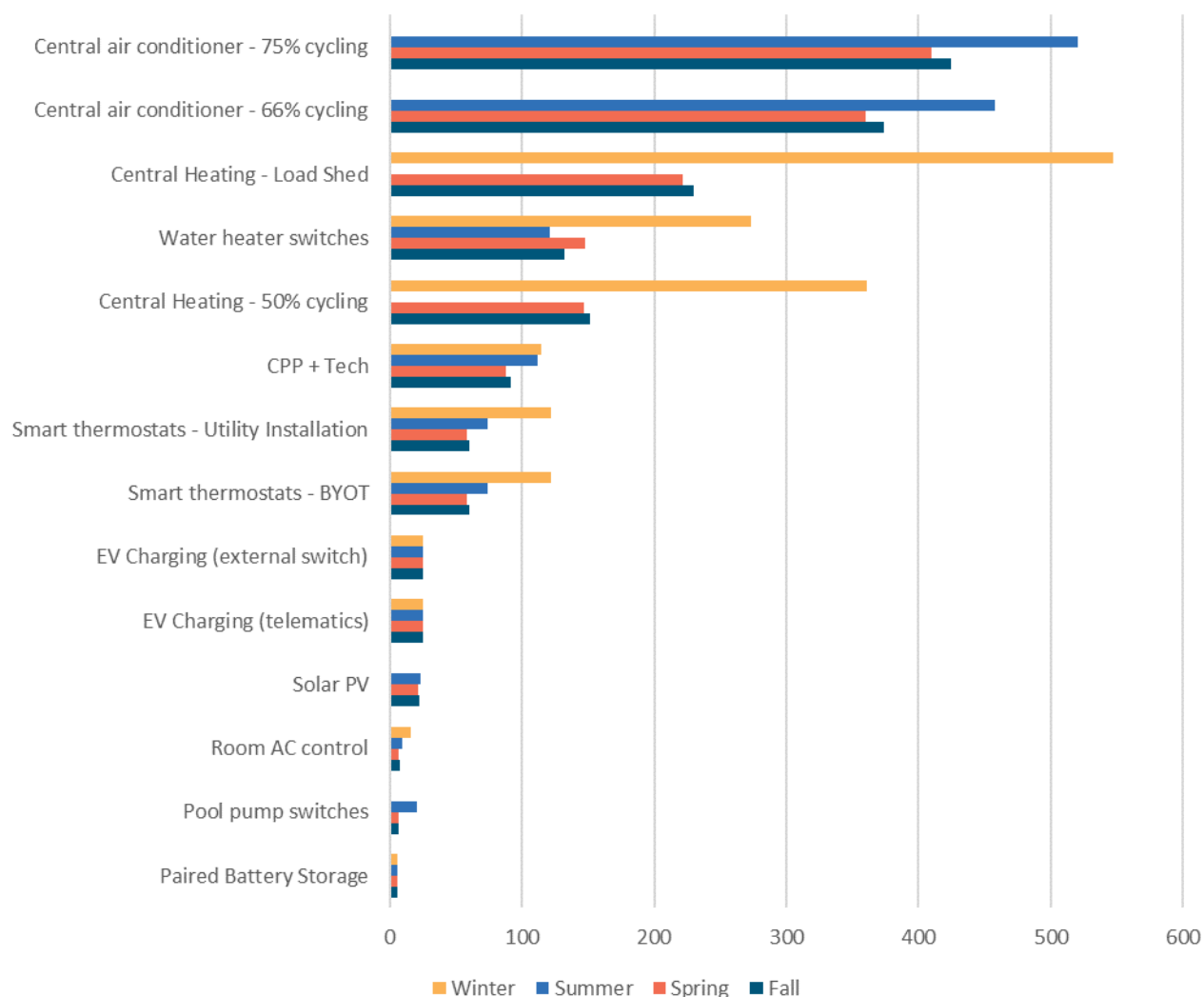
**Table 5-2: DEI DR Technical Potential by Sector**

Sector	Savings Potential			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Fall Peak Demand (MW)	Spring Peak Demand (MW)
Residential	1,469	1,612	1,616	1,581
SMB	176	63	204	209
Large C&I	2,514	1,893	2,312	2,317
<b>Total</b>	<b>4,159</b>	<b>3,568</b>	<b>4,133</b>	<b>4,107</b>

### 5.3.1. Residential

Residential technical potential is summarized by measure and season in [Figure 5-7](#).

**Figure 5-7: Residential DR Technical Potential by Measure and Season**

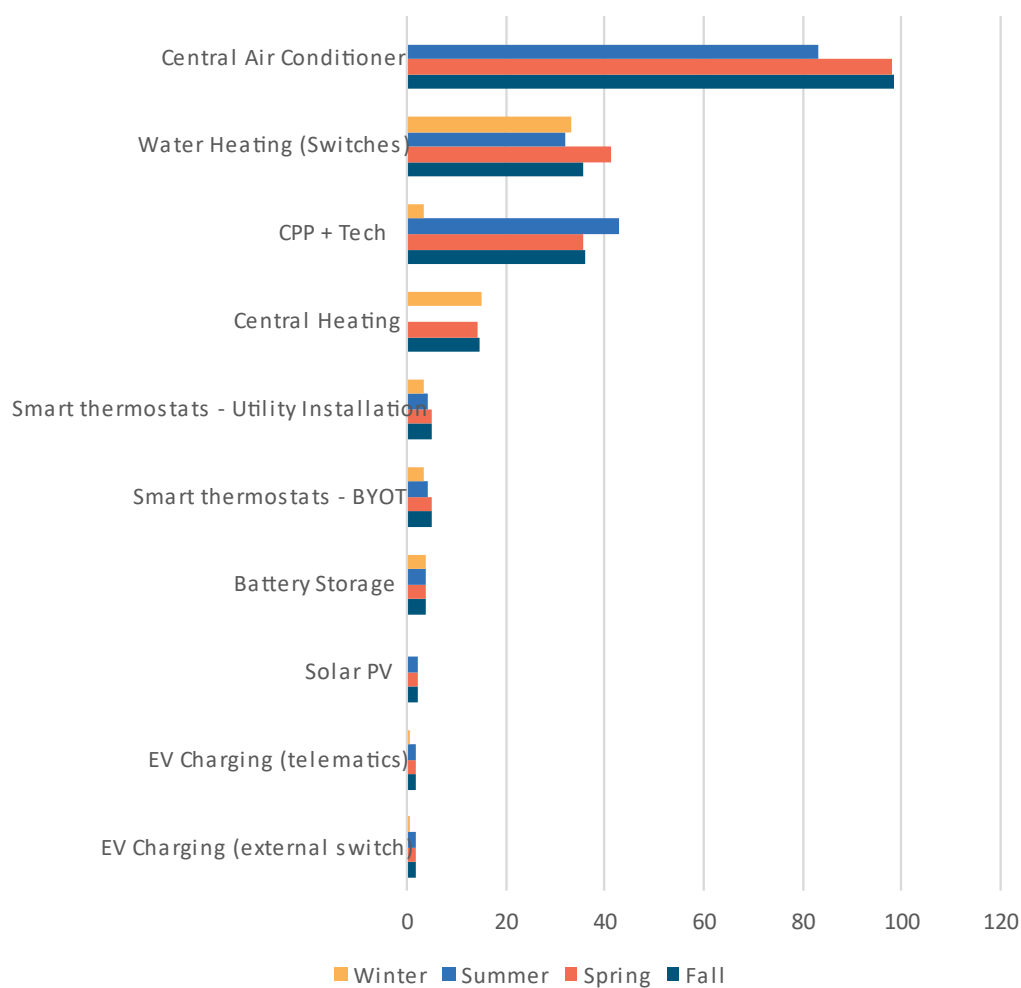


## 5.3.2. Non-Residential

### 5.3.2.1. Small C&I Customers

For small C&I technical potential, Resource Innovations looked at cooling and heating loads, water heating and EV charging. Small C&I technical potential is provided in [Figure 5-8](#).

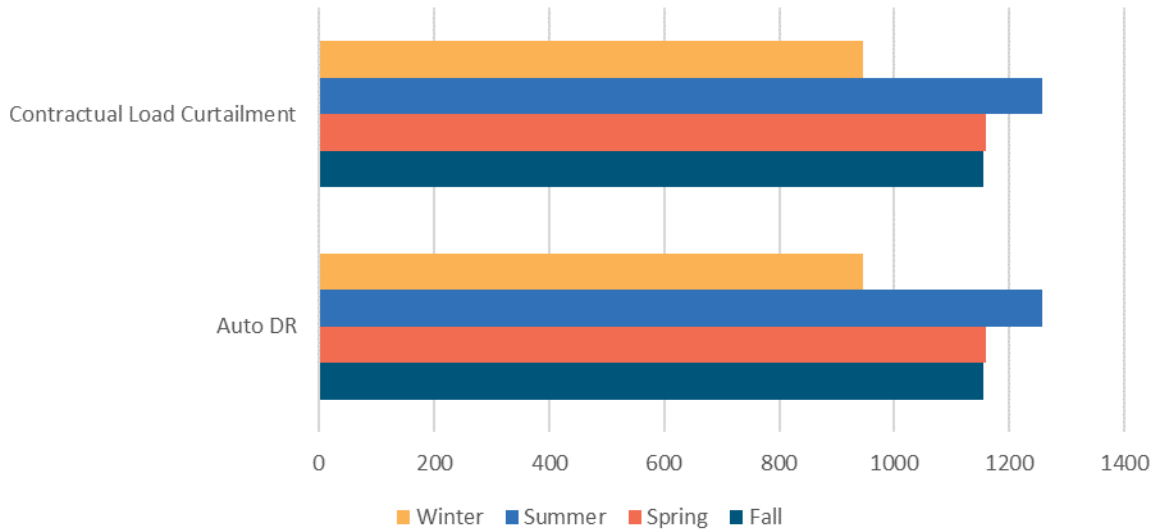
**Figure 5-8: Small C&I DR Technical Potential by Measure and Season**



### 5.3.2.2. Large C&I Customers

Figure 5-9 provides the technical potential for large C&I customers, broken down by measure and season. EV charging and battery storage had zero or negligible potential and were not included in the chart.

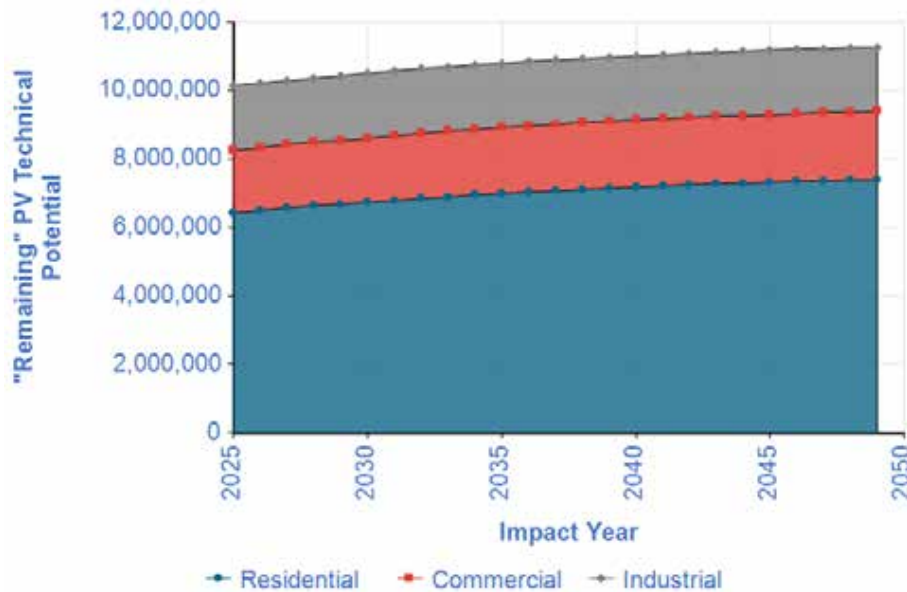
Figure 5-9: Large C&I DR Technical Potential by Measure and Season



## 5.4. Distributed Energy Resources

As described in the Executive Summary, RI presents two different views of DER technical potential: one is based on the nameplate capacity of installed PV, and PV paired with storage systems. The result of the nameplate technical capacity for PV energy reductions is presented below in [Figure 5-10](#):

Figure 5-10: Nameplate PV Technical Potential "Remaining."

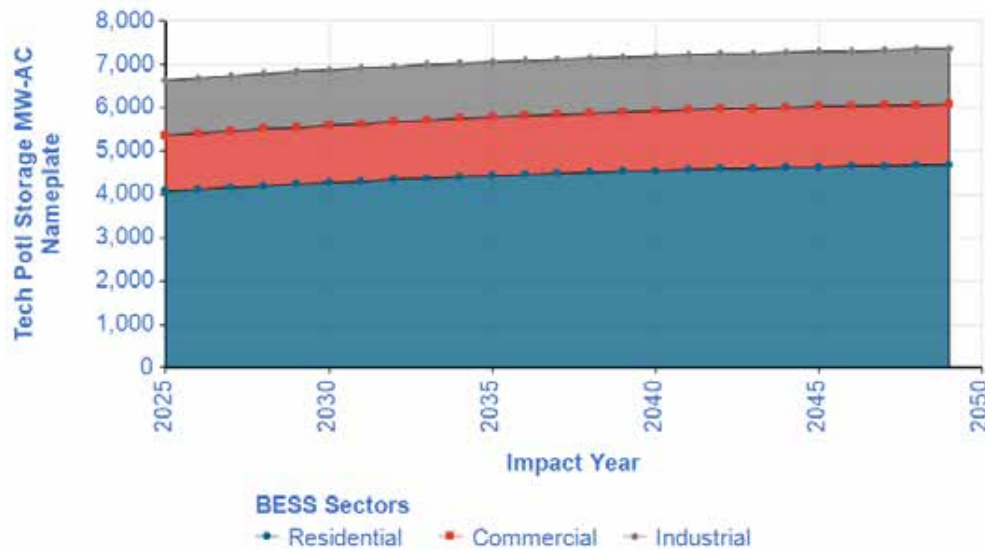




When expressed as a share of DEI baseline consumption, these PV technical potential estimates represent approximately 70%, 38%, and 18% of residential, commercial, and industrial sales (all customers, respectively).

Paired storage nameplate technical potential is equivalent to the nameplate MW-AC of solar PV, assuming storage systems are sized according to max PV capacity. These impacts are shown below in [Figure 5-11](#).

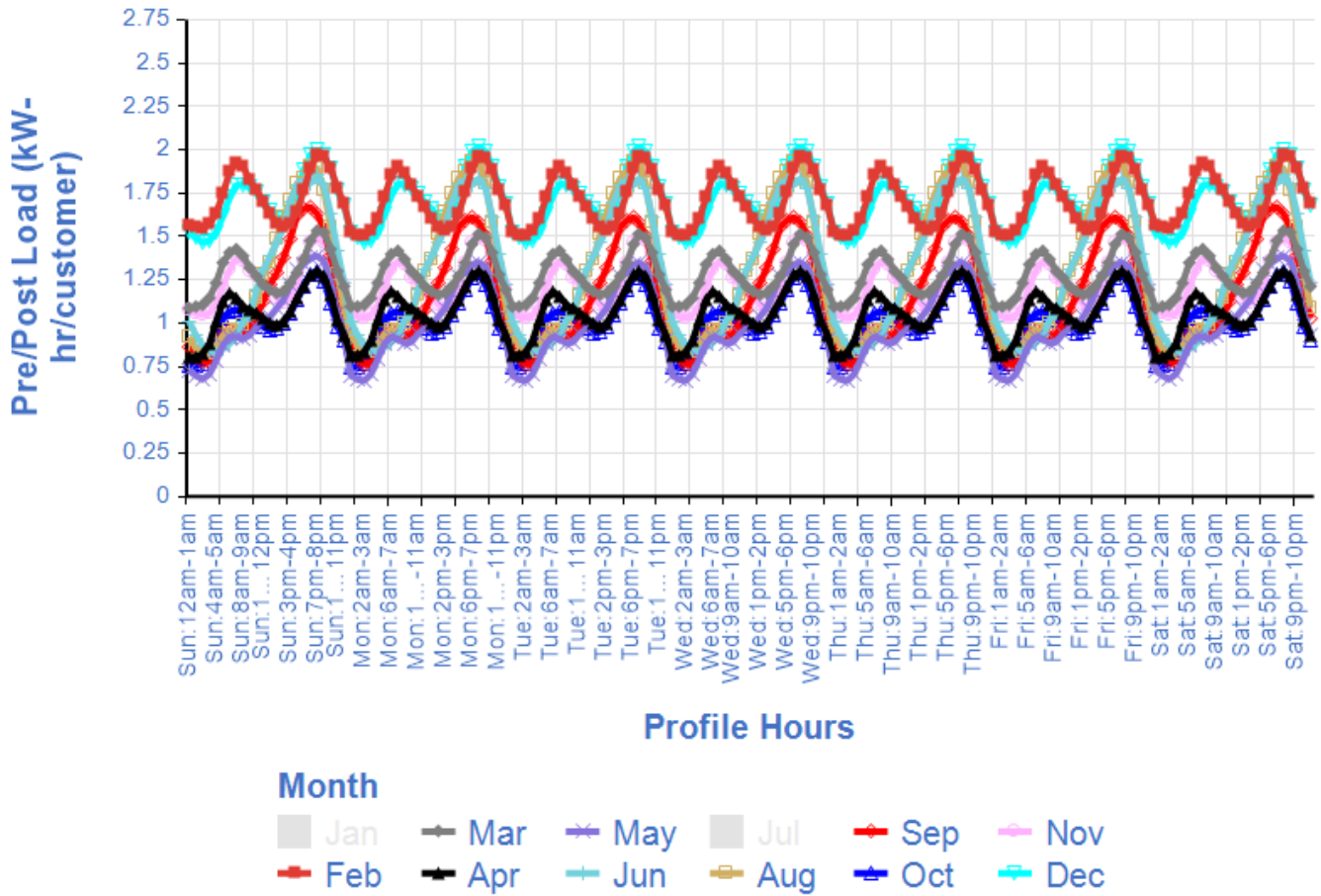
**Figure 5-11: Paired Storage Nameplate Technical Potential**



#### 5.4.1. DER Grid Impacts of Technical Potential

The grid impacts of paired storage technical potential are heavily influenced by how customers are expected to dispatch their systems in the current market environment, with existing rate structures and load shapes. RI compiled monthly load shape data for each DEI customer class for use as a baseline description of energy consumption patterns. [Figure 5-12](#) provides an example for the residential customer class.

Figure 5-12: Monthly Average Load Shapes for DEI Residential Customers (Hourly)



RI's SPIDER model contains a linear program that incorporates current DEI customer rate schedules to calculate optimal dispatch of the battery to maximize customer benefits. Analytical results demonstrate the optimal pre- and post-system installation rates for each customer class, summarized below in [Table 5-3](#).

**Table 5-3: Summary of Optimal Pre- and Post-Installation Rate Schedules**

Sector	System Type	Pre-Installation Rate	Post-Installation Rate*
Residential	Solar + Storage	DEI - 6 (Residential Electric Service)	DEI - 6 (Residential Electric Service) + 73 (Renewable Energy Project Adjustment)
Commercial	Solar + Storage	DEI - 10 (Low Load Factor Service Secondary)	DEI - 10 (Low Load Factor Service Secondary) + 73 (Renewable Energy Project Adjustment)
Industrial	Solar + Storage	DEI - 12 (High Load Factor Service Secondary)	DEI - 12 (High Load Factor Service Secondary) + 73 (Renewable Energy Project Adjustment)

In addition to these rates, RI modeled optional TOU rates 10.4 and 12.4, but pairing storage with a solar system pushed customer economics in the direction of the non-TOU rate as the optimal post-installation rate.

Figure 5-13 provides an example of the optimal hourly dispatch characteristics RI estimated using DEI rates and class load shapes:

**Figure 5-13: Example of Optimal Hourly Battery Dispatch for DER Grid Impacts of Paired Storage**

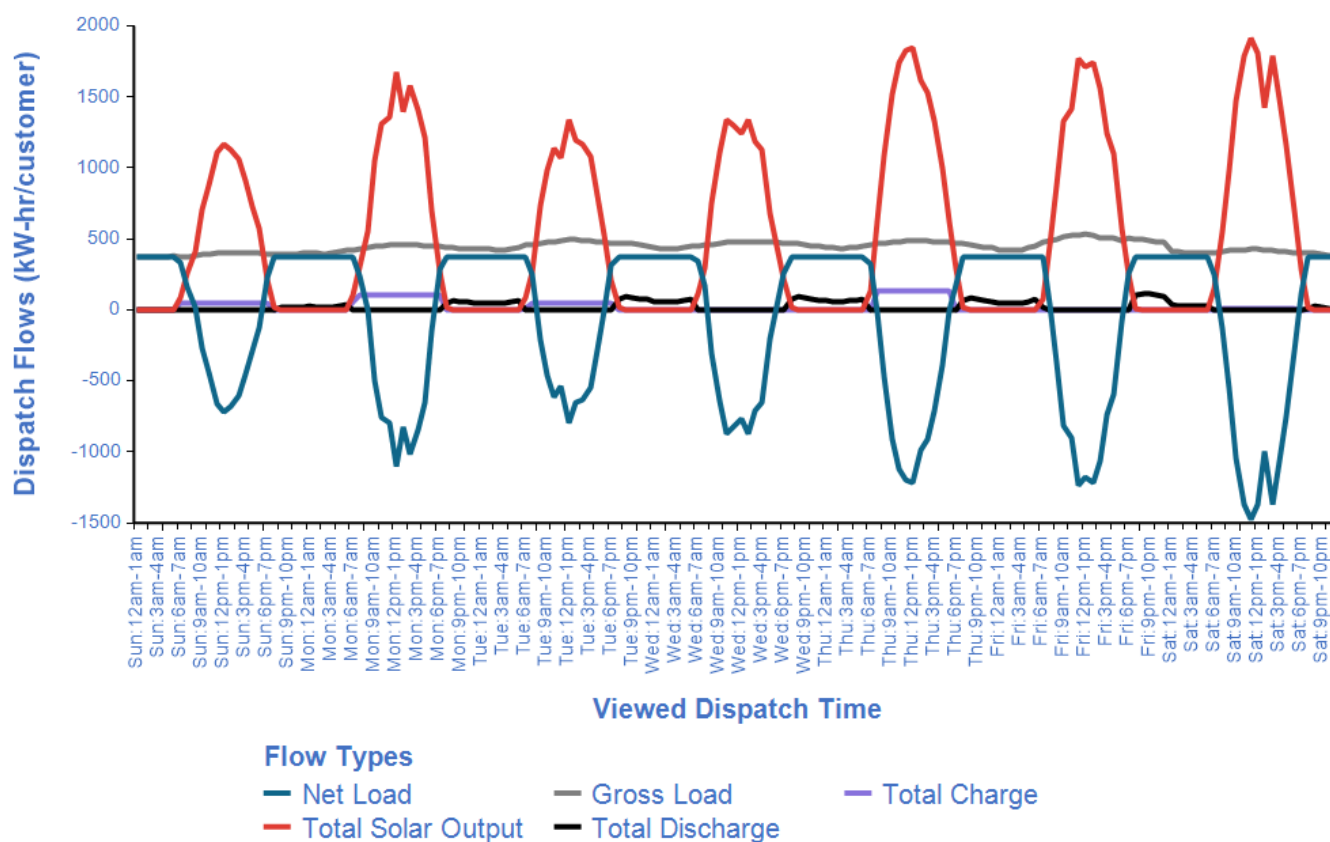


Figure 5-14 contains the results of expected grid impacts for DER technical potential as estimated by baseline consumption patterns, and optimal customer battery dispatch under current DEI rates.

**Figure 5-14: Grid Impact of Paired Storage Technical Potential**

Year	Residential				Commercial				Industrial			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2025	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.68	1.11	-23.85
2026	0	0	0	0	-0.04	-0.17	0	0	-2.91	-20.74	1.11	-23.93
2027	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.77	1.11	-23.98
2028	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.78	1.11	-23.99
2029	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.79	1.11	-24.01
2030	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2031	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2032	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.01
2033	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2034	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2035	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2036	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2037	0	0	0	0	-0.04	-0.17	0	0	-2.92	-20.8	1.11	-24.02
2038	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2039	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2040	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2041	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2042	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2043	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2044	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2045	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2046	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2047	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2048	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02
2049	0	0	0	0	-0.04	-0.18	0	0	-2.92	-20.8	1.11	-24.02

## 6. Economic Potential

Economic potential compares the expected costs and benefits of energy and demand savings provided by EE and DR measures and applies the utility cost test (UCT) to determine whether measures meet the scenario screening criterion of a benefit-cost ratio greater than 1. The economic potential is the sum of the energy savings associated with all measure permutations passing the economic screening.

The benefits of EE and DR measures under the UCT test represent avoided utility costs that result from energy and demand savings. These include avoided energy generation costs, avoided transmission and distribution costs, and avoided costs associated with lower peak capacity demands. The DEI system is a summer-planning system.

### 6.1. DR Cost-Effective Screening Criteria

RI applied the UCT test in this study, as directed by Duke Energy and stakeholders. The UCT is calculated by comparing the total avoided electricity production and delivery costs of a measure to the cost of offering that measure in a utility-sponsored program. The utility cost is the cost of offering incentives and program administrative costs. UCT screening requires inputs for measure incentive rates and utility administrative costs. Resource Innovations used actual program cost data from Duke Energy's 2023 program cycle.

For EE screening, the UCT test is applied to each energy efficiency measure based on installation of the measure in the first year of the study (i.e., avoided cost benefits begin in year one and extend through the useful life of the measure; incremental costs are incurred in year one). By using DSM outputs for lifetime avoided cost benefits, the screening aligns with Duke Energy's avoided cost forecast and allows for a direct comparison of measure costs with these avoided cost benefits. The screening included measures with a UCT ratio of 1.0 or higher for determining economic potential.

For this analysis, the non-incentive and incentive costs for each sector is detailed in [Table 6-1](#). These values are based on the actual DR program spending from Duke Energy and represent reasonable cost estimates in today's dollars with current technology.

**Table 6-1: Utility Costs for DR Measure Screening**

Sector	Measure	Recruitment Incentive	Utility Costs on Equip & Install	Acquisition Marketing	Recurring Incentive	5 Year Recurring Capital Expenditure	Admin Recurring Cost	Maintenance Marketing	Based on Existing Duke Program
Residential	Central air conditioner - 75% cycling	\$35.00	\$303.59	\$123.50	\$10.00	\$3.79	\$28.26	\$11.20	Yes
	Central Heating - Load Shed								Yes
	Central air conditioner - 66% cycling	\$25.00	\$303.59	\$123.50	\$7.50	\$3.79	\$28.26	\$11.20	Yes
	Central Heating - 50% cycling								Yes
	Water heater switches	\$5.00	\$277.22	\$93.02	\$6.00	\$3.47	\$19.61	\$1.85	Yes
	Pool pump switches								No
	Room AC control	\$25.00	\$277.22	\$0.00	\$7.50	\$3.47	\$28.26	\$11.20	No
	Smart thermostats - Utility Installation	\$0.00	\$334.00	\$47.28	\$25.00	\$4.18	\$42.63	\$0.45	Yes
	Smart thermostats - BYOT	\$75.00	\$0.00	\$2.09	\$25.00	\$0.00	\$42.63	\$0.45	Yes
	CPP + Tech	\$0.00	\$334.00	\$144.00	\$50.00	\$4.18	\$42.63	\$0.45	No
	EV Charging (telematics)	\$0.00	\$0.00	\$0.00	\$50.00	\$0.00	\$0.00	\$11.20	No
	EV Charging (external switch)	\$0.00	\$258.00	\$0.00	\$50.00	\$3.23	\$28.26	\$11.20	No
	Solar PV	\$3,600.00	\$0.00	\$47.28	\$0.00	\$0.00	\$28.26	\$11.20	No
	Paired Battery Storage	\$0.00	\$0.00	\$50.00	\$325.73	\$0.00	\$100.00	\$11.20	No
Small C&I	Central Air Conditioner	\$90.00	\$185.00	\$145.00	\$86.00	\$2.31	\$72.00	\$0.00	Yes
	Central Heating								No
	Water Heating (Switches)								No
	Smart thermostats - Utility Installation	\$90.00	\$175.00	\$145.00	\$86.00	\$2.19	\$72.00	\$0.00	No
	Smart thermostats - BYOT	\$90.00	\$0.00	\$145.00	\$86.00	\$0.00	\$72.00	\$0.00	No
	CPP + Tech	\$0.00	\$175.00	\$145.00	\$86.00	\$2.19	\$72.00	\$0.00	No
	EV Charging (telematics)	\$0.00	\$175.00	\$0.00	\$86.00	\$2.19	\$72.00	\$0.00	No
	EV Charging (external switch)								No
	Solar PV	\$0.00	\$2,500.00	\$100.00	\$0.00	\$31.25	\$72.00	\$0.00	No
	Battery Storage	\$0.00	\$0.00	\$100.00	\$2,335.96	\$0.00	\$100.00	\$0.00	No
Large C&I	Auto DR	\$0.00	\$738.00	\$145.00	\$147.82	\$9.23	\$246.56	\$0.00	No
	Contractual Load Curtailment	\$0.00	\$370.00	\$145.00	\$147.82	\$4.63	\$246.56	\$0.00	No
	EV Charging (telematics)	\$0.00	\$175.00	\$145.00	\$86.00	\$2.19	\$72.00	\$0.00	No
	EV Charging (external switch)								No
	Paired Battery Storage	\$0.00	\$0.00	\$145.00	\$0.00	\$0.00	\$100.00	\$0.00	No

The cost of enrolling customers from each customer segment is compared to the marginal benefits provided by enrolling customers in that segment. Because DR programs are called relatively infrequently, very little benefit is derived from avoided energy costs to the point where they are insignificant. Instead, DR derives its value from avoided generation capacity and avoided



transmission and distribution capacity. RI also assumes an attrition rate of 7.5% annually with a measure life of 15 years.

## 6.2. DEI Energy Efficiency Economic Potential

This section provides the results of the DEI energy efficiency economic potential for each of the three sectors.

### 6.2.1. Summary

Table 6-2 summarizes the DEI's cumulative energy efficiency economic potential by sector and levelized cost associated with the identified potential:

**Table 6-2: DEI EE Cumulative Economic Potential by Sector**

Sector	Economic Potential (2025-2049)					
	Energy (GWh)	% of 2025 Base Sales	Demand (MW)			
			Spring	Summer	Fall	Winter
Residential	2,686	28%	812	839	718	410
Commercial	1,101	18%	339	334	336	169
Industrial	1,469	14%	194	194	194	172
<b>Total</b>	<b>5,255</b>	<b>20%</b>	<b>1,345</b>	<b>1,367</b>	<b>1,247</b>	<b>752</b>

### 6.2.2. Sector Details

Figure 6-1 summarizes the DEI residential sector energy cumulative efficiency economic potential by end use.

Figure 6-1: DEI Residential EE Economic Potential – Cumulative 2049 by End-Use

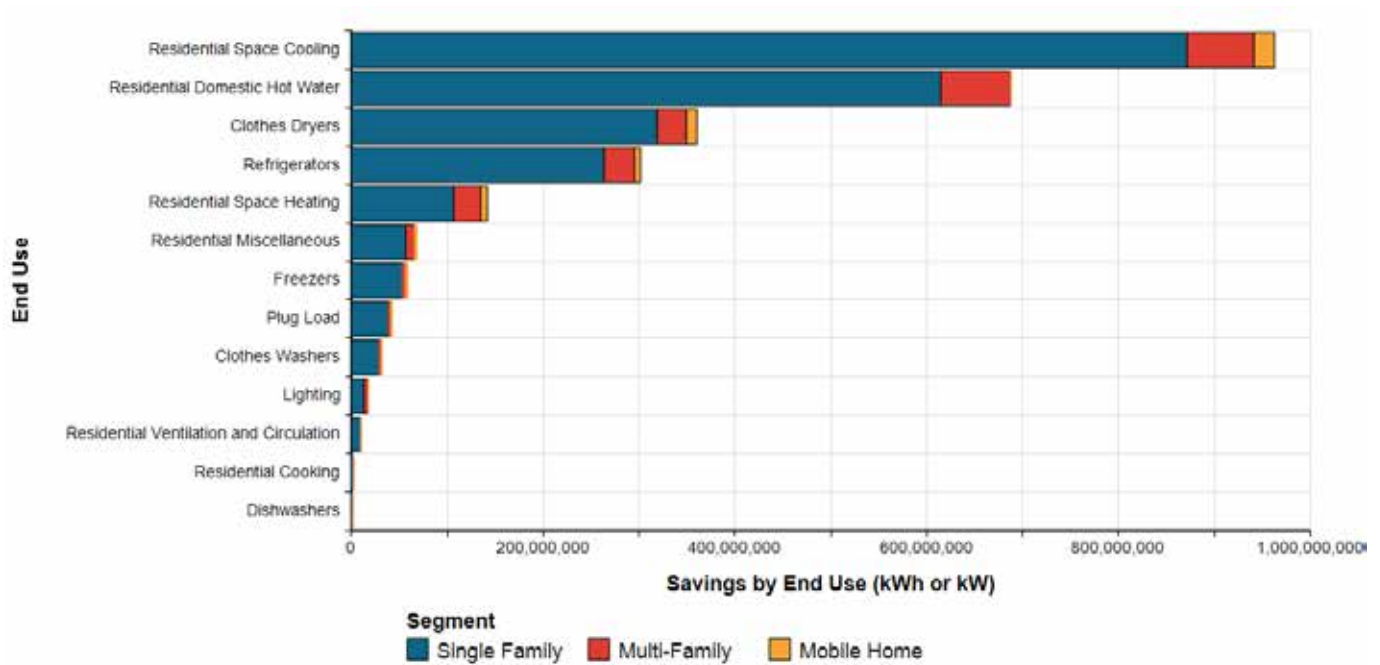


Figure 6-2 summarizes the DEI commercial sector EE economic potential by end use.

Figure 6-2: DEI Commercial EE Economic Potential – Cumulative 2049 by End-Use

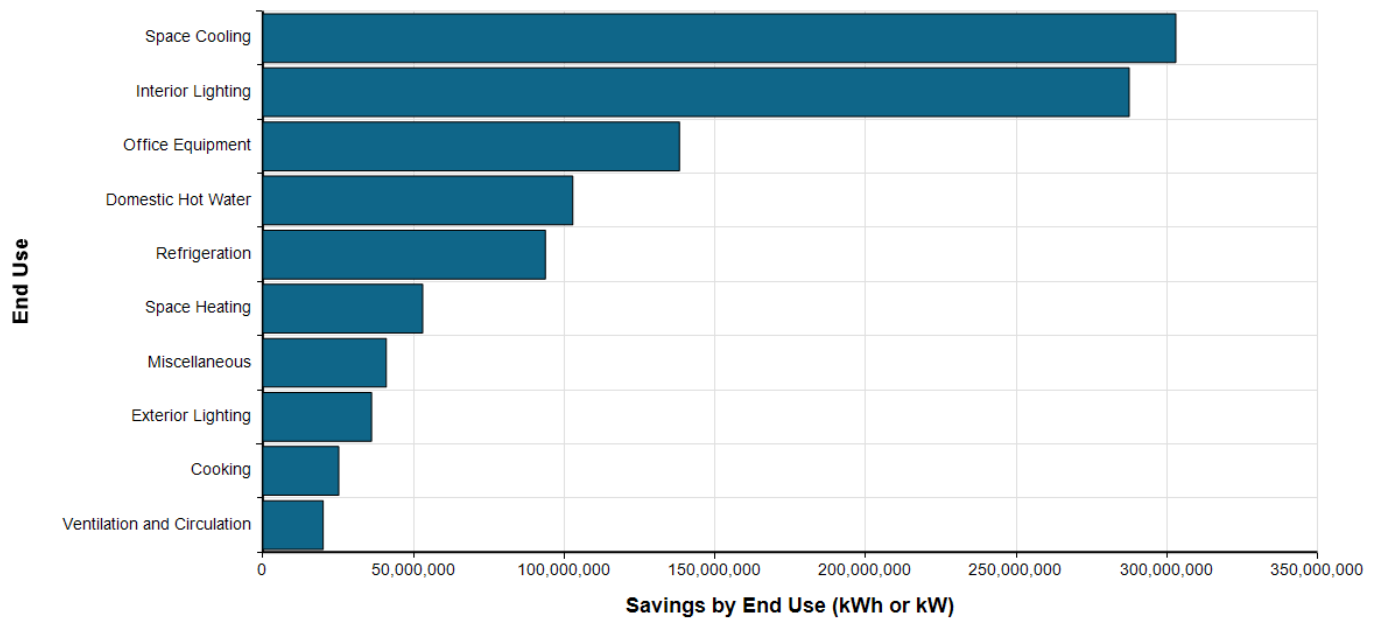


Figure 6-3 provides a summary of DEI energy efficiency economic potential contributions by commercial facility types analyzed in this study.

**Figure 6-3: DEI Commercial EE Economic Potential – Cumulative 2049 by Segment**

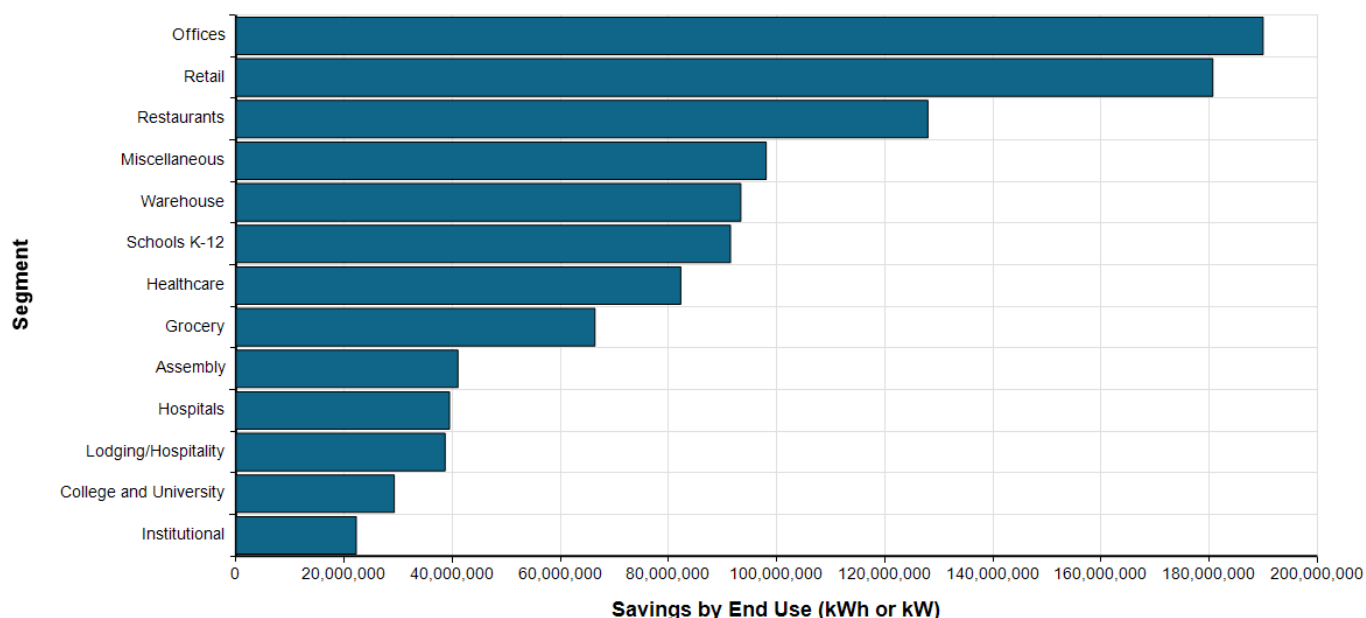


Figure 6-4 summarizes the DEI industrial sector energy efficiency economic potential by end use.

**Figure 6-4: DEI Industrial EE Economic Potential – Cumulative 2049 by End-Use**

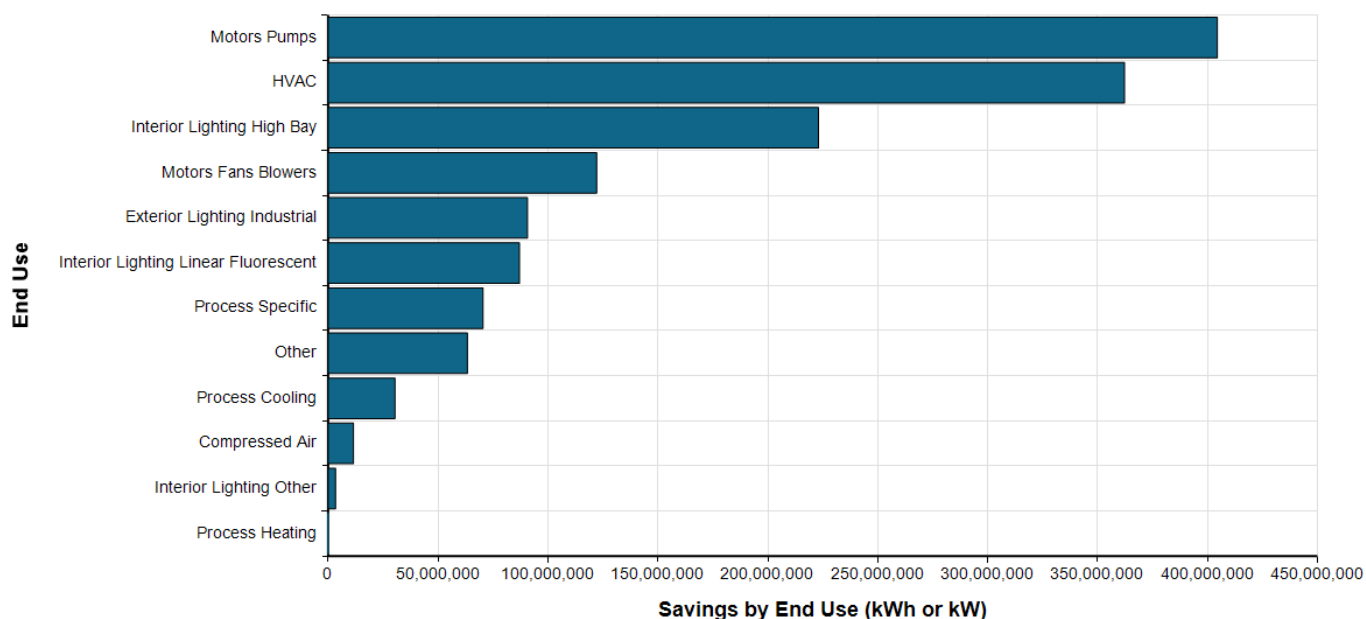
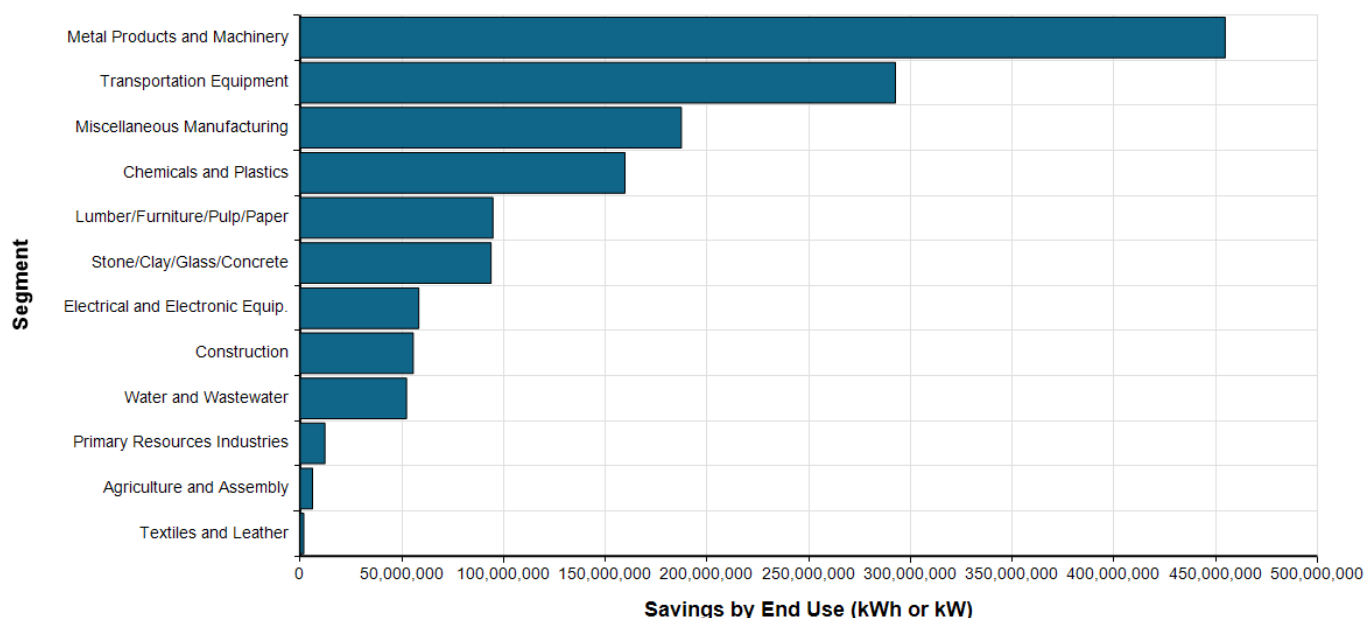


Figure 6-5 provides a summary of DEI energy efficiency economic potential contributions by industrial facility types analyzed in this study.

**Figure 6-5: DEI Industrial EE Economic Potential – Cumulative 2049 by Segment**



### 6.3. DEI Demand Response Economic Potential

DR cost-effectiveness screening for economic potential determines whether the benefits of enrolling a marginal customer for a given customer segment into a demand response program will outweigh the costs. This study uses UCT as screening criteria that considers program administrative and incentive costs. Since economic potential ignores the participation rate in the program (this is considered when determining the achievable potential), cost-effectiveness screening at this point only considers whether a marginal customer for a given customer segment is worth pursuing for participation in the program.

Each measure was screened using a “100% summer” avoided capacity forecast, as well as a seasonal avoided capacity forecast. The larger of these two avoided capacity values were then used as the final avoided cost for economic screening. [Table 6-3](#) shows the economic potential by sector and season.

**Table 6-3: DEI DR Economic Potential by Sector**

Sector	Savings Potential			
	Summer (Agg MW)	Winter (Agg MW)	Fall (Agg MW)	Spring (Agg MW)
Residential	1,369	1,571	1,526	1,494
SMB	119	51	153	160
Large C&I	2,513	1,893	2,312	2,317
<b>Total</b>	<b>4,002</b>	<b>3,514</b>	<b>3,991</b>	<b>3,970</b>

Figure 6-6 presents the aggregate capacity each customer segment would be able to provide during the four seasonal peaks. Most of these customer segments produced a positive marginal net benefit, indicating that there is substantial, cost-effective DR potential available in DEI's territory. Similar figures are presented subsequently for SMB and LCI customers in Figure 6-7 and Figure 6-8, respectively. Any seasonal data missing from these graphs indicate a economic potential value of zero.

Figure 6-6: DEI Seasonal Residential Economic DR Potential (MW)

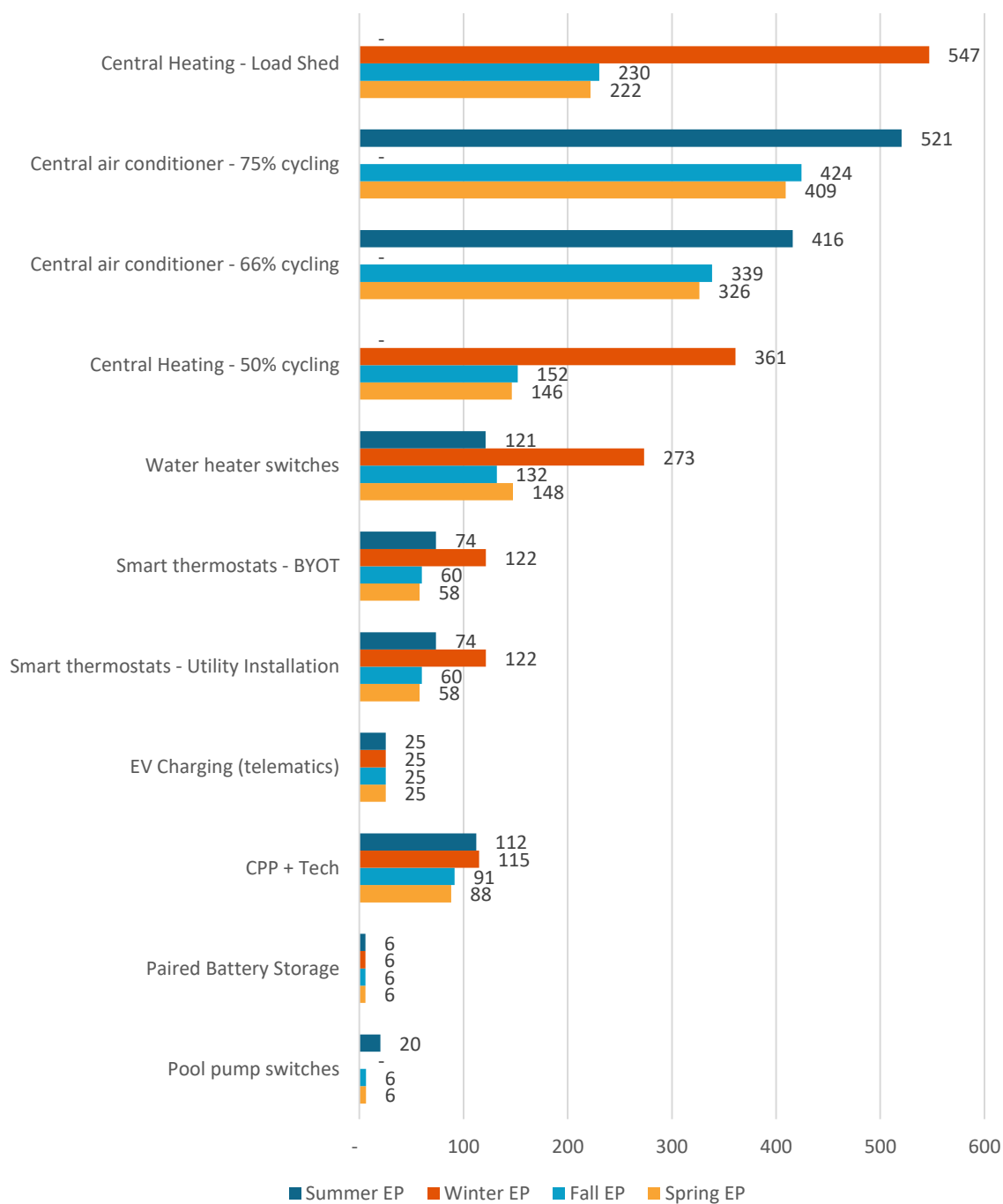




Figure 6-7: DEI SMB Economic Potential Results (MW)

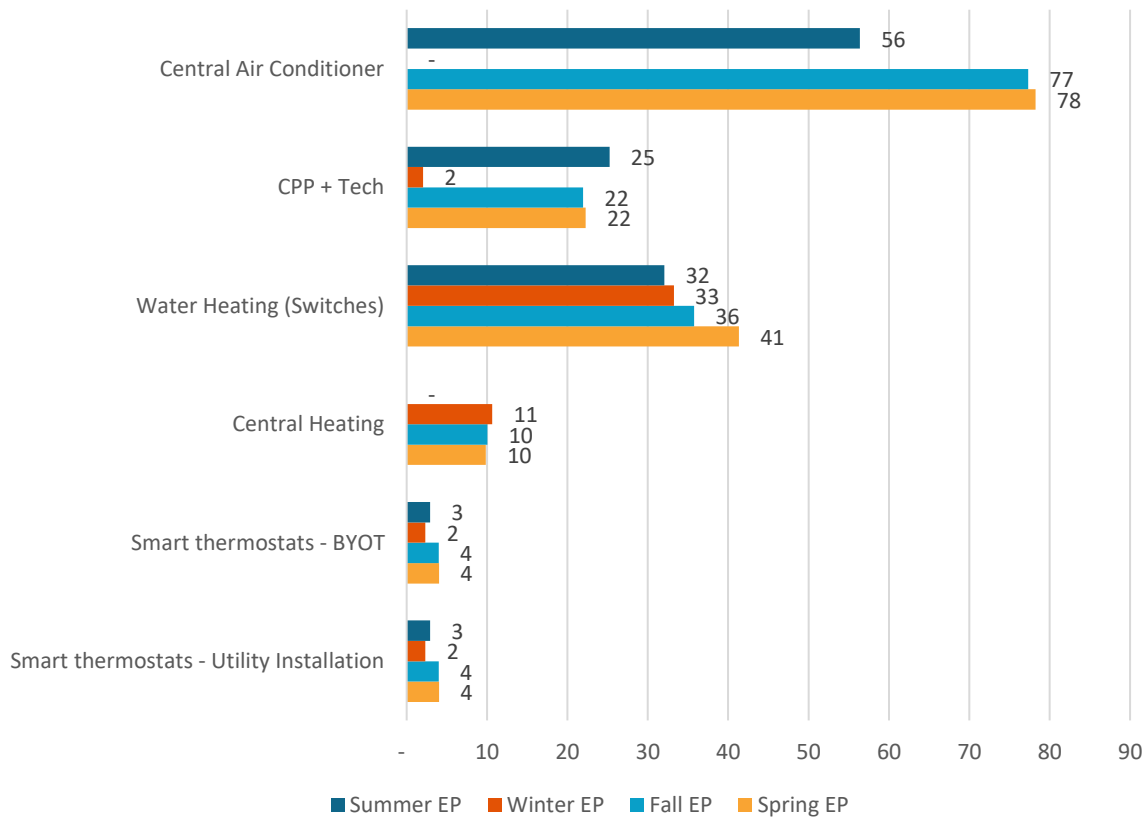
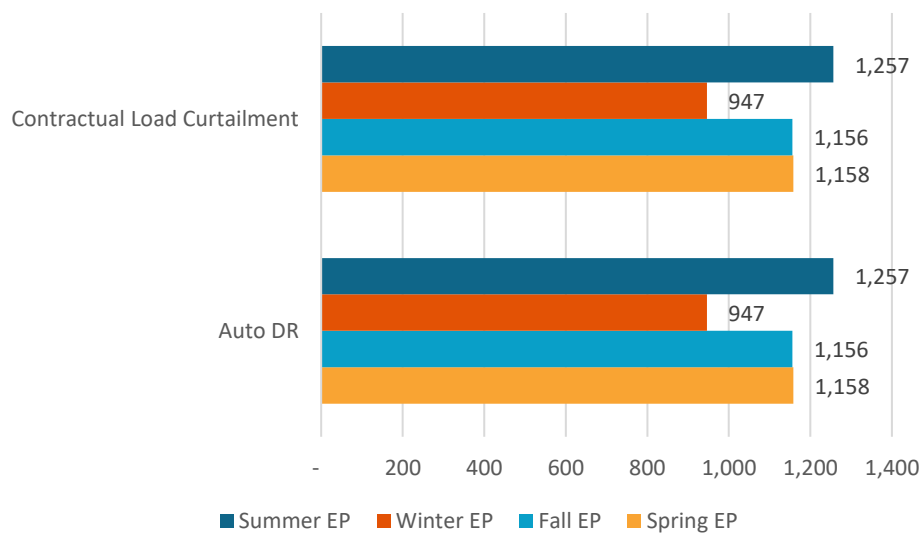


Figure 6-8: DEI Large C&I Economic Potential Results (MW)



## 6.4. Distributed Energy Resources

Economic potential compares the expected costs and benefits of energy and demand savings provided by solar systems and applies the utility cost test (UCT) to determine whether they meet the scenario screening criterion of a benefit-cost ratio greater than 1.

For this analysis, the incentives and administrative costs for each sector is detailed in [Table 6-4](#), with other cost assumptions for the PV technology. These values represent reasonable cost estimates in today's dollars with current technology. As indicated below, solar with paired storage does not pass the UCT cost test when customers are assumed to dispatch optimally under current loads and rate schedules. This analysis does not account for the effects of a possible demand response program for existing batteries. The solar and paired storage forecast of nameplate capacity was analyzed by RI to estimate the impact of demand response incentives on expected program participation. This analysis is a component of the demand response potential estimates, whereas this section focuses on forecasted customer adoption and grid impacts at baseline.

**Table 6-4: Key Assumptions for PV Economic Potential**

Data Item	Res	Comm	Ind	Units	Source/Notes
<b>PV Lifetime</b>	20	20	20	Years	NREL
<b>PV Cost</b>	3,072	2,184	2,184	\$/kW-DC	NREL, RI, DEI (\$2025), assuming 1.15 DC/AC Ratio. Forecast cost declines
<b>PV O&amp;M Cost</b>	21	15	15	\$/year/kW-DC	NREL (\$2025). Forecast cost declines
<b>PV Utility Cost Test</b>	1.14	1.53	1.53	dimensionless	In 2025, Assuming incentive of 30% of purchase price, 5% admin as % of incentives
<b>Storage Lifetime</b>	10	10	10	Years	NREL
<b>Storage Cost</b>	813	347	347	\$/kWh	NREL (\$2025) Assuming 3 hours of storage at peak capacity. Forecast cost declines.
<b>Storage O&amp;M</b>	20	8	8	\$/Year/kWh	NREL
<b>Storage Utility Cost Test</b>	0.0	0.0	0.0	dimensionless	Assuming dispatched economically by customer (this does not account for full dispatch per a possible Demand Response program, which is being analyzed separately)

## 7. Achievable Market Potential

Achievable market potential estimates customer adoption rates for cost-effective measures in a market featuring utility-sponsored programs. In this MPS RI developed customer adoption rates that are independent of historic Duke Energy program participation trends. These were calibrated to start 2023 Duke Energy program performance, but future adoption of measures cost-effectively offered by Duke Energy programs is driven by customer payback. Customer payback describes the number of years required for a customer to save an amount of energy equal to the value of measure first costs (minus incentive payments from utility programs). Utility-sponsored programs are typically focused on addressing market barriers and thereby boosting customer adoption of energy efficiency.

Customers may forego cost-effective EE and DR for a variety of reasons, some of which may include customer preferences for benefits arising from other types of investments; time and effort required to engage with program administration or to satisfy program requirements; high initial costs, lack of time to identify, evaluate, acquire, and install new measures; long investment payback times; payback uncertainty; or even for the inconvenience. Customers may need to overcome non-economic barriers such as: lack of knowledge about electricity consumption and associated technology; principal-agent issues, a.k.a. “split incentive,” problems; inability to capture non-market benefits; or economic conditions that potentially limit availability of some measures, increase measure costs, or affect customers’ incomes. In addition to these economic tradeoffs and market barriers, economic research increasingly demonstrates the strong role that human behavior plays in purchase decisions.

The EE/DR program lifecycle is designed explicitly to address the need for adaptive management of utility programs and to continuously improve program performance against market barriers. It also engages stakeholders to collaborate with utilities around program iterations and offer ideas from outside perspectives. The scope of this MPS does not include program design, as Duke Energy has been offering EE and DR programs for over a decade and has consistently followed the adaptive management principles of the EE/DR program lifecycle: market assessment, program design, program implementation, program evaluation, and adaptation. This study represents the market assessment component of this adaptive management cycle.

### 7.1. Customer Adoption

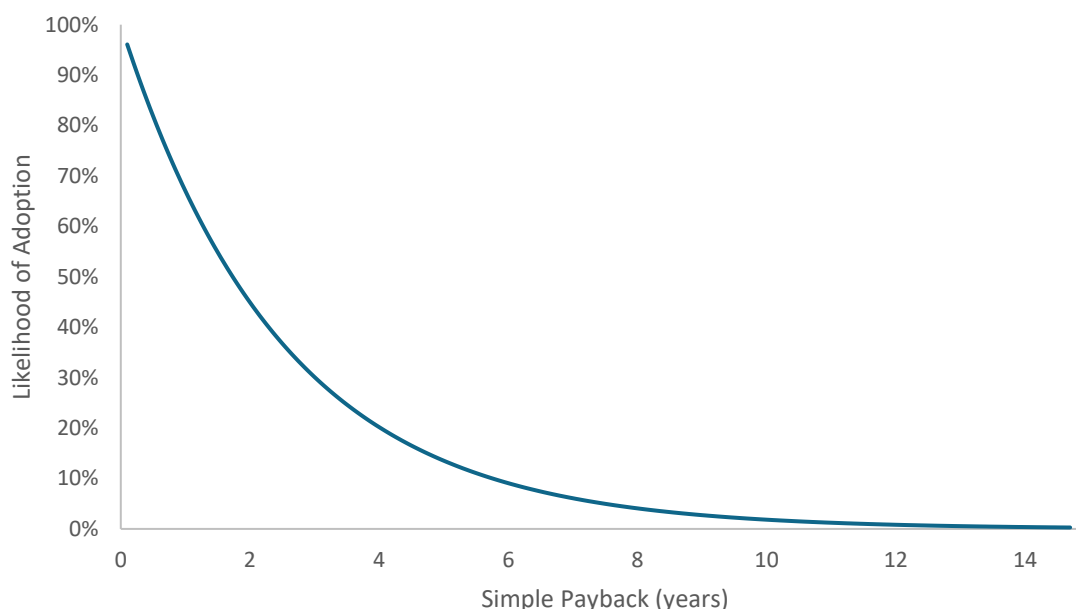
Duke Energy programs follow the EE/DR lifecycle of market analysis, program design, program implementation, program evaluations, stakeholder engagement, and adaptation. As the result of the EE/DR lifecycle process and the efforts of Duke Energy, stakeholders, and customers to erode market barriers, RI developed market adoption curves that reflect assumptions for the influence of DR bill savings on customer adoption rates.

We apply customer payback acceptance curves to all cost-effective measures, which addresses one major market barrier: time preferences for money. Customers value immediate monetary savings much more than future savings, whether due to economic or behavioral factors. Additional barriers may exist, they may lead to lower-than-expected adoption rates, and payback acceptance curves may not fully describe the impacts of market barriers. The magnitude or degree of influence market barriers currently exert in the Indiana service territory is not readily measured by existing data,

though EM&V reports describe ongoing efforts to cost-effectively identify and address them though the EE/DR lifecycle.

The payback acceptance function that was applied is presented below in [Figure 7-1](#). This function relates measures' simple payback time, in years, to the likelihood of the measure being adopted by a typical customer. At one year payback 67% of customers are estimated to adopt the measure; 45% would adopt at payback of two years, 30% would adopt at payback of three years, and adoption likelihood drops to 14% or lower after five or more years.

**Figure 7-1: Payback Acceptance Curve for Achievable Potential**



We used the customer payback acceptance curve to represent the ideal case of well-informed, rational customer decisions with low transaction costs. Owing to these MPS parameters and focus, we describe our estimates as expected EE and DR potential in a market featuring utility-sponsored programs and incentives. The estimates assume adaptive program management is applied to successfully lower market and non-market barriers to customer adoption over time; the customer payback acceptance approach addresses only the barriers of investment costs and opportunity costs.

## 7.2. Achievable Market Potential Scenarios

The achievable market potential scenarios reflect customer adoption of measures that are cost-effective for Duke Energy to offer within an existing program. Customer adoption rates are independent of the program design, as previously described, except for reducing customer first costs by the utility incentive amount. The three scenarios developed for this study are as follows:

- **Base** – reflects current Duke Energy programs and program costs, incentive rates, and utility avoided cost benefits generated by the program.
- **High Incentive** – doubles current incentive rates, if not already 100%, with a cap at 75% of the measure incremental cost; applies utility avoided cost benefits from the base scenario. The model also includes an incentive backstop that limits the incentive increase to the maximum in this range if the increase would otherwise lead to a measure being not cost-effective.
- **High Avoided Costs** – increases utility avoided cost benefits by 50%, uses base scenario incentive rates.

### 7.3. Market Diffusion

Achievable market potential describes a subset of customers expected to take advantage of Duke Energy EE and DR programs. Data concerning individual customer purchases of EE and DR equipment are not widely available and may be sparse in their coverage of EE and DR measure opportunities. EPA's ENERGY STAR program estimates the market penetration of certified products, and EIA's periodic market assessments provide the primary basis for understanding current market penetration of EE technology.

In addition to these sources, Duke Energy conducts residential appliance saturation surveys (RASS) to better understand the energy consumption of residential customers in the Duke Energy service territory. Commercial and industrial building and equipment baselines are limited to the modeling and analysis available from EIA, Duke Energy forecasting, and Duke Energy customer data.

We apply the Bass diffusion model to estimate technology market penetration from customer adoptions over time. The Bass model is a widely accepted description of how new products and innovations spread through an economy over time. It was originally published in 1969, and in 2004 was voted one of the top 10 most influential papers published in the 50-year history of the peer-reviewed publication *Management Science*<sup>4</sup>. More recent publications by Lawrence Berkeley National Laboratories have illustrated the application of this model to conservation and demand management (CDM) in the energy industry<sup>5</sup>.

RI applied general technology diffusion curves describing expected market familiarity with EE and DR measures, which will be enhanced by the ongoing efforts of Duke Energy and stakeholders. The curves represent effective program marketing and sophisticated customer recruitment of cost-effective measures that meet customer payback acceptance criteria.

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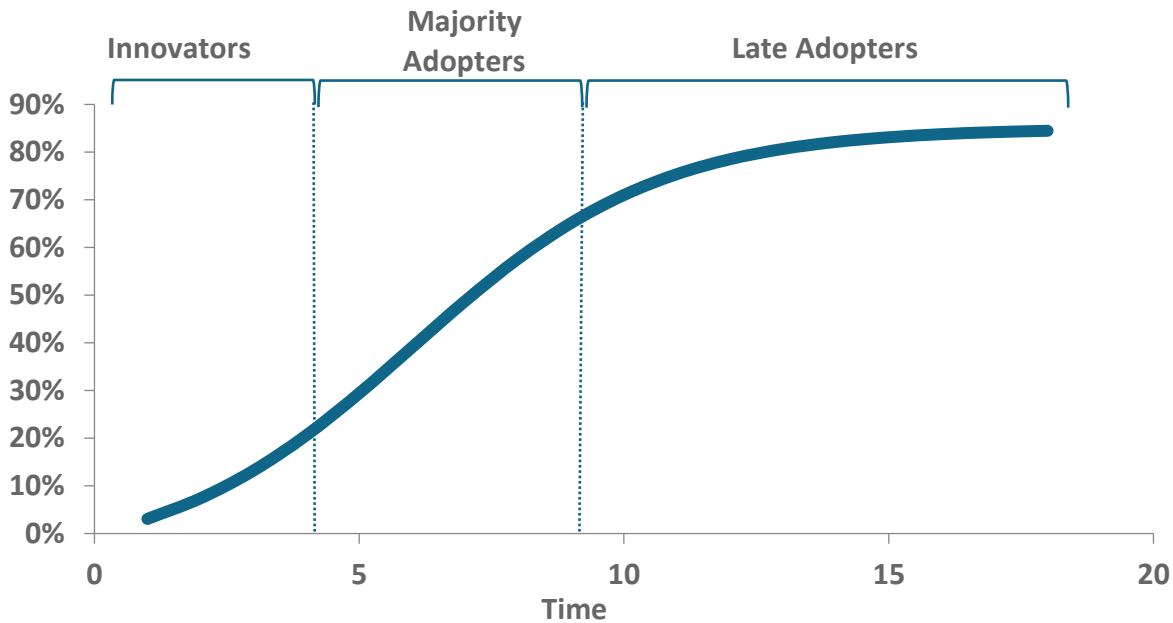
<sup>4</sup> Bass, F. 2004. Comments on "A New Product Growth for Model Consumer Durables the Bass Model" (sic). *Management Science* 50 (12\_supplement): 1833-1840.

<http://pubsonline.informs.org/doi/abs/10.1287/mnsc.1040.0300>. Accessed 01/08/2016.

<sup>5</sup> Buskirk, R. 2014. Estimating Energy Efficiency Technology Adoption Curve Elasticity with Respect to Government and Utility Deployment Program Indicators. LBNL Paper 6542E. Sustainable Energy Systems Group, Environmental Energy Technologies Division. Ernest Orlando Lawrence Berkeley National Laboratory. <http://escholarship.org/uc/item/2vp2b7cm#page-1>. Accessed 01/14/2016.

According to product diffusion theory, the rate of market adoption for a product changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of cumulative market saturation is illustrated in Figure 7-2.

Figure 7-2: Bass Model Cumulative Market Penetration



The Bass Diffusion model is a mathematical description of how the rate of new product diffusion in a market changes over time. Figure 1 depicts the cumulative market adoption with respect to time,  $S(t)$ . The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters. The following equation describes this relationship:

$$\frac{dS(t)}{dt} = \left( p + \frac{q}{m} * S(t-1) \right) * (m - S(t-1))$$

Where:

$\frac{dS(t)}{dt}$  = the rate of adoption for any discrete time period,  $t$

$p$  = external influences on market adoption

$q$  = internal influences on market adoption

$m$  = the maximum market share for the product



$S(t - 1)$  = the cumulative market share of the product, from product introduction to time period  $t-1$

Marketing is the quintessential external influence. The internal influences are characteristics of the product and market; for example: the underlying market demand for the product, word of mouth, product features, market structure, and other factors that determine the product's market performance. RI's approach applied literature reviews and analysis of secondary data sources to estimate the Bass model parameters. We then extrapolated the model to future years; the historic participation and predicted future market evolution serve as the program adoption curve applied to each proposed offering.

## 7.4. DR Achievable Market Potential

Duke Energy offered DR programs for over 10 years, covering a variety of approaches for load management such as direct utility control; contractual programs for guaranteed load drop and emergency load management; and load control programs that incentivize economic load response. These offer types are described in [Table 7-1](#).

**Table 7-1: DR Technologies covered by Duke Energy Programs**

Type of DR	Sector	Technology
Utility controlled loads	Residential	<ul style="list-style-type: none"> <li>Central AC switches</li> <li>Smart thermostat</li> <li>Water heater switches</li> </ul>
	Non-Residential	<ul style="list-style-type: none"> <li>HVAC controls (EMS)</li> <li>Smart thermostat</li> <li>Auto DR for process loads</li> <li>Backup generation</li> </ul>
Contractual	Non-Residential	<ul style="list-style-type: none"> <li>Emergency Load Response</li> <li>Economic Load Response</li> </ul>

### 7.4.1. Participation Rates for DR Programs

While economic potential examines marginal net benefits provided by customers, achievable program potential considers the estimated participation rate and how that affects the overall cost-effectiveness of the customer segment. The magnitude of DR resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), and how programs are marketed. How predisposed are specific customers to participate in DR? What are details of specific offers and how do they influence enrollment rates? What is the level of marketing intensity and what marketing tactics are employed?

For certain DR measures, an additional component of participation relates to the mutual exclusivity of the measures themselves. The achievable potential from measures under the same program, and that target the same customers, are reduced by one another. A customer who enrolls his/her central air-conditioner in a 66% shed load control offering cannot also enroll in the 75% shed offering. To account for the mutual exclusivity of specific measures, the study applied an adjustment to the numbers of eligible customers based on the known distribution of the population under existing programs.

For program-based DR, participation rates are calculated as a function of the incentives offered to each customer group. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DR potential from that segment should be included in the achievable program potential. The following subsections describe how marketing/incentive level, participation rates, and technology costs are handled by this study.

#### 7.4.2. Marketing and Incentive Levels for Programs

Several underlying assumptions are used to define three different marketing levels. The number of marketing attempts and the method of outreach are varied by marketing level, as described in [Table 7-2](#). The enhanced case assumes a high marketing level for program-based DR, while the base case assumes a medium marketing level (the low marketing level was not utilized for this study). Within each marketing level, the participation rate for each customer segment is a function of the incentive level.

The specific tactics included in the low, medium, and high marketing scenarios are not prescriptive but are instead designed to provide concrete details about the assumptions used in the study. There is a wide range of strategies and tactics that can attain the same enrollment levels and the best approach for a jurisdiction is best developed through testing and optimizing the mix of marketing - tactics and incentives.

**Table 7-2: Marketing Inputs for Residential Program Enrollment Model**

Input	Marketing Level			
	No Marketing	Low	Medium	High
Number of marketing attempts (Direct mail)	0	5	5	8
Outreach mode	No marketing	Direct mail	DM + phone	DM + phone + door-to-door
Installation required (%)	0%	100%	100%	100%
Attrition Rate	7%	7%	7%	7%

The incentive level and marketing inputs for each scenario determine the participation rate, assuming that the incentive is uniform across all customer segments within a given customer class.

### 7.4.3. Participation Models

The participation models for the residential and nonresidential customer segments use a bottom-up approach to estimate participation rates. These estimates have been crosschecked with mature programs in other jurisdictions to ensure that the estimated participation rates are reasonable.

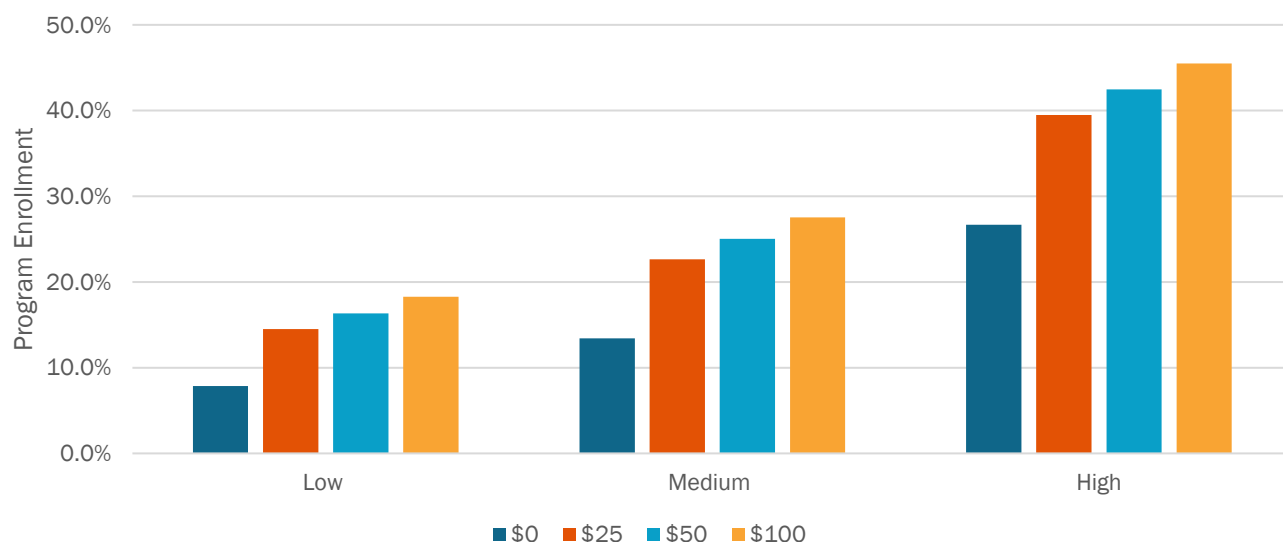
Many DR potential studies rely on top-down approaches which benchmark programs against enrollment rates that have been attained by mature programs. However, aggregated program results often do not provide enough detail to calibrate achievable program potential. In many cases, programs are not marketed to all customers, either because it is not cost-effective to market to all customers or budgets are capped by regulators. Enrollment rates are a function of specific offers and the extensiveness of marketing over many years. They also vary based on the degree to which DR resources are utilized and tend to be higher when payments are high but actual events are infrequent, particularly among large C&I customers.

The RI approach to estimate participation rates involves five steps. The initial step required some modification due available data:

- Estimate an econometric choice model based on who has and has not enrolled in DR programs. The goal is to estimate the pre-disposition or propensity of different customers to participate in DR based on their characteristics. Because micro-level acquisition marketing data were not provided, we relied on differences in participation rates by usage level. This information is based on prior micro-level analysis of program participation by RI.
- Incorporate information about how different offer characteristics influence enrollment likelihood. What is the incremental effect of incentives? How do requirements for on-site installation affect enrollment rates? The two questions above have been analyzed using mature market specific data for residential customers. In each case, regression coefficients describe the incremental effect of each of the above factors on participation rates. It is important to note that while this element of the participation model was derived using non-Duke Energy specific data, it is only being used to determine the incremental impact of additional incentives on participation (i.e., how does increasing the sign-up incentive increase participation in DR programs). The underlying assumption is that customers' response to incremental financial incentives is similar across various geographic regions. Finally, as will be described in subsequent steps, the final participation model is calibrated too, so the baseline level of enrollment reflects the DEI territory.
- Incorporate information about how marketing tactics and intensity of marketing influence participation rates. What is the effect of incremental acquisition attempts? Is there a bump in enrollment rates when phone and/or door-to-door recruitment is added to direct mail recruitment? This relies on data from side-by-side testing designed to explicitly quantify the effect of marketing tactics on enrollment rates.
- Calibrate the models to reflect actual enrollment rates attained by programs in DEI territory used for benchmarking.
- Predict participation rates using specific tactics and incentive levels for programs with and without installation requirements. The enrollment estimates were produced for low, medium, and high marketing levels, where specific marketing tactics are specified for each scenario. All estimates reflect enrollment rates for eligible customers.

As a demonstration of how marketing level and incentive affects participation in DR programs, [Figure 7-3](#) shows an example of how the range of participation rates for each marketing level varies at several different incentive levels.

**Figure 7-3: Example of Program Enrollment Under Different Marketing and Incentive Levels**



Other than residential water heaters, the predicted participation rates were applied to DR measures using the model's outputs as a function of the customer incentive, after calibrating for similar programs. Participation for residential water heaters was estimated as a percentage of the participation for AC cycling load control measures. The reason for this is both measures are currently offered by DEI under the same program, and customers must enroll their AC units to be eligible for enrolling their water heaters. Program data shows that approximately 12% of customers who enroll their ACs in demand response also enroll their water heaters.

#### 7.4.4. Scenario Analysis

Base and Enhanced scenarios were constructed for the DR potential analysis. Base and Enhanced scenarios assume different levels of customer incentive and marketing efforts/costs. The Base Scenario aligns with current Duke Energy offerings for measures covered by existing programs, and assumes conservative incentive and marketing for new measures, while the Enhanced Scenario assumes more aggressive expansion. Major assumptions for both scenarios are listed below:

##### Program Potential - Base

- Assume load control will target applicable, curtailable end uses, such as AC/heating loads, water heaters, pool pumps, etc.
- Include incentives for solar PV and paired battery storage
- Medium marketing level for DR programs

### Program Potential - Enhanced

- 50% higher incentives DR programs compared to current levels, resulting in larger participation
- Increase program marketing and outreach budgets (high marketing level)

## 7.5. DEI Energy Efficiency Program Potential

This section provides the results of the DEI EE achievable program potential for the portfolio, and the residential & non-residential sectors.

### 7.5.1. Summary

Table 7-3 and Table 7-4 summarize the short-term (5-year), medium (10-year) and long-term (25-year) DEI portfolio EE program potential for the base, high incentive, and the high avoided cost scenarios. Impacts are presented as both cumulative impacts and annual incremental impacts at each time step. The cumulative impact's view is important when using MPS results for resource planning purposes because it accounts for how the incremental addition of EE savings will impact the overall system load and load impacts likely to occur as measures reach the end of their useful lives. Annual impacts align with how utilities report their EE achievements in annual cost recovery filings.

**Table 7-3: DEI EE Program Potential – Energy Savings**

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	244,600	214,301	200,437
High Incentive	Annual Incremental Energy (MWh)	277,521	251,706	231,005
High Avoided Cost	Annual Incremental Energy (MWh)	254,363	216,096	200,812
Base	Cumulative Energy (MWh)	820,509	1,577,248	1,703,116
High Incentive	Cumulative Energy (MWh)	963,366	1,874,902	2,188,708
High Avoided Cost	Cumulative Energy (MWh)	858,177	1,653,518	1,742,073

**Table 7-4: DEI EE Program Potential – Demand Savings**

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	48	42	42
High Incentive	Annual Incremental Spring Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	49	42	42
Base	Annual Incremental Summer Peak Demand (MW)	47	41	42
High Incentive	Annual Incremental Summer Peak Demand (MW)	58	50	49
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	49	42	42
Base	Annual Incremental Fall Peak Demand (MW)	44	38	38
High Incentive	Annual Incremental Fall Peak Demand (MW)	53	46	45
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	45	39	39
Base	Annual Incremental Winter Peak Demand (MW)	55	44	39
High Incentive	Annual Incremental Winter Peak Demand (MW)	58	51	43
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	57	44	39
Base	Cumulative Spring Peak Demand (MW)	156	307	347
High Incentive	Cumulative Spring Peak Demand (MW)	201	401	476
High Avoided Cost	Cumulative Spring Peak Demand (MW)	162	319	353
Base	Cumulative Summer Peak Demand (MW)	155	304	344
High Incentive	Cumulative Summer Peak Demand (MW)	201	402	475
High Avoided Cost	Cumulative Summer Peak Demand (MW)	159	314	349
Base	Cumulative Fall Peak Demand (MW)	144	283	322
High Incentive	Cumulative Fall Peak Demand (MW)	185	369	440
High Avoided Cost	Cumulative Fall Peak Demand (MW)	149	293	327
Base	Cumulative Winter Peak Demand (MW)	176	335	326
High Incentive	Cumulative Winter Peak Demand (MW)	190	367	401
High Avoided Cost	Cumulative Winter Peak Demand (MW)	183	350	335

We assigned measures to Duke Energy programs for all achievable market potential scenarios; programs apply to either residential or non-residential customers, so we will combine the commercial and industrial economic sectors in subsequent reporting. Participant and program costs associated with achievable program potential scenarios include the following:

- **Program incentives:** Financial incentives paid by energy-efficiency programs to subsidize purchases of energy-efficiency measures.
- **Program administration costs:** Administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy-efficiency savings.
- **Total program acquisition costs:** Total incentive and non-incentive program costs per sum of annual incremental energy savings achieved.
- **Participant costs:** Incremental costs to purchase, install, and maintain energy-efficiency measures, less utility incentives.



Table 7-5 lists estimated participant and program costs associated with the theoretically achievable scenarios over the first 5 program years.

**Table 7-5: DEI Participation and Program Costs by Scenario (cumulative through 2029)**

Scenario	Program Sector	Program Incentives (\$M)	Program Admin (\$M)	Participant Costs (\$M)	Levelized Cost (\$/kWh)
Base	Residential	\$118.47	\$85.53	\$269.17	\$0.12
Base	Non-Residential	\$24.93	\$27.26	\$58.17	\$0.03
Base	Total	\$143.41	\$112.80	\$327.34	\$0.08
High Incentive	Residential	\$330.95	\$96.68	\$210.65	\$0.22
High Incentive	Non-Residential	\$72.57	\$33.16	\$48.38	\$0.05
High Incentive	Total	\$403.53	\$129.84	\$259.03	\$0.14
High Avoided Cost	Residential	\$171.46	\$93.90	\$392.01	\$0.14
High Avoided Cost	Non-Residential	\$25.03	\$27.29	\$58.40	\$0.03
High Avoided Cost	Total	\$196.48	\$121.20	\$450.41	\$0.11

## 7.5.2. Residential Program Details

Table 7-6 and Table 7-7 summarize the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base, high incentive, and high avoided cost scenarios. Impacts are presented as both cumulative impacts and annual incremental impacts over the stated time horizon (5 years, 10 years, or 25 years):

**Table 7-6: EE Residential Program Potential – Energy Savings**

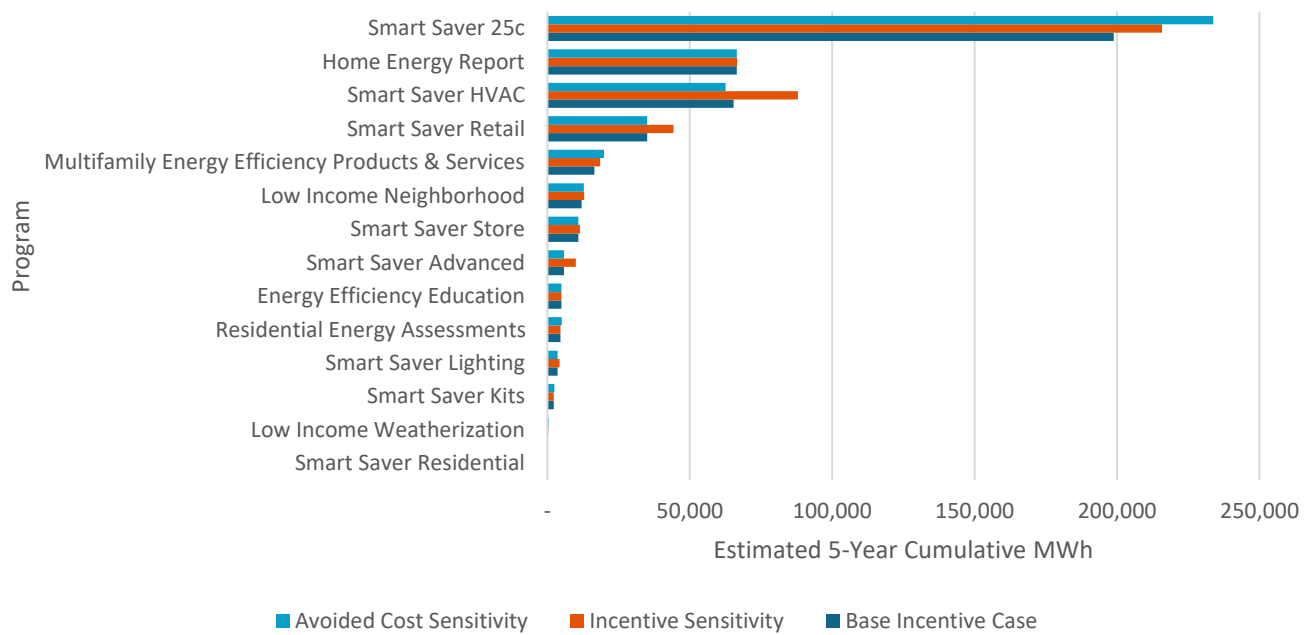
Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	156,108	123,487	129,120
High Incentive	Annual Incremental Energy (MWh)	170,154	141,569	143,233
High Avoided Cost	Annual Incremental Energy (MWh)	165,782	125,192	129,446
Base	Cumulative Energy (MWh)	426,633	813,778	853,847
High Incentive	Cumulative Energy (MWh)	483,907	941,143	1,120,630
High Avoided Cost	Cumulative Energy (MWh)	463,964	889,582	892,462

**Table 7-7: EE Residential Program Potential – Demand Savings**

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	32	25	28
High Incentive	Annual Incremental Spring Peak Demand (MW)	38	29	32
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	33	25	28
Base	Annual Incremental Summer Peak Demand (MW)	32	25	28
High Incentive	Annual Incremental Summer Peak Demand (MW)	39	30	32
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	33	25	28
Base	Annual Incremental Fall Peak Demand (MW)	28	22	25
High Incentive	Annual Incremental Fall Peak Demand (MW)	34	26	28
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	29	22	25
Base	Annual Incremental Winter Peak Demand (MW)	43	31	29
High Incentive	Annual Incremental Winter Peak Demand (MW)	43	35	31
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	45	31	29
Base	Cumulative Spring Peak Demand (MW)	87	169	184
High Incentive	Cumulative Spring Peak Demand (MW)	115	230	264
High Avoided Cost	Cumulative Spring Peak Demand (MW)	92	181	190
Base	Cumulative Summer Peak Demand (MW)	87	170	185
High Incentive	Cumulative Summer Peak Demand (MW)	118	235	268
High Avoided Cost	Cumulative Summer Peak Demand (MW)	92	180	190
Base	Cumulative Fall Peak Demand (MW)	76	148	162
High Incentive	Cumulative Fall Peak Demand (MW)	101	201	232
High Avoided Cost	Cumulative Fall Peak Demand (MW)	81	158	167
Base	Cumulative Winter Peak Demand (MW)	121	229	210
High Incentive	Cumulative Winter Peak Demand (MW)	123	235	253
High Avoided Cost	Cumulative Winter Peak Demand (MW)	129	245	219

Figure 7-4, illustrates the relative contributions to the overall residential program potential by program for the base, incentive sensitivity, and avoided energy cost sensitivity scenarios.

**Figure 7-4: DEI Residential 5-Yr Cumulative Potential by Program**



Detailed program results for the short-term residential EE programs are provided in [Table 7-8](#).

Table 7-8: DEI Residential Program Potential (cumulative through 2029)

Program Scenario	Metric	Low Income Neighborhood	Low Income Weatherization	Energy Efficiency Education	Multifamily Energy Efficiency Products & Services	Residential Energy Assessments	Home Energy Report	Smart Saver 25c	Smart \$aver
Base	Energy (MWh)	11,997	192	4,889	16,536	4,548	66,540	198,888	123,042
High Incentive		12,940	303	4,956	18,544	4,621	66,633	215,833	160,077
High Avoided Cost		12,830	479	4,897	19,913	5,078	66,540	233,844	120,379
Base	Spring kW	1,758	38	309	2,190	959	12,994	42,510	25,769
High Incentive		1,997	60	314	2,504	965	13,030	60,968	34,852
High Avoided Cost		1,871	92	310	2,631	1,031	12,994	48,032	25,412
Base	Summer kW	1,513	39	231	1,931	988	13,274	42,595	26,572
High Incentive		1,769	62	235	2,260	993	13,314	62,783	36,347
High Avoided Cost		1,597	94	232	2,277	1,041	13,274	46,966	26,310
Base	Fall kW	1,420	35	270	1,934	832	11,714	36,719	23,258
High Incentive		1,629	54	274	2,220	837	11,746	52,647	31,563
High Avoided Cost		1,509	84	271	2,315	889	11,714	41,128	22,977
Base	Winter kW	2,836	48	2,093	4,655	1,212	17,304	62,419	30,824
High Incentive		3,139	75	2,119	5,554	1,225	17,325	53,465	40,171
High Avoided Cost		3,028	147	2,095	5,375	1,334	17,304	69,402	30,207
Base	Program Cost (\$Thousands)	13,259	192	1,351	5,667	360	9,672	130,221	43,715
High Incentive		15,151	369	1,369	8,498	401	9,679	245,170	101,570
High Avoided Cost		14,705	791	1,353	6,858	457	9,672	184,409	42,837
Base	Levelized Cost (\$/kWh)	\$0.27	\$0.25	\$0.07	\$0.08	\$0.02	\$0.04	\$0.16	\$0.09
High Incentive		\$0.29	\$0.30	\$0.07	\$0.11	\$0.02	\$0.04	\$0.28	\$0.16
High Avoided Cost		\$0.28	\$0.41	\$0.07	\$0.08	\$0.02	\$0.04	\$0.19	\$0.09

To analyze the costs and benefits of the program potential scenarios, RI used several common test perspectives in the MPS, consistent with the California Standard Practice Manual<sup>6</sup>:

- Total resource cost (TRC): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to that measure's incremental cost. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Utility cost test (UCT): Calculated by comparing total avoided electricity production and avoided delivery costs from installing a measure, to the utility's cost of delivering a program containing that measure. Costs include incentive and non-incentive costs.

<sup>6</sup> California Standard Practice Manual: Economic Analysis of Demand-Side Program and Projects. California Public Utilities Commission. San Francisco, CA. October 2001.

- Participant cost test (PCT): Calculated by dividing electricity bill savings for each installed measure, by the incremental cost of that measure. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Ratepayer Impact Measure (RIM): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to the utility's revenue impacts from lost sales and program delivery.

RI shows achievable program potential estimates and benefits cost ratios according to current administrative cost data provided to RI by Duke Energy. Detailed program design is not part of this scope of work; RI examined the components of the administrative costs provided by Duke Energy and applied them on a dollar-per-kilowatt-hour basis.

Table 7-9 Table 7-9 provides the net benefits expressed as millions of dollars, and benefit-to-cost ratios by program for base scenario:

**Table 7-9: DEI Cost-Benefit Results – Residential Programs (cumulative through 2029)**

Cost-Effectiveness Test	Low Income Neighborhood	Low Income Weatherization	Energy Efficiency Education	Multifamily Energy Efficiency Products & Services	Residential Energy Assessments	Home Energy Report	Smart Saver 25c	Smart \$aver
UCT Net Benefits (\$M)	-\$6.21	\$0.05	\$1.26	\$9.58	\$1.97	\$27.99	\$182.37	\$80.40
UCT Ratio	0.56	1.26	1.93	2.74	3.25	3.89	2.43	2.79
TRC Net Benefits (\$M)	-\$6.21	-\$0.94	\$1.26	\$6.72	\$1.97	\$27.99	-\$31.12	\$28.56
TRC Ratio	0.56	0.21	1.93	1.80	3.25	3.89	0.91	1.29
PCT Net Benefits (\$M)	\$8.85	-\$0.71	\$3.28	\$12.94	\$2.44	\$35.66	\$54.56	\$70.74
PCT Ratio	7.71	0.28	N/A	3.26	5.21	N/A	1.18	1.84
RIM Net Benefits (\$M)	-\$15.06	-\$0.23	-\$2.02	-\$6.23	-\$0.47	-\$7.66	-\$85.68	-\$42.18
RIM Ratio	0.35	0.52	0.56	0.71	0.86	0.83	0.78	0.75

### 7.5.3. Non-Residential Program Details

Table 7-10 and Table 7-11 summarize the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative Non-residential energy efficiency program potential for the base and enhanced scenarios, presented as both cumulative and annual incremental impacts over the stated time horizon (5 years, 10 years, or 25 years):

**Table 7-10: DEI EE Non-Residential Program Potential – Energy Savings**

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	88,492	90,814	71,317
High Incentive	Annual Incremental Energy (MWh)	107,366	110,137	87,772
High Avoided Cost	Annual Incremental Energy (MWh)	88,581	90,904	71,366
Base	Cumulative Energy (MWh)	393,876	763,470	849,269
High Incentive	Cumulative Energy (MWh)	479,459	933,758	1,068,078
High Avoided Cost	Cumulative Energy (MWh)	394,214	763,937	849,610

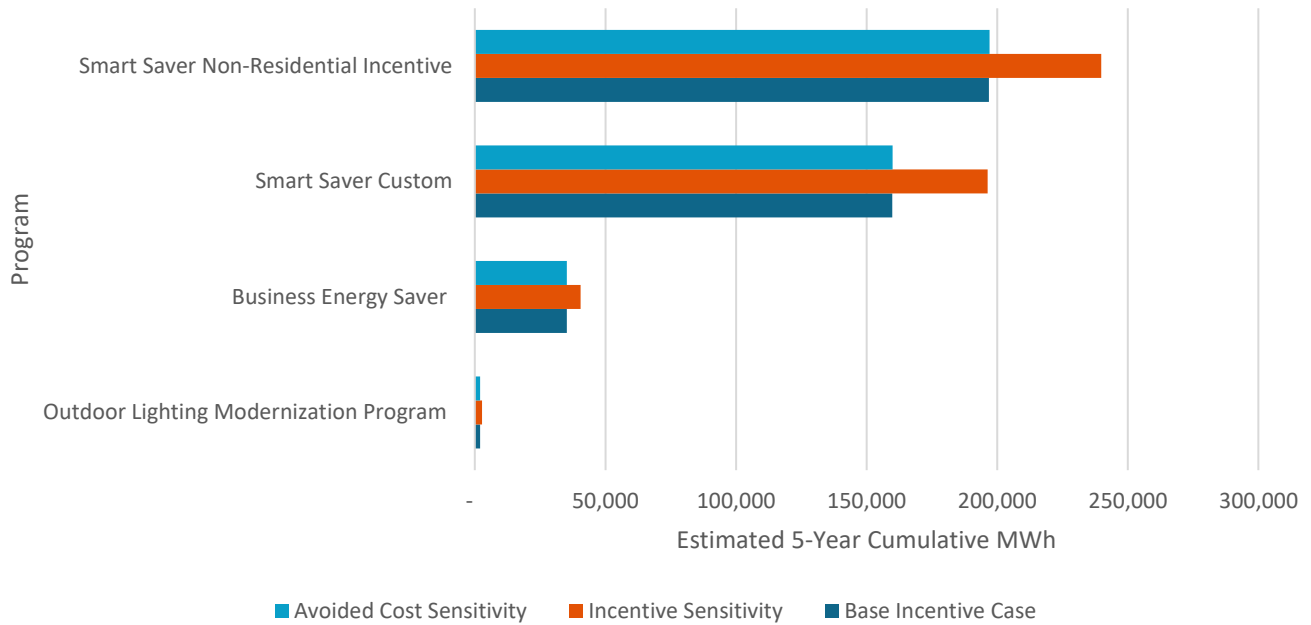
**Table 7-11: DEI EE Non-Residential Program Potential – Demand Savings**

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	16	17	14
High Incentive	Annual Incremental Spring Peak Demand (MW)	20	21	18
High Avoided Cost	Annual Incremental Spring Peak Demand (MW)	16	17	14
Base	Annual Incremental Summer Peak Demand (MW)	15	16	14
High Incentive	Annual Incremental Summer Peak Demand (MW)	19	20	17
High Avoided Cost	Annual Incremental Summer Peak Demand (MW)	15	16	14
Base	Annual Incremental Fall Peak Demand (MW)	16	16	14
High Incentive	Annual Incremental Fall Peak Demand (MW)	19	20	17
High Avoided Cost	Annual Incremental Fall Peak Demand (MW)	16	16	14
Base	Annual Incremental Winter Peak Demand (MW)	12	13	10
High Incentive	Annual Incremental Winter Peak Demand (MW)	15	16	12
High Avoided Cost	Annual Incremental Winter Peak Demand (MW)	12	13	10
Base	Cumulative Spring Peak Demand (MW)	70	138	164
High Incentive	Cumulative Spring Peak Demand (MW)	86	171	212
High Avoided Cost	Cumulative Spring Peak Demand (MW)	70	138	164
Base	Cumulative Summer Peak Demand (MW)	68	134	159
High Incentive	Cumulative Summer Peak Demand (MW)	83	166	207
High Avoided Cost	Cumulative Summer Peak Demand (MW)	68	134	159
Base	Cumulative Fall Peak Demand (MW)	68	135	160
High Incentive	Cumulative Fall Peak Demand (MW)	84	168	208
High Avoided Cost	Cumulative Fall Peak Demand (MW)	68	135	160
Base	Cumulative Winter Peak Demand (MW)	54	105	116
High Incentive	Cumulative Winter Peak Demand (MW)	67	132	148
High Avoided Cost	Cumulative Winter Peak Demand (MW)	54	105	116



Figure 7-5 illustrates the relative contributions to the overall non-residential program potential by program for the base, incentive sensitivity, and avoided energy cost sensitivity scenarios.

**Figure 7-5: Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario**



Detailed program results for the short-term non-residential EE programs are provided in [Table 7-12](#).

**Table 7-12: DEI Non-Residential Program Potential (cumulative through 2029)**

Program Scenario	Metric	Smart \$aver Custom	Business Energy Saver	Smart Saver Non- Residential Incentive	Outdoor Lighting Modernization
Base		159,862	35,234	196,801	1,979
High Incentive	Energy (MWh)	196,403	40,558	239,780	2,719
High Avoided Cost		159,957	35,243	197,035	1,979
Base		21,317	8,003	40,484	0
High Incentive	Spring kW	26,189	9,399	50,365	0
High Avoided Cost		21,331	8,005	40,518	0
Base		21,308	7,573	38,711	0
High Incentive	Summer kW	26,176	8,930	48,354	0
High Avoided Cost		21,322	7,575	38,743	0
Base		21,320	7,593	39,211	0
High Incentive	Fall kW	26,196	8,962	48,985	0
High Avoided Cost		21,334	7,595	39,243	0
Base		19,000	5,676	29,058	456
High Incentive	Winter kW	23,434	6,598	36,637	626
High Avoided Cost		19,011	5,677	29,087	456
Base		20,870	3,988	29,106	290
High Incentive	Program Cost (\$Thousands)	40,711	8,271	60,759	716
High Avoided Cost		20,922	3,994	29,200	290
Base		\$0.03	\$0.03	\$0.04	\$0.04
High Incentive	Levelized Cost (\$/kWh)	\$0.05	\$0.05	\$0.06	\$0.06
High Avoided Cost		\$0.03	\$0.03	\$0.04	\$0.04

Table 7-13 provides the net benefits and benefit-to-cost ratios by program for base scenario:

**Table 7-13: DEI Cost-Benefit Results – Non-Residential Programs (through 2029)**

Cost-Effectiveness Test	Smart Saver Custom	Business Energy Saver	Smart Saver Non-Residential Incentive	Outdoor Lighting Modernization Program
UCT Net Benefits (\$M)	\$86.11	\$18.68	\$106.79	\$1.14
UCT Ratio	5.05	6.12	4.90	4.92
TRC Net Benefits (\$M)	\$63.79	\$13.57	\$76.20	\$0.60
TRC Ratio	2.46	2.55	2.31	1.72
PCT Net Benefits (\$M)	\$138.53	\$21.49	\$151.16	\$1.41
PCT Ratio	5.34	3.94	4.46	2.83
RIM Net Benefits (\$M)	-\$74.73	-\$7.92	-\$74.96	-\$0.81
RIM Ratio	0.59	0.74	0.64	0.64

## 7.6. DEI DR Achievable Market Potential

This section presents the estimated overall achievable market potential for DR opportunities. The results are provided by season and are further broken down by customer segment. All results presented reflect the projected achievable DR potential by 2049.

### 7.6.1. DEI Seasonal Peaking Capacity

Table 7-14 and Table 7-15 provide the overall peak capacity results for the base and enhanced scenario respectively. Most of the peak capacity potential comes from residential customers in all four seasons for the base case. For the enhanced case, most of the peak capacity potential comes from residential customers in the summer and winter seasons, and from SMB customers during the fall and spring seasons.

**Table 7-14: DEI DR Peak Capacity Achievable Potential- Base Scenario**

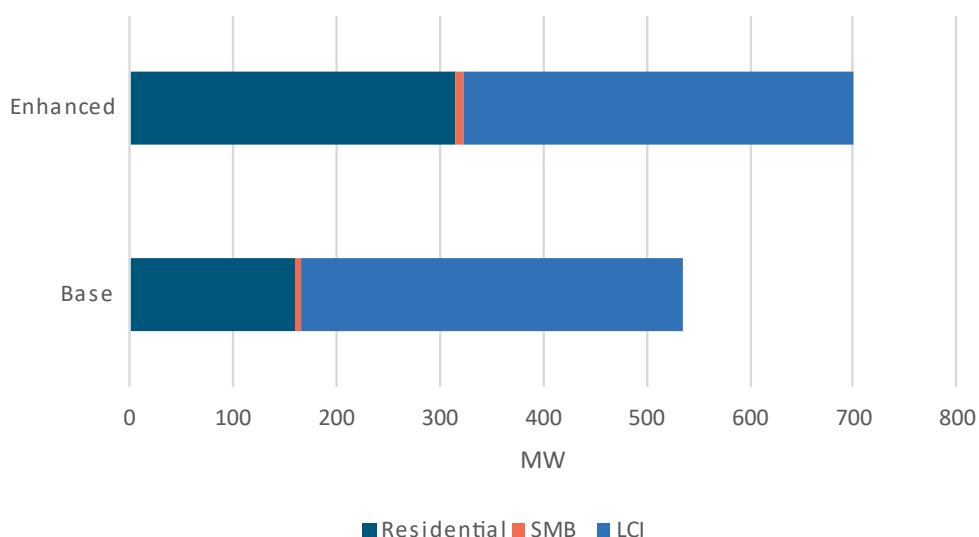
Sector	Savings Potential			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Fall Peak Demand (MW)	Spring Peak Demand (MW)
Residential	159	138	163	158
SMB	6	2	8	9
Large C&I	370	183	315	320
<b>Total</b>	<b>535</b>	<b>322</b>	<b>487</b>	<b>487</b>

**Table 7-15: DEI DR Peak Capacity Achievable Potential- Enhanced Scenario**

Sector	Savings Potential			
	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Fall Peak Demand (MW)	Spring Peak Demand (MW)
Residential	316	278	331	320
SMB	8	3	11	11
Large C&I	376	187	321	326
<b>Total</b>	<b>699</b>	<b>468</b>	<b>663</b>	<b>657</b>

Figure 7-6 presents the overall peak capacity results, broken down by sector and the two scenarios. The capacity is what is expected to be available during the peak hour of system demand.

**Figure 7-6 DEI DR Peak Capacity Achievable Potential**



## 7.6.2. Results by Customer Segment

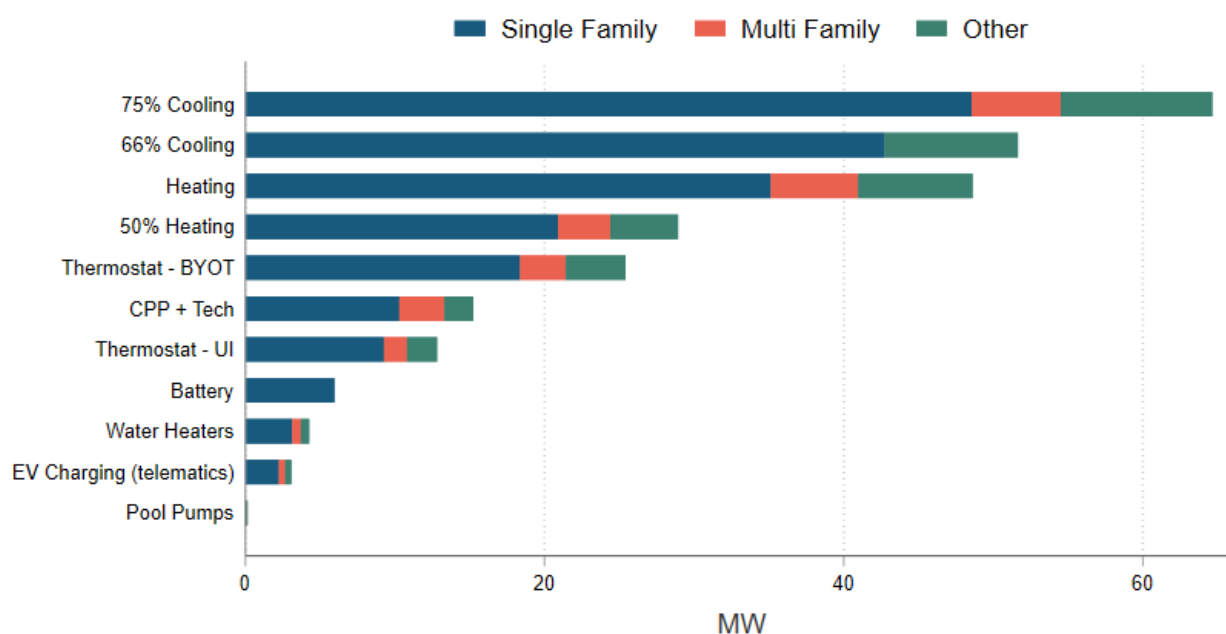
A total of 11 different customer segments were individually analyzed. This includes 3 segments for residential customers, 4 segments for SMB customers, and 4 segments for large commercial and industrial customers. This section presents the segment-level results, focusing on the customer

segments that are most attractive to pursue, allowing for prioritization and targeted marketing of those customer segments.

These results are similar across the two scenarios that were studied, with the main difference being the magnitude of the overall resources being larger for the enhanced scenario due to higher participation rates across all sectors and the inclusion of additional residential end uses dramatically increasing the residential DR capacity. For the sake of simplicity, only the results for the base scenario are presented in this section. Most of the customer segments are cost-effective under the base case assumptions to pursue for DR enrollment.

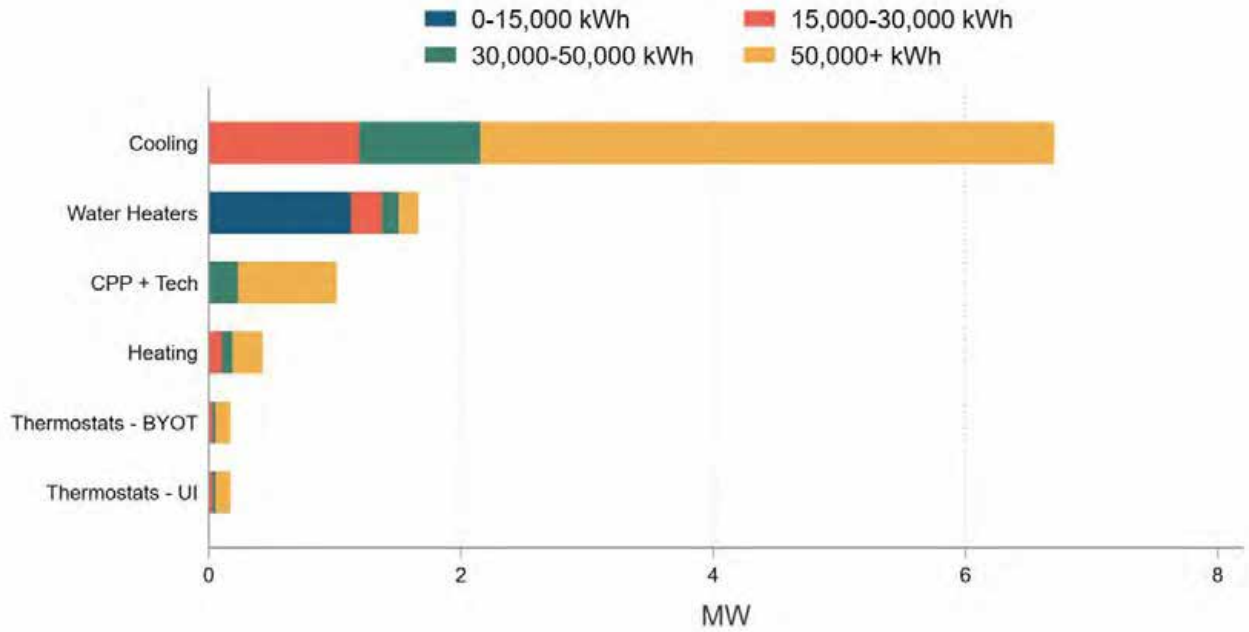
For the residential sector, shown below in [Figure 7-7](#), single-family customers provide the greatest demand response resources. This is not surprising since they tend to have the greatest load available for load reduction, making it possible to enroll significant capacity per marginal dollar spent on acquisition marketing, equipment, and installation costs.

**Figure 7-7: Residential Achievable Potential**



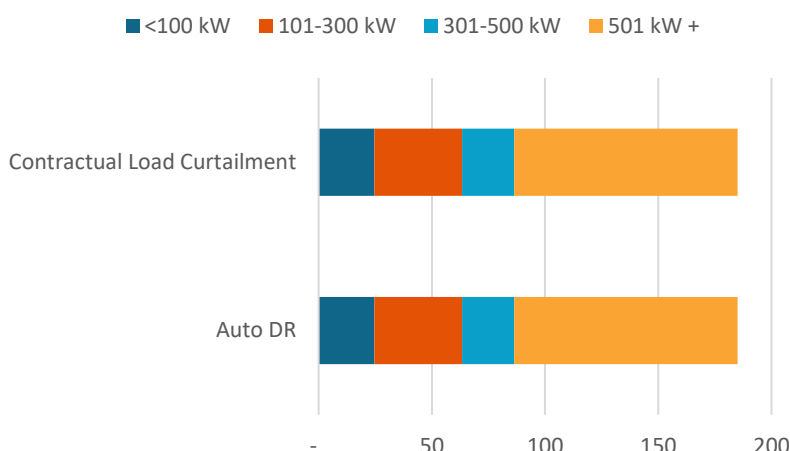
SMB customers do not provide much DR capacity comparably, due to their being a relatively small portion of the overall system load and having lower participation rates. Results for this segment are shown below in [Figure 7-8](#). The largest consumption bin provides the greatest potential.

Figure 7-8: Achievable Potential Results for SMB Demand Response



LCI customers provide the highest DR among the three sectors. Results for this segment are shown below in [Figure 7-9](#). The largest consumption bin provides the greatest potential. The participation rate presented here represents the percentage of the overall peak period load from each customer segment that would be available for curtailment if DR programs are able to reduce participation barriers over time so that potential DR participants can easily capture the economic benefits of utility-sponsored DR offers (e.g. overcoming relevant economic, technical, regulatory, and behavioral barriers (see Section 7.1). The LCI achievable potential excludes the current (as of 2024) 235 MW “at generator,” or 219 MW “at-meter” enrolled capacity.

**Figure 7-9: Achievable Potential Results for LCI Demand Response**



### 7.6.3. Key Findings

The overall DR potential is estimated to be 535 MW of peak seasonal capacity for the base scenario and 699 MW for the enhanced scenario. The extent to whether this potential can be attained in a cost-effective manner depends on the ability to implement programs that target all possible end-uses and cost-effective customer segments. These estimates rely upon assumptions around the future value of capacity.

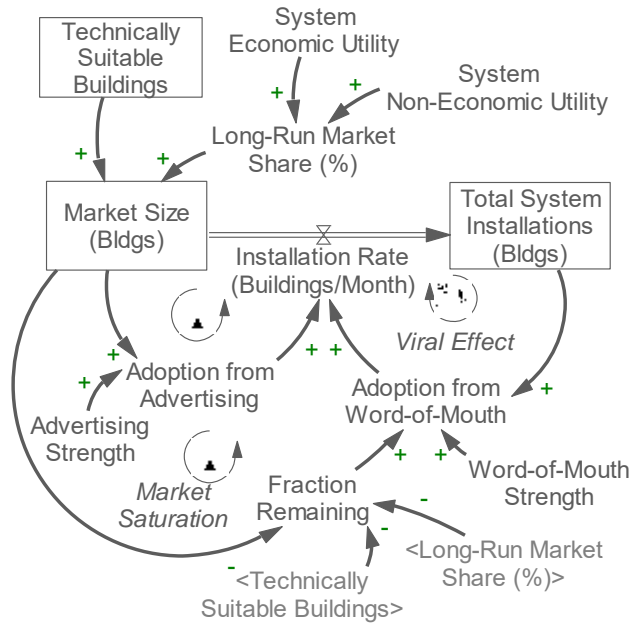
The customer segment-level analysis of the program- and pricing-based DR potential sheds light on which customer segments can provide the greatest magnitude of capacity, as well as which customer segments are most cost-effective to pursue. Unsurprisingly, the most attractive customer segments from a benefit/cost perspective are customers who have more load available for reduction during peak hours. In general, these customers are more capable of shifting load with little inconvenience/cost, and therefore tend to have higher participation levels in DR programs as well as greater willingness to shed a higher percentage of their load.

## 7.7. DER Achievable Potential

Achievable market potential estimates customer adoption rates for cost-effective measures in a market featuring utility-sponsored programs. We calibrated start year adoptions to historic adoptions for solar PVs, but future adoption is driven by modeling Bass diffusion in a system dynamics framework that enables capturing complex DER market dynamics for any future scenario (presented as a simplified Stock and Flow diagram in [Figure 7-10](#)). The approach enables time-varying factors such as costs, investment tax credits, etc.



Figure 7-10. Stock and Flow Diagram

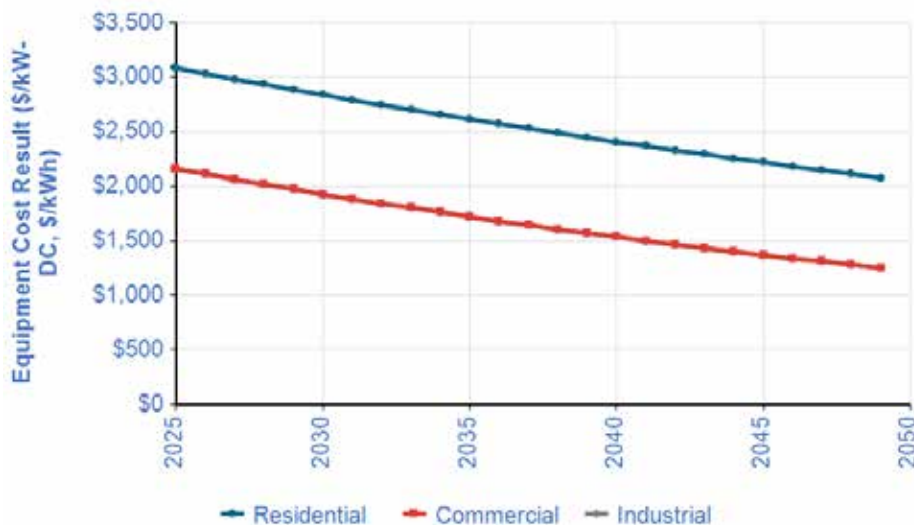


## 7.8. Forecast Cost Impact

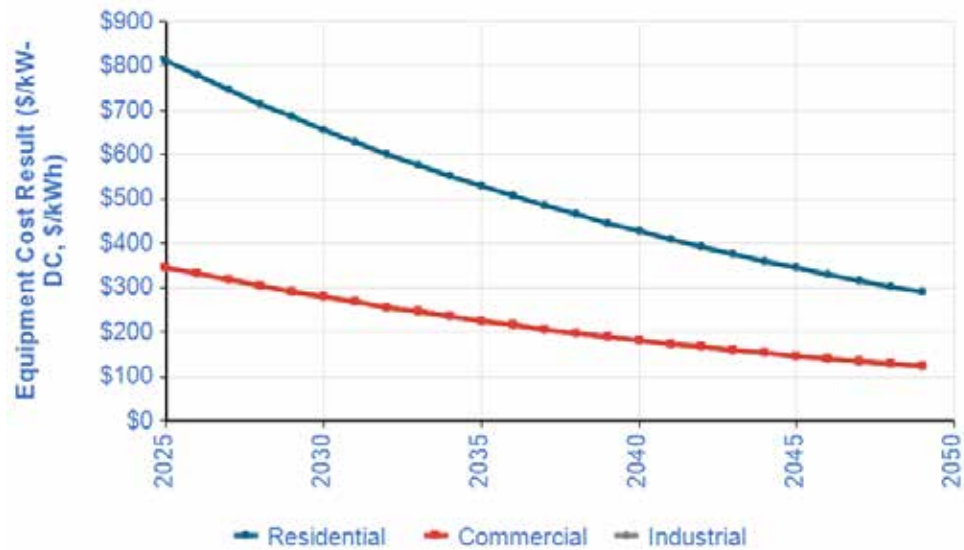
The PV cost and storage cost are forecasted to decline through the end of the study year, which ultimately impacts adoption forecasts by decreasing the payback time. The detailed PV cost forecast and storage cost forecast are displayed in Figure 7-11.

Figure 7-11. Forecast Cost for PV and Storage

PV Cost Forecast (\$/kW-DC)

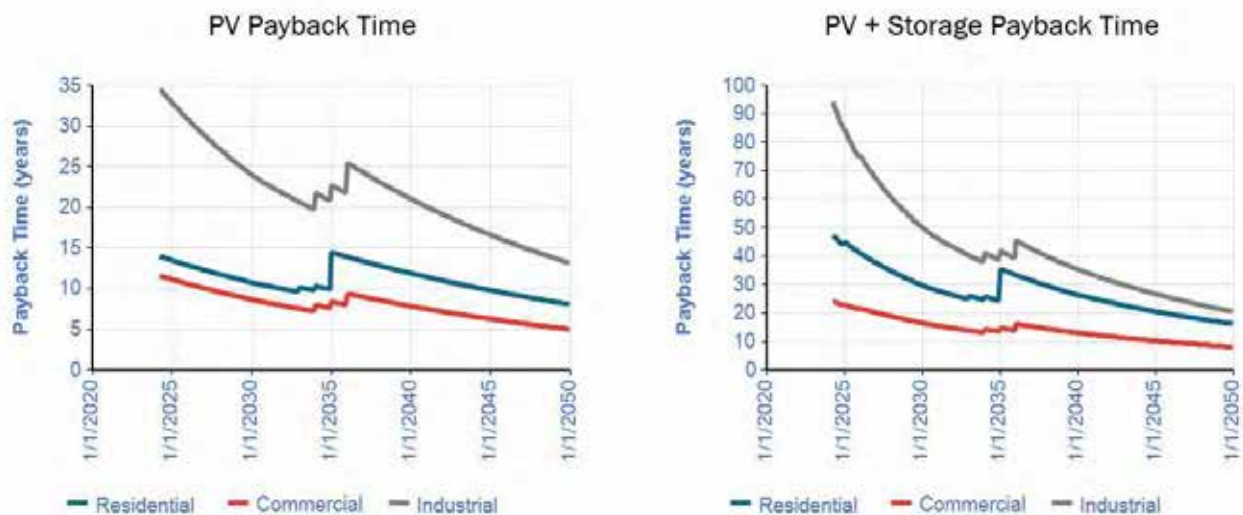


Storage Cost Forecast (\$/kWh, 3-hr system)



The decline in the future costs suggests a decreasing trend in payback time over time. However, due to the phase-out of the investment tax credit (ITC), there is a notable increase in payback time from 2033 through 2035, without any utility incentives. The payback time forecast is presented in [Figure 7-12](#).

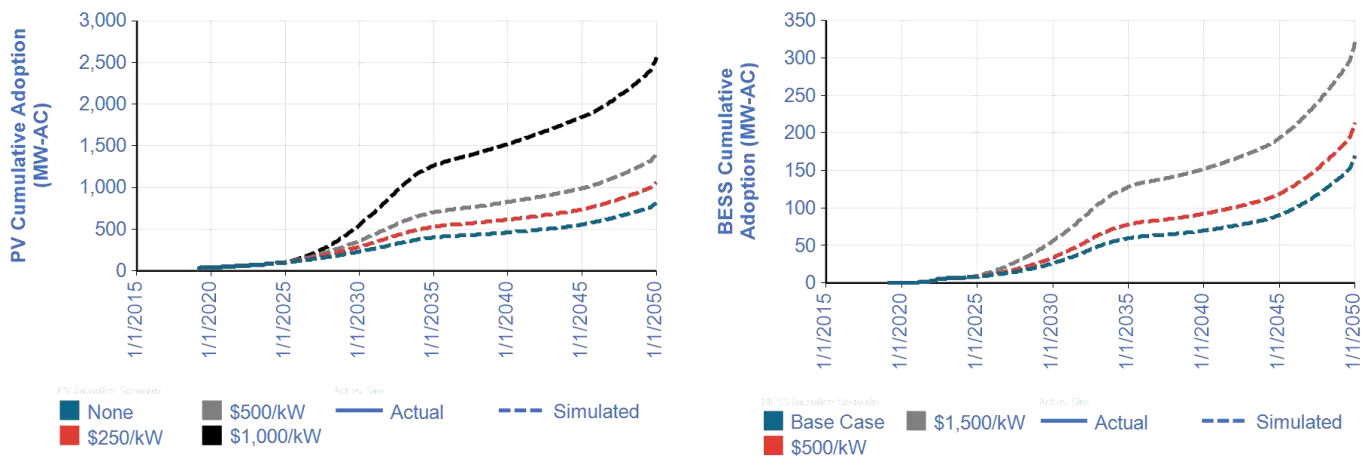
Figure 7-12. Payback Time Forecast (No Utility Incentives)



### 7.8.1. Achievable PV/Storage Forecast Scenarios with Utility Incentives

RI conducted three scenarios on incentives and provided DER forecasts with incentives of \$250/kW, \$500/kW, and \$1,000/kW for PV installations. Paired storage installations examined a high and low case for incentives at \$500 per kW and \$1,500 per kW. Figure 7-13 presents the DER forecasts with the three incentive scenarios. This figure also illustrates expected changes to adoption that result from the expiration of the Energy Efficiency Income Tax Credit in 2033.

**Figure 7-13: PV and Paired Storage Forecasts with a Range of Utility Incentives for Installation**



## Appendix A All Customers APS

Duke Energy's energy efficiency programs in Indiana include an "opt-out" provision approved by the Indiana Utilities Commission. This provision allows non-residential customers receiving electric service at a single site demanding more than 1 megawatt of electric capacity to opt out, along with all accounts in contiguous property. This opt-out provision exempts the customer from the cost recovery mechanism but also eliminates that customer's eligibility for participation in the program.

For this study, technical and economic potential did not consider the impacts of customer opt-outs. For the achievable program potential analysis, Duke Energy provided RI with current opt-out information for Indiana, which showed an opt-out rate of approximately 9.6% of commercial sales and 59.2% of industrial sales in the DEI service territory. We incorporated this opt-out rate into the MPS by excluding sales to non-residential that opted out, and we applied the applicable energy efficiency technologies and market adoption rates to the remaining customer base; the results of this analysis are reported in Section 7.

Resource Innovations also estimated achievable potential with the full customer base as a sensitivity. [Table 7-16](#) presents the results of achievable market potential when all Duke Energy customers are included in the analysis.

**Table 7-16: DEI Energy Efficiency Achievable Potential with All Customers**

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	253,644	261,385	231,924
Base	Annual Incremental Spring Peak Demand (MW)	46	49	47
Base	Annual Incremental Summer Peak Demand (MW)	46	48	47
Base	Annual Incremental Fall Peak Demand (MW)	43	45	43
Base	Annual Incremental Winter Peak Demand (MW)	49	50	42
Base	Cumulative Energy (MWh)	890,727	1,688,706	1,930,627
Base	Cumulative Spring Peak Demand (MW)	156	301	371
Base	Cumulative Summer Peak Demand (MW)	154	296	366
Base	Cumulative Fall Peak Demand (MW)	148	285	350
Base	Cumulative Winter Peak Demand (MW)	153	287	309

## Appendix B Combined Heat and Power

The CHP analysis created a series of unique distributed generation potential models for each primary market sector (commercial and industrial). Only non-residential customer segments whose electric and thermal load profiles allow for the application of CHP were considered. The technical potential analysis followed a three-step process to make this determination. Minimum facility electricity consumption thresholds were determined for each non-residential customer segment by applying power-to-heat ratios to customer billing data. The facilities that were of sufficient size were matched with the appropriately sized CHP technology.

To determine the minimum threshold for CHP suitability, a thermal factor was applied to potential candidate customer loads to reflect thermal load considerations in CHP sizing. CHP size is usually dictated by the thermal load to achieve improved efficiencies. The study collected electric and thermal intensity data from other recent CHP studies and market analysis. Commercial customers, the thermal load is commonly made up of water heating, space heating, and space cooling (in the case of an absorption chiller). [Table 7-17](#), on the following page, presents the values for thermal factors used to estimate technical potential.

**Table 7-17: CHP Thermal Factors by Segment and Prime Mover**

	Microturbines	Fuel Cells	Reciprocating IC Engines	Reciprocating IC Engines	Gas Turbines	Gas Turbines
Application	250-500 kW	250-500 kW	0.5 - 1 MW	1 - 5 MW	5 - 20 MW	>= 20 MW
Assembly	0.75	0.77	0.82	0.94	0.94	1.15
College and University	0.60	0.62	0.66	0.75	0.75	0.92
Grocery	0.17	0.17	0.19	0.21	0.21	0.26
Healthcare	0.22	0.22	0.24	0.27	0.27	0.33
Hospitals	0.41	0.42	0.45	0.52	0.52	0.63
Institutional	0.79	0.81	0.87	0.99	0.99	1.21
Lodging/Hospitality	0.41	0.42	0.45	0.51	0.51	0.62
Miscellaneous	0.33	0.33	0.36	0.41	0.41	0.50
Office	0.59	0.60	0.65	0.74	0.74	0.90
Restaurants	0.41	0.43	0.45	0.52	0.52	0.64
Retail	0.34	0.35	0.37	0.43	0.43	0.52
Schools K-12	0.69	0.71	0.76	0.86	0.86	1.06
Warehouse	0.68	0.69	0.74	0.85	0.85	1.04
Agriculture and Assembly	1.20	1.24	1.32	1.51	1.51	1.85
Chemicals and Plastics	0.74	0.76	0.81	0.93	0.93	1.14
Construction	1.48	1.52	1.63	1.85	1.85	2.27
Electrical and Electronic Equip.	0.29	0.29	0.31	0.36	0.36	0.44
Lumber/Furniture/Pulp/Paper	1.09	1.12	1.19	1.36	1.36	1.67
Metal Products and Machinery	0.29	0.29	0.31	0.36	0.36	0.44
Miscellaneous Manufacturing	1.48	1.52	1.63	1.85	1.85	2.27
Primary Resources Industries	0.38	0.39	0.42	0.48	0.48	0.59
Stone/Clay/Glass/Concrete	2.45	2.52	2.69	3.07	3.07	3.76
Textiles and Leather	0.85	0.87	0.93	1.06	1.06	1.30
Transportation Equipment	0.48	0.49	0.53	0.60	0.60	0.74
Water and Wastewater	0.33	0.33	0.36	0.41	0.41	0.50
Other	0.68	0.70	0.75	0.86	0.86	1.05

RI used the utility-provided customer data to categorize all non-residential customers by segment and size. Customers with annual loads below the consumption thresholds indicated by power-to-heat ratios are not expected to have the consistent thermal loads necessary to support CHP.

In general, internal combustion engines are the prime mover for systems under 500kW with gas turbines becoming progressively more popular as system size increases above that. Based on the available load by customer, adjusted by the estimated thermal factor for each segment, CHP technologies were assigned to utility customers in a top-down fashion (*i.e.*, starting with the largest CHP generators).

### *Interaction of Technical Potential Impacts*

As described above, the technical potential was estimated using separate models for EE, DR, and CHP systems. However, there is interaction between these technologies; for example, a more efficient HVAC system would result in a reduced peak demand available for DR curtailment. Therefore, after development of the independent models, the interaction between EE, DR, and CHP was incorporated as follows:

- The EE technical potential was assumed to be implemented first.
- For CHP systems, the EE technical potential was incorporated in a similar fashion, adjusting the baseline load used to estimate DSRE potential.

For CHP systems, the reduced baseline load from EE resulted in a reduction in the number of facilities that met the annual energy threshold needed for CHP installations. Installed DR capacity was assumed to not impact CHP potential as the CHP system feasibility was determined based on energy and thermal consumption at the facility. It should be noted that CHP systems not connected to the grid could impact the amount of load available for curtailment with utility-sponsored DR. Therefore, CHP technical potential should not be combined with DR potential but used as independent estimates. [Table 7-18](#) presents technical potential for CHP in the DEI jurisdiction.



**Table 7-18: DEI Technical Potential for CHP**

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	14	54,163
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	21	166,602
Commercial	Institutional	4	1	3,158
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	11	26,376
Commercial	Offices	117	145	378,410
Commercial	Restaurants	0	0	0
Commercial	Retail	58	21	57,643
Commercial	Schools K-12	72	37	106,082
Commercial	Warehouse	82	136	359,941
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	86	578,329
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	2	15,248
Industrial	Lumber/Furniture/Pulp/Paper	10	40	258,168
Industrial	Metal Products and Machinery	24	36	242,121
Industrial	Miscellaneous Manufacturing	91	206	1,351,797
Industrial	Primary Resources Industries	1	2	13,781
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	71	459,425
Industrial	Water and Wastewater	0	0	0
<b>Total</b>		<b>568</b>	<b>830</b>	<b>4,071,243</b>

### *CHP Economic Potential*

RI conducted cost research for CHP prime movers and used research on the technology type to identify the appropriate technologies for each segment. Utility costs for existing CHP incentives, utility avoided energy costs, and Installation and O&M costs were used to estimate UCT ratios for CHP technologies at each eligible Duke Energy account.

Baseline energy consumption for CHP economic potential is adjusted by applying results from the EE potential study. Therefore, the baseline energy consumption for CHP economic potential at each account is higher than the baseline energy consumption for technical potential at each account. This is because EE technical potential is larger than EE economic potential. When the EE technical potential and economic potential results are applied to baseline account consumption in the CHP potential, the CHP scenario baseline is higher if energy efficiency impacts are lower. Therefore, the total CHP economic potential is higher than the technical potential. Economic Potential for DEI is presented below in [Table 7-19](#).

**Table 7-19: DEI Economic Potential for CHP**

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	14	54,678
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	21	167,877
Commercial	Institutional	4	1	3,194
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	11	26,766
Commercial	Offices	117	145	386,565
Commercial	Restaurants	0	0	0
Commercial	Retail	58	21	58,229
Commercial	Schools K-12	72	37	106,713
Commercial	Warehouse	82	136	363,813
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	86	586,437
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	2	15,516
Industrial	Lumber/Furniture/Pulp/Paper	10	40	262,662
Industrial	Metal Products and Machinery	24	36	244,531
Industrial	Miscellaneous Manufacturing	91	206	1,375,140
Industrial	Primary Resources Industries	1	2	13,811
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	71	465,706
Industrial	Water and Wastewater	0	0	0
<b>Total</b>		<b>568</b>	<b>830</b>	<b>4,131,638</b>

### *CHP Achievable Potential*

This analysis describes the physical and economic factors that may contribute to facilities' energy savings through the installation of CHP technologies. The data available for characterizing CHP opportunities are limited to representative values for each commercial and industrial segment. These values represent general segment characteristics and describe the order of magnitude for likely drivers of CHP potential in each segment.

The question of which specific facilities are more or less likely to adopt CHP potential bears further research. CHP installations are large projects that are inherently site-specific. Assuming CHP is technical feasible and economic at a given location, there are other important considerations for whether CHP should go forward. Resource Innovations' understanding is that Duke Energy is currently working through a variety of channels to gauge customer interest in CHP technology. Without further research on the topic, we identified project payback period as a potential criterion for screening eligible. Based on our estimates of cost for CHP prime movers and technical feasibility, we find that payback periods for cost-effective CHP program offers made by Duke Energy should be expected to range from 5.9 to 13.1 years among Duke Energy customers.

As in the energy efficiency potential analysis, we apply a payback acceptance curve to these values to generate an estimate of customer adoption. Customer adoption rates range from a low of 1% to a high of 30% for some segments. The results of Achievable Potential analysis for all customers and eligible customers are presented in the following tables, [Table 7-20](#) and [Table 7-21](#).

**Table 7-20: DEI Achievable Potential for CHP (All Customers)**

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	1	2,787
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	2	14,021
Commercial	Institutional	4	0	57
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	0	0
Commercial	Offices	117	4	11,468
Commercial	Restaurants	0	0	0
Commercial	Retail	58	0	8
Commercial	Schools K-12	72	1	1,729
Commercial	Warehouse	82	5	12,938
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	21	141,419
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	0	761
Industrial	Lumber/Furniture/Pulp/Paper	10	12	78,547
Industrial	Metal Products and Machinery	24	2	14,287
Industrial	Miscellaneous Manufacturing	91	32	212,773
Industrial	Primary Resources Industries	1	0	1,600
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	8	54,192
Industrial	Water and Wastewater	0	0	0
<b>Total</b>		<b>568</b>	<b>87</b>	<b>546,587</b>

Eligible customers exhibit slightly higher achievable potential compared to all customers. This difference stems from varying impacts of EE adjustments on baseline energy consumption levels. Eligible customers experience a smaller reduction in their baseline energy consumption due to the EE adjustments. Consequently, their baseline energy consumption for CHP applications remains higher relative to all customers. This higher baseline supports a slightly greater potential for CHP

installations among eligible customers as they are more likely to meet the necessary energy consumption thresholds conducive to CHP deployment.

**Table 7-21: DEI Achievable Potential for CHP (Eligible Customers)**

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	12	1	2,911
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	37	2	14,529
Commercial	Institutional	4	0	67
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	7	0	0
Commercial	Offices	117	5	12,231
Commercial	Restaurants	0	0	0
Commercial	Retail	58	0	10
Commercial	Schools K-12	72	1	1,912
Commercial	Warehouse	82	5	13,152
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	19	21	146,303
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	2	0	761
Industrial	Lumber/Furniture/Pulp/Paper	10	12	79,672
Industrial	Metal Products and Machinery	24	2	15,183
Industrial	Miscellaneous Manufacturing	91	33	217,296
Industrial	Primary Resources Industries	1	0	1,600
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	32	9	58,390
Industrial	Water and Wastewater	0	0	0
<b>Total</b>		568	90	564,017