ANL/ESD-18/9

Prices in Frequency Regulation Markets: Impacts of Natural Gas Prices and Variable Renewable Energy

Energy Systems Division

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by
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May 2018

CONTENTS

FIGURES

FIGURES (CONT.)

TABLES

ACKNOWLEDGMENTS

The author wishes to thank Rima Oueid and Dan Ton of the United States Department of Energy, as well as Robert Broderick and James Ellison of Sandia National Laboratories and Audun Botterud and Zhi Zhou of Argonne National Laboratory for their assistance and guidance throughout the development of this work. The submitted manuscript has been created by UChicago Argonne, LLC, Operator of Argonne National Laboratory ("Argonne"). Argonne, a U.S. Department of Energy Office of Science laboratory, is operated under Contract no. DE-AC02-06CH11357.

Funding: This work was supported in part through funding from the United States Department of Energy Office of Electricity Delivery and Energy Reliability and Office of Energy Policy and Systems Analysis.

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ABSTRACT

Increasing wind and solar penetration and low natural gas prices have reduced electricity prices in competitive power markets in recent years, while also increasing the relative importance of ancillary services in balancing short-term net load variability. As a result, ancillary service markets are providing a valuable alternative revenue stream for many market participants. Yet the price dynamics in these markets are still not very well understood. In this work, we incorporate unit-level ancillary service offer prices and quantities into a production cost model and examine how prices for frequency regulation are impacted by relatively extreme perturbations of several system parameters. Initial offers are first estimated on the basis of limited available public data and are then iteratively calibrated against historic market outcomes. Through a case study of the PJM Interconnection, we find that doubling the natural gas price increases the average annual regulation price by 36%, while replacing all coal generation with natural gas decreases the average price by 42%. Increasing the wind penetration from 2% to 30% in isolation increases the average regulation price by 32%, while further doubling the regulation requirement results in an 84% increase. These price increases can be mitigated by introducing additional battery storage capacity or by increasing offer quantities from hydro and thermal units. Finally, we discuss a number of modeling challenges that are faced when incorporating ancillary services into traditional production cost models. These include poor data availability, inconsistent product definitions across markets, and complex market rules.

Keywords: ancillary services; power system modeling; electricity markets; AURORAxmp; frequency regulation

1 INTRODUCTION

In recent years, power systems in the United States and around the world have undergone a number of changes that are fundamentally altering the way these systems are operated. Notable among these changes are increasing penetration of variable renewable energy (VRE) generation, such as wind and solar; the retirement of coal and nuclear generation in favor of natural gas; and the widespread introduction of distributed energy resources and grid-scale battery energy storage systems. It is anticipated that many of these changes will continue to increase in scope and impact in coming years and decades. Such impacts are of particular interest in restructured power systems that rely on competitive market mechanisms to support both short-term and long-term system reliability. Over the past decade, restructured power markets in the United States have also undergone several key changes, including the introduction of new products such as ancillary services, long-term capacity, operational flexibility, and financial transmission rights. All seven restructured regional transmission organizations (RTOs) and independent system operators (ISOs) in the United States now offer competitive auction-based markets for three primary classes of ancillary services. These can be broadly designated as frequency regulation, spinning reserves, and non-spinning reserves, although the specific names and definitions of these services vary from market to market.

One system transition of particular interest is the rapid influx of low- or zero-marginal-cost wind and solar generation into power systems, which, all else being equal, tends to reduce wholesale electricity prices and reduce revenues for generation resources [1]. A second impact manifests in markets for ancillary services. As the supply of wind and solar generation increases, so too will the demand for ancillary services in order to balance short-term net-load variations and maintain system reliability. As a result, markets for ancillary services may provide an increasingly valuable revenue stream for flexible resources that are able to provide these services, potentially helping to compensate for decreasing revenues in the energy market.

As markets for ancillary services continue to play an increasing role in modern power systems, it is also increasingly important for market operators, market participants and policy-makers to understand how the supply and demand for ancillary services, as well as associated prices, will evolve over time. Yet, the body of research on analyzing ancillary service price dynamics in real-world power systems is still relatively limited. The goal of this work is therefore to expand upon this body of literature by incorporating unit-level ancillary service offer prices and quantities into an established production cost model and calibrating these offers on the basis of historical market outcomes. The model is then applied to examine the frequency regulation price impacts that occur under a range of future sensitivity scenarios. The results of this analysis will be of significant interest to market operators who are developing new market mechanisms to address the reliability challenges of large-scale renewable integration, as well as market participants who operate the growing portfolio of fast-response resources that are well-suited to participate in frequency regulation markets.

1.1 PAPER STRUCTURE AND CONTRIBUTION

This paper first reviews the relevant literature that has established the mathematical theory behind co-optimizing the dispatch of energy and ancillary services in competitive power markets. We also review a range of studies that discuss ongoing system and market evolution and have attempted to quantify the associated ancillary service price impacts that may result. Next, we outline our methodology for incorporating unit-level ancillary service price and offer quantities into the production cost model that is used for this analysis. We then introduce a case study of the PJM Interconnection system and conduct a series of sensitivity analyses to investigate how frequency regulation prices are impacted by changes in a number of key parameters. This paper concludes with a discussion of the unique challenges that are faced when modeling ancillary services in a competitive market environment, including limited data availability and complex and diverse market rules and definitions that are difficult to represent with traditional power system models.

There are several original contributions of this work. First, we synthesize the limited available public data on historical unit behaviors in ancillary service markets to determine realistic unit-level offer prices and quantities. These are then further calibrated against historic market outcomes. Second, we utilize an established commercial production cost model to analyze a detailed representation of the PJM power system, explicitly considering the hourly operational behavior of nearly 2000 individual generation units across 20 load zones. This analysis provides valuable insight into the price impacts that may be observed in real-world power systems. Third, while past studies have examined the price impacts that occur when new wind and solar generation is introduced to a power system in addition to existing generation capacity, we maintain consistent capacity value across all of our scenarios. This approach more closely represents long-term equilibrium conditions and avoids conflating price impacts that may be caused by over-procurement of capacity in the short-term. We also isolate the specific impacts resulting from each of several individual system perturbations, rather than analyzing broad future scenarios that simultaneously consider a number of changes. Finally, we investigate the price effects of several parameter sensitivities that have not yet been widely explored in the literature, including natural gas prices, coal and nuclear retirements, and unit offer prices and quantities.

2 BACKGROUND

There is a wide body of literature that discusses various approaches to formulating and solving mathematical problems to co-optimize the dispatch of energy and ancillary services in a competitive power market. This literature is too expansive to comprehensively review here, but we briefly review a subset of these studies that also explicitly calculate market-clearing prices for ancillary services. Ma and Sun provide an early review of several different approaches to dispatching ancillary services in competitive markets, along with the corresponding market outcomes in a small theoretical test system [2]. Several other studies build upon this foundation by proposing co-optimization formulations, one that is applied to two sample representations of the ISO-NE system [3], one that is applied to a two-zone test system under two different cases [4], and one that considers a full alternating-current optimal power flow formulation that is applied to a three-node test system [5]. Two additional studies compare the market outcomes obtained from co-optimization of energy ancillary services against other mathematical formulations, including a genetic algorithm approach [6] and a sequential scheduling approach [7]. While these studies establish the important mathematical foundation for co-optimizing energy and reserves in competitive power markets, their formulations are typically applied to simplified representations of real power systems or small test systems. This work also generally does not analyze how changes in system configurations or other key parameters may influence prices for ancillary services.

Several more recent studies have specifically investigated how ancillary service markets may evolve in systems with increasing VRE penetration, and analyzed some potential impacts on market-clearing prices. Most of these studies find that prices for non-spinning reserves are relatively unaffected by changes in VRE penetration, while prices for spinning reserves may increase by a small amount [8–11]. One study utilizes a multi-period Nash-Cournot equilibrium approach and finds that prices for both regulation and reserves increase significantly as more wind power is introduced in China over a 35 year time horizon [12]. In general, however, potential price impacts are more apparent in frequency regulation markets. One study of the Electricity Reliability Council of Texas (ERCOT) finds that the average prices for regulation-up and regulation-down increase by 21% and 55%, respectively, as the system evolves from roughly 12% wind penetration to 22% wind penetration [10]. Another study of ERCOT also finds that both regulation-up and regulation-down prices increase with increasing solar penetration, although to a lesser extent; 3% and 30%, respectively, for a transition from 9% solar to 16% solar [8]. A third study analyzes a single combined regulation product in the Colorado region and also finds hypothetical average market prices to increase by about 7% as the system evolves from 15% wind and solar VRE to 35% wind and solar [9]. However, none of these three analyses consider potential unit retirements that may be caused by introducing new VRE capacity into the system, which may in turn limit the supply of regulation capacity and thereby have an upward price impact. Frew et al. present an analysis of unit revenue sufficiency in high wind power systems that considers revenues from ancillary service provision; however, ancillary service prices are not specifically discussed [13]. Brinkman et al. review the provision of ancillary services under several high VRE penetrations, but similarly do not specifically analyze the impacts on market prices [14].

Finally, a number of studies have examined the early design and implementation of competitive markets for ancillary services [15–19], or have reviewed historical ancillary service market evolution in the United States [20]. Others have included ancillary service markets in a broader discussion of market evolution in high-VRE futures [21–23]. Wang et al. analyze historical prices for ancillary services in three North American markets with a specific focus on understanding price variability and extreme prices, and additionally provide some insight into the impacts of market mechanisms and policies [24]. Zhou et al. survey ancillary service market rules and definitions in the seven U.S. RTOs and ISOs and provide annual price summary statistics for each market [25].

3 MATERIAL AND METHODS

3.1 PRODUCTION COST MODEL

A production cost model is a tool that simulates power system operations by minimizing the costs of serving electricity demand while also satisfying a range of other operational constraints. In this report, we first present an approach for incorporating unit-level ancillary service market behavior into a production cost model. We then apply the model to analyze the sensitivity of prices for frequency regulation to changes in the system generation portfolio and a number of other key parameters. For this purpose, we utilize AURORAxmp [26], a commercial production cost model that is widely used by utilities in the United States to conduct integrated resource planning [27], as well as by regulators and industry throughout North America and Europe. AURORAxmp has also been applied to analyze a range of research questions, as in, for example, [28–31]. There are a variety of other production cost models that may be used for similar applications, a number of which are reviewed in detail by Foley et al. [32]. It is also possible to develop custom production cost modeling tools by directly implementing and solving the optimization formulations that were reviewed in Section 2. Such customized tools can provide valuable insights when utilized to analyze specific issues, but it is challenging to apply them to analyze detailed representations of real-world systems, owing to the associated data collection and integration requirements. We chose AURORAxmp for this analysis because it includes a comprehensive database of the PJM power system, including a detailed list of operational characteristics for nearly 2000 individual generation units—e.g., capacities, ramp rates, heat rates, and variable and fixed operating costs—as well as hourly demand profiles for 20 load zones and an associated zonal representation of the transmission system. Having access to this database eliminated the need for the time-intensive process of collecting these data manually and integrating them into another tool. AURORAxmp co-optimizes the dispatch of electricity and ancillary services on an hourly or sub-hourly basis and calculates the associated market-clearing prices for each product. Unit commitment and dispatch decisions are optimized throughout the entire system on a daily basis while the model also considers how these decisions will affect operations on the following day. Additional constraints include resource ramping capabilities, minimum generation levels, minimum up and down times, and transmission constraints. The model further considers resource fuel costs, fixed and variable operations and maintenance costs, startup and shut down costs, and transmission wheeling costs in determining the least-cost solution. However, AURORAxmp does not provide any data to characterize the ability of individual generation units to provide ancillary services or the costs they may incur from doing so. We therefore focused our efforts on synthesizing the limited available public data on unit-level ancillary service provision and incorporating them into AURORAxmp, utilizing the established database and optimization engine of AURORAxmp to calibrate these unit behaviors on the basis of historical market outcomes. This process is outlined in Figure 1 and is further detailed in Section 3.2.4. AURORAxmp also has the ability to analyze unit investment and retirement decisions, but we hold the generation fleet fixed for each scenario in our analysis.

In contrast to many of the previous studies outlined in Section 2, we assume that when new capacity is added to the system, an equivalent capacity value of thermal generation is removed to more accurately reflect long-term equilibrium conditions. All three classes of market-based ancillary services are explicitly modeled with hourly resolution; however, we limit our discussion and analysis to the frequency regulation market, as it proved to be the most interesting and insightful. Our analysis considers a single combined up- and down-regulation product, as is currently offered in PJM.

For each scenario considered, the model is executed for a representative set of 576 one-hour time steps, representing every fourth hour, four days per week, and two weeks per month with a 1% optimality gap. This representative approach was chosen for computational efficiency, owing to the large number of scenarios being analyzed. Selected comparisons against a full 8760-hour execution determined that average annual outcomes were reasonably consistent between the two approaches.

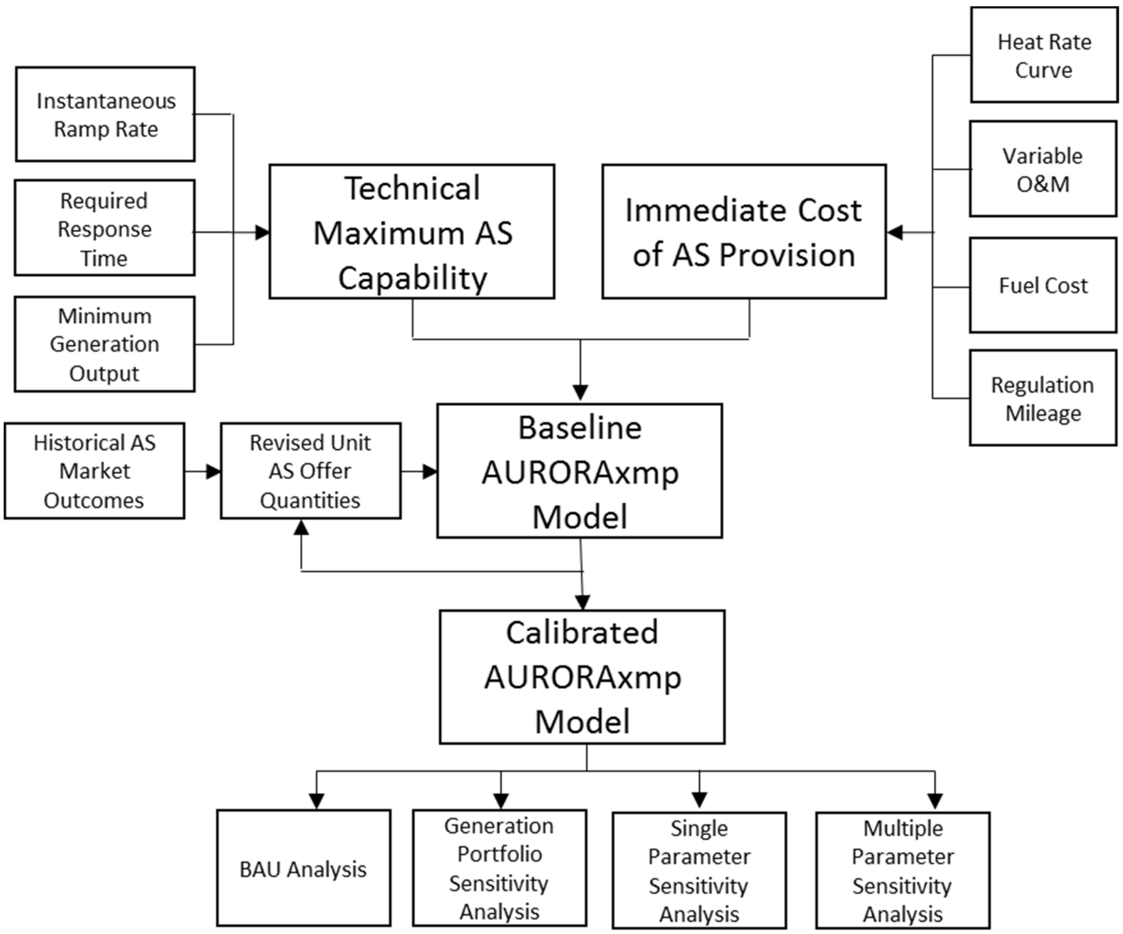

FIGURE 1 Overview of the modeling process utilized for this study (AS = ancillary service)

3.2 ANCILLARY SERVICES IN PJM

PJM currently offers three ancillary services through competitive, hour-ahead markets that are co-optimized with the energy market: frequency regulation, synchronized reserves, and primary reserves.

3.2.1 Frequency Regulation

In compliance with Federal Energy Regulatory Commission (FERC) Order 755, which mandates that ISOs and RTOs provide compensation for regulation reserves that is commensurate with the quality of service that they provide, PJM offers two distinct regulation signals and associated market products. Resources can choose which signal they wish to follow but can only follow one at any given time.

- **Traditional regulation (RegA)**: For ramp-limited resources that follow a slower, smoothed signal to correct for Area Control Error (ACE).
- **Dynamic regulation (RegD)**: For energy-limited resources with very fast response that follow a fast signal to correct for ACE. RegD signals are designed to be energy-neutral for each providing resource over a 15-minute period.

Despite these differences, there is still a single market-clearing price for both regulation products in the PJM market that is broken down into two components, a Capability Price and a Performance Price. PJM clears the market for regulation and calculates a clearing price every five minutes. These five-minute prices are later averaged into an hourly price that is used for settlements. Compensation for resources that provide RegD is augmented through an ex-post process on the basis of how closely they are able to follow the RegD signal.

There is a single regulation requirement for the entire PJM system, which since early 2017 has been 525 MW during off-ramp hours and 800 MW during on-ramp hours [33]. On- and off-ramp hours are defined individually for each three-month seasonal period. The system operator may increase this requirement for short periods in accordance with system reliability needs. Prior to 2017, the regulation requirement was 525 MW during off-peak periods and 700 MW during on-peak periods. The on-peak period was previously defined as 7 am to 11 pm on business days throughout the entire year. The regulation requirement in our model is based on the hourly market procurement levels that were recorded in 2015.

Resources that participate in the PJM regulation market submit both a capability offer and a performance offer for their capacity. These two offers each consist of both a cost-based component and a price-based component. The cost-based component is capped according to the technical specifications of the resource, which are determined on the basis of a methodology outlined in PJM Manual 15 but can also include a margin adder of up to $12/MW-h [34]. The price-based component is capped at $100/MW-h. These offers are then augmented on the basis of the historic performance score and benefits factor of each unit, as well as the projected lost-opportunity cost faced by each unit while providing regulation capacity. Resource settlements are further adjusted on the basis of how closely each unit follows the regulation signal and the system mileage ratio in each period. These offer and settlement processes are detailed in PJM Manuals 11 and 28 [35,36].

3.2.2 Synchronized and Primary Reserves

Synchronized reserves can be provided by any resource that is actively synchronized with the grid and is capable of adjusting its output level within ten minutes of receiving an instruction to do so. PJM distinguishes between two different classes of synchronized reserves. Excess capacity that is available after economic dispatch is classified as Tier 1. If this capacity is insufficient to meet system requirements, PJM will commit additional units to provide more reserve capacity; this capacity is classified as Tier 2.

Primary reserves can be provided by any resource that is capable of increasing its output level within ten minutes of receiving an instruction to do so, regardless of whether or not it is synchronized with the grid. Therefore, primary reserves include all synchronized and non-synchronized reserve capacity. There is no individual requirement specifically for non-synchronized reserves in PJM; instead, there is a single combined requirement for primary reserves.

3.2.3 Additional Ancillary Services

PJM also procures several additional ancillary services through other processes. Day-ahead synchronized reserves are cleared through simultaneous optimization with the day-ahead energy market, and participation is mandatory for all qualified units that participate in the energy market. Reactive supply and voltage control and black start are procured through direct bilateral agreements and do not operate under an organized market framework. These services are not analyzed or discussed further in this work.

3.2.4 Unit Offers

Ancillary service offer data are not publicly available for individual resources and neither are data on ancillary service settlements at the unit level. We therefore synthesize the limited data that are available and implement our own methodology for incorporating realistic unit-level price and offer quantities for each ancillary service into our production cost model. We first calculate the technical maximum ability of each unit to provide each ancillary service on the basis of its instantaneous ramp rate [37], outlined in Table 1, and the required response time of each service. Units must be committed in order to provide regulation or synchronized reserves. Coal and nuclear units are not able to provide non-synchronized reserves, owing to their startup times. We then calculate the immediate costs that PJM assumes each unit incurs when providing ancillary services. This methodology is outlined in detail by PJM [34] and is based on several technical characteristics of each unit, including its heat rate, variable operating cost, fuel cost,

TABLE 1 Ramp rate assumptions utilized in the AURORAxmp model [37]

Unit Type	Instantaneous Ramp Rate (%/min.)
Hydro	5.0%
Coal	2.0%
Natural gas CC	5.0%
Natural gas CT	8.3%

and historic regulation mileage. However, resources can also include margin risk adders into their cost-based offers for both regulation and synchronized reserves of up to \$12/MW-h and \$7.50/MW-h, respectively. Furthermore, resources that offer capacity to the regulation market are allowed to include a price-based adder of up to \$100/MW-h, which is much larger than the immediate cost for most units. Finally, offers can also include a component for the lost-opportunity costs incurred by units while foregoing participation in the energy market to instead provide regulation. As there is no way of knowing to what extent each individual resource will choose to incorporate these adders into its supply offers, it is not possible to precisely estimate or model the historical offer strategies of individual units. We therefore initially assume that each unit offers capacity to the regulation and synchronized reserve markets at its immediate cost as calculated by PJM, without any additional price adders. As a result, *the prices generated by our business-as-usual (BAU) modeling analysis should be interpreted as conservative projections.* We do assume that offers by storage resources—batteries and pumped storage hydro—include an additional cost adder of \$2.50/MW-h to account for energy losses. We also analyze a sensitivity scenario where units increase their offer prices by a factor of two relative to BAU.

The initial offer prices and quantities were incorporated into a baseline AURORAxmp model and this model was executed to simulate hourly operations in 2015. The ancillary service offers and dispatch patterns generated by the model were then validated against PJM references that provide aggregated data on the total qualified regulation capacity by fuel type [38] and the total cleared ancillary service quantities by fuel type [39]. Many units choose not to offer their full technical capacity to ancillary service markets for a variety of economic or operational reasons, while others are unable to do so for technical reasons[1]. As a result, the initial baseline model analysis where units offered their full technical capacity to each ancillary service market resulted in excess qualified capacity and led to dispatch patterns that did not agree with historic market outcomes. For example, PJM documentation suggests that there were roughly 6,835 MW of qualified regulation capacity in the system in July 2016, while the technical maximum calculation results in nearly 30,000 MW of qualified capacity [38]. Therefore, the offer quantities of each unit were updated by validating the model results against historical market outcomes. This process was iterated until both the qualified offer quantities and the modeled cleared quantities by fuel type were in reasonable agreement with historical market outcomes. This process resulted in the unit offer assumptions that are presented in Table 2. Rather than attempting to identify specific units that do or do not participate in the regulation market, we apply these factors uniformly across all units of a particular type. Similar assumptions have been made in previous studies on the basis of input from industry experts [9]. We also analyze a sensitivity scenario where units offer their full technical capacity in all three ancillary service markets.

[1] For example, in order to participate in the regulation market, units must have the technical capacity to respond to automatic generation control signals and must also meet certain telemetry requirements.

TABLE 2 Unit offer quantity assumptions utilized in the AURORAxmp model

	Unit Offer Capacity (% of Technical Max.)				
Ancillary Service	Natural Gas CC	Natural Gas CT	Coal	Hydro	Battery
Regulation	50%	10%	5%	20%	100%
Synchronized Reserves	50%	50%	50%	50%	0%
Primary Reserves	0%	100%	0%	100%	0%

The resultant regulation supply curve for the BAU scenario is shown in Figure 2. Hydro resources are able to provide regulation at the lowest cost, but there is limited capacity available to provide this service, owing to various operational restrictions. Battery storage units have the next lowest cost, followed by some efficient natural gas combined cycle (CC) units, pumped storage hydro, and the coal units that are able to provide regulation. Natural gas combustion turbine (CT) units offer their capacity in the regulation market at higher cost, owing to their relatively high fuel costs.

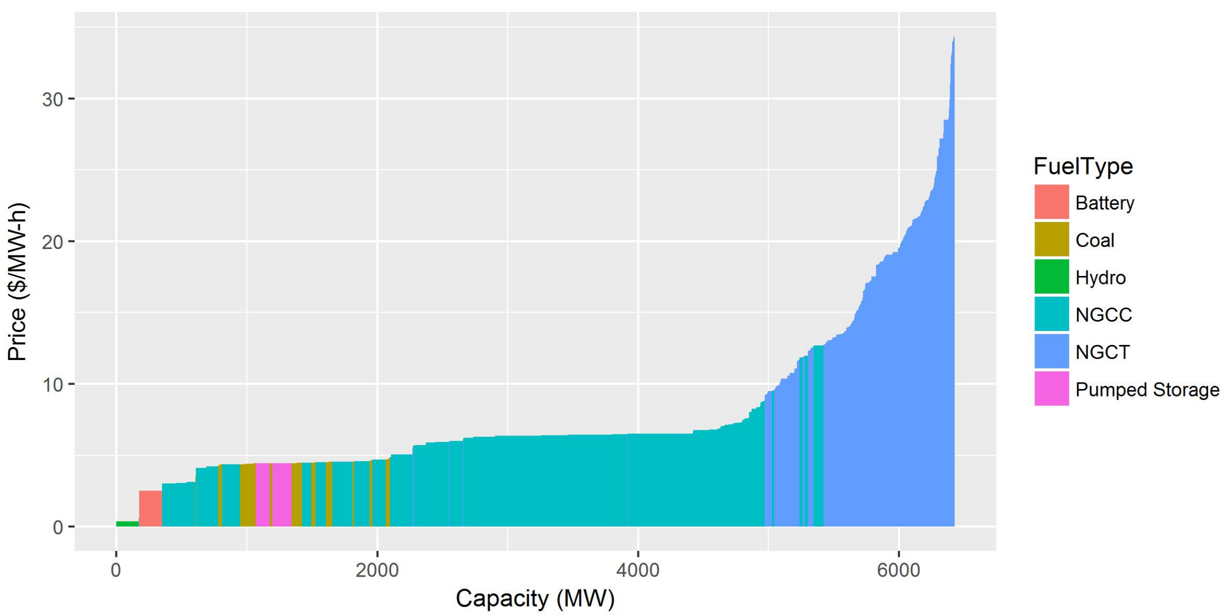

FIGURE 2 BAU regulation offer curve

Analyzing the regulation supply curve in isolation can be deceptive, as the regulation market is co-optimized with the energy market as well as the markets for synchronized and primary reserves. Because of these competing objectives, it is not possible to estimate hourly dispatch of regulation reserves on the basis of a simple merit order analysis of the regulation supply curve. The regulation settlements for hydro resources are a good example of this limitation. Hydro units are able to provide regulation at a very low cost, but they can also provide energy and synchronized reserves at a low cost. If the cost savings obtained by dispatching these units in the energy market are larger than the corresponding savings in the regulation market, then hydro units may not provide as much regulation as they otherwise could. Other considerations (environmental restrictions, prescribed flow rates, etc.) may further restrict hydro units from providing regulation during certain hours, and these factors are not explicitly considered by AURORAxmp.

3.2.5 Operational Assumptions

While the model includes a detailed representation of the PJM system, a number of simplifying assumptions are made with regard to actual market operations and business practices in PJM. First, ancillary service requirements are considered only for the entire PJM system; any separate requirements specific to the Mid Atlantic Dominion sub-zone in PJM are not directly considered. Second, we only determine a single market-clearing price for frequency regulation, as opposed to individual capability and performance components. The historical data presented in Table 3 can be used to estimate the relative contribution of each component. Similarly, the distinctions between RegA and RegD regulation signals and Tier 1 and Tier 2 synchronized reserves are not explicitly modeled, but can be estimated ex-post on the basis of historical data. Price projections are not meant to be interpreted as specific hourly price forecasts benchmarked to a specific year. Rather, they are more appropriately compared in aggregate against the BAU analysis to understand broader price trends stemming from changes to several key system parameters. While the PJM system is chosen as a test bed for this work, we analyze sensitivities to factors that are present in any power system; therefore, the high-level trends that are identified should be broadly applicable to other systems as well. However, some caution must be exercised when extending the results to other systems, as ancillary service definitions, requirements, and other market parameters vary between markets in the United States.

3.3 PJM HISTORICAL MARKET OUTCOMES

Historical annual summary data are shown in Table 3 for the four complete years since PJM implemented several new market policies in October 2012. The minimum hourly price for each service over an entire year is generally zero or very close to zero, and therefore these data are not included in the table. Maximum annual prices may be of particular interest to opportunistic resources that seek to capitalize on infrequent price spikes rather than consistently setting aside capacity to provide these services during periods of low or moderate prices. There were large prices spikes for all three services in early 2014, during the so-called “Polar Vortex” cold-weather event, which corresponded to a period of increased natural gas prices and unit shutdowns that created system scarcity. Average prices for regulation and synchronized reserves

TABLE 3 Historical price statistics for ancillary services in PJM from 2013 to 2016

	Regulation Capability Price ($/MW-h)			Regulation Performance Price ($/MW-h)			Synchronized Price ($/MW-h)			Primary Price ($/MW-h)		
Year	Mean	Median	Max.	Mean	Median	Max.	Mean	Median	Max.	Mean	Median	Max.
2013	24.02	16.93	756.05	4.12	3.49	29.14	0.75	0.00	105.66	0.02	0.00	9.40
2014	39.63	17.69	3296.17	4.07	3.45	25.55	4.21	0.00	1142.35	0.95	0.00	400.00
2015	28.00	16.08	859.30	3.34	2.95	38.56	5.16	0.47	291.48	1.42	0.00	291.48
2016	13.94	9.50	300.43	1.56	0.59	19.73	2.65	0.00	149.13	0.19	0.00	85.65

decreased roughly by half from 2015 to 2016, while primary reserve prices dropped by more than 85%. The PJM Market Monitor has attributed this reduction in the regulation price to corresponding reductions in the lost-opportunity cost component of unit offers, resulting from lower energy prices in 2016 [40]. PJM has typically recorded higher regulation prices than other U.S. ISOs, while its synchronized and primary reserve prices have typically been comparable to or slightly lower than those for similar services from other ISOs [25]. Historical cleared frequency regulation quantities by fuel type are discussed in Section4.1.1.

While PJM has established minimum system-wide requirements for each ancillary service, these requirements can be adjusted hour by hour as needed by the system operator, and actual settled quantities of each ancillary service are generally slightly higher than these minimum requirements. In an effort to capture the effect of these hourly variations, the baseline system requirement for each ancillary service in our model is set equal to the actual 2015 settled quantity in every hour [41]. In 2015, the average hourly quantities were 663.6 MW of regulation, 1835.8 MW of synchronized reserves, and 2642.4 MW of primary reserves (combined synchronized and non-synchronized).

3.3.1 Modeling Scenarios

3.3.1.1 Business-as-Usual Scenario

A BAU scenario is first executed to establish a basis of comparison for the sensitivity scenarios. The BAU scenario is based on the actual PJM 2015 load profile and generation portfolio, which is outlined in Table 4. Wind provides approximately 2% of annual generation under BAU conditions.

TABLE 4 Existing PJM installed generation capacity in the AURORAxmp model

Fuel Type	Capacity (MW)
Coal	62,874
Nuclear	34,083
Natural Gas CC	32,766
Natural Gas CT	31,809
Fuel Oil	12,177
Wind	6,102
Pumped Storage	4,075
Hydro	2,858
Other	2,552
Battery	350
Solar	275
Total	189,921

3.3.1.2 Single-Parameter Sensitivity Scenarios

In addition to the BAU scenario, several single-parameter sensitivity scenarios are explored across different dimensions. These scenarios are intentionally chosen to represent relative extremes—e.g., retiring all coal capacity—and are therefore not based on any judgement of likely future system outcomes. Rather, they are intended to provide insight into the system impacts of perturbations of individual parameters. These impacts are most appropriately analyzed by comparing them with the BAU scenario rather than interpreting them as absolute predictions. These sensitivity scenarios are described qualitatively in Table 5 and assume no technical or policy changes beyond those listed.

TABLE 5 Single-parameter sensitivity scenarios considered by this modeling analysis

Scenario Name	Description
Generation Portfolio	
BAU	2015 PJM generation portfolio
NoCoal	All coal capacity (62,874 MW ICAP) is retired and replaced with an equivalent UCAP value of natural gas CC units (64,112 MW ICAP).
NoNuclear	All nuclear capacity (34,083 MW ICAP) is retired and replaced with an equivalent UCAP value of natural gas CC units (38,783 MW ICAP).
Wind30	Wind capacity is added (93,925 MW ICAP) so that wind can provide up to 30% of total annual system generation. An equivalent UCAP value of coal is retired (13,875 MW ICAP).
Bat5x	Battery storage capacity is increased by a factor of five from 350 MW to 1750 MW. No other changes are made to the generation portfolio.
Natural Gas Price	
BAU	The average annual Henry Hub natural gas price is $2.69/MMbtu. Prices in the model vary monthly on the basis of historical data. Delivered prices to individual units are also adjusted n the basis of geography and historical data.
NG2x	The average annual Henry Hub natural gas price is $5.38/MMbtu.
System Regulation Requirement	
BAU	The regulation requirement is defined by actual 2015 hourly market results. The average requirement is 664 MW and the maximum requirement is 831 MW.
Req2x	The hourly regulation requirement is increased by a factor of two to an average value of 1327 MW.
Unit Regulation Offer Quantity	
BAU	The regulation offer quantity for each unit is assumed to be a fraction of its full technical capacity, as outlined in Table 2.
OfferQFull	Each unit offers its full technical capacity, based on its instantaneous ramp rate, to the regulation market. Coal and natural gas CC units are still unable to provide primary reserves.
Unit Regulation Offer Price	
BAU	Each unit offers capacity to the regulation market at its true immediate cost, as calculated by PJM's methodology [34]. No additional risk or cost-based adders are included.
OfferP2x	The regulation offer price for each unit is increased by a factor of two relative to BAU.

The capacity additions and retirements for the generation portfolio sensitivity scenarios were chosen such that the total system unforced capacity[2] (UCAP) remains unchanged from the BAU scenario. This method ensures that any identified price impacts are due to the change in the generation mix, as opposed to changes in the total quantity of available capacity. The installed capacity (ICAP) values that serve as inputs to AURORAxmp are converted to UCAP by applying the PJM class average equivalent demand forced outage rates (EFORd) presented in Table 6 [42]. This metric is used only to calibrate the capacity mix in each sensitivity scenario and is not a modeling input. AURORAxmp instead uses its own more detailed methodology to define outage rates for individual units on a monthly basis.

TABLE 6 PJM average equivalent demand forced outage rates (EFORd) by unit type [42]

Unit Type	EFORd
Coal	12.0%
Hydro	0.0%
Natural Gas CC	4.6%
Natural Gas CT	13.7%
Nuclear	1.8%
Other	12.0%
Solar	62.0%
Wind	87.0%
Fuel Oil	12.0%

3.3.1.3 Multiple-Parameter Sensitivity Scenarios

While the single-parameter sensitivity scenarios provide insight into the impacts of isolated perturbations of individual parameters, in a real-world power system, numerous interacting parameters will likely evolve simultaneously. For example, increasing wind penetration will likely also result in increased regulation requirements to help balance short-term net load variability and maintain system reliability. Several studies have projected how ancillary service requirements may change in future systems with greater wind and solar penetration. The PJM Renewable Integration Study examined several different future scenarios with up to 30% VRE penetration [43]. The study determined that even at 30% penetration, increased VRE levels would not change the largest system contingency and therefore would not affect synchronized or non-synchronized reserve requirements. However, hourly regulation requirements would necessarily increase by 1,000 MW to 1,500 MW in order to balance the resultant increased variation in short-term net load [43]. Hummon et al. [9] estimate future hourly regulation requirements on the basis of the statistical variability of net load, while Mills and Wiser [44] have assumed the regulation requirement to be 2% of hourly load plus 5% of the day-ahead wind or solar forecast. This latter assumption is based on the heuristic proposed by the Western Wind and Solar Integration Study, which suggests 3% of load plus 5% of forecast wind generation as a conservative operating reserve target [45]. Frew et al. [13] assume that non-spinning, spinning, and regulation requirements are not impacted by wind penetration levels, but introduce an additional flexible ramping requirement in systems with high wind penetrations. Levin and Botterud [11] assume that operating reserve requirements increase with increasing VRE penetration to accommodate forecast errors, but do not explicitly consider frequency regulation.

All else being equal, higher regulation requirements would likely also increase regulation prices. In response, units may decide to offer more of their capacity to regulation markets, making the necessary telemetry or other technological investments in order to capitalize on a

2 The UCAP of a resource is intended to reflect the capacity value that it provides to the system.

new revenue stream. Therefore, we also consider several multi-parameter sensitivity scenarios to gain a better understanding of these potential interactions. Again, these chosen scenarios do not represent any value judgement as to the likelihood of future systems outcomes.

These scenarios center on high wind futures and are outlined in Table 7. The first scenario considers a case where 30% wind penetration leads to a doubling of the regulation requirement without any corresponding change in regulation supply. We then analyze two additional scenarios that consider a market response to this increased requirement. In the first scenario, additional battery storage capacity is introduced to the system. This is a reasonable expectation, based on both current trends and the ability of battery storage to meet the increased demand for regulation. We also analyze an extreme scenario where all units offer their full technical capacity to the regulation market. While it is reasonable to expect that participation in the regulation market will increase in response to the higher requirements, it is unlikely that all units will choose or be able to offer their full technical capacity to the regulation market. However, this scenario does provide an upper bound on what might be possible, given the current generation portfolio.

TABLE 7 Multi-parameter sensitivity scenarios considered by this modeling analysis

Scenario Name	Description
EnergyW30_R2x	Combines the Wind30 and Req2x scenarios outlined in Table 5.
EnergyW30_R2x_Bat5x	Combines the Wind30, Req2x, and Bat5x scenarios outlined in Table 5.
EnergyW30_R2x_OFull	Combines the Wind30, Req2x, and OfferQFull scenarios outlined in Table 5.

4 RESULTS

4.1 BUSINESS AS USUAL

The modeling results for all scenarios are summarized in Table 8 and Table 9, and price results for the BAU scenario are shown in Figure 3 along with historical results from 2014 through 2016. This figure shows a log-scale version of the left tail of the price duration curve to highlight the occurrence of periods with high prices. The price duration fractions for several price levels are also presented numerically in Table 8.

The BAU scenario results in an average annual regulation price of $12.39/MW-h, with a maximum price of $327.47/MW-h. For reference, the average regulation price was $31.35/MW-h in 2015 and the maximum price was $864.81/MW-h. Figure 3 further indicates that modeled prices in the BAU scenario have been consistently lower than historical prices over the past three years. This is to be expected, as we assume that units do not include any risk adders in their regulation offers and instead offer regulation capacity at the immediate cost of its provision. Figure 4 shows the total cleared regulation capacity provided by each fuel type, both historically and in our BAU analysis. Under our BAU scenario, more regulation is provided by coal and hydro resources than was recorded in 2015, while less regulation is provided by battery storage. There are several factors that likely contribute to this result. According to PJM's methodology, hydro and coal resources are able to provide regulation at low cost because of their low or near-zero fuel costs; this ability is apparent in the BAU regulation offer curve presented in Figure 2. At the same time, it is difficult to estimate how much capacity each coal and hydro unit is offering to the regulation market. In particular, most coal units either do not have the technical ability to follow regulation signals or choose not to participate in the regulation market. Hydro units also face a number of operational restrictions that limit their operational flexibility in practice, even if they have the theoretical capability. Finally, the model is unable to distinguish between the RegA and RegD signals. As batteries are able to provide RegD, they would provide additional system benefits and receive additional revenues that are not fully captured by the model. This factor likely contributes to the lower cleared regulation quantities from storage resources.

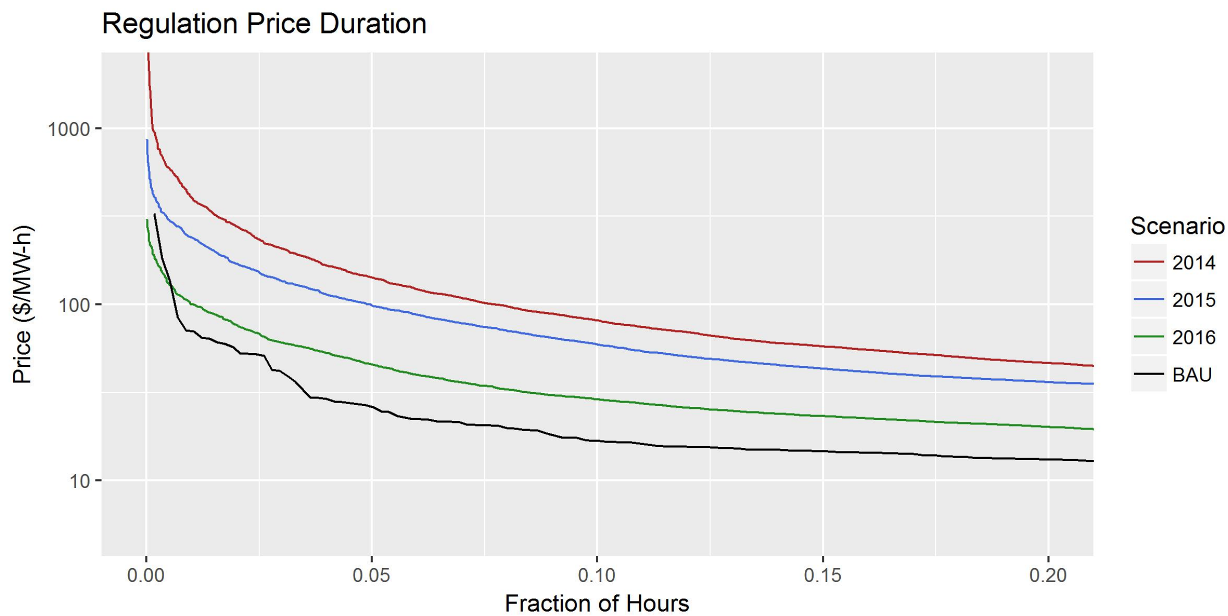

FIGURE 3 Annual duration curves of regulation prices for the BAU scenario and recorded prices from 2014 to 2016. The figure shows the 20% of hours with highest prices and uses a logarithmic scale to more clearly illustrate the impacts during these periods.

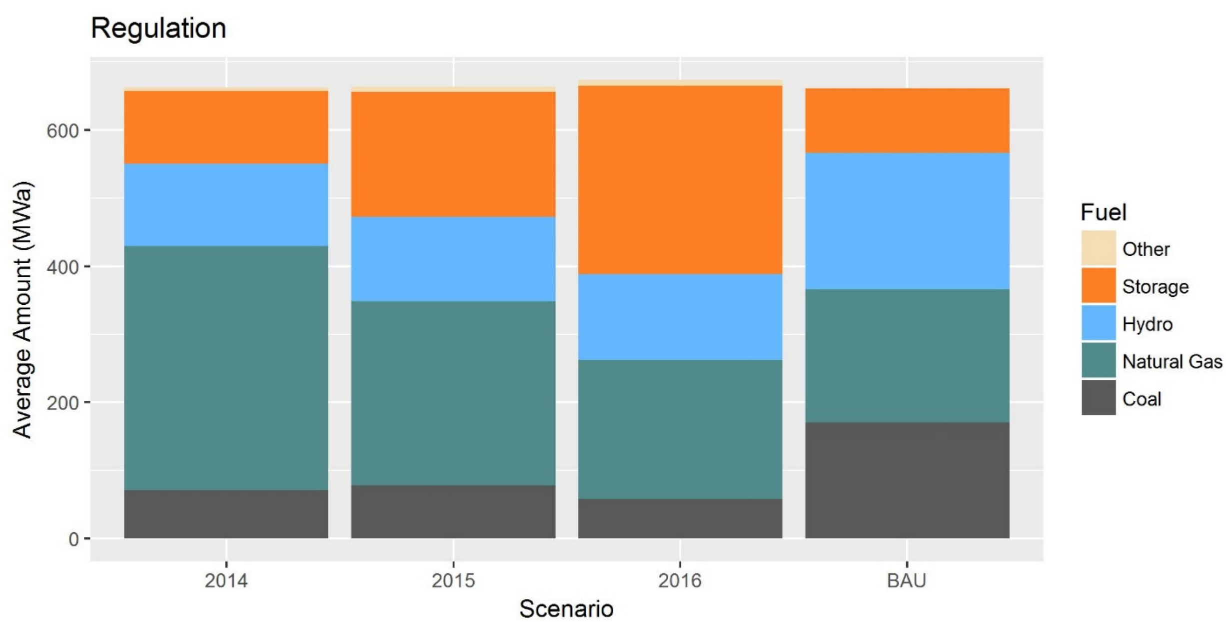

FIGURE 4 Annual average cleared regulation quantities by fuel type in the BAU scenario and in 2014–2016.

4.2 GENERATION PORTFOLIO SENSITIVITY

As mentioned previously, each of the generation portfolio sensitivity scenarios considered here consists of the same total UCAP, so that any price impacts can be attributed to changes in the generation mix as opposed to changes in overall system capacity. These price impacts are shown in Figure 5.

Retiring all coal or nuclear units and introducing an equivalent UCAP value of natural gas CC units into the system decreases the average regulation price by 42% in the case of coal and 11% in the case of nuclear. This result is due to the increased qualified supply of regulation capacity made available by the additional flexible natural gas units. Introducing enough wind capacity to provide 30% of total generation in the system—and retiring an equivalent quantity of unforced coal capacity—increases the average regulation price by 32%. This price increase is wholly due to the reduction in thermal capacity that corresponds to the increased wind penetration. It manifests primarily through a small number of additional hours with very high prices, as evidenced by the far left end of the price duration curve in Figure 5. It is assumed that wind units themselves are not able to provide reserve ancillary services. As discussed previously, this scenario does not necessarily represent a realistic projection of system conditions in a high-wind future, but rather is intended to explore the price impacts that are directly attributable to changes in the generation portfolio. Higher wind penetration would likely also necessitate an increased regulation requirement to maintain system reliability. Therefore, several additional scenarios where the regulation requirement is increased in conjunction with increased wind penetration are explored in the following section. This initial analysis of a high-wind system where the regulation requirement is unchanged is included primarily to provide a benchmark for those scenarios. As might be expected, introducing an additional 1400 MW of battery storage capacity into the system reduces the average regulation price by 28%. The fraction of the regulation requirement met by battery resources also increases from 14% to 39%, as shown in Figure 6.

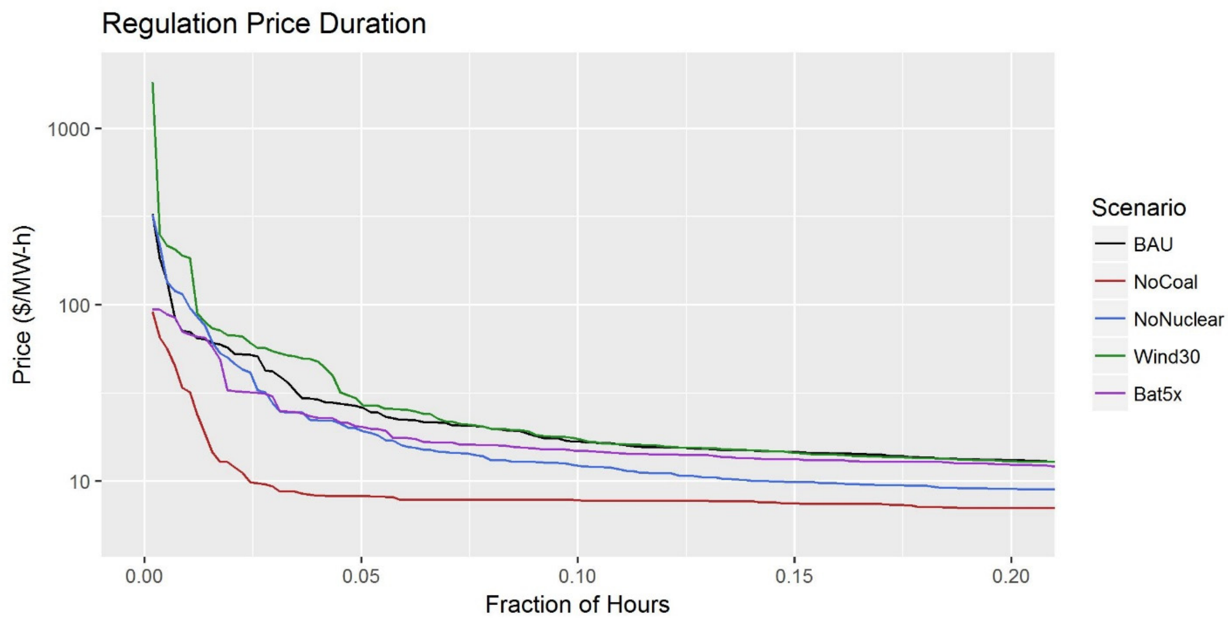

FIGURE 5 Annual duration curves of regulation prices for the generation portfolio sensitivity scenarios. The figure shows the 20% of hours with highest prices, using a logarithmic scale to more clearly illustrate the impacts during these periods.

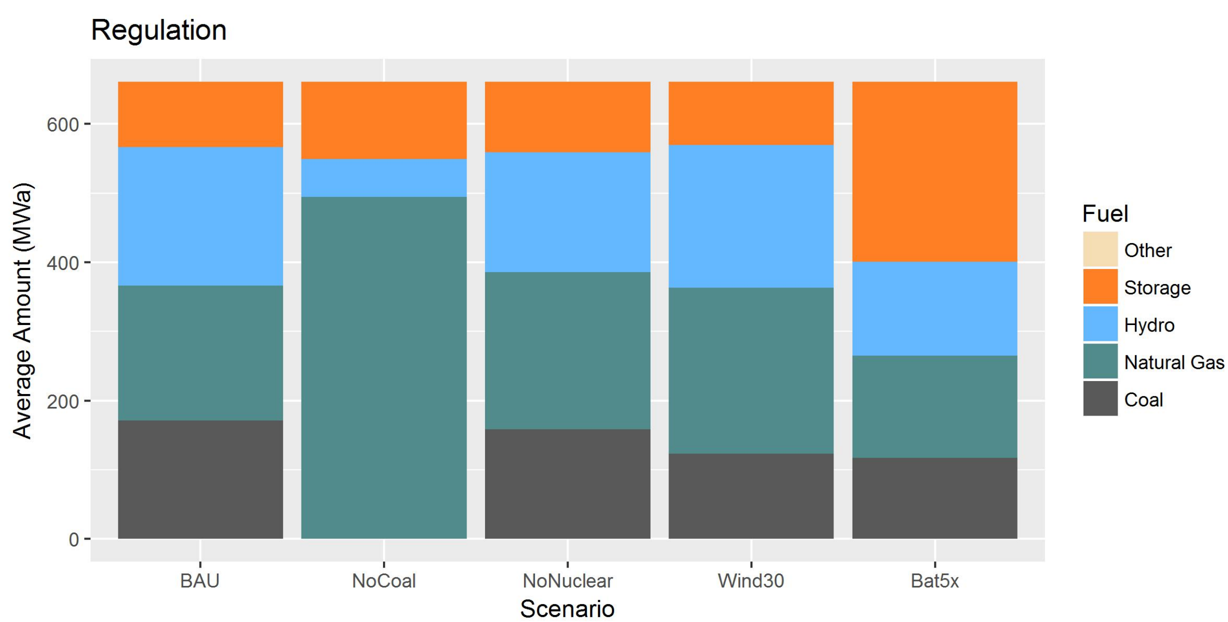

FIGURE 6 Annual average cleared regulation quantities by fuel type in the generation portfolio sensitivity scenarios.

4.3 SINGLE-PARAMETER SENSITIVITY

Several additional scenarios are considered where a single sensitive parameter is adjusted in isolation. The regulation supply curves for two of these sensitivity scenarios are shown in Figure 7 and Figure 8. Figure 7 shows the impact when natural gas prices are doubled to an annual average of $5.38/MMbtu. Natural gas offer prices generally increase by less than a factor of two, as not all costs incurred while providing regulation are influenced by fuel prices. However, the increase is sufficiently large that all pumped storage and coal units are able to provide regulation at lower cost than natural gas resources. Figure 8 shows the impact when units are able to offer their full technical capacity to the regulation market: the supply curve stretches horizontally to reach nearly 30,000 MW of qualified capacity. The primary impact is a large increase in the quantity of coal capacity that is offered to the market at relatively low cost, as well as additional hydro capacity at near-zero cost. Again, while it is unlikely that this scenario represents a realistic future outcome, it is included for context and to provide an upper bound on the regulation supply capability of the current PJM system.

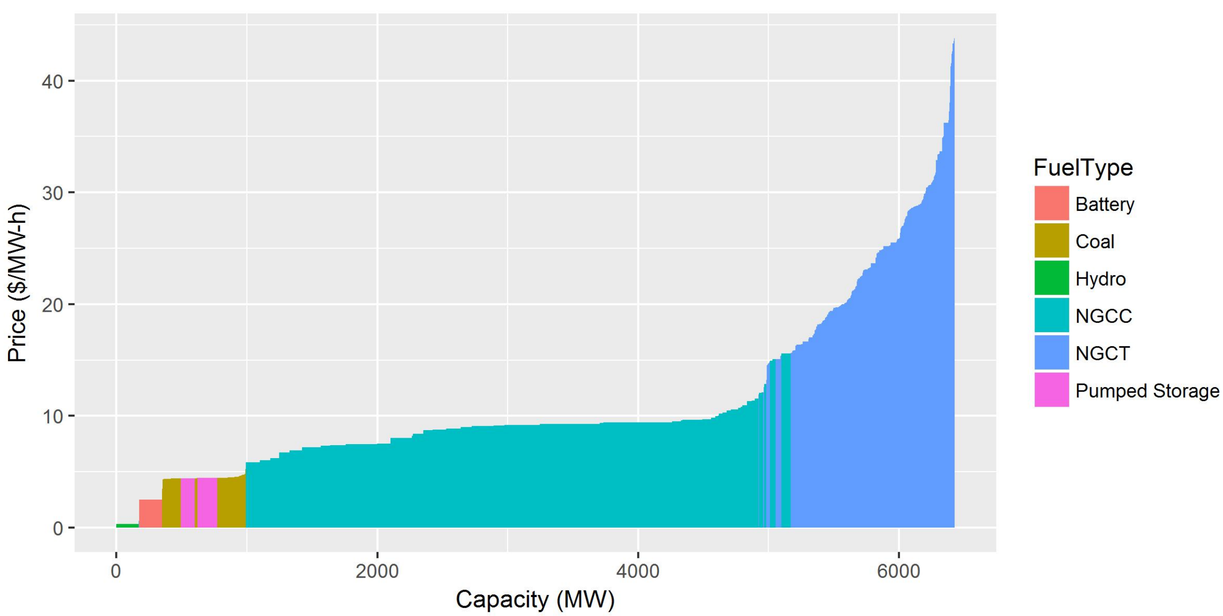

FIGURE 7 Regulation supply curve for the NG2x scenario

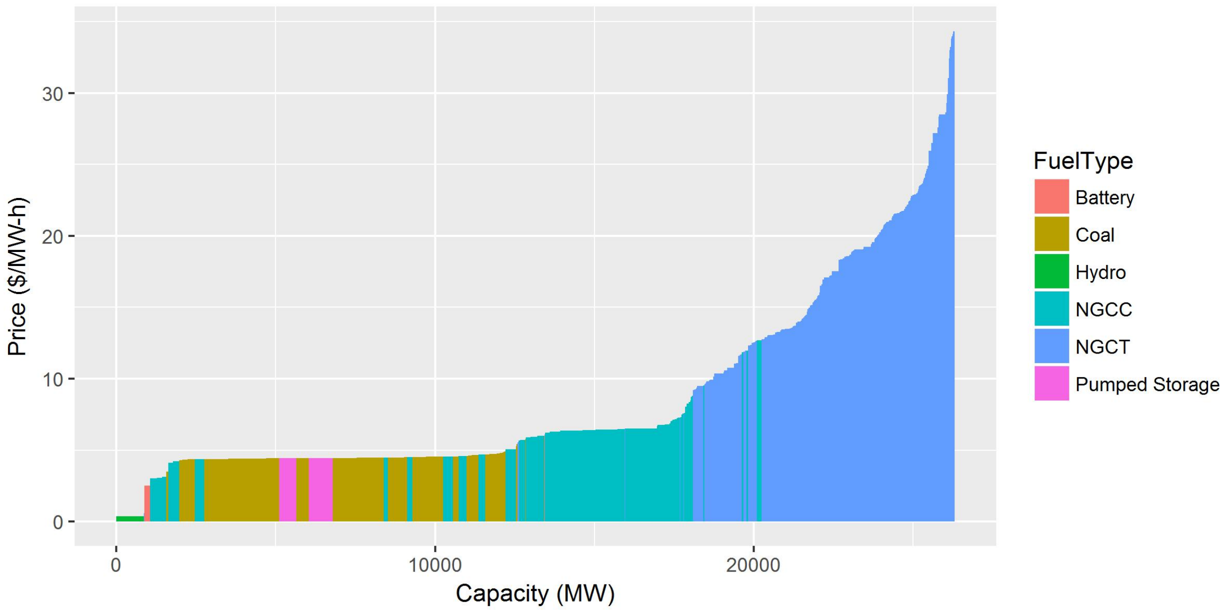

FIGURE 8 Regulation supply curve for the full technical offer scenario

Figure 9 shows the price impacts of these sensitivity scenarios. Doubling the natural gas fuel price causes regulation prices to increase by 36%, on average. The increase can be attributed largely to higher unit offers from natural gas units that incur additional costs for providing regulation. Doubling the regulation requirement without introducing any additional supply also increases the average regulation price by 61%, and prices in excess of $100/MW-h occur twice as frequently as under BAU. The additional requirement is primarily met by natural gas capacity. Doubling the offer price of each unit increases the average regulation price by 58%. Finally, if units offer their full technical capacity to the regulation market, the average price drops by 49%. Figure 10 shows that under these conditions, almost all regulation is provided by hydro units, with some contributions from battery storage and a very small quantity provided by thermal units.

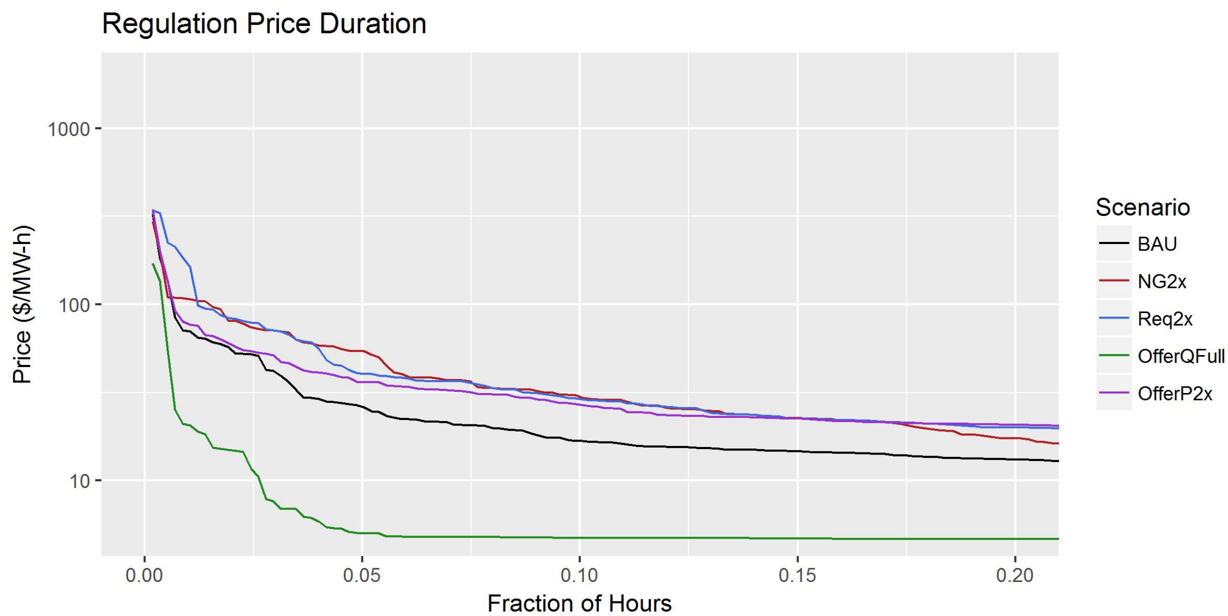

FIGURE 9 Annual duration curves of regulation prices for the single-parameter sensitivity scenarios. The figure shows the 20% of hours with highest prices. A logarithmic scale is used to more clearly illustrate the impacts during these periods.

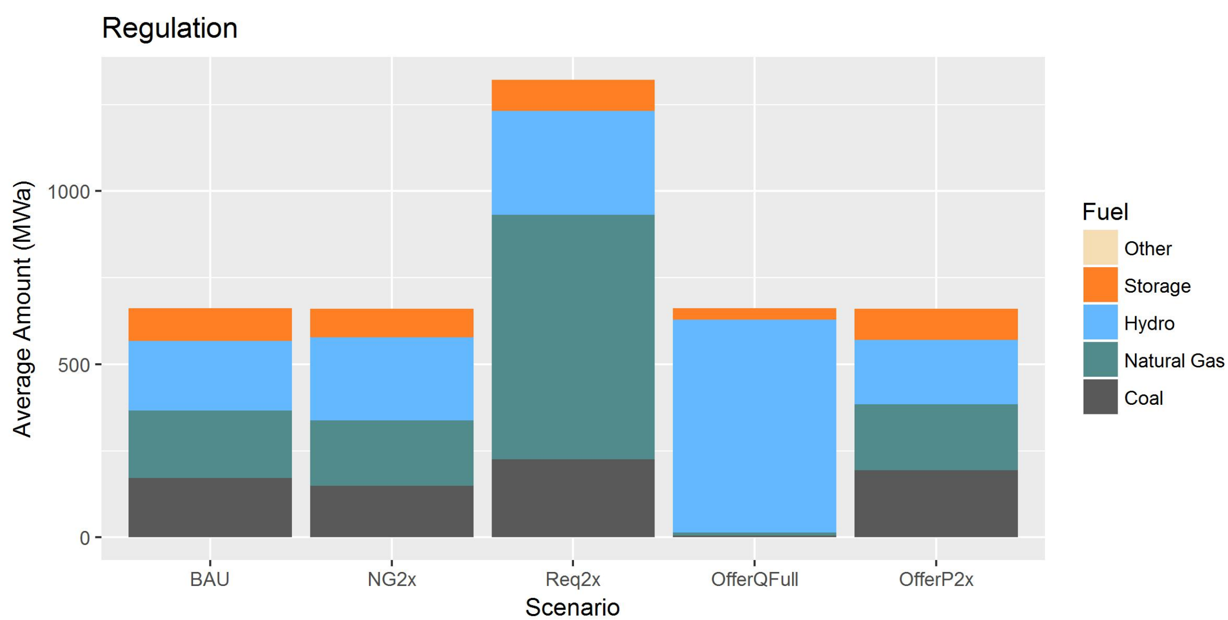

FIGURE 10 Annual average cleared regulation quantities by fuel type in the single-parameter sensitivity scenarios.

4.4 MULTIPLE-PARAMETER SENSITIVITY

In addition to the single-parameter sensitivity scenarios, we also consider three scenarios that examine high wind penetration in conjunction with other system perturbations. The price and settlement results from these scenarios are shown in Figure 11 and Figure 12. A primary additional operational impact in a system with high wind penetration will be an increased regulation requirement in order to balance short-term net load variations and maintain system reliability. We therefore first consider a scenario with 30% wind penetration and a regulation requirement that is twice as large as 2015 settled quantities. Under this scenario, the average regulation price is $22.79/MW-h, 84% higher than BAU, 39% higher than the 30% wind scenario alone, and 14% higher than the scenario that doubled the regulation requirement in isolation. Because this increased demand for regulation, and corresponding increased price, would likely motivate new entry into the regulation market, we also consider two scenarios with additional qualified regulation capacity. In the first, we assume that battery storage capacity increases by a factor of five compared to BAU, from 350 MW to 1750 MW. This change reduces the average regulation price by 16% to $19.05/MW-h, which is still greater than that under BAU conditions. Batteries also provide 38% of the regulation, compared to 14% under BAU and only 7% under the 30% wind scenario with a doubled regulation requirement. In the second scenario, we assume that each unit offers its full technical capacity to the regulation market, as discussed above. This dramatic increase in qualified supply reduces the average regulation price to $6.26/MW-h, well below even the BAU average price. Hydro resources provide 55% of the system regulation and coal resources provide 35%, with batteries making up the bulk of the remainder.

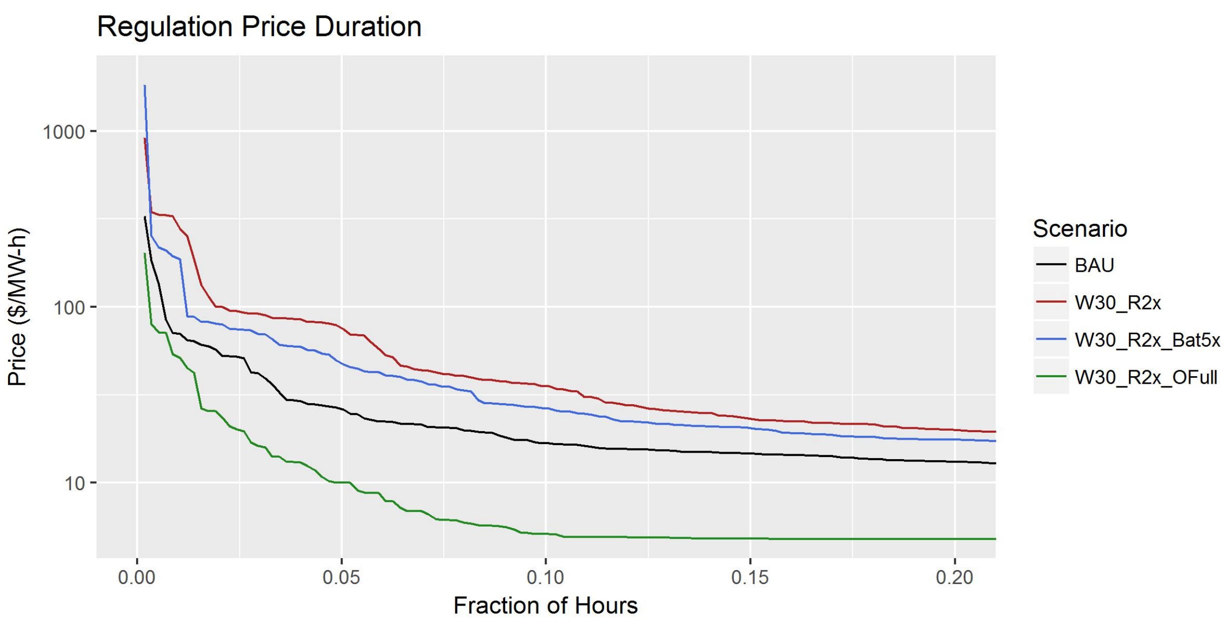

FIGURE 11 Annual duration curves of regulation prices for the multi-parameter scenarios. The figure shows the 20% of hours with highest prices on a logarithmic scale to more clearly illustrate the impacts during these periods.

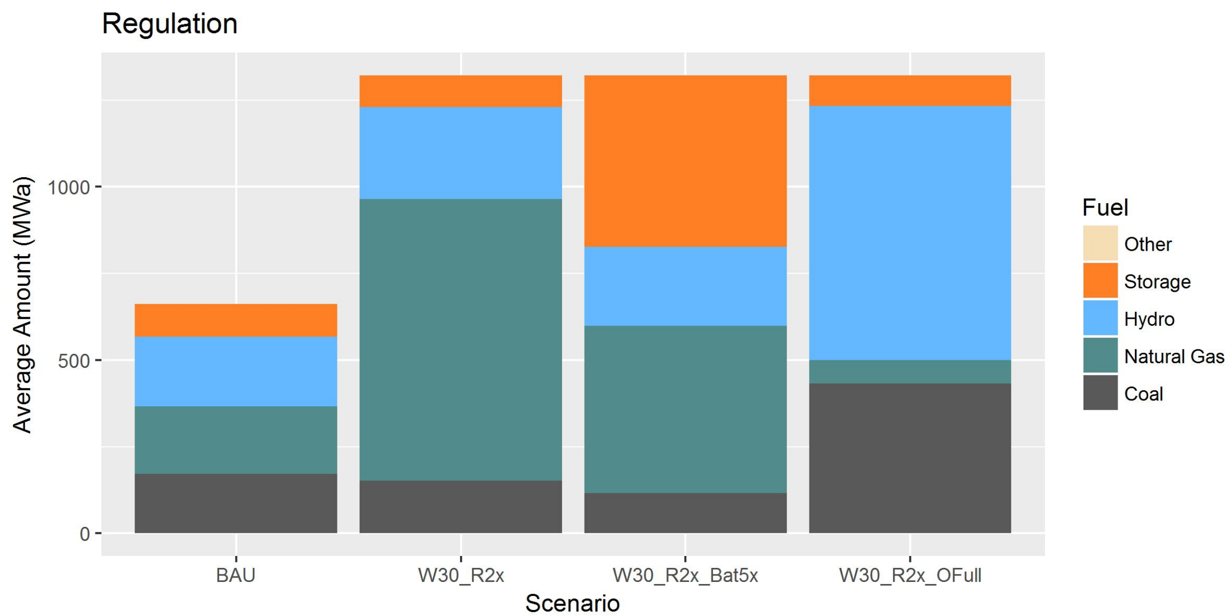

Figure 12 Annual average cleared regulation quantities by fuel type in the multi-parameter sensitivity scenarios.

TABLE 8 Regulation price statistics for 2014–2016 and all modeled scenarios. The exceedance values depict the percentage of hours during which prices were greater than the stated amount.

Scenario	Mean	% Change vs. BAU	Min	Max	Median	$20 Exceedance	$50 Exceedance	$100 Exceedance	$250 Exceedance
2014	$43.70		$0.01	$3,303.87	$22.27	55.4%	18.1%	7.7%	2.3%
2015	$31.35		$0.00	$864.81	$19.99	49.9%	12.2%	4.9%	0.9%
2016	$15.90		$0.00	$305.02	$11.28	20.2%	4.4%	1.0%	0.0%
BAU	$12.39		$4.78	$327.47	$8.63	7.8%	2.6%	0.5%	0.2%
NoCoal	$7.17	-42%	$4.91	$91.81	$6.87	1.2%	0.5%	0.0%	0.0%
NoNuclear	$10.97	-11%	$4.80	$324.51	$7.82	4.9%	1.9%	0.9%	0.2%
Wind30	$16.36	32%	$4.44	$1,831.09	$8.67	7.8%	3.5%	1.0%	0.3%
Bat5x	$8.87	-28%	$2.69	$94.30	$7.35	5.0%	1.6%	0.0%	0.0%
NG2x	$16.86	36%	$5.49	$296.49	$10.90	17.7%	5.4%	1.4%	0.2%
Req2x	$19.94	61%	$6.95	$341.55	$15.14	20.0%	4.0%	1.0%	0.3%
OfferQFull	$3.73	-70%	$0.38	$170.69	$2.69	1.0%	0.5%	0.3%	0.0%
OfferP2x	$19.57	58%	$9.65	$347.38	$16.34	22.9%	3.0%	0.5%	0.2%
W30_R2x	$22.79	84%	$5.43	$917.27	$13.74	20.0%	6.3%	1.9%	1.2%
W30_R2x_Bat5x	$19.05	54%	$4.21	$1,831.09	$9.08	15.5%	4.7%	1.0%	0.3%
W30_R2x_OFull	$6.26	-49%	$4.26	$202.69	$4.76	2.4%	1.0%	0.2%	0.0%

TABLE 9 Average settled regulation quantities (MWa) by fuel type for 2014-2016 and all modeled scenarios.

Scenario	Coal	Natural Gas	Hydro	Storage	Other
2014	62	309	104	92	5
2015	76	261	120	177	8
2016	49	170	106	231	8
BAU	171	195	200	95	-
NoCoal	-	495	55	112	-
NoNuclear	159	227	173	102	-
Wind30	123	239	207	92	-
Bat5x	117	148	136	260	-
NG2x	149	188	240	83	-
Req2x	225	707	299	91	-
OfferQFull	5	9	614	32	-
OfferP2x	193	190	186	91	-
W30_R2x	152	812	266	92	-
W30_R2x_Bat5x	117	482	228	496	-
W30_R2x_OFull	432	68	732	89	-

5 DISCUSSION

Efforts to model the unit-level provision of ancillary services face a number of challenges that are not encountered when conducting similar analyses of energy dispatch. A primary challenge stems from the fact that the data required to accurately model ancillary service markets are not readily available. Production cost models typically assume that generation units engage in rational economic behavior, offering their generation capacity to the energy market at their true marginal cost of generation. In energy markets, these costs can be estimated through a fairly straightforward calculation based on well-known parameters such as a unit's heat rate, cost of delivered fuel, and variable O&M costs. However, this calculation is less straightforward in ancillary service markets, where costs and benefits are not as well understood by market participants. PJM does provide a methodology for determining the tangible costs that a unit incurs while providing regulation or synchronized reserves because of increased maintenance requirements, reduced heat rates and other similar impacts. Yet, compared to the energy market, there is less industry-wide consensus on how these costs should be determined. In addition, units face opportunity costs when withholding capacity from the energy market to instead provide ancillary services; these costs depend on system conditions and market outcomes and are therefore not as straightforward to estimate. Units are also permitted to include large risk adders in their offers, which are largely opaque and may increase the potential for strategic behavior. Therefore, even if it were possible to calculate the true marginal costs incurred by units while providing ancillary services, these values might not provide a reasonable proxy for actual unit offers. A comprehensive analysis of historical unit offer data would be invaluable in gaining an understanding of unit behavior and how each unit perceives its own costs. However, unit-level ancillary service offer data are not typically provided by ISOs—and in the cases where they are, the data are anonymized, making it difficult or impossible to identify the offer behaviors of specific units. In addition to uncertainty regarding ancillary service offer prices, it is not always clear how much capacity a unit is willing or able to offer to a given ancillary service market.

These data challenges are compounded by the fact that there is less standardization across ancillary service markets than is present across energy markets. While all seven U.S. ISOs and RTOs offer some form of frequency regulation, a spinning reserve product, and a non-spinning reserve product, definitions and requirements differ between markets. Furthermore, there are a number of system-specific distinctions that make it difficult to incorporate ancillary services into standard hourly production cost models. Examples include the distinction between Tier 1 and Tier 2 synchronized reserves in PJM and the emergence of RegD and additional performance-based products in other markets. MISO and CAISO have also recently introduced new products to compensate units with flexible ramping capabilities, and it is likely that other markets will also introduce new products in coming years. It is therefore difficult to capture all these unique market rules and operational procedures in a single production cost model that can be broadly applied across multiple markets.

These issues are not specific to AURORAxmp; most other large-scale commercial production cost models would face the same challenges, as they are primarily related to data availability. Existing power system models may need to be enhanced to handle the specifics of ancillary service modeling, or alternatively, new tools may need to be developed. Without improved modeling tools, it will be difficult for policy-makers to understand the economic and technical impacts of power system evolution—e.g., more VRE, changing reserve requirements, the ability of ancillary service revenues to support revenue sufficiency and resource adequacy, or other reliability and flexibility requirements. Furthermore, there is significant uncertainty regarding how market rules may evolve in coming years. This is also the case with ancillary service requirements, which are set administratively on the basis of system conditions. As such, while different future scenarios may be examined to understand broad trends and parameter interactions, it is difficult to identify likely future system outcomes.

6 CONCLUSIONS

We present a methodology for determining unit-level ancillary service price and quantity offers and incorporating them into a commercial production cost model. This model is applied to a case study of the PJM system to better understand how prices for frequency regulation may be impacted by future changes in the generation portfolio and other key parameters. Our results indicate that replacing all coal and nuclear capacity in PJM with more flexible natural gas CC units decreases regulation prices by 42% and 11% for coal and nuclear, respectively. Conversely, introducing sufficient wind capacity to provide 30% of annual generation and retiring an equivalent capacity value of coal increases the average regulation price by 32%, even when the regulation requirement is unchanged. A five-fold increase in battery storage capacity reduces the average regulation price by 28%. Doubling the average Henry Hub natural gas price from $2.69/MMbtu to $5.38/MMbtu results in a 36% increase in the average regulation price. Doubling the regulation requirement leads to a 61% increase in the average regulation price, with much of the additional regulation capacity provided by natural gas resources. Permitting all resources to offer their full theoretical technical capability to the regulation market results in a dramatic 70% reduction in the average prices, as hydro resources with near-zero marginal cost provide 93% of all regulation in the system. Doubling the regulation offer price of each unit leads to a 58% increase in the average regulation price.

In a system with 30% wind penetration and a regulation requirement that is doubled relative to BAU, regulation prices increase by 84%. If a five-fold increase in battery storage capacity is simultaneously considered, the average regulation price decreases by 16%, but it is still 54% greater than BAU. Additionally, allowing units to offer their full technical capacity to the regulation market reduces the average regulation price by 73%, a result that is 49% lower than even the BAU case.

To our knowledge, many of these sensitivities have not yet been explored in the literature, and these results should be of great interest to market operators and participants as power markets continue to evolve. One sensitivity that has been explored to some extent in the literature is the impact of increased VRE penetration. However, it is difficult to directly compare our results to those obtained by previous studies, as important assumptions often differ or are not made clear. For example, LCG Consulting [10] examined a more modest increase in wind penetration from 12% to 22%, finding that regulation-up and regulation-down prices increase by 21% and 55%, respectively. However, this study does not explicitly state whether or how the regulation requirement changes because of the increased wind penetration. Deetjan el al. [8] examined the price impacts that result from an increase in solar penetration from 9% to 16%, observing a 3% and 30% increase in regulation-up and regulation-down prices, respectively. It is hard to draw any concrete comparisons with the latter study, as the impacts caused by increasing wind and solar penetrations likely differ. Also, Deetjan et al. do not explicitly state whether or how the regulation requirement increases to support the additional solar capacity. Finally, Hummon et al. [9] find that the average price of a single regulation product increases by 7% when the system transitions from 15% to 35% wind and solar penetration and the regulation requirement also increases by 35%. Our analysis considers a larger increase in wind penetration, from 2% to 30%, and a correspondingly larger 100% increase in the regulation requirement.

These increases also lead to a much larger 84% increase in the average regulation price. In contrast to [9], our analysis retires an equivalent capacity value of coal generation when introducing new wind generation to the system. This change reduces the overall supply of generation and qualified regulation capacity and thereby has an upward impact on prices. We also differentiate our work from past studies by isolating the price impacts that are caused directly by changes in the generation portfolio from those caused by associated changes in the regulation requirement.

We plan to pursue several streams of future work to build upon the methodologies and results presented in this study. Initial work will focus on incorporating the complex rules and nuances of different ancillary service markets into new and existing modeling tools. Additional work will be conducted to characterize how individual resources strategically structure their price and quantity offers to ancillary service markets, and how changing price signals might influence these decisions. Finally, we will work to quantify how regulation and spinning-reserve requirements may evolve in systems with increasing wind and solar penetration, as there is still not widespread consensus on this important issue.

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