NEPOOL
NEW ENGLAND POWER POOL

Sebastian Lombardi
Assistant Secretary

November 29, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of December 6, 2021 NEPOOL Participants Committee Pathways Study Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the December Pathways Study meeting will be held **via teleconference on *Monday*, December 6, 2021, at 9:30 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, is **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

For your information, the December 6 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

Respectfully yours,

/s/

Sebastian Lombardi, Assistant Secretary

FINAL AGENDA

NEPOOL Participants Committee
Virtual Pathways Study Meeting
December 6, 2021
Start time: 9:30 a.m.

To participate in the special Participants Committee Teleconference,
please dial 1-866-803-2146; Passcode 7169224.
To join the WebEx, click this link and enter the event password **nepool**.

The agenda items for the December 6 virtual meeting are as follows:

1. To approve the draft minutes of the October 25, 2021 Participants Committee "Pathways Study" meeting. The draft preliminary minutes of that meeting are included with this supplemental notice and posted with the meeting materials.

2. Analysis Group to provide updated results for the central cases from the Pathways analyses and preliminary results for a number of scenarios. In addition, the ISO will discuss its proposed Pathways Study project schedule for 2022 (*see* ISO's proposed project schedule included with this supplemental notice). Analysis Group's presentation materials will be circulated under separate cover when received.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 9:30 a.m. on Monday, October 25, 2021. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Acting Secretary, recorded.

APPROVAL OF SEPTEMBER 23, 2021 PATHWAYS STUDY MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the September 23, 2021 Pathways Study meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the Committee unanimously approved those minutes, with an abstention noted on behalf of Michael Kuser by his alternate.

ANALYSIS GROUP (AGI) PRESENTATION

Mr. Cavanaugh then introduced Mr. Todd Schatzki of AGI who reviewed materials circulated and posted in advance of the meeting. Mr. Schatzki informed the Committee that the purpose of the day's presentation was to provide preliminary results and findings of the quantitative analyses of the four alternative Pathways to decarbonizing the New England grid (i.e., Status Quo, Forward Clean Energy Market (FCEM), Net Carbon Pricing (NCP), and Hybrid approaches). He indicated that the preliminary set of results for the core central cases would be presented during the meeting.

Mr. Schatzki then provided an overview of the key preliminary modeling results. He noted that market prices and resulting incentives varied widely across the alternative approaches and thus had important consequences for expected market outcomes. He provided the following examples: (i) storage resource build out and utilization varies depending on energy market incentives created for non-carbon-emitting generation; (ii) the extent of available renewable energy that does not clear energy market ("economic curtailments") varies given market incentives for storage; and (iii) efficiency (and resulting carbon-intensity) of fossil (gas-fired) resources reflects incentives for clean energy versus carbon reduction. He then indicated that the NCP approach produced the lowest production costs, with similar but somewhat higher costs for the FCEM and Hybrid approaches. He further stated that the Status Quo approach led to notably higher costs, reflecting multiple factors including the absence of market incentives for clean energy/decarbonization and higher curtailment of renewable resources. AGI's modeling assumed clean energy resource mixes reflecting state decarbonization "roadmaps" and plans.

Mr. Schatzki then provided a summary overview of AGI's pathways modeling effort, and a recap of the central case assumptions. He reminded the Committee that the focus was on the comparison of the implications of the following four alternative regulatory approaches/pathways on economic outcomes, including the incentives for decarbonization: (i) Status Quo – continued reliance on state-authorized procurements of multi-year contracts for renewable energy from new resources; (ii) FCEM – a market for clean energy, where "clean energy" is assumed to include electricity generated from nuclear, renewables, hydropower and biomass (but not storage); NCP – carbon pricing with generator payments for carbon emitted credited to load; and (iv) Hybrid approach – combination of carbon pricing to cover existing clean energy "missing money" plus a forward clean energy market for not-yet-in-service resources. Recapping key central case assumptions, Mr. Schatzki indicated that such assumptions were held constant across all four policy approaches studied, over a 2020 to 2040 time period, and included an ISO New England system-only geographic scope (with assumed imports) and a decarbonization target of 80% reduction in carbon emissions by 2040 compared to 1990 levels. He also clarified that no Minimum Offer Price Rule (MOPR) was assumed for the central case modeling. Regarding assumed loads for the central case, Mr. Schatzki noted that a high load would be assumed to reflect the electrification of transportation and heating sectors (consistent with Scenario 3 of NEPOOL's Future Grid Reliability Study (FGRS)). He indicated that, over the course of the study, the System would shift from a summer peaking system to a winter peaking system to address how resources are affected. He explained that the system resource mix would include existing and new resources, would follow baseline state clean energy policies, and include incremental resources. In response to a question about state policies as they relate to the role of storage under the Status Quo approach, Mr. Schatzki agreed that state policies would evolve and change and would be accounted for in the model accordingly.

Turning to the preliminary quantitative modelling results, Mr. Schatzki began by reviewing a graph which outlined the resource mix required over the course of the model. He then reviewed carbon emissions throughout the model, noting that, as of 2033, additional clean energy resources would be required to achieve the emissions target(s). In response to a question about carbon emissions constraints and potential resource adequacy implications, he noted that resource adequacy was not fully met with renewables causing a need for some existing dispatched resources. He further explained the resource mix within the central case, and indicated that the model was intended to be a forecast and that factors may change over time.

Mr. Schatzki then proceeded to review resource additions within the central case, with the first decade largely reflecting baseline-assumed state policies, and the second decade reflecting resources needed to meet both resource adequacy and clean energy requirements, including incremental additions of new renewable and dispatchable resources. He further explained that the energy mix that emerged from the central case reflected an evolving resource mix, which included increased supply of renewables, reduced utilization of fossil resources, increased use of batteries, and continued utilization of nuclear resources and imports.

Turning to the differences in resource mix and utilization within the central case results, Mr. Schatzki indicated that policy and economic outcomes reflected the mix of resources arising under each approach and the use of resources given market incentives. He noted that the policy approaches differed in terms of the resources that emerge and their use, reflecting a combination of factors and interactions. He then explained the incentives across the different approaches and how they would likely affect energy market prices and create differences in incentives. He also discussed in greater detail the widely varying distribution of prices (levels, variation and range) across the four alternative approaches. When asked about where renewable energy credits (RECs) were represented in the Status Quo approach, Mr. Schatzki indicated that the current resources backed by state-sponsored power purchase agreements (PPAs) include RECs belonging to states and that, to his knowledge, were generally structured to avoid negative pricing. He also noted that negative pricing would incent storage to charge and then discharge in smaller quantities due to energy losses.

Next, Mr. Schatzki shared preliminary analysis of costs and payments through a comparison of outcomes under the four alternative pathways, but noted that AGI's analysis of payments remained on-going and further results would be presented at the December 6 Pathways Study meeting. He noted that important differences in prices, costs and payments emerge because of a combination of factors affecting quantity, type and utilization of resources under each policy approach.

Mr. Schatzki then provided a brief overview/update on AGI's on-going analyses of the proposed set of scenarios, remarking that the assumptions for these alternative scenarios are different from those in the central case. He shared with the Committee the list of scenarios, noting that the list reflected AGI's current thinking, as supplemented by stakeholder discussion and feedback submitted to date.

Addressing next steps, Mr. Schatzki indicated that updates to central cases, if any, based on stakeholder feedback and on-going research/analysis, would be presented at the December 6 meeting along with the initial set of scenario results.

There being no further business, the meeting adjourned at 12:48 p.m.

Respectfully submitted,

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Sebastian Lombardi, Acting Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE OCTOBER 25, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard		
American Petroleum Institute	Fuels Industry Participant	Paul Powers		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small RG Group Member	AR-RG	Erik Abend		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts	End User			Doug Hurley
AVANGRID: CMP/UI	Transmission		Jason Rauch	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing LP	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission			Parker Littlehale
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati	
Generation Group Member	Generation		Abby Krich	Alex Worsley
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Harvard Dedicated Energy Limited	End User			Doug Hurley
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guibault	Bob Stein	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC	AR-RG		Nancy Chafetz	
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate Officer	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE OCTOBER 25, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew	Ben Griffiths	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
New England Power Generators Association (NEPGA)	Fuels Industry Participant	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian Forshaw; Dave Cavanaugh
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User			Doug Hurley
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Energy Investment Corporation	AR-LR		Doug Hurley	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas and Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	

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DECEMBER 6, 2021 | NEPOOL PARTICIPANTS COMMITTEE WORKING SESSION

Pathways to the Future Grid

Proposed project schedule for 2022

Chris Geissler

CGEISSLER@ISO-NE.COM

Proposed Pathways Stakeholder Schedule for 2022

Key Date	Deadline or Meeting
January 5th	Stakeholders to provide written feedback on December materials to be considered for draft report presented to stakeholders in February.
February (date TBD)	**Stakeholder meeting**: Analysis Group presents draft report with qualitative and quantitative discussion of the pathways, including central case and scenario results.
Early March (date TBD)	Stakeholders to provide written feedback on February draft report to be considered for final report presented to stakeholders in April.
April (date TBD)	**Stakeholder meeting**: Analysis Group presents final report with qualitative and quantitative discussion of the pathways, including central case and scenario results.

ANALYSIS GROUP

Pathways Study

Evaluation of Pathways to a Future Grid

Todd Schatzki and Chris Llop

December 6, 2021

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Overview

- Purpose of today's presentation is to continue to provide preliminary results of the quantitative analysis of the Pathways Study
  - Pathways Study is evaluating alternative policy approaches to decarbonizing the New England Grid
  - Four approaches: Status Quo (SQ), Forward Clean Energy Market (FCEM), Net Carbon Pricing (NCP), and Hybrid
- We will summarize updates to Central Case results and findings:
  - Overview of changes to approach and results due to a change to modeling inputs based on stakeholder feedback at the prior meeting
  - Additional results on production costs and customer payments
- In addition, we will summarize preliminary results of scenario analysis that tests the sensitivity of the central case results to a change in a key input assumption:
  - More stringent decarbonization target
  - Alternative capital costs
  - Additional retirements
  - Alternative allocation of costs across states

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Summary of Key *Preliminary* Modeling Results

Preliminary findings regarding policy approaches include:

- Approaches vary in the incentives created to achieve decarbonization targets, with differences affecting competitiveness of energy storage and more efficient fossil resources, and, in turn, economic curtailment of variable renewables
- Social cost is lowest with Net Carbon Pricing, slightly higher for the FCEM and Hybrid Approach, and notably higher for the Status Quo
- Customer Payments are similar across all policy approaches, but potentially higher under the Status Quo. Difference in total payment outcomes can arise due to several factors – for example:
  - Some policy approaches pay different amounts for clean energy “services” to different types of resources (e.g., paying nuclear or existing renewables less than new renewables)
  - Some policy approaches depend on assumptions regarding the resource mix
- Preliminary scenario results change magnitude of results, but not the general findings (although our assessment continues as we refine and further review results)

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Agenda

- Central Case
  - Updated results
  - Adjustments due to and responses to stakeholder comments
  - Costs, payments and prices
- *Preliminary* Scenario Results
  - More stringent decarbonization target (forthcoming)
  - Alternative capital costs
  - Additional retirements scenario
  - Alternative allocation of costs across states
- Appendix: Additional central case and scenario results

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Updated Central Case Results

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Updated Central Case Results

- Central case analysis have been updated
  - Primary change is allowing resources with out-of-market PPAs to submit negative priced offers
  - Other minor changes
- Responses to stakeholder questions regarding preliminary results provided in October
  - Interpretations of the hybrid case results
  - Differences in variable costs across cases
  - These will be addressed in the course of discussing the results
- Payments and prices
  - Preliminary results presented in October did not include payments and prices

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Contracted Resources and Negative Price Offers

- Certain resources in the ISO-NE fleet have out-of-market PPA contracts for the purchase of electricity
  - All cases assume certain resource PPAs through baseline state policies
  - The Status Quo case includes incremental PPAs sufficient to achieve decarbonization targets
- Results presented in October assumed that these contracted resources would not offer their energy at a price below $0
- Further review of contracts indicates that contracted resources have an incentive to offer energy at the negative of their PPA price
  - Contracts include a “clawback” provision that reduces compensation under the PPA when LMPs are below zero by an amount equal to the negative of the market clearing LMP
  - For example, if the PPA price is $50/MWh and LMP = -$20/MWh, then the resource earns $30/MWh (i.e.., $50/MWh + (-$20/MWh))
  - In this case, the resource continues to earn positive revenues for energy market offers as low as the negative of its PPA price, when it earns $0 per MWh
  - Because variable renewables have variable costs (approximately) equal to $0/MWh, the updated central cases now assume that they offer energy at the negative of their PPA price (i.e., -$50/MWh in the example above)

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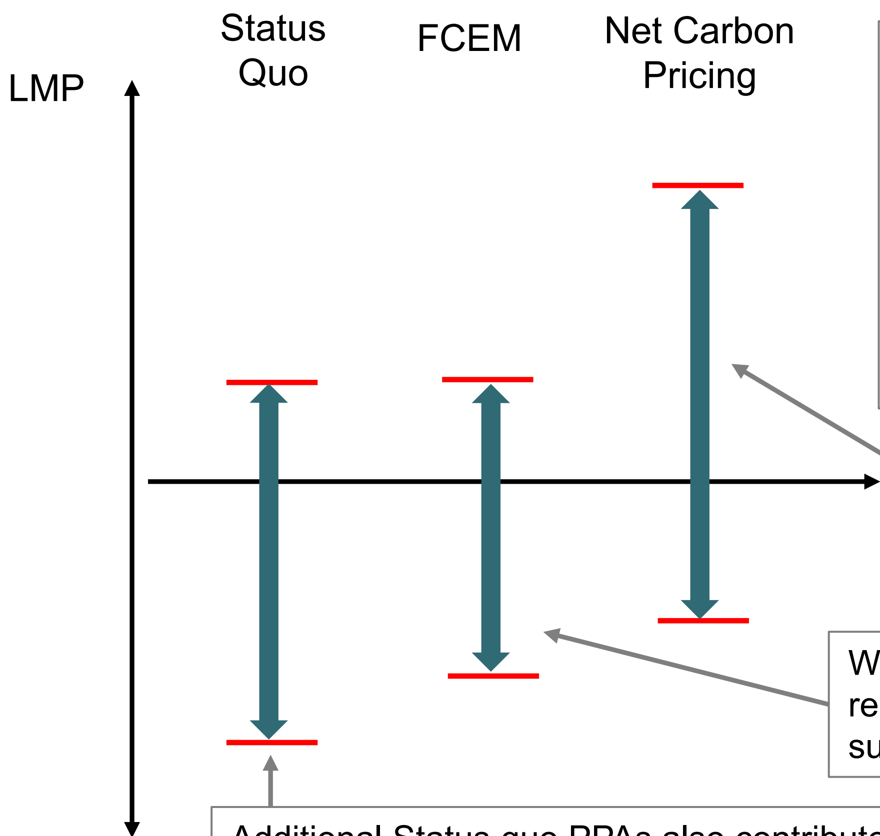
Incentives for Energy Storage Vary with Policy Approach

Energy market spreads vary with offer incentives (*figure illustrative*)



- Storage resource financial viability depends on opportunities arbitrage large LMP price spreads
- Spreads depend on differences in pricing when market clears at higher-price fossil resources and lower-priced renewables
- All approaches include some negative priced energy from baseline state policy renewables with PPAs

With Net Carbon Pricing, carbon price increases LMPs when fossil resources are price-setting because cost of carbon is included in offers

With FCEM, CEC value leads to negative LMPs when renewable resources are price-setting because they submit negative-priced offers to earn CEC subsidy

Additional Status quo PPAs also contributes to negative prices from negative-priced offers from resources with PPAs

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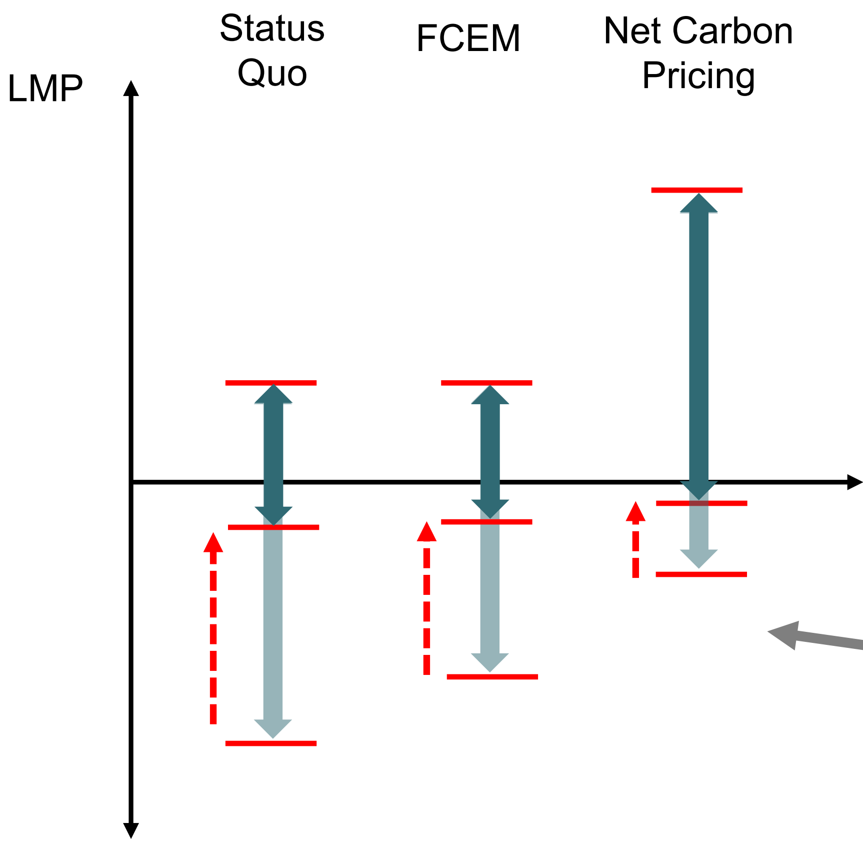
Incentives for Energy Storage Vary with Policy Approach

Negative pricing creates additional incentives for storage



Negative prices provide an opportunity for storage resources to earn money simply by charging and then discharging a smaller quantity due to energy loses:

- With negative prices, storage resource is ***paid*** to charge and ***pays*** to discharge
- Payments received for charging exceed payments made for discharging because a smaller quantity of energy is discharged than charged due to energy losses

Equilibrium negative prices are greater (less negative) due to this storage activity – that is, storage resource tends to reduce the magnitude of negative prices

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Contracted Resources and Negative-Priced Offers

- This assumption affects results for all cases, but especially the Status Quo – compared to results reported in October:
  - Negative LMPs when market clears at renewable resources
  - Larger price spreads in all cases, which increases incentives for energy storage resources
    - Increased battery storage capacity
    - Decreased capacity from fossil resources, as increased battery storage capacity helps meet resource adequacy
  - Lower LMPs lead to an increase in capacity, CEC and carbon prices

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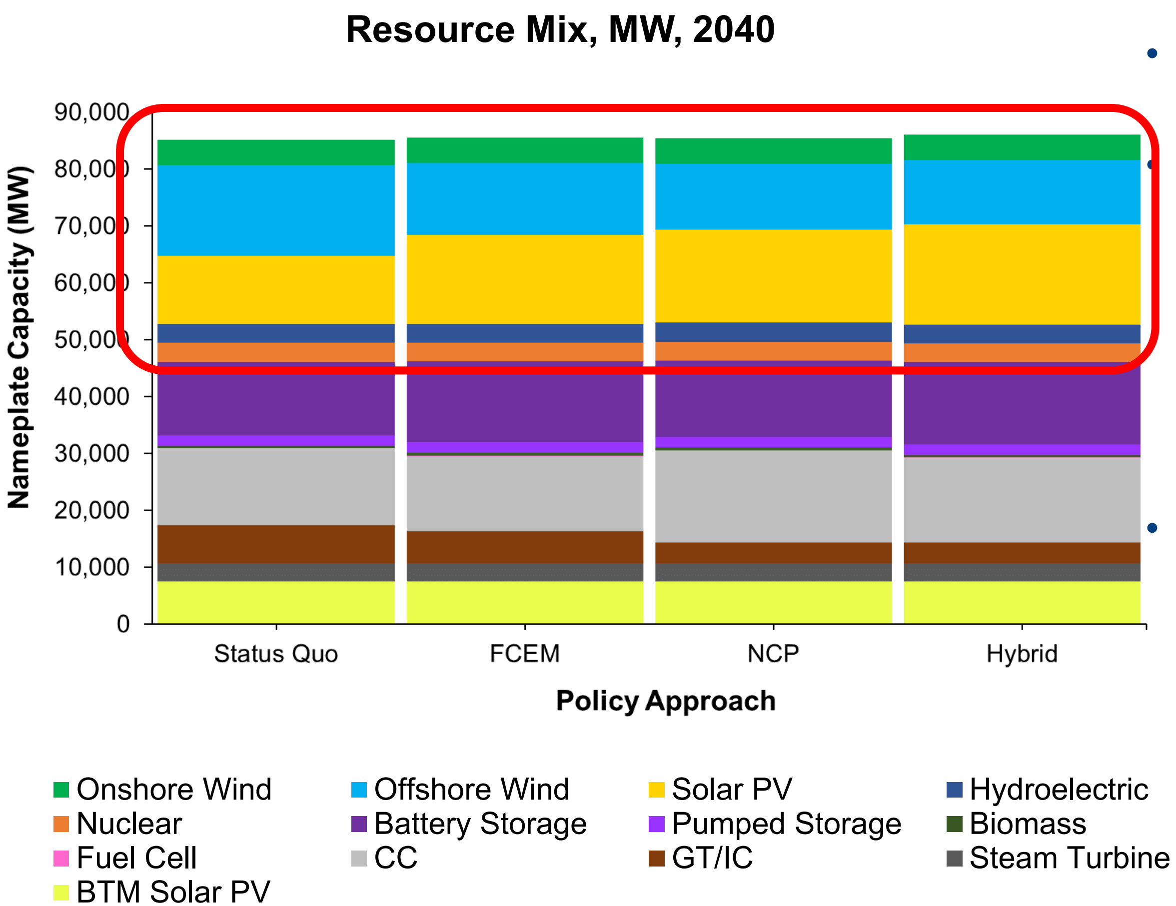
Central Case Results: Capacity Mix by Policy Approach

Policy approach affects renewable resource mix



- Renewable mix varies across approaches
- Balance of offshore wind and solar PV varies across cases – Status Quo has largest share of offshore wind, while Hybrid approach has the lowest share
- Onshore wind equal across cases

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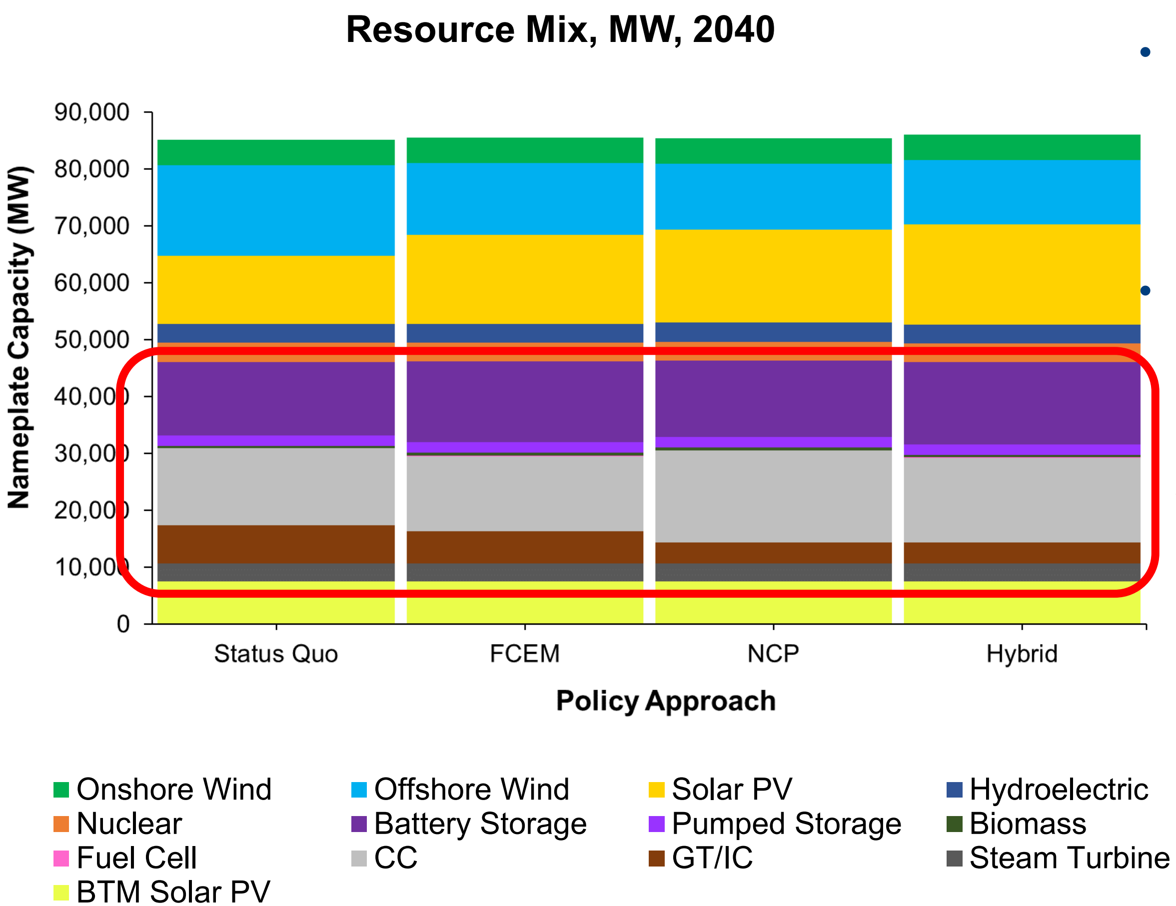
Central Case Results: Resources Mix Changes

Policy approach affects dispatchable resource mix



- SQ battery storage capacity similar across approaches – highest in FCEM, and lowest in Status Quo
- Fossil-fuel mix reflects incentives for fossil fuel efficiency across approaches
  - Hybrid and NCP are sensitive to emissions intensity, thus have more CCs while Status Quo and FCEM have more GT

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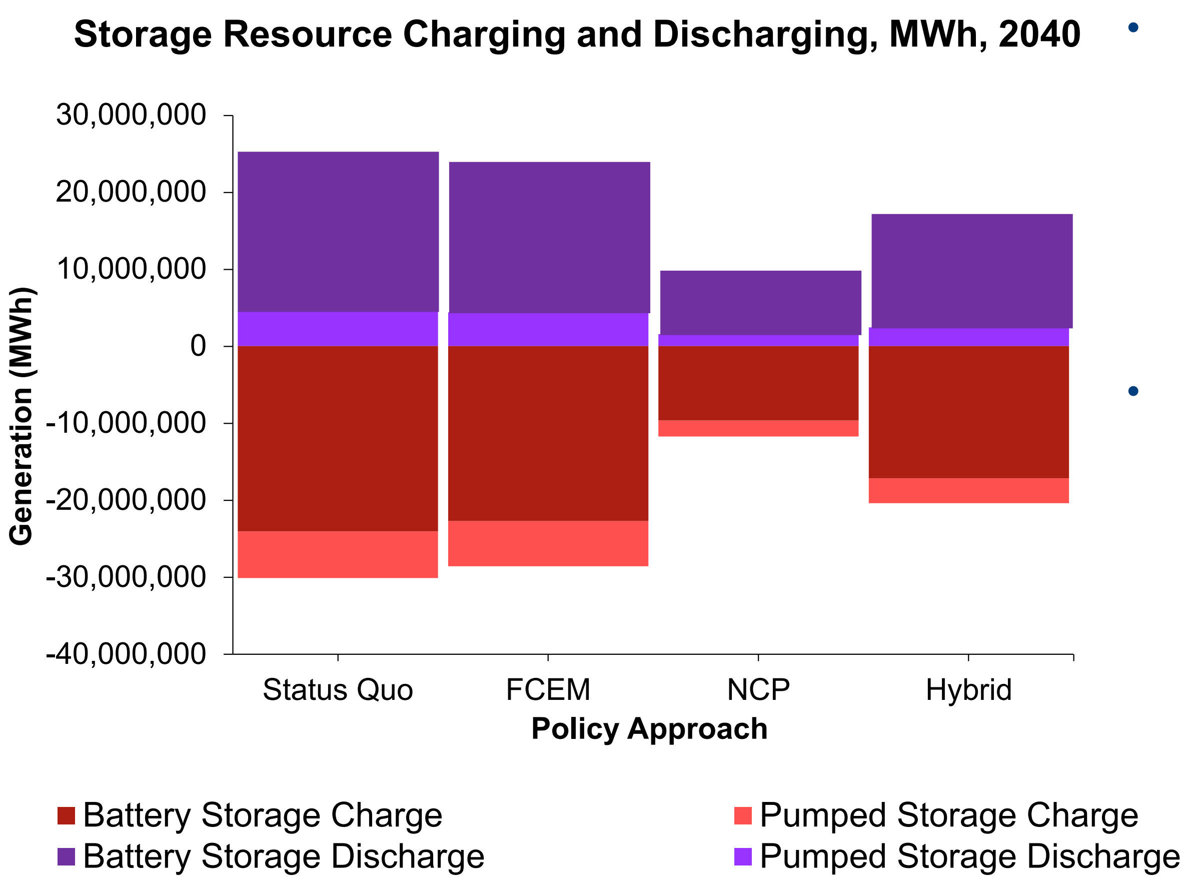
Central Case Results: Storage Charging/Discharging

Market incentives affect opportunities for storage



- Higher frequency of negative pricing with Status Quo and FCEM incents comparatively higher level of storage charging and discharging
- Lower frequency of energy storage utilization in NCP because of fewer hours with negatively charged pricing

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Costs and Prices

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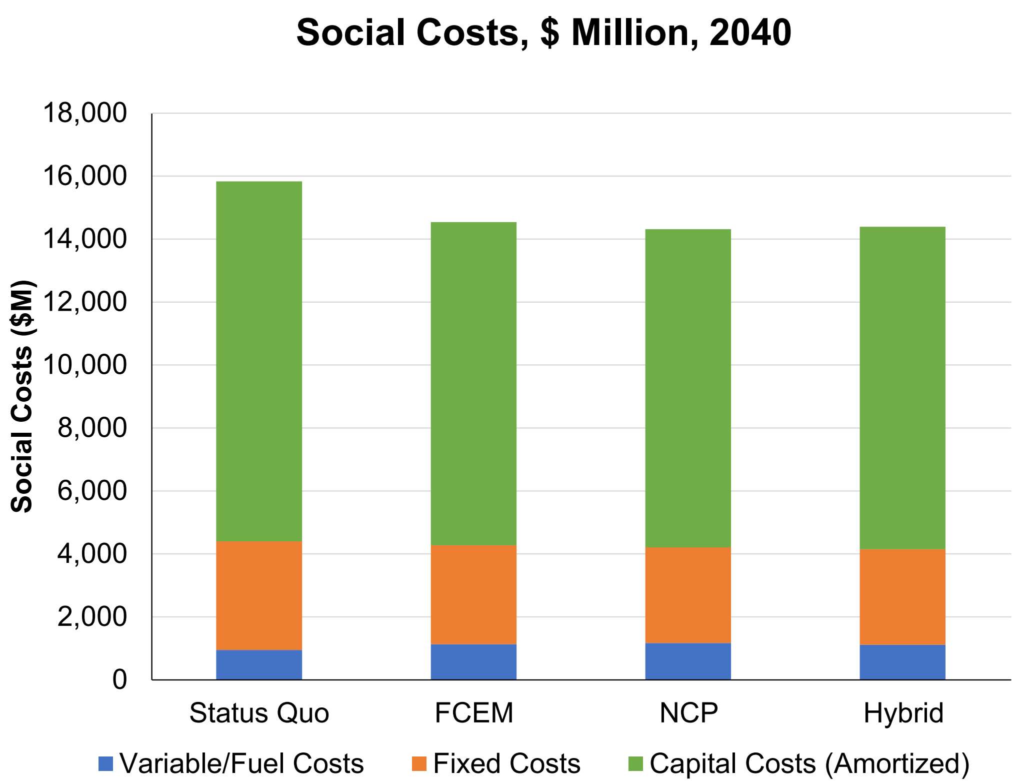
Central Case Results: Social Costs

Social costs similar between FCEM and NCP, higher for Status Quo



- In the electricity sector, social costs include production costs associated with fuel, variable O&M, fixed O&M, and (amortized) capital costs
  - Social costs are highest for Status Quo
  - Costs are lowest for NCP, and similar but somewhat higher for FCEM and Hybrid
  - Cost differences reflect a combination of factors, particularly the differences in energy market incentives for each approach
  - All approaches include the least-cost resources, subject to different constraints
- Analysis does not account for all expected effects (e.g., changes in demand given differences in marginal prices)

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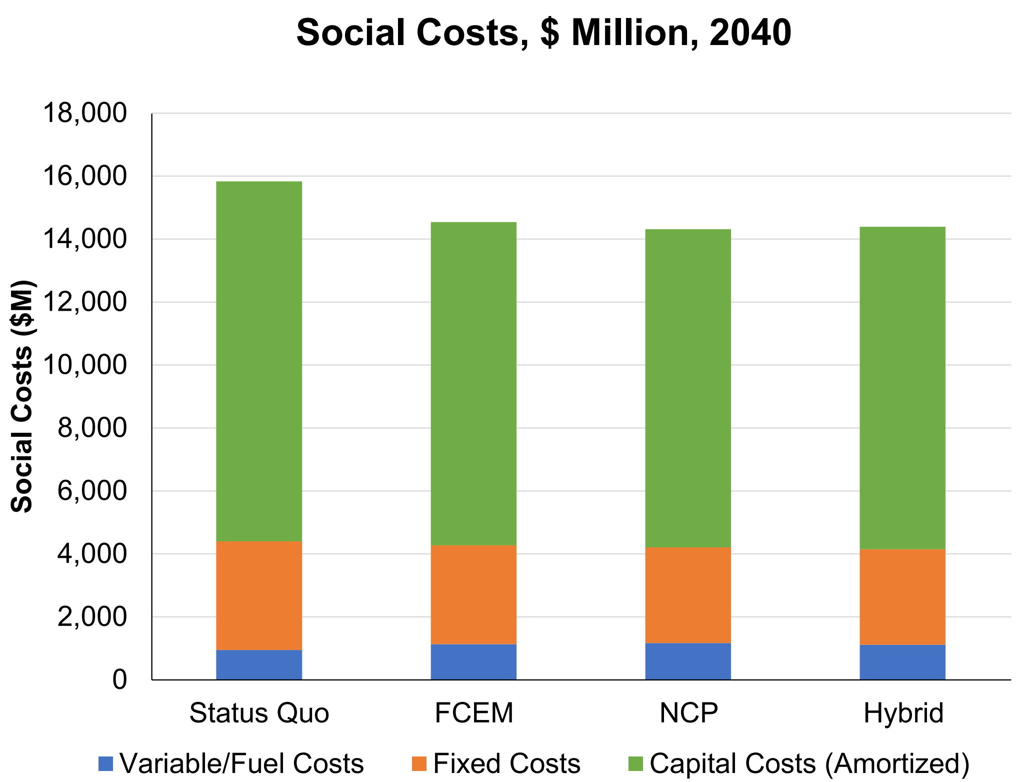
Central Case Results: Social Costs

Social costs similar between FCEM and NCP, higher for Status Quo



Question from October:

- Why does Status Quo have lower variable/fuel costs compared to other cases?

Answer:

- The Status Quo has less fossil-fired generation and more renewable and battery generation relative to the other cases

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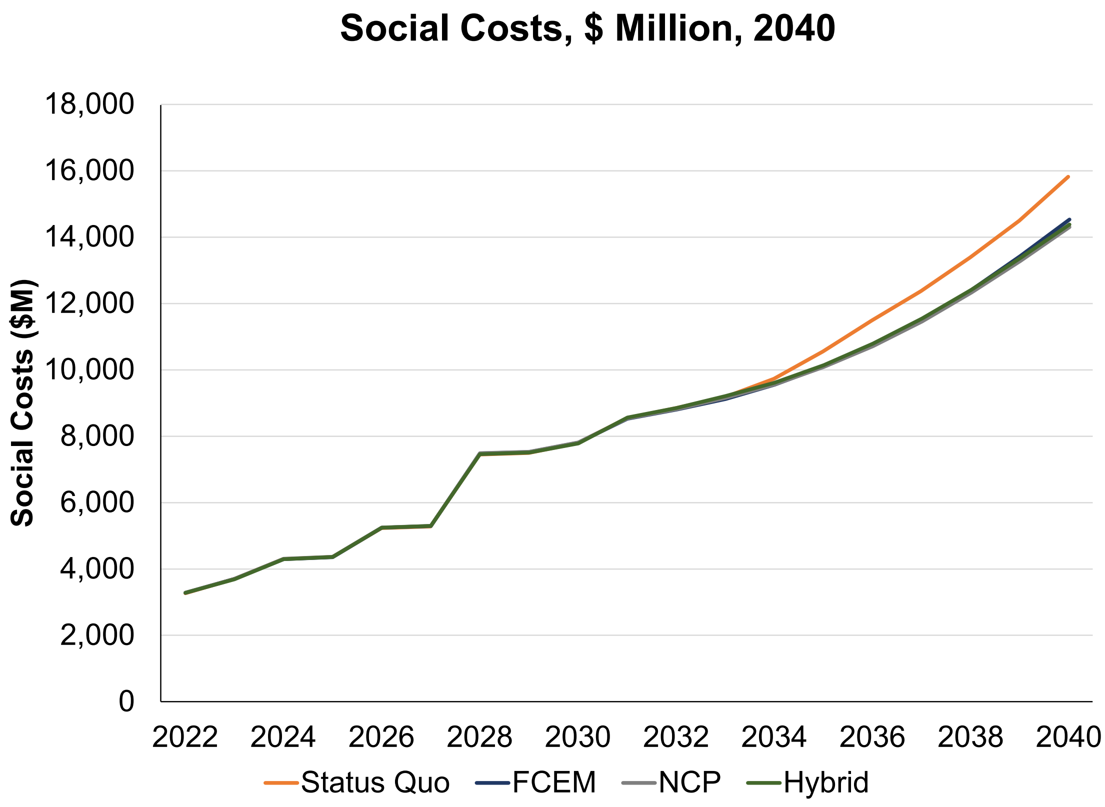
Social Costs over time

Status Quo is most expensive



Note: All values are in $2020

- Social costs are lowest for Net Carbon Pricing and slightly higher for FCEM and Hybrid Approach; costs are highest for the Status Quo
  - Results are consistent with economic theory of relative cost among centralized approaches
  - Status Quo may achieve decarbonization targets less cost-effectively
- Difference between status quo and the other approaches is large and grows over time
  - Cost differences reflect a combination of factors, particularly the differences in energy market incentives for each approach and resource mix chosen in Status Quo

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Central Case Results: Prices

Prices vary widely across policy approaches

LMP Prices by Policy Approach, 2040

	SQ	FCEM	NCP	Hybrid
	[1]	[2]	[3]	[4]
LMP ($/MWh)				
Load-Weighted LMP	-7	1	109	54
Standard Deviation	54	50	60	42
Maximum LMP	68	296	407	180
Minimum LMP	-100	-102	-17	-48
% Hours with $0 LMP	0%	0%	7%	1%
% Hours with Negative LMP	33%	30%	1%	16%

Note: All values are in $2020

Energy prices (LMPs) range across cases

- ***Average LMPs*** range from $-7 to $109 / MWh due to differences in how environmental attribute is priced into energy markets
- Larger fraction of zero or negative prices, reflecting renewable build-out
  - Larger quantity of resources bidding in negative-priced offers compared to prior results

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Central Case Results: Prices

Prices vary widely across policy approaches

LMP and Environmental Prices by Policy Approach, 2040

	SQ	FCEM	NCP	Hybrid
	[1]	[2]	[3]	[4]
LMP ($/MWh)				
Load-Weighted LMP	-7	1	109	54
Environmental Attributes				
Clean Energy Credit ($/MWh)		108		47
Carbon Price ($/MT)			298	117

Note: All values are in $2020

LMPs and prices for environmental attributes vary across cases

- With NCP, higher LMPs because carbon prices included in offers
- With FCEM and Status Quo, CEC value and PPA prices cause negative-priced offers, reducing LMPs
- Hybrid Approach leads to intermediate LMPs, due to CEC subsidy (which lowers LMPs) and carbon prices (which raises LMPs)

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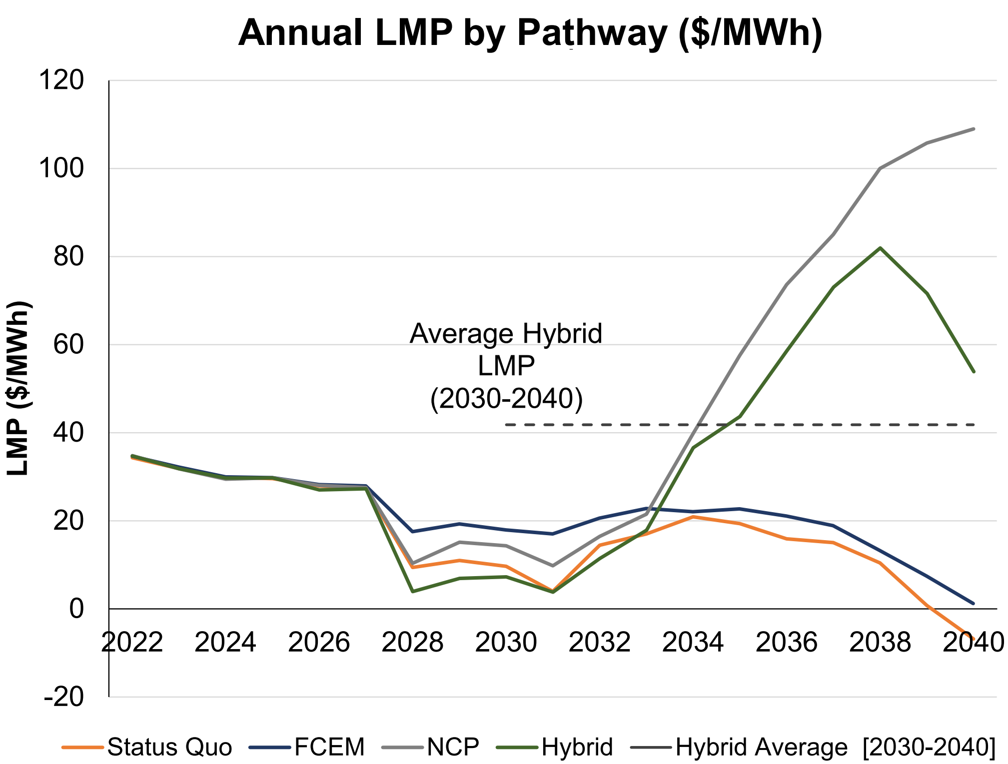
Central Case Results: Prices Over Time

Prices vary widely across policy approaches



Difference in LMPs among the approaches grows over time

- Differences become apparent starting in the late 2020s, as the resource mix is impacted by different responses to anticipated environmental constraints
- When the environmental prices begin to bind, LMPs begin to diverge more dramatically
- Hybrid LMP is ~$41 on average starting in 2030 (relevant as benchmark compensation for existing clean energy resources)

Note: All values are in $2020

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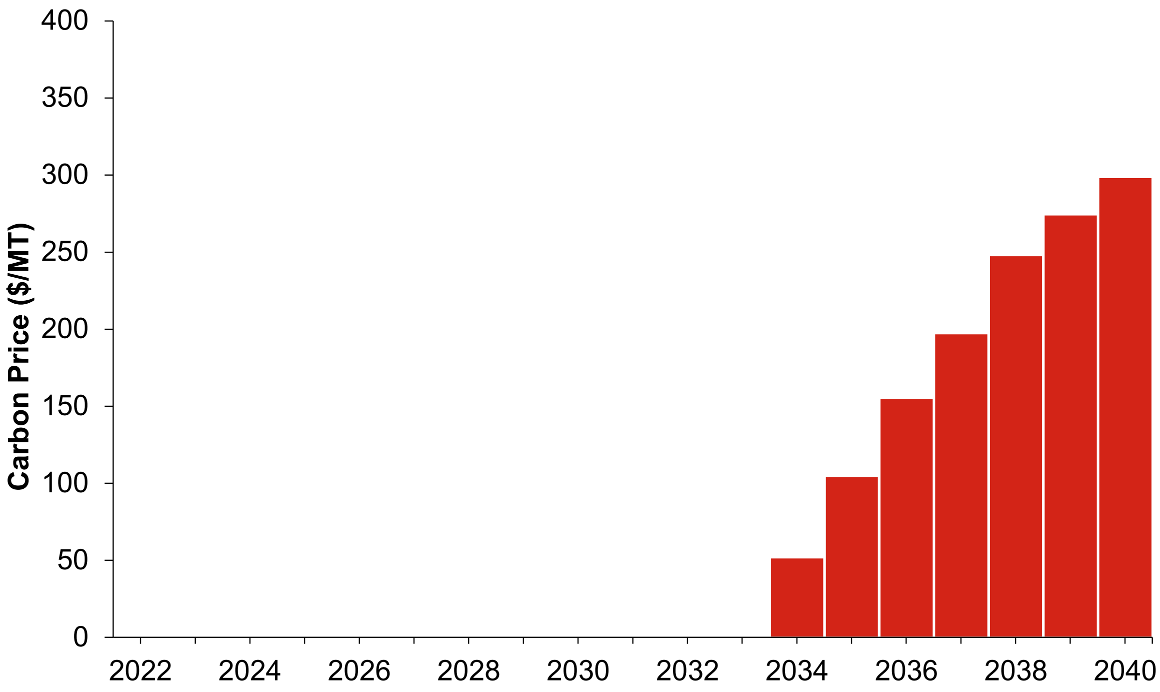
Central Case Results: Carbon Prices Over Time

Carbon prices grow with increasing target stringency

Carbon Price (\$ per Metric Ton of CO_2)



Note: All values are in \$2020

- Assumed baseline state clean energy polices produce sufficient reductions to meet decarbonization targets through 2033
- Carbon prices reflect the cost of marginal abatement in each year
    - Increases in emission target, load, and cost of new entry lead to increases in carbon prices
- Allowance banking would flatten carbon prices – higher in earlier years, lower in later years

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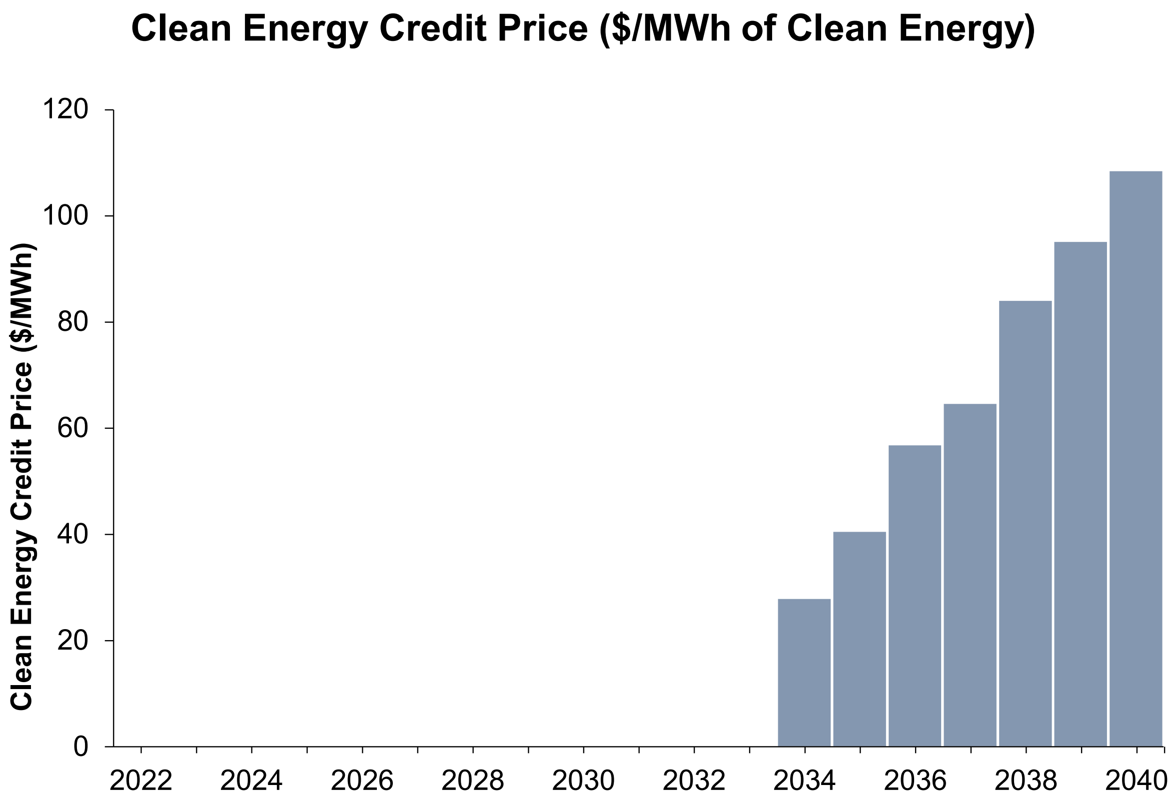
Central Case Results: CEC Prices Over Time

CEC prices grow with increasing target stringency



- Assumed baseline state clean energy polices produce sufficient reductions to meet decarbonization targets through 2033
- CEC prices reflect marginal cost of new clean energy entry
  - Increases in emission target, load, and cost of new entry lead to increases in CEC prices
- CEC banking would flatten CEC prices – higher in earlier years, lower in later years

Note: All values are in $2020

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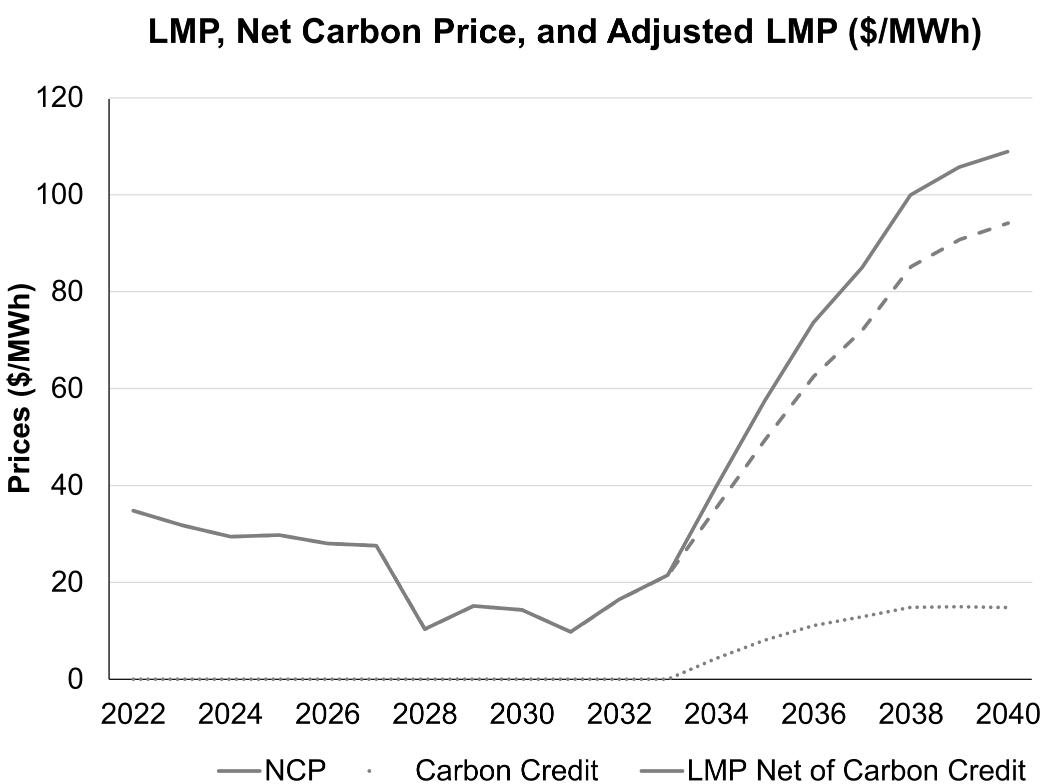
Central Case Results: Net Carbon Price

Credit of carbon prices lowers effective LMP charged to customers



Note: All values are in $2020

- The carbon price does not take into account that the revenues are rebated to load
- LMPs include the impact of carbon taxes on marginal price-setting fossil resources
- The "carbon credit" reflects the impact of carbon credit provided to customers in terms of reducing LMPs
  - In 2040, this is $15/MWh
- The "LMP Net of Carbon Credit", the net energy market price to consumers, reflects the difference between observed LMP and the net carbon price (dashed line)

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Takebacks on the Preliminary Hybrid Results

- At the October meeting, questions were asked about interpretations of the preliminary results for the Hybrid Approach
  - Updated results show that Hybrid Approach outcomes are generally in between (or similar to) FCEM and Net Carbon Pricing
    - For example, quantity of battery storage capacity and other types of capacity is similar to that under FCEM and Net Carbon Pricing
    - Energy storage charging/discharging frequency is generally between that under FCEM and Net Carbon Pricing
    - Hybrid Approach CEC and carbon prices are lower than those under FCEM and Net Carbon Pricing, respectively
  - Analysis allows CEC and carbon prices to vary from year to year, while calibrating levels such that average LMP from 2030-40 hits the target level (i.e., $41/MWh)
    - Relationship among constraints – emission target, CEC constraints and carbon prices (to achieve target LMP) – is complex

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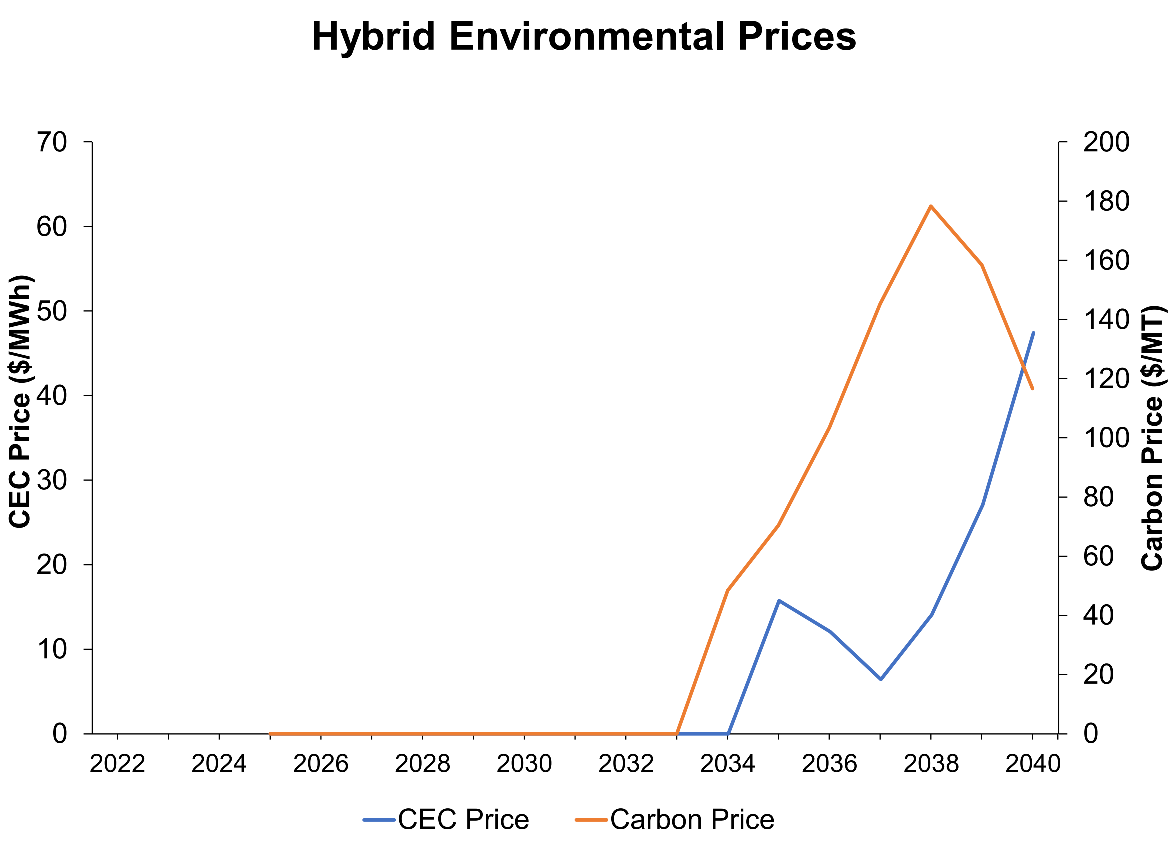
Central Case Results: Hybrid Approach

In Hybrid approach, environmental prices vary from year to year



- CEC and carbon prices vary from year to year
- Tradeoff between CEC and carbon price
  - Carbon price applies to all resources
  - CECs benefit new resources but lower LMPs for existing resources
- Challenging in practice to balance multiple constraints:
  - Emission target
  - CEC target
  - Carbon price, to achieve target LMP (e.g., $41/MWh)
- Other approaches (NCP, FCEM) only have one of these constraints

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Customer Payments

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Customer Payments

- From an economic perspective, social costs provides the best metric for evaluating the (opportunity) costs to society of achieving decarbonization targets
- However, we recognize stakeholder interest in comparing customer payments, which reflects gains to consumers (i.e., consumer surplus) and does not reflect consequences to producers (i.e., producer surplus)
- For each policy approach, total payments by customers reflects four components:
  - Energy market payments, including PPA contracts and LMPs (which reflect competitive offers including carbon prices)
  - Forward Capacity Market payments
  - CEC payments
  - Credit to customers for carbon tax payments (by generators) in Net Carbon Pricing and Hybrid Approach
- For the FCEM, Net Carbon Pricing and Hybrid Approach, the payments reflect in-market payments at market prices, in addition to the PPA contracts for currently legislated procurements assumed in all cases

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Customer Payments – Status Quo Assumptions

- Total payments under the Status Quo approach reflect out-of-market purchases of energy through PPAs
  - Total energy market payments are calculated assuming energy procured through PPAs is paid for at the PPA price, not the market-clearing LMP
  - PPA contract prices reflect levelized cost of supplying energy (net of FCM revenues) given changes in underlying costs (technological change, transmission), escalating curtailments, and market-clearing prices in PPA procurements
  - PPA contract prices include no adjustment for reductions in rate received for energy when LMPs are negative (future analyses may include this adjustment)

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Customer Payments – Status Quo Assumptions

- Total payments for the Status Quo approach are sensitive to whether existing clean energy resources are provided with payments for "clean energy" services in additional to energy market and FCM revenues
  - Absent payments for clean energy, revenues decline over time for existing clean resources with the expansion of procured renewable energy
- We assume that existing clean resources receive supplemental payments for clean energy in light of retirement risks and potential for sales to other regions
  - Existing nuclear receives $41/MWh (e.g., through an extended PPA)
  - Existing renewables (but not nuclear) receive an escalating REC payment, given "outside" options (e.g., sale of clean energy to New York or other region) – RECs rise from $0/MWh in 2030 to $60/MWh in 2040
  - These assumptions are toward the *lower* end of reasonable assumptions about compensation for existing renewables

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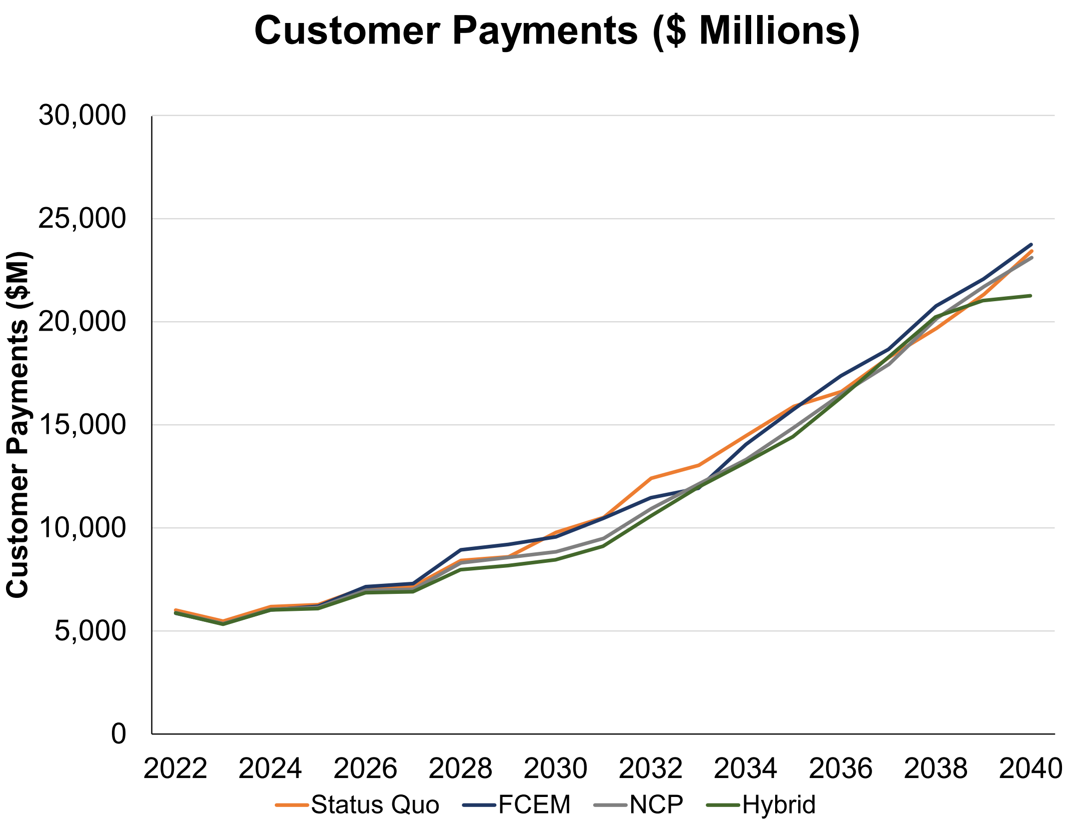
Customer Payments over time

Total payments comparable across approaches



Note: All values are in $2020

- Total payments generally similar across policy approaches, with some year-to-year variation
- FCEM has highest payments, and Hybrid the lowest payments

Pathway	Net Present Value of Total Customer Payments ($M)
Status Quo	136,418
FCEM	136,740
NCP	131,738
Hybrid	128,846

Note: All values are in $2020. NPV calculated assuming 5% discount rate.

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Customer Payments – Alternative Status Quo Assumptions

- Status Quo assumptions in prior slide reflect payments to existing clean energy at lower rates than received by new clean resources (via PPAs)
- In alternative Status Quo assumptions, existing clean energy is compensated at same level as new clean energy (via PPAs)
  - Total payments increase compared to Central Case assumption
- Payments that assume existing clean energy is compensated at the same level as new clean energy reflects an upper bound on plausible payments

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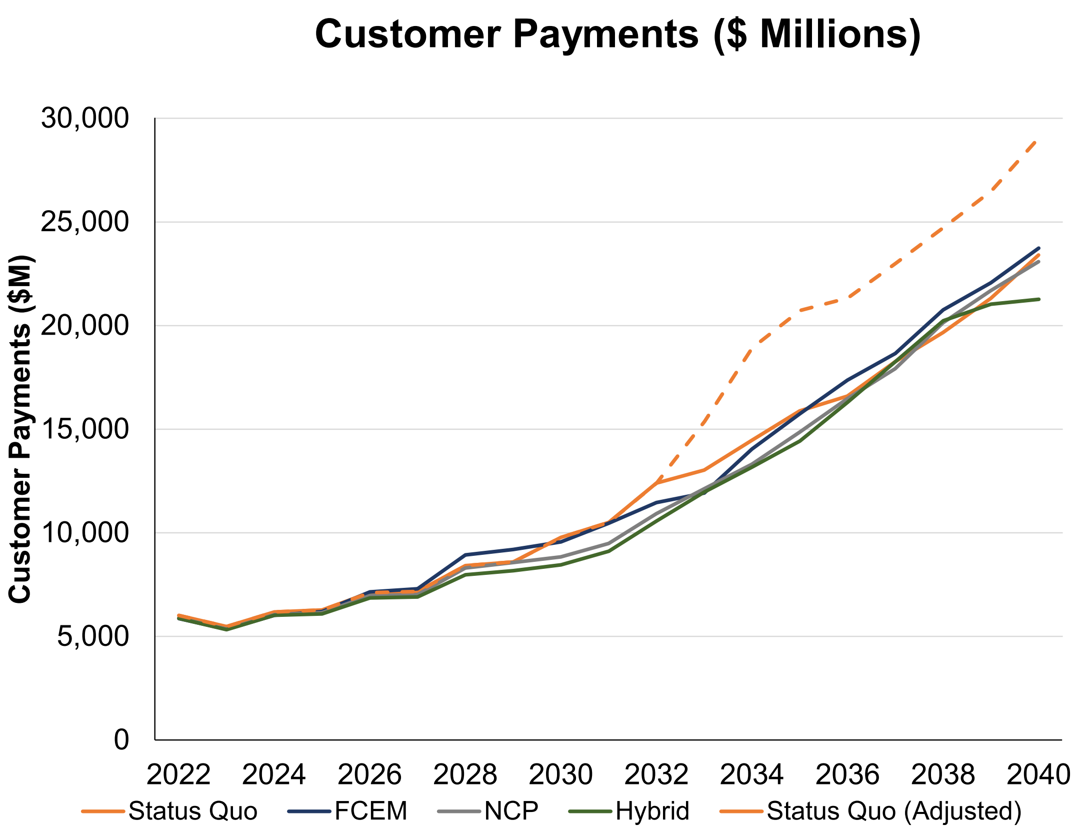
Customer Payments over time

Status Quo payments sensitive to treatment of existing clean energy



Note: All values are in $2020

- If existing clean energy was compensated at same level as new clean energy (via PPAs), total payments would be substantially higher (see dashed line)

Pathway	Net Present Value of Total Customer Payments ($M)
Status Quo	136,418
Status Quo (Adjusted)	154,411
FCEM	136,740
NCP	131,738
Hybrid	128,846

Note: All values are in $2020. NPV calculated assuming 5% discount rate.

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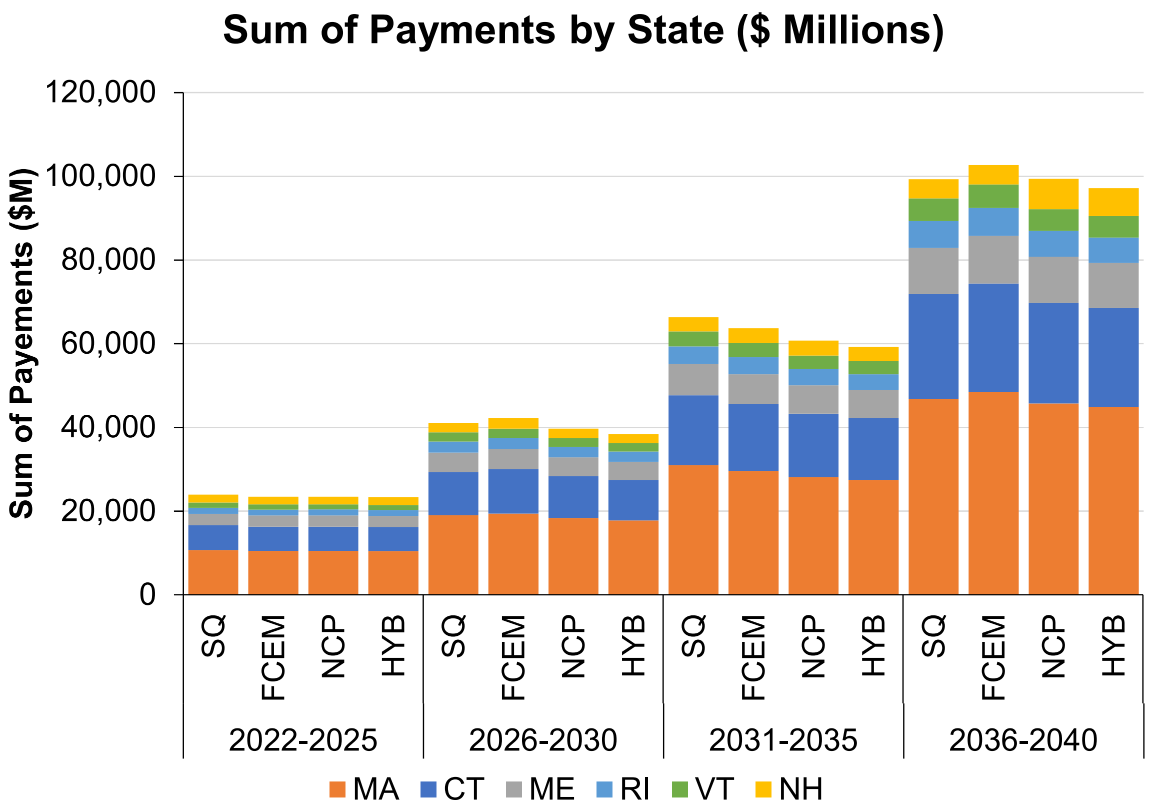
Customer Payments by State

Payments vary by state, largely due to load differences



Note: All values are in $2020

- States with more ambitious emission reduction goals bear a larger fraction of total payments in the Status Quo and FCEM
- When approach includes carbon prices, payments are spread more evenly across states, in proportion to load; Hybrid Approach (combining carbon pricing and CECs) shares payments proportionately, but to a lesser degree

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Comparison of Scenarios

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Quantitative Scenarios

- Preliminary results to be provided today -- each scenario evaluated across all policy approaches:
  - Alternative regional carbon target – 85% below 1990 emission by 2040
  - Alternative levelized costs of new entry for renewable resources
  - Additional retirements
  - Alternative distribution of costs amongst states
- Today's discussion will focus on how model inputs and assumptions differ in each scenario from the Central Case and focusing on key and interesting results, including changes from the Central Case
  - Additional data and tables of scenarios presented today will be included in the final report
- Preliminary results to be provided in 2022
  - Include transmission
  - Hybrid only: alternative LMP targets for existing renewables
  - Status Quo: alternative costs of long-term renewable contract procurement

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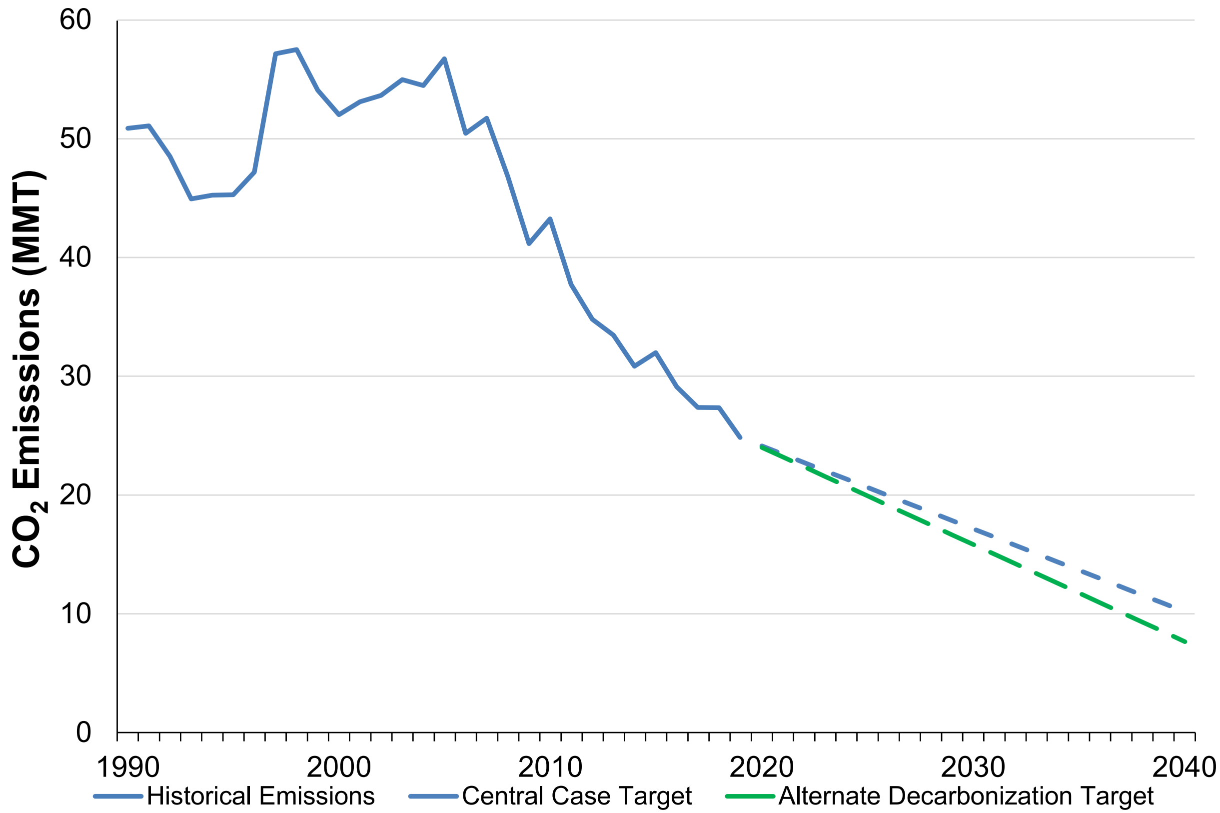
Scenario: Alternative Decarbonization Target

More stringent target – 85% below 1990 levels by 2030



Source: EIA, Electricity, Detailed State Data, available at https://www.eia.gov/electricity/data/state/

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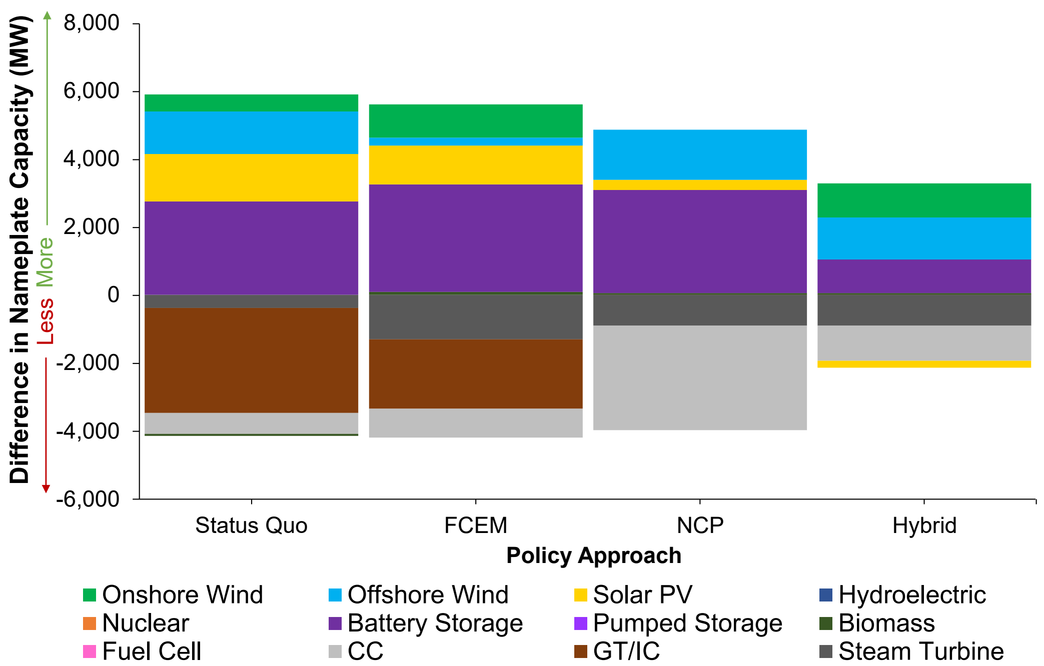
85% Decarbonization Results: Resource Mix

Changes in resource mix vary with policy approach

Difference in Scenario Resource Mix Compared to Central Case, MW, 2040



- Positive value reflects *more* capacity of that technology type than in the central case
- Negative value reflects *less* capacity of that technology type than in the central case
- Reflects changes to retirements *and* new entry
  - More fossil retirements and less new fossil in all cases
  - More new batteries and renewables in all cases
  - New renewable resource entry varies by case

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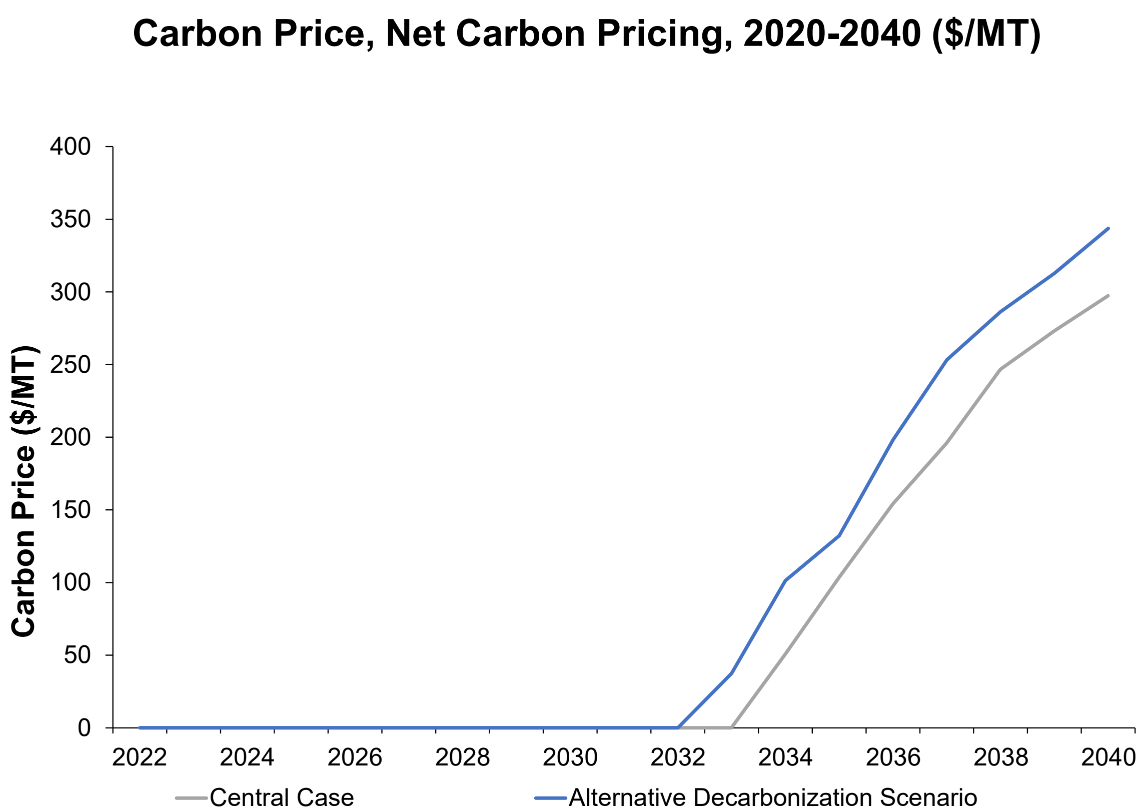
85% Decarbonization Results: Carbon Prices

Higher carbon prices with more stringent target



- Under Net Carbon Pricing, carbon prices are higher with more stringent emission target
  - Carbon price binds one year sooner
  - 2040 carbon price is $344 – 16% higher than central case
  - Trajectory of prices is otherwise very similar

Note: All values are in $2020

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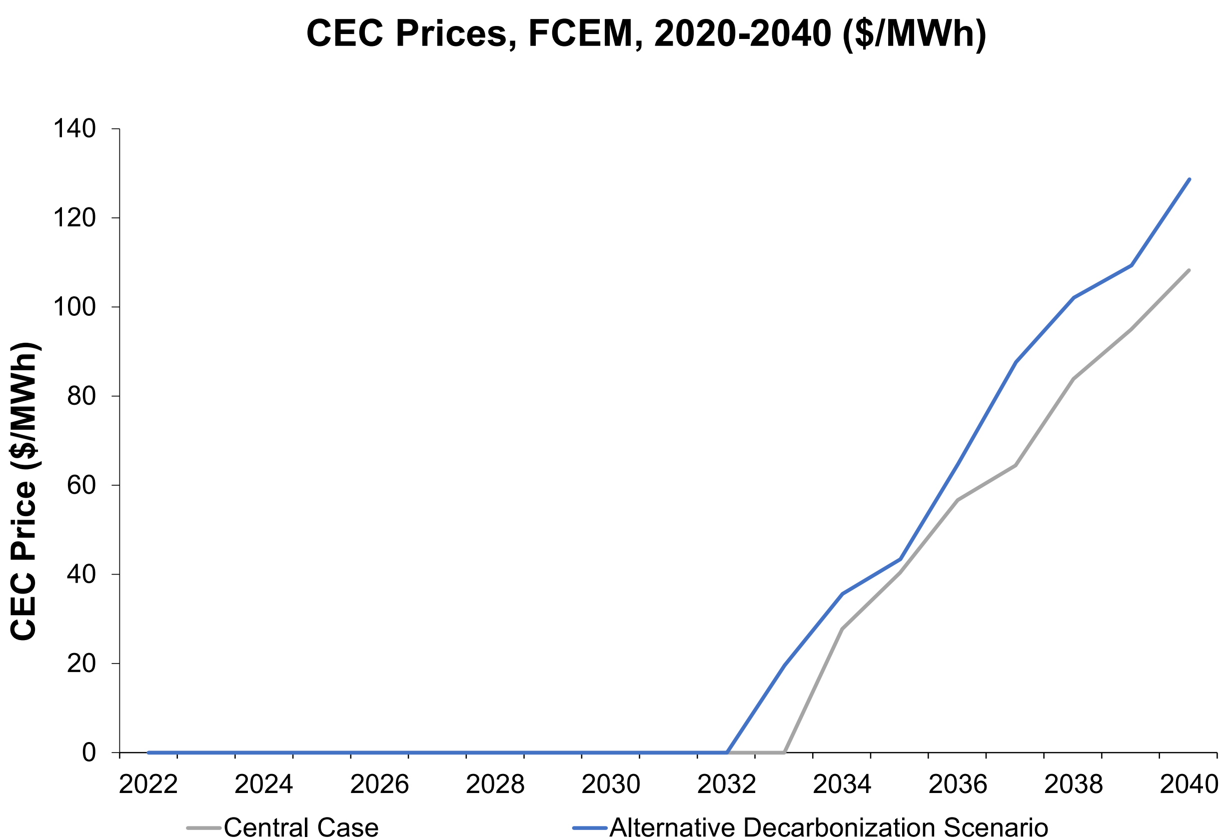
85% Decarbonization Results: CEC Prices

Higher CEC prices with more stringent target



Note: All values are in $2020

- Under the FCEM, CEC prices are higher with more stringent emission target
  - CEC price binds one year sooner
  - 2040 CEC price is $129 – 19% higher than central case
  - Trajectory of prices is otherwise very similar

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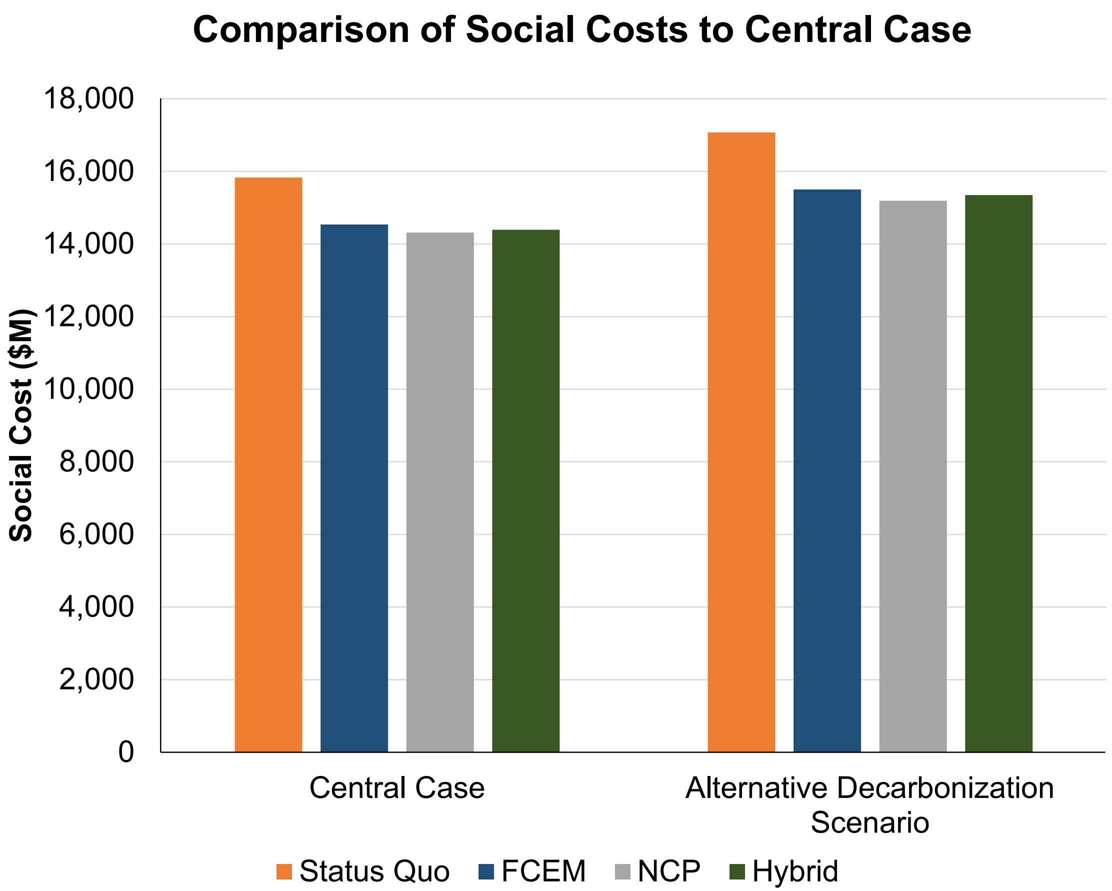
85% Decarbonization Results: Social Costs

Social costs are higher



- Total social costs increase for all policy approaches
- Increase in cost for Status Quo is greater than for the other cases
- Social costs remain highest for SQ, and lowest for the NCP

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Scenario: Alternative Capital Costs

- Central case assumes capital costs based on 2021 EIA AEO
- Alternative capital costs will use NREL's 2021 Annual Technology Baseline
  - Among dispatchable resources, CC become relatively more cost-effective
  - Among renewable resources, onshore wind and offshore wind become more cost-effective relative to solar.
- These changes in the relative costs are reflected in different resource mixes

	Overnight Capital Cost ($/kW)			
	2021		2040	
Resource Type	**EIA AEO**	**NREL ATB**	**EIA AEO**	**NREL ATB**
CT F-Class	801	838	603	730
CC H-Class (2 x 1)	1,134	952	897	871
Battery Energy Storage	1,201	1,282	633	686
Solar	1,276	1,288	808	692
Wind Onshore	1,680	1,291	1,391	819
Wind Offshore	6,360	3,446	3,458	2,112

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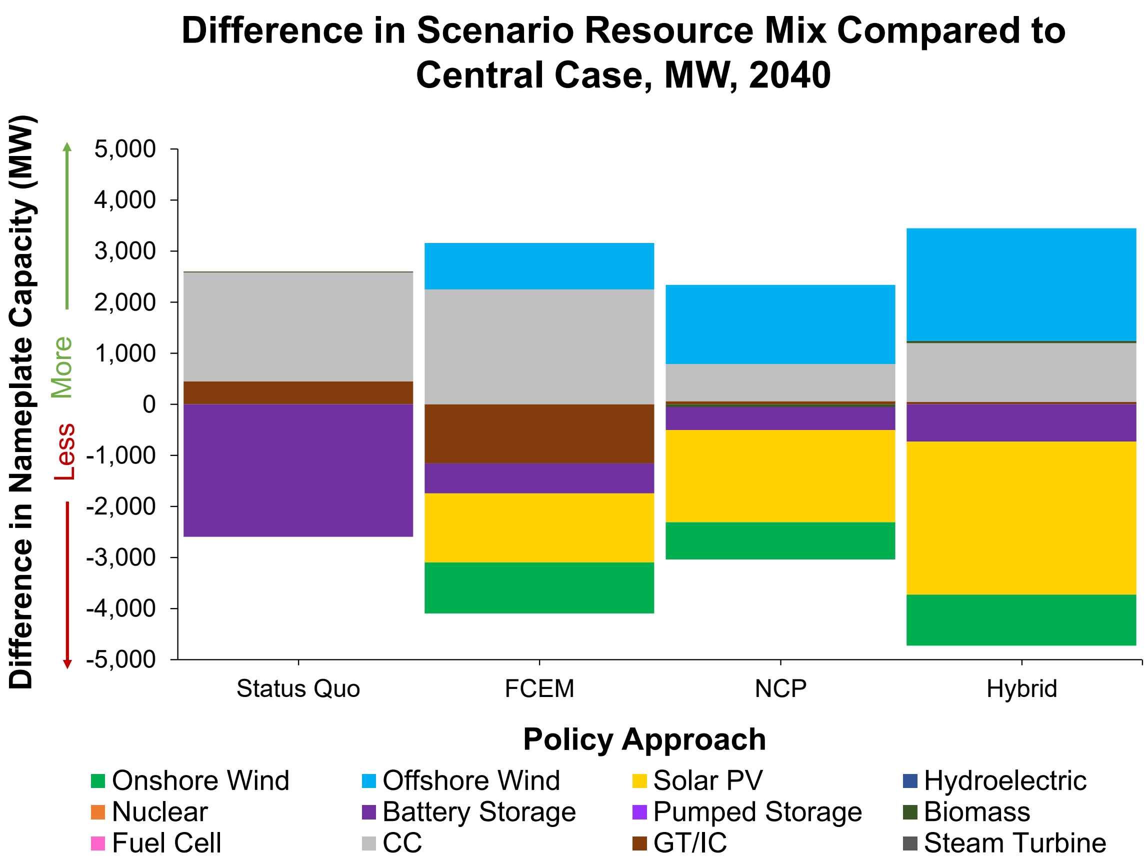
Alternative Capital Costs: Difference in Resource Mix

Resource mix changes reflect differences in relative costs between resources



- Dispatchable resources: More gas-fired and less storage
- Renewables:
  - Status Quo mix assumed to remain unchanged
  - FCEM, NCP, Hybrid: more offshore wind, Less PV solar and onshore wind

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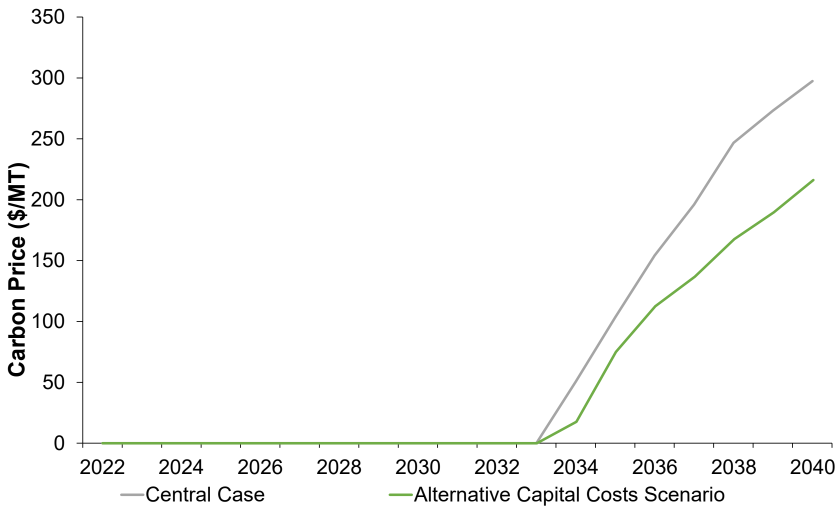
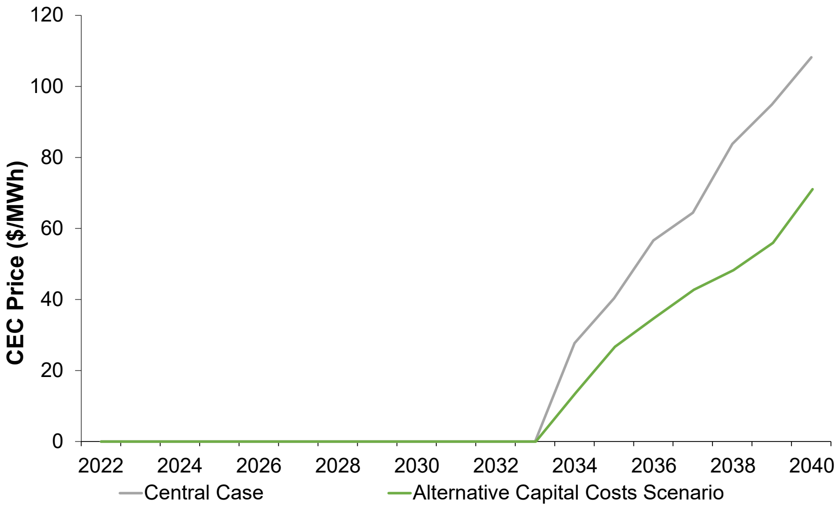
Alternative Capital Costs: Environmental Prices

Consistent with lower capital costs, environmental prices are lower

Comparison of Carbon Prices



Comparison of CEC Prices



Note: All values are in $2020

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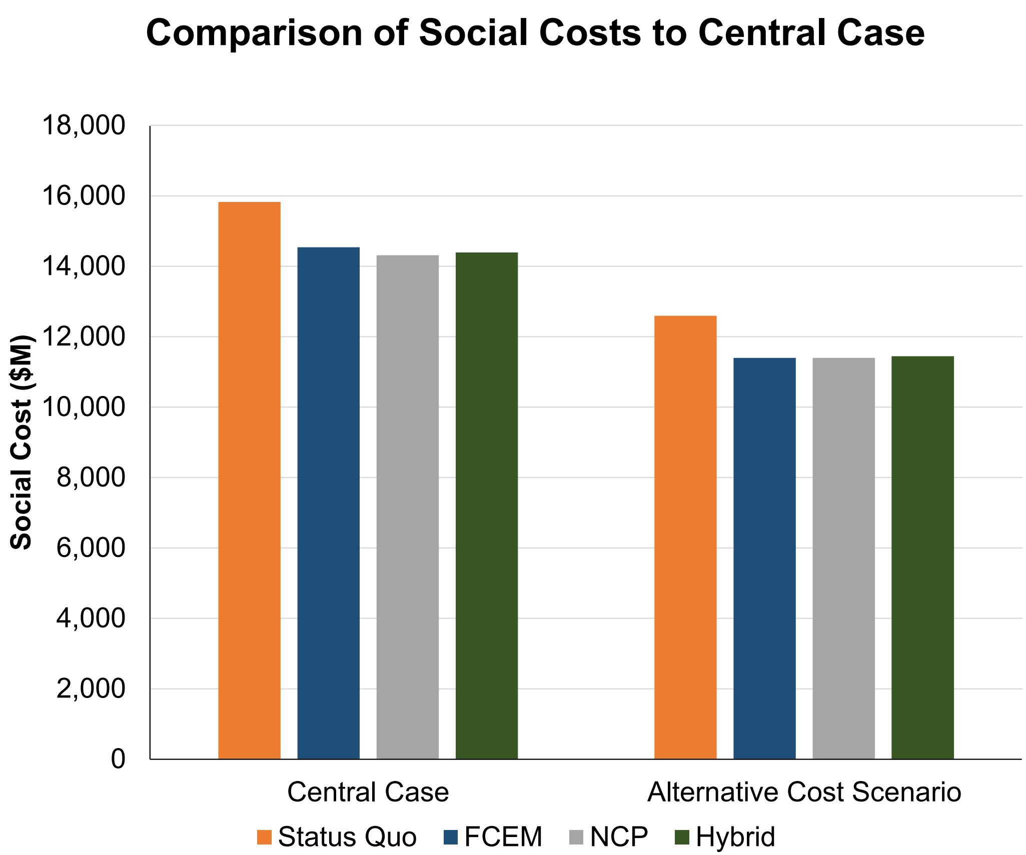
Alternative Capital Costs: Social Costs

Social costs are Lower



Note: All values are in $2020

- Production costs are lower because capital costs of nearly all types of resources are lower
- Status Quo declines more than the other cases
  - This reflects the reliance on offshore wind in the SQ, which had the biggest difference in capital costs

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Scenario: Additional Retirements

Increased fossil retirements, including "at risk" units

- Central case results retire approximately 7,200-7,800 MW of capacity
  - SQ and FCEM retire less, NCP and Hybrid retire more.
- However, the model may not accurately capture all events may cause units to retire, particularly large forced maintenance events requiring large capital cost that can result in an older unit retiring
- We assume that, in addition to all of the retirements in the NCP central case, all of the "at risk" units identified by ISO-New England also retire (see: https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements)
- This assumption results in an approximately 3,700-4,300 MW of retired fossil fuel capacity than in the central cases.

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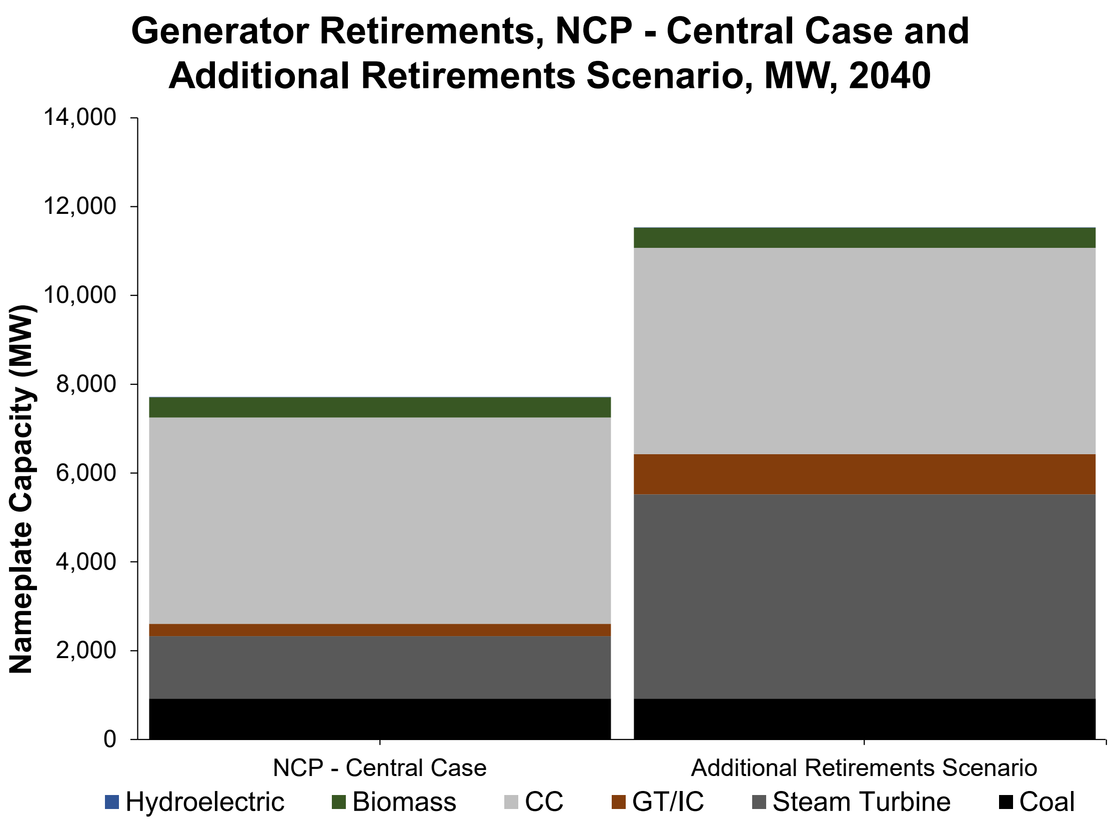
Additional Retirements: Total Retirements

Additional retirements include steam and gas turbine units



- The at-risk units not retired in the NCP central case account for an additional ~3,800MW of capacity
- ~3,200MW are steam units
- Oldest units assumed to retire first
- Timing of additional assumed retirements is distributed from 2024-2040

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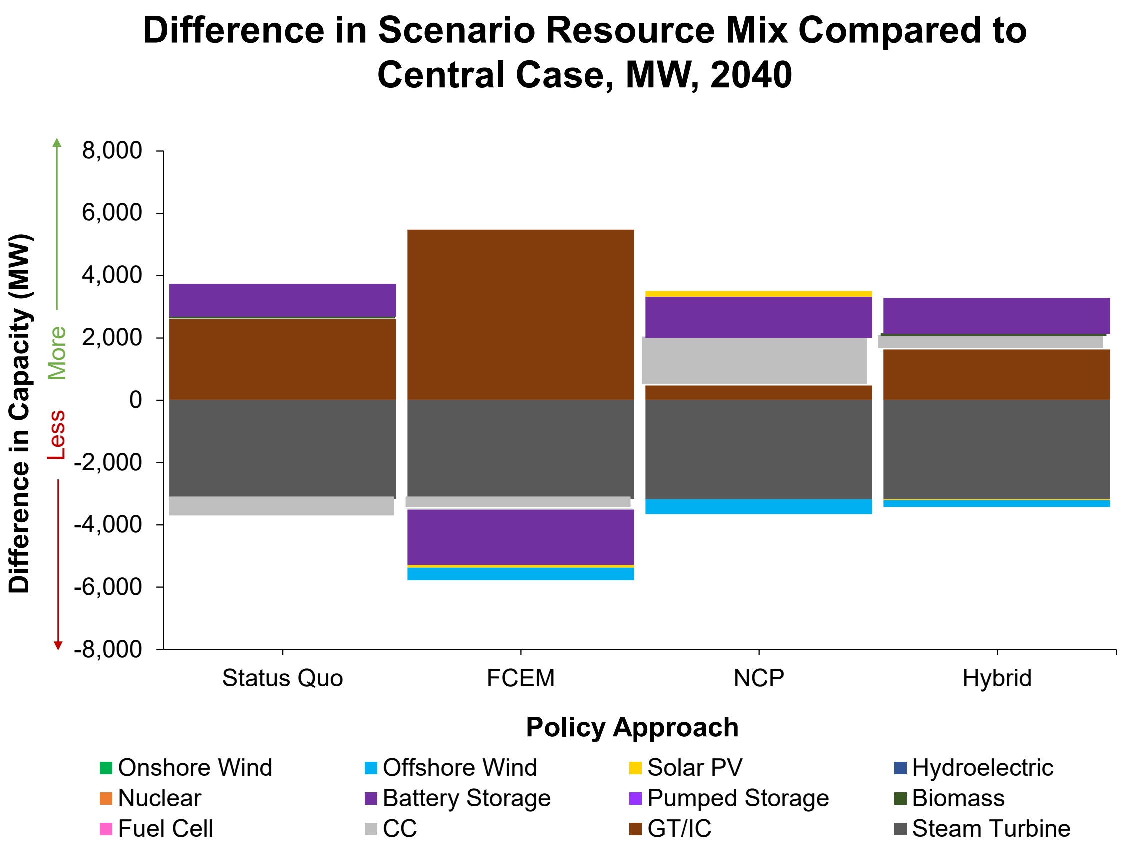
Additional Retirements: Differences in Resource Mix

New, more efficient gas-fired resources and storage replace retired resources



- The additional retirements are replaced by a mix of dispatchable units, not renewables
  - New fossil generation accounts for largest share of replacement resources
  - Additional storage under three of four approaches (less storage in FCEM)
- Less renewables needed because less efficient, higher emission resources retire

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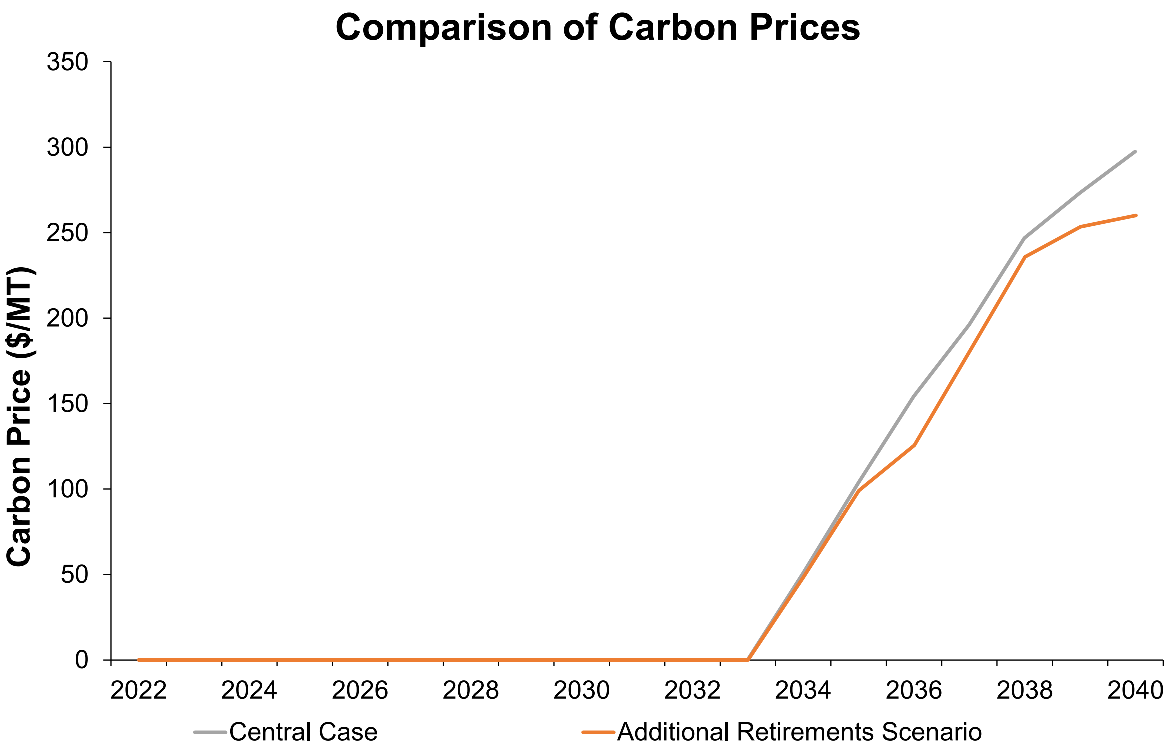
Additional Retirements: Environmental Prices

Environmental prices lower with more efficient gas-fired resources



Note: All values are in $2020

- Carbon prices are lower as at-risk units are very emissions intensive
- These units are replaced by lower emitting units, such that in some hours the marginal unit is now more fuel efficient, lower emission source with a lower carbon cost
- More efficient resources relied on more frequently in later years when peak load is larger, leading to a larger difference in carbon price over time
- Similar story for CEC price

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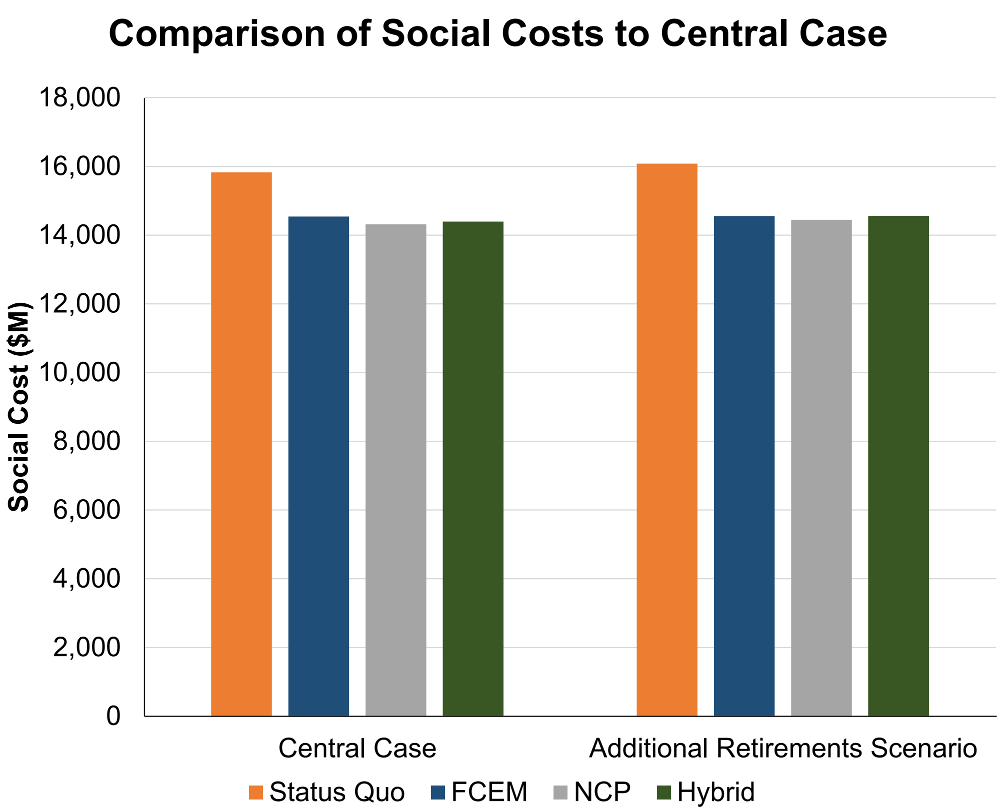
Additional Retirements: Social Costs

Social costs are higher



Note: All values are in $2020

- Production Costs are slightly higher
  - These results show that the "at-risk" units were not retired in the central cases because keeping them was least cost

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Scenario: Alternative Payments by State

Total payments remain unchanged, allocation of payments modified

- In the central case, we assume that customer payments for CECs and the cost of PPAs will be allocated across states based on their relative decarbonization goals
- In the alternative payment allocation:
  - Total payments remain unchanged
  - We assume that each state will bear the cost of the region's clean energy targets in proportion to their share of total electricity demand

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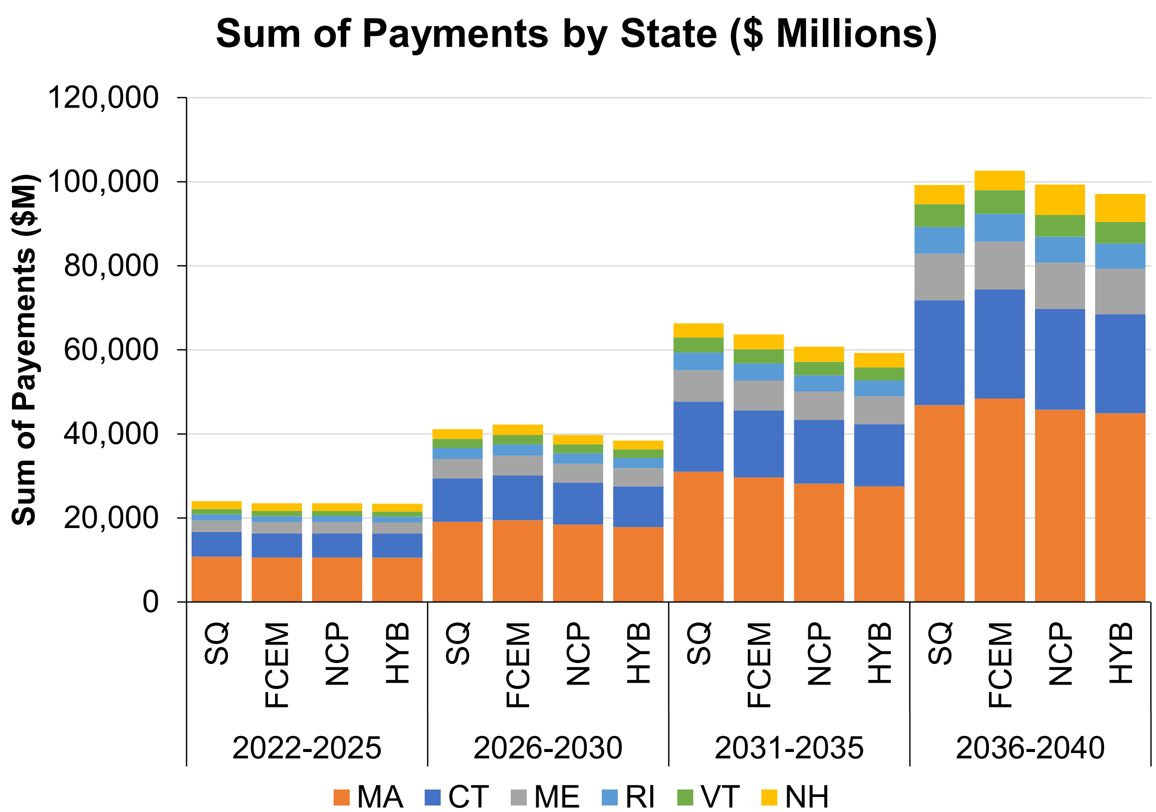
Scenario: Alternative Payments by State

Payments weighted by electricity demand



- Under alternative payment allocation assumption, all costs are proportional to energy consumed

Note: All values are in $2020

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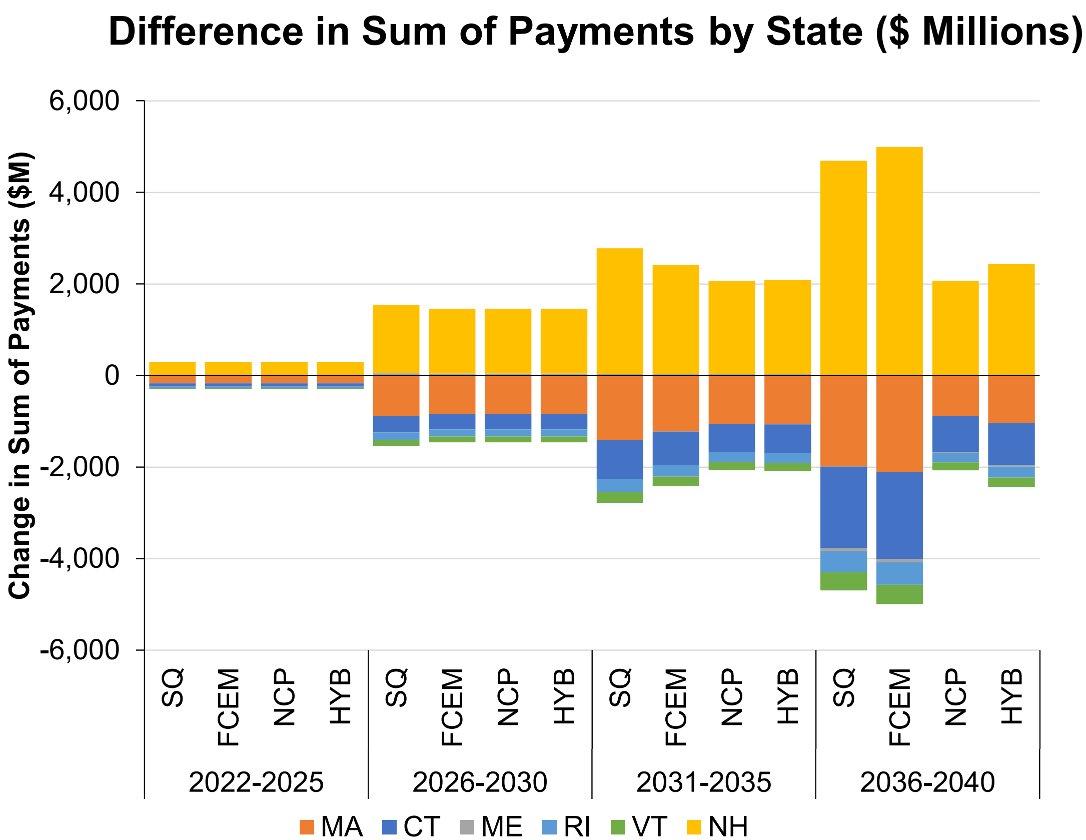
Scenario: Alternative Payments by State

States with lower emission reduction targets pay more



- In alternative payment allocation, costs are shifted to states with lower relative emission reduction contributions in Central Case (i.e., New Hampshire)

Note: All values are in $2020

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Next Steps

- 2022
  - Present draft report with central case and updated scenario results
  - Take feedback on additional scenario results and draft report
  - Present on final report

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Appendix

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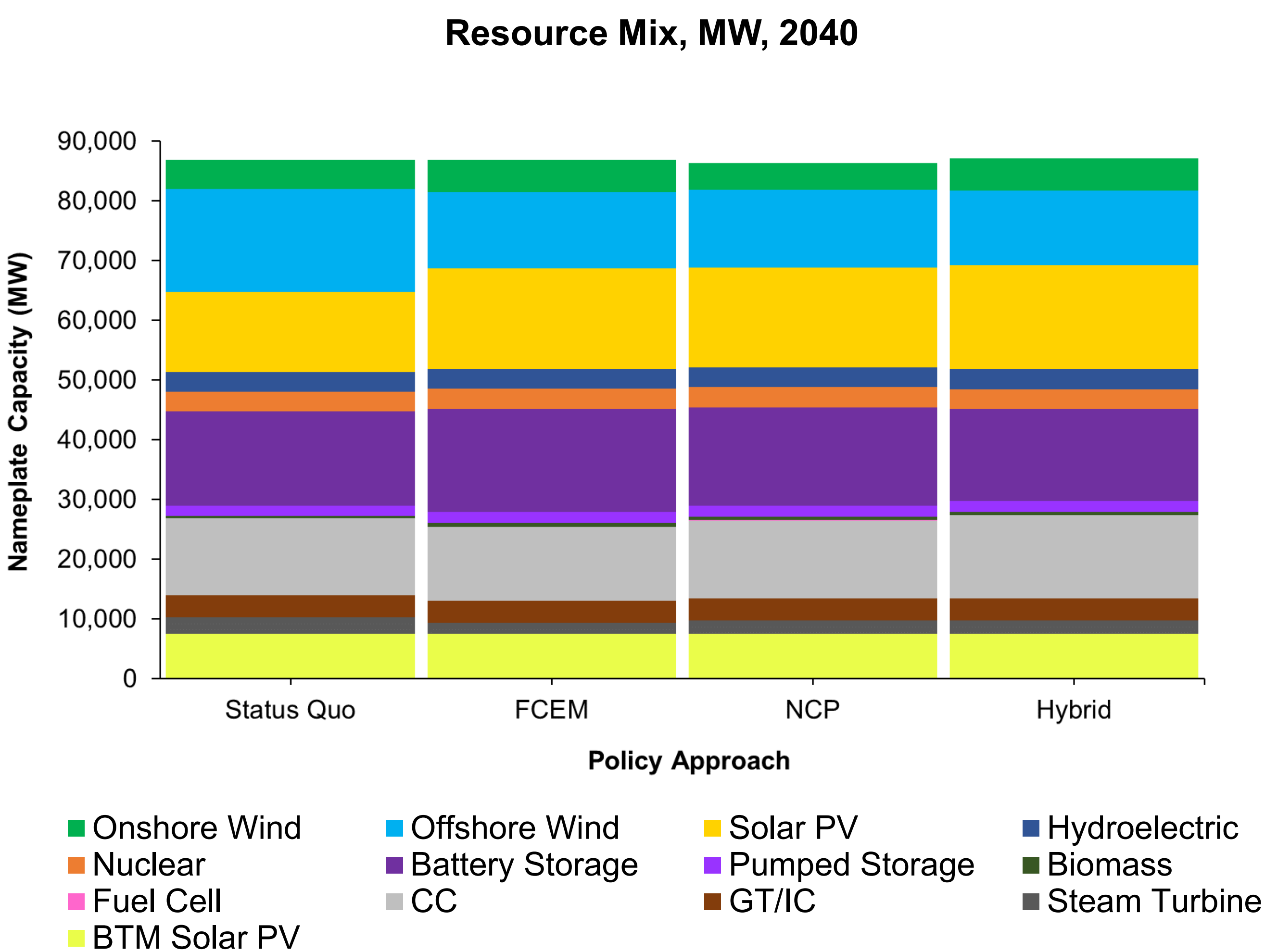
85% Decarbonization Results: 2040 Resource Mix



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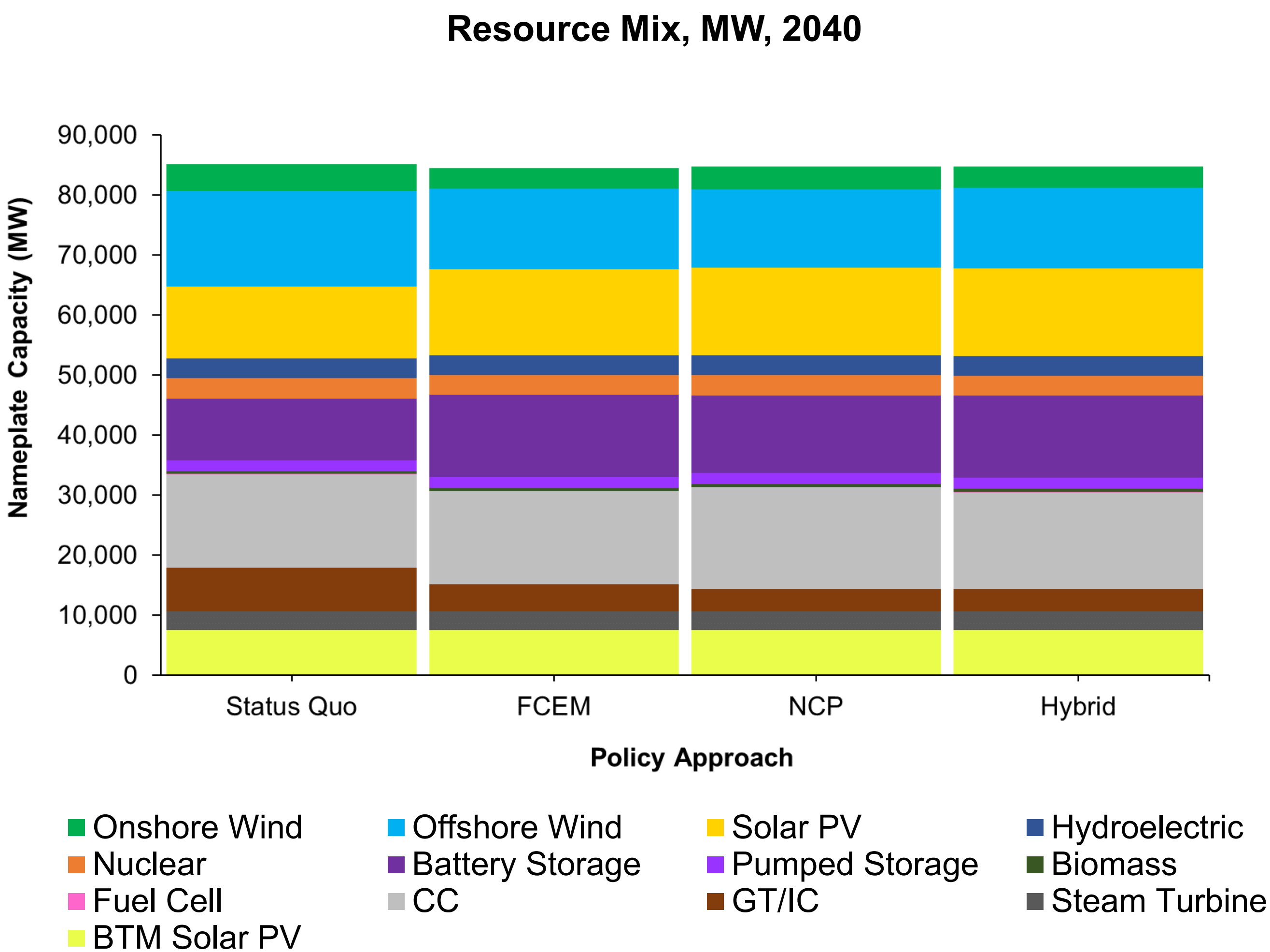
Alternative Capital Costs: 2040 Resource Mix



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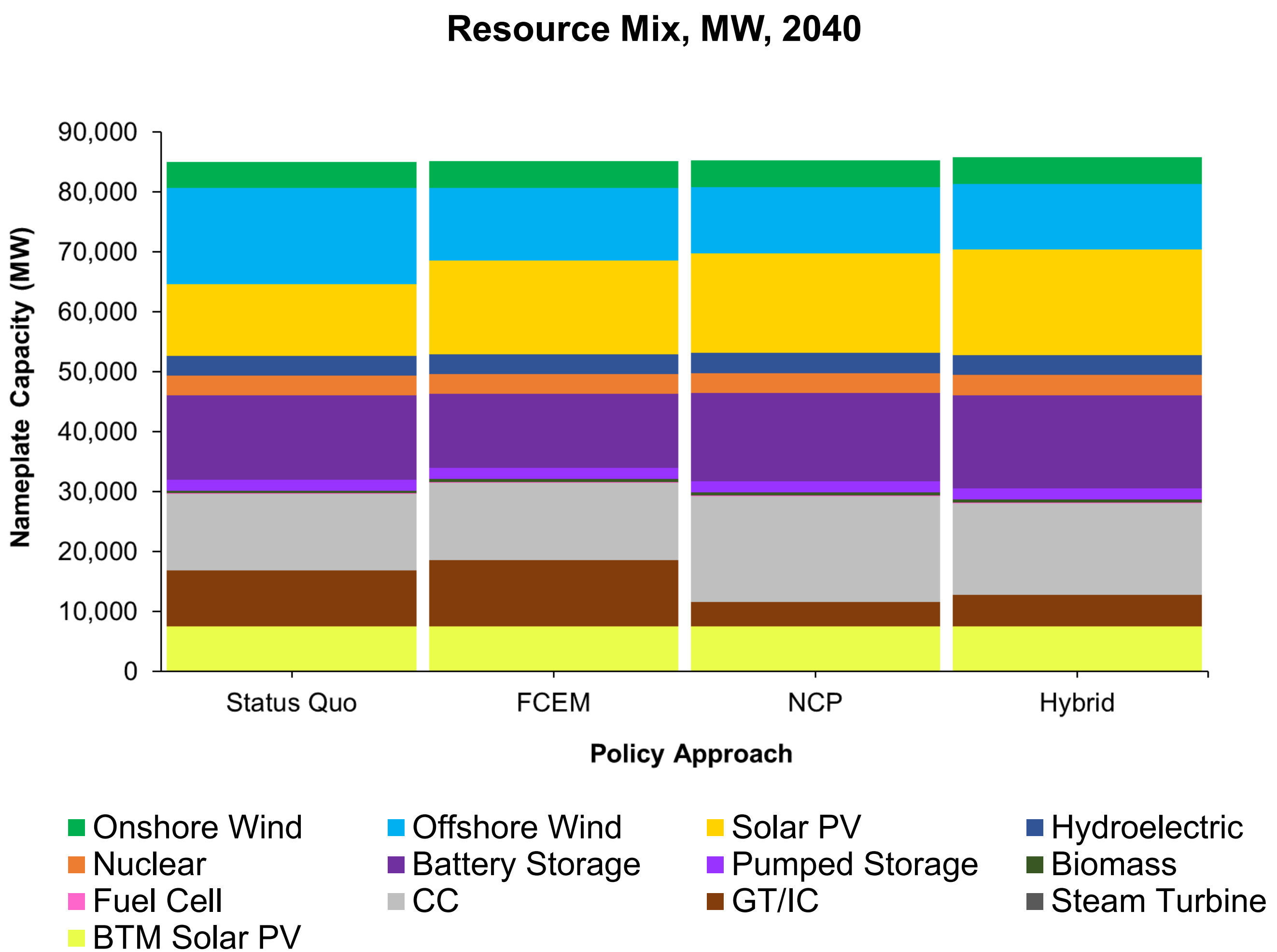
Additional Retirements Scenario: 2040 Resource Mix



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Updated Central Case Results - NCP

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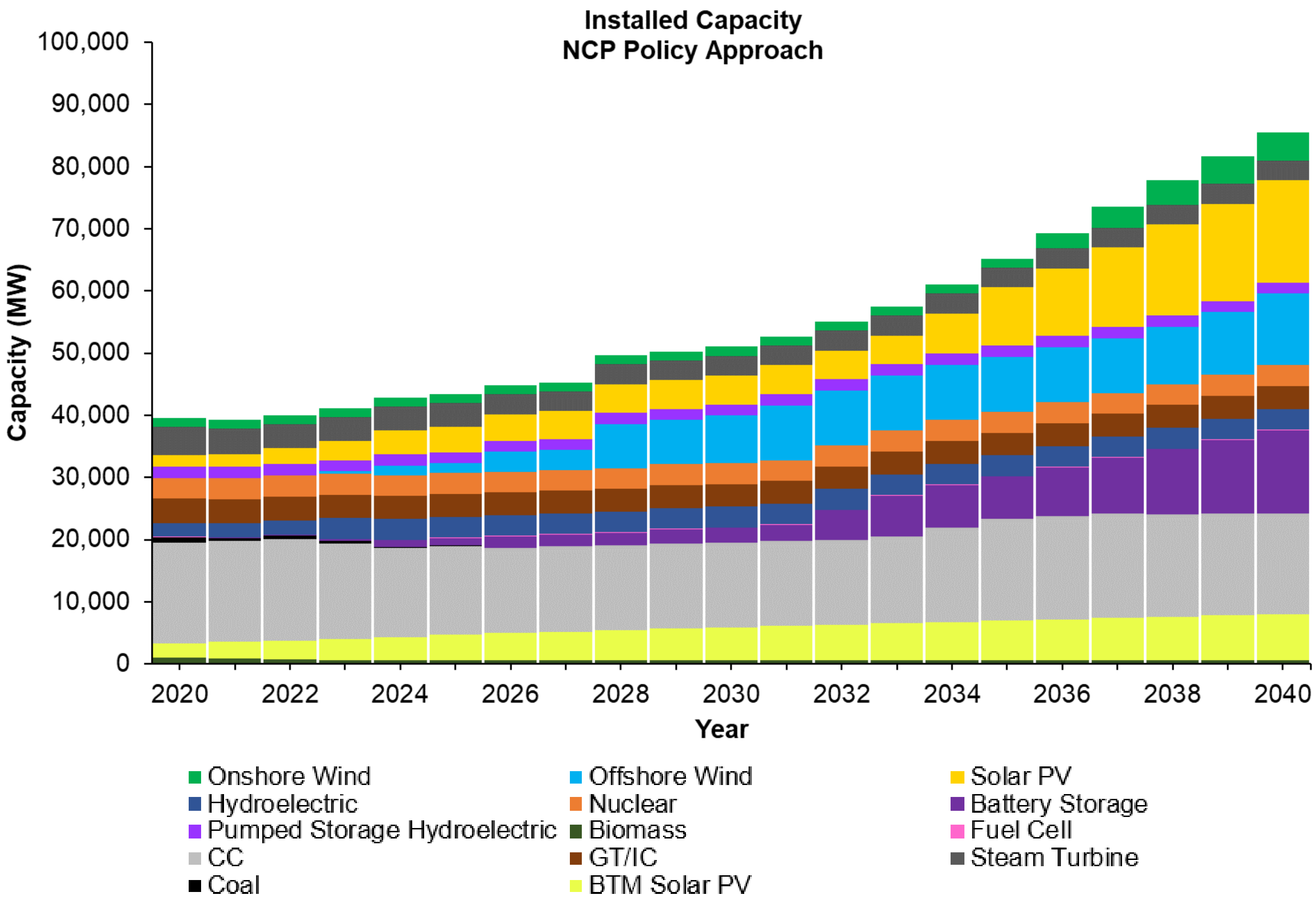
Central Case Results - NCP: Resource Mix



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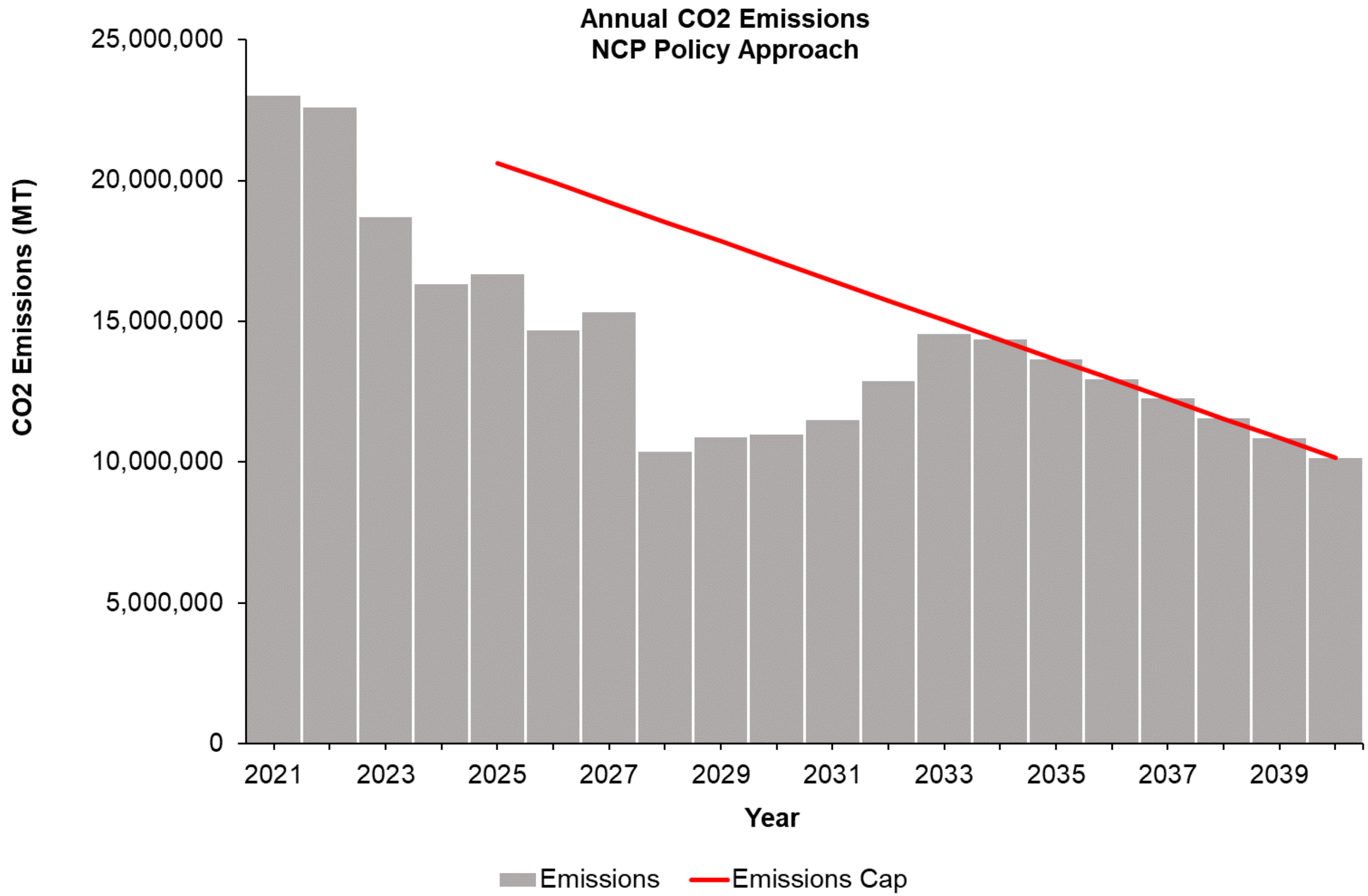
Central Case Results - NCP: Carbon Emissions



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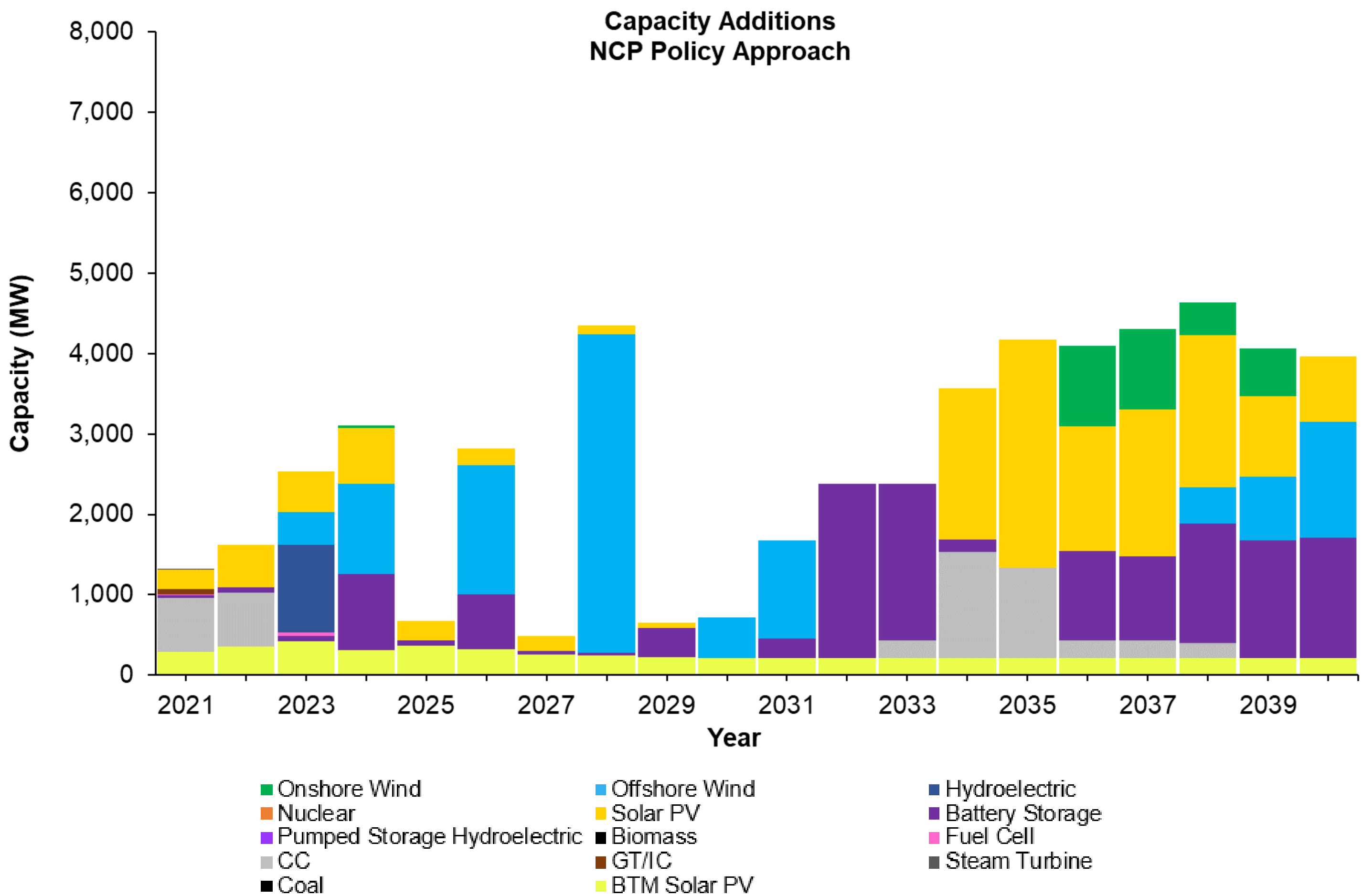
Central Case Results - NCP: Resource Additions



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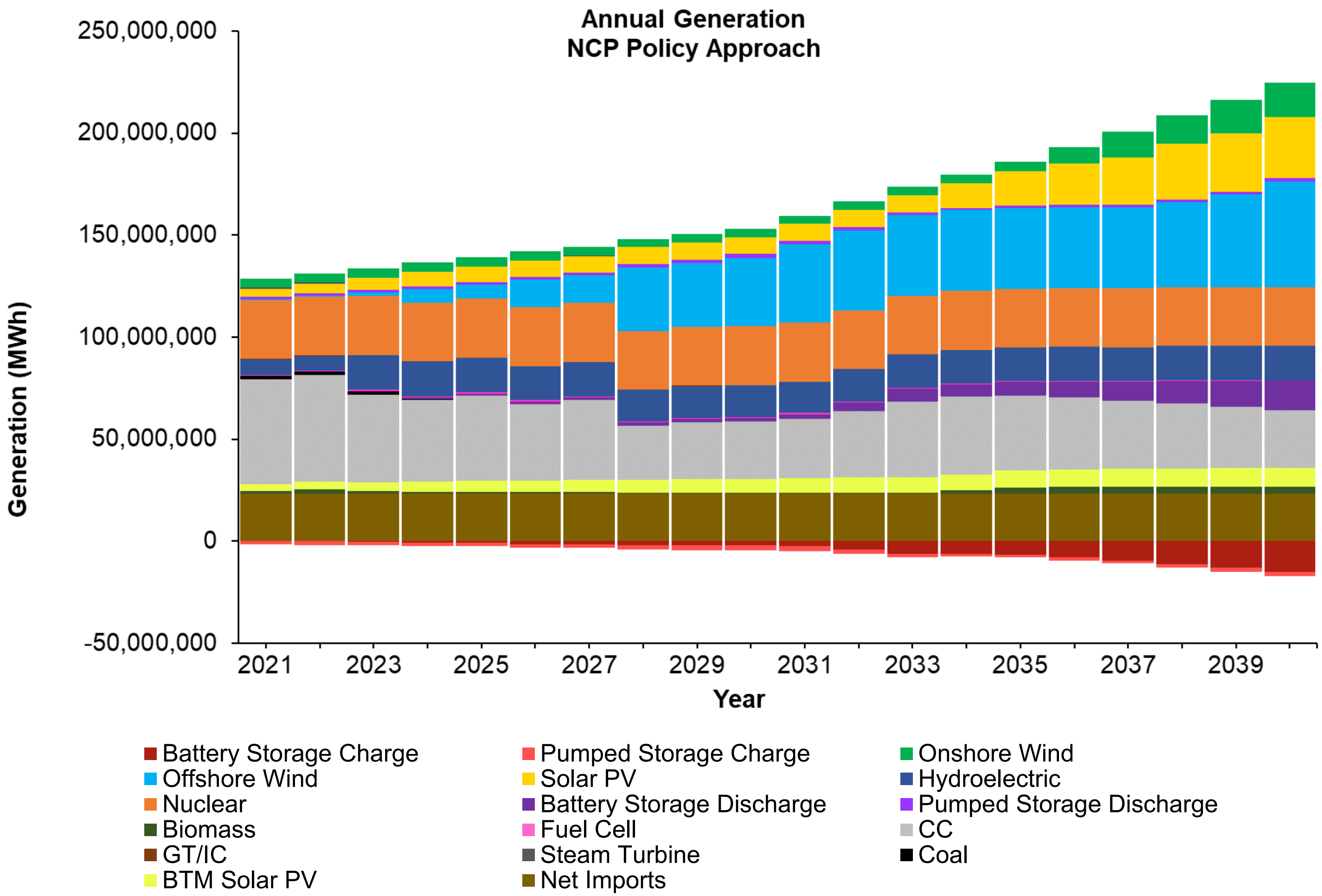
Central Case Results - NCP: Energy Mix



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Updated Central Case Results - FCEM

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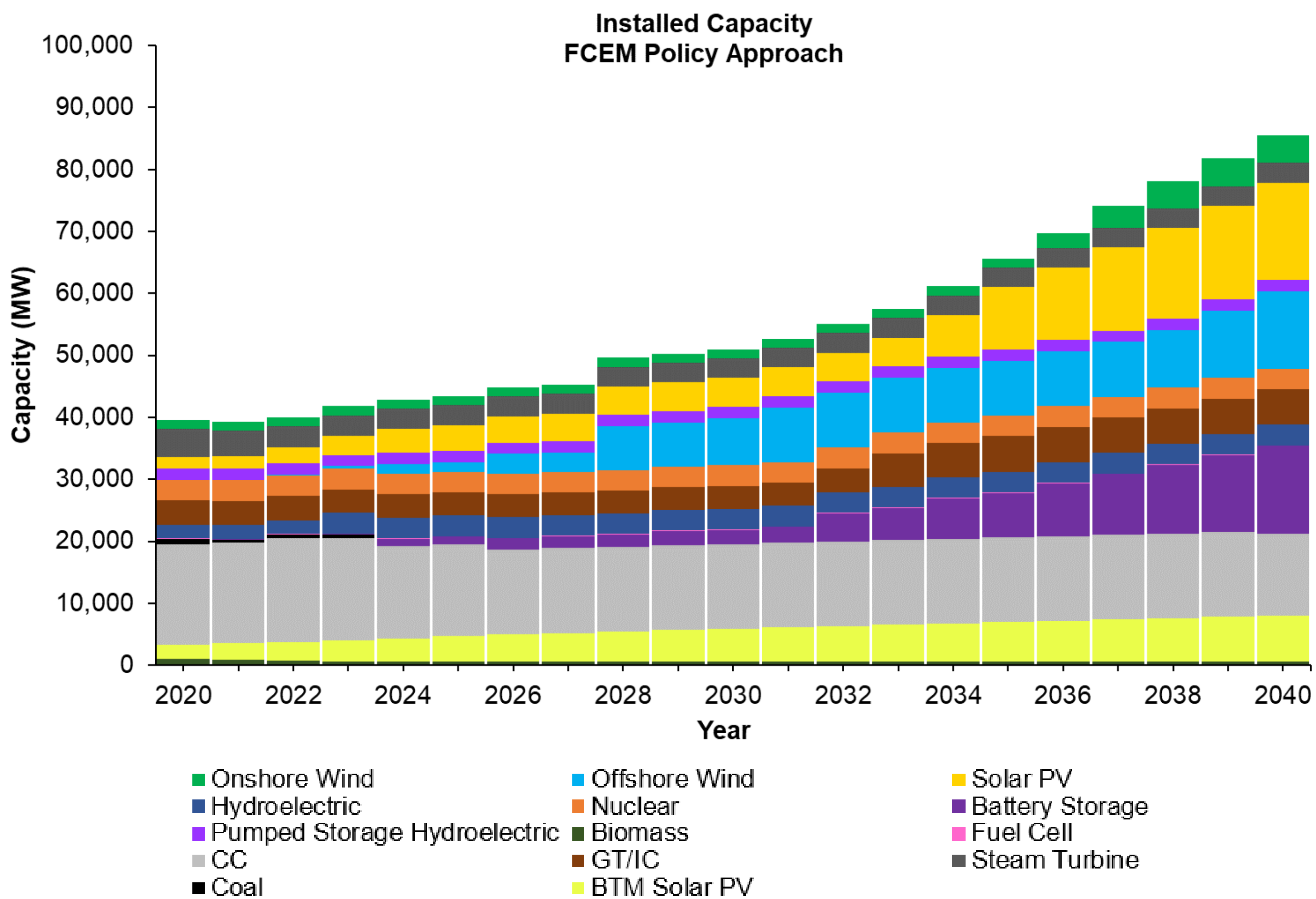
Central Case Results - FCEM: Resource Mix



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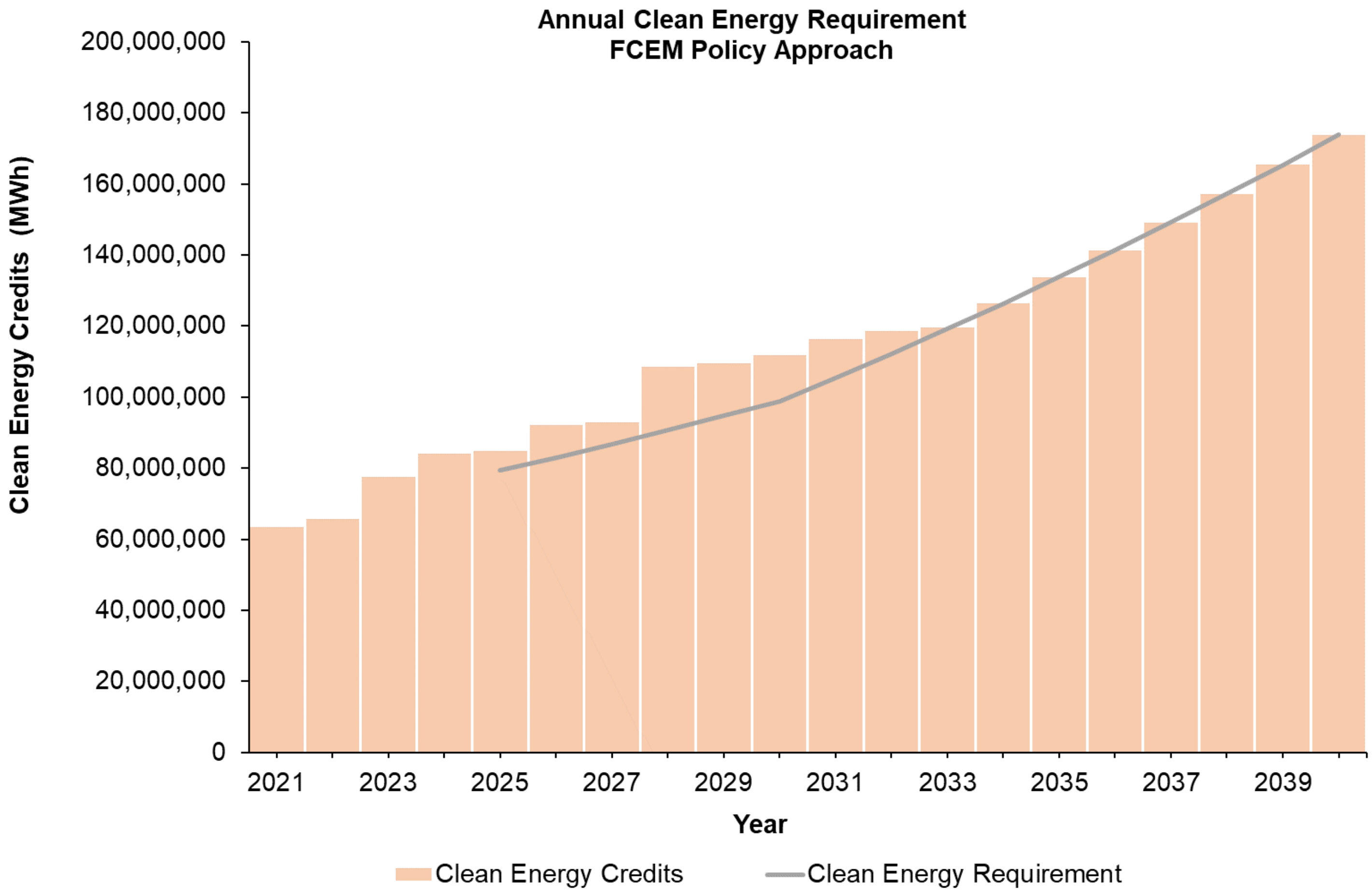
Central Case Results - FCEM: Clean Energy



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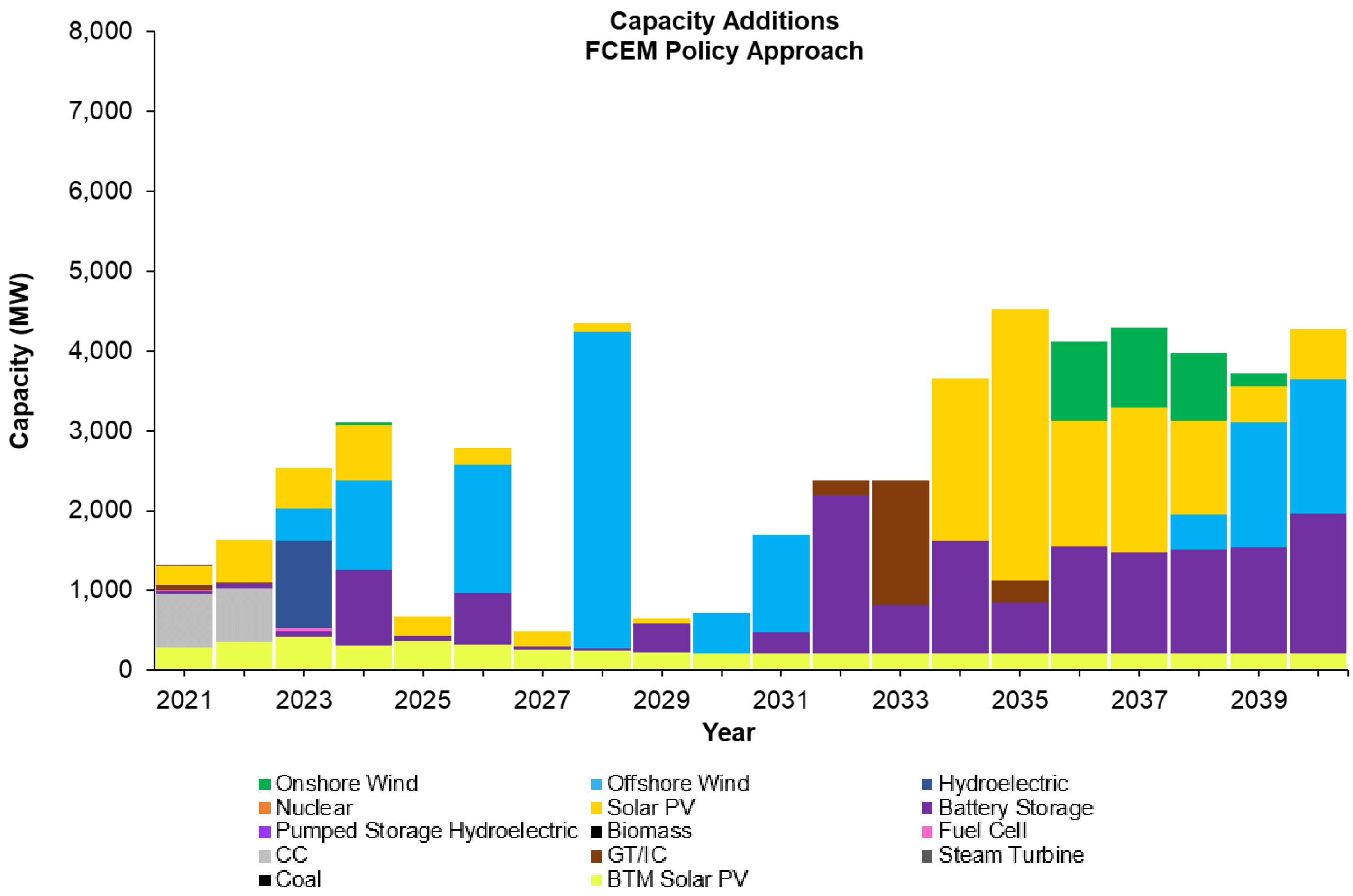
Central Case Results - FCEM: Resource Additions



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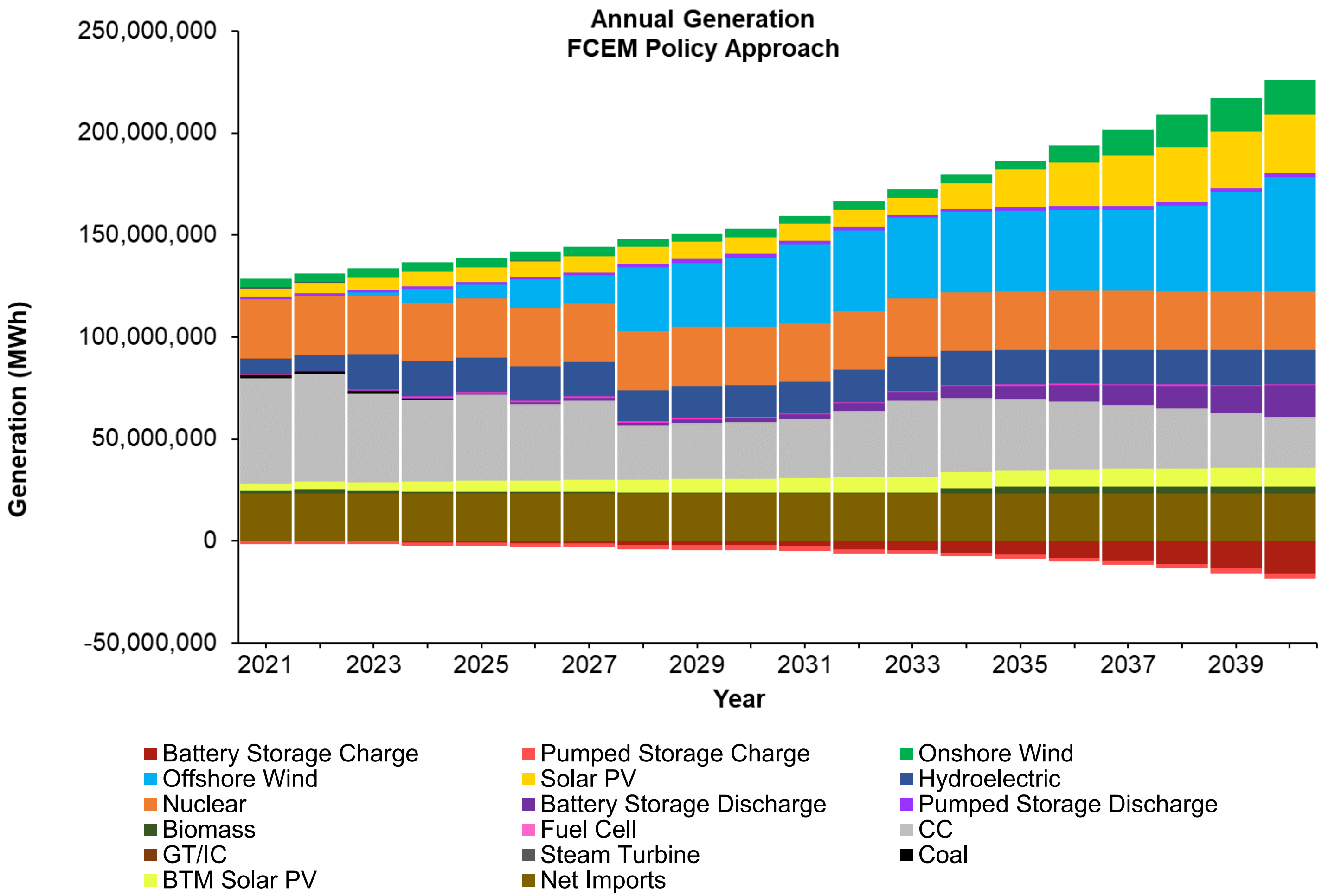
Central Case Results - FCEM: Energy Mix



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Updated Central Case Results – Status Quo

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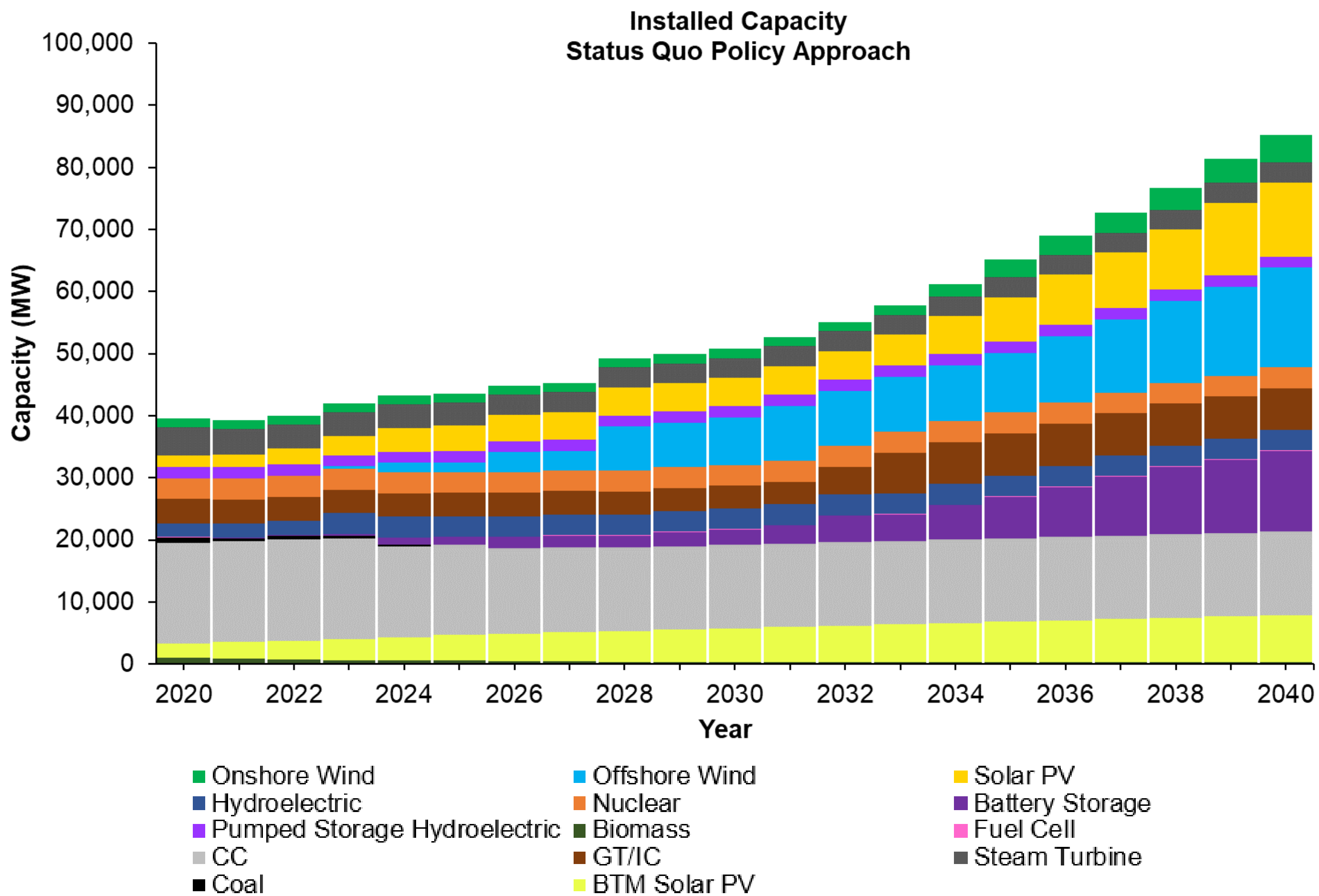
Central Case Results - SQ: Resource Mix



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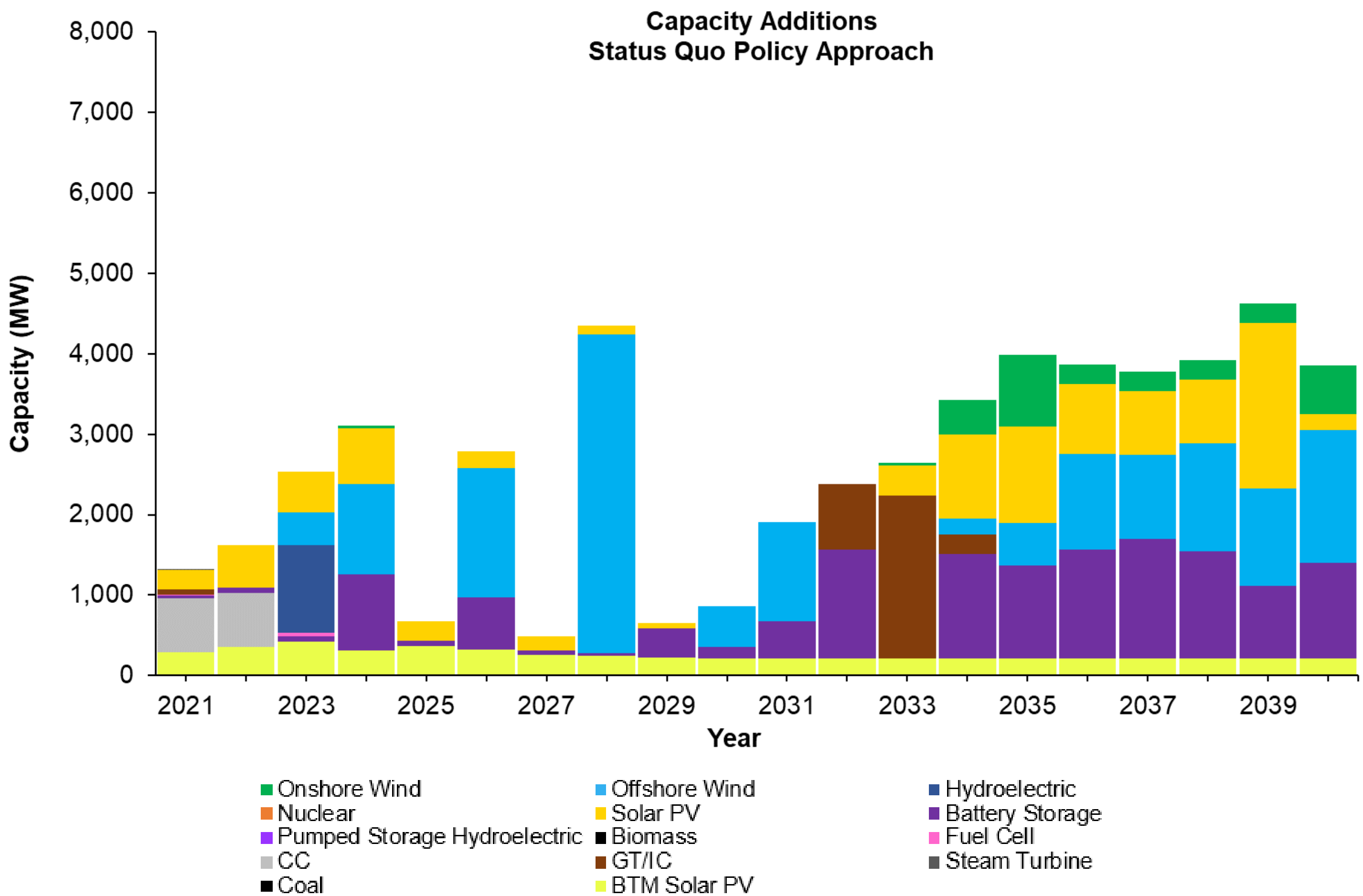
Central Case Results - SQ: Resource Additions



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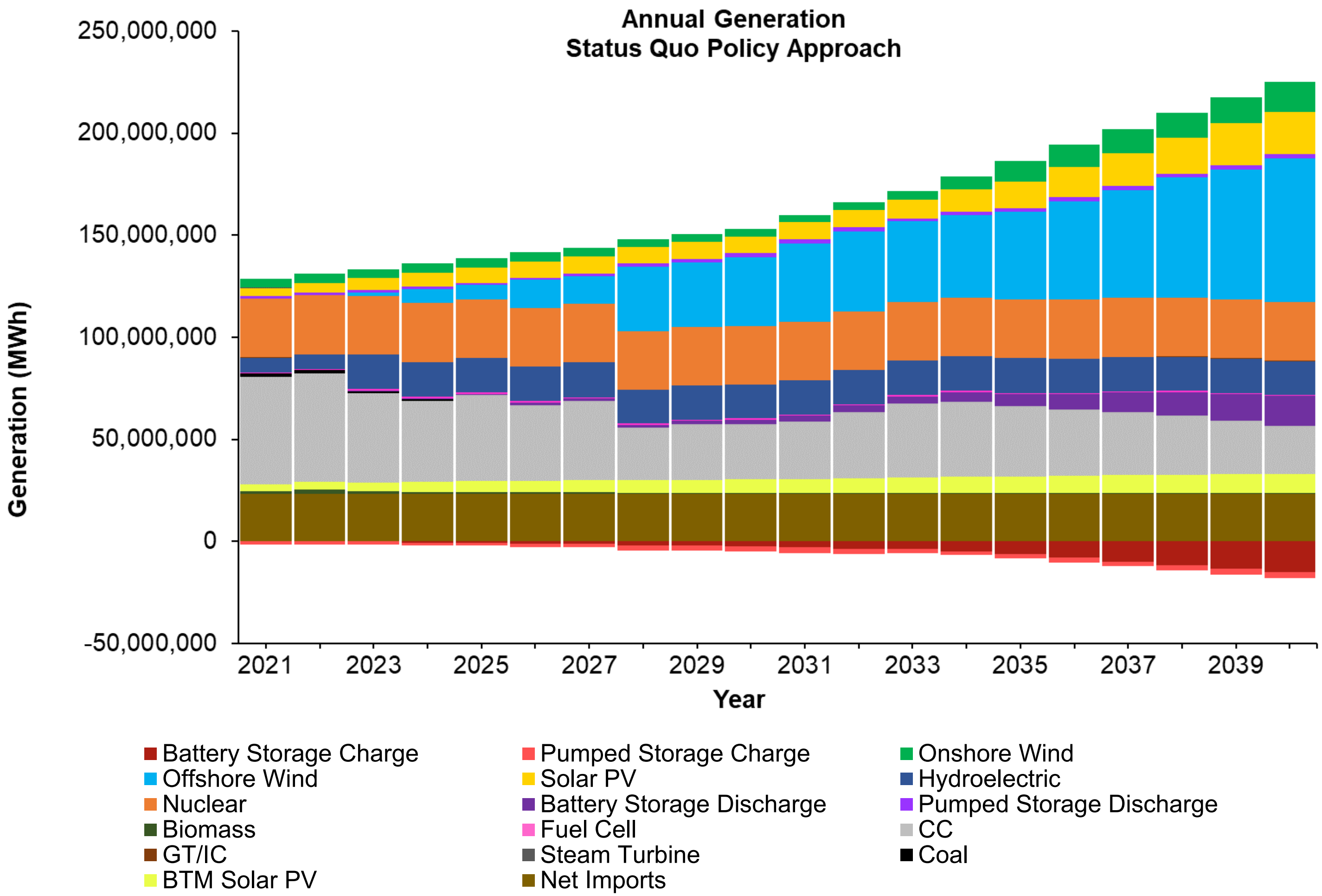
Central Case Results - SQ: Energy Mix



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Updated Central Case Results - HYB

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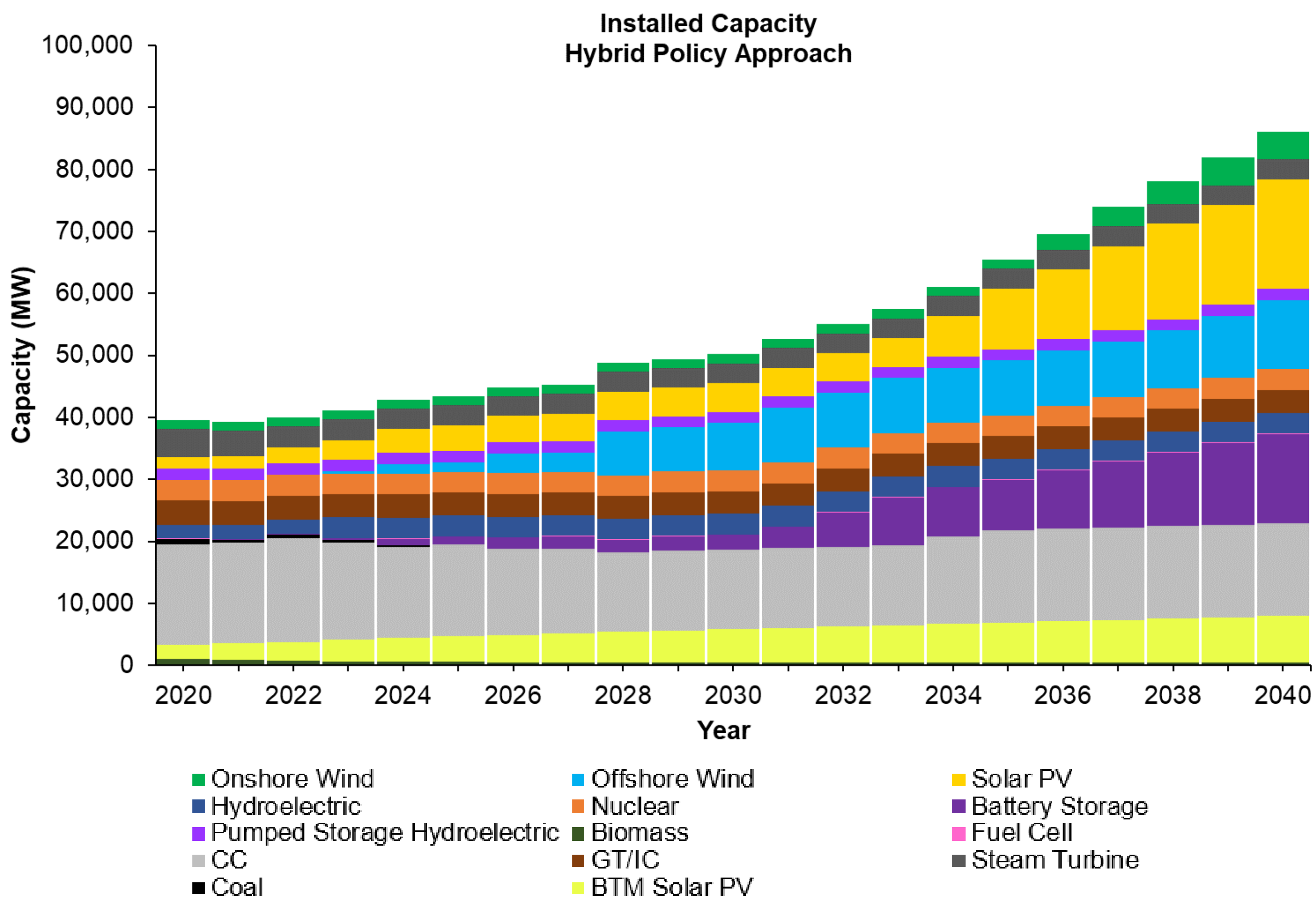
Central Case Results - HYB: Resource Mix



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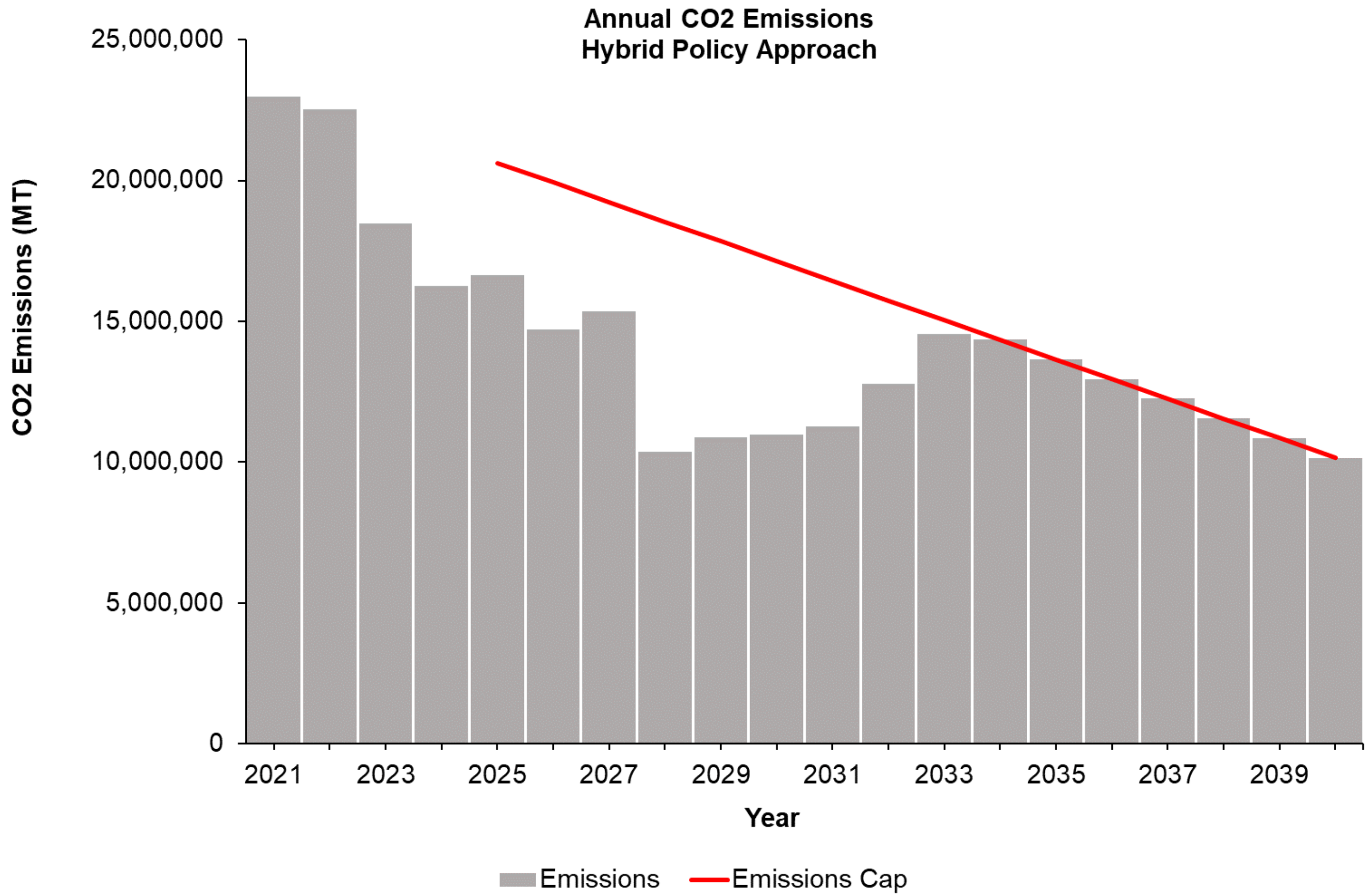
Central Case Results - HYB: Carbon Emissions



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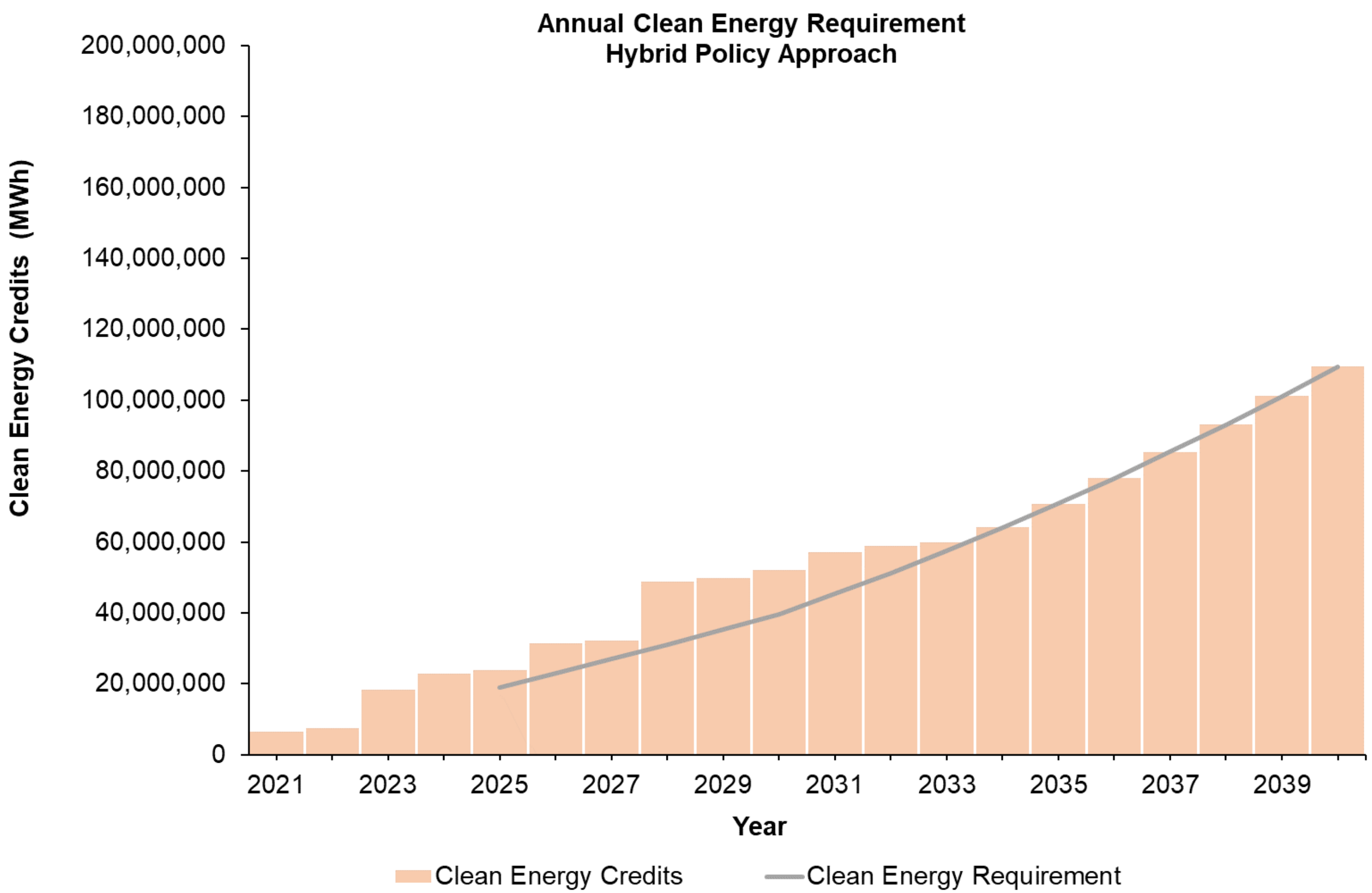
Central Case Results - HYB: Clean Energy



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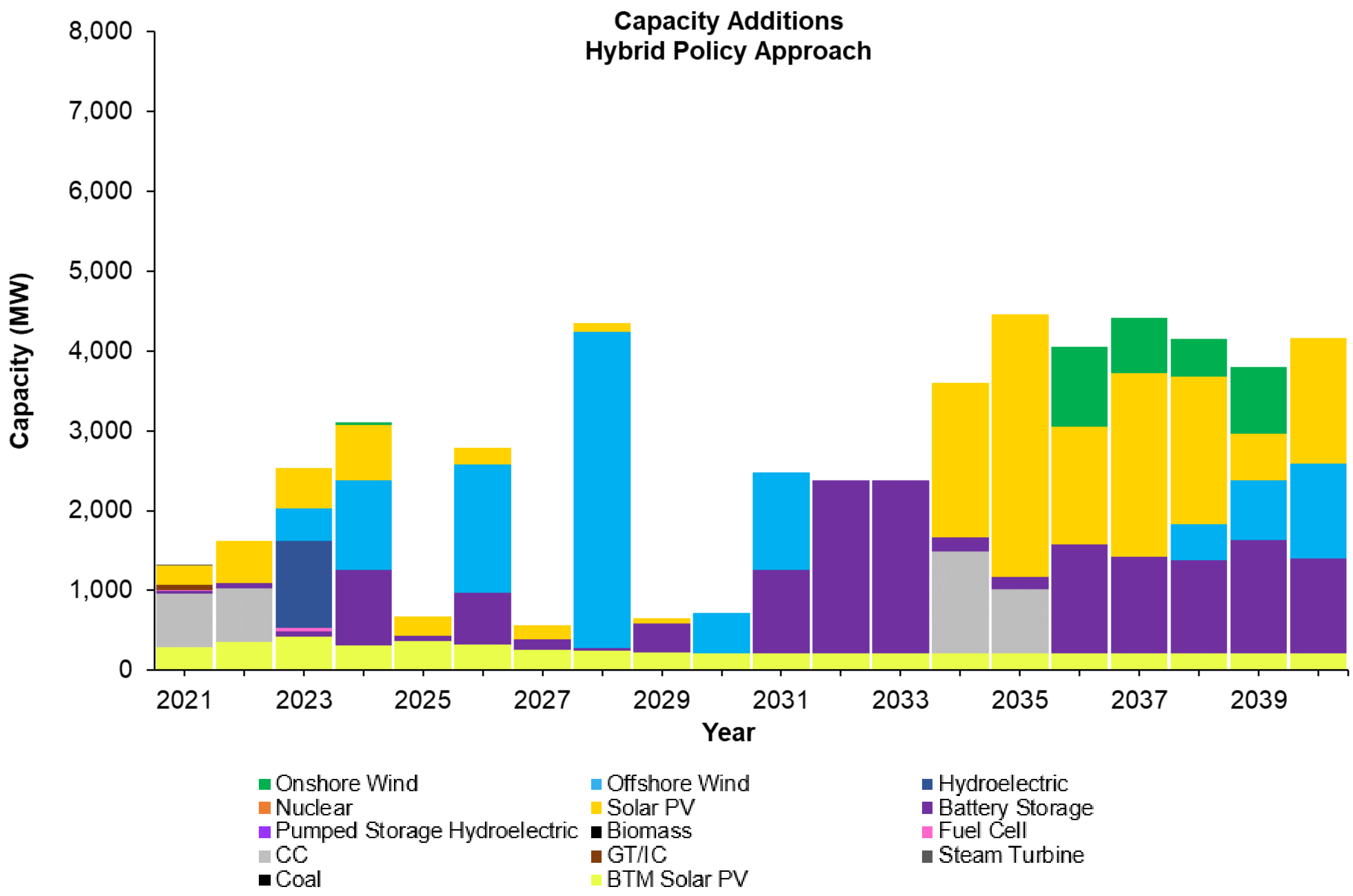
Central Case Results - HYB: Resource Additions



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Central Case Results - HYB: Energy Mix