FINAL

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, April 1, 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. David Doot, Secretary, recorded.

APPROVAL OF MARCH 4, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the March 4, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the March 4, 2021 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), began by reporting on his participation at the FERC's March 23 Technical Conference on Resource Adequacy, where he addressed: (i) the importance of the evolution of all major market components to support a clean energy transition, (ii) the commitment of ISO-NE, together with NYISO and PJM, to capacity markets as the foundational reliability service to supplement the energy market and; (iii) the increasing value that should be recognized in the markets during the clean energy transition of ancillary services markets for operating and energy reserves and other important temporal characteristics (e.g. ramping and inertia), which the ISO viewed as vital complements to energy and capacity markets. He noted that appropriate incremental market changes could be anticipated to produce additional revenues, and that the design and approval process would be challenging and time consuming. He emphasized that, as indicated by the FERC, the Minimum Offer Price Rule (MOPR) was no longer sustainable and an alternative solution must be developed. He expressed his concern that the FERC expects the Eastern RTOs to propose acceptable alternatives to MOPR within the next year or so or risk the initiation of a Federal Power Action (FPA) Section 206 proceeding. He described the ISO's strong preference that an acceptable alternative be worked as fully as possible within the stakeholder process and reported that the ISO would work to develop a high level scope and schedule by June/July 2021. He anticipated further details and insight would be gained from the FERC's yet-to-be-scheduled New England-focused technical conference. He stated that identifying an alternative to MOPR that could be filed with the FERC on a voluntary basis under FPA Section 205 would be the highest priority for the ISO in the second half of 2021 and would likely impact the timing for completion of other deliverables.

Responding to questions about how the effort to identify an alternative to MOPR would affect the ISO's current project schedule and future grid discussions, Mr. van Welie explained that while alternative future grid frameworks, such as the net carbon pricing and forward clean energy market (FCEM) constructs, might in the long term provide solutions for the elimination of the MOPR, the region would not have enough time to define and implement such solutions in the timeframe he believed the FERC expected. He opined that there would be similar timing issues with defining and implementing ancillary services solutions to address the concerns that led to the establishment of the MOPR. He suggested that the issues would need to be addressed in sequence, with an acceptable alternative to address the concerns that led to the MOPR identified first, with efforts continuing thereafter to define further market reforms to advance clean energy objectives and reposition the markets for ancillary services.

ISO COO REPORT

Dr. Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to his April report, which included an analysis of the prior winter and had been circulated and posted in advance of the meeting. He noted that the data in the report was through March 24, 2021, unless otherwise noted. The report highlighted: (i) Energy Market value for March 2021 was $324 million, down $435 million from the updated February 2021 value of $759 million and up $152 million from March 2020; (ii) March 2021 average natural gas prices were 55% lower than February average prices; (iii) the average Real-Time Hub Locational Marginal Prices (LMPs) for March ($37.10/MWh) were 48% lower than February averages; (iv) average March 2021 natural gas prices and Real-Time Hub LMPs over the period were up 144% and 121%, respectively, from March 2020 average prices; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99% during March (down from 99.1% in February), with the minimum value for the month (94.3%) on March 6; and (vi) the Daily Net Commitment Period Compensation (NCPC) payments for March totaled $1.8 million, which was down $0.8 million from February 2021 and up $0.1 million from March 2020. March NCPC payments, which were 0.6% of total Energy Market value, were comprised of (a) $1.7 million in first contingency payments (down $0.6 million from February); (b) $131,000 in second contingency payments (down $12,000 from February), and (c) zero in distribution payments (down $259,000 from February).

Turning to operational highlights from March, Dr. Chadalavada reported that the ISO had missed its load forecast metric in March, which he attributed to highly variable temperatures during the month. He noted that overnight loads on March 20 and 21 were higher than midday loads those days, which he reported were deviations in amounts greater than previously experienced. He predicted there would be many more days to come when midday loads would be lower than overnight loads.

Regarding transmission outages, Dr. Chadalavada reported on a planned May 3-29 outage on Line 373 (Deerfield-Scobie) for the replacement of certain structures. He also identified a planned outage for Line Q169, from April 14-16, which the ISO expected would result in first contingency uplift given the impact of that Line on dispatch for the Northeast Massachusetts Load Zone.

In response to a question regarding second contingency payments, he explained that on some cold days, with modest loads, high west-to-east transfers, and constrained interface limits, the ISO needed to dispatch units out of merit order to cover for contingencies on the east side of New England. That dispatch produced uplift costs.

Turning to the aggregate winter load curve (December through February), Dr. Chadalavada noted the increased midday loads and peaks resulting from work at home arrangements during the pandemic. In response to questions, Dr. Chadalavada noted that the ISO continued to evaluate the impact of the pandemic on load averages and how loads might change as pandemic impacts diminish. He said the ISO was also evaluating the impacts of other factors, such as snowfall on photovoltaic production which he estimated could be responsible for 20-25% of the load variations experienced over the winter.

REMOVAL OF APPENDIX B FROM MARKET RULE 1 AND DELETION OF ASSOCIATED TARIFF PROVISIONS

Ms. Mariah Winkler, Markets Committee (MC) Chair, provided an overview of the proposal to remove Appendix B from Market Rule 1 (which established procedures and standards by which the ISO could impose sanctions, if subsequently approved by the FERC, for sanctionable conduct) and to make conforming changes to the Tariff reflecting the removal of that Appendix. She reported that, at its March 9, 2021 meeting, the Markets Committee had voted, but had not recommended, the proposed changes.

Following her overview, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports removing Appendix B from Market Rule 1 and deleting associated Tariff provisions, as proposed by ISO New England and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Referring to the discussion at the Markets Committee, Participants opposing the removal of Appendix B reiterated concerns with the elimination of Appendix B from the filed rate, without any other guidance provided on conduct that the Internal Market Monitor (IMM) might conclude to be sanctionable. They clarified that they had no objections to the removal of provisions in Appendix B that the ISO concluded were outdated, unclear, or internally inconsistent with other Tariff provisions. They urged the ISO to identify an alternative means for providing such guidance on a going-forward basis.

The motion was then voted and passed with a 60.12% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.70%; Supplier Sector – 10.02%; AR Sector – 0%; Publicly Owned Entity Sector – 16.70%; and End User Sector – 16.70%). (*See* Vote 1 on Attachment 2)

LITIGATION REPORT

Mr. Doot referred the Committee to the March 30 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following:

- ***Deficiency Letter Response in Net Cost of New Entry (CONE) proceeding (ER21-787).*** The ISO's responses to the FERC's March 1, 2021 deficiency letter were filed on March 30, 2021. Comments on those responses would be due April 20, 2021.

- ***Exemption of Energy Efficiency Resources from Pay-for-Performance Settlement (ER21-943).*** The FERC issued an order accepting the ISO's filing, effective April 1, 2021.

- ***FCA16 ORTP Jump Ball Filing:*** The filing of alternative Tariff changes to establish Offer Review Trigger Prices (ORTPs) for the sixteenth Forward Capacity Auction (FCA16) was anticipated to be submitted early the following week (on or about April 7, 2021). In response to questions, the ISO indicated that the filing would request an effective date 60 days from the date of filing.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the April meeting would be a one-day meeting to be held on April 6, rather than a two-day meeting.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the TC was scheduled to meet on April 27. The agenda would likely include a vote on the

Participating Transmission Owners' proposal to address reconstitution of behind-the-meter generation into the Regional Network Load calculation.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC was scheduled to meet on April 13 and the agenda would include a review of the draft load forecast, with a revised Moody's economic forecast incorporated, to be included in the ISO's 2021 Report of Capacity, Energy, Loads, and Transmission.

Joint MC/RC (Future Grid - Reliability Study). Mr. Stein reported that discussion of the Future Grid Reliability Study would move to the Planning Advisory Committee (PAC), with a first report to be provided at the May PAC meeting. There were no joint MC/RC meetings scheduled at that time.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the Subcommittee Chair, announced that the next meeting of the Subcommittee was scheduled for April 22. The April 22 agenda would include consideration of exchange clearing of financial transmission rights (FTRs), clarifying changes to Non-Commercial Capacity Trading Financial Assurance and acceleration of FCM settlement and billing.

Joint Nominating Committee (JNC). Mr. Cavanaugh referred the Committee to the summary of the March 25-26 JNC meetings, which had been circulated with the materials for the meeting. He reported that, during the March 25-26 meetings, the JNC reviewed the qualifications of 23 candidates. The JNC had ranked the candidates and selected nine for first round interviews to take place April 8, 9 and 16. In addition, the JNC discussed the impact of the age limit, waivable by the JNC, on the potential candidate pool but had decided to table further discussion on the age requirement at that time.

ADMINISTRATIVE MATTERS

With respect to review of the 2021 ISO audit results and audit plans, Mr. Cavanaugh reported that no additional audit requests had been received and the audit plan would proceed as described in his February 25, 2021 memo to the Participants Committee included with the materials for the March 4 meeting.

Turning to evolving plans for a return to in-person meetings, Mr. Cavanaugh reported that, subject to further review and evaluation over the summer, the current thinking was to target September for a potential return to in-person committee meetings. He noted that the NPC Summer meeting would be held via WebEx as a regular meeting on June 24. Meetings with the ISO Board would be tentatively scheduled for June 25 and June 28. He noted the need for each Sector to prepare meeting agendas and materials for those meetings with the Board, and identified June 7 as the date for submitting those materials.

Mr. Doot reminded members of the Committee’s April 15 Future Grid Pathways working session and of its May 6 meeting.

FEBRUARY EXTREME COLD WEATHER CHALLENGES (ERCOT EXPERIENCE)

Dr. Chadalavada provided an overview of the extreme weather events in Texas as included in the COO presentation circulated with the materials for the meeting. He summarized the conditions experienced by the Electric Reliability Council of Texas (ERCOT), noting temperature deviations that were 37 to 47 degrees Fahrenheit lower than normal. Such conditions were not part of ERCOT’s planning. The conditions led to high loads, roughly 50% of ERCOT’s 107 gigawatts of installed capacity being unavailable and requiring ERCOT to shed 20 gigawatts of load. Referring to the presentation ERCOT shared with its stakeholders and included with the materials for this meeting, he noted the extreme differences between the 2021 and 2011 ERCOT load shed events.

He then reported that, in response to the Texas experience, the ISO was incorporating in its work plan discussions, evaluations and analyses designed to ensure that lessons learned from the Texas experience could be appropriately incorporated in New England in order to minimize the possibility of similar experiences here. He acknowledged in response to comments New England's reliance on external fuel sources and the need for New England to fully understand and plan for the availability of fuel to generation sources. He reported that the ISO currently was comprehensively reviewing what types of extreme weather and contingencies should be studied, what tools should be used and how outcomes should be quantified in any such study, and how the region should proceed after taking into account all of those factors. He suggested that the studies would initially be conducted using a seven-year time frame, analyzing both current system parameters and parameters emerging from the various future grid models. Responding to a question about how market design could help to protect against such issues, Dr. Chadalavada noted at high level the differences between the New England and ERCOT markets, opining that many aspects of ERCOT's market design that would not work in New England.

At the request of Mr. Cavanaugh, Dr. David Patton, President, Potomac Economics, which is ERCOT's Independent Market Monitor (IMM), provided his perspectives on the issues ERCOT experienced and his recommendations for an overall review and plan for extreme weather events in the future across the country. Dr. Patton first noted from lessons learned how important it was that the system operator have the tools and ability to proactively manage load shed instead of relying on an automated load shed protocol. He opined and members discussed the suggestion that set points for protective devices to shed load during a sustained drop in frequency were set too low, requiring the system operator to step in to shed load in order to protect equipment before the automated devices did so. He said that the ERCOT transmission and distribution utilities had the ability to rotate outages to only 25-30% of load. As a result, ERCOT was required to shed roughly 30% of the load for extended periods, rather than rotate outages in a way that might have reduced the overall impact on customers. Related, he also noted the importance of separating essential and nonessential circuits to permit rotating outages, and in the case of ERCOT, to reduce the potential for power loss and damage to natural gas facilities, well heads and pipeline equipment, that exacerbated supply challenges.

Dr. Patton recommended that ISOs and RTOs evaluate extreme conditions in both summer and winter, noting the simultaneous, unforecasted movement of load and supply in opposite directions. He recommended further that system operators undertake to identify when spikes in forced outages might occur based on ambient temperatures, what supply losses will most likely occur, and when and how loads might increase during such times. With that information, system operators would be better prepared to consider actions to lessen system risks.

In response to questions and comments, Dr. Patton opined that ERCOT’s issues did not demonstrate that an energy only market is less reliable than a market like New England’s with its pay-for-performance (PFP) program. He expressed his view that Market Participants do react to strong economic signals during infrequent shortage events and that the challenge is to properly balance how much can be earned during such low probability events against the risks to generators and costs to customers. He opined that many generators will use the ERCOT experiences to support efforts to improve their weatherization protocols.

Continuing the discussion of the markets, Dr. Patton explained that the Texas energy-only structure relies on administrative add-ons in some circumstances to set energy prices. During the weather event, ERCOT held the energy price at $9,000 for 32 hours after the energy shortage was over, erroneously inflating prices and creating large uplift and serious economic problems for many participants. He noted the importance to market operations of having reliable, objective and repeatable market mechanisms to set prices during such events.

He repeated his previously expressed concern, now reinforced by the ERCOT experience, of setting the PFP rate in New England too high. He worried that, even in less severe circumstances than those experienced by ERCOT, an inflated PFP rate could produce economic issues similar to ERCOT and create major economic consequences through settlements. He urged that the rate more accurately reflect the value of lost load which varies based on circumstances and is best sloped.

He then reacted to comments and responded to questions. He emphasized his view that the Texas event was not a resource adequacy issue but rather was a gas supply and weatherization issue. He explained that, in his view, to provide necessary incentives to perform, the PFP rate needs to be known so market participants can develop probabilities and make financially prudent decisions. PFP is a resource adequacy design that depends on shortage of available capacity. Incentive payments are random and unpredictable. He indicated that turbine availability in New England has helped to eliminate reserve shortages and avoid random PFP events. He observed that the ERCOT experiences will impact future decision making, particularly relating to how risk is evaluated, how hedging is done, and how weatherization of resources occurs. He expected that the FERC would consider whether transmission and pipeline owners could be incentivized to enhance the reliability of their systems to serve load.

Reacting to Dr. Patton's observations, Dr. Chadalavada compared the load shedding relays in Texas, which were set to shed at 59.4 Hz, with New England's set points of 59.5 Hz and rapid rate of change in frequency. He explained that, at the 59.5 Hz set point, relays would shed roughly 7.5 percent of load. With relays also calibrated to measure the rate of change in frequency, a rapid rate of change could cause and extra one to three percent of load to be shed even earlier. He acknowledged the importance of stress tests within the markets and agreed with Dr. Patton on the need for a sloped curve for prices in Real-Time during extreme events. He further expressed his desire to continue discussion on this topic. He also reminded members that the PFP in New England included both monthly and annual stop-loss provisions, which resources could account for in their FCM offers. Lastly, he agreed with Dr. Patton about the importance of reviewing and planning for how load shed could play out during various Real-Time scenarios.

There being no further business, the meeting adjourned at 2:00 p.m.

Respectfully submitted,

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN APRIL 1, 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		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small RG Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
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	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Dominion Energy Generation Mktg	Generation	Mike Purdie	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler; Arnie Quinn
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Englehart CTP (US) LLC	Supplier	Danielle Fazio		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
Exelon Generation Company	Supplier		Bill Fowler	
Excelerate Energy LP	Fuels Industry Participant	Gary Ritter		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	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	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 1, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
Harvard Dedicated Energy Limited	End User			Erin Camp
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	
Industrial Energy Consumer Group	End User	Alan Topalian		
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Marji Philips
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		Erin Camp
Maine Skiing, Inc.	End User	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR		Luke Fishback	Doug Hurley
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		
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	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User		Erin Camp	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Erin Camp
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	
Rodan Energy Solutions (USA) Inc.	Provisional	Aaron Breidenbaugh		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN APRIL 1, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User		Mary Smith	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori	Karin Stamy	
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & 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	

ATTACHMENT 2

VOTE TAKEN AT
APRIL 1, 2021 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1
GENERATION	0.00
TRANSMISSION	16.70
SUPPLIER	10.02
ALTERNATIVE RESOURCES	0.00
PUBLICLY OWNED ENTITY	16.70
END USER	16.70
PROVISIONAL MEMBERS	0.00
% IN FAVOR	**60.12**

GENERATION SECTOR

Participant Name	Vote 1
CPV Towantic, LLC	A
Dominion Energy Generation Mktg	A
FirstLight Power Management, LLC	A
Generation Group Member	A
Nautilus Power, LLC	O
NextEra Energy Resources, LLC	O
NRG Power Marketing, LLC	O
IN FAVOR (F)	0
OPPOSED (O)	3
TOTAL VOTES	3
ABSTENTIONS (A)	4

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1
Renewable Generation Sub-Sector	
Central Rivers Power	O
ENGIE Energy Marketing NA, Inc.	A
Great River Hydro, LLC	O
Jericho Power LLC	A
Wheelabrator/Macquarie	O
Large RG Group Member	A
Small RG Group Member	A
Distributed Gen. Sub-Sector	
CLEAResult Consulting, Inc.	A
Sunrun Inc.	A
Load Response Sub-Sector	
Maple Energy	A
Vermont Energy Investment Corp.	A
Small LR Group Member	A
IN FAVOR (F)	0
OPPOSED	3
TOTAL VOTES	3
ABSTENTIONS (A)	9

TRANSMISSION SECTOR

Participant Name	Vote 1
Avangrid (CMP/UI)	F
Eversource Energy	F
National Grid	F
Versant Power	F
IN FAVOR (F)	4
OPPOSED	0
TOTAL VOTES	4
ABSTENTIONS (A)	0

SUPPLIER SECTOR

Participant Name	Vote 1
BP Energy Company	F
Brookfield Renewable Trading & Mktg	O
Calpine Energy Services, LP	A
Castleton Comm. Merchant Trading	A
Cross-Sound Cable Company	F
DTE Energy Trading, Inc.	F
Clearway Power Marketing LLC	A
Consolidated Edison Energy, Inc.	A
DC Energy, LLC	A
Dynegy Marketing and Trade, LLC	O
Emera Energy Companies	A
Exelon Generation Company	O
Galt Power, Inc.	F
H.Q. Energy Services (U.S.) Inc.	A
LIPA	A
Maine Power, LLC	F
Marble River, LLC	A
Mercuria Energy America, Inc	F
PSEG Energy Resources & Trade	O
IN FAVOR (F)	6
OPPOSED	4
TOTAL VOTES	10
ABSTENTIONS (A)	9

VOTE TAKEN AT
APRIL 1, 2021 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1
Conn. Office of Consumer Counsel	A
Conservation Law Foundation	A
Environmental Defense Fund	A
Harvard Dedicated Energy Limited	A
High Liner Foods (USA) Inc.	F
Industrial Energy Consumer Group	F
Michael Kuser	A
Maine Public Advocate Office	F
Maine Skiing, Inc.	F
Mass. Attorney General's Office	A
Natural Resources Defense Council	A
NH Office of Consumer Advocate	F
PowerOptions, Inc.	A
IN FAVOR (F)	5
OPPOSED	0
TOTAL VOTES	5
ABSTENTIONS (A)	8

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1
Ashburnham Municipal Light Plant	F
Belmont Municipal Light Dept.	F
Block Island Utility District	F
Boylston Municipal Light Dept.	F
Braintree Electric Light Dept.	F
Chester Municipal Light Dept.	F
Chicopee Municipal Lighting Plant	F
Concord Municipal Light Plant	F
Conn. Mun. Electric Energy Coop.	F
Danvers Electric Division	F
Georgetown Municipal Light Dept.	F
Groton Electric Light Dept.	F
Groveland Electric Light Dept.	F
Hingham Municipal Lighting Plant	F
Holden Municipal Light Dept.	F
Holyoke Gas & Electric Dept.	F
Hull Municipal Lighting Plant	F
Ipswich Municipal Light Dept.	F
Littleton (MA) Electric Light Dept.	F
Littleton (NH) Water & Light Dept.	F
Mansfield Municipal Electric Dept.	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1
Marblehead Municipal Light Dept.	F
Mass. Mun. Wholesale Electric Co.	F
Mass. Bay Transportation Authority	F
Merrimac Municipal Light Dept.	F
Middleborough Gas and Elec. Dept.	F
Middleton Municipal Electric Dept.	F
New Hampshire Electric Cooperative	F
North Attleborough Electric Dept.	F
Norwood Municipal Light Dept.	F
Pascoag Utility District	F
Paxton Municipal Light Dept.	F
Peabody Municipal Light Plant	F
Princeton Municipal Light Dept.	F
Reading Municipal Light Dept.	F
Rowley Municipal Lighting Plant	F
Russell Municipal Light Dept.	F
Shrewsbury's Elec. & Cable Ops.	F
South Hadley Electric Light Dept.	F
Sterling Municipal Electric Light Dept.	F
Stowe (VT) Electric Dept.	F
Taunton Municipal Lighting Plant	F
Templeton Municipal Lighting Plant	F
Vermont Electric Cooperative	F
VT Public Power Supply Authority	F
Village of Hyde Park (VT) Elec. Dept.	F
Wakefield Mun. Gas and Light Dept.	F
Wallingford, Town of	F
Wellesley Municipal Light Plant	F
West Boylston Mun. Lighting Plant	F
Westfield Gas & Electric Light Dept.	F
IN FAVOR (F)	51
OPPOSED	0
TOTAL VOTES	51
ABSTENTIONS (A)	0

PROVISIONAL MEMBERS

Participant Name	Vote 1
Rodan Energy Solutions (USA) Inc.	A
IN FAVOR (F)	0
OPPOSED	0
TOTAL VOTES	0
ABSTENTIONS (A)	1