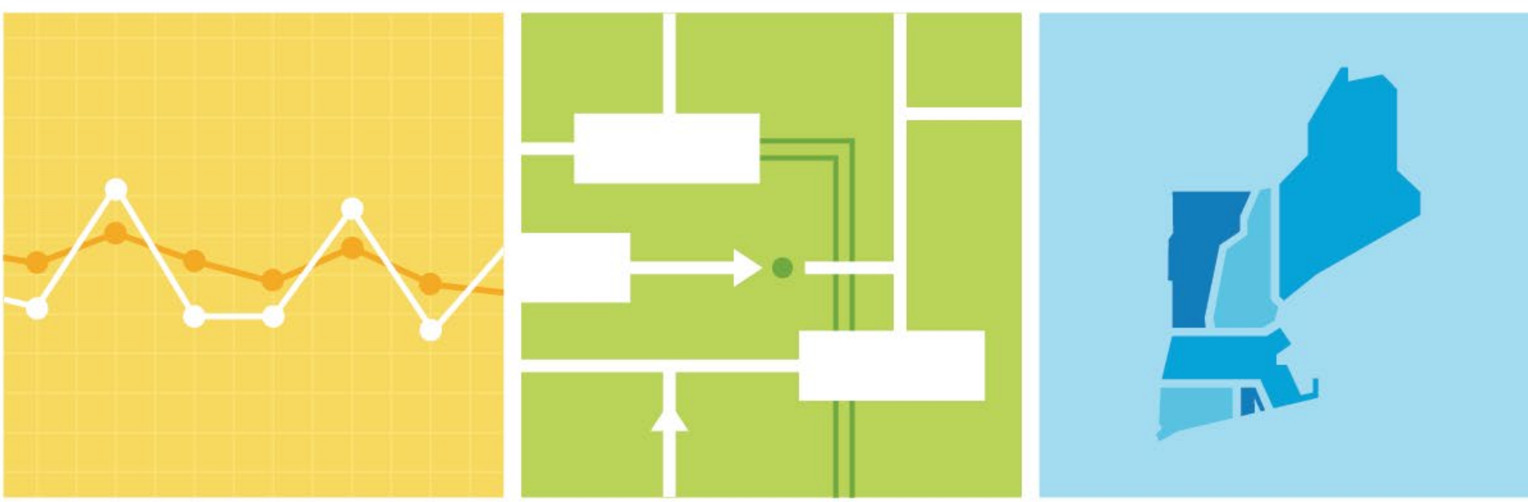
2021 Economic Study: Future Grid Reliability Study Phase 1

Appendix B: Ancillary Services Results

DECEMBER 30, 2022



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Section 1: Introduction and Background

1.1 Background

In recent years, lawmakers across the New England states have enacted ambitious legislation designed to dramatically reduce greenhouse gas emissions over the next several decades. Five of the six New England states have committed to reducing their carbon dioxide emissions by at least 80% in the coming years, and the quantity of wind and solar resources supplying electricity to our power grid is expected to grow exponentially in order to meet these goals. As electrification of heating and transportation rapidly accelerates, demand on the grid will also increase.

In order to assess and evaluate this transformed future grid, the "Transition to Future Grid" Initiative was proposed by NEPOOL at the March 2020 NEPOOL Participants Committee, with ISO New England directed to conduct the study. The study's objective was to assess and discuss the future state of the regional power system in light of current state energy and environmental policies. Beginning in April 2020 and culminating in March 2021, the joint Markets & Reliability Committees of NEPOOL met to discuss and define a scope of work for the initiative, now known as the **Future Grid Reliability Study,** or the FGRS.

As part of the FGRS, four Scenarios for a future grid, and a set of "sub" Scenarios, or alternatives, were used to represent various possible future grid configurations. These Scenarios will be explained in-depth in Section 2. ISO New England conducted **production cost (Appendix A)**, **Ancillary Services (this report, Appendix B)** and **resource adequacy (Appendix C)** analysis of these various Scenarios.

1.2 Study Objective

In the New England power system, the term *Ancillary Services* refers to products and functions that allow grid operators to maintain the balance of power supply and demand and respond to unplanned outages while maintaining a reliable grid. While the capacity and energy market exist to address bulk energy needs, Ancillary Services help fine-tune the energy balance and procure reserves for unexpected shortfalls. The quantities to manage this fine-tuning are typically small and are generally provided by a subset of available resources. For example, under the current system, several hundred MW of spinning reserves are able to serve peak load, which typically reaches 25 GW. Ancillary Services help address the uncertainty of forecasting and the variations of a real-time system. For example, an offline generator that can come online and produce power within ten minutes can participate in the reserves market as "ten-minute non-spinning reserves." Resources must be able to increase or decrease their power output to meet both large and small changes in demand. Grid operators must also keep generation in reserve for unexpected outages or disturbances to the grid. Though Ancillary Services are a small part of today's overall electricity market revenues and are currently often provided as part of the regular function of thermal resources, they are essential in maintaining electrical reliability, and the services they provide may increase in importance as system variability increases.

As part of its 2021 Economic Study request, NEPOOL asked ISO New England to identify if the resource mixes studied in the imagined future grid of 2040 would be able to provide necessary amounts of regulation, reserves, and ramping. The expected market behavior of potential resource mixes under current market rules was also of interest. This Ancillary Services analysis investigates the physical quantities of regulation, reserves and ramping that will be needed to keep the grid stable under different potential future resource mixes.

Section 2: Assumptions

The first half of this section details the main and alternative Scenarios of the FGRS and the assumptions that were common to each type of analysis. This is followed by a description of assumptions more specific to the Ancillary Services analyses.

2.1 Main Scenarios

The final set of FGRS Scenarios included 32 iterations, each evaluating a different set of assumptions. Though none of these Scenarios should be interpreted as a complete forecast of a future grid, trends and relationships between Scenarios can provide an idea of how different assumptions will affect the operation of a future grid.

These 32 iterations included four "main" Scenarios, shown in Table 2-1. Each main Scenario represented a different view of the future grid, with varied assumptions about generator retirements, wind and solar additions, new transmission lines, and other properties. These main Scenarios were numbered zero through three.

Table 2-1: Load and Resource Matrix for Scenarios studied in the FGRS

Resource	Scenario 1 (Peak, MW)	Scenario 1 (Energy, TWh)	Scenario 2 (Peak, MW)	Scenario 2 (Energy, TWh)	Scenario 3 (Peak, MW)	Scenario 3 (Energy, TWh)
Gross Summer Peak	33,707	172.6				
Gross Winter Peak	27,970					
Energy Efficiency	6,777	37.7	6,777	37.7	6,777	37.7
Transportation Electrification	1,817	7.3	3,578	17.9	9,956	40
Heating Electrification	5,214	9.6	2,991	5.4	22,250	38.9
Total Summer Peak [1]	28,060	151.3	30,316	158.2	35,711	213.8
Total Winter Peak [1]	25,767		26,971		43,816	
Total Minimum Load [1]	11,202		11,863		14,102	
BTM Solar [2]	7,681	10.3	11,899	15.6	12,671	16.9
Net Summer Peak [3]	26,555	141.1	28,317	142.7	33,162	196.9
Net Winter Peak [3]	25,767		26,971		43,814	
Net Minimum Load [2,4]	8,562		6,745		8,427	
Onshore Wind [5]	2,582	8.6	2,747	8.6	2,585	8
Offshore Wind [5]	8,029	32.7	8,029	32.4	16,662	69.8
Utility Scale Solar [5]	8,104	9.7	8,820	10.4	15,467	18.8
Battery Storage	2,000	-	3,940	-	600	-

[1] Total Peak load is the max coincident peak value for summer and winter after profiles are combined.
[2] Net Peak load is the total load after the BTM solar profile is added to the load profile.
[3] BTM PV is a resource assumption but added to this slide to show 'net' load profile effect.
[4] BTM PV is a curtailable resource, final Net Min Load could be higher.
[5] Energy values are all pre-curtailment.

2.1.1 Load

All Scenarios used the 2019 weather year as a base assumption. All but Scenario 3 adopted ISO New England's 2021 CELT Report, which contains projections of monthly peak loads through the year 2030. To model the year 2040, growth in monthly peak loads from the last two years of the CELT forecast was linearly extrapolated to the year 2040. Using 2019 as a base weather year, monthly peaks were scaled to the 50/50 monthly peaks[1] for 2040. The winter peak of January and the summer peak of August were scaled to the 80/20 peak loads[2] to reflect seasonal peaks. To provide a clean transition between months, a linear feathering method was applied to each hour between monthly peaks. This feathering scaled the hourly loads from monthly peak to monthly peak to prevent a potential sudden jump in load between the hours of one month and the hours of the next month.

Scenario 3 load was borrowed from the Massachusetts 2050 Deep Decarbonization Roadmap Study. This data originally used the 2012 weather year but was recast into the 2019 weather year for the FGRS.

2.1.2 Scenario 0 (Baseline Decarbonization)

Scenario 0 is also referred to as the reference case or **Baseline Decarbonization** case. It is a projected version of the current system in the year 2040, assuming current growth trends based on the 2021 CELT Report. Scenario 0 consisted of extensions of current ISO trends and forecasts for various resources, with generator retirements and additions through Forward Capacity Auction (FCA) 15 - the ISO's three-year-out capacity market. Scenario 0 included ~3.3 GW (note all values given are nameplate values) of offshore wind farms with state contracts at the end of 2020. The model also contained the contracted New England Clean Energy Connect (NECEC) tie-line. Scenario 0 did not include any additional heating or transport electrification beyond extrapolating current ISO electrification forecasts to 2040. The CELT heating electrification load in this Scenario represented 4.9% of the total load energy, while the CELT transportation electrification[3] load represented 6.8% of the total load energy. Other Scenarios included additional heating and transportation electrification load on top of the CELT load. Overall, Scenario 0 was the most similar to the current day ISO system, with the lowest penetrations of wind and solar, minimal retirement of generators, and CELT baseline adoption of heating and transport electrification.

2.1.3 Scenario 1 (Moderate Decarbonization)

Scenario 1 assumptions were derived from 2020's Economic Study: Interregional Storage's Capability to Facilitate the Effective Use of Clean Energy Resource requested by National Grid. That 2020 Economic Study built upon a 2019 Economic Study request by NESCOE. Scenario 1, also known as the **Moderate Decarbonization** case, modeled a moderate penetration of renewable energy, with moderate heating and transport electrification. Scenario 1 assumed the retirement of all generators that have announced a planned retirement, along with the retirement of all remaining coal units and 75% of the remaining oil units. To compensate for these retirements, Scenario 1 included 8 GW of offshore wind and 2 GW of BESS units. The Scenario increased the total solar nameplate capacity to 15.8 GW. Additional heating and transportation load was 9.6 TWh (5.8% of the total load) and 7.3 TWh (4.4% of the total load) respectively. Scenario 1

[1] 50/50 peak forecast is a value within the distribution that peak demand has a 50% probability of exceeding

[2] 80/20 peak forecast is a value within the distribution that peak demand has a 20% probability of exceeding

[3] Transportation electrification refers to modeled electric vehicles (automobiles) only

utilized an import-priority threshold price order, where wind and utility solar resources were curtailed before tie-line imports.

2.1.4 Scenario 2 (Import-Supported Decarbonization)

Scenario 2 assumptions were derived from Eversource's (unreleased) Grid of the Future Study. Scenario 2, or the **Import-Supported Decarbonization** case, assumed similar properties to Scenario 1, but with a number of adjustments. Scenario 2 retired 8.4 GW of fossil fuel units, including all remaining coal and oil. For additional resources, Scenario 2 included 8 GW of offshore wind, 4 GW of BESS units plus a new 1 GW tie-line with Hydro Québec. Total solar nameplate was 20.3 GW. More emphasis was placed on the electrified transportation load than the electrified heating load, with 3.3% of the total load coming from additional electrified heating and 10.8% of the total load coming from additional transportation electrification. Instead of Import Priority threshold price order, a REC-Inspired (renewable energy credit – an outside electric market payment certain clean resources can earn) threshold order was used where tie-lines were curtailed before wind and solar resources.

2.1.5 Scenario 3 (Deep Decarbonization)

Scenario 3 assumptions were derived from the "All Options Pathway" of the Massachusetts 2050 Deep Decarbonization Roadmap Study and imagined heavy renewable penetration and electrification loads. Scenario 3, also known as the **Deep Decarbonization** case, modeled all retirements through FCA 15 plus all remaining coal, oil. Refuse-burning plants were reduced to 5-8% of their nameplate capacity. Renewable additions were significant, with 16 GW of offshore wind (a doubling from Scenario 2), 28 GW nameplate of solar (a 38% increase from Scenario 2), 600 MW of BESS plus an additional new tie-line with Hydro Québec. Both heating and transportation electrification load additions were substantial.

While all other Scenarios modeled import-only transmission lines, Scenario 3 assumed bi-directional lines during times of surplus renewable energy, allowing New England to export power to New York, New Brunswick, and Québec after curtailing import power. The threshold order pricing in Scenario 3 curtailed renewables only after maximum export capability was reached. Finally, Scenario 3 introduced interchange with New York, while other Scenarios only assumed imports from Québec and New Brunswick. New York imports/exports were not modeled in Scenarios 0, 1, and 2, or in previous Economic Studies. In prior studies, this was to avoid "relying" on New York to serve New England's load when these two regions could be expected to have similar supply and demand conditions. The Massachusetts 2050 Deep Decarbonization study assumed an increase in interconnections in the northeastern United States and, notably, between New England and New York. The results of that study showed significant interchange between New England and New York driven by additional paths to energy storage resources in the Québec reservoirs. This meant that energy could flow from New England to Québec via New York and also into New England from Québec across the New York system.

2.2 Alternative Scenarios

In addition to the main Scenarios, there were several alternative "sub" Scenarios applied to some or all of the main Scenarios. Table 2-2 overviews the alternatives and which main Scenarios they were applied to. The alternatives were named A-G, and were applied to Scenarios 1, 2, and 3 unless otherwise noted below. After running each alternative, the output metrics were compared to the base Scenario to determine the effects of the changes in assumptions.

2.2.1 Alternative A

Alternative A added an unconstrained bi-directional high-voltage direct current (HVDC) tie-line from Québec to Northeast Massachusetts (NEMA), and Québec hydro reservoirs were available for use to function as long-term energy storage. To avoid curtailment, surplus renewable energy could be exported out of New England and reimported later to displace fossil-fuel generation. Threshold prices for triggering the export of energy were defined in order to model the new storage opportunity. The purpose of modeling this new tie-line and storage was to decrease curtailment of renewable resources and displace fossil fuel generation with the reimported energy. Alternative A explored the benefits of increased and bi-directional interregional power exchange between New England and Québec.

2.2.2 Alternative B

Alternative B explored utilizing a portion (25%) of 8 million electric vehicle batteries as vehicle-to-grid storage, also called EV Flex. This concept allows vehicles to both charge and discharge to the grid, rather than only charge. The EVs in this alternative were distributed throughout New England proportional to existing load distributions. The EV batteries would provide price arbitrage to compensate the owners for the increased battery cycling. It was theorized that these batteries would help reduce renewable curtailment and displace fossil fuel generation. Alternative B was only applied to Scenario 3.

2.2.3 Alternative C

Alternative C retired all remaining nuclear generation in New England, removing ~3.4 GW of high-capacity factor carbon-free capacity. New England depends on a relatively small number of nuclear generators for a large portion of its energy. Nuclear energy is used as base generation, meaning it provides a steady amount of energy throughout the day and throughout the year. As of today, each unit of the New England nuclear fleet has been in service for between 35 and 50 years and each of these units will someday retire. Alternative C was identified to show what the New England grid would look like without these resources.

2.2.4 Alternatives D & E

Alternative D retired all fossil fuel generation and added significant amounts of wind, solar, and BESS units. The resulting grid was a carbon-free system, with only nuclear and hydro units remaining from the old fleet. The Alternative D fleet reflected the goal of full decarbonization, as there would be no emissions in this alternative Scenario. Alternative E had the same assumptions as Alternative D, except the offshore wind interconnection points were redistributed to reflect theoretical offshore grids. Connecting significant amounts of offshore wind using only Southeast Massachusetts (SEMA), Connecticut (CT), and Rhode Island (RI) zones as interconnection points is expected to cause major congestion. This Scenario's objective was to analyze different impacts of onshore and offshore grids by bypassing existing constraints of the onshore grid to deliver the offshore wind to load centers as suggested in the 2020 Brattle/GE/CHA study. Alternative E was applied to Scenarios 1, 2 and 3.

2.2.5 Alternative F

Alternative F changed the threshold prices to 'import-priority' order. It is uncertain how future REC prices will affect the order in which resources are more and less economical to run. Significant penetrations of wind and solar will result in periods of oversupply, and the dynamics of RECs will determine which resources can afford to continue operations when LMPs become negative.

Scenario 1's assumption of import priority prices may reflect how the future system operates by illustrating the incremental utilization of wind and solar after imports on existing interconnections are fully committed. Modeling both methods of priority price orders allows stakeholders to understand what LMPs and curtailment figures would look like under both possible Scenarios. Alternative F was only applied to Scenario 2 and Scenario 3, as Scenario 1 already modeled 'import-priority' order.

2.2.6 Alternative G

Alternative G disabled all tie-lines with New York. Using historical flows with New York may not accurately portray a future grid. For example, if New England has a significant excess of solar power in the middle of the day, New York will likely be experiencing similar conditions. Using historical import/export assumptions could model New England's grid as having sufficient power to meet demand when this power may not be available in 2040 at the times it was in past years. Alternative G was designed to isolate the impact of the New York import/export assumption on the results. Alternative G was only applied to Scenario 3.

2.2.7 Additional "Unbalanced" Scenarios

The main Scenarios assumed that the pace of electrified load increase and renewable energy development would be comparable. Two additional Scenarios explored what might happen if one outpaced the other or were "unbalanced." Scenario 2, load 3, resource 2 (S2_L3R2) mixed and matched assumptions from different Scenarios, taking the Scenario 3 EV and heating loads and placing them into a Scenario 2 case. The resulting Scenario had high electrification loads with moderate penetrations of renewables. Another Scenario, Scenario 2, load 2, resource 3 (S2_L2R3) took the Scenario 2 assumptions and replaced the wind, solar, BESS, and generator retirement assumptions with Scenario 3 levels. The resulting model had high penetrations of renewable resources with only moderate electrified loads. These cases were meant to show the effects of uneven advancements in the clean energy transition, as it is unclear whether New England will maintain a balance between development of electrified loads and renewable resources.

Table 2-2: Application of Alternative Scenarios to Main Scenarios

Alt	Description	S1	S2	S3
A	Energy Banking with Canada	X	X	X
B	Vehicle-to-Grid			X
C	Nuclear Retirements	X	X	X
D	100% Carbon-free Energy	X	X	X
E	Alt. D with Offshore Grid	X	X	X
F	Curtailment Priority		X	X
G	No NY Interchange			X

2.3 Additional Assumptions (Common to Production Cost)

A number of additional assumptions were shared between production cost and Ancillary Services analyses. Though some modifications were applied to accommodate for the one-minute time scale of EPECS, the base profiles are the same.

2.3.1 Load

For all but Scenario 3, the 2019 weather year was used as a base assumption. ISO New England's 2021 CELT Report contains projections of monthly peak loads up to the year 2030. To model 2040, growth in monthly peak loads from the last two years were linearly extrapolated to the year 2040. Using 2019 as a base weather year, monthly peaks were scaled to the 50/50 monthly peaks for 2040. The winter peak of January and the summer peak of August were scaled to the 80/20 peak loads to better reflect seasonal peaks. To provide a clean transition between months, a linear feathering was applied to each hour within the month between peaks. This feathering scaled the hourly loads from monthly peak to monthly peak to prevent a sudden jump in load between months. Because of the small one-minute time steps used in this Ancillary Services analysis, a sudden jump between months would occur within a single minute time step if the feathering methodology was not applied.

Scenario 3 load was provided as part of the Massachusetts 2050 Deep Decarbonization Roadmap Study. The data used the 2012 weather year was recast into the 2019 weather year.

2.3.2 Weather Year

A single weather year was used to determine the base profile shape for both expected load and profiled resources. By using one historical year, modeling can determine how weather patterns might affect expected load curves (e.g., how a cold snap might increase demand for electric heating) and provide insight into how certain resources may perform under certain weather conditions (e.g., how lulls in wind and solar might affect variable energy resource production). This Ancillary Services analysis relied on a one minute time period of data rather than one hour, which is the typical time period used for production cost simulation. Over the course of the selected weather year, simulations will typically experience weather conditions that generate the variability in loads and resources which necessitate Ancillary Services. While the inclusion of a range of different weather years into the analysis of Ancillary Services may identify periods that would be even more challenging for system operators, a single weather year is adequate to capture the salient aspects of Ancillary Services needs.

The FGRS used the year 2019 as its base weather year. For wind generation, the ISO used individual profiles from the ISO's Variable Energy Resource Data developed by DNV-GL[4]. For wind farms that do not have a discrete profile, the ISO generated an aggregate profile appropriate for an RSP area. A "random walk" was applied to the wind profiles to create an intra-hour wind variability signal. For solar PV, five-minute aggregate historical solar profiles were used for each RSP zone and applied to every PV generator within each zone. To create minutely data, linear interpolation was used to step between the five-minute data points.

Heating and load data for Scenario 3 were based on the weather year 2012 used in the Massachusetts 2050 Deep Decarbonization Roadmap Study. To ensure a more consistent comparison, load and heating assumptions for this Scenario were recast into the 2019 year, which

[4] https://www.iso-ne.com/system-planning/planning-models-and-data/variable-energy-resource-data

was the common weather year used in all other Scenarios. To achieve this, a correlation between temperature and load was mapped for the year 2012. Using this relationship, 2019 temperatures were recast using the function between demand and temperature. The resulting loads provided the load assumptions from the Deep Decarbonization Roadmap Study with 2019 weather load data.

2.3.3 Resource Threshold Prices

Threshold prices determined how zero-cost resources were curtailed during times of oversupply. Once the LMP fell below the threshold price of a particular resource, that resource was curtailed. Threshold prices are not indicative of "true" cost, expected bidding behavior, or preference for one type of resource over another. Threshold prices were used in the FGRS to determine when to export energy to our neighbors in Scenarios with bi-directional transmission. Once the LMP fell below the export trigger price, energy was sent to our neighbors. Negative threshold prices were used to approximate the cost of RECs incurred by resources.

EPECS could not model bi-directional tie-lines the same way that the production cost analysis could, as imports and exports could only be represented by a static profile. Therefore, the outputs of production cost bi-directional model were fed into EPECS. Though the times of oversupply were the same in the two models, the outputs were checked to ensure that energy was not being exported while there was a reserve shortage.

Two sets of threshold prices were used for the FGRS: Import Priority and REC-Inspired threshold prices. The Import Priority threshold price tended to curtail new resources within New England such as assumed wind and solar PV resources. After all of these resources were curtailed, existing imports were curtailed. Table 2-3 shows the Import Priority threshold price for various resource types.

Table 2-3: Import Priority Threshold Price Order

Resource	Threshold Price ($/MWh)
Imports on New Tie-Line	-5.00
Trigger for Exports on New Tie-Line	-25.00
Onshore Wind	-35.00
Offshore Wind	-40.00
FCM and Energy-Only PV	-45.00
Imports from Existing Canadian Tie-Lines	-50.00
NECEC	-99.00
Behind-the-Meter PV	-100.00

The REC-Inspired threshold price curtailed all imports from our neighbors first, then curtailed New England zero-cost resources. FGRS Scenario 3 assumed the ability to export energy to our neighbors on existing tie-lines. Under this Scenario's assumptions, New England resources would not be curtailed until the full export capability of existing tie-lines had been met. Table 2-4 shows the REC-Inspired threshold price for various resource types.

Table 2-4: REC-Inspired Threshold Price Order

Resource	Threshold Price ($/MWh)
Imports from New York[(a)]	13.00
Imports from New Tie-Line	11.00
Imports from New Brunswick Tie-Lines	10.00
Imports from Existing Hydro-Quebec Tie-lines	5.00
NECEC	2.00
Trigger for Exports to Canada[(a)]	-25.00
Trigger for Exports to New York[(a)]	-28.00
Onshore Wind	-30.00
Offshore Wind	-40.00
FCM and Energy-Only PV	-50.00
Behind-the-Meter PV	-100.00

(a) Applicable only to Scenario 3

Within EPECS, profiled resources (PV, wind, imports, and hydro) were not able to provide ramping or reserve capabilities. The exception was pumped storage hydro, a portion of which was able to provide regulation. These resources could be curtailed in one time block then not curtailed in the next, but could not be counted directly as spinning, non-spinning, or operational reserves.

2.3.4 Fuel Prices

Input values for fuel prices were taken from the 2021 EIA Annual Energy Outlook[5] for the New England Region forecasted for the year 2040. In order to model certain resources such as coal that will likely be retired before the year 2040, the study used the value from the last forecasted year. Figure 2-1 shows the fuel prices used in the FGRS.

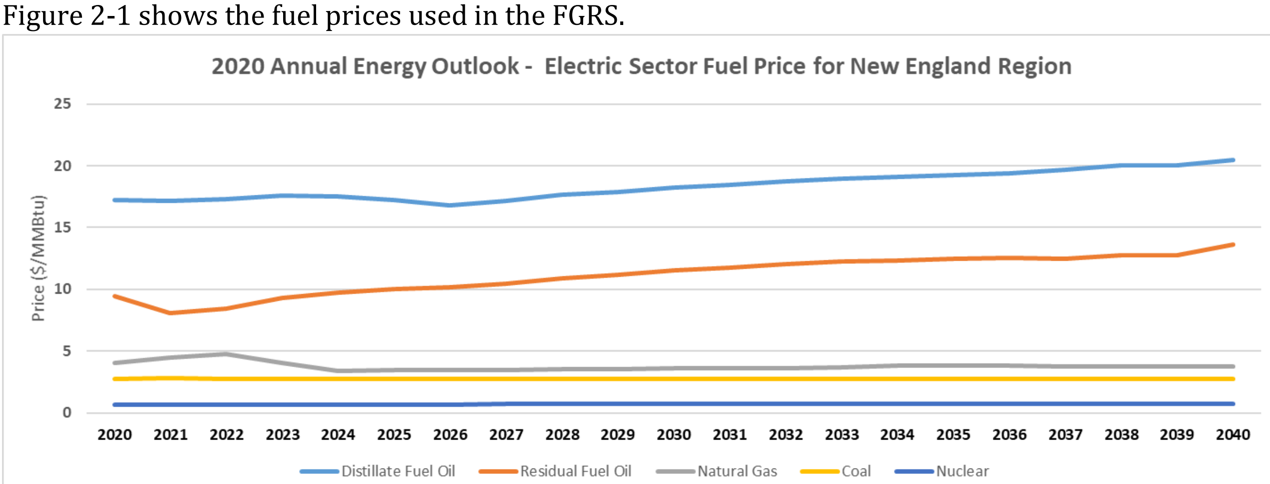


Figure 2-1: 2020 Annual Energy Outlook – Electric Sector Fuel Price for New England Region

[5] U.S. Energy Information Administration, *2021 Annual Energy Outlook, Table 3: Energy Prices by Sector and Source – Case: Reference Case*, *Region: New England* (February 3, 2021), https://www.eia.gov/outlooks/aeo/tables_side.php

A single price was used for the entire year for all fuel types except natural gas. Because software was not capable of modeling fuel switching, the 10% winter increase was included to approximate some higher cost LNG generation designed to supplement NG generation while pipelines were constrained. Consequently, a low summertime gas heating demand was represented by the 10% price reduction.

2.3.5 Emission Adders

The FGRS modeled electric sector emission allowance prices for carbon dioxide (CO_2), nitrous oxides (NO_X), and sulfur dioxide (SO_2). Table 2-5 lists the assumed environmental air emission allowances prices for 2040. Electric Sector CO_2 emissions for fossil-fueled generators in Massachusetts were monitored exogenously to confirm that they met the Massachusetts Global Warming Solutions Act (GWSA) cap allowances.

Table 2-5: Assumed 2040 Emission Allowance Prices

Emission Type	Emission Adder ($/metric ton)
CO_2	47.00
NO_X	4.00
SO_X	2.00

2.3.6 Active Demand Response (ADR)

There were approximately 600 MW of price responsive curtailable load in FGRS simulations divided into two tiers. One tier of 100 MW was priced at $50/MWh, and the second tier of 492 MW was priced at $500/MWh. This flexible load could be "dispatched" if LMPs rose above their price.

2.4 Ancillary Service Specific Assumptions

The Ancillary Services analysis relied on most of the same assumptions as production cost analysis. However, there were some Ancillary Services specific assumptions. These assumptions were related to reserve requirements, requirement violation pricing, and regulation properties.

Most Ancillary Services analyses described in this appendix were simulated using the Engineering System Analytics (ESA) Electric Power Enterprise Control System (EPECS) simulation tool. One Scenario (Scenario 3 Alternative D) was not able to be simulated in EPECS due to the lack of dispatchable generator. The EPECS logic related to uncertainty, energy storage, and regulation commitment for this Scenario was recreated in MATLAB with the same load, wind, solar, hydro, and tie profiles. EPECS allows for investigation into the performance of different resource mixes within the current ISO reserve and market rules.

The original Scenarios investigated under the Ancillary Services scope included main Scenarios 1, 2, and 3, as well as Scenario 3 Alternative B, Scenario 3 Alternative D and Alternative Incremental Scenario 3 (Scenario 3_Inc), which is an Ancillary Services-only Scenario that was designed to explore the effects of a larger reserve margin by increasing the reserve from 120 percent of the largest unit (~1,500 MW) to 175 percent of the largest unit (~2,300 MW to reflect the maximum 10-minute change of wind and solar resources (further described in 4.3.7). As the study progressed, some Scenarios were found to be infeasible within EPECS, and other Scenarios were added that included sufficient resources to satisfy the reliability criterion. By the end of the study, Scenario 0 and proxy Scenarios 3 P1, Scenario 3 P6, and Scenario 3 P7 were added to the scope of the study. Scenario 3 P7 is also referred to as **Resource-Adequate Deep Decarbonization** in the executive summary of the main FGRS report. A summary of the final set of Scenarios included in the Ancillary Services scope can be seen in Table 2-6 below.

Table 2-6: Ancillary Service Scenarios

Scenario	Description
S0	Baseline Decarbonization
S1	Moderate Decarbonization
S3	Deep Decarbonization
S3_Inc	S3 with Increased Reserve Margin
S3_B	S3 with Vehicle-to-Grid Charging
S3_D	S3 with 100% Carbon-free Energy
S3_P1	S3 with Retention of Legacy Generators & New CTs
S3_P6	S3 with Additional Onshore Wind & BESS Units
S3_P7	Resource Adequate Deep Decarbonization
S3_P7_3000	S3_P7 with 18 GW of Renewables & BESS Units Replaced with 3 GW of proxy CTs

Other alternatives and Scenarios were not included in the Ancillary Services scope because it was assumed they would not contribute in a meaningful way towards measuring system flexibility. For example, simulating Alternative C (retirement of all nuclear units) was unnecessary, since nuclear units do not usually provide reserve or ramping capabilities.

2.4.1 Reserve Requirements and Violation Pricing

Real time reserves refer to different ISO market products modeled within EPECS. These products include 10-minute spinning reserves (TMSR), 10-minute non-spinning reserves (TMNSR), and 30-minute operating reserves (TMOR). TMSR are spinning reserves synchronized to the frequency of the electrical grid, which are able to provide power within 10 minutes. TMNSR are not synchronized to the grid but are able to synchronize and ramp up to their reserve contribution within 10 minutes. TMOR are able to synchronize and ramp up to their reserve contribution within 30 minutes.

In addition to modeling ISO reserve products, EPECS attempted to maintain different reserve requirements. The unit commitment and economic dispatch layers of EPECS would try to keep reserve levels above their requirements and would apply a Reserve Constraint Penalty Factor (RCPF) price if the reserve requirement was violated. The reserve requirements modeled were 10-minute spinning requirement (TMSRreq), total 10-minute requirement (TOT10), and the total 30-minute requirement (TOT30). Higher quality products could provide reserves that fulfilled multiple requirements. For example, TMSR could provide reserves for TMSRreq, TOT10, and TOT30. TMOR can only provide reserves for TOT30, because those reserves cannot respond in time to provide reserves for TMSRreq or TOT10. When a reserve requirement was violated, a violation price was assigned to the reserve market. Requirement MW amounts and violation prices are illustrated in Table 2-7. For more information on reserve requirements, see ISO.

The reserve requirements depended on the first and second largest contingencies. The TOT10 requirement needed to cover 120% of the largest contingency, with 60% of that contingency covered by the TMSRreq. Finally, the TOT30 requirement was equal to the TOT10 requirement plus 50% of the second largest contingency.

Table 2-7: Reserve Requirement Properties

Requirement Name	RCPF Price	Requirement (MW)	Contributing Products	Requirement in S3_Inc (MW)
Ten Minute Spinning (TMSRreq)	$50/MWh	60% of largest contingency (750 MW)	TMSR	1,150 MW (+400 MW)
Total 10-Minute (TOT10)	$1,500/MWh	120% of largest contingency (1,500 MW)	TMSR and TMNSR	2,300 MW (+800 MW)
Total 30-Minute (TOT30)	$1,000/MWh	120% of largest contingency + 50% of second largest contingency (2,100 MW)	TMSR, TMNSR, and TMOR	2,900 MW (+800 MW)

2.4.2 Reserves

Within EPECS, certain reserve types could only be provided by certain generators. Any online thermal generator could provide TMSR. By design, TMNSR and TMOR could be provided by generators labeled as fast start generators as well as resources that were synchronized and could respond to system conditions. The amount of reserves a generator could contribute towards these products was dependent on the generator ramp rate. Energy storage, wind, and solar resources could not provide any reserves. Since energy storage could possibly provide some type of reserves in the future, a percentage of energy storage (pumped storage and BESS) capacity was modeled as a regulation generator. Regulation in EPECS will be explained more in the next section, but in general, this assumption was included to allow energy storage to contribute to reserve needs.

2.4.3 Regulation Need

Regulation is the only product in EPECS that can dispatch in the real-time layer of the program. It is important to note that the regulation modeled in this study is not the same as real ISO regulation but is rather a generic type of fast-acting reserve – which could include real ISO regulation – that is able to cover any real time supply and demand divergence between dispatch intervals when resources would have been directed to new operating points. In addition to the 122 MW of regulation that represented regulation provided by conventional generators, each Scenario dedicated 15% of energy storage capacity (pumped storage and BESS) towards regulation. Several metrics were created expressly for the FGRS for the purposes of reporting the results of modeled regulation. If the amount of regulation in a modeled Scenario was exceeded, it was reported as an *imbalance*. Another metric, *regulation need,* combined the regulation that was actually used to follow the divergence between loads and supply, plus the imbalance. Any large *regulation need* implied intervals when additional flexible resources would have been needed that were not part of the orderly transition to new operating points between dispatch intervals. Regulation use was assigned a price based off of total energy and mileage (how regulation MW changes over time).

2.4.4 Dispatch Layers and Forecast Error

There are four dispatch layers in EPECS which attempt to schedule generation and procure reserves to meet real-time load. The layers are as follows: SCUC (security constrained unit commitment, aka day-ahead unit commitment), RTUC (real-time unit commitment), SCED (security constrained economic dispatch), and RT (real-time). The three non-real-time layers modeled a look ahead period in which the one-minute load and generation profiles of intermittent resources would be averaged and combined into larger blocks. A forecast error was then applied to the load, wind, and solar predictions. As the layers became more granular, the forecast error decreased. The reasoning for this layering was to try to introduce moderate uncertainty in the day-ahead forecast, and then achieve progressively more accurate forecasts as the system approached the real-time period. The maximum forecast errors possible are shown in Table 2-8.

Table 2-8: Dispatch Layer Properties

Layer	Period	Look Ahead Period	Load Error	Wind Error	Solar Error
SCUC	1 Hr	24 Hr	1.65 %	12 %	9 %
RTUC	15 Min	4 Hr	1.5 %	3 %	3 %
SCED	10 or 5 Min	Up to 10 Min	0.075 %	1.5 %	1.5 %

The forecast error signals followed different patterns. The SCUC forecast error, shown in Figure 3-1, contained one low frequency sinusoidal error signal which accounted for two-thirds of the maximum forecast error percentage. Added to this signal was a high frequency sine wave with an amplitude equal to one-sixth of the maximum forecast error percentage and a randomly generated number between the maximum and negative maximum of one-sixth of the forecast error percentage. As a result, the day ahead forecasts were very strongly temporally correlated. Each data point in this figure represents the error for a 1-hour forecast period. Figure 3-2 shows that the extreme tail values of the positive and negative maximum possible values were uncommon, while the more moderate values were more common.

The derivation of the RTUC and SCED forecast error signals used a similar principle, but these signals were constructed such that the shorter-term forecast errors were increasingly random.

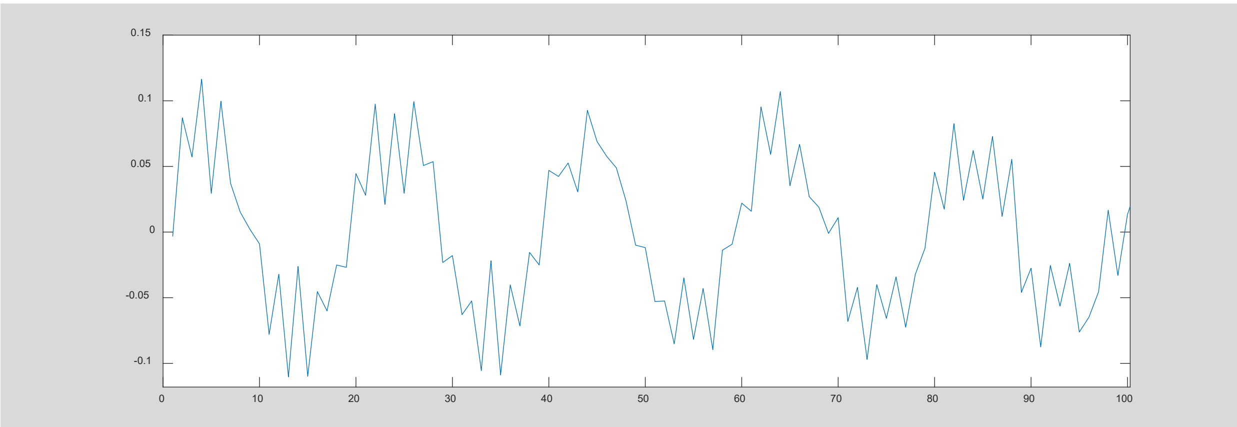


Figure 3-2: 100 Periods of SCUC Forecast Error for Wind

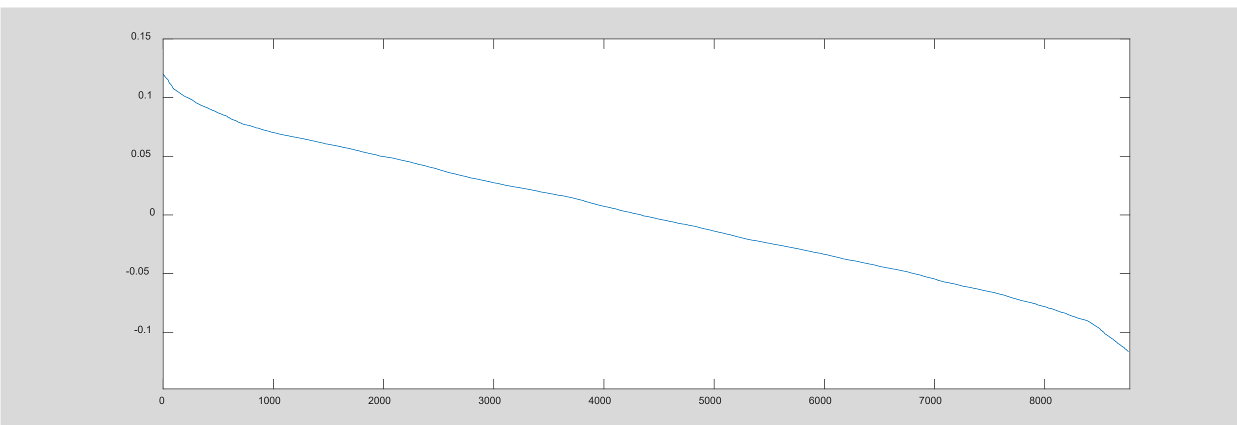


Figure 3-3: SCUC Forecast Error Duration Curve for Wind

The RTUC error signal, shown in Figure 3-3, followed a sinusoidal curve with an amplitude equal to half of the maximum possible forecast error, then added a randomly generated value with maximum and minimum values also equal to half of the maximum possible forecast error. The resulting forecast error was random, but also contained temporally correlated errors. Each data point in this figure represents the error for a 15-minute forecast period. The inclusion of the sinusoidal curve led to less frequency in values close to the positive and negative maximum possible values. The duration curve in Figure 3-4 is flatter in the middle with curving tails, showing a higher probability of more moderate forecast errors.

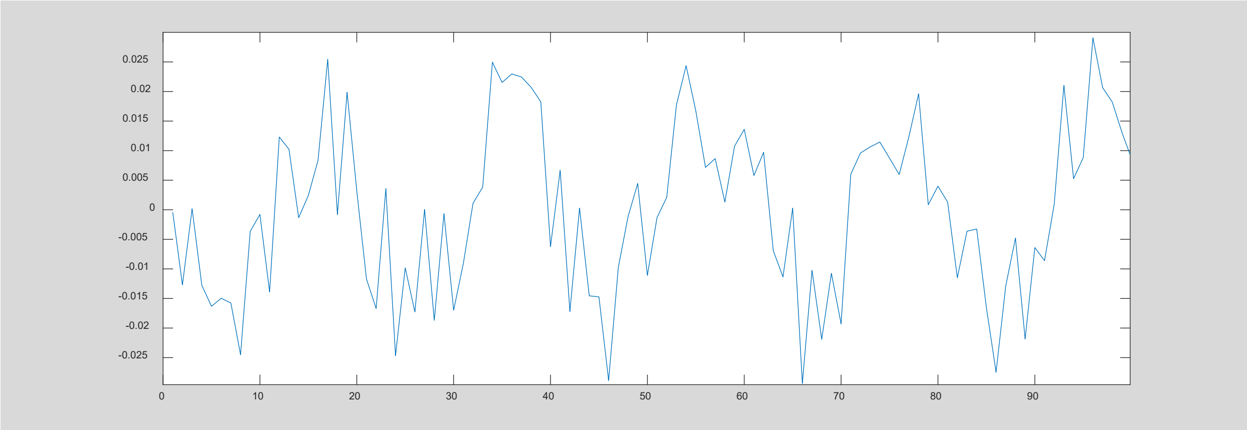


Figure 3-4: 100 Periods of RTUC Forecast Error for Wind

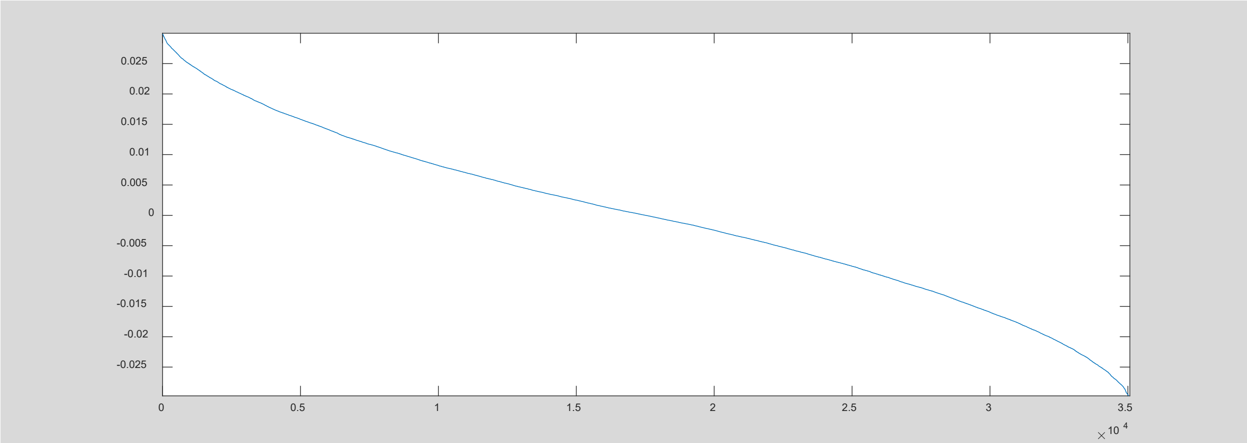


Figure 3-5: RTUC Forecast Error Duration Curve for Wind

The SCED forecast error shown in Figure 3-5 was a randomly generated value between the positive and negative maximum possible values of this type of forecast error. Each data point in this figure represents the error for a 5-minute forecast period. As a result of the uniform random number generation, the duration curve for the SCED forecast error in Figure 3-6 is a straight line, indicating there is equal probability of experiencing both the positive and negative maximum possible values of this type of forecast error.

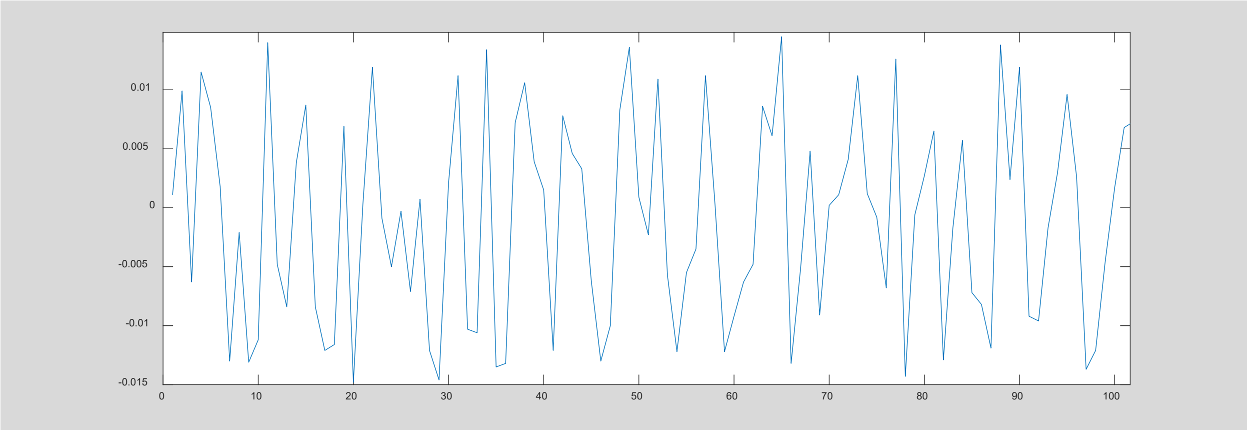


Figure 3-6: 100 Periods of SCED Forecast Error for Wind

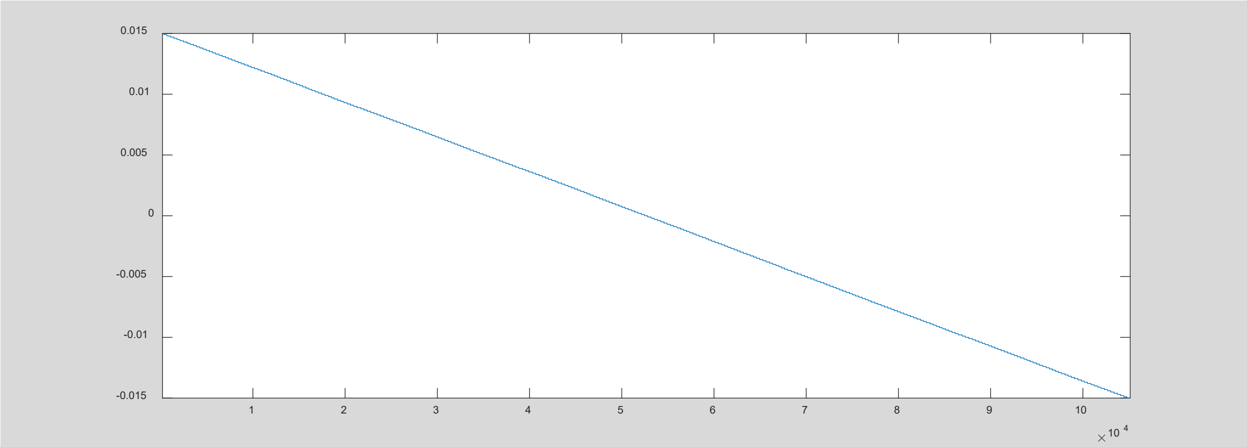


Figure 3-7: SCED Forecast Error Duration Curve for Wind

The specific patterns of the forecast error signals in all three layers led to different relative chances of errors above 90% of the maximum possible values. For a maximum SCUC forecast error of 12%, there were 13 data points out of 8,760 where the SCUC forecast error was at or above 10.8%. For a maximum RTUC forecast error of 3%, there were 514 data points out of 35,060 where the RTUC forecast error was at or above 2.7%. For a maximum SCED forecast error of 1.5%, there were 5,140 data points out of 105,120 where the SCED forecast error was at or above 1.35%. The probability of each error exceeding 90% of their maximum forecast percentage were 4.89% for SCED, 1.47% for RTUC, and 0.15% for SCUC. The same methods of forecast error construction were applied to load and solar forecast errors, but the maximum possible errors were different.

Though variable generation uncertainty is not a huge problem for the current New England grid, accurate day-ahead weather forecasts will become increasingly important as significant portions of power generation and demand become more reliant on weather patterns. Large solar forecast errors already present occasional challenges for the day-ahead prediction in today's grid. Though the largest differences between day ahead and real time net load conditions have historically only been on the scale of several hundred MW, these differences have created moderate real time LMP swings.

2.4.5 Security Constrained Economic Dispatch (SCED) Period

In the earlier stages of the FGRS analysis, EPECS simulations were performed with both 5-minute and 10-minute SCED periods, because EPECS is not able to capture sub-5-minute changes in generation and load profiles. In a real system, system operators are able to dispatch whenever they see available regulation diverging from the desired range, and the process of adjusting regulation is not limited to a fixed 5-minute SCED period. Because a reduction in dispatch period from 10 minutes to 5 minutes was correlated with a reduction in regulation need, the later regulation need results are caveated by the idea that a real system could dispatch even more frequently than 5 minutes during challenging operational periods, although the feasibility of such dispatch practices is unclear.

2.4.6 Tie-Lines and Hydro Generation

EPECS was unable to model tie-lines and hydro generation the same way that Gridview modeled these elements in the production cost model. Both resource types were considered profiled resources, though forecast errors were not applied. Consequently, power generation levels from hydro and tie-lines were available to every dispatch and commitment layer. For Scenarios with only import profiles, a fixed profile was used to represent tie-line flows. For Scenarios with bidirectional modeling, the output from the Gridview model was converted to a one-minute time scale and utilized by EPECS. Similarly, the output of the hydro generators (not including pumped storage) from Gridview was converted to a one-minute time scale and utilized by EPECS. The conversion from hourly time scale to minute time scale was achieved via linear interpolation, as hydro generation and tie-line flows are controllable and not subject to sudden changes in weather patterns.

Section 3: Analysis Methodology

This section describes the details of how the Ancillary Service analysis was performed and its important metrics.

3.1.1 EPECS Dispatch Layers

In EPECS, the different dispatch layers controlled different aspects of generator commitment and dispatch. Each layer had a different net load with different forecast errors. The SCUC layer committed fast start and slow start generators for unit commitment and dispatch on an hourly basis. The RTUC layer could perform unit commitment for fast start generators and energy storage, as well as change dispatch levels of all online generators. The SCED layer could adjust dispatch of all online generators but could not commit any additional units or cause energy storage dispatch changes. The SCED layer also dispatched ADR. Finally, the RT layer committed regulation to compensate for any differences between forecasted net load and actual net load, where net load is equal to the gross load minus the sum of wind generation, solar generation, hydro generation, and tie-line flows.

Each layer attempted to procure the TMSR requirement of 750 MW, though SCED dispatches may have required a violation of the requirement. Then, the SCUC and RTUC layers designated all remaining non-committed fast start resources and generator headroom not available within 10 minutes towards Tot10 and Tot30 requirements.

3.1.2 Study Criteria

EPECS monitored load and generator uncertainty and behavior over one simulation year, including regulation, ramping, and reserves. Each Scenario assumed only a specified amount of each product, and it was possible for a Scenario to exhaust one of these products. After the simulation was complete, the Scenario was analyzed to determine its ability to meet system variability and determine if any of the products were depleted during the simulation. An estimated cost of the reserve market could be calculated based off regulation usage and minutes of reserve shortfall.

3.1.3 Study Metrics

The metrics used to gauge a Scenario's performance included *regulation need, ramping reserves*, *minutes of reserve requirement violation*, and *reserve market revenues*. *Regulation need* was described earlier in section 2.4.3, but it generally measured how much additional flexibility a Scenario required. *Ramping reserves* measured the aggregate headroom of the ramping capability of the conventional generation fleet. In other words, it measures how fast the aggregate generation fleet could ramp in a given minute. If ramping reserves were depleted, it was because the net load was moving faster than the generators could keep up with. The *minutes of reserve requirement violation* metric measured how many minutes the Scenario spent experiencing reserve scarcity. If there were many minutes of reserve scarcity, the Scenario showed a shortfall of available reserves. *Reserve market revenues* tied a financial figure to the reserve requirement violation figure within the context of the current reserves market. Load following reserves, imbalances, and regulation were other metrics discussed in earlier FGRS results but were ultimately discarded to better focus on these more targeted metrics.

3.1.3.1 Regulation Need

Regulation need is defined as the absolute value of regulation plus the absolute value of imbalance for every minute in a year. If the predefined amount of regulation was exceeded, imbalances were defined as the additional amount of capacity needed to respond quickly to changes in net load. Combining the two metrics into one separate metric provided a way to compare each Scenario's need for additional fast-acting generation.

3.1.3.2 Ramping Reserves

Ramping reserves refers to the capability of a generator to increase or decrease its ramp, or rate of change of power output. Figure 4-1 illustrates a generator with a maximum ramp up rate of 50 MW/hr and a maximum ramp down rate of -60 MW/hr. If the generator is scheduled to ramp at 25 MW/hr for the next hour, the generator could theoretically increase ramping by up to 25 MW/hr on top of initial capability or decrease ramping by up to -85 MW/hr from its current schedule. The ramping reserve metric in the results describes the combination of the ramping reserves of all generators.

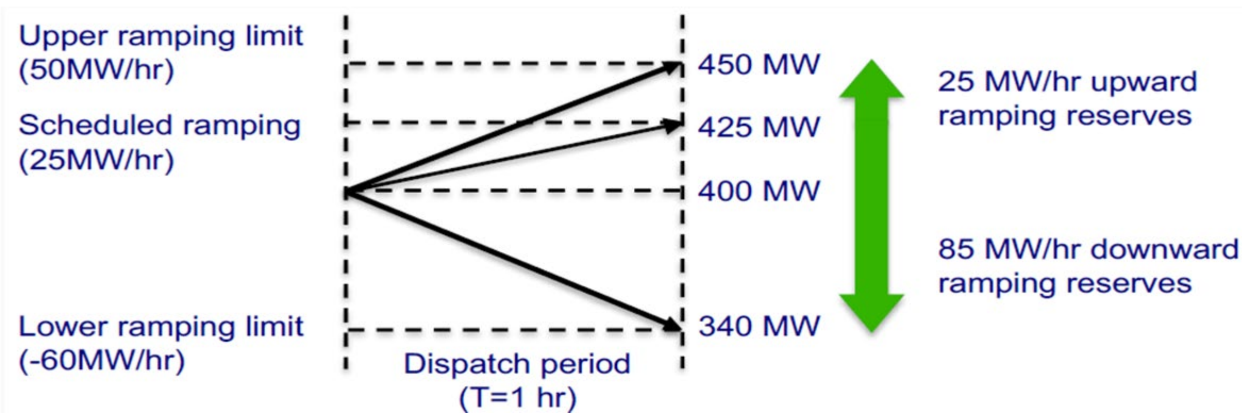


Figure 4-1: Example of Ramping Reserves for One Generator in SCUC Layer

3.1.3.3 Load Following Reserves

Load following reserves refer to the ability of a generator to increase or decrease its overall power output regardless of time dependence, in other words, the total headroom or legroom of a generator available for dispatch. Figure 4-2 shows a generator with a capacity of 500 MW and a minimum stable level of 200 MW dispatched at 400 MW. Because it has 100 MW of headroom and 200 MW of legroom, the generator has 100 MW of upward load following reserves and 200 MW of downward load following reserves.

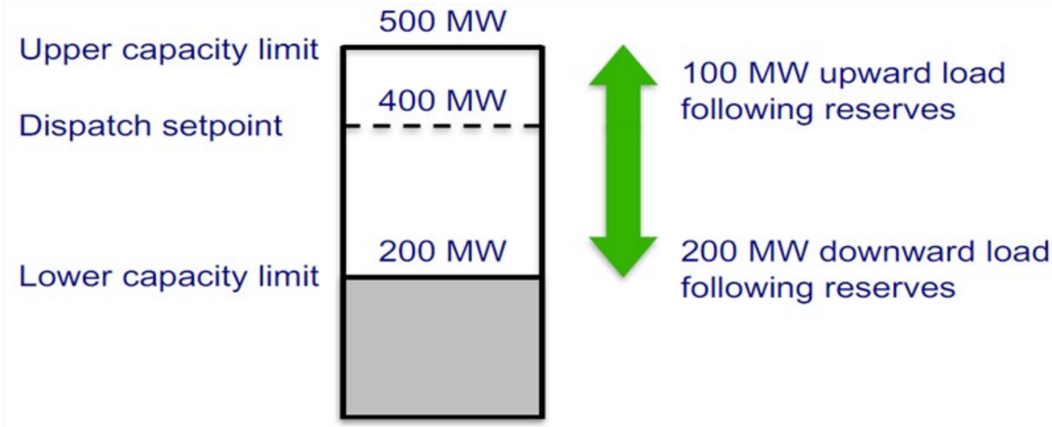


Figure 4-2: Example of a Generator's Load Following Reserves in SCED

3.1.3.4 Imbalances

Imbalances refer to the sum of all generation and imports minus the sum of all load and exports. A positive imbalance refers to an excess of generation and imports yet to be curtailed. A negative imbalance refers to a shortfall of generation. In EPECS, regulation is dispatched in the real-time layer to address imbalances, but any oversupply or shortfall which exceeds the capacity of the regulation is labeled as an imbalance.

3.1.3.5 Regulation

Regulation is the only generator attribute in EPECS which can respond in the real-time layer. EPECS does not model regulation granularly (i.e., by simulating a number of independent online spinning generators) but as one distinct generator. In EPECS, regulation is able to ramp at an unlimited rate to determine the maximum required ramp rate for each Scenario. A percentage of energy storage capacity was dedicated towards regulation in all simulations of the FGRS.

Section 4: Results

4.1 Sample Results

A sample result of EPECS is shown in Figure 4-1. The figure illustrates the difference between day-ahead (SCUC) and real-time (RT) wind and solar *production* as a function of time. The real-time generator dispatch must respond to the difference between the day ahead and real time generation patterns. Figure 4-2 shows the difference between the day-ahead and real-time *dispatches* as a function of time.

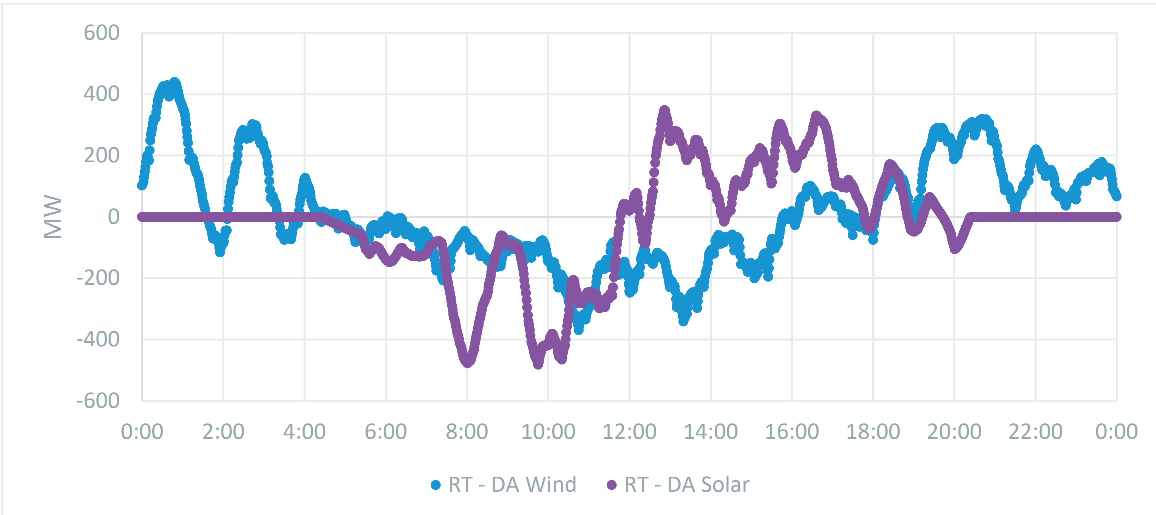


Figure 4-1: Sample of Real Time vs. Day Ahead Forecast Difference for Example Day

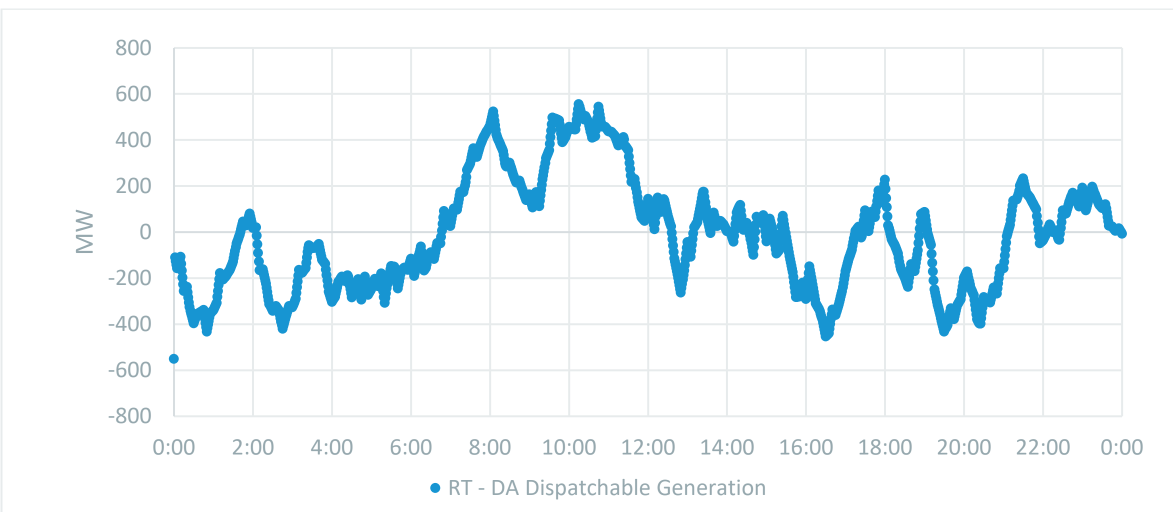


Figure 4-2: Sample of Real Time vs. Day Ahead Thermal Generator Dispatch for Example Day

Large differences in wind and solar forecasts were correlated with differences in generator dispatch. In the samples above, wind produced more power than expected in the early morning leading to a diminished early morning generator dispatch. From 8AM to noon, wind and solar both produced less power than expected, leading to an increase in real-time generator dispatch. The additional generation came from TMSR and TMNSR of the dispatchable 'balancing' resources.

4.2 Initial Scenario Results

There were several rounds of presentations to the PAC during FGRS, and some of the initial Scenarios were removed from the final set after discussion and feedback from stakeholders.

All of the Scenario 3 cases experienced significant periods of reserve scarcity, as shown in Figure 4-3. Additionally, increasing the reserve requirement in Scenario 3_Inc without adding more reserve-capable units generated more minutes of reserve scarcity. Scenario 1, however, experienced significantly fewer periods of reserve scarcity, and Scenario 0 experienced virtually no requirement violations.

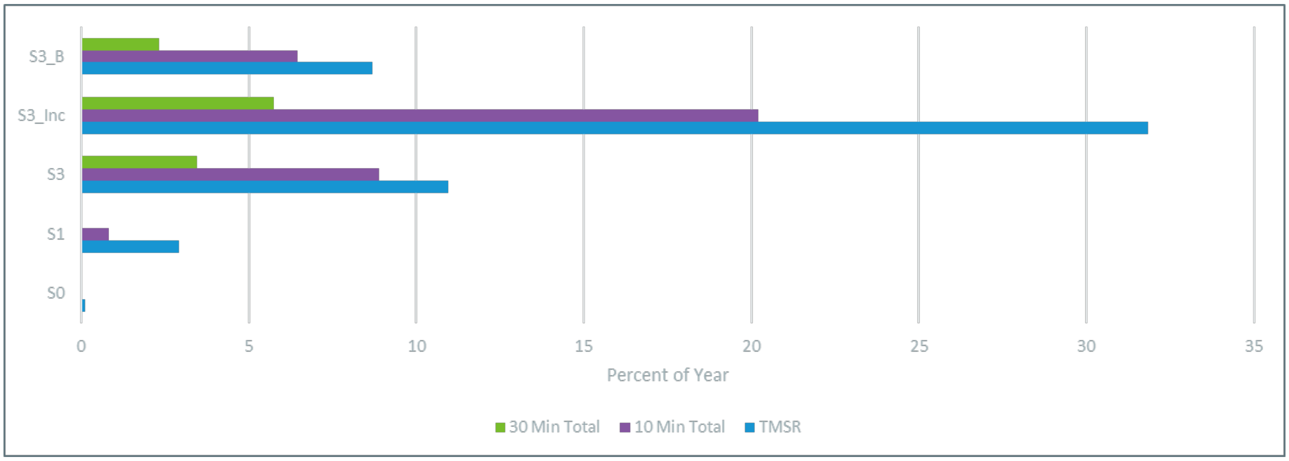


Figure 4-3: Percentages of Year with Reserve Requirement Violations

The individual reserve products followed similar patterns, with all Scenario 3 cases totally depleting TMSR (Figure 4-4) and coming very close to depleting TMNSR and TMOR (Figure 4-5). Figure 4-6 illustrates the behavior of the Scenarios when considering all three reserve products.

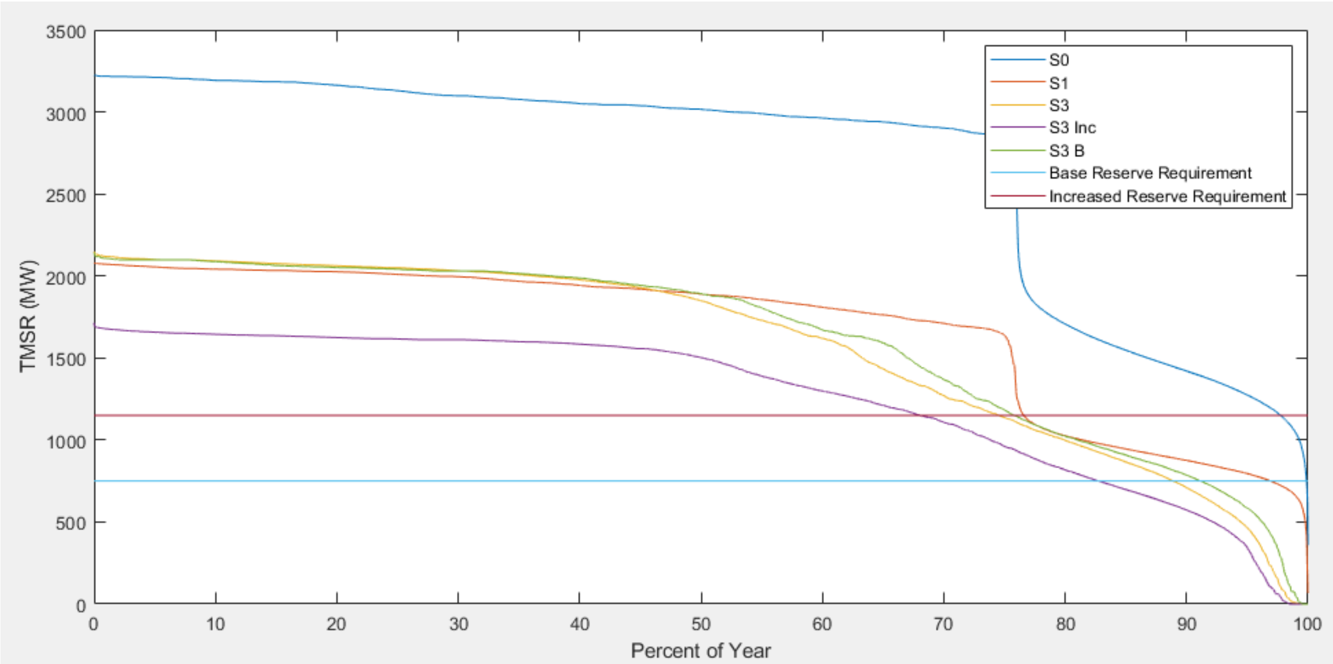


Figure 4-4: TMSR Duration Curve

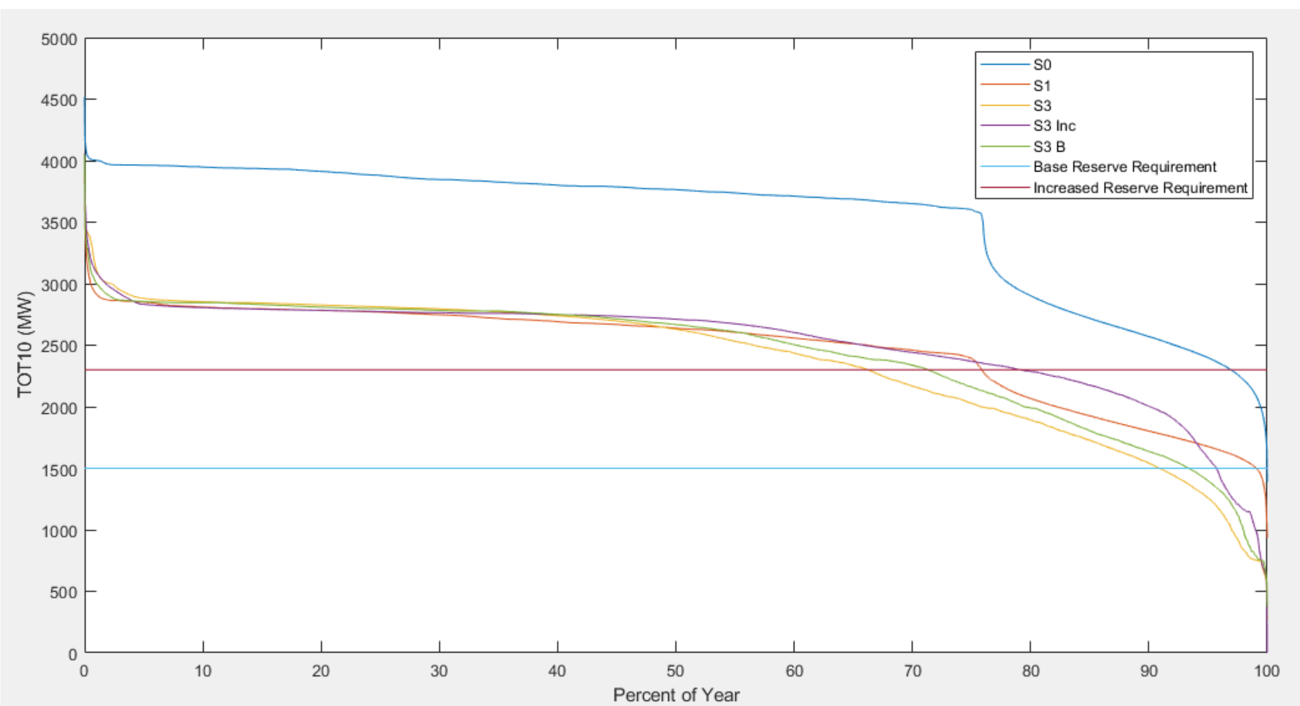


Figure 4-5: Total 10-Minute Reserve Duration Curve (TMSR + TMNSR)

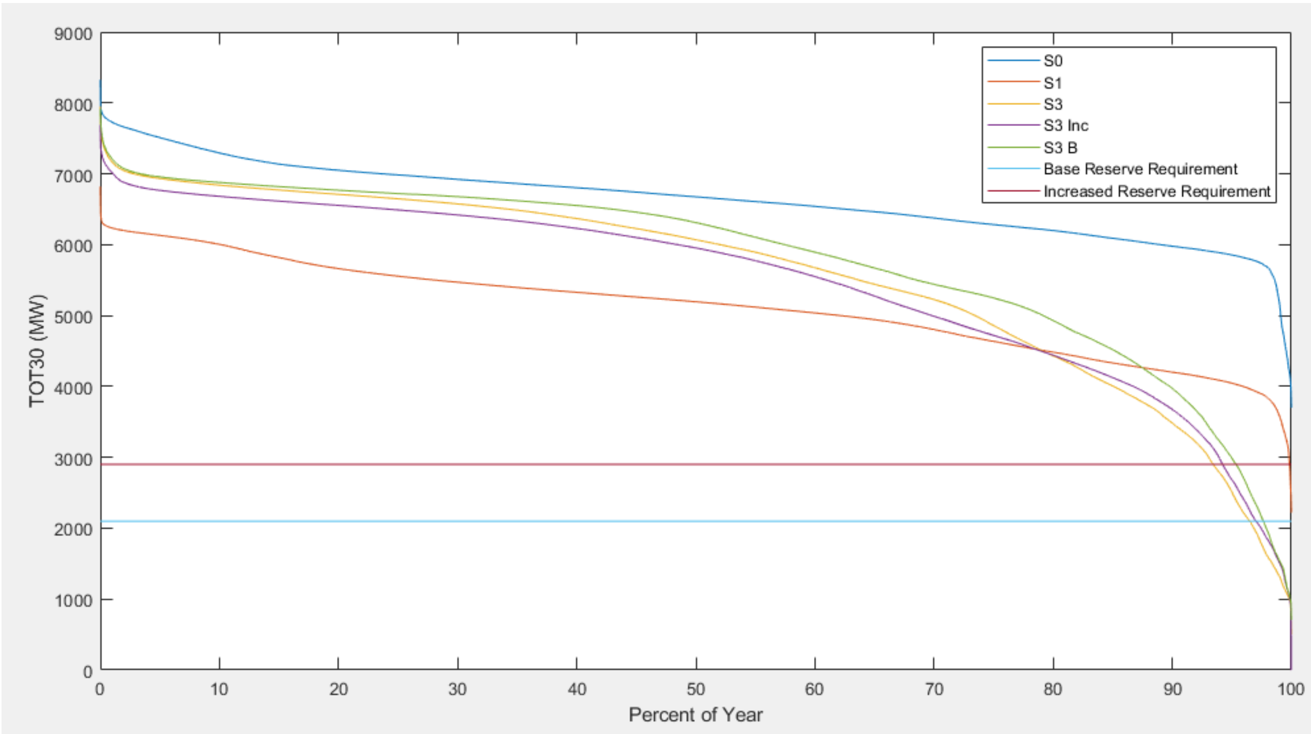


Figure 4-6: Total 30-Minute Reserve Duration Curve

With EPECS able to report individual reserve products, Reserve Constraint Penalty Factors (RCPFs) could be assigned to estimate the value of a future reserves market (Figure 4-7). The values assigned to these RCPFs were:

- TMSR requirement violations: $50/MWh
- Tot10 requirement violations: $1,500/MWh
- Tot10 requirement violations: $1,000/MWh

Additionally, the study assigned the following prices to active demand response and regulation:

- Active DR, which was priced at two tiers: $50/MWh and $500/MWh
- Regulation prices: $16.12/MWh and $0.21/mile (based on the average regulation price for 2020)

Because Scenario 3 was frequently short on reserves, the value of the reserve markets ballooned from millions of dollars to over $1 billion. For context, the 2021 regulation and real time reserves market were worth $26 million and $11 million respectively. This analysis showed the financial implications of the assumed load and resource balance of all Scenario 3 cases, especially variation Scenario 3_Inc. In contrast, the load and resource balance in Scenario 0 and Scenario 1 provided market compensation that would be comparable to the historical range. This suggests that as the system evolved toward S3 conditions, market incentives for more fast-acting dispatchable resources and/or active demand response would increase the willingness of participants to bring them to the market. Reserve market revenues are detailed in Table 4-1.

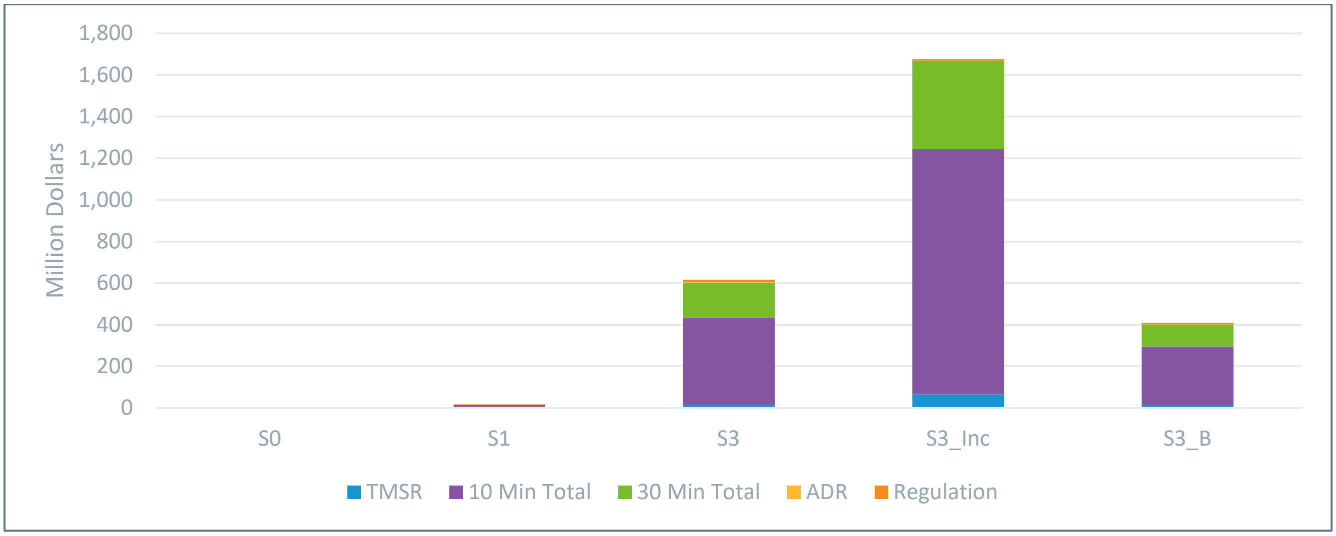


Figure 4-7: Reserve Market Revenues

Table 4-1: Reserve Market Revenues

Requirement Type	S0 Revenue	S1 Revenue	S3 Revenue	S3_Inc Revenue	S3_B Revenue
TMSR	$0.01 M	$1.17 M	$15.68 M	$65.15 M	$10.98 M
Total 10-Minute	$0.01 M	$13.34 M	$416.90 M	$1,180.55 M	$285.13 M
Total 30-Minute	$0.00	$0.00	$170.65 M	$423.41 M	$104.89 M
ADR	$0.00	$141.00	$0.56 M	$0.64 M	$0.24 M
Regulation	$2.00 M	$3.50 M	$12.70 M	$7.90 M	$8.70 M

4.3 Final Analysis Results

The Ancillary Services analysis also included additional proxy Scenarios developed from the resource adequacy analysis. These additional Scenarios used different resource in order to meet the 0.1 days per year LOLE ISO planning reliability criterion as a way to observe the effectiveness of different resource mix changes on the Scenarios' ability to reliably meet high load. These analyses became the final set of results discussed in this section.

4.3.1 Overview

Many variables affected the regulation need and reserve requirement violation metrics, but some variables proved to be more influential than others. The nameplate of intermittent resources in a given Scenario, for example, was correlated with the resulting regulation need. Because the SCED period was fixed at 5 minutes, the resources in a Scenario could only be re-dispatched that frequently. As a result, the more variable energy resources there were in a Scenario, the more intra-dispatch compensation, or regulation, was needed. In a real power system, operators are able to redispatch the available resources as needed. However, as power produced by variable energy resources increased from Scenario to Scenario, more flexibility was demanded from fewer remaining dispatchable and on-line resources to compensate for the increased variability. If variable energy resources were dispatched to manage the regulation requirements, this variability could be reduced. However, since variable energy resources are incentivized to generate as much as possible when fuel is available, pricing in day-ahead and real-time markets would need to provide the incentives for behaviors that would support the needs of a future grid.

For example, analysis consistently showed that adding more dispatchable generation to a Scenario decreased the number of minutes of reserve scarcity. With input assumptions that included the retirement of many older dispatchable generators, some Scenarios did not include enough dispatchable resources to remain above the reserve requirement thresholds for significant portions of the year. Reserve market revenues were correlated with the number of minutes of reserve scarcity, so a system that depleted its reserves more often would have a greater revenue stream for resources that could provide them.

Ramping reserves followed the same pattern as reserve requirement violations. Including more generators in a Scenario that allowed for more ramping capability led to a more flexible system that would be able to earn revenues from regulation and ramping mileage.

4.3.2 Analysis of Scenarios Augmented to Meet Resource Adequacy Reliability Criterion

Several Scenarios augmented to meet the resource adequacy reliability criteria were selected for analysis using EPECS. The augmented cases used Scenario 3 as the base case Scenario and applied various types and combinations of proxy units to bring the system to the resource adequacy reliability criteria. The goal of this analysis was to explore the impact on the regulation and reserve requirements of several different types of resource mixes that met the LOLE criteria.

Because the loads and resources were specified as an input to the FGRS and not run through the PRAA analysis initially, the original Scenario S3 did not have enough capacity to meet the resource adequacy reliability criteria.

These additional cases were:

- **Scenarios 3 P1:** To meet the reliability criteria, 4,396 MW of older fossil fuel resources that had been assumed retired were retained. 9,000 MW of quick-start natural gas combustion turbines were added.
- **Scenario 3 P6:** To meet the reliability criteria, 9,800 MW of onshore wind (ONSW) and 29,000 MW of BESS (four-hour duration) were added.
- **Scenario 3 P7:** To meet the reliability criteria, Scenario 3_P7 adapted Scenario 3 to match the Pathways Study Status Quo resource mix. This mix was then scaled up at a constant ratio until the reliability criteria was met. This required a 70% increase of the PV/ONSW/offshore wind (OFSW)/(4-hr) BESS mix (total nameplate capacity of ~89 GW),
- **Scenario 3 P7_3000:** This Scenario substituted ~17.8 GW of the Scenario 3_P7 variable energy and BESS resource capacity mix with 3,000 MW of dispatchable resources.

4.3.3 Regulation Needs

For context, today's power system utilizes about 120 MW of regulation. As noted earlier, the metric *regulation need* is not exactly the same as regulation in the current system but is rather a measure of the necessary intra-dispatch flexibility between SCED intervals. In general, regulation need was higher for Scenarios with more variable energy resources (see Figure 4-8). Regulation need in Scenarios 0 and 1 did not significantly exceed the quantities currently procured for today's needs, indicating that moderate amounts of variable energy resources can be integrated into the power system without significant changes. However, the levels of load variation and variable energy resource penetration in Scenario 3 required several multiples of the current regulation need. Because load, wind, and PV forecast error assumptions did not change from Scenario to Scenario, Scenario 3's high load and high wind and PV resources led to extreme flexibility needs. Resource variability could potentially be mitigated by variable energy resources with generation-side curtailment, co-located energy storage, or some type of fast-acting reserve product designed to address variabilities inherent in the large-scale use of wind and solar resources. Regardless of how resource and load variability is accounted for, regulation needs will increase as more variability is introduced into the system.

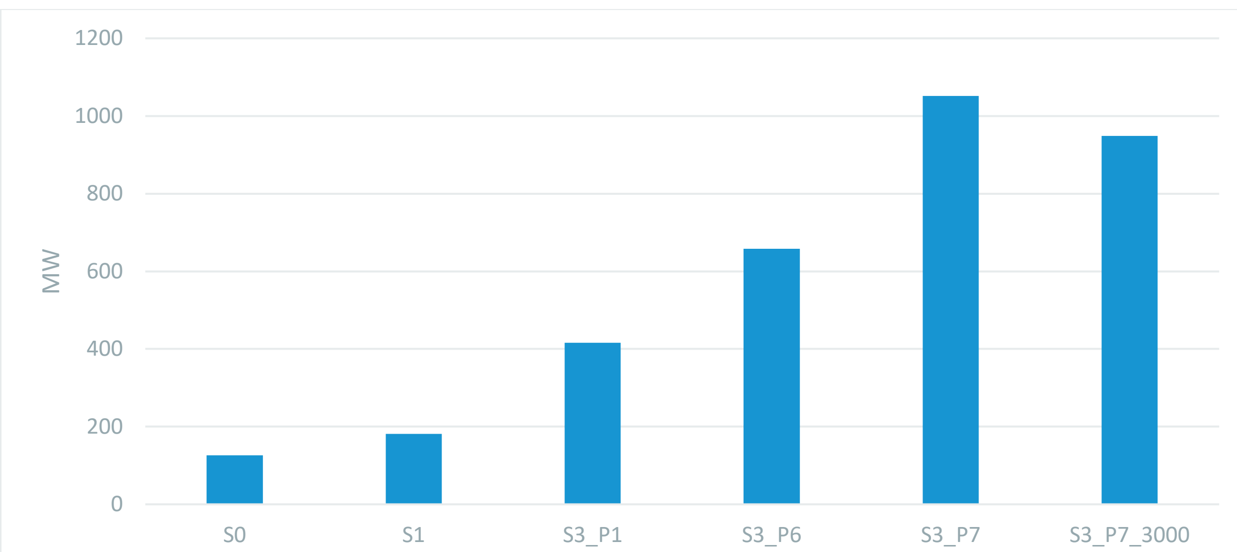


Figure 4-8: Regulation Need by Scenario

4.3.4 Minutes of Reserve Violations and Reserve Market Revenues

In general, Scenarios with more dispatchable resources experienced fewer minutes of reserve requirement violations (see Figure 4-9). Scenarios 0, Scenario 3_P1, and Scenario 3_P7_3000 all contained a significant quantity of dispatchable resources which helped minimize their minutes of reserve scarcity. Additionally, larger resource diversity was correlated with a decrease in minutes of reserve violations. In Scenario 3_P6, the system relied heavily on onshore wind. However, during periods of lower onshore wind production, the system relied heavily on dispatchable resources, and experienced more minutes of reserve scarcity as a result. Scenario 3_P7, which had a more diverse resource mix than Scenario 3_P6, experienced fewer minutes of reserve scarcity despite having an identical fleet of dispatchable resources. Building a more diverse fleet may help compensate for periods when variability from one resource type is driving dispatchable generator utilization, leading to fewer minutes of reserve scarcity.

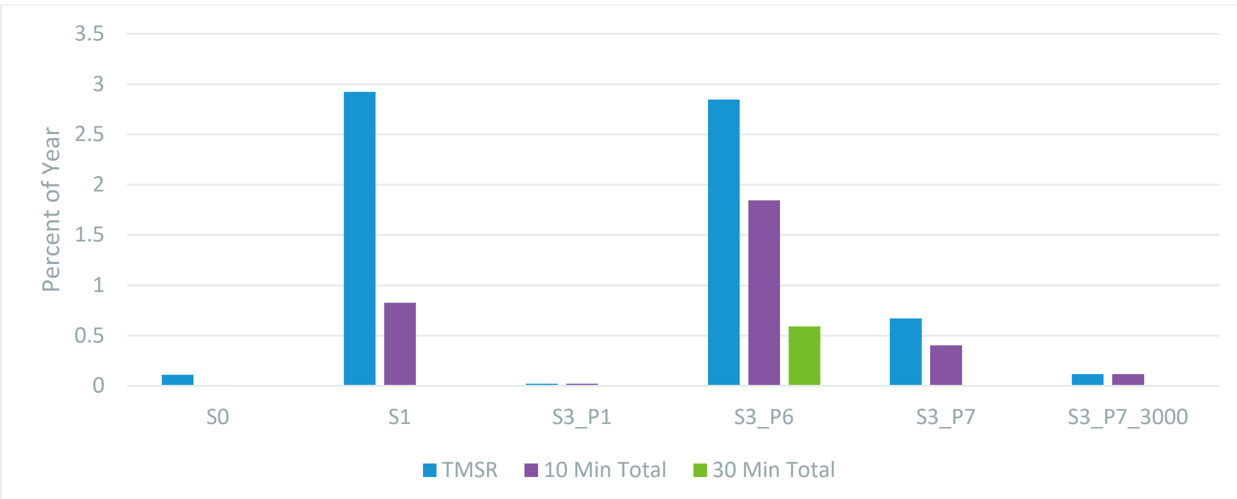


Figure 4-9: Reserve Requirement Violations by Scenario

Reserve requirement violations led to the application of RCPF prices, and thus significantly elevated reserve prices and real-time energy market prices. Most Scenarios were able to minimize minutes of expensive energy. However, Scenario 1 and Scenario 3_P6 experienced a moderate number of Tot10 violations and some Tot30 violations. This led to high reserve market revenues for these Scenarios (see Figure 4-10).

Figure 4-10: Reserve Market Revenues by Scenario

This analysis was limited by the fact that reserves in EPECs can only be provided by dispatchable generation. It is possible that in a future grid, variable energy resources could be incentivized to manage their output and provide 'spinning' reserves or BESS units could provide the equivalent of spinning or non-spinning reserves. Because EPECS lacked this modeling capability, some Scenarios experienced significant minutes of reserve scarcity.

4.3.5 Ramping Reserves

The ramping reserves of a Scenario (see Figure 4-11) describe the aggregate ability of the generation fleet to increase their power over time. Ramping reserves measures the aggregate headroom of the ramping capability of the dispatchable resource fleet. A depleted ramping reserve indicates that net load is increasing faster than the dispatchable resource fleet is able to respond. None of the feasible Scenarios (i.e., were able to be simulated) depleted their ramping reserves, though some came close. Scenario 3_P1 had the lowest average ramping reserves due to increased amounts of reserve from fast-start resources and a lower penetration of variable energy resources compared to other Scenario 3 proxy cases. Consequently, Scenario 3_P7 had the highest penetration of variable energy resources and the highest average ramping reserves, indicating that more ramping capability was needed for potential resource variability. The high penetration of PV in Scenario 3_P7 also likely contributed towards a higher need for ramping.

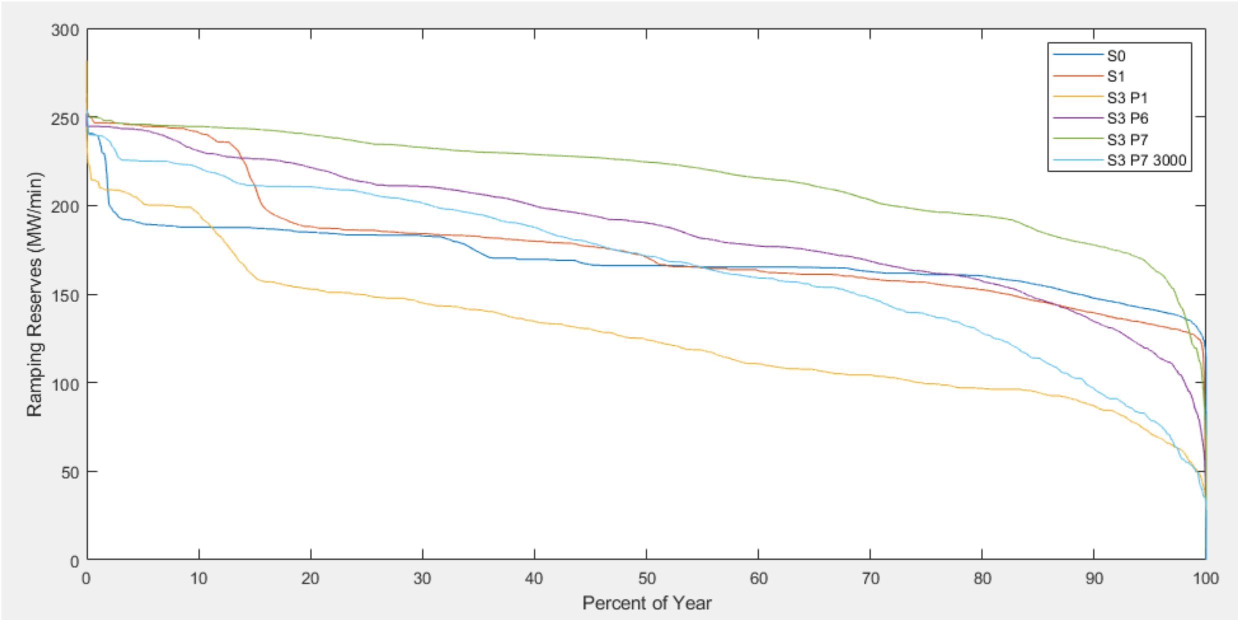


Figure 4-11: Ramping Reserve Duration Curves by Scenario

4.3.6 Scenario 3 and Alternative B Scenario 3

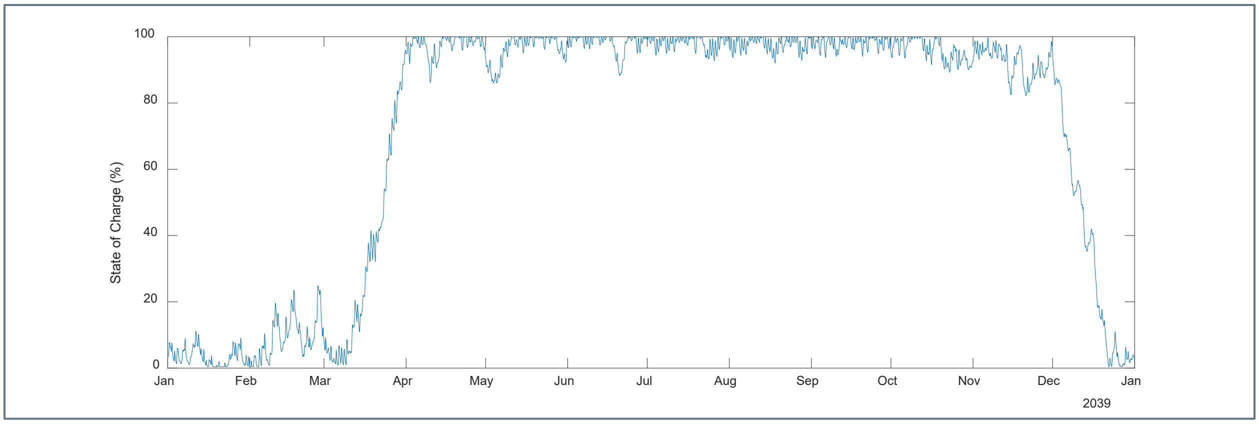
Scenario 3 and Scenario 3 Alternative B both experienced large regulation needs, on the scale of 4,000 to 5,000 MW. These Scenarios also did not meet resource adequacy reliability criteria. Additional analysis revealed that both of these Scenarios depleted reserves entirely, which resulted in large regulation needs. Figure 4-8 through Figure 4-10 do not depict these Scenarios due to the massive scale of their regulation needs, minutes of reserve scarcity, and reserve market revenues. Though the other Scenarios were considered part of a proposed future situation, Scenario 3 and Scenario 3 Alternative B were considered deficient in reserves.

4.3.7 Variation of Scenario 3 (Scenario 3_Inc)

Increasing the reserve requirement in another variation of Scenario 3 (Scenario 3_Inc) did lower regulation need slightly, but dramatically increased reserve requirement violations. Because there were no additional dispatchable resources available to provide reserves, attempting to draw more reserves from the same fleet only produced more minutes of reserve scarcity. As with Scenario 3, this variation was considered deficient in reserves.

4.3.8 Scenario 3 Alternative D

Scenario 3 Alternative D experienced similar challenges in the Ancillary Services analyses as the production cost analyses. The energy storage in this Scenario was depleted quickly in the winter months (see Figure 4-12), and remaining generation was insufficient to serve load. As a result, the regulation need was so massive that the Scenario was considered infeasible.



[6]

Figure 4-12: Scenario 3 Alternative D Annual Storage State of Charge

Ultimately, simulating this Scenario realistically requires either significant additional seasonal storage capability or more resources to provide recharging opportunities to satisfy the demand during the winter months.

[6] In this version of Scenario 3 Alternative D, an initial run was performed, then a second run was performed where the energy storage state of charge on January 1st was set equal to the state of charge on December 31st of the previous run

Section 5: Conclusion

5.1 Relation to Takeaways

As a general trend, increased amounts of variable energy resources (i.e., onshore/offshore wind and solar PV) led to an increased need for regulation and of reserves. Scenarios that contained large amounts of dispatchable resources experienced minimal minutes of reserve requirement violations, which mimics the current ISO New England system. On the other hand, Scenarios that assumed the retirement of many dispatchable resources quickly experienced increased periods of reserve requirement violations.

Since transportation and heating electrification significantly increase demand, power systems must not prematurely retire too many dispatchable resources. Variable energy resources, with support from storage, can provide large amounts of energy to a system when needed, but a near-perfect balance between supply and demand must always be maintained. Some Scenarios even experienced reserve depletion when the system ran out of resources to commit, which resulted in large need for regulation resources. These Scenarios were considered deficient in reserves and unable to meet system flexibility requirements. In other words, these Scenarios experienced many minutes where reserves dropped below the required threshold, triggering high real-time energy and reserves prices. When reserves dropped to zero, the simulated system experienced unserved energy. In a real system, reserve deficiency would lead to scarcity events with expensive electricity and reserves prices and possible rolling blackouts to maintain supply and demand balance.

In Scenarios that did not deplete reserves, a higher need for regulation resources was positively correlated with an increased penetration of variable energy resources. In a future system, resources that are more variable will require more frequent dispatches and/or increased amounts of regulation resources to act between dispatches. Because regulation is traditionally supplied from thermal dispatchable resources, less units may be around to provide regulation. Energy storage may be able to fill the need for regulation.

Reserve requirements will become more crucial in future Ancillary Services configurations. In the current ISO New England grid, reserve requirements are set as a percentage of the first or second largest contingency (i.e., if the largest generator on the system is a 1,200 MW nuclear unit, Tot10 reserve requirement may be 120% of the largest contingency, or 1,440 MW). This ensures that 10-minute reserves can respond to the worst-case unit outage with some margin and return the system supply-demand balance within the required 15 minutes. However, in a future grid with high penetrations of variable energy resources, the largest single loss of generation could be caused by cloud cover over a critical area or an unexpected drop in wind speed across a large, geographically compact wind resource area. Additionally, as more fossil fuel resources are retired, these reserves may need to be provided by wind, solar, or energy storage resources. Variability from variable energy resources can be managed if the resources are able to self-monitor their outputs. For example, a wind generator with a rapidly changing output could self-curtail some production to ease the flexibility requirements of the remainder of the system. The need for Ancillary Services will increase, but fewer traditional dispatchable resources will be available to provide these services. To continue to meet reserve requirements, wind generators, PV generators, and energy storage units may have to be able to provide some reserves. The system will require paradigm shifts to ensure the continuation of functioning Ancillary Services during the clean energy transition.

Stakeholder requests resulted in the analysis of many interesting Scenarios, but some of these Scenarios pushed the abilities of the simulators, and EPECS was no exception. The EPECS model used various simplifications for which there is no industry consensus on an appropriate representation. A significant simplification was the inability to model the behavior of energy storage in real-time. Energy storage could not participate as reserves and could only respond every 15 minutes in the RTUC layer. Also, as a proxy for reserves, some energy storage was manually assigned towards regulation, but this represents just a fraction of the potential for energy storage in Ancillary Services markets. Current market rules allow storage to offer into capacity, energy, and reserve markets, but the very low penetration of current energy storage makes the behavior of a large penetration difficult for software developers to predict and model. While it is expected that modeling capability will likely improve over time, current tools are unable to adequately represent a future energy storage resource whose roles and capabilities are still evolving.

Though wind and solar generation in conjunction with energy storage were able to provide a significant portion of energy demand, a core amount of dispatchable generation was still needed to provide Ancillary Services and energy demand to the system during low production periods from wind and solar resources. New market rules could encourage the current fleet to provide additional flexibility (faster ramp rates, higher/lower max/min power ratings, faster startup times, etc.) as ISO New England may need to incentivize more flexibility from its Ancillary Services markets to maintain balance between the increasingly variable supply and growing weather-dependent demand of the clean energy transition.