FINAL

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 9:30 a.m. on Monday, December 6, 2021. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting.

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

APPROVAL OF OCTOBER 25, 2021 PATHWAYS STUDY MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the October 25, 2021 Pathways Study meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the Committee unanimously approved those minutes, with an abstention noted on behalf of Michael Kuser by his temporary alternate.

ANALYSIS GROUP (AGI) PRESENTATION

Mr. Cavanaugh then introduced Mr. Todd Schatzki of AGI, who reviewed materials circulated and posted in advance of the meeting. Mr. Schatzki informed the Committee that the purpose of the day's presentation was to continue to provide preliminary results and findings of the quantitative analyses of the four alternative policy approaches to decarbonizing the New England grid (i.e., the Status Quo, Forward Clean Energy Market (FCEM), Net Carbon Pricing (NCP), and Hybrid approaches). He indicated that he would provide the Committee with an update to the Central Case results and findings and would summarize the preliminary results of the scenario analysis that tests the sensitivity of the Central Case results to a change in a key input assumption.

Mr. Schatzki began by providing an overview of key preliminary findings regarding the four alternative policy approaches/pathways, which included: (i) approaches vary in the incentives created to achieve decarbonization targets, with differences affecting the competitiveness of energy storage and more efficient fossil resources, and, in turn, economic curtailment of variable renewables; (ii) social cost is lowest with the NCP approach, slightly higher for the FCEM and Hybrid approaches, and notably higher for the Status Quo approach; (iii) customer payments are similar across all policy approaches, but potentially higher under the Status Quo; and (iv) preliminary scenario results change the magnitude of results, but not the general findings.

Mr. Schatzki then reviewed the Central Case results which had been updated since the last working session meeting to include negative-priced offers by resources with out-of-market power purchase agreements (PPAs). He noted the important feedback received from stakeholders regarding contracted resources and negative-price offers, which assisted with and was reflected in Analysis Group's latest update. He provided an example of why resources under a PPA, that may include payment clawback provisions, could have an incentive to offer energy at a price below $0, up to the negative of their PPA price. He indicated that including some negative-priced energy from baseline state policy renewables with PPAs affected results (creating larger price spreads) for all of the approaches, but especially the Status Quo, when compared to the results reported in October. He explained that, particularly for storage resources, negative prices provide an opportunity to earn money simply by charging and then discharging a smaller quantity due to energy losses, increasing storage activity, and thereby reducing the magnitude of negative prices (making the negative prices less negative) and decreasing the capacity from fossil resources. Other resources would have to make up for reduced revenues from lower LMPs through increased capacity, CEC and carbon price revenue.

Mr. Schatzki then responded to questions about the updated Central Case results, which included (i) clarification that the term “CEC subsidies” was used at highest level as a reference to incremental revenues designed to get a resource to do something; (ii) an explanation that, for storage resources, because of energy losses, there could be a revenue opportunity during negative pricing intervals, supporting a strategy for certain kinds of storage resources to discharge within that interval. That behavior was possible even when prices don’t change, and was likely overall to affect (make less negative) the equilibrium price during that interval; (iii) confirmation that the analysis presented to that point had not fully accounted for, quantitatively, the impacts of negative pricing and clawbacks on PPA pricing, but its inclusion would be considered and addressed at a future session; (iv) clarification that economic behavior by storage resources would result in less economic curtailment; and (v) confirmation that, the greater the number of negative-price LMP hours, the higher the resulting CEC and carbon pricing.

Mr. Schatzki then reviewed a series of charts illustrating how, under each of the four policy approaches, the renewable, dispatchable and storage resource mix would be affected. The renewable resource mix varied across approaches. The shares of offshore wind and solar PV were particularly sensitive to the change in policy approach, with offshore wind’s share largest under Status Quo and lowest under the Hybrid approach; conversely, solar PV’s share was lowest under Status Quo and largest under Hybrid. Onshore wind was equal across the four approaches. With respect to dispatchable resources, battery storage, while similar across all approaches, was highest under the FCEM approach and lowest under Status Quo. The Hybrid and NCP approaches were sensitive to emissions intensity, and thus had more combined-cycle resources, while the Status Quo and FCEM approaches had more gas-fired turbines. Storage resources were most affected by market incentives, with a comparatively higher level of storage charging and discharging where there was a higher frequency of negative pricing (under the Status Quo and FCEM approaches) and a lower level where there were fewer hours of negative pricing (under the NCP and Hybrid approaches).

Some members requested additional information about the quantity and participation of batteries accounted for in the modeling. Mr. Schatzki noted that, while the models included simplifying assumptions, cycling of batteries imposed a wear and tear cost and presented operational issues within the models.

Turning to aggregate economic metrics, Mr. Schatzki discussed the applicable social costs for each of the models. The social costs included production costs associated with fuel, variable Operations & Maintenance (O&M), fixed O&M, and capital costs. The social costs were the highest for the Status Quo approach and lowest for NCP, and similar but slightly higher under the FCEM and Hybrid approaches. The social cost differences reflected a combination of factors, particularly the differences in energy market incentives under each approach. In response to a question about the Analysis Group's approach to capital cost amortization, Mr. Schatzki noted that it was the same for all approaches, reflecting a 20-year amortization period and assuming the same weighted average cost of capital. He explained that capital cost differences were higher in the Status Quo approach largely due to state policy goals and the heavy emphasis on offshore wind. He then indicated that, while emission levels had not yet been reported to the Committee, such levels were similar across all four approaches.

Mr. Schatzki then summarized slides illustrating price variance across the approaches, which varied widely and grew over time. Average LMPs ranged from $-7 to $109 / MWh due to differences in how environmental attributes were priced into the energy markets. The spread within each approach was reflected by a standard deviation showing the range of prices across the models.

Carbon prices grew within each approach as state clean energy polices produced sufficient reductions to meet the decarbonization targets. When asked how existing resources would make their monthly revenues in low load-weighted LMP scenarios in the Status Quo and FCEM approaches, Mr. Schatzki pointed to the complicated interactions involved and other implications affecting the model, noting efforts to tease out whether, and if so by how much, other requirements, like capacity payments, would have to be increased, and to identify the scope of other consequences like resource retirements. He explained how hitting a specific target LMP price was challenging in a Hybrid approach, particularly given multiple constraints, and would vary slightly from year to year. He also confirmed that the same would be true for emission targets under the FCEM (CEC), NCP and Status Quo approaches.

Turning to customer payments, Mr. Schatzki noted that, from an economic perspective, social costs provide the best metric for evaluating the (opportunity) costs to society of achieving decarbonization targets. For each policy approach, total payments by customers reflect four components: (i) energy market payments, including PPA contracts and LMPs (which reflect competitive offers including carbon prices); (ii) Forward Capacity Market (FCM) payments; (iii) CEC payments; and (iv) credit to customers for carbon tax payments (by generators) in the NCP and Hybrid approaches. He noted that total payments under the Status Quo approach reflected out-of-market purchases of energy through PPAs. He explained that total customer payments for the Status Quo approach are sensitive to whether existing clean energy resources are provided with payments for "clean energy" services in addition to energy market and FCM revenues. Existing clean resources (e.g., existing nuclear) were also assumed to receive supplemental payments for clean energy in light of retirement risks and potential for sales to other regions. In response to a question, Mr. Schatzki highlighted to need to centralize the goals of each of the six New England states within the model.

Moving to a comparison of the scenarios, Mr. Schatzki shared the preliminary results of each of the scenarios evaluated across all policy approaches, which included (i) alternative regional carbon target – 85% below 1990 emission by 2040; (ii) alternative levelized costs of new entry for renewable resources: (iii) additional retirements; and (iv) alternative distribution of costs amongst states. Responding to a question about the changes under the NCP approach with a more stringent emission target, he noted that the study looked at carbon prices over a 20 year period. When asked about the ideal model for the incorporation of hydrogen, Mr. Schatzki suggested an inability to know what new technologies would present in the market over the next 20 years and how each would affect the models.

Addressing next steps, Mr. Chris Geissler shared the proposed Pathways Study schedule for 2022 which included two additional stakeholder meetings that were planned to take place in March and April. At the next Pathways Study meeting, Analysis Group would review its draft report, and at the April meeting, a final report will be presented. There being no further business, the meeting adjourned at 3:46 p.m.

Respectfully submitted,

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Sebastian Lombardi, Acting Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE DECEMBER 6, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard		
American Petroleum Institute	Associate Non-Voting	Paul Powers		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small RG Group Member	AR-RG	Erik Abend		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
AVANGRID: CMP/UI	Transmission		Jason Rauch	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing LP	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Grant Flagler	Matt Napoli	
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dick Brooks	End User	Dick Brooks		
Dominion Energy Generation Marketing	Generation	Mike Purdie	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission			Parker Littlehale
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation		Abby Krich	Alex Worsley
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 Guibault	Bob Stein	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jupiter Power LLC	Provisional			Ron Carrier
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE DECEMBER 6, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew		
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			Rich Heidorn
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power Generators Association (NEPGA)	Associate Non-Voting	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian Forshaw; Dave Cavanaugh
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept	Publicly Owned Entity		Brian Thomson	
Shell Energy North America	Supplier	Jeff Dannels		
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	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Energy Investment Corporation	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin	David Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	

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