2017 ISO New England System Operational Analysis and Renewable Energy Integration Study (SOARES)

SOARES Project Methodology Report

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Executive Summary

The bulk electric power system in New England is fundamentally changing. The representation of nuclear, coal and oil generation facilities is set to dramatically fall and natural gas, wind and solar facilities will come to fill their place. The introduction of variable energy resources like solar and wind, however, necessitates fundamental changes in the power grid's dynamic operation. Such units introduce greater *uncertainty* and must be accurately forecasted. They also introduce greater *intermittency* and therefore require greater quantities of operating reserve. These new power system dynamics and their impacts on ISO New England's operations need to be systematically and rigorously assessed. To that end, ISO New England has launched the 2017 System Operational Analysis and Renewable Energy Integration Study (SOARES). Given their extensive publications on the topic, ISO-NE has selected the Laboratory for Intelligent Networks of Engineering Systems (LIINES) at the Thayer School of Engineering at Dartmouth to conduct the study. This report describes the project's methodology as the first activity in the project's scope of work.

The heart of the project's methodology is a novel, but now extensively published, holistic assessment approach called the *Electric Power Enterprise Control System* (EPECS) simulator. Most fundamentally, the EPECS methodology is *integrated* and *techno-economic*. It characterizes a power system in terms of the physical power grid and its multiple layers of control including commitment decisions, economic dispatch, and regulation services. Consequently, it has the ability to provide clear trade-offs for any changes to the physical power systems and its associated layers of control.

The report begins with a rationale for EPECS simulation. It argues that with respect to operations the integration of variable energy resources should not be considered as "business-as-usual," and instead a more holistic approach is required. It lays out the requirements for such a rigorous assessment. That discussion contextualizes a review of the methodological adequacy of existing renewable energy integration studies. It highlights several key conclusions found as a consensus across the literature. Combined unit-commitment and economic dispatch (UCED) models are used to assess changes in operating costs. Statistical methods are used to assess the need for greater quantities of operating reserves. The exact degree to which these changes occur ultimately depend on individual power system properties such as generation mix and fuel cost. They also depend on the choice of several significant but not necessarily validated methodological assumptions used in the study. The report identifies several methodological limitations including: 1.) limited scope of the physical power grid, 2.) limited fidelity of enterprise control layers, 3.) limited scope of the economic assessment, 4.) omission of line congestion and voltage management, 5.) a lack of fidelity in balancing operation and accuracy in reserves determination and 6.) a lack of consideration of multiple timescales.

The body of the report describes the EPECS simulator in detail. It provides precise definitions of how variable energy resources and operating reserves are modeled. It also includes detailed models of day-ahead resource scheduling, same-day resource scheduling, real-time balancing operations, regulation as an ancillary service, and event-based contingency operation. The report also includes the zonal-network (i.e. pipe & bubble) model of the physical power grid. The report also includes an extensive demonstration of the EPECS simulator on the IEEE RTS 96 Test Case as a hypothetical system. Each of the simulator's outputs are provided in detail. The report then demonstrates how these simulator outputs can be post-processed to assess operating reserve requirements in response to a broad range of operating scenarios.

The report concludes with a description of how the EPECS simulation methodology is integrated into the SOARES project. The SOARES project work consists of four activities: 1.) the preparation of a state-of-the-art renewable energy integration assessment methodology customized to the operational characteristics of ISO-NE, 2.) the preparation of a set of scenario data to conduct a renewable energy integration assessment study for the years 2025 and 2030, 3.) the development of a validated numerical simulation of ISO-NE renewable energy integration for the year 2014 and 4.) the assessment of the reliability and economic impacts of renewable energy integration for the years 2025 and 2030. The project concludes with a final report that incorporates feedback from PAC meetings and more generally ISO New England.

1 Introduction

The resource mix of ISO New England (ISO-NE) is rapidly changing. Figure 1 shows the evolution of its generation mix from 2005 to 2015 [1, 2]. As of 2015, over 9% of the total generation came from variable energy sources (i.e. wind and photo-voltaic (PV) solar [2]). This percentage is expected to grow as the levelized cost of solar PV and wind installations continues to fall [12]. In the meantime, the representation of nuclear, coal, and oil plants in the generation portfolio is set to dramatically fall for two complementary reasons. First, the emergence of low cost natural gas generation in recent years [13] has partially supplanted these facilities in the economic merit order. Second, these facilities have an average age of over 30 years [1] and are likely to be retired in the coming years. For example, nuclear retirements are expected to bring down the percentage of nuclear generation to 9% [14] by 2025 as compared to the 30% in 2015 [2]. These retirements are likely to be replaced by more wind and natural gas resources in the overall resource mix. The percentage of natural gas powered generation is expected to account for over 55% of the overall generation in 2025 [15]. Furthermore, renewable portfolio requirements of various member states have also driven the ISO-NE resource mix to include more variable energy resources [14]. These requirements vary by state. Some states, like Vermont, require up to 59% of renewable energy generation including large-scale hydro. This supply-side change in resource mix is occurring simultaneously with demand-side investment in energy efficiency measures. It is estimated that over \$6.2 billion [14] will be invested in energy efficiency (EE) between 2019 and 2024 in addition to over \$3 billion already spent on EE between 2009 and 2025 [14, 16].

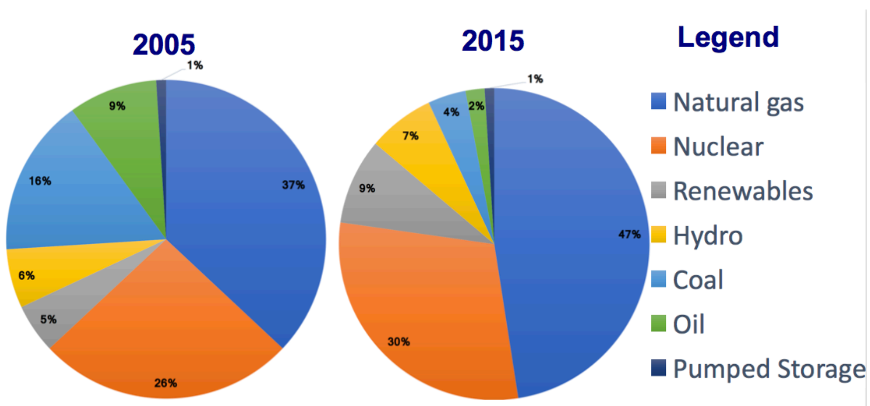

Figure 1: ISO New England Generation Mix in 2005 and 2015 [1, 2].

This changing resource mix, and particularly the introduction of variable energy resources, is set to cause fundamental changes in the power grid's dynamic operation [17]. As shown in Figure 2, traditional power systems have often been built on the basis of an electrical energy value chain which consists of relatively few, centralized, and actively controlled thermal power generation facilities [18,19]. These serve a relatively large number of distributed, stochastic electrical loads [18, 19]. Furthermore, the dominant operating paradigm and goal for these operators and utilities was to always serve the consumer demanded load with maximum reliability at whatever the production cost [20]. Over the years, system operators and utilities have improved their methods to achieve this task [9, 21]. Generation dispatch, reserve management and automatic control has matured. Load forecasting techniques have advanced significantly to bring forecast errors to as low as a couple of percent. System security procedures and their associated standards have evolved equally.

Past:

Generation/Supply	Load/Demand
Thermal Units: (Few, Well-Controlled, Dispatchable Resources)	Conventional Loads: (Fairly Slow Moving, Highly Predictable, Always Served)

Future:

	Generation/Supply	Load/Demand
Well-Controlled & Dispatchable	Thermal Units: (Potential Erosion of Capacity Factor)	
Stochastic/ Forecasted	Solar & Wind Generation: (Variability can cause unmanaged grid imbalances)	Conventional Loads: (Fairly Slow Moving, Highly Predictable, Always Served)

Figure 2: The Evolution of the Power System: (Top) Power system of the past consists of dispatchable generation and stochastic loads. (Bottom) The future power system introduces solar & wind generation as variable energy resources [3].

The introduction of variable energy resources evolves this status quo. As they are added into the grid, the picture of the generation and demand portfolio gains a third quadrant as shown in the bottom half of Figure 2. From the perspective of dispatchability, VERs are non-dispatchable in the traditional sense: the output depends on external conditions and are not controllable by the grid operator[1] [25]; except in a downward direction for curtailment. As VERs displace thermal generation units in the overall generation mix, the overall dispatchability of the generation fleet decreases. In regards to forecastability, variable energy resources increase the uncertainty level in the system [25]. Relative to traditional load, VER forecast accuracy is low, even in the short term [26]. There are two major groups of wind forecasting techniques: numerical weather prediction (NWP) and statistical methods [27, 28]. The former use more complicated models based on the current weather conditions. This kind of model is mainly used for long term wind forecasts; 24 hours ahead and more. The latter is based upon historical data input and is applied to shorter terms. The decreased dispatchability coupled with decreased forecastability summarized by Figure 2 calls for holistic assessment of the electric power system as it evolves.

1.1 Guiding Assessment Structure for Power Grids: Enterprise Control

The integration of variable energy resources will bring about fundamental changes that will necessitate a structured and holistic view for assessing the power system as it evolves. While existing regulatory codes and standards will continue to apply [22–24], it is less than clear how the holistic behavior of the grid will change or how reliability will be assured. Furthermore, it is important to assess the degree to which control, automation, and information technology are truly necessary to achieve the desired level of reliability.

[1] In recent years, significant efforts in both academic and industrial research and development have advanced the potential for variable energy resources to provide ancillary services [22–24]. However, these technologies have yet to become mainstream in the existing fleet of solar PV and wind generation facilities. This work, therefore, assumes that VERs are truly variable.

Thirdly, it is unclear what value for cost these technical integration decisions can bring. From a societal perspective, and beyond simply variable energy integration, smart grid initiatives have been priced at several tens of billions of dollars in multiple regions [29,30]. Therefore, there is a need to thoughtfully quantify and evaluate the steps taken in such a large scale technological migration of the existing power grid.

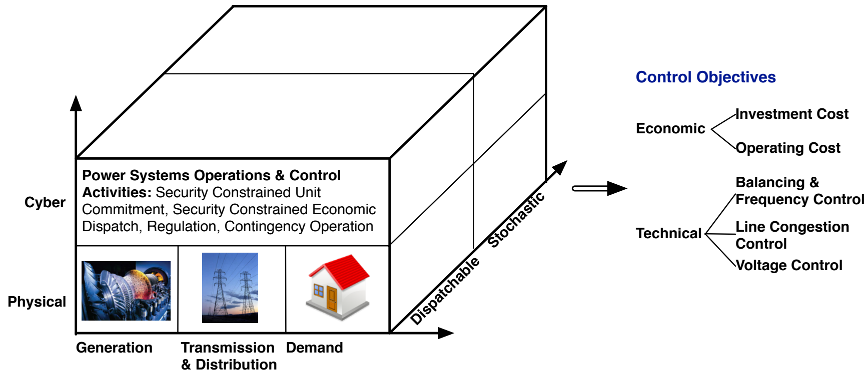

Figure 3: Enterprise Control as Guiding Assessment Structure for Power Grids: The power grid is taken as a cyber-physical system composed of an energy value-chain with dispatchable and stochastic elements that must fulfill certain technical and economic control objectives.

This work, thus, argues that a future electricity grid with a high penetration of renewable energy requires holistic assessment methods. This argument is structured as shown in Figure 3. On one axis, the electrical power grid is viewed as a *cyber-physical* system. That is, assessing the physical integration of renewable energy *must* be taken in the context of the control, automation, and information technologies that would be added to mitigate and coordinate their effects. On another, it is an energy value chain spanning generation and demand. On the third axis, it contains dispatchable as well as stochastic energy resources. These axes holistically define the scope of the power grid system which must meet competing *techno-economic* objectives. Power grid technical objectives are often viewed as balancing operations, line congestion management and voltage management [21]. Economically speaking, the investment decision for a given technology; be it renewable energy resources or their associated control must be assessed against the changes in reliability and operational cost. These economic and control technologies will later be viewed from the lens of dynamic properties including dispatchability, flexibility, and "forecastability". Naturally, such holistic assessment methods will represent an evolution of existing methods. This work thus seeks to draw from the trends and recommendations in the existing literature and frame them within the structure of Figure 3.

This ongoing evolution of the power grid can already be viewed through the lens of *"enterprise control"*. Originally, the concept of enterprise control [31, 32] was developed in the manufacturing sector out of the need for greater agility [33, 34] and flexibility [35–37] in response to increased competition, mass-customization and short product life cycles. Automation became viewed as a technology to not just manage the fast dynamics of manufacturing processes but also to integrate [38] that control with business objectives. Over time, a number of integrated enterprise system architectures [39, 40] were developed coalescing in the current ISA-S95 standard [32, 41]. Analogously, recent work on power grids has been proposed to update operation control center architectures [42] and integrate the associated communication architectures [43]. The recent NIST interoperability initiatives further demonstrate the trend towards integrated and holistic approaches to power grid operation [44]. These initiatives form the foundation for further and more advanced holistic control of the grid [45–49].

1.2 Report Objective

Given the emergence of these trends in New England, ISO-NE has initiated the 2017 System Operational Analysis and Renewable Energy Integration Study (SOARES). This project serves as the last of three Phase II projects of the 2016 economic study [10,50]. Given their extensive publications on the topic, ISO-NE has selected the Laboratory for Intelligent Integrated Networks for Engineering Systems (LIINES) at the Thayer School of Engineering at Dartmouth to conduct the study. This report describes the project's methodology as a whole emphasizing a novel, but now extensively published [11,51–57], holistic assessment approach called the *electric power enterprise control system* (EPECS) simulator. It also situates this new approach relative to the existing renewable energy integration literature. To maintain continuity, the project specifically seeks to study ISO-NE operations in the years 2025 and 2030 for the six scenarios identified during Phase I of the 2016 Economic Study request. The study will specifically address quantify operating reserve requirements, ramp rates over hourly and sub-hourly periods, and identify periods of insufficient operating reserves.

1.3 Report Outline

The rest of this report is structured as follows, Section 2 provides a review of the methodological adequacy of existing renewable energy integration studies. Section 3 presents the Electric Power Enterprise Control System (EPECS) simulation methodology for ISO-NE in detail. Section 4 then describes how the simulator methodology is integrated into the SOARES project as a whole. Finally, the report is brought to a conclusion in Section 5.

2 Review of the Methodological Adequacy of Existing Renewable Energy Integration Studies

It is in the context of the evolution of the physical power grid described above, that the discussion can turn to the adequacy of existing assessment methods. Over the many decades, the fields of electric power engineering and economics have developed a rich and diverse set of assessment techniques to assure reliability and maximize overall economics [21, 58]. Unit commitment, optimal power flow, contingency analysis, state estimation, as well as angular, frequency and voltage stability are but a prominent few. Furthermore, they have been implemented in countless technical standards, codes and regulations [22–24]. A full review of these is certainly intractable and assumed as prerequisite. Furthermore, the rationale presented in this report advocates the enhancement, evolution and combination of these many techniques in holistic frameworks rather than their replacement.

Consequently, in assessing the adequacy of existing methods, the focus is placed on those approaches that facilitate the evolution of the power grid as described in Section 1.1. While the academic literature has produced many works on the role of variable energy [59–62], demand side [20, 63–67], and energy storage resources [68–72], many of these works are dedicated to only one of these resource types or only one power system control function. In contrast, numerous renewable energy integration studies have emerged in the academic and industrial literature [62, 73–75] that give a much more holistic understanding of the power grid and its potential evolution in the future. This section proceeds in two parts. Section 2.1 discusses the key conclusions and methodological elements from these renewable energy integration studies. Section 2.2 then presents some of their limitations that would motivate the need for more holistic assessment methods.

			Physical Layer				Cyber-Layer (Control)			Assessment Method for Power System Objectives						
										Balancing Operation						
	Acronym	Publication Year	Dispatchable Generation	Variable Generation	Traditional Load	Demand Side Resources	Unit Commitment	Economic Dispatch	Regulation	Load Following (Secondary) Reserves	Ramping Reserves	Regulation (Primary) Reserves	Line Congestion Management	Voltage Management	Operating Cost	Investment Cost
1	CA-MA-WIS [165]	2005	✓	Wind	✓	--	N/A -- Stats Only			--	--	--	--	--	--	--
2	CA-ON-WIS [166]	2006	✓	Wind	✓	--	N/A -- Stats Only			Stat-B-VAR 5min	--	Stat-B-VAR 1min	--	--	--	--
3	EU-AI-REIS [167]	2007	✓	All	✓	--	Gen: 1h	Gen: 1h	Gen: 1h	Stoch-WLF 5min	--	Stat-D2-WLF	--	--	UCED	--
4	EU-IB-WIS [168]	2006	✓	Wind	✓	--	N/A -- Dynamics Only			--	--	--	--	--	--	--
5	EU-DE-WIS [169]	2005	✓	All	✓	--	N/A -- Stats Only			Stat-D2-WLF 15min	--	--	PFA, N-1CA	DVSM	--	Physical: Lines, Control: Regulators
6	EU-DE-REIS [170]	2010	✓	All	✓	Storage & DSM	G&D: 1h	G&D: 1h	--	Utilized	Residual Load Duration Curve	--	PFA	SVSM	UCED	Physical: Lines
7	EU-NL-WIS [171]	2009	✓	Wind	✓	Storage	Gen: 1h	Gen: 1h	Gen: 1s	--	--	--	--	--	UCED	--
8	EU-SE-WIS [172]	2005	✓	All	✓	--	N/A -- Stats Only			Stat-B-WLF 1h	--	Stat-B-WLF 15min	--	--	--	--
9	EU-REIS [173]	2012	✓	All	✓	Storage & DSM	G&D: 1h	G&D: 1h	--	Utilized	Residual Load Duration Curve	--	--	--	UCED	Physical: Generation
10	EU-WIS [174]	2010	✓	All	✓	--	Gen: 1h	Gen: 1h	Gen: 1s	--	--	--	PFA, N-1CA	DVSM	UCED	Physical: Lines
11	EU-TW-WIS [175]	2009	✓	Wind	✓	--	Gen: 1h	Gen: 1h	--	--	--	--	PFA	--	UCED	--
12	EU-UK-WIS [176]	2007	✓	Wind	✓	--	N/A -- Stats Only			Stat-B-WLF 30min	--	--	--	--	--	--
13	EU-WI-WIS [177]	2005	✓	Wind	✓	--	--	Gen: 5min	Gen: 1s	Utilized	--	Utilized	UCED	--	UCED	--
14	US-AV-WIS [178]	2007	✓	Wind	✓	Storage	Gen: 1h	Gen: 1h	--	Stat-B-VAR 10min	--	Stat-B-VAR 10min	--	--	UCED	--
15	US-AZ-SIS [179]	2012	✓	Solar	✓	--	N/A -- Stats Only			Stat-D1-WLF 10min	--	--	--	--	Stat	--
16	US-CA-REIS [180]	2010	✓	All	✓	--	Gen: 1h	Gen: 5min	Gen: 1s	Stoch 5min	Stoch 1min	Stoch 1min	--	--	UCED	--
17	US-E-WIS [181]	2010	✓	Wind	✓	--	Gen: 1h	Gen: 1h	--	Stat-D1-WLF Minutes	--	--	--	--	UCED	--
18	US-ERC-REIS [182]	2008	✓	All	✓	--	Gen: 1h	Gen: 1h	--	--	--	Stat-B/ D1-WLF	--	--	UCED	--
19	US-HA-WIS [183]	2011	✓	All	✓	--	Gen: 1h	Gen: 1h	Gen: 1s	Stat-D1 10min	--	Stat-D1 1s	--	--	UCED	--
20	US-ID-SIS [184]	2014	✓	Solar	✓	--	--	Gen: 1h	--	Stat-B 5min	--	--	--	--	UCED	--
21	US-MN-WIS [185]	2006	✓	Wind	✓	--	Gen: 1h	Gen: 1h	--	Stat-B-VAR Minutes	--	Stat-B-Var	PFA	--	UCED	--
22	US-NE-WIS [186]	2010	✓	Wind	✓	--	Gen: 1h	Gen: 10min	--	Stat-D1 10min	--	Stat-D1 10min	--	--	UCED	--
23	US-NEng-WIS [187]	2010	✓	Wind	✓	--	Gen: 1h	Gen: 1h	--	Stat-B 10min	--	Stat-B 10min	--	--	--	--
24	US-NV-SIS [188]	2011	✓	Solar	✓	--	Gen: 1h	Gen: 10min	Gen: 2-4s	Stat-B-VAR 10min	Stat-VAR-1min	Stat-B-VAR 1min	--	--	UCED	--
25	US-NY-WIS [189]	2005	✓	Wind	✓	--	Gen: 1h	Gen: 1h	--	Stat-B-Var 5min	--	Stat-B-Var	--	DVSM	UCED	--
26	US-P-WIS [190]	2010	✓	Wind	✓	--	Gen: 1h	Gen: 1h	Gen: 10min	Stat-B-VAR 1h	--	Stat-B-VAR 10min	--	--	UCED	--
27	US-PJM-REIS [191]	2013	✓	All	✓	--	Gen: 1h	Gen: 1h	--	Stat-D1-VAR 10min	--	Stat-D1-VAR 10min	Trans. overlay	--	UCED	Physical: Lines
28	US-SPP-WIS [192]	2010	✓	Wind	✓	--	Gen: 1h	Gen: 1h	--	Stat-B-WLF 10min	--	Stat-B-WLF	PFA, N-1CA	SVSM	UCED	--
29	US-W-WSIS [193]	2010	✓	All	✓	--	Gen: 1h	Gen: 5min	Gen: 1min	Stat-D1-VAR	--	--	PFA	--	UCED	--
30	US-W-WSIS2 [194]	2013	✓	All	✓	--	Gen: 1h	Gen: 5min	Gen: 1min	Stat-D1-VAR	--	Stat-D1-WLF	PFA	--	UCED	--

Key: PFA -- Power Flow Analysis, N-1CA -- N-1 Contingency Analysis, DVSM - Dynamic Voltage Stability Model, Static Voltage Stability Model

Figure 4: An Analysis of Scope and Methods in Renewable Energy Integration Studies

2.1 Key Conclusions of Renewable Energy Integration Studies

In order to support the need for holistic enterprise control assessment, a review of existing renewable energy integration studies is conducted from the perspective of the guiding structure found in Figure 3. In order to focus on the most developed methodologies, only integration studies published after 2005 are included. The interested reader is referred to [76] for pre-2005 works. Figure 4 summarizes the analysis of the included works ordered alphabetically by their associated acronym [77–106]. This list constitutes a superset of those included in a recent review [62] on the results rather than the methodologies of renewable energy integration studies. Methodologically speaking, Figure 4 addresses the physical layer in terms of the four types of resources shown in Figure 2, the enterprise control in terms of the traditional hierarchical layers of power system operation, and assessment methods in terms of the traditional technical and economic dichotomies shown in Figure 3. The assessment of balancing operations is often viewed through the lens of the quantities of various types of operating reserves. Here, Figure 4 uses the taxonomy of statistical methods developed in Appendix C of [62]. The acronyms used are indicated in the key at the bottom of the figure.

Collectively, the renewable energy integration studies have many similarities [73, 74] [62, 75]. Figure 4 shows that the integration studies generally apply combined unit-commitment and economic dispatch (UCED) models to assess the additional operating costs of renewable energy integration. In contrast, most studies apply statistical methods [73, 74] [62, 75] to assess the required additional operating reserves. The main conclusion of these renewable integration studies is that intermittency and uncertainty will increase reserve requirements in the power system. This will consequently increase the marginal cost of power system operations [107, 108] [62, 109]. The exact degree of additional operational costs ultimately depends greatly on system properties such as generation mix and fuel cost.

Balancing operations and reserves determination are two of the central objectives of renewable energy integration studies. The statistical methods used to determine operating reserves are in general variations on the theme found in [110]. The differences between these approaches has been classified by Brouwer et al [62]. In general, the standard deviation of potential imbalances, σ, is calculated using the probability distribution of net load *or* forecast error. The load following and regulation reserve requirements are then defined to cover appropriate confidence intervals of the distribution based on the experience of power system operators and existing standards. A detailed discussion on the definition and types of operating reserves is provided in Section 3.3. Normally, load following is taken equal to 2σ [110, 111] to comply with the North American Electric Reliability Corporation (NERC) balancing requirements: NERC defines the minimum score for Control Performance Requirements 2 (CPS2) equal to 90% [112]. This corresponds to 2σ for a normal distribution. Other integration studies have used a 3σ confidence interval [113, 114] to correspond to the industry standard of 95% [115]. Based on the experience of power system operators, regulation is normally taken to be between 4σ and 6σ [110, 111, 116].

2.2 Methodological Limitations of Existing Renewable Energy Integration Studies

The discussion of the limitations of existing assessment methods is guided by the structure of Figure 3, builds upon the arguments of the previous sections and draws upon the results found in Figure 4. Additionally, and wherever appropriate, the methodological insights and recommendations found in existing renewable energy integration studies are mentioned.

2.2.1 Scope of the Physical Layer

In regards to the power grid's physical layer, Figure 4 shows that wind (rather than solar) power has attracted relatively more attention given its greater environmental potential in the geographies committed to renewable energy integration. Nevertheless, solar PV has seen significant cost reductions and greater adoption in recent years [91, 96, 100, 117]. Consequently, several recent studies (e.g. the Solar Integration Study by New York ISO (NYISO)) has specifically included solar energy within their scope. Meanwhile, demand side resources including energy storage and electric vehicles are almost entirely absent methodologically from these studies. Nevertheless, several prominent studies do mention the need to include demand side management directly [82, 86]. Such considerations are particularly important as traditional load and renewable energy penetration grows [62,74].

2.2.2 Fidelity of Enterprise Control Layers

In regards to the electric power enterprise control system, Figure 4 shows that most renewable energy integration studies use simulations based upon an integrated UCED model. Fewer studies add a model of regulation as a separate ancillary service. These three enterprise control layers are conducted primarily to assess the additional operating cost of renewable energy integration and are not integrated with a model of the physical grid to calculate technical variables such as potential power grid imbalances [62, 83, 118]. One often cited concern is that these simulations do not correspond to the existing enterprise control practice. For example, time steps, market structure and physical constraints should correspond to the operating reality [62, 74, 75, 119, 120]. In the case of market time step size, it has been confirmed both numerically [11, 51, 74, 75, 109] as well as analytically [53–56] to affect power grid imbalances and costs. Such a conclusion inextricably ties power system operation and control to their associated policies and regulations. For example, the recent FERC requirement to change the minimum frequency of the balancing market from 1 hour to 15 minutes has an associated impact on power grid technical and economic measures.

2.2.3 Scope of Economic Assessment

In regards to the economic assessment in renewable energy integration studies, Figure 4 shows that most are focused on operational costs through UCED simulation models. Comparatively few address the additional investment costs of physical infrastructure; be it in the form of generation or transmission expansion. Interestingly, the DENA 2010 study [82] includes the investment cost of voltage regulators to abate line congestion. Similarly, Mohseni et al. [23] advocate that new grid codes consider the associated investment costs of the requirements that they impose. In contrast, Diaz-Gonzalez et al. [22] describe grid code requirements on the frequency response of wind turbines with no mention of the costs incurred by providing this ancillary service while running in a sub-optimal state. These are telling precedents. They suggest the need to assess the investment costs of various control technologies against the technical improvements that they provide. If such an approach were generalized, it could form the basis for accurate assessments of the long term investment costs of future "smart" grids.

2.2.4 Inclusion of Line Congestion & Voltage Management

While balancing operations have been the focus of renewable energy integration studies, Figure 4 shows that some have also included line congestion and voltage management within their scope. In regards to line congestion management, power flow and N-1 contingency analyses are conducted as a post-process to the UCED simulation results. Holttinen et al. suggest instead that these analyses should be integrated [74, 75]. Furthermore, Muzhikyan et al. have demonstrated that power flow analysis as a physical model of the power grid serves to recalibrate the UCED simulation [11, 51, 52, 57, 121, 122]. More fundamentally, however, line congestion and the stability of balancing operations are ultimately coupled [123–125] and should be integrated in simulation [120]. Aspects of such an approach were begun in the DENA 2010 study [82]. With respect to voltage management, the applicable integration studies are split between static and dynamic models. Again, Holttinen et al. agree with the DENA 2010 study to use dynamic models over key time periods of interest [74,75]. They also advocate considering the effects of different wind turbine technologies, droop and regulator settings etc. Such a recommendation is insightful. If generalized, it could ultimately provide a working framework for the technical assessment of various control technology integrations. These may include variable energy and demand side resources and their respective controllers. This also suggests that renewable energy integration studies are likely to become instruments that influence grid code standards in addition to market and control structure as previously discussed.

2.2.5 Fidelity of Balancing Operation & Accuracy of Reserves Determination

With respect to balancing operations and reserves determination, the first limitation is the lack of methodological consensus [62, 120]. While the existing industrial practice and academic literature revolve around a similar theme, their methodological differences are significant. If they were applied to the data sets of a single study, they would show widely diverging results, thus indicating a need for development of the science in renewable energy integration. Furthermore, the statistical calculations in many integration studies are not validated by simulation [126, 127]. Those wind power integration studies that do use simulation usually do so for a particular study area [128]. Upon careful analysis, these studies make several simplifying assumptions in the modeling that do not necessarily reflect the power system operations knowledge [53–55]:

Assumption 1. Invariance of the Probability Density Function: The probability density function of imbalances will have the same shape from year to year (even as the generation portfolio changes) [110, 111, 113].

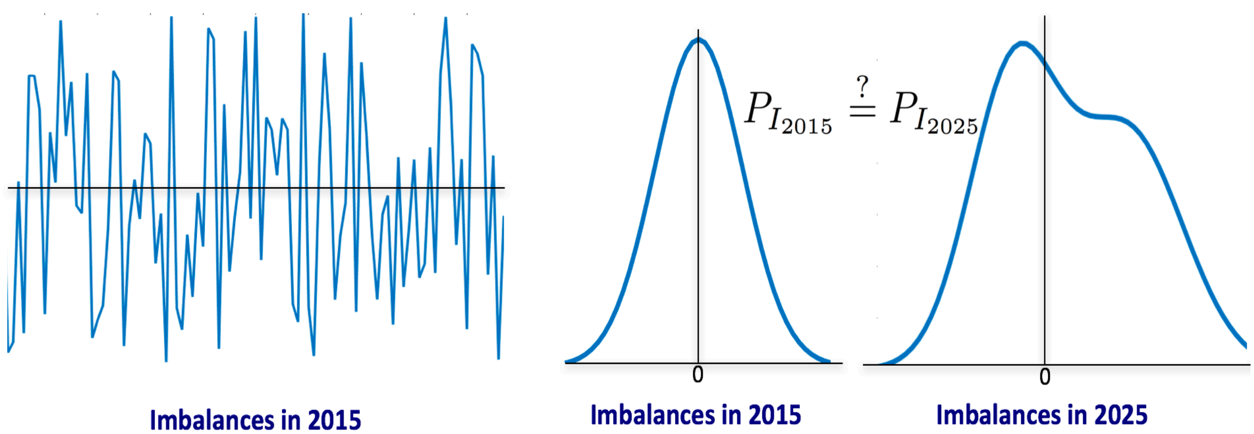

Figure 5: Operating Reserves Assumption 1: Invariance of the Probability Density Function of Imbalances from Year to Year

Assumption 1 suggests that the power system's stochastic processes retain their characteristics from one year to the next, which has no numerical evidence [26, 129, 130]. A fast adoption of variable energy resources over the course of a year would change this distribution. Furthermore, the statement that 2σ approximately corresponds to 90% of probability is true when variability/forecast error has a normal probability distribution, which is normally not true [26, 130–132]. This assumption can be justified using the central limit theorem [133] in the case of deep wind penetration with significantly wide geographical dispersion.

Assumption 2. Equivalence of Standard Deviations: The standard deviation of imbalances is equivalent to either the net load variability or its forecast error in a given year. Some works use variability [110, 116, 134], while others use the forecast error [114, 135–138].

In regards to Assumption 2, a perfectly forecasted but highly variable net load still requires more load following reserves than a modestly variable net load [3, 17]. Similarly, a high forecast error will require greater reserves than low forecast error [3, 17]. Therefore, the reserve requirement is more likely to depend on both variability and forecast error [53–56].

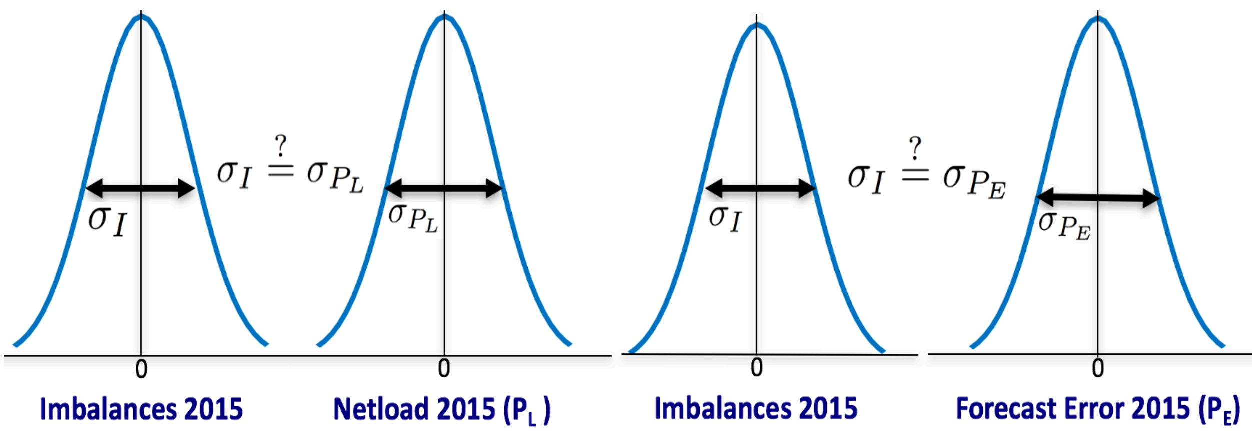

Figure 6: Operating Reserves Assumption 2: Equivalence of the Standard Deviations of Imbalances, Netload, and Forecast Error

Assumption 3. Invariance of the Standard Deviation: The standard deviation of the imbalances will have the same magnitude from year to year [110].

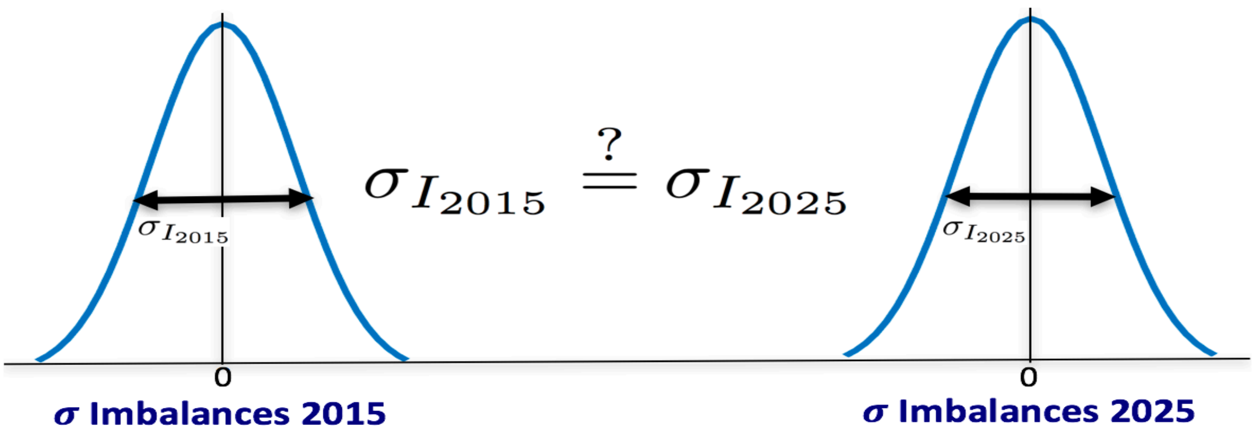

Figure 7: Operating Reserves Assumption 3: Invariance of the Standard Deviation of Imbalances from Year to Year

Assumption 3 suggests that the power system does not evolve over the long term (e.g. a year). However, the variables such as variable energy resource (VER) penetration level, forecast error and variability all have the potential to change from year to year.

Assumption 4. Non-dependence on Power System Operator Decisions & Control: The standard deviation of imbalances does not depend on the endogenous parameters of the power system operator decisions and control. According to Assumption 2, it only depends on the variability and forecast error, which can be viewed as exogenous disturbances to the power system operation and control.

Finally, the recent Federal Energy Regulatory Commission (FERC) requirement [139] to change the minimum frequency of the balancing market from one hour to 15 minutes suggests that power system imbalances do depend on the power system's endogenous characteristics [53–55, 74, 75, 109] contrary to Assumption 4. The revision of European grid codes to require wind plants to contribute to regulation reserves in primary & secondary frequency control [22–24] further invalidates this assumption. Generally speaking,

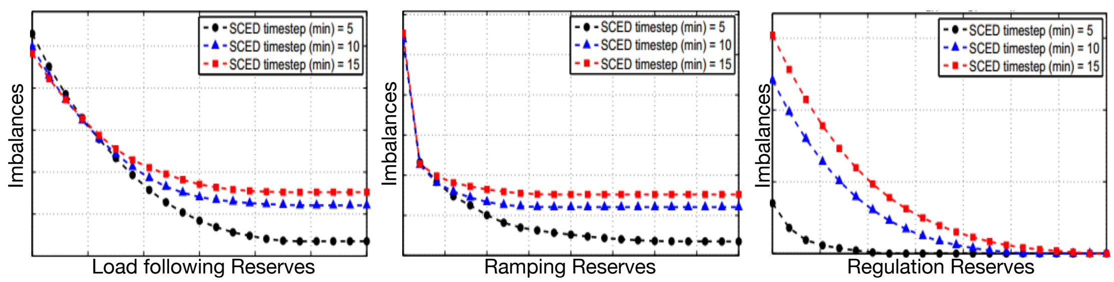

Figure 8: Operating Reserves Assumption 4: Non-dependence of Imbalances on Power System Operator Decisions & Control

from a control theory perspective, it is insufficient to characterize the reliability of a system purely on the basis of the magnitude of a disturbance without equally considering the control functions that attenuate this disturbance. More plainly, the reliability of the power grid depends not just on the quantity and timescale of the reserves but also the manual, semi-automatic and automatic control procedures that utilize them. Although such a requirement would immediately reduce wind variability, rarely is it considered in integration studies. Consequently, as the methodologies in renewable energy integration studies continue to develop it is more likely there will be a shift towards simulation-based [11,51,52,57,121,122,140] and analytical [53–55] techniques.

Recently, methods for assessing *dynamic* operating reserve requirements have been discussed in the literature [141–145]. The traditional *static* methods, currently used in the industry, assess the reserve requirements for the whole observed time period (e.g. one year). In contrast, the dynamic methods take advantage of the fact that the operating reserve requirements vary as the VER generation forecast and the grid conditions change. As a result, the operating reserve requirements assessed by dynamic methods vary for different time periods (e.g. hourly), which is likely to produce significant cost savings. While the rationale of these methods is empirically strong, they still follow Assumptions 1–4. While these assumptions have been made out of a level of engineering practicality, they are unlikely to be formally true [3, 17]. This

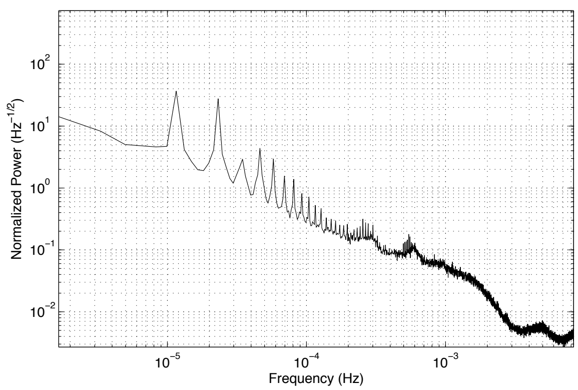

Figure 9: Normalized Power Spectrum of Daily Load (Data from [4]).

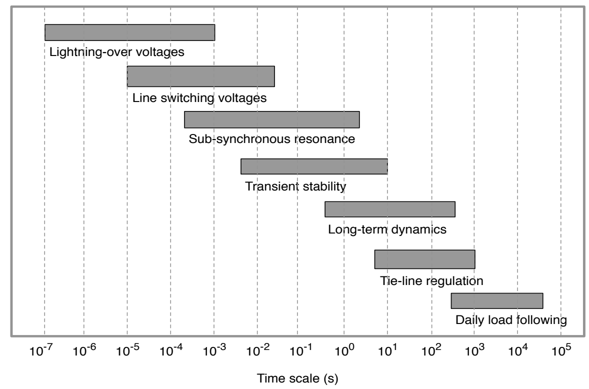

Figure 10: Timescales of Physical Power Grid Dynamics [5]

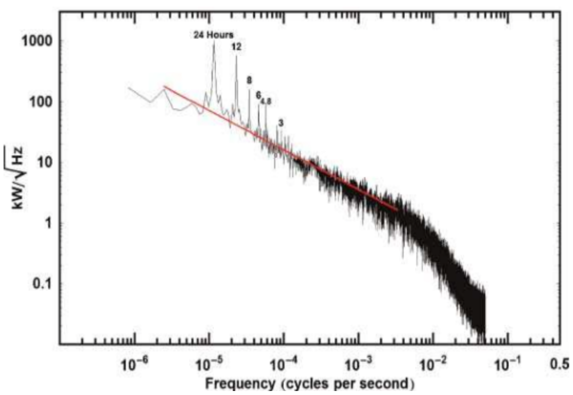

Figure 11: Solar Power Spectrum [6].

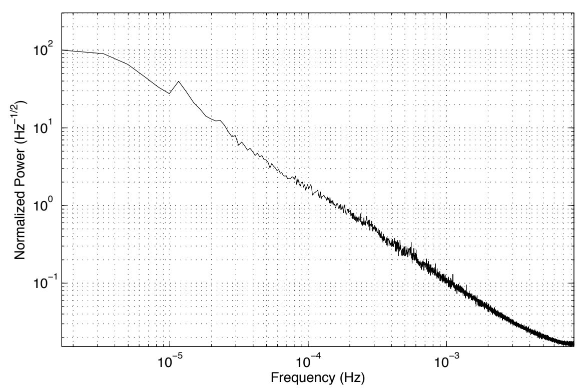

Figure 12: Wind Power Spectrum [7].

work proceeds explicitly avoiding these assumptions.

2.2.6 Consideration of Multiple Timescales:

With respect to timescales, not all studies consider multiple timescales of operation. Consider the spectral characterization of demand shown in Figure 9. It illustrates variations that span a wide range of frequencies with slow variations having larger magnitudes that correspond to the daily periodicity of consumer behavior. Figures 12 & 11 show similar spectra for wind power and solar photovoltaic generation respectively [146, 147]. Naturally, these exogeneous inputs excite and affect *all* the different behavioral phenomena in a power grid shown in 10. Therefore, one can conclude that in order to characterize a power system's imbalances accurately, it is necessary to use a multi-timescale analysis. A single timescale would only capture part of the variability of the net load and leave out either slower or faster phenomena.

Although the many physical power grid phenomena shown in Figure 10 do overlap [5], rarely do renewable energy integration studies address this breadth of operational timescales. For example, Reference [115] does not consider regulation because the available data has 10 minute resolution. References [126, 134] implement only unit commitment models, according to the assumption that wind integration has the biggest impact on unit commitment. Furthermore, Figure 4 shows that another concern is the usage and treatment of different power system timescales in the integration studies. Load following and regulation reserves operate at different but overlapping timescales. Net load variability, as a property exists in all timescales, although with changing magnitudes. Forecast error appears in exactly two timescales: 1 hour (day-ahead forecast error) and 5-15 minutes (short term forecast error). Thus, VER intra-hour variability and day-ahead forecast error are relevant to load following reserve requirements. Meanwhile, 5-15 minute variations and short-term forecast error are relevant to regulation reserve requirements. This division of impacts is not carefully addressed in the literature. In [110], the standard deviation σ is measured based upon the total variability of the net load. The loading following and regulation reserve requirements are then calculated on the basis of the *total* variability. Such an approach contradicts that these two control techniques act in different timescales.

Similar timescale concerns apply to studies that use forecast errors. For example, one study [113] calculates both load following and regulation requirements from the standard deviation of the day-ahead forecast error, and does not consider short-term forecast error. In contrast, another study [115] distinguishes between three different timescales of power system imbalances. The first timescale is regulation which is the difference between the ten minute average net load and the minute-by-minute net load. The second is load following which is the difference between the hourly average net load and the ten minute average net load. The final timescale is imbalance, defined as the difference between the hourly forecasted net load and the hourly average net load. In other words, the following three factors are considered: intra-hour variability, minute-by-minute variability and day-ahead forecast error.

2.2.7 Summary of Methodological Limitations

In conclusion, renewable energy integration studies as a collective body of literature give a much more holistic understanding of the power grid and its potential evolution in the future. While these studies continue to evolve, they have yet to incorporate the real potential of energy storage and demand side resources. Furthermore, in regards to balancing operation, they use statistical methods for which there is a lack of consensus and which are based upon questionable assumptions. It is likely that the assessment of reserves will ultimately shift to simulation-based and analytical methods. UCED simulations form an integral piece of most integration studies and are likely to remain so. However, several authors have already advocated for the need to maintain the coherence between market operating procedures and the simulations. Such a coherence has been suggested equally well in the enterprise control as in the physical layer where line congestion, dynamic stability and voltage management requirements become coupled. Finally, as these simulations gain greater fidelity – representing more of energy and control technology integration decisions, it is likely that they will come to include the associated investment costs.

3 Electric Power Enterprise Control System Simulation Methodology for ISO-NE

3.1 Overview of Electric Power Enterprise Control System Simulation

To overcome the methodological limitations of the existing renewable energy integration literature, the Electric Power Enterprise Control System (EPECS) simulator methodology is proposed. Such an approach is in agreement with several recommendations in the literature for integrated approaches [74, 75, 83, 120]. Furthermore, one work advocates the role of custom-built simulators to assess the future electricity grid [148]. Gathering the discussions from the previous section, such an approach fulfills the following requirements. It:

- allows for an evolving mixture of generation and demand as dispatchable energy resources
- allows for an evolving mixture of generation and demand as variable energy resources
- allows for the simultaneous study of generation, transmission and load
- allows for the time domain simulation of the convolution of relevant grid enterprise control functions

- allows for the time domain simulation of changes to the power grid topology in the operations time scale
- specifically addresses the holistic dynamic properties of dispatchability, flexibility and forecastability
- represents potential changes in enterprise grid control functions as impacts on these dynamic properties
- accounts for the consequent changes in operating cost and the required investment costs

The first five of these requirements are basically associated with the nature of the power grid itself as it evolves. In the meantime, the next two are associated with the behavior of the power grid in the operations time scale. Finally, the last requirement contextualizes the simulation with cost accounting. Most fundamentally, the EPECS methodology is *integrated* and *techno-economic*. Consequently, it has the ability to provide clear techno-economic trade-offs for any changes to the physical power system and its associated layers of control.

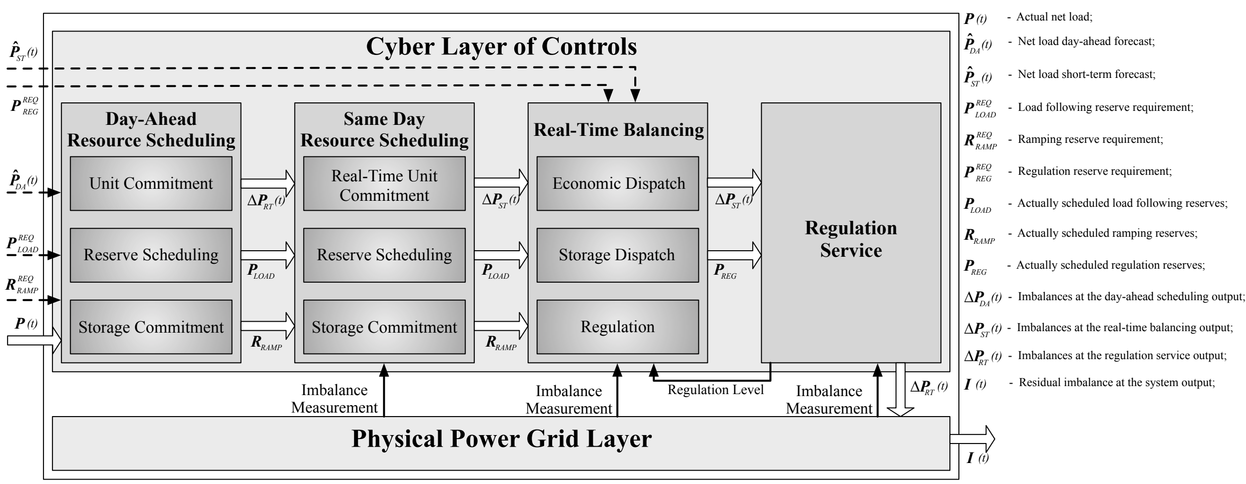

Figure 13: Architecture of the Electric Power Enterprise Control System (EPECS) Simulator Customized for ISO New England Operations

To that effect, this section introduces the EPECS simulator customized for ISO New England's operations. Its architecture is graphically depicted in Figure 13 and may be viewed as extension of several enterprise control works [3, 17] involving variable energy integration [11, 51, 53–56, 121, 122, 149], energy storage [52, 57], and demand response [140, 150–153]. The simulator includes a physical power grid layer and several layers of primary, secondary, and tertiary enterprise control functions as shown in Figure 13. These include day-ahead resource scheduling, same-day resource scheduling, real-time balancing, and the regulation service. Such an approach has several advantages. First, the net load $P(t)$ may be viewed as a system disturbance which is systematically rejected by forecasting and relevant enterprise control functions to give a highly attenuated system imbalance time domain signal $I(t)$. Second, it can address the recommendations in the literature [119] to assess the impact of variable generation on operating reserve requirements. Such an approach helps lay the methododological foundation for understanding renewable energy integration independent of the particularities of a physical power system in a given region [75]. Finally, the EPECS simulator is quite flexible. Its layers are modular and may be modified as necessary to assess the impact of a given control function or technology on the time domain simulation.

This section now explains each of the layers in EPECS simulator in detail; focusing on the specific characteristics of ISO-NE's operations. First, Sections 3.2 and 3.3 introduce several fundamental definitions in order to facilitate the usage of the EPECS simulator across different power systems and introduce greater objectivity in this study's methodology. Section 3.4 describes the day-ahead resource scheduling at ISO-NE in the form of a Security Constrained Unit Commitment (SCUC). Second, Section 3.5 then describes same-day resource scheduling in the form of a Real-Time Unit Commitment (RTUC). Section 3.6 then describes real-time balancing operations in the form of a Security Constrained Economic Dispatch (SCED). Section 3.7 describes a pseudo-steady state model of the regulation service. Section 3.8 then describes the physical power grid model. Section 3.9 then provides a model for event-based contingency operation. Finally, Section 3.10 demonstrates the EPECS simulator on a hypothetical power system test case and provides typical output results.

3.2 Fundamental Definitions on Variable Energy Resources

Within the EPECS simulator, variable energy resources are modeled as a time-dependent exogeneous spatially-distributed quantity that contributes directly to the net load. It is described in terms of a number of non-dimensional quantities.

Definition 3.2.1. *Penetration Level (π)*: The (aggregated) installed VER capacity P_V^{max} normalized by the system peak load P_L^{peak} [154]:

$$\pi = \frac{P_V^{max}}{P_L^{peak}} \tag{1}$$

Definition 3.2.2. *VER Capacity Factor (γ):* The average VER power output $\overline{P_V(t)}$ (e.g., over 1 year period) per installed capacity:

$$\gamma = \frac{\overline{P_V(t)}}{P_V^{max}} \tag{2}$$

Next, it is important to introduce the concept of variability as it is applied to the VERs, the load, and/or the net load. The variability of each of these plays a significant role in balancing operations. Intuitively speaking, variability is associated with the change rates of a given output. In this paper, it is defined as:

Definition 3.2.3. *Variability (A)*: Given the choice of the output $P(t)$ (e.g. the VER generation, the load, the net load), the variability is the root-mean-square of that output's rate normalized by the root-mean-square of that output [53]:

$$A = \frac{rms\,(\mathrm{dP(t)/dt})}{rms\,(P(t))} \tag{3}$$

Since the power spectra of the VER and load have distinctive shapes [6, 146], the way to change the variability of the profile without distorting its spectral shape is temporal scaling [53]. Assume that a default profile $P_0(t)$ has a variability A_0 and $P(t)$ is related to it in the following way:

$$P(t) = P_0(\alpha t) \tag{4}$$

According to (3), the variability of $P(t)$ is:

$$A = \frac{rms\,(\mathrm{dP_0(\alpha t)/dt})}{rms\,(P_0(\alpha t))} = \alpha \cdot \frac{rms\,(\mathrm{dP_0(\alpha t)/d(\alpha t)})}{rms\,(P_0(\alpha t))} = \alpha A_0 \tag{5}$$

Thus, α can be viewed as a scaling factor between the given profile and the default profile variabilities:

$$\alpha = \frac{A}{A_0} \tag{6}$$

The definitions for the forecast and forecast error are introduced next. Fundamentally speaking, while the net load is a continuously varying function in time, the forecast has a specific value resolved with each day ahead market time block (e.g. 1 hour). Therefore, the two are inherently different types of quantities. To address this issue, the concept of a "Best Forecast" is introduced as:

Definition 3.2.4. *The Best Forecast* [53]: Given the output $P(t)$ (e.g. the VER generation, the load, the net load), the best forecast $\bar{P}_k$ is equivalent to the average value of that output during the k^{th} market time block of duration T:

$$\bar{P}_k = \frac{1}{T} \int_{kT}^{(k+1)T} P(t)\mathrm{dt} \tag{7}$$

Similarly, the forecast error defines the deviation between the actual and best forecasts, which in turn may have various measures such as mean absolute error (MAE) and mean square error (MSE) [27]. Here, the VER forecast error is normalized by the installed capacity.

Definition 3.2.5. *VER Forecast Error (ε)* [53]: The standard deviation of the difference between the best ($\bar{P}_k$) and actual VER forecasts ($\hat{P}_k$) is normalized by the installed capacity:

$$\varepsilon = \frac{\sqrt{\frac{1}{n}\sum_{k=0}^{n}\left(\bar{P}_k - \hat{P}_k\right)^2}}{P_V^{max}} \tag{8}$$

The above definitions are used to simulate different integration scenarios. More specifically, in developing sensitivity cases, the VER model systematically changes five main parameters: penetration level, capacity factor, variability, day-ahead and short-term forecast errors. First, the definitions of VER penetration level and capacity factor in (1) and (2) respectively can be used to define the actual VER output.

$$P_V(t) = \frac{P_V(t)}{\overline{P_V(t)}} \frac{\overline{P_V(t)}}{P_V^{max}} \cdot \frac{P_V^{max}}{P_L^{peak}} \cdot P_L^{peak} = p_V(t) \cdot \gamma \cdot \pi \cdot P_L^{peak} \tag{9}$$

where $p_V(t)$ is VER power normalized to a unit capacity factor. Equation (9) shows that if a single $p_V(t)$ is taken as a default profile, the actual VER output can be systematically adjusted with the values of π and γ. Next, the definition of VER forecast error in Equation (8) can be used to define the actual VER forecast error. Two types of forecasts (and their errors) are used in the power system simulations, day-ahead and short-term. The day-ahead forecast is used in the SCUC model for day-ahead resource scheduling. It normally has a 1 hour resolution and up to 48 hour forecast horizon. The short-term forecast is used in the RTUC model for the same-day resource scheduling and the SCED model for real-time balancing operations. It has a ten minute time resolution and up to six hour time horizon [26, 155]. The VER forecast can be expressed as:

$$\hat{P}_V(t) = P_V(t) - E(t) \tag{10}$$

where $\hat{P}_V(t)$ is the forecasted VER profile, and $E(t)$ is the error term. Using the definition of the forecast error in (8), the error term can be written as:

$$\begin{aligned} E(t) &= \frac{E(t)}{std\,(E(t))} \cdot \frac{std\,(E(t))}{P_V^{max}} \cdot \frac{P_V^{max}}{P_L^{peak}} \cdot P_L^{peak} = \\ &= e(t) \cdot \varepsilon \cdot \pi \cdot P_L^{peak} \end{aligned} \tag{11}$$

where $e(t)$ is the error term normalized to the unit standard deviation. Equation (11) shows that if a single $e(t)$ is taken for each type of market as a default profile, the actual error profile can be systematically adjusted with the values of π and ε. It is important to emphasize that the $e(t)$ is different for the day-ahead and short-term applications. They may have different probability distributions and power spectra. Additionally, the forecast error ranges are generally different with the short-term forecast having higher accuracy as compared to the day-ahead forecast. Finally, the actual variability can be similarly adjusted with the value of α. Using Equations (9) and (11) and the properties of variability in Equations (4) and (6), the VER model can be expressed as follows:

$$P_V(t) = p_V(\alpha t) \cdot \gamma \cdot \pi \cdot P_L^{peak} \tag{12}$$
$$\hat{P}_V(t) = (\gamma \cdot p_V(\alpha t) - \varepsilon \cdot e(\alpha t)) \cdot \pi \cdot P_L^{peak} \tag{13}$$
$$\alpha = A/A_0 \tag{14}$$

This set of equations defines the VER model used in this study. As an input, it requires the actual VER profile $p_V(t)$ normalized to unit capacity factor, and the error term profile $e(t)$, normalized to unit standard deviation. The model explicitly includes the five major parameters of VER.

3.3 Fundamental Definitions on Operating Reserves

In addition to the definitions associated with variable energy resources, a number of definitions related to operating reserves are provided. The challenge here is that the taxonomy and definition of operating reserves from one power system geography to the next varies [8]. Furthermore, this taxonomy and definition is often different from the methodological foundations found in the literature [8]. There is even significant differences in the definitions found within the literature itself [8, 156–158]. Therefore, this report first introduces the definitions of operating reserves in the EPECS simulator in Section 3.3.1, then introduces the definitions used in ISO New England in Section 3.3.2, and then concludes by reconciling these concepts in Section 3.3.3.

3.3.1 Operating Reserves in the EPECS Simulator Methdoology

The EPECS simulator methodology adopts the operating reserves concepts found in [8, 127] with minor differences. Figure 14 shows the taxonomy of the various types of operating reserves. The primary distinction is between the operating reserves used to respond to contingency events and those used during normal operation to respond to forecast errors and variability in the net load. Since the outage of any individual wind or solar generation facility has a much smaller impact on the system than the largest thermal plant, solar and wind integration will not increase contingency reserves requirements [8]. Therefore, the focus of most renewable energy integration is on normal operating reserves. They are further classified as load following, ramping, and regulation reserves depending on the mechanisms by which they are acquired and activated.

Definition 3.3.1. *Load Following Reserves* [8, 127]: Power capacity available during normal operations for assistance in active power balance to correct the future anticipated imbalances upward or downward. The actual quantity of upward load following reserves is given by:

$$\sum_{k=1}^{N_G} \left(w_{kt} P_k^{max} - P_{kt} \right) \tag{15}$$

where N_G is the number of generators, w_{kt} is the (binary) online state of the k^{th} generator at time t, P_k^{max} is the maximum capacity of the k^{th} generator, and P_{kt} is the value at which it is currently generating. Similarly,

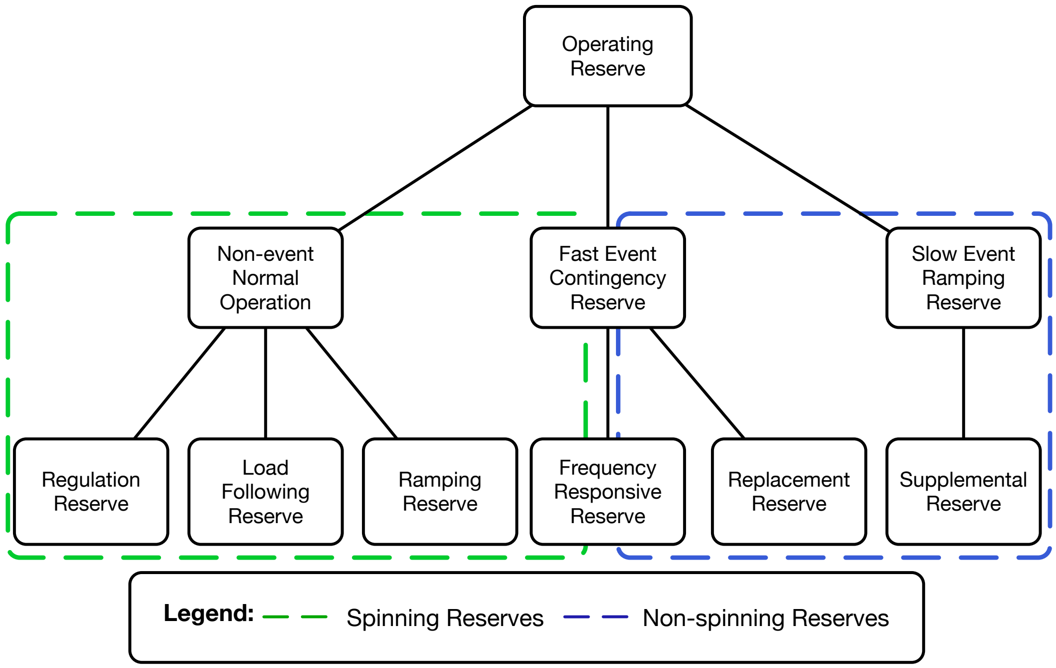

Figure 14: A Classification Operating Reserves (adapted from [8])

the actual quantity of downward load following reserves is given by:

$$\sum_{k=1}^{N_G} \left(P_{kt} - w_{kt} P_k^{min}\right) \tag{16}$$

where P_k^{min} is the minimum capacity of the k^{th} generator. Within ISO-NE, load following reserves are often called economic surplus reserves.

Example 3.3.1. Consider Figure 15 as an example. It consists of a single generator generating at 400MW. It has a maximum capacity of 500MW and a minimum capacity of 200MW. It provides 100MW of upward load following reserves and 200MW of downward load following reserves.

Returning back to Figure 13, load following reserves are acquired during the day-ahead and same-day resource scheduling steps in the EPECS simulator. Furthermore, they are utilized during the real-time balancing operation. Note that this definition of load following reserves is purely a property of the physical system. This is entirely independent of whether some system operators monetize this property in the form of a *reserve product* or not.

Definition 3.3.2. *Ramping Reserves* [8, 127]: Ramp rate capacity available during normal operations for assistance in active power balance to correct the future anticipated imbalances upward or downward. The actual quantity of upward ramping reserves is given by:

$$\sum_{k=1}^{N_G} \left(w_{kt} R_k^{max} - \frac{P_{kt} - P_{k,t-1}}{\Delta T}\right) \tag{17}$$

where R_k^{max} is the maximum upward ramp rate of the k^{th} generator, and ΔT is duration of a time step between the generator levels P_{kt} and $P_{k,t-1}$. Normally, ΔT is equal to one hour. Similarly, the actual

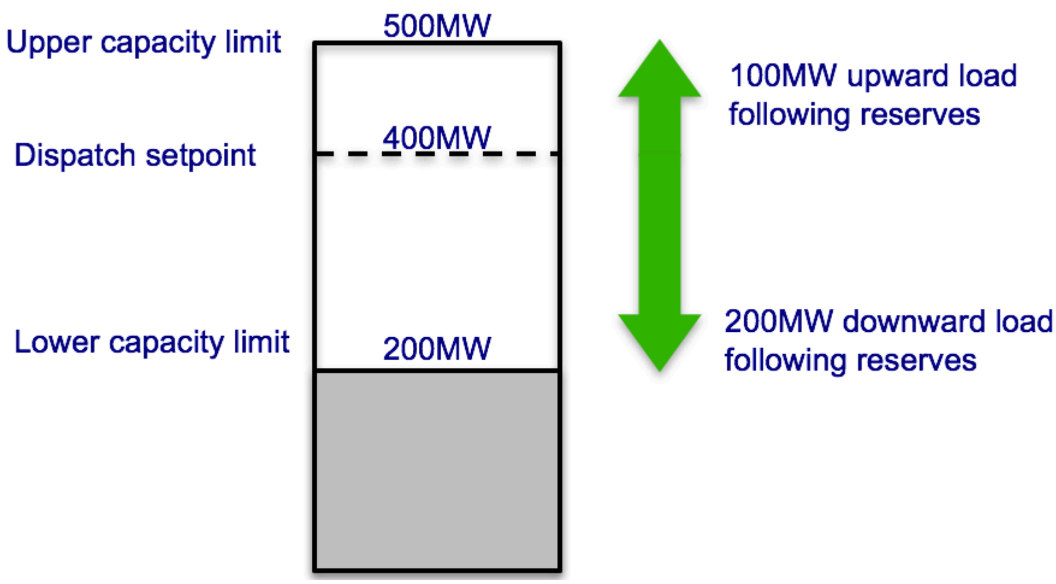

Figure 15: Load Following Reserves Example: A hypothetical generator with a maximum capacity of 500MW, and minimum capacity of 200MW, and dispatched to 400MW provides 100 MW of upward load following reserves, and 200 MW of downward load following reserves.

quantity of downward ramping reserves is given by:

$$\sum_{k=1}^{N_G} \left(w_{kt} R_k^{max} - \frac{P_{kt} - P_{k,t-1}}{\Delta T} \right) \tag{18}$$

where R_k^{min} is the maximum downward ramp rate of the k^{th} generator.

Example 3.3.2. Consider Figure 16 as an example. It consists of a single generator that is scheduled to ramp from 400MW to 425MW within a given period ΔT equal to one hour. It has the ability to ramp up at 50MW/hr and ramp down at 60MW/hr. It provides 25MW/hr of upward ramping reserves and 85MW/hr of downward ramping reserves.

Returning back to Figure 13, ramping reserves, much like load following reserves, are acquired during the day-ahead and same-day resource scheduling steps in the EPECS simulator. Furthermore, they are utilized during the real-time balancing operation. Note that this definition of ramping reserves is purely a property of the physical system. This is entirely independent of whether some system operators monetize this property in the form of a *reserve product* or not.

Definition 3.3.3. *Regulation Reserves* [8, 127]: Power capacity available during normal conditions for assistance in active power balance to correct the current imbalance that requires a fast, real-time, automatic response. The regulation reserve requirement up or down is given by P_{REG}^{REQ}. The regulation level at a given time t is given by G_t. Its absolute value must remain less than the requirement.

Returning back to Figure 13, the regulation reserve requirement is taken as an input and is utilized in the automatic generation control (AGC) algorithm of the regulation service (See Section 3.7 for further details). It is a physical property of the saturation limits on the AGC. In most power systems, this quantity is monetized.

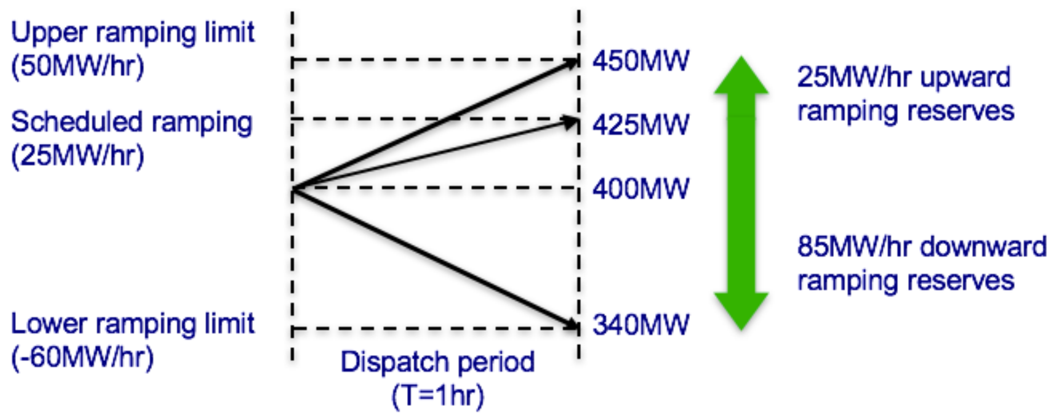

Figure 16: Ramping Reserves Example: A hypothetical generator with maximum ramp up of 50MW/hr and maximum ramp down of 60MW/hr is scheduled to ramp from 400MW to 425MW in one hour. It provides 25MW/hr of upward ramping reserves and 85MW/hr of downward ramping reserves.

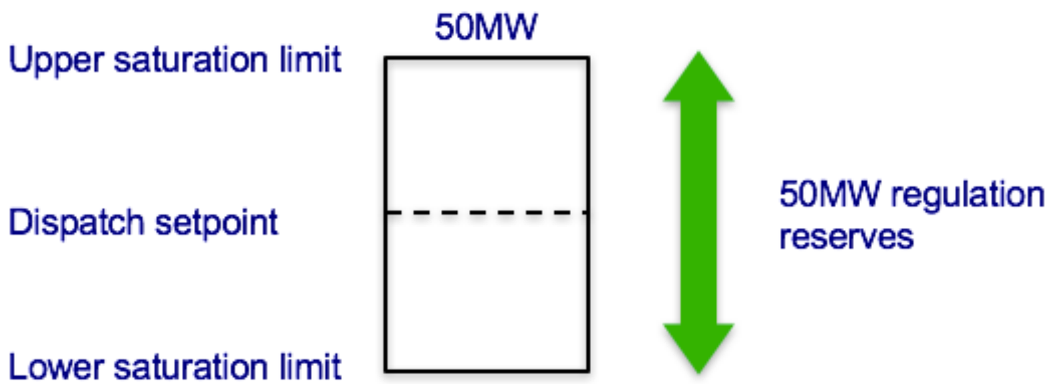

Figure 17: Regulating Reserves Example: A generator with saturation limits of 50MW on its automatic generation control also provides 50MW of regulation reserves.

Example 3.3.3. Consider Figure 17 example. It consists of a single generator that is dispatched to an arbitrary level. Its automatic generation control has saturation limits of 50MW upward and downward. Consequently, it provides 50MW of regulation reserves.

Together, these three types of operating reserves are used to respond to forecast errors and variability in the net load during normal operation. In all cases, the actual quantities of these reserves are physical properties of the power system. They exist regardless of whether the system operator places requirements on these physical quantities or whether they incentivize generators to provide these reserve quantities in the form of reserve products.

3.3.2 Operating Reserve Requirements in ISO New England

In contrast to the above, ISO-NE maintains three types of operating reserve requirements [159].

Definition 3.3.4. *Ten-Minute Spinning Reserve (TMSR) [159]:* The TMSR is the largest reserve product that is provided by *on-line resources* able to increase their output within ten minutes. It is currently set to the largest contingency on the system.

Definition 3.3.5. *Ten-Minute Nonspinning Reserve (TMNSR) [159]:* The TMNSR is the second largest reserve quantity that is provided by *off-line units* that can successfully synchronize to the grid and ramp up within ten minutes. It is currently set to one half of the second largest contingency on the system.

Definition 3.3.6. *Thirty-Minute Operating Reserve (TMOR) [159]:* TMOR is the lowest reserve quantity that is provided by *on-line resources* that can ramp up within 30 minutes and *off-line units* that synchronize to the grid and ramp up within 30 minutes. Furthermore, there exist Local TMOR requirements for three reserve zones: Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABSTN). Until recently, it was set equal to the sum of the two ten-minute operating reserve requirements. As of October 2013, an additional replacement reserve requirement of 160 MW in the summer and 180 MW in the winter was added to the TMOR [159].

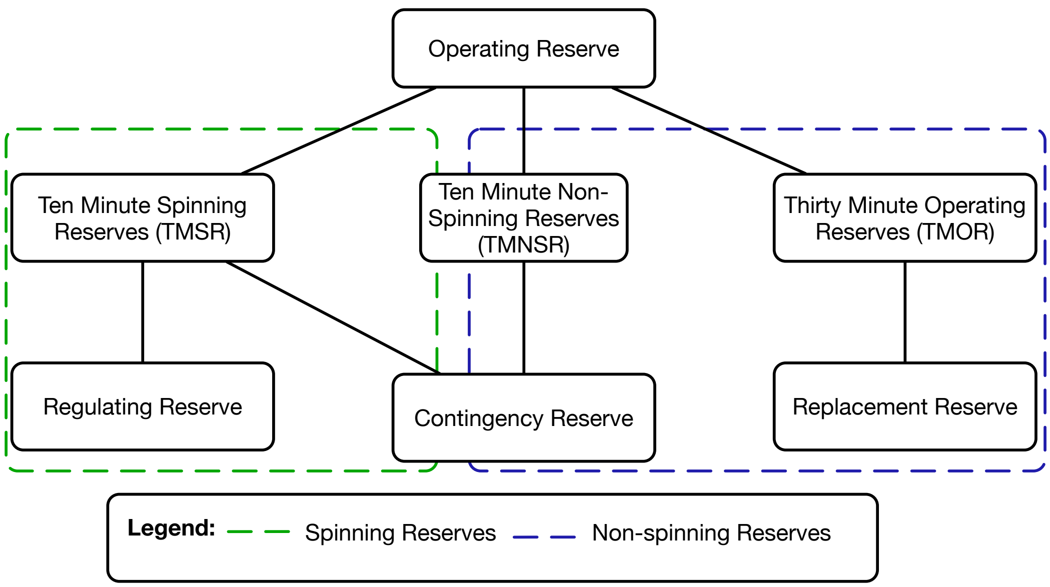

Figure 18: A Classification of Operating Reserve Requirements in ISO New England

The above definitions imply a taxonomy of operating reserves shown in Figure 18. Note that all three of the reserve products are defined in an upward direction as result of their focus on contingency events. Furthermore, the ten-minute spinning reserve includes regulation reserves but also serves as a fast-event contingency reserve.

3.3.3 Reconciliation of Operating Reserve Definitions for the SOARES Project

In order to apply the EPECS simulator methodology to the ISO New England region, the two taxonomies of operating reserves summarized in Figures 14 and 18 must be reconciled. First, it is important to recognize that the EPECS operating reserves definitions reflect physical quantities while the ISO-NE operating reserves definitions reflect requirements. Furthermore, it is beyond the scope of this study to define new types of operating reserve requirements. Therefore, this project makes the following reconciliation:

3.3.3.1 Regulation Reserves: For regulation reserves, there appears to be no conceptual discrepancy. The maximum and minimum quantities of regulating reserves are equated to the regulating reserve requirement.

3.3.3.2 Ten-Minute Spinning Reserves & Load Following Reserves:

For the ten-minute spinning reserves, we observe that this requirement is imposed on the quantity of load following reserves. While the system will continue to require a TMSR of at least the largest contingency on the system, a high penetration of variable energy resources might require this quantity to be significantly increased.

Example 3.3.4. Consider a hypothetical scenario in New England on a year where the peak load is 25GW. A 20% penetration of variable energy resources would equate to 10GW. If 50% of these VERS were to drop out suddenly (beyond the forecast)[2], there would be a 5GW shortfall. This is significantly larger than largest single-facility contingency in the system. Therefore, there would need to be a load following reserve requirement to address such a situation. In the absence of a new reserve requirement, the TMSR can be increased so as to respond to both single-facility contingencies as well as the variability and forecast error of variable energy resources.

Therefore, this study sets the TMSR requirement equal to the greater of two quantities: 1.) the size of the largest contingency 2.) the load following reserve requirement. The determination of the latter is part of the central objective of this work. In this context, the TMSR needs to be understood in both an upward as well as a downward direction.

3.3.3.3 Non-Spinning Reserves:

The two non-spinning reserve requirements will remain unchanged. VER integration is fundamentally a normal operation phenomena. Non-spinning reserves only protect the system in the event of a loss of generation but do not protect the system in the event of an excess of generation. Furthermore, the variability of renewable energy generation means that a system with a negative imbalance can quickly switch to a system with a positive imbalance. Therefore, it is inadvisable to try to protect the power system from VER variability and forecast error with non-spinning reserves.

3.3.3.4 Ramping Reserves:

Finally, in the case of ramping reserves, currently there is no requirement in ISO New England that provides an effective equivalent. This study will determine the ramping reserve requirements for the scenarios described in Section 4.2. Such results may motivate the need for the implementation of a ramping reserve requirement.

3.4 Day Ahead Resource Scheduling at ISO-NE

Power system balancing operations start with day-ahead resource scheduling implemented as a security-constrained unit commitment (SCUC). The goal of the SCUC problem is to choose the right set of generation units that are able to meet the real-time demand at minimum cost. In the original formulation, the SCUC problem is formulated as a nonlinear optimization program with integrated power flow equations and system security requirements [160]. However, the optimization constraints are often linearized, as in [11, 51], to avoid potential convergence issues. The SCUC formulation in [11, 51] has been further modified to reflect ISO-NE operations. In particular:

1. Constraints reflecting minimum up time, minimum down time and maximum number of daily start-ups of the generators are added, which also take the initial online hours into account.
2. The self-scheduled units and the outages are incorporated into the model.
3. The optimization program models pumped-storage units to reflect operating parameters, including the maximum daily energy constraints, the maximum draw down, and the reservoir limitations.

[2] Note that a 50% forecast error is highly unlikely for a system with 20% penetration rate. The choice of values is purely illustrative in nature.

4. Constraints ensuring procurement of system-wide ten-minute and 30-minute reserve requirements are added to the SCUC model.

5. A zonal network model is implemented.

6. External transactions with proper interface limits are modeled.

The generation cost curves are modeled as quadratic functions of heat rates:

$$C(P) = C_F \left(H_F + H_L P + H_Q P^2\right) \tag{19}$$

where H_F, H_L and H_Q are the generator fixed, linear and quadratic heat rates respectively, and C_F is the fuel cost. The total operation cost is a combination of the generation cost, generator startup and shutdown costs, and the pumping cost:

$$\min \sum_{t=1}^{T} \sum_{k=1}^{N_G} C_{Fkt} \left(w_{kt} H_{Fk} + H_{Lk} P_{kt} + H_{Qk} P_{kt}^2\right) + w_{ukt} C_{Uk} + w_{dkt} C_{Dk} + w_{pkt} C_{Pk} \tag{20}$$

The optimization program is subject to the following constraints:

$$\sum_{k=1}^{N_G} m_{ik} P_{kt} + U_{it} - (1+\gamma)\tilde{D}_{it} = \sum_{j=1}^{N_B} B_{ij} \left(\theta_{it} - \theta_{jt}\right) \qquad i = 1:N_B; t = 1:T \tag{21}$$

$$w_{kt} P_k^{min} \leq P_{kt} \leq w_{kt} P_k^{max} \qquad k = 1:N_G; t = 1:T \tag{22}$$

$$R_k^{min} \leq \frac{P_{kt} - P_{k,t-1}}{T_h} \leq R_k^{max} \qquad k = 1:N_G; t = 1:T \tag{23}$$

$$P_{k0} = \xi_k \qquad k = 1:N_G \tag{24}$$

$$F_{ij}^{min} \leq B_{ij} \left(\theta_{it} - \theta_{jt}\right) \leq F_{ij}^{max} \qquad i,j = 1:N_B; t = 1:T \tag{25}$$

$$w_{k,t-1} + w_{ukt} - w_{dkt} + w_{pkt} = w_{kt} \qquad k = 1:N_G; t = 1:T \tag{26}$$

$$w_{kt} \geq w_{uk,(t-\tau)} \qquad k = 1:N_G; t = 1:T, \tau = 1:T_u - 1 \tag{27}$$

$$1 - w_{kt} \geq w_{dk,(t-\tau)} \qquad k = 1:N_G; t = 1:T, \tau = 1:T_d - 1 \tag{28}$$

$$\sum_{t=1}^{T} w_{ukt} \leq w_{uk}^{max} \qquad k = 1:N_G \tag{29}$$

$$O_{kt} w_{kt} = 0 \qquad k = 1:N_G; t = 1:T \tag{30}$$

$$\sum_{k=1}^{N_G} \left(w_{kt} P_k^{max} - P_{kt}\right) \geq P_{res} \qquad t = 1:T \tag{31}$$

$$\sum_{k=1}^{N_G} \left(P_{kt} - w_{kt} P_k^{min}\right) \geq P_{res} \qquad t = 1:T \tag{32}$$

$$\sum_{k=1}^{N_G} \left(w_{kt} R_k^{max} - \frac{P_{kt} - P_{k,t-1}}{T_h}\right) \geq R_{res} \qquad t = 1:T \tag{33}$$

$$\sum_{k=1}^{N_G} \left(\frac{P_{kt} - P_{k,t-1}}{T_h} - w_{kt} R_k^{min}\right) \geq R_{res} \qquad t = 1:T \tag{34}$$

where the following notations are used:

k, j, i, t	generator, bubble, bubble and time indices respectively;
N_B, N_G	number of bubbles and number of generators;
T_h, T	SCUC time step and horizon;
H_{Fk}, H_{Lk}, H_{Qk}	fixed, linear and quadratic heat rates for generator k;
C_{Fkt}	fuel cost of generator k at time t;
C_{Uk}, C_{Dk}, C_{Pk}	startup, shutdown and pumping costs of generator k respectively;
P_k^{max}, P_k^{min}	minimum/maximum power outputs of generator k;
R_k^{max}, R_k^{min}	maximum/minimum ramping rate of generator k;
$F_{ij}^{max}, F_{ij}^{min}$	maximum/minimum power flows between bubbles i and j;
P_{res}, R_{res}	load following and ramping reserve requirements;
T_u, T_d, w_{uk}^{max}	minimum up time, minimum down time and maximum startups in a day for generator k;
O_{kt}	outage schedules; $O_{kt} = 1$ – generator k is scheduled for outage at time t;
$w_{kt}, w_{ukt}, w_{dkt}, w_{pkt}$	ON/OFF state, startup, shutdown and pumping indicators of generator k;
θ_{it}, θ_{jt}	voltage phase on bubbles i and j;
P_{kt}, ξ_k	power output of generator k at time $t \geq 1$ and $t = 0$;
$\tilde{D}_{it}$	demand forecast on bus i at time t
U_{it}	external transaction on bus i at time t
m_{ik}	correspondence matrix of generator k to bus i
B_{ij}	the imaginary part of the nodal admittance matrix;
γ	transmission losses as a percentage of the total demand

Constraint (21) is the DC power flow equation with incorporated loss term. Constraint (22) sets generator maximum and minimum power outputs. Constraint (23) places limits on the generator ramping up and down. Constraint (24) takes into account the generator output levels at the start of the day ($t = 0$). Constraint (25) sets the interface limits. Constraint (26) logically binds the state, startup and shutdown binary variables. Constraints (27) and (28) set the generator minimum up and minimum down times respectively. Constraint (29) limits the maximum number of generator startups in a day. Constraint (30) makes sure the units with scheduled outages are not committed. Constraints (31) and (32) ensure procurement of upward and downward load following (i.e. economic surplus) reserves. Similarly, constraints (33) and (34) ensure procurement of upward and downward ramping reserves.

Drawing from Equations (31)–(34), the actually scheduled reserves (the left-hand-sides) are practically always greater than the reserve requirements (the right-hand-sides). While the reserve requirements are only defined by the net load parameters and the characteristic times of the power system operations [53–56], the actually scheduled reserve amounts depend on the cost-related parameters of the system, such as generator heat rates, startup and shutdown costs, and fuel prices. As a result, the actually scheduled reserve amounts can vary widely for the same reserve requirements. Since the balancing performance of the system is solely determined by the actually scheduled reserves, this situation may give a wrong estimate of the reserve requirements that produce the given system performance. To avoid this, the above SCUC formulation is implemented in such a way as to give a *cost-independent* estimation of the power system reserve requirements for a given operation scenario. For example, changes in fuel costs from one month to the next can result in changes in the committed generation fleet. If all else is held equal, these two power systems will have different reserve quantities and consequently balancing performance as well. The notion of cost-independence assumes that the estimated reserve requirements should be independent of the cost-related parameters listed above. To that effect, the above SCUC formulation is implemented for the *worst-case scenario* when the actually scheduled reserves *are equal to* the reserve requirements.

To achieve this, the amount of actually scheduled reserves is changed by *artificially* manipulating the maximum and minimum generation levels *after* the generation units have been committed. This is achieved with scaling factors defined as the ratio of reserve requirement to actually scheduled reserves:

$$\alpha_t^{PU} = \frac{P_{res}}{\sum_{i=1}^{N_G} w_{it}\left(P_i^{max} - P_{it}\right)} \tag{35}$$

$$\alpha_t^{PD} = \frac{P_{res}}{\sum_{i=1}^{N_G} w_{it}\left(P_{it} - P_i^{min}\right)} \tag{36}$$

According to (35) and (36), the scaling factors depend on time, because the SCUC procures different reserve amounts for different time intervals. The scaling factors are then used to adjust the maximum and minimum outputs of the generators, so that the scheduled reserves are equal to the reserve requirements:

$$P_{it}^{max} = P_{it} + \alpha_t^{PU} \cdot \left(P_i^{max} - P_{it}\right) \tag{37}$$

$$P_{it}^{min} = P_{it} - \alpha_t^{PD} \cdot \left(P_{it} - P_i^{min}\right) \tag{38}$$

Note, that the maximum and minimum outputs of the committed generators change over time. While this process is just a mathematical abstraction, it is required to demonstrate the impact of the reserve requirements on the system imbalances.

The same rationale is applied to the scheduling of ramping reserves. Since the generation units normally have the same ramping limits in both directions, the scaling factors are written as:

$$\alpha_t^{RU} = \frac{R_{res}}{\sum_{i=1}^{N_G} w_{it}\left(R_i^{max} - R_{it}\right)} \tag{39}$$

$$\alpha_t^{RD} = \frac{R_{res}}{\sum_{i=1}^{N_G} w_{it}\left(R_i^{max} + R_{it}\right)} \tag{40}$$

Accordingly, the adjusted maximum and minimum ramping rates of the generators are given by the following equations:

$$R_{it}^{max} = R_{it} + \alpha_t^{RU} \cdot \left(R_i^{max} - R_{it}\right) \tag{41}$$

$$R_{it}^{min} = R_{it} - \alpha_t^{RD} \cdot \left(R_i^{max} + R_{it}\right) \tag{42}$$

3.5 Same-Day Resource Scheduling at ISO-NE

The same-day resource scheduling uses an optimization program similar to that of the SCUC. The optimization program, called real-time unit commitment (RTUC), is modified in the following ways to reflect ISO-NE operations:

1. The optimization only considers 14 time intervals – twelve 15-minute and two 30-minute intervals – spanning a 4-hour period.

2. The process only commits and de-commits fast-start units.

3. The commitment is based upon short-term load and VER forecasts (a couple of hours look-ahead).

4. This optimization model enforces system as well as zonal reserve requirements.

Since only fast-start units are committed and de-committed in the real-time, the objective function will contain the the generation costs of all units, but only startup and shutdown costs the fast-start units:

$$\min \sum_{t=1}^{T} \left(\sum_{k=1}^{N_{G_1}} C_{Fk} \left(H_{Lk} P_{kt} + H_{Qk} P_{kt}^2 \right) + \sum_{\kappa=1}^{N_{G_2}} C_{F\kappa} \left(\omega_{\kappa t} H_{F\kappa} + H_{L\kappa} \mathcal{P}_{\kappa t} + H_{Q\kappa} \mathcal{P}_{\kappa t}^2 \right) + \right.$$
$$\left. + \sum_{\kappa=1}^{N_{G_2}} \left(\omega_{u\kappa t} C_{U\kappa} + \omega_{d\kappa t} C_{D\kappa} + \omega_{p\kappa t} C_{P\kappa} \right) \right) \tag{43}$$

The optimization program is subject to the following constraints:

$$\sum_{k=1}^{N_{G_1}} m_{ik} P_{kt} + \sum_{\kappa=1}^{N_{G_2}} m_{i\kappa} \mathcal{P}_{\kappa t} + U_{it} - (1+\gamma)\tilde{D}_{it} = \sum_{j=1}^{N_B} B_{ij} \left(\theta_{it} - \theta_{jt} \right) \qquad i = 1 : N_B; t = 1 : T \tag{44}$$
$$w_{kt} P_k^{min} \leq P_{kt} \leq w_{kt} P_k^{max} \qquad k \in N_{G_1}; t = 1 : T \tag{45}$$
$$\omega_{\kappa t} \mathcal{P}_\kappa^{min} \leq \mathcal{P}_{\kappa t} \leq \omega_{\kappa t} \mathcal{P}_\kappa^{max} \qquad \kappa \in N_{G_2}; t = 1 : T \tag{46}$$
$$R_k^{min} \leq \frac{P_{kt} - P_{k,t-1}}{T_r} \leq R_k^{max} \qquad k \in N_{G_1}; t = 1 : T \tag{47}$$
$$\mathcal{R}_\kappa^{min} \leq \frac{\mathcal{P}_{\kappa t} - \mathcal{P}_{\kappa,t-1}}{T_r} \leq \mathcal{R}_\kappa^{max} \qquad \kappa \in N_{G_2}; t = 1 : T \tag{48}$$
$$P_{k0} = \xi_k \qquad k \in N_{G_1} \tag{49}$$
$$\mathcal{P}_{\kappa 0} = \zeta_\kappa \qquad \kappa \in N_{G_2} \tag{50}$$
$$F_{ij}^{min} \leq B_{ij} \left(\theta_{it} - \theta_{jt} \right) \leq F_{ij}^{max} \qquad i, j = 1 : N_B; t = 1 : T \tag{51}$$
$$\omega_{\kappa,t-1} + \omega_{u\kappa t} - \omega_{d\kappa t} + \omega_{p\kappa t} = \omega_{\kappa t} \qquad \kappa \in N_{G_2}; t = 1 : T \tag{52}$$
$$\omega_{\kappa t} \geq \omega_{u\kappa,(t-\tau)} \qquad \kappa \in N_{G_2}; t = 1 : T; \tau = 1 : T_u - 1 \tag{53}$$
$$1 - \omega_{\kappa t} \geq \omega_{d\kappa,(t-\tau)} \qquad \kappa \in N_{G_2}; t = 1 : T; \tau = 1 : T_d - 1 \tag{54}$$

$$\sum_{t=1}^{T} \omega_{u\kappa t} \leq \omega_{u\kappa}^{max} \qquad \kappa \in N_{G_2} \tag{55}$$
$$O_{\kappa t} \omega_{\kappa t} = 0 \qquad \kappa \in N_{G_2}, t = 1 : T \tag{56}$$
$$\sum_{k=3}^{N_{G_1}} \left(w_{kt} P_k^{max} - P_{kt} \right) + \sum_{\kappa=1}^{N_{G_2}} \left(\omega_{\kappa t} \mathcal{P}_\kappa^{max} - \mathcal{P}_{\kappa t} \right) \geq 1.25 P_1^{max} + 0.5 P_2^{max} \qquad t = 1 : T \tag{57}$$
$$\sum_{k=1}^{N_G} \left(w_{kt} R_k^{max} - \frac{P_{kt} - P_{k,t-1}}{T_r} \right) \geq R_{res} \qquad t = 1 : T \tag{58}$$
$$\sum_{k=1}^{N_G} \left(\frac{P_{kt} - P_{k,t-1}}{T_r} - w_{kt} R_k^{min} \right) \geq R_{res} \qquad t = 1 : T \tag{59}$$

where the following notations are used in addition to the ones introduced in the previous section:

k, κ	indices of regular and fast-start generators respectively;
N_{G_1}, N_{G_2}	number of regular and fast-start generators respectively;
T_r, T	RTUC time step and horizon;
$\mathcal{P}_{\kappa}^{max}, \mathcal{P}_{\kappa}^{min}$	minimum/maximum power outputs of fast-start generator κ;
$\mathcal{R}_{\kappa}^{max}, \mathcal{R}_{\kappa}^{min}$	maximum/minimum ramping rate of fast-start generator κ;
$T_u, T_d, \omega_{u\kappa}^{max}$	minimum up time, minimum down time and maximum startups in a day for fast-start generator κ
$\omega_{\kappa t}, \kappa_{u\kappa t}, \omega_{d\kappa t}, \omega_{p\omega t}$	ON/OFF state, startup, shutdown and pumping indicators of fast-start generator κ;
$\mathcal{P}_{\kappa t}, \zeta_{\kappa}$	power output of fast-start generator κ at time $t \geq 1$ and $t = 0$;
P_1^{max}, P_2^{max}	capacities of the largest and second largest generators;

Constraint (44) is the DC power flow equation with incorporated loss term. Constraints (45) and (46) set maximum/minimum power outputs for regular and fast-start generators respectively. Constraints (47)–(50) are generator ramping up and ramping down limits that take into account the generator output levels at the start of the day ($t = 0$). Constraint (51) sets the interface limits. Constraint (52) logically binds the state, startup and shutdown binary variables of fast-start units. Constraints (53) and (54) set fast-start generators' minimum up and minimum down times respectively. Constraint (55) limits the maximum number of fast-start generator startups in a day. Constraint (56) makes sure the fast-start units with scheduled outages are not committed. Constraint (57) ensures procurement of load following (i.e. economic surplus) reserves. Constraints (58)–(59) ensure procurement of upward and downward ramping reserves.

3.6 Real-Time Balancing Operations at ISO-NE

The real-time balancing operations move available generator outputs to new setpoints (dispatch) in the most cost-efficient way. In its original formulation, generation dispatch is implemented as a non-linear optimization model, called AC optimal power flow (ACOPF) [161]. Due to problems with convergence and computational complexity [160], most of the U.S. independent system operators (ISO) moved from ACOPF to linear optimization models. The most commonly used model is called security-constrained economic dispatch (SCED) [162]. This SCED formulation has been further modified to reflect ISO-NE operations. In particular:

1. The modified SCED adopts a 15-min look-ahead window, and considers the initial state of a unit (UCM code) and its start-up and shut-down instruction from the RTUC.
2. The units on automatic generation control (AGC) are dispatched according to their regulation parameters.
3. Area interchanges are honored.
4. Reserves constraint penalty factors (RCPF) are considered.
5. System and zonal reserve requirements are considered.

Linearization is achieved by using incremental power values in the optimization model. The cost curve in (19) can be written with incremental power values as follows:

$$\Delta C(P) = C_F\big(H_L \Delta P + 2H_Q P \Delta P\big) \tag{60}$$

Thus, the cost function of the SCED program can be written as:

$$\min \sum_{k=1}^{N_G} C_{Fk}\big(H_{Lk}\Delta P_{kt} + 2H_{Qk}P_{kt}\Delta P_{kt}\big) \tag{61}$$

Use of incremental load and generation values also allows incorporation of sensitivity factors and linearization of the optimization constraints. Sensitivity factors establish linear connections between changes of power injections on the buses and state-related parameters of the system [163]. Two sensitivity factors are used in the SCED. The incremental transmission loss factor (ITLF) for a given bus shows how much the total system losses change, when power injection on that bus increases by a unit [164]. The ITLF allows incorporation of system losses into the linearized power balance constraint. The generation shift distribution factor (GSDF) shows how much the active power flow through the given line changes, when injection on buses increases by a unit [164, 165]. Incorporation of the GDSF into the model results in a linearization of the line flow limit constraint. Thus, using the sensitivity factors, the SCED program constraints for time t can be written as:

$$\Delta P_{it} = \sum_{k=1}^{N_G} m_{ik}\Delta P_{kt} \qquad i = 1 : N_B \tag{62}$$

$$\sum_{i=1}^{N_B}(1-\gamma_{it})(\Delta P_{it} - \Delta\hat{D}_{it}) = I_t + G_t \tag{63}$$

$$P_k^{min} \leq P_{kt} + \Delta P_{kt} \leq P_k^{max} \qquad k = 1 : N_G \tag{64}$$

$$R_k^{min}T_m \leq \Delta P_{kt} \leq R_k^{max}T_m \qquad k = 1 : N_G \tag{65}$$

$$\sum_{i=1}^{N_B} a_{lit}(\Delta P_{it} - \Delta\hat{D}_{it}) \geq F_l^{max} - F_{lt} \qquad l = 1 : N_L \tag{66}$$

where the following notations are used in addition to the ones introduced in previous sections:

N_L	number of lines;
T_m	real-time balancing time step;
ΔP_{kt}	power increment of generator k;
$\Delta\hat{D}_{it}, \Delta P_{it}$	demand forecast and generation increments on bus i;
F_{lt}, F_l^{max}	power flow level and flow limit of line l;
γ_{it}	incremental transmission loss factor (ITLF) of bus i;
a_{lit}	bus i generation shift distribution factor (GDSF) to line l;

Constraint (62) relates the power outputs from generators to the power injection on the buses using the m_{ik} correspondence matrix. Constraint (63) represents the power balance equation with incorporated system losses. It should be noted that the right-hand-side of (63) would be zero for a traditional SCED formulation. However, that formulation always equates the changes of generation and demand; leaving the current

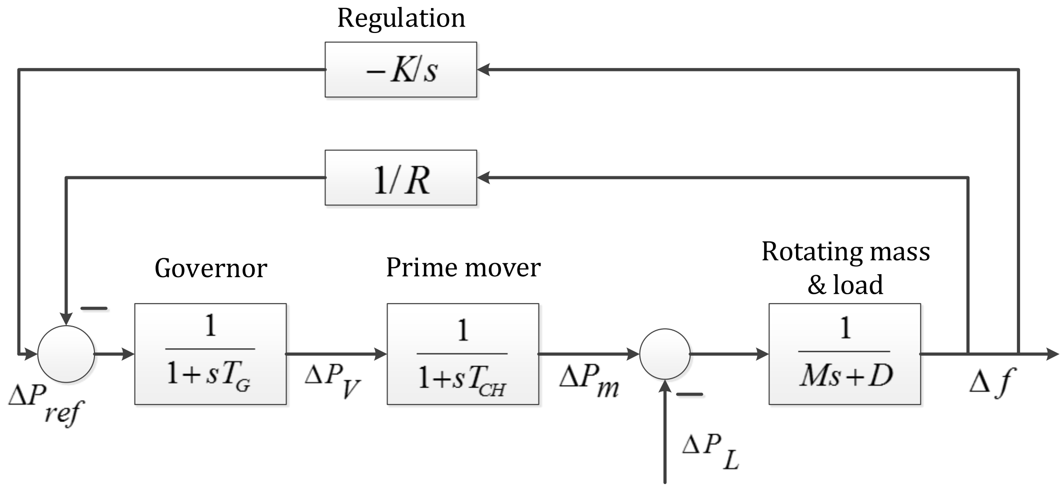

Figure 19: Power System Automatic Generation Control [9]

imbalances untouched. Furthermore, the SCED, as stated, does not replace utilized regulation reserves with firm capacity. As a result, the regulation service can potentially saturate quickly; leaving the system protected only by manual operation. To avoid these issues, the current level of imbalances I_t and the utilized regulation G_t are added to the right-hand-side of (63). Constraints (64) and (65) set the maximum/minimum generation and ramping limits respectively. Constraint (66) enforces the line flow limits.

It is worth mentioning that some input parameters of the SCED problem, such as P_{kt}, F_{lt}, γ_{it}, a_{lit}, depend on the current state of the system. These parameters are calculated before each SCED iteration based on power flow analysis of the system. Such SCED formulations are often referred to as “hot start models” [162].

3.7 Regulation Service Model

The regulation service is provided by generation units that are fully or partially controlled by the dynamic AGC model described in Fig. 19. This study uses one minute increments as its finest time scale resolution. In the meantime, the cycle time of slow transient stability phenomena is approximately ten seconds. Given the 6x difference, the transfer function shown in Fig. 19 can be replaced with the steady-state equivalent of a gain with saturation limits. The regulation service saturation limits are defined by the percentage of the capacity in the corresponding generation unit controlled by AGC. In implementation, the regulation service responds to the imbalances by moving the regulation units in the opposite direction according to their predefined participation factors. The regulation units change their outputs until imbalances are mitigated or regulation service reaches saturation.

3.8 Physical Power Grid Model

The pseudo-steady-state approximation of the regulation service model ties directly to a power flow analysis model of the physical power grid. Normally, the imbalances at the output of the regulation service model would be represented in frequency changes. However, for steady-state simulations, the concept of frequency is not applicable. Instead, a designated *virtual* swing bus consumes the mismatch of generation and consumption to make the steady-state power flow equations solvable. Therefore, for steady state simulations, the power system imbalance is measured at the slack generator output [21].

In the SOARES study, the full AC topology of ISO-NE is replaced by the zonal network (i.e. pipe

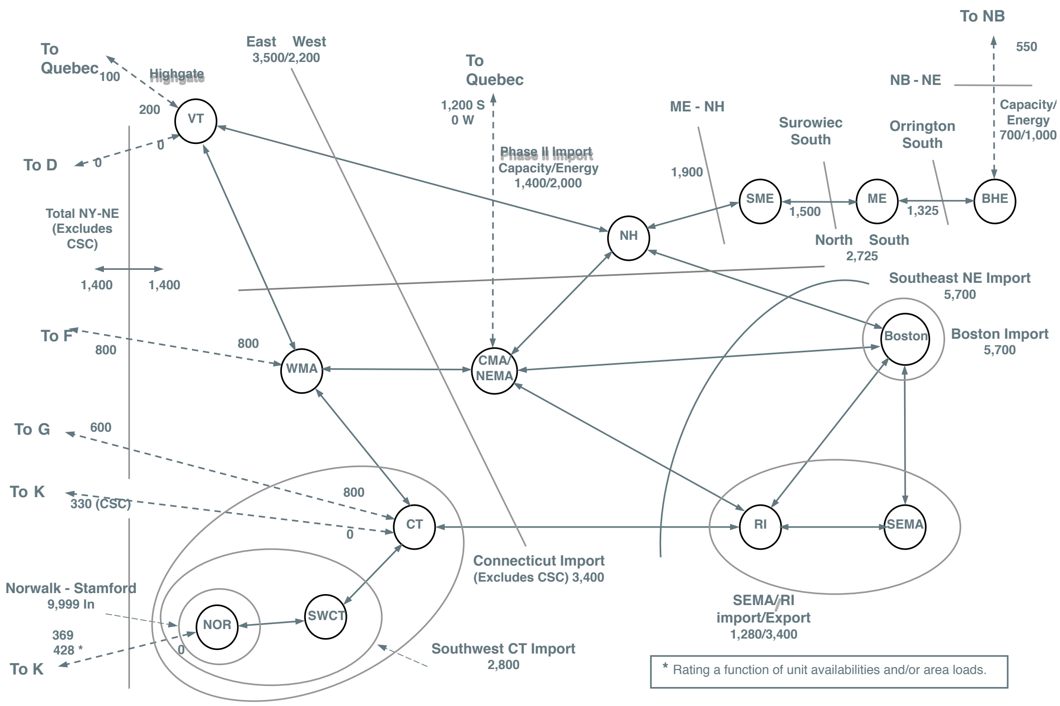

Figure 20: Topology of the ISO-NE Zonal Network Model [10]

and bubble) model shown in Figure 20. It consists of 13 bubbles, their interfaces and external tie-lines with neighboring ISOs. This model is represented by a DC power flow analysis with each zone-bubble represented as a bus and each zone-interface is represented as a line. In order to recognize that ISO New England is part of the Eastern Interconnect, the swing bus is added to represent power imbalances exchanged with New York ISO. This swing bus is connected to the Vermont, Western Massachusetts, Connecticut, and Norwalk bubbles but is distinct from the tie-lines to these bubbles. In such a way, the power flows to and from this New York swing bus also represent the deviations away from scheduled tie-line flows.

3.9 Event-based Contingency Operations

In the normal operating mode, the regulation service and the real-time balancing operations are able to keep the system balanced. However, a sudden line or generator outage can create a large imbalance that the real-time market and regulation service are unable to mitigate. The EPECS simulator is able to address forced outage events by switching from a normal operations to an emergency operations mode. In the event of a forced outage, the ISO-NE contingency operations are assumed to run a RTUC in the same time step. The simulator then continues to run the regulation and SCED models until a time that is evenly divisible by 15 minutes at which point the RTUC is called as in normal operations.

3.10 Demonstration of the EPECS Simulator on the IEEE RTS-96 Test Case

With a full description of the EPECS simulator in place, this section demonstrates it on the IEEE Reliability Test System-1996 (RTS-96) [166]. The RTS-96 is an enhanced hypothetical test system for studying the bulk power system operation that can be used demonstrate the performance of the EPECS simulator. This test case also facilitates the study of multi-area system behavior. The RTS-96 is composed of a three area system developed by merging two single areas using five interconnections, four 230 kV lines and a 138 kV line [166]. The overall system is composed of 70 buses, 3 bus zones, 99 generating units, 73 demand side resources, and a peak load of 8550MW. For simplicity, the EPECS simulator was run without the same-day resource scheduling layer. Section 3.10.1 shows typical raw output results from the EPECS simulator. Section 3.10.2 then shows how such simulator outputs can be used to make conclusions about operating reserve requirements.

3.10.1 EPECS Simulator Outputs

The EPECS simulator provides outputs at each of its layers of operation. The following five simulator outputs are provided for the span of one week of simulation.

1. Summary of Balancing Operations
2. Security Constrained Unit Commitment Schedule
3. Security Constrained Economic Dispatch
4. Regulation and Imbalance Levels
5. Load Following and Ramping Reserve Levels

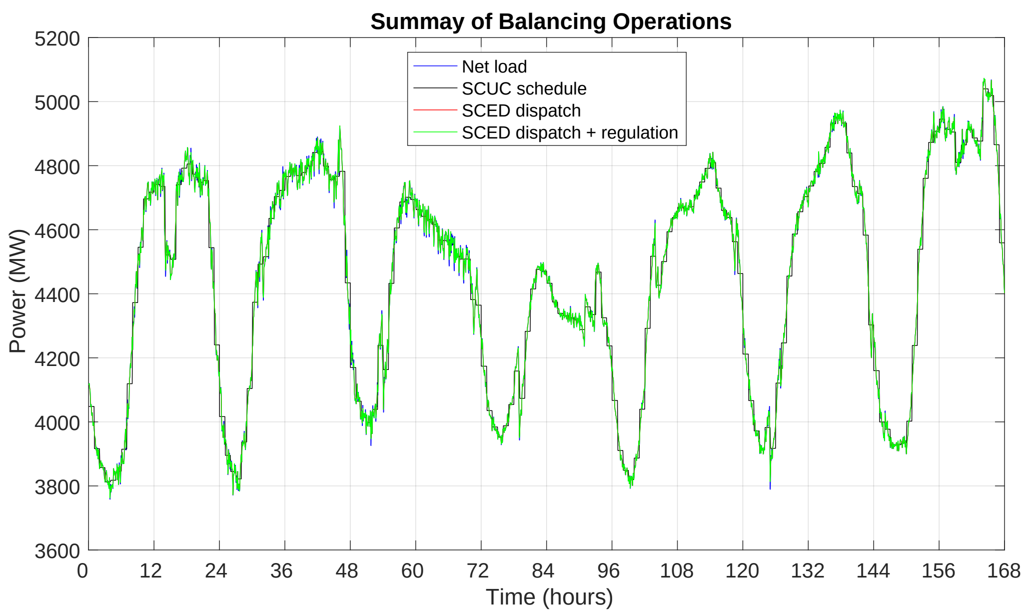

Figure 21: EPECS Simulator Output: Summary of Balancing Operations

3.10.1.1 Summary of Balancing Operations: Perhaps one of the major advantages of the EPECS simulation is that it can transparently show how each consecutive layer of power system operation and control refines the dispatch of generation to more closely serve the net load. Figure 21 shows the time profiles of the SCUC schedule, the SCED dispatch, and the SCED dispatch refined by regulation relative to the net load. In this case, the simulation was run with zero forecast error in the both the SCUC and the SCED. As expected the black and red lines follow the net load with a discretization consistent with their respective optimization time steps. The regulation then tracks the net load at a finer one-minute time step. The small deviations between the blue and green profiles suggests insufficient regulation during those times.

3.10.1.2 Security Constrained Unit Commitment Schedule The security constrained unit commitment schedule can then be viewed as a "stack" of generators in economic merit order. Figure 22 shows the output of the SCUC for the full week with one hour time resolution.

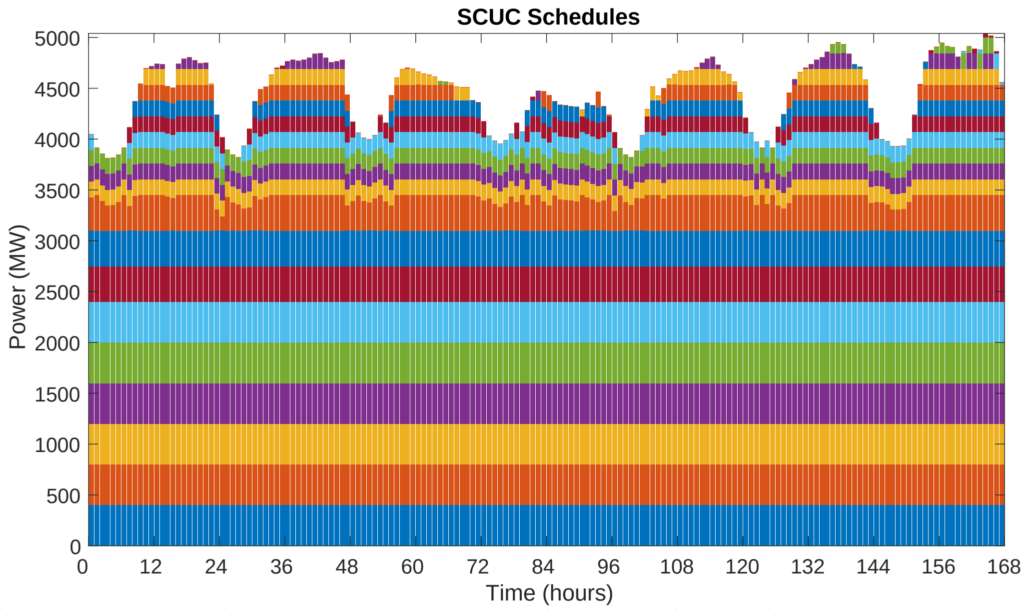

Figure 22: EPECS Simulator Output: The Security Constrained Unit Commitment Schedule

3.10.1.3 Security Constrained Economic Disatpch The security constrained economic dispatch can be viewed similarly. Figure 23 shows the output of the SCED for the full week with five minute time resolution.

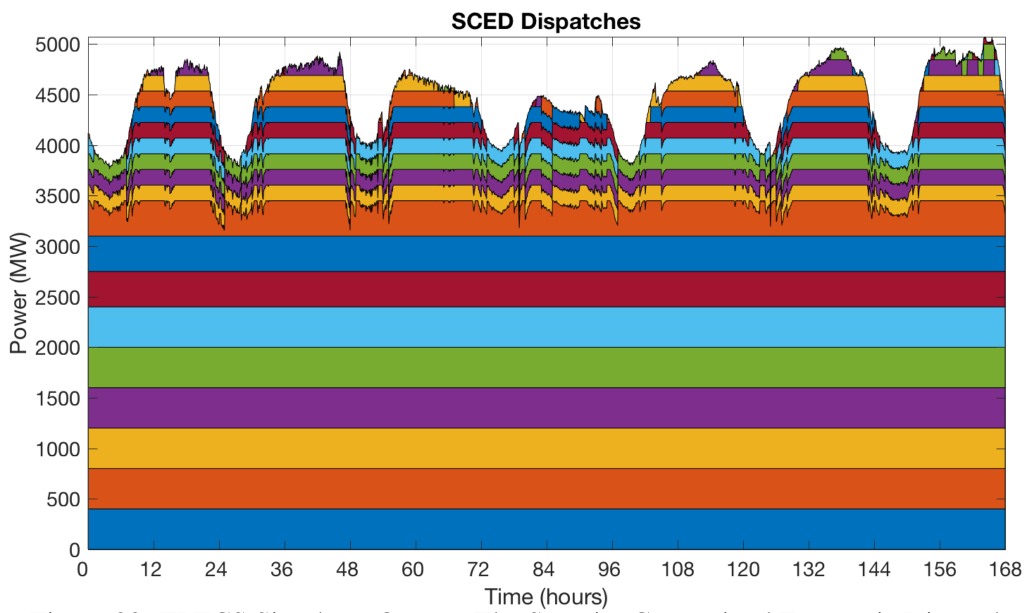

Figure 23: EPECS Simulator Output: The Security Constrained Economic Dispatch

3.10.1.4 Regulation Levels & Imbalances The EPECS simulator can also output the regulation and imabalance levels as a function of time. Figure 24 shows both quantities. The regulation level varies very quickly to account for the variability in the net load. Here, it is constrained between $\pm 6MW$ to indicate the saturation limits of the automatic generation control which also signifies the regulation reserve requirement. The imbalance level also varies quickly in time around the zero center. The time steps in which the imbalance level is nonzero indicates insufficient operating reserves.

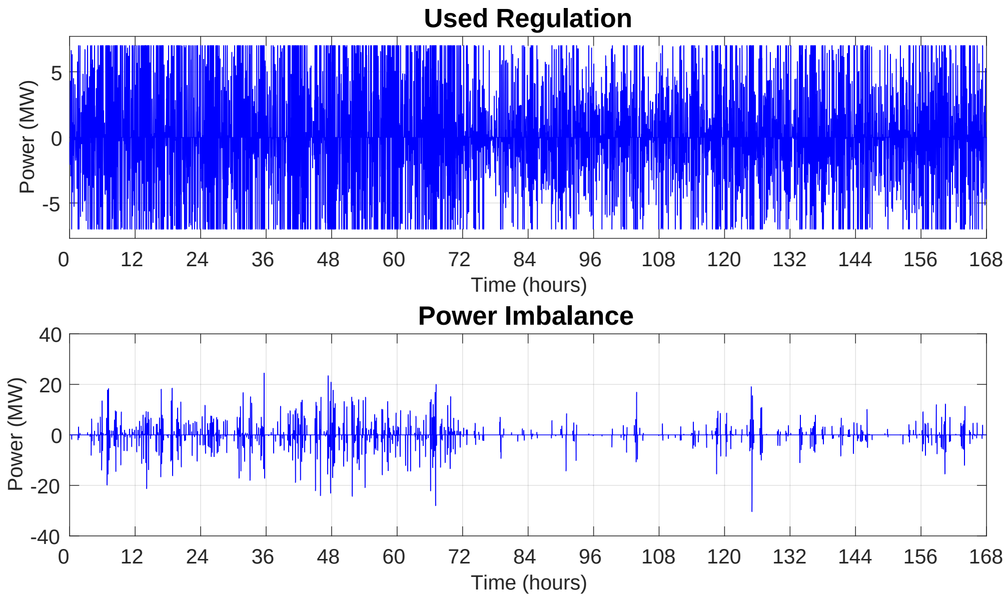

Figure 24: EPECS Simulator Output: (Top) Regulation Level (Bottom) Imbalance Level

3.10.1.5 Load Following and Ramping Reserve Levels The EPECS simulator can also track how much load following and ramping reserves vary over the course of the simulation. Figure 25 shows both of these quantities in the upward and downward directions. Note that while the requirements for load following and ramping reserves remain fixed over the course of the simulation, their actual quantities change for two reasons. First, as generation units are committed and decommitted every hour, they bring these two types of reserves on and off the system. Second, the economic dispatch consumes or returns some of these operating reserves every five minutes in response to changes in the net load. This means that the power system's ability to respond to variations and forecast errors in the net load actually varies in time as well. Part of the objective of this study is to ensure that although the actual quantities of load following and ramping reserves varies in time, it is always kept at a sufficiently high level to assure a high level of balancing performance.

3.10.2 EPECS Simulation for the Assessment of Operating Reserve Requirements

Given the typical simulator outputs provided in the previous section, the EPECS simulation can be used directly to assess operating reserve requirements. This section presents results from a case study that was recently conducted to study the impact of VER penetration on power system balance and reserve requirements [11,51]. The following scenarios were studied as sensitivity analyses.

1. Impact of day-ahead market time step on power system imbalances and reserve requirements.

2. Impact of real-time market time step on power system imbalances and reserve requirements.

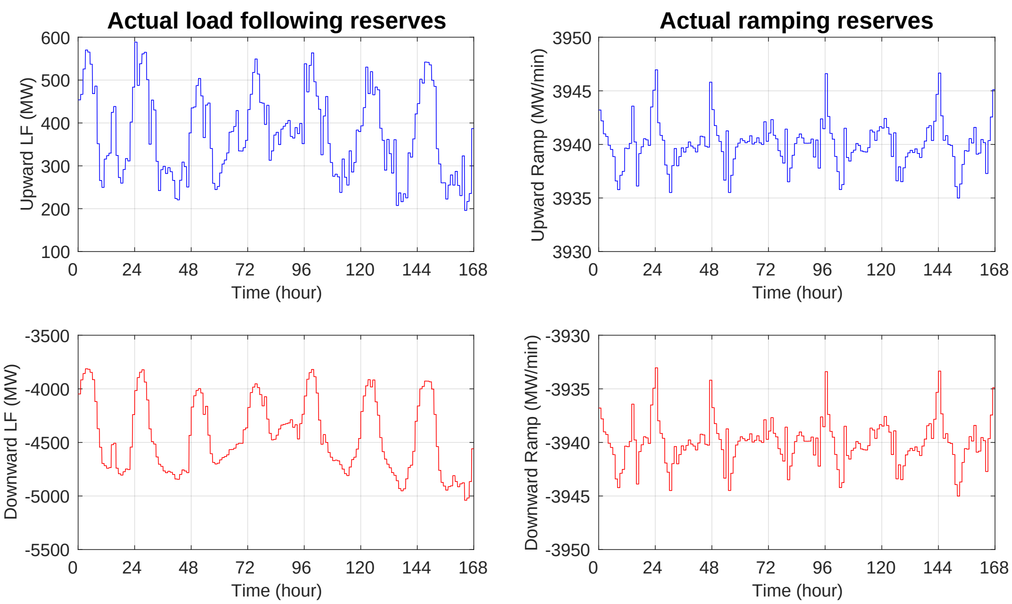

Figure 25: EPECS Simulator Output: (Top Left) Upward Load Following Reserves, (Bottom Left) Downward Load Following Reserves, (Top Right) Upward Ramping Reserves, (Bottom Right) Downward Ramping Reserves

3. Impact of VER variability on power system imbalances and reserve requirements.
4. Impact of VER penetration level of distinct variabilities on power system imbalances
5. Impact of VER day-ahead forecast error on power system imbalances and reserve requirements.
6. Impact of VER short-term forecast error on power system imbalances and reserve requirements.

3.10.2.1 Impact of Day-Ahead Market Time Step on Reserve Requirements: The limited resolution of the day-ahead scheduling process creates a mismatch between the scheduled resources and the real-time demand fluctuations. As part of a case study, simulation studies were performed to test the impact of the day-ahead market time-step on load-following, ramping and regulation reserves. Fig. 26 shows the load following, ramping and regulation reserve requirements for three different scheduling time steps: 60 minutes, 30 minutes and 15 minutes. Each point on these graphs represents a full year simulation with a specific combination of input parameters. The standard deviation of the imbalances time series is then calculated and plotted against its corresponding input parameters of reserve quantities and SCUC time step.

These figures reveal some important aspects of the impact of day-ahead scheduling time step on reserve requirements. They also show similar patterns for load following and ramping reserves. First, all three graphs start at different levels of imbalances in the absence of reserves, which shows that the imbalances are inherently smaller for systems with shorter day-ahead market time steps. Second, the graphs with shorter scheduling time steps reach the saturation level sooner, which indicates that they require less load following and ramping reserves. Third, both graphs have the same saturation level, which means that the fast imbalance is the same for all cases and does not depend on the day-ahead market time step. This fact is clearly demonstrated in the graph on regulation reserves (Fig. 26 on right). The graphs for three different values of the day-ahead market time step replicate each other identically and go to saturation for the same value of regulation reserves. As expected, this shows that the regulation reserve requirement does not depend on the

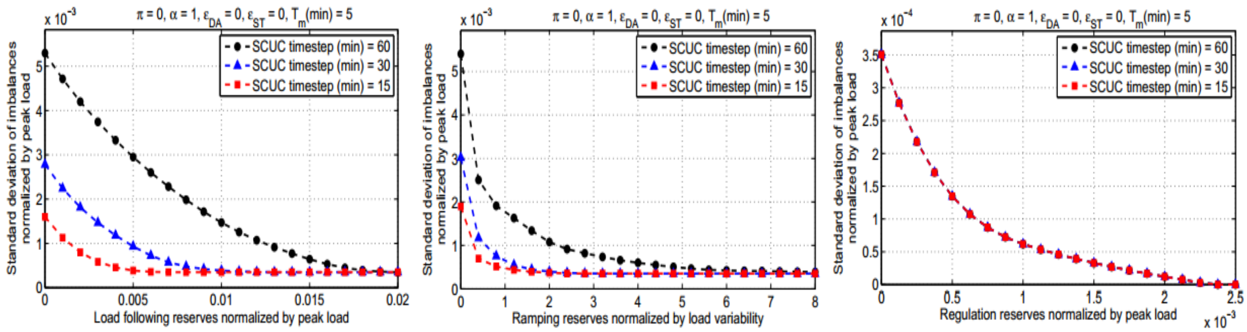

Figure 26: Impact of Day-Ahead Market Time Step on Reserve Requirements [11]

day-ahead market time step. Note here that the zero value for the standard deviation of imbalances means that all steady-state imbalances with one minute resolution have been mitigated. In all, Fig. 26 shows that the SCUC time step reduction potentially reduces the load following and ramping reserve requirements. Such a reduction, however, would have to be assessed in the context of the additional computational burden and require market lead time. These results motivate the study of the ISO-NE RTUC and its impact on balancing performance.

3.10.2.2 Impact of Real-Time Market Time Step on Reserve Requirements The limited resolution of the real-time market creates a mismatch between the dispatched resources and the real-time demand fluctuations. Additional simulations were conducted to study the impact of the real-time market step on load-following, ramping, and regulation reserve requirements. Fig. 27 show the load following, ramping and regulation reserve requirements for three different real-time market time steps: 5 minutes, 10 minutes and 15 minutes.

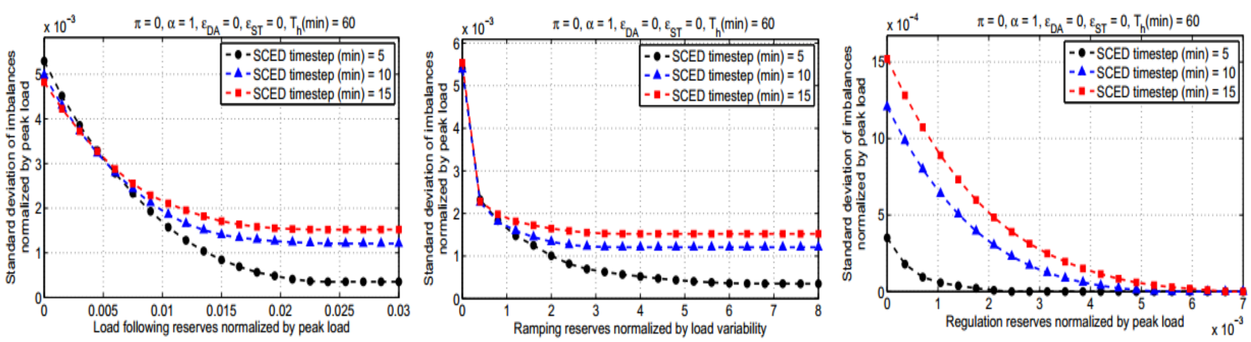

Figure 27: Impact of Real-Time Market Time Step on the Reserve Requirements [11]

Similarly to the previous scenario, the figures for load following and ramping reserve requirements show some common characteristics. First, the graphs start from approximately the same point, which shows that the imbalances stand at the same level in the absence of reserves. This is explained by the fact that the real-time market time step only defines the splitting threshold between slow and fast imbalances but does not affect the magnitude of total imbalances. Second, the graphs reach their respective saturation levels for the same value of reserves, regardless of SCED time step, which indicates that the load following and ramping reserve requirements do not depend on the real-time market time step. Third, the saturation level is always lower for the system with a smaller real-time market time step, which means that the real-time market affects the fast imbalance and the regulation reserve requirement. This fact is clearly demonstrated in Fig. 27 on right. As expected, the system with smaller real-time market time step goes to saturation sooner, which means that it requires less regulation reserve. In all, Fig. 27 shows that the SCED time step reduction potentially reduces the regulation reserve requirement. Such a reduction, however, would have to be assessed in the context of the additional computational burden and generators' ability to adhere to the newly distributed dispatches.

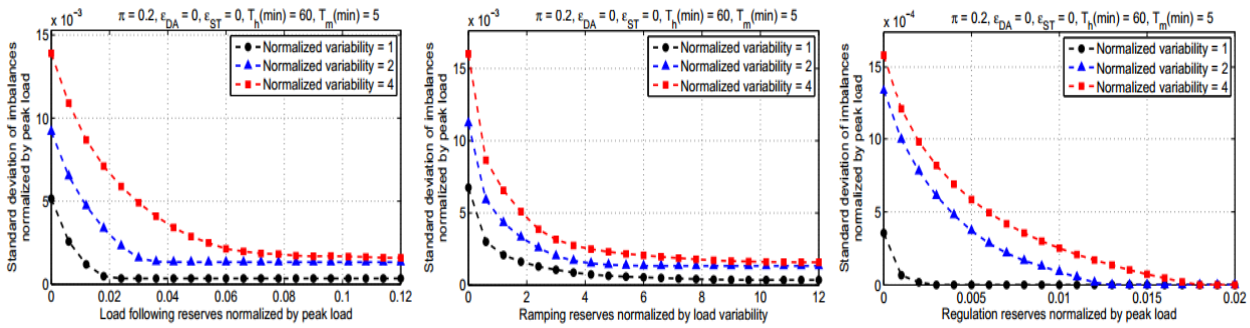

Figure 28: Impact of VER Variability on Power System Imbalances [11]

3.10.2.3 Impact of VER Variability on Power System Imbalances and Reserve Requirements As discussed above, the limited resolutions of the day-ahead and real-time markets create a mismatch between the dispatched resources and the real-time demand fluctuations. While the simulation results from the previous scenarios show that the system imbalances and the reserve requirements depend on the day-ahead and real-time market time steps, the actual variability of the net load also needs to be considered as well. Generally speaking, since the variability indicates the rate of the net load profile fluctuations, changing the scheduling/balancing time step and changing the profile variability should have equivalent effects on the system. Moreover, the variability is the only VER parameter that spans over all timescales and is expected to have impact on all three types of reserves. To this end, three simulation studies are performed to assess the impact of VER variability on each type of reserve requirement. Fig. 28 shows the change of the power system imbalances as the VER penetration level increases for three values of normalized variability: 1, 2 and 4.

Fig. 28 show the load following, ramping, and regulation reserve requirements for different levels of variability. These graphs reveal important aspects of VER variability impact on the reserve requirements. First, the graphs have different imbalance levels in the absence of reserves, which shows that the imbalances are smaller for the system with smaller variability. Second, the graph with smaller variability reaches the saturation level sooner, which indicates that the systems with less variability require less load following, ramping, and regulation reserves. Third, the saturation level for the system with less variability is lower, which means that high variability increases the fast imbalance and the regulation reserve requirement, which is demonstrated in Fig. 28 on the right. As expected, the system with less variability goes to saturation sooner, which means that it has a smaller regulation reserve requirement.

3.10.2.4 Impact of VER penetration level of distinct variabilities on power system imbalances According to the definition of normalized variability, in the absence of forecast errors, increasing the VER penetration level also increases the introduced total VER variability. As a result, increasing VER penetration level has a similar impact on power system imbalances as increasing VER normalized variability. The graphs in Fig. 28 start from the same imbalance level and start to diverge as the VER penetration level increases. This shows that higher levels of imbalances correspond to higher variability, which indicates that in the presence of high variability the adequacy of the existing reserve requirements is challenged.

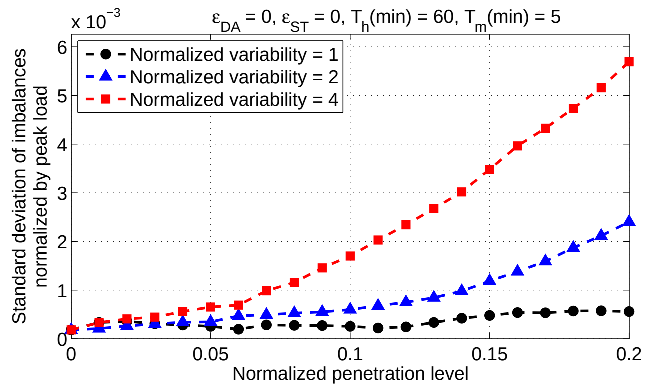

Figure 29: Impact of VER Variability on Power System Imbalances [11]

3.10.2.5 Impact of VER Day-Ahead Forecast Error on Power System Imbalances and Reserve Requirements

The day-ahead forecast error impedes the match of scheduled resources to real-time demand fluctuations and, hence, contributes to the slow imbalance term. As described above, both load following and ramping reserve requirements depend on the day-ahead forecast error, while the regulation reserve operate at a smaller timescale. To this end, three simulation studies are performed to assess the impact of the VER day-ahead forecast error on each type of reserve requirement. Fig. 30 shows the load following,

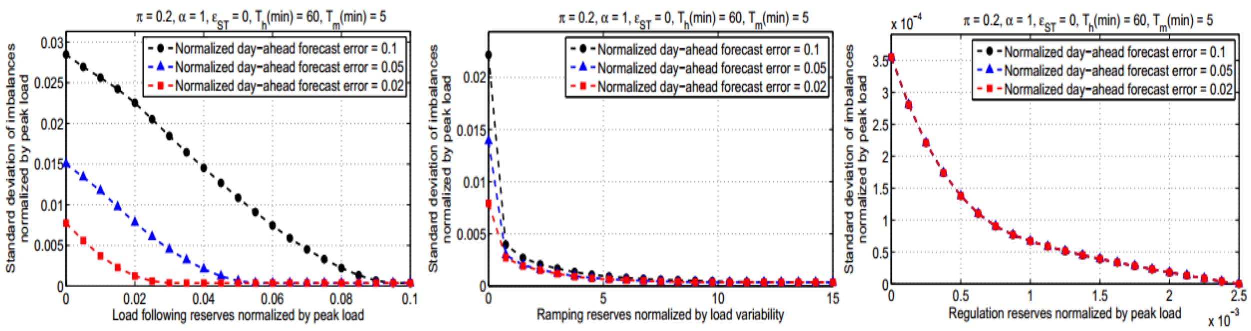

Figure 30: Impact of VER Day-Ahead Forecast Error on Power System Imbalances [11]

ramping, and regulation reserve requirements for three values of normalized VER day-ahead forecast error: 0.02, 0.05 and 0.1. The curves reach saturation for different values of load following reserves, which shows that systems with higher VER day-ahead forecast error have higher load following reserve requirements. In contrast, the middle graph in Fig. 30 shows that the ramping reserve requirements are only slightly affected by the day-ahead forecast error. This is because the day-ahead forecast error appears in the ramping reserve scheduling process in a differential form. Also, both graphs have different imbalance levels in the absence of reserves, which shows that the imbalances are inherently smaller for the system with smaller day-ahead forecast error. Moreover, all three graphs have the same saturation level, which means that the fast imbalance is not affected by the day-ahead forecast error. This phenomenon is clearly demonstrated in Fig. 30 on the right, where all three graphs replicate each other identically. As expected, the regulation reserve requirement is the same for all three values of the day-ahead forecast error. In all, Fig. 30 shows that the mitigation of the day-ahead forecast error potentially reduces the load following and ramping reserve requirements. This suggests that investments to improve forecasting technology can be directly weighed against the value of the required reserves.

3.10.2.6 Impact of VER Short-Term Forecast Error on Power System Imbalances and Reserve Requirements The short-term forecast error creates a mismatch between the dispatched resources and the real-time demand fluctuations. Hence, it contributes to the fast imbalance term. As described above, the dispatching of generation is affected by the short-term forecast error, while the load following and ramping reserves operate at a slower timescale. To this end, three simulation studies are performed to assess the impact of the VER short-term forecast error on each type of reserve requirement.

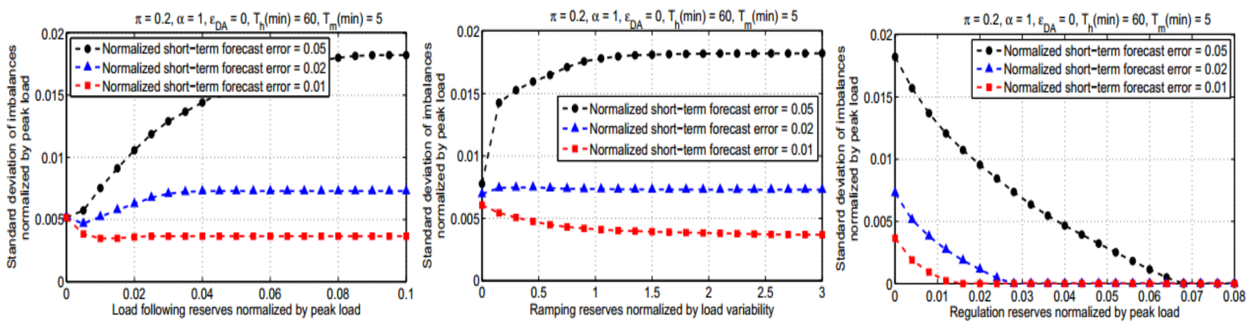

Figure 31: Impact of VER Short-Term Forecast Error on Power System Imbalances [11]

Fig. 31 shows the load following, ramping, and regulation reserve requirements for three normalized short-term forecast errors: 0.01, 0.02 and 0.05. The resulting curves are potentially counter-intuitive but entirely explainable. The conventional wisdom is that adding load following and ramping reserves *always* improves power system imbalances regardless of the short-term forecast error. However, this is not always true. In the absence of load following or ramping reserves, the system has no flexibility and the generation units follow the schedule defined in the day-ahead market. In this case, only the slow imbalance term exists, which is relatively small in the absence of the day-ahead forecast error. However, as the load following and ramping reserves are added to the system, the generation units' added flexibility wrongly track the erroneously forecasted net load. The fast imbalance term accordingly increases in value, which eliminates all the benefits from the mitigation of the slow imbalance term. Such a scenario, however, is purely theoretical. In these simulations, the day-ahead forecast error has been neglected so as to reveal how and why imbalances occur. In practice, the presence of the short-term forecast errors also guarantees day-ahead forecast error. And in such a scenario, the load following and ramping reserves would only improve the system balance.

Since neither load following nor ramping reserves are able to mitigate the imbalances in the case of short-term forecast error, the regulation reserves are the only solution. Since the short-term forecast error creates imbalances when the generators ramp from the current level to the new dispatched value, it is expected that increasing amount of regulation reserves should mitigate the imbalances in this scenario. Fig. 31 (on the right) shows the impact of increasing the regulation reserves on the imbalances of the power system for three different values of short-term forecast error. The curves show that the higher short-term forecast error leads to a higher regulation reserve requirement. In all, Fig. 31 show that the mitigation of the short-term forecast error potentially reduces the regulation reserve requirement. This suggests that investments to improve the forecasting technology can be directly weighed against the value of the required reserves.

4 SOARES Project Methodology

The EPECS Simulation Methodology serves as the cornerstone for the 2017 ISO New England System Operation Analyis and Renewable Energy Integration (SOARES) project. This section describes how the EPECS simulation is integrated into the SOARES project.

4.1 SOARES Project Work Flow

The SOARES project consists of four activities.

1. Prepare a state-of-the-art renewable energy integration assessment methodology customized to the operational characteristics of ISO-NE.
2. Prepare a set of scenario data to conduct a renewable energy integration assessment study for the years 2025 and 2030.
3. Develop a validated numerical simulation of ISO-NE renewable energy integration for the year 2014.
4. Assess the reliability and economic impacts of renewable energy integration for the years 2025 and 2030.

Activity 1 consists of the development of a state-of-the-art assessment methodology that is customized according to ISO-NE's unique operational features, characteristics, and challenges. The methodology should highlight how it specifically addresses ISO-NE, describe the key analytic steps required to complete the project and emphasize how it is a state-of-the-art relative to existing industrial best practice and available literature. This completion of this report effectively address Activity 1 of the project.

In Activity 2, a consistent and complete set of input data for the numerical simulations is prepared based upon the six scenarios from the 2016 economic studies [10, 50]. The input data includes generator heat-rates and other fuel consumption parameters, fuel availability constraints and other availability constraints, generator ramp-rates, frequency response characteristics, maximum and minimum capacity limits and other electrical output parameters. The input data should also include the time series of wind, solar, hydro outputs and load profiles by load zone, and electrical interchanges with New York, New Brunswick, and Quebec. Additionally, benchmark data from the year 2014 and scenario data for years 2025 and 2030 is included. The prepared data allows simulations with the zonal network model of the physical power grid.

For Activity 3, the EPECS simulator is customized to reflect the New England bulk electric power system and ISO-NE operations in 2014. The model includes supply and demand-side resources, load following, ramping and regulation reserves. The model also consists of the day-ahead scheduling in a form of a security constrained unit commitment, the same-day scheduling of fast-start resources as a real-time unit commitment, the real-time balancing in a form of a security-constrained economic dispatch, the regulation service and the physical power grid model. The model is used to perform simulations for the duration of one year with one minute time step. It incorporates all scenarios and sensitivity analyses from Activity 2 including changes in the penetration level, the variability of non-dispatchable energy resources and the mix of dispatchable energy resources. The goal is to produce:

- the generation dispatch levels for the day-ahead unit commitment time stamped with 1 hour resolution,
- the real-time unit commitment time stamped with 15 minute resolution,
- the real-time security constrained economic dispatch time stamped with five minute resolution,
- the actual consumption and generation levels time stamped with one minute resolution,
- the fuel consumption for each generator time stamped with one minute resolution,
- the area control error and frequency time stamped with with one minute resolution and,
- interchange flows time stamped with one minute resolution.

ISO New England will validate these simulations against their historical experience.

Activity 4 consists of a renewable energy integration study using the methodology described in Activity 1, the scenario data described in Activity 2, and the simulation model developed in Activity 3. The goal of the study is to produce the same outputs and analyses as those described in Activity 3. As described below in Section 4.2 six scenarios are studied. These are integrated into a sensitivity analysis consisting of a total of 48 simulation-years. The study is expected to highlight trade-offs in balancing performance and their associated operating reserves.

At the end of the study, a final report will be produced that incorporates feedback from PAC meetings and more generally from ISO New England. Activity 5 consists of developing a final report that incorporates the feedback from the PAC meeting discussions and more generally from ISO-NE.

4.2 SOARES Project Scenarios

The renewable energy integration study described in Activity 4 is organized into six scenarios as presented in Table 1. These scenarios have been extensively discussed in PAC meetings and described exhaustively in [10, 50].

Scenario	Retirements	Gross Demand	PV	Energy Efficiency	Wind	New NG Units	HQ and NB External Ties & Transfer Limits
1	1/2 in 2025 1/2 in 2030	Based on 2016 CELT forecast	Based on 2016 CELT forecast	Based on 2016 CELT forecast	As needed to meet RPSs	NGCC	Based on historical profiles
2	1/2 in 2025 1/2 in 2030	Based on 2016 CELT forecast	BTM Based on 2016 CELT forecast; non-BTM same as wind	Based on 2016 CELT forecast	Used to satisfy net ICR	None	Based on historical profiles
3	1/2 in 2025 1/2 in 2030	Based on 2016 CELT forecast	8,000 MW (2025) 12,000 MW (2030) BTM PV 4,000 MW (2025) 6,000 MW (2030) Utility PV 4,000 MW (2025) 6,000 MW (2030)	4,844 MW (2025) 7,009 MW (2030)	5,733 MW (2025) 7,283 MW (2030)	None	Based on historical profiles plus additional imports
4	No retirements beyond FCA #10	Based on 2016 CELT forecast	Based on 2016 forecast	Based on 2016 forecast	Existing plus those with I.3.9 approval	NGCC	Based on historical profiles
5	1/2 in 2025 1/2 in 2030	Based on 2016 CELT forecast	Based on 2016 CELT forecast	Based on 2016 CELT forecast	Existing plus those with I.3.9 approval	NGCC	Based on historical profiles
6	1/2 in 2025 1/2 in 2030	Based on 2016 CELT forecast	381 MW (2025) 1,611 MW (2030)	Based on 2016 CELT forecast	Onshore wind: 381 MW (2025) 1,611 MW (2030) Offshore wind: 381 MW (2025) 1,611 MW (2030)	None	Based on historical profiles

Table 1: The Six Scenarios of the ISO New England SOARES Project

5 Conclusion

This report describes the project methodology for the 2017 ISO New England System Operational Analysis and Renewable Energy Integration Study (SOARES). It introduces the concept of enterprise control as a holistic approach to the integration of variable energy resources. To situate the discussion a review of the methodological adequacy of existing renewable energy inetgration studies is provided. The body of the report is dedicated to describing the Electric Power Enterprise Control System (EPECS) simulator customized to ISO New England's operations. Finally, the report describes how the simulator is integrated into the SOARES project as a whole. Six scenarios will be studied for the years 2025 and 2030. These are organized into sensitivity cases that include a total of 48 simulation years.

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