NEPOOL
NEW ENGLAND POWER POOL

FINAL AGENDA

NEPOOL Participants Committee
Working Session: Pathways to the Future Grid
September 23, 2021, 1:00 p.m. – 5:00 p.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 final agenda items for the September 23 afternoon working session are as follows:

1. To approve the draft minutes of the July 21, 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 further detail on several modelling inputs and assumptions, including relevant load and resource assumptions, based on their analysis and observations to date. Analysis Group's update on modeling progress and next steps will also be discussed.

**For your information, the September 23 meeting will be recorded, as are all Participants Committee meetings. All those participating are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.*

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 1:00 p.m. on Wednesday, July 21, 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 teleconference meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Acting Secretary, recorded. Mr. Cavanaugh began by reporting that the slate of candidates for election to the ISO Board in 2021 had been conditionally endorsed earlier that morning. Written ballots for approval of the Waiver Agreement to accomplish the temporary waivers of certain provisions of the Participant Agreement required to seat the endorsed four-person slate would be disseminated to members and, following approval by both NEPOOL and the ISO, notice of the supporting waivers would be submitted to the FERC.

APPROVAL OF JUNE 11 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the June 11, 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 by Mr. Michael Kuser's alternate noted.

ISO PRESENTATION ON A POTENTIAL THIRD PATHWAY (HYBRID APPROACH)

On behalf of the ISO, Mr. Chris Geissler reviewed materials that had been circulated and posted in advance of the meeting about the plan of the ISO and Analysis Group Inc. (AGI) to evaluate a potential third pathway (referred to as the hybrid approach). The contemplated analysis of the hybrid approach was requested for consideration by NESCOE. Mr. Geissler explained the work schedule implications, noting that the inclusion of a third pathway in AGI's planned analyses would require additional time to model and complete. He noted that AGI's public report, which would include an assessment of all three approaches (FCEM, net carbon pricing, and the hybrid approach), was expected to be completed in April 2022.

Mr. Geissler then shared the ISO's initial observations of the hybrid approach. He began by noting that the hybrid approach consisted of two components, a net carbon price and a variant of a forward clean energy market (FCEM) and integrated clean capacity market (ICCM). As the ISO understands it, this potential hybrid model is intended to achieve two market outcomes simultaneously -- reducing carbon emissions in the electricity sector and producing average energy market prices that are no less than some administratively-determined value. Mr. Geissler indicated that the ISO and AGI would continue to evaluate how to most appropriately model the hybrid approach, which they expected would be more challenging and time-intensive than the separate evaluations of the two other stand-alone pathways. Given that effort, the ISO anticipated completing the review of all three potential pathways (including the hybrid approach) by April 2022, two months later than originally anticipated. Mr. Geissler noted that the ISO had agreed to study the hybrid approach to provide additional information to the region, but highlighted that the approach appeared to be attempting to meet a diverse set of objectives and might be inconsistent with sound market design. He concluded by requesting stakeholder feedback on various design elements of a hybrid construct (specifically the target LMP level and the limitation of Clean Energy Credits (CECs) to new resources (i.e., eligibility parameters)) and anything else concerning the efforts to study the three identified pathways.

At the Chair's request, Mr. Jeff Bentz, on behalf of NESCOE, provided an overview of the potential hybrid pathway as referenced in the memorandum included in the materials circulated and posted in advance of the meeting. He noted that this additional pathway is not presented as a proposal at this time, but rather as a proxy in the overall analysis that would necessarily require further judgment, analysis and evaluation. He referenced the two potential payment scenarios included in the contemplated hybrid approach, with both set no higher than the price used in AGI's central case.

In response to questions about whether existing resources with new components would be included in the model, Mr. Geissler and Mr. Bentz noted that, if included, those resources should be included in all three models to ensure consistency. When asked about Renewable Energy Credits (RECs) and FCEM clean energy certificates (CECs), Mr. Geissler noted that they would each affect resources differently under a hybrid construct. Further, when asked about the longevity of CEC credits, Mr. Geissler indicated the CEC process was not fixed and could change over time in all models. When asked if adding another approach to the study effort would create differences in outcomes, it was noted that the hybrid approach provided another, different way to look at possible outcomes. A member then provided feedback on the assumed compensation of existing and current renewables/clean energy resources and how the analysis of the model may result in inefficient interaction with the rest of the ISO market. Further, it was acknowledged that FERC Order 2222 would not be included in the scope of the planned modeling.

AGI PRESENTATION

Mr. Cavanaugh then introduced Mr. Todd Schatzki who, along with his AGI colleague. Mr. Chris Llop, reviewed materials, circulated and posted in advance of the meeting, noting the "work in progress" nature of the modeling process. First, Mr. Schatzki reviewed responses to certain questions asked at prior meetings about model assumptions, inputs, and mechanics. He then discussed the proposed set of scenarios that would be evaluated, noting a change from prior presentations due to the introduction of the hybrid approach as well as a sharpened look at the scenarios to ensure they reflect the most valuable output possible. The changes were further detailed, including AGI's decision to exclude NYISO modelling in the central case and the addition of transmission congestion in the proposed set of scenarios (but not in the central case). Mr. Schatzki then reviewed the proposed quantitative scenarios across the different approaches, and the scenarios that would be reviewed separately under each of the three different potential pathways.

In response to a question regarding the use of the U.S. Energy Information Administration's (EIA) cost estimates, Mr. Llop confirmed that, for offshore wind in the first year, they planned to use the cost that includes a 25% adder (which would then decline over time). Turning to carbon pricing relative to state-sponsored contracted resources versus market resources without contracts, Mr. Schatzki indicated that they did not intend to model differences in the costs between multi-year contracts and those under net carbon pricing. AGI planned to keep assumed costs the same between the base/central case and the net carbon pricing market scenario. Discussing the resource mix assumptions further, he noted the inherent nature of the regulatory approaches that, by design, lead to a least-cost outcome, which was not the case with the status quo model. Additionally, in response to a suggestion, Mr. Schatzki noted the importance of taking the many viewpoints and policies into consideration, including legislative mandates.

Addressing next steps, Mr. Schatzki indicated that market simulations would continue to be built through October 2021, with stakeholders engaged throughout the process as needed. A presentation of AGI's preliminary analysis of the results was planned for October. Mr. Cavanaugh noted that the next Future Grid Pathways Study meeting was tentatively scheduled for August 19, and that advanced notice would be provided if cancelled.

There being no further business, the meeting adjourned at 4:10 p.m.

Respectfully submitted,

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Sebastian Lombardi, Acting Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JULY 21, 2021 PM TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
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	
AVANGRID: CMP/UI	Transmission		Jason Rauch	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brooks, Dick	End User	Dick Brooks		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
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		
Conservation Law Foundation (CLF)	End User	Phelps Turner		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc	Generation	Mike Purdie	Mary Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission			Parker Littlehale
Exelon Generation Company	Supplier		Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati	
Generation Group Member	Generation	Dennis Duffy		
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity	John Coyle	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 (Jericho)	AR-RG	Mark Spencer		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JULY 21, 2021 PM TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate’s Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
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 Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power Generators Association (NEPGA)	Fuels Industry Participant	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw; Dave Cavanaugh
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
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	
PSEG Energy Resources & Trade LLC	Supplier		Eric Stallings	
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	Bob Espindola		
Union of Concerned Scientists	End User		Francis Pullaro	
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	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

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ANALYSIS GROUP

Pathways Study

Evaluation of Pathways to a Future Grid

Todd Schatzki and Chris Llop

September 23, 2021

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Overview

- Purpose of today's presentation is to provide information on **outstanding quantitative model inputs and assumptions**
- We have endeavored to provide information on current thinking and will refine based on our continued analysis and additional feedback
- We appreciate stakeholder feedback to date and welcome further feedback on our inputs and assumptions to help ensure our assumptions are reasonable and reflect a range of viewpoints regarding future policies
- We plan to present central case results at the October Participants Committee Working Session

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Agenda

- Proposed approaches to outstanding **model inputs and assumptions**
  - Load Assumptions in Study Years
  - Behind-the-Meter Solar
  - Summer/Winter Qualified Capacity
  - Resource Siting and Transmission Upgrade Costs
  - Status Quo Resource Mix

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Load Modeling Assumptions for Study Years

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Load Modeling Assumptions for Study Years

- Pathways analysis requires annual load for 2020 to 2040. To develop these, we plan to:
  - For years 2030 and 2040, assume loads based on the MA 80x50 Study, as provided by NESCOE
    - Adjusted by ISO-NE System Planning to move from weather year 2012 to 2019
    - Same approach as used in FGRS Load Scenario 3 for 2040
  - For base year, assume actual 2019 load from CELT 2020, as COVID-19 is likely to have impacted loads in 2020 and all modeled years are shaped based on a 2019 weather year
  - Under this proposed methodology, the system will become winter peaking starting in 2029

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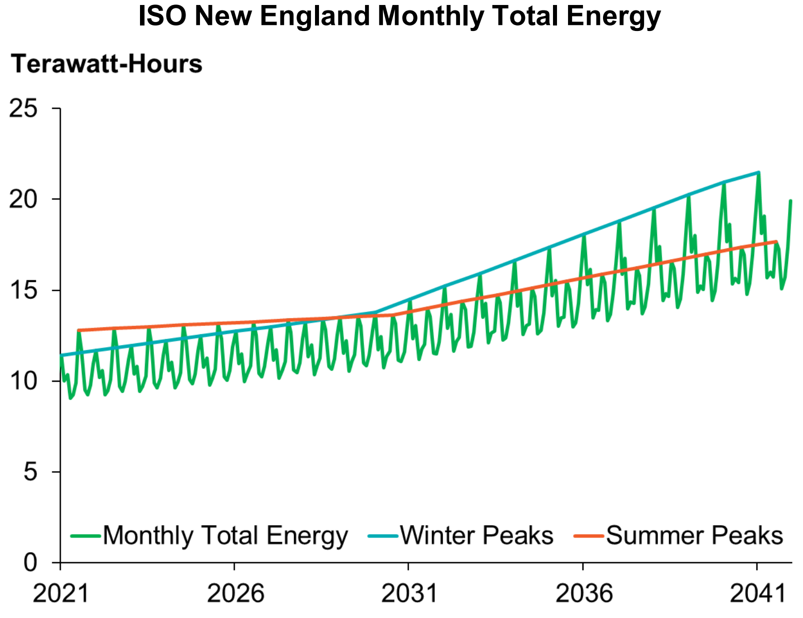
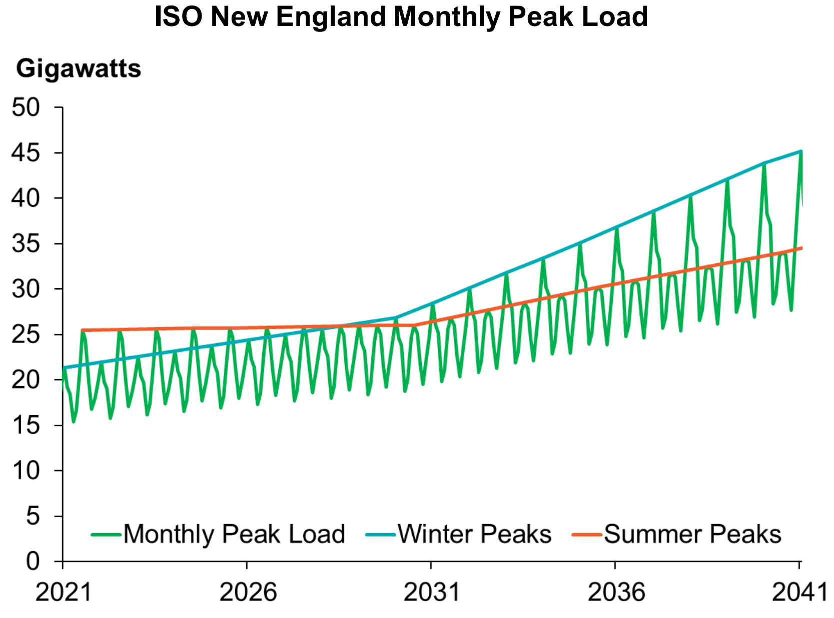
Load Forecast Modeling Assumptions for Intermediate Study Years

- Under this proposed methodology, we linearly interpolate loads in intermediate years





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Behind-the-Meter Solar Modeling Assumptions

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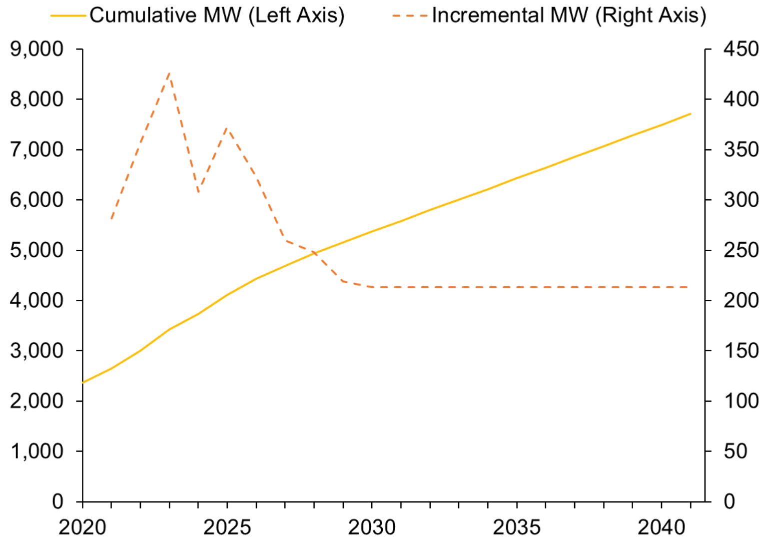
Behind-the-Meter Solar Modeling Assumptions

- Behind-the-meter solar growth in 2021-2030 in all scenarios will be based on the 2021 CELT
- For 2031-2040, growth will be constant and equal to the incremental growth in 2030
- In the figure and table below, 2020 BTM PV includes all existing BTM PV according to CELT
- BTM PV is being modeled as supply and is eligible for CECs

Assumed Model Buildout of BTM Solar



Assumed Model Annual Buildout of BTM Solar, by State (MW) 2021-2030

Year	CT	MA	ME	NH	RI	VT
2020	544	1,187	60	108	71	393
2021	19	187	29	17	8	22
2022	56	197	60	13	11	19
2023	143	180	63	12	10	18
2024	30	165	61	16	14	22
2025	88	203	29	16	14	22
2026	88	179	4	16	14	22
2027	88	116	4	16	14	22
2028	80	112	4	16	14	22
2029	54	109	4	16	14	22
2030	52	105	4	16	14	22

Source: 2021 CELT Report, ISO-NE.

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Qualified Capacity for Resource Adequacy Modeling Assumptions

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Summer/Winter Qualified Capacity Modeling Assumptions

- For all resources, we plan to estimate Qualified Capacity (for meeting resource adequacy) as the simple average of summer and winter Qualified Capacity (QC)
  - The adjustment from current market rules will help to account for the expected change in load profile in future years, including the shift from summer- to winter-peaking
  - It is not intended to approximate or predict potential future changes being contemplated by the region in the Resource Capacity Accreditation project
- For summer and winter QC:
  - For new and existing intermittent resources we use existing ISO rules; in particular, seasonal QC will be the median output during intermittent reliability hours, as defined in the ISO-NE Tariff and calculated using generation profiles that differ by location and rely on 2019 weather patterns
  - For dispatchable resources, the seasonal claimed capacity in CELT is used. If a resource is not in CELT but cleared FCA 15, the summer and winter QC from that auction is used

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Summer/Winter Qualified Capacity Modeling Assumptions

- Qualified Capacity for renewable resources is based on DNV profiles for 2019
- Utility PV has higher QC in the summer
- Wind has higher QC in the winter
- Significant variation in QC for wind based on location, even within the BOEM lease area

	Qualified Capacity as a Percentage of Nameplate Capacity		
Intermittent Resource	Summer	Winter	Average
Utility PV - CT	72%	0%	36%
Utility PV - ME	73%	0%	36%
Utility PV - NH	77%	0%	38%
Utility PV - RI	77%	0%	38%
Utility PV - VT	78%	0%	39%
Utility PV - MA	71%	0%	35%
Existing Onshore Wind - ME	22%	41%	31%
Existing Onshore Wind - NH	17%	33%	25%
Existing Onshore Wind - RI	12%	20%	16%
Existing Onshore Wind - VT	17%	40%	28%
Existing Onshore Wind - MA	17%	51%	34%
New Build Onshore Wind - Maine	30%	47%	38%
Offshore Wind - Block Island	28%	50%	39%
Offshore Wind - Bay State LA	28%	72%	50%
Offshore Wind - Equinor LA	24%	69%	46%
Offshore Wind - Mayflower LA	23%	68%	46%
Offshore Wind - Park City LA	18%	55%	37%
Offshore Wind - Revolution LA	29%	70%	49%
Offshore Wind - South Fork LA	23%	60%	41%
Offshore Wind - Vineyard East LA	24%	68%	46%
Offshore Wind - Vineyard West LA	20%	61%	41%
Offshore Wind - BOEM LA Average	27%	66%	46%
Offshore Wind - Floating off Cape Cod	32%	75%	53%
Offshore Wind - Floating off Maine	26%	66%	46%

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Resource Siting and Transmission Cost Modeling Assumptions

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Resource Siting and Transmission Upgrade Cost Modeling Assumptions

- The Pathways study aims to compare differences in outcomes, including total costs, between alternative approaches to decarbonization
- Because resource siting and transmission upgrade cost modeling assumptions will be the same in all central cases, differences in the level of costs (potentially higher or lower than the true cost) will tend to have comparable effects on each approach
- Nonetheless, we aim to assume reasonable estimates new resource costs that reflect the many factors affecting development of new resources, including plant costs (and cost change due to technological change), transmission costs, and other plant siting challenges
- Below, we provide on overview of the approach we plan to take with respect to onshore and offshore wind; similar approaches will be taken for other resource types, notably utility-scale PV
- We welcome stakeholder feedback on these assumptions

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Resource Siting and Transmission Upgrade Cost Modeling Assumptions

Onshore and Offshore Wind

- New resource capital costs will reflect both generation plant and transmission upgrades for certain technologies (e.g., onshore and offshore wind)
- Transmission upgrade costs will reflect existing available transmission capability and incremental transmission upgrades needed to increase deliverability

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Resource Siting Modeling Assumptions

Onshore Wind

- For onshore wind, buildout will be primarily sited in Maine, to reflect:
  - Relatively higher costs (and potential siting/land availability challenges) of buildout (at scale) outside of Maine
  - Location of majority of wind in the interconnection queue
- Wind profiles will be based on the four hypothetical DNV locations (labeled in green)

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Transmission Upgrade Cost Modeling Assumptions

Onshore Wind

- Many of the onshore wind sites with the highest expected capacity factors, such as those in Maine, are remote and require transmission upgrades to connect to the grid
- At present, transmission from Southern Maine to Southern New England has no incremental headroom. All new onshore wind resources will include the costs of transmission expansion
- Transmission upgrade cost estimates will be based on the ISO-NE Second Maine Resource Integration Study, and unit costs increasing in increments of 1,000 MW

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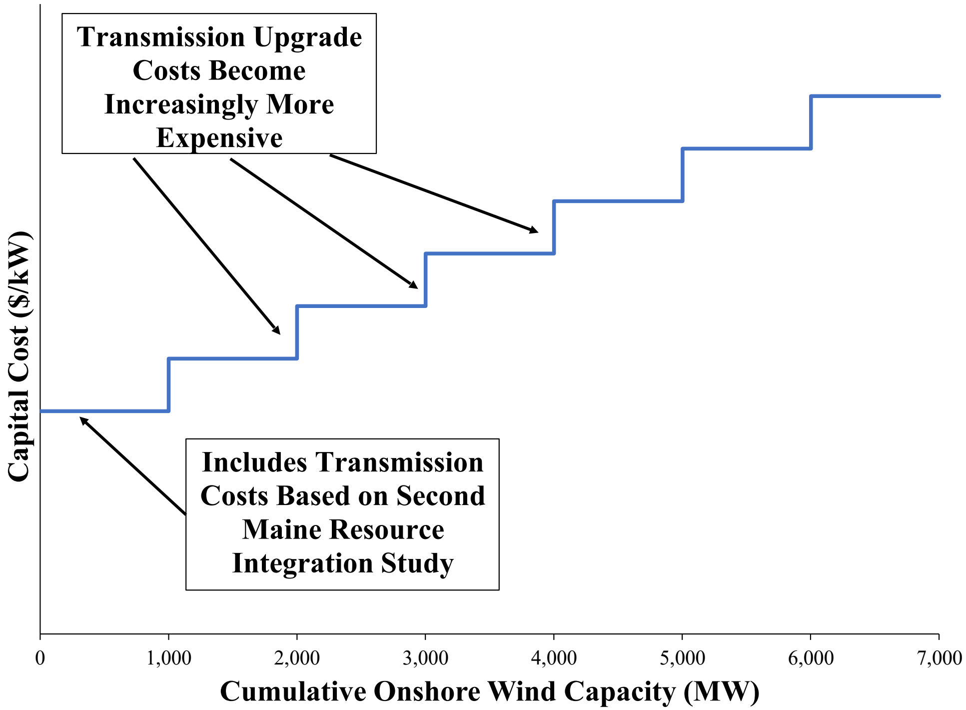
Transmission Upgrade Cost Modeling Assumptions

Onshore Wind

- Model assumes transmission will become increasingly more expensive due to challenges associated with permitting, right of way, and land costs (exhibit is illustrative and not to scale of assumed costs)
- We welcome feedback on this approach as this is not a resource adequacy study



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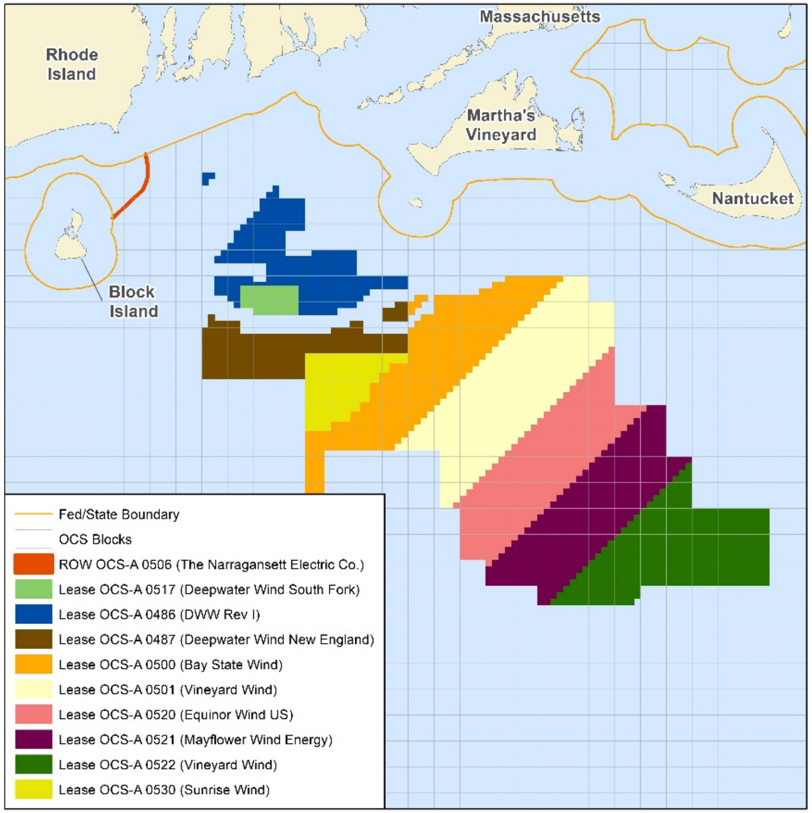
Resource Siting Modeling Assumptions

Offshore Wind

- For offshore wind, we assume that projects will be built in the BOEM lease area first
  - BOEM lease area capacity: 12,124 MW
  - Current procured and legislated offshore wind: 8,796 MW
  - Additional capacity available in BOEM lease areas: 3,328 MW
- Consistent with the MA and RI state-commissioned deep decarbonization studies, we assume an additional 3,000 MW of fixed-bottom offshore wind can be built around the existing BOEM lease areas
- Additional potential offshore wind is assumed to be floating off the southeast coast of Cape Cod or Maine



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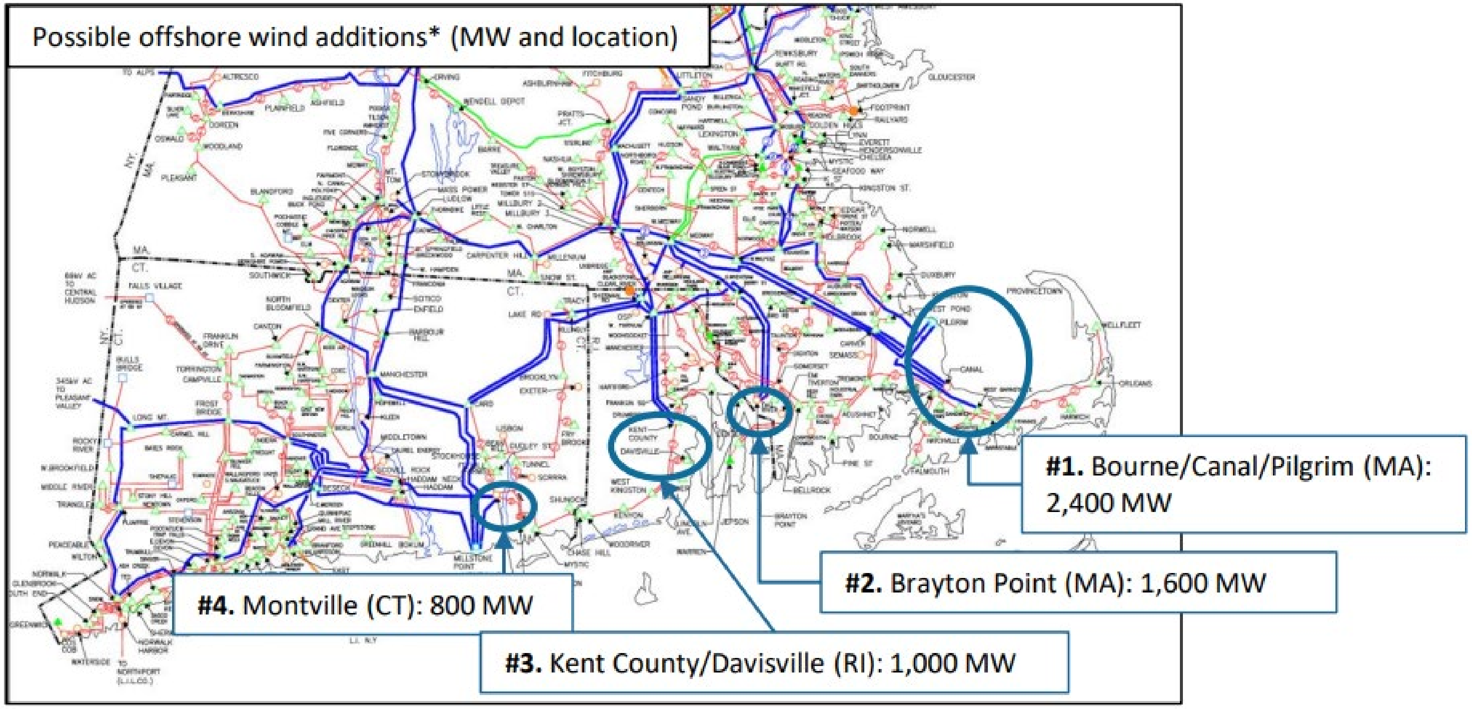
Transmission Upgrade Cost Modeling Assumptions

Offshore Wind

- ISO-NE study estimates ~5,800 MW can be interconnected without significant onshore transmission upgrades (ISO-NE 2019 Economic Study Offshore Wind Transmission Interconnection Analysis)



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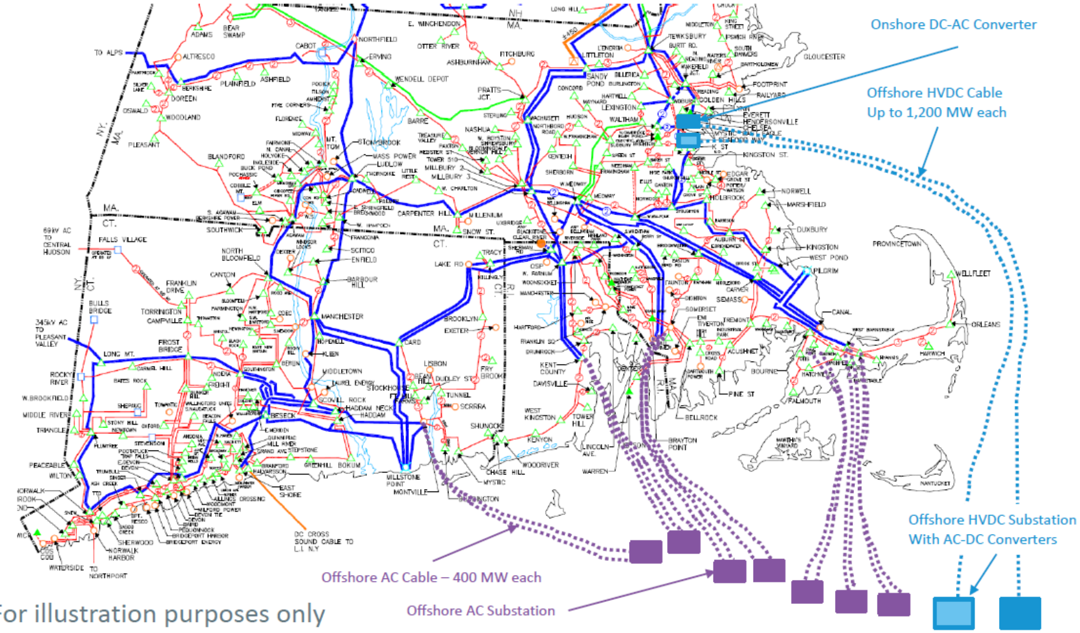
Transmission Upgrade Cost Modeling Assumptions

Offshore Wind

- Additional transmission will either require significant onshore transmission upgrades or offshore HVDC connections that bypass the onshore grid
- As more offshore wind is developed, it will become increasingly costly to find adequate landing sites.



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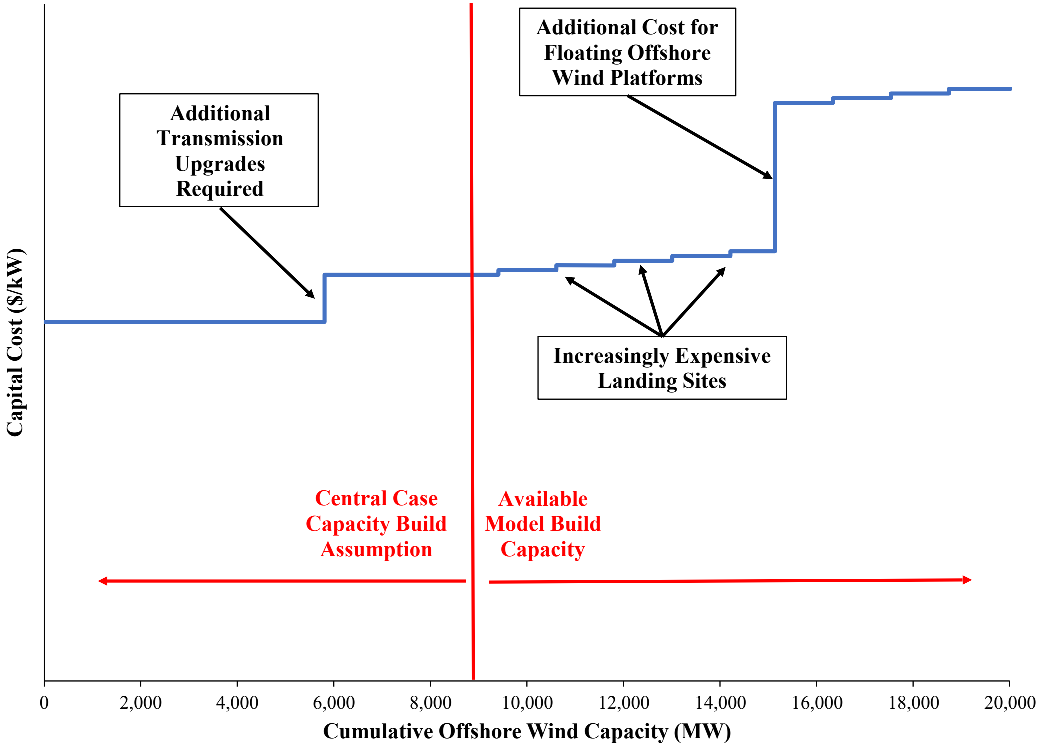
Transmission Upgrade Cost Modeling Assumptions

Offshore Wind

- Costs will become increasingly more expensive due to the need for significant transmission upgrades, siting challenges, and exhausting the BOEM lease areas (exhibit is illustrative and not to scale of assumed costs)



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Status Quo Resource Mix Modeling Assumptions

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Status Quo Resource Mix Modeling Assumptions

- As discussed at July's PC meeting, the Status Quo resource mix will align with the findings of state-commissioned deep decarbonization studies
- Assumed Status Quo resource mix typically reflects a state's decarbonization case and high-load (electrification) scenarios that most closely align with Pathways assumptions (emissions targets, continued operation of nuclear plants)
- Additional buildout required to meet states' clean energy demand and regional emissions reduction target will be determined by the model

	2020-2040 Incremental Build (GW)					
State	**Offshore Wind**	**Onshore Wind**	**Solar**	**Storage**	**NECEC**	**Total**
Connecticut	4.7	0.4	2.3	2.2	-	9.7
Maine	-	2.0	0.7	0.5	-	3.2
Massachusetts	9.2	0.4	5.5	0.4	1.2	16.6
New Hampshire	-	-	-	-	-	--
Rhode Island	2.0	-	1.4	1.0	-	4.4
Vermont	-	0.2	0.8	-	-	1.0
Total	16.0	3.0	10.7	4.1	1.2	35.0

Note: New Hampshire's 2018 State Energy Report expressed a desire to pursue the "lowest cost resources," so its SQ resource mix will be determined by model build.
Sources: AG review of state legislated policies, executive orders, and state-commissioned deep decarbonization studies, which are: Connecticut's "Draft Integrated Resources Plan: Pathways to achieve a 100% zero carbon electric sector by 2040" (2020), Maine's "State of Maine Renewable Energy Goals Market Assessment" (2021); Massachusetts' "Energy Pathways to Deep Decarbonization" (2020), Rhode Island's "The Road to 100% Renewable Electricity by 2030 in Rhode Island" (2020), and Vermont's "Energy Policy Options for Vermont: Technologies and Policies to Achieve Vermont's Greenhouse Gas and Renewable Energy Goals" (2014). NECEC represents the New England Clean Energy Connect.

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Next Steps

- October
  - Present initial set of results for each of the Pathway central cases
  - Discuss final set of scenarios to be run

- December
  - Present updates to central cases, if any, based on stakeholder feedback
  - Present initial set of scenario results

ANALYSIS GROUP

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