Planning Advisory Committee
WebEx Teleconference
June 15, 2022

Attendee	Organization
J. Truswell - Chair	ISO New England Inc.
M. Lyons - Secretary	ISO New England Inc.
J. Adadjo	Eversource Energy
Z. Ahmed	ISO New England Inc.
R. Albrecht	Raymond J. Albrecht LLC
S. Ali	PPL Energy Plus
M. Allen	VELCO
S. Allen	Eversource Energy
B. Anderson	NEPGA
C. Benker	Eversource Energy
P. Bernard	ISO New England Inc.
P. Boughan	ISO New England Inc.
H. Braun	London Economics
J. Breard	ISO New England Inc.
J. Brodbeck	Marble River
J. Burlew	ISO New England Inc.
D. Burnham	Eversource Energy
D. Capra	NESCOE
D. Cavanaugh	Energy New England
B. Chamberlain	Olive Wood Energy

R. Collins	ISO New England Inc.
D. Conroy	RLC Engineering
W. Coste	ISO New England Inc.
F. Dallorto	ISO New England Inc.
B. D'Antonio	Eversource Energy
J. Dong	Eversource Energy
M. Drzewianowski	ISO New England Inc.
L. Durkin	ISO New England Inc.
F. Ettori	VELCO
J. Fenn	Versant Power
E. Foley	ISO New England Inc.
B. Forshaw	CMEEC
B. Fowler	Wheelabrator North Andover Inc.; Exelon Generating Company LLC; Nautilus Power; Dynegy Power Marketing, LLC; Entergy Nuclear Power Marketing LLC; Great River Hydro, LLC
J. Fundling	Eversource Energy
P. Gandbhir	Conservation Law Foundation
N. Gangi	ISO New England Inc.
G. Ghanavati	Eversource Energy
L. Guilbault	HQ US
J. Halpin	Eversource Energy
P. Holloway	Massachusetts DOER
K. Huang	New England Power Company
A. Hubik	New England Power Company
N. Hutchings	ISO New England Inc.

J. Iafrati	Customized Energy Solutions
S. Judd	ISO New England Inc.
S. Kaminski	New Hampshire Electric CoOp
S. Kane	Eversource Energy
T. Kaslow	First Light Power
A. Kniska	ISO New England Inc.
D. Kopin	VELCO
R. Kornitsky	ISO New England Inc.
M. Kotha	ISO New England Inc.
N. Krakoff	Conservation Law Foundation
A. Krich	Boreas Renewables
B. Kruse	Calpine
F. Kugell	Avangrid
A. Kuriakose	New England Power Company
E. Laine	ISO New England Inc.
C. Lambrinos	New England Power Company
S. Lamotte	ISO New England Inc.
J. Liang	Eversource Energy
P. Lopes	Massachusetts DOER
J. Lucas	Eversource Energy
T. Lundin	LS Power
X. Luo	ISO New England Inc.
E. Mailhot	ISO New England Inc.
K. Mankouski	ISO New England Inc.
J. Martin	New England Power Company
A. McBride	ISO New England Inc.

P. Melzen	Eversource Energy
A. Nichols	ISO New England Inc.
S. Nikolov	ISO New England Inc.
B. Oberlin	ISO New England Inc.
R. Panos	New England Power Company
H. Pathan	Eversource Energy
D. Patnaude	Eversource Energy
D. Phelan	New Hampshire Public Utilities Commission
H. Presume	VELCO
M. Purdie	Dominion Energy
S. Rastegar	ISO New England Inc.
C. Richards	PPL Energy Plus
J. Rotger	Galt Power, Cross Sound Cable, BP Energy, Mercuria Energy and DTE Energy
E. Runge	Day Pitney
M. Saravanan	ISO New England Inc.
G. Saulmon	ISO New England Inc.
K. Schlichting	ISO New England Inc.
D. Schwarting	ISO New England Inc.
M. Scott	New England Power Company
C. Sedlacek	Eversource Energy
P. Silva	Synapse Energy
J. Slocum	Massachusetts Public Utilities Commission
C. Soderman	Eversource Energy
R. Somayajulu	New England Power Company
R. Snook	Connecticut Attorney General Office

P. Sousa	Marble River
K. Sreenivasachar	ISO New England Inc.
R. Stein	Generation Group Member, NRG Power Marketing, HQ Energy Services, PSEG Energy Resources & Trade, SunEdison
B. Swalwell	Tangent Energy
Z. Teti	Avangrid
D. Thompson	Connecticut Office of Consumer Counsel
B. Thomson	PPL
R. Vega	ISO New England Inc.
P. Vijayan	ISO New England Inc.
A. Weinstein	Dynegy Marketing and Trade
P. Wong	ISO New England Inc.
A. Worsley	Transmission Analytics
F. Zeng	ISO New England Inc.
J. Zhang	ISO New England Inc.

Item 1.0 – Chairs Remarks

Ms. Jody Truswell welcomed the committee and reviewed the days' agenda.

Item 2.0 – Eversource Scobie Pond 345 kV Trench Replacement and Control House Expansion Project

Mr. Paul Melzen (Eversource Energy) provided an update on the Eversource Scobie Pond 345 kV Trench Replacement and Control House Expansion Project. The substation yard contains separate trench systems for primary and secondary relaying. The Substation control house was originally constructed in 1960s with separate areas for primary and secondary relaying. The substation control house was originally constructed in 1960s with separate areas for primary and secondary relaying. NPCC Directory #4 requires full separation of primary and secondary systems to maintain overall system reliability and robust BPS system protection. Due to asset conditions and overcrowding, both the trench system and control house will be replaced. Estimated cost is $19.7M (-25%/+50%) with a projected in service date of Q2 2025.

In response to stakeholder questions, Eversource provided the following statements:

- The new control house will be almost double the size of the existing control house.

Item 3.0 – Eversource New Hampshire Asset Conditions Wood Structure Replacement Project

Mr. Chris Soderman (Eversource Energy) provided an overview of the Eversource New Hampshire Asset Conditions Wood Structure Replacement Project. The project includes replacing 124 miles of wood transmission structures (162 structures) in the New Hampshire area on five different 345 kV lines and one 115 kV line. Replacement is needed due to rot, pole splitting and woodpecker damage. The existing structures will be replaced with light duty steel poles. The estimated cost is $50.1M (-25%/+50%) and the in service date for all lines is Q4 2023 or earlier.

There were no questions from the committee on this topic.

Item 4.0 – NEP E5 and F6 69 kV Asset Conditions Project

Mr. Rafael Panos (New England Power) provided an overview of the NEP E5 and F6 69 kV Asset Conditions Project. The E5 and F6 69 kV lines were originally constructed in 1911. The dual circuit lines originate at Millbury #5 in Millbury, MA and terminate at Deerfield #4 in Buckland, MA. The total length of each mainline and taps is approximately 67 miles. There are 710 total structures: 73 steel pole, 539 lattice, 98 wood pole. The driver for this project is Asset Condition. Replacement is need due to rot, pole splitting, corroded hardware, deflecting steel members, foundation concerns, damaged insulators and woodpecker damage. Two alternatives are being investigated. A full line rebuild using 115 kV standards or a full line rebuild using 69 kV standards. No cost estimates were provided for either alternative but the expected in service date is December 2030.

In response to stakeholder questions, New England Power provided the following statements:

- This is a presentation to identify conceptual solutions. We intend to come back to the committee with cost estimates in the future.

Item 5.0 – D4 Protection System Solution Study

Mr. Pradip Vijayan (ISO-NE) reviewed the D4 Protection System Solution Study. The D-4 line is a 16.6-mile transmission line between the Vernon 69 kV station in VT and the Deerfield 69 kV substation in western Massachusetts. The Solution Study is to identify regulated transmission solutions to address the time-sensitive need for faster clearing times for 3-phase faults on the D-4 line. Three alternatives were reviewed but the preferred solution is installing a Permissive Over-Reaching Transfer Trip Scheme that relies on OPGW being installed as a part of the A1/B2 asset condition in addition to existing communication networks. In addition, relay and communication upgrades will be performed at the Huntington (new name for Vernon, post asset condition project) and Deerfield substations. Estimated cost is $0.43M. The in service date is projected to be February 2027.

There were no questions from the committee on this topic.

Item 6.0 – Generator Ratings Used in Attachment K Studies

Ms. Sarah Lamotte (ISO-NE) provided an overview of a new method for modelling maximum generator power in transmission planning peak load steady state Attachment K studies (Needs Assessments, Solution Studies, Longer-Term Transmission Studies and Public Policy Transmission Studies) that currently use summer QC to model maximum generator power. The new proposal screens temporary poor audit performance without drastically increasing total modelled generation capability.

In response to stakeholder questions, ISO-NE provided the following statements:

- In response to a question on why the qualified capacity of the median of the last 5 years of audits isn't sufficient for use in the Attachment K studies, ISO replied that if a resource has a significant decrease in its most recent audit, then the summer QC may be based off the most recent audit in lieu of the median of the past 5 years' audits.
- In response to a question on why there is a disconnect between resource adequacy and transmission planning. ISO replied that the FCA is run on a three-year look ahead basis where transmission planning is based on a 10-year look ahead.
- In response to a question regarding the impact of the Resource Capacity Accreditation effort, the ISO said that it will need to revisit aspects of the proposal.

Item 7.0 – RSP Transmission Projects and Asset Conditions – June 2022 Update

Ms. Jinlin Zhang (ISO-NE) reviewed the June 2022 update regarding the RSP Transmission Projects and Asset Conditions. There was one cost estimate change greater than $5M, which is the $14.4M increase for the Sudbury – Hudson 115 kV line due to material costs increase and siting/permitting delays. There was one new project which is the K Street 345 kV 103S Breaker will now operate as normally open. There were three upgrades placed in service (two in MA and one in RI) There were no cancelled projects since the March 2022 update.

There were no questions from the committee on this topic.

Item 8.0 – Generator Outage and Interface Transfer Assumptions for Needs Assessments – Background and Concepts

Mr. Dan Schwarting (ISO-NE) reviewed the Generator Outage and Interface Transfer Assumptions for Needs Assessments presentation. ISO includes generator outages in study base cases to represent higher forced outage rates than transmission system elements based on past experience with simultaneous unplanned outages of generators, unanticipated generator retirements and potential fuel shortages. Pre 2017, ISO used a standard of two generator out of service in the base cases for transmission reliability studies. Post 2017, ISO moved toward a probabilistic method of determining generator outages used in studies using the EFORd for each generator in the region. After five years of using the probabilistic method, a number of issues have come up such a transparency concerns, unavailability thresholds being impacted by large generators, EFORd fluctuations, and surplus MWs in transfer calculations. Based on these issues, ISO is developing a new assumption methodology focusing on generating units and not MWs out of service. The ISO is proposing to change the EFORd calculations from individual units to a fleet wide average. In addition, changing the interface transfer assumptions should account for likely dispatch conditions, while still providing a reasonable level of system stress. The next steps are to take stakeholder feedback on the ISO proposal and update the assumptions in the Transmission Planning Technical Guide later in 2022 and begin using the assumptions in upcoming needs assessments in the second half of 2022.

In response to stakeholder questions, ISO-NE provided the following statements:

- In response to a stakeholder question regarding how NYISO approaches this type of study, ISO stated that NYISO doesn't apply generator outages in their transmission studies. Other ISO's use a system wide percentage reduction versus our unit reduction. Each area has unique issues.

Stakeholders expressed support for this proposal.

Item 9.0 – Limits on Distributed Energy Resources (DER) Tripping for Design Contingencies

Mr. Andrew Kniska (ISO-NE) reviewed the presentation on Limits on Distributed Energy Resources (DER) Tripping for Design Contingencies. DERs interconnected prior to January 2019 were not assumed to have fault ride through capability. DER interconnected after January 1, 2019 require fault ride though capability. As part of the TPCET Pilot Study conducted in 2021, significant amounts of legacy DER were shown to trip (1855 MWs) for design contingencies. DER tripping also contributes to the total loss of source when it happens as a result of a fault that already trips a large conventional generator, such as a fault on a conventional generator's step up transformer. Large losses of source in New England can cause large power swings into New England from the rest of the Eastern Interconnection, leading to voltage problems in the New York and PJM systems. This could lead to an increase in the loading on transmission lines or transformers. ISO proposes to maintain the current 1,200 MW loss of source requirement but include DER tripping in the loss of source calculation. The next steps are to place limits on legacy DER tripping for design contingencies that will be added to the Transmission Planning Technical Guide and ISO-NE Planning Procedure 3. Once Planning

Procedure 3 is updated, legacy DER tripping limits will be enforced in System Impact Studies and Proposed Plan Application studies when these studies begin explicitly modeling the transient behavior of all DERs.

In response to stakeholder questions, ISO-NE provided the following statements:

- In response to a stakeholder question regarding asked how will the models account the legacy DERs decreasing as their inverters become replaced. ISO replied that we expect the replacement inverters on legacy DERs will meet the present day IEEE standards and the amount of legacy DERs will decrease over time.

Item 10.0 – 2021 Economic Study – Future Grid Reliability Study Phase I – Gaps, Key Takeaways and Lessons Learned

Mr. Patrick Boughan (ISO-NE) reviewed the Gaps, Key Takeaways, and Lessons Learned as part of the FGRS 2021 Economic Study. Phase I used stakeholder-defined scenarios to identify operational and reliability challenges in light of current state energy and environmental policies. Analyses performed included Production Cost, Ancillary Services, Resource Adequacy Screen and Probabilistic Resource Availability Analysis (PRAA). Electrification of heating and transportation will increase grid demand. It is assumed that wind and solar will replace gas as the primary fuel source in the region. As a result, emissions are expected to decrease. Electrification is also expected to significantly alter the load shape and increase system complexity.

As part of the study, several gaps were discovered. For energy adequacy, the study shows a need for a significant amount of gas or stored fuels to support variable resources, which could prove difficult to achieve with current infrastructure. There will also be an increased demand for stored energy, which becomes problematic when the storage is depleted during the winter season. In addition, the anticipated retirement of nuclear unit's conflicts with the net-zero emission goals.

For resource and demand flexibility, high electrification and more aggressive retirements of the existing flexible fleet, system-operating reserves may become deficient and at times completely depleted. Both supply and demand may need to offer more flexibility in order to maintain reserve balance in the system. An increase in variable generation will require an increase in dispatchable generation. For resource mix diversity, the reserve margin may need to increase by an order of magnitude by 2040. A lack of diversity in the future resource mix may necessitate the construction of many more new resources. Future grids may not follow old patterns. This study assumes current rules and regulations, which were designed for a historical dispatchable resource mix and summer-peaking grid. As the proportion of variable energy resources increases, and as the grid shifts to winter peaking, these assumptions may need to be refined. Lessons learned in the study include the limitations of using a single weather year, the need for modeling of neighboring regions, the limitations in modeling energy storage, simplification of wind and solar resources, uncertainties in future load shapes and demand modeling. A final report and model data is expected by mid-July. The three technical appendices covering Production Cost, Ancillary Services, and Resource Adequacy will be issued by the end of Q3 2022.

Stakeholders provided a number of comments regarding the study:

- A stakeholder asked when ISO would perform the revenue adequacy analysis (Phase 2). ISO replied that no firm date has been determined to begin the Phase II portion of the study but ISO will provide more details to the PC once it has been decided. Another stakeholder commented that we should begin the Phase II study as soon as possible.
- A stakeholder commented that as resources become more flexible, ISO should consider reducing the dispatch window to less than 5 minutes.
- A stakeholder commented that ISO needs to consider what other control areas are doing when we plan to import or export power. We need to know what their plans are before we make our assumptions.
- Another stakeholder commented that ISO should develop tutorials on the capabilities of the new modeling programs that we are planning to use.

Item 11.0 – Closing Remarks

The next scheduled PAC meeting will be held virtually on Wednesday, July 20, 2022.

Meeting Adjourned at 2:00 PM

Respectively submitted,

Marc Lyons
Secretary, Planning Advisory Committee