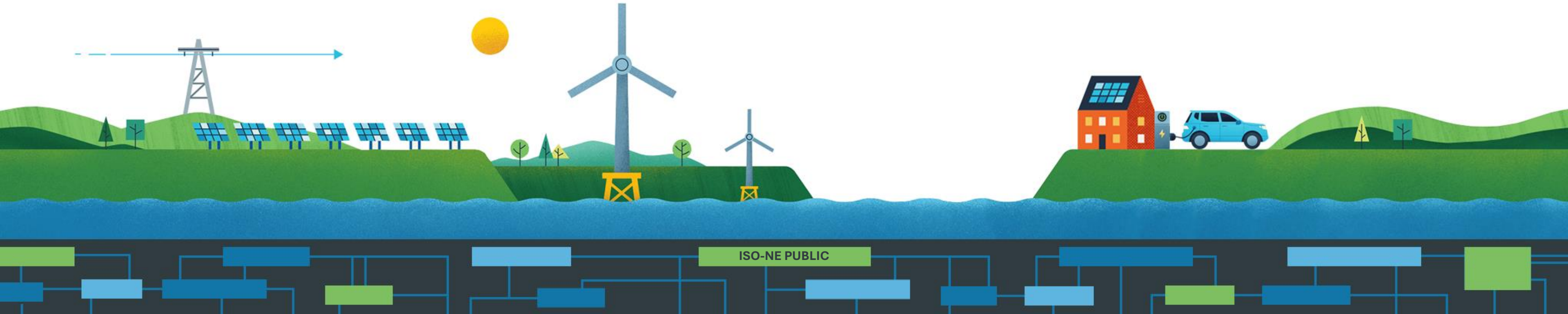
SEPTEMBER 3, 2025

2024 Economic Study

Detailed Results



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OVERVIEW OF THE ECONOMIC STUDIES

Objective of the Economic Study Process

- Provide information to stakeholders to facilitate the evaluation of economic and environmental impacts of New England regional policies, federal policies, and various resource technologies on satisfying future resource needs in the region
  - Identify system efficiency issues on the Pool Transmission Facilities (PTF) portion of the New England Transmission System and, as applicable, evaluate competitive solutions to alleviate identified system efficiency needs

Procedures for the Conduct of Economic Studies are outlined in [Section 17 in Attachment K of the OATT]

Economic Study Reference Scenarios

Benchmark Scenario

Prior Year

Model the previous calendar year and compare it to historical performance to assess model fidelity and improve future scenario accuracy

System Efficiency Needs Scenario

10 Years Out

Model a future year (10-year planning horizon) based on the ISO's existing planning criteria to identify system efficiency issues that could meet the threshold of a System Efficiency Needs Assessment and move on to the competitive solution process for System Efficiency Transmission Upgrades needs

Policy Scenario

Beyond 10 Years

Model future years (10+ year planning horizon) based on satisfying New England region and other energy policies and goals

Stakeholder-Requested Scenario

?

Stakeholders may request analysis with a region-wide scope that is not covered by the other three scenarios; or, they may request additional "sensitivity" analysis on these three scenarios

Sensitivities on the Reference Scenarios

- Following the analyses, runs, and presentation of the results of the Economic Study reference scenarios, stakeholders may request, and the ISO may propose, additional sensitivities to test the effect of a specific change to input assumptions
- The sensitivities shall be limited to a single theme or category of changes to allow for better understanding of the causal effect of the change to the results

Sensitivity

Incremental changes to a Reference Scenario

(e.g., resource additions, transmission modification, economic input changes)

Ex: Add 4,000 MW of dual-fuel capability to existing natural-gas-fired units to the System Efficiency Needs Scenario

VS

Scenario

Requests that would require a new modeling framework that is outside the scope of Reference Scenarios

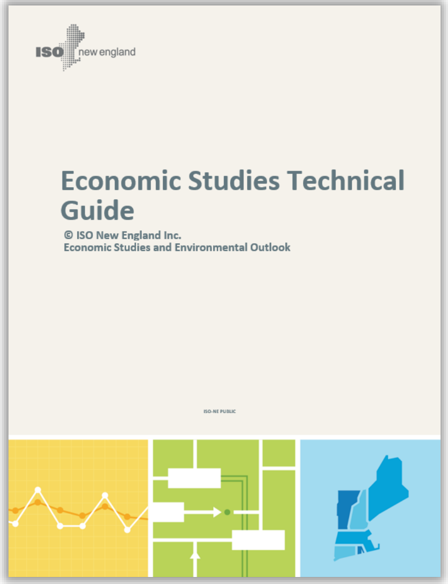
Ex: Analyze the effects on system reliability and resource compensation of PPAs vs PPAs + a reliability adder for the Policy Scenario

2024 Economic Studies Report

- This report includes the Policy, Stakeholder-Requested, and Benchmark Scenarios
- Due to timing constraints from implementation of recent Tariff changes—which affect how the System Efficiency Needs Scenario (SENS) is conducted—and resource limitations from the ongoing LTTP effort, SENS was not included in the report
  - Instead, the ISO will presented SENS results separately to the PAC

Economic Studies Technical Guide

- The ISO published the first version of the Economic Studies Technical Guide (ESTG) on March 25, 2024
  - Revision 1.1 of the ESTG was issued on August 5, 2025
- The ESTG seeks to provide stakeholders, policymakers, and the public with a comprehensive document that describes the Economic Study process
  - Please refer to the ESTG for detailed questions about assumptions and study procedures



BENCHMARK SCENARIO

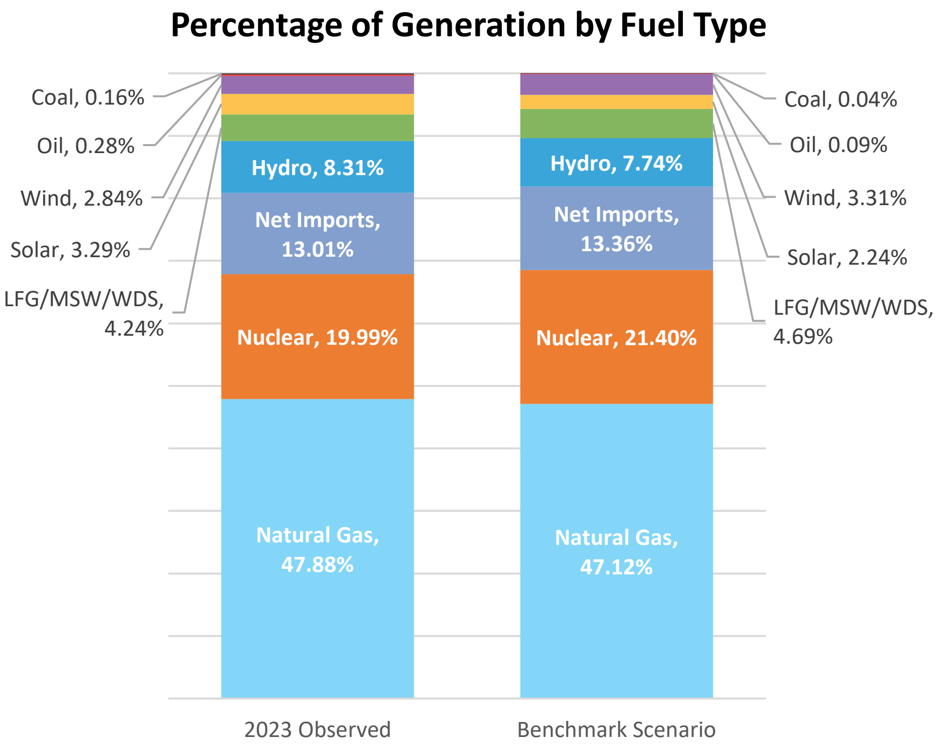
Benchmark Scenario Results Overview

- The Benchmark Scenario models the 2023 New England system to test the fidelity of the model as compared to observed outcomes
- Historical metrics from 2023 SMD real-time results are used to compare data with the Benchmark Scenario, these include:
  - Average and annual LMPs
  - Production by fuel type
  - Interface flows

Benchmark Scenario Preliminary Results

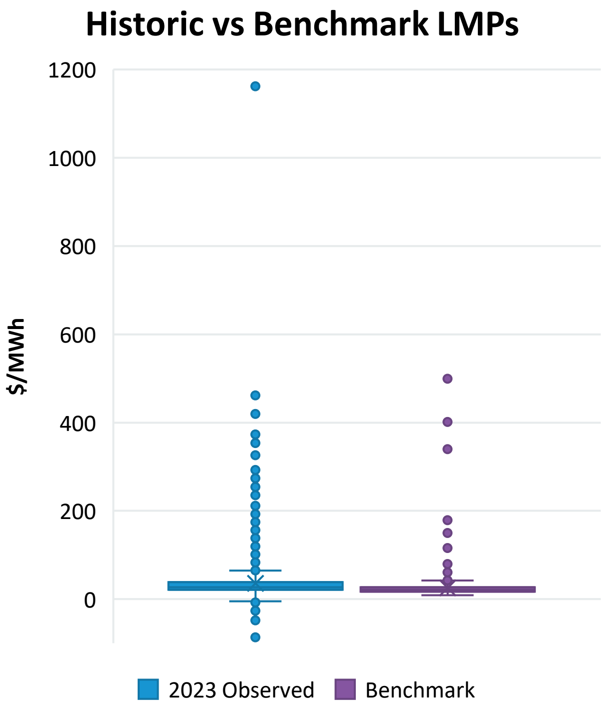
- Model results for generation by fuel type reflect historic results
- Modeled locational marginal prices (LMPs) are lower than historical LMPs due to the model attempting to minimize production cost
  rather than generator bids aimed at maximizing profit
- Some interface flows reflect historic flows better than others, but all have similar average and net flows

Results: Historic vs. Benchmark Scenario Generation by Fuel Type



- Total historic generation was **116.1 TWh** and **113.3 TWh** in the Benchmark Scenario
- Non-emitting resources provided 47.5% of all generation historically and 48% in the Benchmark Scenario
- Wind and solar generation profiles are based on historic weather data, so there may be discrepancies between real-time historic versus profiled generation

Results: Historical Real-Time vs. Benchmark Scenario LMPs



- The average of the historical 2023 real-time LMPs was **$35.70/MWh**, while the Benchmark Scenario LMPs average **$26.40/MWh**
- As expected, the Benchmark Scenario's LMPs are significantly lower than historic LMPs due to PLEXOS' ability to optimize dispatch to minimize cost
  - PLEXOS uses a 1-month look ahead for resource allocation, allowing the model to optimize hydro and storage dispatch and plan for abnormal system conditions
- Historic real-time LMPs reflect impact of generator and transmission contingencies that are outside the scope of the Benchmark Scenario

Transmission Constraints and N-1 Contingencies

- The transmission-constrained model enforces thermal interface transfer limits and line and transformer limits above 115kV
- PowerGEM/TARA was first used to identify 700 monitored contingency (mon/con) pairs that were likely candidates to bind via flowgate analysis

Results: Binding Interfaces and Subareas

Interface	Hours Binding	Shadow Price ($/MW)
Keene Road Export	1,480	18.16
Whitefield-South + GRPW	229	20.00
Sheffield-Highgate Export	215	8.55
Orrington South	158	27.46
Surowiec South	17	55.72
Northwest Vermont Import	3	36.80

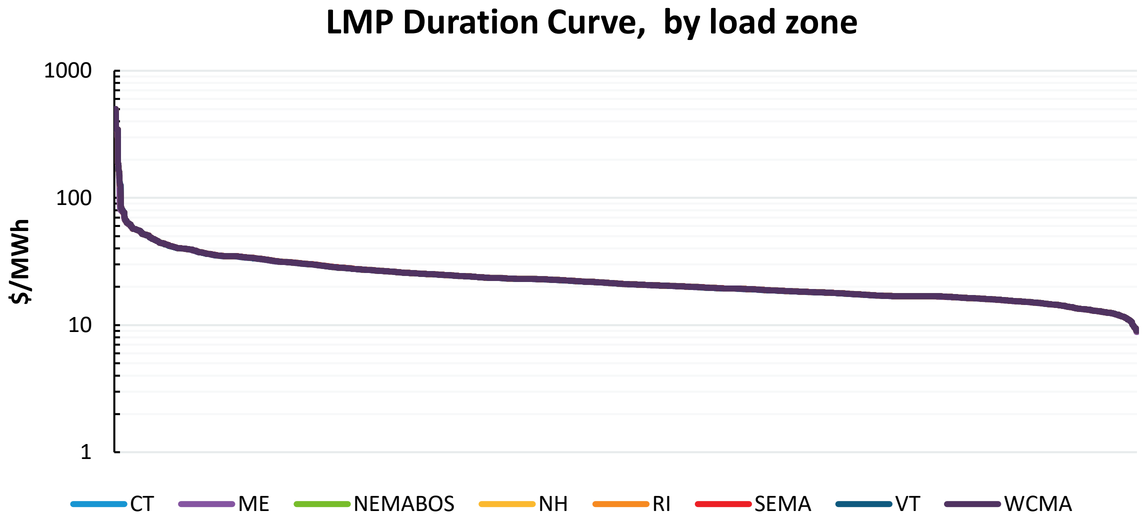
- Operational transfer limits for interfaces fluctuate based on voltage, stability, and thermal constraints and on-going system conditions and are too complex to be modeled in PLEXOS
  - For this reason, 'hours binding' is not a viable metric to use on historic interface flows
  - The ISO's Operations team verified the locations and frequencies of the binding elements that were identified by the model
- 9 contingencies cause additional congestion in the model, 7 of which result in 36 hours of congestion or less
  - Congestion on the 115kV system in northeastern Maine is primarily due to high wind generation
  - Congestion on transmission from northern to southern New England occurs during peak load conditions

Results: Interface Constrained Model

Gen by Fuel (GWh)	Coal	Gas	Hydro	Nuc	Oil	Landfill Gas (LFG)	Municipal Solid Waste (MSW)	Photovoltaic (PV) (Non Behind-the-meter (BTM))	Wind	Wood	Net Tie Flow	Active Demand Response (ADR)	Total
Unconstrained Tx	41	53,417	8,806	24,261	95	370	2,725	2,545	3,766	2,246	15,153	2	113,427
Fully Constrained Tx	41	53,426	8,780	24,261	104	369	2,719	2,545	3,751	2,232	15,153	1	113,383
Difference by Constraining Tx	0	10	-26	0	8	-1	-6	0	-15	-15	0	-1	-43

- The interface constrained model reduces hydro and biomass generation which is supplemented with gas and oil
  - This causes a slight increase in LMPs; $25.59/MWh in the unconstrained model versus $26.40/MWh in the fully constrained model
- Small differences in total generation are due to differences in energy storage dispatch

Results: Zonal LMPs



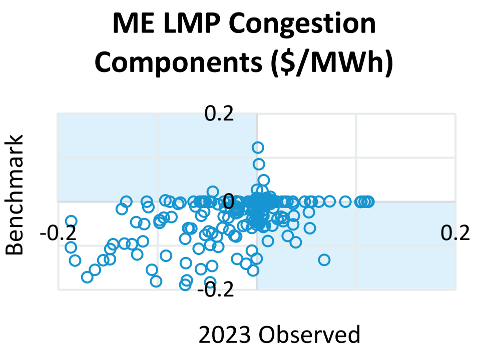
Historic v Benchmark Zonal LMPs ($/MWh)		
Aggregate Load Zone	2023 Observed	Benchmark
CT	35.05	26.42
ME	35.15	26.24
NEMABOS	36.00	26.24
NH	35.84	26.35
RI	35.50	26.20
SEMA	35.95	26.40
VT	35.34	26.91
WCMA	35.71	26.40

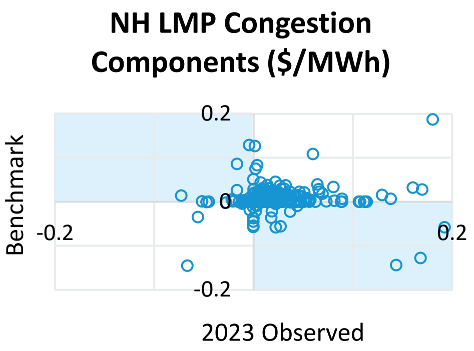
- LMPs vary minimally across load zones, even with fully constrained transmission and N-1 contingencies

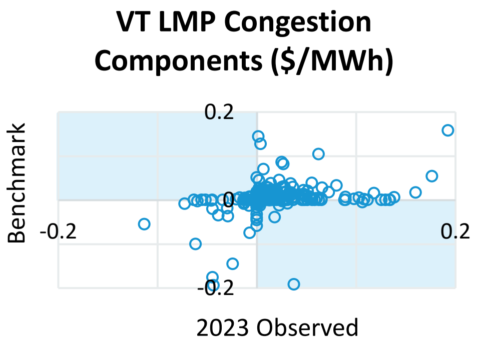
Results: Historic vs. Benchmark Scenario Congestion

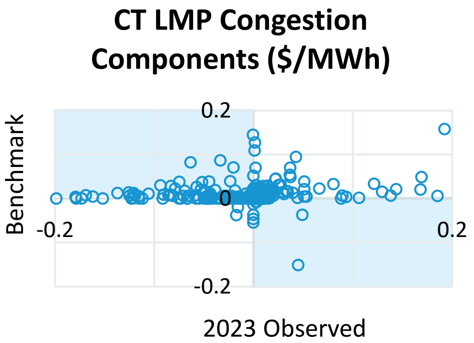
- SMD hourly data include historic real-time congestion components of load zone LMPs
  - Positive congestion components indicate an increase in LMPs due to congestion
  - Negative congestion components indicate a decrease in LMPs due to congestion (typically found in export constrained areas)
- Comparing historic and modeled congestion components indicates that the directionality of the congestion components are the same in both systems

Results: Historic vs. Benchmark Scenario Congestion, cont.





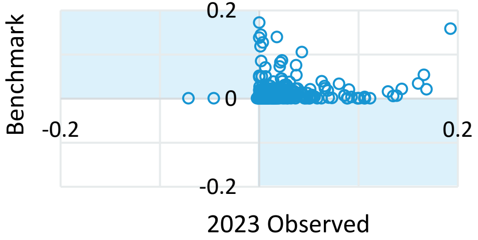




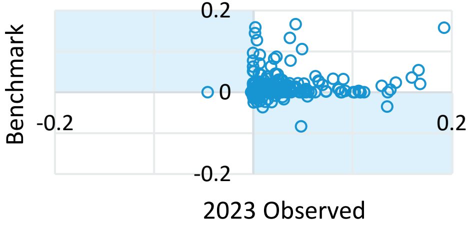
- Negative congestion components in Maine both historically and in the model reflect an export constrained area
- NH and VT experienced primarily positive congestion components in the model and historically
- The model failed to capture negative congestion components that happened historically in CT.
  - Imports into CT are higher in the model because the NE-NY interchange is simplified

Results: Historic vs. Benchmark Scenario Congestion, cont.

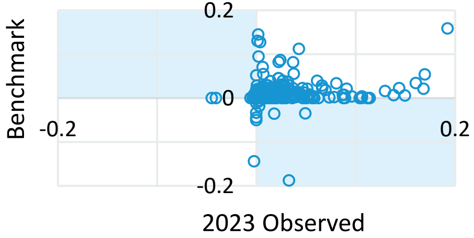
RI LMP Congestion Components ($/MWh)



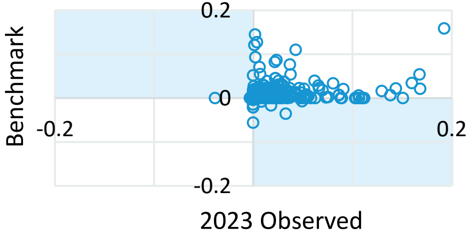
SEMA LMP Congestion Components ($/MWh)



WCMA LMP Congestion Components ($/MWh)

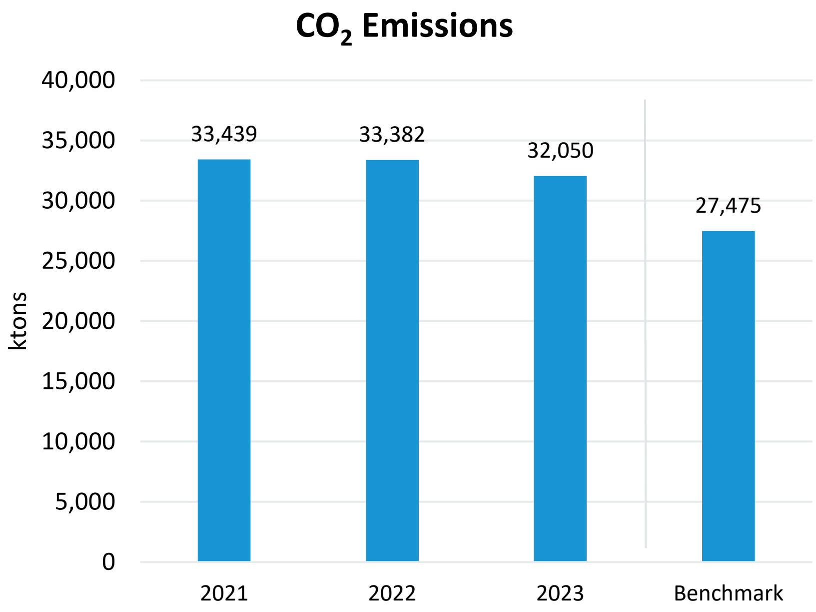


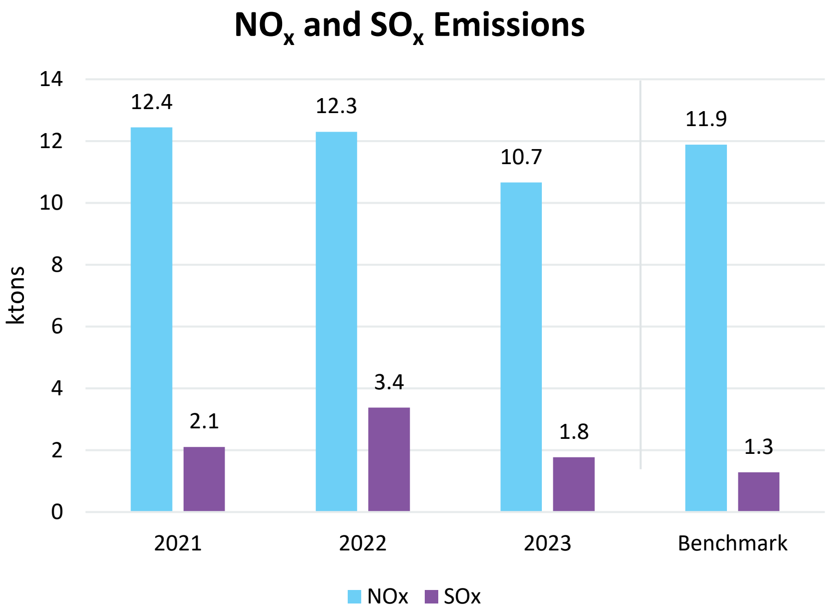
NEMA LMP Congestion Components ($/MWh)



- Clustering in the first quadrant indicates that historic positive congestion components for RI and MA are accurately captured by the model

Benchmark: Historic vs Modeled Emissions





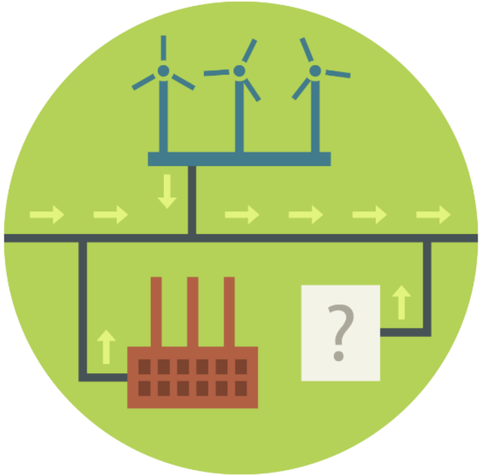
- Nuclear generation was about 1 TWh greater in the model versus historically because nuclear generators were assumed to operate at 100% capacity except during outages. This non-emitting generation displaced historic natural gas (NG) generation, resulting in lower CO_2 emissions

POLICY SCENARIO

Assumptions & Methodology

Overview of the Policy Scenario

- The Policy Scenario uses a capacity expansion model to build new resources between 2033 to 2050
- A reference Policy Scenario was first run followed by many sensitivity simulations
  - The reference Policy Scenario serves as a baseline to compare the many futures modeled in the sensitivities of the Policy Scenario to explore various future grids



Capacity Expansion Methodology

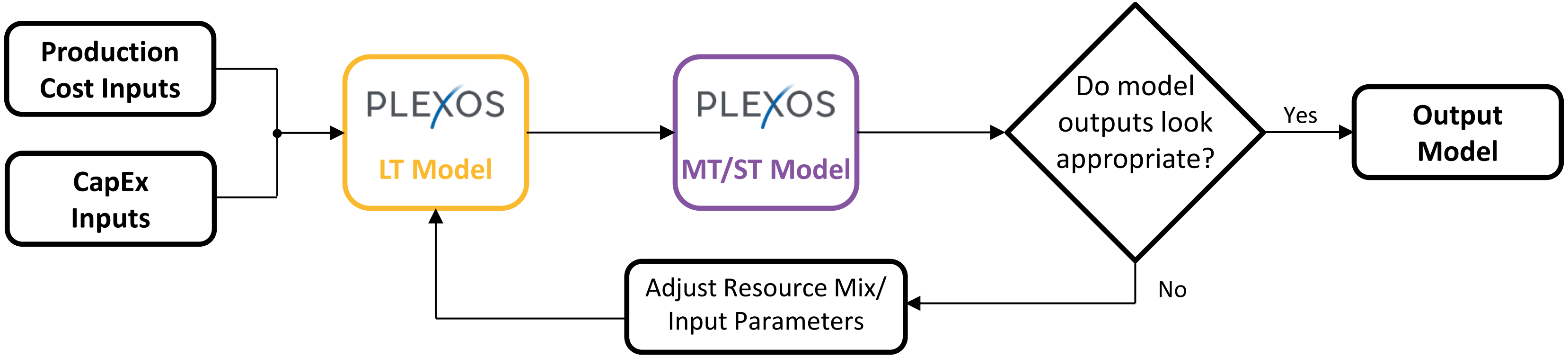
The expansion was performed in a two-step process:

Expansion in the Long-Term (LT) Plan

- Build and retire resources year by year for changing parameters (load, fuel prices, emission costs, etc.)
- Objective function of minimizing net present value (production cost + capital cost)

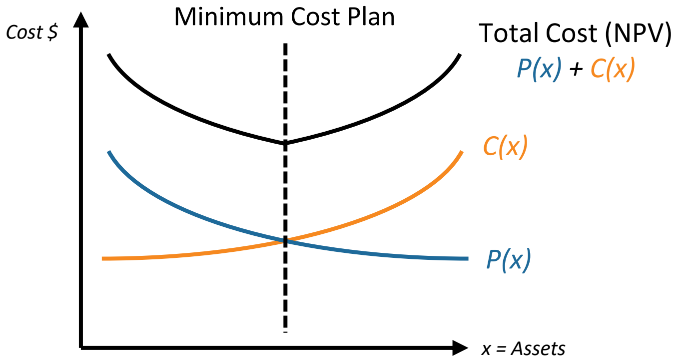
Production cost in the Medium Term (MT)/Short Term (ST) Schedules

- More detailed hourly run with additional constraints
- Tests the built-out system from the LT layer for the year 2050



Cost Minimization vs. Carbon Reduction

- The objective function of the capacity expansion engine is to minimize net present value (NPV) in the LT Phase
  - Net present value is composed of:
    - Production cost (cost of system operation)
    - Capital cost (annualized cost of construction)
- While not the objective function, carbon emission targets may be achieved using custom constraints
  - New generation is expensive, and the nominal least cost path is to build only to meet load growth
  - A hard constraint was be applied to the model to limit annual carbon emissions
- The ISO used a combination of constraints and economic calculations to create a system, which will attempt to meet carbon reduction goals

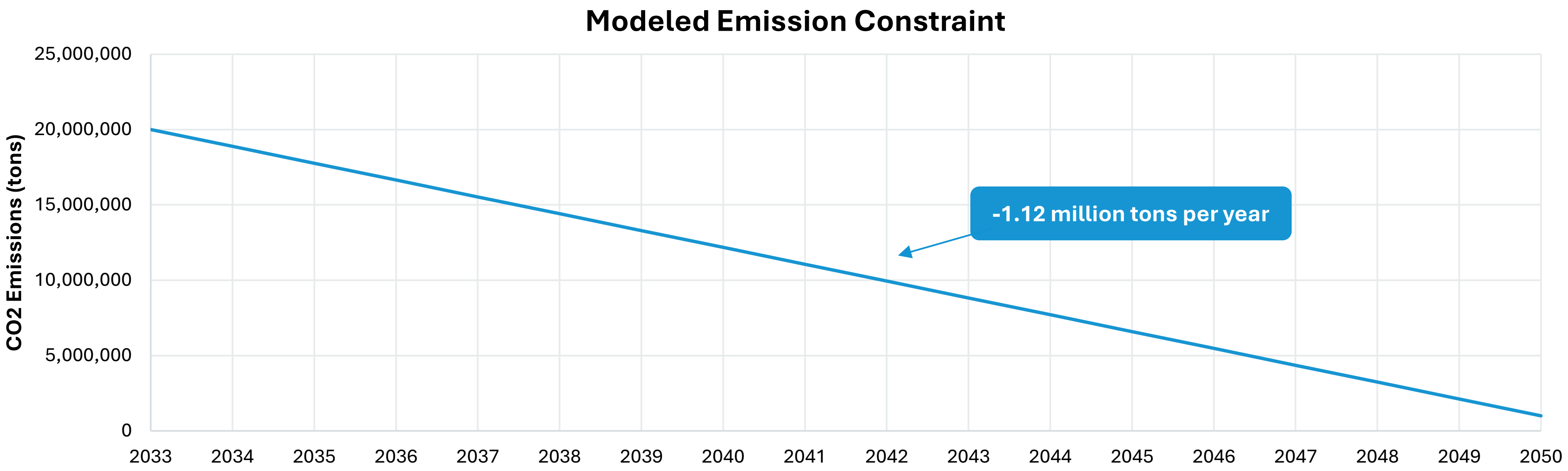


$$Minimize\ [NPV(P(x), C(x))]$$

State Emission Targets

≥80% by 2050	**Five states mandate greenhouse gas reductions economy wide: MA, CT, ME, RI, and VT (mostly below 1990 levels)**
Net-Zero by 2050 80% by 2050	MA emissions requirement MA clean energy standard
100% by 2035	VT renewable energy requirement
100% by 2050 Carbon-Neutral by 2045	ME renewable energy goal ME emissions requirement
100% by 2040	CT zero-carbon electricity requirement
100% by 2033	RI renewable energy requirement

System CO_2 Emissions Constraint Assumption



- CO_2 emissions follow a glide path, decreasing to 1 million short tons annually by 2050
  - Emissions from MSW, LFG, and wood units are not affected by this constraint; they are tracked and reported separately

Policy Scenario Candidate Resources

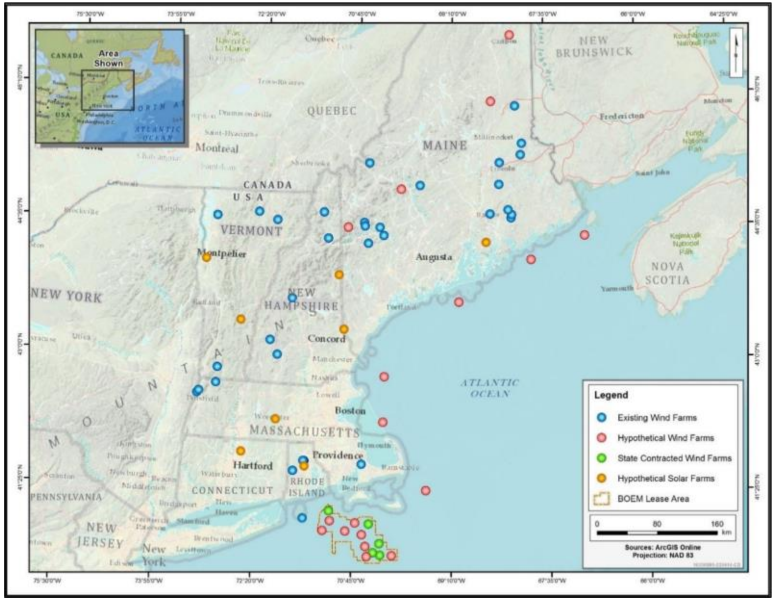
- During the Economic Planning for the Clean Energy Transition (EPCET) study, capacity expansion results showed that a wind, solar, and short-duration battery-only system will become progressively more expensive over time
- To more accurately represent a future resource mix, the Policy Scenario base case candidate resources was expanded to include technologies that are:
    1. Zero-carbon
    2. Currently being constructed for grid interconnection in the U.S. **or** have obtained lease agreements with New England
    3. Geographically feasible in New England

Candidate Resources Availability Assumptions

Offshore Wind (OSW): Total capacities were defined by ISO-NE Transmission Planning, based on the outcomes of the 2050 Transmission Study

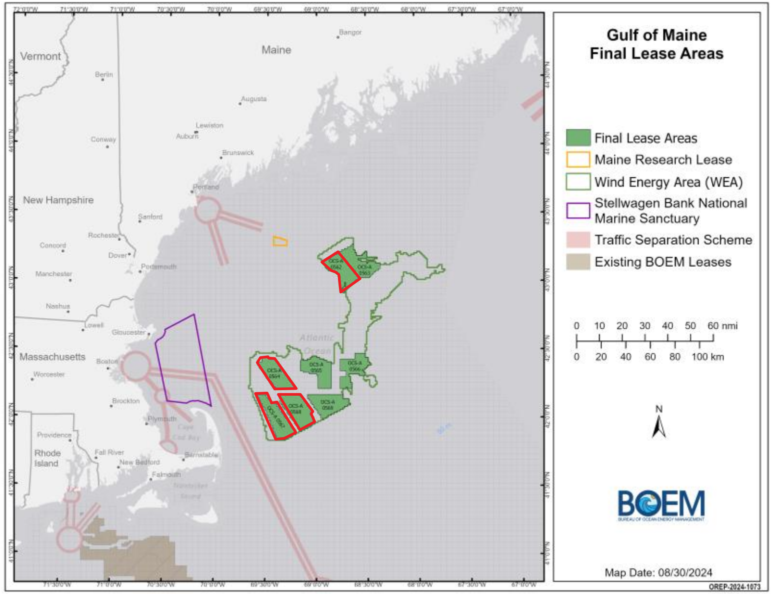
Land-Based Wind (LBW): LBW was restricted to 3.6 GW of new capacity due to limited siting availability

PV, Battery Energy Storage Systems (BESS), Small Modular Reactors (SMRs): There were no limitations on the capacity of these resources. Rather, growth was constrained by economic factors within the model



Floating Offshore Wind Planning and Modeling Assumptions

- Water depths in the Gulf of Maine necessitate the use of floating offshore wind turbines, rather than the fixed turbines used for Block Island Wind and other planned offshore wind farms in southern New England
  - In October 2024, the U.S. Bureau of Ocean Energy Management (BOEM) held the first offshore wind lease auction for the Gulf of Maine. Four lease areas were won with a total capacity potential of 6.8 GW. The total financial investment by Avangrid Renewables and Invenergy NE Offshore Wind was over $21.9 million[1]
- Cost assumptions for floating offshore wind come from the 2024 NREL Annual Technology Baseline (NREL ATB)
  - Build costs of fixed and floating offshore wind include a variable transmission cost adder based on distance to shore
- Offshore wind point of interconnection (POI) locations are based on the results of the 2050 Transmission Study
  - Additional one-time costs are added for POIs that have a required transmission upgrade



[1] https://www.boem.gov/renewable-energy/state-activities/maine/gulf-maine#:~:text=Gulf%20of%20Maine%20Offshore%20Wind,%2421.9%20million%20in%20winning%20bids.

100-Hr BESS Projects

- 100-hour iron-air batteries provide energy storage diversity alongside lithium ion (Li-ion) batteries and pumped storage (PS) hydro. 100-hour BESS were previously modeled in an EPCET Policy Scenario sensitivity
- Form Energy has announced several 100-hour battery projects in the U.S., expecting the first to begin operating by the end of 2025[1]
  - An 85MW/8500MWh iron-air battery in Northern Maine is expected to begin operating in 2028[2]

[1] https://www.utilitydive.com/news/iron-air-battery-developer-long-duration-storage-form-energy-collaboration-ge-vernova/730633/
[2] https://www.canarymedia.com/articles/long-duration-energy-storage/form-energy-set-to-build-worlds-biggest-battery-in-maine

100-Hr BESS Modeling Assumptions

- Cost assumptions and operational characteristics for the 100-hour batteries have been taken from the Form Energy whitepaper: *Clean, Reliable, Affordable: The Value of Multi-Day Storage in New England*
  - 4- and 8-hour battery cost assumptions are from the 2024 NREL ATB, which does not provide data for 100-hour batteries
- For all batteries, each GW of new capacity built within each zone has a 5% overnight capital cost escalation to reflect tightness in supply chains/labor and increases in interconnection cost

	Capital Cost	Fixed Operations and Maintenance (FO&M) Cost	Round trip efficiency	Size	Variable Operations and Maintenance (VO&M) Cost
100-Hour Iron-Air	$2,150/kW	$17.5/kW-yr	42.5%	200 MW 20,000 MWh	$3/MWh
4-Hour Li-ion	Declining ($1,389/kW in 2033; $1,036/kW in 2050)	Declining ($31/kW-yr in 2033, $22/kW-yr in 2050)	86%	100 MW 400 MWh	$3/MWh

Advanced Nuclear Projects

- Two projects recently supported by the U.S. Department of Energy's (DOE) Advanced Reactor Demonstration Program (ADRP) plan to connect to the grid in the next ten years[1]
  - Kemmerer, Wyoming: The 345MW TerraPower Natrium sodium-cooled fast reactor was the first advanced nuclear project to submit a construction permit to the U.S. Nuclear Regulatory Commission (NRC). Initial construction has begun on non-nuclear site features and the reactor could become operational as early as 2030[2]
  - Seadrift, Texas: X-energy plans to construct 4 units of their 80MW Xe-100 high-temperature gas reactors
    - The first unit is expected to be operational by 2030.[3] X-energy also received funding for the U.S.'s first advanced nuclear fuel fabrication facility[4]

[1] https://www.energy.gov/ne/articles/us-department-energy-announces-160-million-first-awards-under-advanced-reactor
[2] https://www.utilitydive.com/news/terrapower-smr-advanced-nuclear-reactor-bill-gates/718722/
[3] https://x-energy.com/seadrift
[4] https://x-energy.com/media/news-releases/x-energy-awarded-148m-investment-tax-credit-for-triso-x-fuel-fabrication-facility

Advanced Nuclear Projects, cont.

- Additionally, in Ontario, Canada, Ontario Power Generation is expecting to begin nuclear construction work on a 300MW GE Hitachi BWRX-300 small modular reactor in early 2025. The boiling water reactor is located at the existing Darlington nuclear site and is set to begin operating in 2029[1]
  - Tennessee Valley Authority (TVA) has partnered with Ontario Power Generation under an agreement to coordinate best practices in advanced nuclear development and deployment. TVA holds an early site permit from the NRC with plans to construct a BRWX-300 SMR at the Clinch River nuclear site[2]

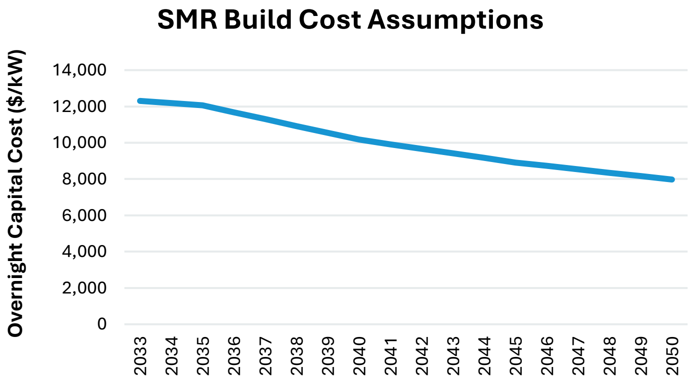
[1] https://www.world-nuclear-news.org/articles/additional-smrs-in-the-pipeline-for-darlington
[2] https://www.world-nuclear-news.org/articles/tva-approves-further-funding-for-clinch-river-smr

Advanced Nuclear Modeling Assumptions

- Given the approximate 10-year timeline for planning, permitting, and construction of current advanced nuclear projects, the Policy base case included 3 00MW small modular reactors as candidate resources beginning in 2033
- The 2024 ATB includes cost and performance parameters for SMRs. Data is sourced from the Idaho National Labs Meta-Analysis of Advanced Nuclear Reactor Cost Estimations, which was sponsored by the DOE's Office of Nuclear Energy

Advanced Nuclear Modeling Assumptions, cont.

Property	Value
Max Capacity	300 MW
Heat Rate	9.18 MMBtu/MWh
Max Ramp Rate	30 MW/min
FO&M Cost	$136/kW-yr
Economic Life	30 yr



- Operating properties for SMRs were taken from NREL's ATB and represent a variety of advanced nuclear reactor technologies
  - Cost assumptions are based on ATB's conservative cost estimates
- The forecasted cost of nuclear fuel is taken from the 2023 EIA Annual Energy Outlook
- Rather than attempting to site SMRs to specific zones, candidates were modeled without a specific zone and build costs escalated by 10% for every 1 GW built within the entire region
  - SMRs require significantly less land than traditional nuclear reactors. The Natrium and Xe-100 sites are 44 acres[1] and 30 acres[2], respectively

[1] https://www.terrapower.com/faq/
[2] https://x-energy.com/seadrift

Disqualified Base Case Candidate Technologies

- Hydrogen, as an electric power generation fuel, is not practical in New England
  - New England lacks the adequate geology to store significant quantities of hydrogen
  - Because of lower energy density hydrogen, dedicated hydrogen pipelines need to be built between generators and storage locations
- Similarly, effective carbon capture and storage (CCS) requires specific geologic formations that don’t exist in sufficient quantities in New England
- New England’s geothermal resources do not reach the temperatures required for geothermal power plants

POLICY SCENARIO

Reference Scenario Results

Pre-Expansion Analysis

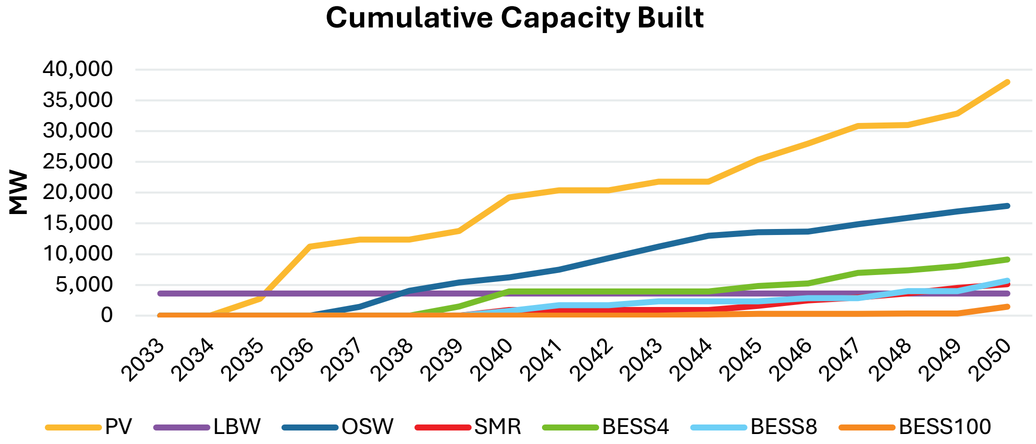
Load Increase Only - No Carbon Constraint			Carbon Constraint Only - No Load Increase		
Load Year	Unserved Energy (GWh)	Emissions (tons)	Carbon Constraint Year	Unserved Energy (GWh)	Emissions (tons)
2033	0	20,954,761	2033	2.69	19,998,846
2034	0	23,061,297	2034	13.86	18,882,353
2035	0	25,486,238	2035	31.08	17,764,967
2036	0	27,999,722	2036	102.32	16,603,800
2037	0	30,534,506	2037	246.02	15,646,102
2038	0	33,001,816	2038	421.71	14,925,863
2039	0	35,758,781	2039	464.60	14,835,055
2040	5.29	38,780,899	2040	495.38	14,937,766

- Before adding any new resources, the 2033 resource mix was tested under two different conditions to determine whether the carbon constraint or load increase would drive the buildout. For 2033-2040, 8,760-hour production cost runs were performed using:
  1. No carbon constraint, forecasted load growth
  2. Declining carbon constraint (glide path), no load growth from 2033 load
- The carbon constraint is driving the buildout from 2033-2039
  – Without the carbon constraint, the 2033 system could serve the increasing load due to electrification up to 2039 without any unserved energy
  – However, without any increasing load, the 2033 system cannot meet the carbon constraint even for the first year
- From 2040-2050, both the carbon constraint and increasing demand contribute to the resource buildout

Carbon Constrained Buildout: Reference Case

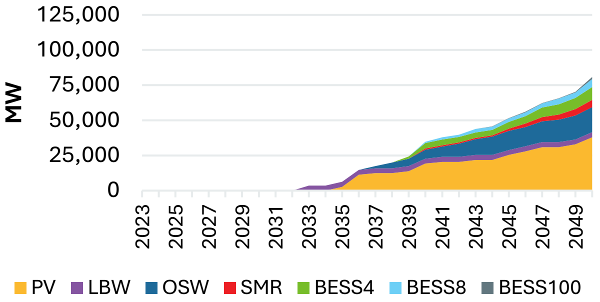
Cumulative Capacity (MW)

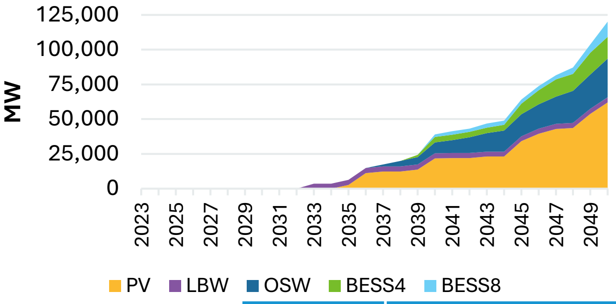
Resource Type	2035	2040	2045	2050
PV	2,722	19,219	25,359	38,000
LBW	3,600	3,600	3,600	3,600
OSW	0	6,250	13,582	17,848
SMR	0	900	1,592	5,117
BESS4	0	3,931	4,830	9,126
BESS8	0	784	2,341	5,684
BESS100	0	0	309	1,451
Total	**6,322**	**34,684**	**51,613**	**80,826**

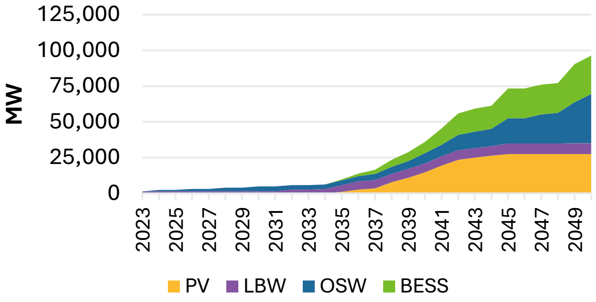


- The total capacity built from 2033-2050 was 81 GW
  - 65 GW generation built
  - 16 GW batteries built

2024 Economic Study vs. EPCET







- The capacity expansion buildout in the 2024 Economic Study is significantly smaller than the EPCET buildout or the 2024 Economic Study buildout when SMRs and long duration energy storage (LDES) are excluded from the candidate resources
  - SMRs reduce the need for vast amounts of energy storage. The greatest impact comes between 2040 and 2050

	2024 Economic Study		**2024 Economic Study no SMRs or LDES**		**EPCET**	
	2040	2050	2040	2050	2040	2050
PV	19,219	38,000	21,772	62,082	14,640	27,538
LBW	3600	3,600	3600	3,600	6,400	7,500
OSW	6,250	17,848	7,897	27,886	7,067	34,406
SMR	900	5,117	-	-	-	-
Li-ion BESS	4,715	14,811	5,794	26,597	7,891	26,904
Iron-air BESS	0	1,451	-	-	-	-
Total	**34,684**	**80,826**	**39,062**	**120,165**	**35,998**	**96,348**

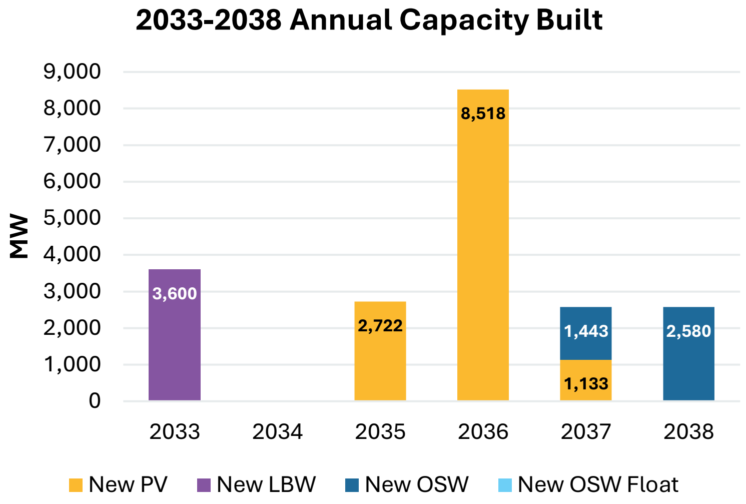
Reference Case Buildout Analysis: 2036 Results

- Additional investigation was performed on the buildout from 2035-2038, specifically the 8.5 GW of PV built in 2036
  – To determine the necessary emission reductions in each year, annual runs were performed using the previous year's resource mix with the base year's load (i.e., what would the emissions be if no new resources were built in that year?)
  – Next, a levelized cost of carbon (LCOC) analysis was performed for 2035-2038 by varying PV, fixed OSW, and floating OSW individually to determine the cost per ton of carbon reduction for each resource type
  – Using the $/ton of carbon and total carbon reduction needed, this analysis shows which resources will be most cost effective at meeting the emission target in a given year

- This analysis was performed using the PLEXOS LT Plan (rather than 8,760 production cost) since expansion decisions are made in the LT Plan

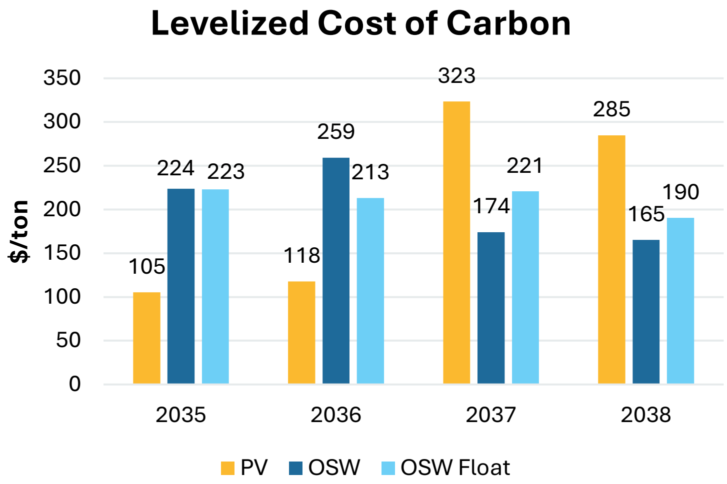
Reference Case Buildout Analysis: 2036 Results, cont.

Year	Emissions Constraint (tons)	No Buildout Emissions (tons)	Carbon Reduction Needed (tons)
2035	17,764,706	19,346,774	1,582,068
2036	16,647,059	20,600,243	3,953,184
2037	15,529,412	17,961,255	2,431,843
2038	14,411,765	17,627,207	3,215,442



- As expected, the large buildout of PV in 2036 is caused by a larger necessary carbon reduction compared to other years
  - The combination of the tightening emission constraint and increase in demand necessitate a larger buildout in 2036
  - 2033 and 2034 are not included in this analysis because the 3.6 GW LBW buildout in 2033 is driven by its ability to reduce net present value, not specifically to meet the emission constraint. No resources are built in 2034 because the system is already meeting the constraint. This also contributes to a smaller buildout in 2035

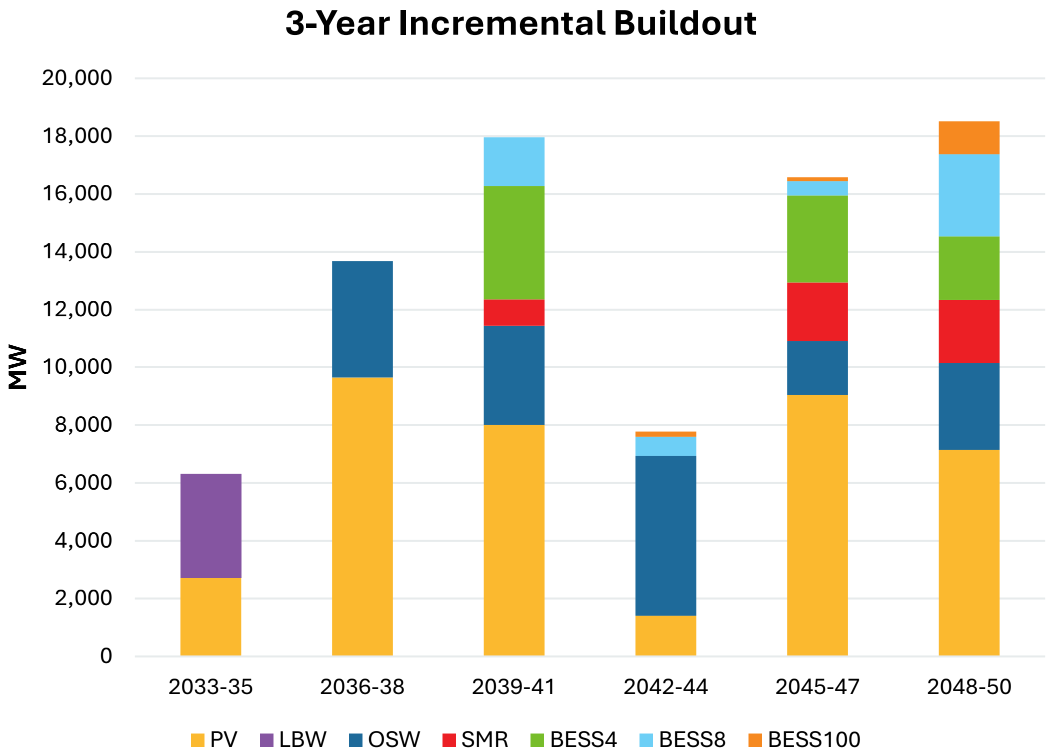
Reference Case Buildout Analysis: 2036 Results, cont.



Year	Carbon Reduction Needed (tons) [A]	Lowest LCOC Resource	LCOC ($/ton) [B]	Cost of Carbon Reduction (million $) [A*B]
2035	1,582,068	PV	105.32	166.6
2036	3,953,184	PV	117.86	465.9
2037	2,431,843	OSW	174.03	423.2
2038	3,215,442	OSW	165.26	531.4

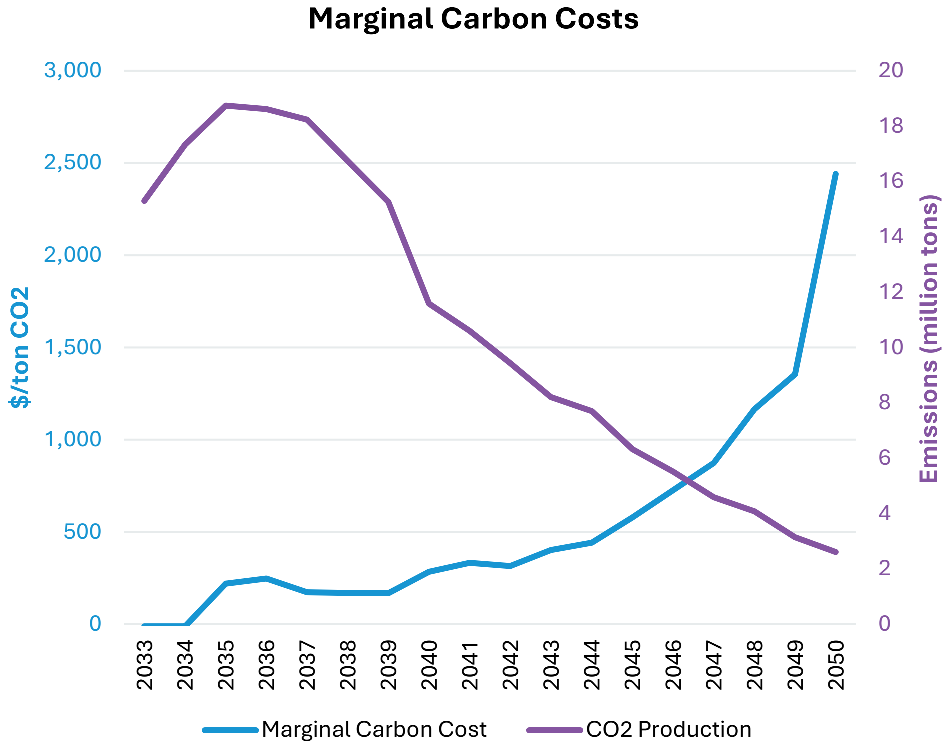
- The goal of the capacity expansion engine is to meet the carbon constraint while minimizing total system cost
- In 2036, the model builds 8.5 GW of PV because it is the lowest cost resource for carbon abatement in that year
  - The levelized cost calculations include cost escalation for PV and transmission cost adders for OSW
- Due to the chronology settings of the capacity expansion model, there may be discrepancies between years of sample days chosen by the model. For example, the sample days in 2036 likely have weather conditions that are better suited for solar than wind

Reference Case Incremental Buildout



- Depending on which sampled days the capacity expansion model selects, some years may be more favorable for solar versus wind and vice versa
  - Over the course of 3-4 years, these inconsistencies will be negated
- In reality, New England will not need to build 8.5 GW of new solar in one year. The model provides a general timeframe for new builds

Marginal Cost of Carbon Analysis

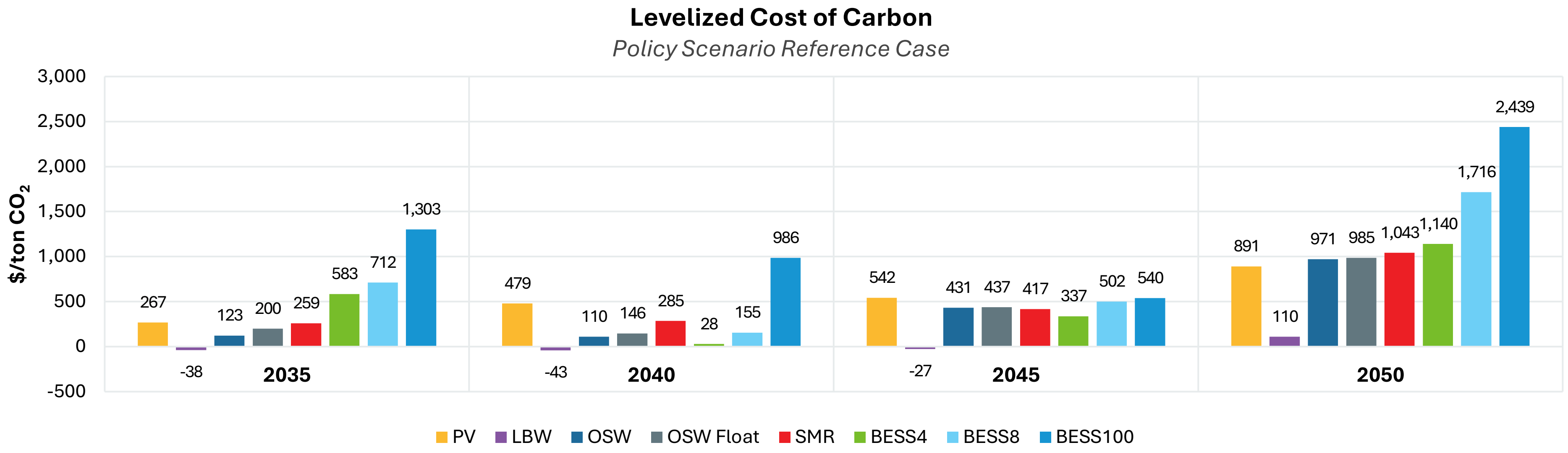


- The marginal cost of carbon (MCC) is calculated by comparing net present value of the total system and emissions before any new resources have been added and after each year's buildout has been added
  - Production cost and emissions are taken directly from ST results
  - Capital costs (annualized build costs + FO&M costs) are taken from LT results in the capacity expansion model
- From 2035-2043, the marginal cost of carbon is relatively stable
  - Hours of high solar and wind generation are easy to decarbonize at a low cost with new PV and LBW
- As the system is decarbonized, new resources are less effective at carbon reduction
  - From 2040-2050, resources are being built for carbon reduction as well as increasing demand
  - The remaining hours left to be decarbonized require energy storage and SMRs, which are more expensive than wind and solar

Levelized Cost Analysis Overview

- A levelized cost analysis was performed manually to verify the decisions made by the capacity expansion model
- The analysis was performed by pausing the expansion build every 5 years and adding 1 GW of each resource type. 8,760 production cost models were run to calculate the change in net present value and emissions for each resource addition
- The results of the analysis show which resource types are most economic for reducing carbon emissions and how they vary from 2033-2050

Policy Scenario Reference LCOC



- Over time, all resource types become less cost effective because they are curtailed or unused for larger periods of the year
  - LBW is consistently the most cost-effective resource, but the capacity expansion model is limited to 3,600 MW due to space availability. In 2035, 2040, and 2045, the production cost savings of an additional 1 GW of LBW are higher than the additional capital costs
    - Transmission adders are not factored into these calculations, so the real capital costs will be higher
  - Battery economics depend on the renewable buildout because they will not add significant value to the system if there's not a lot of excess energy to be stored

Production Cost Results Overview

- Annual hourly production cost models were run for the reference case buildout using the 2019 weather year to investigate detailed energy, emission, and curtailment results
- Additional production cost models were run to show how SMRs and LDES can benefit from non-energy market economic incentives. At this time, it is unclear how these resources will operate under future market structures

Production Cost Results: Economic Metrics

	2035	2040	2045	2050
Annualized Build Cost (million $)	750	6,468	11,887	20,494
Fixed O&M Cost (million $)	1,410	2,349	3,020	4,095
Marginal Cost of Carbon ($/ton)	218.63	283.20	578.36	2,440.30
Production Cost (million $)	2,939	2,600	1,936	1,316
Average LMP ($/MWh)	96.02	78.60	58.71	25.58
Hours with LMP≤$0/MWh	1,120	2,359	3,786	4,527

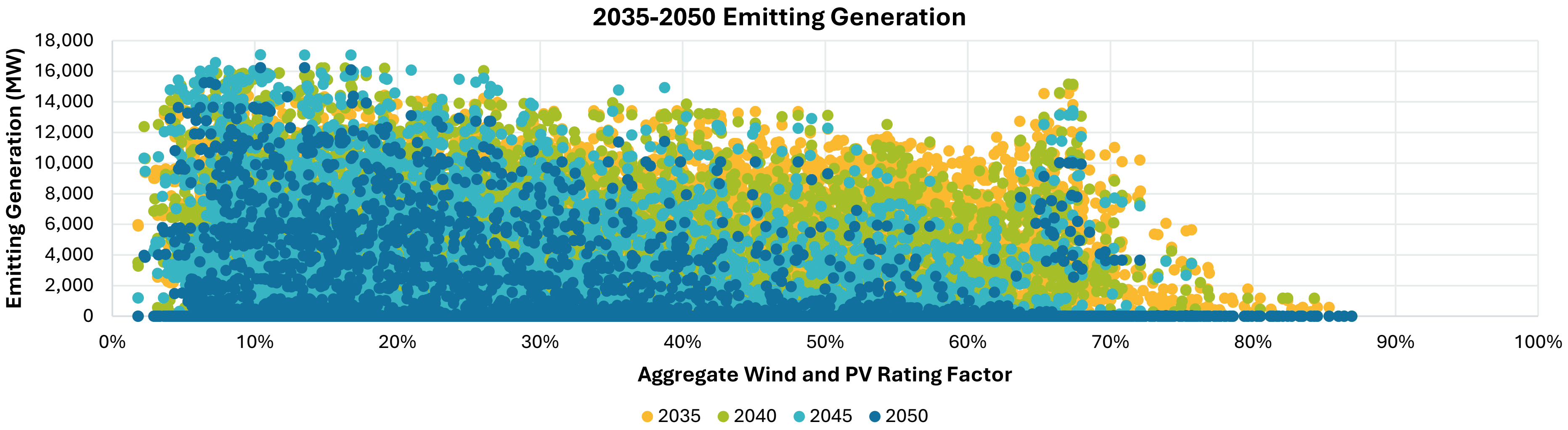
- Over time, build costs and carbon abatement costs increase as the system is decarbonized and more expensive resource types are built. Energy market prices decrease due to the new resources
  - Wind and solar bid negatively to decrease average LMPs

Production Cost Results: Generation and Emissions

	2035	2040	2045	2050
Generation (TWh)	151.4	188.5	208.4	234.1
Non-Emitting Generation (TWh)	109.3	161.9	193.5	227.9
Emitting Generation (TWh)	42.1	26.6	14.9	6.2
Carbon Emissions (tons)	18,739,587	11,580,884	6,318,465	2,604,025
Days with Emitting Generation	365	318	243	111
Curtailment (GWh)	1,797	8,752	20,905	30,979
Storage Generation (GWh)	3,551	11,129	14,462	21,209
Storage Load (GWh)	3,865	12,619	16,846	26,138

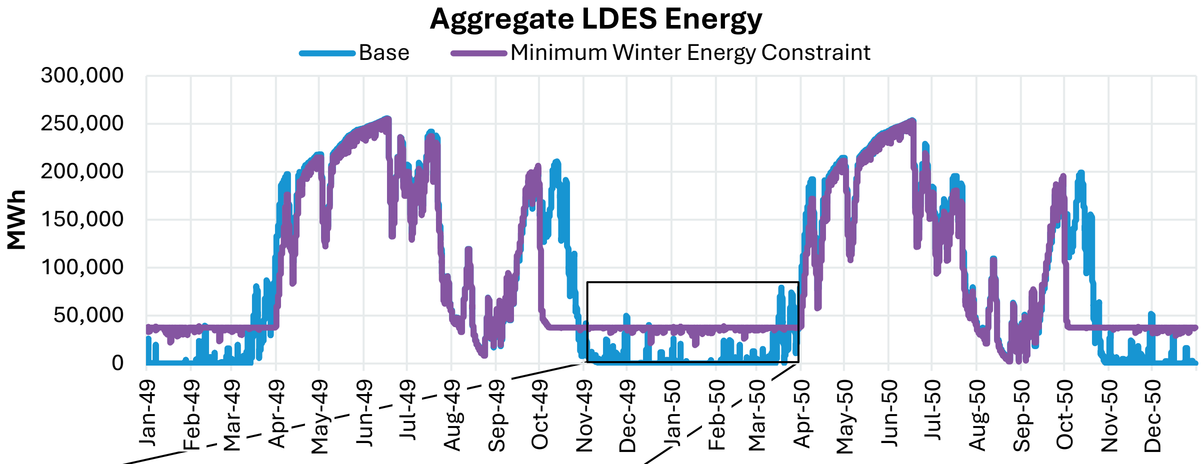
- In 2035, 27.8% of the total generation is from emitting resources. In 2050, emitting generation is reduced to 2.6% of the total
- Carbon emissions decrease at a higher rate per year early in the buildout horizon when there are hours of high wind and solar conditions that can be decarbonized with new wind and PV resources

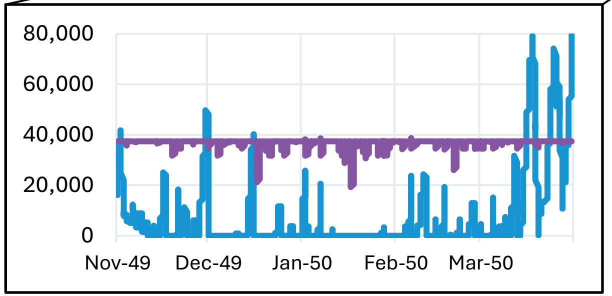
Emission Reductions During High Wind and PV Hours



- The largest emission reductions over time occur in hours that have high wind and solar conditions. As new wind and PV resources are built, these hours are easily decarbonized
- In the hours of the lowest wind and PV conditions, there is minimal decarbonization from 2035-2045. The SMR and LDES capacity buildout from 2045-2050 helps reduce emissions during these low renewable generation periods

LDES Behavior



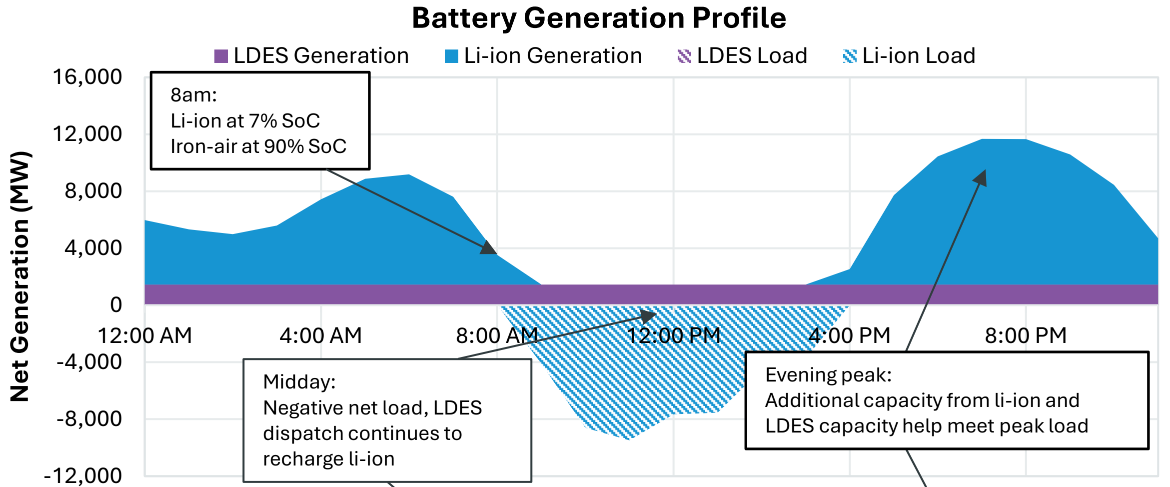


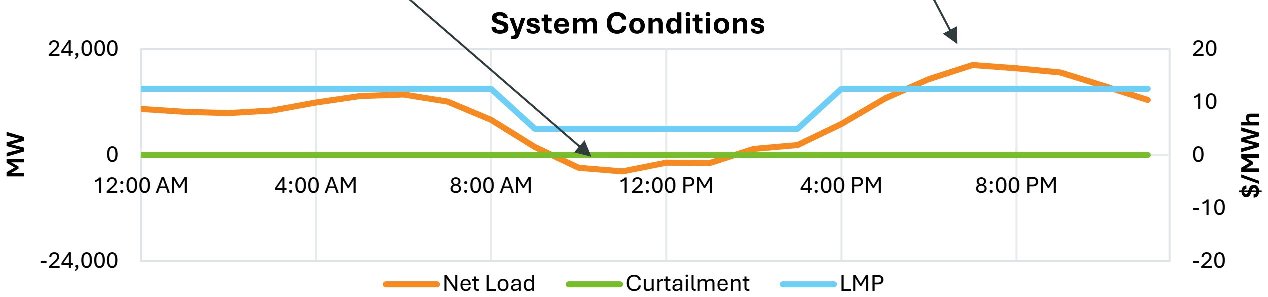
2049-2050 Metrics

	Base	Minimum Energy Constraint
Production Cost (million $)	2,237	2,245
Emissions (tons)	4,758,898	4,947,765

- Using the standard objective to minimize production cost, LDES charges almost fully during the spring and over 50% in the fall. Charge is not maintained through the winter
- A minimum energy constraint was implemented for October-March to incentivize LDES to stay above 20% state of charge (SoC) in the winter. PLEXOS assumes perfect foresight when optimizing the charge and discharge of batteries, but in actual operation, LDES may retain energy to hedge against uncertainties and manage risks
  - PLEXOS dispatches LDES to minimize production cost, but LDES is unlikely to operate this way in real markets. LDES revenues can be maximized by holding a given amount of energy to discharge at the highest LMP hours

Energy Storage Operation: Short vs Long Duration BESS





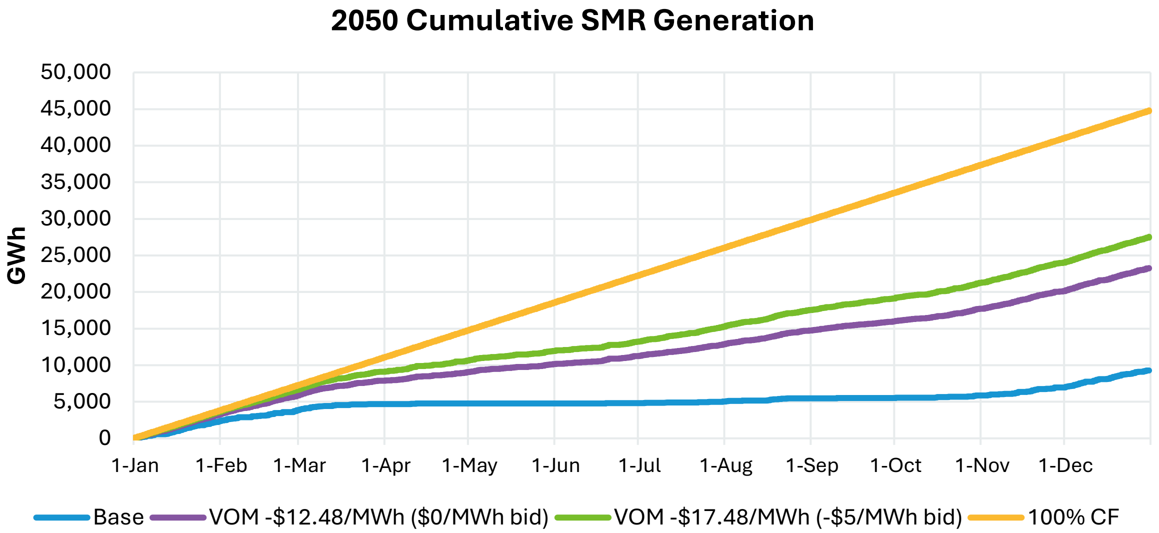
- Under specific conditions, the model uses perfect foresight to charge li-ion batteries from iron-air batteries to increase total generation capacity
  - Low net load
  - Low LMPs
  - No curtailment
- In order to serve high evening peak loads, LDES will discharge during the day to increase storage generation capacity by charging li-ion batteries. LDES is limited to 1.5 GW, but li-ion can generate up to 16.7 GW when fully charged
- This behavior reduces production cost and emissions versus dispatching emitting generation during the evening peak

SMR Energy Market Operation

- In the base assumptions for the Policy Scenario, SMRs are given a $0/MWh VO&M price. Based on their assumed fuel cost and heat rate, SMRs bid into the market at $12.48/MWh
- Due to their capability to provide zero-carbon dispatchable generation, it is possible that SMRs may receive non-energy market revenues and be able to bid at a lower or negative cost
- In addition to the base assumptions, these results show more possibilities for how SMRs would operate in the markets
  1. -$12.48/MWh VO&M cost: $0/MWh offer price
  2. -$17.48/MWh VO&M cost: -$5/MWh offer price

Resource Type	Offer Price ($/MWh)
PV/Wind/Imports	-10
Hydro	0
PS/BESS	3
Large Nuclear, Gas, Oil	14-888
ADR	500

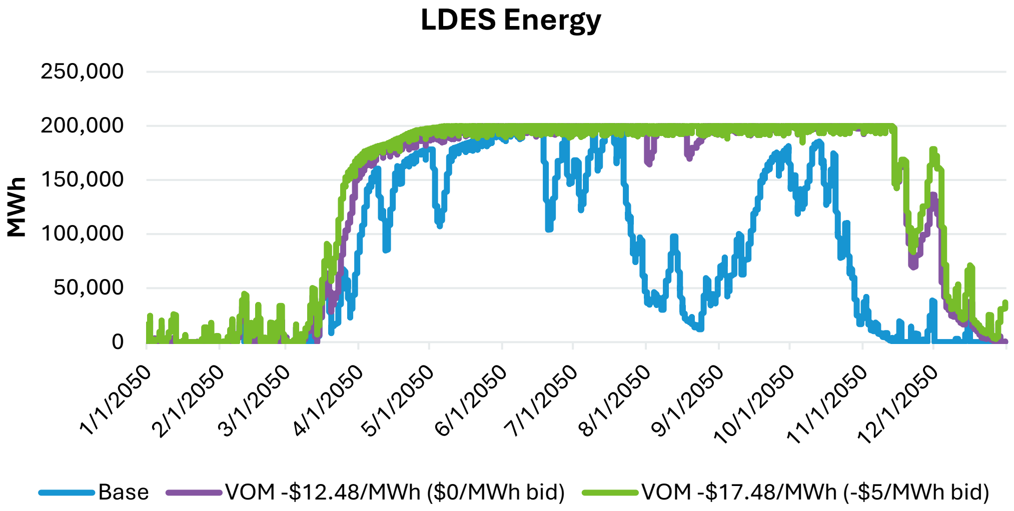
SMR Generation



	Generation (TWh)	Capacity Factor (%)
Base	9.28	20.72
-$12.48/MWh VOM	23.26	51.92
-$17.48/MWh VOM	27.56	61.51
100% Capacity Factor	44.82	100.00

- SMRs operate at 21% capacity factor when they don't have any additional economic incentives to run
- Using a -$12.48/MWh or -$17.48/MWh VO&M cost, SMRs are dispatched to charge storage if there is no curtailment on the system

SMR and LDES Coordination



	Base	-$12.48/MWh	-$17.48/MWh
SMR Generation (h)	2,311	5,108	5,890
LDES Charging (h)	2,988	3,127	3,828
LDES Charging from SMR Generation (h)	63	89	1,069

- When SMRs can bid negatively into the market, they reduce production costs and emissions by dispatching to charge LDES, which displaces emitting generation later in the year. The reduction in production costs still needs to be offset by revenue outside of the energy market
  - Production cost: $295 million reduction between base and -$17.48/MWh VOM scenario
  - Emissions: 580,000 ton reduction between base and -$17.48/MWh VOM scenario

POLICY SCENARIO SENSITIVITY

Multiple Weather Year (MWY) Analysis

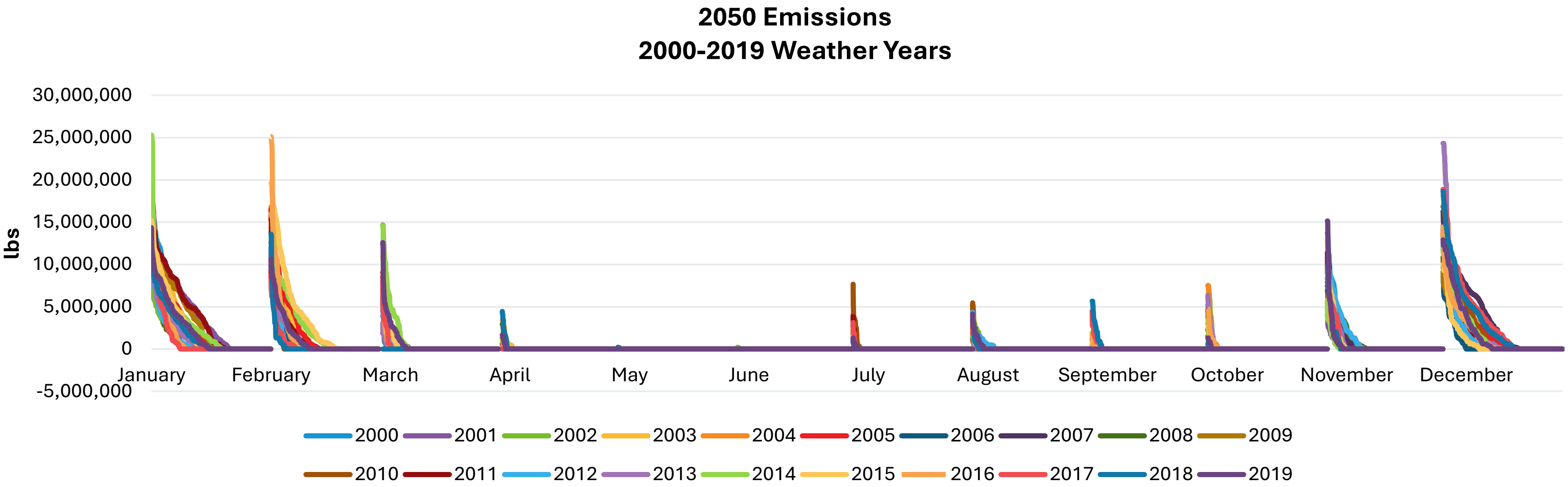
Multiple Weather Year Analysis

- A multiple weather year analysis was performed on the 2050 buildout to test system performance under varying weather conditions
  - 8760-hour production cost runs were repeated using the 2000-2019 weather years
- The focus of this analysis is how load and weather conditions cause variation from year to year in emissions and dispatch of fossil fuel resources

Multiple Weather Year Results

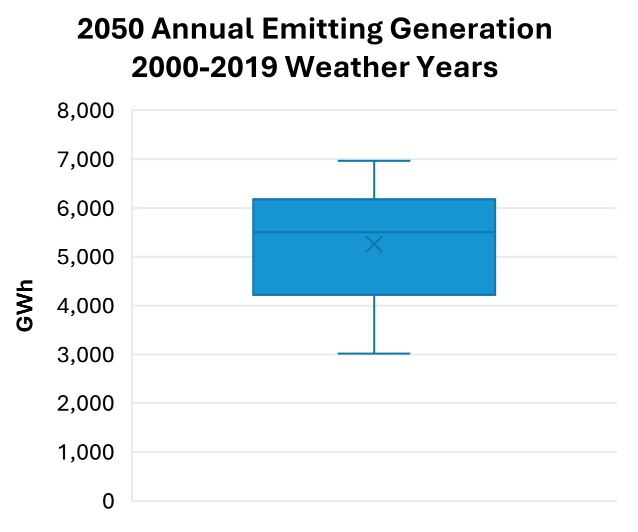
- Over the 20 weather years, three years had small amounts of unserved energy (USE)
  - 2011: 1 hour, 112 MW of unserved energy
  - 2013: 1 hour, 38.3 MW of unserved energy
  - 2014: 1 hour, 8.8 MW of unserved energy
- The buildout is well equipped to serve load under a wide range of weather and load conditions
  - Peak load: 59.5 GW
  - Minimum load: 10 GW
- This analysis assumes no retirements from the 2033 system

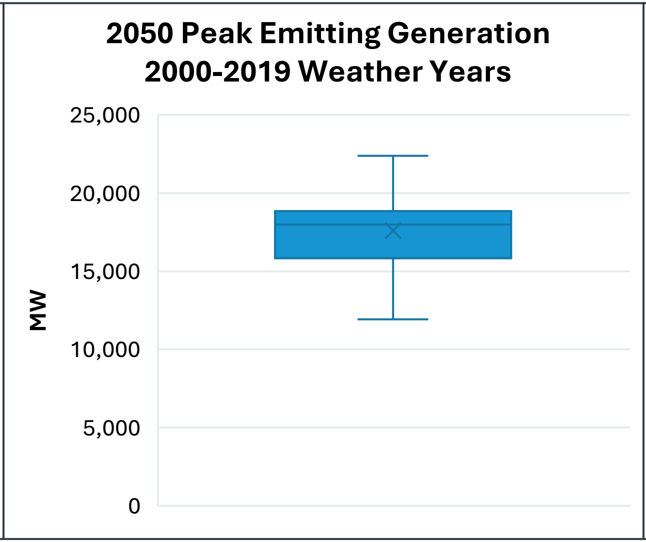
Multiple Weather Year Emissions for 2050

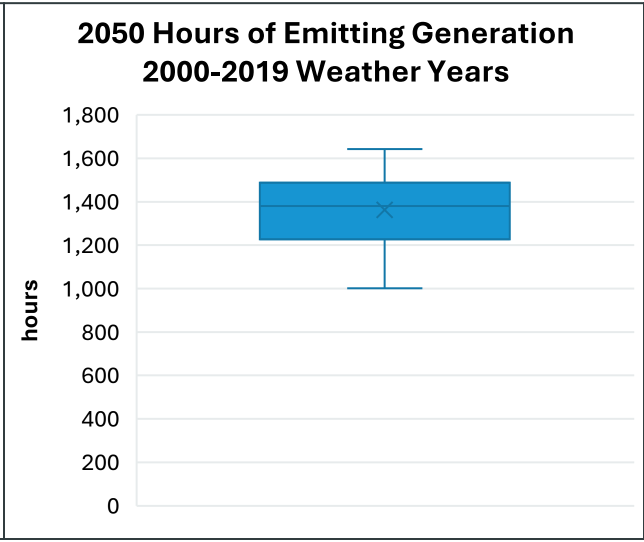


- Across all weather years, there is emitting generation every year in Jan, Feb, Nov, and Dec
- Peak annual emissions occur in the 2014 weather year at 2.9 million tons, while the lowest, at 1.2 million tons, occur in the 2006 weather year

Multiple Weather Year Emitting Generation

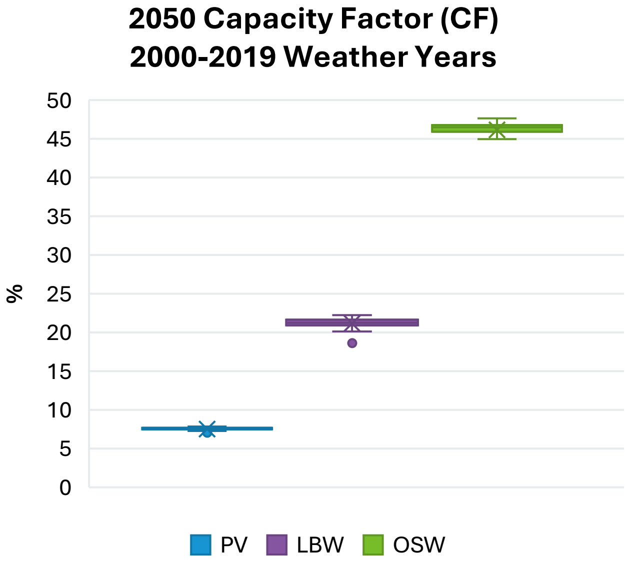


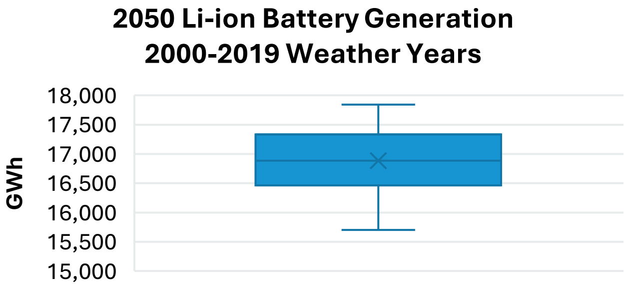


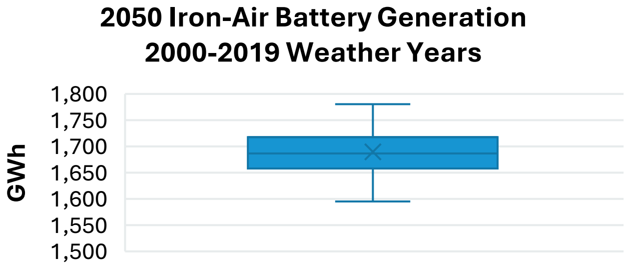


- All modeled weather years require dispatchable emitting generation to serve load
  - Annual emitting generation: max = 6,966 GWh, min = 3,016 GWh, mean = 5,257 GWh
  - Peak hourly emitting generation: max = 22,383 MW, min = 11,917 MW, mean = 17,597 MW
  - Hours of emitting generation: max = 1,643 h, min = 1,002 h, mean = 1,363 h

Multiple Weather Year Renewable Generation and Storage







	Average	Max	Min
PV (%)	7.53	7.83	7.02
LBW (%)	21.14	22.25	18.60
OSW (%)	46.15	48.06	42.32
Li-ion (GWh)	16,882	17,840	15,700
LDES (GWh)	1,690	1,781	1,595

- Across the 20 weather years, there are slight variations in renewable generation capacity factors and battery generation. Regardless of load and weather conditions, new carbon free resources maintain predictable impacts on the annual energy mix

2050 Multiple Weather Year Production Cost Data

	Average LMP ($/MWh)	Production Cost (thousand $)	Carbon Emissions (tons)	Load (GWh)	Unserved Energy (GWh)	Curtailment (GWh)
2000 Weather Year	20.98	1,286,520	2,592,485	204,681	0	37,562
2001 Weather Year	18.53	1,307,166	2,680,320	203,641	0	33,793
2002 Weather Year	19.16	1,073,130	1,712,947	205,210	0	35,763
2003 Weather Year	18.30	1,325,917	2,663,914	209,603	0	30,390
2004 Weather Year	26.14	1,281,140	2,404,110	206,997	0	36,908
2005 Weather Year	23.65	1,338,739	2,708,897	209,867	0	33,131
2006 Weather Year	12.81	939,566	1,215,750	198,817	0	37,614
2007 Weather Year	17.98	1,290,731	2,614,255	208,237	0	34,543
2008 Weather Year	17.23	1,084,968	1,728,641	204,627	0	31,072
2009 Weather Year	18.40	1,234,858	2,371,656	204,408	0	35,368
2010 Weather Year	18.16	1,052,171	1,710,405	205,786	0	35,719
2011 Weather Year	35.18	1,305,330	2,637,344	204,850	0.11	33,859
2012 Weather Year	15.01	1,066,830	1,636,895	200,497	0	31,581
2013 Weather Year	33.08	1,121,624	1,852,002	206,711	0.04	33,436
2014 Weather Year	31.48	1,399,180	2,958,074	207,359	0.01	36,191
2015 Weather Year	20.14	1,334,842	2,688,363	209,100	0	33,857
2016 Weather Year	19.71	1,102,080	1,765,694	205,718	0	34,255
2017 Weather Year	16.61	1,159,328	2,106,172	203,764	0	37,356
2018 Weather Year	18.47	1,070,325	2,167,248	209,005	0	34,791
2019 Weather Year	25.58	1,315,901	2,604,025	207,211	0	30,979

2050 Multiple Weather Year Generation by Type

	ADR	NG	Oil	LFG	MSW	Large Nuclear	Hydro	Wood Waste Solids (WDS)	PV	LBW	OSW	TIE	SMR
2000 Weather Year	46	5,470	22	32	309	29,345	6,719	157	53,819	18,820	77,082	12,607	7,872
2001 Weather Year	38	5,738	10	33	321	29,264	6,851	161	55,036	18,913	72,480	13,658	8,494
2002 Weather Year	21	3,813	10	29	280	29,261	6,806	103	55,307	18,982	77,197	13,150	7,839
2003 Weather Year	33	5,627	30	34	330	29,272	7,299	158	56,657	19,075	75,949	13,855	9,147
2004 Weather Year	76	5,158	31	35	340	29,356	6,759	143	54,201	19,337	76,794	13,250	9,002
2005 Weather Year	48	5,851	24	38	365	29,282	6,780	157	56,052	19,681	75,527	13,957	9,352
2006 Weather Year	36	2,719	0	21	202	29,237	6,657	73	54,338	18,210	75,949	12,410	6,552
2007 Weather Year	26	5,582	20	32	303	29,266	6,891	153	55,045	19,683	76,795	13,411	8,586
2008 Weather Year	26	3,787	8	28	275	29,337	7,068	106	56,367	18,675	74,450	13,999	8,059
2009 Weather Year	38	5,161	0	32	306	29,260	6,673	142	54,653	18,775	75,837	13,117	8,054
2010 Weather Year	31	3,682	10	23	234	29,244	6,634	103	54,867	19,115	79,260	13,015	6,918
2011 Weather Year	49	5,676	25	34	322	29,258	6,815	161	56,016	18,675	73,869	13,498	8,009
2012 Weather Year	39	3,605	5	26	254	29,336	7,039	99	56,039	18,704	71,217	13,810	8,016
2013 Weather Year	40	3,971	37	29	278	29,262	7,029	107	55,177	19,239	77,172	13,784	8,059
2014 Weather Year	42	6,325	52	39	380	29,284	6,713	170	54,916	19,150	75,537	13,090	9,127
2015 Weather Year	37	5,616	43	33	322	29,277	6,636	160	55,746	19,484	76,000	13,628	9,454
2016 Weather Year	43	3,784	42	27	260	29,332	6,854	107	55,729	18,693	77,302	13,404	7,681
2017 Weather Year	30	4,480	16	27	257	29,249	6,696	125	54,206	19,013	76,571	12,926	7,691
2018 Weather Year	32	4,593	28	30	301	29,266	6,741	132	55,378	19,499	78,665	13,210	8,589
2019 Weather Year	43	5,621	20	36	348	29,276	7,018	156	56,492	19,226	73,104	14,256	9,282

Policy Scenario Production Cost Takeaways

- The buildout of new renewables, energy storage, and SMRs is capable of serving load and reducing emissions in 2050, but the cost of reducing emissions each year increases exponentially
  - Carbon emissions in 2050 are 83% less than 2033, but the marginal cost of carbon abatement is 1,015% higher than 2033
  - Hours with high wind and solar conditions are easiest to decarbonize
- Energy storage resources effectively reduce production cost and emissions, but the model does not capture the more realistic operation of long duration storage in providing additional capacity through the winter months
- Without additional revenue incentives, SMRs only operate at a 21% capacity factor, but they successfully provide emission free dispatchable generation in the winter to reduce overall system emissions

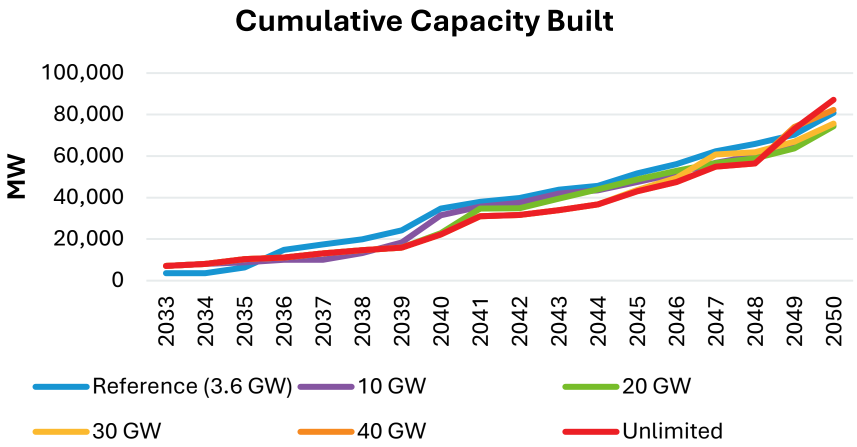
POLICY SCENARIO SENSITIVITY

New Resource Availability and Costs

Policy Scenario Sensitivities

- Due to the uncertainty of resource availability and costs, additional capacity expansion runs were performed using varying assumptions to show a range of possible buildouts and their associated costs
  - Increasing LBW availability:
    1. 10 GW new LBW candidates
    2. 20 GW new LBW candidates
    3. 30 GW new LBW candidates
    4. 40 GW new LBW candidates
    5. Unlimited LBW
  - Constrained annual PV buildout:
    1. Economically constrained using a steeper cost escalation of 10% for each 500 MW per zone (versus 10% per 1 GW in reference case)
    2. Capacity constrained to 5 GW per year
  - Moderate SMR costs:
    1. SMR capital costs reduced by ~40% based on NREL ATB moderate cost estimate

LBW Availability Sensitivity

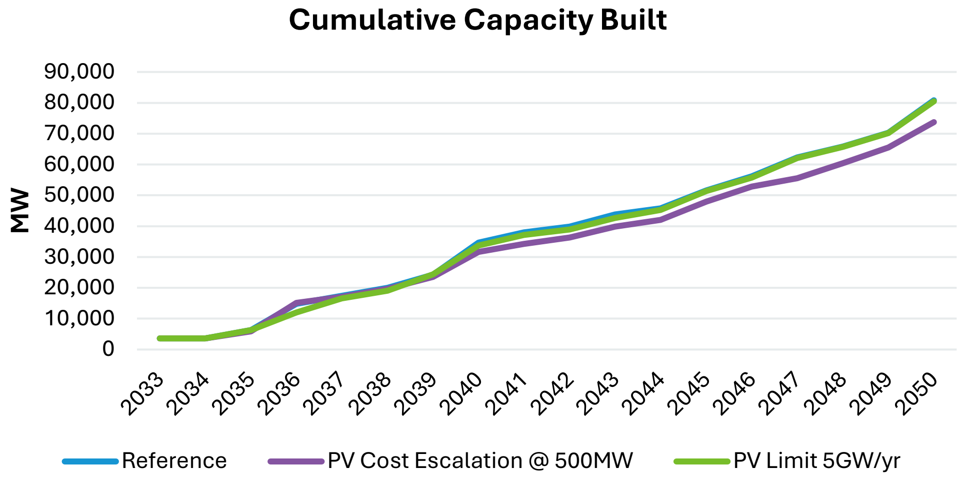


2033-2050 Total New Capacity (MW)

Available LBW Capacity	3.6 GW	10 GW	20 GW	30 GW	40 GW	Unlimited
PV	38,000	34,000	32,048	27,486	24,945	26,000
LBW	3,600	10,000	20,000	30,000	40,000	44,034
OSW	17,848	12,469	5,198	1,092	0	0
SMR	5,117	4,500	3,600	2,473	845	0
Li-ion BESS	14,811	12,073	8,325	5,300	4,344	4,083
Iron-air BESS	1,451	1,797	5,200	9,304	12,138	13,000
Total	**80,826**	**74,839**	**74,371**	**75,655**	**82,272**	**87,117**
2033-2050 Build Costs ($B)	149.7	119.1	92.0	82.6	81.0	80.8

- The reference case assumes 3,600 MW of LBW due to limited land availability. In the preliminary results, LBW was consistently the most cost-effective resource in a levelized cost analysis. These sensitivities highlight the economic benefits of LBW
- When the LBW buildout is unlimited, 7.1 GW LBW are built in 2033 because the production cost savings are higher than the additional capital cost. No OSW is built and the total build costs are reduced by 46% compared to the reference case

Limited Annual PV Buildout Sensitivity

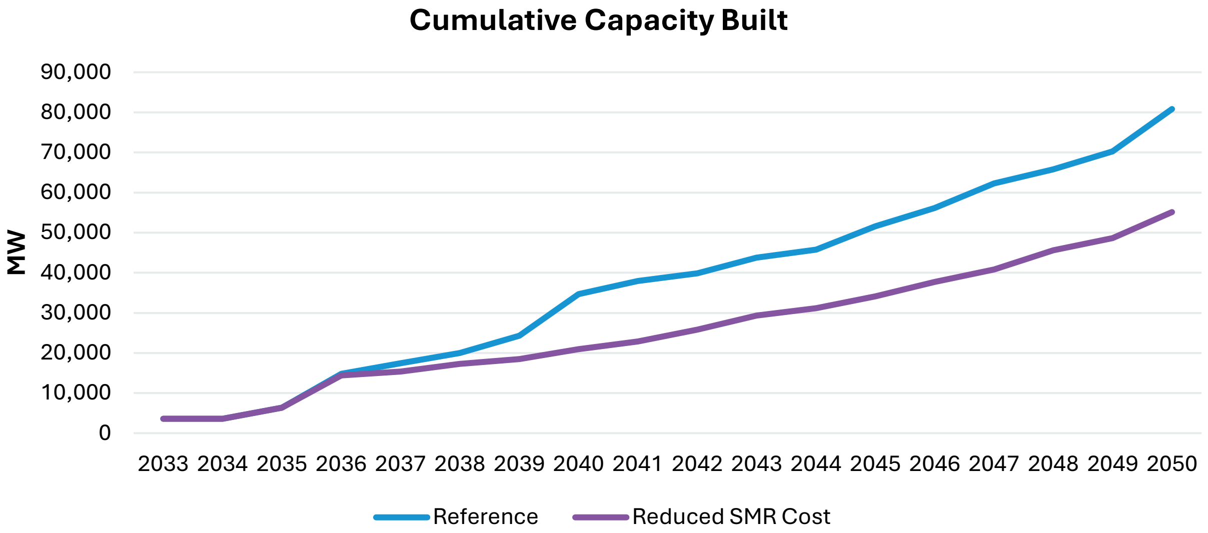


2033-2050 Total New Capacity (MW)

	Reference	PV Cost Escalation @500MW	PV Cap 5GW/yr
PV	38,000	32,050	37,834
LBW	3,600	3,600	3,600
OSW	17,848	18,785	17,757
SMR	5,117	5,400	5,152
Li-ion BESS	14,811	12,351	14,697
Iron-air BESS	1,451	1,549	1,443
Total (MW)	**80,826**	**73,735**	**80,483**
2033-2050 Build Costs ($B)	149.7	151.9	150.4

- At the November PAC, concerns were raised about the 9 GW buildout of PV in 2036. The ISO has performed sensitivities with both an economic constraint and a capacity constraint for the PV buildout
- Under the economic constraint sensitivity, PV capital costs escalate by 10% for every 500 MW built in each zone to represent increasing land and interconnection costs. The reference case uses a cost escalation of 10% for every 1 GW built in each zone. Even with the increased cost escalation, the model still builds 8.5 GW PV in 2036
- Under the capacity constraint sensitivity, the model is limited to 5 GW of new PV resources each year. In this sensitivity, floating OSW is built in 2036 to supplement the reduced PV buildout. Total build costs only increase by about 0.5% compared to the reference case

Moderate SMR Capital Cost Sensitivity



2033-2050 Total New Capacity (MW)

	Reference	Reduced SMR Cost
PV	38,000	22,531
LBW	3,600	3,600
OSW	17,848	9,939
SMR	5,117	9,291
Li-ion BESS	14,811	8,653
Iron-air BESS	1,451	1,118
Total (MW)	**80,826**	**55,133**
2033-2050 Build Costs ($B)	149.7	125.5

- Capital costs for SMRs are more uncertain than PV, wind, and batteries because they have not been commercially produced on a large scale. The reference case uses the NREL ATB's conservative cost estimate to account for this uncertainty, but the ATB also includes a moderate cost estimate that is about 40% less than the conservative estimate
- Under this sensitivity, the total buildout is reduced by 25.7 GW and $24.2 billion
- SMRs are built as early as 2036, while the reference case doesn't build SMRs until 2040

Capacity Expansion Takeaways

- The buildout of PV, LBW, and OSW from 2033-2040 is driven by the carbon constraint
  – From 2040-2050, the buildout is driven by the carbon constraint and increasing system demand
    - The cost of carbon abatement increases exponentially as the system is decarbonized and more expensive resources are needed to serve load while meeting the carbon constraint
- Certain trends arise across capacity expansion models with different input assumptions
  – Land-based wind is highly effective at reducing system costs and emissions. In an unlimited case, 7 GW of LBW were built in the first year of the capacity expansion model and the total build costs were about half the reference build costs
  – SMRs are built to provide emission free dispatchable generation capacity

POLICY SCENARIO SENSITIVITY

Resource Adequacy Analysis for Retirements

PLEXOS Resource Adequacy (RA) Analysis Overview

- In the Policy Scenario, this analysis aims to determine the amount of fossil fuel resources that may still be needed from a resource adequacy perspective in the system built by the capacity expansion model
  - The base resource mix includes all existing generators that do not have announced retirements
  - The goal of the analysis is not to determine the exact capacity of resources required to meet the resource adequacy target (Installed Capacity Requirement (ICR)), but to serve as a feasibility test of the resulting resource mix in meeting resource adequacy need for the studied year

Disclaimer on RA Analysis in PLEXOS

The results of this analysis are for **information only** and **should not be taken out of the context of the Policy Scenario**. The retirements presented in these results are entirely dependent on the resources built by the capacity expansion model and **are not indicative of the ability to retire any of these resources in the existing ISO-NE system**

Resource Adequacy Analysis in PLEXOS

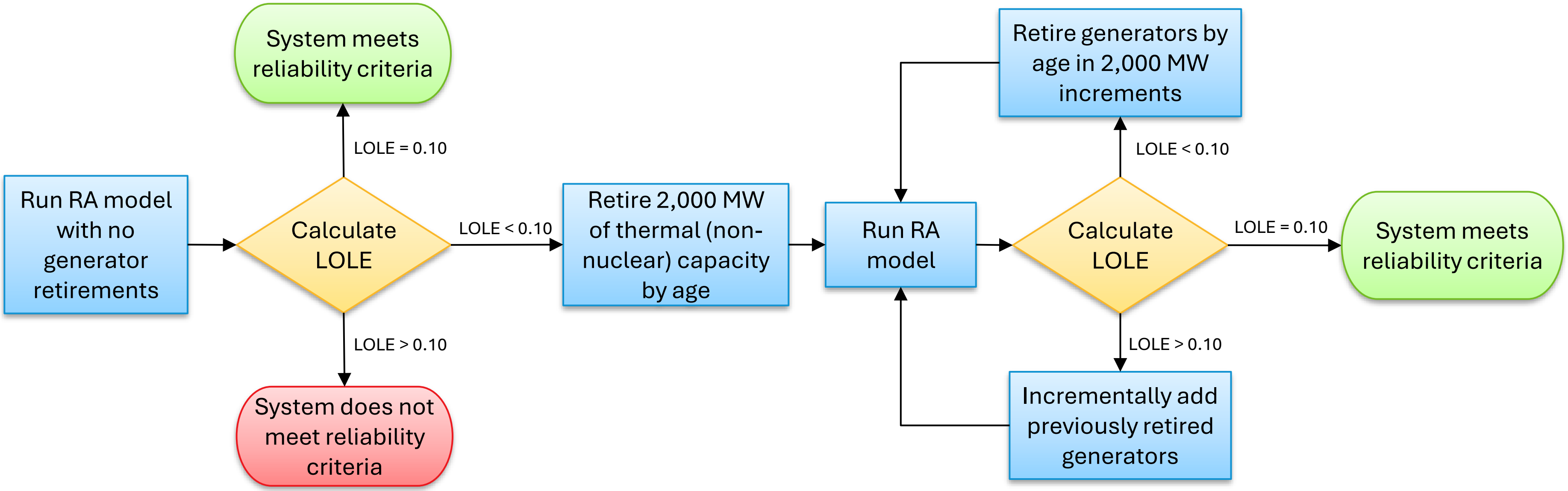
- Economic dispatch parameters are not considered in traditional resource adequacy modeling. In PLEXOS, cost inputs can be manipulated to force the model to behave as an RA model would
  - Fuel, emission, and start costs are removed from the model. Dispatch order is set using VO&M costs. Using the standard objective to minimize production cost, lowest cost resources will be dispatched first
    - Storage resources have the highest VO&M costs to ensure their generation capacity is retained
    - Storage should only be dispatched if an unserved energy event is going to occur
  - The internal cost of unserved energy is increased to $1 billion/MWh. Since PLEXOS is trying to minimize production cost, this very high value ensures the model will dispatch all available resources before allowing USE, which mimics the dispatch logic of RA assessments to minimize load shedding
  - Fuel constraints for 2050 are not considered in this analysis
    - Results could vary if constraints continue to exist

- PLEXOS is not a true RA modeling tool. The ISO's Resource Adequacy and Accreditation (RAA) team uses GE MARS for their analysis, but we are using PLEXOS's probabilistic outage modeling as an alternative for this analysis. It provides some insight into RA results without the time and resource commitment of converting the model to MARS

Resource Adequacy Metrics in PLEXOS

- Results of RA models in PLEXOS will be reported with the following commonly used metrics
  - Loss of Load Expectation (LOLE) [days/year]: Expected number of days during year where a loss of load event (unserved energy) occurs in the system
    - The LOLE RA planning criterion for ISO-NE is 0.1 days/year
  - Expected Unserved Energy (EUE) [MWh/year]: total estimated size of all the loss of load events in a year
- The capacity expansion model builds new resources to meet the emission constraint at lowest cost
  - The buildout does not consider RA criteria beyond the cost optimization that includes the assumed cost of USE

Resource Adequacy Analysis in PLEXOS, cont.



- Rather than using load forecast uncertainty multipliers to account for variation in future load shapes, simulations are run with 20 weather years of correlated wind, PV, and load profiles
- For each of the 20 weather years, 100 samples of outage draws are run using probabilistic modeling in PLEXOS

2050 PLEXOS RA Results

	Base	2,000 MW Retired	4,000 MW Retired	5,150 MW Retired	6,000 MW Retired
Total Capacity Remaining (MW)	129,898	127,898	125,898	124,748	123,898
LOLE [days/year]	**0**	**0**	**0.05**	**0.10**	**0.16**
EUE [MWh/year]	**0**	**0**	**433**	**1,596**	**4,453**

- Up to 5,150 MW of legacy thermal (non-nuclear) generation can be retired by age in 2050 before the system exceeds 0.1 LOLE
- The capacity expansion model buildout surpassed reliability standards because it optimizes production cost by allowing storage to price arbitrage. The RA model incentivizes storage to retain energy

2050 Modeled Capacity

Modeled Capacity in 2050 (MW)

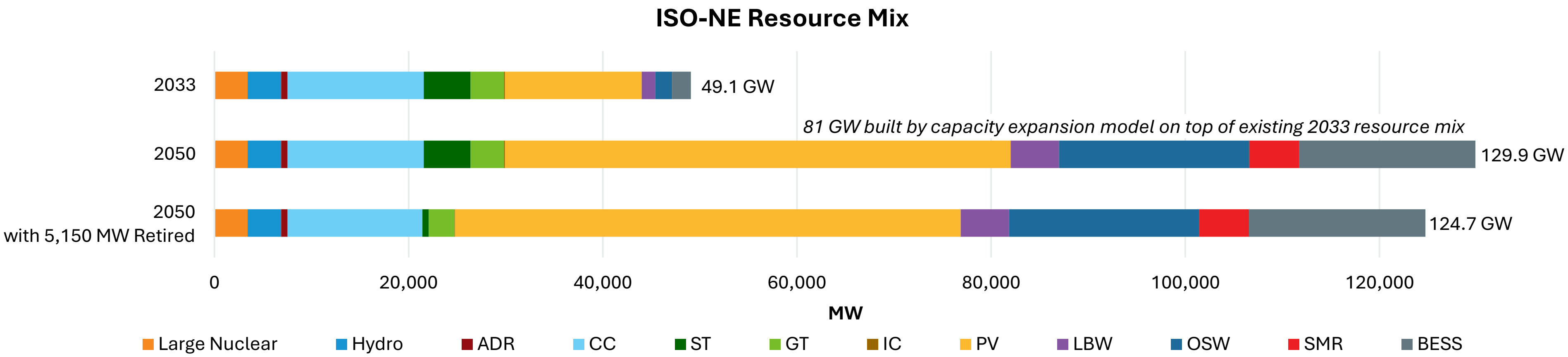
Resource Type	Base	2,000 MW Retired	4,000 MW Retired	5,150 MW Retired	6,000 MW Retired
Gas	15,343	15,315	15,209	15,209	14,807
Oil	6,164	4,241	2,347	1,316	1,298
LFG/MSW/WDS	876	827	827	708	278
Nuclear	8,531	8,531	8,531	8,531	8,531
Hydro	3,449	3,449	3,449	3,449	3,449
PV	52,089	52,089	52,089	52,089	52,089
LBW	4,999	4,999	4,999	4,999	4,999
OSW	19,592	19,592	19,592	19,592	19,592
BESS	18,186	18,186	18,186	18,186	18,186
ADR	669	669	669	669	669
Total	**129,898**	**127,898**	**125,898**	**124,748**	**123,898**

Impact of Retirements on Production Cost Model

- The retirement of 5,150 MW of legacy thermal generation has minimal impact on system operations in the 2050 production cost model
  - In the reference model with no retirements, the generators that will be retired only generate for 158 GWh in 2050, which is 0.07% of the total annual generation. In the model with retirements, this generation is easily replaced by remaining NG generators
  - Production cost does not change after the generators have been retired
  - Emissions from gas and oil increase because there is less generation from LFG/MSW/WDS

	Reference	With Retirements	Delta
Production Cost ($M)	1,316	1,316	0
Emissions (tons)	2,604,025	2,678,024	+73,999

RA for Retirements: Takeaways



- Even with a buildout of 81 GW in the capacity expansion model, the system still needs 44 GW of capacity from the existing 2033 resource mix in order to meet reliability criteria
  - It is unlikely that all of these legacy resources will still be operational in 2050. This would necessitate an even larger capacity buildout
- Retirements do not have a significant impact on system operations during a moderate weather year

POLICY SCENARIO SENSITIVITY

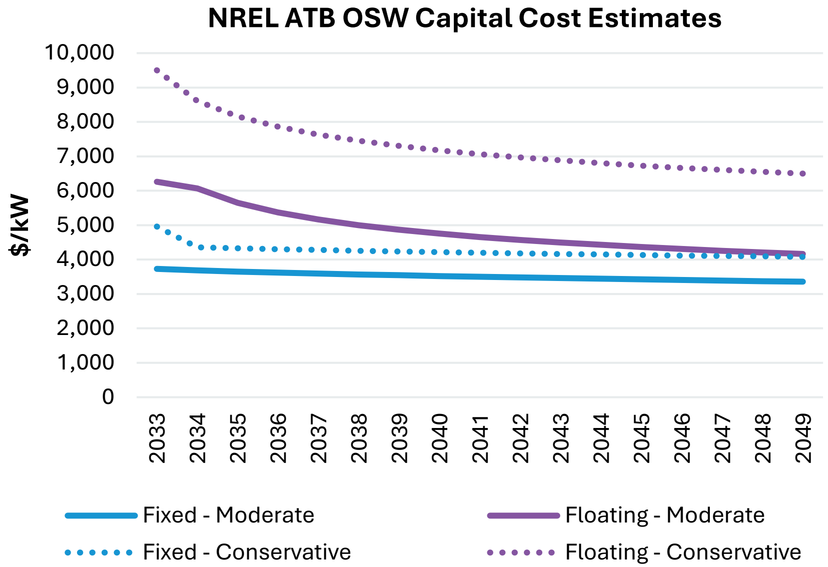
No New OSW, Increased OSW Capital Cost Estimate

Sensitivity Overview – OSW Assumptions

- The Policy Scenario reference case assumes the inclusion of fixed and floating offshore wind as candidate resources

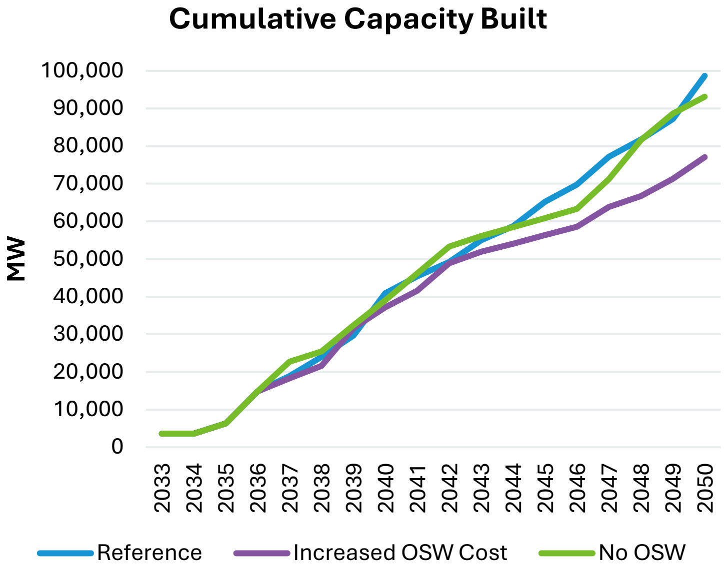
- Recent market trends have shown varying levels of investment across different renewable generation technologies. Participation in OSW has been lower than initially expected. These sensitivities examine the effects of adjusting OSW capital costs and availability in the model

  1. Increased OSW cost: capital costs for OSW are increased to the NREL ATB ‘conservative’ estimate (see graph)
  2. No OSW: OSW is not included as a candidate resource and can’t be built by the capacity expansion model. Existing OSW in the 2033 planned resource mix is still included



OSW Sensitivity Results: Capacity Expansion

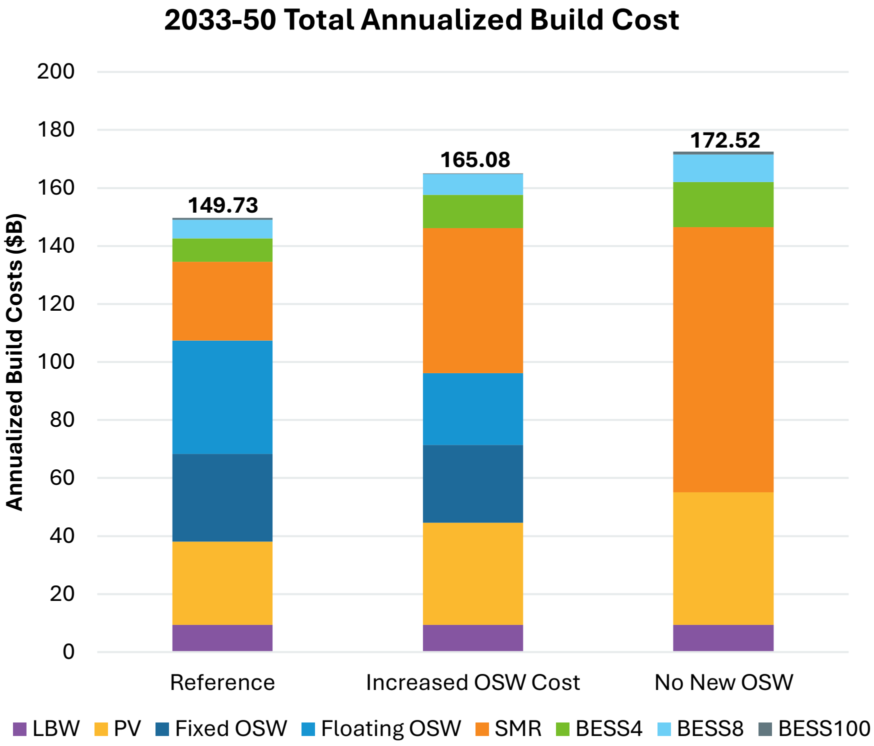
Type	Reference	Increased OSW Cost	Delta (Increased OSW Cost - Reference)	No OSW	Delta (No OSW - Reference)
PV	38,000	38,001	+1	54,000	+16,000
LBW	3,600	3,600	0	3,600	0
Fixed OSW	6,086	4,698	-1,388	0	-6,086
Floating OSW	11,761	7,200	-4,561	0	-11,761
SMR	5,117	7,200	+2,083	11,358	+6,241
Li-ion BESS	14,811	15,239	+429	21,565	+6,755
Iron-air BESS	1,451	1,125	-326	2,600	+1,149
Total (MW)	**80,826**	**77,063**	**-3,763**	**93,123**	**12,297**



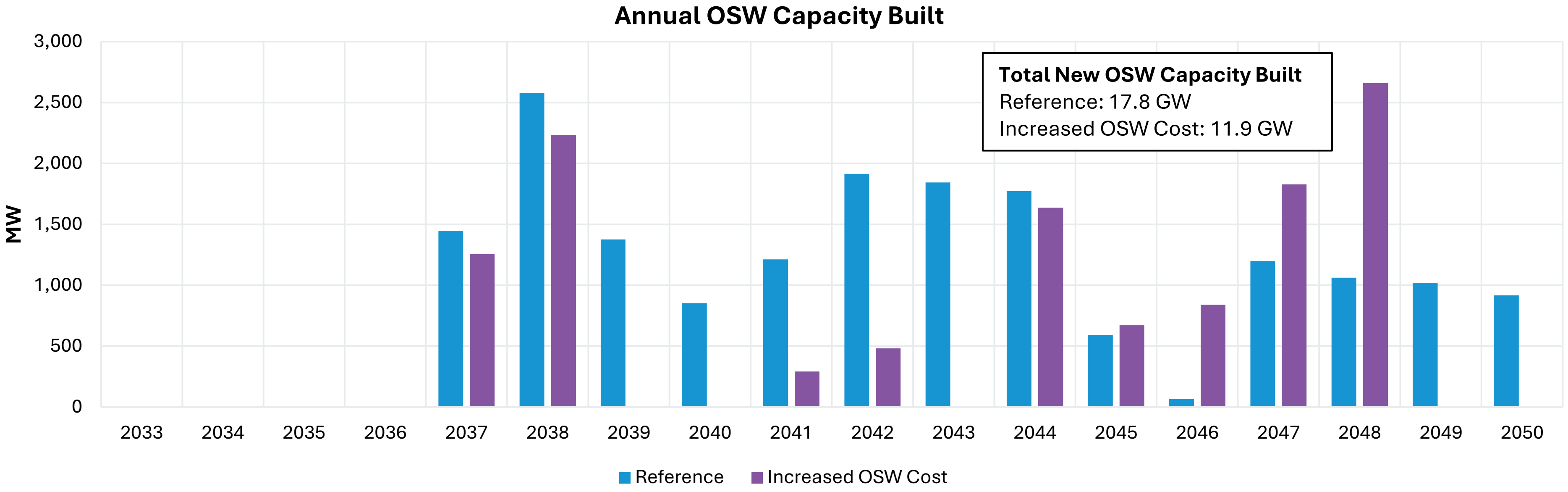
- When the model is not allowed to build OSW, there is a significant increase in the capacity buildout of other resource types, especially PV
  - 11.8 GW of SMRs is equivalent to about 40 units at 300 MW each
- Although the total capacity built in the “Increased OSW Cost” sensitivity is less than the capacity built in the reference case, the model is forced to build more SMRs, which are the most expensive resource

OSW Sensitivity Results: Capital Costs

- To meet the policy-based emission constraint without OSW, the total annualized build costs **increase by $23 billion**, or 15.2%
- Even when OSW is assumed to be more expensive than current estimates, it is still a cheaper option than the extensive PV, SMR, and BESS buildout that is modeled in the "No OSW" sensitivity



OSW Sensitivity Results: OSW Buildout Timeline



- Under the "Increased OSW Cost" sensitivity, the majority of the OSW buildout occurs in the 2040s, but there is still a 3.5 GW build early in the horizon
  - Capital cost estimates decrease over time to account for the development of new technology and supply chains

OSW Sensitivity Results: 2050 Operational Metrics

	Reference	Increased OSW Cost	No OSW
Production Cost ($M)	1,316	1,515	2,063
Annualized Build Cost ($M)	20,494	23,237	26,115
Fixed O&M Costs ($M)	4,095	4,024	4,257
Total 2050 Costs ($M)	25,905	28,776	32,435
Avg LMP ($/MWh)	25.58	32.54	34.83
Load-Serving Entity Energy Expenses (LSEEE) ($M)	7,133	9,167	9,264
Curtailment (GWh)	30,979	17,740	9,820

- In 2050 alone, the total cost of the buildout with no OSW is $6.5 billion higher than the reference case
- Without OSW, the cost of energy to customers increases by about 30% in 2050. Even when OSW capital cost estimates are increased, LSEEE and average LMPs are lower than the no OSW case

OSW Sensitivity: 2050 Generation by Fuel Type (GWh)

Type	Reference	Increased OSW Cost	No OSW
ADR	43	73	52
Oil	20	0	20
NG	5,621	6,292	8,143
LFG/MSW/WDS	541	650	824
Existing Nuclear + SMR	38,558	48,691	71,843
Hydro	7,018	7,442	7,730
Wind	92,330	72,925	23,802
PV	56,492	60,455	82,404
Imports	14,256	17,522	20,528

- The buildouts with less or no OSW must rely more on emitting generation, SMRs, and new PV resources. There is less curtailment of renewables and imports

OSW Sensitivity Takeaways

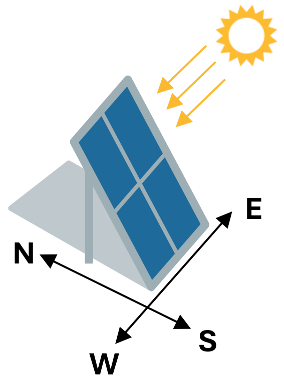
- New England needs new OSW resources to meet state emission goals at the lowest cost
  - In 2050, energy market costs could be up to 30% higher without OSW
- Even if OSW capital costs are higher than current estimates, the system will economically benefit from new OSW resources, although the ideal timeframe for building OSW shifts to after 2040
  - Note that results are dependent on cost assumptions for other resource types. Only OSW costs were varied in this analysis

POLICY SCENARIO SENSITIVITY

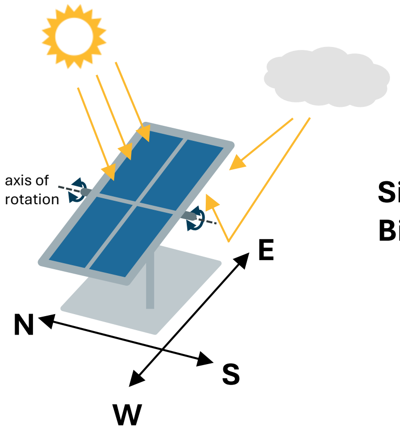
Bifacial Tracking PV

Fixed-Tilt vs. Single-Axis Tracking Bifacial PV

- The Policy Scenario reference case uses cost assumptions and generation profiles correlating to fixed-tilt monofacial PV resources
  - Fixed-tilt PV is typically South-facing
  - Monofacial panels can only generate from the front of the panel. Any light that hits the back of the panel is reflected
- The ISO received a sensitivity request to model all candidate PV resources as single-axis tracking bifacial panels
  - Single-axis tracking PV is typically on a horizontal axis of rotation that is oriented from North to South
  - Bifacial panels can generate from both the front and back of the panel. Light hits the back of the panels when it is scattered by clouds or reflected off the ground

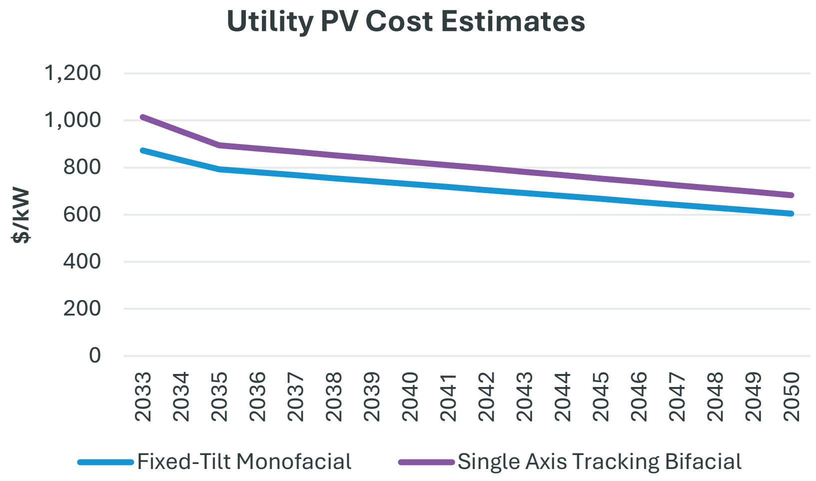


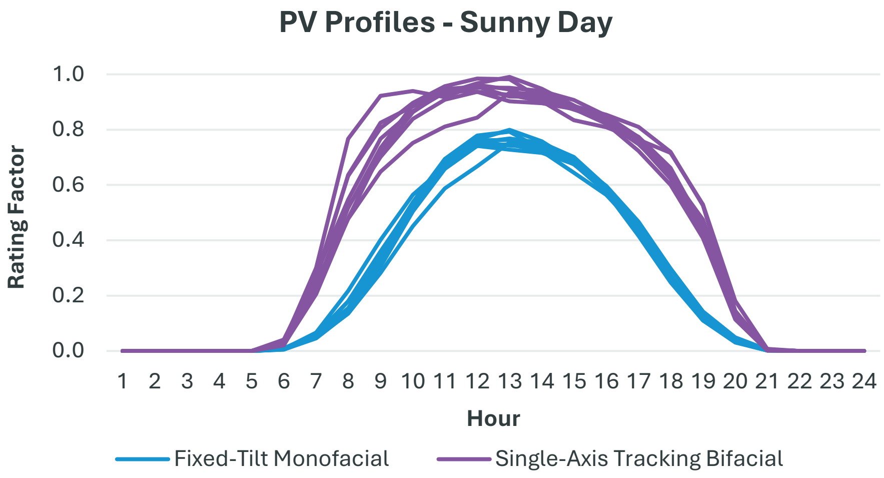
Fixed-Tilt Monofacial Panel



Singe-Axis Tracking Bifacial Panel

Bifacial Tracking PV Assumptions





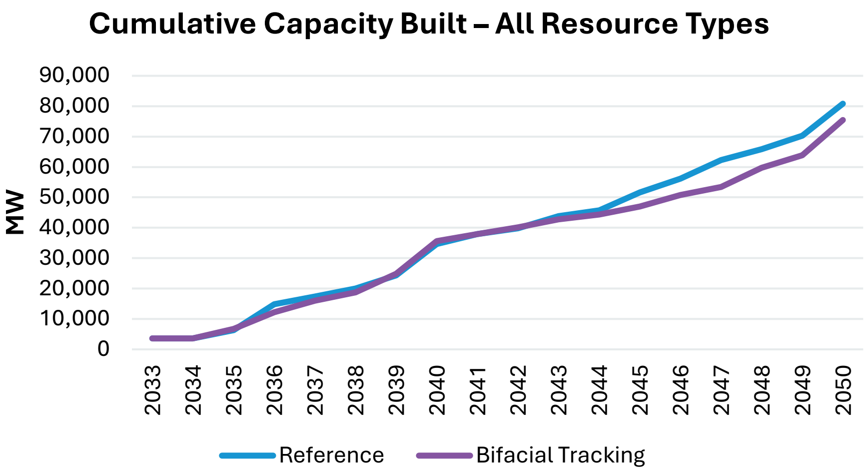
- According to the NREL ATB, single-axis tracking bifacial panels are assumed to be ~15% more expensive than fixed-tilt monofacial panels
- Hourly generation profiles for single-axis tracking bifacial panels are based on existing DNV solar datasets that have been scaled by load zone. Single-axis tracking bifacial PV generates ~45% more than fixed-tilt monofacial

Bifacial Tracking PV Takeaways

- Modeling candidate PV resources as single-axis tracking bifacial **PV reduces overall capacity buildout by 5.4 GW**
  - PV capacity built is reduced by 3.7 GW due to the higher capacity factor of single-axis tracking bifacial PV
  - Total **build costs are reduced by 2.5%**
- **Bifacial tracking PV has an economic advantage over fixed-tilt monofacial PV** for reducing carbon production until 2045
  - At high-levels of renewable penetration, new PV resources are curtailed frequently regardless of panel type which diminishes the benefits from the additional production of bifacial tracking panels

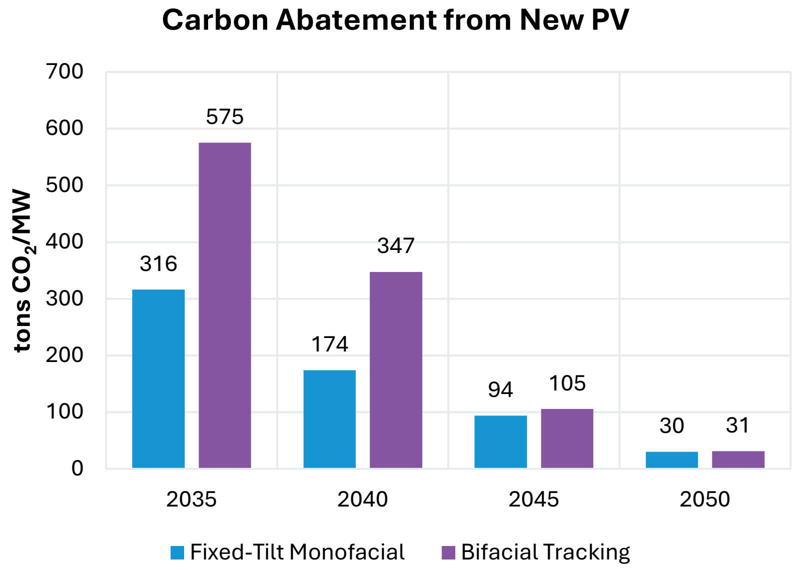
Bifacial Tracking PV: Capacity Buildout

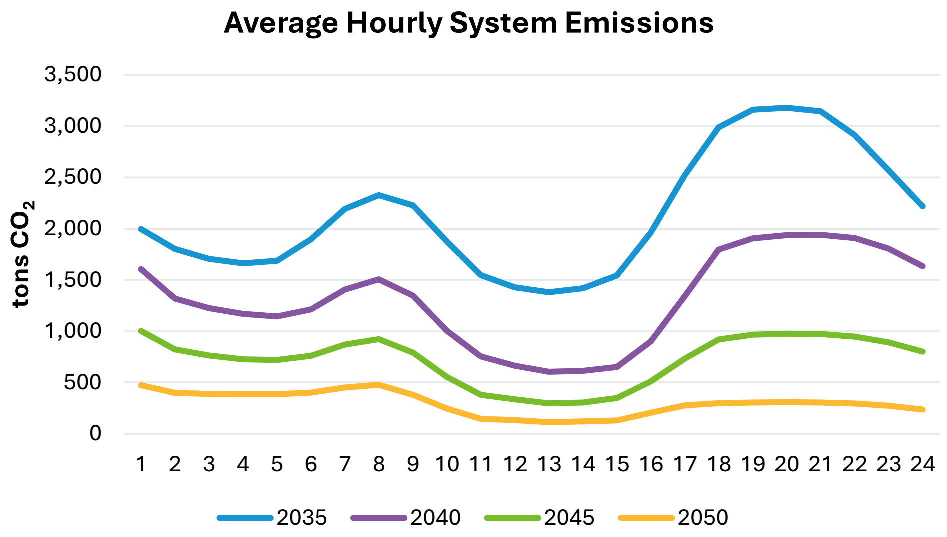
Type	Reference	Bifacial Tracking	Delta
PV	38,000	34,278	-3,722
LBW	3,600	3,600	0
OSW	17,848	18,648	+801
SMR	5,117	4,658	-459
Li-ion BESS	14,811	12,446	-2,364
Iron-air BESS	1,451	1,834	+384
Total (MW)	**80,826**	**75,465**	**-5,361**



- The total capacity of new resources is reduced by 5.4 GW when new PV is modeled as single-axis tracking bifacial
  - The buildouts of PV and short-duration batteries are reduced because of the increased production from bifacial tracking PV

Bifacial Tracking PV: Carbon Abatement

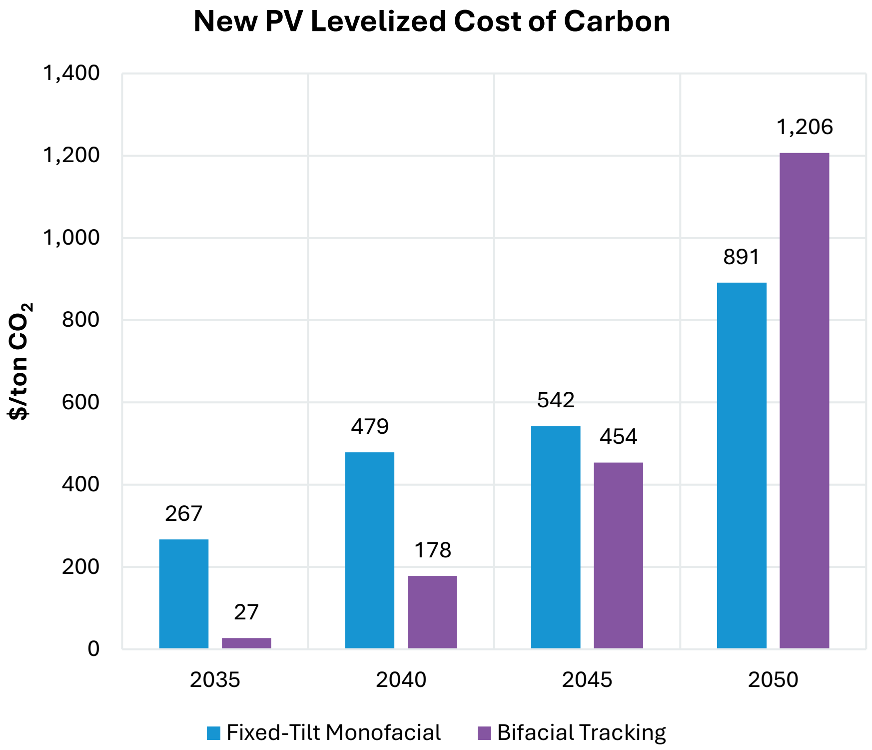




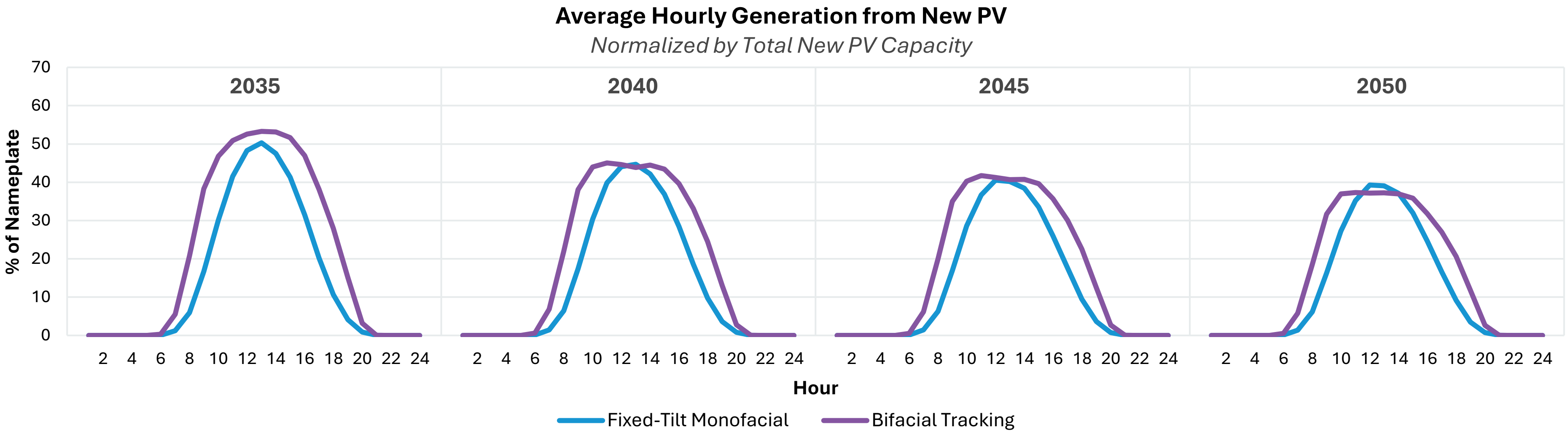
- In 2045 and 2050, bifacial tracking PV has less of an advantage over fixed-tilt PV at reducing emissions
  - Midday hours are mostly decarbonized by 2045, so new PV will be curtailed most days of the year, regardless of the panel type

Bifacial Tracking PV: Levelized Cost of Carbon

- Levelized cost of carbon is a measure of the cost of reducing carbon emissions using different resource types
  - The costs associated with new resources include both capital costs and production costs
- After 2045, the cost of bifacial tracking PV outweighs the benefits of the increased capacity factor
  - Fixed-tilt monofacial becomes more economic than bifacial tracking after 2045



Bifacial Tracking PV: Hourly Generation



- Bifacial tracking PV has an advantage over fixed-tilt monofacial PV during the shoulder hours because of its ability to generate when the sun is lower in the sky
  - During the midday hours, bifacial tracking PV is curtailed in larger amounts than monofacial fixed-tilt PV, especially as the system becomes more saturated with PV
- Contributions from new PV resources decrease over time as an increasing number of days each year already experience curtailment during peak solar generation hours

Bifacial Tracking PV: 2050 Operational Metrics

	Reference	Bifacial Tracking	Delta
Production Cost ($M)	1,316	1,276	-40
Avg LMP ($/MWh)	25.58	21.40	-4.17
Hours with LMP≤$0/MWh	4,527	5,180	+653
Total System Curtailment (GWh)	30,979	45,079	+14,100
New PV Capacity Factor (%)	12.03	15.39	+3.36
New PV Curtailment Factor (%)	17.95	25.99	+8.04

- The bifacial tracking sensitivity buildout has slightly lower energy market costs in 2050 because there is more energy coming from zero cost resources
- Bifacial tracking PV has a higher capacity factor than fixed-tilt monofacial PV, but it is also curtailed at a higher rate

$$Capacity\ Factor\ [\%] = 100 * \frac{Annual\ Energy\ Produced\ [MWh]}{Nameplate\ Capacity\ [MW] * 8{,}760\ [h]}$$

$$Curtailment\ Factor\ [\%] = 100 * \frac{Annual\ Energy\ Curtailed\ [GWh]}{Annual\ Energy\ Curtailed\ [GWh] + Annual\ Energy\ Produced\ [GWh]}$$

POLICY SCENARIO SENSITIVITY

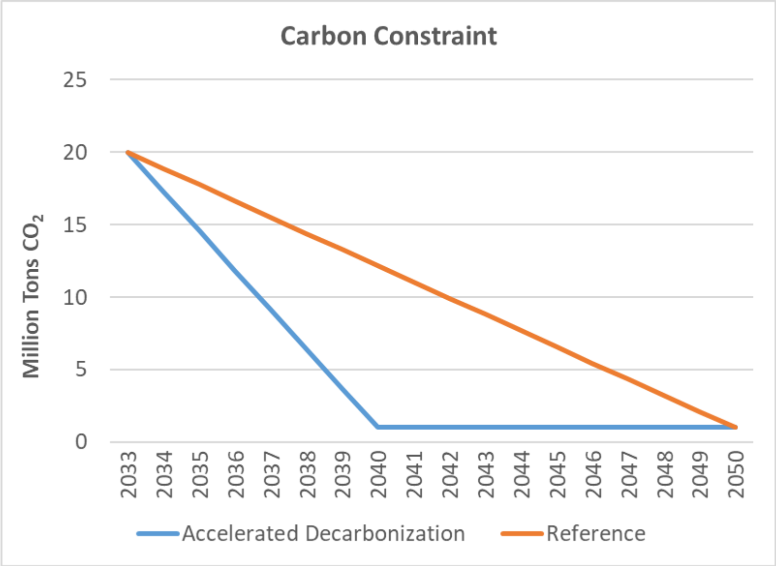
Accelerated Decarbonization

Policy Sensitivity Overview – Accelerated Decarbonization

- In the Policy Scenario reference case, a carbon constraint was enforced to enable the model to build enough zero-carbon resources to meet the region's decarbonization goals by 2050
  - The carbon constraint followed a glide path starting at 20 million tons of CO_2 in 2033 and ending at 1 million tons in 2050
- The ISO received a sensitivity request to model a future system under an accelerated decarbonization timeline, in which the region meets their decarbonization goals in 2040 instead of 2050
  - The results of this sensitivity could help states understand the required investments and consumer cost impacts of more aggressive decarbonization policies

Accelerated Decarbonization - Assumptions

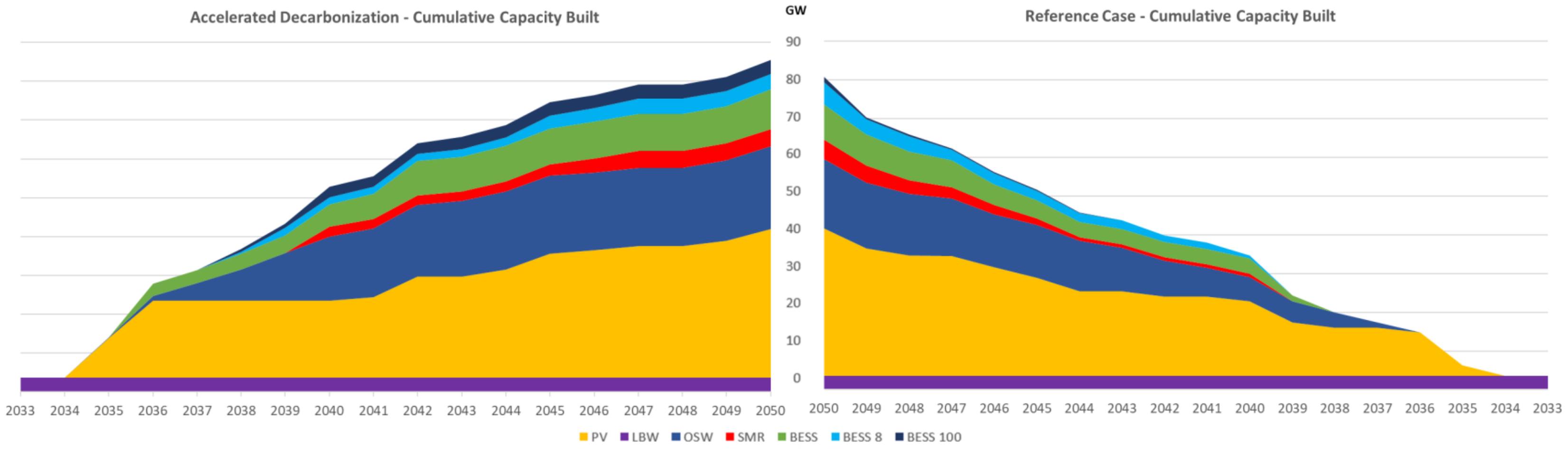
- The carbon constraint from the Policy Scenario reference case was updated to reflect a glide path that **ends at 1 million tons in 2040 instead of 2050 and continues to constrain at 1 million tons from 2040-2050**
  - This sensitivity **does not** consider accelerated decarbonization of the transportation and heating sectors, so load growth assumptions are unchanged from the reference



Accelerated Decarbonization Takeaways

- The buildout of resources under an accelerated decarbonization timeframe would be **more extensive and expensive** compared to the reference Policy Scenario buildout
- The accelerated decarbonization scenario **continued to build resources after meeting the carbon constraint in 2040 to meet increasing electrification load** between 2040-2050
- The marginal cost of carbon under the accelerated decarbonization timeframe **increased much faster** than under the reference Policy Scenario

Accelerated Decarbonization: Capacity Buildout



- The accelerated decarbonization model built 85 GW of capacity, **6% more** than the reference Policy Scenario which built 81 GW
  - Both models built the maximum amount of LBW in the first year as it was the lowest cost resource to build
- The bulk of the SMR buildout occurred in 2040 when the 1 million ton carbon constraint was first enforced, whereas the reference Policy Scenario gradually built SMRs over the last decade

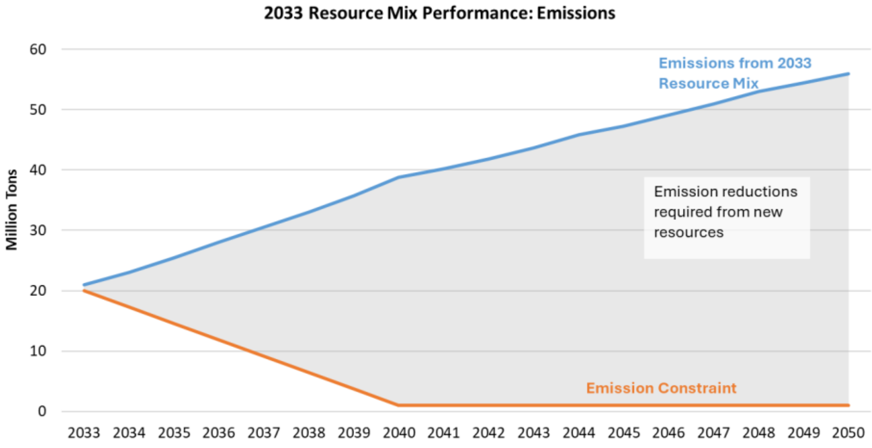
Accelerated Decarbonization: Capacity Buildout

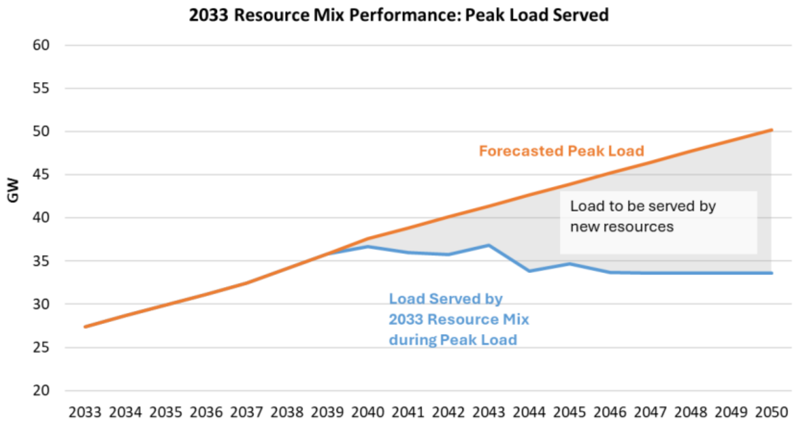
- The accelerated decarbonization **model built less SMRs overall compared to the reference Policy Scenario** because SMRs were not needed as much in the last decade once the carbon constraint is satisfied in 2040
  - The SMR capital costs start to steeply decline **after** 2040 and the cost difference between OSW and SMRs become less drastic, therefore, **more SMRs are built between 2040-2050 in the reference Policy Scenario**
- The accelerated decarbonization model built more 100 hour batteries due to the greater buildout of renewables that would incentivize long duration storage and the accelerated decarbonization

Cumulative Capacity (MW)

Resource Type	Accelerated Decarbonization	Reference
PV	38,303	38,000
LBW	3,600	3,600
OSW	21,296	17,848
SMR	4,500	5,117
BESS 4	10,202	9,126
BESS 8	3,899	5,684
BESS 100	3,637	1,451

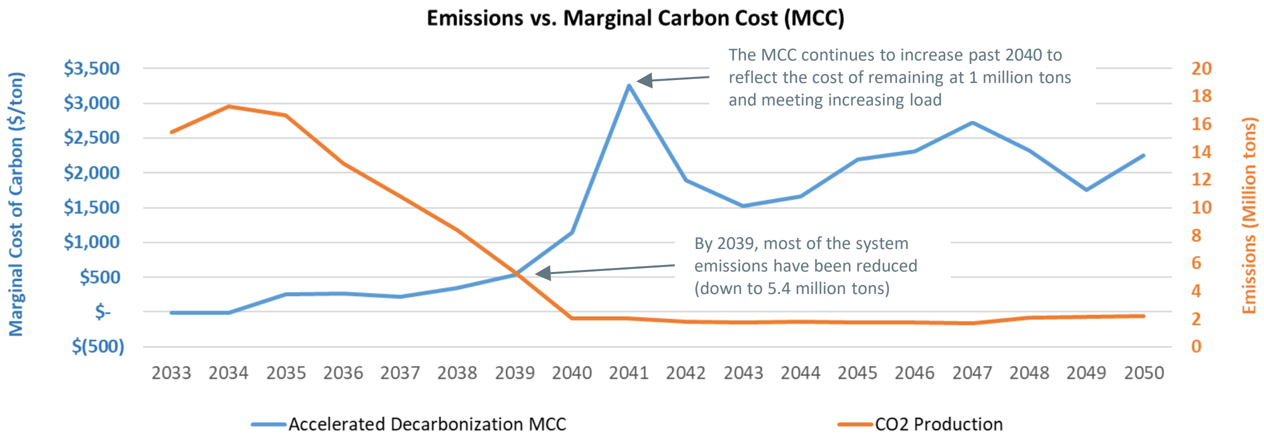
Accelerated Decarbonization: Carbon Constraint vs Load Growth





- The two factors driving capacity expansion are the **emission constraint** and **load growth**
  - The 2033 resource mix **cannot** meet the emission constraint without building new resources early on
  - The 2033 resource mix **can serve** the forecasted load in a moderate weather year until 2040 without needing new resources
    - This is why the model continues building new resources after meeting the carbon constraint in 2040

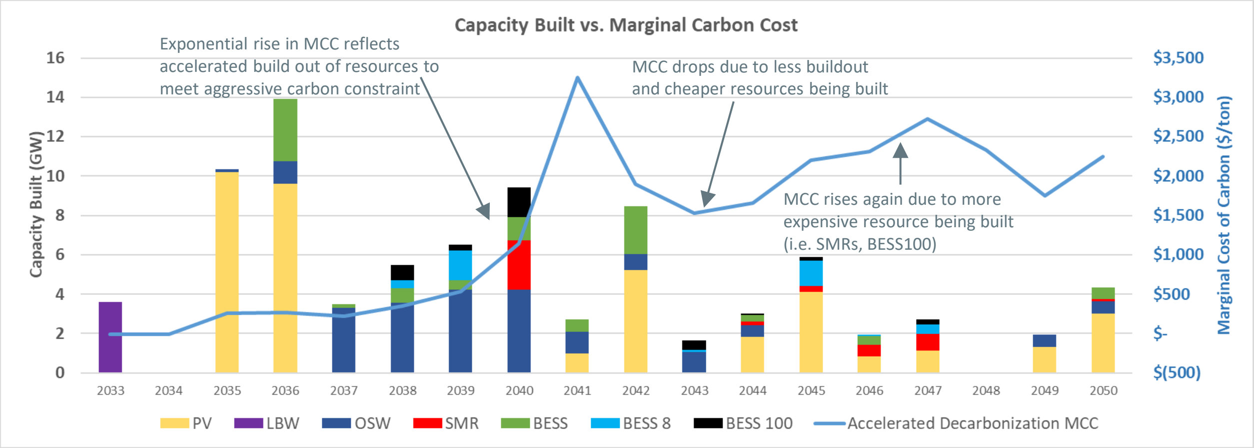
Accelerated Decarbonization: Marginal Carbon Cost



Marginal Carbon Cost (MCC) = Cost of reducing the next additional ton of carbon emission

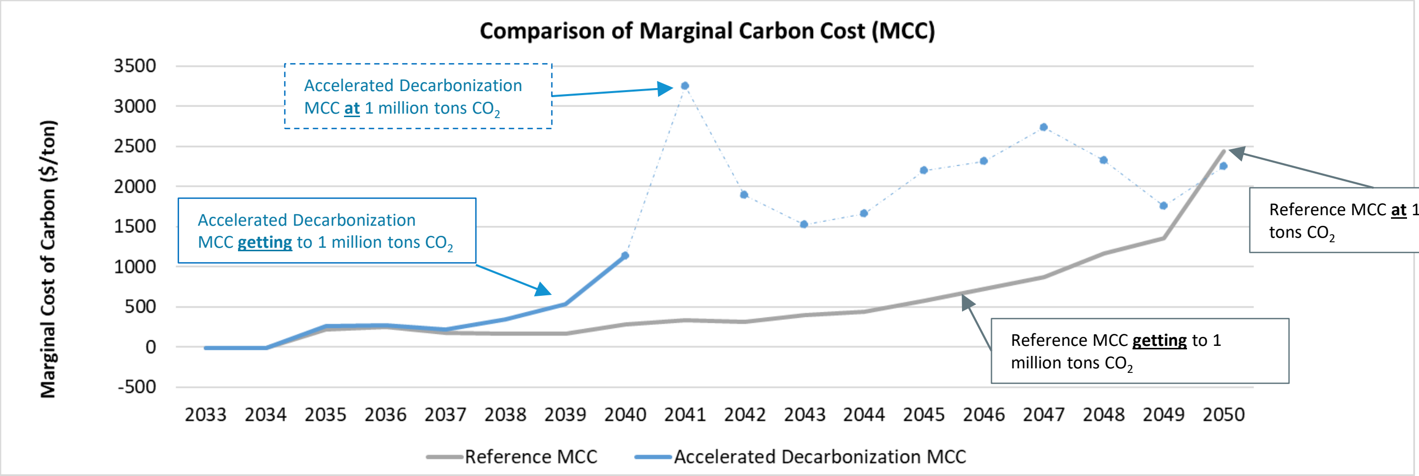
- **Between 2033-2039, the MCC is stable and has small incremental increases year-over-year** since the model primarily builds cheaper resources like PV, LBW, and OSW to achieve most of the system emissions
- The MCC accelerates between 2039-2040 as the model quickly builds more expensive resources (i.e. SMRs, 100-hour batteries) to further reduce emissions by 4.4 million tons
  - The MCC continues to rise after 2040

Accelerated Decarbonization: Marginal Carbon Cost



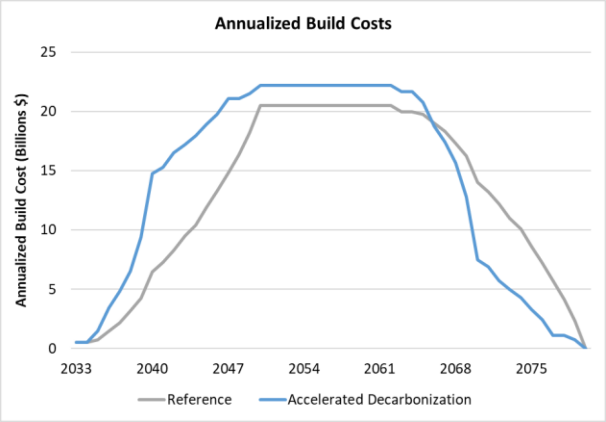
- The MCC fluctuates between 2041-2050 within the range of approx. $1,500/ton and $3,000/ton
  - The model continues to build new resources after 2040 to meet the increasing electrification load and the **fluctuation in the MCC reflects the change in production cost, build costs, and FOM corresponding to the type and quantity of resources that are built for that year**

Accelerated Decarbonization: Comparison of Costs



- **The accelerated decarbonization timeline causes the MCC to escalate much faster than the reference MCC**
  - By 2041, the MCC peaks at $3,254/ton compared to $332/ton in the reference Policy Scenario for the same year
  - The 2050 MCCs for both scenarios are relatively the same: $2,252/ton for the accelerated decarbonization scenario and $2,440/ton for the reference Policy Scenario

Accelerated Decarbonization: Comparison of Costs



Reference Total Build Costs	Accelerated Decarbonization Total Build Costs
$615 billion	$666 billion

- The annualized build costs only account for the costs up to the last year of the model's time horizon, therefore, **to get the total cost of the buildout when every unit has been paid off the costs were projected 30 years (i.e. the economic life of a unit) past 2050**
  - For example, if a unit was built in 2050, the annualized build costs will be zero in 2080 as the unit is paid off after 30 years
- The buildout of non-emitting resources to meet the accelerated carbon constraint is **8% more expensive** than the Reference
  - Resource build costs are assumed to decrease over time as the technology matures, therefore, building resources before 2040 increases costs that would have been built later in the reference Policy Scenario when costs were lower
  - Similar to the MCC, the annualized build costs escalates much faster and has a higher peak than the reference Policy Scenario

Accelerated Decarbonization: 2040 Operational Metrics

	Reference	Accelerated Decarbonization	Delta
Production Cost ($M)	$2,600	$861	-$1,739
Avg LMP ($/MWh)	$78.60	$16.78	-$61.82
Hours with LMP≤$0/MWh	2,359	5,107	+2,748
Total Curtailment (GWh)	8,752	26,452	+17,700
Emissions (tons)	11,580,884	2,026,515	-9,554,368
Hours of Emitting Generation (hr)	6,282	1,782	-4,500

- In 2040, the accelerated decarbonization scenario is building more resources than it can use resulting in **significant curtailment, three times more than in the reference Policy Scenario**

Accelerated Decarbonization: 2050 Operational Metrics

	Reference	Accelerated Decarbonization	Delta
Production Cost ($M)	$1,316	$1,202	-$114
Avg LMP ($/MWh)	$25.58	$18.04	-$7.53
Hours with LMP≤$0/MWh	4,527	5,184	+657
Total Curtailment (GWh)	30,979	36,994	+6,015
Emissions (tons)	2,604,025	2,208,355	-395,669
Hours of Emitting Generation (hr)	1,705	1,381	-324

- The accelerated decarbonization model builds more non-emitting resources to meet the aggressive carbon constraint resulting in greater curtailment and more hours of zero/negative LMPs than the reference Policy Scenario
- **Production cost and average LMPs are lower compared to the reference Policy Scenario** due to less generation from high cost emitting resources and SMRs

POLICY SCENARIO SENSITIVITY

Flexible Demand

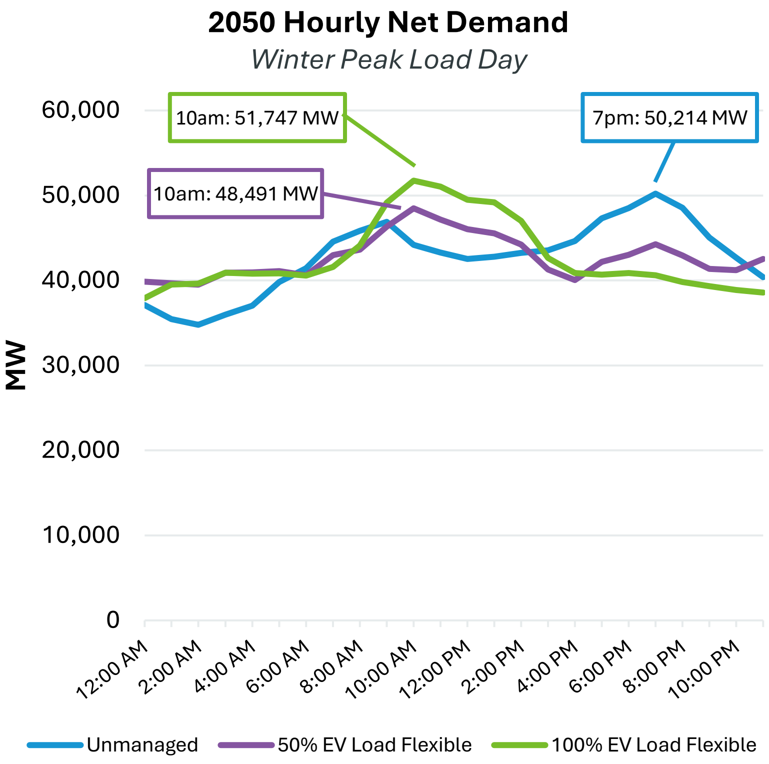
Flexible Demand Overview

- The Economic Studies typically model only existing active demand response based on the 2024 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report), with high dispatch costs limiting its operations to the highest demand hours
- The following sensitivities explore the potential benefits of a **conceptual flexible demand program, where PLEXOS can shift the timing of a portion of baseload or electric vehicle (EV) load within each day to reduce the overall cost of serving demand**
  - This represents a broader range of potential future technologies that increase the attribute of flexibility on the system
- The purpose of these sensitivities is to **assess whether increased demand-side flexibility can reduce inefficiencies in the reference buildout** such as high costs, large capacity requirements, misalignment of supply and demand, and reliance on stored fuels for a small portion of winter days

Preliminary Results: Optimized Demand Profiles

- Preliminary production cost results for 2050 showed production cost savings from implementing flexible demand in the model, but **they also showed potential increases in peak demand**

- From the model's perspective, the most economic way to reduce production cost is to shift as much demand as possible onto the midday hours when PV production is at its peak. This can increase transmission and capacity costs, but the model has no insight into these costs



Load Assumptions and Peak Load Constraint

- The ISO's 2050 Transmission Study[1] found that **increases in peak load above ~51 GW become significantly more expensive with regard to transmission costs**
  - Transmission costs increase by roughly $1.5 billion per GW of load added from 51 GW to 57 GW
  - Higher peak loads → more transmission overloads → more transmission upgrades needed → increased transmission costs

- Based on the 2050 Transmission Study finding, **a 51 GW peak load constraint was implemented in the flexible demand sensitivity capacity expansion and production cost models**. All results will reflect this change

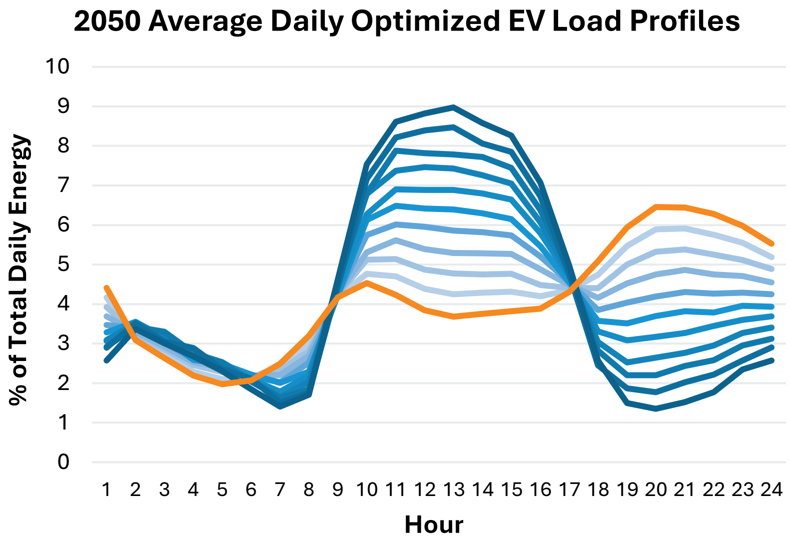
- The peak load constraint is applied to net load because BTM-PV reduce the demand that must be served by the bulk power system
  - Storage charging load is excluded from the constraint based on the assumption that storage is a highly controllable resource and its charging can be shifted in real-time to avoid contributing to system peaks.

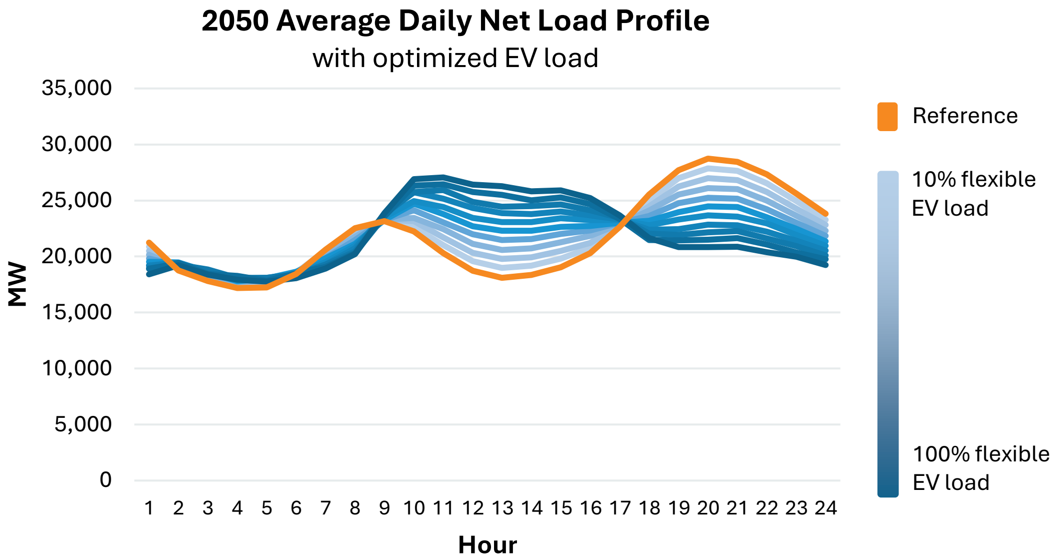
[1] https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

Takeaways: Flexible Demand in Capacity Expansion

- As renewable penetration increases, the most efficient way, given the approach and assumptions, to shift demand is to increase demand midday when solar generation (both utility and BTM-PV) is high and decrease it during evening or winter morning peaks when solar generation is low
- Capital costs savings increase linearly with increasing demand-side flexibility, as represented in this analysis by EV and baseload shifting
  - Flexibility reduces reliance on expensive resources that are only needed for short durations
- Additionally, battery buildouts decline linearly because flexible demand increasingly substitutes for batteries in performing load shifting

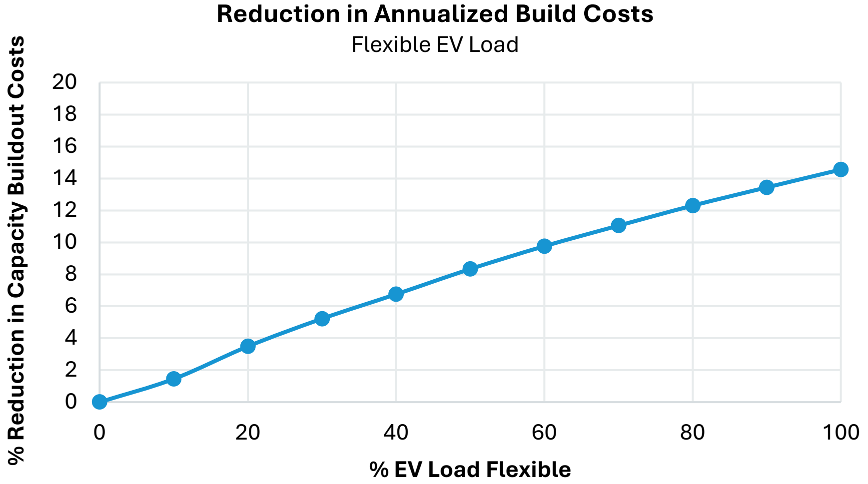
Optimized Profiles: EV Load

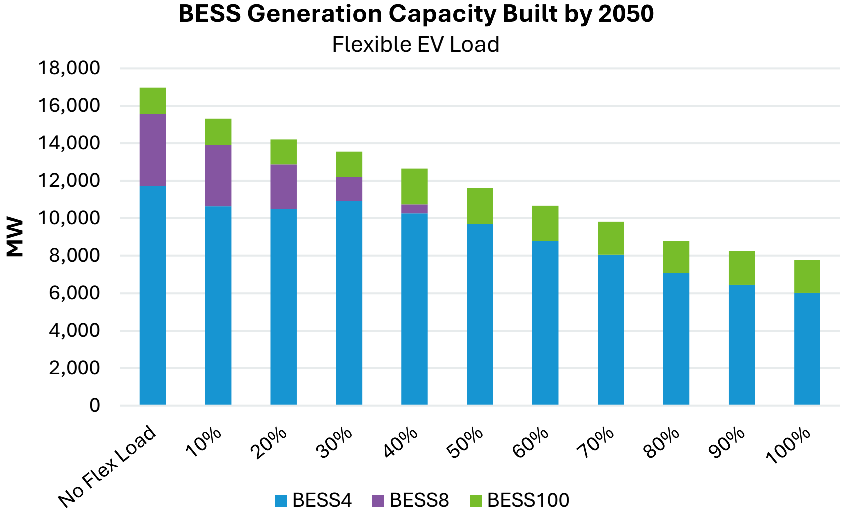




- Profiles are optimized to minimize production cost by shifting load onto low or negative LMP hours
- Optimal charging times appear to shift to midday as the system is decarbonized
  - Additionally, as heating electrification increases, winter peak loads may occur in the morning rather than evening, so the traditional 'on-peak' vs 'off-peak' managed EV charging may vary by season
  - See Appendix III for additional optimized EV and baseload profile results including seasonal average profiles. Note that winter profiles shift load away from morning hours

Capacity Expansion Results: EV Load Flexibility





- Total build costs can be reduced up to 14.6% using optimally managed EV charging and 17.4% using optimally managed baseload, which makes up a larger portion of total load
  - See Appendix III for capacity expansion results of flexible baseload, capacity buildout results for flexible EV load cases, MWh associated with each component in 2050, and 2050 production costs
- Flexible load replaces the role of short-duration batteries in shifting demand within each day, so the total BESS buildout is reduced as more load is allowed to flex
  - Unlike batteries, flexible demand was not modeled with an associated cost for shifting load, making it a more economic solution, under these modeling assumptions, for addressing mismatches between supply and demand

Multiple Weather Year Analysis Overview

- The reference Policy Scenario uses the 2019 weather year load profile, which peaks at 50.2 GW. To investigate how effective demand shifting programs could be in reducing peak loads above 51 GW, **the ISO performed additional 2050 production cost runs with 20 weather year profiles**
  - This analysis assumes a fixed percentage of total daily load is flexible, rather than separating by load component. Results include total MW of load that need to be shifted but do not attribute this flexibility to specific load components
- The resource mix evaluated in **this analysis uses the reference Policy Scenario buildout**
  - This approach isolates the impact of flexible demand on system performance and peak loads without conflating results with differences in resource mix
  - Using the reference buildout represents a more realistic planning scenario in which the grid is not explicitly designed to rely on demand flexibility

2050 Peak Loads Across 20 Weather Years

- The goal of this analysis is to determine
  1. How much flexible demand is required to maintain a 51 GW peak load?
  2. How do system costs change when demand shifting programs are implemented?
  3. To what extent can demand-side flexibility reduce system inefficiencies?

- Across the 20 years of load and weather data, the 2004 weather year has the highest peak net demand at 59,490 MW, requiring **14.3%** load flexibility to reduce the peak to 51GW
  - During the peak hour, this is equivalent to 44% baseload flexibility or 78% EV load flexibility. Distributing load shifting participation across multiple load components reduces stress on any single component
  - This analysis is limited to only 20 years of historic weather data. Extreme weather events could produce even higher peak loads which would require more demand flexibility

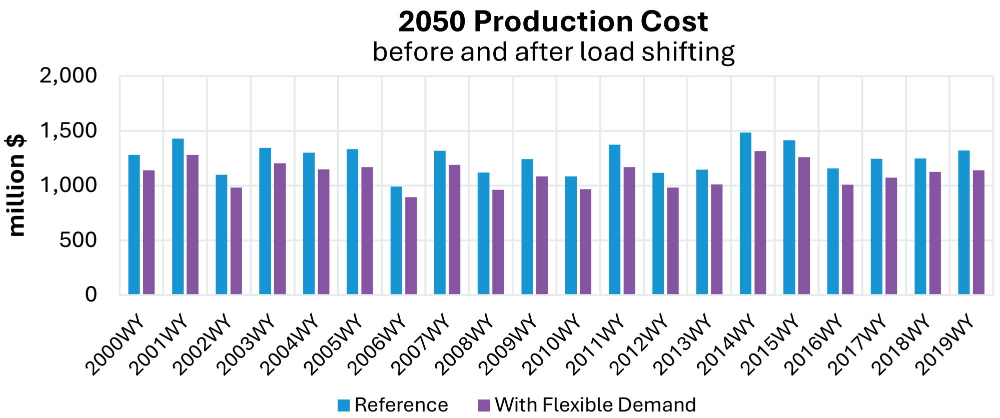
Weather Year	Peak Net Load (MW)	Peak Load Reduction Needed (MW)
2000	48,633	0
2001	42,890	0
2002	44,064	0
2003	50,727	0
2004	59,490	8,490
2005	52,197	1,197
2006	41,697	0
2007	52,170	1,170
2008	46,702	0
2009	54,340	3,340
2010	43,963	0
2011	54,958	3,958
2012	40,934	0
2013	48,879	0
2014	50,512	0
2015	54,199	3,199
2016	52,861	1,861
2017	50,089	0
2018	50,366	0
2019	50,214	0

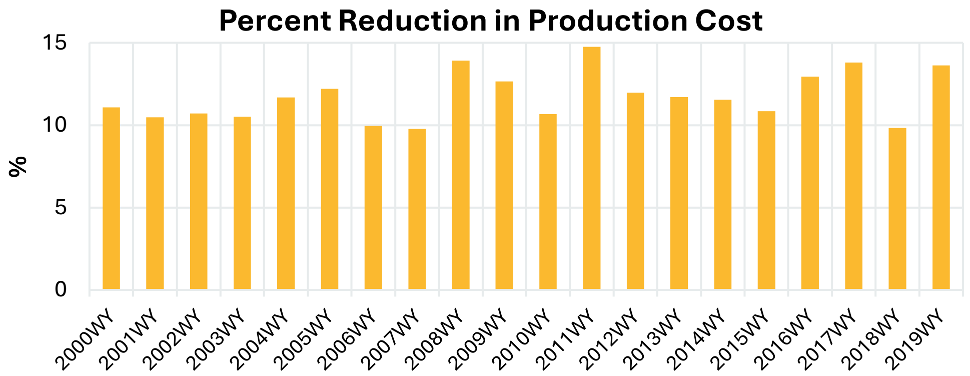
Takeaways: Economic and Operational Impacts of Flexible Demand

- Demand-side flexibility **reduces production costs** by moving load to lower-cost hours
- Demand shifting **can be used to maintain a 51 GW peak load,** even in severe weather years, by rescheduling load to off-peak hours
  - Peak load reductions can avoid costly transmission upgrades, as identified in the 2050 Transmission Study
- Operationally, demand-side flexibility improves the alignment of real-time generation with hourly demand, **reducing reliance on stored fuels and batteries and lowering the risk of winter energy shortfalls**

Economic Impacts of Flexible Demand

Production Cost Savings

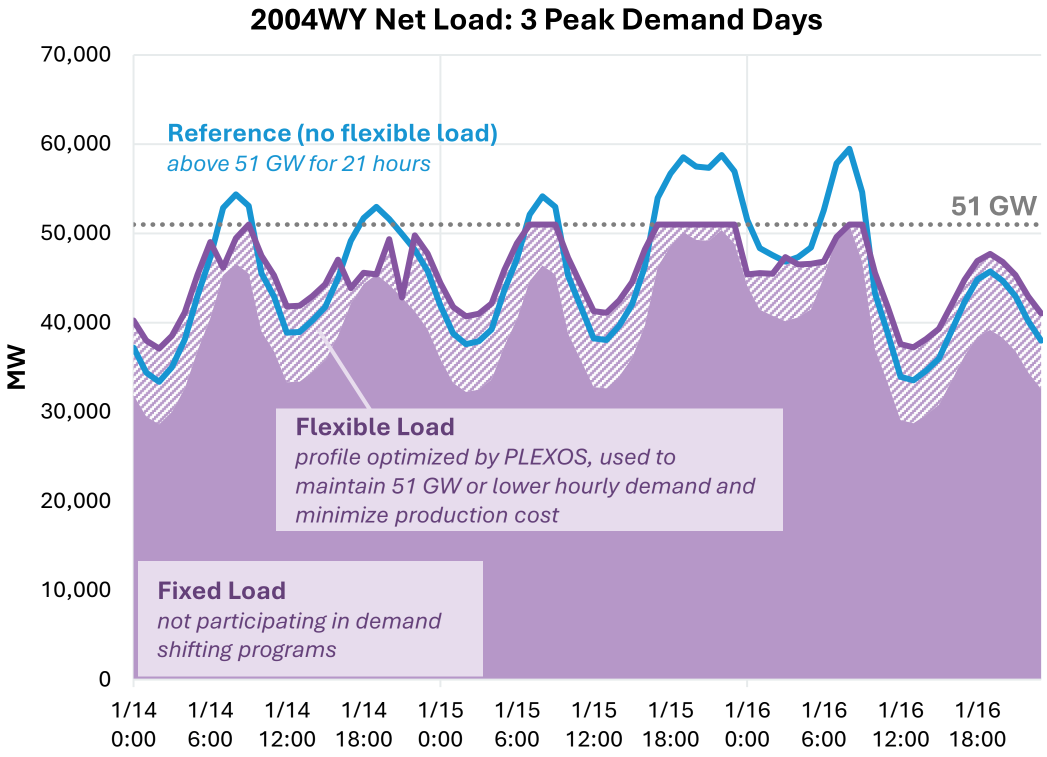




- Flexible demand reduces costs by shifting load away from high-cost hours, improving overall system efficiency. Across the 20 modeled weather years, implementing demand-side flexibility resulted in **production cost savings ranging from 10-15% relative to the reference case**
  - See Appendix III for detailed annual production cost savings and annual energy shifted
  - Note that PLEXOS has perfect foresight and total control over flexible load. In practice, load shifting needs are less predictable and less precise, so these modeled cost savings may be inflated from actual operational savings

Operational Impacts of Flexible Demand

Reductions in Peak Load

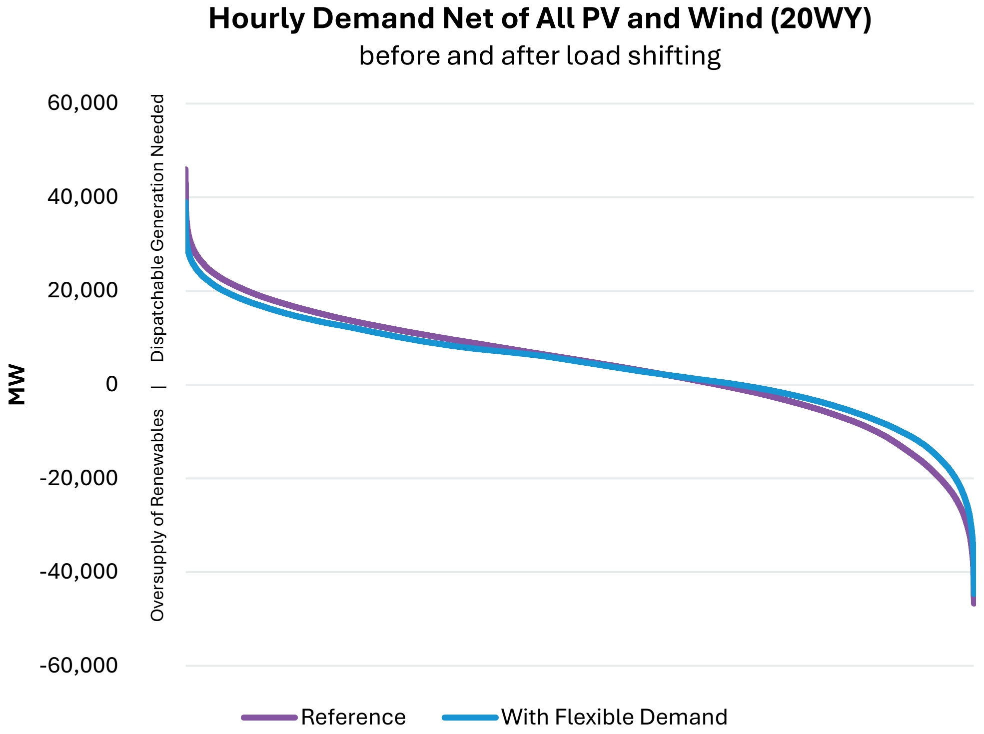


- This graph shows a snapshot of the 2004 weather year peak demand days before and after demand shifting
- With demand shifting, the portion of load that is flexible is strategically rescheduled to off-peak hours, either early morning or midday, which reduces peak demand to 51 GW
  - Total daily demand is still served within each day, but the profile shape is optimized to flatten peaks and improve usage of available renewables
- As identified in the 2050 Transmission Study, transmission costs increase by roughly $1.5 billion per GW of load added from 51 GW to 57 GW
  - The modeled reductions in peak load from demand-side flexibility demonstrate how demand shifting can contribute to significant avoided transmission investment

Operational Impacts of Flexible Demand

Improved Alignment of Supply and Demand

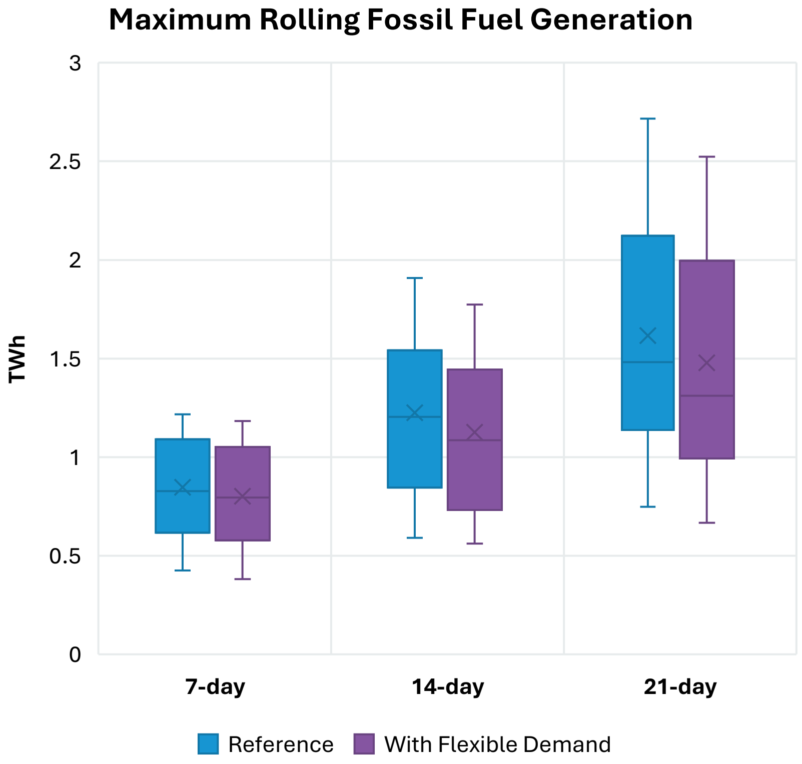
- In a highly decarbonized system, intermittent renewable generation and load both vary drastically. Demand shifting can aid in better coordination between hourly supply and demand
  - Lower peak net demand means less dispatchable generation is needed, reducing emissions
  - Less oversupply of renewables means resources are being used more efficiently with less curtailment



Operational Impacts of Flexible Demand

Winter Energy Deficits: Fossil Fuel Generation

- In order to analyze the potential benefits of flexible demand in reducing winter energy deficits, this analysis calculates the maximum 7-, 14-, and 21-day rolling generation from fossil fuels over 19 winters (Oct-Apr)
  - This analysis does not model fuel constraints
- Results show that **demand shifting consistently reduces fossil fuel drawdowns regardless of weather conditions**
  - Demand shifting reduces morning heating and evening peak loads, which is when fossil fuel generation is most likely to be needed
- Historic[1] (2008-2024) maximum rolling fossil fuel generation is significantly higher than 2050 fossil generation, even in the reference case
  - 7-day: 1.73 TWh
  - 14-day: 3.15 TWh
  - 21-day: 4.56 TWh

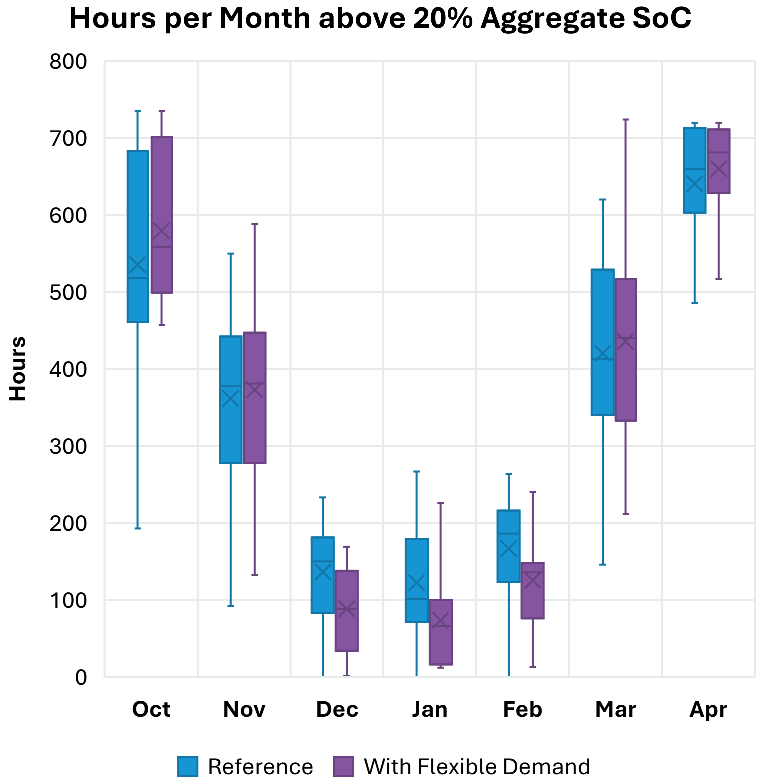


[1] https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type

Operational Impacts of Flexible Demand

Winter Energy Deficits: BESS Drawdown

- Results to date show that battery storage is heavily drawn down in the winter, when surplus renewable generation is limited
  - It's often more economic for the model to leave batteries near empty than to charge them using generators with positive operating costs
- **With demand shifting, winter state of charge levels decline further due to improved alignment of supply and demand**, leaving fewer hours with excess energy available for charging
  - This does not necessarily indicate a higher risk of winter energy shortfalls. Rather, it reflects that **the system is relying less on all forms of stored energy, both from fuels and batteries, because demand is being served more efficiently from real-time generation**
  - The model will still cycle batteries as needed for the most economic dispatch



POLICY SCENARIO SENSITIVITY

Reduced Electrification

Reduced Electrification Sensitivity Overview

- The following sensitivities consider reduced demand from electrification of the heating and transportation sectors
- The reference case assumes full electrification, while these sensitivities evaluate the capacity buildout required to reach 100% electric sector decarbonization when electrification levels reach 75% or 85%
- Additionally, the "Blended" case considers a variety of decarbonization strategies including full adoption of partial heat pumps (HP), where heating switches over to legacy fossil fuel heating below 20°F. The sensitivity also models synthetic natural gas (SNG), new combined cycle units, and no new offshore wind.
  - Assumptions for modeling SNG are taken from the EPCET SNG sensitivity
  - Cost assumptions for new combined cycle generators are from the 2024 NREL ATB

Reduced Electrification Capacity Expansion Results

2033-2050 Total New Capacity Built (MW)

	Reference	85% Electrification	75% Electrification	Blended
PV	38,000	32,654	27,028	37,680
LBW	3,600	3,600	3,600	3,600
OSW	17,848	14,707	12,565	-
SMR	5,117	4,564	4,403	5,263
Li-ion BESS	14,811	13,000	10,427	10,034
100-Hr BESS	1,451	969	352	0
Combined Cycle	-	-	-	5,284
Total	**80,826**	**69,494**	**58,374**	**61,861**
Delta		-11,332	-22,452	-18,965
% Change		-14.02	-27.78	-23.46

2033-2050 Total Annualized Build Costs ($B)

	Reference	85% Electrification	75% Electrification	Blended
PV	28.71	24.62	21.36	28.74
LBW	9.38	9.38	9.38	9.38
OSW	69.32	54.67	47.08	-
SMR	27.15	21.09	16.61	31.58
Li-ion BESS	14.42	11.77	10.07	8.36
100-Hr BESS	0.75	0.61	0.41	0.00
Combined Cycle	-	-	-	7.14
Total	**149.73**	**122.14**	**104.91**	**85.19**
Delta		-27.59	-44.82	-64.54
% Change		-18.43	-29.94	-43.11

- Buildout capacity and costs are reduced up to ~30% in the reduced electrification sensitivities
- The blended case shows that the combination of SNG and new combined cycle generators can avoid the cost increased observed when new OSW is not built

POLICY SCENARIO SENSITIVITY

Reduced Electric Sector Decarbonization and Electrification

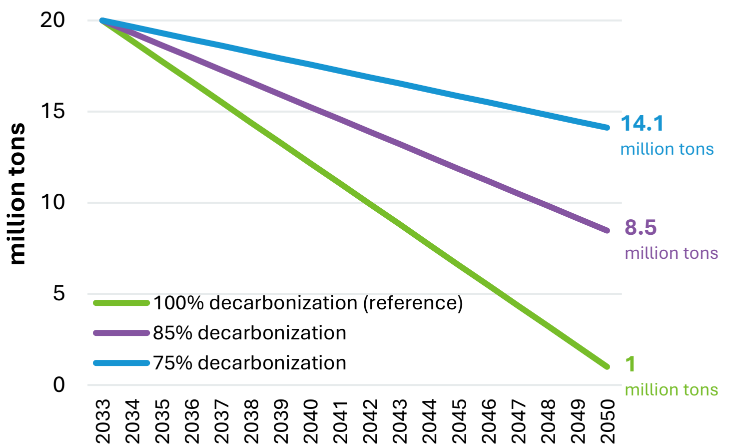
Reduced Decarbonization Sensitivity Overview

- While the reference Policy Scenario models economy-wide decarbonization by 2050, these sensitivities explore how the system may evolve under different assumptions about emissions accounting. The ISO does not model carbon offsetting technologies, which could allow states to achieve net-zero emissions even when modeled emissions remain above zero. **These varied targets are meant to demonstrate a range of possible outcomes based on different interpretations of what constitutes "100%" decarbonization**
  – Electric sector decarbonization is reduced by relaxing the carbon constraint in the capacity expansion model, representing alternate assumptions about emissions targets and accounting. Decarbonization levels are measured against historic state baselines
  – Heating and transportation sector electrification is reduced by lowering demand from HPs and EVs
  – The sensitivities test 75% and 85% decarbonization levels for the electric sector alone and in combination with reduced electrification of the heating and transportation sectors
- **These sensitivities are not policy recommendations. Rather, they serve to identify common economic pathways for investment across a range of alternative futures, including different approaches to defining and achieving net-zero emissions**

2050 Energy by Component (TWh)

Electrification	Base	EV	HP
100%	120.2	56.4	30.6
85%	120.2	47.9	26.0
75%	120.2	42.3	23.0

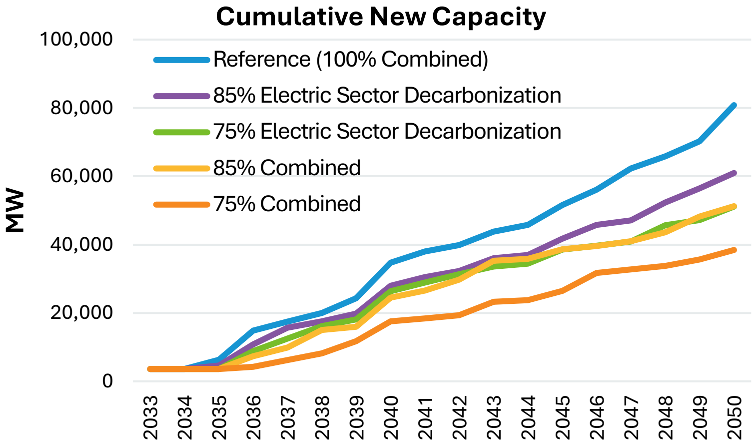
Annual CO_2 Limit



Reduced Decarbonization Takeaways

- Buildout costs are significantly reduced as decarbonization levels decrease
  - This aligns with previous results showing that the majority of buildout costs are concentrated to the last 5 years of the planning horizon. By that point, most emissions from spring and fall have been eliminated, so expensive resources like SMRs are needed to abate emissions in more challenging hours
- Despite the reduced decarbonization targets, many takeaways from the reference case still apply
  - Inexpensive resources like PV, LBW, and short-duration batteries facilitate substantial low-cost decarbonization in the next 10-15 years, providing the majority of early emission reductions
  - LBW remains the most economic resource to build
  - Emissions continue to follow seasonal trends, with elevated levels during winter months

Capacity Expansion Results



2033-2050 Total New Capacity (MW)

	Reference	85% Electric Sector Decarb	75% Electric Sector Decarb	85% Combined	75% Combined
PV	38,000	32,235	28,011	27,191	22,532
LBW	3,600	3,600	3,600	3,600	3,600
OSW	17,848	12,000	10,880	11,075	6,564
SMR	5,117	3,091	1,800	1,976	900
Li-ion BESS	14,811	10,042	6,849	7,414	4,840
100-hr BESS	1,451	0	0	0	0
Total	**80,826**	**60,967**	**51,141**	**51,256**	**38,436**
Delta from Reference		-19,859	-29,685	-29,570	-42,390
% Change		-24.57	-36.73	-36.59	-52.45

*Note: 'Combined' refers to the decarbonization level of electric sector **and** electrification levels of heating and transportation. Each case applies a consistent level across all sectors: 100% (reference), 85%, or 75%. This terminology is used throughout all slides and figures*

- Relative to the reference case, the total new capacity needed is up to 36% lower with reduced electric sector decarbonization levels and up to 52% lower with reduced decarbonization and electrification levels
  - Besides 100-hour batteries, which are only built in the reference Policy Scenario, SMRs show the largest percentage reduction in capacity built between the reference and reduced decarbonization sensitivities. This is consistent with previous findings that SMRs are primarily built to decarbonize the last 15-25% of emissions, which are the most expensive to abate

- Across all cases, 3.6GW of LBW are built in 2033 because the production cost savings from new LBW outweigh the increased capital costs

2050 Total Costs

	Reference	85% Electric Sector Decarbonization	75% Electric Sector Decarbonization	85% Combined	75% Combined
2050 Capital Costs ($B)	20.49	13.32	10.44	10.86	6.71
2050 Fixed O&M Costs ($B)	4.10	3.21	2.81	2.87	2.28
2050 Production Cost ($B)	1.32	2.68	3.68	2.61	3.90
2050 Total Cost ($B)	**25.91**	**19.22**	**16.93**	**16.33**	**12.89**
Delta from Reference ($B)		-6.69	-8.98	-9.57	-13.01
% Change		-25.83	-34.65	-36.96	-50.24

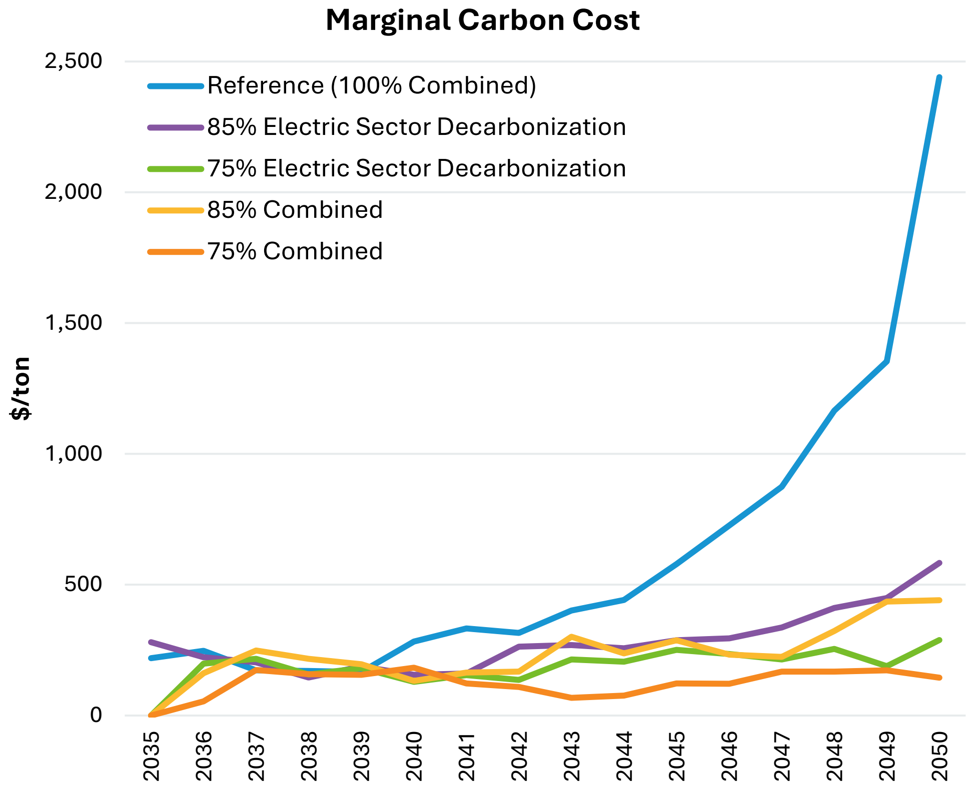
- Total electric sector costs decline across all reduced decarbonization cases, primarily driven by lower capital costs
  - While capital costs decrease, production costs increase due to reduced buildouts of wind and PV, which have no operating costs
  - The 75% combined case shows a 50% reduction in total 2050 costs relative to the reference case
- These results reflect electric sector costs only

2050 Economic and Operational Metrics

	Reference	85% Electric Sector Decarbonization	75% Electric Sector Decarbonization	85% Combined	75% Combined
Avg LMP ($/MWh)	25.58	64.21	82.59	69.93	97.00
Hours with LMP≤$0/MWh	4,527	3,015	2,785	3,161	2,500
SMR Capacity Factor (%)	20.72	47.02	65.53	48.97	57.92
Energy Curtailed (GWh)	30,979	17,479	14,480	16,869	10,660
% Generation from Renewables	69.26	59.13	55.45	58.40	49.98
Peak Emitting Generation (MW)	16,235	17,890	19,349	17,840	18,072

- The reduced decarbonization sensitivities use new resources more efficiently
  - Fewer hours with negative LMPs result in more frequent economic dispatch of SMRs, although this reflects higher energy market costs
  - Renewable curtailment is reduced by up to 65%, as fewer clean resources are built to address decarbonization needs during infrequent high-emission hours
- The reduced decarbonization buildouts have an increased reliance on legacy fossil fuel generation capacity because they have fewer new clean resources

Marginal Carbon Cost



- The reference Policy Scenario found that as the system is decarbonized, low-cost resources like PV and short-duration batteries provide fewer emission reductions because residual emissions are concentrated during peak winter hours. To decarbonize those key hours, more expensive resources like SMRs and 100-hour batteries are built
- Relaxing decarbonization targets avoids the sharp increase in marginal carbon cost seen at high decarbonization levels
- The sensitivities that modify electric sector only decarbonization levels have slightly higher costs than the combined cases due to increased demand from heating and transportation sectors

2050 Monthly Electric Sector Emissions

2050 Monthly Emissions (thousand tons)

	Reference (100% Combined)	85% Electric Sector Decarbonization	75% Electric Sector Decarbonization	85% Combined	75% Combined	2024 Estimated[1]
Jan	939	2,228	2,947	2,017	2,860	2,172
Feb	446	1,313	1,978	1,235	1,942	1,657
Mar	194	685	1,201	719	1,167	1,939
Apr	13	99	250	114	288	1,511
May	0	12	82	21	144	1,709
Jun	0	43	147	75	269	2,318
Jul	13	215	519	319	870	3,102
Aug	50	283	637	386	962	2,806
Sep	0	104	289	150	499	2,294
Oct	10	203	447	245	557	2,517
Nov	178	829	1,362	856	1,479	2,245
Dec	762	1,954	2,624	1,829	2,508	2,228

- As decarbonization targets are relaxed, electric sector emissions increase but continue to follow a seasonal pattern
  - These results do not account for emissions from the heating and transportation sectors
- The reduced decarbonization and electrification sensitivities show lower winter electric sector emissions compared to the electric-sector only cases due to lower heating demand

[1] https://isonewswire.com/tag/monthly-prices/

Additional Capacity Expansion Results

- Building on previous sensitivities that showed cost savings from flexible demand and bifacial tracking PV panels, additional sensitivities were run for the 75% electric sector decarbonization and electrification case. The purpose is to **quantify how much combining these affordable decarbonization strategies can further reduce capacity buildout costs**
- Results in the table below reflect capacity expansion results under the 75% decarbonization and electrification assumptions. Percent changes shown are relative to the 100% economy-wide reference case
  - Detailed buildout results are shown in Appendix IV
- While the combined benefits are smaller than the sum of individual sensitivity cost savings, **stacking reduced decarbonization and electrification, flexible demand, and bifacial tracking PV can reduce capital costs up to 74%**

2033-2050 Annualized Build Cost versus Reference (% Change)

		Flexible Demand Level			
		No Flexible Load	20% Flexible EV Load	50% Flexible EV Load	100% Flexible EV Load
PV Panel Type	Monofacial Fixed Tilt	-65.63	-66.97	-69.68	-72.57
PV Panel Type	Bifacial Single Axis Tracking	-67.00	-69.30	-71.63	-73.90

STAKEHOLDER-REQUESTED SCENARIO

Assumptions & Methodology

Stakeholder-Requested Scenario and Sensitivities

- Stakeholders have the option to submit a Stakeholder-Requested Scenario proposal or request that a sensitivity of the Reference Scenarios be conducted within the framework of the Economic Studies
  - Sensitivities of the Reference Scenarios may be requested at the time each scenario's final results are presented
- Results of the Stakeholder-Requested Scenario or sensitivities of the reference scenarios are considered for informational purposes only
  - The Stakeholder-Requested Scenario/sensitivities **will not be** evaluated as system efficiency needs against the factors and metrics in Section 17.9 of Attachment K

Stakeholder-Requested Scenario Proposals

The ISO received one Stakeholder-Requested Scenario proposal [1]

- Evaluate the operation of peaker generation plants under ISO forecasted heating and EV charging loads combined with expected growth in clean generation
  - Evaluate scenarios of high/low variations in both load and generation

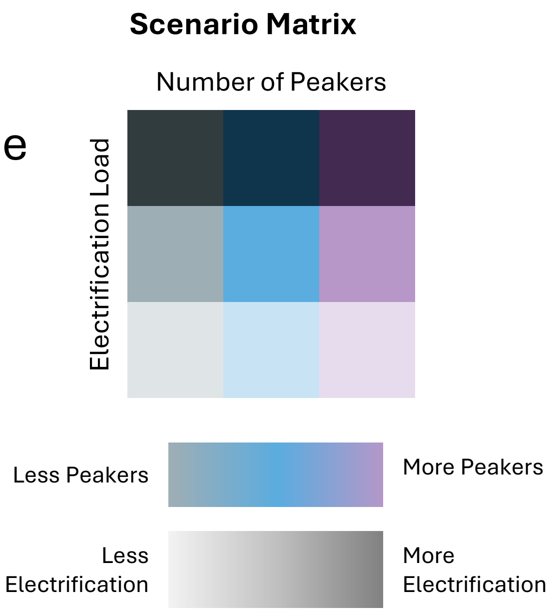
The outcome of the proposal would result in directional guidance to see:

- What combinations of relative growth of grid load vs. clean generation capacity could result in increased or decreased operation of peaker plants
- What level of accelerated clean supply growth or decreased grid load might serve to resolve local peaker plant emissions

[1] *Submitted by Ray Albrecht via email on April 19, 2024*

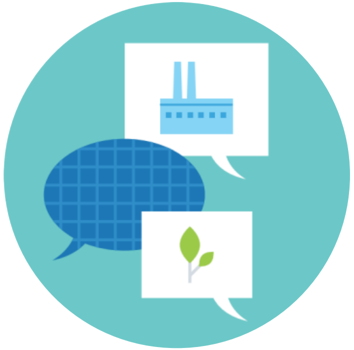
Overview of Assumptions

- A capacity expansion model was run to buildout resources from 2033 to 2040
  - Production cost models will be run in 2040 with the buildout resource mix from capacity expansion
- Input assumptions mirror the Policy Scenario with modifications to the electrification load and the amount of peaker generators
- Today’s results look only at adjustments of electrification **or** peaker capacity, not the combination of the two

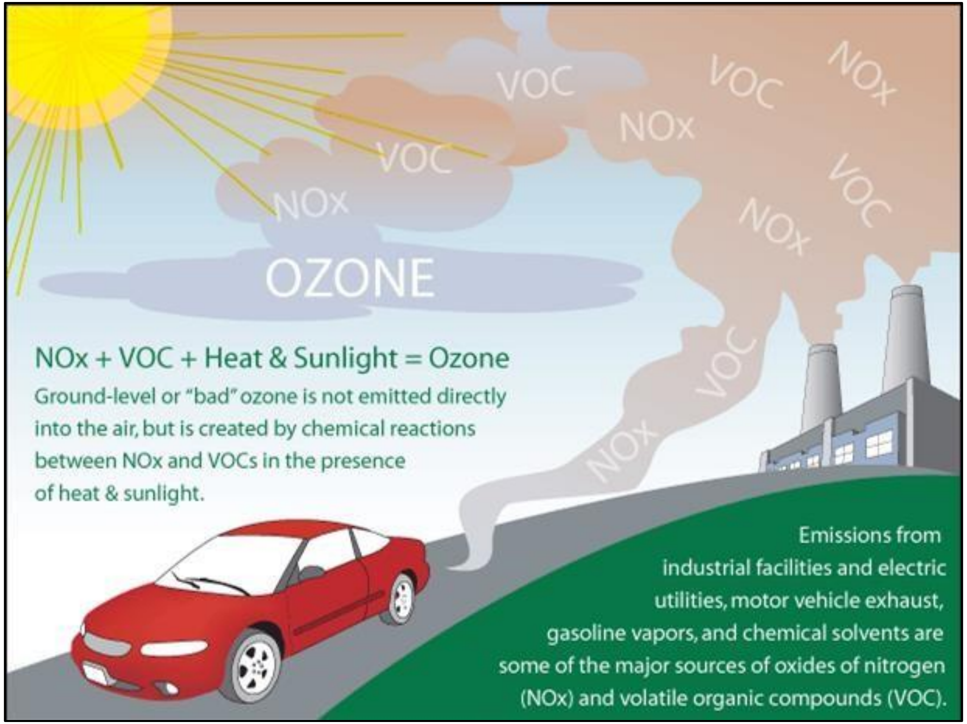


Environmental Modeling

- Part of the proposal asked the ISO to look at hourly emission and transport of Hazardous Air Pollutants (HAPs)
  - PLEXOS is capable of producing primary, point-source emissions of CO_2, NO_X, and SO_X
  - It does **not** track the transport of HAPs or the complex atmospheric interactions in which secondary pollutants form; such as $PM_{2.5}$ and ground-level ozone
- Modeling the transport of HAPs and formation of secondary pollutants requires complex atmospheric models such as the [EPA's CAMQ Modeling System]
  - The ISO does not currently have the technical expertise to run these advanced air-quality models



Example: Ground-Level Ozone Modeling



Source: [EPA Ground-level Ozone Basics]

STAKEHOLDER-REQUESTED SCENARIO

Reference Scenario Results

Modified Electrification Takeaways

- New capacity expansion and build costs **increase** with increasing electrification
- The low electrification scenarios only built PV and wind resources and more expensive resources like SMRs are built in the higher electrification scenarios with additional capacity of PV, wind, and batteries
- Peaker generation remained relatively similar between scenarios while combined cycle generation **decreases with increasing electrification**

Changes to Electrification Assumptions

- Electrification forecasts between 2033 and 2040 are linearly interpolated based on the 2033 and 2040 electrification values then multiplied by the percent corresponding to the electrification

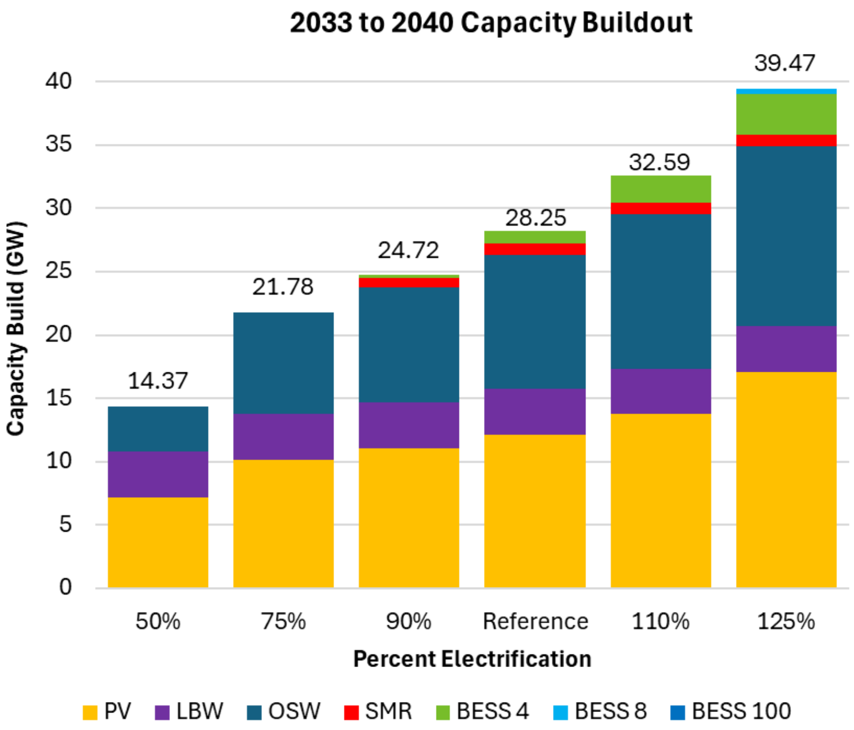
- This analysis is not intended to reflect the ISO Load Forecast but serves as a directional analysis of slower or faster paced electrification

2033 Values	50% Electrification	75% Electrification	90% Electrification	Reference	110% Electrification	125% Electrification
Peak EV (MW)	1,245	1,867	2,240	2,489	2,738	3,112
Peak HP (MW)	1,076	1,615	1,938	2,153	2,368	2,691
Electrification Energy (TWh)	6.3	9.5	11.4	12.7	14.0	15.9

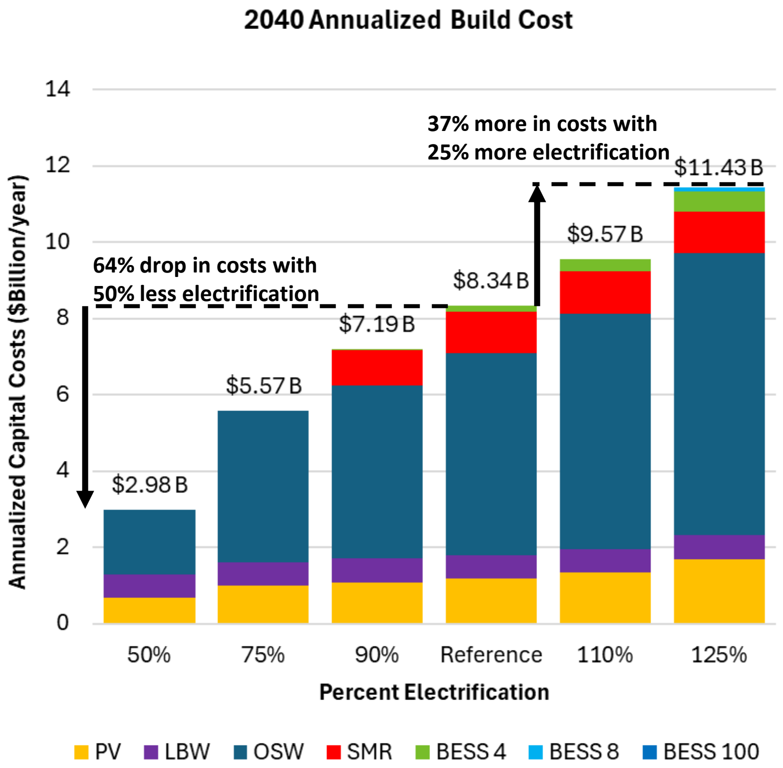
2040 Values	50% Electrification	75% Electrification	90% Electrification	Reference	110% Electrification	125% Electrification
Peak EV (MW)	5,078	7,616	9,140	10,155	11,171	12,694
Peak HP (MW)	7,332	10,997	13,197	14,663	16,129	18,329
Electrification Energy (TWh)	27.9	41.9	50.3	55.9	61.5	69.8

Modified Electrification: Capacity Buildout

- **Capacity buildouts increased with increasing electrification**
- Buildout of land-based wind maxed out at 3,600 MW across all electrification scenarios as it was the most economical resource to build first
- SMRs started getting built at 90% electrification with 762 MW built
  - The higher electrification scenarios each built 900 MW of SMRs in 2040 (125% electrification scenario built SMRs earlier in 2039)
- Only 400 MW of 8-hour batteries were built in total and were only present in the 125% electrification scenario
- **None of the electrification scenarios built 100-hour batteries**
  - Past modelling showed that the buildout of 100-hour batteries were typically economical **after** 2040



Modified Electrification: Capacity Expansion Metrics



- **2040 capital costs increased with increasing electrification** due to more capacity buildout
- The capacity expansion model built cheaper resources like PV and wind first, which were sufficient for the lower electrification scenarios (i.e. 50% and 75% electrification)
- For the higher electrification scenarios, starting with the 90% electrification, the bulk of the expensive resources like SMRs were built towards the end of the modelling horizon in 2039 and 2040

2040 Production Cost: Operational Metrics

Metric	50% Electrification	75% Electrification	90% Electrification	Reference	110% Electrification	125% Electrification
Generation (TWh)	132	146	155	160	166	175
Non-Emitting Generation (TWh)	83	102	111	119	126	137
Emitting Generation (TWh)	23.4	23.1	22.3	21.3	20.3	19.1
Imports (TWh)	22.0	19.1	19.2	18.8	18.1	17.2
Storage Generation (TWh)	4.0	5.2	6.0	7.2	8.7	11.3
Storage Load (TWh)	5.0	6.6	7.4	8.8	10.6	13.6

- As electrification increases, storage operation also increases while emitting generation decreases

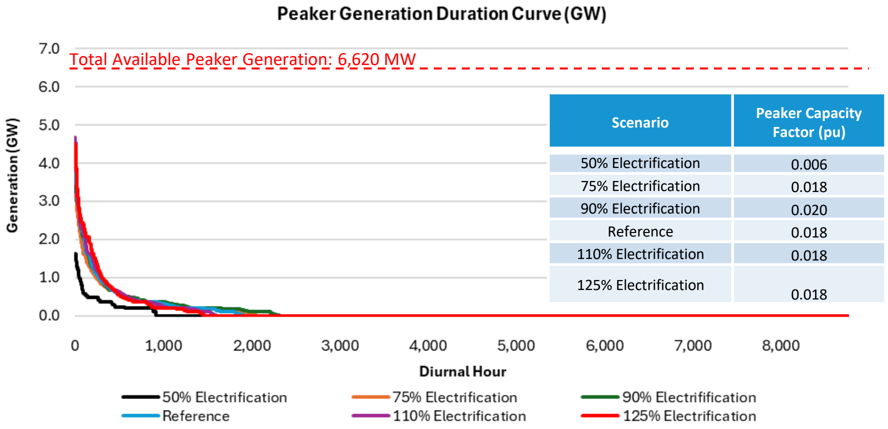
2040 Production Cost: Operational Metrics (cont.)

Metric	50% Electrification	75% Electrification	90% Electrification	Reference	110% Electrification	125% Electrification
Carbon Emissions (tons)	10.4	11.4	11.1	10.6	9.9	9.3
Hours with Emitting Generation	6,780	6,668	6,528	6,088	5,463	4,964
Curtailment (TWh)	5.6	11.8	11.7	12.8	14.7	17.7

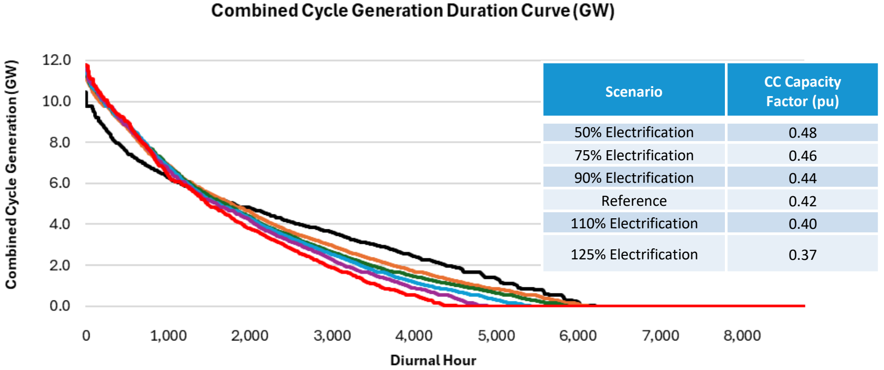
- Emissions generally decrease as electrification increases due to more non-emitting generation displacing emitting generation
- Capacity expansion builds more non-emitting resources than is needed for most of the year resulting in significant curtailment

2040 Thermal Operation

- Peaker generation does not vary significantly between scenarios
  - The only noticeable difference is lower peaker generation in the 50% Electrification which has the lowest load
  - Peaker generation never reaches 100% output
- More variations are seen in combined cycle generation which generally decreases as more non-emitting resources are built and operated in the higher electrification scenarios



Scenario	Peaker Capacity Factor (pu)
50% Electrification	0.006
75% Electrification	0.018
90% Electrification	0.020
Reference	0.018
110% Electrification	0.018
125% Electrification	0.018



Scenario	CC Capacity Factor (pu)
50% Electrification	0.48
75% Electrification	0.46
90% Electrification	0.44
Reference	0.42
110% Electrification	0.40
125% Electrification	0.37

Modified Peaker Retirement Takeaways

- The resource buildouts are relatively the same for the reference scenario and low peaker retirement scenarios
- With all peakers retired, 100-hour batteries are built to provide generation that was once delivered by the peaker units
- Peaker capacity factor decreases as more peakers retire while combined cycle generation had little to no change in output
  - Note that **gas constraints were not enforced** and results could be different if constraints continue to exist

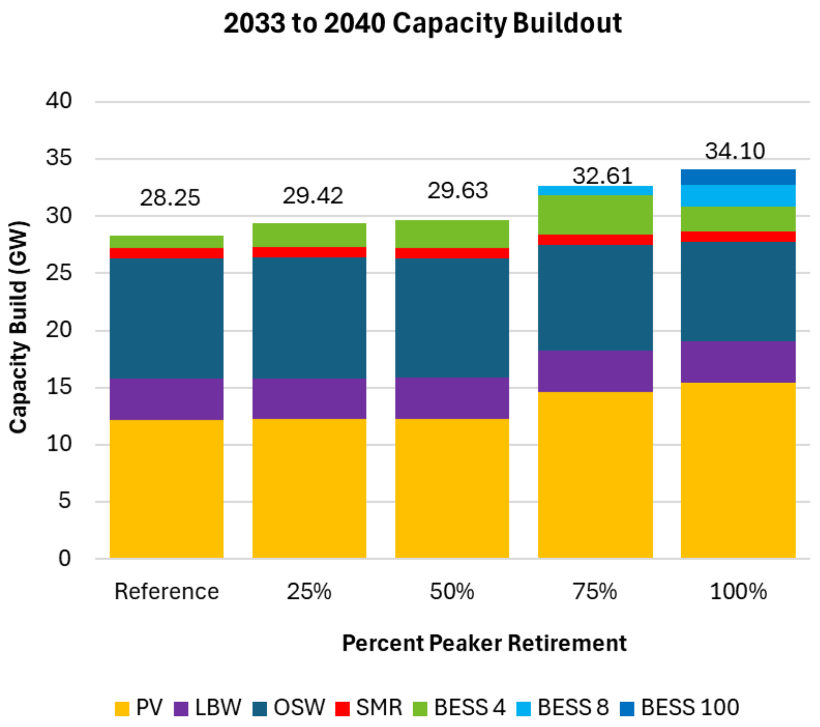
Peaker Retirement Assumptions

- Peaker retirement assumptions have not changed since the preliminary results
- Peaker units include simple-cycle natural gas units and all fossil units whose primary fuel is not natural gas
- Units are retired based on their in-service date, with the oldest units retired first

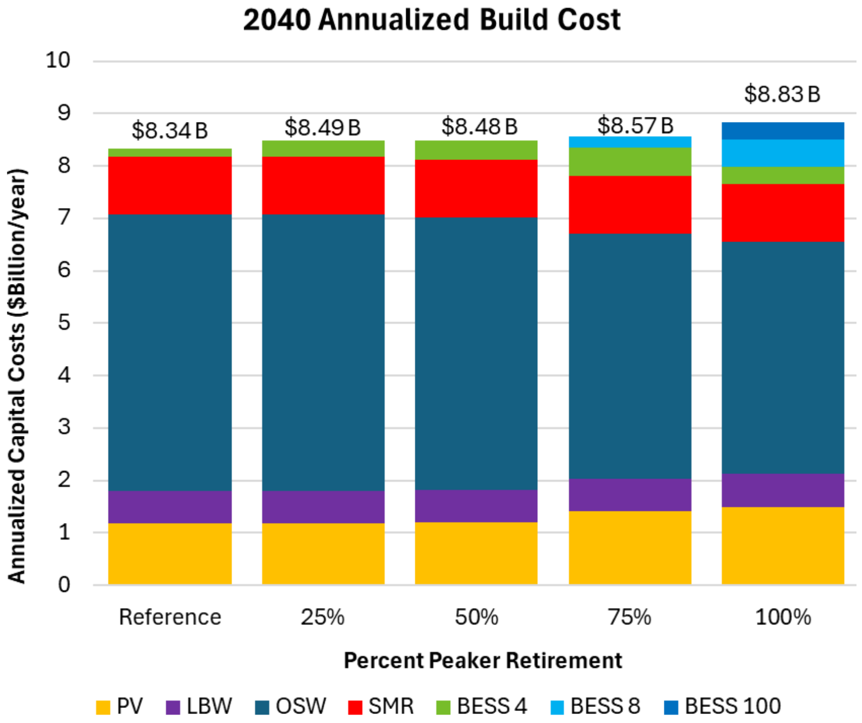
Percent of Peakers Retired	Available Peaker Generation
Reference	6,620 MW
25% Retired	5,119 MW
50% Retired	2,715 MW
75% Retired	1,596 MW
100% Retired	0 MW

Capacity Expansion Buildout

- **The impacts of peaker retirement are not evident until more than half of the peaker units are retired**
  - The buildout for the 25% and 50% peaker retirement scenarios are nearly identical to the Base case
  - Capacity expansion starts to ramp up in the 75% and 100% peaker retirement scenarios with more buildout of batteries and PV
- **The most significant incremental change in buildout was going from 50% to 75% peaker retirement**
  - The 75% peaker retirement scenario built 3 GW more than the 50% Peaker Retirement Scenario
  - The 100% peaker retirement scenario only built 1.49 GW more than the 75% peaker retirement scenario
- Each scenario built 900 MW of SMRs and 3,600 MW of land-based wind
- 100-hour batteries (1,362 MW) were only built in the 100% peaker retirement scenario to serve as additional dispatchable resources in the absence of peakers



Capacity Expansion Metrics



- The 100% peaker retirement scenario had the largest buildout, therefore, it also had the highest build costs in 2040 out of all the scenarios
  - The main difference in build costs can be attributed to the additional $334M/year that was spent on building 100-hour batteries
- While the 50% peaker retirement scenario built 211 MW more capacity than the 25%peaker retirement scenario, the build costs were $6M/year less because the model built more PV and 4-hour batteries whereas the lower peaker retirement scenario built more OSW, which is more expensive
  - Compared to the 25% peaker retirement scenario, the 50% peaker retirement scenario built additional 30 MW PV and 276 MW BESS 4, but 95 MW less OSW

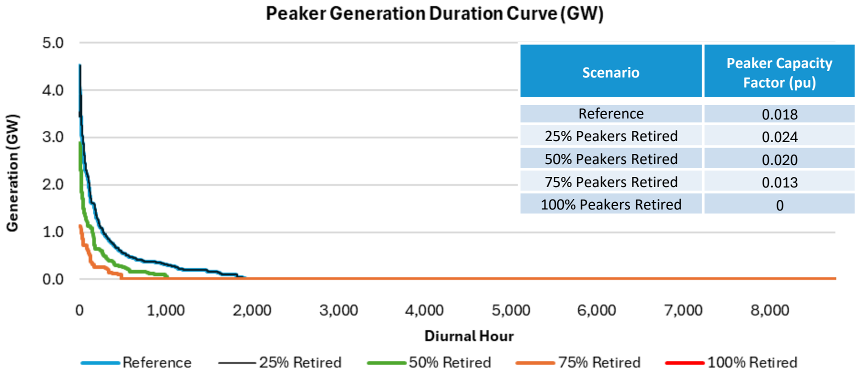
2040 Production Cost: Operational Metrics

Metric	Reference	25% Retired	50% Retired	75% Retired	100% Retired
Generation (TWh)	160	161	161	161	162
Non-Emitting Generation (TWh)	119	119	119	120	120
Emitting Generation (TWh)	21.3	20.4	20.2	19.4	19.4
Imports (TWh)	18.8	19.0	19.2	19.9	20.5
Carbon Emissions (million tons)	10.6	9.8	9.6	8.9	8.9
Hours with Emitting Generation	6,088	5,602	5,548	5,372	5,381
Curtailment (TWh)	12.8	11.9	11.6	9.8	7.9
Storage Generation (TWh)	7.2	8.5	8.7	11.1	12.0
Storage Load (TWh)	8.9	10.3	10.5	13.2	15.3

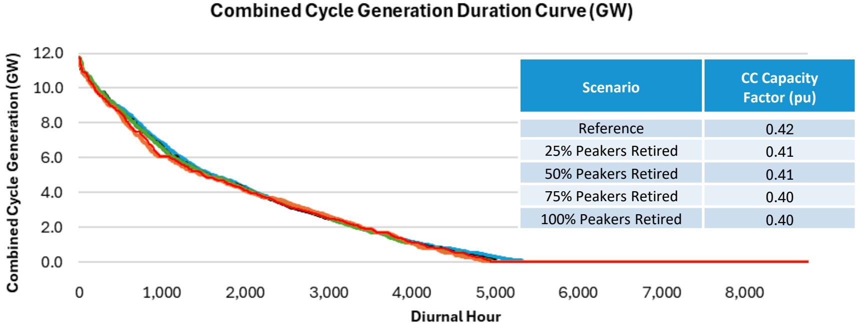
- Results are relatively the same between scenarios with incremental increases in battery operation and less curtailment as more peakers retire

2040 Thermal Operation

- As more peakers retire and more non-emitting resources are built to replace them, existing peakers are utilized less frequently until all peakers are retired
- Combined cycle generation showed little variation with changes in peaker retirement



Scenario	Peaker Capacity Factor (pu)
Reference	0.018
25% Peakers Retired	0.024
50% Peakers Retired	0.020
75% Peakers Retired	0.013
100% Peakers Retired	0

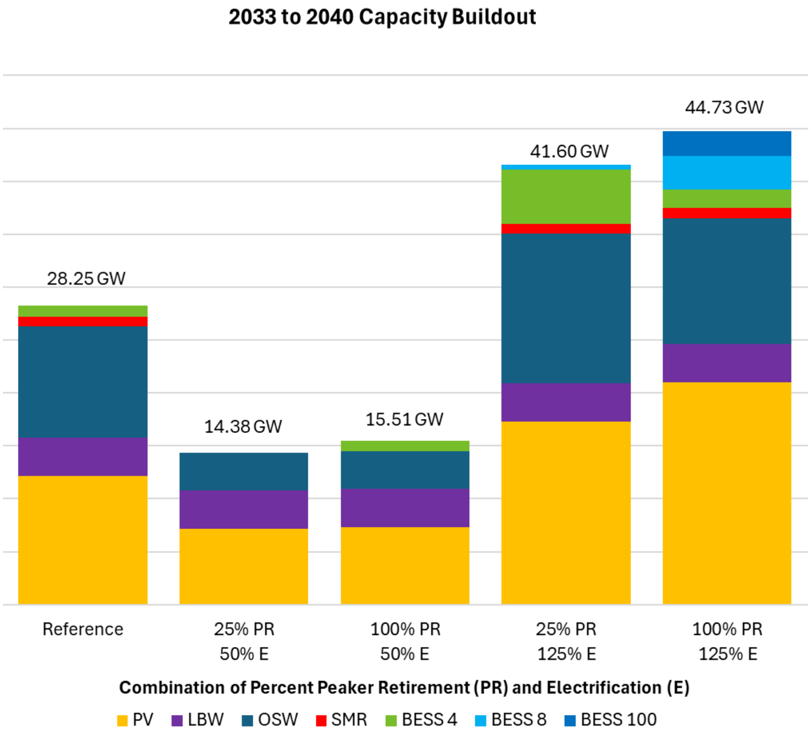


Scenario	CC Capacity Factor (pu)
Reference	0.42
25% Peakers Retired	0.41
50% Peakers Retired	0.41
75% Peakers Retired	0.40
100% Peakers Retired	0.40

Modified Electrification and Peaker Retirement Takeaways

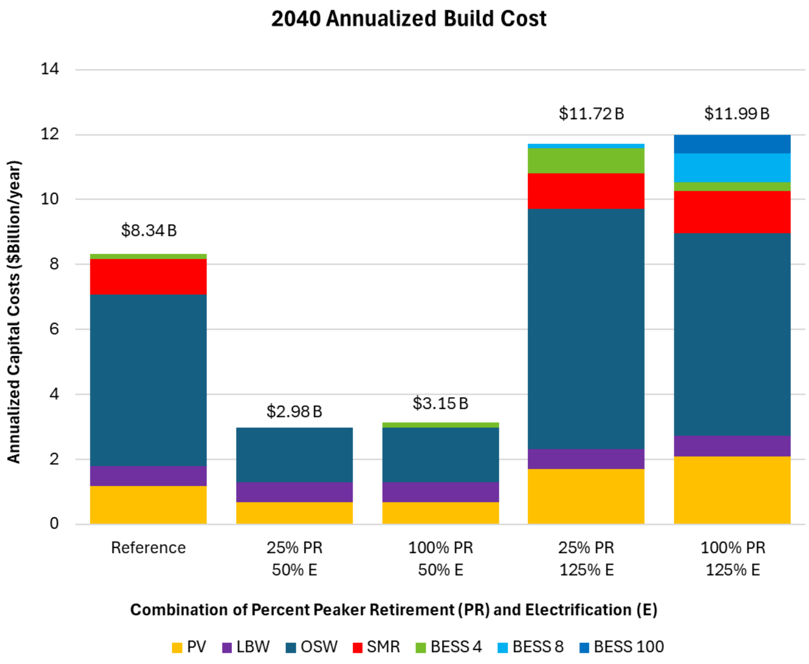
- **Electrification drives capacity expansion and combined cycle generation more than peaker retirement**
- Capacity buildout falls below the reference buildout when electrification is kept to a minimum, regardless of the rate of peaker retirement
- The combination of 125% electrification and 100% peaker retirement scenario yields the largest buildout of non-emitting resources

Capacity Expansion Buildout



- **Capacity expansion is mainly driven by electrification rather than peaker retirement**
- When electrification is kept to a minimum (50% E), the buildout is less than the reference buildout regardless of whether there's more or less peakers retired
  - The buildouts are nearly identical despite the significant difference in peaker retirement
- At the highest electrification level (125% E), the buildout surpasses the reference buildout even when only 25% of peakers are retired
- The combination of highest peaker retirement and electrification (100% PR and 125%E) resulted in the largest capacity buildout
  - This is the only scenario that built 100-hr batteries (2,325 MW)

Capacity Expansion Metrics



- The 2040 build costs reflect the same trend as the capacity buildout
- The build costs for the 50% electrification (50% E) scenarios with varying peaker retirement were nearly the same since they built similar types and amount of resources

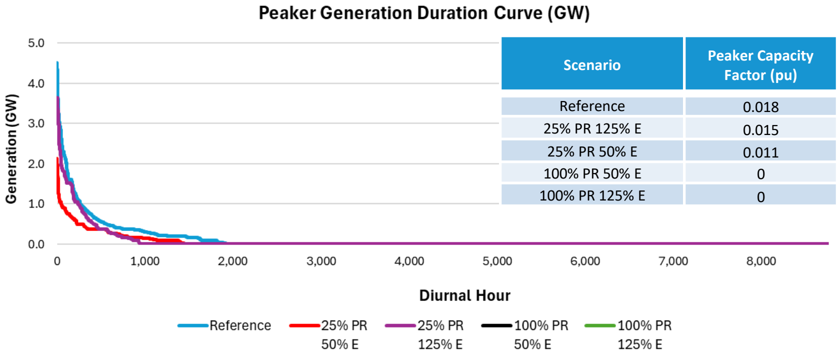
2040 Production Cost: Operational Metrics

Metric	Reference	25% PR 50% E	100% PR 50% E	25% PR 125% E	100% PR 125% E
Generation (TWh)	160	132	132	175	178
Non-Emitting Generation (TWh)	119	83	84	138	139
Emitting Generation (TWh)	21.3	25.0	23.9	18.1	17.8
Imports (TWh)	18.8	21.4	21.6	17.4	19.1
Carbon Emissions (million tons)	10.6	11.9	11.0	8.6	8.3
Hours with Emitting Generation	6,088	7,154	6,903	4,707	4,887
Curtailment (TWh)	12.8	6.1	5.4	16.7	11.2
Storage Generation (TWh)	7.2	4.5	5.9	12.6	15.5
Storage Load (TWh)	8.8	5.7	7.2	15.1	20.4

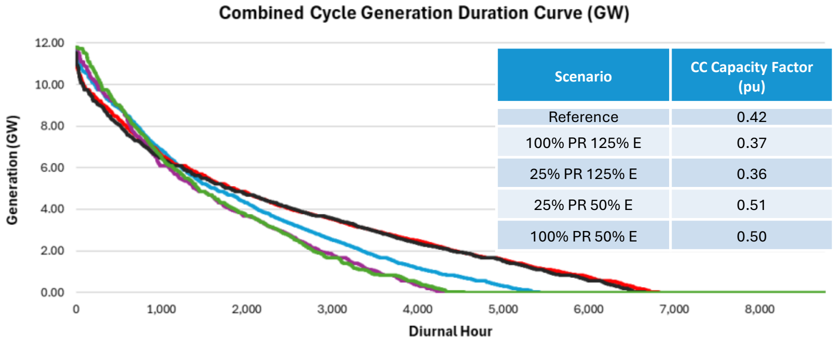
- The combination of the highest electrification and peaker retirement resulted in the lowest carbon emissions

2040 Thermal Operation

- When 25% of peakers are retired, the peaker utilization increases with higher electrification due to higher peak load
- Changes in combined cycle generation were driven by varying electrification levels
  - When electrification was kept constant the combined cycle generation did not change regardless of rate of peaker retirement
  - Combined cycle generation decreases with increasing electrification due to the addition of SMRs and batteries



Scenario	Peaker Capacity Factor (pu)
Reference	0.018
25% PR 125% E	0.015
25% PR 50% E	0.011
100% PR 50% E	0
100% PR 125% E	0



Scenario	CC Capacity Factor (pu)
Reference	0.42
100% PR 125% E	0.37
25% PR 125% E	0.36
25% PR 50% E	0.51
100% PR 50% E	0.50

STAKEHOLDER-REQUESTED SCENARIO

Sensitivity Results

Stakeholder-Requested Scenario Sensitivity

- The ISO received a sensitivity request to lower the capital costs of SMR and BESS100 (100-hour batteries) such that it would enable these resources to be built in the mid-2030s timeframe
  - The results of this sensitivity would help stakeholders understand the economic requirements to facilitate and accelerate earlier adoption of these emerging technologies

- This sensitivity is focused on:
  - Reference scenario
  - 50% electrification scenario
  - 100% peaker retirement scenario

Stakeholder-Requested Scenario Assumptions

- The ISO took SMR capital costs from NREL's 2024 Annual Technology Baseline Workbook (see Appendix D)
  - The ISO lowered cost assumptions from "conservative" (most expensive) to "moderate" and "advanced" (cheapest)
- The ISO took BESS100 capital costs from Form Energy's White Papers[3]
  - The ISO lowered cost assumptions from $2,150/kW to $1,900/kW (moderate) and $1,700/kW (advanced)

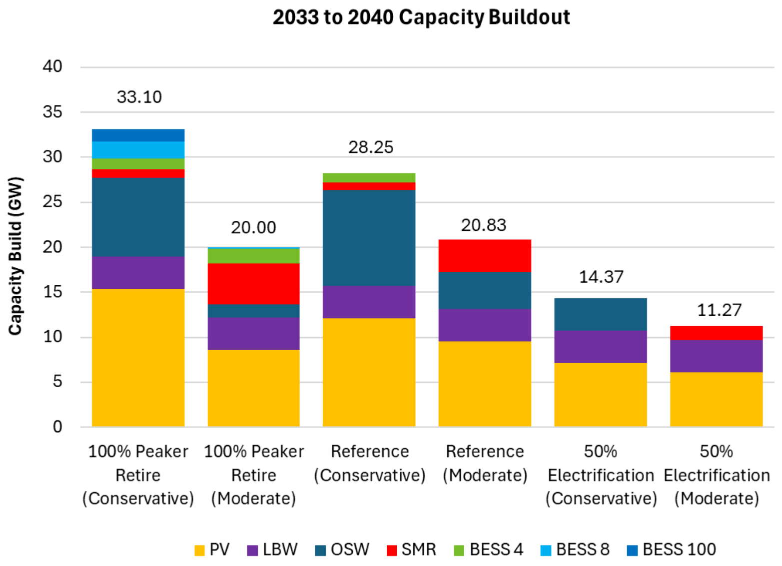
[3] https://formenergy.com/wp-content/uploads/2023/09/Form-ISO-New-England-whitepaper-09.27.23.pdf
https://www.edockets.state.mn.us/documents/%7B00AE3887-0000-C24C-BFC6-45EC1209A3DB%7D/download

Sensitivity Takeaways

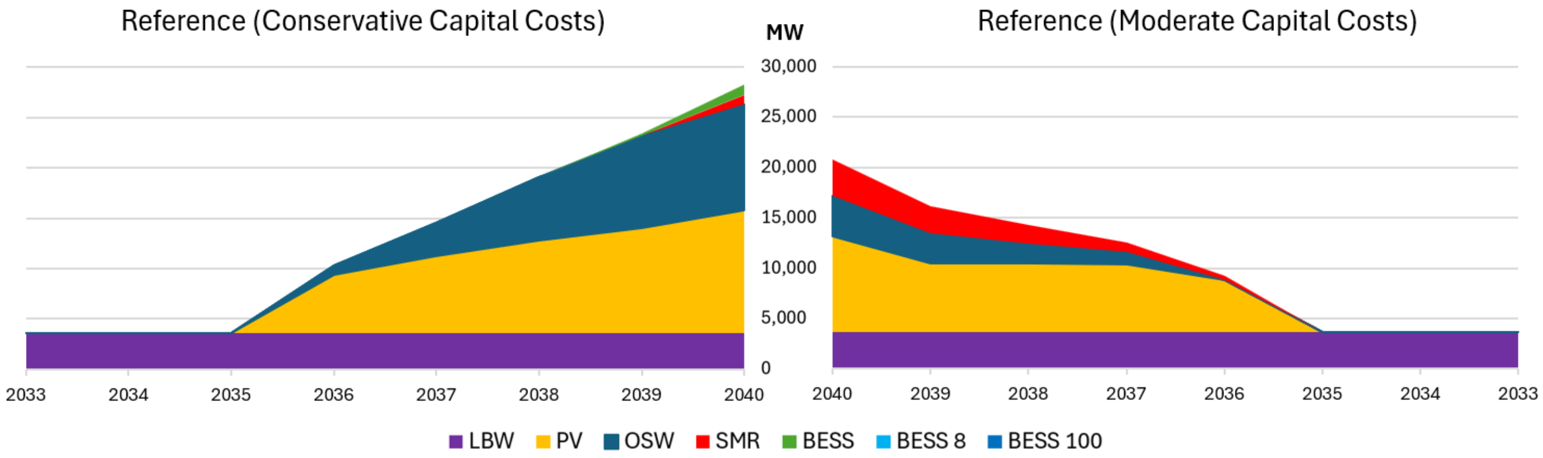
- Lower SMR cost assumptions have a greater impact on capacity expansion than BESS100
- The lower cost assumptions for SMR shifted its buildout from 2039 to mid-2030s and reduced the buildout of other non-emitting resources
- The model did not build any BESS100 in any of the scenarios despite lower cost assumptions

Capacity Buildout: Conservative vs. Moderate Capital Costs

- Moderate SMR capital costs resulted in greater buildout of SMR and less buildout of PV, OSW, and BESS
- Lower BESS100 capital costs did not incentivize earlier buildout
  - ISO ran a test case to exclusively model lowest BESS100 cost assumptions while keeping SMR costs conservative
    - The buildouts were identical to the base buildouts that used conservative capital costs
- **Lower SMR capital costs eliminated the need for BESS100 in the 100%** peaker retirement scenario

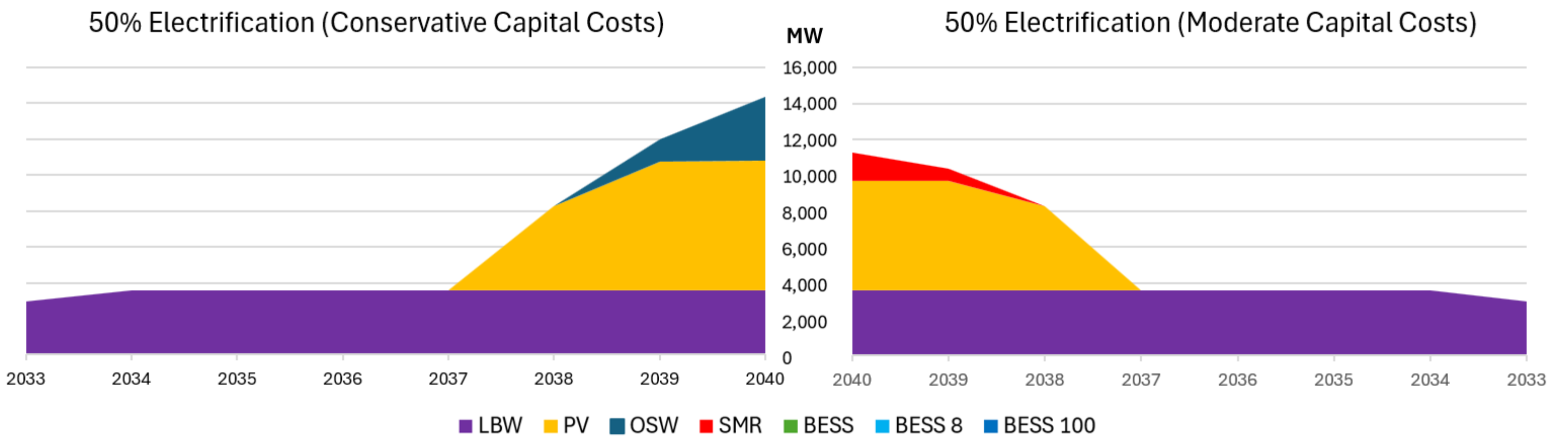


Cumulative Capacity Buildout: Reference Scenario



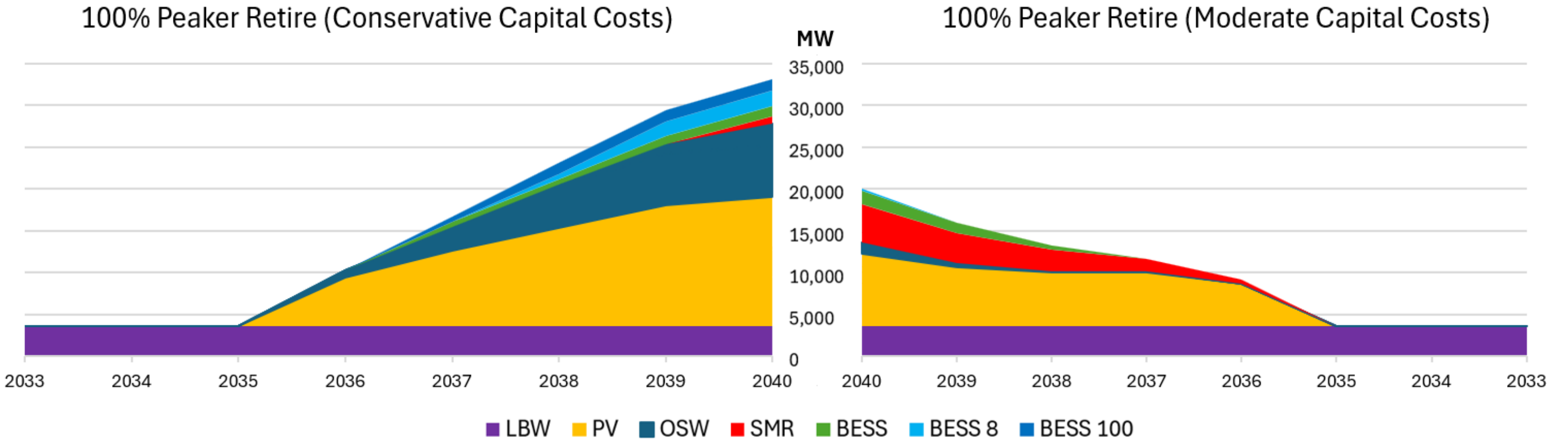
- Model still built maximum amount of LBW (3,600 MW) regardless of changes in SMR and BESS100 cost assumptions
- SMRs are built earlier under the lower cost assumptions, starting in 2036 instead of 2039 as SMRs are more cost effective for reducing emissions than OSW

Cumulative Capacity Buildout: 50% Electrification Scenario



- SMR replaced OSW under the "moderate" capital cost assumptions despite having higher build costs than OSW
- Since SMR is a dispatchable resource, the model doesn't need to overbuild based on a wind profile, therefore, the SMR capacity buildout is less than OSW

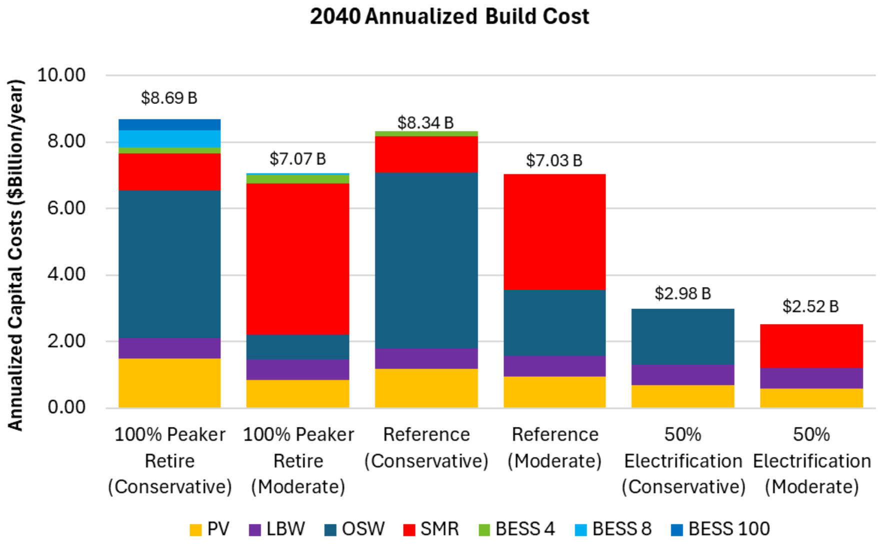
Cumulative Capacity Buildout: 100% Peaker Retirement Scenario



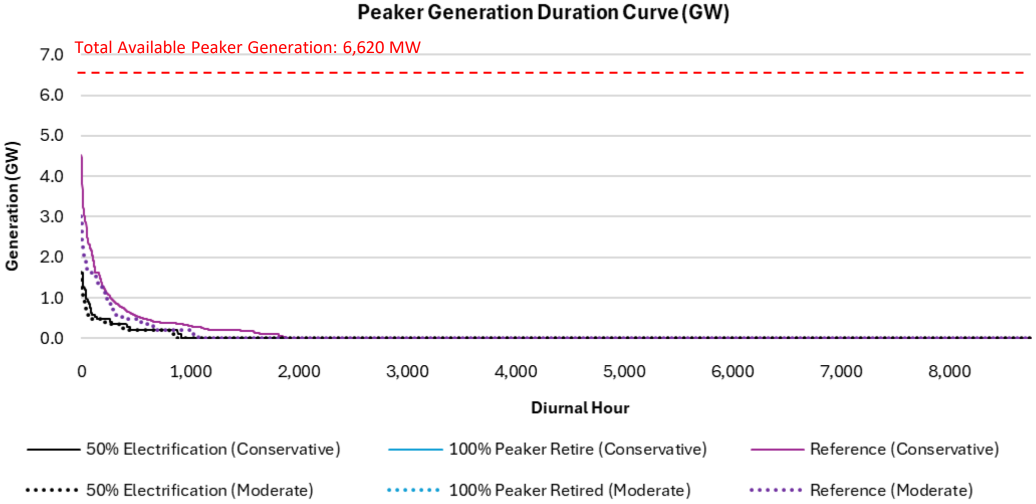
- This is the only scenario that built BESS100 to satisfy the need for additional dispatchable resources in the absence of peakers
  - BESS100 is no longer needed once SMR costs are lowered
- By lowering the SMR capital costs, the total buildout is nearly halved

Capacity Expansion Metrics: Conservative vs. Moderate Capital Costs

- The greater buildout of SMR under the "moderate" cost assumptions reduced the need for other non-emitting resources
- The reduction in capacity buildout resulted in lower total build costs



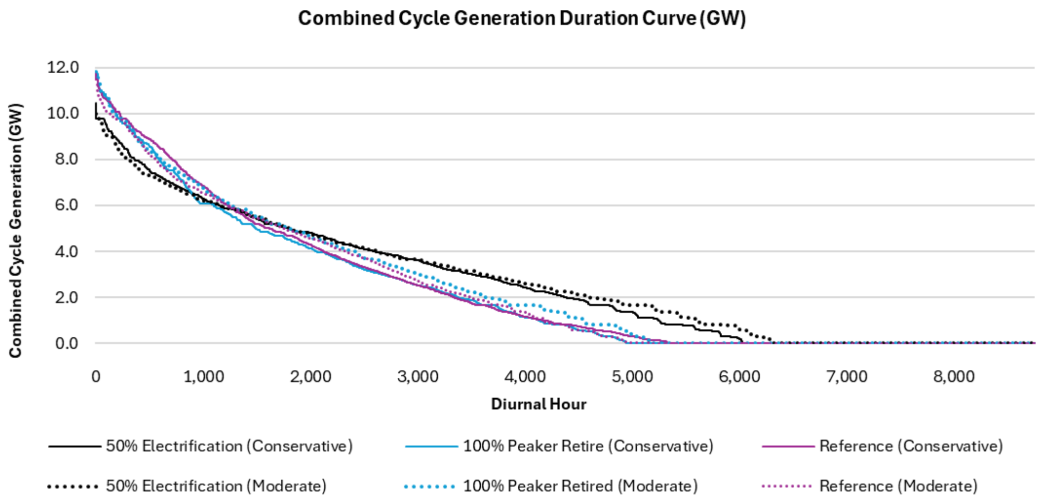
2040 Thermal Operations: Conservative vs. Moderate Capital Costs



Scenario	Capacity Factor (pu)
50% Electrification (conservative)	0.006
50% Electrification (moderate)	0.005
100% Peaker Retired (conservative)	0
100% Peaker Retired (moderate)	0
Reference (conservative)	0.018
Reference (moderate)	0.012

- Peaker generation drops when more SMRs are built and operated
- The reference scenario saw a greater reduction in emitting generation resulting in lower emissions under the "moderate" cost assumptions

2040 Thermal Operations : Conservative vs. Moderate Capital Costs



Scenario	Capacity Factor (pu)
50% Electrification (conservative)	0.48
50% Electrification (moderate)	0.49
100% Peaker Retired (conservative)	0.40
100% Peaker Retired (moderate)	0.45
Reference (conservative)	0.42
Reference (moderate)	0.42

- No change in combined cycle capacity factor for the reference scenario, regardless of SMR capacity
- The most significant change in combined cycle capacity factor was observed in the 100% peaker retirement scenario
  - There's an increased reliance on combined cycle units for additional capacity since the buildout is nearly halved under the lower SMR/LDES cost assumptions, this led to increased emissions

2040 Production Costs: Operational Metrics

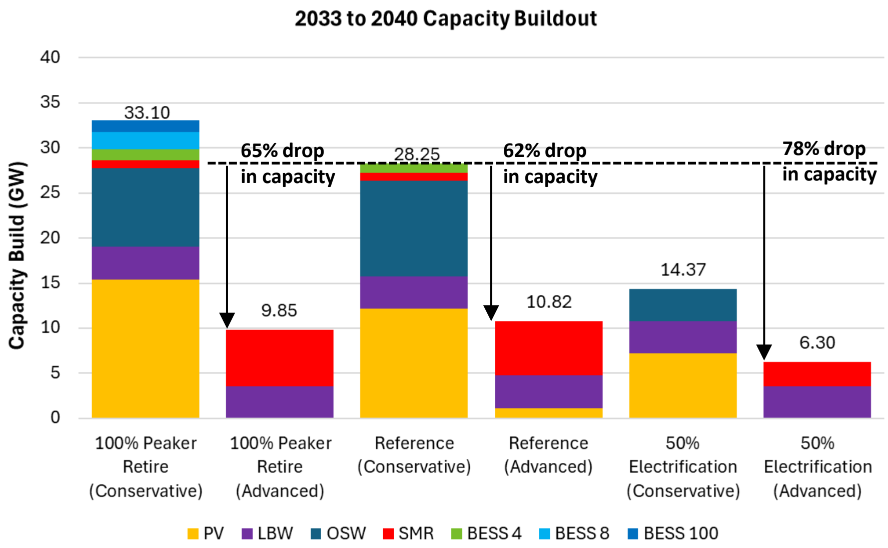
- **Curtailment is significantly reduced across all scenarios** since the model is not overbuilding PV and wind resources
- The greater buildout of SMRs replaced BESS buildout in the reference scenario, thereby, reducing the operating costs of BESS by half resulting in overall reduction in production cost
  - Similar BESS reduction was observed in the 100% peaker retirement scenario, but was offset by the higher SMR and combined cycle generation resulting in increased production cost
  - The 50% electrification scenario had higher production costs due to addition of SMRs, which were not built under the "conservative" cost assumptions

Metric*	100% Peaker Retired	Reference	50% Electrification
Curtailment	-81%	-69%	-57%
Carbon Emissions	+8%	-10%	+2%
Production Cost	+20%	-0.1%	+7%

** Percent change from Conservative capital cost assumptions to Moderate capital cost assumptions (see Appendix D for more details)*

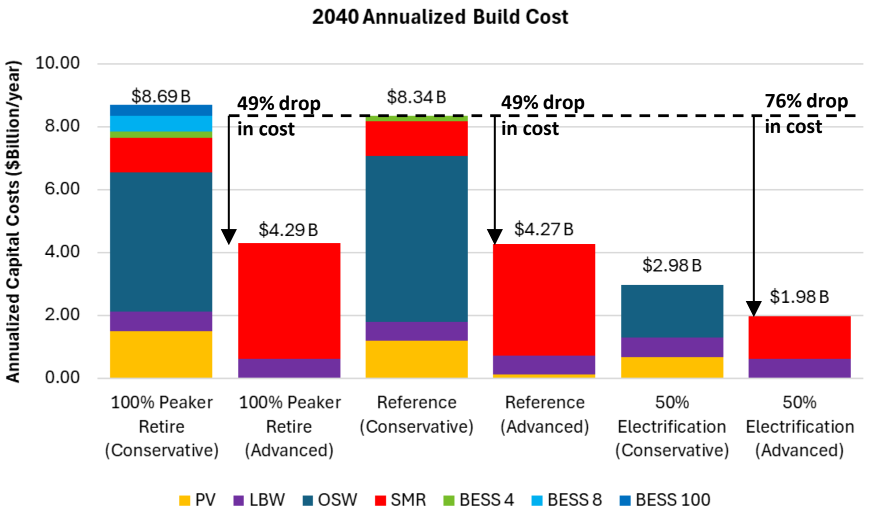
Capacity Buildout: Conservative vs. Advanced Capital Costs

- **Under the "advanced" (cheapest) capital cost assumptions, the model mainly builds SMR and LBW**
- The lowest cost assumptions for SMR significantly reduced total system buildout
- The 100% peaker retirement scenario has the largest SMR buildout (6.25 GW)
  - The reference scenario built 200 MW less SMR but is supplemented by 1.16 GW of PV

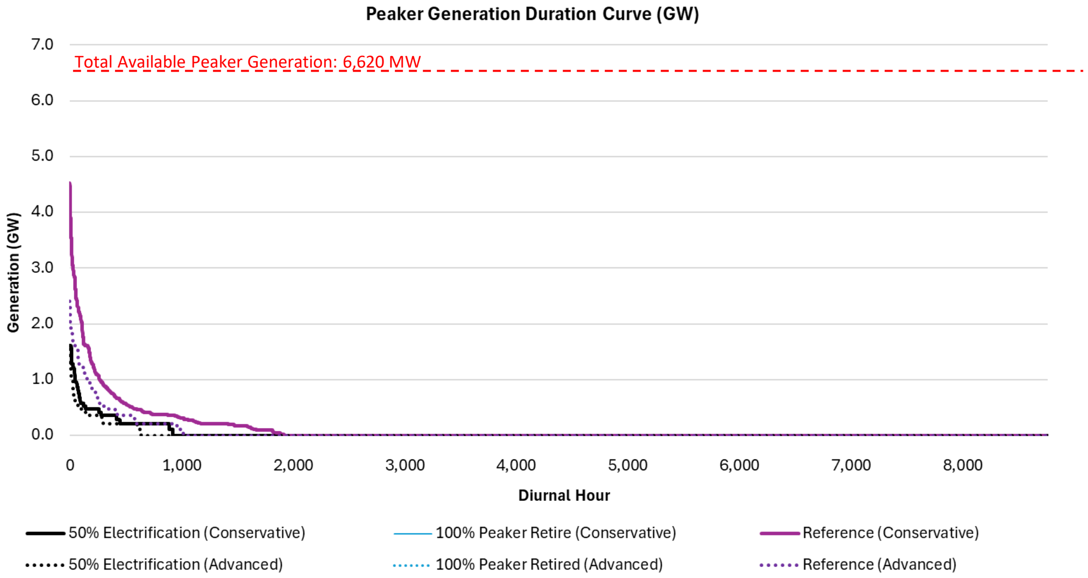


Capacity Expansion Metrics: Conservative vs. Advanced Capital Costs

- Even though the reference scenario built more capacity than the 100%peaker retirement scenario, the annualized cost is lower because PV is significantly cheaper to build than SMR
- While PV is cheaper than SMR, the 100% peaker retirement scenario chooses SMR over PV because it can provide dispatchable energy in the absence of peakers



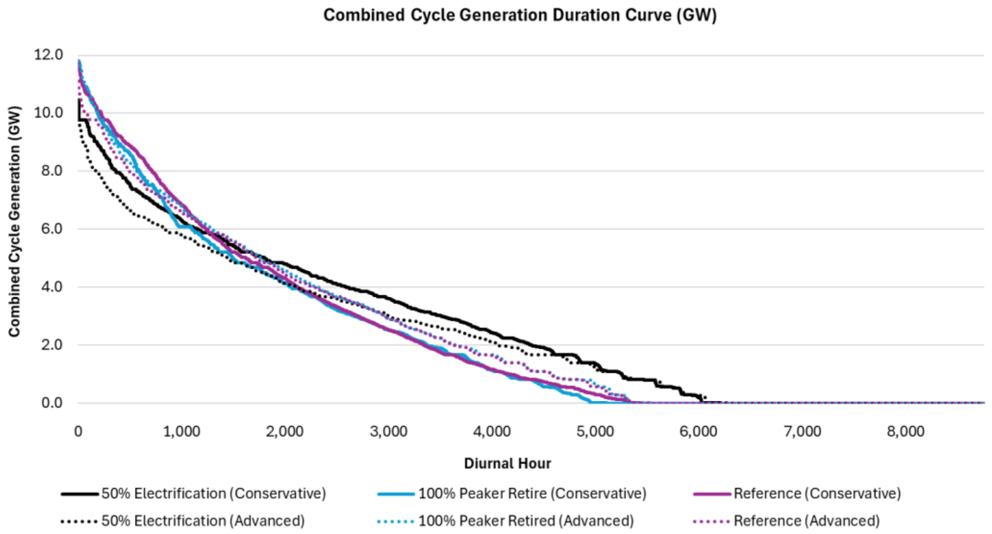
2040 Thermal Operations: Conservative vs. Advanced Capital Costs



Scenario	Capacity Factor (pu)
50% Electrification (conservative)	0.006
50% Electrification (advanced)	0.004
100% Peaker Retired (conservative)	0
100% Peaker Retired (advanced)	0
Reference (conservative)	0.018
Reference (advanced)	0.009

- The reference scenario saw the biggest drop in peaker capacity factor with greater buildout of SMRs (-49%)

2040 Thermal Operations: Conservative vs. Advanced Capital Costs



Scenario	Capacity Factor (pu)
50% Electrification (conservative)	0.48
50% Electrification (advanced)	0.43
100% Peaker Retired (conservative)	0.40
100% Peaker Retired (advanced)	0.44
Reference (conservative)	0.42
Reference (advanced)	0.43

- Combined cycle generators operate more frequently under the 100% peaker retirement scenario (advanced) because of the significant reduction in capacity buildout
- Inversely, the 50% electrification scenario (advanced) saw the biggest drop in combined cycle capacity factor with increased buildout of SMR

2040 Production Cost: Operational Metrics

- **The 100%** peaker retirement scenario (advanced) **was the only scenario that had ADR operating, which indicates that not enough new capacity was built**
  - The model became more reliant on existing dispatchable generation (i.e. emitting generation), resulting in higher emissions
- The 50% Electrification Scenario (advanced) saw a reduction in production costs due to a significant drop in combined cycle generation and to a lesser extent, reduced peaker operations
- The 100% peaker retirement scenario and reference Scenario (advanced) had higher production costs due to increased operation of combined cycle and SMR resources

Metric*	100% Peaker Retired	Reference	50% Electrification
Curtailment	-97%	-98%	-89%
Carbon Emissions	+8%	-8%	-13%
Production Cost	+27%	+11%	-1%

Percent change from conservative capital cost assumptions to advanced capital cost assumptions (see Appendix D for more details)

APPENDIX I

Acronyms

Acronyms

ADR	Active Demand Resource	FOM	Fixed Operation and Maintenance
ARDP	Advanced Reactor Demonstration Program	HP	Heat Pump
BESS	Battery Energy Storage Systems	ICR	Installed Capacity Requirement
BOEM	Bureau of Ocean Energy Management	LBW	Land Based Wind
BTM PV	Behind the Meter Photovoltaic	LCOC	Levelized Cost of Carbon
CCS	Carbon Capture and Storage	LDES	Long Duration Energy Storage
CELT	Capacity, Energy, Load, and Transmission Report	LFG	Landfill Gas
CF	Capacity Factor	Li-ion	Lithium-ion
DOE	Department of Energy	LMP	Locational Marginal Price
EPCET	Economic Planning for the Clean Energy Transition	LOLE	Loss of Load Expectation
EUE	Expected Unserved Energy	LSEEE	Load-Serving Entity Energy Expenses
EV	Electric Vehicle	LT	Long-Term

Acronyms, cont.

MCC	Marginal Carbon Cost
MSW	Municipal Solid Waste
MT	Medium-Term
MWY	Multiple Weather Year
NG	Natural Gas
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL ATB	National Renewable Energy Laboratory Annual Technology Baseline
O&M	Operation and Maintenance
OSW	Offshore Wind
POI	Point of Interconnection
PS	Pumped Storage

PV	Photovoltaic
RA	Resource Adequacy
RAA	Resource Adequacy and Accredidation
SMR	Small Modular Reactor
SNG	Synthetic Natural Gas
SoC	State of Charge
ST	Short-Term
TVA	Tennessee Valley Authority
USE	Unserved Energy
VOM	Variable Operation and Maintenance
WDS	Wood Waste Solids

APPENDIX II

Anonymizing Data for Publicly Released Models

Overview of Public Model

- The ISO released a public version of the Benchmark Scenario to the PAC as part of the Economic Studies
  - CEII Access [1] is required to access the model as the underlying transmission network is built on the ISO-NE Base Case Database
- The model is stripped of market-sensitive attributes of generators and proprietary data provided by vendors
- PLEXOS inputs are object oriented and highly modular
  - Stakeholders may easily modify input assumptions with their own data and/or assumptions as they see fit
- The ISO will not be providing the PLEXOS license which is required to run simulations

[1] *Critical Energy Infrastructure Information (CEII) Access may be requested on the [ISO New England Website]*

Changes to Data Inputs

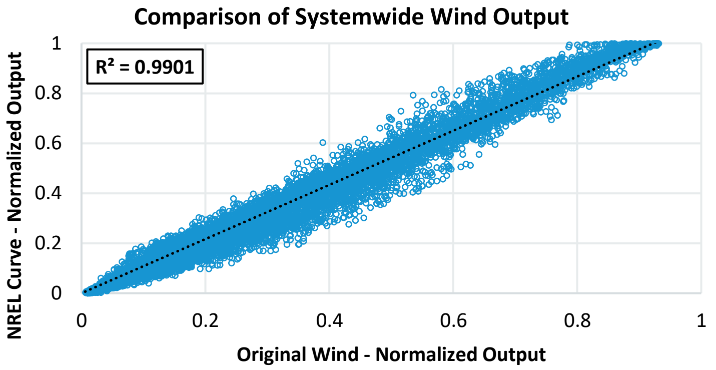
1. Generator Emission Rates (CO_2, NO_X, & SO_2)
   - Use average CO_2 emissions based on fuel type
   - NO_X and SO_2 emissions are not included as these attributes are highly unit specific
2. Fuel Availability of Natural Gas and LNG
   - Published natural gas and LNG availability based on 2023 Heating-Degree Day as static shape
3. Daily Natural Gas Pipeline Prices
   - Average monthly fuel prices will be used
4. Generator Heatrates
   - Use fleet averages based on turbine style scaled to nameplate MW
5. Hydro Generation Max Monthly Energy – *Excluding Pumped Storage*
   - Use fleet averages scaled to nameplate MW

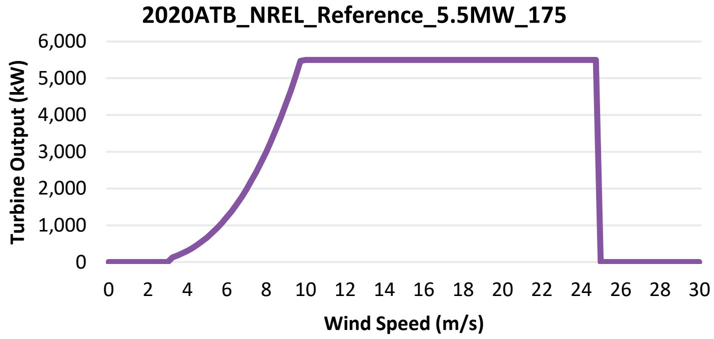
Changes to Data Inputs, cont.

6. Max Ramp Up/Down
   – Use fleet averages based on turbine style scaled to nameplate MW
7. Min Up/Down Time
   – Use fleet averages based on turbine style scaled to nameplate MW
8. Onshore/Offshore Wind Production Profile
   – Recreate wind outputs using publicly available NREL wind power curve and our publicly published wind speed data rather than using confidential wind curves
9. Start Cost
   – Use fleet averages based on turbine style scaled to nameplate MW
10. Generator Outages not included
    – Stakeholders may choose to use the PASA phase to allow PLEXOS to create generator outage schedule

Public Wind Data Methodology

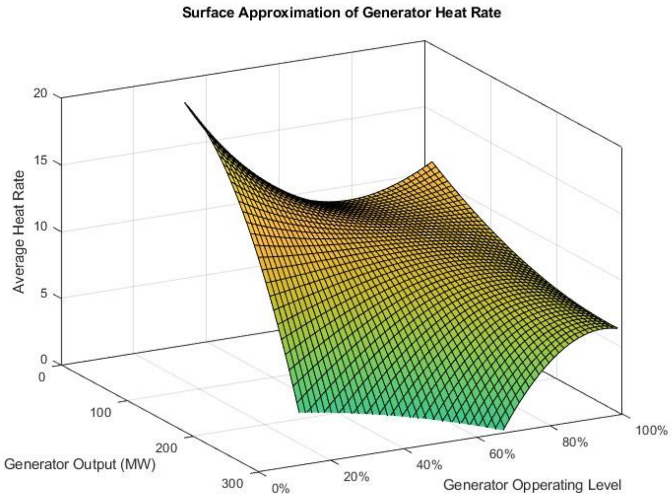
- Original wind data utilized confidential wind curve data
- The ISO has recreated wind profiles utilizing:
  - The ISO's publically posted wind speed data
  - NREL's Turbine Archive
- This is a simplistic approximation that lacks some precision
  - This data still provides a strongly-correlated equivalence





Public Thermal Generation Data Methodology

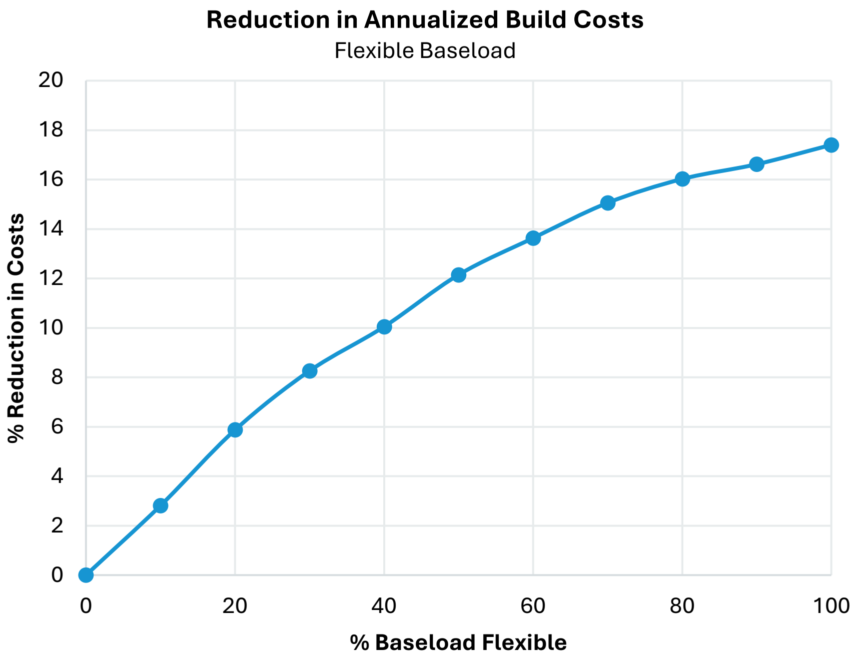
- Approximate heat rates of generators for each subtype were derived from polynomial fits of unit output and operating level
  - For unit subtypes with very few units, national average heat rates were used instead
- Other metrics, such as start cost or ramp rates, were approximated by linear fit based on a units' max capacity

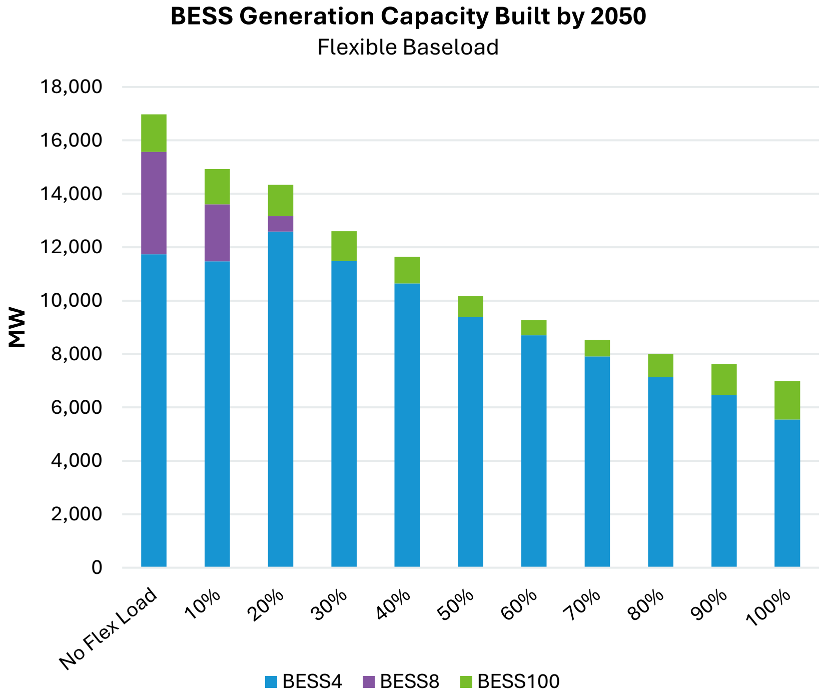


APPENDIX III

Policy Scenario Flexible Demand Sensitivities – Additional Results

Capacity Expansion Results: Baseload Flexibility





- Total build costs can be reduced up to 17.4% using managed baseload

Capacity Expansion Buildout Results: Flexible Baseload

	No Flex Load	10% Flexible Baseload	20% Flexible Baseload	30% Flexible Baseload	40% Flexible Baseload	50% Flexible Baseload	60% Flexible Baseload	70% Flexible Baseload	80% Flexible Baseload	90% Flexible Baseload	100% Flexible Baseload
PV (MW)	38,173	36,758	36,905	36,284	37,149	36,758	37,414	38,965	39,371	41,691	43,000
LBW (MW)	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
OSW (MW)	17,277	17,327	17,356	17,633	18,058	17,169	16,625	16,189	16,250	17,006	17,021
SMR (MW)	5,400	5,400	5,400	5,400	5,179	5,349	5,400	5,400	5,231	4,726	4,574
Li-ion BESS (MW)	15,570	13,612	13,169	11,488	10,643	9,381	8,703	7,908	7,136	6,476	5,548
Iron-air BESS (MW)	1,410	1,313	1,165	1,107	1,000	783	563	631	858	1,152	1,446
Total (MW)	**81,430**	**78,010**	**77,595**	**75,511**	**75,630**	**73,040**	**72,305**	**72,692**	**72,445**	**74,651**	**75,190**
Delta (MW)	0	-3,420	-3,835	-5,919	-5,800	-8,390	-9,124	-8,738	-8,984	-6,779	-6,239
% Change	0.00	-4.20	-4.71	-7.27	-7.12	-10.30	-11.21	-10.73	-11.03	-8.32	-7.66

- Unlike capital costs, capacity buildouts don’t always decrease linearly with the portion of load flexibility. Buildouts will be larger if the resource mix includes more low-cost resource types, especially PV
- Note that the No Flex Load reference results slightly differ from previous versions because this analysis uses fixed representative sample days for capacity expansion modeling across all load flexibility levels. This approach, used in the Stakeholder-Requested Scenario, ensures consistent comparisons across sensitivities with different load profiles

Capacity Expansion Buildout Results: Flexible EV Load

	No Flex Load	10% Flexible EV Load	20% Flexible EV Load	30% Flexible EV Load	40% Flexible EV Load	50% Flexible EV Load	60% Flexible EV Load	70% Flexible EV Load	80% Flexible EV Load	90% Flexible EV Load	100% Flexible EV Load
PV (MW)	38,173	37,534	37,286	37,413	37,581	37,693	38,078	39,000	39,000	39,612	40,577
LBW (MW)	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
OSW (MW)	17,277	17,101	17,053	17,063	17,309	17,176	17,171	17,477	17,523	17,672	17,659
SMR (MW)	5,400	5,400	5,400	5,400	5,400	5,400	5,354	5,157	5,111	4,945	4,794
Li-ion BESS (MW)	15,570	13,915	12,870	12,194	10,748	9,696	8,775	8,056	7,083	6,456	6,026
Iron-air BESS (MW)	1,410	1,398	1,330	1,358	1,906	1,917	1,890	1,771	1,702	1,795	1,743
Total (MW)	**81,430**	**78,949**	**77,539**	**77,028**	**76,543**	**75,481**	**74,868**	**75,061**	**74,019**	**74,080**	**74,400**
Delta (MW)	0	-2,481	-3,890	-4,402	-4,886	-5,948	-6,561	-6,369	-7,411	-7,349	-7,030
% Change	0.00	-3.05	-4.78	-5.41	-6.00	-7.30	-8.06	-7.82	-9.10	-9.03	-8.63

- See previous slide for notes on capacity expansion buildout results

2050 Load Components: 2019 Weather Year

	Base	EV	Heat Pump	Total
Peak (MW)	25,794	14,946	25,495	50,214
Energy (GWh)	120,239	56,367	30,636	207,242

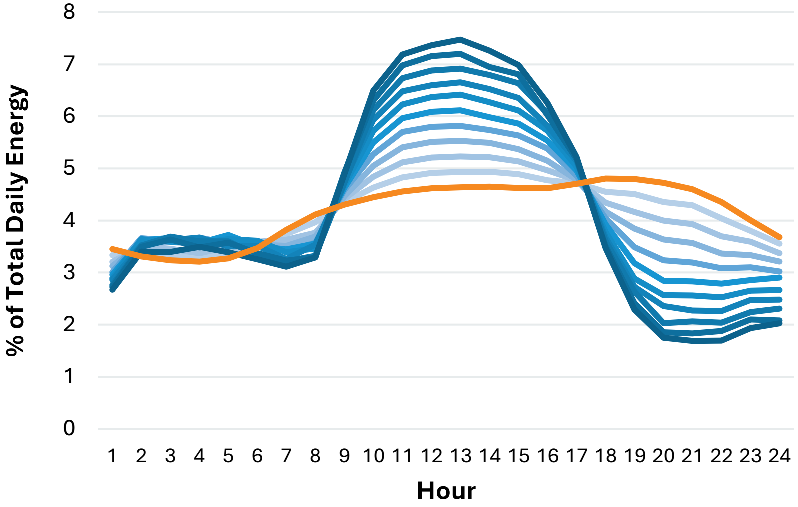
2050 Production Cost Results

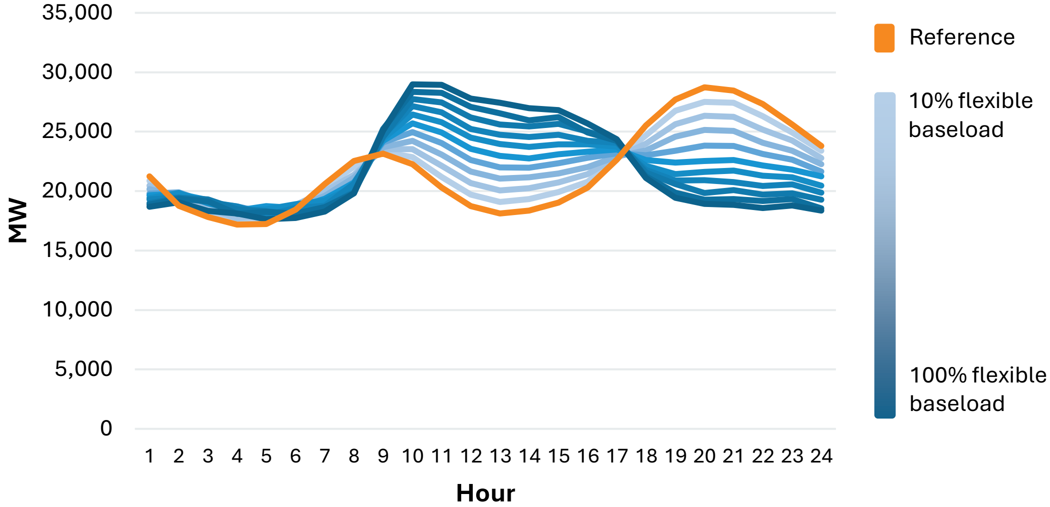
% Baseload Flexible	2050 Production Cost ($M)	Change from Reference ($M)
0	1,320	0
10	1,268	-51
20	1,221	-98
30	1,164	-156
40	1,122	-197
50	1,133	-187
60	1,129	-191
70	1,134	-186
80	1,126	-194
90	1,091	-228
100	1,088	-232

% EV Load Flexible	2050 Production Cost ($M)	Change from Reference ($M)
0	1,320	0
10	1,284	-36
20	1,268	-51
30	1,239	-80
40	1,185	-135
50	1,174	-146
60	1,152	-168
70	1,128	-191
80	1,110	-210
90	1,105	-214
100	1,096	-224

- 2050 production costs are dependent on the resource mix built by the capacity expansion model, but generally an increase in load flexibility reduces production costs
- Flexible demand shifts load away from high cost hours, typically during peaks or low renewable output, and onto lower cost hours with higher production from renewables

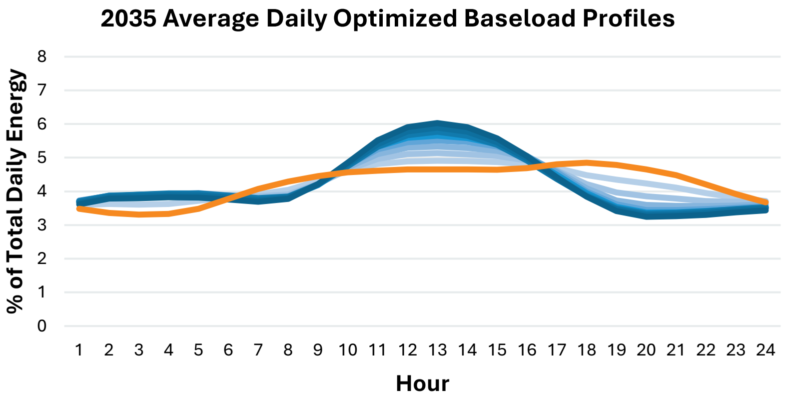
Optimized Profiles: Baseload

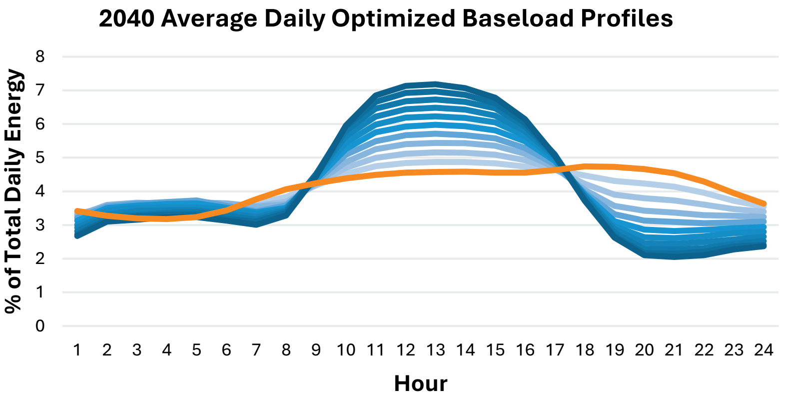


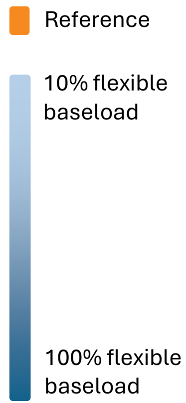


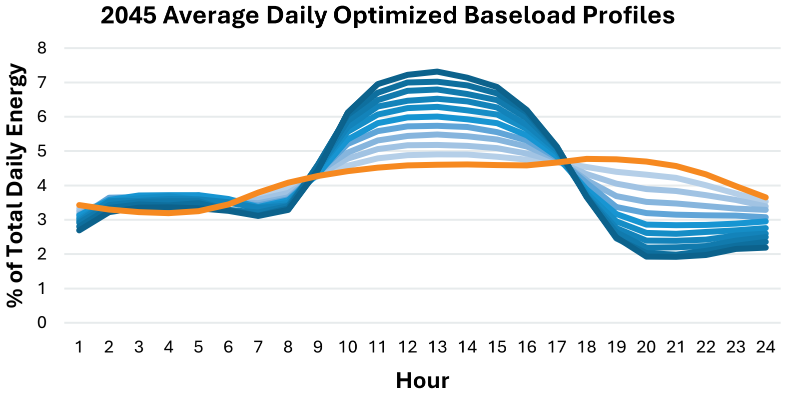
- Profiles are optimized to minimize production cost by shifting load onto low or negative LMP hours
- Usage of baseload appliances like dishwashers, laundry machines, and dryers can be shifted within each day. Customers with BTM-BESS can further support demand shifting by charging during low-cost periods and discharging during peaks

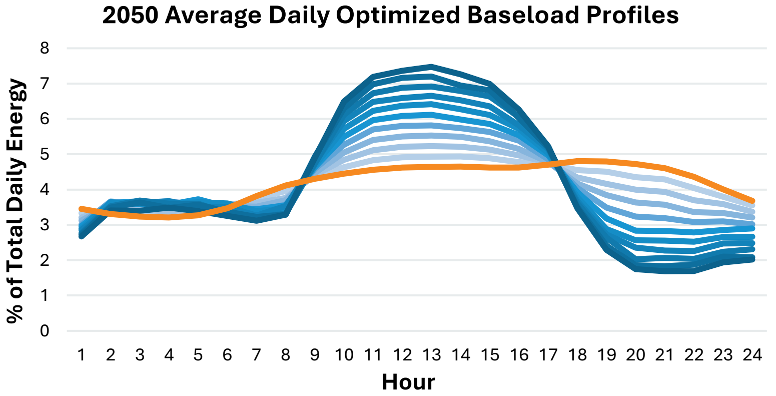
Baseload Shifting Profiles: 2035, 2040, 2045, 2050





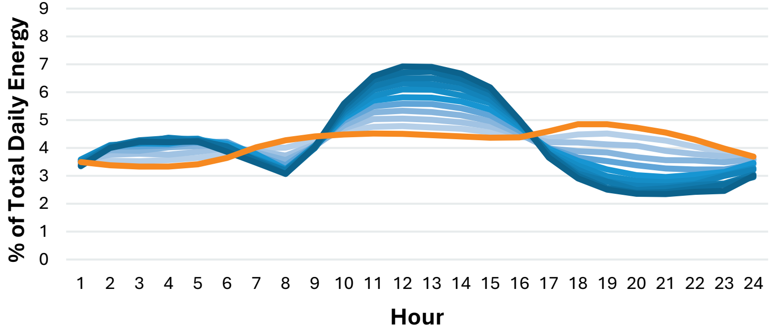




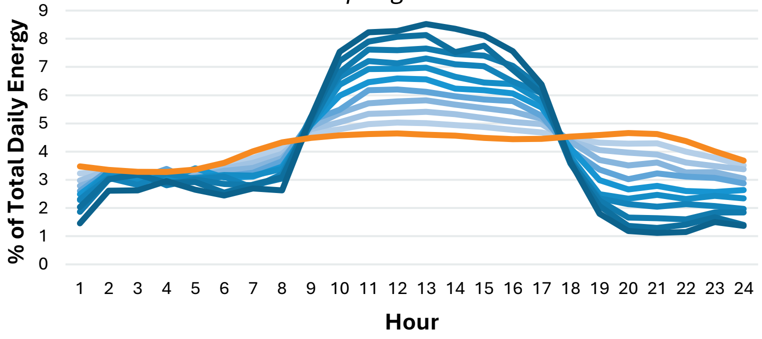


Baseload Shifting Profiles: 2050 by Season

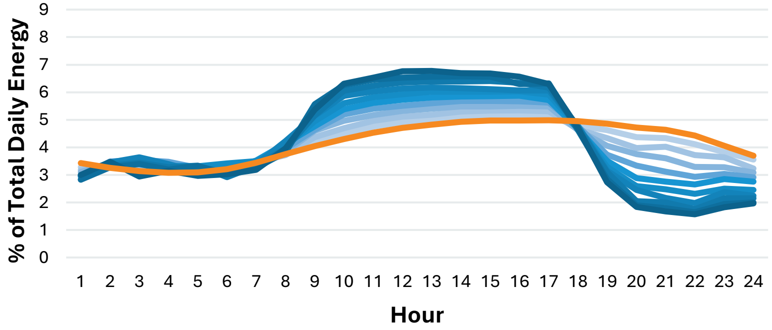
2050 Average Daily Optimized Baseload Profiles
Winter



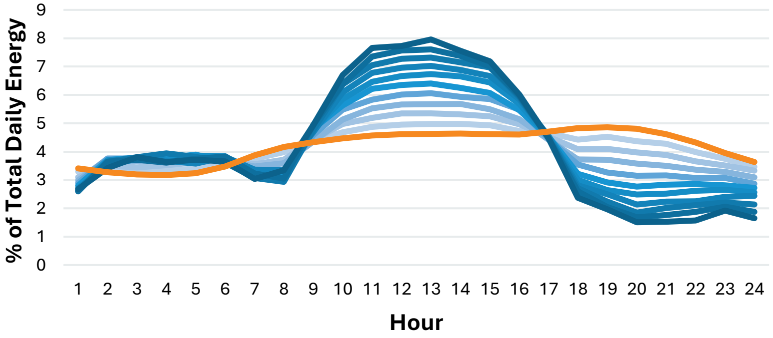
2050 Average Daily Optimized Baseload Profiles
Spring



2050 Average Daily Optimized Baseload Profiles
Summer



2050 Average Daily Optimized Baseload Profiles
Fall

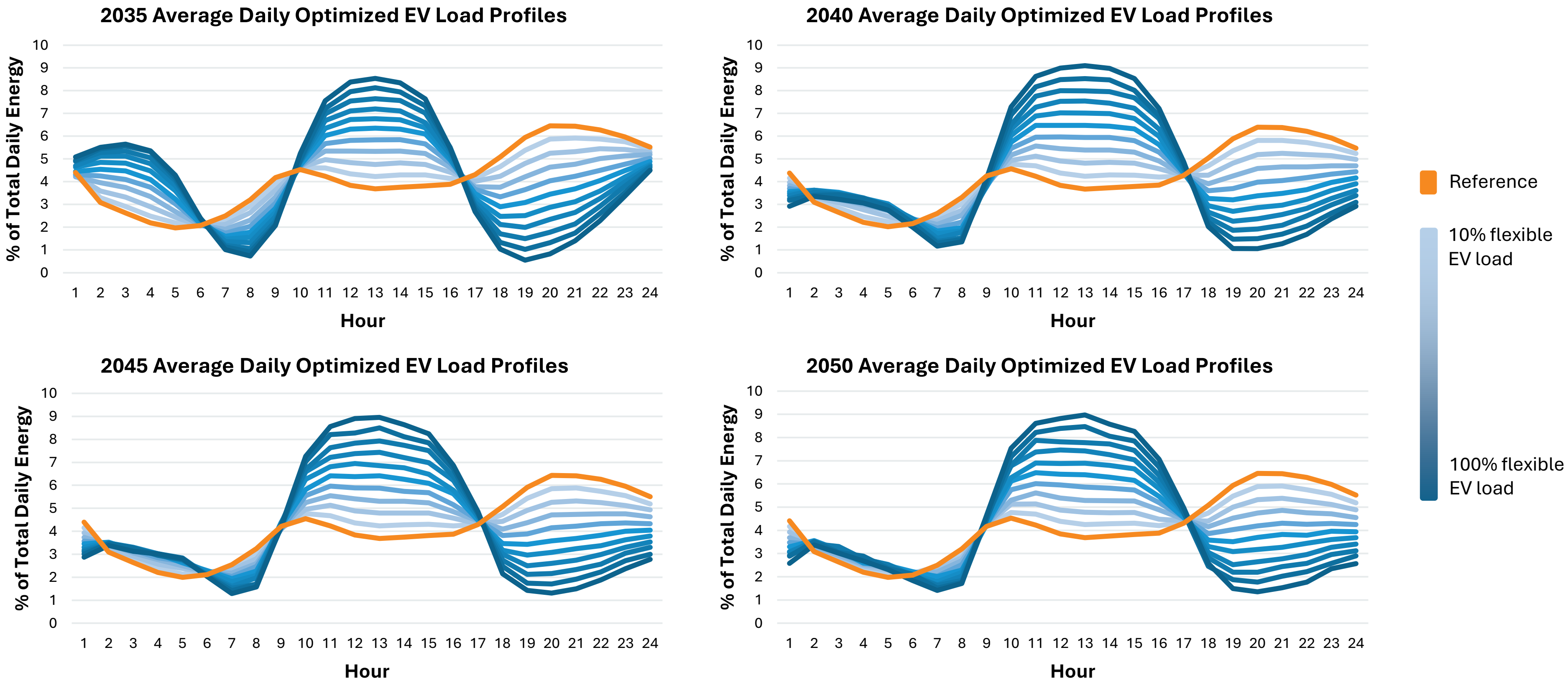


Reference

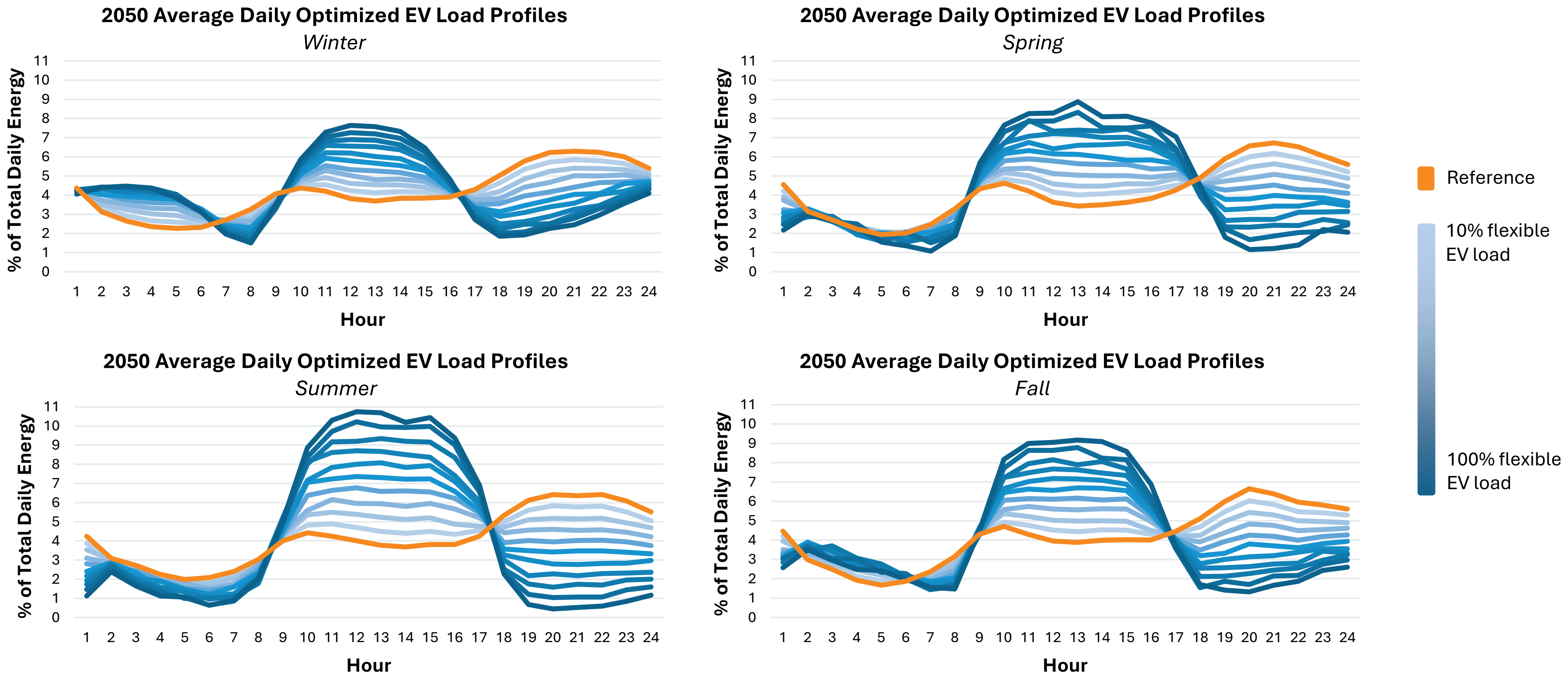
10% flexible baseload

100% flexible baseload

EV Load Shifting Profiles: 2035, 2040, 2045, 2050



EV Load Shifting Profiles: 2050 by Season



Economic Impacts of Flexible Demand: 20 Weather Years

Weather Year	Production Cost without Demand Shifting ($M)	Production Cost with Demand Shifting ($M)	Production Cost Savings ($M)	Total Energy Shifted (GWh)
2000	1,281	1,139	142	19,777
2001	1,429	1,279	150	20,581
2002	1,100	982	118	20,264
2003	1,345	1,204	142	19,897
2004	1,300	1,148	152	21,077
2005	1,332	1,169	163	21,064
2006	992	893	99	20,137
2007	1,318	1,189	129	21,240
2008	1,119	963	156	20,561
2009	1,243	1,085	157	20,731
2010	1,083	968	116	20,917
2011	1,373	1,170	203	20,566
2012	1,116	982	134	20,447
2013	1,145	1,011	134	20,656
2014	1,486	1,314	172	20,794
2015	1,413	1,260	153	21,115
2016	1,158	1,008	150	21,351
2017	1,246	1,074	172	20,541
2018	1,249	1,126	123	20,315
2019	1,320	1,140	180	20,680

APPENDIX IV

Policy Scenario Reduced Decarbonization Sensitivity – Additional Capacity Expansion Results

75% Decarbonization and Electrification Combination Cases: Buildout Capacity Results

2033-2050 Total New Capacity (MW)

	Monofacial Fixed-Tilt PV				Bifacial Single-Axis Tracking PV			
	No Flexible Load	20% Flexible EV Load	50% Flexible EV Load	100% Flexible EV Load	No Flexible Load	20% Flexible EV Load	50% Flexible EV Load	100% Flexible EV Load
PV	22,532	23,054	24,119	28,824	23,025	23,000	24,074	29,548
LBW	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
OSW	6,564	6,212	5,416	3,506	4,388	4,182	3,633	2,788
SMR	900	900	900	900	900	900	900	384
Li-ion BESS	4,840	3,034	984	0	5,090	3,616	1,482	0
100-hr BESS	0	0	0	0	0	0	0	0
Total	**38,436**	**36,800**	**35,019**	**36,830**	**37,003**	**35,298**	**33,689**	**36,321**
Delta from Reference	-42,994	-44,630	-46,411	-44,600	-44,427	-46,132	-47,741	-45,110
% Change	-52.80	-54.81	-56.99	-54.77	-54.56	-56.65	-58.63	-55.40

- Unlike capital costs, capacity buildouts don’t always decrease linearly with the portion of load flexibility. Buildouts will be larger if the resource mix includes more low-cost resource types, especially PV
- Note that the reference results slightly differ from previous versions because this analysis uses fixed representative sample days for capacity expansion modeling across all load flexibility levels. This approach, used in the Stakeholder-Requested Scenario, ensures consistent comparisons across sensitivities with different load profiles

75% Decarbonization and Electrification Combination Cases: Buildout Cost Results

2033-2050 Annualized Build Costs ($B)

	Monofacial Fixed-Tilt PV				Bifacial Single-Axis Tracking PV			
	No Flexible Load	20% Flexible EV Load	50% Flexible EV Load	100% Flexible EV Load	No Flexible Load	20% Flexible EV Load	50% Flexible EV Load	100% Flexible EV Load
PV	16.44	17.34	18.91	22.47	20.29	20.87	22.07	24.94
LBW	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38
OSW	20.47	18.29	14.19	6.49	13.13	11.06	8.70	3.41
SMR	1.80	2.39	2.35	2.39	1.97	2.02	1.56	1.02
Li-ion BESS	2.95	1.65	0.19	0.00	4.23	2.25	0.41	0.00
100-hr BESS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**51.04**	**49.04**	**45.02**	**40.73**	**48.99**	**45.58**	**42.12**	**38.74**
Delta from Reference	-97.43	-99.43	-103.45	-107.74	-99.48	-102.89	-106.35	-109.73
% Change	-65.63	-66.97	-69.68	-72.57	-67.00	-69.30	-71.63	-73.90