Economic Planning for the Clean Energy Transition (EPCET) Pilot Study

Additional Sensitivity Results

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ECONOMIC STUDIES AND ENVIRONMENTAL OUTLOOK

Today's Topics

- PAC Recap
- FGRS Phase 2 Update
- Market Efficiency Needs Scenario sensitivity: Load Components
- Policy Scenario Sensitivity: No Electrification Growth
- Policy Scenario Sensitivity: Nuclear Retirement
- Policy Scenario Sensitivity: Biodiesel

Recap of Past PAC Presentations

- The ISO has previously presented results for the Market Efficiency Needs scenario (MENS) and the Policy scenario
- The MENS case models a 10-year-out system to try to quantify the economic and environmental impacts of congestion
  - Past sensitivities have shown the impact of multiple weather years on winter fuel drawdowns. The additional winter load led to an increase in need for stored fuels
- The Policy scenario models a path towards a decarbonized 2050 system with a capacity expansion model
  - Significant decarbonization was found to become increasingly expensive, with later additions of wind and PV only being used for a fraction of the year
  - It was also found that significant amounts of emitting dispatchable generation were still needed during some hours with low PV and wind generation
  - Past sensitivities have investigated the concept of using carbon neutral gas (SNG) as an expansion candidate, which reduced the total amount of new capacity needed and associated curtailment

FGRS PHASE 2 UPDATE

New England's Future Grid Initiative

- In 2020, ISO New England, market participants, and state entities, including the New England States Committee on Electricity (NESCOE), together launched New England's Future Grid Initiative to assess the future of the regional power system in light of state energy and environmental laws and to explore potential pathways forward to ensuring a reliable, efficient, and sustainable clean-energy grid
- Two tracks have taken place:
  - **Future Grid Reliability Study (FGRS)** – Phase 1, which was performed as the 2021 Economic Study, examined potential reliability gaps in operating the New England system in the year 2040 with more variable energy resources and increased electrification of the overall economy
  - **Pathways to the Future Grid** – This regional study identified, explored, and evaluated potential policy and market frameworks that may help support the New England states' climate and energy goals

Original Scope of Initiative (aka “the Bubble Chart”)

Two Distinct Components: Developing a Gap Analysis then Discussing Solutions

Pathways to A Future Grid

Future Grid Reliability Study Phase 1

Objective

Assess and discuss future state of the regional power system in light of current state energy and environmental policies

Study Process to Define and Assess Future State of Regional Power System

1. Identify Resource Mix in [Year]
2. Identify Resource & Operational/Reliability Needs

**Assumptions, future scenarios, etc. to be developed within stakeholder process*

Gap Analysis

As part of study process, conduct a gap analysis to determine whether, in the future state envisioned, the markets (current design plus ESI) provide resources/ISO-NE what they need to continue to reliably operate the system? If not, what market deficits need to be addressed to assure reliability?

FGRS Phase 2

Discuss Potential Market Approach(es) to Address Gap(s)

Based on study results/gap analysis, explore potential market approaches to address any future gaps identified in the prior step, including evaluation of the pros/cons of different approaches and discussion of how any such market approach contemplates state energy and environmental laws

See NEPOOL Participants Committee Meeting, March 5, 2020, Agenda Item 5, Attachment A (pdf page 215)

EPCET Policy Work To Date

- Using the PLEXOS' capacity expansion tool, the ISO ran multiple cases that build a revenue sufficient resource mix for the 2050 power grid
- The ISO identified imputed carbon and REC prices
- The ISO has also run policy sensitivities using the EPA's social cost of carbon, synthetic natural gas, biodiesel, nuclear retirement, a future without electrification growth, and others
- In summary, the EPCET policy cases have begun work on identifying costs implications of different resource mixes

Merger of FGRS Phase 2 and EPCET

- Given EPCET Policy work that has happened and stakeholder feedback, the ISO seeks to fully merge FGRS Phase 2 into the EPCET policy cases
  - Stakeholder feedback includes a letter from NESCOE requesting the evaluation of an average annual energy price was set to a level that ensured revenue adequacy for existing resources (a “reliability adder”)
- EPCET will replace FGRS Phase 2 as the title for this remaining work
- Market solutions in EPCET will focus on a hybrid market pathway rather than FCEM
- In November, the ISO plans to present the results of policy sensitivities, which include a reliability adder
- These sensitivities will also incorporate a retirement threshold

Merger of FGRS Phase 2 and EPCET (cont.)

- EPCET will be extended to Q1 of 2024 to allow for further sensitivity runs
- The ISO will issue a brief report on the study targeted for late Q2 2024
- This process will continue to be iterative and collaborative
- Merging FGRS Phase 2 into the EPCET policy cases still serves the original goal of the Future Grid Initiative, "assess the future of the regional power system in light of state energy and environmental laws and to explore potential pathways forward to ensuring a reliable, efficient, and sustainable clean-energy grid"

MENS SENSITIVITY – LOAD COMPONENTS

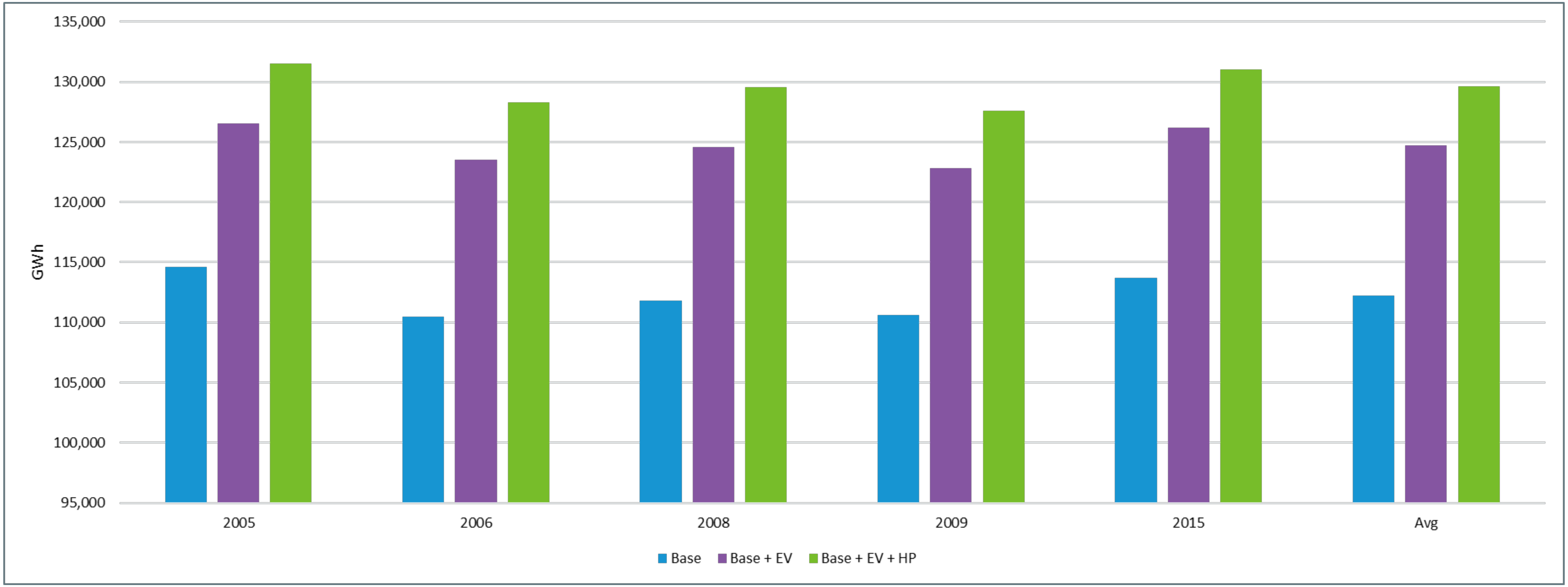
Sensitivity Overview – Load Components

- At the July PAC, the ISO presented results which showed production cost metrics and fuel drawdowns for the 2032 system associated with multiple weather years
  - Reminder: the results shown in the July PAC and in this section have updated load profiles which reflect the 2023 CELT forecast. These differ from the load profiles which have been used for other MENS results
- The ISO has received a request to run production cost analysis on three different versions of these models
  - A version with the EV (electric vehicle) and HP (heat pump) loads removed, only having a base load component (Base)
  - A version with the HP loads removed, only having a base load and EV load (Base + EV)
  - A version with the EV, HP, and base loads included (Base + EV + HP)
- The supply mix is unchanged in the three model versions; only the loads are being changed
- This analysis will allow the ISO to show the incremental effects of electrified load compared to a base model with load akin to what is served today
- A subset of the full 20 weather years were used (2005, 2006, 2008, 2009, and 2015). These were chosen from the July analysis for their high, intermediate, and low 2032 emissions to show a range of results

Sensitivity Takeaways

- Decarbonization of the electric sector would be progressing faster if other sectors (transportation, residential/commercial heating) were not decarbonizing in parallel and transferring their demand into the electric sector
- The trends between load increase and increases in other metrics are not proportional. For a 15.5% increase in load (from HP and EV demand):
  - Average LMPs increase by 84.1%
  - Average LSEEE increase by 114.2%
  - Average production costs increase by 63.6%
  - Average carbon emissions increase by 66.6%
- The additional power sector emissions are expected to be offset by emission reductions in other sectors
- A reduction in stored fuel generation may be possible without the additional electrified load. Because the additional heating and electrification load peak in colder conditions, the additional load likely requires more stored fuel generation

Load Increases



- Averaged across the five weather years, EV additions added 12,493 GWh of load and HP additions added 4,870 GWh of load for a total 15.5% increase in annual load

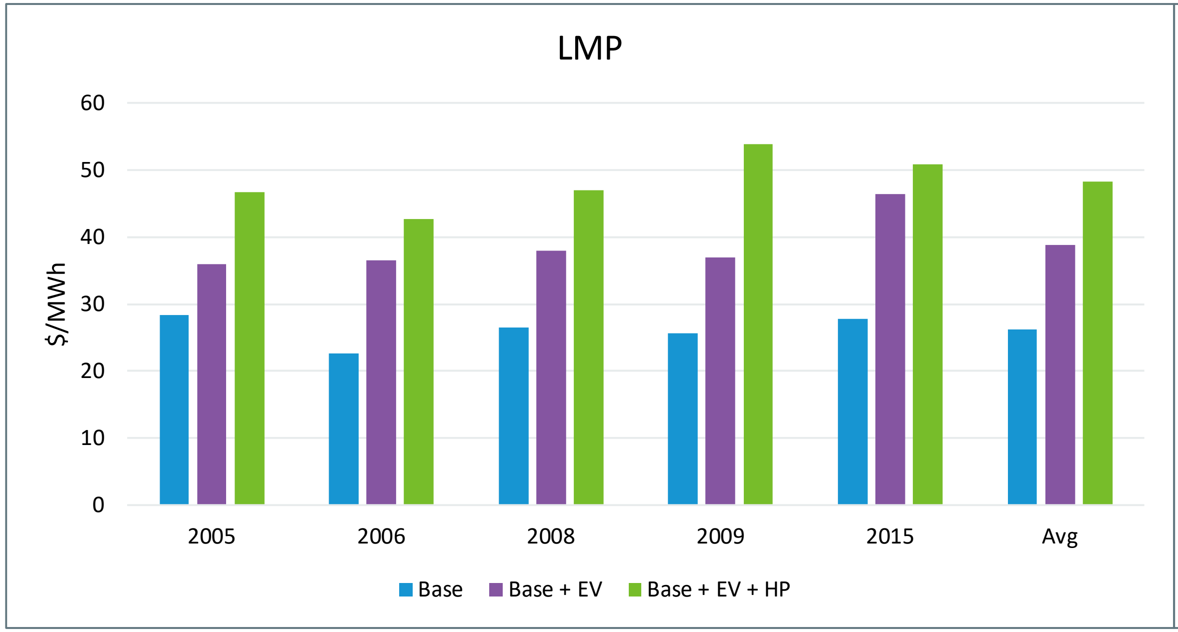
PRELIMINARY RESULTS, DO NOT CITE

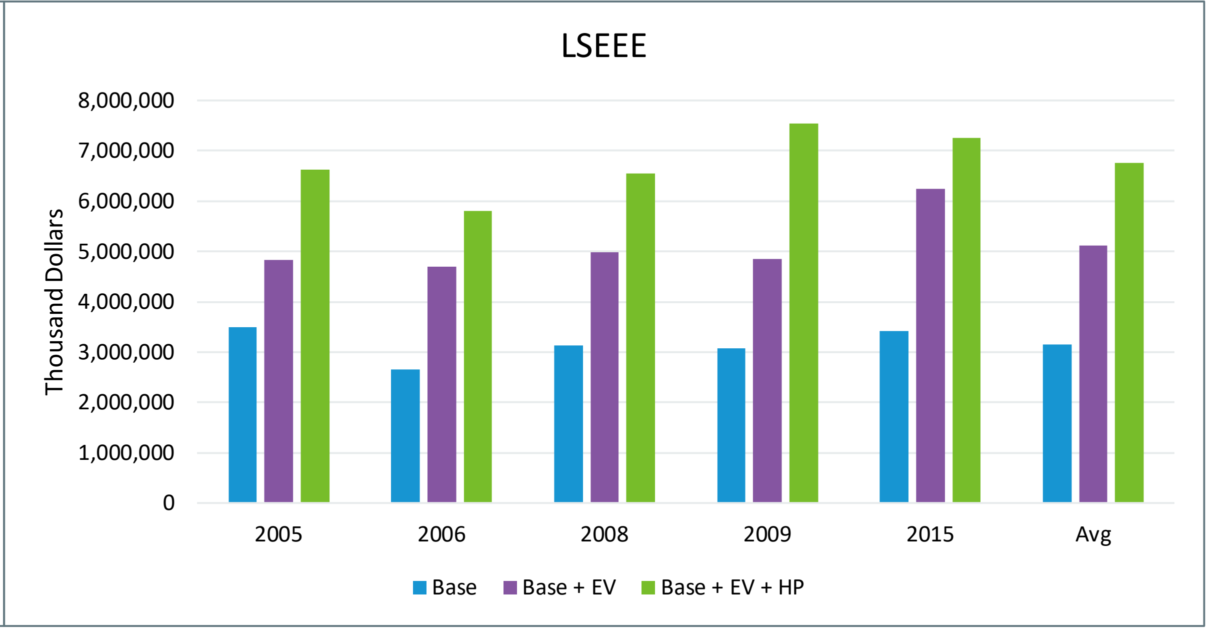
Average Generation by Fuel Type (GWh)

	ADR	COAL	OIL	MSW/LFG/ WOOD	NG	LNG	NUC	HYDRO	PV	LBW	OSW	TIE
Base (GWh)	1	167	11	6,133	12,302	1,185	29,600	6,192	14,323	3,932	13,236	25,636
Base + EV (GWh)	4	312	156	6,321	21,684	1,719	29,600	6,597	14,643	4,175	13,606	26,504
Base – Base + EV % Increase	259	86	1,287	3	76	45	0	6	2	6	3	3
Base + EV + HP (GWh)	7	493	834	6,461	24,668	2,366	29,600	6,592	14,614	4,164	13,525	26,859
Base + EV – Base + EV + HP % Increase	100	58	434	2	14	38	0	0	0	0	0	1

- These values represent the average of the five weather years simulated (2005, 2006, 2008, 2009, and 2015)
- The most significant increases in generation by fuel type are by expensive and/or emitting fuel sources (ADR, coal, oil, NG, and LNG)
- The most significant individual increase is in oil – while the Base case has minimal need for oil (11 GWh), the Base + EV + HP case has a ~7,300% increase in oil generation (834 GWh)

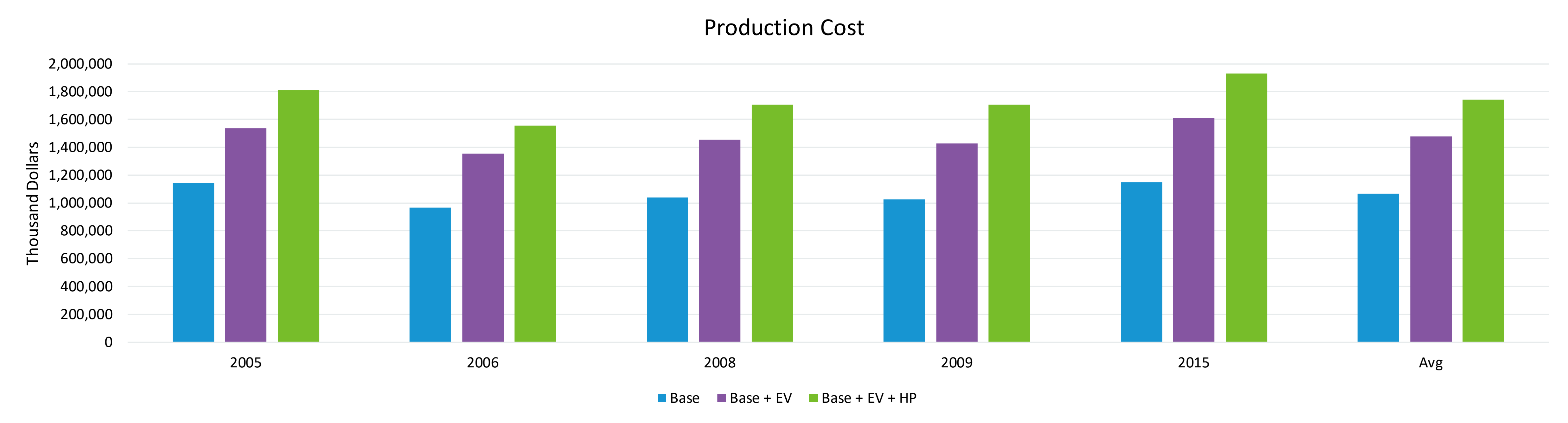
LMPs and LSEEE





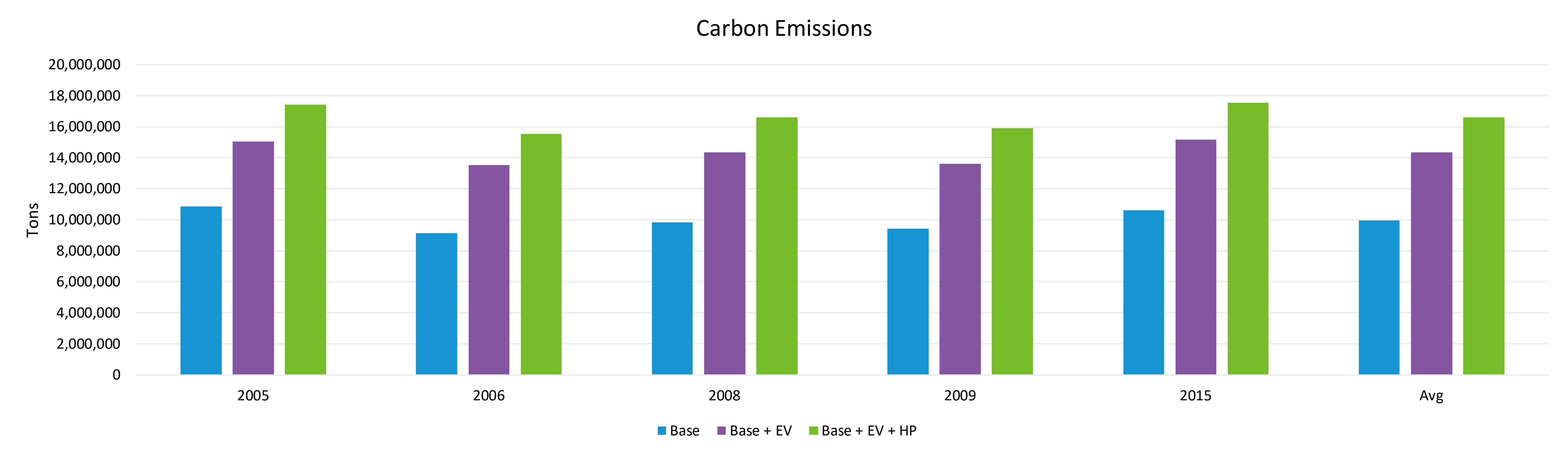
- The additional load is sometimes met by zero cost resources, but is also often served by more expensive generation having to run to meet higher loads and satisfy ramping needs
- Average LMPs increase from $26.18/MWh in the Base model to $38.75/MWh in the Base + EV model, then to $48.21/MWh in the Base + EV + HP model
- Cost to load (LSEEE) increases by $2 billion with EV load, then by another $1.6 billion with the HP load. In total, the cost to load will increase by 114% from the Base model to the Base + EV + HP model while LMPs increased 84%

Production Cost



- Just as with LMPs and LSEEE, the additional electrified load causes more expensive generation to run more frequently
- Average production cost values increase by $413 million with EV load and by another $264 million with HP load. In total, production cost increases by 64% between the Base model and the Base + EV + HP model

Carbon Emissions



- The additional generation which runs to meet the electrified load tends to emit more
- Average emissions increase from 9.9 million tons in the Base model to 14.3 million tons in the Base + EV model, then to 16.6 million tons in the Base + EV + HP model
- Between the Base model and the Base + EV + HP model, average emissions increase by 67%

POLICY SCENARIO SENSITIVITY: NO ELECTRIFIED LOAD GROWTH

Sensitivity Overview – No Electrified Load Growth

- All policy scenario models have been rerun with updated load profiles from the ISO-NE Load Forecasting team
- Policy scenario models have significant load growth by 2050:
  - 2050 EV load: 14,946 MW peak, 56.4 TWh of annual energy
  - 2050 HP load: 25,495 MW peak, 30.6 TWh of annual energy
  - For reference, 2022 New England load was 117 TWh. Load energy is expected to increase by ~75% by 2050
- Deep decarbonization is made more difficult by other sectors shifting their demand from fossil fuels to the electric sector
- To demonstrate what buildout would be needed to decarbonize a load similar to a current day New England load, a capacity expansion model has been run with no EV or HP load growth
- There has been a built in BTM-PV growth in other policy scenario models. This has been disabled in this model, as net loads become negative. Instead, it is held at ~5,500 MW

No Electrified Load Growth: Takeaways

- Just as shown in the 2032 model, decarbonization would be a smaller lift without the added demand from the transportation and heating sectors
- While 40 GW of new capacity is still a massive undertaking, it is a much more feasible goal than almost 100 GW in the base model
- Without a large electrified peak load, significantly less emitting dispatchable generation is needed. New intermittent and energy limited resources could replace a moderate amount of emitting dispatchable generation if loads stay around their current level
- An issue, which is not examined in this analysis, is the management of low net loads. If growth of BTM-PV was included without load growth, net loads would eventually become negative and would require energy storage load or export capability

No Electrified Load Growth: Resource Buildout (MW)

	2050 Nameplate (No Electrified Load)	2050 Nameplate (Base Model)
PV	24,723	26,338
LBW	4,309	7,500
OSW	3,277	30,233
BESS	7,655	33,000
Total	39,314	97,071

- ~40,000 MW of new capacity was built to decarbonize without the electrified load. In the base model with electrified load (+87 TWh), almost ~100,000 MW of new capacity was built
- Smaller amounts of wind are built. The majority of new capacity is from PV and energy storage

No Electrified Load Growth: Expansion & Production Metrics

	No Electrified Load Growth	Base Model
Build Cost (Million $)	3,704	17,944
Fixed Cost (Million $)	2,410	6,249
Production Cost (Million $)	953	913
Zero Carbon Energy (GWh)	108,837	180,375
Carbon Emissions (tons)	651,429	410,719
Curtailed Energy (GWh)	6,272	55,063

- Total costs (build costs + fixed costs + production costs) are significantly lower without electrified load growth. The model only builds cheaper generation
- Curtailment is also significantly lower, though still much higher than amounts seen today

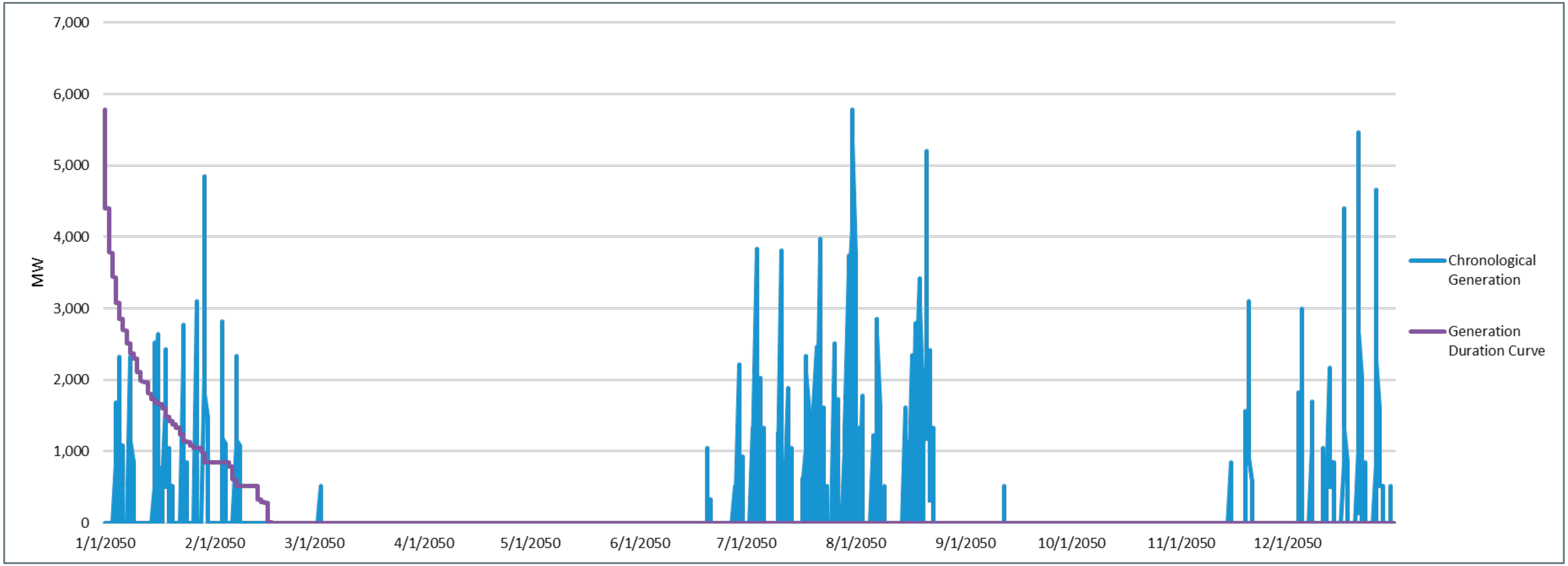
No Electrified Load Growth: 2050 Generation by Fuel Type

	ADR	Coal	Oil	MSW/LFG/ Wood	Gas	Nuc	Hydro	PV	LBW	OSW	Imports
Generation (GWh)	0	0	1	5,595	1,674	29,241	6,016	25,824	19,180	13,635	14,941
% of Total	0	0	0	5	1	25	5	22	16	12	13

- Emitting resources (gas + oil) are a minimal part of system generation (~1.4%)
- The majority of generation is from non-emitting resources (93.8%)
- New England still imports a moderate amount of energy (12.9%)

PRELIMINARY RESULTS, DO NOT CITE

No Electrified Load Growth: Emitting Generation



- Emitting generation (gas + oil) is only needed in the winter and summer months (online for 1,140 hours)
- Less emitting dispatchable capacity is needed than what is installed today (only ~6 GW for the 2019 weather year)

POLICY SCENARIO SENSITIVITY: NUCLEAR RETIREMENT

Sensitivity Overview – Nuclear Retirement

- The New England region has three nuclear generators which provided approximately 26% of energy demand in 2022
- These units provide the majority of New England's native zero carbon energy today
  - However, they are aging, with the oldest unit nearing 50 years of age
  - By 2050, these three units will be between 60 – 75 years old
- Other nuclear resources have retired recently both within New England and elsewhere in the country
  - New England nuclear units which have retired did so between 25 - 47 years of age
- To examine the impact of nuclear retirement, a sensitivity has been run where the New England nuclear units are forced to retire (one in 2030, one in 2040, and one in 2050)
- The buildouts in 2030, 2040, and 2050 have been run in hourly models and compared to the base case buildout

Nuclear Retirement: Takeaways

- The 2050 system is overbuilt to meet the carbon constraint, so for most hours the removal of the nuclear generation leads to increased PV and wind generation due to less curtailment
- The peak of required emitting dispatchable generation is higher by 2.7 GW in the nuclear retirement model. Despite the additional 9 GW of energy storage and OSW, the system would still need to retain additional emitting generation
- In the modeled interim years (2030 and 2040), the retirement of nuclear generators primarily led to a significant increase in gas generation and emissions
- These models were all run without fuel constraints. If fuel constraints continue to exist in New England, the additional emitting generation may actually be met by LNG, oil, or coal

Nuclear Retirement: Resource Buildout (MW)

Type	2050 Nameplate (Nuclear Retirement)	2050 Nameplate (Base Model)
PV	27,538	26,338
LBW	7,500	7,500
OSW	34,400	30,233
BESS	36,492	33,000
Total	105,930	97,071

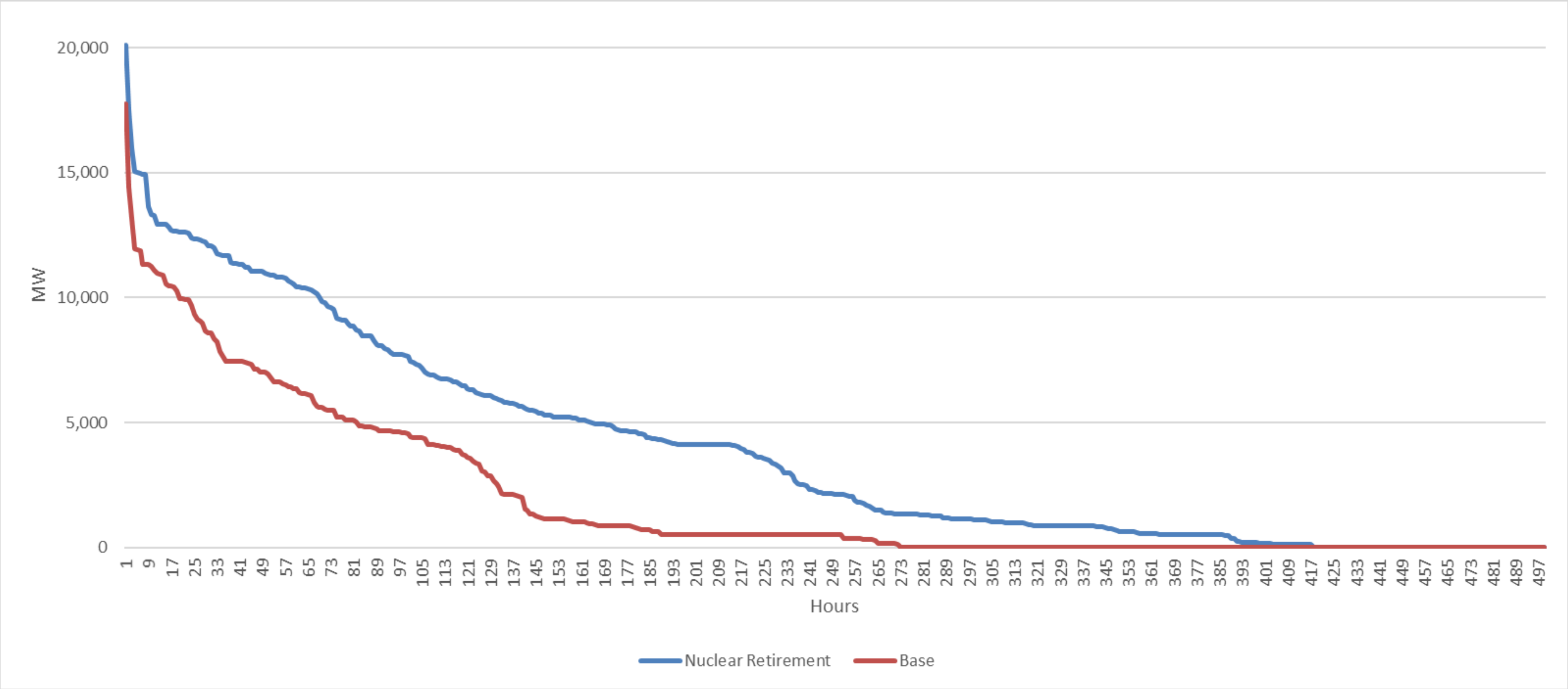
- While retiring 3,300 MW of nuclear units, the model builds an additional ~9,000 MW of mostly OSW and BESS

Nuclear Retirement: Expansion & Production Metrics

	Nuclear Retirement	Base Model
Build Cost (Million $)	20,234	17,944
Fixed Cost (Million $)	5,980	6,249
Production Cost (Million $)	536	913
Zero Carbon Energy (GWh)	180,300	180,375
Carbon Emissions (tons)	844,320	410,719
Curtailed Energy (GWh)	48,653	55,063

- Total costs in 2050 are roughly $2 billion/year higher in the model with nuclear retirement compared to the base model. The avoided fixed costs and production costs from retirement are offset by the high build costs of new generation
- The total zero carbon energy is similar in both scenarios
- The base model curtails ~6,500 GWh more than the nuclear retirement model

Nuclear Retirement: 2050 Hourly Emitting Generation



- With nuclear retirement, emitting generation runs more frequently (417 hours vs 272 hours)
- The peak emitting generation hour has 17,736 MW of gas, oil, and coal online. The peak hour with nuclear retirement has 20,384 MW online
  - Despite new additions of OSW and energy storage, retirement of nuclear generators will require a retention of a similar amount of emitting dispatchable generation (3.3 GW retired, 2.6 GW of additional dispatchable generation needed)

Nuclear Retirement vs. Base: 2030 Generation by Fuel Type

	ADR	Coal	Oil	MSW/LFG/ Wood	Gas	Nuc	Hydro	PV	LBW	OSW	Imports
2030 Nuclear Ret	1	0	6	5,629	35,260	21,541	10,029	390	10,048	10,469	23,892
2030 Base	2	0	4	5,627	28,212	29,241	9,815	388	10,039	10,466	23,496
Nuclear Ret - Base	-1	0	2	+2	+7,047	-7,700	+214	+2	+9	+4	+396

- In the nuclear retirement model, two nuclear units are active in 2030
- The majority of 7,700 GWh of retired nuclear energy is made up by emitting gas generation
- Emissions are higher by 2.9 million tons per year (14.2 million tons vs. 11.3 million tons) in the nuclear retirement model

Nuclear Retirement vs. Base: 2040 Generation by Fuel Type

	ADR	Coal	Oil	MSW/LFG/ Wood	Gas	Nuc	Hydro	PV	LBW	OSW	Imports
2040 Nuclear Ret	3	47	61	5,814	39,996	10,971	9,400	19,367	25,684	27,908	20,582
2040 Base	7	37	66	5,747	31,283	29,321	8,950	14,399	25,401	24,693	19,725
Nuclear Ret - Base	-4	+10	-5	+67	+8,713	-18,350	+450	+4,968	+283	+3,215	+858

- In the nuclear retirement model, only one nuclear unit remains in 2040
- Though wind and PV generation are higher in the nuclear retirement model, there is also an additional 8,700 GWh of emitting gas generation needed to replace the nuclear generation
- Total emissions are higher by 3.7 million tons per year (16.8 million tons vs. 13.1 million tons) in the nuclear retirement model

Nuclear Retirement vs. Base: 2050 Generation by Fuel Type

	ADR	Coal	Oil	MSW/LFG/ Wood	Gas	Nuc	Hydro	PV	LBW	OSW	Imports
2050 Nuclear Ret	1	11	11	5,589	1,949	0.0	4,401	24,137	23,990	119,721	8,052
2050 Base	0	5	1	5,580	964	29,241	3,745	19,900	22,530	97,951	7,009
Nuclear Ret - Base	+1	+6	+10	+9	+985	-29,240.6	+656	+4,237	+1,460	+21,770	+1,043

- The nuclear generation is replaced primarily by more PV and wind generation
- Dispatchable emitting generation (coal, oil, and gas) are higher than in the base model, but emissions are not significantly different (410 thousand tons vs. 840 thousand tons)

POLICY SCENARIO SENSITIVITY: BIODIESEL

Sensitivity Overview – Biodiesel

- At the August PAC, the ISO presented capacity expansion results with a conceptual synthetic natural gas (SNG) as a fuel type
- SNG was assumed to become progressively more expensive but have less carbon content, reaching $40/MMBtu and 0 lbs of carbon/MMBtu by 2050
- The resulting system required less wind, PV, and energy storage resources to achieve deep decarbonization. However, it was shown that in a fuel constrained model, there could still be hours with pipeline constraints, which would require a switch to stored fuel resources
- The ISO has received a sensitivity request to investigate biodiesel, or carbon neutral liquid fuel. Biodiesel could serve as a carbon neutral stored fuel. To reflect the additional energy demand to procure biodiesel, it has been priced at $45/MMBtu

Sensitivity Overview – Biodiesel

- Two models have been run:
  - One capacity expansion model with only biodiesel available (no SNG) with associated production cost runs (BD)
  - One production cost run where the previously presented SNG buildout was updated to include biodiesel as a fuel source (BD + SNG)
    - This model had fuel constraints enabled
- In the BD model, new dual fuel CCs and CTs were available as expansion candidates
- It is assumed that all existing oil and dual fuel units can utilize biodiesel. Gas only resources may not use biodiesel (though it is plausible that they could be retrofit in the future)

Biodiesel Takeaways

- Both SNG and Biodiesel could be useful in decarbonization by reducing the total amount of new generation that must be built. They also allow for continued use of existing infrastructure
- Both fuels would be expensive. Higher carbon prices or RECs would be needed to allow carbon neutral fuels to be utilized if they had to compete with existing emitting fuels
- For the amount of fuel consumption required, biodiesel alone would require retention of large inventory generators and frequent inventory refills throughout the year
- A SNG + biodiesel system would be similar to the current New England gas + oil system: wind, PV and energy storage dispatched first, SNG during renewable lulls (until gas pipelines become constrained), then biodiesel to ride out constrained periods
  - The biodiesel drawdowns would be much more manageable than in the biodiesel only scenario

Biodiesel: Buildout

Type	2050 Nameplate (SNG)	2050 Nameplate (BD)	2050 Nameplate (Base Model)
PV	24,738	24,652	26,338
LBW	6,400	6,450	7,500
OSW	18,888	18,762	30,233
BESS	12,120	12,398	33,000
CC	2,145	6,275	0
Total	64,291	68,537	97,071

- The BD scenario builds less capacity than the base model, but slightly more capacity than the SNG model
- In particular, there is three times more dual fuel combined cycles built compared to the SNG model. This likely reflects a better average heat rate of gas only generators than oil (biodiesel) only generators

Biodiesel: Expansion & Production Metrics

	BD	Base Model
Build Cost (Million $)	10,490	17,944
Fixed Cost (Million $)	4,243	6,249
Production Cost (Million $)	6,476	913
Zero Carbon Energy (GWh)	178,583	180,375
Carbon Emissions (tons)	916,882	410,719
Curtailed Energy (GWh)	30,233	55,063

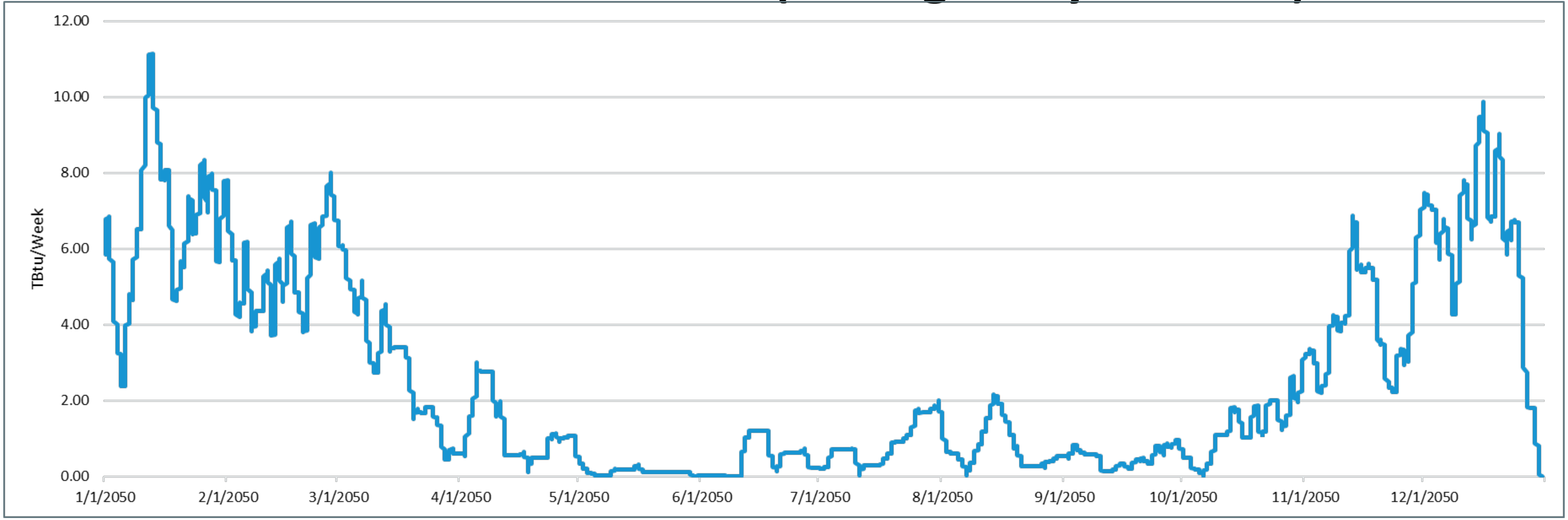
- Total costs (build + fixed + production) are lower in the BD model due to reduced build costs and fixed costs, but production costs are significantly higher due to expensive fuel
- Curtailment is also lower due to the system being less overbuilt

Biodiesel: 2050 Generation by Fuel Type

	ADR	Coal	Biodiesel	MSW/LFG/ Wood	Gas	Nuc	Hydro	PV	LBW	OSW	Imports
Generation (GWh)	39	15	19,169	6,409	2,126	29,241	6,016	23,247	24,558	72,951	15,674
% of Total	0	0	10	3	1	15	3	12	12	37	8

- Over half of all energy is produced by PV and wind
- Biodiesel accounts for ~10% of generation
- Gas and coal still provide some energy

Biodiesel: Biodiesel Drawdown (Rolling 7-day window)



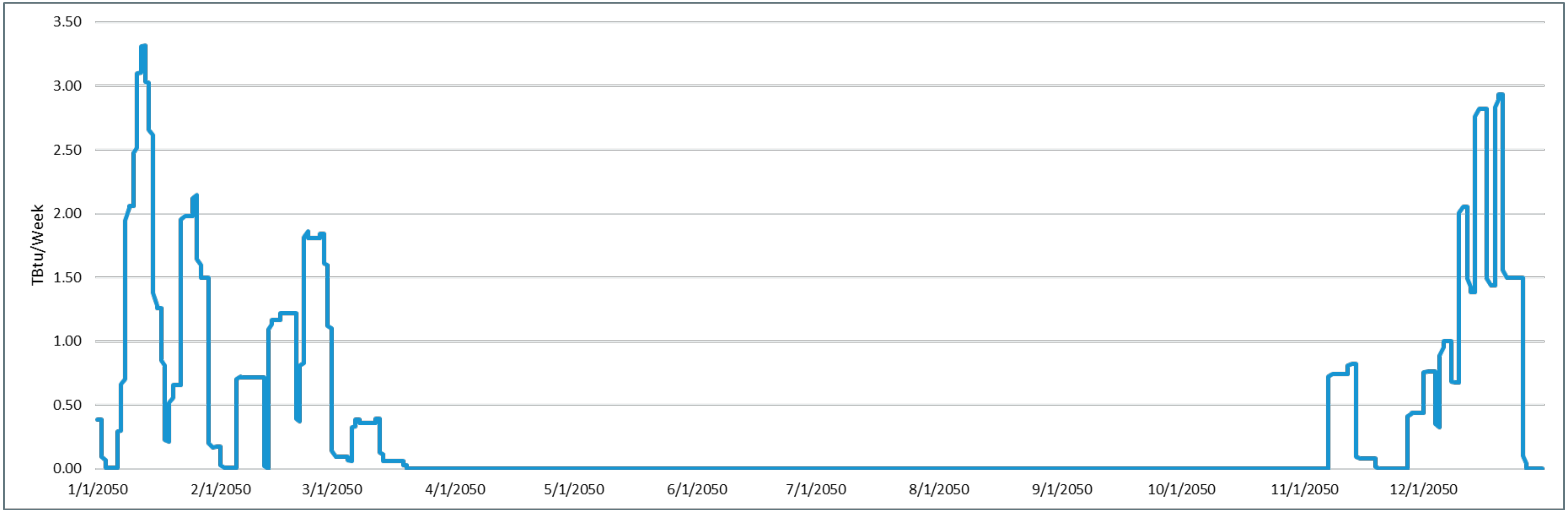
- Though fuel inventories were not constrained, the sum of inventories of all generators in the model was 67 TBtu. Over one year, 134 TBtu of biodiesel was consumed
- At the July PAC, the ISO showed that 2032 fuel drawdowns from all stored fuels could reach 13 TBtu over a one week period
- In this model, biodiesel drawdowns reach similar levels. Large inventory units would be critical in maintaining fuel security, and inventory refueling could be needed frequently over a single winter

SNG + BD: Fuel Constrained (FC) Generation by Fuel Type

	ADR	Coal	Biodiesel	Oil	MSW/LFG /Wood	Gas	Nuc	Hydro	PV	LBW	OSW	Imports
SNG	68	49	N/A	1,924	5,830	27,030	29,241	5,415	24,380	22,444	75,794	11,079
SNG + BD	30	16	2,126	N/A	5,771	27,030	29,241	5,413	24,420	22,426	75,761	11,088

- In the SNG Fuel Constrained (FC) model, oil was used significantly during cold conditions with high demand for generation
- Introducing biodiesel allows generators to switch to a carbon neutral liquid fuel
- The SNG FC model had 1.3 million tons of carbon emissions mostly due to oil generation. With SNG + BD, there were 18 thousand tons of carbon emissions

SNG + BD: Cumulative Biodiesel Drawdown (Rolling 7-day window)



- Total biodiesel drawdown was 17 TBtu
- The short term fuel drawdowns were much more manageable, peaking at 3.3 TBtu/week

Next Steps

- For the November PAC, the ISO will present preliminary results for the NESCOE policy scenario sensitivities
- The ISO will also present additional MENS sensitivity results. These will include New Brunswick imports and a new wind farm in Maine with adjusted interface limits
- The ISO welcomes any comments or requests for sensitivities from the PAC
  – Please send comments and sensitivity requests to PACMatters@iso-ne.com

Questions

Acronyms

ACDR	Active Demand Capacity Resource	EE	Energy Efficiency
ACP	Alternative Compliance Payments	EFORd	Equivalent Forced Outage Rate demand
AGC	Automatic Generator Control	EIA	U.S. Energy Information Administration
BESS	Battery Energy Storage Systems	EPECS	Electric Power Enterprise Control System
BTM PV	Behind the Meter Photovoltaic	EV	Electric Vehicle
BOEM	Bureau of Ocean Energy Management	FCA	Forward Capacity Auction
CCP	Capacity Commitment Period	FCM	Forward Capacity Market
CELT	Capacity, Energy, Load, and Transmission Report	FGRS	Future Grid Reliability Study
CSO	Capacity Supply Obligation	FOM	Fixed Operation and Maintenance Costs
Cstr.	Constrained	HDR	Hydro Daily, Run of River
DER	Distributed Energy Resource	HDP	Hydro Daily, Pondage
DR	Demand-Response	HQ	Hydro-Québec

Acronyms, cont.

HY	Hydro Weekly Cycle
LBW	Land Based Wind
LFG	Landfill Gas
LFR	Load Following Reserve
LMP	Locational Marginal Price
LSEEE	Load-Serving Entity Energy Expenses
MSW	Municipal Solid Waste
NECEC	New England Clean Energy Connect
NESCOE	New England States Committee on Electricity
NG	Natural Gas
NICR	Net Installed Capacity Requirement
NREL	National Renewable Energy Laboratory

OSW	Offshore Wind
O&M	Operation and Maintenance
PHII	Phase II line between Radisson and Sandy Pond
PV	Photovoltaic
RECs	Renewable Energy Credits
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewables Portfolio Standards
SCC	Seasonal Claimed Capability
Uncstr.	Unconstrained
VER	Variable Energy Resource

APPENDIX – EPCET PILOT STUDY OVERVIEW

EPCET Pilot Study Overview

- As part of the 2021 Economic Study (Future Grid Reliability Study – Phase I), the ISO identified areas for improvement in our current Economic Study framework and software tools to perform the analyses
- The ISO filed Tariff revisions for Phase 1 of the Economic Studies process improvements with the Federal Energy Regulatory Commission on January 27, 2023, which were accepted and went into effect on March 31, 2023
- The overall goal of the EPCET study is to prepare our models, tools, and processes such that informative and actionable results can be more readily produced in future Economic Study cycles
- The EPCET is a pilot study and not an Economic Study under the Tariff. The EPCET is a research and development effort that will help inform future study work and the next steps of the Economic Study Process Improvements. As such, the ISO will not be pursuing a market efficiency Needs Assessment under the Tariff based on EPCET results.
- The EPCET study has three main objectives:
  - Take a deep dive into all input assumptions in economic planning analyses, propose updates to any assumptions based on our current experience, and test the effect of those modeling changes
  - Gain experience in the features and capabilities of our new economic planning software
  - Perform a trial run of the Economic Study process improvements

EPCET Pilot Study Scenarios

- ✓ **Benchmark scenario** – Model previous calendar year and compare it to historical system performance. This scenario's purpose is to test fidelity of models against historical performance and improve the models for future scenarios
- ✓ **Market Efficiency Needs scenario (MENS)** – Model future year (10-year planning horizon) based on the ISO's existing planning criteria to identify market efficiency issues that could meet the threshold of a market efficiency need and move on to the competitive solution process for market efficiency needs
- **Policy scenario** – Model future years (>10-year planning horizon) based on satisfying New England region and other energy and climate policies
- **Stakeholder Requested scenario** – After the initial results of the reference scenarios are presented to stakeholders, invite sensitivity requests to test the effect of a specific change to input assumptions (e.g., resource mix, transmission topology, etc.)