Indiana Michigan Power Company

INDIANA IRP STAKEHOLDER MEETING #2

September 24, 2024

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Welcome & Introductions

I&M Leadership Team

David Lucas | Vice President, Regulatory and Finance

Andrew Williamson | Director, Regulatory Services

Ed Locigno | Regulatory Analysis & Case Manager

Stacie Gruca | Manager, Regulatory Services

Austin DeNeff | Regulatory Consultant Senior

1898 & Co.

Brian Despard | Senior Project Manager

GDS Associates, Inc.

Jeffrey Huber | Principal, Energy Efficiency

I&M IRP Planning

Dylan Drugan | Manager, Resource Planning

Mohamed Abukaram | Director, Resource Planning

I&M Infrastructure Development

Tim Gaul | Director, Regulated Infrastructure Development

I&M Load Forecasting

Trenton Feasel | Manager, Economic Forecasting

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Agenda

Time (EST)	Agenda Topic	Lead
1:00-1:10	**Welcome & Introductions**	**Andrew Williamson**
1:10-1:20	**Going-In Capacity Position Review**	**Dylan Drugan**
1:20-1:45	**Load Forecast Assumptions and Methodology**	**Trenton Feasel**
1:45-2:00	**DSM Modeling Inputs**	**Jeffrey Huber**
2:00-2:10	**Short Break**	
2:10-2:25	**Market Assessment of Existing and New Resources** • Queue Analysis Of New Resources	**Tim Gaul**
2:25-3:00	**Resource Modeling Parameters** • Resource costs, build limits, and availability	**Dylan Drugan**
3:00-3:10	**Short Break**	
3:10-3:35	**Key Modeling Inputs** • Assumptions related to IRA credits, Cook, Hydro, and Storage • Implementing Stakeholder Feedback	**Mohamed Abukaram**
3:35-3:45	**Market Scenarios and Sensitivities** • Stakeholder Meetings 3A and 3B	**Dylan Drugan**
3:45-4:00	**Open Discussion** • Feedback From Stakeholders	**Andrew Williamson**

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Preliminary PJM ELCC and FPR Forecasts

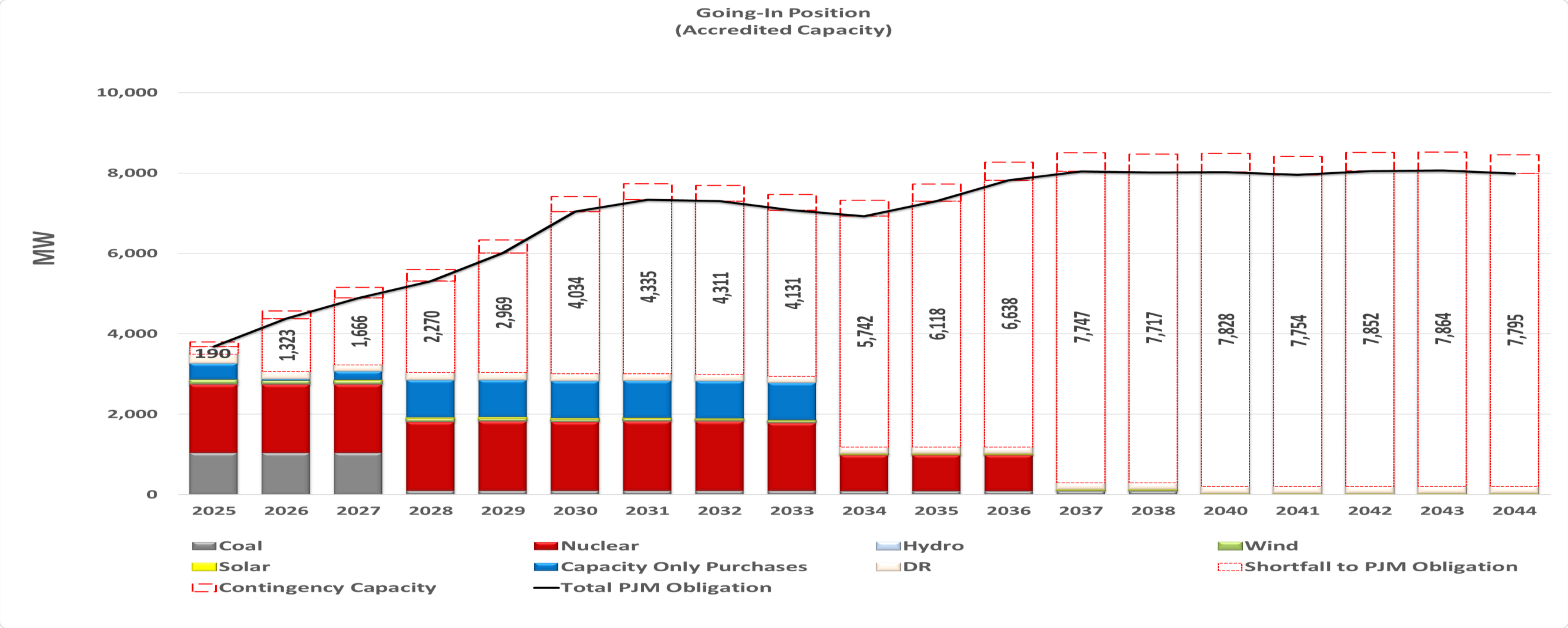
ELCC Class	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Onshore Wind	35%	33%	28%	25%	23%	21%	19%	17%	15%
Offshore Wind	61%	56%	47%	44%	38%	37%	33%	27%	20%
Fixed-Tilt Solar	7%	6%	5%	5%	4%	4%	4%	4%	3%
Tracking Solar	11%	8%	7%	7%	6%	5%	5%	5%	4%
Landfill Intermittent	54%	55%	55%	56%	56%	56%	56%	56%	54%
Hydro Intermittent	38%	40%	37%	37%	37%	37%	39%	38%	38%
4-hr Storage	56%	52%	55%	51%	49%	42%	42%	40%	38%
6-hr Storage	64%	61%	65%	61%	61%	54%	54%	53%	52%
8-hr Storage	67%	64%	67%	64%	65%	60%	60%	60%	60%
10-hr Storage	76%	73%	75%	72%	73%	68%	69%	70%	70%
Demand Resource	70%	66%	65%	63%	60%	56%	55%	53%	51%
Nuclear	95%	95%	95%	96%	95%	96%	96%	94%	93%
Coal	84%	84%	84%	85%	85%	86%	86%	83%	79%
Gas Combined Cycle	79%	80%	81%	83%	83%	85%	85%	84%	82%
Gas Combustion Turbine	61%	63%	66%	68%	70%	71%	74%	76%	78%
Gas Combustion Turbine Dual Fuel	79%	79%	80%	80%	81%	82%	83%	83%	83%
Diesel Utility	92%	92%	92%	92%	92%	93%	93%	93%	92%
Steam	74%	73%	74%	75%	74%	75%	76%	74%	73%

https://www.pjm.com/-/media/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx

Delivery Year	Forecast Pool Requirement (% of Peak Load)
2026/27	93.67%
2027/28	92.69%
2028/29	92.75%
2029/30	93.47%
2030/31	92.96%
2031/32	92.72%
2032/33	92.10%
2033/34	89.99%
2034/35	87.09%

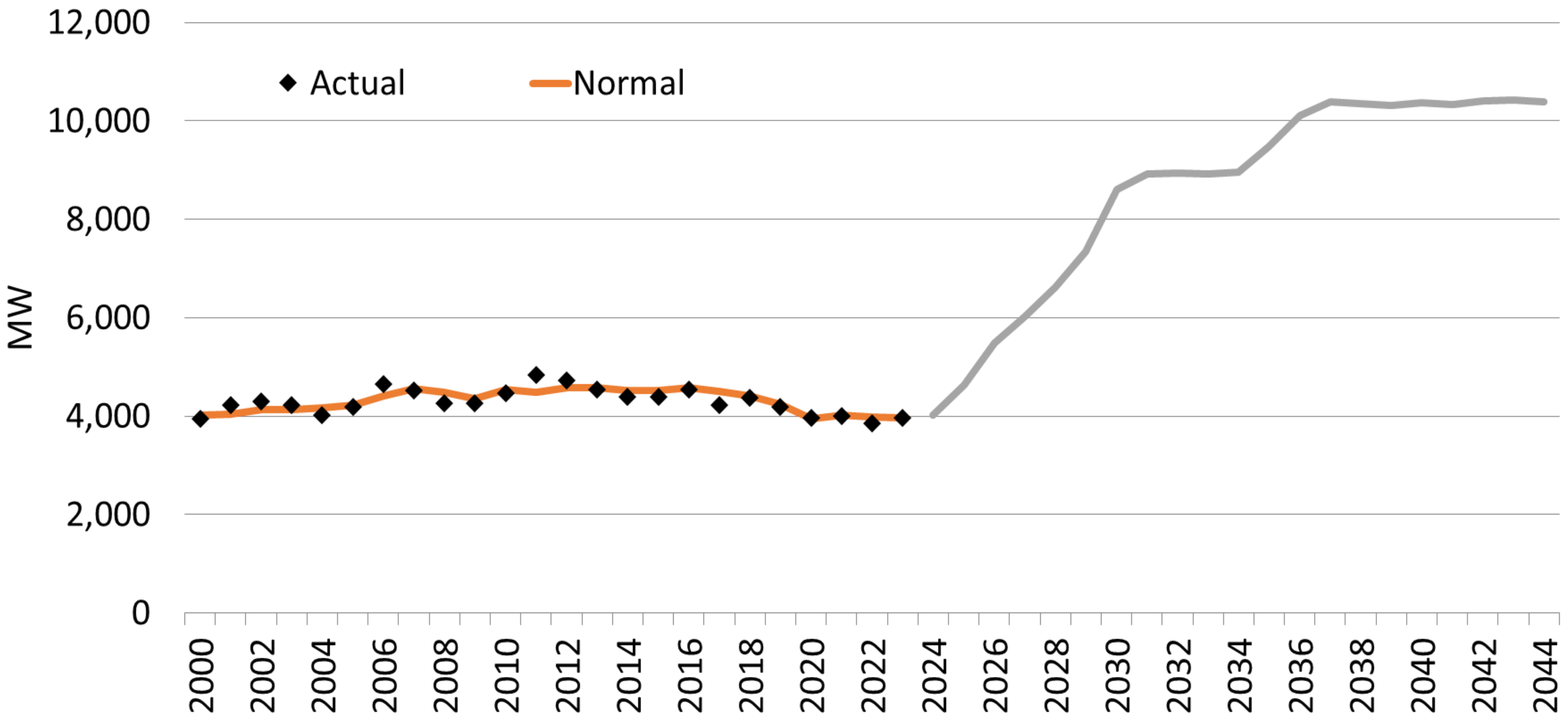
- I&M's forecasted capacity need is influenced by the accredited capacity PJM recognizes for I&M's resources (i.e., ELCC Class values) as well as by the load requirement PJM sets (i.e., the "FPR" or Forecast Pool Requirement).
- PJM's forecasted decline in ELCC class values for resources such as wind, solar, and storage is offset, in part, by a lower forecasted peak load requirement (i.e., a lower FPR).

Capacity Needs Assessment (Preliminary Going-In Position)



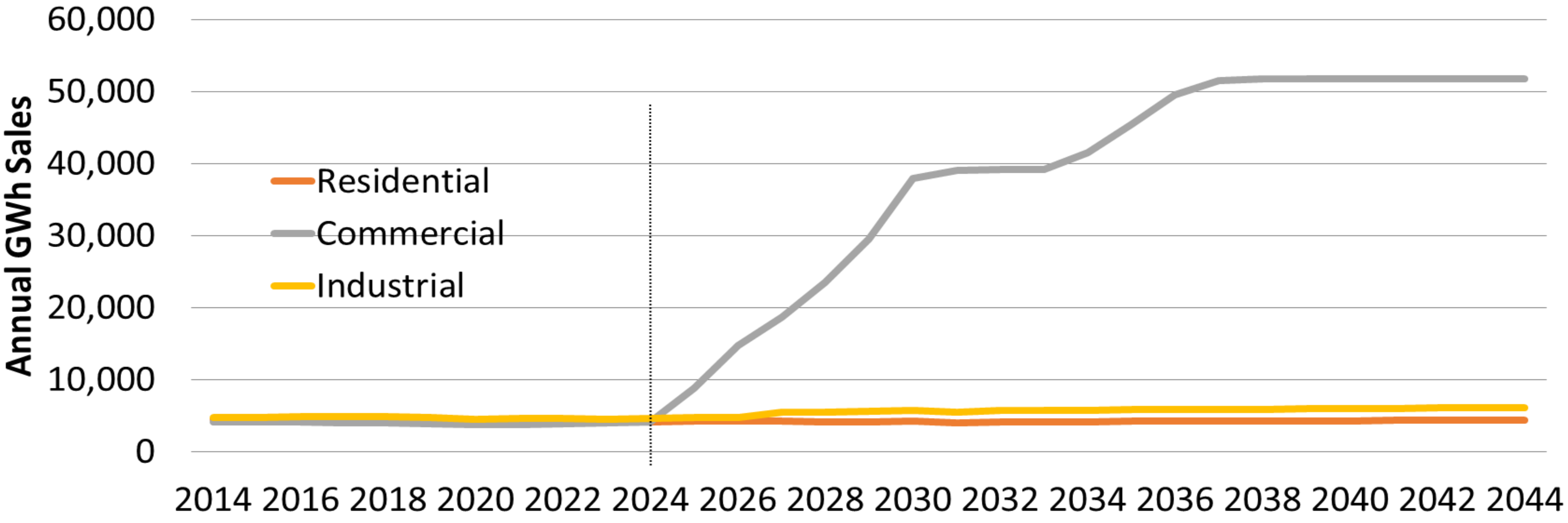
- To reasonably capture contingency risk around future uncertainties such as changes to load obligations and available capacity, a probabilistic risk analysis was performed to evaluate a reasonable amount of ‘Contingency Capacity’ needed for planning purposes.
- The analysis resulted in planning for Contingency Capacity at a level of 5% above the PJM load obligation by 27/28;
  - PJM Load Obligation is ~93% of peak load in 27/28 and, in turn, Contingency Capacity level is at ~98% of peak load (~93% + 5%);
  - Additional 5% for Contingency Capacity results in planning for up to an additional ~450 MW above the PJM Load Obligation.

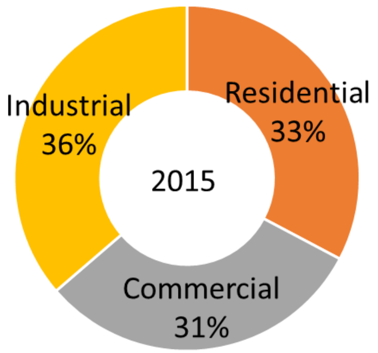
I&M Peak Demand Forecast

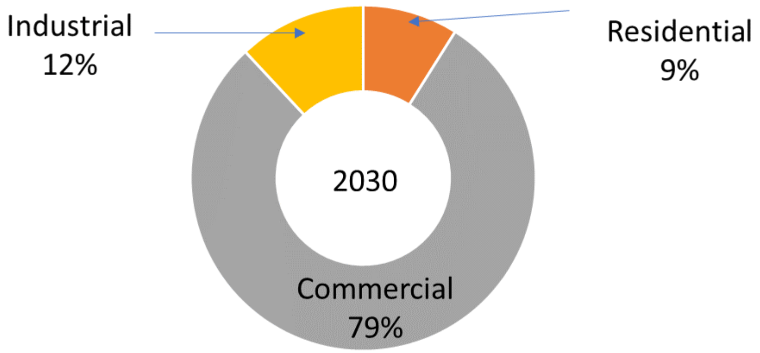


I&M's peak demand forecast is projected to grow at an 8.3% CAGR from 2024-2034, driven by the addition of hyperscaler data center loads in Indiana.

Indiana GWh Sales (Weather Normalized History & Forecast)







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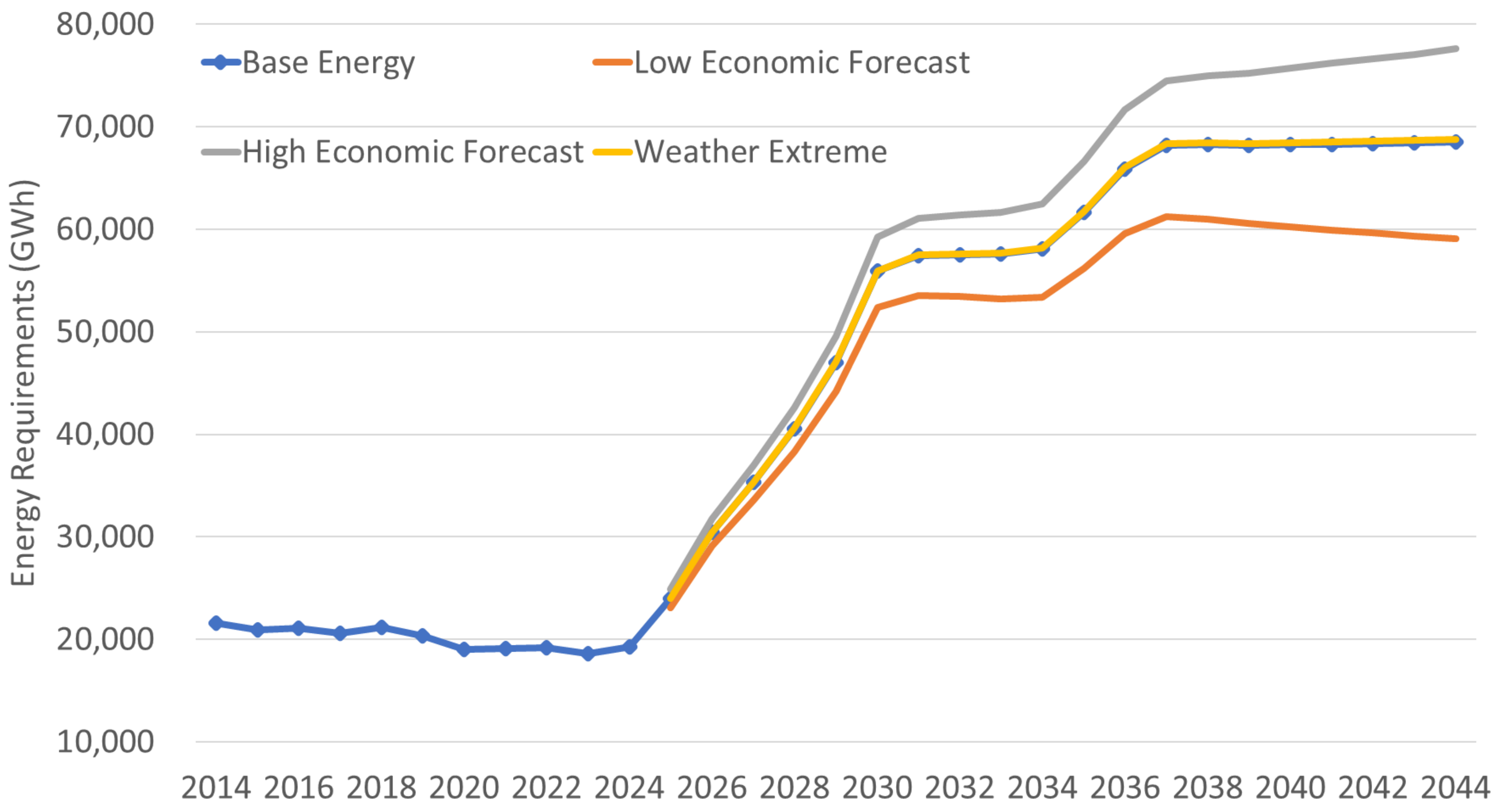
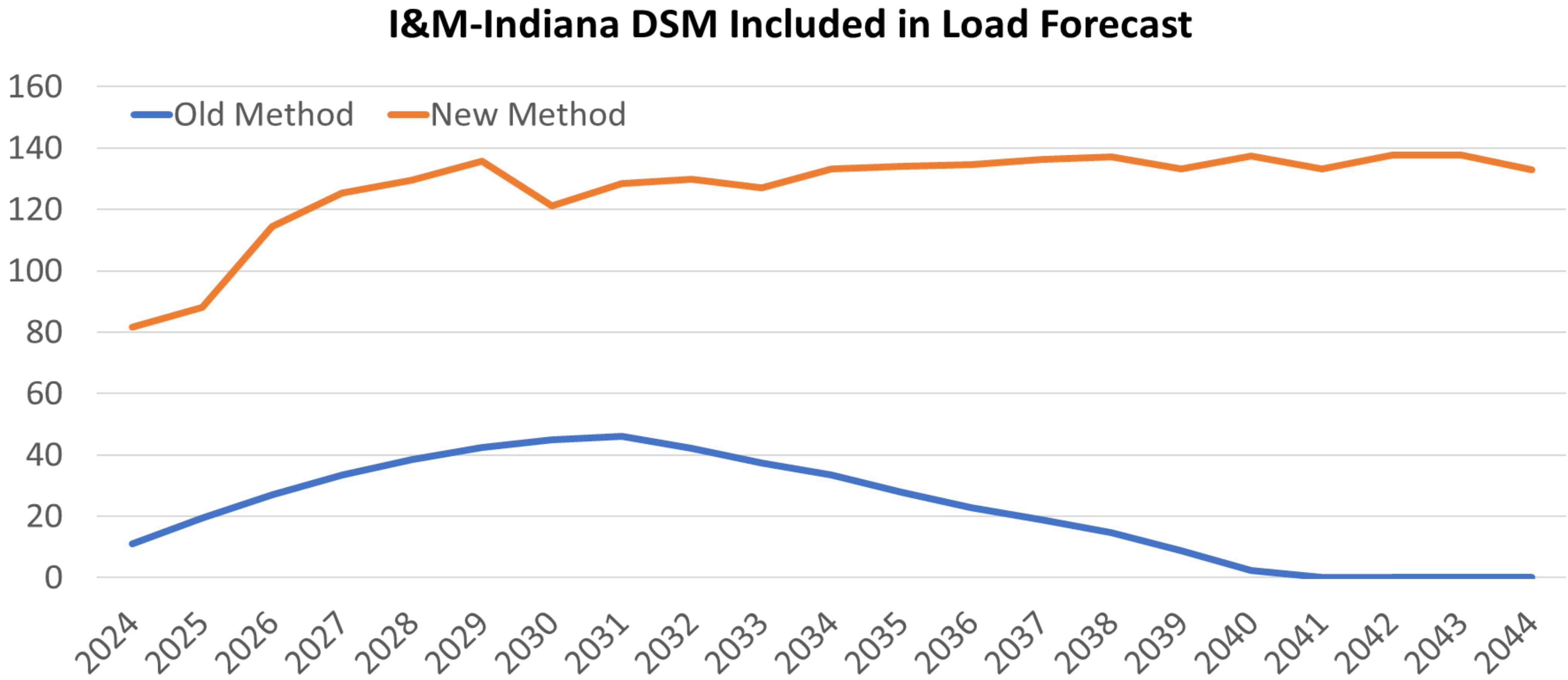
Load Forecast Scenarios

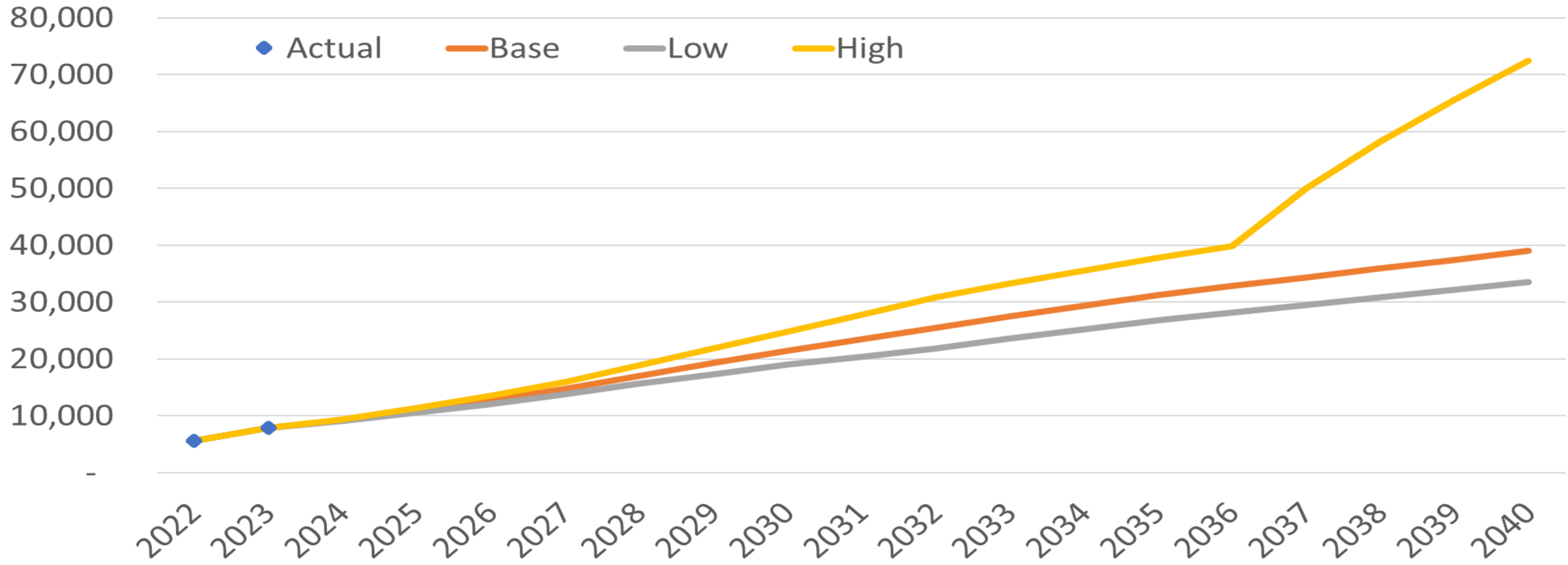


Controlling for DSM/EE



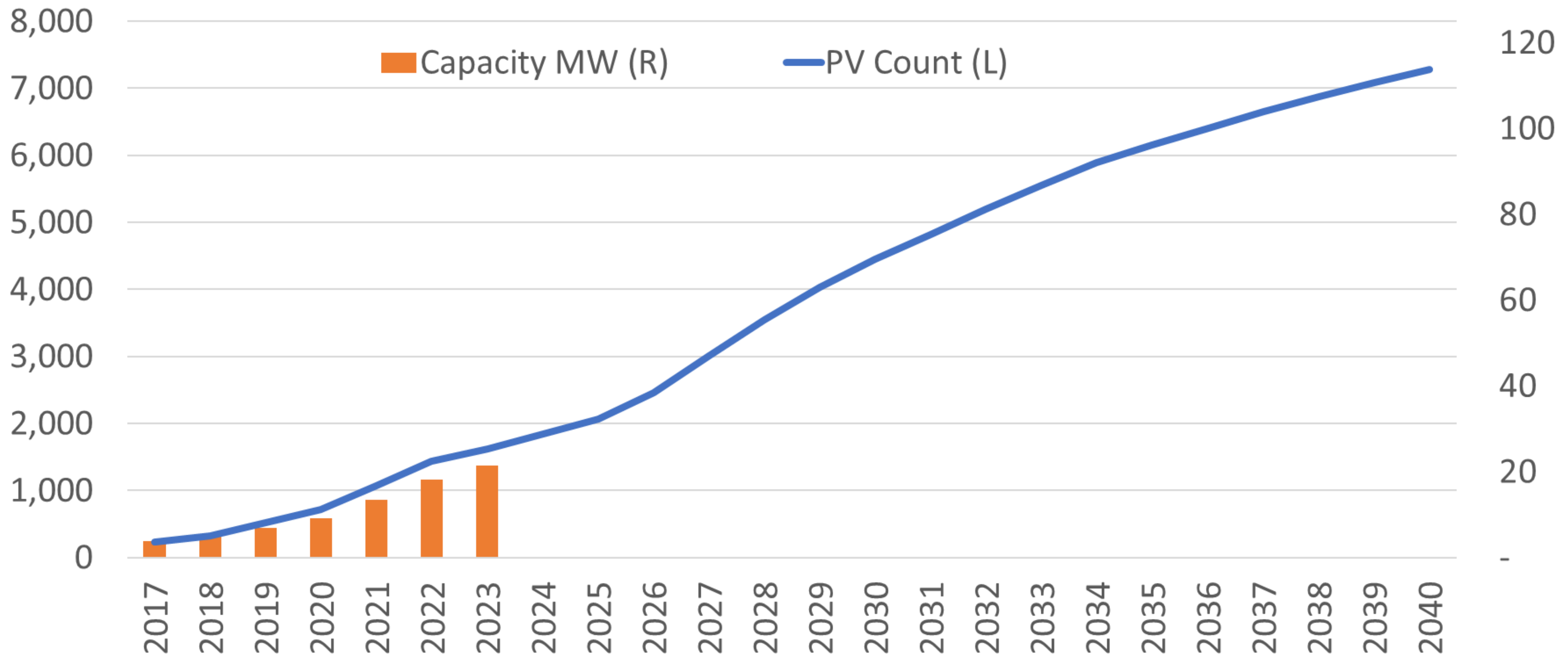
Per Rockport Unit 2 Declination of Jurisdiction Settlement in CN 45546, I&M now explicitly accounts for DSM programs in its econometric model as an additional independent variable. This has led to DSM having a greater impact on the forecast than the prior degradation approach. DSM was a post model adjustment in the “Old Method” and degraded over time. DSM is used as an explanatory variable in the “New Method” and does not reflect the degradation in the “Old Method.”

Indiana Electric Vehicle Count Forecast



Despite projected 12% annual growth over the next decade, EVs will make up a small portion of the roughly 1.8M vehicles in the I&M Indiana territory. There is upside to the should affordability improve and/or mandates occur, as illustrated by the high forecast scenario.

Indiana Solar Forecast



At the end of 2023, customer-owned solar reached a total nameplate capacity of 21 MW, or about 0.5% of I&M's 2023 peak. Adoption is projected to continue increasing as costs are projected to fall. By 2040, customer-owned solar is projected to decrease retail energy by about 0.4%.

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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 a few minor adjustments:
  - 1 non-residential 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 provided for 2 bundles that includes 14 programs / sub-segments. Bundles are sector-based.
- 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.
- Residential
  - DLC Central AC Switch, DLC Thermostat, DLC Water Heating, DLC EV Charging, EV Rate, Behavioral (iControl), Time of Use Rate, Critical Peak Pricing Rate
- C&I
  - DLC Thermostat, Curtailable Rate, Real Time Pricing Rate, Time of Use Rate, Critical Peak Pricing Rate, Capacity Bidding

EE Bundles

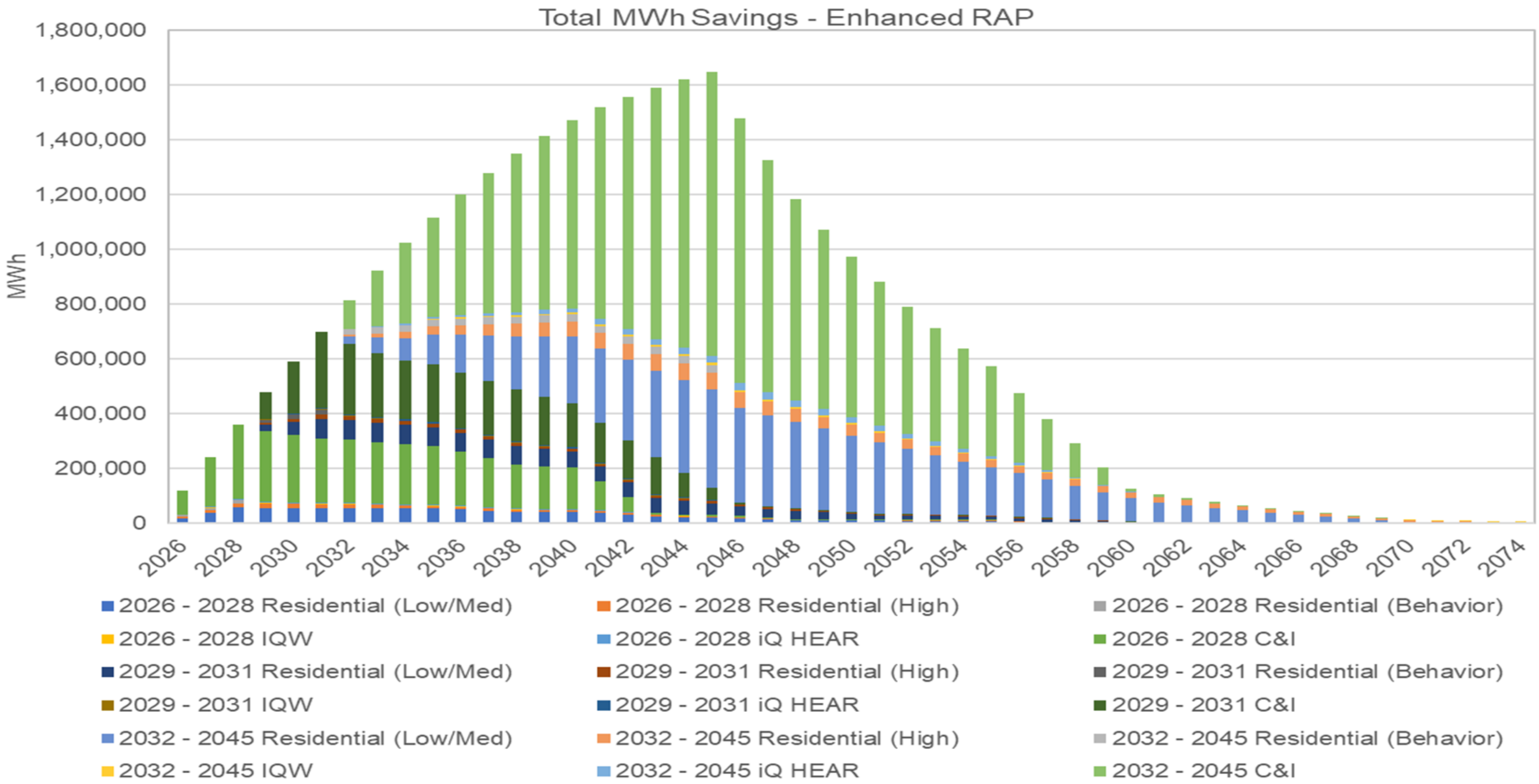
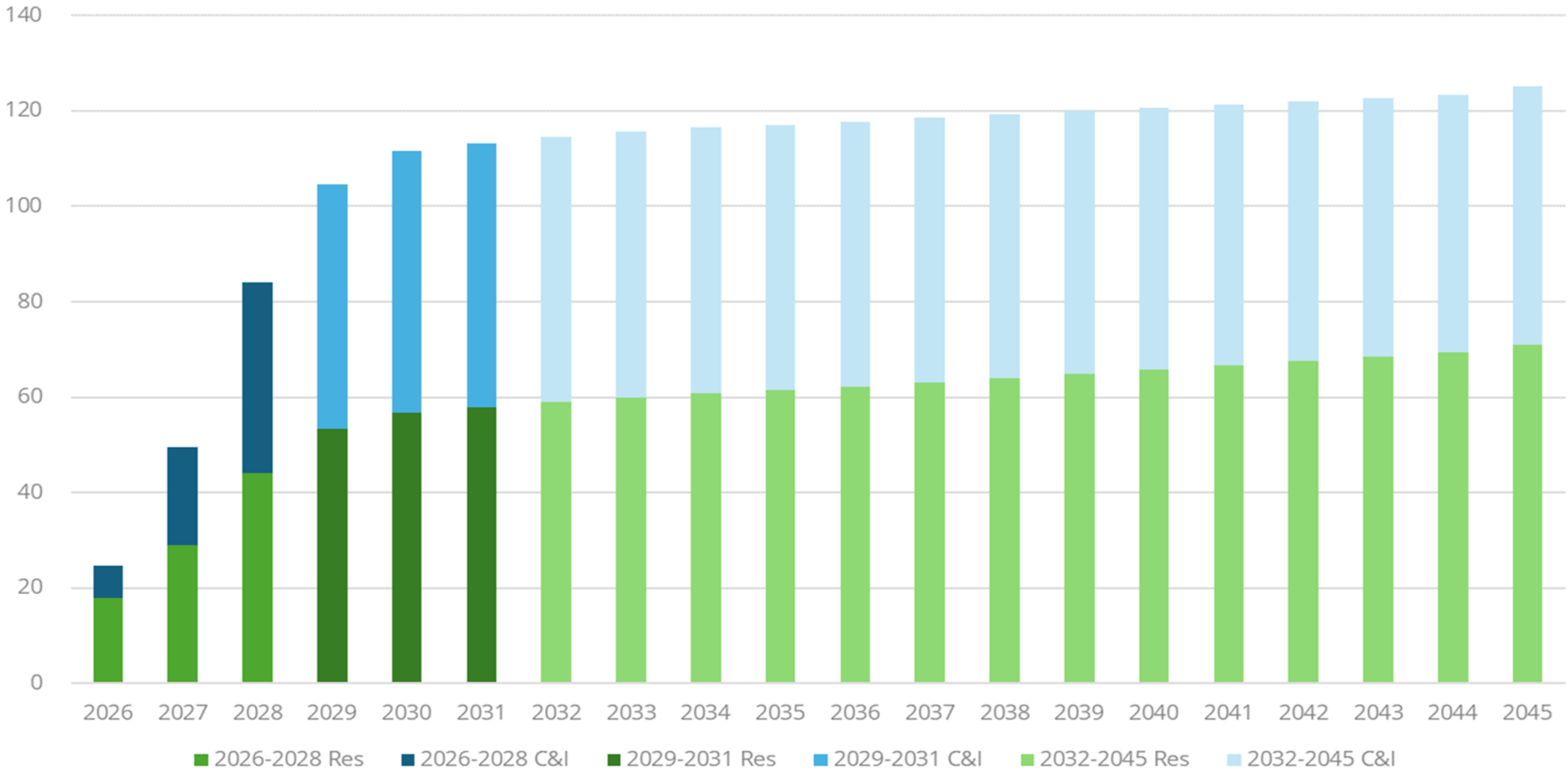


Chart reflects cumulative savings potential available to be selected by the model.

DR Bundles by Sector

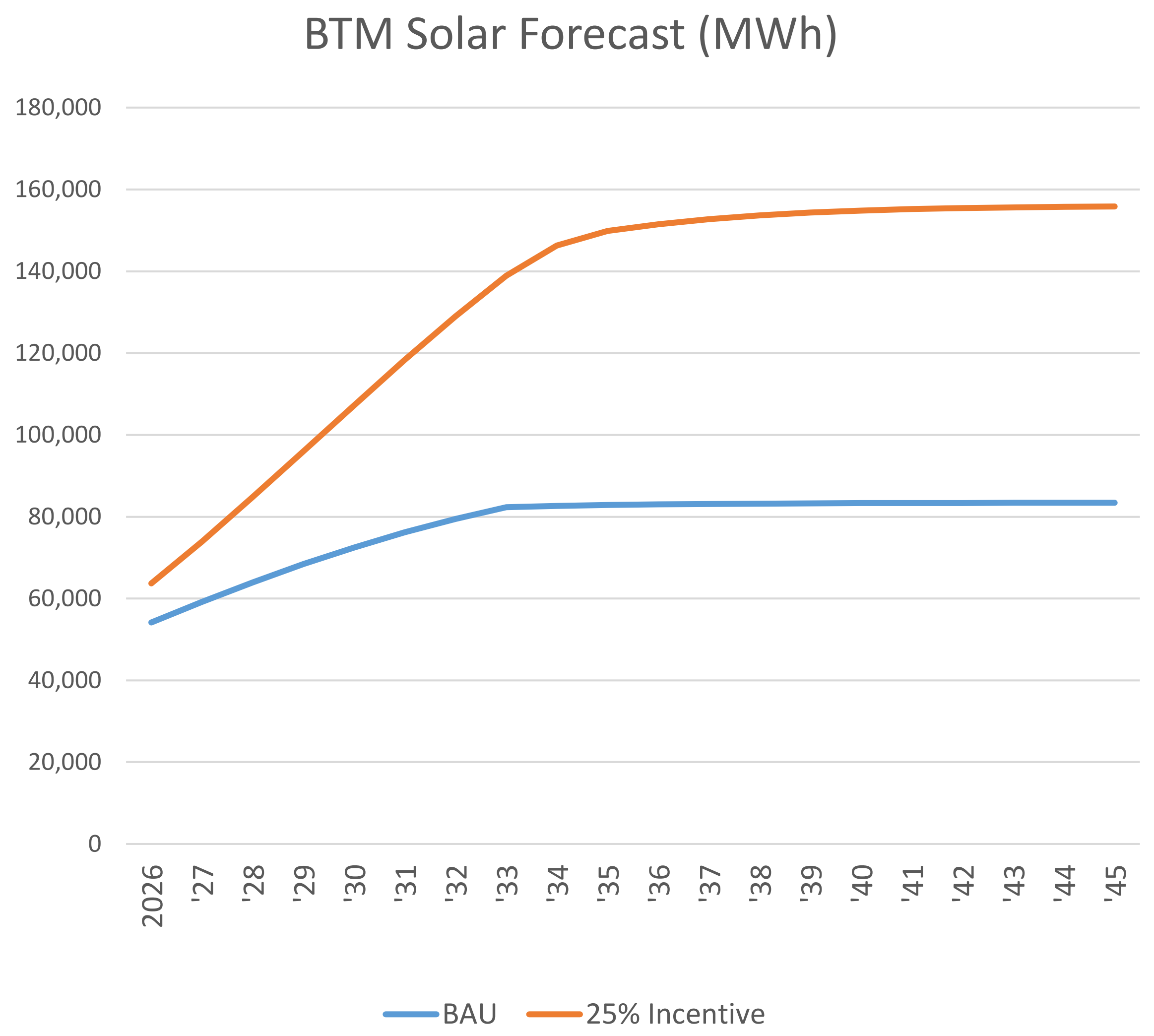


- Preliminary chart that reflects cumulative savings potential for cost-effective measures only;
- However, all DR potential will be available to be selected in model;
- In addition, DER measures (solar and solar + storage) are also being developed and will be available for model selection.

DER Resources

- Behind the Meter (BTM) Solar
  - IRP Inputs based on incremental impacts above and beyond business as usual/no intervention forecast
  - Assumes utility intervention (25% incentive) for solar PV installs
  - PV installs assumed across residential and nonresidential sectors

- Battery Storage
  - Battery Storage considered as part of the Demand Response analysis
  - Program opportunity was tethered to the BTM Solar Forecast that assumes the 25% utility intervention



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- However, all DR potential will be available to be selected in model;
- In addition, DER measures (solar and solar + storage) are also being developed and will be available for model selection.

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CVR Inputs

First Full Year In-Service	# of CVR Projects	Annual Projected Energy Savings (kWh)	Annual Projected Demand Savings (kW)	Sum of Capital Cost	Sum of Annual O&M Cost
2025	25	25,949,992	695	$20,504,336	$386,059
2026	34	31,731,801	1,105	$27,418,013	$525,040
2027	14	16,230,802	436	$11,729,327	$216,193
2028	6	4,942,409	158	$3,174,476	$92,654
2029	10	9,560,529	354	$7,056,004	$154,424
2030	1	1,506,137	19	$565,204	$15,442

- CVR useful life is 20 years. Project annual energy and demand savings will be included in the model for 20 years from "First Full Year In-Service";
- All CVR savings shown above will be forced into the model.

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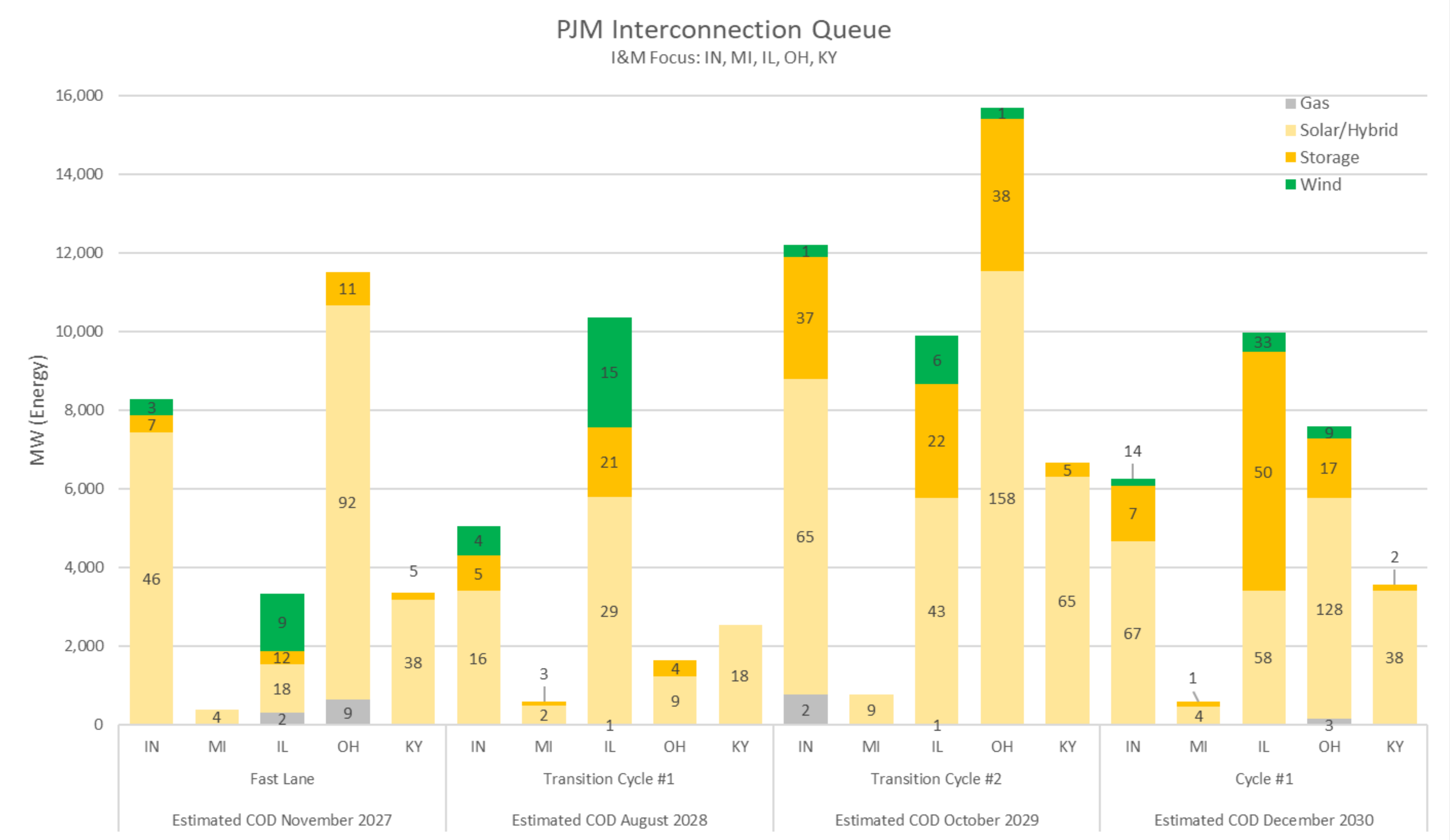
Resource Availability – IN, MI, IL, OH, KY



NOTE: Stacked Bar Chart Labels Represent Project Counts

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Resource Modeling Parameters (Baseload Resources)

Base Load (New Resources)

Resource Type	First Year Available	Annual Build Limit (MW)	Cumulative Build Limit through 2030 (MW)	Total Cumulative Build Limit Through Planning Horizon (MW)	Overnight Cost[1] $/kW
NUCLEAR SMALL MODULAR REACTOR	2037	600	N/A	5,100	$11,700
NEW NG COMBINED CYCLE (2x1)	2031	1,030	N/A	5,600	$1,800
NEW NG COMBINED CYCLE (1x1)	2031	420	N/A		$2,000
NEW NG COMBINED CYCLE W/CARBON CAPTURE SYSTEM (CCS)	2035	380	N/A	3,800	$4,300

Base Load (Existing Resources)

Resource Type	First Year Available	Last Year Available	Annual Build Limit (MW)	Cumulative Build Limit through 2030 (MW)	Total Cumulative Build Limit Through Planning Horizon (MW)	Overnight Cost[1] $/kW	Overnight Cost[1] $/MW-D
EXISTING NG COMBINED CYCLE (5 YEAR)	2028	2031	1,800	3,600	5,400	N/A	$485
EXISTING NG COMBINED CYCLE (10 YEAR)	2028	2031					
EXISTING NG COMBINED CYCLE (20 YEAR)	2028	2031				$1,100	N/A

Note 1: Costs represent nominal dollars in the first year that the resource is available.

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Resource Modeling Parameters (Peaking Resources)

Peaking (New Resources)

Resource Type	First Year Available	Annual Build Limit (MW)	Cumulative Build Limit through 2030 (MW)	Total Cumulative Build Limit Through Planning Horizon (MW)	Overnight Cost[1] $/kW
NEW COMBUSTION TURBINE	2030	920	920	6,670	$1,500
COMBUSTION TURBINES AERODERIVATIVE	2031	330	N/A	1,320	$2,020
RECIPROCATING INTERNAL COMBUSTION ENGINES (RICE)	2031	100	N/A	400	$3,300

Peaking (Existing Resources)

Resource Type	First Year Available	Last Year Available	Annual Build Limit (MW)	Cumulative Build Limit through 2030 (MW)	Total Cumulative Build Limit Through Planning Horizon (MW)	Overnight Cost[1] $/kW	Overnight Cost[1] $/MW-D
EXISTING NG COMBUSTION TURBINE (5 YEAR)	2028	2031	1,000	3,000	4,000	N/A	$320
EXISTING NG COMBUSTION TURBINE (10 YEAR)	2028	2031					
EXISTING NG COMBUSTION TURBINE (20 YEAR)	2028	2031				$540	N/A

Note 1: Costs represent nominal dollars in the first year that the resource is available.

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Resource Modeling Parameters (Intermittent Resources)

Intermittent (Wind & Solar)						
Resource Type	First Year Available	Annual Build Limit (MW)	Cumulative Build Limit through 2030 (MW)	Total Cumulative Build Limit Through Planning Horizon (MW)	Overnight Cost[1] $/kW	Overnight Cost[1] $/MWh
WIND (15 YEAR)	2029	600	800	3,200	N/A	$86
WIND (30 YEAR)	2031	400	N/A		$3,000	N/A
SOLAR (15 YEAR)	2028	600	1,200	4,800	N/A	$85
SOLAR (35 YEAR)[2]	2028	600	1,200	4,800	$2,500	N/A
SOLAR w/STORAGE (4-HOUR)	2028	600	750	1,350	$3,100	N/A

Intermittent (Storage)					
Resource Type	First Year Available	Annual Build Limit (MW)	Cumulative Build Limit through 2030 (MW)	Total Cumulative Build Limit Through Planning Horizon (MW)	Overnight Cost[1] $/kW
NEW STORAGE (4-HOUR)	2028	250	500	3,000	$2,000
NEW STORAGE (6-HOUR)	2029	150	300	1,800	$3,000
NEW STORAGE (8-HOUR)	2029	100	200	1,200	$4,000
NEW STORAGE (100-HOUR)	2032	40	N/A	240	$2,800

Note 1: Costs represent nominal dollars in the first year that the resource is available.
Note 2: I&M plans to incorporate recent stakeholder feedback by modeling a subset of solar resources that are eligible for the Energy Community Tax Credit Bonus

IRA Tax Credit Inputs

Investment Tax Credits (ITC)

- ITC applied to Solar, Storage and SMNR
- Additional Energy Community Credits assumed for subset of renewable options
- Schedule of ITC
  - 2025-36: 30% credit
  - 2037: 22.5%
  - 2038: 15%
  - 2039+: 0%

Production Tax Credits

- PTC applied to Wind
- Schedule of PTC
  - 2025-36: applied to all new build wind for the first 10 years of life (~ in the range of $40/MWh-$58/MWh)
  - 2037: PTC reduced by 25%
  - 2038: PTC reduced by 50%
  - 2039+: No PTC applied to new builds from this year onwards

Carbon Capture Storage Tax Credits

- Credit applied to Carbon Capture Storage technologies for every MWh produced
- Schedule of Carbon Capture Storage Tax Credits
  - 2025-36: applied to all new build CC with CCS for the first 12 years of life (~ in the range of $29/MWh-$44/MWh)
  - 2037+: No CCS tax credits applied to new build from this year onwards

Cook Subsequent License Renewal (SLR) Analysis

Cook Relicensing Optimization

- U1 Current License Expiration Q4 2034;
- U2 Current License Expiration Q4 2037;
- Model will optimize the decision to retire or relicense while considering economics and reliability.

Costs Considered in Cook Relicensing Analysis

- **NOTE:** these are estimates in 2023 Dollars and do not include items such as AFUDC, Overhead Costs, Cost Escalations, etc.;
- **Subsequent License Renewal (SLR) Cost**: $42.5M;
- **One-Time inspection Costs after SLR received:** $20M;
- **Dry Cask Fuel Storage Pad Extension Cost:** $4.1M (reflects assumed DOE reimbursement of certain costs) ;
- **Capital Improvement Costs to support an additional 20 years of life:** $250M;
- On-Going Capital Costs (OGC) and Fixed Operations & Maintenance (FO&M) Cost schedules.

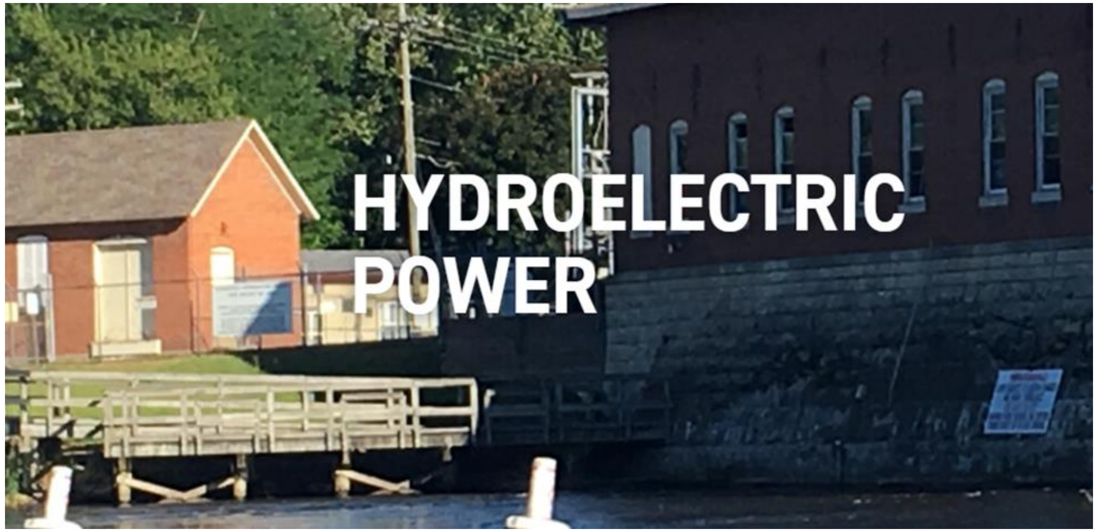
Hydro Subsequent Renewed Operating License Analysis

Hydro Relicensing Optimization

- Analysis only performed on Hydro units that have license expirations occurring within the next 10 years;
- Elkhart Current License Expiration Q4 2030;
- Mottville Current License Expiration Q4 2033;
- Model will optimize the decision to retire or relicense while considering economics and reliability.

Costs Considered in Hydro Relicensing Analysis

- **NOTE:** These are estimates and do not include items such as AFUDC, Overhead Costs, Cost Escalations, etc.;
- Operating License Renewal Cost:
  - $1M for Elkhart and $1M for Mottville;
- On-Going Capital Costs (OGC) and Fixed Operations & Maintenance (FO&M) Cost schedules;
- Decommissioning Costs:
  - Elkhart: $262M
  - Mottville: $115M



Storage Modeling Inputs & Methodology (Utility Scale)

Utility Scale Storage Resource Options

Modeling Steps

- Storage resources are dispatched against Fundamental Market Prices in an hourly chronological production cost model run;
- The Generation and Charge Costs are extracted and placed as inputs in the Expansion Planning Optimization;

Day Ahead, Real Time, and Ancillary Services Market Revenue

- Value in the Ancillary Service and RT Energy Markets are captured through Fixed Cost reductions in the Expansion Planning Optimization. Additional volatility in the DA Market is captured in the same fashion.

Utility - Scaled Storage Options Specs per Block					
Technology	Power (MW)	Duration	Capacity (MWh)	RTE%	Expected Life (years)
Lithium - Ion	50	4	200	87%	20
Lithium - Ion	50	6	300	87%	20
Lithium - Ion	50	8	400	87%	20
Lithium - Ion	50	10	500	87%	20
Iron - Air	20	100	2000	40%	20

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Storage Modeling Inputs & Methodology (Distribution-Sited)

Distribution Storage Resource Options

Modeling Steps

- Distribution Storages Resources are dispatched against Fundamental Market Prices in an hourly chronological production cost model run;
- The Generation and Charge Costs are extracted and placed as inputs in the Expansion Planning Optimization.

2 Use Cases

- "Thermal" Use Case
    - Storage placed at stations nearing thermal overload conditions. Storage adds additional capacity at station and defers the need for upgrades (e.g., upgrading to a larger transformer);
    - Capital cost of storage will be reduced by estimated deferred cost of distribution upgrade;
    - Storage restricted from receiving energy revenues in peak months (mid-July to mid-August) but can receive energy revenues in the remaining months.
- "Reliability" Use Case
    - Storage placed at stations that have had historical reliability issues.
    - 50% of storage capacity always reserved to address reliability events. Remaining 50% of capacity can be used for energy market.
    - Capital cost of storage will be reduced by estimated Avoided Customer Minutes of Interruption (CMI) savings from improved reliability.

Distribution Storage Resource Option Specs								
Target Station(s)	Technology	Power (MW)	Capacity (MWh)	RTE%	Direct Capital Est ($N	Need By (Date)	Expected Life (years)	Primary Use Case
County Road 4	Lithium - Ion	3	12	87%	$18	4/1/2028	20	Thermal
Robison Park	Lithium - Ion	3	12	87%	$18	12/1/2028	20	Thermal
Colfax	Lithium - Ion	3	12	87%	$18	6/1/2029	20	Thermal
Summit	Lithium - Ion	4	16	87%	$24	6/1/2028	20	Thermal
Beech Rd	Lithium - Ion	3	12	87%	$18	6/1/2033	20	Thermal
Pleasant-Yoder	Lithium - Ion	1	4	87%	$6	12/31/2028	20	Reliability
Whitaker-Elk	Lithium - Ion	3	12	87%	$18	12/31/2028	20	Reliability

Note*: The Direct Capital Est is deducted by Deferred Capital Cost for Thermal use cases and CMI Savings for Reliability use cases

Implementing Stakeholder Feedback: Carbon-Free Sensitivity

Carbon-Free Sensitivity Modeling Considerations

- I&M will model a Carbon-Free Sensitivity that optimizes a portfolio that:
  - Meets total system needs and
  - Serves the energy requirements of HSL and large industrial customers with carbon-free resources.
- Model results will provide insight into how early HSL and large industrial customers' energy requirements could be met with carbon-free resources.
- Any market purchases that the model selects will not count as a carbon-free resource.

Market Scenarios

Scenario	Load	Gas Price	Environmental Regulations
Base	Base	Base	Pre-EPA 111d 2023 Proposed Rules
High Economic Growth	High	High	
Low Economic Growth	Low	Low	
Enhanced Environmental Regulations (EER)	Base	Base	EPA 111d 2023 Proposed Rules

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Proposed Market Sensitivities

Sensitivities	Load	Gas Price	Environmental Regulations
Base under EPA 111d Requirements	Base	Base	EPA 111d 2024 Final Rules
Carbon-Free Sensitivity	Base	Base	Pre-EPA 111d 2023 Proposed Rules
Base with High IN Load	High	Base	
Base with Low IN Load	Low	Base	
Rockport Unit 1 Retires 2025	Base	Base	
Rockport Unit 1 Retires 2026	Base	Base	
Exit OVEC ICPA in 2030	Base	Base	
High Technology Cost	Base	Base	

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Public Stakeholder Meetings 3A & 3B

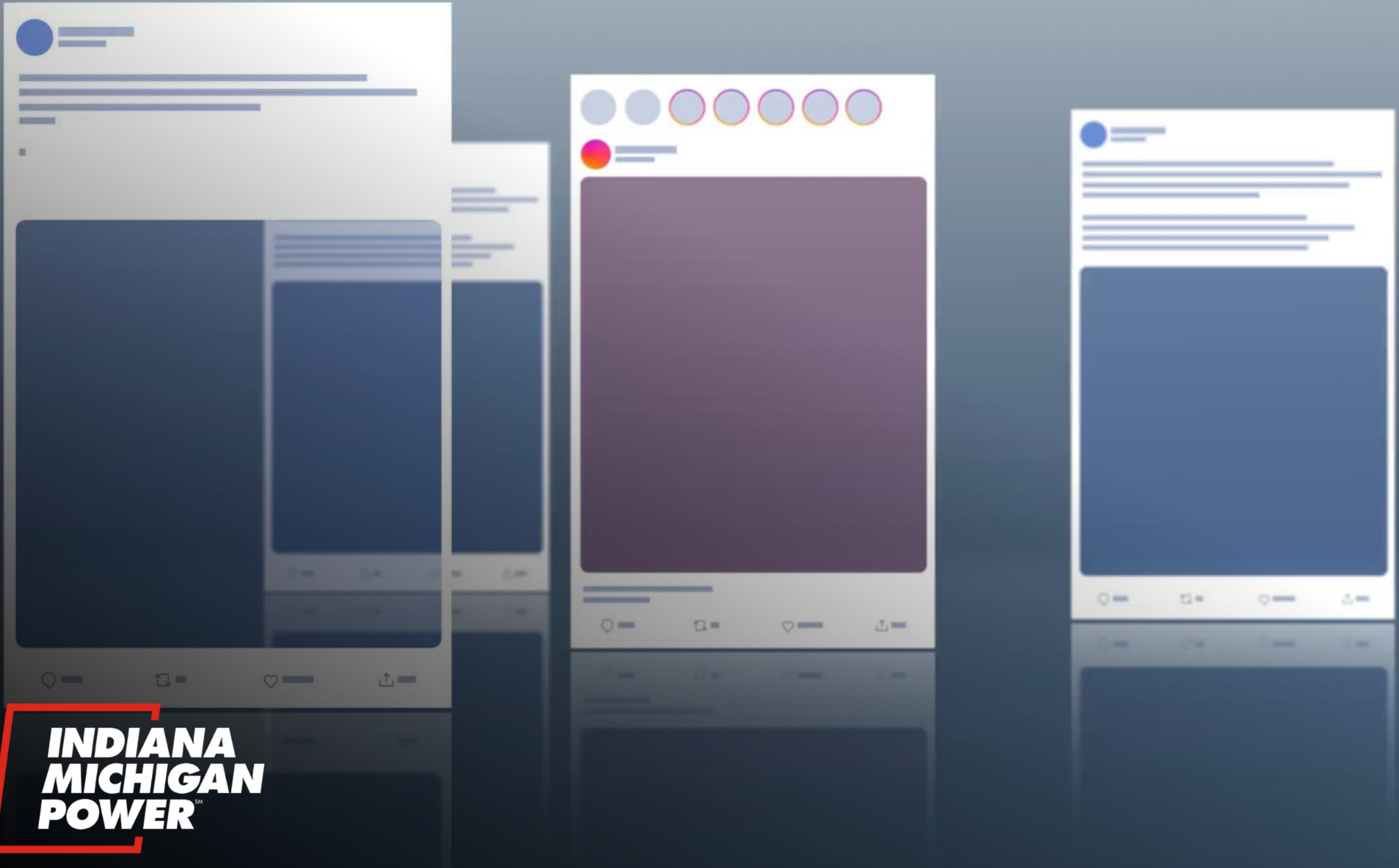
Modeling Results to be Presented at Stakeholder Meetings 3A and 3B

- I&M will begin modeling 4 market scenarios & 8 market sensitivities and present modeling results in 2 upcoming stakeholder meetings (i.e., 3A and 3B);
- I&M is targeting December 2024 to hold Stakeholder Meeting 3A and February 2025 to hold Stakeholder Meeting 3B.

Scenario	Stakeholder Meeting 3A or 3B
Base	3A
High Economic Growth	3B
Low Economic Growth	3B
Enhanced Environmental Regulations (EER)	3B

Sensitivities	Stakeholder Meeting 3A or 3B
Base under EPA 111d Requirements	3A
Carbon-Free Sensitivity	3A
Base with High IN Load	3A
Base with Low IN Load	3A
Rockport Unit 1 Retires 2025	3B
Rockport Unit 1 Retires 2026	3B
Exit OVEC ICPA in 2030	3B
High Technology Cost	3B

Feedback and Discussion



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APPENDIX

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Portfolio Performance Indicators

IURC Pillar	IRP Objective	Performance Indicator	Metric Description
Reliability	Maintain capacity reserve margin and the consideration of reliance on the market for the benefit of customers.	Energy Market Exposure – Purchases	Cost and volume exposure of market purchases (Costs and MWhs % of Internal Load) in 2033 and 2044
		Energy Market Exposure - Sales	Revenue and volume exposure of market sales (Revenues and MWhs % of Internal Load) in 2033 and 2044
		Planning Reserves	Target Reserve Margin
Affordability	Maintain focus on cost and risks to customers	Net Present Value Revenue Requirement (NPVRR) Levelized Rate ($/MWh)	Portfolio 30yr NPVRR Portfolio 30yr Levelized Rate (NPVRR/Levelized Energy)
		Near-Term Rate Impacts (CAGR)	7-year CAGR of Annual Rate
		Portfolio Resilience	Range of Portfolio NPVRR and associated Rate Impact ($/MWh) (at rqd IRP Planning Period) costs dispatched across all Scenarios
Resiliency	Maintain diversity of resources and fleet dispatchability	Resource Diversity	Diversity Index inclusive of Capacity and Energy Diversity
		Fleet Resiliency	% Dispatchable Capacity of Company Peak Load
(Grid) Stability	Maintain fleet of flexible and dispatchable resources	Fleet Resiliency	% Dispatchable Capacity of Company Peak Load
Environmental Sustainability	Maintain focus on portfolio environmental sustainability benefits and compliance costs	Emissions Change	CO_2, NO_x, SO_2 emissions change compared to 2005 levels
		Total Portfolio Costs (NPVRR)	Considered under Affordability Pillar above

INDIANA MICHIGAN POWER
An AEP Company

Fundamentals Enhanced Environmental Regulation (EER) Scenario

Scenario

Scenario Models EPA's 111d Rule Changes
- Proposed Rule Published May 11, 2023

Generators impacted:
- Exiting coal units
- Existing natural gas units >300 MW
- New gas units

Scenario Summary:
- ~50% power price increase on expiration of IRA credits mid-2040s

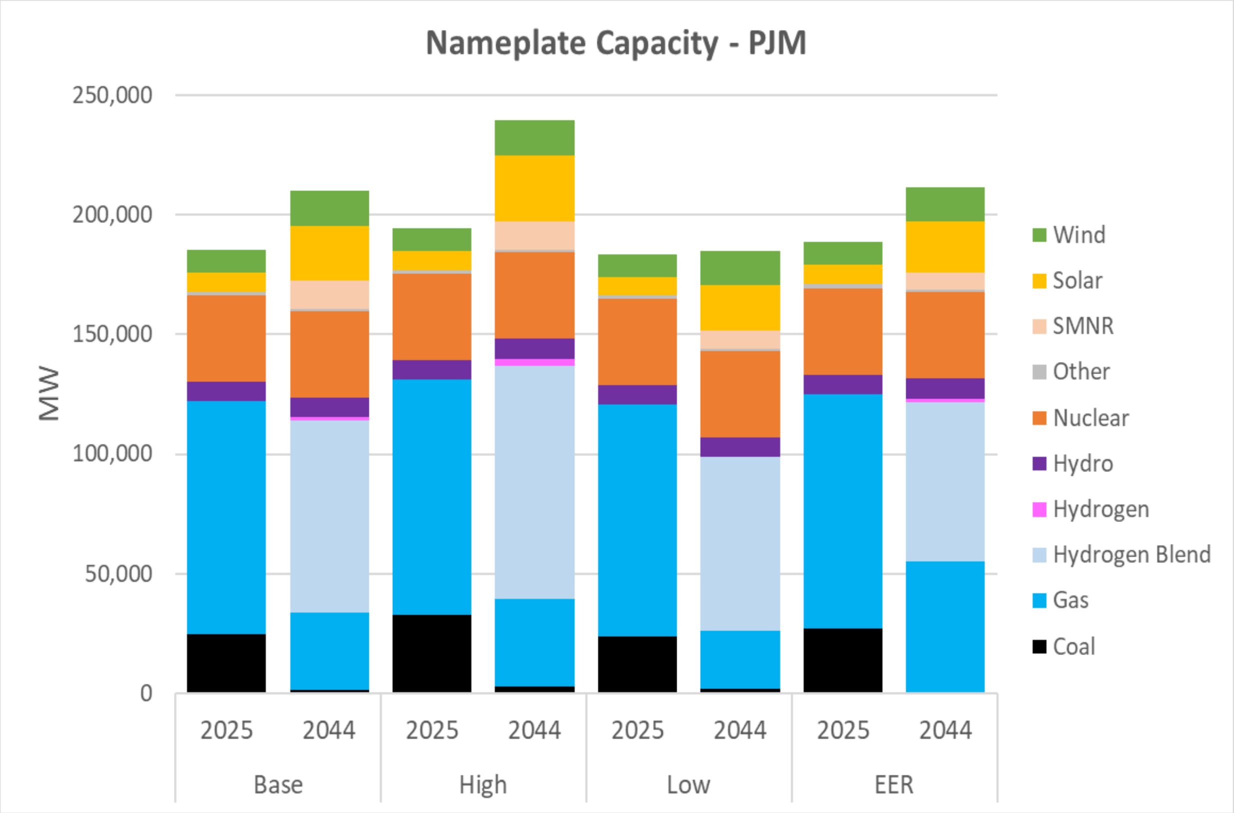
Dispatchable Generation Options

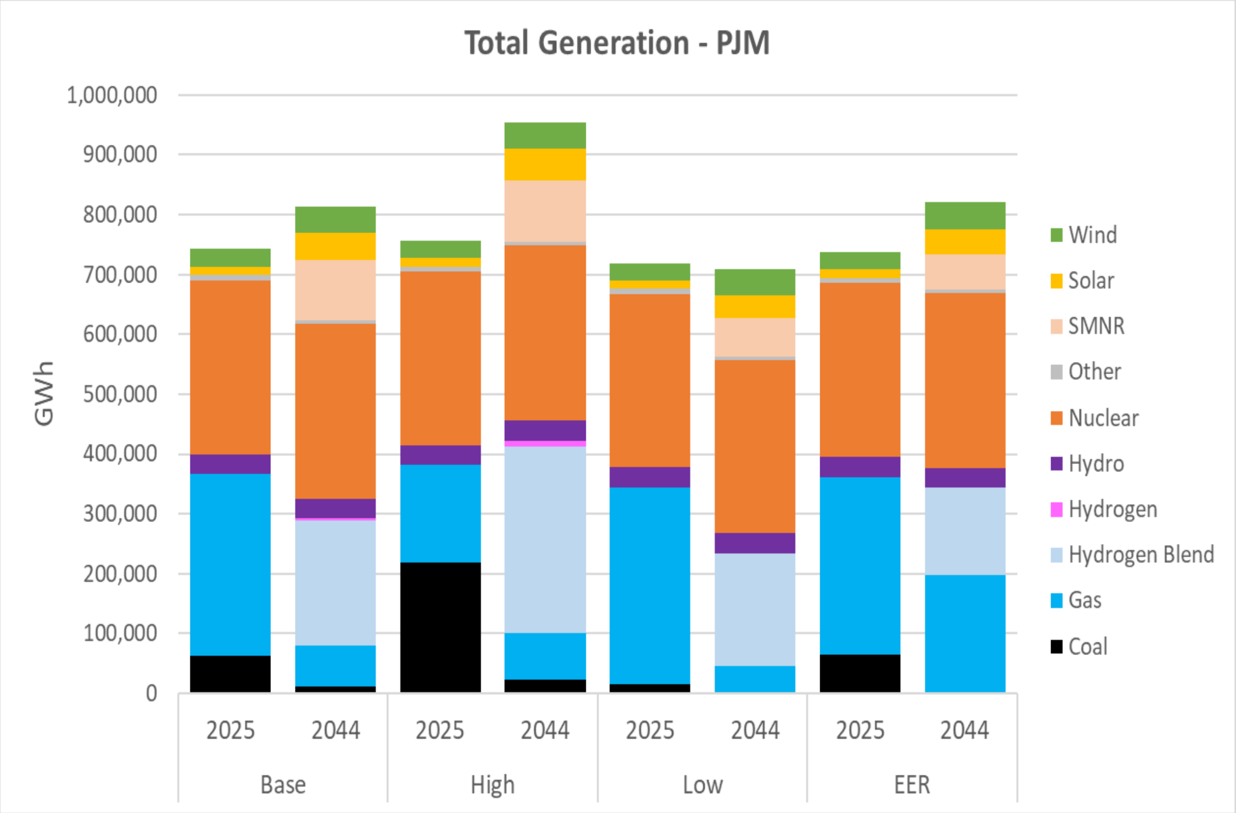
Existing coal units' options to continue operation past 2032 must:
- Limit capacity factor to 20%, retire by 2035
- Blend 40% Natural Gas with coal, retire by 2040
- Install CCS

Existing Natural Gas Units >300 MW and 50% Capacity Factor:
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

New Gas Units:
- Adhere to carbon emission performance standard
- Up to 96% hydrogen 4% natural gas fuel blend
- Install CCS

PJM Supply Mix Changes

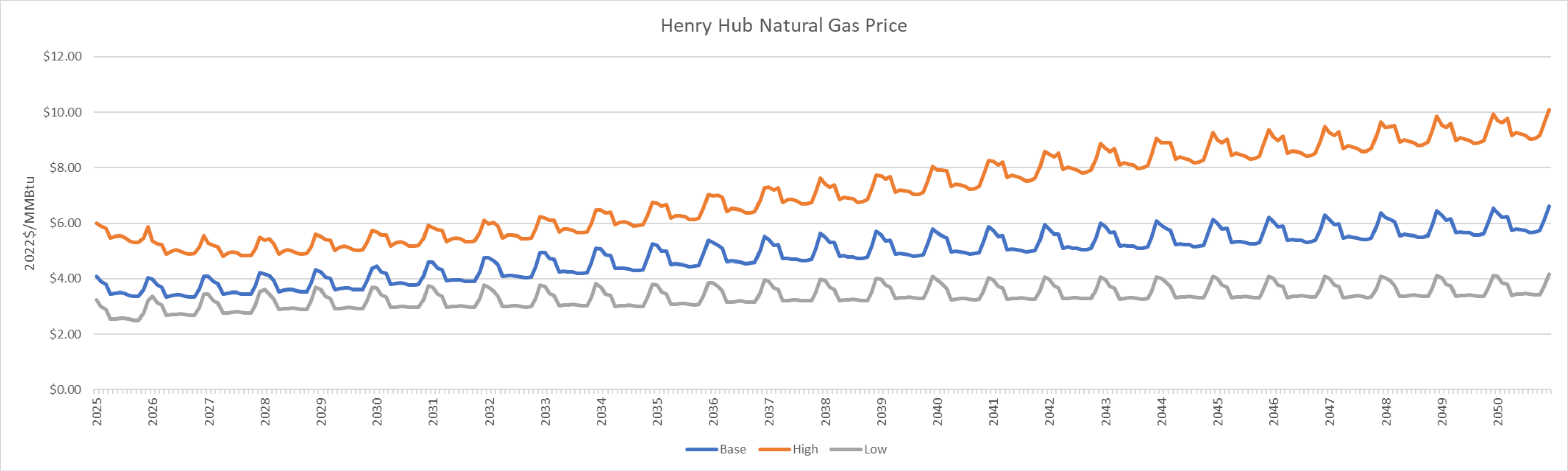




- Under all scenarios, coal is replaced primarily by NG/Hydrogen Blend units
- Solar sees significant growth in the long term
- Wind growth is moderate

- Nuclear and natural gas generation dominate the supply mix
- Natural gas/Hydrogen Blend units provide reliable, dispatchable generation as coal plants are retired

Natural Gas Inputs



- Base case assumes that natural gas demand will increase as natural gas replaces coal
- High and Low cases have similar assumptions to Base except for WTI prices and LNG exports
    - High case assumes higher WTI prices and LNG exports
    - Low case assumes lower WTI prices and LNG exports

PJM Market Prices

- Under all scenarios, energy prices are mainly influenced by natural gas prices
- Peak/Off-Peak spread averages are as follows:
  - Base: $2.71/MWh
  - High: $3.89/MWh
  - Low: $1.47/MWh
  - EER: $2.69/MWh