

2024 NIPSCO Integrated Resource Plan

First Stakeholder Advisory Meeting

April 23, 2024



We exist to deliver safe, reliable energy that drives value to our customers

2024 NIPSCO INTEGRATED RESOURCE PLAN

First Stakeholder Advisory Meeting

April 23, 2024

9 A.M.-2 P.M. CT



Fair Oaks Farms



LOCATION OF
NEAREST EXIT

NEAREST PLACE TO
SEEK SHELTER

IN AN EMERGENCY,
WHO WILL DIAL 911

WHO WILL DIRECT THE
EMERGENCY RESPONDER

LOCATION OF THE
**AUTOMATED EXTERNAL
DEFIBRILLATOR (AED)**

WHO CAN
PERFORM CPR

OTHER **POTENTIAL HAZARDS**

Fire: Exit out any door that is furthest away from the fire. Gather as a group in the front parking lot – near the Tesla chargers.

Shelter: Restrooms, Jasper Ballroom (if closed), Employee Banquet Hallway.

AED Location: On the wall in the Employee Banquet Hallway.

Other Hazards: N/A

Dial 911:

Direct Responders:

CPR:

SAFETY MOMENT: FIRE SAFETY

April 30 concludes the Indiana Spring Fire Season. The risk of fire in homes and workplaces exists all times of year, however. Please remember to protect yourself, your family, and your coworkers by remaining mindful of fire threats and fire safety throughout the year.



Consider two actions that will be impactful

When new positive behaviors are implemented, or unsafe practices are eliminated, safety increases

1. Keep matches and lighters out of children's reach
2. Use flashlights during power outages rather than candles
3. Never leave a burning candle unattended
4. Turn off space heaters when you leave the room, and do not leave them unattended
5. Only use smoking materials outside
6. Keep flammable items away from anything that can get hot, such as space heaters and stove tops

Source: NISTGlobal <https://nistglobal.com/blog/2022/03/home-fire-prevention-safety-tips/>

We exist to deliver safe, reliable energy that drives value to our customers

STAKEHOLDER ADVISORY MEETING PROTOCOLS

- **Your input and feedback is critical to NIPSCO's Integrated Resource Plan (IRP) Process.**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and overall IRP.**
- **We set aside time at the end of each section to ask questions.**
- **Your candid and ongoing feedback is key to this process:**
 - Please ask questions and make comments on the content presented
 - Please provide feedback on the process itself
- **Please identify yourself by name prior to speaking. This will help keep track of comments and follow up actions.**
- **If you wish to make a presentation during a meeting, please reach out to Erin Whitehead (ewhitehead@nisource.com).**

AGENDA

Time *Central Time	Topic	Speaker
9:00-9:10AM	Welcome & Introduction	Tara McElmurry, Communications Manager, NiSource Vince Parisi, President & COO, NIPSCO
9:10-9:20AM	Kick Off	Vince Parisi, President & COO, NIPSCO
9:20-10:00AM	NIPSCO Integrated Resource Planning Process Overview State and Federal Policy Developments Environmental Policy Review	Fred Gomos, Director Strategy, NiSource Pat Augustine, Vice President, CRA Stephen Holcomb, Director Environmental Policy & Sustainability, NiSource
10:00-10:10AM	Break	
10:10-11:00AM	2021 Short Term Action Plan Update Continuous Improvements for 2024 IRP 2024 IRP Analytical Framework	Fred Gomos, Director Strategy, NiSource Pat Augustine, Vice President, CRA
11:00-11:50AM	Lunch	
11:50AM-12:50PM	Reference Case Load Forecast	Pat Augustine, Vice President, CRA Fred Gomos, Director Strategy, NiSource
12:50-1:00PM	Break	
1:00 – 1:30PM	2024 Request for Proposal	Patrick d’Entremont, Manager Planning Commercial Support, NIPSCO Bob Lee, Vice President, CRA
1:30-1:55PM	2024 Public Advisory Process Next Steps	Fred Gomos, Director Strategy, NiSource
1:55-2:00PM	Closing	

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

KICK OFF

Vince Parisi, President & COO, NIPSCO



PREMIER REGULATED UTILITY BUSINESS



NATURAL GAS

COLUMBIA GAS OF KENTUCKY

COLUMBIA GAS OF MARYLAND

COLUMBIA GAS OF OHIO

COLUMBIA GAS OF PENNSYLVANIA

COLUMBIA GAS OF VIRGINIA

NIPSCO GAS

NIPSCO

ELECTRIC

NIPSCO ELECTRIC

SIGNIFICANT SCALE ACROSS 6 STATES

~3.2M

GAS CUSTOMERS

~500K

ELECTRIC CUSTOMERS

We exist to deliver safe, reliable energy that drives value to our customers

NIPSCO PROFILE

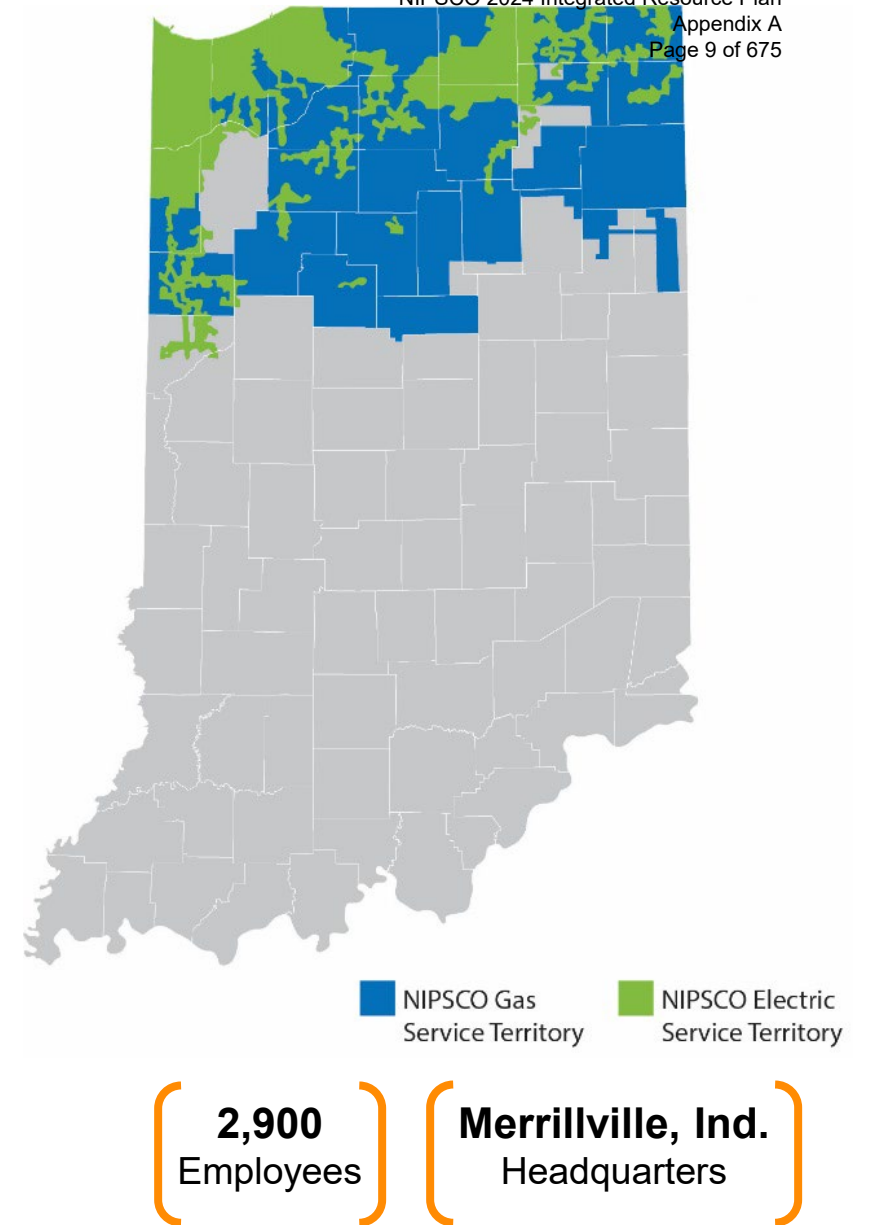
Working to Become Indiana's Premier Utility

Electric

- 483,000 Electric Customers in 20 Counties
- 3,365 MW Generating Capacity
 - 11 Electric Generating Facilities
(2 Coal, 1 Natural Gas, 2 Hydro, 4 Wind, 2 solar)
 - 1,000 MW of New Wind Energy
(Rosewater, Jordan Creek and Indiana Crossroads Wind I & II online in 2020 2021 and 2023)
 - 465 MW of New Solar Energy
(Dunns Bridge I and Indiana Crossroads solar online in 2023)
- 12,800 Miles of Transmission and Distribution
 - Interconnect with 5 Major Utilities (3 MISO; 2 PJM)
 - Serves 2 Network Customers and Other Independent Power Producers

Natural Gas

- 859,000 Natural Gas Customers; 32 Counties
- 17,000 Miles of Transmission and Distribution Line/Main
- Interconnections with Seven Major Interstate Pipelines
- Two On-System Storage Facilities



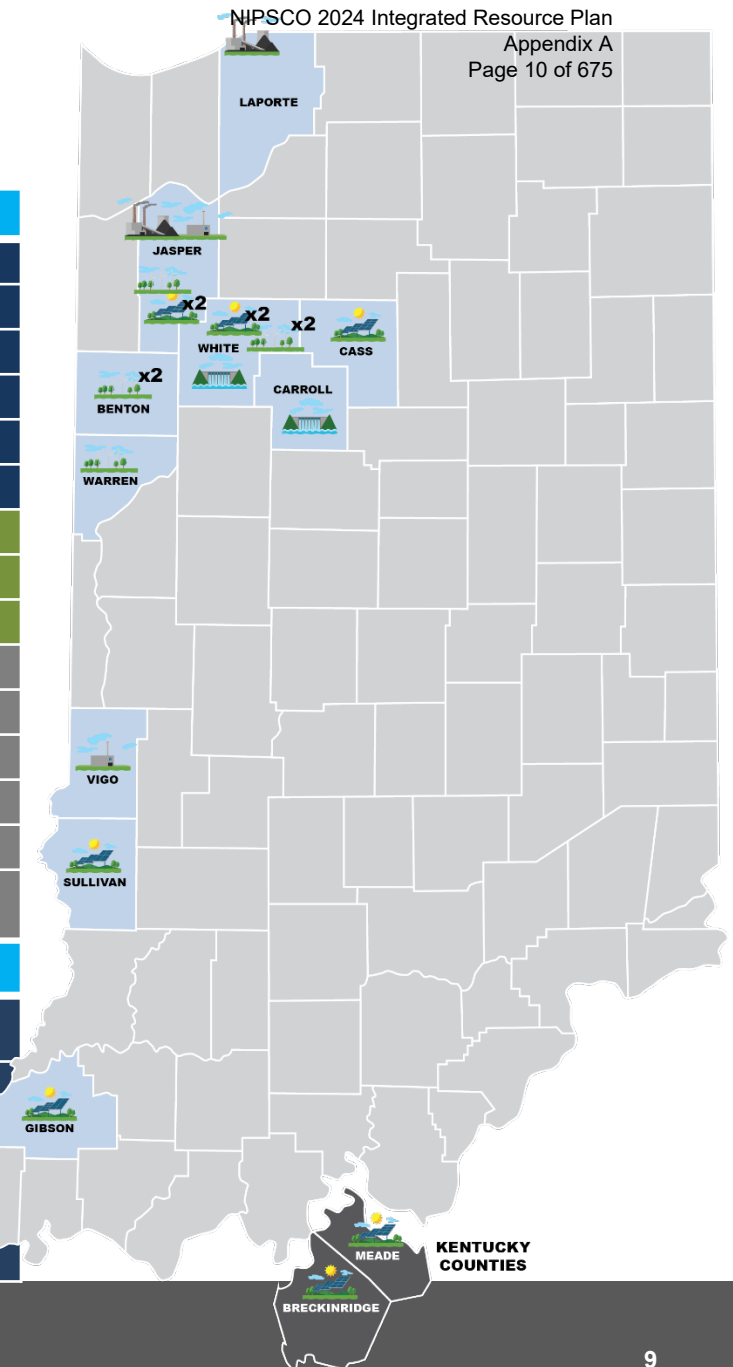
We exist to deliver safe, reliable energy that drives value to our customers

CURRENT & FUTURE NIPSCO GENERATION PORTFOLIO

Robust Renewable Investments in Indiana

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE (KY)	2024 CONSTRUCTION
DUNNS BRIDGE SOLAR II	435 MW + 75 MW BATTERY	JASPER	2024 CONSTRUCTION
CAVALRY SOLAR	200 MW + 60 MW BATTERY	WHITE	2024 CONSTRUCTION
GIBSON SOLAR	200 MW	GIBSON	2025 PRE-CONSTRUCTION
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025 CONSTRUCTION
TEMPLETON WIND	200 MW	BENTON	2025 PRE-CONSTRUCTION
CARPENTER WIND	200 MW	JASPER	2025 PRE-CONSTRUCTION
APPLESEED SOLAR	200 MW	CASS	2025 PRE-CONSTRUCTION
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PRE-CONSTRUCTION PENDING IURC APPROVAL

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2025 (COAL) – 2028 (NG)	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	563 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL



* Since 2018

We exist to deliver safe, reliable energy that drives value to our customers

PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and it's consistent with our goal to transition to the best cost and cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.



**Reliable and
sustainable**

**Flexibility for
the future**

**Local and statewide
economic benefits**

**Best plan for customers
and the company**

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

NIPSCO INTEGRATED RESOURCE PLANNING PROCESS OVERVIEW

Fred Gomos, Director Strategy, NiSource

Pat Augustine, Vice President, CRA



HOW DOES NIPSCO PLAN FOR THE FUTURE?

- At least every three years, NIPSCO outlines its long-term plan to supply electricity to customers over the next 20 years
- This study – known as an Integrated Resource Plan – is required of all electric utilities in Indiana
- The IRP process includes an extensive analysis of a range of resource options evaluated against objectives for portfolios to be reliable, affordable, sustainable, diverse and flexible



Requires Careful Planning and Consideration for:

- NIPSCO's employees
- Environmental regulations and market rules
- The local economy

NIPSCO RESOURCE PLANNING APPROACH

NIPSCO's five-step process is consistent with its approach from the 2018 and 2021 IRPs



Emerging issues for 2024

- *Evolving reliability and social impact objectives*
- *Environmental policy*
- *New technology options*
- *MISO market design evolution*
- *Emerging load trends*
- *Enhanced reliability analysis*
- *MISO market trends*

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

STATE AND FEDERAL DEVELOPMENTS SINCE THE 2021 IRP & ENVIRONMENTAL POLICY REVIEW

Fred Gomos, Director Strategy, NiSource

Pat Augustine, Vice President, CRA

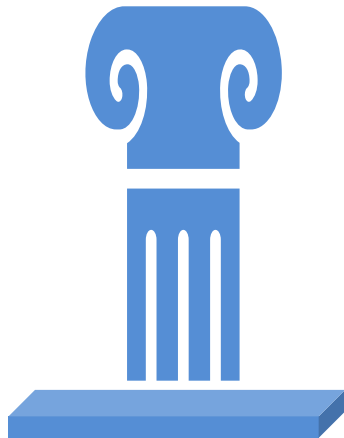
Stephen Holcomb, Director Environmental Policy & Sustainability, NiSource



STATE POLICY CHANGES – FIVE PILLARS OF LONG-TERM PLANNING

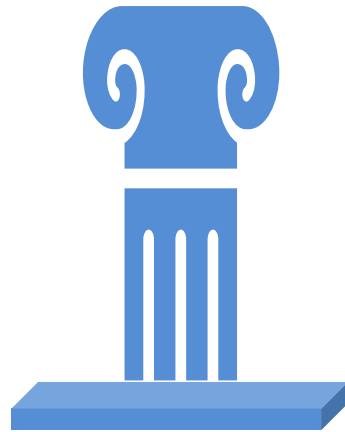
- *House Enrolled Act 1278 led to the creation of the Indiana 21st Century Energy Task Force, which has established **five pillars that utilities must consider when undertaking long-term planning in the state***
- *The Five Pillars are **Reliability, Resilience, Affordability, Stability, and Environmental Sustainability**, which are consistent with the criteria NIPSCO uses for resource planning decisions*

Reliability



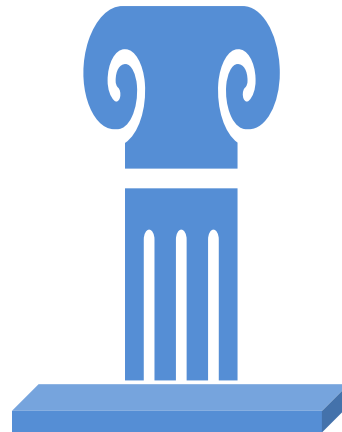
- Resource adequacy
- Operating reliability

Resilience



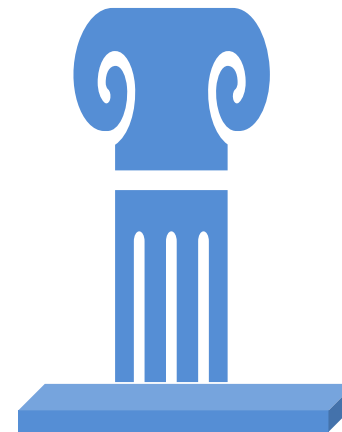
- Respond to catastrophic events

Affordability



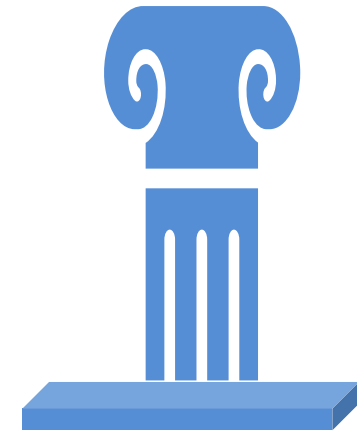
- Affordability across all customer classes
- Diverse resource mix

Stability



- Ability to deliver stable electric service to all customers

Environmental Sustainability



- Account for both environmental regulations and consumers' demands

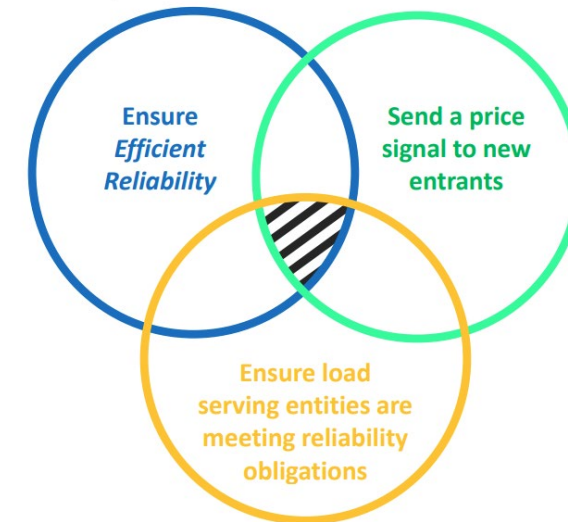
We exist to deliver safe, reliable energy that drives value to our customers

SIGNIFICANT CHANGES IN THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) RESOURCE MIX ARE DRIVING NEW RESOURCE ADEQUACY CHALLENGES

- *MISO's Reliability Imperative is the term MISO uses to describe the shared responsibility of MISO, its members and states to address the urgent and complex challenges to electric system reliability in the MISO region*
- *MISO's Reliability Imperative calls out "Market Redefinition" as a Key Pillar*

Key Initiatives in MISO's Reliability Imperative:

- *Ensure resources are accurately accredited*
- *Identify critical system reliability attributes*
- *Ensure accurate pricing of energy & reserves*



"Resource accreditation is the process of accurately measuring and assigning a capacity value to a resource based on its contribution to system reliability during periods of highest risk."

Sources:

Resource Accreditation White Paper Version 1.1 <https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%201.1630728.pdf>

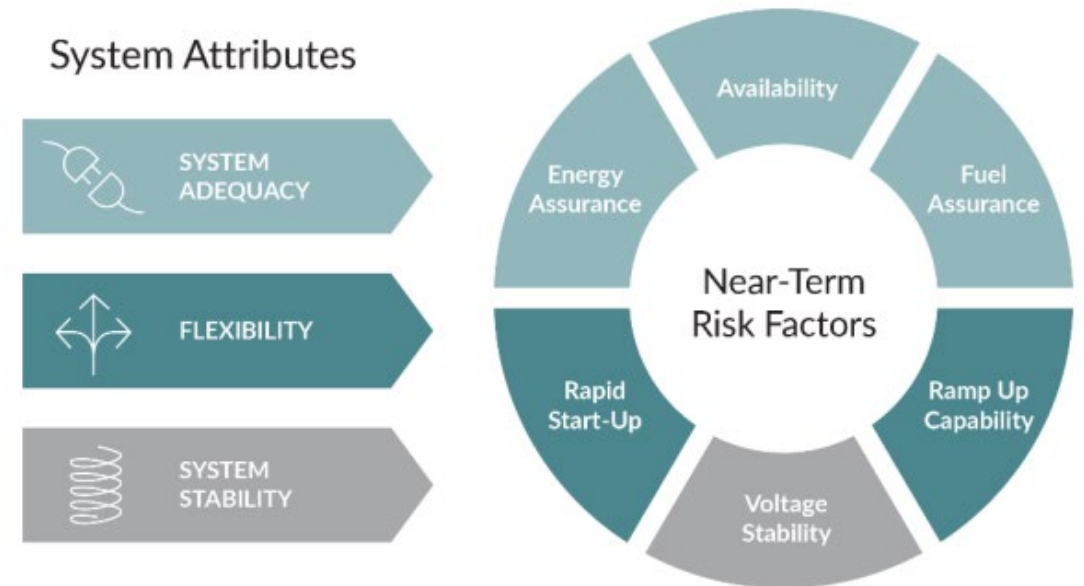
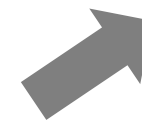
Ensuring Efficient Reliability NEW DESIGN PRINCIPLES FOR CAPACITY ACCREDITATION <https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf>

MISO's Response to the Reliability Imperative, Updated February 2024. <https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216>

We exist to deliver safe, reliable energy that drives value to our customers

RECENT MISO RESOURCE ADEQUACY DEVELOPMENTS AND MARKET REFORMS

- **2023** – MISO implemented a **4-season capacity construct** with obligations and resource accreditations varying by the four seasons across the *MISO Planning Year*
- **2025** – MISO plans to implement a “**downward sloping**” reliability-based **demand curve** to value capacity across a range of reserve margin levels
- **2028** – MISO filed its **Direct Loss of Load (“D-LOL”)** market design proposal on March 28, 2024 with the FERC, driving towards marginal capacity accreditation, with obligations and resource accreditations focused on **performance during tight margin hours**
- Other metrics and markets could be developed for other desired system attributes



Sources:
<https://cdn.misoenergy.org/20240228%20RASC%20Item%2005c%20RA%20Model%20Enhancement%20Presentation631891.pdf>
<https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>

We exist to deliver safe, reliable energy that drives value to our customers

D-LOL KEY TAKEAWAYS

NIPSCO's 2024 IRP will evaluate the potential impacts associated with D-LOL implementation



MISO made its filing on March 28, 2024

FERC approval is still required,
and stakeholders have raised
several questions and concerns



Performance during tight hours will matter more

Strong incentive to perform
during hours when net load
and outages are high



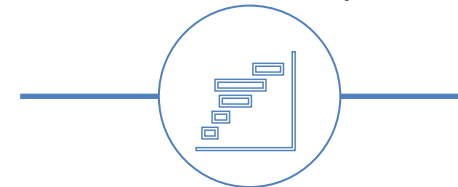
Highly dependent on LOLE* assumptions

Based on historical
weather data and may not
capture all future trends



Accreditations will likely change

MISO has signaled significant
drops for certain technology
types, but future market
conditions will matter



NIPSCO Obligation likely to decline

Shift in timing of tight hours
likely to lead to obligation
declines, but magnitude is
uncertain

* LOLE = Loss of load expectation

We exist to deliver safe, reliable energy that drives value to our customers

INFLATION REDUCTION ACT (IRA)

The Inflation Reduction Act, containing several incentives related to the power sector, was signed into law in August 2022.

- **Production Tax Credit (PTC)**
 - 10-year credit of \$27.5/MWh (growing with inflation)*
 - Re-introduced the PTC for solar and created new universal clean energy PTC
 - Eligibility through 2035**
- **Investment Tax Credit (ITC)**
 - Upfront credit equal to 30% of qualifying investment*
 - Extended the ITC to stand-alone storage
 - Eligibility through 2035**
- **New Hydrogen PTC** (up to \$3/kg)
- Increased 12-year **CCUS[^] credit** value to \$85/ton
- New “bonus” credit opportunities exist:
 - 10% additional credit if cited in an **“energy community”**
 - 10% additional credit for facilities constructed with **domestically manufactured components**
 - 20% additional credit for **low-income benefit projects** at small-scale
- New monetization opportunities via **tax credit transfer**: tax credits can be directly sold to other parties if original beneficiary lacks a tax liability

*Assuming apprenticeship and prevailing wage requirements are met

** Credit availability could be extended longer if U.S. power sector emission reduction targets are not achieved

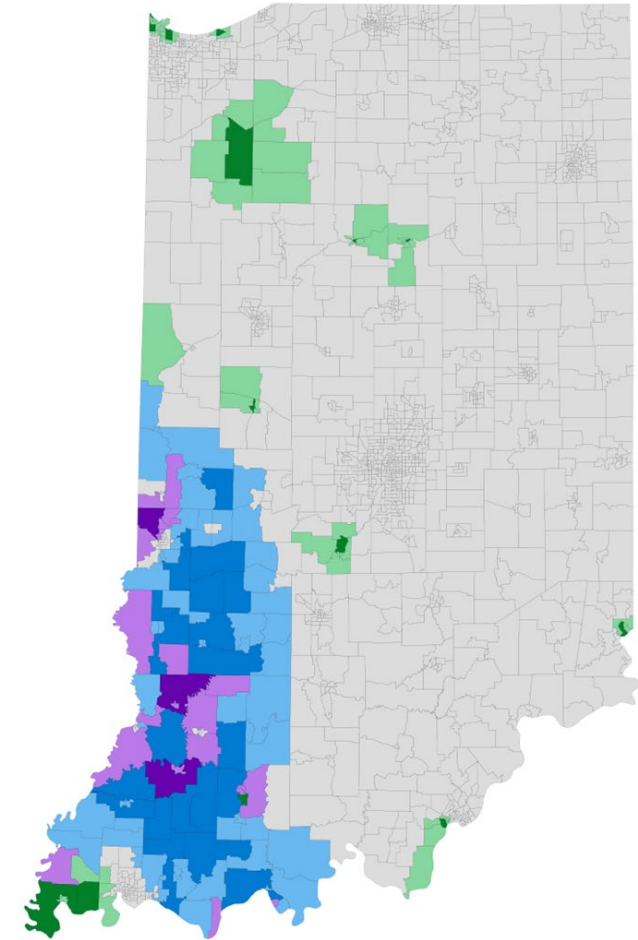
[^] CCUS = Carbon capture utilization and storage

We exist to deliver safe, reliable energy that drives value to our customers

IRA ENERGY COMMUNITY OPPORTUNITIES IN INDIANA

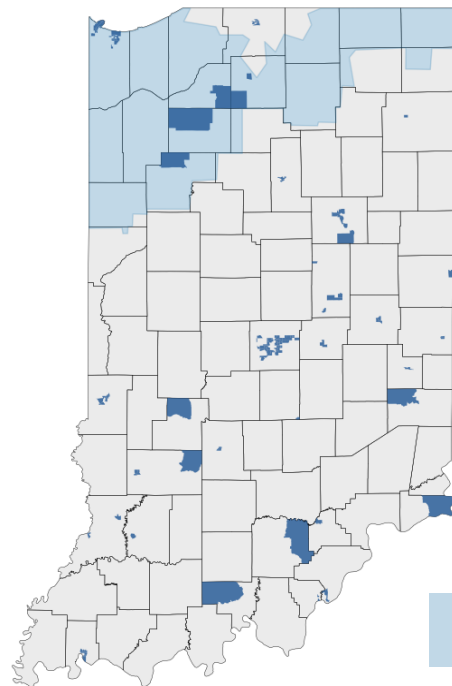
- Many Energy Community locations exist in Indiana, largely due to retired coal generating units or coal mines in the state
- NIPSCO is currently taking advantage of the bonus credits that are available for multiple solar and solar + storage projects currently under construction and in development

Existing Coal-Retirement Census Tracts



IRA LOW-INCOME ECONOMIC BENEFIT PROJECTS (LIEBPs)

- LIEBPs provide 20% ITC credit adders for a limited number of **small-scale (5MW or less)** clean energy projects each year
- Projects must reduce bills for low-income customers and must pass through a competitive US Dept of Energy application process, though strategic site selection and financial benefit allocations could increase likelihood of acceptance
- LIEBPs located in climate justice census tracts will receive priority consideration in the application process, greatly improving chances of project qualification



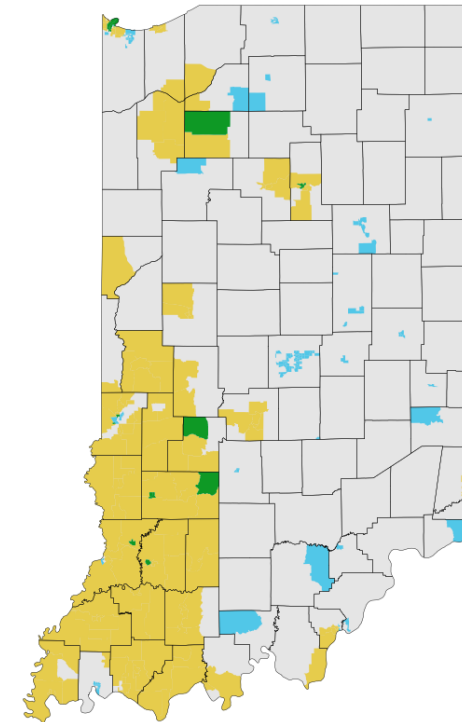
NIPSO Service Territory
Climate Justice Census Tracts

Climate Justice Census Tracts Definition

Census Tracts with both:

- $\geq 65^{\text{th}}$ percentile of low-income households
- $\geq 90^{\text{th}}$ percentile for PM2.5 exposure **or** $\geq 90^{\text{th}}$ percentile for energy burden

Projects located in persistent poverty counties also receive priority consideration. However, there are currently no counties in Indiana under this classification.



30% ITC
40% ITC (energy community only)
50% ITC (LIEBP only)
60% ITC (LIEBP and energy community)

ENVIRONMENTAL POLICY: PROPOSED CLEAN AIR ACT SECTION 111(b) AND (d) RULES

- On May 11, 2023, EPA proposed greenhouse gas standards and guidelines for fossil fuel-fired power plants. This set of proposed rules was published in the Federal Register on May 23, 2023.
- The rule is the latest EPA effort to regulate greenhouse gases from the power sector, following the Clean Power Plan (CPP) and the Affordable Clean Energy Rule (ACE)
- EPA expects to issue a final rule this Spring

EPA Proposed Rule under Clean Air Act Section 111

Existing Coal Units

- Long term operations: CCS at 90% capture rate by 2030
- Retire prior to 2040: Co-fire 40% natural gas by 2030
- Retire prior to 2035: Limit operations to 20% capacity factor
- Retire prior to 2032: No restrictions

Existing Gas Units

- Draft rule initially indicated that existing gas units above a certain size and capacity factor would be subject to CCUS or hydrogen blending requirements
- EPA has now indicated that existing gas units will **not** be covered by **this** rulemaking, but will be covered by another rule

New Gas Units

- Low load: 20% capacity factor max if burning natural gas
- Medium load: Blend 30% H2 by 2032
- High load: Use CCS to achieve 90% reduction by 2035 or blend 30% H2 by 2032 ramping to 96% by 2038

ENVIRONMENTAL REGULATIONS IMPACT PORTFOLIO OPERATIONS AND PLANNING

NIPSCO’s coal fleet remains in compliance with several key environmental regulations, including Effluent Limitation Guidelines (ELG), the Coal Combustion Residuals (CCR) Rule, Mercury and Air Toxics Standards (MATS), and the Good Neighbor Rule

- Retirement of Schahfer Units 17 and 18 by 2025 avoids significant capital costs needed to comply with the ELG and CCR Rules and NPDES permit, as well as future potential costs to comply with the Good Neighbor Rule and the proposed MATS update

	ELG Rule	Schahfer NPDES Permit	CCR Rule
Purpose	Establishes national standards for treatment of wastewater streams	Authorization from IDEM to discharge wastewater in accordance with effluent limitations, monitoring requirements, and other conditions	Regulates new and existing coal ash landfills and certain surface impoundments
Regulated	Wastewater streams associated with bottom ash, boiler slag, FGD, fly ash, flue gas mercury control waste, landfill leachate, and non-chemical metal cleaning waste	Wastewater discharge from Schahfer Generating Station	CCRs from bottom ash, boiler slag, fly ash and certain FGD solids
Compliance Plan	• Michigan City Unit 12 zero liquid discharge • Schahfer Unit 17 & 18 retirement by 2025	• Comply with effluent limitations and monitoring requirements • Closed-cycle cooling via cooling towers • Schahfer Unit 17 & 18 retirement by 2025	Phased Compliance 2015 – 2053+ • Phase I: Separate ponds from generation • Phase II: Close CCR ponds • Phase III: Implement groundwater remedy and monitoring Schahfer Unit 17 & 18 retirement by 2025

ENVIRONMENTAL REGULATIONS IMPACT PORTFOLIO OPERATIONS AND PLANNING

NIPSCO’s coal fleet remains in compliance with several key environmental regulations, including Effluent Limitation Guidelines (ELG), the Coal Combustion Residuals (CCR) Rule, Mercury and Air Toxics Standards (MATS), and the Good Neighbor Rule

- Retirement of Schahfer Units 17 and 18 by 2025 avoids significant capital costs needed to comply with the ELG and CCR Rules and NPDES permit, as well as future potential costs to comply with the Good Neighbor Rule and the proposed MATS update

	MATS	Good Neighbor Rule	Power Plant GHG Rule
Purpose	Regulates mercury emissions and other hazardous air pollutants from coal-fired power plants	Eliminate significant contributions to nonattainment, or interference with maintenance of, the 2015 ozone NAAQS in downwind states	Limit greenhouse gas emissions from power plants under Clean Air Act Section 111
Regulated	Mercury and other hazardous air pollutants	Regulates NOx emissions from emission sources in the electric power and other sectors	Existing coal units plus new gas units (best system of emission reduction based on capacity factor)
Compliance Plan	Operation of existing pollution control technology Facility averaging for Schahfer Unit 17 & 18 mercury emissions Schahfer Unit 17 & 18 retirement by 2025	Operation of existing pollution control technology EPA allocation of emission allowances Schahfer Unit 17 & 18 retirement by 2025	New gas peaker expected to comply, whether by normal operation, by limiting capacity factor below 20%, or by co-firing hydrogen at capacity factors above 20% in 2032+ No impact expected for Sugar Creek Generating Station and NIPSCO’s coal plants.

WE ARE COMMITTED TO MEETING OUR ENVIRONMENTAL IMPROVEMENT TARGETS

On Track to Meet Our Targets Through the Operation of Pollution Control Technology and the Retirement of Coal by 2028

	PROGRESS THROUGH 2023 % REDUCTIONS FROM 2005 LEVELS	TARGET 2025 % REDUCTIONS FROM 2005 LEVELS	TARGET 2030 % REDUCTIONS FROM 2005 LEVELS
CARBON DIOXIDE (CO2) (ELECTRIC GENERATION, SCOPE 1 EMISSIONS)	75%	50%	90%
NITROGEN OXIDES (NOX) EMISSIONS	94%	90%	99%
SULFUR DIOXIDE (SO2) EMISSIONS	98%	90%	99%
MERCURY EMISSIONS	96%	90%	99%
WATER WITHDRAWAL	92%	90%	99%
WATER DISCHARGE	94%	90%	99%
COAL ASH GENERATED	68%	60%	100%

In 2022, we furthered our commitment to sustainability by announcing a 2040 Net Zero Goal for greenhouse gas emissions



Committed to Protecting Human Health and the Environment

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

BREAK





We exist to deliver safe, reliable energy that drives value to our customers

2021 SHORT-TERM ACTION PLAN UPDATE

Fred Gomos, Director Strategy, NiSource
Pat Augustine, Vice President, CRA



PROGRESS ON ADVANCING THE 2021 IRP PREFERRED PLAN AND SHORT-TERM ACTION PLAN

Non-Exhaustive

	2021 Short Term Action Plan	Progress To Date
Retirement	- Retire Schahfer Coal Units 17/18 by 2023¹ - Retire Michigan City Unit 12 and Schahfer 16A/B by 2028 - Identify and implement required reliability/transmission upgrades resulting from the retirement of the units	- Completed transmission upgrades to support the retirement of Schahfer, with the last phase planned completed in June 2023 - Schahfer Units 17/18 on track to retire in 2025¹
Replacement	- Deeper diligence on gas peaker and storage projects - Conduct subsequent RFPs - File CPCNs and other necessary approvals for replacement projects	- Completed technoeconomic and engineering studies to inform gas peaker asset mix that meets portfolio needs - Conducted an RFP for All Source and Schahfer replacement capacity in Fall 2022 - Seeking approval for new and restructured projects
Continue To Monitor	Continue to actively monitor technology and MISO market trends	Performed refreshed 2023 portfolio analysis integrating dynamic market changes impacting the energy industry

¹In 2022 the retirement date for the remaining coal units at Schahfer was moved to 2025 from the previously planned 2023 as a result of various factors impacting the supply chain for NIPSCO's solar projects needed to replace the capacity of the coal units

EVOLUTION OF NIPSCO'S PREFERRED PLAN

- The latest MISO market rules updates, passage of the IRA, and 2022 RFP data resulted in a slight pivot towards resources that can provide more winter capacity and an opportunity to shift the highest-cost solar energy towards incremental wind energy
- As laid out in NIPSCO's 2021 IRP Short-Term Action Plan, flexibility in procurement activities and short-term capacity purchases remain important

Portfolio Components	2021 IRP Preferred Plan	Latest Progress	
Schahfer 17/18 Retirement Date	Mid-2023	Late 2025	Coal retirement dates pushed, and short-term capacity contract amounts vary according to annual needs
Michigan City 12 Retirement Date	Between 2026 and 2028	2028	
Short-Term Capacity Contracts	150 MW	100 MW (10-yr) plus 300 MW+ for nearer-term, as needed	
New Gas Peaking	Up to 300 MW	~400 MW	Winter capacity more valuable and wind energy more competitive relative to solar due to IRA production tax credits
2018-19 RFP Renewable Projects	As per CPCN approvals	Dropped ~600 MW of solar projects with escalating costs	
New Solar	100 – 250 MW	200 MW	
New Wind	Up to 200 MW	400 MW	
Sugar Creek Uprate	30 – 53 MW	~30 MW ¹	Stable components of IRP preferred plan
DSM	~68 MW at summer peak	~68 MW at summer peak	
New Storage	135 – 370 MW	125 – 200 MW	

¹ Sugar Creek received additional capacity in January 2024

We exist to deliver safe, reliable energy that drives value to our customers

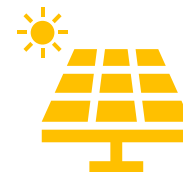
SUMMARY OF THE STATUS OF NIPSCO PORTFOLIO ADDITIONS SINCE 2018 IRP – FACILITIES IN SERVICE

Since the 2018 IRP, NIPSCO has acquired and placed into service four wind farms and two solar farms through PPA or Joint Venture Tax Equity Partnership

In-Service Projects	Technology	Structure	Capacity (MW ICAP)	In-Service Date
Jordan Creek	Wind	PPA	400	12-2020
Rosewater	Wind	Tax Equity Partnership	102	12-2020
Indiana Crossroads Wind I	Wind	Tax Equity Partnership	302	12-2021
Indiana Crossroads Solar	Solar	Tax Equity Partnership	200	06-2023
Dunns Bridge I	Solar	Tax Equity Partnership	265	06-2023
Indiana Crossroads Wind II	Wind	PPA	204	12-2023



~1,000 MW of wind generation capacity placed into service since the 2018 IRP



465 MW of solar capacity placed into service since the 2018 IRP

We exist to deliver safe, reliable energy that drives value to our customers

SUMMARY OF THE STATUS OF NIPSCO PORTFOLIO ADDITIONS – ACTIONS SINCE THE 2021 IRP FOR FACILITIES IN DEVELOPMENT

- *An additional 400 MW of wind capacity, 1,035 MW of solar capacity, and 135 MW of storage capacity have been approved by the Commission and are expected to be in service in 2024 and 2025.*
- *NIPSCO currently has 450 MW of solar capacity and 400 MW of peaking capacity in active proceedings before the IURC.*

	Project	Technology	Structure	Capacity (MW ICAP)	Regulatory Activities Since 2021 IRP	Expected In-Service Date
Approved	Cavalry	Solar + Storage	Full Ownership	200 + 60	Change in cost / ownership structure <i>Approved 01-2024</i>	05-2024
	Dunns Bridge II	Solar + Storage	Full Ownership	435 + 75	Change in cost / ownership structure <i>Approved 01-2024</i>	12-2024
	Green River	Solar	PPA	200	Cost update <i>Approved 07-2023</i>	12-2024
	Appleseed	Solar	PPA	200	New CPCN <i>Approved 09-2023</i>	12-2025
	Templeton	Wind	PPA	200	New CPCN <i>Approved 09-2023</i>	12-2025
	Carpenter	Wind	PPA	200	New CPCN <i>Approved 10-2023</i>	12-2025
Active Proceedings	Fairbanks	Solar	Full Ownership	250	Change in cost / ownership structure <i>Active proceeding</i>	05-2025
	Gibson	Solar	Full Ownership	200	Change in cost / ownership structure <i>Active proceeding</i>	06-2025
	New Peaker	Frame + Aero	Full Ownership	~400	New CPCN <i>Active proceeding</i>	12-2027

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

CONTINUOUS IMPROVEMENTS FOR THE 2024 IRP

Fred Gomos, Director Strategy, NiSource
Pat Augustine, Vice President, CRA



2021 IRP FEEDBACK AND CONTINUOUS IMPROVEMENT PLAN FOR 2024

Category	2021 IRP Feedback	2024 Improvement Plan
1 Load Forecast	- More detail on Electric Vehicle (EV) forecast; for example, penetration has not been able to separate non-NIPSCO-serviced light-duty vehicles (LDVs) from total counts in counties served by more than one utility - Clearer analytic methods regarding forecasting demand from large industrial customers	- More rigorous EV modeling with focus on vehicle counts within service territory and by class and separate truck corridor analysis - Additional econometric analysis of industrial loads, as well as review of potential additional emerging industrial load types (i.e., data centers)
2 Demand-Side Resources	Interaction between energy efficiency (EE) and demand response (DR) resources require further consideration; more attention to meter-based pay-for-performance program designs	- Additional DSM evaluation, including integration with AMI and EV charging management - Continued assessment of distributed energy resources (DERs)
3 Portfolio Analysis	- Positive feedback on reliability assessment: “Based on this initial effort, [NIPSCO] is well positioned to provide future analytical improvements” - Other stakeholders remain interested in various alternative technologies (RICE, storage, grid-forming inverter-based technology SMR)	- Advance continuous improvement around reliability analysis and quantification of risk - Ensure full evaluation of a wide range of new technologies either via the RFP or other means (CCS at Sugar Creek, hydrogen, SMR, LDES)
4 Stakeholder Collaboration	- Joint Commenters requested increased collaboration in the IRP process and the RFP process “...comments emphasized the need for continued collaboration and improvement between stakeholders and NIPSCO for the next IRP filing”	- Facilitate the procurement of Aurora Energy Forecast Software licenses to interested stakeholders to enable visibility into certain modeling files - Provide opportunity for feedback on upcoming RFP for interested stakeholders under a Non-Disclosure Agreement

We exist to deliver safe, reliable energy that drives value to our customers

1 LOAD FORECASTING IMPROVEMENTS

- **Enhancements to EV modeling**
 - Fuller historical data sets for current vehicles in the NIPSCO footprint
 - Class-level assessment (light, medium and heavy duty vehicles, including a detailed transportation corridor assessment for heavy duty vehicles)
 - Deeper assessment of hourly charging shapes based on type of charger, location of charger (public/private), temperature, etc.
 - Integration with DSM analysis on unmanaged vs. managed charging for light duty vehicle class
- **Updated Distributed Energy Resource (DER) modeling**
 - Incorporation of historical customer data across NIPSCO footprint
 - More rigorous uncertainty analysis based on system costs, federal tax credit policy, wholesale and retail rates, and policy construct
- **More rigorous hourly shape analysis for electrification loads**
 - Deeper assessment of MISO Futures study with hourly load impacts by season and time of day
- **New considerations for emerging economic development and data center loads**

2 ADDITIONAL DSM AND DER ASSESSMENTS

- **Evaluating integration of Advanced Metering Infrastructure (AMI) with EV charging management as part of the DSM study**
 - “Managed” charging potential will be incorporated in DSM “bundles”
- **Integrating customer-owned DER analysis with DSM study to assess opportunities for incentives for customer-owned storage installations**
 - Integration with AMI and rate design to evaluate customer-owned storage economics (to improve capacity value of DER resources)
- **Additional integration of DERs with RFP with potential evaluation across various scorecard elements (cost, reliability, environmental justice)**
 - Potential special study around DER values

3 PORTFOLIO OPTIONS

- **Ensuring broad coverage of resource options**
 - Multiple RFP events to assess the landscape of options that might provide different attributes and fulfill different needs
 - Emerging technologies will be encouraged to participate in the RFP, and NIPSCO will also assess options like carbon capture utilization and storage (CCUS), small modular reactions (SMR), long-duration storage, hydrogen, among others
 - Tax credit opportunities will be evaluated for utility scale and distributed energy resources (DER), as appropriate
- **NIPSCO will continue to use a combination of least-cost optimization analysis and thematic portfolio design to assess a range of options to evaluate performance across a range of objectives associated with cost, environmental sustainability, and reliability**

3 RELIABILITY CONSIDERATIONS WITHIN THE PORTFOLIO ANALYSIS

- Continued attention to the three reliability pillars identified in 2021 IRP, with a more robust quantitative framework to evaluate uncertainties in resource adequacy and energy adequacy, **particularly in light of ongoing MISO market design and rule developments**

	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
IRP Considerations	- Co-optimized capacity expansion analysis across all four seasons - Considerations around market design changes to accreditations and obligation	- More robust hourly analysis for new loads - Enhanced stochastic reliability assessment to evaluate correlations between load, renewable output, thermal availability	- Ensure key “non-economic” reliability attributes are present - Assess ancillary services value

4 NIPSCO TO SHARE AURORA MODELING INFORMATION WITH STAKEHOLDERS

- **Aurora Modeling License For Stakeholders:** As a result of the 2021 IRP Stakeholder Advisory Process, NIPSCO committed to facilitating the procurement of Aurora Energy Forecasting Software special use licenses for stakeholders*
- **Purpose:** In order to increase collaboration and allow interested stakeholders to use Aurora modeling files to perform their own analysis with certain shared inputs
- **Software Provider:** Energy Exemplar
- **IRP Use:** NIPSCO and CRA use Aurora for multiple purposes during the IRP process, including to:
 - (i) Develop perspectives and power price forecasts for the wider MISO market
 - (ii) Perform detailed portfolio optimization and production cost/dispatch analysis for the NIPSCO system

Note: The MISO-level databases are proprietary to CRA and cannot be shared with stakeholders, but all information associated with NIPSCO-level analysis will be made available

- **Duration of Use:** the limited license agreement will be 12 months, allowing for stakeholders to use the model as NIPSCO develops the IRP and for several months after NIPSCO's expected submission date during the comment period.

*See NIPSCO's "NIPSCO's Response Comments to Stakeholder Comments." https://www.in.gov/iurc/files/NIPSCO_2021-IRP_Responses-to-Stakeholder-Comments.pdf Submitted on May 24, 2022



We exist to deliver safe, reliable energy that drives value to our customers

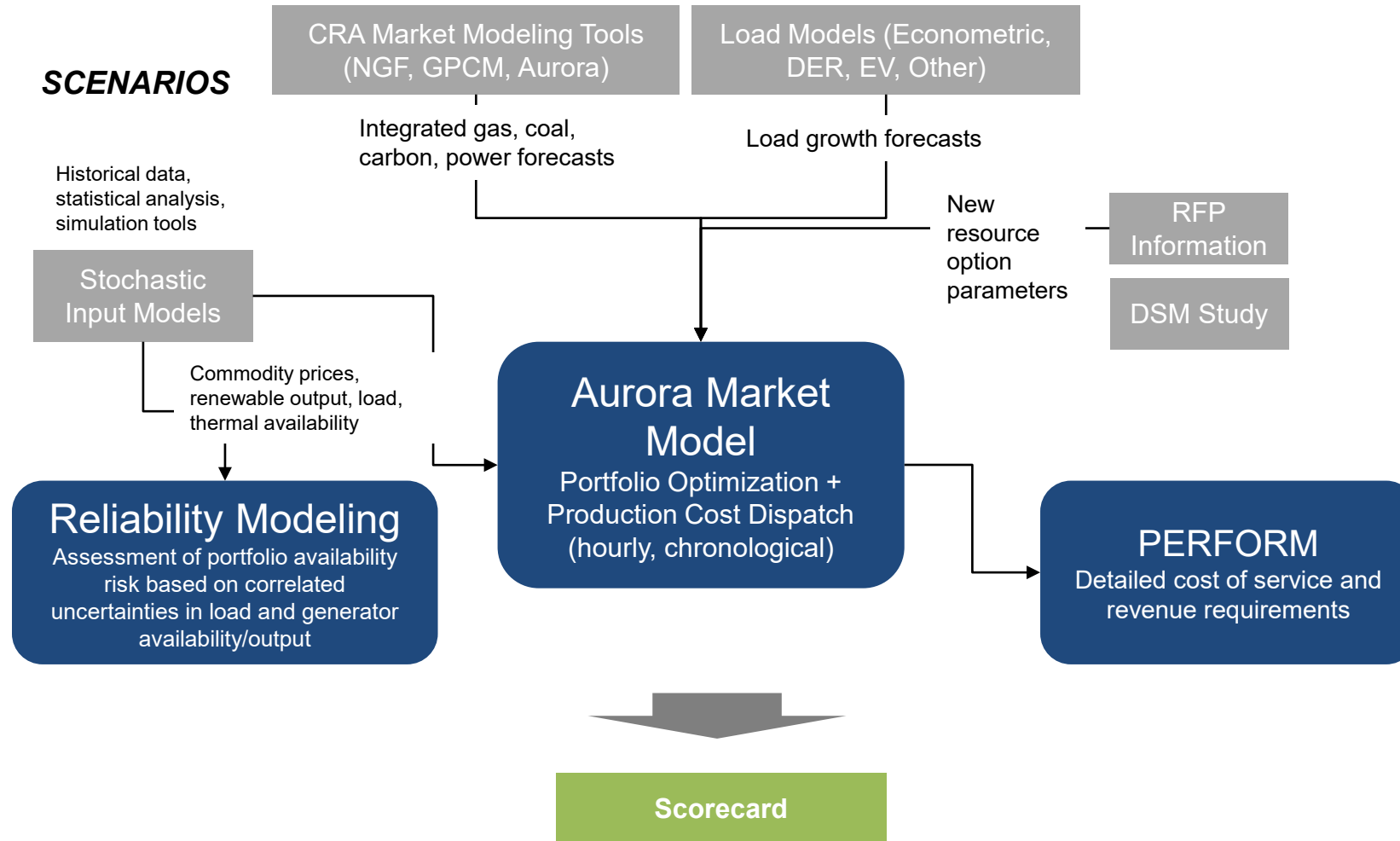
2024 IRP ANALYTICAL FRAMEWORK

Fred Gomos, Director Strategy, NiSource
Pat Augustine, Vice President, CRA



RESOURCE PLANNING APPROACH

Key Modeling and Analysis Tools



- ① Identify key planning questions and approach
 - ② Develop market perspectives (scenarios)
 - ③ Develop integrated resource strategies (NIPSCO portfolios)
 - ④ Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
 - ⑤ Evaluate trade-offs and select preferred plan
- Today's meeting will start*

We exist to deliver safe, reliable energy that drives value to our customers

ANALYTICAL FRAMEWORK FOR EVALUATING FUTURE UNCERTAINTY

- Because resource decisions are generally long-lived, understanding and incorporating future risk and uncertainty is critical to making sound decisions
- NIPSCO's IRP analysis will use both scenarios and stochastic analysis to perform a robust assessment of risk

Scenarios

Single, Integrated Set of Assumptions

- Can be used to answer the “What if...” questions
 - Major events can change fundamental outlook for key drivers
 - New policy or regulation (carbon emissions regulation, tax credits)
 - Fundamental gas price change
 - Major load shifts
- Can tie portfolio performance directly to a “storyline”

Stochastic Analysis:

Probabilistic Distributions of Inputs

- Can evaluate volatility and “tail risk” impacts
 - Uncertainty in renewable resource output, generator availability, and load can impact portfolio costs and key reliability metrics
- **For the 2024 IRP, this analysis will be expanded to include more robust treatment of the correlations between renewable generation, load, resource availability, and commodity prices**

Special Studies:

Focused Research on a Single Topic or Trend

- Can be used to give an enhanced view of specific trends around policy, consumer preferences, or the economics of emerging technologies
 - Potential studies for this IRP include:
 - EV transitory charging
 - Long-duration energy storage (LDES) technology
 - Congestion studies
 - Hydrogen generation market research study
 - Other emerging technology studies

2024 IRP SCENARIOS



Reference Case (REF)

- The MISO market continues to evolve based on current expectations for load growth, commodity price trajectories, technology development, and policy change (IRA incentives continue, EPA power sector rules advance, and MISO resource adequacy enhancements proceed)



Slower Transition (ST)

- IRA incentives are reduced or ended early, and EPA power sector rules are overturned or rescinded; natural gas prices remain low and result in new gas additions remaining competitive versus renewables in the broader region, as coal capacity more gradually fades from the MISO market



Domestic Resiliency (DR)

- Continued geopolitical uncertainty and volatility drives a focus on “domestic energy independence”; electric power demand grows because of onshoring and other industrial growth (data centers); gas prices are higher due to strong demand



Aggressive Environmental Regulation (AER)

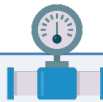
- Carbon emissions from the power sector are regulated more heavily, including through a CO2 price; restrictions on natural gas production increase gas prices



Accelerated Innovation (AI)

- Federal subsidies continue as a bridge until technology breakthroughs drive broad economy-wide decarbonization (including via electrification); new power sector technologies are commercialized, and DER, EV, microgrid, and EE adoption all increase, transforming wholesale load requirements as “Grid Edge” innovations and enabling policy advance

DIRECTIONAL SCENARIO VARIABLE INPUTS

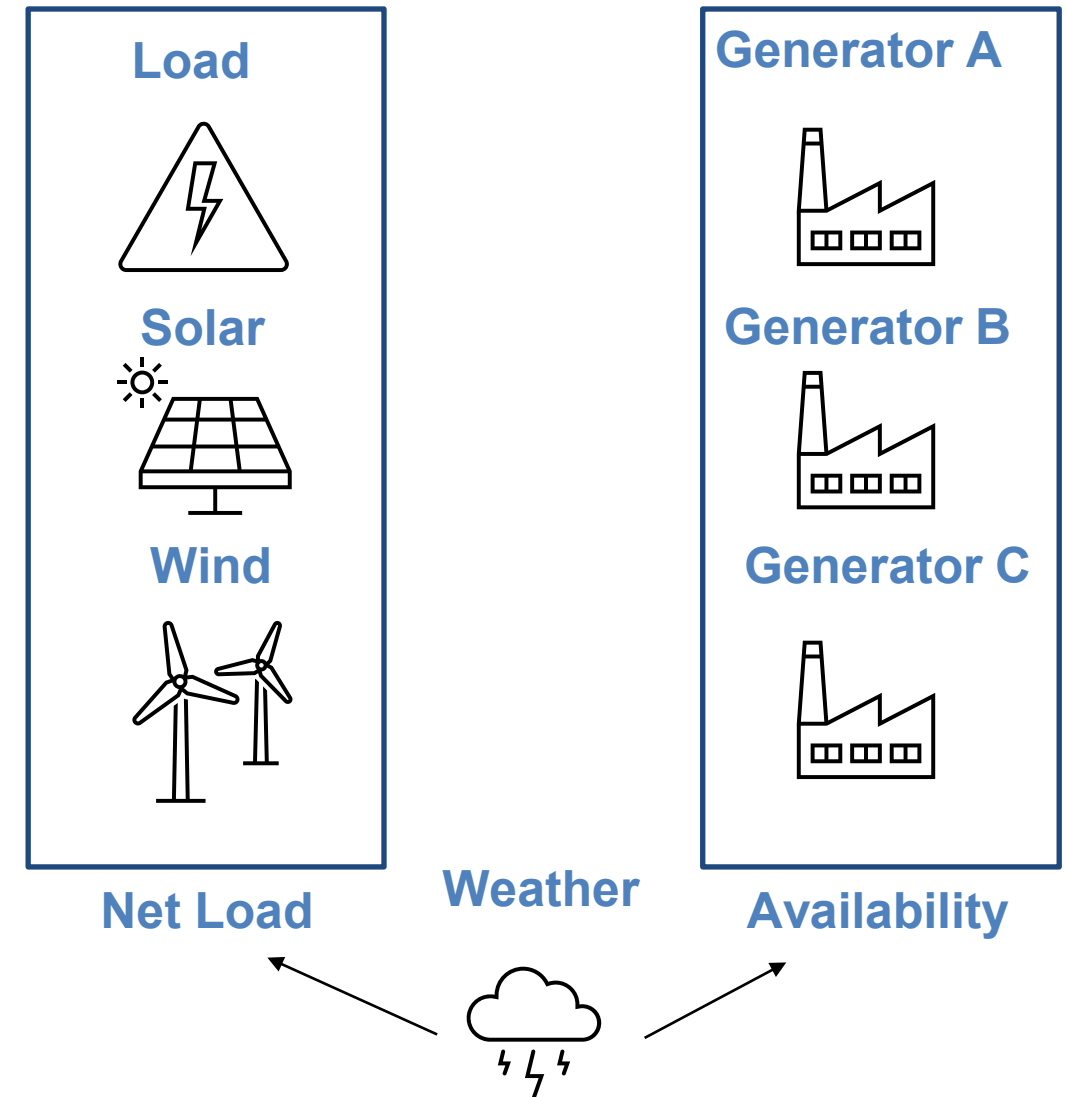
Scenario	 Commodity Prices	 Carbon Policies	 Technology Costs	 Demand	 Market Design
 Reference Scenario (REF)	Baseline	Current Policy, including EPA power sector CO2 emission rules	Baseline	Baseline	Examine alternative capacity accreditation and obligation requirements across alternative market design concepts and based on MISO market outcomes
 Slower Transition (ST)	Low gas price due to abundant resource ↓	IRA pull-back and withdrawn EPA power sector rules ↓	Slower decline for new tech costs; stable IC costs ↑	Low DER and EV	
 Domestic Resiliency (DR)	Higher gas price due to strong demand ↑	Current policy, including EPA power sector CO2 emission rules ■	Higher due to supply chain constraints, onshoring ↑	New large loads (data centers, industrial onshoring)	
 Aggressive Environ. Regulation (AER)	Highest gas price due to production restrictions ↑	EPA power sector CO2 emission rules <i>plus</i> carbon price ↑	Baseline ■	Higher DER and EV; some electrification	
 Accelerated Innovation (AI)	Lower gas price due to demand erosion ↓	Current policy, including EPA power sector CO2 emission rules ■	New tech. advancement and decline in costs; IC cost pressures ↓	High EV and electrification plus new large loads; higher DER	

**Note that NIPSCO portfolio-level technology costs will be heavily informed by RFP data*

We exist to deliver safe, reliable energy that drives value to our customers

STOCHASTIC RELIABILITY ANALYSIS

- Stakeholder feedback from the 2021 IRP and ongoing reliability analysis activities at MISO have influenced NIPSCO's decision to make **enhancements to its stochastic analysis process for the 2024 IRP, focused on economic and reliability metrics**
- In addition to key economic metrics associated with cost to customer, NIPSCO's reliability analysis will assess how often NIPSCO *must* rely on external resources to meet load requirements
- Key enhancements to the process will tie net load (system load and wind and solar output) and generator availability back to weather to **capture correlated events**
- Measures of the **frequency and duration of market exposure**, along with economic impacts, will be evaluated across portfolios



PORTFOLIO PERFORMANCE WILL BE DISTILLED INTO A PROPOSED INTEGRATED SCORECARD

Objectives	Indicators	Proposed Metrics for 2024	Notes
Affordability	Cost to Customer	- Near-term and long-term Impact to customer bills Metric: 10-year and 30-year NPV of revenue requirement (Reference Case scenario deterministic results)	Near-term and long-term perspectives
Rate Stability	Cost Certainty	- Certainty that revenue requirement within the most likely range of outcomes Metric: Scenario range NPVRR and 75th%	
	Cost Risk	- Risk of unacceptable, high-cost outcomes Metric: Highest scenario NPVRR and 95th%	
	Lower Cost Opportunity	- Potential for lower cost outcomes Metric: Lowest scenario NPVRR and 5th%	
Environmental Sustainability	Carbon Emissions	- Carbon intensity of portfolio Metric: Cumulative carbon emissions (2024-40 short tons of CO₂) from the generation portfolio	
Reliable, Flexible, and Resilient Supply	Reliability, Flexibility	- The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules Metric: Loss of load expectation (LOLE) or expected unserved energy (EUE) metrics for NIPSCO system to assess market dependence risk Metric: MW black start and fast start capability	New metrics from fuller reliability analysis based on MISO market rules evolution
Positive Social, & Economic Impacts	Local Investment in Economy	- The effect on the local economy from new projects and ongoing property taxes and targeted investment Metric: NPV of property taxes from the entire portfolio Metric: NPV of potential investment in Justice40/Energy Communities	New environmental justice metric considerations, particularly tied to IRA opportunities

Proposed changes from 2021 Scorecard highlighted in blue

We exist to deliver safe, reliable energy that drives value to our customers

NEXT STEPS FOR SCENARIO AND STOCHASTIC ANALYSIS

- **Developing integrated fuel, carbon, load, and power market outlooks for all five scenarios, detailed outcomes will be provided in the next stakeholder meeting:**
 - NIPSCO load scenario projections
 - Natural gas prices
 - Environmental policy drivers
 - MISO resource mix and power price range (annual, monthly, and hourly impacts)
- **Developing integrated commodity price, weather, load, renewable output, and thermal resource availability stochastic simulations for the next stakeholder meeting**
- **NIPSCO welcomes stakeholder input on proposed scenario concepts and probabilistic analysis approach**
 - NIPSCO is open to one-on-one calls with stakeholders to discuss analysis in more detail



We exist to deliver safe, reliable energy that drives value to our customers

LUNCH





We exist to deliver safe, reliable energy that drives value to our customers

REFERENCE CASE LOAD FORECAST UPDATE

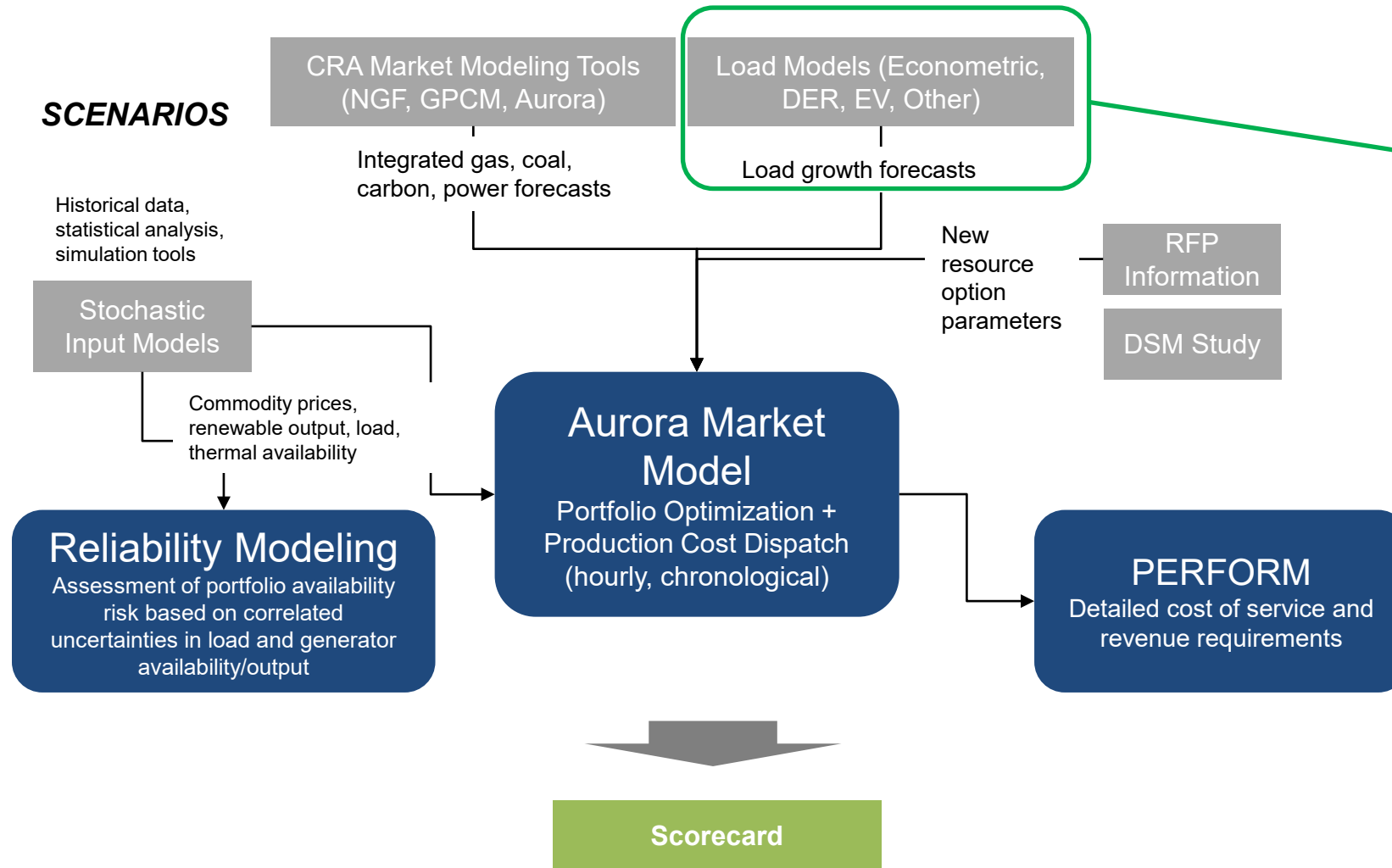
Pat Augustine, Vice President, CRA

Fred Gomos, Director Strategy, NiSource



RESOURCE PLANNING APPROACH: LOAD GROWTH FORECASTS

Key Modeling and Analysis Tools



- 1 Identify key planning questions and approach
- 2 Develop market perspectives (scenarios)
- 3 Develop integrated resource strategies (NIPSCO portfolios)
- 4 Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- 5 Evaluate trade-offs and select preferred plan

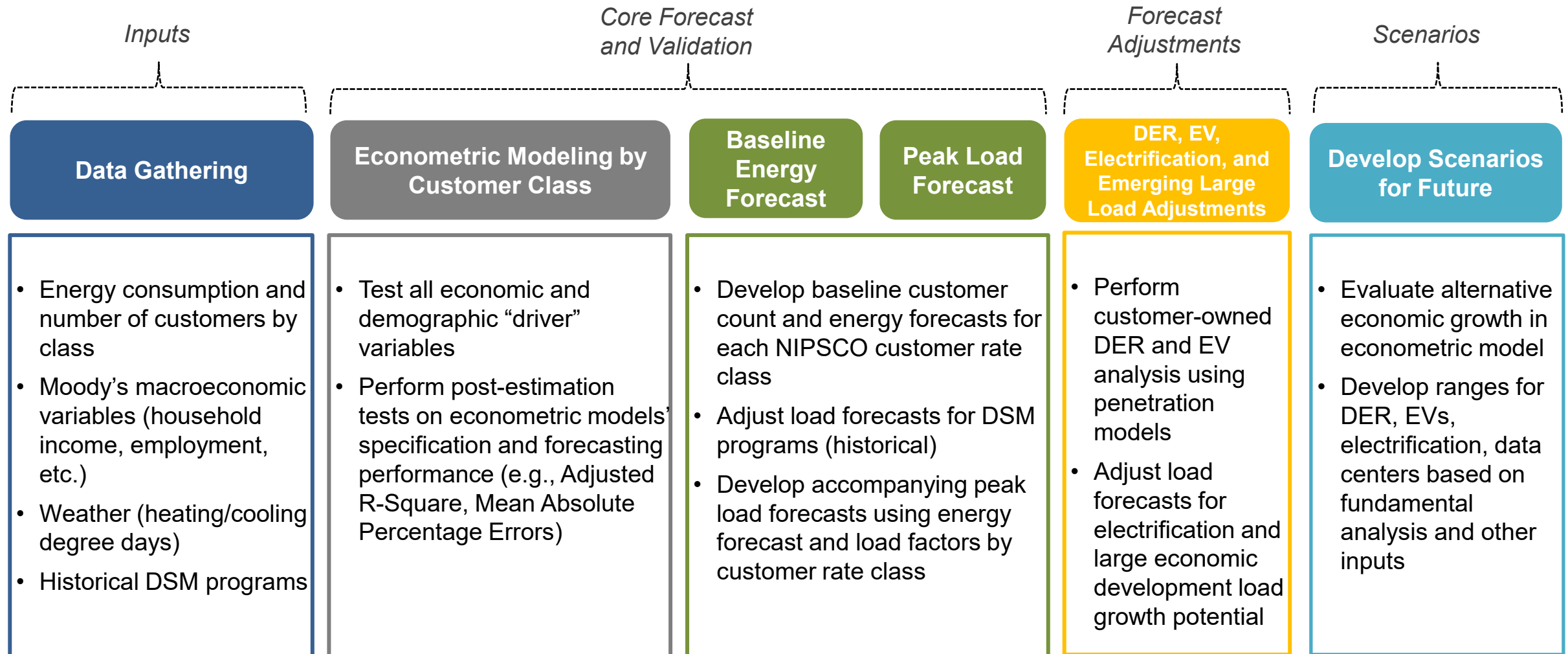


We exist to deliver safe, reliable energy that drives value to our customers

LOAD FORECAST METHODOLOGY OVERVIEW



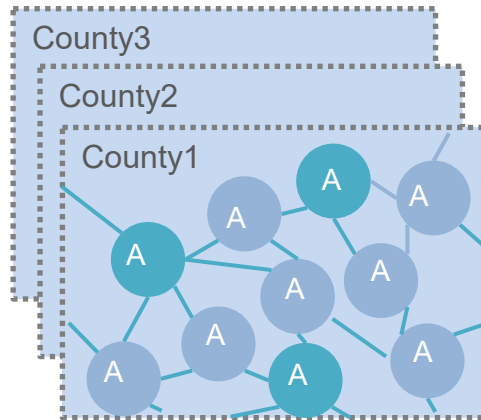
FORECASTING METHODOLOGY OVERVIEW



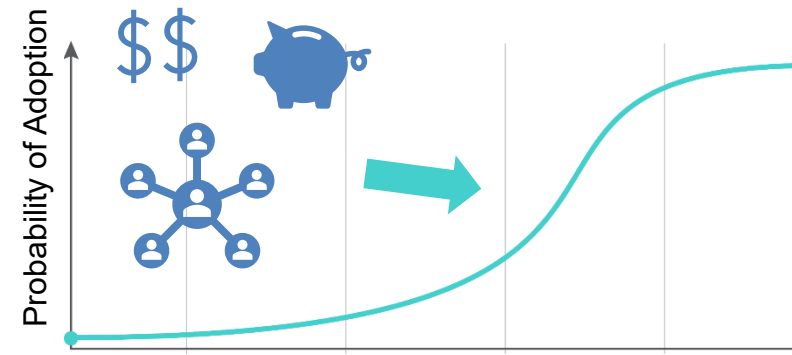
DER MODELING OVERVIEW: DER PENETRATION (PENDER) MODEL

PenDER is an Agent-based model (ABM) that considers NIPSCO customer (“agents”) characteristics, economic decision-making, and social interactions to drive projections of the adoption of DER systems by county

Agent and Network Representation



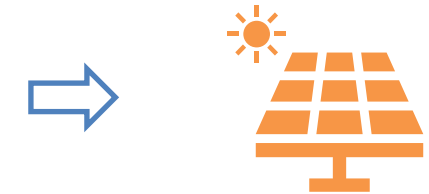
Adoption Decision



Probability of adoption threshold is met based on:

- Payback period
- Customer budget
- Social network adoption rate

Cumulative DER Adoption



Individual adoption decisions aggregated to NIPSCO service territory by customer class

Agents defined by:

Customer Level Data	Individual customer information about DER adoption, location, and customer class (R/C/I)
Socio-Economic Data	Individual customer information on socio-economic status, business type, energy usage

We exist to deliver safe, reliable energy that drives value to our customers

EV FORECASTING OVERVIEW

Penetration Models with Local Datasets

Truck Corridor Charging Tool

Light Duty Vehicle (LDV)

<10,000 lbs

Medium Duty Vehicle (MDV)

10,001 – 26,000 lbs

Heavy Duty Vehicle (HDV)

>26,001 lbs

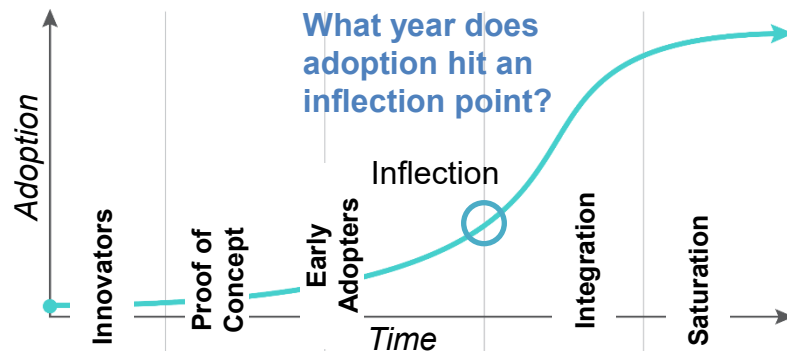
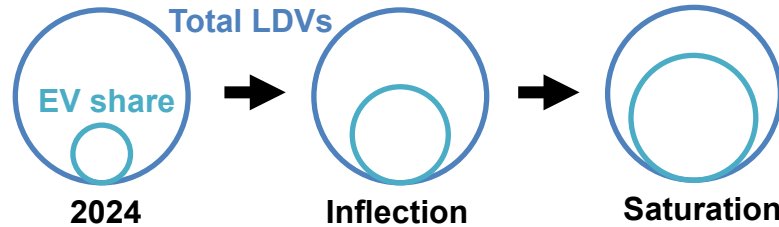
1. Develop growth estimates based on adoption rates applied to S-curve

2. NREL's EVI-Pro-Lite tool and other sources to develop hourly shapes

Analysis includes data from:

- National Performance Management Research Data Set (NPMRDS) via U.S. Dept of Transportation
- Highway traffic counts from Indiana Dept of Transportation
- Freight Analysis Framework
- Institute of Transportation Engineers Trip Generation Database

3. Develop final hourly load forecast based on adoption rates, temperature, efficiency assumptions, and other variables



We exist to deliver safe, reliable energy that drives value to our customers

DRIVERS OF LOAD UNCERTAINTY

	Scenario Name	Description	Economic Growth (C&R, I Count)	EV Penetration	DER Penetration	Electrification (MISO Futures Report)	Large Econ. Development (Data Center) Load
Today's Focus 	Reference Case	Reference Point	Base Moody's Baseline forecast	Base Rate of Adoption	Base Expected Rate of Adoption	Limited (Future 1)	Base None
	Slower Transition	Environmental policy incentives reduce; economic slowdown in region	Low Moody's Low forecast ↓	Low Rate of Adoption ↓	Lowest High capital costs, low tax credits, low wholesale prices ↓	Limited (Future 1)	Base None
	Domestic Resiliency	Influx of new economic development load (data center focus)	Base Moody's Baseline forecast	Base Rate of Adoption	Lower High capital costs ↓	Limited (Future 1)	High ↑
	Aggressive Environmental Regulation	Aggressive decarbonization policy, moderate electrification	Base Moody's Baseline forecast	High Rate of Adoption ↑	High Net metering policy change ↑	High (Future 2) ↑	Base None
	Accelerated Innovation	Faster energy transition, high electrification with additional econ. dev. (data center) load	Base Moody's High forecast	High Rate of Adoption ↑	High Low capital costs, larger installation sizes ↑	Highest (Future 3) ↑	High ↑

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

REFERENCE CASE LOAD FORECAST



CORE ELECTRIC SALES FORECAST – ECONOMETRIC PARAMETERS

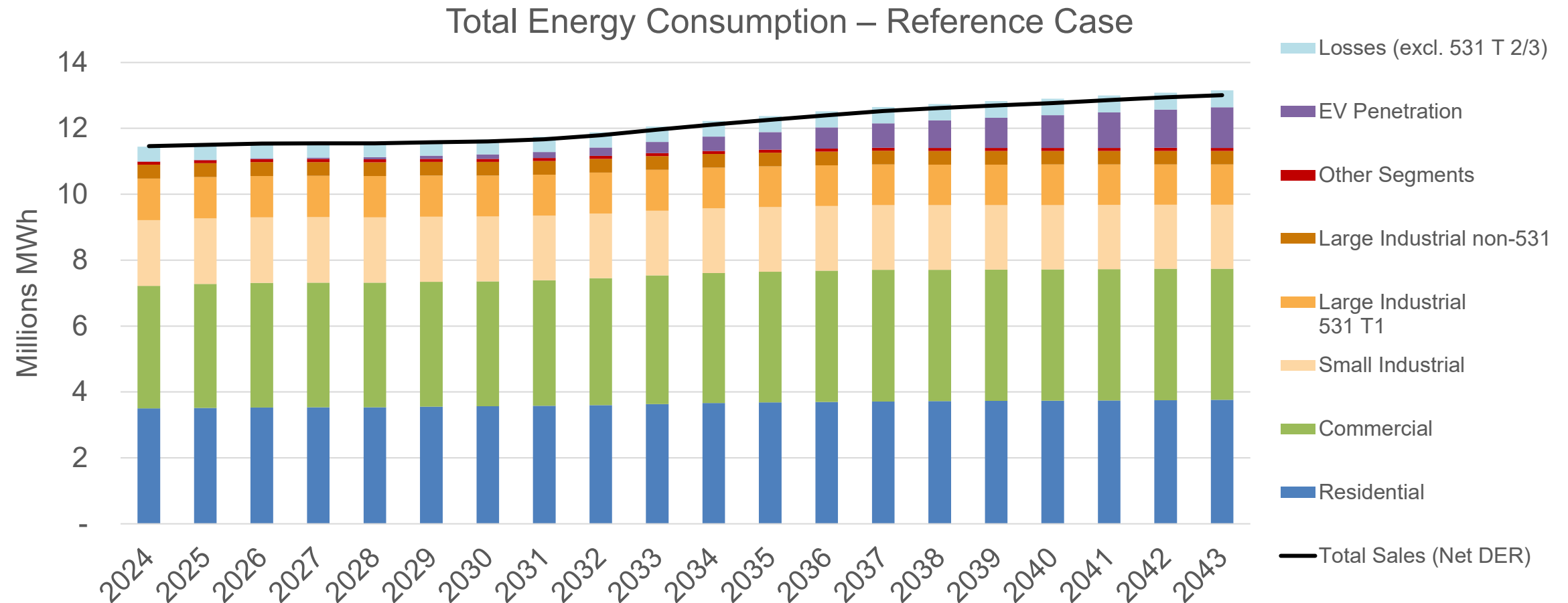
- Baseline customer count and sales per customer energy forecasts by class are projected with best fitting variables
- CRA tested various macroeconomic variables using Moody’s historical and forecast data and selected the presented model based on R-squared, adjusted R-squared, Root Mean Squared Error (RMSE), and Mean Absolute Percentage Error (MAPE)

	Residential	Commercial	Industrial
Customer Count Forecast	Household Income	Household Income, Employment	Manufacturing employment, Metals employment
Baseline Sales per Customer Forecast	Household income, HDD, CDD, seasonal monthly dummies, 2020 and after indicator function	Employment, Manufacturing, CDD, seasonal monthly dummies, 2020 and after indicator function	Seasonal average → decomposed by rate class

Note that large industrial, railroad, street lighting, public authority, and company use forecasts are based primarily on historical trends extrapolated forward

REFERENCE CASE ENERGY SALES / CONSUMPTION

Residential, Commercial, and Industrial customers comprise most energy sales in the Reference Case



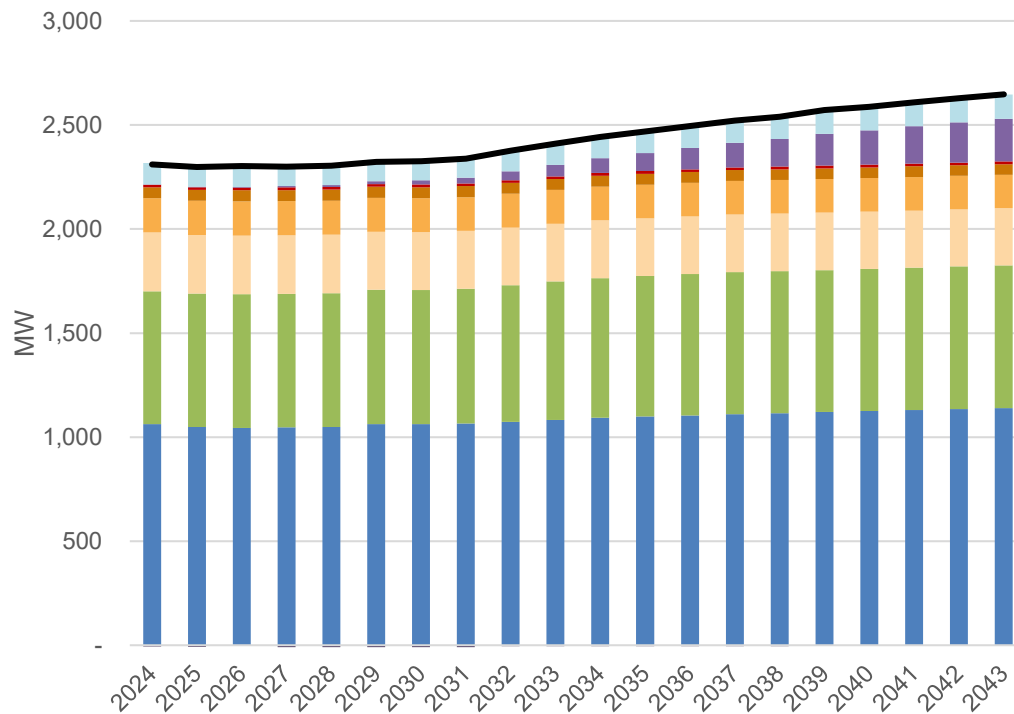
EV = electric vehicles; DER = customer-owned distributed energy resources

We exist to deliver safe, reliable energy that drives value to our customers

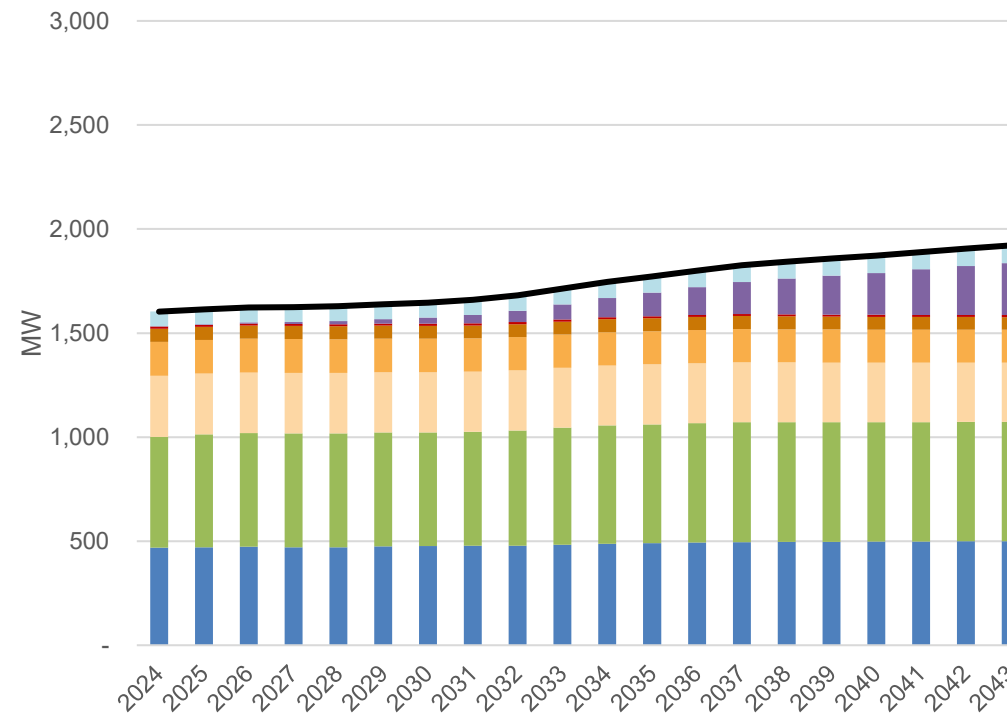
PEAK LOAD FORECAST – FOUR MISO PLANNING SEASONS

NIPSCO is expected to remain summer peaking in the Reference Case

Summer Peak Contributions by Class (MW)



Winter Peak Contributions by Class (MW)



- Losses (excl. 531 T 2/3)
- EV Penetration
- Other Segments
- Large Industrial non-531
- Large Industrial 531 T1
- Small Industrial
- Commercial
- Residential
- Value of CP (Net DER)

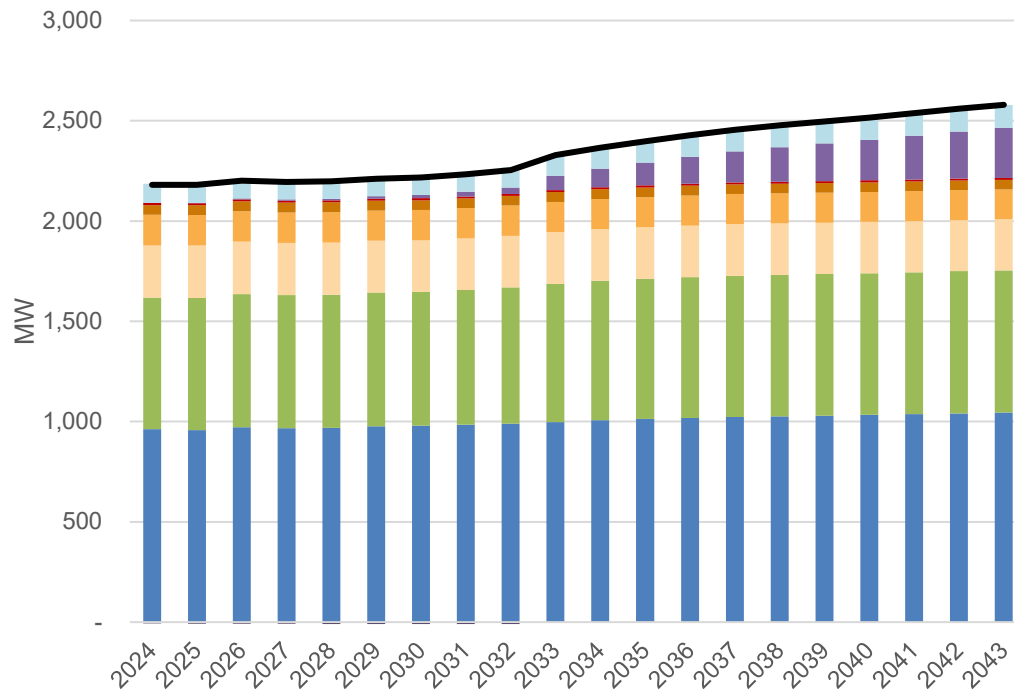
EV = electric vehicles;
DER = customer-owned distributed energy resources
CP = coincident peak for NIPSCO system

We exist to deliver safe, reliable energy that drives value to our customers

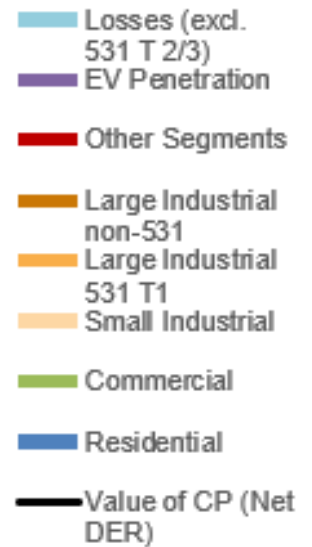
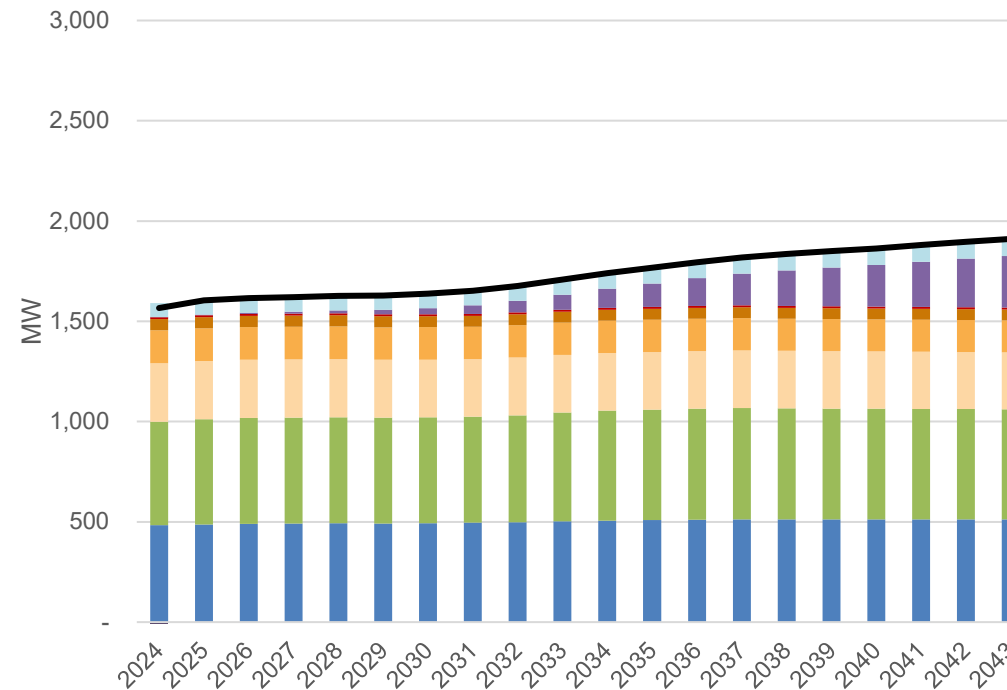
PEAK LOAD FORECAST – FOUR MISO PLANNING SEASONS

Fall loads (September) are likely to be much closer to summer peaks than those in Spring

Fall Peak Contributions by Class (MW)



Spring Peak Contributions by Class (MW)



EV = electric vehicles;
DER = customer-owned distributed energy resources
CP = coincident peak for NIPSCO system

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

LOAD FORECAST: CUSTOMER-OWNED DER REFERENCE CASE



DER MODELING OVERVIEW: PENDER

PenDER is an Agent Based Model (ABM)

Actions (*adoption decisions*) and interactions (*via social networks*) of thousands of autonomous “agents” are simulated to study their effects on DER adoption by customer class

PenDER is designed to:

- Provide granular forecasting of *DER adoption by demographics*
 - By socioeconomic variables (income, age, etc.) that characterize customer groups
 - By technology index of DER adoption (innovators, early adopters, imitators)
 - By region (county/neighborhood or distribution system designation)
- Simulate adoption *response to DER system costs*
 - Cost of DER is a key determinant of adoption decisions
- Simulate adoption *response to utility or market pricing*
 - Expected retail or wholesale rate growth
 - Financial incentives and costs

PENDER MODEL: KEY ASSUMPTIONS

Avoided Costs / Revenues – Estimated as annual production (based on expected solar capacity factor), in kWh, multiplied by avoided retail rate consumption or the **Excess Distributed Generation (EDG)** rate for excess generation, in \$/kWh.

PV Costs – Estimates rely on National Renewable Energy Laboratory's (NREL) *Annual Technology Baseline* (ATB) capital cost assumptions for Class 5 –PV Residential and Commercial Solar technologies– and are inclusive of expected ITC benefits.

Customer Budget – Assigned to each agent via probability distribution informed by the 2022 American Community Survey (ACS) 5-year census estimates. Customer budget is omitted from commercial forecasts, as agents are assumed to act in best economic interest and can utilize loans.

Payback Time – Based on the upfront capital cost, the cash flow from renewable energy incentives (i.e. EDG rates), discount rate, and solar PV lifetime, the payback period is determined by the number of years of discounted annual revenues that are required to cover the upfront PV system cost.

PENDER MODEL: SUMMARY OF MAJOR ASSUMPTIONS

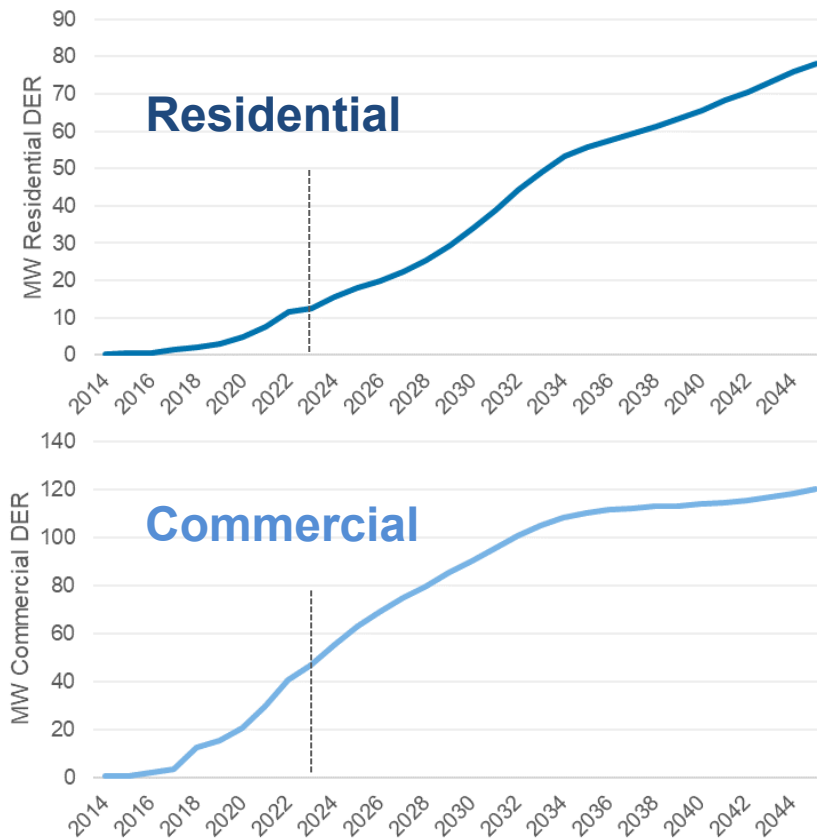
	Residential	Commercial
Solar Costs	NREL Curve w/ ITC	NREL Curve w/ ITC
Solar Capacity Factor	15.5%	15.5%
Solar Lifetime	25 years	25 years
Avg. System Size	8 kW	125 kW
Discount Rate	7.0%	6.0%
Inflation Rate	2.1%	2.1%

- Solar System Characteristics: NIPSCO-approximated capacity factor assumption for a typical DER solar system is based on NREL data and an assumed 25-year life for solar projects.
- Average Solar System Size: assumption based on average system size from NIPSCO historical solar DER adoption by customer class.
- Financial Inputs: assumes that small customers (i.e. residential) have higher financing costs than larger-scale customers with better access to capital

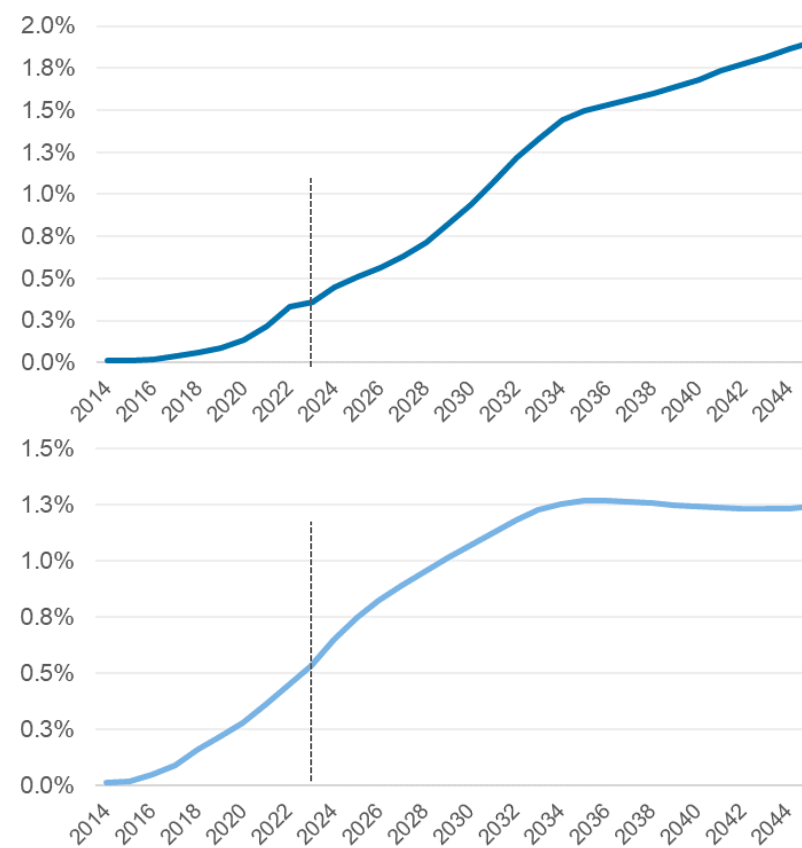
REFERENCE CASE PROJECTIONS

- Among residential customers, a total of 80 MW of installed Solar DER capacity is projected by 2045
- Among commercial customers, a total of 120 MW of installed Solar DER capacity is projected by 2045

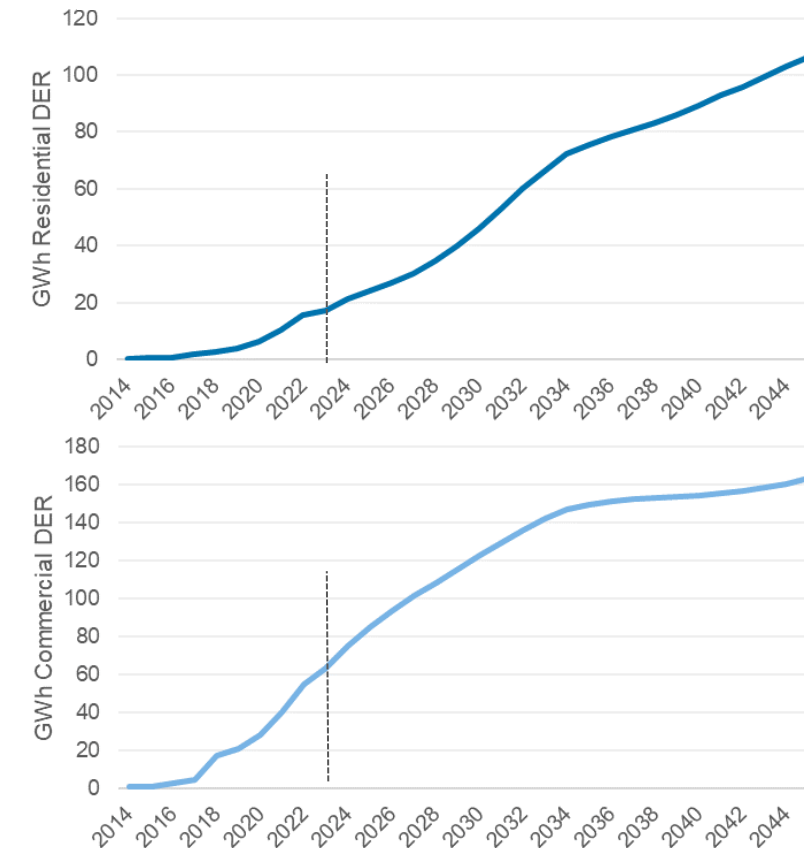
Total DER Capacity (MW)



Customer Penetration (%)



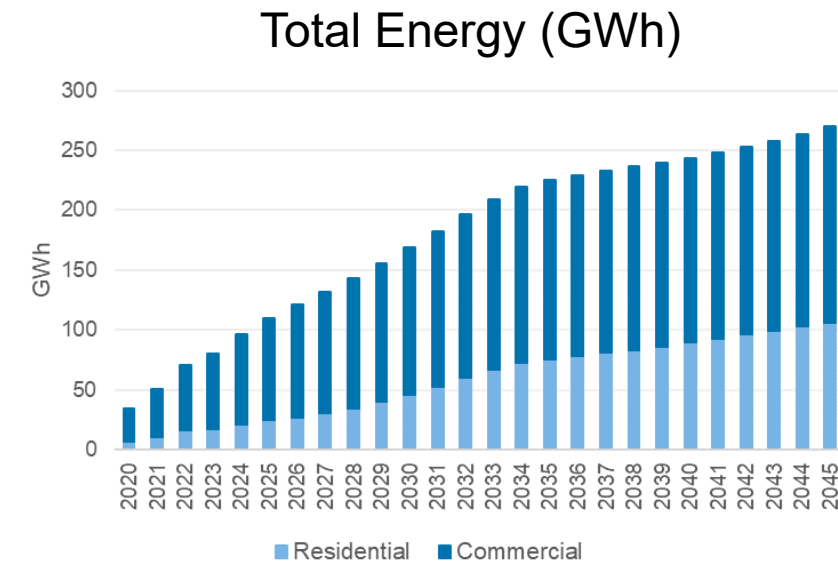
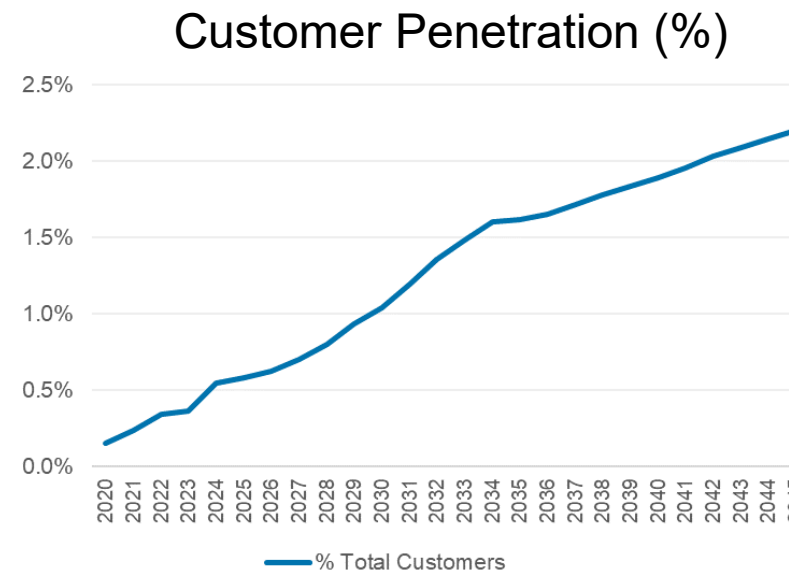
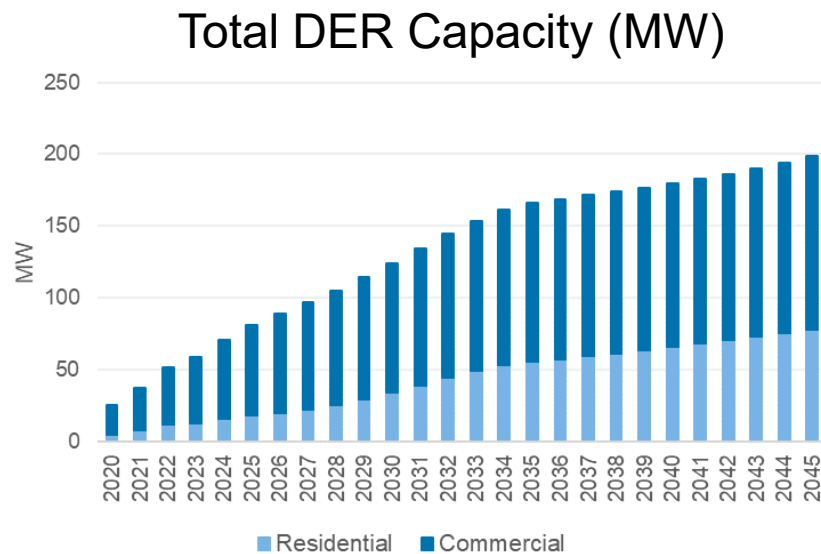
Total Energy (GWh)



We exist to deliver safe, reliable energy that drives value to our customers

REFERENCE CASE SUMMARY

- Overall, for the Reference Case, a total of 166 MW of installed Solar DER capacity is projected by 2035, 180 MW by 2040, and 200 MW by 2045.



We exist to deliver safe, reliable energy that drives value to our customers

DER SCENARIO CONSIDERATIONS

Scenario Name	Description	Capital Cost for Solar	ITC Incentives	Wholesale Rate Growth	Incentive Structure	DER Installation Size
 Reference Case	Reference Point	Base NREL Reference	Base IRA through 2035	Base	EDG Program Program continues unchanged through the planning horizon	Base Historic socioeconomic trends continue
 Slower Transition	Environmental policy incentives reduce; economic slowdown in region	High NREL Conservative ↑	Low IRA phase-out ↓	Low Lower commodity prices ↓	EDG Program Program continues unchanged through the planning horizon	Base Historic socioeconomic trends continue
 Domestic Resiliency	Influx of new economic development load (data center focus)	High NREL Conservative ↑	Base IRA through 2035	High Higher commodity prices. ↑	EDG Program Program continues unchanged through the planning horizon	High Increasing underlying load growth ↑
 Aggressive Environmental Regulation	Aggressive decarbonization policy, moderate electrification	Base NREL Reference	Base IRA through 2035	Highest Highest gas prices; environmental regulation (high CO ₂ price) ↑	EDG → Net Metering DER adoption encouraged through net metering, or another innovative design ↑	Base Historic socioeconomic trends continue
 Accelerated Innovation	Faster energy transition, high electrification with additional econ. dev. (data center) load	Low NREL Low ↓	Base IRA through 2035	Base Close to base, but model logic transitions to Net Metering	EDG Program Program continues unchanged through the planning horizon	Highest Economy-wide electrification driving larger customer UPC ↑

We exist to deliver safe, reliable energy that drives value to our customers

NEXT STEPS FOR DER ANALYSIS

- **Evaluate DER penetration levels across four alternative scenarios (Slower Transition, Domestic Resiliency, Aggressive Environmental Regulation, Accelerated Innovation)**
- **Integrate analysis with DSM study to assess opportunities for incentives for customer-owned storage installations (i.e., to improve capacity value of DER resources)**



We exist to deliver safe, reliable energy that drives value to our customers

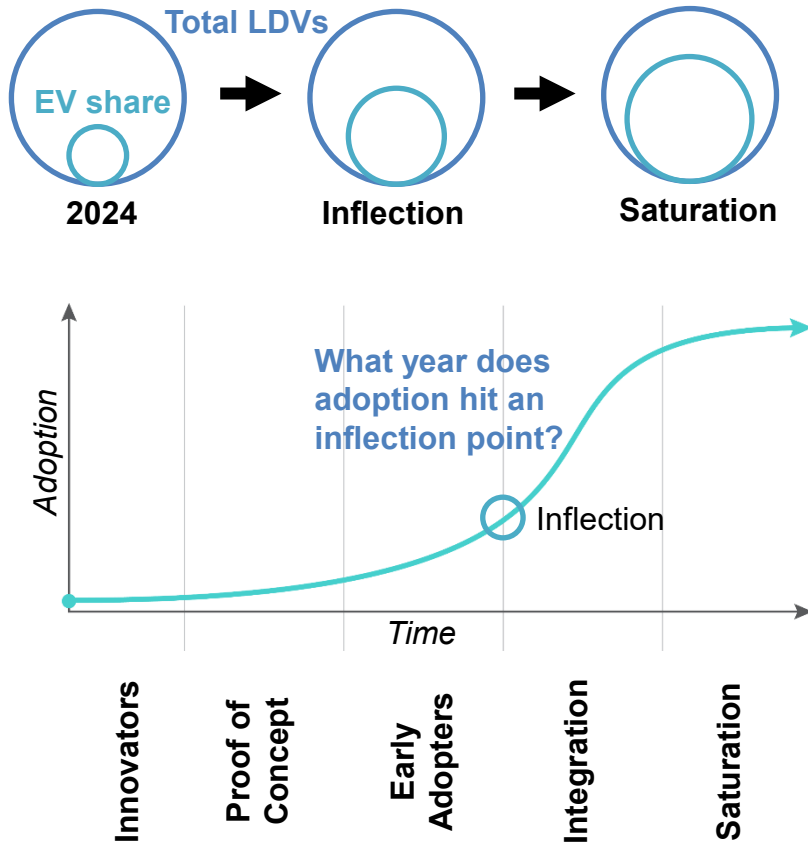
LOAD FORECAST: ELECTRIC VEHICLES REFERENCE CASE



LDV EV LOAD FORECASTING APPROACH

Blends econometric forecast with hourly shapes to capture long-term trends in vehicle growth and charging behavior, while accounting for weather conditions

1. Develop growth estimates based on adoption rates applied to S-curve



2. NREL's EVI-Pro-Lite tool to develop hourly shapes

- Utilize NREL's EVI-Pro-Lite tool to develop hourly shapes
- Develop profiles to address long-term trends in vehicle type and charger behavior

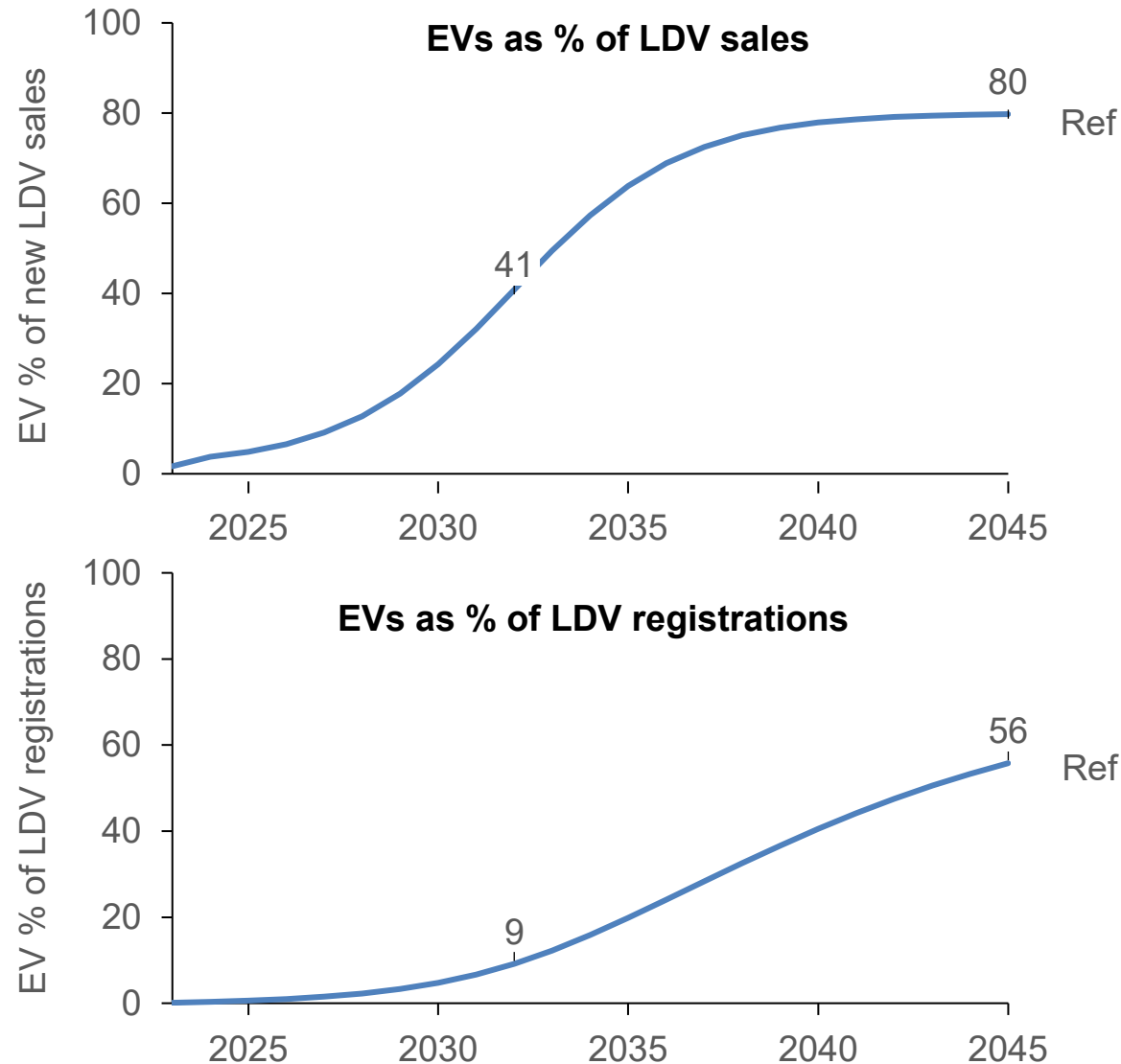
3. Develop final hourly load forecast based on EV projections and hourly shapes

- Econometric model determines total number of electric vehicles and vehicle efficiency, which will scale total EV demand over each year (Step 1)
- Take seasonal charging profiles and create 8760 shapes

We exist to deliver safe, reliable energy that drives value to our customers

LDV EV ADOPTION PROJECTIONS

Reference LDV adoption trajectory would meet New EPA targets



Adoption Overview

- NIPSCO has taken views on how adoption may unfold over time, leveraging current EV data and third-party projections
- Current estimated penetration of ~1.6% of new sales in NIPSCO's service territory (estimate based on analysis of IN Fuel Dashboard data from 2018-2023)
- A sigmoid function is used to create intermediate sales values by year, where the Reference Case reaches an 80% of sales target by 2045

LDV HOURLY SHAPES

Utilizes NREL's EVI-Pro-Lite tool to develop hourly shapes, blending profiles to address long-term trends in vehicle type

As EV adoption becomes more widespread, model forecasts will align with changes in charging behavior and charger / vehicle efficiencies

2024 Load Profile

- Primary home and work charging strategy: *as fast as possible*
- Home charger composition: 20% L1, 80% L2
- Uses EVI-pro default values, assuming same EV efficiency

2030 Load Profile

- Home charger composition: 50% L1, 50% L2
- Efficiency factor applied to dampen the kW per EV required

2040 Load Profile

- Home charger composition: 50% L1, 50% L2
- Continued efficiency factor applied to dampen the kW per EV even more

Other considerations:

- Distinct patterns applied for weekday versus weekend / holiday
- Hourly profile is temperature dependent (nearest 10 degree C)

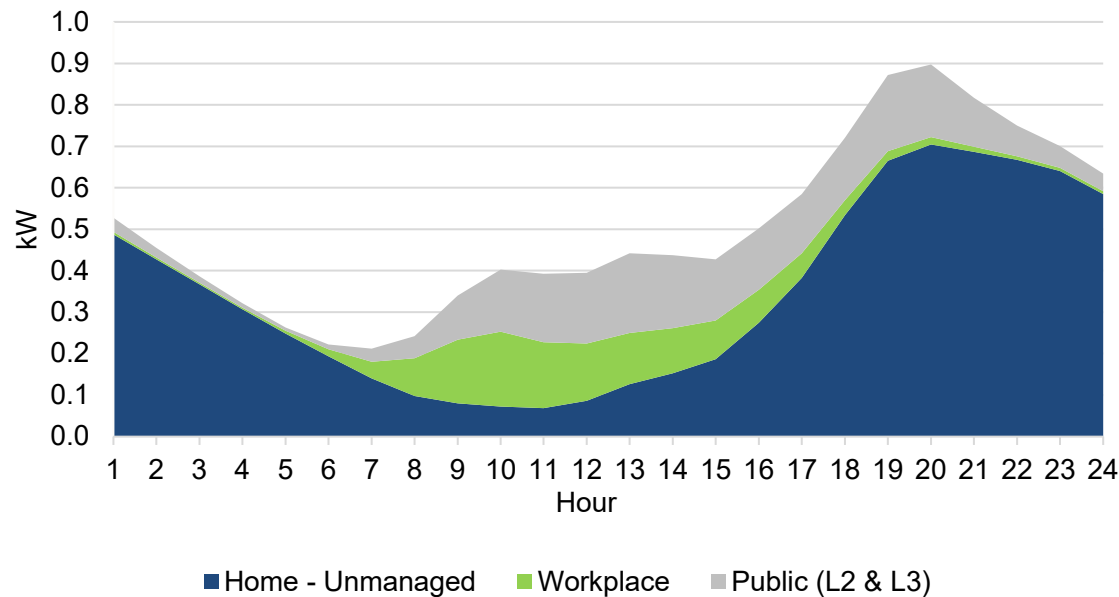
PROJECTED LDV LOAD IMPACTS OVER TIME

	2024	2030	2040
Total EVs	2,006	33,016	283,967
BEV Sedan Efficiency (mi / kWh)	2.57	3.50	5.00
BEV SUV Efficiency (mi / kWh)	2.30	3.00	4.50
Annual Sales (MWh)	8,243	129,000	866,000
Annual Peak (MW)	2.15	32.3	214.5

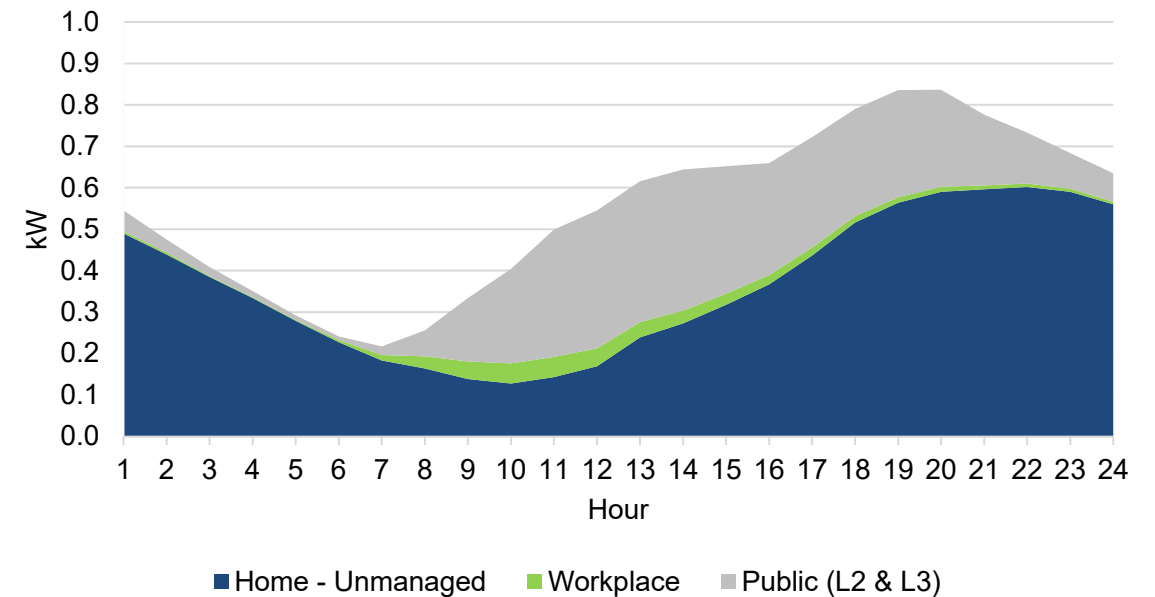
Seasonal Coincident Peaks (MW)

	2024	2030	2040
Winter	1.93	28.8	189
Spring	1.93	29.6	194
Summer	1.34	20.2	156
Fall	1.61	28.8	189

2030 weekday profile (kW / vehicle)



2030 weekend profile (kW / vehicle)

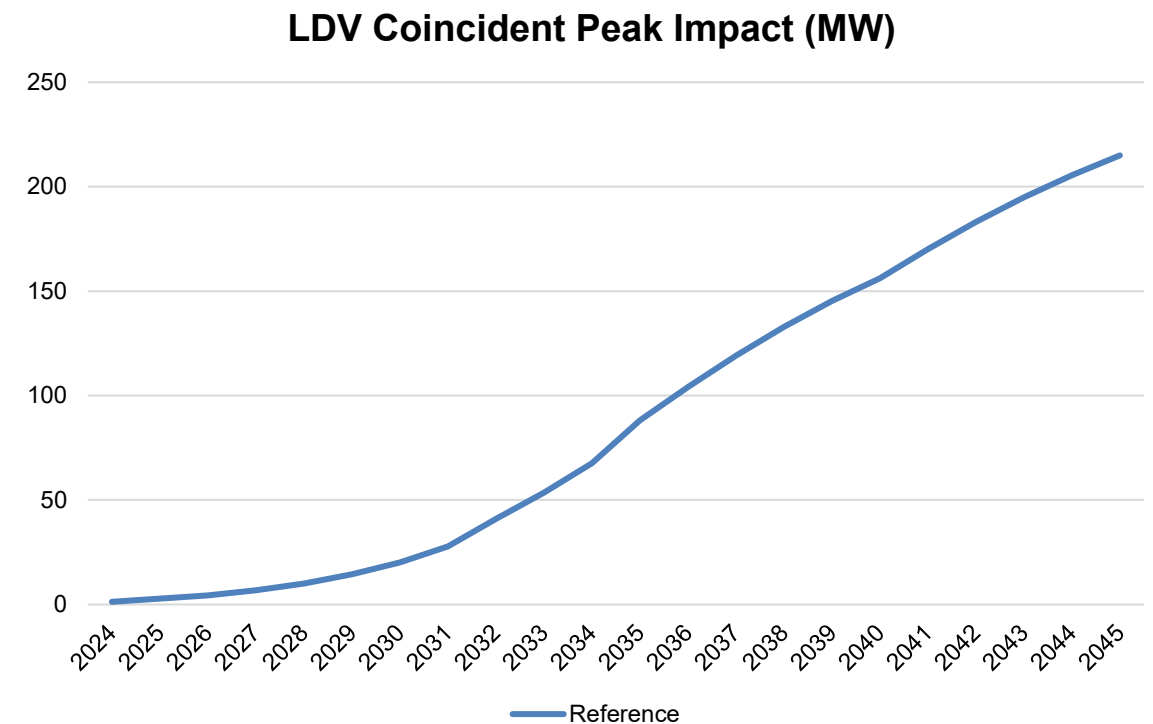
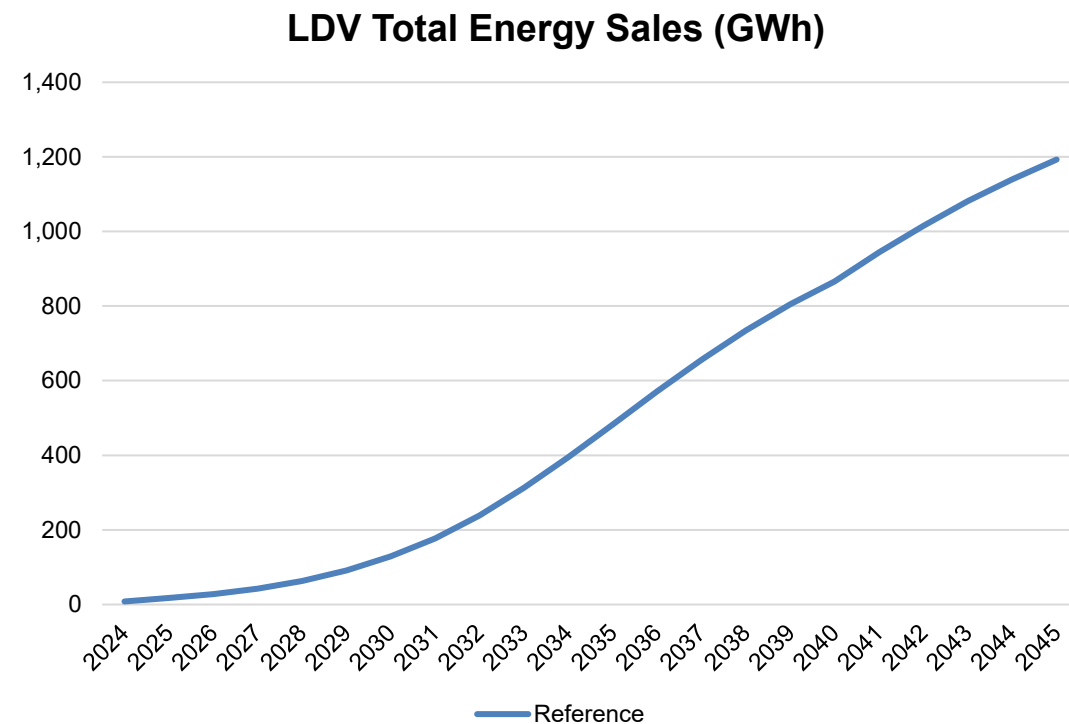


*Note that charging is assumed to be "unmanaged" for LDV segment. DSM analysis will evaluate managed charging programs

We exist to deliver safe, reliable energy that drives value to our customers

LDV SALES AND COINCIDENT PEAK GROWTH, ASSUMING NO INTERVENTION TO ENCOURAGE MANAGED CHARGING

- A relatively modest peak load impact is expected (<20 MW) until 2030, when an inflection in EV sales heightens overall impact of LDV segment
- Steady growth expected to raise peak contributions to more than 150 MW in the reference case by 2040
- Energy sales roughly mirror peaks, with similar dampening of per vehicle kWh contribution driven by higher vehicle efficiencies



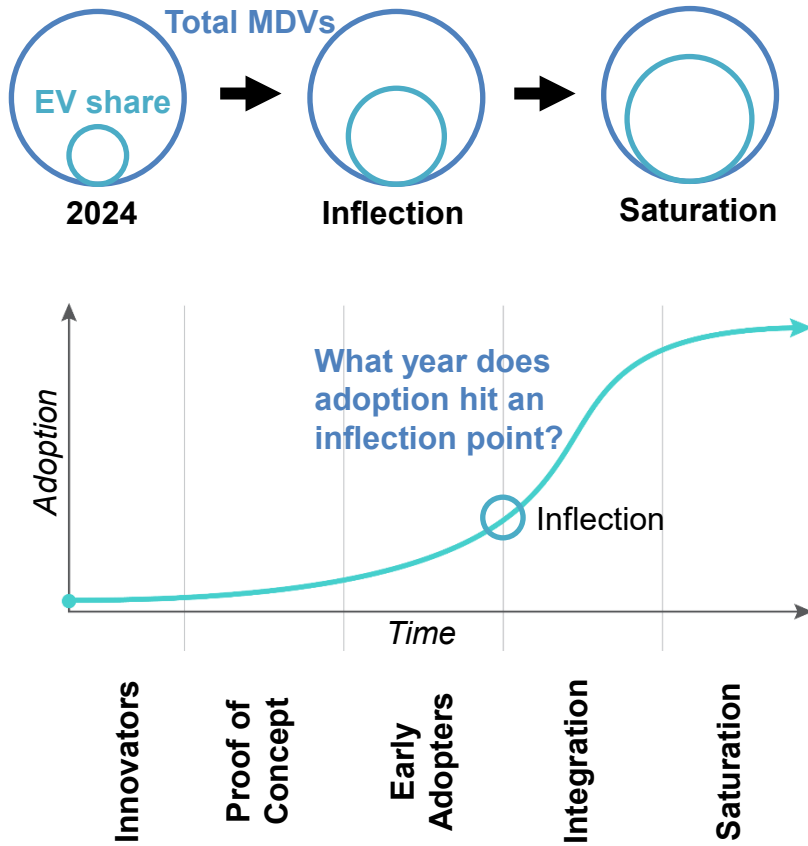
*Note that charging is assumed to be “unmanaged” for LDV segment. DSM analysis will evaluate managed charging programs

We exist to deliver safe, reliable energy that drives value to our customers

MDV EV LOAD FORECASTING APPROACH

Blends econometric forecast with hourly shapes to capture long-term trends in vehicle growth and charging behavior, while accounting for weather conditions

1. Develop growth estimates based on adoption rates applied to S-curve



2. Generic MDV shapes to capture potential hourly dynamics

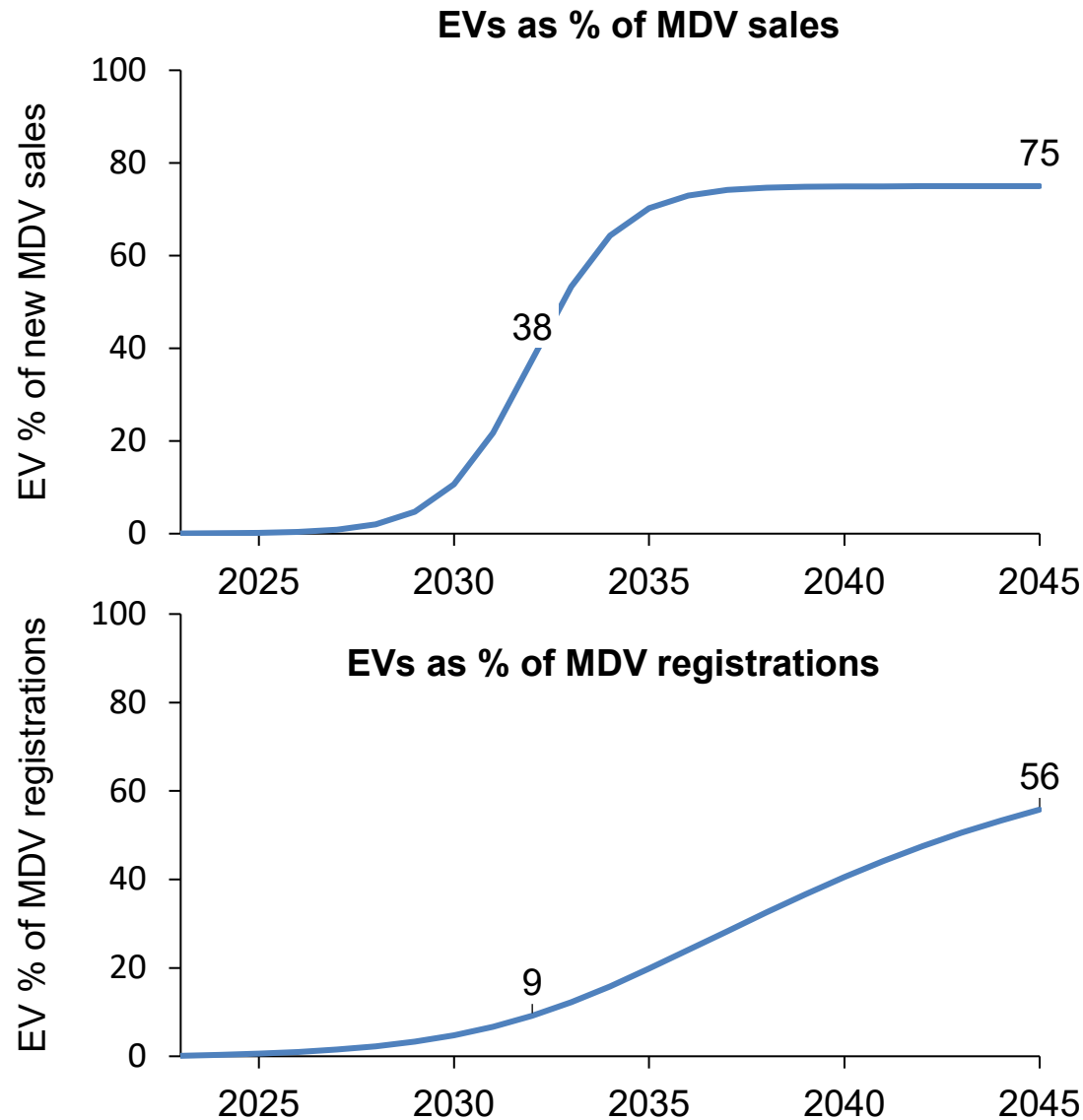
- Utilize charging shapes from existing industry / academic research
- Apply temperature and vehicle efficiency assumptions to create seasonal and long-term adjustments to shape
- Develop profiles to address long-term trends in vehicle type and charger behavior

3. Develop final hourly load forecast based on EV projections and hourly shapes

- Econometric model determines total number of electric vehicles and vehicle efficiency, which will scale total EV demand over each year (Step 1)
- Take seasonal charging profiles and create 8760 shapes

We exist to deliver safe, reliable energy that drives value to our customers

MDV EV ADOPTION PROJECTIONS AIM TO ASSESS CUSTOMER FLEET ELECTRIFICATION



Adoption Overview

- NIPSCO has utilized IN Fuel Dashboard ICE and EV registration data to develop an estimate of the existing EV penetration and ICE fleet and has taken a view on how adoption may unfold over time, leveraging third-party studies
- Current fleet electrification is very small, based on analysis of IN Fuel Dashboard data from 2018-2023
- A sigmoid function is used to create intermediate sales values by year, where the Reference Case achieves a 75 % of sales target by 2045

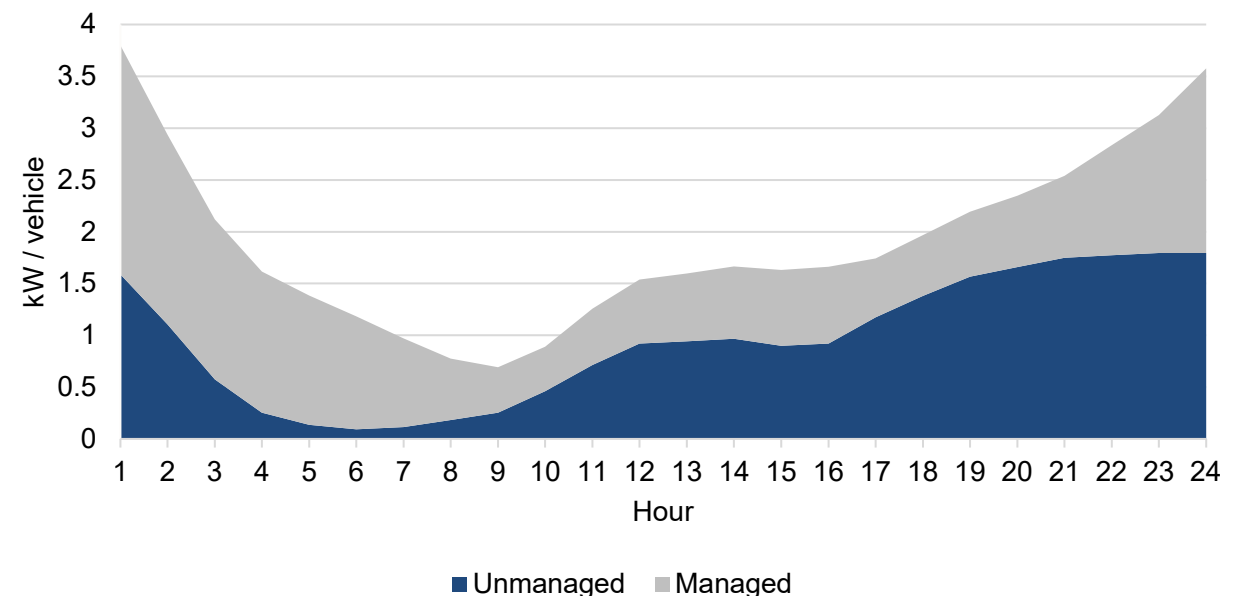
PROJECTED MDV LOAD IMPACTS OVER TIME

Takeaways

- Overall impacts from MDV fleet likely to be modest until the longer-term
- Some level of managed charging is likely to lower evening peak load, distributing impacts to 12am – 2am

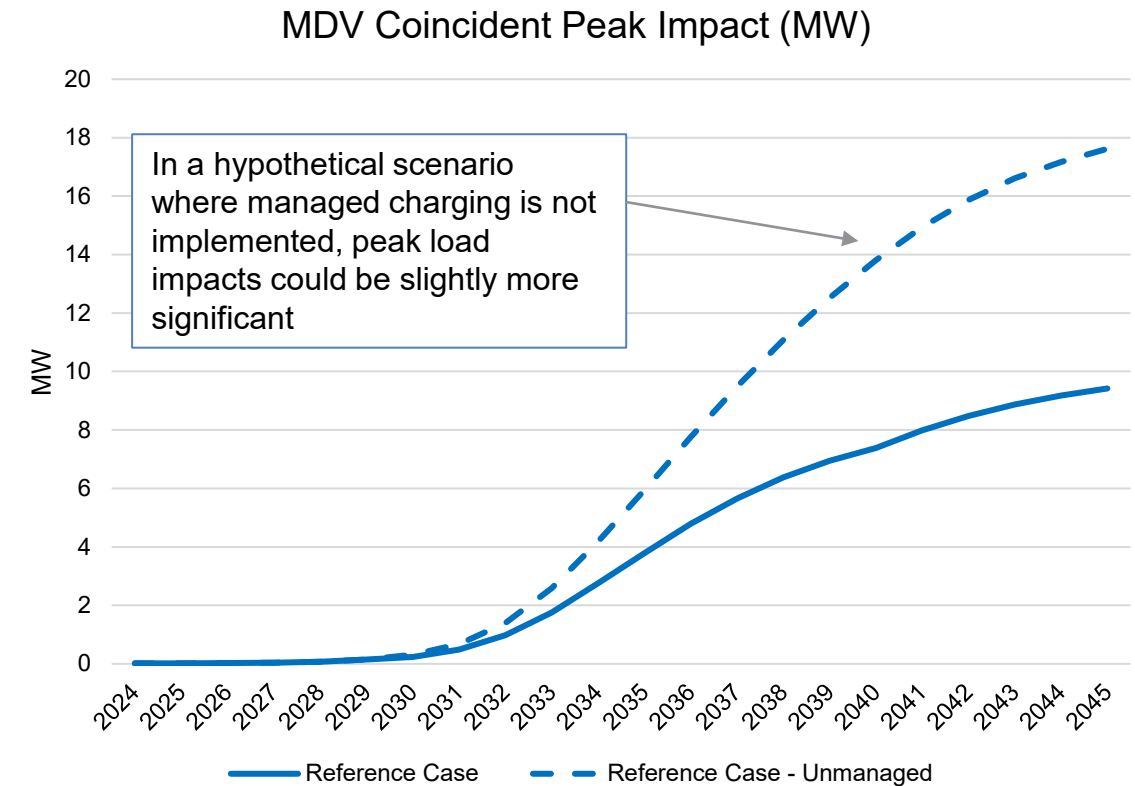
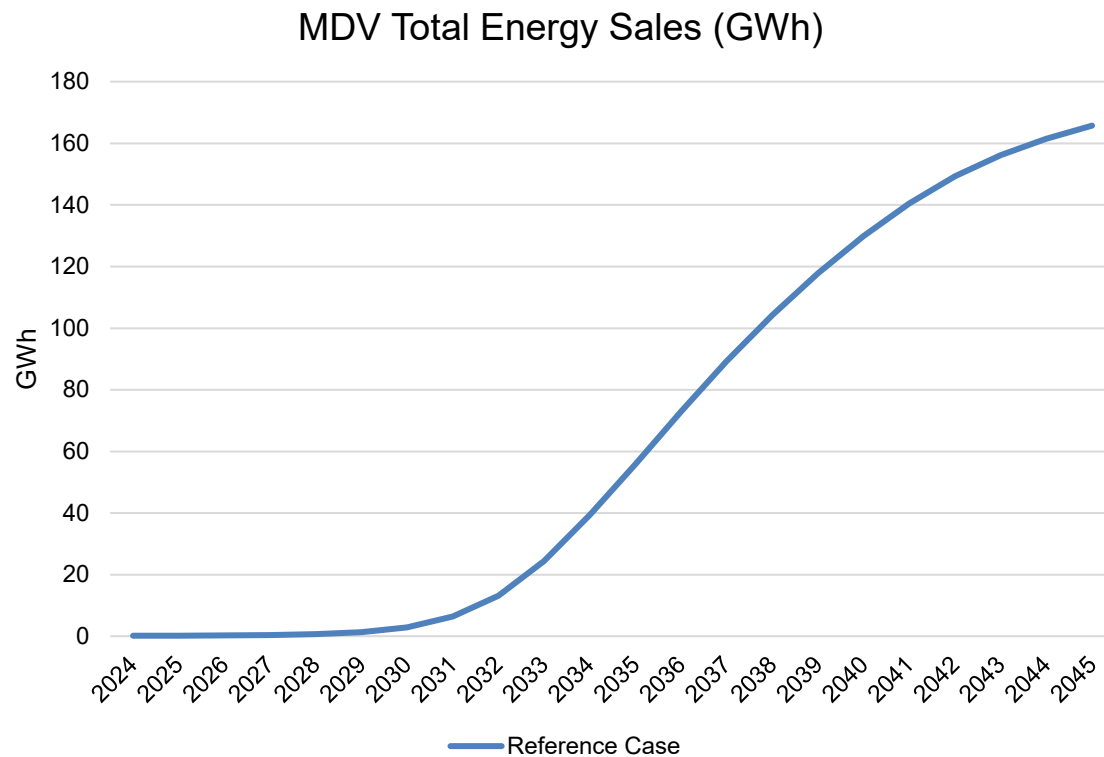
	2030	2040
Total Fleet/Delivery Vehicles	167	8,939
Total Transit Vehicles	4	170
Fleet/Delivery Efficiency (kWh / mi)	1.18	1.05
Transit Efficiency (kWh / mi)	0.81	0.73
Fleet/Delivery VMT / day	37	37
Transit VMT / day	55	55
Annual Sales (MWh)	2,923	130,000
Annual Peak (MW)	0.81	40.6
Coincident Peak (MW)	0.23	7.38

2030 Weekday Profile (kW / vehicle)



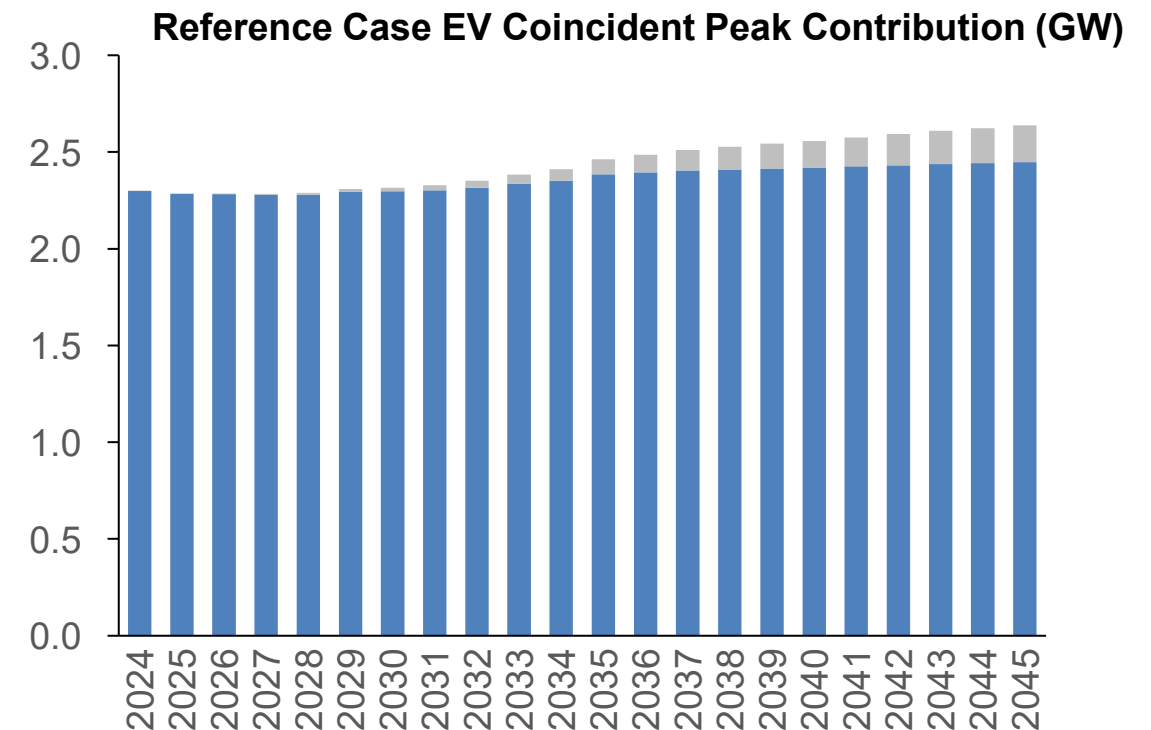
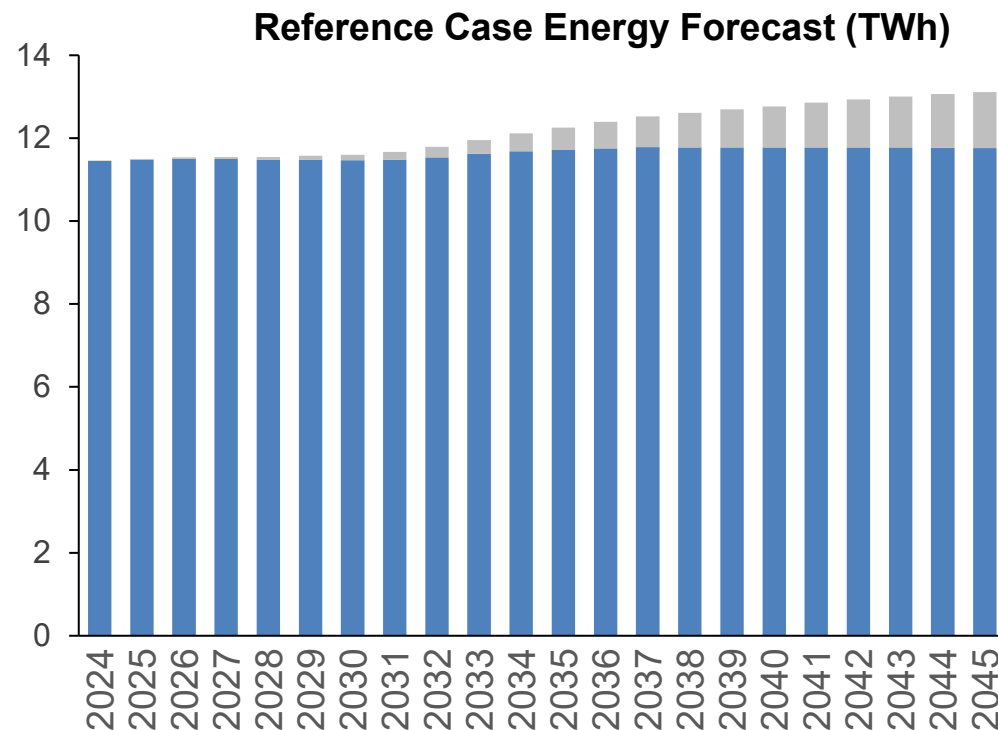
MDV FORECAST: SALES AND COINCIDENT PEAK GROWTH

- MDV are expected to have modest energy sales and load impacts, with roughly 10% of the demand seen in the LDV segment
- Energy sales roughly mirror peaks, with similar dampening of per vehicle kWh contribution driven by higher vehicle efficiencies



WHILE EV ADOPTION IS EXPECTED TO MEET EPA TARGETS IN THE REFERENCE CASE, EV'S HAVE A RELATIVELY MODEST IMPACT ON ENERGY AND PEAKS

- EV energy demand is expected to grow modestly through the mid-2020s, taking off more significantly in the 2030s as EV options and charging infrastructure proliferate
- While EV adoption is expected to reach 80% of LDV sales and 75% of MDV sales by 2045, they are only expected to contribute to ~7% of coincident peak by 2045 in the Reference Case



EV Demand Other Energy

We exist to deliver safe, reliable energy that drives value to our customers

NEXT STEPS FOR EV FORECAST

- Evaluate higher and lower EV penetration levels to map to four alternative scenarios (Slower Transition, Domestic Resiliency, Aggressive Environmental Regulation, Accelerated Innovation)
- Perform study on heavy duty vehicle charging in major transit corridors
- Integrate analysis with DSM study to assess opportunities for managed charging incentives in the LDV segment

NEXT STEPS FOR LOAD FORECAST

- Investigate various levels of DER and EV penetration
- Evaluate transitory charging in the NIPSCO service territory associated with heavy duty vehicles on major highways
- Investigate new load growth driven by new manufacturing and economic development opportunities
- Develop full load forecast scenario range for all key drivers
- Coordinate with DSM team so that evaluations of managed EV charging and customer-owned storage incentives can be studied as part of the portfolio analysis
- NIPSCO welcomes stakeholder input on analysis approach and scenario considerations
 - NIPSCO is open to one-on-one calls with stakeholders to discuss analysis in more detail



We exist to deliver safe, reliable energy that drives value to our customers

BREAK





We exist to deliver safe, reliable energy that drives value to our customers

2024 REQUEST FOR PROPOSALS (RFP) UPDATE

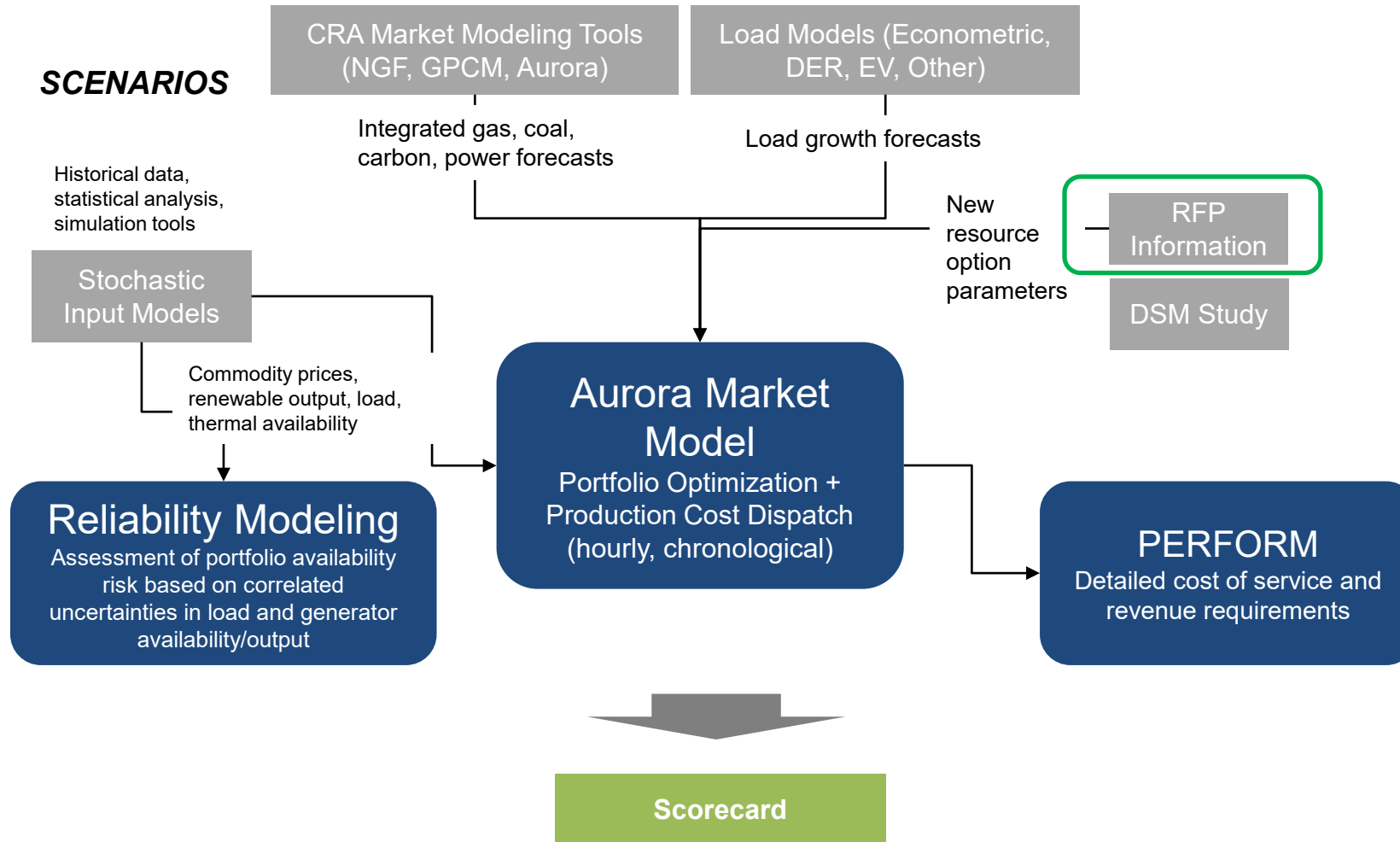
Patrick d'Entremont, Manager Planning Commercial Support, NIPSCO

Bob Lee, Vice President, CRA



RESOURCE PLANNING APPROACH: RFP INFORMATION

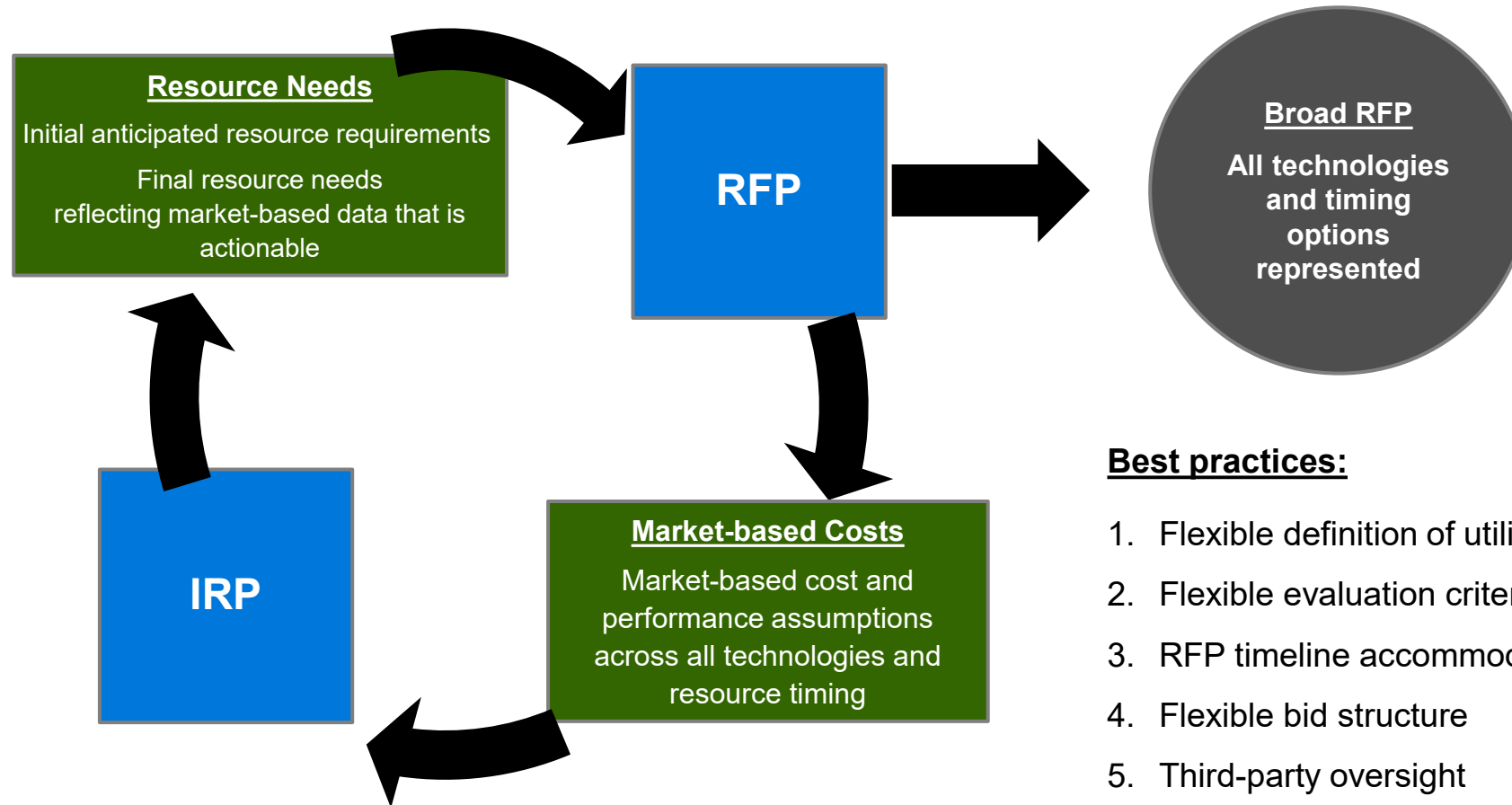
Key Modeling and Analysis Tools



- ① Identify key planning questions and approach
- ② Develop market perspectives (scenarios)
- ③ Develop integrated resource strategies (NIPSCO portfolios)
- ④ Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- ⑤ Evaluate trade-offs and select preferred plan

RFP PROCESS: CONSISTENT WITH 2018 AND 2021, NIPSCO PLANS TO RUN AN RFP AS A PART OF THE 2024 IRP

Integrated IRP to RFP structure



Best practices:

1. Flexible definition of utility needs
2. Flexible evaluation criteria
3. RFP timeline accommodates IRP modeling requirements
4. Flexible bid structure
5. Third-party oversight

OVERVIEW OF NIPSCO'S 2024 RFP PROCESS

- During Q2 2024 NIPSCO intends to issue a series of RFP solicitations designed to identify resources positioned to support the Company's near and long-term resource requirements
- Each individual solicitation will be executed in parallel as part of the RFP and will target specific technologies and resource categories
- As has been done in the past, the asset cost data, and performance and resource availability data derived from RFP bids will be used as inputs into the Company's resource planning process to create a "Preferred Plan" informed by actual market data

PRELIMINARY RFP PLAN

----- All-Source RFP -----

Element	RFP1 – Intermittent	RFP2 – Dispatchable	RFP3 – Bridge Resources	RFP4 – DER
Technology	Renewables and hybrid resources	Thermal, standalone storage, emerging technologies and other (including long-duration storage and NIPSCO site-specific storage options)	Near-term bridge resources that provide both energy and capacity solutions designed to respond to large-scale, new customer activity	Distributed energy resources that qualify for IRA incentives and/or provide MISO capacity credit
Event Size	Up to 400 MW	Up to 600 MW	Between 600-1,000 MW	Up to 10 MW
Ownership Structure	Unit contingent PPA, BTA, existing asset sales	Unit contingent PPA, system power, BTA, existing asset sales, shaped products. Site-specific storage solutions must be for NIPSCO ownership per MISO generator replacement rules	ZRC, PPA, shaped or financial products, unit contingent PPA, BTA, existing asset sales	Unit contingent PPA, existing asset sales
Duration	Targeting resources in 36-60 months with 5+ years duration	Targeting resources in 36-60 months with 5+ years duration	Targeting resources in 18-36 months with 3 to 5+ years duration, and long-term resources in the 5+ year horizon	Targeting resources in 36-60 months with 5+ years duration
Deliverability	LRZ6, NRIS, (N-1-1)	LRZ6, NRIS, (N-1-1)	Flexible	Distribution resources
Qualification Requirements	Credit worthy counterparties	Credit worthy counterparties	Credit worthy counterparties	Credit worthy counterparties

We exist to deliver safe, reliable energy that drives value to our customers

RFP: PRELIMINARY EVALUATION CRITERIA



Project Economics LCOE / LCOC

The economic analysis will be conducted over a fixed planning horizon and a bid-specific planning horizon for all assets. The analysis will reflect all expected costs related to the bid. The project-level analysis will be based on data submitted with the bids, standard assumptions for key commodity considerations, and may reflect adjustments for material uncertainties associated with a bid



Reliability and Deliverability

The asset reliability and deliverability evaluation will include an assessment of transmission reliability, facility age and performance, and fuel risk and fuel security. Transmission reliability scoring will be based on transmission infrastructure and location. Facility performance will be based on the EFORD performance or other accreditation expectations. Fuel reliability will consider fuel availability risk and price volatility



Development

Development risk will consider how many key development milestones have been met to date, as well as the development experience of the potential counterparty



Asset Specific Benefits / Risks

Asset-specific benefits and risks will consider individual, unique, and project-level risks associated with an individual project or counterparty. CRA will evaluate projects based on community benefits, certain social justice goals, minority and women owned business considerations, unique environmental considerations, specific regulatory risks or other considerations

PRELIMINARY RFP TIMELINE

----- All-Source RFP -----

Element	RFP1 – Intermittent	RFP2 – Dispatchable	RFP3 – Bridge Resource	RFP4 – DER
Issue RFP	May 1, 2024	May 1, 2024	May 1, 2024	May 1, 2024
Bidder Information Session	May 6, 2024	May 6, 2024	May 6, 2024	May 6, 2024
Pre-Qualification Deadline	May 15, 2024	May 15, 2024	May 15, 2024	May 15, 2024
Notification of Pre-Qualification	May 20, 2024	May 20, 2024	May 20, 2024	May 20, 2024
Proposals Due	June 7, 2024	June 7, 2024	June 7, 2024	June 20, 2024



We exist to deliver safe, reliable energy that drives value to our customers

2024 STAKEHOLDER ADVISORY PROCESS

Fred Gomos, Director Strategy, NiSource



Tentative

2024 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 April 23rd	Meeting 2 June 24 th	Meeting 3 August 21 st	Meeting 4 September 19 th	Meeting 5 October 8 th
Content	• 2021 Short Term Action Plan Update • Resource Planning and 2024 Continuous Improvements • 2024 Public Advisory Process • 2024 Policy Update (incl. IRA and EPA) • Core demand forecast, new considerations for demand • Scenario Themes – Introduction • RFP Overview	• MISO Regulatory Developments and Initiatives • Update on Key Inputs/Assumptions (commodity prices) • Scenarios and Stochastic Analysis Inputs • Preliminary RFP Results	• DSM Modeling and Methodology • DER Inputs	• Modeling Results, Scorecard • DER and Storage Modeling Results, Scorecard	• Preferred replacement path and logic relative to alternatives • 2024 NIPSCO Short Term Action Plan
Meeting Goals	• Communicate what has changed since the 2021 IRP (incl. IRA changes) • Communicate environmental policy considerations • Communicate updates to key inputs/assumptions • Provide RFP Overview • Communicate the 2024 public advisory process, timing, and input sought from stakeholders	• Common understanding of MISO regulatory updates • Communicate commodity price impacts • Communicate scenario themes and stochastic analysis approach, along with major input details and assumptions • Communicate preliminary RFP results	• Common understanding of DSM modeling methodology • Explain next steps for portfolio modeling	• Develop a shared understanding of economic modeling outcomes and preliminary results to facilitate stakeholder feedback	• Respond to key stakeholder comments and requests • Communicate NIPSCO's preferred resource plan and short-term action plan • Obtain feedback from stakeholders on preferred plan

We exist to deliver safe, reliable energy that drives value to our customers

AURORA MODELING LICENSE GUIDELINES

- Any interested stakeholder will need to declare their interest in a special use stakeholder Aurora license by May 15th
- Stakeholders will be able to sign a limited license agreement with Energy Exemplar for the Aurora software
- Stakeholders will be given access to relevant data sets for NIPSCO portfolio modeling as it becomes available



We exist to deliver safe, reliable energy that drives value to our customers

CLOSING





We exist to deliver safe, reliable energy that drives value to our customers

APPENDIX



NIPSCO'S CURRENT ENVIRONMENTAL CONTROL OVERVIEW

NIPSCO has invested in environmental controls across the fleet and continues a transition to low- and zero-emitting resources

Unit	Year In Service	Fuel Source	Generating Capacity (MW) ⁽¹⁾	Particulate Matter (PM) Control	Sulfur Dioxide (SO ₂) Control	Nitrogen Oxide (NO _x) Control	Mercury (Hg) Control	Coal Ash	Planned Retirement ⁽⁴⁾
MCGS U12	1974	Coal	455	Baghouse	Dry FGD	OFA & SCR	ACI & FA	SFC	2028
RMS U16A	1979	Natural Gas	78	--	--	Water Injection	--	--	2026-2028
RMS U16B	1979	Natural Gas	77	--	--	Water Injection	--	--	2026-2028
RMS U17	1983	Coal	361	ESP	Wet FGD	Advanced LNB w/ OFA & SNCR	--	--	2025
RMS U18	1986	Coal	361	ESP	Wet FGD	Advanced LNB w/ OFA & SNCR	--	--	2025
Sugar Creek ⁽²⁾	2002	Natural Gas	563	--	--	SCR	--	--	--
Norway	1923	Hydro	7	--	--	--	--	--	--
Oakdale	1925	Hydro	9	--	--	--	--	--	--
Rosewater ⁽³⁾	2020	Wind	102	--	--	--	--	--	--
Indiana Crossroads Wind ⁽³⁾	2021	Wind	302	--	--	--	--	--	--
Dunns Bridge I ⁽³⁾	2023	Solar	265	--	--	--	--	--	--
Indiana Crossroads Solar ⁽³⁾	2023	Solar	200	--	--	--	--	--	--

ESP = Electrostatic Precipitator
SCR = Selective Catalytic Reduction
ACI = Activated Carbon Injection

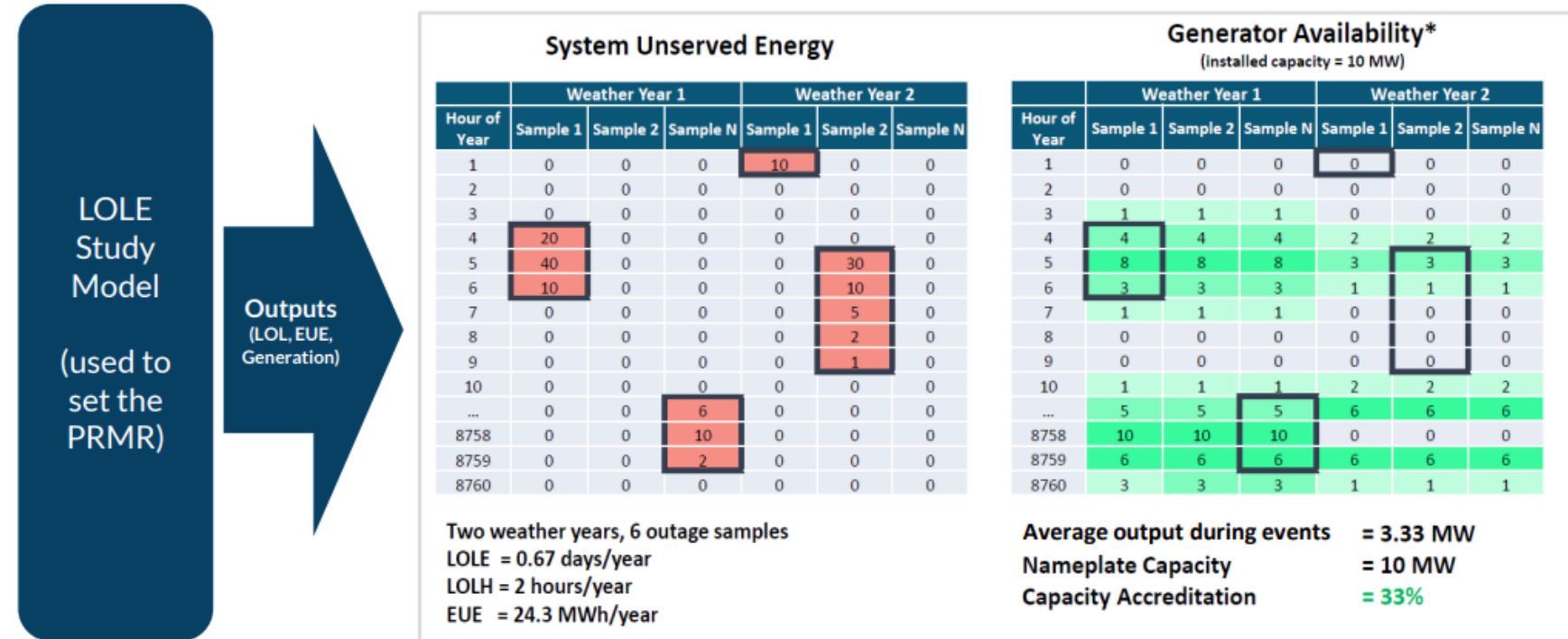
FGD = Flue Gas Desulfurization
LNB = Low NO_x Burners
FA = Fuel Additives

OFA = Over-Fire Air System
SNCR = Selective Non-Catalytic Reduction
SFC = Submerged Flight Conveyor

We exist to deliver safe, reliable energy that drives value to our customers

(1) Represents current net generating capability of each fossil fuel and hydro generating facility. Nameplate capacity is listed for wind and solar generating facilities.
(2) Sugar Creek added additional generating capacity in January 2024.
(3) NIPSCO is the managing partner of these Joint Ventures.
(4) As of April 2024.

MISO'S PROPOSED D-LOL APPROACH USES SAMPLE WEATHER YEARS TO EVALUATE GENERATOR AVAILABILITY DURING PERIODS OF LOSS OF LOAD RISK



Adapted from: <https://www.esig.energy/download/session-5-redefining-capacity-accreditation-derek-stenclik/>

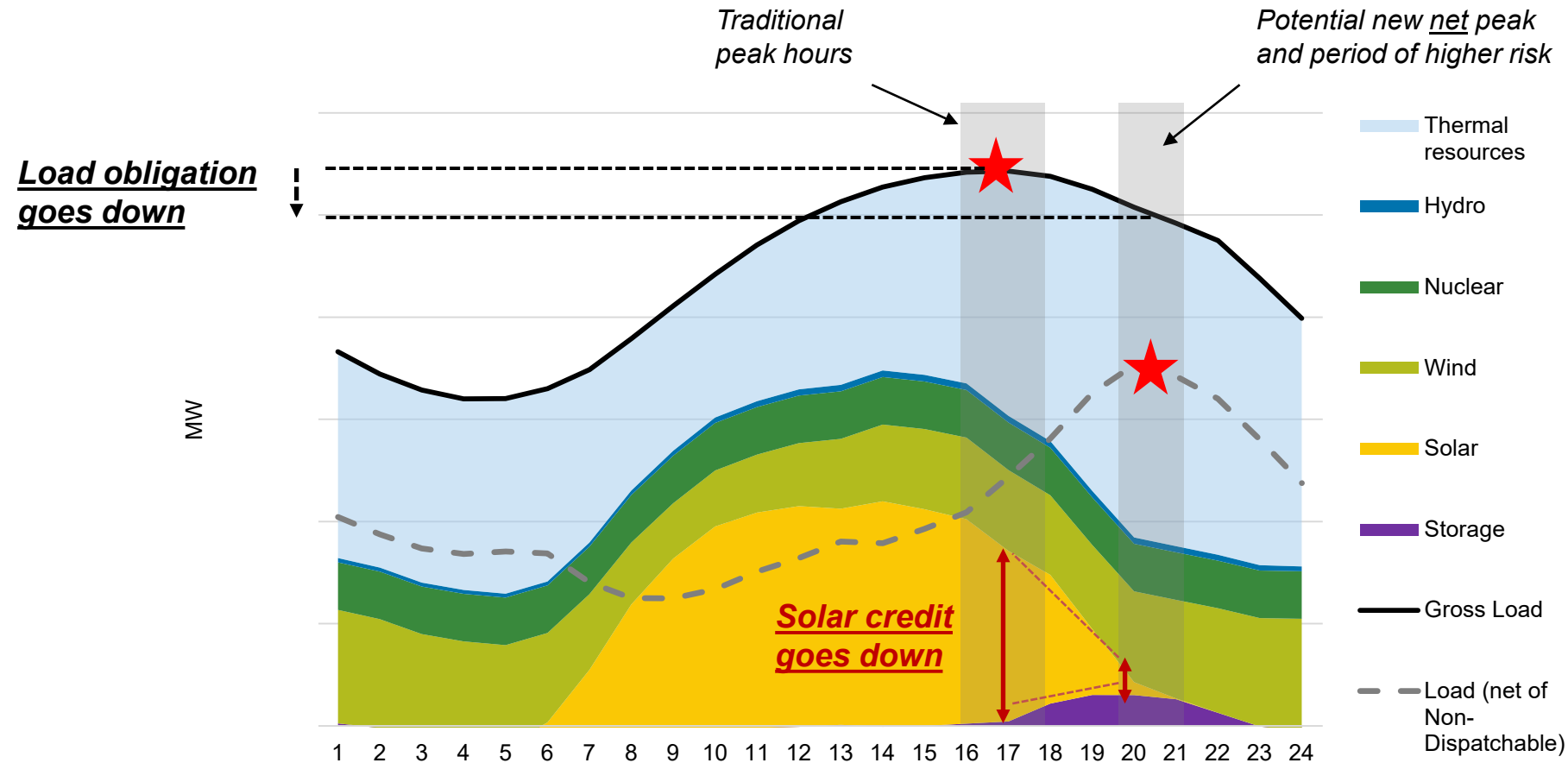
10 LOLH = Loss of Load Hour EUE = Expected Unserved Energy LOLE = Loss of Load Expectation PRMR = Planning Reserve Margin Requirement



Source:
MISO Accreditation Reform: [https://cdn.misoenergy.org/20230117-18%20RASC%20Item%2014b%20Non-Thermal%20Resource%20Accreditation%20\(RASC-2020-4,%20RASC-2019-2\)%20Presentation627472.pdf](https://cdn.misoenergy.org/20230117-18%20RASC%20Item%2014b%20Non-Thermal%20Resource%20Accreditation%20(RASC-2020-4,%20RASC-2019-2)%20Presentation627472.pdf)

We exist to deliver safe, reliable energy that drives value to our customers

ALTHOUGH CAPACITY ACCREDITATIONS WILL DECLINE, THE PLANNING OBLIGATION WILL ALSO LIKELY GO DOWN IN MISO'S D-LOL APPROACH



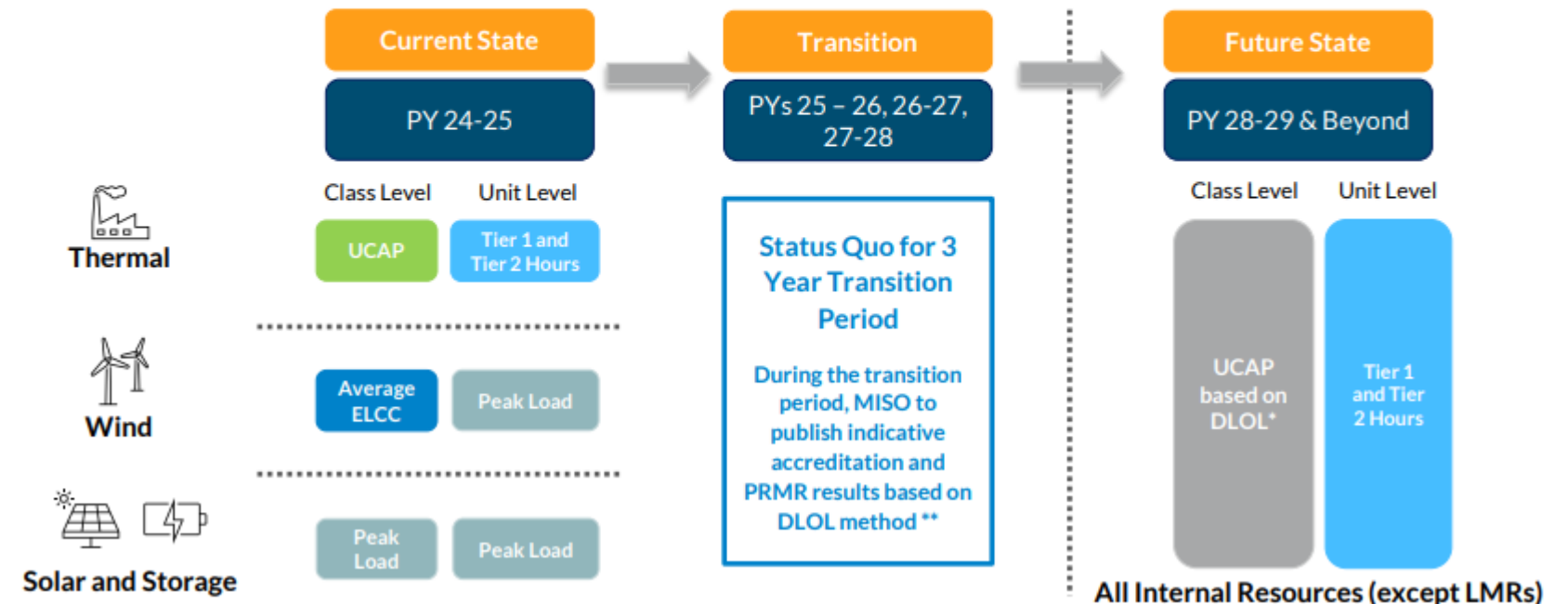
Representative – For Illustration Purposes

We exist to deliver safe, reliable energy that drives value to our customers

A TRANSITION PERIOD IS CONTEMPLATED IN MISO'S D-LOL FILING

- MISO filed its Direct Loss of Load (D-LOL) market design on March 28, 2024 with the FERC
- Stakeholder feedback could still impact final design, and FERC approval is necessary
- MISO would implement a three-year transition period to provide initial market signals before actual market changes are made

A three-year transition allows time for stakeholders to better understand and plan for the accreditation and reserve margin calculations based on DLOL approach

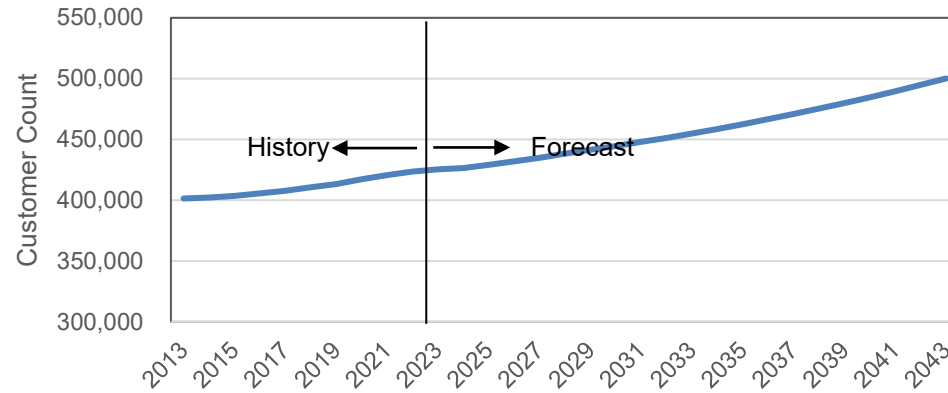


LOAD FORECAST: ACCOUNTING FOR LOSSES

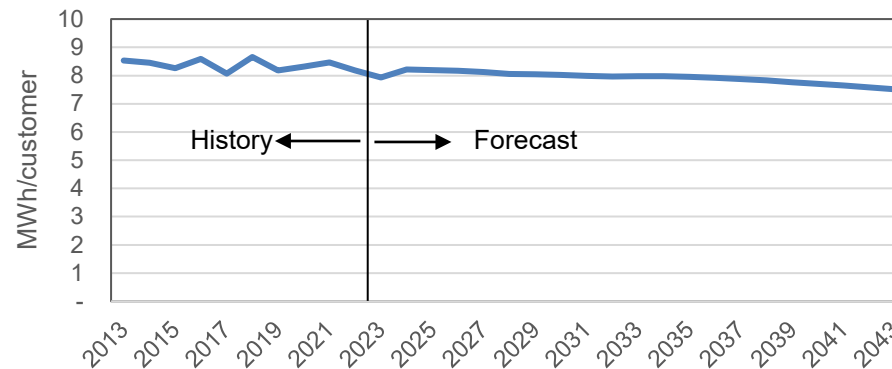
- Although core historical load data is recorded at the meter, IRP modeling must include “gross-ups”
- From an energy perspective, IRP modeling must incorporate the amount of energy that needs to be generated by resources prior to facing losses associated with transmission and distribution to customers
- For MISO peak planning purposes, peak demand needs to be:
 - Inclusive of distribution losses when reporting coincident peaks
 - Grossed up for transmission losses when calculating the planning reserve margin
- Therefore, projected retail sales totals were grossed up by a factor of 4.62%.

RESIDENTIAL FORECAST

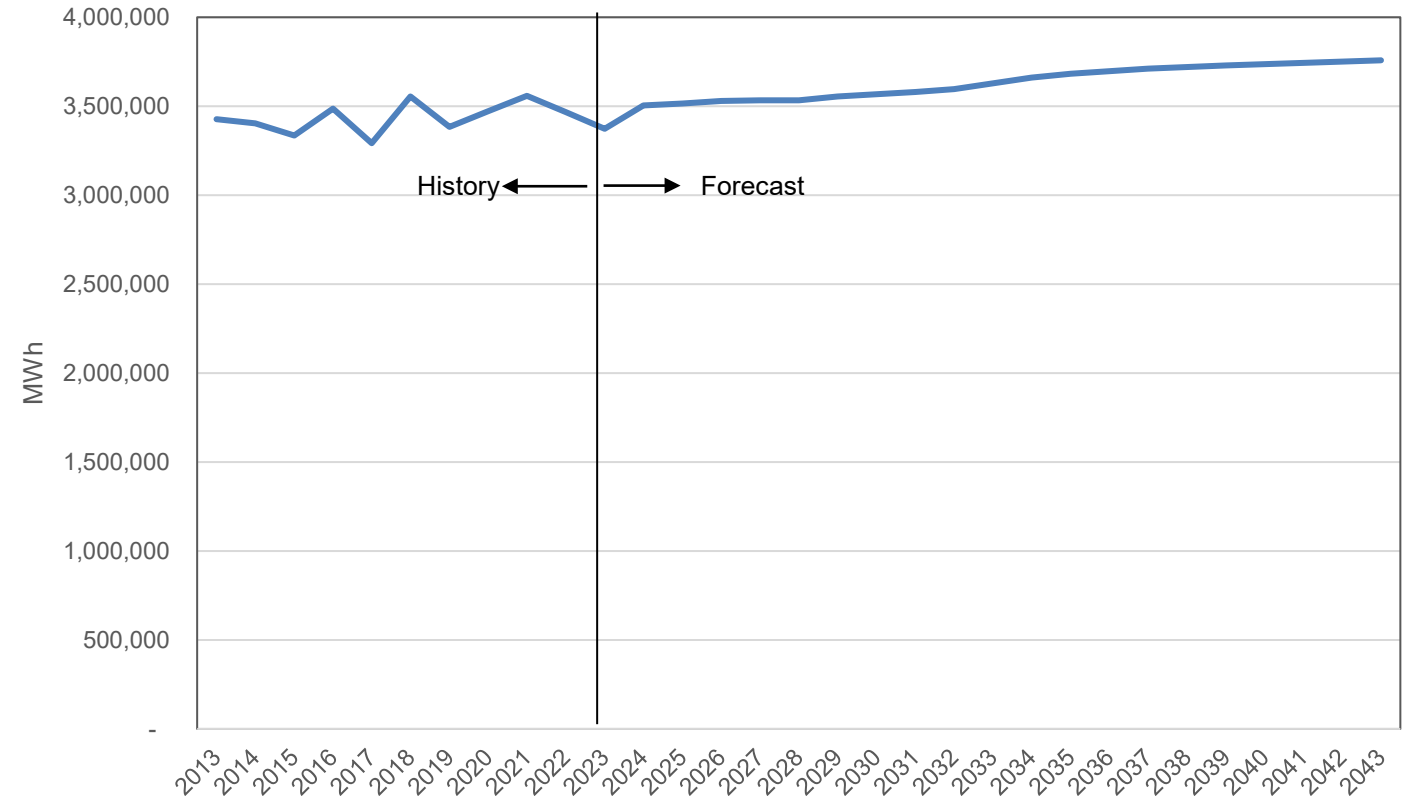
Residential Customer Count



Residential UPC* (MWh/Customer)



Residential Volume (MWh)

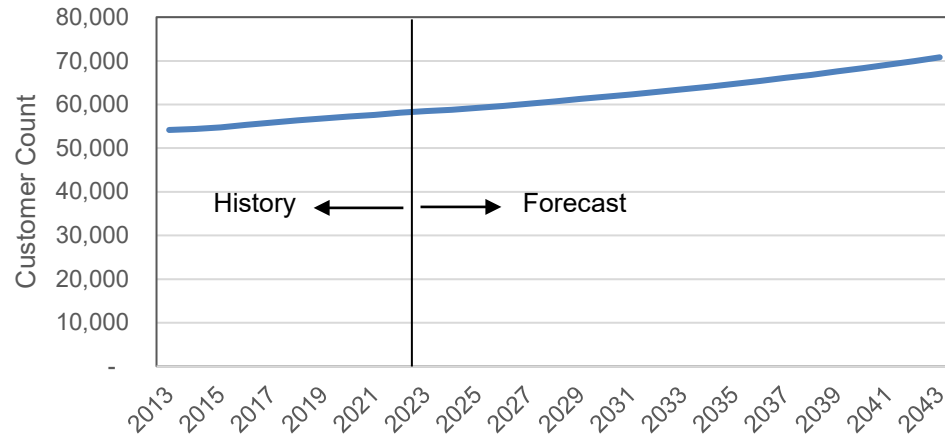


* Annual UPC is calculated as total volume / average monthly customer count

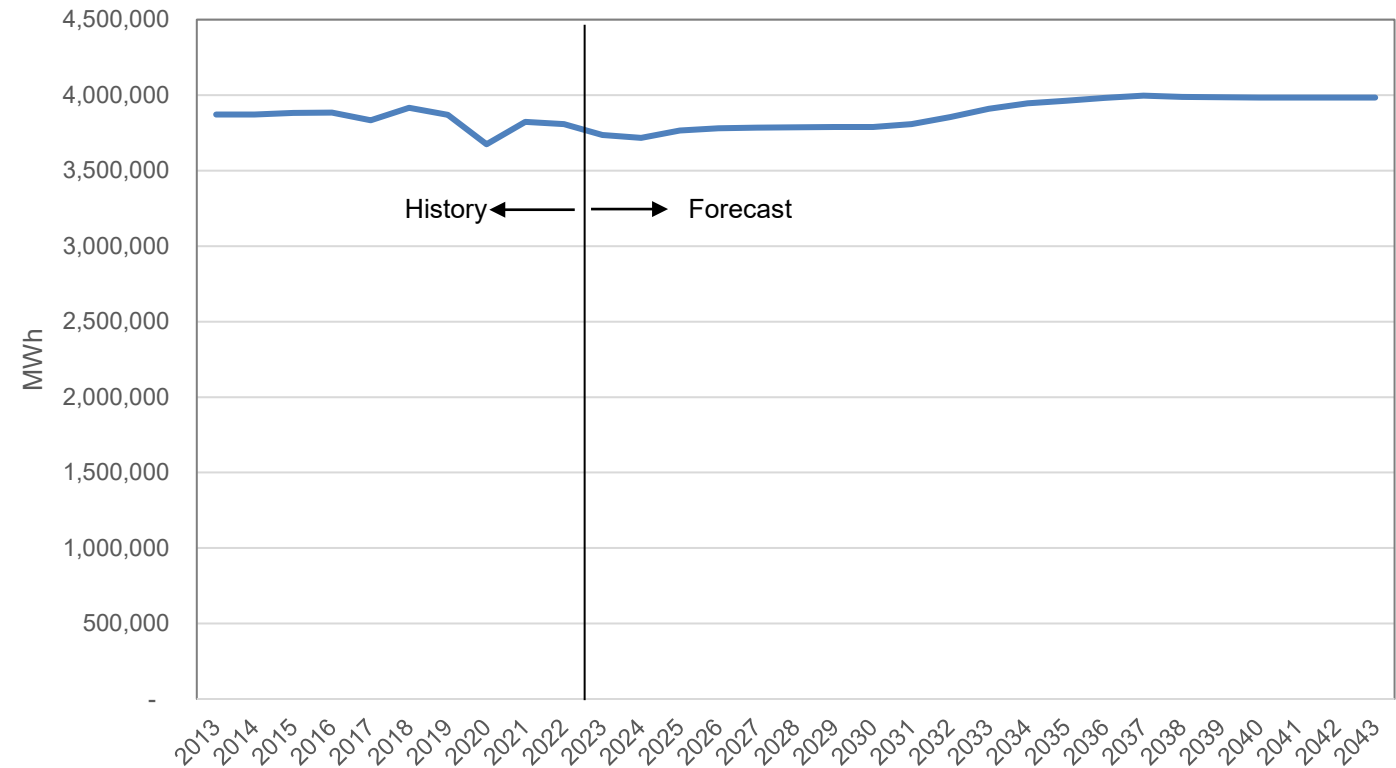
We exist to deliver safe, reliable energy that drives value to our customers

COMMERCIAL FORECAST

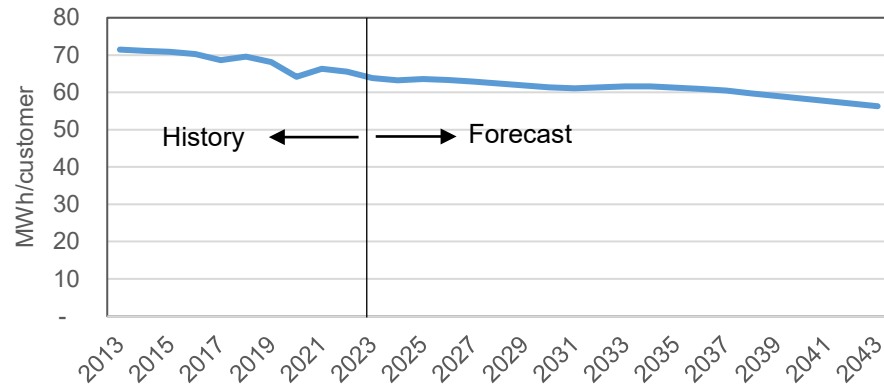
Commercial Customer Count



Commercial Volume (MWh)



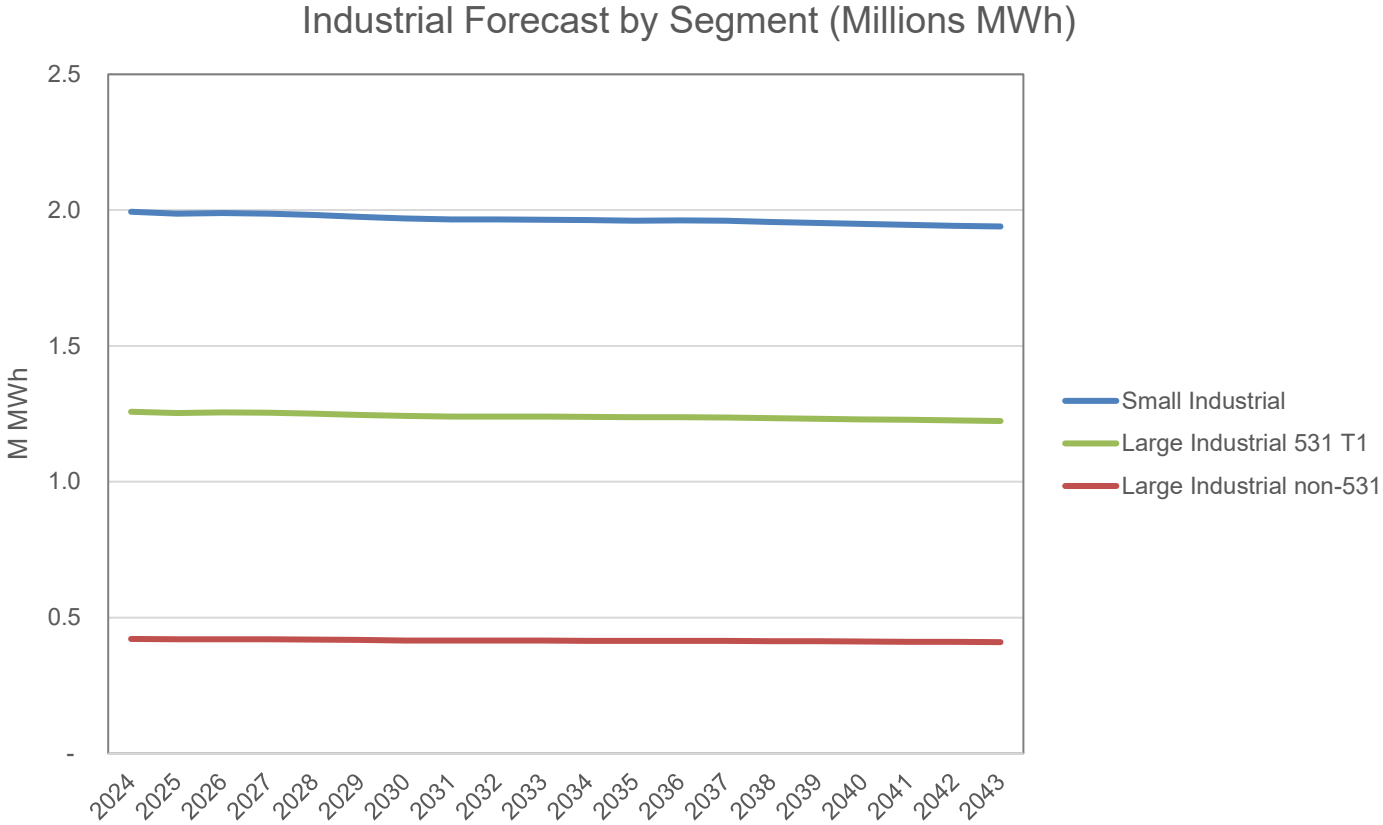
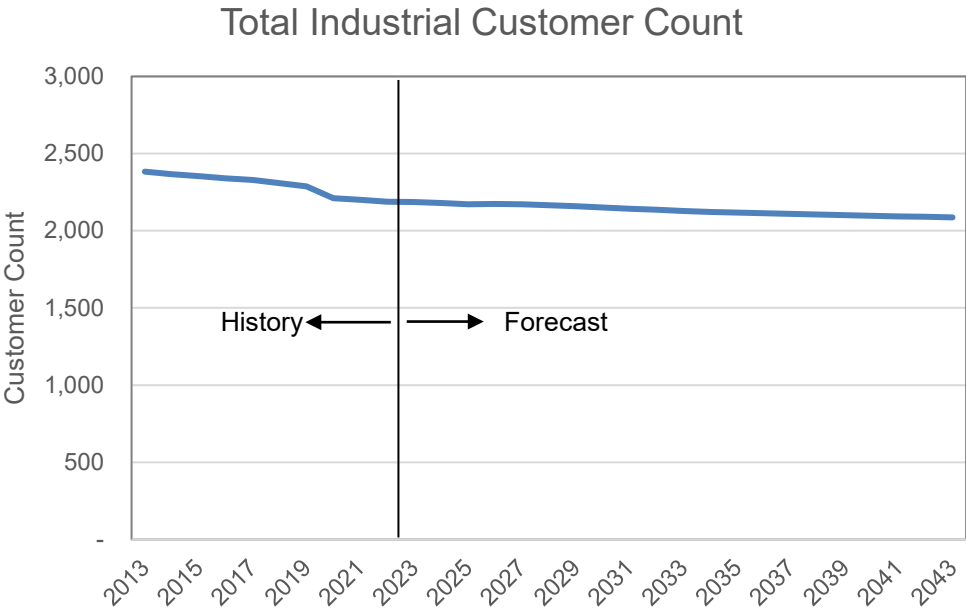
Commercial UPC* (MWh/Customer)



* Annual UPC is calculated as total volume / average monthly customer count

We exist to deliver safe, reliable energy that drives value to our customers

INDUSTRIAL FORECAST



FORECASTING COINCIDENT PEAK – CLASS LOAD FACTORS

- Historical sample meter data provides monthly load factor data by customer class, which was used to develop monthly peak forecasts
- Customer-level load factor data for the 15 largest customers was used for large industrial classes

Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	88.80%	88.80%	88.80%	66.90%	66.90%	51.60%	51.60%	51.60%	51.60%	66.90%	88.80%	88.80%
Commercial	81.60%	81.60%	81.60%	75.30%	75.30%	75.40%	75.40%	75.40%	75.40%	75.30%	81.60%	81.60%
Small Industrial	83.60%	83.60%	83.60%	80.80%	80.80%	83.00%	83.00%	83.00%	83.00%	80.80%	83.60%	83.60%

Equation:

$$\text{Peak Demand kW} = \text{Usage}^{\text{kWh}} / (\text{LF} * \text{CPF} * 24 \text{ hr/day} * X \text{ days/mo})$$

- As an enhancement to NIPSCO’s process, new sources of load (EVs, other electrification, data centers) are evaluated with their own independent load shapes, allowing for modeling of potential changing load factors over time

PENDER MODEL: METHODOLOGY

Agent Development

- “Agents” are modeled as representative of NIPSCO’s customers, and each agent is randomly assigned a household income level based on the American Community Survey (ACS) 2022 income distribution across NIPSCO counties;
- Each agent is assigned a propensity to adopt new technology (bass innovation index);
- Relationships between agents are modeled through “social networks,” with an average size of 13 agents belonging to one network

An agent will adopt DER if:

- the agent’s probability of adoption is sufficiently high (*according to the economics and probability assessment*)
- the agent is an innovator type (if its innovation index surpasses a specified threshold), or a significant portion of the agent’s network has adopted the technology

NIPSCO DER PROGRAMS

DER programs/policies

Excess Distributed Generation (EDG) program: extra generation receives utility bill credits in the amount of 125% of market priced power*.

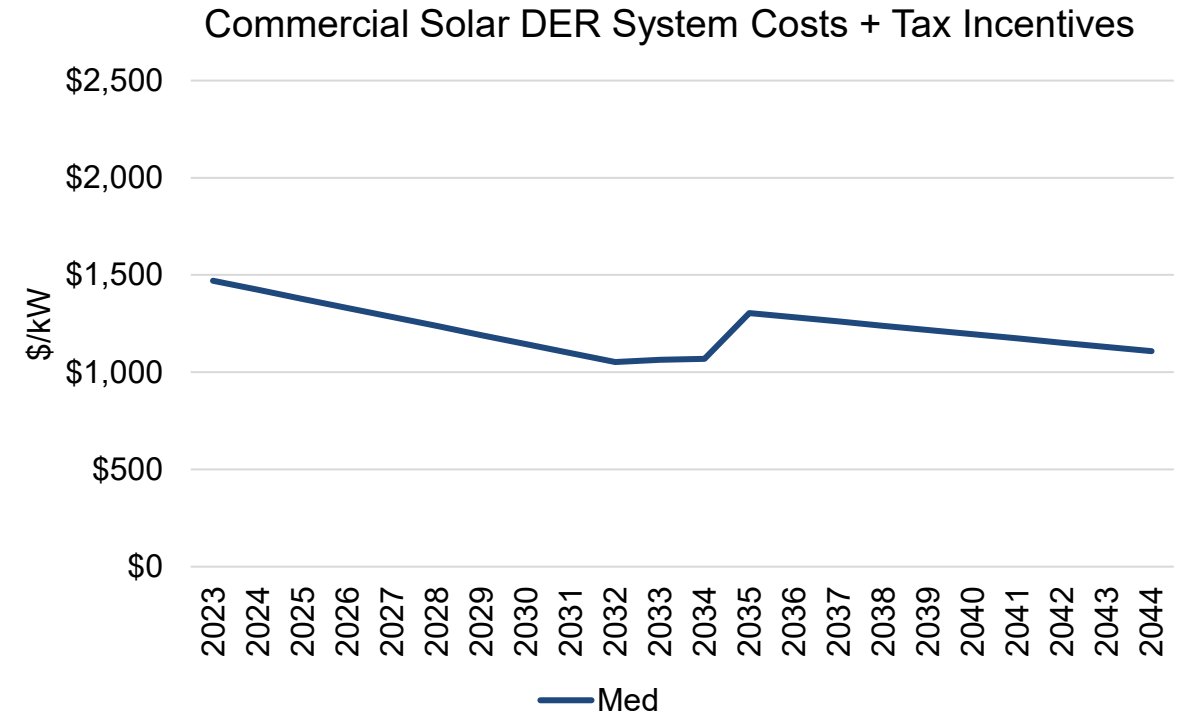
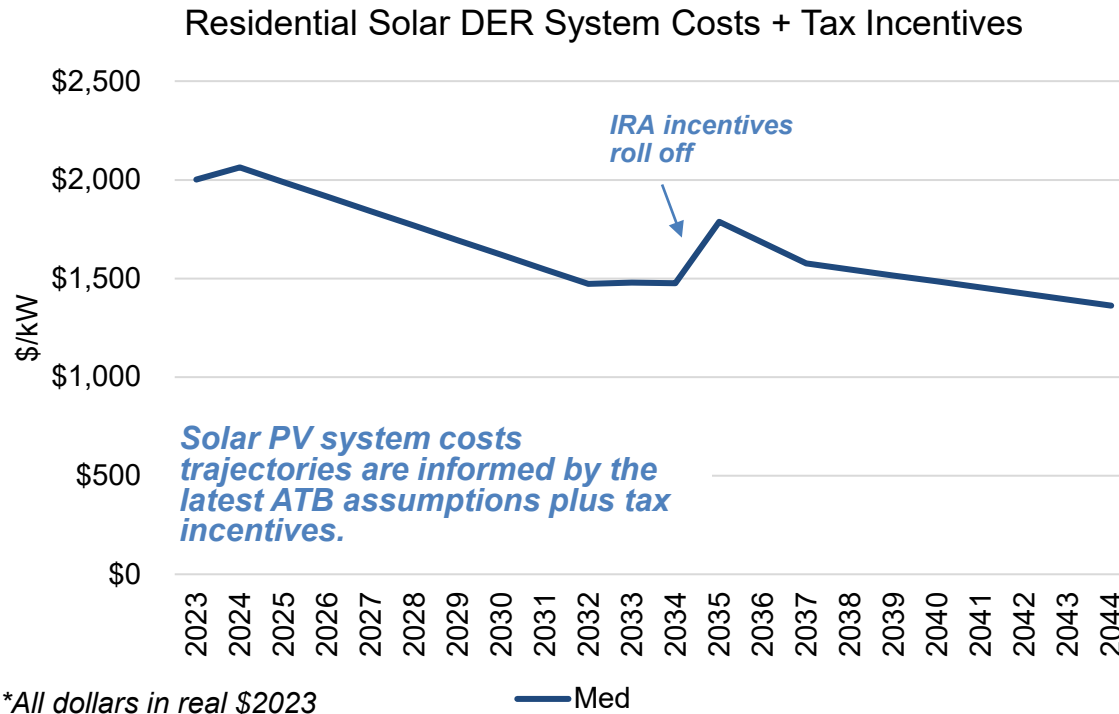
- **Commercial:** Started on October 2, 2021
- **Residential:** Started on July 1, 2022

Net Metering: *extra generation received energy credits that can be applied to future usage (no longer applicable to res. or comm. customers in 2024+ beyond)*

Feed-in Tariff (FIT) program: *customer can sell power back to NIPSCO (no longer applicable to res. or comm. customers in 2024+ beyond)*

* Defined in Rider 589 as the Marginal DG Price, the average hourly real-time price of energy paid by the Company in the MISO market at the NIPS.NIPS commercial pricing node during the most recent calendar year, multiplied by one and twenty-five hundredths (1.25).

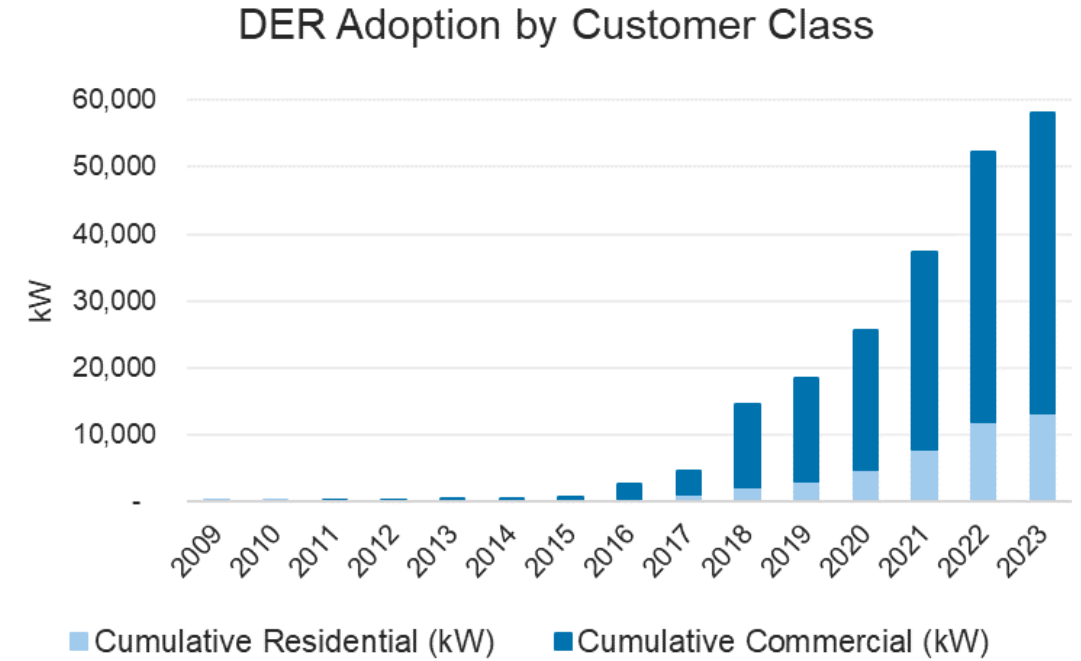
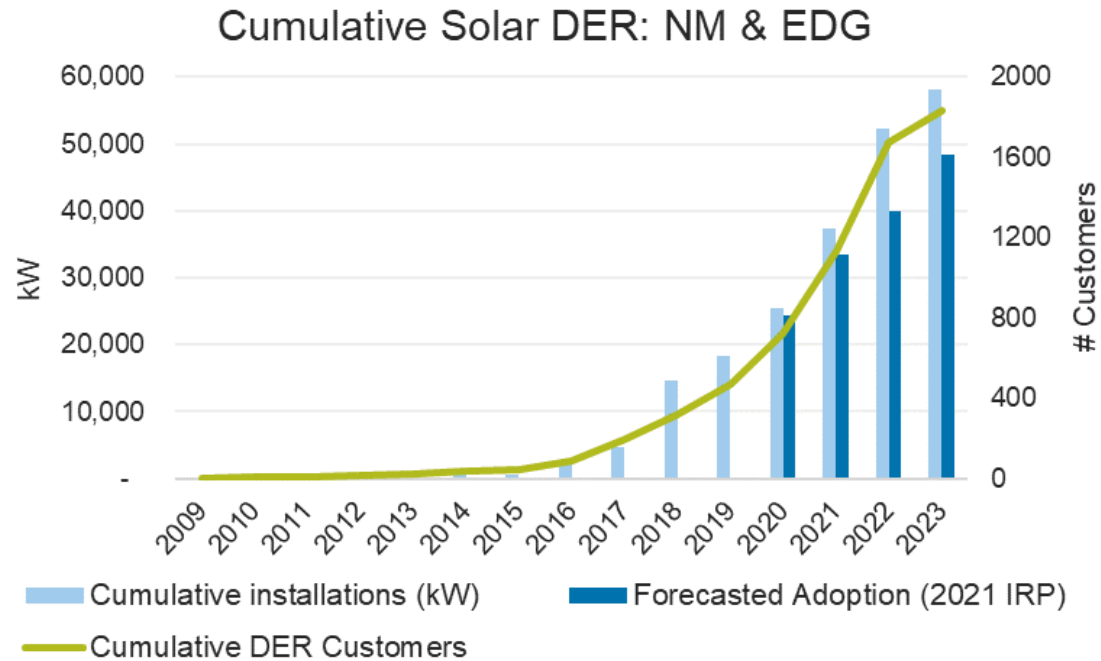
PENDER MODEL: SOLAR PV DER COSTS



- Assumptions regarding capital cost projections, capacity factor, and system life for solar PV were taken from NREL's 2023 Annual Technology Baseline for both residential and commercial solar PV technologies.

Reference Scenario	
DER System Capex	NREL ATB Moderate (Med) - Class 5
ITC	Current IRA incentives
DER Program	EDG ext. through 2040s

HISTORICAL DER ADOPTION IN NIPSCO TERRITORY



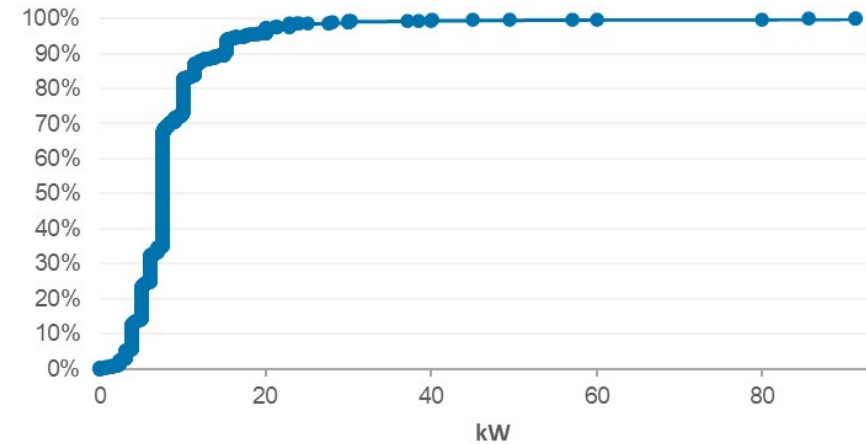
- Since 2020, Solar DER adoption has increased 32% annually.
- After phasing out Net Metering in 2022, growth slowed down.
- To date, 16 customers have adopted battery systems, totaling 98 kW, with an average 2-hour duration.

- Since 2020, residential Solar DER adoption has increased 40% annually; the growth for commercial customers has been 30%.
- Most storage systems have been installed by residential customers, with an average solar to storage ratio of 1.5:1

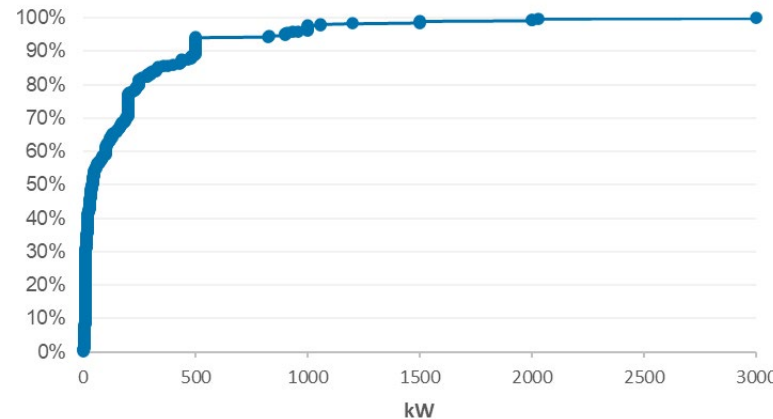
HISTORICAL SOLAR DER SYSTEM SIZE

- For residential customers, the historical average system size is 8.6 kW (median of 7.6 kW), and around 80% of installed systems are below 10kW
- For commercial customers, the historical system average is 178 kW (median of 40 kW), and around 60% of installed systems are below 100 kW. However, in recent years following the EDG rate program, system sizes have averaged 125 kW (median of 35 kW)

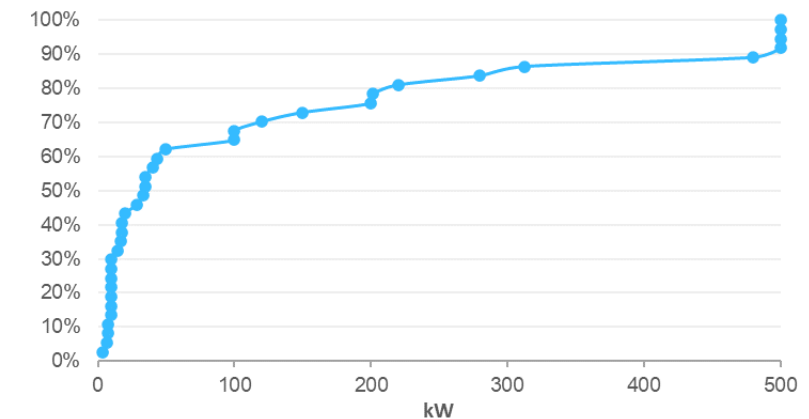
Residential System Size Distribution



Historical Commercial System Size Distribution



Commercial System Size Distribution - 2023

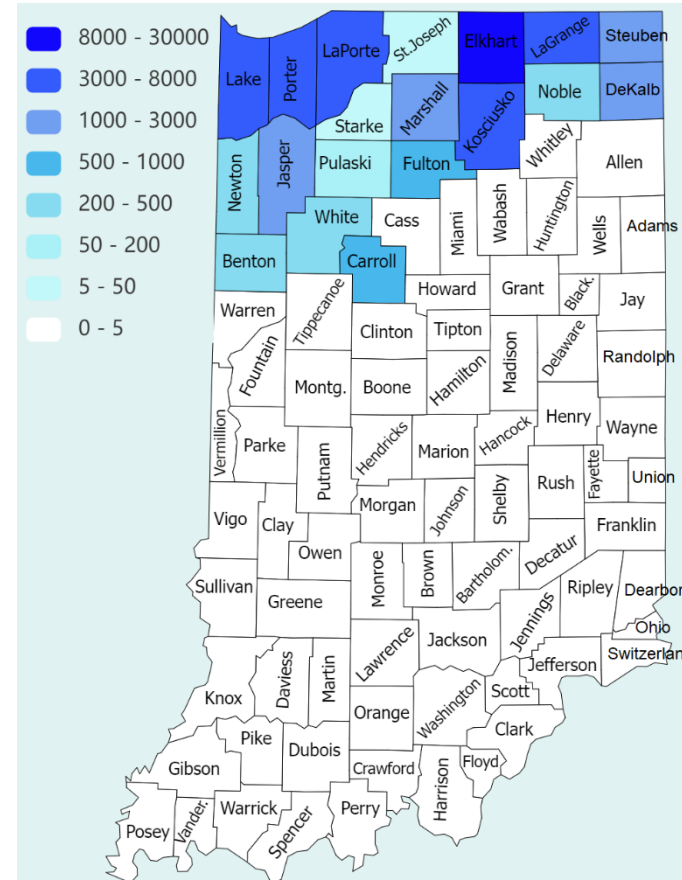


PENDER MODEL: INPUTS

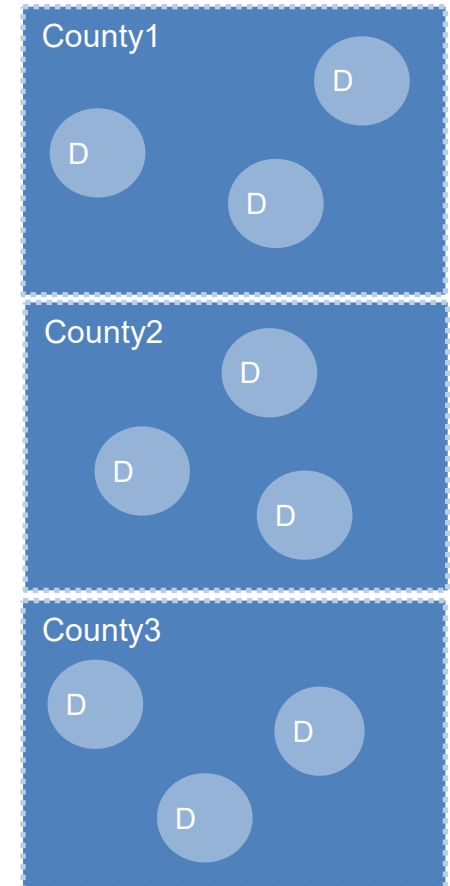
Availability of customer data...

Customer Level Data	Individual customer information about DER adoption, DER programs, location, and customer class (R/C/I)
Socio-Economic Data	Individual customer information on socio-economic status, business type, energy usage
Aggregate NIPSCO Data	Total number of R/C/I customers by geographical grouping

County DER Adoption by total kW...



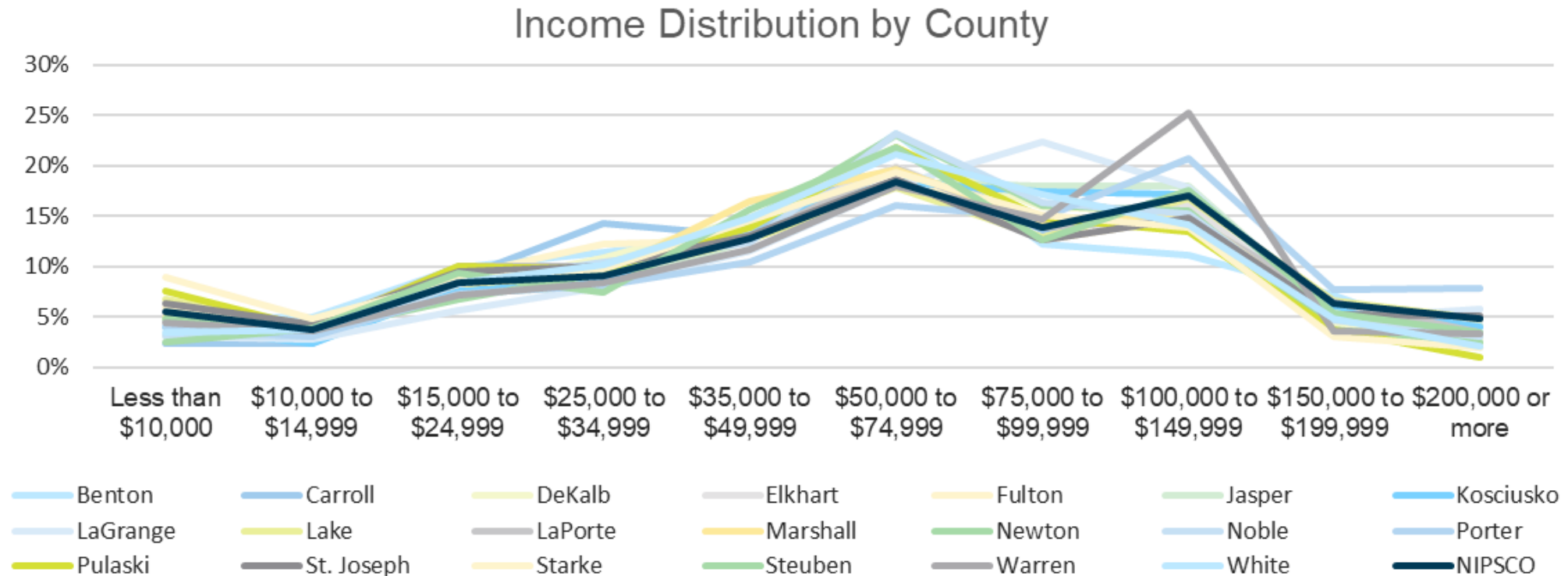
NIPSCO customer-level DER adoption data (D), and average SES* data (S) by county is used to develop *linear regression model for likelihood of adoption*



* SES = Socioeconomic Status

We exist to deliver safe, reliable energy that drives value to our customers

PENDER MODEL: INCOME DISTRIBUTION



- On average, 42% of residential customers, across counties, report a median income above \$75k, with a range between 32% - 51%.

EV FORECASTING APPROACH

Penetration Models with Local Datasets

Truck Corridor Charging Tool

Light Duty Vehicle (LDV)

<10,000 lbs



Sedans



Trucks



Minivans



SUVs



Utility Van

Medium Duty Vehicle (MDV)

10,001 – 26,000 lbs



Step Van



Walk In



Delivery



Mini Bus



Rack/Transport



Bus

Heavy Duty Vehicle (HDV)

>26,001 lbs



Furniture



Medium Semi



Refuse



Tow



Cement



Dump Truck



Semi Tractor



Refrigeration

Source: U.S. DOE, Alternative Fuels Data Center

We exist to deliver safe, reliable energy that drives value to our customers

LDV EV GROWTH: UTILIZE NIPSCO DATA FOR ICE AND EV REGISTRATIONS TO DEVELOP VIEW OF TOTAL LIKELY LDV EV'S, APPLY TO ADOPTION S-CURVE BASED ON PUBLIC STUDIES OF LIKELY INFLECTION POINTS

Econometric model determines total number of electric vehicles, which will scale total EV demand over each year

2024/Today

- Historical EV registration data will give a view of EV adoption in recent years and expected 2024 adoption
- Historical ICE registration data will give a view of total vehicle registrations
 - In all scenarios, we expect that the number of total vehicles will remain constant over time
 - Assumption can be flexed in scenarios

Inflection year

- Determine the year(s) that system integration will begin and how long this will last (based on public studies)
 - Assumption is varied across scenarios

Saturation year

- Determine the year(s) that system saturation will begin (based on public studies)
 - Assumption can be flexed in scenarios
 - Metric: EVs as % of new registrations

MDV EV GROWTH: UTILIZE NIPSCO DATA FOR ICE AND EV REGISTRATIONS TO DEVELOP VIEW OF TOTAL LIKELY MDV EV'S, APPLY TO ADOPTION S-CURVE BASED ON PUBLIC STUDIES OF LIKELY INFLECTION POINTS

Econometric model determines total number of electric vehicles, which will scale total EV demand over each year

2024/Today

- Historical EV registration data will give a view of EV adoption in recent years and expected 2024 adoption
- Historical ICE registration data will give a view of total vehicle registrations
- Transit vehicle counts from 2022 National Transportation Database update
 - In all scenarios, we expect that the number of total vehicles will remain constant over time
 - There may be a case to make that the number increases over time as demand for delivery services rise

Inflection year

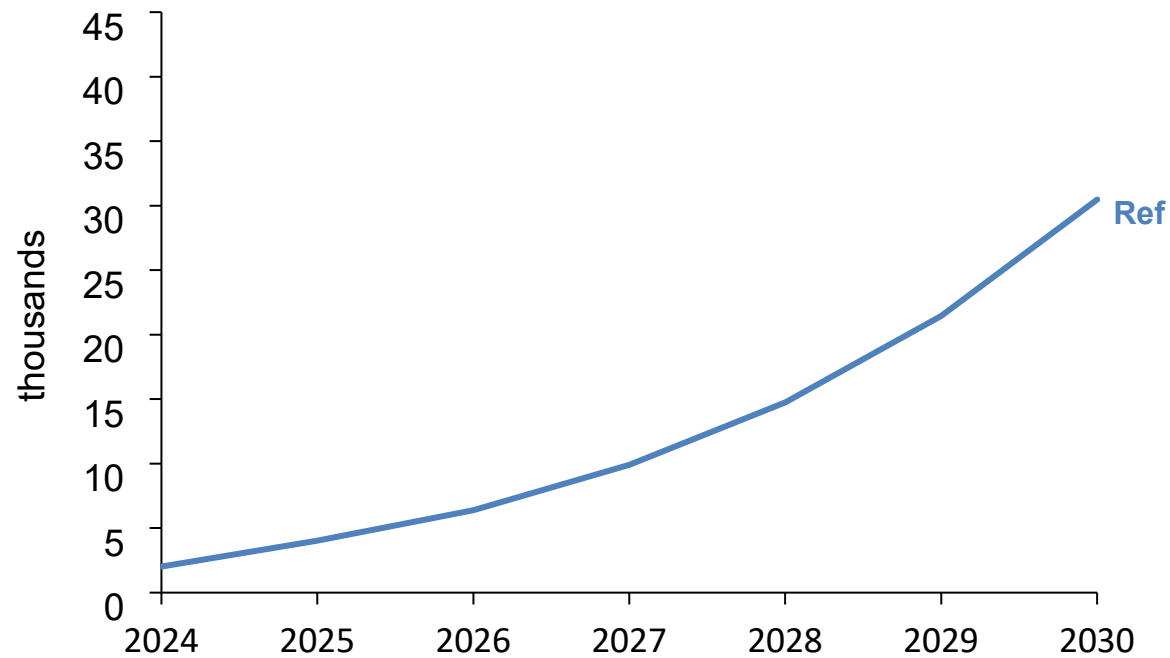
- Determine the year(s) that system integration will begin and how long this will last (based on public studies)
 - Inflection will be steeper in MDV forecast compared to LDV as individual fleets are likely to change over in larger groups

Saturation year

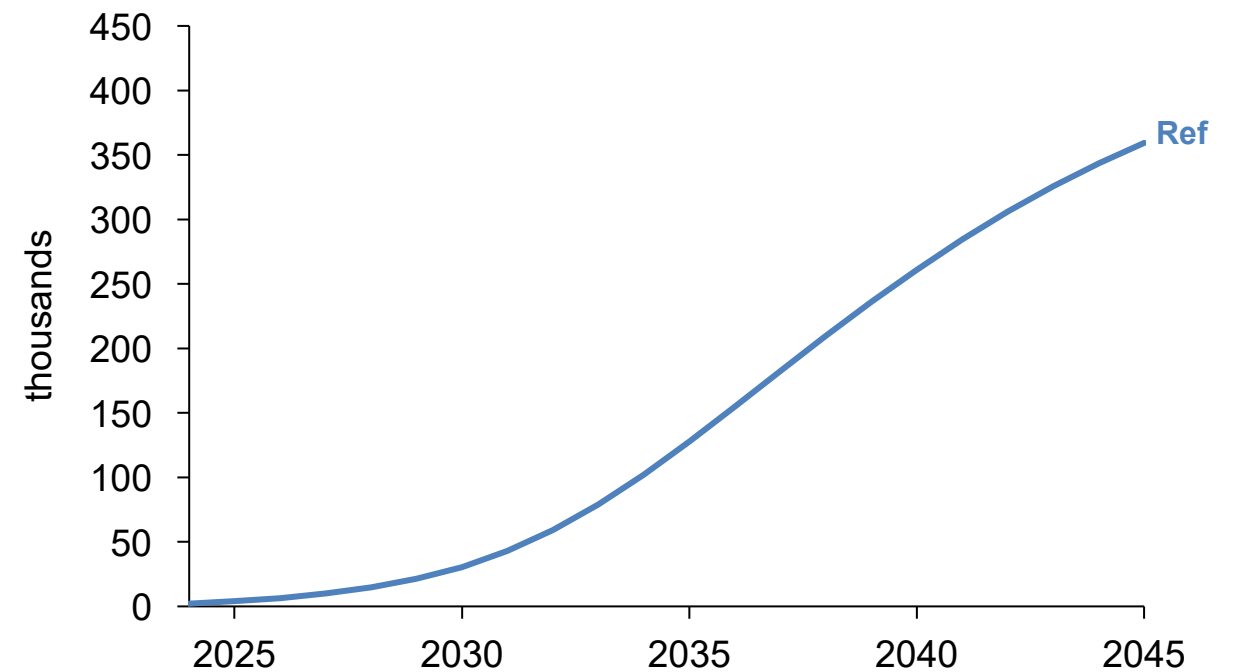
- Determine the year(s) that system saturation will begin (based on public studies)
 - Assumption can be flexed in scenarios
 - Metric: EVs as % of new registrations

REFERENCE LDV ADOPTION TRAJECTORY WOULD MEET NEW EPA TARGETS

Number of EVs registered
'24-'30 timeframe detail



Number of EVs registered
Full forecast period

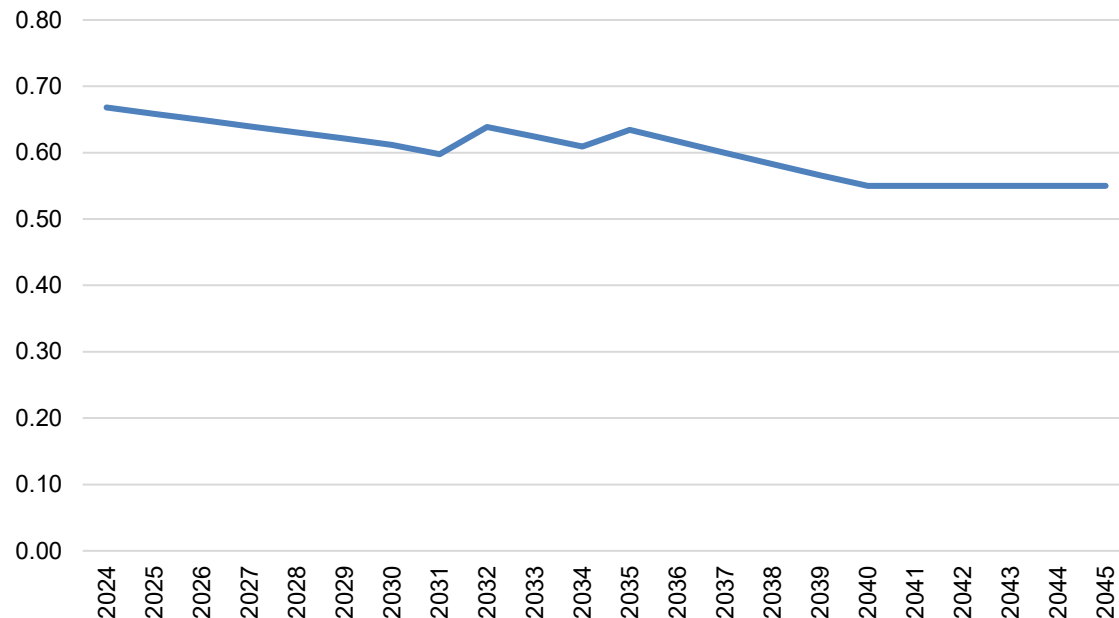


LDV PEAK IMPACTS AND VEHICLE EFFICIENCY

Peak Impacts

- With the increase in vehicle efficiency, each vehicle's contribution to coincident peak loads is expected to decrease over time
- Coincident peaks are expected to shift towards evenings in future years, limiting the impact of vehicle efficiency gains on peak reduction

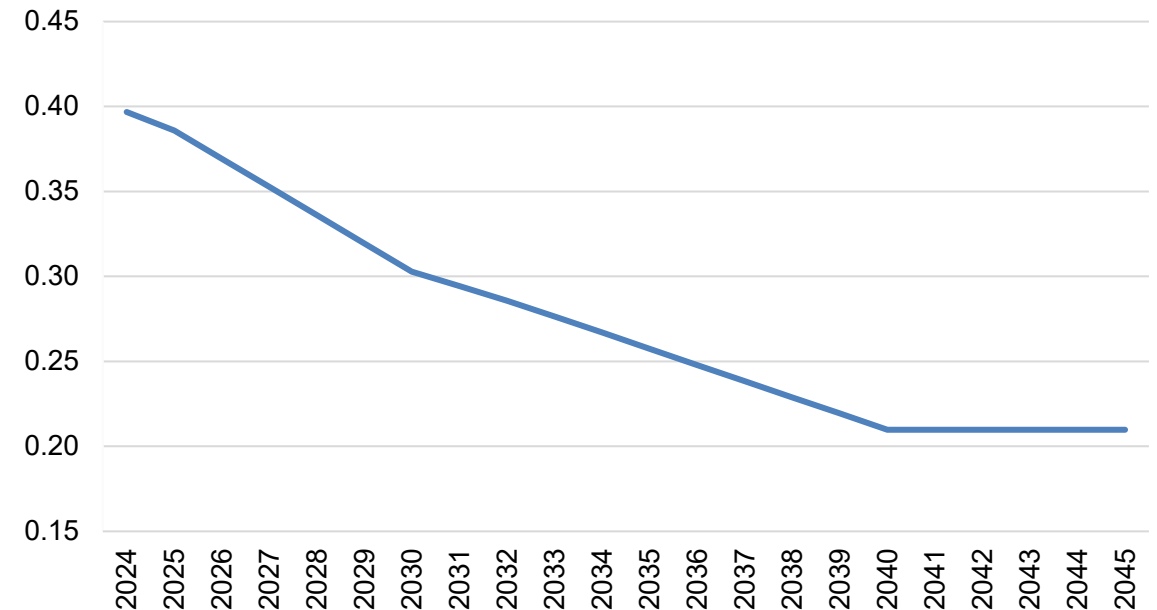
Coincident peak contribution: kW / vehicle



Vehicle Efficiency

- Vehicle efficiency in BEV and PHEVs is forecasted to double by 2040, significantly reducing the per-vehicle impact on total sales
- NIPSCO relied on EV market data and NREL projections to forecast efficiency learning curves
- Despite higher efficiencies, total vehicle miles driven per day is forecasted to increase from 27.5 in 2024 to 40 by 2040

kWh per mile driven - LDV Average



REFERENCE CASE LDV LOAD SHAPES 2024

Total registered EVs: 2,006

EV Type	Count	mi / kWh
BEV Sedan	882	2.57
BEV SUV	721	2.30
PHEV Sedan	281	2.95
PHEV SUV	120	2.40

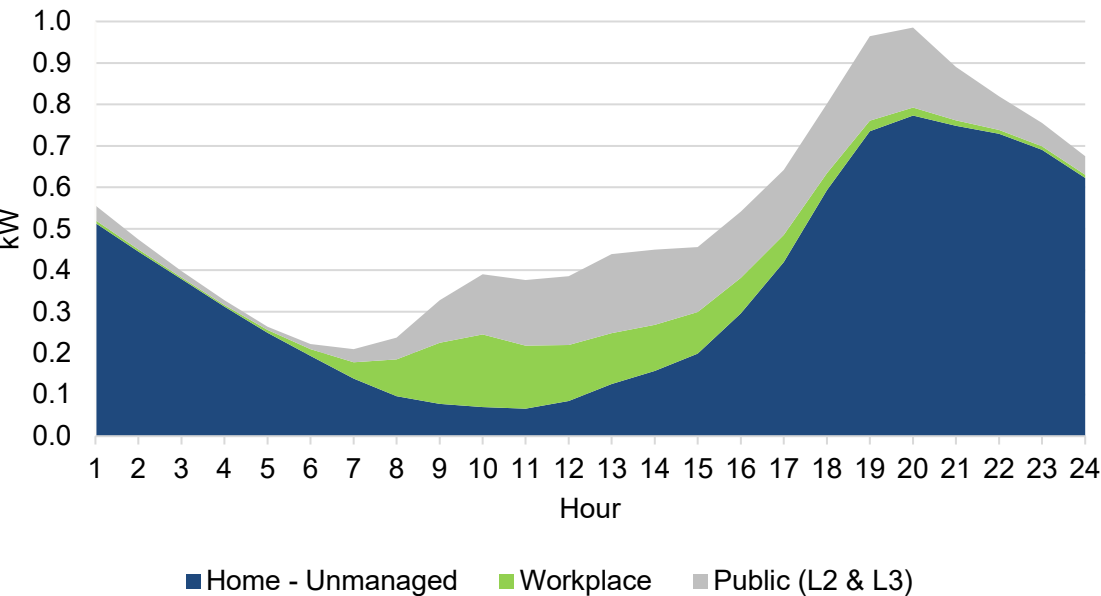
Grid Impacts

Coincident Peak (MW)	1.34
Coincident Peak Time	August, 3pm
Annual Sales (MWh)	8,243
LDV Annual Peak (MW)	2.15
LDV Annual Peak Date	Jan 4, 8pm

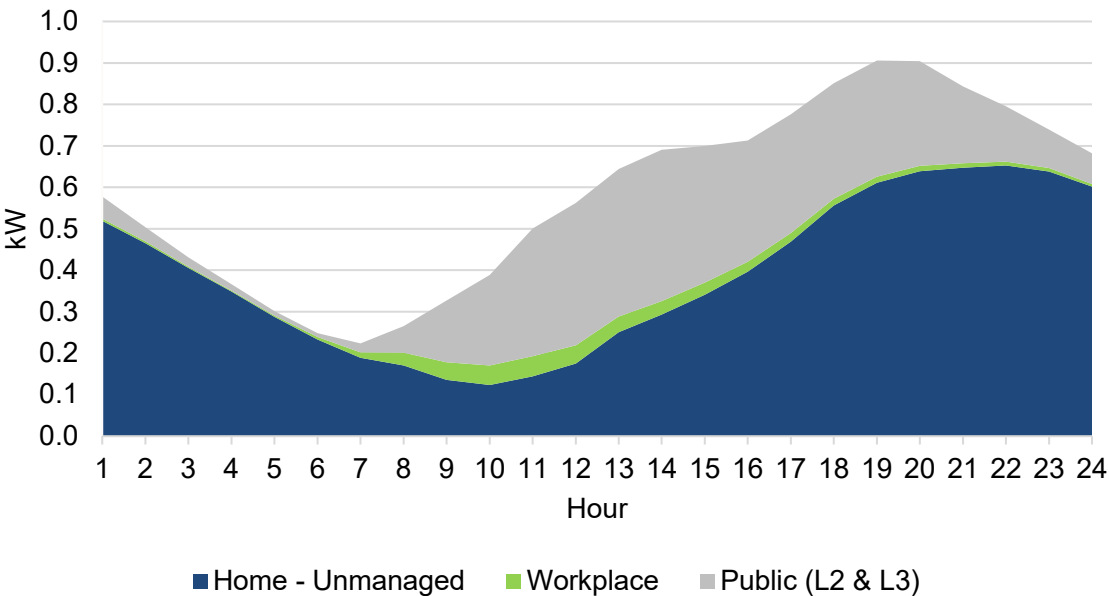
Seasonal Coincident Peaks (MW)

Winter	1.93
Spring	1.93
Summer	1.34
Fall	1.61

2024 weekday profile (kW / vehicle)



2024 weekend profile (kW / vehicle)



REFERENCE CASE LDV LOAD SHAPES 2030

Total registered EVs: **33,016**

EV Type	Count	mi / kWh
BEV Sedan	16,342	3.50
BEV SUV	13,371	3.00
PHEV Sedan	2,311	4.00
PHEV SUV	990	3.25

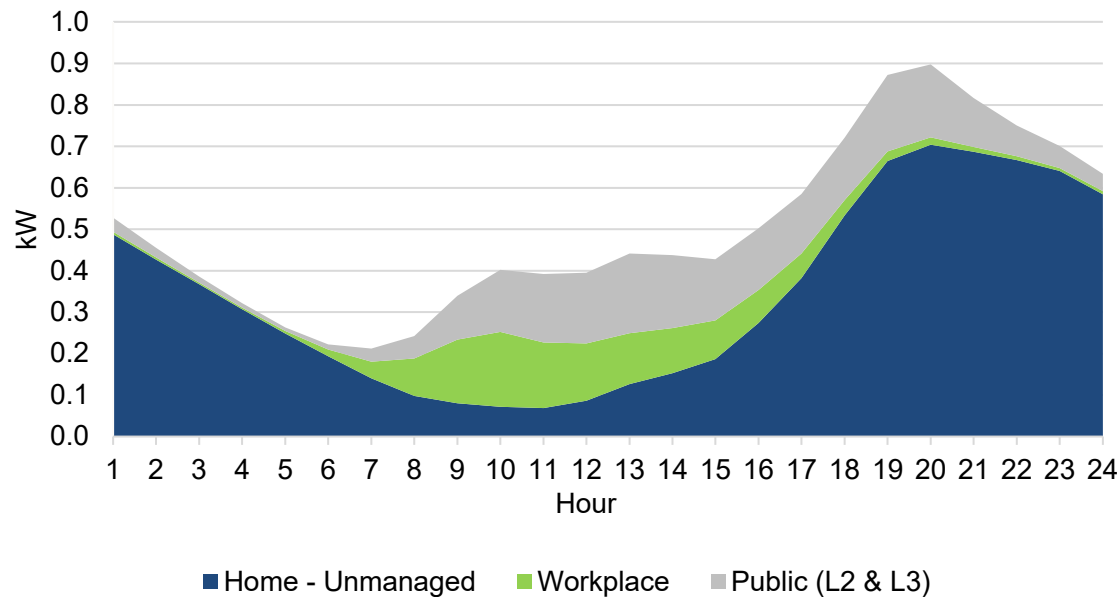
Grid Impacts

Coincident Peak (MW)	20.2
Coincident Peak Time	August, 3pm
Annual Sales (MWh)	129,000
LDV Annual Peak (MW)	32.3
LDV Annual Peak Date	Jan 4, 8pm

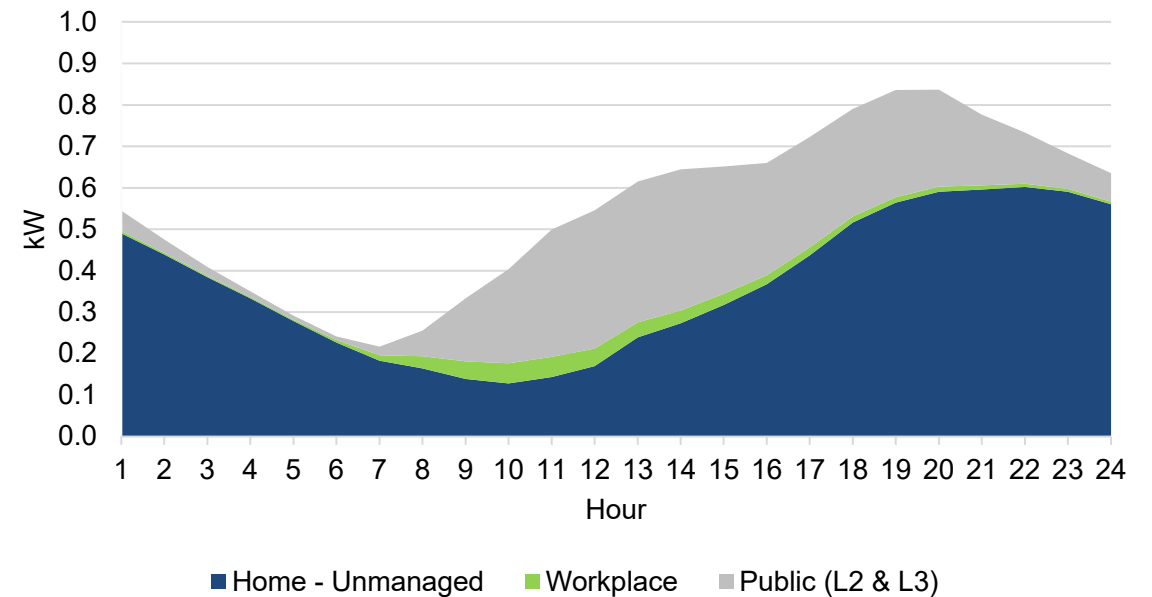
Seasonal Coincident Peaks (MW)

Winter	28.8
Spring	29.6
Summer	20.2
Fall	28.8

2030 weekday profile (kW / vehicle)



2030 weekend profile (kW / vehicle)



REFERENCE CASE LDV LOAD SHAPES 2040

Total registered EVs: 283,967 Grid Impacts

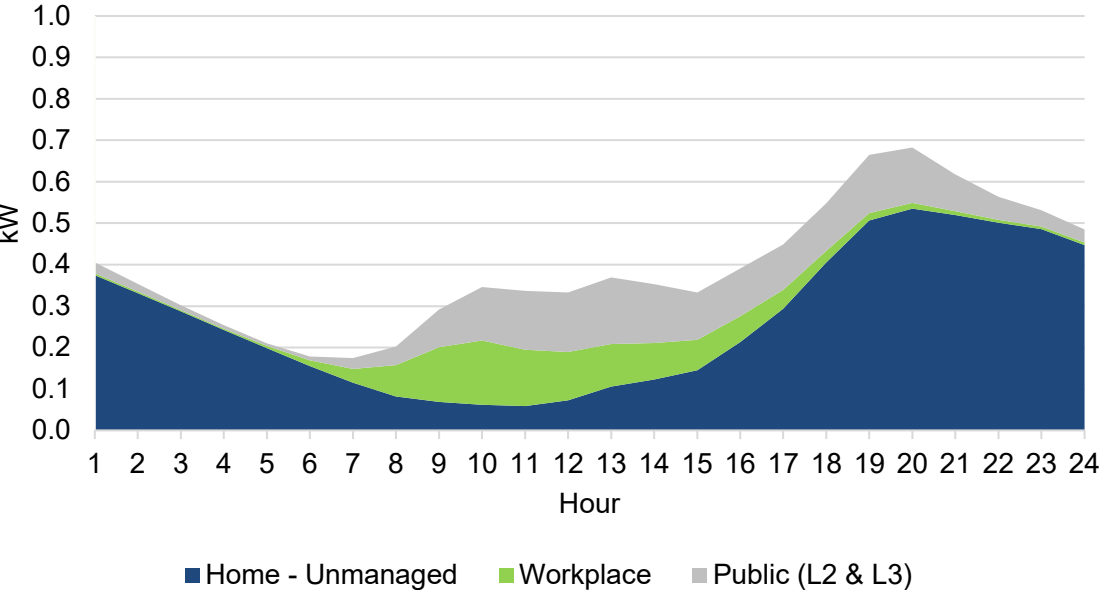
EV Type	Count	mi / kWh
BEV Sedan	148,373	5.0
BEV SUV	121,396	4.5
PHEV Sedan	9,939	5.0
PHEV SUV	4,259	4.5

Coincident Peak (MW)	156
Coincident Peak Time	August, 5pm
Annual Sales (MWh)	866,000
LDV Annual Peak (MW)	214.5
LDV Annual Peak Date	Jan 4, 8pm

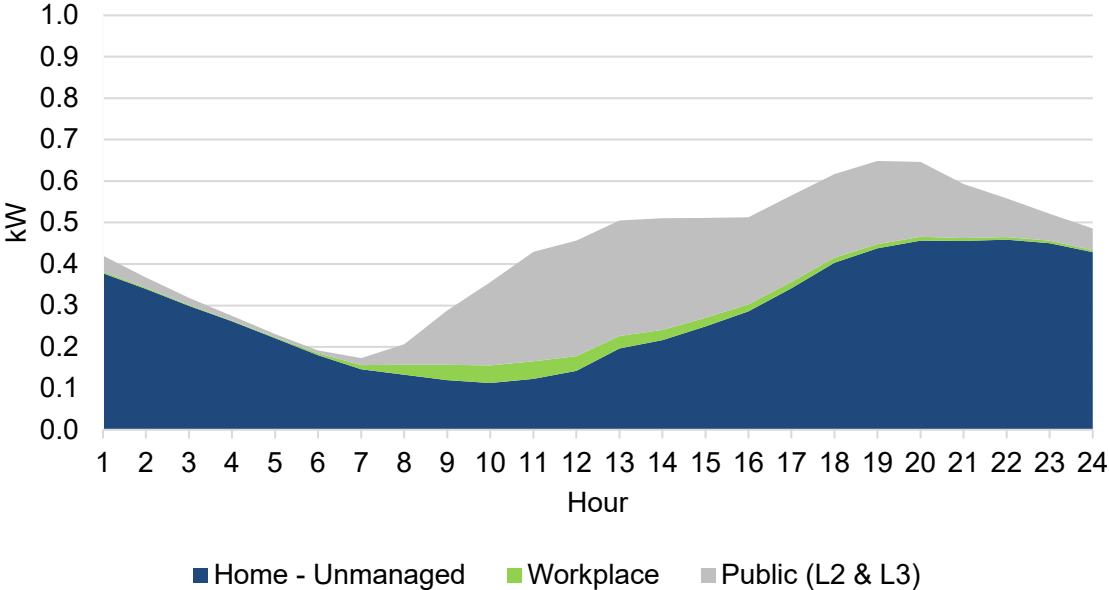
Seasonal Coincident Peaks (MW)

Winter	189
Spring	194
Summer	156
Fall	189

2040 weekday profile (kW / vehicle)



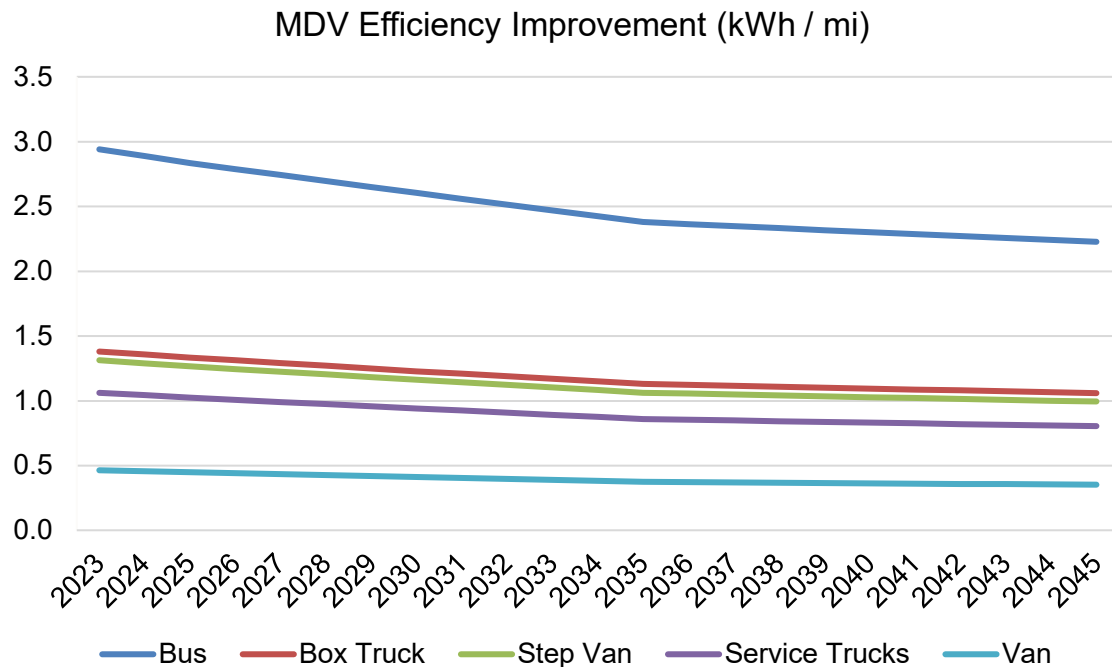
2040 weekend profile (kW / vehicle)



MDV CHARGING EFFICIENCY: TEMPERATURE AND TECHNOLOGY IMPROVEMENT

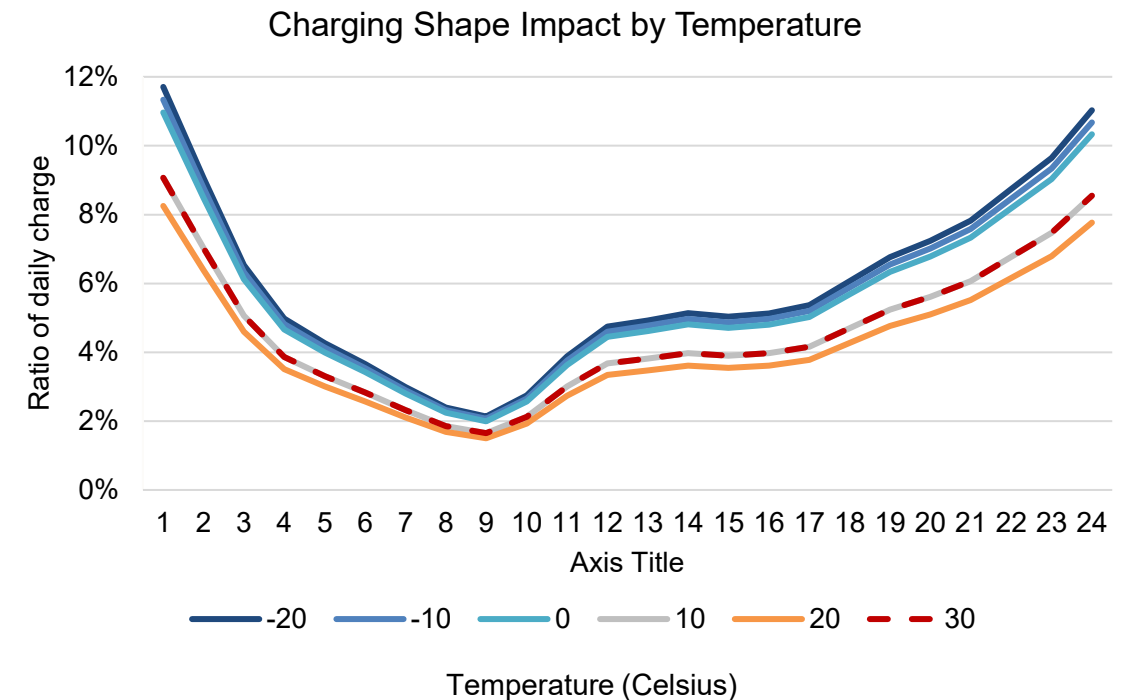
Technology Improvements – Vehicle Efficiency

- Adapted from NREL transportation baseline technology analysis, CRA determined that a range of MDVs will likely see a ~30% improvement in vehicle efficiency over the forecast period, reducing grid impacts over time



Temperature Dependence

- Transit vehicles have high temperature dependence, as larger buses require space heating of large areas with high heat loss
- Estimated 44% energy demand increase for coldest hours of the year, and 10% for hottest hours



MDV (NON-TRANSIT) EV FORECAST

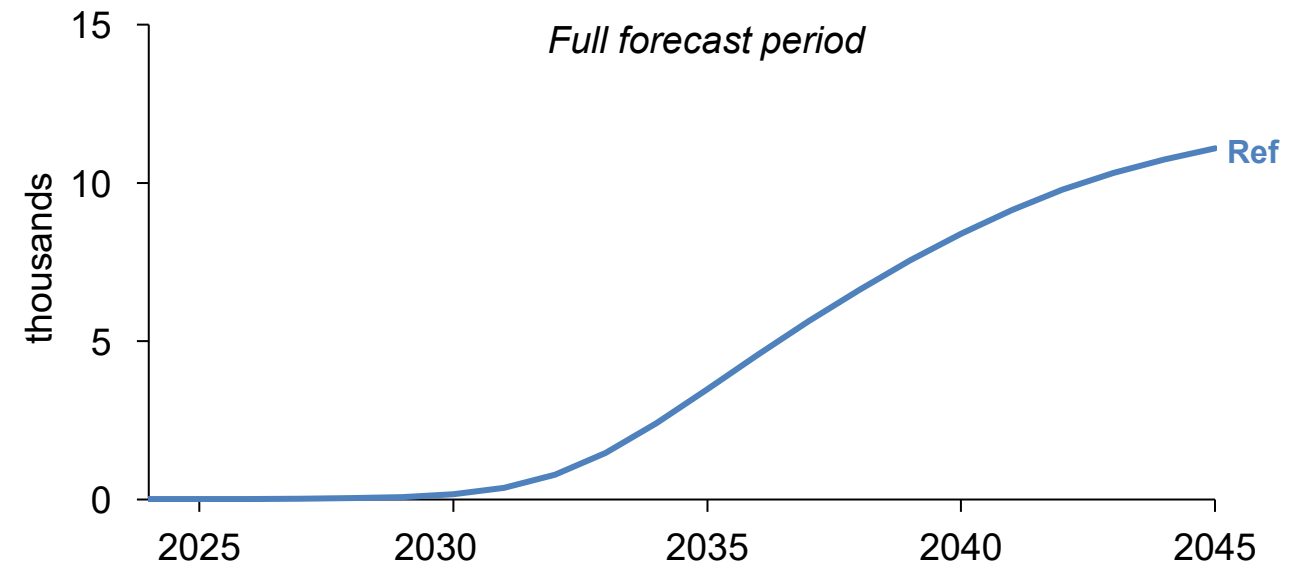
Near-term Trends

- NIPSCO has baselined the existing MDV fleet using EV registration data from the Indiana Fuel Dashboard
- NIPSCO has crafted an approach that uses ICE vehicle turnover (assuming 10-year avg lifespan) and EVs as a % of new MDV vehicle sales to estimate the number of EVs on the road in a given year.

Long-term Trends

- CRA anticipates moderated adoption compared to LDVs, as some MDVs may be difficult to decarbonize with limited EV options available

Number of non-transit MDVs registered



MDV (TRANSIT) EV FORECAST

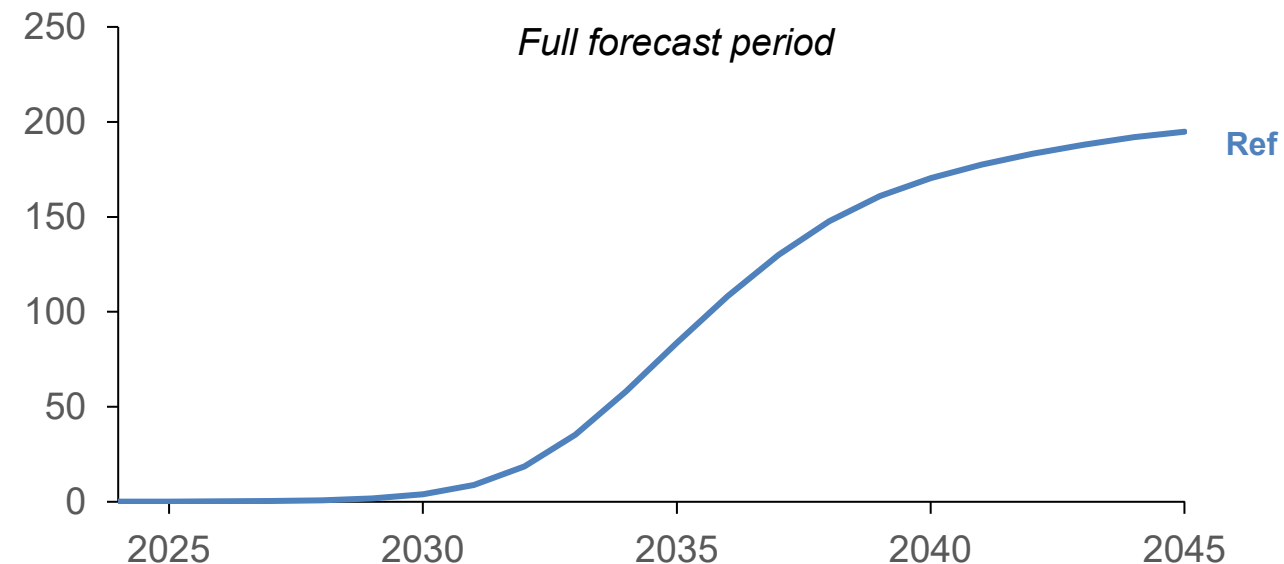
Near-term Trends

- NIPSCO has baselined the existing transit fleet using the 2022 National Transportation Database (NTD)
- NIPSCO has crafted an approach that uses ICE vehicle turnover (assuming avg lifespan by vehicle type from NTD) and EVs as a % of new MDV vehicle sales to estimate the number of transit EVs on the road in a given year.

Long-term Trends

- NIPSCO anticipates moderated adoption compared to LDVs as some MDVs may be difficult to decarbonize with limited EV options available

Number of transit MDVs registered

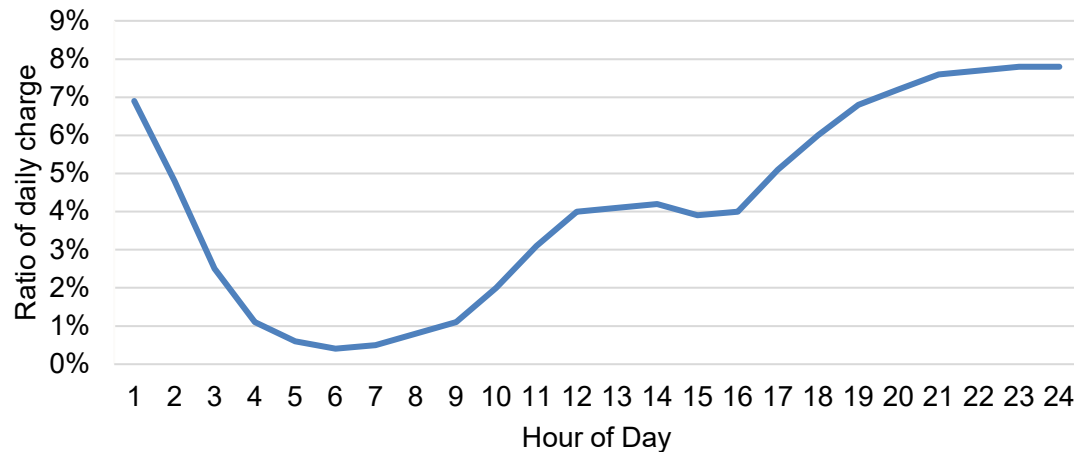


MDV CHARGING BEHAVIOR: UNMANAGED VS. MANAGED CHARGING

Unmanaged charging:

- Current methodology is based on an NREL study, [Field Evaluation of Medium-Duty Plug-In Electric Delivery Trucks](#)
- Utilizes real-meter data (similar approach was taken by NIPSCO in its 2021 IRP)
- Shape is used from 2024 - 2030, when a blend of managed charging loads begins to emerge, based on the assumption that rates and managed charging infrastructure will begin to displace unmanaged behavior in later years

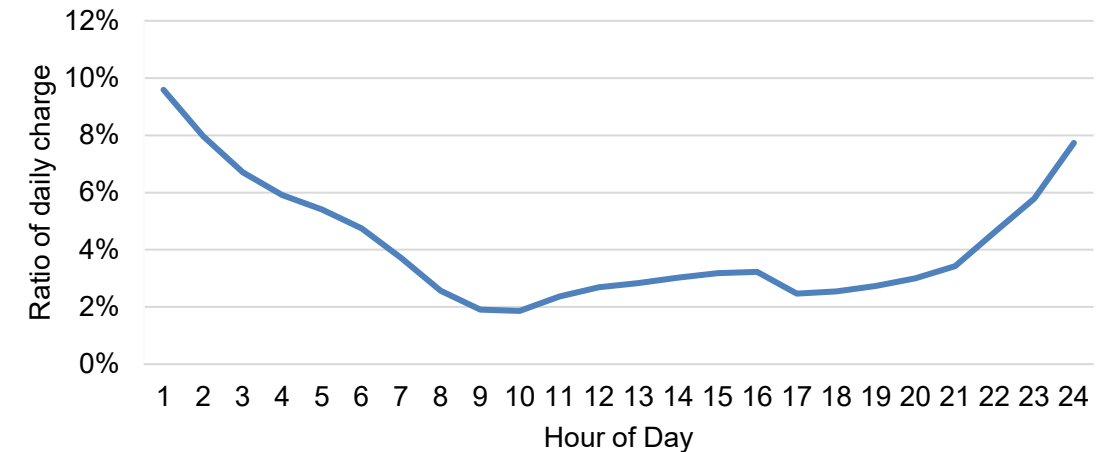
MDV - unmanaged charging behavior



Managed charging:

- Managed profile adapted from recent data releases from 2021 study from [Berkeley Lab](#)
- This approach assumes the adoption of new rate design and managed charging approaches and is used as a baseline future projection for how MDV loads may balance from 2030 – 2045 (although some degree of unmanaged charging remains for the duration of the forecast period)

MDV – managed charging behavior



REFERENCE CASE EV MDV LOAD SHAPES: 2030 REFERENCE (50% managed)

Total registered MDVs: 171

EV Type	Fleet / Delivery	Transit
Count	167	4
kWh / mi	1.18	0.81
VMT / day	37	55

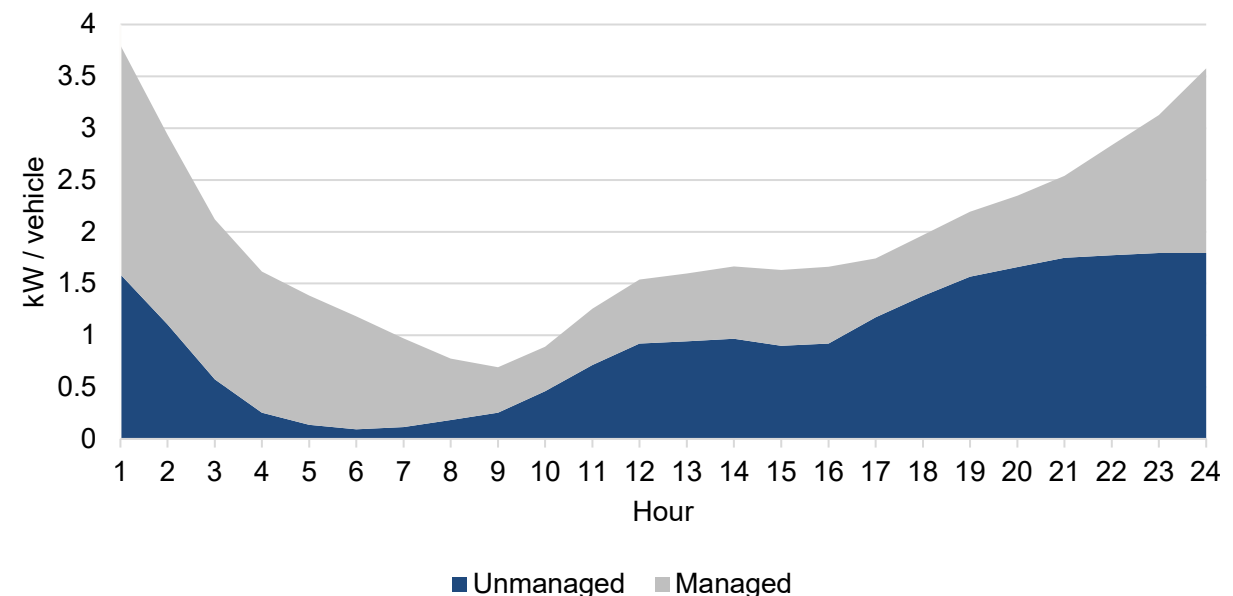
Grid Impacts

Coincident Peak (MW)	0.23
Coincident Peak Date	Aug 5, 6pm
Annual Sales (MWh)	2,923
MDV Annual Peak (MW)	0.81
MDV Annual Peak Date	Jan 4, 1am

Takeaways

- Low adoption of MDVs in 2030 will lead to negligible grid impact from a transmission-level perspective
- Managed charging will lower evening peak load, and distribute to 12am – 2am

2030 Weekday Profile (kW / vehicle)



REFERENCE CASE EV MDV LOAD SHAPES: 2040 REFERENCE (90% MANAGED)

Total registered MDVs: 8,563

EV Type	Fleet / Delivery	Transit
Count	8,939	170
kWh / mi	1.05	0.73
VMT / day	37	55

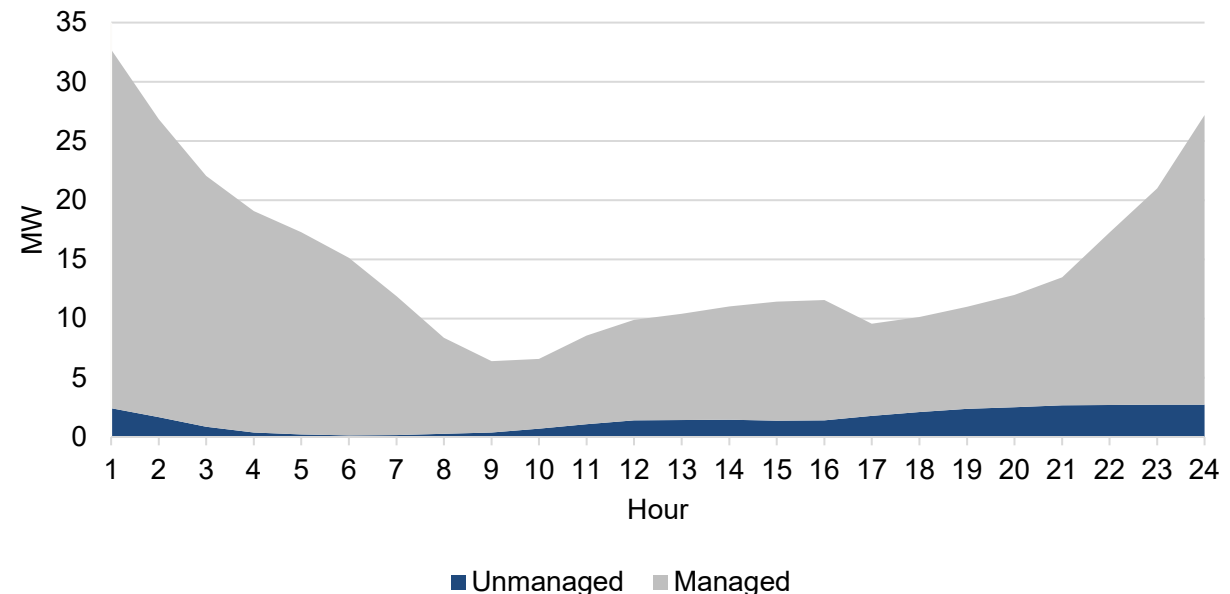
Grid Impacts

Coincident Peak (MW)	7.38
Coincident Peak Date	Aug 5, 6pm
Annual Sales (MWh)	130,000
MDV Annual Peak (MW)	40.6
MDV Annual Peak Date	Jan 4, 1am

Takeaways

- Growth in managed charging behavior as commercial customers adopt time-shifting techniques and concentrate almost 50% of daily charging demand between 10pm – 5am
- High growth of fleet vehicles will drive majority of MDV load impacts, with coincident peak impacts estimated around 7 MW

2040 Weekday Profile (MW)



EV POLICY INCENTIVES, TARGETS, AND FEES WILL IMPACT EV ADOPTION RATES IN INDIANA

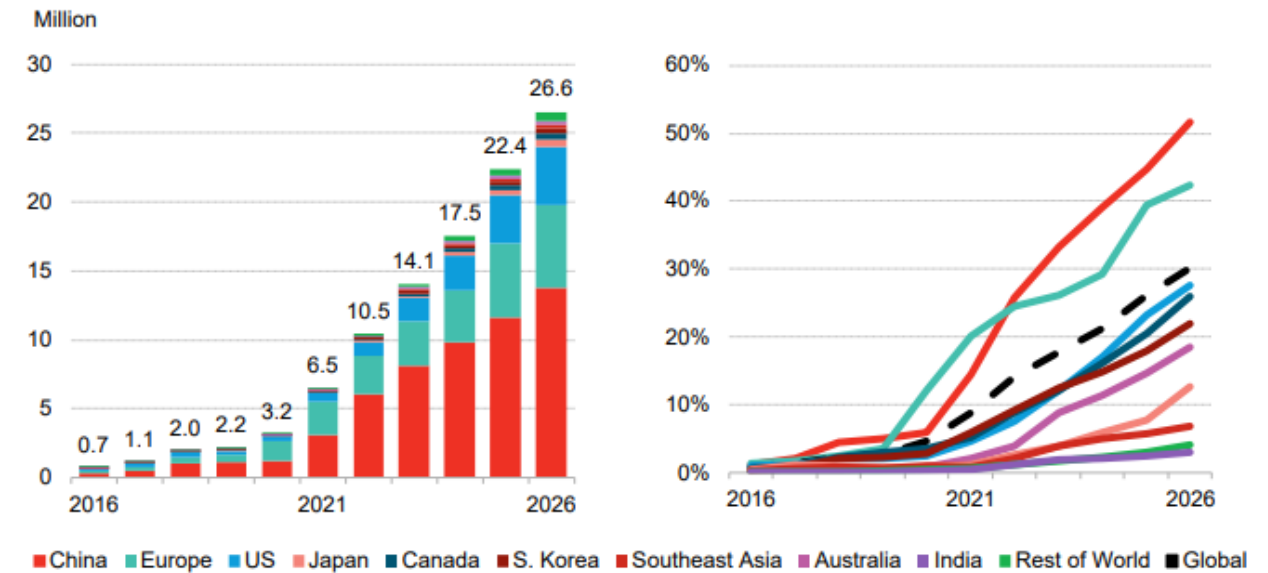
	Federal	Indiana State & Utilities
EV Tax Credits	- Up to \$7,500 tax credit for new EV and PHEV vehicles - Up to \$4,000 or 30% of the price¹ on used EV and PHEVs	Indiana does not have tax credits for new or used EVs
EV Charger Tax Credits	30% of the cost of hardware and installation, up to \$1,000, through 2032 (applies to residential and commercial)	Various utilities have TOU rates and charging station rebates for LDVs and MDVs but there is no centralized state program
Targets	EVs to be 50% of all vehicle sales by 2030	Indiana does not have electric vehicle targets
Other	¹ Used tax credit is for whichever amount is less ² Source: https://www.in.gov/bmv/files/Fee_Chart.pdf	In 2024, EVs and PHEVs will be subject to an additional annual registration fee of \$221 and \$74², respectively. After 2024, fees will be indexed to inflation.

BLOOMBERG NEW ENERGY FINANCE (BNEF) EXPECTS RAPID EV ADOPTION IN THE NEXT 3 YEARS

Overview

- BNEF assumes U.S. EV share of LDV sales to reach nearly 30% by 2026
- The EV share of global new passenger vehicle sales jumps from 14% in 2022 to 30% in 2026.
- In the US, the Inflation Reduction Act causes EVs make up nearly 28% of passenger vehicle sales by 2026, up from 7.6% in 2022.

Figure 1: Global near-term passenger EV sales and share of new passenger vehicle sales by market



Source: BloombergNEF. Note: Europe includes the EU, the UK and EFTA countries. EV includes BEVs and PHEVs.

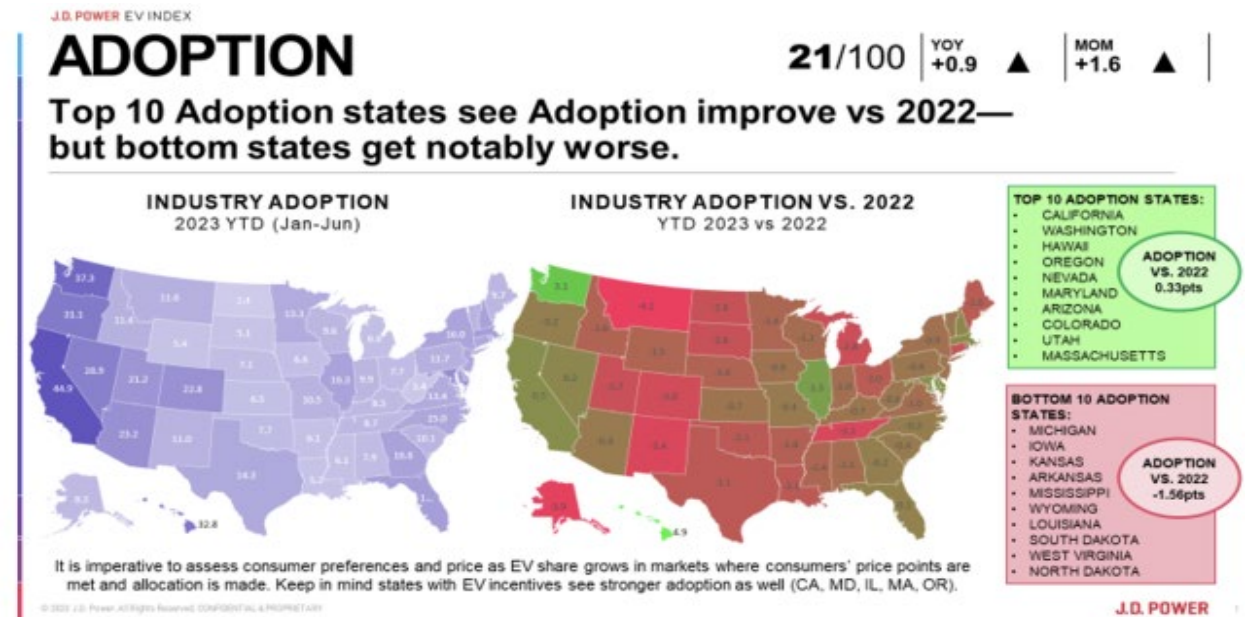
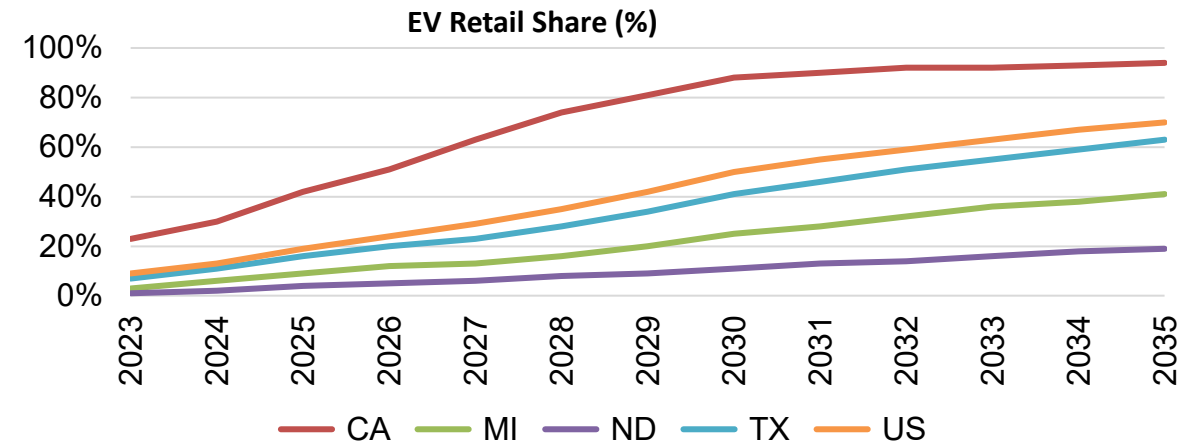
Source: BNEF, [Electric Vehicle Outlook 2023, Exec Summary](#) (2023)

JD POWER EXPECTS EV ADOPTION TO GROW DISPARATELY ACROSS THE STATES BUT TO REACH 70% BY 2035 AT A NATIONAL LEVEL

Overview

- A JD Power September 2023 report shows that nationwide, electric vehicle (EV) adoption is up 1 index point through the first half of 2023 vs. the same period a year ago
 - At the state level, however, a stark division is emerging between the **top 10 states** for EV adoption, where **EV adoption rates are growing steadily**, and the **bottom 10 states** for EV adoption, where **year-over-year average adoption rates are declining**
- They forecast that through 2035, state EV adoption will grow increasingly divided
- At a national level, JD Power estimates 70% EV market share by 2035

Source: JD Power, [America Grows Increasingly Divided on EV Adoption](#) (Sept 2023)



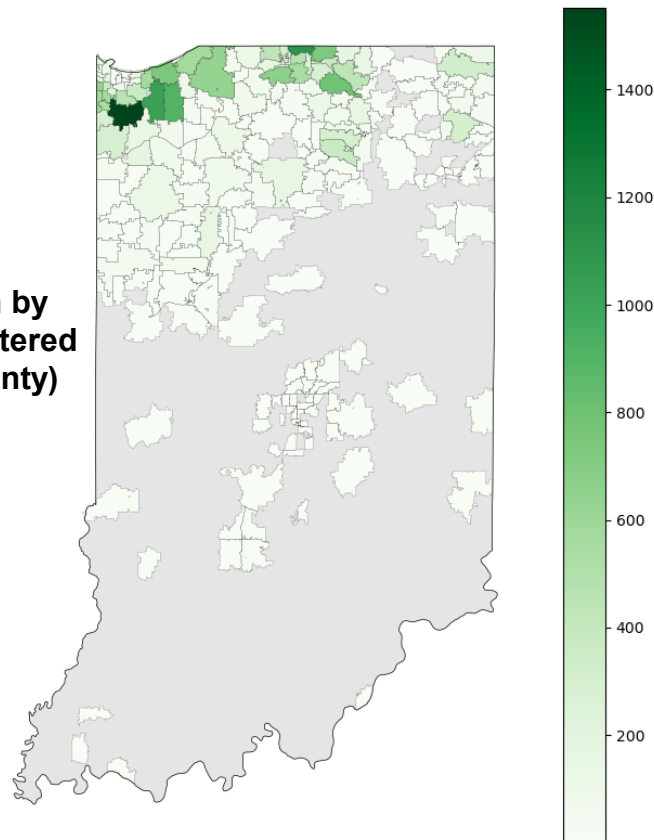
We exist to deliver safe, reliable energy that drives value to our customers

EV: DATA ASSUMPTIONS – VEHICLE TRAVELING DISTANCE

Average daily miles traveled per vehicle: 43 miles

- [Bureau of Transportation Statistics data](#) from 2009 shows Indiana vehicle trips ranged from 32 – 55 miles per day, varying by urban / suburban / rural distinction, 43 miles per day used as midpoint
- No change forecasted in average vehicle miles traveled between 2024 and 2040

EV Penetration by
zip code (registered
in NIPSCO county)

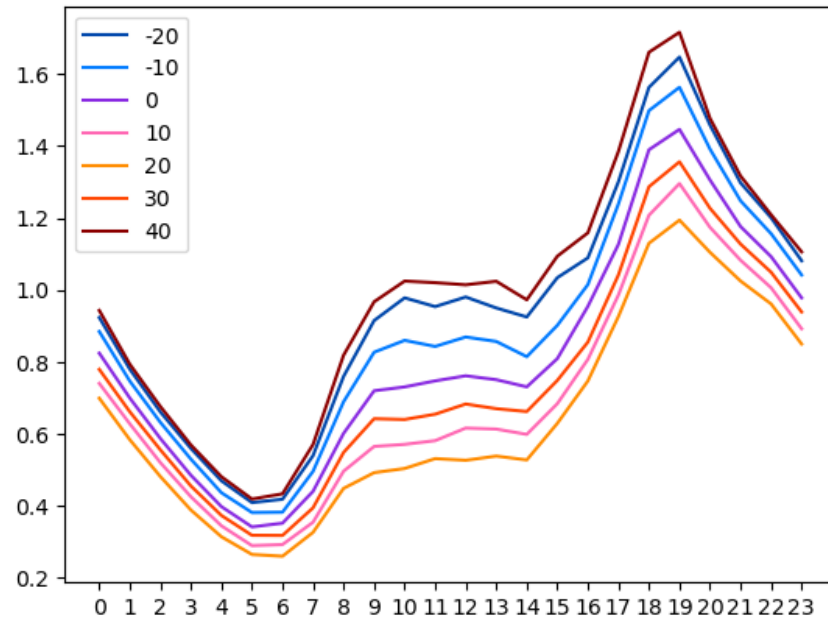


State	Mean Census Tract estimate by urban group					
	Vehicle miles traveled			Vehicle trips		
	Urban	Suburban	Rural	Urban	Suburban	Rural
Indiana	32.89	42.99	55.36	4.99	5.60	5.78

EV: DATA ASSUMPTIONS – TEMPERATURE

Temperature: Variable

- Average temperature data taken from Michigan City weather station
- EVI Pro-Lite takes in increments of 10 degrees Celsius, so it is not essential to perfect this data point, but rather use it to shape seasonal trends



EV shape can vary substantially by temperature, with lowest load in 20 degree Celsius weather.

Given 10 deg C granularity of model, changes in climate patterns **do not** currently appear to have a major impact on long-term EV load



Northern Indiana Public Service Company LLC
2024 Integrated Resource Planning
Public Advisory Meeting #1
SUMMARY

April 23, 2024

Welcome, Safety Moment, and Kick Off
Tara McElmurry, Communications Manager, NiSource

Tara McElmurry opened the in-person and virtual meeting by discussing the meeting protocols and walking through the agenda. A safety moment was then provided by EJ White, Project Consultant, NiSource, related to fire safety. Ms. McElmurry then introduced Vince Parisi, President and COO of NIPSCO, to kick off the meeting. Mr. Parisi shared his personal background along with a general overview of NiSource, NIPSCO's profile and ownership structure, and the company's ongoing generation transition plan.

NIPSCO Integrated Resource Planning (IRP) Process Overview / Developments since the 2021 IRP / Environmental Policy Review
Fred Gomos, Director Strategy, NiSource; Pat Augustine, Vice President, Charles River Associates ("CRA"); Stephen Holcomb, Director Environmental Policy & Sustainability, NiSource

Fred Gomos began with an overview of NIPSCO's IRP process, which is conducted every three years and outlines the company's long-term plan to supply electricity to customers over the next 20 years. The objectives that NIPSCO focuses on during the IRP process include reliability, sustainability, flexibility, diversity, and affordability; while considering company employees, environmental regulations and market rules, and the local economy.

NIPSCO will follow the same five-step process that it used during its 2018 and 2021 IRPs. First, the company identifies planning objectives and key questions. Next, NIPSCO develops market perspectives (scenarios) to determine what could be happening in the markets within which we operate. Third and fourth, NIPSCO develops Integrated Resource Strategies (NIPSCO Portfolios) and then analyzes these portfolios with market, financial, and risk models. Finally, NIPSCO evaluates tradeoffs and then selects its preferred plan. Emerging issues for 2024 include MISO market evolution, environmental policy, and emerging load trends.

Mr. Gomos then presented a slide featuring Indiana's five pillars of electric generation long-term planning. These pillars came out of the Indiana 21st Century Energy Task Force, which was created as a result of the passing of House Enrolled Act 1278. The five pillars are Reliability, Resilience, Affordability, Stability, and Environmental Sustainability, which are consistent with the criteria NIPSCO uses for resource planning decisions. He then passed things over to Pat Augustine to present on ongoing MISO market developments and federal policy changes.

Mr. Augustine began by speaking about some of the significant changes happening at MISO, including how the resource mix is driving new resource adequacy challenges. He walked through MISO's Reliability Imperative, which describes the shared responsibility of MISO and its members to ensure reliability in the MISO region. In 2023, MISO implemented a four-season capacity construct, with obligations and resource accreditations varying by the four seasons across the MISO Planning Year. In 2025, MISO plans to implement a "downward sloping" reliability-based demand curve to value capacity across a range of reserve margin levels. Finally, MISO filed its Direct Loss of Load ("D-LOL") market design proposal with FERC in March 2024, which focuses on performance during tight margin hours, for implementation in 2028.

Next, Mr. Augustine provided a summary of how NIPSCO's 2024 IRP will evaluate the potential impacts associated with D-LOL implementation. He mentioned that accreditations will likely change and that NIPSCO's obligation is likely to decline, but the magnitude of the decline is still uncertain. He noted that this is not a wholesale change to MISO's planning process, but it does make tracking supply and demand more complicated and creates more uncertainty. MISO's D-LOL filing still needs approval from FERC and stakeholders have raised several questions and concerns. NIPSCO will discuss this topic further in future IRP stakeholder meetings.

Mr. Augustine then provided a summary of the Inflation Reduction Act (IRA), which was signed into law in August 2022, and some of the impacts it has had on NIPSCO's business thus far. Changes to the Production Tax Credit (PTC), Investment Tax Credit (ITC), and the new Hydrogen PTC (up to \$3/kg) have all been items that NIPSCO has taken into consideration for business planning in recent years.

Finally, Mr. Augustine discussed bonus tax credit opportunities arising from the IRA. He summarized the Energy Community locations that exist in Indiana and discussed how NIPSCO is currently taking advantage Energy Community incentives for existing projects. He then presented the potential Low-Income Economic Benefit Projects (LIEBPs) opportunities that exist in Indiana and how NIPSCO may evaluate the potential of each. He then handed the presentation over to Stephen Holcomb to discuss environmental policies.

Mr. Holcomb began by covering EPA's proposed Clean Air Act Section 111(b) and 111(d) rules associated with greenhouse gas standards and guidelines for fossil fuel-fired power plants, which were published in the Federal Register on May 23, 2023. This rule is expected to be finalized by EPA this Spring and will be incorporated in NIPSCO's IRP analysis.

Mr. Holcomb then discussed how current environmental regulations are impacting NIPSCO's portfolio operations and planning. NIPSCO's coal fleet remains in compliance with several key environmental regulations, including Effluent Limitation Guidelines (ELG), the Coal Combustion Residuals (CCR) Rule, Mercury and Air Toxics Standards (MATS), and the Good Neighbor Rule. Retiring Schahfer Units 17 and 18 by 2025 will allow NIPSCO to avoid the significant capital costs needed to comply with some of these federal regulations.

Finally, Mr. Holcomb walked through a slide that shows NIPSCO's current progress in meeting environmental improvement targets, as well as progress toward 2030 environmental goals, mainly through the retirement of NIPSCO coal units by 2028. Also, in 2022, NIPSCO furthered its commitment to sustainability by announcing a 2040 Net Zero Goal for greenhouse gas emissions.

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

- Do I understand correctly, that the direct loss of load method, is going to be changing the accreditation on an annual basis? And so each year, MISO is looking to recalculate each

resource and the capacity value that it is providing, and this is done after the fact? Do you know in advance when those tight hours are going to be for a year?

- Yes, that is generally correct. The way it will work is that MISO is going to look at the capacity contribution of classes of resources during times of stress, and different resource classes will be awarded different accreditations. This will be done on a forward-looking basis, assessing the times of greatest risk through stochastic probabilistic modeling, drawing from historic weather years, load outcomes, wind availability, solar availability, and fuel thermal unit outages; based on the times of stress that are identified. MISO will then allocate a capacity accreditation to solar resources for the summer, fall, winter, and spring, then do the same thing for wind, gas, storage, etcetera. On top of that, once MISO has determined a class-level accreditation, MISO will go back and look at historical performance of actual units and then divvy up that class-level allocation to the specific units in each class. So although you will have advance information regarding class-level accreditation trends, you're not going to know well in advance how specific units performed to be able to plan with absolute certainty what capacity accreditation a specific unit will receive. Now, when you've got a new unit, that will get the class-level data until it's got actual historical operating characteristics.

But as I talk through all that, the main message is that it is complicated and we are going to be evaluating the indicative forward-looking accreditations that MISO has published for what they plan to be the first year of implementation, which will be the 2028-2029 period. There's a transition period every year from now until then, and they will publish these indicative expectations to give market participants a sense of where things are going. And, like I said, this is still in front of FERC and we don't know if it'll be approved or if there'll be modifications, but there will be resource-specific accreditation changes that are going to happen year after year, based on MISO calculations, and based on actual historical performance of units that are within the fleet.

Note that NIPSCO must operate similarly right now. For example, for the 2024-2025 capacity year, awards were published indicatively by MISO last fall and the actual awards are then made in the spring prior to the auction. Thus, we do have the same general process now, where resource performance over a historical period does dictate accreditation, but it's getting more complicated because of the forward-looking probabilistic assessment that MISO is going to run.

- (Regarding IRA new “bonus” credit opportunities) Do you know if you can get the total 40% bonus credit? Like, can you add them all up?
 - Yes, you can. Slide 21 shows how projects in different regions can get stacked credits for Energy Communities and other benefits, such as the LIEBP program.
- (Regarding EPA’s Proposed Rule under Clean Air Act Section 111) Can you remind me of the distinction between an existing unit versus a new unit? Is that as of the date of the rule being published, or is there a different date?
 - The distinction actually occurs when the rule was proposed, which was in May 2023. So this is the date by which a gas unit is considered either existing or new, meaning that if the unit is constructed after May 2023, it will be considered a new unit. So, for example, the Schahfer peaker units that have been proposed will be considered new gas units.
- What is the date for retirement for the Michigan City plant?

- We anticipate the Michigan City generating station to be retired by 2028.

2021 Short Term Action Plan Update / Continuous Improvements for 2024 IRP / 2024 IRP Analytical Framework

Fred Gomos, Director Strategy, NiSource and Pat Augustine, Vice President, CRA

Fred Gomos introduced the section by reviewing the progress made on the 2021 Short Term Action Plan and NIPSCO's Preferred Plan. Mr. Gomos noted Schahfer is on track to retire by 2025 and Michigan City is estimated to retire by 2028.

Mr. Gomos provided a summary of NIPSCO portfolio additions since the 2018 IRP, which showed ~1,000 MW of wind generation capacity and 465 MW of solar generation capacity placed into service. He then reviewed expected in-service dates for approved projects, which include Cavalry, Dunns Bridge II, Green River, Appleseed, Templeton and Carpenter.

Next, Patrick Augustine provided an overview of feedback received during the 2021 IRP and the continuous improvement plan for 2024. Feedback resulted in four major categories, which include load forecast, demand-side resources, portfolio analysis and stakeholder collaboration. Mr. Augustine provided additional detail on each category for improvement, including information about Aurora model licenses, which will allow interested stakeholders to use the modeling files to perform their own analysis.

Mr. Augustine closed the section by providing a preview of the IRP analytical framework, along with an introduction to the scenario constructs that are being worked on, including a Reference Case and Slower Transition, Domestic Resiliency, Aggressive Environmental Regulation, and Accelerated Innovation scenarios. NIPSCO's IRP analysis will use scenarios, special studies and stochastic analysis to perform a robust assessment of risk.

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

- Is it possible for Michigan City to retire sooner with a lot of cleaner energy coming online soon?
 - Michigan City is a large facility and would require sufficient replacement energy and capacity. We do not foresee those units retiring sooner.
- Are there any plans to convert Michigan City to gas?
 - No plans to Mr. Gomos' knowledge.
- Since the end of net metering, we have seen a significant decrease in the investment in distributed generation, what is NiSource or NIPSCO's position on potentially increasing incentives and increasing investment in distributed generation?
 - We have always been supportive of distributed generation, but net metering incentives are driven by state policy.
- Follow-up comment: It is within the company's prerogative to introduce and request approval for a new tariff when the current 15-year feed-in-tariff contracts expire.
- Related to the dispatch model, will the model select buying the energy from the wider MISO market or will it always dispatch NIPSCO resources first?
 - The portfolio model will be integrated with the MISO market so that purchases and sales are made economically. If the cost of an energy purchase is lower than the variable cost of operating a NIPSCO resource, an energy purchase will be made. If NIPSCO has more capacity than its native load operating at lower cost than the market price, energy sales will be made.
 - Note that in the portfolio construction phase, NIPSCO will likely set purchases and

sales constraints to avoid developing portfolio concepts that are overly reliant on market purchases and sales over the long-term.

- Are there some constraints around revenue requirement in the modeling or internally? What is NIPSCO's view of what is an appropriate increase in revenue requirement?
 - NIPSCO evaluates relative affordability across the spectrum of potential portfolio pathways that can be pursued. There is not a specific cost constraint per se, but we look at the need of the portfolio, need of megawatts or types of resources, and then assess the trade-offs across the different portfolios.
- Why was the 30-year NPV selected as opposed to what has historically been done in the 20-year IRP?
 - Although NIPSCO has historically run its dispatch models for 20 years, a 30-year NPV has been a key metric in past IRPs. 30 years is chosen because it reflects an average lifespan of new resources that could be added to the portfolio.
- Is it possible that NIPSCO could add a sixth pillar being equity or environmental justice as part of your scorecard and as part of your metric? Would like to see equity as a part of the scorecard.
 - We are contemplating the net present value of investment in Justice 40 communities this year within the Positive Social & Economic Impacts objective. We are proposing here that we would track investment in those communities in addition to some of the broader system wide economic investment metrics. We are available to talk further with you about other metric ideas if you have any.
- Are you intending to actually produce the stochastic price forecasts based on simulations that you would run for each one of the different load and renewable permutations?
 - That's partially correct. We will be using fundamental market runs to assess the future correlations between load, renewable output, and market prices, and then we'll integrate that into historical analysis of weather correlations for all of the variables. Portfolios will then be evaluated against the distributions of outcomes.
- Are you truly performing an LOLE analysis for NIPSCO? I don't think that is the right term to use, since NIPSCO is in MISO and will not experience direct LOLE and EUE risk based solely on its own resources. It will be important to understand whether NIPSCO is facing market exposure risk during the same times as MISO as a whole.
 - Thank you, that's a fair comment. NIPSCO still believes that a probabilistic reliability assessment will help ensure that we're bringing our fair share of reliability attributes to the table as MISO undergoes significant market reforms. However, you're right that LOLE or EUE risk does not exist for NIPSCO on its own. The modeling techniques are still similar, but we can work on some terminology changes like "forced market exposure" and consider assessing NIPSCO exposure hours relative to MISO risk hours. We can discuss further.

Reference Case Load Forecast

Fred Gomos, Director Strategy, NiSource and Pat Augustine, Vice President, CRA

After a break for lunch, Mr. Augustine presented a major part of the IRP process, which is NIPSCO's Reference Case load forecast. He provided an overview of NIPSCO's forecasting methodology, which is similar to previous NIPSCO IRPs. NIPSCO begins with data gathering to create inputs that then go into the core forecast. Econometric modeling by customer class is then used to create baseline energy and peak load forecasts. Finally, NIPSCO develops various

scenarios for the future.

For Distributed Energy Resource (DER) modeling, NIPSCO uses the PenDER model, which considers NIPSCO customer characteristics, economic decision-making, and social interactions to drive projections of the adoption of DER systems by various demographics. NIPSCO is also deploying an EV penetration model with local datasets, with an initial focus on light duty vehicles (LDVs) and medium duty vehicles (MDVs). Next, Mr. Augustine presented a slide about the main drivers of load uncertainty, mapping each of the drivers to the five planning scenarios.

He then went on to describe how NIPSCO determines its core electric sales forecast for Residential, Commercial and Industrial customer groups, saying that baseline customer counts and sales per customer energy forecasts by class are projected with the best-fitting variables. NIPSCO then projects the Reference Case energy sales and consumption by customer class. Mr. Augustine then presented peak load forecasts for the Reference Case, with NIPSCO expected to remain a summer-peaking utility. He then showed the fall and spring forecasts, where the fall load (September specifically) is projected to be much closer to the summer peak than the spring load.

Next, Mr. Augustine dove further into PenDER model key assumptions. These assumptions include avoided costs/revenues, PV costs, customer budget, and payback time. He also walked the group through a summary of other major assumptions that are used in the model. Among residential customers, a total of 80 MW of installed Solar DER capacity is projected by 2045. Among commercial customers, a total of 120 MW of installed Solar DER capacity is projected by 2045. Overall, for the Reference Case, a total of 166 MW of installed Solar DER capacity is projected by 2035, 180 MW by 2040, and 200 MW by 2045.

NIPSCO's next steps for DER analysis include evaluation of DER penetration levels across four alternative scenarios (Slower Transition, Domestic Resiliency, Aggressive Environmental Regulation, Accelerated Innovation) and integrating analysis with the DSM study to assess opportunities for incentives for customer-owned storage installations (i.e., to improve the capacity value of DER resources).

Next, NIPSCO discussed the Electric Vehicles Reference Case. NIPSCO blends a penetration forecast with hourly shapes to capture long-term trends in vehicle growth and charging behavior, while accounting for weather conditions. Mr. Augustine provided an overview of Light-Duty Vehicle (LDV) EV adoption projections, both for sales and registrations. NIPSCO then translates these results to show how adoption rates impact hourly load shapes in the future. NIPSCO utilizes NREL's EVI-Pro-Lite tool to develop hourly shapes, blending profiles to address long-term trends in vehicle type. As EV adoption becomes more widespread, model forecasts will align with changes in charging behavior and charger/vehicle efficiencies. Finally, Mr. Augustine presented a slide showing projected LDV load impacts over time, along with hourly load profile projections in 2030, both for a weekday and a weekend scenario.

Finally, Mr. Augustine walked through slides representing Medium-Duty Vehicles (MDVs), which showed long-term growth projections, in a very similar manner to what was shown for Light-Duty Vehicles (LDVs). MDVs will have a much smaller peak impact over time, compared to LDVs. While overall EV adoption is expected to meet EPA targets in the reference case, EVs have a relatively modest, but growing impact on energy and peaks.

Mr. Augustine closed the section by noting that NIPSCO would next evaluate higher and lower EV penetration levels and perform an additional study on heavy duty vehicle charging in major transit corridors. The team will also be integrating the EV penetration analysis with the DSM study to assess opportunities for managed charging incentives in the LDV segment.

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

- (Regarding drivers of load uncertainty scenarios) So for the domestic resiliency scenario, will that at some point incorporate the increased interest in microgrids? There's a big push all over the country right now, especially for local units of government like police or water departments, in situations where they don't have any power but they have a power system themselves, to keep important, critical emergency services available through microgrids. Do you have any thoughts about including that as part of your discussion?
 - That's a good comment. The Accelerated Innovation scenario is where we've actually contemplated larger microgrid adoption. That's a scenario where we will be mapping larger distributed energy penetration, including around the microgrid theme.
- (Regarding Peak Load Forecast – Four MISO Planning Seasons) I'm just curious, where are you guys putting data centers? Are you considering them as potential Rate 531 customers, or not Rate 531 customers, or are you dropping them in those buckets?
 - Right now they're not in the Reference Case. As we get into the scenario analysis, we're going to have a separate category where we'll call out that data center load. It will likely be in the industrial class, but I think there's some uncertainty about which class and we'll get to that in some of the scenarios and subsequent meetings.
 - Rate 531 was a construct for customers at a certain point in time and there are certain requirements for those customers. Our sense is that as these data center loads show up on the system, that we may have to offer something a little bit different for them, versus steel mills that have their own backup generation and different levels of price sensitivity. I think that there could be potential for other constructs that make sense for those customers. Right now we're assuming that there is new industrial load potential coming onto the system in the scenario analysis, and we will do the analysis based on that.
- Is this projecting a certain amount of Rate 531 Tier 1 load reduction across time, as those customers are expected to step down their Tier 1 load requirements?
 - No, not in the Reference Case, but the step down will be incorporated in the Slower Transition scenario and possibly others. This is still somewhat speculative, as we don't have firm declarations on that yet. So, the Tier 1 load here in the Reference Case is essentially flat. There is some modest decline in all Rate 531 load as we've seen that in the econometric forecast, but we're not stepping down to their minimum takes in the Reference Case.
 - I believe last IRP we had a scenario where we moved Rate 531 off of the system, so we've looked at that as a scenario construct, but it's all speculative at this point because nobody has declared that they're moving off that rate.
- Are you projecting a change in the timing of those summer peaks? Are they shifting later into the evening or anything like that or are you still working on figuring that out?
 - That's a good question. We're in the middle of working on that. I think the biggest driver of that will be the electric vehicle charging. The core profile from just a base customer demand perspective is expected to be pretty constant, but electric vehicles and potential other electrification could shift the net peaks.
- Since NIPSCO is still a summer-peaking electric utility, what is the probability of looking at ways to induce customer-owned DERs to contribute power back into the grid when you need it the most. For example, your PURPA rates reflect seasonality, as well as on peak

and off peak, however the normal NIPSCO rates do not address that.

- We will have some of that specifically integrated into the DSM study. Under current constructs, there is the EDG rate that provides essentially an annual price but through this potential for rate redesign, you could incentivize energy to be offered, or at least avoid self-consumption, at different times of day. So, for example, storage could then be more attractive for a customer. In the DSM study, we will evaluate that further.
- (Regarding the PenDER Model: Summary of Major Assumptions) I've seen a lot of the breakout with respect to solar, but isn't there a lot of CoGen and CHP in your service territory? You've got some large CHP customers and customers on PURPA contracts that you serve. I'm not quite sure where all of that gets incorporated, or is it at all?
 - We pick that up from a load forecast standpoint and I think there is some in the supply/demand balance in the supply stack. We can follow-up on that for the next meeting.
- My understanding is that there's a 1 MW cap on many of the DER resources in the territory. Is there any consideration of making that larger or increasing the cap?
 - No. These are smaller scale residential and commercial customers. To the extent that some larger distributed projects either could participate directly in the RFP or apply for PURPA, I think that's a separate topic from the residential and the commercial DG being summarized here.
- (Regarding the Reference Case inputs) Is this model primarily based on existing market factors and historic adoption? Is it factoring in things like the Solar for All grant, which was just announced yesterday, and then some of the others like not specific tax credits, but specifically grants and financing products that are designed to broaden market adoption and will be implemented in the next several years, permanently from the IRA?
 - The short answer is that some of those are picked up within the scenarios. We are not attempting to model every incentive that might be out there, but the idea is that we want to develop an envelope of outcomes, associated with all-in economic considerations for customers.
- (Regarding Projected LDV Load Impacts Over Time) So, right now, there are 2,000 EVs in the NIPSCO area?
 - Yes, that is the approximate number based on registration data.
- Is NIPSCO going to get into how it plans to help ramp up EV sales? One of the other utilities shows on its website how they're getting into the EV market. So are you going to be doing things to ramp up EV sales?
 - Not directly within the IRP setting. This is a Reference Case that shows a projection for service area penetration, and we'll also be studying a range of potential outcomes. However, there is a state program for EVs and we've been studying how to do something in that space as well. We also did work in our last electric rate case around an EV tariff. We have also deployed eleven fast-charging stations across our territory, which was part of the VW settlement.
- Will you be employing Justice 40 as it relates to where you locate your charging stations? Will you be ensuring that 40% of them benefit disadvantaged communities?
 - The short answer is, yes. We're trying to understand where the demand is, in terms of the IRP. Within the context of EV pilot programs, we're studying how to site charging stations with respect to Justice 40.

- EV charging stations take a lot of energy and we only have a small amount of cushion right now during max periods. Will there be upgrades to the transmission system and upgrades to handle the EV stations that will need to be integrated? Will this topic be brought up in these IRP meetings?
 - The IRP process is more macro but meeting these new loads will require generation, demand-side management, and T&D resources. There is a distribution planning process that does get integrated into the overall IRP process. This IRP process will answer some of your questions, but there are separate implementation elements once the IRP is finished.

2024 Request for Proposal (RFP) / 2024 Public Advisory Process Next Steps
Patrick d'Entremont, Manager Planning Commercial Support, NIPSCO
Bob Lee, Vice President, CRA

Patrick d'Entremont noted that the purpose of the RFP is to bring in new resource parameters. He provided a high-level explanation of where the RFP fits into the IRP process. Bob Lee then outlined the four RFPs planned for this cycle, preliminary evaluation criteria, and the estimated timeline for each.

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

- Could you clarify the difference between the bridge resources and the intermittent dispatchable RFPs?
 - The bridge resource category aims to identify potential projects that may be available and capable of meeting rapid new customer growth. Customer timing delineates the RFP category.
- Is the company planning to share with us the names of the companies that have responded to the RFP?
 - We are anticipating sharing that with stakeholders at the June meeting.
- Will the stakeholders have time to review the RFP?
 - Yes, a draft will be provided for comment for those signing an NDA.
- If you sign an NDA, are you able to bid on the RFP?
 - Typically, the people reviewing and providing comments on the RFP itself are not bidders because we do not want to give a material advantage to any party over another.

Closing
Fred Gomos, Director Strategy, NiSource

Mr. Gomos closed the meeting by thanking stakeholders for their engagement as NIPSCO sets the stage for the 2024 IRP. He provided an overview of the stakeholder advisory meeting roadmap, with dates and expected meeting content, including a summary of the plan for the next meeting in June.

NIPSCO IRP Stakeholder Meeting - April 23, 2024

Contact First Name	Contact Last Name	Contact Email Address	Company
Denise	Abdul-Rahman	darahman17@gmail.com	Indiana State Conference of the NAACP
Levy	Agaronnik	Levy.agaronnik@blackstone.com	Blackstone
Shannon	Anderson	shannon@earthcharterindiana.org	Earth Charter Indiana
Pat	Augustine	paugustine@crai.com	Charles River Associates
Quinn	Beckham	quinn.beckham@keycaptureenergy.com	Key Capture Energy
Alexandra	Boillot Navin	alexandra@rangerpower.com	Ranger Power
Jean	Boling	jboling1@urc.IN.gov	Indiana Utility Regulatory Commission
Drew	Burczyk	dcburczyk@burnsmcd.com	Burns and McDonnell
Chris	Chyung	chris@inconservationvoters.org	ICV
Lou	Donkle	donkle3@gmail.com	none
Sameer	Doshi	sdoshi@earthjustice.org	Earthjustice
Stephen	Dynako	dynako@gmail.com	Stephen Dynako
Michael	Eckert	meckert@oucc.in.gov	OUC
SUZANNE	ESCUDIER	suzanne.escudier@origisenergy.com	Origis Energy
Brian	Flory	bflory@solarunitedneighbors.org	Solar United Neighbors
McKenzie	Fowler	mfowler@crai.com	CRA
Erik	Gage	egage@nationalgridrenewables.com	National Grid Renewables
Emma	Goodnow	emma.goodnow@duke-energy.com	Duke Energy
Doug	Gotham	gotham@purdue.edu	State Utility Forecasting Group
Karen S	Hall	Karen.Hall2@duke-energy.com	Duke Energy
John	Hanks	jhanks@oucc.in.gov	OUC
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
Ben	Inskeep	binskeep@citact.org	Citizens Action Coalition
John	Isaac	john.isaac@leewardenergy.com	2/2/2024
David	Jackson	djackson@flexgen.com	Flexgen
Kelley	Karn	kelley.karn@duke-energy.com	Duke Energy
Genevieve	Kennedy	GENEVIEVE.TGW.KENNEDY@GMAIL.COM	Leeward Renewable Energy
Will	Kenworthy	will@votesolar.org	Vote Solar
Greg	Krieger	gkrieger@oucc.in.gov	Indiana OUC
Reagan	Kurtz	rkurtz@citact.org	Citizens Action Coalition of Indiana, Inc.
Robert	Leah	bleah@nationalgridrenewables.com	National Grid Renewables
Arthur	Longthorne	Alongthorne@solscient.com	Solscient Energy
Sunil	Maheshwari	mahesh67@purdue.edu	Purdue University
Bill	Malcolm	wmalcolm@aarp.org	AARP
Jeremy	Martin	jeremy.martin@centerpointenergy.com	CenterPoint Energy
Debi	McCall	demccall@nisource.com	8LH3-YJLN-47G
Emily	Medine	emilymedine@aol.com	Energy Ventures Analysis, Inc.
Tony	Mendoza	tony.mendoza@sierraclub.org	Sierra Club
Joe	Motuliak	joe.motuliak@nee.com	NextEra Energy Resources
Edwin	Moyo	emoyo@crai.com	CRA International
David	Nderitu	nderitu@purdue.edu	State Utility Forecasting Group
Christopher	Norrick	cnorrick@solarunitedneighbors.org	Solar United Neighbors
Jessica	Nyquist	jnyquist@formenergy.com	Form Energy
Kerwin	Olson	kolson@citact.org	Citizens Action Coalition
Nadia	Pabst	NPabst@aypa.com	Aypa Power
April	Paronish	aparonish@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Harshil	Patel	harshil.patel@leewardenergy.com	Leeward Renewable Energy
Mary	Perren	mary.perren@gmail.com	Hoosier Solar
Matthew	Peterson	Matthew.Peterson@duke-energy.com	Duke Energy
Tim	Phillips	timphillips@purdue.edu	State Utility Forecasting Group
Govind	Ramakrishnan	govind.ramakrishnan@blackstone.com	Blackstone
Stephen	Rodocanachi	srodocanachi@harttreepartners.com	Hartree Partners, L.P.
Colleen	Rosales	cmfrosales@gmail.com	OpenAQ / University of California in Davis
Roopali	Sanka	rsanka@oucc.in.gov	OUC
Zach	Schalk	Zach@solarunitedneighbors.org	Solar United Neighbors
Carter	Scott	carter@rangerpower.com	Ranger Power LLC
Donnita	Scully	donnita4sfs@hotmai.com	NAACP LaPorte County Branch
Zico	Shaker	zico.shaker@leewardenergy.com	Leeward Renewable Energy

NIPSCO IRP Stakeholder Meeting - April 23, 2024

Sebastien	Sherman	Sebastien.Sherman@Blackstone.com	Blackstone
Mark	Simons	mcsimons803@gmail.com	MCSimons Inc
Steve	Smith	steven.smith@franklincovey.com	Franklin Covey
Anna	Sommer	asommer@energyfuturesgroup.com	Energy Futures Group
Will	Talbott	wtalbott@aypa.com	Aypa
Dale	Thomas	dthomas@urc.in.gov	IURC
Susan	Thomas	Susan@jtnwi.org	Just Transition NWI
Marco	Velastegui	mvelaste@purdue.edu	Purdue
Nathan	Vogel	nathan.vogel@inovateus.com	Inovateus Solar LLC
Nathan	Vogel	nathan@inovateus.com	Inovateus Solar LLC
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana (CAC)
Doug	Wester	doug@nationalgridrenewables.com	National Grid Renewables
Rachel	Wilson	rwilson@formenergy.com	Form Energy
Brian	Wright	brwright@oucc.in.gov	OUCC
Gilbert	Zelaya	gzelaya@earthjustice.org	Earthjustice

2024 NIPSCO Integrated Resource Plan
Second Stakeholder Advisory Meeting
June 24, 2024



We exist to deliver safe, reliable energy that drives value to our customers

2024 NIPSCO Integrated Resource Plan

Second Stakeholder Advisory Meeting

June 24th, 2024

9:00AM-2:00PM CST



SAFETY MOMENT – SUMMER HOLIDAY TRAVEL

Gearing up to travel for the Independence Day holiday: enjoy the journey, take breaks and arrive alive

Indiana State Police Summer Travel Safety Tips:

- **Drive Safely**
- **Check Your Tires**
- **Keep Kids Safe**
- **Keep an Emergency Kit**
 - Your vehicle emergency kit should include:
 - water
 - food
 - charged cell phone
 - flashlight
 - fire extinguisher
 - first aid kit
- **Stay Cool**

Source: <https://www.in.gov/isp/driving-safety/summer-travel-safety>



Source: <http://www.my35.org/summer-travel-safety-tips.htm>

We exist to deliver safe, reliable energy that drives value to our customers

MEETING PROTOCOLS

- **Your input and feedback are critical to NIPSCO's Integrated Resource Plan ("IRP") Process**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and overall IRP**
- **We set aside time at the end of each section to ask questions**
- **Your candid and ongoing feedback is key:**
 - Please ask questions and make comments on the content presented
 - Please provide feedback on the process itself
- **While we will mostly utilize the chat feature in Teams to facilitate comments, we will gladly unmute you if you would like to speak. Please identify yourself by name prior to speaking. This will help keep track of comments and follow-up actions**
- **If you wish to make a presentation during a meeting, please reach out to Alison Becker (abecker@nisource.com)**

AGENDA

Time (Central Time)	Topic	Speaker
9:00-9:10AM	Welcome & Introduction	Alison Becker, Manager Regulatory Policy, NIPSCO
9:10-9:20AM	Kick Off/Responses to First Stakeholder Meeting	Vince Parisi, President & COO, NIPSCO Fred Gomos, Sr. Director Environmental & Sustainability, NiSource Pat Augustine, Vice President, CRA
9:20-9:30AM	Scenario Analysis Overview	Pat Augustine, Vice President, CRA
9:30-11:00AM	Scenario Analysis: Key Drivers of NIPSCO Load Uncertainty	Vince Parisi, President & COO, NIPSCO Rick Calinski, Director of Public Affairs and Economic Development, NIPSCO Fred Gomos, Sr. Director Environmental & Sustainability, NiSource Pat Augustine, Vice President, CRA
11:00-11:05AM	Break	
11:05-11:30AM	NIPSCO's Supply-Demand Position: MISO Resource Accreditation and Load Obligation Uncertainties	Pat Augustine, Vice President, CRA
11:30AM-12:20PM	Lunch	
12:20-1:05PM	Scenario Analysis: Commodity Prices, Environmental Policy, and MISO Market Outcomes	Pat Augustine, Vice President, CRA Stephen Holcomb, Director Environmental Policy & Sustainability, NiSource
1:05-1:35PM	Stochastic Analysis	Pat Augustine, Vice President, CRA
1:35-1:40PM	Break	
1:40-2:25PM	Preliminary RFP Review	Patrick d'Entremont, Manager Planning Commercial Support, NIPSCO Bob Lee, Vice President, CRA
2:25-2:30PM	2024 Public Advisory Process Next Steps	Alison Becker, Manager Regulatory Policy, NIPSCO
2:30-2:55PM	Closing & Stakeholder Comments	

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

KICK OFF

Vince Parisi, President & COO, NIPSCO

Fred Gomos, Sr. Director Environmental Policy & Sustainability, NiSource

Pat Augustine, Vice President, CRA



PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and is consistent with our goal to transition to the best cost and cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.



**Reliable and
sustainable**

**Flexibility for
the future**

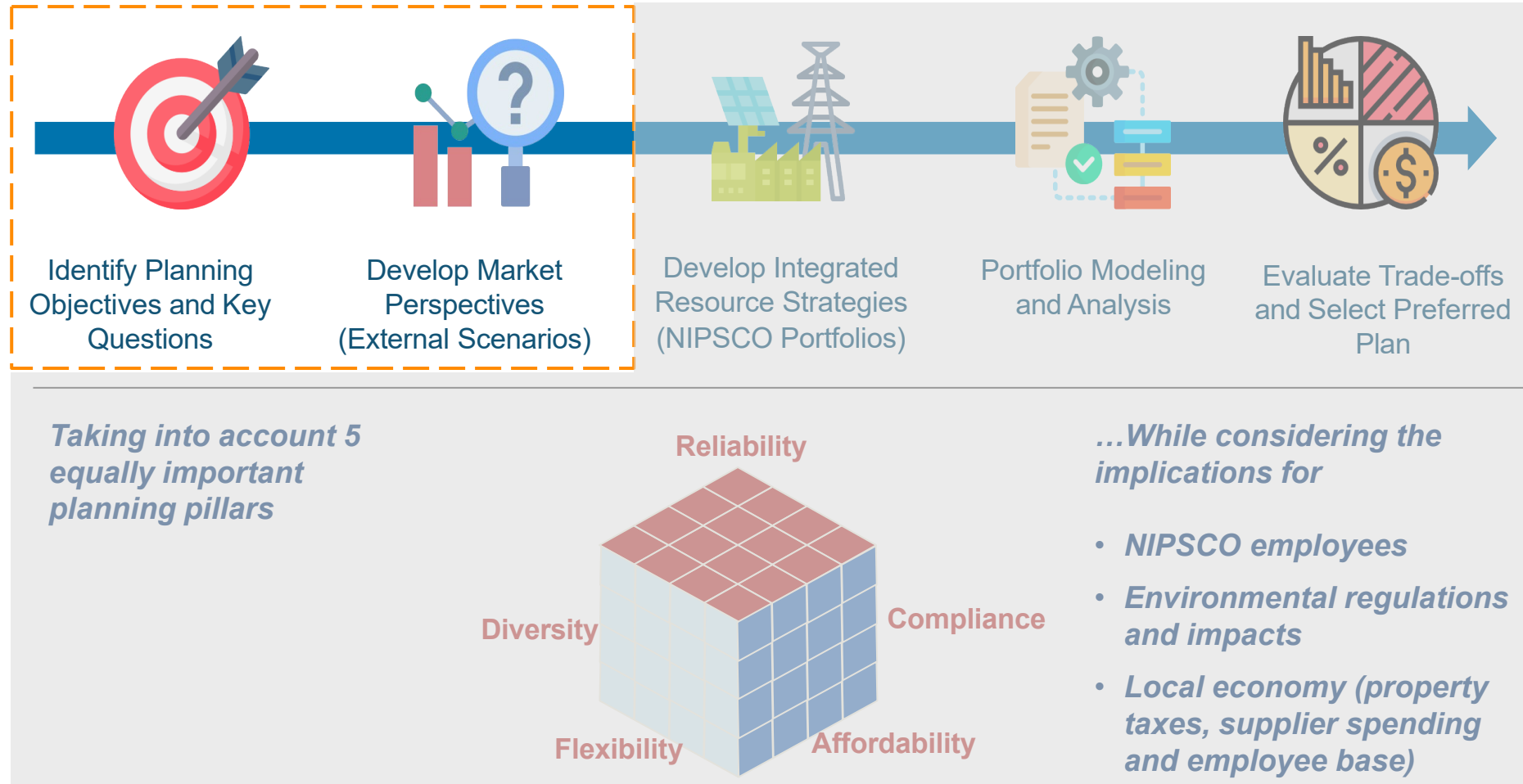
**Local and statewide
economic benefits**

**Best plan for customers
and the company**

We exist to deliver safe, reliable energy that drives value to our customers

APRIL 23 IRP STAKEHOLDER MEETING RECAP

The first IRP Stakeholder Advisory meeting focused on planning objectives and the process of developing external market perspectives



We exist to deliver safe, reliable energy that drives value to our customers

SUMMARY OF STAKEHOLDER FEEDBACK FROM MEETING #1

Category	Stakeholder Comments	NIPSCO Responses
Scorecard Metrics	- Consider additional metrics associated with environmental justice - Consider different metrics for reliability, given NIPSCO is a part of the Midcontinent Independent System Operator, Inc. (“MISO”) and not a stand-alone balancing authority	- NIPSCO welcomes stakeholder feedback on effective long-term planning environmental justice/energy equity metrics - Probabilistic reliability study to be discussed more today, with revised metric considerations
Distributed Solar	Consider Solar for All grant impacts	Tracking potential impact in the context of broad DER scenarios
Reliability Modeling	Reevaluate use of expected unserved energy (“EUE”)/loss of load expectation (“LOLE”) as metrics and provide more details on input development	Probabilistic reliability study to be discussed more today, with revised metric considerations

SOLAR FOR ALL – POTENTIAL IMPACTS IN INDIANA

- On April 22, 2024, EPA announced that the Indiana Solar for All (“ISFA”) coalition was awarded over \$117 million in funding through the Greenhouse Gas Reduction Fund’s Solar For All program.
- At the April 23 Public Advisory meeting, stakeholders expressed interest in potential impacts to NIPSCO’s long-term planning in the 2024 IRP.
- Specifics on the implementation of the ISFA program are unknown at this time, including;
 - How much funding Gary, Indiana will receive
 - The timeframe for the rollout of the residential solar installations
- To the extent stakeholders can provide additional technical information related to ISFA, specifically in Gary, Indiana, NIPSCO welcomes and encourages that feedback to its IRP team.





We exist to deliver safe, reliable energy that drives value to our customers

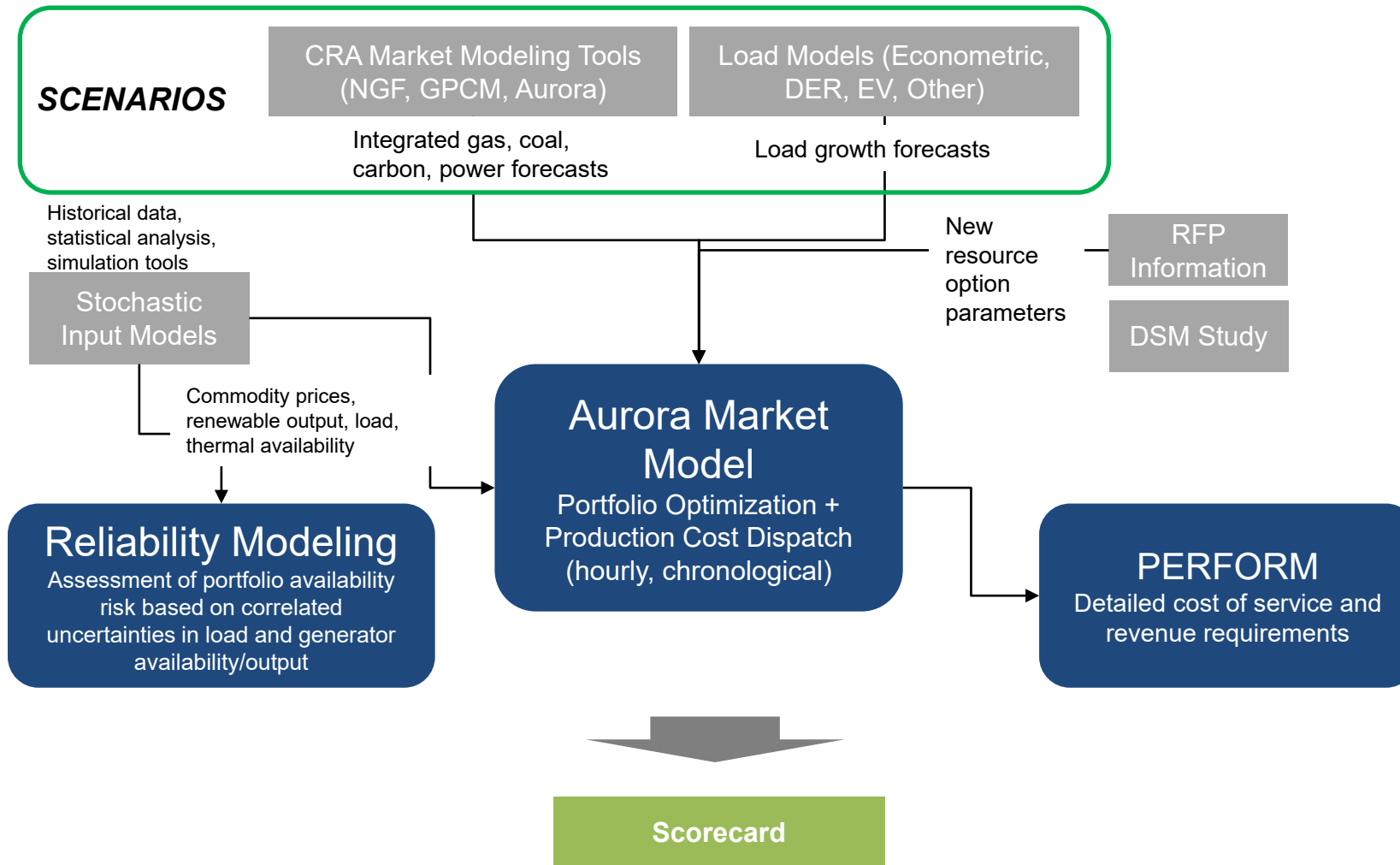
SCENARIO ANALYSIS OVERVIEW

Pat Augustine, Vice President, CRA



RECAP: RESOURCE PLANNING APPROACH

Key Modeling and Analysis Tools



- 1 Identify key planning questions and approach
- 2 Develop market perspectives (external scenarios) } *Today's meeting*
- 3 Develop integrated resource strategies (NIPSCO portfolios)
- 4 Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- 5 Evaluate trade-offs and select preferred plan

RECAP: 2024 IRP SCENARIOS



Reference Case (“REF”)

- The MISO market continues to evolve based on current expectations for load growth, commodity price trajectories, technology development, and policy change (Inflation Reduction Act “IRA” incentives continue, EPA power sector rules advance, and MISO resource adequacy enhancements proceed)



Slower Transition (“ST”)

- IRA incentives are reduced or ended early, and EPA power sector rules are overturned or rescinded; natural gas prices remain low and result in new gas additions remaining competitive versus renewables in the broader region, as coal capacity more gradually fades from the MISO market



Domestic Resiliency (“DR”)

- Continued geopolitical uncertainty and volatility drive a focus on “domestic energy independence”; electric power demand grows because of onshoring and other large loads; gas prices are higher due to strong demand



Aggressive Environmental Regulation (“AER”)

- Carbon emissions from the power sector are regulated more heavily, including through a CO2 price; restrictions on natural gas production increase gas prices



Accelerated Innovation (“AI”)

- Federal subsidies continue as a bridge until technology breakthroughs drive broad economy-wide decarbonization (including via electrification); new power sector technologies are commercialized, and DER, EV, microgrid, and EE adoption all increase, transforming wholesale load requirements as “Grid Edge” innovations and enabling policy advance

DIRECTIONAL SCENARIO VARIABLE INPUTS

Scenario	 Commodity Prices	 Carbon Policies	 Technology Costs	 Demand	 Market Design
 Reference Scenario	Baseline	Current policy, including EPA power sector CO2 emission rules	Baseline	Baseline	Examine alternative capacity accreditation and obligation requirements across alternative market design concepts and based on MISO market outcomes
 Slower Transition	Low gas price due to abundant resource ↓	IRA pull-back and withdrawn EPA power sector rules ↓	Slower decline for new tech costs; stable IC costs ↑	Low DER and EV	
 Domestic Resiliency	Higher gas price due to strong demand ↑	Current policy, including EPA power sector CO2 emission rules ■	Higher due to supply chain constraints, onshoring ↑	High load from new large loads, industrial onshoring, EVs	
 Aggressive Environ. Regulation	Highest gas price due to production restrictions ↑	EPA power sector CO2 emission rules <i>plus</i> carbon price ↑	Baseline ■	Higher DER and EV	
 Accelerated Innovation	Lower gas price due to demand erosion ↓	Current policy, including EPA power sector CO2 emission rules ■	New tech. advancement and decline in costs; IC cost pressures ↓	High EV and electrification plus new large loads; higher DER	

**Note that NIPSCO portfolio-level technology costs will be heavily informed by RFP data*

**Note that NIPSCO-specific analysis will incorporate additional demand uncertainty review*

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: KEY DRIVERS OF LOAD UNCERTAINTY

Vince Parisi, President & COO, NIPSCO

Rick Calinski, Director Economic Development and Major Accounts, NIPSCO

Fred Gomos, Sr. Director Environmental Policy & Sustainability, NiSource

Pat Augustine, Vice President, CRA



DRIVERS OF LOAD UNCERTAINTY

Scenario Name	Description	Economic Growth (C&R, I Count)	EV Penetration	DER Penetration	Electrification (MISO Futures Report)	Large Econ. Development Load
 Reference Case	Reference point	Base Moody's Baseline forecast	Base Rate of Adoption	Base Expected Rate of Adoption	Limited (Future 1)	<i>NIPSCO to discuss current expectations for large loads today.</i>
 Slower Transition	Environmental policy incentives reduce; economic slowdown in region	Low Moody's Low forecast ↓	Low Rate of Adoption ↓	Lowest High capital costs, low tax credits, low wholesale prices ↓	Limited (Future 1)	
 Domestic Resiliency	Influx of new economic development load	Base Moody's Baseline forecast	Base Rate of Adoption	Lower High capital costs ↓	Limited (Future 1)	<i>A separate sensitivity with significant additional economic development load potential across all scenarios will also be evaluated.</i>
 Aggressive Environmental Regulation	Aggressive decarbonization policy, moderate electrification	Base Moody's Baseline forecast	High Rate of Adoption ↑	High Net metering policy change ↑	High (Future 2) ↑	
 Accelerated Innovation	Faster energy transition, high electrification with additional econ. dev. load	Base Moody's High forecast	High Rate of Adoption ↑	High Low capital costs, larger installation sizes ↑	Highest (Future 3) ↑	



We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: LARGE ECONOMIC DEVELOPMENT LOADS



RECENT NEWS LEADING TO SIGNIFICANT REFERENCE CASE LOAD UPDATE

- The utility industry is facing a new driver of load growth over the next 3-10 years from data centers and other large demand.
- Since NIPSCO's first IRP Stakeholder Advisory meeting on April 23, 2024, there has been a significant increase in data center news in Indiana and specifically in our service territory.
- NIPSCO is now releasing an updated Reference Case and a large load sensitivity to incorporate this new potential load to ensure transparency and allow stakeholder feedback on this important development.
- **NOTE:** NIPSCO is not guaranteeing that any amount of new load (referenced in the following slides) will enter our service territory, but we are sharing our current expectations with stakeholders to allow time for feedback as we prepare to conduct our IRP analysis with this significant change.



[Home](#) > [Community](#) > [Business News](#) >
[Microsoft chooses La Porte as first Indiana data center location](#)



Microsoft chooses La Porte as first Indiana data center location

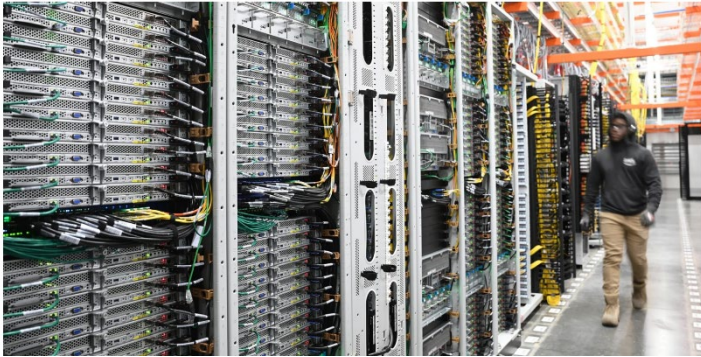
June 4, 2024 / By Heather Pfundstein / [Leave a Comment](#)



ECONOMY GOVERNMENT & POLITICS
IN BRIEF

Amazon Web Services to build \$11B Indiana data center campus

By LESLIE BONILLA MUNIZ - APRIL 25, 2024 11:09 AM



LOCAL NEWS

New lakefront Hammond data center at capacity, to expand

Joseph S. Pete | Feb 27, 2024

Just a few years after opening, the lakefront Hammond data center has already reached capacity and plans to expand.



U.S. NEWS

Google plans to invest \$2 billion to build data center in northeast Indiana, officials say

Updated 1:21 PM CDT, April 26, 2024

Share

FORT WAYNE, Ind. (AP) — Google plans to invest \$2 billion to build a data center in northeastern Indiana that will help power its artificial intelligence technology and cloud

STATE OF INDIANA – DATA CENTER INCENTIVES

Actions by the General Assembly and Governor's Office demonstrate a strong desire for Indiana to be a leader on data centers, and NIPSCO's experience over the last 12 months indicates this is an emerging industry that must be addressed in the IRP.

DATA CENTER GROSS RETAIL AND USE TAX EXEMPTION

- Provides a sales and use tax exemption on purchases of qualifying data center equipment and energy to operators of a qualified data center for a period not to exceed 25 years for data center investments of less than \$750M.
- If the investment exceeds \$750M, the Indiana Economic Development Corporation (“IEDC”) may award an exemption for up to 50 years.
- This program is established by Indiana Code § 6-2.5-15. Local governments may also provide a personal property tax exemption on qualified enterprise information technology equipment to owners of a data center who invest at least \$25M in real and personal property in the facility.

OTHER INDIANA INCENTIVES IN THE AREAS OF:

- JOB CREATION AND BUSINESS INVESTMENT
- REDEVELOPMENT AND QUALITY OF PLACE
- INNOVATION AND ENTREPRENEURSHIP
- RESEARCH AND DEVELOPMENT
- SKILLS TRAINING

DATA CENTER SITE SELECTION: WHY INDIANA? WHY NORTHERN INDIANA?

- Low risk for natural disasters
- Robust transmission network and reliability
- Available land
- Connectivity and fiber
- Access to water
- Proximity to customers/major metropolitan area/construction labor
- Pro business state with strong data center incentives



STRONG DEMAND FOR DATA CENTER INVESTMENT IN NIPSCO SERVICE TERRITORY

- **Over 30 Data Center inquiries over last year**
 - Initial conversations and sharing of high-level energy discussions on sites and areas.
- **Six Active Data Center Projects**
 - High-level load studies shared
 - Sites identified
 - Energy needs shared
 - Rough transmission/distribution cost estimated
 - Rough timeline to build out circuits/substation estimated
 - Compensated engineering studies in motion for some projects
- **Six Projects Estimate up to ~8,600 MW by 2035**



NEW LARGE LOAD SENSITIVITY

Given the potential opportunities in the pipeline from NIPSCO's Economic Development team, the IRP will need to include new large load in the analysis.

Economic Development Potential Opportunities Examples	Potential New Load
2-3 potential projects	Up to ~2,600 MW
6 potential projects	Up to ~8,600 MW

Potential load growth for IRP to analyze

The requirements for new energy, capacity, and demand-side resources to meet this potential new load will be analyzed in the 2024 IRP process using our core analytical framework.

- 2,600 MW of new economic development load by 2035 will be included in each IRP scenario.
- An additional sensitivity will be run with all scenarios to enable a book-end view of the future requirements.

ANALYTICAL FRAMEWORK FOR EVALUATING FUTURE RESOURCE NEEDS

The IRP analytical framework contains scenarios and sensitivities that will be used to highlight states of the world that will drive new resource needs. The IRP analysis will use an emerging large load sensitivity to assess the combined impact with the other scenario assumptions.

Scenarios & Sensitivities

Single, Integrated Set of Assumptions

- Can be used to answer the “What if...” questions
 - Major events can change fundamental outlook for key drivers, altering portfolio performance
 - New policy or regulation (carbon emissions regulation, tax credits)
 - Fundamental gas price change
 - Major load shifts
- Sensitivities are individual variables that can be flexed across all scenarios

Emerging Load

Stochastic Analysis

Statistical Distributions of Inputs

- Can evaluate volatility and “tail risk” impacts
 - Short-term price and generation output volatility impacts portfolio performance
 - The interactions between market price volatility and resource output uncertainty are more complex than what can be assessed under “expected” conditions
 - Commodity price exposure risk is broader than single scenario ranges
- For 2024 IRP, the stochastic analysis will be expanded to include hourly renewable availability in addition to commodity price volatility

Special Studies

Focused Research on a Single Topic or Trend

- Can be used to give an enhanced view of specific trends around policy, consumer preferences, or the economics of emerging technologies
 - Potential studies for this IRP include:
 - EV transitory charging trends
 - Long-duration energy storage (LDES) technology trends and costs
 - Congestion studies
 - Hydrogen generation market research study
 - Other emerging technology studies

We exist to deliver safe, reliable energy that drives value to our customers

IRP SCENARIOS WILL INCLUDE AN EMERGING LARGE LOAD SENSITIVITY

In addition to the 2,600 MW of new load, emerging large load will be used as a sensitivity factor across the five scenarios.

Scenarios <i>Single, Integrated Set of Assumptions</i>		Sensitivity <i>Large Loads</i>
	Reference Case •The MISO market continues to evolve based on current expectations for load growth, commodity price trajectories, technology development, and policy change (IRA incentives continue, EPA power sector rules advance, and MISO resource adequacy enhancements proceed)	In the portfolio analysis phase, NIPSCO will evaluate each scenario under the sensitivity where significant large loads enter the system in addition to the 2,600 MW of load already added to each scenario: • 2,600 MW of new load by 2028 • 4,500 MW of new load by 2030 • 6,000 MW of new load by 2035
	Slower Transition •IRA incentives are reduced or ended early, and EPA power sector rules are overturned or rescinded; natural gas prices remain low and result in new gas additions remaining competitive versus renewables in the broader region, as coal capacity more gradually fades from the MISO market	
	Domestic Resiliency •Continued geopolitical uncertainty and volatility drive a focus on “domestic energy independence”; electric power demand grows because of onshoring and other industrial growth; gas prices are higher due to strong demand	
	Aggressive Environmental Regulation •Carbon emissions from the power sector are regulated more heavily, including through a CO2 price; restrictions on natural gas production increase gas prices	
	Accelerated Innovation •Federal subsidies continue as a bridge until technology breakthroughs drive broad economy-wide decarbonization (including via electrification); new power sector technologies are commercialized, and DER, EV, microgrid, and EE adoption all increase, transforming wholesale load requirements as “Grid Edge” innovations and enabling policy advance	

We exist to deliver safe, reliable energy that drives value to our customers

NIPSCO IRP LOAD GROWTH* WITH NEW LOAD SENSITIVITY

Given the potential opportunities in the pipeline from NIPSCO's Economic Development team, the IRP analysis will include 2,600 MW of new load in all scenarios and a load sensitivity with an additional 6,000 MW.

	Preliminary & Illustrative		
	2028	2030	2035
IRP Peak Load – Original Reference Case**	2,300 MW	2,300 MW	2,500 MW
+New Load Added to All IRP Scenarios	600 MW	1,600 MW	2,600 MW
IRP Peak Load – New Reference Case	2,900 MW	3,900 MW	5,100 MW
+Emerging Load Sensitivity	2,600 MW	4,500 MW	6,000 MW
Total IRP Peak Load with Emerging Load Sensitivity	5,500 MW	8,400 MW	11,100 MW

- The build-out of new energy and capacity resources to meet this potential new load will be analyzed in the 2024 IRP process.

* NOTE: NIPSCO is not guaranteeing that any amount of new load will enter our service territory, but we are sharing our current expectations with stakeholders to allow time for feedback as we prepare to conduct our IRP analysis with this significant change

** Rounded estimate of Reference Case IRP Peak Load was originally shared with stakeholders at the April 23 IRP Public Advisory meeting

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: EVs



EV FORECASTING OVERVIEW

Penetration Models with Local Datasets

Truck Corridor Charging Tool

Light Duty Vehicle (“LDV”)

<10,000 lbs.

Medium Duty Vehicle (“MDV”)

10,001 – 26,000 lbs.

Heavy Duty Vehicle (“HDV”)

>26,001 lbs.

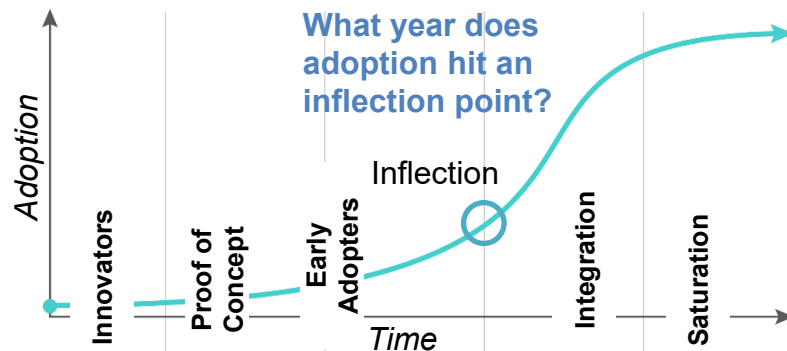
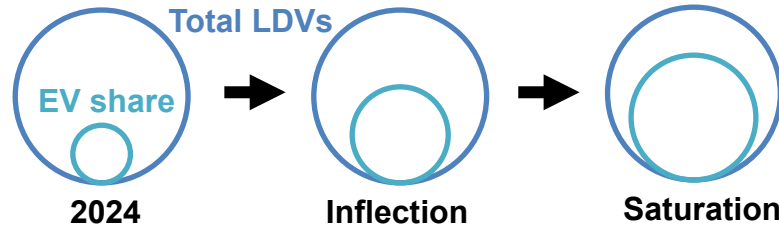
1. Develop growth estimates based on adoption rates applied to S-curve

2. NREL’s EVI-Pro-Lite tool and other sources to develop hourly shapes

Analysis includes data from:

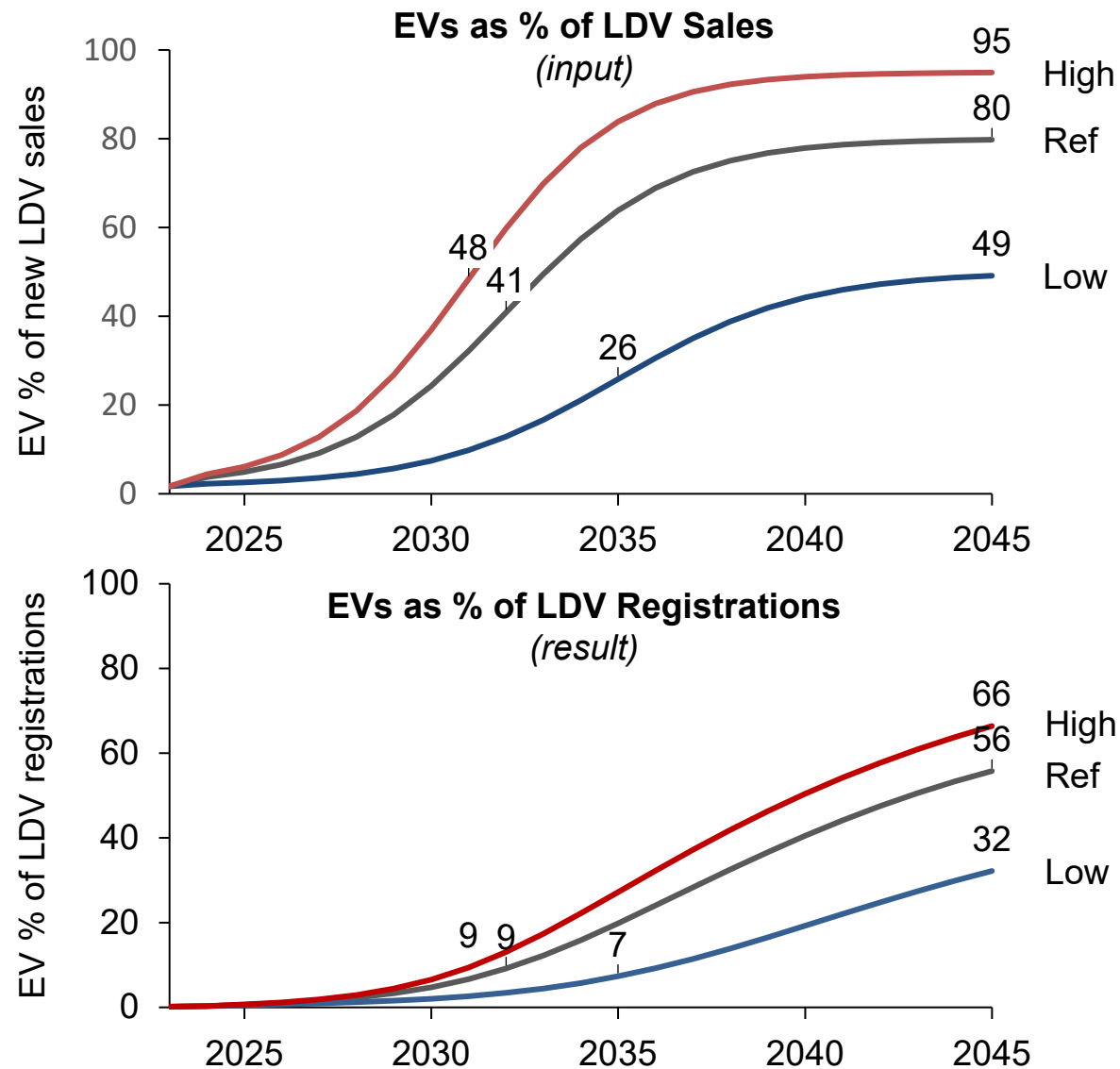
- National Performance Management Research Data Set via U.S. Dept of Transportation
- Highway traffic counts from Indiana Dept of Transportation
- Freight Analysis Framework
- Institute of Transportation Engineers Trip Generation Database

3. Develop final hourly load forecast based on adoption rates, plus temperature, efficiency assumptions, and other variables



We exist to deliver safe, reliable energy that drives value to our customers

LDV EV ADOPTION PROJECTIONS



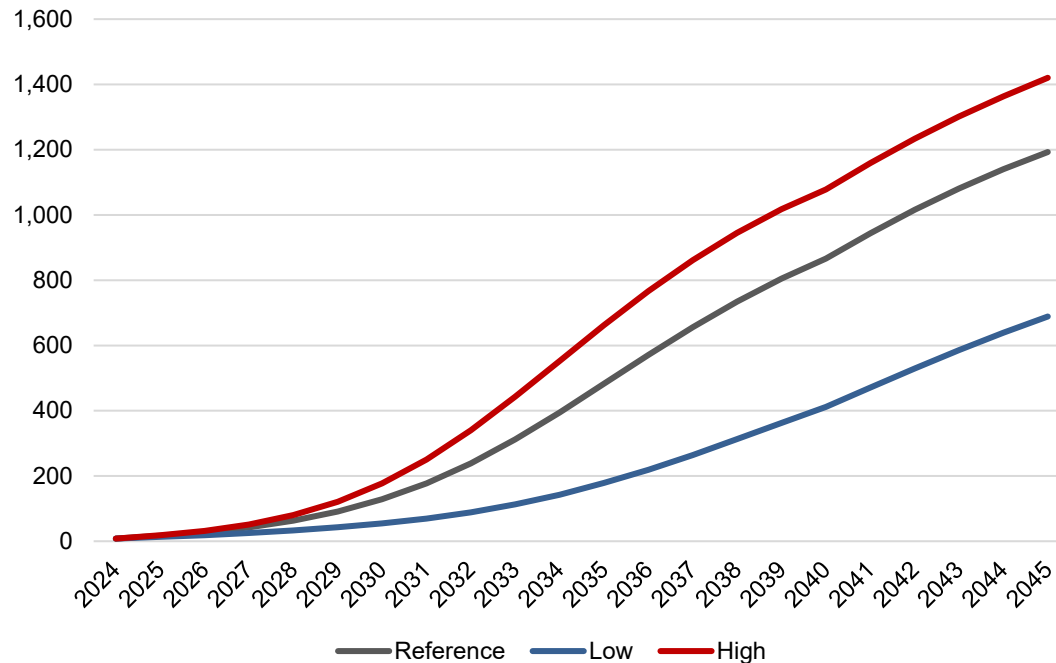
Adoption Overview

- NIPSCO has now developed Reference, High, and Low adoption scenarios over time, leveraging current EV data and third-party projections
- All scenarios begin at an estimated EV sales penetration of ~1.6% (estimate based on analysis of Indiana Fuel Dashboard data from 2018-2023)
- A sigmoid function is used to create intermediate sales values by year, where scenarios each reach a given % of sales target by 2045
 - Low: 50%
 - Ref: 80%
 - High: 95%

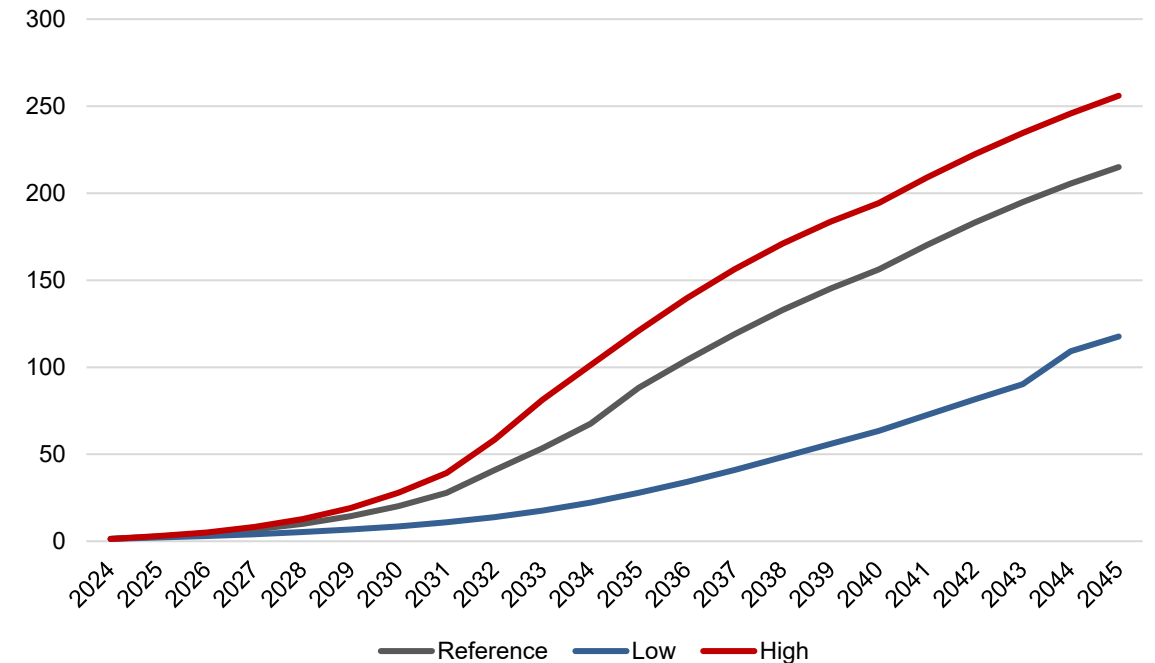
LDV SALES AND COINCIDENT PEAK IMPACT, ASSUMING NO INTERVENTION TO ENCOURAGE MANAGED CHARGING

- Relatively modest peak load impacts will be seen across all three scenarios (<50 MW) until 2030, when an inflection in EV sales heightens overall impact of LDV segment
- Steady growth expected to raise peak contributions to more than 150 MW in the Reference Case and closer to 200 MW in the High case by 2040
- Energy sales roughly mirror peaks, with similar dampening of per vehicle kWh contribution driven by higher vehicle efficiencies

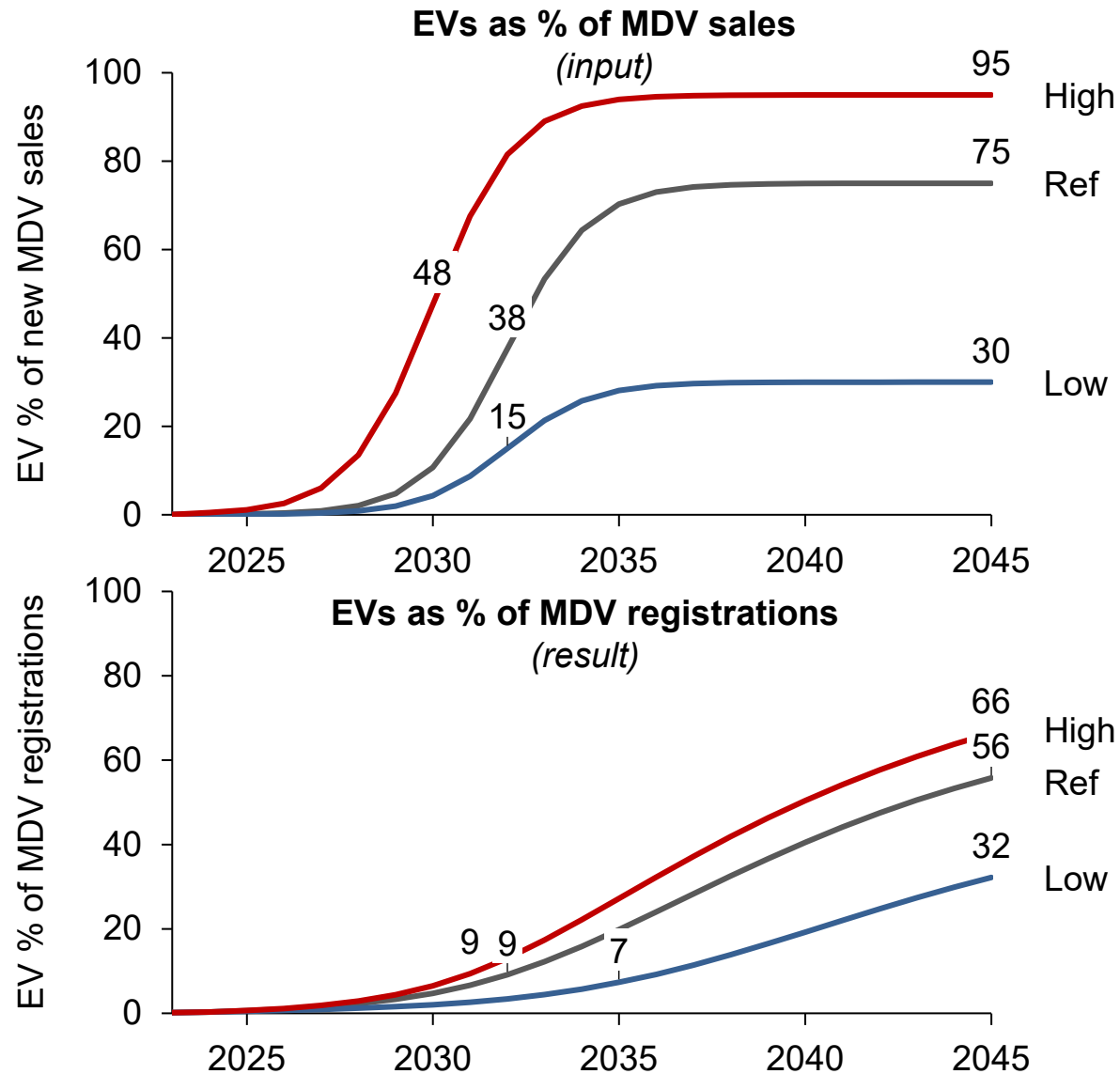
LDV Total Energy Sales (GWh)



LDV Coincident Peak Impact (MW)



MDV EV ADOPTION PROJECTIONS



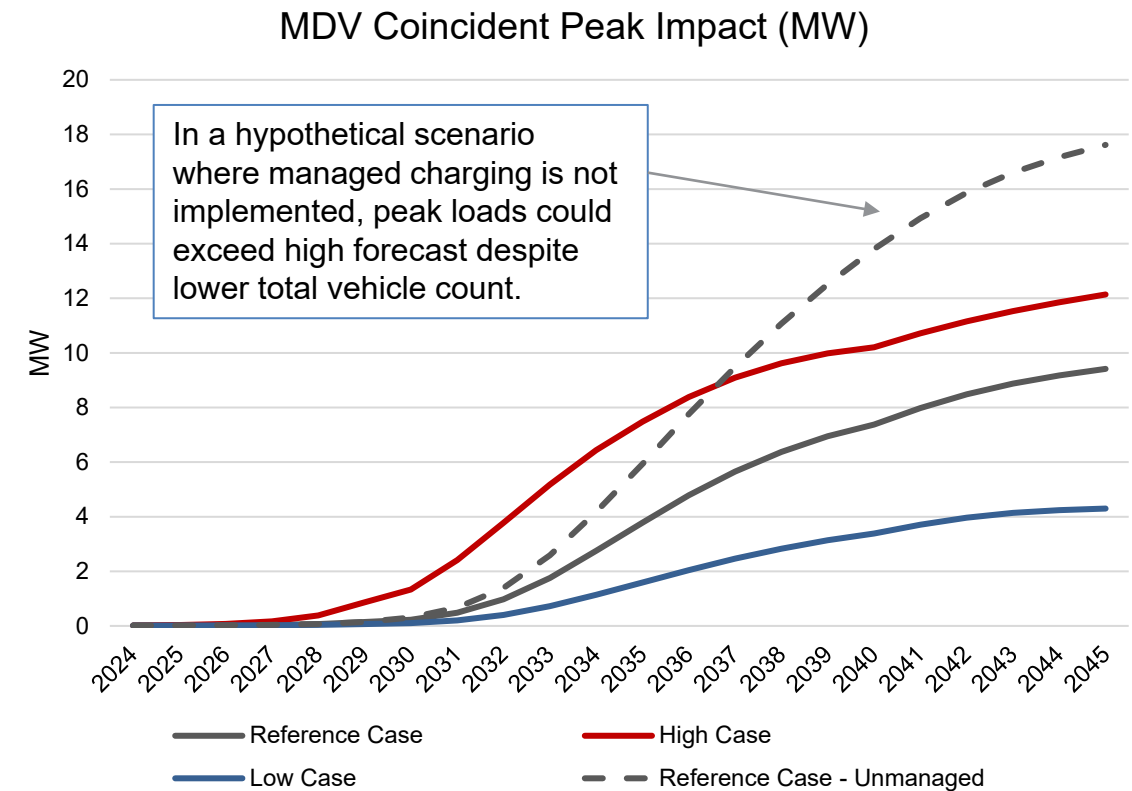
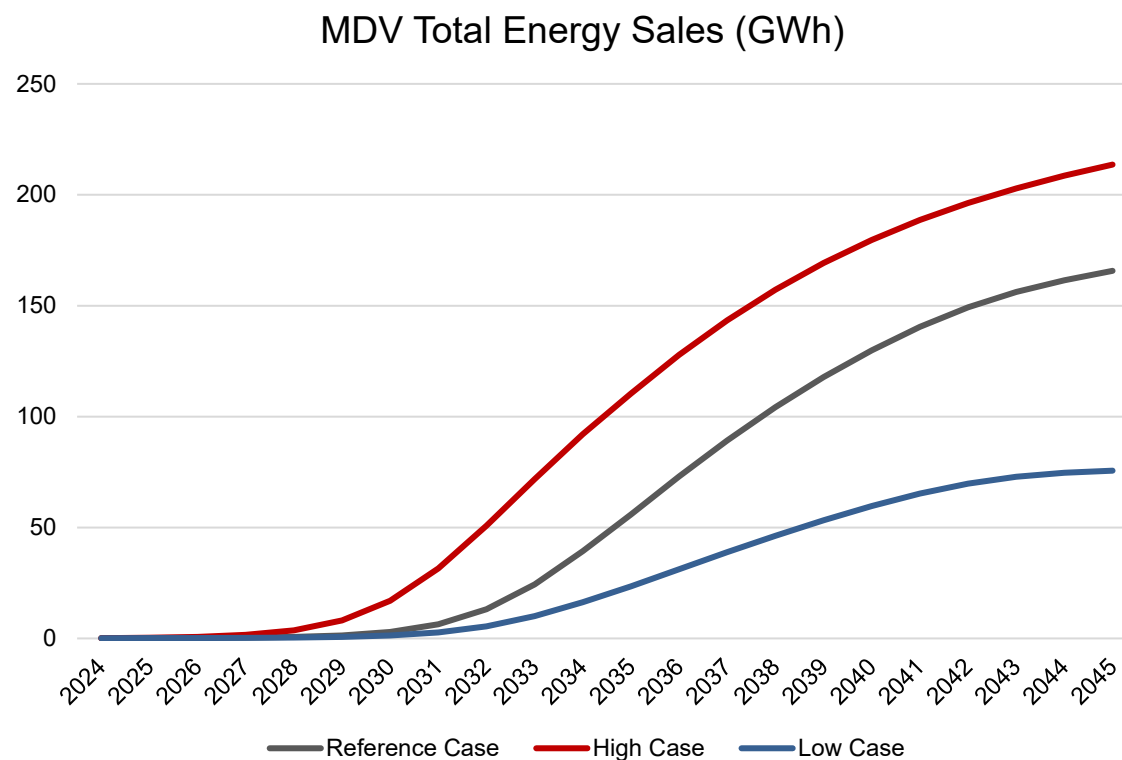
Adoption Overview

- NIPSCO has utilized Indiana Fuel Dashboard traditional vehicle and EV registration data to develop an estimate of the existing EV penetration and traditional vehicle fleets and has now taken a view on how adoption may unfold over time for three scenarios, leveraging third-party studies
- Current fleet electrification is very small, based on analysis of Indiana Fuel Dashboard data from 2018-2023
- A sigmoid function is used to create intermediate sales values by year, where scenarios each reach a given % of sales target by 2045
 - Low: 30%
 - Ref: 75%
 - High: 95%

We exist to deliver safe, reliable energy that drives value to our customers

MDV FORECAST: SALES AND COINCIDENT PEAK GROWTH

- MDVs are expected to have modest energy sales and load impacts, with roughly 10% of the demand seen in the LDV segment
- Energy sales roughly mirror peaks, with similar dampening of per vehicle kWh contribution driven by higher vehicle efficiencies

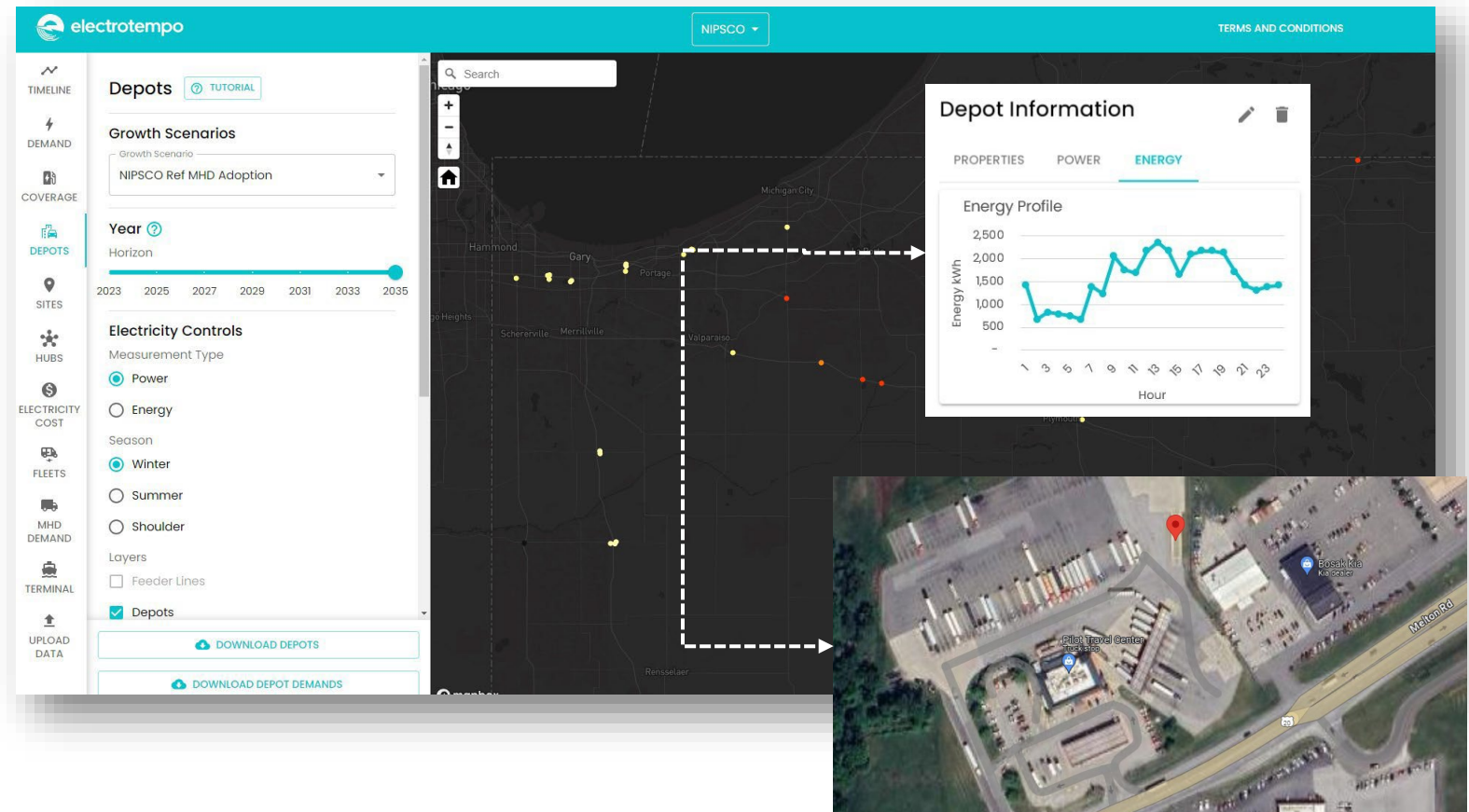


EV HIGHWAY CORRIDOR CHARGING DEMAND

- ElectroTempo prepared a highway corridor EV charging demand forecast:
 - Identification of potential truck charging locations
 - Average daily 24-hour demand profile for each location
 - Three electrification scenarios
- 2035 EV saturation by class:

Scenario	MDV	HDV
Low	5%	0%
Ref	14%	2%
High	27%	10%

ElectroTempo Corridor Charging Data



Example Truck stop location along I-94

HIGHWAY CORRIDOR CHARGING METHODOLOGY

1. Identify current truck refueling locations (43)
2. Calculate average annual daily traffic*
3. Apply EV adoption scenario to calculate total EVs^
4. Apply site-specific capture rate and arrival patterns**
5. Calculate energy requirement per arrival
 - State of Charge (SOC) category based on route origin-destination pairs*** - See table to the right
 - Battery capacity by vehicle category (300 kWh for MDV and 600 kWh for HDV)
6. Calculate power based on charger rating assignments
 - MDV: 150 kW
 - HDV: 450 kW

Distribution of SOC Types for Example Site Along I-94

SOC Cat.	Route Type	Perc. Of Routes	Charging EVs
1	Chi ↔ Det	23%	7
2	Chi/Det to Other	6%	2
3	Other to Chi/Det	11%	3
4	Other to Other	60%	18

ElectroTempo breaks down overall travel data into key routes originating from outside NIPSCO territory. This is translated to charging demand based on EV adoption scenarios and distance traveled per route

* Highway Performance Monitoring System, U.S. DOT Federal Highway Administration

^ MDV scenarios provided by CRA. HDV Ref based on business as usual adoption, High based on EPA Phase 3

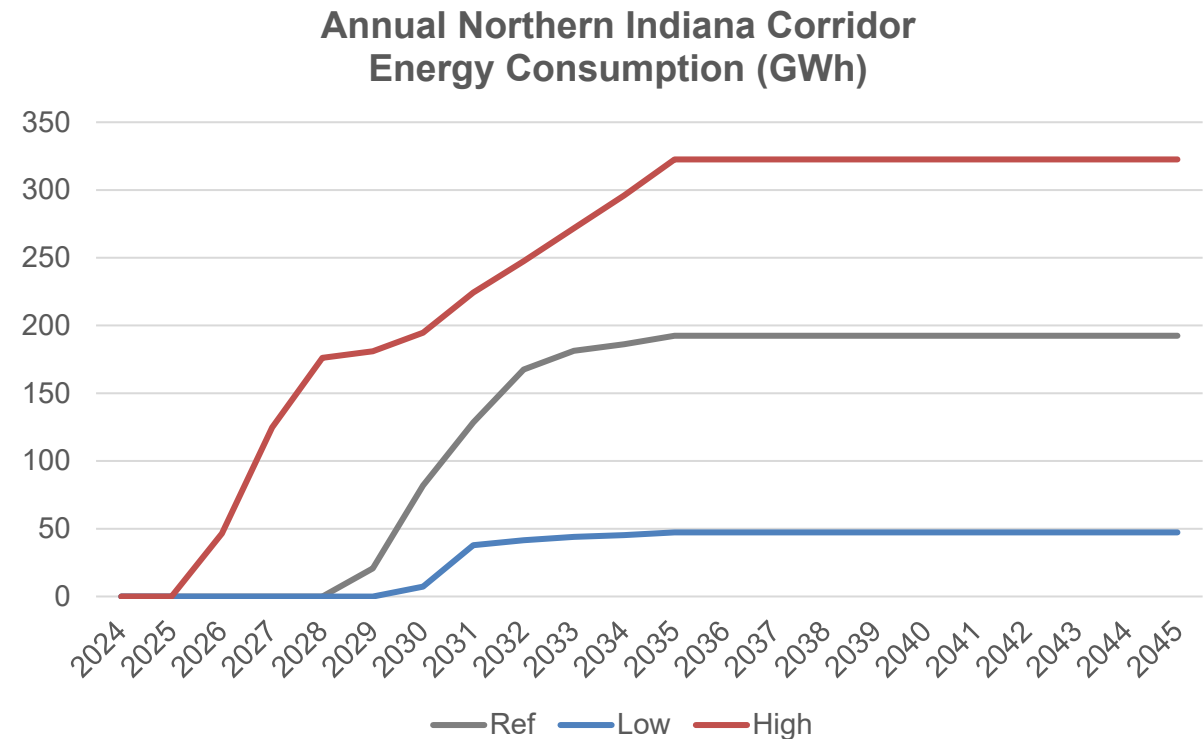
** Institute of Transportation Engineers: Trip Generation Manual, 11th Edition

*** Freight Analysis Framework Version 5 Data Tabulation Tool." Oak Ridge National Laboratory

**** Reference electric vehicles: Volvo VNR Electric Straight Truck/Tractor, Peterbilt Model 220ev, Tesla Semi

HIGHWAY CORRIDOR CHARGING SUMMARY AND KEY TAKEAWAYS

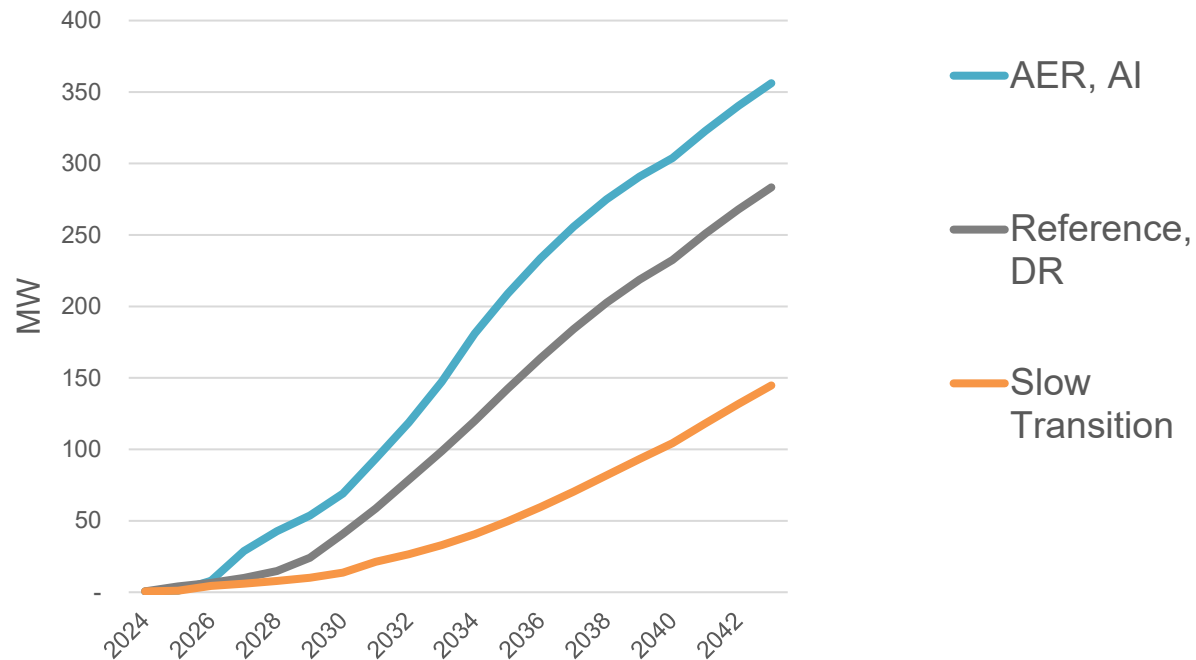
- Potential electrification of the HDV fleet could be a significant driver for overall EV demand.
- Highway corridor EV charging could add close to 200 GWh per year by 2035 in the Reference scenario and as high as 300 GWh in the High scenario.
- I-94 and I-69 are the primary corridors, accounting for a combined 60% of corridor demand.



SUMMARY EV FORECAST BY SCENARIO

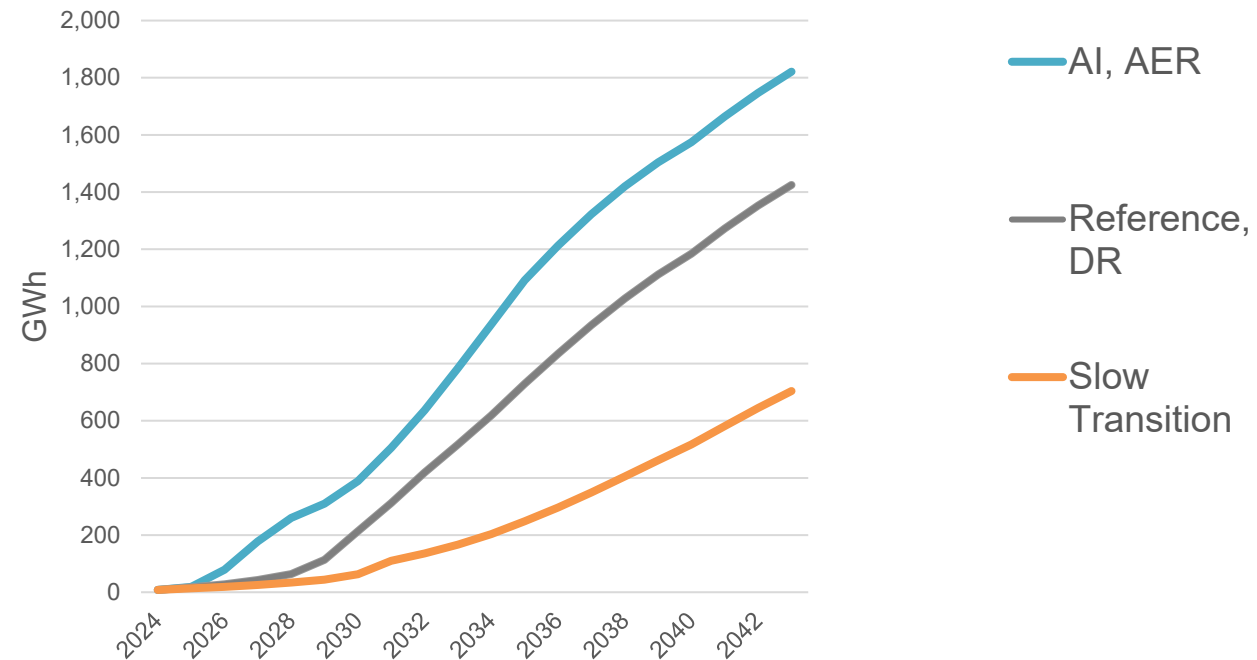
- All five scenarios were mapped to a high, medium, and low EV penetration trajectory

EV Summer Peak Impacts (MW)



Note: AER and AI summer peak demand trajectories diverge in select years due to differences in distributed solar assumptions impacting hours of net peak

Total Annual EV Energy Usage (GWh)



We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

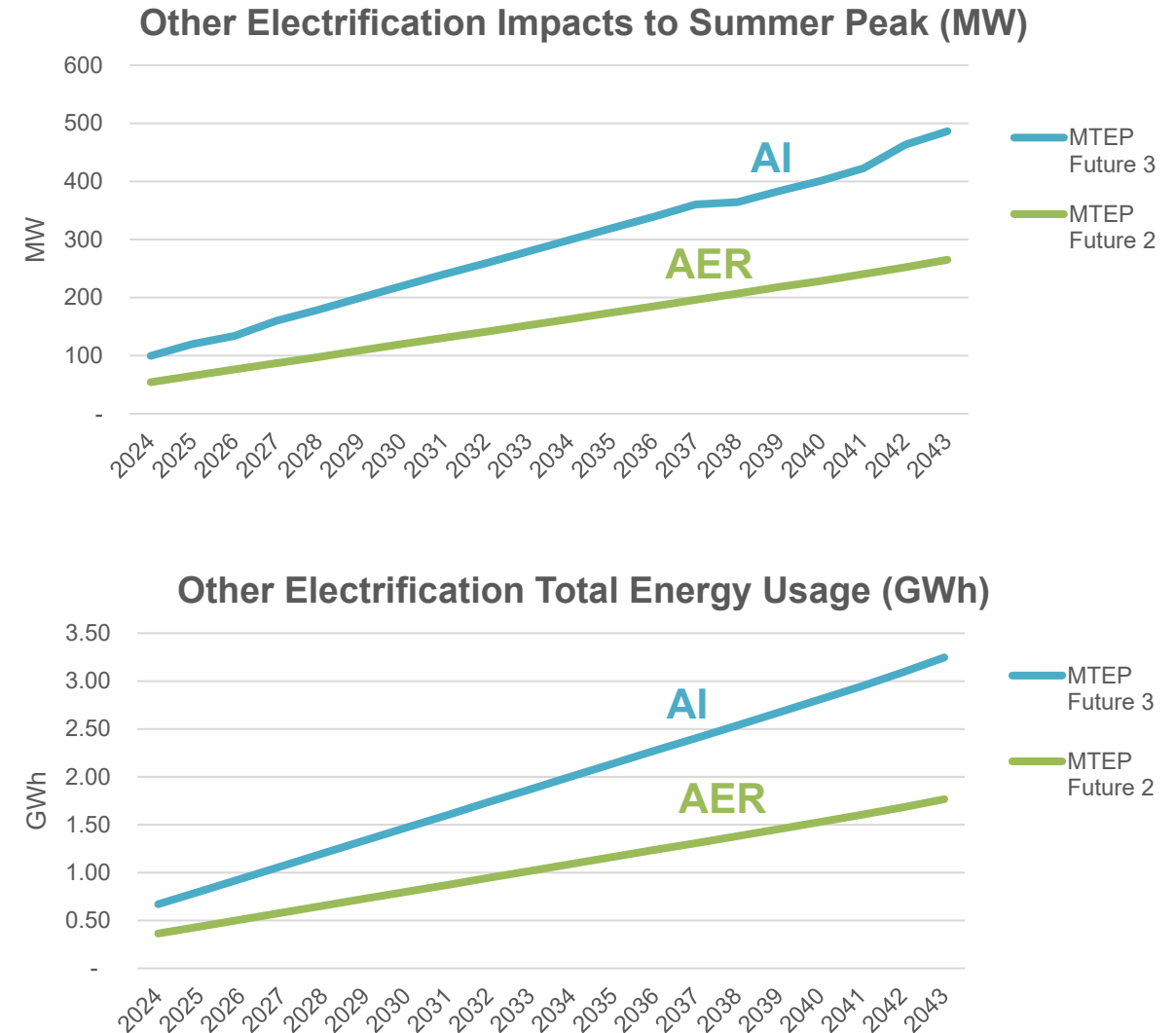
SCENARIO ANALYSIS: ELECTRIFICATION



OTHER ELECTRIFICATION

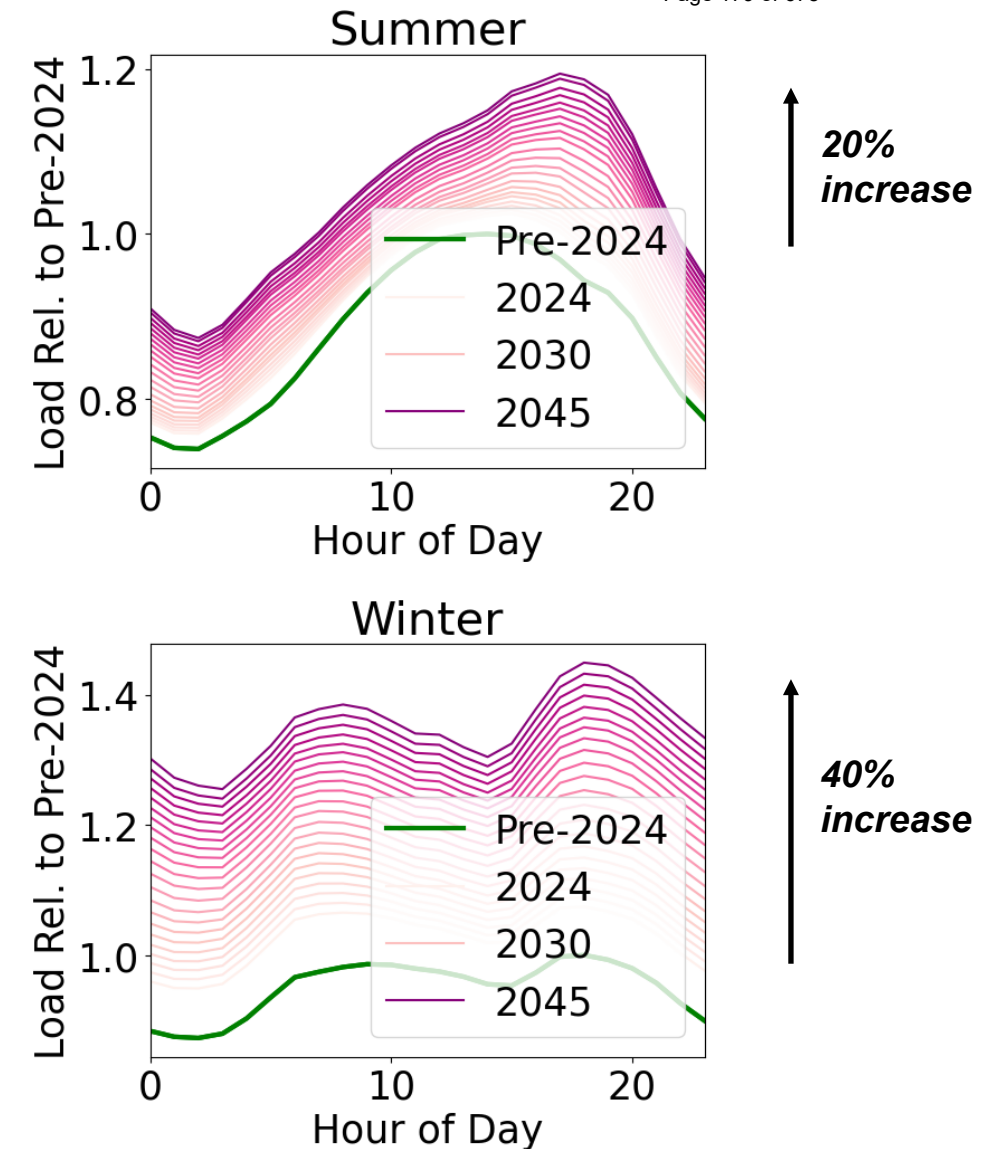
- Aside from electric vehicles, the AER and AI scenarios incorporate long-term impacts associated with electrification of other energy end uses
- NIPSCO drew from MISO Futures Report and Transmission Expansion Plan (MTEP) to develop estimates for growth in energy and peak load needs associated with:
 - Residential HVAC
 - Commercial and Industrial (“C&I”) HVAC
 - Residential appliances
 - Residential water heating
 - C&I water heating
 - C&I processes

Source: [2021 MISO Futures Report](#)



OTHER ELECTRIFICATION: PEAK HOUR IMPACTS

- New sources of electrification are expected to increase winter demand more than summer demand
- In high electrification futures (AI), **electrified heating could push annual peak to winter months**
- All peaks have the potential to be pushed to later in the evenings across all electrification futures





We exist to deliver safe, reliable energy that drives value to our customers

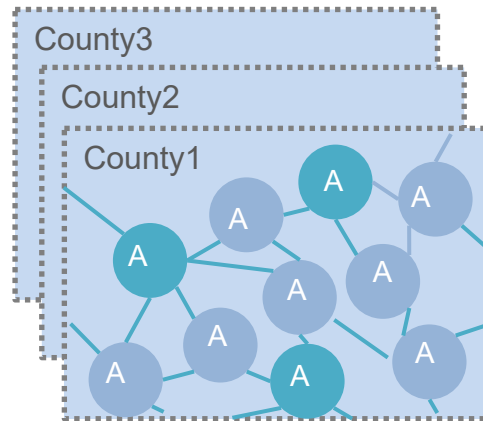
SCENARIO ANALYSIS: DERs



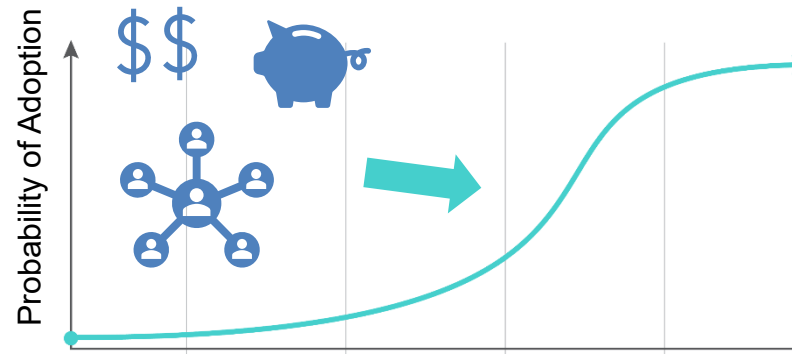
DER MODELING OVERVIEW: DER PENETRATION (PenDER) MODEL

PenDER is an agent-based model (“ABM”) that considers NIPSCO customer (“agents”) characteristics, economic decision-making, and social interactions to drive projections of the adoption of DER systems by county.

Agent and Network Representation



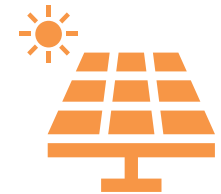
Adoption Decision



Probability of adoption threshold is met based on:

- Payback period
- Customer budget
- Social network adoption rate

Cumulative DER Adoption



Individual adoption decisions aggregated to NIPSCO service territory by customer class

Agents defined by:

Customer Level Data

Individual customer information about DER adoption, location, and customer class (residential, commercial, industrial)

Socio-Economic Data

Individual customer information on socio-economic status, business type, energy usage

We exist to deliver safe, reliable energy that drives value to our customers

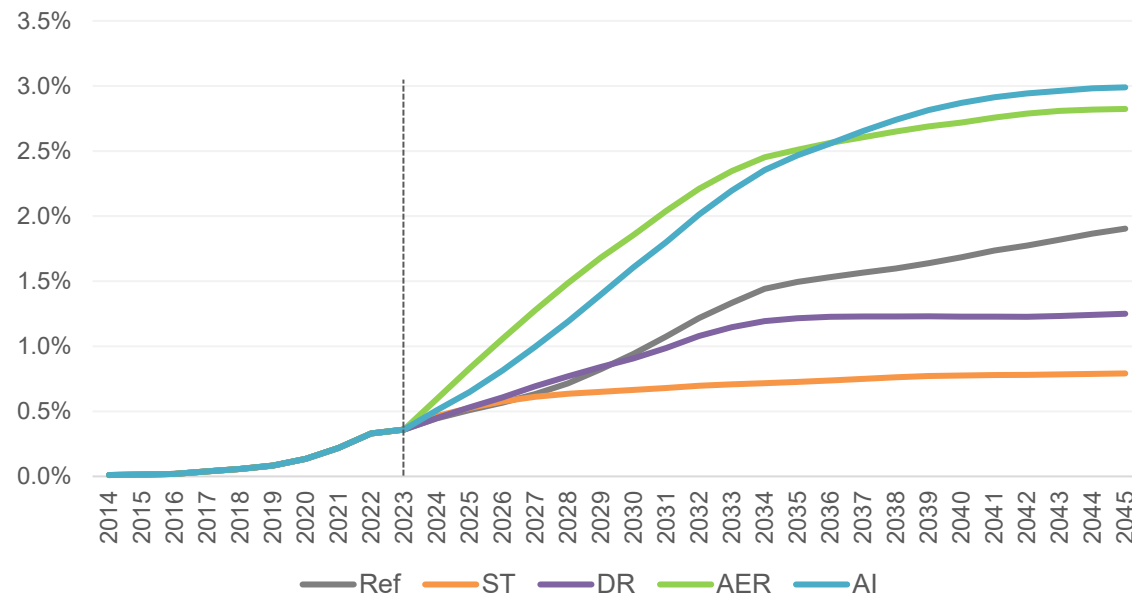
DER SCENARIO CONSIDERATIONS

Scenario Name	Description	Capital Cost for Solar	ITC Incentives	Wholesale Rate Growth	Incentive Structure	DER Installation Size
 Reference Case	Reference point	Base NREL Reference	Base IRA through 2035	Base	EDG Program Program continues unchanged through the planning horizon	Base Historic socioeconomic trends continue
 Slower Transition	Environmental policy incentives reduce; economic slowdown in region	High NREL Conservative ↑	Low IRA phase-out ↓	Low Lower commodity prices ↓	EDG Program Program continues unchanged through the planning horizon	Base Historic socioeconomic trends continue
 Domestic Resiliency	Influx of new economic development load (data center focus)	High NREL Conservative ↑	Base IRA through 2035	High Higher commodity prices. ↑	EDG Program Program continues unchanged through the planning horizon	High Increasing underlying load growth ↑
 Aggressive Environmental Regulation	Aggressive decarbonization policy, moderate electrification	Base NREL Reference	Base IRA through 2035	Highest Highest gas prices; environmental regulation (high CO ₂ price) ↑	EDG → Net Metering DER adoption encouraged through net metering, or another innovative design ↑	Base Historic socioeconomic trends continue
 Accelerated Innovation	Faster energy transition, high electrification with additional econ. dev. (data center) load	Low NREL Low ↓	Base IRA through 2035	Base Close to base, but model logic transitions to Net Metering	EDG Program Program continues unchanged through the planning horizon	Highest Economy-wide electrification driving larger customer UPC ↑

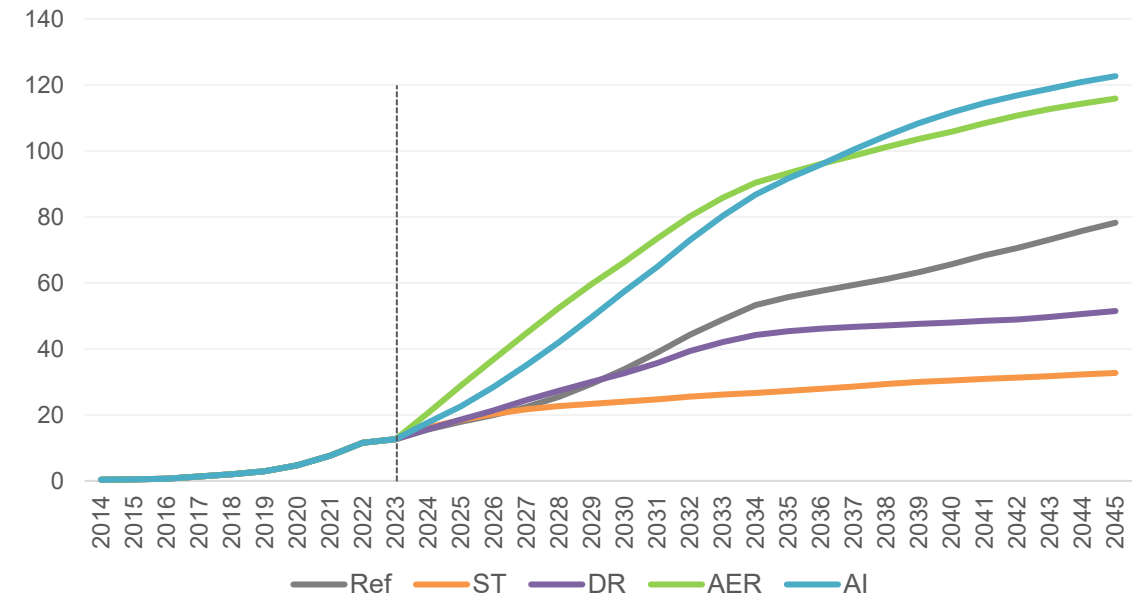
RESIDENTIAL FORECAST – DER PENETRATION BY SCENARIO

- Across scenarios, penetration is estimated to range from 0.8 – 3.0% of customers and 33 to 123 MW of residential customer-owned solar capacity by 2045

% Residential Customers with DER



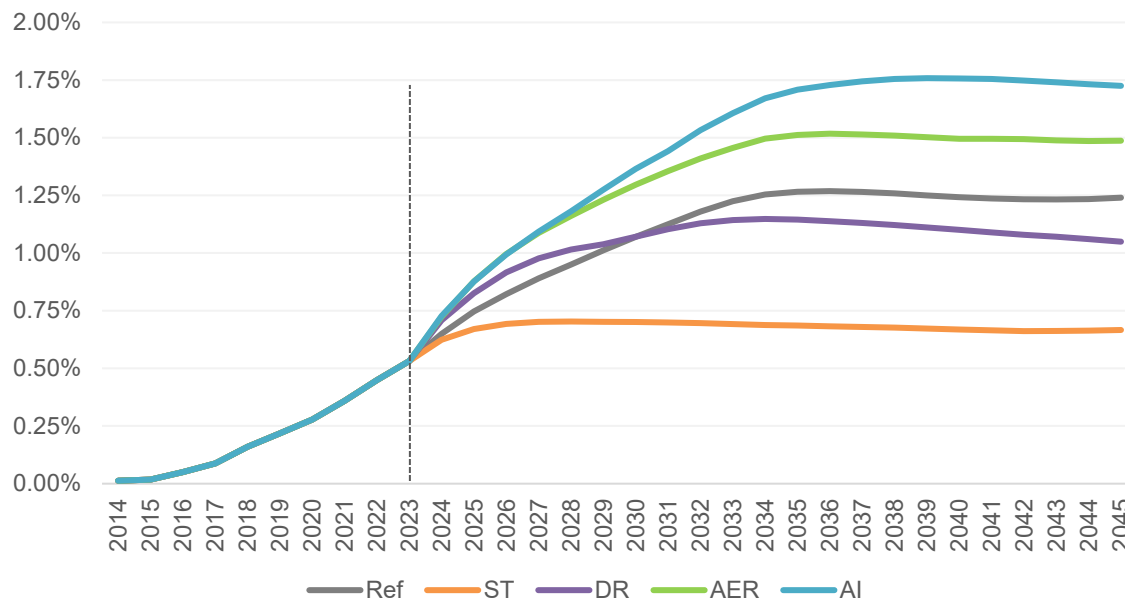
Residential DER Total Capacity (MW)



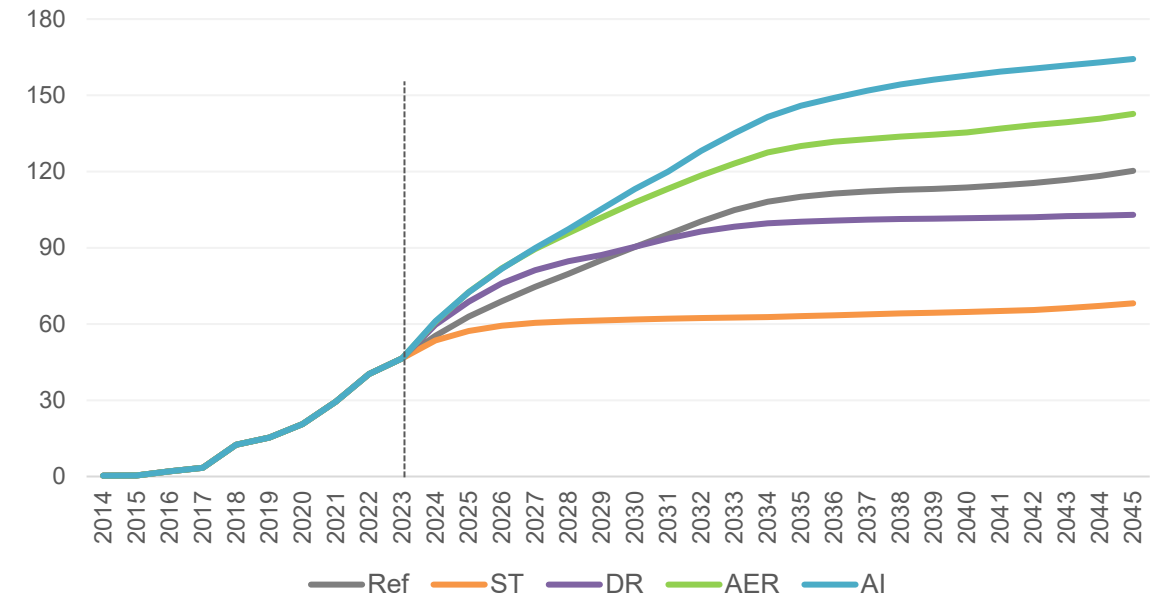
COMMERCIAL FORECAST – DER PENETRATION BY SCENARIO

- Across scenarios, penetration is estimated to range from 0.7 – 1.7% of customers and 68 to 164 MW of residential customer-owned solar capacity by 2045
- Despite lower overall percentage of customers adopting solar, commercial DERs have far larger system sizes, pushing total installed capacity approximately 50% higher than residential values

% Commercial Customers with DER



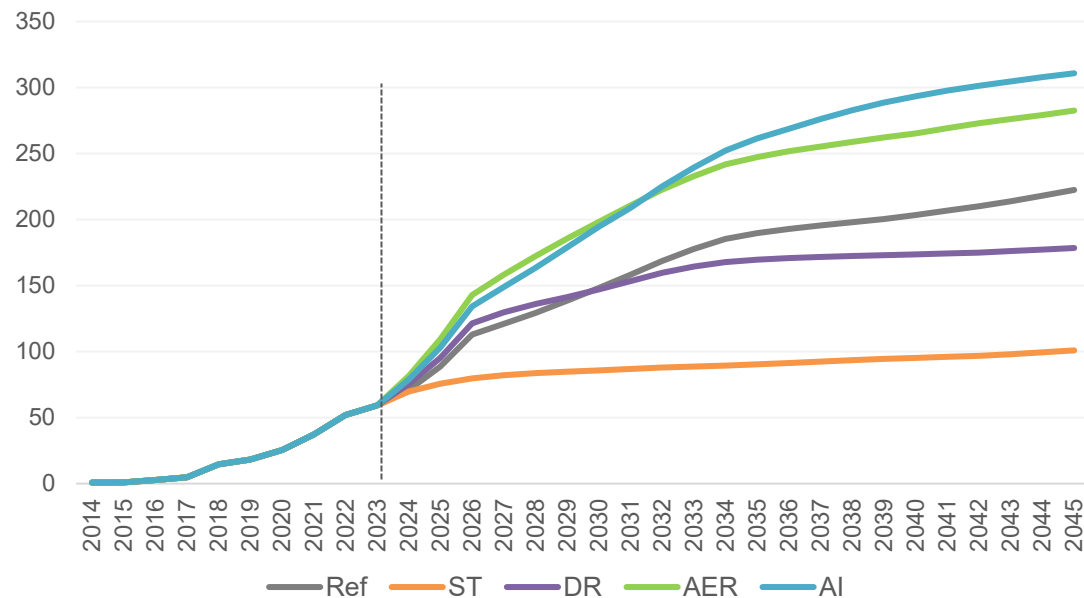
Commercial DER Total Capacity (MW)



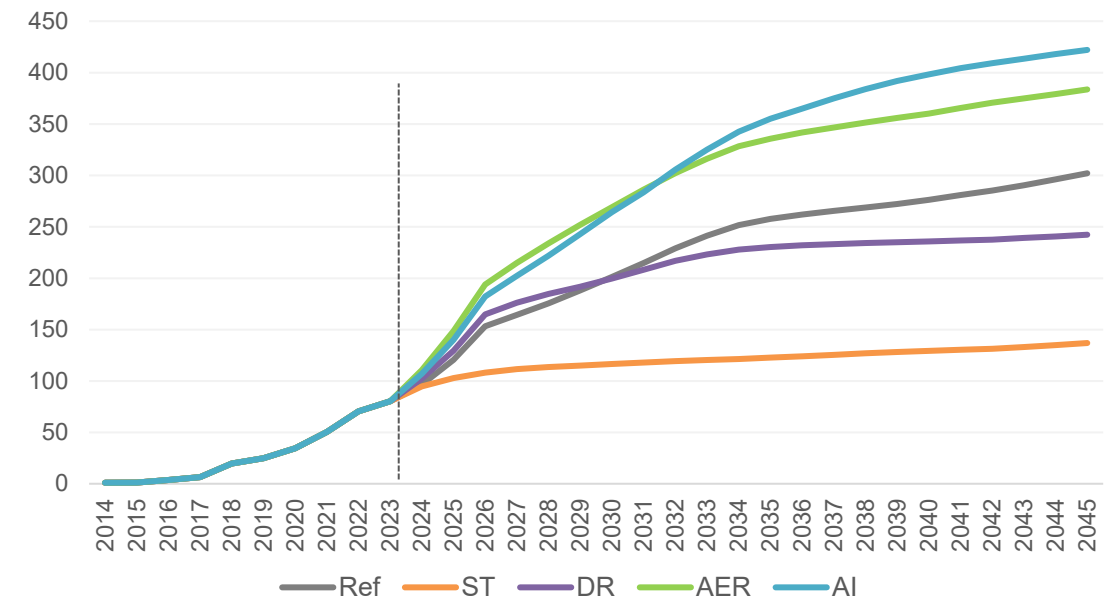
TOTAL DER FORECAST

- Total customer-owned solar DER installations across the scenarios range from 100 MW to over 300 MW by 2045, totaling between 140 GWh and 420 GWh.

Total DER Cumulative Capacity (MW)



Total DER Cumulative Energy (GWh)





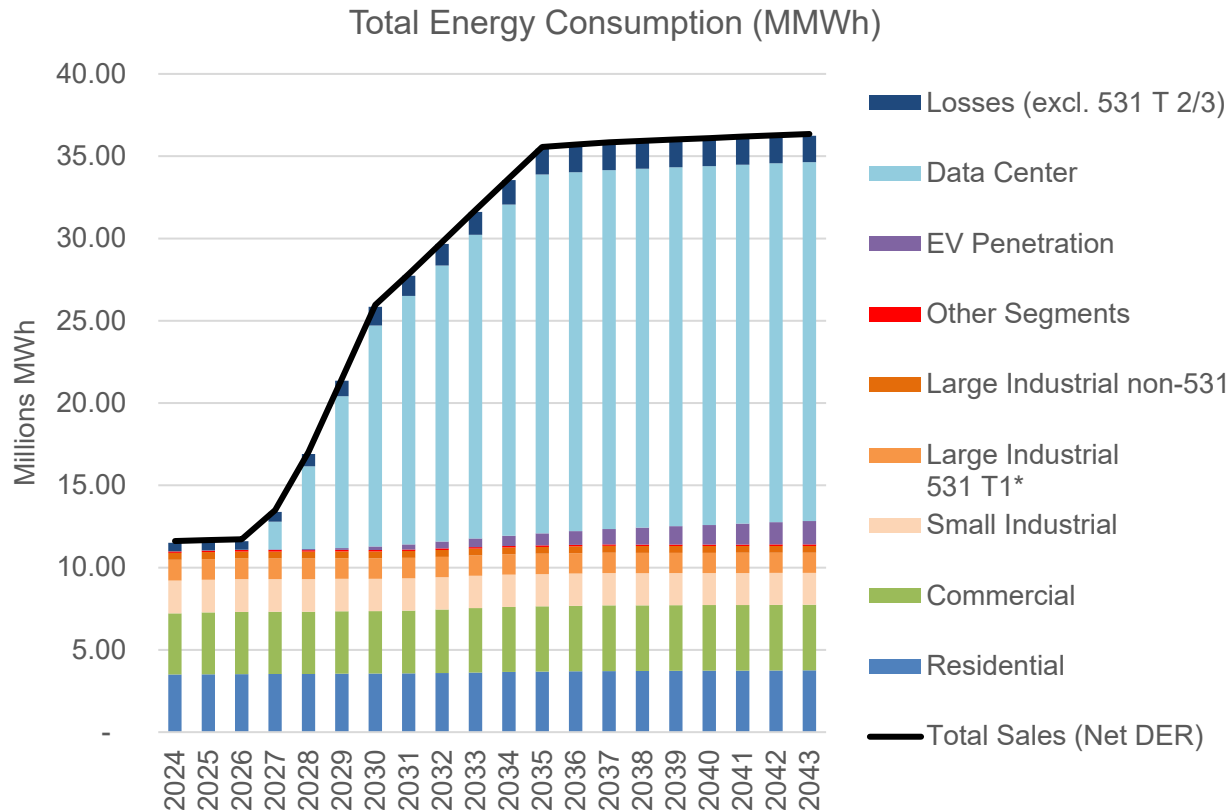
We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: ALL-IN RANGE

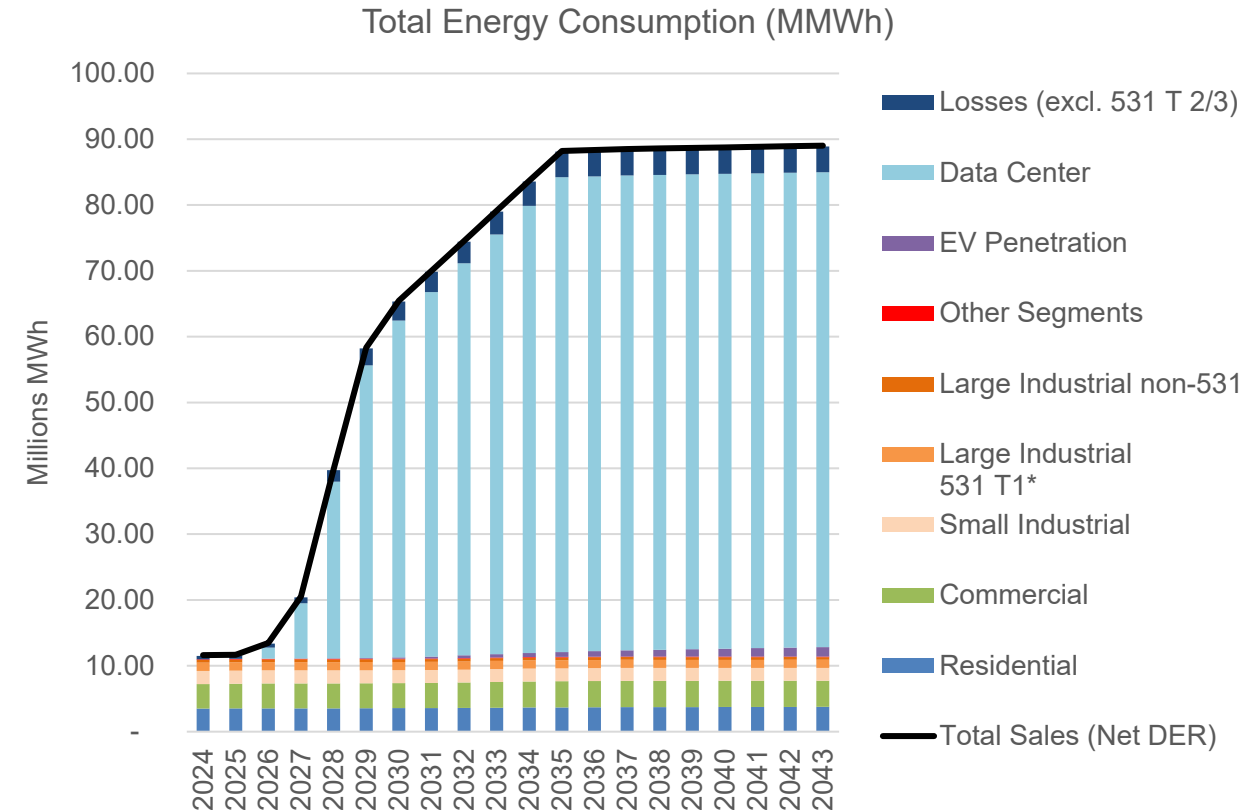


TOTAL ENERGY SALES BY CUSTOMER SEGMENT – REFERENCE CASE

Base

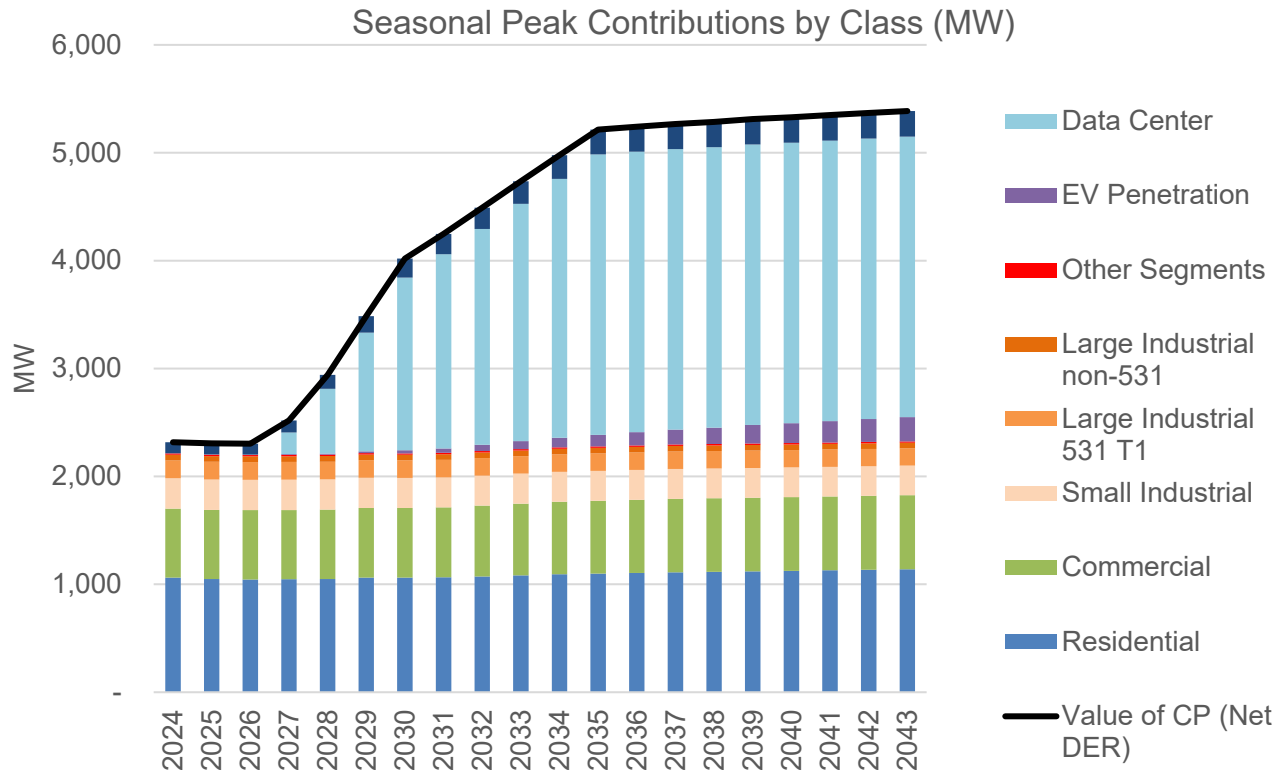


High Large Load Sensitivity

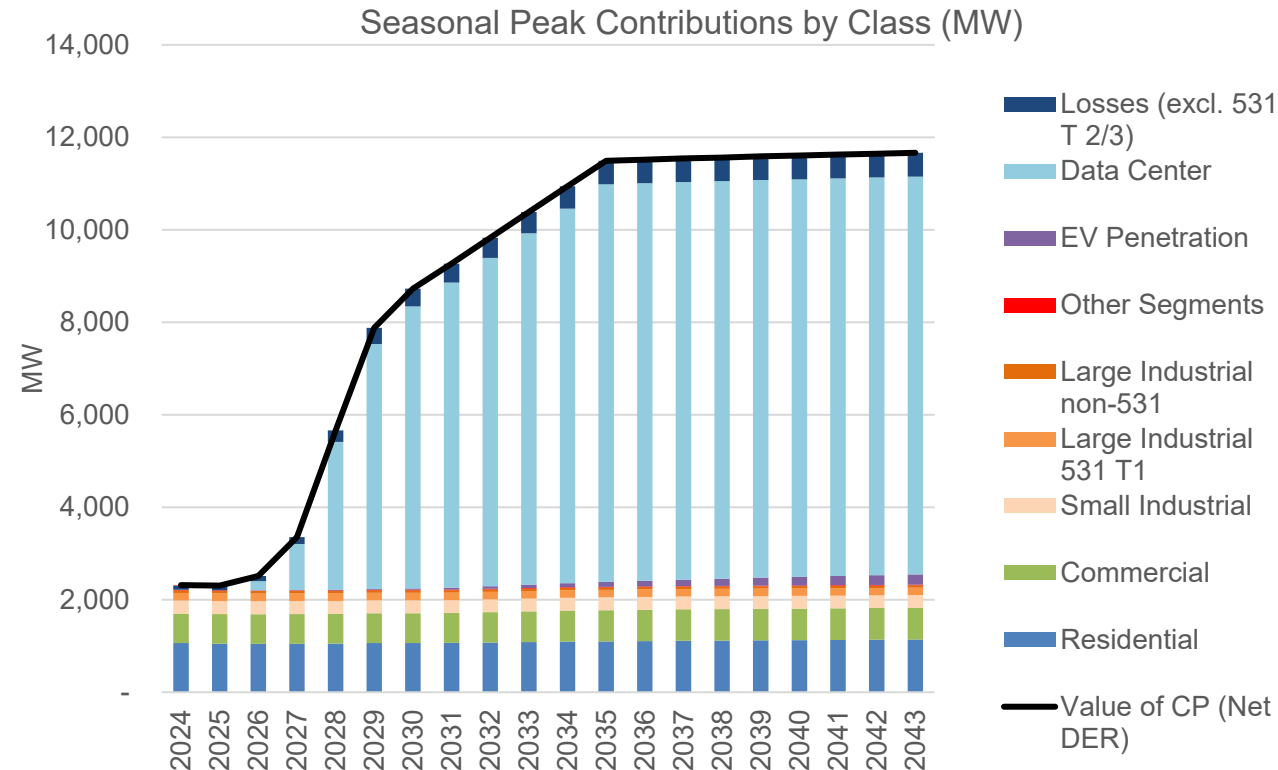


SUMMER PEAK LOAD BY CUSTOMER SEGMENT – REFERENCE CASE

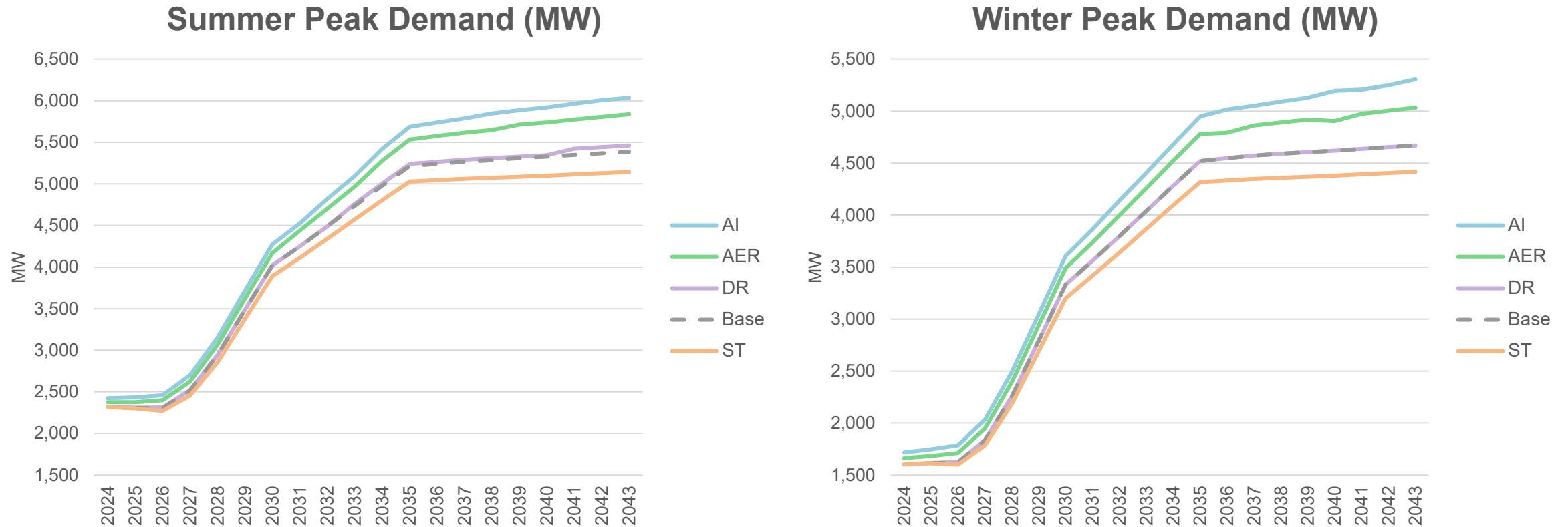
Base



High Large Load Sensitivity



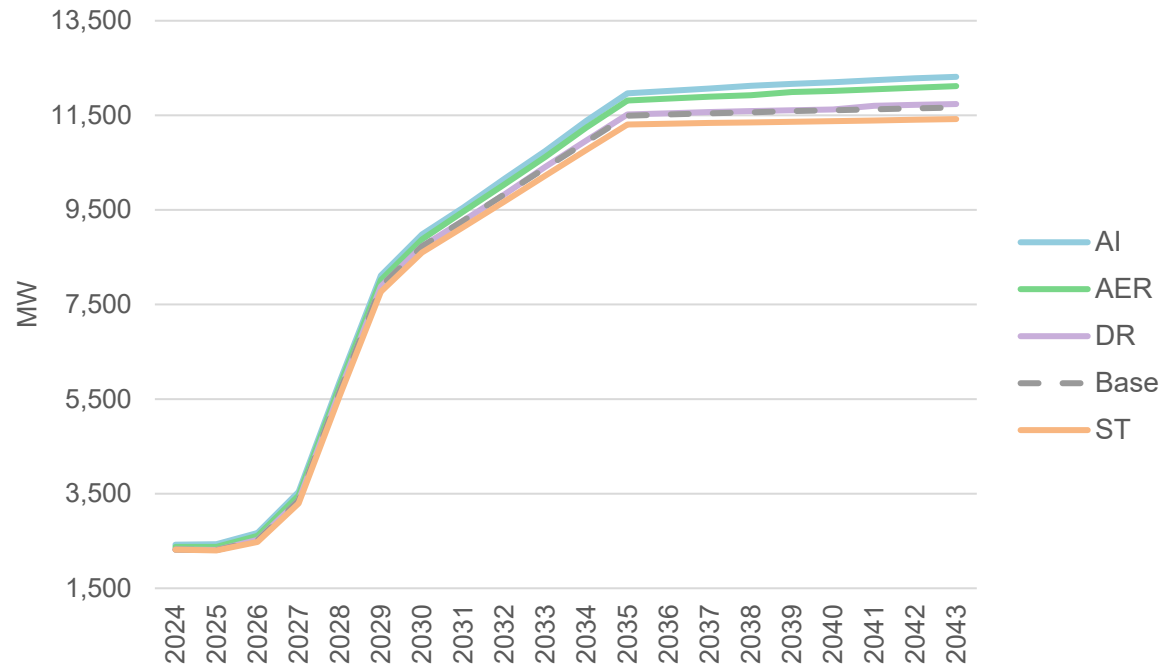
ALL-IN SUMMER AND WINTER PEAK LOAD RANGE – BASE



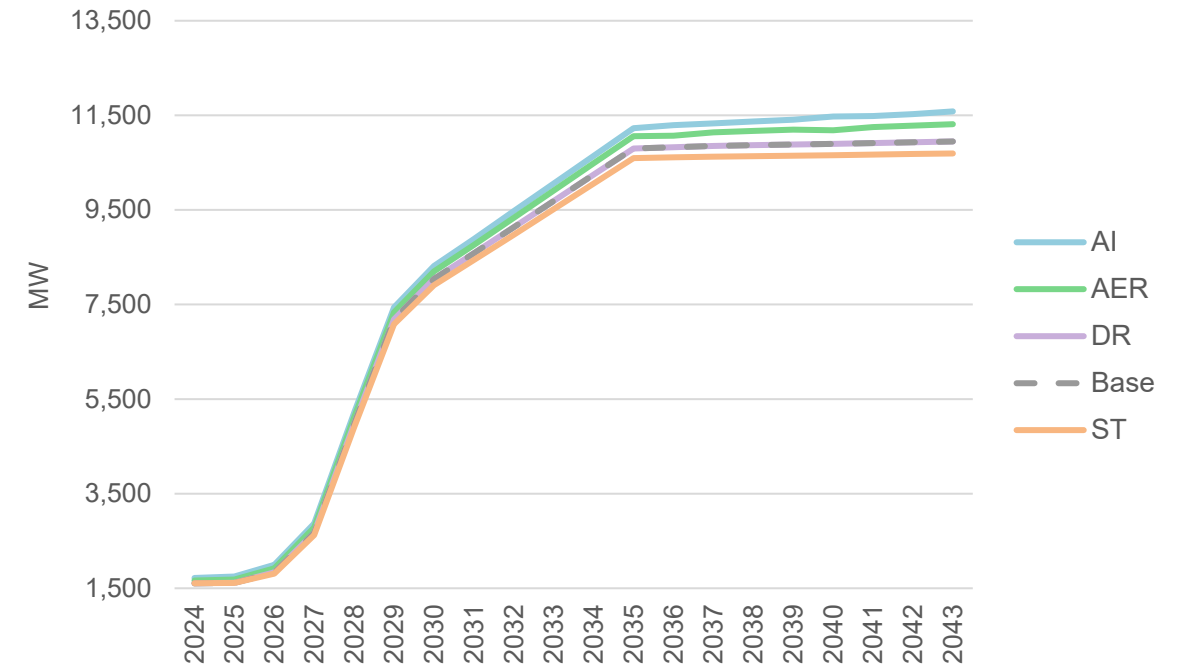
We exist to deliver safe, reliable energy that drives value to our customers

ALL-IN SUMMER AND WINTER PEAK LOAD RANGE – HIGH LARGE LOAD SENSITIVITY

Summer Peak Demand – High Large Load Sensitivity (MW)

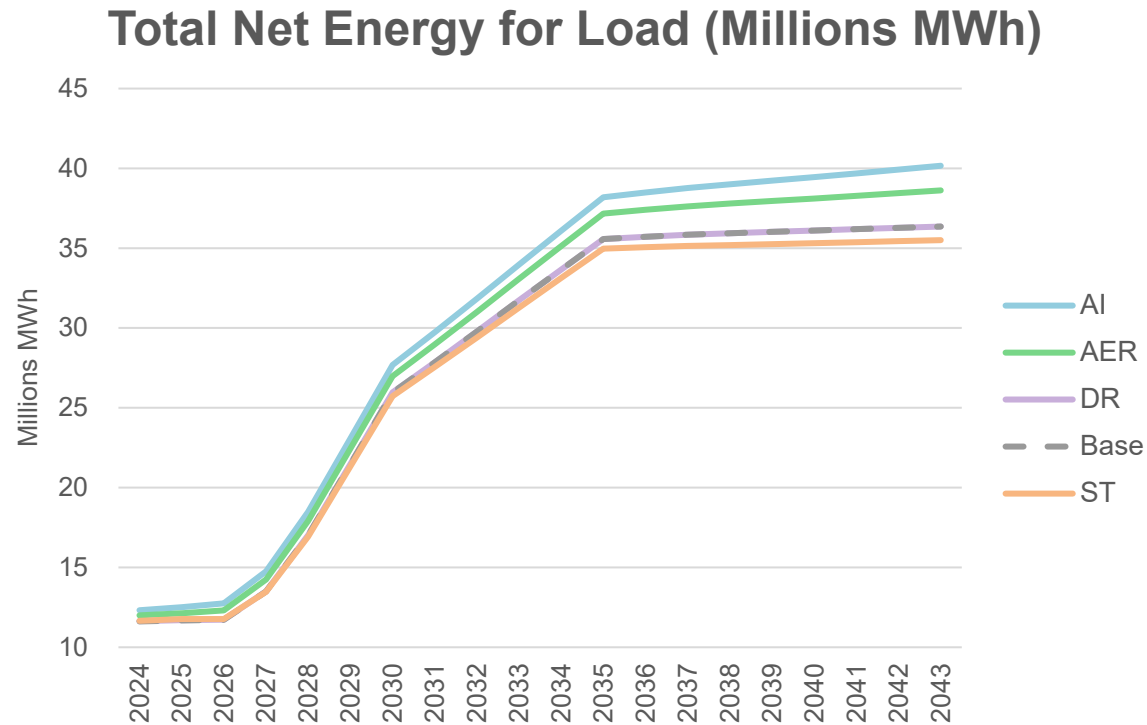


Winter Peak Demand – High Large Load Sensitivity (MW)

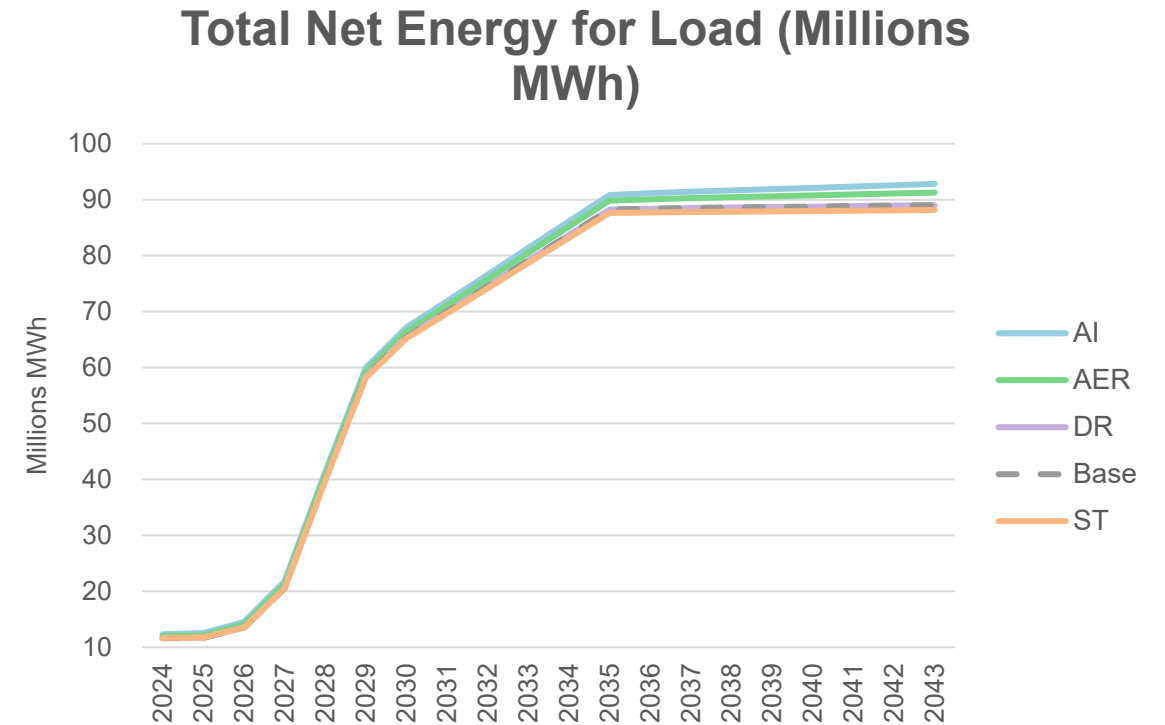


TOTAL ENERGY SALES ACROSS SCENARIOS AND SENSITIVITIES

Base



High Large Load Sensitivity





We exist to deliver safe, reliable energy that drives value to our customers

BREAK





We exist to deliver safe, reliable energy that drives value to our customers

NIPSCO's SUPPLY-DEMAND POSITION: MISO RESOURCE ACCREDITATION AND LOAD OBLIGATION UNCERTAINTIES

Pat Augustine, Vice President, CRA



RECAP: MISO'S DIRECT LOSS OF LOAD ("D-LOL") FILING

NIPSCO's 2024 IRP will evaluate the potential impacts associated with D-LOL implementation



MISO made its filing on March 28, 2024

FERC approval is still required,
and stakeholders have raised
several questions and concerns



Performance during tight hours will matter more

Strong incentive to perform
during hours when net load
and outages are high



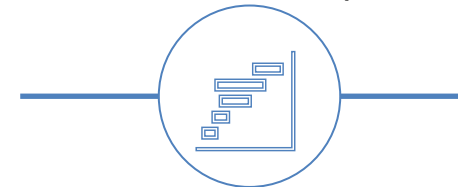
Highly dependent on LOLE assumptions

Based on historical
weather data and may not
capture all future trends



Accreditations will likely change

MISO has signaled significant
drops for certain technology
types, but future market
conditions will matter



NIPSCO obligation likely to decline

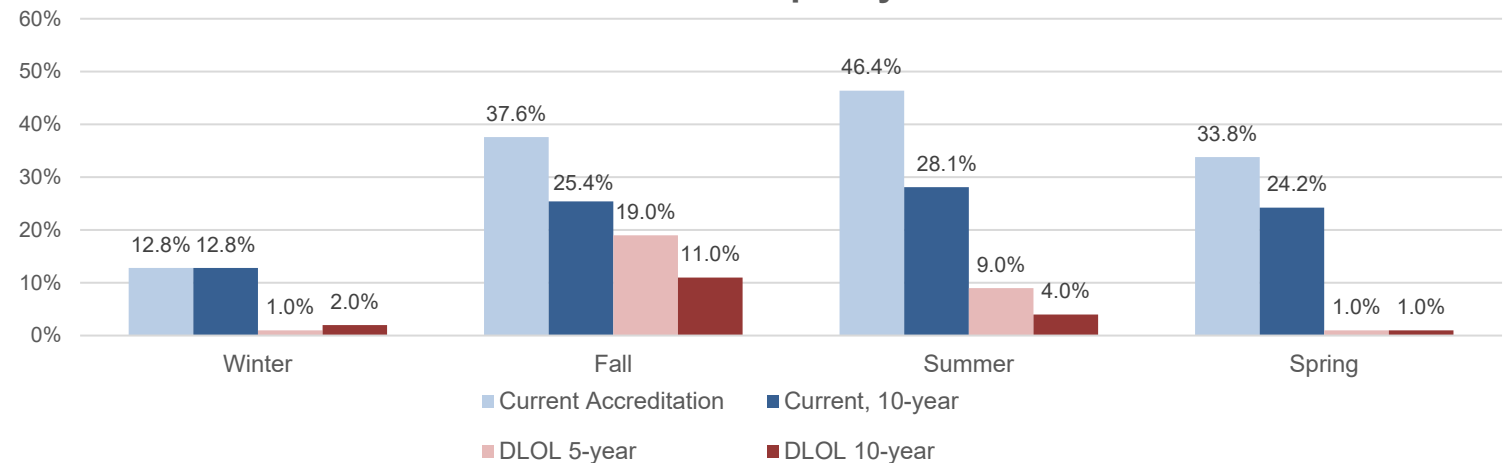
Shift in timing of tight hours
likely to lead to obligation
declines, but magnitude is
uncertain

We exist to deliver safe, reliable energy that drives value to our customers

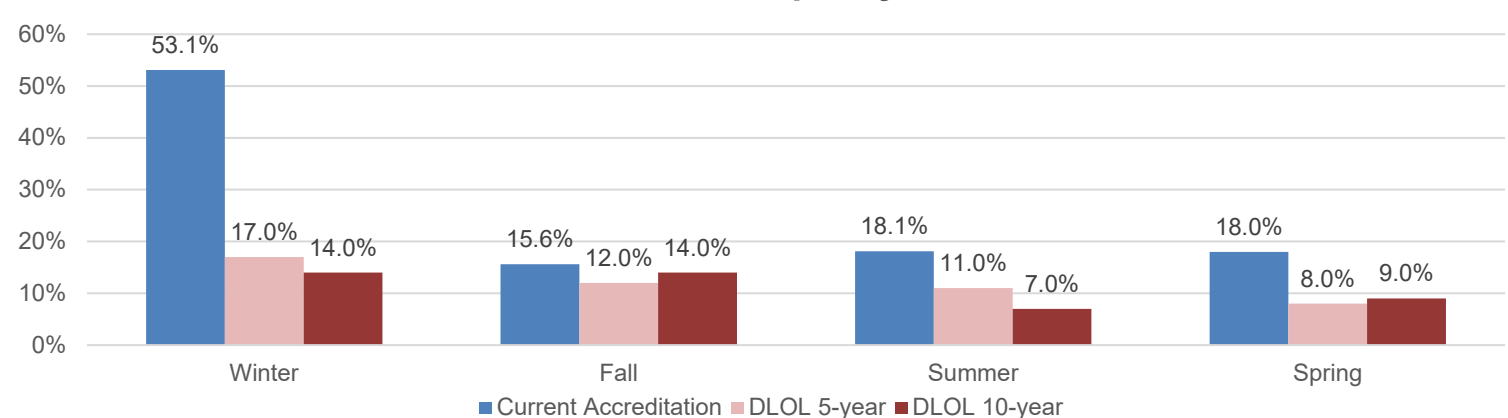
SEASONAL RESOURCE ACCREDITATION* UNDER D-LOL – SOLAR AND WIND

- NIPSCO’s existing and under-development solar and wind resources provide a significant amount of energy value for the portfolio.
- Although solar capacity accreditation has been expected to decline over time, MISO’s *draft indicative* forward-looking D-LOL accreditation projections suggest a more dramatic decline is possible.
- Current wind accreditation is significantly higher in the winter, but D-LOL indications suggest potentially lower values year-round.
- New rules could result in new opportunities to improve capacity accreditation through new storage resources, particularly at existing renewable sites, or other capacity-advantaged resources

DRAFT Indicative Seasonal Capacity Accreditation – Solar



DRAFT Indicative Seasonal Capacity Accreditation – Wind



Source: [MISO RASC: Accreditation Reform](#)

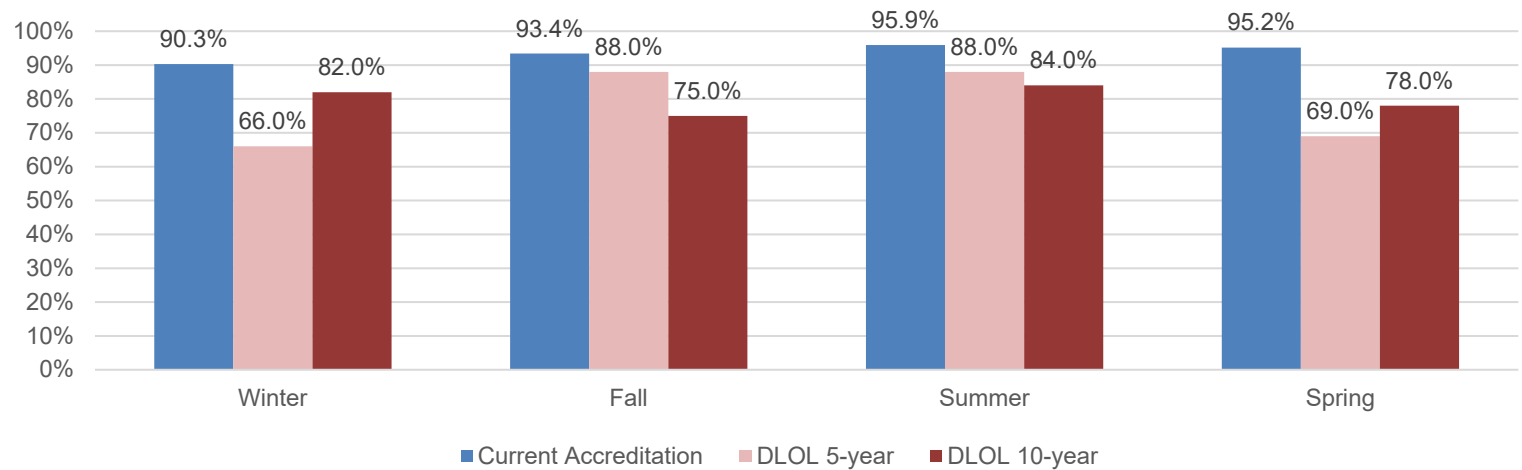
****Actual NIPSCO accreditations will be based on resource-specific performance***

We exist to deliver safe, reliable energy that drives value to our customers

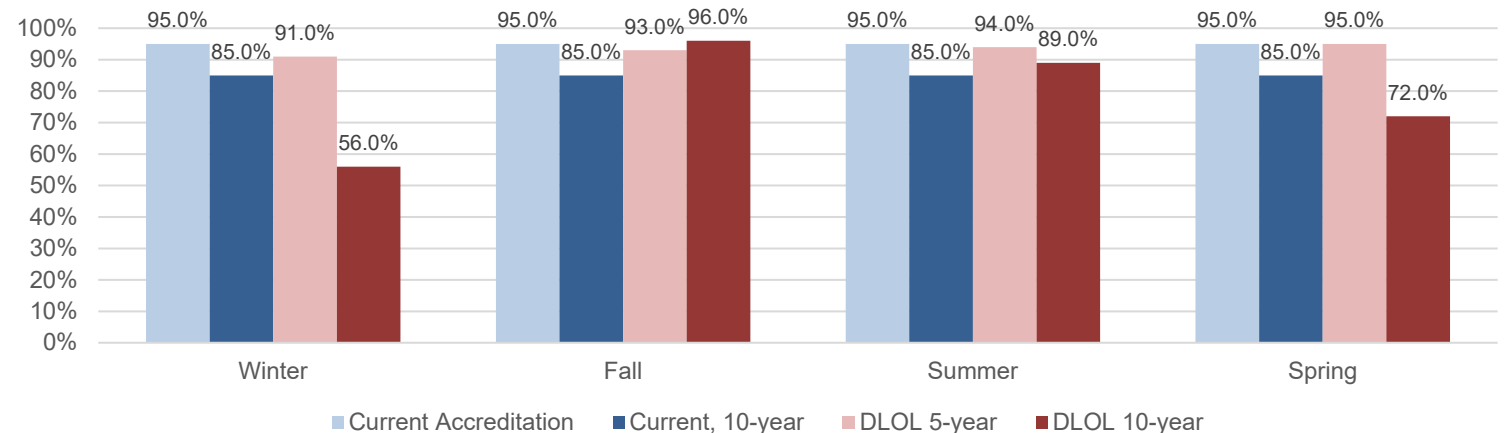
SEASONAL RESOURCE ACCREDITATION* UNDER D-LOL – GAS AND STORAGE

- Gas plant accreditations may be lower than current assumed forced outage rate, depending on performance during stress hours.
- Storage accreditations may fall significantly over time, particularly in the winter and spring seasons. Longer-duration storage resources are likely to be more resilient to accreditation decline risks.

DRAFT Indicative Seasonal Capacity Accreditation – Gas CT



DRAFT Indicative Seasonal Capacity Accreditation – Storage

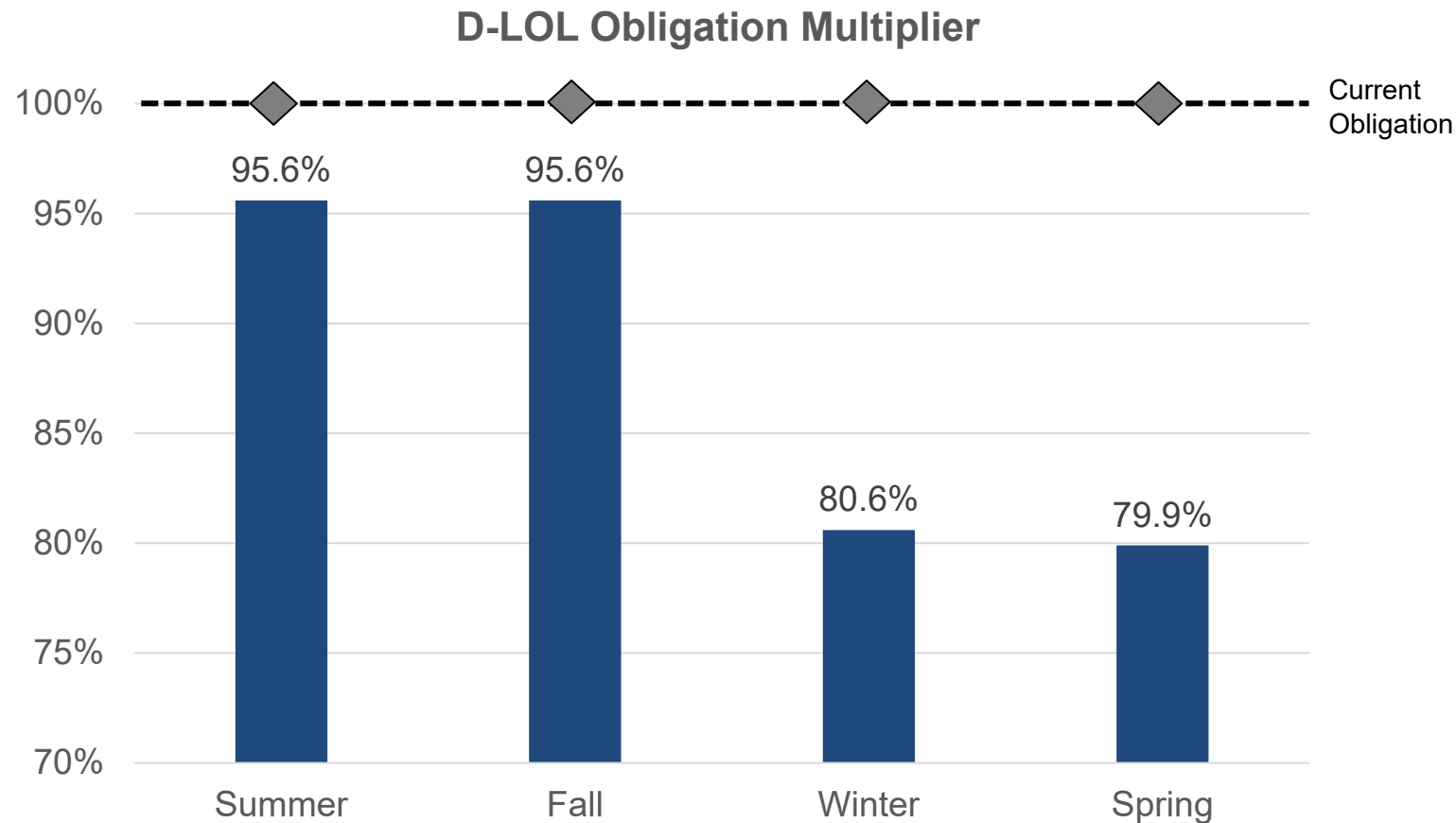


Source: [MISO RASC: Accreditation Reform](#)

****Actual NIPSCO accreditations will be based on resource-specific performance***

We exist to deliver safe, reliable energy that drives value to our customers

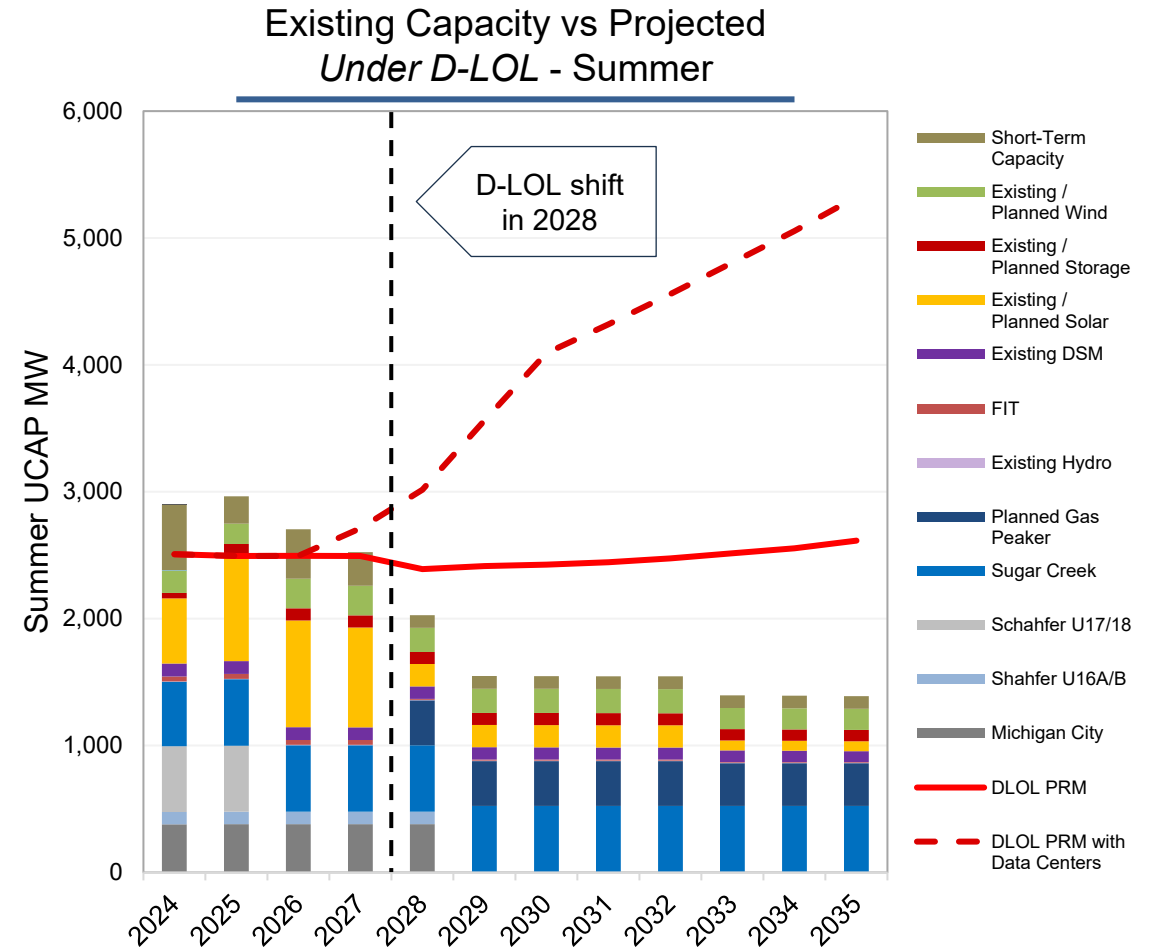
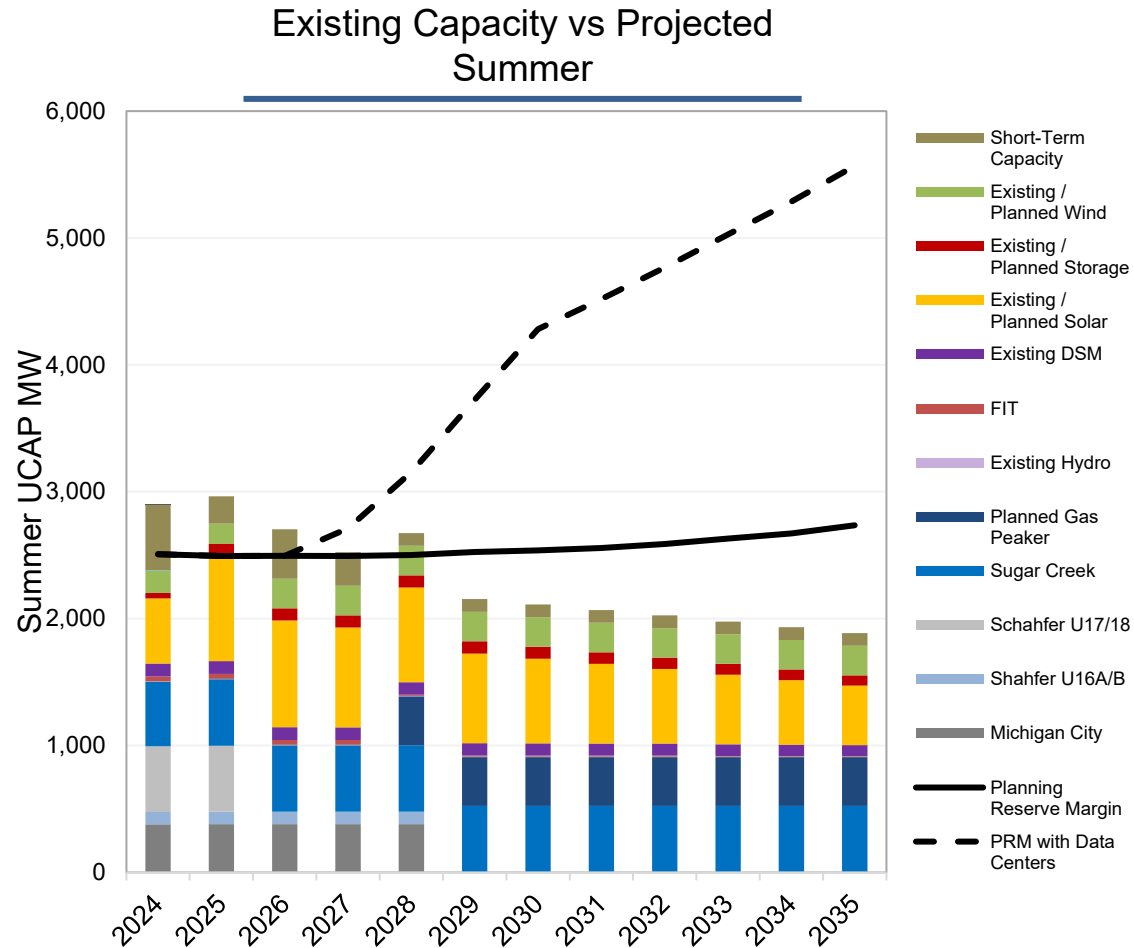
NIPSCO SEASONAL OBLIGATION IMPACTS FROM D-LOL



****Indicative guidance for planning purposes***

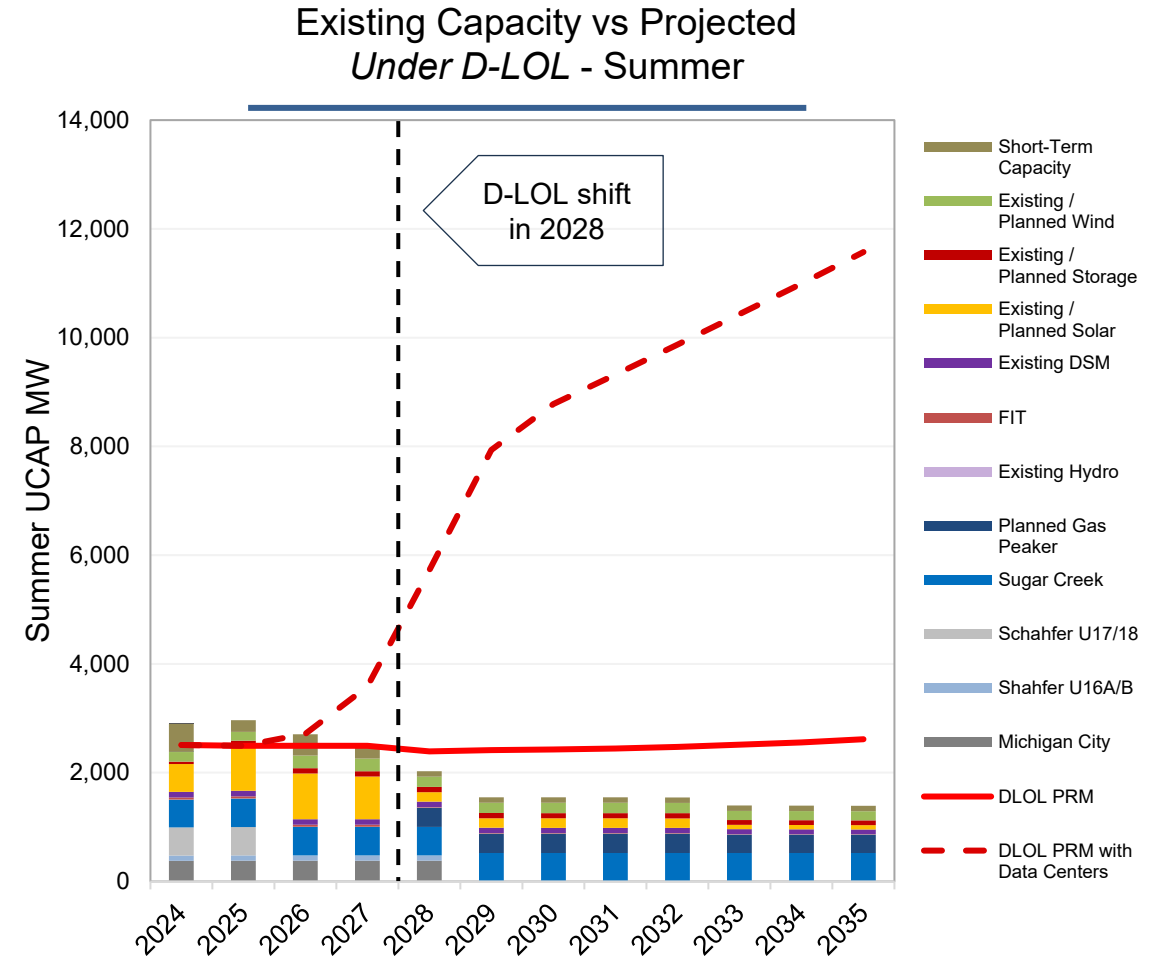
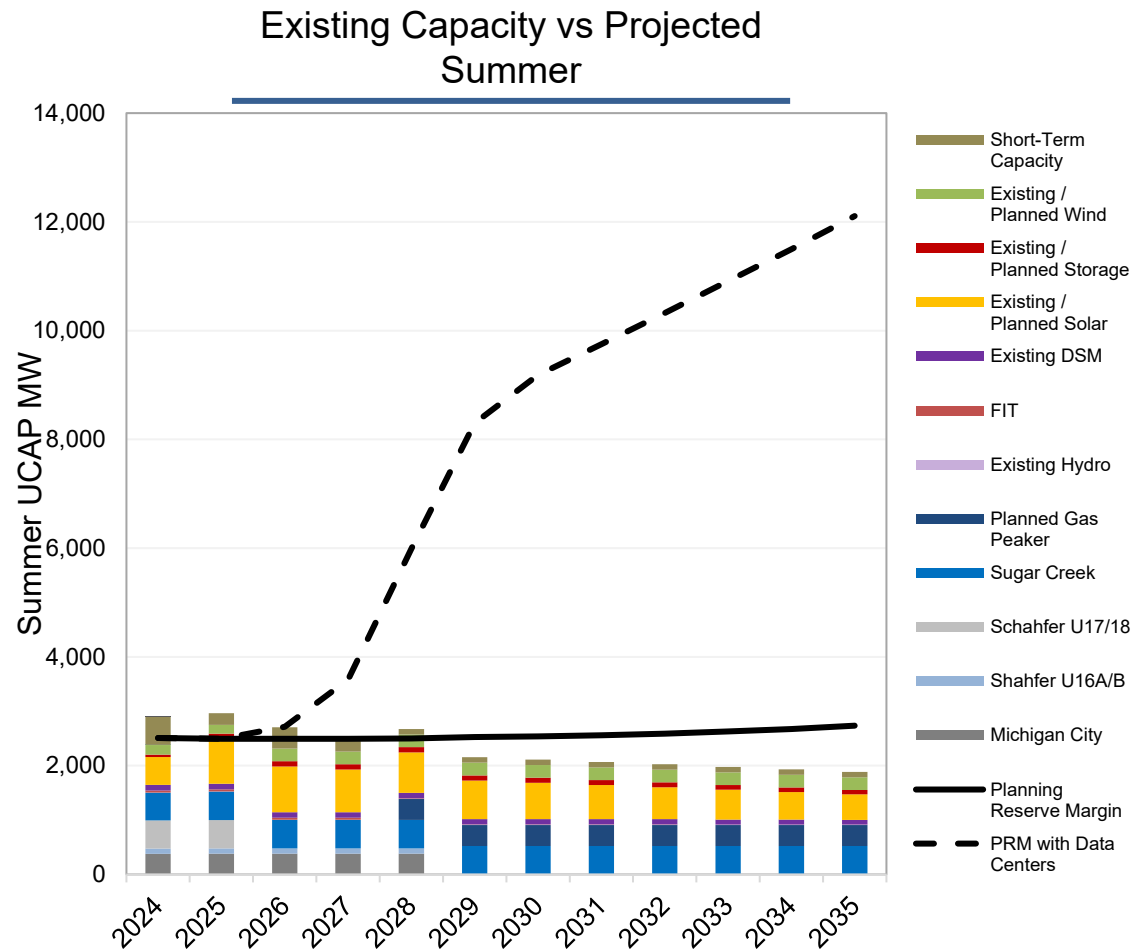
- MISO is anticipating a decrease in the planning reserve margin under D-LOL since hours not aligned with highest overall loads may be identified as having higher risk.
- MISO provided indications to NIPSCO of expected declines under D-LOL for the 2024/25 planning year.
- Significant obligation reductions are possible in winter and spring.

CURRENT NIPSCO CAPACITY POSITION – REFERENCE LOAD – SUMMER



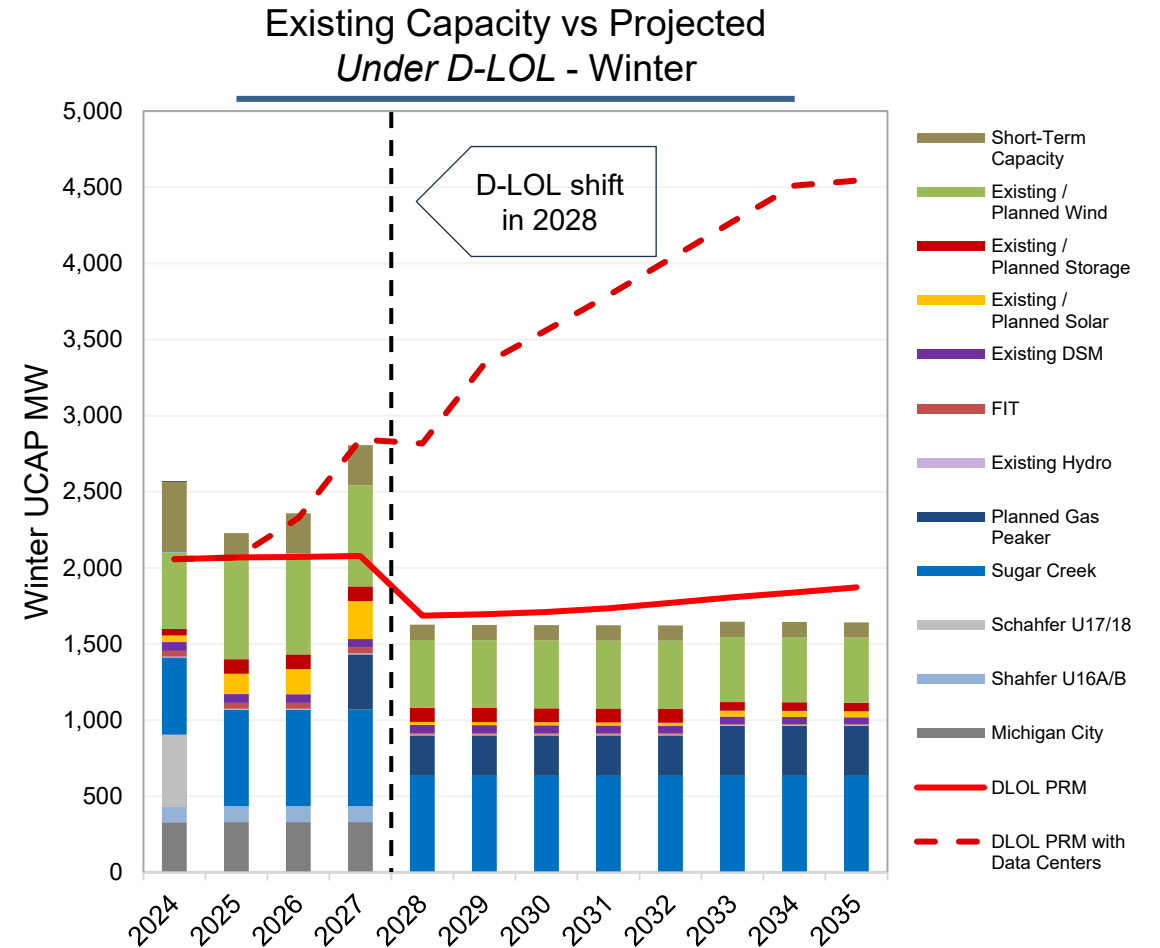
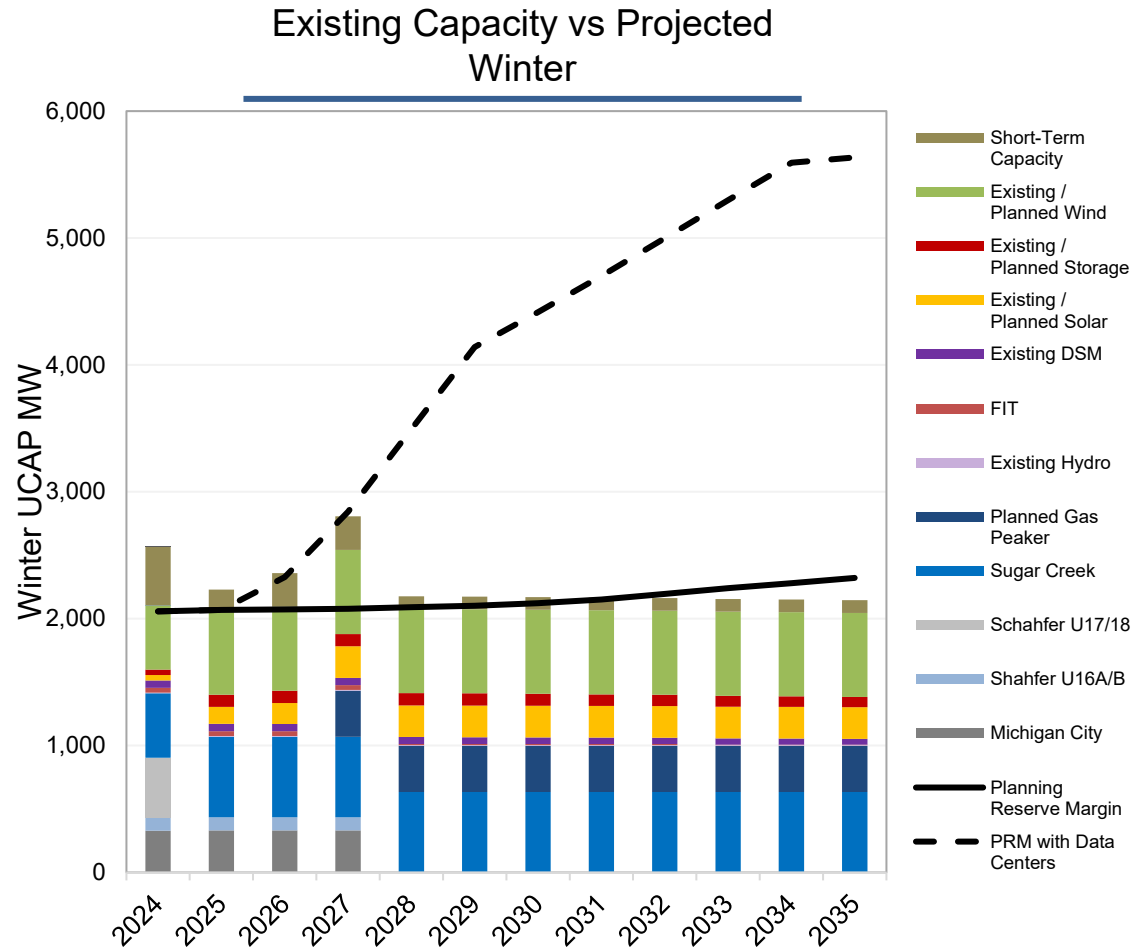
We exist to deliver safe, reliable energy that drives value to our customers

CURRENT NIPSCO CAPACITY POSITION – HIGH LOAD SENSITIVITY – SUMMER



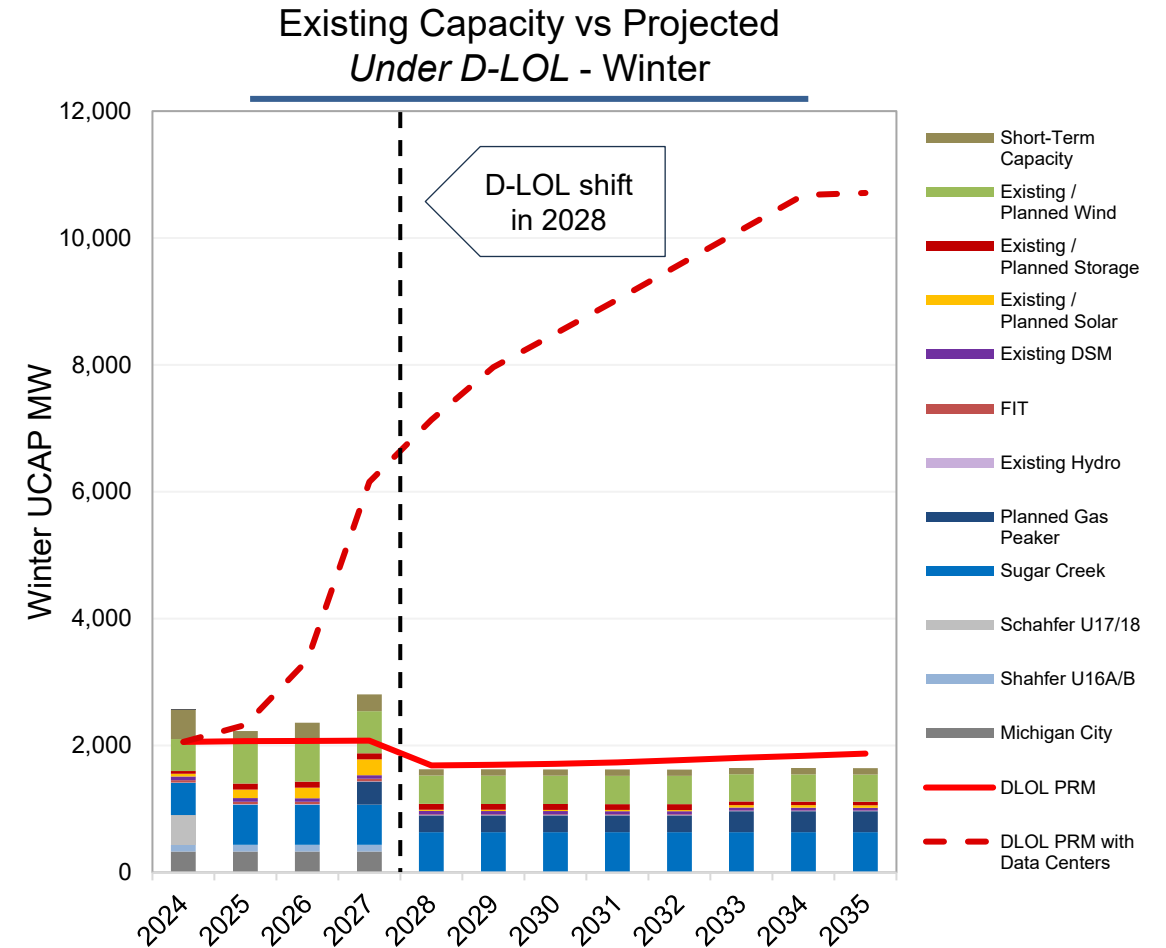
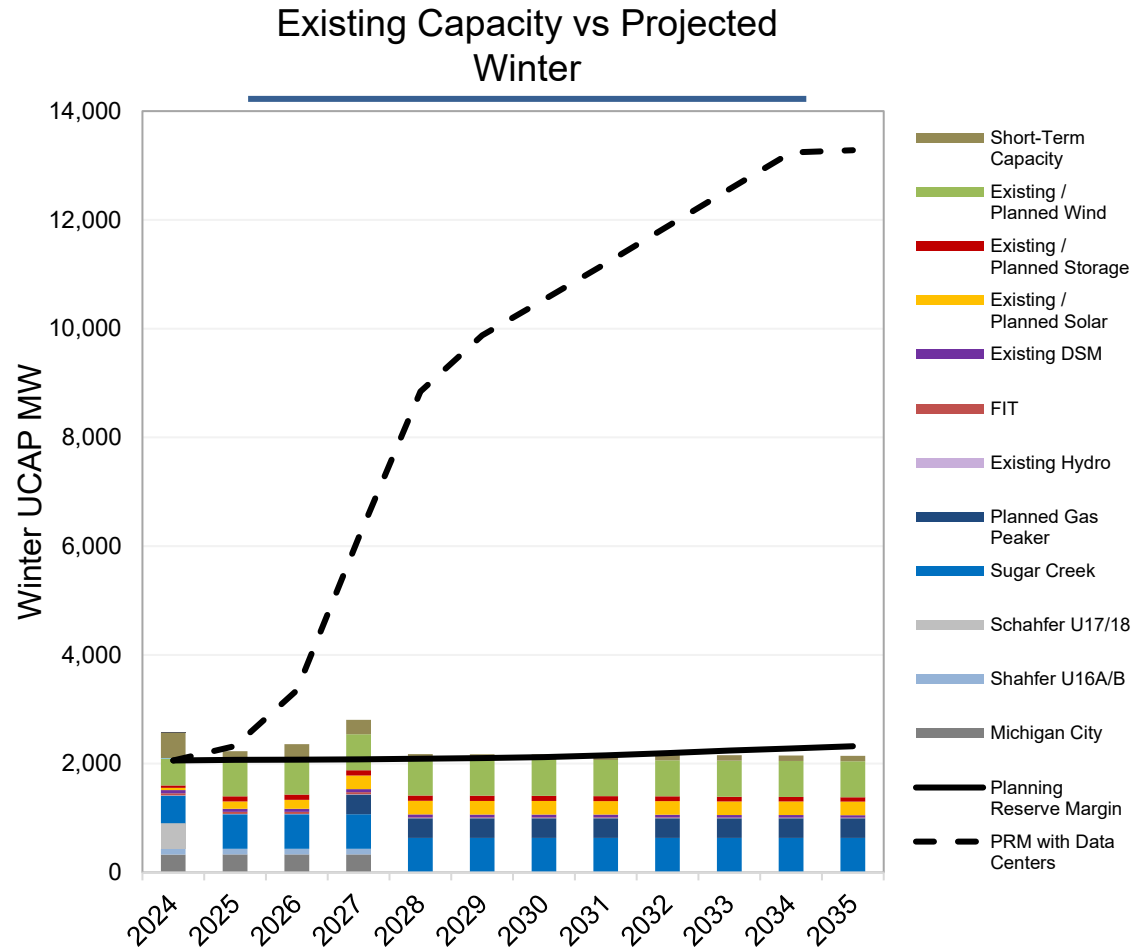
We exist to deliver safe, reliable energy that drives value to our customers

CURRENT NIPSCO CAPACITY POSITION – REFERENCE LOAD – WINTER



We exist to deliver safe, reliable energy that drives value to our customers

CURRENT NIPSCO CAPACITY POSITION – HIGH LOAD SENSITIVITY – WINTER



We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

LUNCH





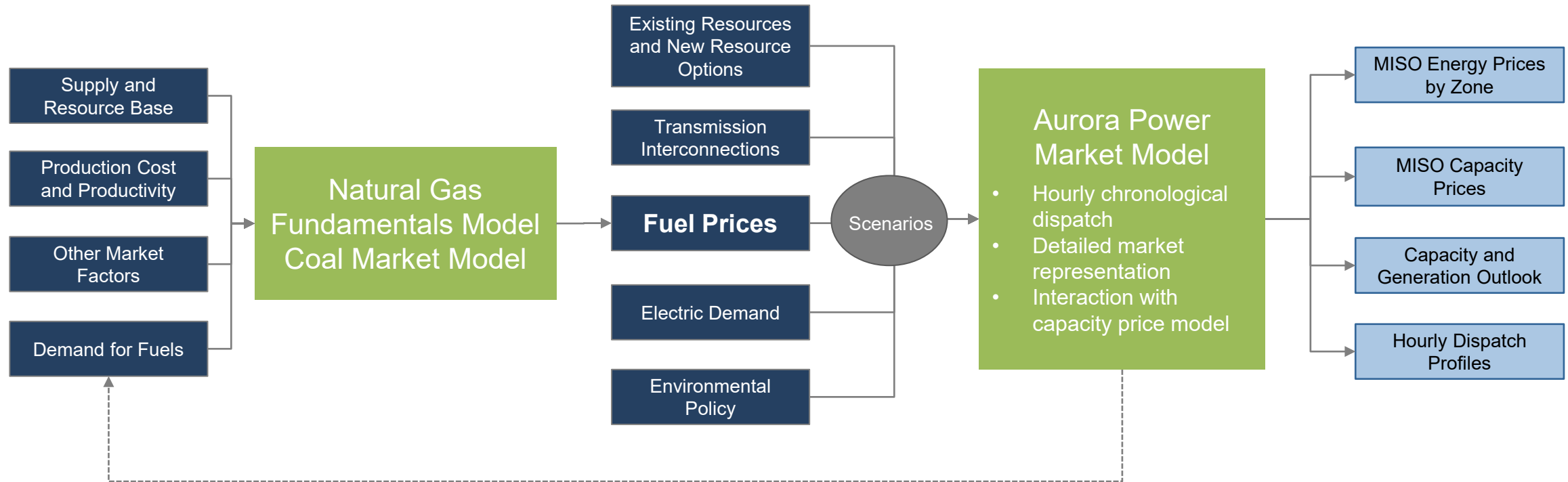
We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: COMMODITY PRICES



FUNDAMENTAL MARKET MODELING STRUCTURE

CRA's fundamental market models simulate the fuel and power markets to produce integrated outlooks for commodity prices, environmental policy, and power market outcomes



**Note that the Aurora model will also be used in “portfolio” mode to assess NIPSCO-specific portfolio analyses*

NATURAL GAS MARKET FORECASTING

Drivers of natural gas pricing and uncertainty change as the forecast progresses in time



Markets

Expectations about weather, storage and markets drive gas price expectations in the short term

Due to composition of demand at the point, Henry Hub is now highly linked to demand for natural gas exports

Fundamentals

The cost of production, price of oil, and composition of demand drive prices in the medium term, as end-use sectors respond to prevailing prices for energy commodities

Corporate activity may also impact prices over this period if different segments of the industry are consolidated

Policy

Policies that impact economy-wide demand and access to supply will drive gas prices over the longer term

Policies that seek to lower green house gas (“GHG”) emissions in the residential, commercial, and industrial sectors may have a significant impact on long-term demand

CRA FORECASTS NATURAL GAS PRICES BASED ON EXPECTATIONS AROUND SUPPLY AND DEMAND

A fundamental price forecast answers the question: “What gas price is needed to satisfy total demand and make producers whole?”

CRA Natural Gas Fundamentals Model (NGF)



Gas Supply

- Total resource in place, proved and unproven
- Resource growth over time
- Wet / dry product distribution
- Historic wells drilled and ongoing production
- Conventional & associated production
- Existing tight & coal bed methane
- Existing offshore production



Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- Initial production rates
- Changing drilling and production efficiencies over time
- Productivity decline curve
- Well lifetime
- Distribution of performance



Gas Demand



- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)



Other Market Drivers

- Value of natural gas liquids and condensates
- Natural gas storage

KEY DRIVERS OF THE REFERENCE CASE

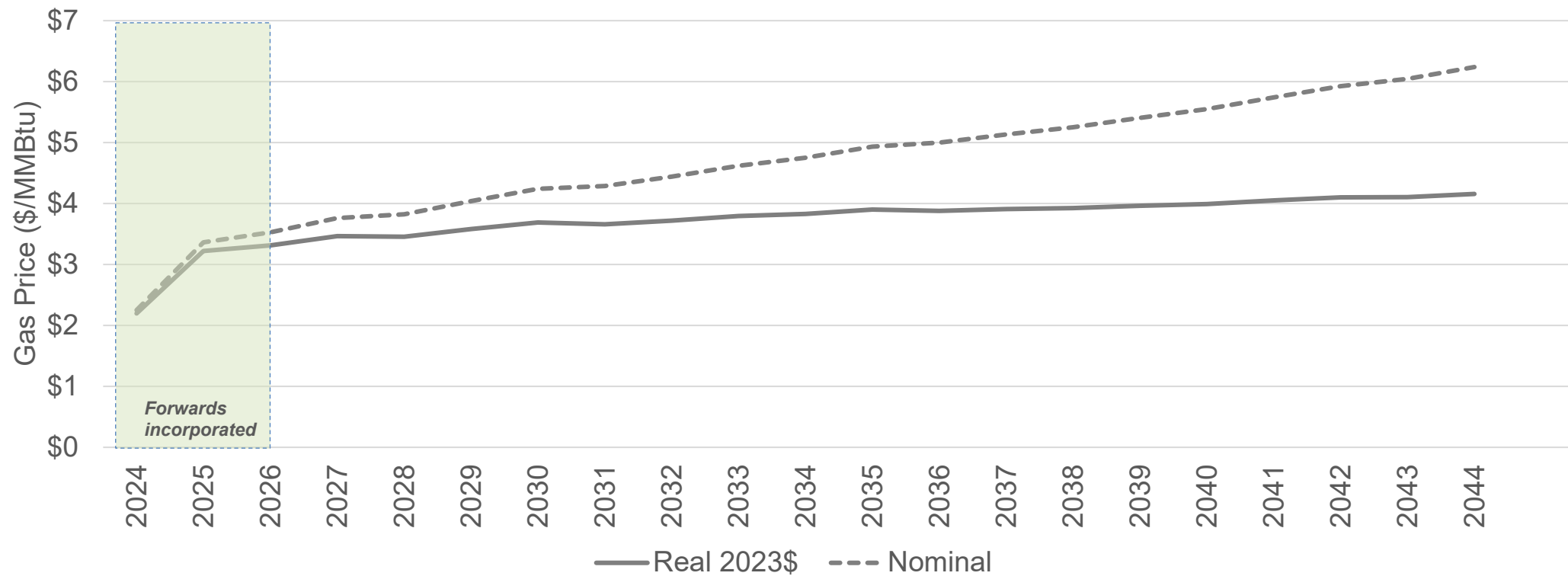
Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (“PGC”) “Most-Likely” unproven estimates	CRA assumes a starting point of PGC 2022 “Minimum” resource, and grows the resource base to achieve PGC 2022 “Most Likely” volumes by 2050 to reflect pace of incremental discoveries over time.
Well Productivity	• Initial Production (“IP”) rates based on historic drilling data • IP improves as per Energy Information Agency (“EIA”) Tier 1 assumptions	CRA bases individual well productivity on historic data analyzed for each producing region; IP rates improve annually, consistent with EIA assumptions.
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA starts from drilling and operating costs reported by major producers in each supply basin; cost improvements over time are based on latest EIA assumptions.
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	CRA uses EIA’s forecast of domestic oil prices and production; this includes the impact of oil production and environmental regulations associated with flaring.

KEY DRIVERS OF THE REFERENCE CASE

Driver	CRA Approach	Explanation
Domestic Demand	• CRA electric power sector simulation • Other sector natural gas demand synthesized from EIA	CRA expects natural gas domestic demand to be relatively stable to slightly declining under the Reference Case, with power sector declines driving the biggest long-term change.
LNG Exports	• Based on review of proposed projects • General uptick in under-construction projects completed and total exports	CRA expects no further export capacity beyond projects that are already operating or which have already achieved Final Investment Decision and are under construction, due to increased competition from suppliers with lower production costs or located closer to demand centers. However, existing and new facilities also have the potential to operate at higher utilization rates over time.
Pipeline Exports	• EIA predictions for net imports	CRA expects modest growth in pipeline exports to Mexico as well as decreasing imports from Canada.

REFERENCE CASE NATURAL GAS PRICE OUTLOOK

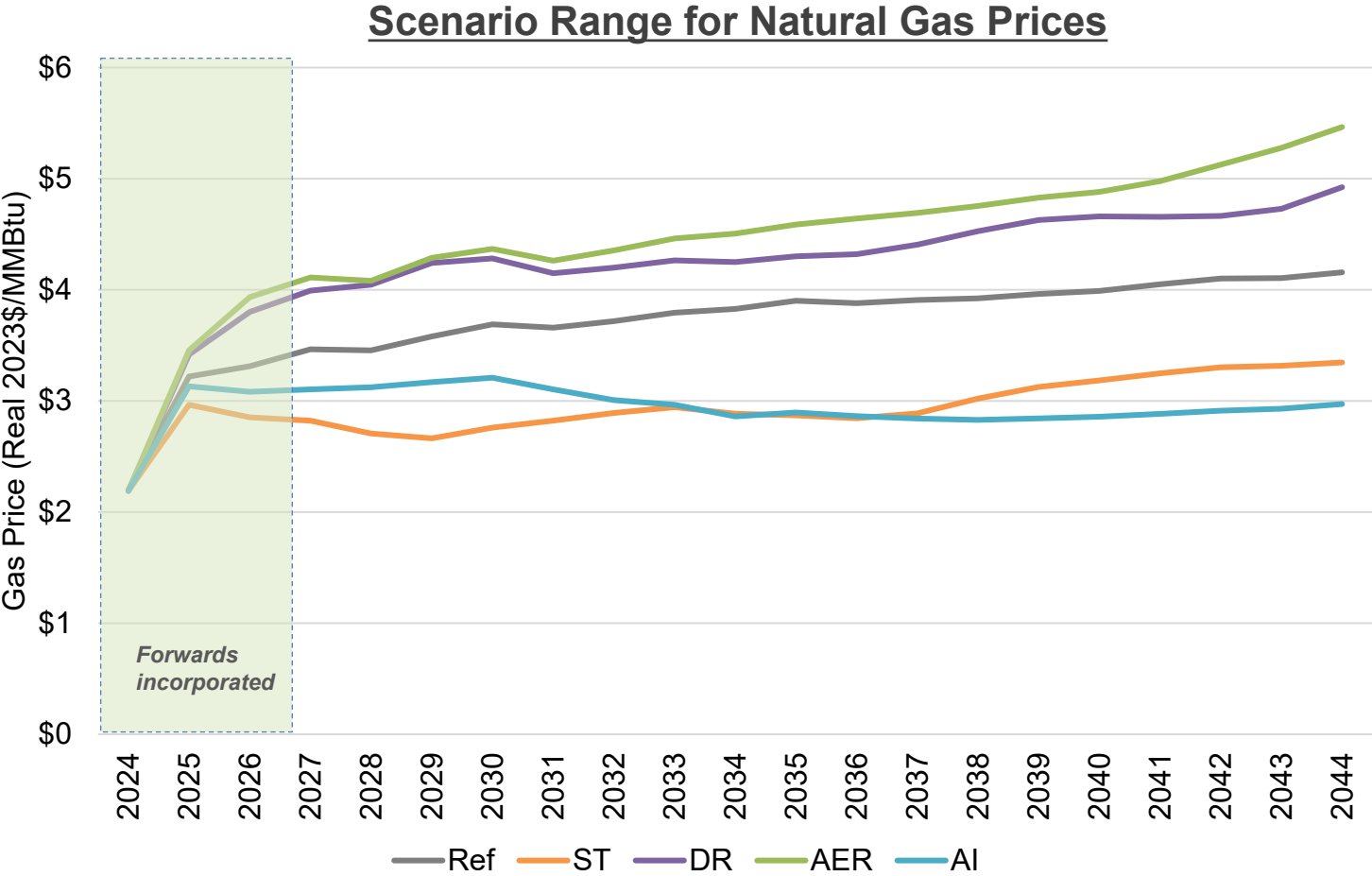
- Beyond the forward period, prices are projected to be in the \$3.50-\$4.00/MMBtu range (real 2023\$) for most of the study period
- Demand is projected to increase gradually through ~2030, largely due to LNG export demand, putting upward pressure on prices
- Thereafter, flattening to slightly declining demand tends to stabilize prices as overall marginal production costs increase slightly



NATURAL GAS PRICE SCENARIO PERSPECTIVES

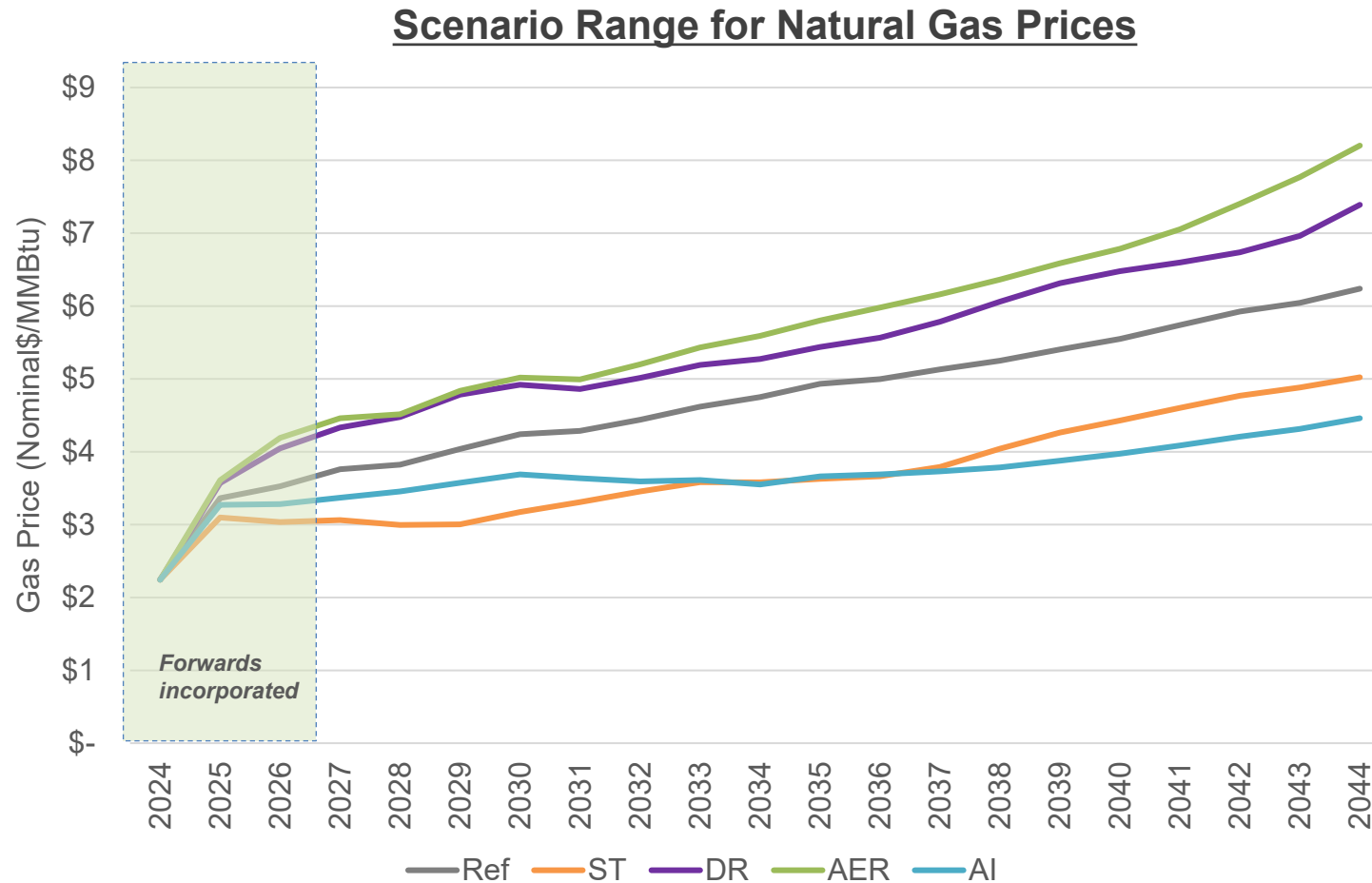
Driver	Reference Case	ST	DR	AER	AI
Resource Size	Rely on Potential Gas Committee (PGC) “Most-Likely” unproven estimates	↑		↓	
Well Productivity	- IP rates based on historic drilling data - IP improves as per EIA Tier 1 assumptions - Resource base is “Poor Heavy”	↑			
Fixed & Variable Well Costs	- Fixed and variable costs based on reported data - Costs improve as per EIA assumptions			↑	
Demand	Electric demand taken from CRA national Reference Case, RCI demand based on AEO Reference Case		↑		↓
Resulting Price	—	↓	↑	↑	↓

NATURAL GAS PRICE SCENARIO RANGE



	Henry Hub Price (in real 2023\$/MMBtu)		
	2025	2035	2043
AER	\$3.46	\$4.59	\$5.28
DR	\$3.42	\$4.30	\$4.73
REF	\$3.22	\$3.90	\$4.11
ST	\$2.97	\$2.87	\$3.32
AI	\$3.13	\$2.90	\$2.93

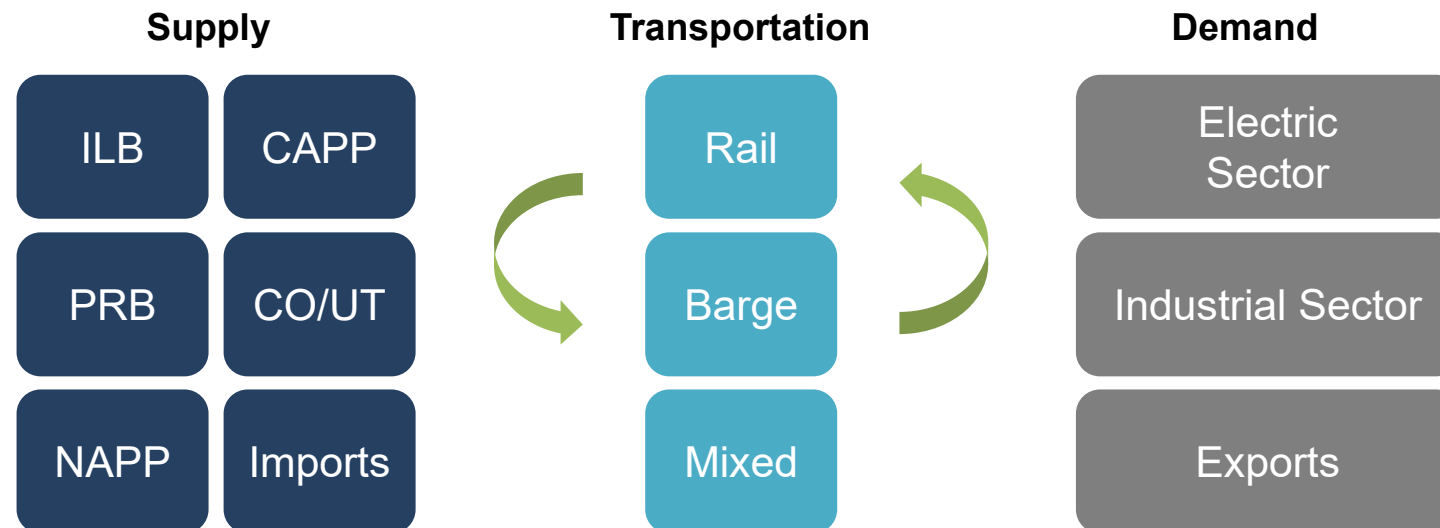
NATURAL GAS PRICE SCENARIO RANGE



	Henry Hub Price (in Nominal\$/MMBtu)		
	2025	2035	2043
AER	\$3.61	\$5.80	\$7.77
DR	\$3.57	\$5.44	\$6.96
REF	\$3.36	\$4.93	\$6.04
ST	\$3.10	\$3.63	\$4.88
AI	\$3.27	\$3.66	\$4.31

COAL FORECASTING OVERVIEW

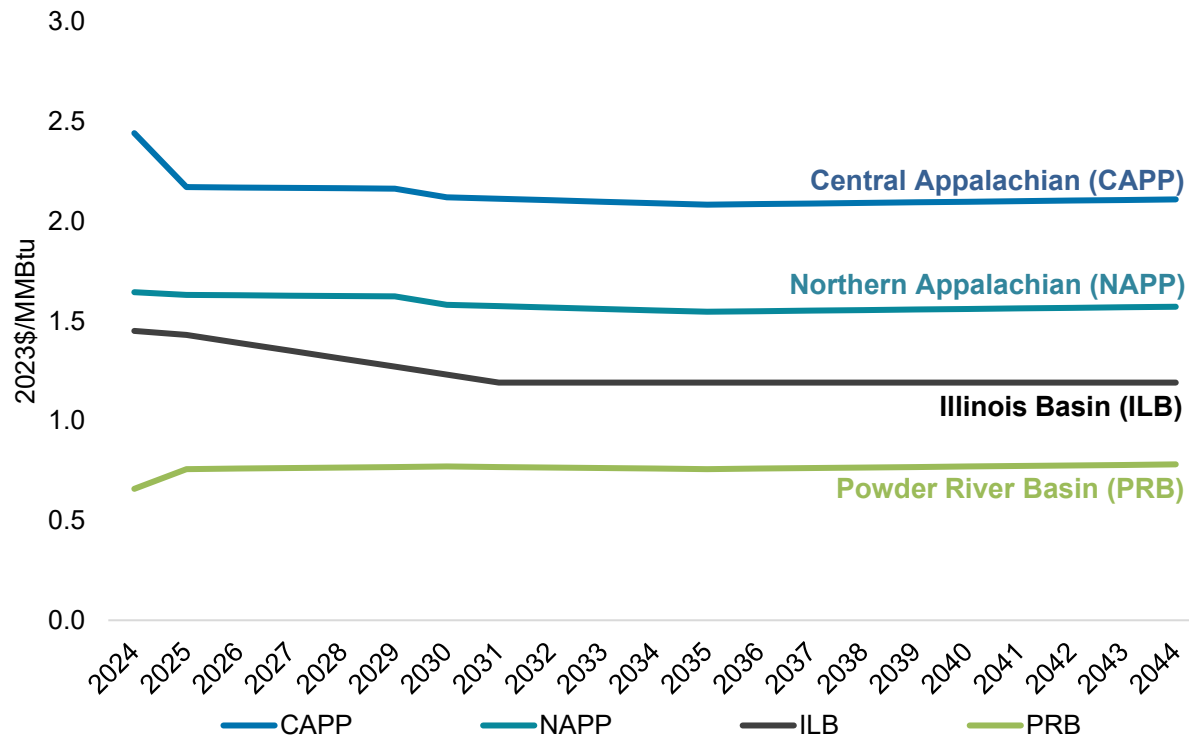
- CRA's process assesses future supply/demand balance for the U.S. coal market based on:
 - Macroeconomic drivers, including domestic and international demand
 - Microeconomic drivers, including trends in mining costs and production trends
- CRA iterates with the Aurora and NGF models to account for electric and gas market feedbacks



COAL PRICE FORECAST

U.S. coal prices are expected to exhibit flat-to-declining trends over the long-term due to declining demand

CRA FOB* Coal Price Forecast



*The Free on Board (FOB) price represents the value of coal at the coal mine and excludes transport and insurance costs

- Spot prices for U.S. steam coal have continued to decline since last year.
- Over the long-term, coal prices are expected to be flat to declining due to increasing renewable penetration and the consequent decline in domestic demand for coal.
- Demand for coal exports is also expected to stabilize over the long-term as international markets decarbonize.

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: ENVIRONMENTAL POLICY



CURRENT ASSUMPTIONS REGARDING EPA GHG RULES

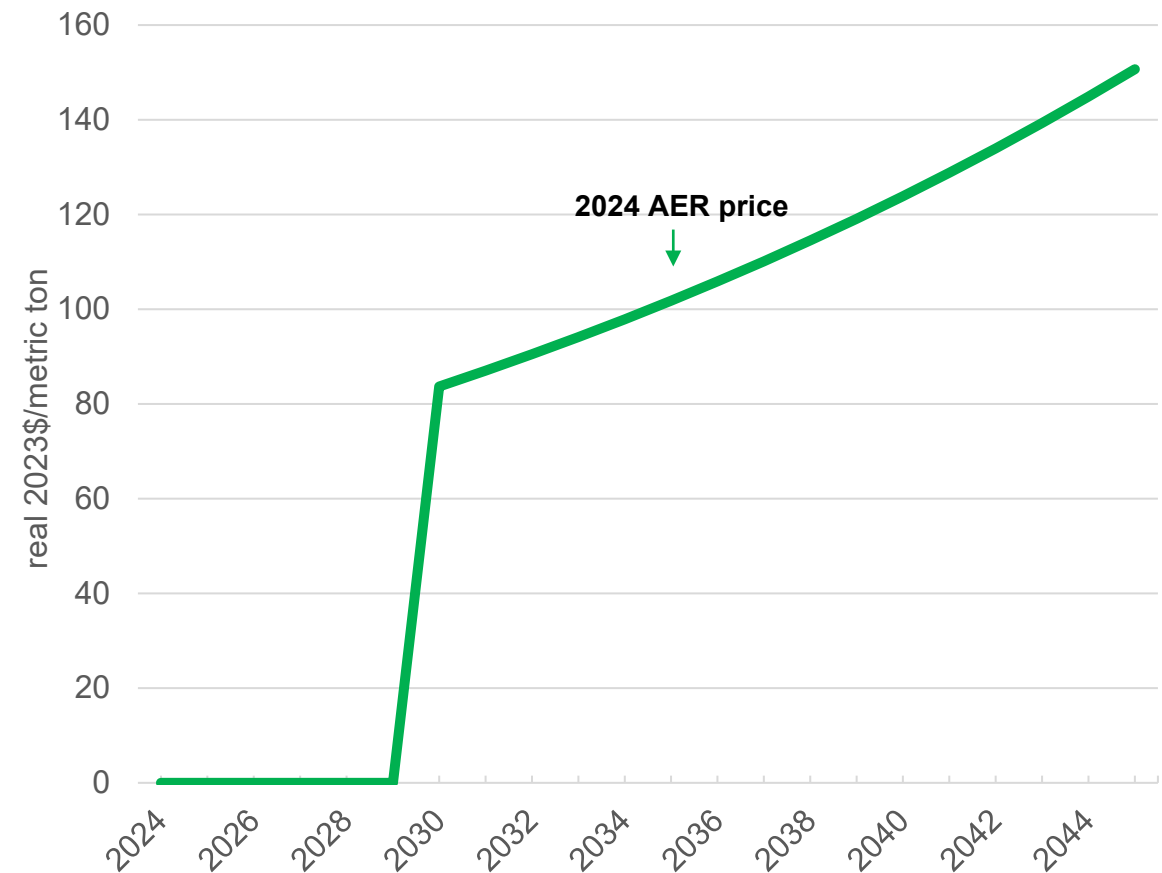
- On May 9, 2024, the EPA published final greenhouse gas standards and guidelines for fossil fuel-fired electric generating units. The proposed rule had been published on May 23, 2023, and was reviewed in the last meeting.
- EPA's final GHG Rule will not affect NIPSCO's existing generation, but is expected to impact existing steam generating units beginning in 2030
- As designed by the EPA, and assuming the final GHG Rule survives litigation, new gas generation would be required to meet certain emission limits based on capacity factor. NIPSCO is including the final rule in four of its five scenarios.
- Two of EPA's previous GHG regulations for power plants (i.e., the Clean Power Plan and Affordable Clean Energy Rule) were overturned

NIPSCO Resources	Impact of GHG Rule	New Stationary Combustion Turbines	Impact of GHG Rule
Schahfer Units 17/18	No impact due to planned retirement by 2025.	Baseload Capacity Factor > 40%	- Timing of Impact - Upon start-up - By 2032 - Limits (CO2/MWh) - By capacity factor range - Methods of Compliance - Capacity factor limits - Best System of Emission Reduction (BSER) - Decarbonization options
Michigan City Unit 12	No impact due to planned retirement by 2028.	Intermediate Load Capacity Factor >20 <= 40%	
Sugar Creek and Schahfer 16A/B	No impact. The GHG Rule does not affect existing gas turbines. A separate rule may be issued in the future.	Low Load Capacity Factor <= 20%	
Planned Schahfer Gas Peakers	See chart at right for Low Load and Intermediate Load gas turbines. Emission limits are dependent on capacity factor.		

<https://www.epa.gov/>

THE AGGRESSIVE ENVIRONMENTAL REGULATION (AER) SCENARIO ASSUMES CARBON EMISSIONS FROM THE POWER SECTOR ARE REGULATED MORE HEAVILY

- NIPSCO has applied a carbon price in previous IRPs
- In this IRP's AER scenario, NIPSCO is applying research from the Brookings Institute regarding implicit carbon prices required to meet global targets
- Carbon prices that limit warming to $\sim 2^{\circ}\text{C}$ by 2100 provide a bookend for the impact from future potential climate policy
 - The AER carbon price starts at \$83 per metric ton (real 2023\$) in 2030 and increases at a constant rate of 4% annually
 - The cost trajectory represents a range of potential future environmental policy options that may impact the cost of emitting carbon, rather than an explicit carbon tax policy



Source: Hansel et al, "Climate Policy Curves: Linking Policy Choices to Climate Outcomes," Brookings Institution, December 2022.



We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: MISO MARKET OUTCOMES





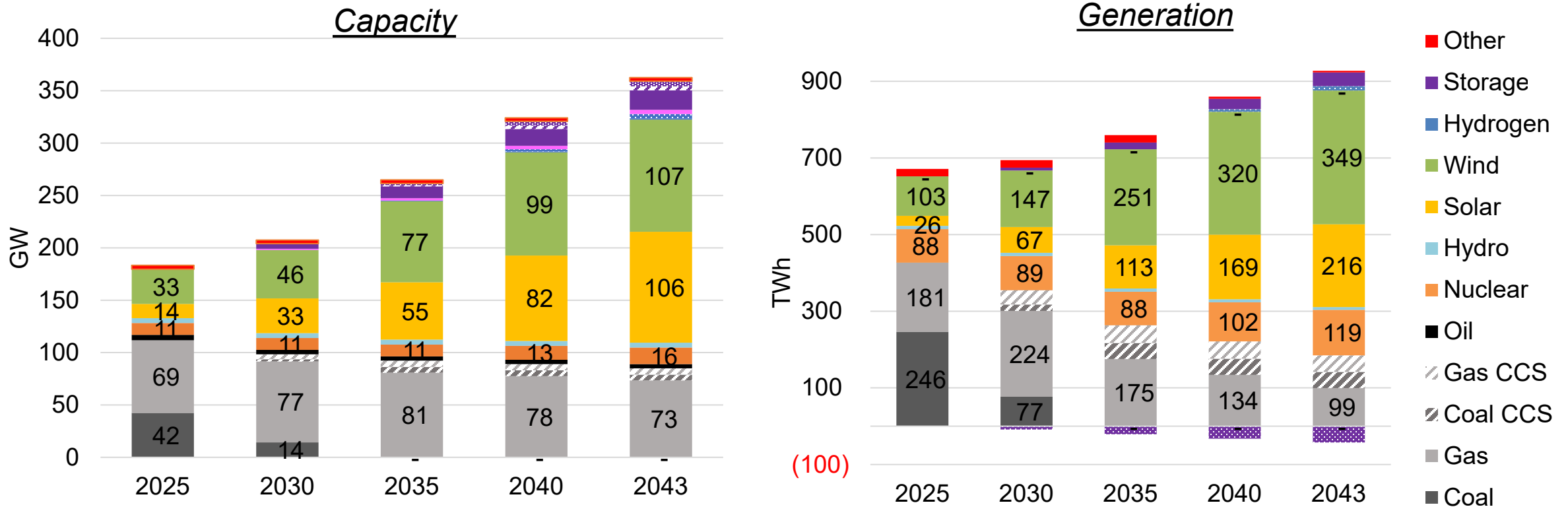
We exist to deliver safe, reliable energy that drives value to our customers

MISO MARKET OUTCOMES – REFERENCE CASE



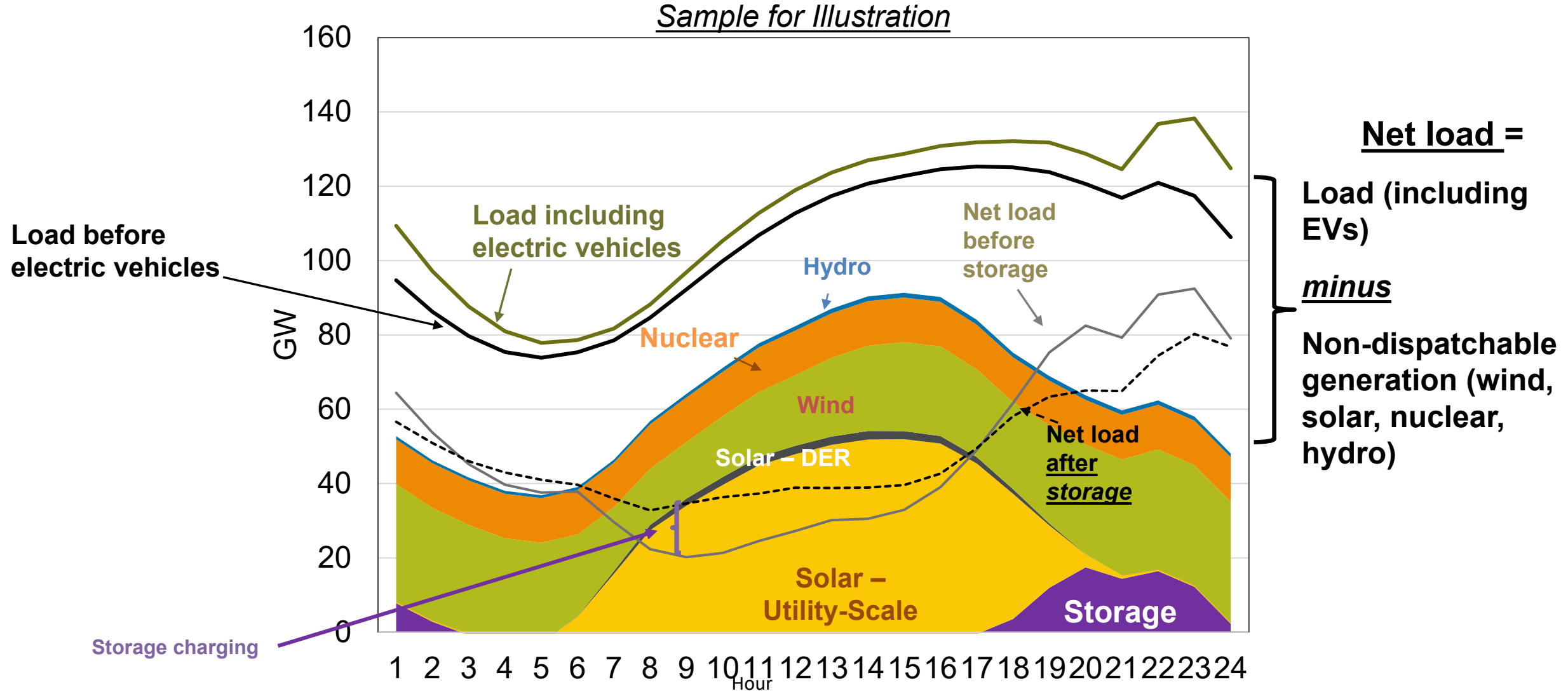
MISO MARKET EVOLUTION – REFERENCE CASE

- EPA power sector emissions rules are expected to result in coal retirements or conversions and a diverse mix of new resources, including gas (with and without CCS), wind, solar, storage, hydrogen, and some new nuclear
- Wind and solar energy are projected to make up close to two-thirds of the energy across MISO by the mid-2040s



We exist to deliver safe, reliable energy that drives value to our customers

HOURLY GENERATION MIX PERSPECTIVES

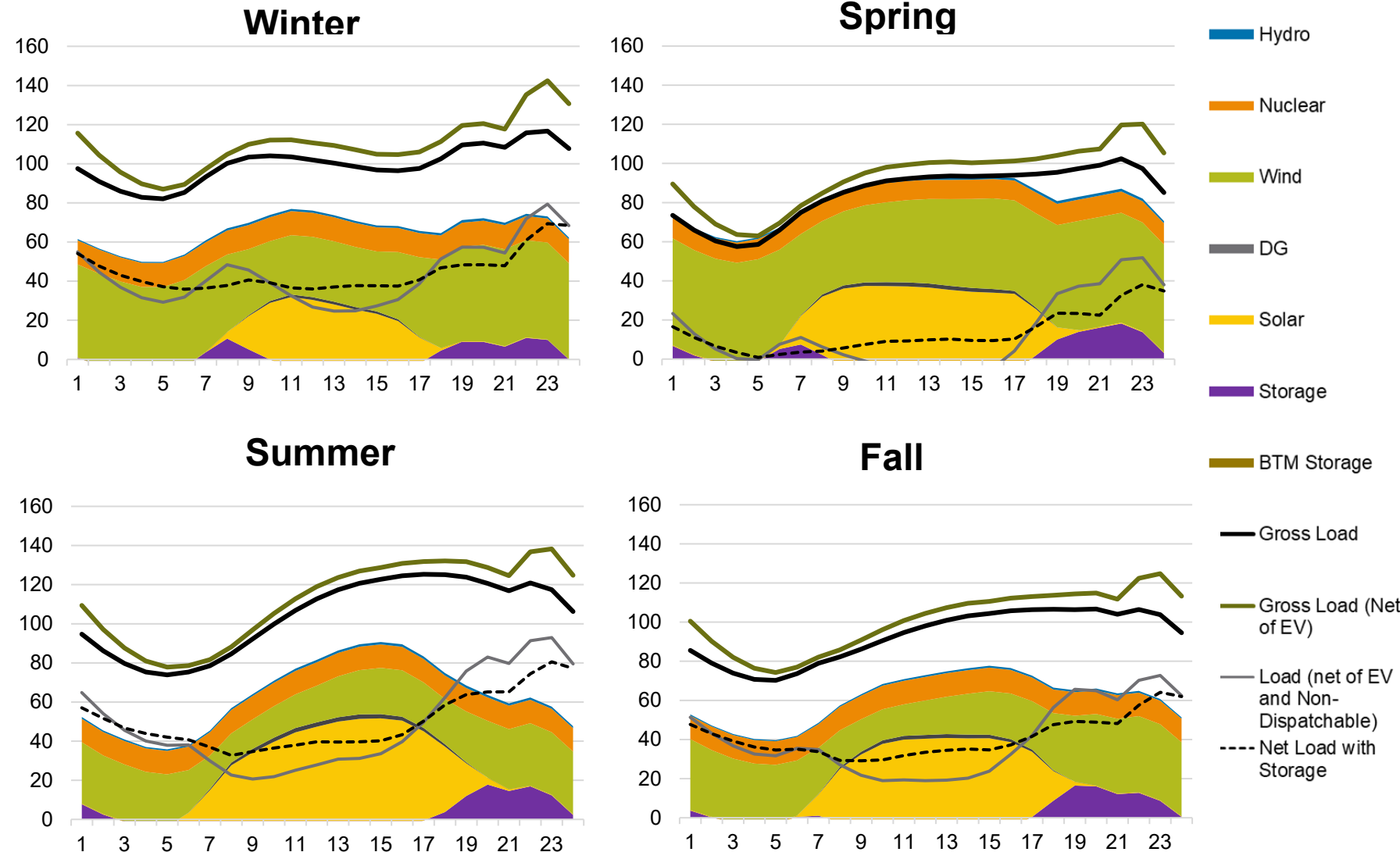


We exist to deliver safe, reliable energy that drives value to our customers

MISO HOURLY ENERGY PROFILE – 2040 (REFERENCE SCENARIO)

- Renewable penetration will impact resource dispatch and MISO hourly prices over time, with differences by season:

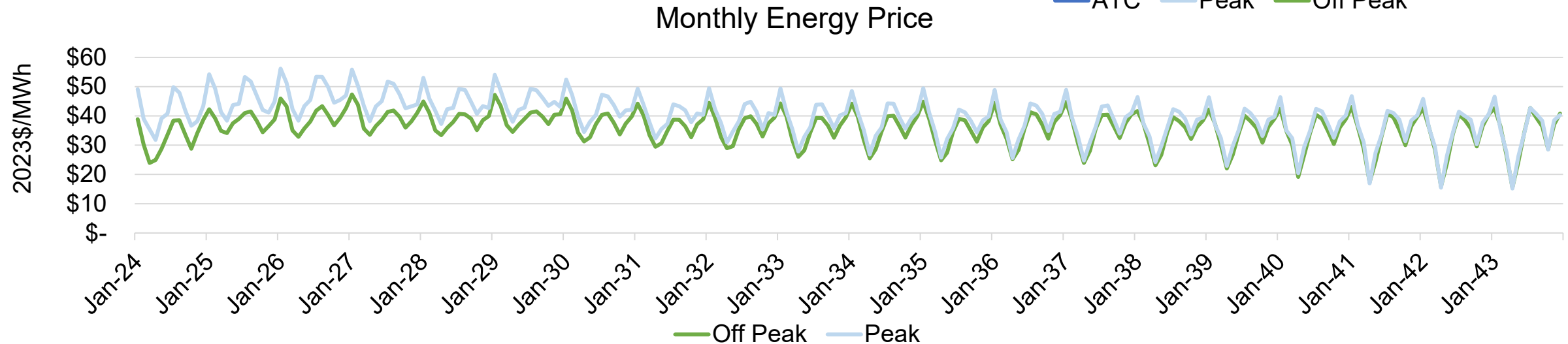
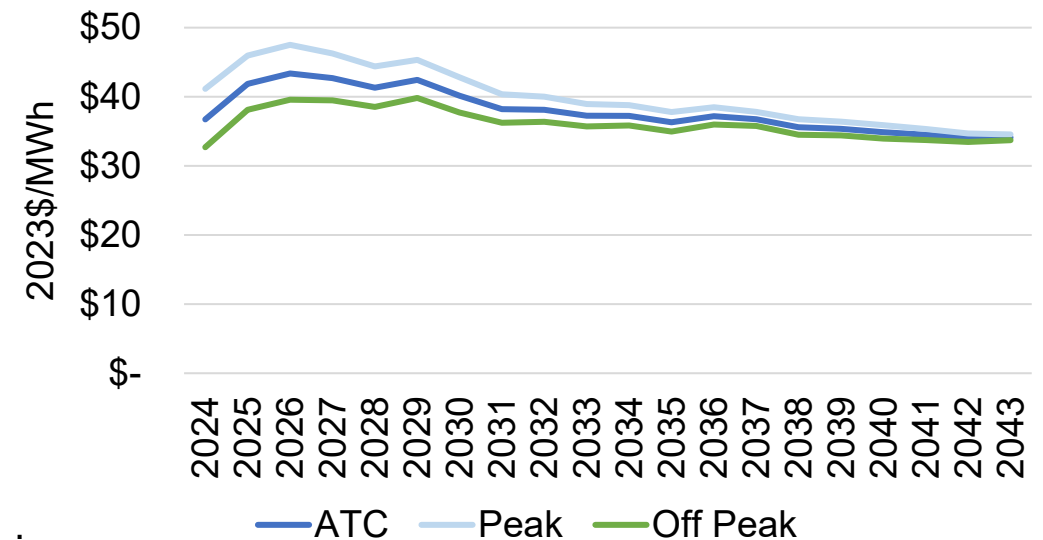
- Combined with baseload nuclear output, mid-day hours in the spring may have more than sufficient generation output to meet demand
- Summer evening peaks will require ramping support



We exist to deliver safe, reliable energy that drives value to our customers

POWER PRICE FORECAST – MISO ZONE 6 (REFERENCE SCENARIO)

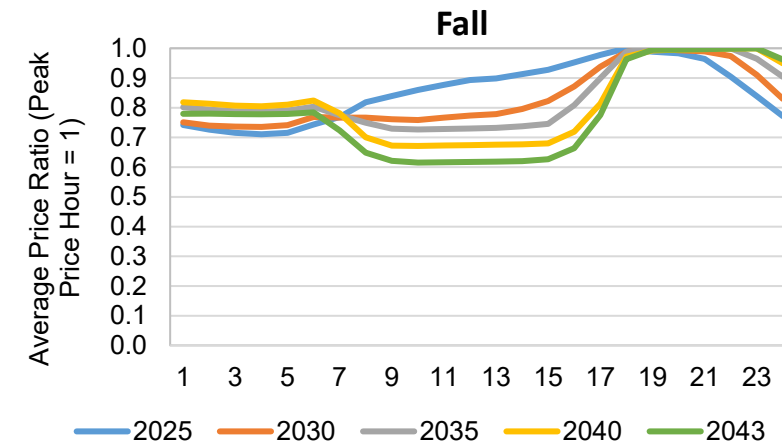
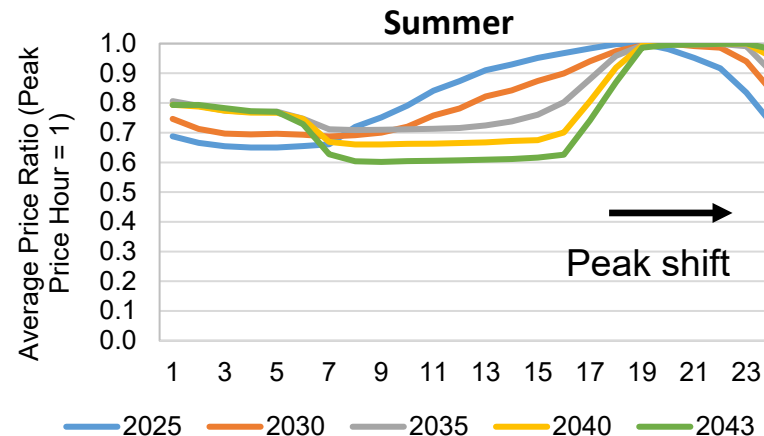
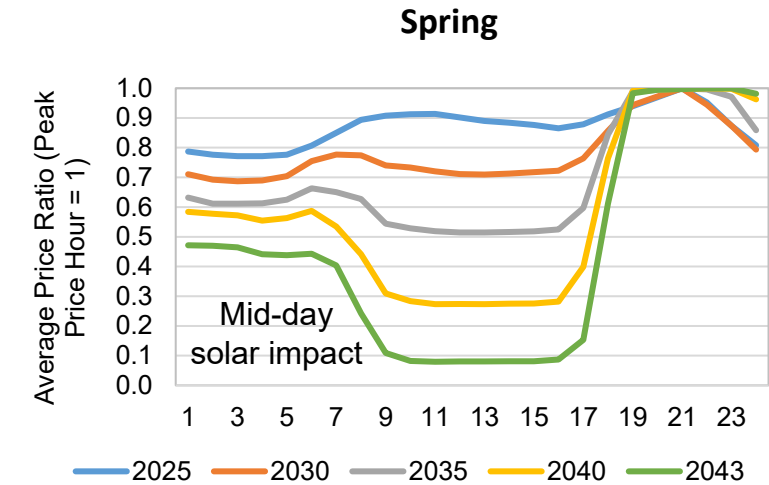
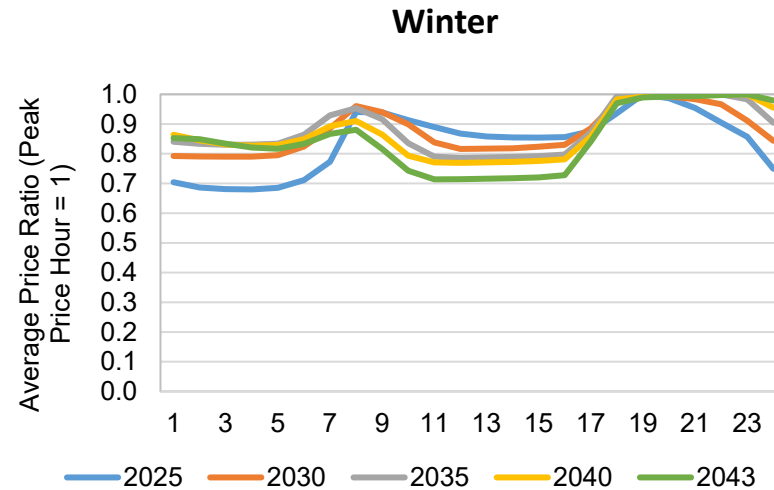
- Power prices are expected to stay relatively flat in real dollars in the near-term, due to expected trends in fuel prices
- Although capacity retirements and load growth may introduce upward pressure on prices, the influx of low variable cost energy is likely to mitigate this impact over time
- Convergence in peak and off-peak prices is expected over time, largely driven by solar penetration



We exist to deliver safe, reliable energy that drives value to our customers

MISO ZONE 6 HOURLY PRICE SHAPES (REFERENCE SCENARIO)

- Hourly price patterns are expected to change over time, particularly as more renewables enter the system
- Mid-day prices are expected to decline as a result of solar output
- Summer peak price periods are expected to shift from mid-afternoon to evening





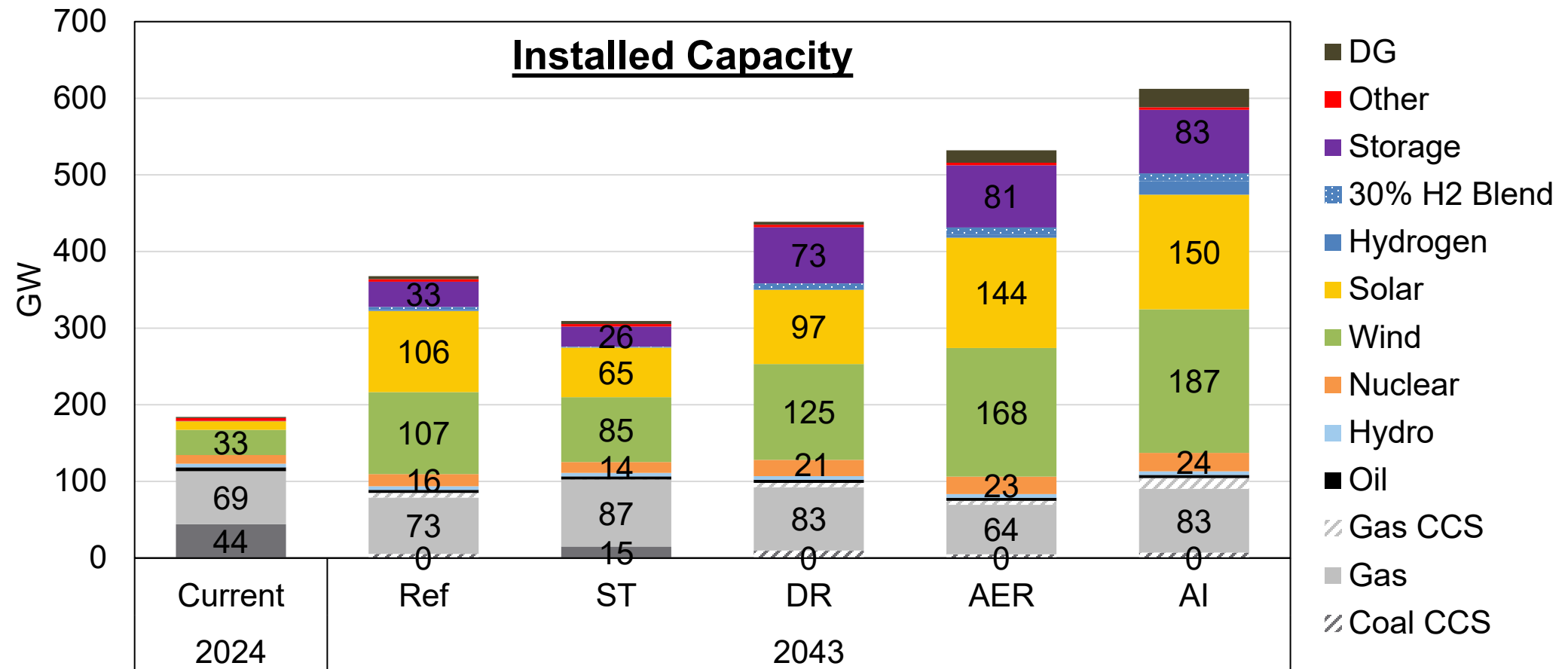
We exist to deliver safe, reliable energy that drives value to our customers

SCENARIO ANALYSIS: ALTERNATIVE SCENARIOS



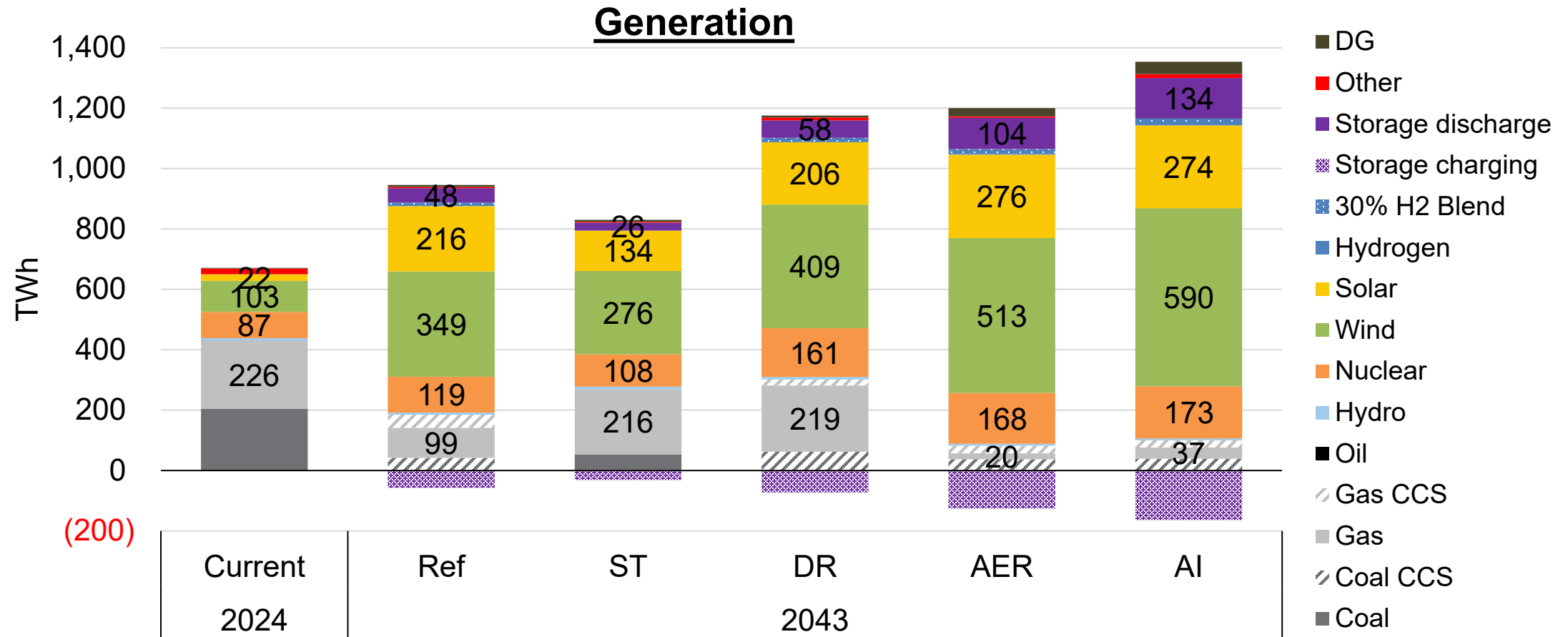
MISO CAPACITY MIX ACROSS SCENARIOS

- A significant shift towards cleaner energy resources is expected across scenarios, although dispatchable capacity is required
- Load growth, carbon price, and fuel prices impact range of resource additions across scenarios



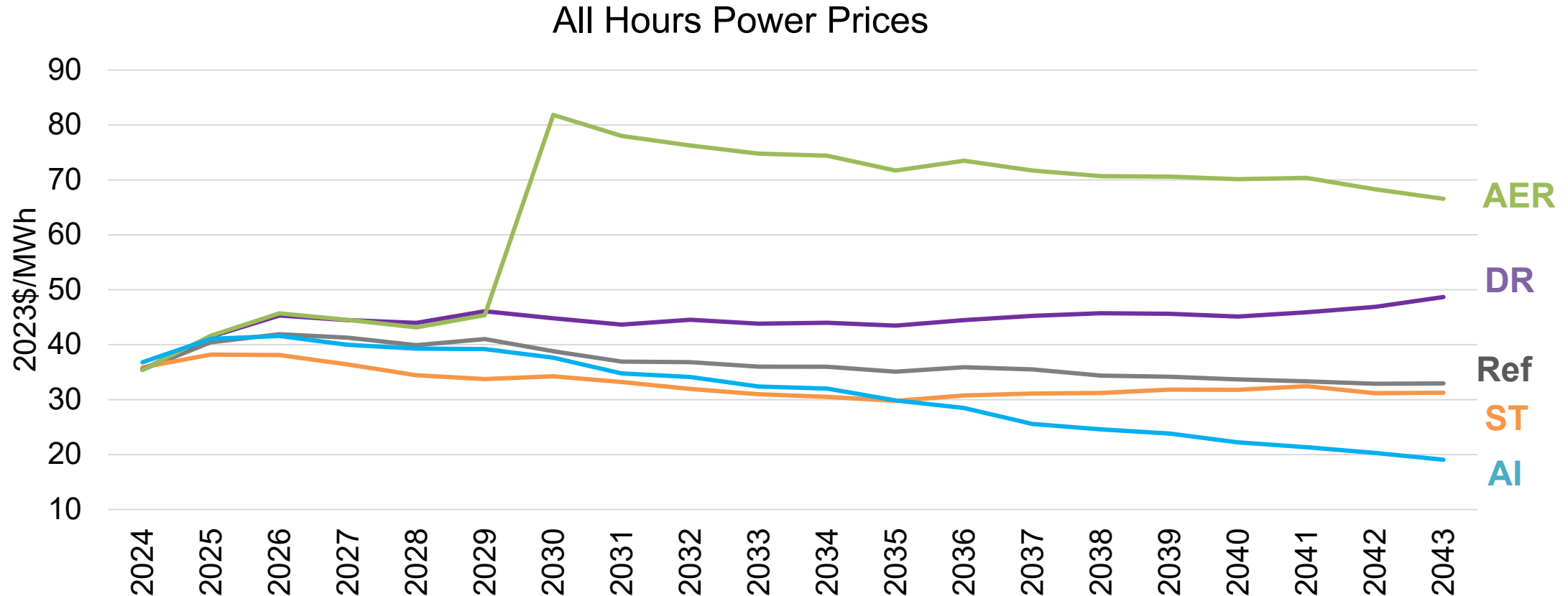
MISO MIX PROJECTED TO SHIFT SIGNIFICANTLY TOWARD CLEAN ENERGY

- Clean energy is expected to grow to 75% or higher of total MISO generation in all scenarios except for ST
- Gas generation maintains a larger role in ST and DR due to policy and load growth impacts, while emerging technologies like storage, CCS, and hydrogen have a role when load is high, policy drives CO2 emission reductions, and technology advances



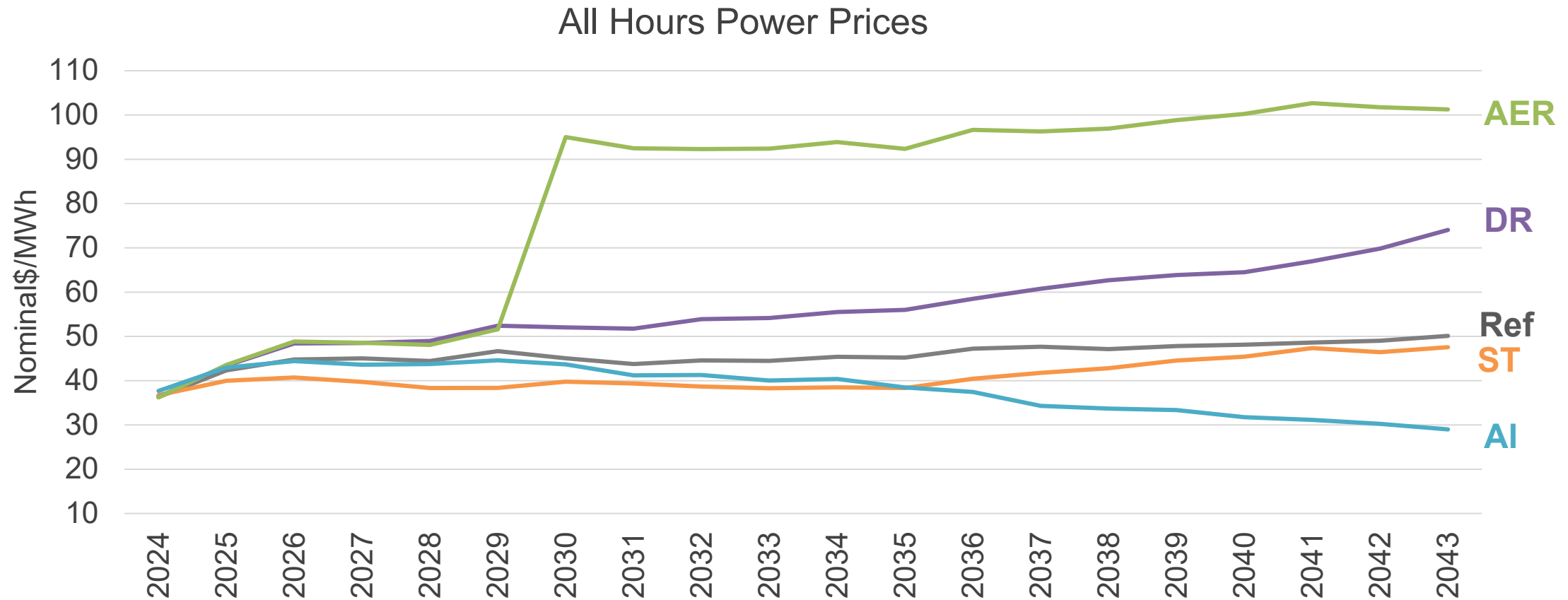
MISO ZONE 6 POWER PRICES

- Power prices are influenced by natural gas prices, carbon prices, load growth, and the regional supply mix



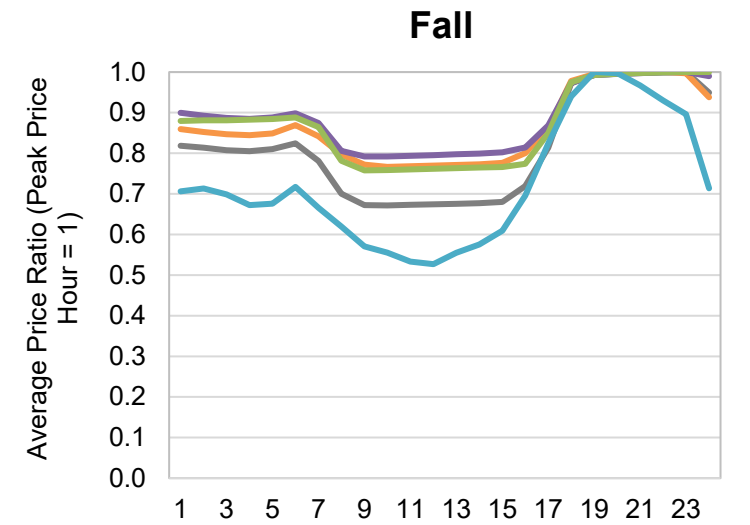
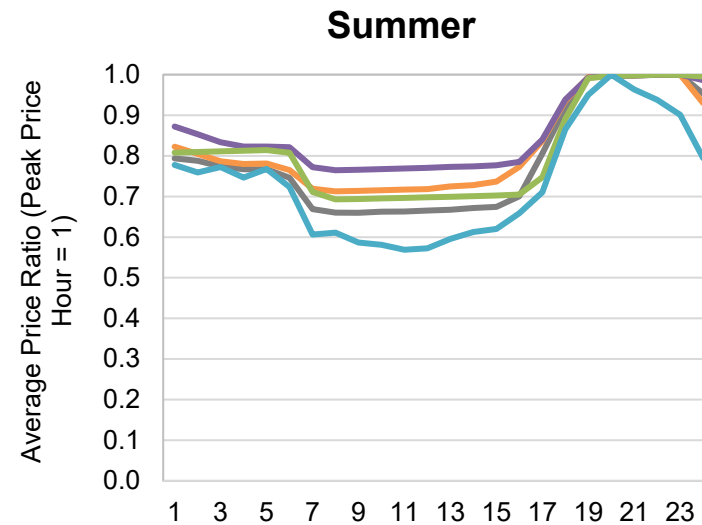
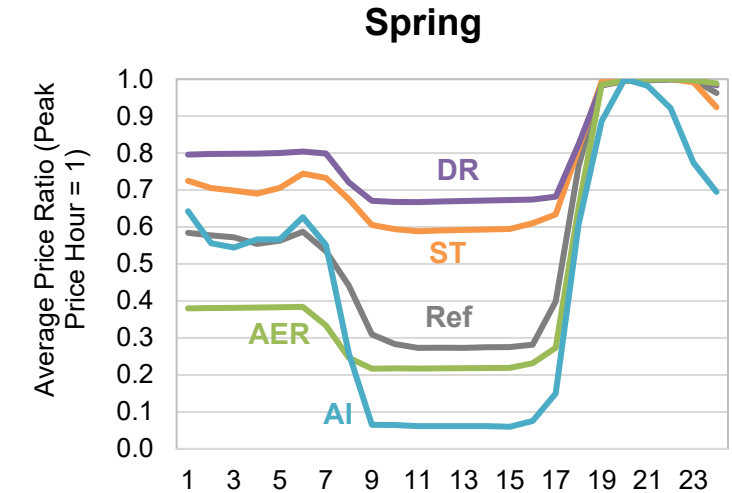
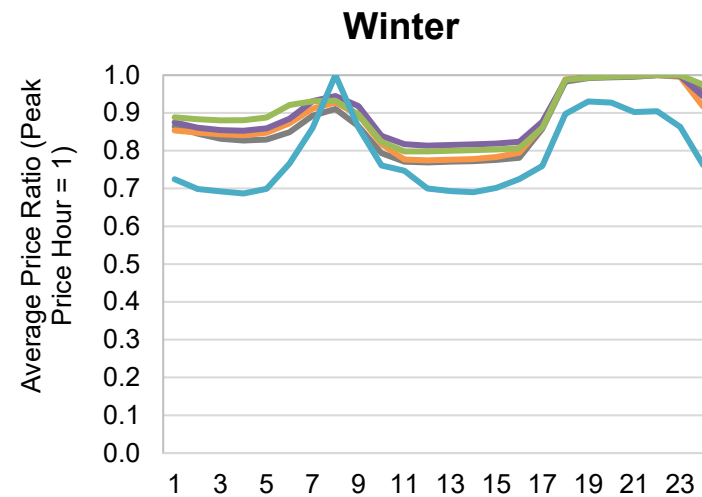
MISO ZONE 6 POWER PRICES

- Power prices are influenced by natural gas prices, carbon prices, load growth, and the regional supply mix



MISO ZONE 6 HOURLY PRICE SHAPES (2040)

- Hourly price patterns are expected to vary across scenarios, particularly as more renewables enter the system due to different gas price forecasts, policy decisions, load requirements and technology costs
 - AI exhibits the most price variance with mid-day solar-driven drops and evening and early morning spikes, particularly in the winter
 - DR and ST retain more typical seasonal price trends due to natural gas units being more frequently on the margin





We exist to deliver safe, reliable energy that drives value to our customers

STOCHASTIC ANALYSIS REVIEW: INPUTS

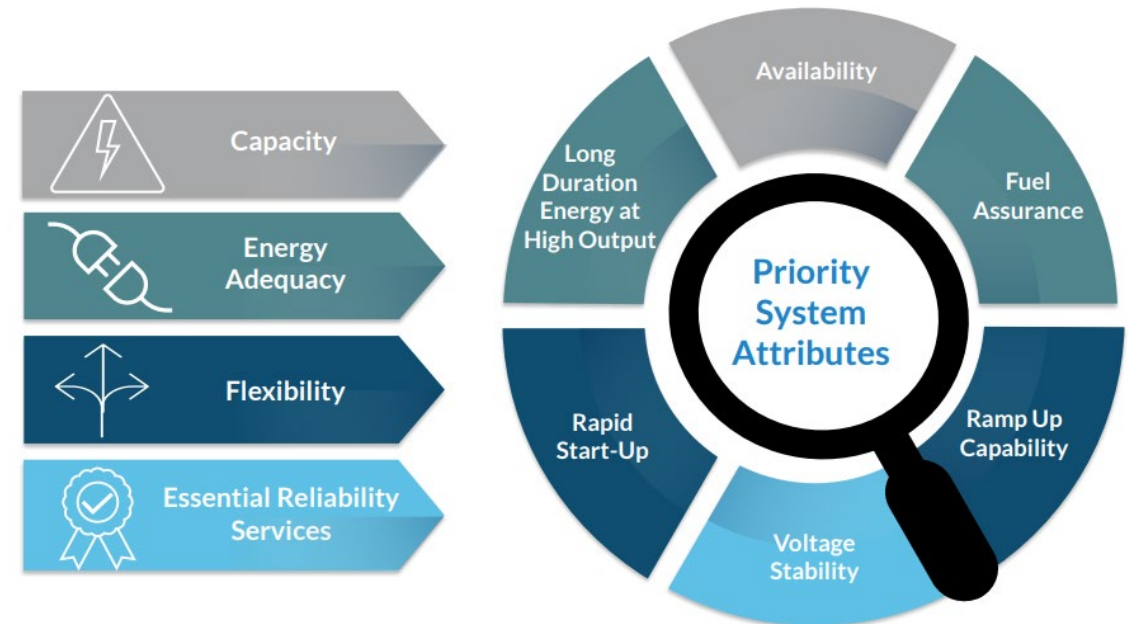
Pat Augustine, Vice President, CRA



BACKGROUND CONTEXT

- To achieve a reliable grid, planners need to address multiple risks, including:
 - Resource adequacy
 - Operational flexibility
 - Forecasting errors
- **Measuring Reliability and Resilience**
 - There is no single all-encompassing metric, but rather a suite of metrics that may be used to assess the reliability and resilience of a portfolio
- **Uncertainty**
 - All forecasting and planning is highly dependent on the characterization of uncertainty
 - It is important to assess key metrics across a range of possible outcomes

Based on insights, MISO proposes six reliability attributes as initial priorities



Source:

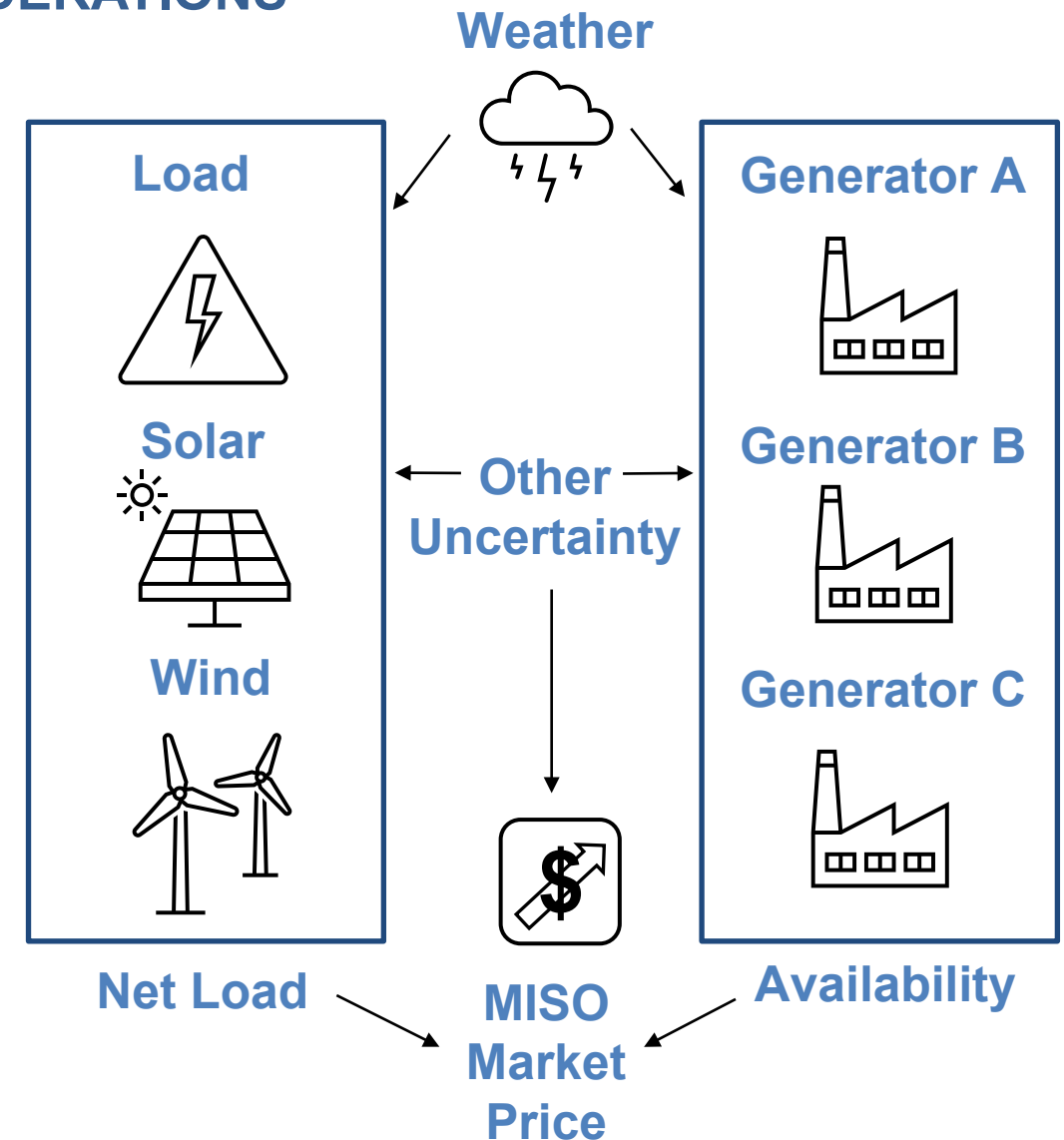
<https://cdn.misoenergy.org/20221012%20RASC%20Item%2008b%20System%20Attribute%20Overview%20Presentation626543.pdf>

MOTIVATION FOR EXPANDED STOCHASTIC RELIABILITY ASSESSMENT

- As NIPSCO's portfolio and the wider MISO market add more variable, intermittent renewable resources, system reliability planning will continue to evolve from single peak load assessments toward a more granular review of operating reliability
- MISO (and *not* NIPSCO) is ultimately responsible for setting planning reserve margin targets and capacity accreditation values and balancing the system in real time, but an understanding of emerging NIPSCO portfolio risk exposure can help ensure NIPSCO develops the best portfolio for customers:
 - Provide quantitative support for key emerging reliability metrics
 - Anticipate MISO rules changes that may impact future resource capacity accreditation and/or result in new markets for flexible capacity by assessing how well different portfolio options mitigate market exposure
- Electrification and customer behavior changes may impact typical load shapes and introduce different risk than has been observed only with historical data
 - EVs and behind-the-meter solar will substantially change the net load shape
 - New data center loads or electrification of heating will increase seasonal and hourly demand shapes

PROBABILISTIC RELIABILITY ANALYSIS CONSIDERATIONS

- Stakeholder feedback from the 2021 IRP and ongoing reliability analysis activities at MISO have influenced NIPSCO's decision to make **enhancements to its stochastic analysis process for the 2024 IRP, focused on economic and reliability metrics**
- In addition to key economic metrics associated with cost to customer, NIPSCO's reliability analysis will assess how often NIPSCO *must* rely on external resources to meet load requirements
- Key enhancements to the process will tie net load (system load and wind and solar output) and generator availability back to weather to **capture correlated events**
- Measures of the frequency and duration of forced market exposure, along with economic impacts, will be evaluated across portfolios



STOCHASTIC ANALYSIS APPROACH

1. Evaluate historical data and employ machine learning to generate a large number of potential “iterations”

Correlated
inputs

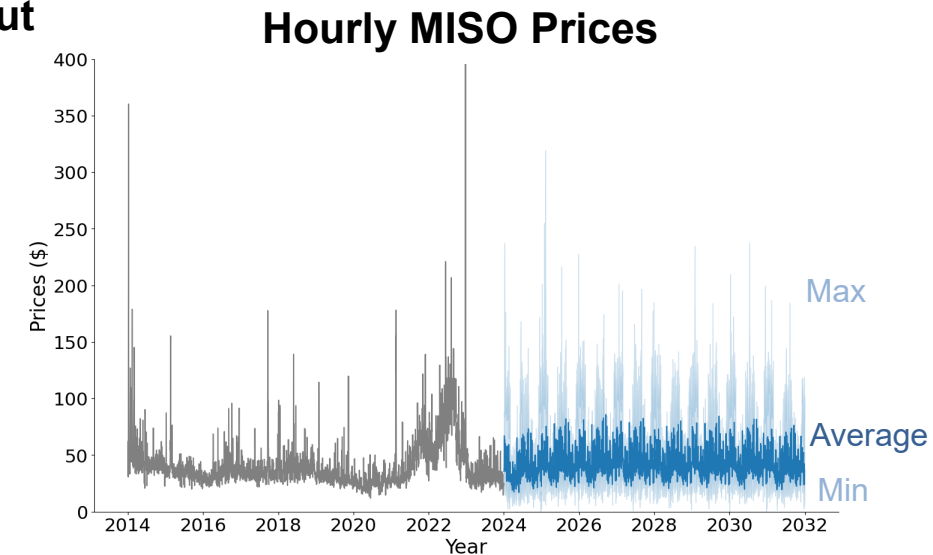
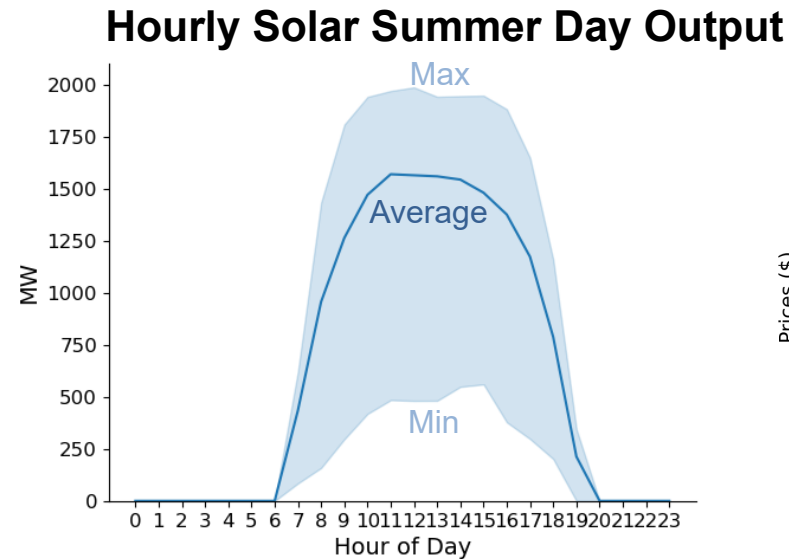
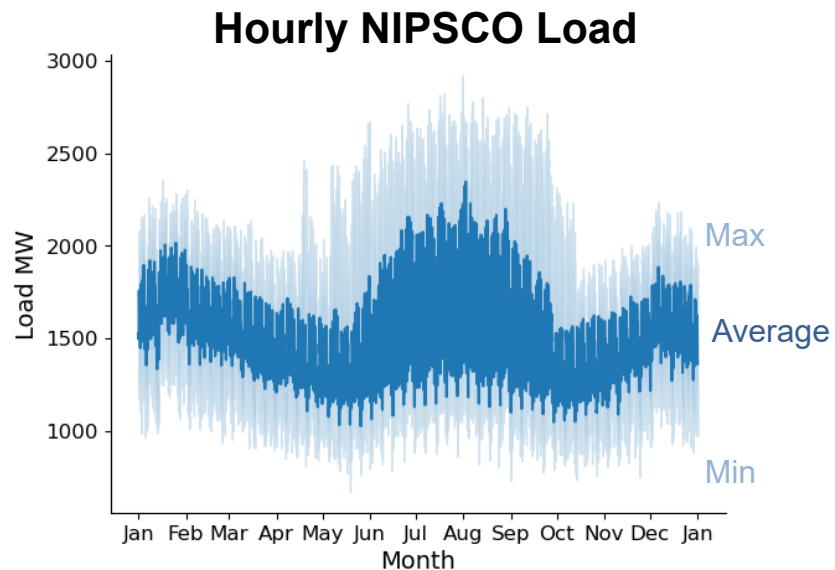
- Wind and solar output
- Energy demand - adjust for possible load futures
- Thermal unit outages
- Integration of commodity price stochastic uncertainty and market pricing data (gas prices and MISO power prices based on fundamental Aurora runs and historical time series analysis)

2. Evaluate performance of candidate portfolios against distributions

3. Record key output metrics for the scorecard

EXAMPLE INPUT DISTRIBUTIONS

- Historical hourly loads, temperature, wind speed, solar irradiance, and market prices are evaluated
- Stochastic and regression models are developed and deployed to propagate forward distributions, respecting key market correlations, such as:
 - Temperature and other weather conditions with load, renewable output, thermal availability
 - Natural gas and power prices
 - Renewable output and power prices based on fundamental forward scenario simulations
- Example distribution summaries (fuller documentation in appendix):



We exist to deliver safe, reliable energy that drives value to our customers

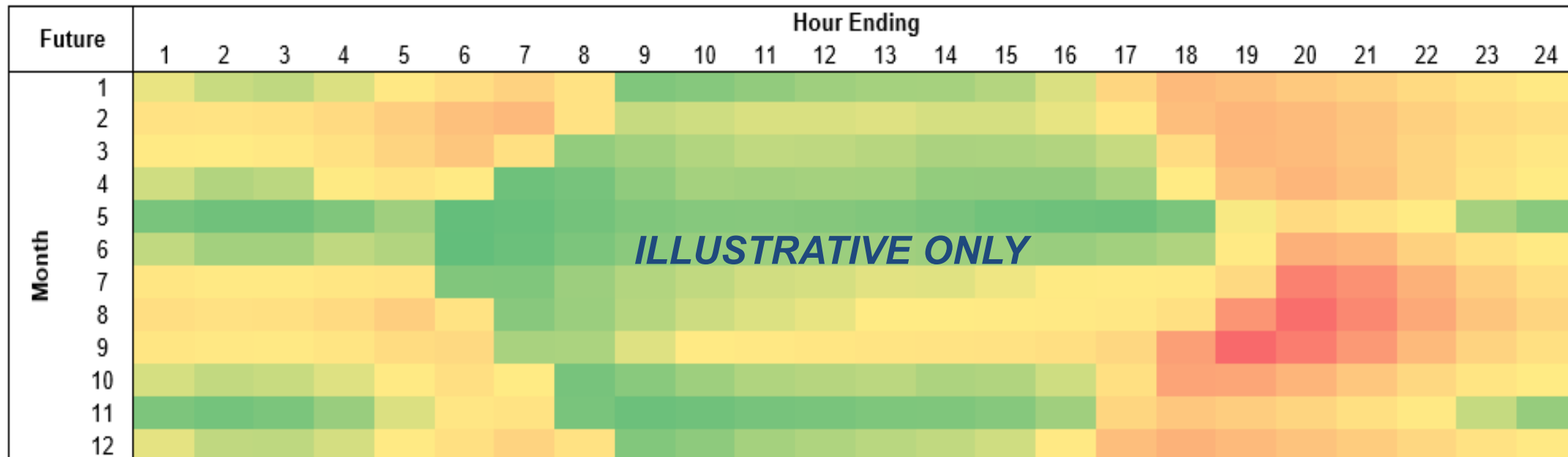
POTENTIAL SCORECARD METRICS FROM STOCHASTIC ANALYSIS

- “Forced Market Exposure”: A measurement of required exposure to the market due to insufficient available capacity in the NIPSCO system to meet load
- Cost Risk: 95th percentile of portfolio cost exposure across the distribution of outcomes
- Note that other metrics associated with Net Load requirements or other ramping needs will be available through the analysis

	Reliability and Flexibility	Cost Risk
	Forced Market Exposure	95 th Percentile Cost Risk OR Value at Risk
<i>Year Ref.</i>	2030	2030
<i>Units</i>	MWh	\$
Portfolio 1		
Portfolio 2		
Portfolio 3		
Portfolio 4		

VISUAL RISK SUMMARIES CAN ASSESS TIMING OF RISKS VS. BROADER MISO DATA

- Periods of forced market exposure can be visualized by time of year and time of day, with hours shaded green having less exposure to the market and hours shaded red having the most significant exposure to the market





We exist to deliver safe, reliable energy that drives value to our customers

BREAK





We exist to deliver safe, reliable energy that drives value to our customers

PRELIMINARY RFP RESULTS REVIEW

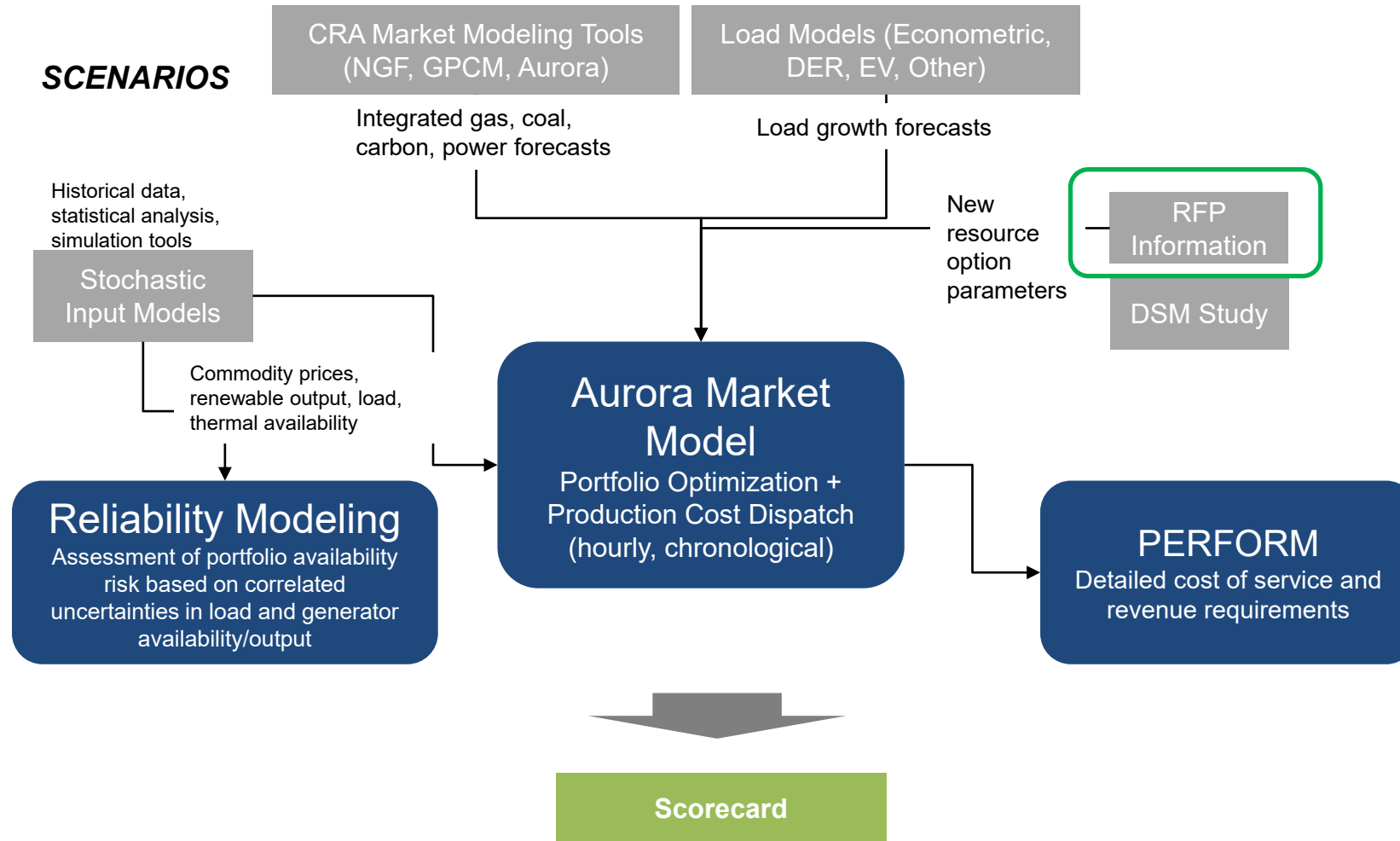
Patrick d'Entremont, Manager Planning Commercial Support, NIPSCO

Bob Lee, Vice President, CRA



RESOURCE PLANNING APPROACH

Key Modeling and Analysis Tools



- 1 Identify key planning questions and approach
- 2 Develop market perspectives (external scenarios)
- 3 Develop integrated resource strategies (NIPSCO portfolios)
- 4 Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- 5 Evaluate trade-offs and select preferred plan

OVERVIEW OF NIPSCO'S 2024 REQUEST FOR PROPOSAL ("RFP") PROCESSES

- On May 1, 2024 NIPSCO issued a series of Requests for Proposal (RFP) processes designed to identify resources positioned to support the Company's near and long-term resource requirements.
- These separate solicitations were executed in parallel with each individual RFP targeting different technologies and resource categories.
- As has been done in the past, asset cost, performance and resource availability by technology derived from RFP bids will be used as inputs into the Company's resource planning process to create a "Preferred Plan" informed by actual market data.

OVERVIEW OF NIPSCO'S 2024 REQUEST FOR PROPOSAL ("RFP") PROCESSES

NIPSCO issued four 2024 Requests for Proposals on May 1st:

- 1. RFP1 and RFP2** together targeted both renewable and dispatchable resources under an All-Source RFP umbrella. Through these RFP, the company targeted approximately 1,000 MW of resources located in, or deliverable to LRZ6. NIPSCO is seeking transmission- interconnected, supply side resources including solar, wind, thermal and storage options in support of the Company's resource requirements
 - As part of the All-Source RFP, the Company is also seeking a development partner for storage resources located at NIPSCO's Schaefer, Michigan City and other sites.
 - Through the All-Source RFP, NIPSCO solicited bids related to emerging technologies including but not limited to long-duration storage, hydrogen fueled CC or CT and other technologies.
- 2. RFP3**, the Bridge Resource RFP, called for resources positioned to support potential NIPSCO needs related to emerging, near-term, large-scale customer loads. The Company is targeting 600-1,000 MW of capacity or capacity and energy resources that can be available within 18-36 months from LRZ6 or neighboring MISO zones and will consider short and long-term resource options including ZRC, physical resources or financial arrangements
- 3. RFP4**, targeted Distributed Energy Resources (DER). NIPSCO is considering up to 10 MW of distribution or transmission interconnected resources qualifying for bonus credits under the Inflation Reduction Act

OVERVIEW OF NIPSCO’S 2024 REQUEST FOR PROPOSAL (“RFP”) PROCESSES

----- All-Source RFP -----

Element	RFP1 – Intermittent	RFP2 – Dispatchable	RFP3 – Bridge Resource	RFP4 – DER
✓ Issue RFP	May 1, 2024	May 1, 2024	May 1, 2024	May 1, 2024
✓ Bidder Information Session	May 6, 2024	May 6, 2024	May 6, 2024	May 6, 2024
✓ Pre-Qualification Deadline	May 15, 2024	May 15, 2024	May 15, 2024	May 15, 2024
✓ Notification of Pre-Qualification	May 20, 2024	May 20, 2024	May 20, 2024	May 20, 2024
✓ Proposals Due	June 7, 2024	June 7, 2024	June 7, 2024	June 20, 2024

- Bids for RFP 4 (the DER RFP) were received on June 20th and are still in the early stages of review.

NIPSCO 2024 RFPS: OVERVIEW OF PROPOSALS RECEIVED

- 53 individual projects across three states with ~9.2 GW (ICAP) represented



We exist to deliver safe, reliable energy that drives value to our customers

NIPSCO 2024 RFPS: OVERVIEW OF PROPOSALS RECEIVED

- **Proposals for RFP 1-3 were received on June 7, 2024**
- **The RFP generated a tremendous amount of bidder interest**
- **109 total proposals were received across a range of deal structures**
- **53 individual projects across three states with ~9.2 GW (ICAP) represented**
 - Many of the proposals offer variations on pricing structure and term length
 - Several instances of renewables paired with storage
 - Majority of the projects are in various stages of development

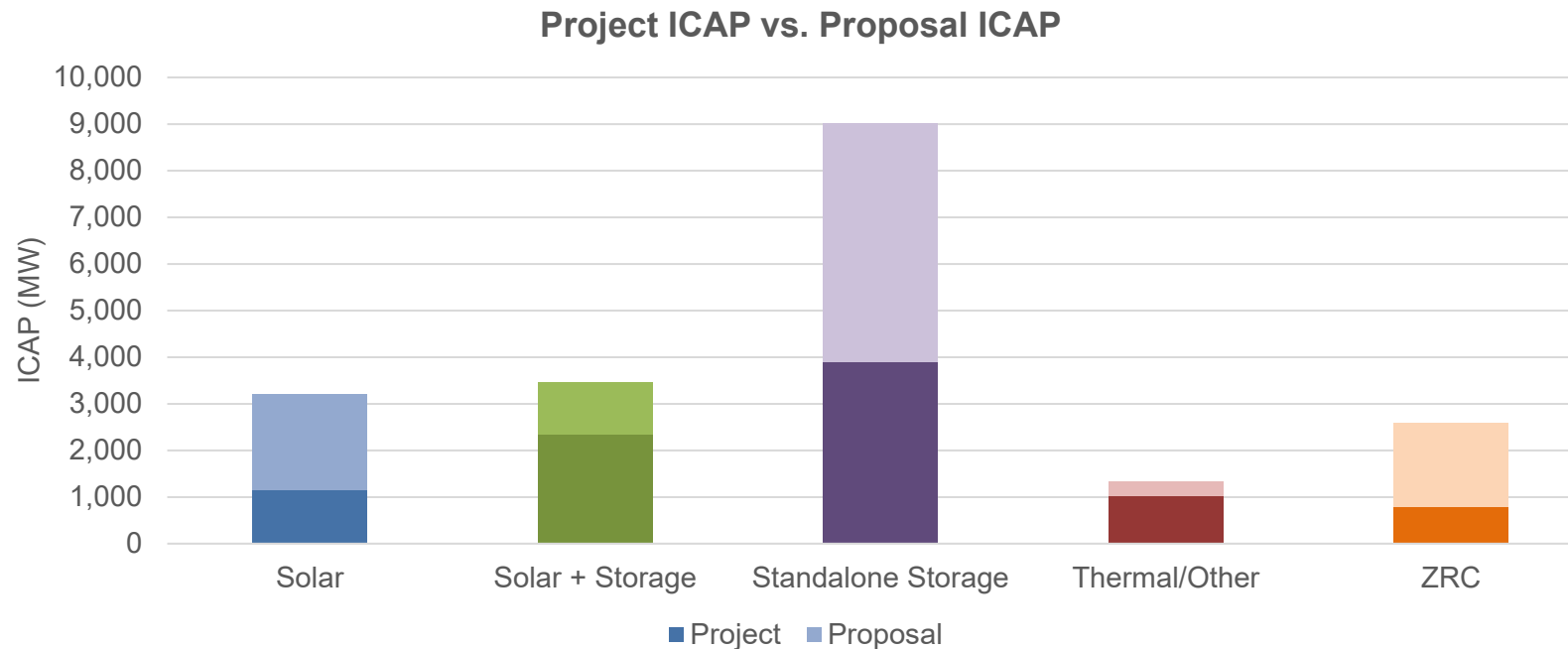
Count of Proposals by Technology and Deal Structure

							Preliminary
Deal Structure	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Wind	Total
Asset Sale	1	3	16	2	-	-	22
PPA/Toll	17	12	32	5	7	-	73
Asset Sale + PPA/Toll	1; 1	3; 3	3; 3	-	-	-	7 (14)
Total Count	20	21	54	7	7	-	109*
Locations	IN, KY	IN, KY	IN, KY	IN, PA	LRZ4, PJM	-	

**Proposal count includes mutually exclusive projects. Projects offered as both Asset Sale and PPA/Toll are counted in the total as two proposals.*

NIPSCO 2024 RFPS: PROJECTS VS. PROPOSALS

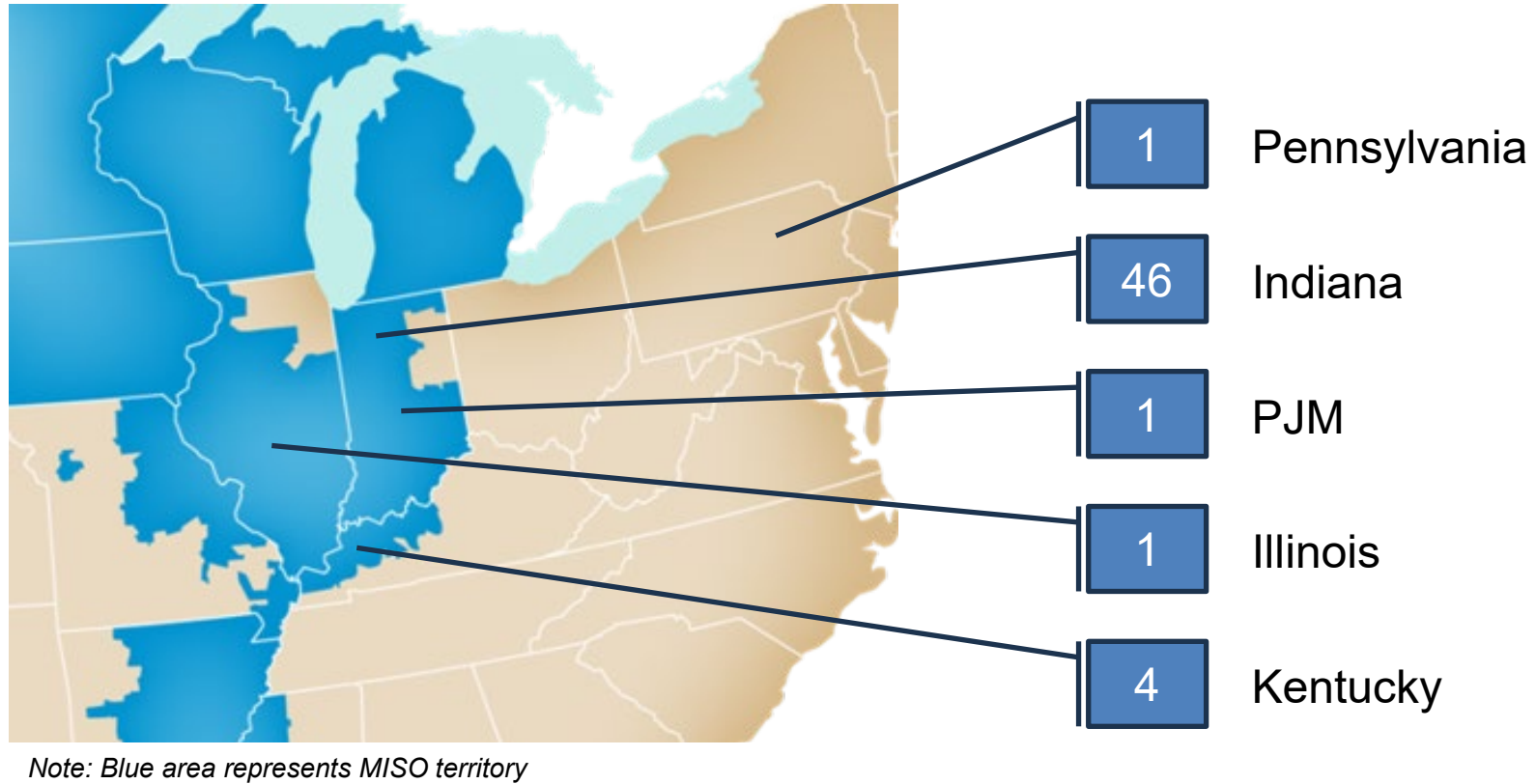
- 53 individual projects across three states with ~9.2 GW (ICAP) represented
- 109 different proposal structures between the 53 individual projects, totaling ~19.6 GW



ICAP (MW)	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Total (MW)
Project	1,156	2,334	3,892	1,024	800	9,205
Proposal	3,211	3,460	5,592	1,324	2,600	19,603

Preliminary

NIPSCO 2024 RFPS: DISTRIBUTION OF PROJECTS RECEIVED



Preliminary

We exist to deliver safe, reliable energy that drives value to our customers

NIPSCO 2024 RFPS: OVERVIEW OF PROJECTS RECEIVED

- 53 individual projects were bid into the RFP across three states with ~9.2 GW (ICAP)
- There were no wind projects bid into the RFP

Project MW ICAP by Location and Technology

Preliminary

Location	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Wind	Total (MW)
Indiana	1,056	2,059	3,692	954	-	-	7,760
Kentucky	100	275	200	-	-	-	575
Pennsylvania	-	-	-	70	-	-	70
LRZ4, PJM	-	-	-	-	800	-	800
Total (MW)	1,156	2,334	3,892	1,024	800	-	9,205

NIPSCO 2024 RFPS: PPA OVERVIEW

Proposal MW ICAP by PPA Term Length (PPA or Both) and Technology						<i>Preliminary</i>
Term (Years)	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Total (MW)
1	-	-	-	-	800	800
2	-	-	-	150	800	950
3	-	-	-	-	800	800
4	-	-	-	-	200	200
5	-	-	-	450	-	450
6-15	201	300	796	-	-	1,297
>15	2,680	2,154	4,701	636	-	10,171
Total	2,881	2,454	5,497	1,236	2,600	14,668

NIPSCO 2024 RFPS: STORAGE OVERVIEW

- NIPSCO received bids for storage both as standalone projects and integrated with solar facilities
- Eleven (11) of the standalone storage projects (1,512 MW of ICAP) are proposals to add storage to existing NIPSCO sites

Storage Project MW ICAP by State and Type

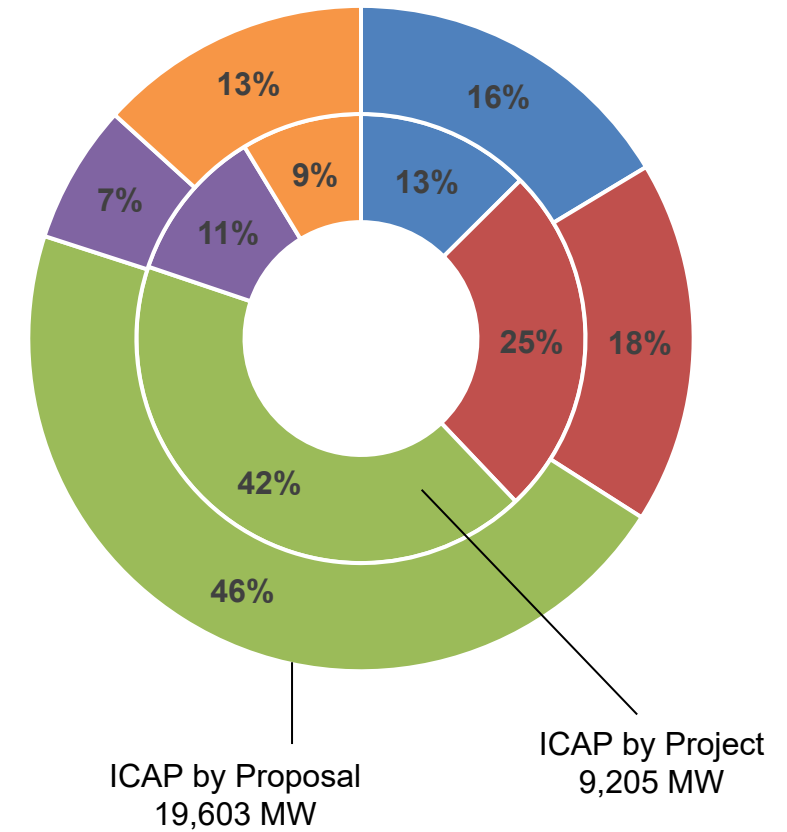
State	Standalone Storage (MW)	Solar + Storage (Storage MW)	Preliminary
			Solar + Storage (Solar MW)
Indiana	3,692	1,185	2,059
Kentucky	200	275	275
Total (MW)	3,892	1,460	2,334

NIPSCO 2024 RFPS: ALLOCATION OF PROPOSALS AND PROJECTS BY TECHNOLOGY

Allocation by Technology (MW ICAP)

Preliminary

	ICAP by Project		ICAP by Proposal	
	MW	%	MW	%
Solar	1,156	13%	3,211	16%
Solar + Storage	2,334	25%	3,460	18%
Standalone Storage	3,892	42%	9,009	46%
Thermal/Other	1,024	11%	1,324	7%
ZRC	800	9%	2,600	13%
Total (MW)	9,205	100%	19,603	100%



NIPSCO 2024 RFPS: SUMMARY OF PRICING

Average Weighted Pricing by Technology & Deal Structure

Preliminary

Technology	Asset Sale		Power Purchase Agreement			Comments
	\$/kW	Count	PPA \$/MWh	\$/kW-Mo	Count	
Solar	\$[REDACTED]	2	\$72.03	-	18	Asset Sale price redacted for confidentiality reasons.
Solar + Storage	\$3,472	6	\$70.98	\$11.18	15	
Standalone Storage	\$1,771	19	-	\$12.97	35	11 (of 25) standalone storage <u>projects</u> are for NIPSCO sites. The total ICAP for these is 1,512 MW with a weighted average price of \$1,740 \$/kW
Thermal/Other	\$[REDACTED]	2	-	\$9.32	5	Asset Sale price redacted for confidentiality reasons.
ZRC	-	-	-	\$5.05	7	

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, O&M and CapEx (where applicable)
- 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

We exist to deliver safe, reliable energy that drives value to our customers

RFP 4: DISTRIBUTED ENERGY RESOURCES

- **Bids into RFP 4 for Distributed Energy Resources (“DER”) were received on June 20th and are still under initial review. The bids consisted of the following:**
 - **Three counterparties submitted proposals**
 - **Five Indiana facilities were bid into the RFP (1 Standalone Storage facility, 1 Solar + Storage facility, and 3 Solar facilities)**
 - **Six proposals total (2 Tolling Arrangements, 4 PPA)**
 - **At a first glance, the facilities may qualify for the following benefits under the Inflation Reduction Act:**
 - **Low-Income Communities Bonus Credit Program**
 - **Energy Community Tax Credit Program**
 - **Domestic content requirements by using a significant portion of materials and equipment sourced from within the United States**

NIPSCO 2024 RFPS: NEXT STEPS IN RFP EVALUATION PROCESS

- **June 8, 2024:** Start of Bid Evaluation Period (currently in progress)
- **Q3 2024:** Bid Evaluation Period Completed (tentative)
- **Q4 2024:** Definitive Agreements Signed with Bidders (tentative)
- Bid evaluation considers both cost and non-cost factors
 - Asset Cost – levelized cost of energy (“LCOE”) or levelized cost of capacity (“LCOC”)
 - Facility Reliability and Deliverability
 - Development Risk
 - Asset Specific Benefit and Risk Factors
- Representative cost and performance characteristics by technology will be developed based on RFP bids and provided to the IRP team for portfolio optimization modeling
- IRP to determine the preferred portfolio for execution



We exist to deliver safe, reliable energy that drives value to our customers

CLOSING



2024 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 April 23	Meeting 2 June 24	Meeting 3 August 21	Meeting 4 September 19	Meeting 5 October 8
Location	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943
Content	• 2021 Short Term Action Plan Update (Retirements, Replacement projects) • Resource Planning and 2024 Continuous Improvements • 2024 Public Advisory Process • 2024 Policy Update (incl. IRA and EPA) • Update on Key Inputs/Assumptions (core demand forecast, new considerations for demand) • Scenario Themes – Introduction • RFP Overview	• MISO Regulatory Developments and Initiatives • Load Scenarios • Update on Key Inputs/Assumptions (commodity prices) • Scenarios and Stochastic Analysis • Preliminary RFP Results	• DSM Modeling and Methodology • DER Inputs	• Modeling Results, Scorecard • DER and Storage Modeling Results, Scorecard	• Preferred Replacement Path and logic relative to alternatives • 2024 NIPSCO Short Term Action Plan
Meeting Goals	• Communicate what has changed since the 2021 IRP (incl. IRA changes) • Communicate environmental policy considerations • Communicate updates to key inputs/assumptions • Provide RFP overview • Communicate the 2024 public advisory process, timing, and input sought from stakeholders	• Communicate resource needs due to potential demand • Common understanding of MISO regulatory updates • Communicate scenario themes and stochastic analysis approach, along with major input details and assumptions • Communicate commodity prices impacts • Communicate preliminary RFP results	• Common understanding of DSM modeling methodology • Explain next steps for portfolio modeling	• Develop a shared understanding of economic modeling outcomes and preliminary results to facilitate stakeholder feedback	• Respond to key stakeholder comments and requests • Communicate NIPSCO's preferred resource plan and short-term action plan • Obtain feedback from stakeholders on preferred plan

We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

APPENDIX: NIPSCO LOAD SCENARIOS



STATE OF INDIANA – DATA CENTER SALES TAX EXEMPTION

DATA CENTER GROSS RETAIL AND USE TAX EXEMPTION

- Provides a sales and use tax exemption on purchases of qualifying data center equipment and energy to operators of a qualified data center for a period not to exceed 25 years for data center investments of less than \$750M.
- If the investment exceeds \$750M, the Indiana Economic Development Corporation (“IEDC”) may award an exemption for up to 50 years.
- This program is established by Indiana Code § 6-2.5-15. Local governments may also provide a personal property tax exemption on qualified enterprise information technology equipment to owners of a data center who invest at least \$25M in real and personal property in the facility.

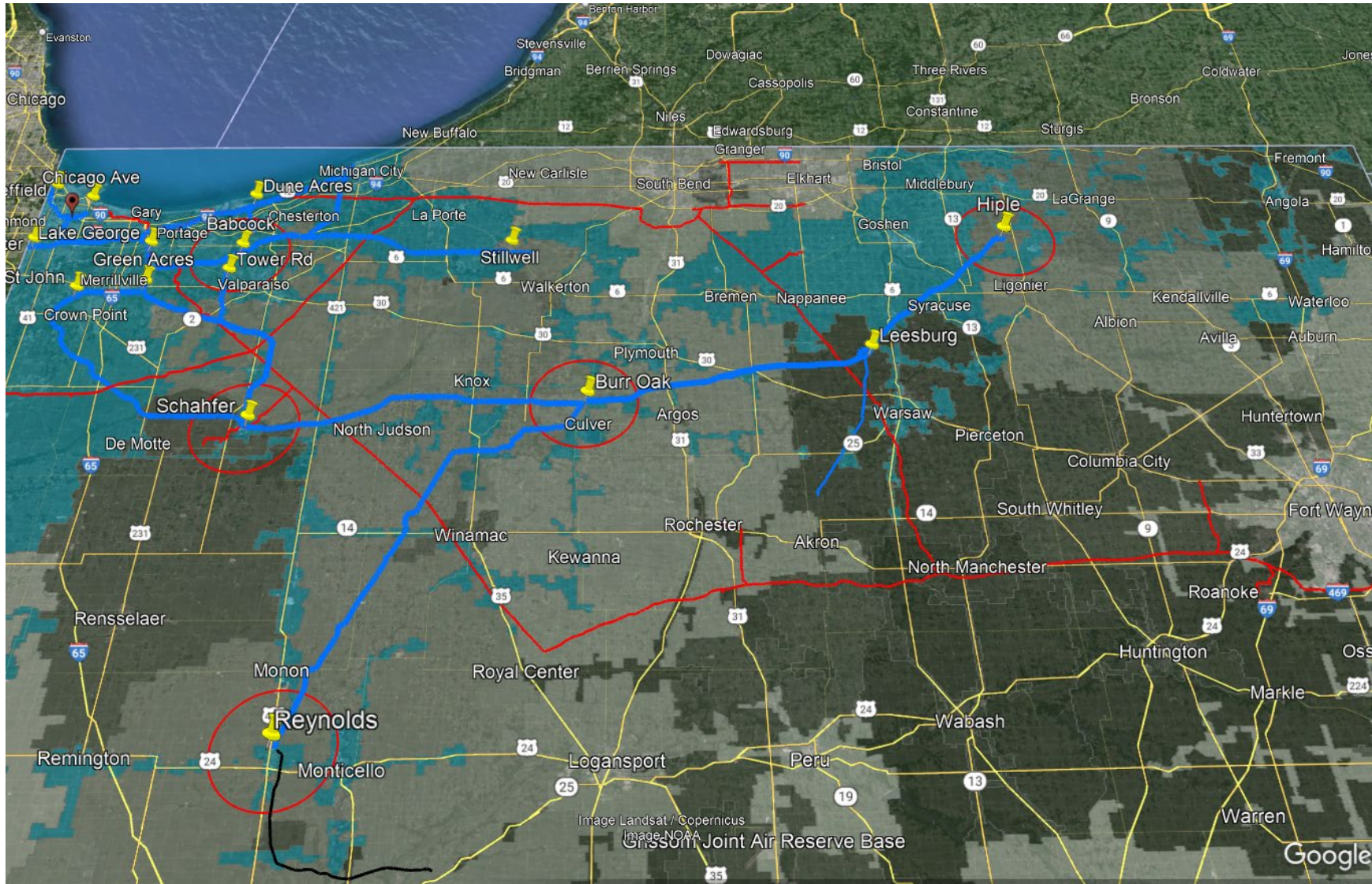
ELIGIBILITY

- To qualify for the exemptions, data centers must reach a certain threshold for investment within 5 years of receiving an exemption certificate from the Indiana Department of Revenue. The minimum investment required is determined by the population of the county in which the qualified data center is located:
 - \$25M in counties with less than 50,000 people
 - \$100M in counties between 50,000 and 100,000 people
 - \$150M in counties with 100,000 or more people
- Equipment that is eligible for the exemption includes the servers and related computer equipment or software purchased or leased for the processing, storage, retrieval or communication of data, as well as other equipment essential to the operation of the data center. This includes electricity used in qualified data center operations. Prior to qualifying for an exemption, the IEDC must approve all planned data center equipment purchases.

OTHER INDIANA INCENTIVES IN THE AREAS OF:

- **JOB CREATION AND
BUSINESS INVESTMENT**
- **REDEVELOPMENT AND
QUALITY OF PLACE**
- **INNOVATION AND
ENTREPRENEURSHIP**
- **RESEARCH AND
DEVELOPMENT**
- **SKILLS TRAINING**

STATE-LEVEL OVERVIEW OF RECOMMENDED SITES

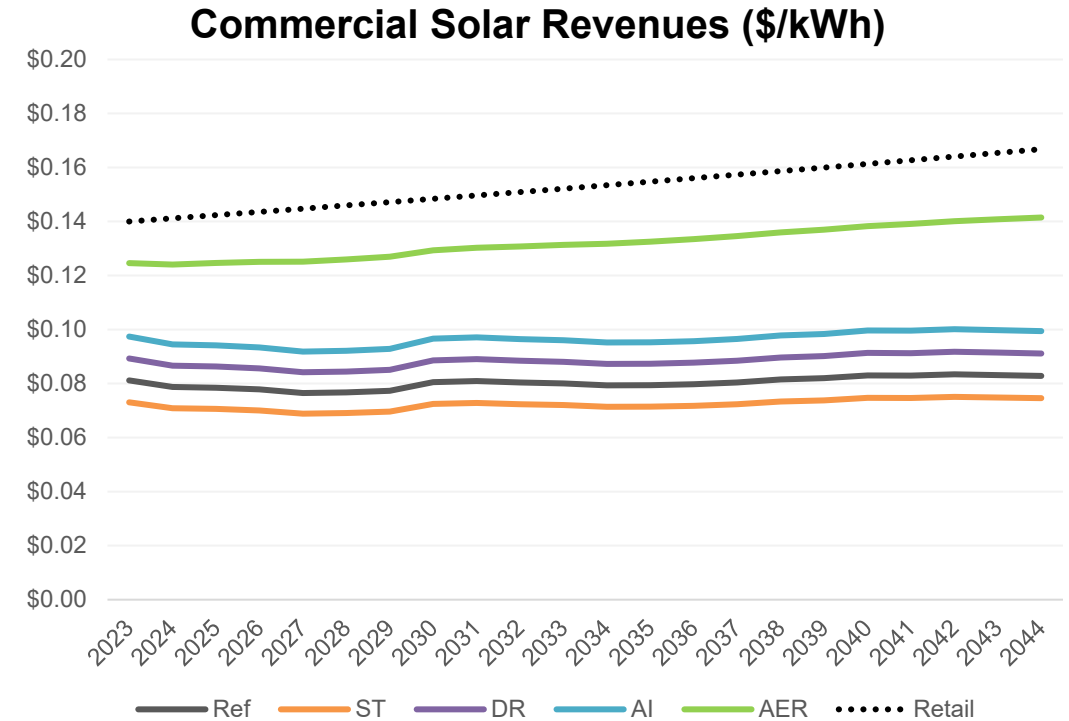
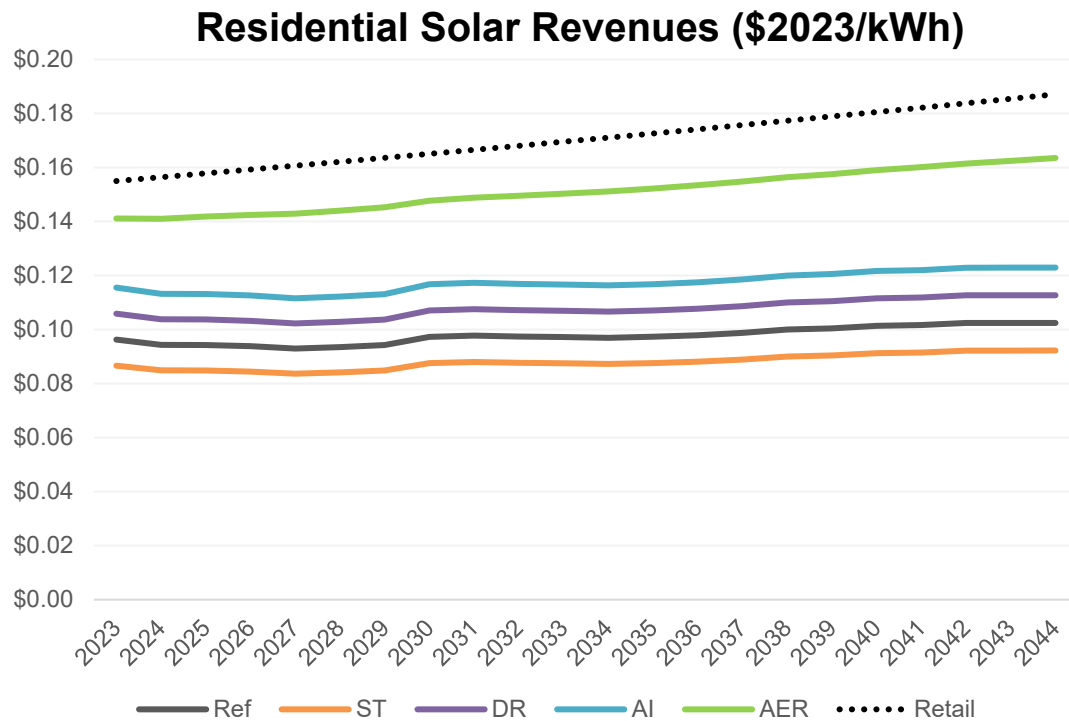


- Blue shaded area indicates NIPSCO electric service territory
- Blue lines represent 345kv circuits
- Yellow pins represent large transmission substations
- Red lines represent large transmission gas lines
- Red circles indicate 5-mile radius around substations = Strategic Target Areas

We exist to deliver safe, reliable energy that drives value to our customers

DER SCENARIO ASSUMPTIONS – SOLAR AVOIDED COSTS / REVENUES

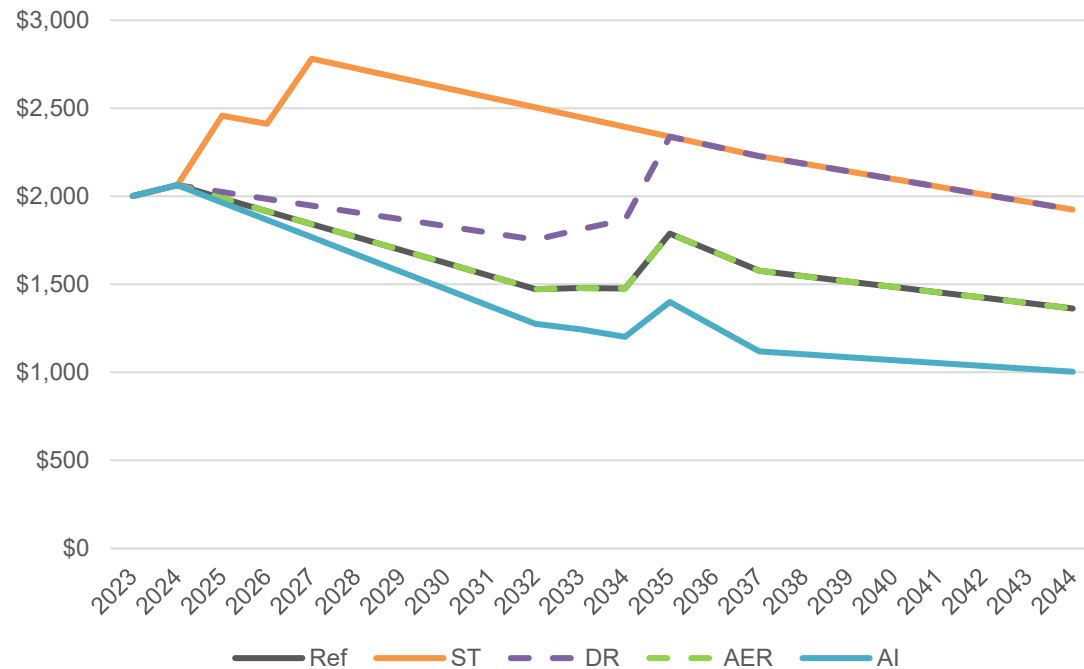
- Both avoided retail rate costs and wholesale rate revenues (EDG compensation) are relevant to customer economics
- For modeling purposes, a range of assumed wholesale energy prices were estimated to develop an all-in avoided cost/revenue projection for residential and commercial customers



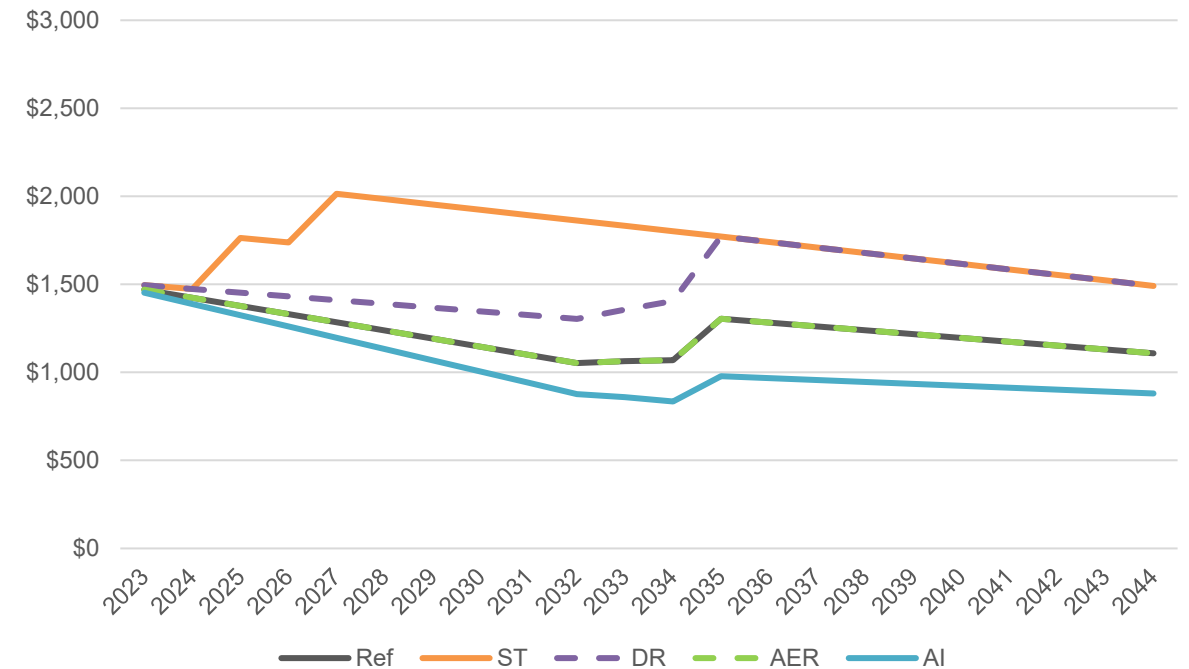
DER SCENARIO ASSUMPTIONS – PV SYSTEM CAPITAL COSTS

- 2023 NREL Annual Technology Baseline was used for DER capital costs:
 - Reference and AER:** NREL ATB moderate forecast with IRA ITC
 - AI:** NREL ATB advanced cost forecast with IRA ITC
 - DR:** NREL conservative cost forecast with IRA ITC
 - ST:** NREL conservative cost forecast with near-term IRA phase-out

Residential Rooftop PV Capital Costs (\$2023/kW)



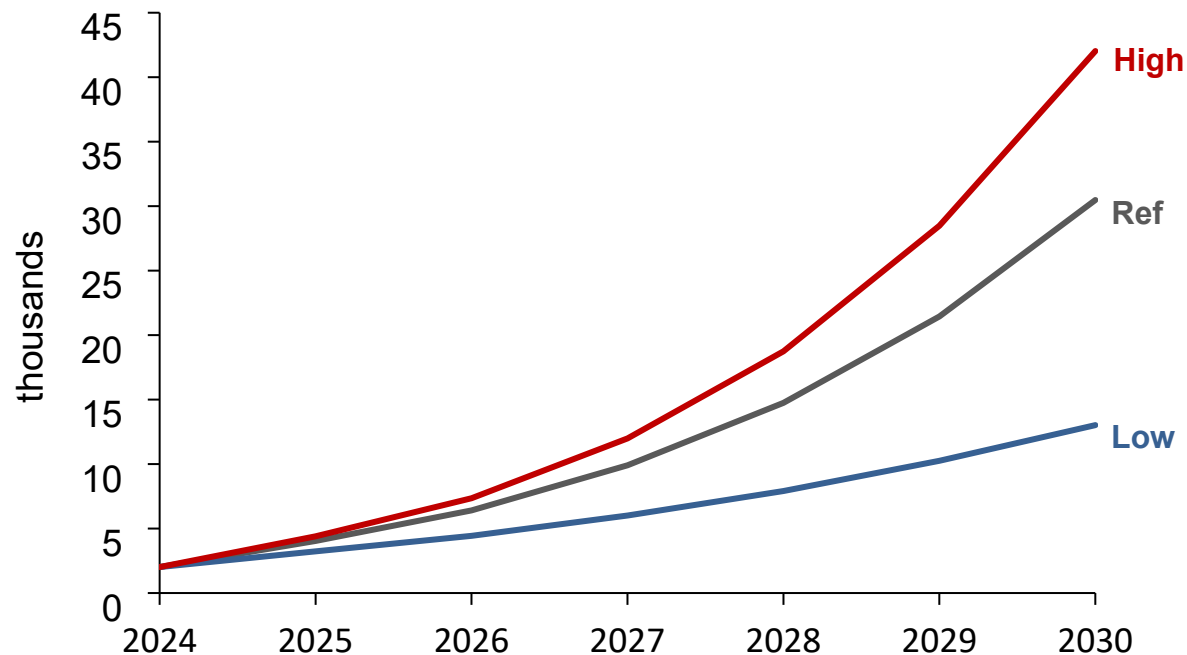
Commercial Rooftop PV Capital Costs (\$2023/kW)



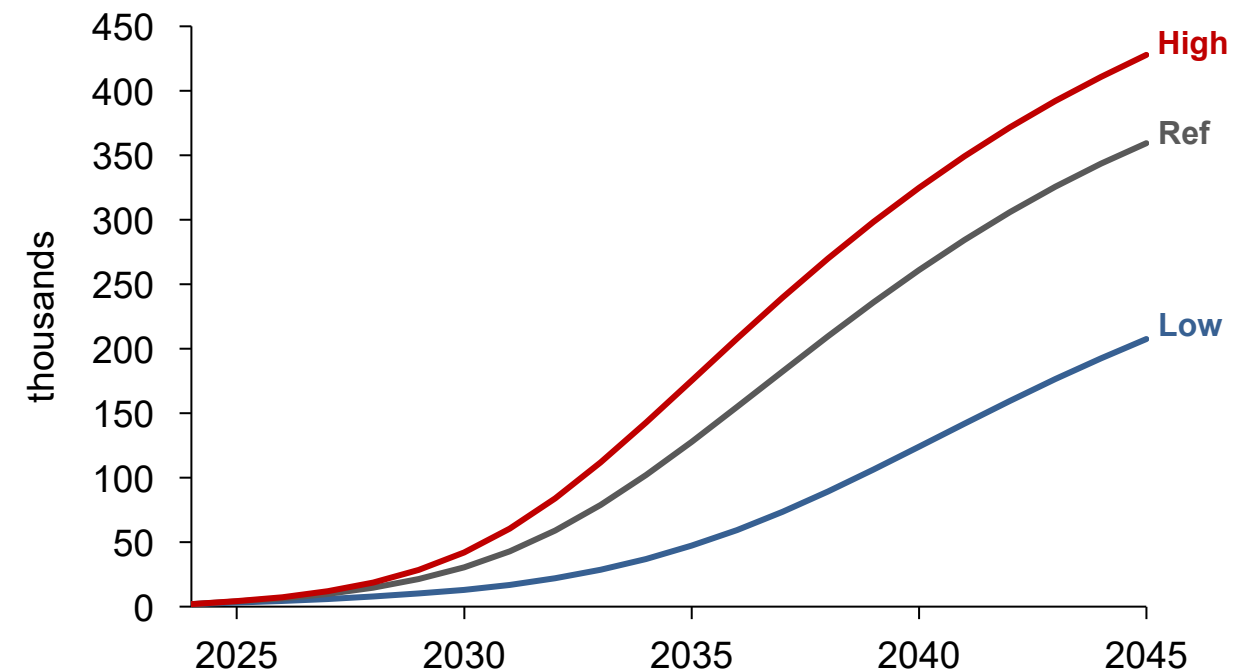
HIGH AND REFERENCE LDV ADOPTION SCENARIOS MEET NEW EPA TARGETS

- Scenarios are crafted to pulse the inflection year and final share of EVs as a % of new LDV sales
- Reference and High cases would meet U.S. EPA standards announced in March 2024

Number of EVs registered
'24-'30 timeframe detail



Number of EVs registered
Full forecast period



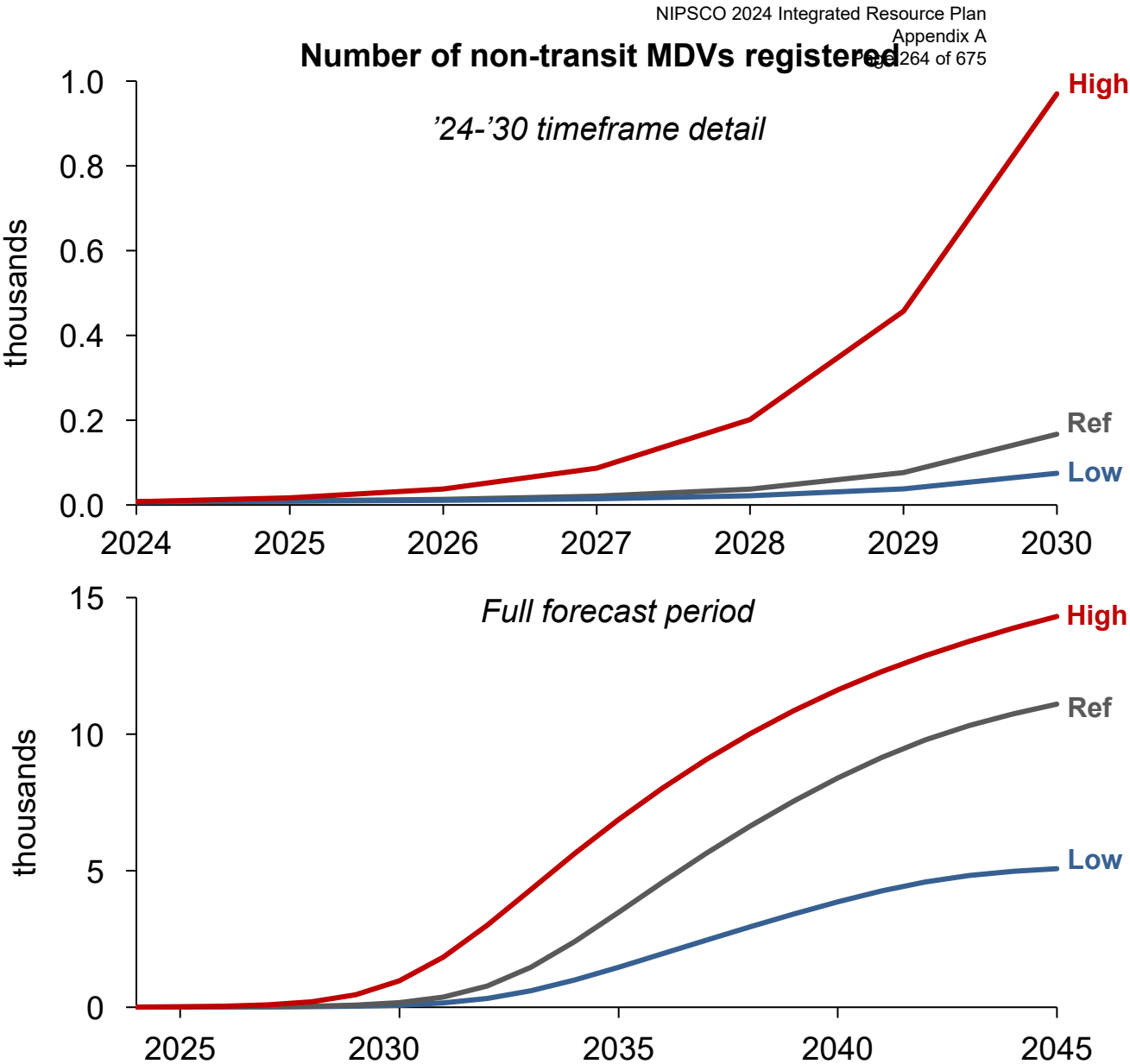
MDV (NON-TRANSIT) EV FORECAST

Near-term Trends

- NIPSCO has baselined the existing MDV fleet using EV registration data from the Indiana Fuel Dashboard
- NIPSCO has crafted an approach that uses ICE vehicle turnover (assuming 10-year avg lifespan) and EVs as a % of new MDV vehicle sales to estimate the number of EVs on the road in a given year.
- Scenarios are crafted to pulse the inflection year and final share of EVs as a % of new MDV sales

Long-term Trends

- NIPSCO anticipates moderated adoption compared to LDVs, as some MDVs may be difficult to decarbonize with limited EV options available



MDV (TRANSIT) EV FORECAST

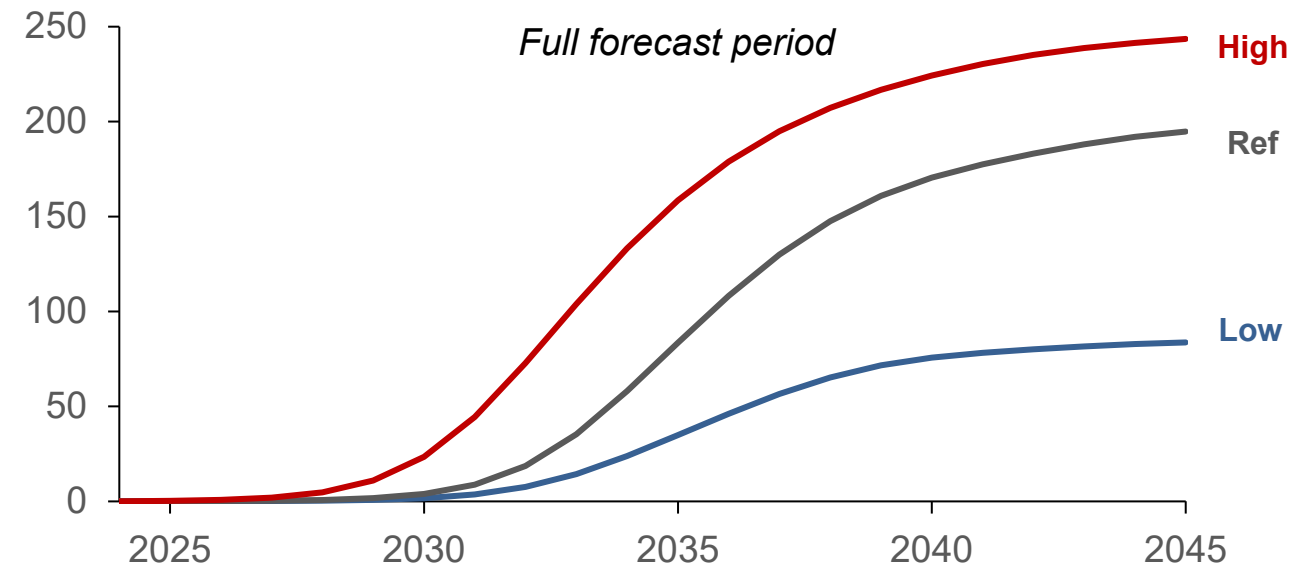
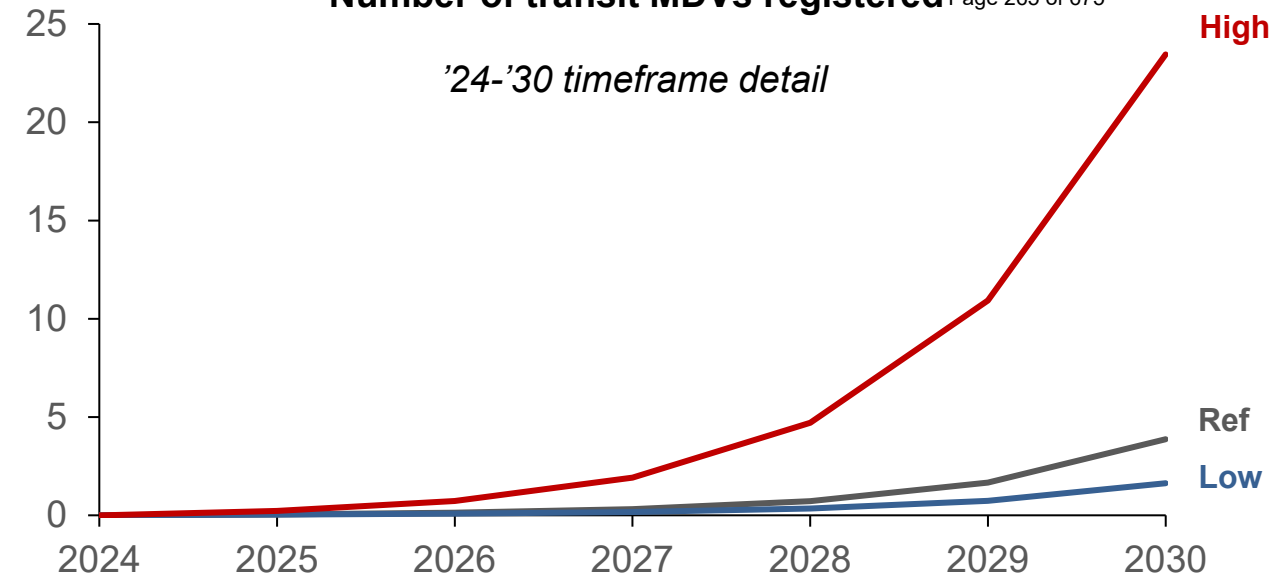
Near-term Trends

- NIPSCO has baselined the existing transit fleet using the 2022 National Transportation Database (NTD)
- NIPSCO has crafted an approach that uses ICE vehicle turnover (assuming avg lifespan by vehicle type from NTD) and EVs as a % of new MDV vehicle sales to estimate the number of transit EVs on the road in a given year.
- Scenarios are crafted to pulse the inflection year and final share of transit EVs as a % of new MDV sales

Long-term Trends

- NIPSCO anticipates moderated adoption compared to LDVs, as some MDVs may be difficult to decarbonize with limited EV options available

Number of transit MDVs registered
'24-'30 timeframe detail

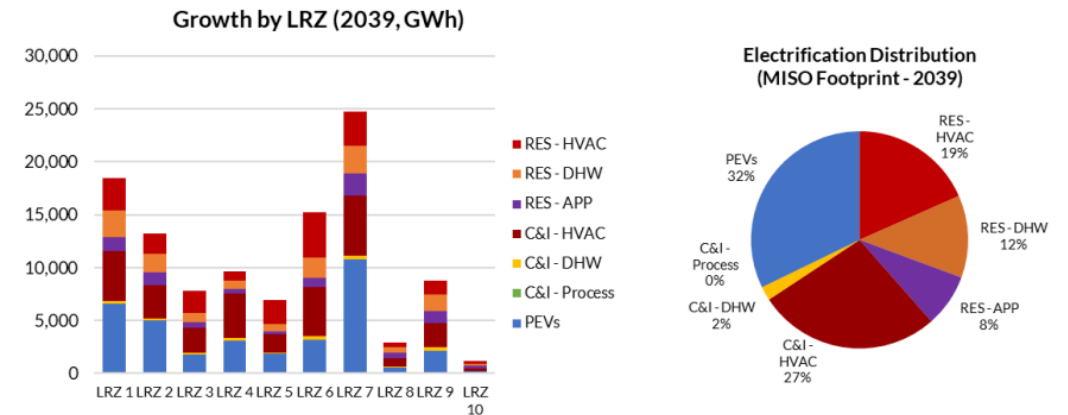


OTHER ELECTRIFICATION

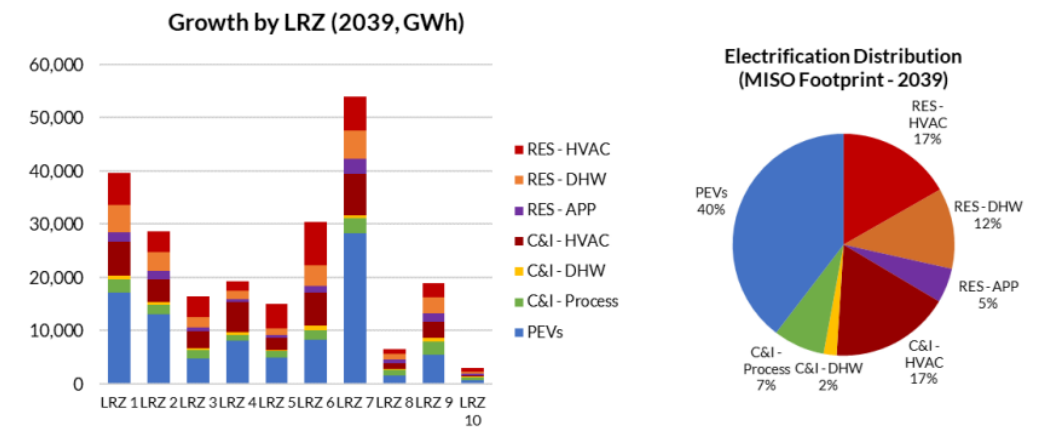
- Aside from electric vehicles, the AER and AI scenarios incorporate long-term impacts associated with electrification of other energy end uses
- NIPSCO drew from MISO Futures report and Transmission Expansion Plan (MTEP) to develop estimates for growth in energy and peak load needs associated with:
 - Residential HVAC
 - C&I HVAC
 - Residential appliances
 - Residential water heating
 - C&I water heating
 - C&I processes

Source: [2021 MISO Futures Report](#)

Future 2 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



Future 3 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



We exist to deliver safe, reliable energy that drives value to our customers



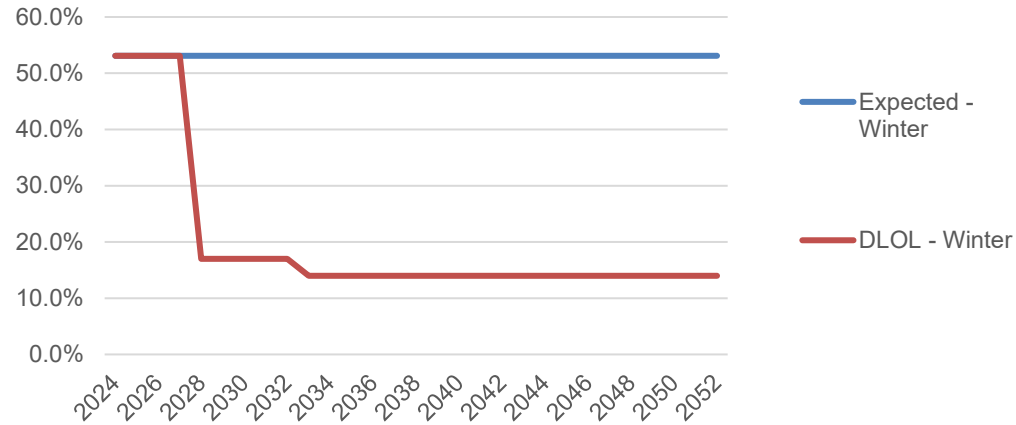
We exist to deliver safe, reliable energy that drives value to our customers

APPENDIX: CAPACITY ACCREDITATION AND NIPSCO OBLIGATION DETAILS

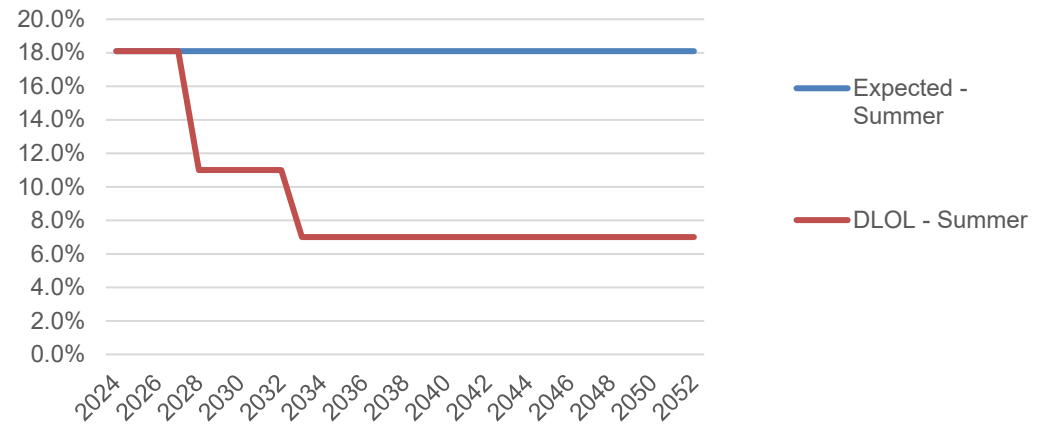


SEASONAL WIND ACCREDITATION

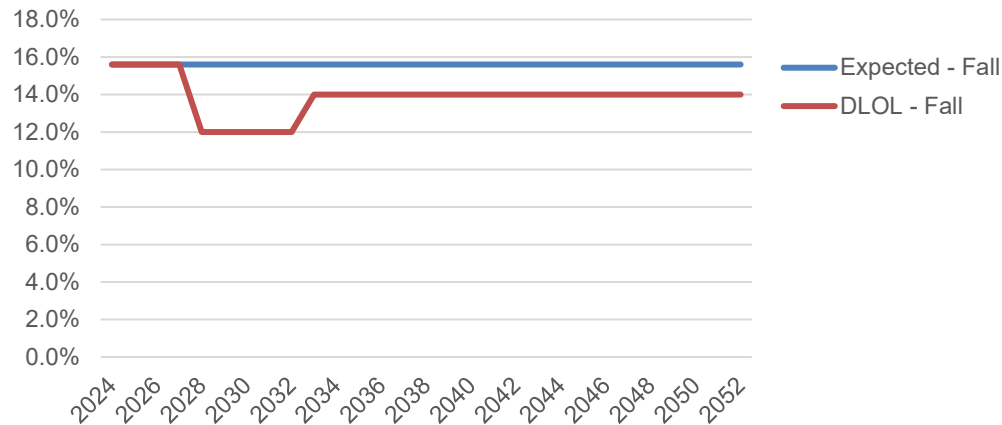
Winter Accreditation - Wind



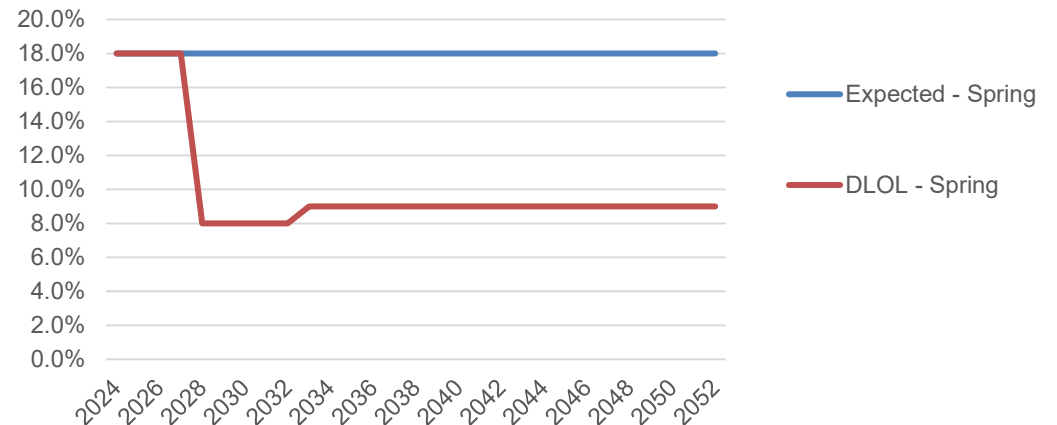
Summer Accreditation - Wind



Fall Accreditation - Wind

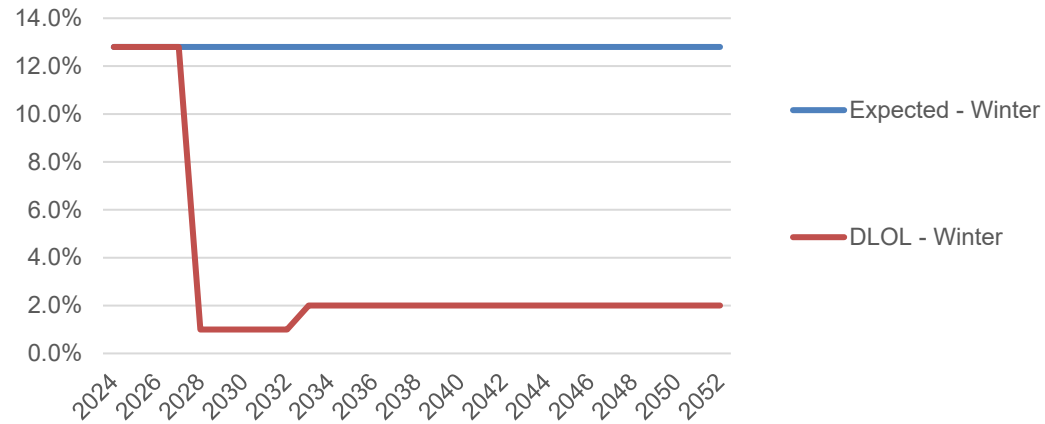


Spring Accreditation - Wind

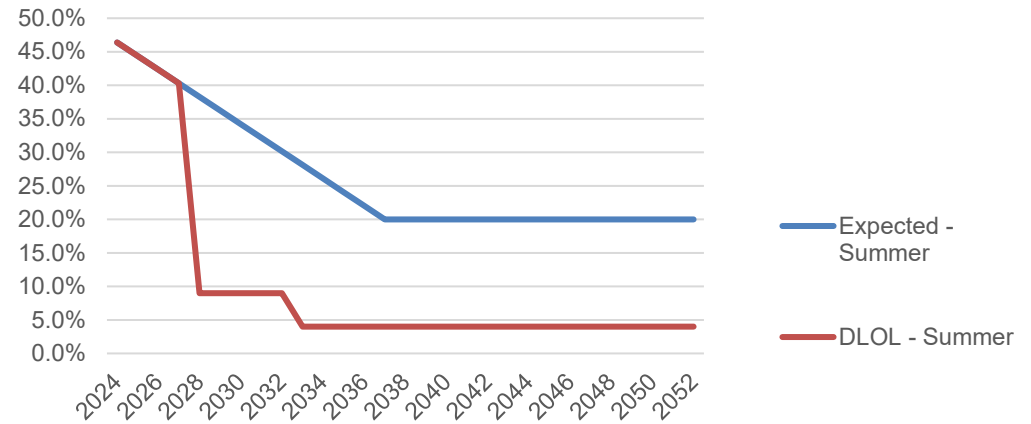


SEASONAL SOLAR ACCREDITATION

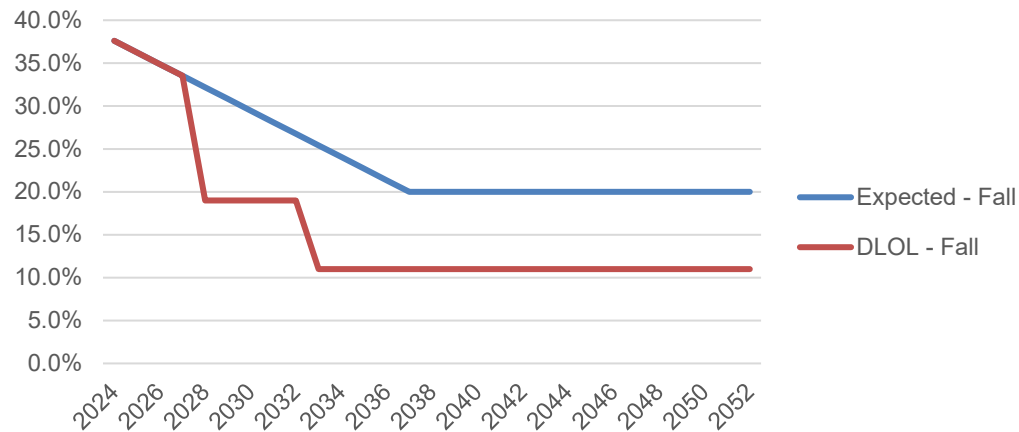
Winter Accreditation - Solar



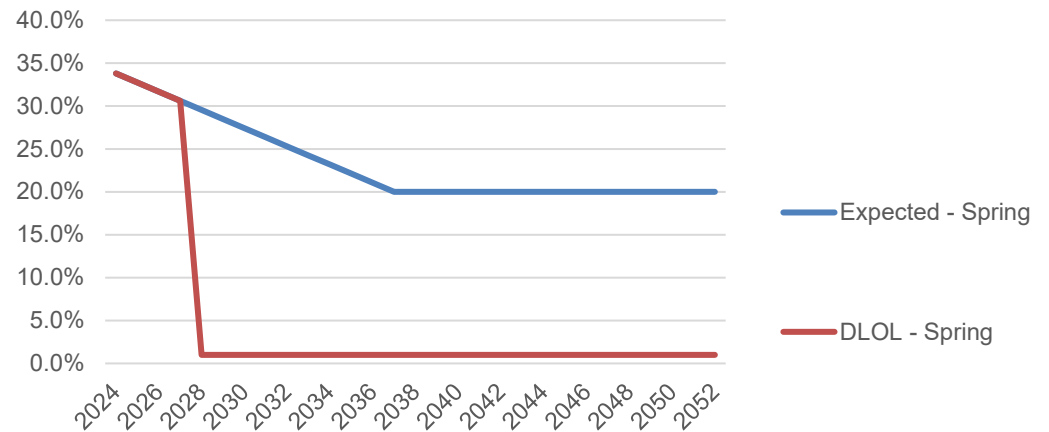
Summer Accreditation - Solar



Fall Accreditation - Solar

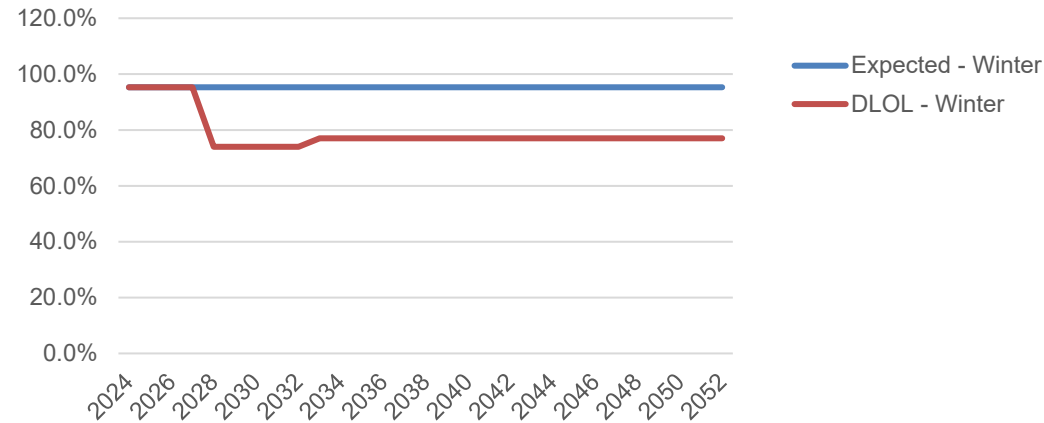


Spring Accreditation - Solar

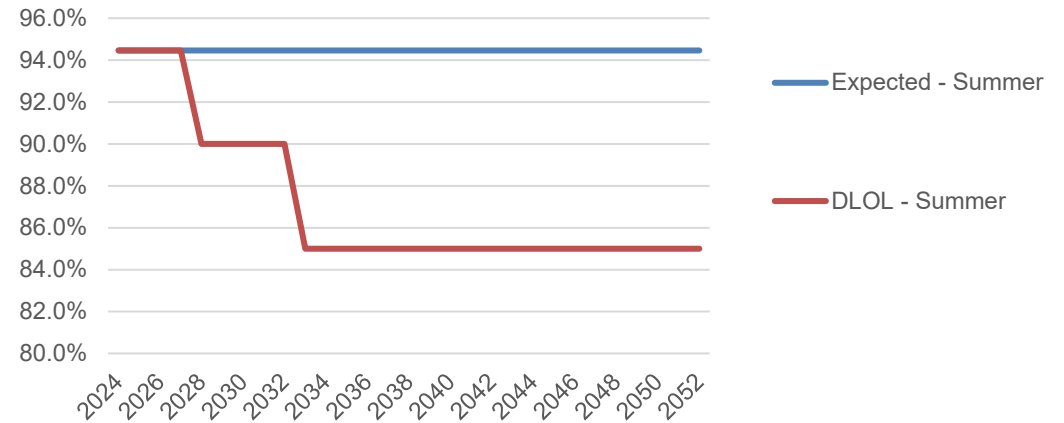


SEASONAL GAS CC ACCREDITATION

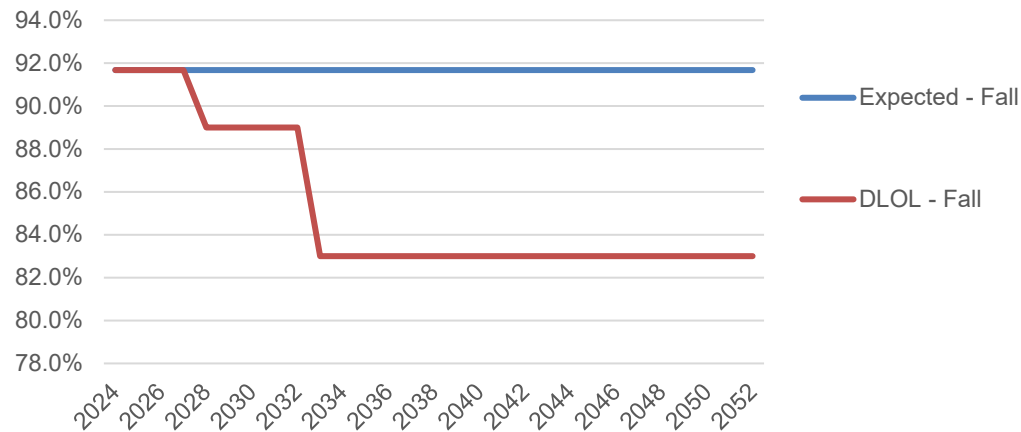
Winter Accreditation - Gas CC



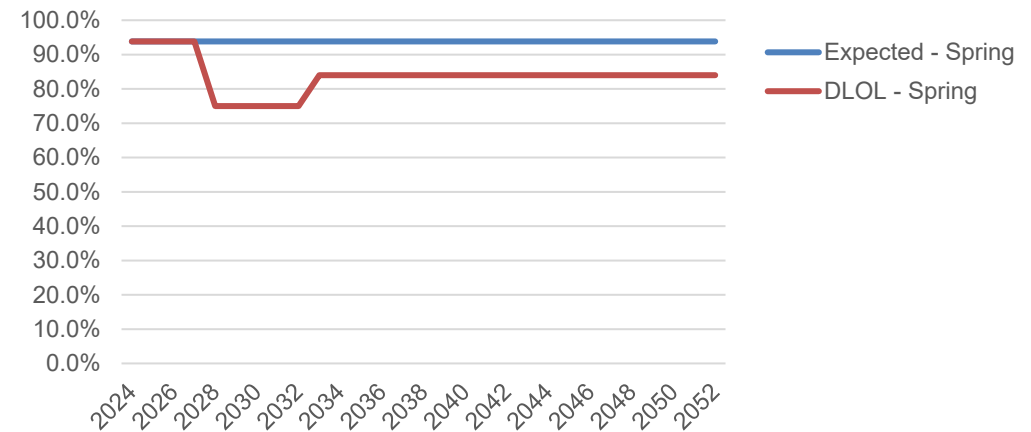
Summer Accreditation - Gas CC



Fall Accreditation - Gas CC

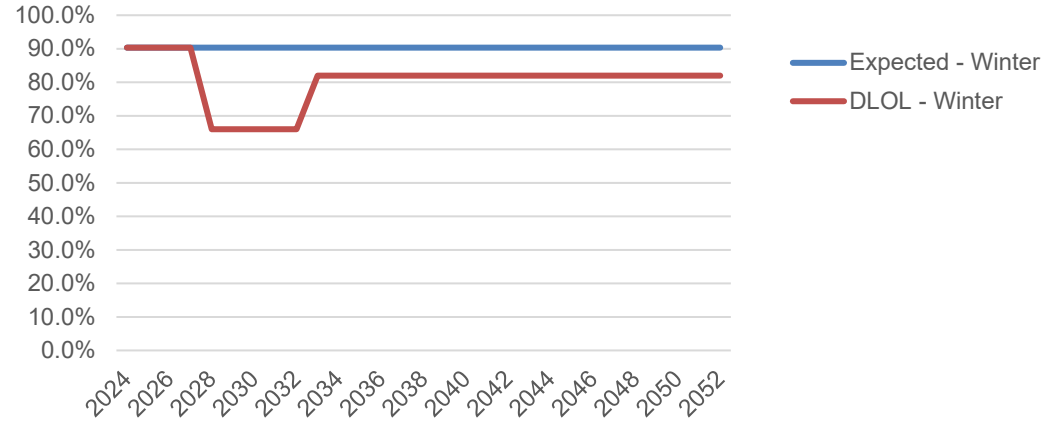


Spring Accreditation - Gas CC

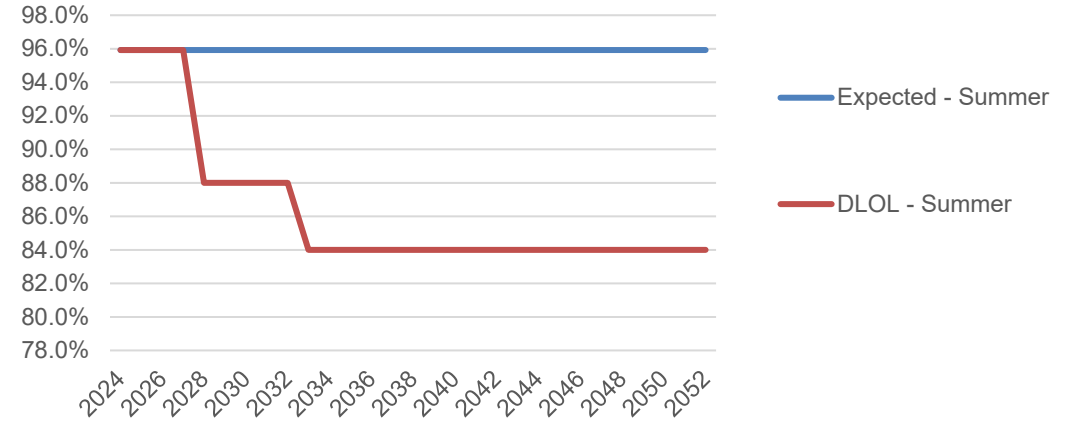


SEASONAL GAS CT ACCREDITATION

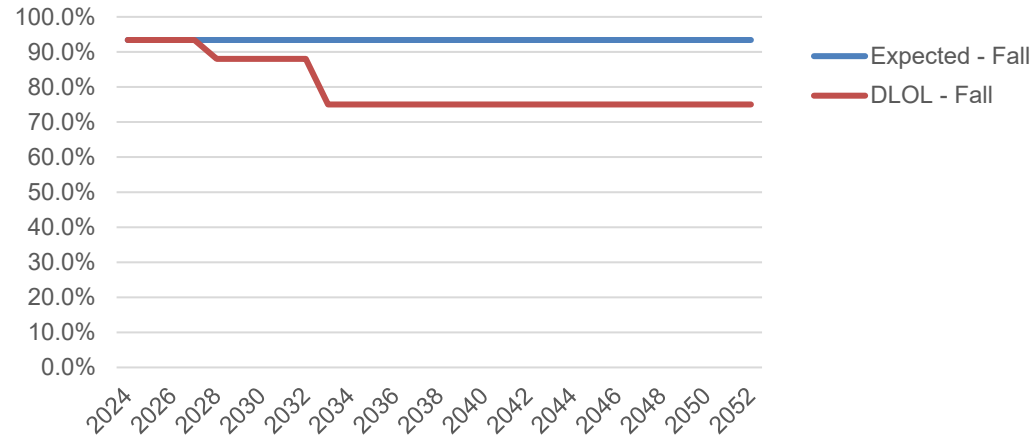
Winter Accreditation - Gas CT



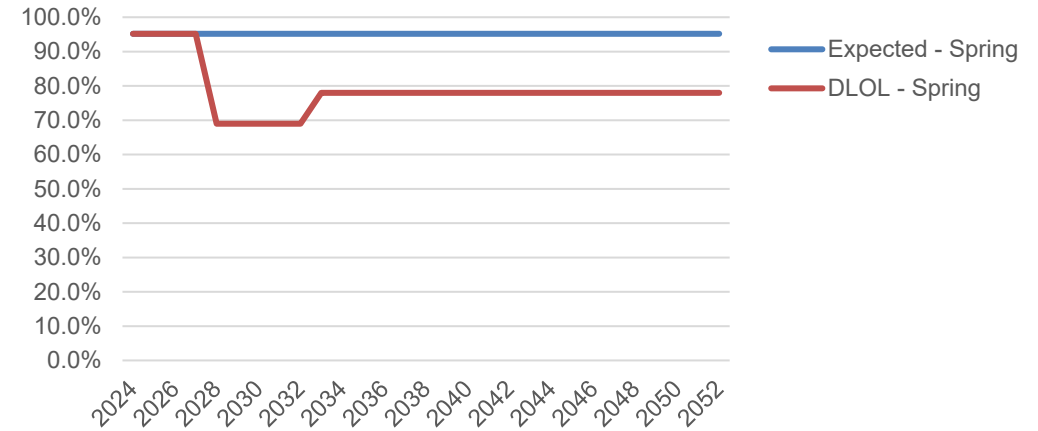
Summer Accreditation - Gas CT



Fall Accreditation - Gas CT

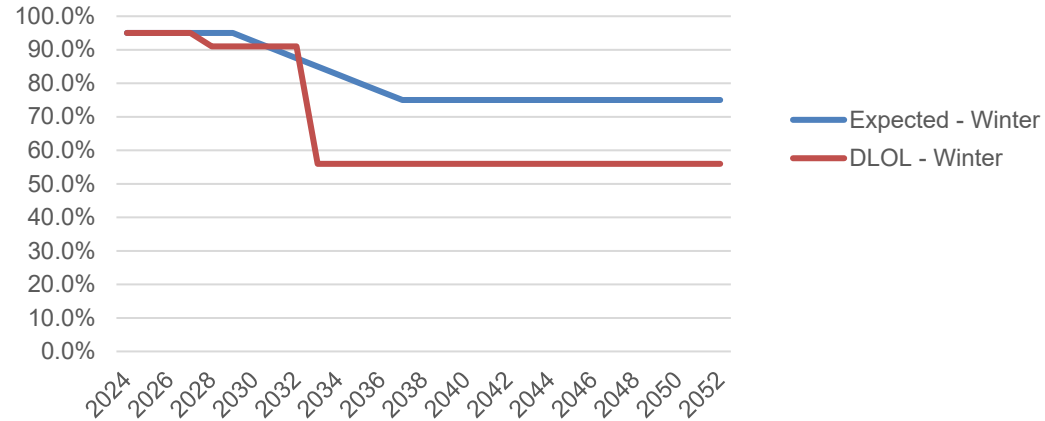


Spring Accreditation - Gas CT

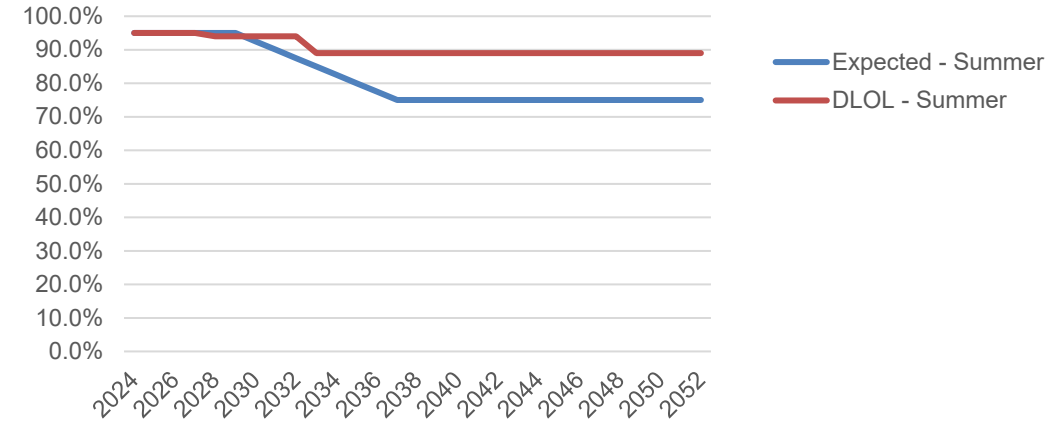


SEASONAL STORAGE ACCREDITATION

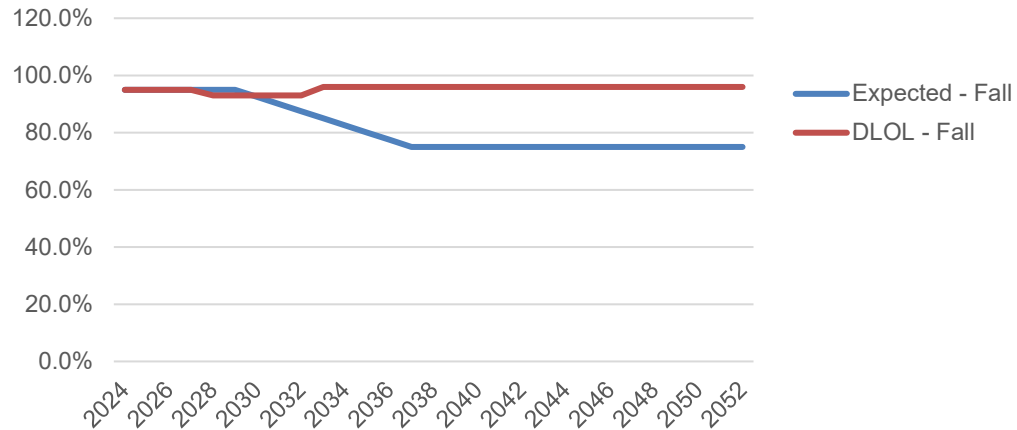
Winter Accreditation - Storage



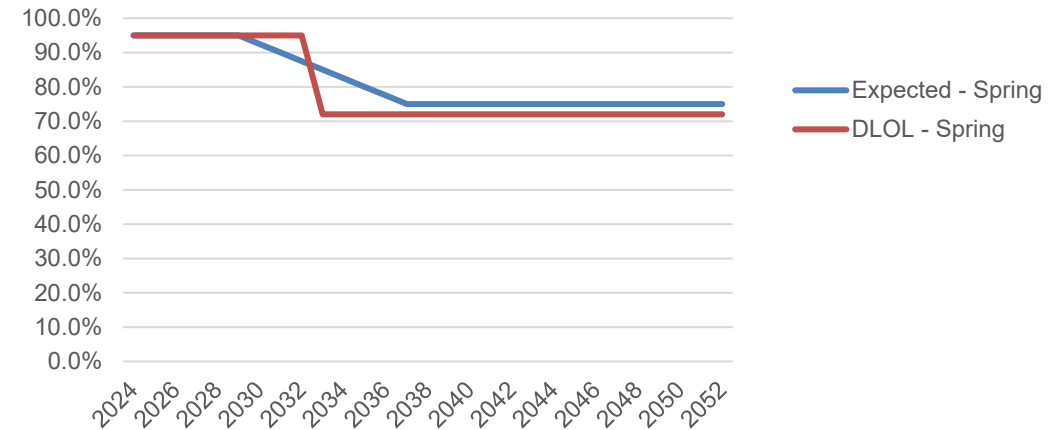
Summer Accreditation - Storage



Fall Accreditation - Storage

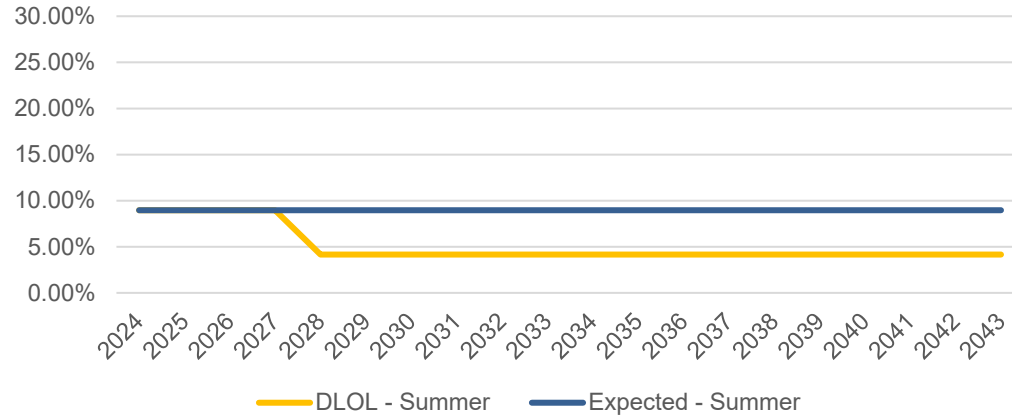


Spring Accreditation - Storage

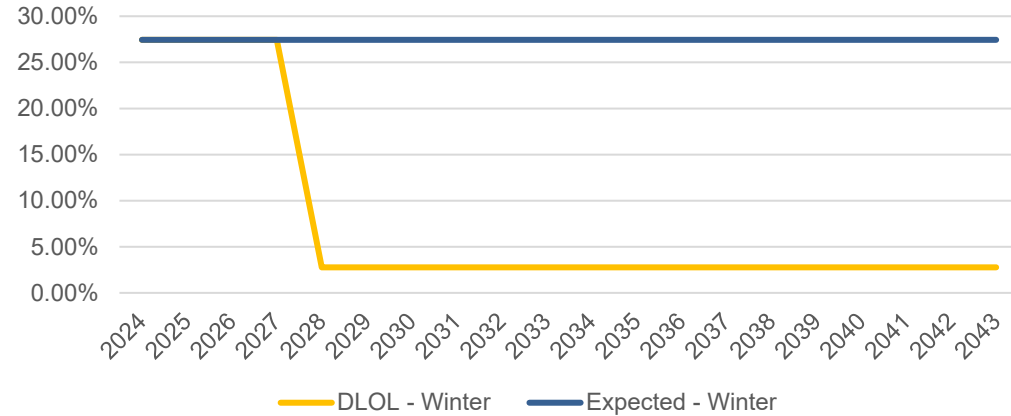


NIPSCO SEASONAL OBLIGATION IMPACTS FROM D-LOL

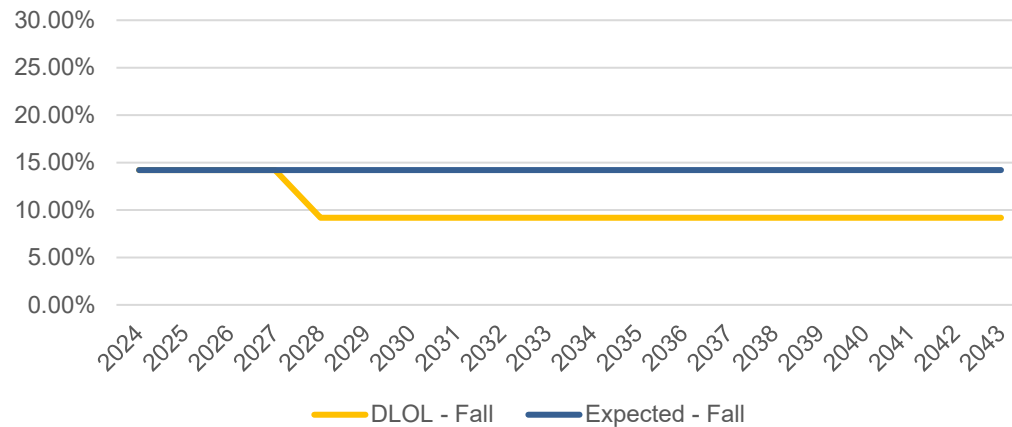
Summer PRMR (%)



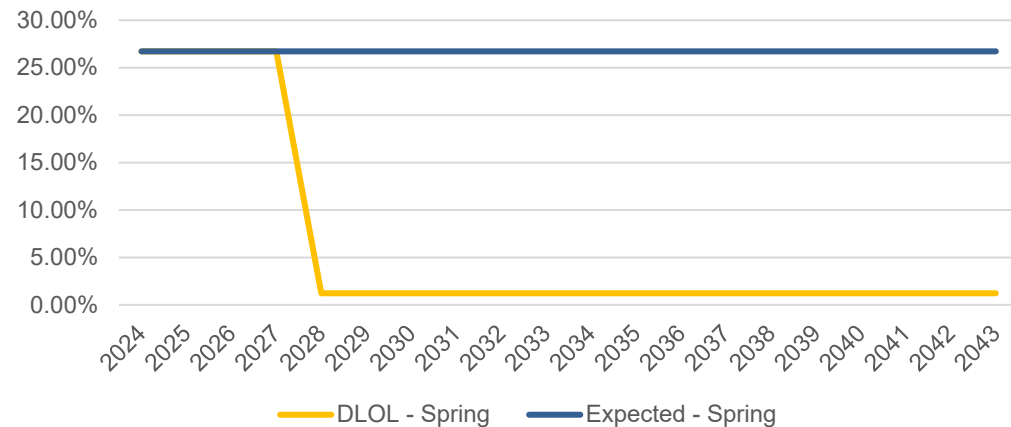
Winter PRMR (%)



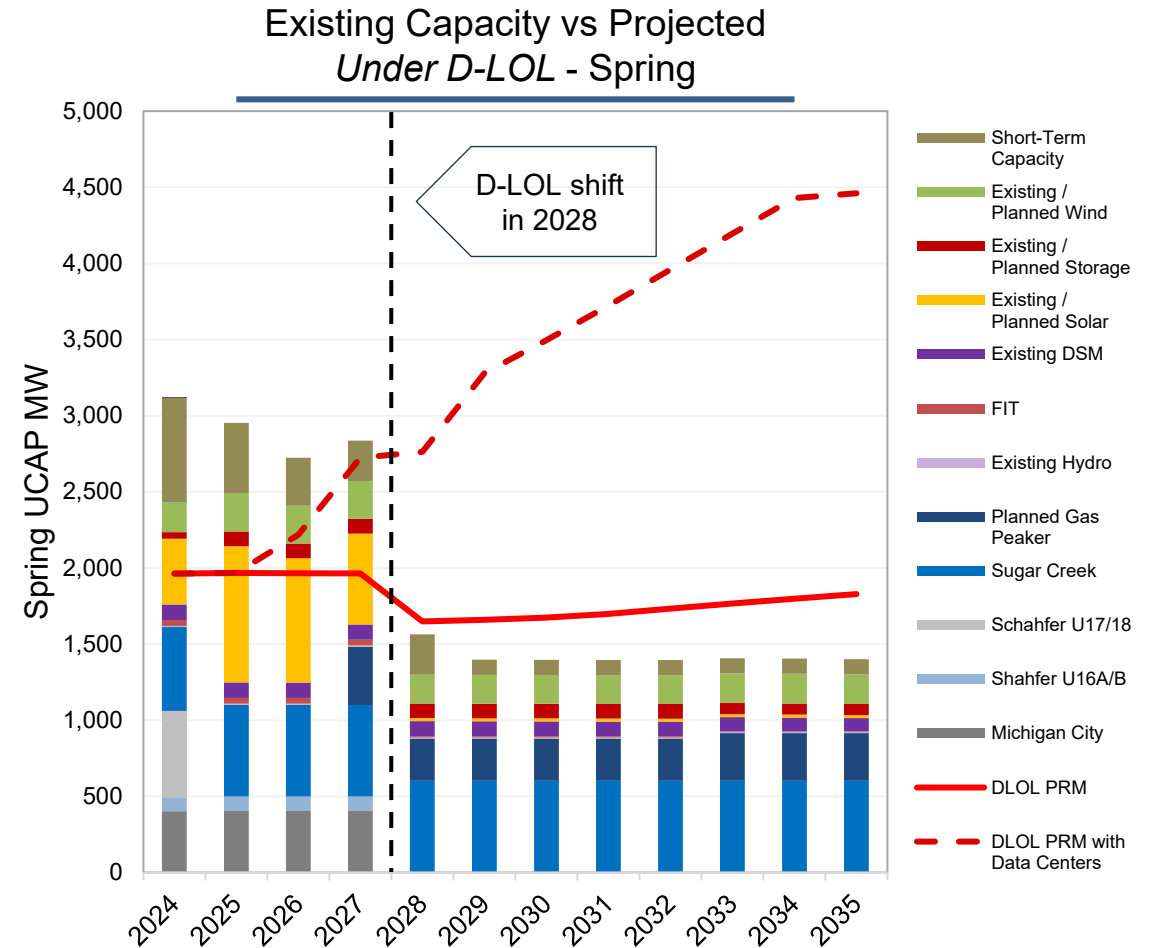
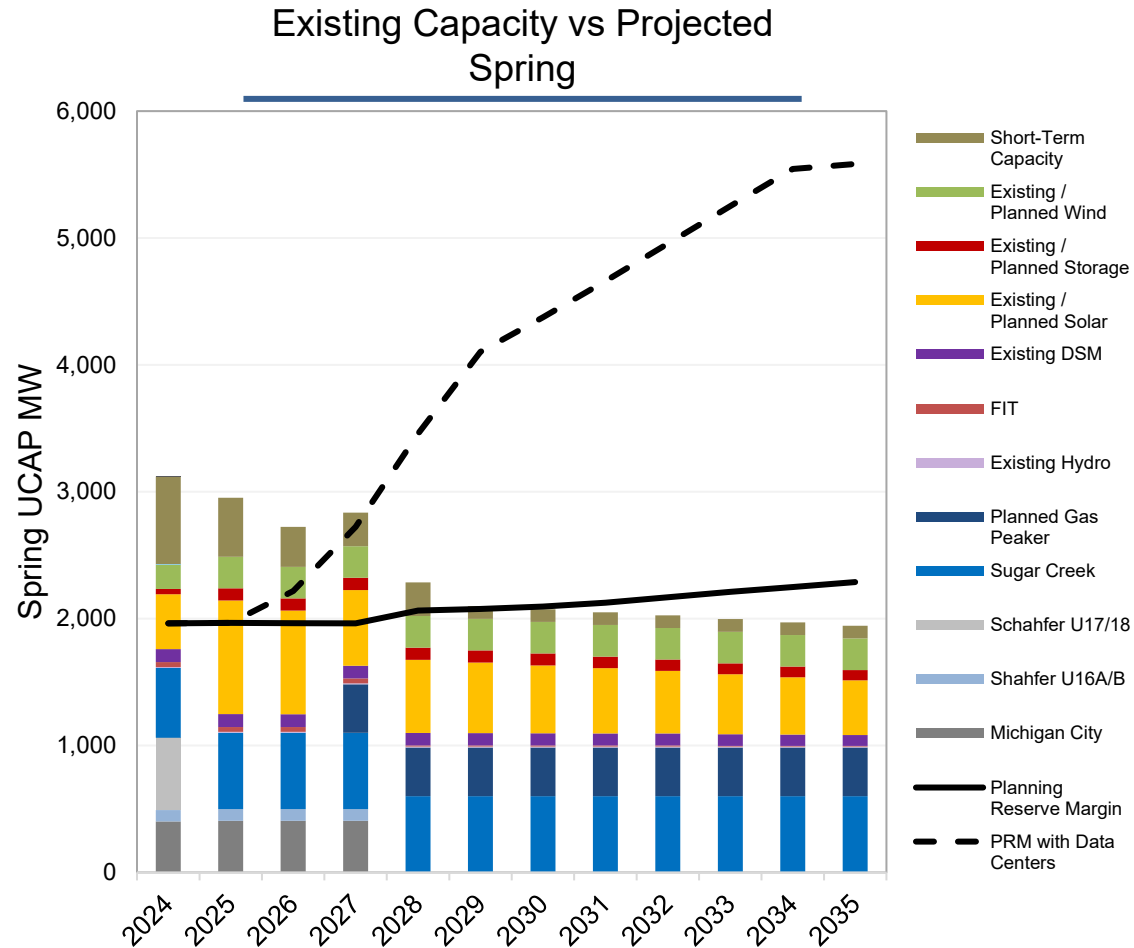
Fall PRMR (%)



Spring PRMR (%)

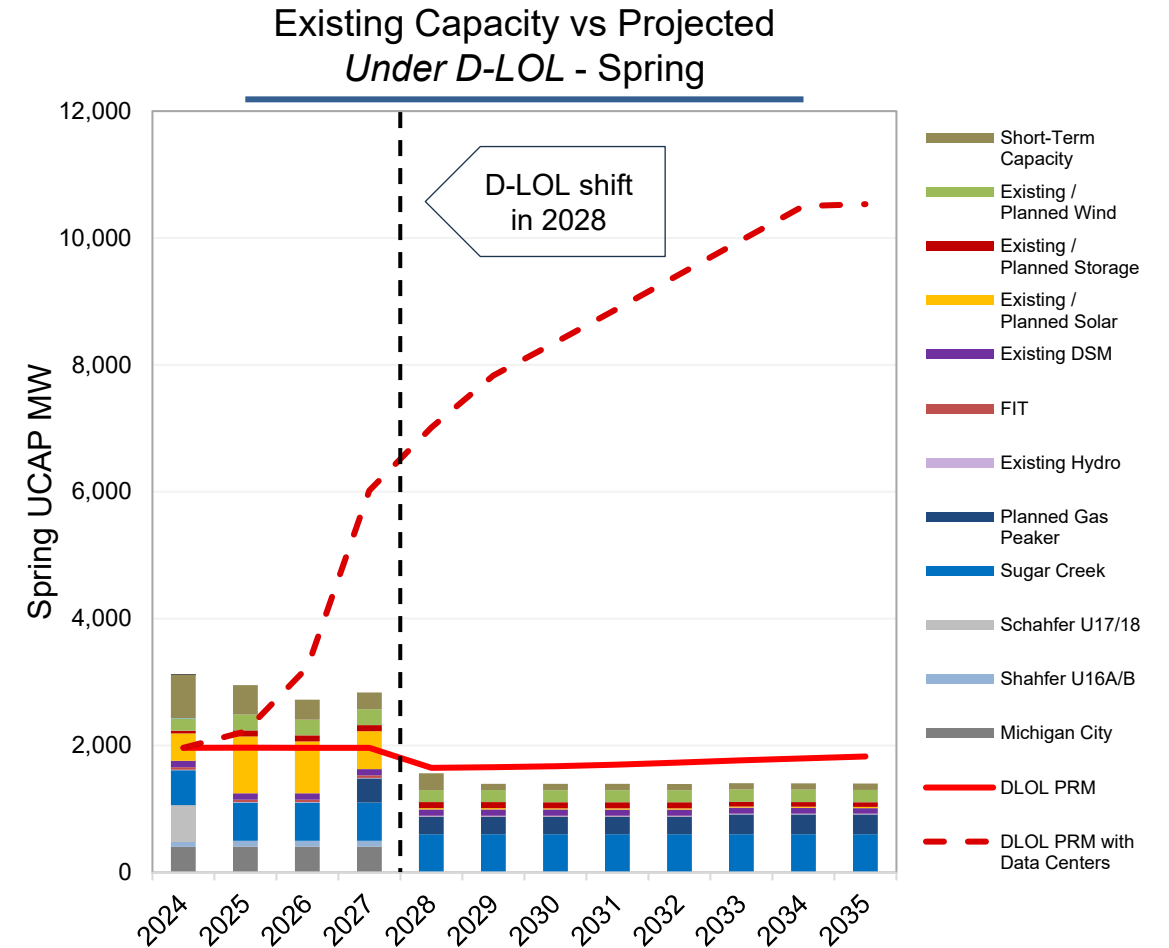
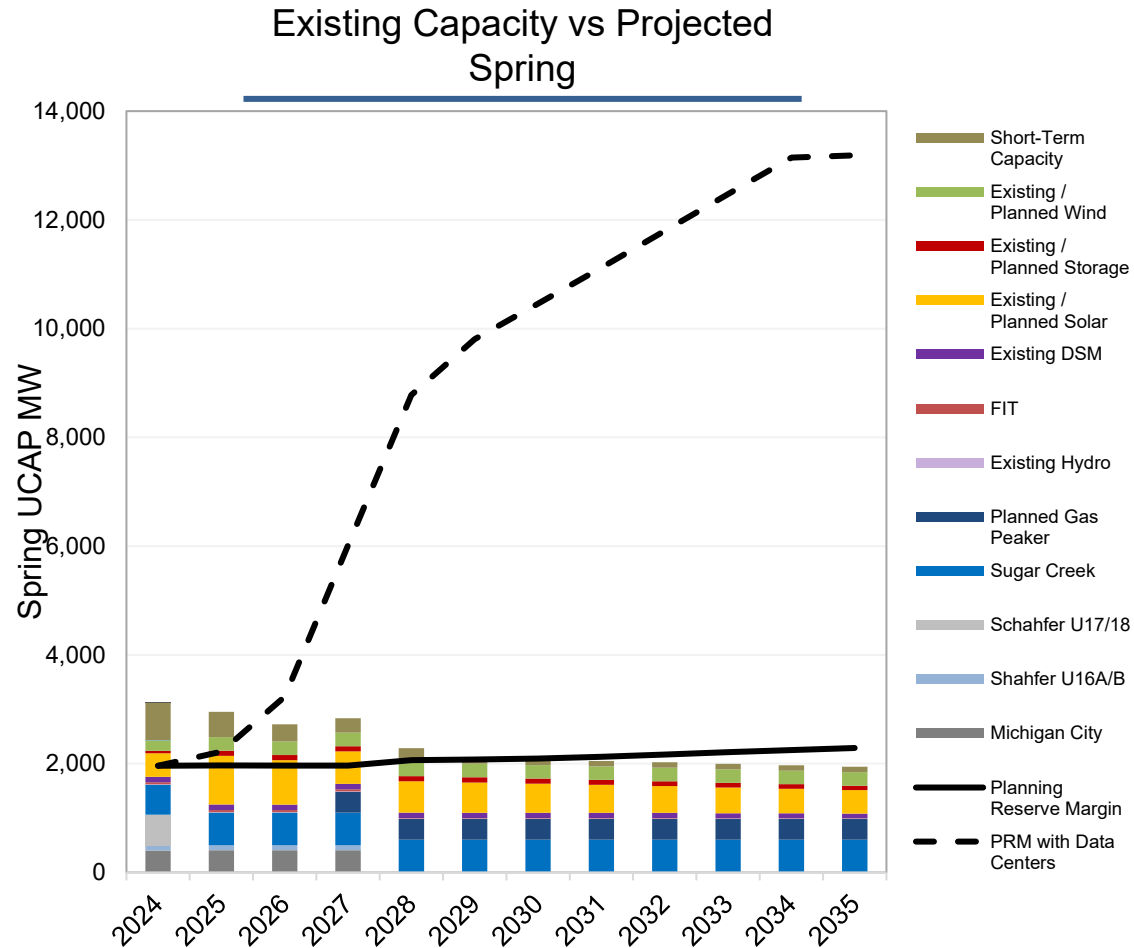


CURRENT NIPSCO CAPACITY POSITION – REFERENCE LOAD – SPRING



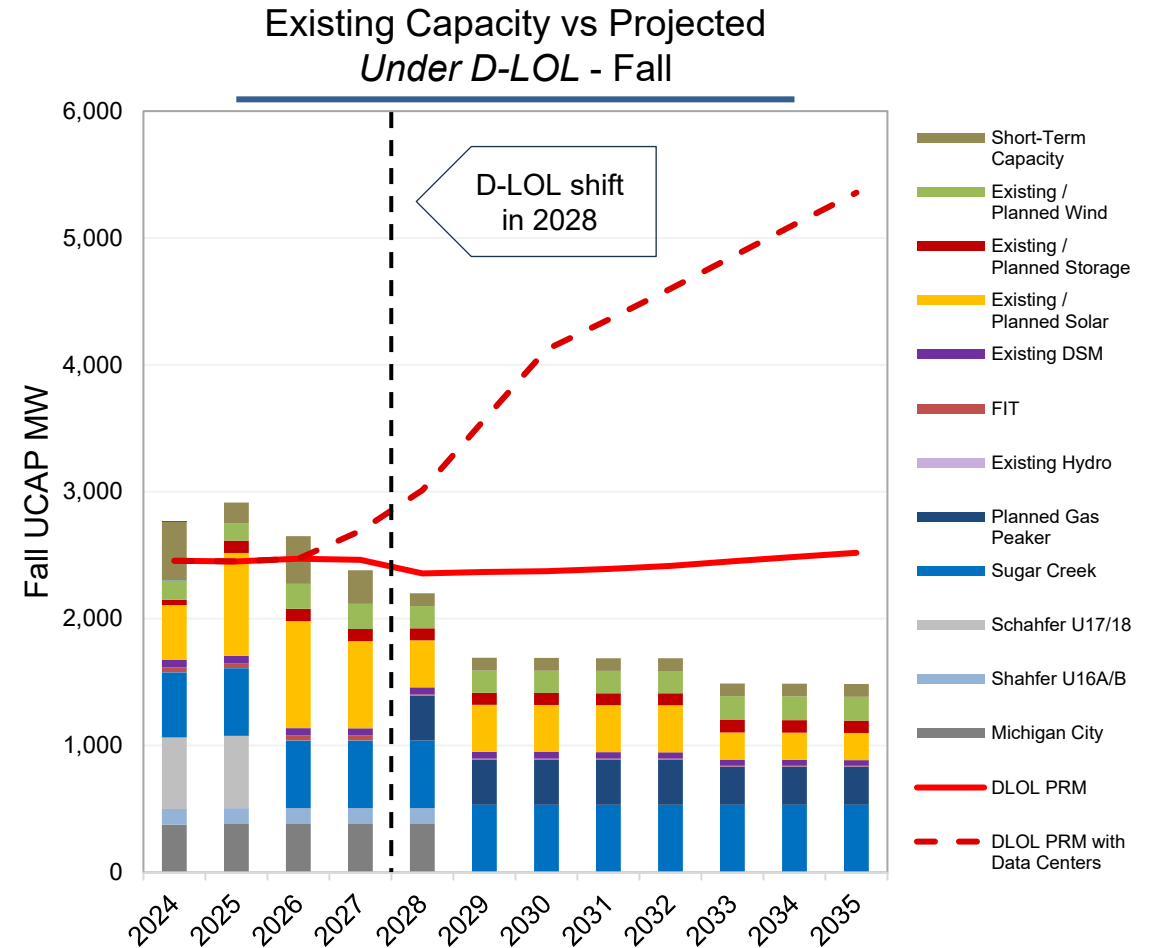
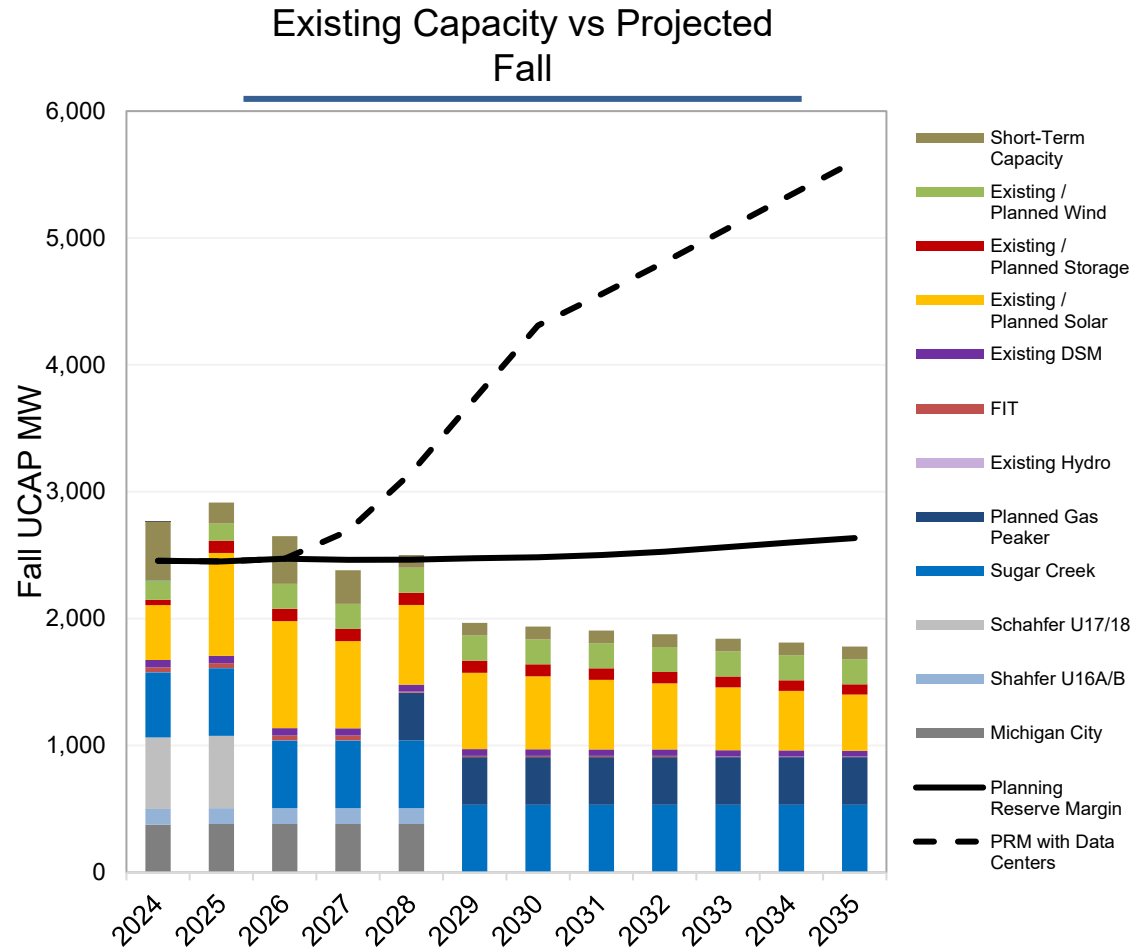
We exist to deliver safe, reliable energy that drives value to our customers

CURRENT NIPSCO CAPACITY POSITION – HIGH LOAD SENSITIVITY – SPRING



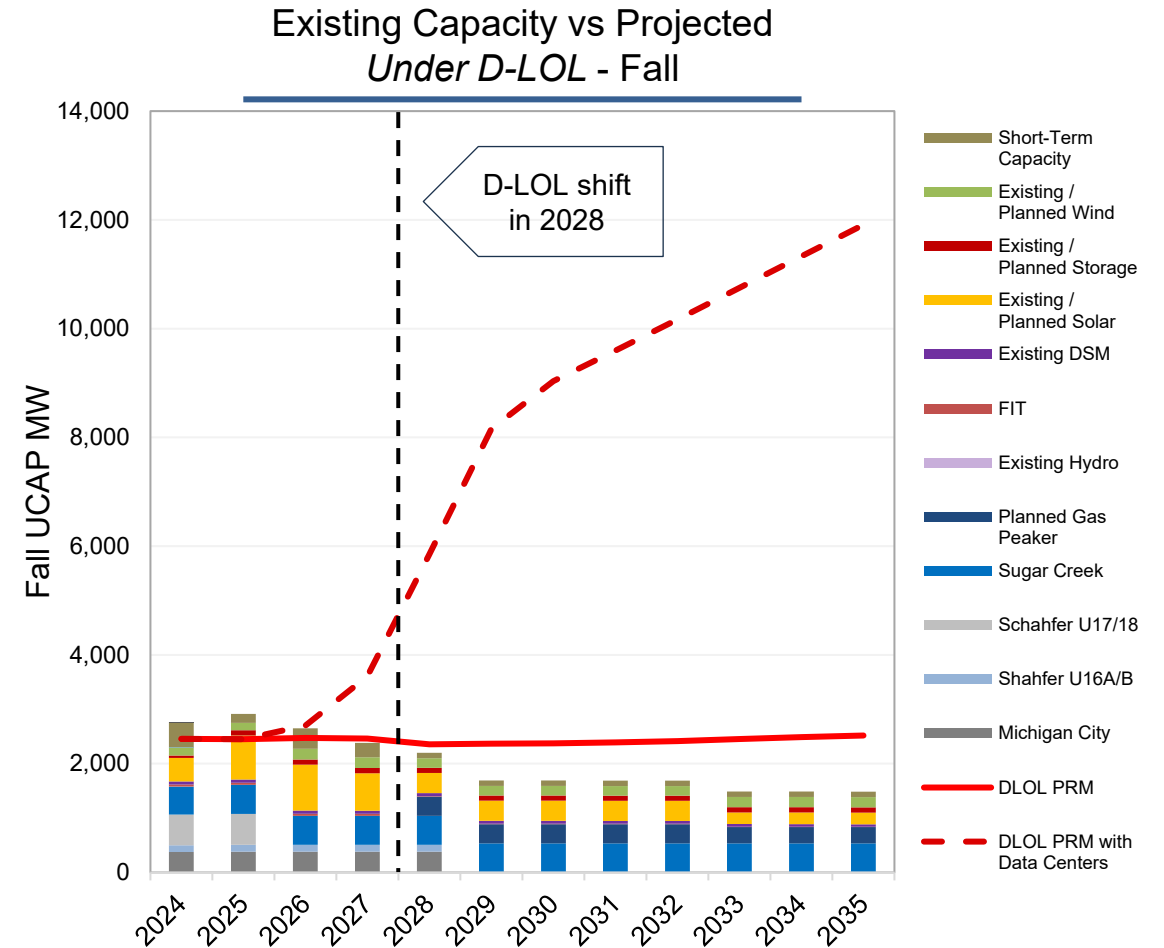
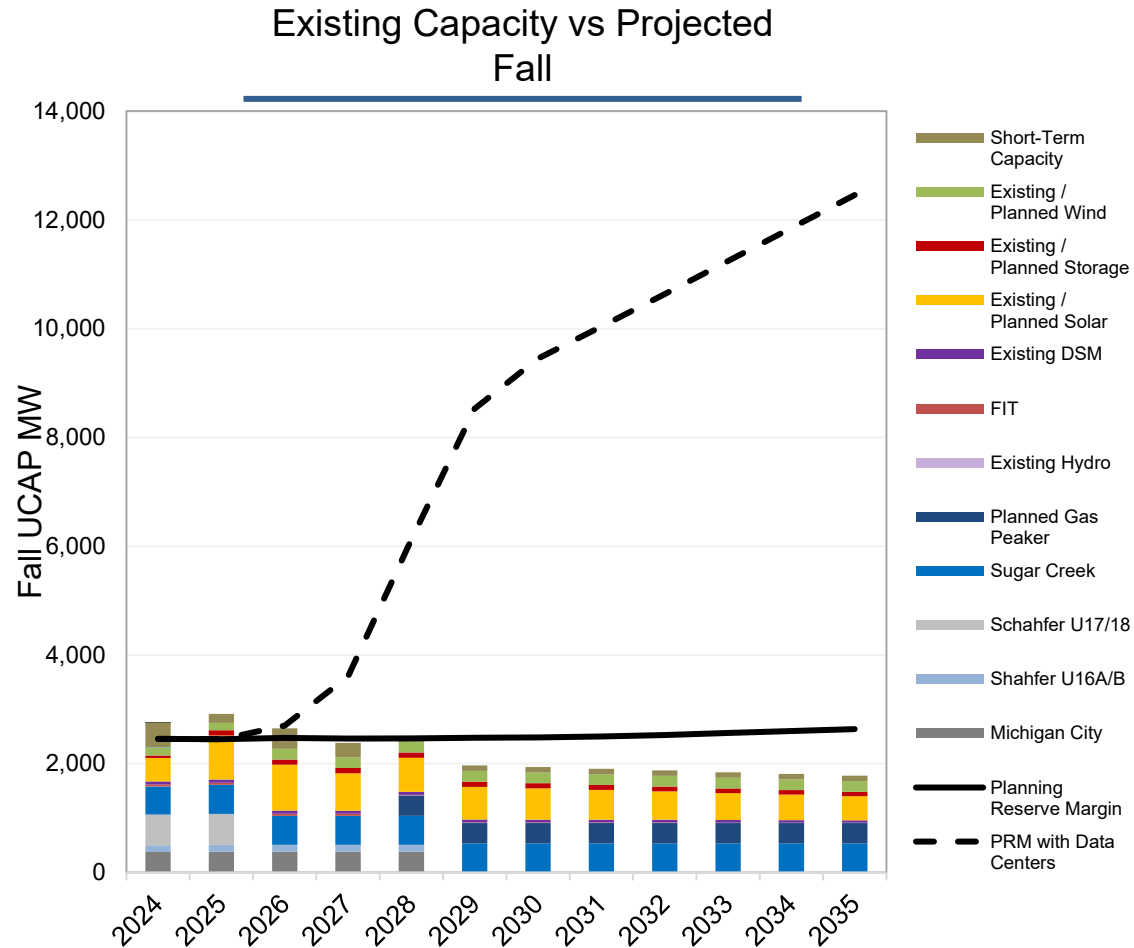
We exist to deliver safe, reliable energy that drives value to our customers

CURRENT NIPSCO CAPACITY POSITION – REFERENCE LOAD – FALL



We exist to deliver safe, reliable energy that drives value to our customers

CURRENT NIPSCO CAPACITY POSITION – HIGH LOAD SENSITIVITY – FALL



We exist to deliver safe, reliable energy that drives value to our customers



We exist to deliver safe, reliable energy that drives value to our customers

APPENDIX: COMMODITY MARKET SCENARIO DETAILS



NATURAL GAS MARKET OVERVIEW – SHORT-TERM DRIVERS

- The forward curve has fallen significantly since Fall 2023 as storage inventories have reached historic highs and LNG demand has fallen about 2 Bcf/d.
- Economic headwinds may cause E&P companies to “tap the brakes” on drilling programs. However, as the Mountain Valley Pipeline (MVP) nears completion, some additional capacity could be provided once it comes online.

Short-Term Market Trends

Natural Gas Supply

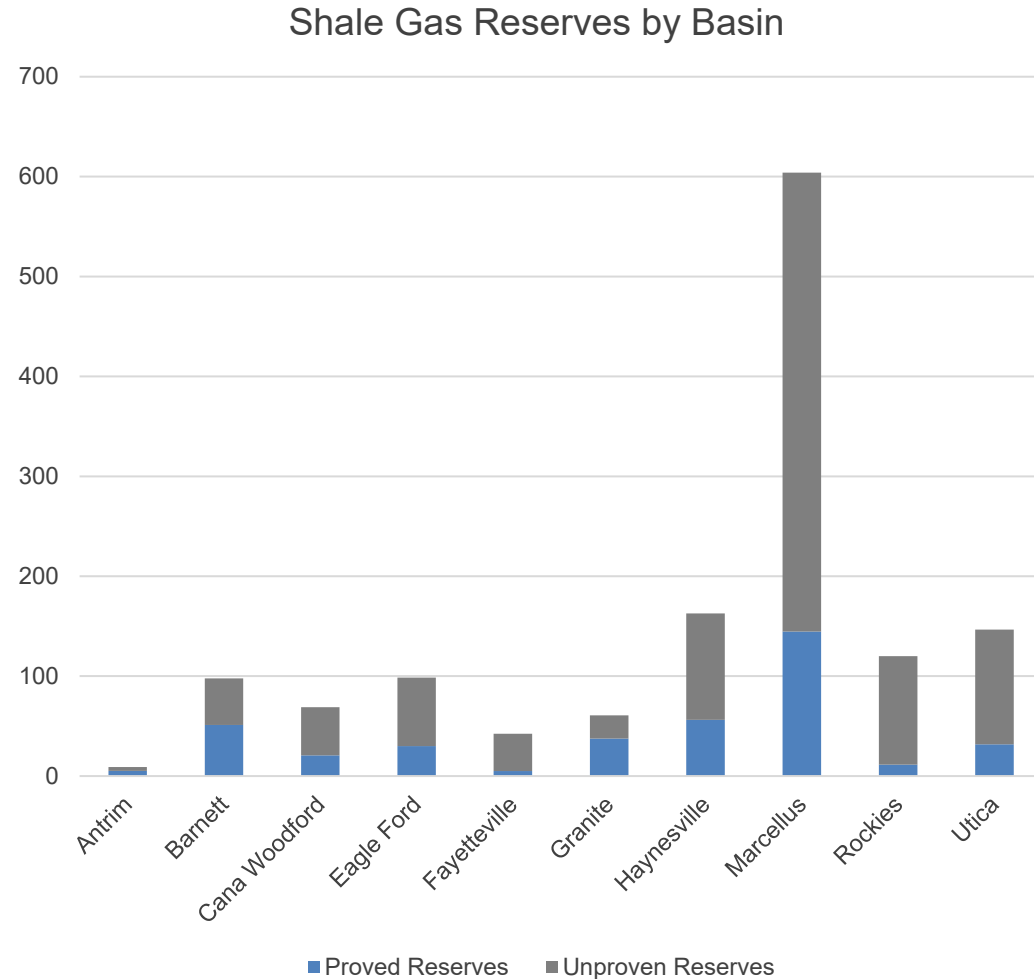
- Continuous modest increases in US production (now around 102 Bcf/d) have sustained lower prices in the shorter term, but gas-focused rigs have declined (down 17% compared to this time last year).
- Now that both the Transco Regional Energy Access Project & Mountain Valley Pipeline (MVP) have been greenlighted for completion, there may be some relief for Northeast Pennsylvania prices.
- After MVP and Transco’s REA Project, there are no new infrastructure projects in the queue, and another round of constraint-driven discounting may be around the corner.

Natural Gas Demand

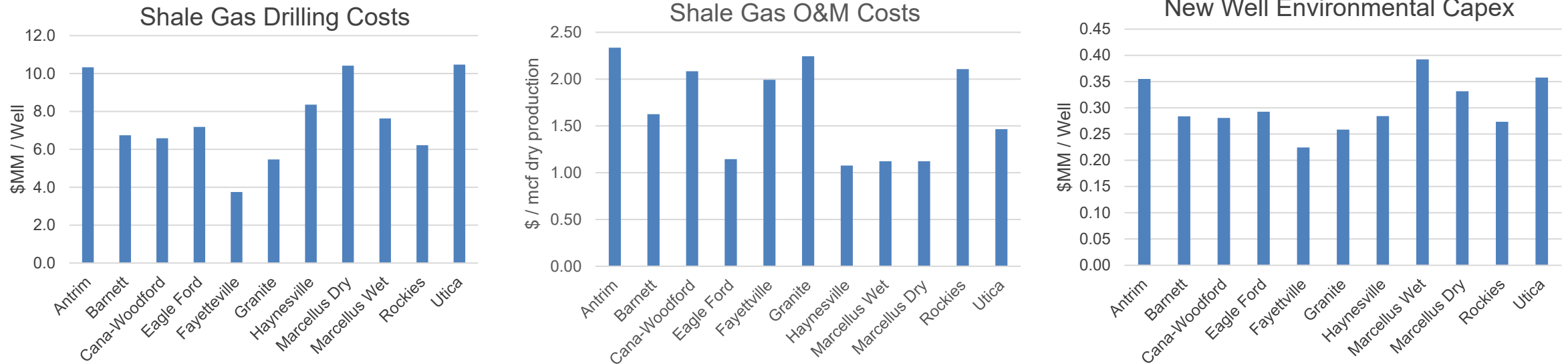
- Feedgas LNG is marginally down ~2 Bcf/d from the winter and is averaging around 12.5 Bcf/d. The next incremental feedgas is expected in the 2025-2027 timeframe. US exports (via LNG and pipeline) remain significant in the first quarter of 2024, reaching an average of 19.1 Bcf/d, up nearly 1 Bcf/d over the same period for 2023.
- Exports to Mexico remain similar to exports over the same period last year and are averaging 5.0 Bcf/d YTD.
- Storage inventories are significantly higher than 2023 and 5-Year average levels for this time of year.

CRA RELIES ON THE POTENTIAL GAS COMMITTEE'S (PGC) “MIN” AND “MOST LIKELY” VIEWS OF UNPROVEN RESERVES

- **CRA combines Unproven reserves from PGC with Proved reserves from EIA**
 - “Proved” reserves are a known quantity and would not vary between the Reference case and alternative scenarios.
 - The quantity of “Unproven” reserves is uncertain and could vary across CRA natural gas price scenarios.
- **PGC assigns resource to three probability categories:**
 - Minimum – 100% probability that stated resource is recoverable.
 - Most Likely – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions.
 - Maximum – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present.



CRA USES DRILLING-RELATED CAPEX FIGURES BY PLAN TO DETERMINE CAPITAL COSTS OF NEW WELL PRODUCTION



- Current elevated costs of capital apply upward pressure on drilling costs.
- Still, producers across most basins have demonstrated improvements in drilling and O&M costs. CRA assumes that these improvements continue. Artificial Intelligence has the potential to reduce drilling costs and produce better exploration outcomes, but this has not yet been reflected in recent numbers.
- Environmental Capex is a function of well size, location and policy. As environmental restrictions mount, costs are likely to increase.

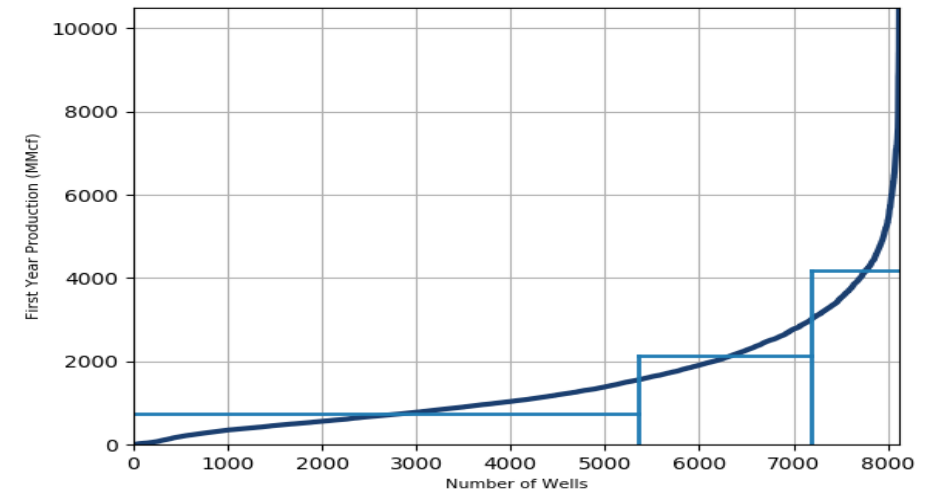
Despite current upward pressure, **CRA** expects production costs to decline in the long term, due largely to technological innovation.

PRODUCTION DYNAMICS ARE USED TO DETERMINE THE YEAR-OVER-YEAR OUTPUT OF WELLS DRILLED

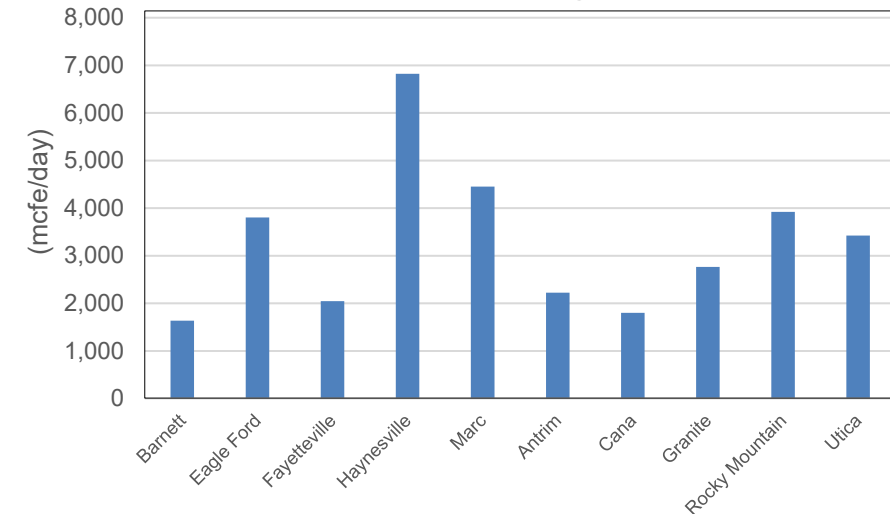
- CRA's view is that historical data has a bias towards higher producing sub-regions
 - Wells that are completed and ultimately produce gas do not reflect a random sampling of the underlying geology in each basin.
 - Rather, these wells reflect areas where producers expected to find favorable geology and wells where the cost of completion was justified by the flow.
- We therefore divide each basin into “Poor”, “Average”, and “Prime” sub-regions and adopt a “Poor-Heavy” distribution.
 - This reflects the notion that remaining resource is more likely to be of lower quality over time as the premium acreage is depleted in each basin.

CRA relies on historical drilling for completed shale wells to develop our view of basin productivity

Productivity Distribution: Appalachia

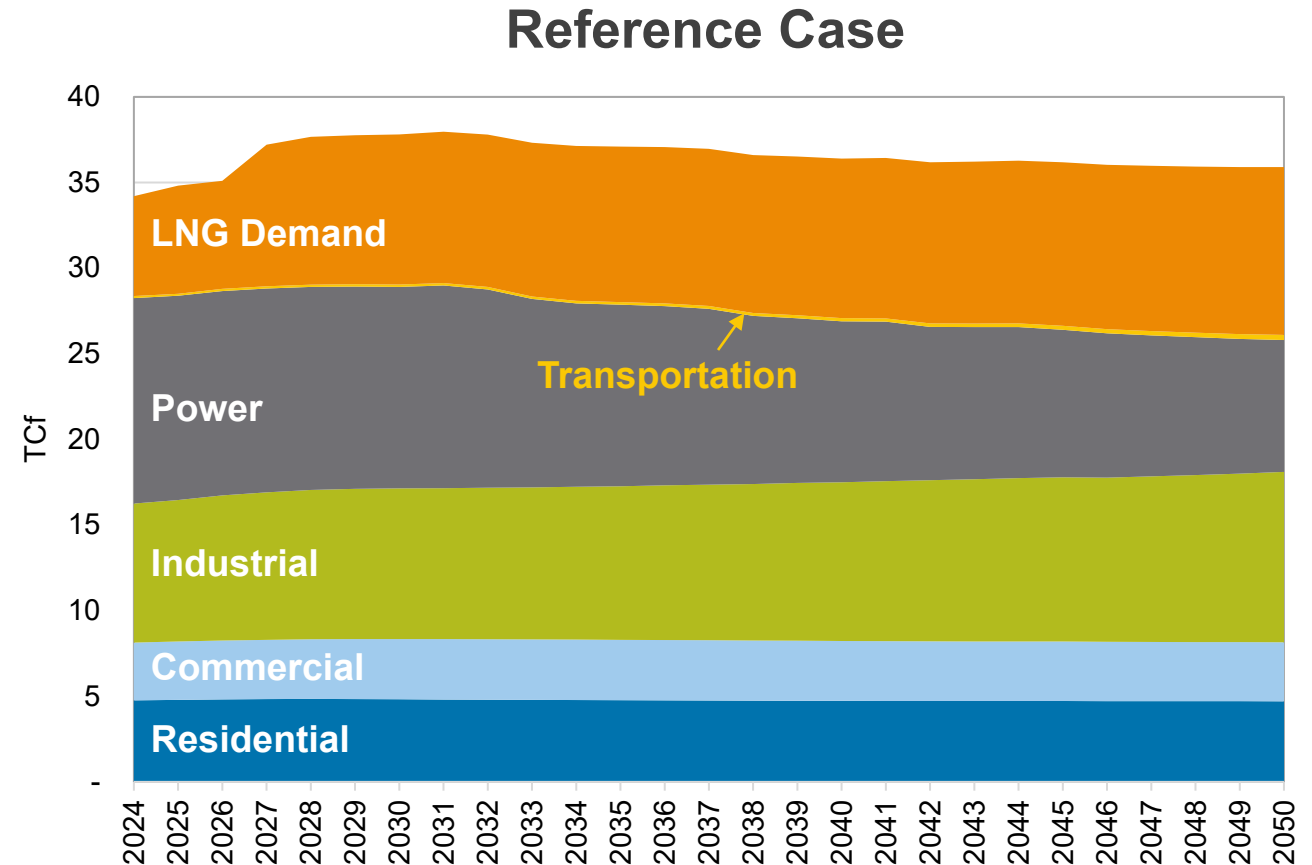


2022 - First Year Average Production Rate

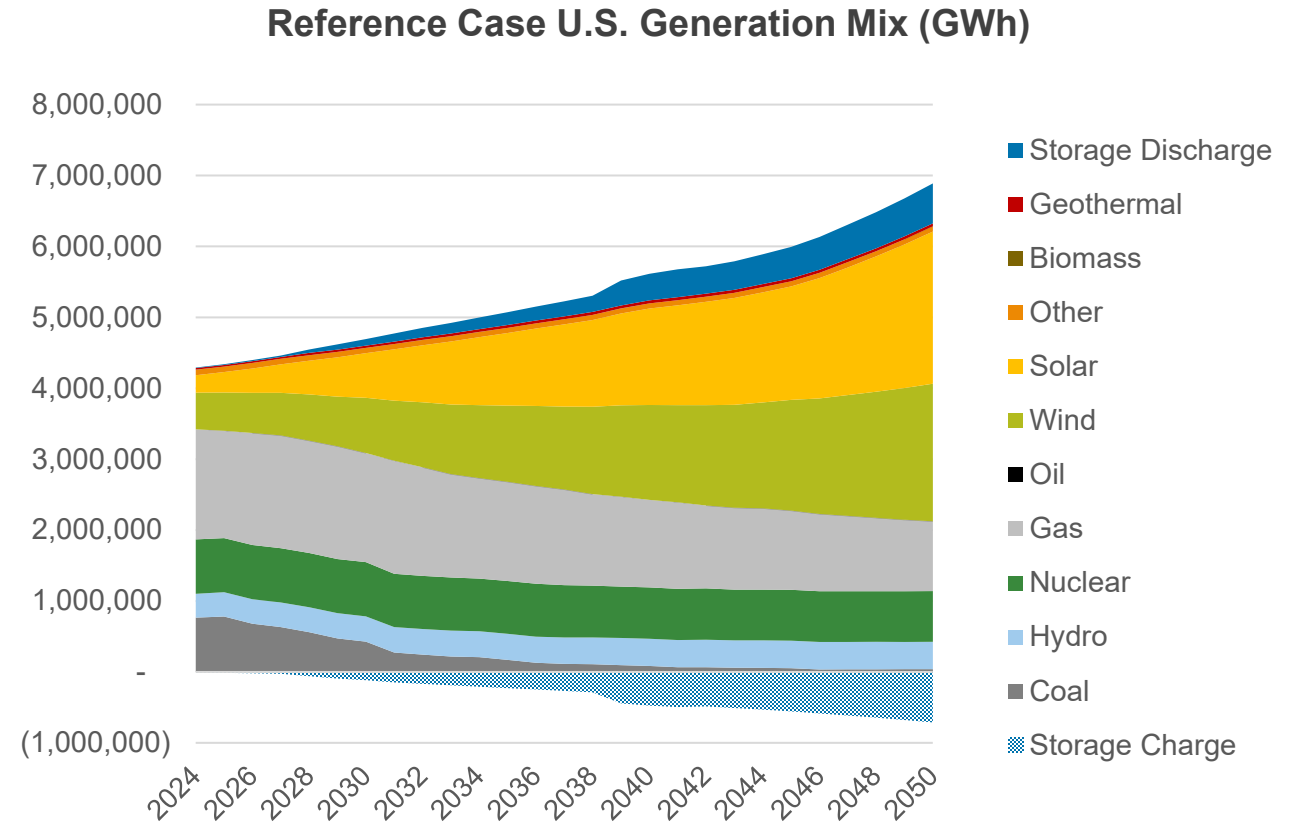
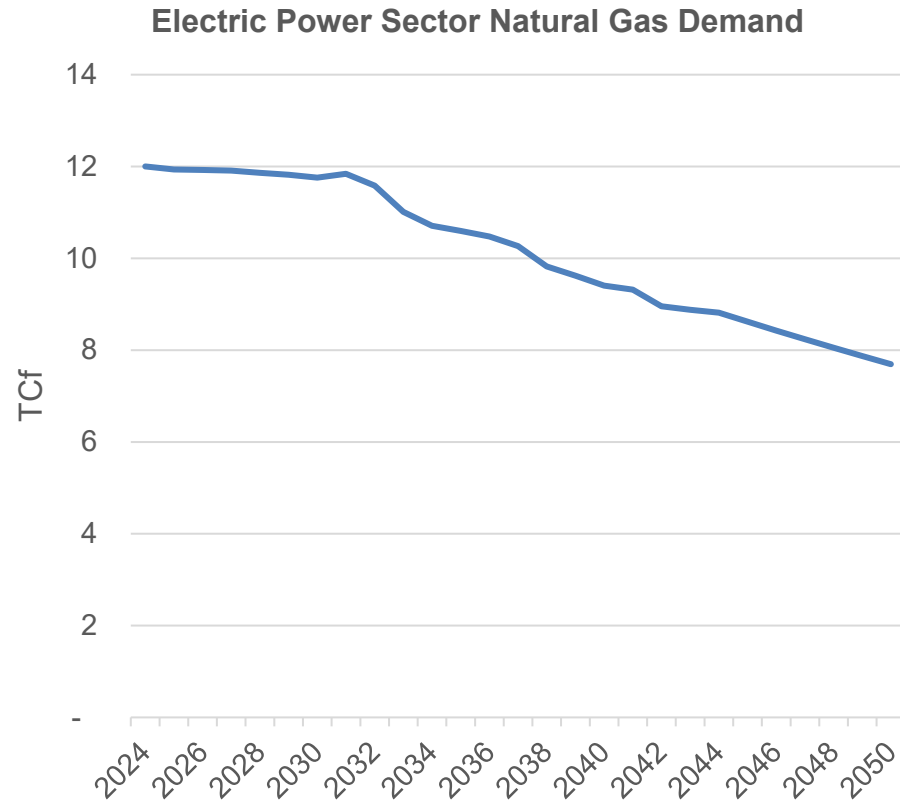


NATIONAL NATURAL GAS DEMAND PROJECTIONS

- Power sector steadily decarbonizes (based on CRA's national power sector outlook), although natural gas retains a significant market share over the long term in the Reference Case.
- The residential and commercial sectors are projected to be relatively flat, with industrial demand growth of ~0.8% per year over the long-term (all based on the AEO base case).
- LNG demand is expected to increase over time, especially in the near-term as under-construction projects enter into service.



POWER SECTOR GAS DEMAND AND NATIONAL GENERATION MIX

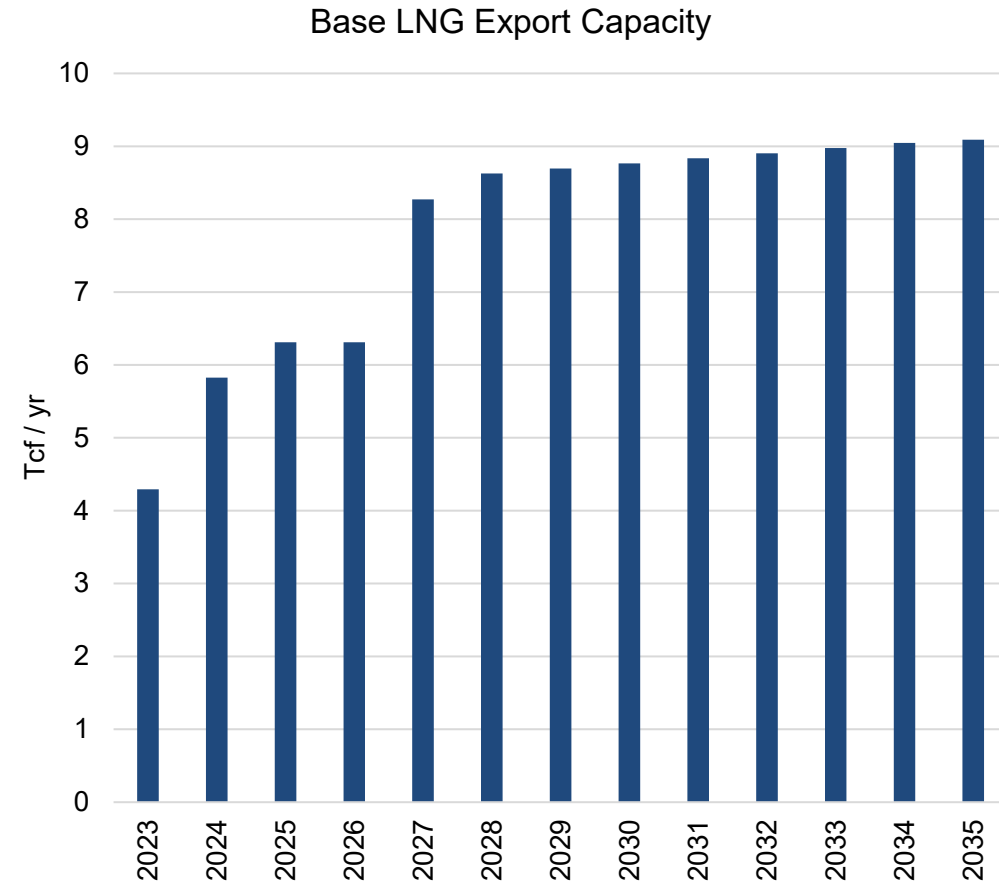


We exist to deliver safe, reliable energy that drives value to our customers

LNG EXPORT DEMAND IS ESTIMATED THROUGH A REVIEW OF PROPOSED AND EXISTING PROJECTS

- LNG export expectations have increased in recent years as additional projects have come online and started construction.
- AEO's long-term view of exports reflects that high demand for US LNG has terminals operating at higher capacity factors than have been observed in recent years.

CRA notes a surge in LNG export demand expectations this year and through 2027, which will likely exert upward pressure on prices.



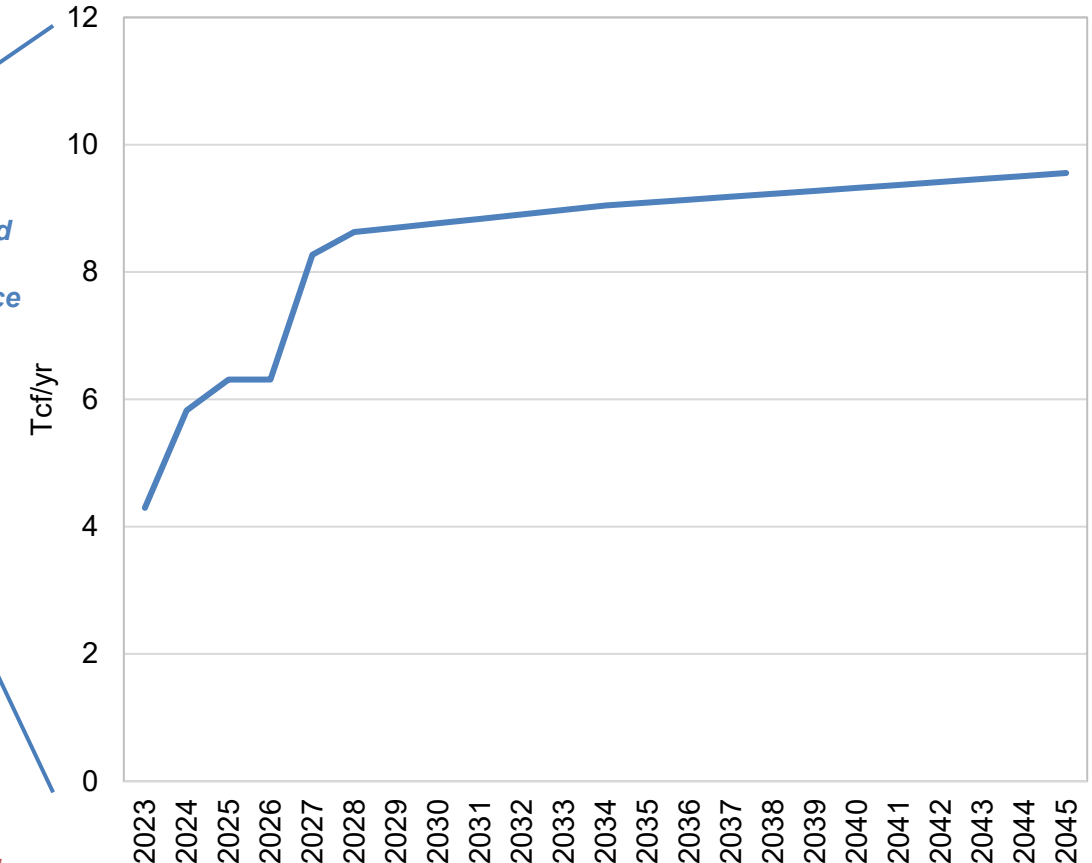
LNG PROJECT LIST

Project	Status	Date	Capacity (Bcf/d)
Sabine (T1-T6)	Operating	2023	4.55
Kenai	Operating	2023	0.20
Cove Point (Full Terminal)	Operating	2023	0.79
Sempra Cameron (T1-T3)	Operating	2023	2.06
Elba/Southern LNG (T1-T10)	Operating	2023	0.35
Freeport (T1-T3)	Operating	2023	2.38
Corpus Christi (T1-T3) TX	Operating	2023	2.40
Cameron Parish (Units 1-4)	Operating	2023	1.11
Plaquemines Parish Phase 1	Under Const.	2024	1.76
Plaquemines Parish Phase 2	Under Const.	2025	1.56
Cameron Parish (units 7-9)	Under Const.	2024	0.61
Calcasieu Parish Phase 1	Under Const.	2027	3.81
Golden Pass	Under Const.	2024	2.57
Corpus Christi TX	Under Const.	2027	1.58
Port Arthur (T1)	Under Const.	2027	0.93
Port Arthur (T2)	Under Const.	2028	0.93
Lake Charles LNG	In Development		2.27
Commonwealth LNG	In Development		1.21
Magnolia LNG	In Development		1.22
Sempra Cameron (T4-T5)	In Development		0.93
Freeport (T4)	In Development		0.74
Jacksonville	In Development		0.13
Texas LNG Brownsville	In Development		0.62
Rio Grande LNG Brownsville	In Development		3.73
Gulf LNG Liquefaction	In Development		1.50
Nikiski	In Development		2.76
Port Arthur (T3-T4)	In Development		1.86
Delfin FLNG	In Development		1.80

Assumed
in CRA
Reference
Case

Excluded

LNG Demand Projection



*Assumes 85% utilization through 2028, with 0.5% increase in demand thereafter

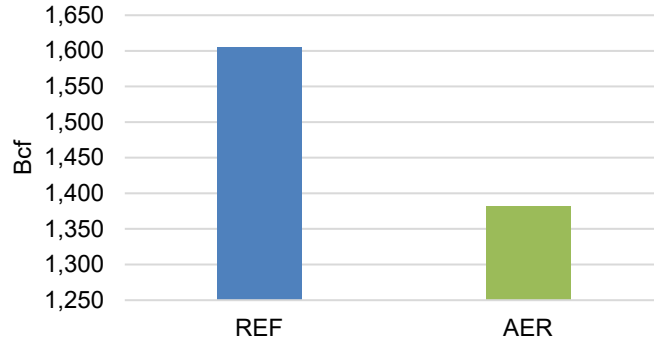
We exist to deliver safe, reliable energy that drives value to our customers

FUNDAMENTAL NATURAL GAS PRICE DRIVERS ACROSS SCENARIOS

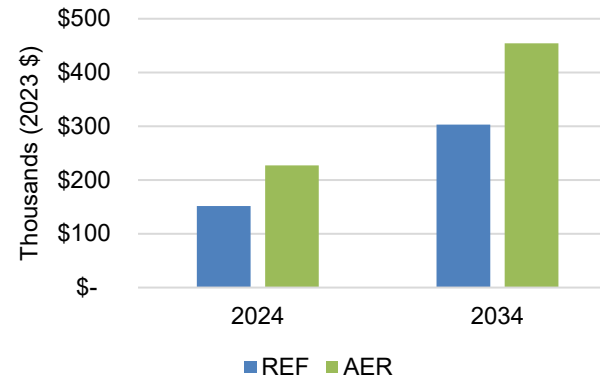
Aggressive Environmental Regulation (AER)

~1.5 multiple applied to environmental capex; PGC min resource value used to simulate fracking ban or other production restrictions.

Total unproven resources



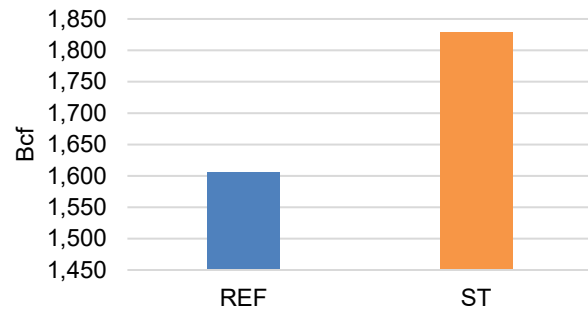
Environmental Capex comparison



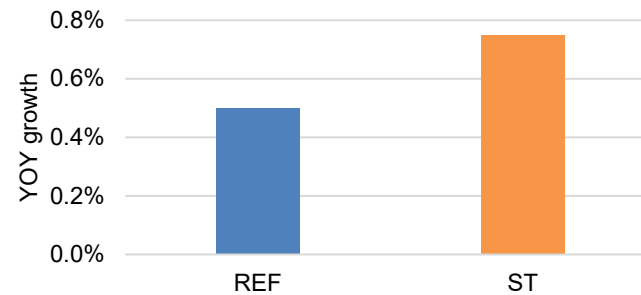
Slower Transition (ST)

PGC unproven resource size increases from Reference; well productivity rates increase due to more focus on gas as opposed to other power sources.

Total unproven resources



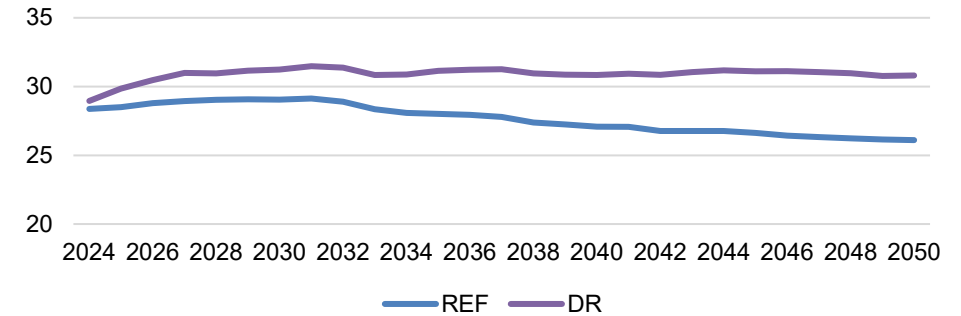
Resource growth YOY



Domestic Resiliency (DR)

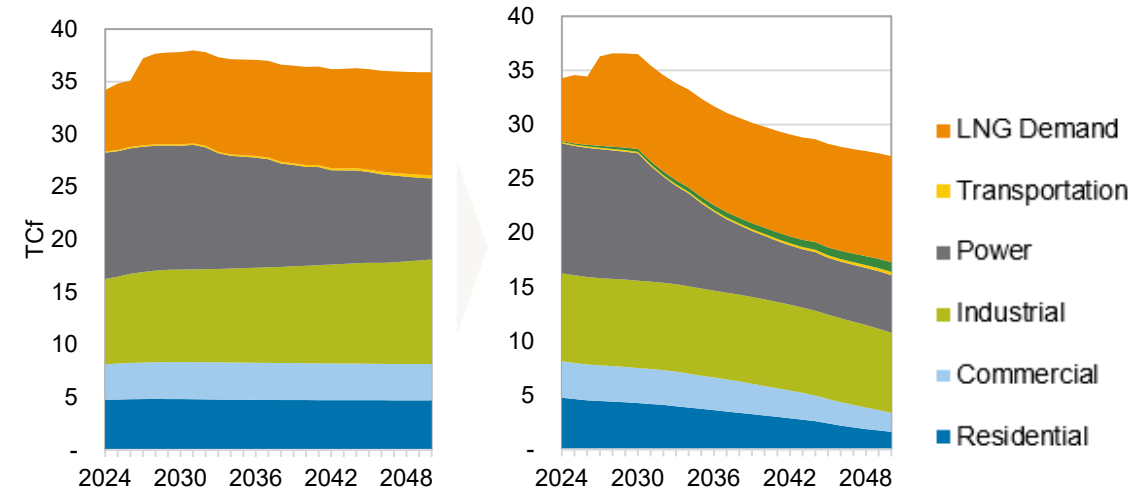
AEO “high oil supply, high gas supply” demand trajectory used instead of AEO reference case. This is the highest of their ~20 trajectories.

Gas Demand Trajectory REF vs DR



Accelerated Innovation (AI)

U.S. Gas Demand



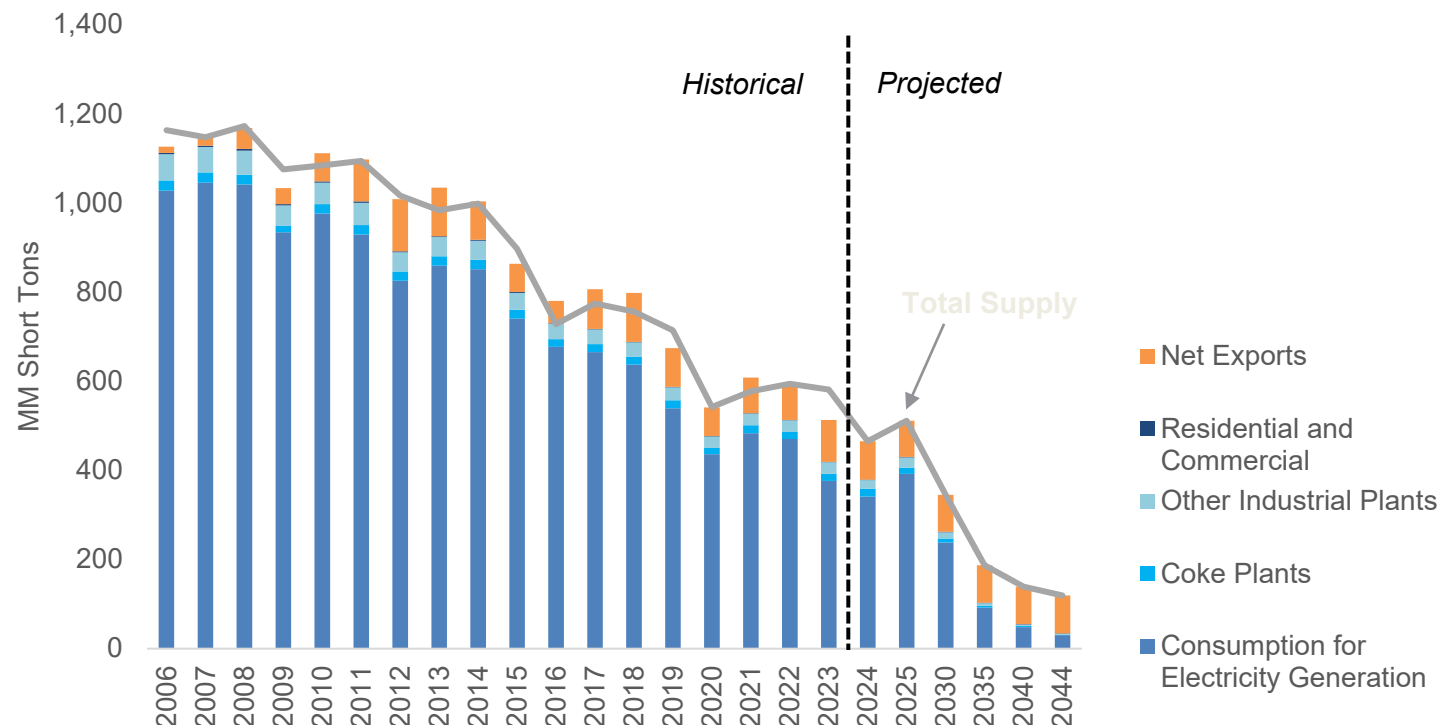
We exist to deliver safe, reliable energy that drives value to our customers

COAL SUPPLY-DEMAND PROJECTIONS

CRA's price forecast reflects declining domestic demand

- A 3% uptick in coal production was experienced in 2022, following a higher 6% increase in 2021 due to elevated gas prices, strong exports, and a greater dependence on coal-fired generation in that period. 2023 production is, however, estimated to have fallen by about 2% to about 581 MM tons.
- Further declines in coal demand are expected in the next 5 years due to continued retirements and increasing penetration of natural gas and renewable resources.

Historical and Forecasted Supply Demand Balance for Coal



Historical: EIA and MSHA
Forecast: CRA Analysis

We exist to deliver safe, reliable energy that drives value to our customers



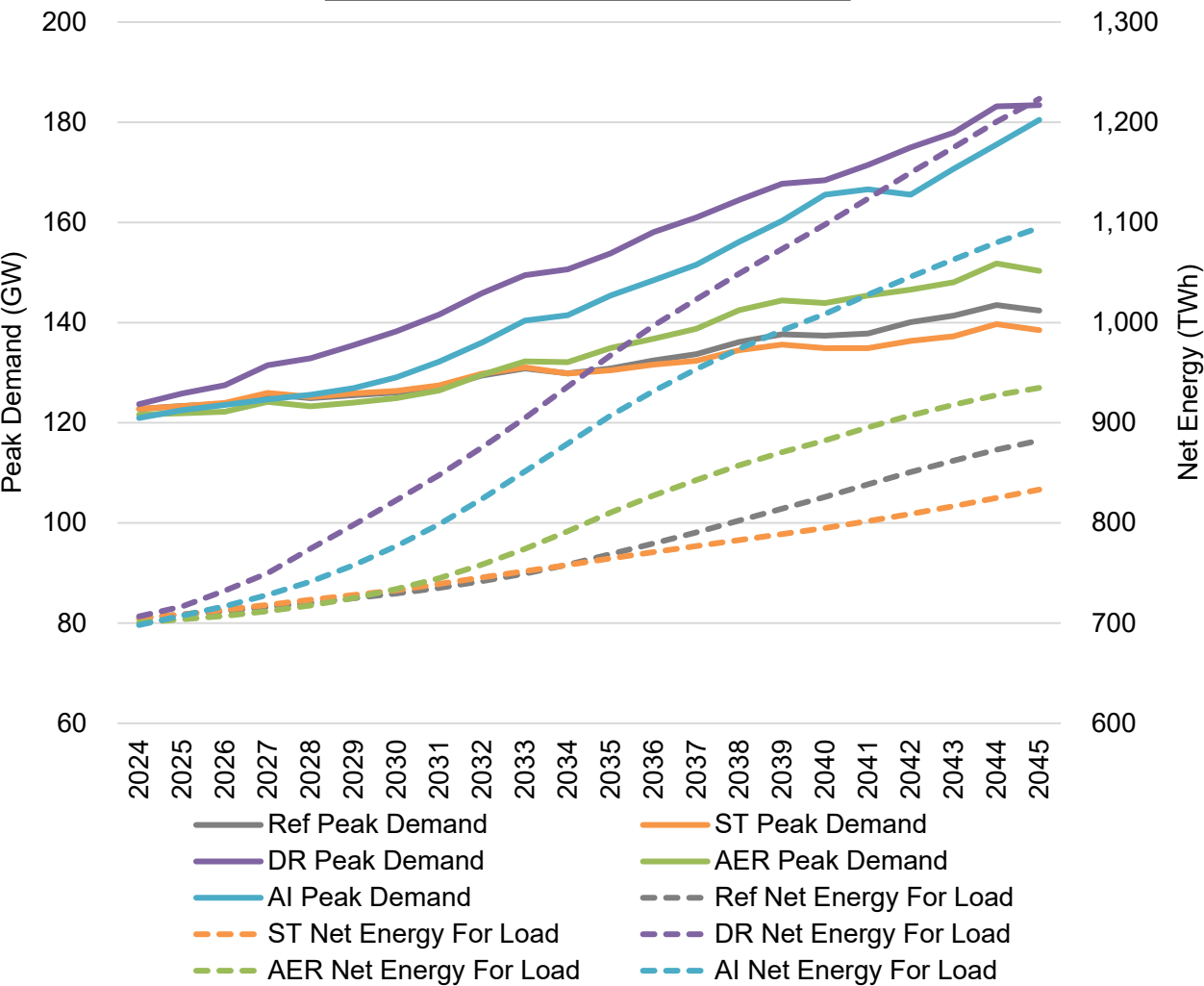
We exist to deliver safe, reliable energy that drives value to our customers

APPENDIX: SCENARIO ANALYSIS MISO MARKET OUTPUTS

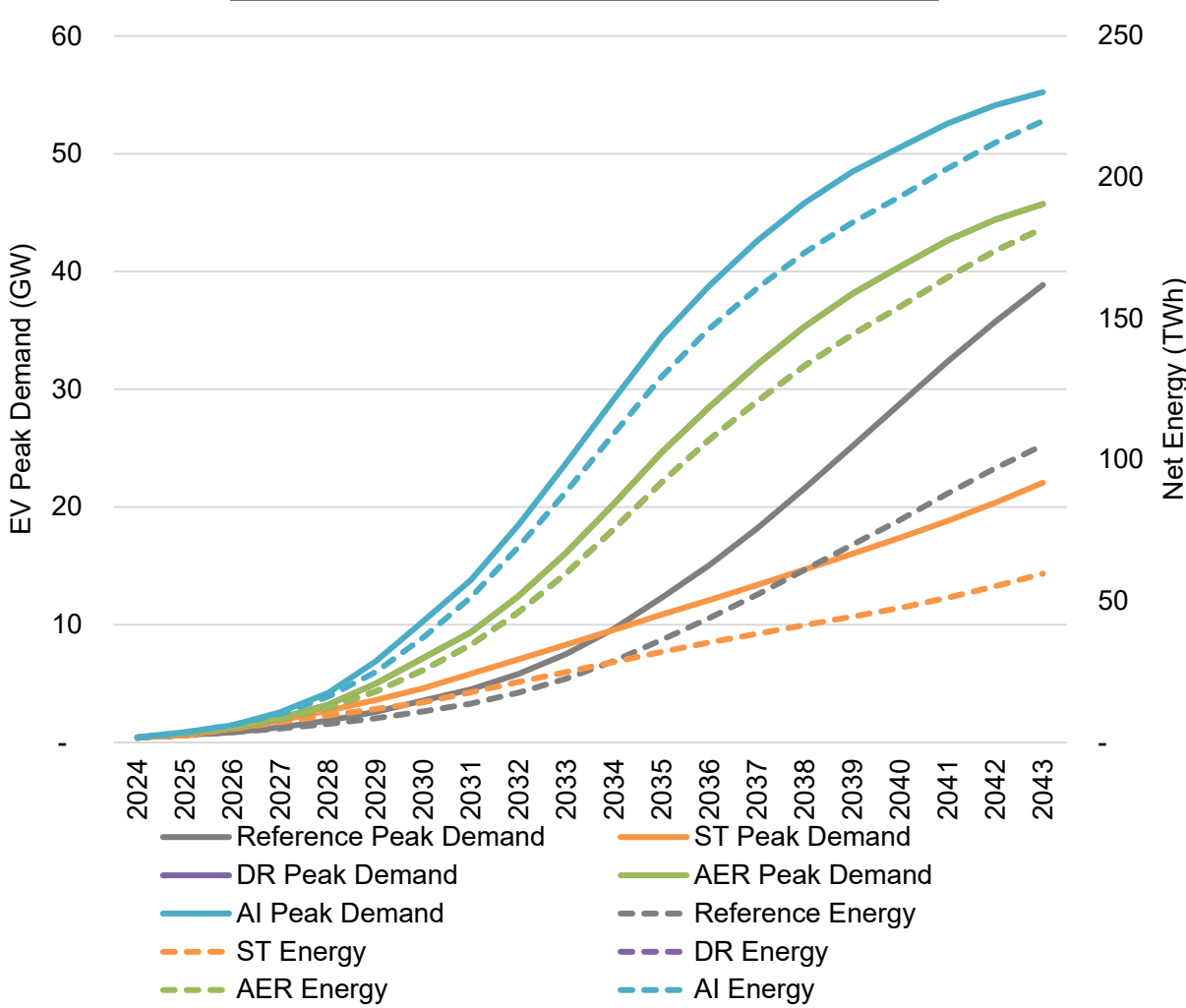


MISO LOAD FORECAST RANGES

Overall Demand Forecast

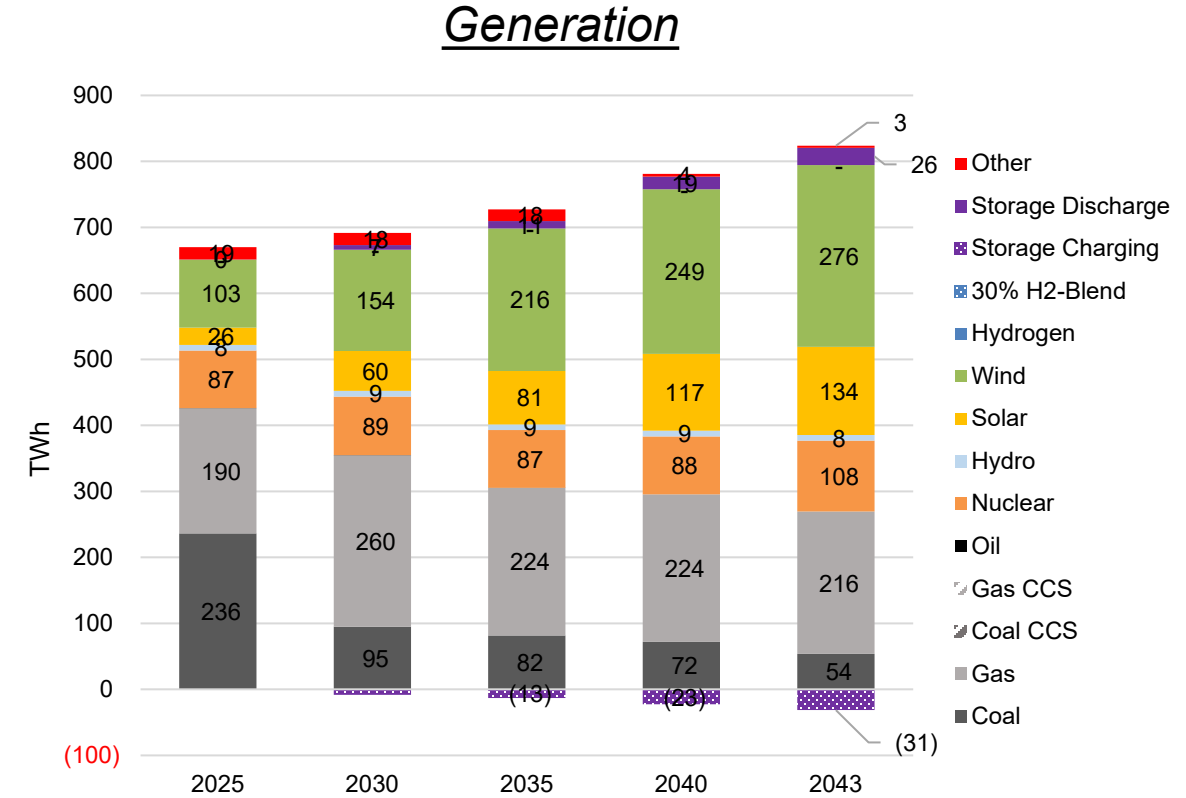
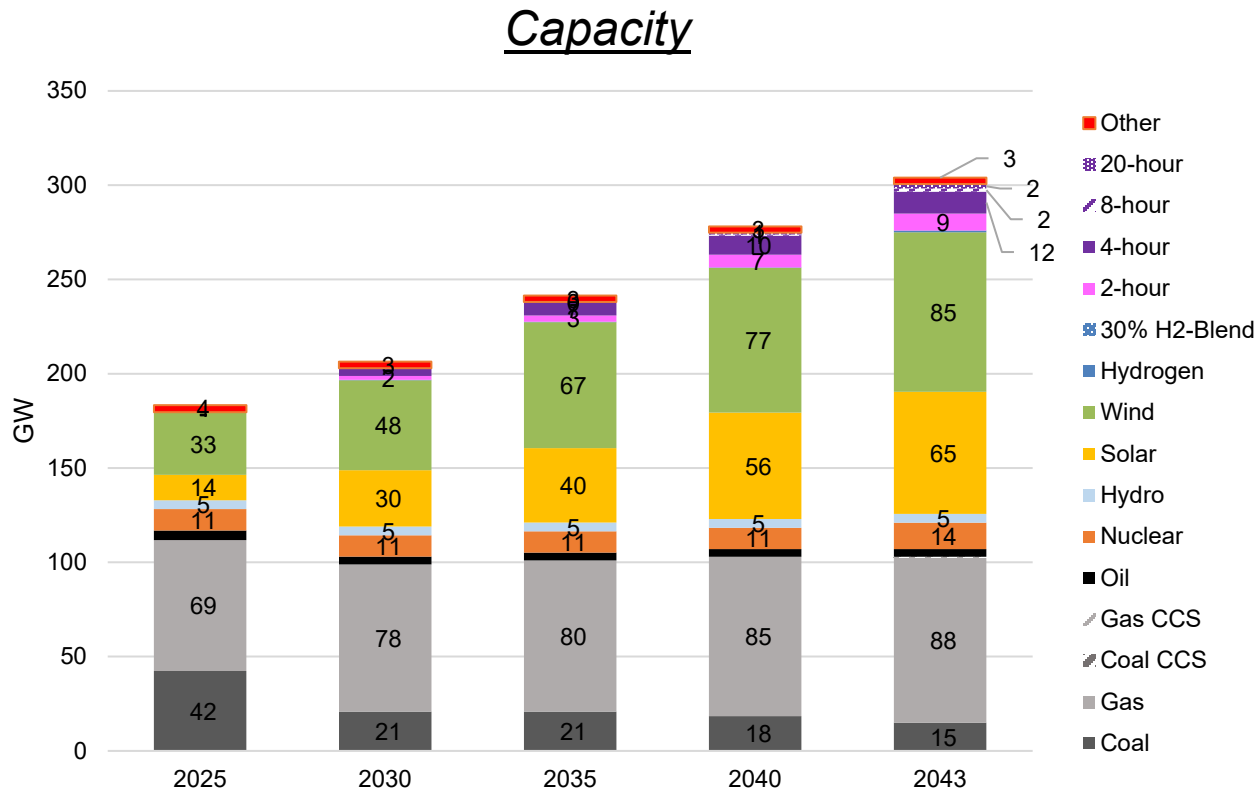


Electric Vehicle Demand Forecast



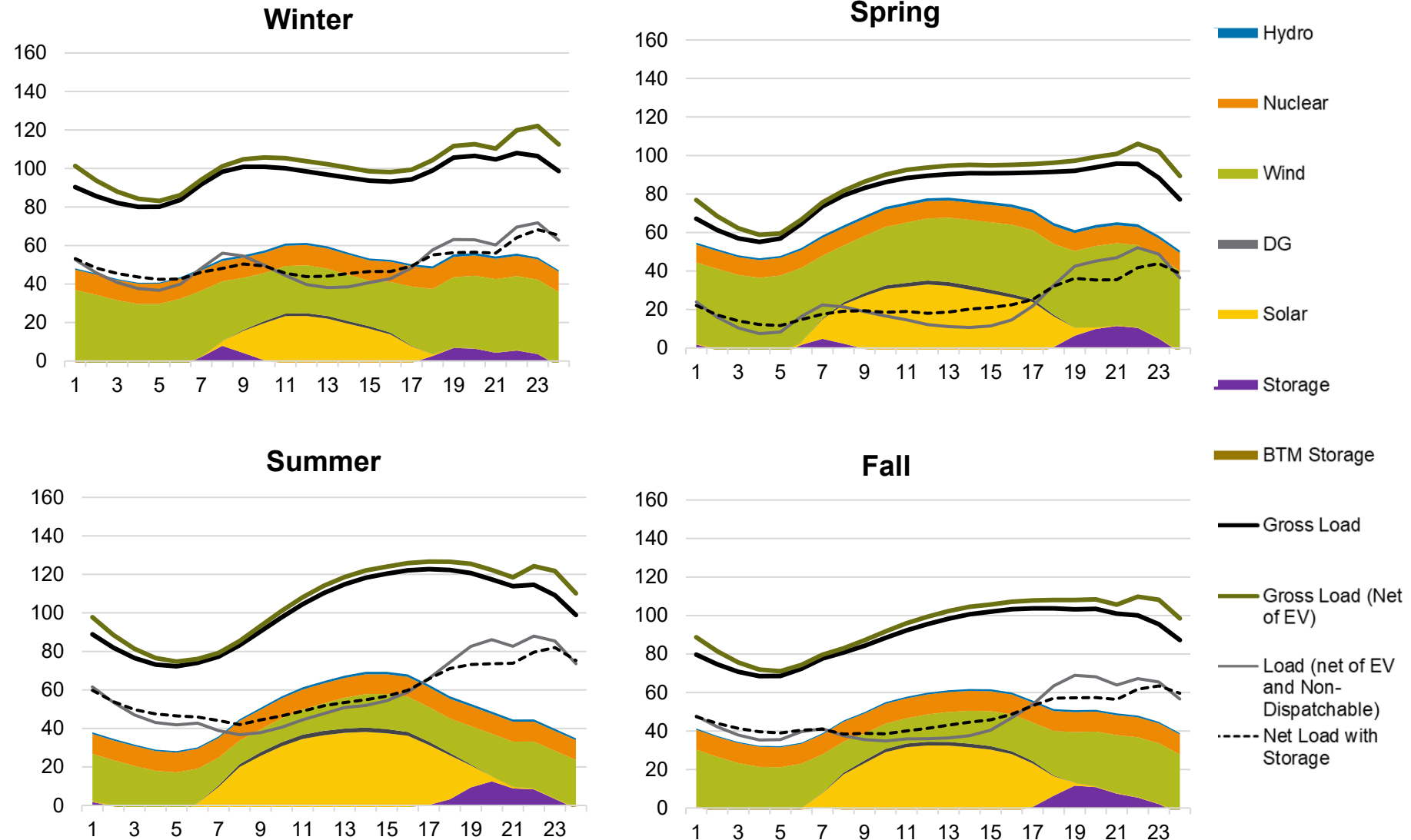
We exist to deliver safe, reliable energy that drives value to our customers

MISO CAPACITY AND GENERATION MIX (SLOWER TRANSITION)



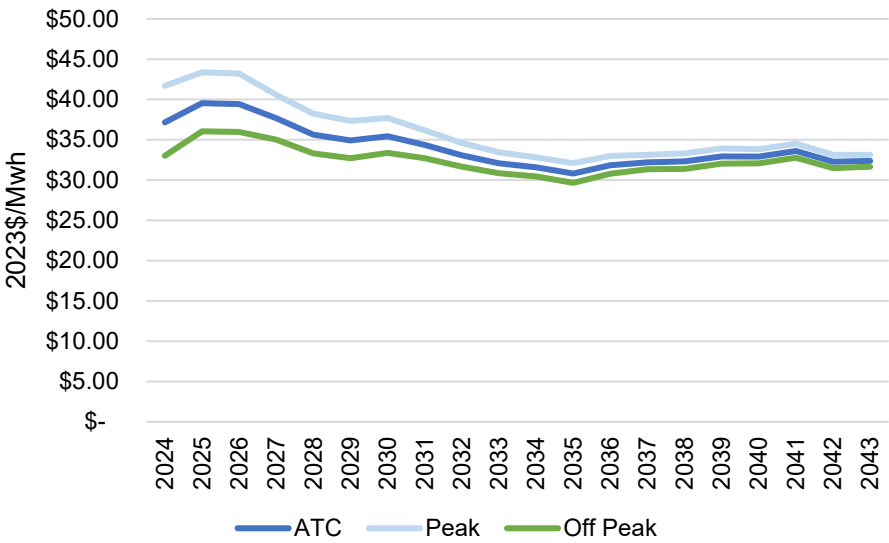
We exist to deliver safe, reliable energy that drives value to our customers

MISO HOURLY ENERGY PROFILE (SLOWER TRANSITION) - 2040

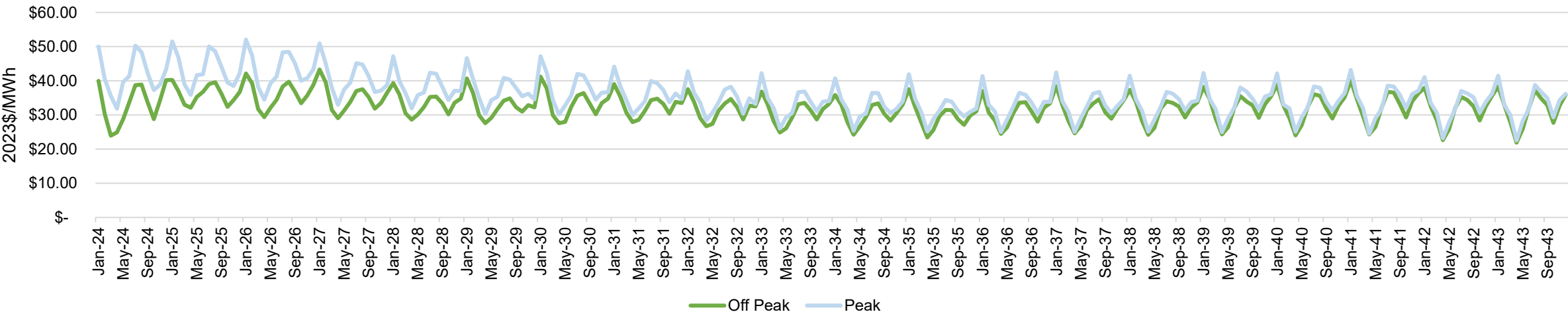


We exist to deliver safe, reliable energy that drives value to our customers

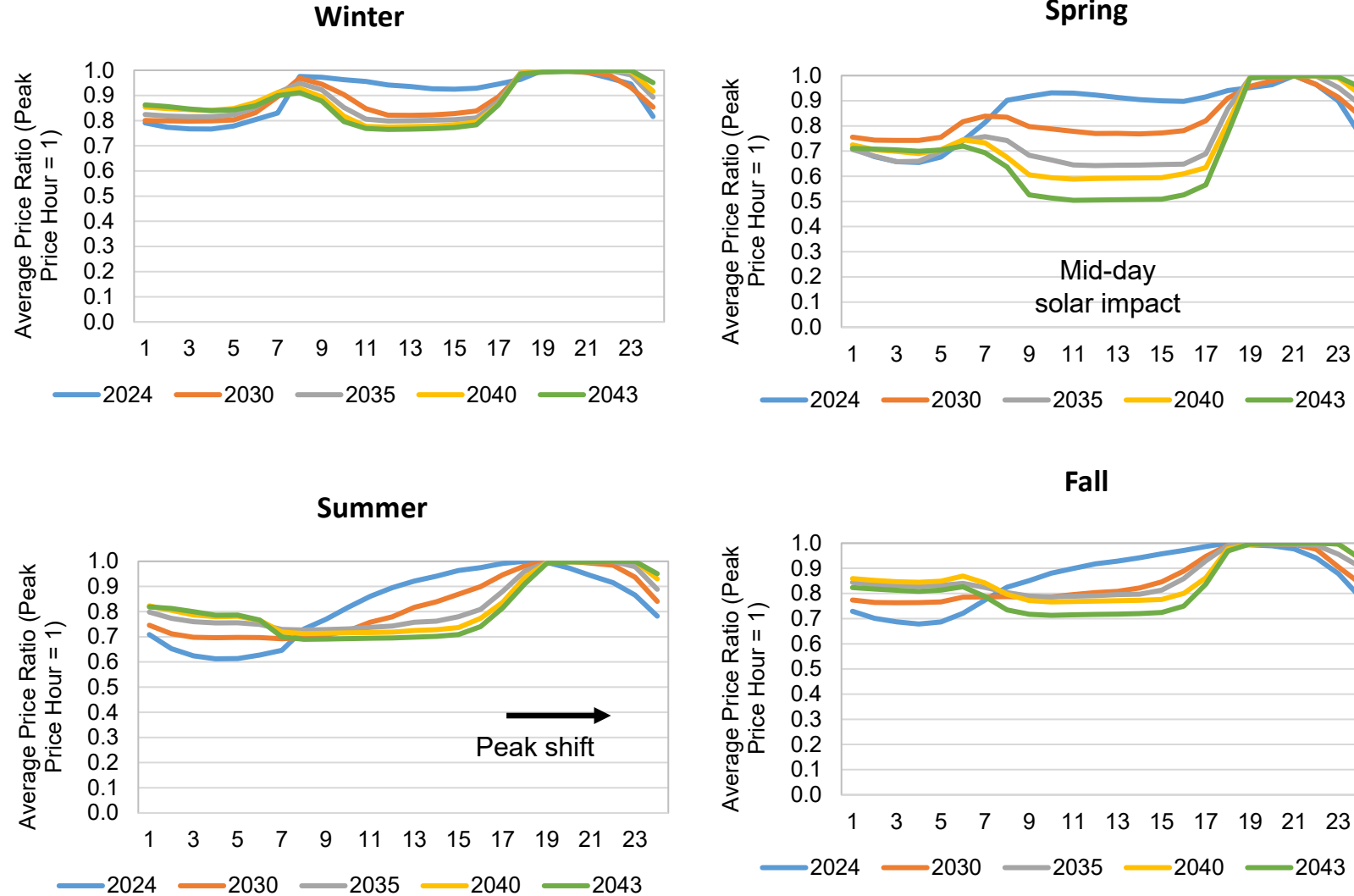
MISO ZONE 6 POWER PRICE PROJECTIONS – SLOWER TRANSITION



Energy Price

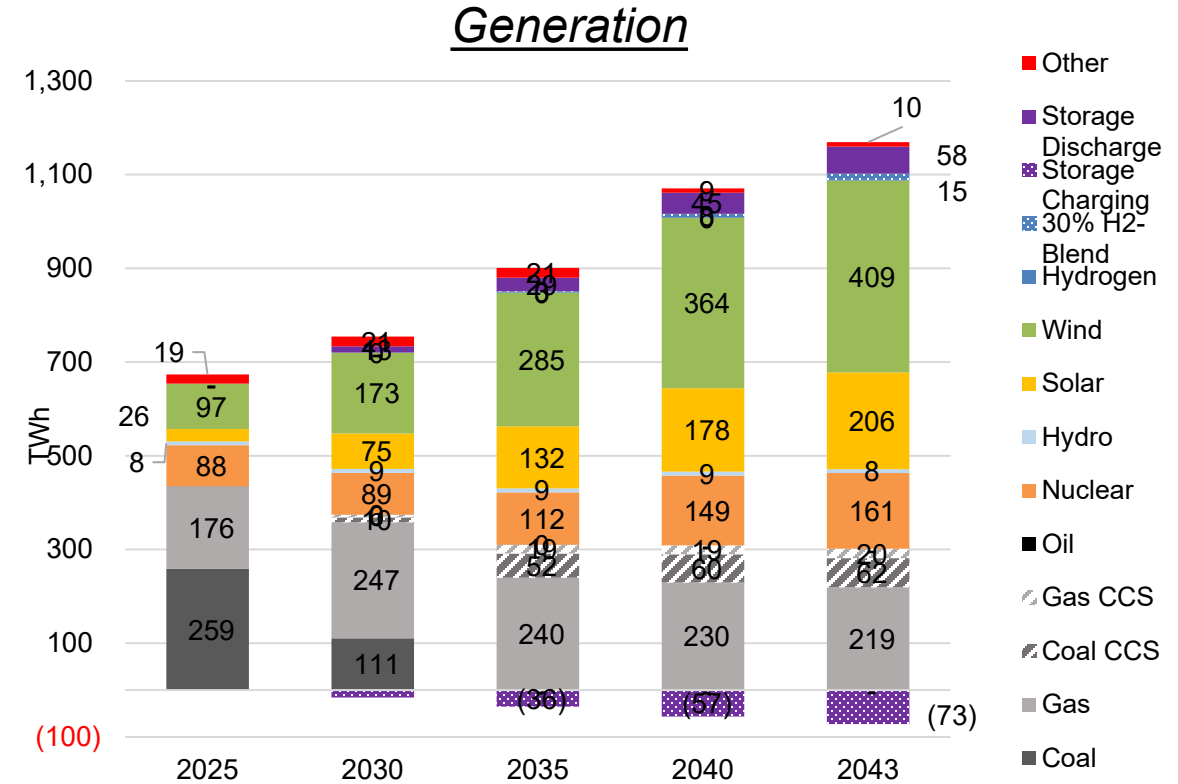
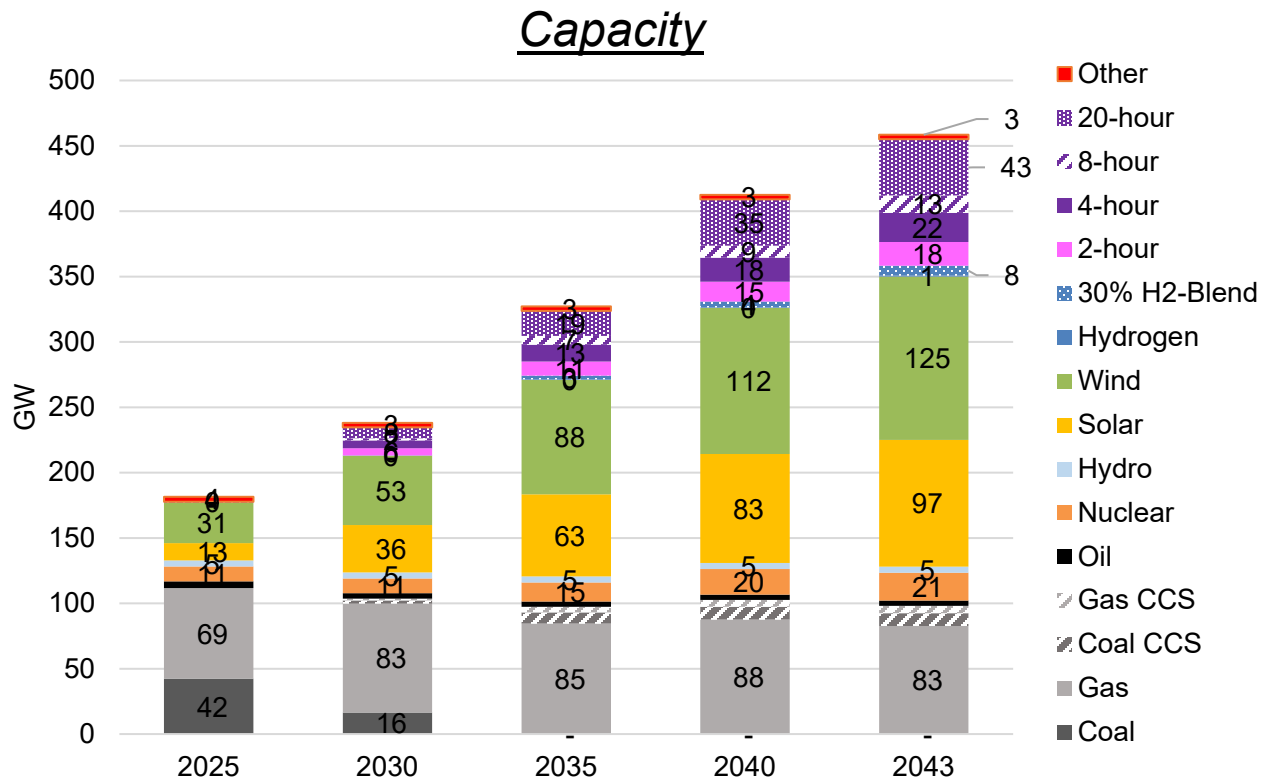


HOURLY PRICE SHAPES – SLOWER TRANSITION



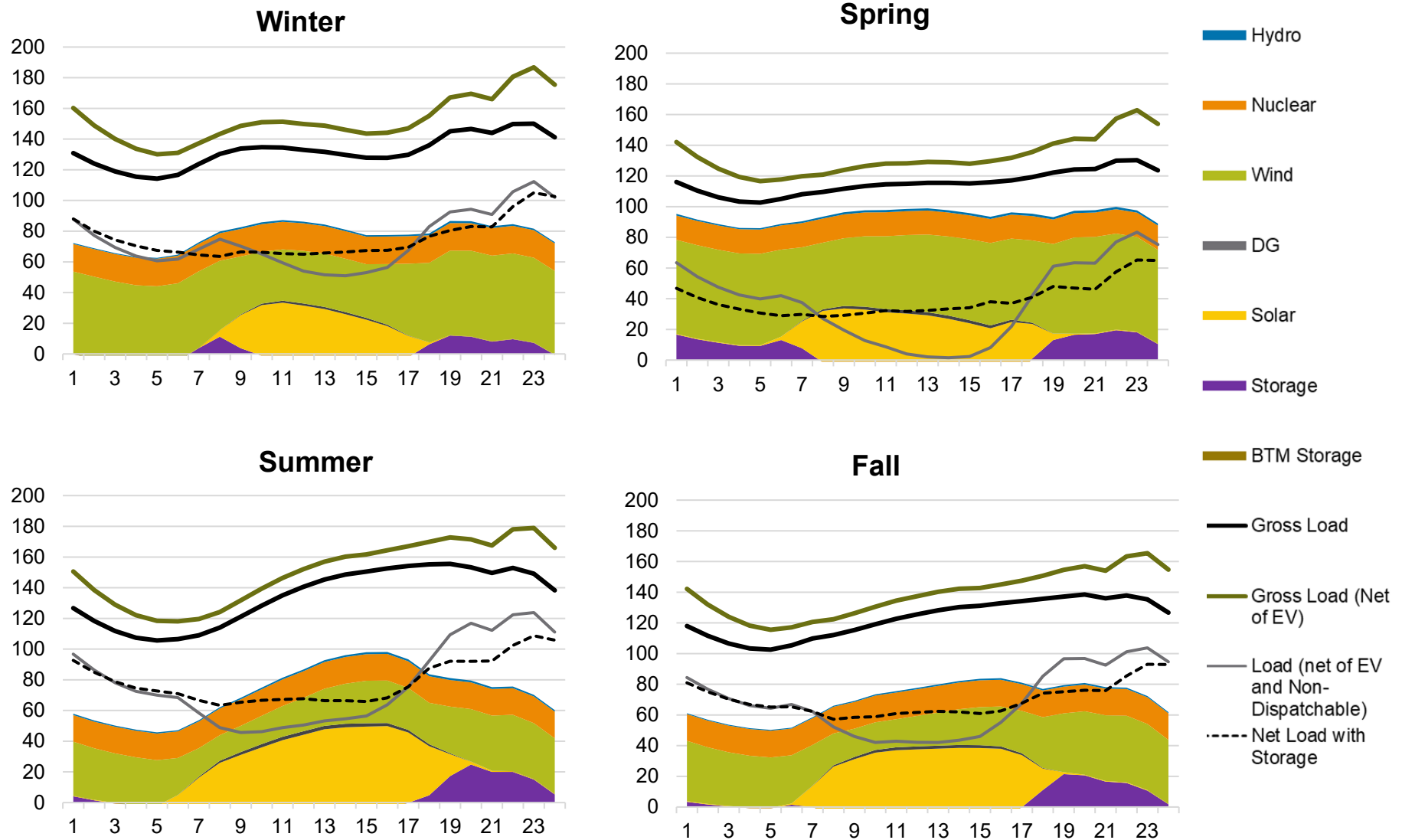
We exist to deliver safe, reliable energy that drives value to our customers

MISO CAPACITY AND GENERATION MIX (DOMESTIC RESILIENCY)



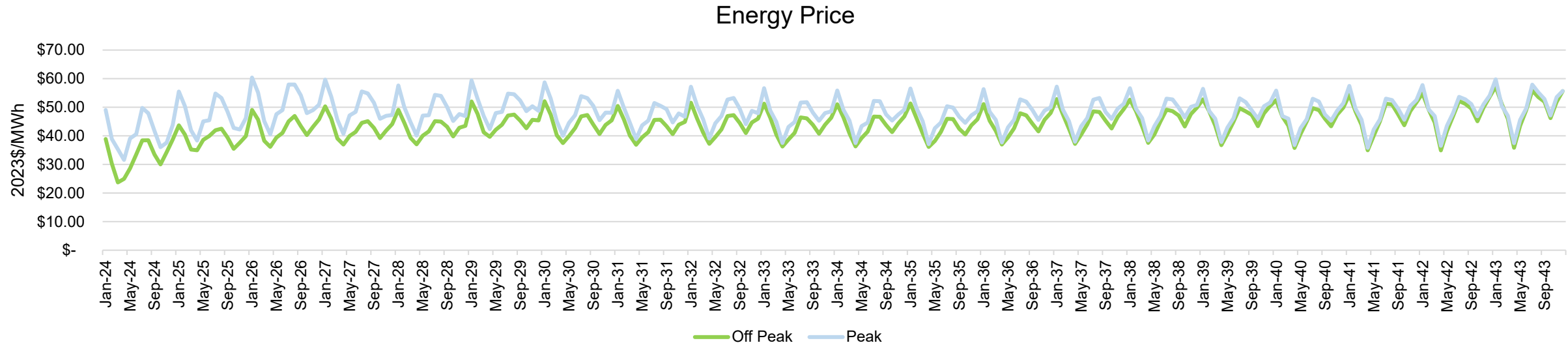
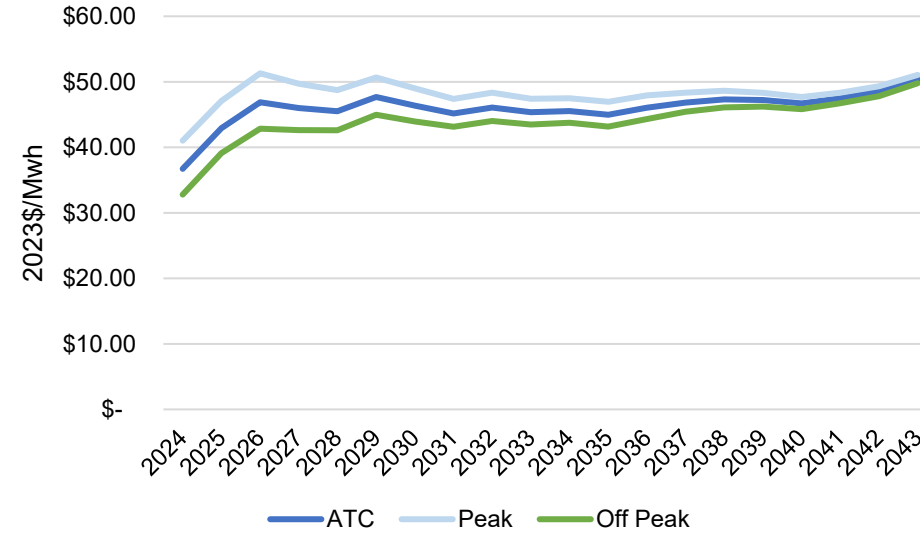
We exist to deliver safe, reliable energy that drives value to our customers

MISO HOURLY ENERGY PROFILE (DOMESTIC RESILIENCY) - 2040



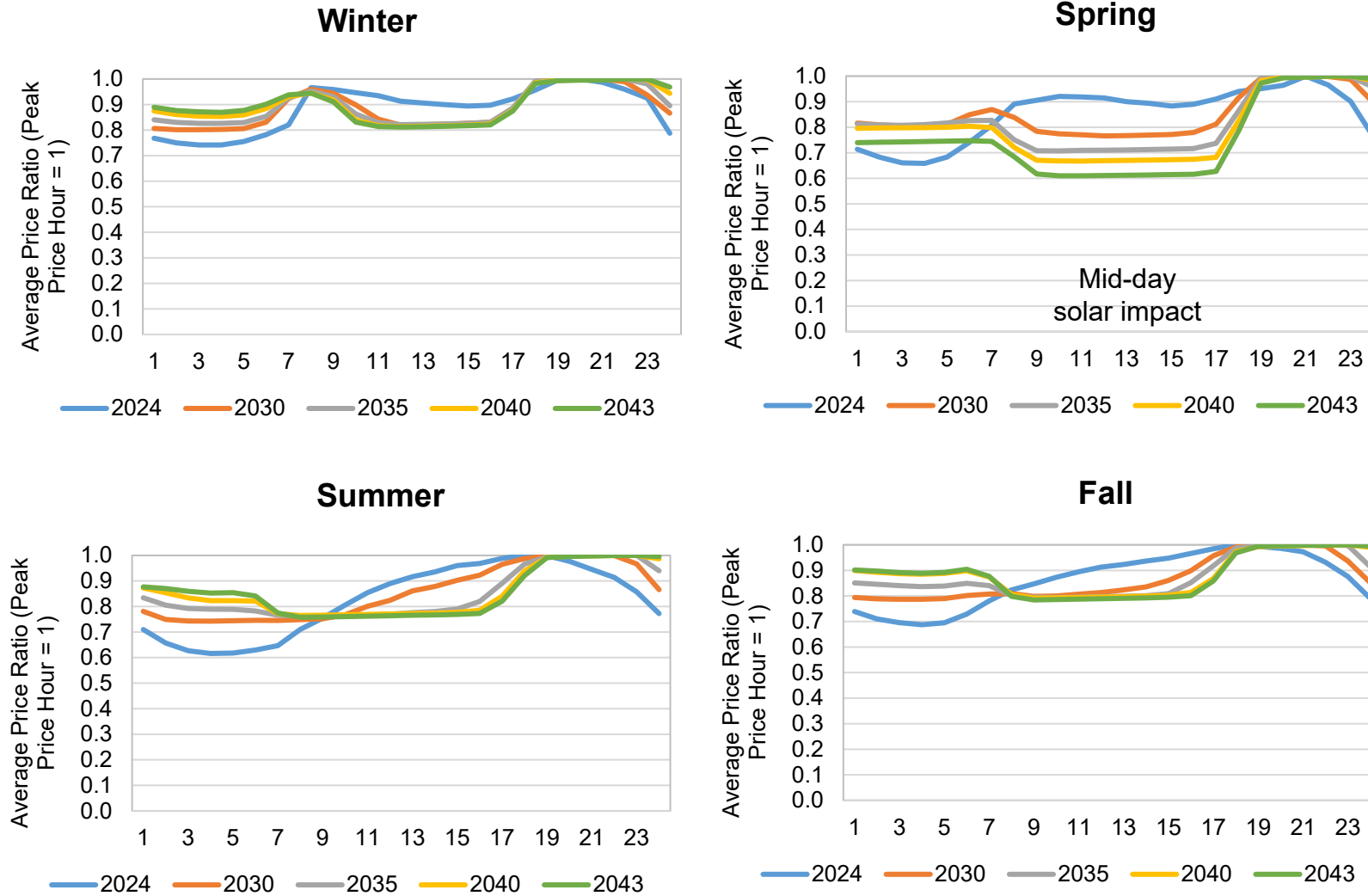
We exist to deliver safe, reliable energy that drives value to our customers

MISO ZONE 6 POWER PRICE PROJECTIONS – DOMESTIC RESILIENCY



We exist to deliver safe, reliable energy that drives value to our customers

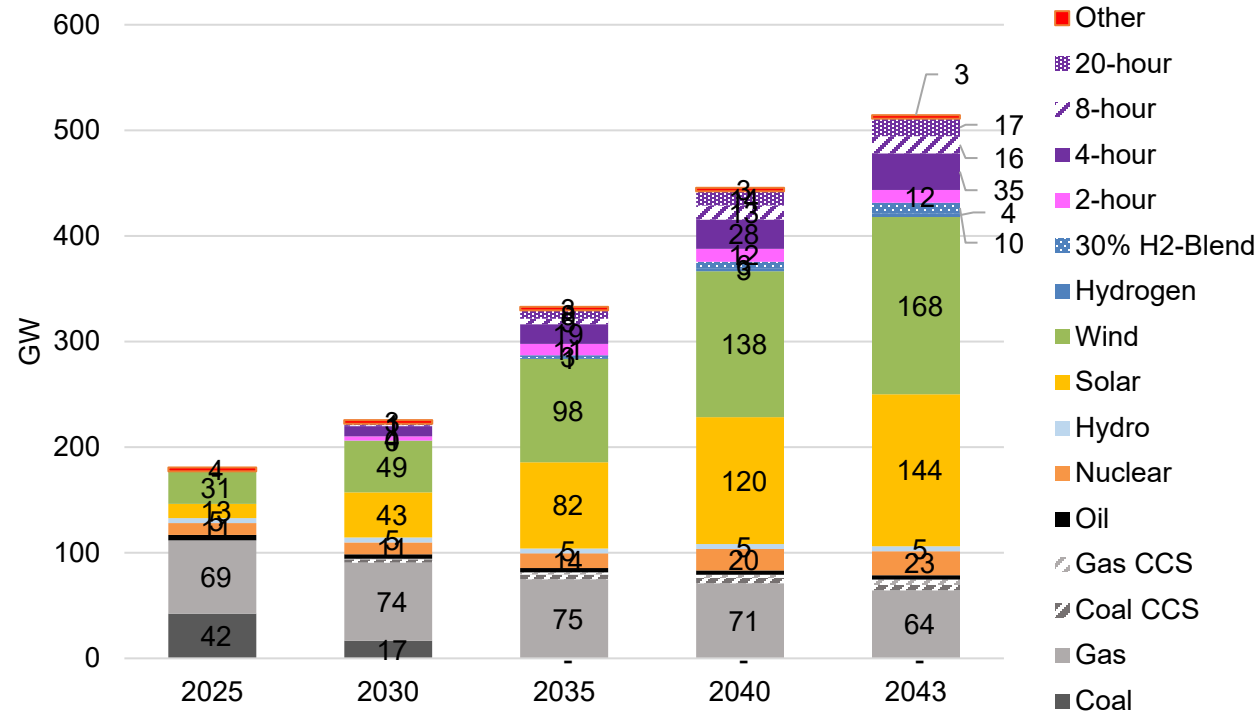
HOURLY PRICE SHAPES – DOMESTIC RESILIENCY



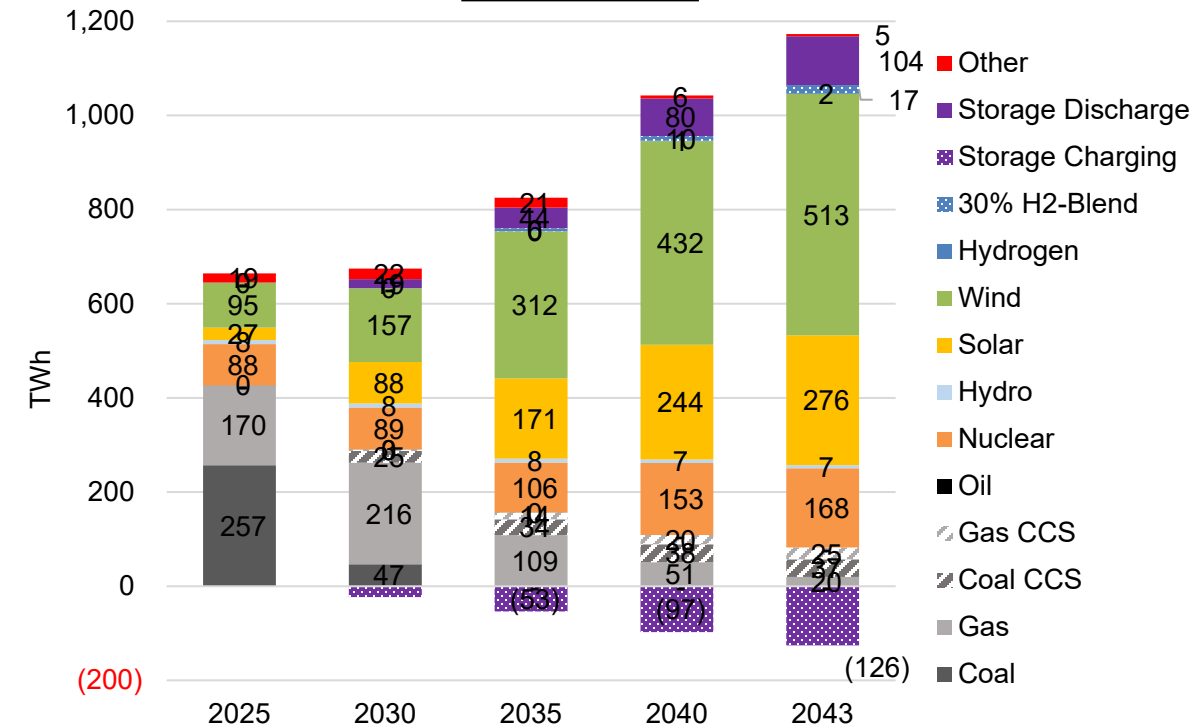
We exist to deliver safe, reliable energy that drives value to our customers

MISO CAPACITY AND GENERATION MIX (AGGRESSIVE ENVIRONMENTAL REGULATION)

Capacity

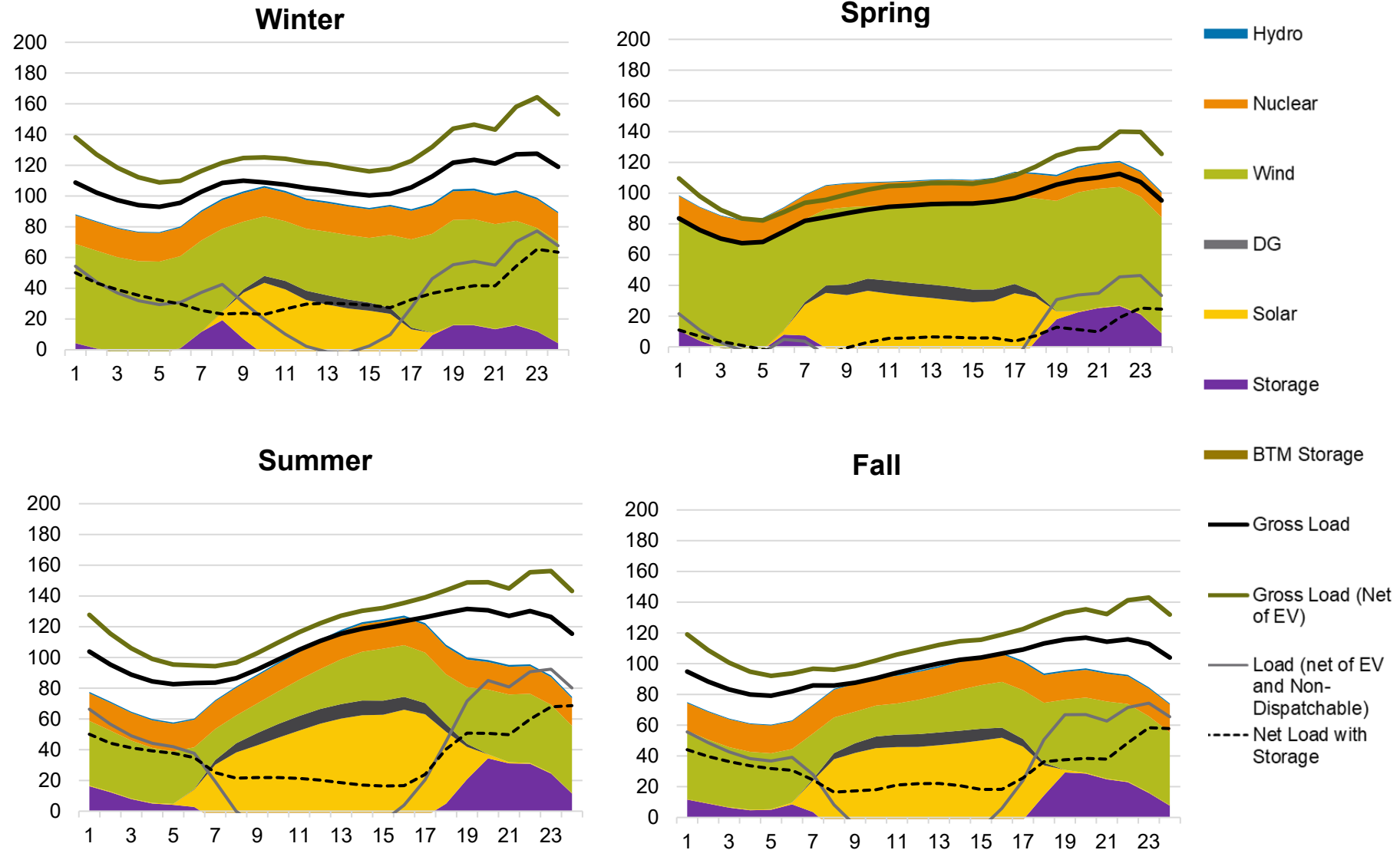


Generation



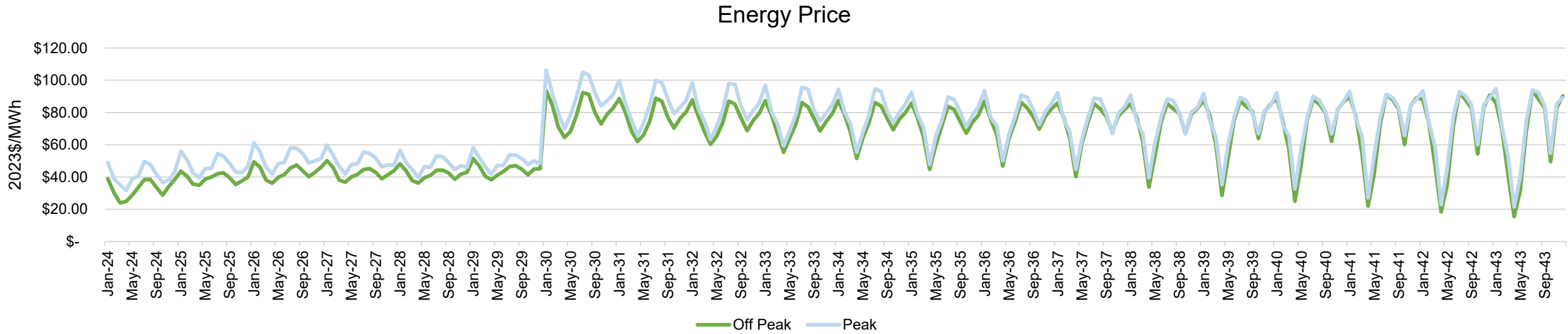
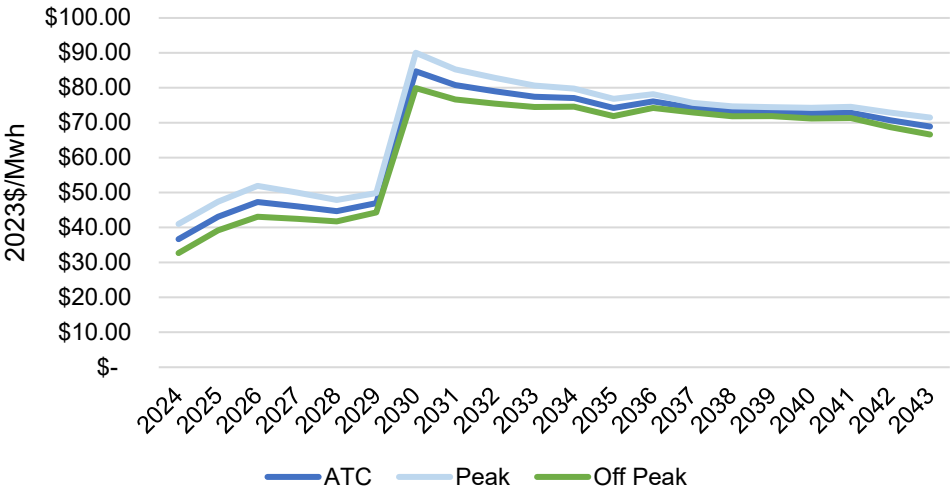
We exist to deliver safe, reliable energy that drives value to our customers

MISO HOURLY ENERGY PROFILE (AGGRESSIVE ENVIRONMENTAL REGULATION) - 2040

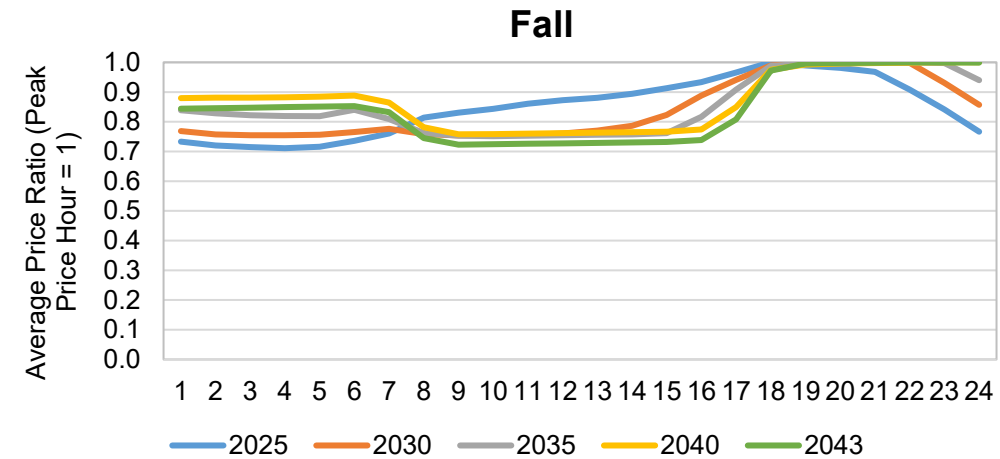
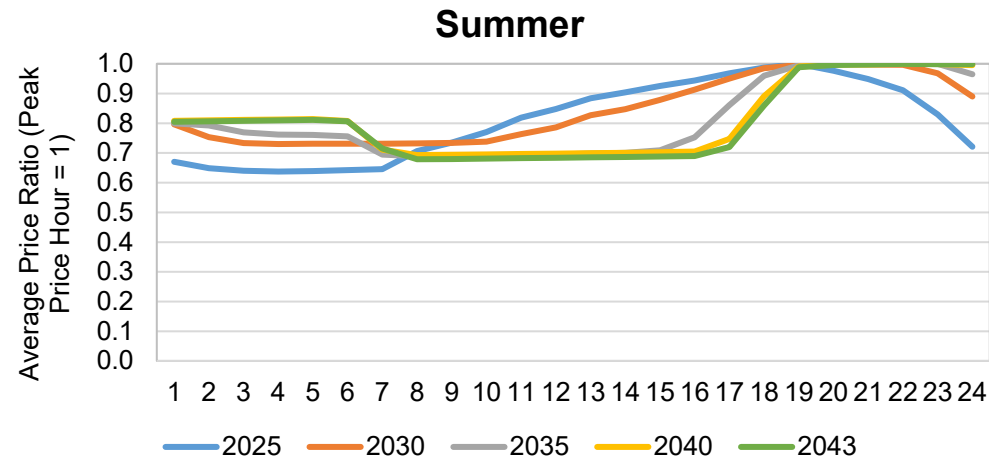
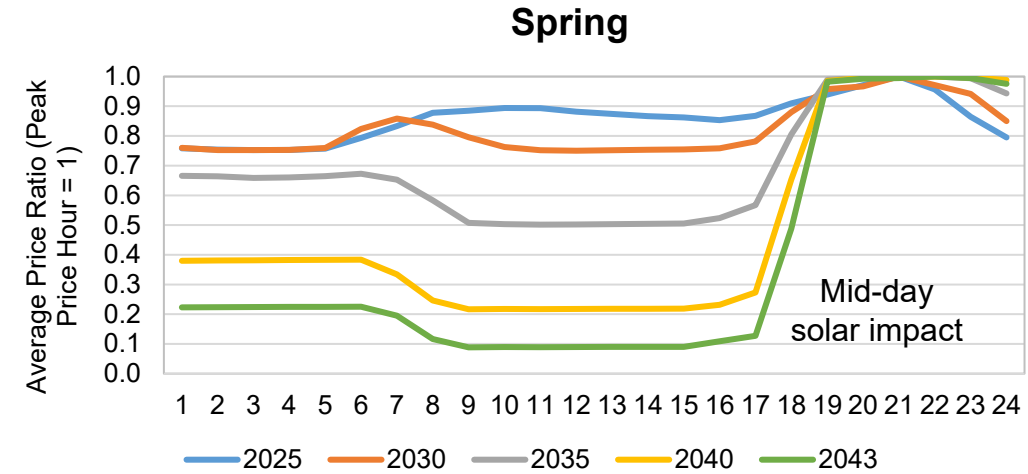
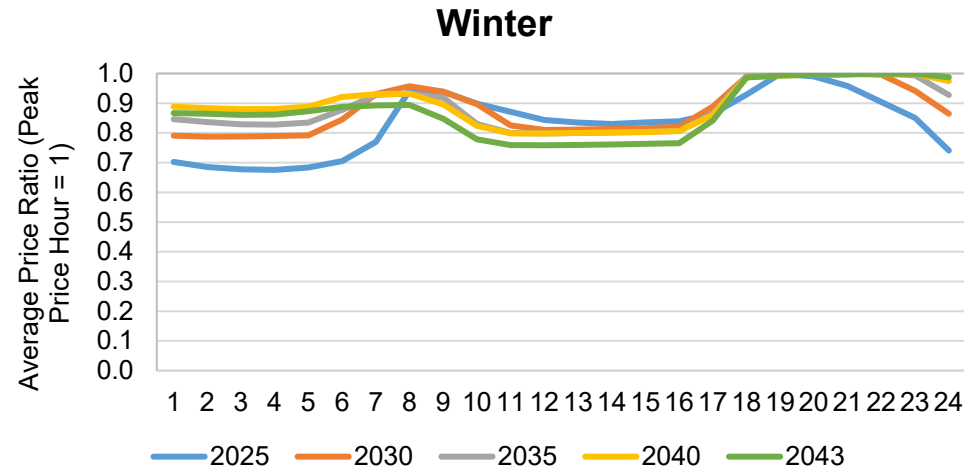


We exist to deliver safe, reliable energy that drives value to our customers

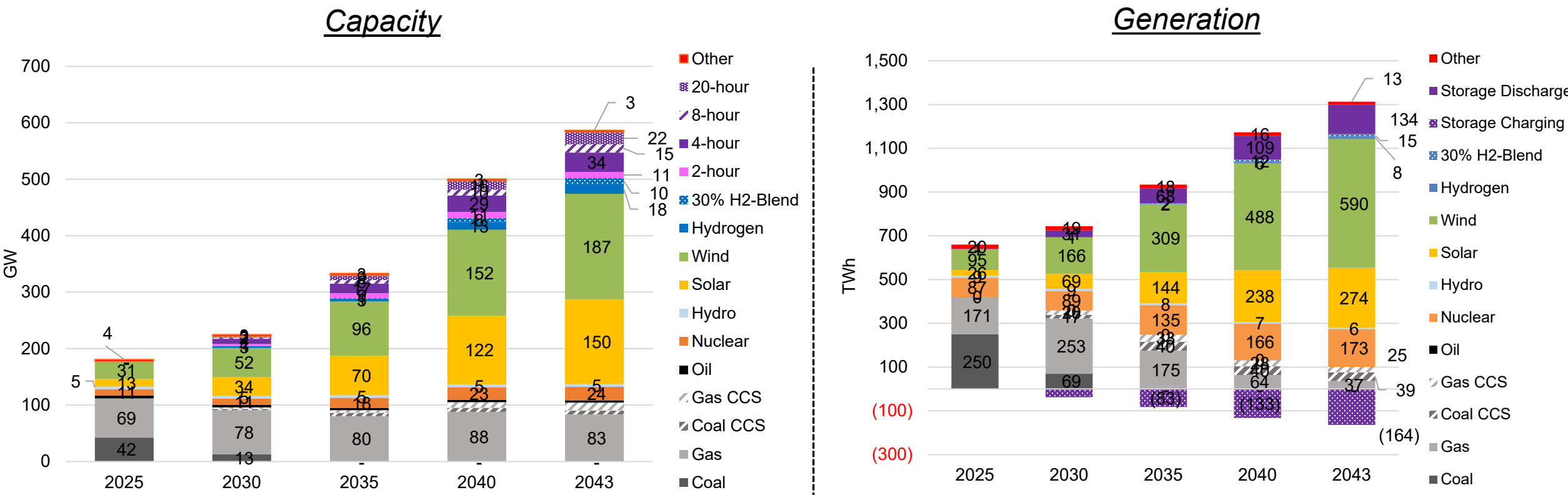
MISO ZONE 6 POWER PRICE PROJECTIONS – AGGRESSIVE ENVIRONMENTAL REGULATION



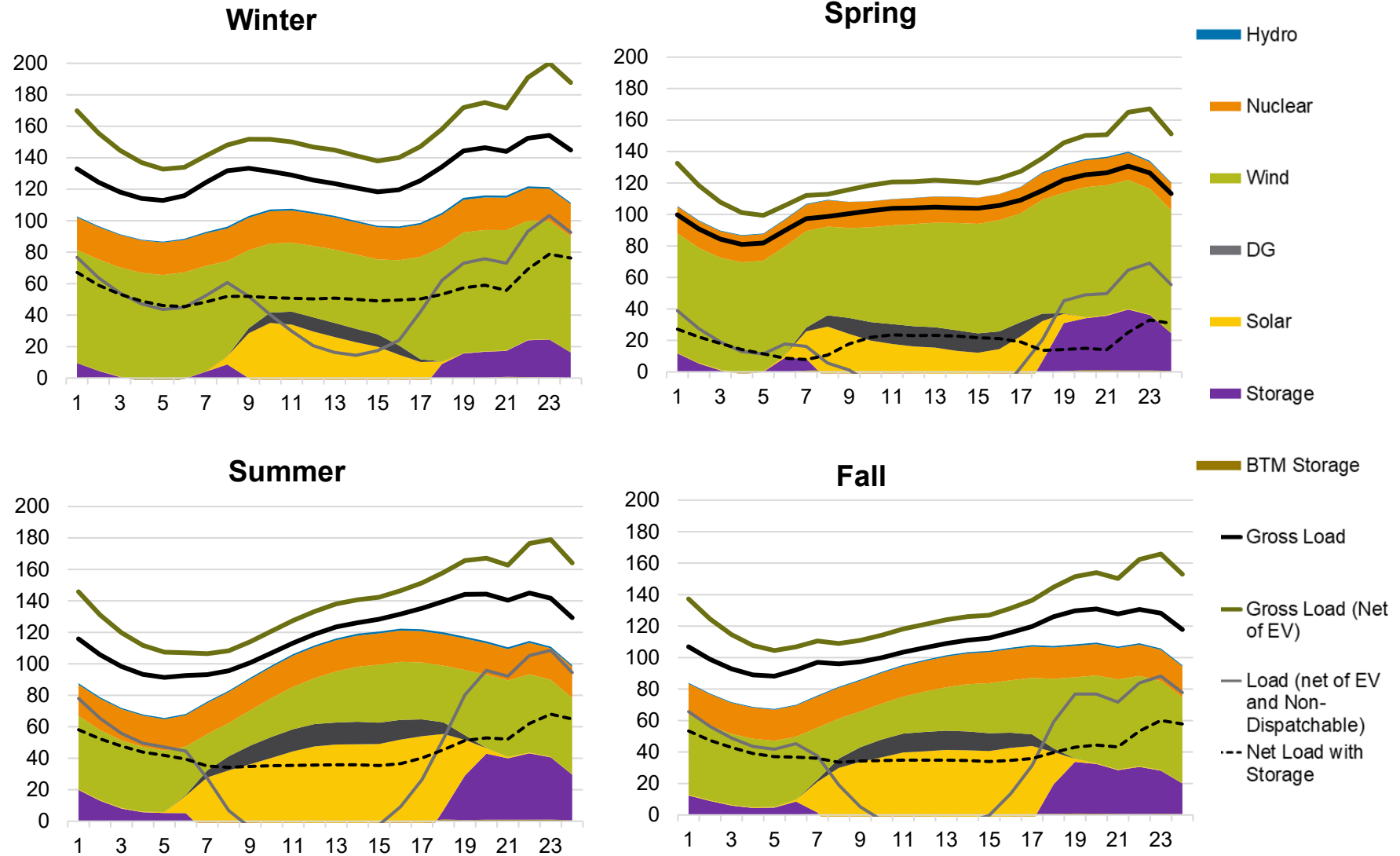
HOURLY PRICE SHAPES – AGGRESSIVE ENVIRONMENTAL REGULATION



MISO CAPACITY AND GENERATION MIX (ACCELERATED INNOVATION)

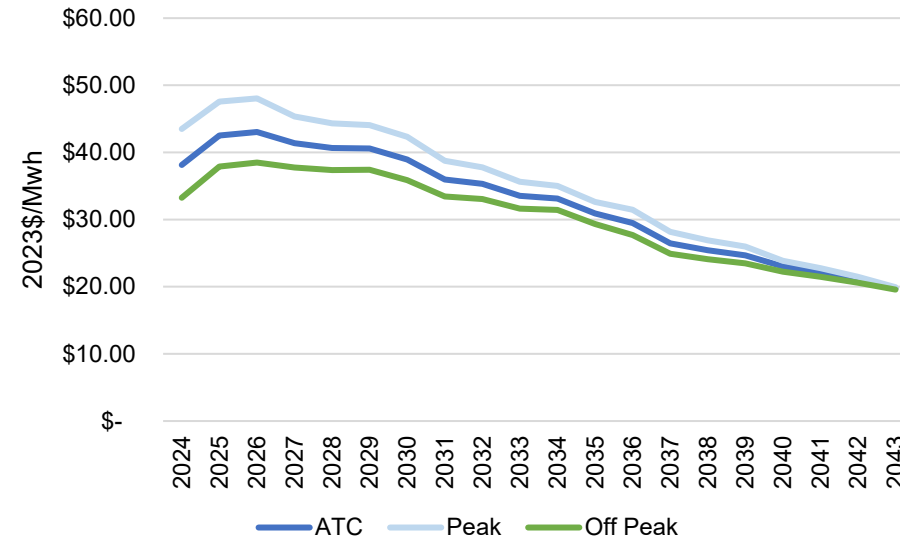


MISO HOURLY ENERGY PROFILE (ACCELERATED INNOVATION) - 2040

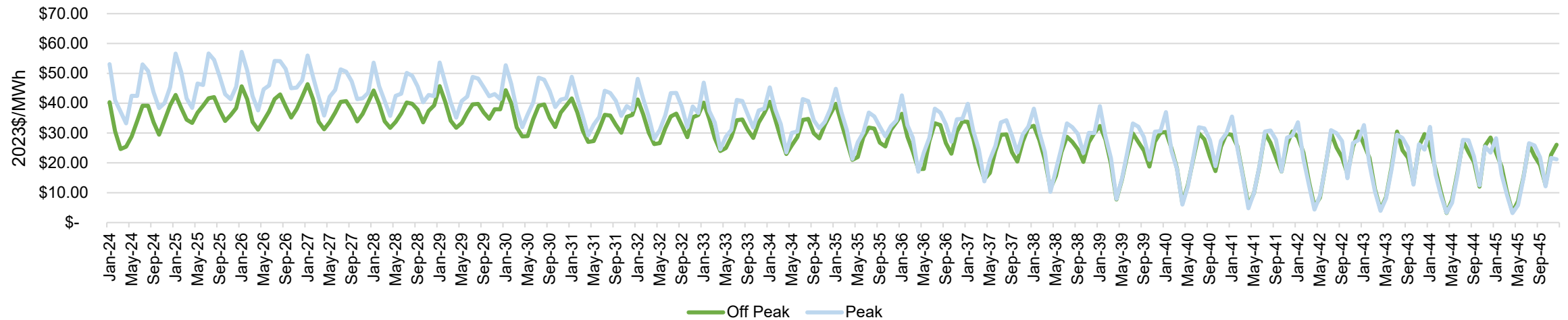


We exist to deliver safe, reliable energy that drives value to our customers

MISO ZONE 6 POWER PRICE PROJECTIONS – ACCELERATED INNOVATION

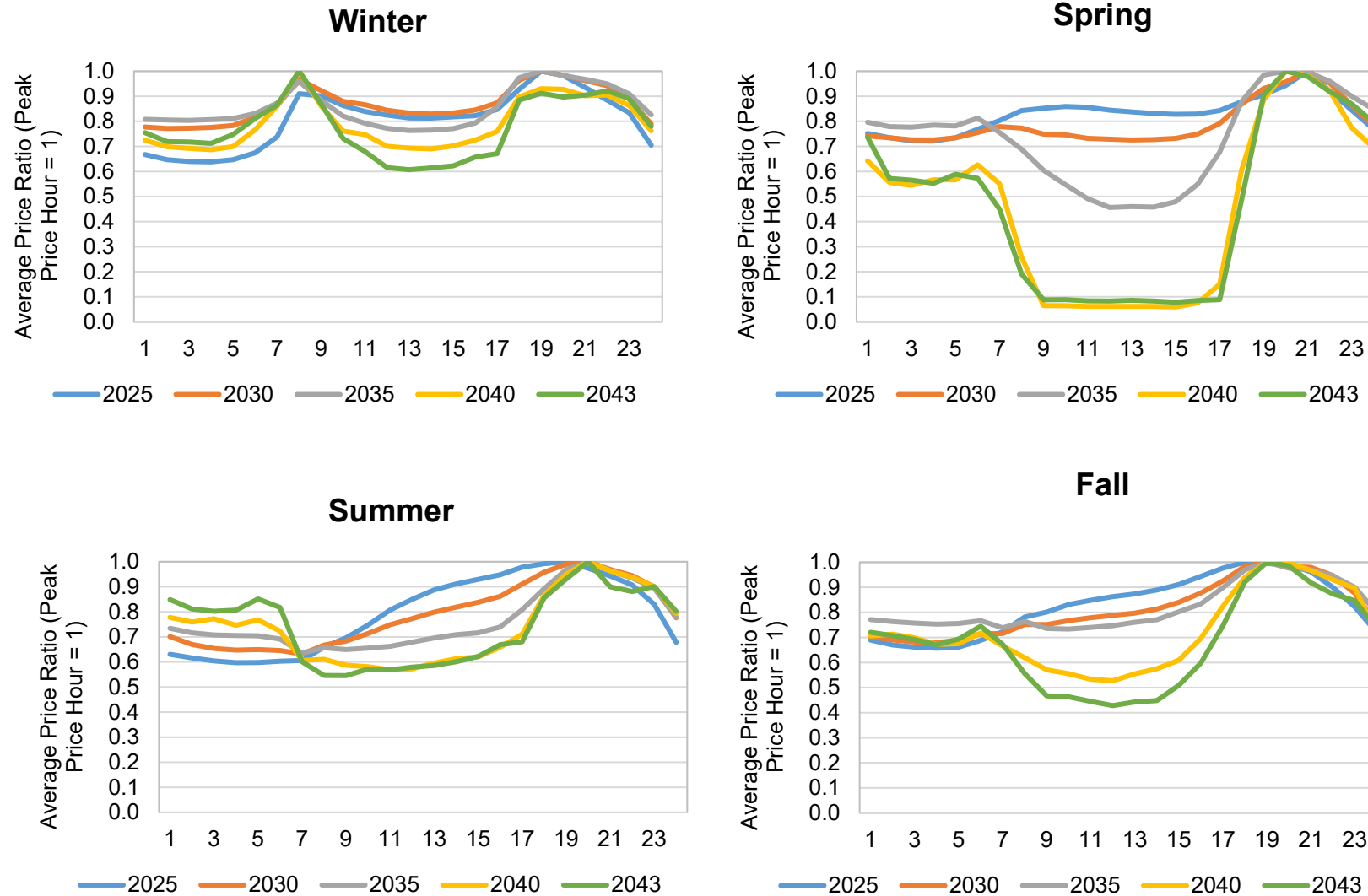


Energy Price



We exist to deliver safe, reliable energy that drives value to our customers

HOURLY PRICE SHAPES – ACCELERATED INNOVATION



We exist to deliver safe, reliable energy that drives value to our customers

2024/2025 MISO SEASONAL CAPACITY MARKET RESULTS PARAMETERS

- MISO's 2024/25 capacity auction prices continued the trend observed in the 2023/24 auction, except Z5 experienced significant price spikes in the Fall and Spring seasons. However, total surplus in summer decreased by approximately 30% due to retirements, increased PRMR, and reduced external offers.
- Market participants in the broader MISO footprint demonstrated surplus across all seasons, with summer remaining the tightest, while participants in MISO North see relative tightness in both summer, fall and spring. The region also utilized cheaper imports from MISO South and external regions to maintain lower prices. MISO South remains more abundant in, but future retirements and load growth could threaten the surplus.
- The auction results remain consistent with CRA's general expectations, where demand growth and continued retirements could create greater upward pressure in prices into the end of the decade.

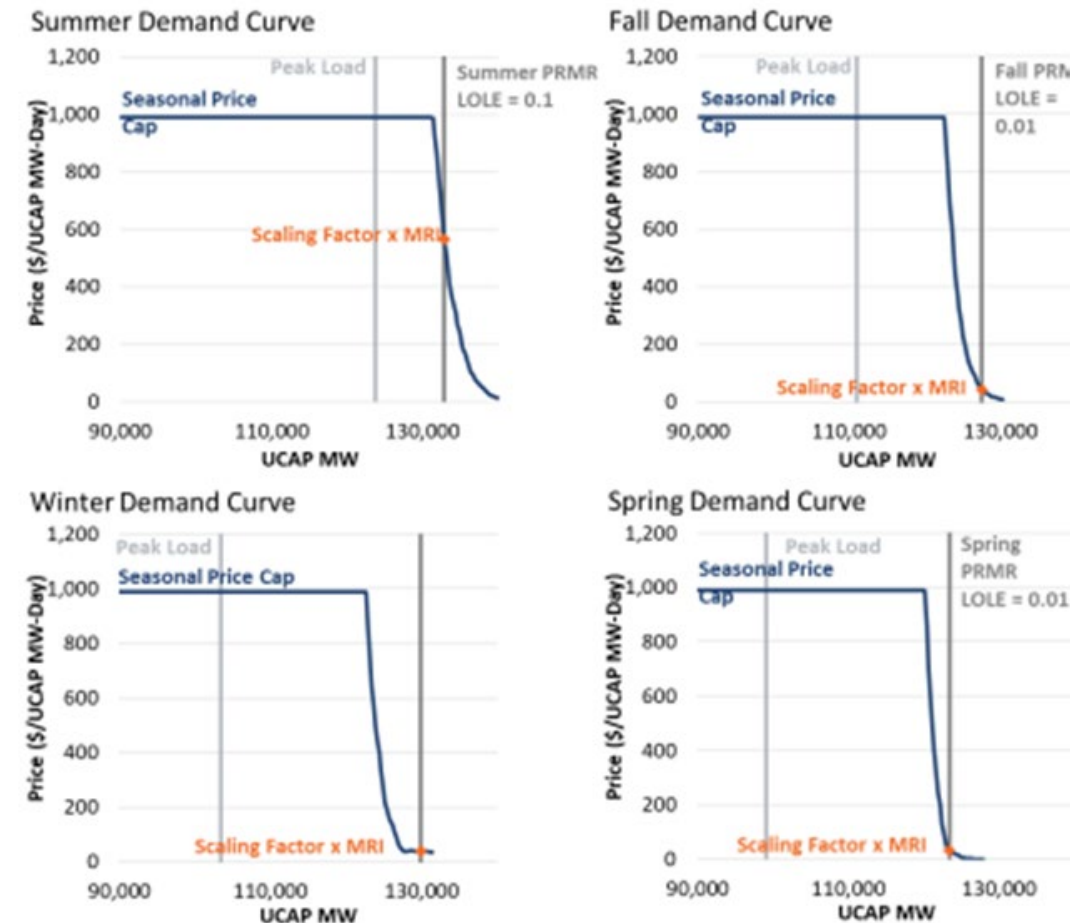
Source: 2024/25 PRA Detailed Report published by MISO, May 20, 2024

MISO PRA DATA PY24-25				
MISO Planning Reserve Margin (PRM)	Summer	Winter	Fall	Spring
MISO Peak Demand (MW)	124,474	102,807	109,686	100,767
MISO UCAP PRM Requirement (MW)	135,691	130,985	125,270	127,696
MISO North Peak Demand (MW)	92,476	74,738	81,116	73,168
MISO North UCAP PRM Requirement (MW)	100,810	95,227	92,643	92,722
MISO South Peak Demand (MW)	31,998	28,069	28,570	27,599
MISO South UCAP PRM Requirement (MW)	34,881	35,759	32,627	34,974
MISO Planning Reserve Margin (%)	9.00%	27.40%	14.20%	26.70%
Total MISO SAC (exclude imports)	141,941	153,277	138,764	142,681
Total MISO Offer+FRAP (exclude imports)	138,631	145,864	132,486	134,136
Total MISO North SAC (exclude imports)	102,454	111,845	99,566	101,583
Total MISO North Offer+FRAP (exclude imports)	100,682	106,527	95,613	95,936
Total MISO South SAC (exclude imports)	39,487	41,432	39,198	41,099
Total MISO South Offer+FRAP (exclude imports)	37,950	39,336	36,874	38,199
MISO % Capacity Surplus (exclude Imports)	11.4%	41.9%	20.8%	33.1%
MISO North % Capacity Surplus (exclude imports)	8.9%	42.5%	17.9%	31.1%
MISO South % Capacity Surplus (exclude imports)	18.6%	40.1%	29.1%	38.4%
Z1-4, 6-7 Clearing Prices (\$/MW-Day)	30.00	0.75	15.00	34.10

MISO CAPACITY MARKET CONSIDERATIONS

- In MISO’s current PRA construct, capacity prices are set by the intersection of supply and demand. In these auctions, the demand for capacity is represented as a vertical line at the PRMR, reflecting the need for market participants to satisfy MISO’s minimum reserve requirement.
- However, by using a vertical demand curve, any additional unit of capacity provided above the minimum requirement is not valued in the PRA.
- To improve this design, MISO has proposed to implement a sloped, or “reliability-based” demand curve (“RBDC”). By assuming sloped demand, MISO’s auctions would value each additional MW of capacity in excess of the minimum requirement at a decreasing rate. A downward sloping demand curve could more accurately reflect the diminishing marginal value an incremental unit of capacity provides to system reliability.
- As a result, market participants should have greater incentive to sell extra capacity and provide reliability benefits above the PRMR.
- However, due to the preliminary status and uncertainty in final design, CRA’s Reference Case does not reflect the proposed changes related to RBDC.

Indicative Seasonal RBDC



Source: MISO



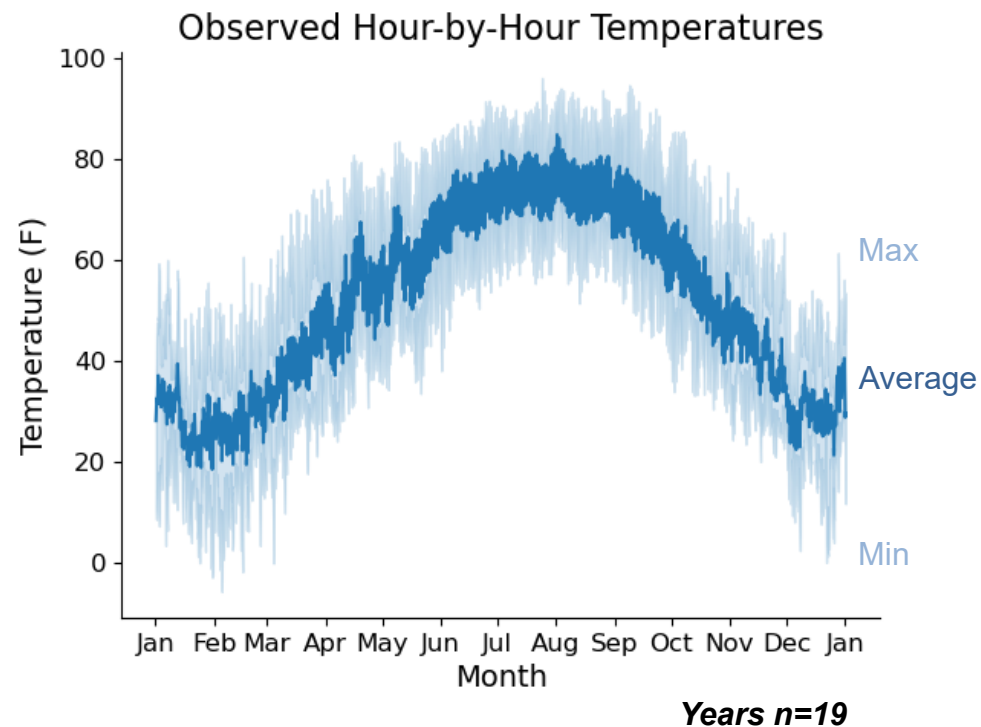
We exist to deliver safe, reliable energy that drives value to our customers

APPENDIX: STOCHASTIC ANALYSIS INPUTS

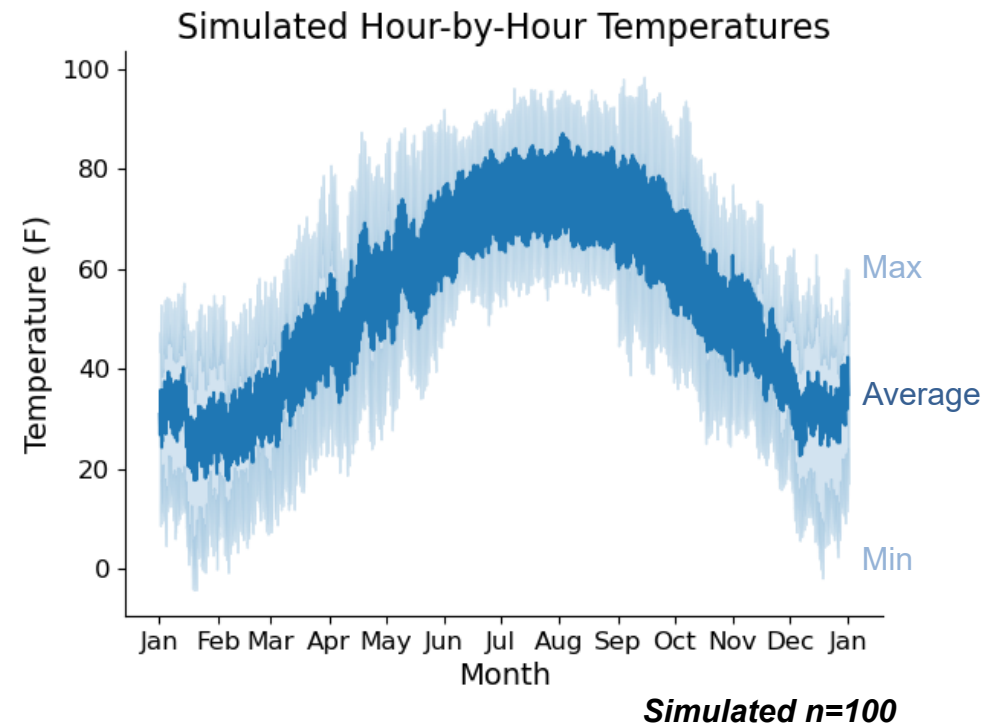


SYNTHETIC TEMPERATURE GENERATION

- A mean reverting random walk-on trend + residual is used to simulate hourly temperatures
- Synthetic data captures high and low temperature extremes, characteristic seasonal behavior, and multi-day temperature cycles



Source: NREL



LOAD TIMES SERIES MODEL ANALYSIS

Data Pre-Processing

- Historical data on hourly loads and temperature data from NREL's NSRDB database
- De-trend load data
- Visual/qualitative analysis

Temperature Model

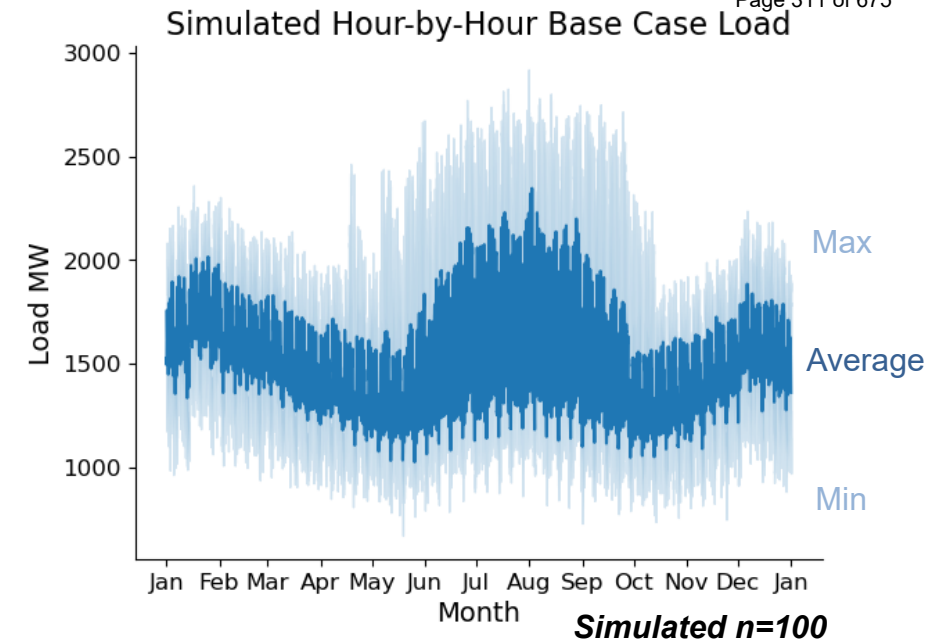
- Stochastic processes on temperature
- Model testing and calibration

Regression Models

- Learn regression models to temperature shock load
- Build regressions on HDD and CDD versus econometric load, EV (scenario-specific level), and electrification (scenario-specific level)

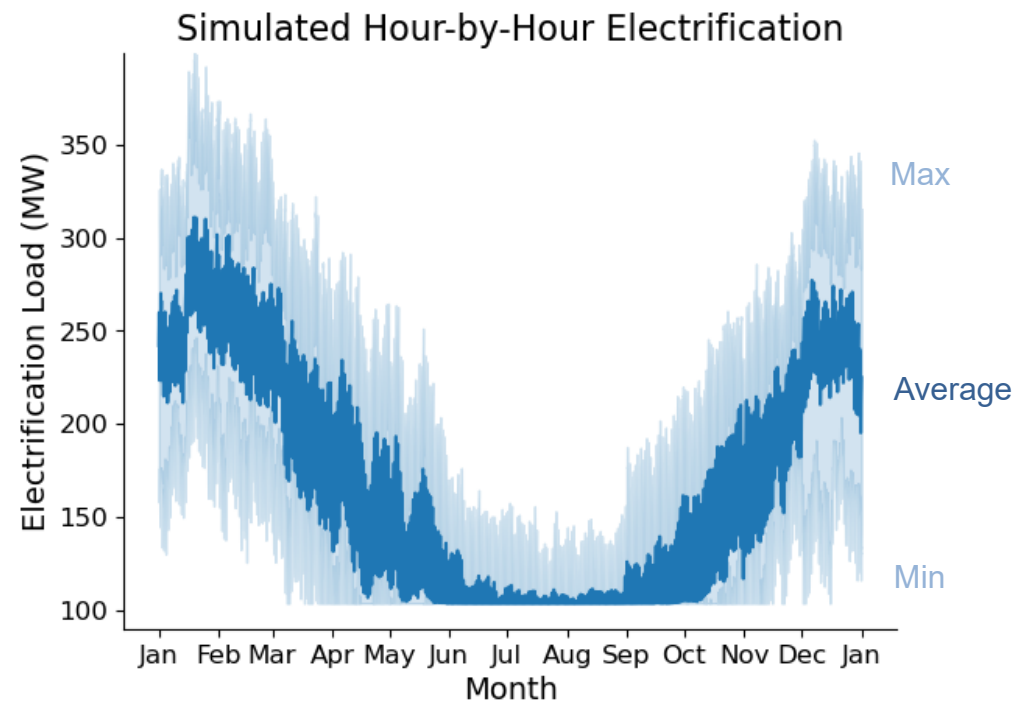
Outputs

- Shift load up to match long-term econometric forecast as needed
- Produce 1000 synthetic load shapes



ELECTRIFICATION LOAD UNCERTAINTY

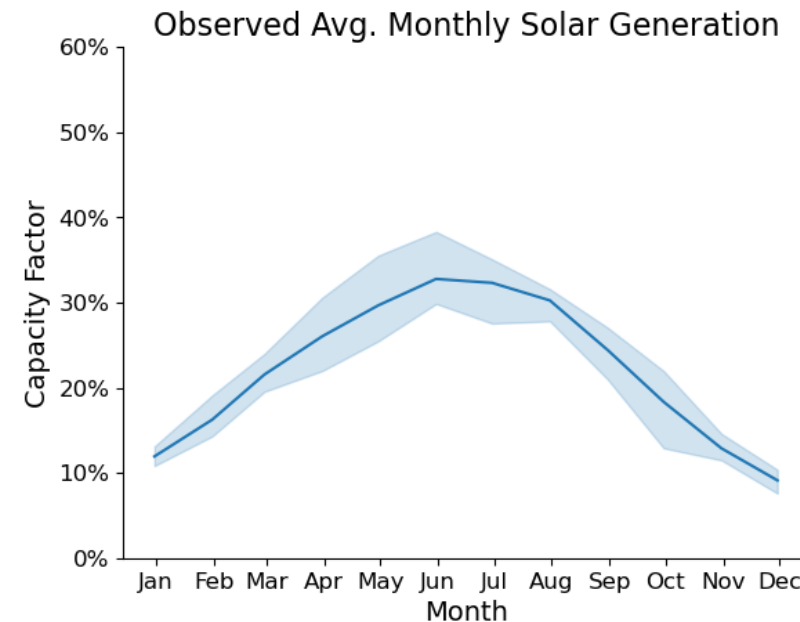
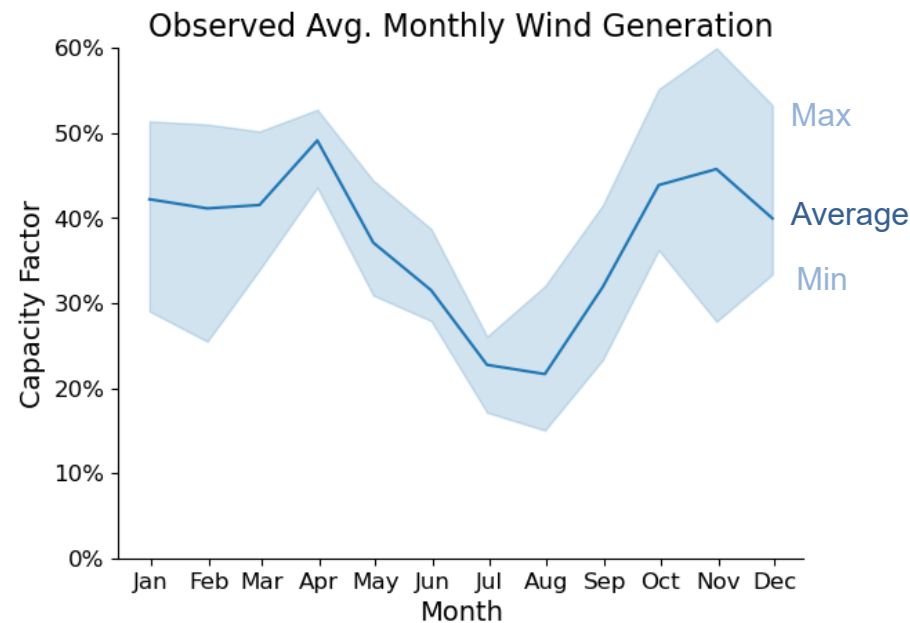
- Temperature has a meaningful impact on potential future electrification loads, since much of it could come from heating demands
- Linear regression model on heating degree days (HDD) is used (Typical Meteorological Year with monthly average HDD)



Simulated $n=100$

NIPSCO RENEWABLE CAPACITY FACTOR UNCERTAINTY

- Based on historical weather data from 2007 through 2014, NIPSCO's renewable portfolio is expected to have an aggregate average wind capacity factor of 37.4% and an average solar capacity factor of 25.3%

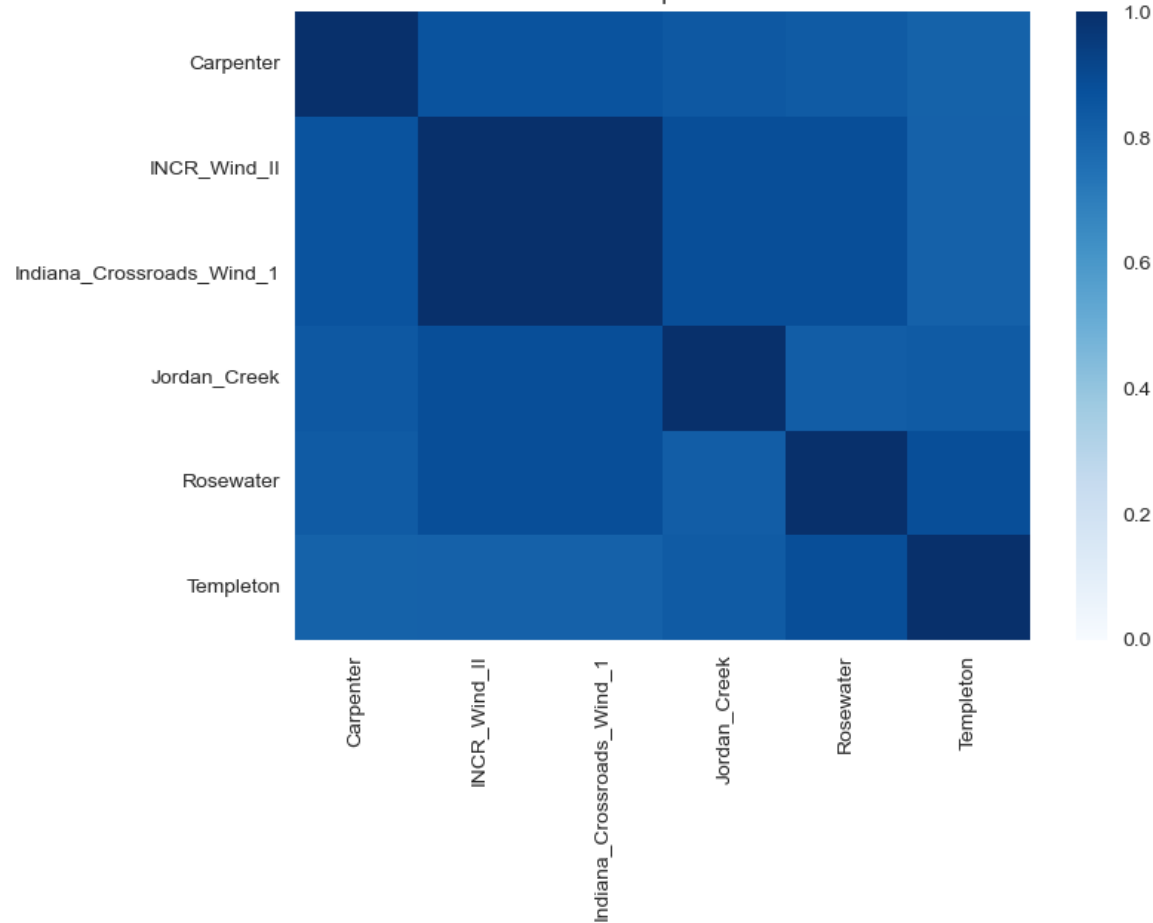


Source: NREL

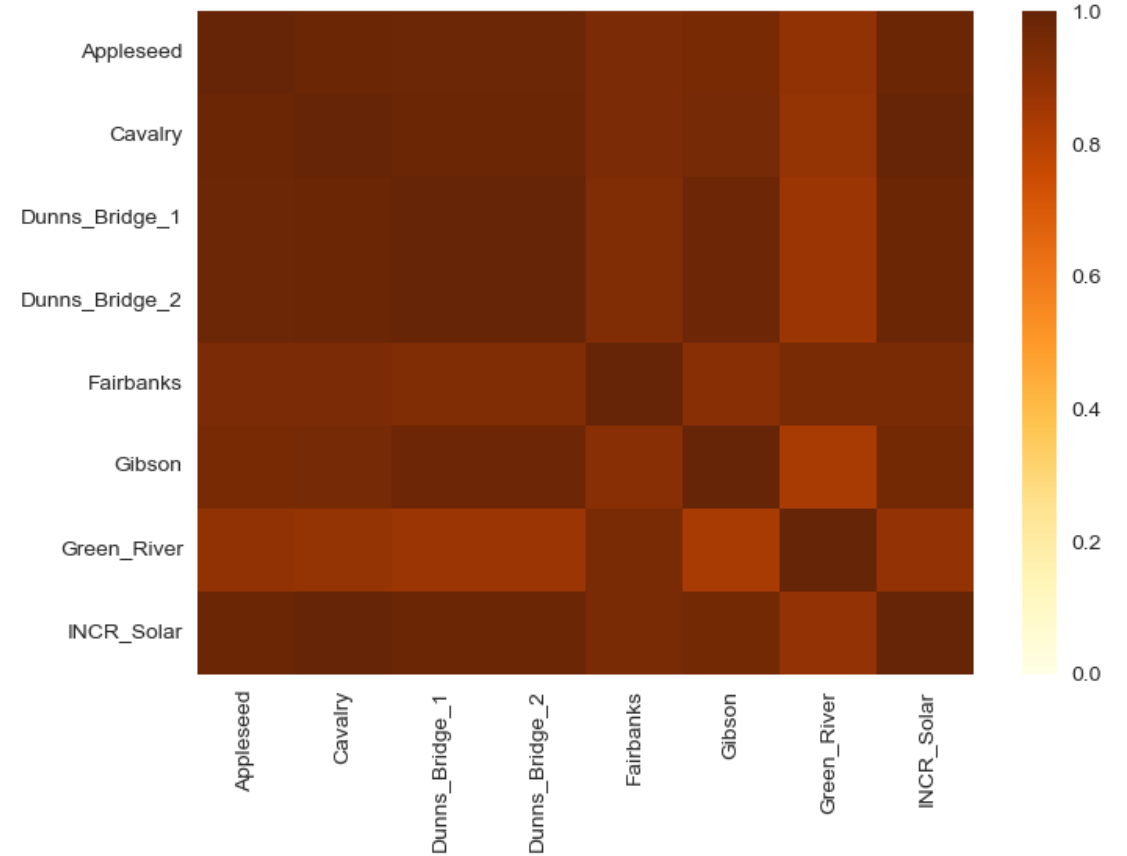
We exist to deliver safe, reliable energy that drives value to our customers

EXPECTED GENERATION FROM NIPSCO'S WIND AND SOLAR SITES IS HIGHLY CORRELATED

NIPSCO Wind Speed Correlation



NIPSCO Solar Clearness Index Correlation



Source: NREL

We exist to deliver safe, reliable energy that drives value to our customers

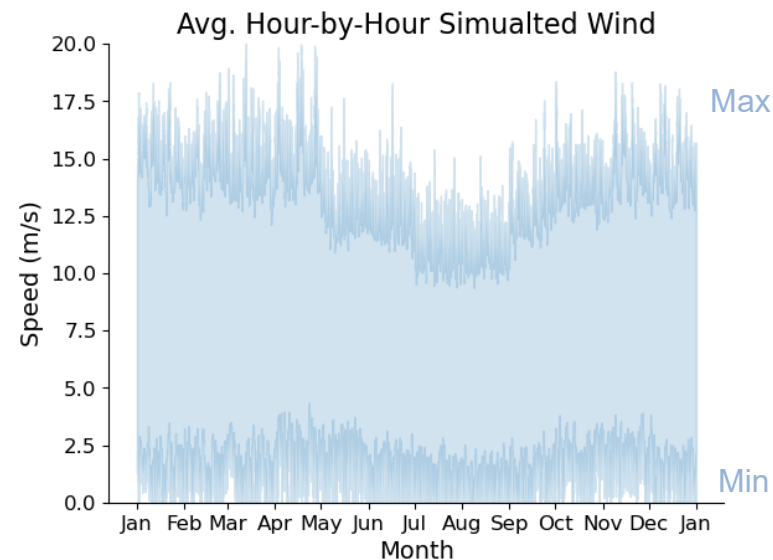
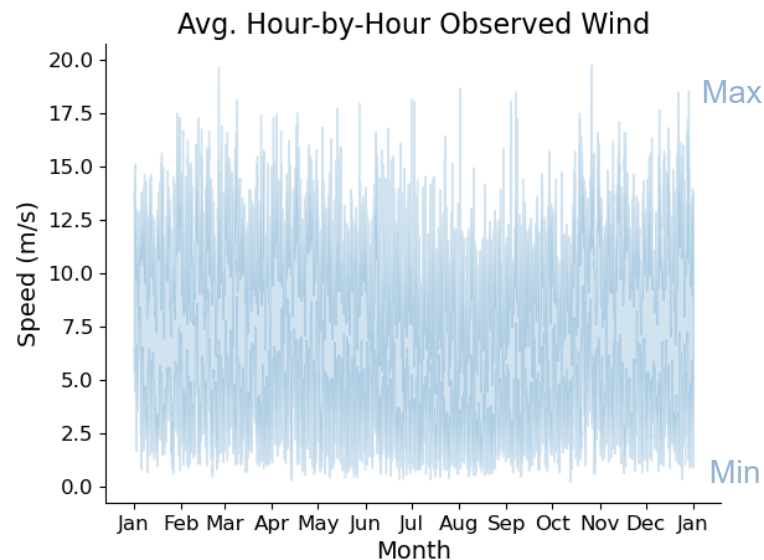
SYNTHETIC WIND SPEED AND POWER PRODUCTION SIMULATIONS

- A mean reverting random walk-on trend + residual is used to simulate hourly wind
- Synthetic wind data captures high and low event extremes and characteristic seasonal behavior
- Power curve models are used to translate speed to MWh for NIPSCO's portfolio

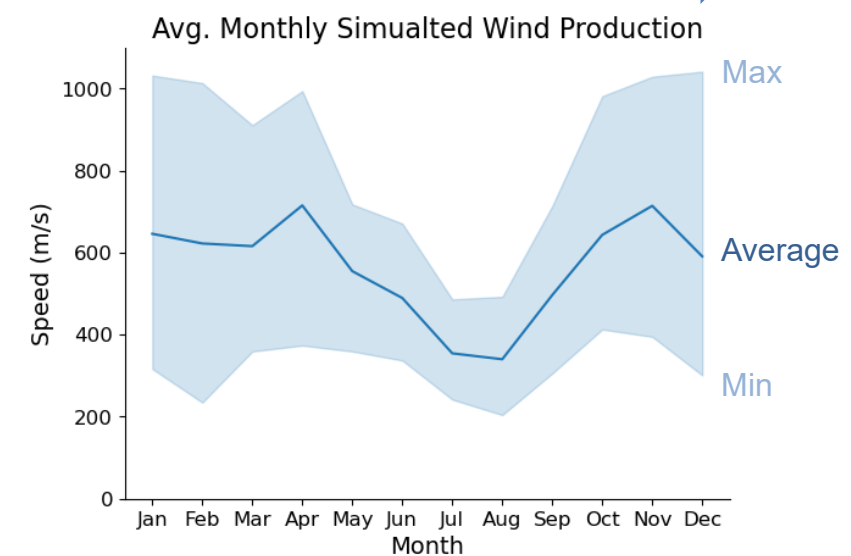
Get Historical Data

Learn Distribution

Simulate Generation



Simulated n=100

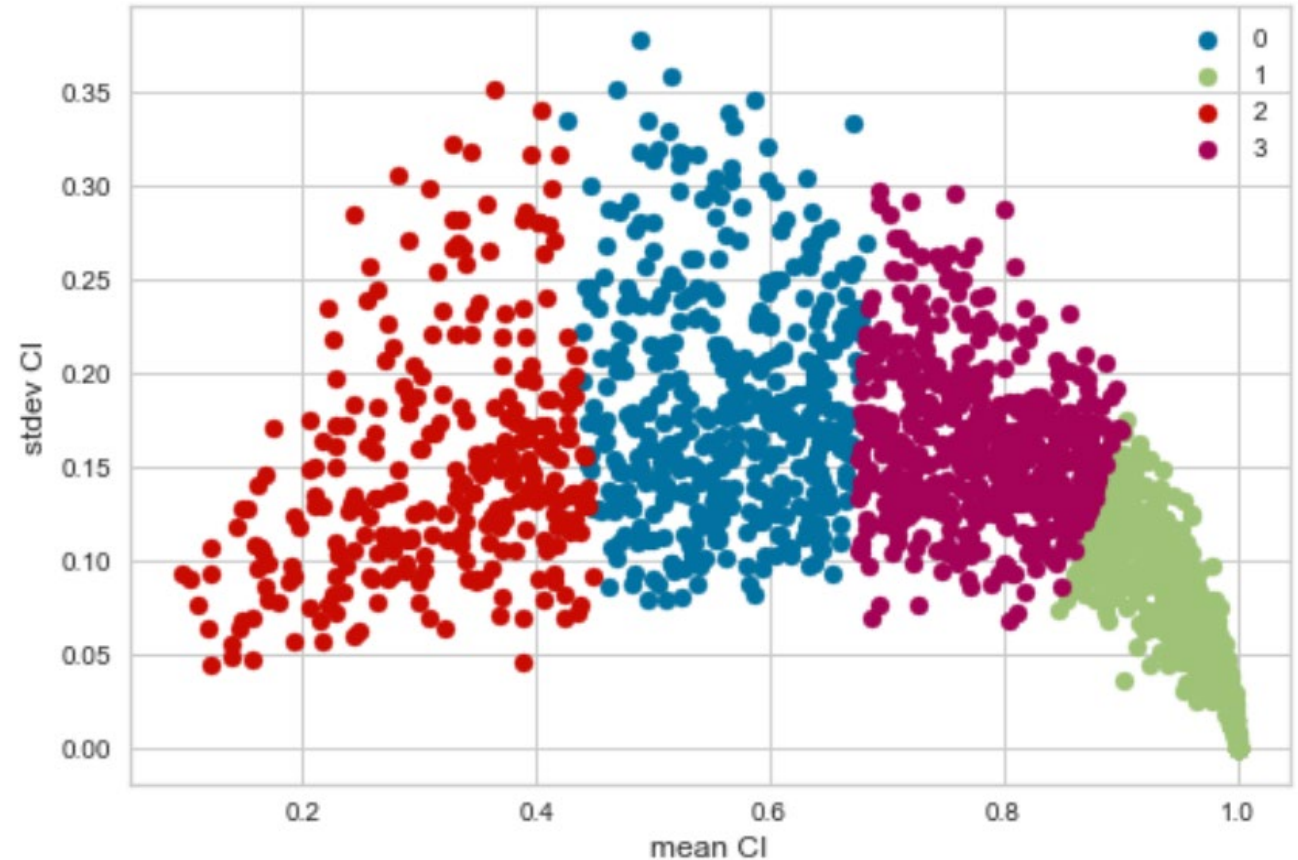


Simulated n=100

We exist to deliver safe, reliable energy that drives value to our customers

SOLAR GENERATION DATA ANALYSIS

- Solar output is simulated using a custom, clustering-based seasonal model
- Historical days are classified into “clusters” (i.e., sunny, intermittent cloudy, total cloudy, etc.) based on Clearness Index: (Irradiance / theoretical maximum)
- Randomly generate series of days, based on Markov transition matrix. Randomly sample from existing days.
- Convert weather to power generation
 - Bifacial, single axis tracking



SOLAR GENERATION INPUT DEVELOPMENT

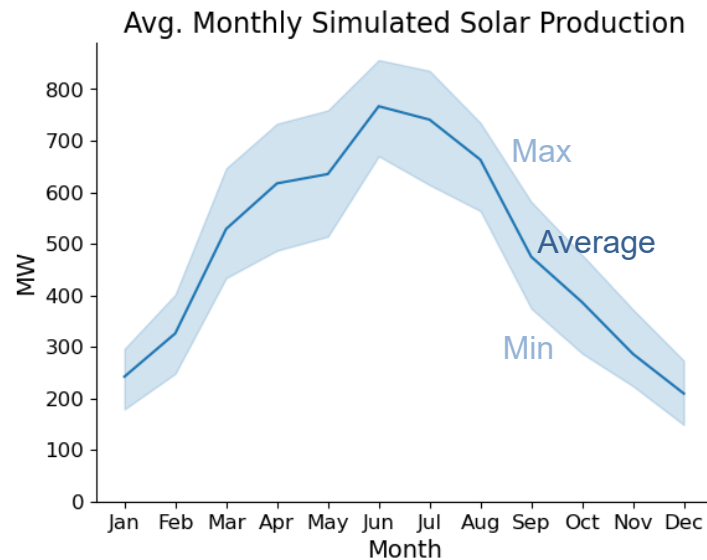
- Simulate solar days across the year based on clearness index clustering and simulated solar irradiance

Sample Year (365 Days)

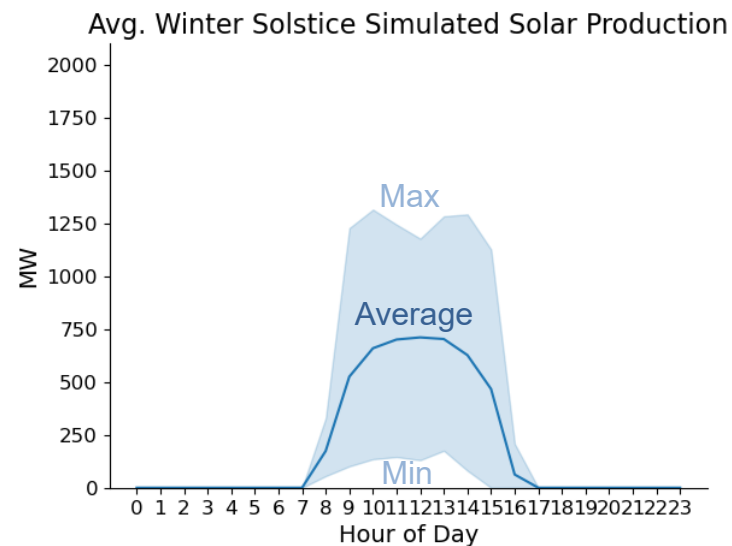


SYNTHETIC SOLAR GENERATION

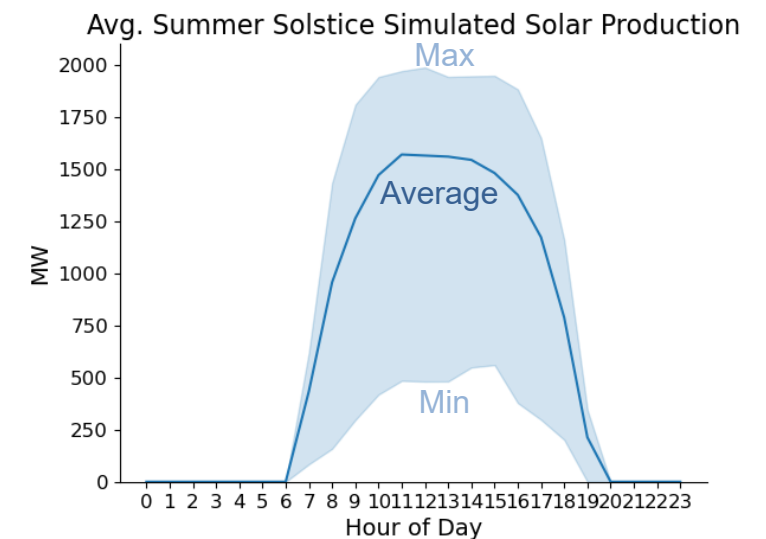
- Pass synthetic irradiance through a power curve
- Synthetic solar data has significant volatility at the hourly level (prior slide), with a range of seasonal and daily/hourly shape outcomes



Simulated n=100



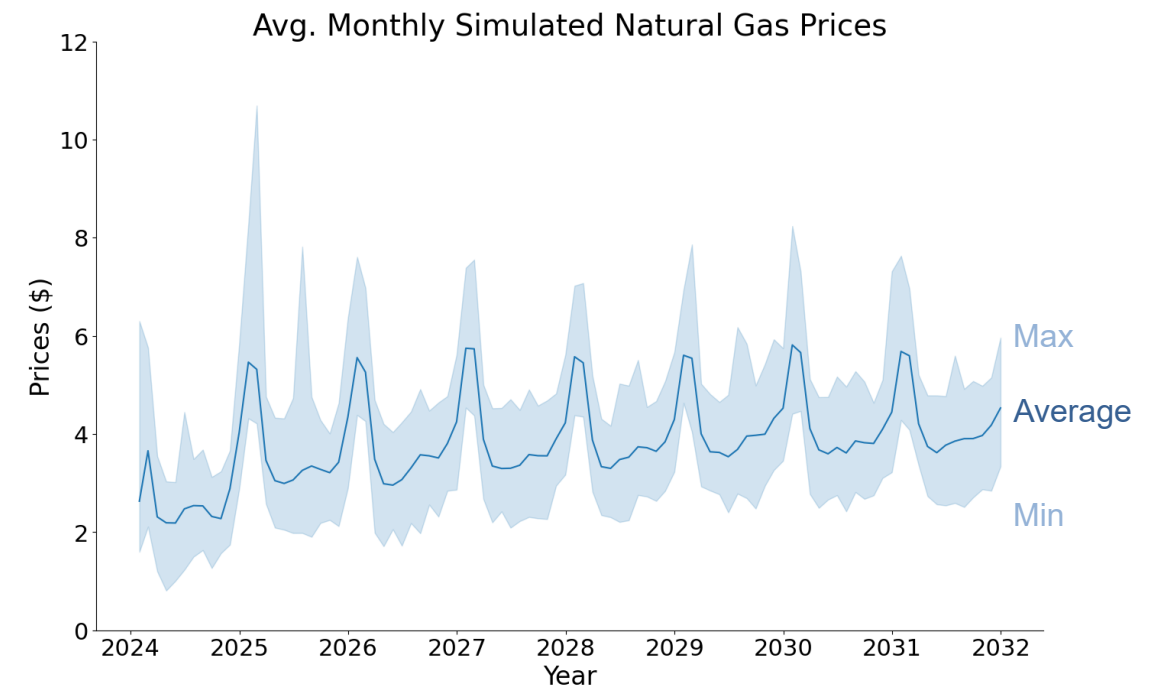
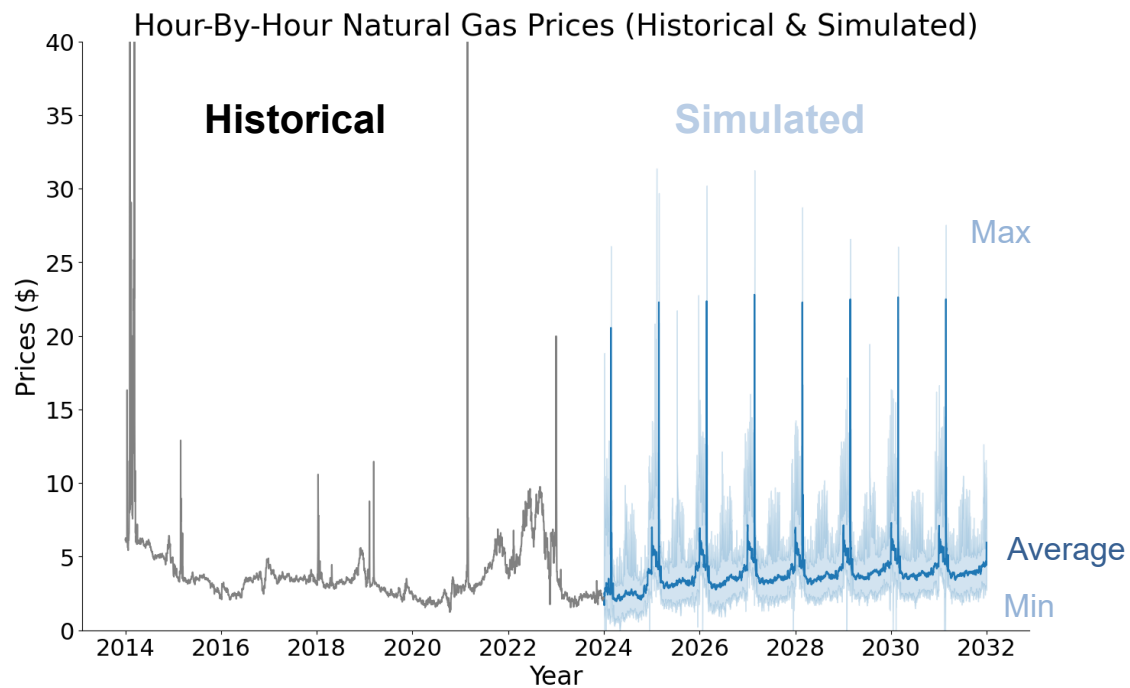
Simulated n=100



Simulated n=100

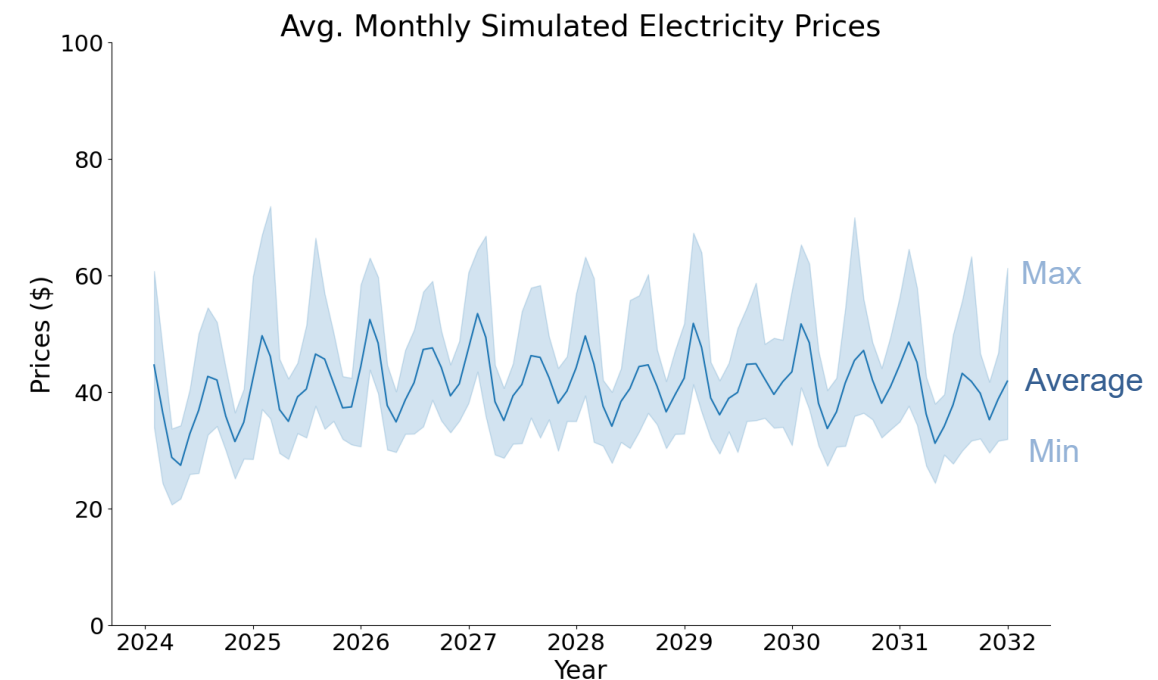
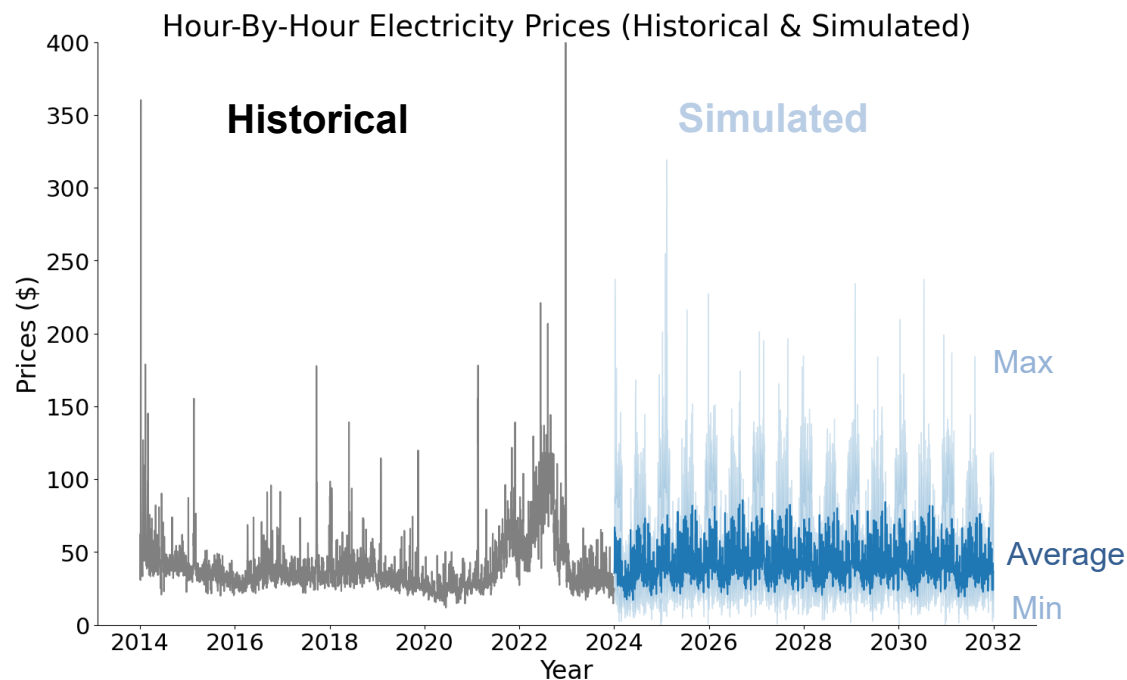
NATURAL GAS PRICE DISTRIBUTIONS

- **Simulated data behaves similarly to historical data, and includes large range of prices across iterations**
 - Daily fluctuations in historical data are well captured within 5th and 95th percentile ranges
 - Monthly fluctuations reflect spiking behavior in the winter, as expected
- **On average, simulated spike values adequately match historical spike events**



MISO POWER PRICE DISTRIBUTIONS

- **Simulated data behaves similarly to historical data**
 - Daily fluctuations in historical data are well captured within 5th and 95th percentile ranges
 - Model sees increased volatility in winter, as expected, but prices fluctuate more in the downward direction as a result of potential renewable energy impacts
- **On average, simulated spike values match historical spike values very well**





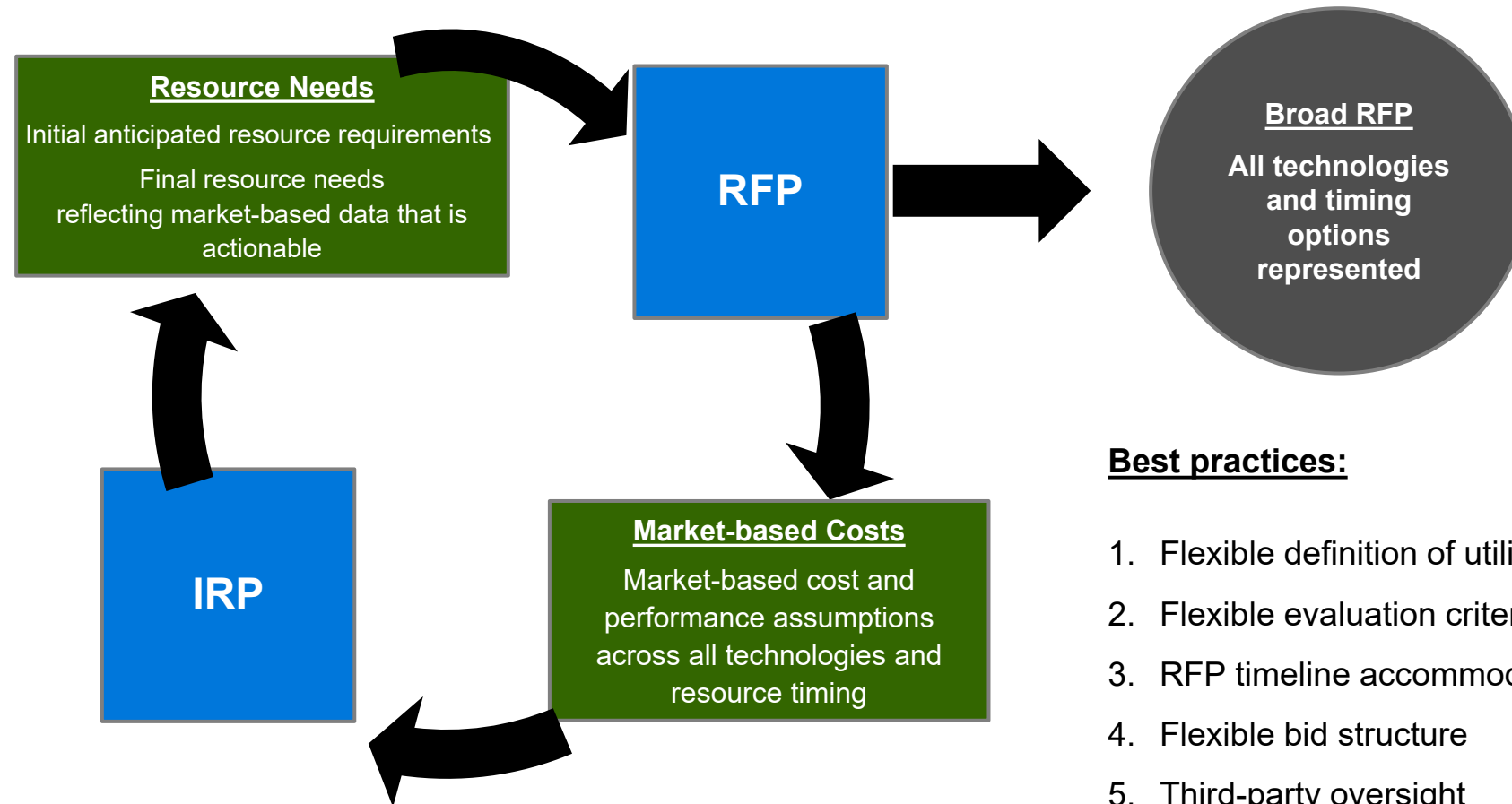
We exist to deliver safe, reliable energy that drives value to our customers

APPENDIX: RFP



OVERVIEW OF NIPSCO'S 2024 REQUEST FOR PROPOSAL ("RFP") PROCESSES

Integrated IRP to RFP structure



Best practices:

1. Flexible definition of utility needs
2. Flexible evaluation criteria
3. RFP timeline accommodates IRP modeling requirements
4. Flexible bid structure
5. Third-party oversight

OVERVIEW OF NIPSCO’S 2024 REQUEST FOR PROPOSAL (“RFP”) PROCESSES

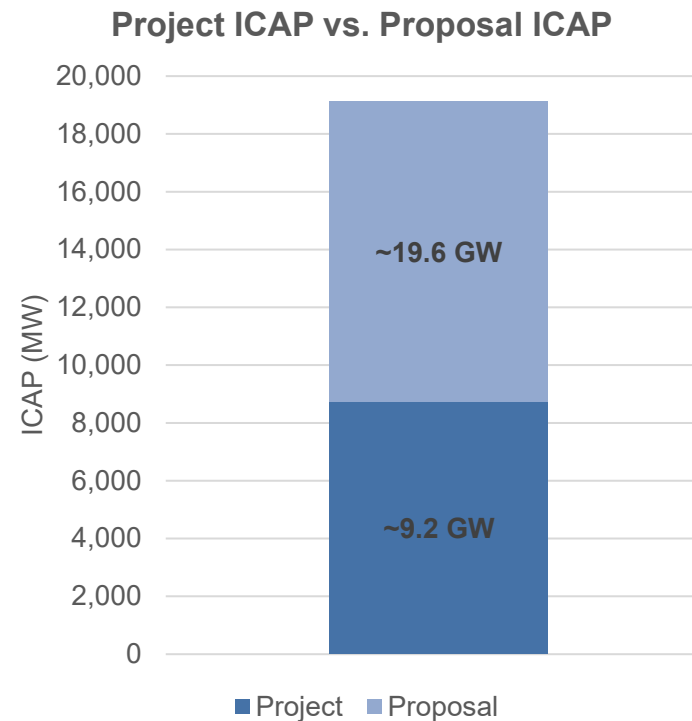
----- All-Source RFP -----

Element	RFP1 – Intermittent	RFP2 – Dispatchable	RFP3 – Bridge Resources	RFP4 – DER
Technology	Renewables and hybrid resources	Thermal, standalone storage, emerging technologies and other (including long-duration storage and NIPSCO site specific storage options)	Near-term bridge resources that provide both energy and capacity solutions designed to respond to large-scale, new customer activity	Distributed energy resources that qualify for IRA incentives and/or provide MISO capacity credit
Event Size	Up to 400 MW	Up to 600 MW	600-1,000 MW	Up to 10 MW
Ownership Structure	Unit contingent PPA, BTA, existing asset sales	Unit contingent PPA, system power, BTA, existing asset sales, shaped products. Site specific storage solutions must be for NIPSCO ownership per MISO generator replacement rules	ZRC, PPA, shaped or financial products, unit contingent PPA, BTA, existing asset sales	Unit contingent PPA, existing asset sales
Duration	Targeting resources in 36-60 months with 5+ years duration	Targeting resources in 36-60 months with 5+ years duration	Targeting resources in 18-36 months with 3 to 5+ years duration, and resources in the 5+ year horizon	Targeting resources in 36-60 months with 5+ years duration
Deliverability	LRZ6, NRIS, (N-1-1)	LRZ6, NRIS, (N-1-1)	Flexible	Distribution resources
Qualification Requirements	Credit worthy counterparties	Credit worthy counterparties	Credit worthy counterparties	Credit worthy counterparties

We exist to deliver safe, reliable energy that drives value to our customers

NIPSCO 2024 RFPS: PROJECTS VS. PROPOSALS

- 53 individual projects across three states with ~9.2 GW (ICAP) represented
- 109 different proposal structures between the 53 individual projects, totaling ~19.6 GW



Preliminary

NIPSCO 2024 RFPS: NEXT STEPS IN RFP EVALUATION PROCESS



Project Economics LCOE / LCOC

The economic analysis will be conducted over a fixed planning horizon and bid specific planning horizon for all assets. The analysis will reflect all expected costs related to the bid. The project level analysis will be based on data submitted with the bids, standard assumptions for key commodity considerations and may reflect adjustments for material uncertainties associated with a bid.



Reliability and Deliverability

The asset reliability and deliverability evaluation will include an assessment of transmission reliability, facility age and performance, and fuel risk and fuel security. Transmission reliability scoring will be based on transmission infrastructure and location. Facility performance will be based on the EFORD performance. Fuel reliability will consider fuel availability risk and price volatility.



Development

Development risk will consider how many key development milestones have been met as well as the development experience of the potential counterparty.



Asset Specific Benefits / Risks

Asset specific benefits and risks will consider individual, unique, project level risks associated with an individual project or counterparty. CRA will evaluate projects based on community benefits, certain social justice goals, minority and women owned business considerations, unique environmental considerations, specific regulatory risks or other considerations.

We exist to deliver safe, reliable energy that drives value to our customers

Northern Indiana Public Service Company LLC

2024 Integrated Resource Planning

Public Advisory Meeting #2

SUMMARY

June 24, 2024

Welcome and Introductions

Alison Becker, Manager, Regulatory Policy, NIPSCO

Vince Parisi, President and Chief Operating Officer, NIPSCO

Fred Gomos, Senior Director, Environmental and Sustainability, NiSource

Ms. Alison Becker, Manager, Regulatory Policy welcomed participants to the meeting and provided information on MeetSafe for the location and a safety moment. She then reviewed the meeting protocols and agenda. Mr. Vince Parisi, President, provided opening remarks for the meeting and Mr. Fred Gomos, Senior Director, Environmental and Sustainability, provided a recap of the April 23, 2024 Public Advisory meeting and responded to Stakeholder feedback received at that meeting.

Scenario Analysis Overview

Patrick Augustine, Vice President, Charles River Associates (“CRA”)

Mr. Patrick Augustine, Vice President, CRA began with a recap of NIPSCO’s first Public Advisory meeting, reiterating the resource planning approach and describing the key modeling and analytical tools that NIPSCO uses when developing its Integrated Resource Plan (“IRP”). Next, Mr. Augustine summarized the five IRP scenarios NIPSCO will consider in the 2024 IRP, which include the Reference Case (“REF”), Slower Transition (“ST”), Domestic Resiliency (“DR”), Aggressive Environmental Regulation (“AER”), and Accelerated Innovation (“AI”). Finally, Mr. Augustine provided a macro view of NIPSCO’s five IRP scenarios with a summary of the major drivers, including commodity prices, carbon policies, technology costs, demand, and market design.

Scenario Analysis: Key Drivers of NIPSCO Load Uncertainty

Pat Augustine

Vince Parisi

Rick Calinski, Director, Public Affairs and Economic Development, NIPSCO

Fred Gomos

Mike Leikin, ElectroTempo

Mr. Augustine kicked off this section by reviewing the key drivers of load uncertainty for each of NIPSCO’s five IPR scenarios. Mr. Augustine then turned over the presentation to Vince Parisi for a recap of recent data center news stories that have led NIPSCO to make a significant update to its reference case load forecast. Mr. Parisi then walked through slides showing the recent growth in the data center industry and how this could impact utility loads in Indiana.

Mr. Rick Calinski, Director, Public Affairs and Economic Development then discussed data center incentives provided by the state of Indiana and how these incentives are driving data centers to consider locating in NIPSCO's service territory. In addition, Mr. Calinski discussed details of Indiana's Data Center Gross Retail and Use Tax Exemption, which was passed in 2019 and noted that NIPSCO is receiving inquiries from data centers on a weekly basis, highlighting how quickly the data center industry is growing. Mr. Calinski then provided some of the reasons why data centers are looking to locate in northern Indiana, including a robust transmission network and reliability, available land, connectivity and fiber, and access to water, among other drivers. Mr. Calinski also mentioned how data center size and need for load has increased over just the last few years. Mr. Calinski then provided details about six active data center projects where NIPSCO has advanced in discussions with the potential customers and made an initial determination that the company has the ability to serve them. Their combined load was estimated to be up to 8,600 MW by 2035.

Mr. Gomos then presented NIPSCO's approach to evaluating new large load customers utilizing sensitivity analysis, and showing the potential load growth that will be analyzed in the IRP. He noted that emerging large load customers will be used as a sensitivity factor across NIPSCO's five IRP scenarios.

Next, Mr. Augustine discussed each of the main inputs that factor into NIPSCO's load growth scenario analysis, beyond new large loads, beginning with an Electric Vehicle ("EV") Forecasting Overview. Mr. Augustine recapped the EV reference case forecast presented in the April stakeholder meeting and presented high and low scenario ranges for light and medium duty EVs. Mr. Mike Leikin with ElectroTempo then presented a highway corridor EV charging demand forecast. Mr. Leikin showed the methodology that ElectroTempo used to determine its projections and then provided a summary, with key takeaways.

Mr. Augustine then provided information on load ranges due to additional electrification and customer-owned distributed energy resource ("DER") penetration. Mr. Augustine summarized the Reference Case customer-owned DER projections provided in the April stakeholder meeting and described the key drivers of future customer DER adoption and how they were mapped to the other four scenarios. Mr. Augustine then closed the section by providing a summary of NIPSCO's all-in load forecast, showing total energy sales by customer segment, summer peak load by customer segment, all-in summer and winter peak load ranges (base and high large load sensitivity), and total energy sales across scenarios and sensitivities.

Participants had the following questions/comments, with answers provided by NIPSCO:

- When did NIPSCO become aware of each of the six prospective data centers in its service area? Did NIPSCO begin discussions and studies with any of these data centers prior to its April IRP meeting?
 - The conversation related to data centers in Indiana has been going on for some time and has been very robust. It has been happening relatively quickly and more information continues to become available. Although NIPSCO has been looking at this for the past several months, along with other utilities in the state, the Company has gotten more information in the last couple of weeks to have more certainty related to what should be considered with respect to a reference case, as well as in the overall IRP process.

- What does it mean that you're releasing an updated Reference Case (I don't think we've gotten any data from NIPSCO thus far in this process)?
 - The updated Reference Case is simply different from what was shared in April.
- Does that mean NIPSCO will be sharing updated data related to the Reference Case (I don't think we've seen any load forecast data)? When can we expect the data?
 - Yes, NIPSCO will share the Reference Case data in this meeting, along with the scenarios. If you would like additional information, NIPSCO can take the request up one-on-one.
- Will the data centers be expected to run 24 hours a day?
 - Typically data centers run 24/7 and they do not have significant ramp up or ramp down expectations. They typically will run around the clock without a lot of downtime.
- Will there be the possibility of interruptible load during high demand times?
 - That is being considered as part of NIPSCO's demand response study. Some data centers can transfer load to other parts of the country, if required. That potential is being considered as part of the market potential study.
- How far into the interconnection process is NIPSCO with these new data center loads? Are these loads that have signed some sort of agreement saying that they are likely to take power and willing to pay for any network upgrade study or other costs that are developed out of that study? Where are you in the interconnection process for each one of these data centers?
 - One of the things NIPSCO has to explore is the interconnection process. The Company has been looking at this new load relatively recently, over the last several months, and the interconnection process will have to be part of what is considered. The Company will continue to work with the Midcontinent Independent System Operator, Inc. ("MISO") to understand how to meet the load requirements as they continue to develop.
- Will you obligate each data center to any network upgrade charges regardless of whether they interconnect or not?
 - One of the things to consider through the process is how we ensure and protect the current customers in the system with respect to any new load that is developed so we will certainly look at those types of issues and come up with good ways to resolve them.
- I'm still a little unclear. Are these inquiries, and how firm are these data center load requests? Is the Chesterton project canceled?
 - NIPSCO has had a number of different groups and organizations ask about data centers in the northwest part of the state, and across the northern part of the state in our system. The Company has examined those and looked at the commercial decisions that have been made. When a potential customer has made a significant commercial decision, an example of that being land acquisition, then we consider the project more plausible. However, most projects are still early in the process.

The Reference Case is certainly not everything related to the various discussions, but includes what we believe has a little more certainty.

- As a follow-up, obviously we have concerns about the impact to other ratepayers and we would like to have further conversations about how to protect other ratepayers as the nation is grappling with this issue. For the 8,600 MW jump that NIPSCO is predicting, how much of that is a situation where the land has been acquired and the customer is moving forward?
 - It is still the early stages and what you will see in the Reference Case is not tied back to any specific end-user. It is really a look at the different parties that NIPSCO is working with and what stage we are in with that development, so it should reflect generally what might come to fruition out of all of that possible load.
- How much of this load is related to artificial intelligence (“AI”)? Is NIPSCO seeing an uptick in current data center usage because of AI?
 - There is some, but there are not a lot of data centers currently on NIPSCO’s system. There is certainly a desire for them to continue to grow and AI is part of that conversation, but it is not all of the conversation. As for potential new load, NIPSCO is not far enough down the path to determine whether it is going to be AI load or more traditional data center load. That is something that will be considered as part of the process and the Company will ultimately decide what kind of capacity is going to be needed to serve them.
- How many MWs is the LaPorte data center?
 - The load for the Microsoft data center that is being referenced has not been finalized. That announcement was a few weeks ago and we are in conversations with the customer now. As there is more information on what that load ultimately looks like, that information will be shared.
- With data centers using load during the 'on peak', are you creating a special rate for the data centers to account for their use during higher locational marginal price (“LMP”) times? Other ratepayers will not want their rates raised because data centers are moving to NIPSCO territory.
 - It is certainly something that NIPSCO is considering, and the Company is studying the best way to serve data centers and creating a new rate is a potential. However, when thinking about rate design, there are other processes for that outside of the IRP. For the IRP, NIPSCO is studying supply and demand, and the conversation here should focus on the demand and the potential ways for NIPSCO to supply that demand.
- Does the data center load modeling include the closing of Michigan City and Schahfer?
 - NIPSCO’s current Reference Case still includes both Schahfer and Michigan City retirements. The planning assumptions on the supply side have not changed.
- Is the large load customer (including data centers) interconnection process in your tariffs?
 - Yes.

- In the reference case, what is the compound annual growth rate (“CAGR”) for the commercial sector if we keep aside data centers for a minute?
 - Without data centers, and this is documented in the April meeting slides, it is 0.37% per year for summer peak growth.
- In addition to more demand on the grid, how much pollution will impact frontline communities? How much projected CO2 emissions in general?
 - It is very early on with respect to the process of really understanding what that potential load would be and then ultimately how that load is served. It is known that this is the type of load that is more 24/7/365 and that will be taken into consideration. The Company is not at a point yet where we can identify the type of generation that will match up with it.
 - This is just one aspect of the resource plan. The process starts with the demand side and then the process considers how to supply that demand. That will be distilled in the scorecard depending on the portfolio selected. The scorecard will provide information on items such as emissions projections. Part of the reason that policy makers are seeking data centers across all jurisdictions is that there is some economic value for the communities, such as construction of the facility. The Company is focusing on the value that these projects can provide to the community from an economic development perspective.
- I think it is important to include the full costs of serving these new loads in the IRP. If cost allocation is uncertain at this point, we should be putting all of them in.
 - One of the things considered in 2018, when NIPSCO started looking at retirements, was including the transmission and interconnection costs associated with those retirements in the analysis. There could be a way of building some sort of infrastructure cost associated with the new load growth from data centers as a proxy. The challenges NIPSCO has now and by the time that this IRP is submitted is that some of these data center project locations are not certain and some of the studies around transmission upgrades are not finalized. But, for every MW added, there is this corresponding amount of transmission and distribution (“T&D”) cost that could be built into the model.
 - With regard to other costs, those would certainly be core to the IRP process, so if there are incremental capacity and energy needs, estimating those would be core to the analysis that is being done for these different scenarios.
- Will the portfolio optimization include the costs of new transmission? Where could I find information on NIPSCO's available transmission capacity?
 - Incremental T&D costs will be incorporated as part of the modeling.
- I think the environmental justice metric needs to be developed in time to include these data center impacts.
 - NIPSCO would absolutely love to have a suggested environmental justice metric. Getting suggestions is the best way for people to get value out of that particular metric.

- I have yet to meet anyone in any community that is excited about data centers in their territory. Your current peak load is 2,300 MW, correct? And you're estimating that these six data center projects will have roughly four times your current load?
 - Yes. With those six developers, what they are saying is, if NIPSCO can meet their needs, that is the amount of load that they estimate that they could use within the next ten years. It is still early in the process with discussions happening about NIPSCO's ability to meet these developer requests.
 - The projected load figure for data centers is based on what developers have told NIPSCO they want. NIPSCO has taken more than 30 inquiries from developers and asks those developers to provide an estimate of load need. NIPSCO must then go through a process to determine how serious the developer is and if they have taken any commercial steps yet. The potential data center load is higher than what is on the slides, but NIPSCO does not know which inquiries will come to fruition. NIPSCO is planning for what happens if the six projects do come online.
 - While there are communities that have pushed back on data centers, there are also communities that have taken significant steps to attract data centers and the economic opportunities that they can bring.
- Just because a law or ordinance got passed does not mean that the community necessarily supported it or even knew about it. We hope NIPSCO is considering customers that are already struggling to pay existing bills and that NIPSCO does not add costs to them in this drive to go after data center load.
 - Understanding that there are customers today that are struggling to pay their utility bill will absolutely inform what NIPSCO does with respect to taking on data center load. NIPSCO will look at how everything integrates into the system and what that looks like for all of its customers, including new customers.
- What is NIPSCO offering data center customers, in terms of incentives? Stakeholders would like to be a part of those conversations. They want any data as soon as possible after agreements are made and felt left out of conversations in previous rate cases regarding industrial customers.
 - There was media early on about NIPSCO providing incentives to data centers, but those reports were incorrect. As the Company continues to work with data centers, it will share information as it becomes available.
- How feasible is adding 8,600 MW of new capacity in only a decade?
 - This is why NIPSCO has this IRP process, to analyze what is feasible. Similar questions were asked in the past about how feasible it was for NIPSCO to transition away from coal in ten years. This process sets the path for NIPSCO to be able to execute on this amount of load, should it materialize in the future.
- Could you describe further what was included in the high-level load studies for the six data centers?
 - So far studies have been more focused on the transmission side and what is NIPSCO's ability to deliver power to a particular site. Determining generation needs is the purpose of the IRP process. A few data centers have compensated NIPSCO for extended engineering studies, but none of those studies are complete.

- On Slide 34, should I-69 instead be I-65?
 - I-69 in the northeast corner of the state would be in NIPSCO's service territory. The appropriate interstate reference will be confirmed.
- Does NIPSCO have a dedicated EV charging rate today?
 - There are two rates today: a dedicated rate for NIPSCO-owned charging stations; and an EV-charging rate that does not have the demand charge associated with it. This is a favored rate with EV charging companies as they are beginning to ramp up. When you get into these larger sized loads in the future, customers would be on some sort of demand combination rate, which could drive specific rate designs for those types of loads.
- On Slide 34, why do all curves look flat after 2035 in the chart?
 - The analysis was a ten-year study that only went through 2035, so NIPSCO is holding things constant after that. There could be more growth after 2035 and that is something that can be explored in the future, if load growth for heavy duty vehicle charging on highway corridors does take off.
- Will you place 40% of EV charging in disadvantaged communities?
 - NIPSCO does not currently have any funds to deploy chargers beyond the ten that already exist. NIPSCO did a study and there is quite a bit of distribution in environmental justice communities, and that is one of the factors the Company considered when conducting the initial deployment.
- How will disadvantaged communities, or DACs benefit from air pollution reduction and EV charging as a form of resiliency if they are not prioritized?
 - NIPSCO can share a map of what is being done thus far and is happy to have a one-on-one discussion if that is helpful.
- NIPSCO should consider rethinking the naming of its Accelerated Innovation ("AI") scenario.
- Are we to assume that NIPSCO views DERs merely as customer-owned resources and is NIPSCO modeling with the assumption that all DERs will be on the customer side?
 - The customer-owned DER study presented here is explicitly focused on customer-driven penetration. However, from a practical modeling perspective, NIPSCO thinks of and models DERs as a supply-side resource. In addition to customer-owned resources, the Company is starting to look at Company-owned DERs with the DER RFP Event that just closed.
 - In the MPS, NIPSCO has storage incentives on the customer side that would potentially be layered on to this, like DSM or time-of-use rates, which would incentivize behavioral change.
- Are you projecting the inclusion of the Climate Pollution Reduction Grant, the Indiana Office of Energy Development Energy Efficiency Program or other investments that will spur DER?

- Not specifically, but NIPSCO did take a closer look at the Solar for All program that was brought up in the last meeting, so if there is additional detail that you could provide that would change these bands or change some of the assumptions, NIPSCO would welcome that.
- Under the different scenarios, I would argue that in the scenario that had restoration of net metering or some other compensation package you would probably see larger systems deployed.
- Are you considering any of these DERs being aggregated together and deployed as virtual power plants to reduce peak demand and provides other benefits to the grid? Is that something that you are considering as part of your modeling efforts?
 - The DSM study in the MPS, which will be covered in more detail in August, is going to incorporate certain potential for those resources to be incentivized to deliver during the times that matter.
- Are you thinking about any of the data centers deploying behind the meter resources as part of your forecast or have you had conversations with any of the customers on the topic?
 - That is a topic of discussion to be worked through with the customers. There is a real mix in terms of what data centers like to do for backup generation.
- There is a fixed amount of DER supply that gets included in your models, correct? It is not a matter of the model taking a portion of it or taking more than is shown in those forecasts, correct?
 - That is correct. The scenario range has been developed, but there is not additional DER capacity to be “selected” in the portfolio development phase.
- To develop those DER supply side forecasts do you know how this was approached in the MPS? Was it assumed that there were incentives given across some or all of the scenarios for generation not just storage, or was it just a matter of natural adoption?
 - The DER scenario range was developed via the PenDER model described today and in the April stakeholder meeting. Referring back to the table on the economic analysis slide, according to the wholesale rate growth and incentive structure, the Excess Distributed Generation (“EDG”) program would compensate extra generation at the wholesale rate and across the different scenarios we have different wholesale rate growth and one scenario that includes net metering.
 - Separately, in the MPS, this information was provided to inform the potential for new rate designs or other programs to encourage additional customer-owned storage, for example.
- I would like to see additional energy-producing DERs with some sort of incentive structure over and above EDG that could be selected by the model. Is that something NIPSCO can add as a resource option? You might wind up with huge amounts of wholesale market energy purchases if you do not have enough energy-producing resources in your model, especially through 2030 when you are going to be most constrained.
 - It is something that can be considered. There is a question of how much of that is feasible and what type of incentives would need to be provided.

- When you look at the load factors for these data center customers that it is capacity and energy that is needed to serve them and that is something that NIPSCO will need to think through. The Company is happy to have the conversation about ideas that could be incorporated into the model but is constrained by state policy in terms of DERs and EDG.
- When I see slide 46 and slide 47 I go straight to cost causation and cost allocation and I would hope that NIPSCO would consider using those slides for cost allocators moving forward. Since data centers are such an extraordinary part of these graphs, does it make sense to consider some sort of sensitivity around data centers being Rate 531 or Rate 531-like customers?
 - This is a process of estimating demand and considering what type of supply resources could meet that demand and I am not sure if the Rate 531 construct falls in the purview of the planning conversation. NIPSCO will continue to look at rate design as it goes through this IRP process to determine what makes sense for these data center customers because they have very different profiles than the Rate 531 customers. The Company has to figure out the best way to serve multiple customers in this arena, not just a single customer. Data centers were not contemplated when NIPSCO was designing what is now Rate 531.
- These constructs and agreements and terms will influence whether or not the data center comes here, so I just want to elevate that this topic is very front of mind for us.

NIPSCO's Supply-Demand Position: MISO Resource Accreditation and Load Obligation Uncertainties

Pat Augustine, Vice President, CRA

Mr. Augustine began by presenting a slide from NIPSCO's last stakeholder meeting, which summarized MISO's March 28, 2024 Direct Loss of Load ("D-LOL") filing. Although FERC approval of MISO's filing is still required, and stakeholders have raised several questions and concerns, NIPSCO's 2024 IRP will evaluate the potential impacts associated with D-LOL implementation. After providing this introduction, Mr. Augustine presented slides showing potential seasonal resource accreditation under D-LOL for solar, wind, gas and storage, as well as NIPSCO's potential seasonal obligation impacts from D-LOL. Finally, Mr. Augustine walked through NIPSCO's current capacity position compared to what it would be under D-LOL, for summer (reference load and high load sensitivity) and winter (reference load and high load sensitivity) seasons.

Participants had the following questions/comments, with answers provided by NIPSCO:

Just for the record, we are still calling for NIPSCO to retire Michigan City ASAP or no later than early 2026. Coal ash, air pollution and negligible job benefits to the residents of Michigan City plus housing declination because of power plant.

- NIPSCO acknowledged the comment and followed up that the Michigan City plant retirement date is scheduled for 2028, not 2026.

Scenario Analysis: Commodity Prices, Environmental Policy, and MISO Market Outcomes

Pat Augustine

Stephen Holcomb, Director Environmental Policy & Sustainability, NiSource

Mr. Augustine began with a review of CRA's fundamental market model, which simulates fuel and power markets to produce integrated outlooks for commodity prices, environmental policy, and power market outcomes. He then explained how natural gas price forecasting is done and discussed the key drivers and pricing outcomes across the five IRP scenarios.

Mr. Stephen Holcomb discussed environmental policy and current assumptions that NIPSCO is making regarding the United States Environmental Protection Agency's ("EPA") greenhouse gas ("GHG") rule. The Aggressive Environmental Regulation scenario assumes carbon emissions from the power sector are regulated more heavily.

Next, Mr. Augustine discussed the MISO market Reference Case and how MISO's evolution could impact NIPSCO's portfolio. EPA power sector emissions rules are expected to result in coal retirements or conversions and a diverse mix of new resources. Mr. Augustine then closed out this section by discussing MISO capacity mix projections across all five of NIPSCO's IRP scenarios and key outcomes associated with MISO market generation and market prices.

Participants had the following questions/comments, with answers provided by NIPSCO:

- On Slide 63, is this flow diagram an iterative process? How do you iterate between the Aurora Power Market Model and the Natural Gas Fundamentals Model, which influence each other?
 - It is partially iterative, since natural gas demand impacts price, which then impacts power market dispatch and resource economics and consequently natural gas demand. However, NIPSCO is not running a full set of convergence iterations across each scenario. Instead, some testing is done to make sure that the narrative around demand and price across scenarios holds together.
- In the Accelerated Innovation scenario, you're assuming that gas prices are lower than they are in the Reference case, which you say is the product of a different model that you are not doing any runs in (the Princeton Model). But the reason for that reduction in price is not visible at all to Aurora and it is hard not to see how that would not potentially compel Aurora to consume more gas if you were modeling the same footprint. It feels like NIPSCO is predetermining the outcome in terms of price, especially for the Accelerated Innovation scenario. But that is going to have the opposite impact from the reason that you lowered that price to begin with, when you get to Aurora.
 - When we get to the Aurora outputs you will see that the gas demand is quite low in the Accelerated Innovation scenario because that is part of the narrative. This is because the scenario construct explicitly incorporates technology improvements, like hydrogen, long duration energy storage ("LDES"), or advanced nuclear, that pick up the slack associated with increased power demand. This is one of the cases where some iterative testing on power sector gas demand and gas price was performed to ensure broad consistency. The overall point is fair, but NIPSCO has tried to develop an internally consistent scenario with some feedback modeling and other assumptions that drive these cases. Those are good comments, but when we get to the Aurora output it should become clear that the narrative holds together.

- It sounds like you've done some initial runs of the NIPSCO system specifically. Will these runs be provided as part of the data release within the next two weeks?
 - No NIPSCO-specific portfolio runs have been done, but the MISO-level data analysis, which will be discussed later in this meeting, could be part of that release. The NIPSCO portfolio analysis is coming next and will be built out against the MISO inputs.
- Will the data centers use natural gas as their backup generator fuel, or will they use diesel as their fuel? Will they do any peak shaving with natural gas? If they use natural gas in their process, it could be significant, so how might that change any of your modeling?
 - From a modeling perspective, NIPSCO is not making explicit assumptions about what data centers or large loads might be using for any on-site generation. That is a big uncertainty, although it is something that might warrant further study at the NIPSCO portfolio level. At the MISO market level, you will see that the Company has different levels of load growth across the broader footprint and different levels of new resource types that can meet them. So, in some of the scenarios, including the Domestic Resiliency one, there is a more robust amount of natural gas in the system, whereas other scenarios like the Accelerated Innovation one are premised more on a cleaner energy future.
- Related to the new coal combustion residuals ("CCR") rule, Michigan City Generating Station made land/CCR area, on the lake, is included in the CCR final rule and the condition of the aging seawall has been recently downgraded. Why not clean that up ASAP as the lake levels and wave ferocity will continue to negatively impact the condition of that degraded wall?
 - The team is analyzing the final Legacy CCR rule, which was finalized around the same time as the GHG rule. The 2015 CCR rule regulated active units while the Legacy CCR rule regulates inactive units and NIPSCO is analyzing and complying with both rules and is committed to protecting human health and the environment. As far as the sea wall goes, these rules do not impact resource planning but that is something that can be addressed outside of the IRP process.
- My question is related to how the NiSource net zero by 2040 is reflected in the IRP?
 - The carbon prices in the aggressive environmental regulation scenario are commensurate with a net zero power sector by 2040.
 - When the discussion gets to the NIPSCO portfolio analysis, there will be an extra layer of analysis with alternative portfolio strategies with varying levels of emission reductions over time.
- On Slide 79, are the capacity figures on the left in terms of installed capacity ("ICAP")? Is the jump in capacity over time motivated by load growth, or by the change in seasonal accredited capacity ("SAC") under DLOL? Do you think the load growth might be understated? Does the change in load growth significantly impact the power prices that you are getting? What is going on with the gas portion of the bars on the graph; why does gas increase and then decrease?
 - Yes, the capacity figures shown are in terms of ICAP.

- The jump in capacity is due to a combination of things. In the Reference Case there is a modest amount of load growth over the next five years, on the order of 3-5 GWs system-wide. The rest of the jump would be more due to the MISO accreditation declines for wind and solar. So, in order to meet reliability needs, the MISO market will need more capacity overall, including some incremental natural gas replacing coal.
 - It is possible that the Reference Case is understating MISO-wide load growth, and the Domestic Resiliency case might be an alternative benchmark that we will consider. Although there may be pockets within MISO that have disproportionately large load growth, if data center load growth does materialize at large scale, we might be shifting more into the Domestic Resiliency world, where the MISO market would have 20 GW of load growth over the next five to ten years, and then about 60 GW of load growth over the 20-year horizon.
 - Yes, the change in load growth does push the price of power up and increases the amount of new resources that need to be developed, and we will get to that in a few slides.
 - This graph does include retirements so there are a couple of older gas peaking across MISO that are slated to retire and by 2035, retirements start outpacing any new builds. This is an all-in view that includes net additions and subtractions.
- Duke's IRP showed CCS being ready by 2035 at the earliest. Why is NIPSCO different from Duke and showing CCS being ready by 2030?
 - That is a fair point and it could be argued that 2030 is aggressive, but from a modeling perspective NIPSCO is trying to look at the broader market system and a range of buildouts for new resources throughout MISO that might enter if the EPA rules are in place. NIPSCO-specific portfolio modeling may have different assumptions based on NIPSCO's location and available resource options.
- Is it true that the MISO prices are LMPs, which are short-run marginal costs? If so, is there concern that Aurora will select it over the long-term marginal cost of other supply resources? That is, the model will select capacity resources rather than energy resources?
 - Yes, the LMP prices that are included here are essentially short-run marginal cost prices. From a broader modeling perspective there are several constraints that must be met. The energy needs of the system and the seasonal capacity requirements have to be met. The premise of your question is correct, but we're not seeing a migration away from a diverse set of energy and capacity resources when all of the constraints are included.
- My concern comes with the NIPSCO modeling steps.
 - That is a fair point. The same constraints would exist in some fashion, though. The Company could run the model completely unconstrained and assume that it could purchase unlimited amounts of energy in the market and there might be a different outcome versus implementing some constraints for overall purchases and sales. The way that NIPSCO has approached this question in the IRP process is that we do not want to build a portfolio that is too heavily reliant on market purchases or too heavily reliant on market sales.
- On Slide 86, what does it mean when NIPSCO shows "Hydrogen" as a standalone resource?

- NIPSCO has two hydrogen categories at the MISO market level. The Hydrogen label refers to a fully hydrogen burning turbine of some sort. The 30% H2 Blend label is mostly consuming natural gas. Such capacity could blend up to 30% hydrogen and this could apply to existing facilities that do not require many upgrades or to new facilities.

Stochastic Analysis Review: Inputs Pat Augustine

Mr. Augustine provided a review of NIPSCO's motivation for conducting an expanded stochastic reliability assessment as part of the 2024 IRP and presented methodologies and illustrative summaries of key inputs associated with the major stochastic variables: NIPSCO load, solar output, wind output, thermal unit outages, natural gas prices, and MISO power prices.

Participants had the following questions/comments, with answer provided by NIPSCO:

- Wanted to clarify why Slide 93 did not mention natural gas as a variable, but was mentioned on slide 94. Wanted to clarify that will be considered.
 - Yes, both gas and power will be part of what is considered.

RFP Progress Recap and Preliminary Results Patrick d'Entremont, Manager, Planning Commercial Support, NIPSCO Robert Lee, Vice President, CRA

Before beginning this section, NIPSCO provided additional details from the morning session: The Company provided information on the EV charging stations in environmental justice ("EJ") communities and those that are close to EJ communities. Out of the nine stations, five are either in or near EJ communities.

Mr. d'Entremont outlined the resource planning approach and provided an overview of the 2024 RFP process. He explained that NIPSCO issued four RFPs: two for renewable and dispatchable resources, one for bridge resources, and one for distributed energy resources.

Mr. Lee then went into more detail regarding the bids that were received as part of the RFP process, including an overview of the projects received. He provided a summary of the pricing for the non-DER bid events and provided an update on DER event, which had just closed on June 20, 2024. He closed by discussing the next steps in the process. In addition, Mr. Gomos provided information on how the RFP information is used in the development of the IRP.

Participants had the following questions/comments, with answer provided by NIPSCO:

- How many bids were from minority business enterprise/disadvantaged business enterprise?
 - That will be considered as part of the evaluation of the bids. It was not considered as part of the preliminary results. CRA is currently looking at inconsistencies, concerns, etc. before turning to more formal evaluation, which will include that type of analysis.

Closing
Alison Becker

Ms. Becker closed the meeting by thanking participants for their participation and their helpful feedback. She reminded participants that NIPSCO is open to both one-on-one meetings with stakeholders as well as presentations as part of the public advisory process. She also noted that this was Doug Gotham's last meeting before he retires on June 30 and expressed appreciation for his participation and valuable input as the executive director of the State Utility Forecasting Group. Finally, she noted that the next meeting will be August 21, 2024, both at Fair Oaks Farms and on Teams and that that meeting will focus on DSM and the results of the MPS.

NIPSCO IRP Stakeholder Meeting - June 24, 2024

Contact First Name	Contact Last Name	Contact Email Address	Company
Earl	M Miller	emiller@hilerindustries.com	Accurate Castings, Inc.(Hiler Ind.)
Connor	Ward	cward@advantagecap.com	Advantage Capital
Anaelle	Croteau	acroteau@advantagecap.com	AdvantageCapital
Erik	Miller	erik.miller@aes.com	AES
Ray	Fu	rfu@bamfunds.com	Balyasny
Denise	Abdul-Rahman	denise@blacksunlight.org	Black Sun Light Sustainability
Govind	Ramakrishnan	govind.ramakrishnan@blackstone.com	Blackstone
Jennifer	Washburn	jwashburn@citact.org	CAC
Taylor	Carpenter	tcarpenter@calfee.com	Calfee
Jeremy	Martin	jeremy.martin@centerpointenergy.com	CenterPoint Energy
Pat	Augustine	paugustine@crai.com	Charles River Associates
Robert	Lee	rlee@crai.com	Charles River Associates
Edwin	Moyo	emoyo@crai.com	Charles River Associates International
Tony	Kazakevicius	tkaz@anacostia.com	Chicago South Shore & South Bend Railroad
Ben	Inskeep	binskeep@citact.org	Citizens Action Coalition
Kerwin	Olson	kolson@citact.org	Citizens Action Coalition of IN
Reagan	Kurtz	rkurtz@citact.org	Citizens Action Coalition of Indiana, Inc.
Tolaver	Rapp	tolaver.rapp@clevelandcliffs.com	Cleveland-Cliffs
Eliza	Gedney	elizagedney@gmail.com	CRA
Oliver	Stover	ostover@crai.com	CRA
Emma	Goodnow	emma.goodnow@duke-energy.com	Duke Energy
Sameer	Doshi	sdoshi@earthjustice.org	Earthjustice
Michelle	Kang	michelle.kang@earthriseenergy.com	Earthrise Energy, PBC
Thomas	Rickabaugh	thomas.rickabaugh@edf-re.com	EDF Renewables
Anna	Sommer	asommer@energyfuturesgroup.com	EFG
Michael	Leikin	mike.leikin@electrotempo.com	ElectroTempo
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
Emily	Medine	emedine@evainc.com	Energy Ventures Analysis, Inc.
Andrea	Schroeder	andrea.schroeder@engie.com	ENGIE
David	Jackson	djackson@flexgen.com	Flexgen
Rachel	Wilson	rwilson@formenergy.com	Form Energy
Steven	Smith	smiste@mac.com	Franklin Covey
Cory	Dutcher	cory.dutcher@ge.com	GE Gas Power
Cory	Dutcher	cory.dutcher@ge.com	GE Vernova / GE Gas Power
Mike	Mooney	mmooney@hepn.com	Hoosier Energy
Richard	Gillingham	rgillingham@hepn.com	Hoosier Energy
LAURA	ARNOLD	Laura.Arnold@IndianaDG.net	Indiana Distributed Energy Alliance
April	Paronish	aparonish@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Brian	Latham	blatham@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Carol Sparks	Drake	CaDrake@oucc.IN.gov	Indiana Office of Utility Consumer Counselor
Gregory	Krieger	gkrieger@oucc.in.gov	Indiana OUCC
Gregory	Krieger	gkrieger@oucc.in.gov	Indiana OUCC
Denise	Abdul-Rahman	darahman17@gmail.com	Indiana State Conference of the NAACP
Luke	Wilson	LuWilson@urc.IN.gov	Indiana Utility Regulatory Commission
Timothy	Powers	tim.powers@inovateus.com	Inovateus Solar LLC
Bradley	Borum	bborum@urc.in.gov	IURC
Dale	Thomas	dthomas@urc.in.gov	IURC
James	Huston	jhuston1@urc.in.gov	IURC
Steph	Hodgin	stehodgin@urc.in.gov	IURC
Susan	Thomas	Susan@jtnwi.org	Just Transition NWI
Bruna	da Silva	bruna.dasilva@keycaptureenergy.com	Key Capture Energy
Quinn	Beckham	quinn.beckham@keycaptureenergy.com	Key Capture Energy
Genevieve	Kennedy	genevieve.kennedy@leewardenergy.com	Leeward Renewable Energy
Zico	Shaker	zico.shaker@leewardenergy.com	Leeward Renewable Energy
Mark	Simons	mcsimons803@gmail.com	MCSimons Inc.
Christopher	Jeffrey	christopher.jeffrey@mizuhogroup.com	Mizuho Securities
Joe	Motuliak	joe.motuliak@nee.com	NextEra Energy
Kay	Nelson	knelson@nwforum.org	Northwest Indiana Forum
Chad	Ritchie	chad.ritchie@oracle.com	Oracle
SUZANNE	ESCUDIER	suzanne.escudier@origisenergy.com	Origis Energy
Brian	Wright	brwright@oucc.in.gov	OUCC
Derek	Leader	dleader@oucc.in.gov	OUCC
JOHN	HANKS	jhanks@oucc.in.gov	OUCC

NIPSCO IRP Stakeholder Meeting - June 24, 2024

Michael	Eckert	meckert@oucc.in.gov	OUCC
Roopali	Sanka	rsanka@oucc.in.gov	OUCC
Richard	Pate	rgpate@pateassociates.com	Pate & Associates
Richard	Pate	rgpate@pateassociates.com	Pate & Associates
Mo	Klefeker	mklefeker@primaryenergy.com	Primary Energy
Sunil	Maheshwari	mahesh67@purdue.edu	Purdue University
Evan	Iskenderian	evan@rangerpower.com	Ranger Power
Carter	Scott	carter@rangerpower.com	Ranger Power LLC
J. Scott	Yaeger	scott.yaeger@rocklandcapital.com	Rockland Capital
Jeffrey	Solomon	jsolomon@savionenergy.com	Savion LLC
Steve	Francis	Sierrasteve@comcast.net	SEED - Sustainable Energy and Economic Development
Tony	Mendoza	tony.mendoza@sierraclub.org	Sierra Club
Zach	Schalk	Zach@solarunitedneighbors.org	Solar United Neighbors
David	Nderitu	nderitu@purdue.edu	State Utility Forecasting Group
Doug	Gotham	gotham@purdue.edu	State Utility Forecasting Group
Gregory	Va Horssen	gvhorssen@vanhorssenlaw.com	Van Horssen Law & Government, PLLC
Richie	Ciciarelli	rciciarelli@veritionfund.com	Verition
Will	Kenworthy	will@votesolar.org	Vote Solar
Aditya	Gandhi	agandhi@wolferesearch.com	Wolfe Research
Elena	Gomez	elena.gomezescalonilla@x-elio.com	X-ELIO
Elena	Gomez	elena.gomezescalonilla@x-elio.com	X-ELIO
Christine	Colon	colongar@aol.com	
Frank	He	fhe@orionrenewables.com	
Gilles	Charriere	Gillescharriere@yahoo.com	
greg	reiss	gregory.reiss@gmail.com	
Greg	Reiss	greiss@veritionfund.com	
Joan	Crist	cristjoan1@gmail.com	
Lucas	Giese	lugiese@iu.edu	
Roy	Dell'Aquila	ROYDELLAQUILA@YAHOO.COM	
Will	Kenworthy	Will@votesolar.org	

2024 NIPSCO Integrated Resource Plan

Third Stakeholder Advisory Meeting

August 21, 2024



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

2024 NIPSCO INTEGRATED RESOURCE PLAN

Third Stakeholder Advisory Meeting

August 21st, 2024
9:00AM-2:15PM CT





OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

WELCOME & INTRODUCTION

Tara McElmurry, Communications Manager, NiSource



FAIR OAKS FARMS



LOCATION OF
NEAREST EXIT

NEAREST PLACE TO
SEEK SHELTER

IN AN EMERGENCY,
WHO WILL DIAL 911

WHO WILL DIRECT THE
EMERGENCY RESPONDER

LOCATION OF THE
**AUTOMATED EXTERNAL
DEFIBRILLATOR (AED)**

WHO CAN
PERFORM CPR

OTHER **POTENTIAL HAZARDS**

Fire: Exit out any door that is furthest away from the fire. Gather as a group in the front parking lot – near the Tesla chargers.

Shelter: Restrooms, Jasper Ballroom (if closed), Employee Banquet Hallway.

AED Location: On the wall in the Employee Banquet Hallway.

Other Hazards: N/A

Dial 911:

Direct Responders:

CPR:

SAFETY MOMENT: EYE WELLNESS



Why does computer use strain the eyes more than reading print material? Mainly because people tend to blink less while using computers. Focusing the eyes on computer screens or other digital displays has been shown to reduce a person's blink rate by a third to a half, which tends to dry out the eyes. We also tend to view digital devices at less than ideal distances or angles.



Consider two actions that will be impactful

- **Keep your distance:** The eyes work harder to see close up. Try keeping the monitor or screen at arm's length, about 25 inches away
- **Reduce glare:** Screens can produce glare that can aggravate the eye. Try using a matte screen filter.
- **Adjust lighting:** If a screen is much brighter than the surrounding light, your eyes have to work harder to see.
- **Give your eyes a break:** Remember to blink and follow the 20-20-20 rule. Take a break every 20 minutes by looking at an object 20 feet away for 20 seconds. This allows your eyes to relax.
- **Stop using devices before bed.**

Read more at:

<https://www.cornerstoneoptometry.com/post/protect-your-eyes-from-too-much-screen-time>

Tips to Ease Eye Strain



Sit at arm's length, or 25 inches, from the computer screen.



Follow the "20-20-20" rule.



Adjust your room lighting and increase the contrast on your computer.



Use artificial tears to refresh your eyes when they feel dry.

STAKEHOLDER ADVISORY MEETING PROTOCOLS

- **Your input and feedback is critical to NIPSCO's Integrated Resource Plan (IRP) process.**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and overall IRP.**
- **We set aside time at the end of each section to ask questions.**
- **Your candid and ongoing feedback is key to this process:**
 - Please ask questions and make comments on the content presented
 - Please provide feedback on the process itself
- **Please identify yourself by name prior to speaking. This will help keep track of comments and follow up actions.**
- **If you wish to make a presentation during a meeting, please reach out to Erin Whitehead (ewhitehead@nisource.com).**

AGENDA

Time *Central Time	Topic	Speaker
9:00AM-9:05AM	Welcome & Introduction	Tara McElmurry, Communications Manager, NiSource
9:05AM-9:10AM	Kick Off	Vince Parisi, President & COO, NIPSCO
9:10AM-9:30AM	Public Advisory Process and Responses to Second Stakeholder Meeting Comments	Abe Lang, Manager Strategy & Risk, NiSource
9:30AM–11:00AM	Developing the Demand Side Management (DSM) Study	Jeffrey Huber, Managing Director –Energy Efficiency, GDS Jesse Smith, Partner, Demand Side Analytics
11:00AM-12:00PM	Lunch	
12:00PM–1:45PM	Incorporating New Resource Options in the IRP and Overview of Portfolio Modeling Approach • DSM Bundles • 2024 Request for Proposals (RFP) Tranche Review • Other Resource Options	Abe Lang, Manager Strategy & Risk, NiSource Pat Augustine, Vice President, CRA Patrick d'Entremont, Manager Planning Commercial Support, NIPSCO
1:45PM-1:55PM	2024 Public Advisory Process Next Steps	Tara McElmurry, Communications Manager, NiSource
1:55PM-2:15PM	Closing & Stakeholder Comments	



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

KICK OFF

Vince Parisi, President & COO, NIPSCO



PREMIER REGULATED UTILITY BUSINESS



NATURAL GAS

COLUMBIA GAS OF KENTUCKY

COLUMBIA GAS OF MARYLAND

COLUMBIA GAS OF OHIO

COLUMBIA GAS OF PENNSYLVANIA

COLUMBIA GAS OF VIRGINIA

NIPSCO GAS

NIPSCO

ELECTRIC

NIPSCO ELECTRIC

SIGNIFICANT SCALE ACROSS 6 STATES

~3.2M

GAS CUSTOMERS

~500K

ELECTRIC CUSTOMERS

NIPSCO PROFILE

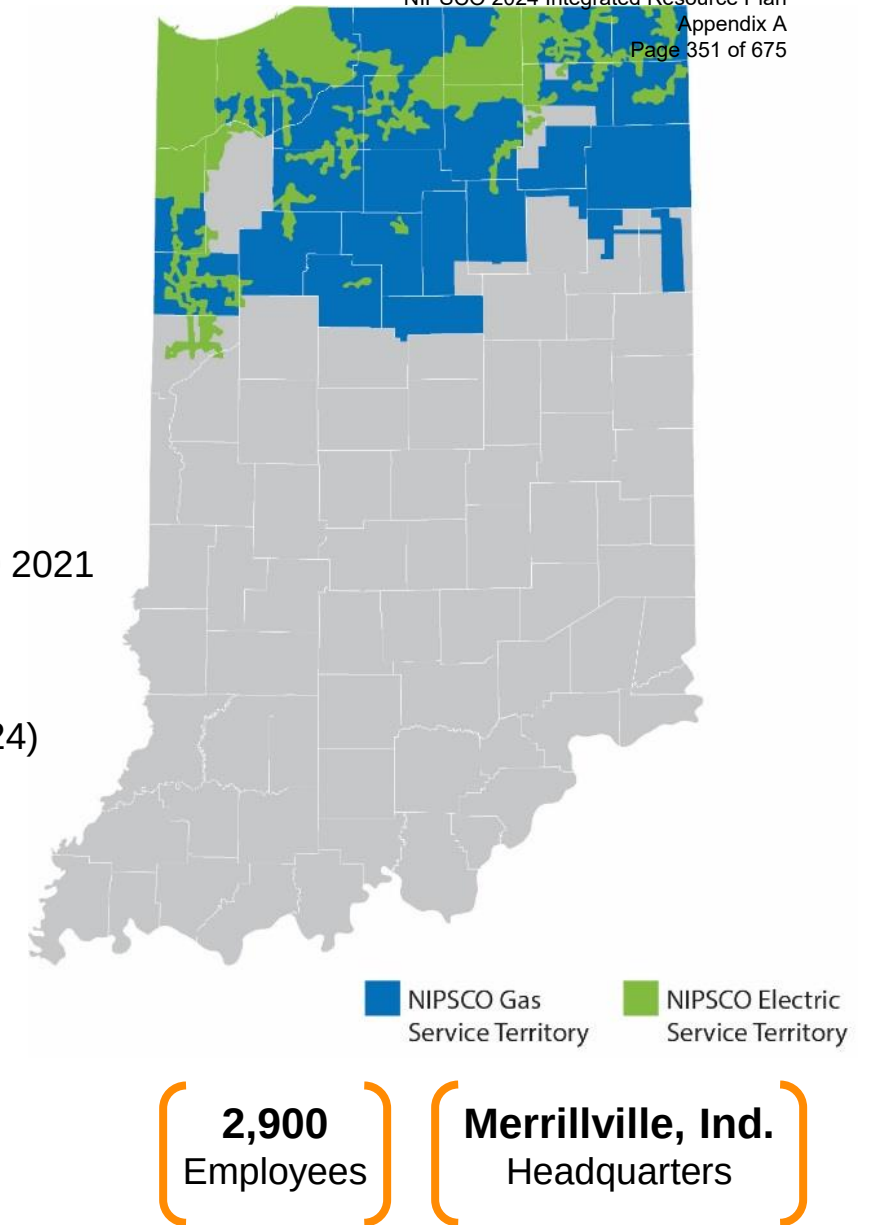
Working to Become Indiana's Premier Utility

Electric

- 483,000 Electric Customers in 20 Counties
- 3,625 MW Generating Capacity
 - 12 Electric Generating Facilities
(2 coal, 1 natural gas, 2 hydro, 4 wind, 2 solar, and 1 solar-plus-storage)
 - 1,000 MW of New Wind Energy
(Rosewater, Jordan Creek and Indiana Crossroads Wind I & II online in 2020 2021 and 2023)
 - 665 MW of New Solar Energy
(Dunns Bridge I, Indiana Crossroads solar online in 2023, and Cavalry in 2024)
- 12,800 Miles of Transmission and Distribution
 - Interconnect with 5 Major Utilities (3 MISO; 2 PJM)
 - Serves 2 Network Customers and Other Independent Power Producers

Natural Gas

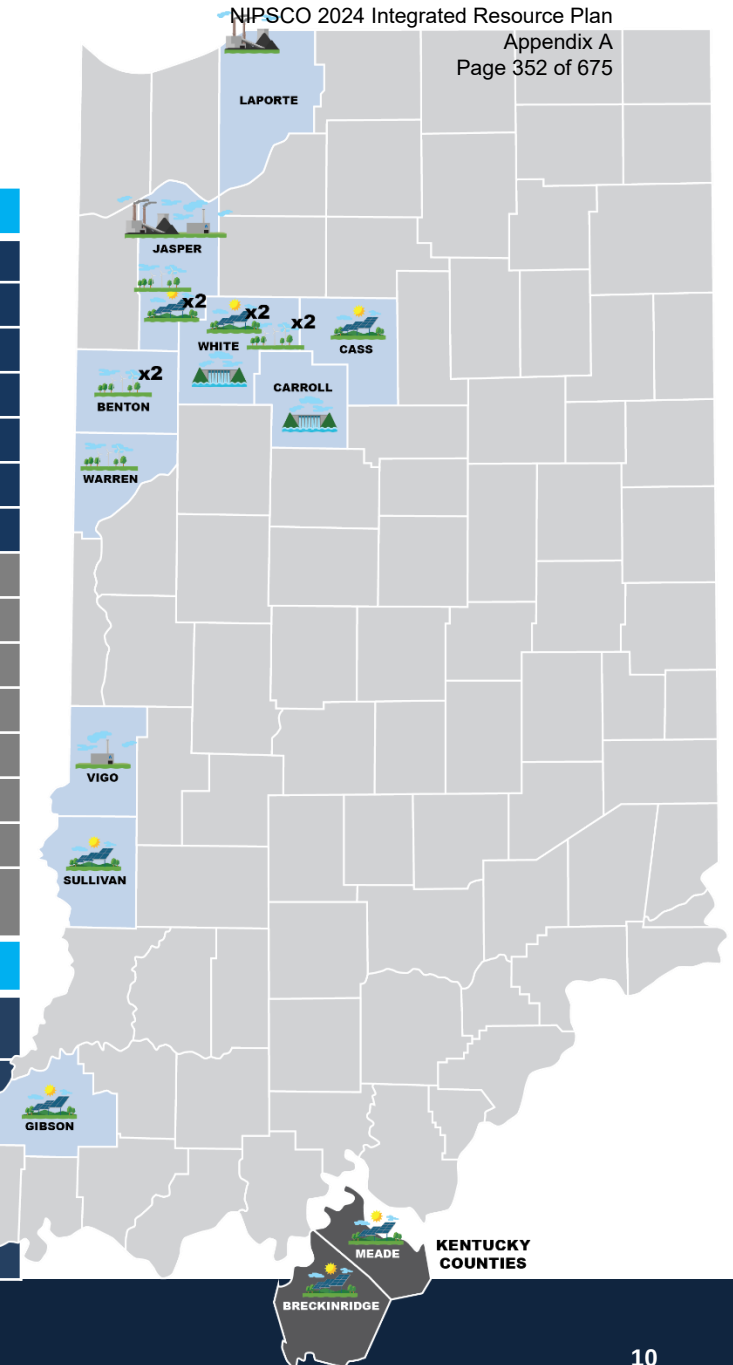
- 859,000 Natural Gas Customers; 32 Counties
- 17,000 Miles of Transmission and Distribution Line/Main
- Interconnections with Seven Major Interstate Pipelines
- Two On-System Storage Facilities



CURRENT & FUTURE NIPSCO GENERATION PORTFOLIO

Robust Renewable Investments in Indiana

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
CAVALRY SOLAR	200 MW + 60 MW BATTERY	WHITE	2024 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE (KY)	2025
DUNNS BRIDGE SOLAR II	435 MW + 75 MW BATTERY	JASPER	2025
GIBSON SOLAR	200 MW	GIBSON	2025
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025
TEMPLETON WIND	200 MW	BENTON	2025
CARPENTER WIND	200 MW	JASPER	2025
APPLESEED SOLAR	200 MW	CASS	2025
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PENDING IURC APPROVAL
GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2025 (COAL) – 2028 (NG)	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	563 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL



* Since 2018

PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and it's consistent with our goal to transition to the best cost and cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.



**Reliable and
sustainable**

**Flexibility for
the future**

**Local and statewide
economic benefits**

**Best plan for customers
and the company**



PUBLIC ADVISORY PROCESS AND RESPONSES TO SECOND STAKEHOLDER MEETING COMMENTS

Abe Lang, Manager Strategy & Risk, NiSource



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 354 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



FEEDBACK FROM JUNE 24, 2024 IRP STAKEHOLDER MEETING

There was significant interest on the load growth scenarios from stakeholders at the IRP meeting on June 24th.

Questions and discussion centered around:

- Identity of these data center customers and stages of discussion
- Certainty of assumed load growth
- Ratemaking and customer protections (generally outside the scope of the IRP)
- Specific questions:
 - When did NIPSCO become aware of the potential for this load growth?
 - Where is this load in the interconnection process?
 - Is there sufficient transmission? Have the appropriate network upgrade studies been completed?
 - Will the data centers be charged appropriately for the interconnection and the appropriate rate?
 - Concerns that other ratepayers are projected from payer higher rates because of the addition of this load.
 - What will data centers do to pollution/CO₂ concerns?
 - Is there economic value for these communities and do they want the addition of data centers?
 - Has demand response been considered in this modeling?

REVIEW: NIPSCO IRP LOAD GROWTH* WITH NEW LOAD SENSITIVITY

Given the potential opportunities in the pipeline from NIPSCO's Economic Development team, NIPSCO communicated the following load expectations at the June 24th IRP Stakeholder Advisory meeting.

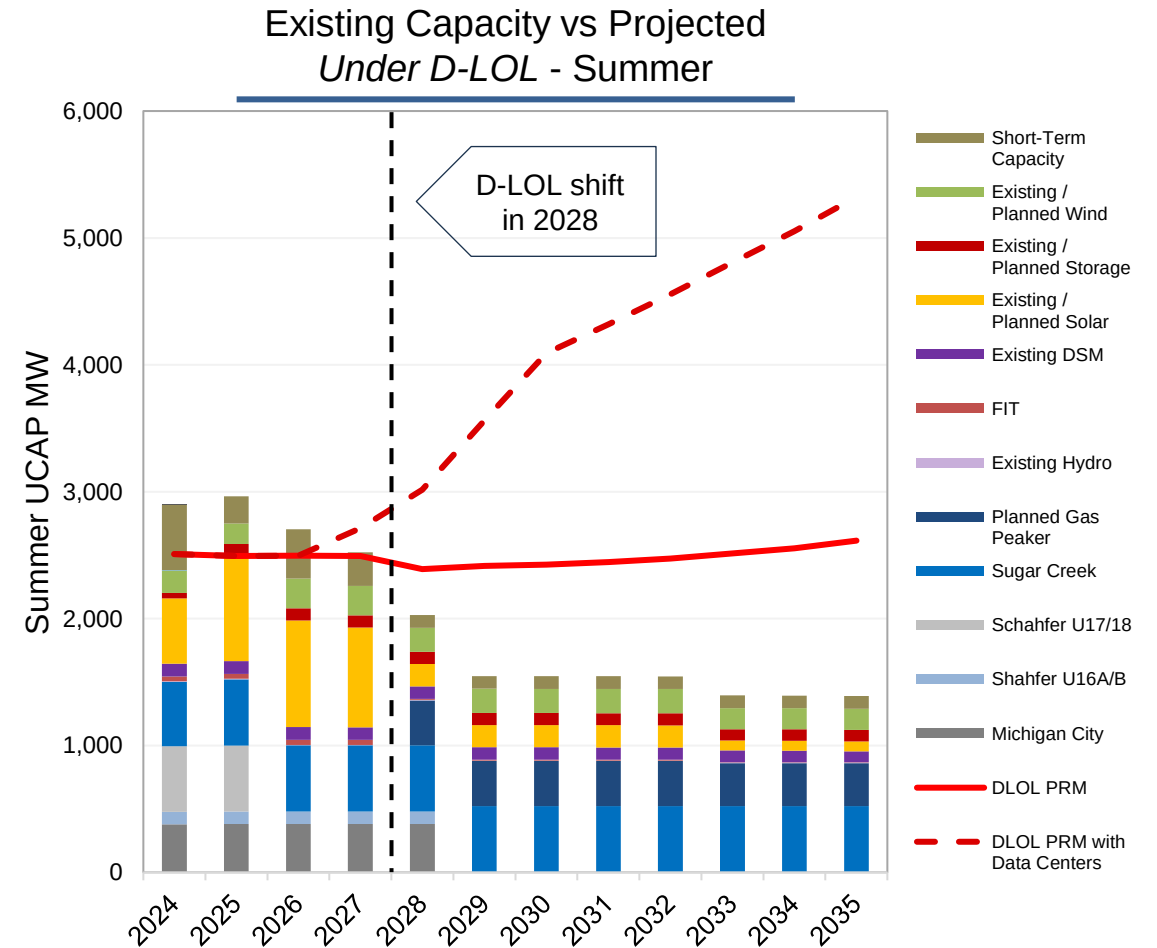
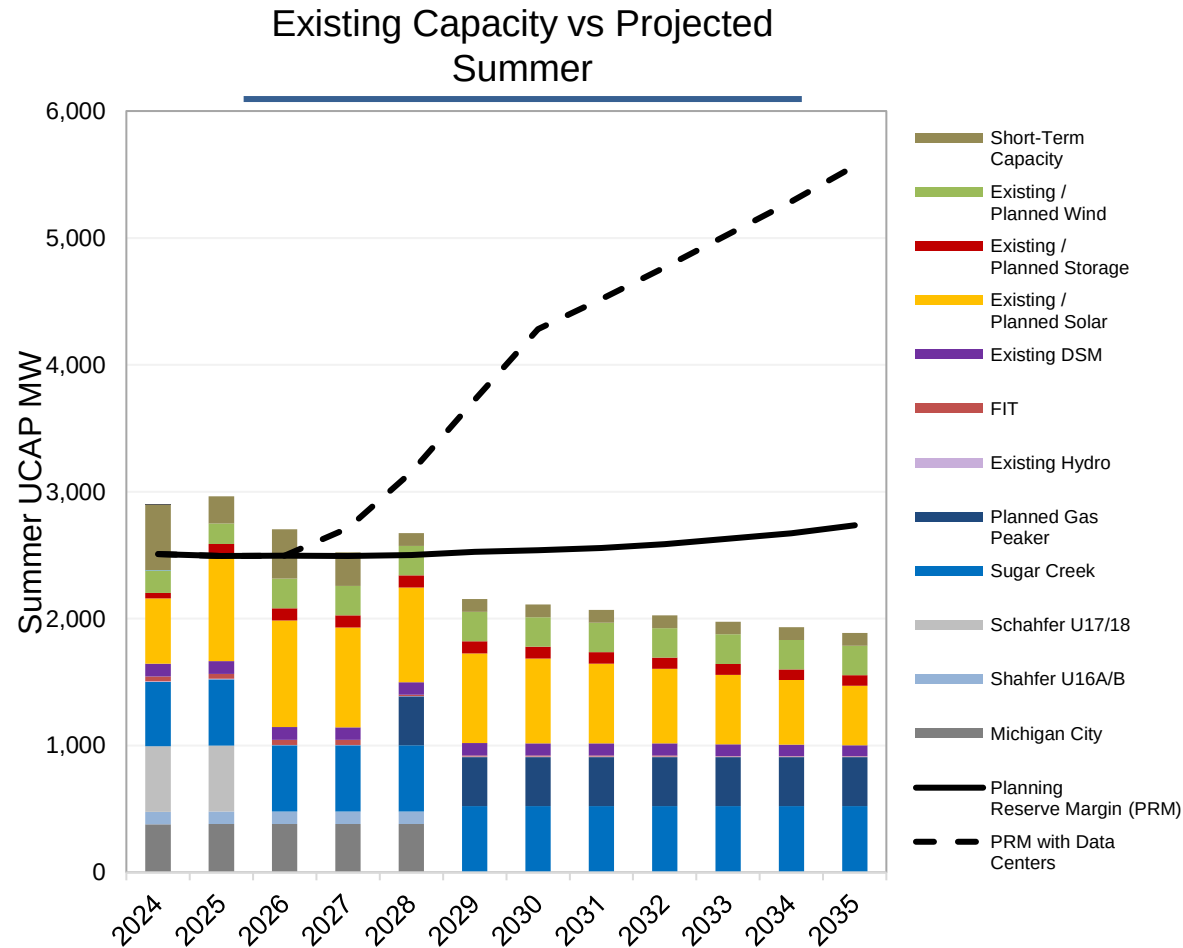
	Preliminary & Illustrative		
	2028	2030	2035
IRP Peak Load – Original Reference Case**	2,300 MW	2,300 MW	2,500 MW
+ <i>New Load Added to All IRP Scenarios</i>	<i>600 MW</i>	<i>1,600 MW</i>	<i>2,600 MW</i>
IRP Peak Load – New Reference Case	2,900 MW	3,900 MW	5,100 MW
+ <i>Emerging Load Sensitivity</i>	<i>2,600 MW</i>	<i>4,500 MW</i>	<i>6,000 MW</i>
Total IRP Peak Load with Emerging Load Sensitivity	5,500 MW	8,400 MW	11,100 MW

- The build-out of new energy and capacity resources to meet this potential new load will be analyzed in the 2024 IRP process.

* NOTE: NIPSCO is not guaranteeing that any amount of new load will enter our service territory, but we are sharing our current expectations with stakeholders to allow time for feedback as we prepare to conduct our IRP analysis with this significant change

** Rounded estimate of Reference Case IRP Peak Load was originally shared with stakeholders at the April 23 IRP Public Advisory meeting

REVIEW: CURRENT NIPSCO CAPACITY POSITION – REFERENCE LOAD – SUMMER



2024 NIPSCO IRP ANALYSIS INPUTS SUMMARY – “WHAT’S IN, WHAT’S OUT, AND WHAT’S TO COME”

Category	Directly Assessed in IRP	Comments
DSM	✓	- Incorporated Market Potential Study RAP, Enhanced RAP, and MAP studies - Integrated EV analysis to include unmanaged vs. managed charging for light duty vehicle class including evaluation of integrating AMI - Included an estimate for data center demand response - Assessed impact of customer-owned DERs (see more below)
EVs	✓	- Class-level assessment (light, medium and heavy duty vehicles, <u>including a detailed transportation corridor assessment for heavy duty vehicles</u>) - Deeper assessment of hourly charging shapes based on type of charger, location of charger (public/private), temperature, etc.
Economic Development	✓	Additional econometric analysis of industrial loads, as well as review of potential additional emerging industrial load types (i.e., data centers)
DER	✓	- Incorporation of historical customer data across NIPSCO footprint - More rigorous uncertainty analysis based on system costs, federal tax credit policy, wholesale and retail rates, and policy construct - Issued DER-specific RFP Event for 2024 IRP
MISO D-LOL	✓	MISO filing and early indications of impact incorporated into core portfolio analysis (ex: solar and wind resources capacity accreditation evaluated based on MISO D-LOL guidance)
EPA GHG Rule	✓	Final rule incorporated into core portfolio analysis (ex: new gas-fired resources will be modeled with constraints within NIPSCO’s portfolio analysis)

2024 NIPSCO IRP ANALYSIS INPUTS SUMMARY – “WHAT’S IN, WHAT’S OUT, AND WHAT’S TO COME”

Category	Generic Assumption	Deferred beyond this IRP	Comments
SMR			NIPSCO will continue to track and monitor as technology continues to mature
Hydrogen			NIPSCO will continue to track and monitor as technology continues to mature
Long-Duration Energy Storage (LDES)			Two LDES offers came in via the 2024 RFP, which guided cost assumptions. NIPSCO will continue to track and monitor as technology continues to mature
CCUS			NIPSCO will continue to track and monitor as technology continues to mature
Solar For All			• High-level assumption in core IRP analysis • 2024 RFP contained an Event specific to DER to assist NIPSCO in gaining experience with integration of DERs on the system • NIPSCO engaging with Solar For All through City of Gary and Indiana CCA
AMI			• NIPSCO anticipates its AMI rollout to be completed in 2027/2028 • AMI will be incorporated into the IRP planning process as the AMI rollout is completed • NIPSCO will continue to evaluate and integrate AMI into IRP processes

PORTFOLIO PERFORMANCE WILL BE DISTILLED INTO AN INTEGRATED SCORECARD

Objectives	Indicators	Proposed Metrics for 2024	Notes
Affordability	Cost to Customer	- Near-term and long-term impact to customer bills Metric: 10-year and 30-year NPV of revenue requirement (Reference Case scenario deterministic results)	Near-term and long-term perspectives
Rate Stability	Cost Certainty	- Certainty that revenue requirement within the most likely range of outcomes Metric: Scenario range NPVRR	
	Cost Risk	- Risk of unacceptable, high-cost outcomes Metric: 95th% cost risk from probabilistic analysis	
	Lower Cost Opportunity	- Potential for lower cost outcomes Metric: 5th% cost risk from probabilistic analysis	
Environmental Sustainability	Carbon Emissions	- Carbon intensity of portfolio Metric: Cumulative carbon emissions (2024-40 short tons of CO2) from the generation portfolio	Other emissions will be reported but not included in the Scorecard
Reliable, Flexible, and Resilient Supply	Reliability, Flexibility	- The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules Metric: Loss of Load Expectation proxy ("Forced market exposure") metrics for NIPSCO system from probabilistic reliability analysis Metric: Capacity able to respond within 10 mins & 30 mins	New metrics from fuller reliability analysis based on MISO market rules evolution
Positive Social, & Economic Impacts	Local Investment in Economy	- The effect on the local economy from new projects and ongoing property taxes and targeted investment Metric: NPV of property taxes from the entire portfolio	NIPSCO solicited Stakeholder feedback to consider potential metrics to measure Environmental Justice and Energy Equity but received no further input from Stakeholders. NIPSCO continues to welcome this input.



DEVELOPING THE DEMAND SIDE MANAGEMENT (DSM) STUDY

Jeffrey Huber, Managing Director –Energy Efficiency, GDS

Jesse Smith, Partner, Demand Side Analytics



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 361 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



DSM AT NIPSCO – ENERGY EFFICIENCY (“EE”) AND DEMAND RESPONSE (“DR”)

- NIPSCO has had a robust history of actively promoting and implementing energy conservation and efficiency to both its employees and customers since 2010
- NIPSCO actively works with its Oversight Board (“OSB”) to provide direction for both implementation and evaluation of NIPSCO energy efficiency programs
- NIPSCO and the OSB work with third-party administrators TRC Companies and Oracle to offer cost-effective energy efficiency programs for its customers
- Although NIPSCO previously offered an air conditioning cycling program, the demand response programs were historically focused on interruptible rate programs with NIPSCO’s largest customers, which now directly participate in the MISO demand response markets as part of Rate 531 Industrial Customer Service Structure
- NIPSCO has approved plans through 2026, and the current IRP will plan for potential continued and new programs starting in 2027

NIPSCO MARKET POTENTIAL STUDY FOR DSM RESOURCES - ENERGY EFFICIENCY AND DEMAND RESPONSE

- To support the development of the 2024 IRP, the NIPSCO OSB worked with GDS Associates to develop a market potential study (“MPS”) to assess the potential level of energy efficiency and demand response savings opportunities and the associated costs
- NIPSCO’s MPS developed residential and commercial and industrial portfolio demand side management market potential and costs over the 20-year planning horizon (2027 – 2046) for:
 - Utility sponsored energy efficiency
 - Demand Response
- The MPS estimates the maximum achievable potential (“MAP”) and realistic achievable potential (“RAP”) for energy efficiency and demand response for the residential and commercial and industrial customer segments, along with the cost of acquiring the two levels of achievable potential
 - In the process NIPSCO coordinated with the OSB to develop a third level of achievable potential (“Enhanced RAP”)
- The outputs of the MPS analysis will be used as inputs to be incorporated by CRA within the broader IRP portfolio analysis

DSM MODELING STEPS

Step 1	Step 2	Step 3
Market Potential Study - Evaluate detailed energy efficiency and demand response program-level opportunities in NIPSCO service territory - Identify energy efficiency and demand response program impacts and associated costs	Identify “bundles” based upon market segments and savings potential - Aggregate detailed measures into bundles of measures at the residential and commercial & industrial segment at the RAP and Enhanced RAP levels - Produce bundles with detailed energy and demand savings characteristics and costs	Evaluate DSM bundles in IRP portfolio models - Allow DSM bundles to be selected in optimization analysis, along with other supply-side candidates - Evaluate alternative DSM portfolios (i.e., MAP DR and Enhanced RAP EE) through sensitivity analysis
GDS NIPSCO DSM Team		CRA NIPSCO IRP Team

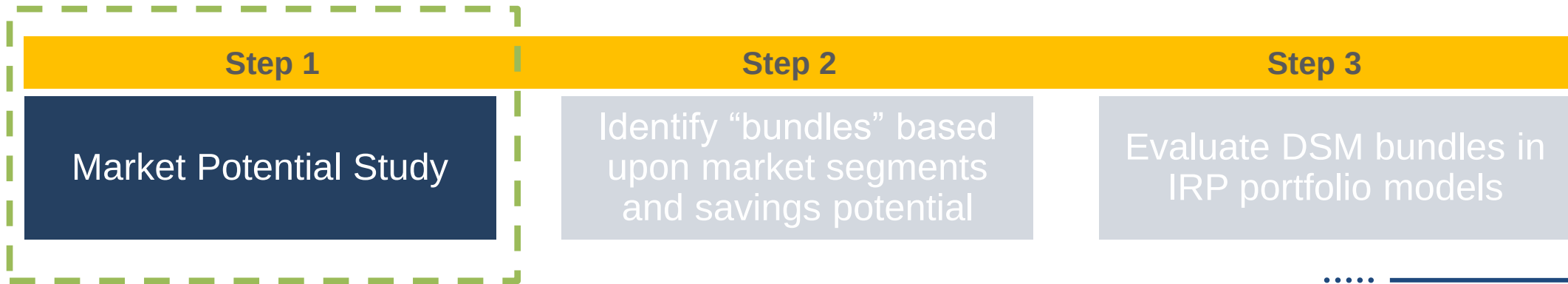


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

MARKET POTENTIAL STUDY OVERVIEW

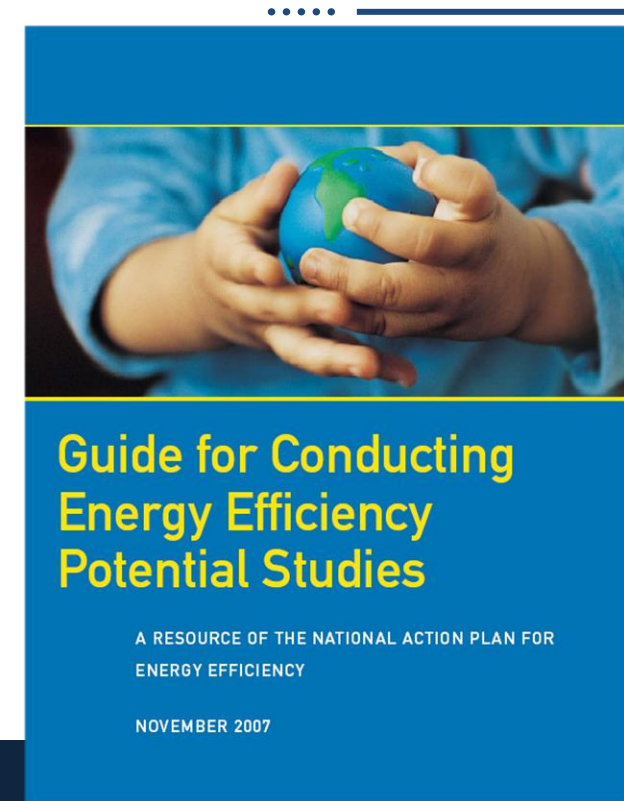


WHAT IS A MARKET POTENTIAL STUDY?



Simply put, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies.

-National Action Plan for Energy Efficiency



TYPES OF POTENTIAL

TECHNICAL POTENTIAL

All technically feasible measures are incorporated to provide a theoretical maximum potential.

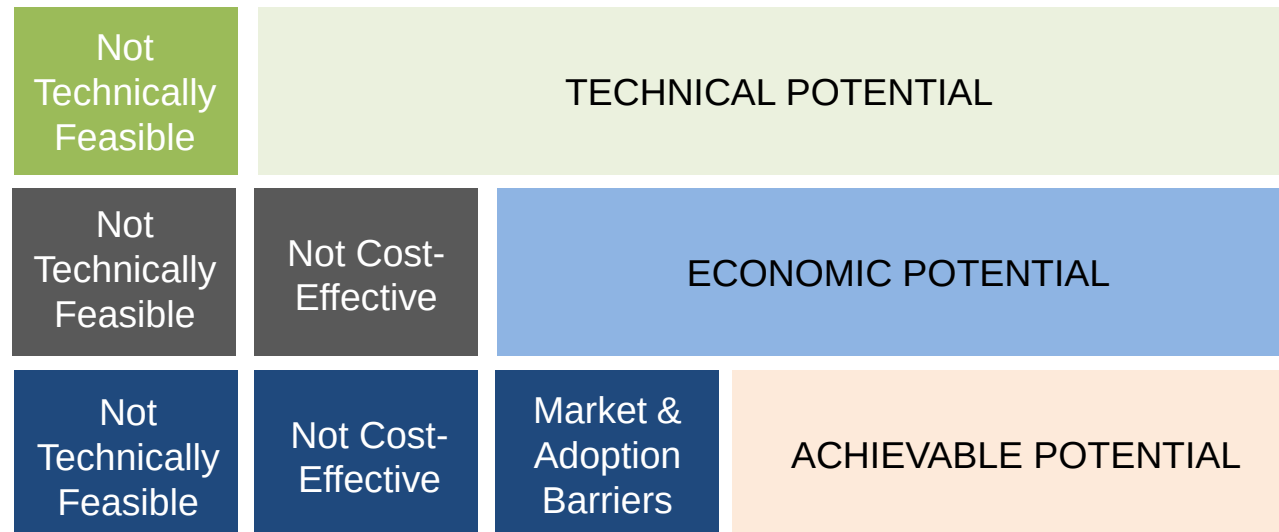
ECONOMIC POTENTIAL

All measures are screened for cost-effectiveness using the Utility Cost Test (“UCT”). Only cost-effective measures are included.

ACHIEVABLE POTENTIAL

Cost-effective energy efficiency potential that can practically be attained in a real-world program delivery case, assuming that a certain level of market penetration can be attained.

Types of Energy Efficiency Potential



Two achievable scenarios

Maximum Achievable Potential (MAP) assumes 100% incentives and more aggressive adoption levels

Realistic Achievable Potential (RAP) assumes incentives that align with current levels

WHAT IS A MARKET POTENTIAL STUDY?



The MPS represents the starting point for developing inputs for the IRP modeling



The savings potential from this analysis will be used to create DSM resources and levels to be modeled in the IRP



DSM selections from the IRP will be used to create NIPSCO's DSM plan for 2027-2029 as well as contribute to the long-term preferred portfolio



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

MARKET CHARACTERIZATION OVERVIEW



KEY GLOBAL INPUTS AND DATA SOURCES

**NIPSCO Electric
Load Forecast***

**Forecasts of
Avoided Costs**

Inflation Rate

Discount Rate

**Planning Reserve
Margin**

**Line Loss
Assumptions**

**Energy efficiency
and demand
response measure
costs, kWh and kW
savings, useful lives**

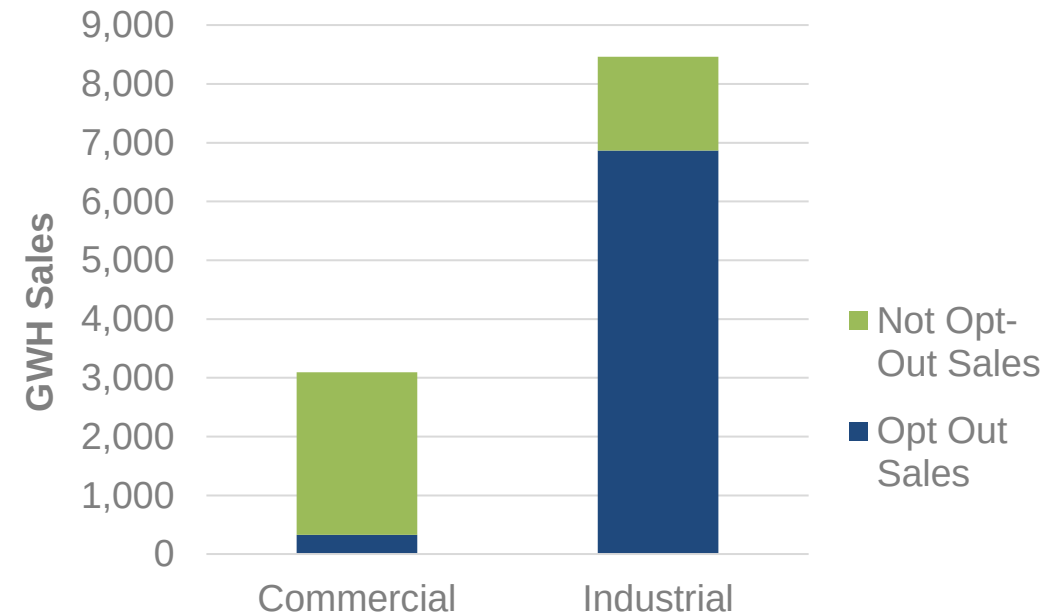
**Market
Characteristic Data***

** To be discussed in more detail*

NIPSCO ELECTRIC LOAD FORECAST

- The internal NIPSCO sales forecast was modified for use in the MPS
 - Adjustment removed embedded assumptions about future energy efficiency based on historical DSM performance.
 - MPS also removed sales of current opt-out customers from eligible sales forecast (see graphic to the right)

Opt-Out Sales* by C&I Sector (2027)**

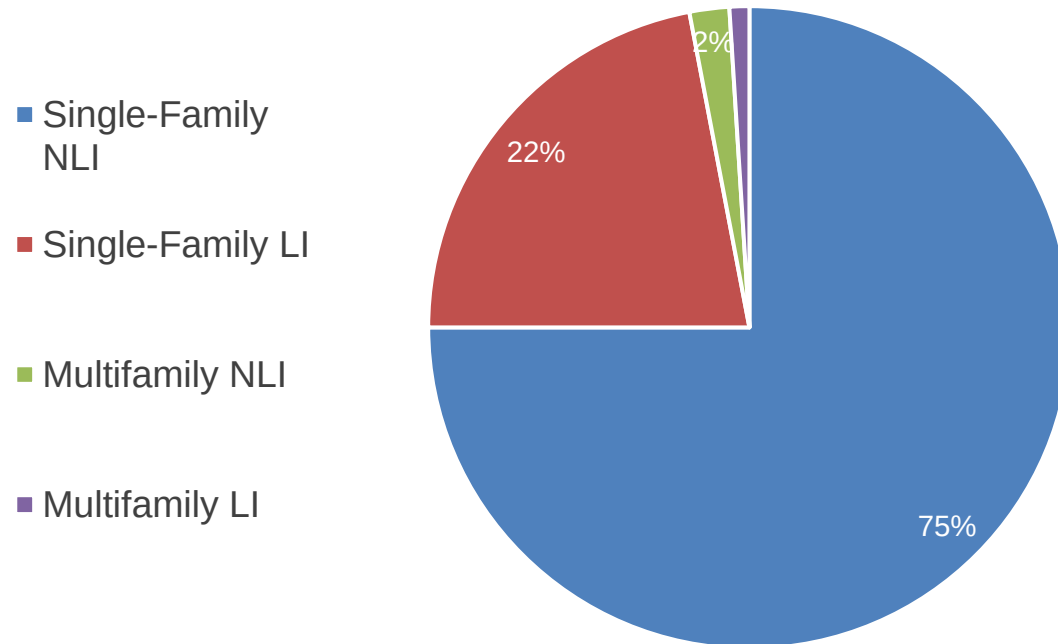


*Opt-out sales are the portion of the load that do not contribute to the energy efficiency fund and were not considered to be eligible for energy efficiency improvements in the MPS

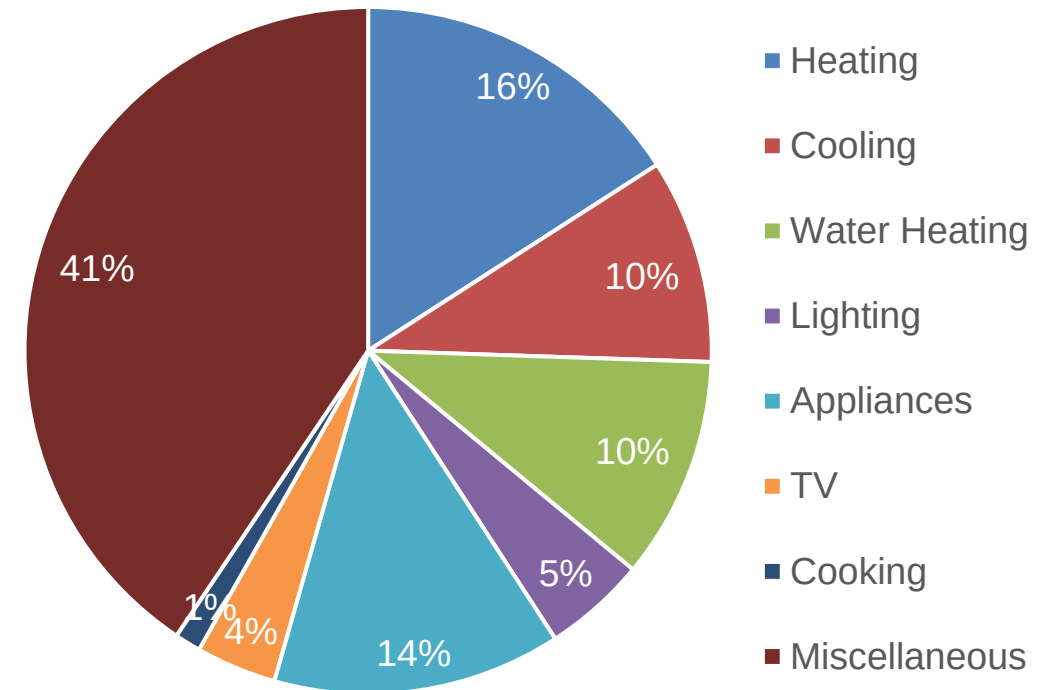
**Note that the industrial load shown here includes some non-firm Rate 531 customers. The non-firm component, however, is not included in NIPSCO's IRP load forecast.

MARKET CHARACTERISTICS DATA

Residential Sales by Home & Income Type



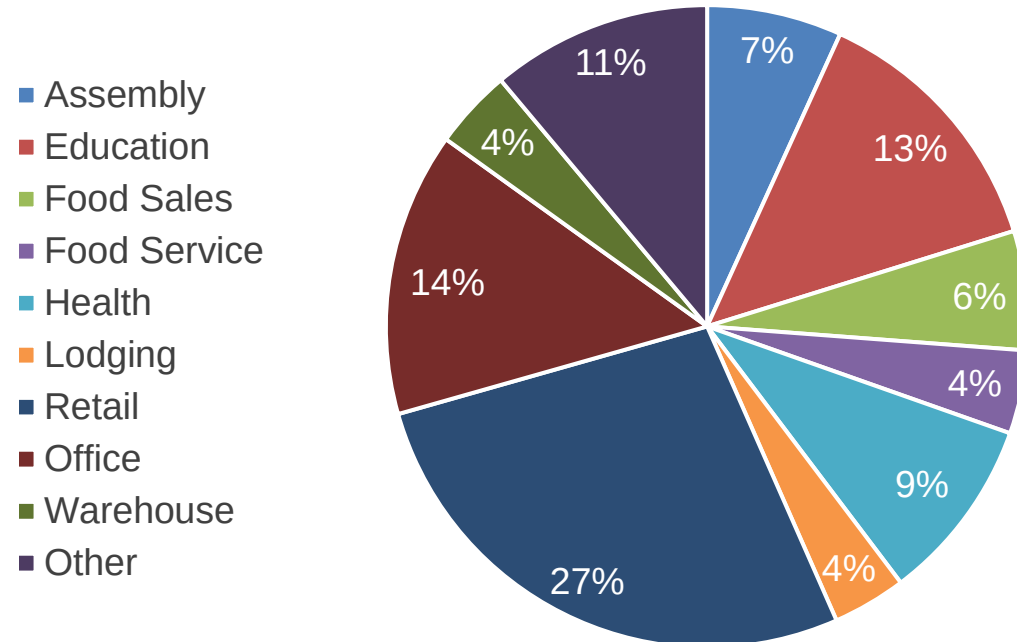
Residential Sales by End Use



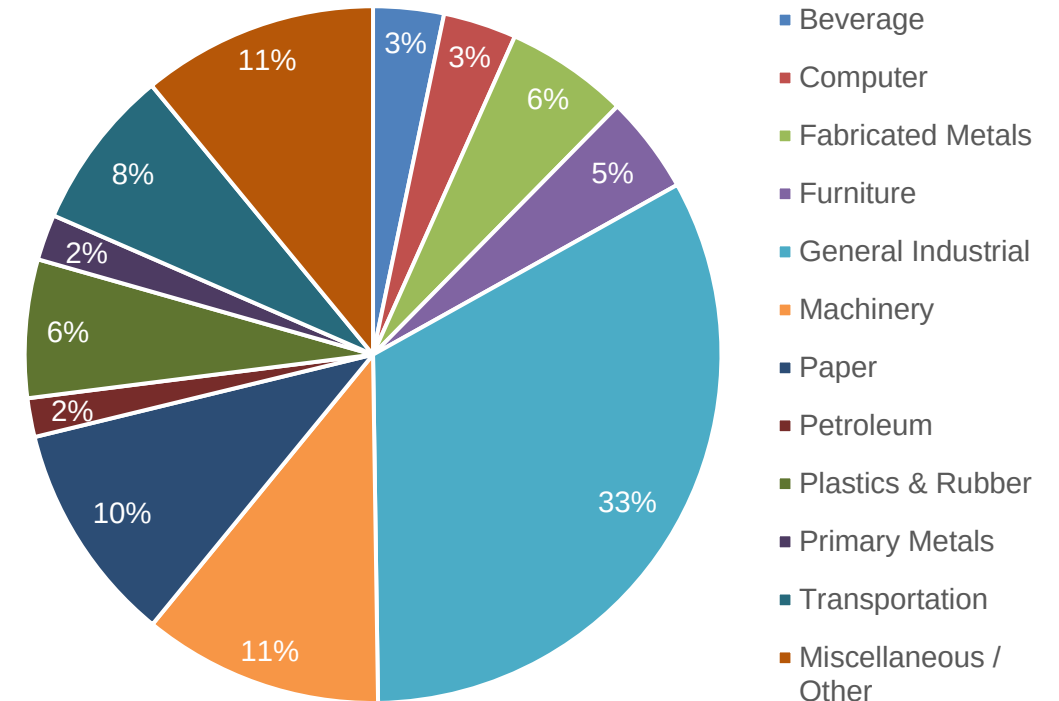
Residential sector analysis uses a bottom-up approach; understanding sales by home type and end use are critical components of the bottom-up approach.

MARKET CHARACTERISTICS DATA

Commercial Sales by Building Type



Industrial Sales by Manufacturing Type



Nonresidential sector analysis uses a top-down approach; understanding sales by building/industry type is a critical component of the top-down approach.

MARKET CHARACTERISTICS DATA

End Use	0% Incentive	25% Incentive	50% Incentive	75% Incentive	100% Incentive
Appliances	25.3%	43.1%	61.1%	78.8%	97.5%
Insulation	14.4%	28.6%	48.3%	72.0%	96.4%
HVAC	23.0%	39.9%	57.4%	76.8%	96.6%

Investment Type	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
Major Investment	42.8%	58.1%	67.6%	74.6%	81.2%
Minor Investment	41.0%	56.1%	65.7%	73.1%	80.8%

- Willingness-to-Participate (“WTP”) survey data (from 2021 MPS) used to inform long-term adoption rate estimates in the achievable potential scenarios.
- Residential homeowner and commercial business/property managers indicated their likelihood to participate across various incentive/payback performance levels and end-use/investment types.
- Adoption rates help transition from economic potential (100% adoption) to more achievable levels.
- 2024 MPS removed awareness factor from WTP results
 - A “Custom” awareness factor was added back in for C&I measures
- Measures eligible for Inflation Reduction Act / other tax credits received boost in participation estimates

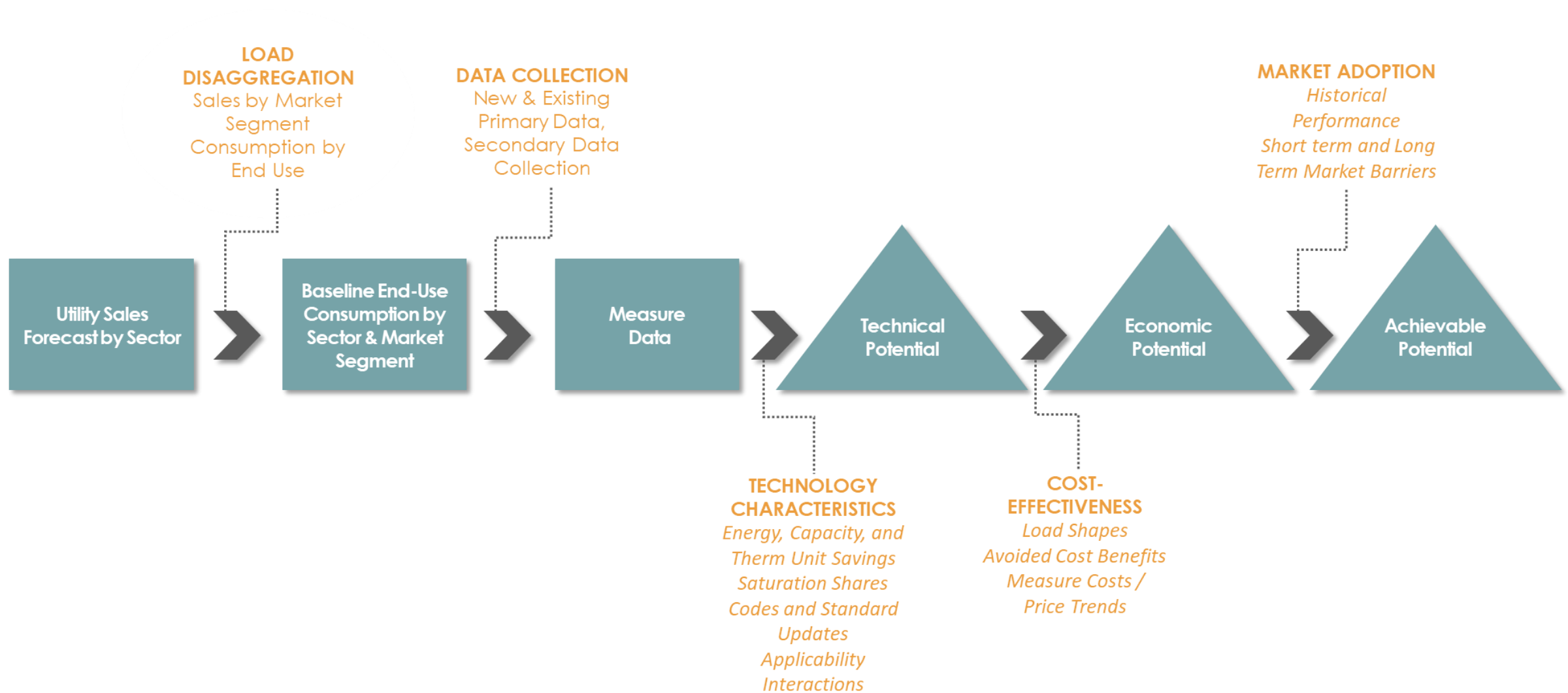


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

ENERGY EFFICIENCY



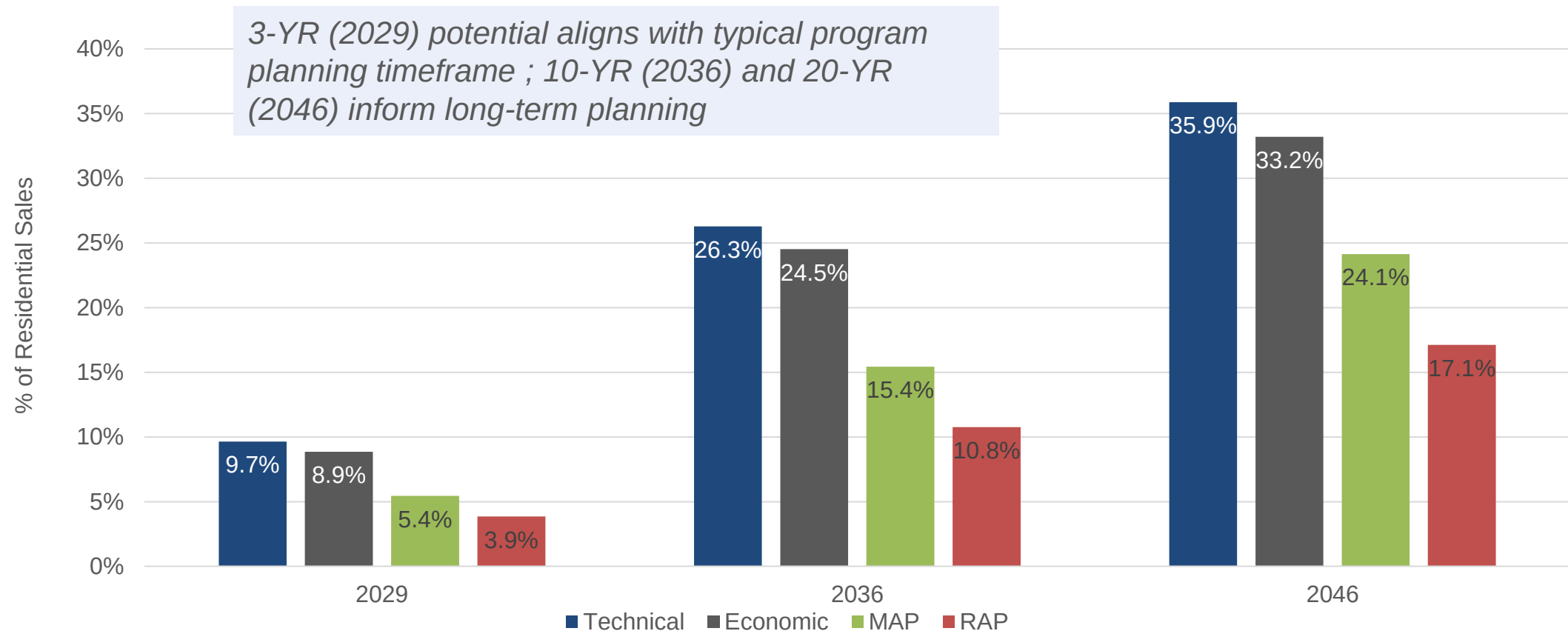
ENERGY EFFICIENCY METHODOLOGY – STUDY APPROACH



ENERGY EFFICIENCY METHODOLOGY – KEY CONSIDERATIONS

- 1. Measure list included all current offerings as well as additional emerging measures/technologies**
- 2. Industrial sector potential excluded opt-out customers**
- 3. The Utility Cost Test (UCT) was used to screen measure cost-effectiveness**
- 4. Two achievable scenarios: Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP)**
- 5. Estimates of technical, economic, and achievable potential are gross (i.e., not adjusted for free-riders and/or spillover)**
- 6. Adoption Rates**
 - a. Relied on adoption rates from prior MPS
 - b. Removed awareness factor that created distinctions across end-uses
 - c. Added custom awareness factor (in C&I)
 - d. Added IRA/tax credit implications
- 7. Saturation Estimates**
 - a. Updated estimates of energy efficiency saturations (regional and national data sources)
 - b. Assume some portion of current efficient technologies will be eligible in the future: 50% for market opportunity; 10% for retrofit (including C&I lighting)

ENERGY EFFICIENCY POTENTIAL SUMMARY

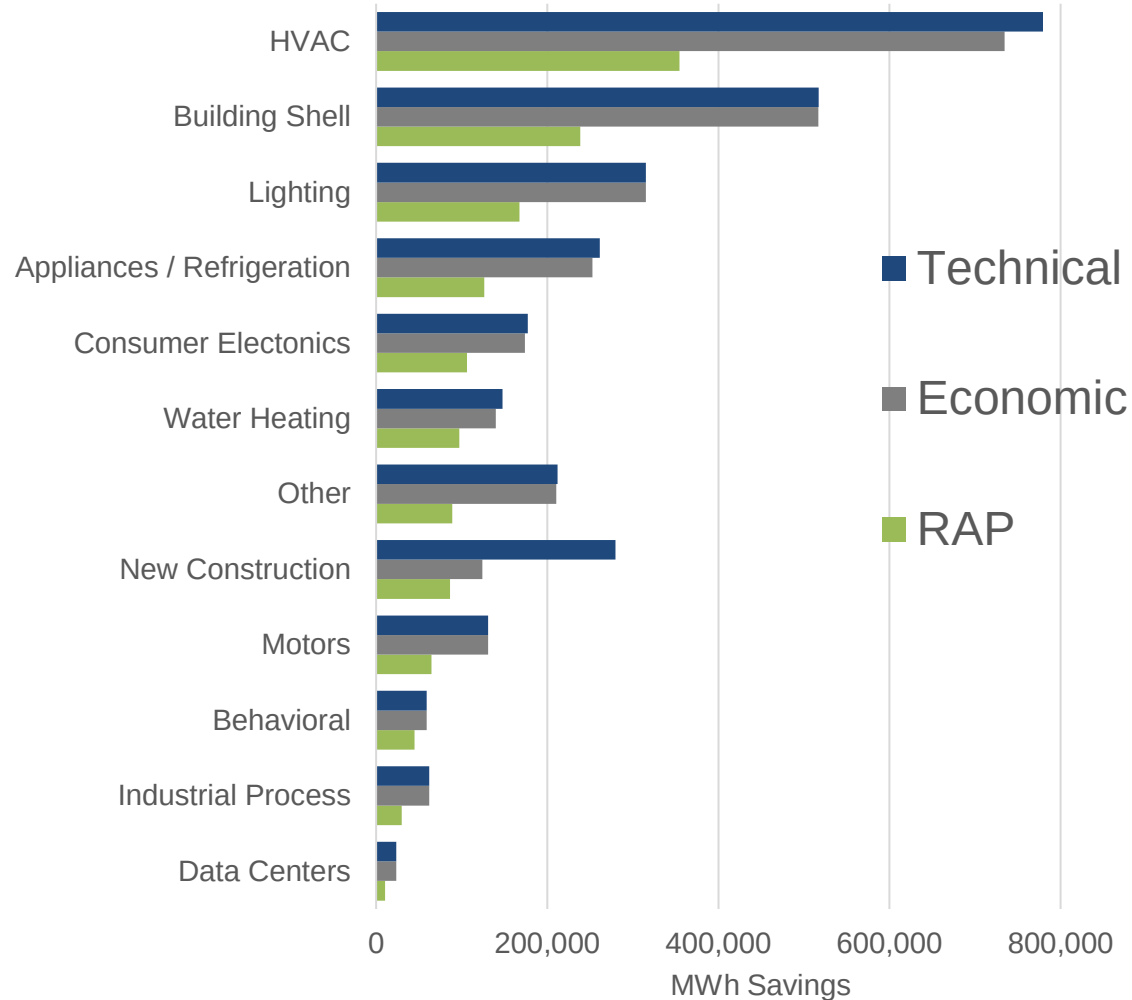


Results in chart show **cumulative annual** savings

- Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)

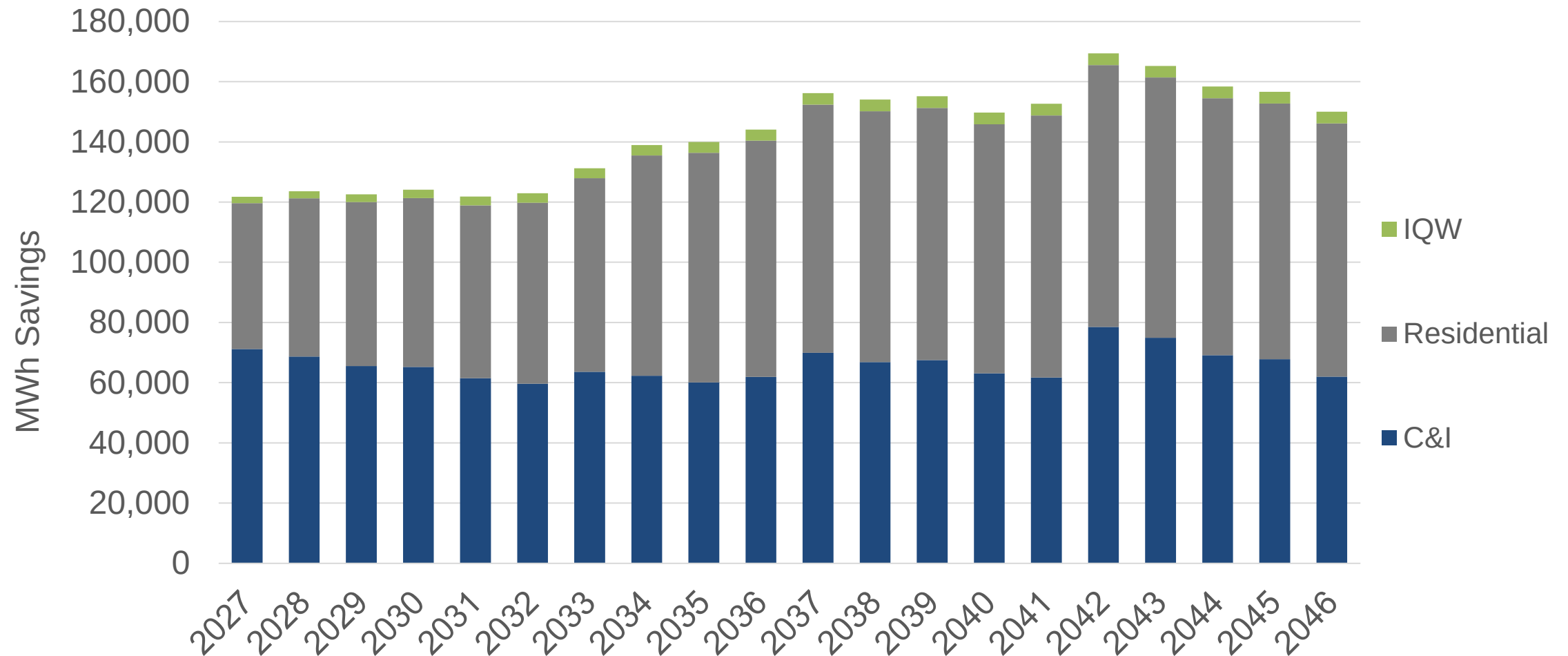
20-YEAR CUMULATIVE ANNUAL POTENTIAL BY END-USE

All Sectors Combined



- Large amount of potential in the HVAC end use
 - HVAC includes heating, cooling, ventilation equipment and building shell measures
- Lighting is primary in the C&I sector
- Refrigeration third largest end-use in C&I sector
- “Other” includes a variety of smaller end-uses like compressed air, cooking, pools, etc.

INCREMENTAL RAP BY SECTOR



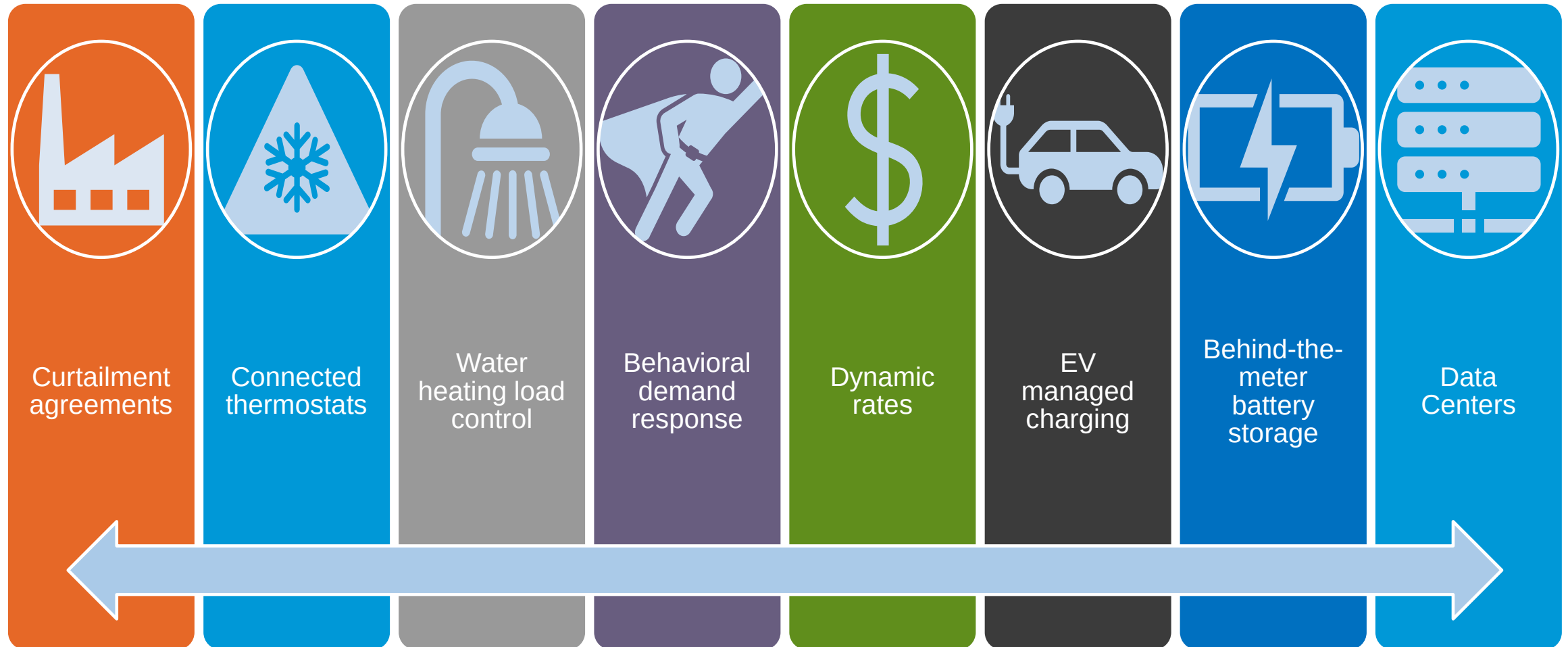


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

DEMAND RESPONSE



PROGRAM TYPES CONSIDERED IN THE DEMAND RESPONSE (“DR”) MARKET POTENTIAL STUDY



DER MODELING - ALIGNMENT WITH BROADER IRP INPUTS

The goal of the DR MPS is to develop IRP inputs, but the studies share common assumptions where possible

- **Peak load forecast by season and rate class**
 - Including projected data center load additions
- **Behind-the-meter solar penetration forecast**
 - Number of accounts, average system size, and production profile
- **Electric vehicle adoption forecast and unmanaged load profile**
 - Reference case forecast of vehicle counts, energy contribution, and hourly profile

STARTING POINT FOR DEMAND RESPONSE POTENTIAL

As of Summer 2024, NIPSCO has zero MW of DR programming – but that will likely change by 2027

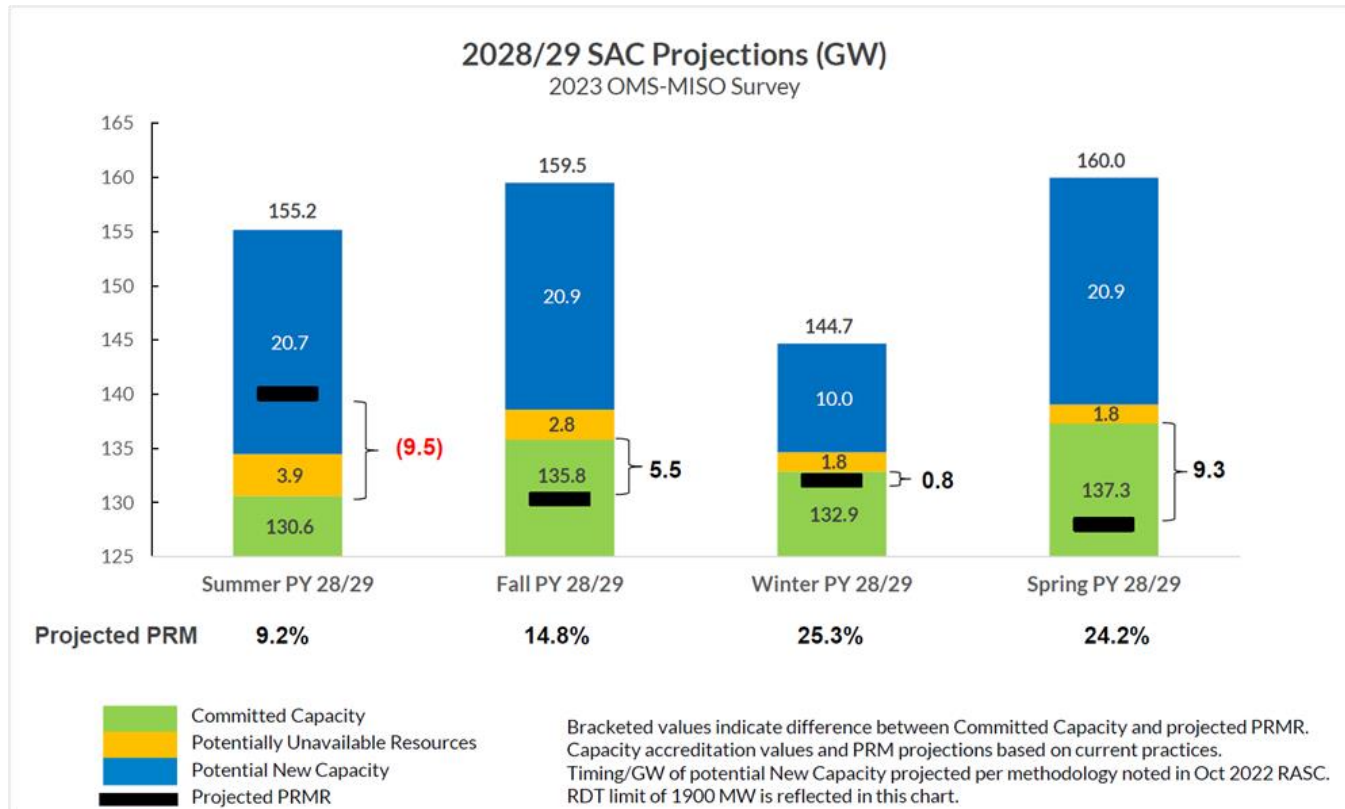
Historic DR Program Offerings

- **Residential AC cycling:** program suspended in 2015
- **Rate 531 (large industrial customers) interruptible loads:** no longer part of the NIPSCO DR portfolio
 - Prior to 2018 rate case, NIPSCO offered ~675 MW of interruptible loads to MISO as a load modifying resource (LMR)
 - Since 2018 rate case, NIPSCO is only required to serve firm load for Rate 531 customers of roughly 167 MW
 - Rate 531 interruptible load is not included in this study as DR. We also assume zero DR potential from the firm Rate 531 peak load.

Programs Under Active Consideration

- **Residential Bring Your Own Thermostat Program**
 - Third party implementer handles enrollment and communications with Wi-Fi thermostats
 - Allow NIPSCO to control customer AC usage during event windows to reduce loads
 - Events would be called by NIPSCO and not registered at MISO
- **Large C&I Demand Response Program**
 - Third party implementer handles recruitment, dispatch, and support MISO registration
 - Event calls would be guided by MISO
- **Electric Vehicle Pilot**
 - Mitigate load growth from transportation electrification through managed charging and fleet advisory services
 - Number of vehicles would be capped during pilot phase

TRANSITION TO A SEASONAL RESOURCE ADEQUACY CONSTRUCT ADDS COMPLEXITY



- **2021 DR MPS considered summer DR**
 - Assigned annual capacity value to summer
 - No value in other seasons so no DR potential
- **Changes at MISO to a seasonal resource adequacy construct necessitate a new approach**
- **Option #1: make assumptions about the allocation of capacity cost across seasons and model accordingly**
 - Study outcomes would be highly sensitive to these assumptions
- **Option #2: assign full value to each season and allow the IRP model to select resources for the binding season(s)**
 - Requires careful reporting because MW and expenditures are not independent or additive

CALCULATING PEAK LOAD CONTRIBUTION

Using Seasonal Resource Adequacy Hours (https://cdn.misoenergy.org/RA_Hours_PY_24_25630518.xlsx)

- Peaking risk by hour and season

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Fall	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.1%	4.7%	4.1%	3.6%	3.0%	4.1%	7.1%	9.5%	11.8%	13.6%	14.2%	12.4%	4.7%	3.0%	0.0%	0.0%	0.0%
Spring	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	3.1%	3.6%	4.1%	3.1%	3.6%	4.6%	8.7%	10.3%	10.3%	11.8%	10.8%	9.7%	8.2%	5.6%	1.0%	0.0%	0.0%
Summer	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.5%	1.0%	4.1%	6.7%	12.3%	15.9%	19.5%	17.9%	13.8%	5.1%	1.5%	1.0%	0.0%	0.0%
Winter	1.1%	0.5%	0.5%	0.5%	0.5%	0.5%	1.6%	4.8%	10.8%	9.1%	8.1%	7.5%	5.4%	3.8%	2.2%	1.6%	2.7%	4.3%	8.6%	9.7%	6.5%	5.4%	3.2%	1.1%

- Seasonal end use load shape

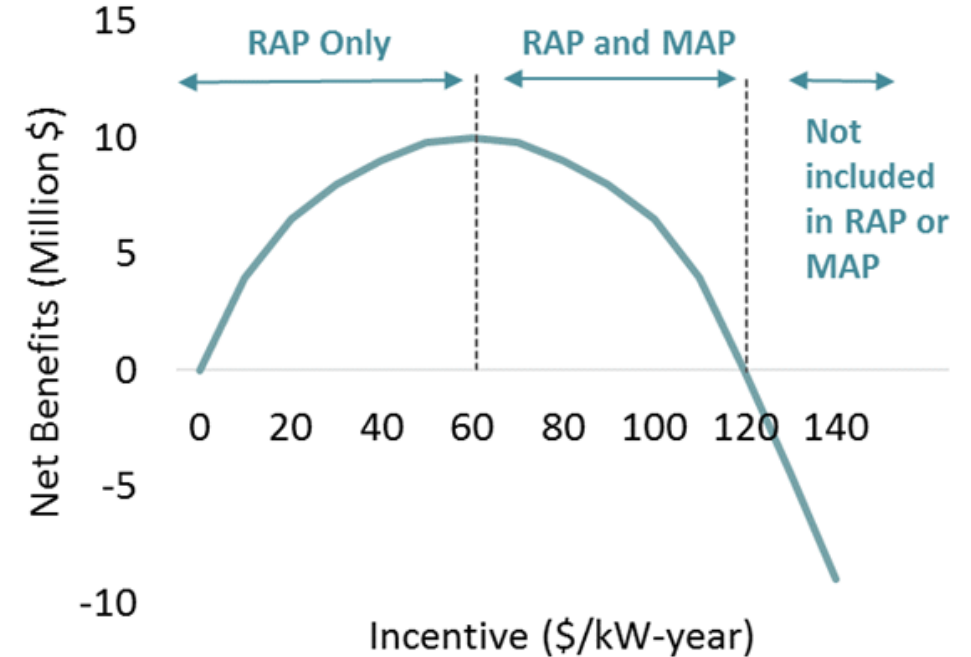
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EV Load Shape (kW)	0.411	0.349	0.289	0.232	0.185	0.151	0.143	0.165	0.215	0.243	0.245	0.261	0.281	0.296	0.297	0.371	0.458	0.578	0.700	0.723	0.675	0.626	0.582	0.511

- Unmanaged EV peak load contribution by season (meter-level)

Year	Fall	Spring	Summer	Winter
2027	0.477	0.494	0.476	0.532

METHODOLOGY OVERVIEW

- **Programs are screened for cost-effectiveness using the Utility Cost Test (UCT)**
 - UCT = ratio of NPV benefits to NPV costs per program over 20-year lifespan
 - DR Offerings with a UCT ratio less than 1.0 are presented as resource options to the IRP model
- **MPS contains two DR Potential scenarios:**
 1. **RAP (Realistic Achievable Potential):** A “realistic” projection of future DR potential at typical incentive rates and marketing levels
 2. **MAP (Maximum Achievable Potential):** An “aggressive” projection of future cost-effective DR, achieved by offering more generous incentives or establishing programs as opt-out (default)

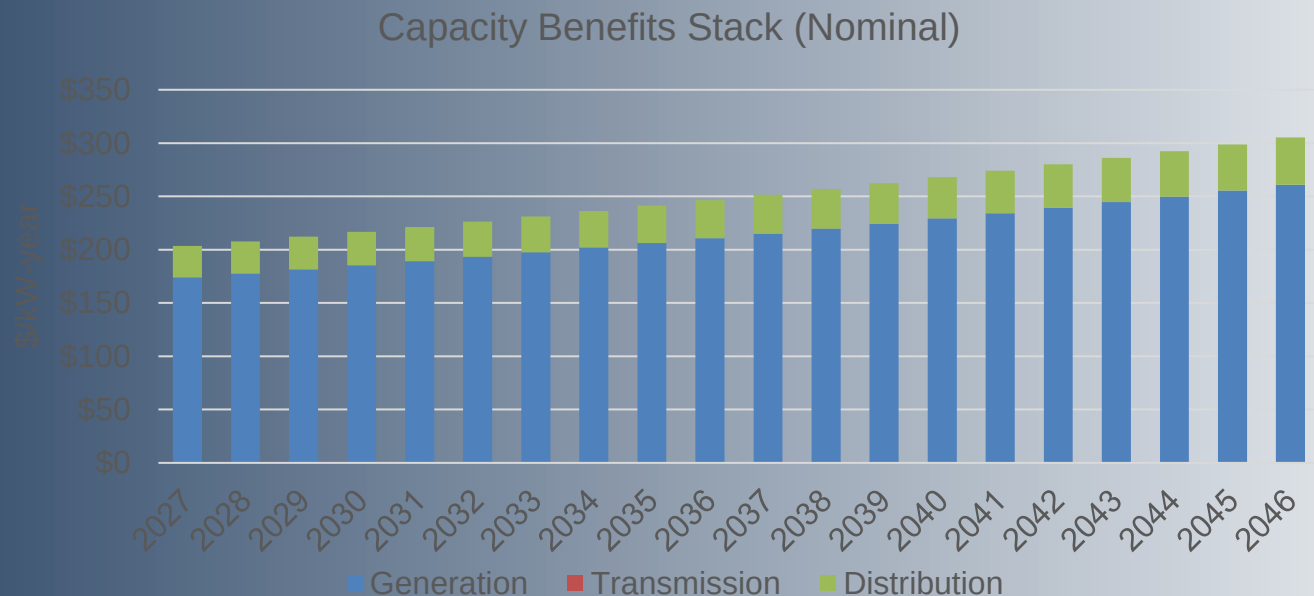


AVOIDED COST OF CAPACITY ASSUMPTIONS

Cost-effectiveness testing compares the cost of acquiring DR resources to traditional generation resources

Avoided T&D benefits are treated as a reduction in cost when developing IRP model inputs to recognize the ability of DR to avoid or defer localized capital projects

- The avoided cost of generation capacity is based on a combined cycle natural gas plant
 - The avoided cost of transmission capacity is \$0/kW-year
 - Distribution capacity starts at ~ \$30/kW-year and grows with inflation
- The MPS also considered an alternative set of avoided costs
 - Lower generation capacity value, but much higher avoided T&D value



KEY MODELING ASSUMPTIONS

- **All programs start in 2027 except dynamic rates in 2030 (NIPSCO does not have necessary AMI today)**
 - Economic results for dynamic rates programs do not include AMI meter costs
 - All programs incorporate two or three-year ramp-up period
- **All reported NPV values are in 2027\$**
 - Assume a 6.89% nominal discount rate and 3.21% inflation rate
- **All impacts are reported in system-level MW**
 - Impacts include line losses and customer opt-outs
- **Data center load is assumed to be transmission-connected**
 - Do not receive avoided distribution costs
- **All programs are designed to receive 100% capacity credit under current MISO LMR accreditation rules**
 - Programs may be called five times each for summer and winter and three times for spring and fall
 - We assume the average number of calls will be lower than the availability requirement
 - Triggered by Energy Emergency Alert 2 (EEA2)
 - Response within 6 hours or dispatch and must be able to provide load relief for 4 consecutive hours

NON-RESIDENTIAL LOAD CURTAILMENT AND DATA CENTERS (EXCLUDE RATE 531)

2021 Study Approach

- **Top-down price elasticity of supply model**
 - RAP = maximize net benefits
 - MAP = maximize MW
- **Elasticity values derived from detailed Pennsylvania C&I DR program results**
 - Converted from day-ahead to day-of
- **Compared to PJM auction results as a robustness check**

TABLE 5-3. PRICE ELASTICITY VALUES

Business Type	Day-Of Elasticity
Medium C&I	0.0006
Large C&I	0.0022

2024 Study Approach

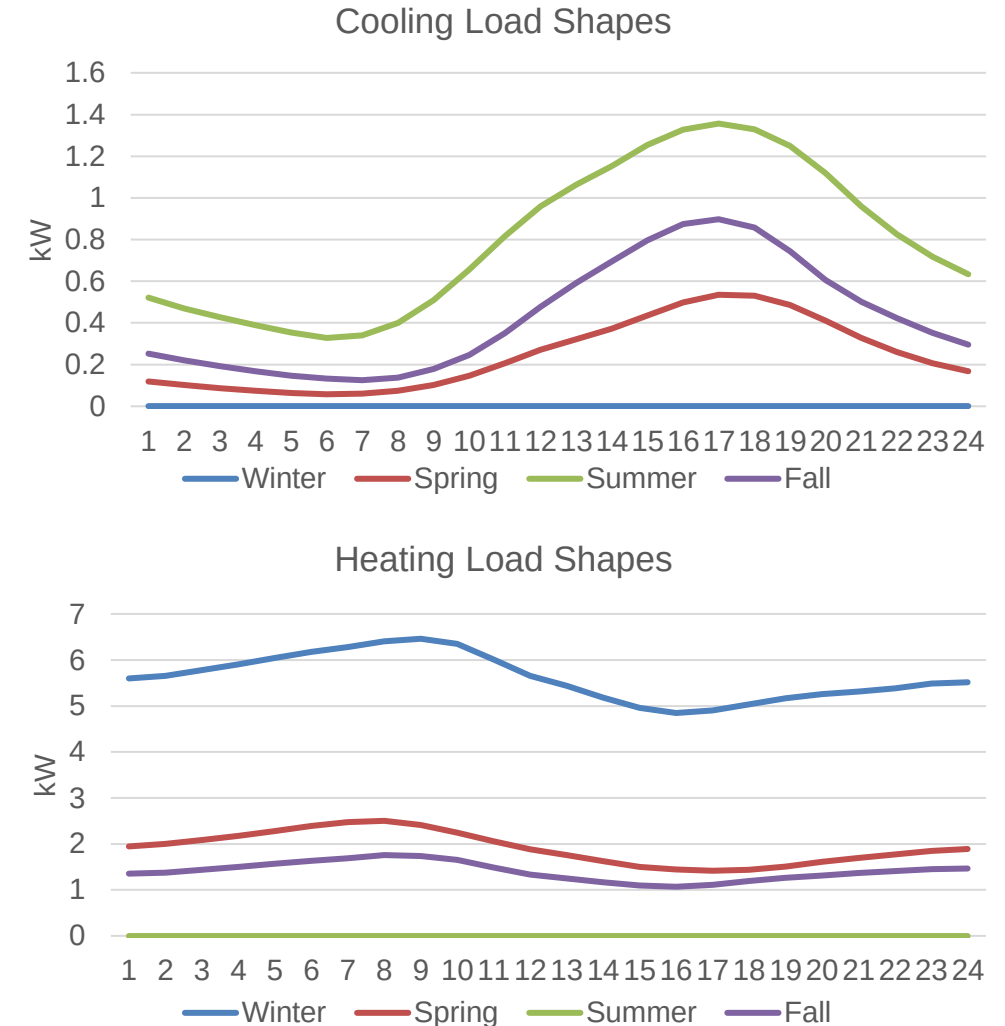
- **Same price elasticity of supply model and RAP/MAP perspective**
- **Elasticity values derived from PJM auction results and calibrated to MISO**
 - Compile seven years of cleared MW, seasonal peaks, and clearing prices
- **Number of calls per season aligned with MISO Seasonal Accredited Capacity rules for LMR**
 - Summer and Winter, n=5 calls
 - Spring and Fall, n=3 calls

Summer	Winter	Spring	Fall
0.0011	0.0010	0.0011	0.0010

CONNECTED THERMOSTATS

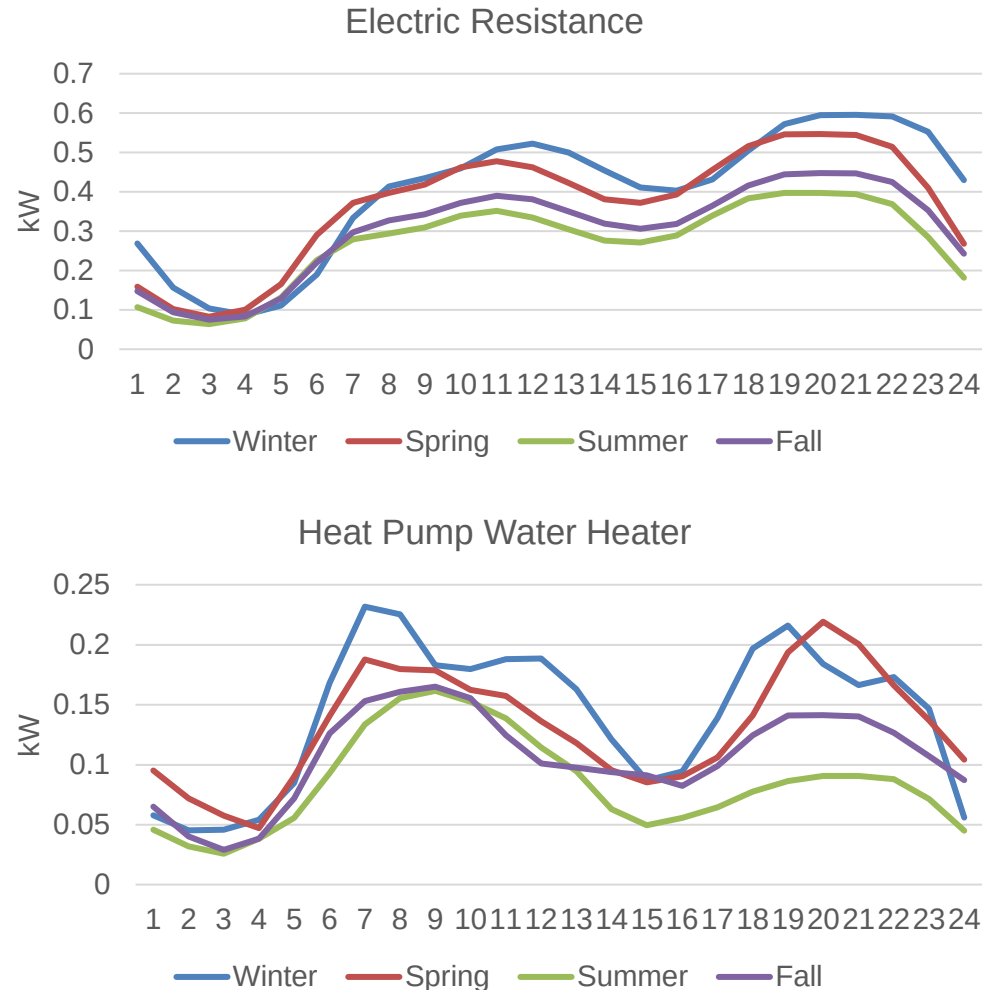
MAP reflects a higher upfront and recurring incentive level, which leads to higher adoption

- **End use load shapes are based on the NREL ResStock load profiles for Indiana**
 - Average demand reduction of 50% over a four-hour event window
- **The number of homes with connected thermostats is aligned with EE MPS outputs**
 - Significant growth over the study horizon
- **Winter and spring are heating peaks, while summer and fall are cooling peaks**
 - Winter and spring potential is limited by the share of homes with electric heat
- **Fixed and recurring program delivery costs are based on similar program costs and vetted with the vendors NIPSCO is in discussions with to design this type of program**



DOMESTIC WATER HEATING LOAD CONTROL

Includes a mix of traditional electric resistance units and heat pump water heaters (“HPWH”)

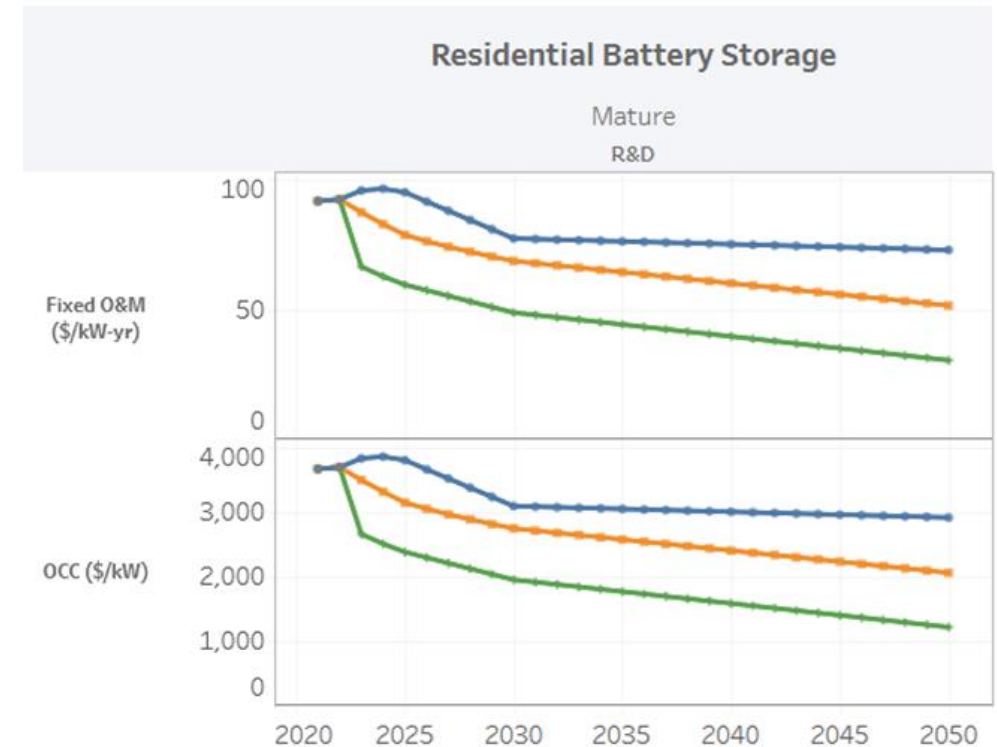


- **Electric fuel share is a key input**
- **This offering did not pass the UCT in the 2021 DR MPS**
 - Water heating load is much more coincident with winter peaks
- **The transition of equipment stock to HPWH will be driven by both programs and federal standards**
- **Integrated EE/DR offering for HPWH**
 - Increasingly new ENERGY STAR units will be DR-enabled from the manufacturer
 - Avoids the capital cost of after-market controllers and installation
- **HPWH are a poor DR measure for the same reason they are such a strong EE measure**
 - High efficiency limits the available load for DR

BEHIND THE METER SOLAR + STORAGE

Pairing battery storage with solar improves the capacity factor of solar installations

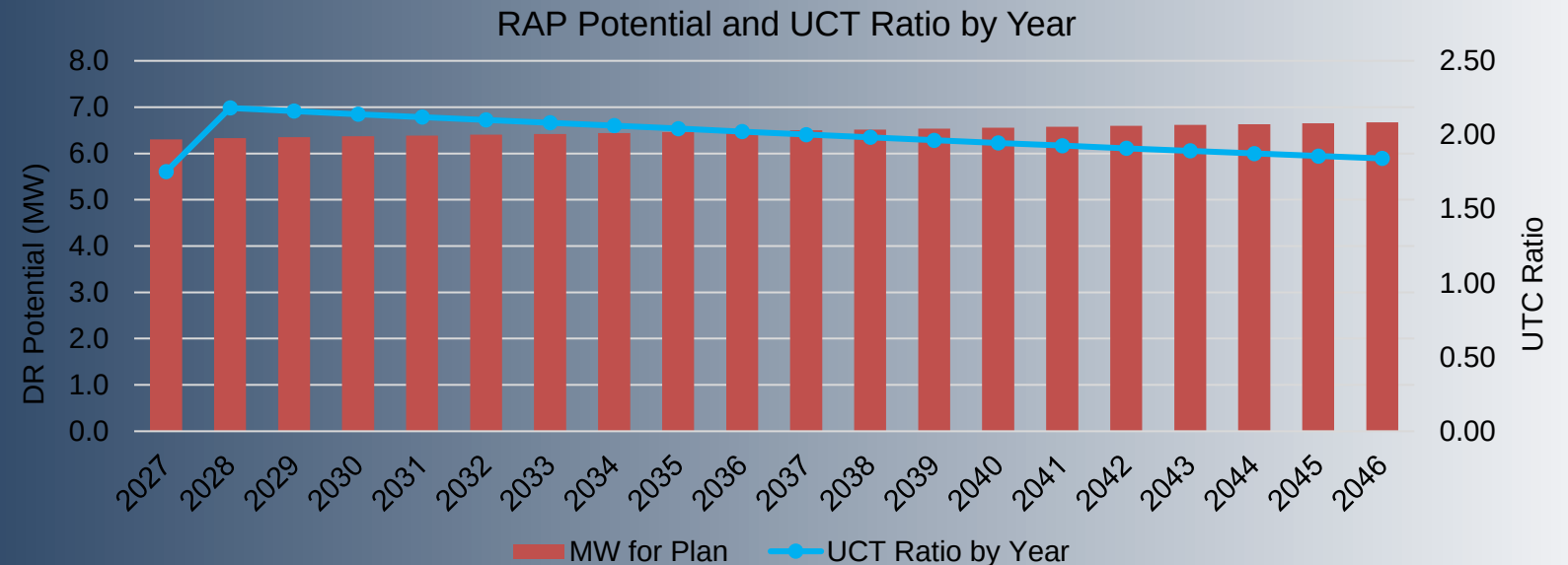
- **Program opportunity is tethered to the reference case forecast of solar adoption**
 - Reaches approximately 10,000 homes by the end of the study horizon
- **Bring Your Own Battery**
 - Further limited by share of homes with solar + storage
- **Intercept Design**
 - Program pays a portion of the upfront battery cost in exchange for access to storage during grid constraint.
 - Increased adoption but costs are front-loaded and difficult to overcome
- **Three different battery cost forecasts from NREL**
 - Advanced (green line)
 - Moderate (orange line - used for IRP inputs)
 - Conservative (blue line)
 - UCT ratios only reach ~ 0.5 with advanced (lowest) cost estimates



BEHAVIORAL DEMAND RESPONSE

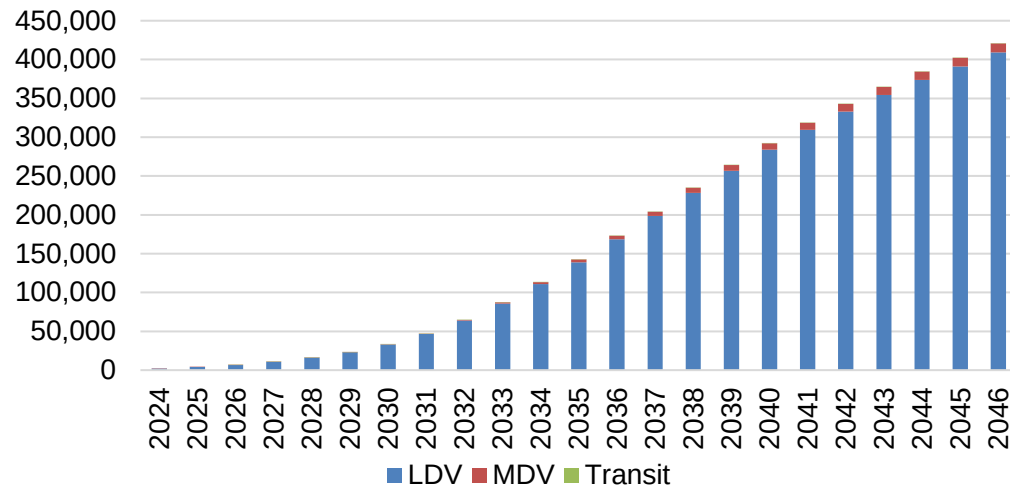
Like the Home Energy Report program offering within EE, but dispatchable and targeting conservation for specific hours

- **Small impacts per-home (50 Watts)**
 - Across many homes
- **Programs typically target the larger energy users**
 - Only homes with an email or cell phone number on file are eligible since all communications are digital
- **BDR could be a useful interim program for 2027-2029, teaching participants the underlying concepts of time-varying rates**

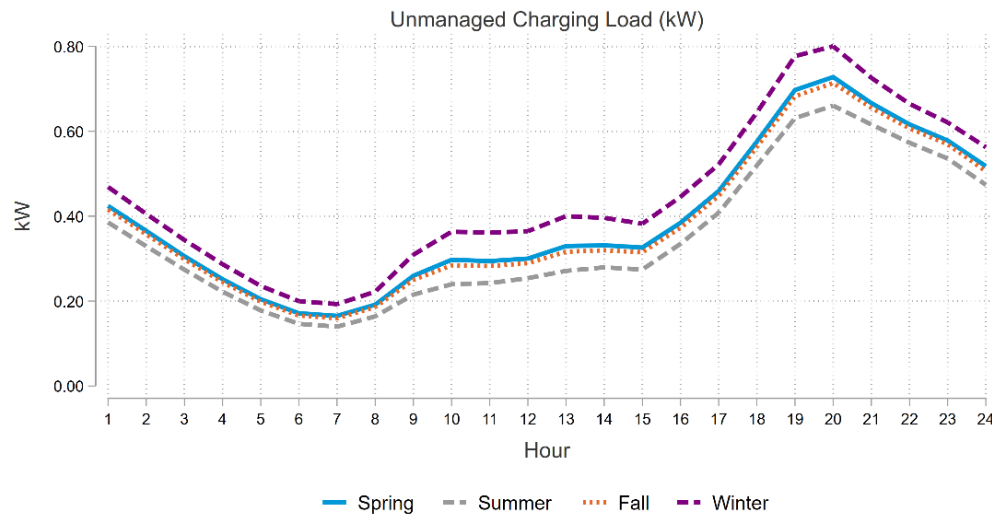


ELECTRIC VEHICLE MANAGED CHARGING

Eligible Vehicle Forecast



- **Modeling considered multiple program types**
 - Active versus passive
 - Chargers versus vehicles (telematics)
 - Flat rate versus dynamic pricing
 - Load impacts and cost structure varies by design
- **RAP and MAP assume customers face a flat rate**
 - Reference loads in the dynamic rates model do not include EV load additions (no double counting)
 - In practice time-varying rates could be an effective strategy to manage load growth due to electric vehicles
- **The managed charging program has a UCT ratio less than 1.0 for both RAP and MAP using the primary avoided cost assumptions**
 - Both RAP and MAP have UCT ratios slightly above 1.0 using the alternate avoided cost assumptions with higher avoided T&D benefit streams



REALISTIC ACHIEVABLE POTENTIAL (RAP)

System-level MW potential in 2046 by season and program type

Program	UCT Result	Spring	Summer	Fall	Winter
Connected Thermostats	Pass	12.5	48.7	26.4	42.4
Water Heaters	Fail	0.7	0.4	0.6	0.8
Behavioral DR	Pass	7.4	6.7	6.7	7.4
Dynamic Rates	Pass	30.5	66.1	60.9	30.6
EV Managed Charging	Fail	10.6	9.9	10.2	11.8
BTM Storage	Fail	0.7	0.7	0.7	0.4
C&I Load Curtailment	Pass	27.0	29.4	28.8	25.3
Data Centers - Base	Pass	58.9	58.9	58.9	58.9
Total		148.4	220.8	193.2	177.6
Total with UCT > 1		136.3	209.8	181.6	164.6

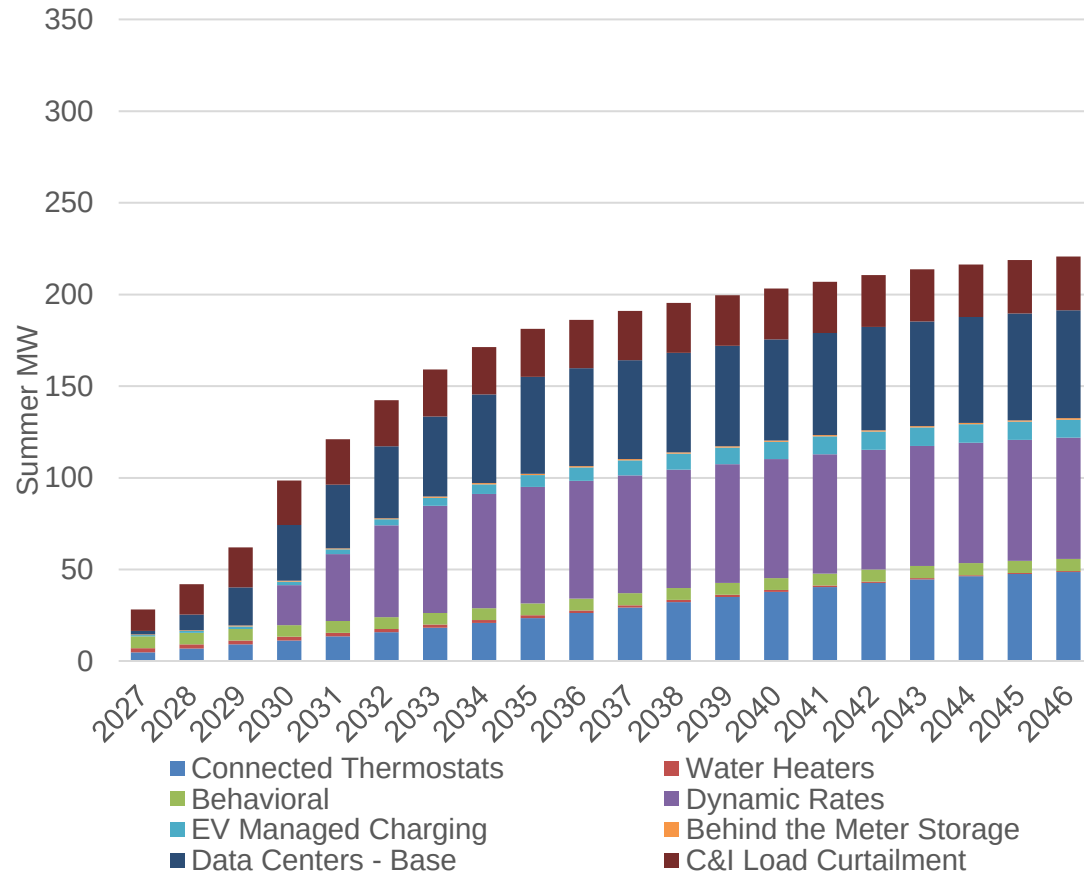
MAXIMUM ACHIEVABLE POTENTIAL (MAP)

System-level MW potential in 2046 by season and program type

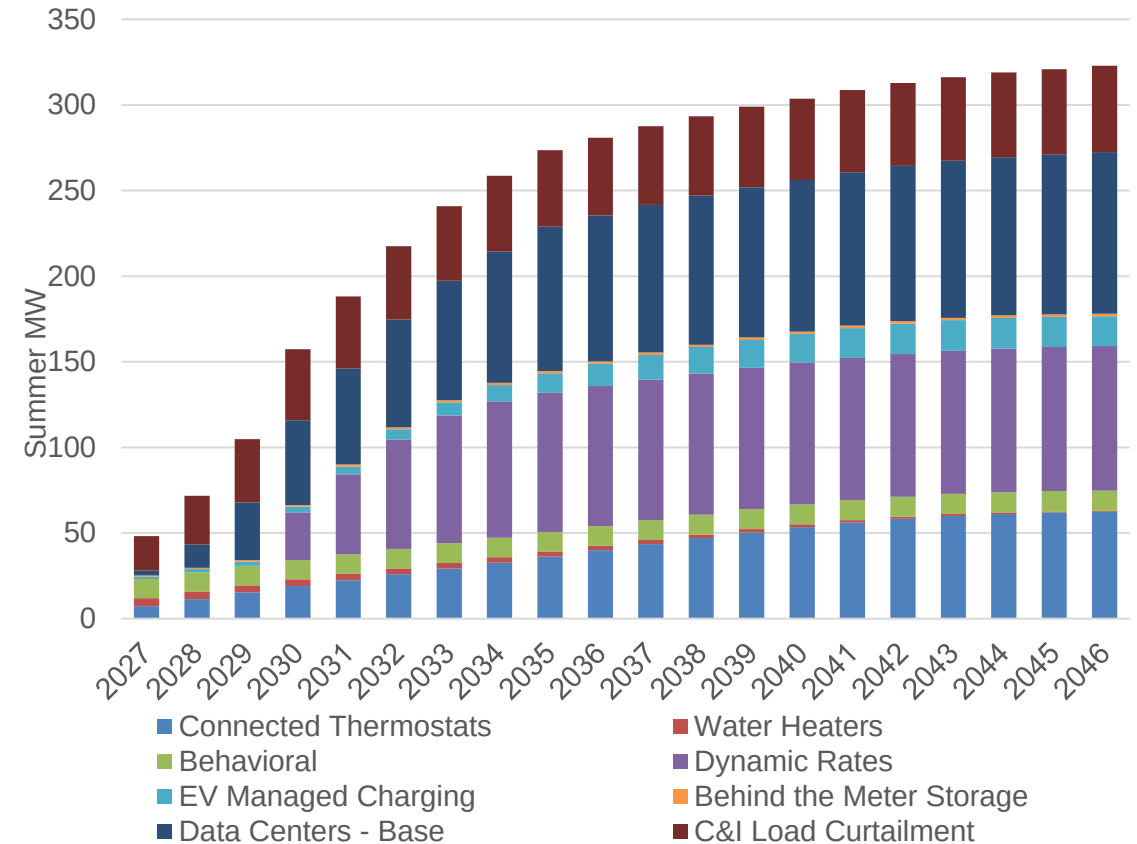
Program	UCT Result	Spring	Summer	Fall	Winter
Connected Thermostats	Fail	19.4	62.3	33.8	66.0
Water Heaters	Fail	1.0	0.5	0.8	1.2
Behavioral DR	Pass	9.9	11.9	11.9	9.9
Dynamic Rates	Pass	39.0	84.4	77.7	39.0
EV Managed Charging	Fail	18.9	17.5	18.2	21.0
BTM Storage	Fail	1.5	1.5	1.5	0.7
C&I Load Curtailment	Pass	46.3	50.4	49.3	43.4
Data Centers - Base	Pass	94.4	94.4	94.4	94.4
Total		230.3	322.9	287.6	275.6
Total with UCT > 1		189.5	241.0	233.3	186.6

RAP AND MAP BY YEAR AND PROGRAM – WITHOUT UCT SCREENING

RAP

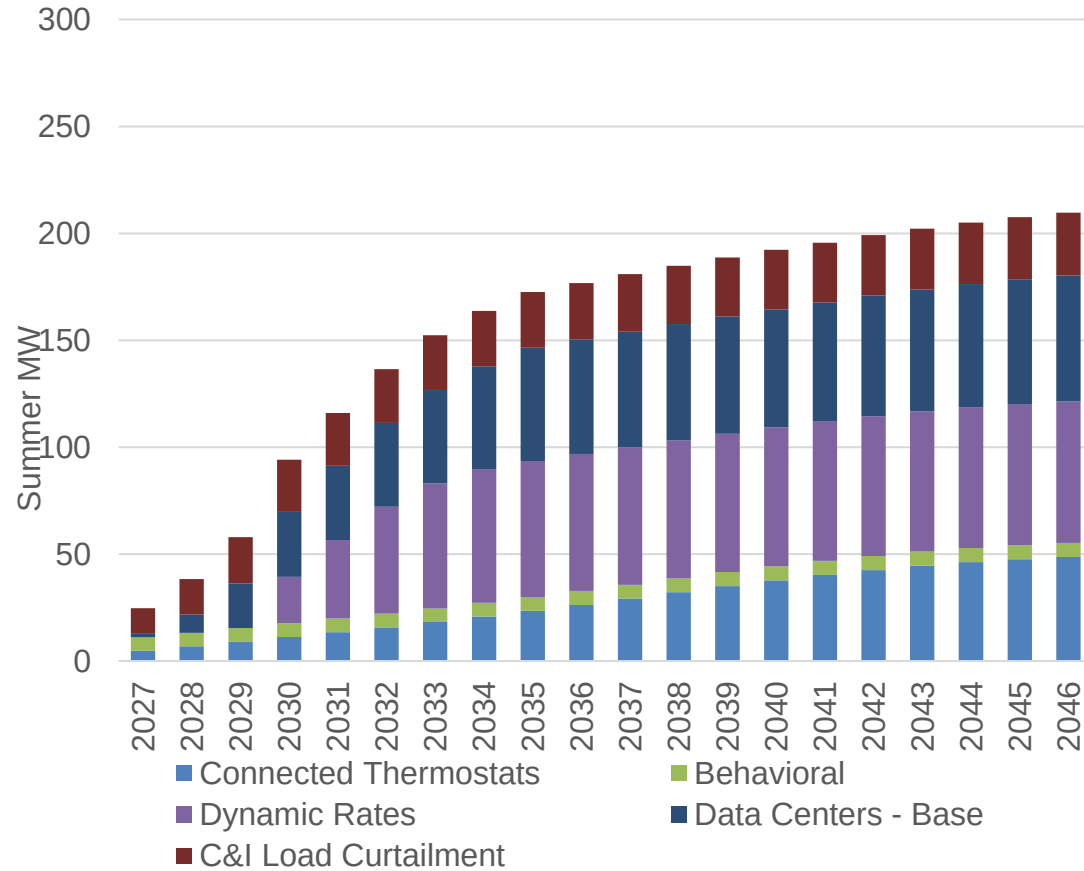


MAP

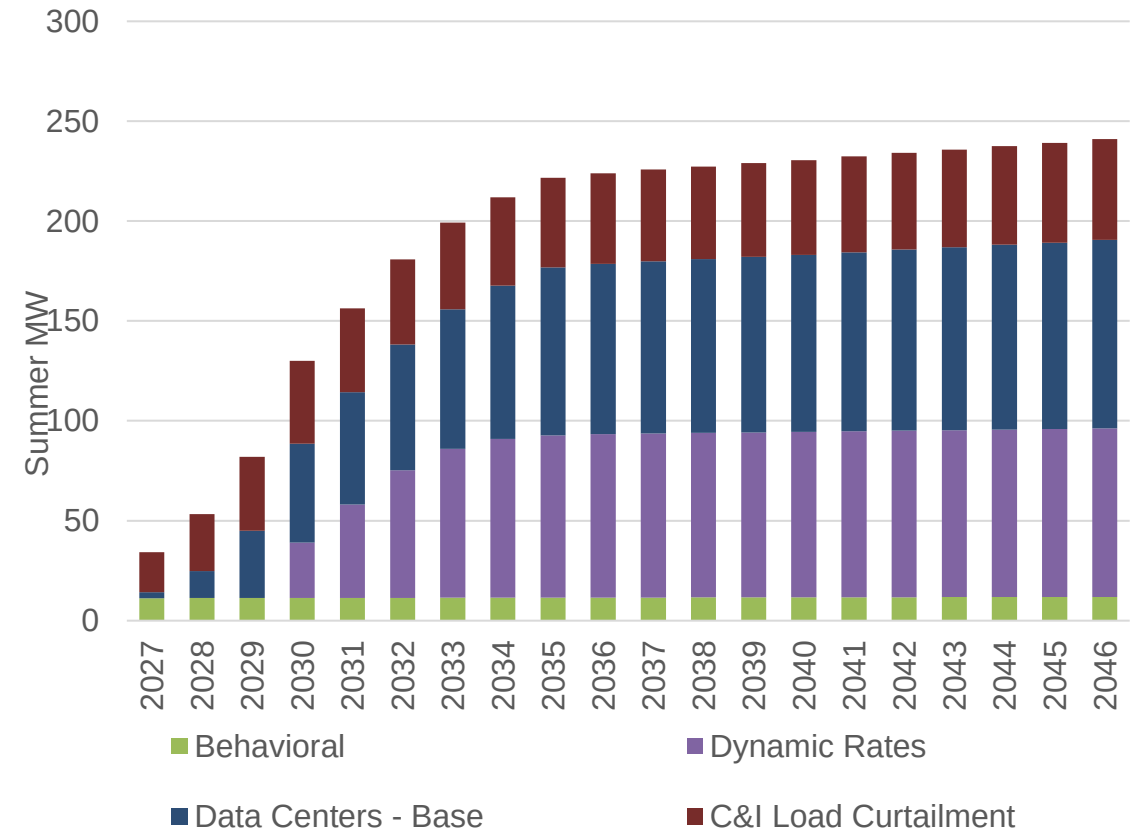


RAP AND MAP BY YEAR AND PROGRAM – WITH UCT SCREENING

RAP



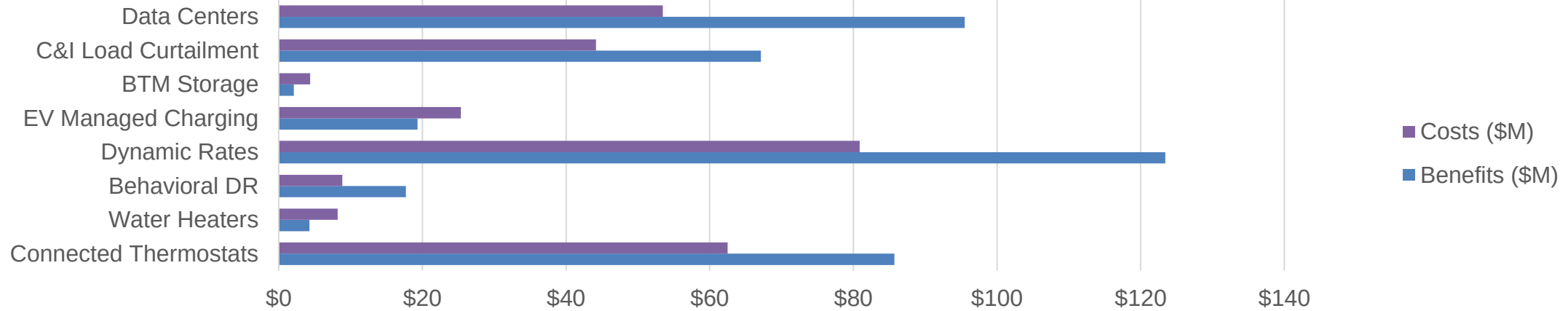
MAP



NPV COSTS AND BENEFITS BY PROGRAM

All values shown are net present values (NPV) in million 2027\$ for the study horizon

RAP



MAP



PROGRAM INVESTMENT BY YEAR

MW are differentiated by season, but costs are rolled up to annual totals for IRP inputs and reporting

Reflects the base forecast of data center load growth and DR potential from data centers

- **For IRP inputs the cost profile is adjusted by subtracting the estimated T&D benefits**
 - Program costs still bear the full cost of delivery and incentives
- **Selection of all RAP or MAP options would increase the annual DSM significantly compared to current levels**
 - Current spending is EE-only
- **Table values are in nominal dollars**

Year	RAP (\$M)	MAP (\$M)
2027	\$7.3	\$15.4
2028	\$5.3	\$13.3
2029	\$7.5	\$19.1
2036	\$27.5	\$51.1
2046	\$44.2	\$82.8



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

EE/DR MODELING IN IRP



MARKET POTENTIAL STUDY SAVINGS AND DSM INPUTS FOR IRP



- **NIPSCO will model DSM impacts (EE & DR) based on the results from the 2024 Market Potential Study**
- **EE and DR estimates for IRP modeling are aggregated at the sector level:**
 - Both RAP and Enhanced RAP (sensitivity testing) levels
 - Three vintage blocks: 2027-2029, 2030-2032 and 2033-2046 (2025 and 2026 DSM levels are informed by the current approved DSM Plan)

MARKET POTENTIAL STUDY SAVINGS AND DSM INPUTS FOR IRP

Energy Efficiency

- RAP and Enhanced RAP Potential Savings were provided for input into the IRP using 6 total bundles and includes a few minor adjustments
 - 1 nonresidential bundle, 3 residential market rate bundles, and 2 income-qualified bundles
 - 3 residential bundles include behavior, low/medium cost, and high-cost measures
 - 2 income-qualified bundles include traditional income-qualified program savings as well as additional potential impacts from federal funded programs
- EE impacts were adjusted to reflect net savings (not gross) at the generation level (line loss adjustments)
- Avoided transmission and distribution capacity benefits were treated as a reduction in annual program costs
- Each sector bundle has its own 8,760 shape based on measure mix

Demand Response

- RAP and MAP were provided for eight program sub-segments
- Each DR program type was modeled separately with its own seasonal MW potential and annual cost profile
- Avoided transmission and distribution capacity benefits were treated as a reduction in annual DR program cost
- Data center load is assumed to be transmission-connected so it does not receive the avoided cost of distribution capacity under either avoided cost scenario

DSM BUNDLE EVALUATION IN IRP PORTFOLIO MODELING



- NIPSCO and CRA will be incorporating the DSM bundles into the portfolio development process, which will allow for portfolio selection from several resource options (to be discussed in more detail in the next section)
- As NIPSCO conducts the portfolio analysis, additional DSM sensitivity evaluation will be performed for Enhanced RAP (EE) and MAP (DR) for a sample of portfolios



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

LUNCH





INCORPORATING RFP RESULTS INTO THE IRP AND OVERVIEW OF PORTFOLIO MODELING INPUTS

Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA



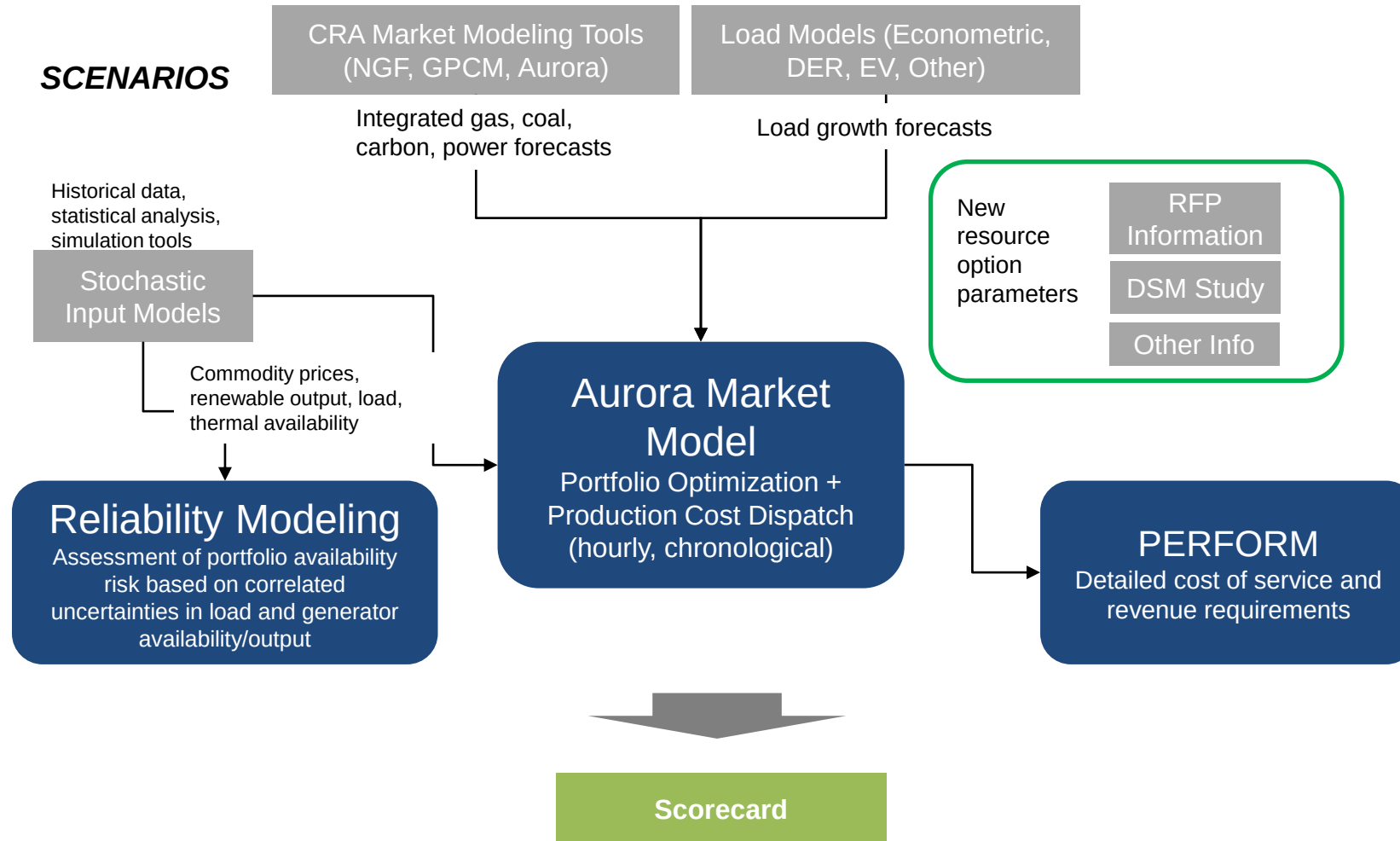
NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 407 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



RESOURCE PLANNING APPROACH



- ① Identify key planning questions and approach
- ② Develop market perspectives (external scenarios)
- ③ Develop integrated resource strategies (NIPSCO portfolios)
- ④ Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- ⑤ Evaluate trade-offs and select preferred plan

NEW RESOURCE OPTIONS

Resource Option		Available through 2029	Available 2030-2034	Available 2035+
Resources offered in the RFP	Demand side management (EE and DR) programs	From MPS and DSM Study		
	Solar	From RFP Data	Benchmarked to RFP Data plus Third-Party Data Sources for the Long-Term	
	Li-Ion Battery Storage			
	Long Duration Storage			
	Solar + Storage Hybrid			
	Near-Term Thermal Options			
	Near-Term Capacity Purchases (ZRCs)			
	New Natural Gas Peaking Build (H2-enabled up to 30%)	From NIPSCO Internal Engineering Analysis and Project Experience		
	New Gas CC Build (H2- enabled up to 30%)			
	Wind		Benchmarked to NIPSCO Project Experience	
	New Gas CC with CCS		From NIPSCO and Third-Party Data Sources	
	New Gas with H2			
	CCS Retrofit (at Sugar Creek)			
	H2 Retrofit (at Sugar Creek)			
	Small modular reactor (SMR)			



DSM BUNDLES FOR IRP MODELING



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 410 of 675

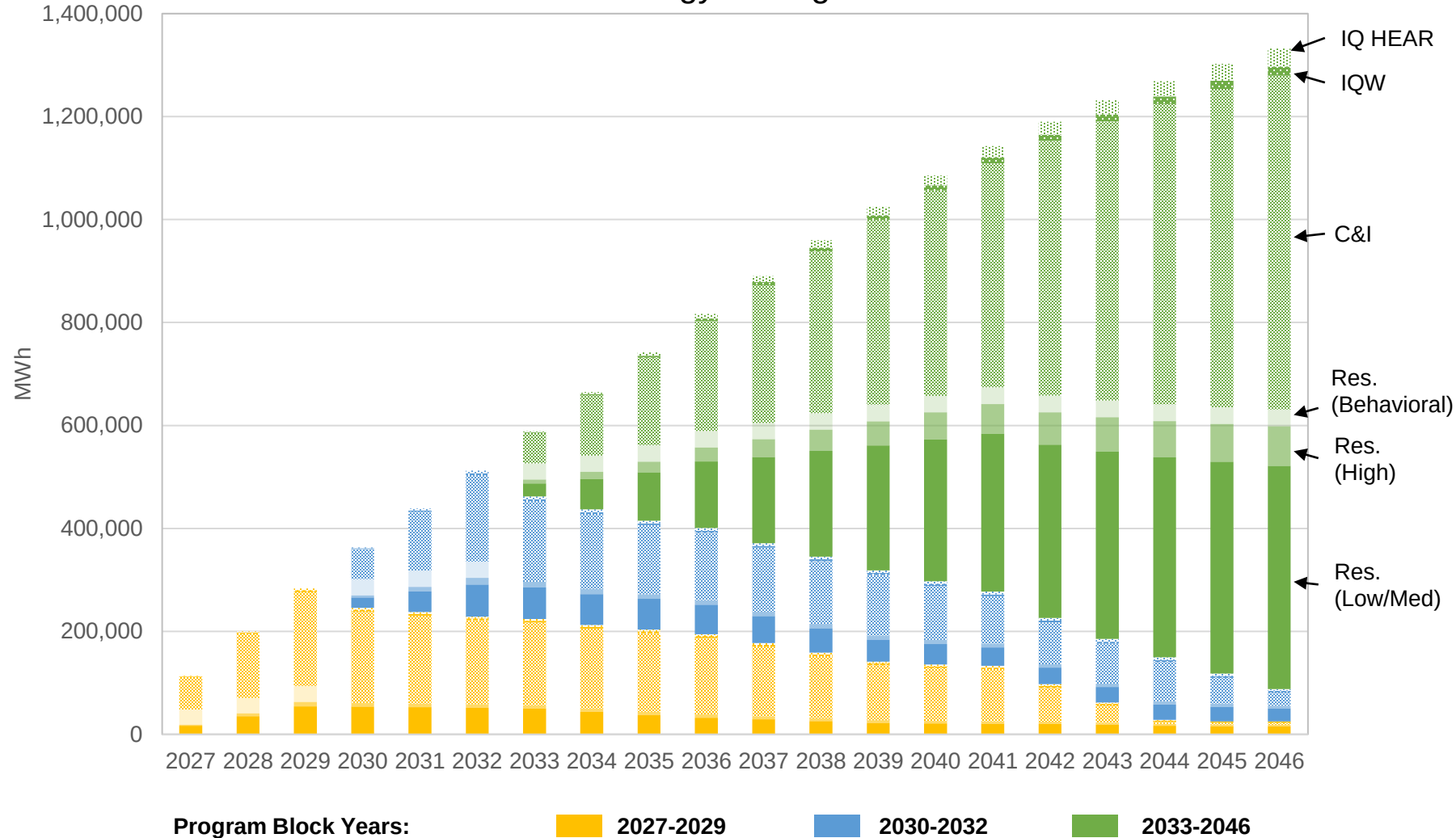


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



DSM ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

Total Energy Savings - RAP

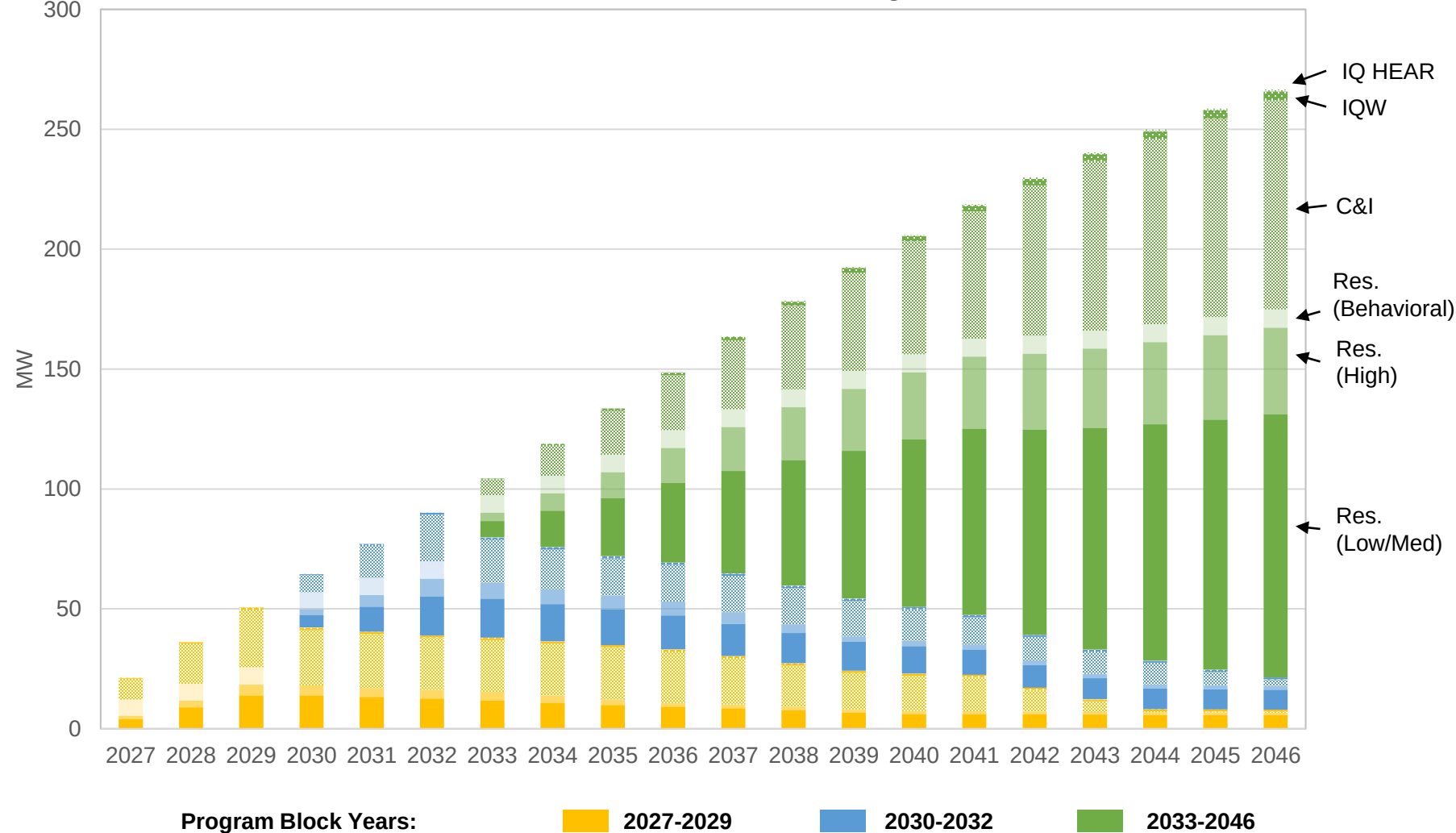


Bundle	Lifetime Levelized Cost (\$/MWh)		
	2027-2029	2030-2032	2033-2046
IQ HEAR*	89.09	91.67	99.93
IQW*	77.50	80.02	87.62
C&I	15.81	18.69	22.35
Res. (Behavioral)	58.21	62.13	73.39
Res. (High)	101.51	102.34	106.77
Res. (Low/Med)	26.56	24.95	27.84

*The HEAR bundle is for savings associated with measures allocated towards income qualified customers but which would be offered through a program tied to federal funding rather than a NIPSCO-funded program. The IQ HEAR and IQW savings are "hardcoded" into the IRP modeling.

DSM ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

Summer Peak Demand Savings - RAP

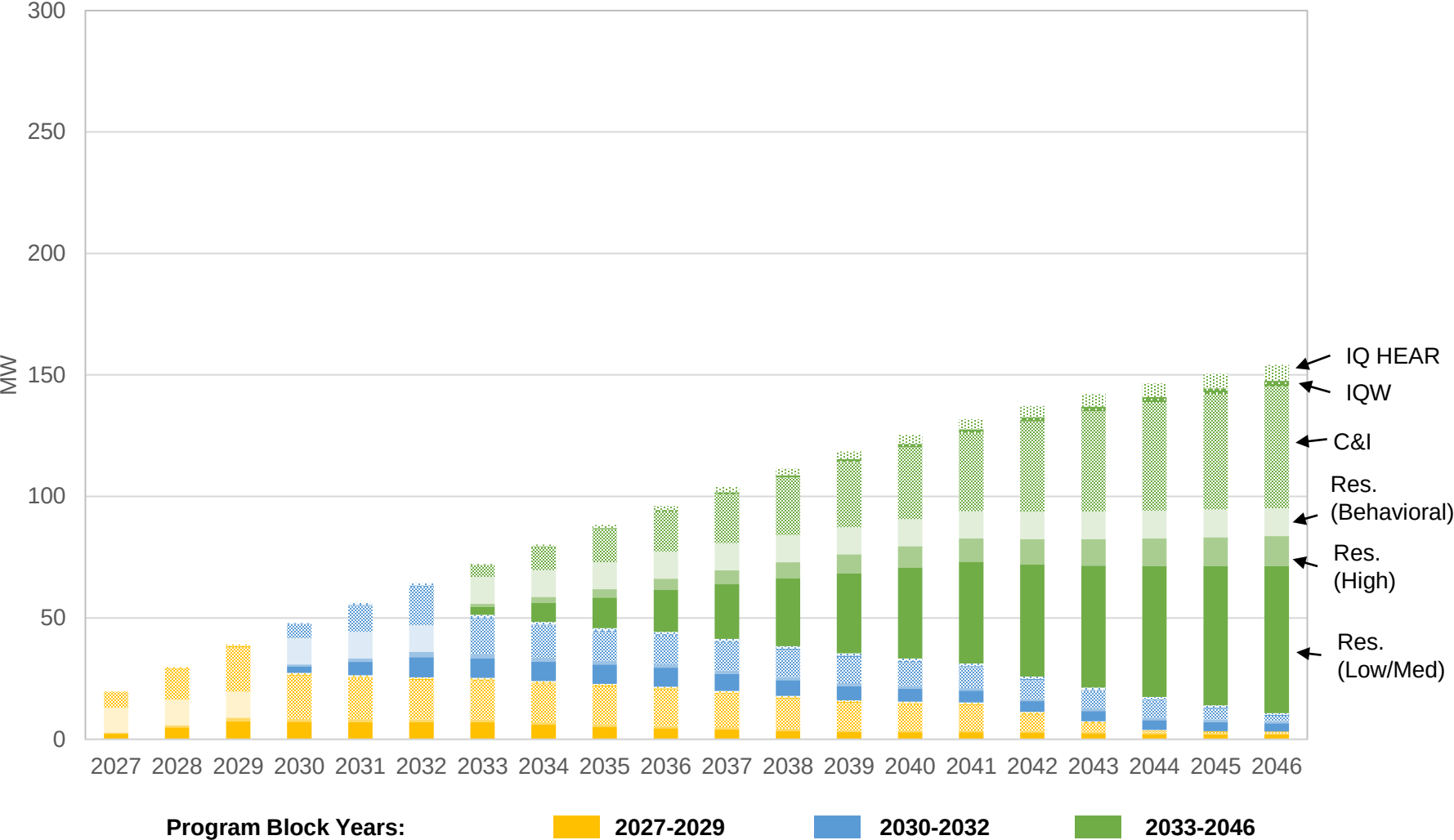


Bundle	Lifetime Levelized Cost (\$/MWh)		
	2027-2029	2030-2032	2033-2046
IQ HEAR*	89.09	91.67	99.93
IQW*	77.50	80.02	87.62
C&I	15.81	18.69	22.35
Res. (Behavioral)	58.21	62.13	73.39
Res. (High)	101.51	102.34	106.77
Res. (Low/Med)	26.56	24.95	27.84

**The HEAR bundle is for savings associated with measures allocated towards income qualified customers but which would be offered through a program tied to federal funding rather than a NIPSCO-funded program. The IQ HEAR and IQW savings are "hardcoded" into the IRP modeling.*

DSM ENERGY EFFICIENCY BUNDLES FOR IRP MODELING

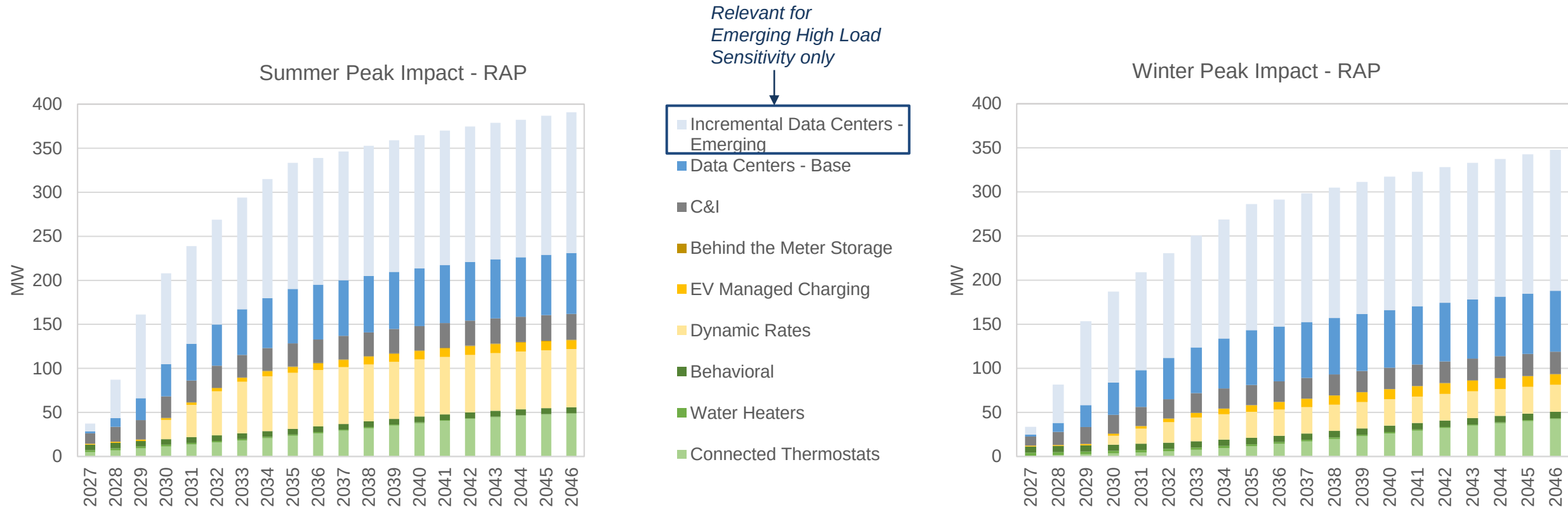
Winter Peak Demand Savings - RAP



Bundle	Lifetime Levelized Cost (\$/MWh)		
	2027-2029	2030-2032	2033-2046
IQ HEAR*	89.09	91.67	99.93
IQW*	77.50	80.02	87.62
C&I	15.81	18.69	22.35
Res. (Behavioral)	58.21	62.13	73.39
Res. (High)	101.51	102.34	106.77
Res. (Low/Med)	26.56	24.95	27.84

DSM DEMAND RESPONSE BUNDLES FOR IRP MODELING

- Demand response bundles are individually evaluated with seasonal peak demand impacts and associated fixed costs



*Note that DR bundles have been developed for all four seasons. Summer and winter are shown for illustration purposes.

DSM MODELING APPROACH TO DSM

- **RAP bundles will be used as the baseline input for all core portfolio development and analysis**
- **After initial portfolio evaluation, a subset of portfolio concepts will be tested against Enhanced RAP (EE) and MAP (DR) bundles**
 - Add new DSM bundles
 - Remove equivalent energy and capacity
 - Performed cost evaluation



2024 REQUESTS FOR PROPOSALS (RFP) TRANCHE REVIEW

Patrick d'Entremont, Manager Planning Commercial Support, NIPSCO
Pat Augustine, Vice President, CRA



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 416 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



OVERVIEW OF NIPSCO’S 2024 ALL-SOURCE REQUEST FOR PROPOSAL (“RFP”) PROCESSES

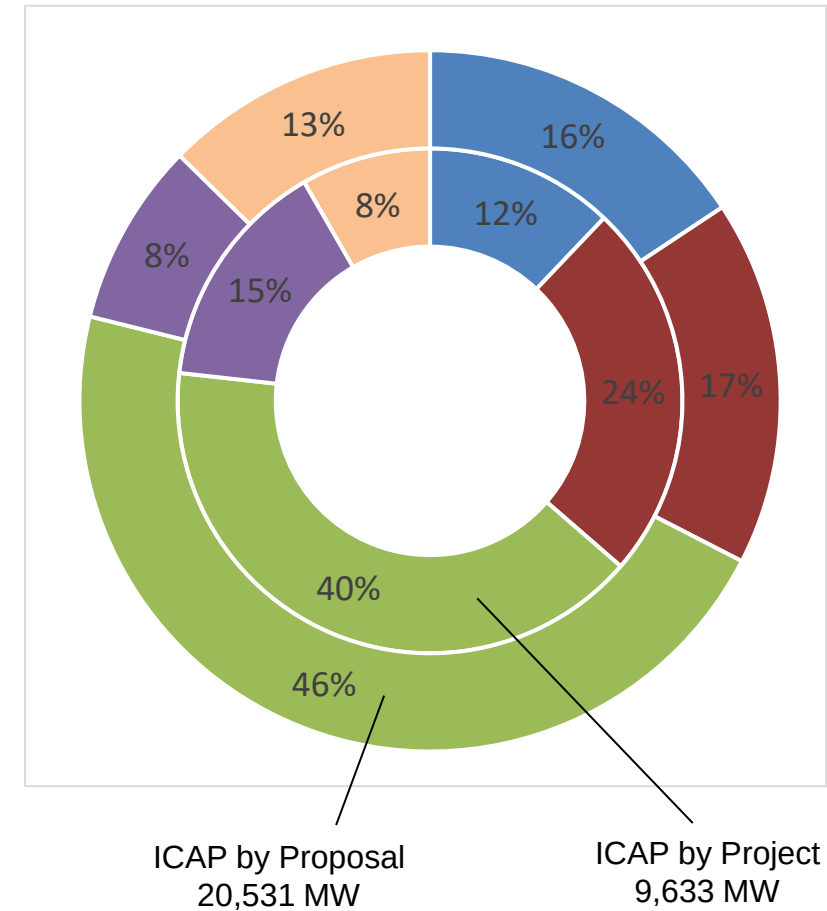
- On May 1, 2024, NIPSCO issued a series of Requests for Proposal (RFP) processes designed to identify resources positioned to support the Company’s near and long-term resource requirements
- As has been done in the past, asset cost, performance and resource availability by technology derived from RFP bids will be used as inputs into the Company’s resource planning process to create a “Preferred Plan” informed by actual market data.

Element	RFP1 – Intermittent	RFP2 – Dispatchable	RFP3 – Bridge Resources	RFP4 – DER
Technology	Renewables and hybrid resources	Thermal, standalone storage, emerging technologies and other (including long-duration storage and NIPSCO site specific storage options)	Near-term bridge resources that provide both energy and capacity solutions designed to respond to large-scale, new customer activity	Distributed energy resources that qualify for IRA incentives and/or provide MISO capacity credit
Event Size	Up to 400 MW	Up to 600 MW	600-1,000 MW	Up to 10 MW
Ownership Structure	Unit contingent PPA, BTA, existing asset sales	Unit contingent PPA, system power, BTA, existing asset sales, shaped products. Site specific storage solutions must be for NIPSCO ownership per MISO generator replacement rules	ZRC, PPA, shaped or financial products, unit contingent PPA, BTA, existing asset sales	Unit contingent PPA, existing asset sales
Duration	Targeting resources in 36-60 months with 5+ years duration	Targeting resources in 36-60 months with 5+ years duration	Targeting resources in 18-36 months with 3 to 5+ years duration, and resources in the 5+ year horizon	Targeting resources in 36-60 months with 5+ years duration
Deliverability	LRZ6, NRIS, (N-1-1)	LRZ6, NRIS, (N-1-1)	Flexible	Distribution resources
Qualification Requirements	Credit worthy counterparties	Credit worthy counterparties	Credit worthy counterparties	Credit worthy counterparties

NIPSCO 2024 RFPS: ALLOCATION OF PROPOSALS AND PROJECTS BY TECHNOLOGY

Allocation by Technology (MW ICAP)

	ICAP by Project		ICAP by Proposal	
	MW	%	MW	%
Solar	1,166	12%	3,221	16%
Solar + Storage	2,338	24%	3,464	17%
Standalone Storage	3,892	40%	9,509	46%
Thermal/Other	1,438	15%	1,738	8%
ZRC	800	8%	2,600	13%
Total (MW)	9,633	100%	20,531	100%



NIPSCO 2024 RFPS: SUMMARY OF PRICING

Average Weighted Pricing by Technology & Deal Structure

Technology	Asset Sale		Power Purchase Agreement			Comments
	\$/kW	Count	PPA \$/MWh	\$/kW-Mo	Count	
Solar	\$ [REDACTED]	2	\$72.09	-	21	Asset Sale price redacted for confidentiality reasons.
Solar + Storage	\$3,472*	6	\$70.98	\$10.60	16	
Standalone Storage	\$1,718	21	-	\$12.97	35	11 (of 25) standalone storage projects are for NIPSCO sites. The total ICAP for these projects is 1,512 MW with a weighted average price of \$1,671 \$/kW
Thermal/Other	\$ [REDACTED]	2	-	\$12.47	6	Asset Sale price redacted for confidentiality reasons.
ZRC	-	-	-	\$5.05	7	

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

**Note: For summary purposes, the cost per kW is shown per kW of solar capacity only. The IRP modeling tranches present the information per kW of total capacity.*

- Average bid prices shown for 'Asset Sale' represent capital costs and exclude on-going fuel, O&M and CapEx (where applicable)
- Figures shown are for representation and do not purport competition between technologies; Separate short-listed assets are created for each RFP event

NIPSCO 2024 RFPS: NEXT STEPS IN RFP EVALUATION PROCESS

- **June 8, 2024:** Start of Bid Evaluation Period (currently in progress)
- **Q3 2024:** Bid Evaluation Period Completed (tentative)
- **Q4 2024:** Definitive Agreements Signed with Bidders (tentative)
- Bid evaluation considers both cost and non-cost factors
 - Asset Cost – levelized cost of energy (“LCOE”) or levelized cost of capacity (“LCOC”)
 - Facility Reliability and Deliverability
 - Development Risk
 - Asset Specific Benefit and Risk Factors
- Representative cost and performance characteristics by technology “tranche” (*next slides*) have been provided to the IRP team for portfolio modeling
- IRP to determine the preferred portfolio for execution



2024 REQUESTS FOR PROPOSALS (RFP) TRANCHE REVIEW – APPLICATION TO IRP PORTFOLIO MODELING



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 421 of 675

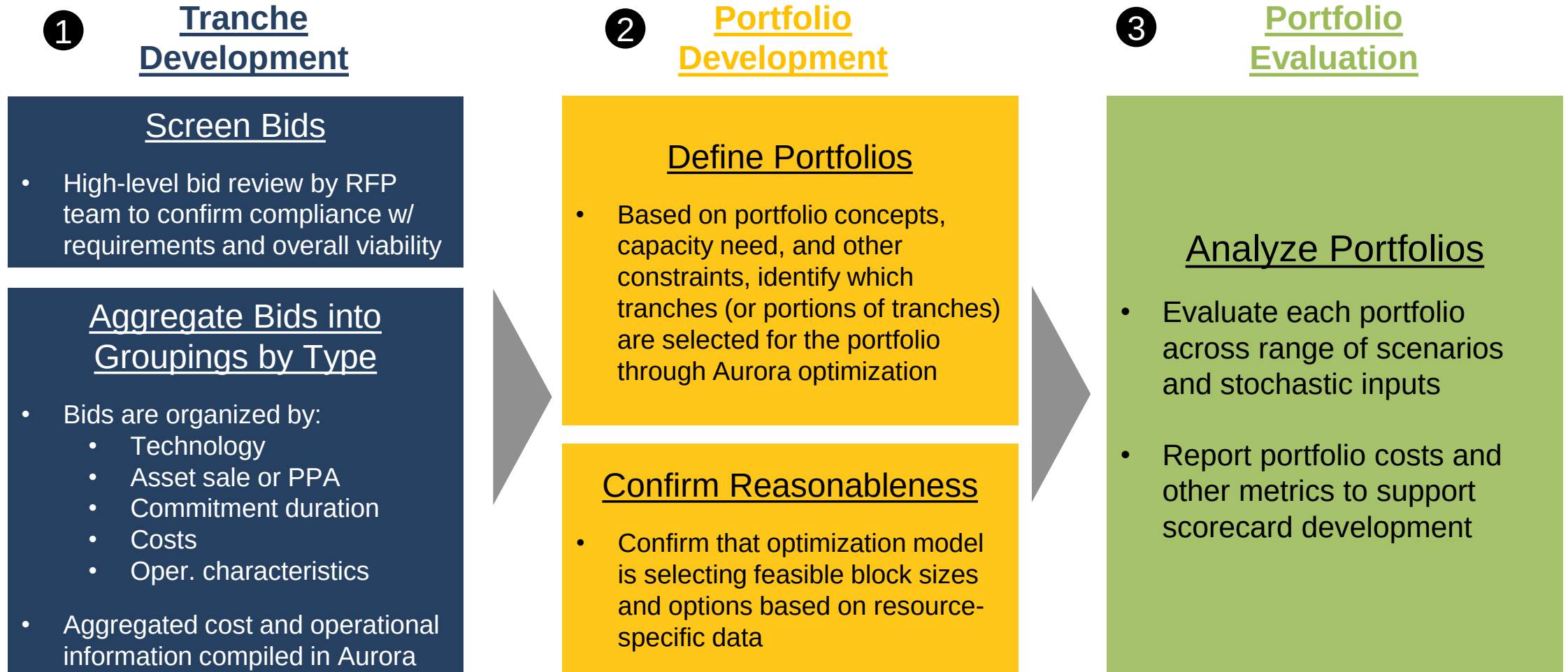


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



IRP ANALYSIS: TRANCHE DEVELOPMENT AND ASSESSMENT

A three-step process to incorporate RFP data and run the IRP models



STAND-ALONE STORAGE TRANCHES*

	Installed Capacity (MW)	In-Service Year ¹	Storage Duration (Hours)	Round Trip Efficiency	PPA Price (\$/kW-mo)	PPA Term (Years)	Asset Sale Price (\$/kW)	ITC Assumption	Fixed O&M (2024 \$/kW-yr) ²
Storage PPA 1	768	2028	4	85%	\$11.99	20	N/A	N/A	N/A
Storage PPA 2	200	2028	4	85%	\$14.95	20	N/A	N/A	N/A
Storage PPA 3	261	2027	4	85%	\$15.59	20	N/A	N/A	N/A
Storage PPA 4	166	2029	4	85%	\$16.85	20	N/A	N/A	N/A
Storage Sale 1	1,750	2028	4	85%	N/A	N/A	\$1,534	40%	\$40
Storage Sale 2	900	2028	4	85%	N/A	N/A	\$2,144	40%	\$40
Storage Sale 3	18	2027	10	75%	N/A	N/A	Redacted – single bid / tech data	40%	Redacted – single bid / tech data
Storage Sale 4	100	2028	100	35%	N/A	N/A		40%	
DER Storage PPA	10	2027	4	85%	Redacted – single bid	20	N/A	N/A	N/A

*Each tranche listed represents a group of mutually exclusive projects.

1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.

2: Baseline assumptions from NREL ATB used for tranche modeling purposes.

SOLAR TRANCHES*

	Installed Capacity (MW)	In-Service Year ¹	PPA Price (\$/MWh)	PPA Term (Years)	Asset Sale Price (\$/kW)	ITC Assumption	Fixed O&M (2024 \$/kW-yr) ²
Solar PPA 1	425	2028	\$68.75	20	N/A	N/A	N/A
Solar PPA 2	325	2027	\$69.42	20	N/A	N/A	N/A
Solar PPA 3	201	2028	Redacted – single bid	15	N/A	N/A	N/A
Solar PPA 4	200	2028	\$75.45	25	N/A	N/A	N/A
Solar Sale 1	130	2027	N/A	N/A	\$2,096	40%	\$23
Solar Sale 2	200	2029	N/A	N/A	\$2,350	40%	\$23
DER Solar PPA 1	10	2028	Redacted – single bid	20	N/A	N/A	N/A

*Each tranche listed represents a group of mutually exclusive projects.

1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.

2: Baseline assumptions from NREL ATB used for tranche modeling purposes.

SOLAR + STORAGE HYBRID TRANCHES*

	Installed Solar Capacity (MW)	Installed Storage Capacity (MW)	Storage Duration (Hours)	In-Service Year ¹	PPA Price (\$/MWh)	PPA Price (\$/kW-yr)	PPA Term (Years) ²	Asset Sale Price (\$/kW) ³	ITC Assumption	Fixed O&M (2024 \$ /kW-yr) ⁴
Hybrid PPA 1	453	250	4	2028	\$64.33	\$10.94	20	N/A	N/A	N/A
Hybrid PPA 2	300	225	4	2027	\$64.96	\$11.26	20	N/A	N/A	N/A
Hybrid PPA 3	250	125	4	2028	\$72.58	\$13.13	20	N/A	N/A	N/A
Hybrid PPA 4	200	100	4	2027	\$81.49	\$12.05	25	N/A	N/A	N/A
Hybrid Sale 1	164	164	4	2027	N/A	N/A	N/A	\$1,944	40%	\$35
Hybrid Sale 2	300	125	4	2028	N/A	N/A	N/A	\$2,007	40%	\$30
Hybrid Sale 3	343	171	4	2028	N/A	N/A	N/A	\$2,538	40%	\$31

*Each tranche listed represents a group of mutually exclusive projects.

1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.

2: For modeling purposes, the shortest PPA term in the tranche was used even though the Hybrid PPA 2 and Hybrid PPA 3 tranches have bids varying between 20 and 25 years.

3: Note that asset sale price is based on the total installed capacity (solar + storage) of the tranche.

4: Assumptions from NREL ATB used for tranche modeling purposes, weighted by solar:storage ratio within the tranche.

THERMAL AND ZRC TRANCHES*

	Installed Capacity (MW)	In-Service Year ¹	Comments	PPA Term (Years)
Thermal PPA 1	600	2028	New Gas CC	20
Thermal PPA 2-4	150	2026	Various contractual options (heat rate call or blocks)	5
Thermal PPA 5	150	2027	Coal-based energy and capacity	2
Thermal Sale 1	18	2027	Existing gas peaker	N/A
ZRC 1-4	200	2025/26 – 2029/30	PJM external resource delivered to MISO border	Multiple options
ZRC 5-7	600	2025/26 – 2026/27	LRZ 4 delivery	Multiple options

*Each tranche listed represents a group of mutually exclusive projects.

1: In-service year may be in the middle of the reported year.



GENERIC RESOURCE OPTIONS

Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 427 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



NEW RESOURCE OPTIONS

Resource Option		Available through 2029	Available 2030-2034	Available 2035+
Resources offered in the RFP	Demand side management (EE and DR) programs	From MPS and DSM Study		
	Solar	From RFP Data	Benchmarked to RFP Data plus Third-Party Data Sources for the Long-Term	
	Li-Ion Battery Storage			
	Long Duration Storage			
	Solar + Storage Hybrid			
	Near-Term Thermal Options			
	Near-Term Capacity Purchases (ZRCs)			
	New Natural Gas Peaking Build (H2-enabled up to 30%)	From NIPSCO Internal Engineering Analysis and Project Experience		
	New Gas CC Build (H2- enabled up to 30%)			
	Wind		Benchmarked to NIPSCO Project Experience	
	New Gas CC with CCS		From NIPSCO and Third-Party Data Sources	
	New Gas with H2			
	CCS Retrofit (at Sugar Creek)			
	H2 Retrofit (at Sugar Creek)			
	Small modular reactor (SMR)			
			From NIPSCO and Third-Party Data Sources	

KEY NEW RESOURCE COST BENCHMARKS FOR LONG-TERM OPTIONS

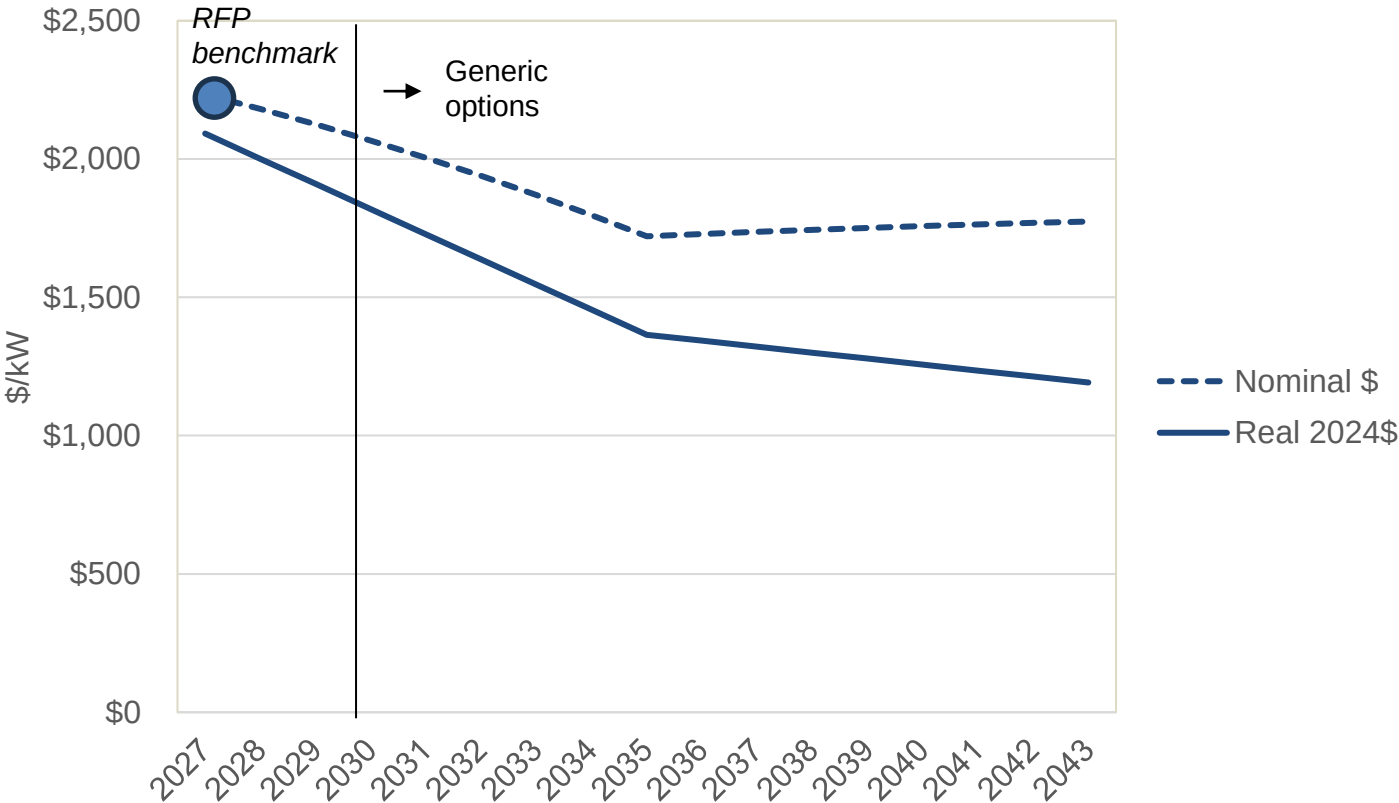
Resource ¹	Benchmark Year	Benchmark CAPEX (2024\$/kW ²)	FOM (2024\$/kW-yr ²)	Tax Credit Assumption	Benchmark Source ³
New Solar	2027	\$2,092	\$22	40% ITC	2024 RFP
New Wind	2026	\$2,248	\$34	PTC	NIPSCO – ES&O current wind project/ development experience
New 4-hr Li Ion Storage	2027	\$1,612	\$40	40% ITC	2024 RFP
New LDES	2027	\$2,800 - \$3,000	\$40	40% ITC	2024 RFP
New CCGT	2028	\$1,225	\$42		NIPSCO – Major Projects
New CT	2028	\$1,284	\$28		Schahfer CT Project
New SMR	2035	\$8,659	\$150	30% ITC	2023 NREL ATB
New Gas CCUS	2030	\$3,325	\$82	45Q (\$85/ton)	New Gas (See “New CCGT/CC” above), Incremental CCUS – EPA/EIA
New H2-enabled CC	2030	\$1,625	\$42	45V (assumed in fuel cost)	NIPSCO, Major Projects and vendor estimates
Hydrogen Retrofit	2035	\$400	\$27 ⁴	45V (assumed in fuel cost)	NIPSCO and vendor estimates
Gas CCUS Retrofit	2035	\$1,860	\$47 ⁴	45Q (\$85/ton)	NIPSCO – Major Projects

Notes:

1. CCGT=Combined Cycle Gas Turbine; CT=Simple Cycle Gas Turbine; LDES = Long Duration Energy Storage; SMR = Small Modular Reactor; CCUS = Carbon Capture, Utilization, and Storage
2. kW=kilowatt; all capital costs assumed to be direct costs only, without indirect cost adders; kW-yr=kilowatt per year
3. Source for initial capital costs. All resources leverage NREL ATB “Moderate” cost curves beyond the benchmark. CCUS specific data taken from EIA/EPA.
4. Values represent total FOM: incremental FOM for H2 and CCUS respectively are \$0 and ~\$25/kw-yr

LONG-TERM SOLAR RESOURCE INPUTS

The NREL “moderate” cost curve is applied from the RFP benchmark point

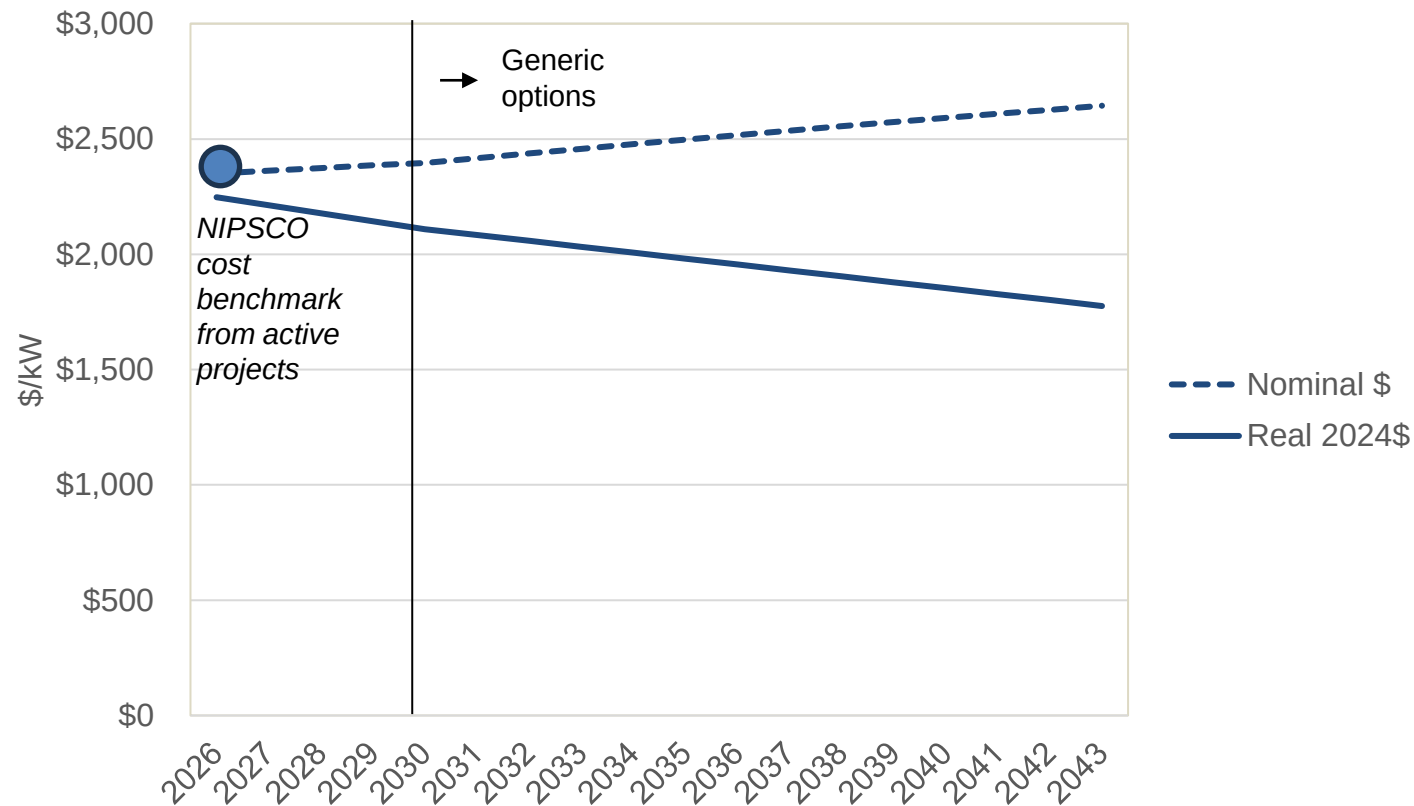


Category	Assumption
Fixed O&M (2024\$/kW-yr)*	\$22
Capacity Factor	25%
Tax Credit Eligibility Assumption	40% ITC

*NREL ATB assumptions for 2027 benchmark year

LONG-TERM WIND RESOURCE INPUTS

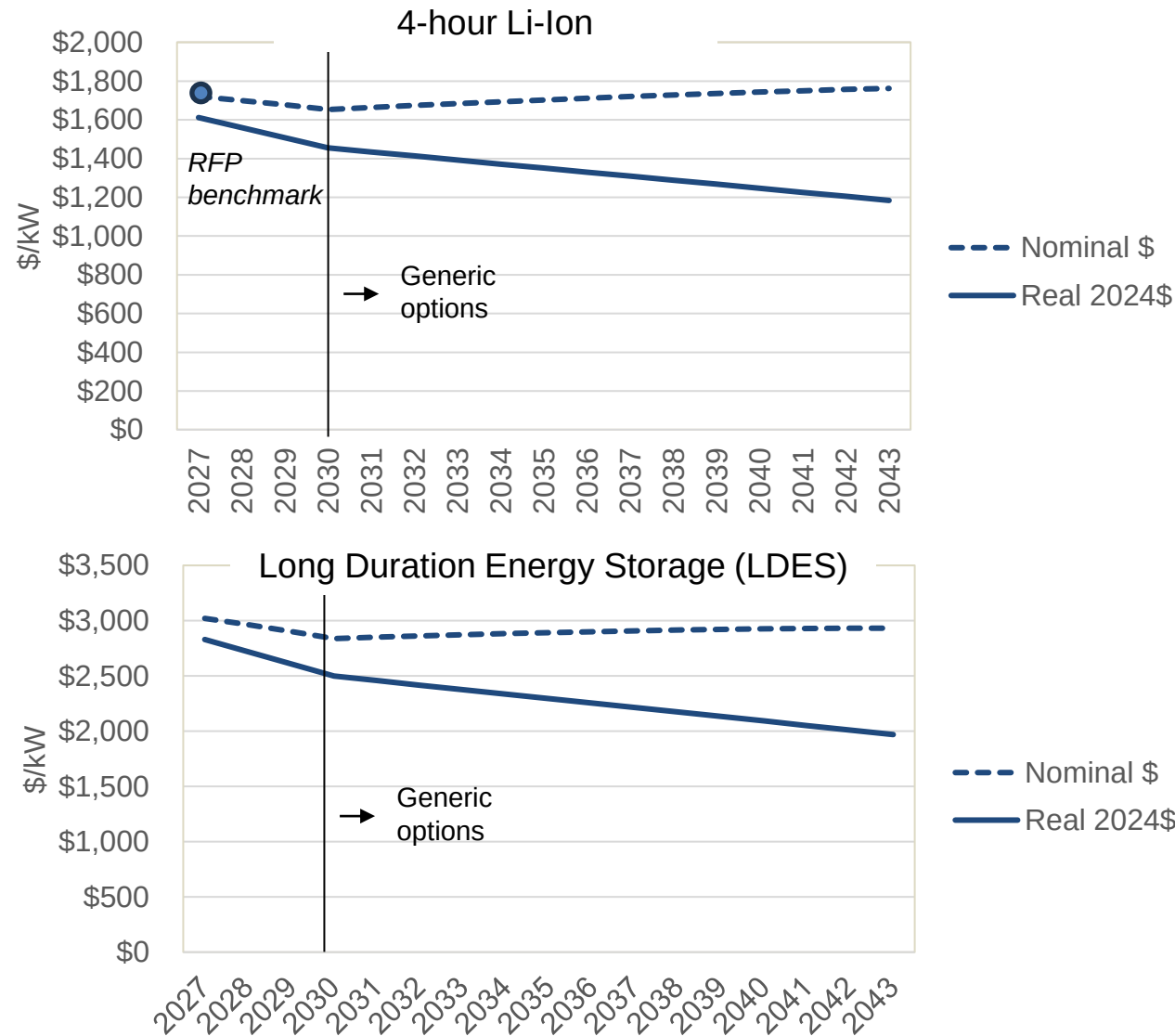
The NREL “moderate” cost curve is applied from NIPSCO’s internal benchmarks from active projects.



Category	Assumption
Fixed O&M (2024\$/kW-yr)*	\$34
Capacity Factor	39%
Tax Credit Eligibility Assumption	PTC

**NREL ATB assumptions for 2026 benchmark year*

LONG-TERM STORAGE RESOURCE INPUTS

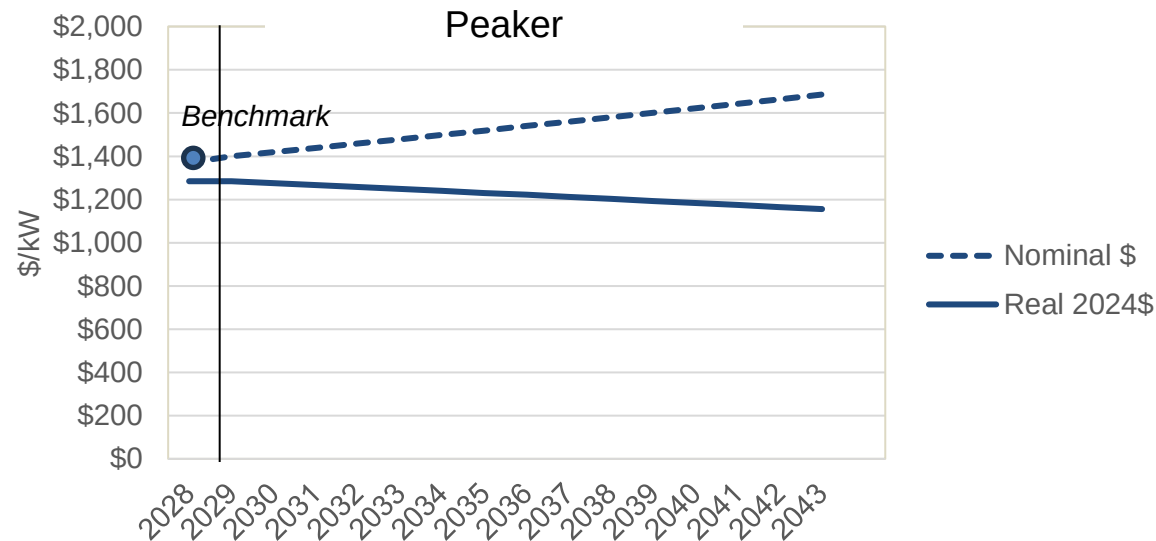
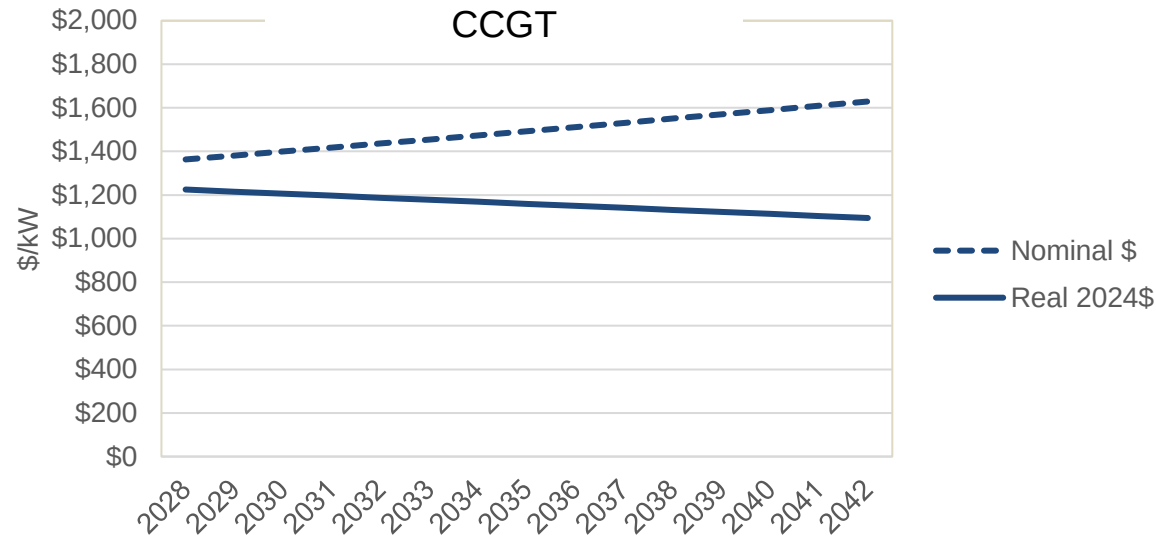


- NIPSCO benchmarked costs based on RFP results and public studies to identify 4-hour and a representative long duration energy storage technology.
- NREL “moderate” cost curves are applied from the RFP benchmark points

Category	4-Hour Li-Ion	LDES
Fixed O&M (2024\$/kW-yr)	\$40*	\$40
Round Trip Efficiency	85%	35%
Tax Credit Eligibility Assumption	40% ITC	40% ITC

*NREL ATB assumptions for 2027 benchmark year

NEW NATURAL GAS PLANT BUILD



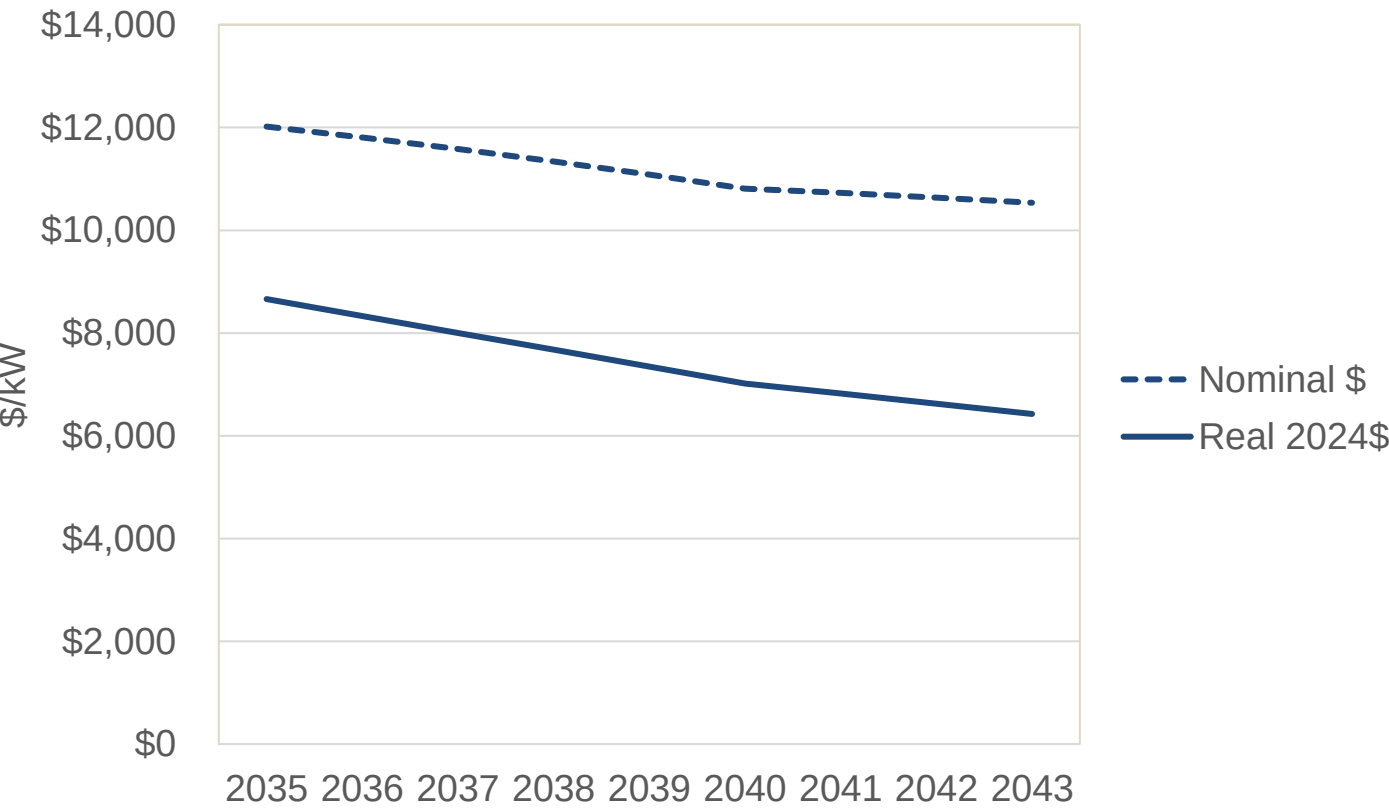
- New natural gas plant cost information based on NIPSCO internal engineering studies and ongoing gas peaker experience
- NREL cost curves applied over time

Category	Peaker	CCGT
Fixed O&M (2024\$/kW-yr)*	\$28	\$42
First Available Year	2028	2028

*NREL ATB assumptions for appropriate benchmark years

SMALL MODULAR REACTOR

NREL projections are used for SMR

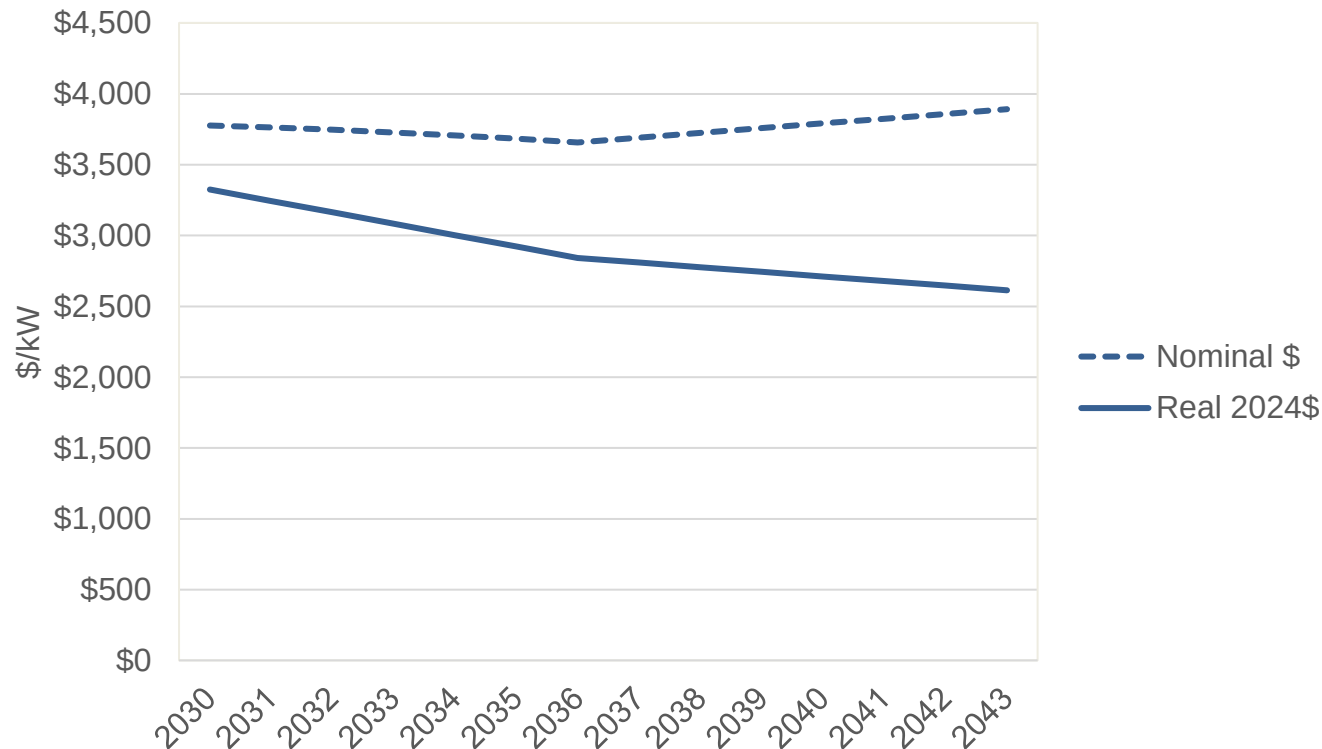


Category	Assumption
Fixed O&M (2024\$/kW-yr)*	\$150
First Available Year	2035
Tax Credit Eligibility Assumption	30% ITC

**NREL ATB assumptions for 2035 benchmark year*

CARBON CAPTURE UTILIZATION AND STORAGE

- **Retrofit to Sugar Creek**
 - Projected to be ~\$1,860/kW-yr, increase in VOM by factor of 2.29x; increase in FOM by factor of 1.96x; increase in heat rate by factor of 1.11x
- **New Gas CCS Plant**

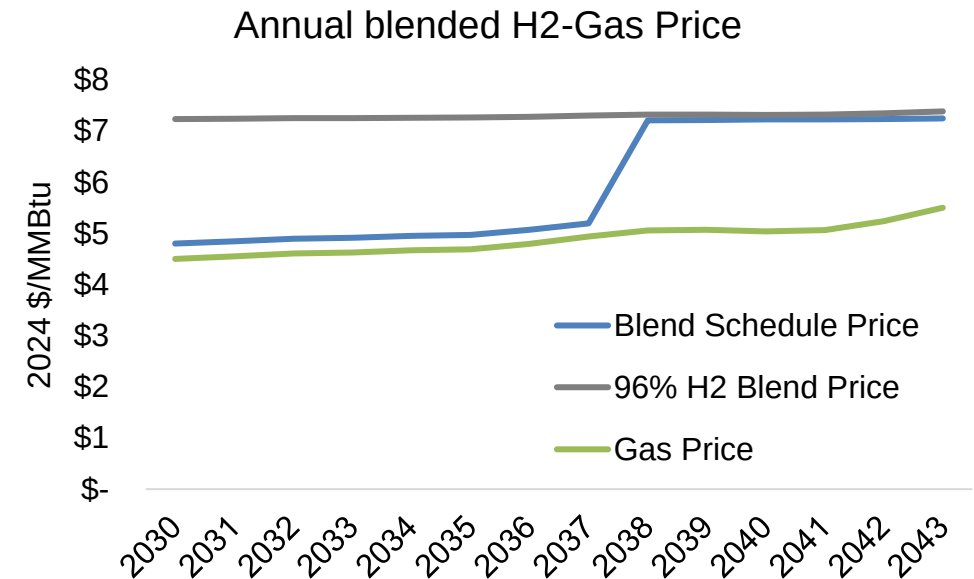


Category	Assumption
Fixed O&M (2024\$/kW-yr) ¹	\$82.02
CO2 Transportation Cost (2022\$/ton) ²	\$7.50
CO2 Sequestration Cost (2022\$/ton) ²	\$4.86
First Available Year	Between 2030 - 2035
Tax Credit Eligibility Assumption	45Q credit (\$85/metric ton)

1. NREL ATB assumptions for 2030 benchmark year
2. EPA assumption for Indiana Illinois basin.

POTENTIAL USE OF GREEN HYDROGEN

- **Incremental capital for thermal plants**– An assumption of \$400/kW (2024\$) of incremental capital was used for retrofits to allow for full hydrogen blending
- **Fuel price assumption** – A price of ~\$4/kg or ~\$30/MMBtu (2024\$) was used for hydrogen throughout the forecast period
 - An assumption that green hydrogen is readily available was made, allowing 45V credits to be earned for all H2 fuel used
 - The green hydrogen tax credit of \$3/kg is worth approximately ~\$22.5/MMBtu, leading to a ~\$7.25 - \$7.50/MMBtu net price in 2024\$
- **Blend Schedule** –
 - For Sugar Creek: assumption of 30% H2 blend prior to 2038, and 96% from 2038 onward
 - For new units: runs on 96% blend during entire time in service



2024 IRP FEDERAL TAX CREDIT ASSUMPTIONS – REFERENCE CASE

In-Service Year ⁶	Production Tax Credit ^{1, 2}	Investment Tax Credit ^{1, 2}	CCS (Section 45Q) ¹	Hydrogen PTC (Section 45V) ^{1, 3}
	10-year \$/MWh	Up front portion of investment	12-year \$/metric ton-CO2	10-year \$/kg
	\$30/MWh in 2024\$ ⁵	%	\$85 in 2026\$ ⁵	\$3/kg ⁴ in 2022\$ ⁵
2024-2035	100% of value	30%	Available	Available
2036	75% of value	22.5%		
2037	50% of value	15%		
2038+	0%	0%	\$0	\$0

Notes:

1. Assumes prevailing wage and apprenticeship requirements met.
2. A 10% “energy community” bonus is available for projects located in proximity to retired coal infrastructure or in statistical areas with high historical employment in the fossil fuel sector and unemployment rates greater than the national average. The bonus adds 10% to the ITC and increases the PTC amount by 10%.
3. For modeling purposes, NIPSCO is assuming a price for hydrogen (net of tax credits) rather than investment in an electrolyzer and associated green hydrogen production. Since the hydrogen PTC has a 10-year term, tax credits are expected to be eligible for hydrogen fuel purchased through the fundamental modeling horizon through 2043.
4. Assuming green hydrogen with a lifecycle emission rate below 0.45 kg CO2e/kg-H2.
5. The tax credit values are tied to inflation. Baseline years are provided for reference.
6. Tax credit eligibility is defined by commence construction dates. For modeling purposes, safe harbor construction periods are assumed, and these assumptions are presented for projects entering into service during the specified years.

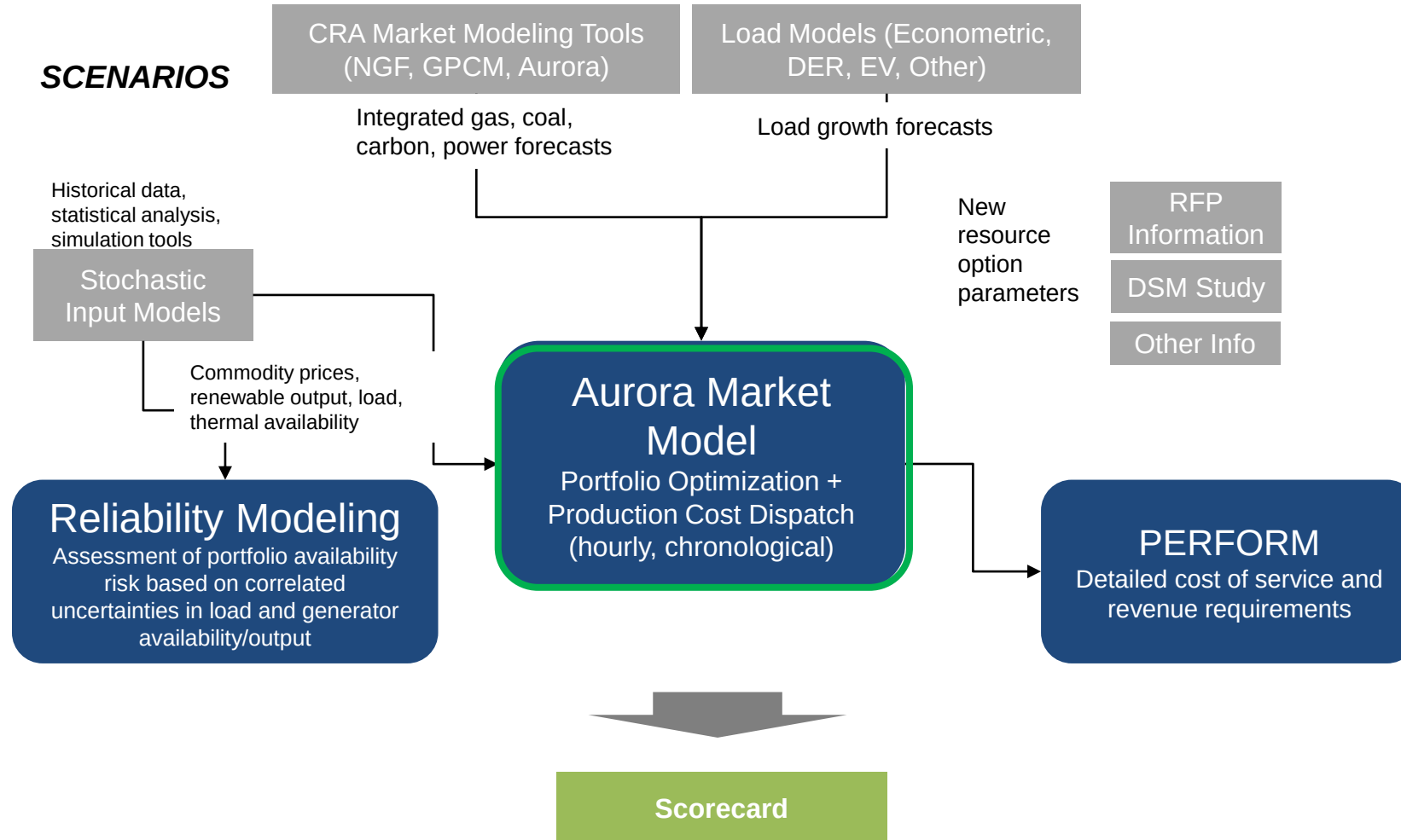


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

PORTFOLIO DEVELOPMENT APPROACH



RESOURCE PLANNING APPROACH

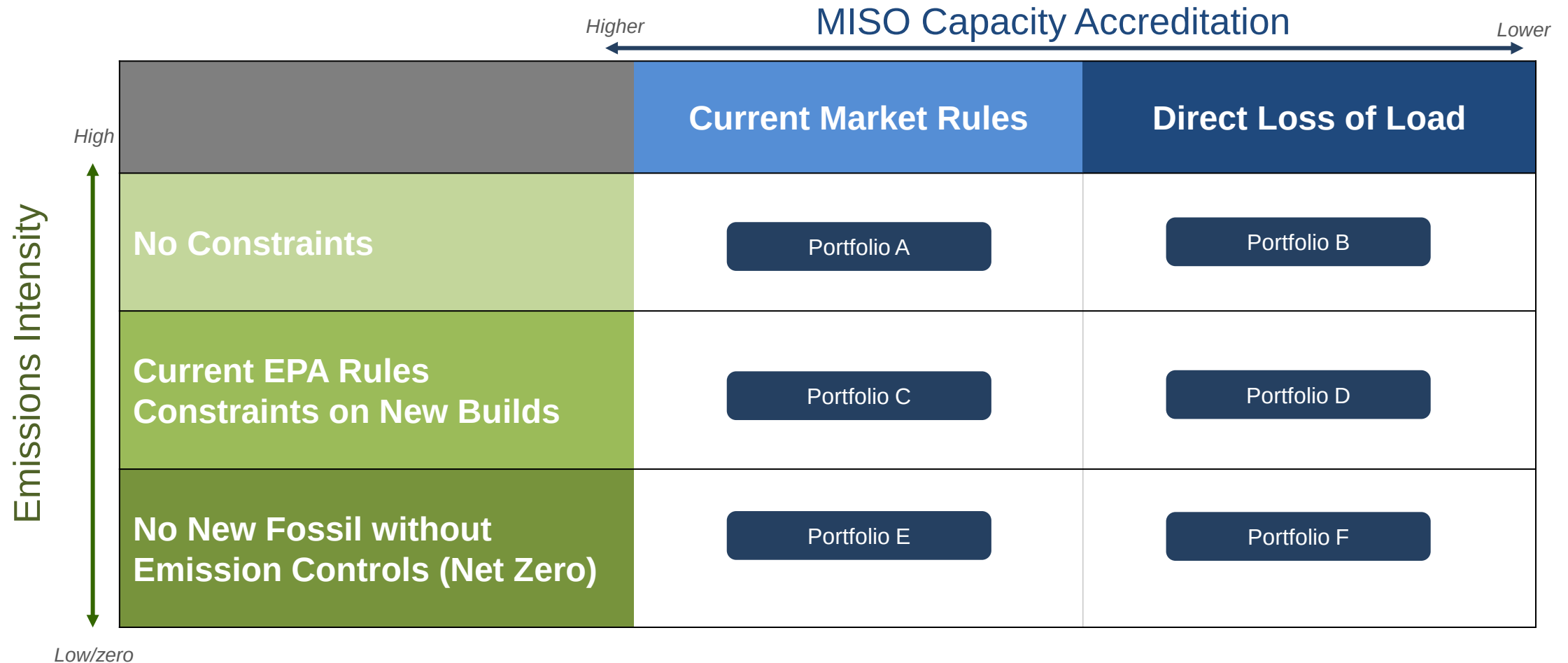


- ① Identify key planning questions and approach
- ② Develop market perspectives (external scenarios)
- ③ Develop integrated resource strategies (NIPSCO portfolios)
- ④ Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- ⑤ Evaluate trade-offs and select preferred plan

PORTFOLIO CONSTRUCTION FRAMEWORK

Six portfolios will be constructed to highlight the two primary constraints:

- 1) MISO's proposed rules: reduce the capacity value primarily for solar and wind resources
- 2) EPA's emissions rules: constrain output or increase cost of new gas generation



PORTFOLIO ANALYSIS APPROACH

1

Portfolio Development

Define Portfolios

- For **each of the six portfolio concepts**, perform optimization analysis in Aurora to identify long-term resource portfolios
 - Reference Load
 - High Load Sensitivity

Eligible Resources

- DSM bundles (EE and DR)
- RFP tranches
- Other new resource options (mid- and long-term)

2

Portfolio Evaluation

Analyze Portfolios

- Evaluate **all 6 portfolios** against 5 market scenarios, which vary:
 - Natural gas price
 - Environmental policy
 - MISO market price
 - NIPSCO Load
- Evaluate **all 6 portfolios** across stochastic distribution of key variables:
 - Commodity prices
 - Wind and solar output
 - NIPSCO Load
 - Unit outages

Sensitivity Analysis

- High load portfolio review
- Enhanced RAP / MAP DSM Review

3

Preferred Portfolio Selection

Populate Scorecard

- Summarize data for scorecard
 - Costs
 - Cost risk
 - Carbon emissions
 - Reliability metrics
 - Local economy metrics
- Assess tradeoffs and identify preferred portfolio



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

2024 PUBLIC ADVISORY PROCESS NEXT STEPS

Tara McElmurry, Communications Manager, NiSource



2024 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 April 23rd	Meeting 2 June 24 th	Meeting 3 August 21 st	Meeting 4 September 19 th	Meeting 5 October 8 th
Location	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943
Content	2021 Short Term Action Plan Update (Retirements, Replacement projects) - Resource Planning and 2024 Continuous Improvements 2024 Public Advisory Process 2024 Policy Update (incl. IRA and EPA) - Update on Key Inputs/Assumptions (core demand forecast, new considerations for demand) - Scenario Themes – Introduction - RFP Overview	- MISO Regulatory Developments and Initiatives - Load scenarios - Update on Key Inputs/Assumptions (commodity prices) - Scenarios and Stochastic Analysis - Preliminary RFP Results	- DSM Modeling and Methodology - RFP detailed update - Portfolio modeling input review	- Initial modeling results, initial scorecard indications - High-load sensitivity modeling results	- Additional modeling results and scorecard - Preferred plan and logic relative to alternatives 2024 NIPSCO Short Term Action Plan
Meeting Goals	- Communicate what has changed since the 2021 IRP (incl. IRA changes) - Communicate environmental policy considerations - Communicate updates to key inputs/assumptions - Provide RFP Overview - Communicate the 2024 public advisory process, timing, and input sought from stakeholders	- Communicate resource needs due to potential demand - Common understanding of MISO regulatory updates - Communicate scenario themes and stochastic analysis approach, along with major input details and assumptions - Communicate commodity prices impacts - Communicate preliminary RFP results	- Common understanding of DSM modeling methodology - Provide detailed update on the RFP and verification - Explain next steps for portfolio modeling	Develop a shared understanding of economic modeling outcomes and preliminary results to facilitate stakeholder feedback	- Respond to key stakeholder comments and requests - Communicate NIPSCO's preferred resource plan and short-term action plan - Obtain feedback from stakeholders on preferred plan



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

CLOSING & STAKEHOLDER COMMENTS





OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

APPENDIX – RFP RELATED INFORMATION



OVERVIEW OF NIPSCO'S 2024 REQUEST FOR PROPOSAL ("RFP") PROCESSES

- *On May 1, 2024, NIPSCO issued a series of Requests for Proposal (RFP) processes designed to identify resources positioned to support the Company's near and long-term resource requirements.*
- *As has been done in the past, asset cost, performance and resource availability by technology derived from RFP bids will be used as inputs into the Company's resource planning process to create a "Preferred Plan" informed by actual market data.*

NIPSCO issued four 2024 Requests for Proposals on May 1st:

1. **RFP1 and RFP2** together targeted both renewable and dispatchable resources under an All-Source RFP umbrella. Through these RFP, the company targeted approximately 1,000 MW of resources located in, or deliverable to LRZ6. NIPSCO is seeking transmission- interconnected, supply side resources including solar, wind, thermal and storage options in support of the Company's resource requirements
 - As part of the All-Source RFP, the Company is also seeking a development partner for storage resources located at NIPSCO's Schaefer, Michigan City and other sites.
 - Through the All-Source RFP, NIPSCO solicited bids related to emerging technologies including but not limited to long-duration storage, hydrogen fueled CC or CT and other technologies.
2. **RFP3**, the Bridge Resource RFP, called for resources positioned to support potential NIPSCO needs related to emerging, near-term, large-scale customer loads. The Company is targeting 600-1,000 MW of capacity or capacity and energy resources that can be available within 18-36 months from LRZ6 or neighboring MISO zones and will consider short and long-term resource options including ZRC, physical resources or financial arrangements
3. **RFP4**, targeted Distributed Energy Resources (DER). NIPSCO is considering up to 10 MW of distribution or transmission interconnected resources qualifying for bonus credits under the Inflation Reduction Act

OVERVIEW OF NIPSCO’S 2024 REQUEST FOR PROPOSAL (“RFP”) PROCESSES

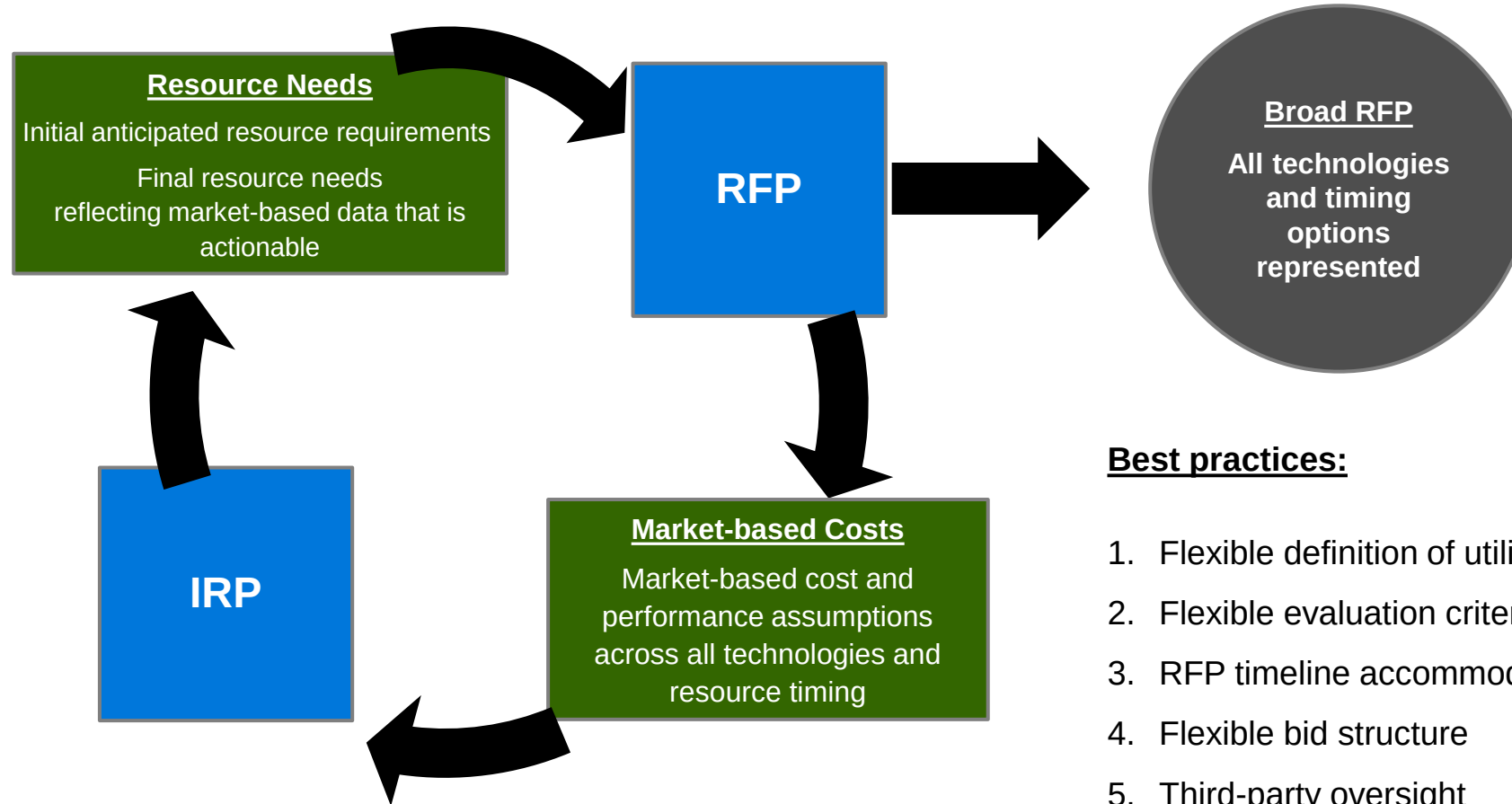
----- All-Source RFP -----

Element	RFP1 – Intermittent	RFP2 – Dispatchable	RFP3 – Bridge Resource	RFP4 – DER
✓ Issue RFP	May 1, 2024	May 1, 2024	May 1, 2024	May 1, 2024
✓ Bidder Information Session	May 6, 2024	May 6, 2024	May 6, 2024	May 6, 2024
✓ Pre-Qualification Deadline	May 15, 2024	May 15, 2024	May 15, 2024	May 15, 2024
✓ Notification of Pre-Qualification	May 20, 2024	May 20, 2024	May 20, 2024	May 20, 2024
✓ Proposals Due	June 7, 2024	June 7, 2024	June 7, 2024	June 20, 2024

- Bids for RFP 4 (the DER RFP) were received on June 20th and were not included in the preliminary version of this presentation. The details of those bids have since been included in all tables and figures.

OVERVIEW OF NIPSCO'S 2024 REQUEST FOR PROPOSAL ("RFP") PROCESSES

Integrated IRP to RFP structure



Best practices:

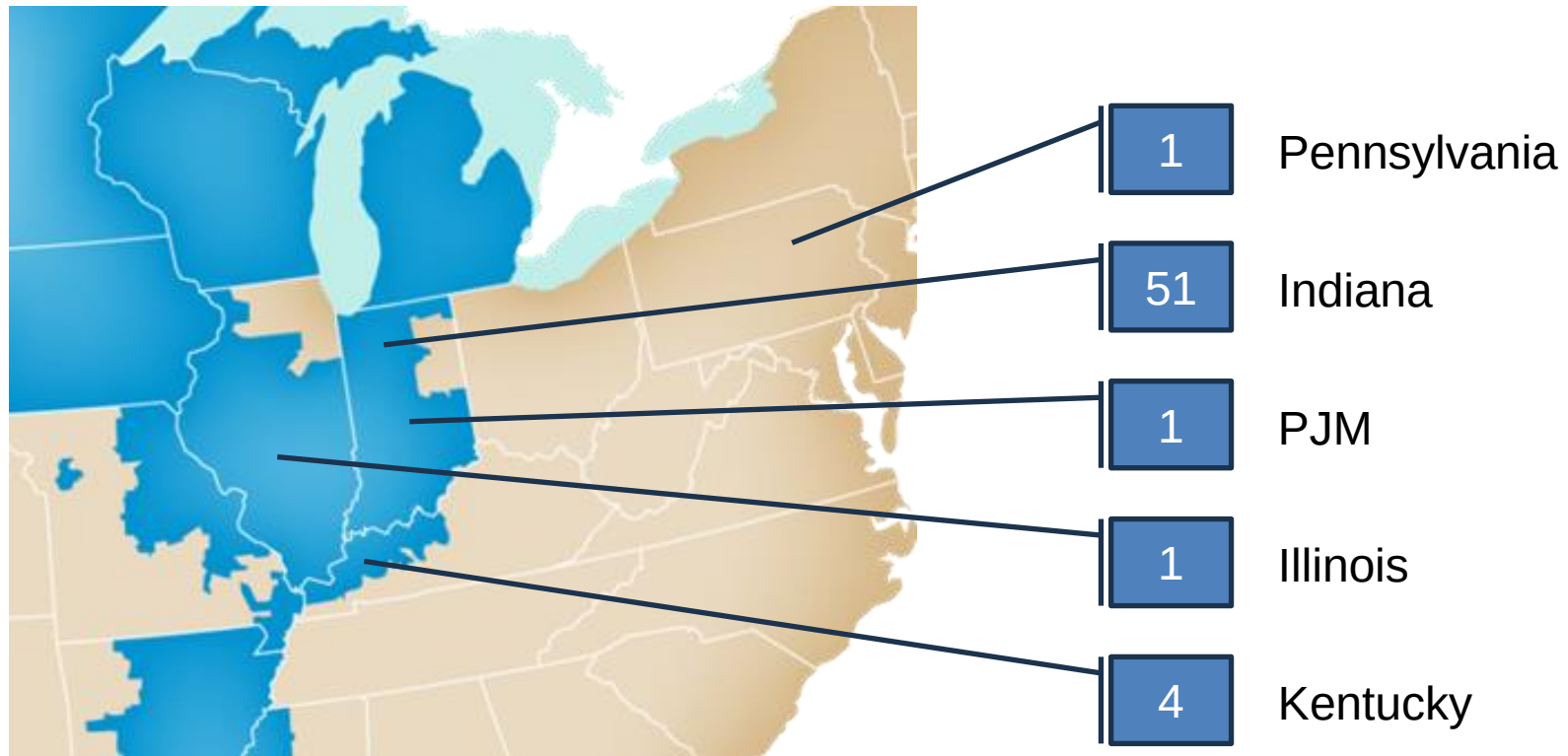
1. Flexible definition of utility needs
2. Flexible evaluation criteria
3. RFP timeline accommodates IRP modeling requirements
4. Flexible bid structure
5. Third-party oversight

NIPSCO 2024 RFPS: OVERVIEW OF PROPOSALS RECEIVED

- 53 individual projects across three states with ~9.2 GW (ICAP) represented



NIPSCO 2024 RFPS: DISTRIBUTION OF PROJECTS RECEIVED



Note: Blue area represents MISO territory

NIPSCO 2024 RFPS: OVERVIEW OF PROPOSALS RECEIVED

- Proposals for RFP 1-3 were received on June 7, 2024
- Proposals for RFP 4 were received on June 20, 2024
- The RFP generated a tremendous amount of bidder interest
- 116 total proposals were received across a range of deal structures
- 58 individual projects across three states with ~9.63 GW (ICAP) represented
 - Many of the proposals offer variations on pricing structure and term length
 - Several instances of renewables paired with storage
 - Majority of the projects are in various stages of development

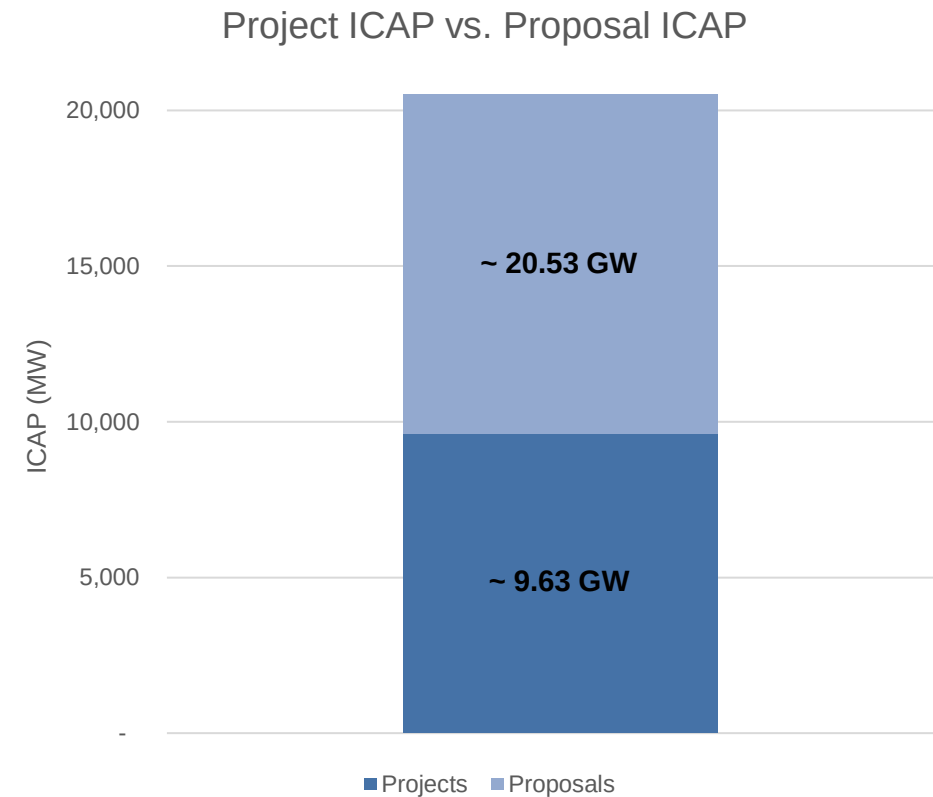
Count of Proposals by Technology and Deal Structure

Deal Structure	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Wind	Total
Asset Sale	1	2	12	2	-	-	17
PPA/Toll	20	12	26	6	7	-	71
Asset Sale + PPA/Toll	1; 1	4; 4	9; 9	-	-	-	14 (28)
Total Count	23	22	56	8	7	-	116*
Locations	IN, KY	IN, KY	IN, KY	IN, PA	LRZ4, PJM	-	

**Proposal count includes mutually exclusive projects. Projects offered as both Asset Sale and PPA/Toll are counted in the total as two proposals.*

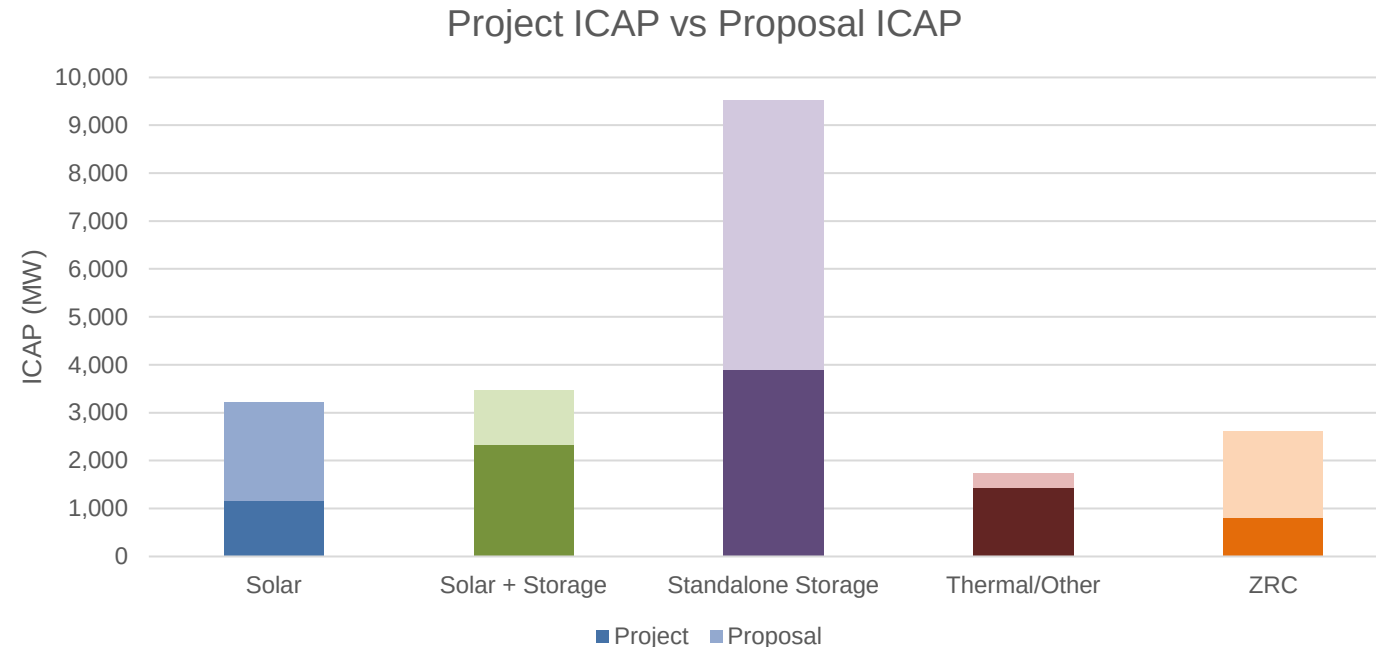
NIPSCO 2024 RFPS: PROJECTS VS. PROPOSALS

- 58 individual projects across three states with ~9.63 GW (ICAP) represented
- 116 different proposal structures between the 58 individual projects, totaling ~20.53 GW



NIPSCO 2024 RFPS: PROJECTS VS. PROPOSALS

- 58 individual projects across three states with ~9.63 GW (ICAP) represented
- 116 different proposal structures between the 58 individual projects, totaling ~20.53 GW



ICAP (MW)	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Total (MW)
Project	1,166	2,338	3,892	1,438	800	9,633
Proposal	3,211	3,464	9,509	1,738	2,600	20,531

NIPSCO 2024 RFPS: OVERVIEW OF PROJECTS RECEIVED

- 58 individual projects were bid into the RFP across three states with ~9.63 GW (ICAP)
- There were no wind projects bid into the RFP

Project MW ICAP by Location and Technology

Location	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Wind	Total (MW)
Indiana	1,066	2,063	3,692	1,368	-	-	8,188
Kentucky	100	275	200	-	-	-	575
Pennsylvania	-	-	-	70	-	-	70
LRZ4, PJM	-	-	-	-	800	-	800
Total (MW)	1,166	2,338	3,892	1,438	800	-	9,633

NIPSCO 2024 RFPS: PPA OVERVIEW

Proposal MW ICAP by PPA Term Length (PPA or Both) and Technology

Term (Years)	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Total (MW)
1	-	-	-	-	800	800
2	-	-	-	150	800	950
3	-	-	-	-	800	800
4	-	-	-	-	200	200
5	-	-	-	450	-	450
6-15	201	300	796	-	-	1,297
>15	2,690	2,158	4,726	1,050	-	10,624
Total	2,891	2,458	5,522	1,650	2,600	15,121

NIPSCO 2024 RFPS: STORAGE OVERVIEW

- NIPSCO received bids for storage both as standalone projects and integrated with solar facilities
- Eleven (11) of the standalone storage projects (1,512 MW of ICAP) are proposals to add storage to existing NIPSCO sites

Storage Project MW ICAP by State and Type

State	Standalone Storage (MW)	Solar + Storage (Storage MW)	Solar + Storage (Solar MW)
Indiana	3,692	1,187	2,063
Kentucky	200	275	275
Total (MW)	3,892	1,462	2,338

NIPSCO 2024 RFPS: NEXT STEPS IN RFP EVALUATION PROCESS



Project Economics LCOE / LCOC

The economic analysis will be conducted over a fixed planning horizon and bid specific planning horizon for all assets. The analysis will reflect all expected costs related to the bid. The project level analysis will be based on data submitted with the bids, standard assumptions for key commodity considerations and may reflect adjustments for material uncertainties associated with a bid.



Reliability and Deliverability

The asset reliability and deliverability evaluation will include an assessment of transmission reliability, facility age and performance, and fuel risk and fuel security. Transmission reliability scoring will be based on transmission infrastructure and location. Facility performance will be based on the EFORD performance. Fuel reliability will consider fuel availability risk and price volatility.



Development

Development risk will consider how many key development milestones have been met as well as the development experience of the potential counterparty.



Asset Specific Benefits / Risks

Asset specific benefits and risks will consider individual, unique, project level risks associated with an individual project or counterparty. CRA will evaluate projects based on community benefits, certain social justice goals, minority and women owned business considerations, unique environmental considerations, specific regulatory risks or other considerations.

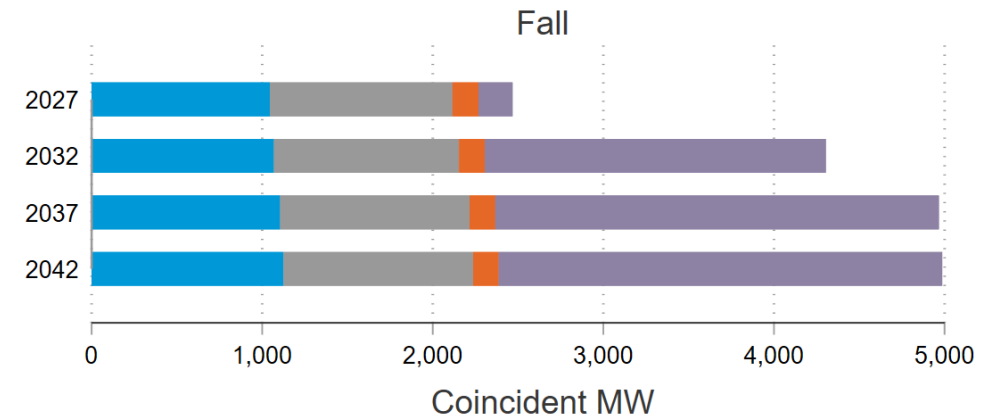
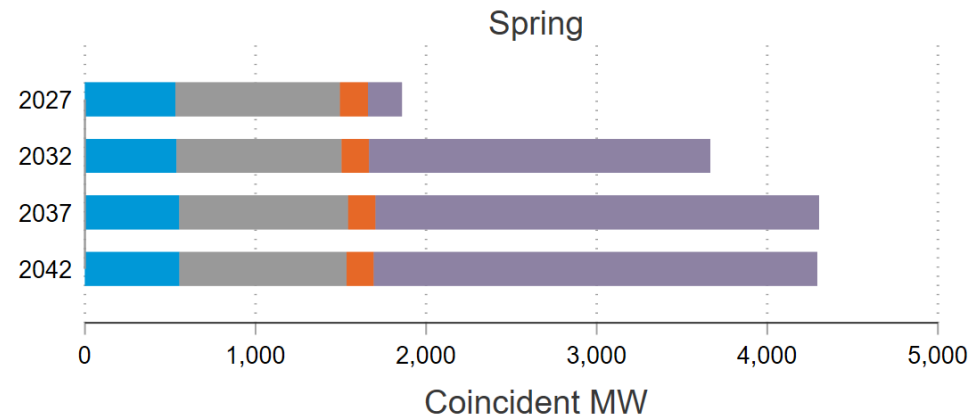
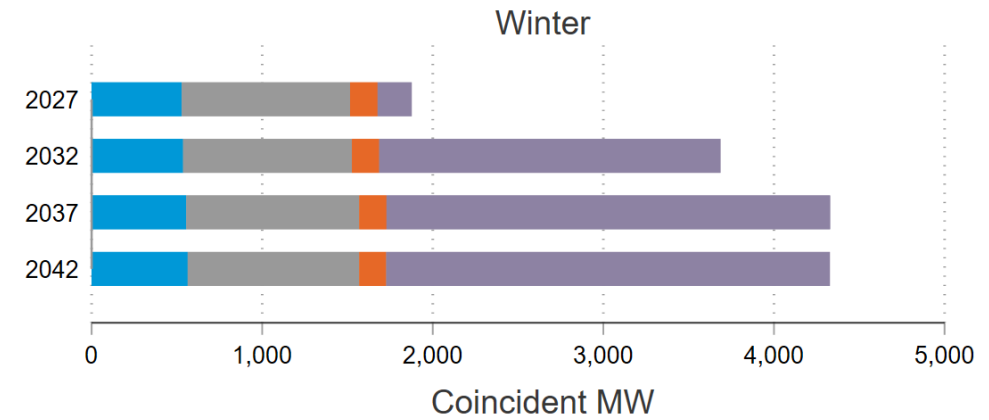
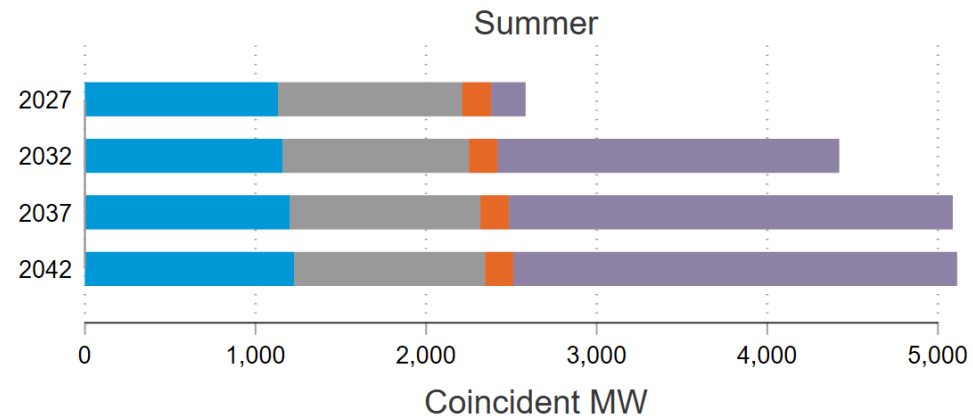


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

APPENDIX – DSM STUDY



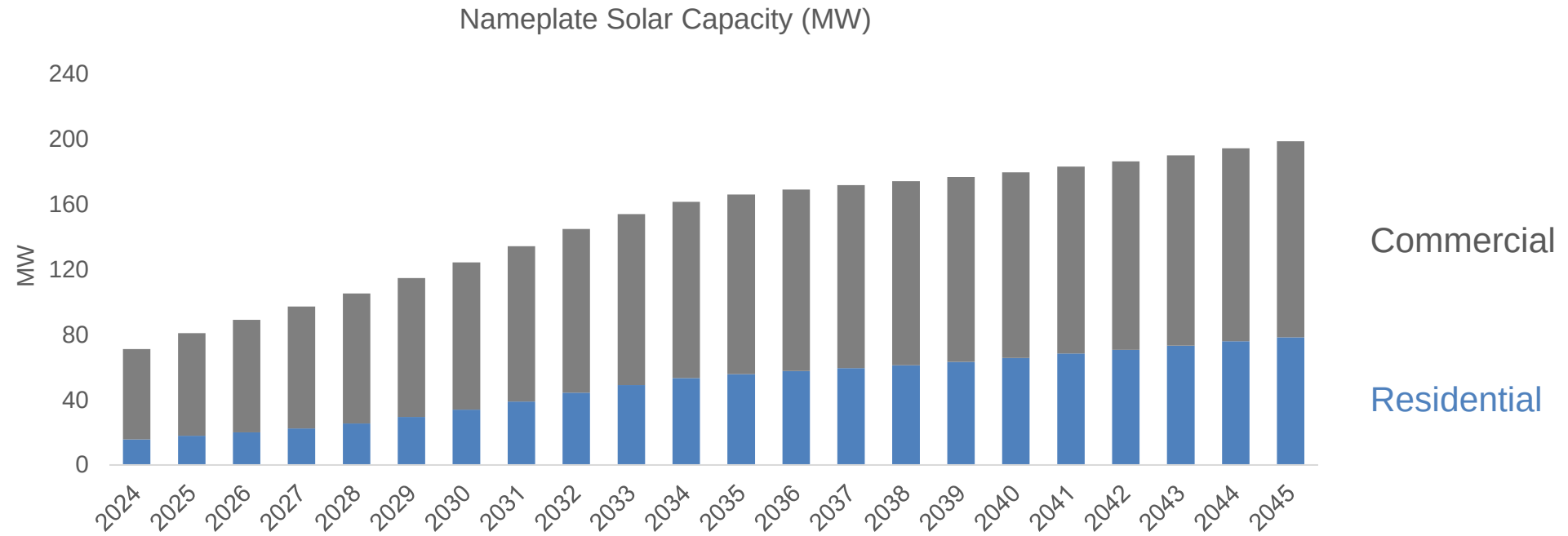
IRP PEAK LOAD FORECAST BY SEASON – WITHOUT ADJUSTMENT FOR EV OR SOLAR



Residential Non-Residential Rate 531 Firm Data Center

DER MODELING - ALIGNMENT WITH BROADER IRP INPUTS

DER Solar Penetration is consistent with the IRP inputs reviewed in meetings #1 and #2



IRP INPUTS – SUMMER RAP

With T&D benefits treated as a reduction in cost

Year	RAP															
	Connected Thermostats		Water Heaters		Behavioral		Dynamic Rates		EV Managed Charging		Behind the Meter Storage		Data Centers - Base		C&I	
	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)
2027	4.85	\$242.35	2.30	\$1,058.80	6.30	\$86.55			0.74	\$760.97	0.37	\$1,993.83	1.87	\$90.41	11.75	\$80.29
2028	6.98	\$136.34	2.19	\$180.55	6.33	\$65.01			1.02	\$325.62	0.40	\$481.28	8.46	\$89.71	16.68	\$81.13
2029	9.15	\$130.41	2.09	\$187.37	6.35	\$67.34			1.39	\$311.72	0.45	\$506.15	20.80	\$91.58	21.75	\$82.91
2030	11.34	\$128.03	1.98	\$196.59	6.37	\$69.75	21.73	\$246.81	1.89	\$303.02	0.50	\$496.21	30.40	\$93.87	24.40	\$85.49
2031	13.56	\$127.61	1.88	\$206.84	6.39	\$72.23	36.64	\$146.23	2.55	\$304.79	0.56	\$496.38	34.75	\$97.44	24.70	\$88.48
2032	15.85	\$128.57	1.78	\$218.53	6.41	\$74.79	50.00	\$130.66	3.37	\$305.58	0.63	\$482.47	39.18	\$100.99	25.12	\$89.59
2033	18.26	\$130.41	1.67	\$232.03	6.42	\$77.45	58.46	\$117.82	4.32	\$306.19	0.67	\$446.27	43.68	\$104.57	25.54	\$92.50
2034	20.81	\$132.85	1.58	\$247.85	6.44	\$80.20	62.33	\$110.15	5.35	\$305.95	0.71	\$426.09	48.25	\$108.16	25.87	\$95.42
2035	23.50	\$135.72	1.47	\$266.68	6.46	\$83.06	63.68	\$108.08	6.38	\$305.76	0.72	\$312.37	52.88	\$111.75	26.13	\$98.35
2036	26.33	\$138.84	1.37	\$289.23	6.48	\$86.02	64.12	\$109.81	7.32	\$305.01	0.71	\$314.71	53.46	\$115.36	26.38	\$101.26
2037	29.24	\$142.14	1.27	\$316.41	6.50	\$89.08	64.35	\$113.19	8.10	\$305.47	0.71	\$327.15	53.98	\$118.96	26.83	\$105.34
2038	32.18	\$145.60	1.17	\$349.23	6.52	\$92.23	64.54	\$117.11	8.71	\$309.07	0.70	\$335.49	54.45	\$122.56	27.16	\$109.41
2039	35.06	\$149.18	1.07	\$389.10	6.54	\$95.49	64.73	\$121.24	9.13	\$314.19	0.70	\$359.19	54.88	\$126.17	27.47	\$113.48
2040	37.81	\$152.86	0.97	\$437.70	6.56	\$98.86	64.92	\$125.52	9.36	\$321.72	0.71	\$376.62	55.26	\$129.77	27.77	\$117.51
2041	40.35	\$156.69	0.87	\$497.38	6.58	\$102.33	65.11	\$129.92	9.74	\$319.40	0.72	\$398.68	55.58	\$133.38	28.03	\$121.53
2042	42.62	\$160.72	0.77	\$573.99	6.59	\$105.91	65.31	\$134.48	9.98	\$318.26	0.72	\$398.28	56.35	\$138.18	28.29	\$125.53
2043	44.60	\$164.98	0.68	\$666.58	6.61	\$109.63	65.50	\$139.20	10.08	\$318.24	0.73	\$416.73	57.07	\$142.98	28.51	\$129.52
2044	46.26	\$169.48	0.59	\$781.26	6.63	\$113.46	65.71	\$144.14	10.06	\$319.21	0.74	\$434.91	57.74	\$147.79	28.70	\$133.50
2045	47.61	\$174.22	0.51	\$921.58	6.65	\$117.41	65.93	\$149.17	9.94	\$321.39	0.74	\$434.53	58.33	\$152.59	29.06	\$138.63
2046	48.66	\$179.23	0.44	\$1,098.79	6.67	\$121.49	66.15	\$154.36	9.87	\$336.80	0.75	\$448.97	58.86	\$157.39	29.42	\$143.73

Each program will be considered separately for DR (no bundling)

IRP INPUTS – SUMMER MAP

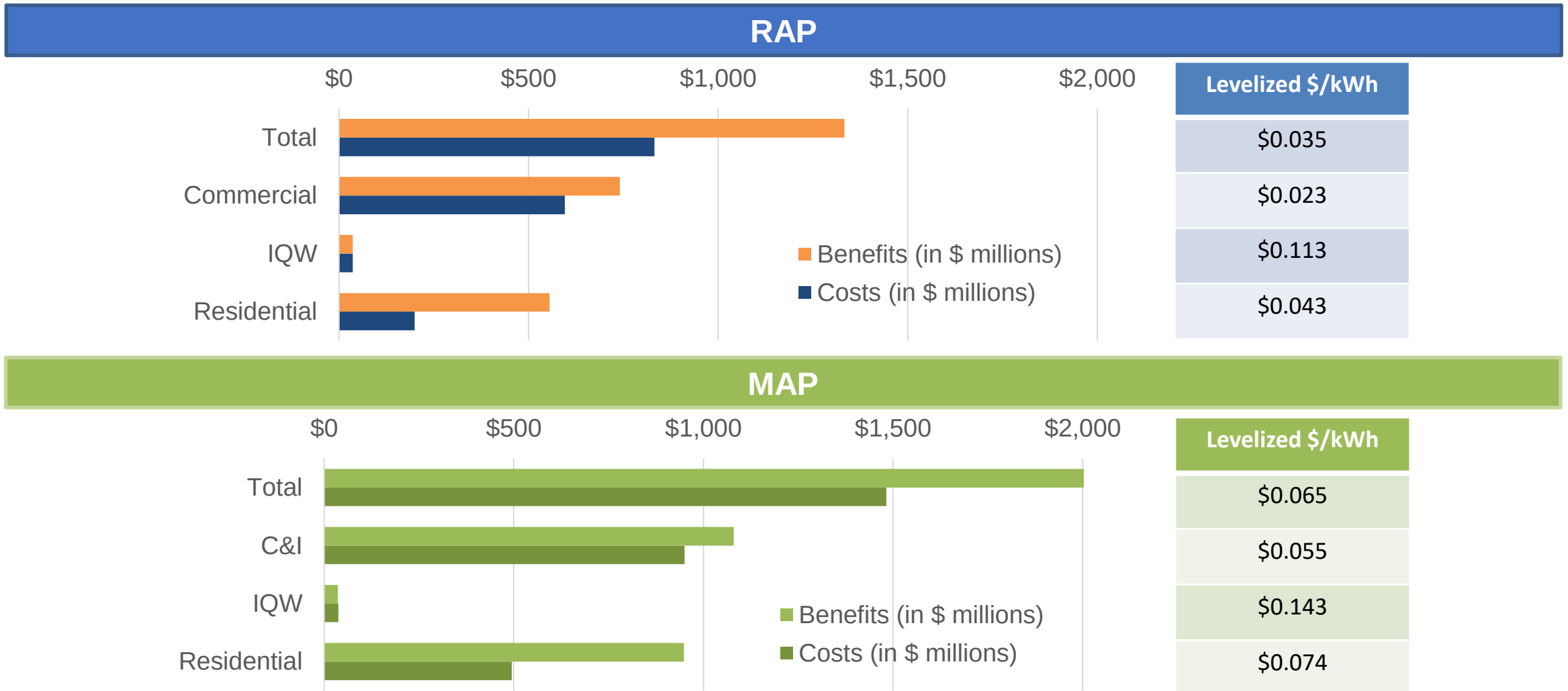
With T&D benefits treated as a reduction in cost

MAP															
Connected Thermostats		Water Heaters		Behavioral		Dynamic Rates		EV Managed Charging		Behind the Meter Storage		Data Centers - Base		C&I	
DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom \$/kW-yr)
7.29	\$427.69	4.61	\$924.71	11.21	\$78.76			1.31	\$308.62	0.75	\$2,926.77	2.98	\$140.51	20.04	\$149.05
11.40	\$260.06	4.38	\$216.14	11.25	\$67.73			1.80	\$212.14	0.81	\$552.33	13.61	\$143.37	28.43	\$153.17
15.28	\$241.25	4.16	\$224.55	11.29	\$70.17			2.48	\$214.79	0.91	\$609.55	33.67	\$147.84	37.05	\$157.84
18.95	\$233.27	3.95	\$234.78	11.32	\$72.69	27.73	\$657.92	3.36	\$219.55	1.01	\$618.03	49.50	\$152.57	41.54	\$162.97
22.43	\$230.57	3.74	\$246.27	11.36	\$75.29	46.76	\$280.98	4.53	\$228.61	1.13	\$645.13	56.21	\$157.35	42.02	\$168.33
25.84	\$231.45	3.53	\$259.51	11.39	\$77.97	63.79	\$201.19	5.98	\$238.75	1.26	\$652.66	62.97	\$162.12	42.70	\$172.57
29.24	\$234.49	3.31	\$275.02	11.42	\$80.75	74.59	\$129.87	7.68	\$250.03	1.35	\$573.98	69.79	\$166.91	43.40	\$177.87
32.70	\$238.94	3.10	\$293.51	11.45	\$83.63	79.53	\$80.53	9.51	\$262.35	1.43	\$555.16	76.66	\$171.70	44.18	\$184.36
36.24	\$244.21	2.88	\$315.98	11.48	\$86.62	81.25	\$56.01	11.35	\$275.85	1.44	\$316.34	84.16	\$177.70	44.83	\$190.86
39.85	\$249.89	2.66	\$343.49	11.52	\$89.71	81.81	\$48.42	13.01	\$290.49	1.43	\$300.26	85.20	\$183.70	45.46	\$197.35
43.44	\$255.68	2.44	\$377.56	11.55	\$92.91	82.10	\$47.95	14.40	\$306.58	1.42	\$313.23	86.15	\$189.70	46.03	\$203.81
46.97	\$261.60	2.21	\$420.01	11.59	\$96.21	82.35	\$49.44	15.48	\$324.54	1.41	\$326.68	87.01	\$195.70	46.39	\$210.27
50.31	\$267.41	1.98	\$473.50	11.62	\$99.63	82.59	\$51.35	16.23	\$344.23	1.42	\$356.82	87.81	\$201.70	46.97	\$217.91
53.34	\$273.15	1.76	\$541.68	11.66	\$103.15	82.84	\$53.36	16.65	\$365.92	1.43	\$387.24	88.51	\$207.71	47.51	\$225.52
55.98	\$278.94	1.53	\$630.16	11.69	\$106.78	83.08	\$55.43	17.31	\$375.89	1.45	\$411.88	89.62	\$214.91	47.99	\$233.10
58.18	\$284.93	1.31	\$751.74	11.72	\$110.54	83.33	\$57.58	17.73	\$386.43	1.45	\$400.96	90.65	\$222.11	48.46	\$240.68
59.89	\$291.24	1.09	\$912.88	11.76	\$114.43	83.57	\$59.81	17.92	\$397.52	1.46	\$434.95	91.60	\$229.31	48.87	\$248.24
61.14	\$297.95	0.89	\$1,136.24	11.79	\$118.44	83.85	\$62.40	17.88	\$409.16	1.48	\$455.99	92.47	\$236.52	49.42	\$256.97
61.93	\$305.03	0.71	\$1,452.68	11.83	\$122.58	84.12	\$64.78	17.67	\$421.38	1.49	\$457.27	93.23	\$243.72	49.93	\$265.68
62.30	\$312.66	0.54	\$1,936.68	11.86	\$126.86	84.40	\$67.24	17.55	\$436.11	1.50	\$473.50	94.36	\$252.12	50.43	\$274.36

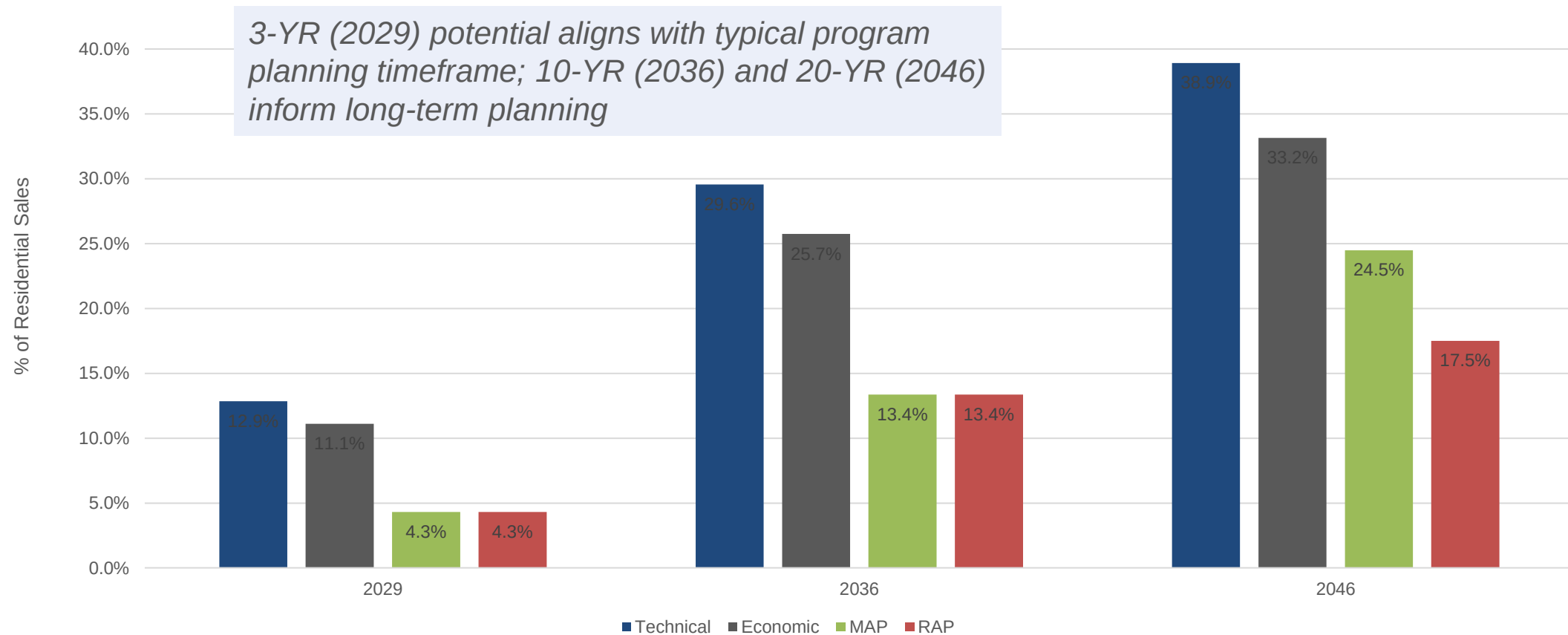
Each program will be considered separately for DR (no bundling)

NPV COSTS AND BENEFITS BY SECTOR

All values shown are 20-year net present values (NPV) in 2027\$ for the 2027-2046 time period



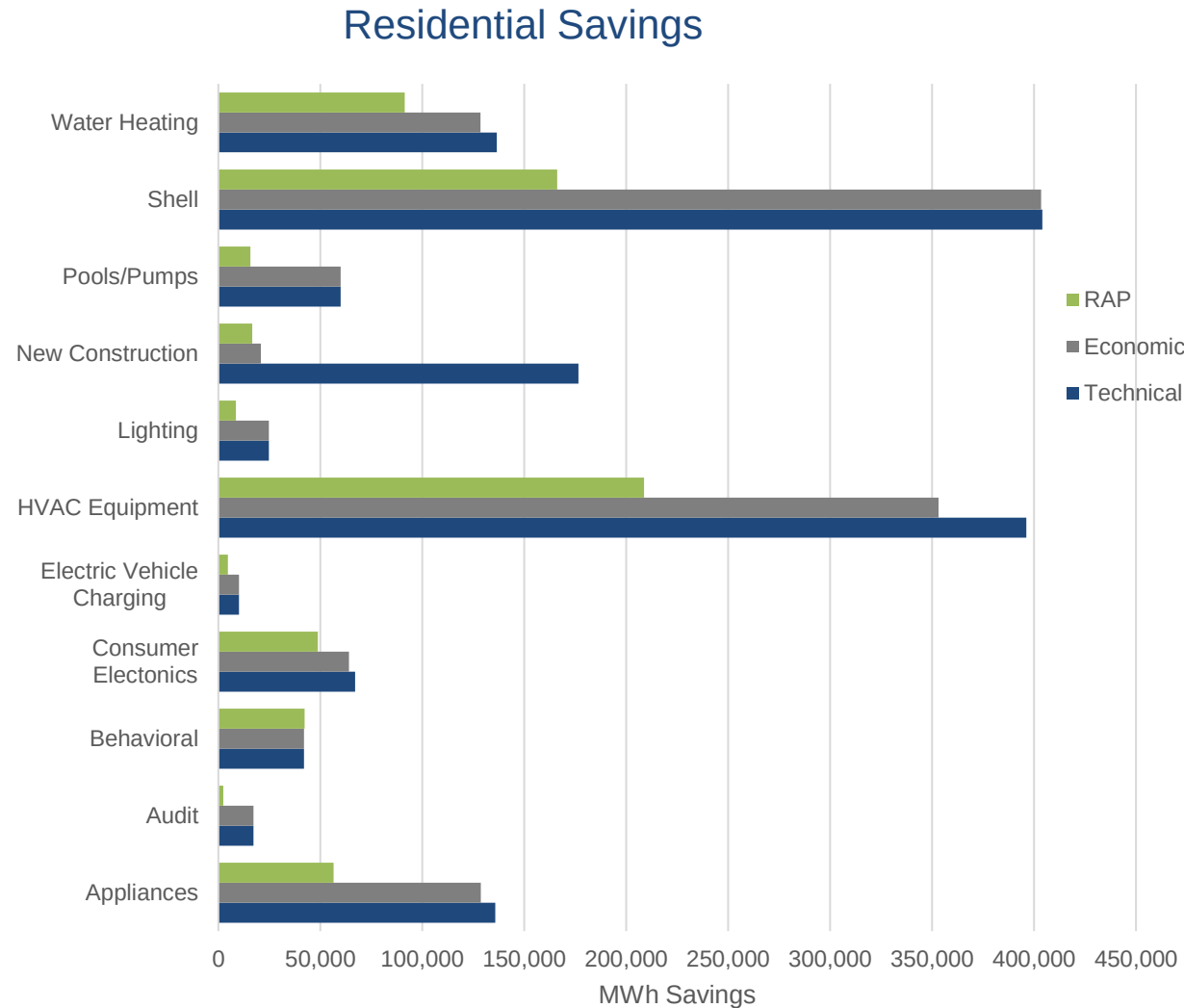
RESIDENTIAL ENERGY EFFICIENCY POTENTIAL SUMMARY



Results in chart show **cumulative annual** savings

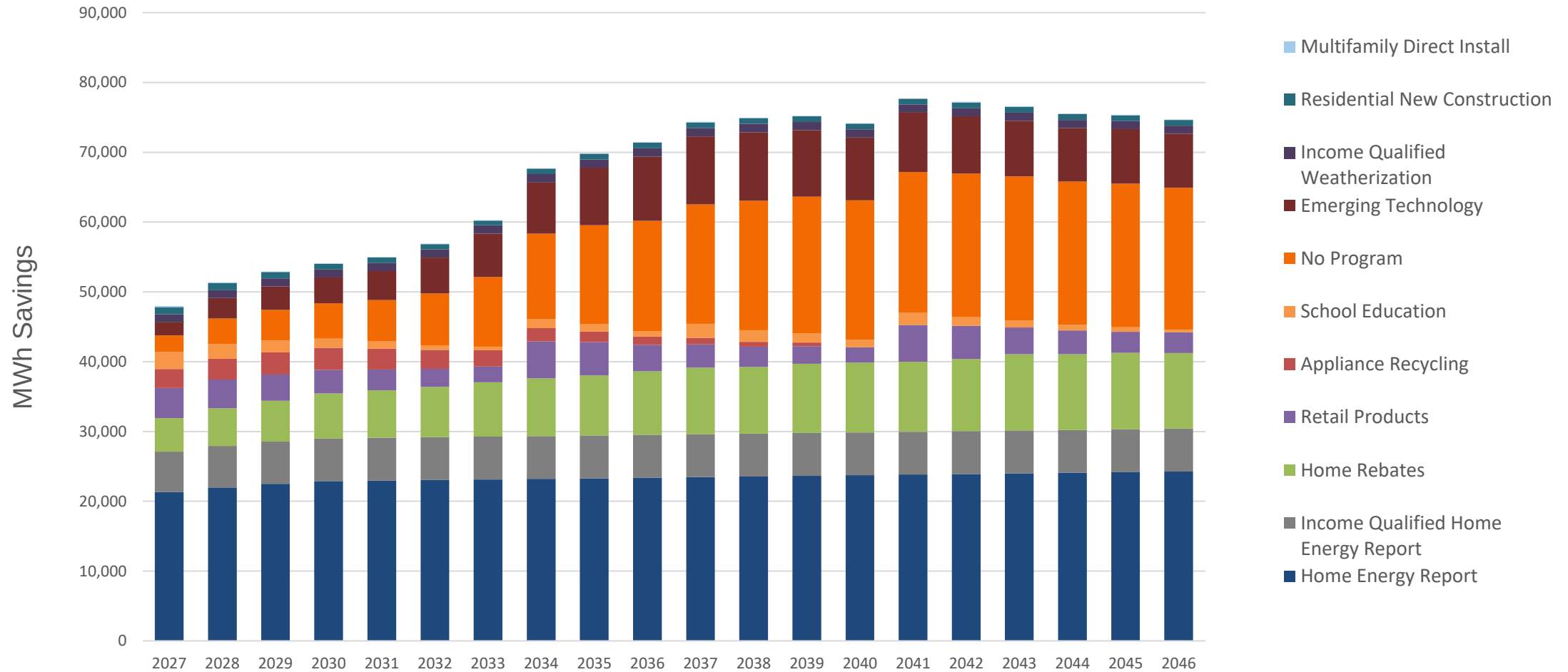
- Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)

20-YEAR CUMULATIVE ANNUAL RESIDENTIAL POTENTIAL BY END-USE



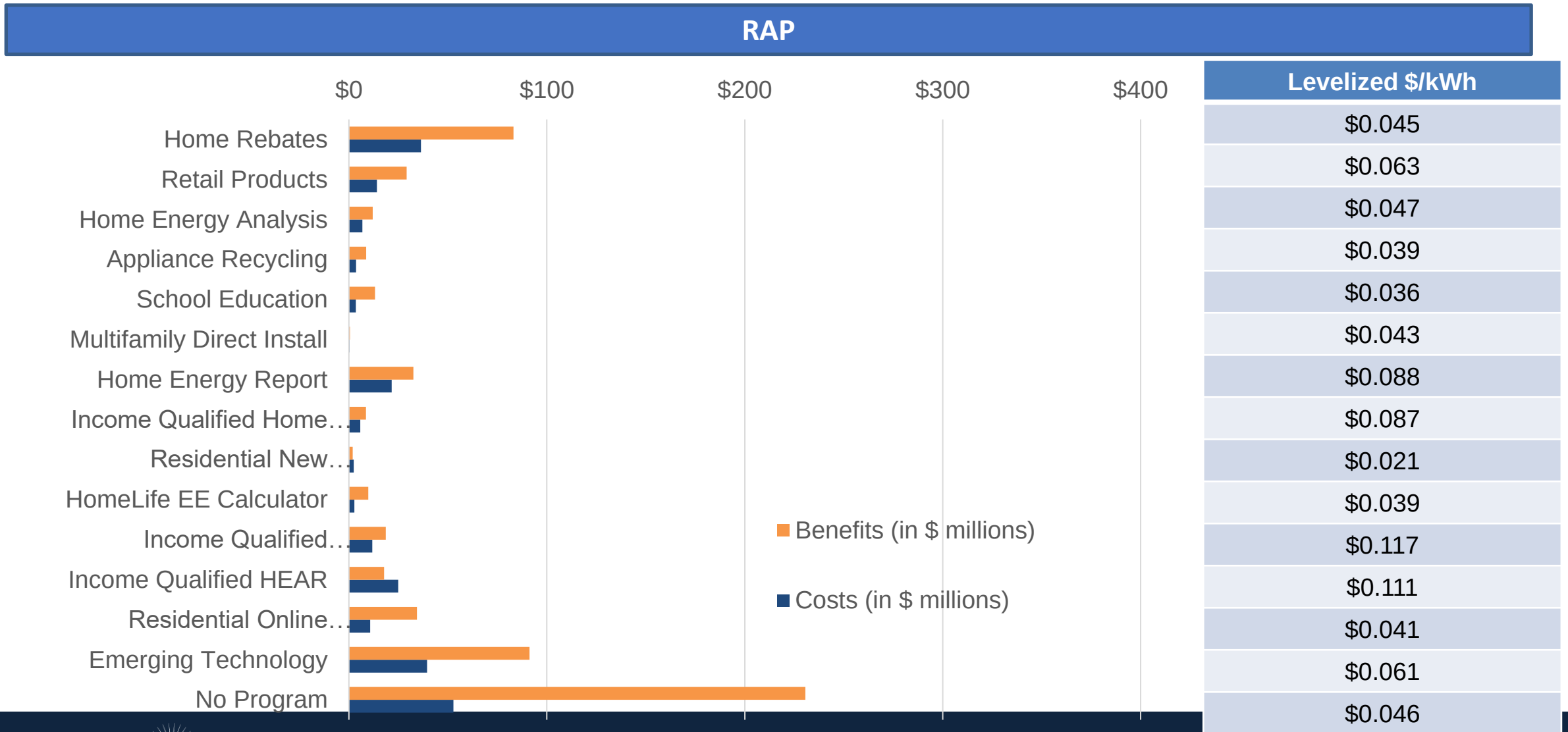
- Large amount of technical and economic potential in the Shell and HVAC Equipment end uses
- HVAC Equipment, Shell, Water Heating, Appliances, Consumer Electronics in the RAP level

RESIDENTIAL INCREMENTAL RAP BY PROGRAM TYPE



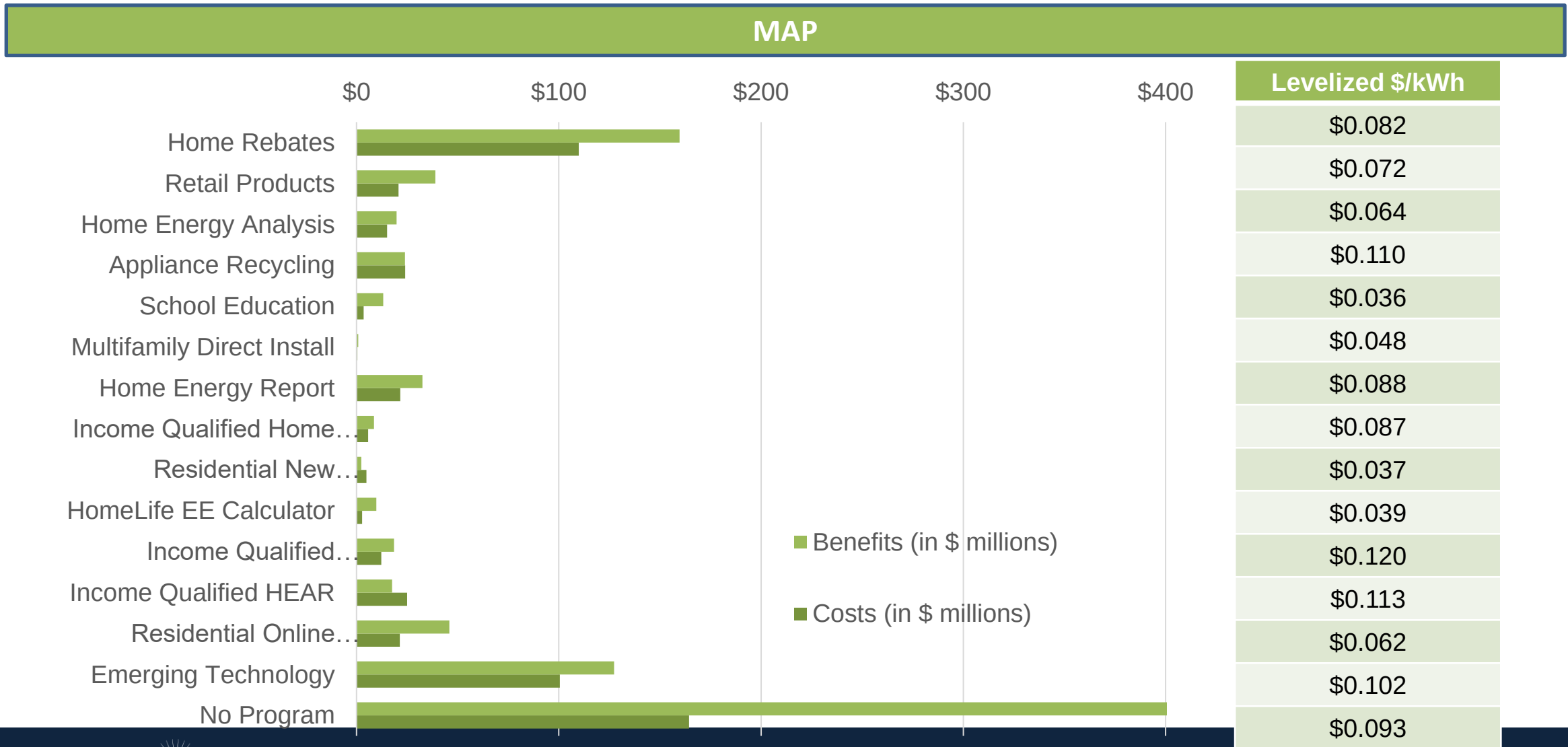
RESIDENTIAL NPV COSTS AND BENEFITS BY PROGRAM

All values shown are 20-year net present values (NPV) in 2027\$ for the 2027-2046 time period

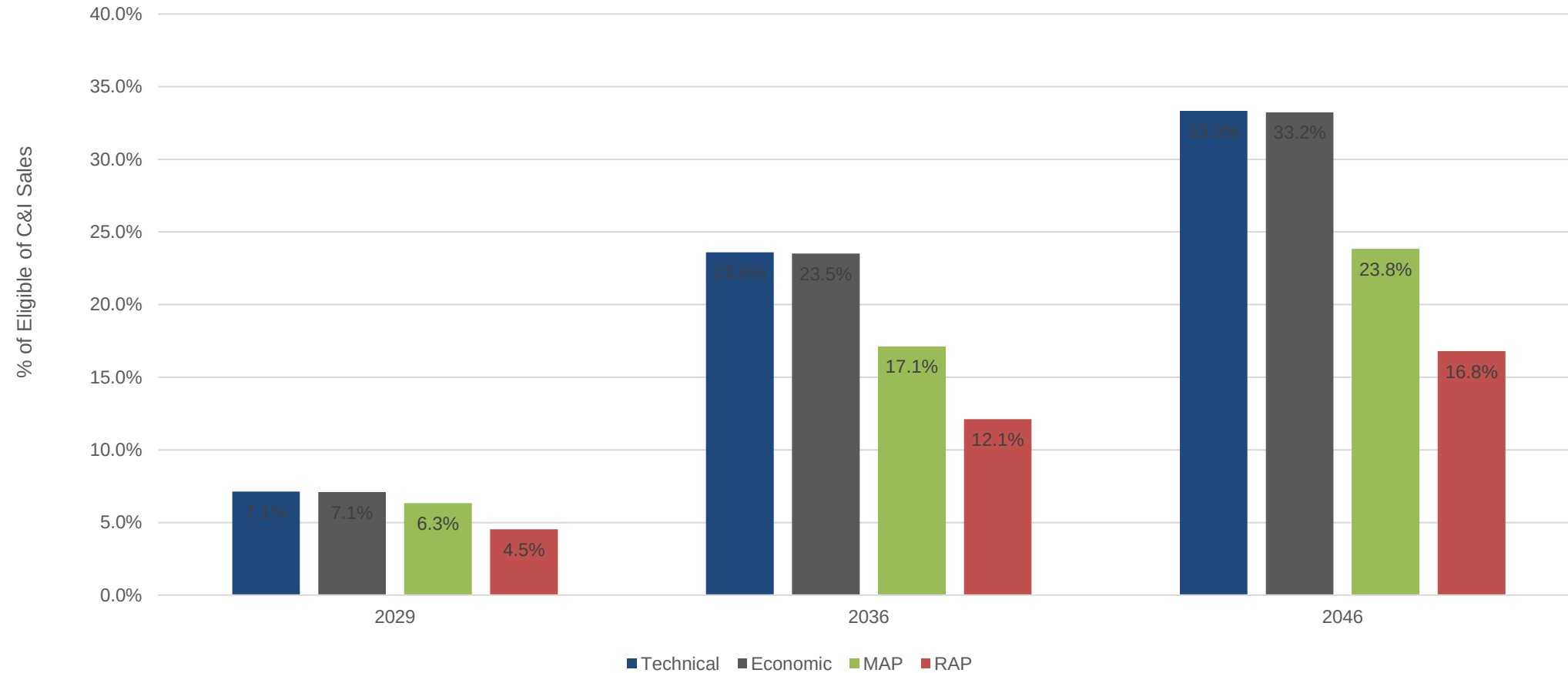


RESIDENTIAL NPV COSTS AND BENEFITS BY PROGRAM

All values shown are 20-year net present values (NPV) in 2027\$ for the 2027-2046 time period

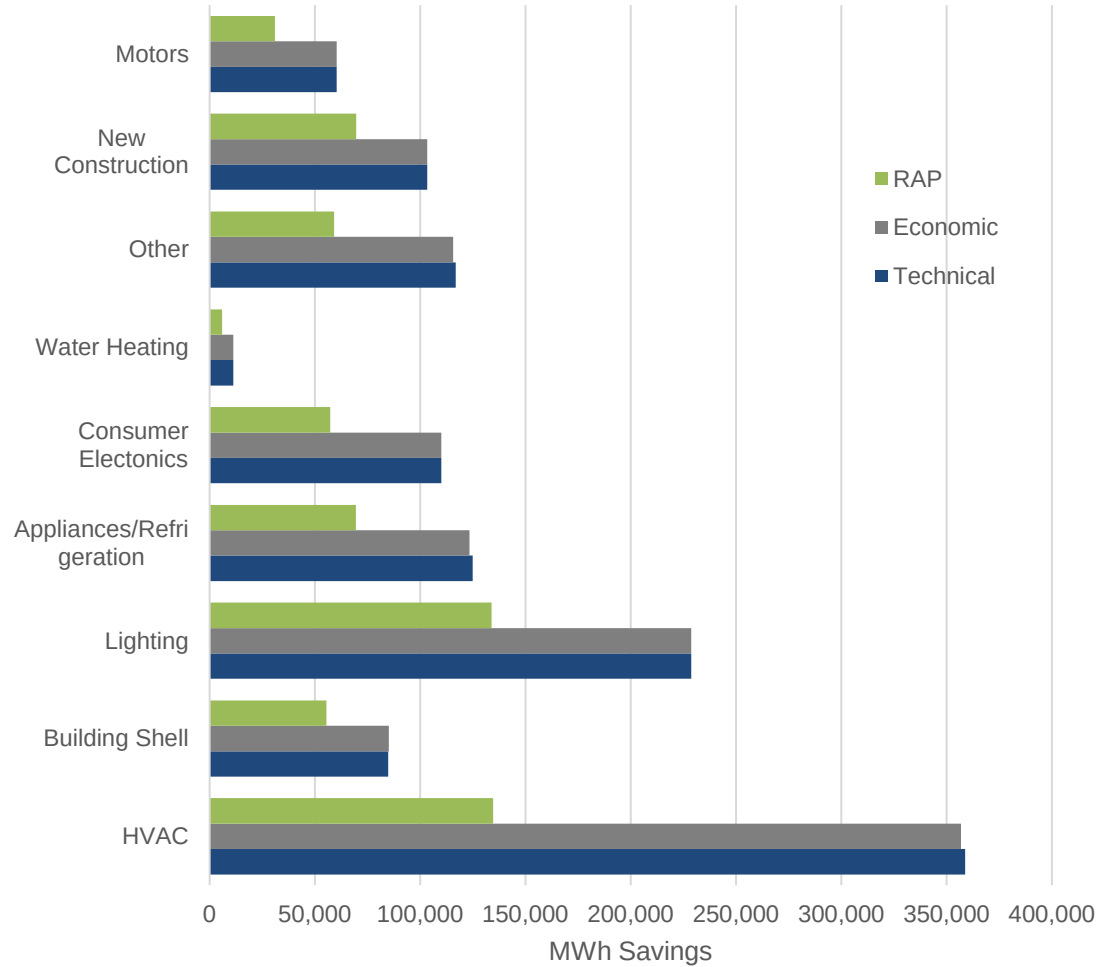


C&I ENERGY EFFICIENCY POTENTIAL SUMMARY

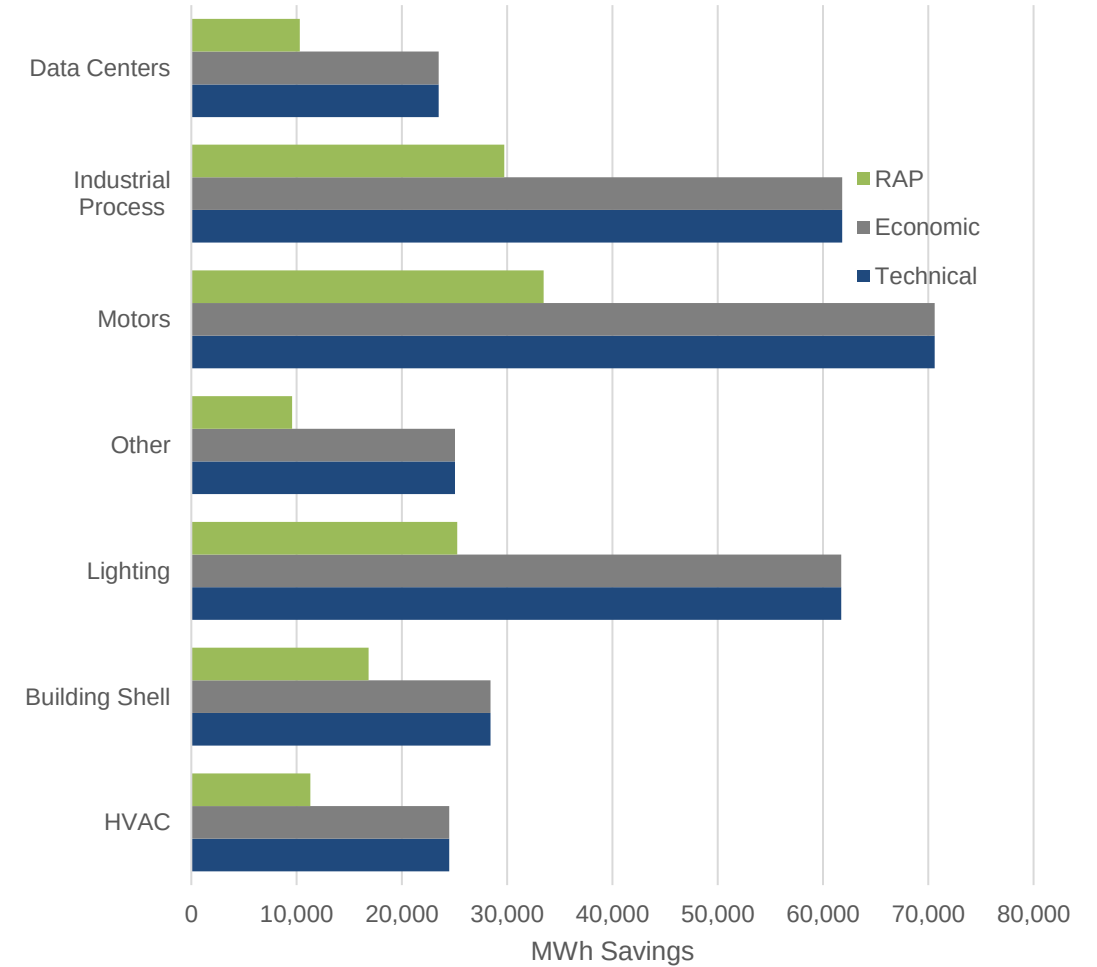


20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY END-USE

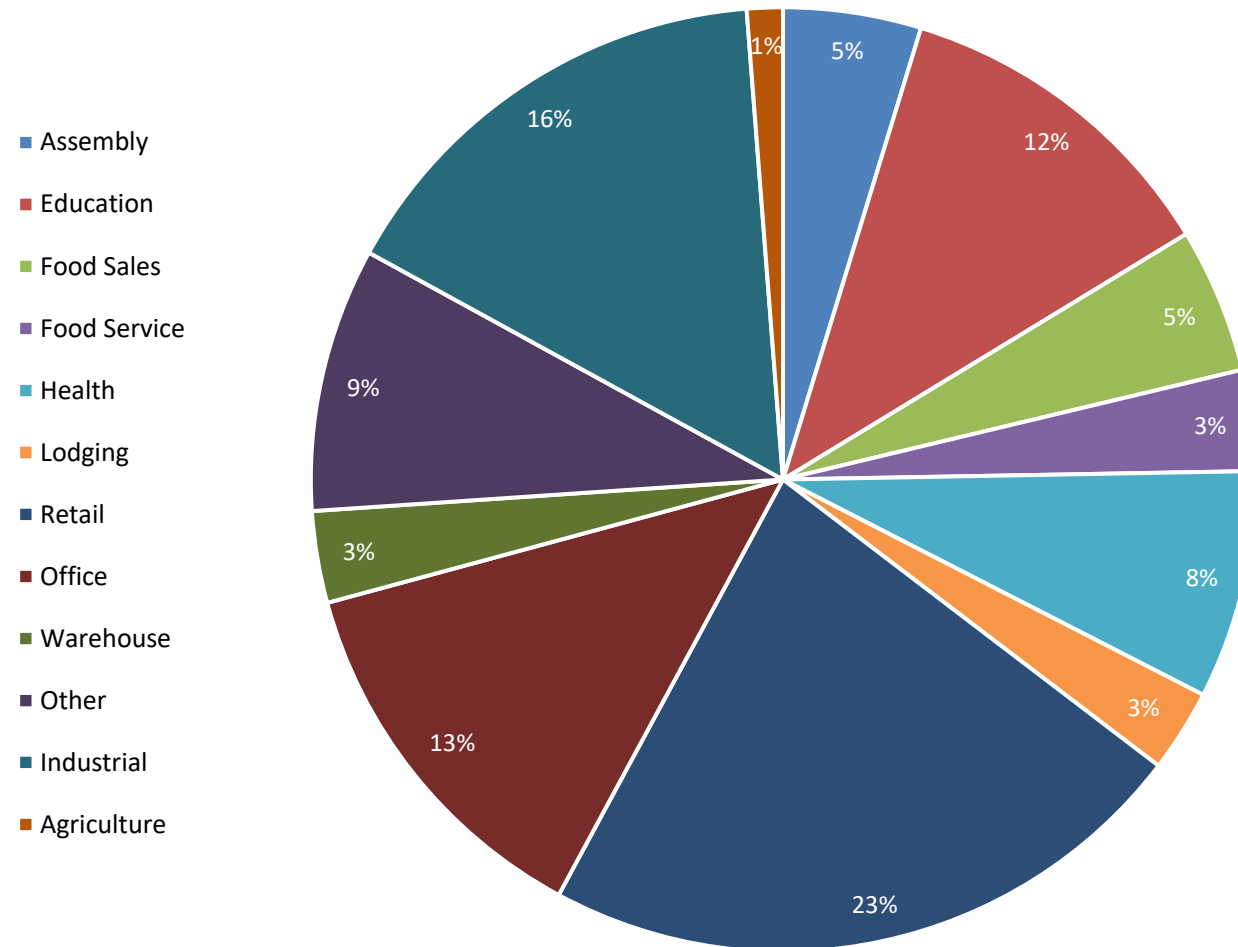
Commercial Savings



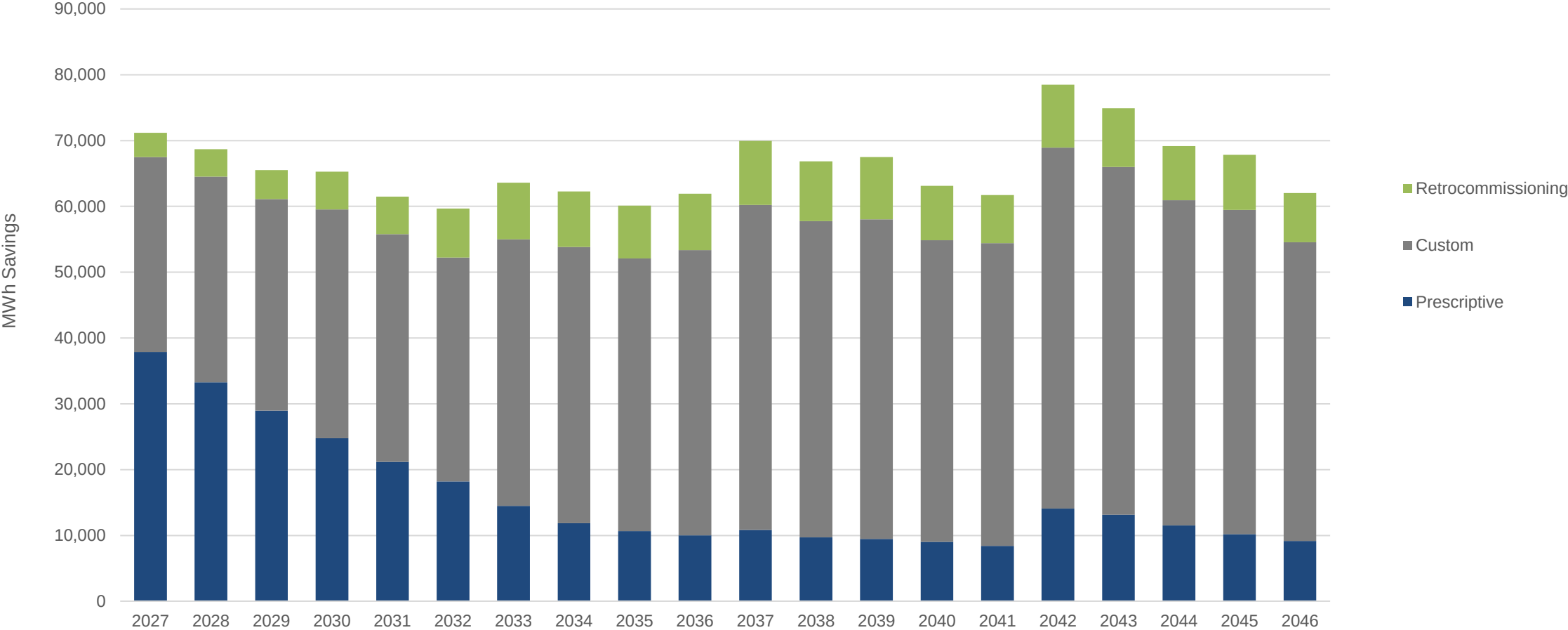
Industrial Savings



20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY BUILDING/INDUSTRY TYPE

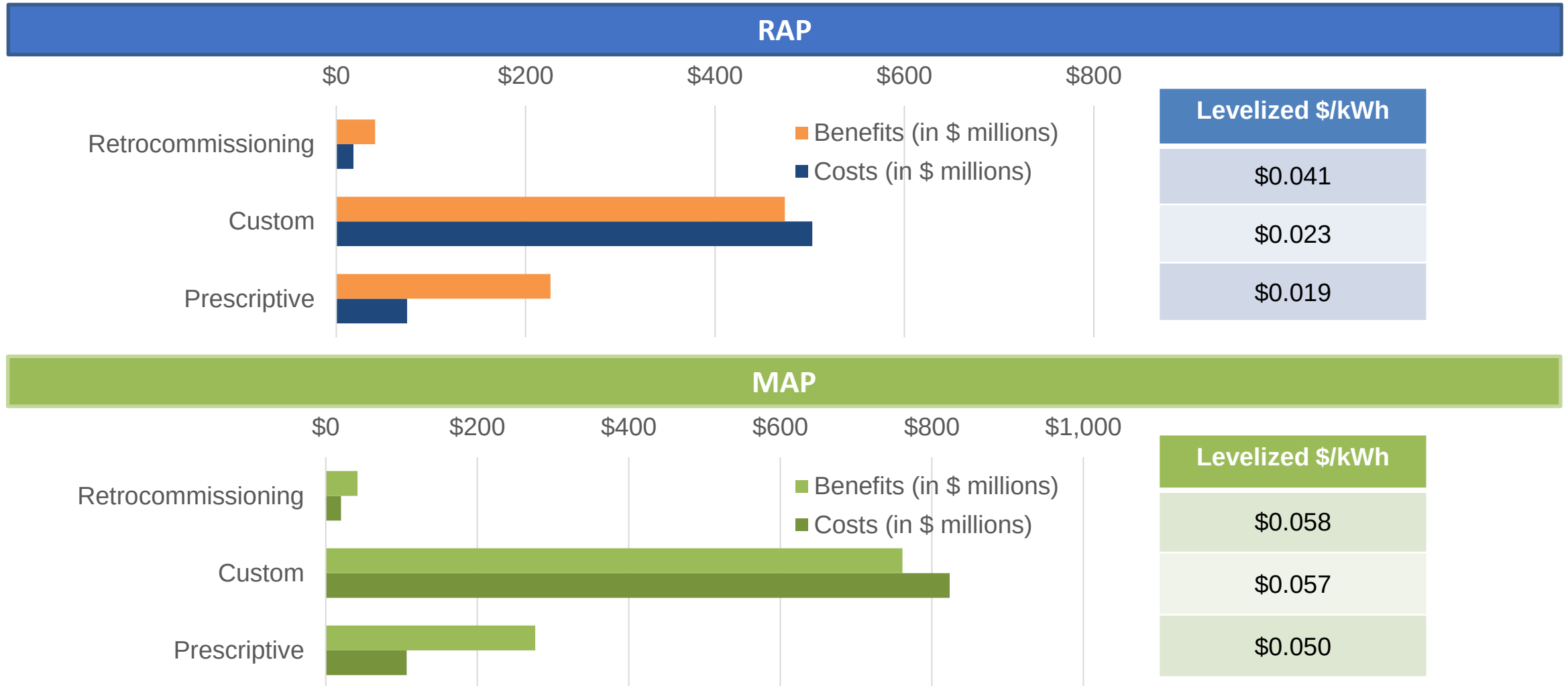


C&I INCREMENTAL RAP BY PROGRAM TYPE



C&I NPV COSTS AND BENEFITS BY PROGRAM

All values shown are 20-year net present values (NPV) in 2027\$ for the 2027-2046 time period



DYNAMIC PRICING MODELING CONSIDERED 11 DIFFERENT RATE VARIANTS

RAP and MAP were selected following discussions with NIPSCO's Oversight Board. RAP is a default time-of-use rate with enabling technology. MAP is default peak time rebates with a supplemental opt-in critical peak pricing offering.

	Metric	MAP				RAP				MAP		
		TOU Default No Tech Cost-Reflective	TOU Default w/ Tech Exaggerated	CPP Default No Tech Cost-Reflective	CPP Default w/ Tech Cost-Reflective	TOU Opt-In No Tech Cost-Reflective	TOU Opt-In w/ Tech Exaggerated	CPP Opt-In No Tech Cost-Reflective	CPP Opt-In w/ Tech Exaggerated	PTR Default No Tech Cost-Reflective	PTR Opt-In w/ Tech Exaggerated	CPP Opt-In w/ Tech against TOU
Summer	MW 2036 System-Level	12.8	63.4	41.0	82.5	9.4	11.6	13.7	35.6	64.1	32.4	18.4
	Levelized Cost (\$/kW-year)	\$284	\$154	\$92	\$121	\$84	\$126	\$63	\$62	\$167	\$95	\$119
	Modified Levelized Cost (\$/kW-year)	\$247	\$117	\$55	\$84	\$47	\$89	\$26	\$25	\$130	\$58	\$82
	Lifetime NPV of Benefits (2027\$)	\$24,734,871	\$122,084,675	\$79,000,133	\$158,870,626	\$18,133,661	\$22,404,711	\$26,426,888	\$68,470,281	\$123,436,554	\$62,405,663	\$35,411,430
	Lifetime NPV of Costs (2027\$)	\$27,594,148	\$73,847,902	\$28,435,944	\$75,532,393	\$6,002,291	\$11,082,157	\$6,532,943	\$16,564,731	\$80,866,163	\$23,290,842	\$16,564,731
	Participants in 2036	354,918	354,918	354,918	354,918	63,220	39,929	63,220	63,220	354,918	63,220	63,220
	UCT Ratio	0.90	1.65	2.78	2.10	3.02	2.02	4.05	4.13	1.53	2.68	2.14
	Average kW Savings per Participant	0.04	0.18	0.12	0.23	0.15	0.29	0.22	0.56	0.18	0.51	0.29
	Present Value of Net Benefits	-\$2,859,278	\$48,236,773	\$50,564,189	\$83,338,233	\$12,131,370	\$11,322,553	\$19,893,945	\$51,905,550	\$42,570,391	\$39,114,820	\$18,846,699
Winter	MW 2036 System-Level	5.9	29.3	19.0	38.2	4.4	5.4	6.3	16.4	29.6	15.0	8.5
	Levelized Cost (\$/kW-year)	\$614	\$333	\$198	\$262	\$182	\$272	\$136	\$133	\$281	\$177	\$257
	Modified Levelized Cost (\$/kW-year)	\$577	\$296	\$161	\$225	\$99	\$235	\$96	\$96	\$244	\$140	\$221
	Lifetime NPV of Benefits (2027\$)	\$11,437,695	\$56,453,390	\$36,530,591	\$73,463,647	\$8,385,218	\$10,360,202	\$12,220,104	\$31,661,464	\$57,078,515	\$28,857,113	\$16,374,662
	Lifetime NPV of Costs (2027\$)	\$27,594,148	\$73,847,902	\$28,435,944	\$75,532,393	\$6,002,291	\$11,082,157	\$6,532,943	\$16,564,731	\$63,006,927	\$20,109,665	\$16,564,731
	Participants in 2036	354,918	354,918	354,918	354,918	63,220	39,929	63,220	63,220	354,918	63,220	63,220
	UCT Ratio	0.41	0.76	1.28	0.97	1.40	0.93	1.87	1.91	0.91	1.43	0.99
	Average kW Savings per Participant	0.02	0.08	0.05	0.11	0.07	0.13	0.10	0.26	0.08	0.24	0.13
	Present Value of Net Benefits	-\$16,156,453	-\$17,394,511	\$8,094,648	-\$2,068,746	\$2,382,927	-\$721,956	\$5,687,161	\$15,096,733	-\$5,928,412	\$8,747,448	-\$190,069
Spring	MW 2036 System-Level	5.9	29.3	18.9	38.1	4.3	5.4	6.3	16.4	29.6	15.0	8.5
	Levelized Cost (\$/kW-year)	\$615	\$333	\$198	\$262	\$182	\$273	\$136	\$133	\$281	\$178	\$258
	Modified Levelized Cost (\$/kW-year)	\$578	\$297	\$161	\$225	\$99	\$236	\$96	\$96	\$244	\$141	\$221
	Lifetime NPV of Benefits (2027\$)	\$11,419,843	\$56,365,277	\$36,473,574	\$73,348,984	\$8,372,131	\$10,344,032	\$12,201,031	\$31,612,046	\$56,989,427	\$28,812,072	\$16,349,104
	Lifetime NPV of Costs (2027\$)	\$27,594,148	\$73,847,902	\$28,435,944	\$75,532,393	\$6,002,291	\$11,082,157	\$6,532,943	\$16,564,731	\$62,982,950	\$20,105,394	\$16,564,731
	Participants in 2036	354,918	354,918	354,918	354,918	63,220	39,929	63,220	63,220	354,918	63,220	63,220
	UCT Ratio	0.41	0.76	1.28	0.97	1.39	0.93	1.87	1.91	0.90	1.43	0.99
	Average kW Savings per Participant	0.02	0.08	0.05	0.11	0.07	0.13	0.10	0.26	0.08	0.24	0.13
	Present Value of Net Benefits	-\$16,174,305	-\$17,482,624	\$8,037,630	-\$2,183,408	\$2,369,839	-\$738,126	\$5,668,088	\$15,047,315	-\$5,993,523	\$8,706,679	-\$215,627
Fall	MW 2036 System-Level	11.8	58.4	37.8	76.0	8.7	10.7	12.6	32.8	59.0	29.9	16.9
	Levelized Cost (\$/kW-year)	\$308	\$167	\$99	\$131	\$91	\$137	\$68	\$67	\$175	\$101	\$129
	Modified Levelized Cost (\$/kW-year)	\$271	\$130	\$63	\$94	\$55	\$100	\$31	\$30	\$138	\$64	\$92
	Lifetime NPV of Benefits (2027\$)	\$22,779,523	\$112,433,606	\$72,754,994	\$146,311,544	\$16,700,154	\$20,633,568	\$24,337,783	\$63,057,551	\$113,678,616	\$57,472,354	\$32,612,077
	Lifetime NPV of Costs (2027\$)	\$27,594,148	\$73,847,902	\$28,435,944	\$75,532,393	\$6,002,291	\$11,082,157	\$6,532,943	\$16,564,731	\$78,239,965	\$22,823,051	\$16,564,731
	Participants in 2036	354,918	354,918	354,918	354,918	63,220	39,929	63,220	63,220	354,918	63,220	63,220
	UCT Ratio	0.83	1.52	2.56	1.94	2.78	1.86	3.73	3.81	1.45	2.52	1.97
	Average kW Savings per Participant	0.03	0.16	0.11	0.21	0.14	0.27	0.20	0.52	0.17	0.47	0.27
	Present Value of Net Benefits	-\$4,814,625	\$38,585,704	\$44,319,051	\$70,779,152	\$10,697,863	\$9,551,410	\$17,804,840	\$46,492,820	\$35,438,651	\$34,649,303	\$16,047,346

EXCEPTIONAL AT THE ESSENTIALS

Today and Always

BY FOCUSING ON THE ESSENTIALS TODAY, YOU ARE DIRECTLY ENABLING OUR STRATEGY



SAFETY



PEOPLE &
CULTURE



OPERATIONAL
EXCELLENCE



SUSTAINABILITY



CUSTOMER
EXPERIENCE



FINANCIAL
STEWARDSHIP



POLICY &
REGULATORY



INNOVATION &
TECHNOLOGY





Northern Indiana Public Service Company LLC
2024 Integrated Resource Planning
Public Advisory Meeting #3
SUMMARY

August 21, 2024

Welcome & Introduction

Tara McElmurry, Communications Manager, NiSource

Kick Off

Vince Parisi, President & COO, NIPSCO

Public Advisory Process and Responses to Second Stakeholder Meeting Comments

Abe Lang, Manager Strategy & Risk, NiSource

Abe Lang, Manager Strategy & Risk at NiSource, provided a summary of stakeholder comments from NIPSCO's second stakeholder meeting and reviewed the impacts of NIPSCO's updated reference case and emerging high case load forecasts on the project supply-demand balance. He then provided an overview of the key inputs and resource assumptions for the IRP's portfolio modeling and closed the section with a review of the scorecard being used in NIPSCO's 2024 IRP.

Developing the Demand Side Management (DSM Study)

Jeffrey Huber, Managing Director of Energy Efficiency, GDS

Jesse Smith, Partner, Demand Side Analytics

Jeffrey Huber, Managing Director of Energy Efficiency at GDS, provided an overview of NIPSCO's demand side management ("DSM") programs and the overall modeling approach for DSM in the 2024 IRP. He then defined the market potential study ("MPS") and provided a detailed review of the key inputs necessary to develop the MPS. Next, Mr. Huber provided an overview of the energy efficiency analysis methodology and a summary of energy efficiency potential across four evaluation categories: technical potential, economic potential, maximum achievable potential ("MAP"), and realistic achievable potential ("RAP"). He closed his section by summarizing cumulative annual potential by end-use across key categories.

Jesse Smith, Partner at Demand Side Analytics, then presented the demand response ("DR") program types evaluated in the DR MPS, summarized how key input assumptions were aligned with others from the IRP, and described how the overall methodologies were deployed for the study. He then reviewed key inputs and outputs associated with eight distinct DR programs along with key cost and benefit benchmarks. Jeffrey Huber then closed the section with a summary of how the DSM study outputs were aggregated and compiled for use in the broader IRP portfolio analysis.

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

- Is NIPSCO still open to stakeholder feedback on the previous slides where you were going through some of the different cost assumptions, as CAC is still waiting on the first big data dump with the modeling files and inputs? My broader point is that we have had a lot of information coming at us in terms of the data centers and also on the MPS front, and we are concerned about having enough time to provide good feedback, understanding how long it can take for NIPSCO to put things through its model, so I just wanted to flag that concern.
 - NIPSCO is open to feedback and has not changed the timing of anything related to its RFP as of now but we are open to feedback and will take your concerns into consideration.
- I am curious about what you are looking at on the Behavioral side? Do you have anything to share?
 - In the energy efficiency study, we are generally looking at one of the historical programs, the Home Energy Reports, which are reports that get offered to customers, telling them how they are using their energy and if their usage is high relative to other homes in the area with similar baseline usage and similar characteristics. These customers receive tips on how to impact their energy usage and also a statistical look at the savings associated with that. As AMI rolls out, there might be ways to use that and break away from the paper format. There are also some Behavioral DR options associated with that on the commercial and industrial (“C&I”) side.
- How exactly is that facilitated on the C&I side, regarding relative usage intensity from one manufacturer versus another manufacturer within the same subsector, how would that be measured and how would those tips improve the efficiency of the user base?
 - I will say that most of the Behavioral savings that we look at are on the Residential side but there is the Strategic Energy Management program on the C&I side, which is a similar type of program for building operators. This program does require going in and performing an audit, looking at usage and the current energy management systems they have. This is a much more extensive program than what I was talking about on the Residential side. This program is still in its early stages and is currently focused on the commercial sector, including grocery stores, schools and healthcare. The Industrial side of this program has been much harder for us to gain traction, as far as finding a core group to participate and benchmark and share best practices and other things of that nature.
- What was the thinking behind using the utility cost test (“UCT”) for screening instead of a total resource cost (“TRC”) test?
 - The UCT test is the primary test that is used in Indiana to look at energy efficiency measures. There are other tests out there like the TRC test, which looks at a little bit broader of a perspective. So there are other perspectives to look at but the UCT is the driving test in Indiana.
- Do any of NIPSCO’s C&I customers participate in MISO DR offerings? If so, does the current study factor in expected DR reductions from these customers in the future?
 - No, not within NIPSCO’s firm load obligation, but there is about 500-600 MW of interruptible, non-firm load amongst NIPSCO’s large industrial Rate 531 customers that participates in the MISO market.
- On the data center slide, there are a lot of unknowns about the details of NIPSCO’s expected data center load. Are there ways that we can throttle up or down the assumptions that you’ve included? How do we deal best with all of the uncertainty?
 - The key assumption that we have in there now is that a data center will have the same responsiveness as an industrial customer. A data center might even have more DR potential than an industrial customer. Right now, industrial demand

response in the Midwest is a mature market and so we are assuming that data centers will respond similarly, but there are unknowns and you would only want to refine these assumptions once you have a better idea of the type of data center load that is coming onto the system.

- You mentioned that you used the solar projection to input the universe of potential NIPSCO customers that could participate in this program (behind the meter solar plus storage) and you also mentioned that this has been informed historically by net metering and now excess distributed generation (“EDG”), which has much lower compensation. Would the outcome of the model change if there were more solar owners and could that potentially influence an argument for different compensation for solar, or other incentives, to get more solar deployed by customers to feed into a program like this?
 - It could, but one of the big things that this program has a hard time overcoming is the fixed costs, which would include things like a program manager, so when your participation is only in the hundreds, rather than the thousands, it is tough to overcome your fixed costs. We keyed off of the Reference Case solar forecast but there are alternative forecasts as well, which were presented in the last meeting, which included potential changes to policy design, such as a return to net metering. The Reference Case shows about half the penetration of the high-end alternative modeling. We would be willing to swap into the model the most aggressive solar forecast alternative for a sensitivity analysis, to see what the results look like and if that would be enough to overcome the fixed costs of the program to make it cost-effective.
- How much are the UCT results sensitive to the assumed 20-year time horizon used in the study?
 - I would say they are not terribly sensitive because everything gets a full life. There are certain capital investments, like a water heater, where we will let the measure stretch out past the 20-year horizon to the full life of the equipment, just so that you do not have any truncation. Everything gets the full life of the equipment, so the horizon is not really a factor.
- Are all DR reductions considered ‘net’?
 - Yes, they are.

Incorporating New Resource Options in the IRP and Overview of Portfolio Modeling Approach

- **DSM Bundles**
- **2024 Request for Proposals (RFP) Tranche Review**
- **Other Resource Options**

Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA

Patrick d’Entremont, Manager Planning Commercial Support, NIPSCO

Abe Lang provided a summary of the new resource types NIPSCO is evaluating as part of the 2024 IRP and their general availability and timing before handing the presentation to Pat Augustine, Vice President at CRA. Mr. Augustine first provided an overview of the DSM bundles to be deployed in the portfolio modeling, summarizing the potential and cost information reviewed in the earlier session by Mr. Huber and Mr. Smith. He explained that the IRP’s portfolio analysis would focus on the RAP bundles, with an Enhanced RAP analysis for energy efficiency and a MAP analysis for DR also to be performed via select sensitivity testing.

Patrick d’Entremont, Manager Planning Commercial Support at NIPSCO, then provided a review of NIPSCO’s 2024 RFP and a high-level summary of the offers received and their costs. Mr. Augustine then discussed how the RFP bids were turned into resource tranches for IRP portfolio modeling purposes and reviewed tranche-level detail for stand-alone storage, solar, hybrid solar

plus storage, and thermal and zonal resource credit (“ZRC”) tranches. He then provided a summary of additional generic supply-side resource options being evaluated in the IRP process and their associated costs and operational characteristics, including tax credit eligibility. Abe Lang then closed the section with an overview of the portfolio concepts that NIPSCO will be evaluating and the next steps in the analysis.

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

- How are the block sizes defined on the previous screen? Are they fixed or variable?
 - They are variable. Each tranche has a specific size based on the information provided via the RFP. We’re not dividing the bids into equal sets of megawatts, but we’re trying to organize them into natural characteristics and similar prices and attributes. So, as you can see on this slide, you’ve got a big tranche of storage PPA at about \$12 per kilowatt-month representing almost 770 megawatts, whereas the next tranche is at a higher price with a size of 200 megawatts. So, it is really dependent on the characteristics of the bids.
- Are these prices before or after the ITC/PTC?
 - These are prior to the ITC so all the prices that are noted here, at least for the ownership/sale tranches, are prior to any tax credits. So, this is the price that NIPSCO could acquire the project for, and then there would be a tax credit available for NIPSCO that would be taken after that acquisition price. So, the price is prior to any adjustment that could be made for the tax credit. I will note, however, that there is no further tax credit adjustments for the PPAs because the developer is presumed to monetize that tax credit as they would see fit. That net cost that is being offered in the RFP is essentially net of that tax credit. So, any PPAs here are post tax credit because we don’t have visibility on how the developer is monetizing or taking that tax credit or calculating it into their ultimate offer price.
- For the two ZRCs, I thought I heard you say that there is a financial product associated with them. Can you please elaborate on that?
 - Yes, the offer that is being made is for capacity or zonal resource credits (“ZRCs”). I think I used the term “financial” just to note that this type of transaction would be NIPSCO paying the counterparty for rights to the ZRCs without a specific asset commitment. Thus, they are essentially financial transactions for capacity credits.
- Oftentimes, when we see assumptions around these IRA credits with other IRPs, they tended to assume all or nothing depending on the scenario that we’re talking about. And, I think the reason for that is because that’s oftentimes what had happened in the past. Therefore, it is essentially two different scenarios: one where you’ve had the tax credits available throughout the study period, and then one would expire--let’s say 2035-- and they are not renewed. I do not see a scenario, or it does not seem likely to me that you would have a scenario, in which the value of the PTC and ITC would go down over a period of years. And then, CCS and Hydrogen credits would only be available over that short period of time. That seems like a big risk for these industries, and one I do not think would be politically possible. So, I think it makes more sense to extend these credits throughout the study period and then do a second sensitivity where you let them lapse, say in 2035.
 - This table here is aligned with the current law of the land, contingent upon certain nationwide CO2 emission reductions being achieved. I think you make a fair point that in the future, these could be further extended. I guess the long-term impacts may be somewhat muted in terms of what NIPSCO is looking at for its near and mid-term implementation plan. But, that’s a fair comment and it is actually an easier modeling setup to just extend them over the full horizon if you want to look at it that way. We will consider this during the portfolio modeling phase.

- In terms of your—I know we're here on the electric side, but for NiSource and your gas business—have you guys done any assuming that perhaps that gas customer base would move to electric?
 - We have an electrification set of assumptions, which we reviewed at our June stakeholder meeting on June 24. So that deck is out there, where you can see how much electrification we're assuming within NIPSCO service territory. But we do not do a detailed call out of what is moving from gas to electric, we just have broader assumptions around electrification as it relates to our electric service territory.

2024 Public Advisory Process Next Steps
Tara McElmurry, Communications Manager, NiSource

Closing & Stakeholder Comments

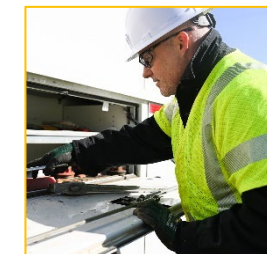
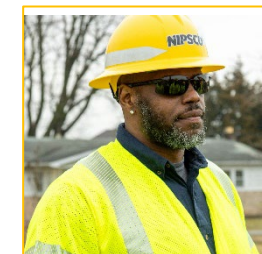
NIPSCO IRP Stakeholder Meeting - August 21, 2024

Contact First Name	Contact Last Name	Contact Email Address	Company
Michael	Hardie	michael.hardie@aes.com	AES Indiana
Will	Talbott	wtalbott@aypa.com	Aypa Power
Denise	Abdul-Rahman	denise@blacksunlight.org	Black Sun Light Sustainability
Levy	Agaronnik	levy.agaronnik@blackstone.com	Blackstone
Jeff	Lichy	jlichy@bluegrottocapital.com	blue grotto
Kristina	Wheeler	kwheeler@boselaw.com	Bose McKinney & Evans LLP
Marc	Blanchard	marc.blanchard@bp.com	bp
Taylor	Carpenter	tcarpenter@calfee.com	Calfee
Taylor	Carpenter	tcarpenter@calfee.com	Calfee
Jeremy	Martin	jeremy.martin@centerpointenergy.com	CenterPoint Energy
Leslie	Hamby	leslie.hamby@centerpointenergy.com	CenterPoint Energy
Matt	Rice	matt.rice@centerpointenergy.com	CenterPoint Energy
Aidan	Gibbons	agibbons@crai.com	Charles River Associates
Edwin	Moyo	emoyo@crai.com	Charles River Associates
Pat	Augustine	paugustine@crai.com	Charles River Associates
Robert	Lee	rlee@crai.com	Charles River Associates
Theodore	Why	twhy@crai.com	Charles River Associates
Edwin	Moyo	emoyo@crai.com	Charles River Associates International
Edwin	Moyo	emoyo@crai.com	Charles River Associates International
Tony	Kazakevicius	tkaz@anacostia.com	Chicago South Shore & South Bend RR
Ben	Inskeep	binskeep@citact.org	Citizens Action Coalition
Kerwin	Olson	kolson@citact.org	Citizens Action Coalition of IN
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana
Jesse	Smith	jsmith@demandsideanalytics.com	Demand Side Analytics, LLC
Alan	Mok	alan.mok@duke-energy.com	Duke Energy
Emma	Goodnow	emma.goodnow@duke-energy.com	Duke Energy
Emma	Goodnow	emma.goodnow@duke-energy.com	Duke Energy
Sameer	Doshi	sdoshi@earthjustice.org	Earthjustice
Anna	Sommer	asommer@energyfuturesgroup.com	EFG
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
Dan	Mellinger	dmellinger@energyfuturesgroup.com	Energy Futures Group
Donald JACK	Groves	poweresi@comcast.net	ENERGY SOUTHWEST INC.
Emily	Medine	emedine@evainc.com	Energy Ventures Analysis, Inc.
David	Jackson	djackson@flexgen.com	Flexgen, Inc.
Rachel	Wilson	rwilson@formenergy.com	Form Energy
Stephen	Rodocanachi	srodo@hartreepartners.com	Hartree Partners, LP
Stephen	Rodocanachi	srodo@hartreepartners.com	Hartree Partners, LP
Earl	M Miller	emiller@hilerindustries.com	Hiler Industries
Laura	Arnold	Laura.Arnold@IndianaDG.net	Indiana Distributed Energy Alliance
Laura	Arnold	Laura.Arnold@IndianaDG.net	Indiana Distributed Energy Alliance
Denise	Abdul-Rahman	darahman17@gmail.com	Indiana NAACP
April	Paronish	aparonish@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Greg	Krieger	gkrieger@oucc.in.gov	Indiana OUCC
Greg	Krieger	gkrieger@oucc.in.gov	Indiana OUCC
Ren	Norman	rnorman@urc.in.gov	Indiana Utility Regulatory Commission
Bradley	Borum	bborum@urc.in.gov	IURC
Bradley	Borum	bborum@urc.in.gov	IURC
Dale	Thomas	dthomas@urc.in.gov	IURC
Michael	Beeler	mbeeler@urc.in.gov	IURC
Bruna	da Silva	bruna.dasilva@keycaptureenergy.com	Key Capture Energy
Quinn	Beckham	quinn.beckham@keycaptureenergy.com	Key Capture Energy
Zico	Shaker	Zico.shaker@leewardenergy.com	Leeward Renewable Energy
Andy	White	andrew.white@leewardenergy.com	LRE
Joe	Motuliak	Joe.Motuliak@nexteraenergy.com	NextEra Energy
Zachary	Melda	zachary.melda@nexteraenergy.com	NextEra energy
Kay	Nelson	knelson@nwiforum.org	Northwest Indiana Forum
Kay	Nelson	Knelson@nwiforum.org	Northwest Indiana Forum
Suzanne	Escudier	suzanne.escudier@origisenergy.com	Origis Energy
Brian	Wright	brwright@oucc.in.gov	OUCC
Michael	Eckert	michael_eckert_911@comcast.net	OUCC

NIPSCO IRP Stakeholder Meeting - August 21, 2024

Michael	Eckert	meckert@oucc.in.gov	OUCC
Michael	Eckert	meckert@oucc.in.gov	OUCC
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Roopali	Sanka	rsanka@oucc.in.gov	OUCC
Richard	Pate	rgpate@pateassociates.com	Pate & Associates
Sunil	Maheshwari	mahesh67@purdue.edu	Purdue University
Carter	Scott	carter@rangerpower.com	Ranger Power LLC
Steve	Francis	Sierrasteve@comcast.net	SEED, Sustainable Energy & Economic Development
Zach	Schalk	Zach@solarunitedneighbors.org	Solar United Neighbors
Tim	Phillips	timphillips@purdue.edu	State Utility Forecasting Group
Tim	Phillips	timphillips@purdue.edu	State Utility Forecasting Group
David	Nderitu	nderitu@purdue.edu	SUFG
Jonathan	Burke	jburke@tac.nrg.com	Tactical Energy Group, Inc.
Micheal	Zhang	micheal.zhang@blackstone.com	The Blackstone Group
Amanda	Bersing	amanda.bersing@wellsfargo.com	Wells Fargo Securities
Alex	Cooley	acooley@nisource.com	
Alex	Cooley	acooley@nisource.com	
Levy	Agaronnik	lagaronnik@gmail.com	
Matthew	Peterson	Matthew.Peterson@duke-energy.com	
Steve	Francis	Sierrasteve@comcast.net	
Tim	Koenning	tkoenning@npca.org	

2024 NIPSCO Integrated Resource Plan
Fourth Stakeholder Advisory Meeting
October 8, 2024



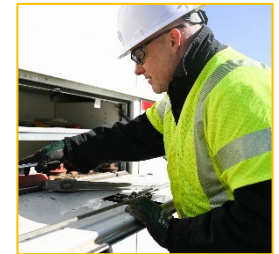
OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

2024 NIPSCO INTEGRATED RESOURCE PLAN

Fourth Stakeholder Advisory Meeting

October 8th, 2024
9 A.M.-1 P.M. CT





OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

WELCOME & INTRODUCTION

Tara McElmurry, Communications Manager, NiSource



FAIR OAKS FARMS



LOCATION OF
NEAREST EXIT

NEAREST PLACE TO
SEEK SHELTER

IN AN EMERGENCY,
WHO WILL DIAL 911

WHO WILL DIRECT THE
EMERGENCY RESPONDER

LOCATION OF THE
**AUTOMATED EXTERNAL
DEFIBRILLATOR (AED)**

WHO CAN
PERFORM CPR

OTHER **POTENTIAL HAZARDS**

Fire: Exit out any door that is furthest away from the fire. Gather as a group in the front parking lot – near the Tesla chargers.

Shelter: Restrooms, Jasper Ballroom (if closed), Employee Banquet Hallway.

AED Location: On the wall in the Employee Banquet Hallway.

Other Hazards: N/A

Dial 911:

Direct Responders:

CPR:

SAFETY MOMENT

FIVE TIPS TO IMPROVE YOUR MENTAL HEALTH



PHYSICAL

Exercise (think "baby steps!"... even a short walk helps), drink lots of water, see your doctor, eat foods that make you healthier, take time to stretch throughout the day



MINDFUL

Try yoga, meditation, make a list of three things you are grateful for, engage in random acts of kindness, spend time in nature or outdoors when possible



SOCIAL

Try something new and creative, call a friend/family member, send a card/note, organize lunch/dinner over video chat with friends or family



EMOTIONAL

Focus on the present moment, not what might happen; increase positive self-talk—be a cheerleader for yourself or a friend, find activities that relieve stress and tension, journal, try therapy or support group



MENTAL

Try something new and creative, call a friend/family member, send a card/note, organize lunch/dinner over video chat with friends or family



STAKEHOLDER ADVISORY MEETING PROTOCOLS

- **Your input and feedback is critical to NIPSCO's Integrated Resource Plan (IRP) Process.**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and overall IRP.**
- **We set aside time at the end of each section to ask questions.**
- **Your candid and ongoing feedback is key to this process:**
 - Please ask questions and make comments on the content presented
 - Please provide feedback on the process itself
- **Please identify yourself by name prior to speaking. This will help keep track of comments and follow up actions.**
- **If you wish to make a presentation during a meeting, please reach out to Erin Whitehead (ewhitehead@nisource.com).**

AGENDA

Time *Central Time	Topic	Speaker
9:00AM-9:05AM	Welcome & Introduction	Tara McElmurry, Communications Manager, NiSource
9:05AM-9:10AM	Kick Off	Vince Parisi, President & COO, NIPSCO
9:10AM-9:20AM	Recap of 2024 IRP Process	Abe Lang, Manager Strategy & Risk, NiSource
9:20AM-9:40AM	Public Advisory Process and Responses to Third Stakeholder Meeting Comments	Abe Lang, Manager Strategy & Risk, NiSource
9:40AM-11:00AM	Portfolio Development Process and NIPSCO Portfolio Construction	Abe Lang, Manager Strategy & Risk, NiSource Pat Augustine, Vice President, CRA
11:00AM-12:00PM	Lunch	
12:00PM-12:45PM	NIPSCO Portfolio Construction Continued and Next Steps	Abe Lang, Manager Strategy & Risk, NiSource Pat Augustine, Vice President, CRA
12:45PM – 1:00PM	Closing & Stakeholder Comments	



KICK OFF

Vince Parisi, President & COO, NIPSCO



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 490 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



PREMIER REGULATED UTILITY BUSINESS



NATURAL GAS

COLUMBIA GAS OF KENTUCKY

COLUMBIA GAS OF MARYLAND

COLUMBIA GAS OF OHIO

COLUMBIA GAS OF PENNSYLVANIA

COLUMBIA GAS OF VIRGINIA

NIPSCO GAS

NIPSCO

ELECTRIC

NIPSCO ELECTRIC

SIGNIFICANT SCALE ACROSS 6 STATES

~3.2M

GAS CUSTOMERS

~500K

ELECTRIC CUSTOMERS

NIPSCO PROFILE

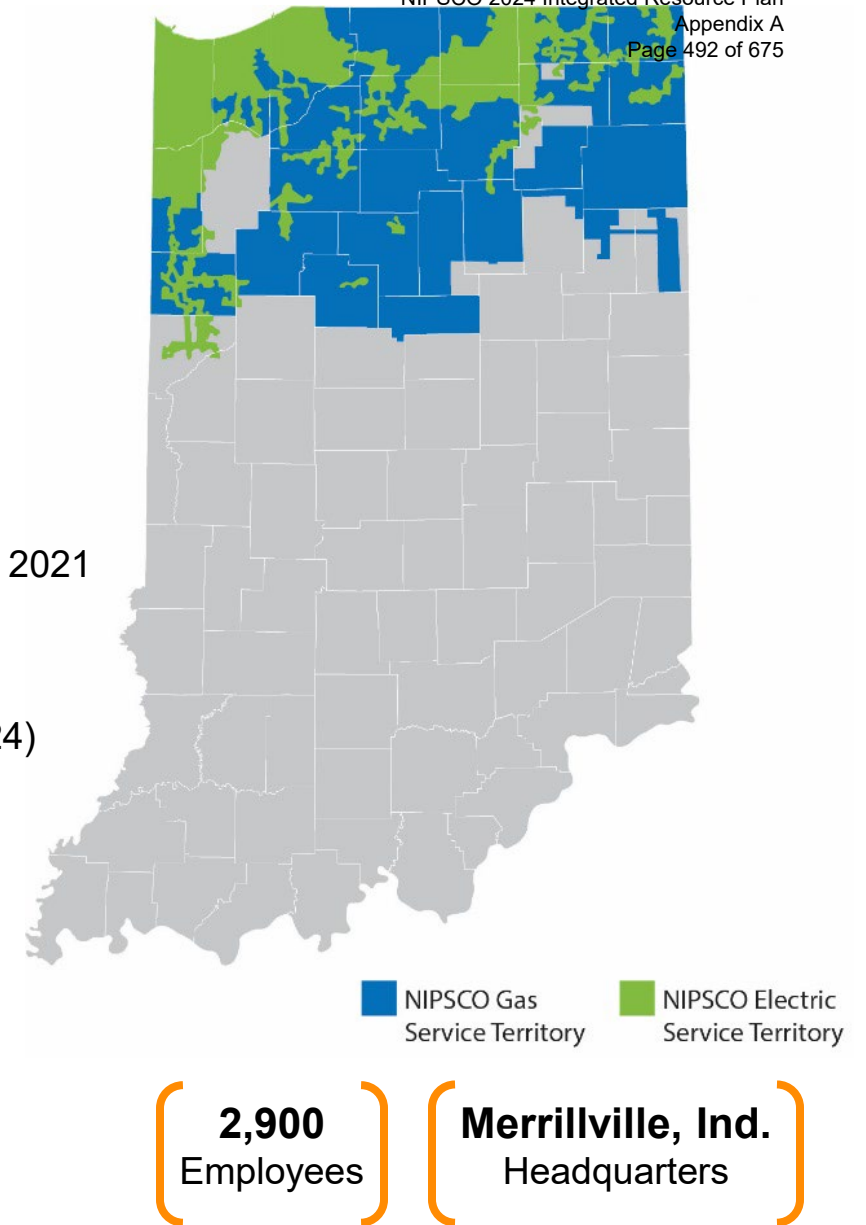
Working to Become Indiana's Premier Utility

Electric

- Approximately 500,000 Electric Customers in 20 Counties
- 3,625 MW Generating Capacity
 - 12 Electric Generating Facilities
(2 coal, 1 natural gas, 2 hydro, 4 wind, 2 solar, and 1 solar-plus-storage)
 - 1,000 MW of New Wind Energy
(Rosewater, Jordan Creek and Indiana Crossroads Wind I & II online in 2020 2021 and 2023)
 - 665 MW of New Solar Energy
(Dunns Bridge I, Indiana Crossroads solar online in 2023, and Cavalry in 2024)
- 12,800 Miles of Transmission and Distribution
 - Interconnect with 5 Major Utilities (3 MISO; 2 PJM)
 - Serves 2 Network Customers and Other Independent Power Producers

Natural Gas

- Approximately 900,000 Natural Gas Customers; 32 Counties
- 17,000 Miles of Transmission and Distribution Line/Main
- Interconnections with Seven Major Interstate Pipelines
- Two On-System Storage Facilities



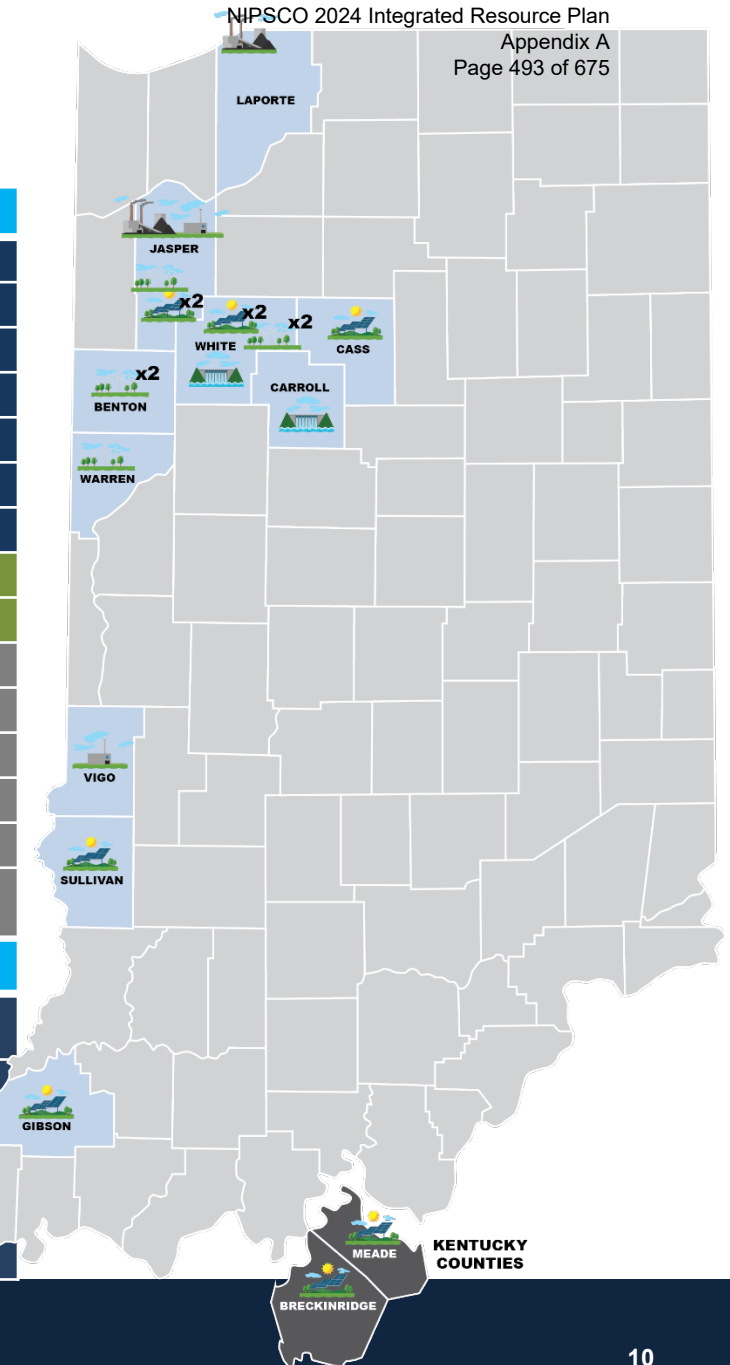
CURRENT & FUTURE NIPSCO GENERATION PORTFOLIO

Robust Renewable Investments in Indiana

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
CAVALRY SOLAR	200 MW + 45 MW BATTERY	WHITE	2024 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE (KY)	2025 CONSTRUCTION
DUNNS BRIDGE SOLAR II	435 MW + 56.25 MW BATTERY	JASPER	2025 CONSTRUCTION
GIBSON SOLAR	200 MW	GIBSON	2025 PRE-CONSTRUCTION
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025 CONSTRUCTION
TEMPLETON WIND	200 MW	BENTON	2025 PRE-CONSTRUCTION
CARPENTER WIND	200 MW	JASPER	2025 PRE-CONSTRUCTION
APPLESEED SOLAR	200 MW	CASS	2025 PRE-CONSTRUCTION
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PRE-CONSTRUCTION PENDING IURC APPROVAL

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2025 (COAL) – 2028 (NG)	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	563 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL

* Since 2018



PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and it's consistent with our goal to transition to the best cost and cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.



**Reliable and
sustainable**

**Flexibility for
the future**

**Local and statewide
economic benefits**

**Best plan for customers
and the company**



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

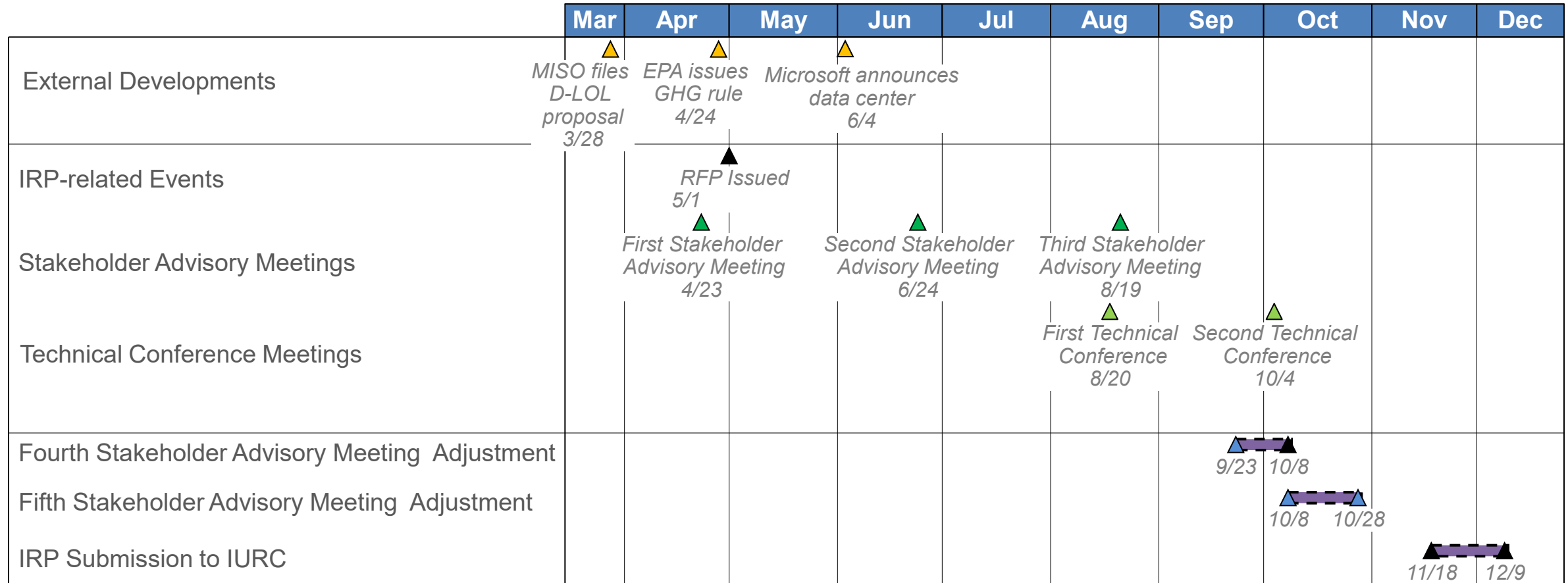
RECAP OF STAKEHOLDER PROCESS

Abe Lang, Manager Strategy & Risk, NiSource



2024 IRP STAKEHOLDER ADVISORY PROCESS TIMELINE & ADJUSTMENTS

The Indiana Commission has approved NIPSCO's request to adjust its 2024 IRP submission date from November 18th to December 9th. This will afford NIPSCO and stakeholders additional time to analyze the impacts of several significant external developments impacting long-term planning.





PUBLIC ADVISORY PROCESS AND RESPONSES TO THIRD STAKEHOLDER MEETING COMMENTS

Abe Lang, Manager Strategy & Risk, NiSource



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 497 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



SUMMARY OF STAKEHOLDER FEEDBACK SINCE MEETING #3

Category	Stakeholder Comments	NIPSCO Responses
Energy Efficiency	- How are efficiency variations between commercial and industrial customers considered in the analysis? - What was the thinking behind using the utility cost test (“UCT”) for screening instead of a total resource cost (“TRC”) test?	- Tracked through the Strategic Energy Management program on the C&I side, currently focused on grocery stores, schools and healthcare. The Industrial side is more difficult to benchmark among various industrial customer types. - The UCT test is the primary test that is used in Indiana to look at energy efficiency measures.
Demand Response	- Are there ways that we can throttle up or down the assumptions that you’ve included related to data center Demand Response (DR) offerings? - How much are the UCT results sensitive to the assumed 20-year time horizon used in the study? - Are all DR reductions considered ‘net’?	- Right now, industrial DR in the Midwest is a mature market and so we are assuming that data centers will respond similarly; we will continue to refine these assumptions once data center load comes onto the system. - UCT results are minimally impacted by the 20-year time horizon because all end-use appliances are assumed to operate for their full life. - Yes, all DR reductions are considered ‘net.’

SUMMARY OF STAKEHOLDER FEEDBACK SINCE MEETING #3

Category	Stakeholder Comments	NIPSCO Responses
RFP & Portfolio Development	- Are the capital costs assumed for new resources before or after the ITC/PTC? - Would NIPSCO consider a sensitivity where IRA tax credits are extended throughout the study period and then do a second sensitivity where you let them lapse, say in 2035? - Are there any assumptions related to electrification, including gas customer base migration to electric?	- Capital costs are assumed before the ITC/PTCs are factored in, but these will be included in all customer cost (NPVRR) analyses. - NIPSCO is open to considering a sensitivity with extended IRA tax credits, but believes its core scenarios cover the appropriate range with tax credits available for key resource decisions through the next decade. - NIPSCO's AER and AI scenarios include significant electrification growth. See slides 37 and 38 from Meeting #2. - NIPSCO provided portfolio modeling input files to requesting stakeholders.
IRP Timing	- Requested that NIPSCO extend the timing of our Integrated Resource Plan (IRP), given announcements by at least one other utility to extend their IRP into 2025, due to the significant increases in expected load. - Certain stakeholders requested additional technical meetings to discuss large load additions and portfolio impacts.	- NIPSCO extended its IRP by the following dates to allow for more time for analysis and stakeholder feedback on the significant large load additions to the portfolio: - Stakeholder Advisory meeting #4 moved from September 19th to October 8th - Stakeholder Advisory meeting #5 moved from October 8th to October 28th - IRP Report submission to the Indiana Utility Regulatory Commission (IURC) moved from November 18th to December 9th - NIPSCO has scheduled technical meetings with requesting stakeholders and will continue to do so upon request.



PORTFOLIO DEVELOPMENT PROCESS AND NIPSCO PORTFOLIO CONSTRUCTION

Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 500 of 675

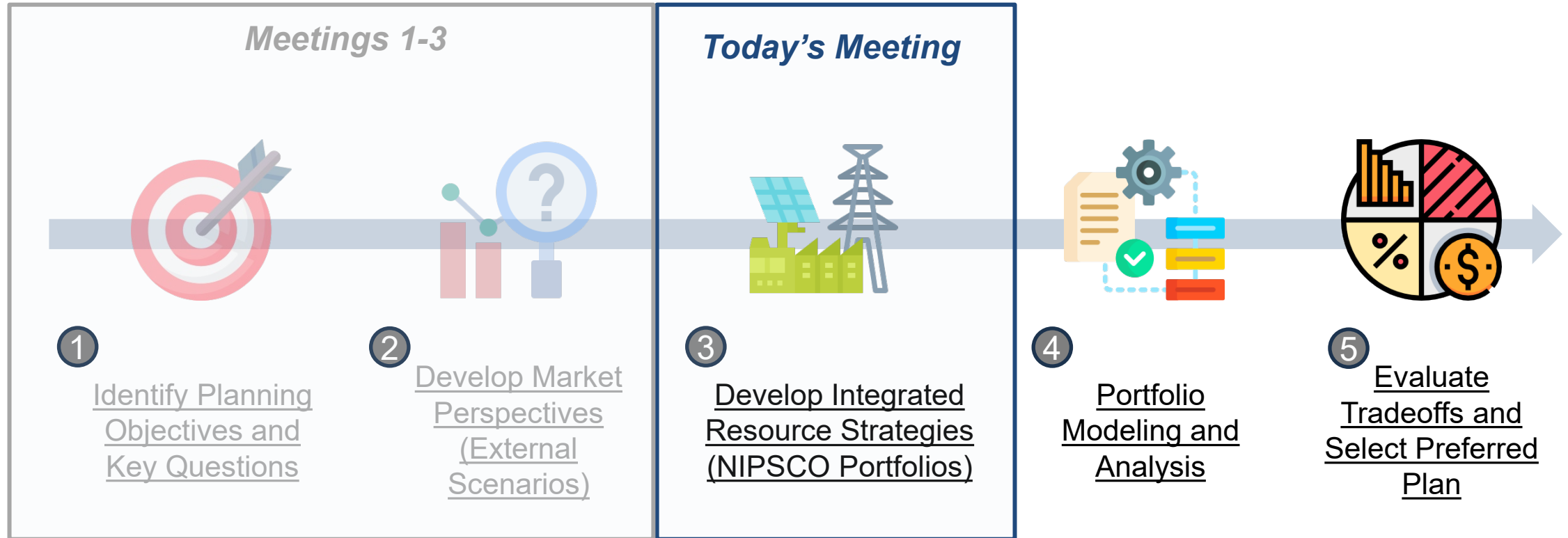


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

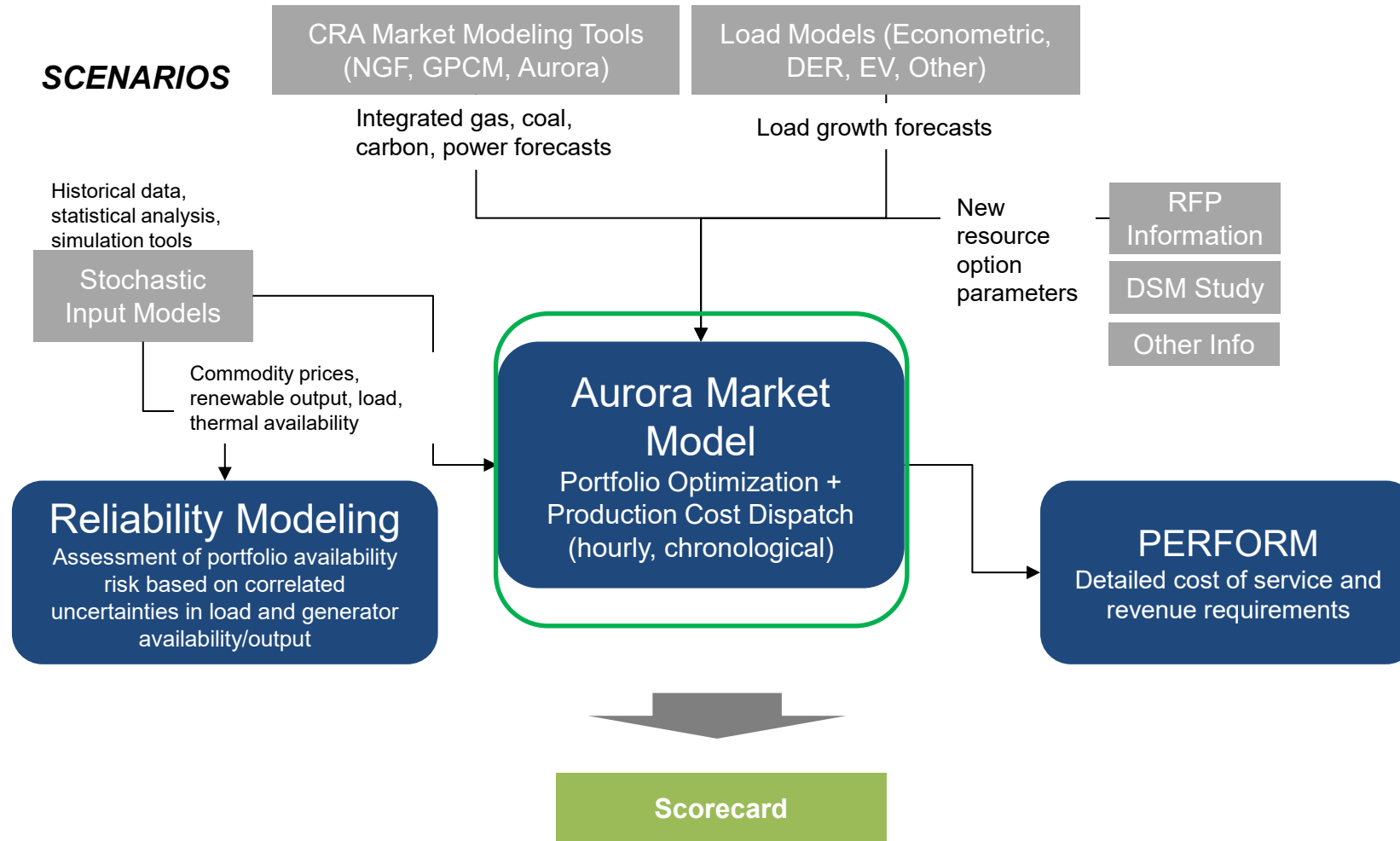


OVERALL RESOURCE PLANNING APPROACH

STEPS:



RESOURCE PLANNING APPROACH



- 1 Identify key planning questions and approach
- 2 Develop market perspectives (external scenarios)
- 3 Develop integrated resource strategies (NIPSCO portfolios)
- 4 Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- 5 Evaluate trade-offs and select preferred plan

KEY PORTFOLIO CONSTRUCTION CONSIDERATIONS

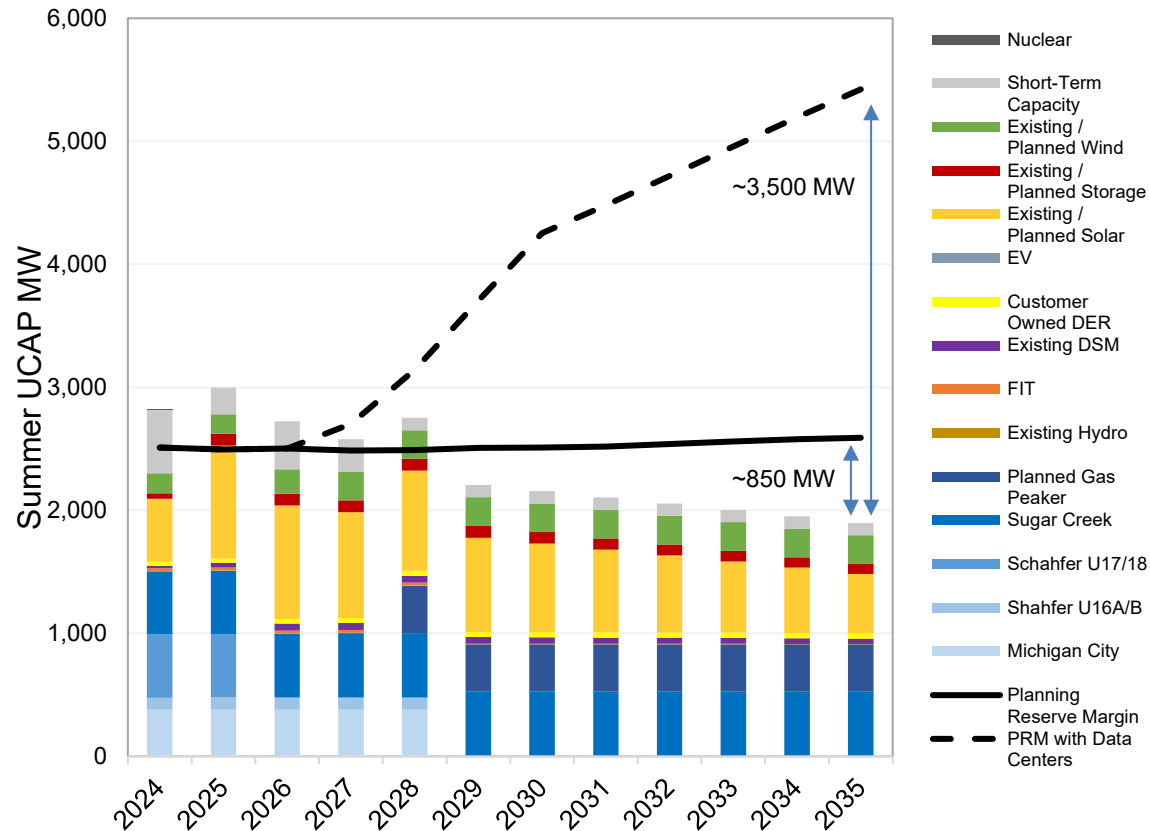
Portfolio development is based on a series of input assumptions and constraints

Key Inputs	Notes and Reminders
NIPSCO Existing Portfolio	Reviewed in Meeting #1
Reference Load Forecast	Reviewed in Meeting #1 and #2
Reference Case MISO Market Conditions	Reviewed in Meeting #2
MISO Market Rules (Current and D-LOL)	Reviewed in Meeting #2
New Resource Options (DSM, RFP, Other)	Reviewed in Meeting #3
Different Portfolio Concepts	Introduced in Meeting #3
Reserve Margin (MW) Constraints	Minimum Targets for all 4 Seasons
Energy Market Purchases/Sales	Target no more than ~20% annual purchases or ~10% annual sales (with seasonal input constraints)

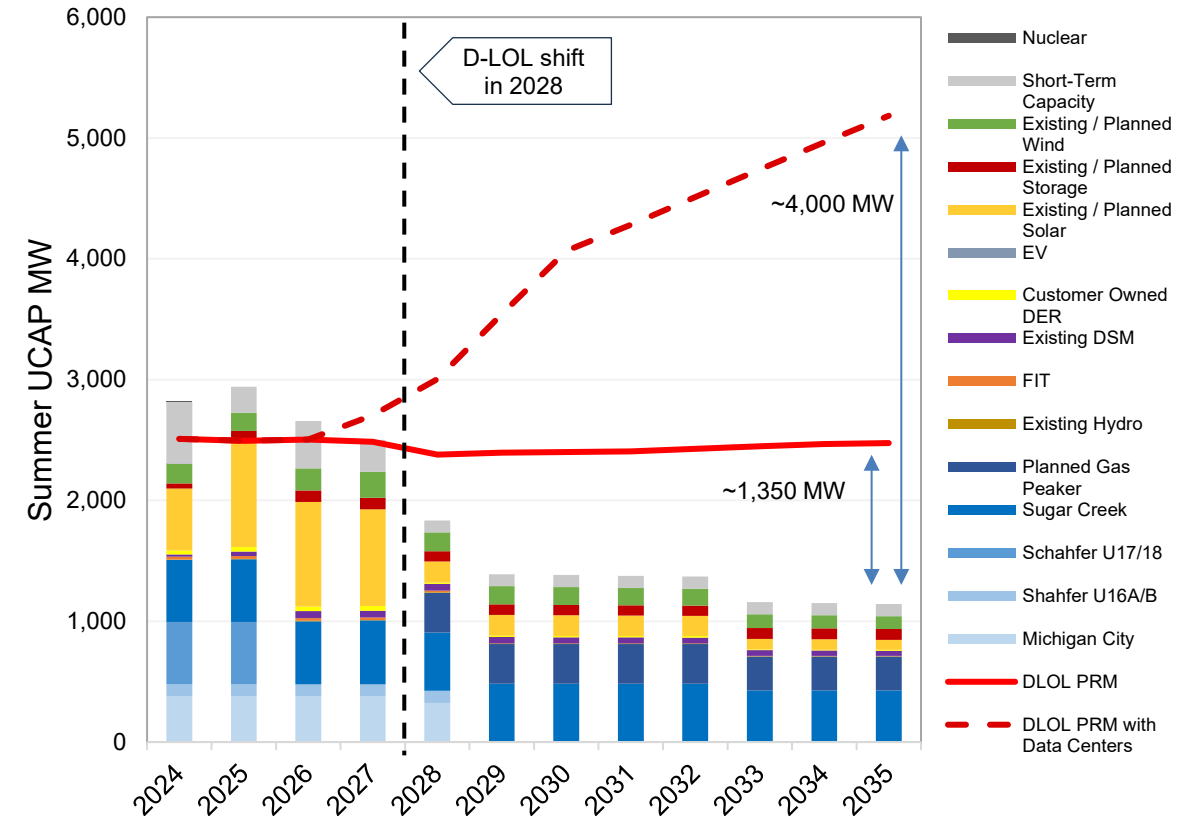
CURRENT NIPSCO CAPACITY POSITION – REFERENCE LOAD – SUMMER

Even without data center demand, NIPSCO would need ~850 MW of additional accredited capacity for the summer season by 2035; MISO’s proposed D-LOL rule could amplify this need by up to an incremental 500 MW.

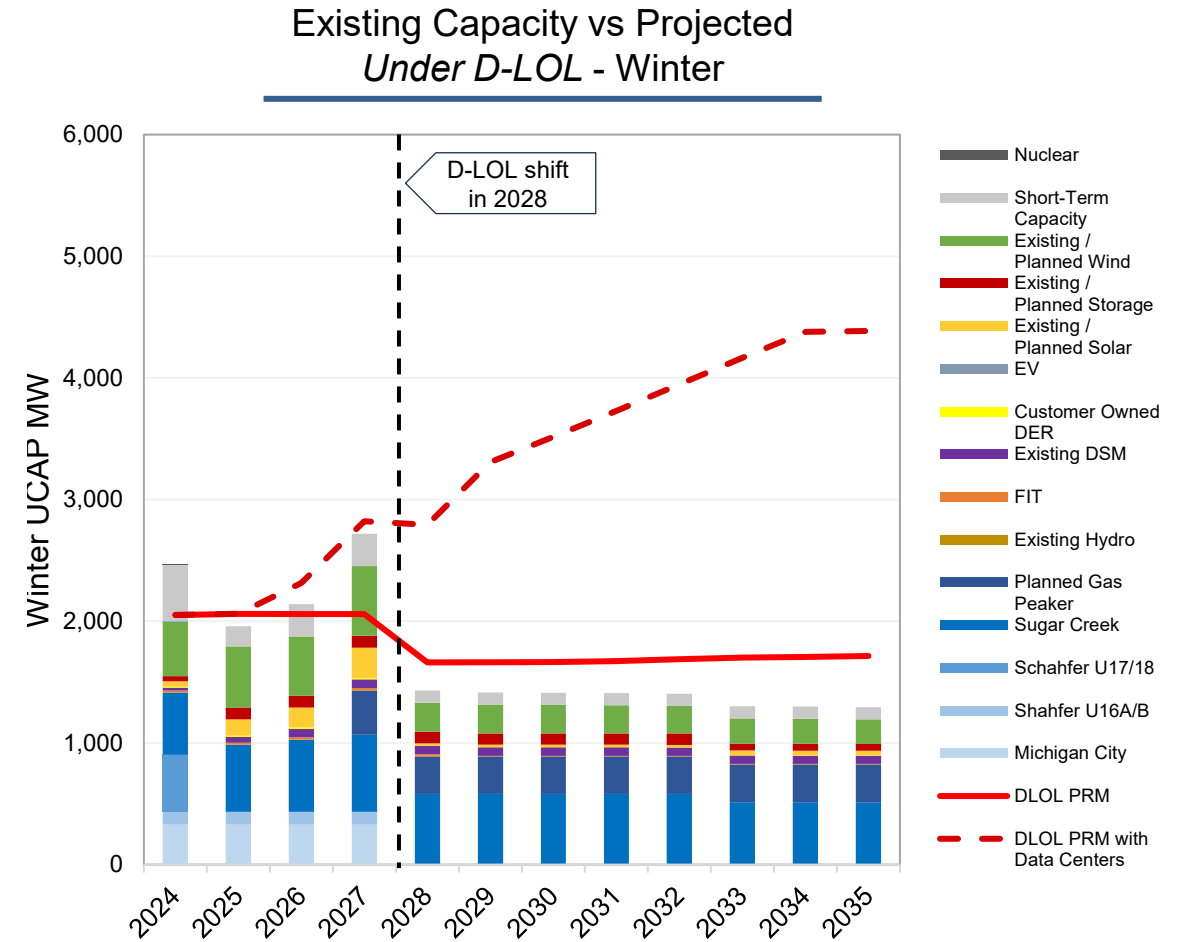
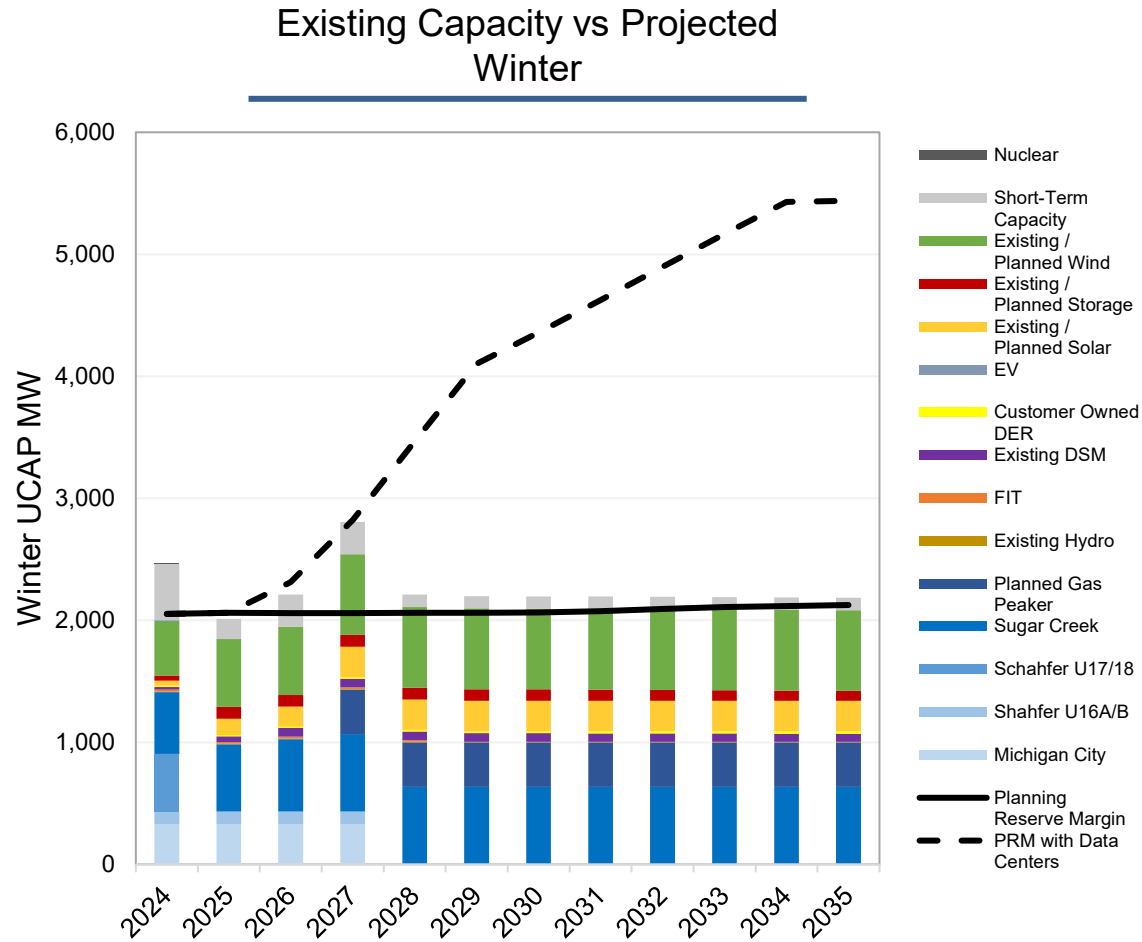
Existing Capacity vs Projected Summer



Existing Capacity vs Projected Under D-LOL - Summer



CURRENT NIPSCO CAPACITY POSITION – REFERENCE LOAD – WINTER



NEW RESOURCE OPTIONS

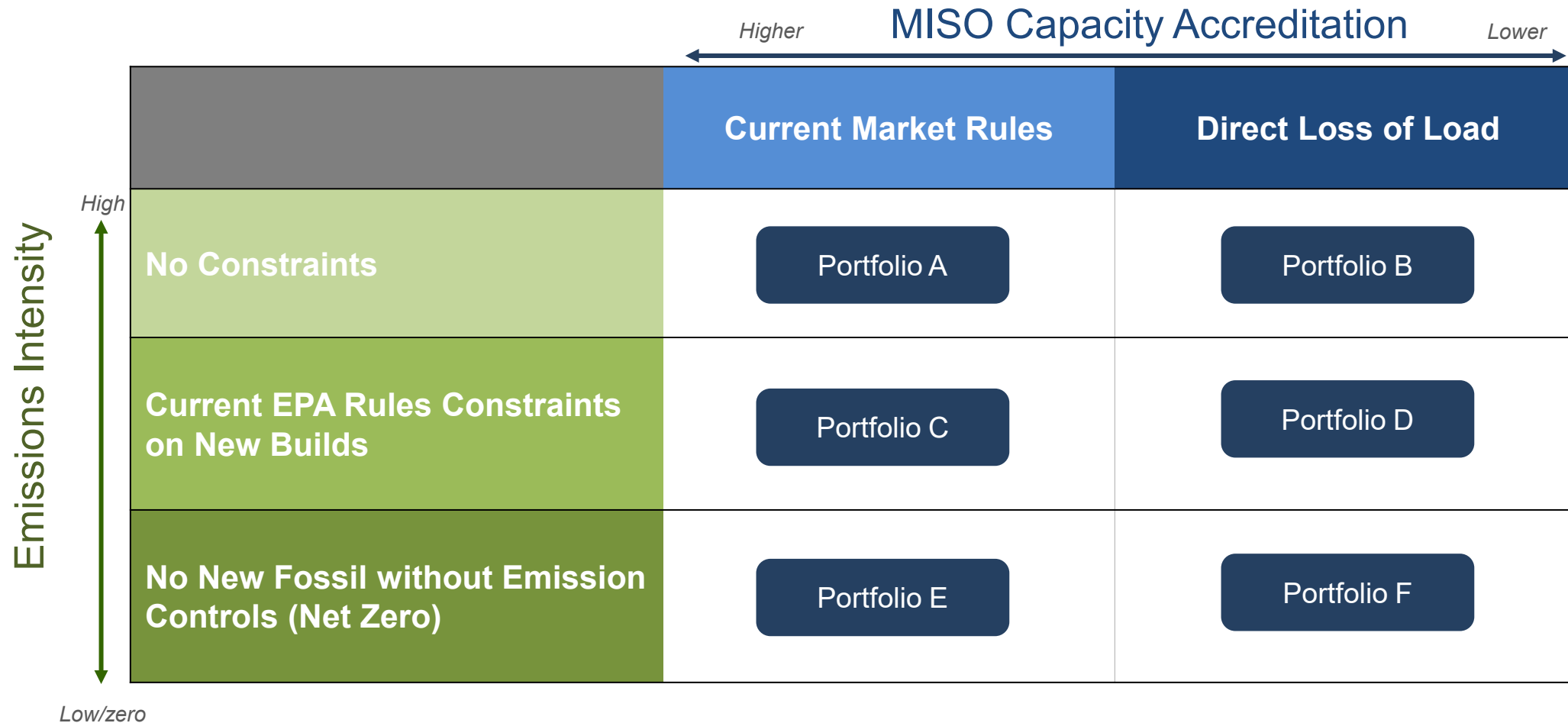
Resources offered in
the RFP

Resource Option	Available through 2029	Available 2030-2034	Available 2035+
Demand side management (EE and DR) programs	From MPS and DSM Study		
Solar	From RFP Data	Benchmarked to RFP Data plus Third-Party Data Sources for the Long-Term	
Li-Ion Battery Storage			
Long Duration Storage			
Solar + Storage Hybrid			
Near-Term Thermal Options			
Near-Term Capacity Purchases (ZRCs)			
New Natural Gas Peaking Build (H2-enabled up to 30%)	From NIPSCO Internal Engineering Analysis and Project Experience		
New Gas CC Build (H2- enabled up to 30%)			
Wind		Benchmarked to NIPSCO Project Experience	
New Gas CC with CCS		From NIPSCO and Third-Party Data Sources	
New Gas with H2			
CCS Retrofit (at Sugar Creek)			
H2 Retrofit (at Sugar Creek)			
Small modular reactor (SMR)			

PORTFOLIO CONSTRUCTION FRAMEWORK

Six portfolios were constructed to highlight the two primary constraints:

- 1) MISO’s proposed D-LOL rules: reduce the capacity value primarily for solar and wind resources
- 2) EPA’s emissions rules: constrain output or increase cost of new gas generation



PORTFOLIO A – RESOURCE ADDITIONS (NAMEPLATE MW)

No EPA GHG Constraints

A

Current Market Rules

Resource	Through 2029 ¹	2030-2034	2035+
Wind		800	700
Solar		500	1,625
4-hr Li-Ion Storage	644	450	125
Long Duration Energy Storage		30	
Gas CCGT	1,300	1,300	
Gas Peaking			
Short-Term Thermal PPA & ZRCs	350 ²		
Gas CCGT w/ CCUS			
H2-enabled CC			
Sugar Creek			650 ³

1: Note that 4-hr Li-Ion Storage and Short-Term Thermal PPA & ZRCs are RFP tranches. The gas CCGT is a generic resource addition.

2: Includes 150 MW of thermal PPA and 200 MW ZRC.

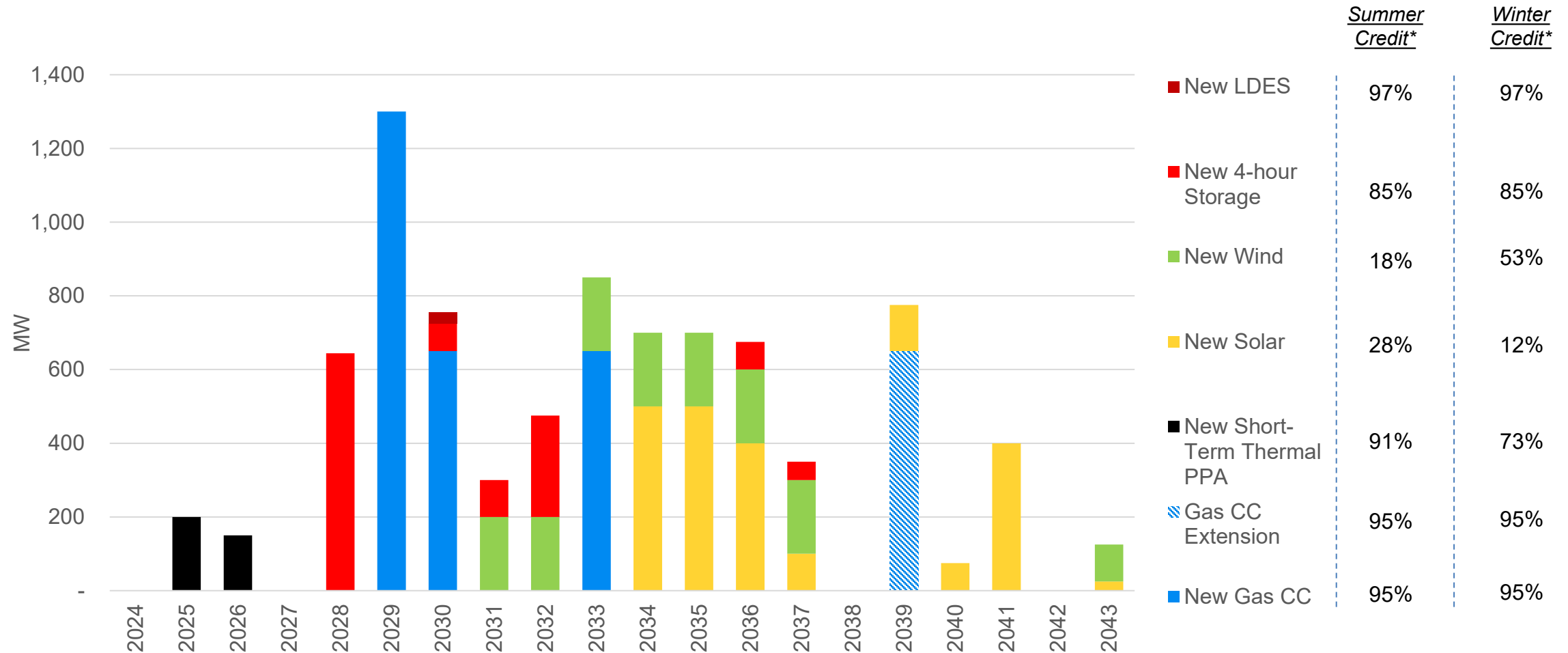
3: Extended on natural gas

Note: All selected DSM and DR are summarized separately across portfolios

PORTFOLIO A – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

No EPA GHG Constraints

A Current Market Rules



Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

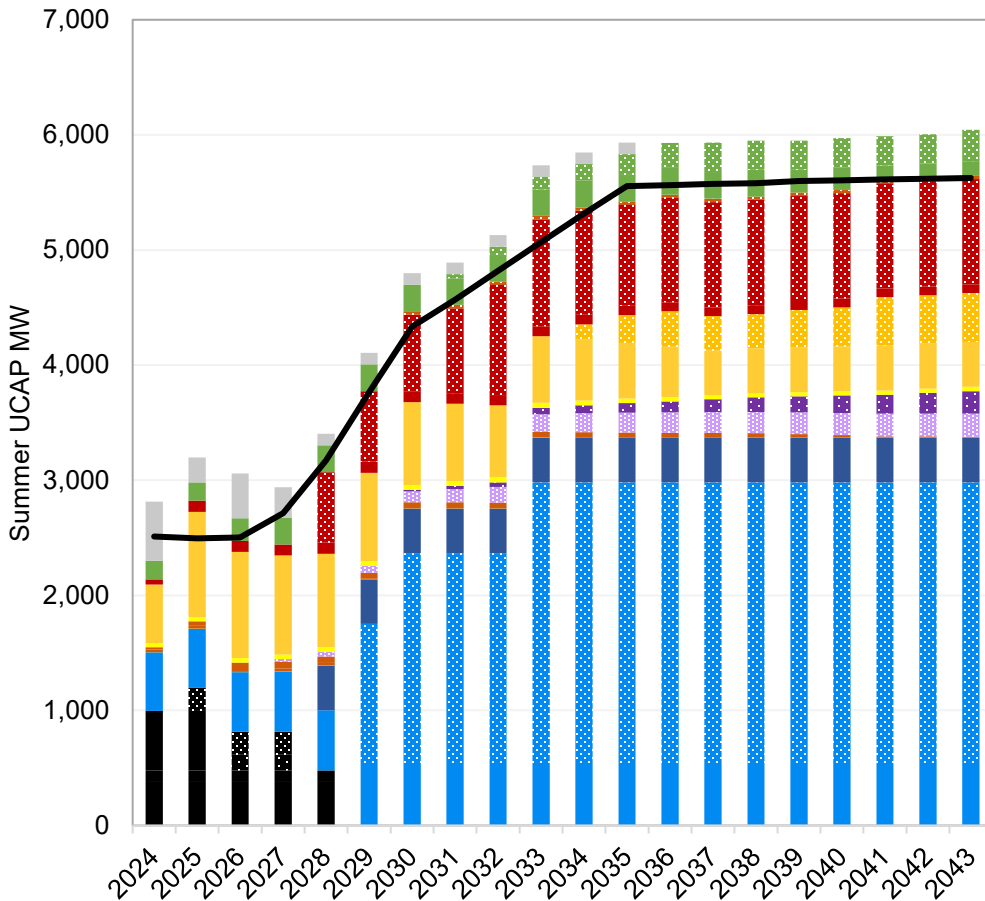
*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

PORTFOLIO A – SUPPLY-DEMAND BALANCE

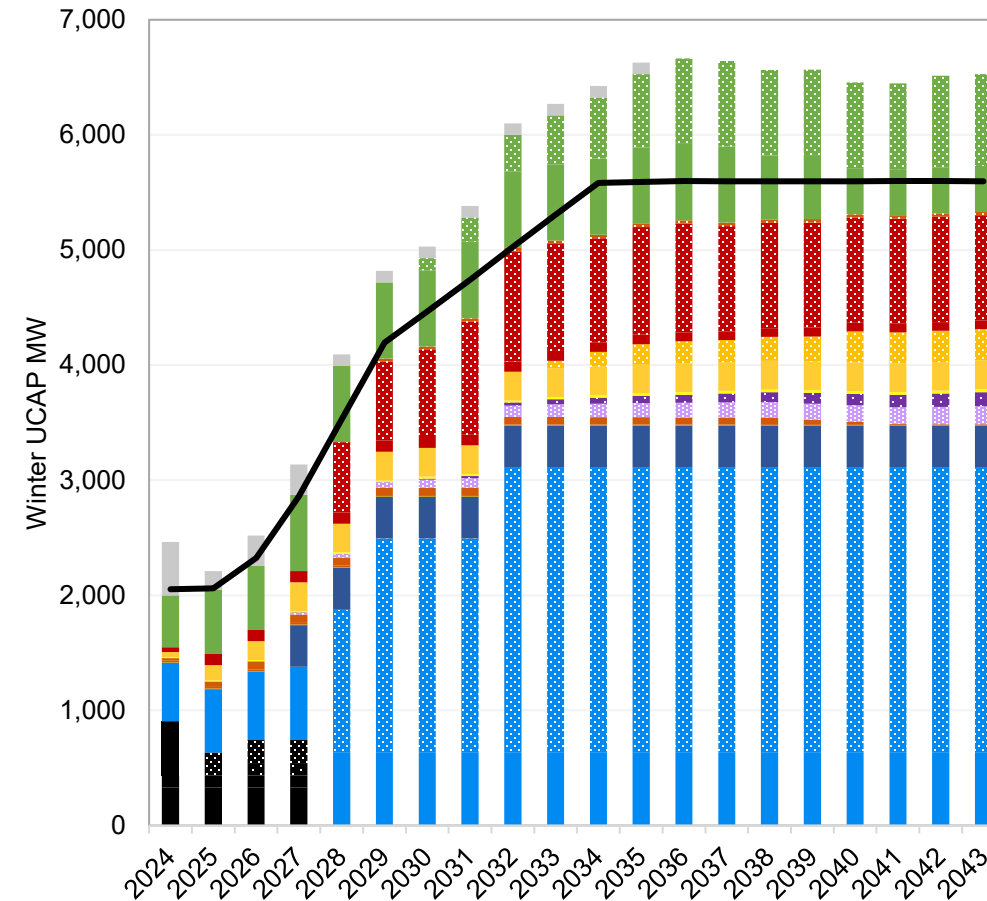
No EPA GHG Constraints

A Current Market Rules

Summer Cap. vs. PRM



Winter Cap. vs. PRM



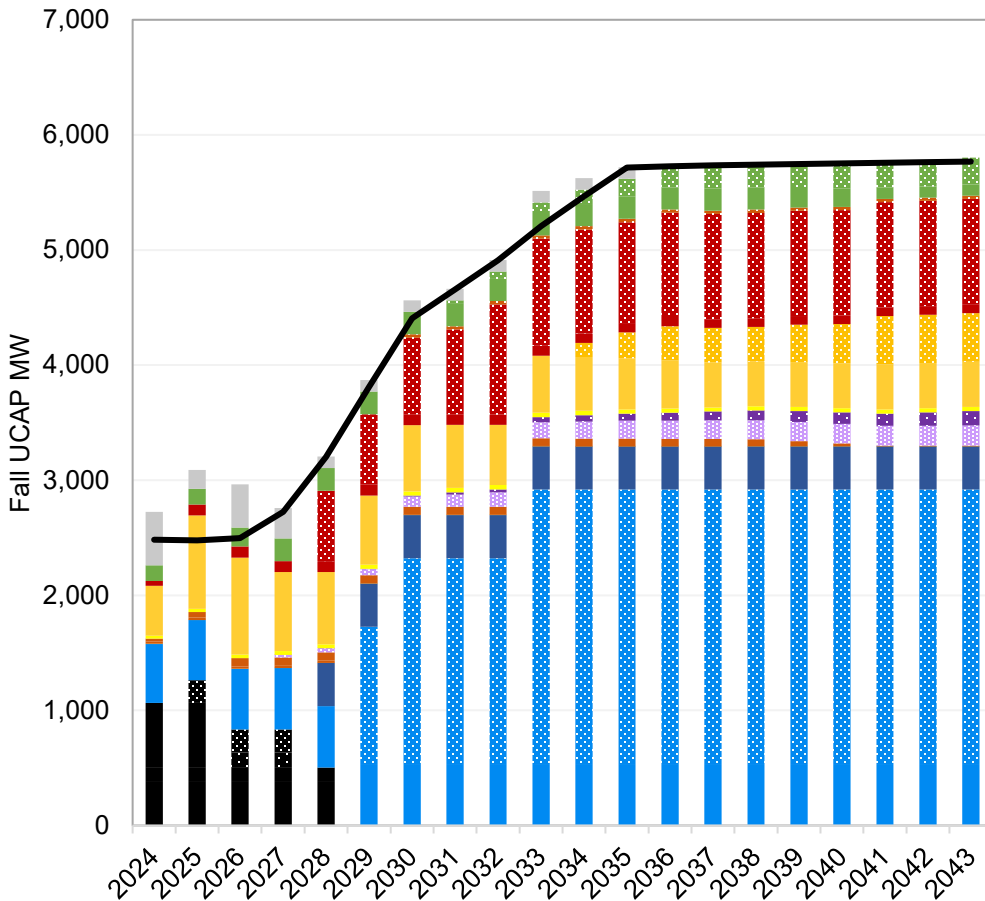
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

PORTFOLIO A – SUPPLY-DEMAND BALANCE

No EPA GHG Constraints

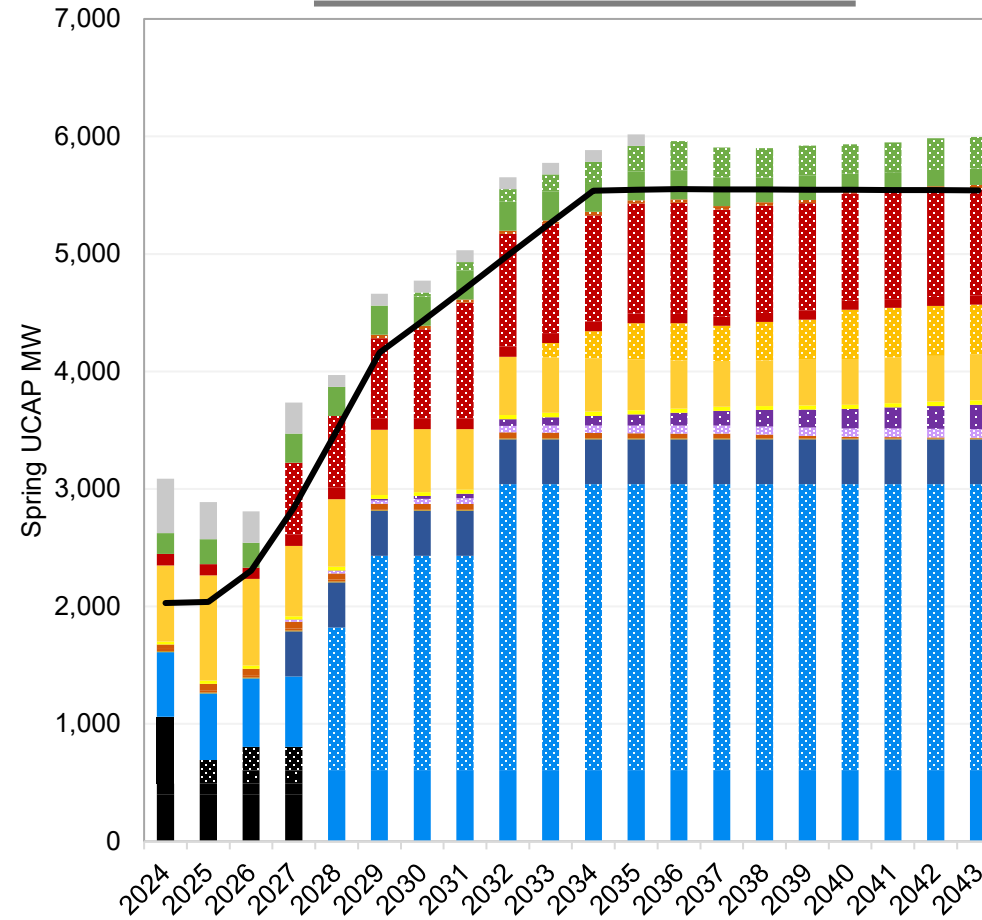
A Current Market Rules

Fall Cap. vs. PRM



Generally Binding Season

Spring Cap. vs. PRM



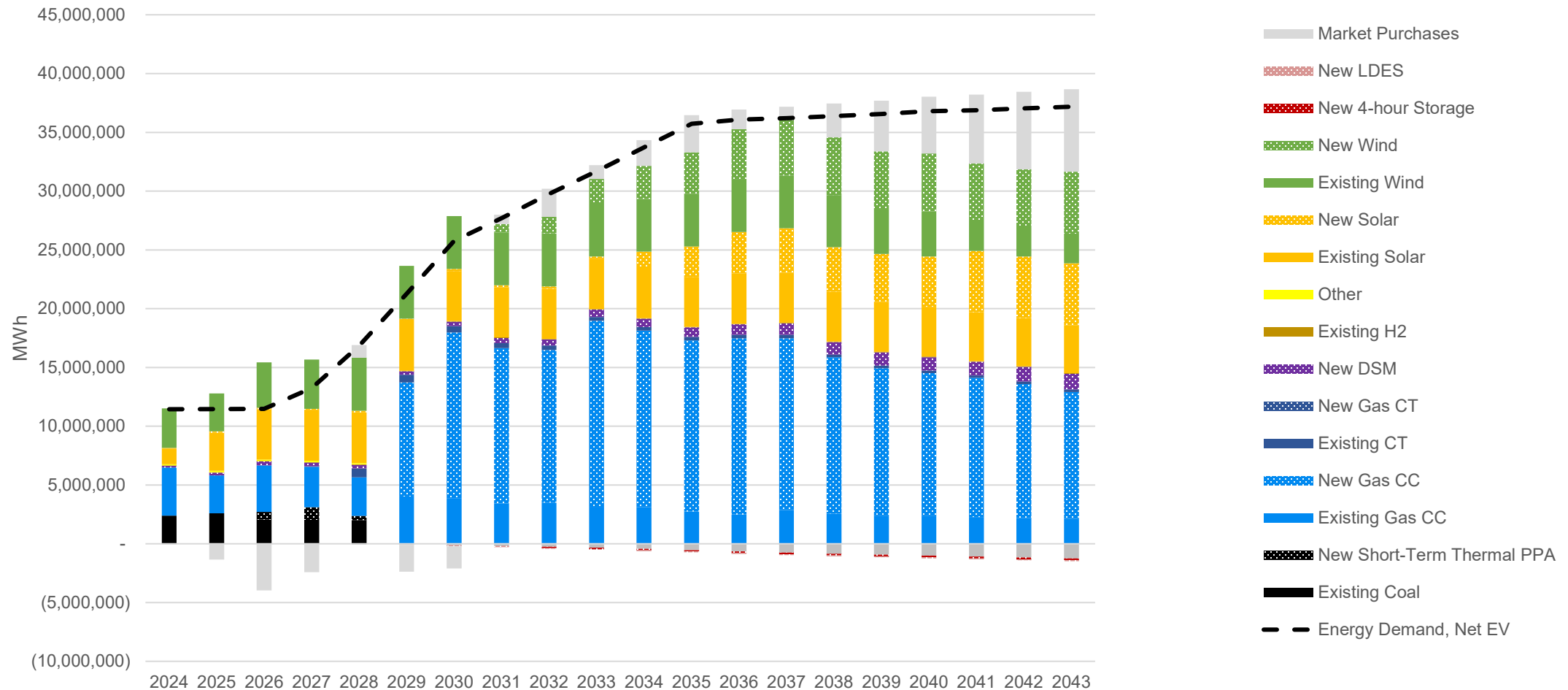
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

PORTFOLIO A – ENERGY POSITION

No EPA GHG Constraints

A

Current Market Rules



Note: The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.

PORTFOLIO B – RESOURCE ADDITIONS (NAMEPLATE MW)

No EPA GHG Constraints

B

Direct Loss of Load

Resource	Through 2029 ¹	2030-2034	2035+
Wind		800	1,050
Solar			675
4-hr Li-Ion Storage	1,227	450	175
Long Duration Energy Storage		30	
Gas CCGT	1,300	1,300	
Gas Peaking			
Short-Term Thermal PPA & ZRCs	350 ²		
Gas CCGT w/ CCUS			
H2-enabled CC			
Sugar Creek			650 ³

1: Note that 4-hr Li-Ion Storage and Short-Term Thermal PPA & ZRCs are RFP tranches. The gas CCGT is a generic resource addition.

2: Includes 150 MW of thermal PPA and 200 MW ZRC.

3: Extended on natural gas

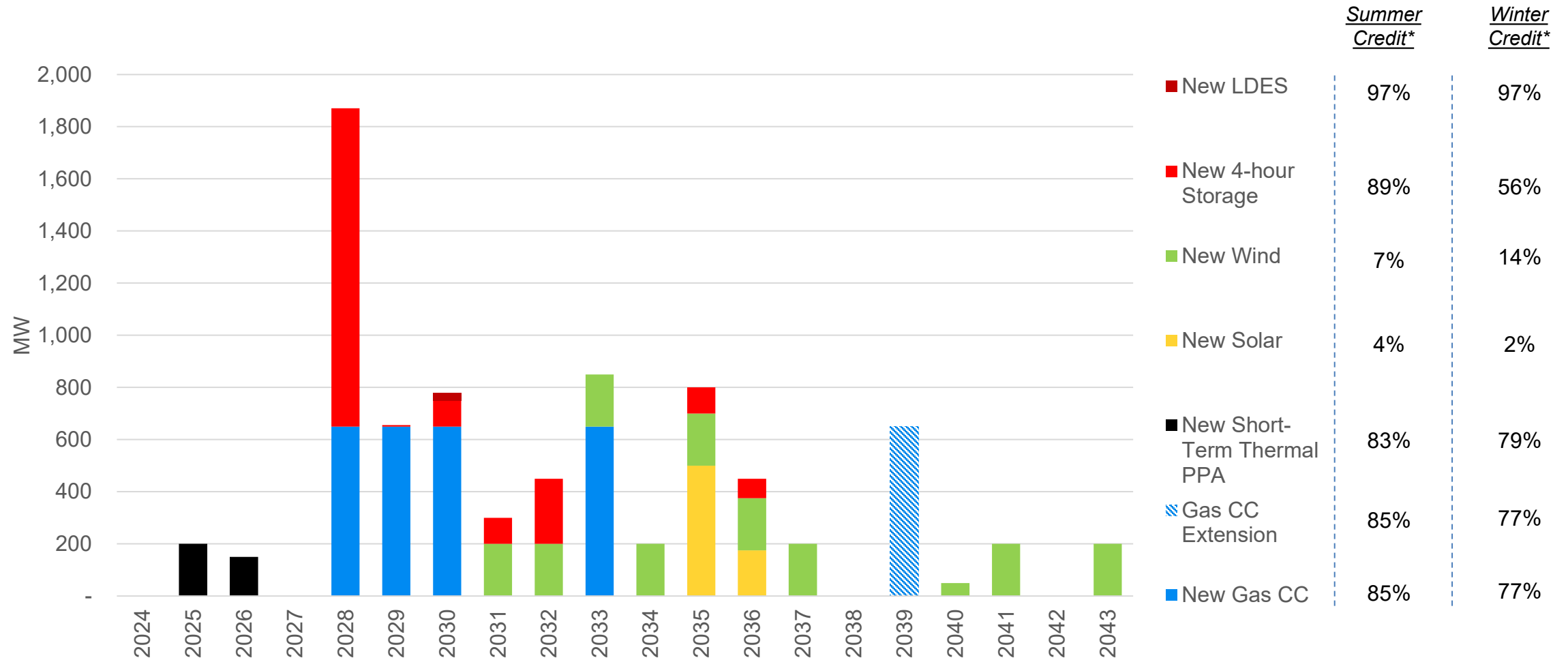
Note: All selected DSM and DR are summarized separately across portfolios

PORTFOLIO B – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

No EPA GHG Constraints

B

Direct Loss of Load



Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

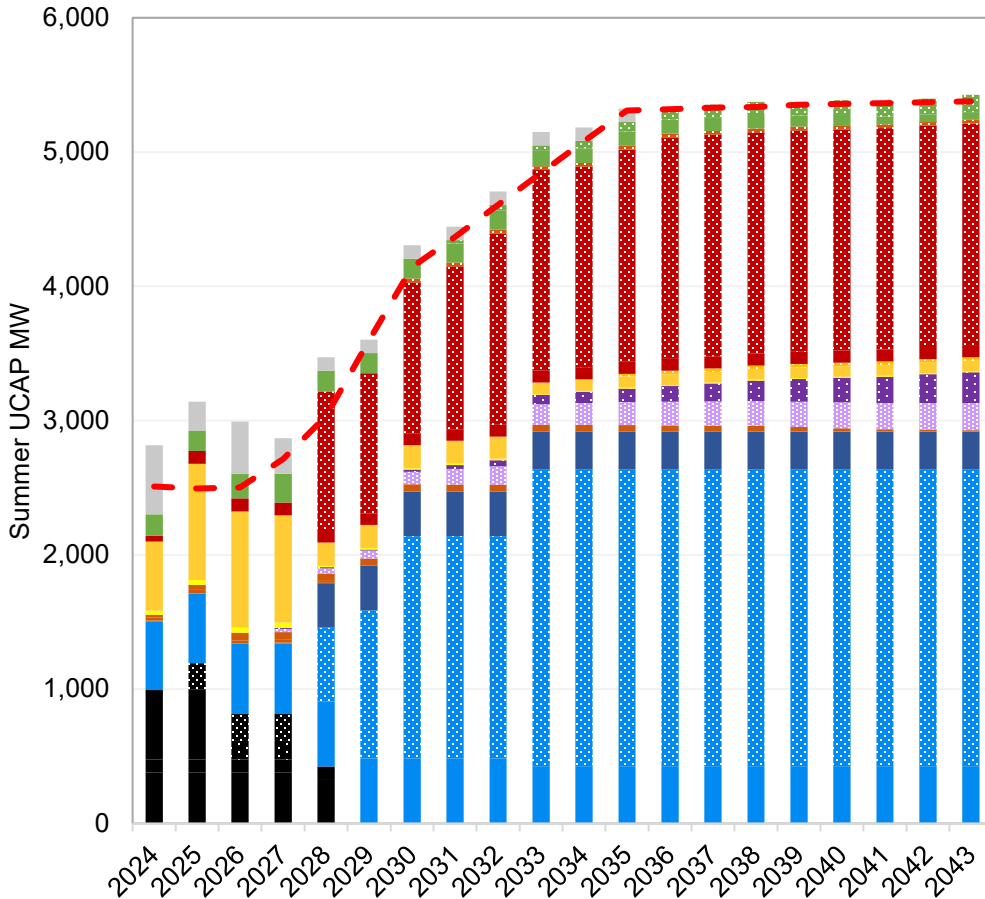
PORTFOLIO B – SUPPLY-DEMAND BALANCE

No EPA GHG Constraints

B

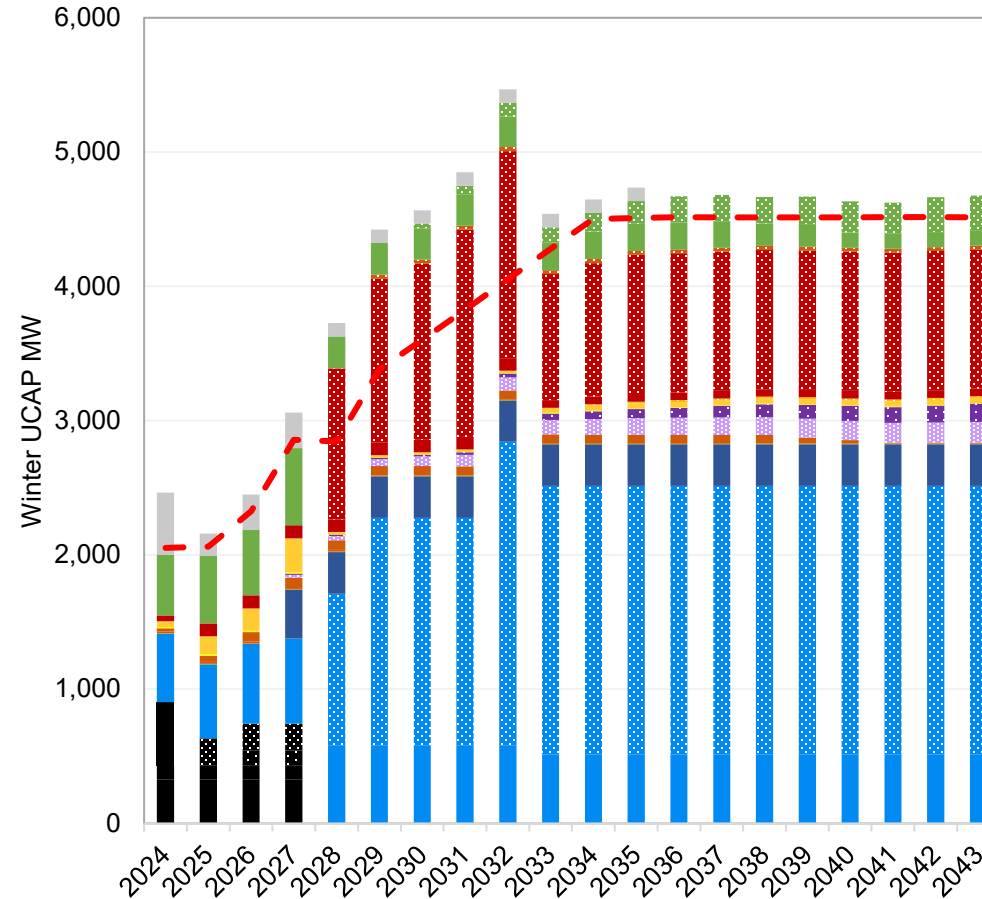
Direct Loss of Load

Summer Cap. vs. PRM



Generally Binding Season

Winter Cap. vs. PRM



- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- DLOL PRM

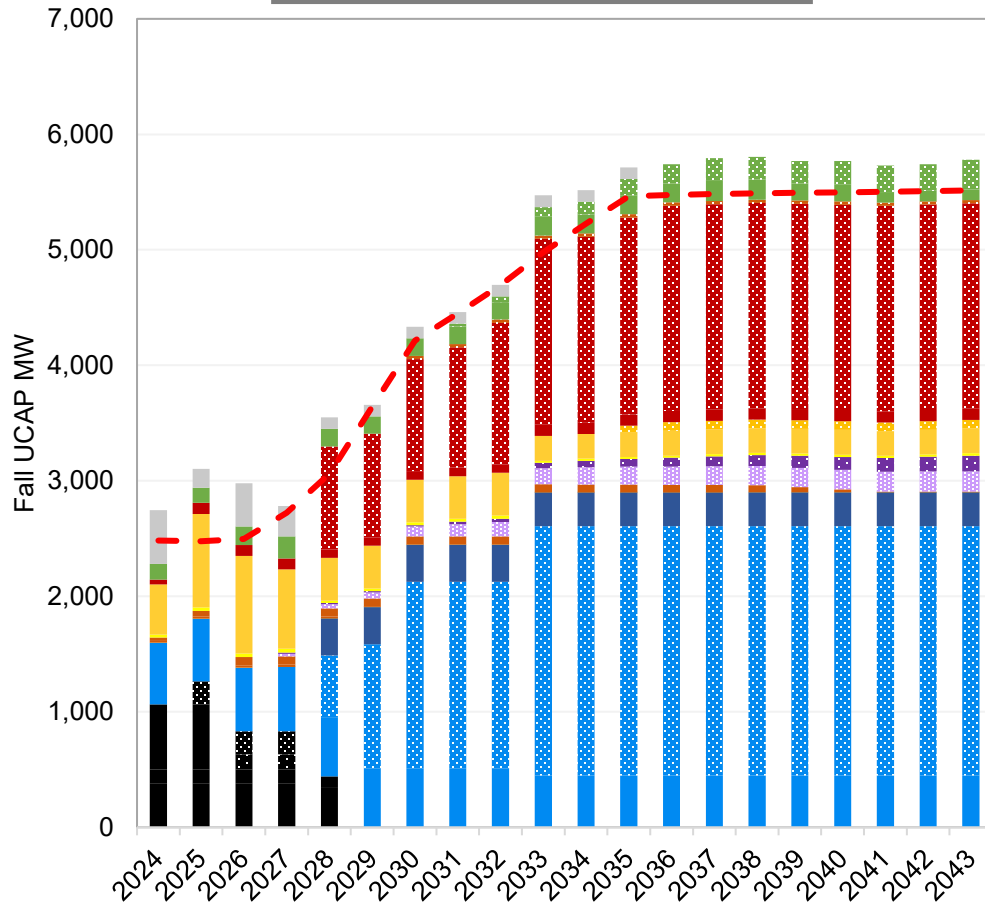
PORTFOLIO B – SUPPLY-DEMAND BALANCE

No EPA GHG Constraints

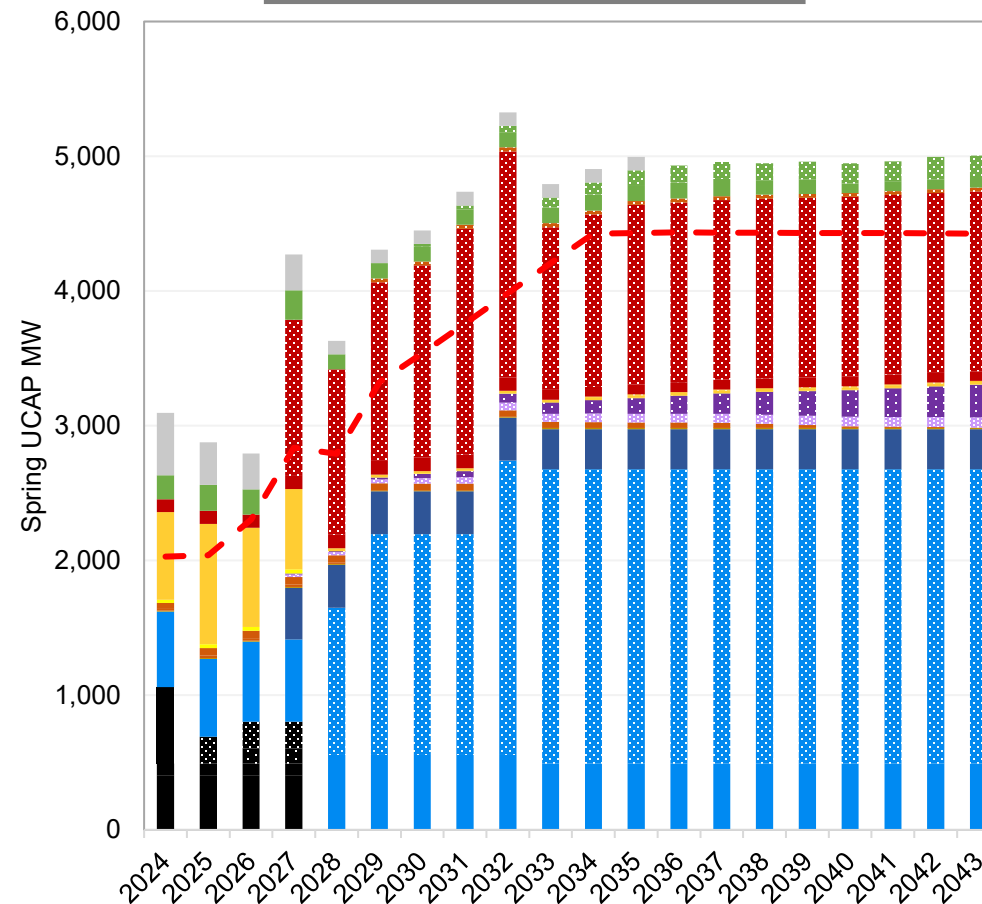
B

Direct Loss of Load

Fall Cap. vs. PRM



Spring Cap. vs. PRM



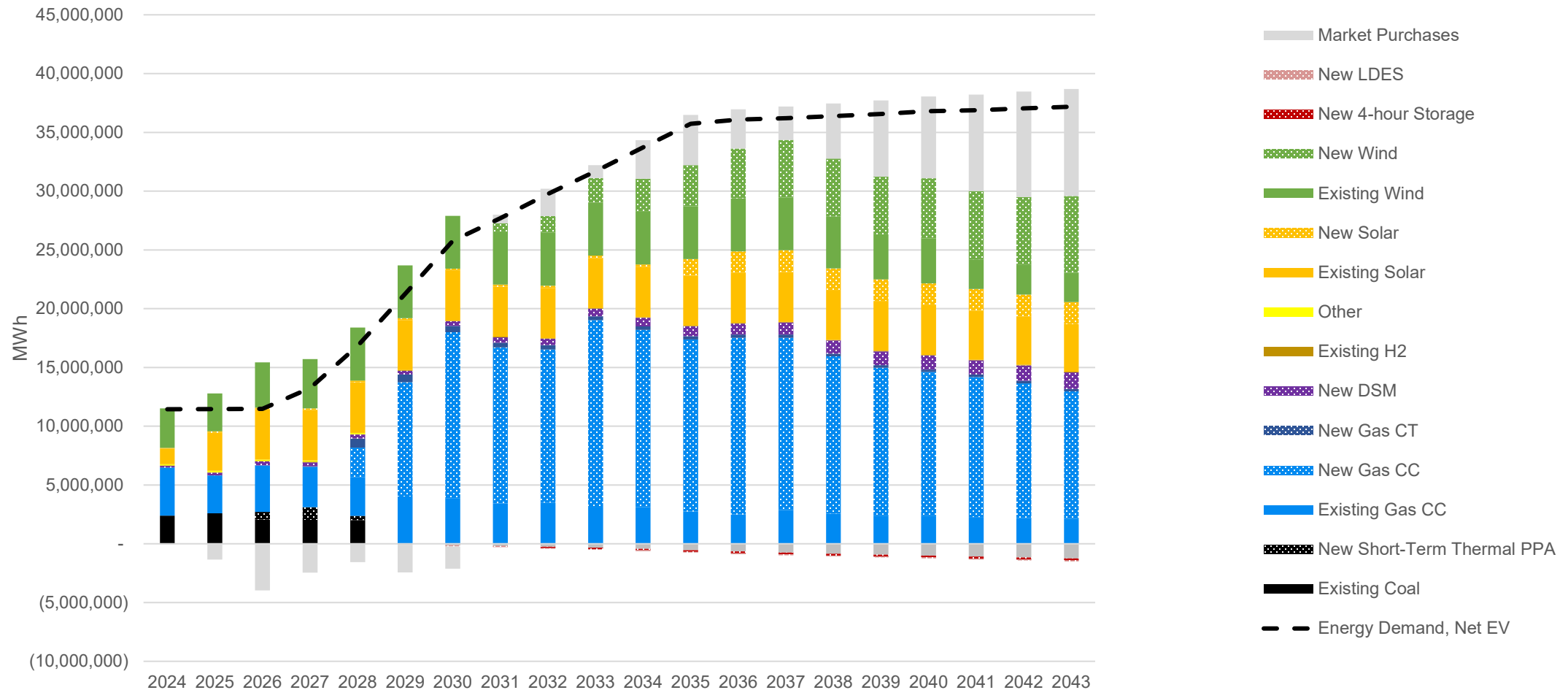
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- DLOL PRM

PORTFOLIO B – ENERGY POSITION

No EPA GHG Constraints

B

Direct Loss of Load



Note: The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.

PORTFOLIO C – RESOURCE ADDITIONS (NAMEPLATE MW)

EPA GHG Rules



Current Market Rules

Resource	Through 2029 ¹	2030-2034	2035+
Wind		800	1,000
Solar	335	1,725	1,175
4-hr Li-Ion Storage	511	150	150
Long Duration Energy Storage			
Gas CCGT	1,285	1,300	
Gas Peaking			400
Short-Term Thermal PPA & ZRCs	350 ²		
Gas CCGT w/ CCUS			
H2-enabled CC			
Sugar Creek			650 ³

1: Note that Solar, 4-hr Li-Ion Storage, 635 MW of Gas CCGT PPA, and Short-Term Thermal PPA & ZRCs are RFP tranches. The remaining 650 MW of Gas CCGT is a generic resource addition.

2: Includes 150 MW of thermal PPA and 200 MW ZRC.

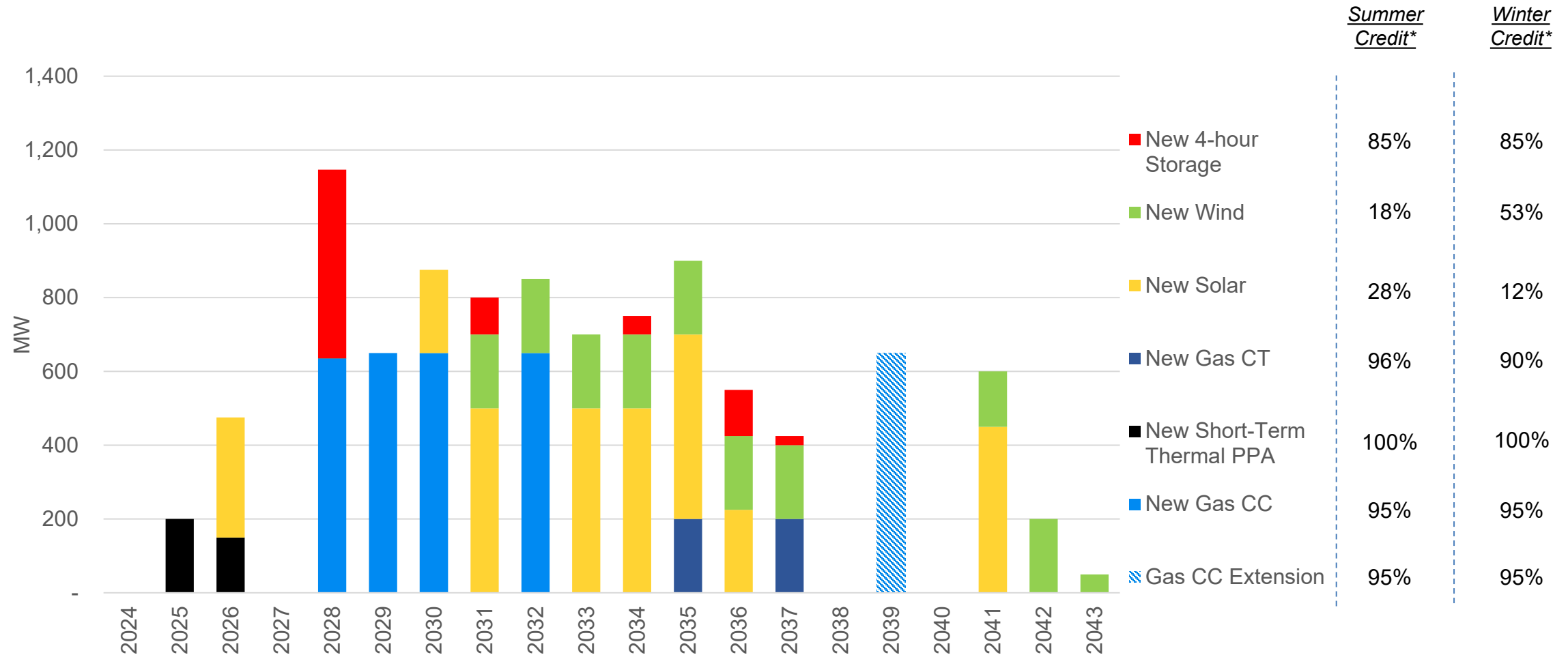
3: Extended on natural gas

Note: All selected DSM and DR are summarized separately across portfolios

PORTFOLIO C – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

EPA GHG Rules

C Current Market Rules



Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

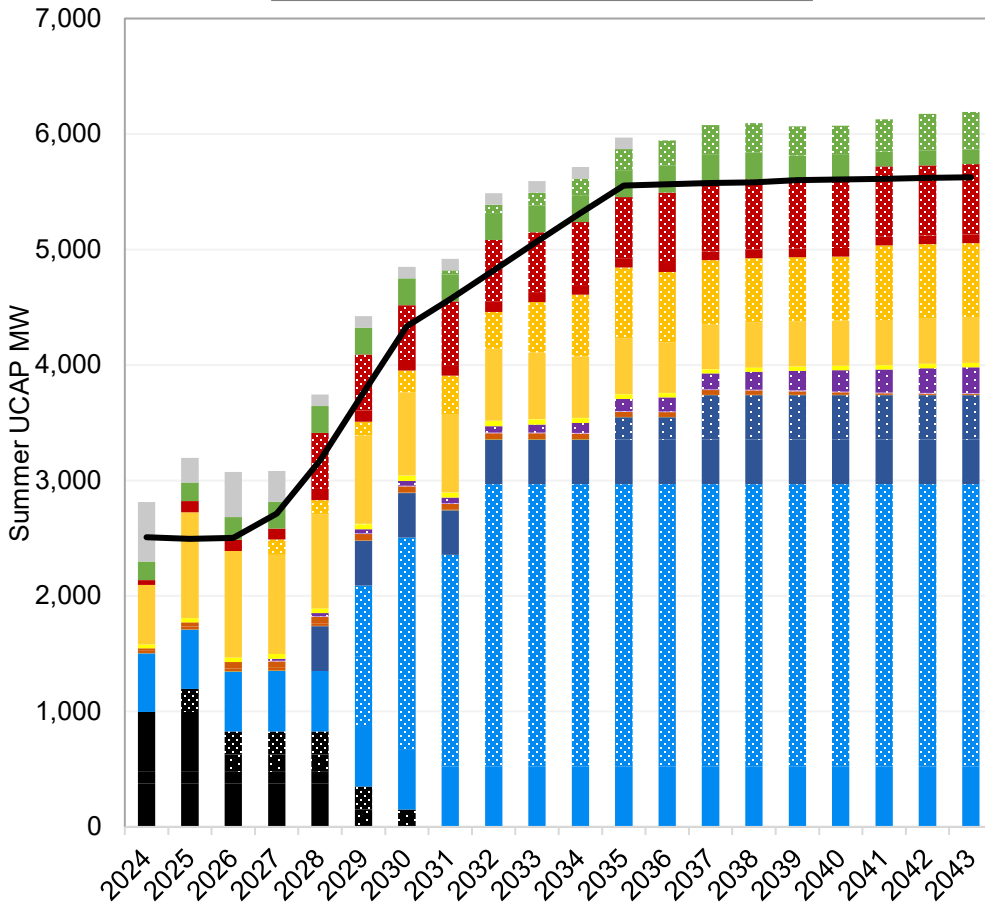
*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

PORTFOLIO C – SUPPLY-DEMAND BALANCE

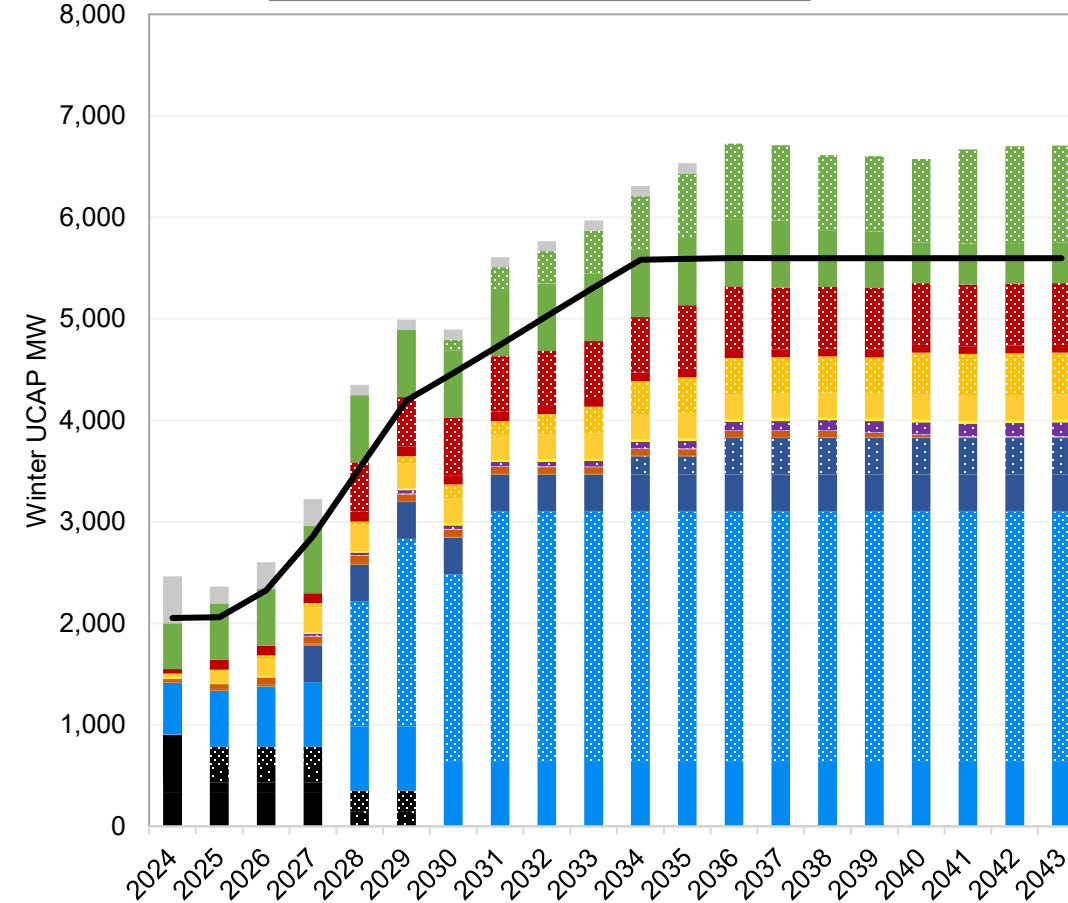
EPA GHG Rules

C Current Market Rules

Summer Cap. vs. PRM



Winter Cap. vs. PRM



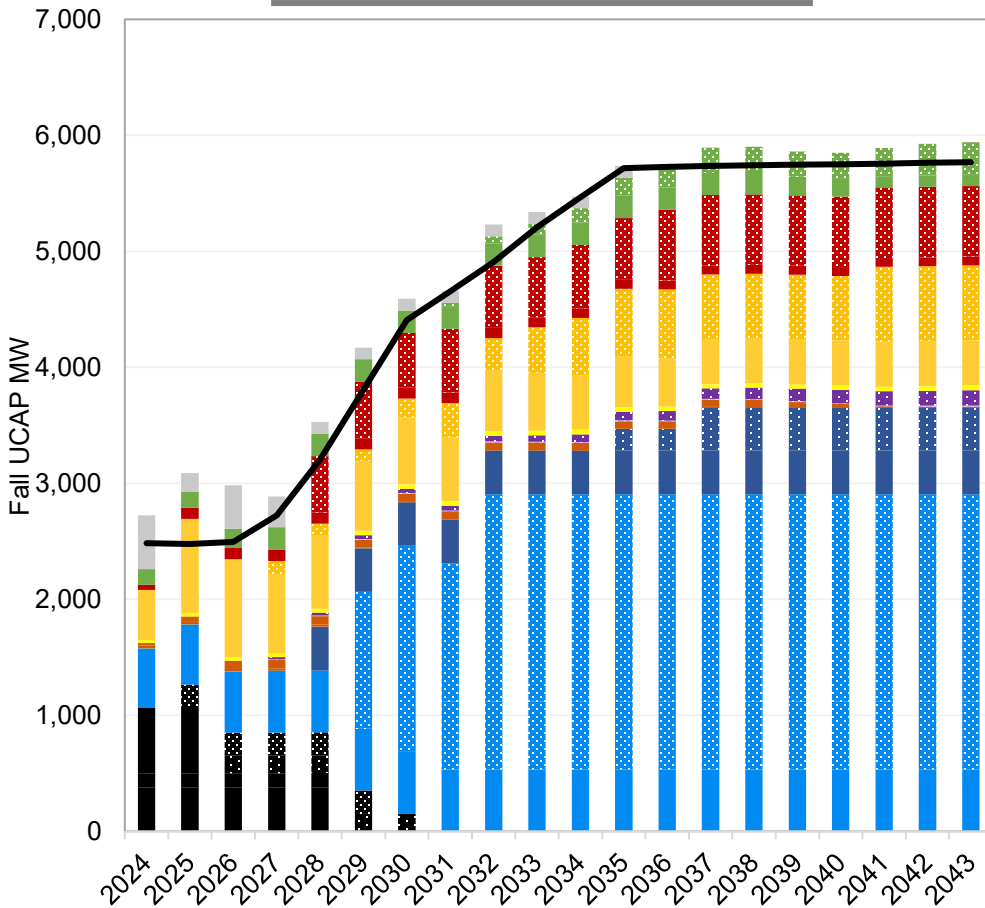
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

PORTFOLIO C – SUPPLY-DEMAND BALANCE

EPA GHG Rules

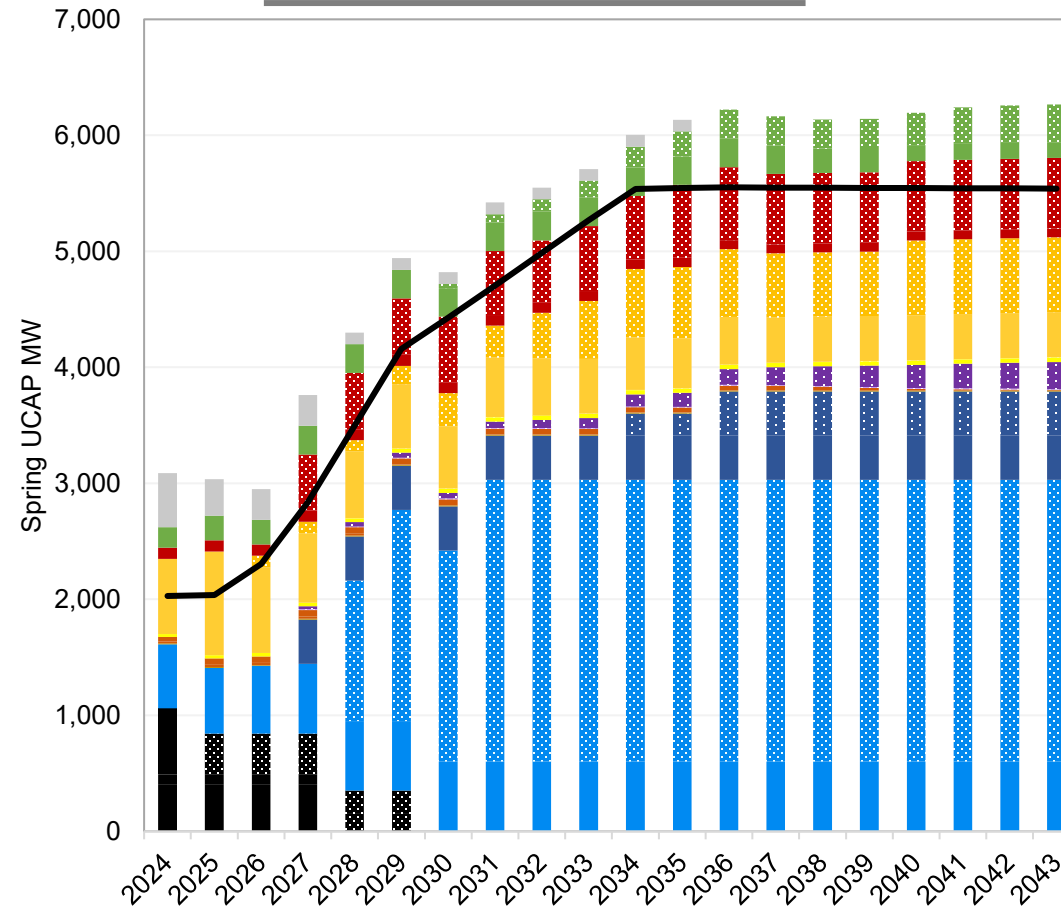
C Current Market Rules

Fall Cap. vs. PRM



Generally Binding Season

Spring Cap. vs. PRM



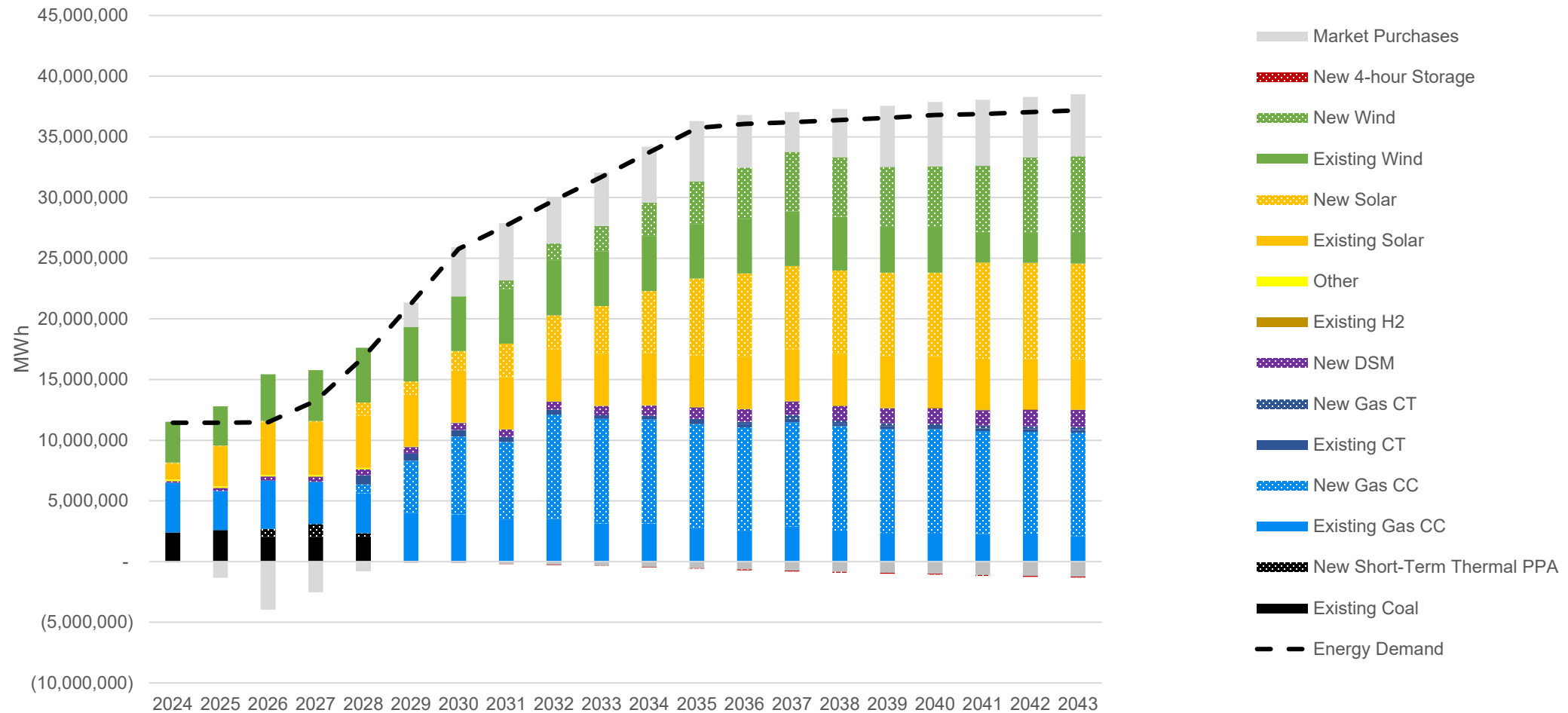
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- New 4-hour Storage
- Existing Storage
- New Solar
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

PORTFOLIO C – ENERGY POSITION

EPA GHG Rules



Current Market Rules



Note: The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.

PORTFOLIO D – RESOURCE ADDITIONS (NAMEPLATE MW)

EPA GHG Rules

D

Direct Loss of Load

Resource	Through 2029 ¹	2030-2034	2035+
Wind		650	900
Solar		750	525
4-hr Li-Ion Storage	909	50	
Long Duration Energy Storage			
Gas CCGT	1,285	1,950	
Gas Peaking	418	200	
Short-Term Thermal PPA & ZRCs	350 ²		
Gas CCGT w/ CCUS			
H2-enabled CC			
Sugar Creek			650 ³

1: Note that Solar, 4-hr Li-Ion Storage, 635 MW of Gas CCGT PPA, ~20 MW of Gas Peaking, and Short-Term Thermal PPA & ZRCs are RFP tranches. The remaining 650 MW of Gas CCGT and 400 MW of Gas Peaking are generic resource additions.

2: Includes 150 MW of thermal PPA and 200 MW ZRC.

3: Extended on natural gas

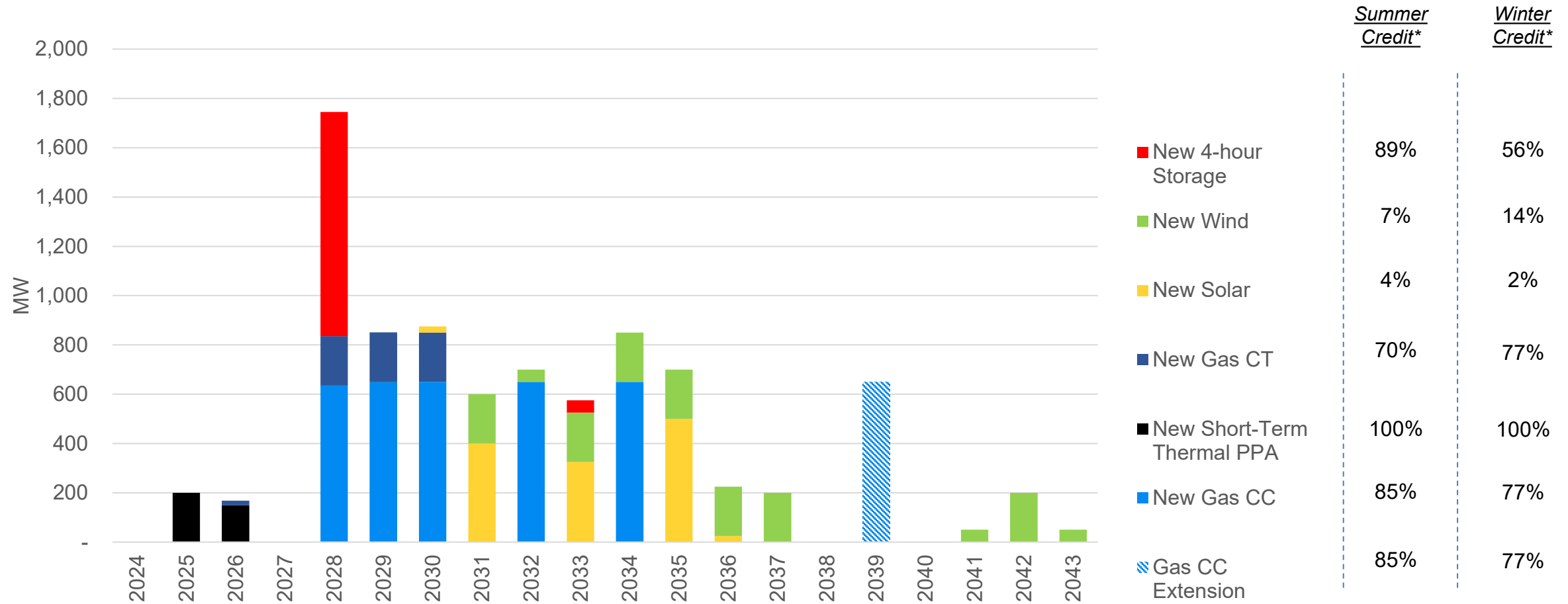
Note: All selected DSM and DR are summarized separately across portfolios

PORTFOLIO D – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

EPA GHG Rules

D

Direct Loss of Load



Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

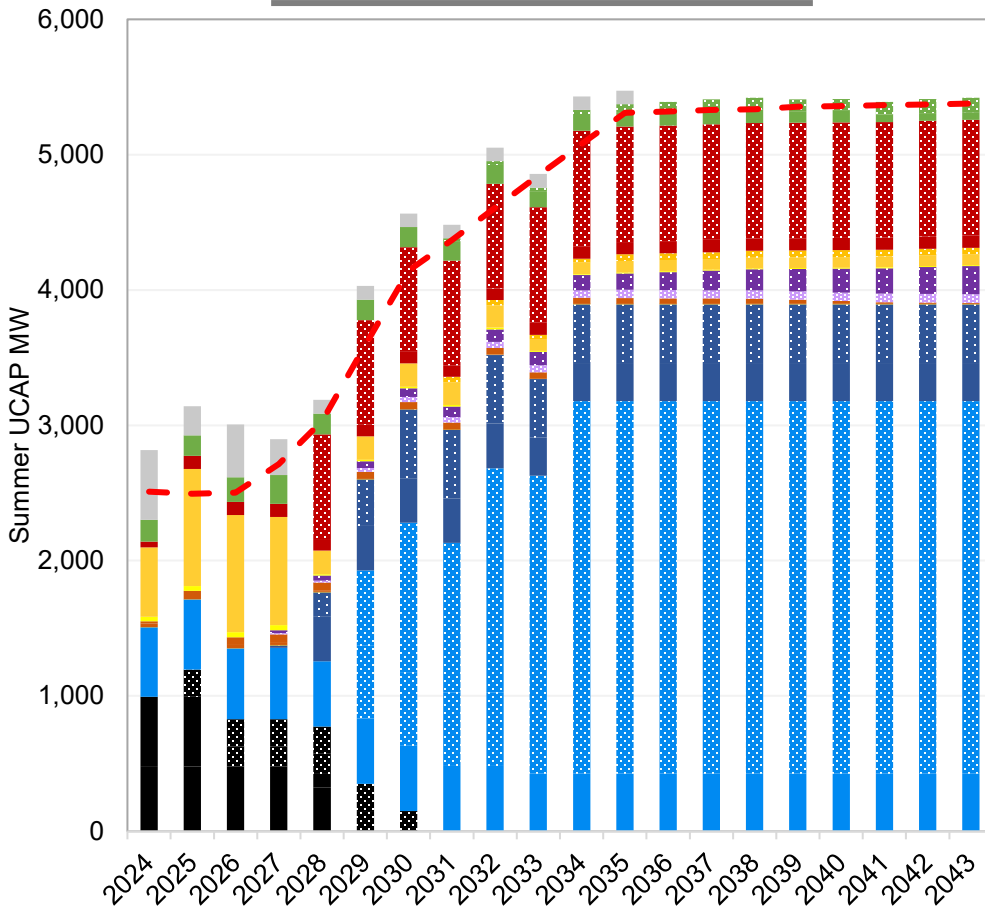
PORTFOLIO D – SUPPLY-DEMAND BALANCE

EPA GHG Rules

D

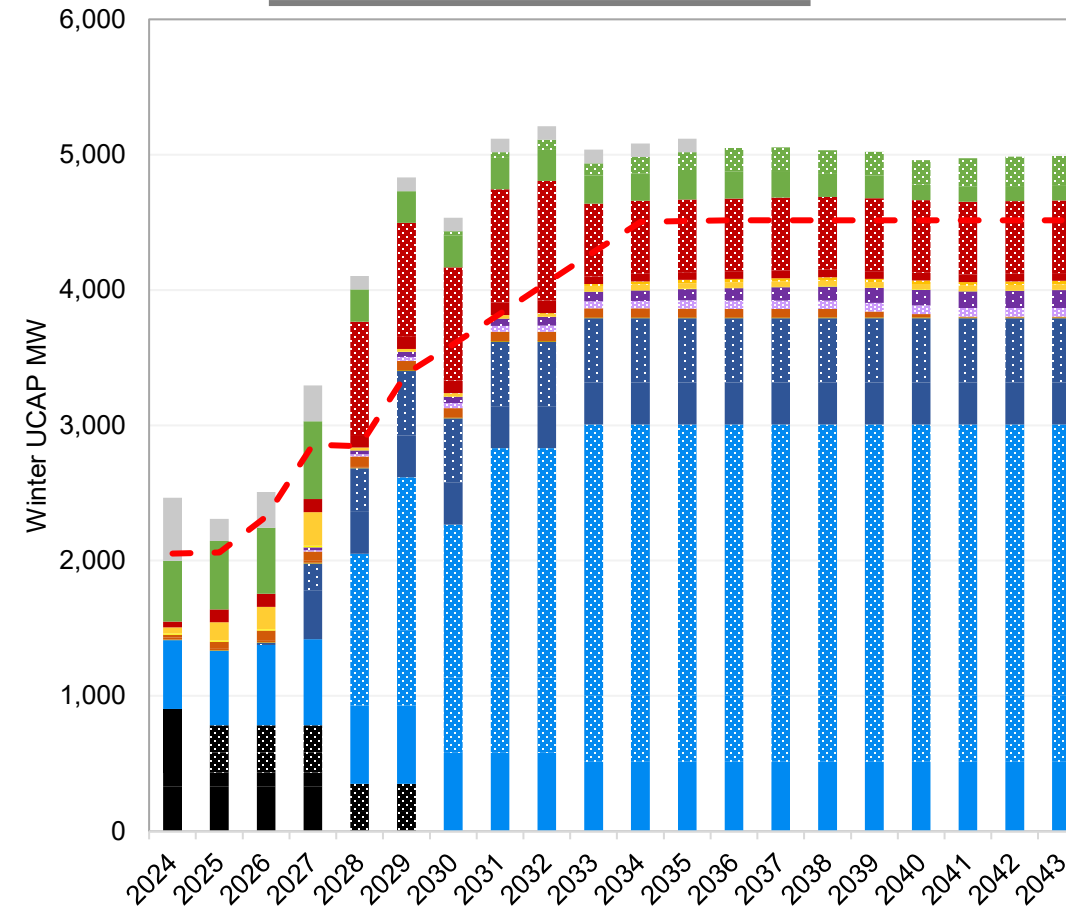
Direct Loss of Load

Summer Cap. vs. PRM



Generally Binding Season

Winter Cap. vs. PRM



- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- DLOL PRM

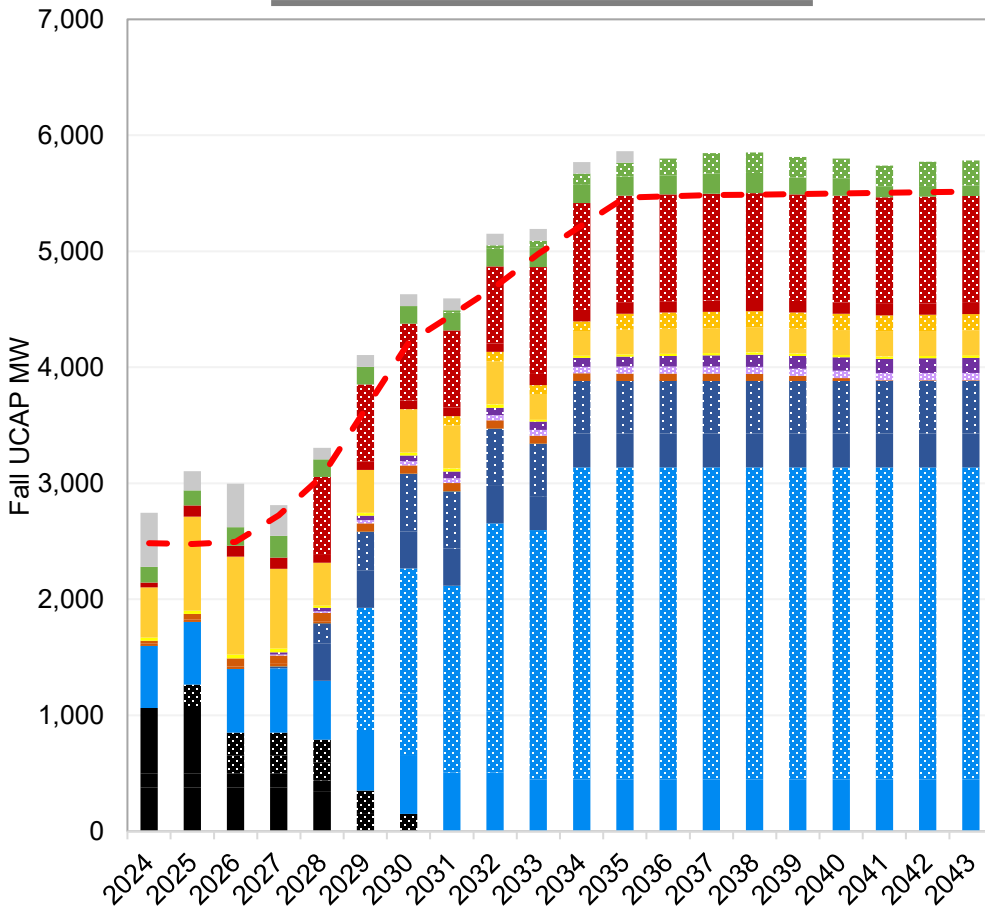
PORTFOLIO D – SUPPLY-DEMAND BALANCE

EPA GHG Rules

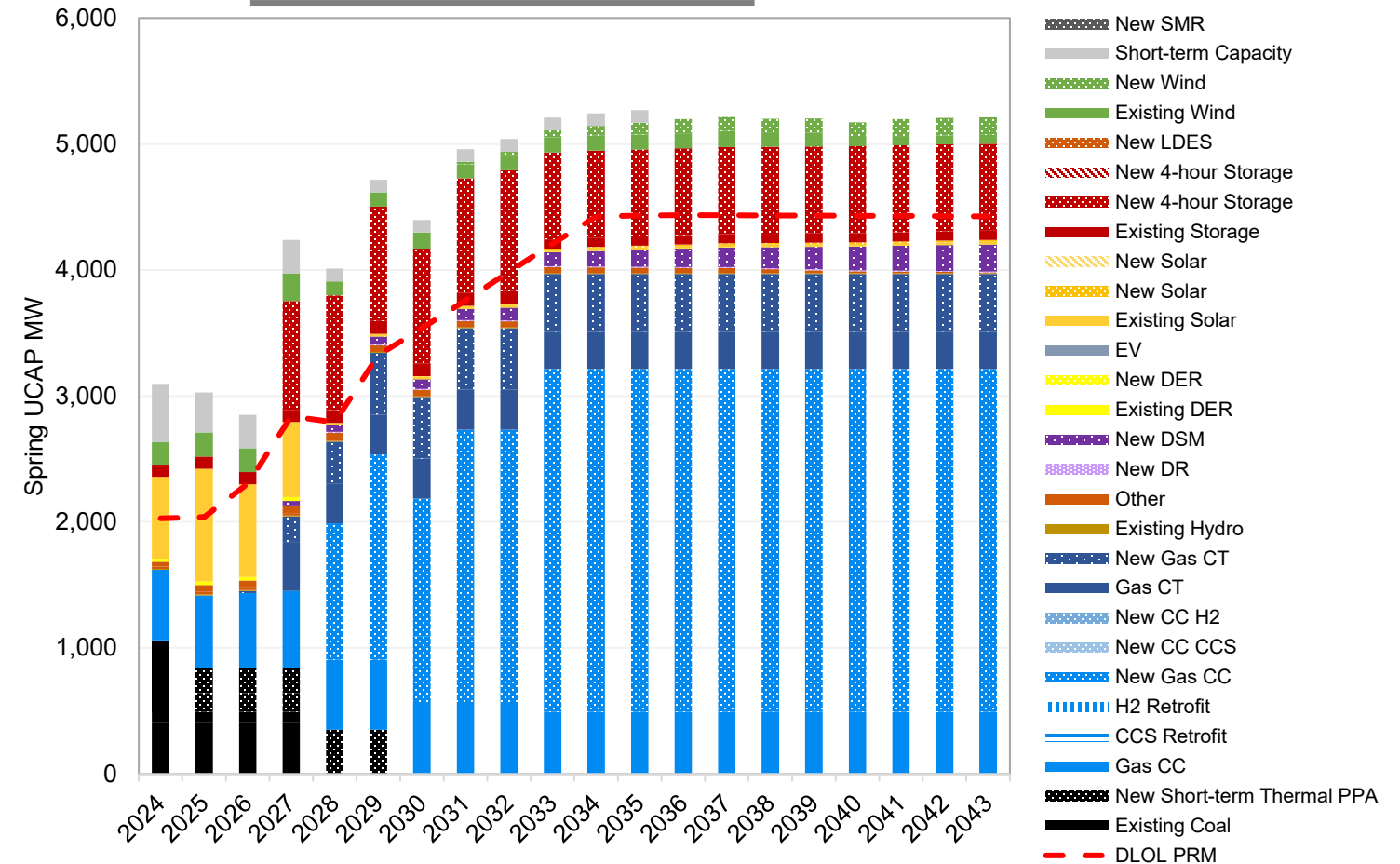
D

Direct Loss of Load

Fall Cap. vs. PRM



Spring Cap. vs. PRM

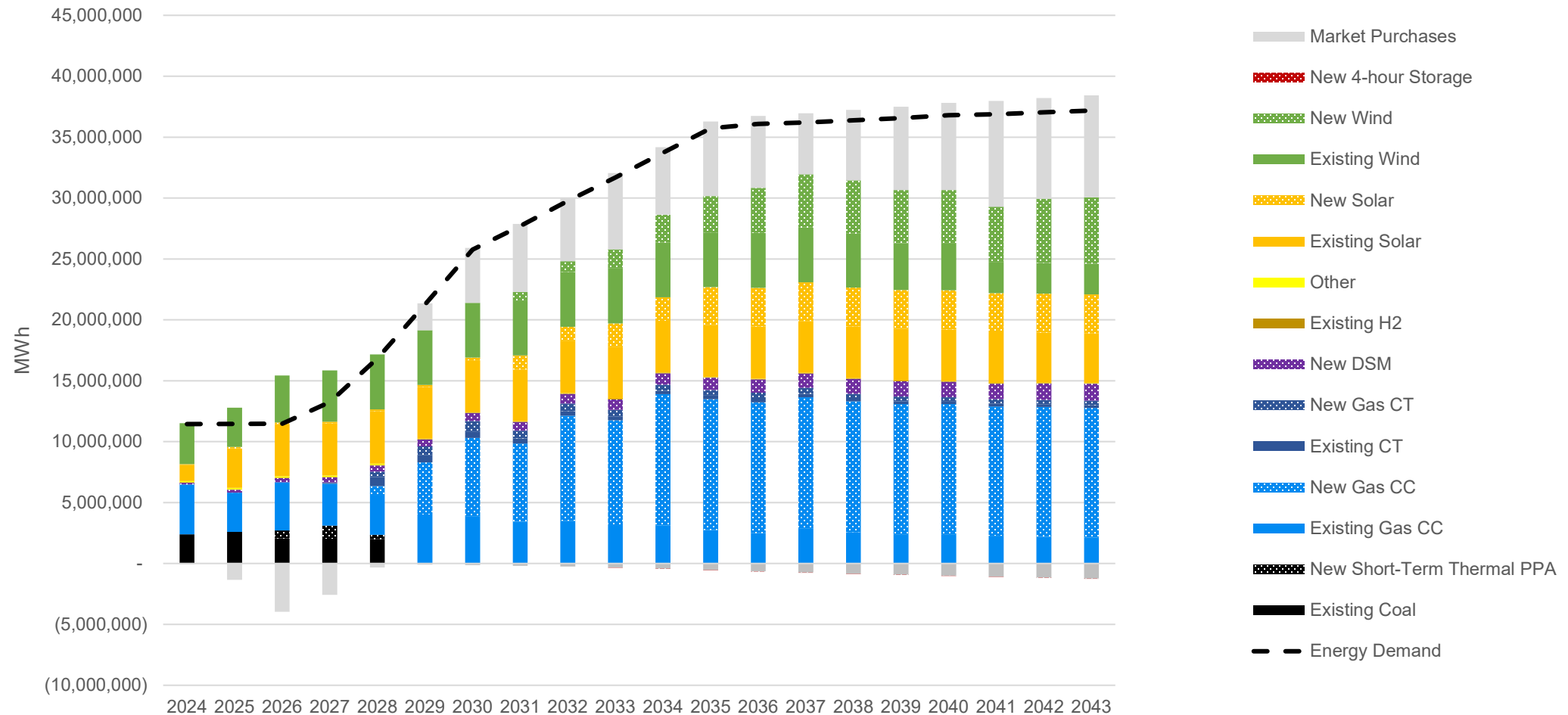


PORTFOLIO D – ENERGY POSITION

EPA GHG Rules

D

Direct Loss of Load



Note: The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.

PORTFOLIO E – RESOURCE ADDITIONS (NAMEPLATE MW)

No New Uncontrolled Fossil

E

Current Market Rules

Resource	Through 2029 ¹	2030-2034	2035+
Wind		800	1,450
Solar	997	1,000	325
4-hr Li-Ion Storage	1,009	300	
Long Duration Energy Storage	100		
Gas CCGT			
Gas Peaking			
Short-Term Thermal PPA & ZRCs	350 ²		
Gas CCGT w/ CCUS		1,755	585
H2-enabled CC			
Sugar Creek			650 ³

1: All resources through 2029 are from the RFP.

2: Includes 150 MW of thermal PPA and 200 MW ZRC.

3: Retrofit to hydrogen in 2035

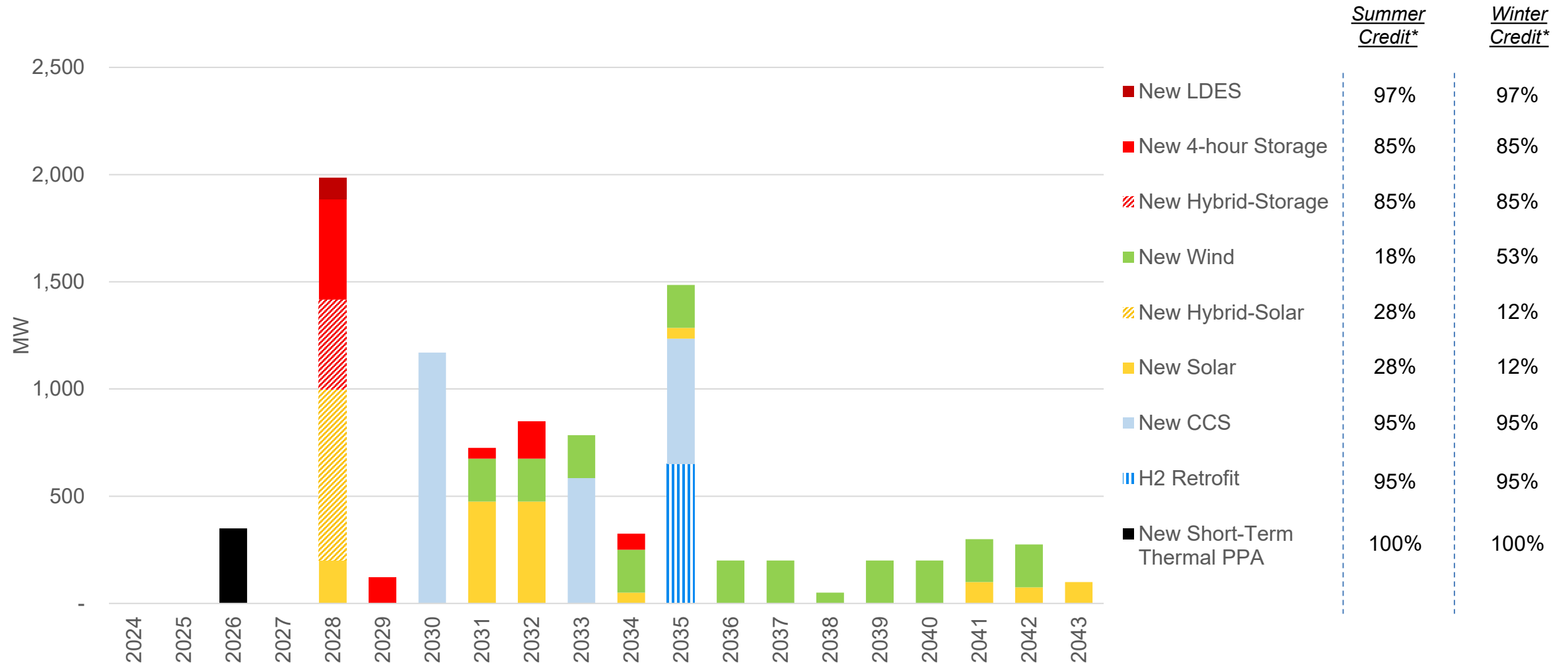
Note: All selected DSM and DR are summarized separately across portfolios

PORTFOLIO E – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

No New Uncontrolled Fossil

E

Current Market Rules



Note: There are two short-term PPAs in 2026. 200 MW lasts from 2026-2029, and 150 MW lasts from 2026-2030.

*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

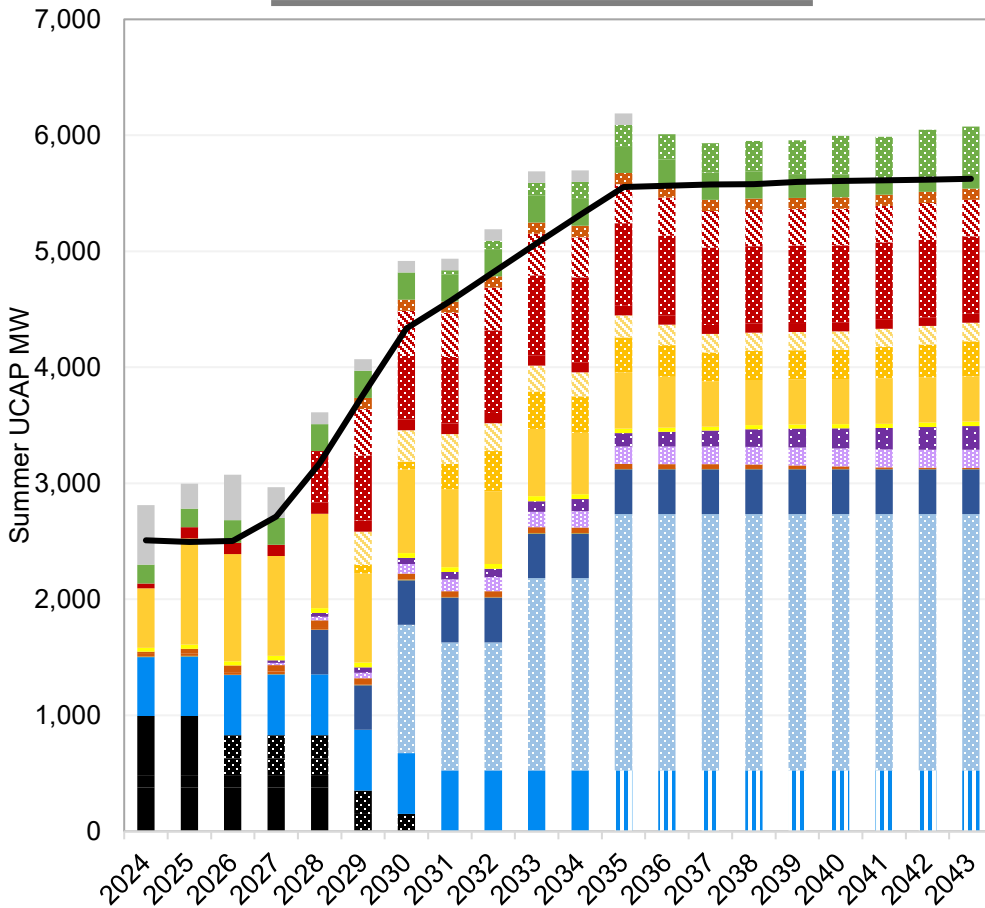
PORTFOLIO E – SUPPLY-DEMAND BALANCE

No New Uncontrolled Fossil

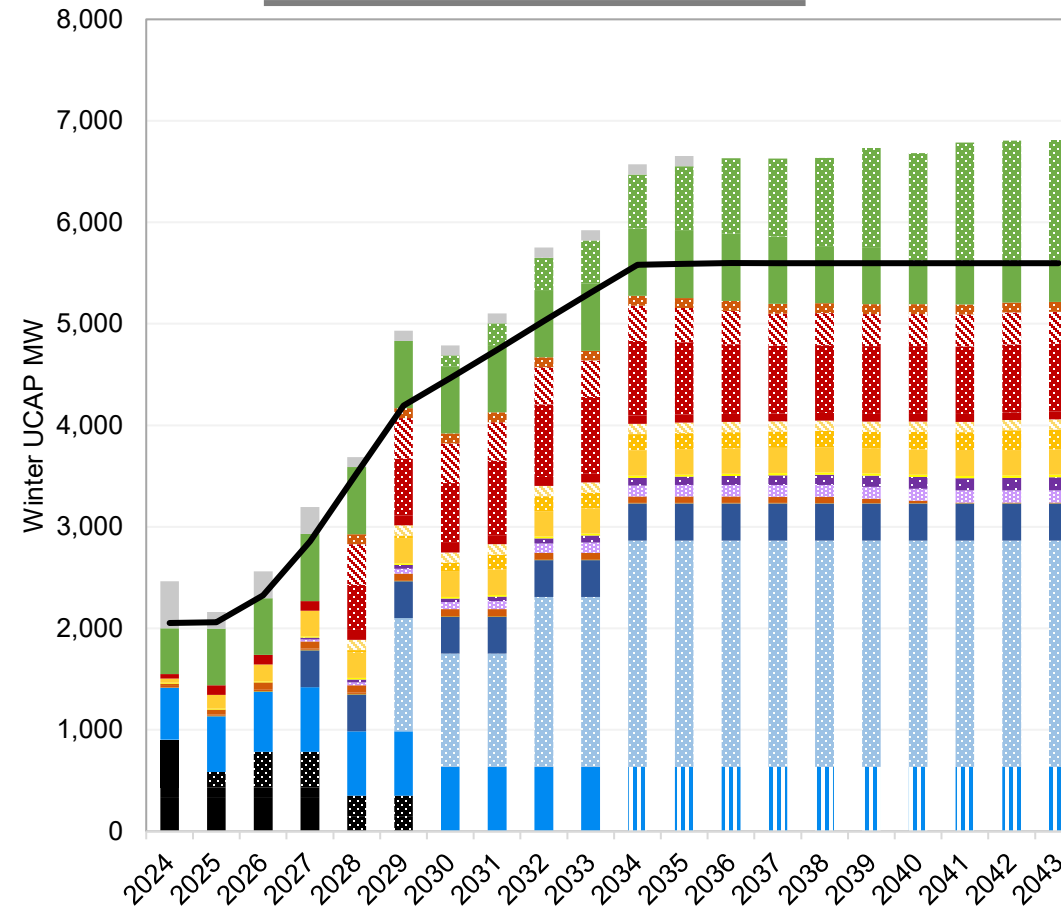
E

Current Market Rules

Summer Cap. vs. PRM



Winter Cap. vs. PRM



- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

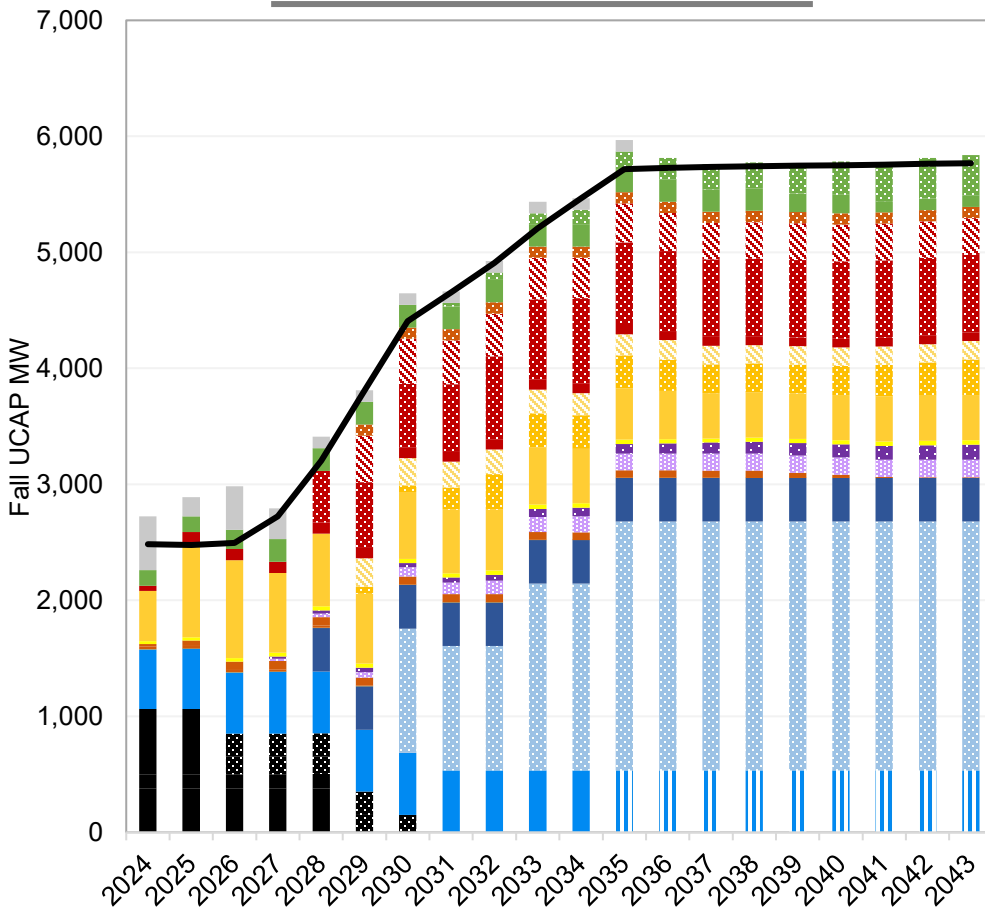
PORTFOLIO E – SUPPLY-DEMAND BALANCE

No New Uncontrolled Fossil

E

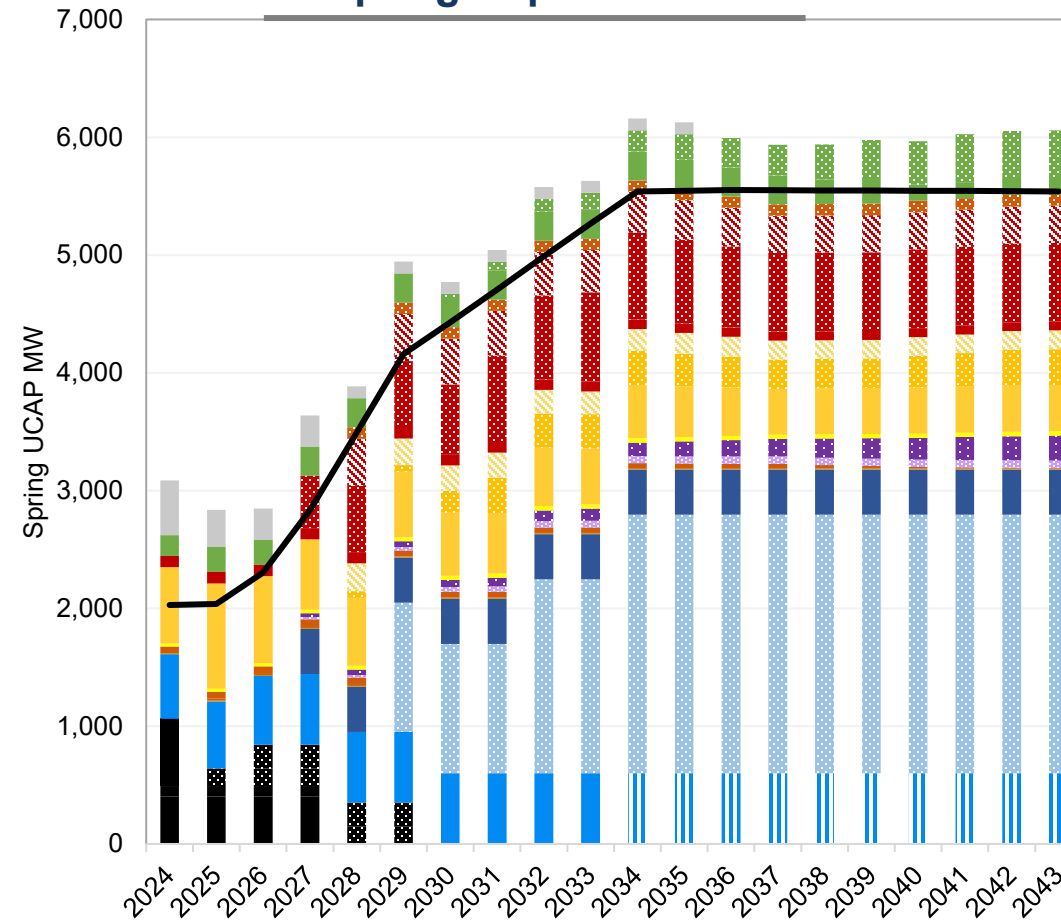
Current Market Rules

Fall Cap. vs. PRM



Generally Binding Season

Spring Cap. vs. PRM



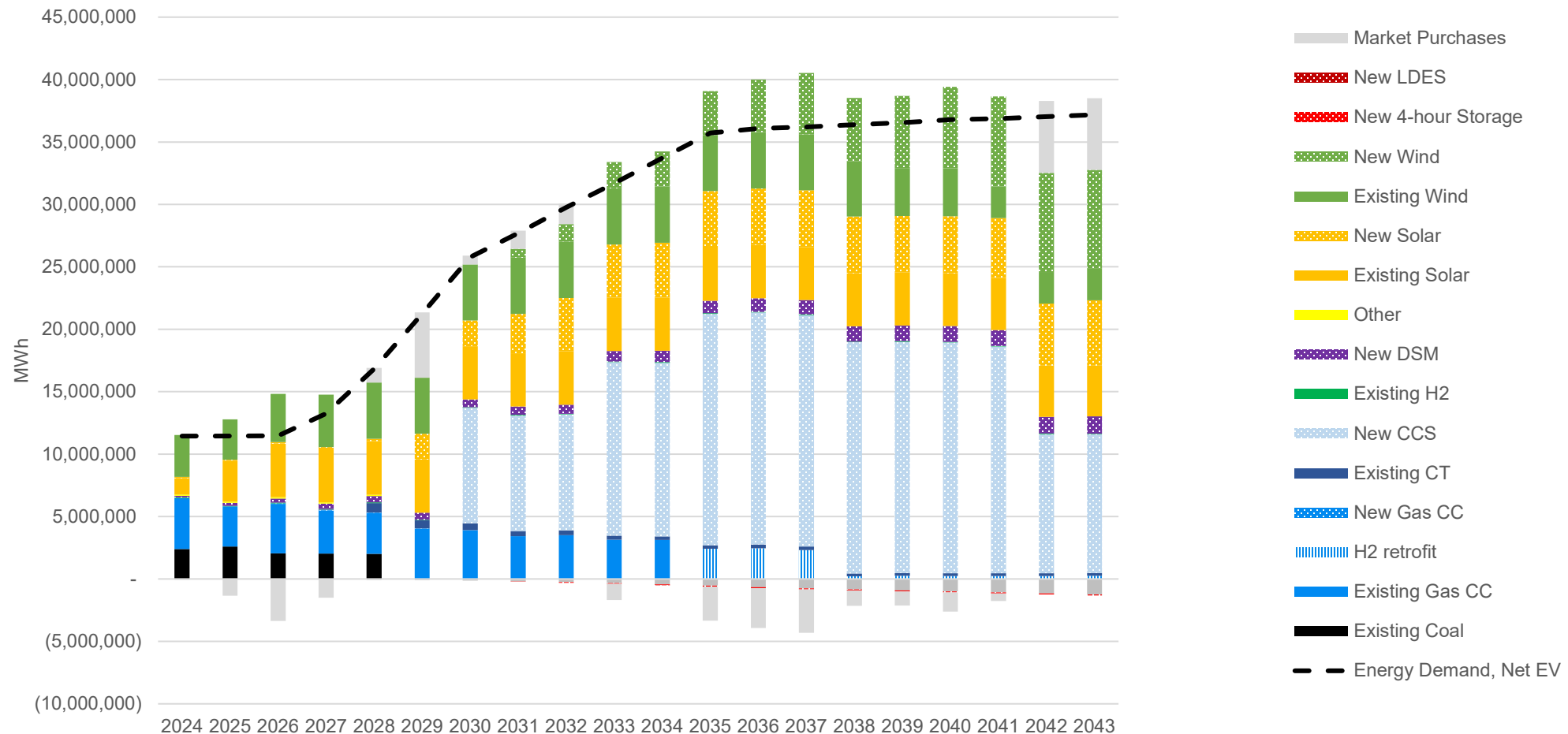
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

PORTFOLIO E – ENERGY POSITION

No New Uncontrolled Fossil

E

Current Market Rules



Note: The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.

PORTFOLIO F – RESOURCE ADDITIONS (NAMEPLATE MW)

No New Uncontrolled Fossil

F

Direct Loss of Load

Resource	Through 2029 ¹	2030-2034	2035+
Wind		800	1,550
Solar	797	100	1,025
4-hr Li-Ion Storage	1,886	125	
Long Duration Energy Storage	100		
Gas CCGT			
Gas Peaking			
Short-Term Thermal PPA & ZRCs	350 ²		
Gas CCGT w/ CCUS		2,340	
H2-enabled CC			
Sugar Creek			650 ³

1: All resources through 2029 are from the RFP.

2: Includes 150 MW of thermal PPA and 200 MW ZRC.

3: Retrofit to hydrogen in 2035

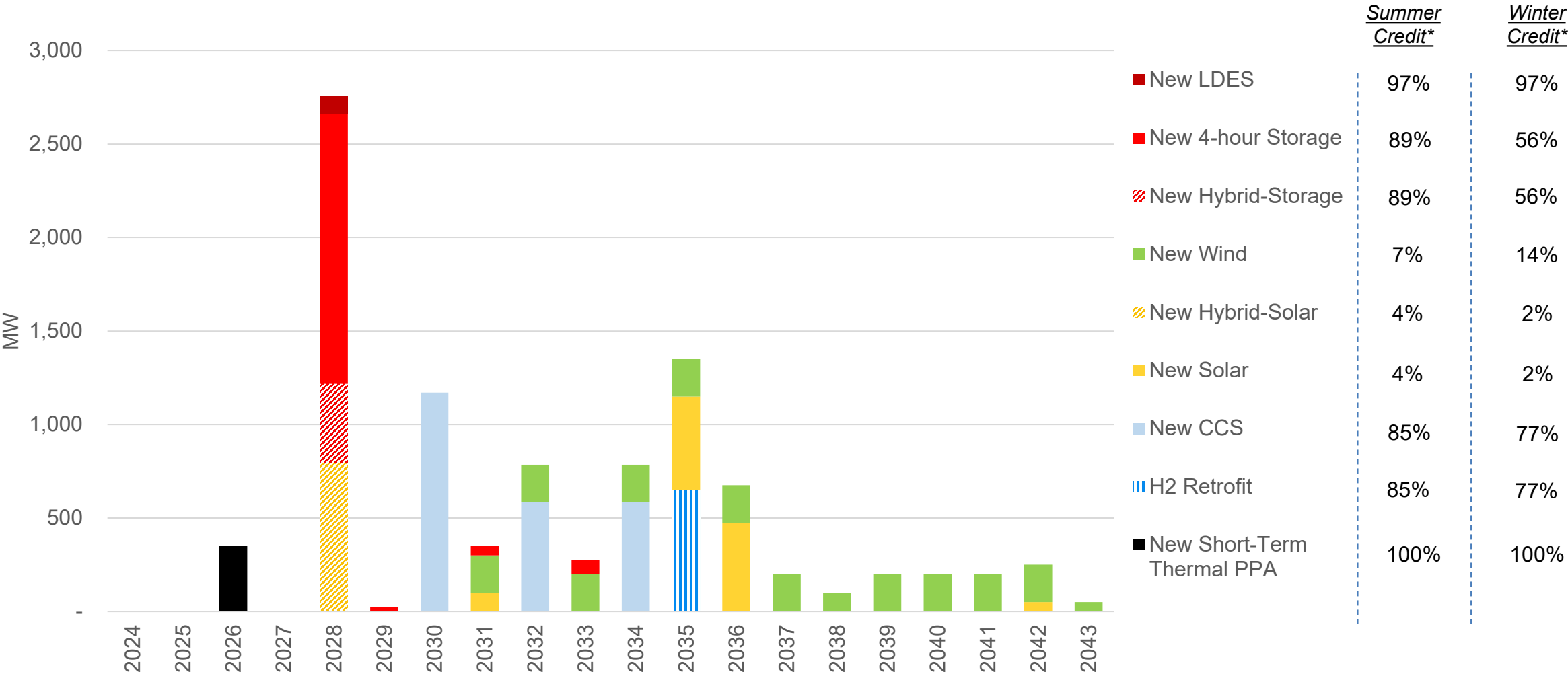
Note: All selected DSM and DR are summarized separately across portfolios

PORTFOLIO F – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

No New Uncontrolled Fossil

F

Direct Loss of Load



Note: There are two short-term PPAs in 2026. 200 MW lasts from 2026-2029, and 150 MW lasts from 2026-2030.

*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

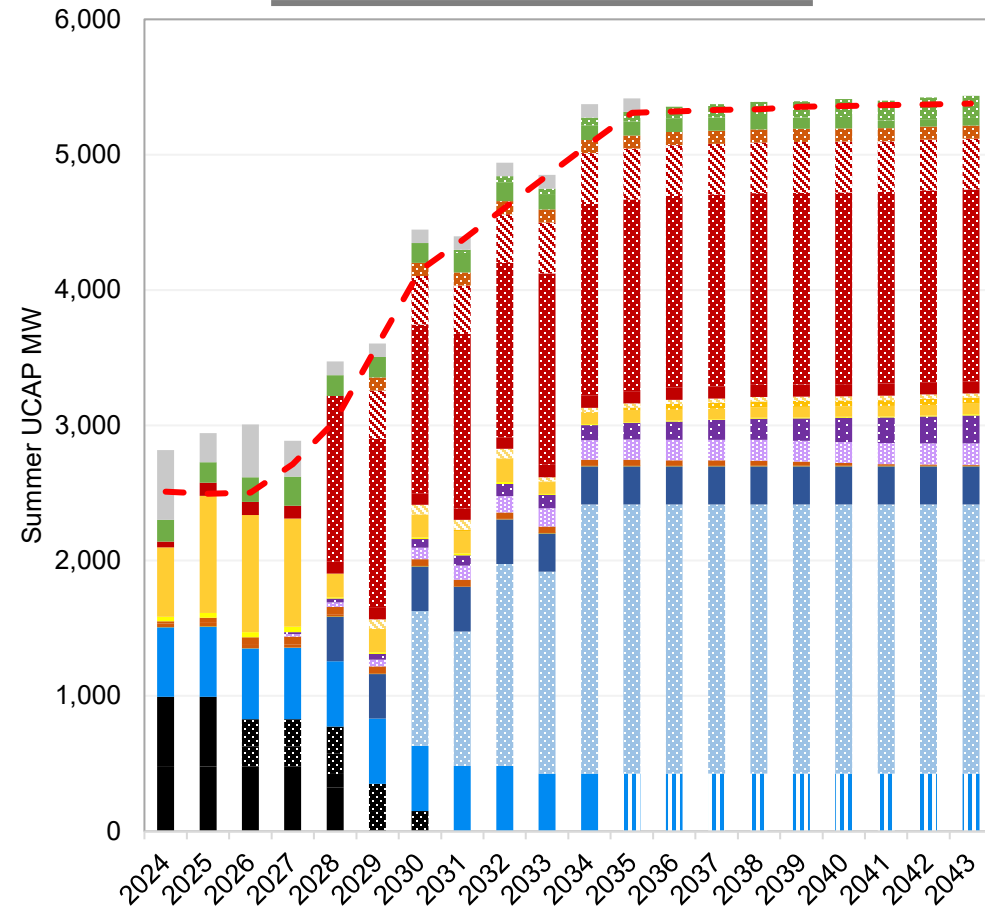
PORTFOLIO F – SUPPLY-DEMAND BALANCE

No New Uncontrolled Fossil

F

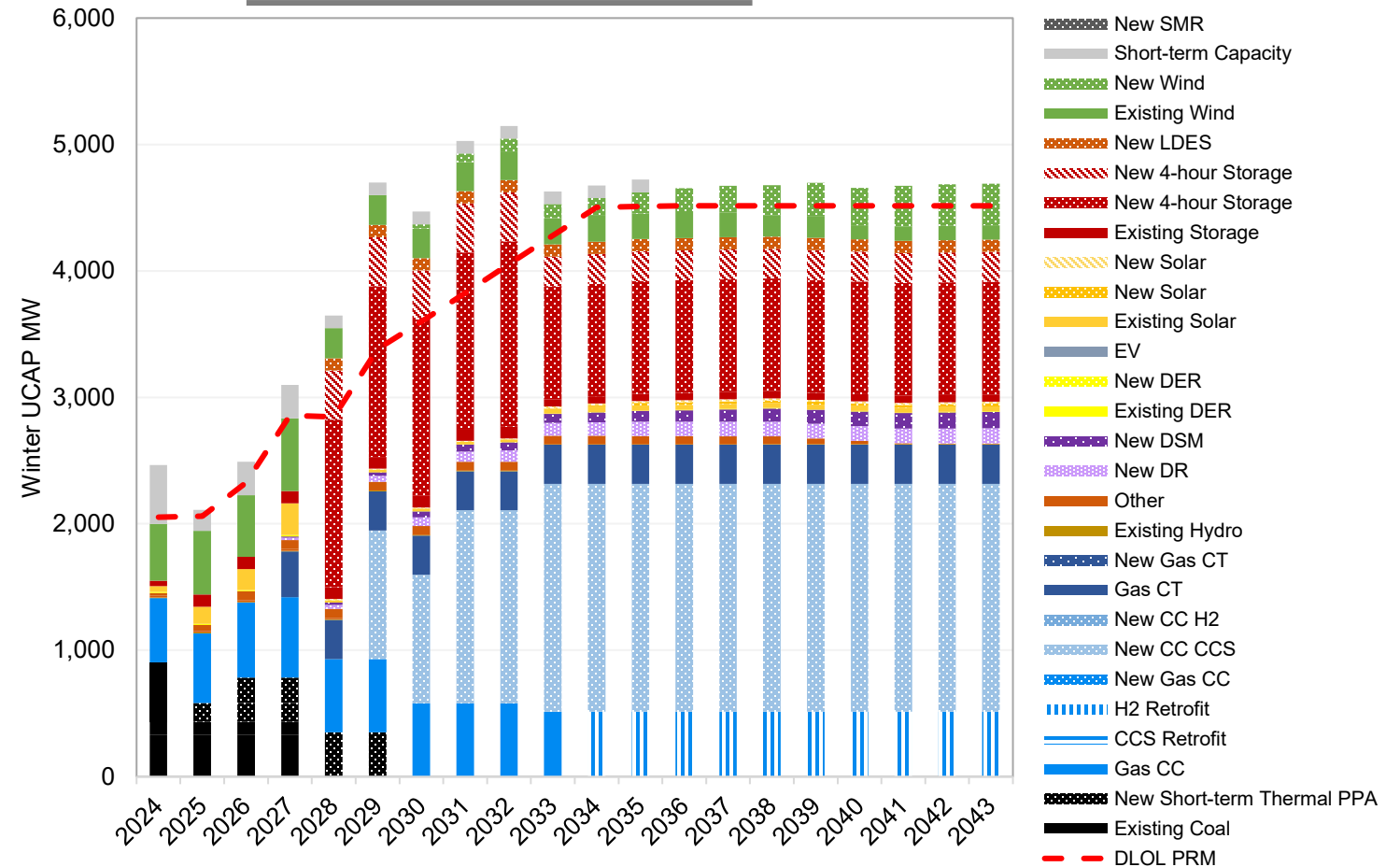
Direct Loss of Load

Summer Cap. vs. PRM



Generally Binding Season

Winter Cap. vs. PRM



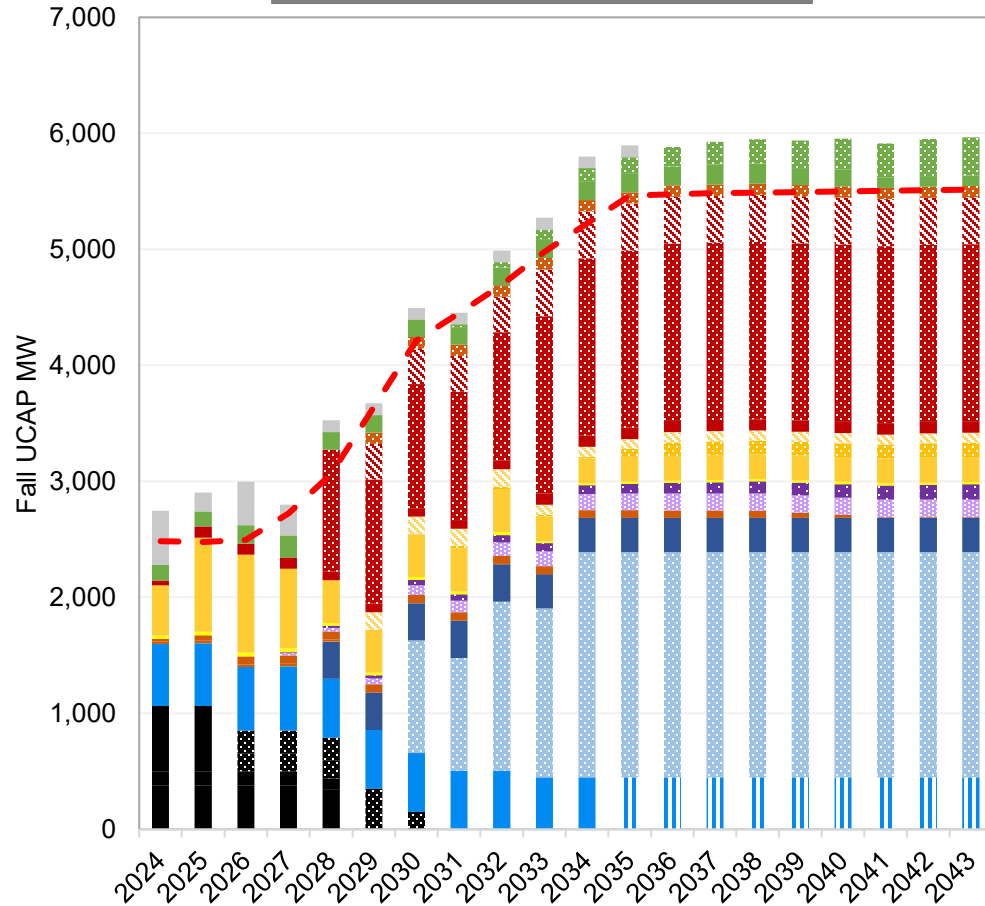
PORTFOLIO F – SUPPLY-DEMAND BALANCE

No New Uncontrolled Fossil

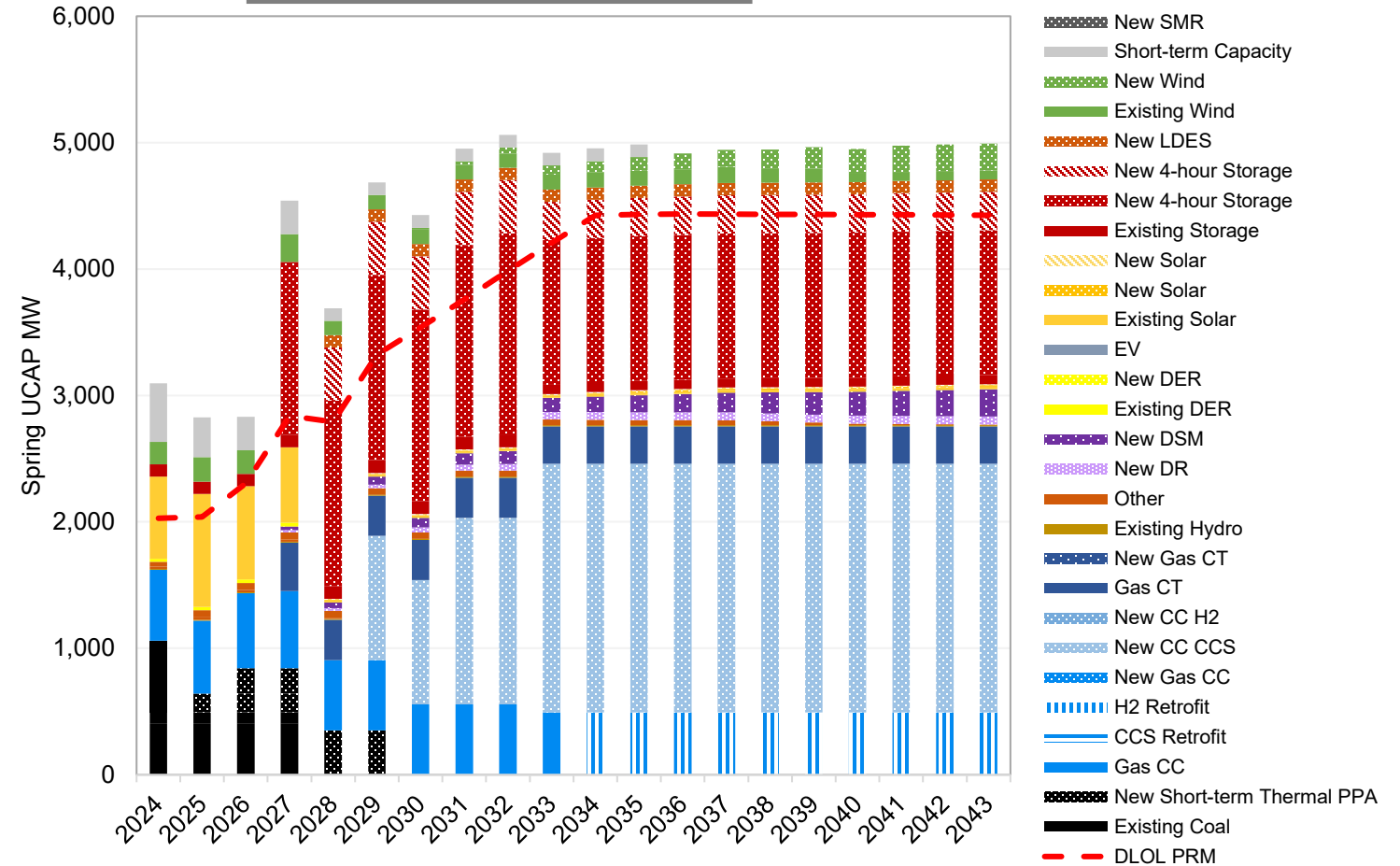
F

Direct Loss of Load

Fall Cap. vs. PRM



Spring Cap. vs. PRM

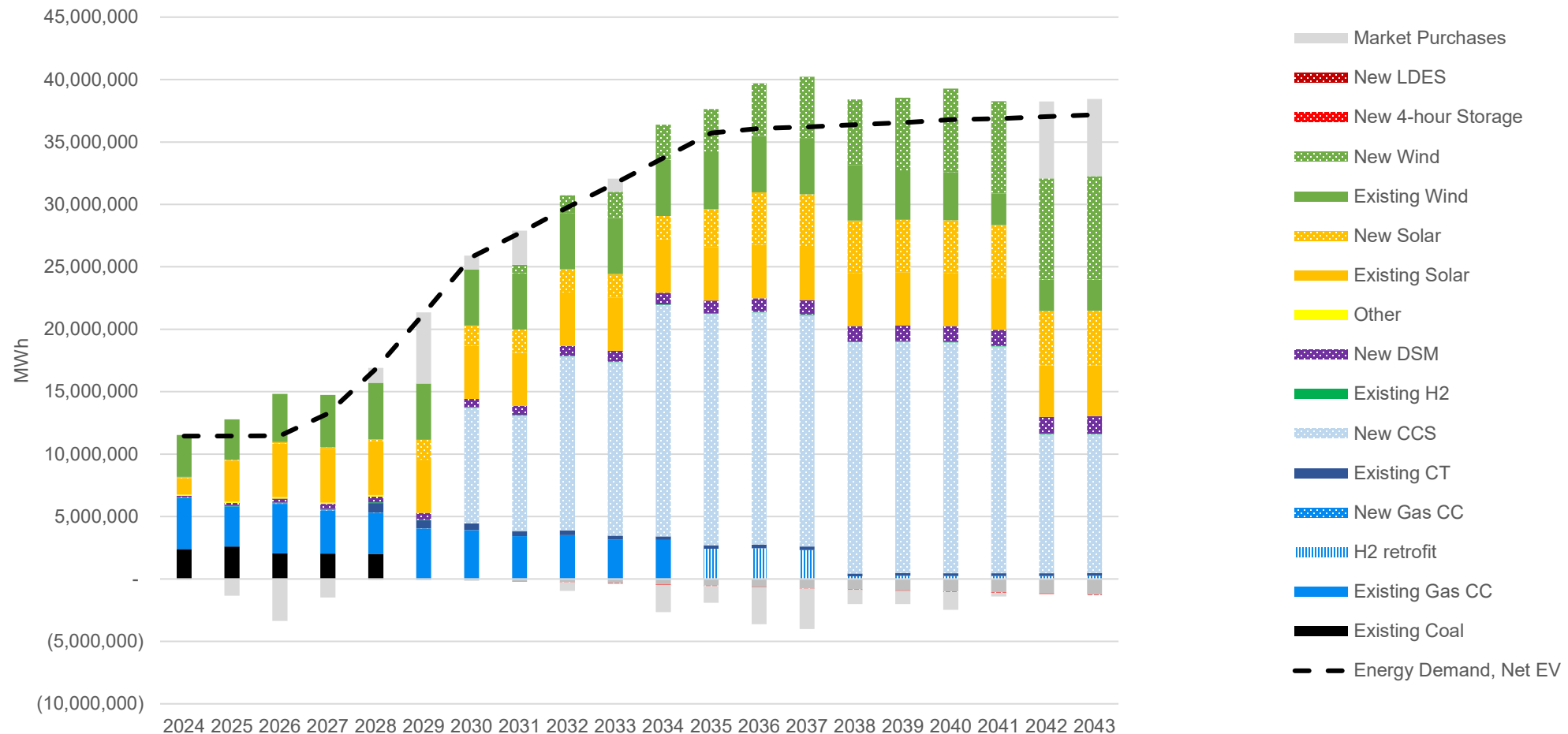


PORTFOLIO F – ENERGY POSITION

No New Uncontrolled Fossil

F

Direct Loss of Load



Note: The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.

ENERGY EFFICIENCY SELECTION

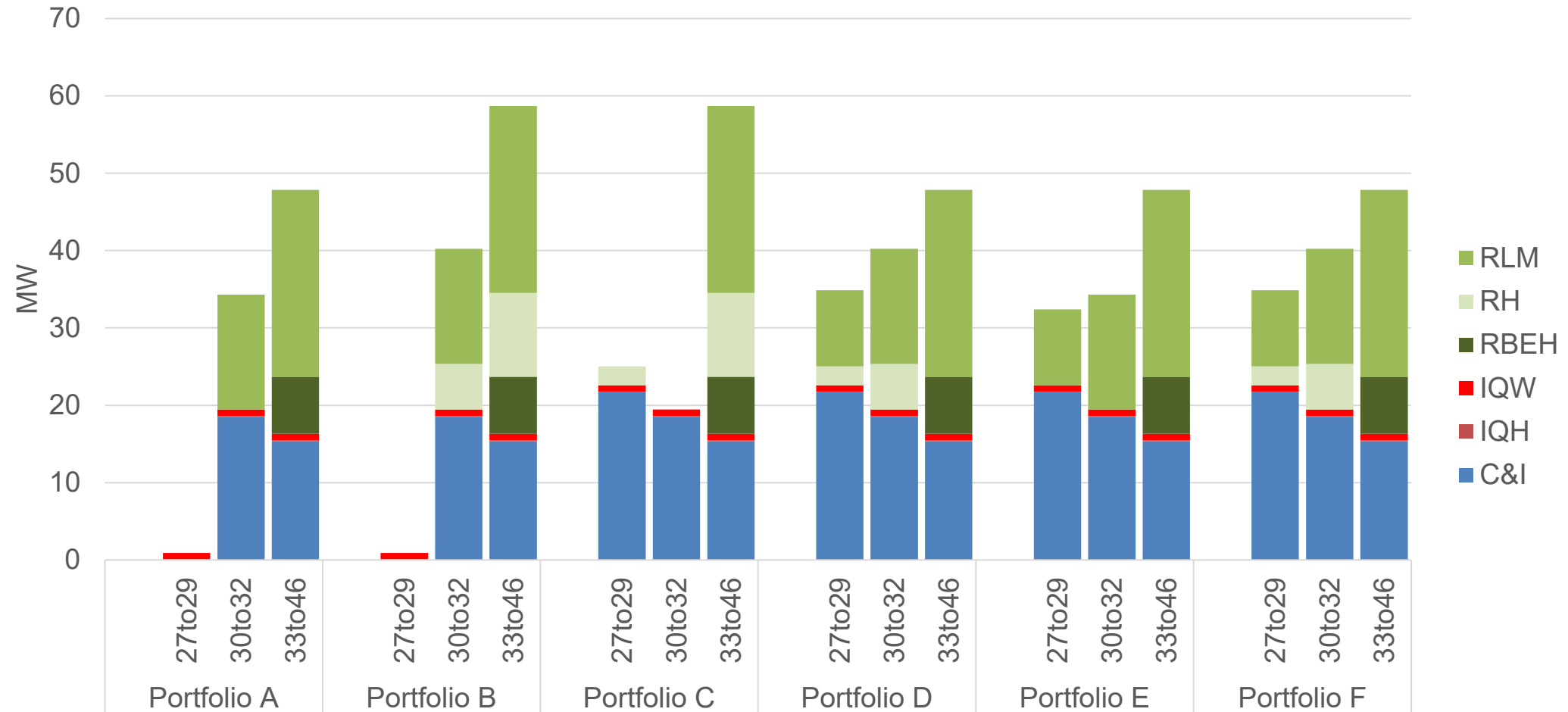
- The Low/Med Residential and C&I bundles are generally selected
- High Residential and Behavioral bundles are more marginal, but still selected across many years/portfolios

Program	Portfolio A			Portfolio B			Portfolio C			Portfolio D			Portfolio E			Portfolio F		
	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46
Res (Low/Med)	○	X	X	○	X	X	○	○	X	X	X	X	X	X	X	X	X	X
Res (High)	○	○	○	○	X	X	X	○	X	X	X	○	○	○	○	X	X	○
Res (Behavioral)	○	○	X	X	○	X	X	X	X	X	X	X	X	○	X	○	X	X
C&I	○	X	X	○	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQW	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQHear	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

X = Selected

○ = Not Selected

ENERGY EFFICIENCY IMPACT TO SUMMER PEAK (2035 SAMPLE YEAR)



DEMAND RESPONSE SELECTION ACROSS PORTFOLIOS

Program	Portfolio A	Portfolio B	Portfolio C	Portfolio D	Portfolio E	Portfolio F
RAP Thermostats	X	X	O	O	O	O
RAP Water Heaters	O	O	O	O	O	O
RAP Behavioral	X	X	X	X	X	X
RAP Dynamic Rates	X	X	O	O	X	X
RAP EV Managed Charging	O	O	O	O	O	O
RAP BTM Storage	O	O	O	O	O	O
RAP C&I	X	X	O	O	X	X
RAP Data Center	X	X	O	X	X	X

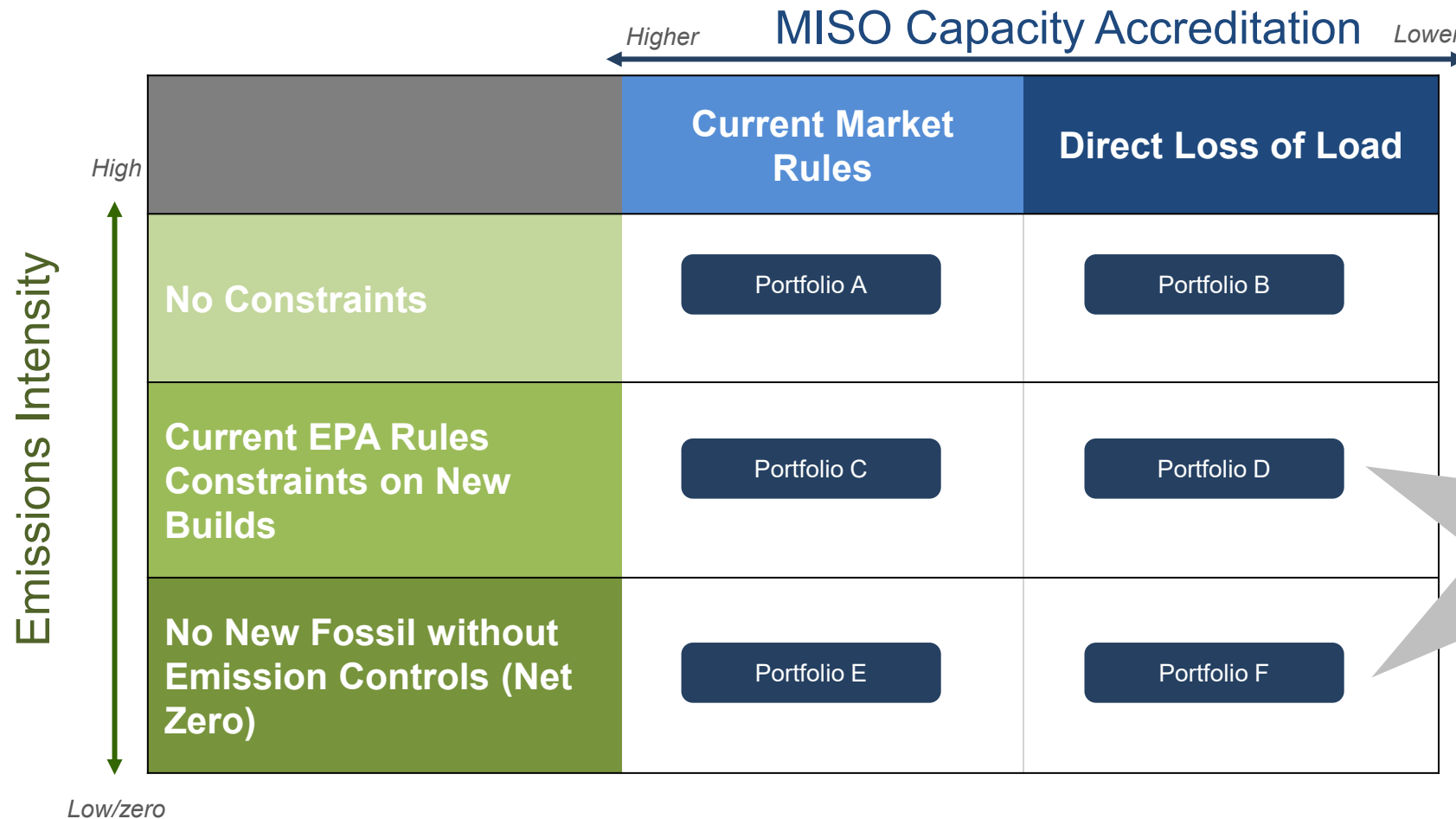
X = Selected
O = Not Selected

- Behavioral, data center, C&I, and dynamic rates demand response programs are most often selected across portfolios and will be considered as NIPSCO evaluates its preferred portfolio
- The thermostat program is selected in Portfolios A & B
- Water heater, EV managed charging, and BTM storage programs are not selected

ADDITIONAL PORTFOLIO CONSIDERATIONS

Six original portfolios were constructed to highlight the two primary constraints:

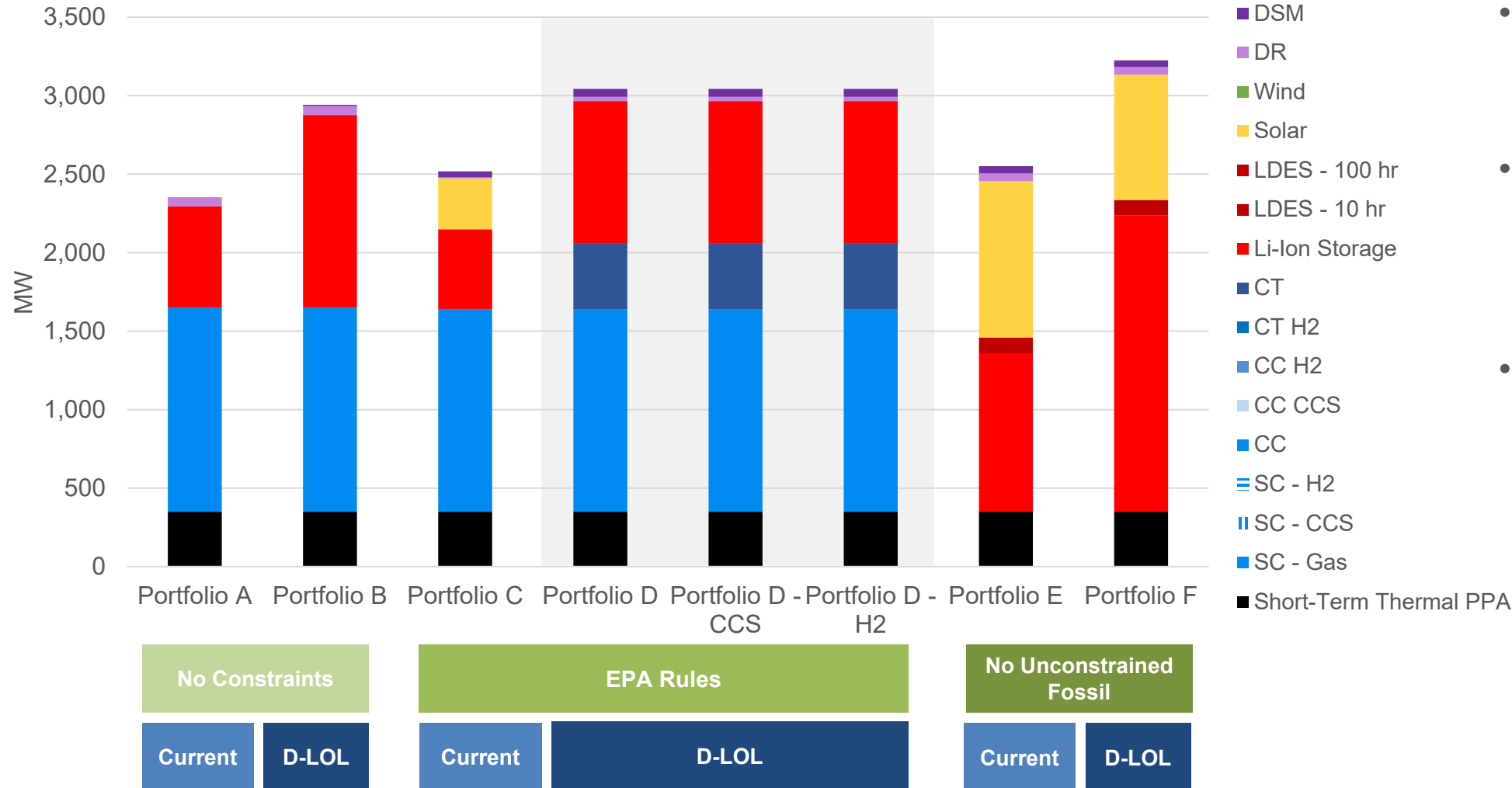
- 1) MISO's proposed D-LOL rules: reduce the capacity value primarily for solar and wind resources
- 2) EPA's emissions rules: constrain output or increase cost of new gas generation



PORTFOLIO D “VARIANTS”

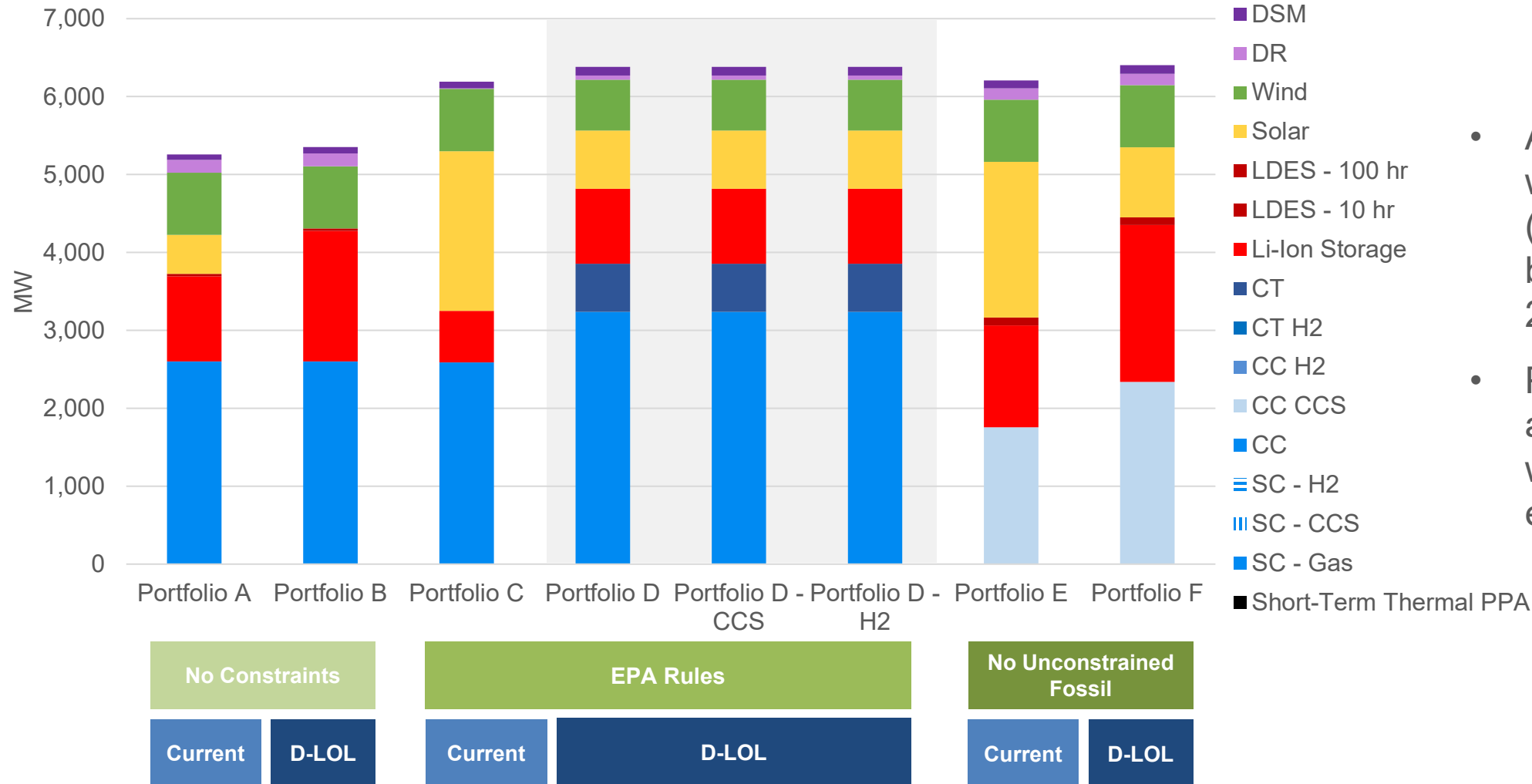
- **In order to assess potential portfolio variants that would allow new fossil resource additions without emission controls at the initial construction in the near-term, but still achieve net zero by 2040, NIPSCO contemplated variants to Portfolio D:**
- **Portfolio “D_CCUS”**
 - Preserve optimized expansion plan from original inputs and constraints
 - Assume future CCUS retrofit on up to 2,000 MW of new combined cycle capacity over the 2035-2037 time period
 - Assume remaining combined cycle and natural gas peaking capacity is retrofit to burn up to 100% hydrogen over the long-term
- **Portfolio “D_H2”**
 - Preserve optimized expansion plan from original inputs and constraints
 - Assume all thermal resources are retrofit to burn up to 100% hydrogen over the long-term

RESOURCE ADDITIONS COMPARISON ACROSS PORTFOLIOS – CUMULATIVE NAMEPLATE Through 2029



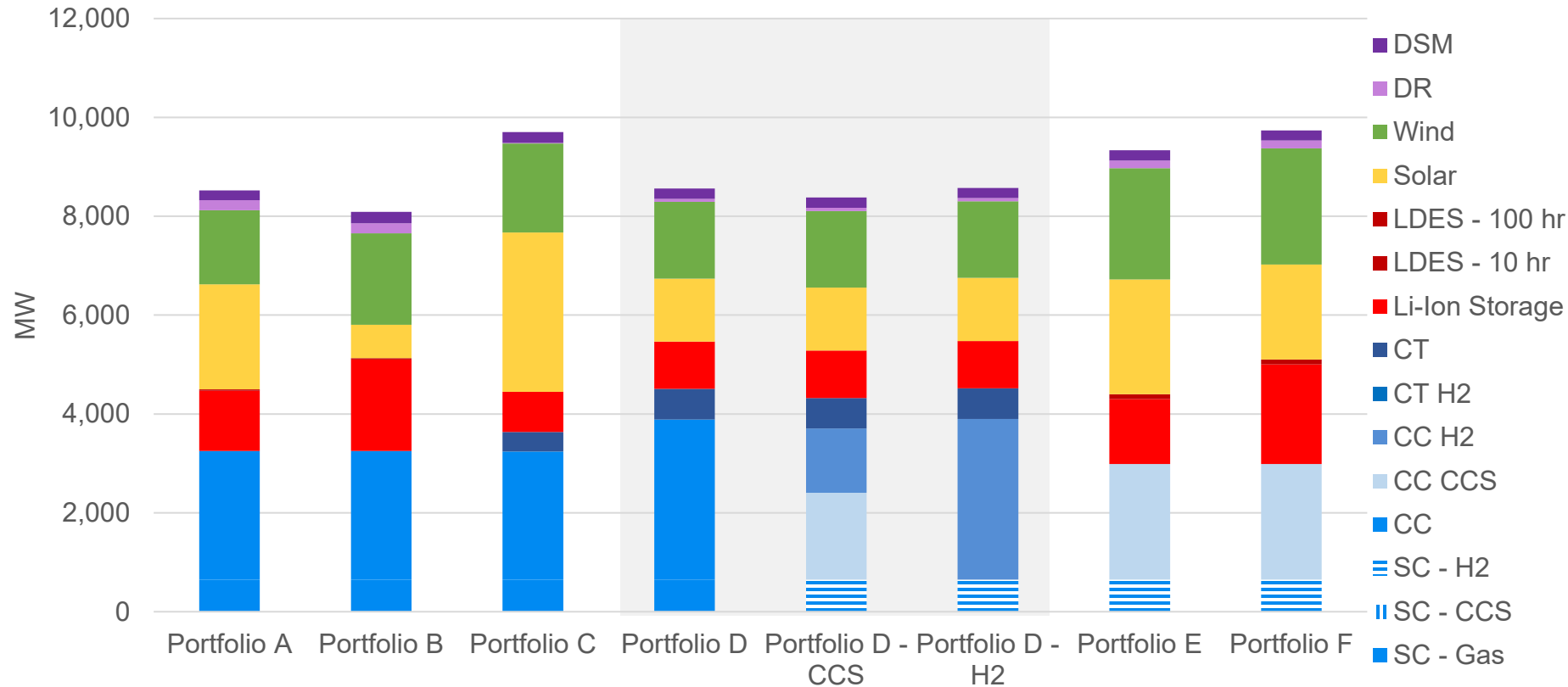
- D-LOL portfolios have more capacity overall.
- Portfolios with greatest emissions restrictions add more solar.
- Portfolios E and F would rely exclusively on solar, storage, short-term contracts, and EE/DSM through 2029.

RESOURCE ADDITIONS COMPARISON ACROSS PORTFOLIOS – CUMULATIVE NAMEPLATE Through 2034



- All portfolios add wind and solar (aside from B) between 2030 and 2034.
- Portfolios E and F add natural gas CC with CCUS in the early 2030s.

RESOURCE ADDITIONS COMPARISON ACROSS PORTFOLIOS – CUMULATIVE NAMEPLATE Through 2043



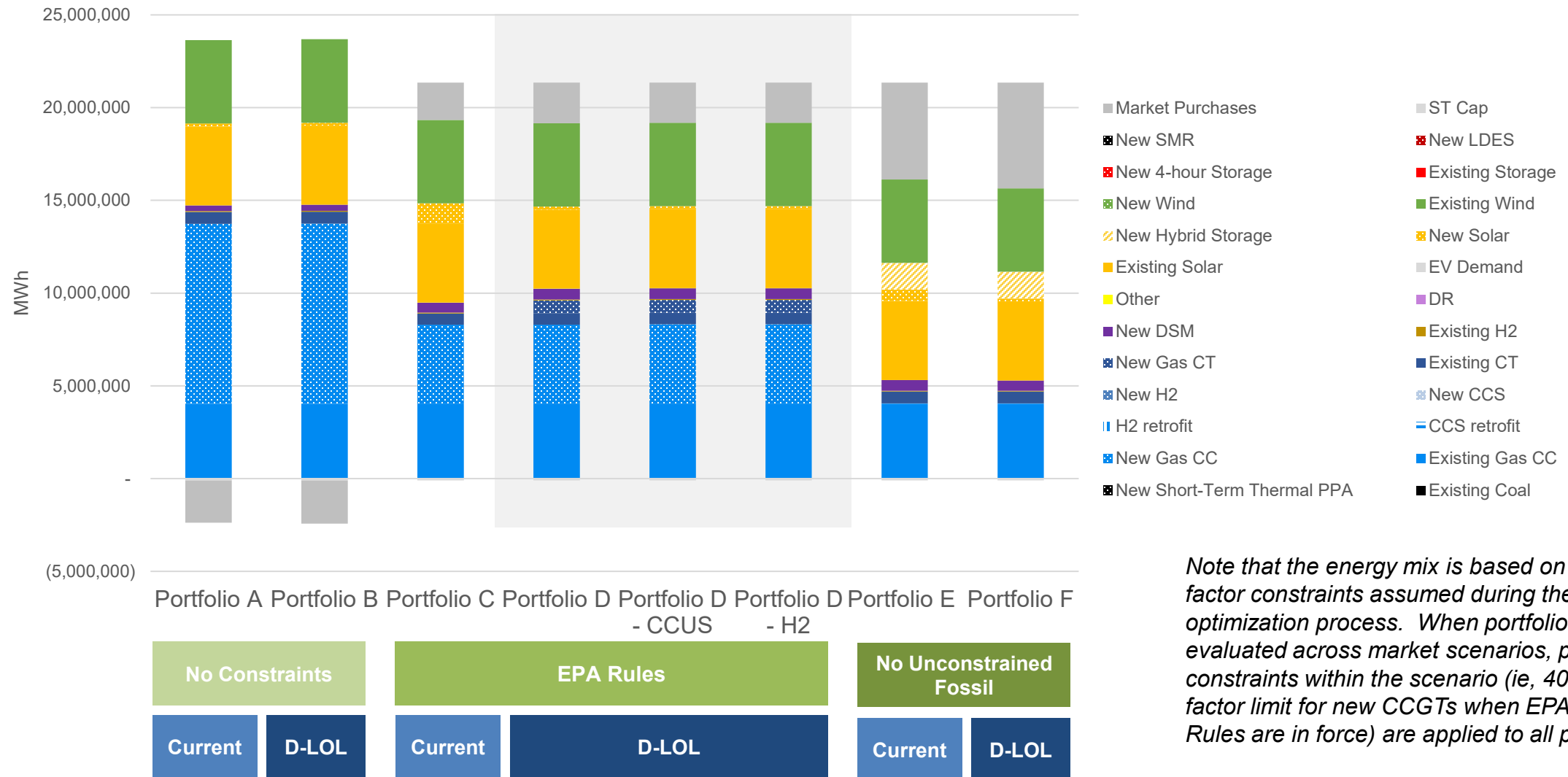
- All portfolios add long-term wind and solar.
- Portfolio D variants would retrofit CCGT or peaking capacity with CCUS or hydrogen capability.



Note that the three converted CCUS units in the D-CCUS Portfolio would be expected to be de-rated from 650 MW to 585 MW. Small resulting seasonal capacity shortfalls are assumed to be covered via short-term capacity purchases.

ENERGY MIX ACROSS PORTFOLIOS

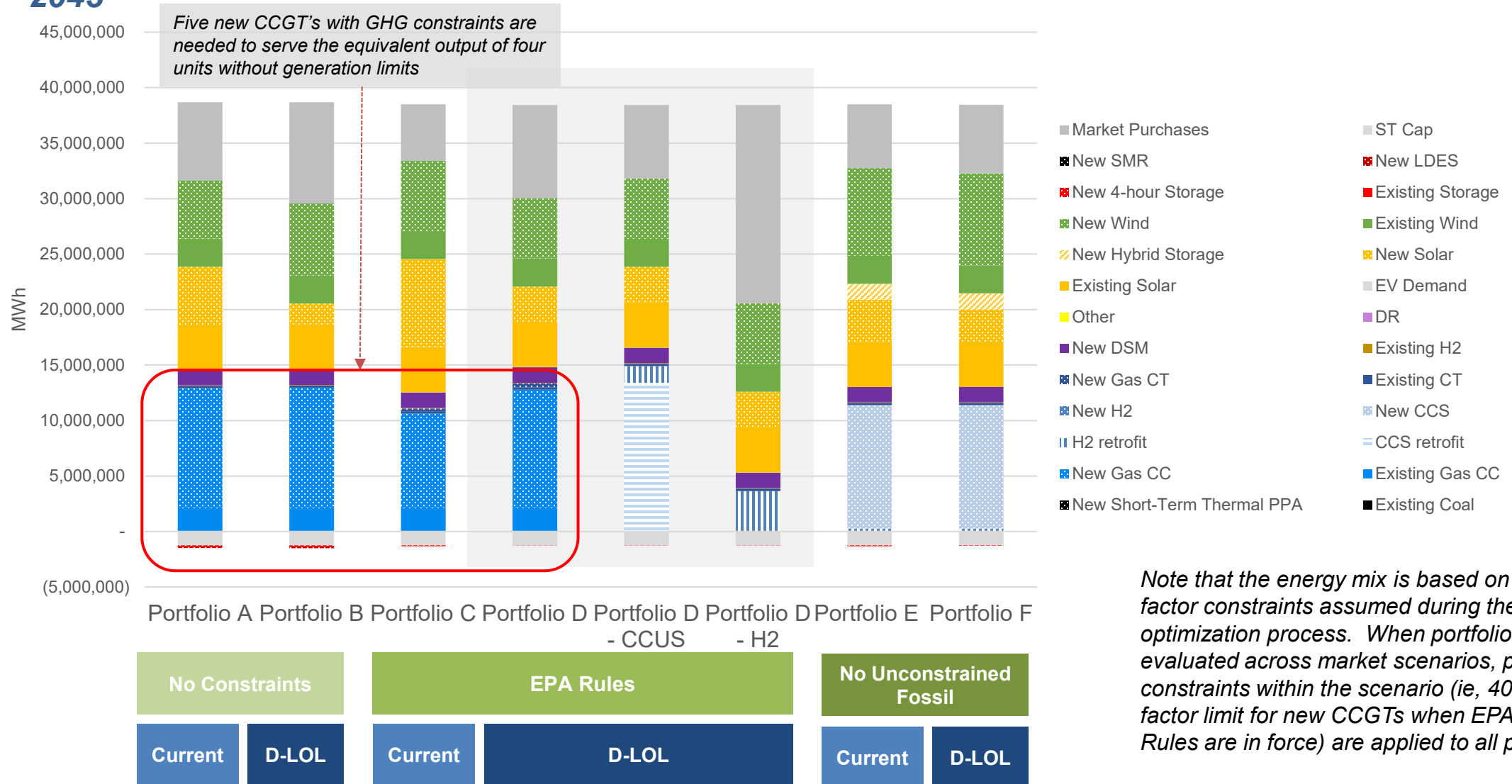
2029



Note that the energy mix is based on capacity factor constraints assumed during the portfolio optimization process. When portfolios are evaluated across market scenarios, prevailing constraints within the scenario (ie, 40% capacity factor limit for new CCGTs when EPA GHG Rules are in force) are applied to all portfolios.

ENERGY MIX ACROSS PORTFOLIOS

2043



Note that the energy mix is based on capacity factor constraints assumed during the portfolio optimization process. When portfolios are evaluated across market scenarios, prevailing constraints within the scenario (ie, 40% capacity factor limit for new CCGTs when EPA GHG Rules are in force) are applied to all portfolios.

PORTFOLIO COMPARISON – RESOURCE ADDITIONS ABOVE CURRENT PLAN

Given the lower expected seasonal capacity credit of renewables with or without MISO’s D-LOL rule, NIPSCO would need to add installed capacity that is around double its supply-demand gap (summer) in almost all portfolios.

	A	B	C	D (all)	E	F
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	Late 2030s	At Start-up	At Start-up
Wind	1,500	1,850	1,800	1,550	2,250	2,350
Solar	2,125	675	3,235	1,275	2,322	1,922
Storage*	1,249	1,882	811	959	1,409	2,111
Gas CCGT	2,600	2,600	2,585	3,235		
Gas Peaking			400	618		
Gas CCGT w/CCUS					2,340	2,340
Sugar Creek	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DR / DSM	440	440	330	315	370	410
Total ICAP Additions Through 2043 (excl. DSM/DR)	7,474 MW	7,007 MW	8,831 MW	7,637 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer) Covered	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

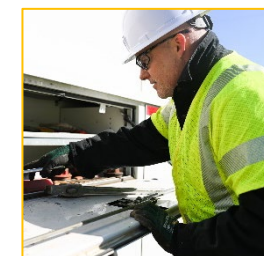
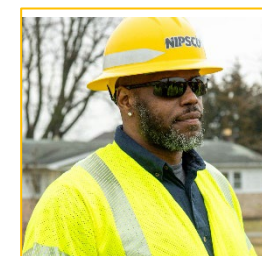
*Includes both 4-hour Lithium-ion and long-duration storage

KEY SUMMARY OBSERVATIONS AND CONCLUSIONS

- **Short-term capacity purchases serve as an effective bridge to new resources, especially given uncertainty in D-LOL accreditation and large load growth potential.**
- **Storage additions will play a major role in meeting incremental capacity requirements through the end of the decade.**
 - NIPSCO will need to be flexible around the quantities of new storage to be procured from the RFP, as storage additions will be positioned as a key “swing resource” to meet evolving capacity needs that will be heavily influenced by D-LOL accreditation reforms.
 - Long duration energy storage (LDES) was selected in certain portfolios and will likely have a role to play in the near-to-mid term. NIPSCO will need to track technology developments, costs, and accreditation data for different storage technologies and adapt resource additions accordingly.
- **New natural gas combined cycle capacity is needed to meet potentially significant energy and capacity needs associated with new large load growth across all MISO accreditation and emission reduction portfolio concepts.**
- **Significant energy efficiency and demand response is included across all portfolios and is likely to continue to play an important role in NIPSCO’s portfolio.**



LUNCH



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER





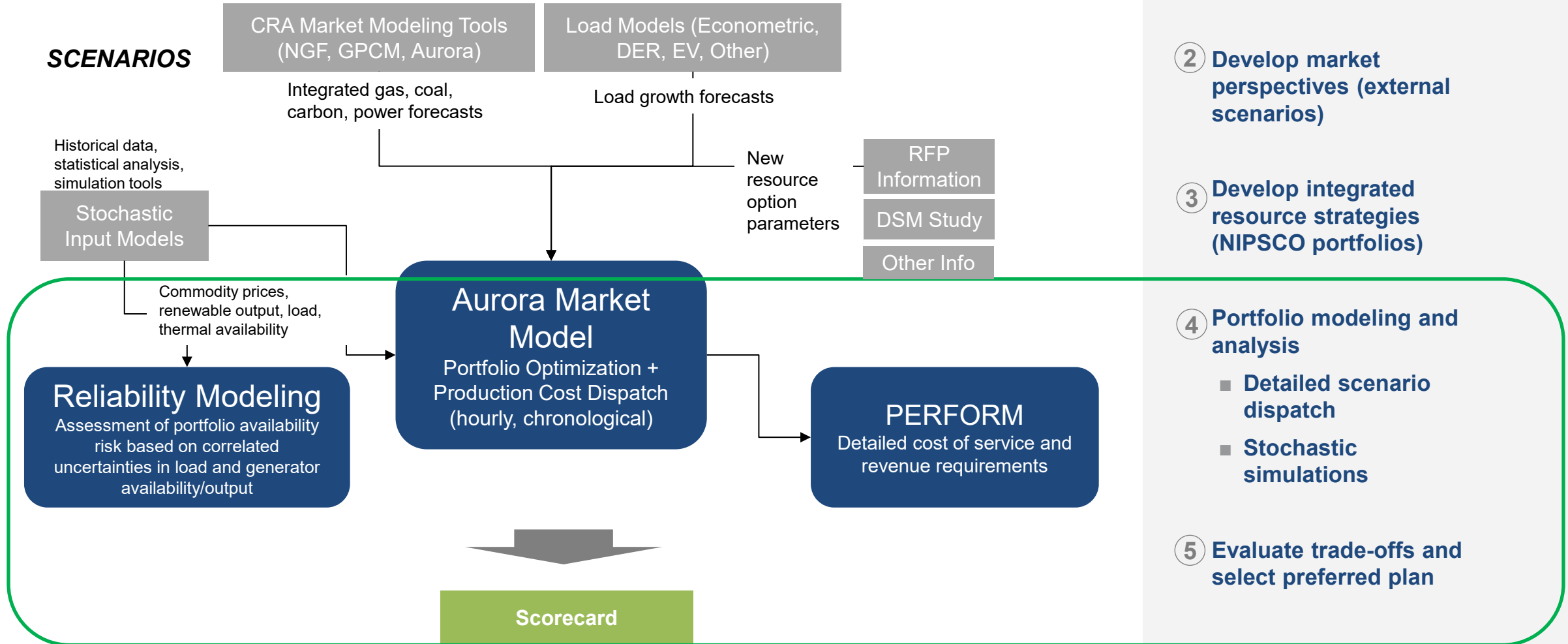
OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

2024 PUBLIC ADVISORY PROCESS NEXT STEPS

Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA



RESOURCE PLANNING APPROACH



REMAINING ANALYSIS COMPONENTS

- **Full Portfolio Analysis across Five Scenarios**
 - NIPSCO will analyze each portfolio within each scenario to assess cost and emission profiles
- **Stochastic Analysis**
 - NIPSCO will analyze stochastic risks associated with wind and solar output, load, thermal resource availability, and natural gas and power price uncertainty for Portfolios A-F for the sample year of 2030
- **Portfolio Scorecard**
 - NIPSCO will assess portfolio performance across key objectives and metrics

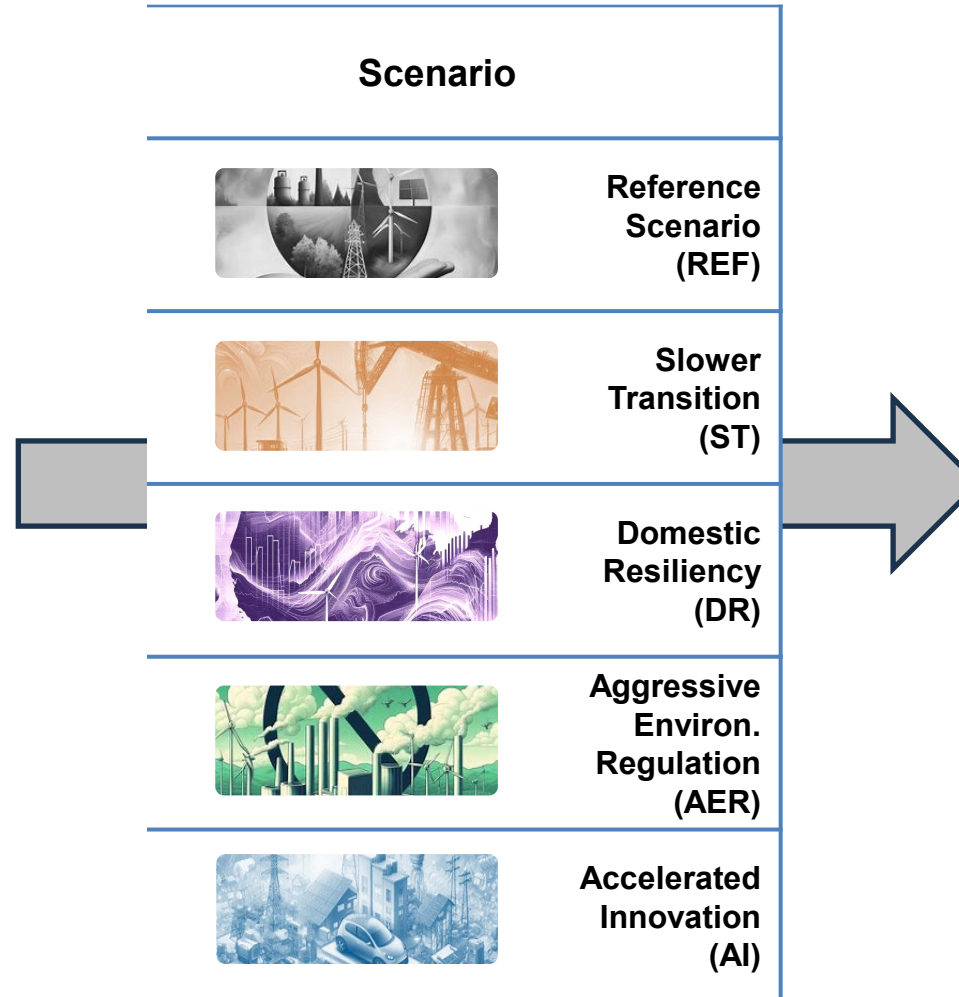
REMAINING ANALYSIS COMPONENTS

- **Alternative “Flat Load” Portfolio Analysis**
 - Based on stakeholder input, NIPSCO will evaluate portfolio implications without the addition of new large loads
- **High Emerging Load Sensitivity Testing**
 - NIPSCO will evaluate portfolio requirements for the high emerging load sensitivity for a sample of portfolio concepts
- **DSM Sensitivity Testing**
 - NIPSCO will perform an additional DSM sensitivity evaluation for Enhanced RAP (EE) and MAP (DR) for a sample of portfolios

SCENARIO ANALYSIS

Each of the eight portfolios will be evaluated across the five market scenarios to assess relative impacts under different states of the world with varying:

- Fuel prices
- MISO power prices
- Environmental policy (EPA rules, tax credits)
- Load

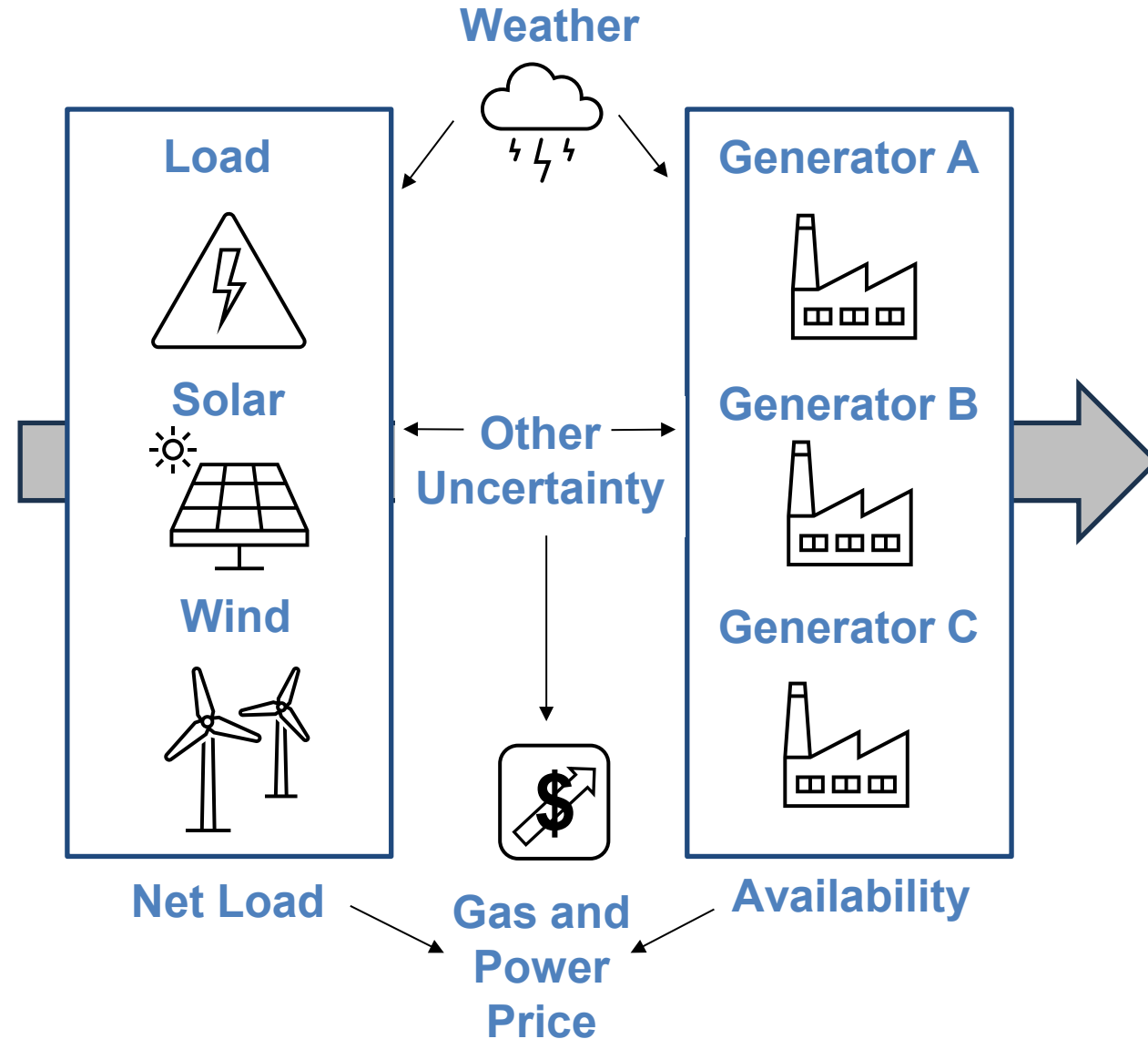


Key Outputs

- Annual revenue requirements
- Net present value of revenue requirements (30-year and 10-year)
- CO2 Emissions
- Other portfolio performance metrics

STOCHASTIC ANALYSIS

- Each of the eight portfolios will be evaluated across the stochastic distribution of key variables for the 2030 sample year:
 - Fuel prices
 - MISO power prices
 - Load
 - Solar and wind output
 - Thermal resource availability



Key Outputs

- Forced market exposure metrics
- 95th and 5th percentile cost metrics

PORTFOLIO PERFORMANCE WILL BE DISTILLED INTO AN INTEGRATED SCORECARD

Objectives	Indicators	Metrics for 2024
Affordability	Cost to Customer	- Near-term and long-term Impact to customer bills Metric: 10-year and 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	Cost Certainty	- Certainty that revenue requirement within the most likely range of outcomes Metric: Scenario range NPVRR
	Cost Risk	- Risk of unacceptable, high-cost outcomes Metric: 95th% cost risk from probabilistic analysis
	Lower Cost Opportunity	- Potential for lower cost outcomes Metric: 5th% cost risk from probabilistic analysis
Environmental Sustainability	Carbon Emissions	- Carbon intensity of portfolio Metric: Cumulative carbon emissions (2024-40 short tons of CO2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	Reliability, Flexibility	- The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules Metric: Loss of Load Expectation proxy ("Forced market exposure") metrics for NIPSCO system from probabilistic reliability analysis Metric: Capacity able to respond within 30 mins
Positive Social, & Economic Impacts	Local Investment in Economy	- The effect on the local economy from new projects and ongoing property taxes and targeted investment Metric: NPV of property taxes from the entire portfolio

2024 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 April 23 rd	Meeting 2 June 24 th	Meeting 3 August 21 st	Meeting 4 October 8 th	Meeting 5 October 28 th
Location	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943	Fair Oaks Farms, 865 N 600 E, Fair Oaks, IN 47943
Content	2021 Short Term Action Plan Update (Retirements, Replacement projects) - Resource Planning and 2024 Continuous Improvements 2024 Public Advisory Process 2024 Policy Update (incl. IRA and EPA) - Update on Key Inputs/Assumptions (core demand forecast, new considerations for demand) - Scenario Themes – Introduction - RFP Overview	- MISO Regulatory Developments and Initiatives - Load scenarios - Update on Key Inputs/Assumptions (commodity prices) - Scenarios and Stochastic Analysis - Preliminary RFP Results	- DSM Modeling and Methodology - RFP detailed update - Portfolio modeling input review	Initial portfolio modeling results	- Modeling results and scorecard - Preferred plan and logic relative to alternatives 2024 NIPSCO Short Term Action Plan
Meeting Goals	- Communicate what has changed since the 2021 IRP (incl. IRA changes) - Communicate environmental policy considerations - Communicate updates to key inputs/assumptions - Provide RFP Overview - Communicate the 2024 public advisory process, timing, and input sought from stakeholders	- Communicate resource needs due to potential demand - Common understanding of MISO regulatory updates - Communicate scenario themes and stochastic analysis approach, along with major input details and assumptions - Communicate commodity prices impacts - Communicate preliminary RFP results	- Common understanding of DSM modeling methodology - Provide detailed update on the RFP and verification - Explain next steps for portfolio modeling	Develop a shared understanding of modeling outcomes and preliminary results to facilitate stakeholder feedback	- Respond to key stakeholder comments and requests - Communicate NIPSCO's preferred resource plan and short-term action plan - Obtain feedback from stakeholders on preferred plan



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

CLOSING & STAKEHOLDER COMMENTS





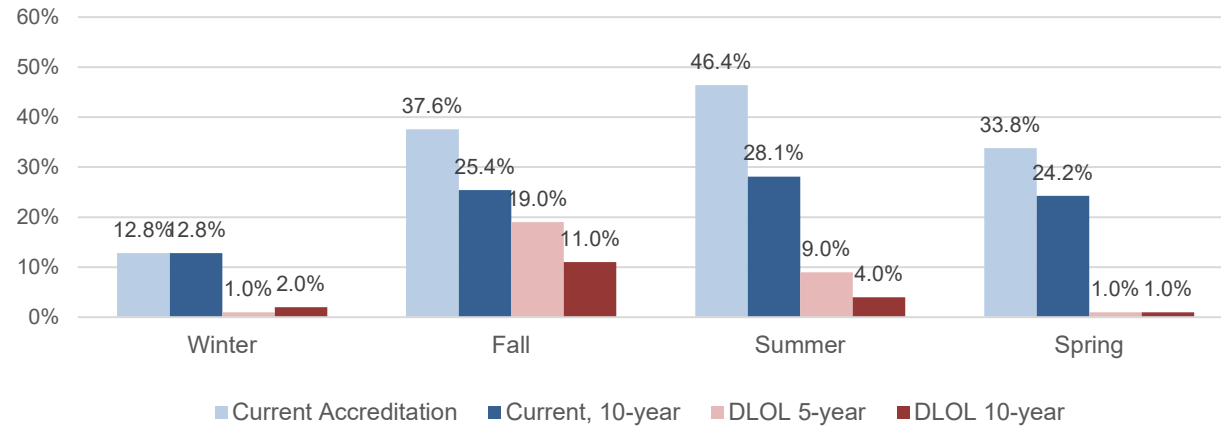
OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

APPENDIX

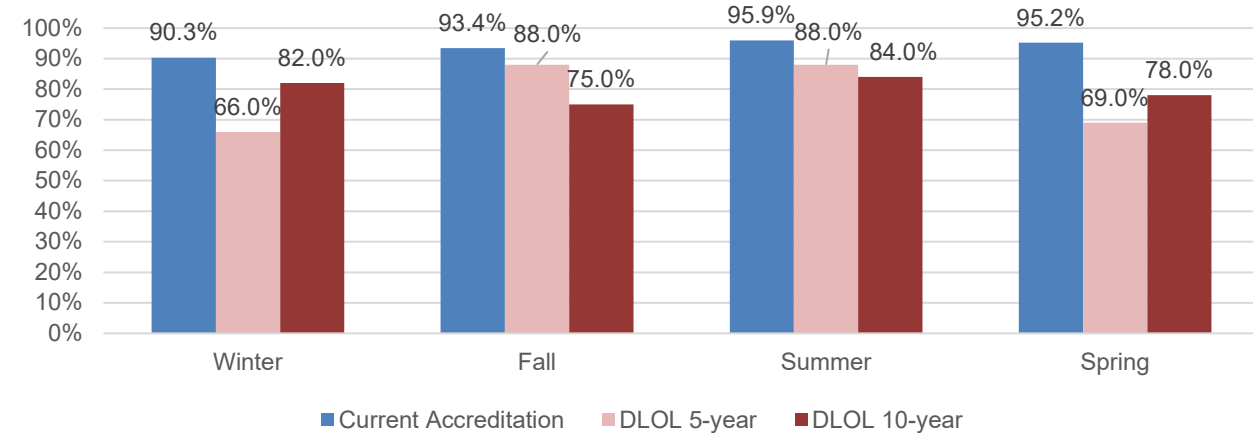


CAPACITY ACCREDITATION TRAJECTORIES UNDER D-LOL

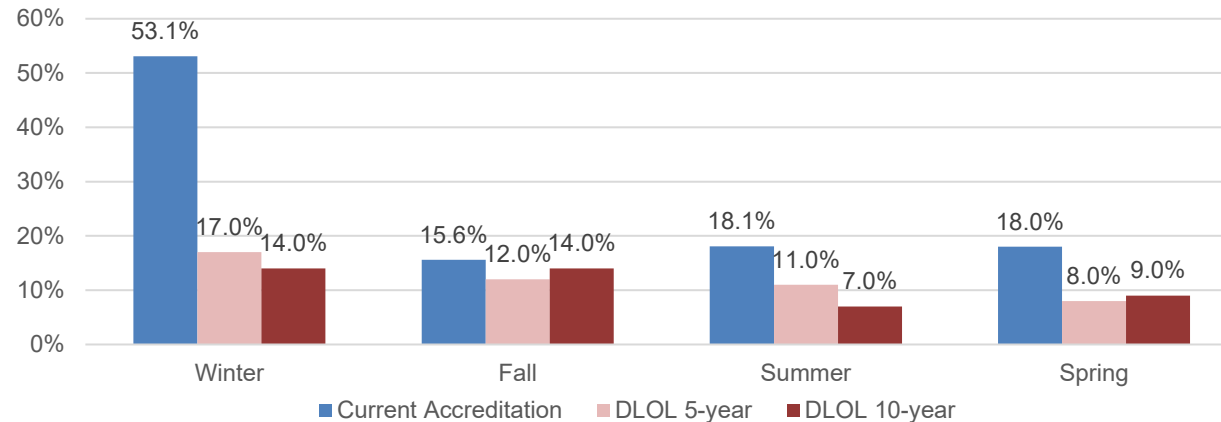
Indicative Seasonal Capacity Accreditation - Solar



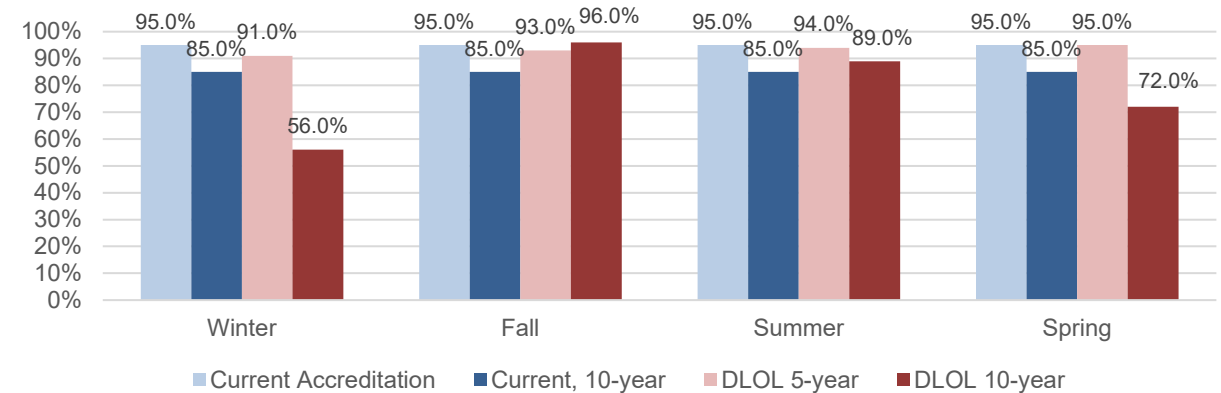
Indicative Seasonal Capacity Accreditation – Gas CT



Indicative Seasonal Capacity Accreditation - Wind



Indicative Seasonal Capacity Accreditation - Storage





Northern Indiana Public Service Company LLC
2024 Integrated Resource Planning
Public Advisory Meeting #4
SUMMARY

October 8, 2024

Welcome & Introduction

Tara McElmurry, Communications Manager, NiSource

Kick Off

Vince Parisi, President & COO, NIPSCO

Recap of 2024 IRP Process

Abe Lang, Manager Strategy & Risk, NiSource

Abe Lang, Manager Strategy & Risk at NiSource, provided an overview of the revised stakeholder advisory process timeline, including the dates for rescheduled stakeholder meetings and the revised IRP submission date. He then summarized stakeholder questions and feedback received during and since Public Advisory Meeting #3.

Public Advisory Process and Responses to Third Stakeholder Meeting Comments

Abe Lang, Manager Strategy & Risk, NiSource

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

- We received Aurora files from you all on September 17th. As part of the last IRP's process there had been an agreement between CAC and NIPSCO to give the CAC an Aurora license to be able to look at those files because we hadn't been able to in the last IRP. We have a license agreement with Energy Exemplar but we cannot use Aurora right now, so it has been almost a month since NIPSCO has given us the files but we cannot look at them. Energy Exemplar's rep has now referred us to a different technical support person. So we have only been able to look at the summary files that NIPSCO sent over and I just wanted to be clear that there are a lot of things that we haven't been able to look at yet and comment on and I want to make sure that there is still time in the process to do all that and provide feedback to be incorporated into the IRP filing.
 - We can take this offline and talk through it today. We are going to be releasing additional data files today and NIPSCO can try to help facilitate things with Energy Exemplar to make sure that your license is usable. We have extended the IRP timeline for a variety of reasons but we can work with you guys at the conclusion of today's meeting to talk through what is needed to get that license working.

Portfolio Development Process and NIPSCO Portfolio Construction

Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA

Abe Lang kicked off the section with a review of NIPSCO's overall resource planning approach and modeling process. He then outlined the key considerations associated with portfolio construction, including major input assumptions and modeling constraints. Mr. Lang then provided a recap of NIPSCO's current capacity position, the new resource options under consideration, and the portfolio construction framework that defined six distinct themes based on MISO capacity accreditation rules and the emission intensity of NIPSCO's portfolio.

Pat Augustine, Vice President at CRA, then provided a detailed overview of the six portfolios (Portfolios A through F) that were developed through NIPSCO's portfolio optimization analysis. This included a summary of resource additions over time, portfolio supply-demand balances over time across all four MISO seasons, and projections of the portfolio's energy mix over time. Mr. Augustine then reviewed the energy efficiency and demand response selection for all six portfolios.

Mr. Lang then noted that after the development of NIPSCO's initial six portfolio, two additional "variants" on Portfolio D were developed to assess an emission trajectory between Portfolios D and F which would represent a more gradual trajectory towards Net Zero. Mr. Augustine then summarized the capacity additions and energy mix for the full set of eight portfolios, along with a set of key observations and conclusions.

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

- There were two LDES options that submitted to the RFP, a battery with ten hours of duration and a battery with 100 hours of duration. Which LDES resource is being selected in these portfolios?
 - As we go through this presentation, we will have several different LDES selections that are shown. Most of the LDES selected in the various portfolios, including the post-2030 selections shown here in Portfolio A, is 100-hour in duration. This is due to very strong capacity accreditation with limited derating over time and an ability to shift energy over multiple hours. However, beyond the 2030 time period, NIPSCO is likely to continue to evaluate different storage technologies, so it's unlikely that this IRP will conclude that a specific technology is preferred. A bit later in this presentation we will see some of the portfolio concepts that restrict the amount of new resource available through the remainder of the decade, which contributes to earlier 100-hour LDES coming into the portfolio.
- Correct me if I am wrong but your RFP results seem to indicate that your thermal bids were maybe at a lesser capacity than what is in a lot of your portfolios here for 2029 and 2030. I thought there was under 2,000 MW of thermal bids and it looks like we are talking 2,600 MW maybe by the early 2030s here. Can you please explain the discrepancy here?
 - Yes, we had a limited amount of thermal capacity in the RFP. There was one combined cycle offer and several other peaking or existing units offered, but as a part of the modeling setup we did incorporate an assumption for additional generic thermal resource capacity which is included in what is shown here.
 - We had one bid for a CCGT which was just around 650 MW. What you will be seeing here in the modeling is that many of the CCGTs that come up are based on the self-build assumption. We have also included the RFP result in here but anything above that is based on a self-build assumption, which we are assuming that we can get into place within the timelines listed. I know there may be some constraints from a supply chain perspective but we are assuming based on what is modeled here that we can get those into place within the timeline shown.
- Are the CC options 1x1's and what technology are they?
 - From a modeling perspective, a 650 MW block size was evaluated, which is

generally considered a 2x1, but it depends on the turbine class. Given the size of the potential total CCGT additions, different configurations could be identified. However, from a modeling perspective, the general assumption is a 650 MW, 2x1 combined cycle. If NIPSCO were to pursue a specific project, there would likely be additional diligence on the specific turbine manufacturer and potential configuration. In stakeholder meeting #3 we laid out the relevant assumptions in more detail, and as we go forward in this presentation you will see that a lot of the additions are in block sizes of approximately 650 MW.

- I just wanted to note an overarching concern from CAC about data centers and that we do not have signed contracts. We do know that the data centers are shopping around talking to different service territories, so it kind of seems like the tail wagging the dog, when you're trying to meet load that you are not sure is even coming, especially with this portfolio showing an investment in a CC in a very short period of time.
 - Next meeting we will come back to look at some portfolios that will be constructed without the incremental data center load, so that feedback has been heard previously.
 - Yes, in response to similar previous feedback, we are working on views of the portfolio without any data center load included and what the resources would look like under that scenario, and we will share those publicly at the next stakeholder meeting.
- It looks like your portfolios are including a new CC by 2028, including Portfolio C. 2028 seems like an extremely ambitious timeline to build a new CC, especially when the gas peaker that is being built has already been pushed back to 2028. I am struggling to see how a new CC by 2028 is possible given that other utilities like Duke have told us that they cannot build one by 2030. So how is NIPSCO envisioning this as a realistic scenario?
 - We have been working with our Major Projects team as we built our self-build assumptions that went into this modeling. There is risk to anything when you are talking about 2028 and 2029, which is when you see the CC coming on here but that is what we have modeled because we believe it is possible. If we end up executing a project, there will obviously be other considerations that need to be taken into account.
- Can you build wind by 2028?
 - We did not receive any external bids for wind. As far as building wind ourselves, particularly given the land restrictions in Indiana, the places where wind could be sited are becoming more and more limited, which is why we did not build any wind into the model before 2028.
- Those local siting restrictions do not apply to NIPSCO as a public utility in the state of Indiana, correct?
 - Theoretically, a utility could use eminent domain in order to do a self-build, however we have restricted wind in the model to beyond 2030 based on the RFP results and likely challenges associated with development and land acquisition in the state. We appreciate the feedback though, and this is something that we can take into consideration.
 - Additionally, the difference in land use that we are talking about for a CC versus a wind farm is substantial, so that would add to the timing issue. We have land where a CC theoretically could be sited, but for a wind farm we would have to buy up a lot more land, so that is something to consider as we think about modeling and timing.
- For the gas that is coming online in the late 2020s and early 2030s in your model, do you already have specific sites in mind, like Michigan City or Schahfer?
 - We have not built specific locations in for anything that has been modeled, so nothing that you are seeing here assumes a location. This is only resource

selection based on economics. We do have bids in our RFP for specific locations, whether it is for storage or solar, but we did not assume any of those locations in the modeling.

- Are pipeline extensions a concern if you're going to build somewhere that needs a connection to an interstate gas pipeline?
 - That is all factored into our assumptions around the timing.
- In stakeholder meeting #5 could you share your seasonal target reserve margins used in this modeling, unless you have already shared those?
 - The assumptions were broadly laid out in one of the earlier stakeholder meetings, when we showed the supply versus demand balance. Under the current market rules, we are using:

<u>Reserve Margin</u>	<u>Expected</u>
Summer	8.97%
Winter	27.44%
Fall	14.21%
Spring	26.72%

- In the DLOL construct we have received some guidance from MISO on how NIPSCO's obligation is likely to change, so you will note that each of these supply/demand balances reflect that, and there is expected to be a lower obligation in all of the seasons as a result of the fact that the MISO risky hours do not just happen the day of the peak but could happen at other times. The obligation discount for that is most significant in the winter and in the spring, so in the supply/demand balances you will see a kink in the line where it goes down when DLOL comes in.
- Following up on the load forecast portfolio that does not include the data center load, will we be able to see that portfolio with both the DLOL and the current market rules?
 - Yes. We are going to show it under both.
- Was the modeling used to select an optimal retirement date for existing coal? Is that the most economical date for coal to be retired? Or was the retirement date determined outside of the modeling process?
 - That was predetermined before we began with the modeling. We used the retirement dates that had previously been communicated and that is what is assumed in all of our modeling. So 2025 for Schahfer and 2028 for Michigan City are what has been assumed for our modeling.
- Do you have any thoughts on why the gas peaker is getting selected in Portfolio D, where it does not look like it is being selected in the other portfolios? To what extent could additional lithium-ion battery storage reduce the need for that peaker? Is it a close case?
 - To the first part of your question, I think it is close but there a lot of trade-offs in play. You potentially have more value from energy when your CCs are capped and you have MISO DLOL rules in place where we are modeling an expectation for a bigger hit on storage resources in certain seasons than natural gas resources. As a reminder, in the winter season those storage resources that are 4-hour duration go down to 56% accreditation while natural gas is in the 75-80% range. So, although these are low-capacity factor resources, they are operating 5-15% of the time and when you are capping your CCs you get into this position where in order to meet your energy constraints, a little bit of extra energy from natural gas peakers provides value.
 - To the second part of your question, the two technologies certainly offer similar attributes, but there are tradeoffs that would be considered in resource selection, as I just noted. Given that we see a lot of storage get picked up across the board, I do think storage and gas peaking remain a broadly comparable set of resources

that have different attributes that could be traded off across seasons and across the different values that they could offer the portfolio.

- Is there a carbon tax associated with energy from carbon resources that is included in the modeling?
 - The reference case, which we have shown for all of these portfolios, does not have a carbon price. As we get into the various scenarios next meeting, we have one particular scenario, the Aggressive Environmental Regulation scenario, which does have a carbon price coming in during the early 2030s and then scaling up to a fairly significant level.
- Will there be an estimate of what an annual bill impact would be under the different portfolios and maybe a compound annual growth rate for each one?
 - As we get to the customer cost results there will be an annual revenue requirement that comes out of this so you will be able to see the total cost of generation year-by-year, other various costs, and then ultimately for scorecard purposes the NPV, so that data will be coming and looked at as we run through all of the scenarios.
 - At stakeholder meeting #5 we will share the revenue requirement comparison between these various portfolios and what that looks like, as well as the costs on a \$/MWh basis. But the revenue requirement is the main thing that we are including in our scorecard for each one of these and we show it on an NPV basis so that you can see 30 years discounted to today.
- Will we be able to see how much revenue is associated with each rate class and if the data centers fall under the commercial class?
 - For the purposes of the IRP presentation in the stakeholder meetings, we do not break things out by customer group, we just show the total revenue requirement.
- Can you explain again what “No New Uncontrolled Fossil” means?
 - From a portfolio construction perspective it means that we are not allowing new CCs or new gas peaking units to be selected or added to the portfolio unless they are controlled with carbon capture and storage technology or fully hydrogen enabled, meaning that they can blend up to 100% hydrogen.
 - In the modeling, what that assumption pragmatically means is that the cost of CCUS or hydrogen is included in the resource cost for a new gas build and we would not include it without that cost in Portfolios E and F.
- What is assumed about the GHG rulemaking underway for existing natural gas?
 - Given that there is no final rule for existing natural gas resources, there have been no constraints put on the Sugar Creek facility in general. In portfolios E and F, we have modeled the Sugar Creek resource converting to hydrogen blending capability, so you can see that the royal blue Sugar Creek slice would go away. But in the other portfolios, there is no explicit constraint associated with the operation of Sugar Creek beyond current finalized rules, because current rules do not apply to existing natural gas resources.
- Do you have a target minimum percentage for reliability; the percentage of NIPSCO’s system peak that must be dispatchable generation as a constraint for the long-term expansions?
 - Not specifically defined in that way, no. The long-term expansion was modeled under the two different accreditation regimes with associated seasonal obligations and accreditation assumptions. So that is attempting to proxy the reliability requirements that NIPSCO would have to meet across all four seasons, and that is essentially how the capacity expansion model was evaluated. One other point I will make is that one of the analysis steps is our stochastic reliability assessment, which will look at each of these portfolios in a 2030 sample year and flex the uncertainties associated with wind and solar output, thermal resource availability, and peak load and take a look at potential forced market exposure and rank the

portfolios across that type of metric. So that is the type of analysis that might get at what you are asking about. So, we are looking at it in a couple of different ways but there is not a specific mandate that we need a certain amount of dispatchable capacity as a fraction of peak load.

NIPSCO Portfolio Construction Continued and Next Steps
Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

Abe Lang kicked off the section with another recap of the overall modeling process and an overview of the remaining analysis components for NIPSCO's 2024 IRP. Pat Augustine then explained how the portfolios that were reviewed earlier would be evaluated across all five of NIPSCO's planning scenarios and across a distribution of stochastic uncertainty in renewable output, NIPSCO load, thermal resource availability, gas price, and power price. Mr. Lang then closed the section with a review of NIPSCO's integrated scorecard and the agenda for the final stakeholder meeting on October 28.

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

- Can you please confirm that you will be doing ratepayer cost analysis by customer class?
 - The IRP process is about the total portfolio and the revenue requirement on a total portfolio basis. We are not breaking it down by customer class. That would be a separate discussion while this is about resource selection from our generation side, so we will only be showing the all-in customer cost right now.
- Under the Five Pillars statute, the requirement is actually to do a rate analysis by customer class, so are you saying that you are not planning to do that?
 - In the final IRP report, we will include customer class considerations at a high level, but in the next stakeholder meeting we will not break it down by customer class.
- I want to make sure that the stakeholders who are engaged in the process will have an opportunity to comment on all of the Aurora files and have stakeholder feedback incorporated, to the extent necessary, into NIPSCO's modeling?
 - Yes, we will be following up today to find out what the issue is with Energy Exemplar and the license that the CAC is using. We have another data file release today that should go out shortly after the end of this meeting, where we will be releasing the output files that went into the slides that you see today from Aurora. We will make sure to answer any stakeholder questions and incorporate feedback before we finalize our IRP for the modeling. You can continue to use your license and comment after we submit our IRP in December as well.
- Could you talk more about the High Emerging Load Sensitivity Testing? Is that attempting to vary the amount of load associated with each of the data centers?
 - Yes, we discussed this briefly at stakeholder meeting #2 I believe, how we got to our reference case figure of 2,600 MW by 2035 of additional load on top of what we currently serve today. The high load sensitivity is 8,600 MW on top of our existing load, so it is three to four times more than what we are talking about in our reference case. The way we got to that is we looked at potential opportunities that were in the queue, where people had approached us with projects, and we built in somewhere between 2-3 projects that led to the 2,600 MW figure in our reference case and then around 6 projects that led to the 8,600 MW figure. This is just a snapshot in time as the situation with every potential data center is fluid, and we are not guaranteeing that we would see either of those amounts in our portfolio.
- When it comes to the 40% limitation on operating CCs under the EPA assumption

scenarios, can you talk about how that is going to be modeled and are there any sensitivities to that? For example, I am thinking about how you might not know when to operate the plant and when not to operate the plant with those limitations in place. How does NIPSCO think about that?

- From a modeling perspective, the approach we have taken is to cap the total capacity factor at 38% and allow the model to optimize the top hours across the year when it would make economic sense, which is likely to be the most economic for NIPSCO's customers. These models have a fairly complex optimization algorithm that targets those periods of time under which it is most economic to operate, so it is not as if we are just running at 40% every hour of the year or hard coding in a set of dispatch patterns. But to your point, in real life, we will not have perfect foresight about future weather patterns so there is uncertainty associated with operating under this regime. The reason we left the 2% buffer is to reflect this risk and to leave open the possibility of unexpected events. Any given year will be different and so this will present some operational challenges if the rule comes into force.
- I was wondering about the stochastic variables associated with load and thermal resource availability. Could you please elaborate on these further?
 - On the load, it is really more short-term, weather-driven load uncertainty. In the stochastic analysis we are still within our reference case load forecast and we are not varying within this analysis the amount of data center or other economic development load that could come in. So, this is only focused on our base load forecast for this year but load is highly dependent on weather, and it is just random in certain hours and on certain days. Two meetings ago we showed some of our distributions and if you have further questions or want to see some backup data, we can certainly share that but it is really about weather-driven load uncertainty once you have your expected load assumption in place.
 - On thermal resource availability, it is also correlated to the weather to some extent. We have looked at NIPSCO's actual operating data for outages at the Sugar Creek facility, if they have or have not been correlated to weather, incorporating in forced outage rates and mean time to repair. There is some correlational to weather here but it is a bit weak based on NIPSCO's historical operational characteristics but what we want to pick up there is that thermal resources have uncertain operations as well.
- So, the thermal resource availability is for NIPSCO's thermal resources in particular?
 - Yes, this is a NIPSCO-portfolio specific evaluation, incorporating existing and potentially new thermal resources.
- How are you coming up with your purchased power prices?
 - The power prices are based on MISO-level market simulations.
- How do you come up with resource plans for each of the utilities that would be setting the MISO power price?
 - That would be done in the MISO-wide capacity expansion element of the work. Although we incorporate public announcements, the analysis over the long-term is done on a general MISO-zonal basis.
- My question really is, who sets those numbers? Where do those numbers come from? The resources in MISO, how do you know how much each utility is going to have of a specific resource?
 - We get these from a mix of public announcements for the near-term but the long-term is our independent, system-wide capacity expansion analysis. So we are actually solving for the long-term buildouts through that process and through this model.
- Is that information available so that we can see what your assumptions are?
 - Yes, that information was summarized in the second meeting. I think we also have

a set of spreadsheet details that went out in our first data release but we can certainly share that with you as well.

- Do you guys consider the data centers to be in the commercial customer class, instead of the industrial customer class?
 - That is something that we are still working through right now.
- We would appreciate if the load associated with the hyperscalers is broken out from the other rate classes.
 - Yes, we are not commenting on that right now, but more to come.
- Speaking about economic impacts to the community, I just wanted to note about the upcoming proposed rate hike in northwestern Indiana and the impacts it could have. There is a study that shows that the third largest stressor for northwest Indiana is their ability to pay their utility bill. Please take into account the community when you propose these rate hikes. I would urge to adjust your philosophy on this.
 - We appreciate your feedback.

Closing & Stakeholder Comments

NIPSCO IRP Stakeholder Meeting - October 8, 2024

Registrant First Name	Registrant Last Name	Registrant Email Address	Company
Erik	Miller	erik.miller@aes.com	AES
Erik	Miller	erik.miller@aes.com	AES
Quintin	Thompson	quintin.thompson@aes.com	AES IN
Michael	Hardie	michael.hardie@aes.com	AES Indiana
Will	Talbott	wtalbott@aypa.com	Aypa Power
Nick	Kile	Nicholas.kile@btlaw.com	Barnes & Thornburg
Ryan	Wilhelmus	ryan.wilhelmus@bigrivers.com	Big Rivers Electric Corporation
Ryan	Wilhelmus	ryan.wilhelmus@bigrivers.com	Big Rivers Electric Corporation
Levy	Agaronnik	levy.agaronnik@blackstone.com	Blackstone
Micheal	Zhang	micheal.zhang@blackstone.com	Blackstone
KRISTINA	WHEELER	kristinawheeler@sbcglobal.net	Bose McKinney & Evans LLP
Alexandra	Jones	ajones@boselaw.com	Bose, McKinney, & Evans LLP
Joshua	Siegel	joshua.siegel@bp.com	BP
Marc	Blanchard	marc.blanchard@bp.com	BP
Jeremy	Martin	jeremy.martin@centerpointenergy.com	CenterPoint Energy
Joshua	Swanson	joshua.swanson@centerpointenergy.com	CenterPoint Energy
Edwin	Moyo	emoyo@crai.com	Charles River Associates International
Ben	Inskeep	Binskeep@citact.org	Citizens Action Coalition
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana
Reagan	Kurtz	rkurtz@citact.org	Citizens Action Coalition of Indiana, Inc.
Emma	Goodnow	emma.goodnow@duke-energy.com	Duke Energy
Sameer	Doshi	sdoshi@earthjustice.org	Earthjustice
Max	Lee	max.lee@edp.com	EDP Renewables
Anna	Sommer	asommer@energyfuturesgroup.com	EFG
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
Emily	Medine	emedine@evainc.com	Energy Ventures Analysis, Inc.
Hadiza`	Felicien	hfelicien@formenergy.com	Form Energy
Jessica	Nyquist	jnyquist@formenergy.com	Form Energy
Rachel	Wilson	rwilson@formenergy.com	Form Energy
Nikhil	Kumar	nikhil@gridlab.org	GridLab
Richard	Gillingham	rgillingham@hepn.com	Hoosier Energy
Regiana	Sistevaris	rsistevaris@aep.com	I&M
Edward	Locigno	ejlocigno@aep.com	Indiana Michigan Power Company
David	Savage	dsavage@urc.in.gov	Indiana Utility Regulatory Commission
Spark	Li	sli8@jefferies.com	Jefferies
Susan	Thomas	Susan@jtnwi.org	Just Transition NWI
Bruna	da Silva	bruna.dasilva@keycaptureenergy.com	Key Capture Energy
Quinn	Beckham	quinn.beckham@keycaptureenergy.com	Key Capture Energy
Mark	Simons	mcsimons803@gmail.com	MCSimons Inc.
Ryan	Pfefferle	rypfefferle@microsoft.com	Microsoft
Christopher	Jeffrey	christopher.jeffrey@mizuhogroup.com	Mizuho Securities
Christopher	Jeffrey	christopher.jeffrey@mizuhogroup.com	Mizuho Securities
Joe	Motuliak	joe.motuliak@nee.com	NextEra Energy
Bryan	Mills	bryan.mills@nexteraenergy.com	NextEra Energy Resources
Kay	Nelson	knelson@nwiforum.org	Northwest Indiana Forum
Spencer	Summers	ssummers@nwiforum.org	Northwest Indiana Forum
Suzanne	Escudier	suzanne.escudier@origisenergy.com	Origis Energy
JOHN	HANKS	jhanks@oucc.in.gov	oucc
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Roopali	Sanka	rsanka@oucc.in.gov	OUCC
Marco	Velastegui	mvelaste@purdue.edu	Purdue
Davis	McCourt	davis@rangerpower.com	Ranger Power
Carter	Scott	carter@rangerpower.com	Ranger Power LLC
Jeff	James	jjames@savionenergy.com	Savion, LLC
Tim	Phillips	timphillips@purdue.edu	State Utility Forecasting Group
David	Nderitu	nderitu@purdue.edu	SUFG

Will	Kenworthy	will@votesolar.org	Vote Solar
Amanda	Bersing	amanda.bersing@wellsfargo.com	Wells Fargo Securities
Leslie	Hamby	Leslie.Hamby@centerpointenergy.com	
Ryan	Baker	Ryanbaker@usw12775.org	
Steven	Smith	smiste@mac.com	
Taylor	Carpenter	tcarpenter@calfee.com	

2024 NIPSCO Integrated Resource Plan
Fifth Stakeholder Advisory Meeting
October 28, 2024



2024 NIPSCO INTEGRATED RESOURCE PLAN

Fifth Stakeholder Advisory Meeting

October 28th, 2024
9 A.M.-3:30 P.M. CT

These modeled portfolios are regulatory requirements made in connection with integrated resource planning that contain the company's forward-looking assumptions. These modeled portfolios are not an indication of actual future events and should not be relied upon as such.



NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 573 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER





OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

WELCOME & INTRODUCTION

Tara McElmurry, Manager Communications, NiSource



FAIR OAKS FARMS



LOCATION OF
NEAREST EXIT

NEAREST PLACE TO
SEEK SHELTER

IN AN EMERGENCY,
WHO WILL DIAL 911

WHO WILL DIRECT THE
EMERGENCY RESPONDER

LOCATION OF THE
**AUTOMATED EXTERNAL
DEFIBRILLATOR (AED)**

WHO CAN
PERFORM CPR

OTHER **POTENTIAL HAZARDS**

Fire: Exit out any door that is furthest away from the fire. Gather as a group in the front parking lot – near the Tesla chargers.

Shelter: Restrooms, Jasper Ballroom (if closed), Employee Banquet Hallway.

AED Location: On the wall in the Employee Banquet Hallway.

Other Hazards: N/A

Dial 911:

Direct Responders:

CPR:

SAFETY MOMENT

Parking Lot Safety

Don't be fooled by slow-moving vehicles: 1 in 5 accidents occur in a parking lot

- Don't become distracted by your cell phone or headphones.
- Be aware of your surroundings. Walk with confidence to buildings and to your car.
- Keep your car locked, even if you are running a quick errand.
- Park near the building in a visible and well-lit area.
- Look twice for pedestrians, bicycles, and other vehicles.
- Drive slowly and obey posted speed limits and signs.
- Stay in lanes and avoid cutting across lots.



Source: [Oceaneering](#)

STAKEHOLDER ADVISORY MEETING PROTOCOLS

- **Your input and feedback is critical to NIPSCO's Integrated Resource Plan (IRP) Process.**
- **The Public Advisory Process provides NIPSCO with feedback on its assumptions and sources of data. This helps inform the modeling process and overall IRP.**
- **We set aside time at the end of each section to ask questions.**
- **Your candid and ongoing feedback is key to this process:**
 - Please ask questions and make comments on the content presented
 - Please provide feedback on the process itself
- **Please identify yourself by name prior to speaking. This will help keep track of comments and follow up actions.**
- **If you wish to make a presentation during a meeting, please reach out to Erin Whitehead (ewhitehead@nisource.com).**

AGENDA

Time *Central Time	Topic	Speaker
9:00AM-9:05AM	Welcome & Introduction	Tara McElmurry, Manager Communications, NiSource
9:05AM-9:10AM	Kick Off	Vince Parisi, President & COO, NIPSCO
9:10AM-9:20AM	Recap of 2024 IRP Process	Abe Lang, Manger Strategy & Risk, NiSource
9:20AM-9:40AM	Public Advisory Process and Responses to Fourth Stakeholder Meeting Comments	Abe Lang, Manager Strategy & Risk, NiSource
9:40AM–11:00AM	Portfolio Recap and Portfolio Scenario Analysis	Abe Lang, Manager Strategy & Risk, NiSource Pat Augustine, Vice President, CRA
11:00AM-12:00PM	Lunch	
12:00PM–12:45PM	Stochastic Risk Analysis	Abe Lang, Manager Strategy & Risk, NiSource Pat Augustine, Vice President, CRA
12:45PM-1:30PM	Sensitivities – High Emerging Load and DSM	Abe Lang, Manager Strategy & Risk, NiSource Pat Augustine, Vice President, CRA
1:30PM-1:40PM	Break	
1:40PM-3:00PM	Scorecard Summary, Preferred Portfolio, and Short-Term Action Plan	Abe Lang, Manager Strategy & Risk, NiSource Pat Augustine, Vice President, CRA
3:00PM – 3:30PM	Closing & Stakeholder Comments	



KICK OFF

Vince Parisi, President & COO, NIPSCO



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



PREMIER REGULATED UTILITY BUSINESS



NATURAL GAS

COLUMBIA GAS OF KENTUCKY

COLUMBIA GAS OF MARYLAND

COLUMBIA GAS OF OHIO

COLUMBIA GAS OF PENNSYLVANIA

COLUMBIA GAS OF VIRGINIA

NIPSCO GAS

NIPSCO

ELECTRIC

NIPSCO ELECTRIC

SIGNIFICANT SCALE ACROSS 6 STATES

~3.2M

GAS CUSTOMERS

~500K

ELECTRIC CUSTOMERS

NIPSCO PROFILE

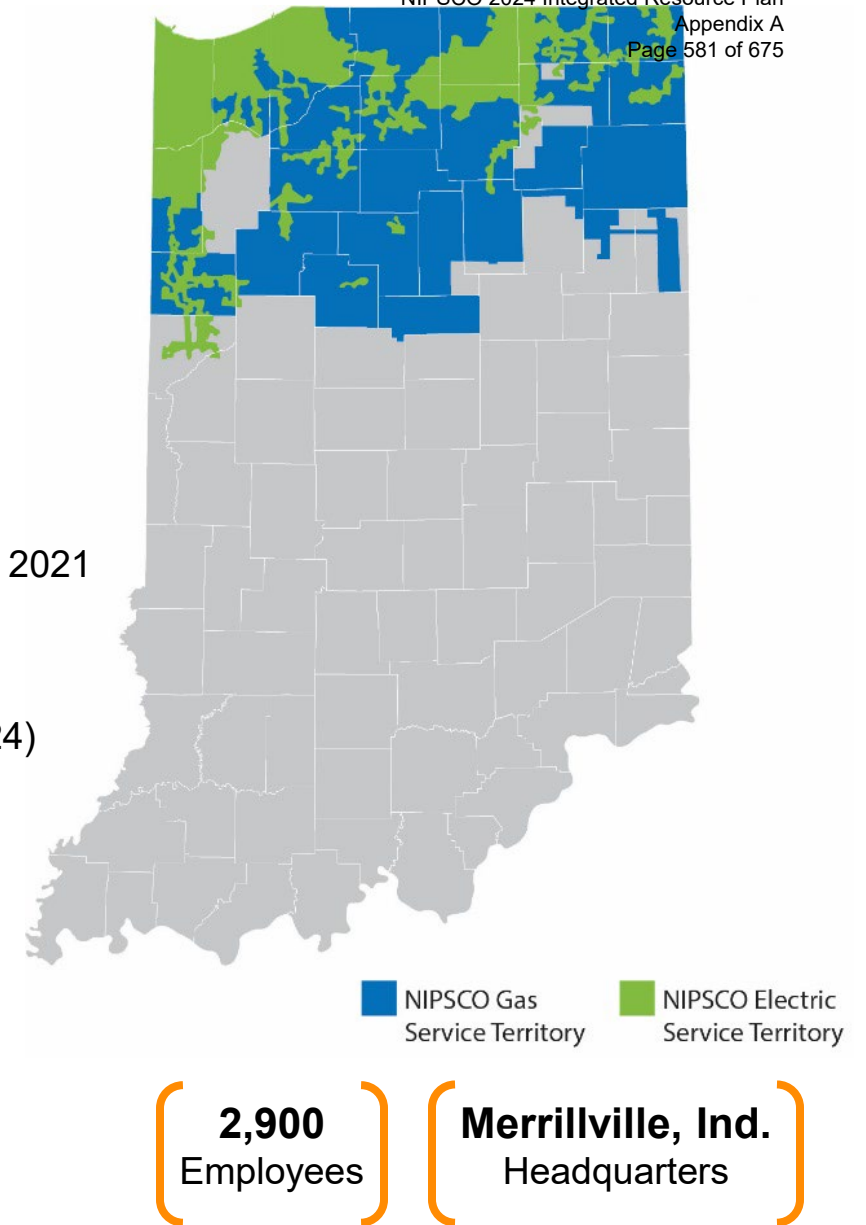
- **Working to Become Indiana's Premier Utility**

Electric

- 483,000 Electric Customers in 20 Counties
- 3,625 MW Generating Capacity
 - 12 Electric Generating Facilities
(2 coal, 1 natural gas, 2 hydro, 4 wind, 2 solar, and 1 solar-plus-storage)
 - 1,000 MW of New Wind Energy
(Rosewater, Jordan Creek and Indiana Crossroads Wind I & II online in 2020 2021 and 2023)
 - 665 MW of New Solar Energy
(Dunns Bridge I, Indiana Crossroads solar online in 2023, and Cavalry in 2024)
- 12,800 Miles of Transmission and Distribution
 - Interconnect with 5 Major Utilities (3 MISO; 2 PJM)
 - Serves 2 Network Customers and Other Independent Power Producers

Natural Gas

- 859,000 Natural Gas Customers; 32 Counties
- 17,000 Miles of Transmission and Distribution Line/Main
- Interconnections with Seven Major Interstate Pipelines
- Two On-System Storage Facilities

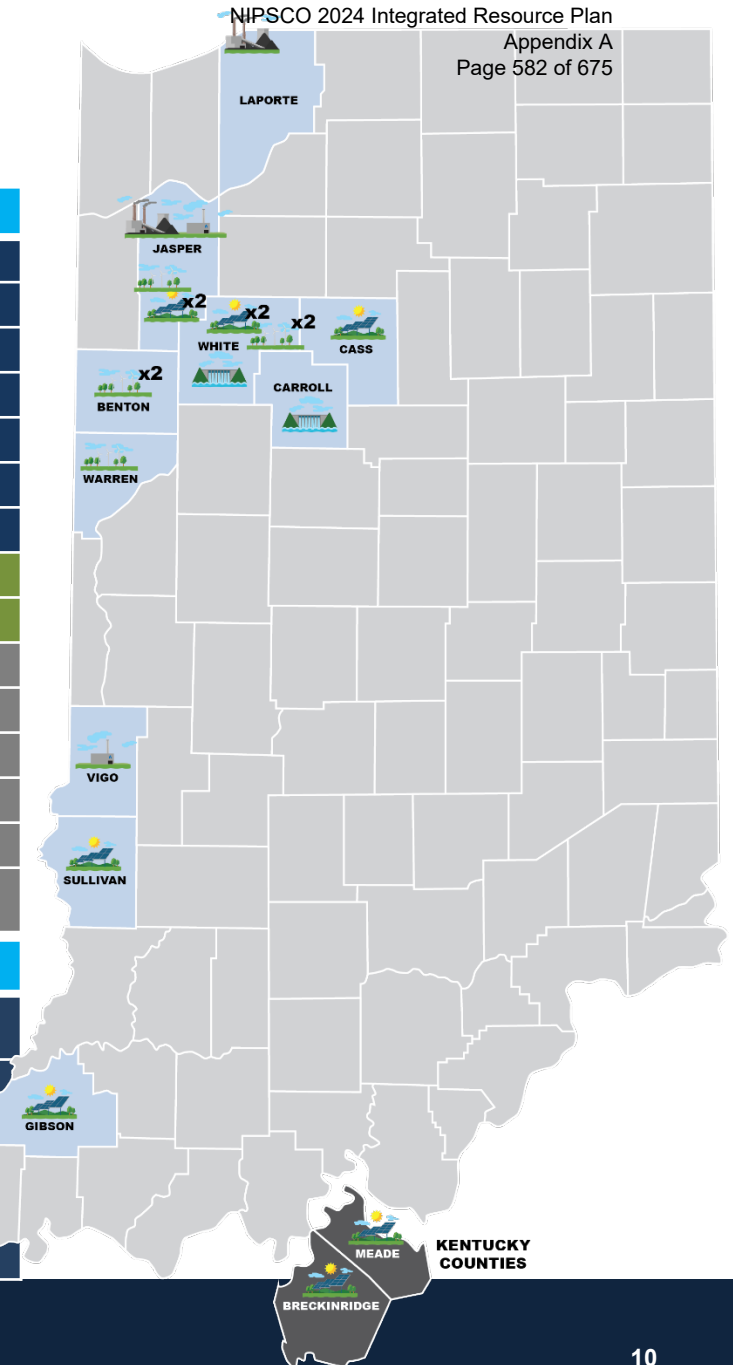


CURRENT & FUTURE NIPSCO GENERATION PORTFOLIO

• Robust Renewable Investments in Indiana

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
CAVALRY SOLAR	200 MW + 45 MW BATTERY	WHITE	2024 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE (KY)	2025 CONSTRUCTION
DUNNS BRIDGE SOLAR II	435 MW + 56.25 MW BATTERY	JASPER	2025 CONSTRUCTION
GIBSON SOLAR	200 MW	GIBSON	2025 CONSTRUCTION
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025 CONSTRUCTION
APPLESEED SOLAR	200 MW	CASS	2025 PRE-CONSTRUCTION
CARPENTER WIND	200 MW	JASPER	2025 PRE-CONSTRUCTION
TEMPLETON WIND	200 MW	BENTON	2025 PRE-CONSTRUCTION
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PRE-CONSTRUCTION

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2025 (COAL) – 2028 (NG)	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	563 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL



* Since 2018

PILLARS OF OUR ONGOING GENERATION TRANSITION PLAN

This plan creates a vision for the future that is better for our customers and it's consistent with our goal to transition to the best cost and cleanest electric supply mix available while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.

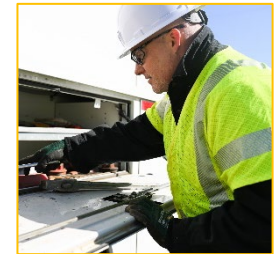


**Reliable and
sustainable**

**Flexibility for
the future**

**Local and statewide
economic benefits**

**Best plan for customers
and the company**



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

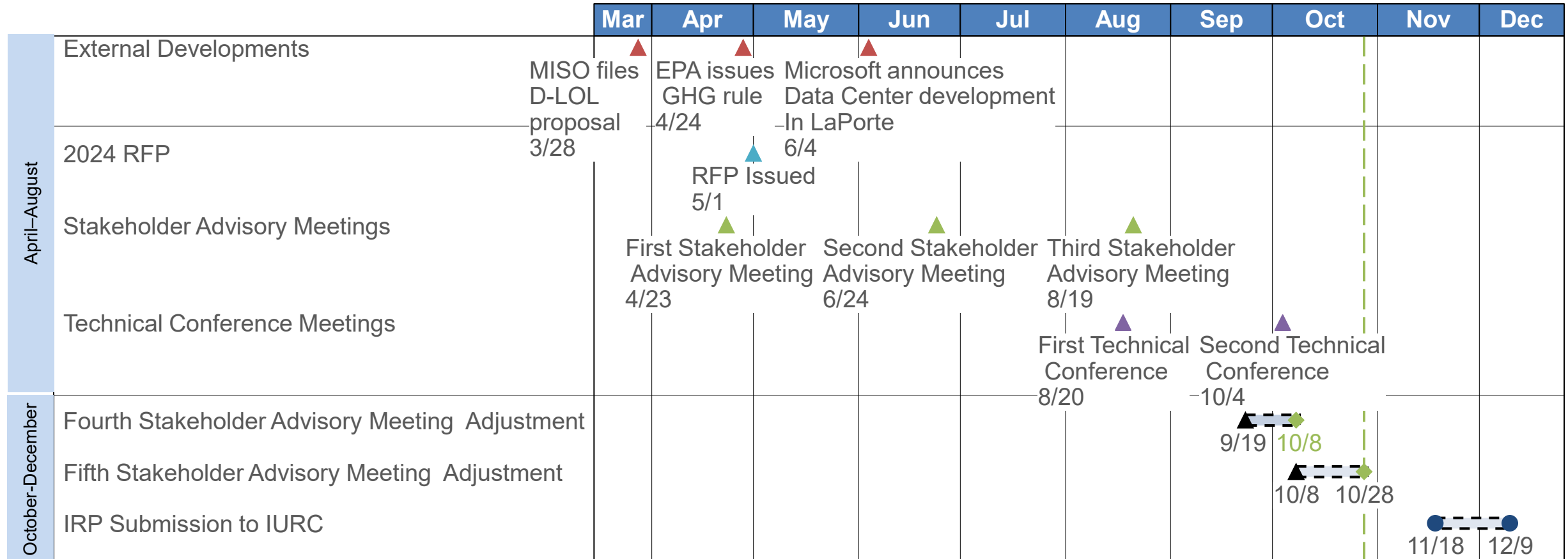
RECAP OF STAKEHOLDER PROCESS

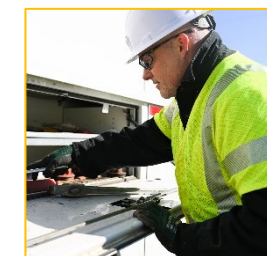
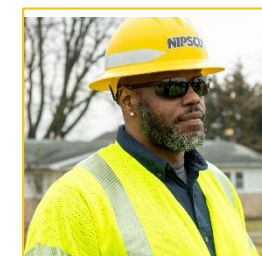
Abe Lang, Manager Strategy & Risk, NiSource



RECAP: 2024 IRP STAKEHOLDER ADVISORY PROCESS TIMELINE & ADJUSTMENTS

To afford NIPSCO and Stakeholders additional time to analyze the impacts of several significant external developments impacting the long-term planning to maintain reliable and affordable energy for our customers, the Indiana Commission has approved NIPSCO's request to adjust the 2024 IRP submission date from November 18th to December 9th





OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

PUBLIC ADVISORY PROCESS AND RESPONSES TO FOURTH STAKEHOLDER MEETING COMMENTS

Abe Lang, Manager Strategy & Risk, NiSource



SUMMARY OF STAKEHOLDER FEEDBACK SINCE MEETING #4

Category	Stakeholder Comments	NIPSCO Responses
CCGT Resource Options	• Less than 2,300 MW of thermal bid into the RFP, but portfolios have 2,600 MW+ of thermal capacity. Is this feasible? • What is the configuration of the CC options? • Data center load may not materialize, and would these CCGT additions be needed without the new loads? • Most portfolios contemplate a CCGT in 2028. Is that feasible? • What is assumed about the GHG rulemaking underway for existing NG plants?	• CCGT installed capacity in excess of the installed capacity bid into the RFP is modeled as generic “self-build.” • The 650 MW blocks evaluated were modeled generally under a 2x1 configuration. That may change as needs dictate; however, the block size was modeled at 650 MW for planning purposes. • In response to similar previous feedback, we are working on views of the portfolio without any data center load included and what the resources would look like under that scenario, and we are sharing those publicly at Stakeholder Meeting #5. • NIPSCO appreciates the development risk. The date modeled was based on consultation with NIPSCO and NiSource internal Major Projects and Supply Chain teams. Other considerations may have to be taken into account during project execution. • The EPA GHG rule was changed to exempt existing gas-fired plants, and we have modeled the GHG rule accordingly.

SUMMARY OF STAKEHOLDER FEEDBACK SINCE MEETING #4

Category	Stakeholder Comments	NIPSCO Responses
Renewable Resource Options	- A 10-hour and 100-hour duration battery were bid into the RFP, which is being selected? - Can NIPSCO self build wind? - In Portfolio D, to what extent could Lithium-ion batteries be used rather than the gas peaker?	- The 100-hour battery option was generally selected when LDES was part of portfolios (either in the near-term or over the longer-term). However, the values in this IRP may be thought of as placeholders for LDES technology generally, while the eventual technology will undergo further due diligence. - Current land limitations hinder wind development. Additionally, a CCGT or CT can be sited at existing NIPSCO-owned facilities. - MISO's D-LOL proposal discounts storage more than CTs/CCs in the winter, and CTs do provide incremental energy to the portfolio which batteries cannot. Given that the model selected large amounts of storage, however, storage and gas peaking remain comparable resources that offer similar attributes.
Bill Impact/Cost to Customer	- Will there be a bill impact analysis? - Please confirm you will be doing a ratepayer cost analysis by customer class?	- NPVRR results will be provided at the Fifth Stakeholder meeting across all the scenarios (with annual revenue requirements in supporting data files). - NIPSCO will ensure it includes all legally required customer cost information as a part of its final IRP report on December 9th.

SUMMARY OF STAKEHOLDER FEEDBACK SINCE MEETING #4

Category	Stakeholder Comments	NIPSCO Responses
Other Questions Raised	- Could you share seasonal target reserve margins in Stakeholder meeting #5? - What are the carbon tax/cost assumptions? - Can you provide more color on the assumptions driving the Emerging Load Sensitivity?	- Seasonal Target Reserve Margins: 9% in Summer, 27% in Winter, 14% in Fall, 27% in Spring – based on the current MISO capacity accreditation and resource adequacy rules. For D-LOL, NIPSCO utilized guidance from MISO on the impacts to NIPSCO's obligation as shown in the supply-demand graphics. - The Reference Case has no CO2 price, although the AER scenario has a CO2 price starting in 2030 and ramping up to a significant level (~\$100/tonne by 2035 in real \$). See Stakeholder Meeting #2 slides for more detail. - NIPSCO evaluated potential large load projects in the queue and built its Reference Case under the assumption of 2-3 new large projects. The Emerging Load Sensitivity evaluates the potential for 6 new data center projects.



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

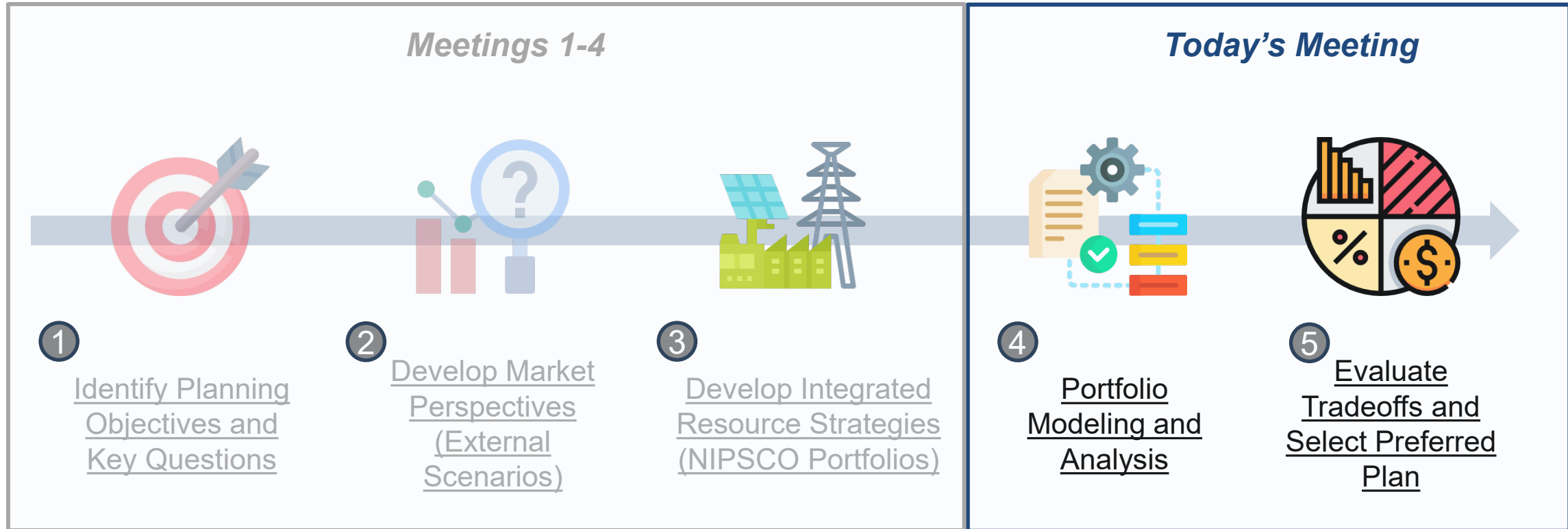
PORTFOLIO DEFINITION

Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

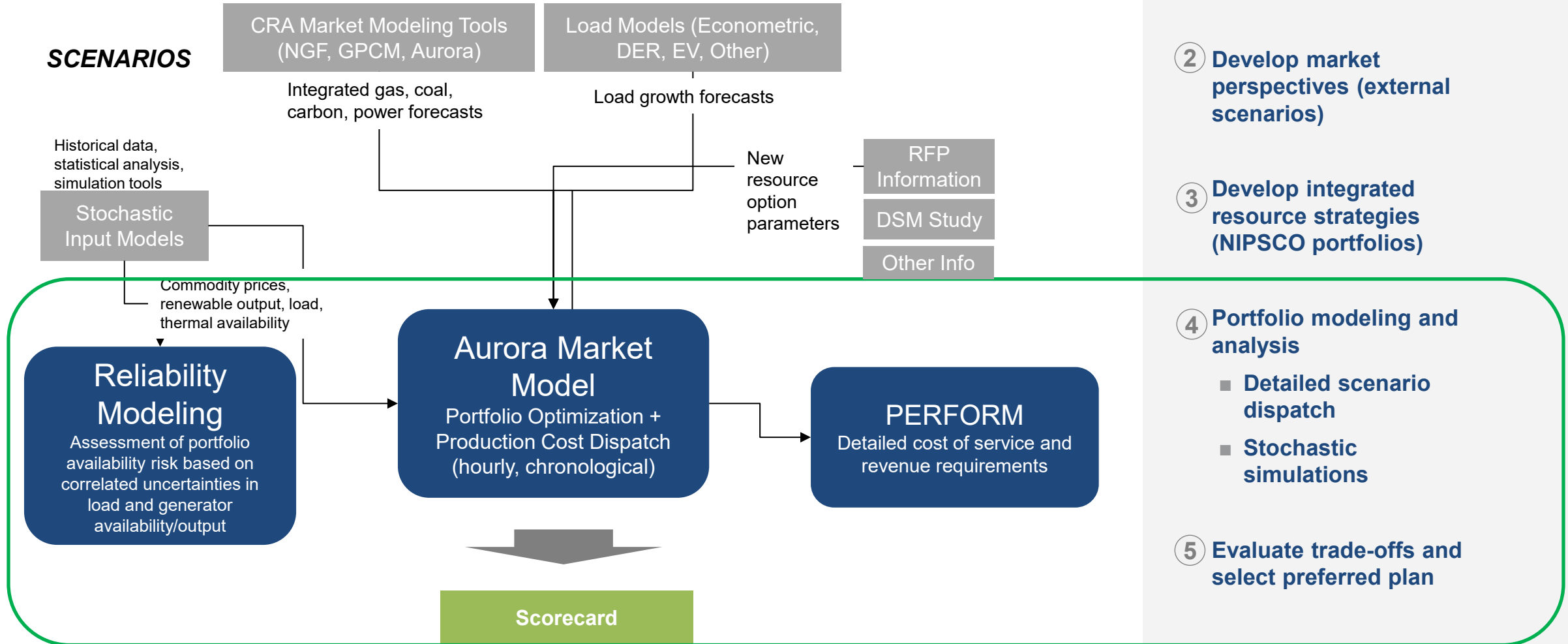


OVERALL RESOURCE PLANNING APPROACH

STEPS:



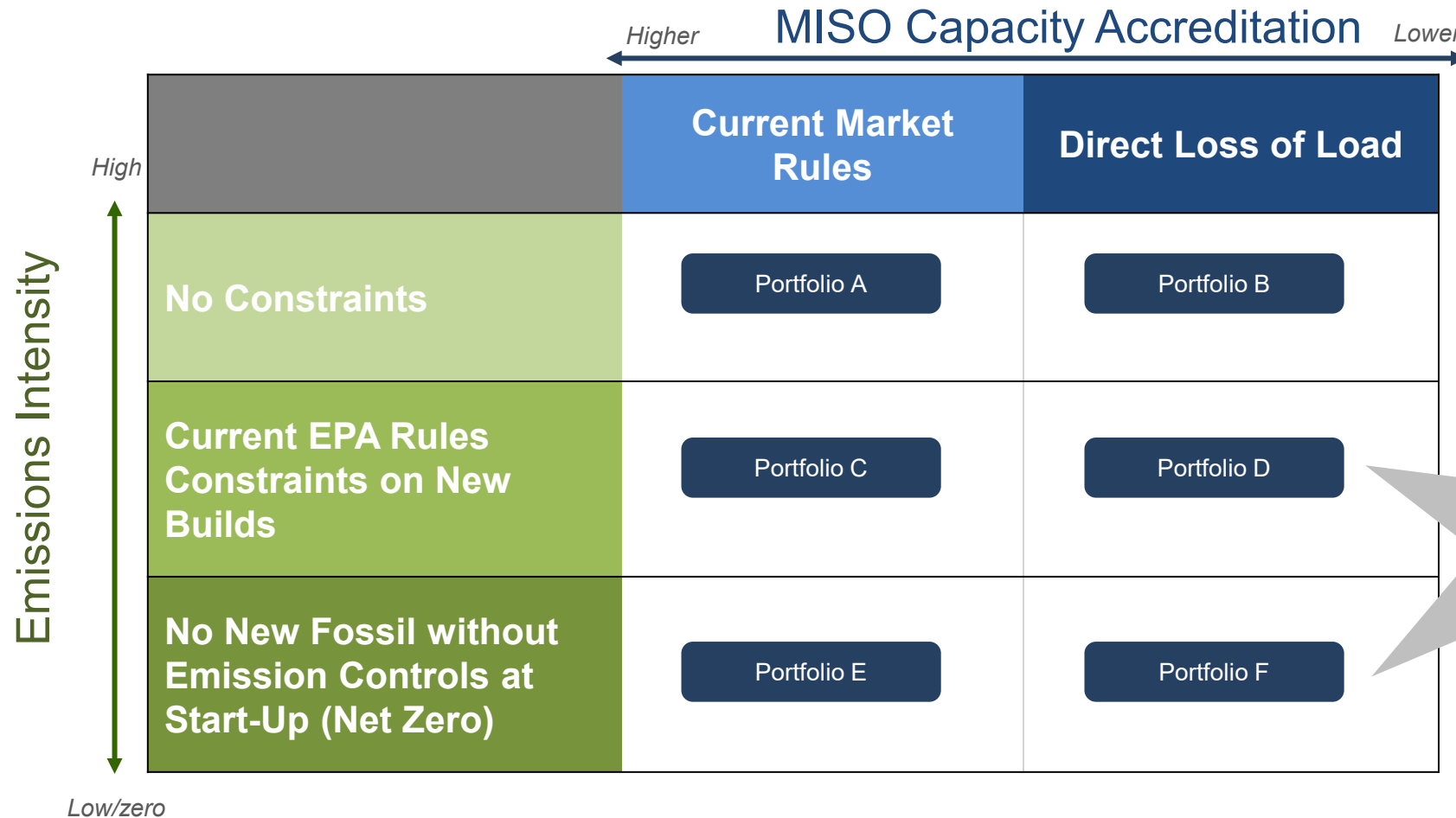
RESOURCE PLANNING APPROACH



RECAP: PORTFOLIO CONSIDERATIONS

Six original portfolios were constructed to highlight the two primary constraints:

- 1) MISO's proposed D-LOL rules: reduce the capacity value, primarily for solar and wind resources
- 2) EPA's GHG emissions rules: constrain output or increase cost of new gas generation



Two additional portfolios were developed to evaluate:

- Portfolio variants between D and F but with a more gradual reduction to Net Zero by 2040

Portfolio D - CCUS

Portfolio D - Hydrogen

RECAP: PORTFOLIO COMPARISON – RESOURCE ADDITIONS ABOVE CURRENT PLAN

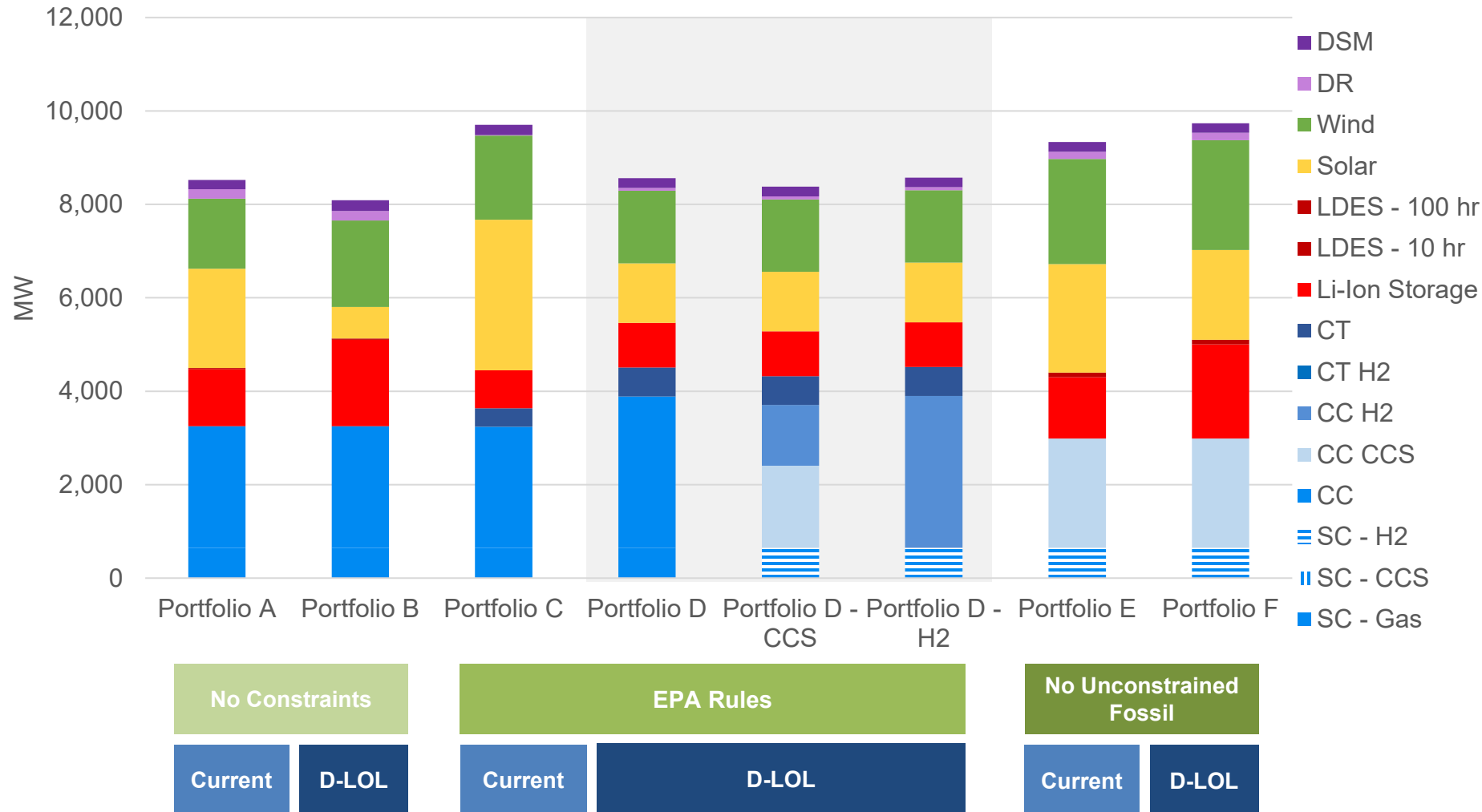
Given the lower seasonal capacity credit of renewables with or without MISO’s D-LOL rule, NIPSCO would need to add installed capacity that is around double its supply-demand gap (summer) in almost all portfolios.

	A	B	C	D (all)*	E	F
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	Late 2030s	At Start-up	At Start-up
Wind	1,500	1,850	1,800	1,550	2,250	2,350
Solar	2,125	675	3,235	1,275	2,322	1,922
Storage ¹	1,249	1,882	811	959	1,410	2,111
Gas CCGT	2,600	2,600	2,585	3,235		
Gas Peaking			400	618		
Gas CCGT w/CCUS					2,340	2,340
Sugar Creek	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DR / DSM ²	400	430	230	270	365	365
Total ICAP Additions (excl. DSM/DR)	7,474 MW	7,007 MW	8,831 MW	7,637 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer)	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

¹ Includes both 4-hour Lithium-ion and long-duration storage

² DR/DSM additions calculated as peak capacity contribution in summer of 2043

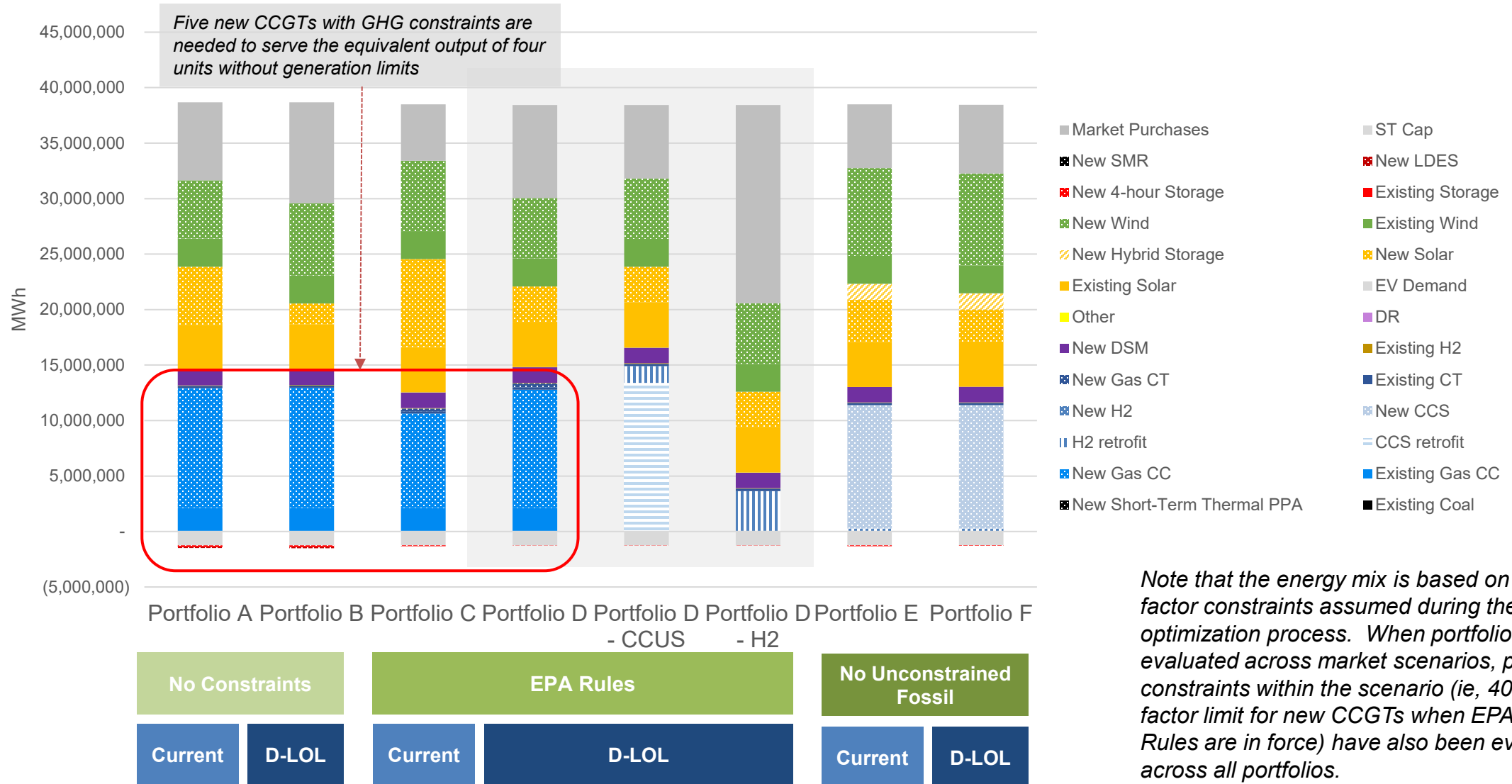
RESOURCE ADDITIONS COMPARISON ACROSS PORTFOLIOS – CUMULATIVE NAMEPLATE THROUGH 2043



- Portfolio D variants would retrofit new CCGT capacity additions with CCUS or hydrogen capability.

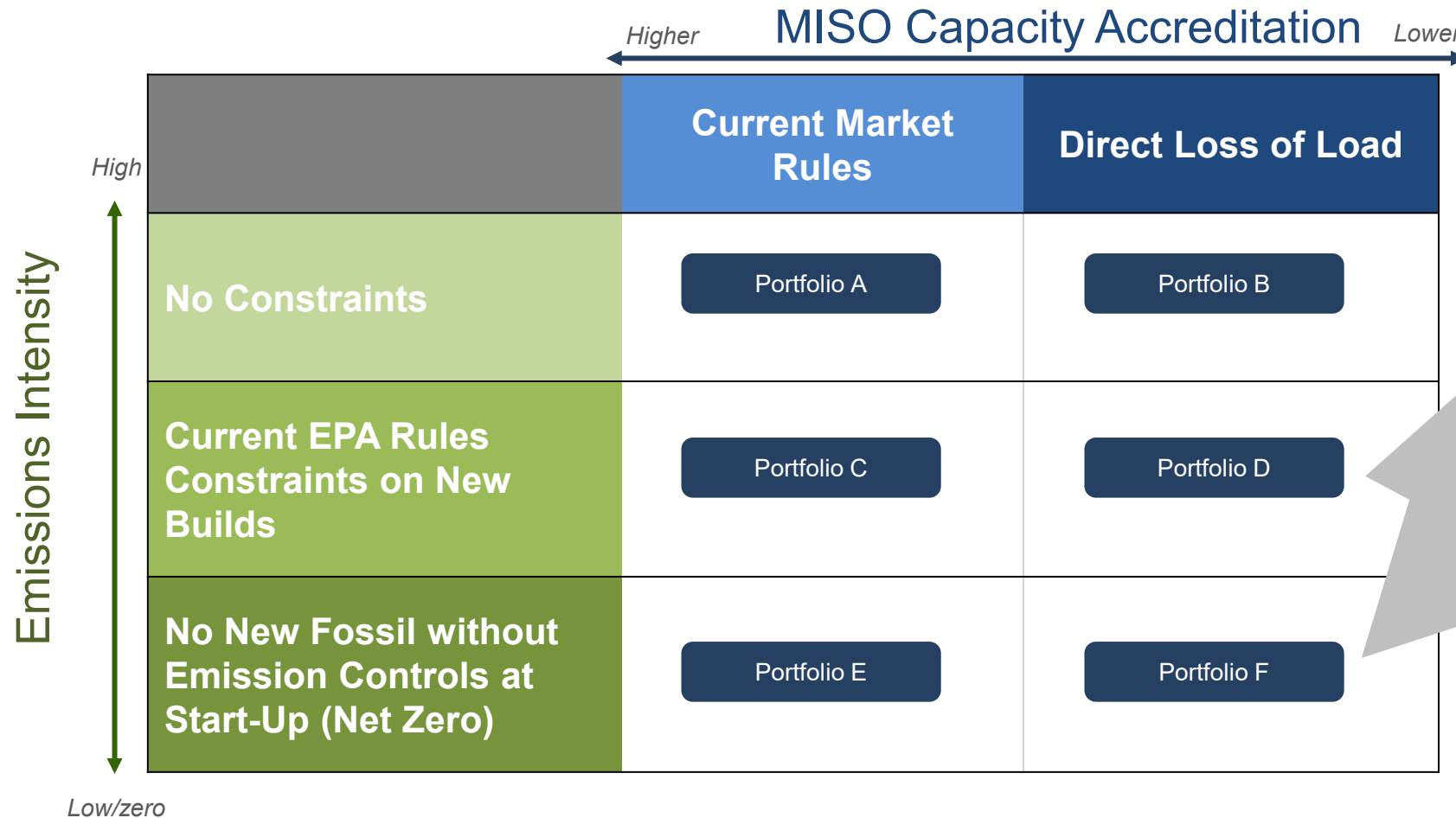
Note that the three converted CCUS units in the D-CCUS Portfolio would be expected to be de-rated from 650 MW to 585 MW. Small resulting seasonal capacity shortfalls are assumed to be covered via short-term capacity purchases for modeling purposes.

ENERGY MIX ACROSS PORTFOLIOS – ANNUAL SNAPSHOT 2043



ADDITIONAL PORTFOLIO CONSIDERATIONS – FLAT LOAD

In addition to the Portfolio D variants, stakeholders have expressed interest in understanding the portfolio implications if new large loads do not materialize in NIPSCO's service territory.



Two additional portfolios were developed to highlight:

Portfolios with EPA rules and under the D-LOL construct (the “D” theme), but without data center load (Flat Load).

Portfolio Flat Load

Portfolio Flat Load - DLOL

Portfolio D - CCUS

Portfolio D - Hydrogen

FLAT LOAD 1 – RESOURCE ADDITIONS (NAMEPLATE MW)

Flat Load

1 Current Market Rules

Resource	Through 2029 ¹	2030-2034	2035+
Wind		350	200
Solar			450
4-hr Li-Ion Storage	143	325	200
Long Duration Energy Storage	118		
Gas CCGT			
Gas Peaking			200
Short-Term Thermal PPA & ZRCs	200 ²		
Gas CCGT w/ CCUS			
H2-enabled CC			
Sugar Creek			650 ³

1: All resources through 2029 are from the RFP.

2: Includes 200 MW ZRC.

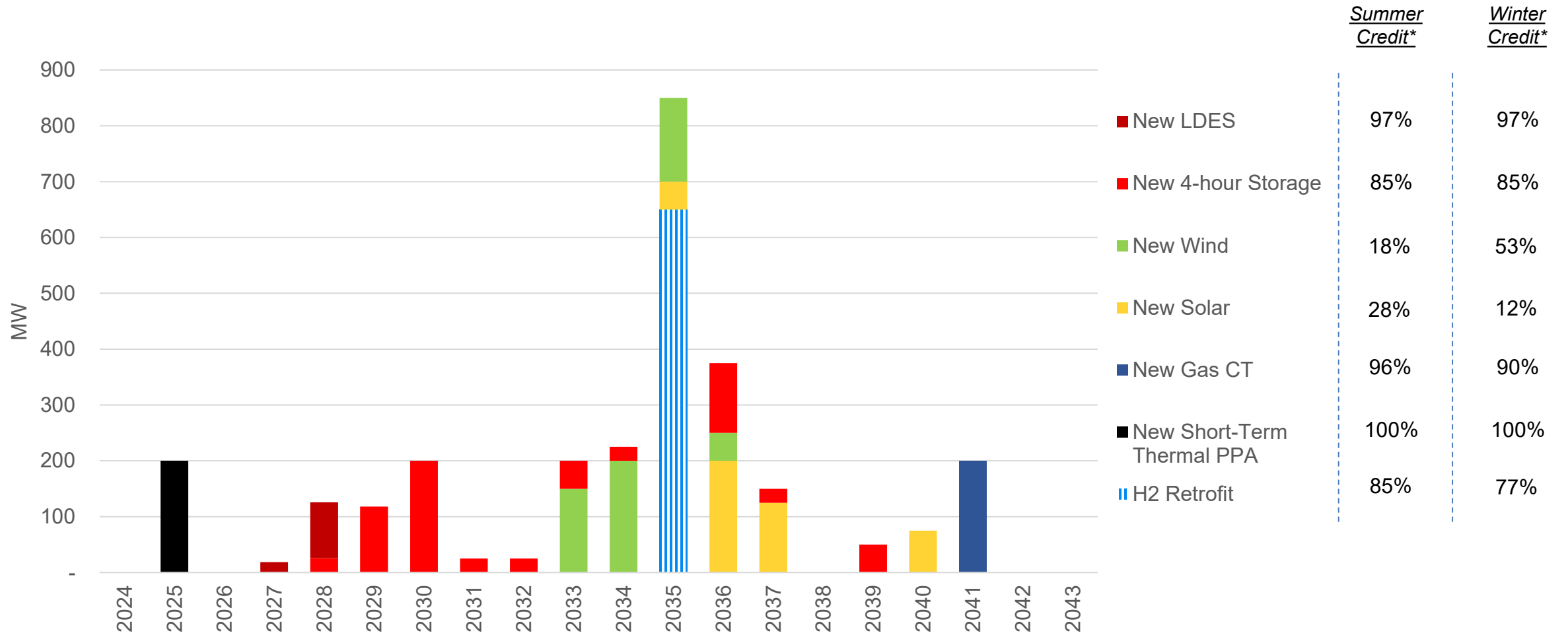
3: Retrofitted to H2-enabled CCGT in 2035

Note: All EE programs selected except for first tranche of C&I (2027-2029) and all Residential High and Behavioral. All DR selected except for Water Heaters, EV Charging, and BTM Storage

FLAT LOAD 1 – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

Flat Load

1 Current Market Rules



Note: The 2025 short-term PPA lasts through 2029.

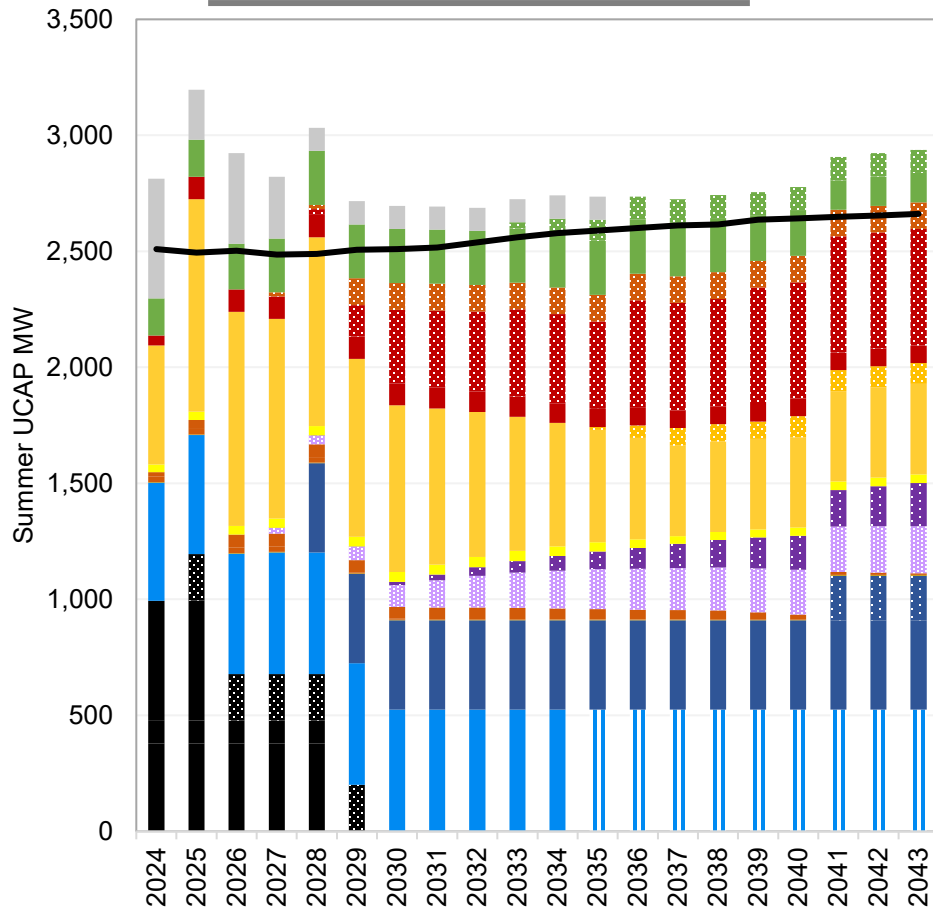
*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

FLAT LOAD 1 – SUPPLY-DEMAND BALANCE

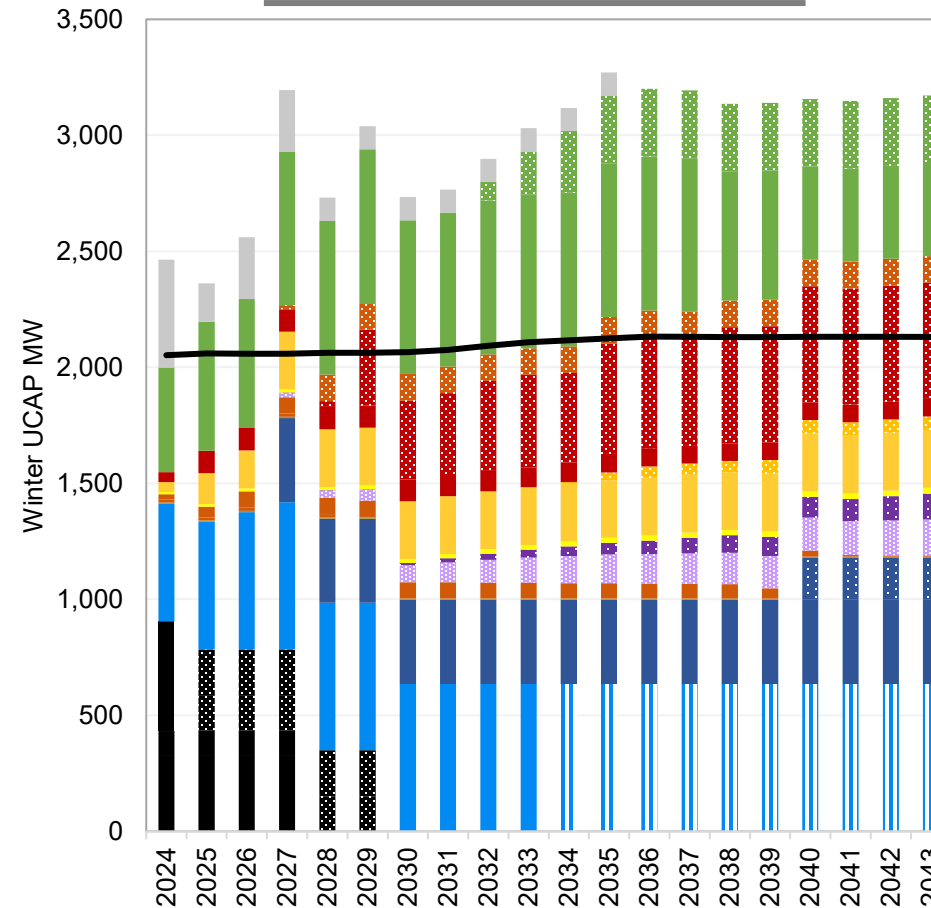
Flat Load

1 Current Market Rules

Summer Cap. vs. PRM



Winter Cap. vs. PRM



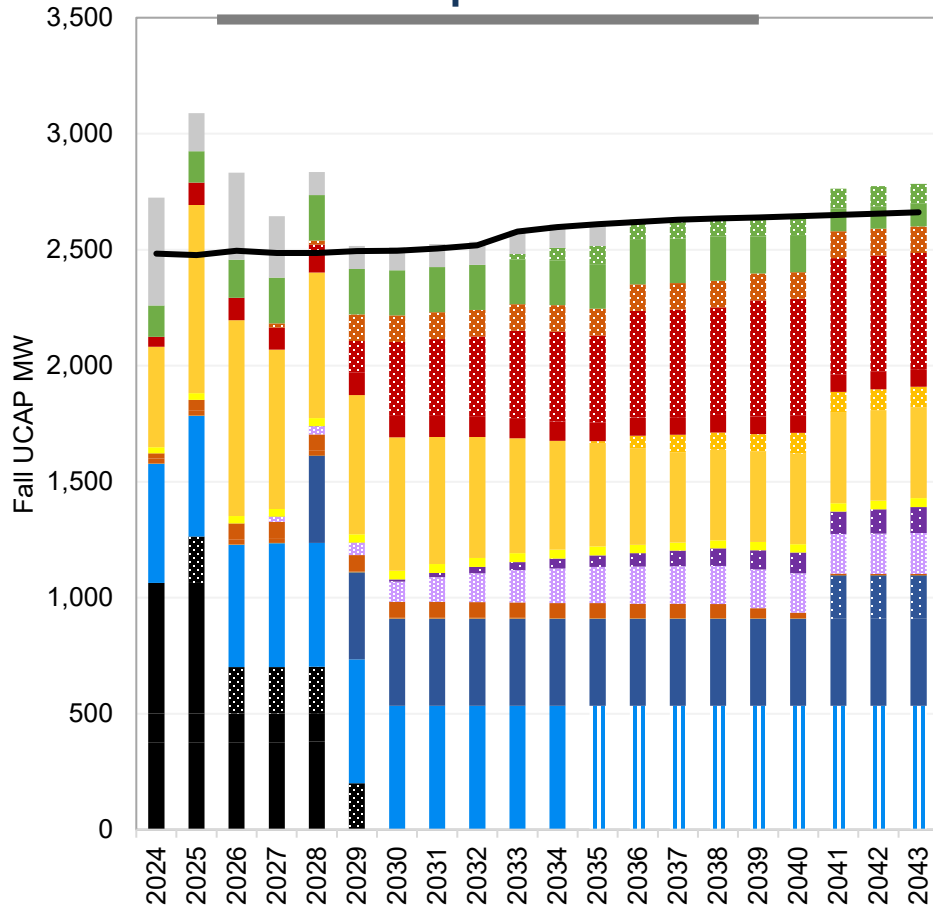
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

FLAT LOAD 1 – SUPPLY-DEMAND BALANCE

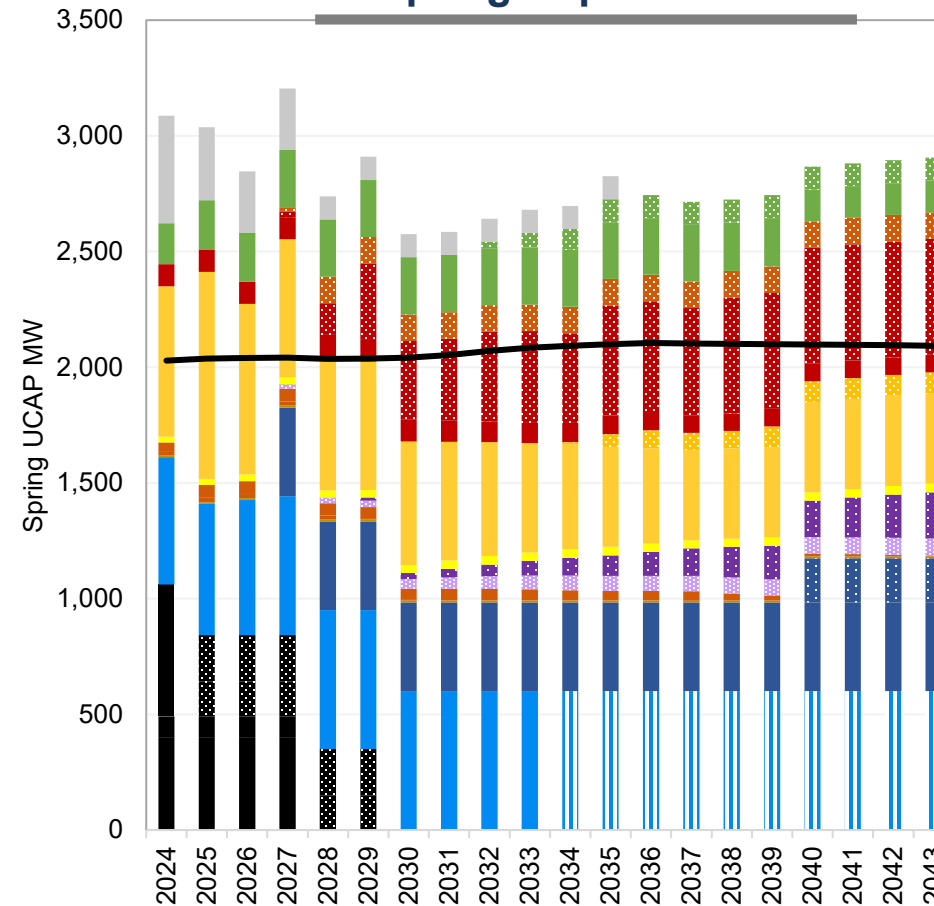
Flat Load

1 Current Market Rules

Fall Cap. vs. PRM



Spring Cap. vs. PRM



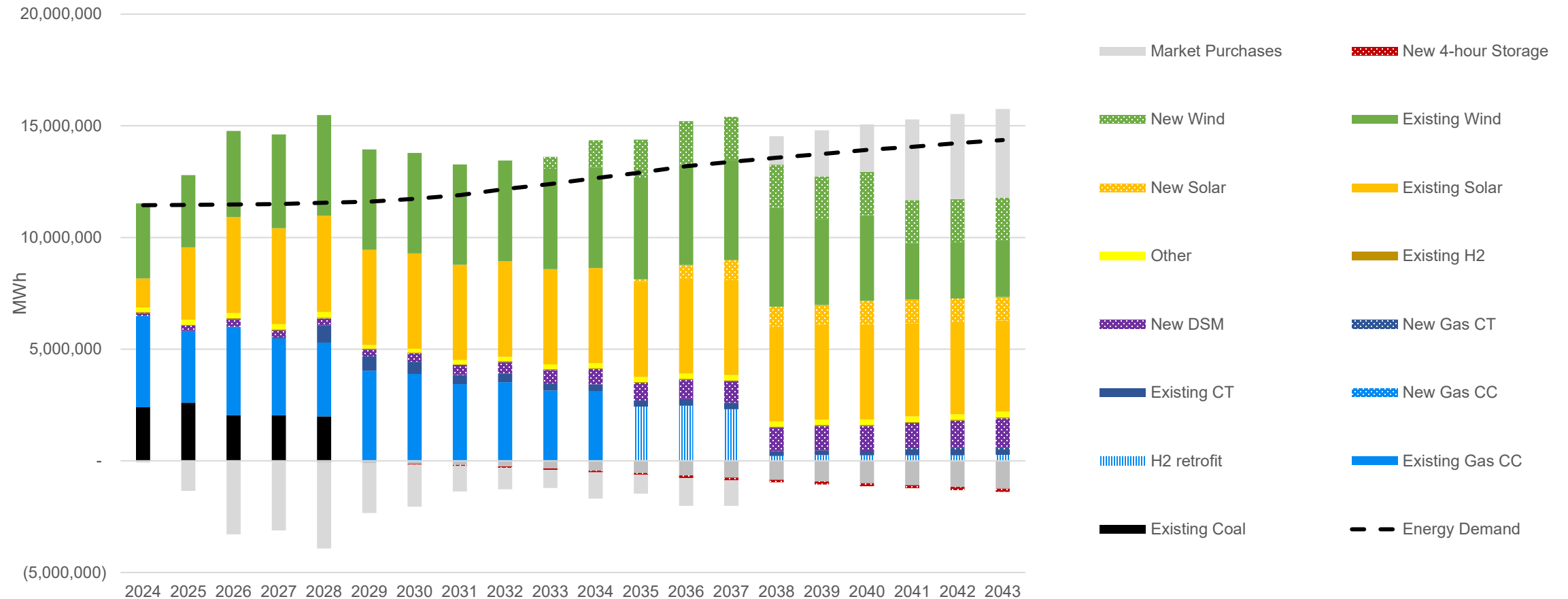
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- New 4-hour Storage
- Existing Storage
- New Solar
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- Planning Reserve Margin

Generally Binding Season

FLAT LOAD 1 – ENERGY POSITION

Flat Load

1 Current Market Rules



Notes:

- The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.
- The portfolio was optimized under an assumption that Sugar Creek continues operating on natural gas. This display shows potential hydrogen blending under the Reference Case, which could leave the portfolio energy short.

FLAT LOAD 2 – RESOURCE ADDITIONS (NAMEPLATE MW)

Flat Load

2

Direct Loss of Load

Resource	Through 2029 ¹	2030-2034	2035+
Wind		150	200
Solar			
4-hr Li-Ion Storage	1,146	125	25
Long Duration Energy Storage			
Gas CCGT			
Gas Peaking			
Short-Term Thermal PPA & ZRCs	150 ²		
Gas CCGT w/ CCUS			
H2-enabled CC			
Sugar Creek			650 ³

1: All resources through 2029 are from the RFP.

2: Includes 150 MW of thermal PPA.

3: Retrofitted to H2-enabled CCGT in 2035

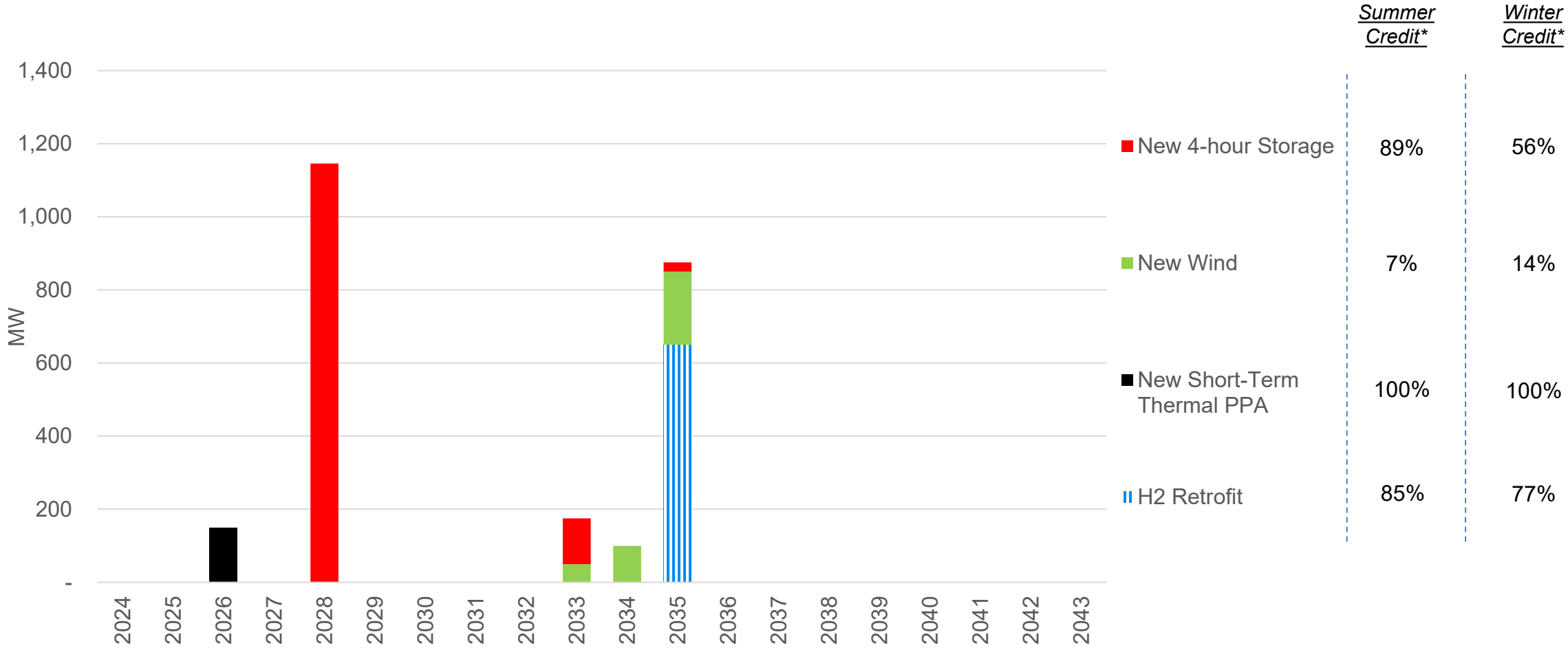
Note: All EE programs selected except for first tranche of C&I and Residential High (2027-2029) and first two tranches of Behavioral DSM (2027-2032). All DR selected except for Water Heaters, EV Charging, and BTM Storage

FLAT LOAD 2 – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)

Flat Load

2

Direct Loss of Load



Note: The 2026 short-term PPA lasts from 2026-2030.
*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

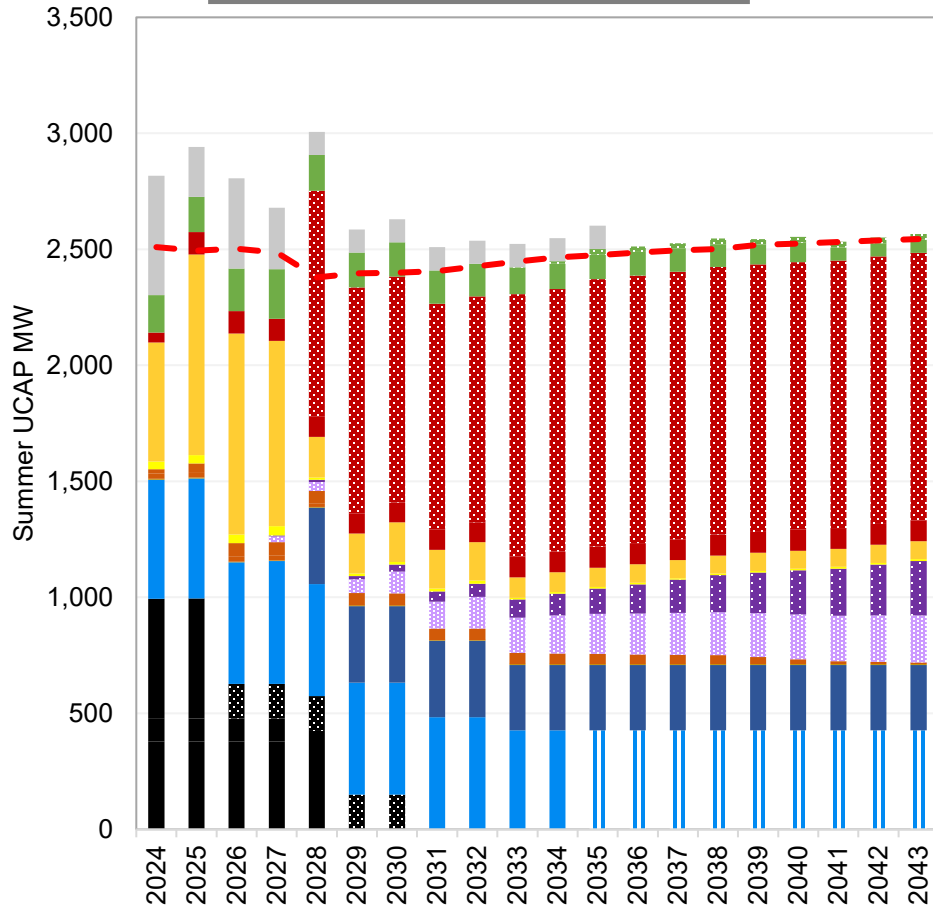
FLAT LOAD 2 – SUPPLY-DEMAND BALANCE

Flat Load

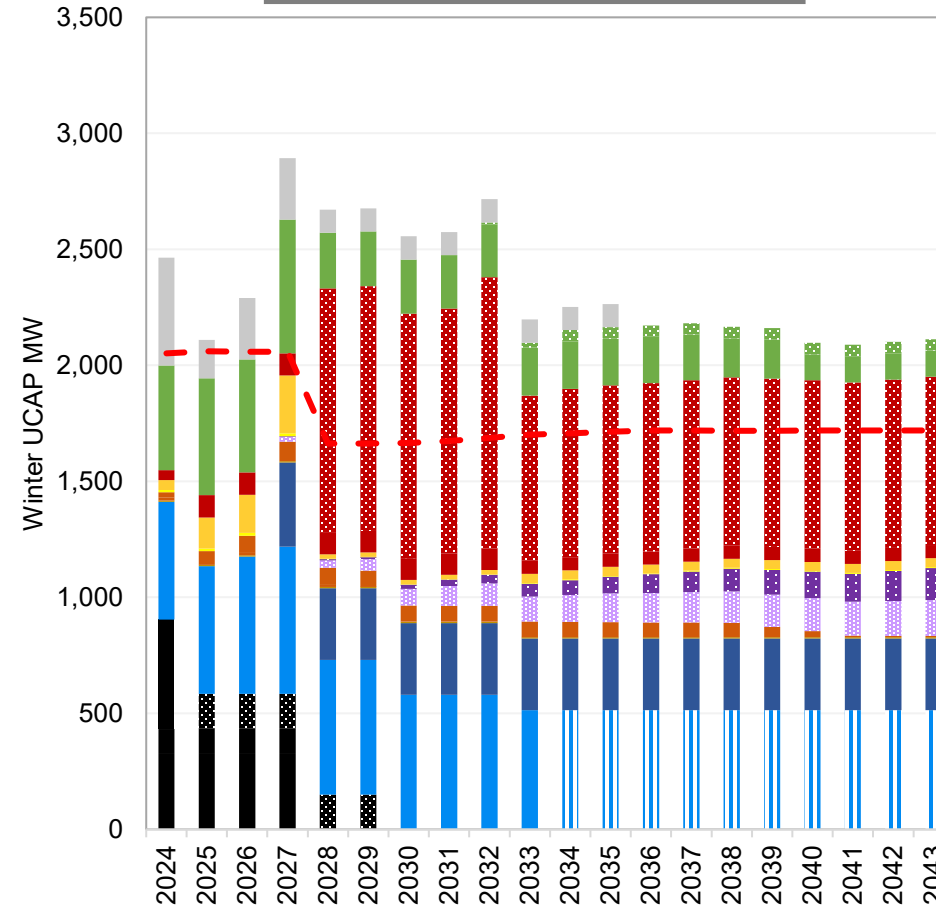
2

Direct Loss of Load

Summer Cap. vs. PRM



Winter Cap. vs. PRM



- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- Existing Coal
- DLOL PRM

Generally Binding Season

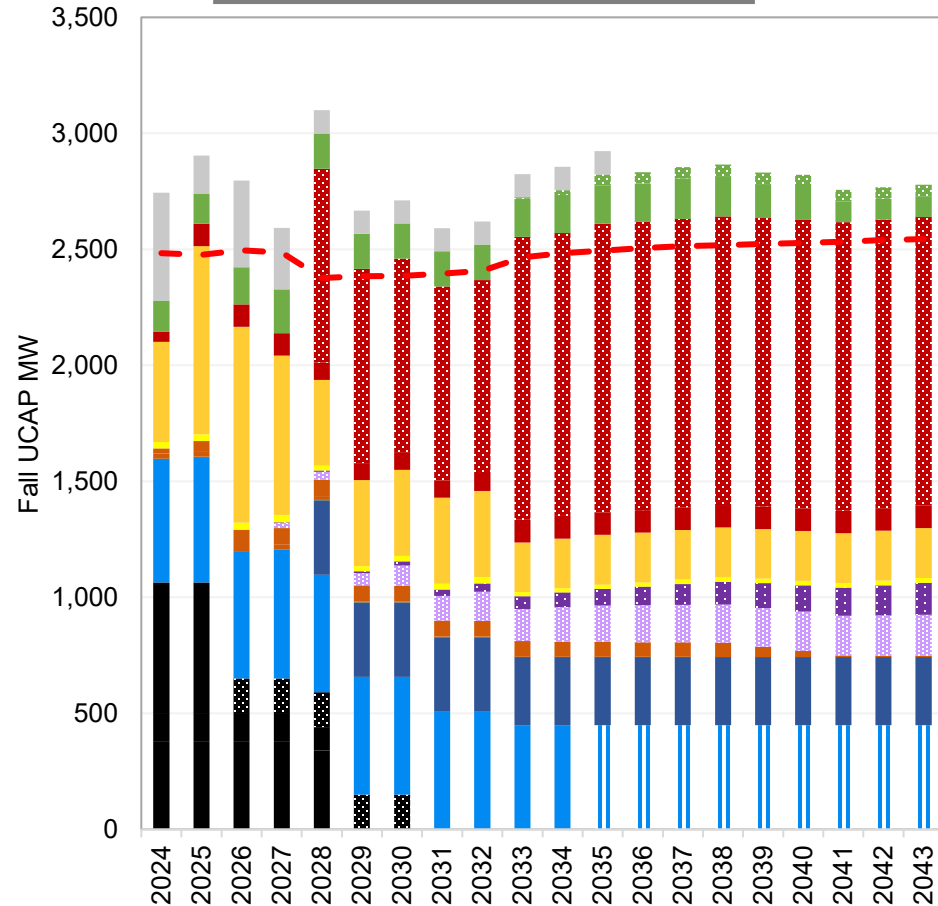
FLAT LOAD 2 – SUPPLY-DEMAND BALANCE

Flat Load

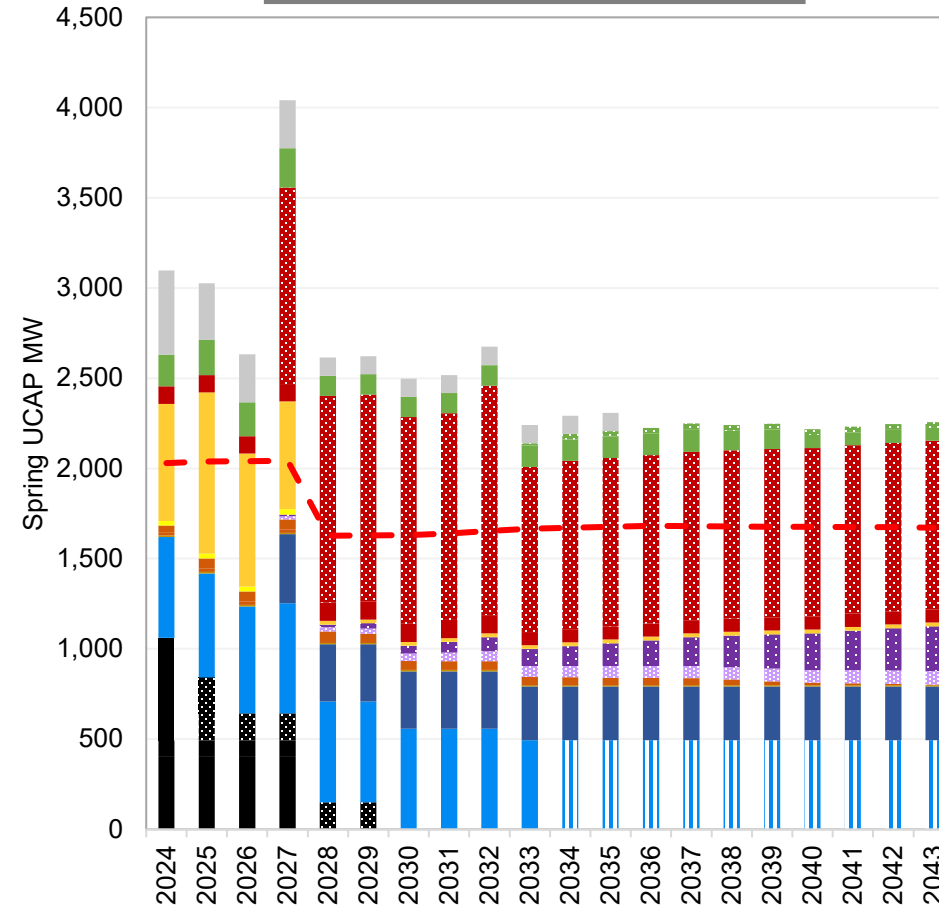
2

Direct Loss of Load

Fall Cap. vs. PRM



Spring Cap. vs. PRM



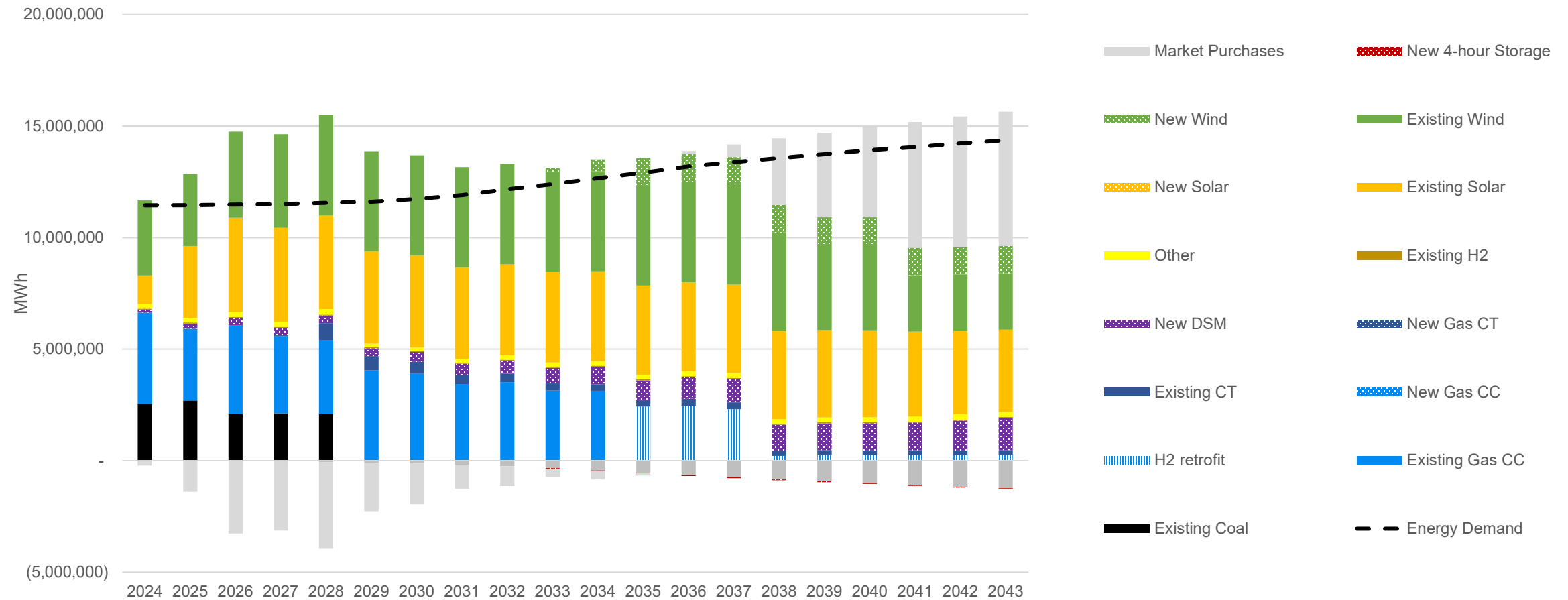
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- DLLO PRM

FLAT LOAD 2 – ENERGY POSITION

Flat Load

2

Direct Loss of Load



Notes:

- The net impact of storage is shown, which results in an energy "loss," given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.
- The portfolio was optimized under an assumption that Sugar Creek continues operating on natural gas. This display shows potential hydrogen blending under the Reference Case, which could leave the portfolio energy short.

PORTFOLIO COMPARISON – RESOURCE ADDITIONS ABOVE CURRENT PLAN

	Flat Load	Flat Load DLOL	A	B	C	D (all)*	E	F
Data Center Load	None	None	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	CCGT<40%	CCGT<40%	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	None	None	Late 2030s	At Start-up	At Start-up
Wind	550	350	1,500	1,850	1,800	1,550	2,250	2,350
Solar	450		2,125	675	3,235	1,275	2,322	1,922
Storage ¹	786	1,296	1,249	1,882	811	959	1,409	2,111
Gas CCGT			2,600	2,600	2,585	3,235		
Gas Peaking	200				400	618		
Gas CCGT w/CCUS							2,340	2,340
Sugar Creek	H2 (or CCUS) Retrofit	H2 (or CCUS) Retrofit	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DSM (DR/EE) ²	390	440	400	430	230	270	365	365
Total ICAP Additions Through 2043 (excl. DSM/DR)	1,986 MW	1,646 MW	7,474 MW	7,007 MW	8,831 MW	7,637 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer) Covered	~850 MW	~1,350 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

¹ Includes both 4-hour Lithium-ion and long-duration storage

² DSM additions calculated as peak capacity contribution in summer of 2043

KEY SUMMARY OBSERVATIONS AND CONCLUSIONS

- **Capacity purchases will serve as an effective bridge to new resources and could allow NIPSCO to firm up its near-term capacity position as needed, given the uncertainty in D-LOL accreditation and large load growth potential.**
- **Storage additions will play a major role in meeting incremental capacity requirements through the end of the decade with or without new large loads.**
 - NIPSCO will need to be flexible around the quantities of new storage to be procured from the RFP, as storage additions will be positioned as a key “swing resource” to meet evolving capacity needs that will be heavily influenced by D-LOL accreditation reforms.
 - Long duration energy storage (LDES) was selected in certain portfolios and will likely have a role to play in the mid term. NIPSCO will need to track technology developments, costs, and accreditation data for different storage technologies and adapt resource additions accordingly.
- **New natural gas combined cycle capacity is needed to meet potentially significant energy and capacity needs associated with new large load growth across all MISO accreditation and emission reduction portfolio concepts.**
- **Significant energy efficiency and demand response is included across all portfolios and is likely to continue to play an important role in NIPSCO’s portfolio.**

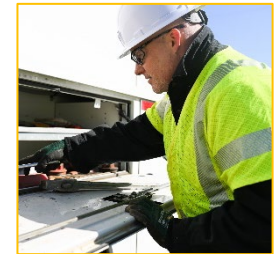


PORTFOLIO ANALYSIS – SCENARIOS

Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA



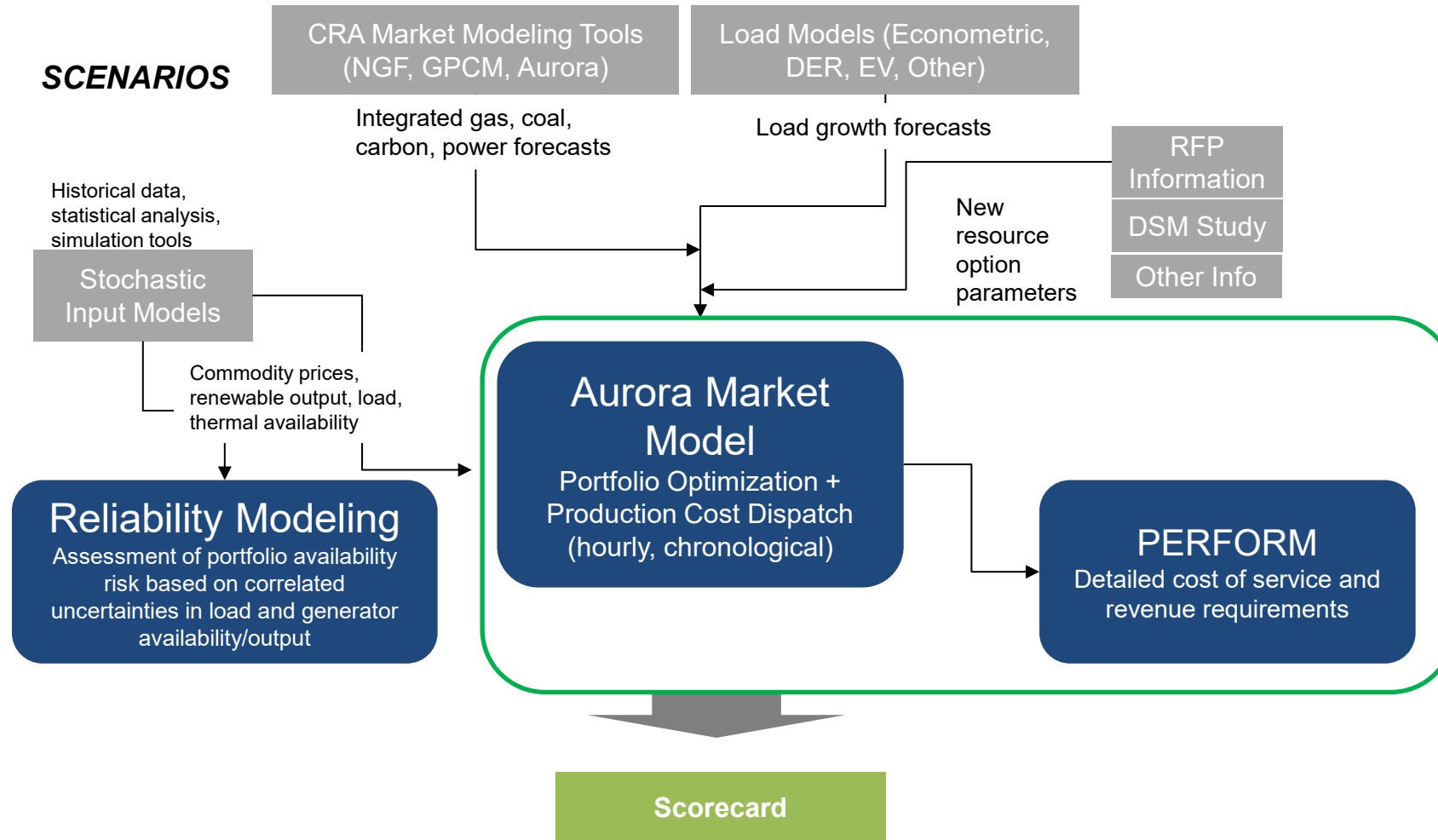
NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 610 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

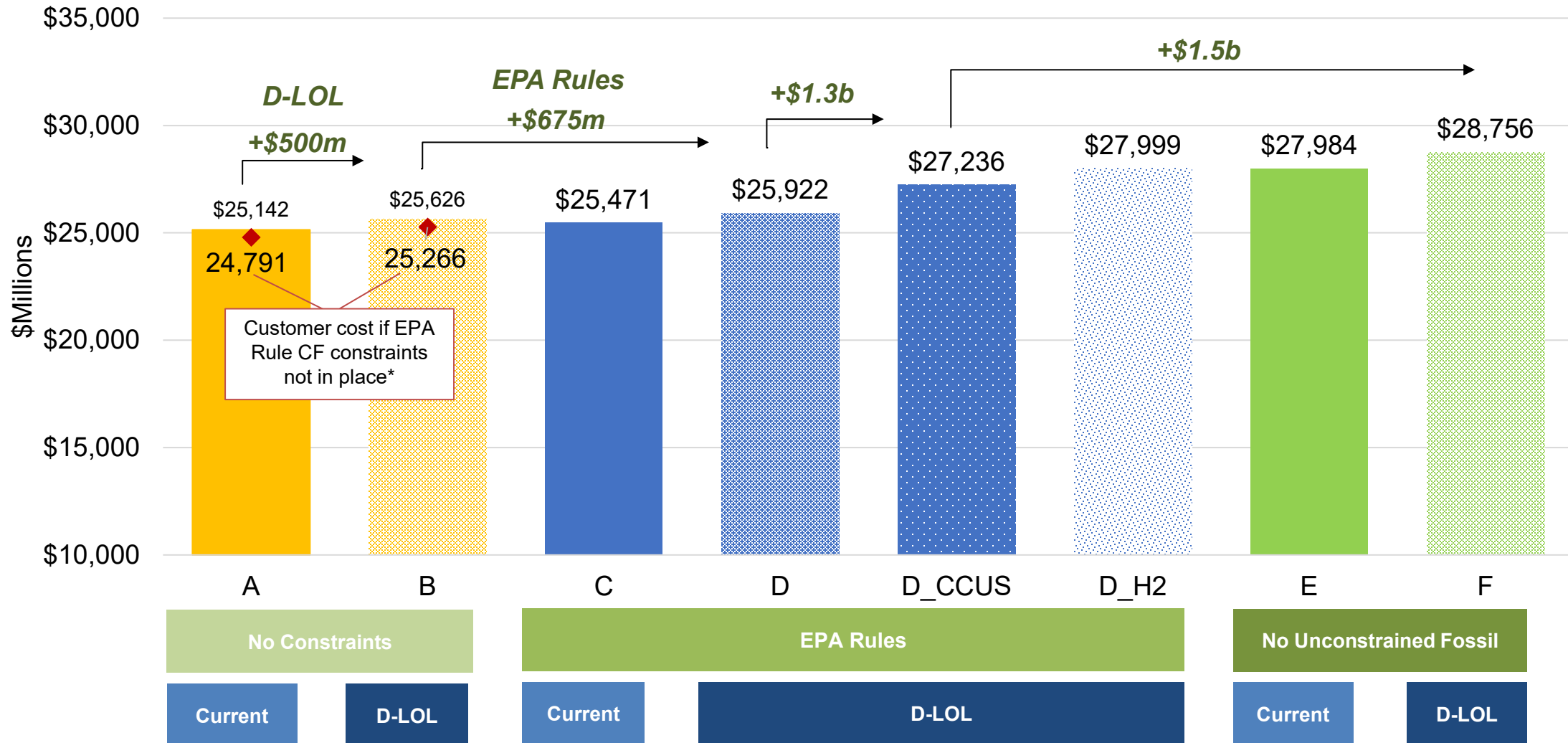


RESOURCE PLANNING APPROACH



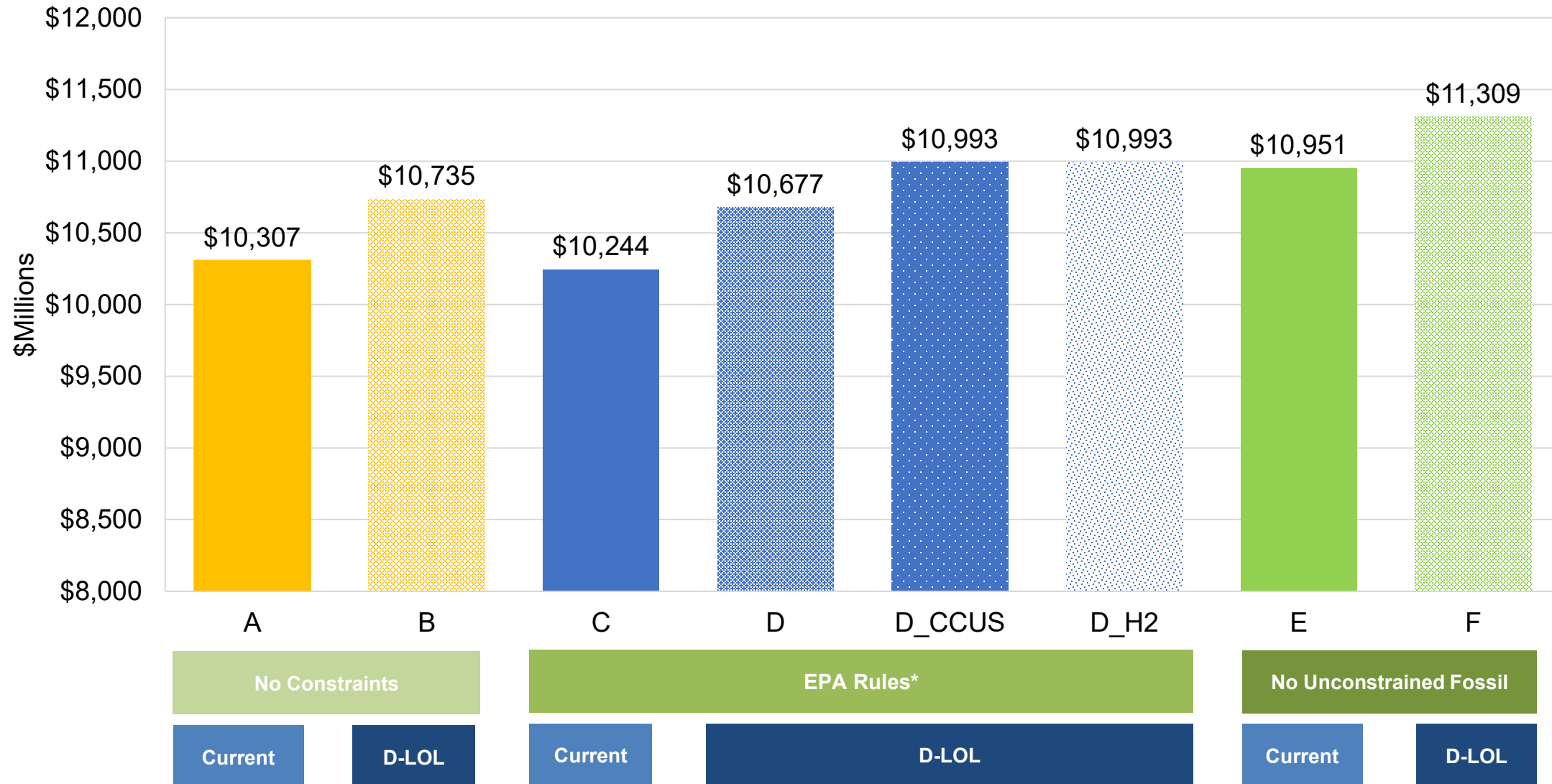
- 1 Identify key planning questions and approach
- 2 Develop market perspectives (external scenarios)
- 3 Develop integrated resource strategies (NIPSCO portfolios)
- 4 Portfolio modeling and analysis
 - Detailed scenario dispatch
 - Stochastic simulations
- 5 Evaluate trade-offs and select preferred plan

30-YR NET PRESENT VALUE OF REVENUE REQUIREMENT SUMMARY – REFERENCE CASE



**EPA GHG Rules implementation assumes new CCGTs can run without capacity factor limits through 2031 and then are limited to 40% in 2032+. Portfolios A and B were also evaluated without capacity factor limits for the entire study period (as represented by the red diamonds above).*

10-YR NET PRESENT VALUE OF REVENUE REQUIREMENT SUMMARY – REFERENCE CASE



**EPA GHG Rules implementation assumes new CCGTs can run without capacity factor limits through 2031 and then are limited to 40% in 2032+. Portfolios A and B were also evaluated without capacity factor limits for the entire study period (as represented by the red diamonds above).*

KEY SUMMARY OBSERVATIONS AND CONCLUSIONS – REFERENCE CASE

- **Implementation of D-LOL would drive more capacity additions and raise portfolio costs**
 - Over the 30-year NPVRR period, portfolio costs are projected to be ~\$450-500 million higher in Portfolios B and D relative to A and C; a similar cost increase is evident over the initial 10 years of the study period as well due to additional near-term capacity needs.
- **Customer costs are projected to be higher in Portfolios C/D relative to Portfolios A/B due to new EPA GHG rules**
 - The level of cost premium is around \$675 million in NPV assuming no constraints on combined cycle operation under Reference Case market conditions. If the optimized portfolios were held to the 40% capacity factor constraints, available energy market purchases would still result in lower costs for A and B relative to C and D.
- **With the assumed load growth, a cost premium is associated with meeting net zero goals and restricting new fossil resources to only those with emission controls. Assuming no technology cost and performance risk with CCUS and assuming full monetization of all 45Q tax credits:**
 - There is a ~\$1.3 billion 30-year NPVRR premium associated with achieving net zero with CCUS and H2 relative to continuing to operate Portfolio D with combined cycle additions and no subsequent retrofits.
 - There is an *incremental* ~\$1.5 billion 30-year NPVRR premium associated with restricting new fossil resources to only those with emission controls (Portfolio F). Over the first 10 years, the *incremental* NPVRR impact is about \$300 million.

RECAP: 2024 IRP SCENARIOS



Reference Case (REF)

- The MISO market continues to evolve based on current expectations for load growth, commodity price trajectories, technology development, and policy change (IRA incentives continue, EPA power sector rules advance, and MISO resource adequacy enhancements proceed)



Slower Transition (ST)

- IRA incentives are reduced or ended early, and EPA power sector rules are overturned or rescinded; natural gas prices remain low and result in new gas additions remaining competitive versus renewables in the broader region, as coal capacity more gradually fades from the MISO market



Domestic Resiliency (DR)

- Continued geopolitical uncertainty and volatility drives a focus on “domestic energy independence”; electric power demand grows because of onshoring and other large loads; gas prices are higher due to strong demand



Aggressive Environmental Regulation (AER)

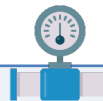
- Carbon emissions from the power sector are regulated more heavily, including through a CO2 price; restrictions on natural gas production increase gas prices



Accelerated Innovation (AI)

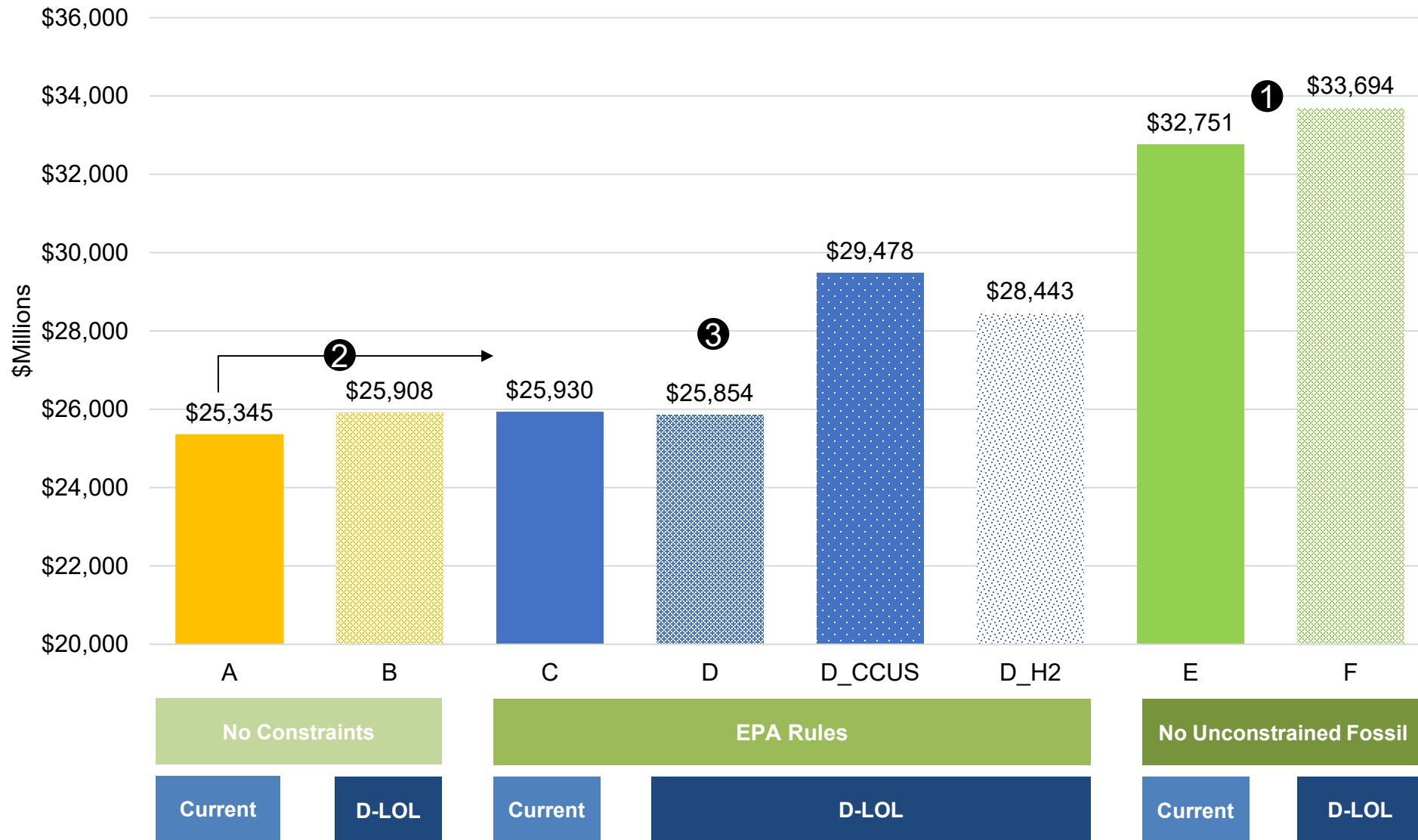
- Federal subsidies continue as a bridge until technology breakthroughs drive broad economy-wide decarbonization (including via electrification); new power sector technologies are commercialized, and DER, EV, microgrid, and EE adoption all increase, transforming wholesale load requirements as “Grid Edge” innovations and enabling policy advance

DIRECTIONAL SCENARIO VARIABLE INPUTS

Scenario		 Commodity Prices	 Carbon Policies	 MISO-wide & NIPSCO Demand
	Reference Scenario (REF)	Baseline	Current Policy, including EPA power sector CO2 emission rules	Baseline
	Slower Transition (ST)	Low gas price due to abundant resource ↓	IRA Pull-Back and withdrawn EPA power sector rules ↓	Low DER and EV
	Domestic Resiliency (DR)	Higher gas price due to strong demand ↑	Current Policy, including EPA power sector CO2 emission rules ■	High load from new large loads and industrial onshoring MISO-wide* Higher EV
	Aggressive Environ. Regulation (AER)	Highest gas price due to production restrictions ↑	EPA power sector CO2 emission rules <i>plus</i> carbon price ↑	Higher DER and EV
	Accelerated Innovation (AI)	Lower gas price due to demand erosion ↓	Current Policy, including EPA power sector CO2 emission rules ■	High EV and electrification; higher DER

**Note that data center load growth uncertainty is separately modeled for NIPSCO as a sensitivity.*

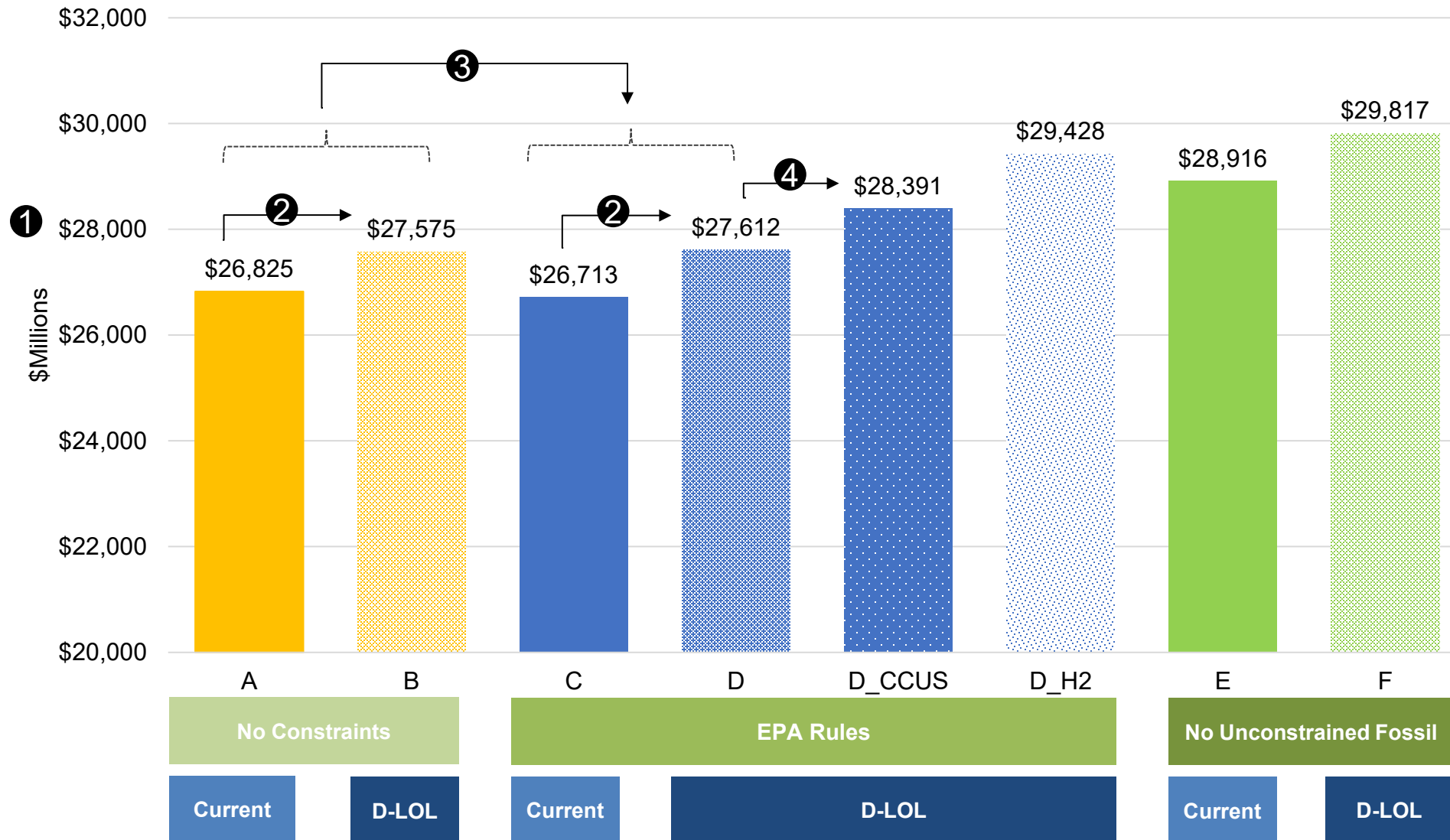
NET PRESENT VALUE OF REVENUE REQUIREMENT SUMMARY – ST SCENARIO



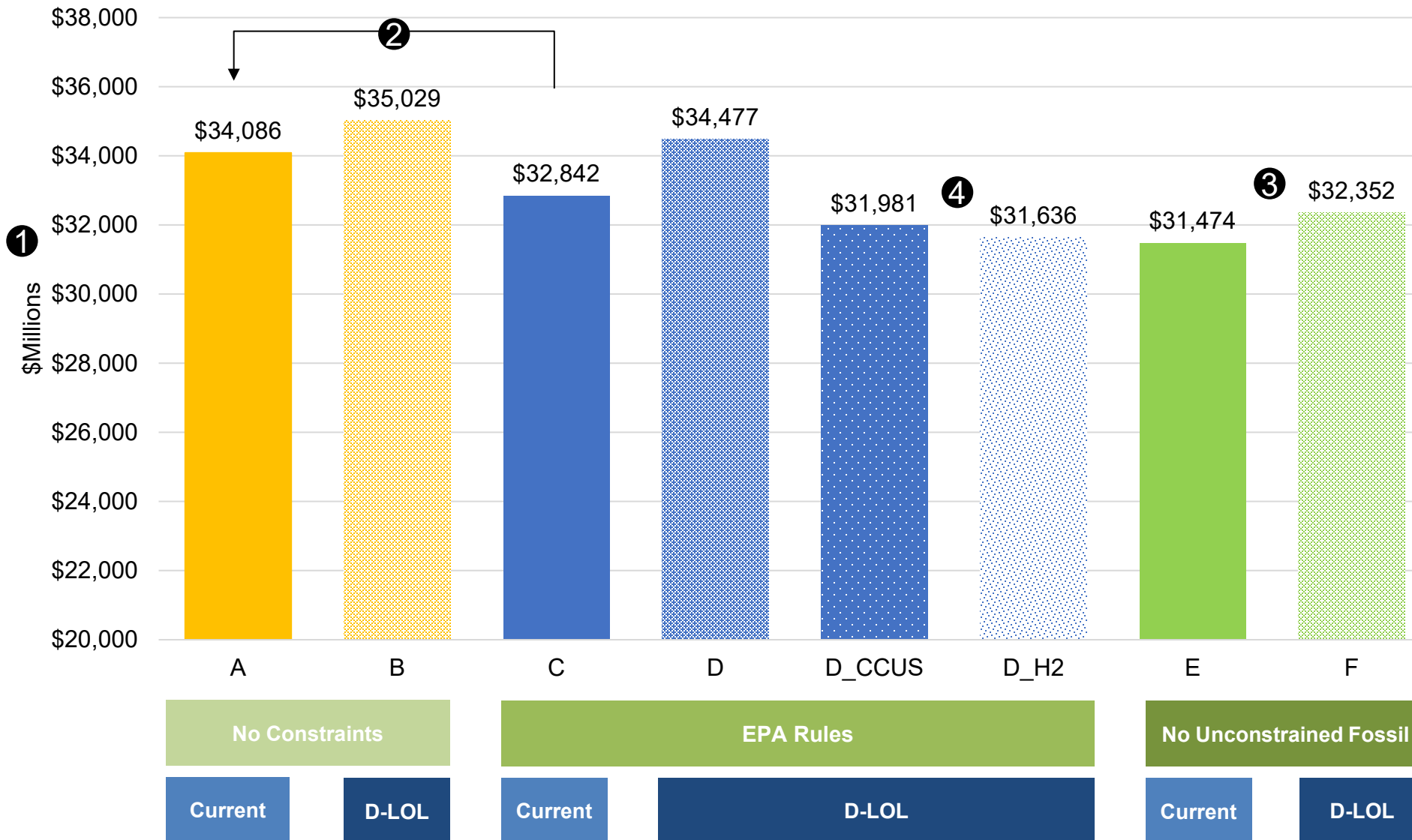
Relative to the Reference Case:

- Costs for portfolios (E, F, and D_CCUS) that rely heavily on federal tax credits for significant clean energy additions face the largest cost increases.
- The premium associated with Portfolio C (developed under EPA Rule constraints) relative to Portfolio A decreases when both portfolios are not subject to capacity factor constraints.
- Portfolio D (with an additional CCGT built under D-LOL) is lower cost than Portfolio C, given no constraints on capacity factor and lower gas prices.

NET PRESENT VALUE OF REVENUE REQUIREMENT SUMMARY – DR SCENARIO



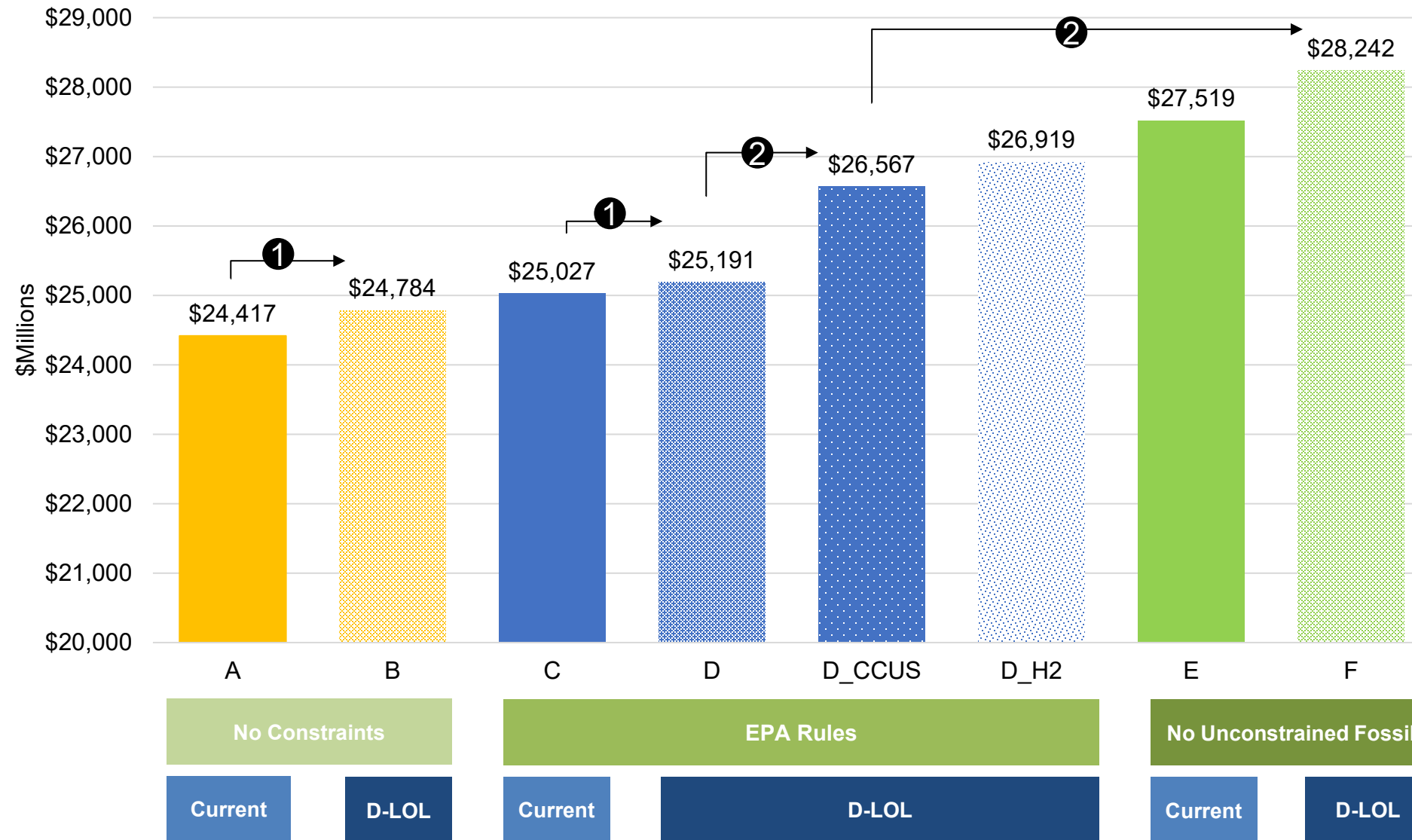
NET PRESENT VALUE OF REVENUE REQUIREMENT SUMMARY – AER SCENARIO



Relative to the Reference Case:

- Overall portfolio costs are significantly higher, driven by higher natural gas prices and implementation of a CO2 price.
- Costs for portfolios optimized without EPA Rules are higher than those optimized with the rules in place; Portfolio A/B higher cost than Portfolio C/D.
- Portfolios E and F are lower cost than A/B and C/D due to the high CO2 price.
- Hydrogen optionality lowers long term costs for D variants when natural gas and carbon prices are high. Both are lower cost than F.

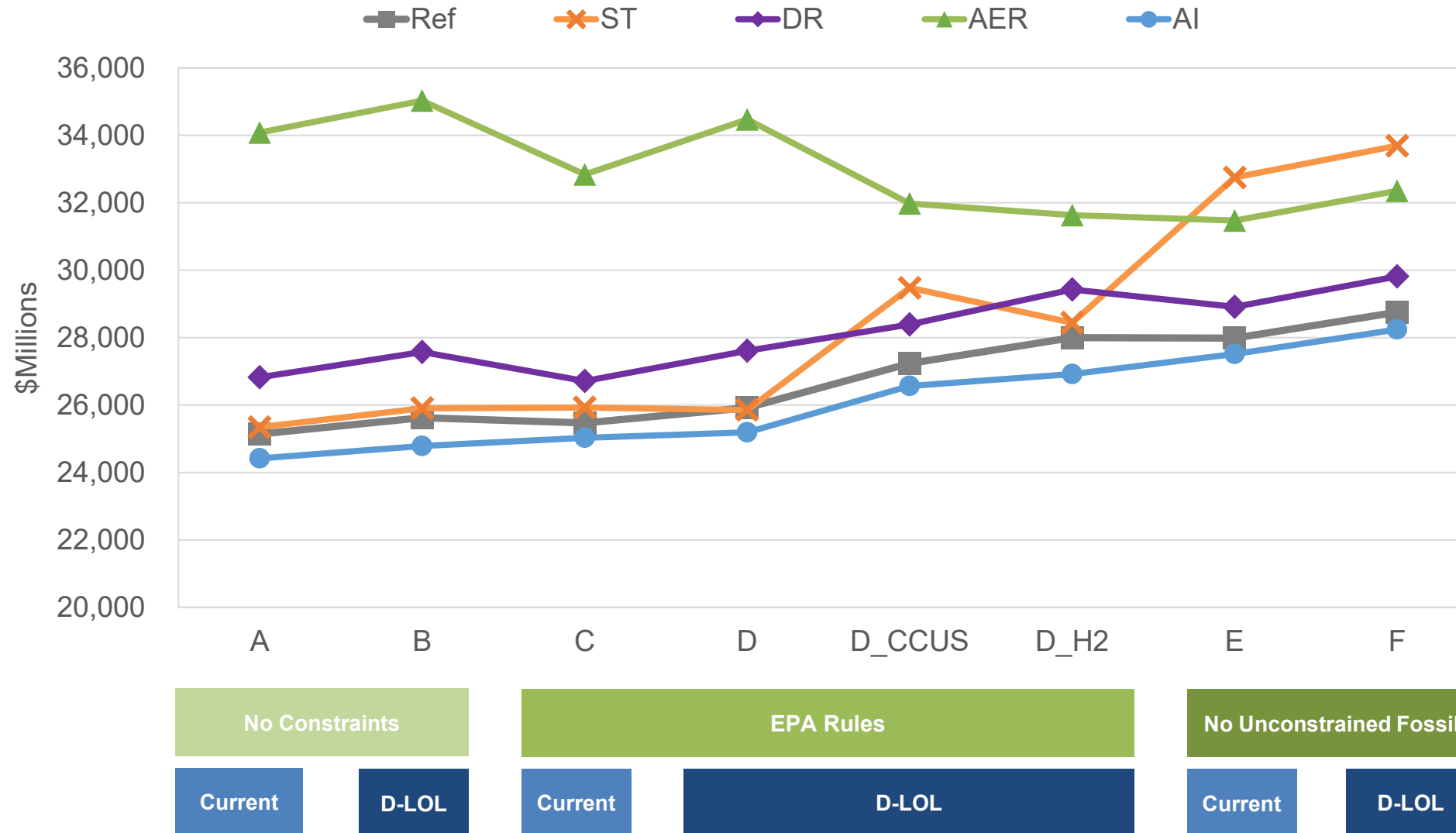
NET PRESENT VALUE OF REVENUE REQUIREMENT SUMMARY – AI SCENARIO



Relative to the Reference Case:

- Higher overall load growth increases costs for portfolios with fewer capacity additions (A & C) relative to those with more (B & D), and the “D-LOL premium” is narrower.
- Lower long-term natural gas prices slightly increase the premium associated with the portfolios that move towards net zero by 2040.

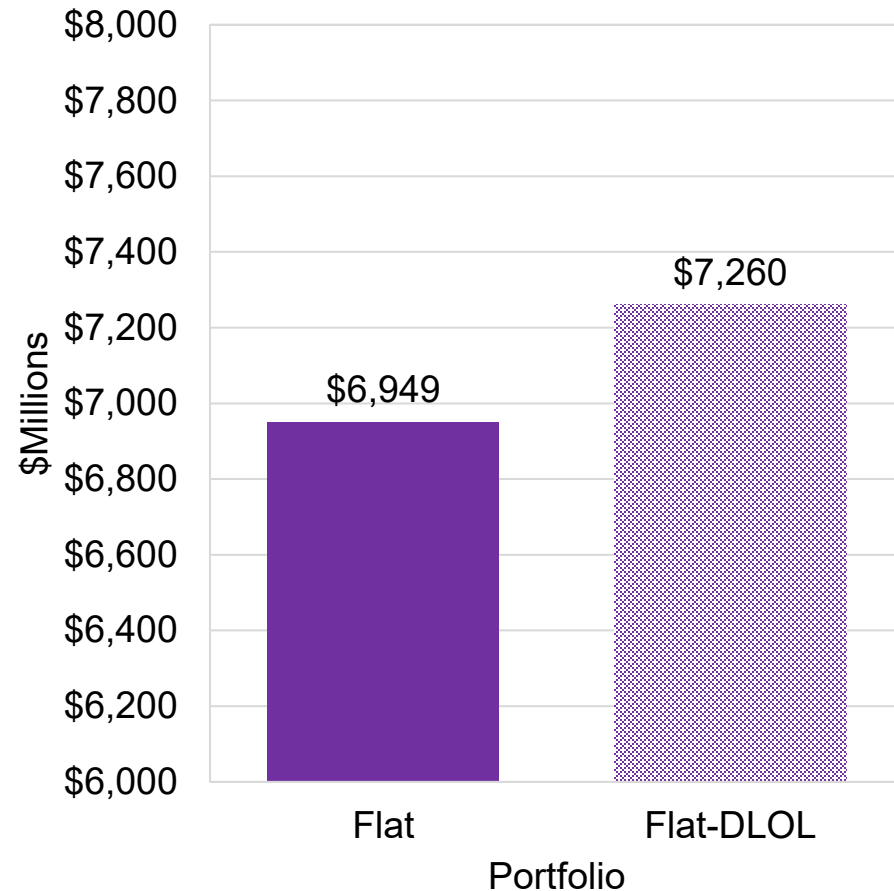
NET PRESENT VALUE OF REVENUE REQUIREMENT SUMMARY – SCENARIO ANALYSIS



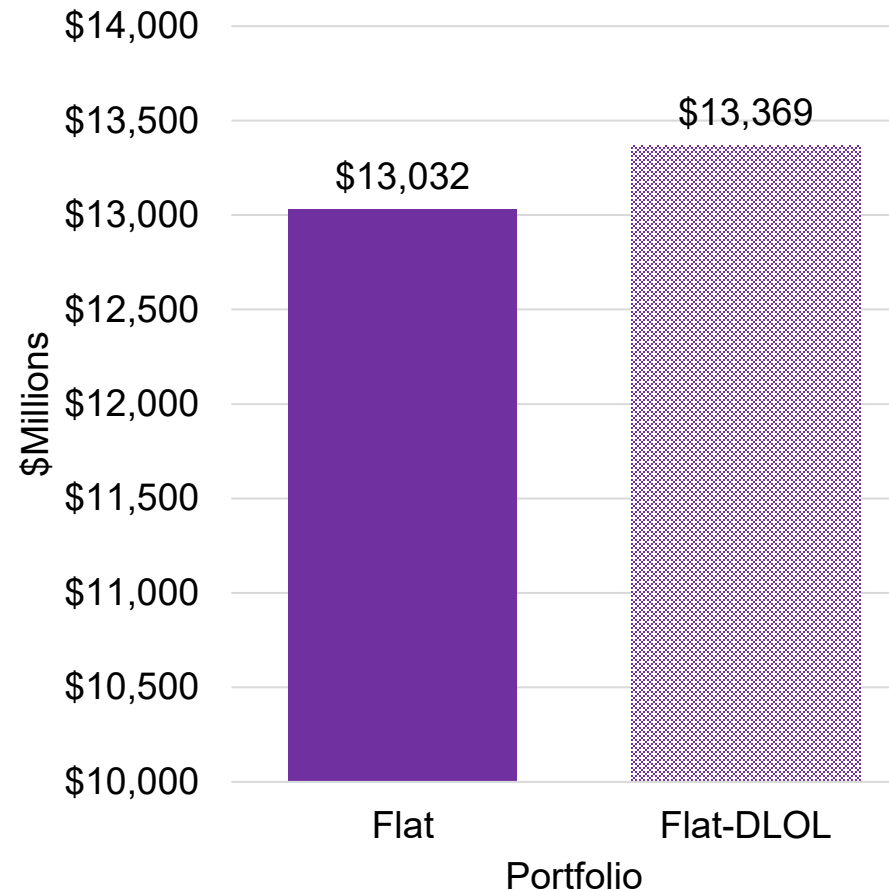
- Portfolios that do not control long-term CO₂ emissions (A,B,C,D) are highest cost in AER
- Portfolios relying heavily on near-to-mid-term tax credits (E,F) are highest cost in ST
- Optionality embedded in D_CCUS and D_H2 concepts result in a low scenario range

FLAT LOAD PORTFOLIO COSTS

10 Year NPV

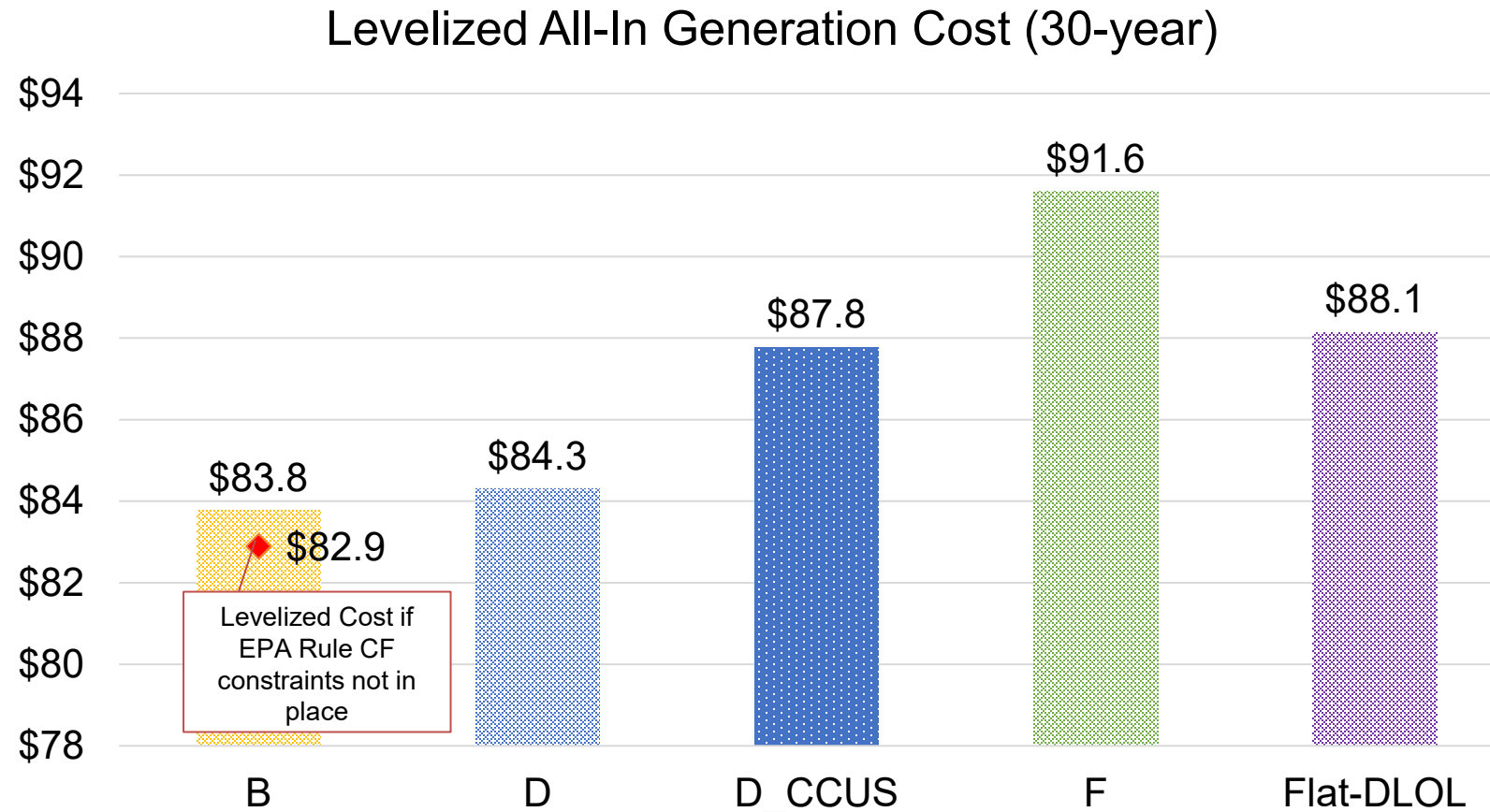


30 Year NPV



- **Total revenue requirements are lower overall with less load to serve**
 - ~65% of the total revenue requirement over ten years
 - ~50% of the total revenue requirement over 30 years

PORTFOLIO LEVELIZED COST OF ENERGY – REFERENCE CASE (D-LOL)



- Over the 30-year planning horizon, the levelized cost per MWh for the Flat Load portfolio is higher than all other concepts aside from Portfolio F.



LUNCH

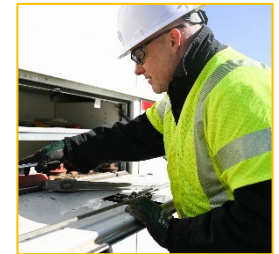


NIPSCO 2024 Integrated Resource Plan
Appendix A
Page 624 of 675



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER





OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

PORTFOLIO ANALYSIS – STOCHASTIC RISK

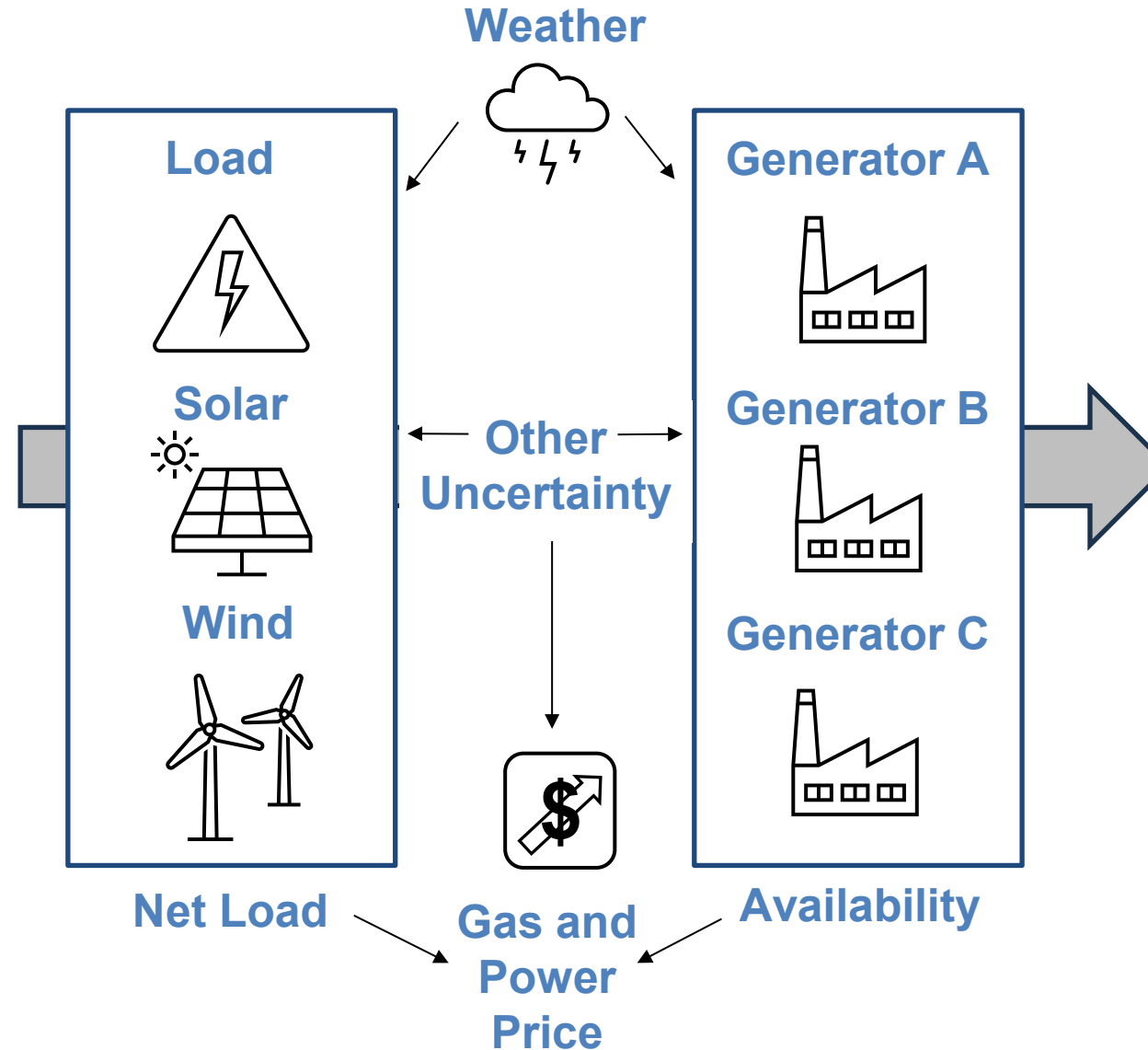
Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA



RECAP: STOCHASTIC ANALYSIS OVERVIEW

- Each of the eight portfolios has been evaluated across the stochastic distribution of key variables for the 2030 sample year:

- Fuel prices
- MISO power prices
- Load
- Solar and wind output
- Thermal resource availability



Key Outputs

- Forced market exposure metrics
- 95th and 5th percentile cost metrics

RECAP: STOCHASTIC ANALYSIS APPROACH

*Reviewed
during
Meeting
#2*

1. Evaluate historical data and employ machine learning to generate a large number of potential “iterations”

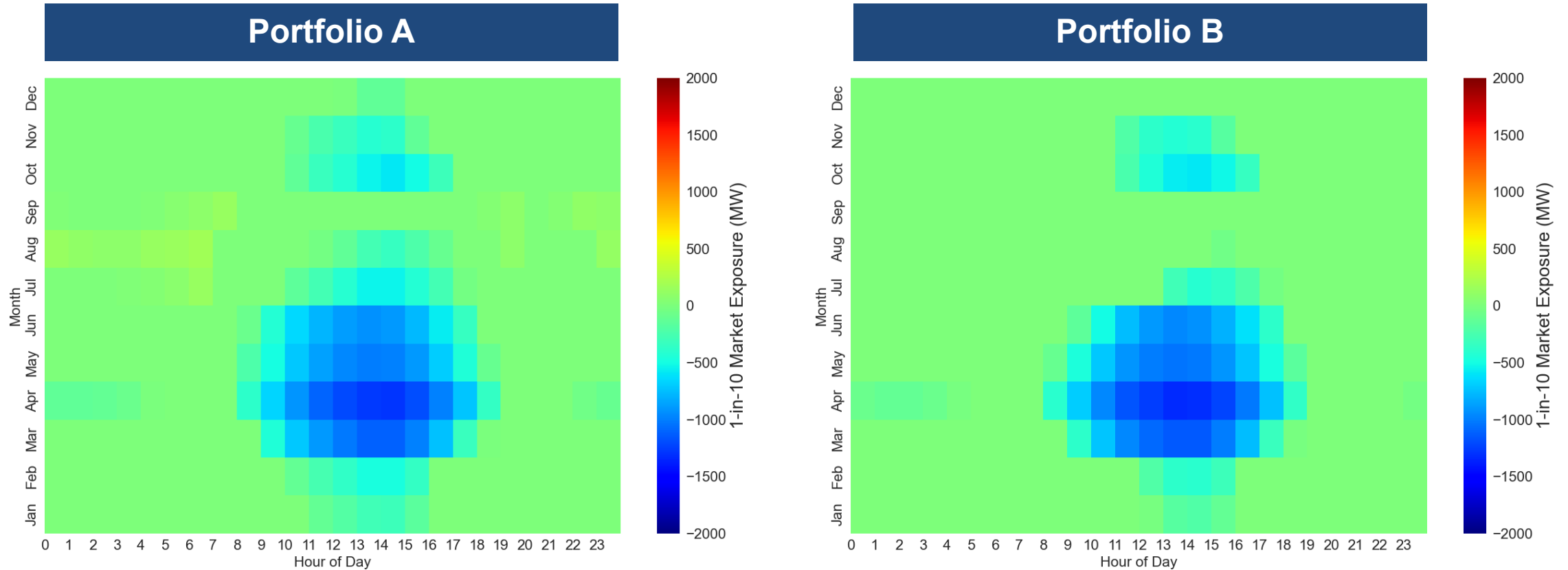
- Wind and solar output
- Energy demand - adjust for possible load futures
- Thermal unit outages
- Integration of commodity price stochastic uncertainty and market pricing data (gas prices and MISO power prices based on fundamental Aurora runs and historical time series analysis)

2. Evaluate performance of candidate portfolios against distributions

3. Record key output metrics for the scorecard

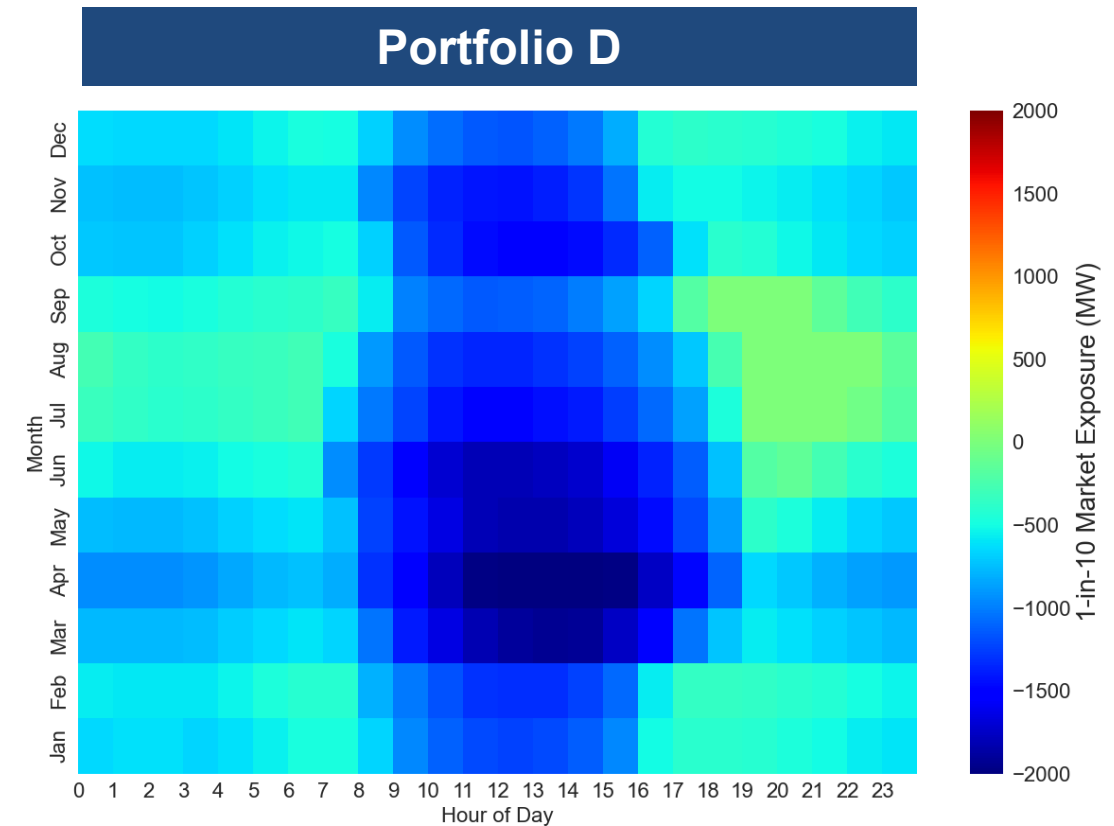
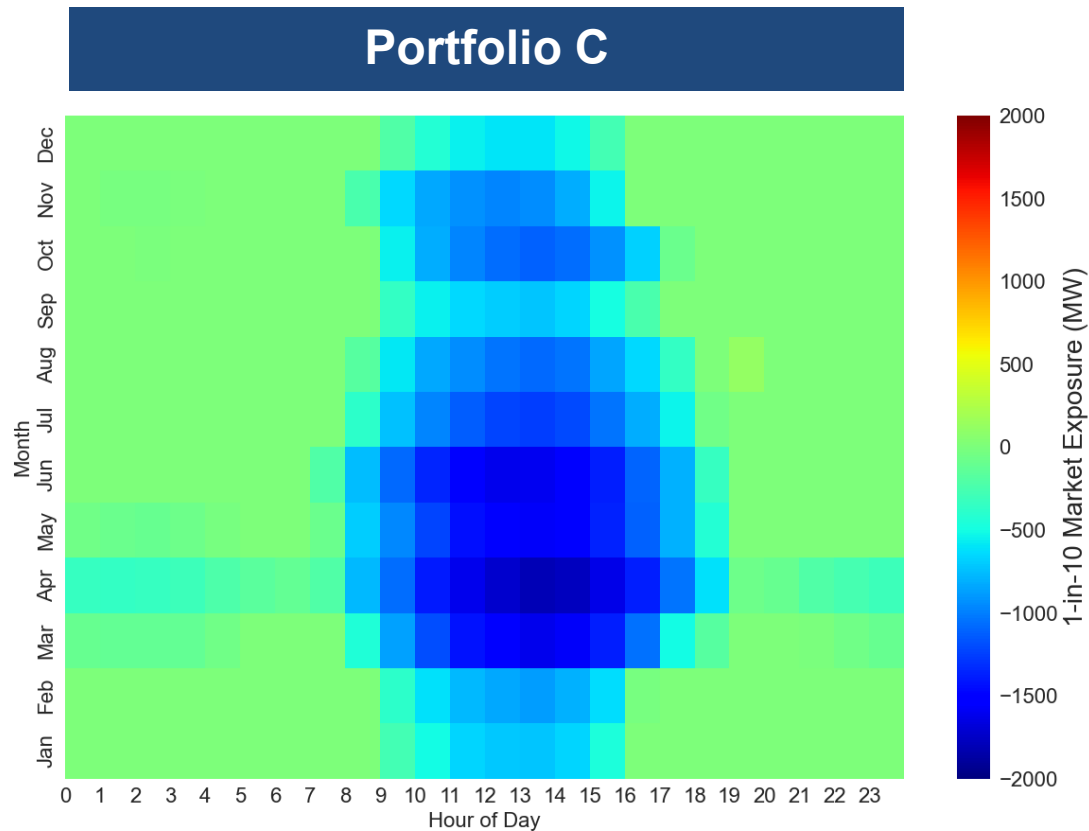
PORTFOLIOS A AND B – 90TH PERCENTILE FORCED MARKET EXPOSURE

- Under extreme conditions, the portfolios have modest forced market exposure during hours without solar resources.



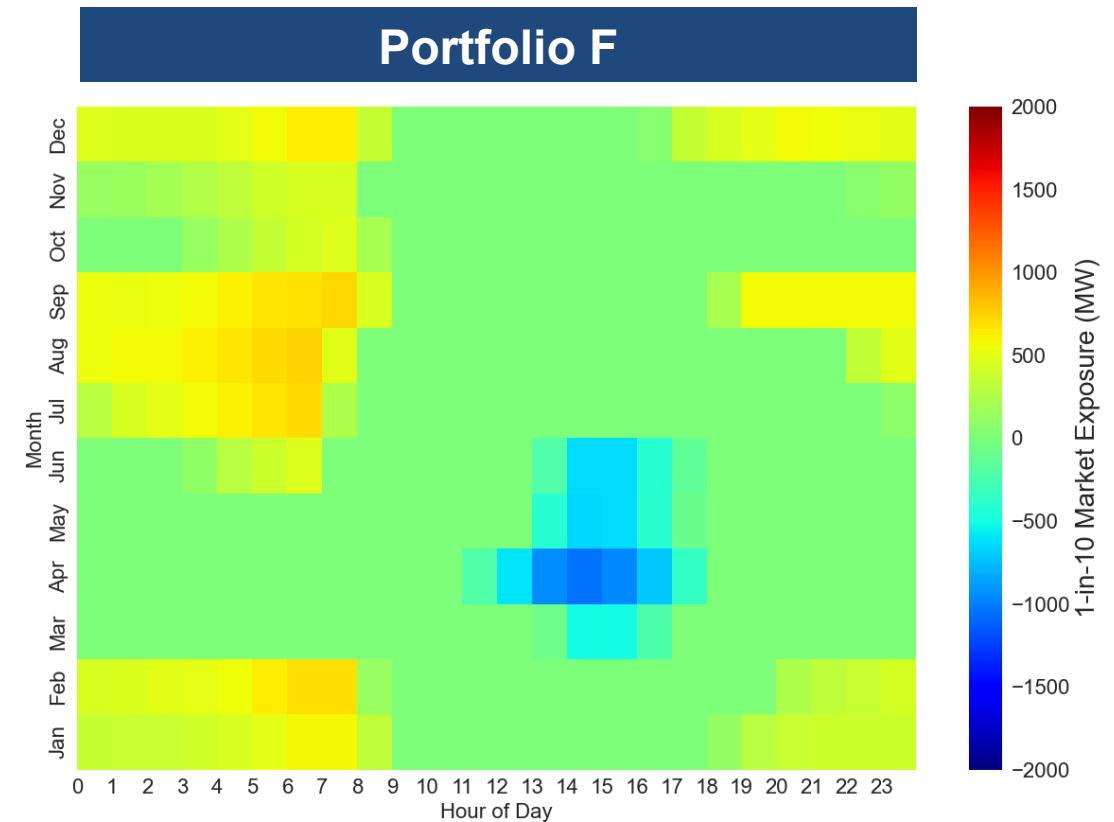
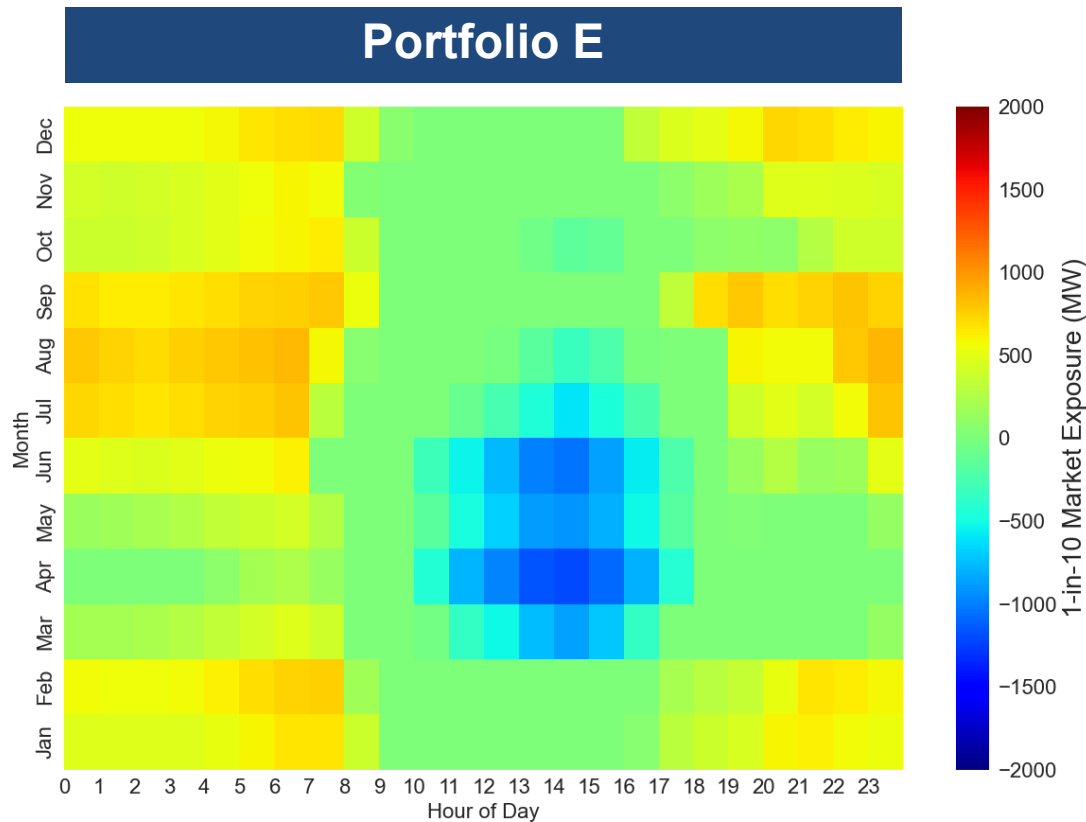
PORTFOLIOS C AND D (ALL VARIANTS) – 90TH PERCENTILE FORCED MARKET EXPOSURE

- Additional solar in C firms up the mid-day exposure risk in fall relative to A and B.
- Additional dispatchable capacity in D reduces risk across the board, with modest exposure only in the summer evenings.



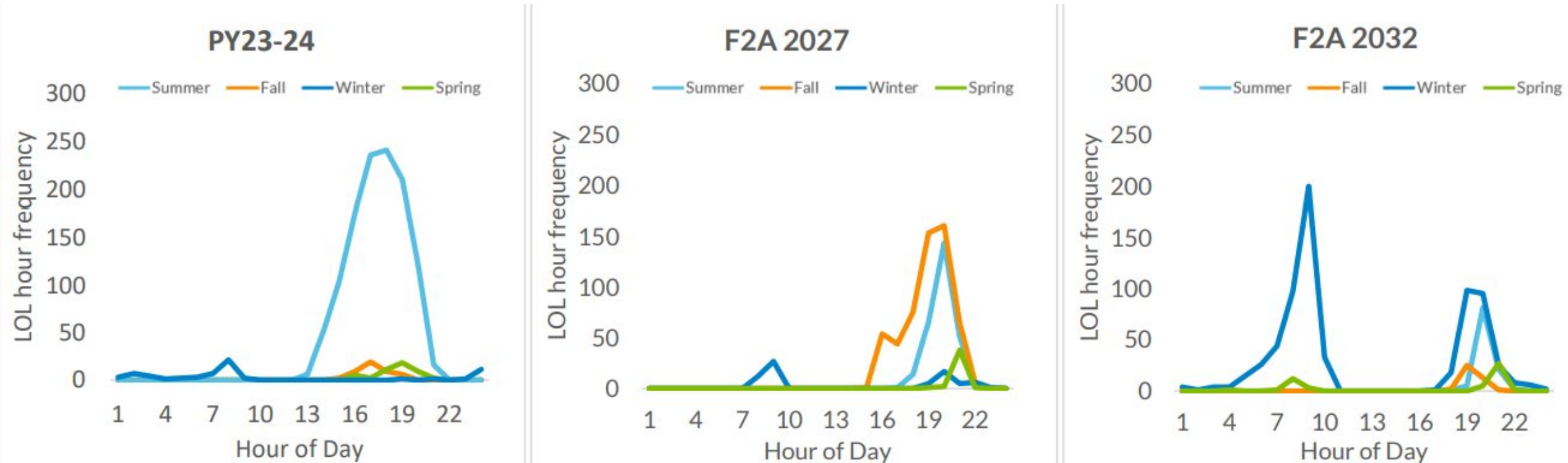
PORTFOLIOS E AND F – 90TH PERCENTILE FORCED MARKET EXPOSURE

- Portfolio E has the greatest risk during evening and overnight hours, particularly in the summer and winter due to less long-duration dispatchable capacity.
- Portfolio F is relatively less exposed due to additional storage capacity, although modest overnight forced exposure risk is present in certain summer and winter months.



MISO EXPECTS SYSTEM RISK HOURS TO SHIFT LATER IN THE EVENINGS AND OVERNIGHT

- MISO expects risk hours to shift primarily from summer afternoons to periods of time later in the evening and during overnight hours.
- Fall and winter seasons are expected to contain many risk hours in the future.



Source: MISO RASC Meeting, November 7-8, 2023

[https://cdn.misoenergy.org/20231107-08%20RASC%20Item%2011ai%20Resource%20Accreditation%20Presentation%20\(RASC-2020-4%202019-2\)630757.pdf](https://cdn.misoenergy.org/20231107-08%20RASC%20Item%2011ai%20Resource%20Accreditation%20Presentation%20(RASC-2020-4%202019-2)630757.pdf)

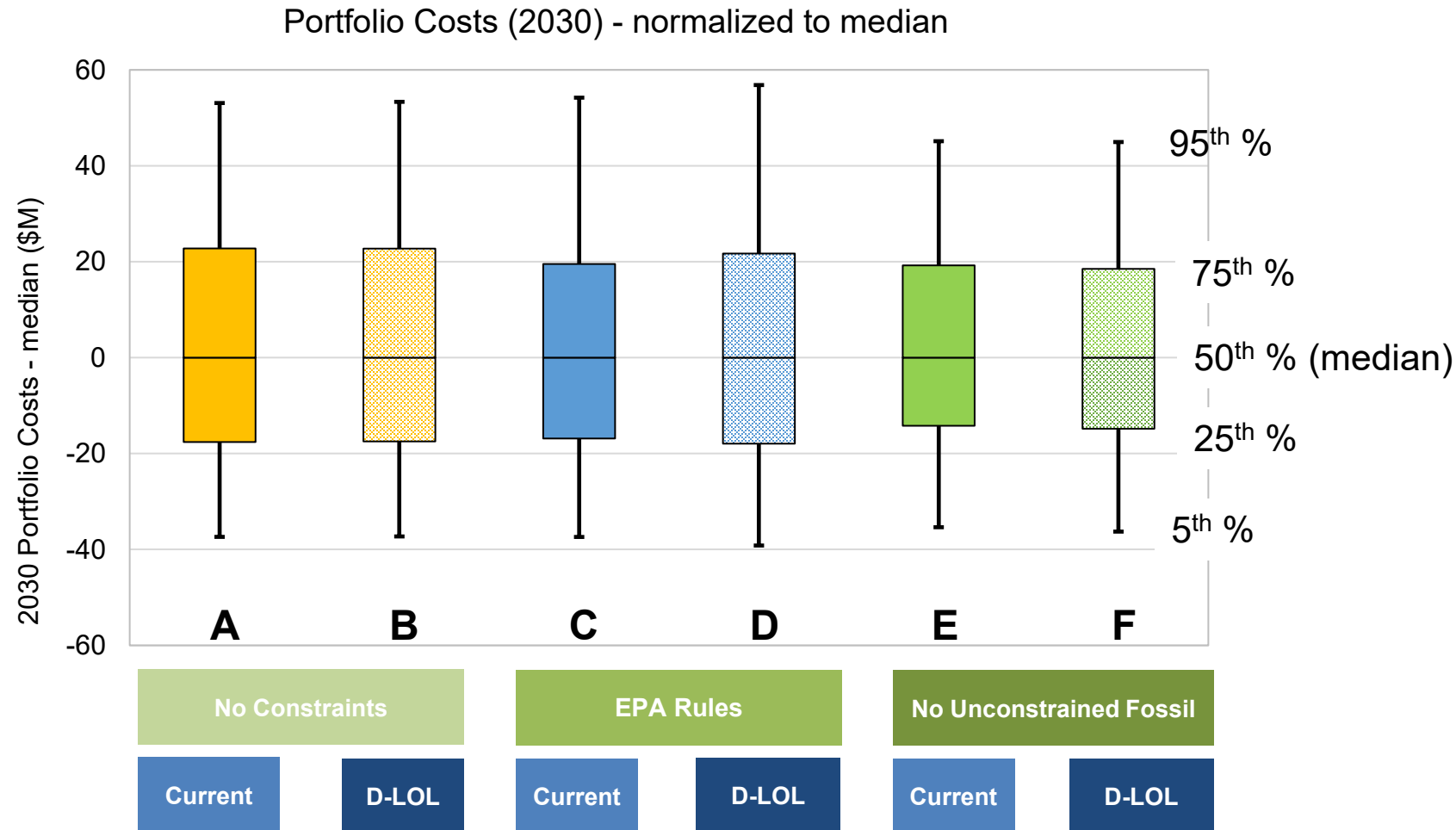
RELIABILITY SCORECARD METRIC – FORCED MARKET EXPOSURE

- Portfolios E and F are at risk of experiencing the most significant forced market exposure, amounting to between 2-3% of total MWh served in 2030.
- The D Portfolios are in the strongest position to mitigate against forced market exposure risk and be “in control of their own destiny.”

Portfolio	Forced Market Exposure – Expected Value (GWh)	Forced Market Exposure Relative to Total Load (%)
A	235	0.91
B	86	0.33
C	89	0.34
D (all variants)	4	0.02
E	793	3.08
F	515	2.00

COST RISK

A sample of iterations were evaluated in the Aurora model with full economic dispatch to assess portfolio variable cost risk in the year 2030 (prior to EPA Rules driving capacity factor constraints for new CCGTs)



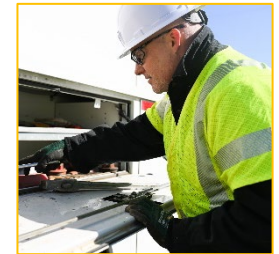
- Portfolios A through D have broader distributions of cost uncertainty overall (higher and lower) as a result of the impact of natural gas price uncertainty.
- Portfolios E and F have more comparable 75th percentile risk due to significant MISO market exposure, but both have lower tail risk than A-D.

COST RISK SUMMARY METRICS

- Portfolios E and F have less upside cost risk, particularly at the 95th percentile.
- Portfolios A through D have wider tails, given more exposure to natural gas commodity price uncertainty. This means higher 95th percentile cost risk, but also greater downside cost opportunity at the 5th percentile.

Portfolio	50 th Percentile <i>minus</i> 5 th Percentile	75 th Percentile <i>minus</i> 50 th Percentile	95 th Percentile <i>minus</i> 50 th Percentile
A	37.4	22.8	53.1
B	37.3	22.7	53.3
C	37.4	19.5	54.2
D	39.2	21.7	56.8
E	35.4	19.2	45.1
F	36.3	18.5	45.0

Values represent nominal 2030 portfolio costs in \$M



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

PORTFOLIO ANALYSIS – SENSITIVITIES

Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA



EMERGING HIGH LOAD SENSITIVITY

- Given the potential opportunities in the pipeline from NIPSCO's Economic Development team, a High Emerging Load Sensitivity was developed.
- To assess the potential impacts for NIPSCO's portfolio, an optimization analysis was performed under the "D" concept: EPA Rules and D-LOL.

	2028	2030	2035
IRP Peak Load – Flat Load*	~2,300 MW	~2,300 MW	~2,500 MW
+ <i>New Load Added for Reference Case</i>	+600 MW	+1,600 MW	+2,600 MW
IRP Peak Load – New Reference Case	~2,900 MW	3,900 MW	5,100 MW
<i>+Emerging Load Sensitivity</i>	+2,600 MW	+4,500 MW	+6,000 MW
Total IRP Peak Load With Emerging Load Sensitivity	5,500 MW	8,400 MW	11,100 MW

Incremental to
Reference
Case

* Rounded estimate of peak load forecast originally shared with stakeholders at the April 23rd IRP Stakeholder Advisory meeting and recently referred to as the "Flat Load" sensitivity.

HIGH LOAD – RESOURCE ADDITIONS (NAMEPLATE MW)

EPA GHG Rules

D

Direct Loss of Load

Resource	Through 2029 ¹	2030-2034	2035+
Wind		800	1,600
Solar	3,494	3,750	4,450
4-hr Li-Ion Storage	2,868		
Long Duration Energy Storage	18		
Gas CCGT	3,885	4,550	
Gas Peaking	420	200	
Short-Term Thermal PPA & ZRCs	1,100 ²		
Gas CCGT w/ CCUS			585
Nuclear (SMR)			500
H2-enabled CC			
Sugar Creek			650 ³

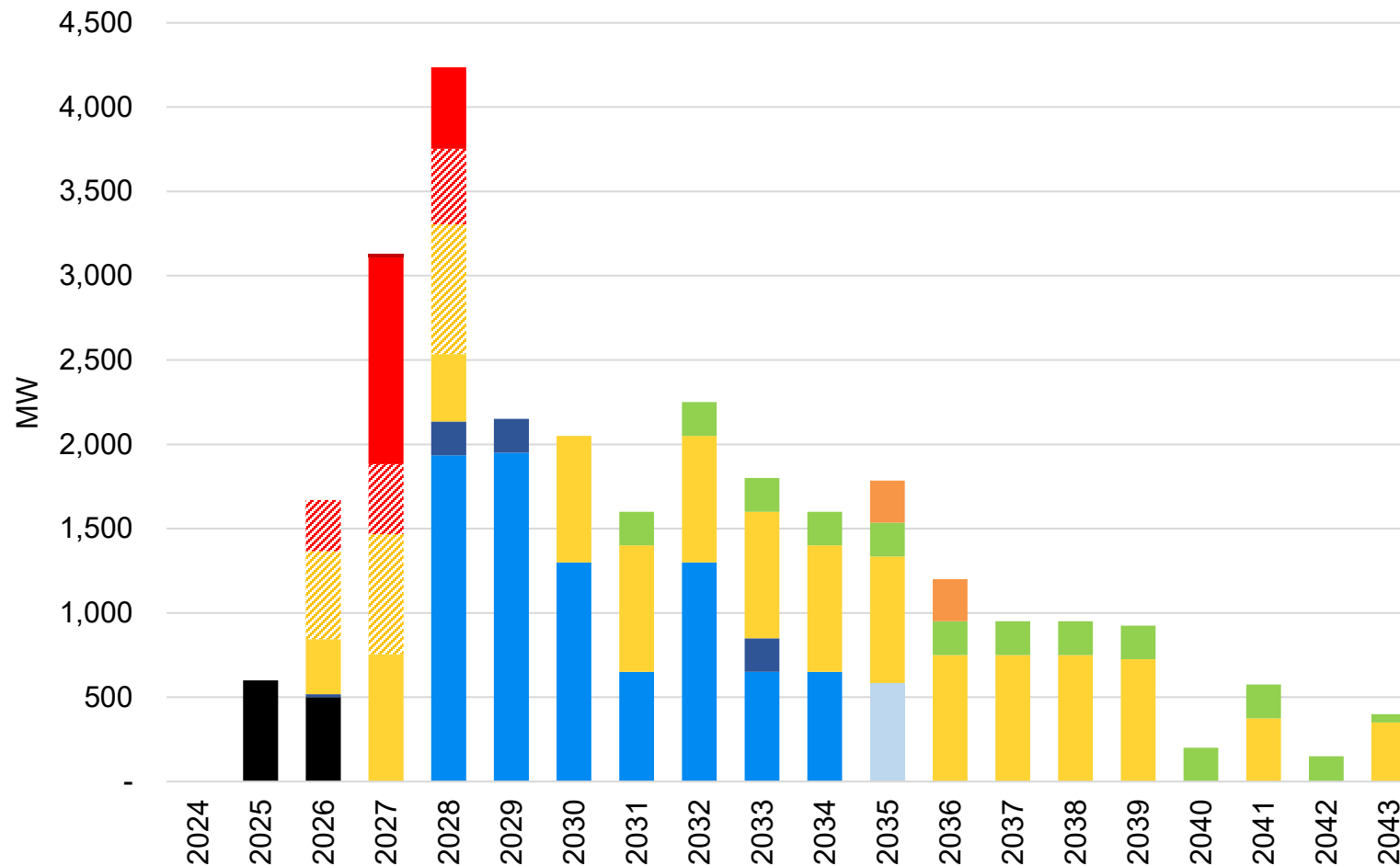
1: Note that Solar, 4-hr Li-Ion Storage, 635 MW of Gas CCGT PPA, ~20 MW of Gas Peaking, and Short-Term Thermal PPA & ZRCs are RFP tranches. The remaining Gas CCGT and Gas Peaking are generic resource additions.

2: Includes 300 MW of thermal PPA and two groups of ZRCs (600 MW in 2025-2027, 200 MW in 2026-2029).

3: Extended on natural gas

Note: All EE programs selected except for final tranche of C&I, Residential High, and Residential Low-Medium (2033-2046). All DR selected except for Dynamic Rates.

HIGH LOAD – ANNUAL RESOURCE ADDITIONS (NAMEPLATE MW)



Note: The short-term PPAs have various durations through 2030.

*Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.

EPA GHG Rules

D

Direct Loss of Load

	Summer Credit*	Winter Credit*
New SMR	91%	90%
New LDES	97%	97%
New 4-hour Storage	89%	56%
New Hybrid-Storage	89%	56%
New Wind	7%	14%
New Hybrid-Solar	4%	2%
New Solar	4%	2%
New CCS	85%	77%
New Gas CT	70%	77%
New Gas CC	85%	77%
New Short-Term Thermal PPA	100%	100%

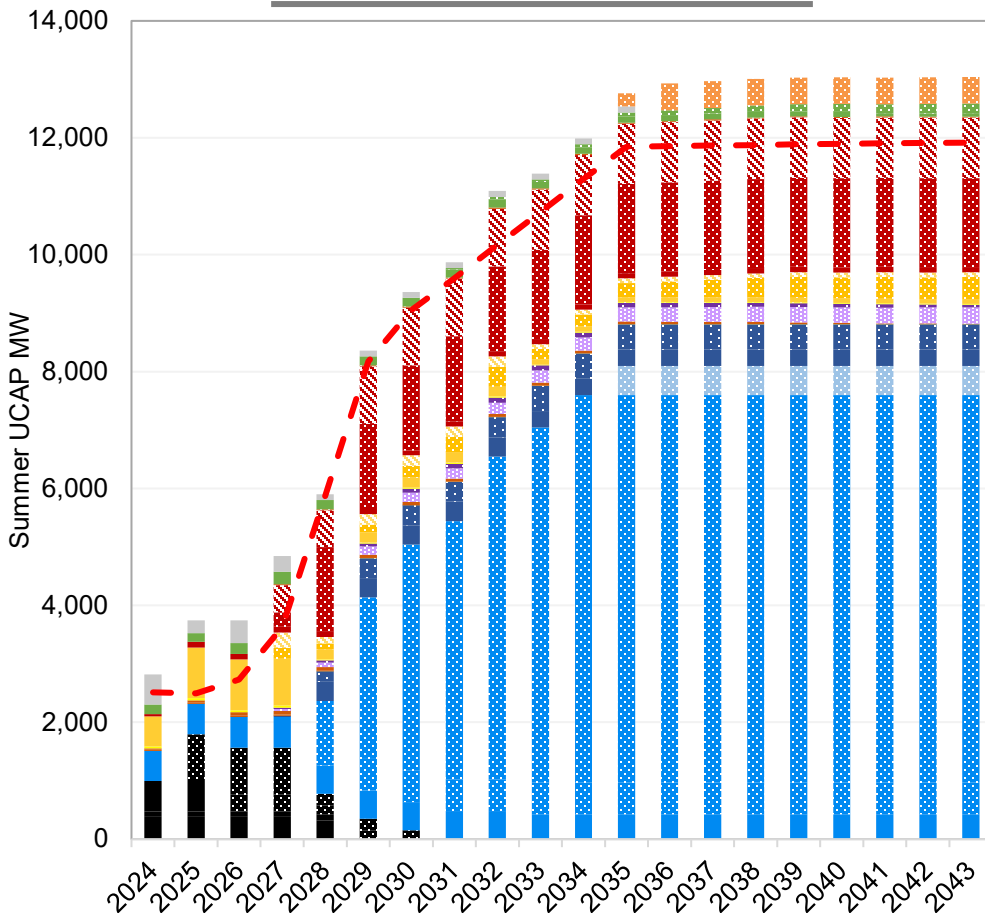
HIGH LOAD – SUPPLY-DEMAND BALANCE

EPA GHG Rules

D

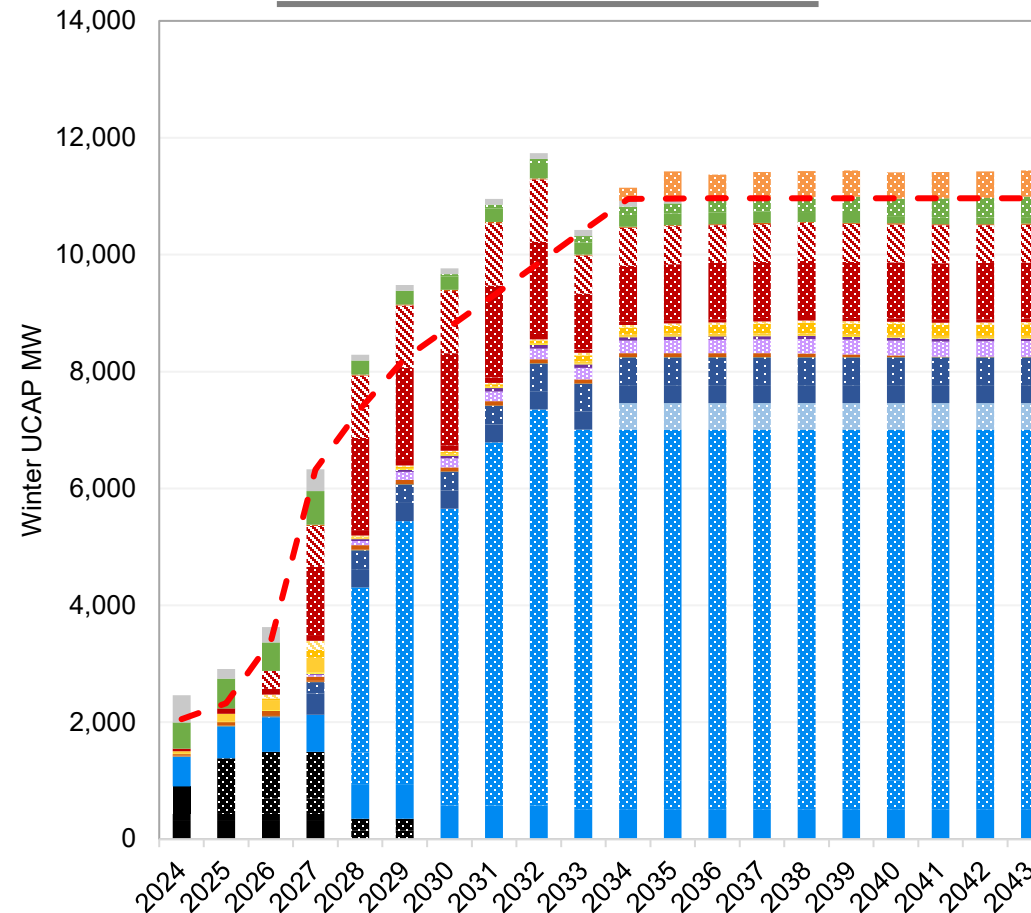
Direct Loss of Load

Summer Cap. vs. PRM



Generally Binding through 2035

Winter Cap. vs. PRM



Generally Binding post-2035

- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- Existing Storage
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- DLOL PRM

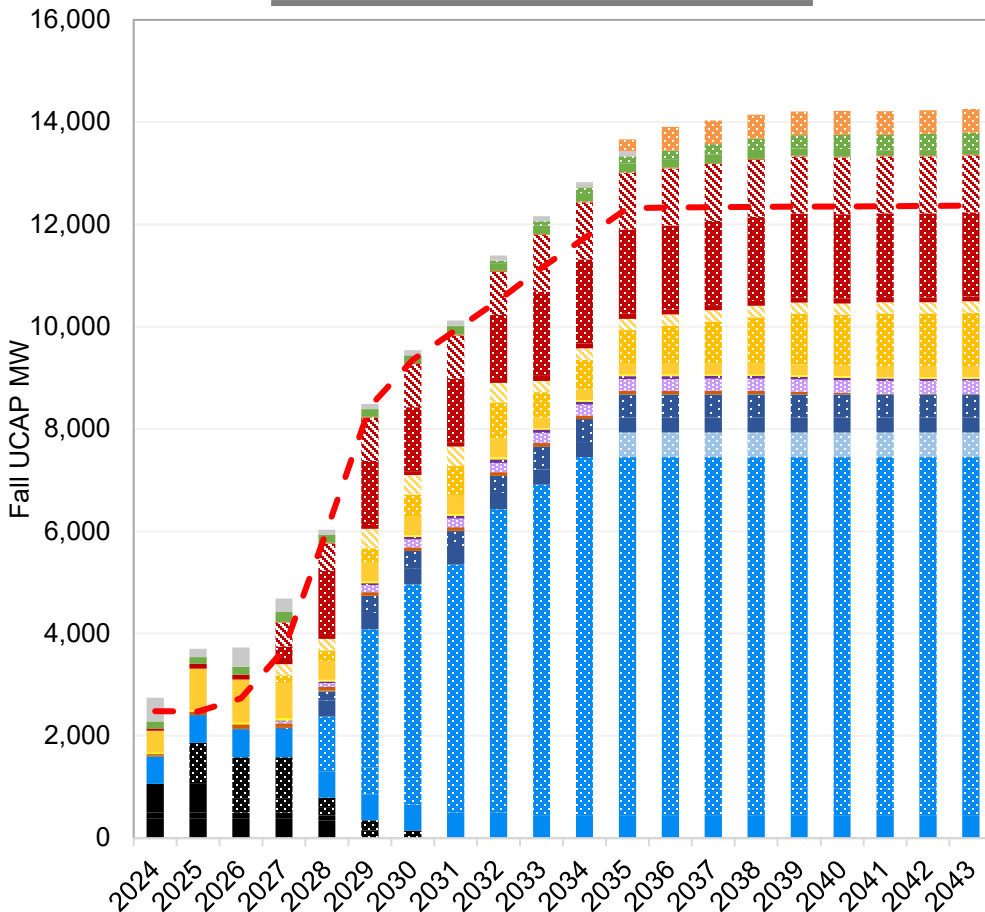
HIGH LOAD – SUPPLY-DEMAND BALANCE

EPA GHG Rules

D

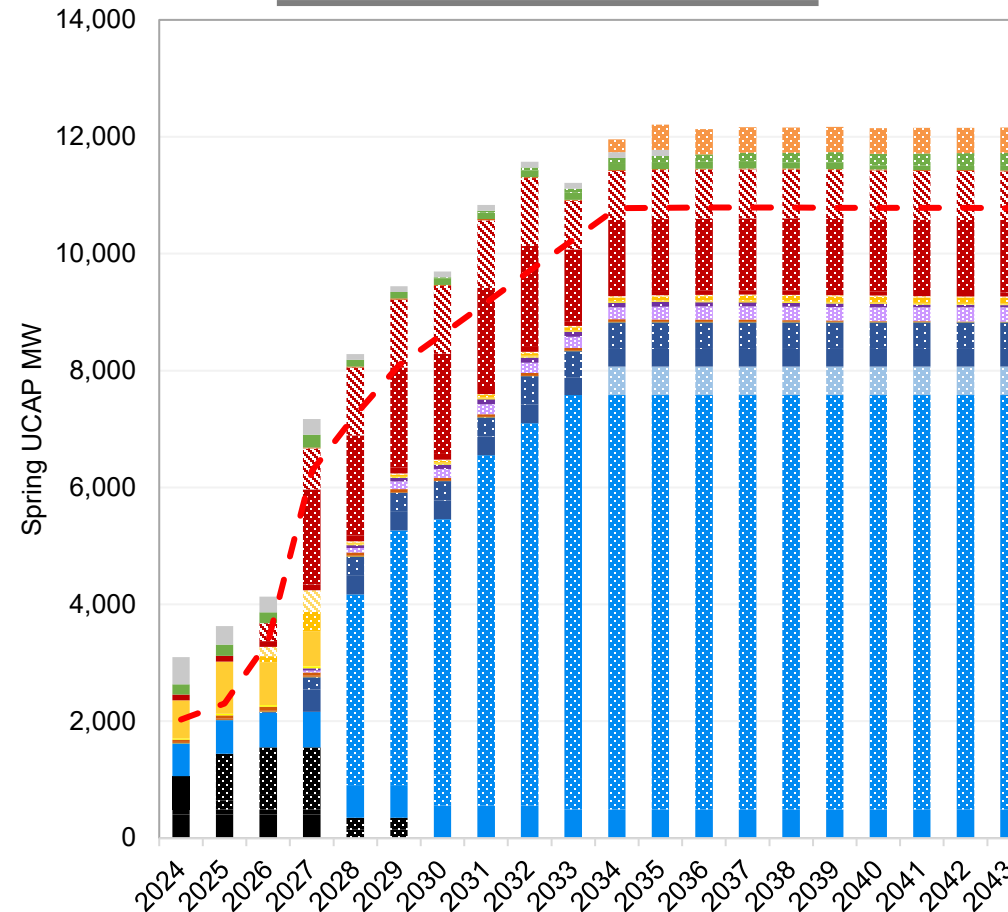
Direct Loss of Load

Fall Cap. vs. PRM



Binding through 2030

Spring Cap. vs. PRM



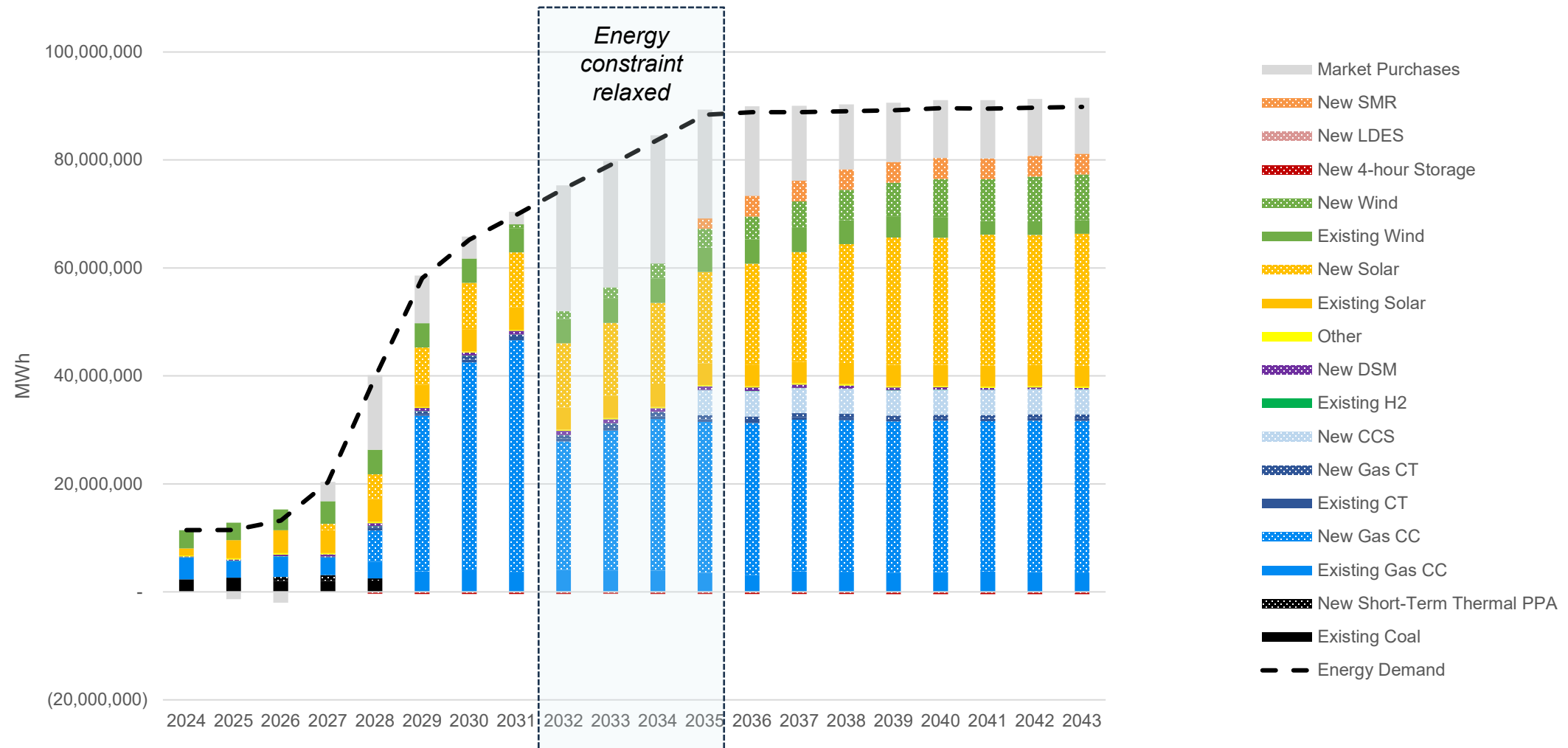
- New SMR
- Short-term Capacity
- New Wind
- Existing Wind
- New LDES
- New 4-hour Storage
- New 4-hour Storage
- Existing Storage
- New Solar
- New Solar
- Existing Solar
- EV
- New DER
- Existing DER
- New DSM
- New DR
- Other
- Existing Hydro
- New Gas CT
- Gas CT
- New CC H2
- New CC CCS
- New Gas CC
- H2 Retrofit
- CCS Retrofit
- Gas CC
- New Short-term Thermal PPA
- Existing Coal
- DLOL PRM

HIGH LOAD – ENERGY POSITION

EPA GHG Rules

D

Direct Loss of Load



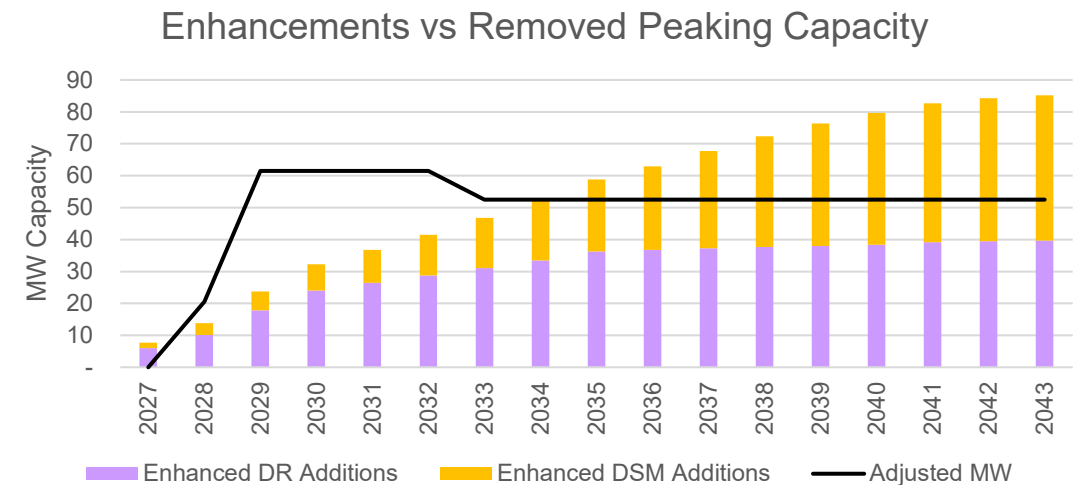
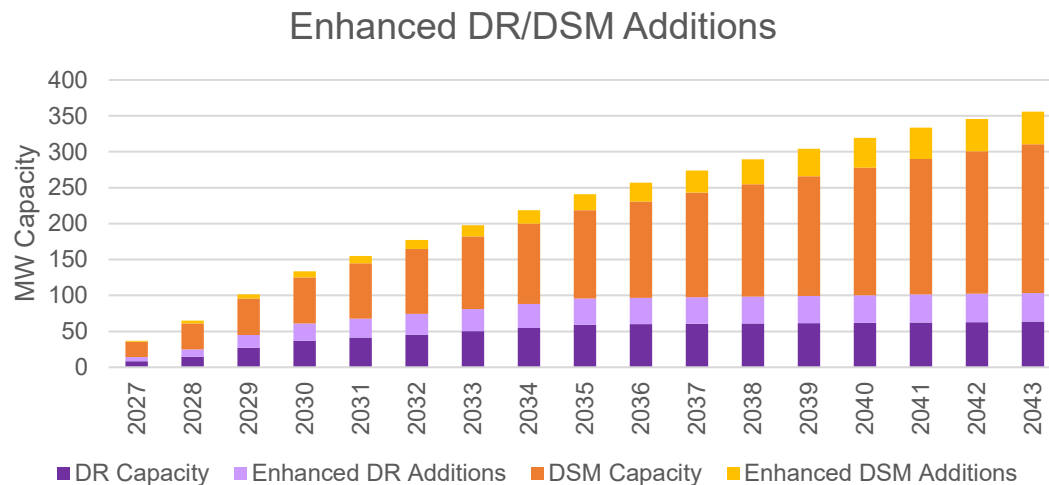
Note: The net impact of storage is shown, which results in an energy “loss,” given efficiency less than 100%. Over the course of a day or year, storage is charging during some hours and discharging during others.

KEY OBSERVATIONS – EMERGING HIGH LOAD SENSITIVITY

- **Significant near-term load growth would require large capacity additions through 2029.**
 - Over 1,000 MW of Thermal PPAs and ZRCs
 - Nearly 3,500 MW of solar and nearly 3,000 MW of storage
 - Over 4,000 MW of natural gas capacity
- **New combined cycle capacity is needed for near-term energy requirements.**
 - The portfolio could be short energy for periods of time depending on the pace of new CCGT additions
 - Flexibility to operate CCGTs above 40% prior to 2032 could allow for most energy needs to be met, but EPA Rules on capacity factor constraints thereafter could result in higher levels of energy market purchases
- **A diverse mix of long-term resource additions would be required, contingent upon resource availability constraints and technological advancement.**
 - Additional CCGT and gas peaking capacity
 - Significant amounts of post-2030 solar (8,200 MW) and wind (2,400 MW)
 - CCUS and SMR capacity in 2035+ as it becomes available
- **Significant energy efficiency and demand response additions would be expected to support portfolio requirements.**

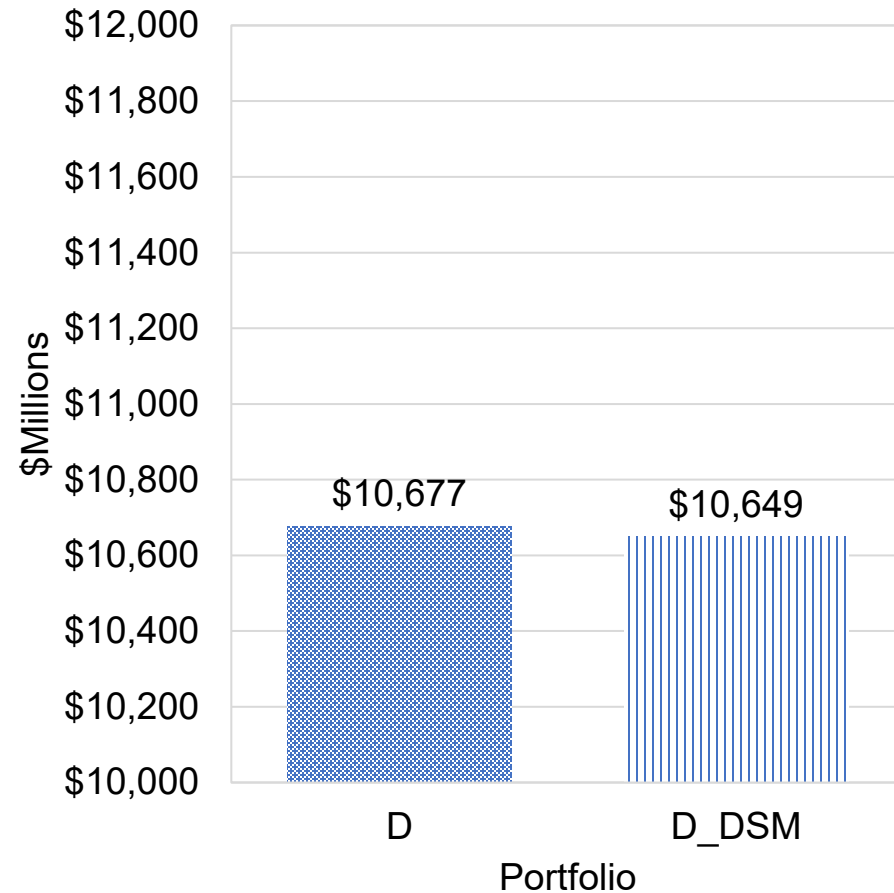
DSM SENSITIVITY

- **NIPSCO performed a DSM sensitivity analysis based on the inputs reviewed in Stakeholder Meeting #3:**
 - Moving from RAP → Enhanced RAP for energy efficiency (“EE”)
 - RAP → MAP for Demand Response (“DR”)
- **Under Portfolio D:**
 - Enhanced RAP EE and MAP DR would result in ~85 MW of additional capacity by 2043.
 - This would allow for a reduction in marginal natural gas peaking additions of 75 MW ICAP.

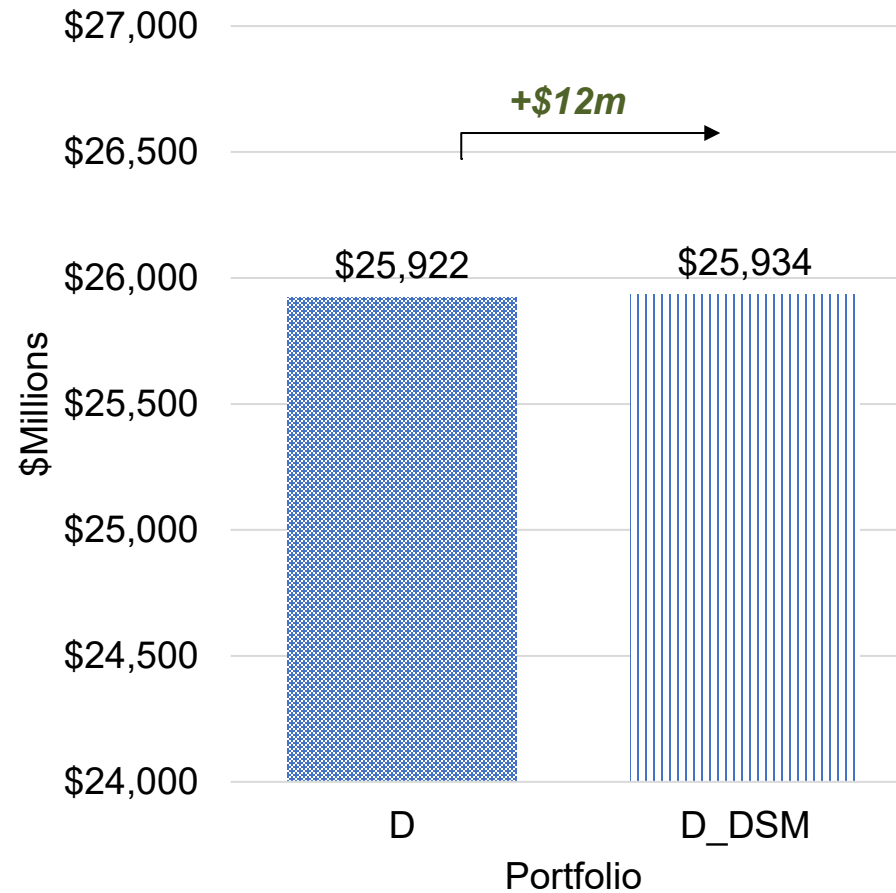


DSM SENSITIVITY RESULTS

10 Year NPV



30 Year NPV



- In the first 10 years, total revenue requirement for the D_DSM portfolio is lower than D due to avoided capital and O&M costs from reduced gas capacity.
- Over 30 years, D_DSM portfolio costs are higher than portfolio D as higher DSM costs outweigh capital cost savings.



BREAK



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER





OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

SCORECARD SUMMARY

Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

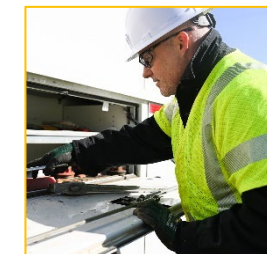
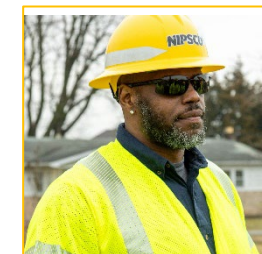


PORTFOLIO PERFORMANCE IS DISTILLED INTO AN INTEGRATED SCORECARD

Objectives	Indicators	Metrics
Affordability	Cost to Customer	- Near-term and long-term Impact to customer bills Metric: 10-year and 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	Cost Certainty	- Certainty that revenue requirement within the most likely range of outcomes Metric: Scenario range NPVRR
	Cost Risk	- Risk of unacceptable, high-cost outcomes Metric: 95th%-50th% cost risk from probabilistic analysis
	Lower Cost Opportunity	- Potential for lower cost outcomes Metric: 50th%-5th% cost risk from probabilistic analysis
Environmental Sustainability	Carbon Emissions	- Carbon intensity of portfolio Metric: Cumulative carbon emissions / cumulative generation (2024-40 short tons/MWh of CO₂)
Reliable, Flexible, and Resilient Supply	Reliability, Flexibility	- The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules Metric: Loss of Load Expectation proxy ("Forced market exposure") metrics for NIPSCO system from probabilistic reliability analysis Metric: Capacity able to respond within 30 mins
Positive Social, & Economic Impacts	Local Investment in Economy	- The effect on the local economy from new projects and ongoing property taxes and targeted investment Metric: NPV of property taxes from the entire portfolio

SCORECARD

		A	B	C	D	D-CCUS	D-H2	E	F
Carbon Emissions Constraint		No EPA GHG Constraints		EPA GHG Rules				Emissions Controls At Start-Up	
MISO Market Rules		Current Market Rules	Direct Loss of Load	Current Market Rules	Direct Loss of Load			Current Market Rules	Direct Loss of Load
Cost To Customer	10-year NPVRR (Ref Case) \$M	\$10,307	\$10,735	\$10,244	\$10,677	\$10,993	\$10,993	\$10,951	\$11,309
		+\$62	+\$491	-	+\$433	+\$749	+\$749	+\$705	+\$1,065
	30-year NPVRR (Ref Case) \$M	\$25,142	\$25,626	\$25,471	\$25,922	\$27,236	\$27,999	\$27,984	\$28,756
		-	+\$484	+\$329	+\$780	+\$2,094	+\$2,857	+\$2,842	+\$3,614
Cost Certainty		\$9,669	\$10,245	\$7,815	\$9,286	\$5,414	\$4,717	\$5,232	\$5,451
30-year Scenario Range NPVRR \$M		+\$4,952	+\$5,529	\$3,098	\$4,569	\$697	-	\$516	+\$735
Cost Risk		\$53.1	\$53.3	\$54.2	\$56.8	\$54.1	\$54.1	\$45.1	\$45.0
95 th % Cost Risk		+\$8.1	+\$8.4	+\$9.2	+\$11.9	+9.2	+9.2	+\$0.2	-
Lower Cost Opp.		-\$37.4	-\$37.3	-\$37.4	-\$39.2	-\$38.9	-\$38.9	-\$35.4	-\$36.3
5 th % Cost Risk		+\$1.8	+\$1.9	+\$1.8	-	+\$0.3	+\$0.3	+\$3.8	+\$2.9
Carbon Emissions		0.21	0.22	0.19	0.22	0.18	0.20	0.09	0.09
M of tons/MWh 2024-40 Cum. (Scenario Avg.)		+0.12	+0.13	+0.10	+0.13	+0.09	+0.11	-	-
Reliability		235	86	89	4	4	4	793	515
Forced Market Exposure (GWh)		+231	+82	+85	-	-	-	+789	+511
Flexibility		3,849	4,482	4,121	4,812	4,632	4,812	3,905	4,456
New capacity able to respond within 30 mins (MW)		-963	-330	-691	-	-180	-	-907	-356
Local Economy		\$1,849	\$1,853	\$1,938	\$1,840	\$2,229	\$2,097	\$2,619	\$2,698
NPV of property taxes		-\$849	-\$845	-\$760	-\$858	-\$484	-\$609	-\$79	-



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

NIPSCO PREFERRED PORTFOLIO AND SHORT-TERM ACTION PLAN

Abe Lang, Manager Strategy & Risk, NiSource



PORTFOLIO D AND PORTFOLIO F: PROVIDE CAPACITY AND EMISSIONS COMPLIANCE

	A	B	C	D*	E	F
Data Center Load	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA rule constraints (capacity factor)	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%

Given the need for dispatchable capacity in MISO, NIPSCO should plan for compliance with the D-LOL rule (or a similar rule), focusing on portfolios B, D, and F.

New ICAP through 2029	B	D*	F
EPA rule constraints (capacity factor)	None	CCGT<40%	CCGT<40%
Solar			797
Storage	1,227	909	1,986
Gas CCGT	1,300	1,285	
Gas Peaking		418	

Portfolio B does not prepare to comply with EPA rule constraints (as it would need additional peaking capacity or additional solar + storage to make up for the capacity factor limitations on CCGTs)

New ICAP through 2030	D	D-CCUS	D-H2	F
Emission Controls on new Fossil	None	Later in 2030s	Later in 2030s	At Start-up
Solar				797
Storage	909	909	909	1,986
Gas CCGT	1,935	1,935	1,935	
Gas Peaking	620	620	620	
Gas CCGT w/CCUS				1,170

Portfolio D variants have the same resource mix through 2030, but portfolio D without CCUS or Hydrogen does not reduce emissions over time. Also, future hydrogen supply is more uncertain than CCUS, leaving portfolio D-CCUS and Portfolio F.

PORTFOLIO D-CCUS: LOWER COST AND MORE RELIABLE THAN PORTFOLIO F

	D	D-CCUS	D-H2	F	
Data Center Load	2,600 MW	2,600 MW	2,600 MW	2,600 MW	Portfolio D variants and portfolio F are both compliant with the EPA rule and MISO's D-LOL rule. Portfolio D variants provide more optionality around decarbonization.
MISO Capacity Rules	D-LOL	D-LOL	D-LOL	D-LOL	
EPA rule constraints (capacity factor)	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%	
Emission Controls on new Fossil	None	Later in 2030s	Later in 2030s	At Start-up	
Cost To Customer	10-year NPVRR (Ref Case) \$M	\$10,677	\$10,993	\$10,993	Lower customer cost due to lower storage needs through 2030 and due to delaying decarbonization retrofits until they are more feasible in the 2030s.
	30-year NPVRR (Ref Case) \$M	\$25,922	\$27,236	\$27,999	
Cost Certainty 30-year Scenario Range NPVRR \$M	\$9,286	\$5,414	\$4,717	\$5,451	Comparable cost certainty to Portfolio F, if emissions controls are installed, given it would reduce potential impacts from any new GHG regulation.
Cost Risk 95 th % Cost Risk \$M	\$56.8	\$54.1	\$54.1	\$45.0	
Lower Cost Opp. 5 th % Cost Risk \$M	-\$39.2	-\$38.9	-\$38.9	-\$36.3	Marginally higher annual cost risk due to higher commodity price risk.
Carbon Emissions M of tons/MWh 2024-40 Cum. (Scenario Avg.)	0.22	0.18	0.20	0.09	Higher emission intensity due to additional gas generation, but still decarbonizes by end of 2030s.
Reliability Forced Market Exposure (GWh)	4	4	4	515	Significantly higher reliability due to more dispatchable gas-fired capacity.
Flexibility New capacity able to respond within 30 mins (MW)	4,812	4,632	4,812	4,456	Better resource flexibility due to more dispatchable gas-fired capacity.
Local Economy NPV of property taxes \$M	\$1,840	\$2,229	\$2,097	\$2,698	Lower local property tax revenue due to lower capital spend.

Portfolio D CCUS has:



PREFERRED PLAN (PORTFOLIO D-CCUS): NIPSCO SUPPLY RESOURCE PLAN AND TIMING

Given the decarbonization pathway and customer cost considerations, the following actions are proposed to maximize optionality:

	Near Term	Mid Term	Long Term
Timing	2025-2029	2030-2034	2035 & Beyond
Retirements	- Schahfer Units 17, 18 (by 2025) - Schahfer Units 16A/B (by 2027) - Michigan City Unit 12 (by 2028)	N/A	N/A
Preferred Plan – Capacity Additions	<i>Storage (500-900MW)*</i> <i>Thermal Contracts (350 MW)*</i> - Gas CCGT (1,285 MW) - Gas Peaking (420 MW)	<i>Storage (125 MW)*</i> <i>Wind (150-650MW)*</i> - Solar (750 MW) - Gas CCGT (1,950 MW) - Gas Peaking (200 MW)	<i>Storage (25 MW)*</i> <i>Wind (200-900 MW)*</i> - Solar (525 MW) - Sugar Creek Retrofit - Hydrogen - CCGT Retrofits – CCUS
Other Activities	- Monitor changing regulatory policy (MISO, EPA, local) and technology advancements - Previously planned additions (~2,100 MW) ~1,700 MW of renewable projects ~400 MW gas peaker	- Reevaluate decarbonization options including CCUS, H2 and other emerging technologies for best fit - Add additional renewables as needed to support higher energy needs	- Implement most cost-effective retrofits - Determine final steps to achieve net zero

Storage Investment	CCGT / Gas Peaking Investment	Monitor / Respond To Changes	Execute Previously Planned Activities
~500-900 MW of storage, contingent on MISO capacity accreditation	CCGT additions to support data center load and gas peaking investment as needed for additional capacity	MISO rules; EPA rules; Long-duration energy storage; Hydrogen; Carbon capture; Nuclear	Schahfer & Michigan City retirements; Renewable Projects ~1,700 MW, ~400 MW Gas Peaker



CLOSING & STAKEHOLDER COMMENTS



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



NEXT STEPS



Seeking Feedback

- Seeking feedback regarding the plan presented today
- Reach out to Erin Whitehead (ewhitehead@nisource.com) for 1x1 meetings
- NIPSCO IRP Email: nipsco_irp@nisource.com



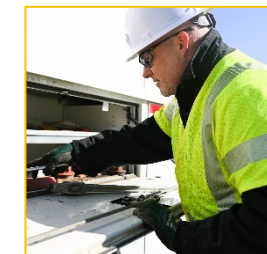
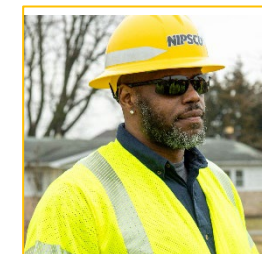
IRP Submission

- NIPSCO will submit its 2024 IRP report to the IURC by **December 9th**
- IRP Website: www.nipsco.com/irp

Stakeholder engagement is a critical part of the IRP process



APPENDIX

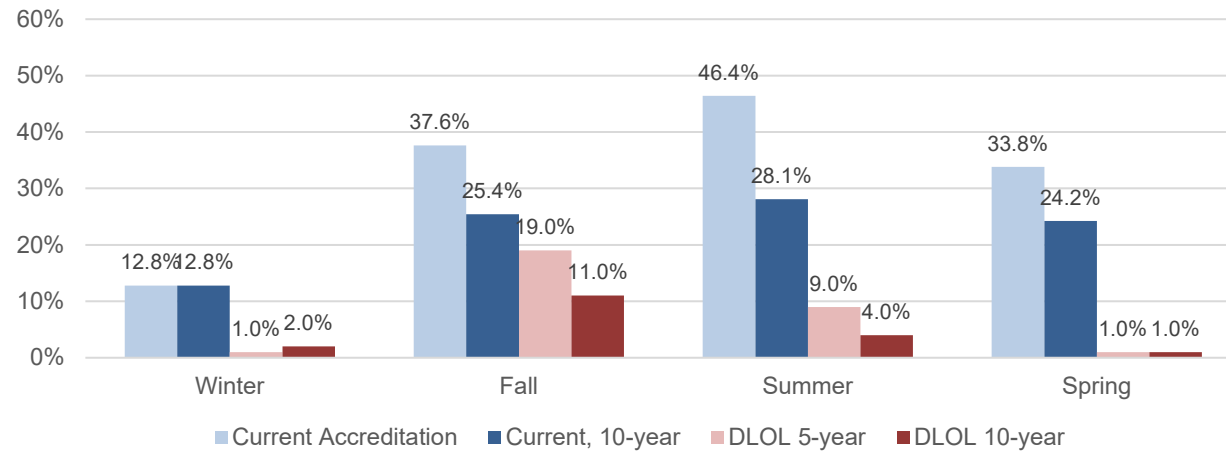


OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

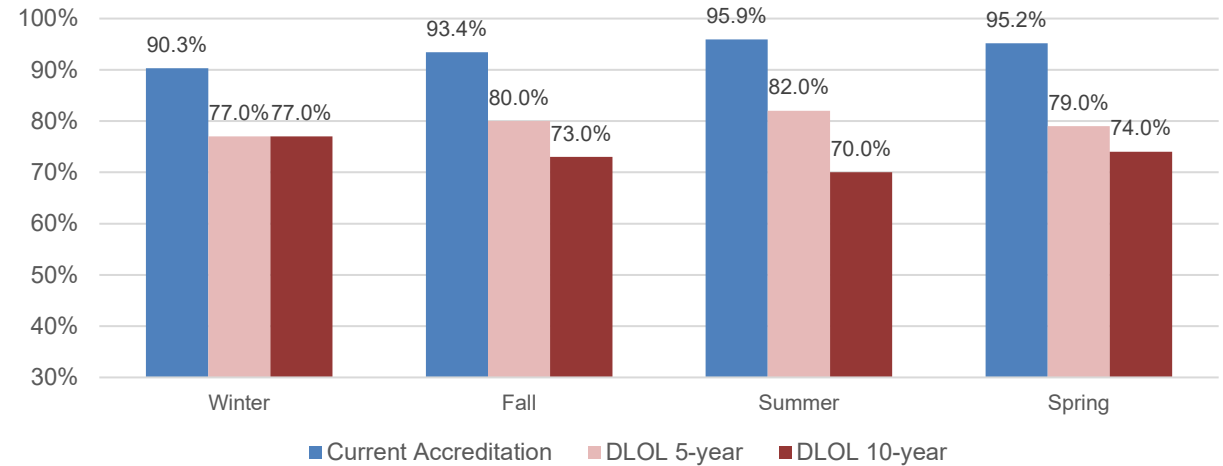


CAPACITY ACCREDITATION TRAJECTORIES UNDER D-LOL

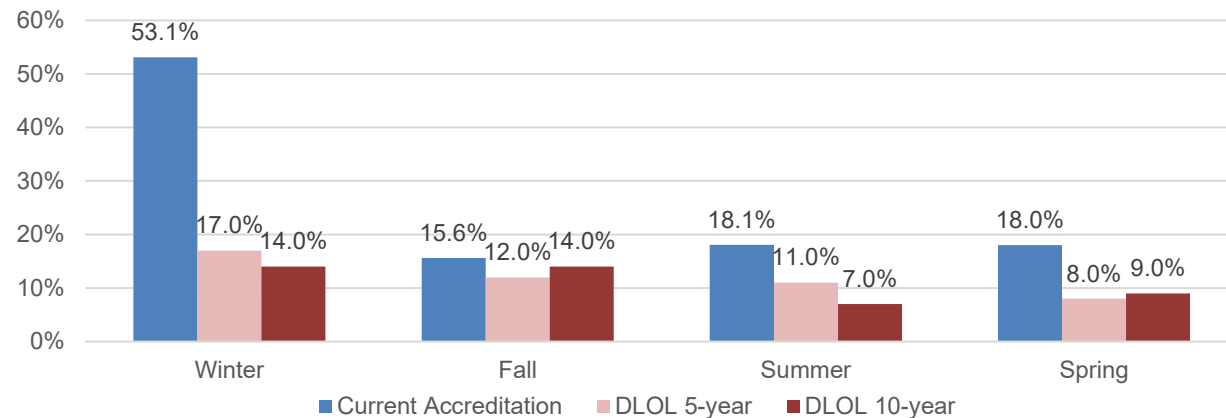
Indicative Seasonal Capacity Accreditation - Solar



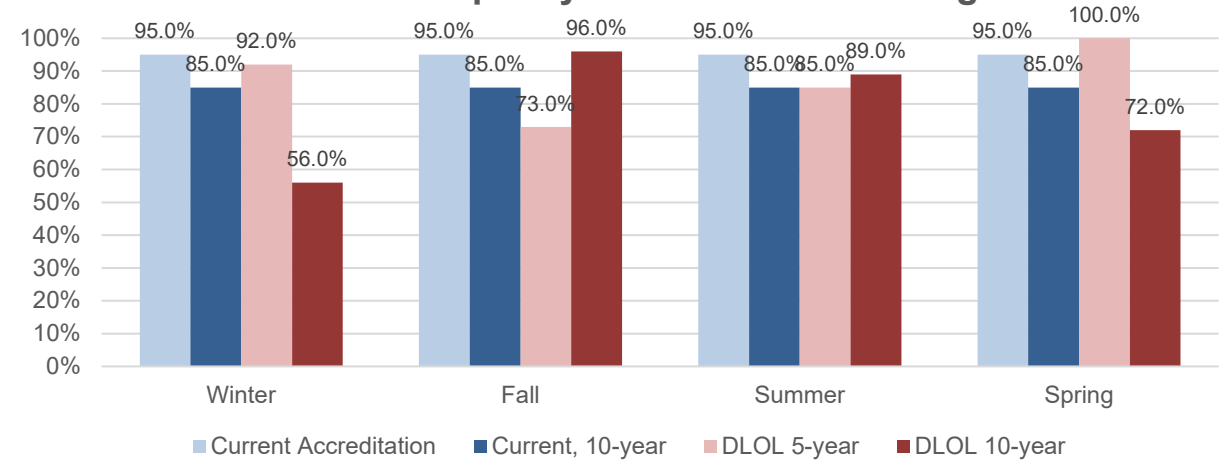
Seasonal Capacity Accreditation - Gas CT



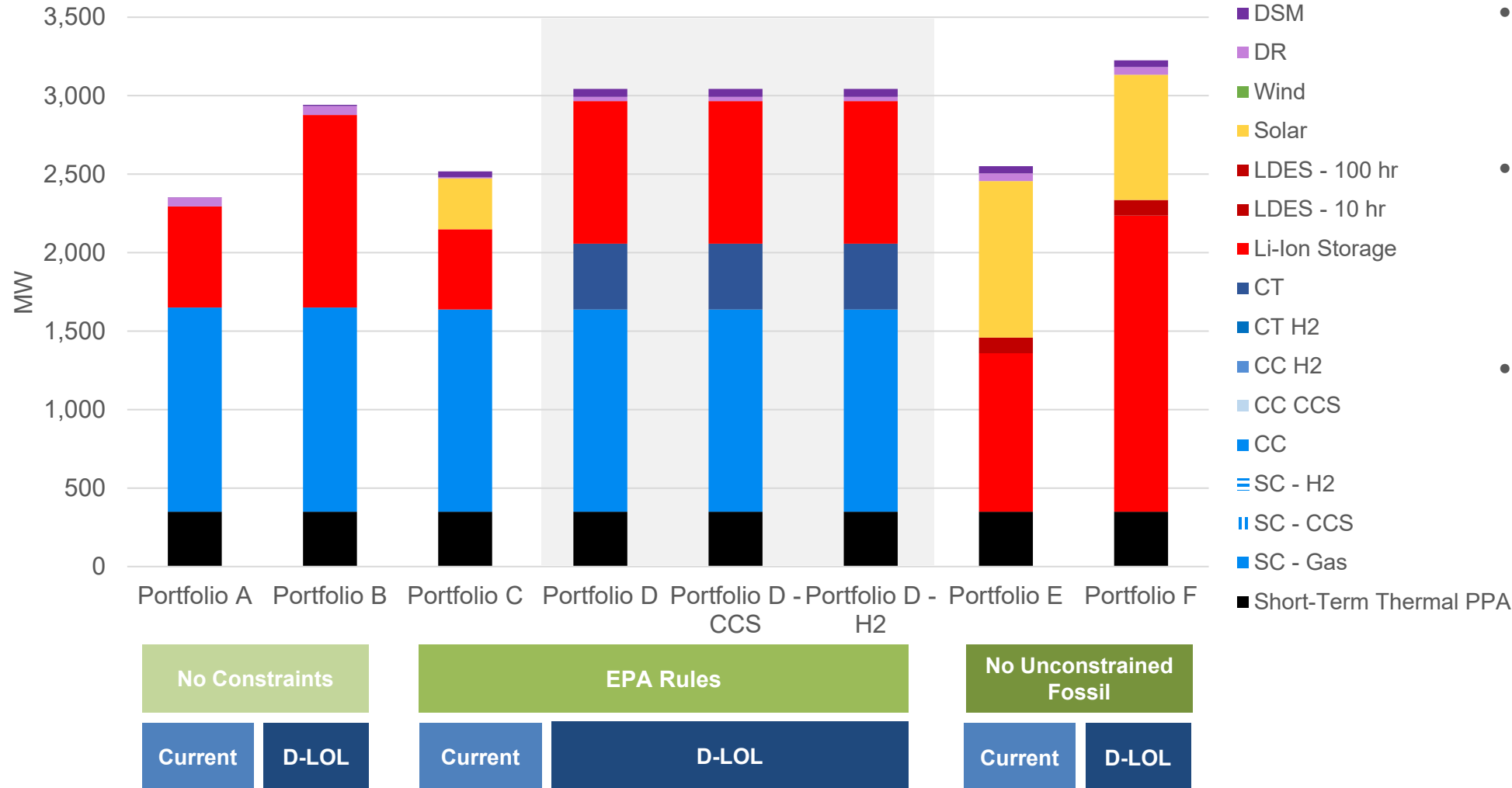
Indicative Seasonal Capacity Accreditation - Wind



Seasonal Capacity Accreditation - Storage

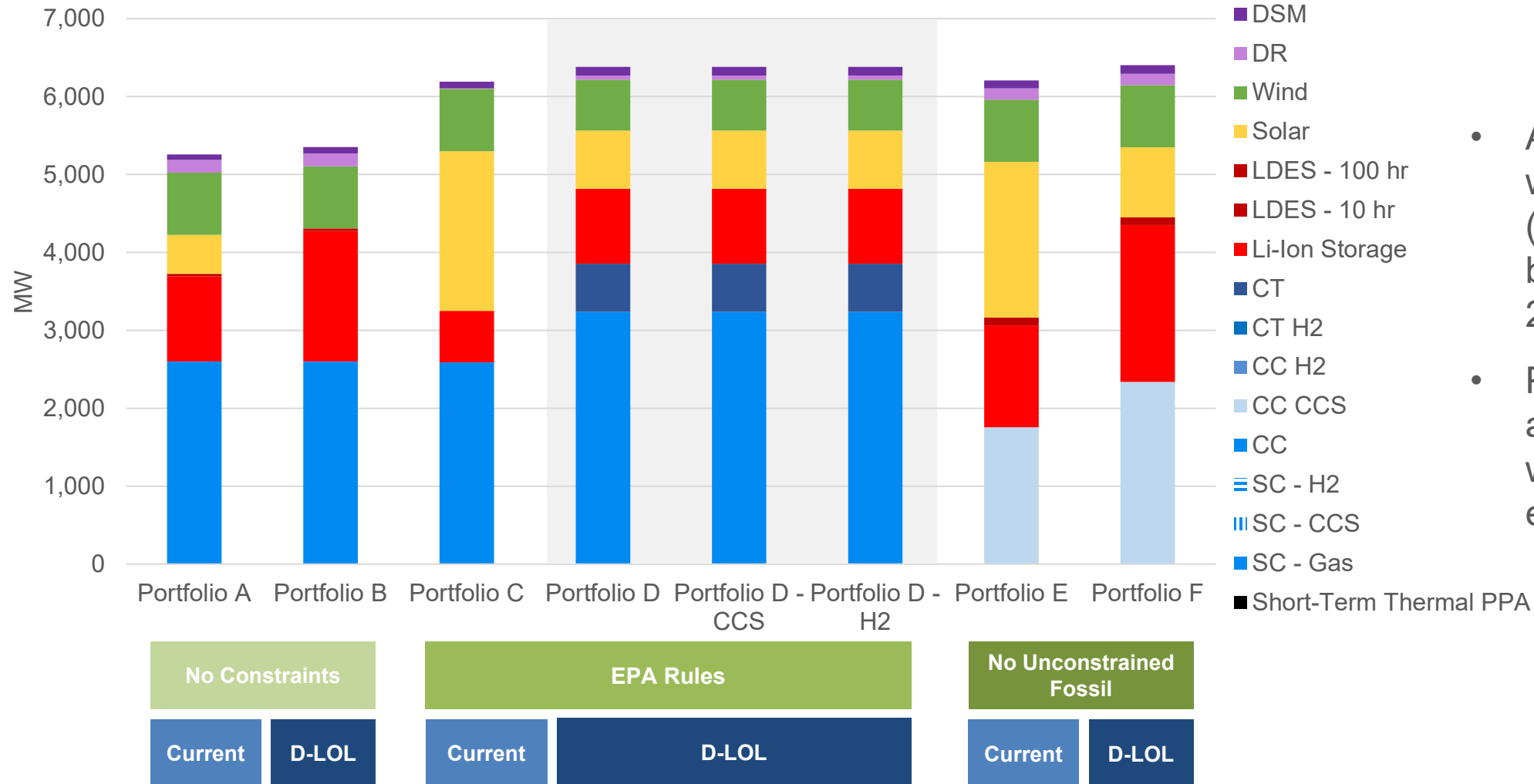


RESOURCE ADDITIONS COMPARISON ACROSS PORTFOLIOS – CUMULATIVE NAMEPLATE THROUGH 2029



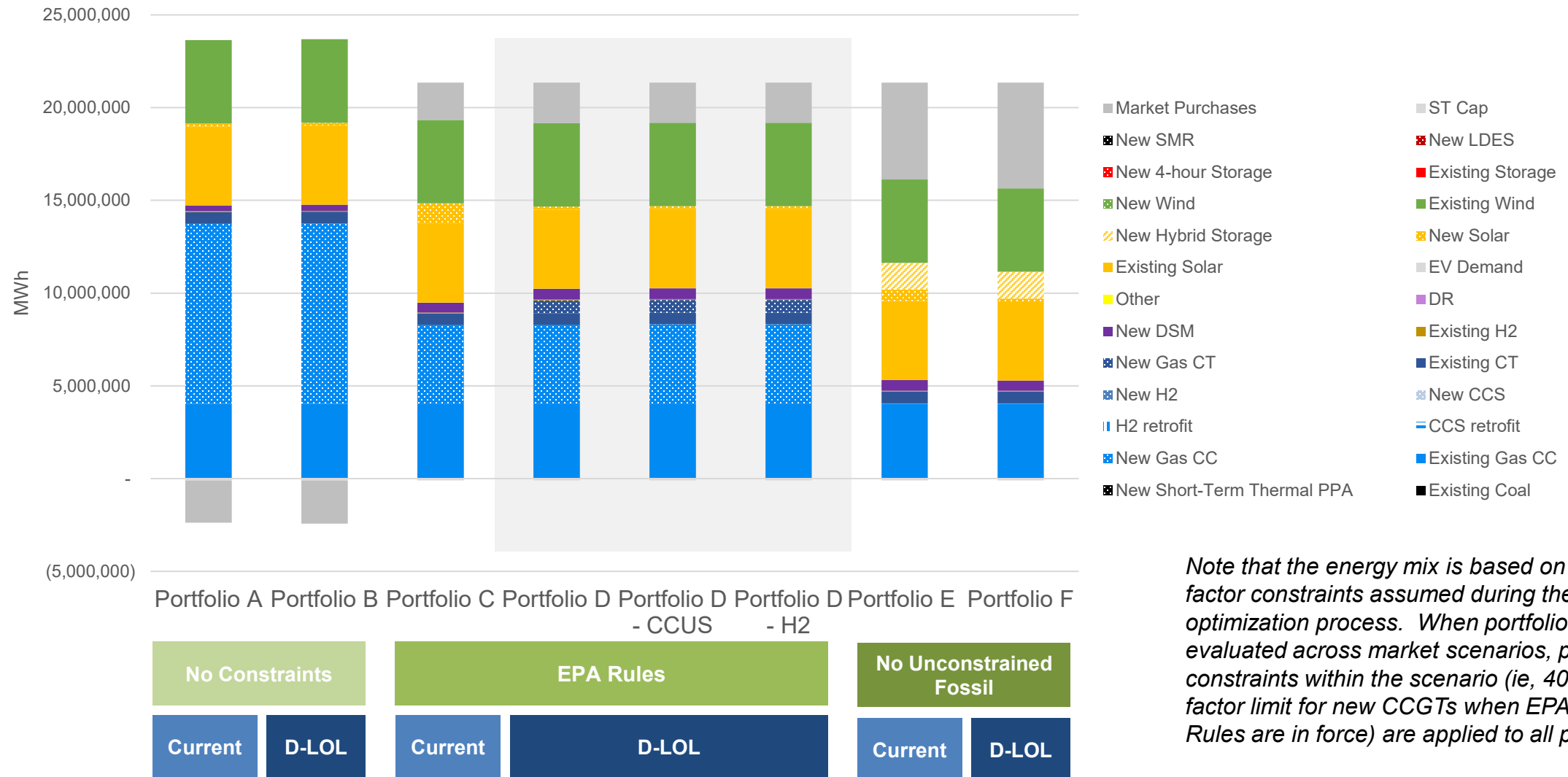
- D-LOL portfolios have more capacity overall.
- Portfolios with greatest emissions restrictions add more solar.
- Portfolios E and F would rely exclusively on solar, storage, short-term contracts, and EE/DSM through 2029.

RESOURCE ADDITIONS COMPARISON ACROSS PORTFOLIOS – CUMULATIVE NAMEPLATE THROUGH - 2034



- All portfolios add wind and solar (aside from B) between 2030 and 2034.
- Portfolios E and F add natural gas CC with CCUS in the early 2030s.

ENERGY MIX ACROSS PORTFOLIOS - 2029



Note that the energy mix is based on capacity factor constraints assumed during the portfolio optimization process. When portfolios are evaluated across market scenarios, prevailing constraints within the scenario (ie, 40% capacity factor limit for new CCGTs when EPA GHG Rules are in force) are applied to all portfolios.

ENERGY EFFICIENCY SELECTION

- The Low/Med Residential and C&I bundles are generally selected
- High Residential and Behavioral bundles are more marginal, but still selected across many years/portfolios

Program	Portfolio A			Portfolio B			Portfolio C			Portfolio D			Portfolio E			Portfolio F		
	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46	'27- '29	'30- '32	'33- '46
Res (Low/Med)	○	X	X	○	X	X	○	○	X	X	X	X	X	X	X	X	X	X
Res (High)	○	○	○	○	X	X	X	○	X	X	X	○	○	○	○	X	X	○
Res (Behavioral)	○	○	X	X	○	X	X	X	X	X	X	X	X	○	X	○	X	X
C&I	○	X	X	○	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQW	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IQHear	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

X = Selected

○ = Not Selected

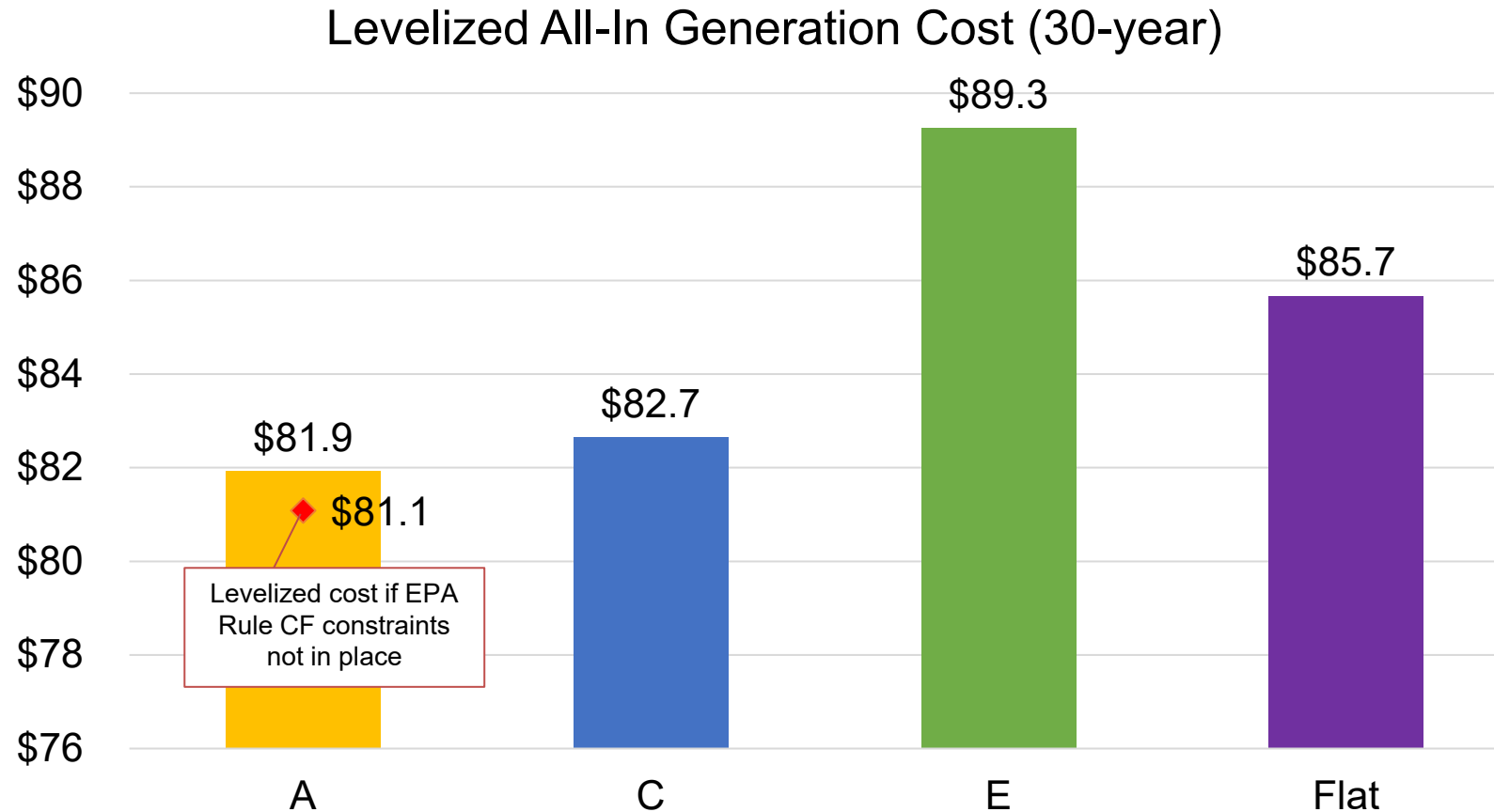
DEMAND RESPONSE SELECTION ACROSS PORTFOLIOS

Program	Portfolio A	Portfolio B	Portfolio C	Portfolio D	Portfolio E	Portfolio F
RAP Thermostats	X	X	O	O	O	O
RAP Water Heaters	O	O	O	O	O	O
RAP Behavioral	X	X	X	X	X	X
RAP Dynamic Rates	X	X	O	O	X	X
RAP EV Managed Charging	O	O	O	O	O	O
RAP BTM Storage	O	O	O	O	O	O
RAP C&I	X	X	O	O	X	X
RAP Data Center	X	X	O	X	X	X

X = Selected
O = Not Selected

- Behavioral, data center, C&I, and dynamic rates demand response programs are most often selected across portfolios and will be considered as NIPSCO evaluates its preferred portfolio
- The thermostat program is selected in Portfolios A & B
- Water heater, EV managed charging, and BTM storage programs are not selected

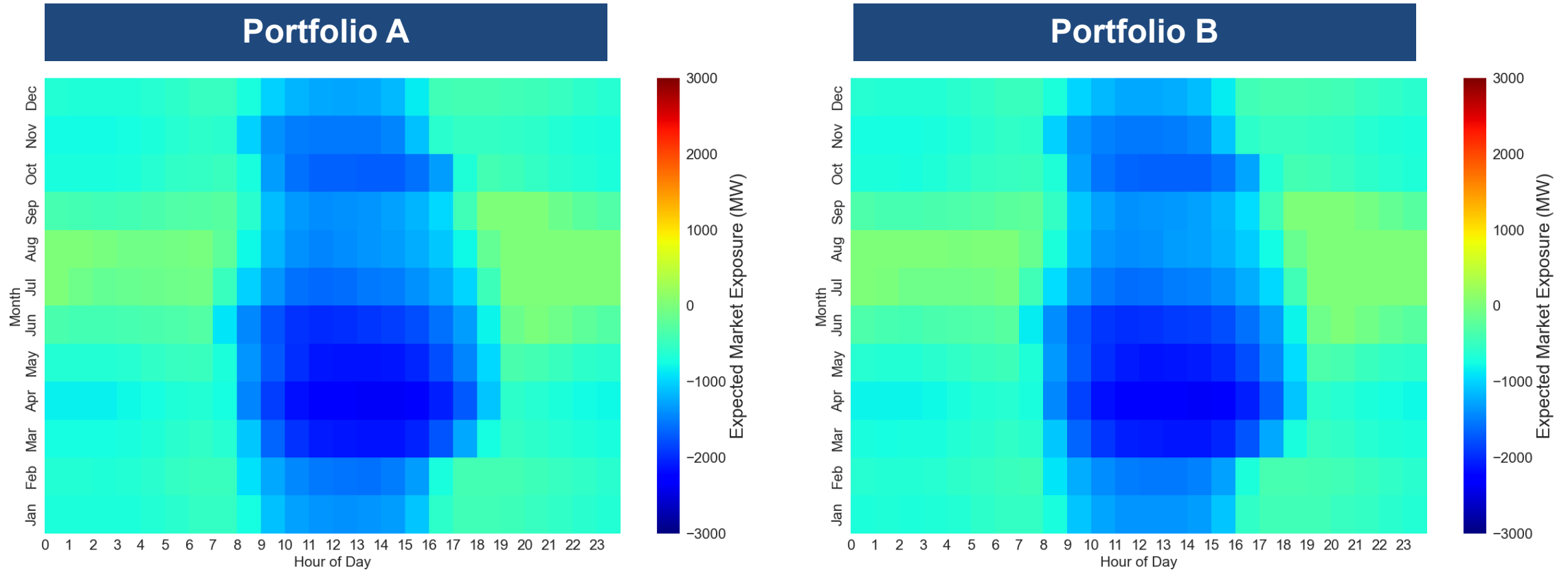
PORTFOLIO LEVELIZED COST OF ENERGY – REFERENCE CASE (CURRENT MKT RULES)



- Over the 30-year planning horizon, the levelized cost per MWh for the Flat Load portfolio is higher than Portfolios A and C.

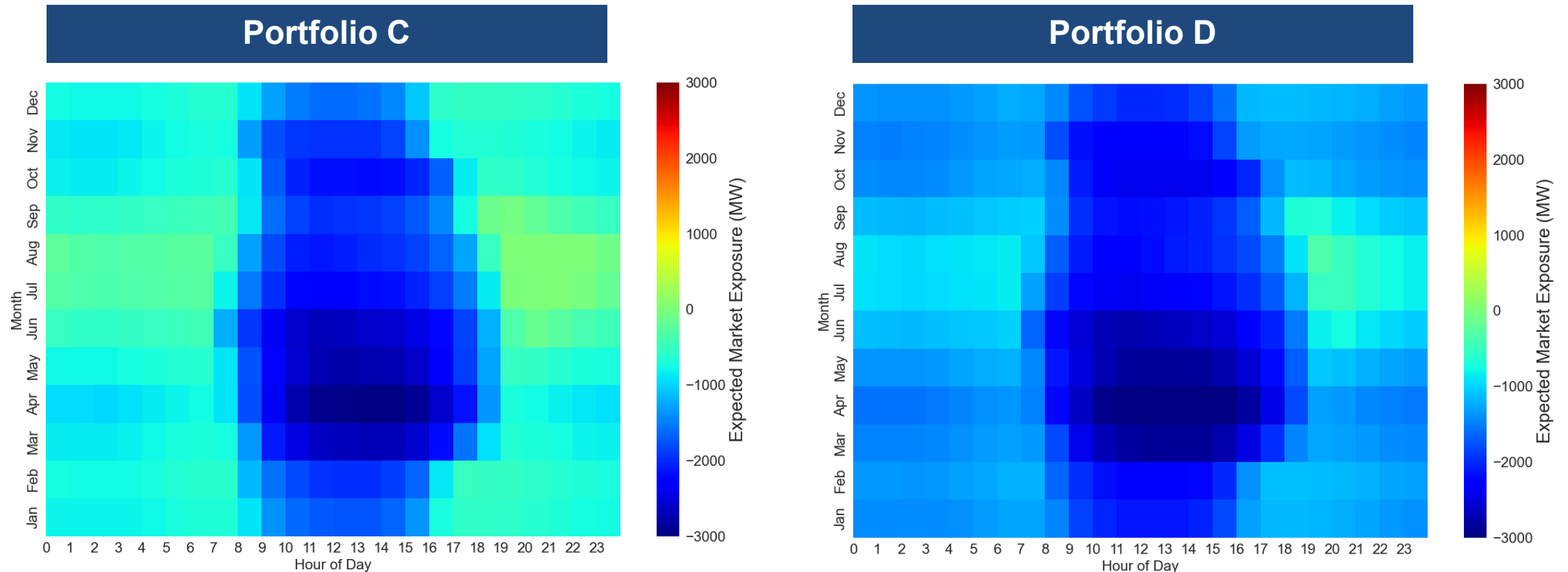
PORTFOLIOS A AND B – 50TH PERCENTILE FORCED MARKET EXPOSURE

- At the 50th percentile, the portfolios have modest forced market exposure during summer evenings and overnight hours



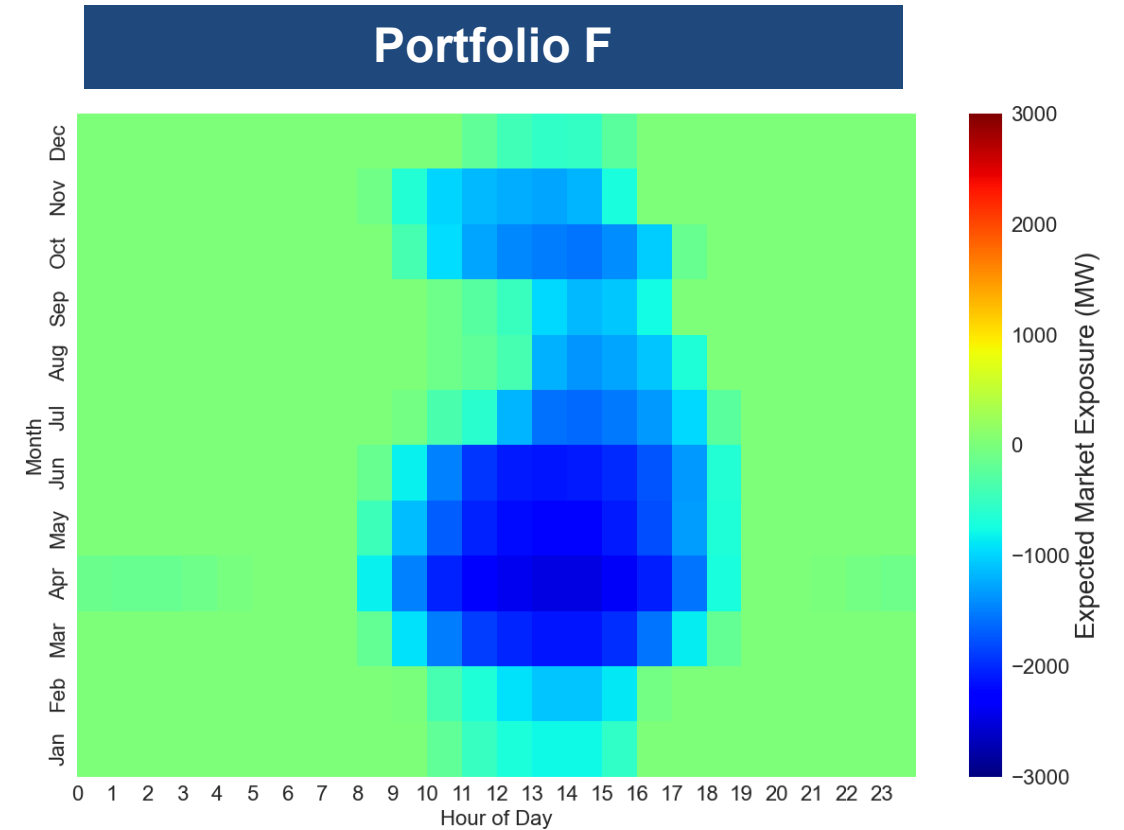
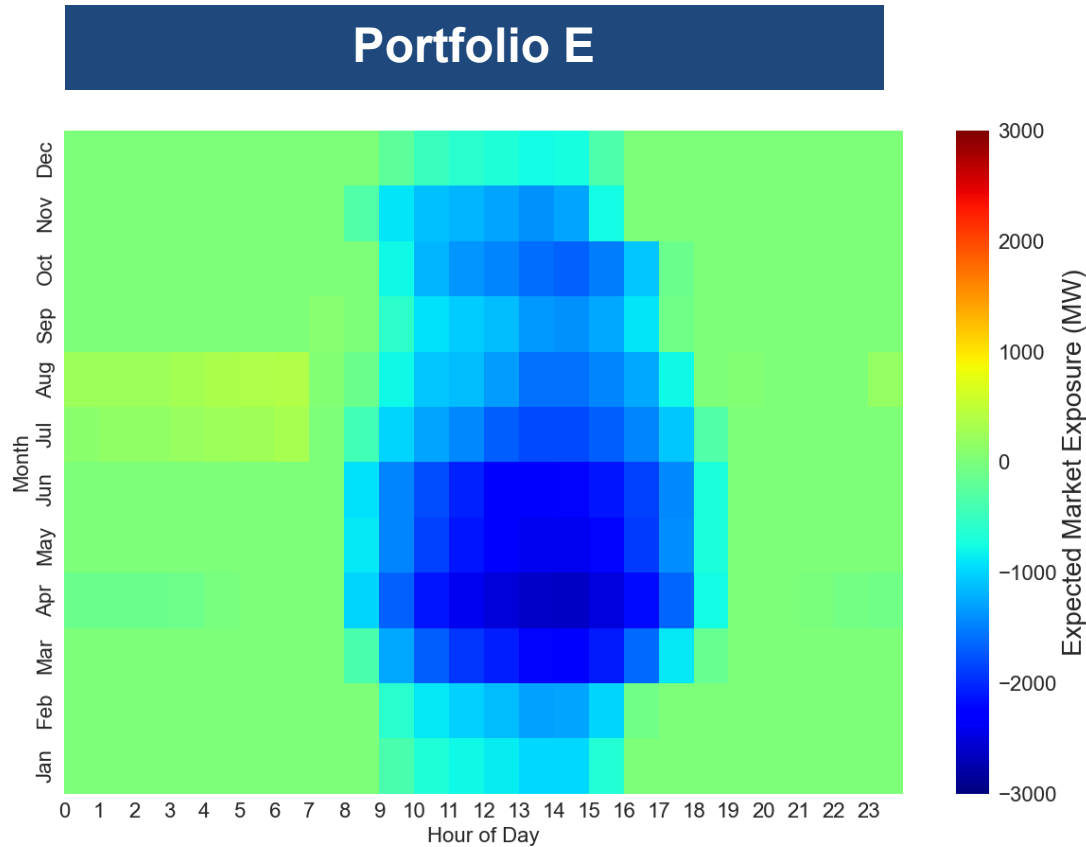
PORTFOLIOS C AND D (ALL VARIANTS) – 50TH PERCENTILE FORCED MARKET EXPOSURE

- At the 50th percentile, Portfolio C has modest forced market exposure risk in the summer evenings and overnight hours, while Portfolio D is covered across all hours



PORTFOLIOS E AND F – 50TH PERCENTILE FORCED MARKET EXPOSURE

- At the 50th percentile, the portfolios have modest forced market exposure during evenings and overnight hours throughout the year

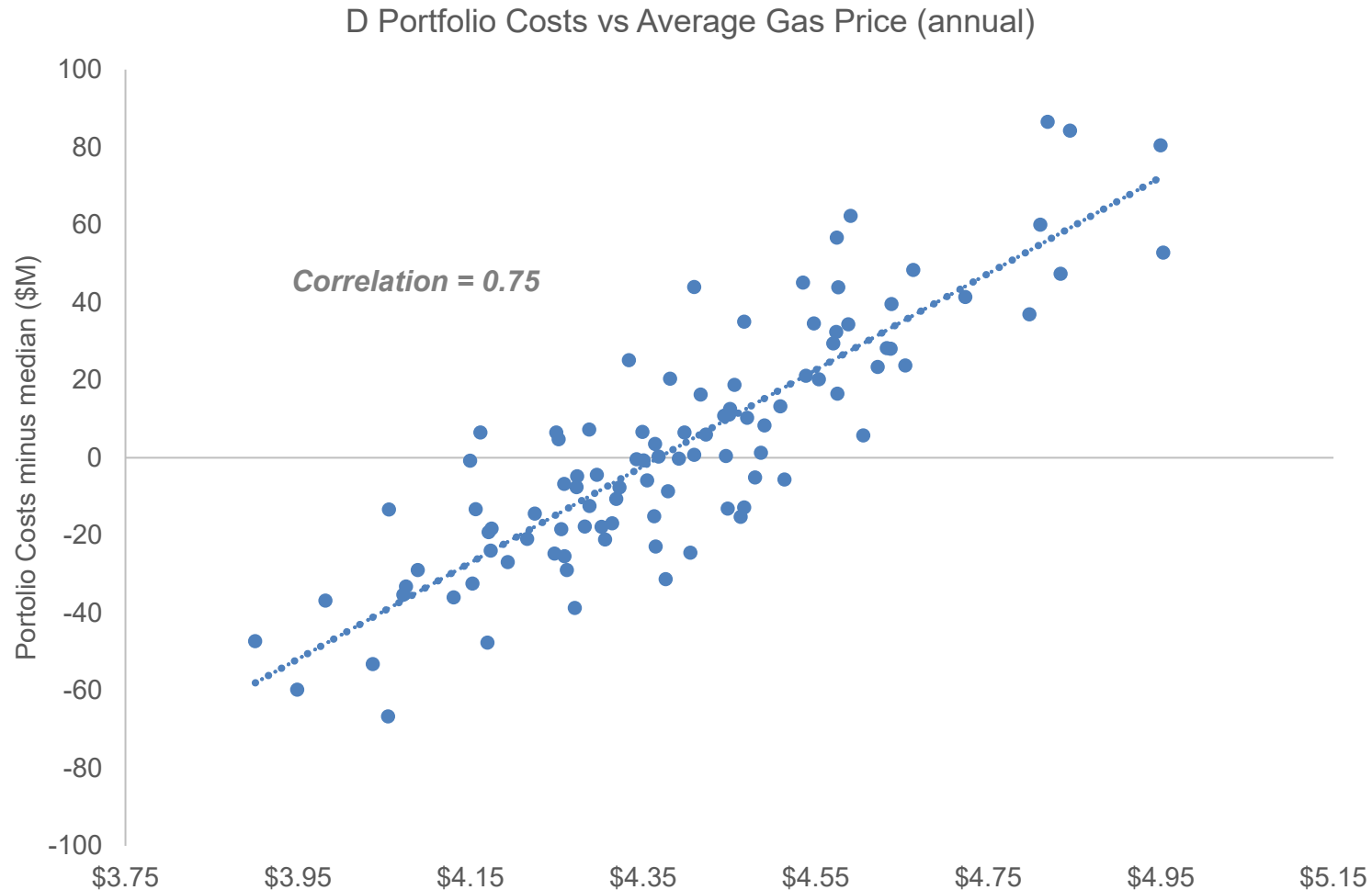


KEY RELIABILITY METRICS

- Portfolios E and F could experience significant forced market exposure risk. The event magnitude could be substantial, but their expected duration is usually relatively short
- The D Portfolios are best suited to mitigate against potential forced market exposure risk and are largely “in control of their own destiny.”

Portfolio	LOLE (days/year)	Forced Market Exposure (GWh)	Forced Market Exposure Relative to Total Load (%)	Forced market exposure (MM\$) (50/90%)
A	57	235	0.91	10.9/16.0
B	24	86	0.33	3.9/7.0
C	41	89	0.34	4.1/6.9
D (all variants)	2	4	0.02	0.1/0.6
E	192	793	3.08	37.8/47.6
F	100	515	2.00	24.4/33.7

COST RISK – IMPACTS OF NATURAL GAS ON PORTFOLIO COSTS



- All portfolios had a strong correlation between total costs and natural gas prices
- For portfolio D, a \$1 increase in gas price corresponds to an expected \$125M increase in portfolio costs



Northern Indiana Public Service Company LLC
2024 Integrated Resource Planning
Public Advisory Meeting #5
SUMMARY

October 28, 2024

Welcome & Introduction

Tara McElmurry, Communications Manager, NiSource

Kick Off

Vince Parisi, President & COO, NIPSCO

Recap of 2024 IRP Process and Responses to Fourth Stakeholder Meeting Comments

Abe Lang, Manager Strategy & Risk, NiSource

After introductory comments, Abe Lang, Manager Strategy & Risk at NiSource, provided a recap of the stakeholder process and timeline as well as a summary of stakeholder feedback since Meeting #4.

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

- Will NIPSCO address the impact of customer cost allocation in its IRP filing?
 - We will provide any legally required items related to customer costs and rates. Right now, we do not have anything to share about customer rate impacts. We will show total revenue requirement expectations, and we will show the total divided by megawatt hours of sales. We do not have any specific rate information to share about what data center customers are going to pay. We are still working through the process and cannot guarantee that we will have a specific call out as to what they are going to be charged until we have more information. When we have more information available on rate impacts, we can share that.
- When you model data centers, are you assuming they are going to be responsible for all the costs associated with their construction. Is any modeling considering whether they terminate early or operate shorter than the contract term?
 - In our current IRP modeling, we are looking at the system costs and everything as a whole. It is NIPSCO's strategy and position to have these large load customers carry the cost of their generation and transmission needs.

Portfolio Recap and Portfolio Scenario Analysis

Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA

Abe Lang began the section with an overview of NIPSCO's overall resource planning approach and the portfolio concepts under evaluation. Mr. Patrick Augustine, Vice President at CRA, then

provided additional detail regarding the resource additions and energy positions of the eight portfolios that were developed and presented in Stakeholder Meeting #4. Mr. Augustine then presented two new portfolios that were developed under a “Flat Load” condition with no incremental data center load. He reviewed annual capacity additions and the projected energy balance of these new portfolios and compared them with the original eight concepts.

Mr. Augustine then presented the results of NIPSCO’s portfolio analysis, starting with the net present value of revenue requirements (“NPVRR”) under Reference Case market conditions. He then reviewed NIPSCO’s alternative scenario constructs and presented the NPVRRs for each portfolio across each scenario. He closed the section with a comparison of the levelized generation costs per MWh for the various portfolios, including those developed under Flat Load conditions.

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

- What sensitivities did NIPSCO include about assumed carbon capture, utilization, and storage (“CCUS”) technology performance?
 - After the IRP filing and over the next 10 years, we are going to evaluate the feasibility and timing of CCUS. All portfolio analysis has made assumptions about performance as reviewed during Meeting #3, and we have also run Portfolios E and F, which assumed that you could have CCUS by 2030 vs. Portfolio D_CCUS, which assumed that we could get it by 2035. We have two different looks that we are showing today. We will continue to evaluate CCUS after the IRP filing.
- Is the only driver in the portfolio cost per MWh differences more megawatt hours with additional loads?
 - That is the primary driver of the cost per MWh relationship. The cost for the entire system is projected to go down with growing load. This conclusion is dependent on the starting point for NIPSCO’s system. NIPSCO currently has a portfolio that is relatively energy rich and potentially capacity short given evolving MISO rules, which means incremental resources that are coming into the system are needed to provide capacity and not energy, which will drive up the cost of the existing system per MWh. Adding high load factor loads into the system can allow the system to more efficiently absorb new resources that offer both energy and capacity.

Stochastic Risk Analysis

Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA

Pat Augustine introduced the section with a recap of the stochastic analysis process and approach, including a review of the uncertainty variables that were evaluated. He then reviewed the expected forced market exposure of the different portfolio options by displaying market exposure risk profiles across the day and year, along with key quantitative metrics. Mr. Augustine then presented NIPSCO’s cost risk analysis and presented distributions of cost outcomes for the various portfolio options, particularly at the 5th and 95th percentiles.

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

- Is Portfolio D relying on CCUS?
 - No, not in 2030. This is a 2030 view and it is relying on new combined cycle capacity and gas peaking capacity. Portfolios E and F do have some CCUS additions, but Portfolio D does not have CCUS until the later 2030s. In this simulation, where we are focused on the year 2030, all requirements are met by conventional gas units.

- But doesn't the whole portfolio rely on a 20-year outlook?
 - Yes, cost metrics and some of the other metrics that we will talk about later are evaluated over the full 20-year outlook, but for this stochastic risk assessment we are doing an assessment of the year 2030, so the role of CCUS in Portfolio D is not showing up. Earlier CCUS is showing up in Portfolios E and F but this risk assessment is designed to be a snapshot in time.
- Do Portfolios E and F have any risk related to CCUS?
 - From a thermal outage perspective, yes, their thermal outage uncertainty is slightly higher, given the CCUS. They also have additional risk associated with some of the other resources that are in the mix due to limitations on with new gas build options. But for purposes of this analysis we are not measuring the risk of not being able to complete a project by that point in time.
 - This analysis is not looking at any feasibility or execution risk as related to the generation projects themselves, rather it is looking at what the year 2030 looks like, as far as if we have enough generation to support our load, if we implement these portfolios. In the times that we do not, that will show up in the yellow or reddish colors in these charts [on slides 56-58].
- I think relying on CCUS and not having any risks around costs or operations is a little bit short sighted.
 - That is something we will continue to evaluate beyond this IRP and you will see when we get to our preferred portfolio, we take all of these feasibility and execution-related concerns into consideration, between now and when we would actually be implementing CCUS. We will have to continue to study CCUS and what our best options are to continue to decarbonize after the IRP process is complete. Our preferred portfolio gives us some time to assess what the best decarbonization options are for natural gas units, and right now CCUS is probably the most feasible, although we will continue to also study and monitor the potential for a hydrogen economy to develop over the next couple of years.
- When you say 95th percentile, are you talking about with respect to load? Or peak net load? Or some other metric or driver that you looked at?
 - Net load is the correct way to think about it. These graphics are showing the 90th percentile of the net load – the capacity available minus the load in any given hour/month combination. For each little square on the graphic we are looking at the 90th percentile of that value. Across the distribution we have 1,000 runs for hour one in January, as an example, and for each of those iterations we can take the available capacity minus the NIPSCO load and then pull the 90th percentile from that distribution, so it is a net load view here.
- What size is the combined cycle resource that you modeled in Aurora?
 - Those are generally 650 MW blocks
- As you guys went through the stochastic analysis, was it possible for the model to have any correlated outages between units? And did you see any of those outages in your analysis? If you did, would it make sense to show a similar graphic for those events too?
 - Perhaps. We have correlations between thermal resource outages and weather and naturally there will then be some correlation between units, because if there is a particular weather event that is within an iteration that results in a unit being more likely than not to be in outage condition, that would likely be the case across the board. I do not have on hand what the correlation of combined cycle unit outages might look like so maybe we can follow up with some more data, but I will say that these types of instances are embedded within here so there might be some interesting data that we could look at.
- Can you generalize about which seasons of the year you are showing these iterations that are flying into the 90th percentile?
 - The graphic here has the twelve months on the Y axis so the 90th percentile is

being recorded at every block. We are showing the net load at the 90th percentile here within each block of time. We could potentially follow up with some additional data, but these graphics show that in certain seasons our exposure may be better or worse.

- You are trying to address the timing of potential risks through this set of graphics but I wonder if it also makes sense to think about the magnitude of the risks and is there a way to think about modeling today's portfolio and load to give a sense of where the exposure is currently in the system, compared to how that might change in 2030?
 - Yes, there is certainly a way to do that. This is a developing situation and for this IRP we tried to give some different potential views but I think your points are good and warrant additional review as the market changes.
- Is there an opportunity to put some of that, especially the comparison to today's portfolio, into the IRP?
 - Yes, we can follow up and potentially take this offline and try to include what you are asking for in our final report. We can set up a one off conversation to go over the exact details of what you are looking for.
- Does CCUS mean a CC with CCUS?
 - Yes, that is correct. That bullet indicates a CCGT, with CCUS being included.
- What is the parasitic load of CCUS in your modeling assumptions?
 - We have CCGT with CCUS blocks offering 585 MW of net load to the system, versus the 650 MW block of CCGT. So this would represent 65 MW of parasitic load, so essentially a ten percent de-rate of the net capacity to the grid.

Sensitivities – High Emerging Load and DSM
Abe Lang, Manager Strategy & Risk, NiSource
Pat Augustine, Vice President, CRA

Pat Augustine began the section with a review of the emerging high load sensitivity load growth parameters and then presented the resource additions and projected energy mix of the portfolio optimized under high load. He then summarized the assumptions associated with the DSM sensitivity (moving from RAP to Enhanced RAP/MAP) and presented the portfolio implications and cost results.

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

- Does a peaker plant provide power when there is a parasitic load?
 - No, not necessarily. The parasitic load terminology is associated with a CCUS-facility, where there is a significant demand for energy to perform those CCUS activities on site, so a portion of the capacity associated with the resource is needed on site, leaving less energy for the grid. Peaker capacity refers to a separate facility that would be expected to operate economically but during periods when load is peaking throughout the system.
- What makes up the difference when there is a parasitic load? Where does that power come from?
 - It would come from other resources that would have to be added to the mix. So, when we look at a portfolio that has a CCUS facility that is operating at 585 MW rather than the 650 MW for a regular combined cycle, other resources would then be added to the mix. That could potentially be a peaking plant but it could also be additional solar, storage, or other. So, essentially, other resources in the portfolio are factored in to make up the difference.

Scorecard Summary, Preferred Portfolio, and Short-Term Action Plan
Abe Lang, Manager Strategy & Risk, NiSource

Abe Lang started the session with a review of NIPSCO's integrated scorecard objectives and metrics and then presented a fully populated scorecard for all portfolios. He then discussed the rationale for the selection of NIPSCO's preferred portfolio and presented NIPSCO's short-term action plan.

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

- Why did NIPSCO change the environmental sustainability metric to emission intensity? This is inconsistent with what NIPSCO has previously stated would be the metric in this IRP throughout this stakeholder process. It is also inconsistent with NIPSCO's 2021 IRP. We urge NIPSCO to use total emissions, not emission intensity.
 - We used this to show how emissions progressed relative to the amount of megawatt hours that are produced and we thought this was a more helpful metric when comparing the portfolios. However, in our December 9th final IRP report we will have all of the emissions numbers for all of these portfolios included, to be consistent with what we have provided in the past.
- In terms of due diligence regarding CCUS, what has NIPSCO done around seismic activity and community safety?
 - We are still in the process of evaluating the feasibility of CCUS, among other decarbonization options, and when we have more information that we can share publicly around associated risks from a cost or safety standpoint, we will make sure to share that. There are a variety of concerns that people have about CCUS and we acknowledge that.
- Is NIPSCO responsible for the seismic testing that is occurring around Sugar Creek, or is that someone else?
 - I am not familiar with this occurring but I do not believe that would be us.
- What is the true reality of carbon capture for coal or gas-fired power plants? It does not seem feasible in terms of costs right now.
 - It is more than double, or even up to triple the cost, to build a new CCGT with CCUS versus building a new CCGT without carbon capture included. There are also many unknown costs when it comes to things like preparing underground wells or piping the carbon, so we are still working through an understanding of what those costs would be. Our preferred plan does not include CCUS by 2030 because we do not think that is feasible by then, but we will have more time to evaluate whether or not it is feasible by 2035 and beyond. We currently see CCUS as being the more viable by then than hydrogen, as of today.
- How does carbon capture compare then to the new small nuclear units that are being developed?
 - A new small modular nuclear reactor has not been built in the United States to date, so it is difficult to say. But the costs of nuclear plants have notoriously run higher than whatever is initially estimated, so there is still a lot of uncertainty around this new technology and how costly it will be. The cost assumptions we used in this IRP for new nuclear were presented in Meeting #3.
- Where will the CCGT, CCUS and Gas Peaker plants be located?
 - We do not have locations at this time. The IRP only selects the resource types and MW amounts. Once we move towards trying to execute this preferred plan, we will have more information on where those locations would be.
- Which capacity addition amounts represent what will be needed for data centers?
 - [on slide 80] Any resources that are not italicized and do not have an asterisk next to them represent what would be needed for data center load. If we never end up signing a data center customer up, we might not end up needing these resources. Anything that is italicized and anything listed in the "Other Activities" will be needed no matter what.

- Then where is the gas peaker located? Is that the one that says “Thermal Contracts”?
 - The gas peaker that we are currently working on is listed in the first column, in the “Other Activities” row, where it says “~400 MW gas peaker”. Anything listed in the “Other Activities” row is already a part of NIPSCO’s existing plan. Everything that is in the “Preferred Plan – Capacity Additions” row is incremental to that plan, with resources that will definitely be needed italicized and resources that might be needed for data center load non-italicized.

Closing & Stakeholder Comments

NIPSCO IRP Stakeholder Meeting - October 28, 2024

Registrant First Name	Registrant Last Name	Registrant Email Address	Company
Erik	Miller	erik.miller@aes.com	AES
Erik	Miller	erik.miller@aes.com	AES
Michael	Hardie	michael.hardie@aes.com	AES Indiana
Ryan	Wilhelmus	ryan.wilhelmus@bigrivers.com	Big Rivers Electric Corporation
Denise	Abdul-Rahman	denise@blacksunlight.org	Black Sun Light Sustainability
KRISTINA	WHEELER	kristinawheeler@sbcglobal.net	Bose McKinney & Evans LLP
Taylor	Carpenter	tcarpenter@calfee.com	Calfee
Jeremy	Martin	jeremy.martin@centerpointenergy.com	CenterPoint Energy
Matt	Rice	matt.rice@centerpointenergy.com	CenterPoint Energy
Aidan	Gibbons	aidanrgibbons@gmail.com	Charles River Associates
Pat	Augustine	paugustine@crai.com	Charles River Associates
Edwin	Moyo	emoyo@crai.com	Charles River Associates International
Edwin	Moyo	emoyo@crai.com	Charles River Associates International
Ben	Inskeep	binskeep@citact.org	Citizens Action Coalition
Kerwin	Olson	kolson@citact.org	Citizens Action Coalition of IN
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana
Reagan	Kurtz	rkurtz@citact.org	Citizens Action Coalition of Indiana, Inc.
Sameer	Doshi	sdoshi@earthjustice.org	Earthjustice
Paul	Dort	paul.dort@edp.com	EDP Renewables North America
Anna	Sommer	asommer@energyfuturesgroup.com	EFG
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
Emily	Medine	emedine@evainc.com	Energy Ventures
Hadiza	Felicien	hfelicien@formenergy.com	Form Energy
Hadiza	Felicien	hfelicien@formenergy.com	Form Energy
Jessicq	Nyquist	jnyquist@formenergy.com	Form Energy
Rachel	Wilson	rwilson@formenergy.com	Form Energy
Garrett	Culp	gculp@indianaenergy.org	Indiana Energy Association
Cynthia	Armstrong	carmstrong@oucc.in.gov	Indiana OUCC
Greg	Krieger	gkrieger@oucc.in.gov	Indiana OUCC
David	Savage	dsavage@urc.in.gov	Indiana Utility Regulatory Commission
Ren	Norman	rnorman@urc.in.gov	Indiana Utility Regulatory Commission
Jordan	Covely	jordan.covely@inovateus.com	Inovateus Solar LLC
Bradley	Borum	bborum@urc.in.gov	IURC
Dale	Thomas	dthomas@urc.in.gov	IURC
James	Huston	jhuston1@urc.in.gov	IURC
Susan	Thomas	sthom1113@gmail.com	Just Transition NWI
Bruna	da Silva	bruna.dasilva@keycaptureenergy.com	Key Capture Energy
Zico	Shaker	zico.shaker@leewardenergy.com	Leeward Renewable Energy
Ryan	Pfefferle	rypfefferle@microsoft.com	Microsoft
Sally	Lei	sally.lei@nexteraenergy.com	Nexetra Energy Resources
Bryan	Mills	bryan.mills@nexteraenergy.com	NextEra
Kay	Nelson	Knelson@nwiforum.org	Northwest Indiana Forum
Suzanne	Escudier	suzanne.escudier@origisenergy.com	Origis Energy
Brian	Wright	brwright@oucc.in.gov	OUCC
Derek	Leader	dleader@oucc.in.gov	OUCC
John	Hanks	Jhanks@oucc.in.gov	OUCC
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Roopali	Sanka	rsanka@oucc.in.gov	OUCC
Richard	Pate	rgpate@pateassociates.com	Pate & Associates
Sunil	Maheshwari	mahesh67@purdue.edu	Purdue University
Davis	McCourt	davis@rangerpower.com	Ranger Power
Edward	Twarok	ehtwarok@comcast.net	Retired
Steve	Francis	Golden12@aol.com	SEED
Tim	Phillips	timphillips@purdue.edu	State Utility Forecasting Group
Amanda	Bersing	amanda.bersing@wellsfargo.com	Wells Fargo Securities
Alex	Cooley	acooley@nisource.com	
David	Nderitu	nderitu@purdue.edu	

Geraldine	Black	babygirlhosea@gmail.com	
Kimberly	Graham	akgraham7@comcast.net	
lois	osborn	bornsoil@gmail.com	
Maxwell	Santiago	maxsanti@iu.edu	