Planning Advisory Committee
WebEx Teleconference
July 22, 2020

Joe Adadjo	Eversource Energy
Bob Andrew	Eversource Energy
Carl Benker	Eversource Energy
Denis Bergeron	Maine Public Utilities Commission
Peter Bernard	ISO New England Inc.
Jon Black	ISO New England Inc.
Patrick Boughan	ISO New England Inc.
Jon Breard	ISO New England Inc.
William Buchanan	Eversource Energy
Erin Camp	Synapse Economics
Dorothy Capra	NESCOE
Digaunto Chatterjee	Eversource Energy
Wayne Coste	ISO New England Inc.
Vandan Divatia	Eversource Energy
Janny Dong	New England Power Company
Michael Drzewianowski	ISO New England Inc.
Frank Ettori	VELCO
Jeff Fenn	Emera Maine
Brian Forshaw	CMEEC
Bill Fowler	Exelon
Nick Gangi	Eversource Energy
Julia Grasse	New England Power Company
Nick Hutchings	ISO New England Inc.
Jeff Iafrati	Customized Energy Solutions
Steve Judd	ISO New England Inc.
Steve Kaminski	New Hampshire Electric CoOp
Shelia Keane	Massachusetts Department of Public Utilities
Steve Kirk	Exelon
Andrew Kniska	ISO New England Inc.
Richard Kornitsky	ISO New England Inc.
Rich Kowalski	ISO New England Inc.
Abby Krish	Boreas Renewables
Brett Kruse	Calpine
Kaushal Kumar	ISO New England Inc.
Jacob Lewis	
Paul Lopes	Massachusetts DCAM
Marc Lyons	ISO New England Inc.
Eva Mailhot	ISO New England Inc.
Kevin Mankouski	ISO New England Inc.
Anne Margolis	Vermont Public Utilities Commission
Tim Martin	New England Power Company
Diedre Mathews	New England Power Company

Paul Melzen	Eversource Energy
Bruce McKinnon	South Hadley Electric CoOp/Norwood Municipal
Don Nelson	Massachusetts Public Utilities Commission
Brent Oberlin	ISO New England Inc.
Theodore Paradise	Anbaric
Dan Phelan	New Hampshire Public Utilities Commission
Hantz Presume	VELCO
Joseph Roberts	ISO New England Inc.
Victoria Rojo	ISO New England Inc.
Jose Rotger	Cross Sound Cable
Eric Runge	Day Pitney
Meenakshi Saravanan	ISO New England Inc.
Arash Sarmqadi	New England Power Company
Kerry Schlichting	ISO New England Inc.
Dan Schwarting	ISO New England Inc.
Melissa Scott	New England Power Company
Carissa Sedlacek	ISO New England Inc.
Chris Soderman	Eversource Energy
Kannan Sreenivaschar	ISO New England Inc.
Bob Stein	HQUS/PSEG/NRG/Footprint
Mark Stevens	New England Power
Brad Swalwell	Tangent Energy
Phil Tatro	EIG
Dave Thompson	Connecticut Public Utilities Commission
Phelps Turner	Conservation Law Foundation
Pradip Vijayan	ISO New England Inc.
Haizhen Wang	ISO New England Inc.
Lawrence Willick	LS Power
Jinlin Zhang	ISO New England Inc.

Item 1.0 – Chairs Remarks

Mr. Peter Bernard welcomed the committee and reviewed the day's agenda.

Mr. Bernard announced that there is a change to the August PAC meeting date. The August PAC meeting will be moving from Thursday, August 13th to Thursday, August 27th. Please update your calendars.

The Notification of Public Policy Local Transmission Planning has been posted to PAC and the TOPAC locations on the ISO-NE external website.

Item 2.0 – Glenbrook Station STATCOM Asset Condition Replacement

Mr. Paul Melzen (Eversource Energy) reviewed the Glenbrook Station STATCOM Asset Condition Replacement Project.

The original STATCOM was installed in 2004. It provides +/- 150 MVAR support through two parallel units (+/- 75 MVAR each). It is connected to 115 kV bus at Glenbrook (SWCT). It was installed to provide post-contingency low voltage support to avoid voltage collapse.

There is limited space available in the substation, which limits options for any upgrades.

Availability of this STATCOM has decreased to 81% while the original target was 98%. The design of this STATCOM is unique, making it difficult to maintain. Continued maintenance or refurbishment of existing STATCOM is not a viable option.

Q- Why is the STATCOM being placed in power factor mode rather than voltage control mode?
A - Eversource said their system is not designed to work well in voltage control mode. Voltage control would conflict with the control systems of other devices.

In evaluating the medium voltage equipment, it was found that the transformers were in good condition. There was no damage to structure/foundation around STATCOM. The structure should exceed lifespan of a new STATCOM.

A few of the required criteria for the new device are the new STATCOM will have at least as much reactive capability as the previous device and it should have a minimum availability factor of 98%.

A synchronous condenser was considered but would need a larger footprint, which was a problem here. Another possible solution was the installation of a SVC. A larger SVC would be required to achieve the same capabilities as the existing STATCOM. A new STATCOM was chosen to keep similar footprint and provide equal or better performance than the previous STATCOM.

Eversource issued a request for information (RFI) from manufacturers. They got competitive bids on several different options. The solution that was chosen was using the existing STATCOM building and just getting new STATCOM.

The new STATCOM will have everything fully redundant which will help with reliability.

The target in-service date is April 2021. The total cost is expected to be $21.6 M (-25%/+50%).

Q – What outages will be need for the STATCOM installation?
A – Eversource replied that the preferred outage method will keep one of the existing units in-service to prevent a total outage.
Q - Are these new STATCOM's modular, multi-level units?

A – Yes, they multi-level units and the individual components are modular and easier to replace than some of the pre-existing equipment.
Q - Who is the STATCOM vendor?
A - The vendor is HICO.

<u>Item 3.0 – Revised SEMA/RI 2029 Needs Update</u>
Mr. Kaushal Kumar (ISO-NE) reviewed the Revised SEMA/RI 2029 Needs Update.

In April, 2020 the SEMA/RI 2029 Needs Assessment Update was presented to PAC. This was undertaken to account for decreases in forecasted loads in the study area since the 2026 Solutions Study.

The Revised SEMA/RI 2029 Needs Assessment Update has updated cases since the April presentation was made. In addition, several sensitivities were analyzed as shown below:

- Non-coincident peak loads on the Cape
- Reduced OSW output applied to existing OSW projects
- Addition of future OSW projects at a reduced OSW output

There were a number of changes made to the cases:

- Project 1782 (reconductoring J16S line) was inadvertently included. This was removed for this new case.
- Automatic load throwover was not used in N-1-1 contingency analysis.
- Modelling corrections for transformers and load power factor at Candle Street were also changed.

The summary of needs are as follows:

- For N-1 thermal results, there was a new need discovered at L14-7 (Canonicus to Dexter W).
- For N-1 voltage, there were no new needs.
- For N-1-1 thermal, there were several new needs; the L14-7, J16S (Staples to Highland Park), 112-1, 112-2, and 112-3 (Tremont to Industrial Park Tap) and 136-1 (Hatchville to Falmouth Tap).
- For N-1-1 voltage, new no violations. Kingston voltage violation was removed but Brook Street is still a need.

The revised Needs Assessment still shows consequential load loss totals greater than 300 MW for two N-1-1 contingency events.

The J16S line need can be solved by reconductoring J16S line (project 1782). Project 1782 was a candidate to be cancelled at April PAC but is now needed.

To solve 112-1, 112-2, 112-3 line issues, Project 1721 (installing 37.5 MVAR cap at Bell Rock and reconfiguring Bell Rock to breaker and a half) and Project 1731 (install 35.3 MVAR cap at High Hill and 35.3 MVAR cap at Wing Lane) are needed.

To solve L14-7, Project 1721 is needed.

To solve 136-1, Project 1725 (build new 115 kV line (144) from Bourne to West Barnstable). Project 1725 was a candidate to be cancelled at April PAC but is now needed.

All of the needs were found to be time-sensitive.

More than 85% of Tremont East load is on Cape Cod. Net load for this area was 556 MW. The new load using CELT 2020, the new net load was 587 MW. There were 25 days from 2016 – 2019 where the net load exceeded 570 MW.

Tremont East peaks on weekends due to tourism. ISO load peaks on weekdays.

The first sensitivity was adjusting the load in Tremont East to 720 MW based on reconstituted PV. This effectively increased net Tremont East load by 43 MW.

It was found that 17% availability for PV may be more appropriate for this study. The second Cape Cod Load sensitivity used this 17% value. This effectively increased net Tremont East load by 74 MW.

For these sensitivities, N-1-1 thermal overloads were observed for 136-1, 136-2, 107-1, and 137 lines. These violations will be solved by Project 1725 (building 115 kV line from Bourne to West Barnstable).

Comment – The Cape battery storage project was not referenced and should be included in the sensitivity. That should decrease the peak.
A – The battery storage was not taken into account as they don't have an obligation in the FCM.

Sensitivities were performed for different values of offshore wind. Peak load output of wind is very low. Vineyard Wind and Revolution Wind were modeled at 5% of nameplate. The Cape Cod load sensitivity 2 was also applied. Significant result changes to Cape Area were for N-1-1 thermal violations, where there were numerous overloads. This sensitivity showed more severe thermal overloads on 115 kV lines along the path between Bourne and West Barnstable. All of the other results were relatively unchanged. These new needs would be resolved by project 1725 (115 kV line from Bourne to West Barnstable).

An additional sensitivity was performed for the addition of future offshore wind projects with a reduced output. Vineyard Wind 2 (800 MW) and Mayflower Wind (804 MW) were modelled at West Barnstable substation. These were modeled as 5% of nameplate, similar to Vineyard Wind and Revolution Wind. Falmouth showed low voltage for N-1. The results show a lower number and less severe thermal overload levels on the 115 kV lines along the path between Bourne and West Barnstable than the results of the reduced OSW output applied to existing OSW projects sensitivity results. Needs would be solved by Project 1725.

Q - Why are the overloads related to offshore wind not show up for the interconnection studies for these projects?
A - These were studied at different levels since this study used 5% capacity factor and interconnection uses higher value. These overloads were a result of less offshore wind.

For projects no longer needed, the ISO will reach out to TO's on the status of these projects. The ISO will collect comments until August 6, 2020. Whether the ongoing projects should move forward or be cancelled will be presented in August 2020.

<u>Item 4.0 – Scope of Work for Stochastic Time Series Modeling for ISO-NE</u>
Mr. Stephen Judd (ISO-NE) reviewed the Scope of Work for Stochastic Time Series Modeling for ISO-NE.

The time series modelling is provided to ISO-NE by DNV GL. In 2019, ISO decided that new data for wind was needed. DNV GL was hired to use weather modelling software to develop historical data from 2012-2018. They were also hired to provide 2019 wind data. Work is currently being performed to try to extend the data series all the way back to 2000.

DNV GL will model 1000 realistic time series for hourly wind generation, BTM solar generation, and load. That data will be used to determine likelihood of various events such as large wind ramp events, high wind shutdowns, etc.

Q - Will there will be onshore, offshore, solar, and load time series.
A – Yes, the data will be provided for all these types of resources.

New to this presentation is the addition of solar generation time series using irradiance data from five cities in each of the New England load zones. DNV GL will also determine historical load data. Taking 2003-2019 data from ISO and modelling backwards to get 2000-2003 period as well for each load zone.

Q - Why is the solar time series only being done for behind the meter (BTM) resources? Will same profile be assumed for in-front-of-the-meter resources as well?
A - DNV GL is making an overall profile for solar in NE, so this data can also be applied to any solar installation whether BTM or larger as long as angle, tracking, etc. is known.
Q - How are tilt angles and other specific information being obtained? Is this based on what was online or what is now being installed?
A - Generic assumptions are used for each location and then will be benchmarked against ISO's historical data. We are not sure if we are gathering information about the about the more specific assumptions.
Q - How will the model handle the effects of snow?
A – We will coordinate with DNV GL to get that information
Q - How they are going to get the load from 2000 – 2003?
A – ISO-NE has overall NE loads back to 2000 and before. DNV GL is mainly figuring out how to break down that overall load into each load zone.

The stochastic engine is a tool from DNV GL. Phase 1 will involve creating weather-to-generation models. This will then be entered into the stochastic engine to create 20,000 years-worth (1000 20-year simulations) of data. The engine will attempt to figure out how often the wind turbines will be shutdown based on wind speed modelling. Phase 3 will be probabilistic modeling. The 1,000 20-year datasets will be used to determine the probability of different events (like wind shutdown) occurring. Phase 1 is expected in mid-July. Phase 2 is expected in early-mid August. Phase 3 expected by late August or early September. ISO-NE wants stakeholder suggestions on what to look at in the data by July 31, 2020.

Q – Has DNV GL performed this work for other regions.
A - ISO-NE is the first ISO to do this with them although other large developers have used them.
Q – What is the progress on Phase 1 since it was expected in Mid-July.
A – ISO-NE expects to receive the data in the next few days.
Q – Will there be subsequent PAC presentations on this topic?
A – ISO-NE will provide another presentation to PAC after Phase 3 is completed.
Comment – A stakeholder recommended that this effort be shared with other groups at ISO-NE. They will follow-up with ISO-NE to provide more detail. ISO-NE replied that we are making and effort to keep everyone at ISO-NE well informed of this work.

Item 5.0 – 2020 Economic Study – Draft Scope of Work and High Level Assumptions for Production Simulations

Mr. Richard Kornitsky (ISO-NE) provided an update regarding the 2020 Economic Study – Draft Scope of Work and High-Level Assumptions for Production Simulations.

There was one economic study request submitted by National Grid for 2020. The goal was to analyze possible ways to best use MWh of clean energy to meet state goals cost-effectively, leveraging transmission and storage as needed. This was part 3 of presentations made in May and June 2020. This will cover revisions to previous scenarios.

Q – Have there been any changes made to the EV charging profiles?
A - No changes have been made for this presentation.

Two different amounts of offshore wind were studied. There are also bi-directional scenarios for using tie line and Hydro Quebec as virtual storage. This presentation replaces old scenarios and threshold pricing assumptions. The new scenarios are retired coal, 75% of oil, and renewables and nuclear set as must-run. It also included 2.2 million EVs and 2000 MW of battery storage. Threshold prices now have utility scale PV, onshore and offshore wind as having the highest threshold prices.

Q - How is the NECEC transmission project being treated?
A - Exports will only be from Phase II but the NECEC can still import.
Q – Why are there different thresholds for the incremental scenarios compared to the bi-directional cases?
A - The bi-directionality was triggered through the price thresholds so they had to be different to implement this.
Comment - The different thresholds were due to NGRID's suggestion. To make bi-directional, this had to change for this particular scenario.
A - The bi-directional case changes both the order and the magnitude.

The goal of the bi-directional cases was to reduce renewables spillage. Hydro Quebec would be used to store extra water and curtailed production during times of high renewables in NE. This could potentially be achieved with bi-directional contracts. Renewable Energy Credits (RECs) will be taken into account for prices. Threshold prices are assumed to be $0/MWh minus the value of any REC. Threshold price hierarchy more important than magnitude of that price. Onshore and offshore prices were made slightly different to help illustrate any differences that occur between these resources' behavior. With the value of REC's included, imports will curtail first, followed by wind, and then PV.

Q – Why was a $-25/MWh threshold price used for exports?
A - This was set to make it very observable when exports occur since there are no other prices close to that. Another reason was that negative prices are being seen more and more commonly in the real world when excess renewables are produced.

Q - How will it be determined how long the power may go up to Quebec before coming back and how will all of this will be tracked?
A - They will not be keeping track of every single MWh. It will be noted on an annual basis and not more granular than that.
Q – Is the graph on slide 16 an actual result or just an example?
A - This was an actual run but not on a National Grid case. It was more for illustrative purposes.
Comment – We like having the no-flow section to minimize the choppiness of import/export.
Q - Why was Highgate excluded from exports?
A - This was part of National Grid's initial request.
Comment - The import capability in that portion of the Quebec's system is very limited.

Capacity vs. Net ICR (net installed capacity requirement) did not match in the last column, capacity was lower than Net ICR. They are looking at how to fill in the additional MWs. All scenarios will include an additional 1,330 MW of onshore wind. 8,000 MW of offshore wind will be used based on NESCOE study. PV resources were based on National Grid values. They are using a new hydro model in GridView which does not require a threshold price. The hydro data from 2013-2020 had a lot of variability. The new method using GridView's models reduces this variability.

Comment – The capacity factor for different resources needs to be seen before finding the difference in capacity and Net ICR.
Q – Can the Capacity vs. Net ICR table be explained in more detail?
A – The values in this table were capacity ratings and not energy ratings.
Q - Why is oil was so much higher in the incremental 8000 case?
A – This was the base case. The other cases retire a lot of oil so they are all much lower.
Q – Why was a scenario run that had a capacity deficiency?
A – ISO-NE will be looking into how to fill that deficiency, but we have no specific path in mind yet.
Comment – Is the wind in the study proportional to what is in the ISO's queue? This distribution has been changing and a table should be provided to show what the current distribution looked like.
Q – Do any of the different PV categories matter?
A - All of these categories will be curtailed similarly. There will be some differences for capacity, small capacity values (2%) given to BTM PV, 20% for FCM. Energy-only PV assumed 0% capacity.
Q – Is the capacity an obligation or capability for capacity?
A - For imports they used average of past three years' CSO.
Comment – We believe that they are mixing their capacity definitions.
Comment – We believe the capacity factor for PV was a bit low. DNV considered using the data developed by Steven Judd?

A – They are using historical values from 2015. The DNV GL data was used in 2019 studies but just not the stochastic data from them. Currently we have the DNV wind data but we do not yet have the solar data.
Q – Does the NECEC transmission project have a capacity value of 800 MW?
A – Yes, the capacity values is 800 MWs.

DNV GL will use similar fuel price multiplier for natural gas that was used in previous economic studies. (1.1 in winter, 0.9 in summer). Forced outages will be accounted for by de-rating the units' capacities. For heat pumps 5,214 MW will be used.

Q – How are the heat pump numbers developed? Does this compare with Jon Black's information?
A – This data came from the most recent CELT report. This was estimated from a top-down approach for the region. It assumed an adoption rate of heat pumps. This was just seen from National Grid's perspective and did not reflect state policies necessarily. It looked more at economics of oil vs. electric heating with a focus on air-source heat pumps.
Q – What is the shape of the heat pump curve?
A – This was only focused on cooling and not on heating.
Q - Why was some of the heating studied during high temperatures?
A – This was from hot-water heating electrification.
Q – Will the batteries be split between its three use-cases?
A - Regulation use will be looked at later. Price-sensitive batteries are what will be looked at in GridView. Batteries will respond to price signals to be as profitable as possible.
Q – What is the expected MWh of each installation?
A - They are assuming that the batteries will be good for four MWh.
Comment – We believe two MWh was currently more common.
Q - How will arbitrage work for the batteries? Are there threshold prices?
A – They were modeled using GridView model. Using same engine as pumped storage, batteries had different efficiencies in the model. Look for delta between prices to make as much as possible based on LMP.
Q – Is this part of modelling reserves?
A - Some reserves are being held in batteries, but not much.
Q – What is considered "unacceptable wear-and-tear" for batteries?
A - High and low charge states affected wear-and-tear more than cycling so batteries will operate based on price signals while keeping within the proper operating range.
Comment – First Light expressed concerns with variable O&M costs being ignored for batteries. The comparison to Tesla power walls was irrelevant considering that the actual batteries are much larger and operate differently. First Light thought that O&M costs should be included in the battery assumptions.

Next steps: In Q3 2020 ISO-NE will present the draft production simulation results. In Q4 2020, ISO-NE will present the sensitivity results. In Q1 2021, ISO-NE will present the draft and final 2020 Economic Study reports.

<u>Item 6.0 – Horton Cove Asset Condition and Optical Ground Wire (OPGW) Project</u>
Mr. Christopher Soderman (Eversource Energy) reviewed the Horton Cove Asset Condition and Optical Ground Wire (OPGW) Project.

There are three 115 kV lines (1080, 1280, 1410) and one 69 kV line (100) that cross Horton Cove adjacent to the Thames River in Montville, CT. Lines 100 and 1410 were built in the 1920's. Currently the conductors are 556 kcmil ACSR. The 1080 and 1280 lines were built in the 1960's. Currently the conductors are 1272 kcmil ACSR

The quad-circuit lattice towers create the potential for disturbances on multiple circuits. The geometry also increased probability of faults from lightning strikes. There were 19 disturbances since 2010 caused by lightning in this area. Maintenance on this sometimes requires outages of several circuits due to the configuration. The H-frame and lattice structures are deteriorating. The project will replace 11 existing quad, double, and single circuit structures with 2 double-circuit steel monopoles, 12 single-circuit steel monopoles, and 5 single-circuit steel H-frames, as well as install lightning arresters.

One of the alternatives that was looked at was just replacing the quad-circuit river crossing with four dead-end monopole structures. However, this does not address lightning issues and would require taller/more expensive structures for the river crossing.

The preferred solution is to replace 11 structures, two shield wires, and reconductoring 0.6 miles of 1080 and 1280 and reconductoring 0.85 miles of 1410. Expected project cost is $13.8 million.

Q – Regarding the 69 kV Line 100, will that be upgraded to 115 kV?
A – The structures will be designed for 115 kV clearance and operation.

<u>Item 7.0 – 1768 115 kV Lattice Tower Asset Condition and OPGW Project</u>
Mr. Christopher Soderman (Eversource Energy) reviewed the 1768 115 kV Lattice Tower Asset Condition and Optical Ground Wire (OPGW) Project.

The 1768 Line was originally built in 1924 totaling 15.4 miles in length. 7.5 miles of the line are on double-circuit lattice towers that were reconductored in the 1990s. The lattice towers have corrosion, rust, lack of redundant bracing. There have also been several tower-arm failures, making them dangerous to even climb. The preferred solution is to replace 70 double-circuit steel lattice towers with 63 direct-embed steel monopoles and seven engineered weathering steel monopoles on concrete foundations and install 62 lightning arrestors. The 7.5 miles of the line will be replace bundled 556 kcmil ACSS with 1272 ACSS. The alternative would be to repair/replace only the deteriorated components on select structures. This would only be a short-term fix. The estimated cost of the project is $22.6 million (-25%/+50%) with an in service date of Q4 2021.

Q – Is this in the same Right of Way (ROW) as the 345 kV line between MA-CT?
A – Yes.
Q – Why is only 75' shown in diagram?
A – This is not the entire ROW.
Q – Is Eversource working with NSTAR West on the MA side of the project?
A – The circuits there are already on the 345 kV structure. This asset condition project replaces the last of this old section of line.

<u>Item 8.0 – Other Business</u>
The next PAC meeting was rescheduled from August 11, 2020 to August 27, 2020. It will be held via WebEx Teleconference.

Planning Advisory Committee meeting adjourned at 2:15 PM

Respectively submitted

Marc Lyons
Secretary, Planning Advisory Committee