FINAL AGENDA

NEPOOL Participants Committee
Working Session: Pathways to the Future Grid
July 21, 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 agenda items for the July 21 working session are as follows:

1. To approve the draft minutes of the June 11, 2021 Participants Committee "Pathways Study" meeting. A copy of the draft meeting minutes are included with this supplemental notice.

2. Presentation and continued discussion to help scope and define the ISO's pathways analysis, including discussion of additional hybrid pathway analysis, and modeling details with the Analysis Group.

**For your information, the July 21 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 9:30 a.m. on Friday, June 11, 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 expressed appreciation to those who provided written comments thus far in the process and provided an overview of the agenda for the meeting.

APPROVAL OF MAY 13 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the May 13, 2021 Pathways meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the Committee unanimously approved the preliminary minutes of the May 13, 2021 meeting as circulated.

ISO PRESENTATION ON SCOPE AND DEFINITION OF PATHWAYS ANALYSIS

On behalf of the ISO, Mr. Steven Otto reviewed materials that had been circulated and posted in advance of the meeting that continued discussions on the modeling approach and assumptions that the ISO, together with Analysis Group, Inc. (AGI) planned to use to evaluate the forward clean energy market (FCEM) and net carbon pricing (NCP) frameworks.

Mr. Otto began by reviewing the work completed to that point, including a draft of a “Final Scoping Report” that was included with the materials circulated and posted for the meeting. The Scoping Report described the modeling approaches for the FCEM and NCP frameworks and plans for a comparison against a "status quo" framework, which would allow for key model outputs from each framework to be directly compared. He expressed appreciation for the feedback that had been received to date and posted on the NEPOOL website. He welcomed and encouraged any additional feedback relating to the details in the draft final scoping report.

Turning to the eligibility of imports in a FCEM, Mr. Otto identified the concerns that the ISO sought to balance – (1) allowing resources from outside of New England to contribute to the region's decarbonization goals can reduce costs to consumers and (2) other regions may not have clean energy requirements and so "double-counting" of clean energy may occur. In seeking to balance these two concerns, he explained that the ISO proposes that AGI's model permit clean and renewable resources from Canada and resources in New York that sell RECs into New England to qualify for clean energy certificates (CECs) but not permit New York resources that are clean but are non-renewable to be eligible to sell CECs into New England.

Mr. Henry Yoshimura then presented the ISO's proposed approach for the development of a model for a "hybrid" pathway analysis. He explained that, since the hybrid model builds upon the FCEM and NCP frameworks, the ISO's and AGI's current thinking was to complete the analysis of those two frameworks first, in the previously-committed timeframe, and then to complete analysis of and report on the hybrid pathway thereafter. Draft results on the FCEM and NCP frameworks were expected to be available before the end of 2021, with a final report on those modeled market outcomes to be shared with stakeholders and finalized in the first quarter of 2022.

Members commented on, and expressed concerns regarding, the extended timeframe for completion of the hybrid pathway analysis. Mr. Yoshimura and Mr. Todd Schatzki of AGI provided further insight and reasons for that proposed timeframe. A NESCOE representative offered to explore how NESCOE might provide to support acceleration of the process.

AGI PRESENTATION

Mr. Cavanaugh then introduced Mr. Schatzki who, along with his AGI colleague Mr. Chris Llop, reviewed materials, circulated and posted in advance of the meeting, that included an update on several of the proposed modeling inputs and assumptions for the central case, and provided more information in response to several stakeholder questions from previous meetings. Mr. Schatzki began with an overview of the contemplated modeling approach, which included modules to simulate the region's electricity markets (i.e. Energy and Ancillary Service (reserve) markets (EAS), FCM, and the proposed FCEM and NCP frameworks). The "capacity expansion" model would first arrive at a future resource mix and then analyze outcomes in the EAS and capacity markets, reflecting the impacts of the FCEM, NCP and *status quo* frameworks. He explained that this model would by design include simplifying assumptions but offered a desirable level of flexibility.

In response to questions, Mr. Schatzki clarified how conceptually resource retirements would be identified and simulated in the model. He stated that, with respect to resource adequacy, preliminary plans were to assume a reserve margin based on a planning study (e.g. load plus a percentage), with details yet to be finalized. Addressing timeframes, he noted plans to run the Capacity Expansion Module for a full 20 years (to 2040) and possibly to run market simulations for the EAS and FCEM frameworks for one or two interim years (e.g. 2030 or 2035) to obtain additional details.

After a brief recess, Mr. Schatzki continued the discussion on modeling inputs and assumptions, beginning with a review of the preliminary new entry capital costs, which were to rely on the 2021 U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) overnight capital costs (and potentially other factors still under consideration). He explained, in response to a question, the reasons for choosing these cost assumptions rather than other recently developed and differing new entry capital cost assumptions. He confirmed that the list of technologies identified in the presentation would be the full set of resources to be considered in the capacity expansion model. He explained that, for reasons related to pricing determination and siting complexities, Canadian hydro had not been included, but noted AGI's openness to reconsideration in this area. Further, when evaluating current technology "optimism" factors, he clarified that the model would use the details consistent with EIA's usage of the data. When asked about how state policies would influence the capacity expansion model, specifically with respect to onshore and offshore wind, Mr. Schatzki explained that such policies would be reflected in the resource mix used for comparing the status quo with other cases/scenarios.

Mr. Schatzki then reviewed the status quo resource mix, which under all central cases, would reflect region-wide electricity sector emissions 80% below 1990 levels. He noted that the modeling analysis would assume long-term contracts incenting new resource financing and a resource mix consistent with New England States' policy assessments. He then reviewed the policy contribution allocation by state for both the status quo and the FCEM analyses. Responding to a question regarding decarbonization levels, he noted that modeling would begin with status quo levels and move gradually to the carbon targets over the full time period. When asked about the approach to capacity expansion, he clarified that in all three scenarios, AGI intended to pre-determine carbon levels, though the mix of resources that would achieve those levels would be different within each model. He also noted that the process by design wouldn't incent the least cost resource.

Turning to resource retirement assumptions, Mr. Schatzki noted that all three central cases would assume that any currently announced retirements have taken effect, and both Seabrook and

Millstone would remain within the models. He then reviewed the proposed set of scenarios that will be evaluated within the planned models.

Mr. Cavanaugh then introduced Mr. Chris Llop from AGI who addressed stakeholder questions from previous meetings. Mr. Llop reported, among other things, that AGI, in its modeling, proposed to allow clean resources in neighboring states and provinces to import CECs if they also import the associated certificates for all clean/renewable attributes (AGI assumed New York nuclear generation would be used to meet New York's clean energy goals, and would not supply CECs to New England). AGI would address transmission considerations by assuming no transmission congestion in the central cases, considering adjustments to costs for new renewable generation from export-constrained areas to account for incremental transmission costs, and evaluating a scenario with the existing transmission system and power flows to analyze how outcomes differ under each policy approach. Given expected modeling and/or policy complexities, AGI was not likely to specifically account for system engineering constraints associated with integrated solar and storage resources or to focus on municipal solid waste or biomass considerations.

Addressing next steps, Mr. Llop indicated that market simulations and analysis would begin in July and run through August. Stakeholders would be engaged throughout the process as needed, with a presentation of AGI's preliminary analysis of the results planned for October. Mr. Cavanaugh noted that the next Future Grid Pathways Study meeting was scheduled for July 21.

There being no further business, the meeting adjourned at 3:12 p.m.

Respectfully submitted,

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Sebastian Lombardi, Acting Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN JUN 11, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Actual Energy, Inc.	Supplier		John Driscoll	
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American Petroleum Institute	Fuels Industry Participant			Paul Powers
Ampersand Energy Partners LLC	Supplier			Julia Frayer
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Avangrid Renewables	Transmission	Kevin Kilgallen		
AVANGRID: CMP/UI	Transmission		Alan Trotta	
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	Supplier	Aleks Mitreski		
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	
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		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
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		Mary Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Eversource Energy	Transmission			Parker Littlehale
Exelon Generation Company	Supplier		Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation		Abby Krich	
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			Marji Philips

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 11, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Marble River, LLC	Supplier		John Brodbeck	
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	
Nautilus Power, LLC	Generation		Bill Fowler	
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	
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	
Shell Energy North America (US), L.P.	Supplier	Matt Picardi		
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	
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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ISO new england

Pathways to the Future Grid

Evaluating frameworks to advance the region's clean energy transition: Hybrid Request

Chris Geissler

CGEISSLER@ISO-NE.COM

ISO and AGI plan to evaluate a third pathway – the hybrid approach

- A hybrid approach was requested for consideration by NESCOE; other stakeholders supported the concept of evaluating the approach
- NESCOE then provided further detail on the hybrid approach in its memo, available at https://nepool.com/wp-content/uploads/2021/06/FGP_NPC_20210721_NESCOE_Hybrid_Approach_Assumptions_20210622.pdf
- The hybrid approach shares some design elements with FCEM and net carbon pricing, although it also has some unique features

Implications for pathways work schedule

- Pathways Study scope of work originally contemplated the study of two pathways – an FCEM and net carbon pricing (plus status quo), with a public report to be completed in February 2022
- The inclusion of this third pathway expands the scope of work requiring additional time to model and complete; we expect the public report, which will include an assessment of the hybrid approach, will be completed in **April 2022**
  - Consistent with stakeholder requests, we plan to share results of each studied pathway simultaneously
    - Includes the public report, preliminary results, etc.
- As with earlier discussions regarding the FCEM and net carbon pricing, we welcome stakeholder questions and feedback

Upcoming pathways schedule

- Today
  - ISO/stakeholders: Overview of hybrid approach framework
  - AGI: Further discussion of modeling approach and scenarios
- August
  - Stakeholders/ISO: Finalize key design elements of hybrid approach framework
  - AGI: Close out any outstanding core design elements
- September/October
  - Provide updates on modeling work, as needed, at PC or PC Working Session
- Q4 2021
  - Discuss preliminary model results for central cases

ISO'S PRELIMINARY OBSERVATIONS REGARDING THE HYBRID APPROACH

ISO's summary of hybrid approach: two primary components

- Based on NESCOE memo and related discussions, the ISO anticipates the hybrid approach would consist of two components
- Component 1: A net carbon price
  - Carbon price is applied to all emitting resources and will increase revenues for lower and non-emitting resources
  - Generally consistent with how this mechanism is applied in the net carbon pricing framework
- Component 2: A variant of FCEM/ICCM
  - FCEM pathway awards clean energy certificates (CECs), and their corresponding revenues, to all resources that provide clean energy
  - Hybrid approach only awards CECs to "new" resources for their clean energy production
  - "New" clean resources therefore receive greater revenues under this approach than "existing" clean resources

ISO's summary of hybrid approach: simultaneous market outcomes

- Set carbon and FCEM/ICCM targets with aim of simultaneously achieving two market outcomes
- Outcome 1: Reduce carbon emissions in the electricity sector
  - Central case will assume same level of decarbonization as other pathways and status quo
  - Corresponds with an 80 percent reduction relative to 1990 levels
- Outcome 2: Produce average energy market prices that are no less than some administratively determined value
  - NESCOE's memo proposes that the model parameters be set to produce an average annual LMP of $41
  - This value is calculated using a measure of average historic hub LMPs and "the Millstone contract rate" of $49.99/MWh
  - NESCOE contends that such energy market revenues may support Millstone's continued operation

Modeling the hybrid approach

- The ISO and AGI continue to evaluate how to most appropriately model the hybrid approach
  - May evolve based on stakeholder feedback and/or as design details of the hybrid approach unfold
- The hybrid approach may be more challenging and time-intensive to model than the two other pathways; hence the additional time for reporting
  - Other pathways seek to satisfy a carbon emissions outcome
  - Hybrid approach cases must also satisfy a second market outcome – the average LMP value
- For the model to meet both market outcomes, our preliminary thinking is that the model will need to iteratively "tune" the CEC parameter until both outcomes are satisfied

Preliminary ISO policy observations and stakeholder feedback

- While the ISO has agreed to study the hybrid approach to provide information to the region, the ISO notes that this pathway appears to be attempting to meet a diverse set of objectives
- The ISO also wishes to highlight two ways in which this pathway appears to be inconsistent with sound market design
  - The hybrid approach limits CEC awards to new resources only and, therefore, does not pay a uniform price for the desired clean energy attribute
  - The hybrid approach does not let market decide how desired environmental attributes can be provided at least cost – instead aims to set energy prices to ensure operation of desired resource(s)
- ISO is interested to hear stakeholder feedback on various design elements put forth in the NESCOE memo, including:
  - Target LMP level
  - Limitation of CECs to new resources (eligibility parameters)

ISO looks forward to working with stakeholders to evaluate Pathways to the Future Grid

- With help of stakeholders and the Analysis Group, ISO will evaluate market outcomes under forward clean energy market, net carbon pricing, and hybrid frameworks
- Continue to welcome stakeholder feedback on these efforts, including the frameworks to be studied
- Share final report on modeled market outcomes with stakeholders in April 2022

Pathways Study

Evaluation of Pathways to a Future Grid

Todd Schatzki and Chris Llop

July 21, 2021

ANALYSIS GROUP

Overview

- Purpose of today's presentation is to:
  - Provide **responses** to certain questions asked in prior committee meetings' discussions of model assumptions, inputs, and mechanics
  - Discuss current thinking about **scenarios** to be evaluated and provide an opportunity for feedback
  - Moving forward, we will transition our focus to building the model and developing preliminary results
- As with our prior presentations, inputs and assumptions discussed today are work-in-progress; we have endeavored to provide information on current thinking, and will refine based on our continued analysis and additional feedback
- We appreciate the stakeholder feedback to date and encourage further feedback to help ensure our assumptions are reasonable and reflect a range of viewpoints regarding future policies

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Agenda

- Questions and Answers from Prior Meetings
- Proposed Set of Scenarios
- Appendix (for reference purposes):
  - June 2021 AG Pathways Presentation
  - May 2021 AG Pathways Presentation

Questions and Answers from Prior Meetings

REC and CEC Eligibility within ISO-NE

Question: What technology types will be REC/CEC eligible within New England?

- REC-eligibility will be generally consistent with how the majority of New England states determine a technology to be REC-eligible
- The detailed set of REC-qualifying units is available in the NEPOOL GIS system
- As there are 30 classes of RECs in the NEPOOL GIS system, AG will make some simplifying assumptions and model a single REC product

Technology	Eligible for RECs?	Eligible for CECs?
Onshore wind	✓	✓
Offshore wind	✓	✓
Utility-scale solar	✓	✓
Behind-the-meter solar	✓	✓
Canadian/NYPA (large) hydro	N/A	N/A
Run-of-river hydro	✓	✓
Pondage hydro	✓	✓
Pumped storage	✗	✗
Nuclear	✗	✓
Battery storage	✗	✗
Solar + storage	✓	✓
Municipal solid waste	✓	✓
Other biomass	✓	✓
Fuel cells	✗	✗

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REC and CEC Eligibility of "Clean" Imports

Question: What technology types will be REC/CEC eligible when considering imports?

- Clean imports will be CEC-eligible if they are bundled with RECs, to address concerns about the same MWh being used to meet clean energy goals in both New England, and, e.g., New York
- While Canadian hydro will not be eligible for RECs, it will be eligible for CECs (See ISO-NE's June PC slide 9, on CEC eligibility)
- BTM PV from neighboring areas is expected to be utilized by native loads and is therefore not expected to be exported as wholesale power

Technology	CEC eligibility of Imports from…	
	New York	Canada
Onshore wind	✓	✓
Offshore wind	✓	✓
Utility-scale solar	✓	✓
Behind-the-meter solar	×	×
Canadian/NYPA (large) hydro	✓	✓
Run-of-river hydro	✓	✓
Pondage hydro	✓	✓
Pumped storage	×	×
Nuclear	×	✓
Battery storage	×	×
Solar + storage	✓	✓
Municipal solid waste	✓	✓
Other biomass	✓	✓
Fuel cells	×	×

Ancillary Services

Question: How will the analysis model ancillary services, and what services will be modeled?

- The Pathways model will ensure the system secures an hourly requirement of ancillary services for the following products, including the cascading nature of the current ISO-NE reserve product requirements
  - Ten-Minute Spinning Reserve (TMSR), with hourly requirement of 600 MW
  - Ten-Minute Non-Spinning Reserve (TMNSR), with hourly requirement of 1,600 MW
  - Thirty-Minute Operating Reserve (TMOR), with hourly requirement of 2,400 MW
  - Regulation, modeled based on ISO's 2021 Daily Regulation Requirement
    - The hourly Regulation Capacity Requirement ranges from 50 MW to 190 MW, depending on the hour, day and month
- Pathways is not a reliability study, and the FGRS should be looked to instead for any technical analysis of reliability and reserve shortages

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Capital Costs for Renewable Resources

Question: The proposed capital costs for solar resources (EIA) are based on solar PV with sun-tracking. Does this align with the DNV profiles used to model generation?

- Yes, the model inputs are properly aligned
- At the June meeting, we proposed to use the EIA capital costs as a starting point for capital costs in 2021. We proposed to project changes in capital costs over time based on estimates available from EIA or NREL
- The DNV profiles published in 2021 include profiles for ground mounted single-axis tracking solar, which is aligned with the EIA's projected capital costs
  - The 2020 profiles did not include single-axis tracking
- These profiles are also aligned with both the EIA and NREL cost growth estimates, which are for single-axis tracking solar

Table 2-3 Basic PV system configuration used by power model.

Parameter	Value
AC Capacity	100 MW
Maximum Panel Tilt	60 degrees East-West
Array Axis Tilt	0 degrees (horizontal)
Array Axis Azimuth	0 degrees
Panel Module Type	Monocrystalline Silicon
Inverter Type	Central Inverter
Mounting System	Ground Mounted Single Axis Tracker
DC/AC ratio	1.3[1]

1 This is the same ILR ratio used for the load zone distributed solar profiles.

Source: "Wind and Solar Time Series Modeling and 2020 Update", ISO-NE, March 22, 2021.

Capital Costs for Renewable Resources (Cont.)

Question: The proposed use of EIA for offshore wind capital costs includes a 25% "optimism factor," reflecting excessive optimism regarding actual capital costs. Will the optimism factor remain in place for the entire 20 years of modeling?

- No, the optimism factor will diminish over time, as assumed by the EIA
- At the June meeting, we proposed to use the EIA capital costs as a starting point for capital costs in 2021. We proposed to project changes in capital costs over time based on estimates available from EIA or NREL
- The EIA offshore wind capital costs include a 25% multiplier for "technology optimism" (*i.e.*, that current capital cost estimates are too low due to optimism). EIA projects cost reductions that assume this optimism will diminish over time, after the first four offshore wind plants are built

New Imported Hydro Modelling

Question: Will Canadian hydro be a modeled option for potential new entry, and what capital cost estimates will we use?

- The New England Clean Energy Connect project will be included in the central cases (see AGI's May slides, Assumed State Targets and Procurements)
- We are proposing to evaluate additional, new Canadian hydro resources (supported by new transmission) within a scenario
- We have not yet determined the estimated capital cost for new Canadian hydro power that will be assumed in this scenario

Policy Targets by State

Question: How will the analysis determine state-level clean energy policy targets?

- Assumed state-level FCEM, Hybrid and Status Quo commitments will reflect each state's existing policy (legislation and executive orders)
  - The **All State Policies** column in the table below includes all commitments in **RPS+CES+Other,** plus additional clean energy required for certain states (MA, VT) to meet economy-wide emissions targets, as determined by their state-commissioned studies
  - Under **All State Policies** assumptions, 89% of energy to meet load would be from clean energy
  - The quantity of clean energy needed to meet the 80% decarbonization target will depend on carbon intensity of fossil-generation, as reflected in model runs
- Cost allocation will depend on each state's level of commitment for FCEM, Hybrid and Status Quo

	2040 Quantities			
State	**Load (MWh)**	**RPS**	**RPS + CES + Other**	**All State Policies**
Connecticut	46,096,394	48%	100%	100%
Maine	22,010,571	80%	80%	90%
Massachusetts	89,745,057	57%	74%	95%
New Hampshire	18,724,458	25%	25%	25%
Rhode Island	11,815,643	39%	100%	100%
Vermont	10,102,929	75%	75%	99%
Total (load weighted)	198,495,052	54%	77%	89%

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).

Status Quo Resource Mix

Question: How will the resource mix in the Status Quo pathway be established?

- Under the Status Quo, we assume states continue to meet environmental goals via out-of-market procurement of multi-year contracts with wind, solar, and hydro resources
- For states that have provided or supported public materials (e.g., “roadmaps” or studies) describing plans to meet environmental objectives, the model will assume that the contracted resources align with the mix of resources from these materials
- We welcome feedback from stakeholders regarding these items

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Proposed Set of Scenarios

Scenarios

- Assumptions different from those in the central case will be evaluated quantitatively through alternative scenarios, to the extent feasible
- When considering the number of scenarios that can be studied, we note that each scenario must be developed and then interpreted across multiple approaches
  - For example, scenario development includes a time-intensive calibration process to ensure that total carbon emissions are consistent across scenarios
- The list of scenarios presented today reflects our current thinking and review of all submitted feedback and stakeholder discussion to date, plus the removal of some scenarios given the addition of the hybrid approach
- We appreciate all the feedback, discussion, and continued interaction from stakeholders to date. We will continue to welcome input moving forward and adjust the scenarios accordingly

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Potential Quantitative Scenarios

- Across approaches:
  - Alternative regional carbon target
  - Alternative levelized costs of new entry for renewable resources (given uncertainty in cost trajectory)
  - Alternative load forecasts (e.g., different levels of electrification of heating, transportation)
  - Remove existing (central case) state policies (e.g., remove RPS, of interest only if it binds)
  - Inclusion of basic transmission congestion (to support qualitative assessment of approach differences)
  - Inclusion of NYISO (to support qualitative assessment of approach differences)
    - We do not plan to include NYISO in the central case, but instead model as a scenario
  - Alternative distribution of costs amongst states
  - Include potential entry of new Canadian Hydro, with new transmission (limited incremental capacity)
- Status Quo
  - Alternative costs of long-term renewable contract procurement
  - Alternative mix of renewable resource technologies
- FCEM / ICCM
  - "Dynamic" CEC pricing (may be studied in an abridged fashion)
- Hybrid
  - Alternative carbon price levels

Next Steps

- August – October
  - Continue building simulation model
  - As needed, additional meetings to discuss further detail on inputs, assumptions and methodologies
- Q4 2021
  - Continue building simulation model and scenarios
  - Presentation of preliminary analysis results

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Appendix – June 2021 AG Pathways Presentation

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Pathways Study

Evaluation of Pathways to a Future Grid

Todd Schatzki and Chris Llop

June 11, 2021

Overview

- Purpose of today's presentation is to give an update on several of the proposed modeling inputs and assumptions for the central case, and to provide more information on several questions from the May meeting
- As with our May presentation, inputs and assumptions discussed today are preliminary; we have endeavored to provide information on current thinking, and will refine based on our continued analysis and additional feedback
- We appreciate the stakeholder feedback to date and encourage further stakeholder feedback to help ensure our assumptions are reasonable and reflect a range of viewpoints regarding future policies

Agenda

- Overview of Capacity Expansion Model
- Continued Discussion of Modeling Inputs and Assumptions
  - Capital Costs of New Entry
  - Status Quo Procurements
  - Central Case Retirement Assumptions
- Proposed Set of Scenarios
- Questions and Answers from Prior Meetings
- Appendix: May 2021 AG Pathways Presentation

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Overview of Capacity Expansion Model

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Overview of Modeling Approach: Model Components

- Analysis will use a multi-module model to simulate the New England electricity markets:
  - Energy and ancillary service (reserve) (EAS) markets
  - Forward capacity market
  - Proposed forward clean energy market (FCEM) frameworks
  - Proposed net carbon pricing framework
- Except for the proposed FCEM and net carbon pricing frameworks, models will reflect current market structures and rules, and not include potential modifications that may occur in the future
- Model follows two steps:
  1. Determine the future resource mix using a “capacity expansion” model
  2. Analyze outcomes in EAS market, and capacity market, reflecting approach taken to meeting decarbonization target (status quo, FCEM or net carbon pricing)

Overview of Capacity Expansion Module

- The Capacity Expansion Model (CEM) simulates outcomes in energy and capacity markets over an extended time horizon (i.e., 2021-2040)
  - Mix of resources selected to minimize the costs of meeting energy demand and capacity requirements given:
    - Decarbonization targets and approaches (mechanisms) take to achieve those targets (e.g., FCEM requirements or carbon pricing)
    - Inputs regarding full cost of operation, including annualized (amortized) capital costs for new builds, fixed O&M costs, and generation costs (variable O&M, emissions, fuel costs, heat rates)
  - Timing of new resource entry and resource exit reflects multiple factors, including evolving loads (levels and profiles), evolving costs (e.g., new technology improvements) and evolving environmental requirements
  - CEM simplifies certain aspects of market operations, particularly the net EAS market simulation
  - CEM allows for the specification of annual carbon limits or technology requirements (e.g., RPS or CEC)

Overview of Energy and Capacity Modules

- Energy and reserve market modules
  - Provides more granular representation of energy market outcomes, reflecting full 8760 hour analysis with resource commitment
  - Model simulates provision of both energy and ancillary services in each hour
  - Refined estimates of net EAS revenues to reflect more granular representation
- Capacity market module
  - Capacity market prices reflect “missing money” required for the marginal non-CO_2 emitting resource
  - Market price for environmental certificates (e.g., CECs and RECs) reflecting “missing money” for clean resources relative to other resource types
  - Estimates market outcomes for capacity and environmental reflects more granular net EAS revenue estimates

Overview of Modeling Approach: Model Components

Inputs and Assumptions

- Existing resource going-forward costs
- Costs of new entry
- Variable O&M
- Fuel prices
- Heat rates
- Load
- Etc.

Market Simulation

Capacity Expansion

Resource entry/exit

- Embedded EAS market
- Resource adequacy requirements
- Policy targets

Energy & Ancillary Service (EAS) Market

- Energy
- Operating reserves
- Carbon pricing

Net EAS Revenues

Forward Capacity Market (FCM) and Forward Clean Energy Market (FCEM)

- Based on going-forward costs, given net EAS revenues
- Resource adequacy requirements
- FCEM requirements

Results

EAS Market

- Payments
- Production costs
- LMPs
- Carbon prices
- Emissions
- Generation mix

Forward Market

- Capacity prices
- CEC prices
- CEC payments

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Continued Discussion of Modeling Inputs and Assumptions

Preliminary New Entry Capital Costs

- Criteria for costs of new entry (capital costs)
  - Independent and publicly available
  - Region-specific cost factors (*e.g.*, labor costs, project requirements, etc.)
  - Full scope of installed costs (*e.g.*, interconnection, transmission)
  - Forward-looking time period (*i.e.,* present to 2040)
- Preliminary proposal for current capital costs – EIA AEO 2021 overnight capital costs
  - Independent, region-specific cost factors
  - Bottom-up cost engineering analysis
  - Only region specific for current year
  - Includes certain transmission costs
- Other cost factors still under consideration (e.g., transmission infrastructure necessary for a significant capacity build-out in certain regions, e.g., Maine)

Preliminary 2021 Capital Costs

- EIA costs include:
  - Project contingency
  - One-mile of transmission
  - Regional adjustment for New England
- Offshore wind (EIA) additionally includes:
  - Offshore transmission line
  - Interconnection costs
  - 5 miles of onshore transmission
  - Regional adjustment that accounts for further distance from coast
  - 25% increased cost due to current “technology optimism”
- Costs do not reflect investment tax credits

Technology	Overnight Costs ($/kw)
Onshore wind	$1,680
Offshore wind	$6,360
Utility-scale solar	$1,276
Battery storage (four hour)	$1,201
Biomass	$4,842
Combined cycle H-class (1x1)	$1,298
Combined cycle H-class (2x1)	$1,134
Combustion turbine F-class	$801

- We propose to use the EIA capital costs as a starting point for 2021, and then project out the change in capital costs, based changes in costs over time
  - Potential sources for capital cost projections include EIA and NREL

Status Quo Resource Mix

- Under all central cases, region-wide emissions from the electricity sector will be **80% below 1990 levels** in 2040
- Under the Status Quo, we assume states meet environmental goals via procurement of multi-year contracts with wind, solar, and hydro resources
  - State statutes do not specify many aspects of how targets will be met – i.e., how resource development will be achieved, resource preferences, etc.
  - State policy analysis suggest certain resource preferences, in some cases developed through certain analyses or plans – for example:
    - Massachusetts has indicated a preference for offshore wind and solar resources, premised on these being the lowest cost resources (MA 2050 Decarbonization Roadmap)
    - Connecticut has developed an Integrated Resource Plan, and Rhode Island has developed a “Road to 100% Renewable Electricity by 2030 in Rhode Island”

Status Quo Resource Mix

- The Status Quo modeling analysis will assume:
  - Incenting of resource finance through long-term contracts
  - Resource mix consistent with New England State's policy assessments
- Analysis Group is reviewing prior PPA agreements as one source of information regarding technology types procured and agreement term and conditions
- Scenario analysis can explore the impact of changes to both technology mix and assumed contract costs
- We welcome feedback from stakeholders regarding these items

Status Quo and FCEM Policy Contribution Allocation

- States have expressed varying preference for the quantity and the technology of future renewables through statute, executive orders and other policy pronouncements
- The Status Quo and FCEM analyses will allocate policy contributions (long-term contracts and CEC demand) across states based on assumed state preferences
  - Scenario analysis can consider alternative allocations of contributions with corresponding changes in allocation of costs
- Below is a preliminary Status Quo/FCEM allocation, informed by current RPS demand and other state-level policies – assumes that 90% of total energy must be non-CO_2 emitting to meet the 80% decarbonization target (reflects an outside-the-model approximation):

	2040 Quantities	
State	**Load (MWh)**	**% Renewable**
Connecticut	46,096,394	95%
Maine	22,010,571	85%
Massachusetts	89,745,057	95%
New Hampshire	18,724,458	60%
Rhode Island	11,815,643	95%
Vermont	10,102,929	80%
Total (load weighted)	198,495,052	90%

[1] Load based on FGRS Load Scenario 3.

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Resource Retirement

- The model will assume that any currently announced retirements have taken effect in all three future cases
  - Roughly 2,400 MW Turbines, 1,800 MW Combined Cycles, and 950 MW Coal
- Additional retirements will be determined via the capacity expansion module, which may find new entry to be less expensive than the continued operation of more costly plants
- For the purposes of the pathways study, we propose to assume that both Seabrook (1,309 MW) and Millstone (2,163 MW) remain in operation for all three central cases:
  - Seabrook's operating license is approved until 2050
  - Millstone Unit 2 is licensed until 2035, and Unit 3 is licensed until 2045, and the current contracts extend through 2029; however, going forward costs are uncertain
  - If desired, scenarios assuming retirement of Millstone (and/or Seabrook) can be evaluated

Proposed Set of Scenarios

Scenarios

- Assumptions different from those in the central case will be evaluated through alternative scenarios, to the extent feasible
- Scenario analysis will be completed after the central cases are built; however, early discussion of the potential scenarios are important to ensure the model is built in a way that makes specific scenarios possible to run
- In addition to quantitative scenarios, key features of the proposed policy approaches will be studied qualitatively

- We look forward to input from stakeholders on a mix of scenarios
  - Timely input will increase likelihood that model is capable of evaluating or can reasonably evaluate the desired scenario

Potential Scenarios

- Across approaches:
  - Alternative regional carbon target
  - Alternative levelized costs of new entry for renewable resources (given uncertainty in cost trajectory)
  - Alternative load forecasts (e.g., different levels of electrification of heating, transportation)
  - Alternative natural gas price projection
  - Remove existing (central case) state policies (e.g., remove RPS, of interest only if it binds)
  - Inclusion of basic transmission congestion
- Status Quo
  - Alternative costs of long-term renewable contract procurement
- FCEM / ICCM
  - “Dynamic” CEC pricing (may be studied in an abridged fashion)
  - CEC penalty rate (binding, with corresponding increase in emissions)
- Net Carbon Pricing
  - Leakage rules

Questions and Answers from Prior Meetings

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CEC Resource Eligibility

Question: Should municipal solid waste (MSW) and other biomass be eligible for CECs?

- Based on feedback provided, we are proposing that MSW and other biomass be eligible for CECs
- These resources are exempt from RGGI compliance and eligible to supply RECs under some state RPS
- We are still reviewing the implications of modeling BTM PV as eligible to receive CECs

Technology	Eligible for CECs?
Onshore wind	✓
Offshore wind	✓
Utility-scale solar	✓
Canadian hydro	✓
Run-of-river hydro	✓
Pondage hydro	✓
Pumped storage	✗
Nuclear	✓
Battery storage	✗
Municipal solid waste	✓
Other biomass	✓
Natural gas combined cycle	✗
Fuel cells	✗

CEC eligibility of “clean” imports from outside ISO-NE

Question: Will we assume clean resources outside New England (e.g., New York and Quebec) be eligible for CECs?

- At present, compliance with RPS requirements can be achieved through REC from eligible resources in other states or provinces, so long as double-counting of benefits does not occur
- We are proposing to allow clean resources in neighboring states and provinces to import CECs if they also import the associated certificates for all clean/renewable attributes (e.g., RECs)
- As a result, we will assume that nuclear generation in New York will be used to meet NY’s clean energy goals, and that nuclear resources in NYISO will not supply CECs to New England
- Note that our analysis will assume that New York is decarbonizing in parallel to ISO-NE (*e.g.*, the New York Climate Leadership and Community Protection Act calls for 100% zero-emission electricity by 2040), and thus zero-carbon generation will be required to meet these environmental targets

Transmission

Question: How will the analysis account for transmission, including export constrained regions (e.g., Maine)?

- Stakeholders have reached out to ask for more information regarding AG's proposed decision not to model transmission in the central cases
- The Pathways study aims to understand the differences in economic outcomes under the three potential policy approaches; it is not intended to be a reliability study or a systems transmission planning study
- Transmission considerations are important when evaluating the future renewables pathways for the ISO-NE region. Given this, we propose to address transmission through several approaches:
  - In the central cases, assume no transmission congestion
  - Consider adjustments to costs for new renewable generation from export-constrained areas to account for incremental transmission costs
  - Evaluate a scenario with the existing transmission system and power flows to analyze how outcomes differ under each policy approach

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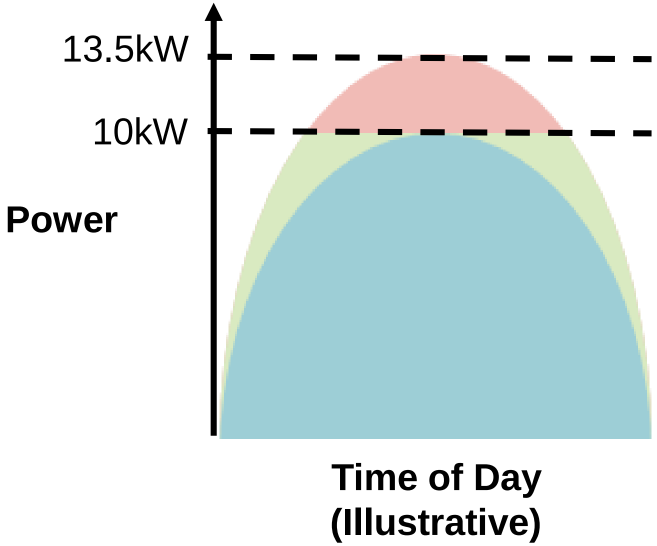
Integrated solar + storage

Question: Will the analysis consider integrated solar+storage resources?

- Some stakeholders asked whether we would model integrated solar+storage resources to address system engineering constraints. For example, developers may pair solar and storage resources to save on inverter costs and/or in response to injection constraints. This leads to inverter clipping:
  - In the diagram below, the 13.5 kW solar array is limited by a 10kW inverter. As a result, the red portion of the figure is ‘clipped’ and cannot be immediately injected; however, if paired with storage, this ‘clipped’ energy can be stored and discharged at a later period
- Accurately modeling such behavior is complex
- AG is still considering whether these complexities can reasonably be modeled, but currently believes that accounting for these engineering limitations and complications is not warranted given the purposes of the Pathways study



Model Year(s)

Question: Will the model results include runs in intermediate years, between now and the 2040 central cases?

- Analysis Group is still evaluating the tradeoffs to producing results for intermediate model years, given the scale of the analysis already underway, the value (information) provided by results in intermediate years (given the study's focus on the comparison of approaches), and the existing stakeholder feedback regarding other desired scenarios
- We may be able to provide targeted information on particular items of interest
  - For example, as discussed in May, cost allocation outcome may differ across approaches at different levels of stringency/cost; analysis could focus on this (and other issues sensitive to timing), rather than providing full analysis for interemediate years

Model Outputs

Question: Will the model outputs allow for drawing insights into the changes in payments to different types of generators, including efficient fossil-fuel resources, under net carbon pricing?

- Specifically, PowerOptions/ NH Customer Advocate requested information on the extent to which a “more efficient [gas-fired] generator would see increased revenue despite not generating any carbon free energy that the region is seeking” because its emissions rate is lower than that of the marginal (marketing-clearing) unit
  - The request suggested certain outputs to facilitate this analysis, including the marginal impact of carbon pricing on LMPs, output (MWh) by resource type, and carbon price payments
- We plan to analyze these issues and provide results informative to them, but are still assessing how best to measure and quantify output relevant to developing a better understanding these effects

Next Steps

- July
  - Begin market simulations and analysis
  - As needed – meet with stakeholders to discuss responses to any additional feedback from stakeholders and/or present any updates to inputs, assumptions, and potential scenarios
- August
  - Continue simulations
  - As needed, additional meetings to discuss further detail on inputs, assumptions and methodologies
- October 2021
  - Presentation of preliminary analysis results

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Appendix – May 2021 AG Pathways Presentation

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Pathways Study

Evaluation of Pathways to a Future Grid

Todd Schatzki and Chris Llop

May 13, 2021

Overview

- Purpose of today's presentation is to review our **proposed** modeling inputs and assumptions for the central analysis cases
  - The proposal reflects multiple considerations, including appropriate data and analysis regarding future market conditions (*e.g.*, input costs, loads, *etc.*) and technology (*e.g.*, costs, performance), and input received to date from stakeholders
- We encourage further stakeholder feedback to help ensure our assumptions are reasonable and reflect a range of viewpoints regarding future policies
- Future iterations on modeling inputs and assumptions will be shaped by this feedback
- Assumptions different from those in the central case will be evaluated through alternative scenarios, to the extent feasible

Agenda

- Modeling Inputs and Assumptions
  - Study parameters
  - Resource characteristics, operating costs, and operating specifications
  - Entry, exit and going-forward costs
  - Load and electrification
- Case Assumptions
  - State policies
  - Status Quo
  - FCEM/ICCM
  - Net Carbon Pricing
- Proposed Outcomes

Modeling Inputs and Assumptions: Study Parameters

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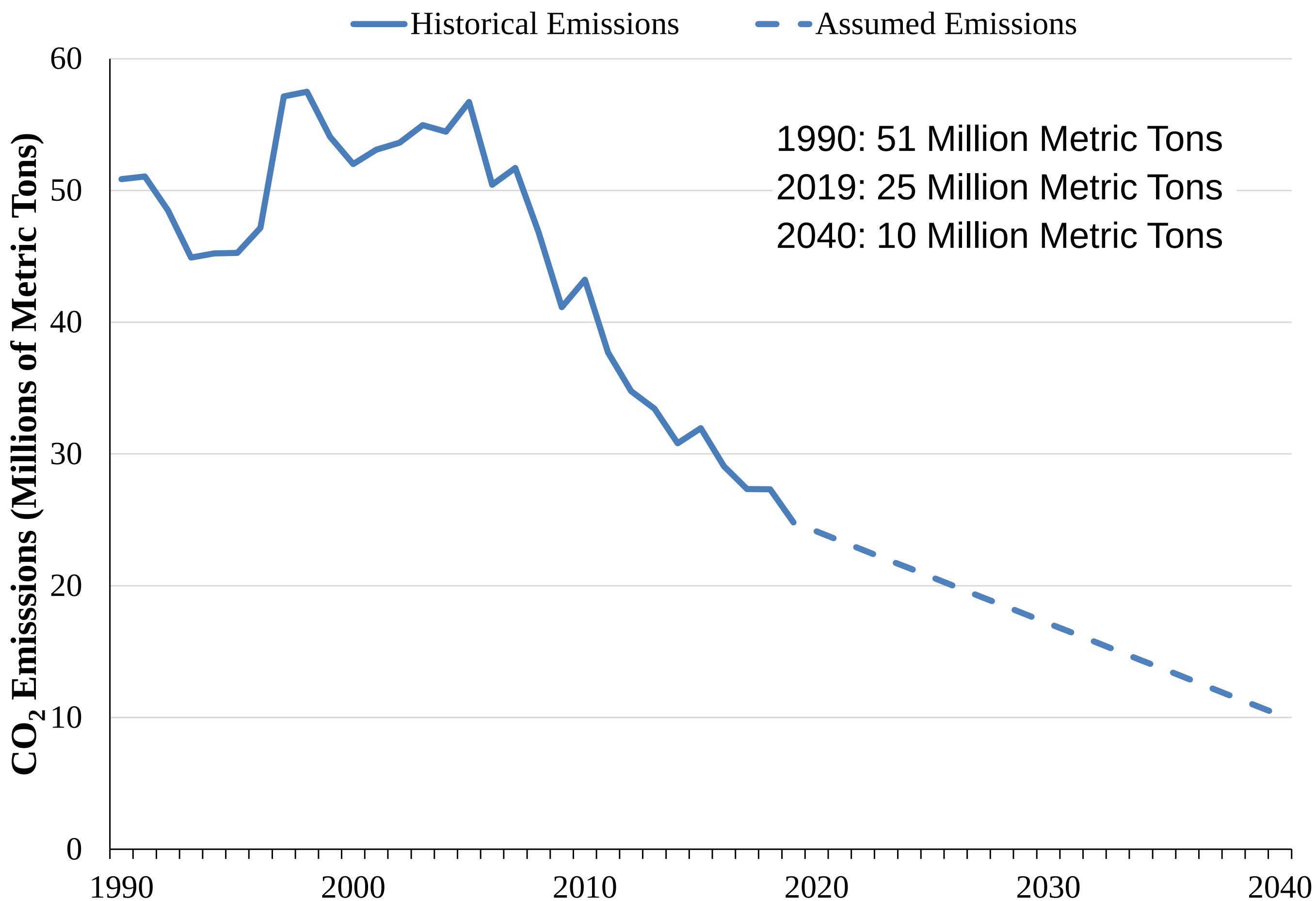
Study Parameters

- Study year
  - Analysis will evaluate detailed outcomes in year **2040**
    - Consistent with Future Grid Reliability Study (FGRS)
  - Resource mix will be reported for (certain) intermediate years
  - Potential to include full results for other years or certain policies/scenarios, particularly if we determine that intermediate years provide meaningful information to assess differences between approaches
- Regional carbon target
  - Under all cases, region-wide emissions from the electricity sector will be **80% below 1990 levels** in 2040
    - *For example*, consistent with achieving target of 80% below 1990 levels by 2050 (e.g., MA Global Warming Solutions Act's economy-wide target) assuming faster decarbonization in the electricity sector compared to other sectors
  - Annual emissions target will be linear interpolation between 2021 and 2040 using a straight line annual target
  - This assumption will be met in all central cases, but may be modified in scenario analysis

Annual Historical and Assumed CO_2 Emissions



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

Modeling Inputs and Assumptions: Resource Characteristics, Operating Costs and Operating Specifications

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Resource Mix

- Existing resources will include:
  - Resources (from most-recent CELT report) and resources that were awarded capacity obligations in FCA 15, adjusted for announced additions/retirements
  - Resources procured through legislated renewable procurements and announced contracts entered into by New England states (see next slide)
- Future changes in resource mix
  - New entry
    - Depending on the case, will reflect both resources prescribed through assumed state policies (e.g., Status Quo) and resources that are most economical/least-cost given incentives from FCEM and net carbon pricing
  - Retirements
    - Reflect resources that are not economical given assumed and/or economic entry

- *More detail on new entry and retirements provided in next section*

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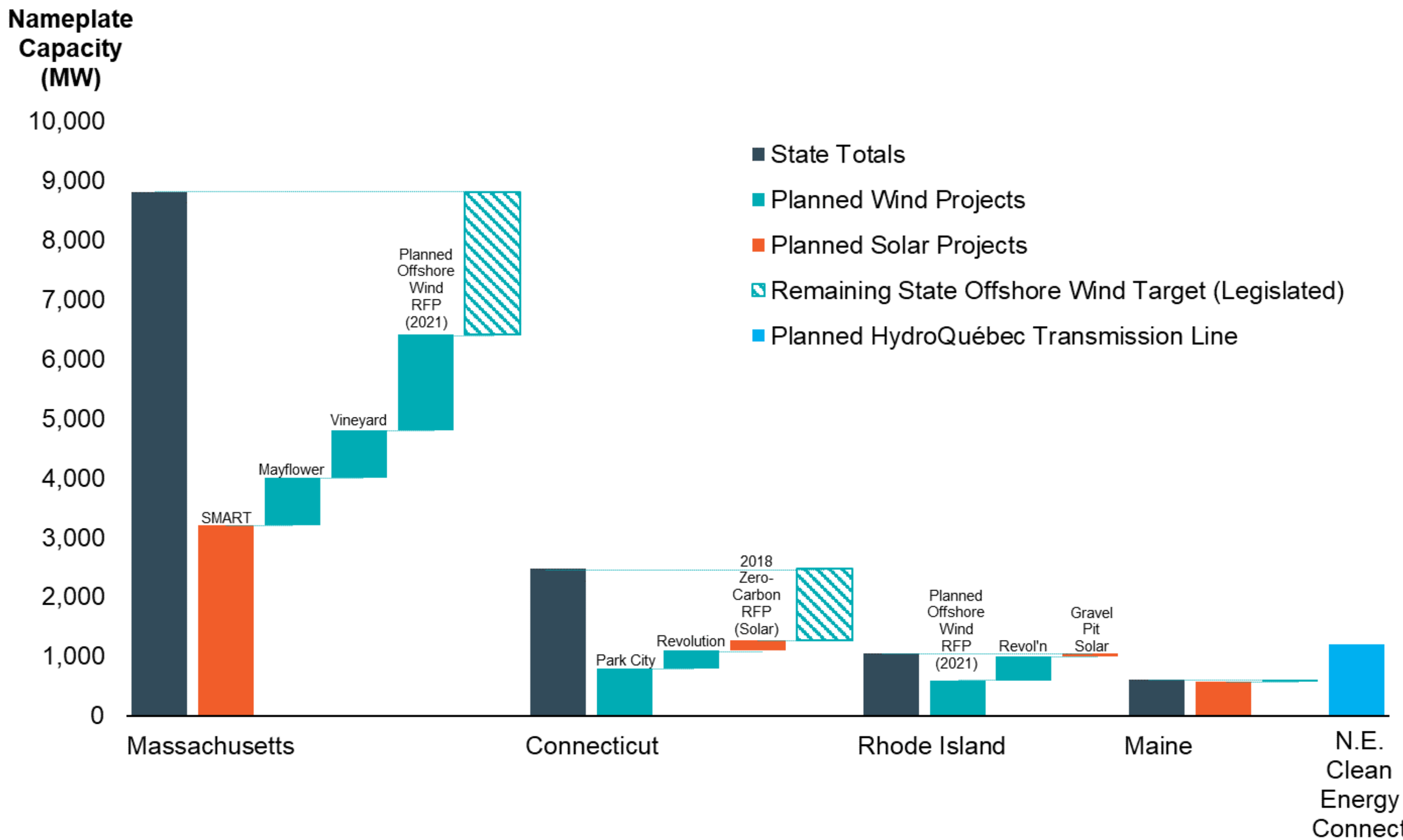
Assumed State Targets and Procurements

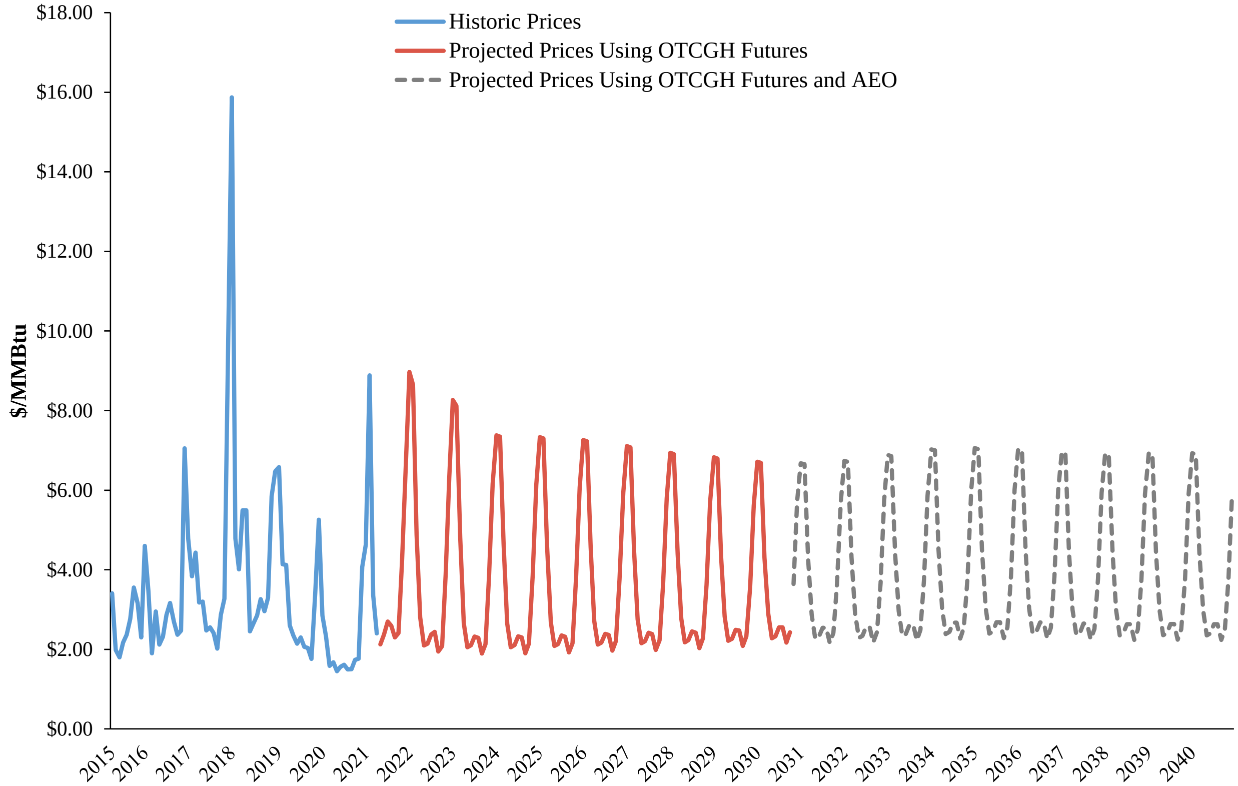
- The resources listed below will be included in addition to the resources in the CELT report and that were awarded capacity obligations in FCA 15



Fuel Prices

- Fuel price assumptions based on reasonable estimates of likely market clearing prices, recognizing that such assumptions are subject to uncertainty
- Natural gas
  - One natural gas price, based on Algonquin City Gates pricing
  - Source: OTC Global Holdings (OTCGH) future prices plus U.S. Energy Information Administration Annual Energy Outlook (EIA AEO) growth rates
  - As electrification in the heating sector increases, consider potential impact of medium/long-run changes in total winter and summer gas demand on winter and summer basis
- Oil prices
  - Source: OTCGH future prices plus EIA AEO growth rates
- Coal prices
  - Source: EIA AEO

Natural Gas Algonquin City Gates Monthly Price Series (April 2015-December 2040)



Sources:
[A] "SNL Day-Ahead Natural Gas Prices" (Algon Gates), S&P Global Market Intelligence.
[B] "Natural Gas Forwards & Futures" (As of 4/30/2021), S&P Global Market Intelligence.
[C] "Table 3: Energy Prices by Sector and Source," EIA Annual Energy Outlook 2021.

Variable Operating Costs

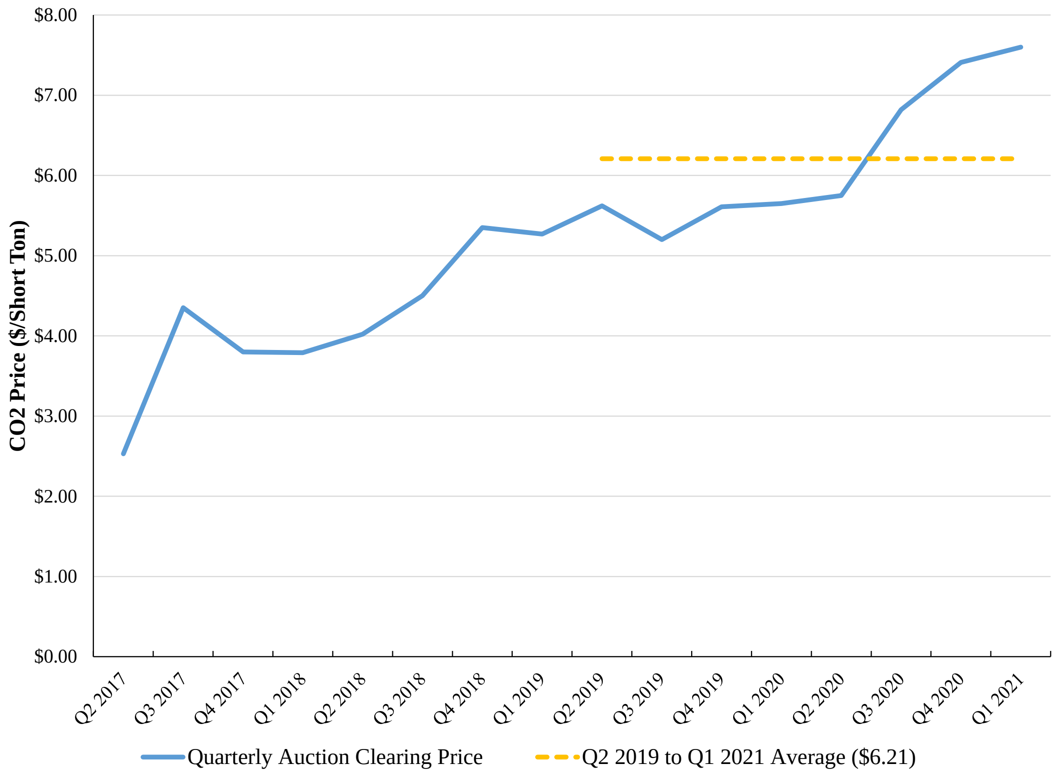
- Variable operations and maintenance costs ("Variable O&M") for existing generation will be based on recent historical Variable O&M
  - FERC Form 1 or RUS 12 annual filings as reported by SNL
  - For new generation, we will rely on historical Variable O&M costs from comparable existing resources, by technology type
  - We will assume that Variable O&M costs are constant over time

- Emission costs
  - Only CO_2 emissions under RGGI will be quantified and costed
  - NO_X and SO_2 emissions do not impose incremental costs in New England under current federal regulations

Emissions Prices

- We will assume that RGGI still exists. The RGGI price will be set at the average of the price from recent auctions (e.g., the last two years)

RGGI CO_2 Auction Clearing Price (Q2 2017 – Q1 2021)



Non-Fossil Fuel Resource Assumptions

- Renewable Hourly Resource Profiles
  - For existing and new generation, rely on DNV profiles
- Battery Storage
  - Will earn net energy market revenues by charging when prices are low and discharging when prices are high (*i.e.*, price arbitrage)
  - Gains to charging and discharging must exceed hurdle rate reflecting roundtrip efficiency of 85% and other opportunity costs
  - Can also supply ancillary services, subject to ISO-NE rules
  - Co-located solar + battery resources modeled as separate solar and battery resources
- Imports/Exports
  - Imports from Canada will be modeled using an hourly profile
  - NYISO will be modeled concurrently

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Modeling Inputs and Assumptions: Entry, Exit and Going-Forward Costs

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Going-Forward Costs for Existing Resources

- Consistent with market rules, Going-Forward Costs (GFC) for existing resources will reflect the expected avoidable costs from suspension of operations
  - The GFC will take into account fixed operations and maintenance costs (“Fixed O&M”) as well as expected energy and ancillary service (“EAS”) market net revenues, consistent with current market rules
  - Fixed O&M for existing resources will be based on data from SNL
  - Expected EAS net revenues will be estimated within the simulation model

Potential Resource Additions

- Consider resource additions for commercially available technologies with costs that potentially support economic entry and meaningful new resource potential
- Certain technologies not evaluated due to cost considerations (e.g., fuel cells) or limited resource opportunities (e.g., non-Canadian hydro)

Technology	Modeled for Potential New Entry?
Onshore wind	✓
Offshore wind	✓
Utility-scale solar	✓
Canadian hydro	✓
Run-of-river hydro	×
Pondage hydro	×
Pumped storage	×
Nuclear	×
Battery storage	✓
Solar + storage	✓
Municipal solid waste	×
Biomass	✓
Natural gas combined cycle	✓
Fuel cells	×

New Entry Capital Costs

- Costs of new entry (capital costs) will be based on independent, reliable and representative estimates of current costs – such estimates need to reflect, among other things:
  - Region-specific cost factors (*e.g.*, labor costs, project requirements, etc.)
  - Full scope of installed costs (*e.g.*, transmission)
  - Forward looking time period (*i.e.,* present to 2040)
- Costs are assumed only for the purpose of evaluating alternative approaches to achieving decarbonization targets
  - Rely on publicly available sources
  - Rely on sources with information for multiple resource types of technologies to best characterize the relative costs across resource types given common assumptions regarding underlying cost factors
  - May combine information from different sources regarding different components of costs (*e.g.*, cost trajectories, region-specific cost factors, transmission costs, *etc*.)

Other Market Rule-Related Issues

- MOPR
  - A process to remove the MOPR has been proposed (*Updated 2021 Annual Work Plan*), although specific rules to replace the MOPR are yet known
  - In light of this proposal and other factors (e.g., FERC identification of this as a priority), assume no MOPR in the central case for modeling simplicity
  - Assumption made only for modeling purposes of the Pathways project
- Capacity credits for variable renewable
  - Analysis will need to account for capacity credits for renewable resources
  - The analysis will assume current rules regarding capacity credits to variable renewables
    - ISO-NE is currently working to assess if the existing methodology to determine resource capacity contributions should be modified to account for the increase in variable renewables such as wind and solar
    - However, this work is just beginning, and we do not expect any changes would be determined in time to be considered as part of this modeling effort

Modeling Inputs and Assumptions: Load Assumptions

Load Shape

- Assume FGRS Load Scenario 3 in our central case
  - Reflects (MA) goal to achieve 80% economy-wide carbon reduction by 2050
  - Assumes:
    - Investment in energy efficiency
    - Heating and transportation electrification that reduces emissions from these sources by two-thirds relative to 2020 levels
      - Heating: 38.9 TWh
      - Transportation: 40.0 TWh
  - Total energy: 198.5 TWh (excluding Behind-the-Meter (BTM) solar)
  - Based on 2019 load shape, modified for the future changes described above
  - We will test modifications to the load shape in scenario analysis
- BTM solar will be based either on the most recent CELT report or FGRS assumptions
  - If CELT, growth from 2031-2040 will be based on 3-year compound annual growth rate

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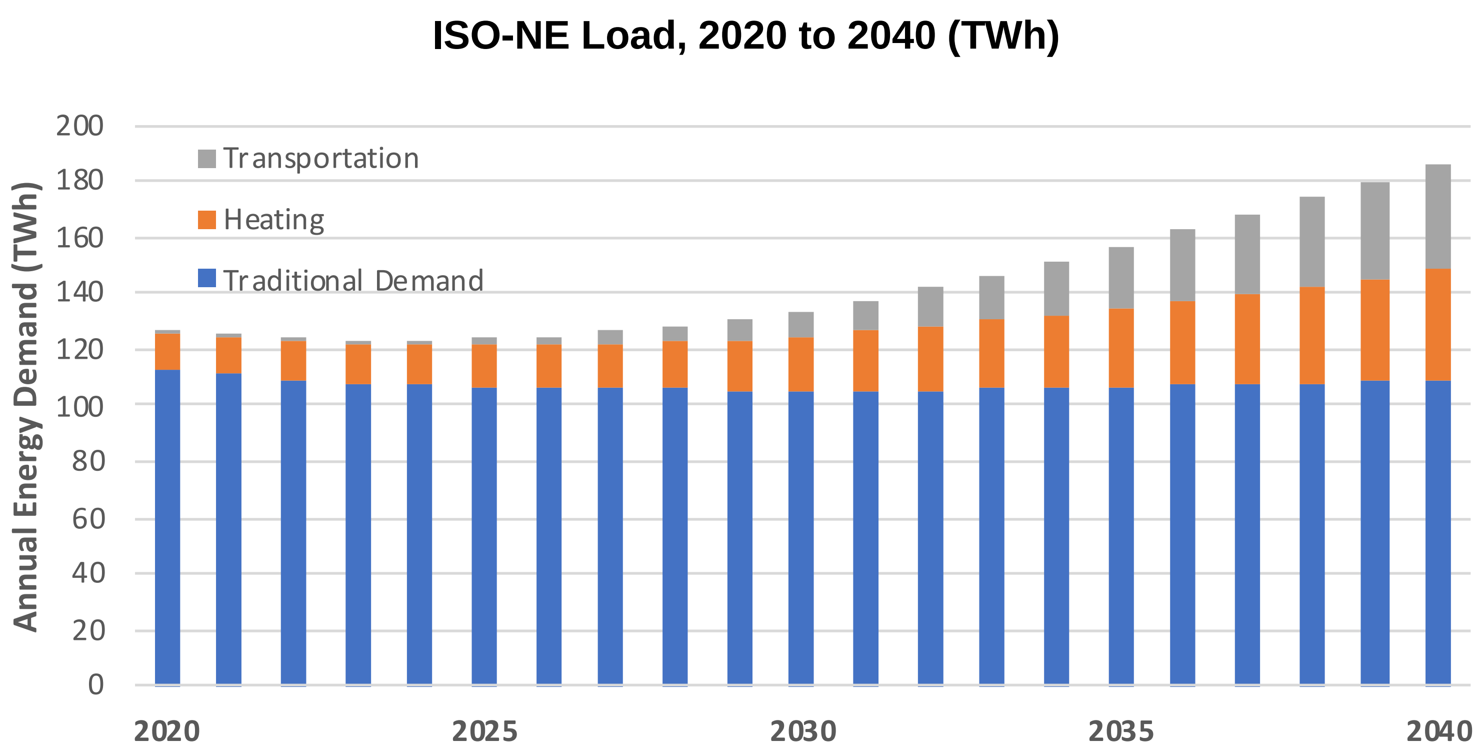
FGRS Scenario 3 Load Growth



Source: Scenario 3 Load Assumptions, NESCOE

Case Assumptions:
State Policies

Existing State Policies

- For all central cases, assume existing RPS remain in place
- Analysis will assume RPS targets, but measures/instruments used to achieve those targets will vary across cases

State	2040 Requirement Quantity (% of Load) RPS Only
Connecticut	48%
Maine	80%
Massachusetts	57%
New Hampshire	25%
Rhode Island	39%
Vermont	75%
Total (load weighted)	54%

Note: Estimates by AG based on review of state legislative mandates. Load weighting based on ISO-NE's 2029 load forecast, net of behind the meter solar and energy efficiency.

Meeting Decarbonization (and RPS) Target

- Resources used to meet 80% decarbonization target (and RPS) will differ across cases
- Status Quo:
  - New clean energy resource entry assumed reflecting recent procurements, state policy plans, and other policy indications
  - Resources will be financed through long-term contracts
- FCEM/ICCM and Net Carbon Pricing
  - Entry (and exit) will occur to minimize costs of meeting decarbonization target (and RPS) given the different ways in which the policy mechanisms incent decarbonization:
    - FCEM/ICCM – provides additional revenues to “clean” resources that do not emit carbon
    - Net Carbon Pricing – imposes a direct cost on all carbon emissions (which makes clean resources more competitive)
  - No long-term contracts beyond what are currently in place or legislated to be procured

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Case Assumptions:
Status Quo

Approach and Resource Mix

- States have indicated that they plan to meet their environmental goals primarily via procurement of multi-year contracts with wind, solar, and hydro resources
  - States have not specified binding procurement plan
  - State policy analysis suggest different preferences for mix of technical approaches and resources to achieve decarbonization
- Analysis will assume:
  - Resource mix consistent with New England State’s policy assessments (we will provide a proposed mix at a future meeting)
  - Incenting of resource finance through long-term contracts
- Additional information on approach to resource procurement under the Status Quo will be presented at the next PC meeting

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Case Assumptions: FCEM/ICCM

FCEM Assumptions

- Model will determine capacity and CEC awards simultaneously
  - This approach is consistent with an ICCM
  - ICCM outcomes are similar those of an FCEM in which resources have perfect foresight about FCM outcomes (assuming the FCEM goes first)
  - Thus, from a modeling standpoint, these approaches result in identical outcomes (absent introduction of assumptions regarding differences between expected and actual outcomes of the FCM)
- Proposed resource types eligible for CECs include wind, solar, nuclear, and all hydro
  - Only criteria for eligibility is technology type
- Storage will not be eligible, but we expect it to benefit
  - More detail is provided in ISO-NE's materials
- CECs imports
  - Imports will be eligible for CECs, including Hydro Quebec imports
  - Other out of state resources will need to bundle CECs and RECs to avoid double payment

CEC Resource Eligibility

- Proposed CEC eligibility reflects stakeholder input and certain market design considerations
- Combined solar + storage resource eligibility to reflect solar capacity only
- Look forward to further stakeholder feedback before determining study assumptions

Technology	Eligible for CECs?
Onshore wind	✓
Offshore wind	✓
Utility-scale solar	✓
Canadian hydro	✓
Run-of-river hydro	✓
Pondage hydro	✓
Pumped storage	✗
Nuclear	✓
Battery storage	✗
Solar + storage	✓
Municipal solid waste	?
Other biomass	?
Natural gas combined cycle	✗
Fuel cells	✗

Clean Energy Credit Assumptions

FCEM / ICCM will assume:

- No partial CECs for efficient gas-fired resources
- CEC banking
- Static CEC value based on the results of the FCEM / ICCM
  - The process for studying dynamic credits is still under development and will be studied separately
- New England states demand the necessary quantity of CECs to meet the regional decarbonization target
  - We will assume that individual States' demand is proportional to their current RPS/clean energy policy requirements, not exceeding their load

CEC Offers and Settlement

- Resource CEC offer quantity
  - Existing dispatchable resources will offer an amount of clean energy consistent with recent performance
  - Existing wind, solar, and hydro will offer based on 2019 performance
  - Wind and solar added through the capacity expansion model will offer based on 2019 performance of a similar existing resource or DNV profiles
- Compliance penalty
  - Resources can fulfill CEC obligations through generation or purchase of CECs
  - Compliance penalty, in effect, reflects a price at which resources can purchase CEC’s in lieu of generating or purchasing CEC’s
    - Like an Alternative Compliance Payment in state RPS programs
  - Thus, in effect, the compliance penalty acts as a price cap on CECs
  - In the central cases, we will not assume any compliance penalty

Case Assumptions:
Net Carbon Pricing

Net Carbon Pricing

- Carbon price will be set to achieve the 80% electricity sector decarbonization target
  - In practice, carbon price could be set through a fixed carbon price or through a quantity-based approach
    - Under a fixed carbon price, the price would be fixed and the resulting emissions would be uncertain
    - Under a quantity-based approach (e.g., a cap-and-trade system), the quantity would be fixed (at the policy target), and the price would be uncertain
  - Analysis will encompass both price-based and quantity-based carbon pricing, as it will not evaluate the distribution of outcomes given price/quantity uncertainty
  - Analysis will equalize emissions across approaches to facilitate comparison of carbon pricing, FCEM and status quo
- Carbon revenues will be credited against EAS costs
  - The specific method for allocating costs by load is under consideration
- To offset leakage, we will include a cost adder for imports when the marginal generator in the exporting region is an emitting resource.

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Outcomes

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Proposed Study Outcomes

- This study will focus on differences in outcomes across approaches to give insight into how outcomes may differ under each approach.
  - This will be assessed by holding relevant central case assumptions constant across approaches: total emissions, existing state policies and procurements, load, fuel prices, etc.
- Potential quantitative outcomes include:
  - Customer payments
  - Total production costs, by technology type
  - Changes in net revenues, by technology type, relative to status quo case
  - Wholesale energy and reserve prices (LMPs)
  - Capacity prices
  - Environmental prices (carbon, CEC)
  - Total CEC payments by states
  - Total carbon price payments by resources
  - Emissions, by technology type
  - Resource mix, by technology type (MW, MWh)

Proposed Study Outcomes

- Qualitative analysis
  - Quantitative analysis will capture some but not all differences in approaches, while qualitative analysis will aim to identify and evaluate other consequential differences in outcomes across approaches
- As with feedback on input and modeling assumptions, we encourage stakeholder feedback on additional outcomes of interest

Next Steps

- June
  - Review any additional feedback from stakeholders
  - Present finalized assumptions and inputs
  - Present initial set of proposed scenarios

- Summer
  - As needed, additional meetings to discuss further detail on inputs, assumptions and methodologies

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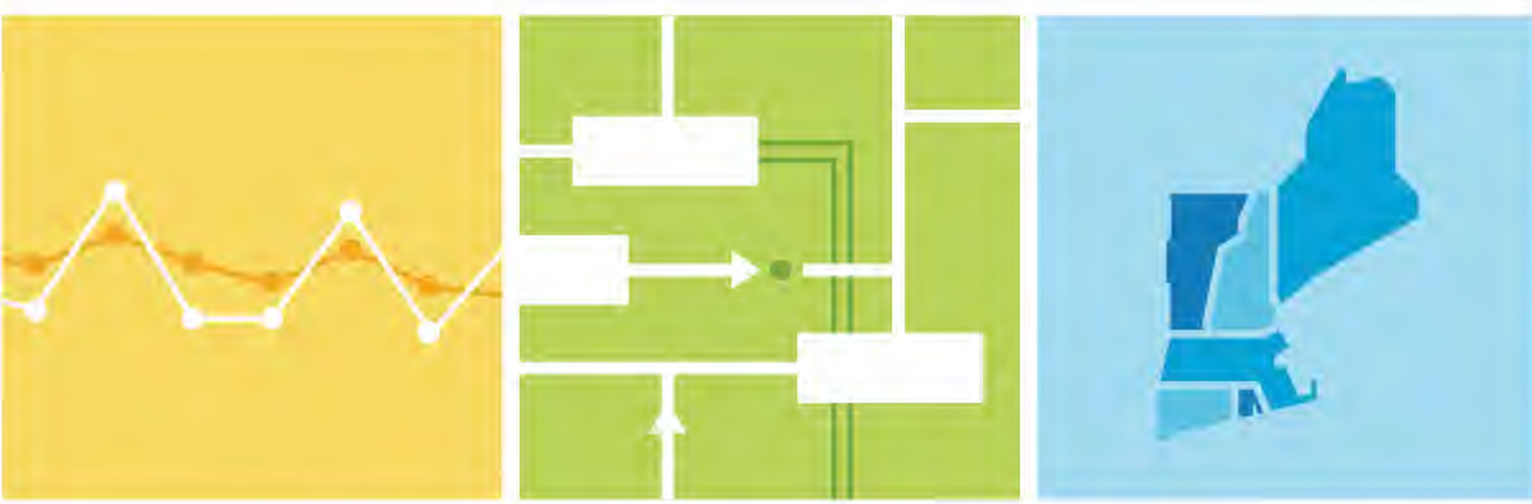
Pathways to the Future Grid: Defining the Frameworks for the Modeling Efforts

JULY 14, 2021



Contents

Section 1
Introduction

As part of the Future Grid Initiative, the Pathways to the Future Grid process will model potential market designs that will help the region decarbonize the New England electric system. In the first half of 2021, stakeholders discussed a variety of pathways and the ISO agreed to undertake the modeling of two decarbonization frameworks – a forward clean energy market (FCEM) and net carbon pricing – that will be studied as part of this process.[1]

In a FCEM, the states would submit demand bids that specify the quantity of clean energy they wish to procure in a given year and the price they are willing to pay for this energy. "Clean" resources (the definition of which is discussed later in this document) would then sell that clean energy forward and use this additional revenue to cover their costs. In a market with net carbon pricing, a carbon price would be implemented so that carbon-emitting resources pay for each unit of carbon they emit while generating energy. Carbon-emitting resources would incorporate this price into their energy offers, and the higher energy prices would incent clean and efficient resources to enter ISO-NE's markets. The revenue gained from the carbon price would be rebated to consumers.

As part of the Pathways analysis, both of these frameworks will be compared to a "status quo" framework, where there are no substantial changes to current market rules and that the region's decarbonization goals are satisfied using long-term power purchase agreements with clean resources. Each framework – i.e., the status quo, FCEM, and net carbon pricing – will be designed to meet a regional decarbonization target of 80 percent reduction in carbon emissions by 2040 compared to 1990 levels and will have consistent assumptions (e.g., load forecast, resource costs, fuel prices, etc.). This will allow the key model outputs for each framework to be directly compared.

This document describes the two frameworks and some of the important decisions ISO staff and stakeholders have made with respect to their designs. When deciding on elements of the frameworks, the ISO used three criteria:

i. Choose design options that more closely align with sound market design principles and allow the region to decarbonize in a cost-effective manner;
ii. Put forth frameworks that are conducive to quantitative modeling; and
iii. Where possible, choose design options that are consistent across frameworks, allowing for more easy comparison.

If the New England stakeholders ultimately were to consider market rule changes to introduce a FCEM or net carbon pricing, the Pathways analysis may provide guidance about some potential design parameters and their expected outcomes. However, a process to further flesh out design details, more comprehensively assess implementation questions, and to draft market rules would still be needed and would involve significant additional time and effort.

The remainder of this document details design questions and the modeling approach AGI will take in this analysis. The second section specifically discusses the FCEM, with Table 1 providing an overview of relevant design questions. The third section considers net carbon pricing, with Table 4

[1] Analysis Group Inc. (AGI) was retained by the ISO to model and evaluate proposed alternative approaches to a more decarbonized future grid.

providing an overview of its related design questions and approaches. The fourth section lists the key outputs AGI's model will provide.

Section 2
Forward Clean Energy Market framework to be analyzed

2.1 Overview

Table 1 below summarizes the key design elements for the FCEM framework that we will analyze. Column [a] highlights the design question and column [b] then offers an answer based on ISO and stakeholder discussions. Finally, column [c] notes the section in this memo that discusses this question in greater detail.

Table 1: Summary of FCEM Framework Elements

	[a]	*[b]*	*[c]*
	Design Question	**Approach to Framework**	**Section**
A. Who Receives Clean Energy Certificates?			
[1]	Technology types that receive clean energy certificates	Wind, Solar, Hydro, Nuclear, Municipal Solid Waste	2.2.1
[2]	Does storage receive clean energy certificates?	No	2.2.2
[3]	Are clean energy certificates static or dynamic?	Static	2.2.3
[4]	Are there additional clean energy products?	No, there is only a single product	2.2.4
[5]	Are imports eligible to earn Clean Energy Certificates (CECs)?	Quebec based Hydro resources are eligible to earn CECs. Other resources outside of New England that also sell RECs to New England are eligible for CECs	2.2.5
B. Settlement			
[6]	What is the settlement structure for sellers?	Two settlement structure where supplier buys/sells certificates to true up forward position	2.3.1
[7]	What is the non-compliance penalty rate?	Given AGI's model, identifying a non-compliance penalty is not necessary at this time.	2.3.2
[8]	Cost allocation for clean energy certificates bought forward	Allocated to RTLO in states that buy clean energy certificates forward	2.3.3
C. Interaction with existing programs			
[9]	How do clean energy certificates interact with existing state programs such as RECs?	It is not necessary to specify precisely how this interaction would occur at this stage; the model is general enough to handle a range of approaches	2.4
D. Integration with Forward Capacity Market			
[10]	Is the forward clean energy certificate procurement separate from or integrated with FCM?	AGI will model a FCEM that is integrated with the FCM, but the model is general enough that its results can be viewed as consistent with a separate FCEM as well	2.5

As this table illustrates, the framework outlined in this document specifies potential technologies for which resources receive a clean energy certificate (CEC) for each MWh of energy production (section 2.2). It also outlines a settlement structure for suppliers and a cost allocation methodology for consumers (section 2.3). It presumes that the FCEM and FCM are integrated, such that forward clean energy is procured jointly with forward capacity (section 2.4).

2.2 Determination of clean energy certificates

2.2.1 What technologies receive clean energy certificates?

The Pathways analysis will generally assume that resources that do not produce carbon emissions will be eligible to earn CECs when they generate energy. Under such a definition, resources that are categorized as renewable energy resources, including wind and solar, could receive clean energy certificates for their production. Moreover, generation that comes from other technologies that do not emit carbon, including hydropower and nuclear, would also receive clean energy certificates.

This approach would not award clean energy certificates to generation technologies that emit carbon, such as natural gas, oil, and coal. However, given stakeholder feedback, the analysis will consider some technologies that emit carbon eligible for CECs if they are currently eligible for state RECs. For example, municipal solid waste plants emit carbon when they produce energy, but, on net, they reduce green house gas emissions and so are awarded RECs by some states. AGI will assume that such resources are eligible for CECs for the modeling effort.

2.2.2 Treatment of storage

The Pathways analysis will assume that storage resources are not eligible to earn CECs when they discharge energy. The ISO and stakeholders discussed this approach for the following reasons:

- Unlike renewable, nuclear, and hydro resources, the electricity discharged from batteries is not necessarily carbon-free. Indeed, the environmental attributes of the discharged energy are a function of the resource that was marginal at the time the storage resource charged.
- In some instances, storage resources will contribute to the region's clean energy goals. More specifically, when storage resources charge in hours when clean resources are marginal and discharge electricity in hours when carbon resources are marginal, storage shifts electricity production from carbon resources to clean resources.[2] However, storage resources will be compensated for this contribution to the region's clean energy goals because they will see a larger spread between energy prices when they charge and discharge if a FCEM is implemented. For example, if a clean resource is marginal when the storage resource is charging, the storage resource would expect to face a lower energy price as the clean resource would incorporate their expected CEC revenue into their energy offer.

For more details and examples on the treatment of storage resources, see the memo the ISO distributed to stakeholders on this topic located in Appendix A.

2.2.3 Employing "fixed" rather than "dynamic" clean energy certificates simplifies design

The Pathways analysis will award a CEC for each MWh of energy produced by a resource that is eligible to receive CECs for its energy production. We refer to this as a "fixed" certificate approach, as the quantity of certificates awarded for each MWh of clean energy produced is fixed across all hours of the delivery period. Stakeholders have raised the possibility of pursuing a dynamic

[2] Storage may have many contributing roles in a decarbonized future (see Appendix A), including contributions to decreasing the carbon content of energy supply, and this is not intended to be an exhaustive list but is limited to the relevant issues pertinent to scoping this study model.

approach, where the compensation for providing clean energy is weighted by the emissions rate associated with the marginal supplier.[3] The fixed approach is simpler than a dynamic approach for purposes of modeling, and so AGI will consider fixed certificates for the FCEM framework.

More specifically, there appear to be many outstanding questions with how a dynamic approach would work in practice. Importantly, a dynamic approach requires a methodology to determine the weights that correspond with marginal emissions. These weights can either be determined before the corresponding interval (ex-ante), or they can be calculated based on actual system conditions during the relevant interval (ex-post). Each approach introduces potential challenges for the modeling efforts, and possibly for clean energy suppliers making FCEM and energy offers.

An ex-ante approach raises numerous questions about how these weights would be estimated, including how granular they are with respect to time of day, season, day of week, and how frequently they are re-estimated. Consideration of such an approach would add significant complexity to the model. Moreover, if these weights were not known to sellers before the forward auction is run (three years before the delivery period), they face a new form of risk associated with selling clean energy on a forward basis, as they must not only forecast their energy production during the delivery period, but they must also develop expectations about the applicable weights that would be used when they are generating. If their expectations of these weights are incorrect, they may fail to provide sufficient energy to meet their forward position.

An ex-post approach that determines weights using the actual marginal emissions rate introduces potential modeling challenges and raises a similar concern about suppliers' ability to forecast the weights when determining how much clean energy to sell forward. Moreover, it also introduces a new source of uncertainty for suppliers: they must forecast the weights when bidding into the energy market, as these values will not be determined until the interval has occurred.

For these reasons, the Pathways analysis will model a fixed certificate approach by awarding a CEC for each MWh of energy produced by a resource that is eligible to receive CECs for its energy production.

2.2.4 Consideration of additional clean energy products

A FCEM framework that only includes a single clean energy product simplifies the modeling process by limiting the number of demand parameters that must be defined and modeled. Using a single clean energy product will therefore help facilitate the production of model results in a more timely manner than if the model framework allowed for multiple forward clean energy products to be procured.

Additionally, by only specifying a single product, the approach will foster greater competition between clean energy suppliers than if there were multiple products. This will help ensure that the framework will procure clean energy in a cost-effective manner.

While the FCEM framework will model the procurement of a single clean energy product, the model will account for the procurement of related products through separate state programs (e.g.,

[3] For further discussion of this dynamic approach see slides 24 through 28 of the pathways presentation by Kathleen Spees from August 6, 2020, available at https://nepool.com/uploads/FGP_NPC_20200806_Spees.pdf.

renewable energy certificates) that can be produced by the same clean energy resources. The interaction of the FCEM with these separate state programs is discussed in Section 2.4 below.

2.2.5 Are Imports eligible to earn CECs?

Allowing resources from outside New England to earn CECs can decrease the costs of the FCEM by allowing low cost, importing resources to contribute to region's clean energy goals. However, stakeholders have raised concerns that allowing resources from outside of New England to earn CECs may result in the "double-counting" of clean energy, where the same MWh of clean energy is counted toward two regions' goals. Given these two considerations, for the purposes of the modeling efforts, imports eligiblity will be defined as follows:

- Quebec based hydro resources will be eligible for CECs.
- To be eligible to earn CECs, other resources from outside of New England will have to sell RECs into New England as well.

If the region decides to pursue a FCEM in the future, further consideration of the treatment of imports will be necessary, such as specific processes to account for an import resource's clean-energy and any renewable attributes to ensure that such attributes are not double-sold into two separate regional markets.

2.3 Settlement and cost allocation

2.3.1 Settlement for energy suppliers

As the ISO has noted in numerous proceedings and projects, a forward market most sensibly settles against a corresponding spot market. Employing a two-settlement approach will create strong incentives for market participants to satisfy their forward positions in a cost-effective manner while helping to meet the region's clean energy goals. Consistent with this observation, the FCEM framework will include a "spot market" for CECs that allows suppliers to buy and sell CECs if their production during the delivery period turns out to be higher or lower than what they sold forward.[4]

This approach would create strong incentives for resources to deliver clean energy (and thus, receive clean energy certificates) during the delivery period to meet the CECs that were sold forward. More specifically, resources that sold CECs forward would have a strong incentive to produce this clean energy during the delivery period to satisfy their positons. Resources that did not sell clean energy forward would also have strong incentives to produce clean energy as they could sell the CECs they created to participants that may otherwise not meet their forward positions.

The inclusion of a spot market for clean energy certificates would tend to reduce energy market offers from clean resources relative to current market rules. More specifically, resources that receive clean energy certificates for their spot market production would tend to lower their

[4] This spot market could resemble those currently in place for existing environmental certificates, where participants buy and sell certificates to satisfy their obligations (and therefore avoid non-compliance penalties). These transactions could be conducted bilaterally between market participants, or the ISO could take a more direct role in this process. However, for purposes of the Pathways analysis, we do not believe it is necessary to determine whether the ISO has a role in administering this market at this time.

competitive energy offer price to reflect the fact that if they generate electricity they receive a certificate that can then either be used to meet their forward position (thus preventing them from having to buy this certificate from another participant) or be sold.[5] In either case, the value of this certificate is equal to the price at which it could be sold. Thus, if the spot price at which certificates were sold is $10 per MWh, we would expect resources that produce clean energy to reduce their energy market offer price by $10 per MWh to reflect this value.

2.3.2 Non-compliance penalty rate

For an implemented FCEM, a non-compliance penalty would be applied to any resource that falls short of its forward clean energy obligation, where revenues associated with such a penalty would be rebated to load. Such a non-compliance penalty would be necessary to give resources the incentive to deliver clean energy consistent with their forward positions. A higher penalty rate will tend to reduce the likelihood that the region produces less clean energy than was procured forward, but it also is likely to increase clean energy certificate prices because resources must consider higher charges if they fail to procure sufficient certificates to meet their forward position.[6]

For the purposes of modeling the FCEM, the ISO has determined that it is not necessary to set a non-compliance penalty rate at this time, as AGI's model will assume that all resources meet their forward clean energy obligations with clean energy production during the delivery year. If stakeholders opt to pursue a forward clean energy framework, more detailed discussion and consideration of the non-compliance penalty rate would be necessary.

2.3.3 Cost allocation

The costs associated with compensating energy suppliers for providing forward clean energy will be covered by new charges to consumers in states that buy this clean energy using a two-step process. First, each state's total costs associated with this forward procurment are calculated as the product of the clean energy price and the quantity of clean energy awarded to that state, as determined by its accepted demand bid(s). Second, these costs are then allocated within each state on a pro-rata basis to Real-Time Load Obligation (RTLO) over the course of the delivery period.[7] This cost allocation methodology is illustrated via a simple numerical example.

Imagine that there are three states with different levels of load for the delivery period, and differing environmental goals that lead to varying levels of clean energy procurements. This is illustrated in Table 2 below, which considers these three states (column [a]) and for each, shows the total clean energy procurements for the commitment period (column [b]), and their total RTLO for the commitment period (column [c]). In this example, small state 1 serves the entirety of its 1,000 MWh of load via clean energy, large state 2 serves 1,500 MWh of its 3,000 MWh of load via clean energy, and medium state 3 does not serve any of its 2,000 MWh of load via clean energy.

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[5] This same logic leads resources that receive RECs or production tax credits for their electricity to reduce their competitive energy market offer price to reflect the expected revenues associated with these credits.

[6] Furthermore, this penalty rate acts as a price ceiling for the certificates, as participants would never pay more than this price to procure a certificate.

[7] Whether these charges are administered by the ISO or another entity, the precise manner and frequency by which these charges are assessed, and the process to "true up" any deviations that occur if expected load differs from realized load would need to be determined for a fully developed proposal, but is not be critical for the purpose of modeling the FCEM framework.

Table 2: Clean Energy Procurements and Load		
[a]	*[b]*	*[c]*
State	Clean Energy Procured *[MWh]*	Total RTLO *[MWh]*
State 1	1,000	1,000
State 2	1,500	3,000
State 3	0	2,000
Total	2,500	6,000

With these procurement and RTLO quantities established, consider how the costs associated with these forward clean energy procurements are distributed to consumers across the three states. We start with the first step, which determines the total costs borne by each state. These values are shown in column [d] of Table 3 (where columns [a] through [c] follow from those in Table 3). Because state 1 procures 1,000 MWh of the clean energy certificates, its consumers bear total costs of $10,000 (1,000 MWh × $10/MWh). Similar logic indicates that consumers in state 2 incur total costs of $15,000 for clean energy certificates. Because state 3 does not procure any clean energy forward, it does not bear any incremental costs.

Table 3: Clean Energy Costs and Charge Rates				
[a]	*[b]*	*[c]*	*[d]*	*[e]*
State	Clean Energy Procured *[MWh]*	Total RTLO *[MWh]*	Total Costs *[$]*	Charge Rate *[$/MWh]*
State 1	1,000	1,000	$10,000	$10
State 2	1,500	3,000	$15,000	$5
State 3	0	2,000	$0	$0
Total	2,500	6,000	$25,000	

For the second step, we calculate the charge rates to RTLO that states 1 and 2 apply to cover their respective forward clean energy costs. These values are given in column [e] of Table 3. When the $10,000 of costs in state 1 are distributed to its RTLO from the delivery period, this results in an additional cost of $10 for each MWh of energy consumed on top of the wholesale electricity price, thereby reflecting that a forward certificate is procured at a cost of $10 for every MWh of energy consumed. For consumers in state 2, the additional cost is instead $5 per MWh. This lower cost reflects the fact that only half of state 2's energy consumption is clean. Thus, the incremental charge associated with forward clean energy in state 2 is equal to half of the cost of a clean energy certificate.

2.4 Interaction with existing state programs (RECs, etc.)

The ISO and stakeholders discussed several potential approaches on how the clean energy certificates could interact with existing state programs. Broadly, three approaches were considered:

Approach 1: Clean energy certificates reflect a clean attribute that does not overlap with other environmental attributes. Under this approach, a wind resource that qualifies under existing state renewable energy programs would receive both a clean energy certificate and a renewable energy certificate for each MWh of production.

Approach 2: Clean energy certificates encompass all environmental attributes. Under this approach, a wind resource that qualifies under existing state renewable energy programs and sells clean energy certificates would not receive renewable energy certificates for its production.

Approach 3: The existing programs are discontinued, and the region uses clean energy certificates to meet its environmental objectives. Under this approach, the wind resource is only awarded a clean energy certificate, as this is the only environmental attribute for which the region provides compensation.

After consultation with AGI, the ISO concluded that AGI's model is consistent with multiple approaches, and so it is not necessary to specify precisely how the programs would interact with each other. However, given stakeholder feedback, the AGI will assume that the existing state programs continue and so they will be accounted for in the modeling effort. For more material on this topic, see an ISO memo on regulatory integration in Appendix B, as well as slides 5-14 from the ISO's May presentation, located here, that clarify the ISO's rationale.

2.5 Integration of the FCEM with the Forward Capacity Market

Stakeholders have expressed interest in exploring the feasibility of determining forward clean energy positions as part of a single joint optimization with the existing Forward Capacity Market (FCM) that simultaneously determines clearing awards and prices for both capacity and forward clean energy. Such a design is referred to as an Integrated Clean Capacity Market (ICCM) and may reduce the uncertainty that occurs under a sequential approach where participants do not know the awards or prices for the second product when determining offers for the first.

As the ISO explains in its memo titled "Evaluation of an Integrated Forward Clean Energy Market," located in Appendix C, our analysis to date suggests that the joint clearing of capacity and clean energy in a single auction is theoretically feasible and thus we plan to model a framework where these products are procured jointly.

Under the approach outlined in the ISO's integrated FCEM memo, resources would submit a single price, much like under the current FCM. In addition to submitting a capacity quantity, they would also submit a clean energy parameter that reflects the MWh quantity of forward clean energy they would sell for each unit of capacity sold. The auction would determine capacity and clean energy awards to maximize social surplus and specify separate prices for each product.

While we believe that the ICCM is theoretically feasible and the concept put forth can be modeled as part of the Pathways analysis, significant additional work would be necessary to evaluate the challenges that may come with translating this novel concept into a fully developed and economically sound auction framework.

Finally, note that while AGI will model an ICCM, their model is consistent with both i) sequential clearing of clean energy and capacity products, and ii) the simulataneous clearing of both products (ICCM). For more information on this modeling equivalence, see an ISO memo on this topic, located in Appendix D.

Section 3
Net carbon pricing framework to be analyzed

3.1 Overview

Table 4 below summarizes the key design elements for the net carbon pricing framework that we will analyze. Column [a] highlights the design question and column [b] then offers an answer based on ISO and stakeholder discussions. Finally, column [c] specifies the section in this document where the topic is discussed further.

Table 4: Summary of Net Carbon Pricing Framework Elements			
	[a]	*[b]*	*[c]*
	Design Question	**Approach to Framework**	**Section**
A. Product definition			
[1]	What is the product in this framework?	Suppliers pay for each unit of carbon they emit to generate electricity	3.2
B. Settlement			
[2]	What is the settlement structure for sellers?	Pay carbon price for each unit of carbon emissions from electricity generation	3.3.1
[3]	How are revenues from carbon price distributed?	Allocated to RTLO across all states	3.3.2
C. Interaction with existing programs'			
[4]	How does a carbon price interact with existing state programs such as RECs?	The carbon price does not interact with these programs, which are assumed to continue	3.4

Compared to the FCEM framework being analyzed, this summary includes fewer design elements because net carbon pricing is a less novel concept that has been employed in numerous settings. For example, a net carbon price is better defined and more widely understood, and has been implemented in some regions to address carbon emissions or for other types of emissions (e.g., for sulfur oxides). Further, the net carbon price framework does not require the development of a forward procurement of the relevant product or the determination of details such as a non-compliance penalty rate.

3.2 Product definition

Under a net carbon price,[8] the product is defined as carbon emissions arising from electricity production. This product definition is simple and transparent. Carbon emissions can be measured, and carbon markets have been used in New England and elsewhere. For example, the Regional Greenhouse Gas Initiative (RGGI) represents a carbon emissions market that includes the six New England states as well as New York and several states in the Mid-Atlantic. To limit the scope of work for these modeling efforts and to allow for more sensible comparisons between market design frameworks, AGI's model will limit the carbon market to the electricity sector.[9]

[8] The term "net" reflects the fact that revenues collected from generators are rebated to load. This is discussed further in section 3.3.

[9] In theory, this carbon market could be expanded to other sectors of the economy, but such a framework is outside the scope of the Pathways analysis.

One design question with any carbon pricing market is to decide whether to fix the carbon price, which ensures a constant price per unit of carbon emissions, or to fix the quantity of carbon, which instead sets a maximum carbon emissions quantity and allows the price associated with carbon emissions to float. While these two approaches may have different practical implications, for purposes of modeling a conceptual framework for the Pathways analysis, we do not believe it is critical to specify one approach over the other, as quantitative analysis of net carbon pricing can provide information on both approaches. Note that AGI's model will set a carbon price to achieve 80% electricity sector decarbonization from 1990 levels by 2040, consistent with the goals for the forward clean energy framework and the status quo framework.

There are a number of product definition details and questions that would require further consideration if the region were to develop net carbon pricing market design, which would necessitate additional discussion.

3.3 Settlement and cost allocation

3.3.1 Settlement for energy suppliers

With a net carbon price, energy suppliers are charged a cost based on carbon emissions from producing electricity. Thus, a participant's total cost associated with the carbon price is equal to the product of the carbon price and the total carbon emissions. We expect suppliers to reflect this new cost in their energy offer price.[10]

This will have two primary effects that will be considered in the modeling efforts. First, it will tend to reorder the energy market supply stack so that non-emitting and lower-emitting resources are more likely to sell energy. Second, it will increase the net revenues for non-emitting and lower-emitting resources, as these resources incur lower costs associated with carbon emissions than the marginal resource that sells energy. This will reduce the missing money for such resources, and may therefore make them more likely to enter or remain in the New England market relative to current market rules. Both of these effects will reduce the region's carbon emissions by displacing electric generation from higher emitting resources with that from lower emitting resources.

3.3.2 Revenue allocation

Unlike an FCEM framework where the payments made to clean resources result in charges to load, a net carbon pricing framework collects revenues from carbon emitting generators which are then rebated to load.

While there are many ways to distribute any revenues collected from carbon-emitting suppliers, AGI's model will allocate these revenues on a pro-rata basis to all Real-Time Load Obligation (RTLO) in New England.[11] Under such an approach, the rebate to each MWh of RTLO during the delivery period would be constant across states, and would be equal to the product of net carbon

[10] This would be similar to how, under current market rules, carbon-emitting generators would include any carbon costs associated with RGGI in their energy market offer price.

[11] Whether these charges are administered by the ISO or another entity, the precise manner and frequency by which the rebates are distributed, and the process to "true up" any deviations that occur if expected load differs from realized load would need to be determined for a fully developed proposal. We would seek policymaker and stakeholder input on how carbon price proceeds ought to be distributed.

price and the average carbon emissions per MWh of energy produced for the relevant delivery period. This approach is illustrated using a simple example.

Imagine that the carbon price is $50 per ton of carbon emissions and that there are three resources that provide energy during the delivery period. Resource A generates 175 MWh of energy without emitting carbon. Because it does not emit carbon, it does not incur a carbon charge. Resource B is an efficient combined cycle resource that produces 250 MWh of energy and emits 0.5 tons of carbon per MWh. Finally, resource C is a less efficient peaking resource that produces 75 MWh of energy, with 1 ton of carbon emissions for each MWh produced.

Table 5: Total Carbon Pricing Charges to Resources					
		Rate of Carbon Emissions	Energy Generated	Total Carbon Emissions	Carbon Charges
		Tons/MWh	*MWh*	*Tons*	*$*
Resource A		0	175 MWh	0	$0
Resource B		0.5	250 MWh	125	$6,250
Resource C		1	75 MWh	75	$3,750
	Total		500 MWh	200	$10,000

In this example, the three resources emit a total of 200 tons of carbon during the delivery period for which they are charged $10,000 (200 tons × $50/ton). This revenue would then be distributed back to the 500 MWh of load from this delivery period on a pro-rata basis. Thus, the rebate to load during this period would be equal to $20 per MWh ($10,000 / 500 MWh).

3.4 Interaction with existing state programs (RECs, etc.)

The ISO and stakeholders discussed two broad approaches for the interaction between a net carbon pricing framework and the existing state environmental programs.

Approach 1: The carbon price does not interact with the existing state programs. Under this approach, the existing state renewable energy programs would persist and resources that can provide renewable energy would continue to be compensated for these environmental attributes. Thus renewable resources may receive increased energy market revenues via the net carbon price, and they would also continue to receive additional revenues for their environmental attributes associated with these state polices.

Approach 2: The net carbon price replaces the state programs. Under Approach 2, the net carbon pricing framework would replace the existing state environmental programs. As such, resources would no longer be directly compensated for providing renewable energy via renewable energy certificates. Rather, non-emitting resources (and lower emitting resources) would be compensated via larger energy market revenues than they receive under current market rules, where no such carbon price is in place.

After continued discussions with stakeholders, AGI will assume that the existing programs will continue and will run concurrently with the carbon price in their model – i.e., Approach 1 will be assumed.

Section 4
Key model outputs

AGI's model will produce several outputs to allow for comparison across the frameworks, including:

- Total customer payments
- Total production costs, by technology type
- Changes in net revenues, by technology type, relative to the status quo case
- Wholesale energy and reserve prices
- Capacity prices
- Environmental prices (carbon price, CEC price)
- Total CEC payments by states
- Total carbon price payments by resources
- Emissions by technology type
- Resource mix, by technology type (MW, MWh)

Section 5
Next steps

This document, in addition to Analysis Group's slides from the June PC Working Session, defines the structure for the central cases of the Pathways modeling efforts. In addition to the central cases, AGI will also conduct a series of scenarios/sensitivities, where AGI will examine the impact of changes to certain input values or on modest changes to the model's structure. ISO and AGI will continue discussions on the development of potential scenarios in the coming months.

AGI will launch their internal modeling efforts in July and will be spending the next few months fine tuning their model and running simulations. They will prepare initial results for discussion with stakeholders and then present a final report on the pathways in 2022.

Section 6
Appendices

This report contains four appendices (Appendix A through Appendix D). These appendices include external memos that the ISO distributed to stakeholders and provide additional details on the topics discussed in the report.

Appendix A. Storage Resources and Pathways to a Future Grid

Introduces a series of numerical examples that consider storage's impact on production costs, clean energy production, and carbon emissions. Finds that it is most consistent with sound market design to not award storage resources with clean energy certificates.

Appendix B. The FCEM and Existing State Programs

Considers three approaches to the modeling interaction between the FCEM and existing state programs, such as RECs. The memo shows that under many circumstances, the different approaches will yield identical modeling results.

Appendix C. Evaluation of an Integrated Forward Clean Energy Market

Provides a high-level discussion of a possible approach to a FCEM that is integrated with the Forward Capacity Market.

Appendix D. Modelling Equivalence of the FCEM and ICCM

Considers the potential modeling differences between the FCEM and the ICCM. Concludes that the two frameworks will produce identical results, given AGI's model.

Appendix A. Storage Resources and Pathways to a Future Grid

memo

To: NEPOOL Participants Committee Working Session

From: Market Development

Date: April 8, 2021

Subject: Storage Resources and Pathways to a Future Grid

As the ISO and its stakeholders evaluate pathways to a future grid, a key consideration is the role of storage resources in this transition, and the extent to which the frameworks being evaluated facilitate their participation in the decarbonization of the region's energy sector. While this discussion in ongoing, the ISO prepared this memorandum in order to offer some practical observations about the implications of various treatments for energy storage, including if it is eligible to receive clean energy certificates under an forward clean energy market (FCEM) framework,[1] and how it participates in a net carbon pricing framework.

To evaluate these treatments, the memorandum introduces a series of numerical examples that consider storage's impact on production costs, clean energy production, and carbon emissions. These examples then evaluate storage's compensation under current market rules, an FCEM framework considering cases where storage does and does not receive clean energy certificates, and net carbon pricing.

These examples, summarized in Table 1 below, find that storage resources are compensated for their marginal contributions to clean energy production via increased energy market revenues under an FCEM framework. As such, it is most consistent with sound market design to not award clean energy certificates to storage resources as this would lead them to be compensated at a rate above their clean energy contributions. The examples also find that a net carbon pricing approach that does not charge storage resources for carbon emissions will appropriately compensate them for its contributions to carbon emissions reductions.

[1] In this document, the FCEM refers generally to the forward clean energy procurement framework as has been discussed recently at the NEPOOL Participants Committee and is outlined in the scoping memo, available at https://nepool.com/wp-content/uploads/2021/03/1a-FCEM-Scoping-Memo_vfinal.pdf. The observations provided in this memo apply equally whether the forward procurement of clean energy occurs outside of the Forward Capacity Market (where this is commonly referred to as the FCEM framework), or if this procurement is instead integrated with the Forward Capacity Market (where this approach is commonly referred to as the Integrated Clean Capacity Market, or ICCM).

Table 1: Summary of Examples			
	Market Rules	**Storage's Impact on Outcomes**	**Key Takeaways**
Example a1	Current Market Rules	Storage transfers production from peaker to clean baseload resource	Storage is compensated for its contributions to reducing production costs.
Example b1	FCEM	Storage transfers production from non-clean peaker to clean baseload, increases clean energy production.	Storage is compensated for its contributions to reducing production costs and increasing clean energy production without being awarded clean energy certificates.
Example b2	FCEM	Storage transfers production from non-clean peaker to non-clean baseload, does not increase clean energy production.	Storage is compensated for its contributions to reducing production costs without being awarded clean energy certificates.
Example c1	Net Carbon Pricing	Storage transfers production from carbon emitting peaker to non-emitting baseload, reduces carbon emissions.	Storage is compensated for its contributions to reducing both production costs and carbon emissions.
Example c2	Net Carbon Pricing	Storage transfers production from carbon emitting peaker to less carbon emitting baseload, reduces carbon emissions.	Storage is compensated for its contributions to reducing both production costs and carbon emissions. While storage transfers energy production in same manner as Example b2 (where it does not increase clean energy production), under a carbon price framework, it reduces carbon emissions and is compensated as such.

1. Storage's role in the region's decarbonization

Storage's role in energy production differs from that of other technologies, as it charges (withdraws / consumes) during lower priced periods and then discharges (injects / generates) during higher priced periods. Thus, rather than producing energy like a traditional generator, energy storage enhances the market's efficiency by allowing some of the peak load, which is typically supplied by high-cost peaking generation, to be met by lower cost generation stored during off-peak hours. In addition to lowering costs, storage can play an important role in the region's decarbonization. For example, it may allow generation to be shifted from peak hours, where the marginal energy supplier emits greater levels of carbon for each MWh of energy produced, to off-peak hours, where the marginal energy supplier may emit relatively less carbon.[2]

By transferring the energy production to lower emitting resources, storage can help to reduce the region's total carbon emissions. Applying similar logic, storage resources may increase the region's production of clean energy if it shifts energy generation from peak hours when the marginal resource is not producing clean energy to off-peak hours when it is. It is therefore appropriate to evaluate the potential treatment of storage resources under an FCEM or net carbon pricing framework to determine what approach most

[2] While storage may also provide other benefits that help to facilitate the region's decarbonization, such as reliability services, these are outside the scope of this memo.

appropriately compensates them for their environmental contributions in a manner that is commensurate with other resource types.

2. Numerical Examples

While the numerical examples make a number of simplifying assumptions, their findings generalize to a broad set of market and resource conditions. They consider two hours – an off-peak hour when energy demand is low, and an on-peak hour when energy demand is high. They assume that there are two generating resources that can meet this demand. The first generator is a lower cost “baseload” resource, B, which has 100 MW of capacity. This resource is assumed to be marginal during off-peak hours, as its capacity exceeds energy demand, and its offer therefore sets the clearing price in this hour. However, during on-peak hours, it is infra-marginal as demand exceeds its maximum output. In these examples, we consider outcomes when the baseload resource is one of two different kinds of technologies: a clean, non-emitting resource (examples a1, b1, and c1), and a (relatively) low emission, natural gas generator (examples b2 and c2).

The second generator is a higher cost “peaker” resource, P, which also has 100 MW of capacity. This generator does not run during the off-peak hour (as demand can be met entirely by the lower cost “base” resource), but it is needed to meet the higher energy demand during the on-peak hour. In this on-peak hour, resource P is the marginal resource, and its offer sets the clearing price.

Finally, each example considers two cases. In case 1, energy demand in both hours is met entirely by these two generators. In case 2, we introduce a storage resource, S, that charges at a rate of 10 MW during the off-peak hour (meaning total energy supplied from the non-storage generators increases by 10 MWh during this hour), and discharges at a rate of 10 MW during the on-peak hour (meaning total energy supplied by the non-storage generators decreases by 10 MWh).[3]

For simplicity, we assume that this storage resource incurs no costs except for those associated with buying energy during the off-peak hour. In each example, we compare outcomes between these two cases, with a focus on how storage’s participation impacts the production costs incurred to meet electricity demand, clean energy production, and carbon emissions.

These assumptions are summarized in Table 2 below.

[3] We assume for simplicity that storage resource is a price-taker as demand in the off-peak hour, and is a price-taker as supply in the on-peak hour. Moreover, for simplicity, we assumes S incurs no losses between charging and discharging. However, the key observations would apply even when storage is not 100 percent efficient.

Table 2: Example Assumptions		
Assumptions Applicable to Both Cases		
Baseload capacity	100 MW	
Peaker capacity	100 MW	
Off-peak demand	80 MWh	
On-peak demand	150 MWh	
Assumptions that Vary Between Cases		
	Case 1: No Storage	**Case 2: Storage**
Off-peak (non-storage) generation	80 MWh	90 MWh
On-peak (non-storage) generation	150 MWh	140 MWh
Total generation	230 MWh	230 MWh

After evaluating storage resource's impact on production costs and environmental outcomes, we consider the storage resource's compensation under case 2. For the FCEM, this includes consideration of market rules that do not award storage clean energy certificates as well as those that do award it such certificates. This analysis seeks to determine which set of market rules better aligns storage's compensation with its marginal contributions to reducing production costs and increasing clean energy production.

a. Compensation for storage resources under current market rules

We begin with an example that employs the current market rules. More specifically, this example assumes that neither an FCEM nor a net carbon price framework is in effect.

Example a1: Storage shifts energy production from the on-peak hour to the off-peak hour

In this example, we assume that the baseload resource B is a clean resource that has "physical" marginal costs[4] of producing electricity of $0 per MWh, and the peaker resource P is a combustion turbine generator with "physical" marginal costs of producing electricity of $100 per MWh. Market outcomes under cases with and without the participation of storage resource S are illustrated in Table a1.1 below.

[4] We define "physical" marginal costs as the costs that the resource incurs to produce electricity before consideration of any environmental costs or rebates. We will use these costs to determine the production costs that are considered in addition to environmental costs or benefits in the examples throughout.

Table a1.1: Energy Awards and Production Costs		
Case 1: No Storage		
	Generation *[MWh]*	Production Costs *[$]*
[1] Off-peak	80 MWh	$0 *[80 MWh × $0/MWh]*
[2] On-peak	150 MWh	$5,000 *[100 MWh × $0/MWh + 50 MWh × $100/MWh]*
[3] Total	230 MWh	$5,000
Case 2: Storage		
	Generation *[MWh]*	Production Costs *[$]*
[4] Off-peak	90 MWh	$0 *[90 MWh × $0/MWh]*
[5] On-peak	140 MWh	$4,000 *[100 MWh × $0/MWh + 40 MWh × $100/MWh]*
[6] Total	230 MWh	$4,000
Change in Costs Due to Storage Participation		
	Generation *[MWh]*	Production Costs *[$]*
[7]	0 MWh	($1,000)

Case 1 is given in the top panel of the table (rows [1] through [3]), where storage resource S does not participate. In this case, the 80 MWh of demand in the off-peak hour is met by the base resource B (row [1]) and the entire 150 MWh of demand in the on-peak hour is met by generation in that hour (row [2]). This results in total production costs of $5,000, where, because the base resource has physical marginal costs of $0 per MWh, these costs come entirely from the 50 MWh provided by peaker P during the on-peak hour. The total generation and production costs are summed across the off- and on-peak hours in row [3].

Case 2 is illustrated in the second panel of the table (rows [4] through [6]), where storage resource S consumes electricity during the off-peak hour, thus increasing off-peak demand by 10 MWh to 90 MWh, as shown in row [4], and discharges this energy during the on-peak hour, thereby reducing on-peak generation by this same 10 MWh to 140 MWh (row [5]).

The impact of the storage resource's participation, measured as its total reduction in production costs, is illustrated in the row [7]. In this example, storage reduces the production costs to meeting demand across these two hours by $1,000 ($100/MWh × 10 MWh) as the costly peaker P now only provides 40 MWh of energy, 10 MWh less than in Case 1. This reduction in production costs is calculated by subtracting the total production costs without storage participation (row [3]) from those with storage participation (row [6]).

In this example, storage resource S is compensated for its contributions to reducing production costs based on the difference between energy prices when it charges and discharges. More specifically, as shown in Table a1.2 below, storage incurs no costs when charging in the off-peak hour because it consumes 10 MWh of electricity at a price of $0 per MWh (row [1]). It then receives total payments equal to $1,000 during the on-peak hour when it discharges because it produces 10 MWh of energy that is sold at $100 per MWh (row [2]). Thus, storage resource S receives total compensation of $1,000 (row [3]), equal to its revenues from energy sold less its costs from energy bought. This compensation is commensurate with the degree to which its shifting energy production from the higher cost peaker P to base resource B reduces the total production costs, as shown by comparing production costs between the cases in Table a1.1 (rows [3] and [6]).[5] Under these current market rules, which do not compensate resources for either for clean energy production or reductions in carbon emissions, storage does not receive any additional compensation for its contributions to these environmental objectives.

Table a1.2: Storage Revenues			
	[a]	*[b]*	*[c] = [a] × [b]*
	Energy Clearing Price	Cleared Supply	Storage Net Revenues
	[$/MWh]	*[MWh]*	*[$]*
[1] Off-peak	$0/MWh	-10 MWh	$0
[2] On-peak	$100/MWh	10 MWh	$1,000
[3]	Total	0 MWh	$1,000

b. Storage's compensation under an FCEM

We now consider a pair of examples that are similar to that presented above, except they now presume that an FCEM is in place and consider two additional factors – how storage contributes to the production of clean energy, and how storage's compensation changes with the introduction of this new market. In each case, we assume that the FCEM specifies a value of $10 per MWh of clean energy produced.[6]

Additionally, consistent with the cost allocation methodology put forth in the straw FCEM framework, we presume that the new costs associated with procuring clean energy certificates are allocated to Real-Time

[5] The energy market price is based on marginal costs and as such, a resource's profits from the energy market are based on its contributions to reducing production costs at the margin. In this example, and those that follow, these profits are also equal to the storage resource's total contributions to reducing production costs (and improving environmental outcomes) because the storage resource's participation does not change the marginal resource in either the off- or on-peak hour, and as a result, its first MWh charged/discharged yields the same reduction in production costs as its last. Thus, while resources are generally compensated based on their marginal contribution to production costs (and environmental outcomes), the assumptions in this example lead the storage resource's compensation to also equal its total contribution to production costs (and environmental outcomes). This assumption helps to simplify the comparison of storage's compensation and contributions to production costs (and environmental outcomes).

[6] The example's takeaways would hold under a range of assumed clean energy certificate prices, where this price reflects the value of a certificate as specified during the delivery period.

Load Obligation (RTLO). This approach does not allocate these new clean energy costs to storage resources when they are charging.[7]

In the first of these examples, we assume that baseload resource B produces clean energy, whereas in the second, we presume that it is an efficient gas-fired combined cycle plant that does not produce clean energy.

Example b1: Storage increases clean energy production

In this example, baseload resource B again produces energy with phystical marginal costs of $0 per MWh. However, these MWh are now considered clean, and thus produce clean energy certificates that are valued at $10 per MWh. This is reflected Table b1.1 below, which builds appears similar to Table a1.1 from the earlier example. This table includes a new column that calculates the total benefit from clean energy production as the product of baseload resource B's production and $10 per MWh (column [c]).[8] In case 1 (no storage participation) where B produces a total of 180 MWh across the two hours, the total clean energy benefit provided is $1,800, equal to the product of 180 MWh of energy generated by clean resource B and the $10 per MWh value associated with this clean energy.

[7] While the memo does not explicitly evaluate approaches that would allocate clean energy costs to storage, such approaches do not appear well-equipped to robustly compensate storage commensurate with their clean energy contributions across a range of market and resource conditions.

[8] Thus, these calculations assume that consistent with the payment rate of $10 per MWh of clean energy production provided to suppliers, the social benefits from an incremental 1 MWh of clean energy production are $10.

Table b1.1: Energy Awards, Production Costs, and Clean Energy Benefits				
	[a]	*[b]*	*[c]*	*[d] = [b] - [c]*
Case 1: No Storage Participation				
	Generation *[MWh]*	Production Costs *[$]*	Clean Energy Benefit *[$]*	**Total Costs *[$]***
[1] Off-peak	80 MWh	$0 *[80 MWh × $0/MWh]*	$800 *[80 MWh × $10/MWh]*	**($800)**
[2] On-peak	150 MWh	$5,000 *[100 MWh × $0/MWh + 50 MWh × $100/MWh]*	$1,000 *[100 MWh × $10/MWh]*	**$4,000**
[3] Total	230 MWh	$5,000	$1,800	**$3,200**
Case 2: Storage Participation				
	Generation *[MWh]*	Production Costs *[$]*	Clean Energy Benefit *[$]*	**Total Costs *[$]***
[4] Off-peak	90 MWh	$0 *[90 MWh × $0/MWh]*	$900 *[90 MWh × $10/MWh]*	**($900)**
[5] On-peak	140 MWh	$4,000 *[100 MWh × $0/MWh + 40 MWh × $100/MWh]*	$1,000 *[100 MWh × $10/MWh]*	**$3,000**
[6] Total	230 MWh	$4,000	$1,900	**$2,100**
Change in Costs and Benefits due to Storage Participation				
	Generation *[MWh]*	Production Costs *[$]*	Clean Energy Benefit *[$]*	**Total Costs *[$]***
[7]	0 MWh	($1,000)	$100	**($1,100)**

Observe that in this example, where the FCEM values clean energy at a price of $10 per MWh, the clean energy benefit is $100 greater in case 2 than in case 1, as shown in row [7]. This increase in the clean energy benefit occurs because the storage resource shifts 10 MWh of production from peaker P, which does not produce clean energy to baseload resource B, which does produce clean energy. In total, clean energy generation from baseload resource B therefore increases by 10 MWh with the participation of storage.

Thus, when we consider storage's impact on total costs, which are equal to the production costs less the clean energy benefits, the participation of storage reduces total costs by $1,100, equal to the difference between the total costs in cases 1 and 2 (rows [7], column [d]). Storage's benefit in this example is greater than that estimated in example a1 because storage not only reduces production costs by $1,000 (the same amount as in example a1), but it now also increases clean energy production by 10 MWh, which when valued at the $10 per MWh of clean energy, yields an incremental clean energy benefit of $100.

With the understanding that storage reduces total costs by $1,100, we now consider how two different FCEM eligibility criteria would impact storage's compensation, and how each relates to its contributions to reducing costs, as measured using both production costs and clean energy production.

To do so, we must first consider the impact of the FCEM on energy market prices. Recall from the earlier example that the baseload resource B that sets the clearing price during the off-peak hour has physical marginal costs of producing this energy of $0 per MWh. Under current market rules, we would expect this resource to offer into the energy market at these costs, and because it is the marginal resource in this hour, the off-peak clearing price would therefore be $0.

Under the FCEM, where the value of clean energy is assumed to be $10, we expect resource B to internalize this revenue in its energy offer price. More specifically, rather than offering at $0, its competitive offer price would decrease to –$10 per MWh because for each MWh of energy produced, it receives a clean energy certificate valued at $10.[9] As a result, in this example, the introduction of the FCEM would reduce the energy clearing price in the off-peak hour by the price of the clean energy certificates to –$10 per MWh.

Table b1.2 illustrates the total compensation to storage under two potential FCEM eligibility treatments. Under the first treatment, storage is not directly credited with certificates for clean energy production for each MWh of energy it supplies during the peak hour (illustrated in column [c]). Under the second treatment, storage is credited with clean energy certificates for this supply (column [e]). Observe that in both treatments, the storage resource is paid $100 to consume 10 MWh of energy in the off-peak hour, as the energy price in this hour is -$10 per MWh.

Table b1.2: Storage Revenues with and without Clean Energy Credits

	[a]	*[b]*	*[c] = [a] × [b]*	*[d]*	*[e] = [c] + [d]*
	Energy Clearing Price	Cleared Supply	**Storage Net Revenues without Clean Energy Credits**	Storage Clean Energy Credit Revenues	**Storage Net Revenues with Clean Energy Credits**
	[$/MWh]	*[MWh]*	***[$]***	*[$]*	***[$]***
Off-peak	-$10/MWh	-10 MWh	**$100**	$0	**$100**
On-peak	$100/MWh	10 MWh	**$1,000**	$100	**$1,100**
Total		0 MWh	**$1,100**	$100	**$1,200**

Under the first treatment, where storage is not directly credited with clean energy production, its compensation is nonetheless greater than it would be under current market rules. More specifically, its total net revenues increase by $100 from $1,000 to $1,100. This increase in revenues paid to the storage resource appropriately accounts for its contributions to clean energy production, as this $100 in additional revenues is equal to the product of the incremental clean energy facilitated by the resource (10 MWh) and the value associated with this clean energy ($10 per MWh).

[9] This reduction in offer prices is consistent with those observed for other programs for environmental attributes such as Renewable Energy Certificates (RECs) and production tax credits, where resources with low physical marginal costs lower their offer prices to reflect the value of these credits and this results in negative offer prices.

Importantly, this property will hold more generally. Storage resources will facilitate additional clean energy production when they charge during periods where the marginal resource produces clean energy, and when they discharge during periods where the marginal resource does not produce clean energy. In such cases, the energy price when the storage resource charges (that is, the price the storage resource pays to consume electricity) will decrease relative to current market rules because the marginal resource's energy offer price will be reduced to reflect the value of of clean energy certificates. However, there will not be a corresponding decrease in the price the storage resource is paid to discharge because the marginal resource in this hour is not clean, and it therefore does not reduce its energy offer price. Thus, storage's net revenues would increase because the spread between the price it is paid to supply energy, and the price it is charged to consume energy increases.

We now consider the second treatment, where storage is also credited with clean energy certificates for the energy it provides during the on-peak hour. Under this scenario, the storage resource's net revenues increase by another $100 relative to the first treatment to reflect the fact that it is awarded clean energy certificates for its 10 MWh of energy that it supplies during the on-peak hour. In this second treatment, the storage resource is effectively compensated twice for its contributions to clean energy production. It is compensated indirectly via greater energy market revenues than under current market rules because of the impact of the clean energy certificates on the energy market clearing price. Under this treatment, it is now also compensated a second time via revenues from clean energy certificates.

In this example, the storage resource helps to facilitate greater clean energy production by transferring generation from the non-clean peaker P to the clean base resource B. Yet, it is appropriately compensated for these contributions under the first treatment when it is not awarded a clean energy certificate for the energy it discharges. In fact, when it is credited with providing clean energy, as occurs in second treatment, its total compensation exceeds its contributions to the region's clean energy production because it effectively gets paid twice for its contributions to clean energy production – once via increased revenues from the energy market, and a second time via clean energy certificates.

Based on these observations, this example suggests that to awarding clean energy certificates to storage resources would not align the FCEM framework with sound market design, as they are already appropriately compensated for their clean energy contributions in the energy market. Moreover, such an approach helps to prevent consumers from "paying twice" for 10 MWh of clean energy that is produced by clean base resource B in the off-peak hour, consumed by storage resource S in this same hour, and then discharged by S in the on-peak hour.

Example b2: Storage does not increase clean energy production

The assumptions in this example mirror those from b1, with one key difference. The baseload resource is no longer a clean resource that has physical marginal costs of $0 per MWh. Rather, it is now a combined cycle resource that emits 3 units of carbon per MWh and therefore does not receive clean energy certificates. This resource has physical marginal costs of $30 per MWh. As with example b1, peaker P has physical marginal costs of $100 per MWh, where this corresponds with carbon emissions of 10 units per MWh.

Table b2.1 below shows energy awards, production costs, and clean energy benefits under cases with and without storage participation. Observe that in this example, where neither the baseload nor peaker unit produces clean energy, the total clean energy production is equal to 0 MWh under both cases, and thus there is no clean energy benefit with or without the participation of the storage resource (this is shown in column [c]).

Table b2.1: Energy Awards, Production Costs, and Clean Energy Benefits					
		[a]	[b]	[c]	[d] = [b] - [c]
Case 1: No Storage Participation					
		Generation [MWh]	Production Costs [$]	Clean Energy Benefit [$]	Total Costs [$]
[1]	Off-peak	80 MWh	$2,400	$0	$2,400
[2]	On-peak	150 MWh	$8,000	$0	$8,000
[3]	Total	230 MWh	$10,400	$0	$10,400
Case 2: Storage Participation					
		Generation [MWh]	Production Costs [$]	Clean Energy Benefit [$]	Total Costs [$]
[4]	Off-peak	90 MWh	$2,700	$0	$2,700
[5]	On-peak	140 MWh	$7,000	$0	$7,000
[6]	Total	230 MWh	$9,700	$0	$9,700
Change in Costs and Benefits due to Storage Participation					
		Generation [MWh]	Production Costs [$]	Clean Energy Benefit [$]	Total Costs [$]
[7]		0 MWh	($700)	$0	($700)

In this example, while storage does not impact the clean energy benefit (which is $0 across all hours), it does reduce production costs by $700 by shifting energy production from the higher cost peaker to the lower cost baseload unit (shown in row [7], column [b]).

Table b2.2 considers the storage resource's total compensation under these same two eligibility treatments, where the first treatment does not credit storage with clean energy production for each MWh of energy it supplies during the peak hour (column [c]), and the second treatment does (column [e]).

Table b2.2: Storage Revenues with and without Clean Energy Certificates					
	[a]	[b]	[c] = [a] × [b]	[d]	[e] = [c] + [d]
	Energy Clearing Price	Cleared Supply	Revenues without Clean Energy Certificates	Storage Clean Energy Certificate Revenues	Storage Net Revenues with Clean Energy Certificates
	[$/MWh]	[MWh]	[$]	[$]	[$]
Off-peak	$30/MWh	-10 MWh	($300)	$0	($300)
On-peak	$100/MWh	10 MWh	$1,000	$100	$1,100
Total		0 MWh	$700	$100	$800

As occurred with the first treatment in example b1, if storage is not credited with delivering clean energy, its total net revenues are equal to the benefits it provides when accounting for both production costs and clean energy. This compensation is equal to $700, the amount by which it reduces total costs (in this case, just through reduced production costs), as shown by comparing total costs in cases 1 and 2 in row [7] of Table b2.1. Importantly, under a clean energy framework, while the storage resource reduces carbon emissions by shifting production from peaker P, which emits 10 units of carbon per MWh of energy produced to baseload resource B, which only emits 3 MWh, it receives no incremental revenues for these contributions because these contributions do not increase clean energy production. As explained later in example c2, a carbon price would allow the storage resource to be compensated for these carbon emisison reduction contributions.

However, if storage is also credited with delivering clean energy as occurs under the second eligibility treatment, it would instead receive total compensation of $800, where this additional $100 corresponds with the value of these certificates. This value exceeds the benefits that it provides, as measured using the FCEM framework which values clean energy production at $10 per MWh, but does not directly value carbon emissions reductions. More specifically, it compensates the storage resource as if it increased the region's clean energy output by 10 MWh, even though the storage resource's participation has no impact on clean energy production.

This example again illustrates an instance where storage is appropriately compensated for its contributions to reducing system production costs and clean energy production when it is not credited with providing clean energy. If it was credited with providing clean energy, this would result in the storage resource receiving compensation that exceeds its contributions to system efficiency, as it would incorrectly indicate that storage's participation increased clean energy production.

Awarding clean energy certificates to storage could undermine FCEM's effectiveness in increasing clean energy production

As examples b1 and b2 illustrate, directly crediting storage resources with clean energy certificates would lead such resources to be compensated at a level that exceeds their contributions to clean energy production. By overcompensating storage resources when they cycle, this approach would create financial incentives for storage resources to charge and discharge (cycle) in order to receive clean energy certificates, including instances when this cycling does not benefit the system, as measured by production costs, clean energy production, or carbon emissions reductions.[10]

Additionally, by overcompensating storage resources, this approach may undermine the FCEM's ability to increase actual clean energy production, as this increased cycling by storage resources would reduce the number of certificates available for other types of clean generation. While states may adjust clean energy targets upwards to account for storage activity, forecasting the quantity of clean energy certificates

[10] Taken to its extreme, if storage receives clean energy certificates for its energy supplied, a facility with two adjacently-located storage assets could be simultaneously charging one while discharging the other. Because this energy is simply being transferred back and forth between the facilities, it provides no value to the system. However, the asset could profit from the clean energy certificates it is awarded.

awarded to storage resources would likely prove challenging and may therefore increase uncertainty about the states' ability to achieve their desired environmental outcomes in a cost-effective manner.

As illustrated in examples b1 and b2, not awarding clean energy certificates to storage resources compensates storage resources for their contributions to reducing production costs and increasing clean energy production. By not compensating storage resources above their contributions, it avoids creating these perverse incentives for storage resources to cycle to receive clean energy certificates even when this act does not reduce system production costs, increase clean energy production, or reduce carbon emissions.

c. Storage's compensation under a net carbon price

This section now considers storage's contributions and compensation under a net carbon pricing framework. It uses the same pair of numerical examples as are presented in section b, where, rather than employing an FCEM, there is now a carbon price of $1 per unit of carbon emitted. In this example, when the baseload resource is a clean resource, as occurs in example c1, it produces no carbon emissions and thus does not increase its offer price to reflect a cost for emitting carbon.

The peaker resource is a combustion turbine generator that emits 10 units of carbon per MWh of energy produced. To account for the cost associated with these emissions, this unit adds a $10 per MWh to its energy offer.

Similar to the discussion of the FCEM framework above, these examples assume that any new revenue that is collected via a net carbon price is rebated to RTLO, where this distribution does not extend to storage resources.[11]

Example c1: Storage shifts generation to non-emitting resources

This example mirrors examples a1 and b1, where the base resource B is clean and does not emit carbon. Rather than including a clean energy benefit as is consistent with an FCEM construct, this example considers the costs associated with carbon emissions in a manner consistent with a net carbon pricing framework, which effectively assigns a cost to carbon emissions. This results in carbon costs being added to the production costs to produce total costs, whereas in the earlier examples the clean energy benefits were subtracted from the production costs.

As previously, case 1 reflects the total system costs when the storage resource does not participate, and case 2 illustrates the costs when the storage resource does participate.

[11] While the memo does not explicitly consider approaches that would rebate carbon revenues to storage, such approaches appear to be less effective in compensating storage for their contributions to carbon reductions.

Table c1.1: Energy Awards, Production Costs, and Carbon Emissions Costs					
		[a]	*[b]*	*[c]*	*[d] = [b] + [c]*
Case 1: No Storage Participation					
		Generation *[MWh]*	Production Costs *[$]*	Carbon Emissions Costs *[$]*	Total Costs *[$]*
[1]	Off-peak	80 MWh	$0 *[80 MWh × $0/MWh]*	$0 *[80 MWh × $0/MWh]*	$0
[2]	On-peak	150 MWh	$5,000 *[100 MWh × $0/MWh + 50 MWh × $100/MWh]*	$500 *[100 MWh × $0/MWh + 50 MWh × $10/MWh]*	$5,500
[3]	Total	230 MWh	$5,000	$500	$5,500
Case 2: Storage Participation					
		Generation *[MWh]*	Production Costs *[$]*	Carbon Emissions Costs *[$]*	Total Costs *[$]*
[4]	Off-peak	90 MWh	$0 *[90 MWh × $0/MWh]*	$0 *[90 MWh × $0/MWh]*	$0
[5]	On-peak	140 MWh	$4,000 *[100 MWh × $0/MWh + 40 MWh × $100/MWh]*	$400 *[100 MWh × $0/MWh + 40 MWh × $10/MWh]*	$4,400
[6]	Total	230 MWh	$4,000	$400	$4,400
Change in Costs due to Storage Participation					
		Generation *[MWh]*	Production Costs *[$]*	Carbon Emissions Costs *[$]*	Total Costs *[$]*
[7]		0 MWh	($1,000)	($100)	($1,100)

As can be seen by comparing total cost between cases (row [7], column [d]), the participation of the storage resource reduces total costs by $1,100, where $1,000 of this cost reduction comes via lower production costs (consistent with examples a1 and b1 and shown in column [b]), and the remaining $100 comes via reduced carbon emissions (as illustrated in column [c], 10 MWh of generation that produce 100 units of carbon at total cost of $100 are replaced by non-emitting generation).

We now consider storage resource S's revenues under such a framework which depend on the energy prices in the off- and on-peak hours. Importantly, the baseload resource B will offer its energy at a price of $0, to reflect the fact that it has physical marginal costs of $0, and it incurs no incremental costs associated with the carbon price. Thus, in the off-peak hour, the energy price will be $0 per MWh. The peaker P will set the energy price at $110 per MWh, reflecting its physical marginal costs of $100 and a carbon adder of $10 per MWh.

These revenues are shown in Table c1.2, where storage resource S is appropriately compensated for the $1,100 reduction in costs it provides, as this revenue accounts for both the decrease in production costs, and the value associated with storage resource S's role in reducing carbon emissions. In this example, the introduction of a carbon price has no impact on storage's costs to buying energy during the off-peak hour relative to current market rules because the marginal resource (clean resource B) does not emit carbon.

However, the carbon price increases its revenues during the on-peak hour because the marginal resource, peaker P, does emit carbon and thus increases its energy offer price. As a result, its total compensation accounts for its contributions to reducing carbon emissions, as the net carbon price leads it to receive higher revenues when discharging without impacting its costs to charge.

Table c1.2: Storage Revenues under Net Carbon Pricing			
	[a]	*[b]*	*[c] = [a] × [b]*
	Energy Clearing Price	Cleared Supply	Storage Net Revenues without Clean Energy Credits
	[$/MWh]	*[MWh]*	*[$]*
Off-peak	$0/MWh	-10 MWh	$0
On-peak	$110/MWh	10 MWh	$1,100
Total		0 MWh	$1,100

Thus, a net carbon price leads the marginal carbon emissions rate to be incorporated in the energy price in the hours when storage is charging and discharging. This leads the storage resource's profits to include its marginal contributions to reducing carbon emissions.

Example c2: Storage shifts generation to lower-emitting resources

Finally, we consider the example where the base resource B is no longer clean, and instead is a combined cycle resource that emits 3 units of carbon per MWh of energy produced. As a result, in this example, base resource B adds $3 per MWh to its energy offer to account for the cost associated with its carbon emissions under this net carbon pricing framework, resulting in an energy offer of $33 per MWh.

This example is analogous to example b2, except that we now assume a carbon price is in place rather than an FCEM. The impact on total costs, including those associated with carbon emissions, is included in Table c2.1.

	[a]	[b]	[c]	[d] = [b] + [c]
Case 1: No Storage				
	Generation [MWh]	Production Costs [$]	Carbon Emissions Costs [$]	Total Costs [$]
[1] Off-peak	80 MWh	$2,400	$240	$2,640
[2] On-peak	150 MWh	$8,000	$800	$8,800
[3] Total	230 MWh	$10,400	$1,040	$11,440
Case 2: Storage				
	Generation [MWh]	Production Costs [$]	Carbon Emissions Costs [$]	Total Costs [$]
[4] Off-peak	90 MWh	$2,700	$270	$2,970
[5] On-peak	140 MWh	$7,000	$700	$7,700
[6] Total	230 MWh	$9,700	$970	$10,670
Change in Costs due to Storage Participation				
	Generation [MWh]	Production Costs [$]	Carbon Emissions Costs [$]	Total Costs [$]
[7]	0 MWh	($700)	($70)	($770)

As shown in row [7], the participation of the storage resource in this example reduces costs by $770, where $700 of this cost reduction stems from decreased production costs, and the remaining $70 comes from a decrease in carbon emissions.

As illustrated in table c2.2, a carbon price framework would appropriately compensate the storage resource for these contributions, as its net revenues are equal to this reduction in total costs. In this example, the storage resource's costs associated with consuming energy during the off-peak hour increase relative to current market rules because the marginal resource increases its offer price by $3 per MWh to reflect the costs associated with its carbon emissions. However, this increase in costs is more than offset by an increase in revenues during the on-peak hour, where the price increases by $10 per MWh, thus indicating that storage is shifting energy production from a higher emitting resource (peaker P) to a lower emitting resource (baseload B).

Table c2.2: Storage Revenues under Net Carbon Pricing

	[a]	[b]	[c] = [a] × [b]
	Energy Clearing Price [$/MWh]	Cleared Supply [MWh]	Storage Net Revenues without Clean Energy Credits [$]
Off-peak	$33/MWh	-10 MWh	-$330
On-peak	$110/MWh	10 MWh	$1,100
Total		0 MWh	$770

Importantly, the carbon price framework more directly connects compensation to carbon emissions, rather than employing a binary eligibility criteria to determine what technologies are clean. This allows the storage resource (and other lower emitting resources that are not characterized as clean) to be compensated for their contributions to reducing carbon emissions, even if they do not increase the quantity of clean energy produced. This can be seen in the above example in which the net carbon pricing framework leads the storage resource to receive $70 for its contribution to reducing carbon emissions.

3. Conclusion

The memorandum highlights how storage contributes to clean energy production or reduction in carbon emissions by shifting energy production from higher emitting resources during on-peak hours to lower- or non-emitting resources during off-peak hours. It then considers a series of examples to assess how storage are appropriately compensated for these contributions under FCEM and net carbon pricing frameworks using a series of numerical examples.

Examples b1 and b2 find that storage resources would be appropriately compensated for their contributions to reducing production costs and increasing clean energy production under an FCEM framework if they are not awarded clean energy certificates. This outcome occurs because the energy market revenues storage receives would reflect its contribution to clean energy production because the price it pays to consume electricity and that it receives for discharging electricity both account for the clean energy contributions of the marginal resource.

In fact, if energy supply provided by storage resources was awarded clean energy certificates under an FCEM framework, storage's compensation would exceed its clean energy contribution. This outcome would adversely impact the region's ability to cost-effectively meet its environmental objectives via an FCEM and create incentives for storage resources to cycle even when doing so did not reduce production costs or increase clean energy production. Thus, awarding storage resources clean energy certificates in the FCEM framework is inconsistent with sound market design.

The memorandum also shows that a net carbon pricing framework is well situated to appropriately compensate storage resources for their contributions to reducing carbon emissions. Under this framework, both the price storage pays to consume electricity and the price it is paid to discharge electricity include carbon costs associated with the emissions rate of the marginal resource. Thus, if storage is shifting energy production from a higher emitting resource to a lower emitting resource, the higher carbon adder will be included in the energy price it is paid, and the lower carbon adder will be embedded in the energy price it is charged. This outcome is illustrated in Examples c1 and c2.

The examples also illustrate instances where different pathways the region is evaluating, an FCEM and net carbon pricing, produce dissimilar outcomes for storage resources based on the new product definitions. More specifically, examples b2 and c2 identify an instance where storage's participation has no impact on clean energy production, but it would reduce carbon emissions by transferring generation from a higher emitting resource to lower emitting (but not a carbon-free) resource. Storage would be compensated for this contribution under a net carbon pricing framework, as its contributions are consistent with the environmental attribute targeted – carbon emissions reduction. However, under an FCEM approach it would not be compensated for this contribution because its participation does not impact clean energy production.

Appendix B. The FCEM and Existing State Programs

memo

To: NEPOOL Participants Committee Working Session

From: Market Development

Date: April 8, 2021

Subject: The FCEM and Existing State Programs

Introduction

Stakeholders and the ISO are scoping the framework for a "Forward Clean Energy Market" (FCEM) that would procure clean attribute certificates (CECs) years in advance. We seek to clarify necessary scoping details so that the ISO and the Analysis Group (AGI) can complete the modelling framework for quantitative analysis. A key outstanding question is the extent to which the new CECs would be integrated with existing state programs, which are designed to help facilitate the development of resources with specific environmental attributes. Because this design choice will likely affect CEC and REC pricing, it may be important for modelling purposes. The ISO and stakeholders are evaluating three approaches, summarized below:[1]

Approach 1: Clean energy certificates reflect a clean attribute that is distinct from and does not overlap with other environmental attributes so that clean resources that are eligible can earn both CECs and renewable energy certificates (RECs) with each MWh of energy production during the delivery year.

Approach 2: Clean energy certificates encompass all environmental attributes, so that a resource that chooses to sells CECs in the FCEM cannot also sell a REC in the delivery year for the same MWh.[2]

Approach 3: The existing programs are discontinued, and the region uses clean energy certificates to meet its environmental objectives.

This memo considers six cases (labelled A through F) that demonstrate total payments to resources under the different approaches and with different relationships between CEC demand and REC demand. In the numerical examples, there are two renewable resources that produce both renewable and clean energy, and therefore can sell both CECs and RECs, and two clean resources that can sell only CECs. The cases assume competitive markets for both CECs and RECs, meaning that the price that is set for each of these

[1] See Section 4 of the FCEM Scoping memo, https://nepool.com/wp-content/uploads/2021/03/NPC_FG_20210318_Supplemental-1.pdf.

[2] Approach 2 would require clear rules regarding how a resource eligible to produce either a CEC or a REC would determine which type of credit it would like to generate.

certificates is based on the “break even” cost that must be recovered by the marginal resource that provides this product, outside of revenue from other markets such as the real-time energy market. The table below summarizes the cases, their assumptions, and key takeaways.

Summary of Cases and Results			
	Approach	**Relationship between REC and CEC Demand**	**Key Takeaways**
Case A	Current Market Rules	Only REC Demand	Under current market rules, resources recover their costs through REC revenue. Total payment for certificates is $200,000.
Case B	Approach 1	CEC Demand > REC Demand	CEC demand is introduced and is greater than REC demand. Resources can now recover costs through REC and/or CEC revenue. Total payment for RECs and CECs is $210,000, with the increase compared to Case A due to the increased quantity of clean energy. The resources that sell CECs and RECs don't receive double payment compared to Case A.
Case C	Approach 1	CEC Demand >>> REC Demand	CEC demand is set far greater than REC demand. The REC constraint is not binding and the REC price is $0/MWh. Total payments increase to $475,000, reflecting the larger quantity of clean energy demanded. No double payment occurs.
Case D	Approach 3	Only CEC Demand	CEC demand is kept at the higher level but the state REC programs are discontinued so that there is no REC demand. This case clears the same quantity of MWhs from the same resources at the same price as Case C. When CEC demand is sufficiently large relative to REC demand, Approach 1 and Approach 3 yield equivalent results.
Case E	Approach 2	CEC Demand > REC Demand	CEC demand is set as in Case B but we assume Approach 2. The renewable resources satisfy the REC demand and the clean resources satisfy the clean energy demand. Total payments are $335,000, larger than Case B's total payments = $210,000. This increase in payments reflects the fact that more clean MWhs have to clear to meet the same clean energy demand.
Case F	Approach 2	CEC Demand < REC Demand	CEC demand is decreased to avoid purchasing excess clean energy. Total payment for RECs and CECs is $210,000, as in Case B.

The cases demonstrate three key points:

1. Stakeholders have expressed concern about the possibility of “double payments” under Approach 1, where resources that can sell both CECs and RECs will see increased payments per MWh of energy relative to Approach 2 and Current Market Rules. The examples suggest that such double payments may not materialize because CEC and REC prices adjust to ensure that marginal resources that are capable of selling both CECs and RECs will recover their costs, but no more than that amount.[3]

2. Approach 1 and Approach 3 yield equivalent outcomes when CEC demand is sufficiently large compared to REC demand, because this may lead to a quantity of renewable energy that is greater than or equal to the state requirements.

3. Approach 2 can lead to additional payments compared to Approach 1. Approaches 1 and 2 may yield equivalent results when CEC demand is reduced to account for the existing programs, but it

[3] Costs here, and throughout the memo, refer to incremental costs that the resource does not expect to recover through other wholesale markets, like the real-time energy market and capacity market.

may be difficult to make these approaches equivalent in practice, given the large number of state programs, where these each have different eligibility criteria, non-compliance rates, etc.

Given the above observations, the ISO proposes that AGI assume Approach 1 for the straw FCEM framework, as this appears to align most appropriately with the criteria the ISO identified for choosing between design options.[4] More specifically, it appears relatively simple to model, avoids the double payment concern identified by stakeholders, and allows for the continuation of the existing state programs. However, as the examples in this memo show, this approach may produce similar outcomes as Approach 2.

This memo, however, should not suggest that the ISO has finalized its thinking on the extent to which the existing programs should be integrated with the new CECs for the purposes of modelling. Indeed, the ISO welcomes stakeholder feedback on the proposed approach, particularly as it may relate to stakeholder's goals for the FCEM framework, and looks forward to further discussion.

Case A: Current Market Rules

Table 1 below summarizes the parameter values for the resources in all six cases considered in this memo. In each of the cases, there are two clean resources (Clean 1 and Clean 2) that can sell only CECs, and two renewable resources (Renewable 1 and Renewable 2) that can sell both CECs and RECs. The renewable resources are assumed to have greater costs and so need to be compensated at a higher rate to be economical.[5] For example, Renewable 2 would need to be paid at least $25/MWh for their clean energy or renewable attributes. If they are not paid at least this much, their resource will not be built. Clean 1, on the other hand, has fewer costs and so only needs to be paid $10/MWh to be built. All four resources have the same maximum certificate award of 5,000 MWh, so that no resource can sell more than 5,000 MWhs of CECs and the two renewable resources cannot sell more than 5,000 MWhs of RECs. Note that for simplicity and ease of comparison, we assume each resource submits fully rationable offers, so that there is no lumpiness in REC or CEC awards. Finally, we assume that the markets for both the RECs and the CECs are competitive, so that the marginal resource breaks even on their investment.

Table 1: Parameter Summary for Resources

		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	Unrecovered Costs/MWh	$10	$15	$20	$25
[2]	Maximum Certificate Award	5,000 MWh	5,000 MWh	5,0000 MWh	5,000 MWh
[3]	Qualified to Sell RECS?	No	No	Yes	Yes
[4]	Qualified to Sell CECs?	Yes	Yes	Yes	Yes

While all six cases assume these same resource properties, they will produce different results based upon assumptions about the demand for each environmental attribute and whether resources can receive both

[4] For further discussion of these criteria, see the ISO's memo on the straw FCEM framework, available at https://nepool.com/pathways-study-process/1a-fcem-scoping-memo_vfinal/.

[5] Because resources that qualify as renewable must have additional attributes, they generally have higher costs than resources that are only "clean." In practice, some resources that qualify as renewable may be cheaper than other resources that qualify as "clean."

clean and renewable energy certificates for each MWh produced. These cases begin with current market rules, where there are renewable energy credits, but no clean energy credits.

Under current market rules, there are no CECs so the resources can only recover their costs with REC revenue. The table below summarizes the results for Case A, where the REC demand is set at 8,000 MWh.[6]

Case A: Current Market Rules, No CEC Demand						
			Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand		8,000 MWh			
[2]	CEC Demand		-			
[3]	REC Award		0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award		-	-	-	-
[5]	REC Price		$25/MWh			
[6]	CEC Price		-			
[7]	Resource Revenue/MWh		$0/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments		$200,000			
[9]	Total CEC Payments		-			
[10]	Total Payments		$200,000			

In this case, Renewable 1 clears for its entire capability so Renewable 2 is marginal as it provides 3,000 MWh of renewable energy. Because Renewable 2 is the marginal resource for RECs, it sets their price at its "breakeven" cost of $25/MWh. In total, the resources sell 8,000 MWh of RECs and so satisfy the REC requirement. Total payments to the resources is $200,000.

Note that, without CEC demand, there is not compensation for clean energy. Thus, the clean resources that are eligible only for CECs earn no incremental revenues from the sale of environmental attributes. As a result, neither clean resource is developed and the region's energy mix doesn't include any clean energy beyond what is provided by the two renewable resources.

Case B: CEC Demand > REC Demand, Approach 1

Under Approach 1, the renewable resources can sell both CECs and RECs for the same MWhs. Assume the CEC demand is 9,000 MWh, REC demand remains unchanged from Case A at 8,000 MWh, and that the resources have the same parameter values as in Table 1. The table below summarizes the results for Case B.

[6] For simplicity, we assume the demand bids are vertical.

Case B: CEC Demand > REC Demand, Approach 1					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	9,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	1,000 MWh	0 MWh	5,000 MWh	3,000 MWh
[5]	REC Price	$15/MWh			
[6]	CEC Price	$10/MWh			
[7]	Resource Revenue/MWh	$10/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$120,000			
[9]	Total CEC Payments	$90,000			
[10]	Total Payments	$210,000			

As in Case A, the least cost way to meet the REC demand is to award Renewable 1 with 5,000 MWh of RECs and Renewable 2 with 3,000 MWh of RECs. With Approach 1, Renewable 1 and Renewable 2 can be awarded CECs in addition to RECs, and so Renewables 1 and 2 also receive 5,000 MWh and 3,000 MWh of CECs, respectively. To meet the remainder of CEC demand, Clean 1 provides the final 1,000 MWh at least cost.

While the change in awards from Case A is modest, the pricing implications are important. First, Clean 1 is now marginal for CECs and so sets the CEC price. That is, if the CEC demand was increased by 1 MWh, Clean 1 would clear for an additional MWh of CEC at a cost of $10. This increase in costs sets the CEC price at $10/MWh. Note that this price is the “break even” price for Clean 1.

Second, Renewable 2 remains marginal for RECs. However, because Renewable 2 receives $10/MWh for each CEC it is awarded, it can recover its costs while receiving a lower REC payment than in Case A. More specifically, Renewable 2 only needs to be paid $15/MWh for RECs to break even as this will result in it fully recovering its costs of $25/MWh ($15 for each REC sold, and another $10 for each CEC sold). As a result, Renewable 2 sets the REC price at $15/MWh.

Note that despite the fact that the two renewable resources are paid twice for each MWh, their total compensation per MWh is still $25. (Row [7] is the same in both of the above tables for the two renewable resources.) Thus, the double payment concern that has been highlighted with respect to Approach 1 does not appear to materialize.

Finally, note that the total payment to the resources for both CECs and RECs is $210,000. The additional $10,000 in total payments in Case B compared to Case A reflects Clean 1’s cost for providing CECs.

Case C: CEC Demand >>> REC Demand, Approach 1

Continuing with Approach 1, Case C is identical to Case B except the CEC demand is increased by 10,000 MWh to 19,000 MWh. The table below summarizes the results for Case C.

Case C: CEC Demand >>> REC Demand, Approach 1					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	19,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	4,000 MWh
[4]	CEC Award	5,000 MWh	5,000 MWh	5,000 MWh	4,000 MWh
[5]	REC Price	$0/MWh			
[6]	CEC Price	$25/MWh			
[7]	Resource Revenue/MWh	$25/MWh	$25/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$0			
[9]	Total CEC Payments	$475,000			
[10]	Total Payments	$475,000			

Clean 1, Clean 2, and Renewable 1 all clear for their maximum capabilities, so Renewable 2 is marginal for both RECs and CECs. Note, however, that the REC demand is no longer binding: the 9,000 MWhs of RECs awarded is greater than the 8,000 MWh demand.[7] As a result, the REC clearing price is $0/MWh. The CEC demand is still binding, however, and Renewable 2 sets the CEC price at $25/MWh. Note that this $25/MWh CEC price is necessary for Renewable 2 to break even and recover their costs because, in this case, they expect no additional revenue from RECs.

The total payment to the resources for both CECs and RECs is $475,000. The additional payments reflect the fact that substantially more CECs are awarded in Case C than in Case B. Despite the additional payments, there is still no "double payment": the two renewable resources are still paid $25/MWh, as in Case A and Case B. (Row [7] is unchanged for the renewable resources.)

Case D: Approach 3, No REC Demand

With Approach 3, the state programs are assumed to be discontinued so that there is no REC demand. CEC demand is unchanged from Case C at 19,000 MWh. The table below summarizes the results for Case D.

[7] Whether the REC demand bid binds is a function not only of the size of CEC demand, but also of supply conditions. For example, if the maximum capability of clean resources was substantially decreased, the REC demand could be rendered non-binding in Case B as well.

Case D: No REC Demand, Approach 3						
			Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand			-		
[2]	CEC Demand			19,000 MWh		
[3]	REC Award		-	-	-	-
[4]	CEC Award		5,000 MWh	5,000 MWh	5,000 MWh	4,000 MWh
[5]	REC Price			-		
[6]	CEC Price			$25/MWh		
[7]	Resource Revenue/MWh		$25/MWh	$25/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments			-		
[9]	Total CEC Payments			$475,000		
[10]	Total Payments			$475,000		

Renewable 2 is still marginal for CECs, as Clean 1, Clean 2, and Renewable 1 clear for their entire capability. Without REC demand, there is no REC price, and the resources recover their costs entirely from CECs. As in Case C, the total payment to the resources is $475,000, and the renewable resources are paid $25/MWh. There is no double payment to the renewable resources.

Note that Approaches 1 and 3 will generally yield the same results when REC demand is not binding, as occurred with Case C. If, however, REC demand is binding, as in Case B, Approach 1 will yield different outcomes than Approach 3. In particular, under Approach 3 without the REC demand, fewer renewable resources and more clean (but not renewable) energy resources are likely to clear than under Approach 2 when REC demand is binding. Approach 3 will generally result in lower costs for the same quantity of clean energy but it will yield less renewable energy.

Case E: CEC Demand > REC Demand, Approach 2

With Approach 2, the renewable resources can be compensated for either CECs or RECs, but not both. More specifically, for the purposes of this memo, we assume that each MWh's attributes can only be counted for one product. In practice, we expect the resources to sell the highest value certificates, subject to their capability. In this case, where the REC price is higher than CEC price, we expect the renewable resources to sell the RECs and the clean energy resources to sell the CECs. To ease comparisons, CEC and REC demand are the same as in Case B with Approach 1, as illustrated in the table below.

Case E: CEC Demand > REC Demand, Approach 2					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	9,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	5,000 MWh	4,000 MWh	0 MWh	0 MWh
[5]	REC Price	$25/MWh			
[6]	CEC Price	$15/MWh			
[7]	Resource Revenue/MWh	$15/MWh	$15/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	$135,000			
[10]	Total Payments	$335,000			

Renewable 2 is marginal for the RECs and sets the REC price at $25/MWh, while Clean 2 is marginal for the CECs and sets their price at $15/MWh. Because the renewable resources cannot sell both CECs and RECs, their total revenue per MWh is $25/MWh. Note that the total revenue to the renewable resources is the same in Case E as in all of the other cases.

Despite the fact that CEC demand is only 9,000 MWh, the resources sell 17,000 MWhs of energy that could yield CECs, where this remaining 8,000 MWh of energy instead is used to satisfy only demand for RECs. As a result, the total overall payment to the resources in Case E ($335,000) is substantially higher than in Case B ($210,000).

Case F: CEC Demand < REC Demand, Approach 2

To avoid the increased costs seen in Case E that result from procuring excess clean energy, Case F reduces CEC demand to 1,000 MWh, so that Cases F and B result in the same total payments. See the table below.

Case F: CEC Demand < REC Demand, Approach 2					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	1,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	1,000 MWh	0 MWh	0 MWh	0 MWh
[5]	REC Price	$25/MWh			
[6]	CEC Price	$10/MWh			
[7]	Resource Revenue/MWh	$10/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	$10,000			
[10]	Total Payments	$210,000			

Once again, Renewable 2 is marginal for RECs and sets their price at $25/MWh. Reducing CEC demand from 9,000 MWh to 1,000 MWh decreases Clean 1 and Clean 2's CEC awards, so that Clean 1 is now marginal for CECs and sets their price at $10/MWh. These prices ensure that each Clean 1 and Renewable 2 both recover their costs and break even. Note that the total resource revenue per MWh (Row [7]) and total payments to the resources (Row [10]) are the same in Cases B and F.

Case F demonstrates that it is possible to achieve the same outcomes with Approaches 1 and 2, as this outcome is effectively equivalent to Case B, where resources are permitted to sell both clean energy certificates and RECs. However, given that there are often many different RECs, where the products vary by state, technology, and location, it may not be practical to adjust clean energy demand to produce an outcome that meets both the region's clean energy targets and its many REC requirements in a cost-effective manner.

Conclusion

The six cases above show that, given competitive REC and CEC markets, we do not expect renewable resources to receive additional revenue per MWh with the introduction of clean energy certificates. However, given the same levels of demand, we do observe increased costs with Approach 2 compared to Approach 1. These increased costs from Approach 2 can be alleviated by adjusting demand, but the ISO believes that this may be difficult in practice, given the large number of overlapping state programs with different eligibility criteria, noncompliance rates, etc. Finally, Approach 1 and Approach 3 will often yield identical results, and when the two approaches yield different results, Approach 3 will generally entail lower costs.

Given these observations, the ISO proposes that, for modelling purposes, AGI assume Approach 1 so that the CECs are not integrated with the existing state programs. This approach appears to be relatively simple to model, avoids the double payment concern identified by stakeholders, and allows for the continuation of the existing state programs. The ISO has not finalized its thinking on this issue, however, and welcomes stakeholder input and feedback in the coming weeks as we move towards a decision.

Appendix C. Evaluation of an Integrated Forward Clean Energy Market

memo

To: NEPOOL Participants Committee Working Session

From: Market Development

Date: March 11, 2021

Subject: Evaluation of an Integrated Forward Clean Energy Market

Introduction

As part of the Future Pathways project, stakeholders have requested feedback on the feasibility of a forward clean energy market (FCEM) that is integrated with the forward capacity market, also known as an integrated clean capacity market (ICCM). This memo describes, at a high level, the ISO's current assessment of a potential conceptual approach for an ICCM construct for purposes of the pathways analysis. The ISO welcomes feedback on the approach and looks forward to continued discussion of a forward clean energy framework that will be modeled in these pathways efforts.

Conceptually, an ICCM would jointly procure both conventional capacity and clean energy on a forward basis to satisfy both sets of demand bids at least cost. Under such an approach, "clean" resources would be able to sell forward both capacity and clean energy, where the states would submit demand bids for clean energy.[1] More specifically, as part of their capacity offers, "clean" resource owners would include an offer parameter indicating how many MWh of forward clean energy they wish to sell for each unit of capacity awarded. As a result, capacity and clean energy awards would be bound together in a single procurement. The next section provides a more in-depth review of the formulation, including a numerical example.

While there are still many outstanding questions, this memo provides a high-level discussion of a possible conceptual approach for an integrated design. As such, stakeholders should not consider the details included in this memo as ISO recommendations or implicit confirmation that the ISO could implement such an approach. Rather, as is typical with the development of novel auction constructs, significant additional work would be necessary to evaluate critical design details, potential pricing rules (given there are multiple products and non-rationable offers), and potential implementation challenges.

[1] The ISO presumes that the forward positions would settle against a "spot" position that is determined by the resource's actual clean energy production during the delivery period. Further discussion of how this may work is included in the FCEM scoping memo.

Design Details

In an ICCM that procures clean energy forward, the FCM would be expanded to include clean energy bids determined by the states. In the following subsections, the memo details the ISO's current thinking on i) how participants might formulate and submit offers under this ICCM construct, ii) how the integrated auction clearing process would assign awards, and iii) how prices would be determined (when the marginal offer for each product is rationable). The memo concludes with a numerical example to illustrate these points.

Offer Structure

With the FCM as currently structured, resources submit offers that reflect the minimum amount of payment needed for the resource to take on a Capacity Supply Obligation (CSO). Such an offer includes, at a minimum, any "missing money" that the resource would need to recover its capital costs as well as any forgone revenues associated with selling capacity forward under pay-for-performance. With this $/unit of capacity offer, resources also have a qualified capacity value that represents the maximum capacity award that they can receive. The capacity offers can be rationable, where the CSO awarded can be less than the resource's qualified capacity, or non-rationable, where the resource's CSO award is all-or-nothing.

The ISO anticipates that a conceptual ICCM framework could build off this structure: participants would still submit a $/unit of capacity offer, their capacity awards would still be capped by their qualified capacity, and the resources would still be able to submit rationable or non-rationable offers. New to the FCM through an ICCM construct, however, is that resources would also submit a clean energy parameter that reflects the MWh quantity of clean energy they would sell on a forward basis per unit of capacity awarded. This clean energy parameter would bind the resource's CSO award with their clean energy award, so that, for each MW of CSO awarded, they are also awarded a forward clean energy position equal to their offered clean energy parameter.

Note that allowing non-rationable offers, as under the current FCM construct, may raise additional questions and challenges with current rules, including numerous questions about the pricing rules and the possibility of make-whole payments in the primary forward capacity auction.

Integrated Auction Clearing

The ICCM would clear resources based on their offers and their contribution to both the capacity and the clean energy bids. The capacity demand bids would be set in a manner consistent with the current FCM rules, but the clean energy demand bids would be set by the states. The auction would then clear bundles of capacity and clean energy to maximize social surplus, where the social surplus considers the benefits of both products. Holding a resource's offer constant, resources that are willing to take on larger forward clean energy positions would have a higher chance of receiving forward positions in the auction because their award would contribute more to meeting the region's clean energy demand.

Numerical Example

Three tables below outline a numerical example. Table 1 below contains key parameters for the example.[2]

[2] Note that, to simplify the incorporation of clean energy awards in these examples, offers and CSO awards are measured in MW-Year rather than the typical kW-Month.

Table 1. Resource Parameters

Generator	Max Capacity	Clean Energy Parameter	Offer
Non-Clean 1	500 MW-Year	-	$60,000/MW-Year
Non-Clean 2	500 MW-Year	-	$70,000/MW-Year
Clean 1	300 MW-Year	6000 MWh/MW-Year	$150,000/MW-Year
Clean 2	300 MW-Year	7000 MWh/MW-Year	$200,000/MW-Year

In the example, there are two resources that can sell clean energy forward (Clean 1 and Clean 2) and two resources that cannot (Non-Clean 1 and Non-Clean 2). Each resource submits offers that are fully rationable, meaning the auction can award it forward positions that are less than its maximum capacity capability.[3]

Non-Clean 1 and Non-Clean 2 are each qualified to sell 500 MW-Year of capacity and Clean 1 and Clean 2 are each qualified to sell 300 MW-Year of capacity. Non-Clean 1 and Non-Clean 2 submit offers to sell capacity of $60,000/MW-Year and $70,000/MW-Year, respectively. These offers reflect the minimum payment per MW-Year that Non-Clean 1 and Non-Clean 2 must receive to sell capacity. Clean 1 and Clean 2 offer to sell both capacity and clean energy forward. For every MW-Year of capacity that Clean 1 sells, it would also sell a quantity of clean energy forward. More specifically, for each MW-Year of capacity that Clean 1 sells, it would sell 6,000 MWhs of clean energy. Clean 1's offer of $150,000/MW-Year indicates that to sell both one MW-Year of capacity and 6,000 MWhs of clean energy, Clean 1 would need to be paid at least $150,000. Similarly, for every MW-Year of capacity that Clean 2 sells, it would sell 7,000 MWh of clean energy forward. Clean 2's offer of $200,000/MW-Year indicates that Clean 2 would need to be paid at least that price per MW-year of capacity to sell its capacity and clean energy.[4] Note that the offers from Clean 1 and Clean 2 of $150,000 and $200,000 per MW-Year, respectively, represent an offer to sell a bundled product of capacity and clean energy on a forward basis. As such, their offers include both costs associated with capacity and costs associated with taking on a forward clean energy position. See Appendix A for a more detailed examination of how participants might submit offers in an ICCM.

For simplicity, this example assumes vertical demand curves for capacity and clean energy set at 850 MW and 2,500,000 MWh, respectively.[5] Given the offers and clean energy parameters in Table 1 above, Table 2 below contains the awards and clearing prices for this simple ICCM.

[3] This assumption allows prices for each product to be set based on the marginal supply offer. If these offers were instead assumed to be non-rationable, it is less clear how prices for each product would be established.

[4] The difference between the two resources' clean energy parameters could reflect differences in expected production or risk preferences.

[5] This ICCM concept can be applied similarly to instances where sloped demand curves are employed.

Table 2. ICCM Clearing and Awards			
Generator	Offer	Capacity Award	Clean Energy Award
Non-Clean 1	\$60,000/MW-Year	450 MW	0 MWh
Non-Clean 2	\$70,000/MW-Year	0 MW	0 MWh
Clean 1	\$150,000/MW-Year	300 MW	1,800,000 MWh
Clean 2	\$200,000/MW-Year	100 MW	700,000 MWh

Non-Clean 1 is the marginal resource for capacity and sets the capacity price at \$60,000/MW-Year. This is the price Non-Clean 1 is paid per MW-Year. To see how this price is determined, consider an incremental increase in the installed capacity requirement of one MW-Year without a corresponding increase in the clean energy bids. To meet this additional MW-Year of capacity demanded, Non-Clean 1 would receive an additional one MW-Year of capacity award, at a cost to the system of \$60,000/MW-Year. Note that, absent the clean energy requirement, Non-Clean 2 would be marginal for capacity and would set the capacity price at \$70,000/MW-Year.

Clean 2 is the marginal resource for the forward clean energy positions and so sets the forward clean energy price at \$20/MWh. To see how this price is determined, consider an incremental increase in the forward clean energy demand bids of one MWh. To meet this additional one MWh bid, Clean 2 must be awarded an additional $\frac{1}{7000}$ MW-Year of CSO,[6] costing the system $\frac{1}{7000} * \$200{,}000 = \$28.57$. Because Clean 2 clears for an additional $\frac{1}{7000}$ MW-Years of CSO, however, Non-Clean 1's CSO award can be decreased by $\frac{1}{7000}$ MW-Years, saving the system $\frac{1}{7000} * \$60{,}000 = \$8.57$. The total change in system costs is thus \$28.57 - \$8.57 = \$20, and so the forward clean energy price is \$20/MWh.

The total price paid to each resource per unit of capacity awarded is the capacity clearing price (\$60,000/MW-Year) plus their clean energy parameter times the forward clean energy price (\$20/MWh). That is, resources can be paid different prices per unit of capacity sold if their clean energy parameters differ. Table 3 below details price formation for the three resources that receive capacity awards.

Table 3. Resource Specific Clearing Prices					
			Non-Clean 1	Clean 1	Clean 2
[1]	CSO Clearing Price		\$60,000/MW-Year	\$60,000/MW-Year	\$60,000/MW-Year
[2]	Clean Energy Parameter		0 MWh/MW-Year	6000 MWh/MW-Year	7000 MWh/MW-Year
[3]	Forward Clean Energy Price		\$20/MWh	\$20/MWh	\$20/MWh
[4]	Resource Price Per MW-Year	=[1]+[2]*[3]	\$60,000/MW-Year	\$180,000/MW-Year	\$200,000/MW-Year

Note that Clean 2 is paid more per MW-Year than Clean 1 because Clean 2 sells an additional 1,000 MWh of clean energy forward each awarded MW-Year of capacity.

[6] From Table 1, Clean 2 provides 7000 MWh of clean energy/MW-Year of capacity, so one additional MWh of clean energy from Clean 2 requires 1/7000 MW-Year of additional capacity from Clean 2.

Key Observations

- This formulation effectively yields two prices for the procured products – one for capacity in $/MW-Year and one for forward clean energy in $/MWh. This is necessary to account for the fact that the optimization procures two distinct products, and there are different costs associated with each.

- Some stakeholder presentations have discussed an ICCM with fully non-rationable offers for both capacity and clean energy. The concept proposed in this memo allows for participants to offer the products in a more flexible manner, as their offers can be either non-rationable or rationable. This is consistent with the current capacity market rules. However, allowing participants to submit non-rationable offers for both capacity and clean energy may raise additional challenges that need to be investigated further.

- At present, the ISO has not evaluated the work or implementation challenges that may arise when considering whether this conceptual framework could be sensibly translated into a more fully developed market design. We expect it would likely add significant complexity to the FCM process, and there would require a number of substantial changes to the FCM rules, schedule, and processes to implement such an approach. Further consideration of these challenges is outside the scope of these pathway efforts.

Conclusion

Based on preliminary analysis, the ISO believes that the joint procurement of capacity and clean energy in an integrated forward market is conceptually feasible as illustrated above and thus can be considered in the pathways analysis. However, additional work would be necessary to fully evaluate if this conceptual approach can be sensibly translated into a more concrete market design, and such work is outside the scope of these efforts. The ISO welcomes observations and feedback from stakeholders on this approach.

Appendix A

Table A1 below displays the offer components for "Clean 2", a resource that features prominently in the numerical example above.

Table A1. Clean 2's Optimal Offer, $/MW of CSO				
	Offer Components		Capacity Only	Capacity + Clean Energy
[1]	Expected PFP Settlement		$60,000/MW-Year	$60,000/MW-Year
[2]	Clean Energy Parameter		N/A	7000 MWh/MW-Year
[3]	Expected Spot Clean Energy Price		N/A	$20/MWh
[4]	Clean 2's Offer	=[1] + [2]*[3]	$60,000/MW-Year	$200,000/MW-Year

In the FCM as it currently exists (capacity only), Clean 2's offer for capacity is simply the expected PFP settlement. (For simplicity, we are assuming that the resource has no missing money.) With an ICCM, however, the resource would also submit a clean energy parameter, given in Row [2]. Because Clean 2 could opt not to sell their clean energy forward and instead sell it in the delivery year, they must be paid at least the expected clean energy price in the delivery year per MWh of clean energy they sell forward. As such, their ICCM offer is the sum of the expected PFP settlement (Row [1]) plus their offered clean energy parameter (Row [2]) times the expected clean energy price in the delivery year (Row [3]). Note that Clean 2's offer is substantially larger in an ICCM than in a "capacity only" market. This reflects the additional costs of the forward clean energy position Clean 2 would take if they receive an award.

Appendix D. Modeling Equivalence of the FCEM and ICCM

memo

To: NEPOOL Participants Committee Working Session

From: Market Development

Date: May 6, 2021

Subject: Modelling Equivalence of FCEM and ICCM

Introduction

The Pathways to the Future Grid study explores potential market frameworks that will help the region achieve clean energy goals. As part of this process, Analysis Group (AGI) will model a forward clean energy framework and a net carbon pricing framework to compare their expected market outcomes to a "status quo" framework where there are no substantial changes to the region's markets and states continue using bilateral contracts to achieve their policy objectives. In previous meetings and materials, stakeholders and the ISO have discussed whether AGI should model a forward clean energy market that is integrated with the capacity market or model a forward clean energy market that is conducted separately from the capacity market.[1]

Under an integrated clean capacity market (ICCM) construct, resources would submit a single offer for the forward sale of both capacity and clean energy, while in a separate forward clean energy market (FCEM) resources would first participate in a forward market for clean energy before submitting offers in a subsequent forward market for capacity. While both frameworks would require significant work to translate the high-level concepts into fully developed designs, the ISO views the ICCM as having particularly complex design and implementation challenges, given the added difficulties associated with jointly procuring two distinct products through a single auction.[2] Nonetheless, the ISO feels that AGI's modeling can simulate outcomes from a high-level ICCM framework, which will provide stakeholders with some insight about its theoretical application.

This memo considers potential differences between the FCEM and the ICCM concepts, with a focus on how these approaches may be similar or different in the context of the modeling efforts that are part of the Pathways to a Future Grid study. In particular, given AGI's proposed modelling structure and the

[1] See the "Scoping" document for the FCEM, located here: https://nepool.com/wp-content/uploads/2021/03/1a-FCEM-Scoping-Memo_vfinal.pdf

[2] While the ISO cannot fully evaluate the work or implementation challenges that may arise under an ICCM design that has not yet been established, we imagine that, at a minimum, the ICCM would likely add significant complexity to the FCM process. For more information on the ICCM, see the "Evaluation of an Integrated Forward Clean Energy Market," located here: https://nepool.com/wp-content/uploads/2021/03/NPC_FG_20210318_Supplemental-1.pdf

corresponding model inputs and assumptions, the memo concludes that the two approaches should produce identical awards and compensation. This result holds because the model makes two key assumptions: i) under an FCEM, resources account for their expected capacity revenue when formulating their competitive clean energy offers, and ii) that these expectations are accurate (i.e., the *expected* FCM prices are the same as the *actual* prices.) Based on this finding, it does not appear critical for the region to choose between an FCEM and an ICCM for the distinct purpose of finalizing the straw forward clean energy framework to be modeled.[3]

The memo begins by describing some of the key assumptions for the following examples. The memo next considers a numerical example that demonstrates awards, prices, and total compensation to resources in a hypothetical ICCM. The memo follows with a similar numerical example for a FCEM with the same assumptions and resource parameters as the ICCM example. The numerical examples show that the FCEM and ICCM will yield identical awards, prices, and total revenue for each resource, given the aforementioned assumptions. The memo concludes with a discussion of AGI's model mechanics and how their assumptions compare to those employed in these examples. It finds that because the assumptions listed in the memo's first section mirror AGI's model structure, the memo's numerical examples are consistent with the model output we would expect from AGI under equivalent conditions.

Given that AGI's expected modelling results can be viewed as consistent with either the FCEM or the ICCM, the ISO does not believe it is necessary for the region to pick one over the other for the purpose of studying a straw forward clean energy framework. The ISO welcomes stakeholder feedback on this issue and looks forward to further discussion.

Key Assumptions and Parameters for Numerical Examples

This section lists the key assumptions for the numerical examples in the subsequent section. Note that these assumptions reflect those AGI will make in their modelling efforts.

Assumption 1: Resources submit offers for capacity and clean energy based on their missing money, where their missing money is defined as the revenue they would need to receive, in addition to that from the energy and ancillary service markets, to recover their costs.[4]

Assumption 2: The markets for renewable energy certificates (RECs) and clean energy certificates (CECs) are competitive, so that the marginal resource recovers its missing money, but no more. In practice, if the REC or CEC markets were not competitive and the marginal resource recovered more than their missing money, we would expect additional resources to enter the markets to profit themselves. As more resources enter the markets, we would expect that competition would increase until the marginal

[3] While the modelling efforts are unlikely to detect differences between the FCEM and the ICCM, there will likely be important differences in practice. As a result, if the region decides to pursue a forward clean energy framework, further consideration of the pros and cons of an FCEM versus an ICCM, as well as additional design details, will be necessary. Moreover, we will seek to provide qualitative information on these differences to help inform the region before it proceeds further into developing potential proposals.

[4] This is a simplifying assumption and generalizes to cases where resources submit offers based on the maximum of their missing money and the "common value component", or the expected opportunity cost of taking on a forward position.

resources earn no profit. Note that this is a natural extension of Assumption 1: if resources submit offers to recover their missing money, the marginal resource will recover its missing money and earn no profits.

Assumption 3: Resources offer to sell the entirety of their clean energy and capacity capability forward. For example, if a clean energy resource expects to produce 3,000 MWh of clean energy for each MW of capacity during the delivery year, they will offer to sell this entire 3,000 MWh of clean energy in the forward markets. We make this assumption because, in equilibrium, we expect the forward clean energy price to equal the expected clean energy price in the delivery period, so that resources cannot profit from selling some of their clean energy in the spot market rather than the forward market.

Assumption 4: Resources submit fully rationable (i.e., non-lumpy) offers for capacity. This is a simplifying assumption to make the examples easier to follow.

Assumption 5: Resources have perfect foresight, so that they can exactly predict the capacity clearing price, their capacity award, their real-time energy profits, their clean energy production, etc.

Assumption 5 is an important modeling assumption that may not hold in practice, as it is likely that actual capacity prices will differ from those expected by resources when formulating the clean energy offer prices. However, it is consistent with the model framework that AGI will employ in the pathways efforts. Without this assumption, we might observe divergent outcomes between the ICCM and the FCEM, particularly when the resources have different beliefs about the expected capacity prices.[5]

Key Parameter Values for the Numerical Examples

The following numerical examples consider market outcomes for four resources. More specifically, the examples consider how the resources offer to sell their capacity and clean energy in a FCEM and an ICCM, and the resulting awards, prices, and compensation in each framework. The examples show that each framework results in the same awards and prices so that the resource's total compensation is identical in both the FCEM and the ICCM.

Table 1 below lists parameter values for the four resources included in this memo's numerical examples. Note that the parameter values are held constant across the two examples so that the results are comparable. Row [1] contains each resource's missing money per MW. This represents the revenue they would need to recover from capacity or clean energy to be economical. Row [2] contains their maximum capacity award, which is the maximum quantity of capacity the resource can sell in a FCM or an ICCM. Row [3] lists each resource's expected clean energy production during the delivery year. Row [4] sets the CSO demand at 1,200 MW and Row [5] sets the clean energy demand at 3,000,000 MWh. Note that we assume vertical demand curves, for simplicity, but the results generalize to sloped demand curves as well.

[5] While it may not be possible to fully eliminate this divergence, there may be mechanisms that would tend to reduce this divergence by decreasing the uncertainty of the price for the second product and ensuring that there are retrading opportunities for both products after the primary auction. If the region chooses to pursue a forward clean energy framework, further consideration of these mechanisms may be worthwhile when evaluating the relative merits of an FCEM versus an ICCM.

Table 1. Resource Parameters for Numerical Examples						
			Non-Clean 1	Clean 1	Clean 2	Clean 3
[1]	Missing Money Per MW		$60,000/MW	$160,000/MW	$150,000/MW	$200,000/MW
[2]	Max Capacity Award		1,000 MW	300 MW	300 MW	300 MW
[3]	E[Clean Energy]		-	6,000 MWh/MW	3,000 MWh/MW	7,000 MWh/MW
[4]	CSO Demand		1,200 MW			
[5]	Clean Energy Demand		3,000,000 MWh			

Numerical Example: Integrated Clean Capacity Market

With an ICCM, capacity and forward clean energy are procured simultaneously in one forward auction. Resources submit a single $/MW offer to provide both clean energy and capacity, where their offer includes a "clean energy parameter" that defines the quantity of forward clean energy they would need to sell per unit of capacity. In effect, the clean energy parameter "binds" a resource's capacity award with their clean energy award, so that a resource's capacity award cannot be increased without also increasing the resource's clean energy award by their clean energy parameter.[6]

For example, suppose that Clean 2 submits an offer of $150,000/MW into the ICCM with a clean energy parameter of 3,000 MWh/MW (equal to their expected clean energy production from Table 1). This offer suggests that they would need to be paid at least $150,000/MW to be awarded both 1 MW of CSO and 3,000 MWh of forward clean energy. If Clean 2 is awarded a MW of CSO, they must also be awarded 3,000 MWh of forward clean energy.

Table 2 below contains the resource offers, awards, prices, and total revenue in the ICCM, given the parameter values in Table 1.

Table 2. Resource Offers, Awards, Prices, and Revenue in ICCM						
			Non-Clean 1	Clean 1	Clean 2	Clean 3
[1]	ICCM Offers		$60,000/MW	$160,000/MW	$150,000/MW	$200,000/MW
[2]	Clean Energy Parameter		-	6,000 MWh/MW	3,000 MWh/MW	7,000 MWh/MW
[3]	CSO Award		728.6 MW	300 MW	0 MW	171.4 MW
[4]	CSO Price		$60,000/MW	$60,000/MW	$60,000/MW	$60,000/MW
[5]	Clean Energy Award		-	1,800,000 MWh	0 MWh	1,200,000 MWh
[6]	Clean Energy Price		-	$20/MWh	$20/MWh	$20/MWh
[7]	Total Revenue	=[3]*[4]+[5]*[6]	$43,714,800	$54,000,000	$0	$34,285,200

Rows [1] and [2] define the offer parameters for the resources. Row [1] provides the $/MW offer for each resource. These offers represent the amount of money the resources would need to be paid to sell 1 MW of CSO and the accompanying forward clean energy defined by their clean energy parameter, displayed in

[6] Stakeholders have questioned whether it would be possible for some resources to sell only clean energy in an ICCM. While submitting "clean energy only" offers in an ICCM is not considered in this memo, the ICCM (and AGI's model) can likely be modified to accommodate such offering behavior.

Row [2]. Note that the offers in Row [1] equal each resource's missing money in Table 1 Row [1]. Because Non-Clean 1 does not provide clean energy, they do not submit a clean energy parameter and their offer only represents the minimum amount they would need to be paid to sell capacity. In these examples, Non-Clean 1 would need to be paid $60,000/MW for capacity.

Row [3] lists CSO awards. Clean 1 clears for their entire capability because, as we will see, they are infra-marginal for clean energy and their capacity award is bound to their clean energy award by their clean energy parameter. Clean 3 is awarded 171.4 MW of capacity, but they are not marginal for capacity, as Non-Clean 1 can provide capacity more cheaply than Clean 3. Indeed, Clean 3 is awarded capacity because, when they sell capacity, they also sell clean energy that contributes to meeting the clean energy demand.

Row [4] lists the CSO clearing price. Non-Clean 1 is marginal for capacity and sets the CSO price at $60,000/MW. To see how this price is determined, consider an incremental increase in the installed capacity requirement of 1 MW, without a corresponding increase in clean energy demand. The least-cost way to meet this increment is to increase Non-Clean 1's CSO award by 1 MW, at a cost to the system of $60,000. Thus, Non-Clean 1 sets the CSO clearing price at $60,000/MW.

Note that Clean 2 does not clear for capacity despite the fact that their offer is less than Clean 3's offer (See Row [1]). While Clean 2 submits a lower-priced capacity offer, their clean energy parameter is also much smaller than Clean 3's and so they contribute less to clean energy demand. From the perspective of the optimization problem, Clean 3's additional contributions to clean energy demand per MW outweigh their increased cost, and so they are awarded capacity and clean energy positions ahead of Clean 2.

Row [5] lists the forward clean energy awards. Clean 1 is infra-marginal for clean energy and so clears for their entire capability, 1,800,000 MWh. Because they clear their entire clean energy capability, they also clear for their entire capacity capability. Clean 3 is awarded 1,200,000 MWh of forward clean energy to meet the remaining clean energy demand.

Row [6] lists the forward clean energy price. Clean 3 is the marginal resource for the forward clean energy positions and sets their price at $20/MWh. To see how this price is determined, consider an incremental increase in the forward clean energy demand of 1 MWh, without a corresponding increase in CSO demand. To meet this additional 1 MWh demanded, Clean 3 must be awarded an additional $\frac{1}{7000}$ MW of CSO, costing the system $\frac{1}{7000} * \$200,000 = \$28.57$. Because Clean 3 clears for an additional $\frac{1}{7000}$ MW of CSO, however, Non-Clean 1's CSO award can be decreased by $\frac{1}{7000}$ MW, saving the system $\frac{1}{7000} * \$60,000 = \$8.57$. The total change in system costs is thus $28.57-$8.57 = $20, and so the forward clean energy price is $20/MWh.

Finally, Row [7] lists the total revenue to each resource. Because Non-Clean 1 cannot sell clean energy, their total revenue is equal to their capacity revenue: $60,000/MW * 728.6 MW = $43,714,800. For the clean resources, their total revenue is the sum of their capacity revenue and their clean energy revenue. Clean 3's total revenue, for example, is their capacity revenue ($60,000/MW * 171.4 MW = $10,285,200) plus their clean energy revenue ($20/MWh * 1,200,000 MWh = $24,000,000), for a total of $34,285,200. Note that Clean 3's per MW revenue is their total revenue divided by their capacity award, $\frac{\$34,285,200}{171.4\ MW} =$

$\$200{,}000/MW$. That is, Clean 3 is paid their offer for their capacity and clean energy, and so they exactly recover their missing money. This is consistent with Assumption 2, the competitive markets assumption, as it indicates that the marginal resource for clean energy does not earn infra-marginal profits.

Numerical Example: Forward Clean Energy Market

In a market where forward clean energy is purchased in advance of the capacity market, clean resources submit offers to sell clean energy in the FCEM and then subsequently submit offers in the FCM. That is, unlike the ICCM which has one optimization that solves for both capacity and clean energy awards, the FCEM has two sequential optimizations, the first for clean energy and the second for capacity. As a result, resources know their forward clean energy awards and revenue before they submit offers for capacity in the FCM. This section considers 1) clean resource's offers into the FCEM, 2) the resulting forward clean energy awards and prices given those offers, 3) the resource's CSO offers in the capacity market, given the awards and prices in the FCEM, and, finally, 4) the capacity prices and awards in the FCM.

Resource Offers in the FCEM

Clean resources submit offers into the FCEM that reflect the missing money they would need to recover to enter the market or remain in operation. However, the calculus associated with this decision differs from that in the ICCM because clean energy and capacity are awarded in separate auctions. While resources seek to recover their missing money via payments for their clean energy and capacity (as they do in the ICCM), they now must determine their competitive FCEM offers before the capacity market price has been determined. Thus, when submitting their FCEM offers, the resources do not know how much of this missing money would be recovered via the sale of capacity. [7]

However, we assume that these resources have perfect foresight regarding the capacity clearing price when developing their clean energy offers (consistent with Assumption 5.) As such, resources set their clean energy offers as the remaining missing money that they must recover, net of their future capacity revenues. Table 3 below displays the clean resource's FCEM offers.

Table 3. Clean Resource Offers in FCEM

			Clean 1	Clean 2	Clean 3
[1]	Missing Money		$160,000/MW	$150,000/MW	$200,000/MW
[2]	E[Capacity Price]		$60,000/MW	$60,000/MW	$60,000/MW
[3]	E[Clean Energy Production]		6,000 MWh/MW	3,000 MWh/MW	7,000 MWh/MW
[4]	FCEM Offer	=([1]-[2])/[3]	$16.67/MWh	$30.00/MWh	$20.00/MWh

Row [1] contains each resource's missing money, where this value does not account for their expected capacity revenue. In other words, the values in Row [1] are the quantity of money the resources need to recover through both capacity and clean energy revenue. For example, Clean 3 needs to be paid $200,000 for each MW of capacity they sell *and* the clean energy they expect to produce with that capacity. Note that values in Row [1] above are the same as those in Row [1] of Tables 1 and 2.

[7] The results illustrated in this example would still hold if the order of the markets were reversed, so that the FCM occurs before the FCEM and where resources would develop their capacity offer prices using the expected clean energy price.

Row [2] contains the expected capacity price. By Assumption 5, each of the resources perfectly predicted the capacity price at $60,000/MW. (We will see in subsequent tables that the capacity clearing price in the FCM is indeed $60,000/MW, meaning each resource's expectations about this price is correct.)

Row [3] contains their expected clean energy production per MW, which is identical to the clean energy parameter the resources submitted as part of their offers in the ICCM example above. (See Assumption 3 in the first section.)

Finally, Row [4] contains each resource's per MWh offer. For each resource, they subtract their expected capacity revenue from their missing money (Row [1] – Row [2]), as they expect to recover this revenue via the capacity market and therefore do not include it in their clean energy market offers. They then divide the remaining missing money by their expected clean energy production per MW (Row [3]). This is the missing money they need to recover for each MWh of clean energy that they deliver, and therefore reflects their competitive clean energy market offer price.

FCEM Awards, Prices, and Revenue

Given the offers in Table 3 above, Table 4 contains the awards, prices, and revenue to each clean resource in the FCEM. As in the case of the ICCM, total demand for clean energy is equal to 3,000,000 MWh.

Table 4. Resource Awards, Prices, and Revenue in FCEM

			Clean 1	Clean 2	Clean 3
[1]	FCEM Offer		$16.67/MWh	$30/MWh	$20/MWh
[2]	Clean Energy Award		1,800,000 MWh	0 MWh	1,200,000 MWh
[3]	Max Clean Energy Award		1,800,000 MWh	900,000 MWh	2,100,000 MWh
[4]	Clean Energy Price		$20/MWh	$20/MWh	$20/MWh
[5]	FCEM Revenue	=[2]*[4]	$36,000,000	$0	$24,000,000

Each resource's FCEM offer is listed in Row [1], for convenience. Row [2] contains each resources clean energy award and Row [3] contains their maximum clean energy capability. Note that Clean 1 clears for their entire capability and so are infra-marginal.

The forward clean energy clearing price is listed in Row [4]. Clean 3 is the marginal resource and sets the price at $20/MWh. To see how we arrive at this price, consider an incremental increase in forward clean energy demand of 1 MWh. To meet this increase in clean energy demand, Clean 3's forward clean energy award is increased by 1 MWh at a cost to the system of $20. As a result, Clean 3 sets the forward clean energy price at $20/MWh. Note that the forward clean energy price is the same here as in the ICCM example, and in each case, it is set to Clean 3's incremental cost of supplying a MWh of clean energy (Row [5] of Table 2.) This will be important when we compare the two frameworks.

The total FCEM revenue for each resource is listed in Row [5]. Their total revenue is the product of the forward clean energy clearing price ($20/MWh) and their FCEM award, listed in Row [2].

Clean 3's CSO Offers after the FCEM

Now that the FCEM has been run and forward clean energy awards have been assigned, the FCM is conducted. Each resource will submit offers into the FCM that seek to recover any outstanding missing money while accounting for their revenue from the FCEM. Table 5 below lists only Clean 3's offer, for brevity.

Table 5. Clean 3's CSO Offer after FCEM

			Clean 3
[1]	Missing Money		$200,000/MW
[2]	E[Capacity Award]		171.4 MW
[3]	Maximum Capacity Award		171.4 MW
[4]	FCEM Revenue		$24,000,000
[5]	FCEM Revenue Per E[MW of CSO]	=[4]/[2]	$140,000/MW
[6]	Missing Money Less FCEM Revenue	=[1]-[5]	$60,000/MW
[7]	CSO Offer	=[6]	$60,000/MW

First, note that Clean 3 was awarded 1,200,000 MWh of forward clean energy in the FCEM. Because Clean 3 sold 57 percent of its forward clean energy capability (1,200,000 MWh out of a possible 2,100,000 MWh), we also assume that it seeks to sell 57 percent of its capacity capability, which as illustrated in Row [2] of Table 5 is 171.4 MW.[8] As a simplifying assumption, we assume that Clean 3 submits only one offer with a maximum award of 171.4 MW, as shown in Row [3].[9]

Clean 3 thus submits their CSO offer to recover the missing money associated with this 171.4 MW of capacity that was not recovered in the FCEM. To do so, Clean 3 incorporates the FCEM revenue it received, which totals $24,000,000. Given that its total missing money on this block of capacity is $34,284,000 (its missing money in Row [1], $200,000/MW, times its maximum offered capacity, 171.4 MW), it must recover the remaining $10,284,000 via the FCM. When this remaining missing money is translated into a $/MW value by dividing it by 171.4, it comes to $60,000 per MW. Thus, in order to recover the missing money on this 171.4 MW of capacity, Clean 3 offers its capacity at $60,000/MW.

Key Takeaway: For Clean 3's 171.4 MW of offered capacity, they only need to be paid $60,000/MW to recover their missing money because they also recovered some of their missing money in the FCEM.

Total Revenue to Resources Via the FCEM and FCM

Once the FCEM has been run and resources have received their forward clean energy awards, a separate FCM will be run to procure the region's capacity. Table 6 contains each resource's CSO offer and award, the CSO clearing price, and their total revenue across both the FCEM and the FCM.

[8] In any example, for the FCEM outcome to be an equilibrium, the clean resources have to recover missing money on the entirety of the capacity they would need to support their forward clean energy positions.

[9] In practice, Clean 3 may submit another offer block at a higher price for its remaining capacity that did not sell clean energy, where this second block may be priced at $200,000/MW to reflect the fact that all of their missing money per MW would need to be recovered by capacity revenue.

Table 6. Resource Awards, Prices, and Revenue in FCM after FCEM						
			Non-Clean 1	Clean 1	Clean 2	Clean 3
[1]	CSO Offer		$60,000/MW	$40,000/MW	$150,000/MW	$60,000/MW
[2]	CSO Award		728.6 MW	300 MW	0 MW	171.4 MW
[3]	CSO Price		$60,000/MW	$60,000/MW	$60,000/MW	$60,000/MW
[4]	FCM Revenue	=[2]*[3]	$43,714,800	$18,000,000	$0	$10,285,200
[5]	FCEM Revenue		-	$36,000,000	$0	$24,000,000
[6]	Total Revenue	=[4]+[5]	$43,714,800	$54,000,000	$0	$34,285,200

Each resource's CSO offer is listed in Row [1]. Note that Clean 3's offer has a maximum award of 171.4 MW. This quantity of capacity will result in enough clean energy to satisfy their forward obligation. Note also that Clean 1 submits an infra-marginal offer of $40,000/MW. Clean 1 has received sufficient revenue in the FCEM that they are price-takers in the FCM.

Row [2] lists each resource's CSO award. Clean 1 is infra-marginal for capacity and sells their entire capability. Clean 3 also sells their entire offered capability of 171.4 MW.[10] Non-Clean 1 satisfies the rest of the capacity demand, providing 728.6 MW of CSO.

Row [3] contains the CSO price. Non-Clean 1 is marginal for capacity and sets the capacity clearing price at $60,000/MW. To see how this price is determined, consider an incremental increase in the installed capacity requirement of 1 MW, without a corresponding increase in the clean energy bids. The least-cost way to meet this increment is to increase Non-Clean 1's CSO award by 1 MW, at a cost to the system of $60,000. Thus, Non-Clean 1 sets the CSO clearing price at $60,000/MW.

Row [4] provides each resources FCM revenue, defined as the CSO price (Row [2]) times their CSO award (Row [3]). Row [5] pulls each resources FCEM revenue from Table 4 Row [4]. Finally, Row [6] provides each resource's total revenue, defined as their FCM revenue (Row [4]) plus their FCEM revenue (Row [5]).

Comparison of Awards, Prices, and Total Revenue Between ICCM and FCEM

Table 7 below lists the CSO and clean energy awards and prices, as well as total revenue for each resource under both frameworks. As illustrated by comparing the ICCM and FCEM results, the awards, prices, and revenues are equivalent for each of the four resources between the two cases. Thus, in these examples and any examples with Assumptions 1-5, there is no difference between market outcomes under an ICCM and an FCEM.

[10] While the example assumes that Clean 3 submits the same offer as Non-Clean 1, Clean 3 is willing to accept Non-Clean 1's offer as the clearing price and so would likely submit an offer just below Non-Clean 1's offer. Thus, as a simplifying assumption, we assume that Clean 3 clears before Non-Clean 1.

Table 7: Awards, Prices, and Total Revenue Comparison					
		Non-Clean 1	Clean 1	Clean 2	Clean 3
[1]	ICCM CSO Award	728.6 MW	300 MW	0 MW	171.4 MW
[2]	FCEM CSO Award	728.6 MW	300 MW	0 MW	171.4 MW
[3]	ICCM CSO Price	$60,000/MW	$60,000/MW	$60,000/MW	$60,000/MW
[4]	FCEM CSO Price	$60,000/MW	$60,000/MW	$60,000/MW	$60,000/MW
[5]	ICCM Clean Energy Award	-	1,800,000 MWh	0 MWh	1,200,000 MWh
[6]	FCEM Clean Energy Award	-	1,800,000 MWh	0 MWh	1,200,000 MWh
[7]	ICCM Clean Energy Price	$20/MWh	$20/MWh	$20/MWh	$20/MWh
[8]	FCEM Clean Energy Price	$20/MWh	$20/MWh	$20/MWh	$20/MWh
[9]	ICCM Total Revenue	$43,714,800	$54,000,000	$0	$34,285,200
[10]	FCEM Total Revenue	$43,714,800	$54,000,000	$0	$34,285,200

Key Takeaway: Table 7 shows that, given the assumptions listed in the first section, the ICCM and FCEM will yield identical outcomes for each resource. Under an FCEM, resources incorporate their future capacity revenue when determining how much missing money they must recover by selling clean energy forward. When these capacity revenue predictions are accurate, as we assume in the above examples, we get equivalent results under an FCEM or an ICCM.

Analysis Group's Model Framework

Analysis Group's modeling efforts determine the resource mixes under i) a forward clean energy framework, ii) a net-carbon pricing framework, and iii) a "status quo" framework. As part of this effort, AGI's model will make assumptions that are generally consistent with those employed in the above examples. Specifically, the model used to simulate market outcomes will assume the following: i) the markets for RECs and CECs are competitive, ii) resources submit offers to sell clean energy based on their clean energy production in the delivery period, iii) resources submit fully rationable offers for capacity and clean energy, and iv) resources have perfect foresight about future prices and awards in all markets when making entry/exit decisions.

Digging deeper into the modelling details, the capacity expansion model that will be used to determine the resource mix in each framework conducts a single, global optimization that considers each resource's costs and solves for the lowest cost set of resources that meet a series of constraints. In this case, the model will include constraints corresponding with i) capacity demand, ii) renewable energy demand, or renewable portfolio standards, and iii) clean energy or carbon emissions abatement demand. As such, this modelling approach does not clearly distinguish between a sequential FCEM and a simultaneous ICCM because it is equally consistent with either i) an ICCM where capacity and clean energy awards are determined simultaneously, as in the first example, or ii) a FCEM where resources correctly forecast capacity prices when formulating their clean energy offers, as in the second example. Thus, given these assumptions, this modeling approach is consistent with either an FCEM where resources correctly internalize the actual capacity price when formulating their clean energy offer price, or an ICCM where clean energy and capacity are procured jointly.

Conclusion

Using two numerical examples, this memo demonstrates that a FCEM and an ICCM will yield identical pricing, awards, and total revenue to resources under assumptions that mirror Analysis Group's modelling approach. Specifically, in an ICCM, capacity and clean energy are procured simultaneously in one optimization problem. In an FCEM, clean energy and capacity are procured separately in two sequential optimization problems. When determining their clean energy offers in an FCEM, resources will make predictions about the amount of revenue they will receive in the capacity market. If these predictions are accurate, then the same resources will sell the same quantity of capacity and clean energy at the same prices in a FCEM as in an ICCM, leading both approaches to produce equivalent results.

AGI's model output for the "forward clean energy framework" can thus be viewed as broadly consistent with either a FCEM or an ICCM. As a result, the ISO proposes that it is not necessary for stakeholders to choose one framework over the other at this time. Rather, the model results can be interpreted as representing both a FCEM and an ICCM. If the region chooses to pursue a clean energy framework, the region may wish to further consider the tradeoffs between a FCEM and an ICCM, including those that are not fully captured in the modeling during the pathways efforts.