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March 2021

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Energy and Ancillary Service Markets

Market Operations Report: March 2021 - Total Energy Market value dropped $435 M from $759 M in February to $324 M in March; this was $152 M higher than the March 2020 total. The average monthly natural gas price fell 55% from February but rose 144% from March 2020. The monthly average RT Hub LMP fell 48% from February to $37.10 / MWh; this was 121% higher than the March 2020 average. The monthly average DAM Hub LMP was $38.83 / MWh in March. During March, an average of 99% of peak hour forecasted load cleared as physical energy in the DAM, down slightly from 99.1% in February; this metric reached its minimum daily value of 94.3% on Saturday, March 6. During March, Price Responsive Demand (PRD) resources cleared approximately 900 MWh in the DAM and delivered approximately 1,350 MWh in the RTM; the total Energy market value of these deliveries was about $80 K.

Uplift Report March 2021 - Total daily NCPC payments decreased $800 K from February to $1.8 M in March; this was $100 K higher than the March 2020 total. First Contingency (Economic) payments fell $600 K from February to $1.7 M, of which $728 K was charged to DALO, $519 K to RT Deviations, and $424 K to RTLO. Total Second Contingency decreased $12 K from February to $131 K; there were no NCPC payments for Distribution or Voltage support during March. NCPC payments represented 0.6% of total Energy Market value during March.

In response to the extreme weather and load shedding events in ERCOT, SPP and MISO in February, ISONE has begun considering how to ***revise its approach to the Energy Security Improvements (ESI) construct***, which was rejected by FERC. ISONE has not yet established the degree to which the reliability risks that ESI is intended to mitigate should be addressed by market-based mechanisms.

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Forward Capacity Market

CEO Gordon van Welie discussed ***ISONE's response to the FERC's March 23 FERC Technical Conference on Resource Adequacy in the Evolving Electricity Sector***. FERC suggested that ISONE and NEPOOL focus on redesigning the Capacity market to support both the Clean Energy Transition and the reliability of the Energy markets. Mr. van Welie indicated that while efficient pricing and procurement of adequate operating reserves is vital for ensuring the availability of sufficient ramping and frequency regulation capability as the grid evolves, ancillary service markets can only complement the Energy and ICAP constructs. Mr. van Welie anticipates that FERC will order ISONE to eliminate the Minimum Offer Price Rule (MOPR) provisions within the next 12 months and noted that most New England states have also expressed support for eliminate these rules. ISONE will therefore begin discussions with NEPOOL in the regarding the scope and schedule for this effort in June or July; elimination of the MOPR provisions will likely become ISONE's highest priority project during the second half of 2021. Mr. van Welie emphasized that this project will need to address the increased risks of price suppression resulting from removal of the MOPR while at the same time incorporating clean energy and environmental objectives into the markets.

ISONE posted ***FCA16*** Qualified Capacity values for existing resources on March 5. Aggregate data regarding Retirement (RDB) and Permanent Delist Bid (PDB) submittals were posted on March 17. The FCA16 CONE, Net CONE, and Capacity Performance Payment Rate (PPR) values are currently pending FERC approval; the final capacity zone calculations and the final summary of RDBs and PDBs will be posted once FERC issues a final order on those values. The Dynamic Delist Bid Threshold (DDBT) price is now posted on the ISONE website. The Power Supply Planning Committee (PSPC) will begin discussing the input assumptions for the Installed Capacity Requirement (ICR) and Related Values on May 20.

ISONE reviewed the schedule for ***development of the ICR-Related Values to be used in the FCM auctions that will be conducted in 2022***. For each FCM auction, ISONE and NEPOOL must develop the following values: 1) Hydro-Quebec Interconnection Capability Credits (HQICC); 2) Installed Capacity Requirement (ICR); 3) Local Sourcing Requirements (LSR) for import-constrained zones; 4) Maximum Capacity Limits (MCL) for export-constrained zones; and 5) the Marginal Reliability Impact (MRI) demand curves for each Capacity Zone and the Rest of System. ISONE will discuss the input assumptions and methodology for developing each of these values with the PSPC first before presenting them to the RC and PC for advisory approval. During 2021, ISONE will develop these ICR-Related Values for (i) FCA16, (ii) the Third Annual Reconfiguration Auction (ARA3) for the 2022-23 Capacity Commitment Period (CCP13), (iii) ARA1 for CCP15 (2024-25), and (v) ARA2 for CCP14 (2023-24). Development of the FCA16 ICR-Related Values will begin at the PSPC in May and the RC will conduct its initial review in early September; RC action is scheduled for the end of September and the PC will vote on these Values on October 7 to support filing by the November 9 deadline. Development of the ICR-Related Values for all 2022 ARAs will begin with PSPC review of all input assumptions in August. RC action is scheduled for late October and PC action is scheduled for November 4; these Values must be filed with FERC by November 30.

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Forward Capacity Market

Load Serving Entities with Capacity Load Obligations (CLO) must post Financial Assurance (FA) to cover their monthly capacity charges. This FA posting, which is referred to as the FCM Capacity Charge Requirement, is the product of the LSE's Estimated CLO times the applicable FCM Charge Rate, which is calculated in a manner similar to that used to determine the Net Regional Clearing Price (NRCP). ISONE publishes forecasted FCM NRCPs and the FCM Charge Rates for each Capacity Commitment Period (CCP) once results from the associated 3rd Annual Reconfiguration Auction (ARA3) have been approved. The ***FCM Charge Rates for CCP12*** (2021-22) are: 1) Rest-of-Pool = $4.980 / kW-month; 2) Northern New England (NNE) = $4.599 / kW-month; and 3) Southeast New England (SENE) = $5.601 / kW-month.

On March 31, FERC accepted a joint ISONE / NEPOOL proposal which ***revised the treatment of Energy Efficiency Resources (EER) under the Pay For Performance*** rules.

External Transactions

The MC recommended PC approval of ISONE's proposed OP-9 ***revisions pertaining to the curtailment of Coordinated Transaction Scheduling (CTS) transactions during Operating Reserve Deficiencies and Minimum Generation Emergencies***. These changes clarify the order and timing of actions taken by the System Operators to reduce transactions on the CTS-Enabled interface (New York North) when the net schedule of Real-Time CTS transactions is contributing to an Emergency condition. Before or during an Operating Reserve Deficiency, Operators will be permitted to reduce any exports on the CTS interface if the resulting interchange (i) is not a net export and (ii) is between 0 MW and the net of cleared DAM CTS transactions. Before or during a Minimum Generation Emergency, Operators will be permitted to reduce any imports on the CTS interface if the resulting interchange (i) is not a net import and (ii) is between 0 MW and the net of cleared DAM CTS transactions. Additionally, DAM-scheduled transactions on the CTS interface will be protected from curtailment; currently, this protection is only available to DAM-scheduled transactions on other interfaces. The PC will be asked to approve this proposal in May.

FTR Markets

ISONE introduced a proposal to ***transfer the clearing of Financial Transmission Rights (FTR) to an independent clearing organization***, Nodal Exchange, LLC. Although ISONE has collateral and related requirements in place to protect against defaults by FTR Holders, there is still a risk of defaults that need to be socialized to other Market Participants. Under the proposed design, this default risk would be placed on Nodal, which will act as the counterparty for every transaction. ISONE would continue to run the FTR auction to create initial FTR positions; Nodal will convert the ISONE-awarded FTRs into defined source and sink-based futures contracts (referred to as "Exchanges for FTRs," or EFTR). Nodal will operate the trading platform, provide price transparency, and establish and maintain the margin requirements for each contract. Margin requirements will include "initial margin," which covers the potential for default due to price movements that could occur over a specified number of days, and "variation margin," which covers the potential daily or intra-daily market exposure. Nodal will also provide trade risk limit verification services to assist ISONE in administering the FTR auction. FTR Market Participants will be required to submit their initial margin to Nodal prior to submitting FTR auction orders to ISONE; a participant's bids will be rejected prior to the auction if it has submitted insufficient initial margin. ISONE will then run the FTR Auction. Market Participants will participate in the FTR auctions through one or more of Nodal's 14 clearing member institutions rather than through ISONE; these institutions will hold the responsibility for ensuring that a Market Participant has sufficient margin amounts deposited in its account(s). FTR Holders will also be required to post daily "variation margin" adjustments to ensure that any market losses do not accumulate; the existing collateral mechanism does not account for changes in the value of an FTR obligation across its term. ISONE will no longer pay Congestion Revenues directly to FTR Holders; instead, it will credit variation margin equivalent to the difference in the LMP Congestion Components at the source and sink into the clearing member accounts of an FTR holder. ISONE also noted that the proposed approach provides a mechanism for forcing the liquidation of a defaulted FTR position; this is not permitted under the current rules. ISONE will review the associated changes to the Billing and Financial Assurance Policies with the Budget and Finance Subcommittee; this project and the associated Tariff, Market Rule 1 and Information Policy changes will be discussed with the Markets Committee beginning in August. MC action will be sought in October/November and PC action will be sought in November/December; implementation is currently targeted for Q3/Q4 2022.

System Operations and Planning

System Operations Report: March 2021 - Peak load for the month of 17,647 MW occurred on March 2 in hour ending 19:00. There were no OP-4, M/LCC#2 (Abnormal System Conditions), or Minimum Generation Emergency events and no Minimum Generation Warnings issued. There was one or NPCC Simultaneous Activation of Reserve event on March 28 to support a loss of 800 MW in IESO. Midday loads fell below overnight lows on several days during the month; ISONE expects this to occur more frequently in the future. Evening peaks have been higher than historical averages because more people are working from home. The monthly average temperature in Boston was 3.3°F above normal; local temperatures ranged from a minimum of 13°F to a maximum of 74°F. Total Boston precipitation (1.69") was 2.22" below normal levels and included 0.10" of snowfall. The monthly average temperature in Hartford was 3.0°F above normal; local temperatures ranged from a minimum of 13°F to a maximum of 77°F. Total Hartford precipitation (2.25") was 1.01" below normal levels and included 0.10" of snowfall. Temperatures were more variable than normal during March; as a result, ISONE's operational load forecasts had a monthly mean average percent error of 2.02% (target threshold = 2%). Peak load forecast error remained within the target during the month; However, reported that its forecasts have become more accurate over the past year due to improvements in its modeling of the load impacts caused by the COVID-19 pandemic. ISONE noted that actual loads exceeded the forecast by 1,100 MW in one hour on March 1.

ISONE reported that ***winter 2020-21 operations*** was marked by a few periods of consecutive days with temperatures below normal, but no periods of sustained significant cold weather; average regional winter temperatures were approximately 1.8°F above historical normal levels. The region experienced three moderate cold snaps (December 15-20, January 28-February 1, February 7-13) as well as 31 consecutive days with above-normal temperatures (December 21–January 20). Total snowfall in Hartford (39.1") was 8.4" above normal while total precipitation was 1.5" above normal. Total snowfall in Boston (34.1") was 1.3" above normal while total precipitation was 0.4" below normal. COVID-19 appears to have had a noticeable impact on both the load curve and overall energy demand. Increases in remote work and learning drove loads above normal levels across the region, primarily during business hours. In each month of this winter, "backcast" simulations based on actual weather and pre-COVID forecast models yielded forecasts that were lower than actual values for (i) average evening peak load, (ii) mid-day load, and (iii) monthly energy demand. ISONE noted that higher energy demand was due in part (≈22%) to higher than normal snowfall, which reduced PV output. The 2020-21 winter peak hourly demand of 18,703 MW occurred on January 29. ISONE did not implement MLCC-2 (Abnormal Conditions Alert) or OP-4 (Capacity Deficiency) actions at any time during the season. Surplus generation capacity was available throughout the season. Overall natural gas demand was higher than in previous years, but there were no significant reductions in natural gas availability; scheduled LNG injections were slightly above average. Fuel oil usage was minimal and supplies remained steady throughout the season. Consistent with normal operating practice, transfer capability on the New York Northern AC ties was increased from 1,400 to 1,500 MW for the entire winter period.

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System Operations and Planning

ISONE presented a summary of the ***Texas extreme weather load shed event*** in February. Beginning Sunday February 14, the ERCOT Interconnection experienced severe weather and record-setting extreme low temperatures that led to an imbalance of supply and demand. Temperatures were 37°F to 47°F degrees below normal levels and were at or below freezing (i) for 140 consecutive hours in Dallas, (ii) for 162 consecutive hours in Austin, and (iii) for 44 consecutive hours in Houston. At the peak of the event, approximately 48.6% of generation (52,277 MW) of all technology types was forced out of service or unavailable (natural gas = 25 GW, wind = 18 GW, coal = 5 GW, solar = 2 GW, nuclear = 2 GW). Factors contributing to these outages included fuel supply disruptions caused by loss of power to gas compressors, reduced fuel quality, freezing of infrastructure, icing and snow cover. Emergency conditions in neighboring areas also limited ERCOT's ability to import emergency energy over its DC ties during the event. To prevent a statewide blackout, electric demand was limited to available generation supply through the implementation of controlled power outages, beginning at 1:20 am on Monday, February 15. Additional generation outages required further shedding of load throughout the early morning hours. Power system frequency dropped to 59.3 Hz around 1:55 am. Approximately 20 GW of load was shed at the event's peak; the magnitude of generation unavailability and the number of circuits with critical load limited the ability of local utilities to rotate these outages. Because some distribution companies in Texas have not separated their essential and non-essential circuits, these outages caused extended power losses to natural gas well heads and pipeline equipment, further exacerbating the fuel supply disruptions. At 12:42 am on Thursday, February 18, ERCOT canceled the last of the controlled outage orders, although there were still some power outages caused by ice storm damage. ERCOT returned to its normal operations posture by 10:35 am on Friday, February 19. The average ERCOT 345 kV Hub price from February 14-19 was $6,612.23 / MWh in the DAM and $6,579.59 in the RTM; energy was priced at or near the $9000 / MWh administrative cap for many hours throughout the multi-day event. Some stakeholders argued that this event has demonstrated the ineffectiveness the ERCOT market's reliance on very high energy prices to incent investments in winter reliability preparations.

Planning Report: April 2021 - The 373 (Deerfield-Scobie Pond) 345 kV Line will be out of service from May 3 to 29. ISONE estimates that the 2021 CELT gross load forecast for summer 2025 will be approximately 1,500 MW lower than was forecast in the 2020 CELT; the Planning Advisory Committee (PAC) will discuss the final draft forecast in April; the final 2021 CELT ten-year forecast will be posted on April 30. ISONE is projecting the lowest Spring Operable Capacity Margins for the week beginning May 8; ISONE is projecting the lowest Preliminary Summer Operable Capacity Margins for the week beginning September 11.

System Operations and Planning

ISONE presented a summary of the final draft values for the long-term energy and demand forecasts for the period 2021-2030 that will be published in the ***2021 Capacity, Energy, Loads, and Transmission (CELT) report***. The gross load forecasts incorporate expected load additions from electrification of transportation and heating. The net load forecasts account for projected demand reductions from BTM PV and Demand Capacity Resources (i.e., energy efficiency, distributed generation, price-responsive demand). ISONE noted that the 2021 CELT forecasts reflect the offsetting impacts of (i) a new methodology for reconstituting the impact of passive demand resources (PDR) and (ii) economic forecasts that exhibit more optimistic projections regarding the evolving impacts of the pandemic. The final draft gross annual energy forecast increases from 140,836 GWh in 2021 to 163,116 GWh in 2030; net annual energy is projected to grow from 121,692 GWh to 133,960 GWh. Gross 50/50 summer peak demand, which is projected to rise from 28,324 MW to 30,177 MW across the forecast horizon, incorporates modest increases in expected transportation electrification (from 7 MW to 675 MW). However, net 50/50 summer peak demand is projected to decrease slightly (from 24,810 MW to 24,796 MW) due to significant growth in energy efficiency (from 2,677 MW to 4,294 MW) and BTM PV (from 836 MW to 1,087 MW). Gross 90/10 summer peak demand is projected to increase from 30,225 MW to 32,197 MW; forecasted net 90/10 summer peak demand is expected to increase slightly, from 26,711 MW to 26,816 MW. Gross 50/50 winter peak demand is forecasted to increase from 22,214 MW for the 2021-22 season to 25, 041 MW for the 2030-31 season. The winter 2021-22 projections include transportation electrification demand of 22 MW and heating electrification demand of 52 MW; by winter 2030-31, these values are expected to rise to 916 MW and 1,556 MW, respectively. The net 50/50 winter peak forecasts exhibit somewhat more modest growth, rising from 19,710 MW to 21,158 MW due to an increase in energy efficiency (from 2,503 MW to 3,883 MW). BTM PV MW are assumed to be 0 MW at the winter peak. Gross 90/10 winter peak loads, which incorporate more heating electrification demand than the 50/50 projections, are forecasted to increase from 22,853 MW to 25, 821 MW. As with the 50/50 winter peaks, net 90/10 winter peak demand is expected to experience slower growth, from 20,349 MW in 2021-22 to 21,939 MW in 2030-31.

ISONE described three potential approaches to ***modeling the existing state renewable energy programs within the Forward Clean Energy Market framework in the "Pathways" study***. Clean Energy Credits (CEC) could be treated as an environmental attribute distinct from other renewable energy attributes, so an eligible resource could receive both CECs and RECs for the same MWh of energy. CECs could incorporate all environmental attributes, so a resource selling CECs would not be eligible to receive RECs for the same energy production. Alternately, the existing state programs could be discontinued and all environmental objectives would be met by awarding CECs. ISONE presented several examples of the first two approaches which demonstrate (i) that awarding CECs and RECs for the same energy production will not result in "double payments" to some suppliers and (ii) that awarding only CECs or RECs for a given MWh would likely result in over-procurement of clean energy; thus, while the second approach would avoid "double payment," total costs to consumers would be higher. ISONE noted that over-procurement could be avoided if the demand for CECs is adjusted to account for the amount of MWh that are sold as RECs. ISONE argued that the first approach since it would (i) be relatively simple to model, (ii) avoid the "double payment" concern, and (iii) allow for the continuation of the existing state programs.

ISONE explained the rationale underlying its proposed approach for ***modeling storage resources in the Pathways studies*** of the FCEM and Net Carbon Pricing frameworks. Storage resources contribute to the region's decarbonization by charging from lower-/non-emitting resources during off-peak hours and discharging during on-peak hours; this displaces energy production from higher emitting resources. ISONE argued that awarding Clean Energy Certificates (CEC) to storage resources would compensate them at a rate that exceeds their contributions, since the FCEM will compensate them for their marginal contributions to clean energy production even when they are not awarded CECs. Because clean resources will reduce their Energy offer prices to reflect the value of receiving CECs, Energy prices will be lower when storage resources are charging during off-peak periods. This will increase the Energy price spreads earned by storage resources, since the price they are credited for Energy supplied during on-peak hours will remain unchanged. ISONE argued that these increased Energy market revenues reflect the true marginal value of a storage resource's contributions to clean energy production. However, if a storage resource also receives CECs, it would be compensated twice for its clean energy contributions. Further, awarding CECs to storage resources could allow them to be compensated for discharging in hours in which they do not increase clean energy production. Under Net Carbon Pricing, storage resources will be appropriately compensated for their marginal contributions to reducing carbon emissions if they are not assessed carbon charges. Because the carbon adder to the Energy price will be larger during periods when the marginal emissions rate is greater, a storage resource can increase its Energy price spread by discharging when the marginal supplier has a higher carbon emissions rate and charging when the marginal supplier's emissions rate is lower. As with the FCEM, this increased price spread reflects a storage resource's marginal contribution to reducing carbon emissions.

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Renewable and Storage Resources

The MC approved proposed revisions to the NEPOOL Generation Information System (GIS) Operating Rules to support the ***inclusion of the Maine RPS' Thermal Renewable Energy Credit (REC) requirement in the GIS***. The changes to the GIS and its Operating Rules for Maine Thermal RECs are similar to those implemented to support the addition of thermal energy requirements in the New Hampshire and Massachusetts RPSs. Thermal RECs will be awarded to facilities certified by the Maine PUC that produce heat, steam, hot water or another form of thermal energy, either (i) from sunlight, biomass, biogas or liquid biofuel or (ii) as a byproduct of electricity generated by a qualified Class I or Class IA resource under the Maine RPS. To qualify for Thermal RECs, a facility must have begun operation after June 30, 2019 and the thermal energy must be (i) delivered to an end user in Maine and (ii) generated or delivered in accordance with the Maine PUC's energy efficiency standards. Competitive electricity suppliers in Maine must demonstrate that they have purchased a certain level of Thermal RECs each year, starting at 0.4% in 2021 and increasing to 4% in 2030 and thereafter.

Small Resource Notifications - The Reliability Committee accepted its Consent Agenda, which included: 1) 3 Solar Notifications (11.494 MW total, 1 in Maine and 2 in Connecticut), 4 Solar + Battery Notifications (14.422 MW PV + 9.25 MW / 20.548 MWh battery, all in Massachusetts), and 2 PPA Withdrawal Notifications (3.5 MW total, both PV in Massachusetts).

The RC recommended ISONE approval of Energy Storage Resources (ESR), LLC's Proposed Plan Application (PPA) for the installation of the ***Cross Town Energy Battery Energy Storage System Project***, a 175 MW / 350 MWh battery energy storage plant in Gorham, Maine; the proposed in-service date of the project is April 1, 2023.

The RC recommended ISONE approval of ***Nellie Solar***, LLC's PPA for the installation of a 15 MW solar array in Newport, New Hampshire; the proposed in-service date of the project is October 1, 2022.

The RC recommended ISONE approval of ***Pembroke Solar***, LLC's PPA for the installation of a 17.5 MW solar array in Bow, New Hampshire; the proposed in-service date of the project is October 1, 2022.

The RC recommended ISONE approval of a PPA for the ***NextGrid Berry Street PV and BESS project***, a 4.99 MW solar array and 4.0 MW / 15.84 MWh battery located in Plainville, Massachusetts; the proposed in-service date of the project is July 1, 2023.

The RC recommended ISONE approval of Brookfield Renewable Trading and Marketing's PPA for the ***replacement of the automatic voltage regulator (AVR) on Unit 3 of the Pontook Hydro-Electric generating station*** in Berlin, New Hampshire. The existing analog AVR that was installed in 1986 is obsolete and will be replaced with a new digital device. The proposed in-service date of the project is Q2 2021.

Distributed and Demand Resources

The Meter Readers Working Group (MRWG) discussed the ***metering requirements, impacts to data submission and processing systems, and upgrades necessary for implementing ISONE's Order 2222 compliance design***. Several technical enhancements are needed to implement wholesale market settlement of Distributed Energy Resource Aggregations (DERA), regardless of whether the final market design allows or prohibits sub-metering of DER. These requirements include: 1) installation of Revenue Quality Metering (RQM) for each DER at its Point of Interconnection (POI) or at the Retail Delivery Point (RDP) of the end-use facility; 2) implementation of telecommunication capability at each DER; 3) upgrades to the MV90 software used to enable utility billing systems to read meter data to support management of a potentially unlimited of DER data points; 4) implementation of a mechanism for identifying DER meter data and aggregating it to the DERA's Generator Asset ID; 5) upgrades to the Meter Data Management (MDM) Systems and the Host Participant Assigned Meter Readers' (HP AMR) Settlement Systems to accommodate hourly interval meter data submissions from the new DER load and generator Asset IDs; 6) upgrades to support the processing of additional load and generation data; and 7) installation of Advanced Metering Infrastructure (AMI) devices and associated data collection systems to obtain hourly meter readings for participants in any DERA program. If sub-metering of DERs is permitted, further modification of the MV90, AMI and MDM Systems will be needed to support the reconstitution of sub-metered consumption or generation to the remaining facility loads. It will also be necessary to develop new business processes for modifying meter readings from sub-metered DER. Several issues could impact the costs and timeline for implementing DER metering: 1) increased data storage capabilities will be needed; 2) the Load Asset enrollment process must be enhanced to ensure that all DER in a DERA are located in the same Aggregation Zone; 3) extensive software system upgrades are required to support reporting of 5-minute DER interval data to ISONE for settlement; 4) the current process for obtaining missing meter readings could become unmanageable; and 5) the time required to upload meter data and perform load settlement calculations would increase significantly. Accurate time and cost estimates for addressing these requirements cannot be until each HP AMR gains thorough understanding how the FERC Order 2222 requirements will impact their various metering, settlement and billing systems. The MRWG will continue its work to evaluate these impacts and will provide periodic updates regarding its progress to the MC.

Generation and Transmission

The RC recommended ISONE approval of Dynegy Marketing & Trade's Proposed Plan Application for the ***replacement of the Automatic Voltage Regulators (AVR) on Units 1-3 of the Lake Road generator*** in Killingly, Connecticut. The existing AVRs have reached the end of their useful life and the limited availability of replacement parts and software upgrades is expected to affect the reliability of these units. The proposed in-service date for the AVR upgrades to Units 1 and 3 is April 30, 2021; the proposed in-service date for the upgrade to Unit 2 is May 7, 2021.

The RC concurred with ISONE's Level 0/I classification of New England Power's Transmission Notification for its ***Billerica Transformer T2 Replacement project***, which will replace a failed 30/40/50 MVA load-service transformer at the Billerica Substation in Billerica, Massachusetts with a new 33/44/55 MVA unit. The proposed in-service date is June 2021.

The RC recommended ISONE approval of Eversource Energy's Proposed Plan Application for the ***replacement of two +/- 75 MVAR STATCOMs at the Glenbrook Substation*** in Stamford, Connecticut; this work is being undertaken due to asset condition issues. The proposed in-service date is April 18, 2021.

The RC recommended ISONE approval of Eversource Energy's Proposed Plan Application for the ***expansion of the Bunker Hill Substation*** in Waterbury, Connecticut; the proposed in-service date is September 1, 2022. This project consists of: 1) installation of 3 new 115 kV circuit breakers and 7 vertical disconnect switches; and 2) relocation and reconnection of the 3X, 1789 Line, and 1029 Line terminals.

Eversource Energy introduced the ***Boston Area Optimized Solution*** (BAOS); the proposed in-service date of this project is October 2023. Eversource and National Grid jointly developed the BAOS as the Backstop Transmission Solution to the non-time sensitive needs identified in the Boston 2028 Needs Assessment. This Project includes: 1) installation of series reactors on the 345 kV 346 and 365 cables at Eversource's North Cambridge Substation in Cambridge, Massachusetts; 2) installation of a bypass breaker in parallel with each series reactor; 3) installation of a Direct Transfer Trip (DTT) scheme at National Grid's Ward Hill Substation in Haverhill, Massachusetts; 4) installation of a new +/- 167 MVAR static synchronous compensator (STATCOM) at National Grid's Tewksbury 22A Substation in Tewksbury, Massachusetts; and 5) installation of a new 345 kV bay position at Tewksbury 22A substation.

The RC recommended ISONE approval of Eversource Energy's Transmission Cost Allocation (TCA) application for $114.789 M in pool supported PTF costs associated with the ***Seacoast Reliability Project***, which was placed into service May 29, 2020. This Project installed the new 12.9 mile 115 kV F107 (Madbury – Portsmouth) Line, which consists of (i) 10.5 miles of overhead line (primarily in existing Eversource distribution Right-of-Way), (ii) 1.3 miles of underground cable, and (iii) a 1.1 mile submarine cable that crosses Little Bay from Durham to Newington. Associated work included terminal additions at the Madbury and Portsmouth substations.

Generation and Transmission

The RC recommended ISONE approval of Eversource Energy's TCA application for $6.051 M in pool supported PTF costs associated with the construction of a ***new control house at the 115 kV Eddy Substation*** in Hillsborough County, New Hampshire; this project will be placed into service in December 2021. This project was undertaken to ensure that the Substation's transmission and distribution protection and control systems must be housed in a secure building that remains under Eversource access and control following divestiture of certain assets. This project includes: 1) expansion of the substation yard and the associated fencing, lighting and ground grid to accommodate the new control enclosure; 2) installation of new conduit and cable trench throughout the entire yard for the new and existing equipment; 3) installation of new protection and control systems.

The RC recommended ISONE approval of Eversource Energy's TCA application for $6.081 M in pool supported PTF costs associated with ***upgrades to the protection and control systems at the Amherst Substation*** in Hillsborough County, New Hampshire; this project will be placed into service in November 2022. This project will replace obsolete electromechanical relays and eliminate the existing carrier powerline systems to improve reliability.

The RC recommended ISONE approval Eversource Energy's TCA application for $10.322 M in pool supported PTF costs associated with the ***115 kV Branford 11J A3 Substation Bus Replacement Project***; this project will be placed into service in December 2021. This project will replace (i) the existing duct bank self-contained fluid filled (SCFF) cable system with a solid dielectric cable system and (ii) two existing bus support structures at the Branford Substation located in New Haven County, Connecticut. Eversource reported that frequent leaking of the existing SCFF system for the past 16 years has raised reliability concerns and a potential environmental risk to the nearby waterway; the manufacturers of this equipment are no longer in business to provide support.

The RC recommended ISONE approval of Eversource Energy's TCA application for $69.893 M in pool supported PTF costs associated with the ***Bourne Substation Rebuild Project***, which will be placed into service in March 2023. This project will replace the existing Bourne Switching Station in Bourne, Massachusetts with a new 4 bay, 8 terminal 115 kV switching station. The existing station cannot accommodate expansion needed to support installation of the new 115 kV Bourne-West Barnstable line that was identified in the SEMA/RI 2026 Solution Study as a solution alternative for the Cape area; this project will also address all other identified deficiencies. The existing Station is the termination point for seven 115 kV transmission lines and is one of the main supply points to the Cape Cod, Plymouth and New Bedford areas in Eastern Massachusetts; five of these lines would be lost under N-1-1 contingency conditions. Additionally, all 115 kV disconnect switches are rusted, difficult to open, have failed repeatedly and require urgent replacement; two are currently inoperable. Further, performing work on the bus side of each transmission line would leave the entire Cape (~550 MW at high loads) on a single line. Finally, the station must be upgraded to meet NPCC design requirements for BPS stations.

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Generation and Transmission

The RC recommended ISONE approval of Eversource Energy's TCA application for $18.699 M in pool supported PTF costs associated with the ***replacement of the STATCOM at the Glenbrook Substation*** located in Stamford, Connecticut; this project was placed into service in April 2021. The existing STATCOM has many failing components due to its age and obsolescence; however, this equipment is becoming increasingly difficult to maintain and continued maintenance / refurbishment is not a viable option.

NEPOOL Counsel discussed the FERC's recent ***Supplemental Notice of Proposed Rulemaking (NOPR) on Transmission Incentives***. The Supplemental NOPR focuses on several issues pertaining to the incentives that are made available to transmission owners that participate in RTOs. FERC proposed an ROE incentive adder of 50 basis points for TOs that participate in an RTO. FERC also suggested that these incentives should only be available to TOs for the first 3 years after they join an RTO; currently, TOs are eligible for these incentives for as long as their facilities remain under RTO operational control. TOs that have received this incentive for more than 3 years would be required to file tariff revisions removing the incentive within 30 days of issuance of the final rule. This incentive would not be available to transmission assets previously owned by an RTO member that were transferred to a non-member which subsequently joins the RTO. Finally, FERC is requesting comment regarding whether a TO should be eligible to receive this incentive if it joins an RTO involuntarily (i.e., because it is required to do so under a state law). NEPOOL Counsel noted that there is some disagreement among the FERC commissioners regarding whether the proposed limit on the duration of the incentive would discourage a TO from maintaining its membership in the RTO. During the discussion, it was noted that (i) the proposed incentive may not be sufficient to induce the Northern Maine Independent System Administrator (NMISA) to join the ISONE RTO and (ii) it is unlikely that any other entities in New England would be potentially eligible for this incentive. The NEPOOL organization has not typically commented on transmission rate rulemaking proceedings and will take no position on this NOPR. Initial comments are due May 26; reply comments are due June 10.

Finance and Miscellaneous Matters

The PC approved ISONE's proposed Tariff revisions that ***remove Market Rule 1 Appendix B ("Imposition of Sanctions by ISONE")*** and clarify that a resource will be subject to a referral to FERC for any sanctionable behavior. Appendix B details the process by which ISONE issues formal warnings and imposes penalties on Market Participants for any of the sanctionable behaviors that are defined within the Appendix. However, because the FPA, FERC regulations and MR1 Appendix A ("Market Monitoring, Reporting and Market Power Mitigation") all take precedence over Appendix B, ISONE has not utilized the Appendix B procedures.

The TC recommended PC approval of the New England Participating Transmission Owners' (PTO) proposed Tariff revisions that address the ***treatment of behind-the-meter (BTM) generation in the allocation of charges for Regional Network Service*** (RNS). The proposed changes: 1) eliminate the currently undefined term "behind-the-meter" from the definition of RNL; and 2) revise the definition of Monthly RNL to exclude load that is offset either (i) by a resource that is not a wholesale Generator Asset or (ii) by any portion of the output of a wholesale Generator Asset that is located behind the retail customer meter. This proposal responds to concerns raised by the IMM regarding the potential for inappropriate shifting of transmission costs between loads because different distribution utilities were not applying a consistent treatment of BTM generation in their Regional Network Load (RNL) calculations. These inconsistencies arise in part because there is no clear Tariff definition for the term "behind-the-meter." The PTOs argued that eliminating the undefined term "behind-the-meter" from the RNL Tariff language avoids the need for NEPOOL to undertake a potentially lengthy stakeholder process to approve a new Tariff-defined term. At the same time, the revised proposal would provide utilities with clear guidelines for when to include the output of BTM facilities in calculation of Monthly RNL, which is the allocator that is used to calculate RNS charges. The TOs also noted that their proposal aligns the load values used in the Monthly RNL calculation with those that are used (i) to allocate FCM costs, (ii) in Energy market settlements and (ii) in the transmission system planning models. Finally, the TOs argued that their proposed Tariff changes will not conflict with ISONE's Order 2222 compliance requirements, will have minimal impact on transmission costs, and will not impose any additional metering requirements on existing resources. The TOs will request stakeholder action on their proposal changes in April (TC), May (MC) and June (PC); the targeted effective date is August 2021.