Appendix A2. MARS Modeling

This section describes the scope and procedures used by DEEP/LAI to perform capacity resource adequacy modeling performed with the assistance of ISO-NE in running the GE Multi-Area Reliability Simulation (MARS) model. MARS is the industry standard simulation tool, often used by regional transmission organizations, including ISO-NE. MARS simulation output reports loss-of-load expectation (LOLE) results. The scope of MARS modeling was limited to an assessment of the preliminary results of four scenarios over the 2021-2040 IRP study period. The scenarios were Base Reference, Base Balanced Blend, Electrification Reference, and Electrification Balanced Blend.

To provide data inputs to MARS, two Aurora models were run in sequence. The first run solved for the long-term, least-cost schedule of annual new resource builds and existing resource retirements that meet resource development potential constraints and both annual reserve capacity and emissions constraints. The second run used the more detailed operational Aurora model mode to simulate hourly charging and generation of battery storage units more accurately. These results were used to derate the capacity contribution of battery units for the expected energy content available at the start of a period with high available resource capability requirements.[1]

ISO-NE regularly uses MARS to conduct its Installed Capacity Requirement (ICR) analysis for the Forward Capacity Auction (FCA) and for various economic studies. ISO-NE uses the typical LOLE threshold of a one-day-in-ten-years ("1-in-10") loss of load as its measure of resource adequacy. DEEP/LAI provided ISO-NE with assumptions to set the scope and details of the MARS modeling. DEEP appreciates the work of ISO-NE in supporting DEEP's request.[2] For each of four scenarios tested, MARS was run with several thousand Monte Carlo randomized simulations of generation unit and transmission outage contingencies and seven probabilistic load levels for all hours of the 20-year study period. These simulations produced the LOLE measure of resource capacity adequacy.

The MARS resource adequacy analysis is limited to consideration of capacity capability ratings, random forced outages, and probabilistic discrete loads. The MARS model does not include chronological commitment decisions, minimum up and down times, ramp rates, day-ahead forecast uncertainty, and other operational constraints that may result in lack of resource adequacy. Those chronological operational resource adequacy issues are addressed in the Aurora chronological hourly simulation modeling. High penetration of wind and solar energy, especially PV solar, and high penetration of electric vehicles will both tend to shift peak hours of net load over time and increase the need for active load management and flexible, dispatchable generation resources. Aurora was used to simulate the ability to meet load during these operational stress conditions.

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[1] Operating reserve capacity constraints were excluded from the resource capacity plan runs because Aurora would take too long to solve. A third Aurora run for each scenario was later done for the purpose of including ancillary service requirements and other operational details to provide more detailed production cost and emissions results.

[2] While ISO-NE provided data for this analysis, all assumptions and modeling results are attributable to DEEP/LAI.

1 Modeling Procedures and Data Inputs

The purpose of the MARS modeling runs is to measure resource adequacy. DEEP/LAI specified MARS modeling procedures and provided a partial dataset for each of the four scenarios for variables and parameters that differ from those that ISO-NE has in its MARS database. At DEEP/LAI's request, ISO-NE used its database and modeling assumptions for the remaining inputs, though all assumptions and modeling results should be attributed to DEEP/LAI. The high-level division of data sources and assumptions for each input variable category is summarized in Table 1. ISO-NE and LAI MARS Data Inputs and Assumptions. This section highlights key differences in modeling approach taken by DEEP/LAI in relation to how ISO-NE normally performs MARS studies for its own purposes.

The Aurora model used ISO-NE's current installed capacity reserve margin (RM) factor net of Hydro-Quebec Interconnection Capability Credits (HQICCs) for the 2023/24 FCA year of 14.2% in its economic optimization of annual retirement and resource addition decisions.[3] The reserve margin needed to avoid excessive LOLE will likely increase over time due to the penetration of more VERs and electrification, which increase weather-based fluctuations in generation and load. Hence, the LOLE results of trial MARS runs were used to make certain manual adjustments in the resource portfolios with the goal of bringing years with excess LOLE below the standard reliability threshold of 0.1 day/year. Adjustments were limited to extending resource retirement dates and adding more battery resources in the most-constrained RSP subareas.

[3] Energy efficiency (EE) contributions were netted out of both qualified capacity and peak demand, as Aurora inputs netted EE against demand in the peak calculation.

Table 1. ISO-NE and LAI MARS Data Inputs and Assumptions

Variables	Data Sources and Assumptions
Resources	
Non-Intermittent Generating Resources	FCA 14 Existing Qualified Capacity values including outage parameters (EFORd, forced outages transition, maintenance weeks, and nuclear refueling scheduled outages)
Intermittent Generating Resources	FCA 14 Existing Qualified Capacity values including outage parameters (EFORd, forced outages transition, maintenance weeks). Exclude PV, wind, and battery resources.
Active Demand Capacity Resources	FCA 14 Existing Qualified Capacity values including outage parameters (EFORd, forced outages transition, and maintenance weeks)
Passive Demand Resources	FCA 14 Existing Qualified Capacity values including outage parameters (EFORd, forced outages transition, maintenance weeks). Exclude EE resources.
Import Capacity Resources	FCA 13 Cleared Import Capacity Resources with the 2019 (FCA 14) EFORd and maintenance weeks values
Tie Benefits and OP 4 Load Relief	
Tie Benefits	FCA 13 Tie Benefits including the FCA 13 EFORd and maintenance weeks values
Voltage Reduction	FCA 14 Voltage Reduction benefit (1% of demand)
Minimum Operating Reserves	700 MW
Hourly Data	
Land Based Wind	LAI data aggregated by RSP subarea
Off Shore Wind	LAI data
EE	LAI data aggregated by RSP subarea
Utility PV	LAI data aggregated by RSP subarea
BTM PV	LAI data aggregated by RSP subarea
Load (gross load + EV + ASHP)	LAI data aggregated by RSP subarea
Non-hourly Data	
Battery resources	LAI data aggregated by RSP subarea, season, and duration (hours) at full output
Wind, solar, and ETU grid resources	LAI data for capacity ratings, assumed HQ Phase II forced outage parameters and maintenance weeks for ETUs
Unit retirements and additions	LAI data
Uncertainties	
BTM PV	+/− 3 day sampling window
UPV	+/− 3 day sampling window
LBW, OSW	+/− 15 day sampling window
Load	LAI data for 7 probabilistic load levels
Transmission Interface limits	
Interarea and multiarea interface limits	ISO transfer capability assumptions for 2021 to 2029 with updates from February 20, 2020 PAC meeting. Increase the Surowiec South transfer limit to 2500 MW effective in 2023. Extend 2029 internal transfer limits through 2040.

1.1 Distinct MARS Modeling Procedures and Data Inputs

Due to the 20-year IRP study horizon, significant penetration of VERs, and the high penetration of EV and ASHP loads in Electrification, DEEP/LAI configured the MARS analysis to differ from ISO-NE's usual study framework in several respects. To simulate LOLE more realistically in a future system with significant shares of wind, PV, and battery resources in the regional mix, procedures that derate the generation capabilities more heavily than ISO-NE's were applied, based on normal weather fluctuations.[4] Also, ISO-NE had not modeled EV charging or ASHP loads for its CELT 10-year load forecasts by the start of this project in late 2019, and had not specified an approach for inclusion of weather-based electrification load distribution for its 2020 CELT. ISO-NE instead used deterministic EV and ASHP load projections. Moreover, several differences in the modeling framework were specified by DEEP/LAI to account for weather-based uncertainties affecting both electrification load and VERs.

Specific differences in procedures include four key elements. DEEP/LAI's modeling approach and reasons for each procedural difference are described in the following subsections. Overall, these alternative approaches result in more realistic and conservative estimates of the LOLE impacts of scenarios that include substantial contributions of wind and solar PV resources, batteries, and electrification.

1.1.1 RSP subarea transmission transfer limits

ISO-NE's multi-area MARS model used for economic studies was selected instead of the ISO's single-area MARS model used for its annual ICR studies. Given high VER entry and new Canadian HVDC ties over the IRP study period, the reason for selecting the multi-area configuration is to account for certain subareas of New England that may become a transmission bottleneck. One example is that additions of land-based wind (LBW) are confined to Maine, which has limited transmission to load centers to the south. Another example is that offshore wind (OSW) with interconnection points in Southeast Massachusetts (SEMA) and Rhode Island may trigger the SEMA/RI export limit. A final example is that the Boston RSP subarea and Southeast New England (SENE) capacity zone have import limits.[5] Although the Aurora capacity expansion model uses the same set of subarea transfer limits, its resource addition and retirement decisions were based on median (normal) loads, deterministic summer and winter derates of capacity-constrained resources, and less weather-based fluctuation of VER output than modeled with probabilistic simulation of load, forced outages, and VER output in MARS.

DEEP/LAI requested that ISO-NE use the most recent set of annual internal transmission system transfer limits, which include an update of limits for two transmission interfaces (Boston and SENE) for the projected years through 2029, and to keep the 2029 values constant in later study

[4] For the GE Energy Consulting, *New England Wind Integration Study* (NEWIS), 2016, for ISO-NE, MARS was run for three years (2004-2006) of hourly wind and load data.

[5] The SENE capacity zone is a collection of the Boston, SEMA, and RI RSP subareas.

years. Details were provided in a presentation at the February 20, 2020 Planning Advisory Committee meeting.[6] LAI used the same transfer limits in Aurora.

1.1.2 Random sampling of grid solar PV and wind resource output

ISO-NE's procedure for simulating VERs in MARS has been to use the seasonal claimed capability (SCC) of solar PV and wind resources that participate in the Forward Capacity Market (FCM). SCC values are calculated according to the procedure in Market Rule 1. For BTM PV resources, ISO-NE uses random sampling of a day's hourly generation within a seven-day centered window because they do not participate in the FCM so they do not have SCC values.

Using the Market Rule 1 procedure in MARS for the ISO's annual ICR study is less appropriate for this long-term IRP study. Rapid growth in solar PV and wind resources will increasingly put more strain on the region's resources whenever weather conditions result in widespread low energy generation from aggregate solar and/or wind resources. The Market Rule 1 procedure measures capability as the average of the previous five years median net output during Summer and Winter Intermittent Reliability Hours.[7] With spatially correlated weather (windspeed, cloud cover, etc.) conditions across New England, aggregate solar PV output and wind output will often be less than the sum of median seasonal net outputs of individual resources of each type. Resource adequacy, as measured by the LOLE metric, should be based on the probability distribution of energy generation by VERs, not merely by their average output during certain hours. For example, the results of a study by DNV GL for ISO-NE found that for the top 1% of summer gross load days over seven years (2012-2018), the minimum simulated LBW and OSW capacity factors simulated for sites across New England are 5.23% and 1.47%, respectively.[8] These values are consistent with the distribution of output from the NREL WIND Toolkit database that LAI used to develop wind energy profiles for this analysis.

A second reason for not adopting the SCC method is that with the growth of solar PV capacity, summer peak hours for load minus PV generation will shift towards evening hours. The SCC method does not account for a shift in the five peak hours for other resources needed to follow load net of VER generation in future years.

DEEP/LAI's approach was to specify that all existing and new VERs be modeled with the same type of random sampling method that ISO-NE now applies to BTM PV resources. DEEP/LAI requested that grid-connected (utility-scale) solar PV (UPV) resources also be sampled with random draws of a day within a seven-day centered moving window. For LBW and OSW resources, DEEP/LAI specified random draws of a day within a 31-day centered moving window.

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[6] The materials sourced from the February 20, 2020 PAC meeting were CEII but the same internal transfer limits were presented in March 18, 2020 PAC meeting: https://www.iso-ne.com/static-assets/documents/2020/03/a10-fca-15-zonal-dev-march-2020-pac.pdf

[7] Summer Intermittent Reliability Hours include all hours ending 1400 through 1800 in June through September. Winter Intermittent Reliability Hours include all hours ending 1800 and 1900 in October through May. In addition, for each season all hours in which there was a Capacity Scarcity Condition system-wide or for resources in an import-constrained Capacity Zone are included.

[8] Steven Judd, ISO-NE, *Wind and Power Time Series Modeling of ISO-NE Wind Plants*, February 20, 2020 presentation to the Planning Advisory Committee, slides 19-20. Link: https://www.iso-ne.com/static-assets/documents/2020/02/a7a_wind_power_time_series_isone.pdf

The reason for allowing a larger window for sampling of wind generation is that wind speeds are similar during all hours of a day and there is less dependency on the annual solar cycle. In contrast, solar energy potential on clear days has a continuously changing annual pattern of the length of the daylight period and the sun's angle, both of which affect potential solar energy. Use of the 31-day window has similar sampling size to wind energy studies that summarize output profiles in month by hour tables but has the benefit of using weather conditions equally before and after the simulated day. A comparison test that ISO-NE ran using random daily sampling within a calendar month had similar LOLE results.

To account for spatial correlations, DEEP/LAI aggregated VERs' potential energy generation by RSP subarea in the hourly capability data inputs to MARS. Spatial correlations among the individual solar PV and wind resources modeled separately in Aurora at the many locations selected from the NREL wind and solar energy databases are implicitly accounted for by using the same weather year for their location-specific hourly output profiles. The concurrent weather conditions simulated in the detailed geographic grid of NREL's meteorological database ensure that spatial weather patterns are accurately represented.

Finally, Aurora curtails wind and solar energy capability when needed due to transmission constraints. Hence, DEEP/LAI provided the aggregate UPV, LBW, and OSW hourly capability data by RSP subarea as the MARS data input, rather than Aurora's generation output. BTM PV generation was modeled in Aurora as part of net demand, and therefore without curtailment.

1.1.3 Battery storage resources derated for average energy availability

ISO-NE models storage resources as seasonal generation capability-constrained resources in MARS.

DEEP/LAI specified that ISO-NE's SCC method be applied to existing hydro pumped storage resources, which are capable of full generation capability output for over five hours for Bear Swamp and for eight hours at Northfield Mountain. There is less resource adequacy risk of running out of stored energy for storage resources capable of generating for that long because ISO-NE's summer peak period is five hours. However, today's battery storage technologies are generally economic when the battery component is sized to provide full generation for shorter durations. At the outset of this study, LAI modeled 2, 4, and 8-hour duration battery storage resource options. Few 8-hour units were selected as economic in Aurora's resource capacity optimization model in initial runs. To obtain faster results the final Aurora runs to provide the data inputs for MARS only included 2 and 4-hour batteries.

For battery storage resources, DEEP/LAI used a method that derates generation capability. The specific reasons for derating batteries are twofold. First, four hours may be insufficient to span a period when the system needs to call on all available resources. Second, not all battery storage units will be fully charged when called, limiting the time that they can operate at full generation. This is because batteries are expected to be used primarily for scheduled and real-time charging and dispatch to reduce system demand-supply imbalances, which will increase with growing penetration of VER resources.

Two alternative derating methods were considered for developing the battery capability inputs to MARS. One approach would be to represent battery charging and generation as a deterministic hourly profile based on Aurora dispatch results for its single simulation iteration. This hourly (positive and negative) capability schedule would be modeled in MARS the same way as for the Aurora modeling of hourly output capabilities of wind and solar PV resources. However, this approach would not allow the resource adequacy contribution of batteries to react to forced outage contingencies or higher than expected load net of VER generation. The battery load modification profile would not be able to respond to the probabilistic sampling of different load levels or the random sampling of VER output from a day within its time window.

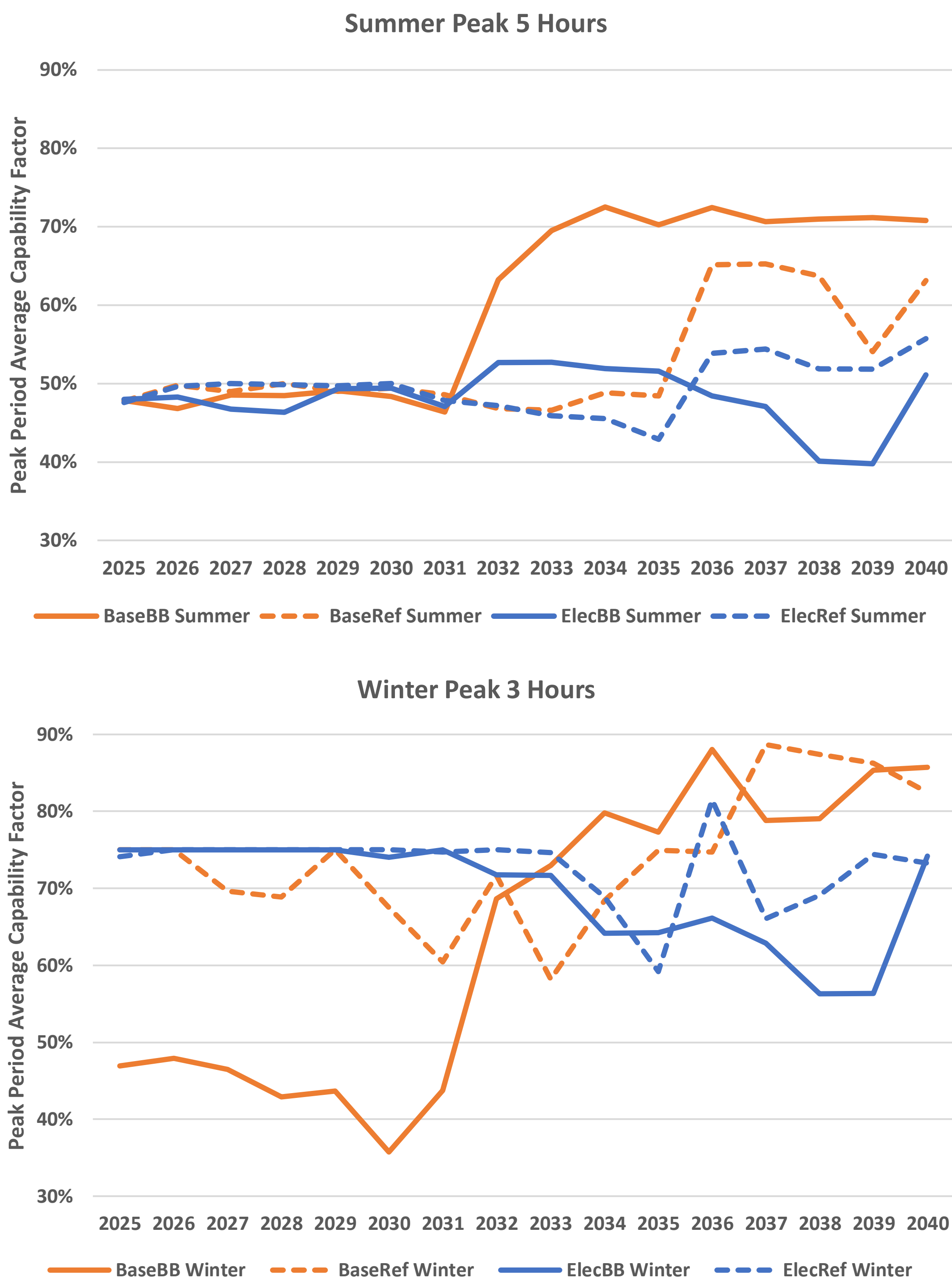
Instead, the procedure specified for modeling battery resources in MARS was to derate its seasonal generation capacity to account for the fact that battery storage energy content will not always be full at the start of a resource adequacy need spell of one to several hours. Due to unknowable forced outage events and weather forecast errors that affect both load and VER generation, typically less than the maximum energy storage content will be scheduled to be available during periods that have unpredictably tight load-resource balances.

DEEP/LAI's method is to calculate the average summer and winter energy content of battery storage units at the start of the daily peak load period as the basis for annual capability ratings for total battery resources in each RSP subarea as the MARS input. The available stored energy in batteries was assessed at the beginning of a dynamic five-hour daily peak average load period during summer months and a dynamic three-hour daily peak period during winter months of each year and RSP subarea. While the length of the summer peak period is the same as for ISO-NE's method for calculating the average capacity value of wind and solar PV resources, ISO-NE uses two hours for winter. The reason for using a three-hour peak period in winter is that as solar PV capacity penetration grows, the winter peak period for load minus VER output becomes wider and flatter.

To obtain more detailed and accurate economic dispatch of battery performance, LAI ran each of the capacity plans in Aurora's operational mode and calculated the average energy content of each battery resource at the start of the daily peak period in July and January. First, the Aurora hourly results were filtered to include only weekdays and the top net demand hours each day were tagged. Then the top ten net demand days in each season's peak month were tagged. For this subset of peak hours on peak days, battery average energy content values were converted into seasonal average derated generation capability values for MARS data input by storage duration and RSP subarea. Figure 1 **Error! Reference source not found.**shows the weighted-average availability factors used to derate battery resource capacities in the resource seasonal capability data in the four scenarios.

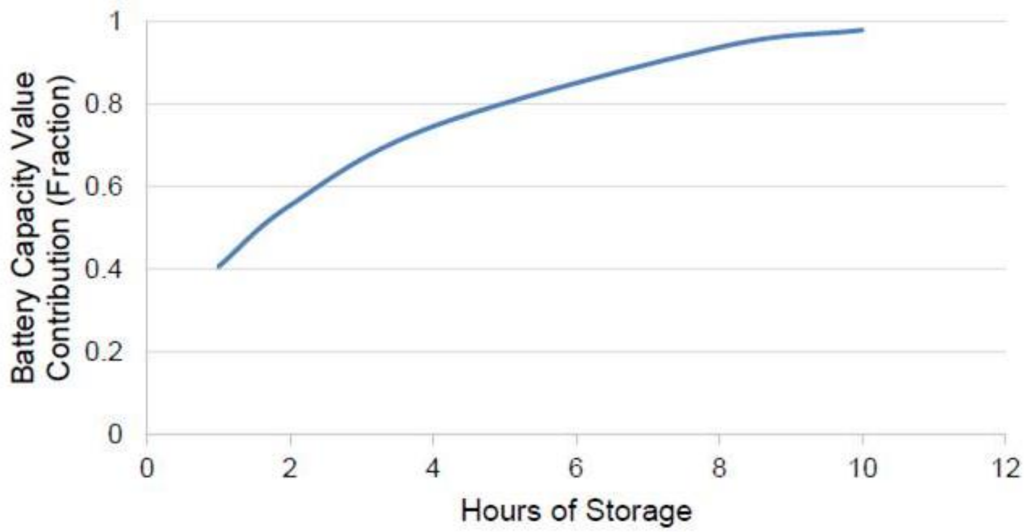
In large part, the winter derating values are higher than for summer because the winter peak period is only three hours long, versus five hours in summer. The maximum values that would be attainable if all batteries were fully charged at the start of the daily peak period is 80% in summer for the four-hour battery type and 40% for the two-hour type because the peak period is longer than their full generation duration capability.

Figure 1. ISO-NE Battery Capacity-weighted Average Capability Factors by Scenario



The more critical summer season derating factor values are generally close to those found by NREL in a study of high wind and solar PV penetration in the West, shown in Figure 2. LAI had applied those derating values in the Aurora capacity planning model to guide its selection of the optimal mix of generation and storage resources. The capacity value curve values of 0.553, 0.747, and 0.935 for 2, 4, and 8-hour storage duration batteries, respectively, were used in Aurora to calculate the firm capability of battery resource additions towards meeting annual planning capacity requirements. Some differences are expected between the NREL values and those from our Aurora simulation due to differences in regional resource mixes.

Figure 2. Battery Capacity Value Function of Battery Duration



Source: NREL 2019, *ReEDS Model Documentation: Version 2018*, Figure 32, p. 66.

1.1.4 Electrification included in load distribution parameters

ISO-NE uses historical weather data in regression models to estimate the response of traditional load to weather deviations from normal, and then simulates the distribution of future load based on historic weather data. From the simulated distribution, a set of seven seasonal (summer, winter) load probabilistic scaling factors are calculated. The MARS simulation calculates seven gross load levels as the product of the forecast of normal hourly gross load times the load distribution parameter. Each load case is used in proportion to its probability weight.

ISO-NE uses its LT load forecasting model to project expected loads over the 10-year period documented in the annual CELT Report. For the first time, the 2020 CELT Report includes separate EV charging and ASHP space heating load components. However, unlike the rest of the gross load forecast modeled in MARS at seven probabilistic levels, ISO-NE's 2020 load forecast did not analyze these electrification load components' weather-based uncertainty.

The current load forecast modeling methods and data available from ISO-NE have certain limitations in the context of a longer-term IRP study horizon, especially in the context of the Electrification Load case. Good quality gross load distribution parameter values are needed for probabilistic load simulation for LOLE modeling because most of the loss-of-load events occur in the extreme high load tail of the distribution. Four specific types of limitations were:

- ISO-NE's forecast is based on 2002 hourly load shape for ICR studies and 2015 for economic studies, while the weather year selected for this study is 2011 and the needed NREL wind and solar hourly profiles used by LAI are for 2007-2012.
- ISO-NE has not included separate projections of ASHP or EV loads in past studies, so it does not have distribution parameter values for gross load inclusive of those now rapidly growing, weather-sensitive demand components.
- ISO-NE's distribution parameter values, which vary by year as forecasted load shape evolves over a 10-year horizon, are not well-suited for extrapolation over the last 11 years of the IRP study period, when the load uncertainty distribution will vary more as a result of electrification.
- ISO-NE's distribution parameter values are close to those for the DEEP/LAIs load projections over the first nine years of the study horizon. However, the much larger portion of weather-dependent summer and winter loads in the Electrification case means that load uncertainty distribution parameters will likely vary substantially from ISO-NE's values.

To address these limitations, DEEP/LAI provided load distribution parameter data for MARS. Three sets of parameter values were provided, varying by electrification assumptions of the scenarios. LAI first developed and applied a method that simulated EV and ASHP load functions of temperature to estimate the probability distributions of those new end uses. Then the resulting electrification load distributions were added to the probability distribution of traditional load based on statistical regression modeling of actual load and weather data. Both EV load and ASHP load are temperature sensitive. Hence, with the high penetration of these forms of electrification, it is important to consider temperature deviations from normal, which enlarges the weather uncertainty of traditional load for resistance heating and air conditioning.

DEEP/LAI generally followed the procedures documented in ISO-NE's long-term forecasting method presentation.[9] Only non-holiday weekdays are included, the same as for ISO-NE.[10] Due to limited data availability, DEEP/LAI used 20 years of historical loads instead of the ISO's selection of a 30-year history. DEEP/LAI used a standard numerical formula like the one used by ISO-NE for calculating skew normal load distribution parameters for the same seven probability intervals as used by ISO-NE in MARS. The "new gross" (for lack of a standard term) load, where NewGross = Gross + ASHP + EV, has greater dispersion with more skew, and "Gross" is traditional gross load.

DEEP/LAI adapted a typical or average EV charging profile to be temperature-dependent based on daily average temperature by location in the 2011 base weather year used for the study. For the Electrification load case, EV charging demand incremental to the fixed profile EV charging demand in the Base load case was modeled in Aurora as a constrained, dispatchable demand resource. The result is that the EV hourly profile in the Electrification load case has a different shape than in the Base load case.

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[9] Jon Black and Victoria Rojo, ISO-NE, *Long-Term Forecast Methodology Overview*, September 27, 2019 presentation to the Load Forecast Committee meeting, slides 42-48. Link: https://www.iso-ne.com/static-assets/documents/2019/09/p1_load_forecast_methodology.pdf

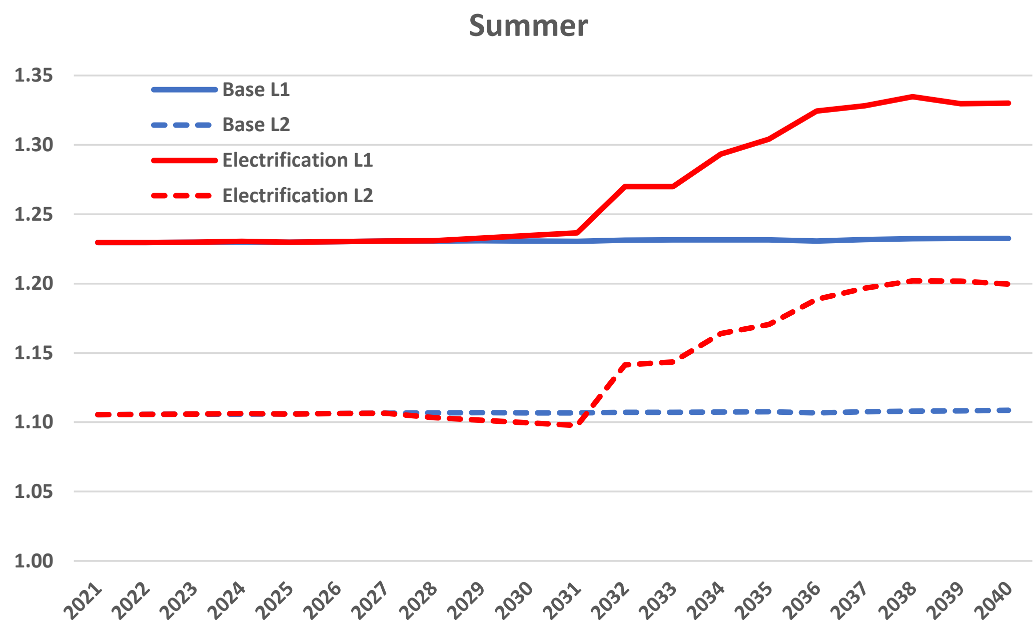
[10] The ISO's report of seasonal peak loads since 1980 has no occurrences of weekends for summer or winter.

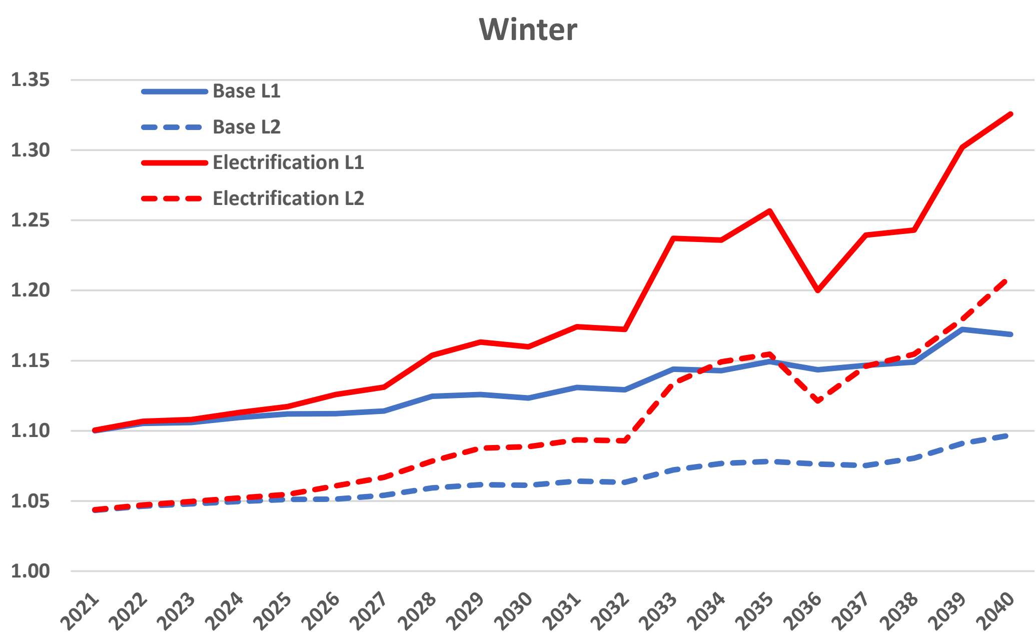
DEEP/LAI used the effective temperature function of dry bulb temperature and wind speed provided by ISO-NE to create an effective HDD (EHDD) index to capture the wind chill effect.[11] In our study winter load will become larger so it will be more important to include the wind chill effect. The heating season, with positive HDD values, is October through April.

Figure 3 illustrates the parameters for the top two load levels for the summer and winter seasons. The L1 values represent load in the highest 0.62% of the probability distribution, and the L2 values are for the next 6.06% bin of the distribution. For the more important summer season, the Electrification load distribution parameters begin to rise steadily from 2031 because of growing EV charging demand. For the winter season, the Base load distribution L1 and L2 parameter values rise steadily over the entire study period due to growing ASHP load. The Electrification L1 and L2 parameter values increase faster over the entire study period due to its higher penetration of ASHP load.

[11] Jon Black and Victoria Rojo, September 27, 2019 *op. cit*., slide 33.

Figure 3. Level 1 and 2 Gross Peak Load Distribution Parameters





1.2 ISO-NE Standard MARS Modeling Procedures

1.2.1 Base Year for Load and VER Profiles

In order to follow the IRP timeframe and adhere more closely with how ISO-NE runs MARS with a single base weather year (2002), LAI chose to provide 2011 weather year hourly profile data for load and for wind and solar PV capability, rather than multiple years (2007-2012) of profile values.

1.2.2 Resource Seasonal Capability Ratings

For each scenario, DEEP/LAI provided a list of projected resource retirements by date for ISO-NE to mark in its database. For resource additions, DEEP/LAI requested that ISO-NE first remove all existing solar, wind, and battery resources from its database. For grid-scale solar PV and LBW resources, LAI provided hourly schedules of aggregate generation capability by RSP subarea. For OSW resources, LAI provided hourly schedules of generation capability of named projects injecting into specified subareas. For battery resources, LAI provided the schedule of annual summer and winter season capability ratings for aggregated battery resources in each RSP subarea. Finally, for HVDC hydro import projects, LAI provided the start date and summer and winter season capability ratings. ISO-NE used its data to specify the frequency and length of forced outages of conventional existing resources. At DEEP/LAI's request, ISO-NE applied the same forced and maintenance outage parameter values for the new HVDC tie hydro projects as experienced by the HQ Phase II facility. DEEP/LAI did not project any growth for renewables other than wind, solar and imports of hydro.

1.2.3 External Interfaces

LAI accepted that external interfaces would provide Tie Benefits consistent with ISO-NE's FCA 13 Tie Benefits, which include the FCA 13 EFORd and maintenance weeks data. Any new HQ HVDC tie lines were modeled like a generator located inside the ISO-NE region.

1.2.4 Energy Efficiency

LAI followed ISO-NE's practice of not modeling uncertainty for EE resources because EE participates in the FCM and has SCC values. However, LAI provided hourly EE capabilities for each load case, instead of the seasonal capability values from FCAs that ISO-NE uses for its MARS studies. Non-EE PDR was held constant over the forecast period. Only a small amount of PDR clears in the FCA.

1.2.5 Operating Reserve Requirements

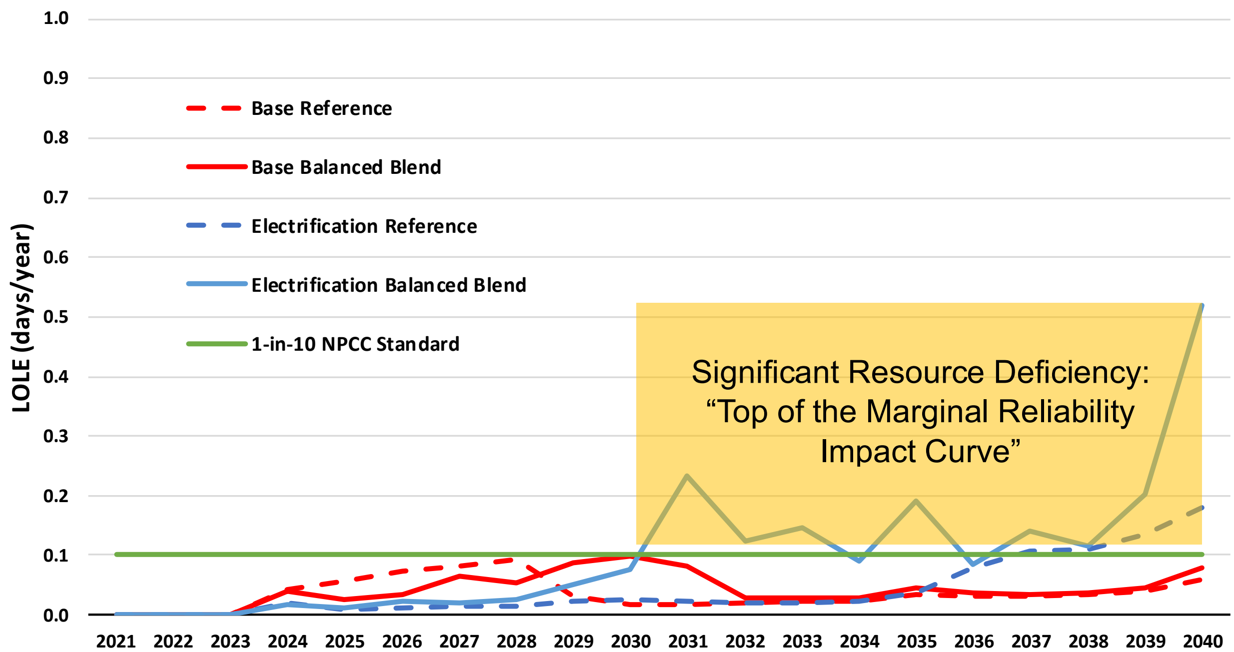
LAI specified that the present 700 MW minimum operating reserves requirement modeled in MARS should be used for each scenario. This requirement is the bare minimum before load-shedding actions. It is substantially less than the hourly-varying scheduled operating reserves requirements, not modeled in MARS.

2 Loss-of-Load Expectation Results

2.1 MARS LOLE Results

The final MARS runs, based on Aurora's automated capacity expansion plan results, with a few manual resource adjustments in import-constrained areas, resulted in LOLE values below the 0.1 day/year standard for all months and subareas in the two Base load scenarios, and in all but a few final years for the two Electrification load scenarios. These results are shown in Figure 4. The Base load scenarios both had maximum annual LOLE close to the 2029 retirement of Millstone, with 0.094 days/year in 2028 in the Base Reference scenario, and 0.098 days/year in 2030 in the Base Balanced Blend scenario. In contrast, the maximum system annual LOLE values in the Electrification scenarios were both in the final year, 2040, with 0.18 days/year in the Electrification Reference case and 0.519 days/year in the Electrification Balanced Blend scenario.

Figure 4. ISO-NE System Annual LOLE by Scenario



The Electrification Reference scenario had only slight LOLE target exceedance in 2037 and 2038, with 0.110 d/y or less. Small resource capacity additions or undone retirements would eliminate the larger resource capability deficits in 2039 and 2040. The Electrification Balanced Blend had its second highest LOLE, 0.233 d/y, in the first deficit year, 2031. Additional new resource capacity or undone retirements in 2031 would also resolve the smaller deficits until 2040, when more new resources would be needed.

Given the substantially more conservative methods for MARS modeling described in the previous section, there was little concern about apparent violations of the LOLE standard in the two Electrification scenarios. Refinements of these methods for developing data inputs and for operation of MARS may result in lower LOLE results without further increases in nameplate resource capacities.

2.2 Planning Reserve Margin Requirement Adjustments for Aurora Simulations

Based on the LOLE results for the multiple trials of these four scenarios, DEEP/LAI developed approximate planning reserve margin (PRM) schedules for the Base and Electrification load cases. Specifically, the adjustments were based on the resource capacity by technology and location inputs to MARS and its LOLE results by RSP subarea and year for the two Balanced Blend scenarios, which have the same gross loads and probabilistic load distribution in the remaining scenarios to be modeled in Aurora. For the Electrification Balanced Blend scenario, DEEP/LAI also drew on the results of the (third) MARS run prior to the (fourth) final run, which included manual additions of battery capacity and deferral of some retirements, which reduced LOLE in the final run in the years after the first capacity adjustment.

For the Base Reference and Base Balanced Blend scenarios, DEEP/LAI cured LOLE issues during its MARS modeling sessions workflow with ISO-NE. After coming close to meeting the LOLE criterion in the revised MARS simulations, LAI proposed targeted solutions for the Boston and SENE subregions with small changes to the Aurora capacity expansion solve. The Base Reference case was revised to include 1,000 MW of battery additions in the Boston subarea to meet resource adequacy. The Base Balanced Blend case was revised to defer several retirements to 2030, which preserved resource adequacy in SENE.[12] These changes were included in the LOLE calculations shown above in Figure 4. Subsequent Base Load scenarios should not require any increase to current 14.2% PRM factors to meet LOLE standards but must preserve generating capacity in the Boston and SENE subregions.

DEEP/LAI did not arrive at a capacity mix that met LOLE standards for the Electrification Reference or Balanced Blend scenarios despite several rounds of input revisions, which included more than 1,000 MW of incremental dispatchable capacity through battery storage and undone retirements. In order to estimate the overall capacity need, LAI utilized the extensive MARS input revisions and associated results to estimate the marginal impact of an incremental MW of dispatchable resource (either a deferred retirement or a battery addition) on the expected LOLE value at various points on the LOLE curve. The overall capacity need increased by more than 3,000 MW by 2040 in both Electrification scenarios relative to the initial assumptions made in LOLE modeling when accounting for discrete model revisions and incremental capacity estimated through marginal impact estimates. While this technique is a second-best approach to being able to test the remaining scenarios in MARS, the increases in the PRM factors shown in Figure 5 are expected to result in LOLE values that are reasonably close to the one-in-ten target value. There is somewhat less concern about excess LOLE in the Millstone Extension scenario as nuclear units generate at full available capability during system peak periods.

[12] Retirements could be deferred, rather than completely undone, as the HQ ETU injection point in SEMA to offset the loss of Millstone contributes to meeting resource adequacy. The ETU is placed in service in October 2029 and is available for the summer peak in 2030.

Figure 5. Adjusted PRM Factors, Electrification Scenarios