NIPSCO
A NiSource Company

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

NIPSCO MEETSAFE

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

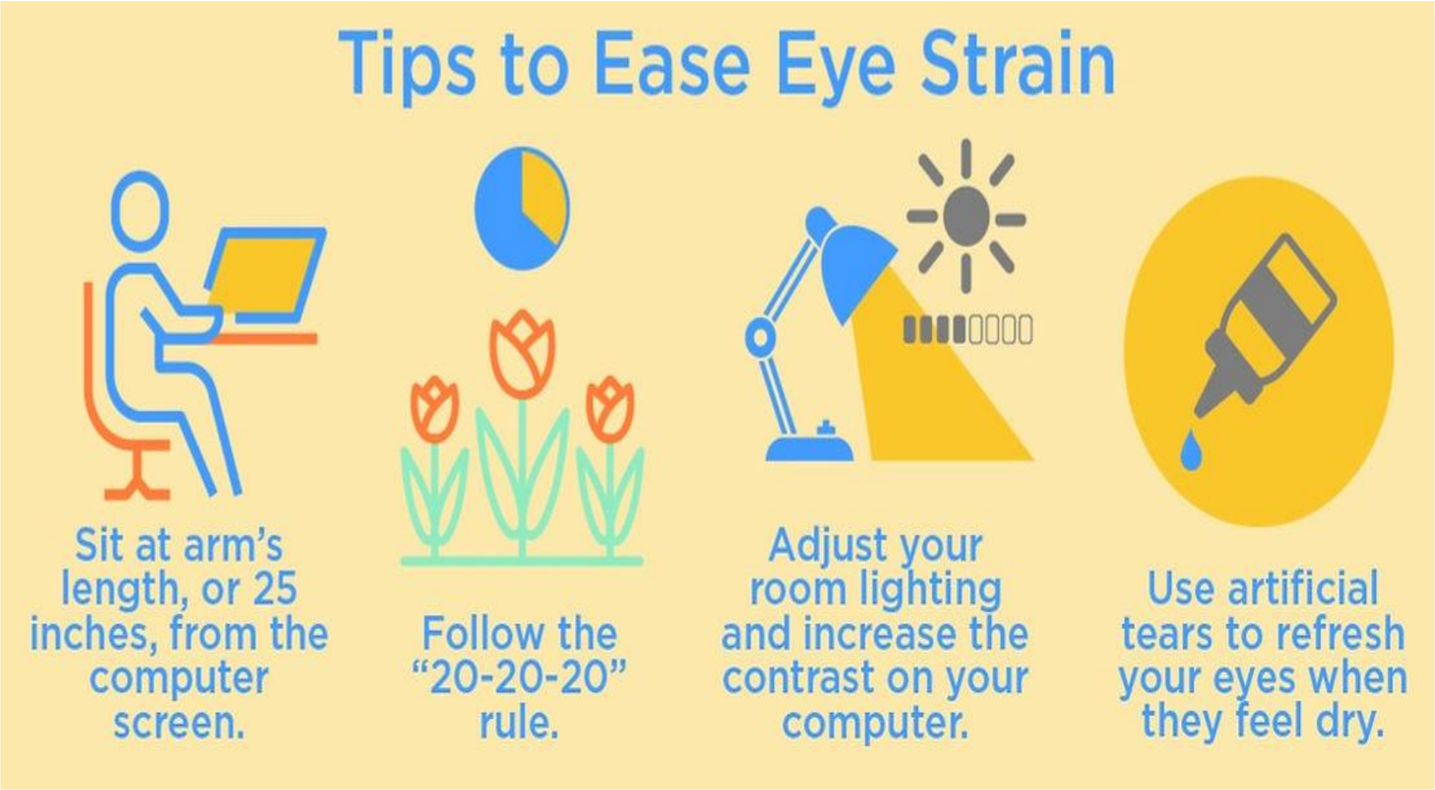
Dial 911:

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

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

NiSource

- NATURAL GAS
  - COLUMBIA GAS OF KENTUCKY
  - COLUMBIA GAS OF MARYLAND
  - COLUMBIA GAS OF OHIO
  - COLUMBIA GAS OF PENNSYLVANIA
  - COLUMBIA GAS OF VIRGINIA
  - NIPSCO GAS
- ELECTRIC
  - NIPSCO ELECTRIC

NIPSCO

SIGNIFICANT SCALE ACROSS 6 STATES

~3.2M

GAS CUSTOMERS

~500K

ELECTRIC CUSTOMERS

NIPSCO PROFILE

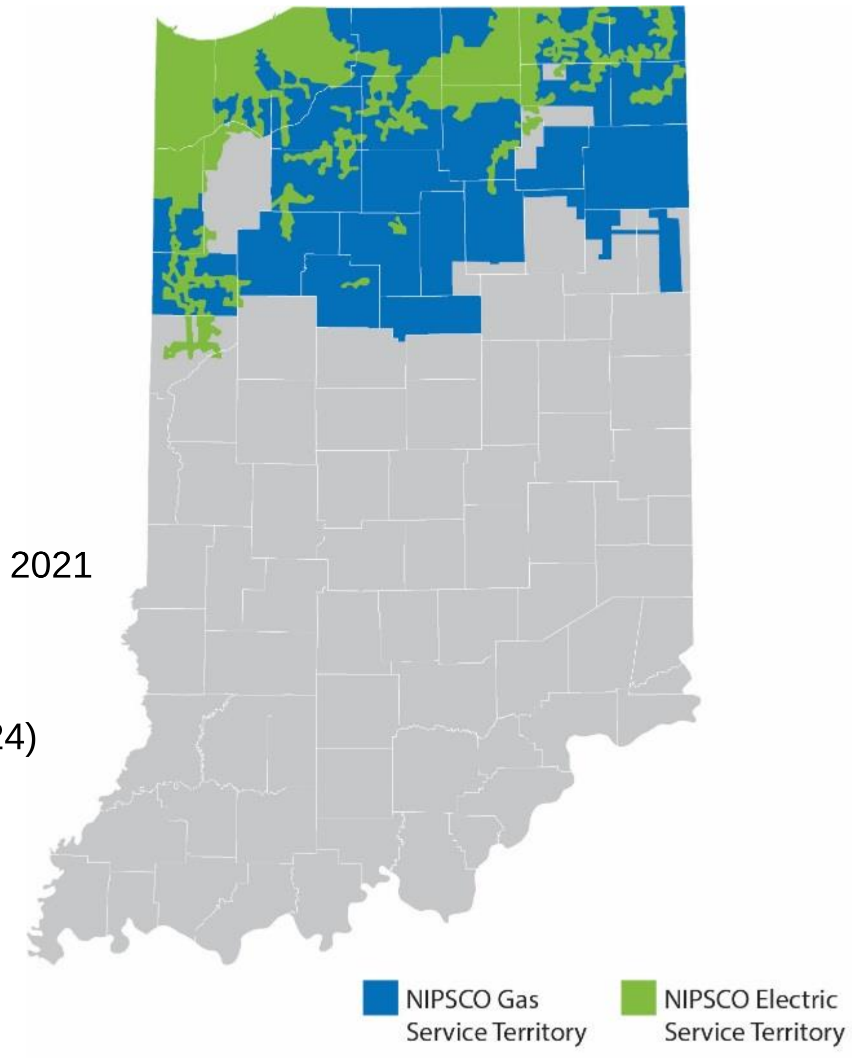
Working to Become Indiana's Premier Utility

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



2,900 Employees

Merrillville, Ind. Headquarters

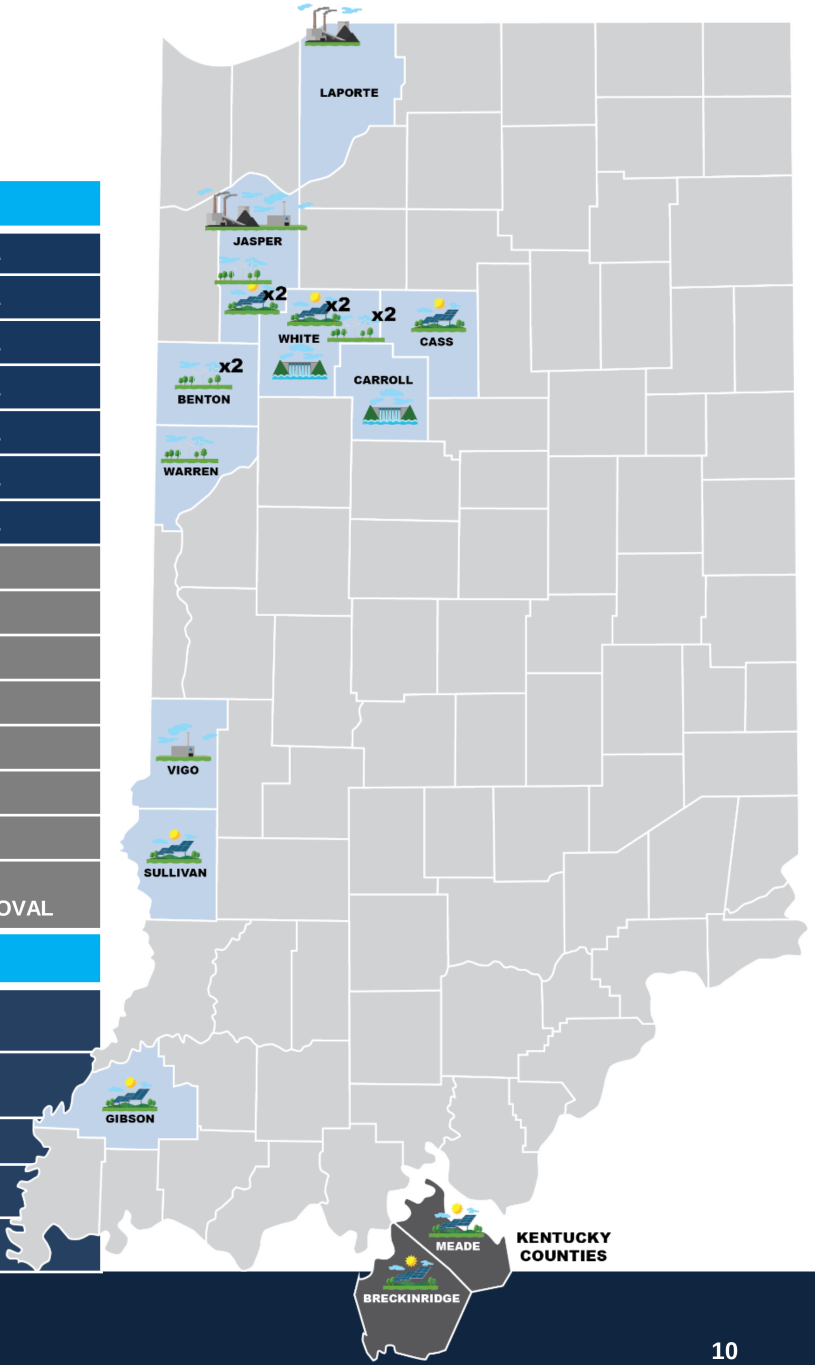
CURRENT & FUTURE NIPSCO GENERATION PORTFOLIO

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

NIPSCO
A NiSource Company

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

PUBLIC ADVISORY PROCESS AND RESPONSES TO SECOND STAKEHOLDER MEETING COMMENTS

Abe Lang, Manager Strategy & Risk, NiSource

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/CO_2 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

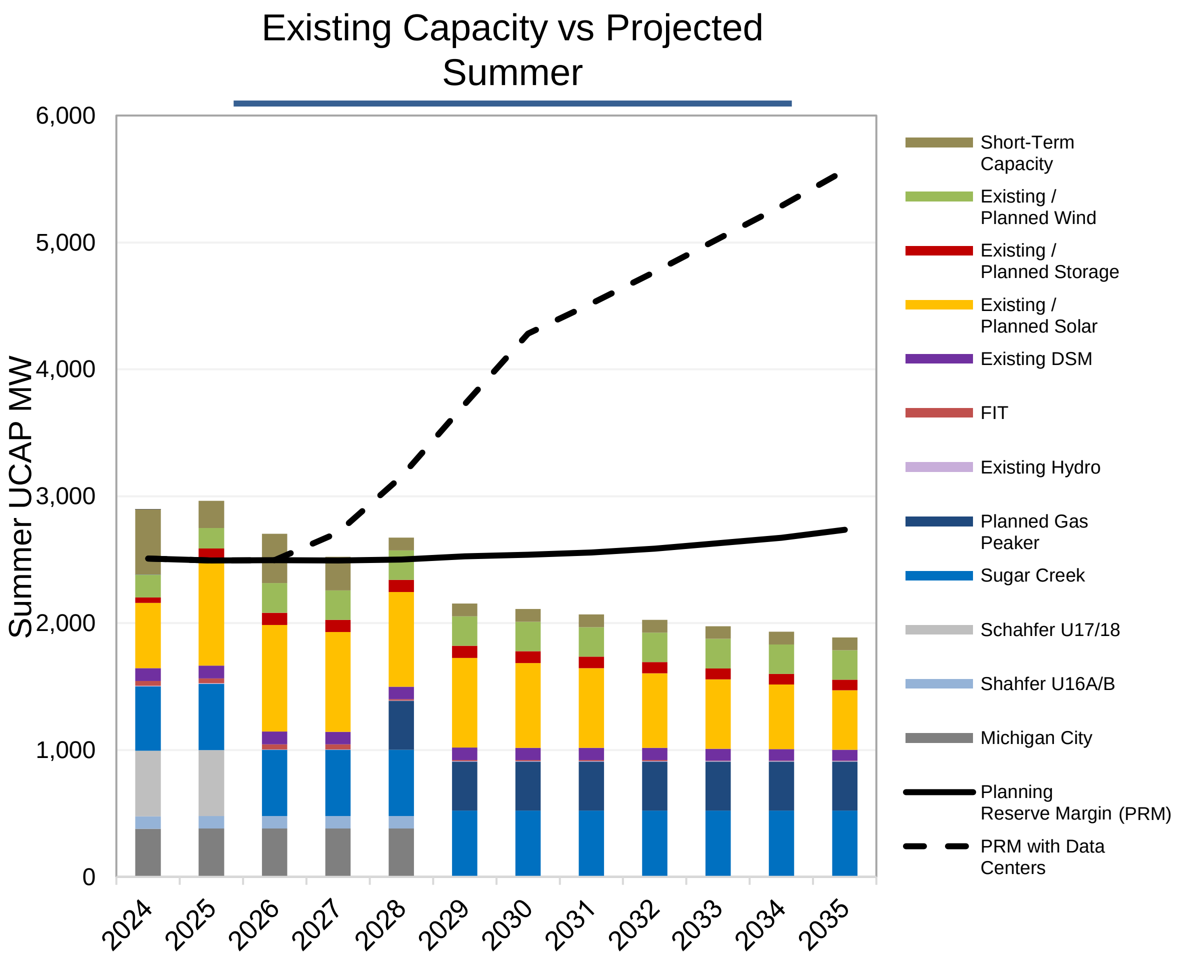
	2028	2030	2035
IRP Peak Load – Original Reference Case**	2,300 MW	2,300 MW	2,500 MW
+New Load Added to All IRP Scenarios	*600 MW*	*1,600 MW*	*2,600 MW*
IRP Peak Load – New Reference Case	**2,900 MW**	**3,900 MW**	**5,100 MW**
+Emerging Load Sensitivity	*2,600 MW*	*4,500 MW*	*6,000 MW*
Total IRP Peak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

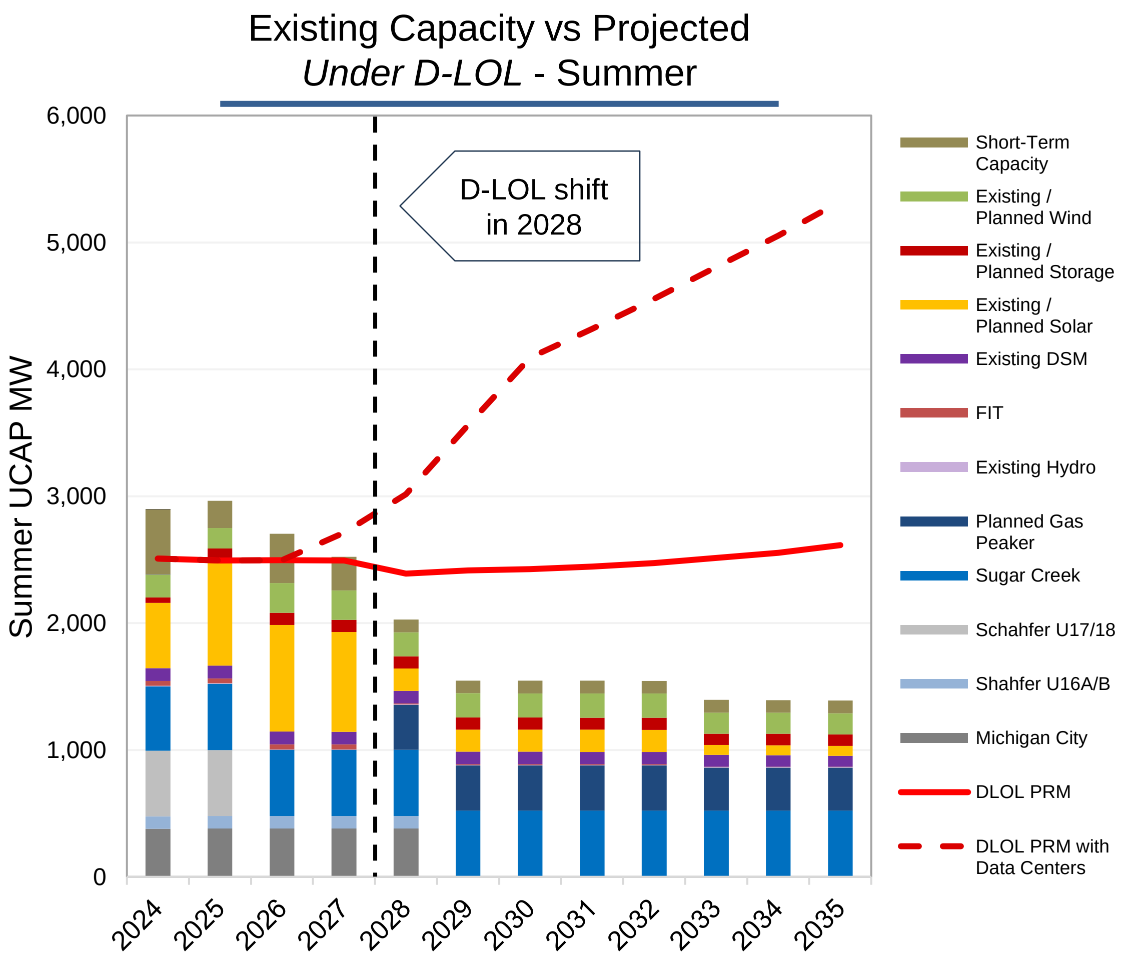
- The build-out of new energy and capacity resources to meet this potential new load will be analyzed in the 2024 IRP process.

** 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*

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, *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.
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 CO_2) 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

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 RESONSE

- 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	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models
• 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	• 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	• 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** (Steps 1–2)		**CRA** **NIPSCO IRP Team**

NIPSCO
A NiSource Company

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

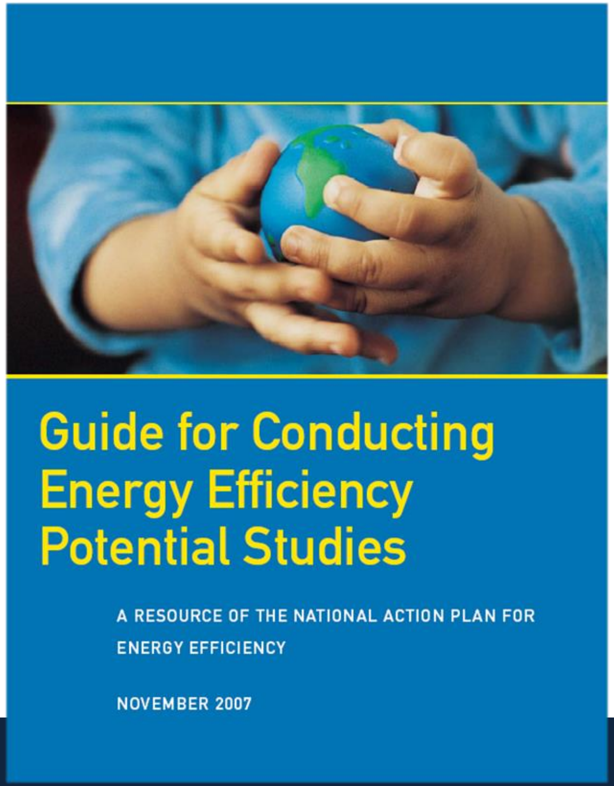
MARKET POTENTIAL STUDY OVERVIEW

WHAT IS A MARKET POTENTIAL STUDY?

Step 1	Step 2	Step 3
Market Potential Study	Identify “bundles” based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

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.

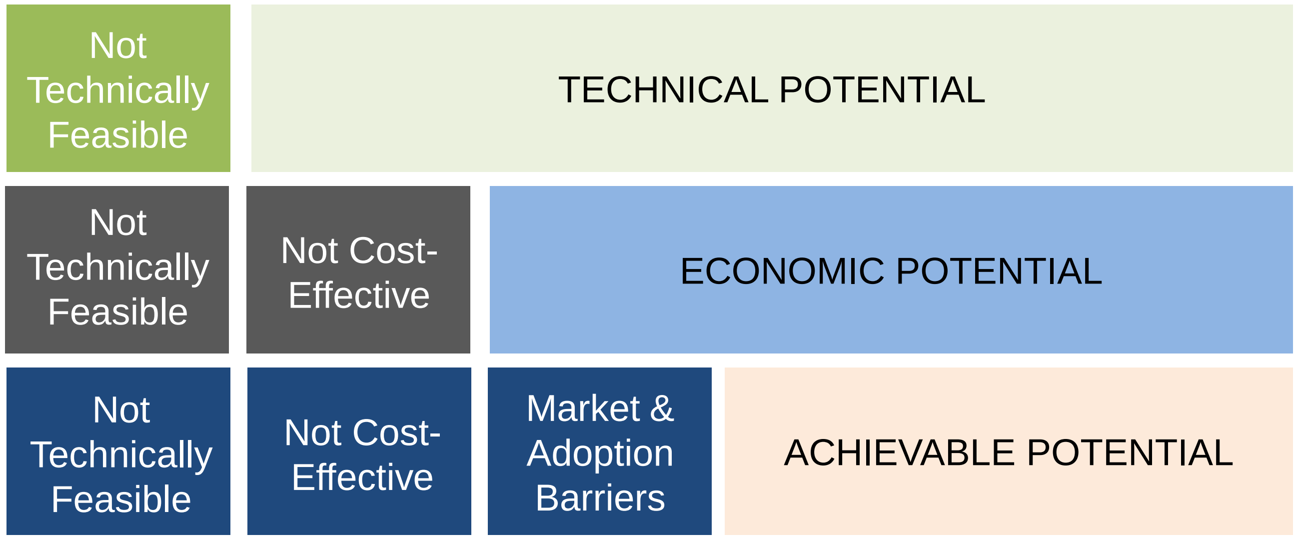
ECONOMIC POTENTIAL

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

NIPSCO
A NiSource Company

MARKET CHARACTERIZATION OVERVIEW

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

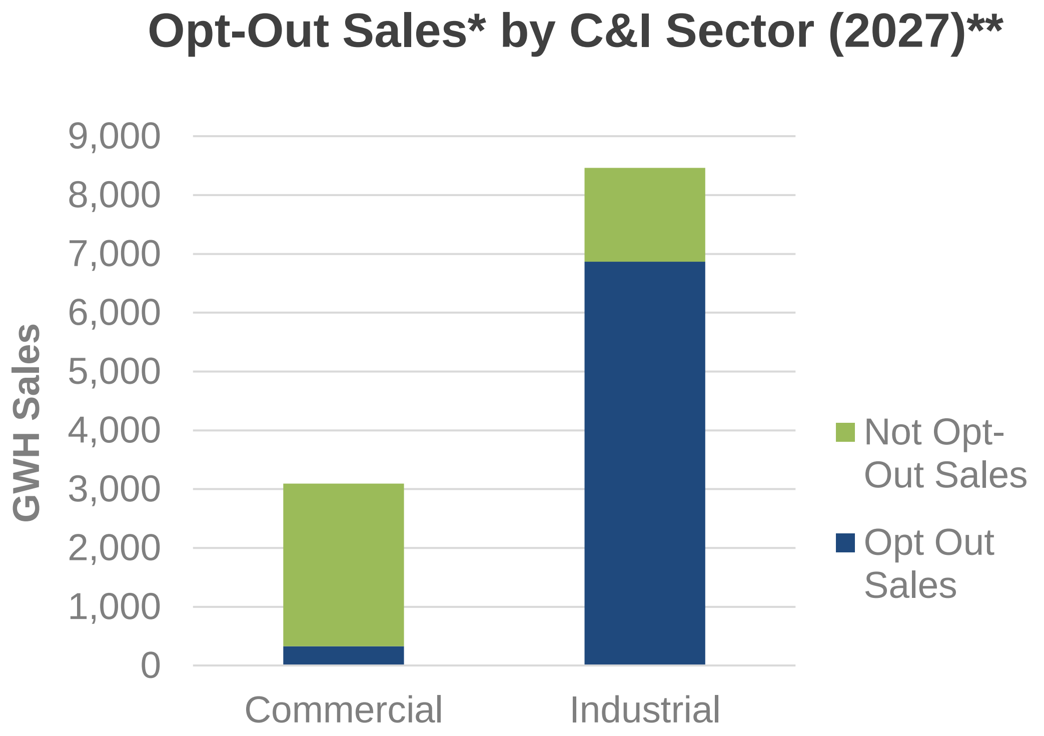
KEY GLOBAL INPUTS AND DATA SOURCES

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*

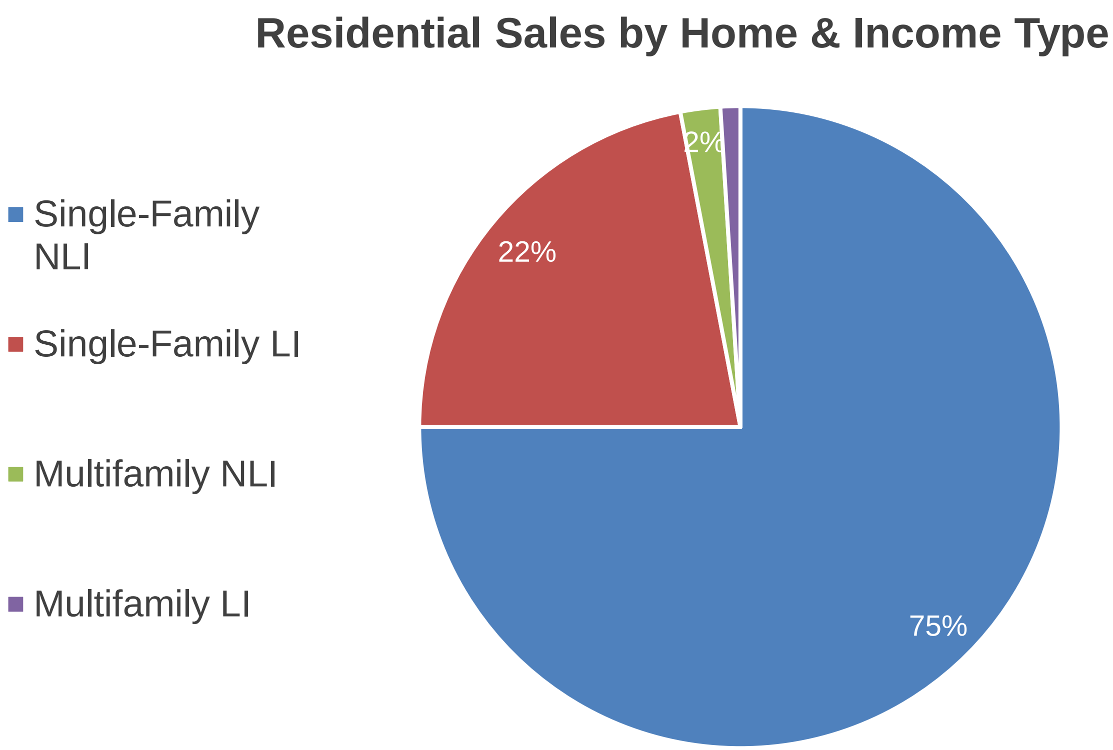
NIPSCO ELECTRIC LOAD FORECAST

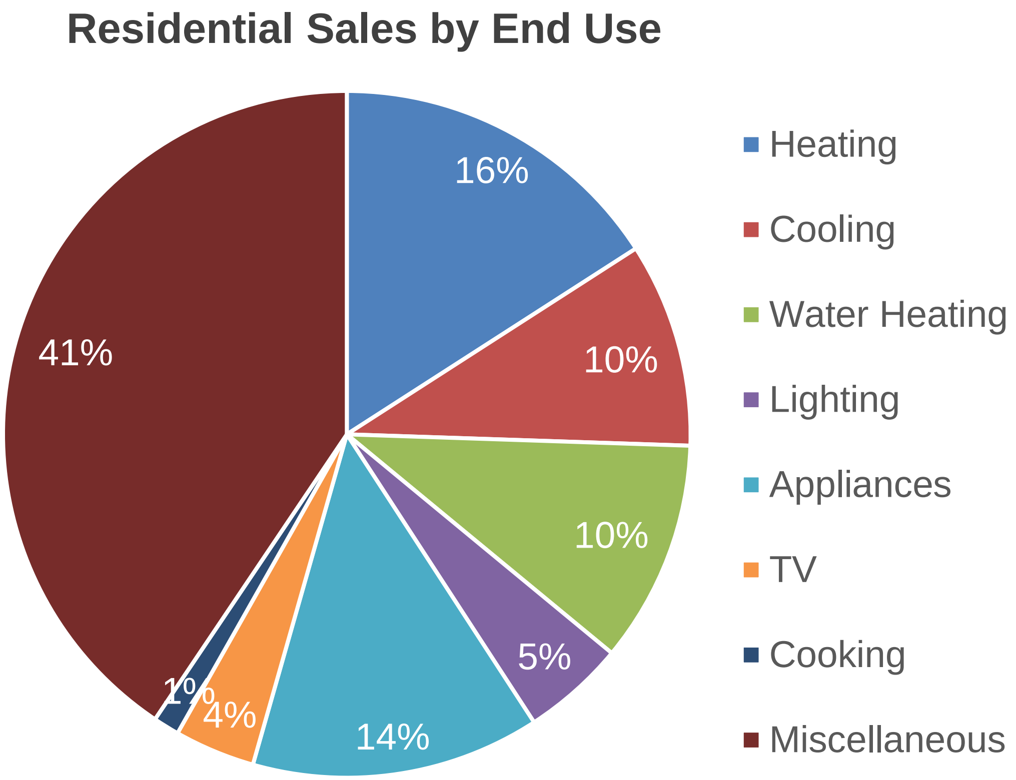
- **The internal NIPSCO sales forecast was modified for use in the MPS**
  - Adjustment removed embedded assumptions about future energy efficiency based on historical DSM performance.
  - MPS also removed sales of current opt-out customers from eligible sales forecast (see graphic to the right)



**Opt-out sales 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.*

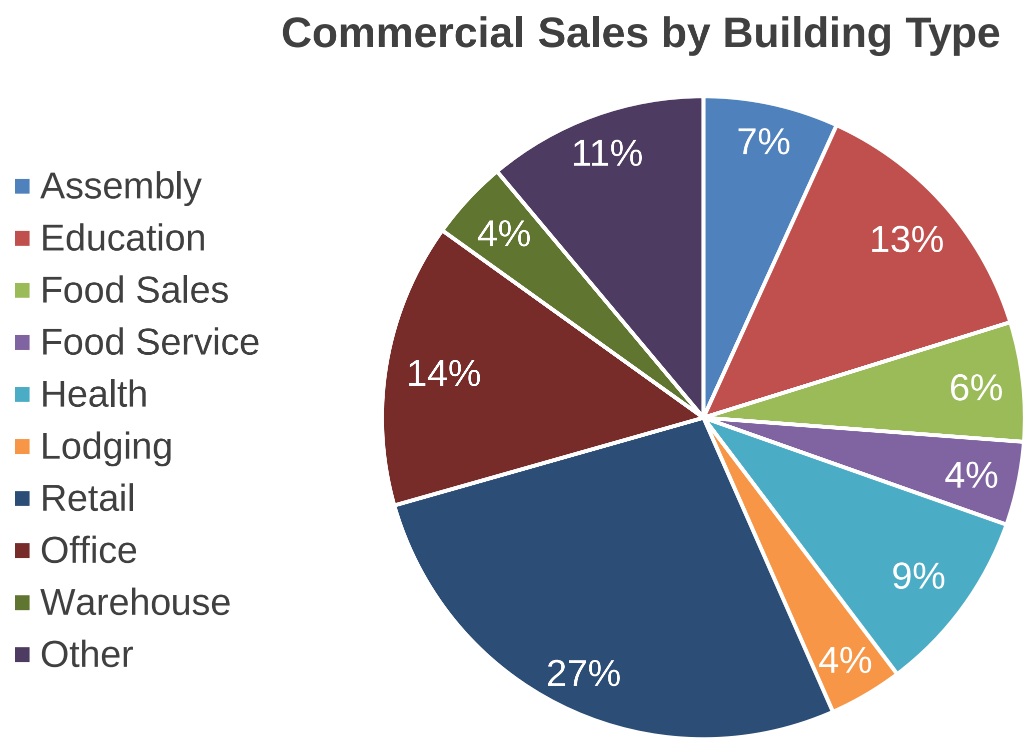
MARKET CHARACTERISTICS DATA

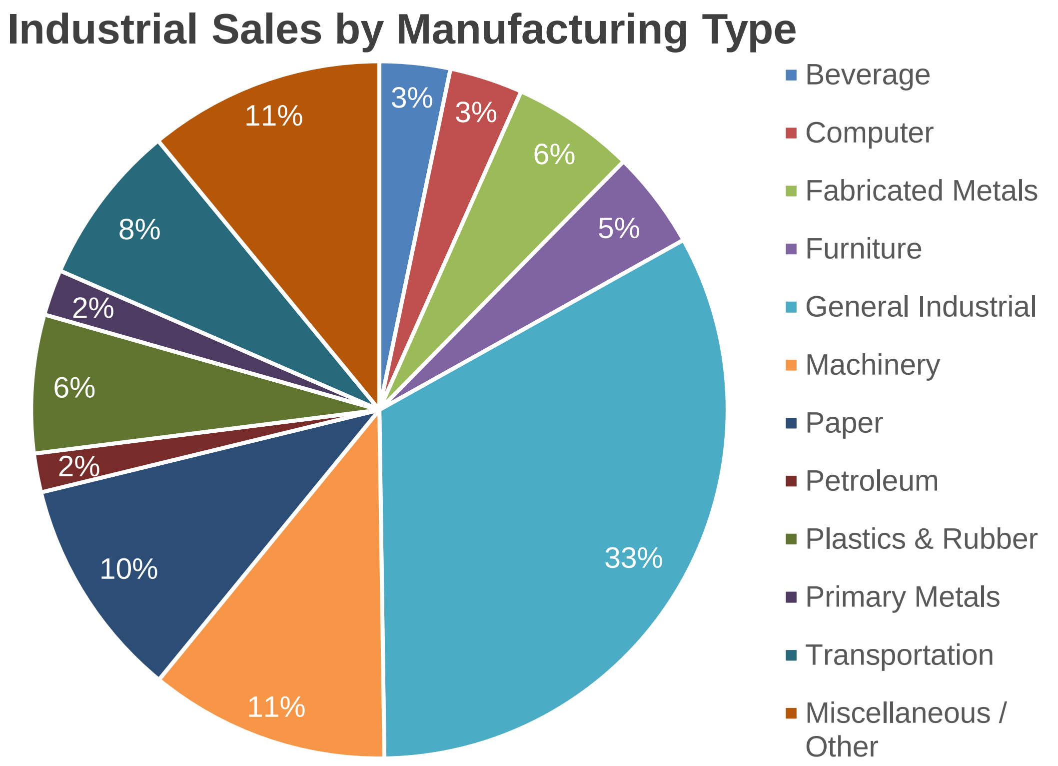




Residential sector analysis uses a bottom-up approach; understanding sales by home type and end use are critical components of the bottom-up approach.

MARKET CHARACTERISTICS DATA





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%

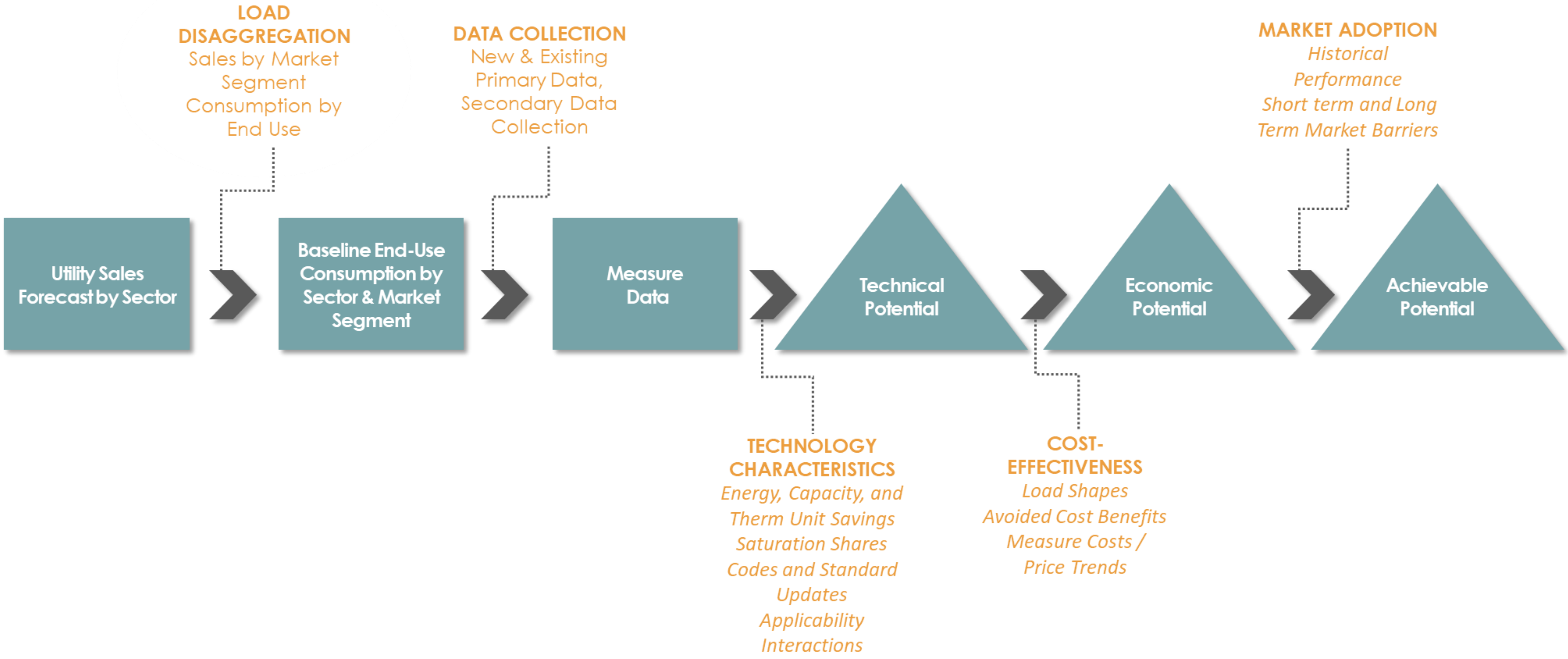
- Willingness-to-Participate (“WTP”) survey data (from 2021 MPS) used to inform long-term adoption rate estimates in the achievable potential scenarios.
- Residential homeowner and commercial business/property managers indicated their likelihood to participate across various incentive/payback performance 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

NIPSCO
A NiSource Company

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

ENERGY EFFICIENCY

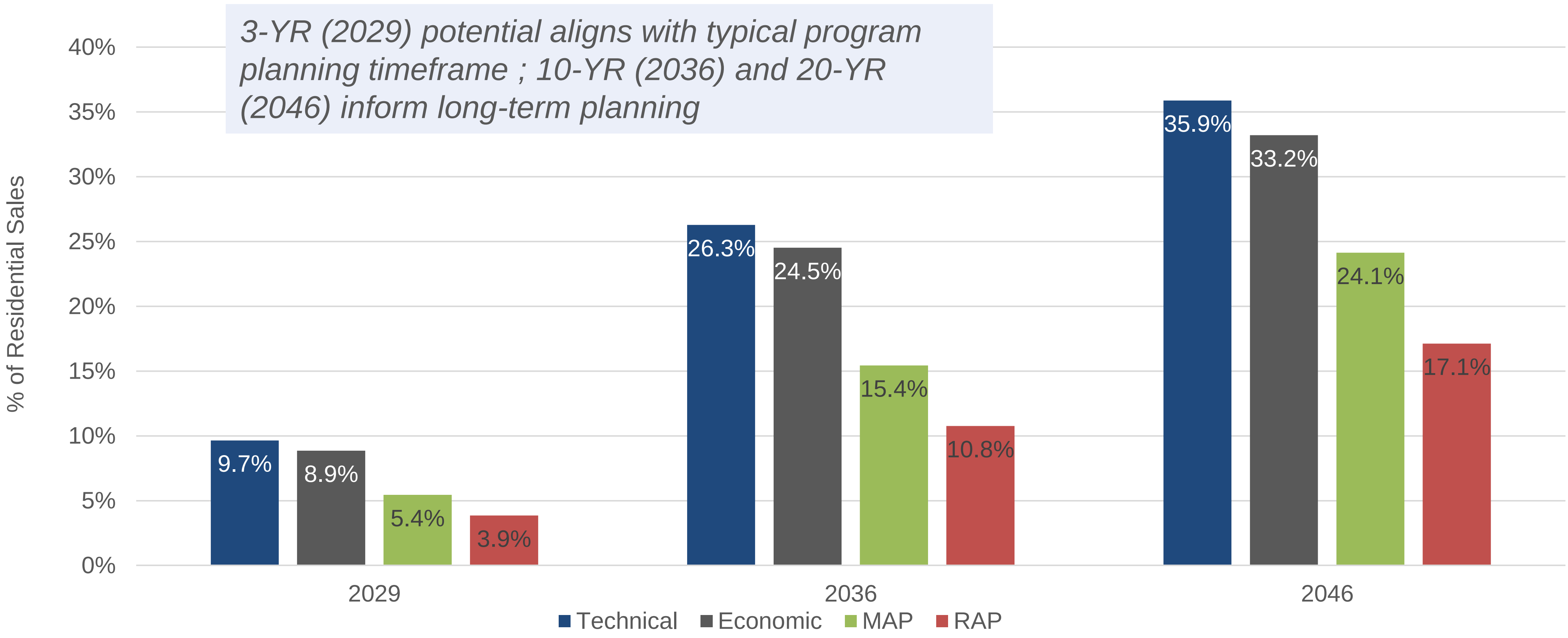
ENERGY EFFICIENCY METHODOLOGY – STUDY APPROACH



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)

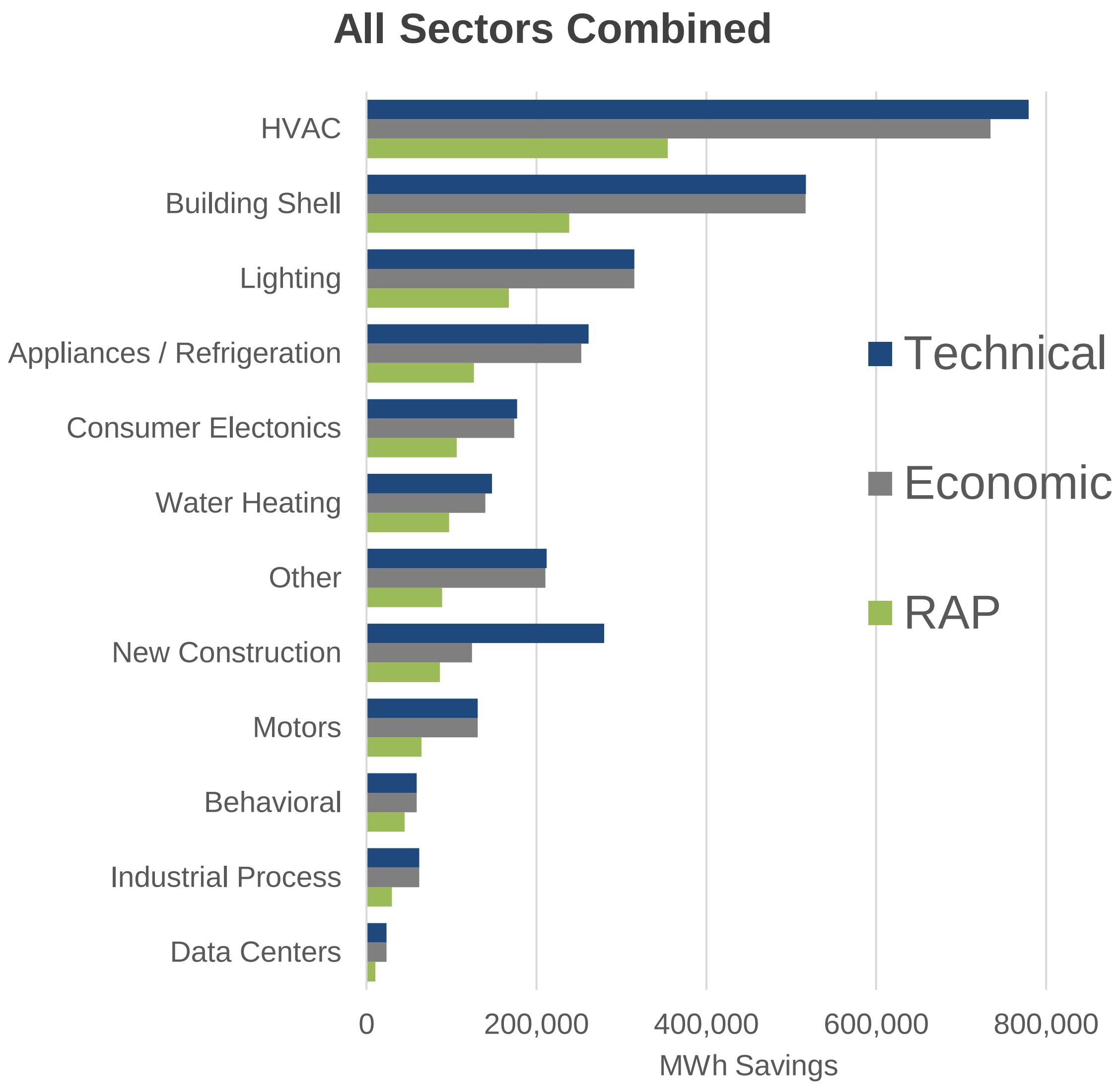
ENERGY EFFICIENCY POTENTIAL SUMMARY



Results in chart show ***cumulative annual*** savings

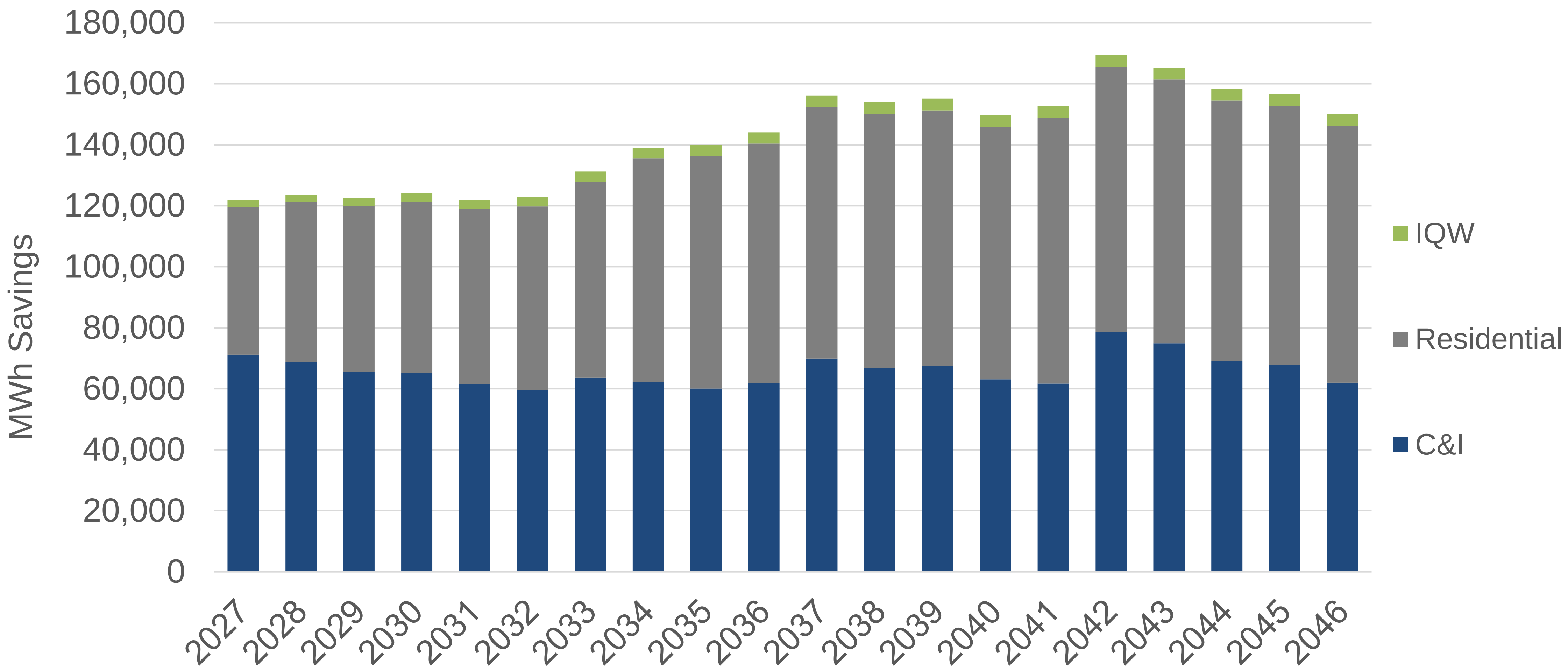
- *Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)*

20-YEAR CUMULATIVE ANNUAL POTENTIAL BY END-USE



- 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

- Curtailment agreements
- Connected thermostats
- Water heating load control
- Behavioral demand response
- Dynamic rates
- EV managed charging
- Behind-the-meter battery storage
- Data Centers

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

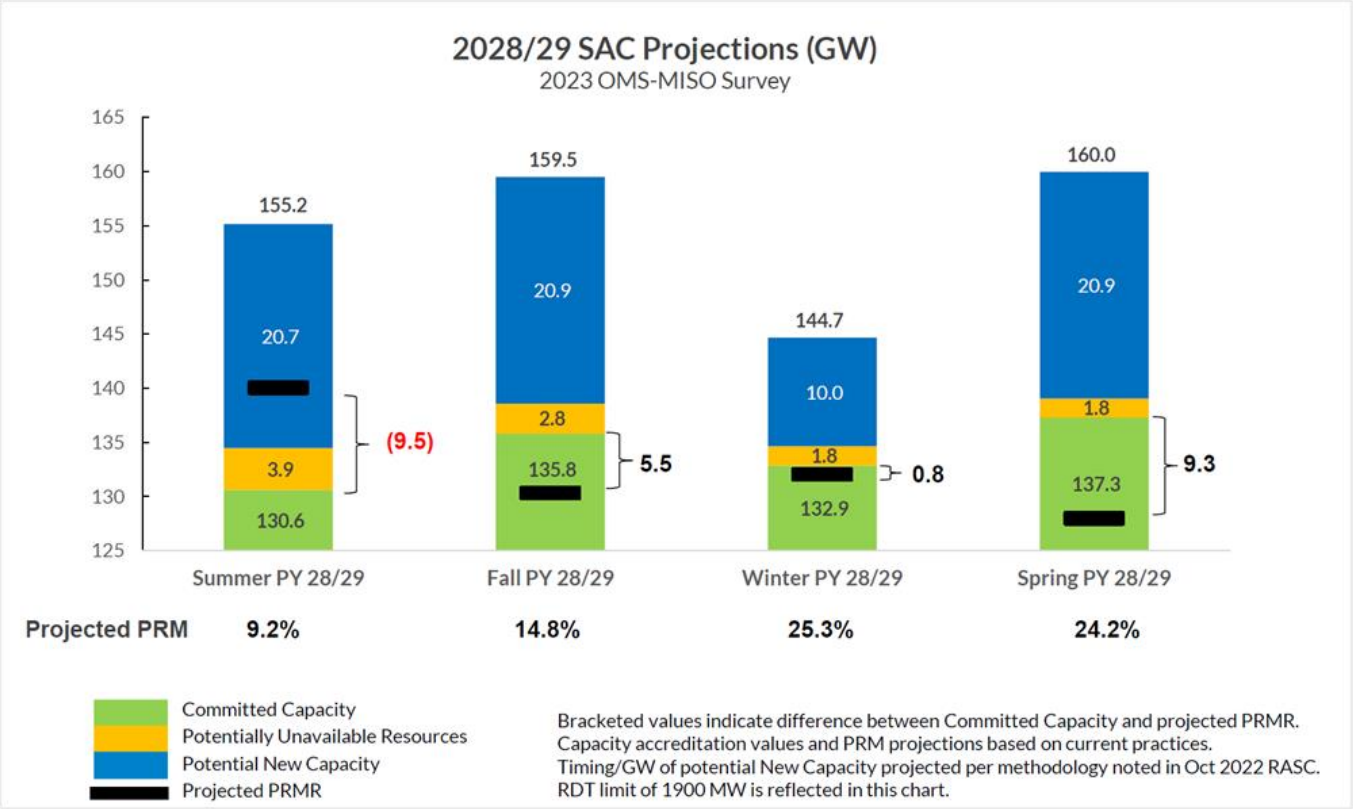
Historic DR Program Offerings

- **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

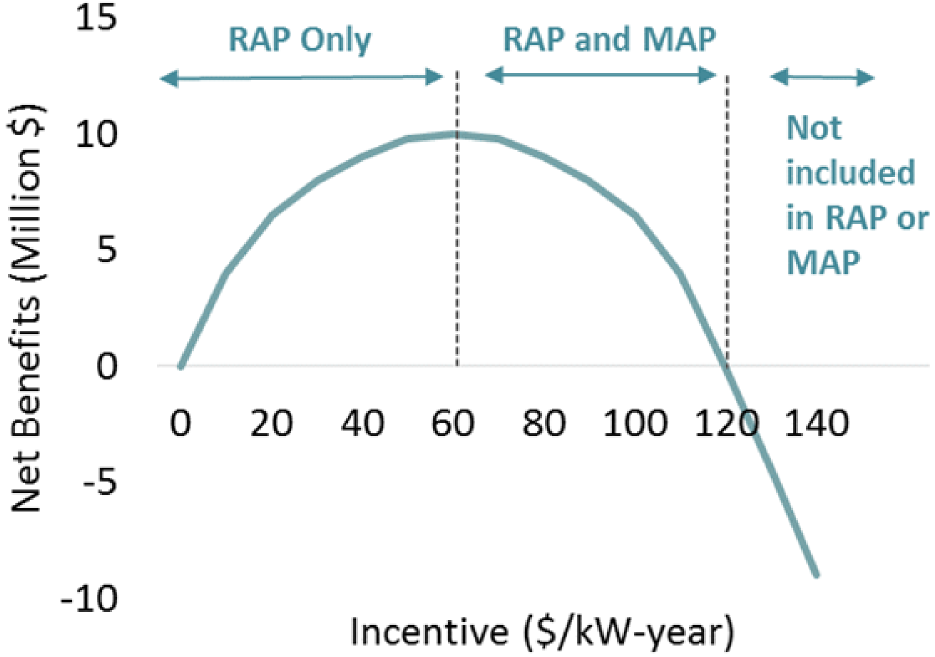
- **Unmanaged EV peak load contribution by season (meter-level)**

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)

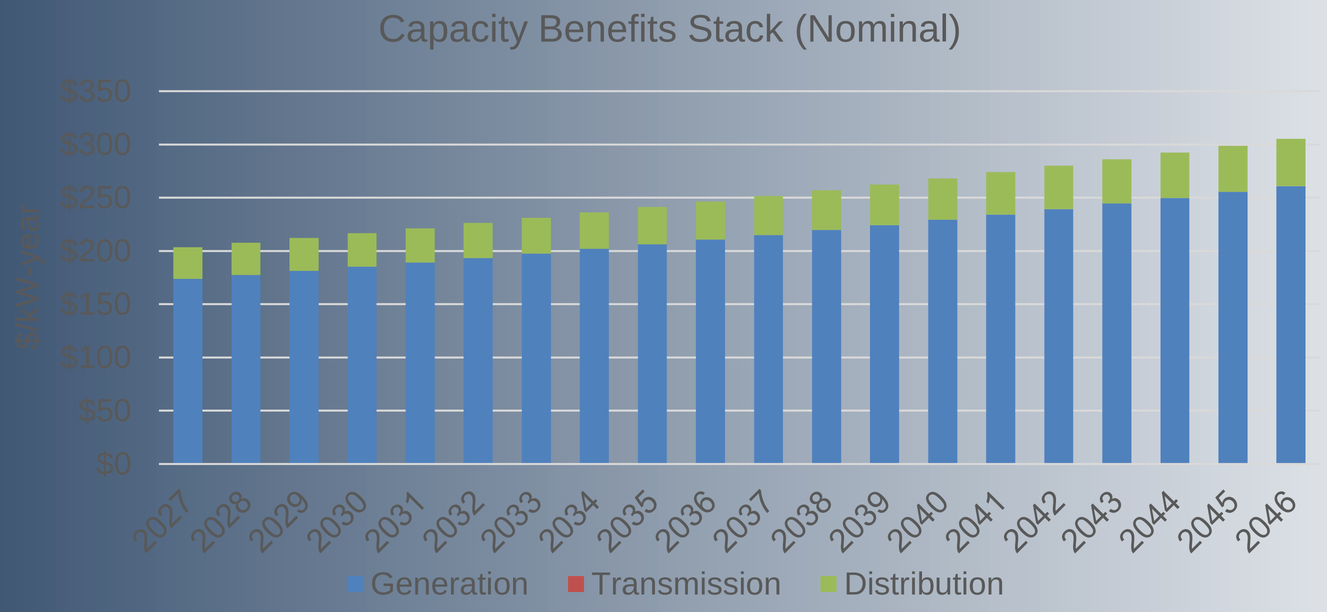


AVOIDED COST OF CAPACITY ASSUMPTIONS

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

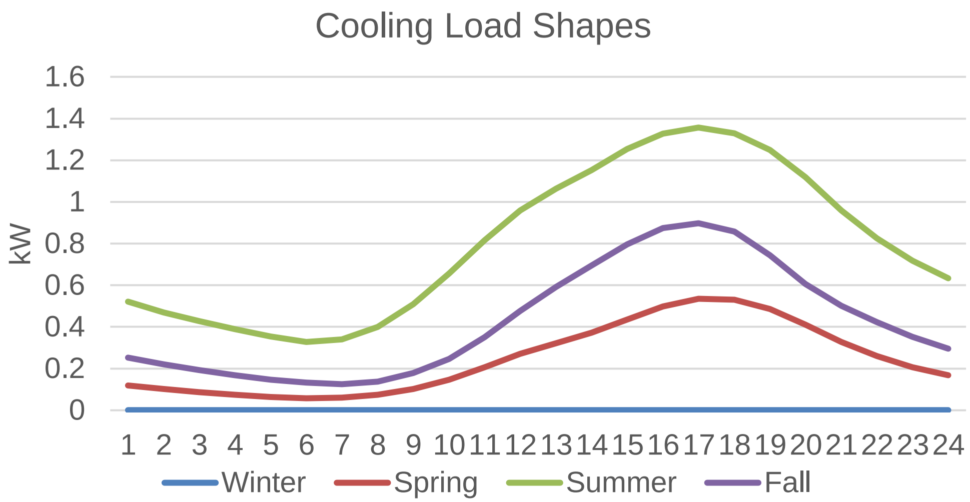
- **Same price elasticity of supply model and RAP/MAP perspective**
- **Elasticity values derived from PJM auction results and calibrated to MISO**
  - Compile seven years of cleared MW, seasonal peaks, and clearing prices
- **Number of calls per season aligned with MISO Seasonal Accredited Capacity rules for LMR**
  - Summer and Winter, n=5 calls
  - Spring and Fall, n=3 calls

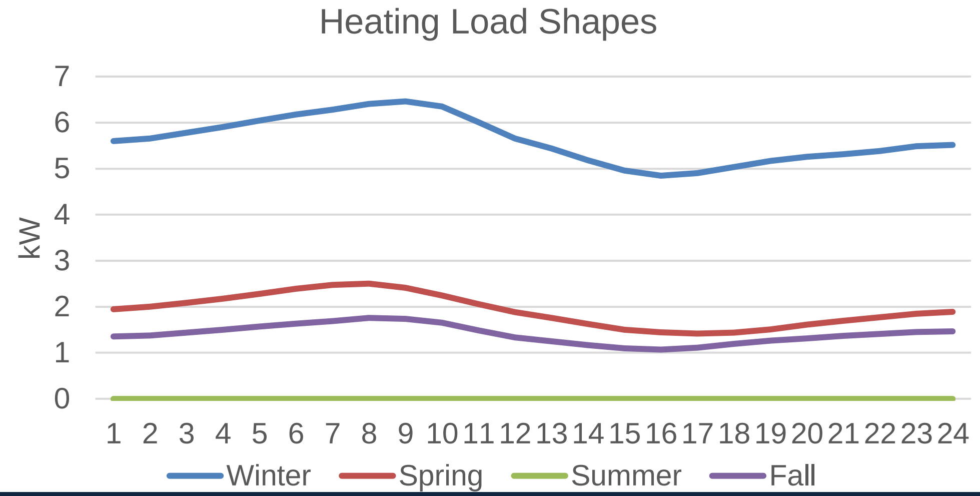
Summer	Winter	Spring	Fall
0.0011	0.0010	0.0011	0.0010

CONNECTED THERMOSTATS

MAP reflects a higher upfront and recurring incentive level, which leads to higher adoption

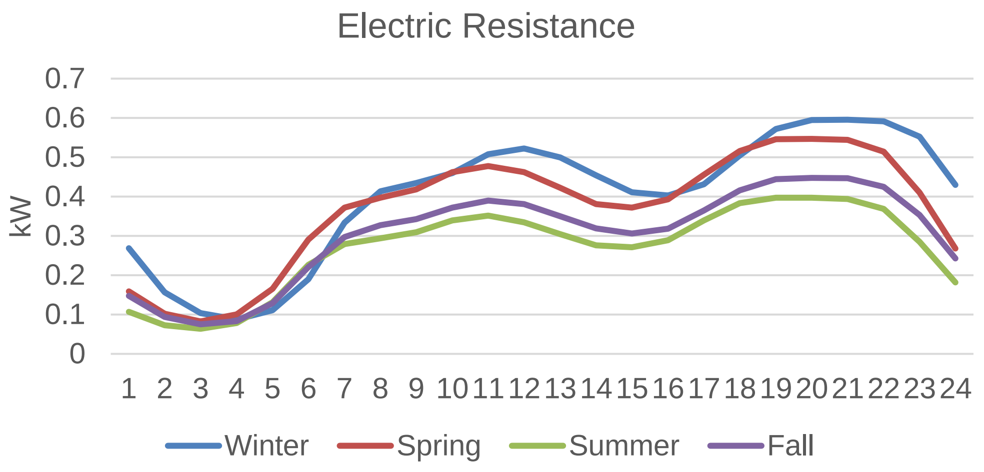
- **End use load shapes are based on the NREL ResStock load profiles for Indiana**
  - Average demand reduction of 50% over a four-hour event window
- **The number of homes with connected thermostats is aligned with EE MPS outputs**
  - Significant growth over the study horizon
- **Winter and spring 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**

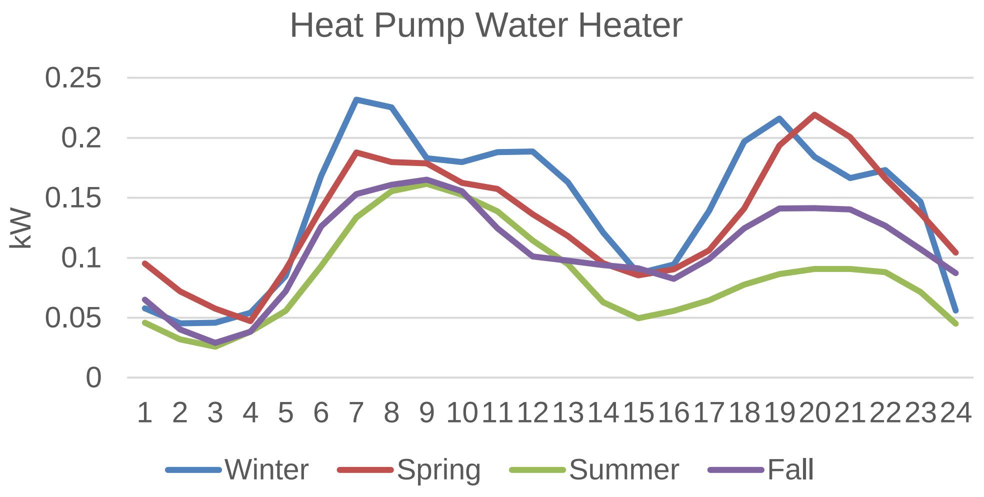




DOMESTIC WATER HEATING LOAD CONTROL

Includes a mix of traditional electric resistance units and heat pump water heaters (“HPWH”)



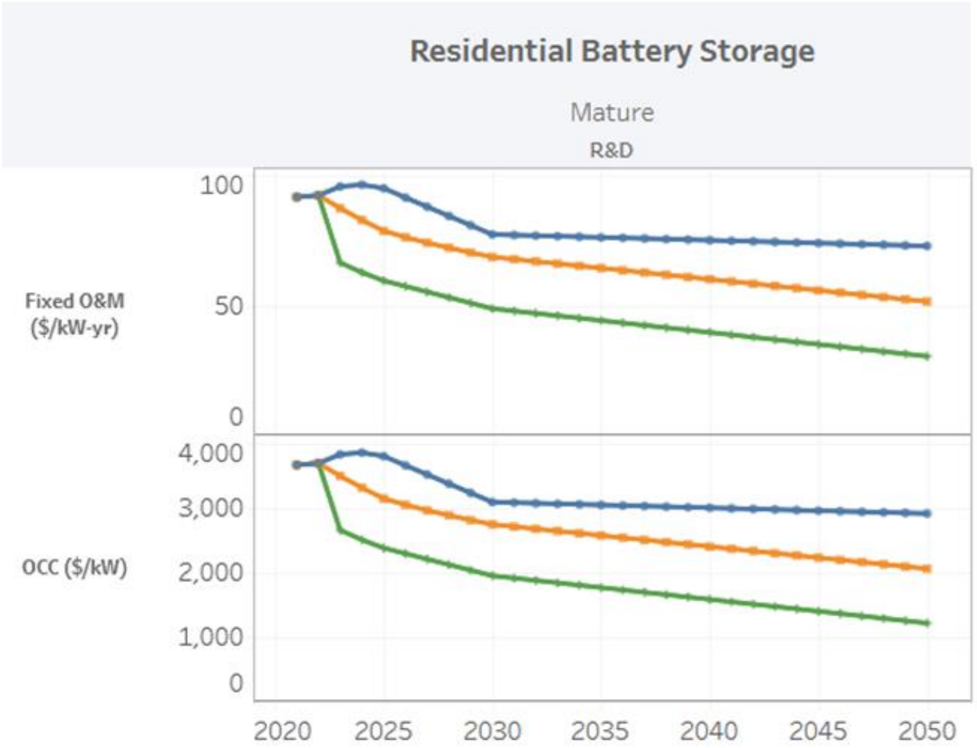


- **Electric fuel share is a key input**
- **This offering did not pass the UCT in the 2021 DR MPS**
  - Water heating load is much more coincident with winter peaks
- **The transition of equipment stock to HPWH will be driven by both programs and federal standards**
- **Integrated EE/DR offering for 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

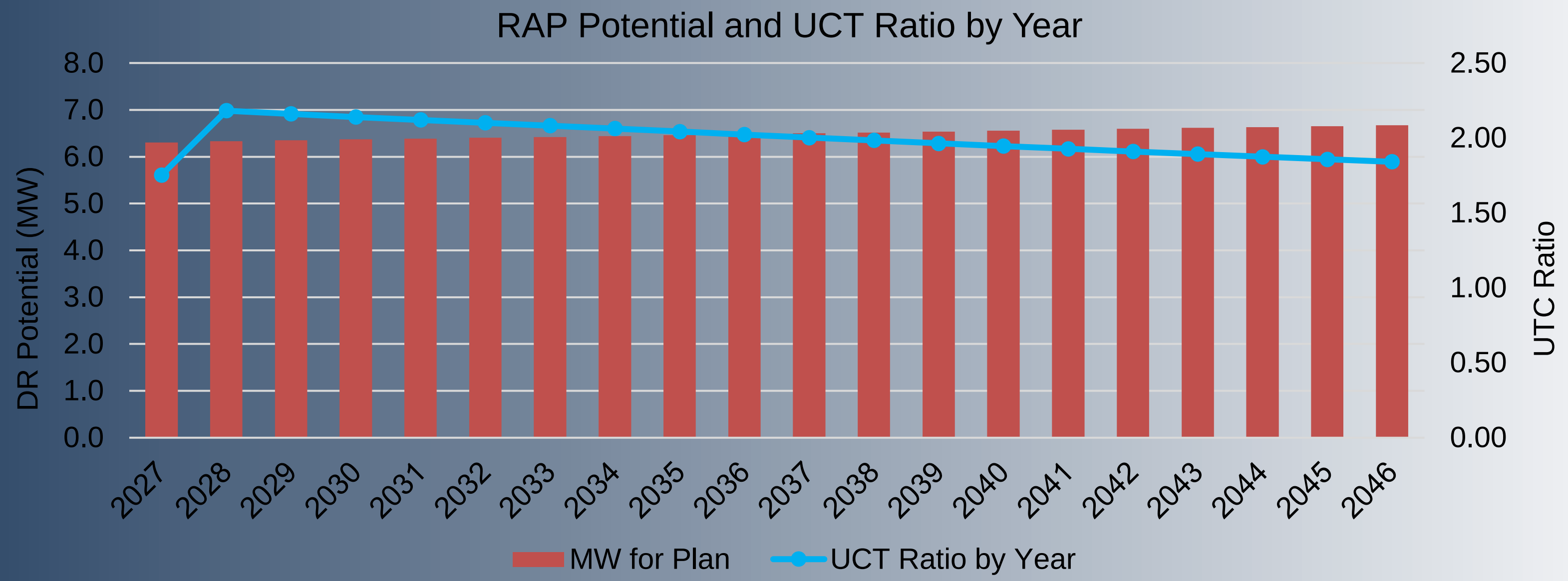
- **Program opportunity is tethered to the reference case forecast of solar adoption**
  - Reaches approximately 10,000 homes by the end of the study horizon
- **Bring Your Own Battery**
  - Further limited by share of homes with solar + storage
- **Intercept Design**
  - Program pays a portion of the 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



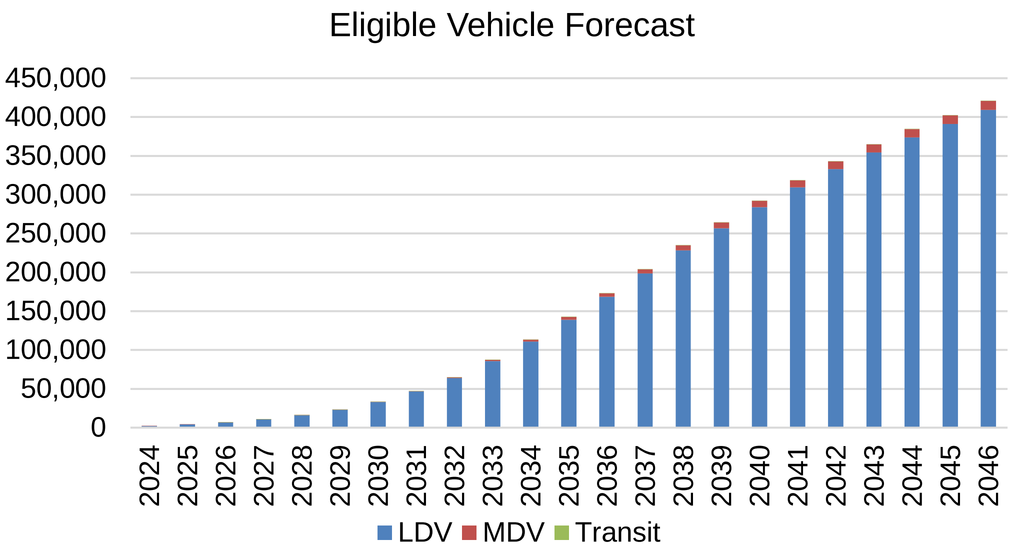
BEHAVIORAL DEMAND RESPONSE

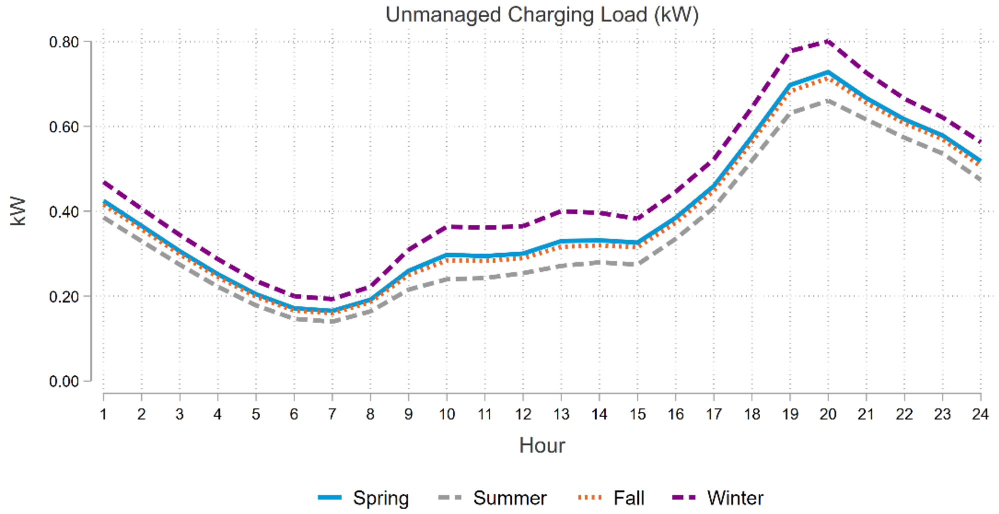
Like the Home Energy Report program offering within EE, but dispatchable and targeting conservation for specific hours

- **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





- **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**

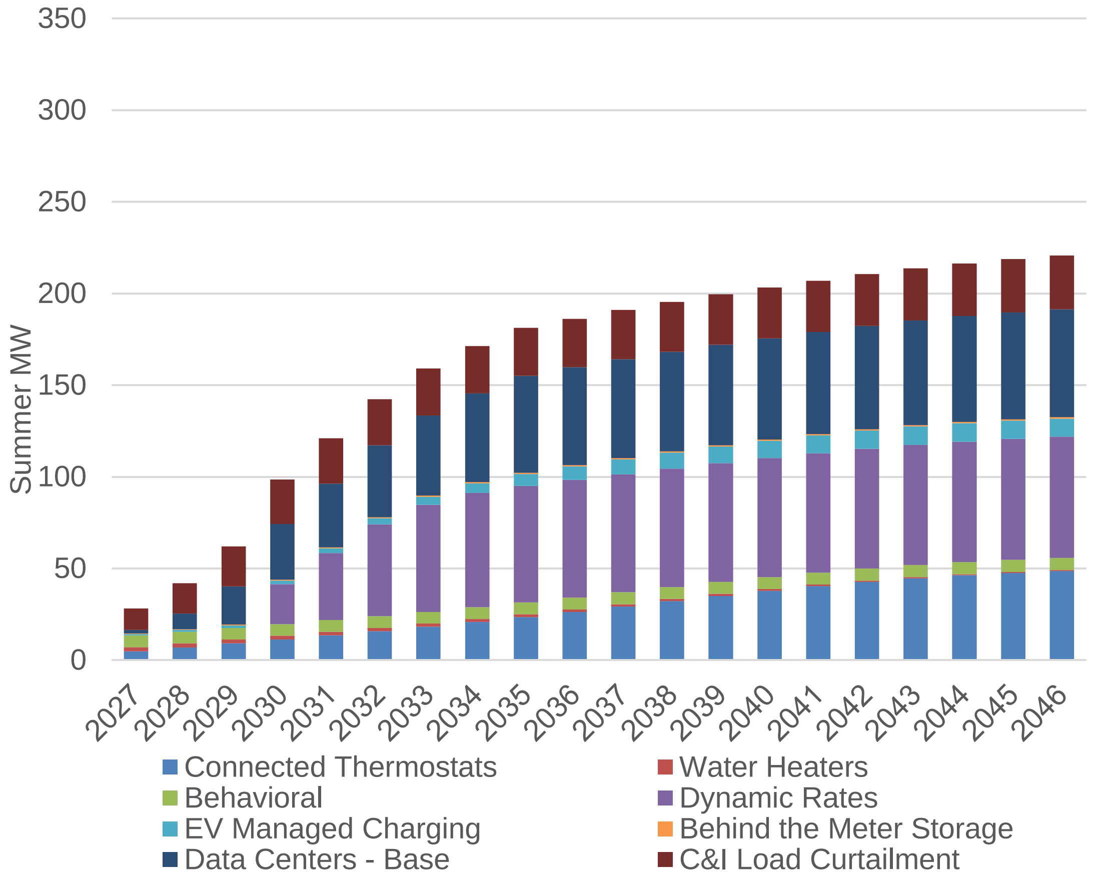
MAXIMUM ACHIEVABLE POTENTIAL (MAP)

System-level MW potential in 2046 by season and program type

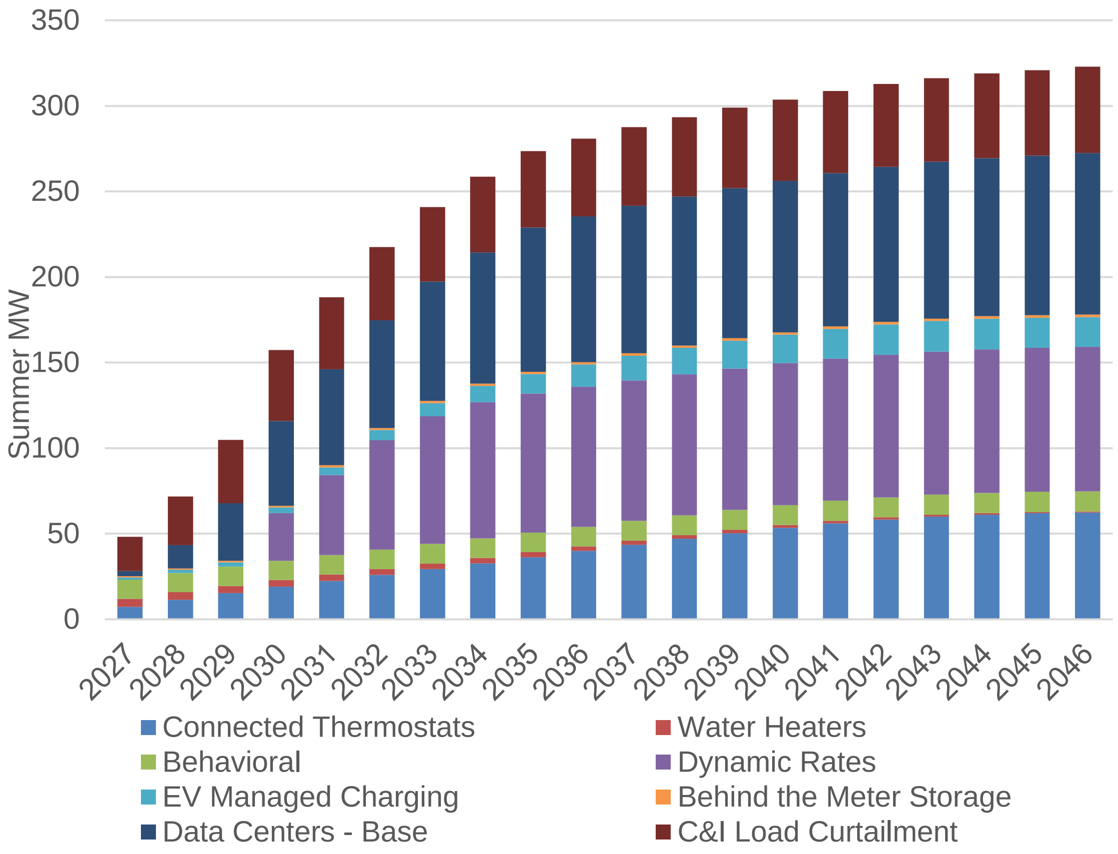
Program	UCT Result	Spring	Summer	Fall	Winter
Connected Thermostats	Fail	19.4	62.3	33.8	66.0
Water Heaters	Fail	1.0	0.5	0.8	1.2
Behavioral DR	Pass	9.9	11.9	11.9	9.9
Dynamic Rates	Pass	39.0	84.4	77.7	39.0
EV Managed Charging	Fail	18.9	17.5	18.2	21.0
BTM Storage	Fail	1.5	1.5	1.5	0.7
C&I Load Curtailment	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



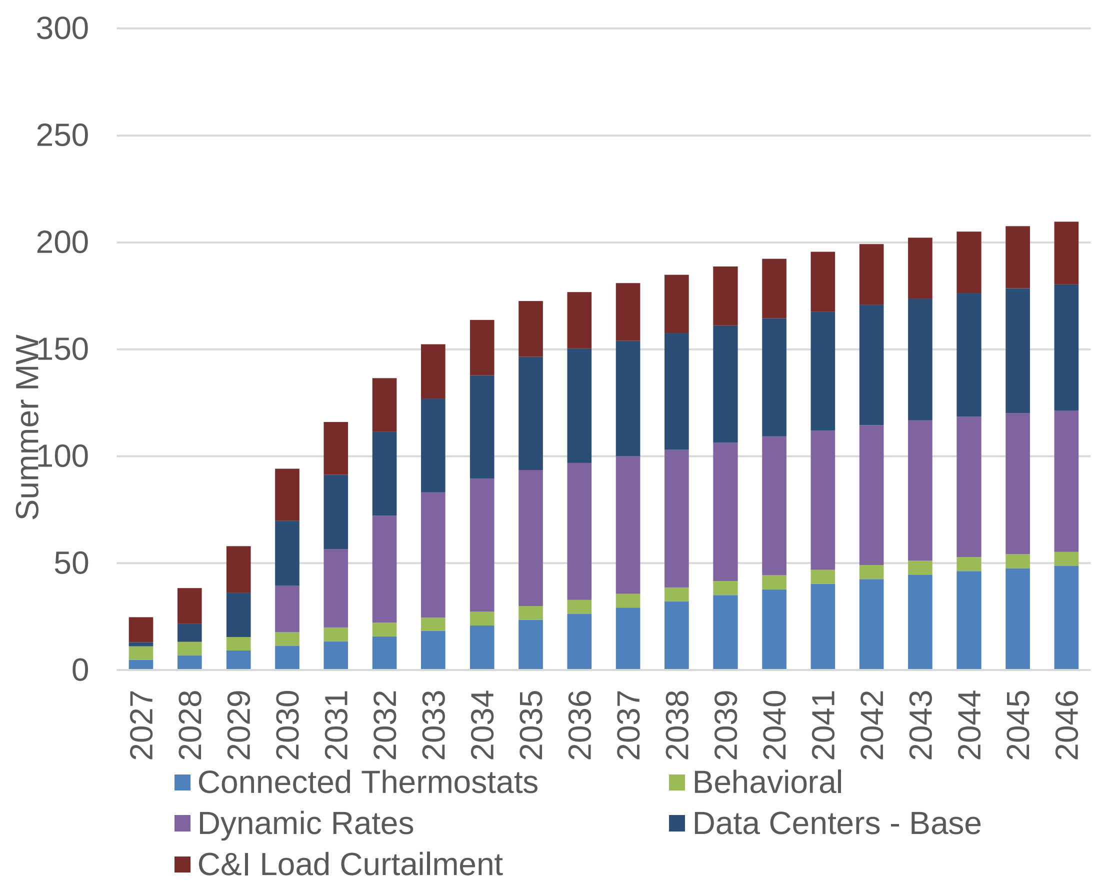
MAP

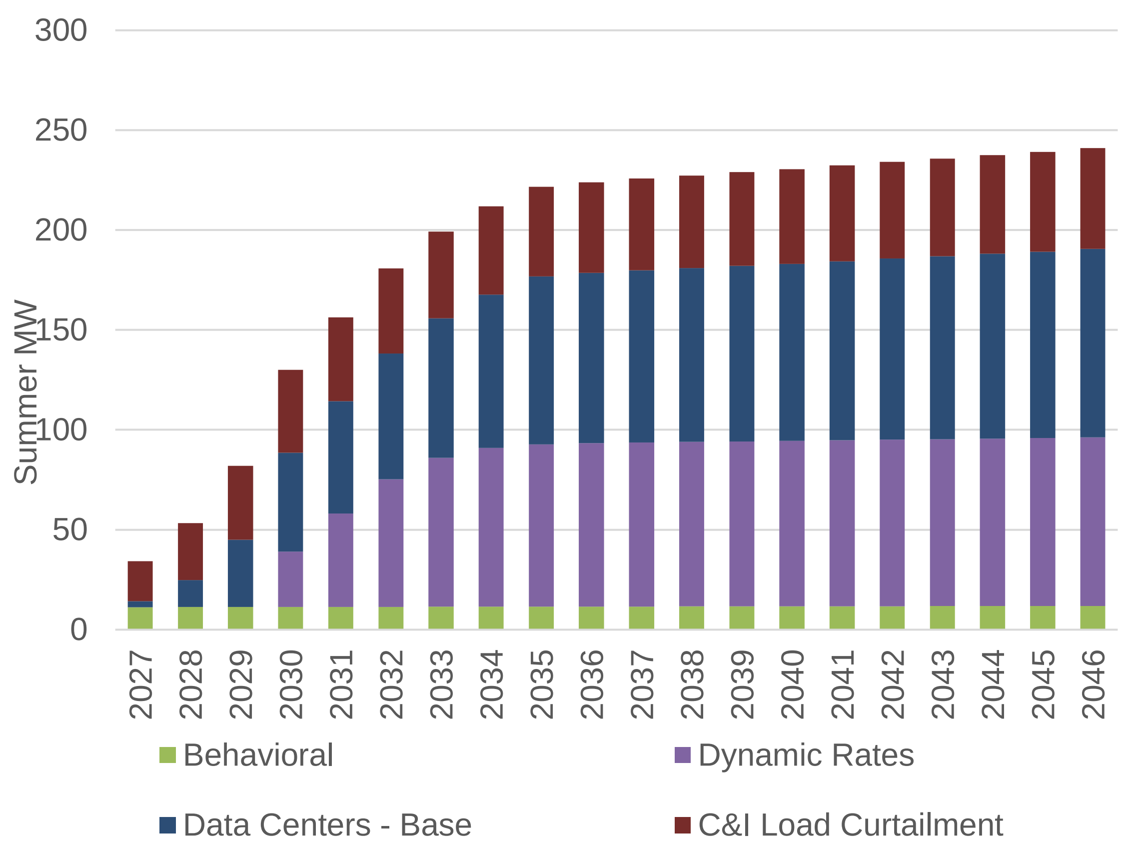


NIPSCO
A NiSource Company

RAP AND MAP BY YEAR AND PROGRAM – WITH UCT SCREENING

RAP	MAP

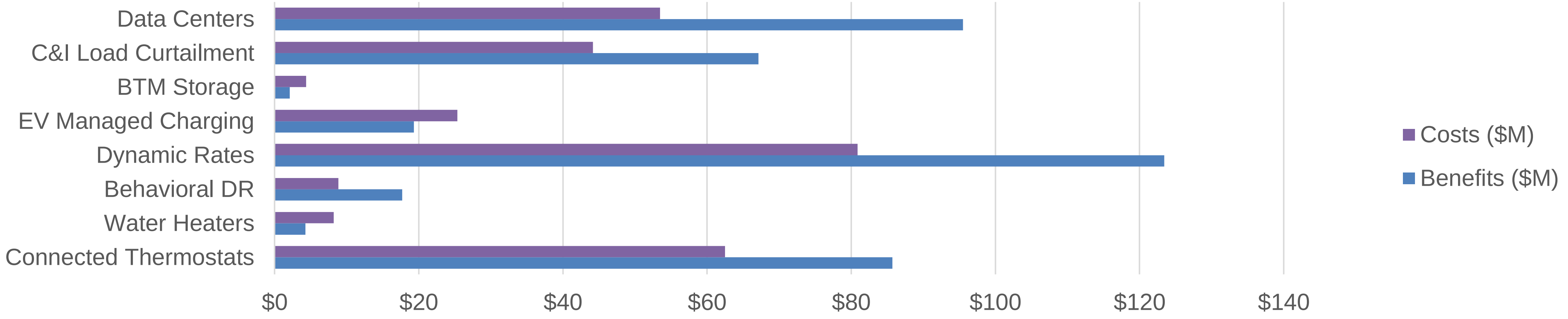




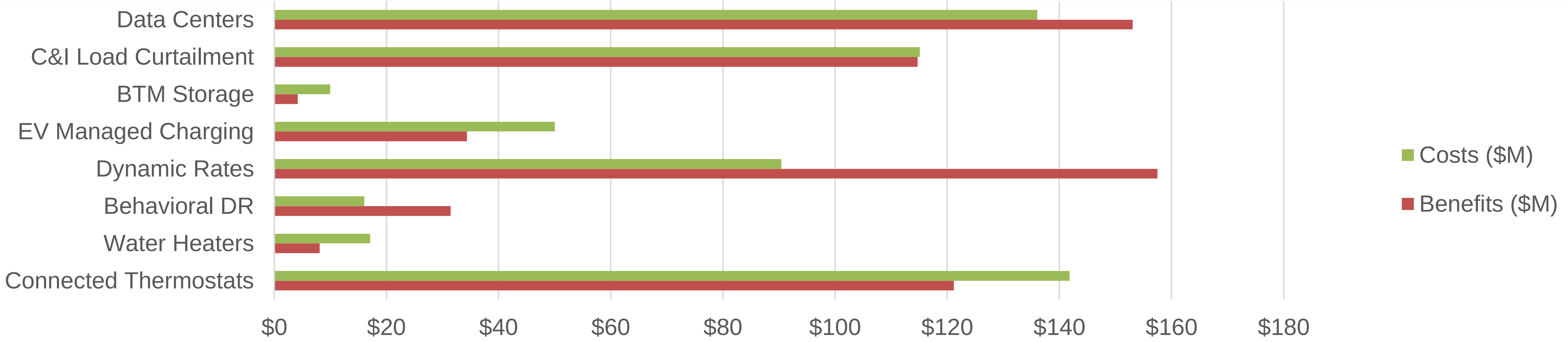
NPV COSTS AND BENEFITS BY PROGRAM

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

Step 1	Step 2	Step 3
Market Potential Study	Identify “bundles” based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

- **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

Step 1	Step 2	Step 3
Market Potential Study	Identify "bundles" based upon market segments and savings potential	Evaluate DSM bundles in IRP portfolio models

- 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

OUR VISION IS TO BE A

PREMIER, INNOVATIVE & TRUSTED

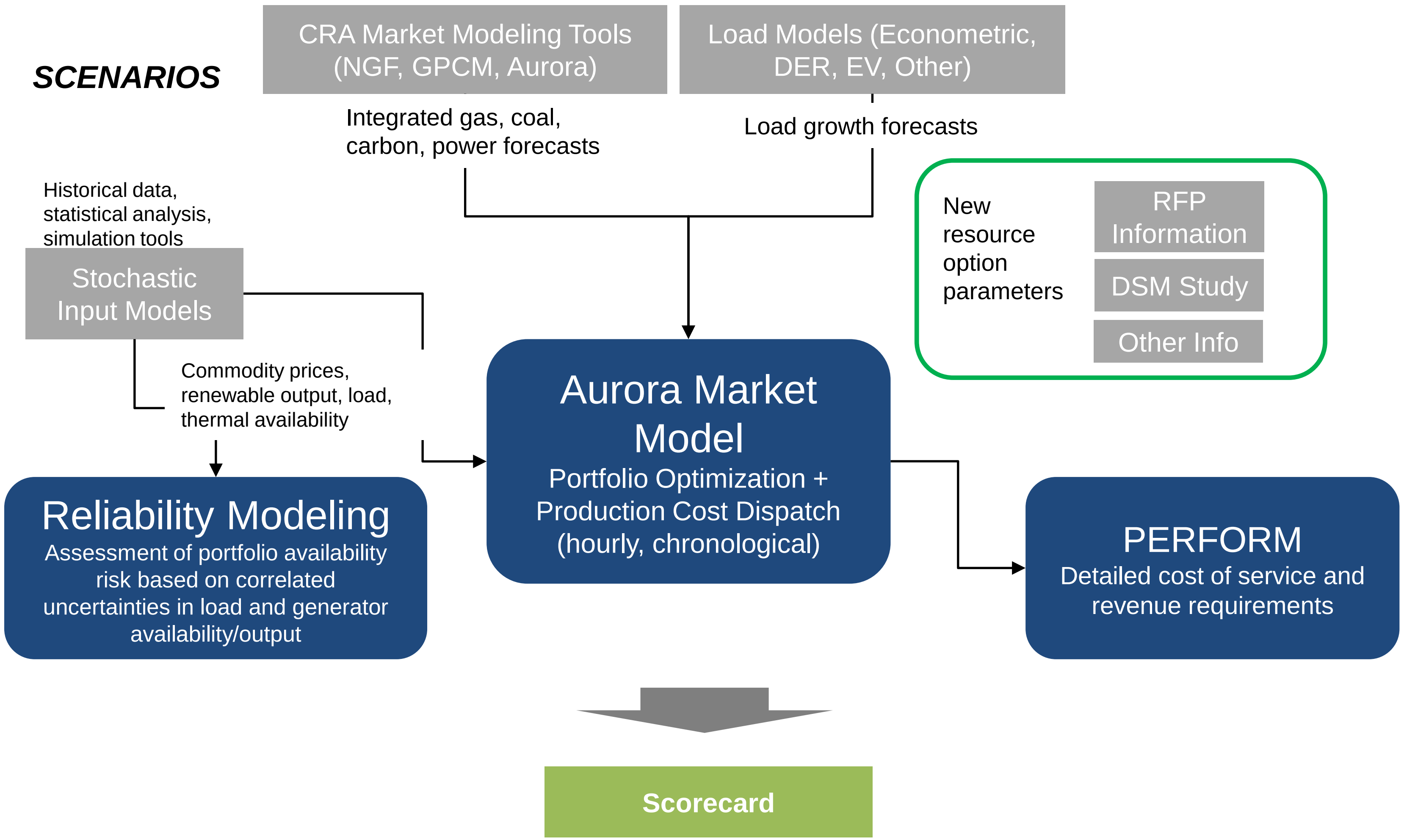
ENERGY PARTNER

INCORPORATING RFP RESULTS INTO THE IRP AND OVERVIEW OF PORTFOLIO MODELING INPUTS

Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA

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

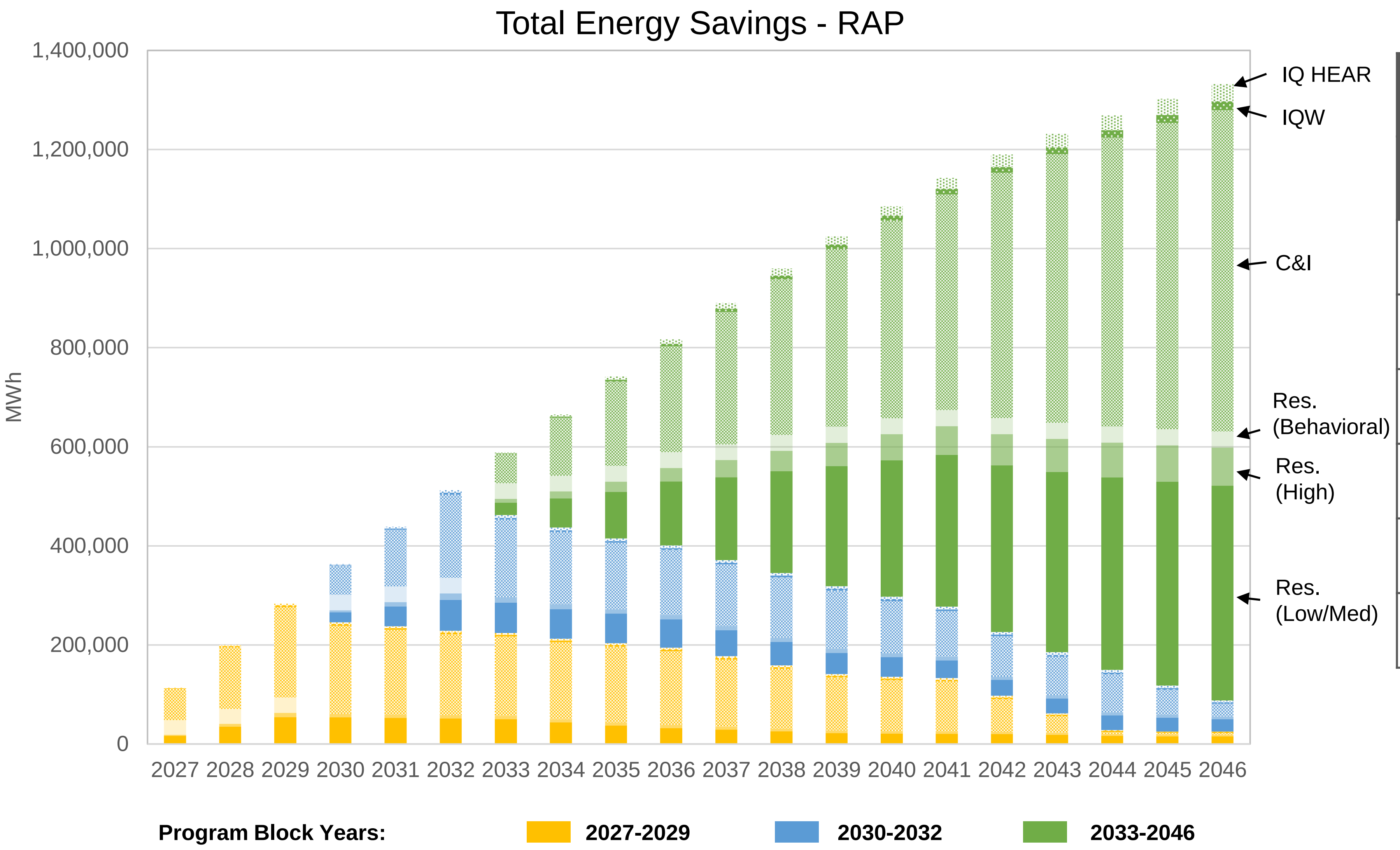
Resources offered in the RFP: Solar; Li-Ion Battery Storage; Long Duration Storage; Solar + Storage Hybrid; Near-Term Thermal Options; Near-Term Capacity Purchases (ZRCs)

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)			From NIPSCO and Third-Party Data Sources
H2 Retrofit (at Sugar Creek)			
Small modular reactor (SMR)			

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

DSM BUNDLES FOR IRP MODELING

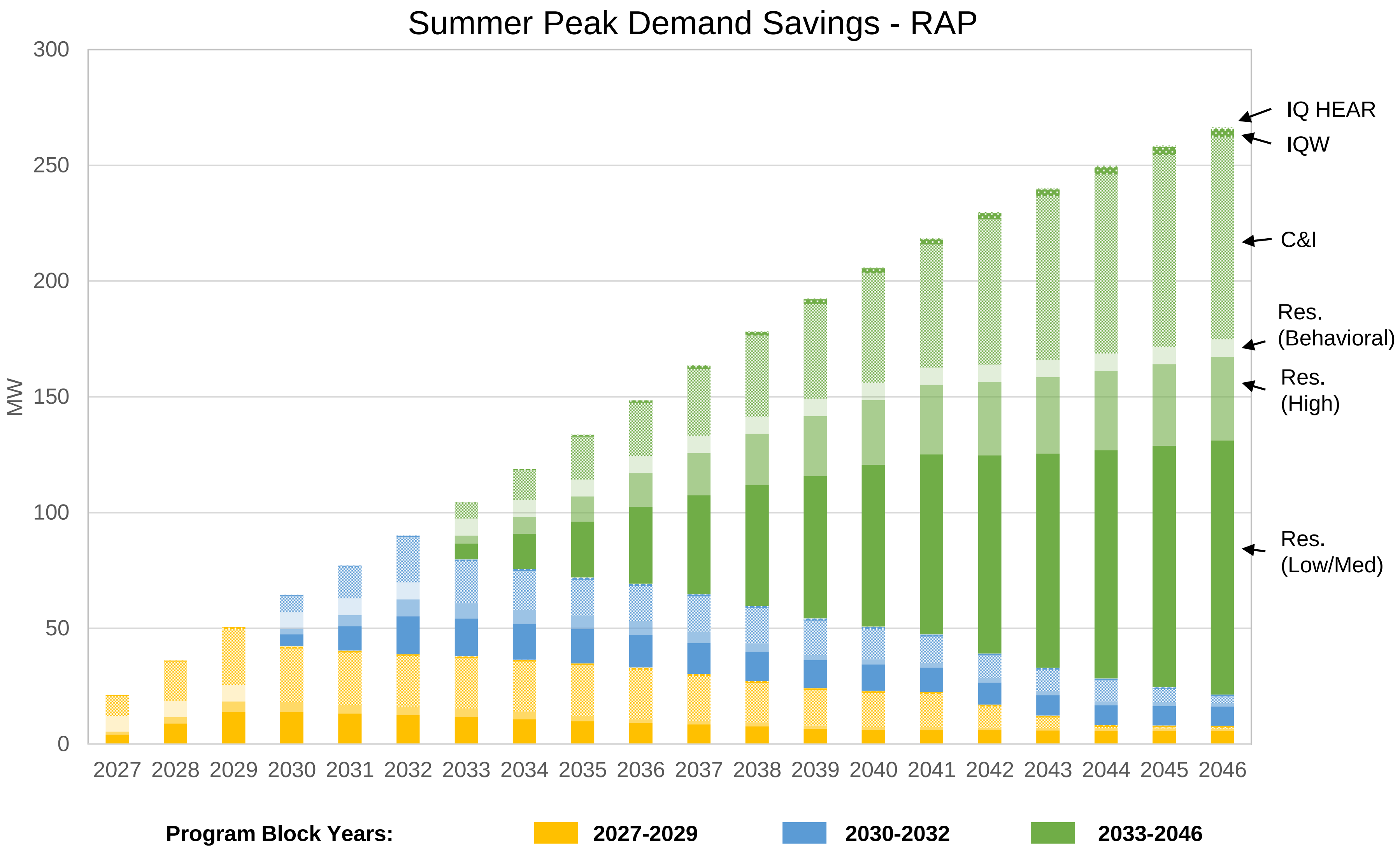
DSM ENERGY EFFICIENCY BUNDLES FOR IRP MODELING



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.*

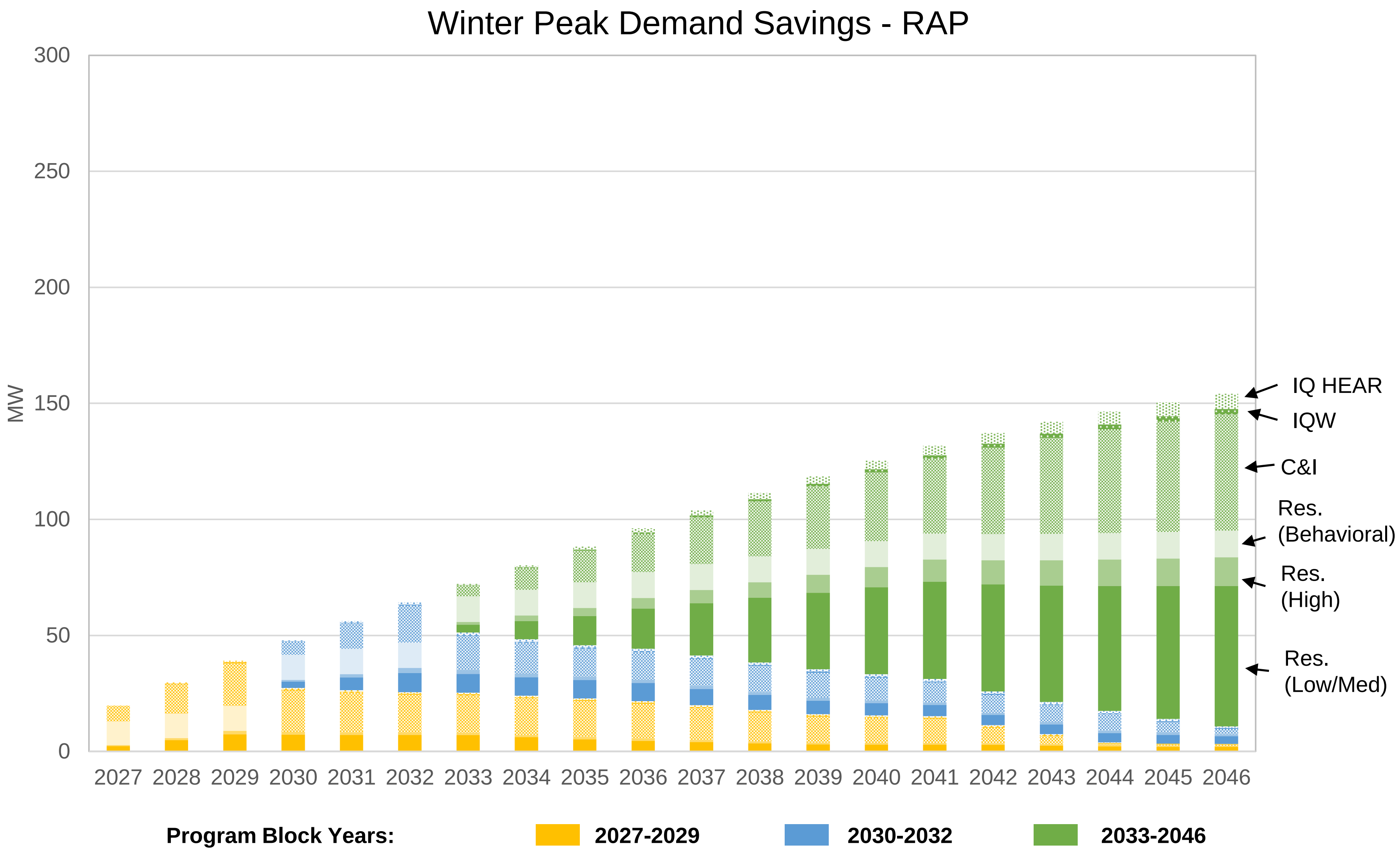
DSM ENERGY EFFICIENCY BUNDLES FOR IRP MODELING



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.*

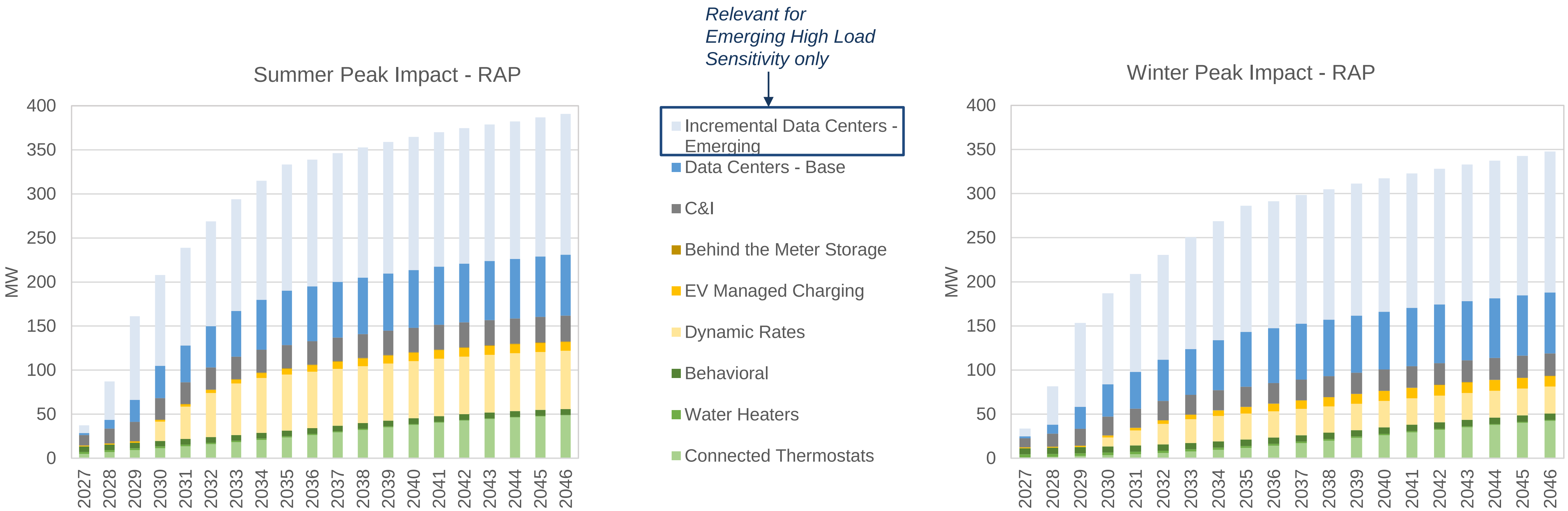
DSM ENERGY EFFICIENCY BUNDLES FOR IRP MODELING



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

OUR VISION IS TO BE A

PREMIER, INNOVATIVE & TRUSTED

ENERGY PARTNER

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

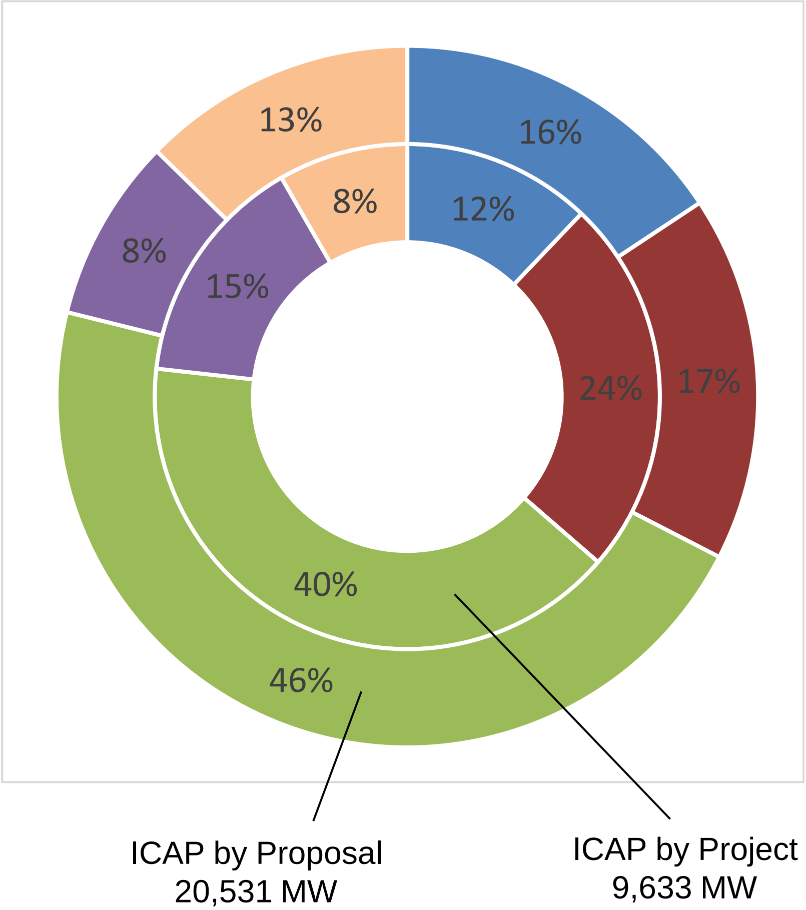
- *On May 1, 2024, NIPSCO issued a series of Requests for Proposal (RFP) processes designed to identify resources positioned to support the Company's near and long-term resource requirements*
- *As has been done in the past, asset cost, performance and resource availability by technology derived from 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

NIPSCO
A NiSource Company

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

2024 REQUESTS FOR PROPOSALS (RFP) TRANCHE REVIEW – APPLICATION TO IRP PORTFOLIO MODELING

IRP ANALYSIS: TRANCHE DEVELOPMENT AND ASSESSMENT

A three-step process to incorporate RFP data and run the IRP models

1 Tranche Development

Screen Bids

- High-level bid review by RFP team to confirm compliance w/ requirements and overall viability

Aggregate Bids into Groupings by Type

- Bids are organized by:
  - Technology
  - Asset sale or PPA
  - Commitment duration
  - Costs
  - Oper. characteristics
- Aggregated cost and operational information compiled in Aurora

2 Portfolio Development

Define Portfolios

- Based on portfolio concepts, capacity need, and other constraints, identify which tranches (or portions of tranches) are selected for the portfolio through Aurora optimization

Confirm Reasonableness

- Confirm that optimization model is selecting feasible block sizes and options based on resource-specific data

3 Portfolio Evaluation

Analyze Portfolios

- Evaluate each portfolio across range of scenarios and stochastic inputs
- Report portfolio costs and other metrics to support scorecard development

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.

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

GENERIC RESOURCE OPTIONS

Abe Lang, Manager Strategy & Risk, NiSource

Pat Augustine, Vice President, CRA

NEW RESOURCE OPTIONS

<table>
<tr><th></th><th>Resource Option</th><th>Available through 2029</th><th>Available 2030-2034</th><th>Available 2035+</th></tr>
<tr><td></td><td>Demand side management (EE and DR) programs</td><td colspan="3">From MPS and DSM Study</td></tr>
<tr><td rowspan="6">Resources offered in the RFP</td><td>Solar</td><td rowspan="6">From RFP Data</td><td colspan="2" rowspan="4">Benchmarked to RFP Data plus Third-Party Data Sources for the Long-Term</td></tr>
<tr><td>Li-Ion Battery Storage</td></tr>
<tr><td>Long Duration Storage</td></tr>
<tr><td>Solar + Storage Hybrid</td></tr>
<tr><td>Near-Term Thermal Options</td><td colspan="2" rowspan="2"></td></tr>
<tr><td>Near-Term Capacity Purchases (ZRCs)</td></tr>
<tr><td></td><td>New Natural Gas Peaking Build (H2-enabled up to 30%)</td><td colspan="3" rowspan="2">From NIPSCO Internal Engineering Analysis and Project Experience</td></tr>
<tr><td></td><td>New Gas CC Build (H2- enabled up to 30%)</td></tr>
<tr><td></td><td>Wind</td><td rowspan="6"></td><td colspan="2">Benchmarked to NIPSCO Project Experience</td></tr>
<tr><td></td><td>New Gas CC with CCS</td><td colspan="2" rowspan="2">From NIPSCO and Third-Party Data Sources</td></tr>
<tr><td></td><td>New Gas with H2</td></tr>
<tr><td></td><td>CCS Retrofit (at Sugar Creek)</td><td rowspan="3"></td><td rowspan="3">From NIPSCO and Third-Party Data Sources</td></tr>
<tr><td></td><td>H2 Retrofit (at Sugar Creek)</td></tr>
<tr><td></td><td>Small modular reactor (SMR)</td></tr>
</table>

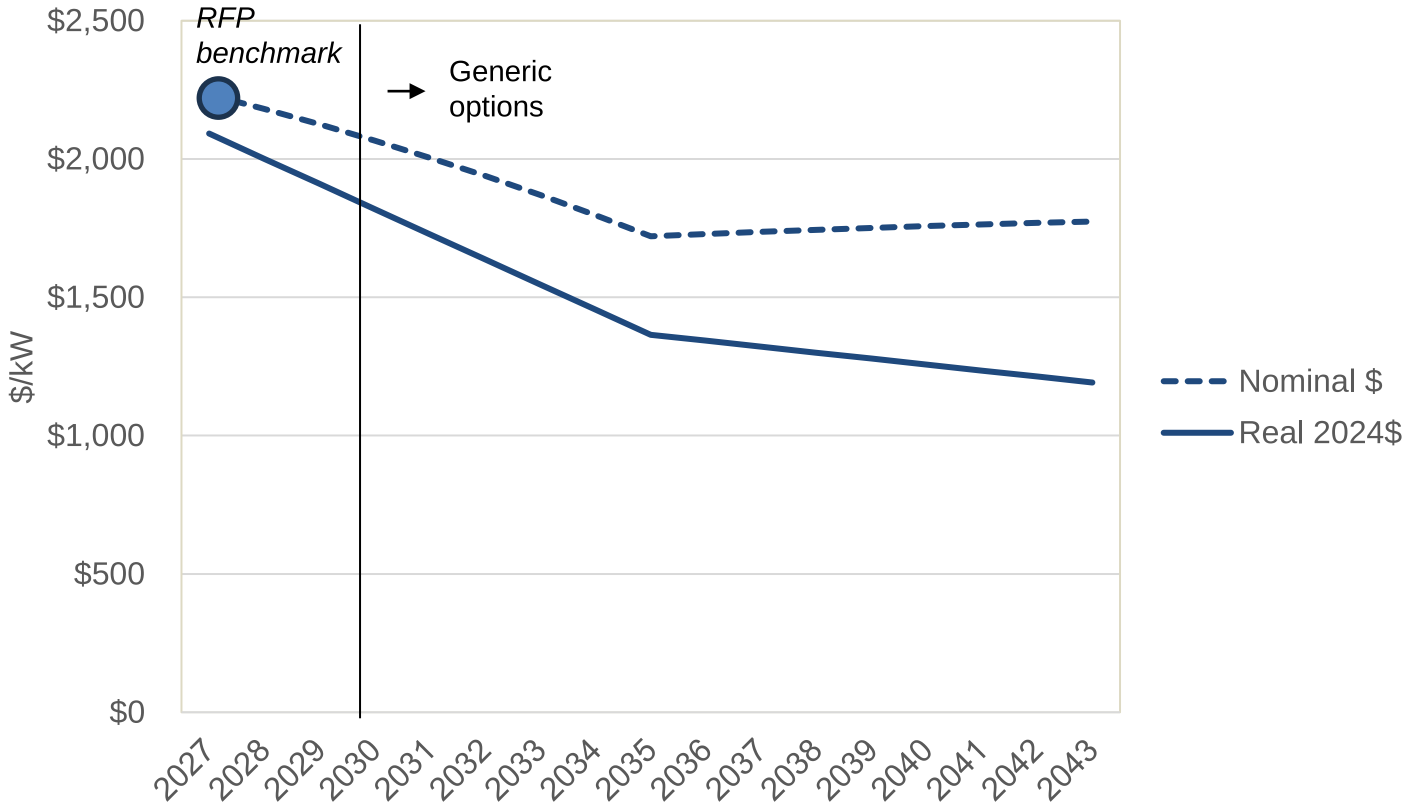
KEY NEW RESOURCE COST BENCHMARKS FOR LONG-TERM OPTIONS

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

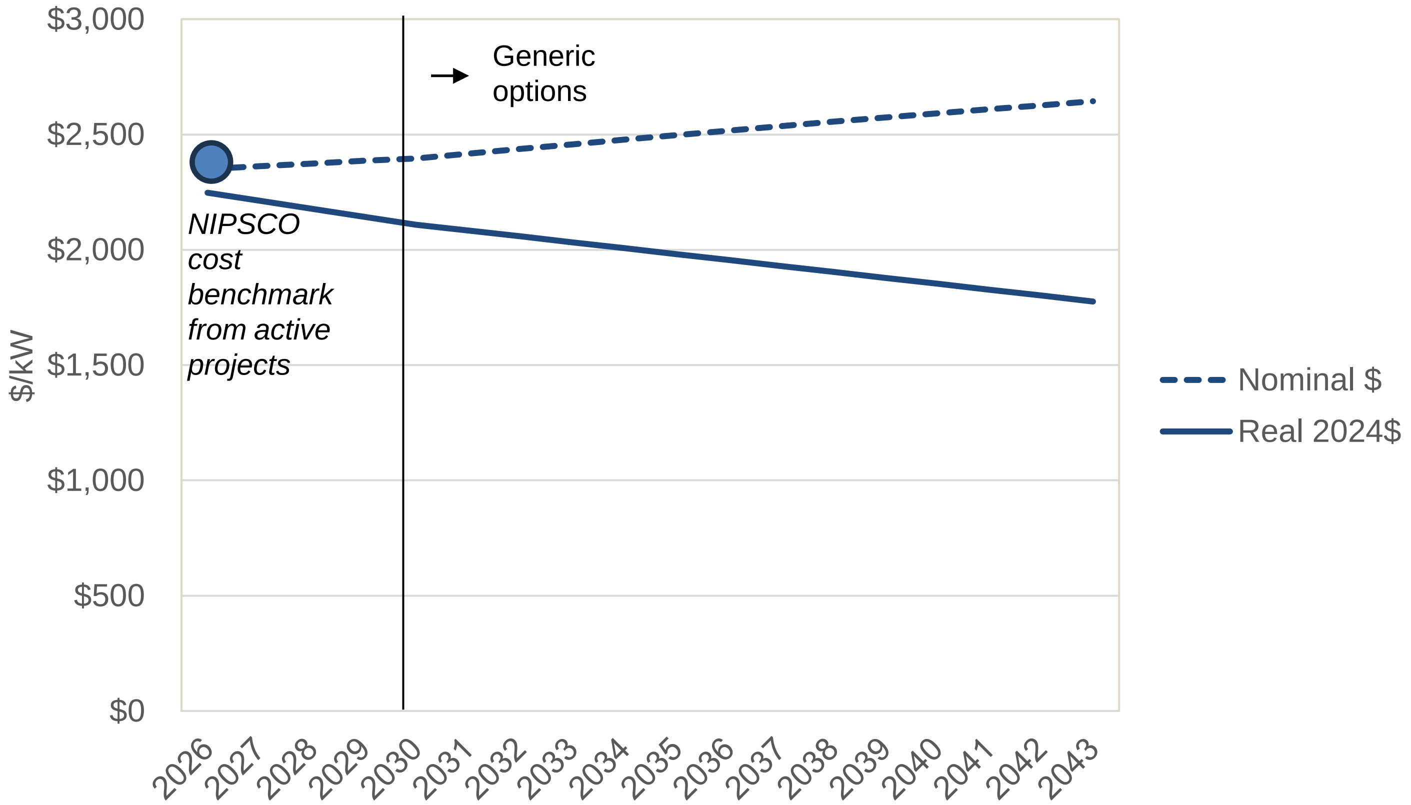


Category	Assumption
Fixed O&M (2024$/kW-yr)*	$22
Capacity Factor	25%
Tax Credit Eligibility Assumption	40% ITC

**NREL ATB assumptions for 2027 benchmark year*

LONG-TERM WIND RESOURCE INPUTS

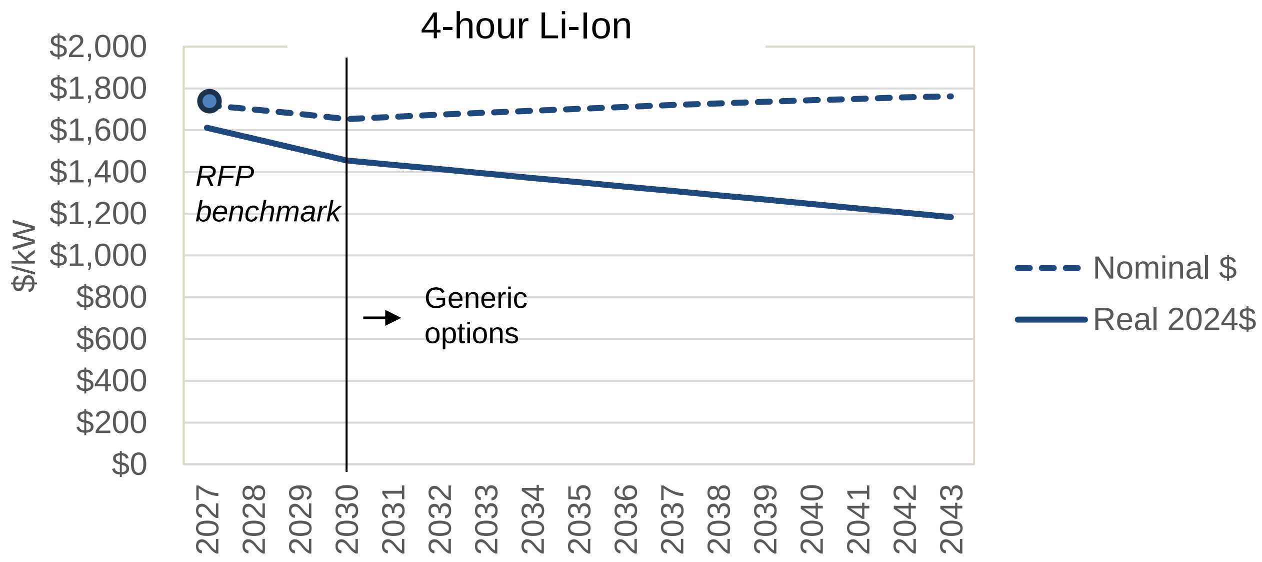
The NREL "moderate" cost curve is applied from NIPSCO's internal benchmarks from active projects.

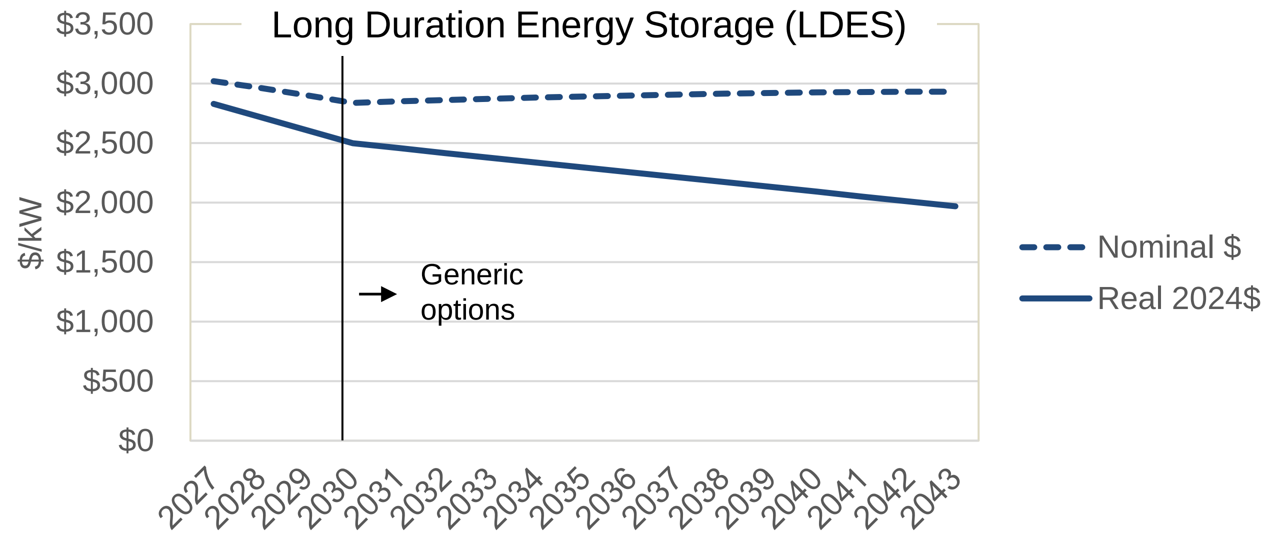


Category	Assumption
Fixed O&M (2024$/kW-yr)*	$34
Capacity Factor	39%
Tax Credit Eligibility Assumption	PTC

**NREL ATB assumptions for 2026 benchmark year*

LONG-TERM STORAGE RESOURCE INPUTS



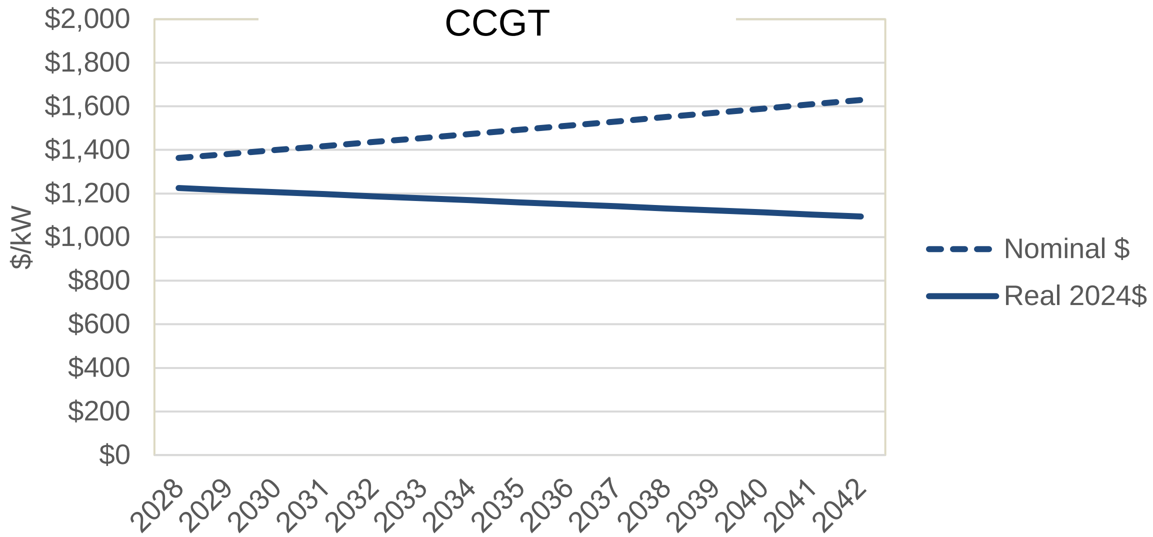


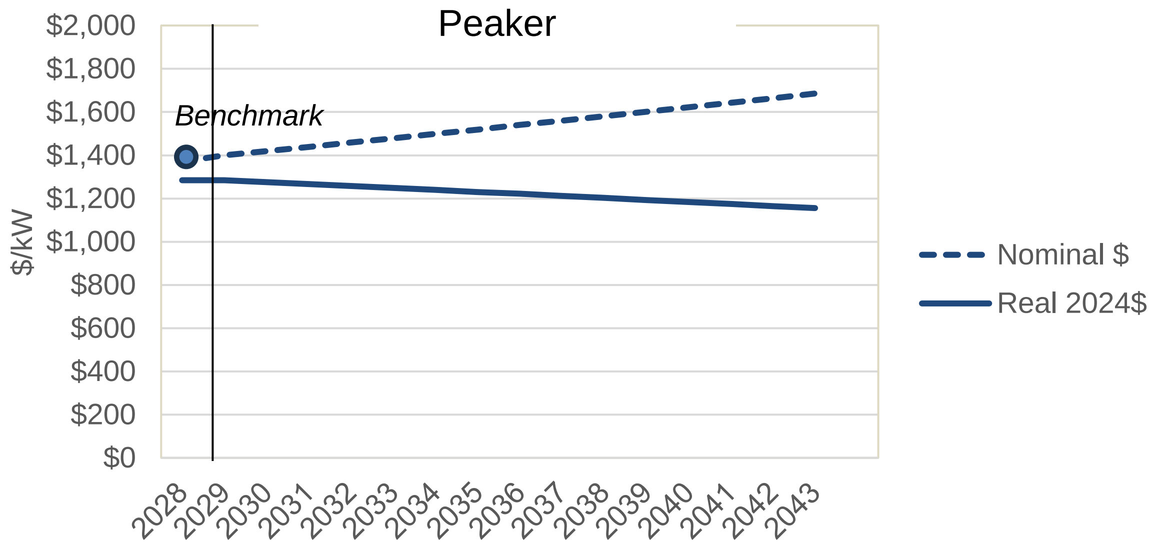
- NIPSCO benchmarked costs based on RFP results and public studies to identify 4-hour and a representative long duration energy storage technology.
- NREL "moderate" cost curves are applied from the RFP benchmark points

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





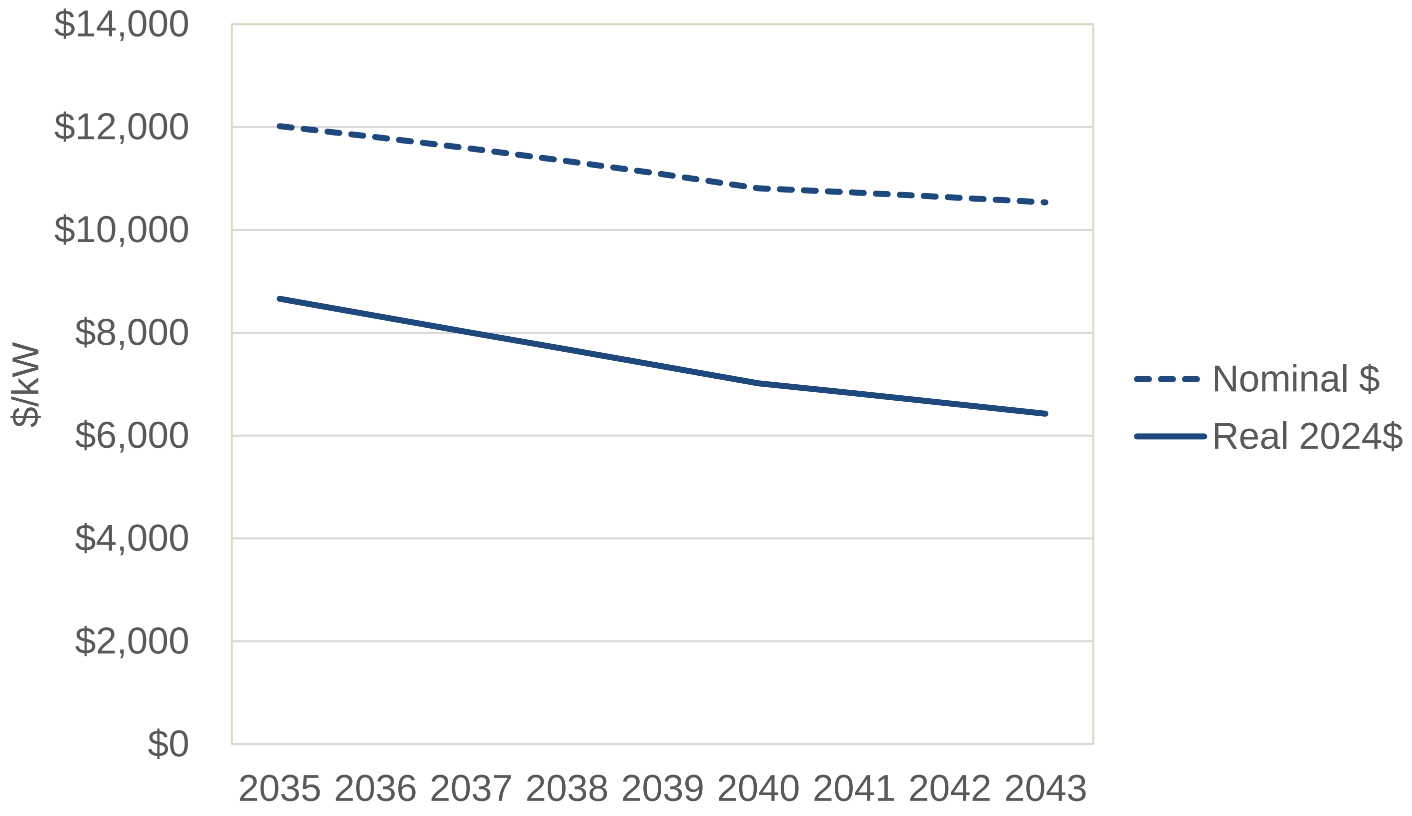
- New natural gas plant cost information based on NIPSCO internal engineering studies and ongoing gas peaker experience
- NREL cost curves applied over time

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

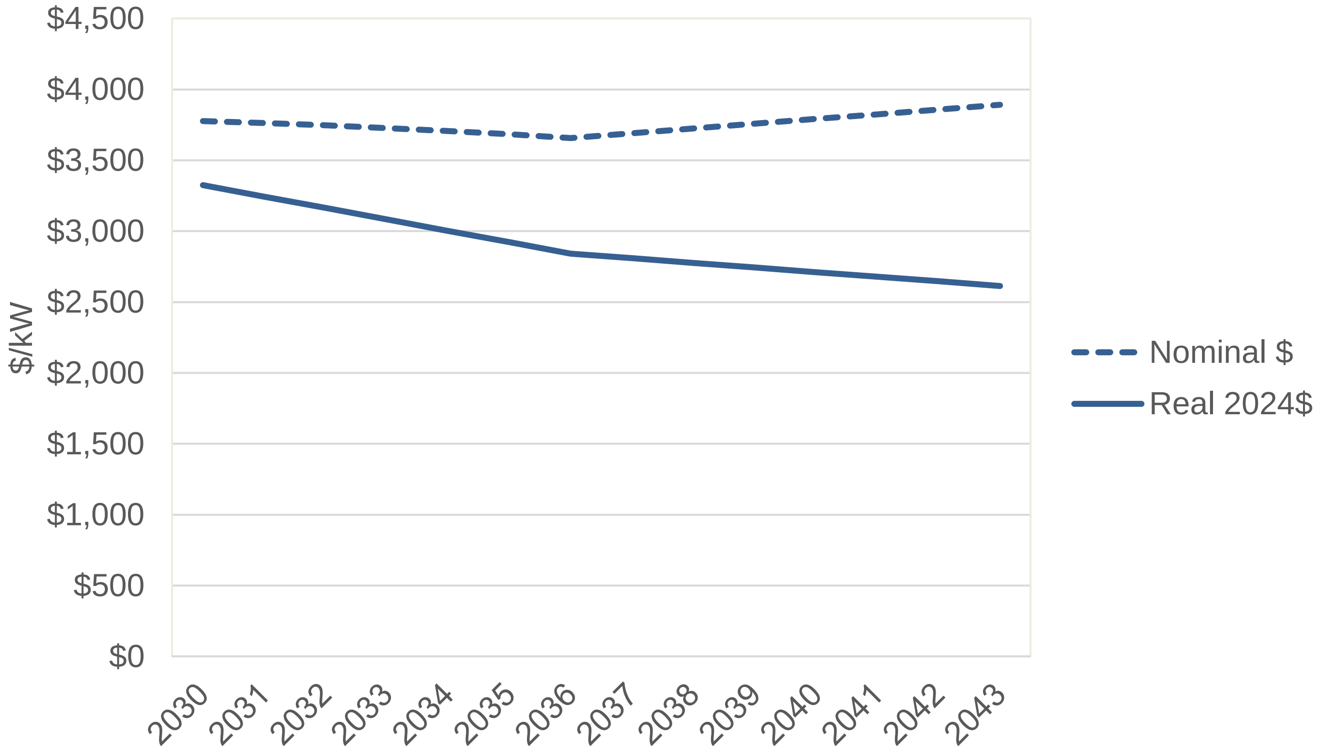


Category	Assumption
Fixed O&M (2024$/kW-yr)*	$150
First Available Year	2035
Tax Credit Eligibility Assumption	30% ITC

**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**

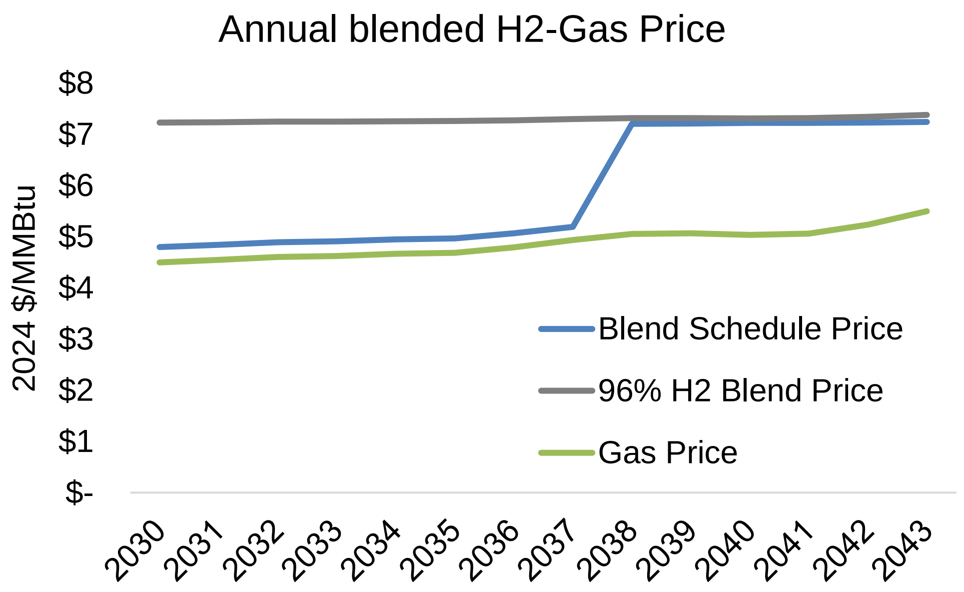


Category	Assumption
Fixed O&M (2024$/kW-yr)[1]	$82.02
CO2 Transportation Cost (2022$/ton)[2]	$7.50
CO2 Sequestration Cost (2022$/ton)[2]	$4.86
First Available Year	Between 2030 - 2035
Tax Credit Eligibility Assumption	45Q credit ($85/metric ton)

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

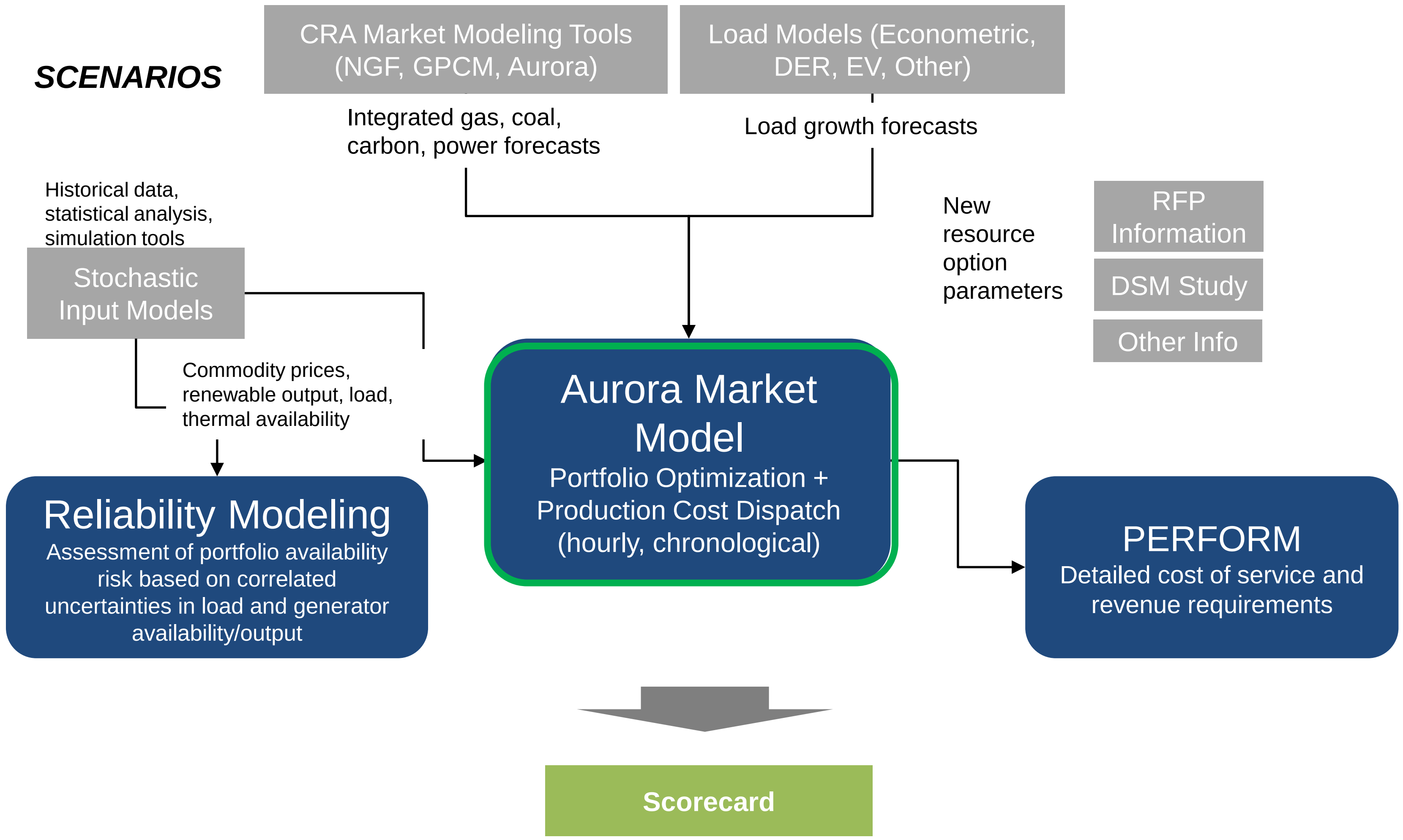
Notes:
1. Assumes prevailing wage and apprenticeship requirements met.
2. A 10% "energy community" bonus is available for projects located in proximity to retired coal infrastructure or in statistical areas with high historical employment in the fossil fuel sector and unemployment rates greater than 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.

NIPSCO
A NiSource Company

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

Higher — MISO Capacity Accreditation — *Lower*

Emissions Intensity: *High* — *Low/zero*

	Current Market Rules	Direct Loss of Load
No Constraints	Portfolio A	Portfolio B
Current EPA Rules Constraints on New Builds	Portfolio C	Portfolio D
No New Fossil without Emission Controls (Net Zero)	Portfolio E	Portfolio F

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

NIPSCO
A NiSource Company

2024 PUBLIC ADVISORY PROCESS NEXT STEPS

Tara McElmurry, Communications Manager, NiSource

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

2024 STAKEHOLDER ADVISORY MEETING ROADMAP

Meeting	Meeting 1 April 23rd	Meeting 2 June 24th	Meeting 3 August 21st	Meeting 4 September 19th	Meeting 5 October 8th
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

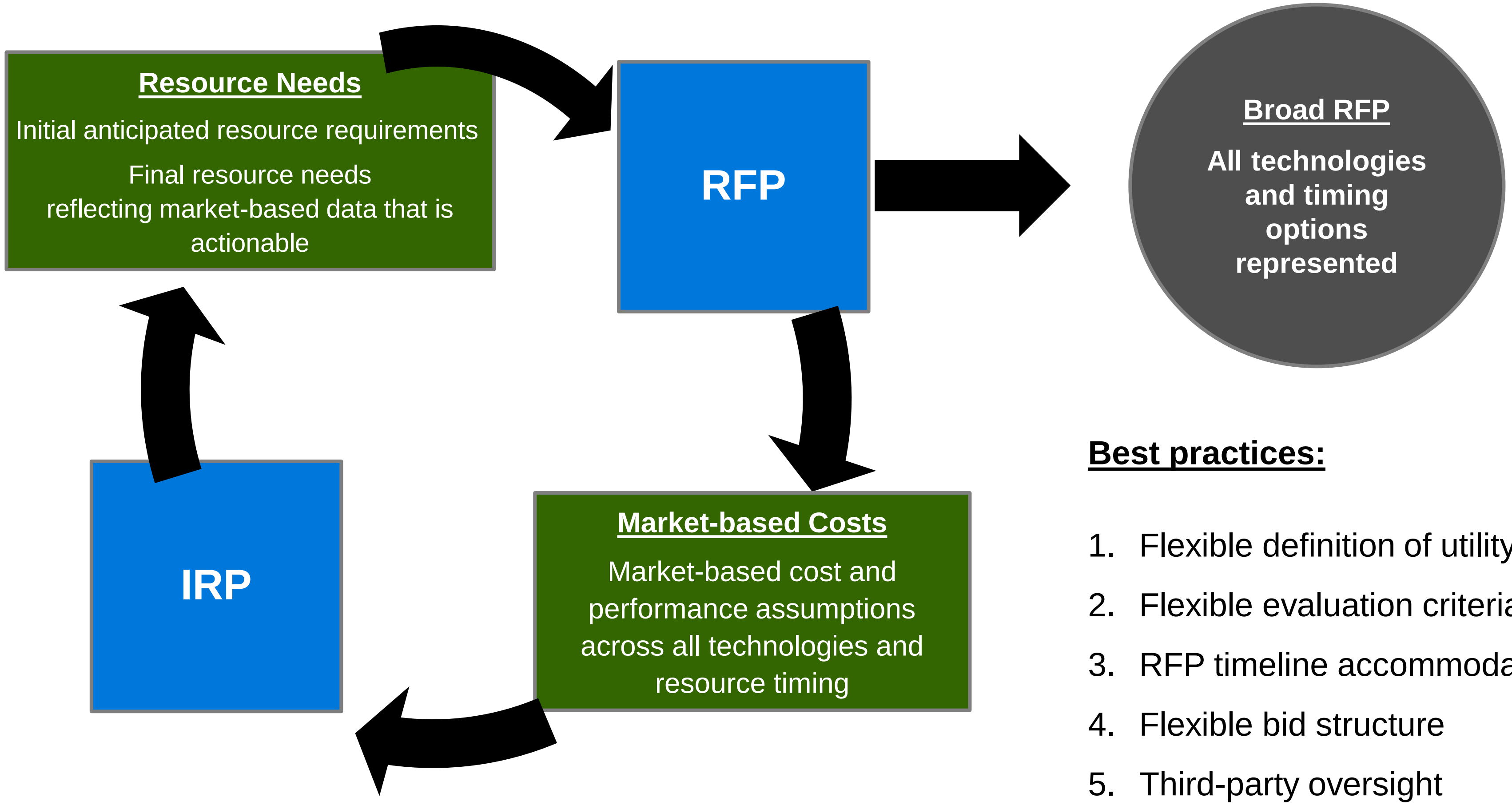
------------------ All-Source RFP ------------------

	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:

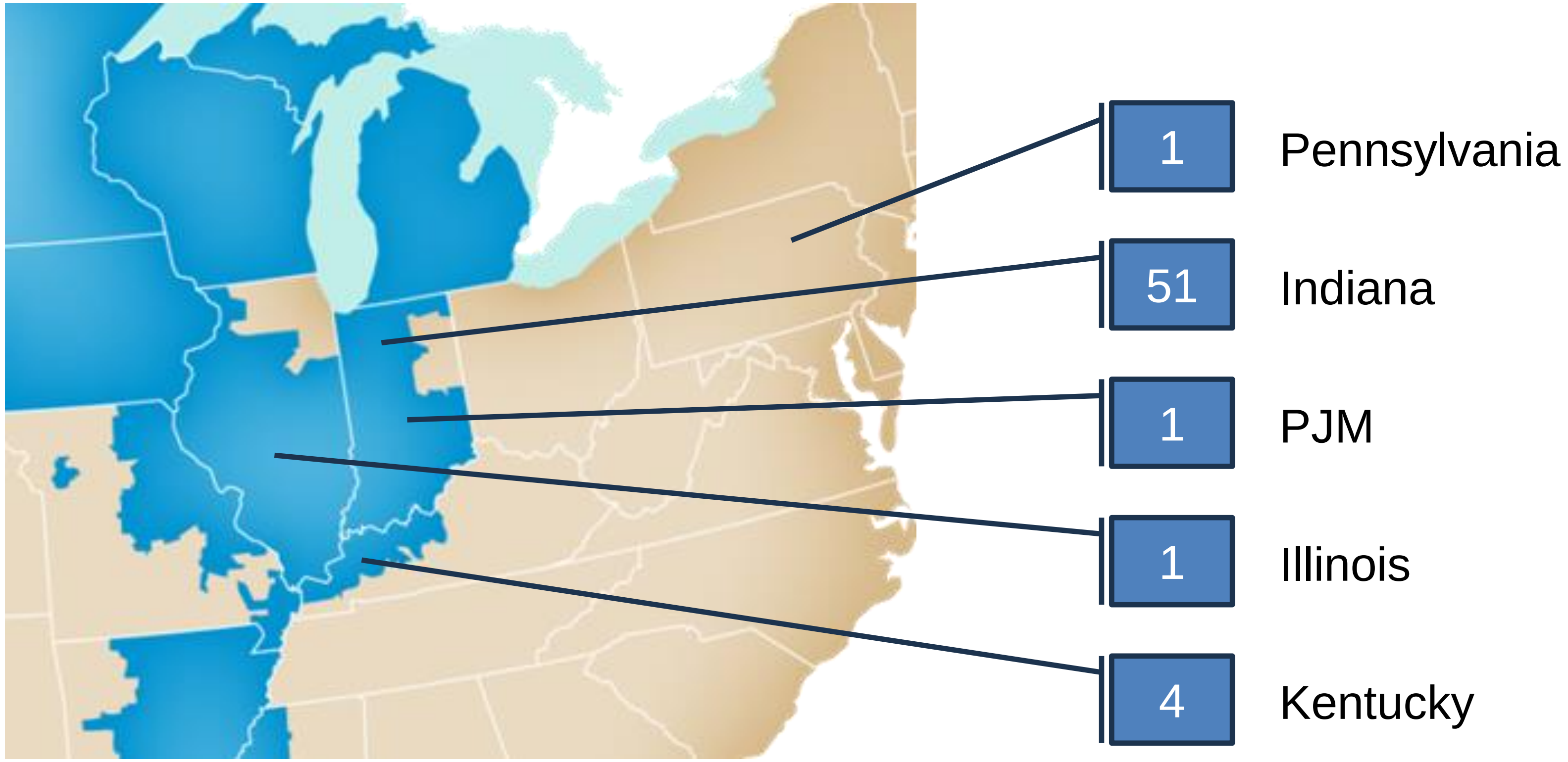
1. Flexible definition of utility needs
2. Flexible evaluation criteria
3. RFP timeline accommodates IRP modeling requirements
4. Flexible bid structure
5. Third-party oversight

NIPSCO 2024 RFPS: OVERVIEW OF PROPOSALS RECEIVED

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

bp
LEEWARD renewable energy
lightsource bp
RANGER POWER
ORION Renewable Energy Group LLC
NEXTera ENERGY
Form energy
renewables RECLAIM | REIMAGINE | REPOWER
Advantage Capital
engie
edp
BRIGHTNIGHT
Deriva Energy
ENERGYDOME GROUND-BREAKING ENERGY STORAGE
KEY CAPTURE ENERGY
HALLADOR ENERGY COMPANY
PROLOGIS
APEX CLEAN ENERGY
Hartree
nrg
energyRe
Avangrid
Clēnera AN ENLIGHT COMPANY
PEREGRINE ENERGY
aypa
CORDELIO POWER
TENASKA
longroad ENERGY
Invenergy
DEPCOM POWER
ADVANCED POWER & ENERGY
AREVON
eDF

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

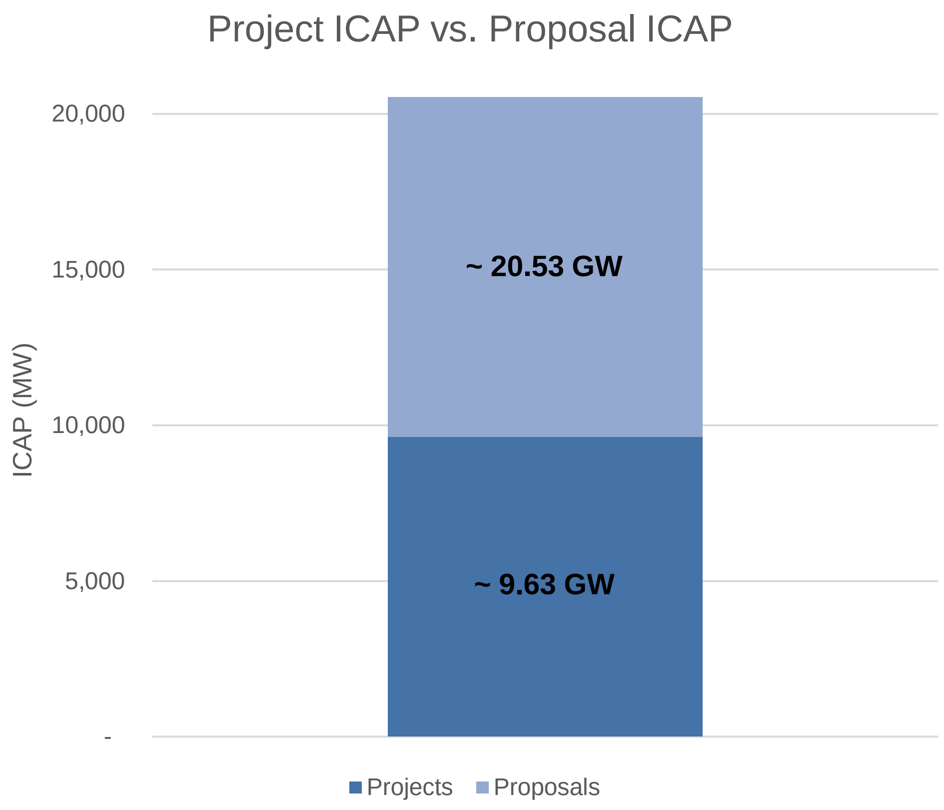
Count of Proposals by Technology and Deal Structure

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.*

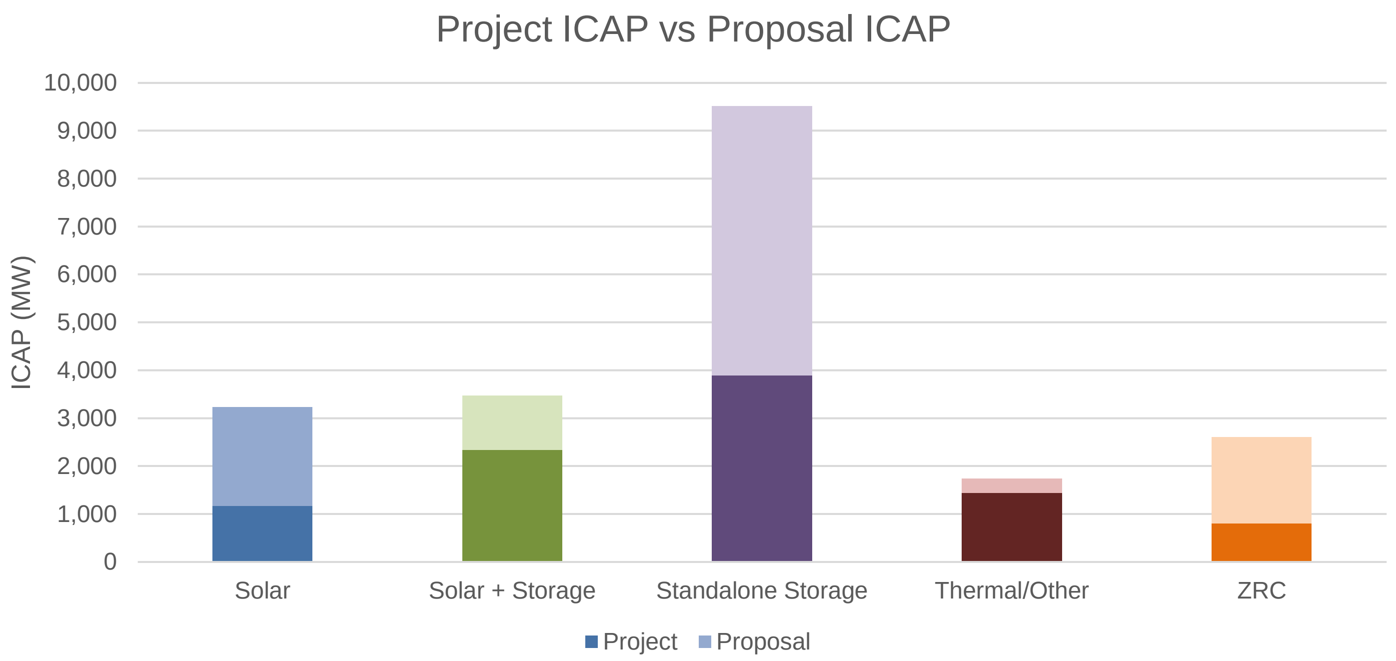
NIPSCO 2024 RFPS: PROJECTS VS. PROPOSALS

- **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

CRA Charles River Associates

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.

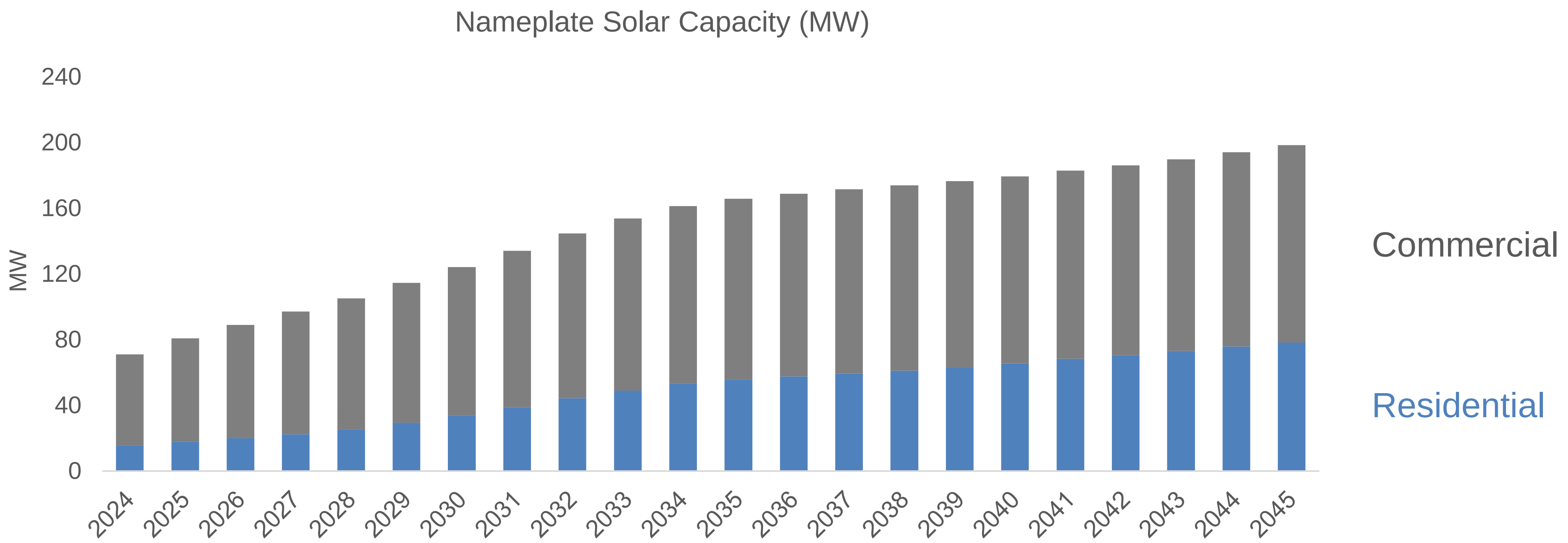
OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

APPENDIX – DSM STUDY

IRP PEAK LOAD FORECAST BY SEASON – WITHOUT ADJUSTMENT FOR EV OR SOLAR

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

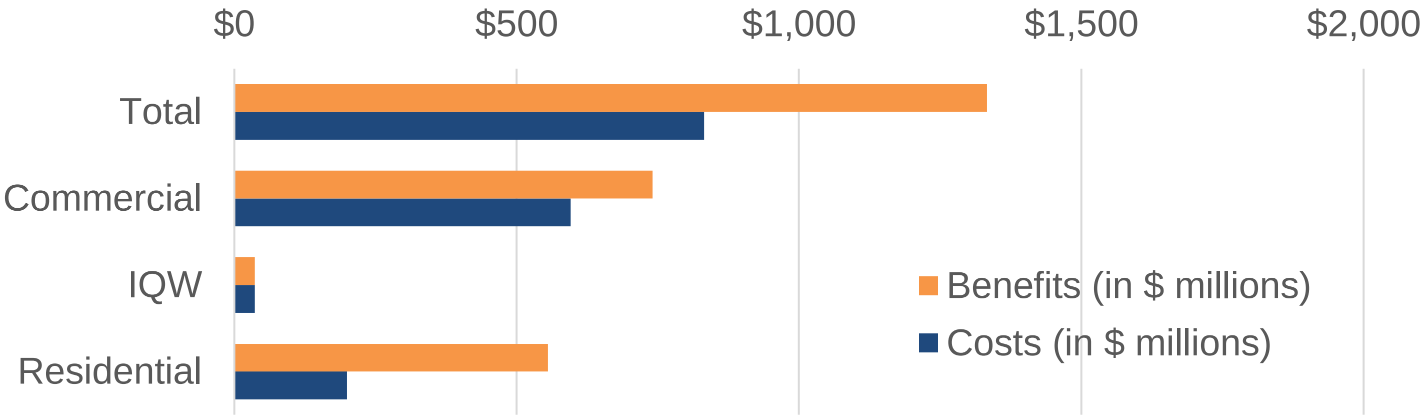
MAP															
Connected Thermostats		Water Heaters		Behavioral		Dynamic Rates		EV Managed Charging		Behind the Meter Storage		Data Centers - Base		C&I	
DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	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

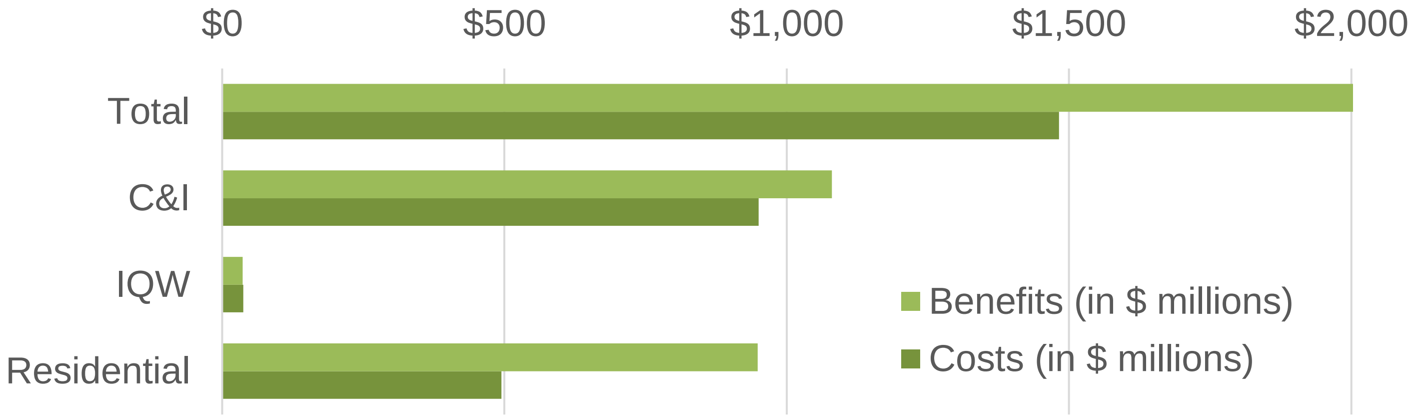
All values shown are 20-year net present values (NPV) in 2027$ for the 2027-2046 time period

RAP



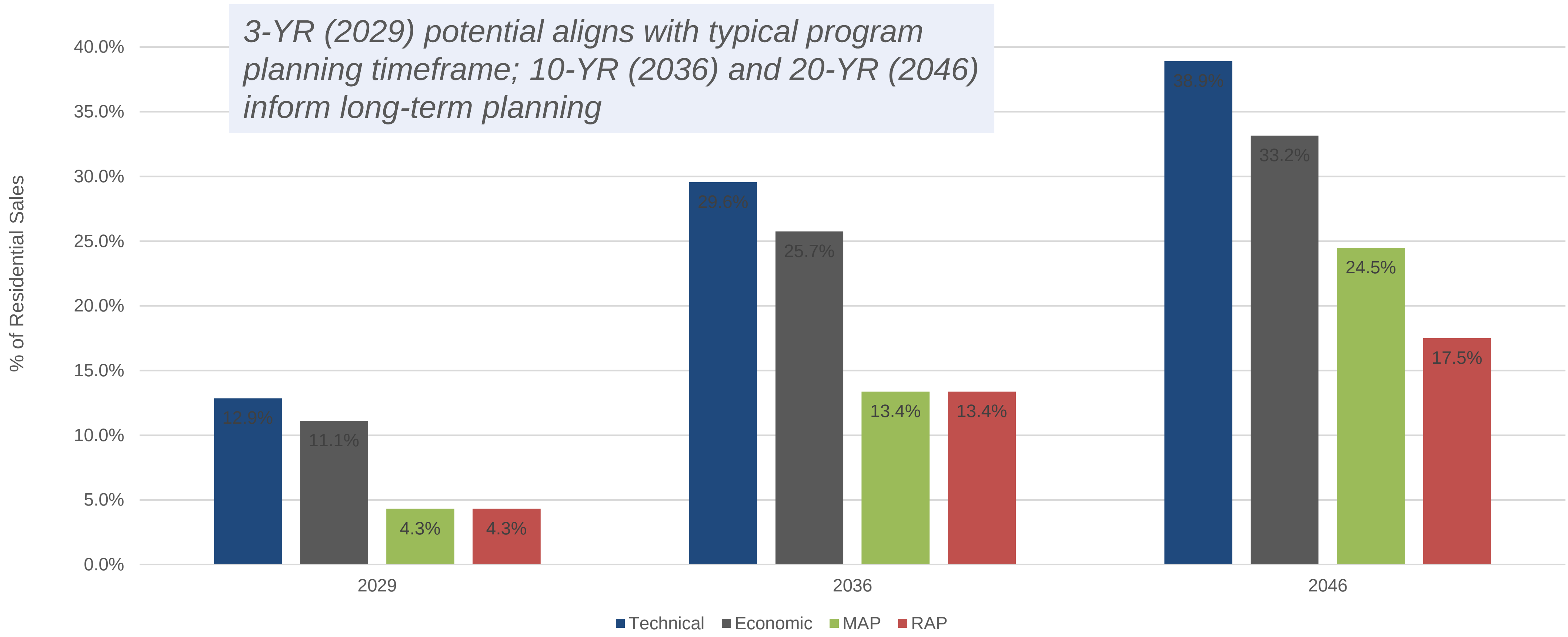
Levelized $/kWh
$0.035
$0.023
$0.113
$0.043

MAP



Levelized $/kWh
$0.065
$0.055
$0.143
$0.074

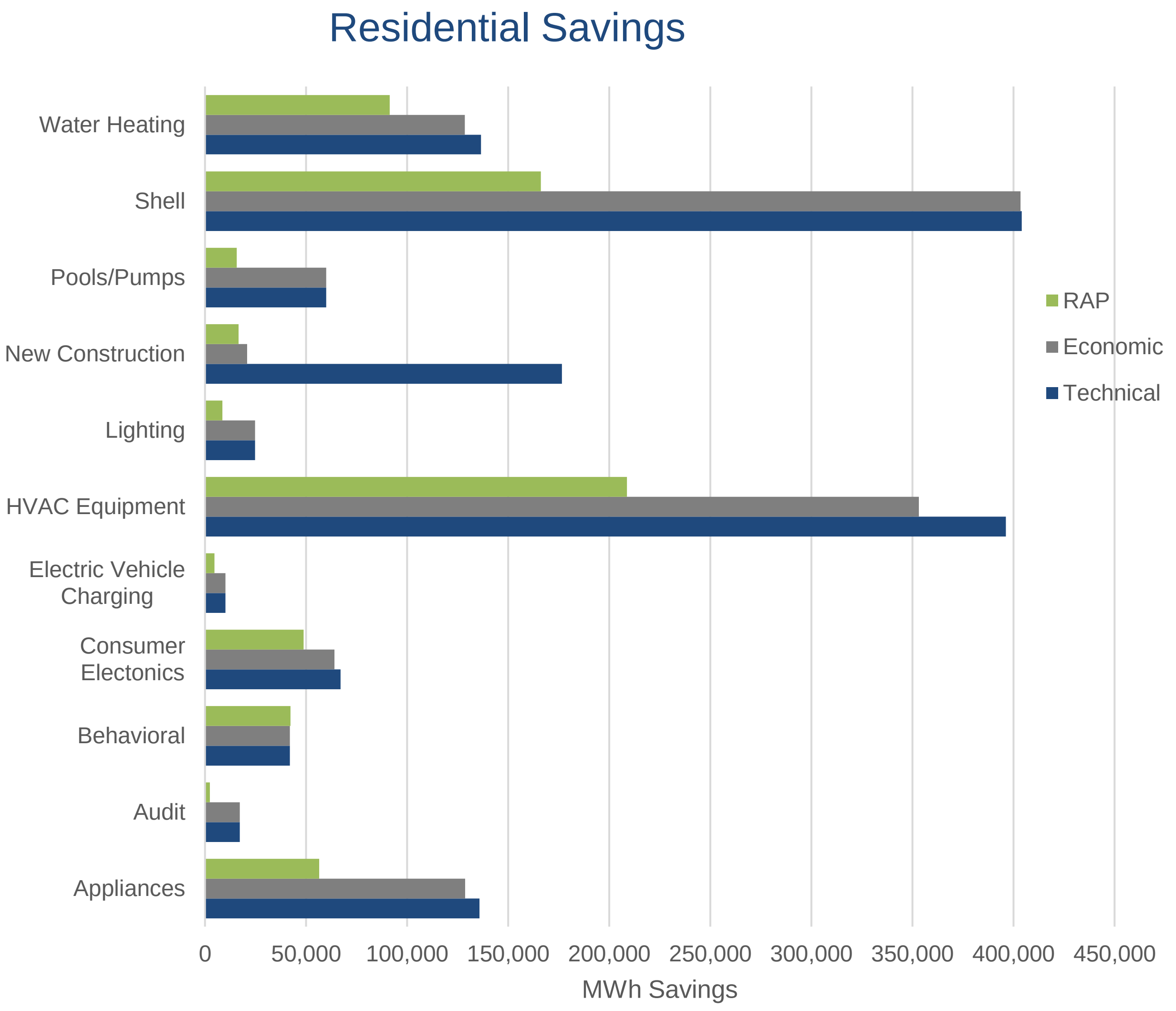
RESIDENTIAL ENERGY EFFICIENCY POTENTIAL SUMMARY



Results in chart show ***cumulative annual*** savings

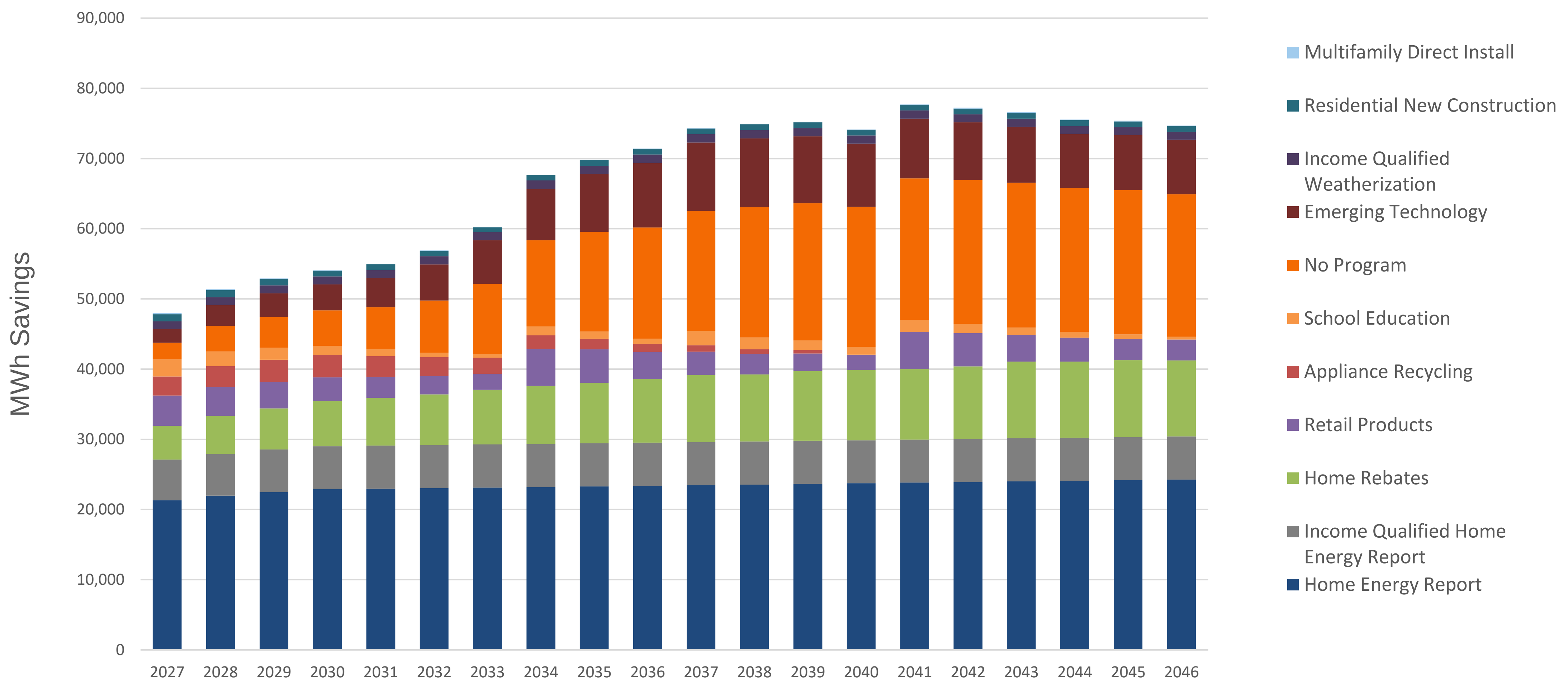
- *Cumulative Annual savings in Year X represent both the incremental (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL)*

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

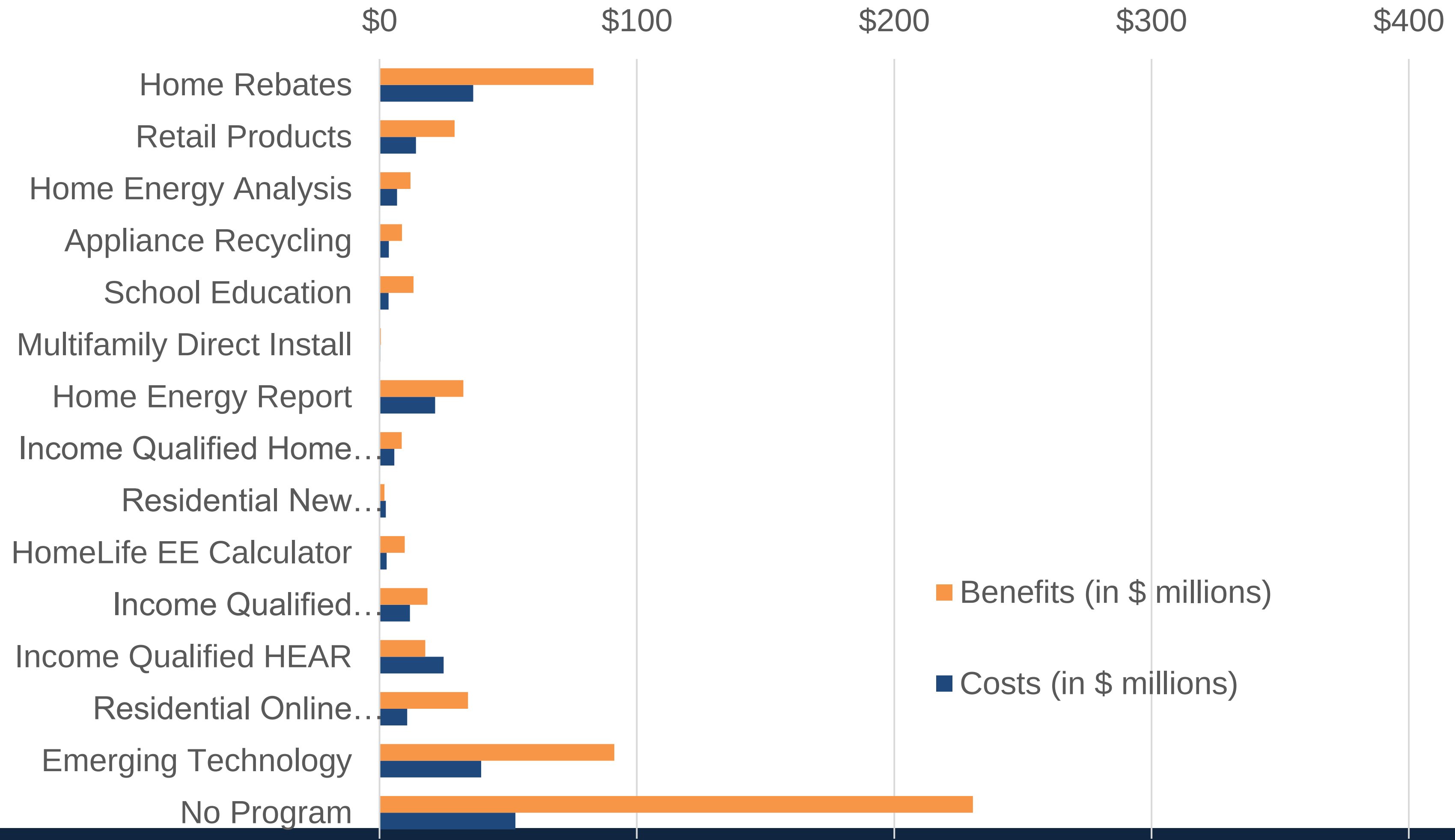
RESIDENTIAL INCREMENTAL RAP BY PROGRAM TYPE



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

RAP

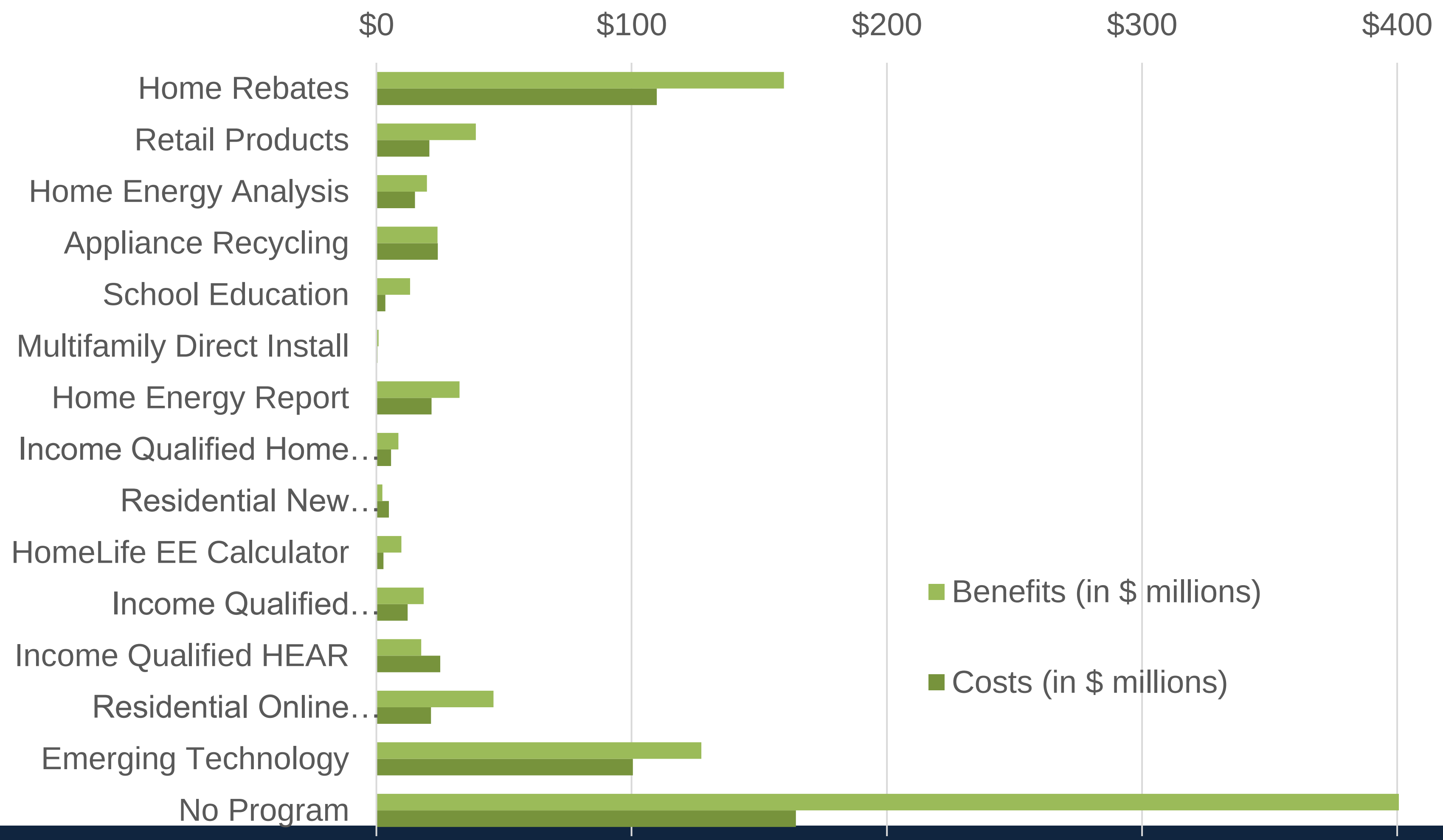


Levelized $/kWh
$0.045
$0.063
$0.047
$0.039
$0.036
$0.043
$0.088
$0.087
$0.021
$0.039
$0.117
$0.111
$0.041
$0.061
$0.046

RESIDENTIAL NPV COSTS AND BENEFITS BY PROGRAM

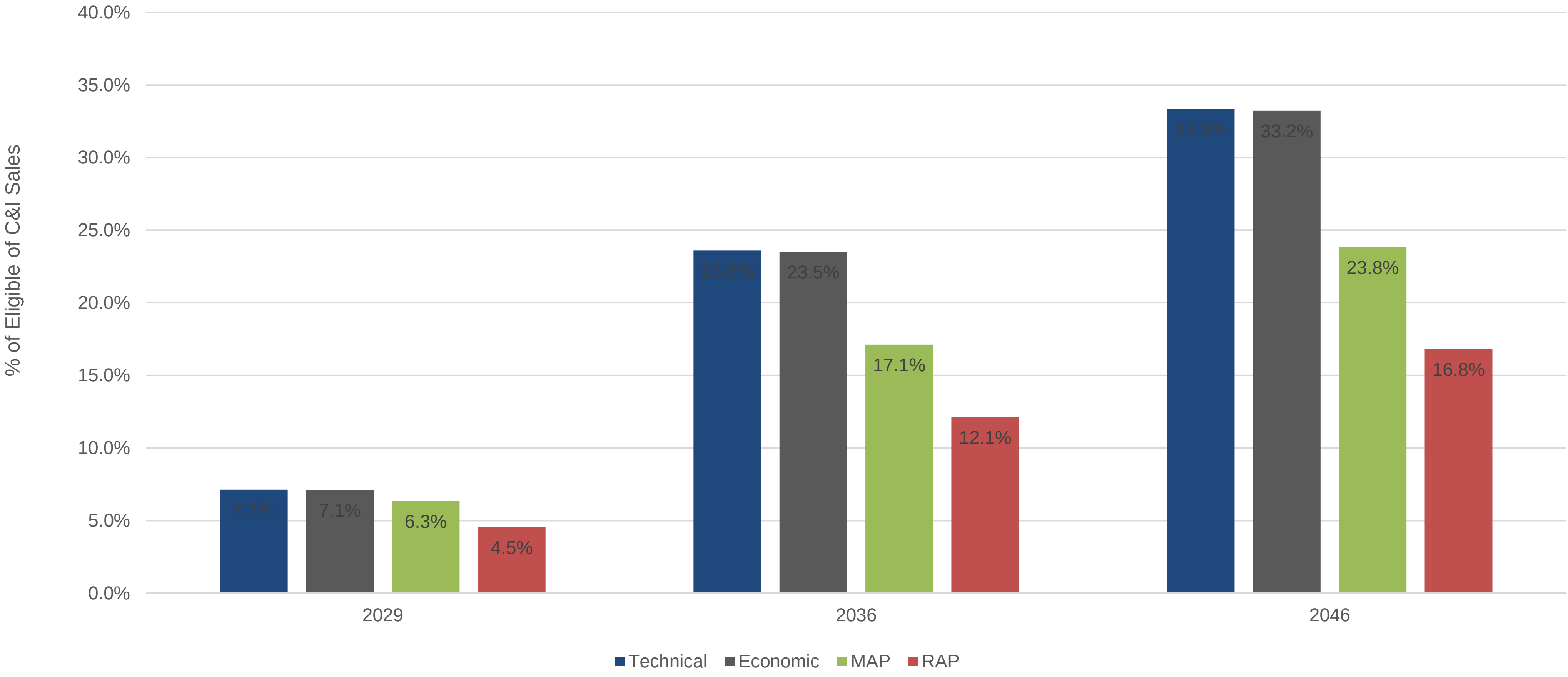
All values shown are 20-year net present values (NPV) in 2027$ for the 2027-2046 time period

MAP

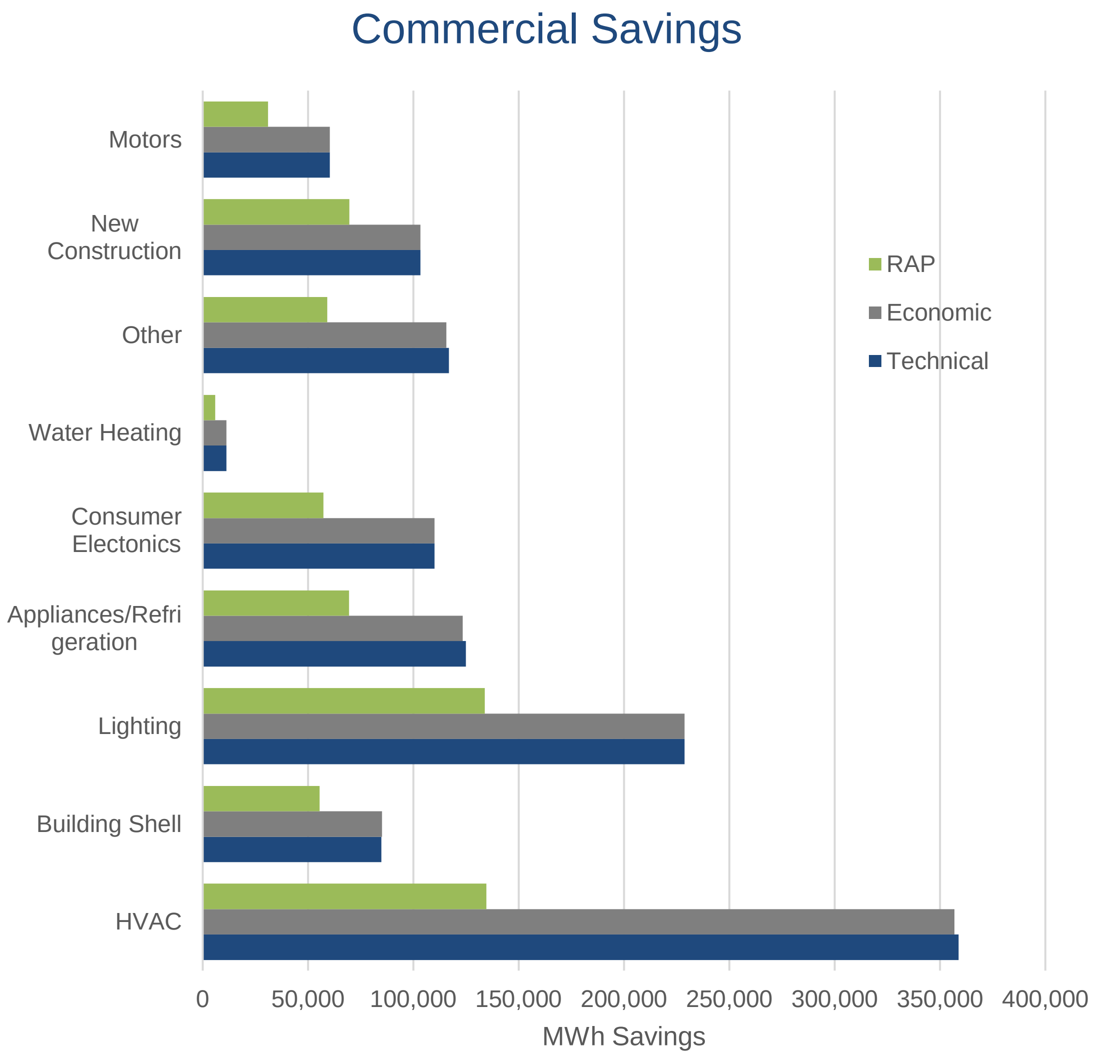


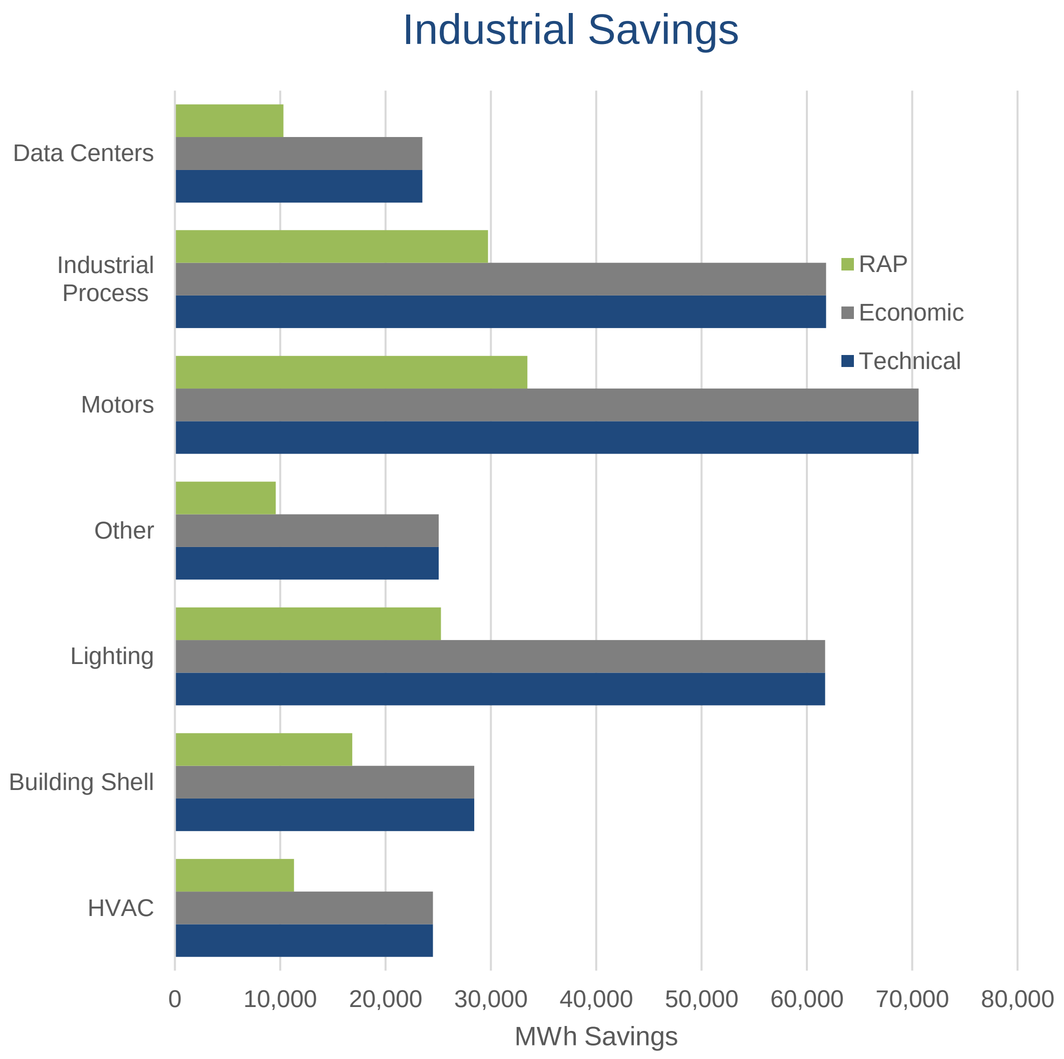
Levelized $/kWh
$0.082
$0.072
$0.064
$0.110
$0.036
$0.048
$0.088
$0.087
$0.037
$0.039
$0.120
$0.113
$0.062
$0.102
$0.093

C&I ENERGY EFFICIENCY POTENTIAL SUMMARY



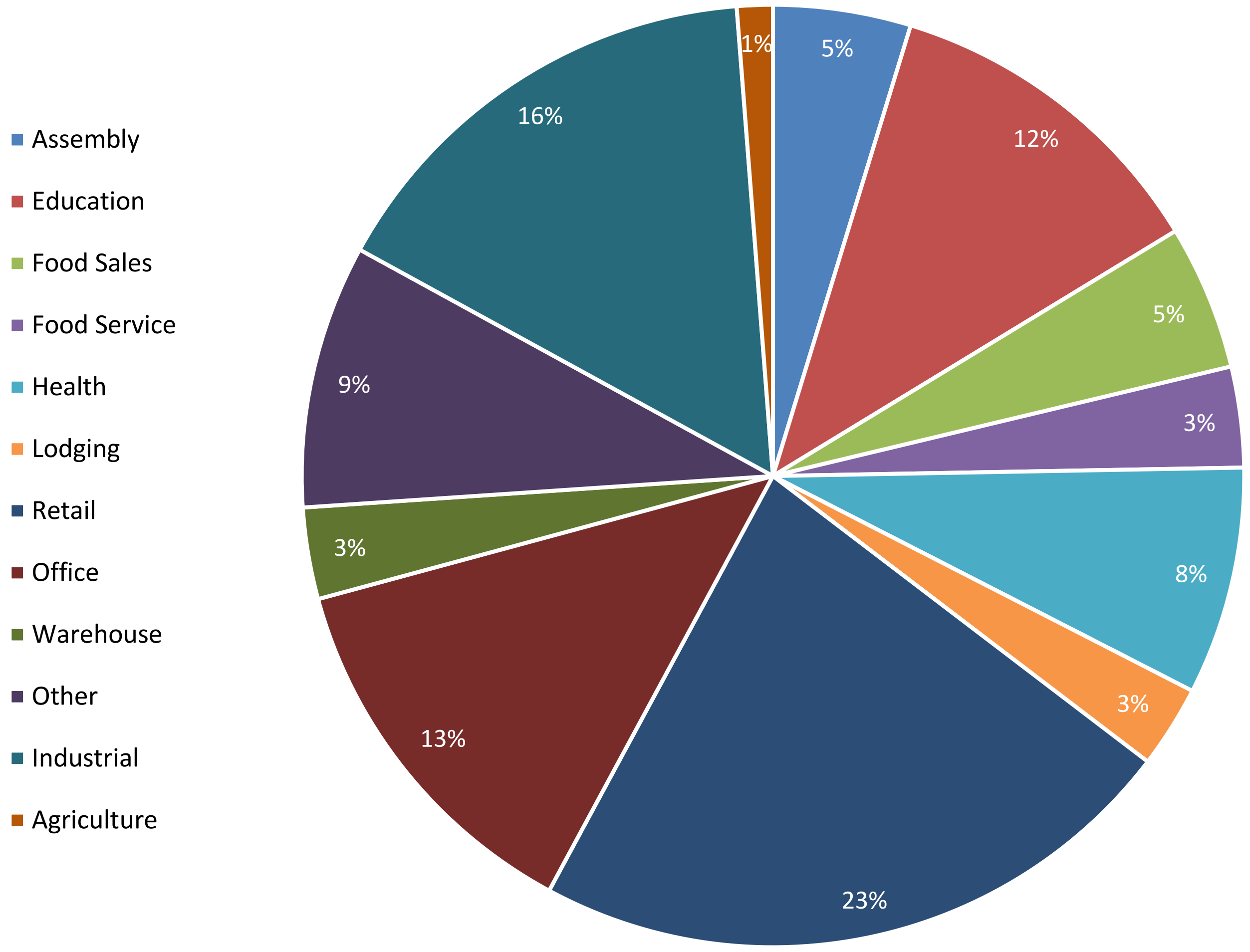
20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY END-USE



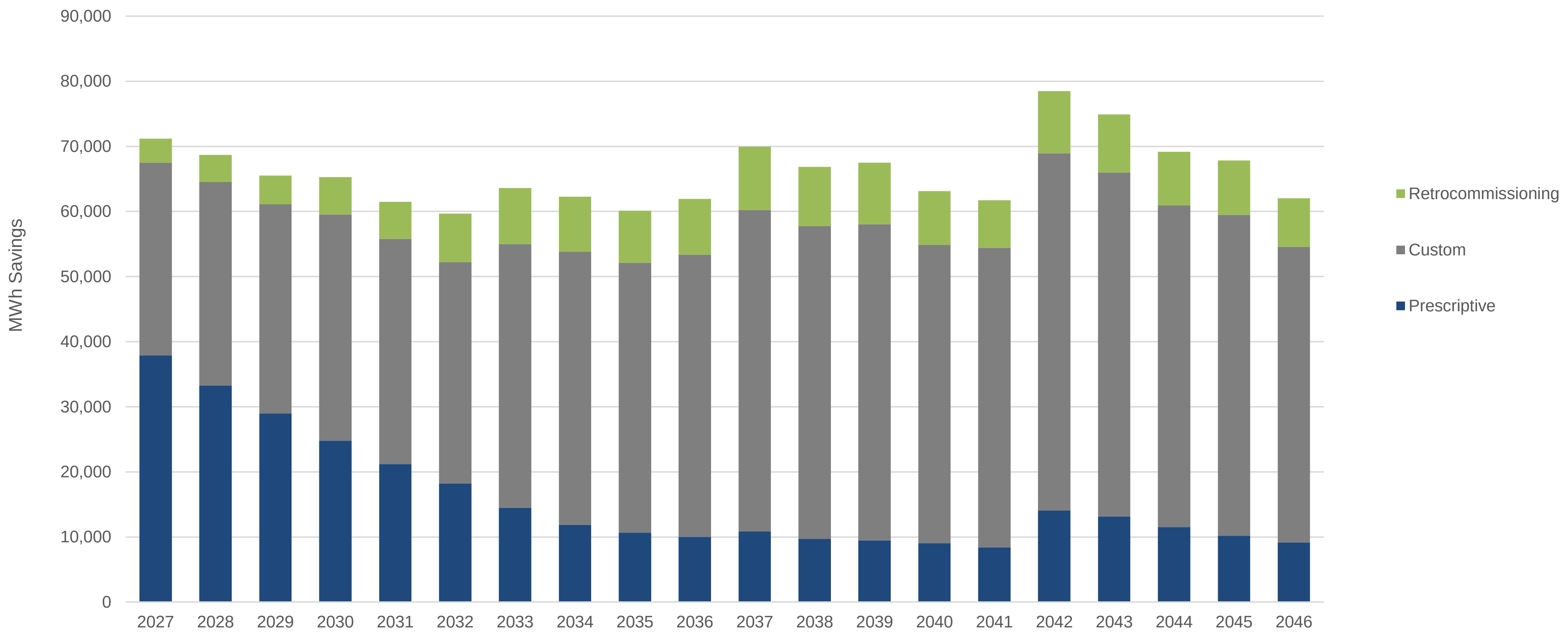


NIPSCO A NiSource Company

20-YEAR CUMULATIVE ANNUAL C&I POTENTIAL BY BUILDING/INDUSTRY TYPE



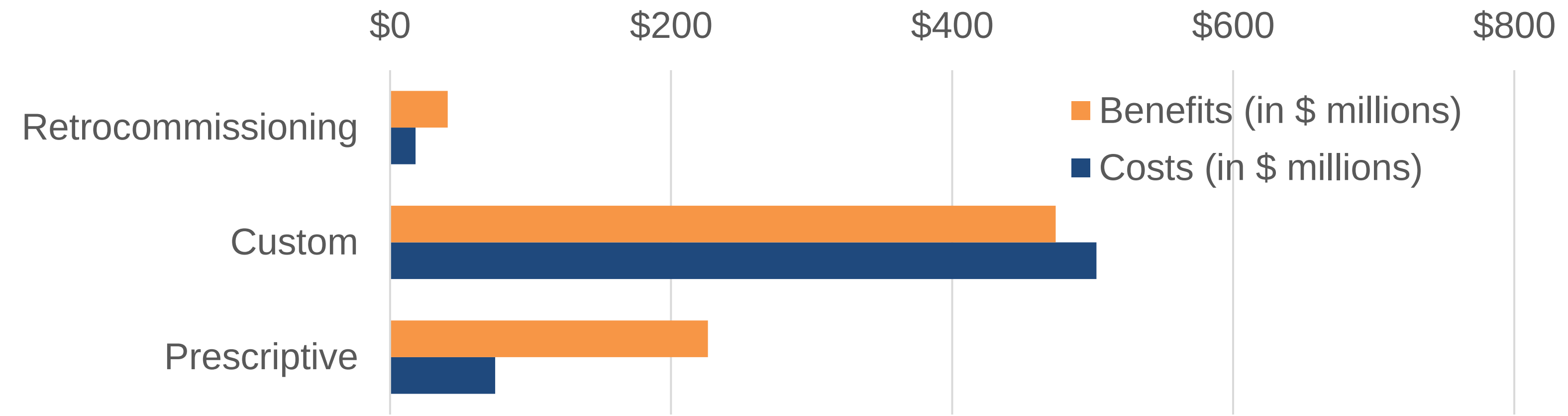
C&I INCREMENTAL RAP BY PROGRAM TYPE



C&I NPV COSTS AND BENEFITS BY PROGRAM

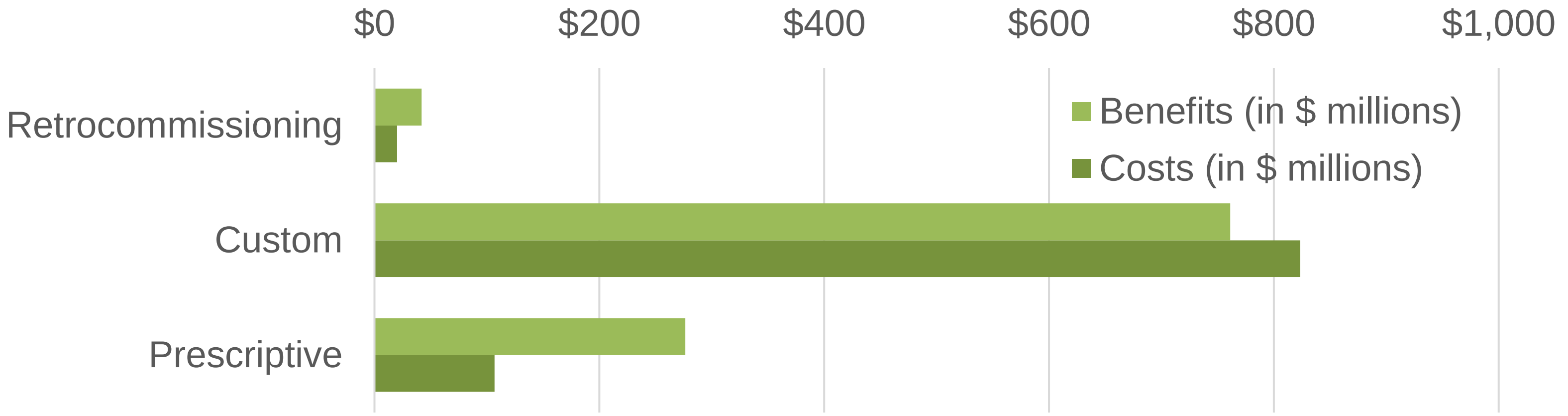
All values shown are 20-year net present values (NPV) in 2027$ for the 2027-2046 time period

RAP



Levelized $/kWh
$0.041
$0.023
$0.019

MAP



Levelized $/kWh
$0.058
$0.057
$0.050

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.

		MAP							RAP		MAP
Summer – Metric	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
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 – Metric	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
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	$145	$235	$99	$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 – Metric	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
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	$146	$236	$99	$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 – Metric	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
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