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

MENS Sensitivities and Policy Scenario Results

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ECONOMIC STUDIES AND ENVIRONMENTAL OUTLOOK

Today's Topics

- PAC Recap
- Market Efficiency Needs Scenario – Relived Interface Limits Sensitivity Results
- Policy Scenario Methodology for Sensitives on Expansion Reliability and Resource Compensation
- Policy Scenario Results: PPA Only
- Policy Scenario Results: PPA + RA
- Policy Scenario Results: Total Cost
- Policy Scenario Results: The Impact of Weather on a Reliability Adder

MARKET EFFICIENCY NEEDS SCENARIO SENSITIVITY – RELIEVED INTERFACE LIMITS

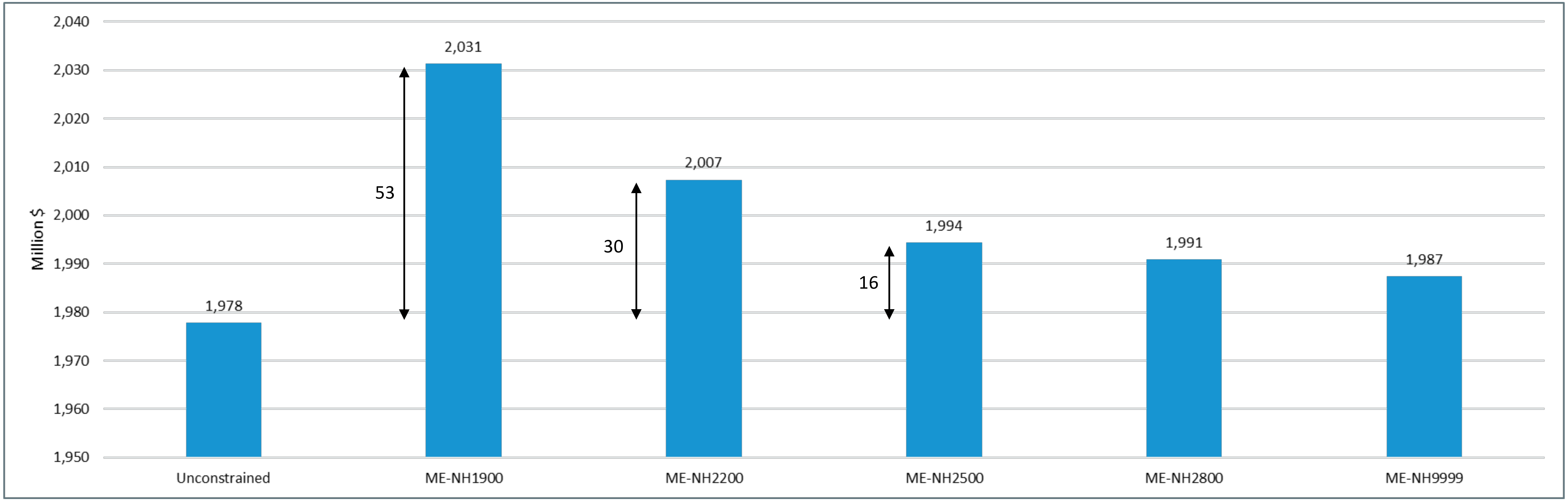
Relieved Interface Limits Overview

- At the August PAC, the ISO presented results for a MENS sensitivity where diurnal flows from New Brunswick and a new 1 GW wind farm in Aroostook county, ME were included
- In a transmission constrained model, the ME-NH interface was found to be significantly congested (almost 7,000 hours out of the year)
- The ISO received a request to run this scenario with increased ME-NH limits. The ISO has run six model versions:
  - An unconstrained model (unconstrained)
  - A constrained model with the ME-NH interface at 1,900 MW (ME-NH1900)
  - Three models with the ME-NH limit increased by 300 MW intervals (ME-NH2200, ME-NH2500, and ME-NH2800)
  - A model with the ME-NH interface limit removed (ME-NH9999)
  - Note: all constrained models included N-0 and N-1 transmission analysis
- Following feedback from the ISO Transmission Planning team, the ISO has removed a limit on the North-South interface and let the individual lines congest
- Note: some model settings have been tweaked since the August PAC, resulting in slightly different results in the base constrained and unconstrained model

Relieved Interface Limits Takeaways

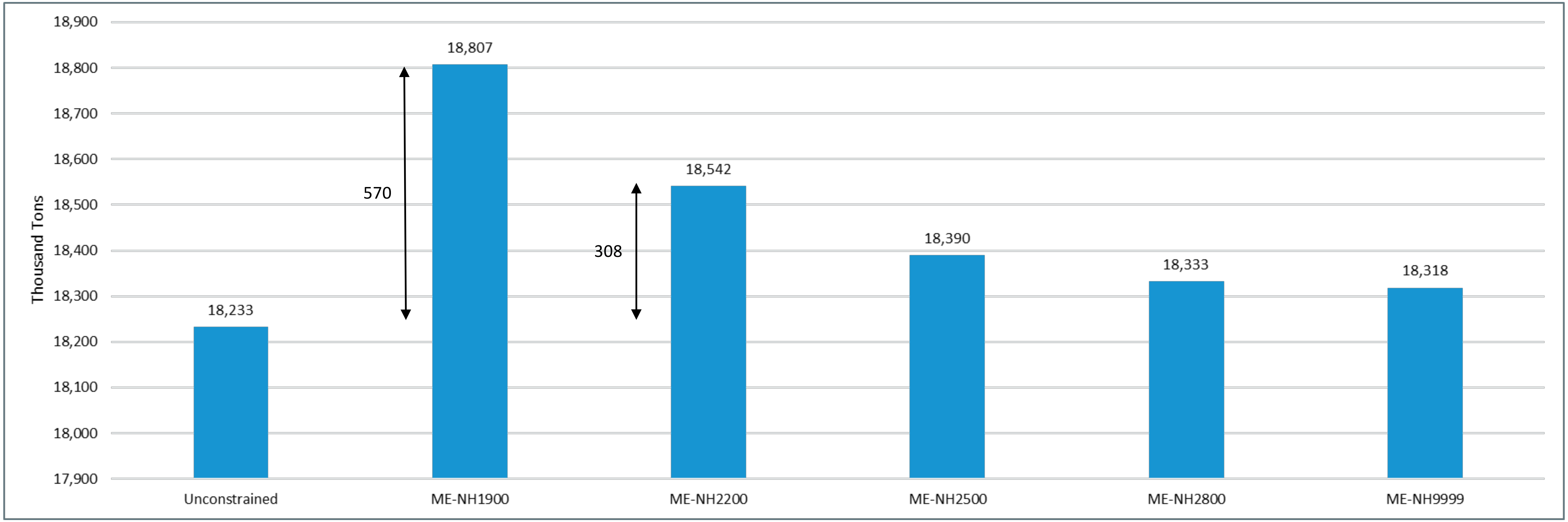
- In terms of production cost, CO_2 emissions, and curtailment, the first 300 MW transfer limit upgrade has the most significant effect. Subsequent increases in interface limits have a declining effect
- ME-NH is still the most binding interface in the scenarios until the limit is increased to 2,800 MW
- As the ME-NH limit is raised, some congestion shifts onto interfaces and lines in and around ME-NH

Relieved Interface Limit - Production Cost



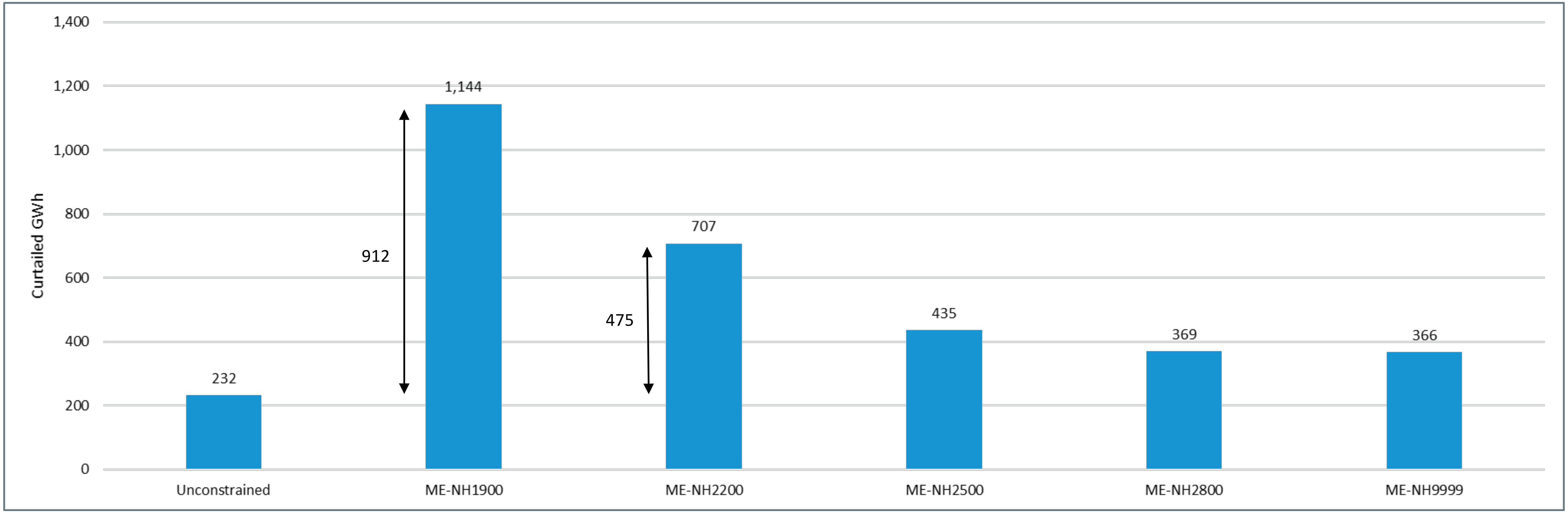
- With existing ME-NH limits (ME-NH1900), there is approximately $53 million dollars of congestion across the system
- The first 300 MW relief of ME-NH reduces this to approximately $30 million dollars. The second 300 MW relief reduces this to $16 million dollars
- Subsequent relief of ME-NH has a declining impact on production cost

Relieved Interface Limit - CO_2 Emissions



- The trend with CO_2 emissions follows production cost. The ME-NH1900 case has approximately 570 thousand tons of additional emissions
- Additional emissions are reduced to 308 thousand tons with a 300 MW upgrade

Relieved Interface Limit - Curtailment



- Transmission constraints caused an additional 912 GWh of curtailment in the ME-NH1900 model
- Increasing the interface limit by 300 MW reduces curtailment by 437 GWh

Hours of Congestion for Binding Elements

Element	ME-NH1900	ME-NH2200	ME-NH2500	ME-NH2800	ME-NH9999
Maine - New Hampshire (Interface)	6,907	5,075	3,161	978	0
Surowiec South (Interface)	0	11	190	1,108	1,349
Orrington South (Interface)	9	25	48	143	171
NNE - Scobie + 394 (Interface)	0	1	30	319	471
LN_64 (Line)	0	3	49	189	238
LN_373 (Line)	0	0	0	134	262
ES_385_CMP (Line)	0	0	0	0	9

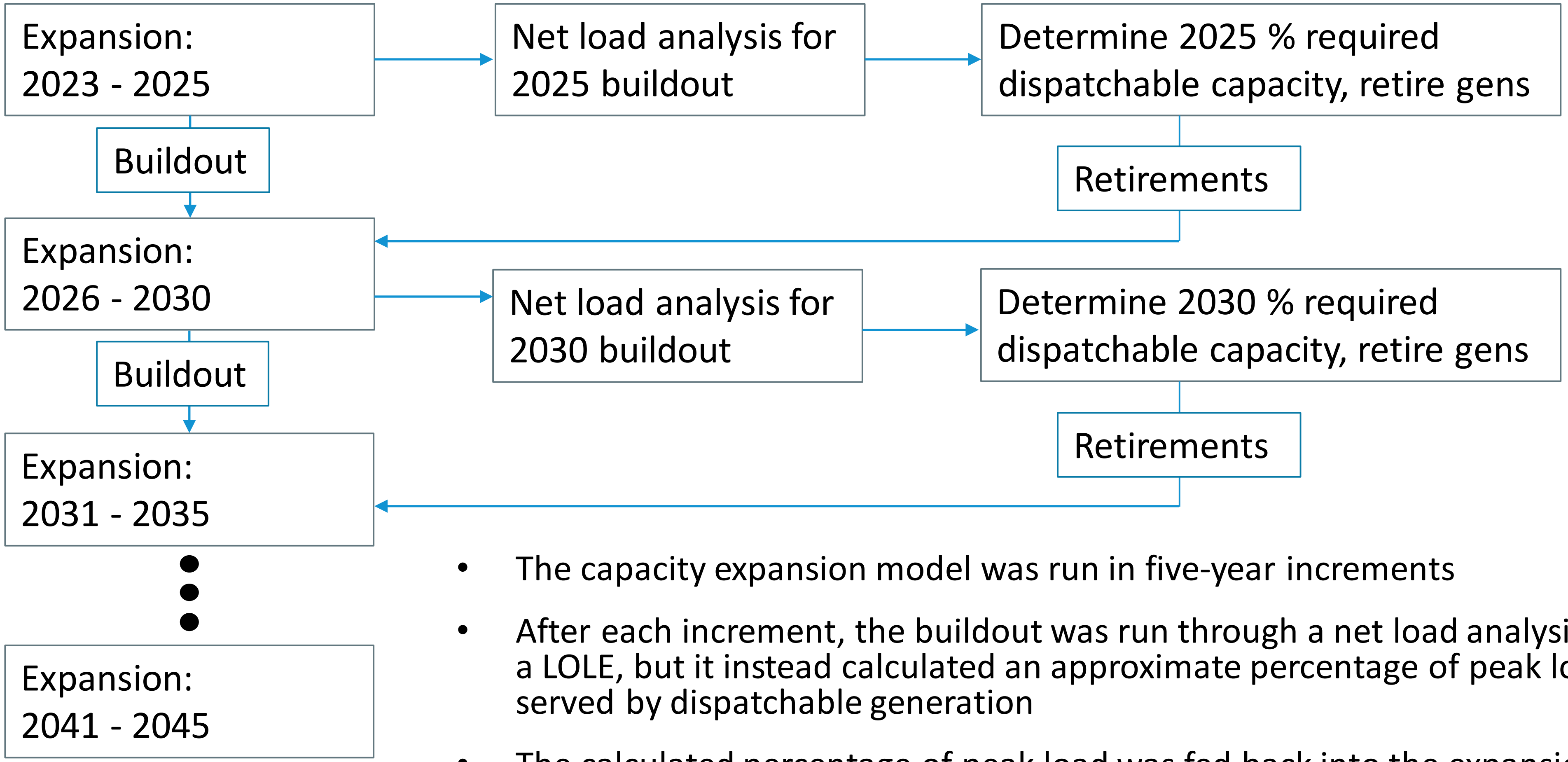
- In the ME-NH2200 and ME-NH2500 cases, the ME-NH interface is still frequently binding
- Interfaces to the north and south of ME-NH start to bind slightly more as ME-NH becomes relieved. Lines in and around ME-NH also start to hit their thermal limits
- Surowiec and Scobie become the next most binding elements

POLICY SCENARIO – METHODOLOGY FOR SENSITIVES ON EXPANSION RELIABILITY AND RESOURCE COMPENSATION

Overview of Methodology for Sensitives in this Presentation

- All capacity expansion runs presented thus far have systems built out to meet a 2050 load profile. However, these systems are not necessarily resource adequate
- While the ISO cannot perform a full resource adequacy analysis on the system at this time, this methodology created an approximate need for dispatchable resources as a percentage of peak load
- With this methodology, generator retirement decisions were made during the capacity expansion model
- Different compensation mechanisms were be examined with the new methodology
- Disclaimer: None of these methodologies are used in real ISO markets or systems. These were only utilized to give an approximate future representation of current ISO practices

Expansion Reliability Methodology

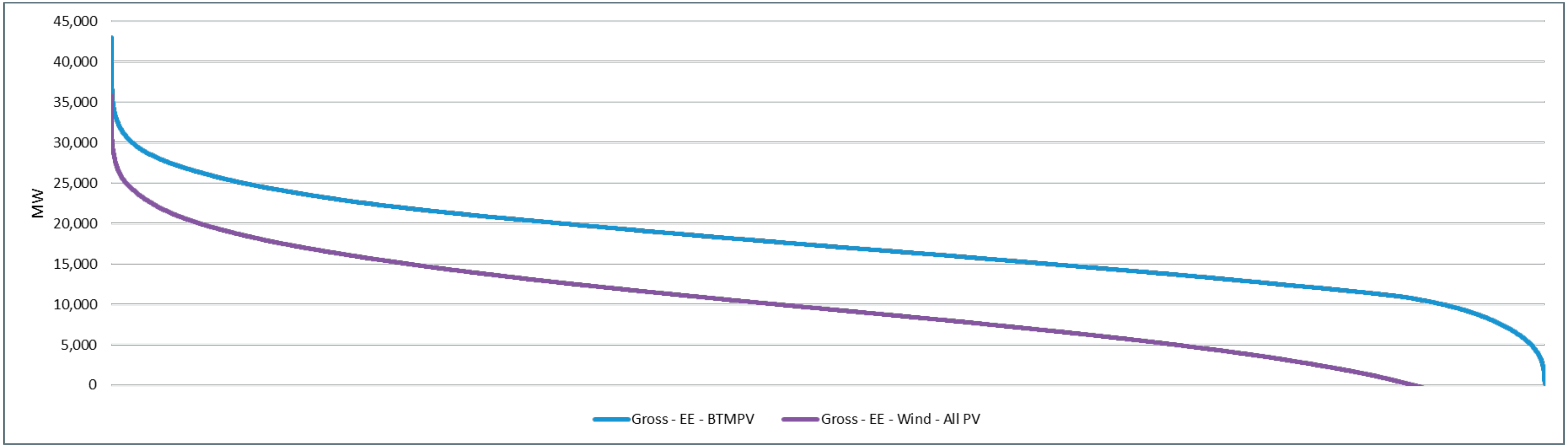


- The capacity expansion model was run in five-year increments
- After each increment, the buildout was run through a net load analysis. This did not calculate a LOLE, but it instead calculated an approximate percentage of peak load which must be served by dispatchable generation
- The calculated percentage of peak load was fed back into the expansion model. For the next five year step, the model built/retained dispatchable capacity to meet the constraint
- Retirement decisions were made based on the calculated percentage of peak load – if the model had more dispatchable capacity than was needed, resources were retired based on age

Additional Detail – Net Load Analysis & Dispatchable Ratio

- The net load analysis included 20 weather years of wind, PV, and load data
- From the 20 weather years, the ISO identified the hours with the highest net loads
  - Net loads = gross load – energy efficiency – wind generation – PV generation (BTM + Utility)
  - This is the load that had to be served by dispatchable generation
- For the highest remaining net load hours, the necessary amount of dispatchable resources was calculated to reflect a reasonable margin
  - The net load peak was increased by 10% to account for forced outages of dispatchable resources
  - The net load peak increased by 20% set an upper limit on capacity (with excess being retired)
- The calculated ratio was compared with the total nameplate of dispatchable resources
  - If the model had more dispatchable capacity than the maximum ratio, resources were retired based on age
  - If the model was found to be deficient in dispatchable capacity, the next expansion phase would build additional dispatchable capacity to satisfy the ratio
  - Energy storage was assumed to have 100% firm capacity regardless of duration. This assumption may be revised based on feedback and discussion

Expansion Reliability Methodology Example – 2040 Net Load Analysis



- Across 20 weather years of data, peak load (gross after EE – BTM-PV) is 43,031 MW
  - With the capacity expansion created buildout, peak net load (gross after EE – all PV – wind) was 35,784 MW. This was the load that must be met by dispatchable generation
- The model will try to maintain 110% - 120% of the calculated need for dispatchable resources (39,362 MW – 42,941 MW)
  - If the model had more than 42,941 MW of dispatchable capacity, resources were retired based on age. If the model had less than 39,362 MW of dispatchable capacity, resources would be added

Overview of Compensation Mechanisms

- Having established a reliability methodology to ensure a continued balance of supply and demand, the ISO can model compensation mechanisms
- Two methods of compensation were modeled
  - Power Purchase Agreements (PPA) only
  - PPAs + reliability adder (PPA + RA)
- PPA
  - PPA modeling mimics existing state policies
  - New zero carbon generating resources were paid a credit for each MWh of energy produced
  - The price for this credit was determined via the marginal cost of zero carbon energy in each time block
  - All resources were assumed to have a 25-year economic life. A new generator received a locked in PPA price calculated for the time block when it came into service
  - Energy storage resources did not receive a PPA, but they benefited from arbitrage with negative prices from new resources
- PPA + RA
  - In each five year-block, a PPA price and a reliability adder were calculated together. The reliability adder is a charge to carbon emitting resources which improves energy market revenues for units needed for system reliability
  - These prices were determined such that the time weighted annual average LMP ensures revenue adequacy for the largest zero carbon resource on the system

Formulation of Compensation Mechanisms

- After a capacity expansion block, two versions of hourly production cost models were run: one with all built resources, and one with the last resource built removed
- The marginal resource has an annualized build cost B_1 and fixed O&M costs F_1
- The two production cost models will have zero carbon energy Z_1 and Z_2
- The PPA price was calculated as $PPA\left(\frac{\$}{MWh}\right) = \frac{B_1 + F_1}{Z_1 - Z_2}$
- For the PPA + RA scenario, the PPA methodology was first applied, then the reliability adder price was calculated such that average time weighted LMPs = $41/MWh
- Existing wind and PV resources were assumed to have a PPA of $10/MWh. While this is not representative of true existing PPAs, it was meant to demonstrate how the entry of new zero carbon resources with larger PPAs could impact their revenue streams

Compensation Mechanisms, cont.

- All zero carbon energy resources were assumed to have their PPA over a 25-year economic life
- This PPA was implemented as a negative VO&M charge. The zero carbon energy resource revenue was from their PPA revenues
  - In hours with positive LMPs, the total revenue per MWh was be equal to the PPA price
  - In hours with negative LMPs, the total revenue was reduced
    - For example, if the PPA is $50/MWh and the LMP is -$30/MWh, the resource revenue will be equal to $20/MWh
- When calculating total cost to load, the load was assumed to incur costs by buying the energy from the generator at the PPA price when LMPs are positive
  - For example, if the PPA is $50/MWh and the LMP is $30/MWh, load will pay $50/MWh for the energy from the generator
  - If the PPA is $50/MWh and the LMP is -$30/MWh, load will pay $20/MWh for the energy from the generator

Overview of PPA vs. PPA + RA Analysis

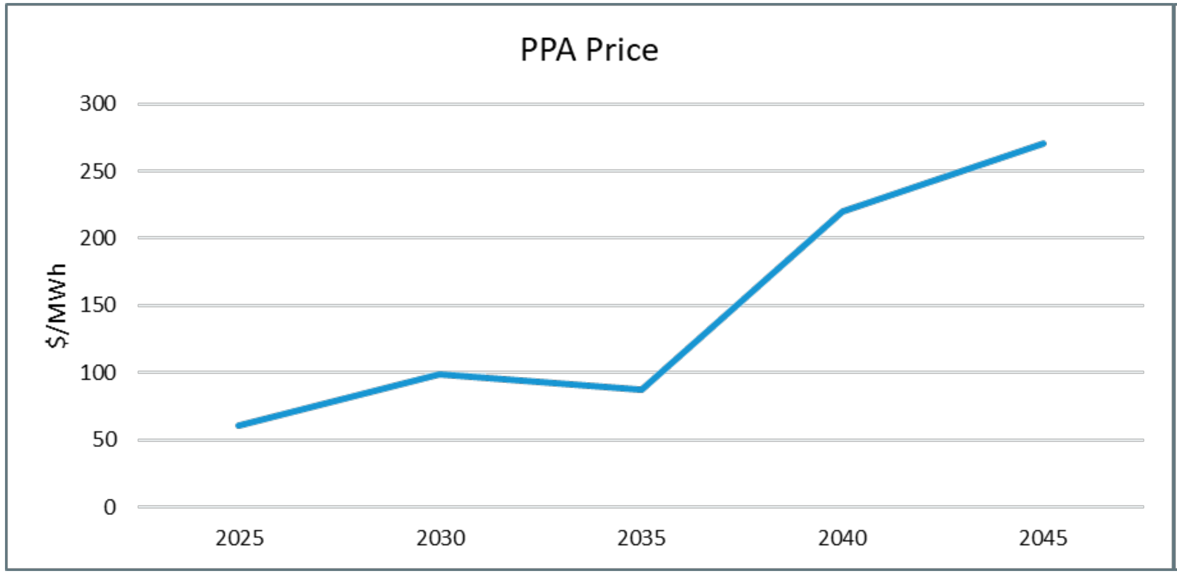
- The aforementioned methodologies have been applied to two capacity expansion models running from 2023 to 2045
- These results are assumption driven, but directional trends can be observed from the prescribed policy
- Both models build out a system that reduces CO_2 emissions to ~6 million tons by 2045
- LMPs, resource adequacy buildout metrics, and generator profits will be examined at five-year intervals

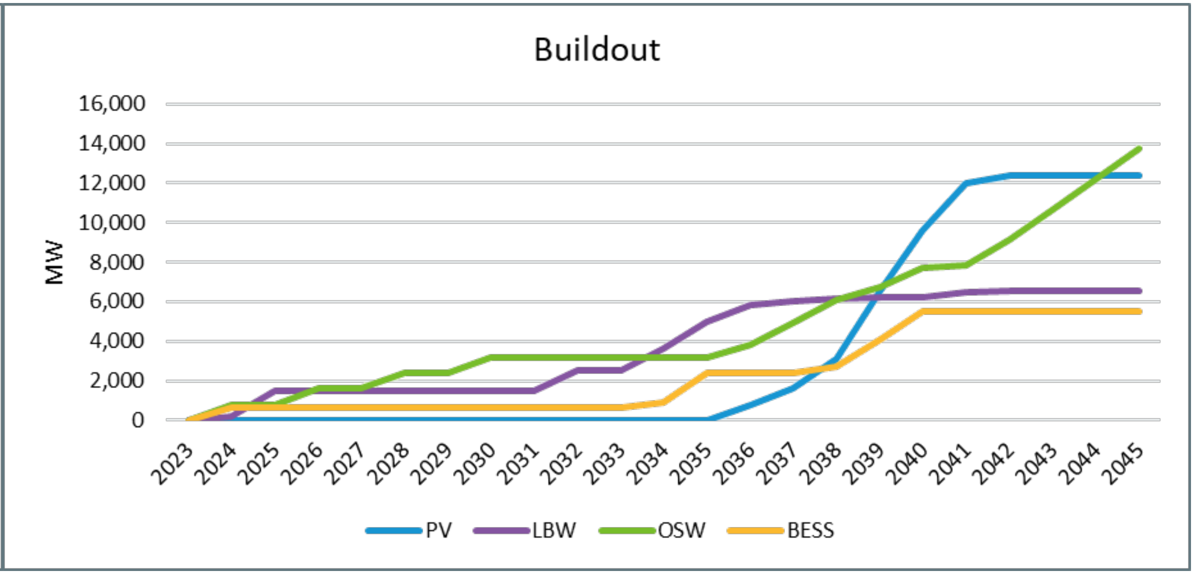
POLICY SCENARIO – PPA ONLY RESULTS

Takeaways of PPA Only Scenario

- PPAs get larger over time, as new resource additions later in the model horizon are curtailed for increasing percentages of the time
- New zero carbon energy resources are able to bid more negatively than existing resources, allowing for revenue adequacy for new resources
- Existing zero carbon energy resources are underbid by new zero carbon energy resources, leading to lower generation and less revenue over time. Some of the resources built in the first years of expansion experience that same effect
- Baseload resources see decreased profits over time as they are exposed to increased frequency of low and negative LMPs
- Though resources were able to retire, no additional resources were retired beyond announced retirements. Large amounts of dispatchable energy storage (4-hour BESS) are also added for resource adequacy

PPA Only: Buildout & PPA Prices





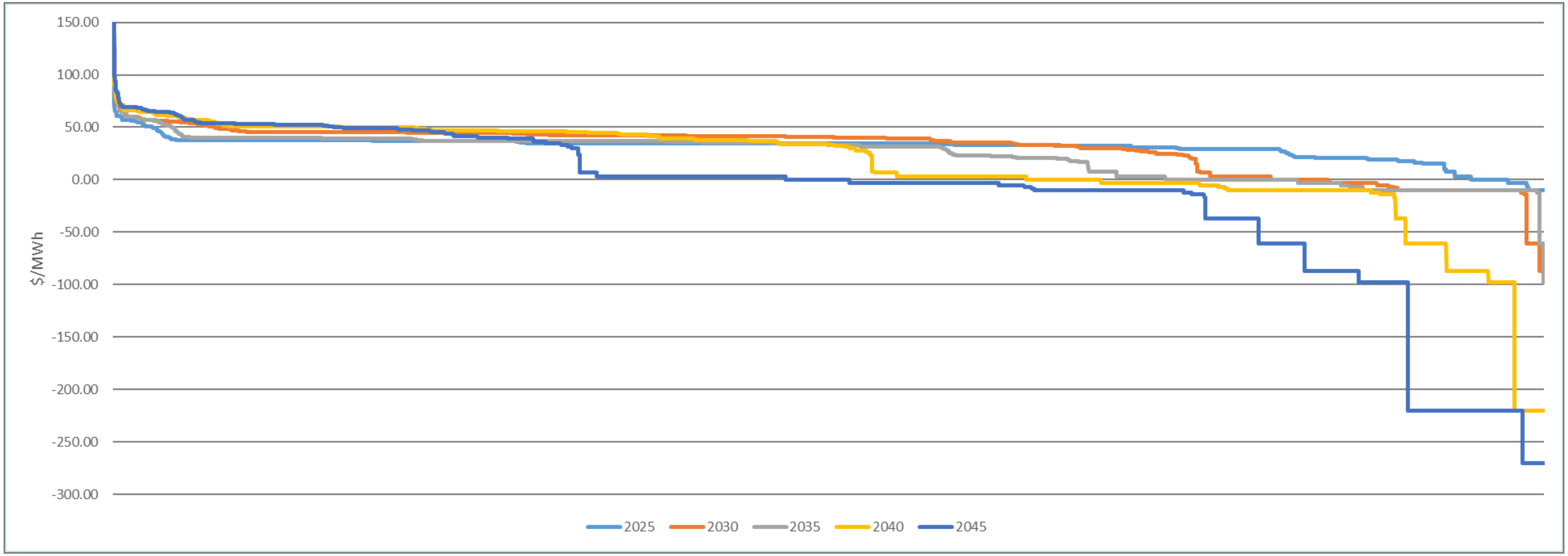
- Model builds 38 GW of new generating resources for decarbonization (this does not include 10 GW of energy storage resources added for resource adequacy)
- PPA prices are relatively steady initially, but begin to increase after 2035. New resources added in 2040 and 2045 lower the capacity factor of existing and previously added resources, increasing marginal costs of new zero carbon energy

PPA Only: Buildout Adequacy

	2025	2030	2035	2040	2045
Peak Gross Load (MW) (Gross – EE – BTM-PV)	25,591	27,403	33,551	43,031	50,789
Peak Net Load (MW) (Gross – EE – All PV – Wind)	25,004	25,469	28,674	35,784	40,927
Min RM (10%) (MW) (110% of Peak Net)	27,504	28,016	31,541	39,362	45,020
Max RM (20%) (MW) (120% of Peak Net)	30,005	30,563	34,409	42,941	49,112
Dispatchable Requirement as a % of Peak Gross	107.5	102.2	93.5	91.5	89.5
Dispatchable Nameplate (MW)	29,988	29,988	31,700	34,830	39,362
Capacity Added for Adequacy (MW)	0	0	0	4,532	5,657

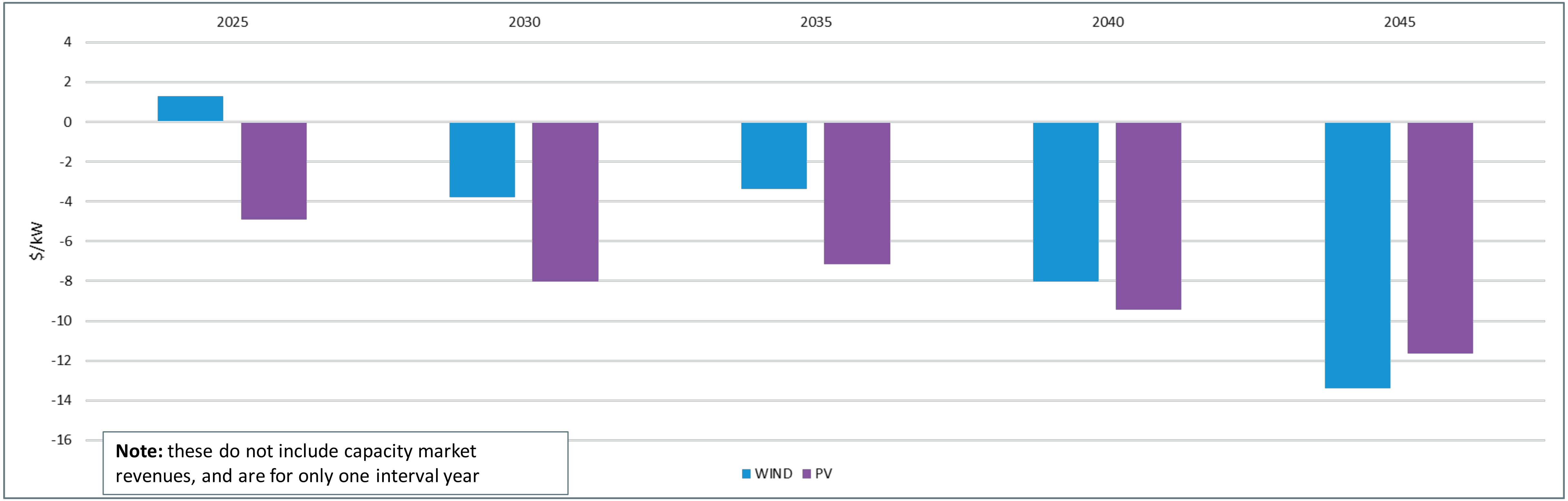
- No additional resources are retired in early years, as the 120% maximum reserve margin is never exceeded
- The resource adequacy constraint becomes binding in 2040/2045, ultimately adding ~10,000 MW of energy storage. If additional resources were retired earlier, they would likely have to be replaced with more dispatchable generation later
- In 2045, a 50,800 MW peak load is reduced to 40,900 MW by intermittent resources. To maintain the 110% of the peak net load, the model needs 45,000 MW of dispatchable resources. This results in needing to be able to cover 90% of the peak gross load with dispatchable resources

PPA Only: LMPs



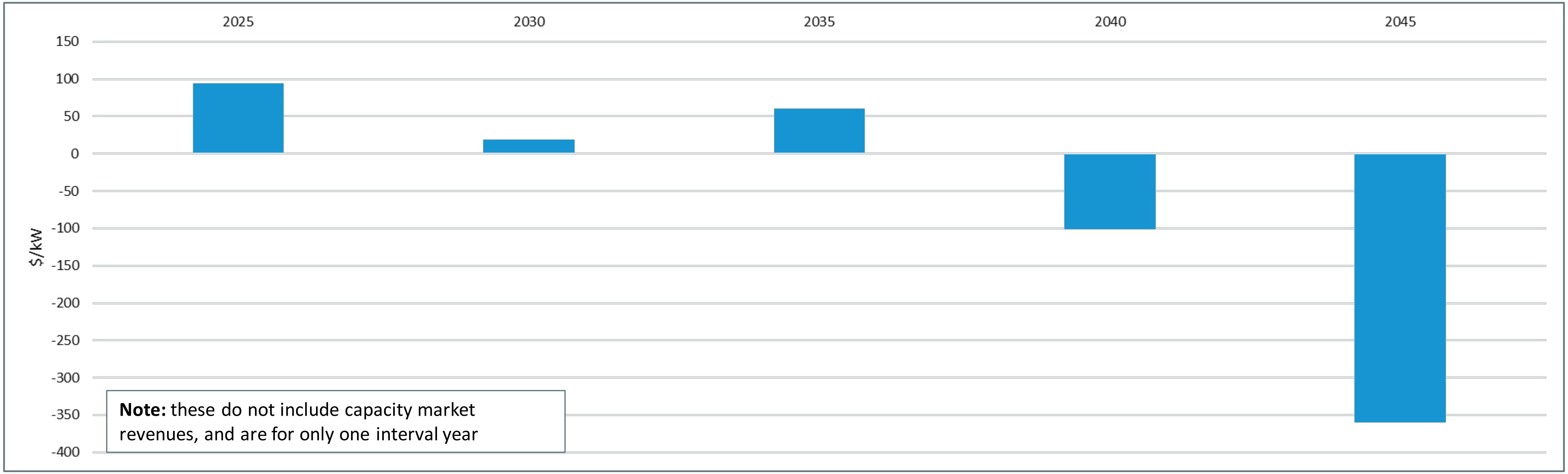
- LMPs become increasingly negative over time, reaching a time weighted value of $-15.83/MWh by 2045. 2045 has negative LMPs for 53% of hours and LMPs less than $41/MWh for 75% of hours
- There are some hours with very low LMPs in 2040 and 2045, indicating significant periods when new and existing zero carbon resources did not run for economic reasons
  - This includes resources built from 2036-2045

Average Annual Net Profit by Resource Type: Existing Wind and PV Energy Resources



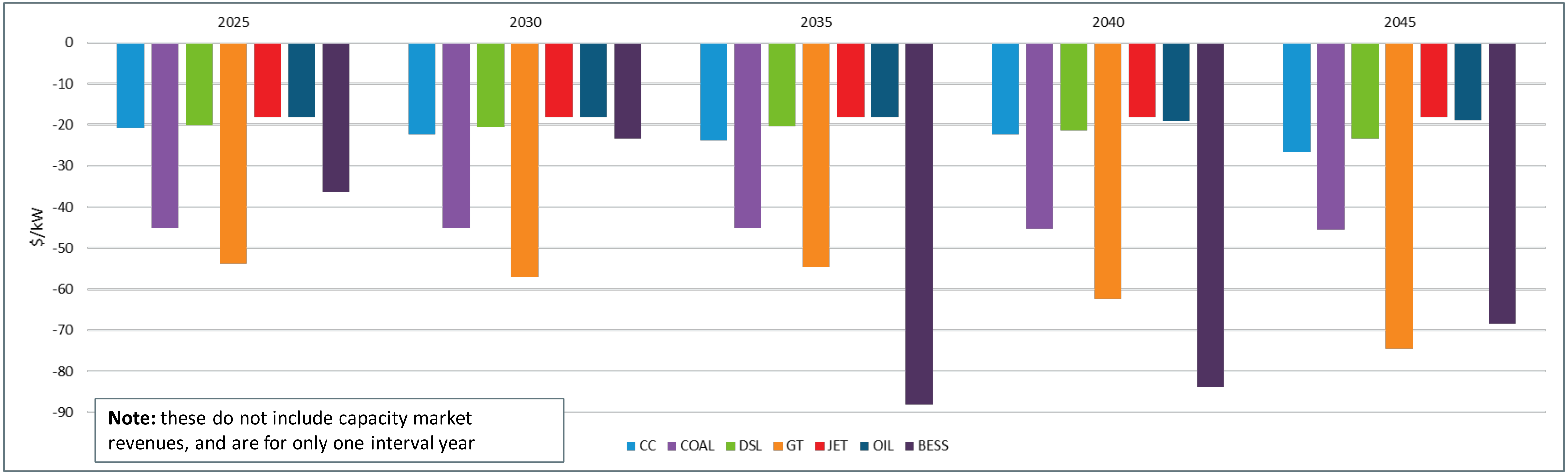
- Note: profits shown do not include revenue from the capacity market. Profit = revenue – production costs – fixed costs – annualized build costs
- Net profits for existing zero carbon energy resources decline over time. Existing PV and wind resources are increasingly underbid by new resources with higher priced PPAs
- Some of the new zero carbon energy resources built in the earlier blocks are also frequently curtailed as they are underbid by resources built later in the horizon

Average Annual Net Profit by resource Type: Nuclear Generators



- Nuclear resource net profitability (absent capacity payments) decline over the study period as energy prices decrease
- These profits are significantly impacted by fixed cost assumptions. The ISO is using generic assumptions from the EIA for nuclear resources rather than resource specific cost assumptions. These results can be used to identify trends over time. However, profitability isn't guaranteed through 2040

Average Annual Net Profit by Resource Type: Dispatchable Resources



- Most dispatchable resources are operating in the negative. Revenues made in the energy market are small compared to their fixed costs
- Large amounts of energy storage is added starting in 2035. With significant penetration of energy storage, the profit each resource can make is decreased due to the smoothing effect on LMPs
  - With large amounts of storage, high LMPs are reduced and low LMPs are increased

2035 - 2045 Single Resource Analysis: New LBW

Metric	Unit	2035	2040	2045
Generation	GWh	198.15	184.80	163.58
Energy Curtailed	GWh	0.04	12.92	34.61
Percent Curtailed	%	0.02	6.53	17.46
FO&M Cost	Thousand $	1,500.00	1,500.00	1,500.00
Annualized Build Cost	Thousand $	14,570.95	14,570.95	14,570.95
Total Costs	Thousand $	16,070.95	16,070.95	16,070.95
PPA Revenue	Thousand $	16,739.56	14,830.22	12,678.54
Net Profit	$/kW-yr	13.37	-24.81	-67.85

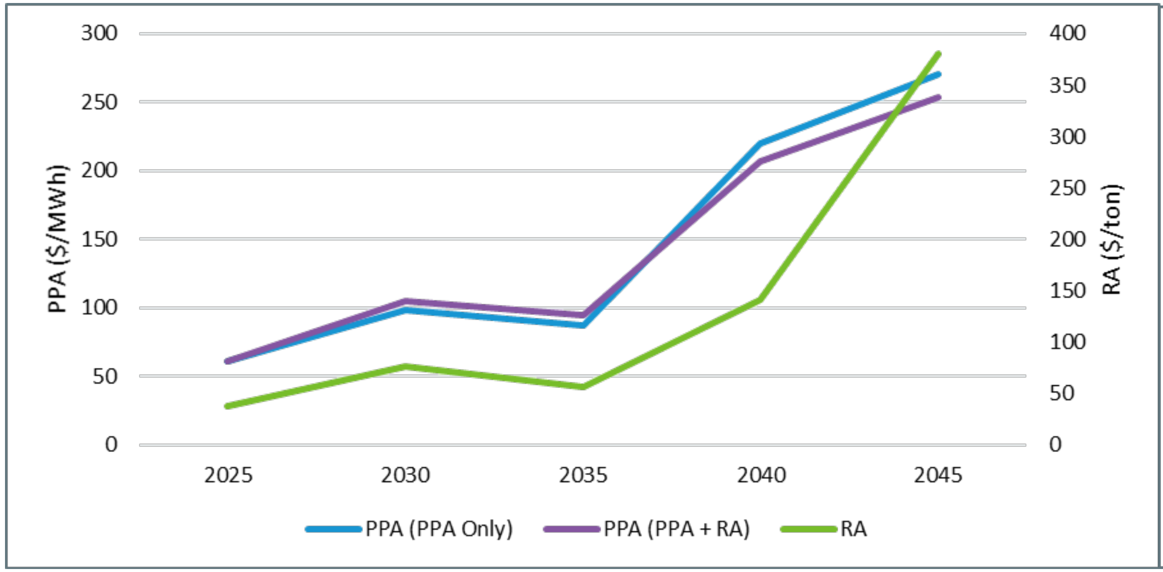
- This is a 50 MW new LBW resource built in 2035 receiving a PPA of $87/MWh
- As load starts to grow rapidly at the horizon of the CELT load growth (after 2033), curtailment of new resources and PPA prices drop
- While the PPA price ensures revenue adequacy in 2035, new additions in 2040 and 2045 are given higher priced PPAs and are able to underbid this resource. Within five years of entry, this resource is no longer profitable at the original PPA price
- Many existing and new clean energy resources may require escalations of PPAs

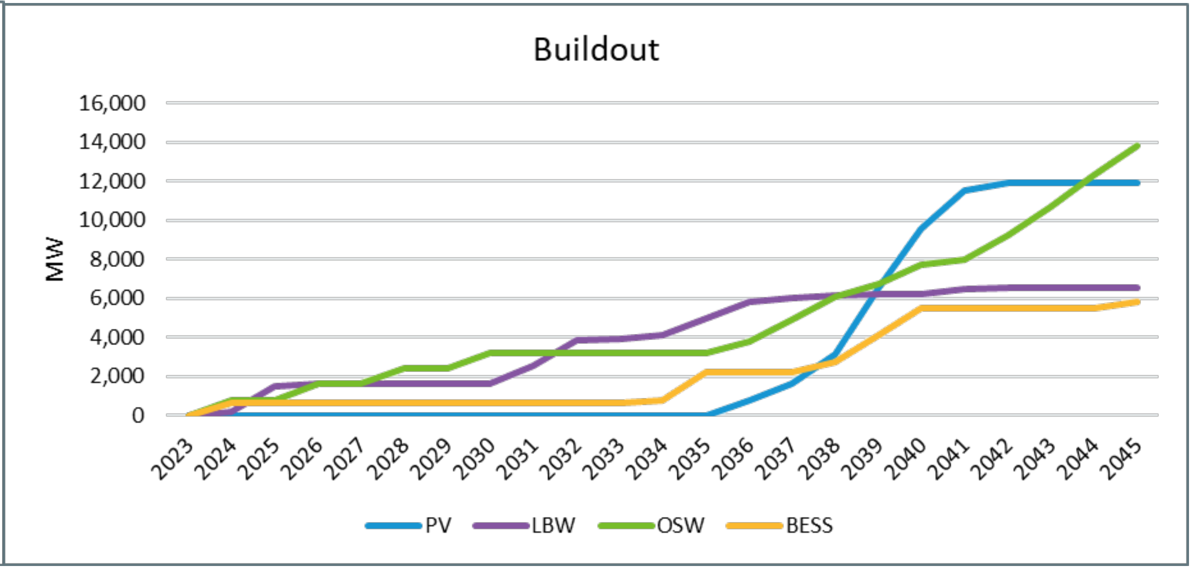
POLICY SCENARIO – PPA + RA RESULTS

Takeaways of PPA + RA Scenario

- PPA prices are similar in both scenarios because PPA resources see no additional revenue from the reliability adder
- Nuclear profits remain steady over time in the PPA + RA scenario
  – Whereas, in the PPA only scenario, nuclear profits fall significantly over time
- Because most resources are receiving more revenue in the energy market, capacity payments or other compensation streams are expected be lower for resources needed for resource adequacy or reliability
- With a shrinking number of hours with positive LMPs, the reliability adder will increase significantly in price in later years. This will drive price volatility
- Adding significant amounts of energy storage for reliability creates a smoothing effect on LMPs
  – Negative LMPs are raised, high LMPs are reduced

PPA + RA: Buildout & PPA/RA Prices





- Buildout is similar to the PPA only scenario. An identical carbon constraint leads to a similar buildout
- With the reliability adder, PPA prices are very similar to the PPA only scenario. This is because PPA resource revenues are unaffected by the reliability adder
- There is a growth in the reliability adder value in the later years of the model due to there being fewer and fewer hours with positive LMPs

PPA + RA: Buildout Adequacy

	2025	2030	2035	2040	2045
Peak Gross Load (MW) (Gross – EE – BTM-PV)	25,591	27,403	33,551	43,031	50,789
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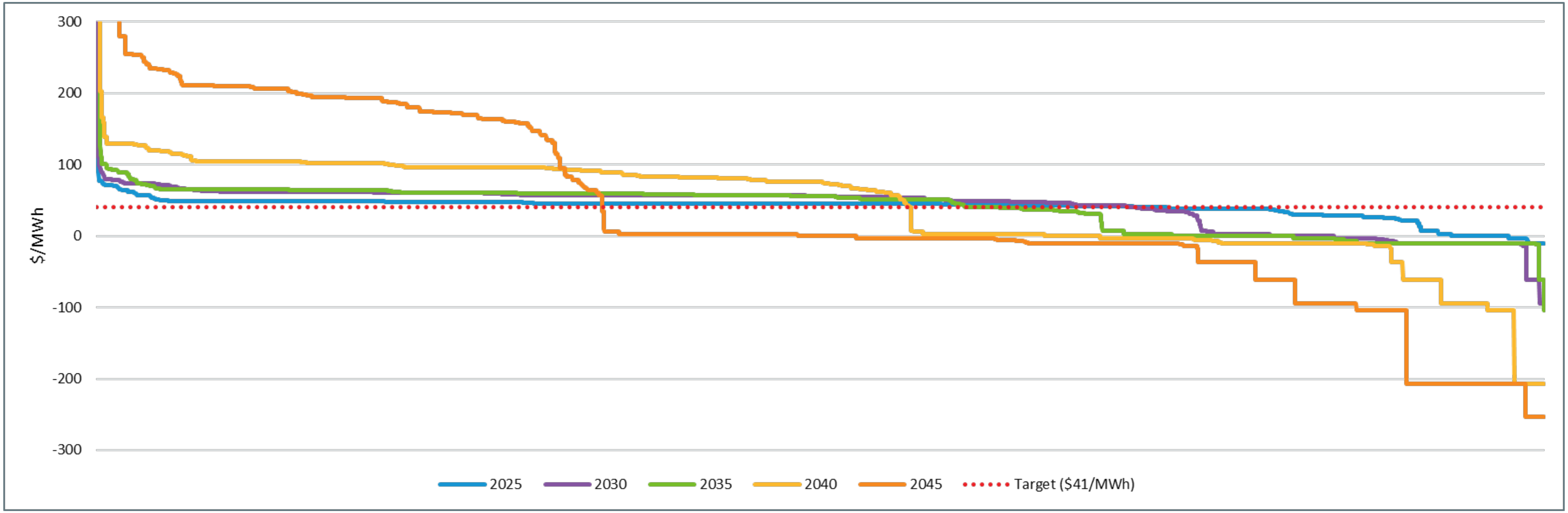
Min RM (10%) (MW) (110% of Peak Net)	27,504	28,002	31,541	39,362	45,022
Max RM (20%) (MW) (120% of Peak Net)	30,005	30,547	34,409	42,941	49,115
Dispatchable Requirement as a % of Peak Gross	107.5	102.2	94.0	91.5	88.6
Dispatchable Nameplate (MW)	29,988	29,988	31,578	34,829	39,689
Capacity Added for Adequacy (MW)	0	0	0	4,533	5,333

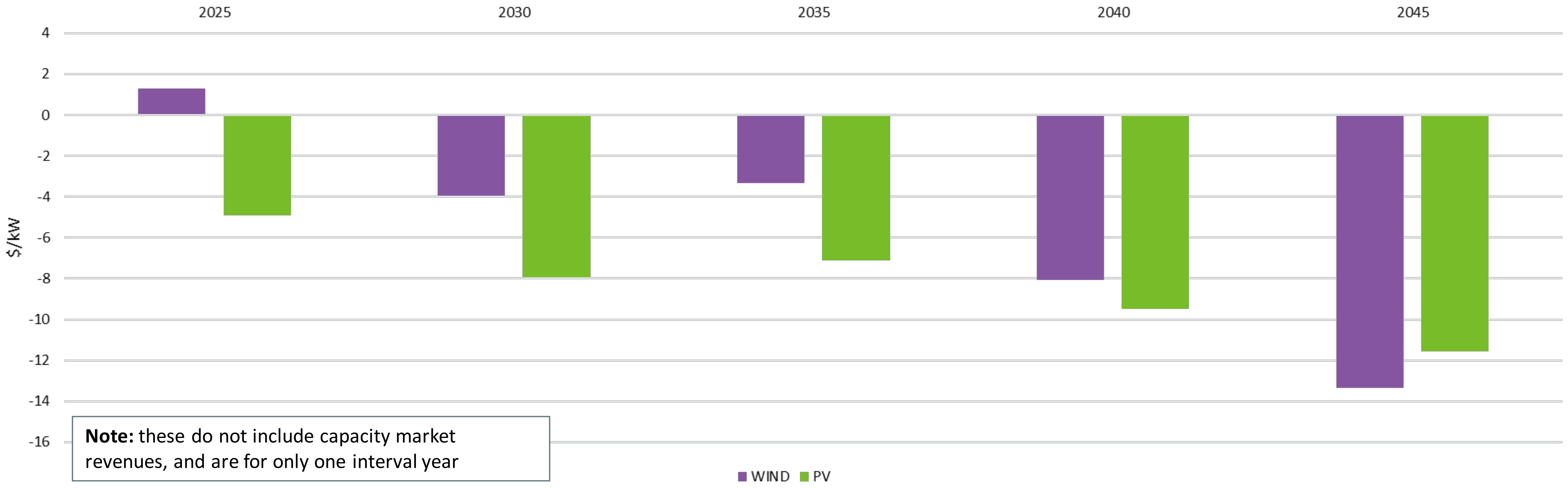
- Resource adequacy takeaways are similar to the PPA only scenario due to similar buildouts
- Approximately 10,000 MW of dispatchable energy storage was added for resource adequacy. 89% of the peak load still needs to be covered by dispatchable capacity

PPA + RA: LMPs



- Average LMPs are maintained at $41/MWh
- Over time, more hours have negative LMPs, and hours with negative LMPs become more negative due to larger PPA prices
- As a result, the declining number of hours with positive LMPs have higher and higher LMPs

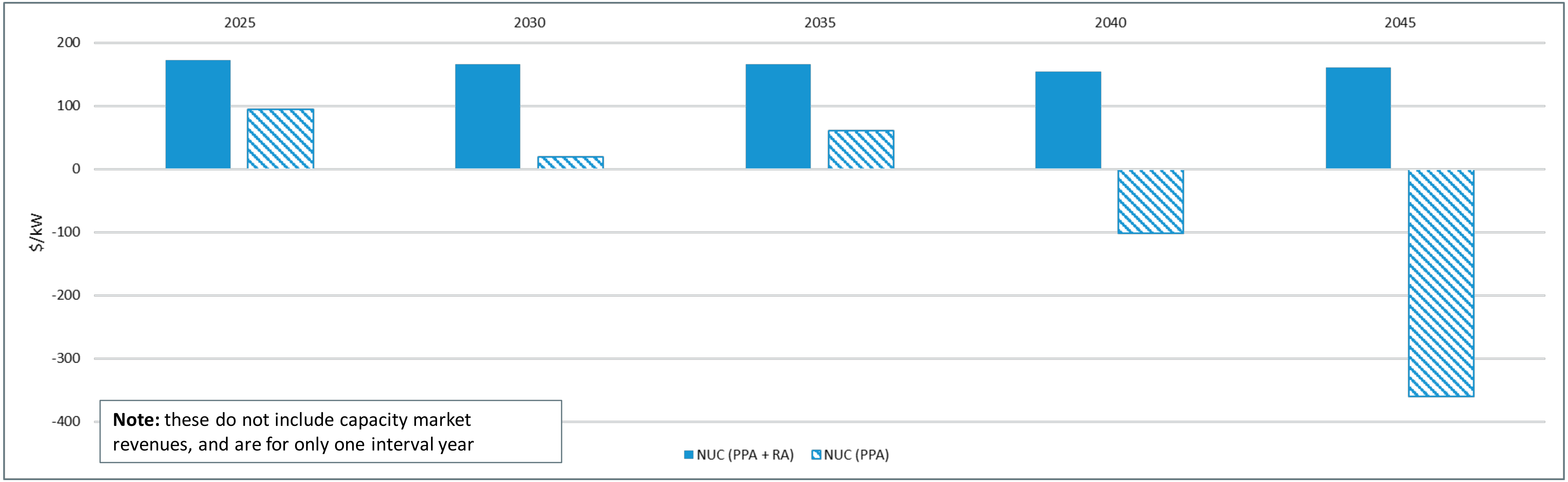
Average Annual Net Profit by Resource Type: Existing PV and Wind Resources



Note: these do not include capacity market revenues, and are for only one interval year

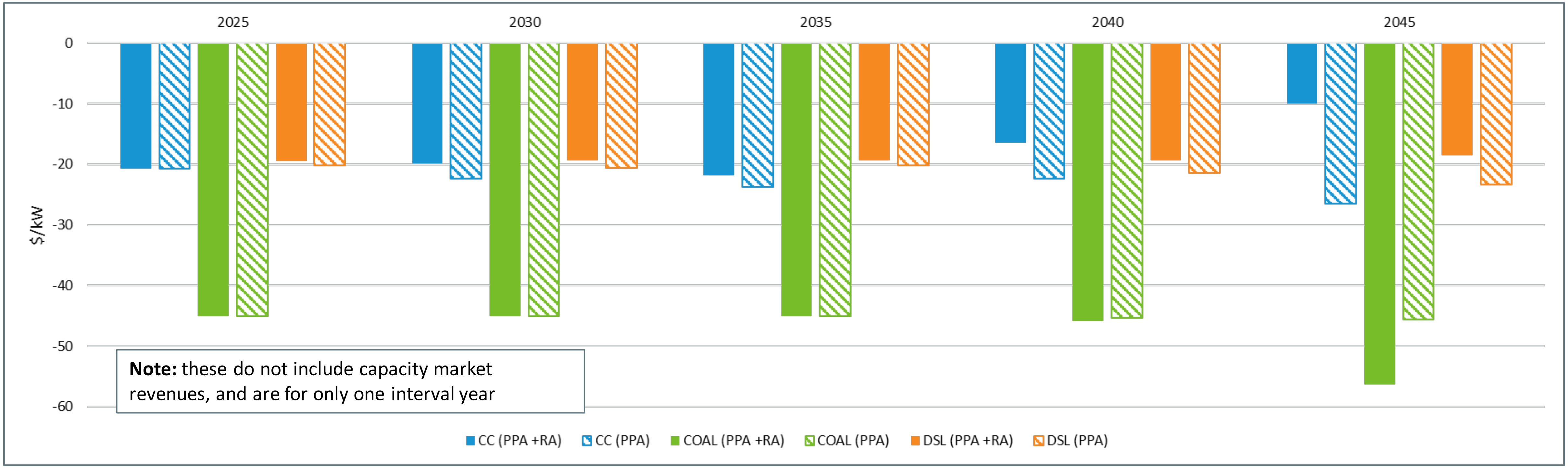
- Profits for existing wind and PV resources still decrease over time as they are underbid by new resources with higher priced PPAs
- The reliability adder has no impact on existing wind and PV resource profits

Average Annual Net Profit by Resource Type: Nuclear Generators



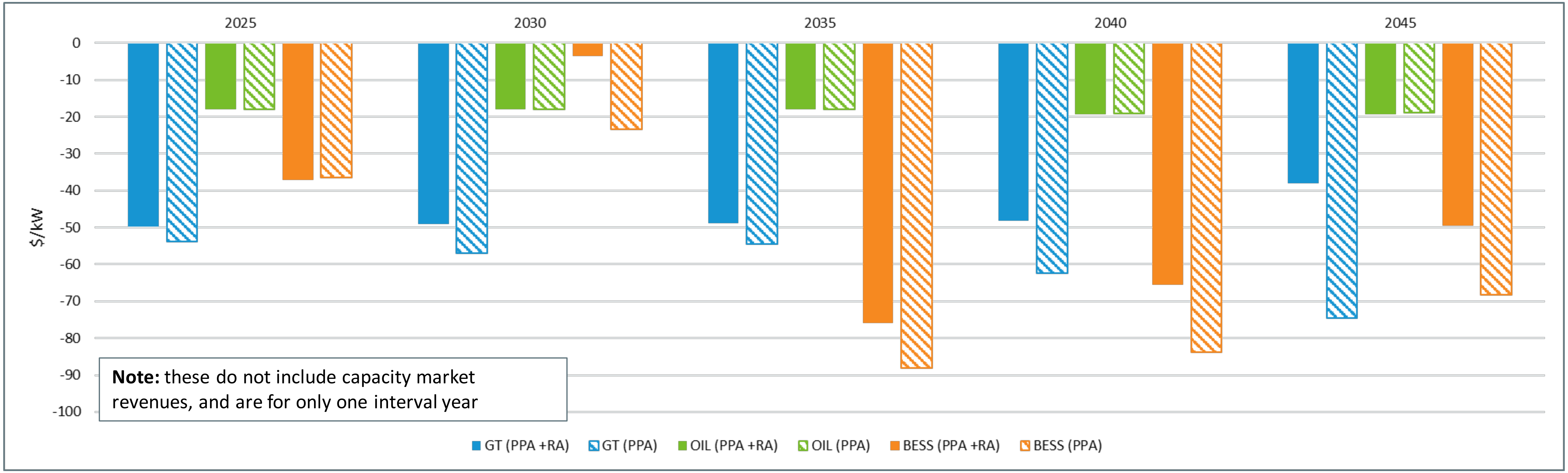
- With every year having a time weighted LMP of $41/MWh in the PPA + RA scenario, the nuclear resource profits are steady. In the PPA only scenario, profits decline over time
  - There are slight variations due to time weighted LMPs being approximately (but not exactly) equal to $41/MWh

Average Annual Net Profit by Resource Type: Dispatchable Resources



- Most dispatchable resources are still operating in the negative, but the majority are earning more revenue than they did in the PPA only scenario
- With a high reliability adder, lower emitting resources (CCs) are in the best position to earn more revenue, while higher emitting resources (coal STs) are earning less revenue

Average Annual Net Profit by Resource Type: Dispatchable Resources, cont.



- The energy market is still saturated with storage, but storage resources are earning more revenue on average under the PPA + RA scenario
  - Energy storage stands to earn more from arbitrage with higher annual average LMPs

POLICY SCENARIO – TOTAL COST RESULTS

Takeaways of PPA vs. PPA + RA Costs

- Specific resource profits can be very assumption driven
  - For example, this model does not have a unique fixed O&M cost for each resource. A generic EIA $/kW value is used for each resource type (which may be very different from the current & future actual fixed costs)
- In earlier years, the additional LSEEE expense from the reliability adder tends to be more expensive than the higher capacity costs in the PPA only scenario
- However, there is a clear trend that most resources will need increasing amounts of non-energy market compensation as energy market revenues shrink. The PPA + RA scenario reduces the amount of non-energy market compensation because more money is kept in the energy market
- The PPA + RA scenario generally does a better job of securing resource revenue adequacy. Providing greater revenues to baseload resources may reduce the likelihood of retirement

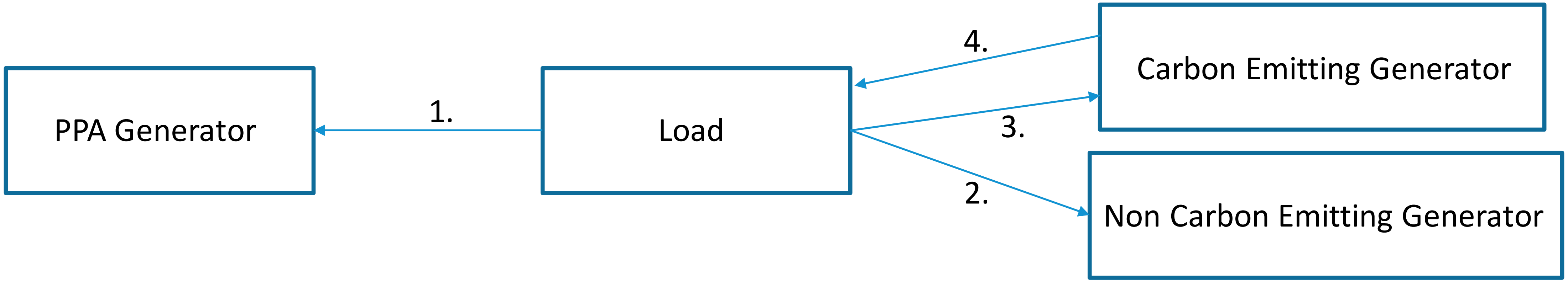
Policy Scenario Total Cost Overview

- *Results are highly driven by assumptions. None of these values are certain, and are meant to only provide directional results*
- Total costs to load are broken down into three categories:
  - Load serving entity energy expense (LSEEE): sum of hourly (positive) LMP ($/MWh) x Load (MWh)
  - PPA costs: for each resource with a PPA, sum of generated MWh x PPA price ($/MWh)
  - Capacity costs: most negative profit ($/kW) x (peak renewable reduction + firm capacity requirement) (MW)
    - Example: 2040 has a 43,031 MW peak load reduced down to a 35,784 MW net load. Peak renewable reduction = 43,031 – 35,784 = 7,247 MW. Firm capacity requirement = 1.1 x 35,784 = 39,362 MW. Total MW for capacity cost calculation = 7,247 + 39,362 = 46,609 MW
  - There are also rebates associated with the reliability adder
- This analysis was done with an unconstrained transmission model. Transmission/distribution upgrades and their associated costs are excluded from this cost analysis. There will be additional cost when those are considered
- The modeled scenarios include reserve requirements (120% of largest contingency as 10 minute, 50% second largest contingency as 30 minute). With energy storage being allowed to provide reserves and a lack of retirements of fast start resources, reserve requirement violations are infrequent and total reserve revenue is small
  - It is important to note that this model has perfect dispatch foresight and does not model the intricacies of DA vs. RT dynamics or outages. There is the potential for DA vs. RT uncertainty to create more revenue opportunities for flexible resources that is not captured here

Discussion of Nuclear Profits in the PPA Scenario

- When estimating capacity prices, the ISO has made an assumption that negative $/kW profits will roughly correspond with a resource's capacity bid
- As resources start to be added for resource adequacy, the capacity price is equal to the new energy storage resources coming online
- However, in the PPA scenario, nuclear net profits are so low in 2040/2045 that their capacity bid would be higher than the bid of an equivalent amount of new energy storage capacity coming online
- What would likely happen would be nuclear retirement and replacement with dispatchable energy storage. However, because the 2045 system is still rapidly adding new resources for resource adequacy and the removal of all nuclear resources would have significant resource adequacy impacts, it is assumed here that the nuclear resources remain and the market clears at the high nuclear capacity bid

Discussion of RA Rebates – Money Flow Example



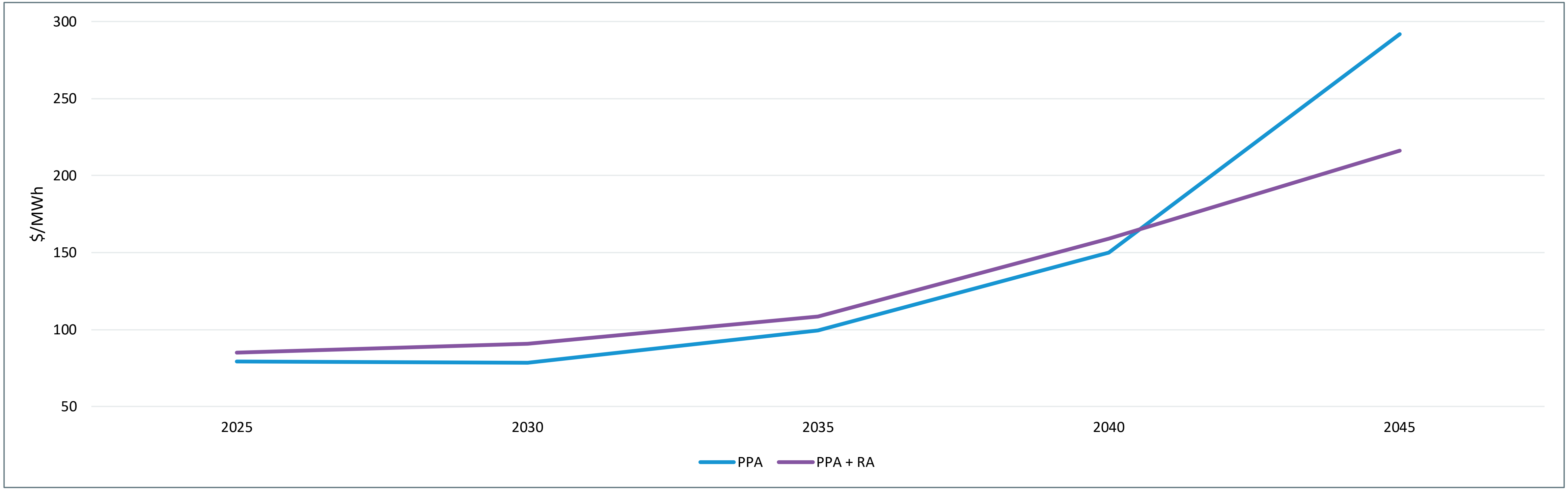
- Under the PPA + RA framework, emitting generators must purchase allowances. As a result of the adder, their bids (and LMPs) are larger, driving up LSEEE costs
- However, the original purchase of allowances are rebated back to load
- The above diagram visualizes the flow of money
  – 1. Load pays the PPA generator at the PPA price when LMPs are positive. When LMPs are negative, the generator is paid the difference between the LMP and the negative of the PPA price
  – 2. Load pays the non-carbon emitting generator at the LMP
  – 3. Load pays the carbon emitting generator at the LMP
  – 4. However, there is an RA rebated from the emitting generator back to the load

PPA vs. PPA + RA Capacity Costs ($/kW-month)

	2025	2030	2035	2040	2045
PPA + RA	6.53	6.30	7.83	7.30	6.13
PPA	6.61	6.66	7.84	8.68	30.15

- The PPA + RA mechanism will keep capacity prices slightly lower due to most resources making more money in the energy market
- Under the PPA only scenario, capacity prices may need to increase further to support continued operation of certain baseload resources

PPA vs. PPA + RA Costs ($/Zero Carbon MWh)



- The presence of the RA in the capacity expansion phase encourages the model to build more zero carbon generation. This leads to lower carbon emissions but somewhat higher costs
- The PPA + RA scenario exhibits slightly higher costs until the last block. However, the PPA + RA scenario guarantees nuclear revenue sufficiency without needing large capacity payments, which ultimately drives the PPA only cost spike in 2045

PPA vs. PPA + RA Costs (Million $)

	PPA				PPA + RA				
	LSEEE	PPA	Capacity	**Total**	LSEEE	PPA	Capacity	Rebates	**Total**
2025	3,264	846	2,227	**6,337**	4,208	849	2,200	-454	**6,803**
2030	2,616	1,933	2,394	**6,944**	4,350	2,045	2,265	-608	**8,052**
2035	3,578	3,062	3,421	**10,061**	4,957	3,222	3,426	-662	**10,944**
2040	3,004	11,763	4,853	**19,620**	6,443	11,448	4,086	-1,221	**20,756**
2045	2,267	22,485	19,856	**44,609**	9,770	21,365	4,037	-2,230	**32,942**

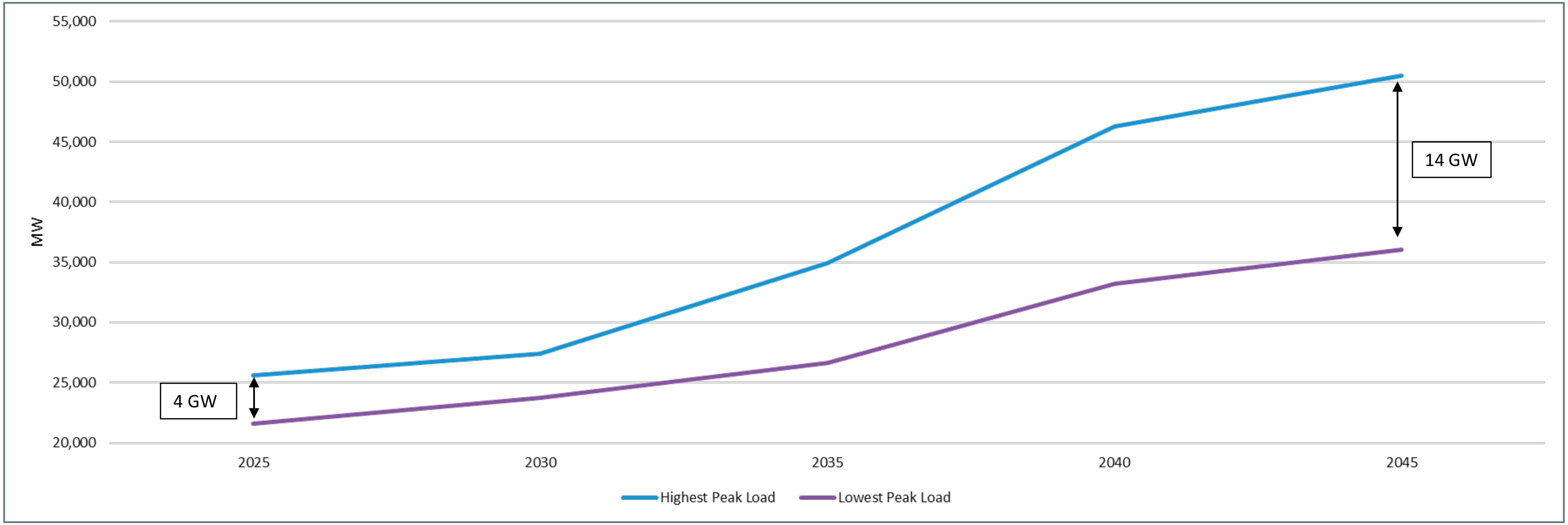
- Both scenarios have significant cost escalation from large PPA payments. The reliability adder does nothing to directly reduce this because PPA resources are being compensated outside of the energy market
- The PPA + RA scenario has large energy market payments. Though a significant amount of these payments are rebated back to load, the energy market still stays smaller in the PPA only scenario
- Capacity payments are larger in the PPA only scenario, as resources unable to make money in the energy market or from PPAs must make money elsewhere. This is escalated in 2045 as nuclear revenues are very negative

POLICY SCENARIO – THE IMPACT OF WEATHER ON A RELIABILITY ADDER

Overview of Weather Year Uncertainty

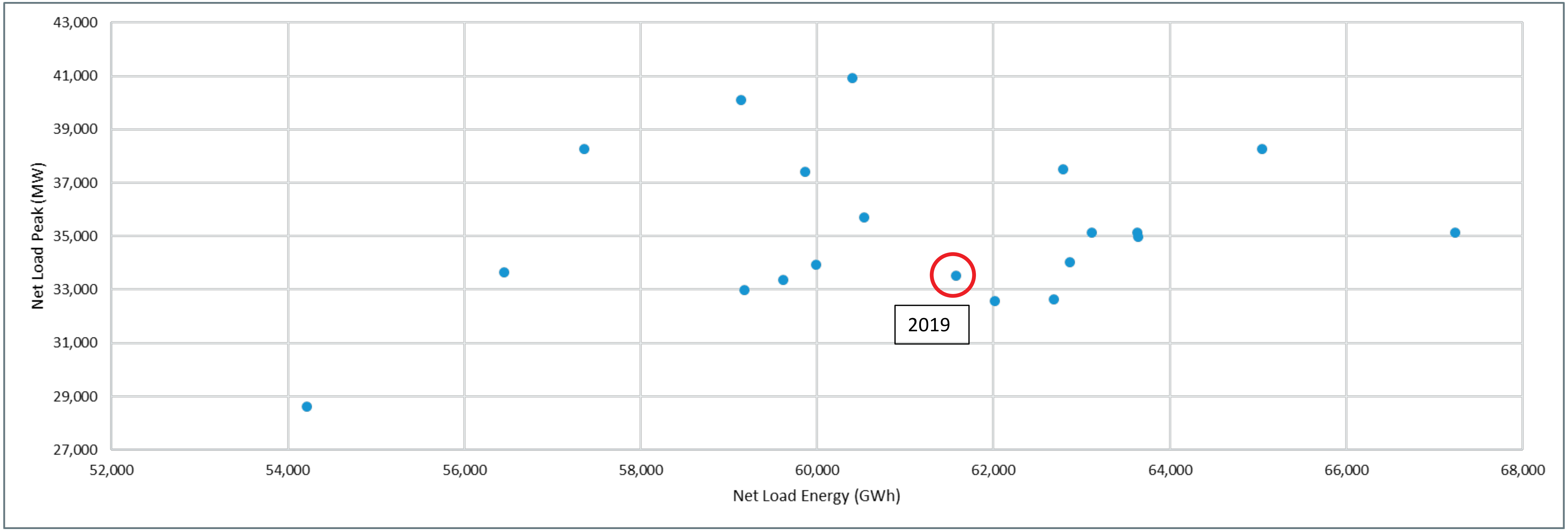
- As electrification loads increase and renewable energy penetration increases, both supply and demand will become increasingly sensitive to weather
- This has a significant impact on energy demand from resources besides wind and solar. Between different weather years, the peak energy demand and variability in net load will drive revenue adequacy
- Resource adequacy constraints have been implemented to ensure that sufficient dispatchable resources are included to cover the peak net load of multiple weather years
- However, the planned RA price shown so far was calculated for a single weather year (2019). In alternate weather years, the RA price may be more than needed or not enough to ensure revenue adequacy
- It is impossible to know with much accuracy what weather patterns may be more than a few days in advance. Extreme uncertainty regarding weather patterns will have significant impacts on revenue adequacy

Peak Load Distributions



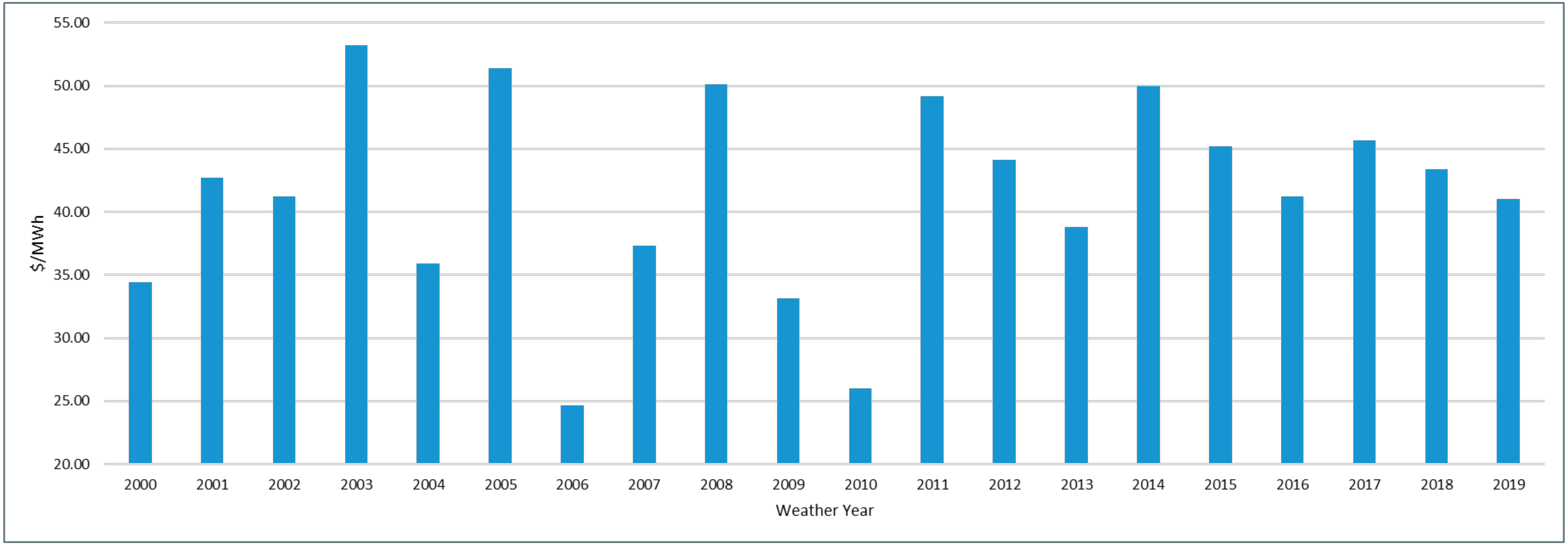
- Note: These loads are gross load after EE – BTM PV
- The possible range of peak loads is expected to increase over time. As loads become increasingly sensitive to weather and temperature, the difference between a mild winter and a cold winter will have significantly more impact in 2045 than in 2025
  - In 2025, the gap between the maximum and minimum peak load weather years is 4 GW. In 2045, this gap is 14 GW
- This has implications for resource and revenue adequacy. The system will be built for resource adequacy for the worst case weather year, but a mild weather year may have many resources sitting unused which still must be compensated

2045 Net Load Peak & Energy (After Wind + PV)



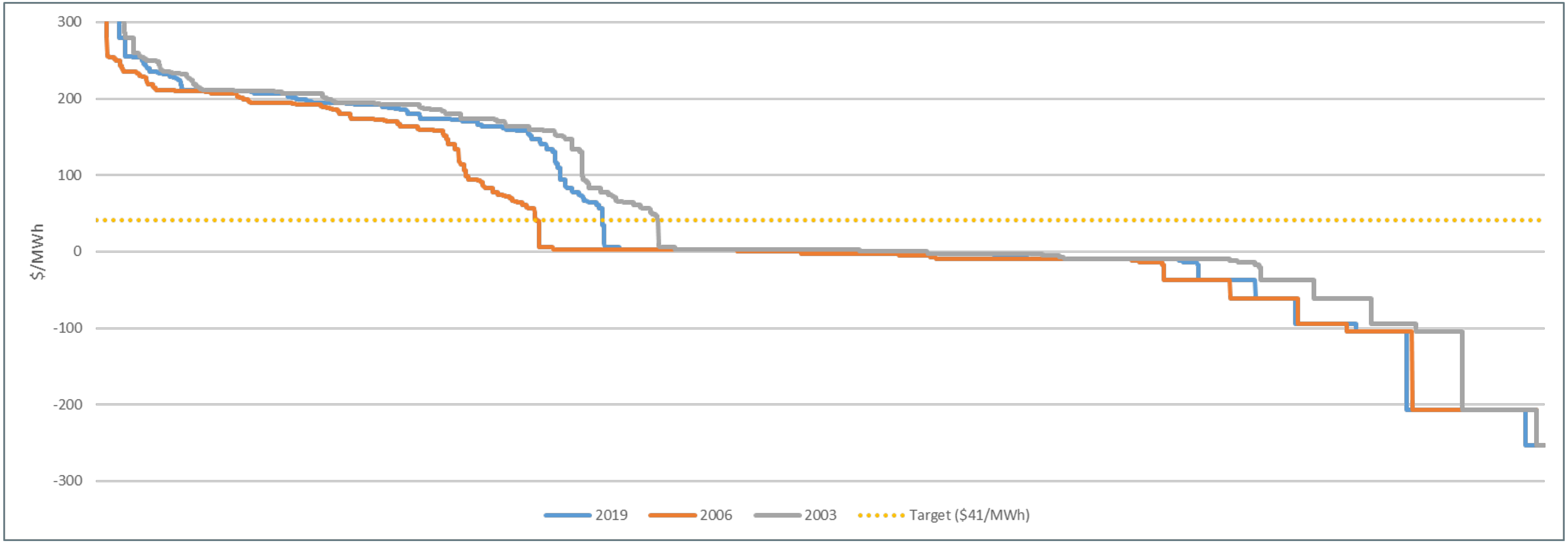
- Note: these loads are gross – EE – all PV – all wind (the amount of load which needs to be met by dispatchable capacity)
- The graph above shows the possible variation in net peak load and energy between weather years. This is the peak load and energy that must be met by dispatchable resources
- The 2019 weather year (which was used for PPA and RA calculations) is a relatively average year. A year with higher or lower demands for dispatchable generation will have different revenue adequacy outcomes with the calculated prices

2045 Multiple Weather Year Time-Weighted LMPs



- These average LMPs are from a 2045 system with the PPA + RA buildout, PPA prices, and RA prices. Depending on the weather year, time-weighted LMPs can be far above or below the target of $41/MWh
  - Time-weighted LMPs vary between $24/MWh with the 2006 weather year and $53/MWh with the 2003 weather year

2045 LMPs for 2019, 2006, and 2003 Weather Years



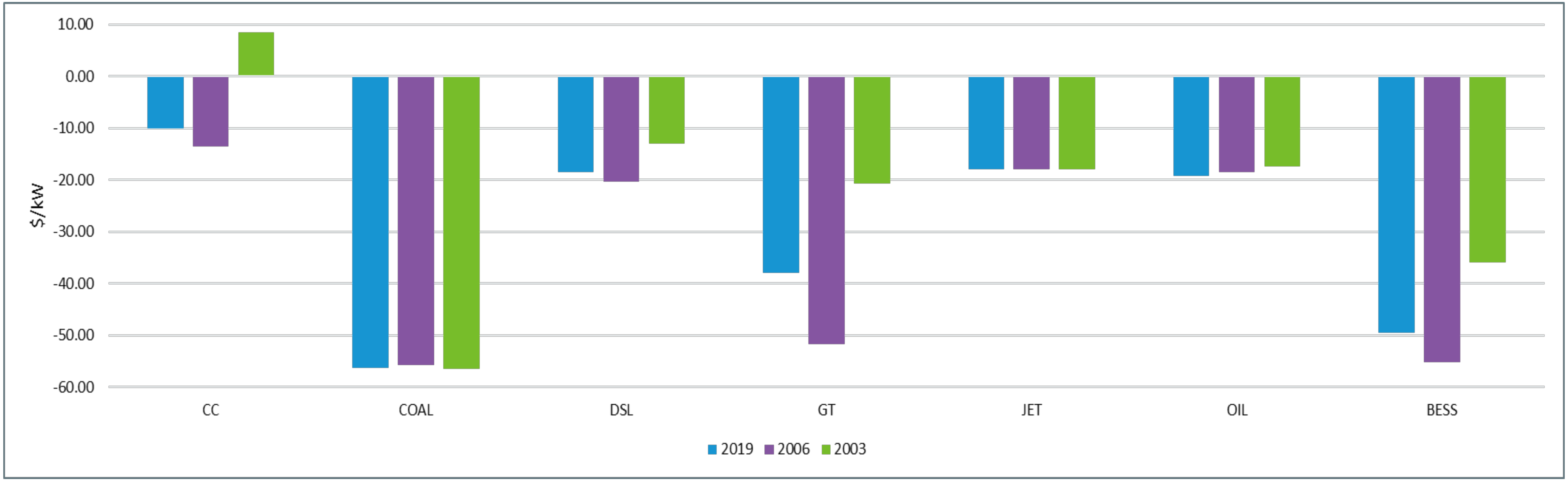
- A year with more need for dispatchable resources (2003) will have higher time-weighted LMPs, while a year with a lower need for dispatchable resources (2006) will have lower time weighted LMPs
  - The 2003 weather year had 17 TWh of generation from emitting resources (6.9 million tons of carbon emissions) while the 2006 weather year had 10 TWh (4.3 million tons of carbon emissions)

2045 Average Capacity Factors for 2019, 2006, and 2003 Weather Years

	CC	COAL	DSL	GT	OIL	WIND	PV	New PV	New LBW	New OSW
2019	9.45	0.26	2.06	4.75	0.10	23.21	7.60	13.52	32.83	47.57
2006	7.52	0.17	2.00	4.56	0.02	20.95	7.83	13.12	32.55	48.88
2003	10.87	0.32	2.18	5.46	0.38	23.81	9.21	12.66	32.94	50.04

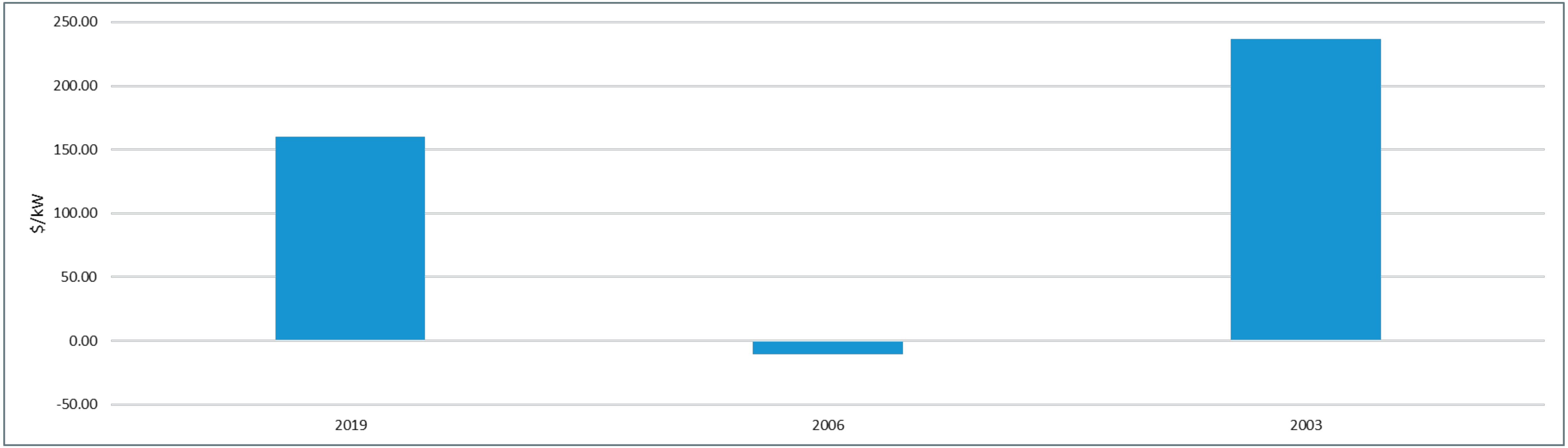
- Some years are slightly sunnier/windier than others. Newer clean energy resources always have larger capacity factors as they can underbid existing resources
- Capacity factors of dispatchable resources differ year to year depending on the hourly net load

2045 Multiple Weather Year Dispatchable Net Profits



- Higher LMPs (2003 weather year) mean that most dispatchable resources are earning more revenue. Lower LMPs (2006 weather year) mean that most dispatchable resources are earning less revenue

2045 Multiple Weather Year Nuclear Net Profits



- While the calculated reliability adder guaranteed constant nuclear profit for the 2019 weather year, it was likely too low for the 2006 weather year and too high for the 2003 weather year

2045 Multiple Weather Year Costs (Million $)

	LSEEE	PPA	Capacity	Rebates	Total
2019	9,770	21,365	4,037	-2,230	**32,942**
2006	7,247	20,947	5,304	-1,700	**31,798**
2003	10,484	21,513	3,359	-2,634	**32,722**

- Total costs did not change significantly between bookend weather years, but the allocation of costs did change somewhat:
  - Weather years with *less* need for dispatchable generation had *more* money in the capacity market and *less* money in the energy market
  - Weather years with *more* need for dispatchable generation had *less* money in the capacity market and *more* money in the energy market
- The region will not know ahead of time how much dispatchable generation will be needed. Capacity bids may reflect this uncertainty

2045 Multiple Weather Year Discussion

- For a resource adequate and revenue adequate system, the New England region may have to build and maintain a large fleet of dispatchable resources which may only run occasionally
  - To ensure resource adequacy, the region will have to plan for the year with the highest need for dispatchable resources
  - To ensure revenue adequacy, the region will have to plan for the year with the lowest need for dispatchable resources
- The hours with the most need for dispatchable resources will likely be in harsh winter conditions which may not be suitable for demand response
- For a forward compensatory market, there will be extreme uncertainty year to year surrounding how often dispatchable resources will be needed

Policy Scenario Takeaways

- In the PPA only scenario, nuclear resources experience declining revenues which could decrease their financial viability. Assuming that their missing money will be made up in the capacity market will lead to an increase in capacity prices
- The PPA + RA scenario prevents larger capacity payments by enabling most resources to continue making money in the energy market. However, this also results in higher energy market costs
  - The RA does nothing to reduce PPA payments, which becomes one of the larger costs to the region in the later years
- Both PPA prices and RA prices escalate as the region decarbonizes. If there are fewer and fewer hours with carbon emissions to decarbonize, the marginal cost of abatement / new zero carbon energy will rise
- Uncertainty surrounding how often dispatchable resources will actually be needed may lead to a need for higher capacity payments. The region may end up paying for a pool of resources which are only needed once every few years
- Despite significant addition of intermittent resources, most of the expected peak load (~90%) will need to be covered by dispatchable resources. Significant amounts of dispatchable resources were added starting in the 2030s, and any resources retired in the short term may have to be replaced in the future

Policy Scenario Analysis Limitations

- Both scenarios see significant amounts of negative LMPs. New load-side resources could find a way to benefit from utilizing excess renewable energy at low/negative LMPs
- Significant development of demand response resources could help alleviate the uncertainty surrounding multiple weather years. However, it may prove difficult to curtail some load (such as heating, cooling, or transportation) during periods of extreme weather
- The resource adequacy process is making a significant simplification by assuming all dispatchable resources are equal. If energy storage is being added for dispatchable capacity, either larger amounts or longer duration storage may be needed for adequacy
- No fuel constraints were modeled due to uncertainty regarding what the future of the gas pipeline and LNG facilities will be. However, if constraints continued to exist in some form:
  - Average LMPs would likely be higher due to expensive stored fuel generation running more frequently
  - Additional resources would likely be needed for winter peaking resource adequacy

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	OSW	Offshore Wind
LBW	Land Based Wind	O&M	Operation and Maintenance
LFG	Landfill Gas	PHII	Phase II line between Radisson and Sandy Pond
LFR	Load Following Reserve	PV	Photovoltaic
LMP	Locational Marginal Price	RECs	Renewable Energy Credits
LSEEE	Load-Serving Entity Energy Expenses	RFP	Request for Proposals
MSW	Municipal Solid Waste	RGGI	Regional Greenhouse Gas Initiative
NECEC	New England Clean Energy Connect	RPS	Renewables Portfolio Standards
NESCOE	New England States Committee on Electricity	SCC	Seasonal Claimed Capability
NG	Natural Gas	Uncstr.	Unconstrained
NICR	Net Installed Capacity Requirement	VER	Variable Energy Resource
NREL	National Renewable Energy Laboratory		

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.)