Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing, and Costs

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Executive Summary

We synthesize available literature, data, and analysis on the degree to which growth in variable renewable energy (VRE) has impacted to date or might in the future impact bulk power system assets, pricing, and costs. We do not analyze impacts on specific power plants, instead focusing on national and regional system-level trends. The issues addressed are highly context dependent—affected by the underlying generation mix of the system, the amount of wind and solar penetration, and the design and structure of the bulk power system in each region. Moreover, analyzing the impacts of VRE on the bulk power system is a complex area of research and there is much more to be done to increase understanding of how VRE impacts the dynamics of current and future electricity markets.

While more analysis is warranted, including additional location-specific assessments, several high-level findings emerge from this synthesis:

- **VRE Is Already Impacting the Bulk Power Market:** The temporal and geographic patterns in wholesale prices have changed in some areas with higher penetrations of VRE, e.g. in CAISO and ERCOT. Negative prices have also sometimes increased with VRE penetration, though the prevalence of negative pricing remains limited in most locations. For the nation as a whole, negative prices have concentrated in areas with significant VRE and/or nuclear generation along with limited transmission, with negative pricing also typically occurring during periods with lower system-wide load. (see Chapter 3)
- **VRE Impacts on Average Wholesale Prices Have Been Modest:** Analysis of wholesale prices in several regions demonstrates that the impact of VRE on average annual wholesale prices has been limited so far. Since 2008, the dominant factor driving wholesale prices lower has been the declining price of natural gas, with VRE playing a comparatively modest role overall. (see Chapter 3)
- **VRE Impacts on Power Plant Retirements Have So Far Been Limited:** Given the relatively modest impact so far of VRE on average annual wholesale electricity prices, it is not surprising that we do not find evidence of a widespread impact of VRE on power plant retirements. While VRE impacts on electricity markets may be a contributor to retirement decisions for some specific units, to date there is little relationship between the location of *recent* (2010-2016) coal, nuclear, and other thermal retirements and VRE penetration levels.
- **VRE Impacts on the Bulk Power Market will Grow with Penetration:** Though operators are reliably integrating VRE, modeling demonstrates that higher penetration of VRE will tend to: (1) prioritize flexible (both existing and new) and low-capital cost generation units over less-flexible and high-capital cost units; (2) require greater amounts of aggregate capacity (including VRE and non-VRE capacity), flexibility, and reserves to manage reliability; (3) alter the temporal and geographic patterns of wholesale electricity prices, and (4) reduce wholesale electricity prices and potentially increase ancillary service prices, especially before capacity equilibration occurs over the longer term. (see Chapters 2 and 4)
- **The 'System Value' of VRE will Decline with Penetration:** The system value of VRE—specifically, the ability of VRE to offset the cost of other bulk power system assets—will tend to decline on the margin as VRE penetrations increase. These declines result from changes in the energy and capacity values of VRE, and the changing need for balancing services and transmission capacity. Comparing resources based only on their levelized cost of energy (LCOE) does not adequately capture differences in contributions to system value or system costs. (see Chapter 5)
- **Power System Flexibility Can Reduce the Rate of VRE Value Decline:** Flexibility provided by generation, load, transmission, storage, operational procedures, and market design become more important with VRE. Such flexibility measures reduce the rate of decline in system value of VRE as

penetrations increase, but sometimes come at a cost to the consumer that is not always accounted for in generation portfolio decision-making. (see Chapters 2 and 5)

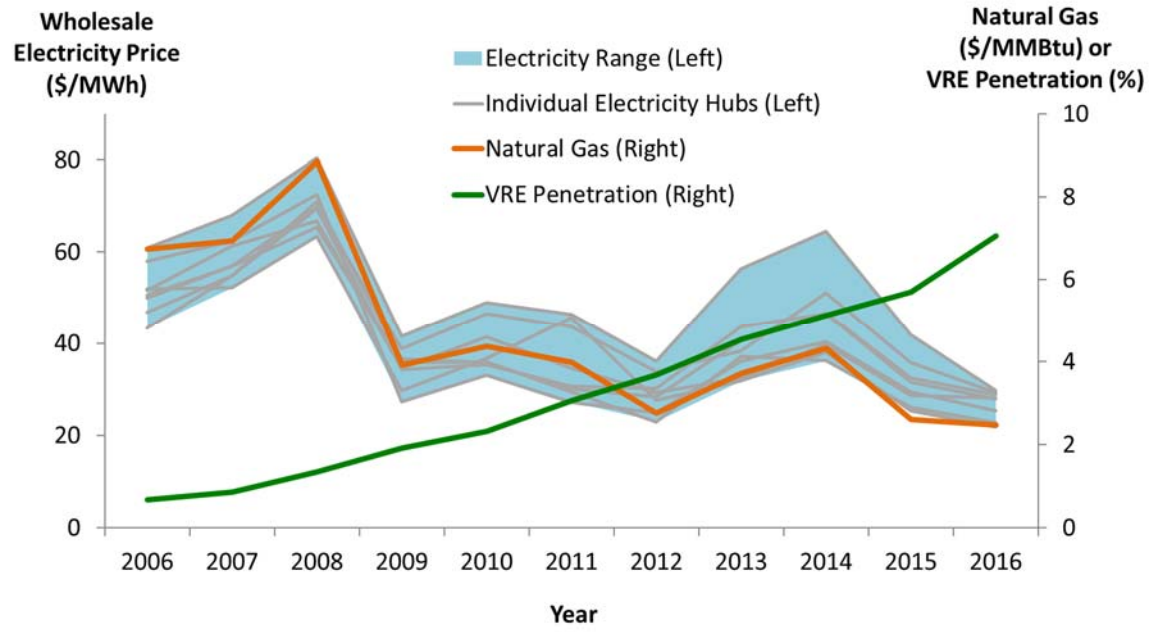
All generation types are unique in some respect—bringing benefits and challenges to the power system—and wholesale markets, industry investments, and operational procedures have evolved over time to manage the characteristics of a changing generation fleet. With increased VRE penetrations, power system planners, operators, regulators, and policymakers will continue to be challenged to develop methods to smoothly and cost-effectively manage the reliable integration of these new and growing sources of electricity supply.

1 Introduction

1.1 Background: Setting the Stage

Wholesale power pricing and the composition and operation of the bulk power system in the United States have witnessed changes in recent years:

(1) Wholesale Prices:[1] As shown in Figure 1, wholesale prices have declined substantially since 2008, but also experienced substantial temporal and geographic variability. Some of the drivers for these wholesale price patterns are discussed later; the figure contains data on two possible influencing factors—natural gas prices and the amount of variable renewable generation (VRE, wind and solar).



Sources: Annual average prices for Mass Hub, PJM West, Indiana Hub, ERCOT North, Palo Verde, SP15, NP15, and Mid C from ABB Velocity Suite and EIA, excluding any separate capacity market or ancillary services revenue; natural gas price for Henry Hub from ABB; VRE penetration from ABB and LBNL estimates of utility-scale and distributed solar generation.

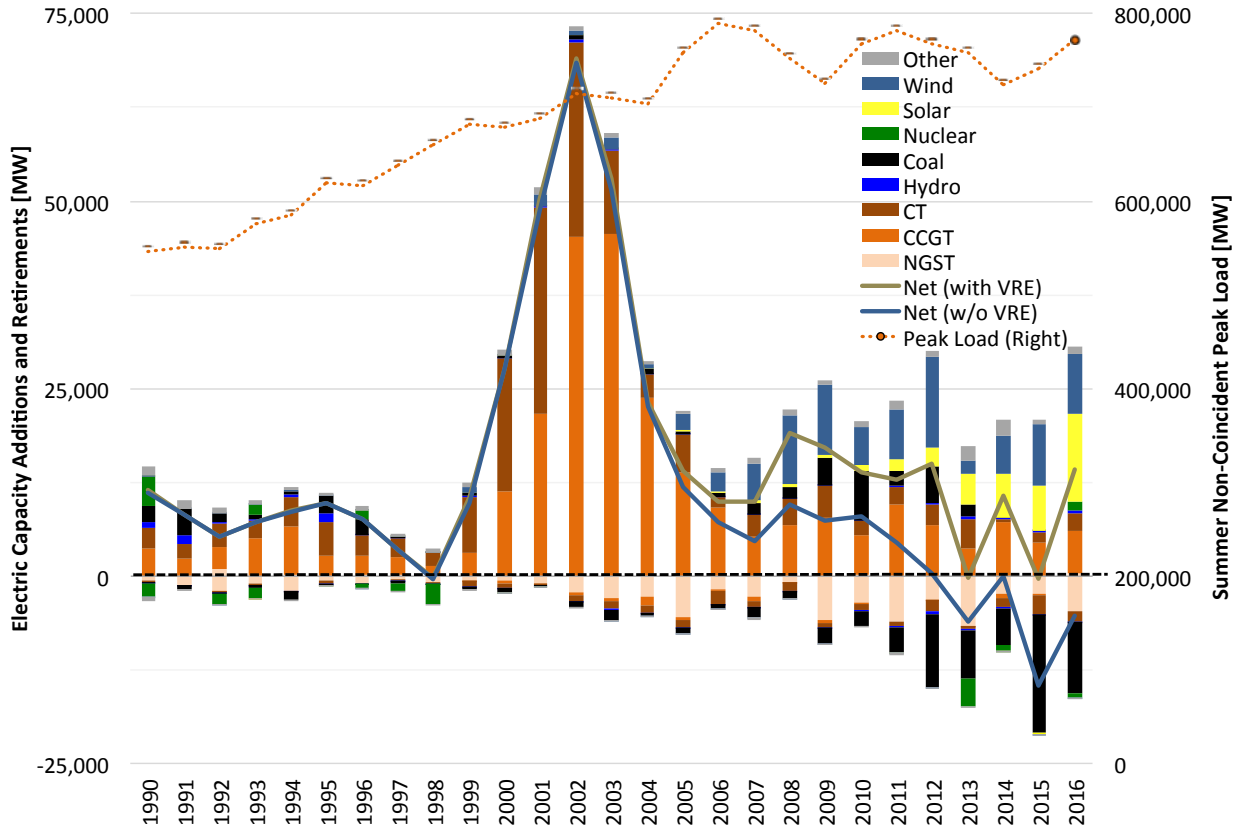
Figure 1. Wholesale Electricity Price Trends, 2006-2016

(2) Retirements and Additions: There have been significant retirements of thermal generation assets in recent years (Figure 2), driven by a variety of market, policy, and plant-specific factors (DOE 2017). Perhaps most importantly, following natural gas prices, average annual wholesale electricity prices have declined, reducing the revenue of more-inflexible generation units (BNEF 2017; Hartman 2017; Houser, Bordoff, and Marsters 2017; Chang et al. 2017; Hibbard, Tierney, and Franklin 2017; Jenkins 2017; DOE 2017; Linn and McCormack 2017; Burtraw et al. 2012; Haratyk 2017); more-flexible dispatchable units, meanwhile, are in a better position to withstand average price declines as they can avoid operating when prices are below operating costs.[2] Additionally, new power plants may offer advanced

[1] Reference to wholesale electricity prices in this report are most commonly associated with markets that feature an ISO/RTO. Less-liquid bilateral markets exist outside of ISO/RTO regions. Note also that substantial amounts of generation even in ISO/RTO regions are locked-into longer-term physical or financial contracts, in which case available wholesale market prices signal opportunity costs but may not affect immediate revenue generation for those existing generators; wholesale pricing will, of course, still affect market entry decisions for new generation.

[2] Where active wholesale markets do not exist, the same basic dynamics hold: the declining cost of natural gas, for example, puts economic pressure on inflexible units even in markets that do not feature an ISO/RTO.

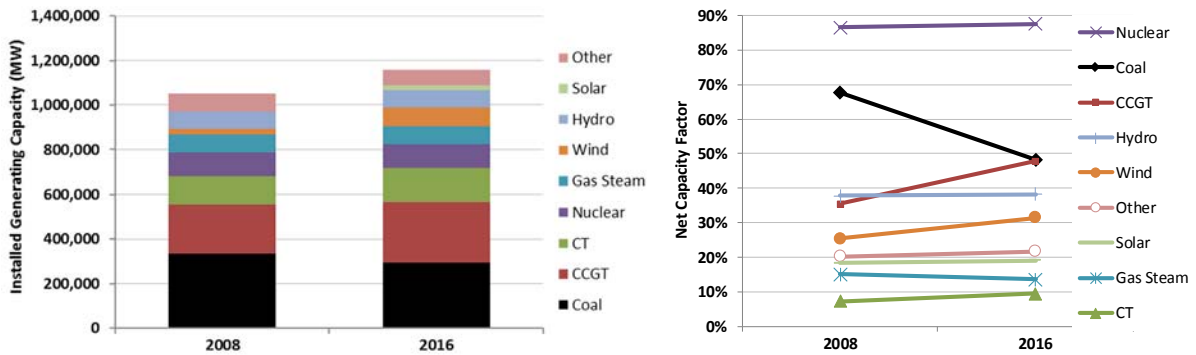
technologies that enable improved heat rates, lower operating costs, lower emissions, and/or increased flexibility in operations, putting pressure on the economic position of older and smaller plants that use less-advanced technology (Gifford et al. 2017; EIA 2016; DOE 2017). Related, the operating costs of many existing plants are rising over time, as those plants age and reach the end of their planned lifetimes and/or face increased regulatory pressures as a consequence of environmental regulations (e.g., coal and gas plants) or relicensing needs (e.g., nuclear and hydropower) (Rode, Fischbeck, and Páez 2017; Pratson, Haerer, and Patiño-Echeverri 2013; DOE 2017; EIA 2017b; Linn and McCormack 2017; Burtraw et al. 2012). The capacity-weighted age of coal and natural gas steam plants that retired from 2010-2016 was around 50 years; the same is largely true for planned retirements (Mills, Wiser, and Seel 2017). EIA (2016), DOE (2017), Mills, Wiser, and Seel (2017) and others have found that retiring coal and natural gas power plants tend to be older, smaller, less efficient, more-emitting, and operating at lower capacity factors than the remaining fleet. A wide array of local, state, ISO/RTO, and federal incentives directed at power plants of all types and geographic locations may also influence retirement decisions (Gifford and Larson 2017, 2016; Lovins 2017; Makovich and Richards 2017). Finally, while retirements have increased recently, sizable capacity additions of natural gas, wind, and solar plants are also apparent. National (non-coincident) peak load, meanwhile, has not increased since 2006 for a number of reasons including the economic recession, improved energy efficiency, and growth in demand side resources. While the same is not true in each region of the country, low load growth combined with continued capacity additions may also help explain the increased rate of retirements in recent years(Linn and McCormack 2017; Burtraw et al. 2012; Haratyk 2017), as many regions continue to have excess capacity as reflected in NERC-estimated reserve margins (NERC 2016a, 2016b).



Sources: LBNL analysis of ABB Velocity Suite data, with solar estimates from GTM/SEIA and IREC.

Figure 2. Retirements and Additions to the U.S. Generation Fleet

(3) Composition and Operation: With reduced natural gas prices, lower demand growth than previously anticipated, and a changing generation capacity mix, the operation of conventional thermal assets has also changed (DOE 2017; Linn and McCormack 2017; Houser, Bordoff, and Marsters 2017; Burtraw et al. 2012; Johnsen, LaRiviere, and Wolff 2016; Fell and Kaffine 2014). Figure 3 depicts both the changing composition of the generation plants in the United States from 2008 to 2016 and the altered utilization of that mix on a national basis, with strong growth in the average capacity factors for CCGT and even CT units (along with wind), but with declining capacity factors for coal units. As a consequence of lower natural gas prices, Lim and Vilgalys (2017) show that coal plants in the West are increasingly operating flexibly and not in a traditional 24x7 'baseload' fashion.



Source: LBNL analysis of EIA-860 data. 'Net capacity factor' calculated based on net generation (excluding station use) for each year relative to total capacity at the end of each year. The 2008 EIA-860 data file lists multiple energy source codes for some generators: the first one listed was presumed dominant. Data for 2016 and even 2008 are partially estimated by EIA.

Figure 3. The Altering Composition and Operation of the U.S. Generation Mix

Concurrent with the above trends, and as shown in Figure 1 through Figure 3, has been a substantial growth in variable renewable energy (VRE) resources—wind and solar photovoltaics. This growth has been motivated, in part, by the declining cost and price of wind and solar (Wiser and Bolinger 2017; Bolinger, Seel, and LaCommare 2017; Barbose and Darghouth 2017), along with a recent increase in corporate procurement of renewables.[3] Growth has also been greatly affected by federal policy (e.g., tax incentives) and state policy (e.g., renewables portfolio standards (RPS), financial incentives for distributed solar, net metering, etc.).[4] An open question is whether and to what degree VRE deployment and the specific incentives motivating that deployment are contributing factors to the wholesale price, retirement, and asset operation trends noted above, as well as the degree to which such impacts might grow in the future. The balance of this report attempts to provide some initial insights that address these questions.

1.2 Content and Structure

In this report, we synthesize available literature, data, and analysis on the degree to which growth in VRE has influenced or might in the future impact bulk power system assets, pricing, and costs. We do not analyze impacts on specific power plants, instead focusing on national and regional system-level trends.

Specifically, we highlight the possible impacts of VRE on:

- wholesale power market pricing
- operation of other power plants, and

[3] See, for example: http://businessrenewables.org/corporate-transactions/
[4] See, for example: http://www.dsireusa.org/

- incentives for generation asset retirement and investment

Where possible, we frame these past or prospective impacts of VRE within the context of other possible drivers for some of the same trends.

Finally, consequent to the unique characteristics of VRE, concerns have also been raised about the 'lower system value' or 'additional system cost' of wind and PV, as a large-scale expansion of VRE tends to drive down the marginal energy and capacity value of those VRE resources and may increase the need for transmission and distribution infrastructure as well as certain system services. If all generation sources were homogenous, decision-making by regulators, utilities, and power plant investors would be simple: purchase from or invest in the source with the lowest levelized cost of energy (LCOE). However, power plants have widely varying technical and economic characteristics, and so deliver different services, requiring an assessment of both cost and value. As such, the final chapter highlights the implications of our findings for the 'system value' or 'system costs' of VRE.

A number of critical notes on scope and limitations of this analysis deserve special attention:

(1) This report is primarily a synthesis of the available literature and data. The literature is broad and deep, and important conclusions can be reached based on well-regarded and peer-reviewed material. However, to claim that the literature is complete would be misleading. Analyzing the impacts of VRE on bulk power markets is a complex area of research and there is much more work to be pursued in all of the areas covered in this report.
(2) Much of this report focuses on restructured, wholesale electricity markets. Many of the issues addressed are also relevant—at least broadly—to regions with vertically-integrated electric utilites that operate outside of those markets. This is not always the case, however. As applicable, we identify where issues differ depending on industy structure.
(3) This report does not comprehensively address issues related to short-time-scale variations in VRE and technical characteristics of VRE as they affect power system reliability and VRE integration. There is a rich literature in those areas, given actual operator experience and prospective issues at still-higher penetrations. A brief summary is offered in Text Box 1, and we later address the possible cost implications of managing aspects of this form of integration.
(4) This report does not address market design and compensation mechanism design given the changing mix of generation resources underway, a focus of a recent FERC conference[5] and considerable other additional work (e.g., Ela et al. 2016; Milligan et al. 2016; IEA 2016b; Keay 2016; DOE 2017; Hogan and Pope 2017; Makovich and Richards 2017; Walton 2017; Newell and Lueken 2016; Hogan 2010; Newberry et al. 2017; Gimon 2017; Orvis and Aggarwal 2017; Ela et al. 2017; Haratyk 2017). At least three core issues are currently being actively debated in the research literature as well as in industry: (a) resource adequacy and the need for and design of capacity markets as the resource mix changes; (b) design of energy and ancillary services[6] (AS) markets under changing resource mixesand (c) how 'out of market' subsidies and incentive schemes should be designed, and accounted for in wholesale market designs.
(5) This report does not identify possible secondary concerns associated with the issues covered (e.g., if reduced coal or nuclear capacity due to VRE growth impacts resilience due to less on-site fuel

[5] See FERC Docket No. AD17-11-000. "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C."
[6] NERC has replaced the term 'ancillary services' with the term 'essential reliability services.' We use ancillary services in this report.

storage), or highlight in detail possible technical, economic, or policy solutions (e.g., making coal or nuclear plants more flexible or adding on-site fuel storage to natural gas plants).

(6) Finally, while we seek to draw some generalizable findings from the available literature and conduct new analysis of available market data at the regional level, all of the issues addressed in this report are highly context dependent—affected by the underlying generation mix of each region in question, the amount of wind and solar penetration, and the design and structure of the bulk power system in the region. Regional differences are extensive in the electricity sector, and thus different conclusions may exist from one region to the next.

The remainder of the report is organized as follows. First, based on available literature and theory, we qualitatively describe the expected nature and direction of possible VRE impacts on bulk power system assets and pricing. Second, we summarize data and literature on the degree to which those impacts have already been observed in the U.S. bulk power system. Third, we highlight how these impacts might develop in the future at still-higher shares of VRE. Finally, we assess the implications of our findings for the 'system value' or 'system costs' of VRE.

Text Box 1. Grid Integration of Variable Renewable Energy

Integration of VRE into the nation's power grids requires both economic integration (the main focus of this report) as well as technical integration. Technical integration involves managing the power system to maintain reliable operation under increased penetration of VRE and is, of course, linked to the issues of economic integration that are otherwise the main emphasis of this report.

Compared to conventional thermal generation, wind and PV are marked by three characteristics of particular concern to power grid operators as it relates to reliability: variability, uncertainty, and non-synchronous generation. Understanding and addressing these factors is the subject of a rich literature of integration studies as well as over a decade of real-world operator experience. Most grid integration studies to date have focused on the first two characteristics, specifically, evaluating the power system's ability to balance supply and demand, including the ability to ramp other generators to respond to the increased variability of net demand (normal demand minus the contribution from VRE). Several of these studies are listed in Table 4 in Chapter 4. In general, these studies have shown how the existing generation mix, when combined with increased transmission capacity or transmission utilization, use of state of the art wind and solar power forecasting, and new operational practices, can enable penetration of wind and solar PV to at least 35% of load on an annual basis while maintaining reliability, considering the specific reliability attributes that can be readily modeled and analyzed. One tool of several for integrating these levels of VRE is more-flexible operation of existing thermal generation, which, as discussed in Chapter 4, lowers their capacity factors and increases cycling costs and, in some cases, may reduce operating profits. In addition to detailed technical integration studies, system operators have real world experience with instantaneous (i.e., not year-round) VRE penetrations that have exceeded 50% in several regions of the United States, and even greater internationally (Martinot 2016).

An increasing number of studies have focused on the third characteristic, non-synchronous generation, to better understand the impact of high penetrations of VRE on voltage support and frequency stability (Eto et al. 2010; NERC 2015), both essential elements of power system reliability. Conventional generators operate in a different manner to VRE, and inherently offer certain technical services, including inertia, or the natural ability of the grid to arrest system failures. In recent years, modern wind turbines and PV systems have demonstrated their ability, if either required to or compensated by markets, to provide similar reliability services historically only provided by synchronous generators, including the provision of automatic generation control, primary frequency response, as well as synthetic inertia (Ela et al. 2014; CAISO 2017a). Within the limits of the studies, detailed grid simulations (Miller et al. 2014; Miller, Leonardi, and D'Aquila 2015) have concluded that with appropriate planning and engineering, systems with high VRE penetrations are able to maintain the same level of reliability that already exists in the U.S. power system.

To ensure that attention is focused on the efforts required to maintain reliability as the generation mix changes (e.g., coal and nuclear retirements while wind and solar generation increases), NERC has created both an 'Integration of Variable Generation Task Force,' and more recently a new 'Essential Reliability Services Task Force.'

2 Economic Underpinning and Expectations

2.1 Drivers for Wholesale Prices, Operations, and Retirement

Wholesale prices and asset operations are affected by the presence of VRE and the incentives motivating VRE deployment, but also by a wide array of other factors, including:

- Fuel prices of natural gas, coal, oil, nuclear, biomass, and other power plants
- Environmental regulations and emissions allowance prices
- Other variable operating costs of power plants of all types
- Physical flexibility of generation units (and load) and cost of accessing that flexibility
- Contractual and regulatory practices that limit flexibility in plant operations (and load)
- Total load and peak load growth and the diurnal and seasonal pattern of demand
- Generation plant investment and retirement decisions
- Transmission availability and investment
- Basic market design and integration with other regional markets
- Scarcity pricing rules in energy and reserves markets
- Policy mechanisms that affect fuel prices,operating costs, bidding practices, and load response

As discussed earlier, retirement decisions are also impacted by numerous factors. First, reductions in wholesale prices will tend to reduce the revenue of more inflexible generation units that face those prices[7]; more-flexible dispatchable units, meanwhile, are in a better position to withstand average price declines as they can avoid operating when prices are below operating costs, but still can be impacted by overall reduced revenue. Second, new power plants may offer advanced technologies, putting pressure on the economic position of older plants that have higher operating costs and use less-advanced technology. Third, especially as plants age or face new regulatory requirements, the fixed and variable operating costs may rise, increasing pressure to retire. Finally, a wide array of local, state, ISO/RTO, and federal incentives directed at power plants of all types can affect decisions.

2.2 Unique Attributes of VRE that Can Impact the Bulk Power Market

All generation types are unique in some respect, imposing varying forms of physical and operational limitations, and wholesale markets and industry investments and operations have evolved over time to manage new challenges. Wind and solar PV, meanwhile, have four somewhat-unique characteristics that are relevant to this report in that they can influence bulk power-system operations, investments, pricing, and cost (IPCC 2011; Hirth 2013; UKERC 2017):[8]

- Weather-driven variability in electricity production, which can impact energy and capacity markets as well as ramping and ancillary service needs
- Uncertainty in forecasts of future output, which can impact ancillary service needs and costs
- Resource-driven location dependencies that, in some cases, can impact the need for or benefit of new transmission investment
- Low, or even negative (under certain VRE incentive schemes like the PTC) marginal costs, which tend to place VRE before resources in the dispatch merit order

[7] Generation that is locked-into longer-term physical or financial contracts (or that is located outside of ISO/RTO regions) may be temporarily isolated from some of these forces, but will still be affected by natural gas and wholesale price changes at least over the longer term.

[8] Hydropower and even geothermal plants also have some of these same characteristics. Note also that additional specific technical characteristics are identified in Text Box 1.

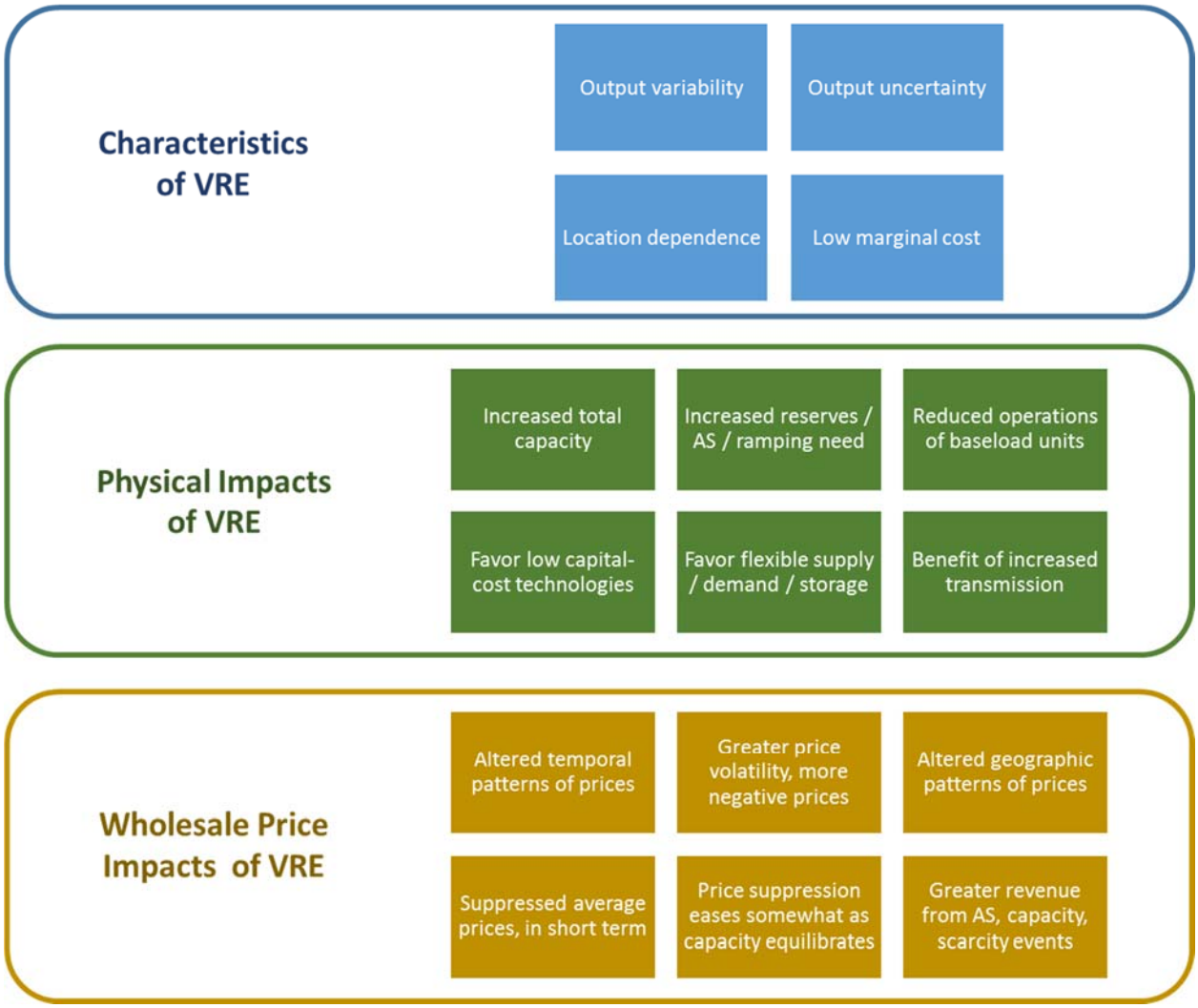


Figure 4. Characteristics and Expected Impacts of VRE on the Bulk Power System

2.3 Physical Impacts of VRE on the Bulk Power Market

Basic power system economics demonstrates that growing levels of VRE would, given the characteristics noted above and all else being equal, have the following physical impacts (see Figure 4):

- Increase the total amount of generation capacity (including non-VRE and VRE capacity) needed to maintain planning-level reliability standards (because the capacity credit[9] of wind and PV is well below their nameplate capacity, in part due to the relatively low capacity factors of VRE overall and, in some cases, a tempotal mismatch between VRE generation and net load)
- Increase the total amount of ancillary services (regulation, spinning, and non-spinning reserves), and ramping to maintain operating reliability (because of VRE variability and uncertainty)
- Reduce the operating hours and capacity factors of dispatchable 'baseload' power plants as those plants dispatch down in the presence of VRE

[9] As defined by NERC (2011), the capacity credit of a resource measures an individual generator's contribution to overall long-term resource adequacy, and represents the fraction of the nameplate capacity of a resource that contributes to lowering the risk that demand for electricity will exceed the available supply.

- As it relates to asset investment and retirement, favor low capital-cost non-VRE units over higher capital-cost units (because of the expected decrease in capacity factors)
- As it relates to asset investment and retirement as well as plant operations for existing units, favor more-flexible supply, demand, and storage over inflexible options (because of greater variability in energy market prices, more variations between day-ahead and real-time prices, growing ancillary service needs, and higher ancillary service prices)
- Favor additional transmission investment (given that the best VRE resource locations are sometimes far from load centers, but also that transmission allows larger geographic areas to balance across)

A sizable literature demonstrates the above tendencies as VRE penetrations increase. Most of the literature is based on modeled scenarios with higher levels of VRE penetration than are currently experienced (e.g., Traber and Kemfert 2011; Lamont 2008; Bushnell 2010; DOE 2012, 2015; NREL 2012; Mills and Wiser 2012a, 2015, 2014; Steggals, Gross, and Heptonstall 2011; Di Cosmo and Malaguzzi Valeri 2014; De Jonghe et al. 2011; Chao 2011; Brouwer, van den Broek, Zappa, et al. 2016; Clò and D'Adamo 2015; Levin and Botterud 2015; Bloom et al. 2016; GE Energy 2010b; Agora 2015; Green and Léautier 2015). However, some of these influences are already apparent and/or are being discussed in current systems internationally and in some regions of the United States (e.g., Makovich and Richards 2017; Potomac Economics 2017b, 2017c; SPP 2017; CAISO 2017b).

2.4 Impacts of VRE on Wholesale Power Prices

Related to these physical impacts, growing shares of VRE are expected to have implications for wholesale power prices, including (see Figure 4):

- Temporal patterns in wholesale electricity prices will change, with lower prices when VRE generation is high, and higher prices when VRE generation is low
- Price volatility and unpredictability would be expected to increase, as a consequence of the weather-dependent, variable, and uncertain nature of VRE generation
- Geographic patterns in wholesale electricity prices will change, with lower prices in regions with concentrated VRE deployment and limited transmission capacity
- Wholesale electricity market prices will, especially before capacity equilibration, be lower as a greater share of low (or even negative)-marginal cost generation is deployed
    - The degree of price suppression will depend on the nature of the overall supply curve from other generation sources: a 'flatter' supply curve will yield less price suppression, whereas presence of inflexible generators that use low bids to avoid startup/shutdown costs can increase price suppression
    - The effect is not present to the same extent for vertically integrated utilities that operate in a cost-plus environment and in markets where wholesale purchases are a subset of supply costs
    - The degree of price suppression may also depend on any policy incentives (e.g., the PTC) that impact bidding behavior: incentives that lower bid prices will yield lower overall prices when those bids are on the margin
    - This price suppression effect is not unique to VRE in that any low-marginal-cost resource or a reduction in demand would have a similar directional effect in the short term

    - Price suppression affects electricity customers and generators differently: customer electricity costs tend to be reduced by virtue of lower wholesale prices, but this consumer benefit is offset by reduced revenues earned by generators
- Price suppression may result in earlier retirements of some—and especially inflexible—generation units; moreover, new units will tend to have lower capital costs (and, therefore, can afford higher operating costs) and greater dispatch flexibility than in scenarios with low VRE (Chapter 4 discusses these impacts as well as those in the following bullet in more detail)
- Capacity 'equilibration' along the lines of the previous bullet implies that, as investment and retirement decisions adjust to higher penetrations of VRE over the longer term, the impact of VRE on average wholesale prices will be different and not as sizable as in the short run
    - The VRE impact on pricing variability will remain even in the longer term after capacity equilibration
    - But the impact on *average* wholesale prices will be lower in the longer term as long-term capital investment and retirement decisions are made based on market conditions, especially the retirement of more-inflexible units and the incentive to invest in lower capital-cost (but potentially higher operating-cost) technologies under high VRE scenarios
- There will be a tendency towards greater revenue from AS markets, from capacity markets (where they exist), and/or from scarcity events; less revenue may derive from the general energy market
- Outside of restructured wholesale markets, some of the above tendencies would also be experienced, with effects seen in terms of variations and adjustments to short term operational costs rather than wholesale electricity prices and products
- To be clear, none of the above observations directly relate to the full impact of VRE on total costs; while VRE would be expected to reduce wholesale prices, this is not a proxy for total system costs, which naturally must consider the cost of the VRE including any 'system costs' or 'system values' not otherwise included in wholesale prices—see Chapter 5 for additional detail

A substantial literature demonstrates the above tendencies. Much of that literature is based on modeled scenarios with higher levels of VRE penetration than are currently experienced (for U.S.-based literature, see, e.g., GE Energy 2005, 2010a, 2014, Fagan et al. 2012, 2013; NESCOE 2017; Brancucci Martinez-Anido, Brinkman, and Hodge 2016; LCG 2016; ISO-NE 2016; Tabors et al. 2015; Tabors, Rudkevich, and Hornby 2014; NY-ISO 2010; ABB 2014; NREL 2012; Deetjen et al. 2016; ISO-NE 2017a; Green and Léautier 2015). However, a growing literature has assessed some of these impacts as expressed through past market outcomes from the U.S. (e.g., Maggio 2012; Woo et al. 2011, 2013, 2014; Woo, Horowitz, et al. 2016; Woo, Moore, et al. 2016; Gil and Lin 2013; Wiser et al. 2016; Jenkins 2017; Hogan and Pope 2017; Makovich and Richards 2017; DOE 2017; Bajwa and Cavicchi 2017; Haratyk 2017).[10,11]

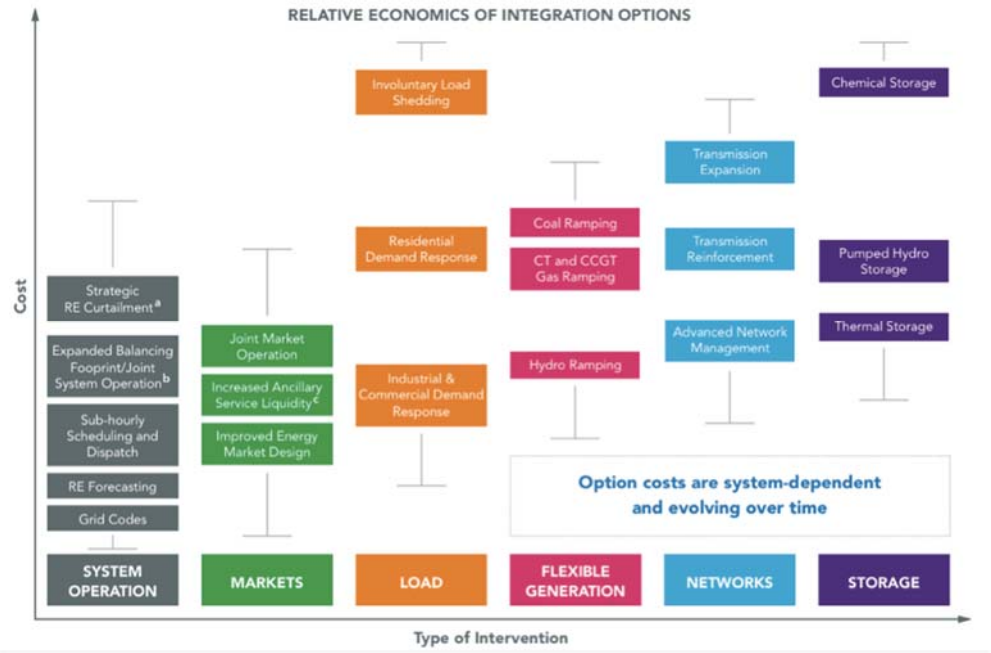
[10] To read the many diverse pre-conference statements, see: https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=05/01/2017&View=Listview.

[11] Literature from Europe and Australia also includes empirical and modeled assessments (Sensfuß, Ragwitz, and Genoese 2008b; Welisch, Ortner, and Resch 2016; Perez-Arriaga and Batlle 2012; Kyritsis, Andersson, and Serletis 2017; Brouwer, van den Broek, Zappa, et al. 2016; Würzburg, Labandeira, and Linares 2013; Cludius et al., n.d.; Cutler et al. 2011; MacCormack et al. 2010; Ederer 2015; Haas et al. 2013; Clò, Cataldi, and Zoppoli 2015; Sáenz de Miera, del Río González, and Vizcaíno 2008).

2.5 The Importance of Physical and Institutional Flexibility

Many of the impacts described above are affected by the underlying physical and institutional flexibility of the electricity system (e.g., Cochran et al. 2014; Denholm et al. 2016; IEA 2011). Simply put, some of the physical and wholesale price impacts enumerated above are less pronounced when the rest of the electricity system is flexible and better able to respond to shifts in demand and VRE availability (e.g., Chang et al. 2017). VRE impacts and system costs will be driven lower as power systems transform to manage the unique characteristics that VRE resource introduce. Power systems with less flexibility will experience greater challenges in maintaining reliability and managing costs as VRE penetrations increase. At the same time, of course, it is important to recognize that flexibility is not always free: tradeoffs are inherent when evaluating the costs and benefits of flexibility investments.

A wide spectrum of VRE integration and system flexibility options exist, as depicted conceptually in Figure 5. These range from institutional options related to system operations and market design that—in part—help extract flexibility from the existing electricity system, to physical options related to electrical load, supply, networks, and storage (Orvis and Aggarwal 2017). A range of costs applies across these various options, costs that may vary by location and with time as technology advances. A core responsibility for power system planners and operators will be to balance these options in a way that maintains reliability and resilience while minimizing total system cost. And, in regions with wholesale markets, the key challenge is designing market rules and products that incentivize a least-cost mix of reliability- and resilience- enhancing flexible technologies.



Source: Cochran et al. (2014)
a. There is a tradeoff between costs of flexibility and benefits of reduced (or no) curtailment, hence a certain level of curtailment may be a sign that the system has an economically optimal amount of flexibility.
b. Joint system operation typically involves a level of reserve sharing and dispatch co-optimization but stops short of joint market operation or a formal system merger.
c. Wind power can increase the liquidity of ancillary services and provide generation-side flexibility. Curtailed energy is also used to provide frequency response in many systems, for example Xcel Energy, EirGrid, Energinet.dk.

Figure 5. System Flexibility Options as VRE Penetrations Increase

2.6 Impacts of Policies and Incentives Supporting VRE Deployment

In addition to the unique physical characteristics of VRE, wind and solar have obtained and continue to receive state and federal incentives. Wind energy, for example, receives a 10-year federal production tax credit (PTC), an incentive that is currently being phased-out over a multi-year period (at times, wind plants have also had the opportunity to take investment-based support in lieu of the PTC). Additionally, both solar and wind benefit from renewables portfolio standards (RPS) in many states. Both the PTC and the RPS create incentives for VRE plant owners and purchasers to bid that generation into wholesale markets at negative prices. The reason is simple: curtailment of generation will result in not only lost energy-based revenue but also potentially lost incentive value (Hogan and Pope 2017). Nor are these policy incentives the only reason that a VRE project may bid at negative price: market demand for 'green energy' by residential, corporate, and governmental entities yields positive prices for renewable energy certificates (RECs), even in the absence of RPS programs.

To be clear, wind and solar are not the only resources that bid negative prices in wholesale electricity markets, or that generate during negative-price hours. The lack of flexibility from existing nuclear power plants in the United States, for example, means that these plants will often bid negative prices to avoid costly shutdowns and start-ups. Fossil (whether coal or natural gas) units may also—at times—bid negative prices due to the costs of operating flexibility. Even hydropower plants sometimes generate during negative-priced hours, in some cases due to run-of-river operations and in others as a result of environmental constraints. In other cases, units may have contractual requirements that create the same incentives for negative bidding, or may be required for reliability purposes regardless of market pricing. In Chapter 3 we show that some units of these technologies regularly operate during negative price hours.

Overall, where transmission is unlimited, these plant-specific bidding strategies may have relatively little impact on overall wholesale prices unless the volume of negative price bids is very sizable. Especially in the presence of transmission congestion and/or during periods with lower system-wide load, however, suppliers with negative price bids will more-frequently become the marginal units, leading to negative wholesale prices in congested regions.

Wind and solar are also not the only resource that benefit from federal, state, or local incentives of one form or another (Sherlock 2011, 2013; CBO 2012; EIA 2015; Griffiths et al. 2016).[12] Some argue that the significant nuclear plant additions of past decades would not have occurred absent the Price-Anderson Act, the nuclear weapons complex that helped bring the technology to commercial viability, the complicity of state regulatory bodies, and many other factors (e.g., Koplow 2011). All existing nuclear units in the U.S. were constructed before the implementation of competitive markets, and the small number of new units under construction are located in regions that are served by traditional regulated monopolies. Multiple states have also recently awarded or are considering awarding nuclear plants with 'out of market' support to help ensure continued operations (Gifford and Larson 2017, 2016; Tsai and Gülen 2017; Haratyk 2017); new nuclear generators, meanwhile, are eligible for federal production tax credits. Over the decades, fossil fuel supply and generation has also benefited from the generosity of local, state, and federal policy (see earlier citations, and also Pfund and Healey 2011). And many

[12] See also: https://earthtrack.net/

economists and others argue—as many did at the recent FERC conference[13]—that current energy markets do not fully account for environmental (e.g., carbon) damages (or fuel diversity, or other possible public goods), representing yet another market failure and an implicit subsidy for higher-emitting generation sources that distorts market outcomes[14]; in part as a consequence, many ISOs are exploring methods to better integrate carbon costs (and, more broadly, state policy preferences) into their market designs (Newell et al. 2017; ISO-NE 2017c; PJM 2017).

The relative magnitude of support delivered to different generation sources is a debate that we do not seek to resolve here. However, while this report focuses narrowly on VRE, we also acknowledge that some policymakers, analysts, economists and industry stakeholders view the current and/or past support provided to other forms of generation—either directly via incentives or indirectly via unpriced externalities—equally as or even more 'distortionary' than those provided to VRE.

Notwithstanding these arguments, it is true that recent VRE deployment has been highly policy motivated, in some cases resulting in deployment where an obvious physical energy-system need for additional electricity capacity is lacking. Moreover, the production-based support delivered via the federal tax code and state incentives can yield negative wholesale price bids. State and federal incentives delivered to other generation sources may also influence their bids, but do not—at present—have the same effect on negative price bidding, even if those incentives have been large in cumulative sum over time and remain sizable in absolute magnitude today (Griffiths et al. 2016). As one example, estimates in the literature suggest that removal of federal tax support for natural gas production might yield gas price increases of anywhere from less than 1% to as much as 10% (Allaire and Brown 2009; Metcalf 2016). On the highest end of this range, elimination of federal tax support for natural gas would yield market bids by an efficient combined-cycle gas turbine roughly $2.2/MWh higher than today (assuming $3/MMBtu gas, 7,600 Btu/KWh heat rate). The resultant impact on unit bidding is therefore smaller than the one that comes from the federal PTC for wind energy, and does not create a strong incentive for natural gas plants to bid into wholesale markets at negative prices; that being said, because natural gas plants regularly set prices in wholesale markets, even this smaller bid impact may have an out-sized impact on market-clearing price outcomes.

As in Hogan and Pope (2017), it is useful to separate the two distinct effects of policy support for VRE (or any other type of generation): one that affects deployment, and the other that impacts bidding behavior. Any form of policy that motivates or supports VRE deployment will impact the bulk power system as described earlier by adding low-marginal-cost supply. Production-based support (the PTC and RPS, for example, but not the investment-based tax credit provided to solar), meanwhile, may have an additional impact by affecting bidding behavior that, in the case of VRE, may yield negative price bids.

Whether either of these impacts—the deployment impact or the bidding impact—is considered a severe 'market distortion' depends on perspective. On one hand, many economists would argue that supporting VRE (or any other specific resource) via policy-based incentives is market distorting on its face: if policy is warranted, that policy should be focused on desirable attributes (low emissions, fuel

[13] To read the many diverse pre-conference statements for the FERC conference, see: https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=05/01/2017&View=Listview.

[14] To be fair, the same conference had some economists citing the role of state and Federal policies favoring renewables as distorting markets.

diversity, learning spillovers, etc.) rather than on only certain classes of generation (Keay 2016; Borenstein 2012; Fischer and Newell 2008; Makovich and Richards 2017; Hogan 2010; Andor and Voss 2016). Others place some emphasis on the type of support, suggesting that policy that encourages negative bidding distorts the market (Huntowski, Patterson, and Schnitzer 2012; De Vos 2015; Hogan and Pope 2017; Cavicchi 2017; Green and Léautier 2015; Newberry et al. 2017; Bajwa and Cavicchi 2017). Some of these analysts argue further that investment-based rather than production-based support would be preferable, in that such support would not encourage negative bidding (Huntington et al. 2017; Cavicchi 2017; Rosnes 2014).[15] On the other end of the spectrum are those who believe that renewable electricity is delivering unaccounted-for societal benefits for every MWh delivered. In that case, to them, negative bidding may be an acceptable way to prioritize renewable energy over other generation sources, especially in a 'second-best' world in which full pricing of attributes (e.g., carbon, fuel diversity, etc.) directly appears politically infeasible (Höfling et al. 2015; Kalkuhl, Edenhofer, and Lessman 2013). Millstein et al. (2017), for example, find that the historical air pollution and climate benefits of wind and solar are comparable to past levels of state and federal financial support. In still other cases, analysis suggests that a modest degree of negative bidding consistent with the PTC has relatively little distortionary effects, but that severe negative bidding may cause inefficient market outcomes (Deng, Hobbs, and Renson 2015). Others show that, in certain circumstances, production-based support is superior to investment-based support (Pahle et al. 2016) Many of these diverse argumements were on full display during a recent FERC conference, and in the related witten testimony provided by a wide range of electricity market stakeholders.[16]

We make no effort to resolve these debates here. In later chapters of the report, however, we do explore the impact of VRE on wholesale markets, the prevalence of negative prices in wholesale markets, and the possible future impacts of VRE on the bulk power market. More generally, moving from qualitative and directional assessments to quantitative analysis, the following two chapters of this report address the critical question of the magnitude of VRE impacts, both past and possible future. After all, it is the magnitude of the effects that determine the scale of the impacts on market outcomes.

[15] On the other hand, there is an extensive literature—not cited here—that describes the risks of investment-based support given the desire to maximize energy delivery not simply capacity installation.

[16] To read the many diverse but related pre-conference statements, see: https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=05/01/2017&View=Listview. A subset of the relevant perspectives represented by these comments is summarized in DOE (2017).

3 Historical Observed Impacts of VRE on the Bulk Power System

3.1 Overview and Summary

Here we review literature, analyze wholesale market data, and utilize simple power market models to better understand the impact of VRE on the bulk power system, as seen in historical empirical data. We focus on impacts to average annual wholesale prices, impacts to wholesale price variability and temporal patterns with a focus on negative prices, and the relationship between VRE and recent power plant retirements. This is an initial analysis of these issues: further, more-detailed work is warranted.

We focus some of our analysis on prices at selected major electricity-trading hubs in ISOs identified by EIA[17] (Figure 6), along with our own choice of hubs not listed by EIA (SPP South near Oklahoma City in SPP and Zone G near the Hudson Valley in NYISO). We then place additional attention on specific 'constrained' pricing points, as discussed later in the chapter. Some of our analysis includes day-ahead prices (DA), but our focus is primarily on real-time (RT) prices where the impacts of VRE are more readily observed. DA prices are most relevant to inflexible plants that only sell power in the DA market and do not participate in RT balancing (e.g., nuclear and some coal units). RT prices, on the other hand, reflect the value (or cost) of generation deviating from its day-ahead schedule to support (or hinder) real-time balancing between supply and demand. In part we focus on RT markets because we assume that DA markets will tend to mimick RT markets, on average. For example, even if negative prices are more common in the RT market than in the DA market, we anticipate that those negative RT prices will affect longer-term average pricing in the DA market (Bajwa and Cavicchi 2017). In fact, on an annual basis, the average of DA prices and RT prices do tend to be similar. For example, across the hubs included in our analysis, the average DA price was $0.5/MWh lower to $1.1/MWh higher (2% lower to 5% higher) than the average RT price in 2016. All of the ISOs now use 5-min markets for real-time balancing, though our analysis is based on hourly averages of those real-time prices; only hourly data are reported in our main data source, ABB's Velocity Suite.

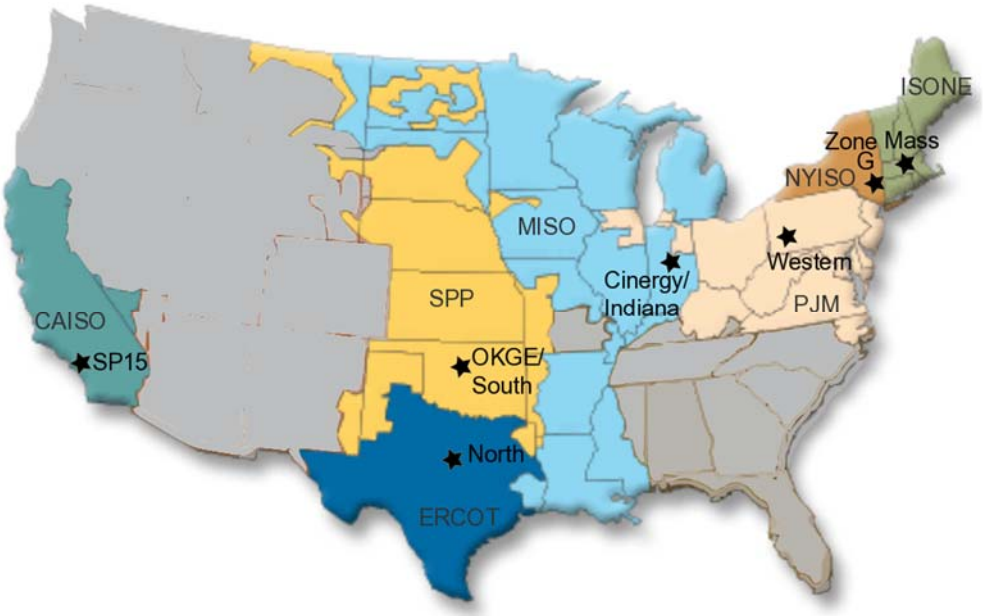


Figure 6. Locations for a Portion of the Selected Electricity Pricing Points Investigated in this Analysis

[17] http://www.eia.gov/electricity /wholesale/

Overall, our analysis of electricity market data through 2016 indicates that VRE so far has had a relatively modest impact on historical average annual wholesale prices across entire market regions, at least in comparison to other drivers; this is true even in those ISOs with the largest VRE penetrations. The reduction of natural gas prices is the primary contributor to the decline in wholesale prices since 2008. And, because of the low price of natural gas, regional 'supply curves' are particularly flat; this is a core reason why VRE has had a relatively modest impact on annual prices so far. Although some specific power plants may have retired in part due to the impacts of VRE, we find little relationship between the location of recent thermal-plant retirements and VRE. Moreover, given the relatively modest impact of VRE on average annual wholesale electricity prices across large market regions, it is unlikely that VRE has influenced retirements on a *widespread* basis so far.

We also find, however, that the temporal and geographic patterns in wholesale prices have changed in areas with higher levels of VRE. Specifically, negative prices have sometimes increased with VRE, though the prevalence of negative pricing so far remains limited at most of the selected large pricing hubs that are the focus of our analysis, and the net impact of negative prices on overall average wholesale prices at these same hubs has also been minor. CAISO pricing is, to a degree, the exception. Moreover, negative pricing is a larger issue in specific, often transmission-constrained zones, and especially during periods of relatively low system-wide load. We find that VRE is generally correlated with negative price hours; inflexibly operated nuclear plants are also major contributors.

As and if VRE penetrations increase, the impacts of VRE on wholesale market pricing and bulk power assets would also be expected to increase; these possible future impacts are the topic of Chapter 4.

3.2 Challenges of Attributing Changes to VRE

Wholesale prices have decreased dramatically since their peak in 2008 (see Chapter 1). While VRE penetration has increased over this same period, there have been other simultaneous changes, including (among others) a large decrease in the price of natural gas, higher volumes of natural gas generation, and limited load growth. Identifying the relative contribution of VRE or any other single factor to this decline in prices is challenging and we recommend more work in this general area. We present a preliminary analysis of the role of VRE, but this should not be considered definitive.

We also note that our analysis of historical observed wholesale price impacts is limited to locational marginal prices (LMP). This has several limitations. First, LMPs do not embed all of the costs for operating the bulk power system, such as ancillary services, the cost of capacity (outside of the 'energy-only' market design in ERCOT), or the full cost of transmission. The aggregate revenue of a generator participating in a wholesale market depends on the LMPs, ancillary service prices, capacity prices and the dispatch of that generator. Our focus on only LMPs therefore does not cover the full impact to generator revenues. Moreover, as the analysis in this chapter also does not address the cost of VRE or the cost of transmission, it does not assess the full costs of electricity supply (for more on this topic as it relates to VRE, see Chapter 5). Second, many contracts between generators and loads exist outside of spot markets. In this case, the LMP establishes the opportunity cost of not selling into or buying from the spot market but it does not necessarily have a direct impact on contracting parties. Finally, several regions of the country lack liquid LMP-based spot markets; our analysis of LMPs is only partially relevant for those regions.

3.3 Impacts on Average Annual Historical Wholesale Electricity Prices

Several studies have used historical observations or simple models to estimate the impact of VRE on wholesale prices for different regions of the U.S. (Woo et al. 2011, 2013, 2014; Woo, Moore, et al. 2016; Gil and Lin 2013; Wiser et al. 2016; Jenkins 2017; Haratyk 2017). The addition of VRE with low marginal costs shifts the supply curve out to the right leading to lower wholesale prices, all else being constant; the same would be true for any low-marginal-cost generation source. Incentives for VRE to bid into markets at negative prices may accentuate this effect, but only when those bids are on the margin. This price reduction is often referred to as the 'merit-order effect', and is often touted as a benefit to consumers, though it is sometimes discussed as a transfer from suppliers rather than a net social benefit (Felder 2011).

Studies focused on the U.S. and their estimates of the effect of VRE on average wholesale prices are summarized in Table 1. For most studies, we report the effect of VRE as the decrease in the average RT wholesale price with the average amount of VRE over the study period, relative to the average price without the VRE; in two cases, however, the estimates represent the reduction in wholesale prices over time due to total growth in VRE. Where available, we also report the VRE penetration as the average VRE over the period relative to the average demand over the period. The empirically estimated reduction in average wholesale electricity prices from wind and solar range from $0-8.9/MWh, depending on the region, the time period of the analysis, the VRE technology and its level of penetration, and the study. A study focused on ERCOT finds higher merit order effects in the wind-rich West Texas region, where transmission constraints led to reduced and negative prices before Competitive Renewable Energy Zones (CREZ) transmission assets were completed in 2013 (EIA 2014).

Table 1. Average Wholesale Price Reduction Associated with VRE Growth

Study	Applicable Region	Time Period	Average VRE Penetration (% of demand)	Decrease in Average Wholesale Price from Average VRE
Woo et al. 2011	ERCOT	2007-2010	Wind: 5.1%	Wind: $2.7/MWh (ERCOT North) $6.8/MWh (ERCOT West)
Woo et al. 2013	Pacific NW (Mid-C)	2006-2012	N/A	Wind: $3.9/MWh
Woo et al. 2014	CAISO (SP15)	2010-2012	Wind: 3.4% Solar: 0.6%	Wind: $8.9/MWh Solar: $1.2/MWh
Woo et al. 2016	CAISO (SP15)	2012-2015	Wind: 4.3% Solar: 2.6%	Wind: $7.7/MWh Solar: $2.1/MWh
Gil and Jin 2013	PJM	2010	Wind: 1.3%	Wind: $5.3/MWh
Wiser et al. 2016[a]	Various regions	2013	RPS energy: 0%-16% depending on the region	RPS energy: $0 to $4.6/MWh depending on the region
Jenkins 2017[b]	PJM	2008-2016	N/A	Wind: $1-2.5/MWh
Haratyk 2017[b]	Midwest Mid-Atlantic	2008-2015 2008-2015	N/A	Wind: $4.6/MWh Wind: $0/MWh

Notes: a – Price effect is estimated impact of RPS energy relative to price without RPS energy in 2013 before making adjustments due to the decay effect discussed by the authors. b – Decrease in average wholesale price is based on change in wind energy from 2008-2016 (Jenkins 2017) or 2008-2015 (Haratyk 2017), rather than the decrease from average wind reported in other rows.

Additional studies, sometimes using more stylized and/or partial assessments, are not included in the table above. Makovich and Richards (2017), for example, find that wind in ERCOT reduced market-

clearing prices by one-third during the 2014 peak-demand period, but that "wind output wholesale price suppression around the average load segement is relatively modest because the supply curve is relatively flat." A quantitative assessment of the price suppression impacts outside of the peak-demand period is not provided, and no annual average estimate is presented. Makovich and Richards (2017) also exlore the impacts of wind in PJM in 2015, finding that wind output suppressed prices by 24% during the 15% of maximum net-load hours, 4% during the 15% of hours around average net load, and by 9% during the minimum net-load hours. Again, annual average impacts are not calculated. Hibbard, Tierney, and Franklin (2017) and Hogan and Pope (2017) present somewhat similar analyses, for PJM and ERCOT, respectively, but neither offers a clear assessment of historical impacts on annual average prices.

This sample of U.S. focused studies is a subset of a much broader literature of similar analyses of the price effect of wind and solar in Europe, with many of the studies summarized by Welisch, Ortner, and Resch (2016), Würzburg, Labandeira, and Linares (2013), and Bublitz, Keles, and Fichtner (2017). The range of the merit order effect in Table 1 is within the range of results for wind and solar in European countries as summarized in Welisch, Ortner, and Resch (2016). Additional studies—from Europe and the United States—explore possible future impacts from increasing shares of VRE: those studies are highlighted in Chapter 1, and a subset are summarized in Chapter 4 of this report.

Growth in VRE, of course, is not the only factor affecting average wholesale prices. We use a simple fundamental merit order model to quantify the contribution of different factors to the observed decline in wholesale prices between 2008 and 2016 for the CAISO, a region with recent growth in both utility-scale and distributed solar, and ERCOT, a region with significant growth in wind (Figure 7). We select these two regions for two primary reasons: (1) they represent regions with among the highest shares of VRE, and (2) as single-state ISOs, they are relatively easier to model than multi-state markets.

The simple fundamental model uses a merit-order supply curve based on individual generator capacity and marginal costs along with hourly observed demand and VRE production to estimate hourly prices. Following generally similar approaches used to explain the decrease in wholesale prices in Germany (Kallabis, Pape, and Weber 2016; Hirth 2018; Bublitz, Keles, and Fichtner 2017)[18] as well as in the Midwest and Mid-Atlantic (Haratyk 2017), we isolate the impact of each individual factor on the decline in wholesale prices by holding all factors from 2016 fixed except for one that is changed from its 2016 value to its 2008 value.[19] For example, we estimate the impact of growing amounts of renewable energy by changing the renewable electricity supply from its 2016 value to its 2008 value, while keeping other factors constant at their 2016 levels. Green bars represent the estimated magnitude of each factor that contributed to a decline in wholesale prices between 2008 and 2016, whereas red bars represent factors that mitigated the price decline over the same period.

The results presented in Figure 7 were found using 2016 as the base year. Alternatively, we could have held all factors at their 2008 level and changed each driver to its 2016 level (i.e., 2008 as the base year). The higher natural gas prices in 2008 lead to a steeper supply curve, which tends to increase the effect of individual factors. For completeness, we present the estimates of individual contributions to the overall price decline using both 2008 and 2016 as the base year in Table 2 and Table 3. For assessing the impact of current levels of VRE and potential implications in the near future, 2016 as the base year is the

[18] Somewhat more-stylized and partials attempts to conduct similar analysis in various regions of the United States can be found in: Hogan and Pope 2017; Hibbard, Tierney, and Franklin 2017; and Makovich and Richards 2017.

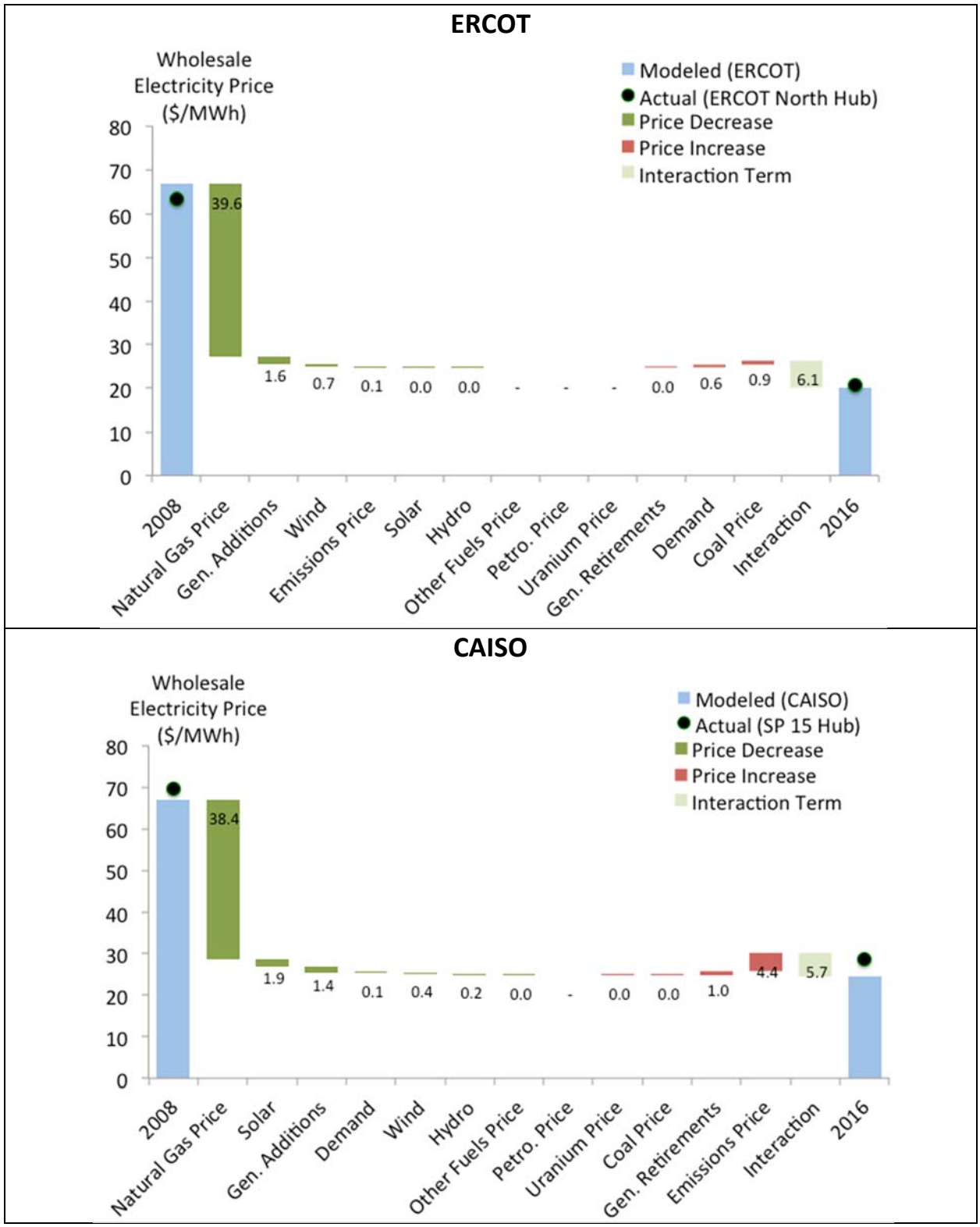
[19] Additional details on the methodology and data sources are provided in Appendix A.

more relevant starting point as natural gas prices are not anticipated to climb to their 2008 levels any time soon. We therefore focus the remainder of our discussion on results where 2016 is the base year.

Even with the many simplifications used to model wholesale power prices in this way, the supply curve model is able to reasonably match the 2008 and 2016 observed average wholesale prices in CAISO and ERCOT (see the comparison between the black markers and the blue bars in the figure). The model does not, however, replicate the hour-to-hour variability in prices since it ignores transmission constraints, operating limits on thermal generators, negative price bids from VRE, etc.; related, by only exploring market-wide averages, the model is not able to assess geographic variations in pricing as might be caused by transmission congestion.

With those caveats in mind, we do see clear evidence that the primary driver of the decline in average wholesale electricity prices between 2008 and 2016 in ERCOT and CAISO is the decline in natural gas prices. We find that growth in VRE generation contributed less than 5% to the overall price decline, whereas natural gas price reductions contributed 85-90% of the overall decline in wholesale electricity prices in these markets. Other factors considered in the model include: other types of generation additions (typically natural gas); changes in emissions allowance prices; changes in coal, oil, uranium, and other fuel prices; generation unit retirements; changes in electricity load; and variations in hydropower output. The 'interaction' term, meanwhile, represents the difference between the 2008 and 2016 modeled wholesale prices that this method was not able to attribute to individual factors due to interactions between multiple factors. For example, we show the impact of VRE and natural gas when changed individually, but they likely have a different impact when changed simultaneously. In summary, these various additional factors also individually contribute to accelerating or mitigating the overall price decline in ERCOT and CAISO, but, as with VRE, all are minor contributors compared to natural gas price shifts.

These findings are consistent with recent analysis focused on wholesale prices affecting nuclear plants in Illinois. In particular, using statistical techniques, Jenkins (2017) estimates the drivers for wholesale price reductions from 2008 through 2016, finding that the decline in natural gas prices was the dominant factor, resulting in wholesale price reductions of roughly $20/MWh (42-43% reduction). Growth of wind in MISO and PJM was found to have a much smaller effect of ~$1-2.5/MWh (2-5% reduction). Haratyk (2017), meanwhile, estimates the drivers for wholesale price reductions from 2008 to 2015 in the Midwest and Mid-Atlantic regions, finding that natural gas price declines and load reductions were the two dominant drivers with growth in wind playing a relatively smaller role. Future research should extend this and related work to a larger number of regions and pricing hubs in order to determine how generalizable the results are over time and in a larger number of localities.



Note: 2016 used as the base year.

Source: LBNL analysis using simple supply curve model and data from ABB Velocity Suite, EIA, and assumptions.

Figure 7. Estimated Contribution of Various Drivers to the Observed Decline in Average Wholesale Electricity Prices in ERCOT and CAISO

*Table 2. Estimated Contribution of Various Drivers to 2008-2016 Price Decline with **ERCOT** Model with 2008 as the Base Year or 2016 as the Base Year*

Base Year	Natural Gas Price	Non-VRE Generation Additions	Wind Addition	Emissions Price	Solar	Non-VRE Generation Retirements	Coal Price	Demand	Interaction
2008	$-47 (-99%)	$-5.5 (-12%)	$-5.9 (-13%)	$0.0 (0%)	$-0.1 (-0%)	$0.4 (1%)	$0 (0%)	$3.2 (7%)	$7.6 (16%)
2016	$-40 (-85%)	$-1.6 (-3%)	$-0.7 (-2%)	$-0.1 (-0%)	$0.0 (0%)	$0.0 (0%)	$0.9 (2%)	$0.6 (1%)	$-6.1 (-13%)

Note: Contribution of individual factors are shown in $/MWh and in percent of modeled price change between 2008-2016; effect of petroleum fuel price, uranium fuel price, other fuel price and hydro was less than $0.1/MWh for both 2008 and 2016 as base years, and are not shown in table.

Source: LBNL analysis using simple supply curve model and data from ABB Velocity Suite, EIA, and assumptions

*Table 3. Estimated Contribution of Various Drivers to 2008-2016 Price Decline with **CAISO** Model with 2008 as the Base Year or 2016 as the Base Year*

Base Year	Natural Gas Price	Non-VRE Generation Additions	Solar Addition	Demand	Wind Addition	Non-VRE Generation Retirements	Emissions Price	Interaction
2008	$-44 (-103%)	$-5.3 (-13%)	$-7.0 (-16%)	$-0.7 (-2%)	$-1.8 (-4%)	$7.8 (18%)	$4.7 (11%)	$4.3 (10%)
2016	$-38 (-90%)	$-1.4 (-3%)	$-1.9 (-4%)	$-0.1 (-0%)	$-0.4 (-1%)	$1.0 (2%)	$4.4 (10%)	$-5.7 (-13%)

Note: Contribution of individual factors are shown in $/MWh and in percent of modeled price change between 2008-2016; effect of petroleum fuel price, coal price, uranium fuel price, and other fuel prices was less than $0.1/MWh for both 2008 and 2016 as base years, and are not shown here; effect of hydro was less than 1% for both 2008 and 2016 as base years, so is also not shown in the table; solar includes utility and distributed, while demand is not affected by DPV growth from 2008-2016.

Source: LBNL analysis using simple supply curve model and data from ABB Velocity Suite, EIA, and assumptions

3.4 Impacts on Historical Wholesale Price Variability

Prevalence and Impact of Negative Pricing at Selected Pricing Hubs

In addition to affecting average wholesale prices, VRE can impact wholesale price variability, which may be particularly evident by tracking the frequency of negative prices. Negative prices typically arise from surplus supply along with technical or economic constraints that prevent reductions in generation output. Transmission limitations tend to be an accelerant of negative pricing, driving prices lower in congested markets as the surplus supply is unable to find other markets to which to sell. As negative pricing is a symptom of excess supply, it is not surprising that the prevalence of negative pricing is greater during periods with lower system-wide load. The PTC and RPS programs that prioritize generation from renewable resources provide an incentive for renewable generators to continue to produce energy even when the energy price is negative. Rigid contracts that do not allow for economic curtailment yield similar results. Even market demand for 'green energy' yields positive prices for RECs, creating incentives for negative-price bids by VRE. Of course, VREs are not the only resources that bid negative prices in wholesale electricity markets. The lack of flexibility from existing nuclear power plants in the United States, for example, means that these plants will often bid negative prices to avoid costly shutdowns and start-ups. Fossil units (whether coal or natural gas) may also—at times—bid negative prices due to the costs of flexible operations. Even hydropower plants sometimes generate during negative-priced hours, in some cases due to run-of-river operations and in others as a result of

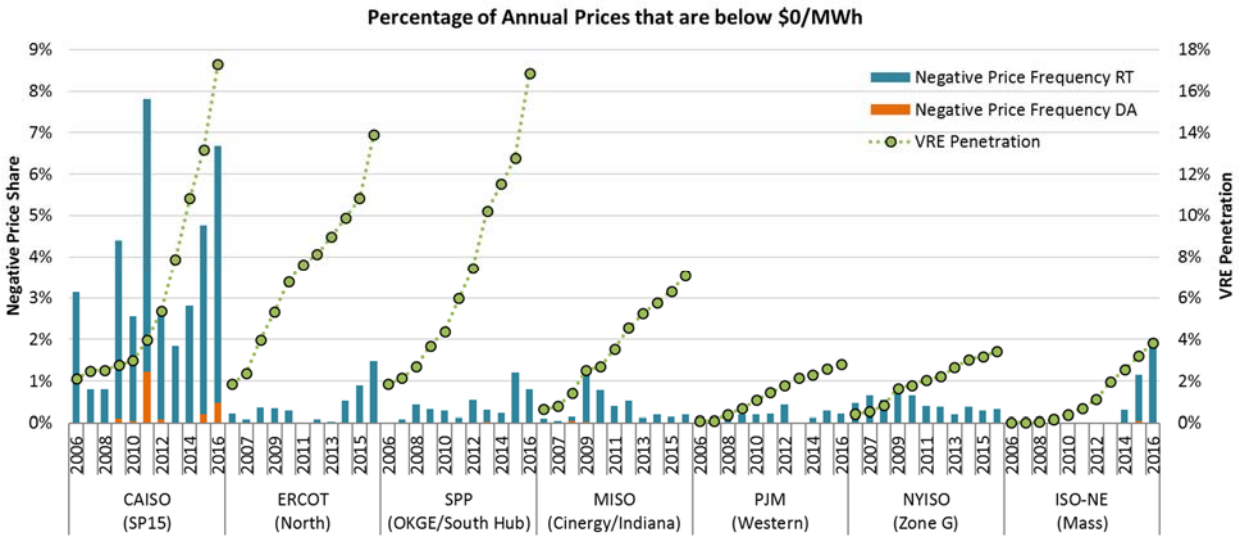
environmental constraints. Other units may have contractual requirements that create the same incentives for negative bidding, or may be required to operate for reliability purposes regardless of market pricing. The fact that many types of power plants—at times—continue to generate power when prices at major hubs are negative is demonstrated below.

In this section, we summarize the frequency, impact, and causes of negative pricing at a select set of larger pricing hubs; a later section then places additional emphasis on a small number of constrained areas, where the prevalence and impact of negative pricing is more substantial. We do not discuss or evaluate measures to reduce negative price bidding, but note that physical, institutional, and market and policy design options exist to increase power system flexibility, thereby reducing the prevalence of price fluctuations including negative prices. Some of these options come at a cost, however, necessitating tradeoffs between the cost and value of such investments or market design revisions.

Overall, the frequency of negative prices at a select number of large electricity pricing hubs (Figure 8) indicates that negative prices in most of these hubs continue to be rare, and almost non-existent in day-ahead prices, though there is some indication of increased frequency of negative real-time prices with increasing shares of VRE resources. The SP15 hub in CAISO shows a markedly higher frequency of negative real-time prices than other hubs (6.6% in 2016, compared to 2% or less in all other selected hubs shown in the figure), and the frequency is expected to rise significantly in 2017 due to growth in VRE and high hydropower production (Trabish 2017). Several initiatives in the West including expansion of the CAISO Energy Imbalance Market, potential regional expansion of CAISO to include PacifiCorp and other interested utilities, and improved coordination and utilization of transmission capacity with the Pacific Northwest may all help mitigate this increase in negative price frequency over time (Trabish 2017). Even in CAISO, however, it is clear that VRE is not the only contributing factor to negative prices. The highest share of negative price hours occurred in 2011 (nearly 8% of hours in real-time market and over 1% of hours in day-ahead market), before the recent large-scale growth in solar.

Outside of CAISO, the figure suggests that recent growth in VRE may be contributing to negative real-time pricing at the selected major trading hubs in ERCOT, SPP, and perhaps in ISO-NE: in all three regions, the prevalence of negative pricing has increased recently, along with the growth in VRE, demonstrating correlation if not causation.[20] The same cannot be said for the selected major hubs in MISO, PJM, and NYISO, however. If anything, the prevalence of negative pricing in these specific hubs has declined in recent years, though other research suggests that pricing at still other hubs in these areas has been impacted by the growth in VRE (Bajwa and Cavicchi 2017). Regardless, at all of these specific hubs, negative pricing remains rare. In the real time market, negative pricing occurred 2% of hours or less in 2016; in the day ahead market—which is most relevant for inflexible baseload generation—negative pricing outside of California has been almost non-existent at these specific hubs.

[20] Further analysis of the time- and geographic- profile of negative pricing events can help identify some of the causes. For example, Hogan and Pope (2017) find that the profile of negative pricing in ERCOT is correlated with wind production and CAISO (2017b) shows that negative prices occurred during daytime hours in 2016, times of high solar, whereas most were during night-time hours in 2012. Bajwa and Cavicchi (2017) review numerous hubs in many of the U.S. ISOs/RTOs, tracking negative pricing trends over time and diurnally, finding that the trends in negative price hours is suggestive of a VRE impact.



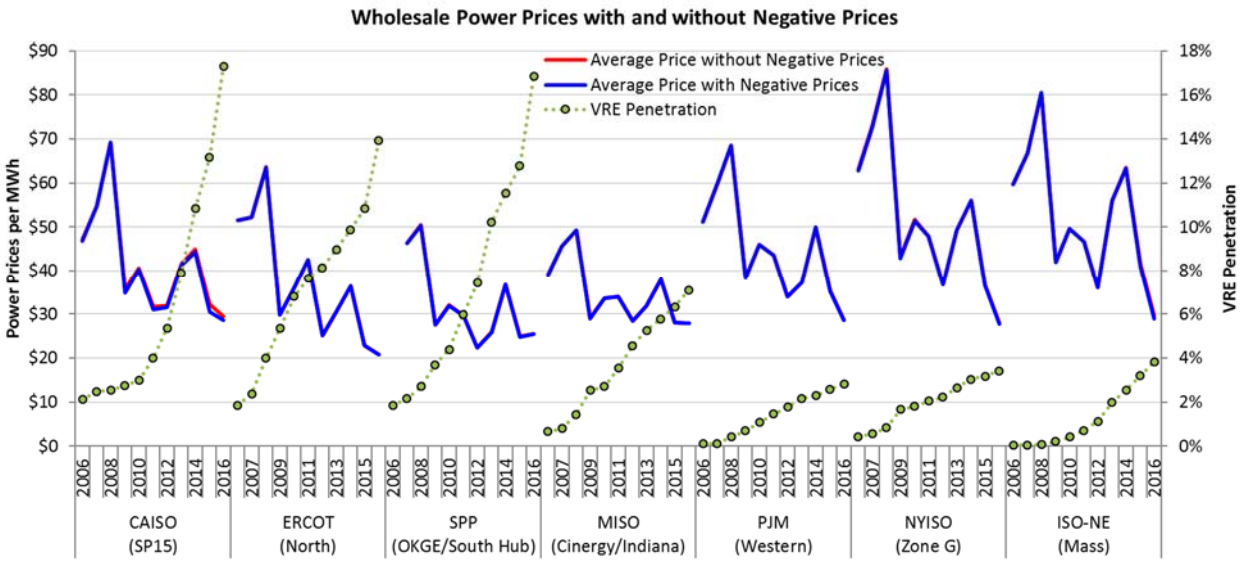
Sources: Negative price share comes from LBNL analysis of ABB Velocity Suite data. VRE regional penetration estimates come, in part, from annual wind generation reported in ABB's Velocity Suite divided by total generation in the region. Since ABB does not include generation <1 MW and since large-scale solar generation data were incomplete for the year 2016, we estimate solar generation based on state-level capacity, and regional capacity factors from NREL. Distributed solar generation is also added to total generation when calculating VRE penetrations.[21]

Figure 8. Frequency of Negative Wholesale Electricity Prices in the Real-Time and Day-Ahead Markets at Several Major Trading Hubs

Given the rarity of negative pricing at most of these major trading hubs so far, it comes as little surprise that they have had almost no impact on average day-ahead prices (not shown) and little impact on average real-time wholesale electricity prices at these specific hubs (Figure 9). Here we estimate the real-time wholesale price had there been no negative prices by comparing the actual average wholesale price to the average after replacing negative prices with $0/MWh. In effect, this removes any potential impact of policies like the PTC or RPS that would incentivize a VRE generator to submit a negative bid, though it also removes any impact of inflexible generation that sets the price with a negative bid.

Among these specific hubs, a noticeable effect is apparent in CAISO, where real-time wholesale prices in 2015 were $1.7/MWh (6%) lower due to negative prices than they would have been without negative prices. This gap equals $0.9/MWh (3%) in 2016, and is expected to grow in the near term due to increases in VRE and high river flows driving increased production from hydropower facilities. At all other large trading hubs explored here, negative prices have had no noticeable effect on the *annual average* day-ahead or real-time wholesale prices for every year examined.

[21] Based on our calculation the VRE penetration in CAISO is 17.3% of in-region generation. Readers may be more familiar with penetration numbers based on served load. Accounting for distributed solar in both generation and load estimates, the CAISO VRE penetration is 16.1% of served load.



Source: LBNL analysis of ABB Velocity Suite data with VRE regional penetration estimates as described earlier.

Figure 9. Impact of Negative Prices on Average Wholesale Electricity Prices in the Real-Time Market at Several Major Trading Hubs

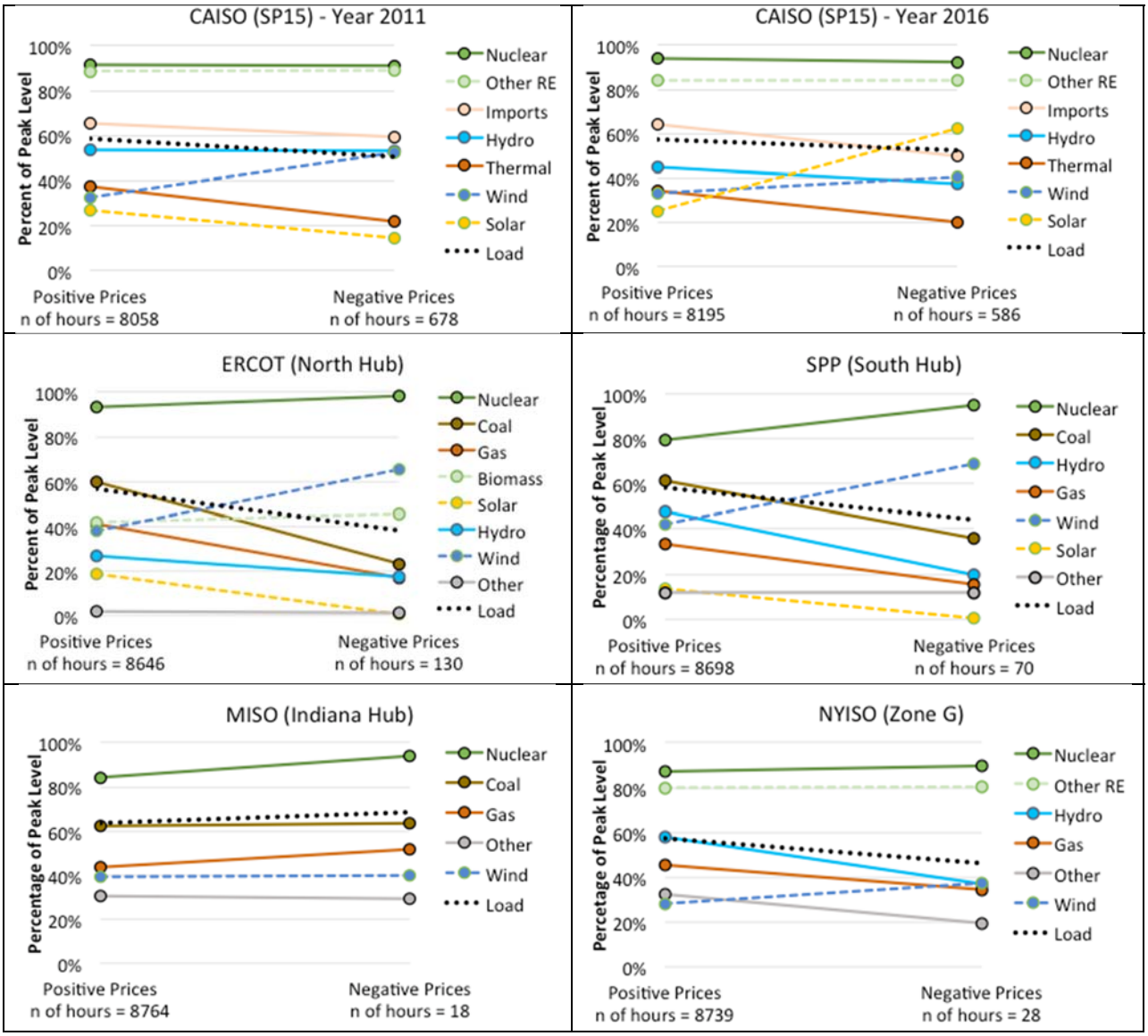
The prevalence of negative prices will be higher than reported here at locations near significant amounts of VRE or other types of inflexible generation, especially where transmission constraints do not enable market integration with broader regions (Bajwa and Cavicchi 2017). Here we focus on major trading hubs, as these hubs are of most relevance to loads and most other generators. Later in this chapter, however, we focus narrowly on two constrained trading hubs where noticeably higher levels of negative pricing are apparent.

Contributors to Negative Pricing at Major Hubs

To understand which resources are potentially contributing to negative real-time prices at the selected major pricing hubs, we utilize hourly aggregate generation data provided by five ISOs (CAISO, ERCOT, SPP, MISO, and NYISO[22]). Specifically, we compare average generation—by generation type—during positive price hours to average generation during negative price hours in 2016 (Figure 10 and Figure 11).[23] Figure 10 also shows total system-wide load during positive and negative price hours in 2016. Note that some of the regions have a very low number of negative price hours, making generalizations difficult. Since the frequency of negative prices in CAISO was highest in 2011 we include an analysis of 2011 for CAISO in addition to 2016.

[22] PJM only reports hourly wind generation, but not aggregate generation from other resources. ISO-NE does not report hourly aggregate generation of any resource. As such, neither PJM nor ISO-NE are included in this analysis.

[23] In contrast to our approach, Goggin (2017) explores the frequency of negative pricing hours that are specifically of the magnitude one might expect from the PTC and RPS. This method is appropriate if one is only interested in the 'bidding effect' of the PTC and RPS in inducing negative-priced bids. However, as described earlier, VRE can also influence the prevalence of negative prices in wholesale markets though the 'deployment effect' by virtue of affecting the supply stack with large volumes of zero-marginal-cost generation. Our approach implicitly accounts for both effects.



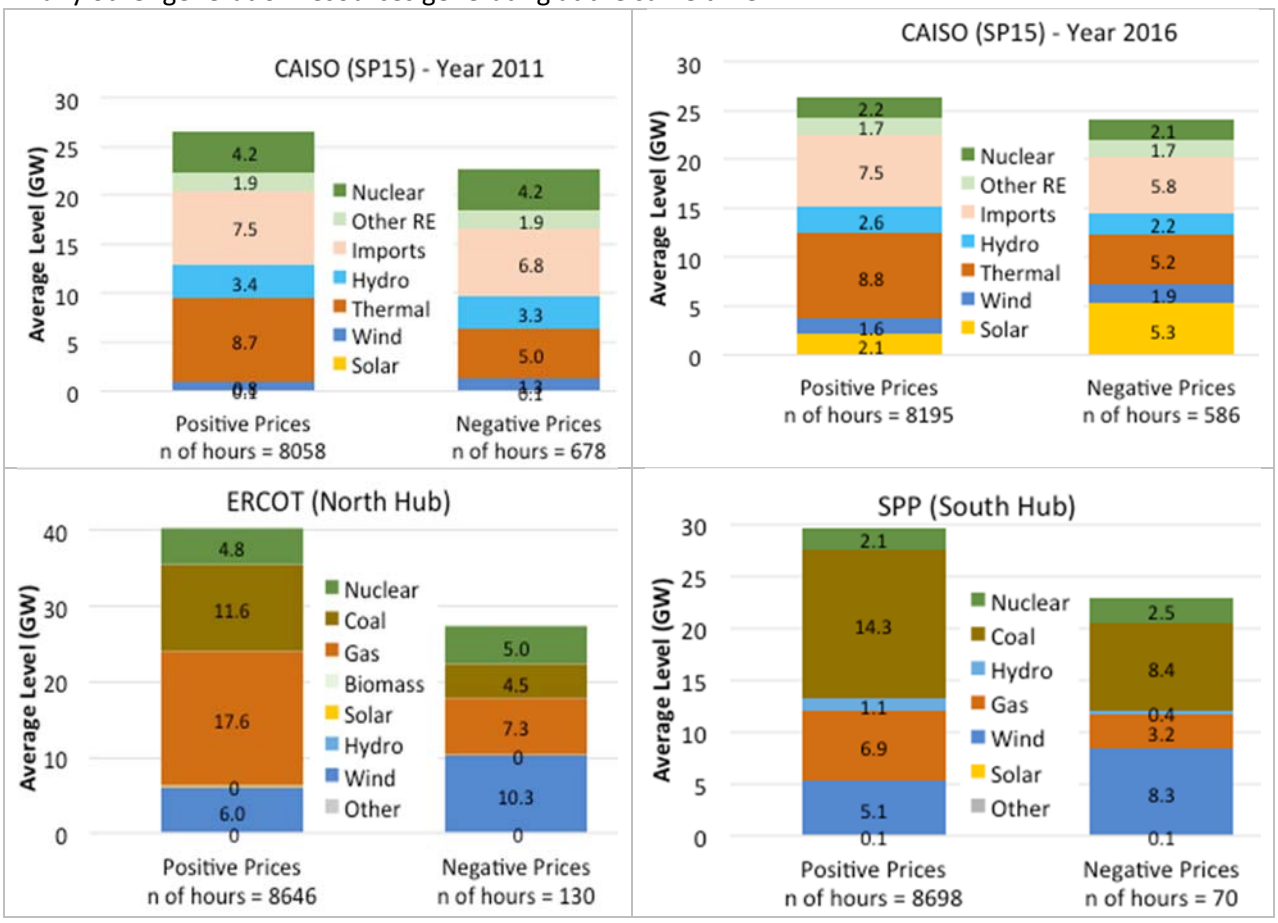
Source: LBNL analysis of ABB Velocity Suite data.

Figure 10. Generation of Various Resources during Positive and Negative Price Periods in 2016 as a Percentage of the Peak Level Observed in 2016 (and, for CAISO, also 2011)

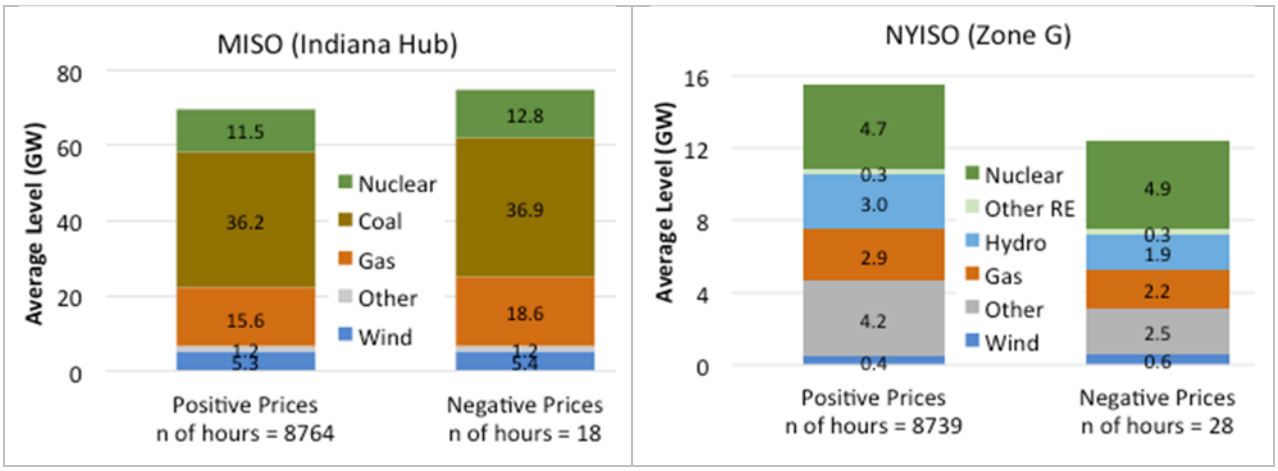
Starting with Figure 10, except in MISO, negative prices in 2016 occurred at times when aggregate system load was, on average, lower than load during positive price times. VRE also tended to generate more during negative price hours at major hubs than during positive price hours, though the contribution of VRE varies by technology and region. In 2016, solar in CAISO is clearly generating more during negative price hours at the SP15 hub, on average, than during positive price hours. But, in 2011, solar in CAISO was generating less on average during negative price hours at the SP15 hub. Solar was not generating at all during negative prices in 2016 in ERCOT or SPP. Wind is almost always generating more—on average—during negative price hours, with the exception of the few negative price hours at MISO's Indiana Hub. In contrast, more flexible generation like hydro and gas tend to produce significantly less power on average during negative price hours than during positive price hours. Coal in

ERCOT and SPP similarly produces less during negative price hours. Nuclear plants tend to operate at full power during periods of negative prices, and also during periods of positive prices.[24]

The charts in Figure 10 are useful in understanding the per-MWh impact of different sources in impacting negative price hours and highlight the responsiveness of different resources to negative prices. They do not, however, illustrate the magnitude of the different resources during negative price hours. Figure 11 therefore compares average generation—by generation type—during positive price hours to average generation during negative price hours in 2016 (and 2011 for CAISO) focusing on the *absolute* generation level. Even though negative prices had the highest frequency in 2011 at the SP15 hub in CAISO, comparison of the absolute level of generation in 2011 and 2016 shows that VRE was much lower in 2011. In 2011, hydropower and nuclear were considerably higher than in 2016 in both positive and negative price hours; imports also decreased to a lesser degree in 2011 during the negative price hours. As shown earlier in Figure 8, the frequency of negative prices dropped in 2012; this timing correlates with the 2 GW San Onofre Nuclear Generating Station being taken offline as well as a decline in hydropower output; the effect of hydropower on historical negative price events in California and the Northwest is also coverered in Davis (2017). This illustrates that the drivers for negative pricing are not limited to VREs but also arises during periods without much flexibility but with significant nuclear and hydropower generation. While VRE resources are generating more in negative price hours there are also many other generation resources generating at the same time.



[24] The lower average generation during positive price hours relative to negative price hours for nuclear plants in SPP and MISO was due to large nuclear outages that occurred during periods of positive prices. These outages led to lower nuclear production over the year, though the plants were closer to full output during negative price hours.



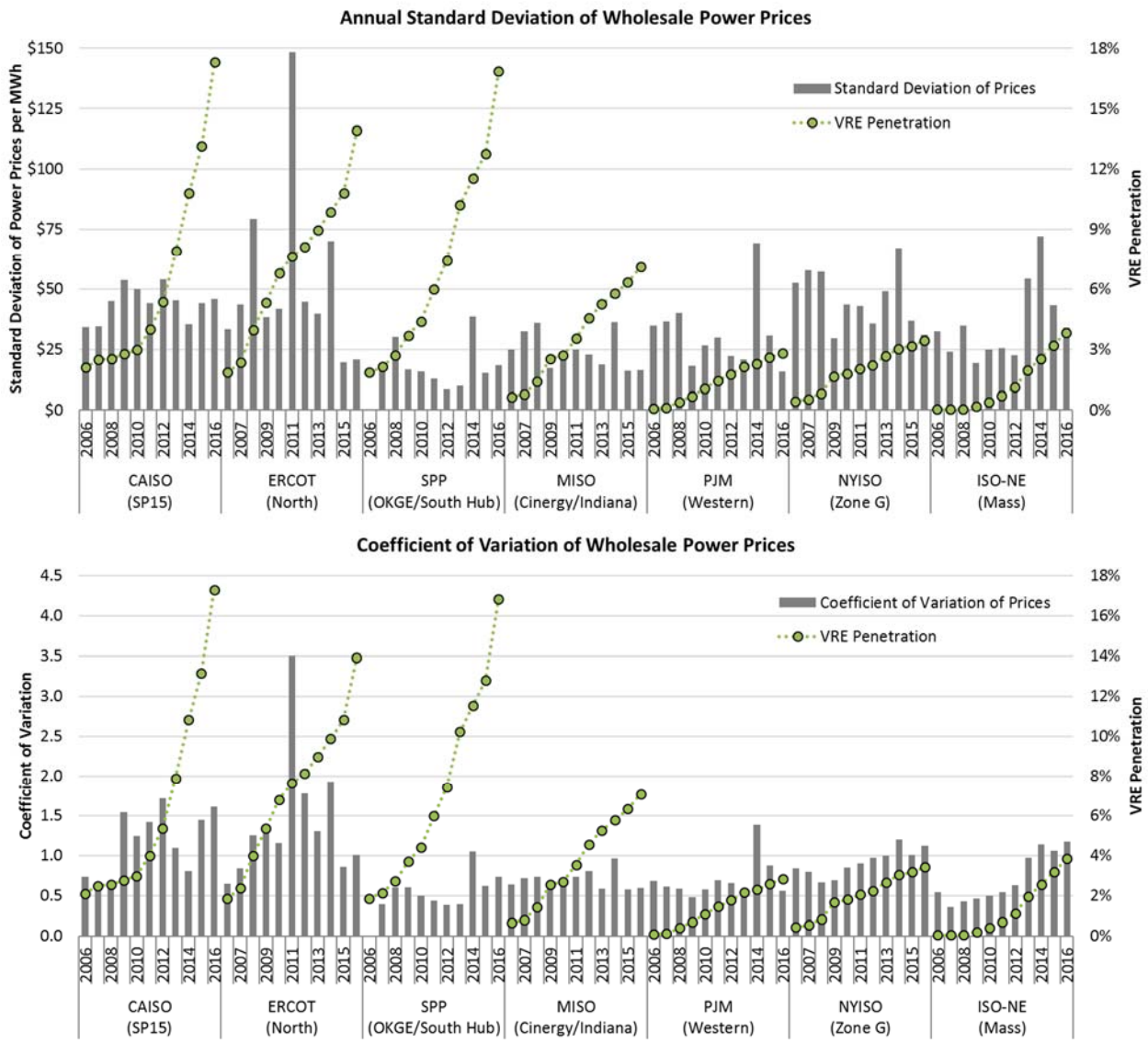
Source: LBNL analysis of ABB Velocity Suite data.

Figure 11. Generation of Various Resources during Positive and Negative Price Periods in 2016 (and, for CAISO, also 2011)

Other Indicators of Price Variability: Volatility, High-Price Events, and Temporal Variations

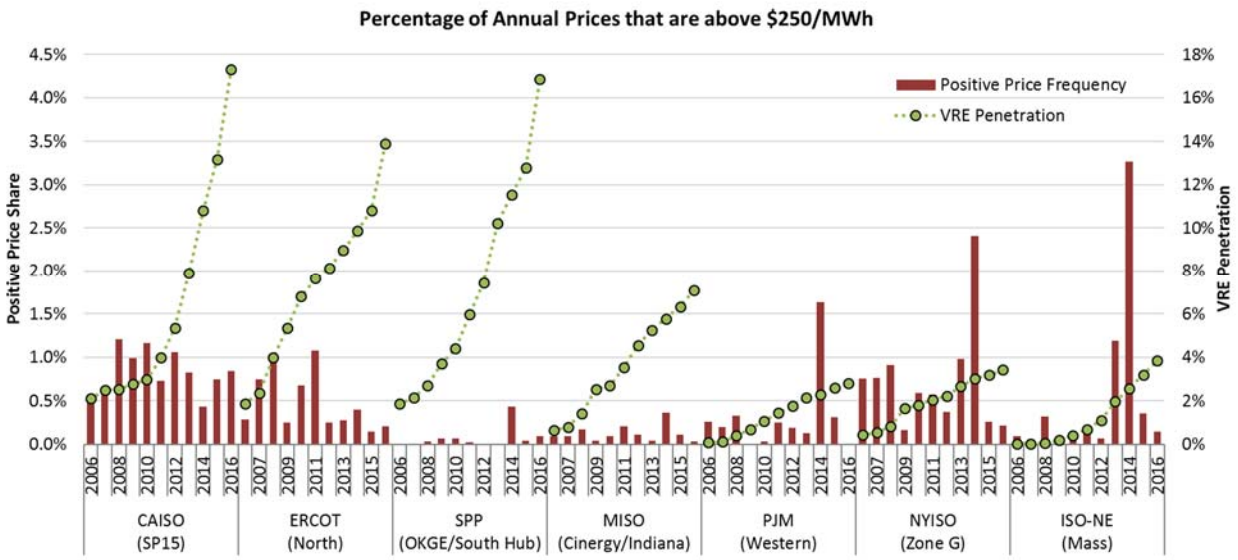
Wholesale electricity prices are also expected to become more volatile with increasing shares of VRE. Woo et al. (2011), for example, predicts that a 10% increase in wind will increase the variance of wholesale prices by 1% in ERCOT North and 5% in the wind-rich ERCOT West; other work, however, has found that growth in wind has had a particularly large price-suppression effect during peak-hour periods, at least in ERCOT and PJM (Makovich and Richards 2017).

We examined the volatility of real-time prices for each year at the selected major hubs, but did not find any compelling trends over time as it relates to increasing VRE penetrations (Figure 12). We show this volatility in pricing both in absolute terms (the standard deviation) and after normalizing the standard deviation of real-time prices by the annual mean (the coefficient of variation). The coefficient of variation hints at a correlation of increasing volatility with increasing VRE penetration, though it may be just an artifact of the shrinking denominator (the declining average wholesale price) over this period. We similarly did not find obvious trends in the frequency of price spikes above $250/MWh as it solely or specifically relates to growing shares of VRE (Figure 13). Major weather events that led to high prices had a very significant impact on volatility and the frequency of price spikes—the 2011 Southwest cold-weather event in ERCOT (FERC and NERC 2011) and the Polar Vortex for PJM, NYISO, and ISO-NE (NERC 2014)—but visual inspection of these trends relative to VRE penetration does not reveal an obvious major driver. The market monitor for ERCOT, however, has suggested that higher volatility in the spring and fall months of 2015 and 2016 is associated with higher wind volatility and load and wind forecast errors (Potomac Economics 2017b). Additional, more-sophisticated analysis would be needed to explore these trends further.



Source: LBNL analysis of ABB Velocity Suite data with VRE regional penetration estimates as described earlier.

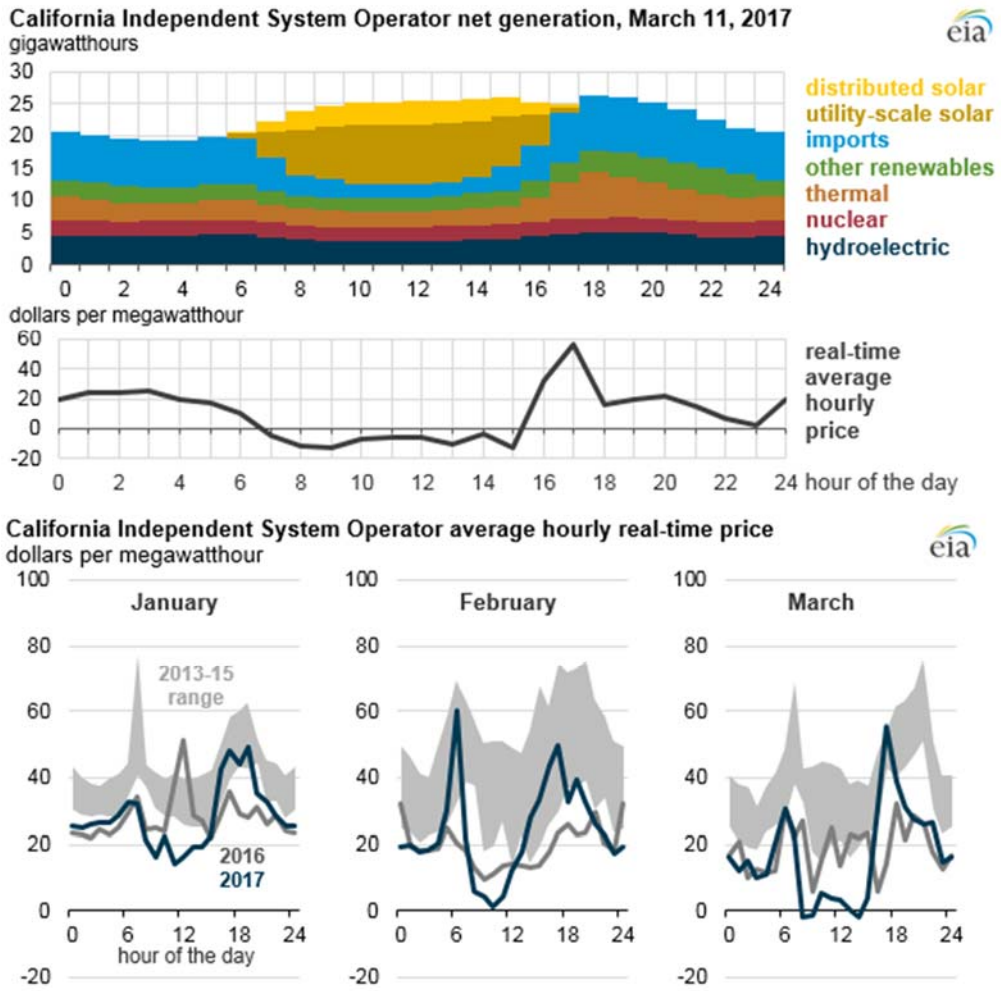
Figure 12. Standard Deviation and Coefficient of Variation of Wholesale Electricity Prices in the Real-Time Market at Several Major Trading Hubs



Source: LBNL analysis of ABB Velocity Suite data with VRE regional penetration estimates as described earlier.

Figure 13. Frequency of Positive Spikes in Wholesale Electricity Prices (>$250/MWh) in the Real-Time Market at Several Major Trading Hubs

The temporal patterns of wholesale electricity prices are also changing as a result of growth in VRE supply. Nowhere is this more apparent than in CAISO, where strong solar output can reduce prices during sunny mid-day periods (especially when hydro runoff is also significant, and load is low), but then cause prices to increase as the sun sets and other generation resources respond to the system's net-load ramp. Figure 14 presents data consistent with these trends for a single weekend day (top) and for typical patterns for January through March for the years 2013- 2017; the same impacts are generally less apparent during other parts of the year given lower levels of hydropower and/or higher loads. CAISO analysis of the timing of negative prices, meanwhile, shows that negative prices were more common in daytime hours in 2016 whereas negative prices were more common in night-time hours in 2012 (CAISO 2017b).

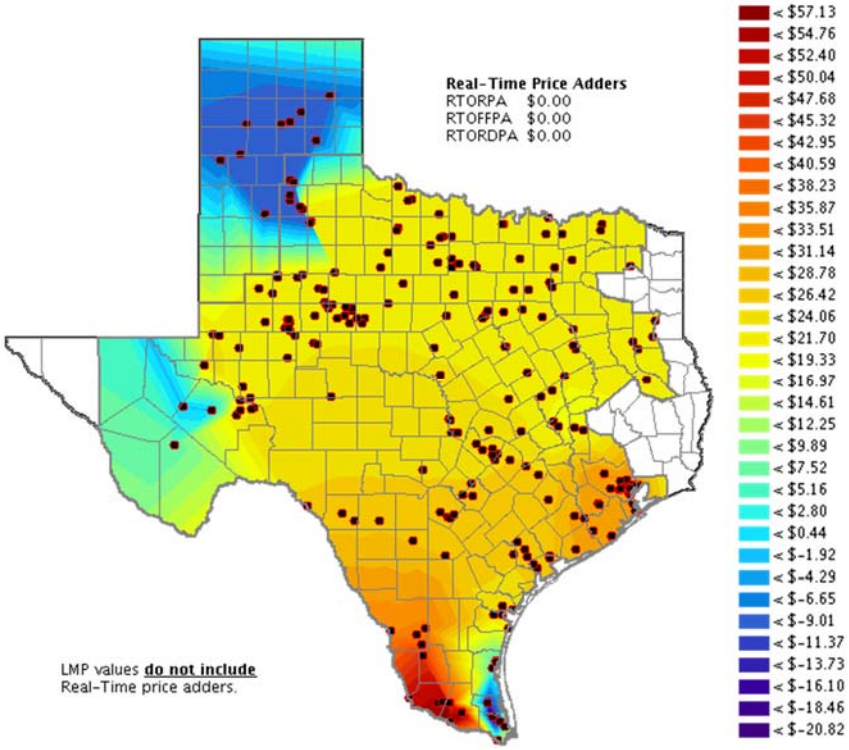


Source: EIA "Today in Energy," April 17, 2017; https://www.eia.gov/todayinenergy/detail.php?id=30692.

Figure 14. Temporal Variations in CAISO Wholesale Prices in Part as a Result of Solar Generation

Locational Impacts: The Influence of Transmission Limits on Specific Trading Hubs

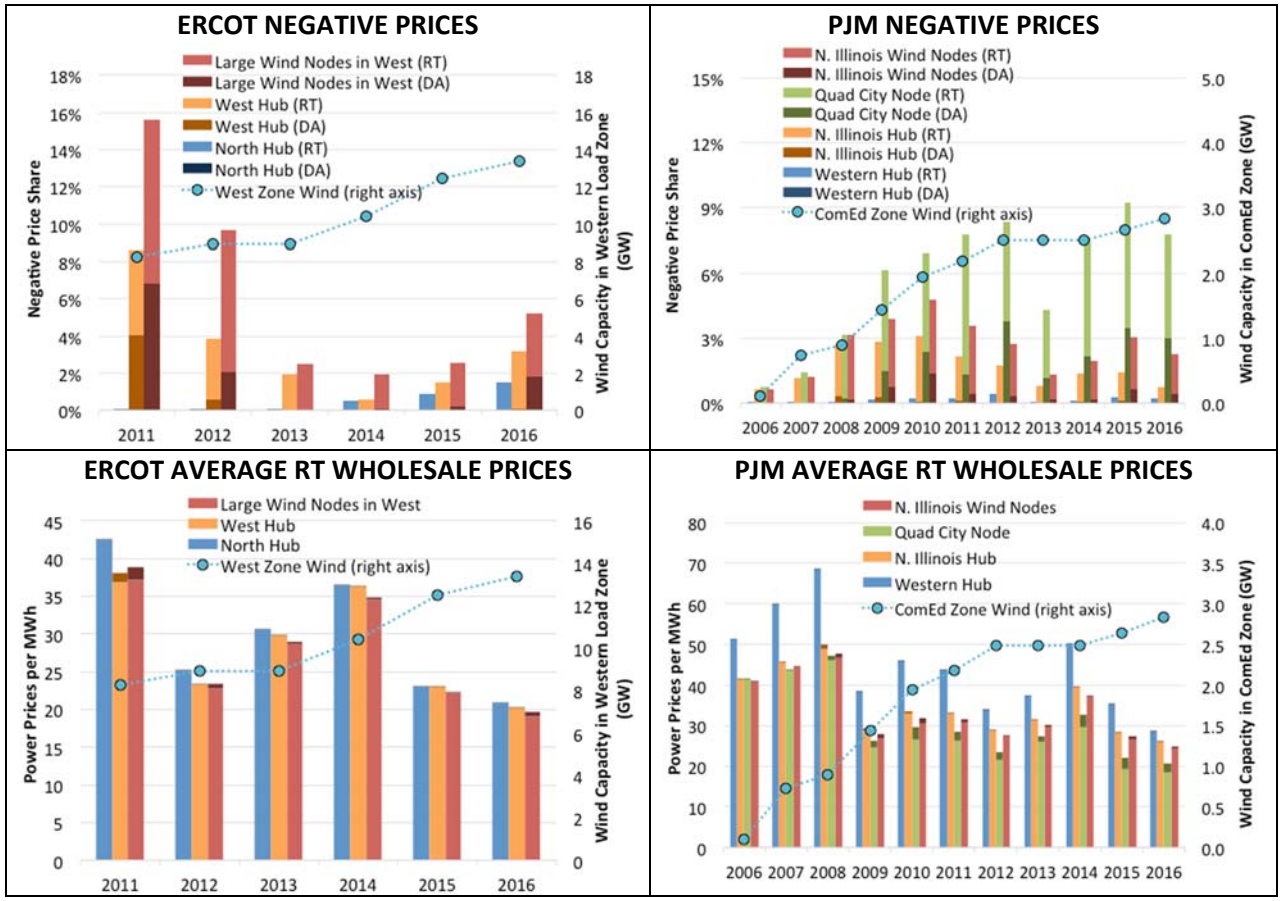
Major trading hubs do not reveal the full story of VRE impacts. Transmission limits between where generation is located and load centers can lead to congestion and a higher prevalence of negative pricing in constrained zones and nodes. According to a recent report by DOE, for example, PJM has indicated that impacts can be more severe on specific buses, and can impact the economics of specific generating units. In particular, PJM observed that "Since 2014, PJM has seen prices go negative at nuclear unit buses in approximately 2,176 hours—representing 14 percent of off-peak hours" (DOE 2017). West Texas, meanwhile, is a wind-rich region in ERCOT. Transmission investments through the CREZ initiative started to be completed in 2011, significantly reducing congestion in West Texas and the prevalence of negative price hours in that region. However, price differentials between wind-rich parts of the state and the rest of ERCOT still occur (Figure 15, for example, shows real-time LMPs at a specific point of time for the entire ERCOT region).



Source: http://www.ercot.com/content/cdr/contours/rtmLmpHg.html; Real time LMP on May 11, 2017, at 12:10

Figure 15. ERCOT Real-time Price Contour Map on a Recent Day

To more systematically demonstrate the geographic differences in wholesale prices between major trading hubs and selected pricing nodes, Figure 16 compares the frequency of negative day-ahead and real-time prices and average annual real-time prices between the ERCOT North Hub, the ERCOT West Hub, and the average of ten pricing nodes in the West zone with the largest amount of wind power in 2016. Negative prices in real-time and day-ahead markets were significantly more prevalent in the wind-rich regions in 2011 and 2012 at the start of the CREZ transmission expansion, before declining dramatically through 2014 as the CREZ lines were completed (Potomac Economics 2017b). Average annual real-time prices at the ERCOT West hub and the ten selected wind-rich pricing nodes have consistently been lower than prices at ERCOT North. Negative prices, in particular, caused the average *real-time* price at wind nodes to be nearly $2/MWh (5%) lower than they would have been without negative prices in 2011, though by 2016 the impact of negative prices was less than $0.6/MWh (3%). Negative prices caused the average *day-ahead* price at wind nodes to be $0.5/MWh (1%) lower than without negative prices in 2011, dropping $0.2/MWh (1%) less in 2016 (note, day-ahead prices are not shown in the figure). Negative prices—while still rare—are again on the rise since 2014 as wind penetration continues to increase in ERCOT; moreover, negative real-time prices are now spreading outside of the wind-rich West zone (see also, Hogan and Pope (2017) and Bajwa and Cavicchi (2017), which also evaluate ERCOT pricing).



Note: Average real-time prices without negative prices are shown as the dark band on top of the average wholesale prices with negative prices.
Source: LBNL analysis of ABB Velocity Suite data.

Figure 16. Comparison of Frequency of Negative Prices and Average Real-Time Prices between Major Trading Hubs and Constrained Nodes in ERCOT and PJM

The same comparison is conducted for the PJM Western Hub (in Pennsylvania) and the N. Illinois Hub, the latter of which is near a large nuclear plant (Quad City) and several wind plants in the ComEd zone of PJM (Figure 17); we therefore compile data on pricing at the two hubs, but also at the Quad City pricing node and various wind project pricing nodes (Figure 16 and Figure 17). Though negative pricing is infrequent at the PJM Western Hub, it is far more common at the other locations. This is particularly true at the Quad City node, where negative prices have occurred for more than 6% of the hours in seven out of the last eight years, and have reduced annual average *real-time* prices by roughly $2.3/MWh (10%) over the last eight years (Figure 18). Negative *day-ahead* prices have reduced the annual average day-ahead prices by less than $0.2/MWh (1%) over the same timeframe. The increase in the frequency of negative prices at the Quad City node tends to track the cumulative installed capacity of wind in the ComEd zone of PJM. On average, wholesale prices at the N. Illinois Hub, and at the Quad City and wind nodes analyzed here, are substantially lower than the PJM Western Hub. Persistent differences in LMPs across nodes may signal the need for additional investment in transmission to resource-rich areas. Additional factors to explore in future analysis include whether similar increases in negative prices are observed at other nuclear and other fuel plants in the ComEd region, additional factors other than

growth in wind that may be correlated with the increase in frequency of negative pricing, and the extent to which the frequency of negative prices would be reduced without the PTC.

Related to these additional analysis possibilities, the PJM market monitor reports that 3-5% of the marginal units in the real-time market in PJM were wind between 2012 and 2016 while less than 0.1% of the marginal units were nuclear between 2012 and 2015 and 1% were nuclear in 2016 (Monitoring Analytics 2017). MISO, meanwhile, has areas where local prices are frequently set by wind, even though wind set the system-wide marginal price less than 1% of the time in 2016 (Potomac Economics 2017c). Bajwa and Cavicchi (2017), meanwhile, explore the frequency and temporal profile of negative pricing in a wide variety of hubs across the United States.

Source: Power plant capacity and plant zip code from ABB Velocity Suite data, with locations estimated from zip codes.

Figure 17. Location of Quad Cities Nuclear Plant, Large Wind Pricing Nodes, N. Illinois Hub, and Western Hub in PJM

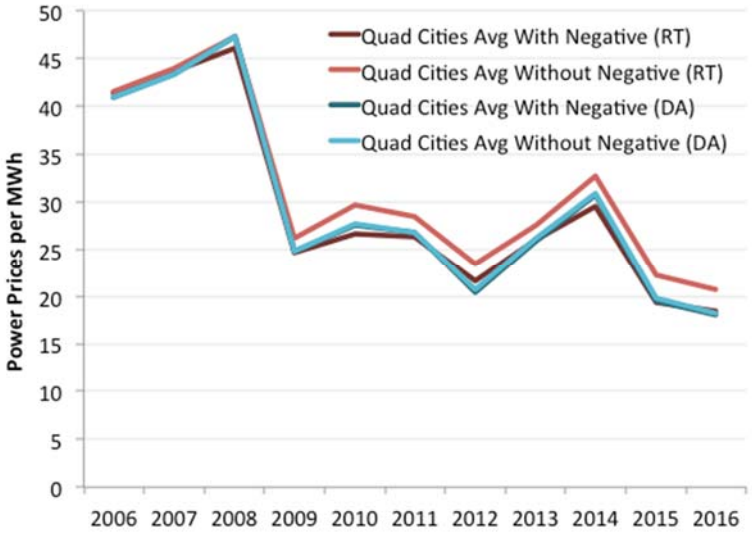


Figure 18. Average Wholesale Price (RT and DA) at the Quad Cities Node with and without Negative Prices

3.5 Impacts on Recent Thermal-Plant Asset Retirements

There has been a significant amount of retirements of thermal generation assets in recent years, with Mills, Wiser, and Seel (2017), EIA (2016), DOE (2017), and others finding that retiring coal and natural-gas plants tend to be older, smaller, less efficient, more-emitting, and operating at lower capacity factors than the remaining fleet. For example, as shown in Mills, Wiser, and Seel (2017), coal plants that retired between 2010-2016 had an average age of 52 years while coal plants that did not retire or are scheduled for retirement had an average age of 37 years in 2016. Retired coal plants had an average capacity of 122 MW, whereas plants not scheduled for retirment are larger at 239 MW on average. The heat rate of retired coal plants was slightly higher (10,386 Btu/kWh) than plants not scheduled for retirement (10,046 Btu/kWh), indicating that the plants that retired were also somewhat less efficient. The heat rate of retired gas plants (CCGT and CTs), meanwhile, was considerably larger than plants not scheduled for retirement. Finally, the most dramatic difference in the characteristics of retired coal plants compared to coal plants not scheduled to retire is the average SO_2 emissions rate: the average emissions rate of coal plants that retired between 2010-2016 was 1.2 lbs SO_2/MMBtu, while the emissions rate of the plants not scheduled for retirement was 0.2 lbs SO_2/MMBtu.

Plant retirements have been driven by a variety of market, policy, and plant-specific factors, with reductions in natural gas prices often identified as the most impactful single cause (Gifford and Larson 2017, 2016; EIA 2016; Hibbard, Tierney, and Franklin 2017; DOE 2017; Linn and McCormack 2017; Haratyk 2017). There is uncertainty, however, on the relative contributions of various factors, and on the specific role of VRE growth (Rode, Fischbeck, and Páez 2017; Pratson, Haerer, and Patiño-Echeverri 2013; BNEF 2017; Gifford et al. 2017; Houser, Bordoff, and Marsters 2017; Chang et al. 2017; DOE 2017; Makovich and Richards 2017; Linn and McCormack 2017).

The set of charts shown in Figure 19 correlate regional retirement percentages (2010-2016 retirements, relative to total non-VRE capacity in 2016) with a subset of possible factors that may be contributing to the strikingly different levels of recent retirement experienced in various regions. Most charts provide data points for both total thermal-plant retirements and, separately, only coal and nuclear retirements. In some cases, however, the investigated factors are most likely to affect only coal and/or gas plants; we focus in those instances solely on those plant types.

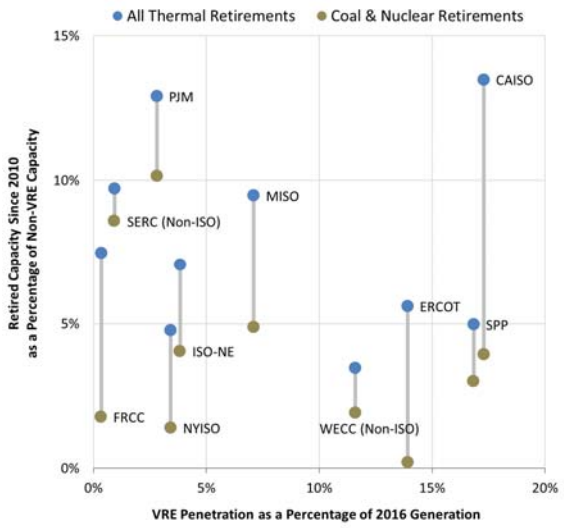
Nine specific possible explanatory factors are explored:

- VRE penetration in percentage terms, considering utility-scale wind and PV and distributed PV
- Regional growth (or contraction) in electrical load from 2010 to 2016
- Average planning reserve margin (based on summer capacity and peak loads) from 2010 to 2016
- Average SO_2 emissions rates of the 25% of coal plants in each region with the highest emissions
- Average percent sulfur content of coal delivered to the region from 2010 to 2015
- Ratio of delivered coal prices to delivered gas prices in the region from 2010 to 2016
- Average regional delivered natural gas price from 2010 to 2016
- Average age of the oldest 25% of thermal power plants in the region in 2010
- New non-VRE capacity additions since 2010 as a percentage of total non-VRE capacity

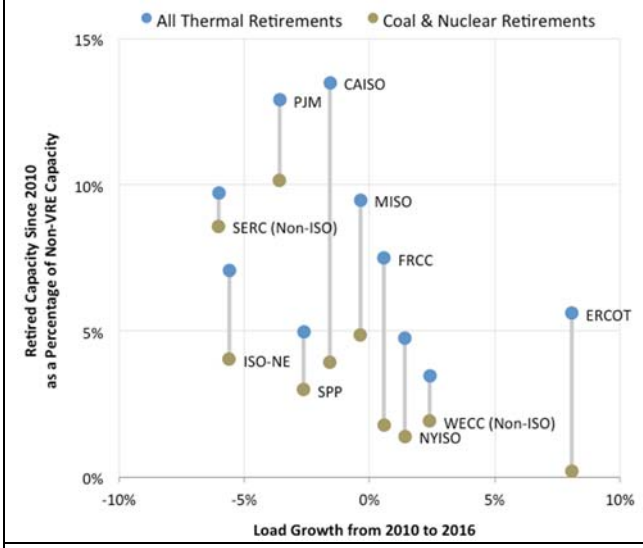
Visual inspection of these figures does not offer perfect clarity on the core drivers for regional retirement trends. Nor do historical trends necessarily tell us what might drive retirement decisions on a going-forward basis. However, we observe the following based on these graphics:

- *VRE Penetration:* There does not appear to be any obvious widespread relationship between VRE penetration and recent historical regional retirement decisions. PJM and SERC, both with very low VRE penetrations, have among the largest amount of recent total thermal-plant and coal & nuclear plant retirement. ERCOT, SPP, and the non-ISO portion of WECC, on the other hand, all have sizable VRE penetrations but low retirement percentages. CAISO has experienced strong growth in VRE and has the highest level of total thermal-plant retirements on a percentage basis, most of which are older natural-gas steam plants; many of those plants have retired as a compliance mechanism with California's policy to phase out once-through cooling (CEC 2017).
- *Load Growth:* There appears to be a relatively strong inverse relationship between load growth and retirement percentages. Regions that have experienced load contraction from 2010 to 2016 tend to have larger amounts of retirement than those regions that have experienced growth.
- *Reserve Margins:* There appears to be a relatively strong relationship between summer planning reserve margins and retirement percentages. Regions with higher reserve margins (indicative of an 'overbuild' or 'excess capacity' situation) from 2010 to 2016 tend to have larger amounts of retirement than those regions with lower reserve margins, suggesting a market correction.
- *SO_2 Emissions Rate of Coal:* One might anticipate that coal plants with high SO_2 emissions rates may be subject to more-stringent environmental upgrade and retrofit needs, which may then drive retirement decisions. This relationship is clearly apparent in the graphic, suggesting that environmental compliance has been a key driver of coal retirements especially in PJM and SERC.
- *Sulfur Content of Coal:* The relationship between the average sulfur content of coal in the region and coal retirements is not as robust as for the SO_2 emissions rate, presumably reflecting adoption of control equipment in areas with high sulfur coal but lower emissions rates.
- *Coal-to-Gas Price Ratio:* Gas and coal compete in the dispatch stack, and there appears to be a weak relationship between the ratio of delivered coal-to-gas prices and the level of regional coal retirement. Some regions that have relatively lower cost coal and/or relatively higher cost natural gas have tended to experience a somewhat lower level of coal retirement. Some regions with inexpensive gas and/or high cost coal, on the other hand, have tended to see more coal retirement.
- *Gas Price:* It is widely recognized that reductions in natural gas prices have been a core driver for lower wholesale prices, and resulting thermal-plant retirements. One might also expect that regions with relatively lower delivered gas prices might have experienced greater levels of retirement. A weak relationship of this nature appears to exist.
- *Power Plant Age:* One would expect that regions with older power plants might witness a greater amount of retirement. The graphic suggests that this relationship may exist, especially for coal & nuclear plants, with the notable exception of CAISO having significant retirements with relatively younger plants.
- *Non-VRE Power Plant Additions:* There does not appear to be a clear relationship between growth in non-VRE capacity additions since 2000 and the level of recent retirements.
- *ISO vs. Non-ISO Regions:* It is not obvious that the recent growth in thermal-plant retirements is affected by whether the region has a wholesale market overseen by an ISO. SERC is traditionally regulated and has among the highest amount of retirement of all regions. The WECC (not including California) and FRCC also remain under traditional regulation, but have experienced relatively lower levels of retirement so far. Among the many regions with ISOs, retirement percentages vary widely.

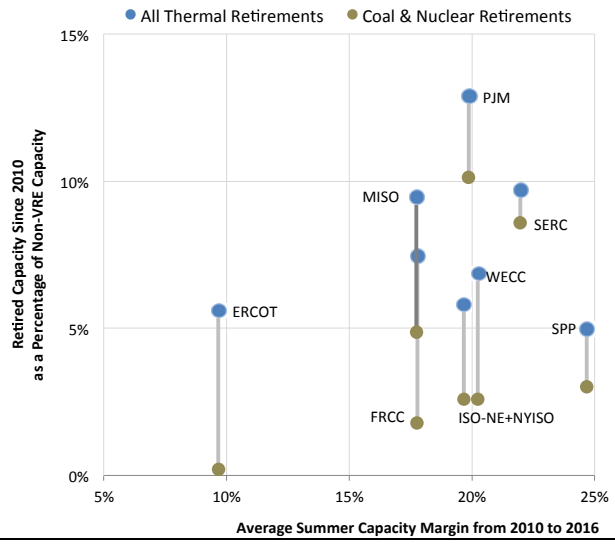
VRE PENETRATION



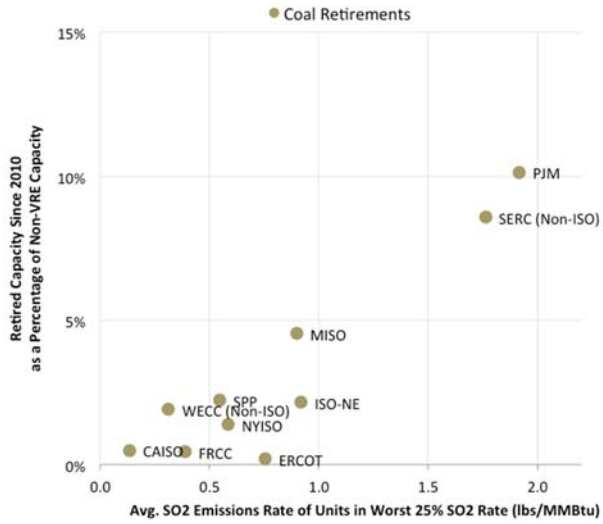
LOAD GROWTH



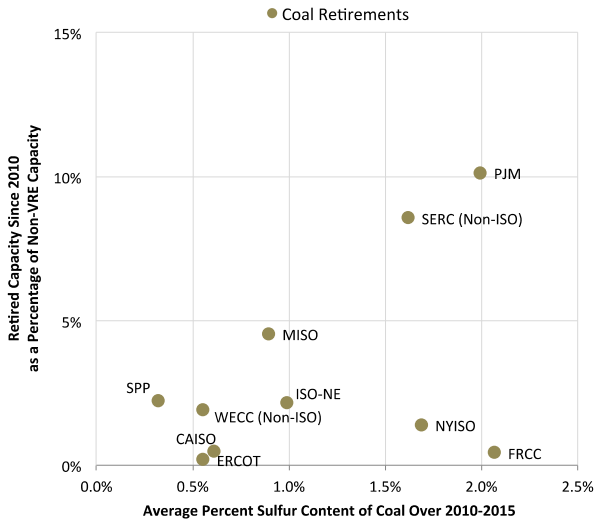
RESERVE MARGIN

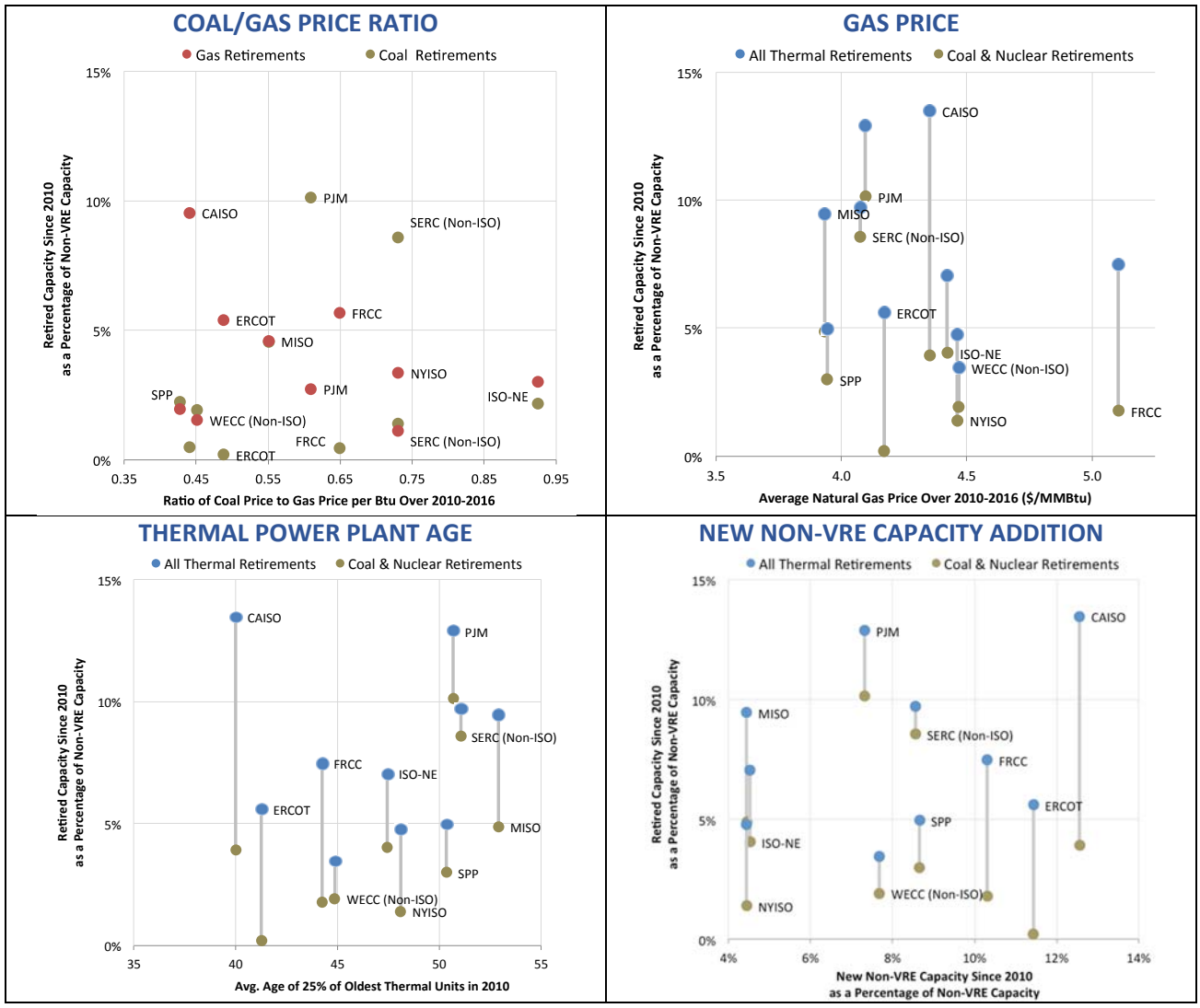


SO_2 EMISSIONS RATE OF COAL



SULFUR CONTENT OF COAL





Source: Historical retirement data, power plant age, and SO_2 emissions rates come from ABB's Velocity Suite dataset, accessed in May 2017. VRE regional penetration estimates come, in part, from annual wind generation reported in ABB's Velocity Suite divided by total generation in the region. Since ABB does not include generation <1 MW and since large-scale solar generation data were incomplete for the year 2016, we estimate solar generation based on state-level capacity, and regional capacity factors from NREL. Distributed solar generation is also added to total generation when calculating VRE penetrations. Summer planning reserve margins come from EIA-Form 411, updated as of March 2017. Regional demand growth comes from EIA's dataset of retail sales of electricity by state, with each state assigned to one of the ISO or non-ISO regions. Regional sulfur content of coal comes from EIA's dataset on the quality of fossil fuels in electricity generation: sulfur content of coal by state. Delivered gas and coal prices, by region, come from generation-weighted regional averages of the monthly power plant fuel costs between 2010-2016 reported in ABB's Velocity Suite dataset.

Figure 19. Possible Drivers for Regional Retirement Trends

Again, visual inspection of these charts is not dispositive in establishing causal relationships. Nor do these charts explore every possible driver for regional retirement variations. Moreover, future retirement decisions may be influenced by different factors than those that have affected past decisions. Nonetheless, based on these simple correlation graphics, the strongest predictors of regional retirement differences appear to include SO_2 emissions rates (for coal), planning reserve margins (for all thermal units), variations in load growth or contraction (for all thermal units), and the age of older thermal plans (for all thermal units). Additional apparent predictors of regional retirements include the

ratio of coal to gas prices and delivered natural gas prices. Other factors appear, based on this simple analysis, to play lesser roles; these include VRE penetration, recent non-VRE capacity additions, and whether the region hosts an ISO or remains traditionally regulated.

The fact that VRE growth has, so far, had relatively little obvious *widespread* impact on retirements is consistent with the findings presented earlier in this chapter on the relatively modest impact of VRE on average wholesale power prices, at least at the selected major trading hubs.

Notwithstanding the limited evidence of a widespread impact of VRE on historical retirement decisions, that is not to say that VRE has had no such impact, or will not in the future. Growth in VRE does place some downward pressure on wholesale prices and tends to reduce the capacity factors of thermal plants; these effects tend to be larger in transmission-constrained zones and when there are lower levels of overall flexibilty. Inflexible generation sources may be at special risk given these dynamics. In part as a result, PG&E specifically notes growing levels of VRE as one of the many reasons to retire the Diablo Canyon nuclear plant in California:

> *As the electric grid in California continues to evolve, so too will the character of resources needed to operate the California electric system reliably. Given California's energy goals that require increasing reliance on renewables—at least 50 percent by 2030—the California electric system will need more flexible resources while the need for baseload electricity supply will decrease. PG&E will need less non-renewable baseload generation to supply its electricity customers. Hence the need for baseload power from Diablo Canyon will decrease after 2025… Another aspect of this changing California electric system is the prospect of mounting "overgeneration" conditions. As more solar generation comes on line over time, and when its output is at peak supply (e.g., in the middle of the day), there is less room on the electric system for energy from inflexible and large baseload resources such Diablo Canyon. Overgeneration conditions can force the system operator to take action to curtail generation (e.g., dispatch generators down, or even disconnect supply from the grid) in order to maintain electric system reliability. Retirement of Diablo Canyon on the timeframe agreed to in the Joint Proposal will allow for increased flexibility for the California electric system so as to help maximize the value of solar and other variable resources that will be a crucial part of meeting PG&E's renewable targets and California's renewable and GHG emissions goals. Additionally, due to expected overgeneration throughout parts of the year, Diablo Canyon may contribute to higher system costs as its current generation profile causes challenges for efficiently integrating renewable resources. Therefore, if Diablo Canyon were not relicensed, the cost to integrate renewables could be lower* (PG&E 2016).

3.6 Directions for Future Research

While we have partially assessed some of the historical and recent impacts of VRE on the bulk power system, there is clearly more research to be done in this area, including:

- **Identifying and quantifying drivers for wholesale prices:** This chapter offers an initial analysis of the drivers for historical average wholesale electricity prices, as well as trends and correlates to pricing variability. This type of analysis could be extended in multiple directions, including: (1) expansion of the scope to additional regions of the country; (2) investigation of a broader array of specific pricing hubs and nodes within larger regions; (3) further exploration of impacts on day-ahead LMPs, the hour-to-hour difference between day-ahead and real-time LMPs (the so-called DART spread), capacity and AS markets, and bilateral contracts; and (4) assessments of the core drivers for the observed trends using more-sophisticated fundamental models and statistical analyses, in part enabling one to "peek ahead" into possible near-term future impacts. The implications of these

various trends for plant profitability, considering impacts on revenues and operating costs, could also be investigated.

- **Analysis of trends and drivers for retirement decisions:** This chapter and other related work, including DOE (2017) and Mills, Wiser, and Seel (2017), provide a first look at retirement trends and drivers, but by no means are the final word on the subject. To understand these trends and drivers in more detail would require an understanding how each possible driver affects plant profitability, an exploration of additional drivers, and a better understanding of interactions among the possible drivers. Following DOE (2017), such analysis might usefully focus on specific resource types separately (e.g., coal, nuclear, or CCGTs), be conducted on a regional as opposed to solely a national basis, and consider planned as well as recent retirements. It may be useful to consider, for a wider variety of possible drivers, not only regional averages but the distribution of plants within those averages. Assessing retirement drivers over time, not only across regions, may be informative. In conducting further analysis, additional drivers to consider include: (1) additional existing and prospective state, regional, and federal policies and regulations (e.g., carbon, NO_x, mercury, water, plant relicensing procedures, RPS, etc.); (2) the specific impacts of wear-and-tear, cycling, and other factors on operational costs; (3) regional trends in wholesale energy and capacity prices; (4) the possible differential impacts of wind and PV, as opposed to the combined impact of VRE; and (5) thermal-plant heat rates and capacity factors. Regression analysis and reviews of regulatory and financial filings offer useful tools to help better identify the underlying causes of investor decisions.
- **Analysis of trends in power plant operations:** This chapter focuses on wholesale market prices and asset retirements, but VRE deployment and other market factors are also impacting the operations of existing power plants. Further analysis might quantify the physical impacts of VRE as well as reduced natural gas prices on thermal-plant capacity factors, ramping, cycling, starts and stops, and AS delivery. Exploration of the costs of such altered operations is warranted, as well as the ability of generation units to recover these costs through energy, capacity, and AS markets.

Clear, objective, independent analysis of the different factors influencing wholesale electricity prices, power plant operations, and power plant retirement decisions will support decision makers. Direct support to at-risk generation is easier to justify if the drivers are 'dysfunctional market conditions' or 'market distortions', for example, rather than simply decreased competitiveness relative to lower natural gas prices. This analysis might also inform policy at the federal and state levels by quantifying the degree to which policy support for one type of technology (e.g., VRE) is impacting the operations and profitability of other beneficial generation sources. Moreover, by potentially melding historical analysis with forward-looking estimates, one might assess the degree to which recent trends are expected to continue or even be exacerbated into the future, further informing the need for and value of various mitigation measures.

4 Prospective Future Impacts of VRE on the Bulk Power System

4.1 Overview and Summary

Building on the anticipated directional impacts discussed in Chapter 2 and the historical observed impacts summarized in Chapter 3, in this chapter we review selected literature that attempts to model prospective future impacts of high VRE penetrations in the United States. These studies generally presume restructured, competitive wholesale electricity markets; nonetheless, some of the results are also applicable directionally in systems that lack liquid wholesale markets. At the same time, it is important to recognize that most of the studies were conducted using power systems models that do not necessarily capture the detailed market architectures of each specific market or system, relying instead on least-cost optimization approaches to approximate economically efficient market outcomes. Therefore, the results observed in each region are likely influenced primarily by differences in physical system attributes, e.g. generation portfolios, demand profiles, transmission infrastrucutre etc., as opposed to differences in market architecture. In part as a result, the results presented in this chapter should generally be interpreted by analyzing trends over different VRE penetration scenarios within each individual study (i.e., for a given set of assumptions), as opposed to making direct quantitative comparisons across different studies and regions. It is also important to note that this is by no means an exhaustive summary of the work in this area. The studies covered in this chapter were selected because they present concrete quantitative projections for how various metrics may change as more VRE is introduced into power systems. We make no claim that this review is comprehensive. Nor do we seek to synthesize relevant available literature from outside the United States.[25]

All of the studies model the dispatch of generation, but they differ in how they treat decisions to invest in or retire generation capacity. The reviewed studies are listed in Table 4, and have been broadly segmented into two general categories based on the modeling approach:

- Studies that fix the capacity of the existing generation fleet irrespective of the introduction of new VRE capacity into the system
- Studies that use capacity expansion models or assumptions to define investment and retirement of thermal units for each scenario of VRE capacity

There are significant limitations to this review, driven by the many differences that exist among the synthesized studies. Each study seeks to quantify the future bulk-power system impacts of introducing additional VRE capacity to a U.S. power system. However, care must be exercised when making direct comparisons between the results of individual studies, as the studies were conducted at different times, cover different regional electricity systems, apply different scheduling and dispatch models, and use varying parameter assumptions (e.g., fuel prices, model year, load growth, unit expansion and retirement, VRE penetration, etc.). Additionally, these studies take a number of different approaches to modeling system evolution in response to increasing VRE penetrations. Detailed modeling of system dispatch and market clearing prices also vary across the studies. For example, many renewable integration studies have traditionally focused on modeling system costs rather than market clearing prices. The diversity of assumptions, approaches, and regions make normalization and direct comparison across studies difficult. *As such, the primary goal of this chapter is to discuss impacts on a general, qualitative and directional basis—in part using these results to bolster the discussion of anticipated VRE impacts described qualitatively in Chapter 2.* Considerable additional work would be

[25] There are a number of international studies that cover similar topics. Relevant studies from Europe, for example, include: Brouwer, van den Broek, Özdemir, et al. 2016; Welisch, Ortner, and Resch 2016; Winkler, Gaio, et al. 2016; Sensfuß, Ragwitz, and Genoese 2008b; and Agora 2015. Many of the qualitative findings are similar to those reported in the U.S. literature.

needed to identify key differences across regions, across varying system conditions, between wind and solar, at varying levels of VRE penetration, etc.

Although we focus on bulk power system impacts in this review, it is important to keep in mind that the models employed usually include constraints (e.g., for operating reserve requirements or capacity planning margins) with the purpose of ensuring that reliability is maintained for any resulting future configuration of the power system. As such, within the limits of the individual models employed, the electricity systems contemplated by the studies reviewed here would all at least maintain adequate planning and operational reliability margins; in fact, a number of the studies exceed adequacy needs, especially when VRE is added to a fixed fleet that is already sufficient to meet adequacy requirements.

An important distinction when analyzing the impacts of VRE on bulk power systems is the short- vs. long-term implications of higher VRE penetration levels. In the short term, VRE may be introduced into electric systems in part through incentives and to-a-degree outside of regular market mechanisms. If load growth is low, this may lead to surplus capacity if the system already has adequate supplies of other generation resources, further affecting plant operations and reducing wholesale prices. In the long term, however, the market should approach a new economic equilibrium where the portfolio of resources adapts to meet the future electricity demand in a cost-efficient manner. In long-run economic equilibrium, all resources in the generation portfolio recover their costs in expectation, by definition. If surplus capacity reduces electricity prices, for example, then some suppliers will naturally exit the market, and the corresponding reduction in supply will tend to cause prices to rebound. Of course, policy decisions (e.g., environmental goals and other societal objectives) will also influence the configuration of this new long-run equilibrium. Moreover, the transition from current non-adapted systems with increasing VRE levels to a new long-term equilibrium may take decades, and may be slowed or accelerated by policy interventions. In practice, conditions will continually evolve. The system may trend towards a new equilibrium point, but will likely never truly settle into a stable state; as a result, the cost recovery of individual units will vary somewhat from year-to-year. Many of the studies reviewed below do not seek a long-run equilibrium solution, but rather look at short- to medium-term effects where the resource portfolio is not fully adapted to the higher penetration of VRE. The results should be interpreted accordingly.

The specific impacts assessed by the studies are context dependent, and will be affected by the underlying structure of the bulk power system and how it evolves over time. Moreover, most of the studies explored aggressive VRE penetration levels—in many cases well above what is experienced in many or all regions of the United States today. As such, extrapolating the results broadly requires great caution. Nonetheless, several summary observations can be made based on this review, all of which are consistent with the summary of potential impacts covered in Chapter 2:

- The surveyed studies are generally in agreement that increasing VRE penetrations will decrease average wholesale energy prices (i.e., LMPs) in the short run (in non-restructured electricity markets, meanwhile, VRE would be expected to reduce average short-run marginal operating costs).
- The long-run wholesale energy price impacts are less clear as many of the surveyed studies do not reflect long-run equilibrium conditions. In the long run (and at fixed VRE levels), price impacts may be less pronounced due to changes in the generation mix as that mix adapts to higher levels of VRE.
- Electricity price variability may increase with increasing VRE penetrations. This effect was more-clearly evident when introducing solar generation as opposed to wind generation. However, very few of the surveyed studies present results on price variability.

- Though wholesale energy prices (LMPs) are anticipated to decline with increasing VRE, the surveyed studies show a general trend of increasing prices for regulation reserves with increasing VRE penetrations. Prices for spinning and non-spinning reserves (reserve levels for which are often set by the single largest contingency, and not VRE) appear to be more stable, however the picture is less clear for these reserve products given limited coverage in the literature.
- In most cases, capacity factors decrease for thermal units with increasing VRE penetrations. Nuclear units are typically modeled as inflexible baseload generation, in which case capacity factors are not influenced by VRE. Coal cycling costs appear to increase at higher VRE penetrations, however results may be unit-or technology-specific and it is difficult to broadly generalize these outcomes. Some studies have found that the cycling costs of natural gas CTs are lower at higher VRE penetrations.
- Nuclear and coal operating profits and revenues were generally found to decrease at higher VRE penetrations, however the magnitude of this effect differed between studies. The operating profits (i.e., revenue minus operating costs) of natural gas fired generators are less exposed to increasing VRE levels given their flexibility characteristics and resultant ability to dispatch down and save operating costs when wholesale prices are low. Studies differed in how they account for different potential revenue streams, e.g. few studies comprehensively included possible revenues from capacity and ancillary service markets, making comparisons difficult.
- Some of the surveyed studies demonstrated that changes in natural gas prices have a significant impact on wholesale electricity prices. In many cases, natural gas price sensitivity scenarios produced price impacts that were comparable to impacts produced by the VRE scenarios.
- One study analyzed the impact of removing the production tax credit for wind power and found the potential wholesale price impact to be small compared to natural gas price impacts.
- The above impacts may be more pronounced in the short run if VREs are added to systems that already have an adequate capacity margin, given the consequent surplus in capacity. Impacts in the longer term may be less pronounced, since market forces should drive the generation portfolio towards a new economic equilibrium. Most of the studies reviewed here represented intermediate stages, where the generation portfolio has not fully adapted to the higher VRE levels.

To be clear, this analysis focuses on insights derived from modeling studies on the possible impacts of VRE on restructured, competitive wholesale markets, and on the operations of existing and new thermal power plants. This chapter does not address the aggregate, system-wide cost of increasing VRE in electricity systems, which necessarily would need to consider a wide array of other factors, most notably the cost and value of that VRE. Chapter 5 begins to touch on these broader issues.

With this overview and summary, we now turn to an identification of the reviewed modeling studies, and a synthesis of their results.

4.2 Studies Selected for this Review

In this section, we briefly describe the studies reviewed in this chapter.

Studies with Fixed Thermal Capacity Expansion

The Western Wind and Solar Integration Study (WWSIS) (GE Energy 2010b) was conducted to examine the technical and physical barriers to operating the grid with high levels of wind generation. The WWSIS found that 30% wind and 5% solar penetration would be operationally feasible for the West Connect region provided that some changes are implemented over time, including: increased balancing area

cooperation, implementation of sub-hourly scheduling, and expansion of transmission infrastructure as appropriate. This study utilized a production cost model that did not consider any additional changes to the generation mix beyond what was planned at the time. The WWSIS was followed up with a Phase 2 report (WWSIS-2) that more closely examined the impacts of increasing wind and solar penetration on the fossil-fueled fleet (Lew et al. 2013).

GE Energy (GE Energy 2014) examined the wholesale market impacts of achieving a 14% renewable energy share in PJM by 2026, and also several renewable scenarios that achieved 20% and 30% penetration. The study examined a number of different pathways to reach 20% and 30% VRE penetration; the results discussed in this chapter emphasize the scenario in which 10% of new wind capacity is developed offshore, and onshore wind is developed in locations with the best resources. LCG (2016) developed a model of the ERCOT system using their UPLAN Network Power Model, and analyzed the impacts of adding 7.1 GW and 14.2 GW of new wind capacity to the system by 2021.

Brancucci Martinez-Anido et al. (2016) analyzed the impacts of increasing wind penetrations in ISO-NE using PLEXOS, a commercial power systems model. They examined several scenarios; the results discussed in this chapter assume that state-of-the-art, but still imperfect, forecasting methodologies are used and that wind curtailment is allowed. NYISO (2010) similarly developed a model of their own system to analyze the impacts of introducing additional wind generation, however no additional thermal unit additions or retirements were considered.

Deetjen et al. (2016) presented a model of the ERCOT system, and compared the impacts of large-scale solar PV development in three different geographic regions. The results presented in this chapter represent an average of these three scenarios. Hummon et al. (2013) presented a model of the Colorado power system that was applied specifically to identify factors that drive prices for ancillary services and included a sensitivity analysis of several VRE penetration levels. Frew et al. (2016) presented a model of an 'ERCOT-like' energy-only power market that was applied to explore revenue sufficiency issues for thermal generators and also included a sensitivity analysis of VRE penetration.

Brinkman et al. (2016) used PLEXOS to analyze 23 different future scenarios that achieve 50% carbon emissions reductions from the California power sector by 2030. A Baseline scenario assumes 20% solar penetration and 7% wind penetration, with all of these resources located internal to California. A more ambitious Target scenario assumes 24% solar penetration and 18% wind penetration, with two-thirds of the wind generation provided by resources located outside of California. A number of additional scenarios and sensitivities are also considered and discussed in further detail, however the results reported here stem from these two core scenarios.

Studies with Thermal Capacity Defined for Each VRE Scenario

Like the WWSIS, the Eastern Wind Integration and Transmission Study (EWITS) (EnerNex Corp. 2010) examined technical and physical barriers to operating the grid with high levels of wind generation. Unlike the assumption of fixed thermal capacity in WWSIS, the EWITS study used the EGEAS capacity expansion model from EPRI to conduct a regional capacity expansion analysis for each wind scenario. It found that 30% wind penetration in the Eastern Interconnection (EI) would be technically feasible with significant expansion of transmission infrastructure. It also determined the system balancing costs of wind to be roughly $5/MWh-wind for all wind scenarios. The data presented in Figure 20 for the EWITS represent our own approximations of load-weighted average wholesale prices across the entire Eastern Interconnection based on data provided in the report. The Eastern Renewable Generation Integration Study (ERGIS) also examined the operational impacts of up to 30% wind and solar penetration in the EI

(Bloom et al. 2016). A capacity expansion model, ReEDS, was used to determine the quantity and location of all generation additions and requirements for each predefined scenario. These expansion plans were then passed to a production cost simulation model (PLEXOS) to optimize one year of power system operations at 5-minute temporal resolution.

The Renewable Electricity Futures Study (Hand et al. 2012) explored the implications of high renewable electricity generation levels throughout the entire United States, examining future scenarios with renewable penetrations from 30% to 90% (14% to 64% VRE penetration) in 2050 that are combined with a number of different sensitivity scenarios. We present study results based on the original scenarios analyzed in 2012 assuming low demand and incremental technology improvement as these sensitivities offer the most robust set of results.

NESCOE (2017) presented an economic analysis of several future renewable generation scenarios in the ISO-NE; unit expansion and retirement decisions were determined through a simulation of the ISO-NE capacity market, and the potential impacts to the market clearing capacity price from increased VRE penetration were evaluated. Fagan et al. (2012) analyzed the introduction of new wind capacity in the MISO system for a total capacity of up to 50 GW by 2020 and 110 GW by 2030. They also examined three different coal retirement scenarios where 3 GW, 12 GW, or 23 GW of coal capacity is retired. The results presented in this chapter are for the 12 GW coal retirement scenario in 2020 and also assume that 10 GW of both natural gas combined-cycle and natural gas combustion turbines are added under baseline conditions, and an additional 10 GW of natural gas combustion turbines are added under the high wind scenarios.

Levin and Botterud (2015) developed a new modeling framework to determine the least-cost thermal unit expansion, hourly commitment and dispatch of energy and ancillary services in a power system. They applied the model to a case study of a simplified 'ERCOT-like' system that bundles thermal generators into four unit types: nuclear, coal, natural gas combined-cycle, and natural gas combustion turbines. They examined the impacts to generation expansion, energy prices, ancillary services prices, and thermal unit revenue sufficiency that would result under 10% (baseline), 20%, 30%, and 40% wind generation.

Bistline (2017) presented a model that co-optimizes capacity planning with unit dispatch based on representative hours. The model was applied at a national level and two distinct case studies were presented, the first examining impacts of high wind penetrations in Texas and the second examining impacts of high solar penetrations in California.

Mills and Wiser (2012a) developed an original investment and dispatch model to estimate the long-run economic value of renewable generation as both wind and solar penetrations increase in California. The data from these two case studies are reported independently in this chapter. The model accounts for changes in the generation mix due to technical and economic factors, and was also applied to analyze changes in wholesale market prices and thermal unit revenues. A later study by the same authors used the same model and scenarios to examine the effectiveness of several strategies to mitigate the decline in VRE value with penetration levels; those results are noted briefly in Chapter 5 and are not included here.

All of the studies described above establish fixed VRE targets and analyze how the system may respond to integrate those particular levels of renewable penetration. In contrast to those studies, Shavel et al. (2013) presented a model that optimizes investments in all new generation capacity (wind, solar, and

thermal) in the ERCOT system in response to various parameter sensitivities, e.g. natural gas prices, renewable technology costs, and carbon emissions regulations. Therefore, the resultant VRE penetrations in each of six different scenarios are determined endogenously by the model itself, as with all other types of generation in order to minimize costs. The initial expansion results determined by the model are, however, sometimes further augmented to ensure that system reliability is maintained. To isolate the impacts specifically caused by changes in VRE penetration as much as possible, we compare the 'High Gas Prices plus Low Renewable Costs' and 'Stronger Federal Carbon Rule' scenarios, which both use the same natural gas and renewable cost assumptions. Their 'Reference Case' also provides some insight into market outcomes with lower natural gas prices.

Note that the studies in this category, with the exception of the last one, impose VRE exogenously. Moreover, they assume a substantial amount of existing resources, which are not adapted to a high VRE resource mix. Since it may take decades for the resource portfolio to fully adapt, and also since retirement decisions are not considered in all the studies, the resulting generation mix will likely deviate from what would emerge from a greenfield long-run equilibrium analysis. The results summarized in this chapter should be interpreted accordingly.

Table 4. Studies Reviewed to Assess Potential Future Impacts of VRE on the Bulk Power System

Title	Author	Year Published	Region	Target Year	Model	Key Scenarios
Thermal Capacity Fixed Across VRE Penetrations						
Western Wind and Solar Integration Study: Phase 1	GE Energy	2010	WestConnect	2017	MAPS	· 3% wind, 0% solar · 10% wind, 1% solar · 20% wind, 3% solar · 30% wind, 5% solar
Growing Wind: Final Report of the NYISO 2010 Wind Generation Study	NYISO	2010	NYISO	2018	GridView	· 1,275 MW wind (current) · 8,000 MW wind total (10%+)
Western Wind and Solar Integration Study: Phase 2	Lew et al.	2013	Western Interconnection	2020	ReEDS/PLEXOS	· No renewables · 9.4% wind, 3.6% solar · 25% wind, 8% solar · 4. 8% wind, 25% solar · 16.5% wind, 16.5% solar
Fundamental Drivers of the Cost and Price of Operating Reserves	Hummon et al.	2013	Colorado	2020	PLEXOS	· 15% - 35% VRE
PJM Renewable Integration Study	GE Energy	2014	PJM	2026	GE MAPS	· 2% VRE · 14% VRE · 20% VRE (several cases) · 30% VRE (several cases)
Market Effects of Wind Integration in ERCOT	LCG Consulting	2016	ERCOT	2021	UPLAN	· 15.8 GW wind · 22.9 GW wind · 30 GW wind
The Impact of Wind Power on Electricity Prices	Brancucci Martinez-Anido et al.	2016	ISO-NE	Not specified	PLEXOS	· 0% wind · 5.0% wind · 8.6% wind · 15.6% wind · 21.2% wind
Impact of Market Behavior, Fleet Composition, and Ancillary Services on Revenue Sufficiency	Frew et al.	2016	ERCOT	2012 to 2014	PLEXOS	· 10% wind · 20% wind · 20% wind w/ flexibility req.

Solar PV Integration Cost Variation Due to Array Orientation and Geographic Location in the Electric Reliability Council of Texas	Deetjen et al.	2016	ERCOT	2012	PLEXOS	· 9.3% wind · 9.3% wind + 6.8% solar
Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California	Brinkman et al.	2016	California	2030	PLEXOS	· 20% solar + 7% wind · 24% solar + 18% wind
Thermal Capacity Varied With VRE Penetration						
Eastern Wind Integration and Transmission Study	EnerNex Corporation	2011	Eastern Interconnection (EI)	2024	PROMOD	· 6% wind · 20% wind (3 cases) · 30% wind
Renewable Energy Futures Study	Hand et al.	2012	United States	2050	ReEDS and GridView	·6.9% VRE (baseline) ·13.7% - 64.1% VRE
The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region	Fagan et al.	2012	MISO	2020 and 2030	ProSym	· 10 GW wind · 30-50 GW wind (2020) · 60-110 GW wind (2030)
Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California	Mills and Wiser	2012	CAISO	2030	Original model	· 0% - 40% wind · 0% - 40% solar
Exploring Natural Gas and Renewables in ERCOT Part II: Future Generation Scenarios for Texas	Shavel et al.	2013	ERCOT	2032	Xpand/PSO	· Reference · High Gas, Low Renewable Costs (HGLR) · HGLR + Stringent Carbon Rule
Electricity market design for generator revenue sufficiency with increased variable generation	Levin and Botterud	2015	ERCOT	2024	Original model	· 10% - 40% wind
Eastern Renewable Generation Integration Study	Bloom at al.	2016	Eastern Interconnection (EI)	2026	ReEDS/PLEXOS	· 3% wind, 0% solar · 12% wind, .25% solar · 20% wind, 10% solar · 25% wind, 5% solar
NESCOE Issues Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study	NESCOE	2017	ISO-NE	2025 and 2030	Original model	· 26.28%/28.71% RPS (2025/2030) · 35%/40% RPS (2025/2030) · 40%/45% RPS (2025/2030)

Economic and technical challenges of flexible operations under large-scale variable renewable deployment	Bistline	2017	CAISO and ERCOT	2030	US-REGEN	· 0-100 GW wind (ERCOT) · 0-100 GW solar (CAISO)

4.3 Bulk Power System Impacts

As discussed in Chapter 2, it is well established that increasing VRE with low (or even negative) marginal costs tends to reduce average wholesale energy prices (LMPs), at least in the short term (in non-restructured markets, meanwhile, VRE would be expected to reduce short-run marginal operating costs). All else being equal, lower wholesale electricity prices will generally result in reduced revenues for generation units. These reduced revenues may place particular strain on the operating profits of inflexible units that are not able to respond to the price signals by dispatching down when wholesale prices drop below short-run operating costs. The capacity factors and cycling behavior of some units will be affected as well, reducing electricity generation and possibly increasing operating costs for some units. High VRE penetrations may also increase ancillary service requirements, however, and therefore may increase the market clearing prices for operating reserves, creating additional revenue opportunities for units that are able to provide these services. Increased wholesale price volatility will similarly provide signals to the market of increased value from providing flexibility to the grid.

While some of these effects have been observed in practice over the past decade, as indicated in the previous chapter, VRE penetrations are too low in many regions to easily identify a specific VRE impact. In the subsections that follow, we summarize selected modeling results of the studies highlighted above, which generally focus on higher levels of VRE penetration than are currently experienced in the United States. It should be noted that this summary is based on data that, in most cases, were extracted from figures in the underlying studies; as such, these should be considered as approximations with a primary focus on trends as opposed to exact values.

Wholesale Energy Prices

In restructurted electricity markets, wholesale energy prices (i.e., LMPs) are generally set by the generation offer cost of the marginal unit in a given time period at a given location.[26] Currently, in most U.S. power systems this marginal generation unit is most frequently a flexible natural gas unit that is dispatched up and down to follow daily load patterns. The expansion of wind power shifts the merit-order supply curve to the right, lowering the market-clearing price. Additionally, during periods when wind generation is high, loads are low, and constraints prevent temporary shut-down of other generation resources, wind may be the marginal generation unit, resulting in zero or (with the PTC or RPS) negative market clearing prices. As VRE penetrations increase, these effects might be expected to grow in magnitude. However, unless the recent trend of low natural gas prices change course significantly, natural gas units will continue to set the wholesale price a substantial fraction of the time. Moreover, in the longer-term, lower wholesale prices will tend to reduce the incentives for investment in generation capacity, potentially shifting new investments toward generation with lower capital cost but higher fuel costs; some power plants will also decide to retire given the lower wholesale prices (Sáenz de Miera, del Río González, and Vizcaíno 2008). In turn, shifting new generation toward generation with higher fuel costs, and the retirements of some units, will tend to mitigate the reduction in wholesale prices over the long run.

Finally, it is worth noting that the merit order effect as it relates to average wholesale prices in restructured markets is primarily affected by the low marginal generation costs of VREs. A market with high penetrations of other low or zero marginal cost resources—nuclear for example—would experience similar dynamics. The specific impact of the variability of VRE on the geographic and temporal variability of wholesale prices, on the other hand, is unique to VRE.

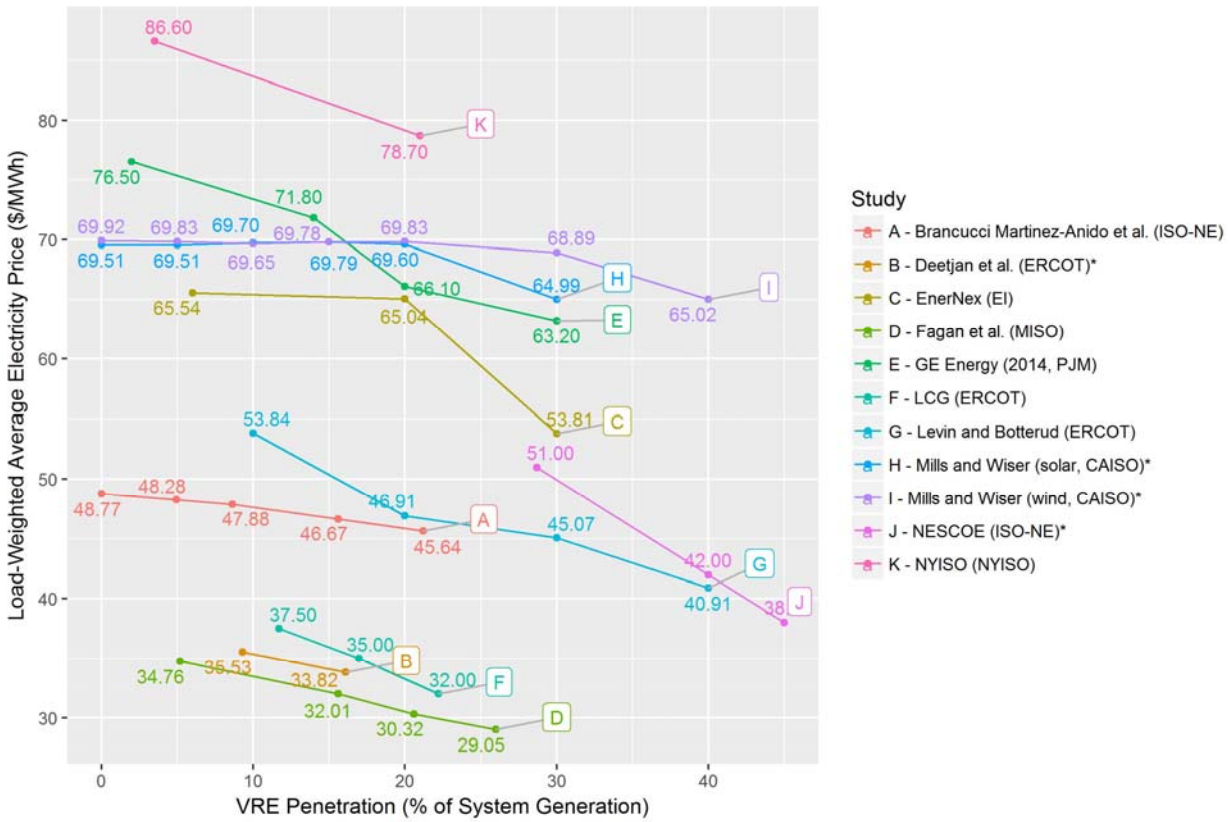
[26] The marginal resource could also be a demand side bid.

Summary of Findings in Literature

NESCOE (2017), Deetjen et al. (2016), and Mills and Wiser (2012a) reported simple average wholesale electricity prices while the remaining studies presented some form of a load-weighted average prices. These metrics do not typically differ too significantly although each provides a slightly different perspective. The load-weighted average price reflects the total consumer cost of obtaining sufficient energy to meet demand (absent transmission and distribution charges)—or the total revenue provided to generators. Alternatively, a simple average may be of more interest to an inflexible baseload unit that generates at a constant level throughout the year.

Despite the different methodological approaches and the range of parameter assumptions applied, there appears to be broad consensus that higher levels of VRE will result in lower average wholesale electricity prices, or LMPs (Figure 20). This trend is further highlighted in Table 5. which presents the change in average wholesale energy price that corresponds with a 1% increase in VRE penetration. These values range from -$0.80 to -$0.10 across the selected studies, with an average value of -$0.37. In interpreting these results, it is important to consider that different generation technologies have different exposure to the reductions in the average price. A flexible plant will be less exposed to periods of low (or even negative) wholesale energy prices since they can dispatch down when LMPs are lower than the generator's short-run marginal operating costs. A non-hedged fully inflexible plant (whether inflexible physically, contractually, or otherwise), on the other hand, will be exposed to the full reduction in average prices because such a plant will not dispatch down even when wholesale energy prices fall below short-run operating costs. Electricity purchasers and customers, meanwhile, will benefit from these wholesale energy price reductions; note, however, that other system costs not embedded in LMPs may increase (e.g., the direct and transmission costs associated with VRE).

It is also important to keep in mind that most of the studies do not reflect long-run equilibrium conditions, but rather systems where the generation portfolio has not fully adapted to the higher levels of VRE. Price formation in fully adapted systems in long-run equilibrium may therefore differ from the trends revealed in the majority of our sample of studies.



Note: Studies denoted with an asterisk report a simple average price while the remainder report a load-weighted average price.

Figure 20. Projected Wholesale Electricity Prices with Increasing VRE Penetrations

Table 5. Relationship Between Average Wholesale Electricity Price and VRE Penetration

Study	Change in price ($/MWh) per % increase in VRE penetration
Brancucci Martinez-Anido et al. (ISO-NE)	-$0.15
Deetjan et al. (ERCOT)*	-$0.25
EnerNex (EI)	-$0.46
Fagan et al. (MISO)	-$0.28
GE Energy (2014, PJM)	-$0.50
LCG (ERCOT)	-$0.52
Levin and Botterud (ERCOT)	-$0.41
Mills and Wiser (solar, CAISO)*	-$0.13
Mills and Wiser (wind, CAISO)*	-$0.10
NESCOE (ISO-NE)*	-$0.80
NYISO (NYISO)	-$0.45

Electricity price volatility may also be expected to increase in systems with high VRE penetrations. Although it is hard to capture the full spectrum of market price volatility in modeling studies, Levin and Botterud (2015) and Mills and Wiser (2012a) calculated the coefficient of variation for day-ahead wholesale electricity prices, defined as the standard deviation of hourly energy prices divided by the annual mean electricity price. Figure 21 suggests that energy market price volatility generally increases

with increasing VRE penetration, with some individual data points contradicting the broader trend. The increased volatility is more-clearly evident when introducing solar generation, as opposed to wind generation, at least based on this small sample of surveyed studies.

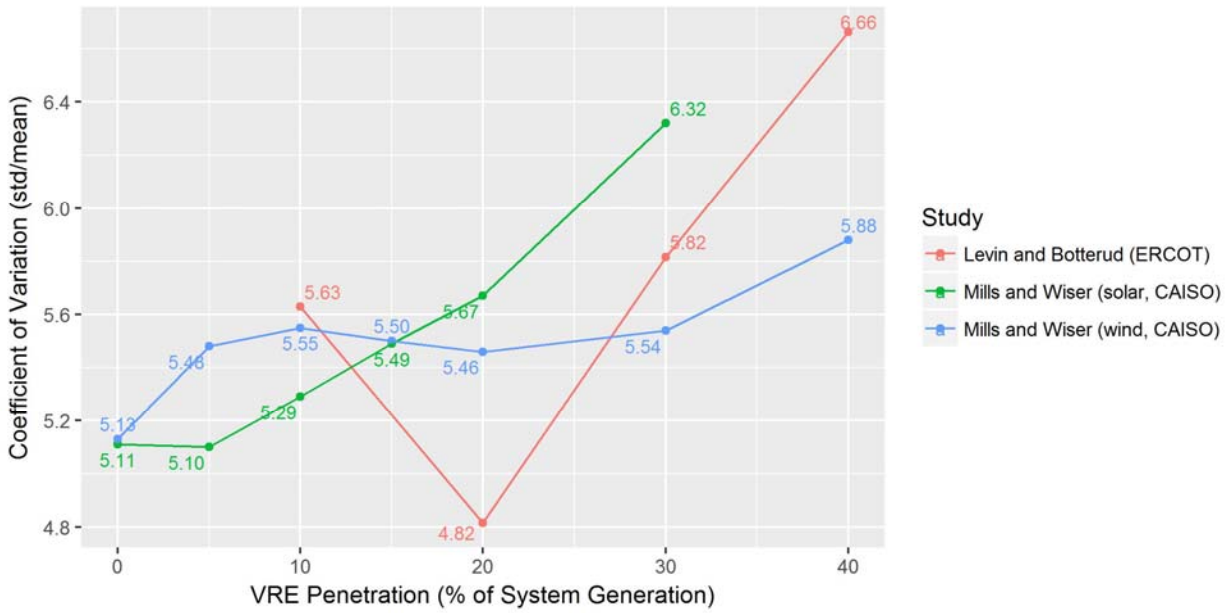


Figure 21. Projected Hourly Price Volatility with Increasing VRE Penetrations

Operating Reserve Prices

While the impacts of high VRE penetrations on wholesale energy prices have been studied in some detail, the impacts on prices for operating reserves[27] are generally not as well understood; this is the case for a number of reasons. Reserve markets are much smaller than energy markets in terms of total value. Reserve markets have also been introduced more recently than energy markets, are less uniform across different ISOs, and their market rules have been adjusted frequently over the past decade, making it more difficult to isolate the primary drivers of price impacts. Hence, modeling reserves markets is more challenging than energy markets. However, as VRE penetrations increase, AS markets may serve as a mechanism for monetizing a portion of the value of flexibility in power systems, thereby providing an increasingly important revenue stream for flexible generating units.

The main impact of VREs on reserves prices is introduced through increased *demand* for these services. In the wholesale energy market, low marginal cost VREs influence prices (i.e., LMPs) directly from the supply-side, by providing generation at low (or negative) marginal cost, which most studies indicate lead to lower market clearing prices in the short term (Figure 20). In contrast to the energy market, however, VREs have not typically supplied operating reserves themselves, at least historically, and therefore do not necessarily affect the market from the *supply-side*.[28] The impact of VREs on reserve prices is instead felt on the *demand-side*, as higher VRE penetrations will likely require greater AS quantities to balance

[27] We focus primarily on the operating reserves that are typically procured through market mechanisms in the United States, i.e., regulation and contingency reserves.

[28] This has historically been the case due to a combination of technical limitations, market rules that prevent participation, economic opportunity costs that may limit voluntary participation, and VRE generation incentives that are foregone by units while they provide reserves. However, VREs may begin to provide more operating reserves as penetration levels increase. VRE has the technical capacity to provide downward spinning reserves under most system conditions, and also upward spinning reserves under certain system conditions (e.g., if the VRE generator is currently being curtailed).

the increasing overall variability and uncertainty in the system in order to maintain system reliability within given relability standards, thereby also driving up AS prices. This is particularly the case with regulation reserves, which are typically procured hourly through day-ahead and/or real-time markets. Resources that participate in the regulation reserve market must be able to adjust their generation output level in response to automatic generation control signals that are sent roughly every four seconds, or less in the case of fast-frequency response signals that are being implemented in some markets. As VRE penetrations increase so too will short-term net load variability, and greater quantities of regulation reserves will be required to ensure that supply and demand are balanced in real-time; this increased demand for regulation reserves may tend to increase prices for the service.

For example, an analysis of 30% VRE penetration in PJM found that an additional annual average of 1,000 MW to 1,500 MW of regulation reserves would be required to maintain system reliability; on the other hand, no additional spinning or non-spinning reserves would be required (GE Energy 2014). Hummon et al. (2013) calculated hourly regulation requirements based on the statistical variability of load, wind, and solar generation, while Mills and Wiser (2012a) assumed the regulation requirement to be 2% of hourly load plus 5% of the day-ahead wind or solar forecast. Both of these latter studies assumed that contingency reserve requirements are independent of VRE penetration; these requirements are instead impacted by the possibility of large generator or transmission outages. This assumption reveals a more-general truth: VRE is not alone in impacting reserve needs and markets, as inflexible baseload units also must be complemented by more flexible units that are able to follow load and provide operating and contingency reserves; in other words, the amount and nature of AS requirements may vary based on technology, but various reserves are required for all generation types (Stark 2015; Milligan et al. 2011).

Reserve requirements are set administratively and therefore a primary challenge of modeling the AS markets is that prices are typically largely dependent on administratively determined parameters, such as hourly AS requirements, scarcity pricing rules, or in the case of ERCOT, the shape of the operating reserve demand curves. Therefore, while it is possible to model market outcomes under different assumed future scenarios, it is difficult to predict how market design will evolve in the long term to accommodate changes in the bulk power system. Moreover, the costs of providing reserves, which consist partly of opportunity costs from not providing services in other markets (e.g., energy in the energy market), is complex to estimate, adding to the reserve market modeling challenge.

Summary of Findings in Literature

Due in part to the complexities described above, there are relatively few studies that reported reserve prices. The results of the relevant studies reviewed here are summarized in Figure 22 and Figure 23. Overall, the picture is not as clear as for energy prices. There is a general trend of increasing prices for regulation with higher VRE penetrations. The picture for spinning and non-spinning reserves is somewhat less clear, with studies showing a combination of relatively stable or increasing reserve prices with the VRE level. Overall, it is difficult to draw any strong conclusions from this sample.

Levin and Botterud (2015) found that under an ERCOT-like operating reserve demand curve (ORDC) framework, the average annual spinning reserve price remains at a relatively consistent level around $15/MWh as wind penetration increases from 10% to 40%. In this analysis, non-spinning reserves rarely have a non-zero price under all wind penetration levels resulting in average prices close to zero. This is consistent with early market results from ERCOT after the ORDC was implemented in June 2014; through the end of 2016, the average offline reserve price adder has been less than $.01/MWh. This study did not consider frequency regulation. LCG (2016) found that prices from all four considered

reserve products—regulation-up, regulation-down, spinning reserves, and non-spinning reserves—increase with increasing wind penetrations. However, Hummon et al. (2013) identified a decline in prices for contingency reserves as VRE penetrations increase. This decrease is explained by the additional thermal generation capacity that is *displaced* by VRE generation and is therefore available to provide reserve capacity at low-cost. However, the Hummon et al. analysis does not consider potential unit retirements, which would reduce the availability of this excess capacity if they were to occur, thereby restricting the supply and raising the price of these reserves.

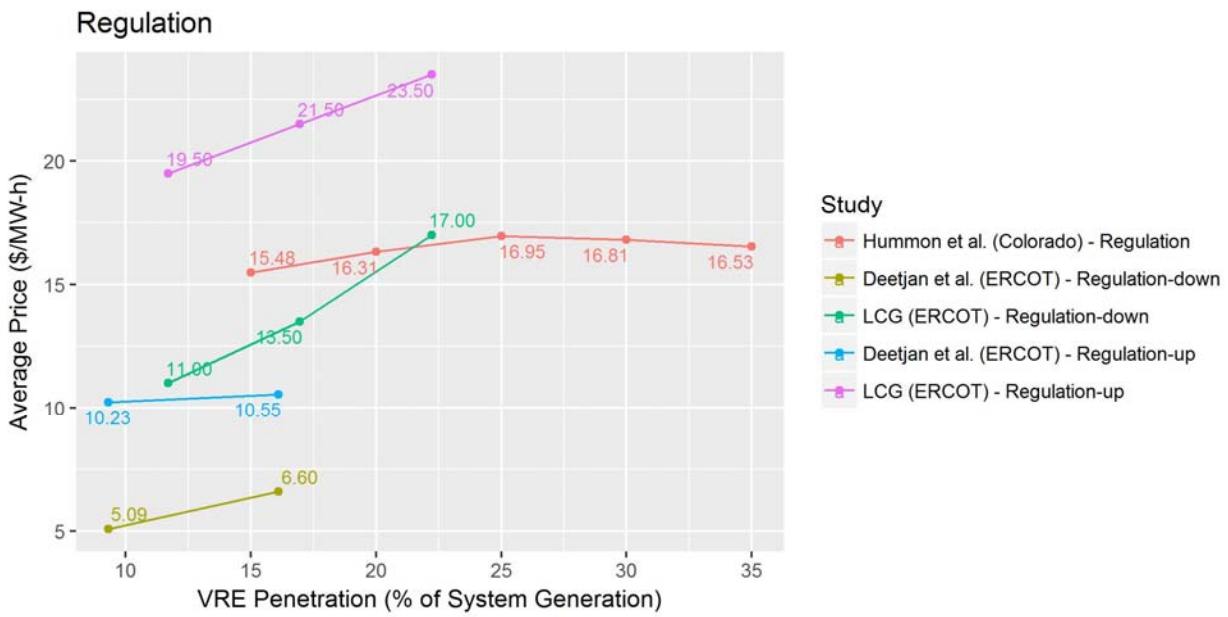


Figure 22. Projected Prices for Frequency Regulation Reserve with Increasing VRE Penetrations

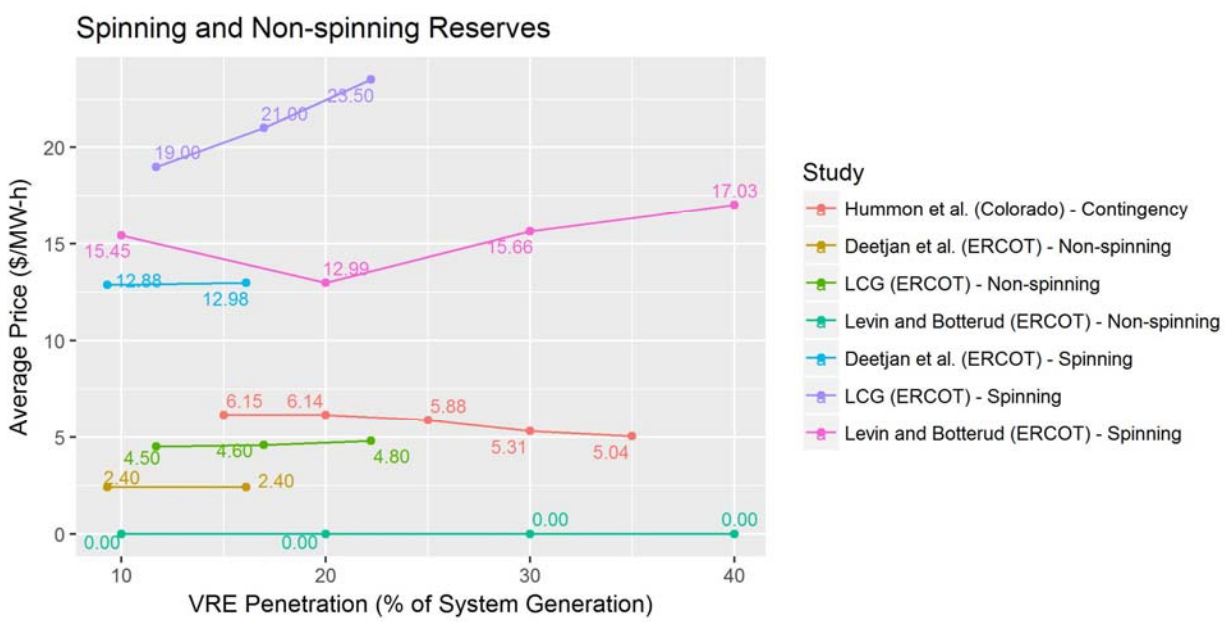


Figure 23. Projected Prices for Spinning and Non-Spinning Reserves with Increasing VRE Penetrations

System Dispatch, Thermal-Plant Capacity Factors, and Cycling Costs

The overall dispatch of the power system changes as VRE penetrations increase; this is true in both restructured and non-restructured systems. Since VREs enter at the lowest marginal cost end of the merit-order dispatch curve, other technologies with higher marginal costs tend to be dispatched less. The capacity factors of thermal generators will therefore tend to decrease. This effect will be particularly pronounced if VREs are added on top of existing generation resources, leading to a surplus of available capacity. In the longer run, the generation portfolio of the system is likely to settle around an equilibrium solution where the mix of generation shifts toward resources with lower fixed costs and VREs replace some of the existing generation resources, with the degree of displacement affected by the capacity credit of VRE as well as any policy or regulatory decisions that speed or slow the transition. Still, since the capacity credit of VREs is lower than that of thermal units, especially at higher penetrations, the level of displaced capacity will not be as significant as the amount of added VRE. Hence, the capacity factors of the remaining dispatchable generation technologies are likely to decrease, on average, though the increased need for system flexibility may mitigate these declines for some specific plant types.

Another potential consequence of increasing VRE levels is that dispatchable units may have to cycle more often. Some studies have examined how increased VRE penetrations will impact the cycling of thermal units and the corresponding costs that may be incurred; in restructured markets, altered wholesale energy price patterns and increases in AS needs and prices may—to a degree, at least—compensate dispatchable units for these increased cycling demands.

There are several specific reasons for cycling-related cost increases. First, thermal unit ramping—i.e., adjusting generation output—typically causes some mechanical fatigue and may therefore increase long-term maintenance costs. Second, unit startups and shutdowns cause similar unit fatigue, and units also incur additional fuel costs for startups. These costs can be exacerbated by longer idle times that require warm or cold starts, as opposed to hot starts. Finally, units may be operated more frequently at lower output levels, which typically means that the operational efficiency is lower with a corresponding increase in fuel use and variable generation costs. These latter costs are generally not included in cycling cost calculations, and are instead embedded in the estimated impacts of VRE on system production costs; as such, we do not report these results here.

Resources on the grid continuously interact to meet time-varying demand and it is hard, if not impossible, to precisely map the characteristics of one resource group to the ramping needs from another. In reality, many generation technologies create ramping needs for the system (e.g., inflexible baseload plants have always created a need for flexible peaking plants to load follow). Additionally, as noted above, dispatchable units can—to a large extent—include cycling costs in their energy and AS offers (or, outside of wholesale markets, in their contracts with purchasers), and therefore would recover these costs from the electricity market if they are committed and dispatched (i.e., through the energy price, AS prices, or make-whole side payments). Units that are more flexible and able to startup and shutdown at lower-cost have a competitive advantage that should be rewarded; related, efficient markets would also encourage load to offer flexibility to the system, potentially reducing cycling on the supply side of the market. VREs, meanwhile, do not have the same access to these additional revenues, and so are 'penalized' in the market relative to more-flexible resources.

Summary of Findings in Literature

The modeled impacts of high VRE scenarios on thermal-plant capacity factors are summarized in Figure 24 through Figure 26. The figures show that capacity factors decrease in most cases for thermal

technologies, including coal, natural gas combined-cycle, and natural gas combustion turbines.[29] Note that most studies assumed that nuclear units are inflexible and therefore their capacity factors either do not change significantly or are not explicitly analyzed.

Several reported impacts of increasing VRE on unit cycling costs are shown in Figure 27. GE Energy (2014) found that natural gas combined-cycle units were the most significantly affected due to increased startup and shutdown requirements. Coal units were also affected, primarily due to increased ramping and load following. In contrast, the cycling costs of natural gas CTs were found to decrease at higher VRE levels.

Bloom et al. (2016) found that the variability of wind and solar cause thermal units to ramp, startup, and shutdown more frequently. While cycling costs were presented jointly for all thermal plants, several operational impacts were presented for different plant types. At 30% VRE penetration, coal plant ramps increase by about 33% and natural gas combined-cycle ramps increase by about 25%, both on a per unit of energy basis compared to the baseline. Starts increase by roughly 20% for coal plants and 40% for combined-cycle units, while natural gas CT starts decrease; this is consistent with the decreasing cycling costs that GE Energy (2014) reports for CTs.

Lew et al. (2013) also reported cycling costs jointly for all thermal plants, but discussed operational impacts for specific plant types. High wind scenarios were found to increase starts for coal plants, but high solar scenarios did not impact coal starts significantly. Similar to GE Energy (2014) and Bloom et al. (2016), they found that CT starts are reduced at high wind levels due to overall decreases in generation from those plants. In contrast, coal plants ramp more frequently with both increased wind and solar; natural gas combined-cycle ramps also increase slightly, whereas CT ramping is largely consistent. The cycling costs reported by Lew et al. (2013) include O&M costs from starts and ramping as well as start-up fuel costs. We present the average value of their reported upper and lower bounds. All of these cycling costs are reported per unit of fossil generation. Increased per unit cycling costs may therefore be partially caused by both increased total cycling costs and decreased generation.

[29] Deetjen et al. (2016) presented total generation by unit type but not the total capacity. To estimate capacity factors for this study, assumptions were made regarding the capacity of each unit type in ERCOT at the time based on other sources. Therefore, while the general trends displayed in the figure are accurate representations of the model results, the specific capacity factor values may differ to some extent.

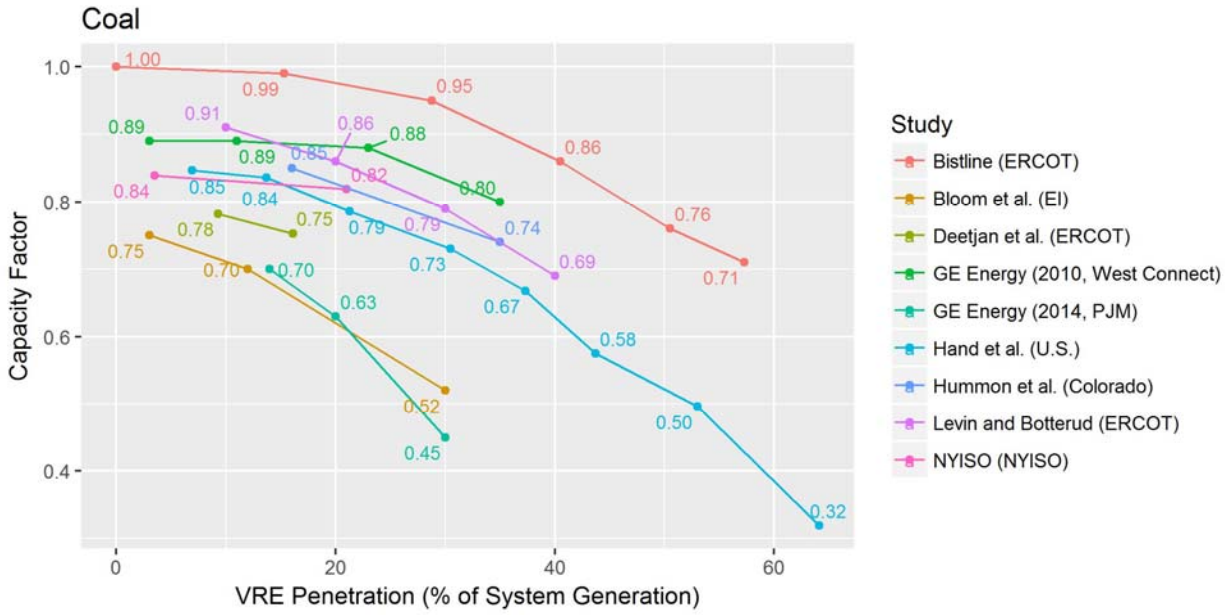


Figure 24. Capacity Factors for Coal Plants with Increasing VRE Penetrations

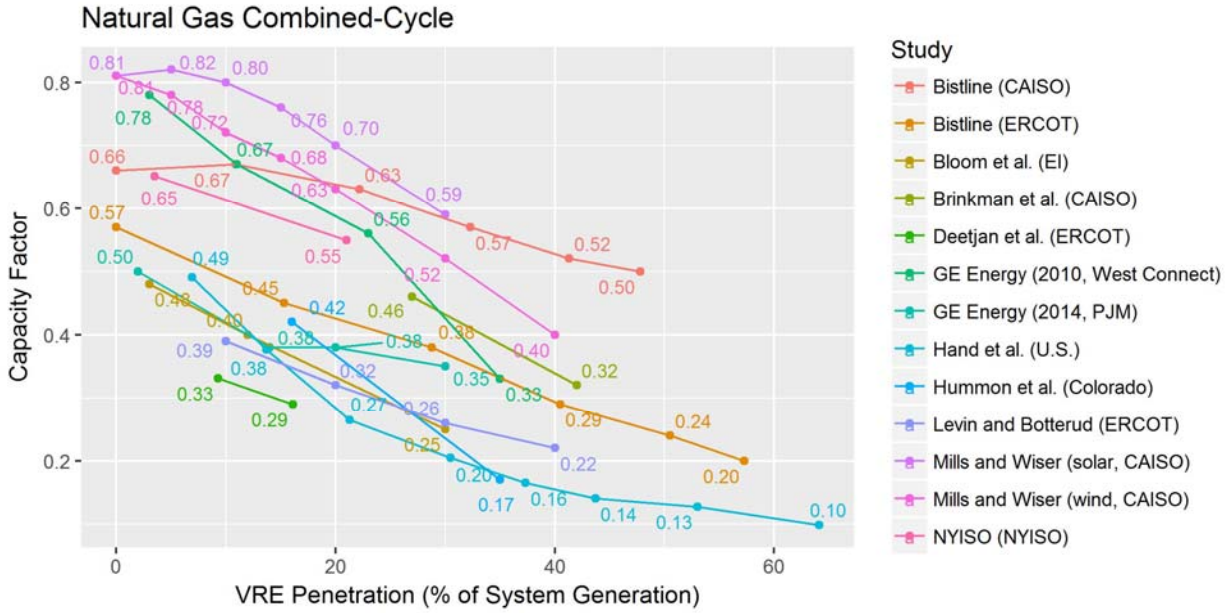


Figure 25. Capacity Factors for Natural Gas Combined-Cycle Plants with Increasing VRE Penetrations

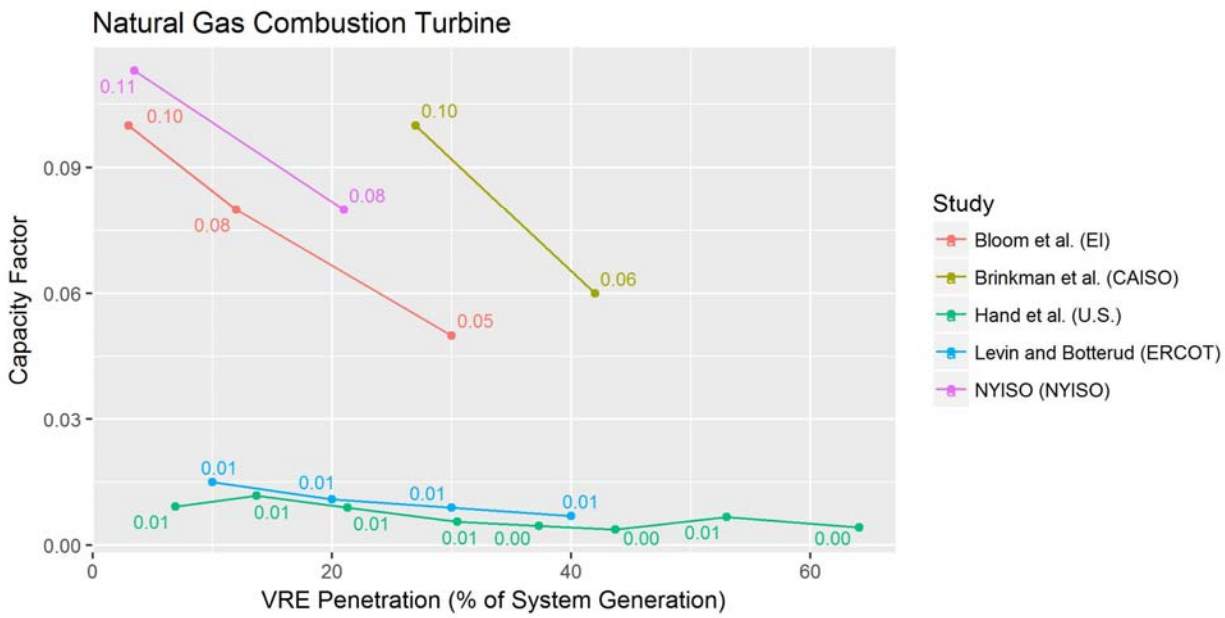


Figure 26. Capacity Factors for Natural Gas Combustion Turbine Plants with Increasing VRE Penetrations

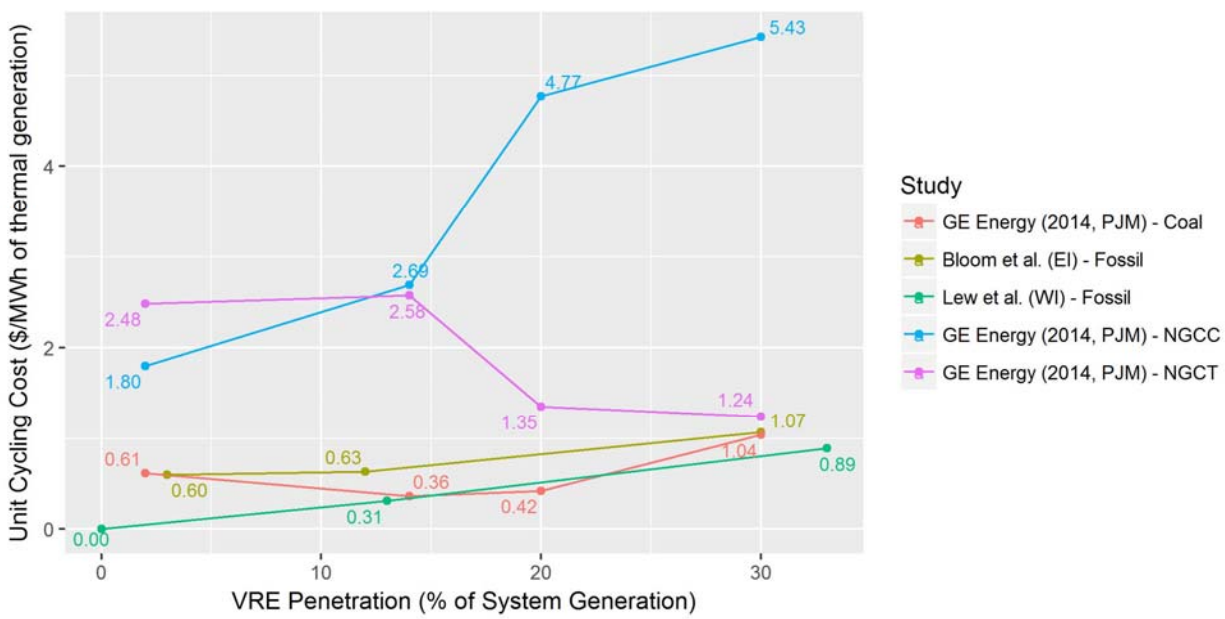


Figure 27. Cycling Costs for Thermal Plants with Increasing VRE Penetrations

Revenues and Operating Profits for Generators

Revenue impacts originate from changes in wholesale prices (which influence the revenues received for each unit of generation) as well as changes in capacity factors (which influence the total quantity of generation a plant is able to sell into the market). Some studies focused on projected plant revenues and profits to anticipate plant types that may be at-risk for retirement, but did not explicitly consider such unit retirements in their modeling. As plant retirements decrease generation supply, these would likely have an upward influence on price and profitability for the remaining units in the long term. Not all studies considered this longer-term dynamic, and the results should be interpreted accordingly.

In restructured markets, most generators receive the majority of their revenues through wholesale energy markets (see the various ISO/RTO market monitoring reports, e.g., Potomac Economics 2017b, 2017c; SPP 2017; Potomac Economics 2017a; ISO-NE 2017b; CAISO 2017b). Reserve markets have delivered additional revenue to some generators, but generally in small quantities. That said, reserve markets may play an increasingly important role for some units as VRE penetration increases and as the demand for these services grow (see earlier subsection in this chapter that addresses this issue). In some regions, capacity markets (or requirements that lead to bilateral capacity contracts) provide additional revenue to encourage resource adequacy, whereas in others (e.g., ERCOT) it is presumed that energy-market prices will embed compensation for capacity during scarcity events. Regardless of the details, the important point for this review is that revenues from AS and capacity markets/contracts were not included in all studies, and so results should be interpreted with some caution. Note, finally, that all reviewed studies simulated the operation of a restructured wholesale market; power plants in regions that lack such markets or that have physical or financial contracts that hedge against wholesale market price variations may be—at least partially—immune from immediate revenue impacts as signaled by wholesale market prices and dynamics.

Summary of Findings in Literature

Figure 28 through Figure 31 summarize the reported impacts on operating revenues and profits for nuclear, coal, natural gas combined-cycle and CT plants. Studies differed in how they report revenues and profits: some strictly presented plant revenues, while others presented operating profits (i.e., revenues less operating costs but not considering capital costs). Table 6 indicates which cost and revenue streams were considered by each study. The studies that reported revenues (i.e., absent of operating costs) are also identified in the figure legend with a star, while the remainder reported operating profits. As indicated in Table 6, none of the studies considered capital costs. Overall, it should be stressed, once again, that it is more appropriate to analyze these figures for the trends that are identified within each individual study, as opposed to making comparisons of the specific values identified across different studies.

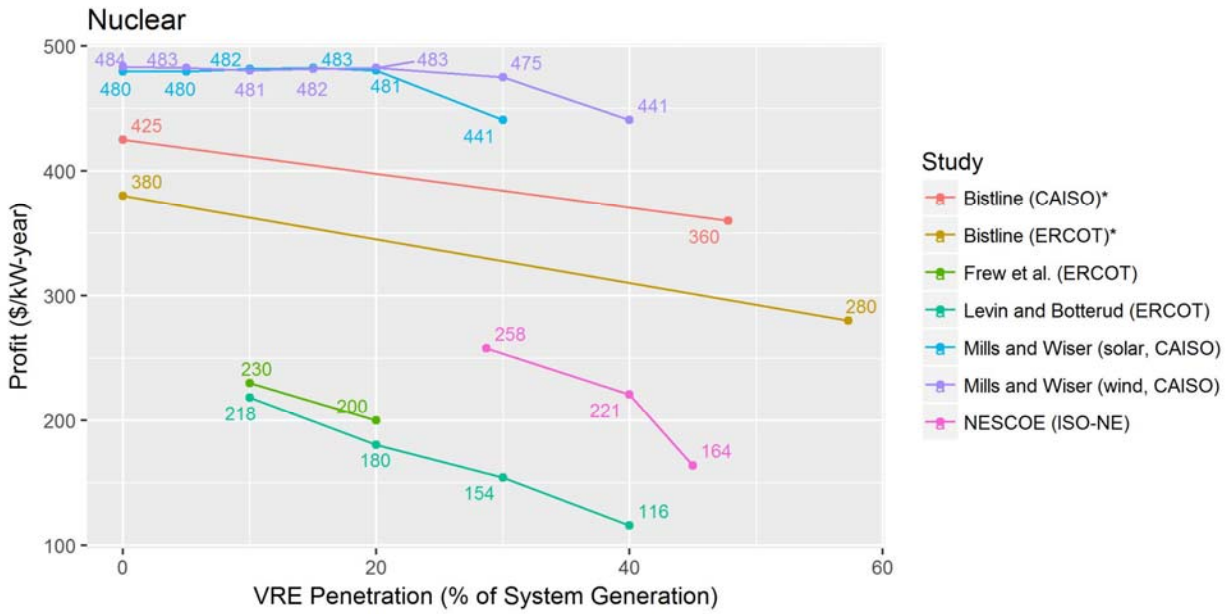
Table 6. Revenue and Cost Streams Included in the Revenue Analysis Presented by Each Study

Study	Energy Market Revenue	AS Market Revenue	Capacity Market Revenue	Operating Costs	Capital Costs
Bistline (CAISO and ERCOT)	X		n/a		
Frew et al. (ERCOT)	X	X	n/a	X	
GE Energy, 2010 (ERCOT)	X		n/a		
Levin and Botterud (ERCOT)	X	X	n/a	X	
Mills and Wiser (CAISO)	X	X	n/a	X	
NESCOE (ISO-NE)	X		X	X	
Shavel et al. (ERCOT)	X	X	n/a	X	

Note: Several of these studies embed capacity compensation in energy-market prices (e.g., through assumptions about scarcity pricing), even if capacity markets are not separately modeled.

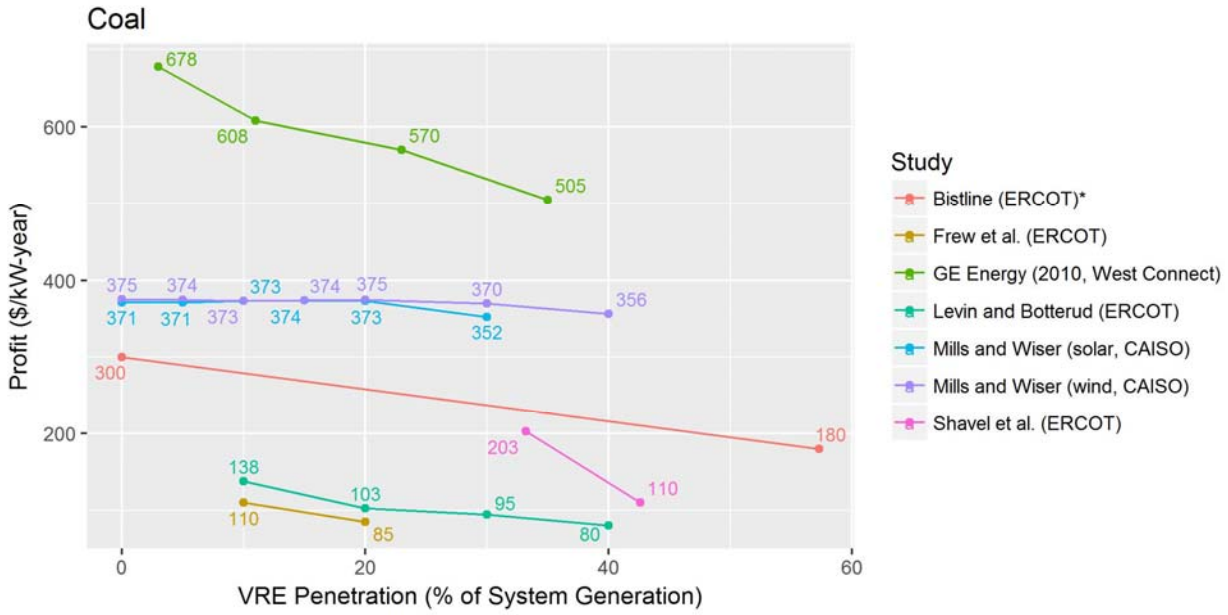
Overall, these studies show a downward sloping trend in revenue and operating profits fornuclear and coal plants as VRE penetrations increase. Natural gas fired generation tends to see a reduction in

revenue with increasing VRE penetration but operating profits are generally less-affected. This is partly because operating costs are largely variable in nature—any reductions in total generation output also significantly reduces fuel costs. Those studies that assessed long-term equilibrium effects on profitability sometimes found that flexible gas plants fare reasonably well under higher VRE penetrations, at least in terms of operating profit: natural gas fired generation tends to be a competitive option with low fixed costs and low gas prices, and gas units are flexible and therefore tend to benefit from price spikes and to be less exposed to average price reductions compared to nuclear and coal generation. Note that GE Energy (2010b) assumed a relatively high natural gas price ($9.50/MMbtu), and also included a $30/ton cost of carbon. This leads to higher reported energy prices and correspondingly higher revenues than reported by other studies.



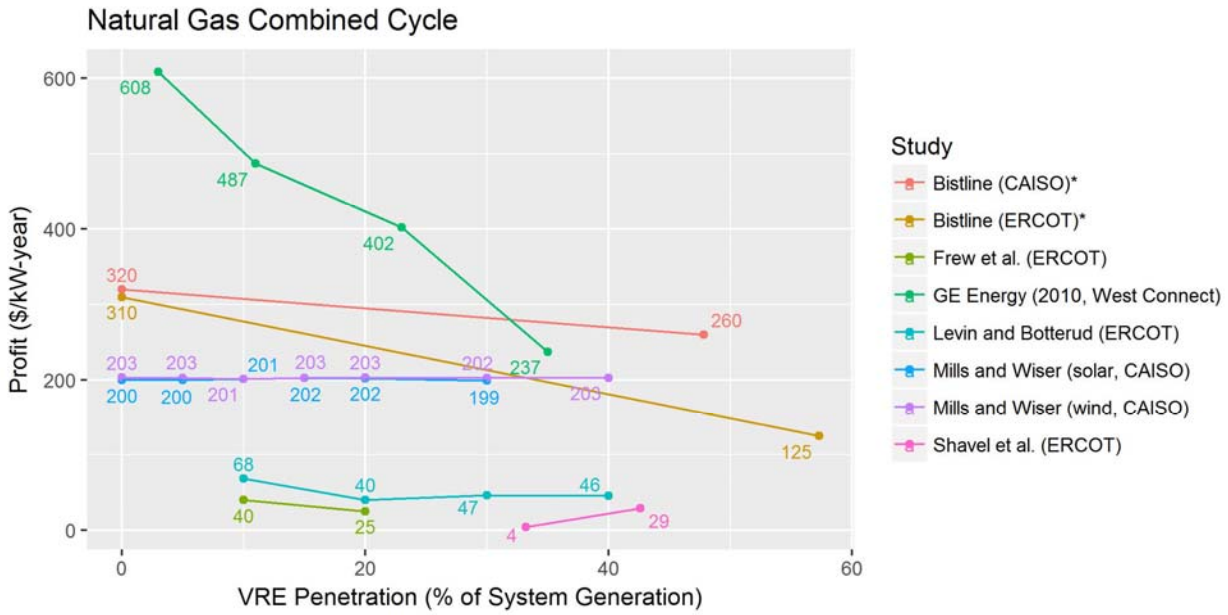
Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 28. Operating Profits and Revenues for Nuclear Plants with Increasing VRE Penetrations



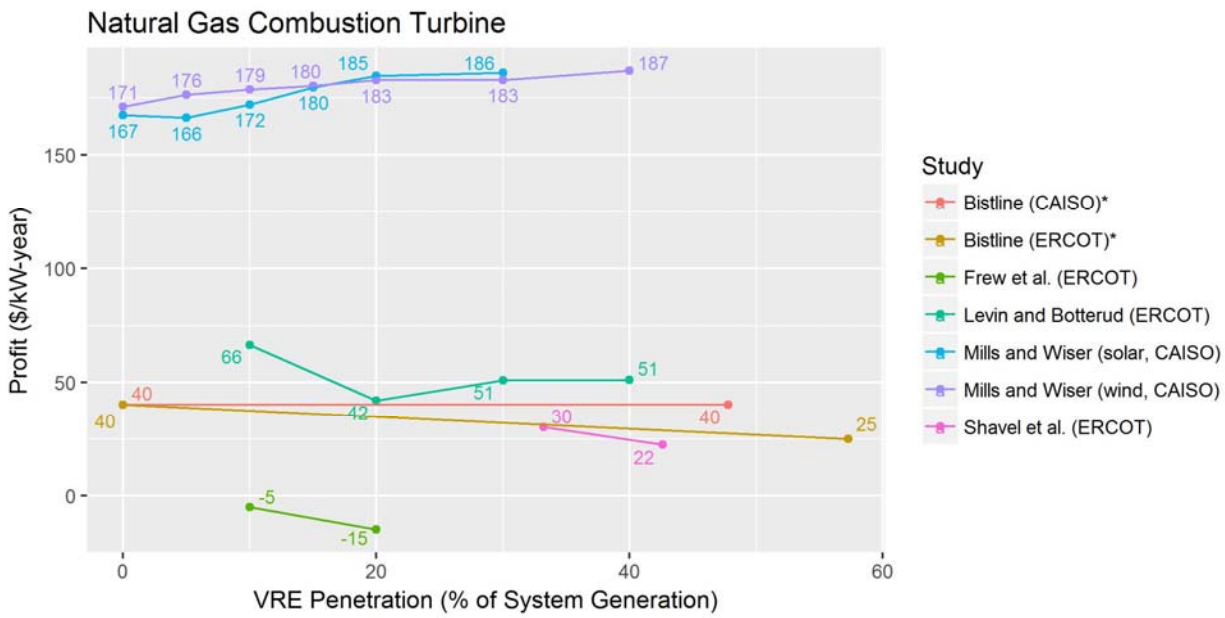
Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 29. Operating Profits and Revenues for Coal Plants with Increasing VRE Penetrations



Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 30. Operating Profits and Revenues for Natural Gas Combined-Cycle Plants with Increasing VRE Penetrations



Note: Studies denoted with an asterisk report unit revenues while the remainder report operating profits.

Figure 31. Operating Profits and Revenues for Natural Gas Combustion Turbine Plants with Increasing VRE Penetrations

Impacts of Natural Gas Prices

While it has been shown that increasing VRE penetrations may cause wholesale electricity prices to decline, the price of natural gas is another primary driver of electricity prices. The previous chapter shows that lower natural gas prices are by far the most important factor in explaining recent observed declines in wholesale electricity prices. This is not surprising, as natural gas-fired generation sets the marginal price a large fraction of the time in most U.S. electricity markets,[30] and the cost of generation at these plants is heavily dependent on the cost of obtaining natural gas fuel stocks. Several of the reviewed studies analyzed the system impacts that result from changes in natural gas fuel prices.

Levin and Botterud (2015) found that the load-weighted average wholesale electricity price decreases by 24%, from $54/MWh to $41/MWh, when wind penetration is increased from 10% to 40%. A comparable price reduction (23%) was observed when the natural gas fuel price is reduced from its baseline value of $5.15/MMbtu to $3.00/MMbtu. Increasing the natural gas fuel price to $8.00/MMbtu similarly results in a 34% increase in the load-weighted average electricity price (and, therefore, also an increase in generator revenue).

GE Energy (2014) found that achieving a 14% renewable energy target in 2026 reduces the load-weighted average wholesale electricity price by 6.2% relative to a baseline (2% VRE) scenario. This electricity price reduction is comparable to the impact of reducing natural gas prices from the baseline assumption of $8.02/MMbtu to $6.50/MMbtu (7.4%). The reference scenario presented by Shavel et al. (2013) assumed lower natural gas prices (roughly $5.80/MMbtu vs. $7.50/MMbtu) and higher renewable costs than those assumed in the high renewable sensitivity scenarios.Reducing the natural gas price and increasing renewable costs has two primary impacts in this equilibrium analysis with endogenously determined VRE penetration. First, there is substantially less wind and solar generation—accounting for 7% of the system total compared to 33%. All else equal, previous evidence suggests that wholesale electricity prices (i.e., LMPs) should increase as a result of the reduced VRE generation. Second, natural gas prices are also lower in this case and this has a downward impact on electricity prices. The combined effect is an overall decrease in average wholesale prices from approximately $58/MWh to $46/MWh. This suggest that in a long-run equilibrium setting, reducing natural gas prices will likely also reduce electricity prices, even if VRE generation is simultaneously reduced as well.

Impacts of VRE Incentives

Levin and Botterud (2015) analyzed the system impacts of removing the federal PTC for wind generation, isolating the bidding impact of the PTC from its deployment effect (i.e., the wind penetration level was independent of the PTC assumption). In the base cases, wind generators were assumed to receive a $23/MWh tax credit. Note that the PTC is currently being phased out, and all wind units commencing construction on or after January 1, 2020 will no long be eligible to receive the incentive. In the meantime, and for the first 10 years of operation for projects that receive the incentive, the PTC is one factor motivating negative bids from wind generators.

The study found that removing the PTC, but keeping wind penetration constant, does not influence electricity prices at 10% wind penetration, as wind never provides the marginal unit of generation under these conditions. In reality, there would likely be some impacts even at 10% wind penetration as the study did not consider geographical and transmission constraints, which may cause wind to occasionally

[30] This is confirmed by the many market-monitoring reports published by the ISOs/RTOs (Potomac Economics 2017a, 2017b, 2017c; SPP 2017; CAISO 2017b; ISO-NE 2017b; Monitoring Analytics 2017).

set the marginal price at certain nodes. At 20% and higher wind penetration levels, on the other hand, the study did observe price impacts driven by the bidding impacts of wind power. The study found that removing the PTC increases the load-weighted average electricity price by 0.3%, 2.2% and 10.4% for 20%, 30% and 40% wind penetration respectively. This effect is still small compared to the impact of changes in natural gas prices.

4.4 Directions for Future Research

As noted earlier, synthesizing the available literature on the potential future impacts of VRE on wholesale power markets and bulk power assets and operations is challenged by the diverse nature of the literature. Our review of the literature reveals that there are many research areas where more work is needed to better understand how a transition to high VRE penetration levels might influence future electricity markets and bulk power system assets. Important directions for future research include:

- Detailed investigations of the long-run effects of a transition towards high level of VRE, where the portfolio of generation resources fully adapts to the growth in low marginal cost VRE resources, so at to determine the degree to which short-term impacts are likely to persist long term.
- Analysis of capacity markets and requirements, and their influence on the overall revenues and profitability of various resources with increasing VRE levels. This aspect is not covered at all in the current review, and yet capacity markets or requirements exist in many areas of the country.
- Detailed investigation of the impact of different energy and environmental policy mechanisms (e.g., technology specific tax credits and RPS mechanisms, regional/national carbon markets/taxes, etc.) on wholesale electricity markets, to ascertain the scale of relevant differences from policy interventions.
- Assessments of the impact of improved representation of operational details in long-term electricity market models with increasing shares of VRE, so at to ensure that those models are accurately capturing the system-wide impacts of VRE and other resources.
- Exploration of the degree to which market products and policies reveal the value of flexibility, and mechanisms to more fully incentivize resources to provide flexibility with increasing levels of VRE.
- Further analysis of the impacts of VRE on the cycling costs of different generation options, and the multiple other options for delivering similar flexibility to the system via demand flexibility, storage, transmission, institutional and market reform, etc.

These research directions will contribute to improved insights into possible transitions of the electrical power grid and how electricity market design and energy policy decisions influence the viability of different supply, demand, and storage technologies, as well as the overall resource portfolio of the grid.

5 System Value and System Costs of Variable Renewable Energy[31]

5.1 Moving Beyond LCOE as a Means of Comparing Resource Options

A primary function of electricity regulators and the utilities they regulate is to minimize the total cost of reliably meeting demand for electricity, subject to other policy, societal, and legal constraints. A primary function of wholesale electricity markets, meanwhile, is to assist in meeting these goals by maximizing societal welfare in delivering electricity services, primarily through creating markets that enable efficient dispatch and investment decisions.

If all generation sources were homogenous, decision-making by regulators, utilities, and power plant investors would be simple: purchase from or invest in the source with the lowest levelized cost of energy (LCOE). However, power plants have widely varying technical and economic characteristics, and so deliver different services, e.g. a natural gas combustion turbine may operate only in the 5% of peak hours in a year, whereas a nuclear plant may operate on a 24x7 basis for the majority of the year. Understanding the LCOE of a technology is critical, and seeking ways to reduce technology LCOE is a proper function for energy innovators and R&D managers. However, *comparing* the LCOE of *different* technologies that provide varying services is misleading. This is true when comparing a natural gas combustion turbine to a nuclear plant, and is also true when comparing the LCOE of VRE to the LCOE of a dispatchable thermal power plant (Joskow 2011; Borenstein 2012; Edenhofer et al. 2013; Hirth 2013; EIA 2017c; Makovich and Richards 2017). Both wind and PV have unique characteristics that create new challenges and opportunities for electric power systems; the same is true for all other generation types. The idealized role of power sector planners and wholesale power markets is to balance the various characteristics of different generation sources and create an optimal least-cost mix of the available options.

In an idealized perfectly competitive wholesale electricity market, efficient investment decisions occur when a generator is able to cover its total fixed and variable cost through the revenue it earns in the market (Stoft 2002). The prices for electricity services (energy, capacity, congestion relief, AS) and the quantity of services provided by the generator dictate the revenue earned, in effect its 'market value'. If an investor has a technology whose LCOE is lower than the market value as revealed in wholesale markets, then an investment would be profitable for the investor and efficient in the sense of maximizing welfare. Similarly, the revenue earned by a VRE generator in a perfectly designed competitive wholesale market reveals its direct economic value and can indicate whether it would be efficient to invest in more of that VRE resource (Figure 32). If the goal is to maximize welfare, then the marginal value, as opposed to the average value, should be compared to the LCOE. Prices in wholesale markets similarly reflect impacts at the margin. The marginal value of VRE, meanwhile, will tend to decline at progressively higher penetrations, as discussed later; this is because the ability of VRE to offset the cost of other bulk power system assets (whether related to energy, capacity, balancing, or transmission) generally declines on the margin as penetrations increase.

Electricity planners, investors, and forecasters often use complex computer models (or combinations of models) to simulate dispatch and capacity expansion, and to assess what combination of resources will best minimize total costs, considering generation, transmission, and distribution. These models are able

[31] Note that the focus of this report is on bulk power system impacts. As such, we touch only briefly on the impacts of distributed renewable resources on disibution-system expenditures.

to capture not only the LCOE of each resource, but also the specific values (or costs) that each resource brings to the grid—energy, capacity, balancing, and transmission. Internally, the models are similarly comparing technology cost and marginal system value of each technology choice to find the portfolio of resources that minimize total system costs, subject to reliability and other constraints.[32] These same models are also sometimes used to assess the 'system value' of VRE in providing electricity services, and to assess how that system value changes with increasing penetration and altered conditions. Furthermore, some utilities use these system value calculations to help compare different technology options in procurement processes where transparency needs limit the ability to simply rely on complex models. Specifically, utilities determine which option is most attractive by finding the technology with the lowest LCOE net of its system value (or conversely the technology the highest system value net of its LCOE). This 'system value' perspective is the basis for comparing bids from different technologies in the 'Least-cost/ Best-fit' process used by California utilities in evaluating RPS bids (Mills and Wiser 2012b).

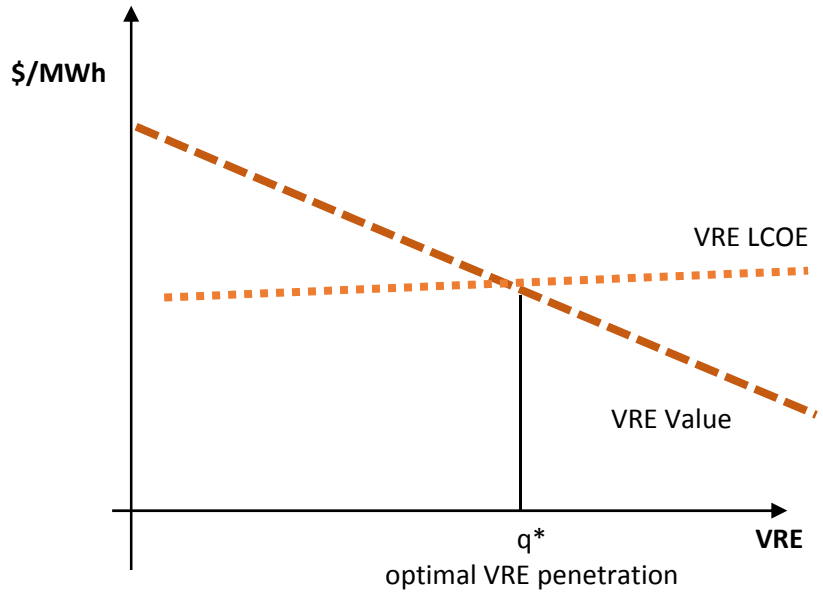


Figure 32. Welfare is Maximized When the Penetration of VRE is Such that the Marginal Value of VRE is Equal to the Marginal LCOE of VRE (presuming that the value captures all relevant private and social costs and values, including balancing needs, environmental costs, etc.)

A few brief definitions will be useful at this point, with additional detail provided later. *'System value'* as used in this chapter refers to the ability of any bulk-power system asset to contribute to meeting demand such that it avoids the cost of instead using other bulk-power system assets. In general, costs that might be avoided include those related to energy, capacity, balancing, and transmission. Of these, *'energy value'* is often based on the ability of a resource to offset the production costs of other resources; in competitive markets, wholesale market LMPs are sometimes used to estimate this value. *'Capacity value'* measures a generator's contribution to overall long-term resource adequacy via an ability to offset the need (and cost) for capacity from other sources. *'Balancing'* (sometimes also called integration) needs originate from the required flexibility to maintain a continuous operational balance between supply and demand, with some resources increasing these needs and related costs and others offsetting those needs and costs. Finally, *'transmission'* refers to the differential impact of resources on

[32] Appendix B in Mills and Wiser (2012a) illustrate this point by showing how a capacity expansion model compares the cost of a resource to the value of that resource to identify the portfolio of options that minimize the total cost.

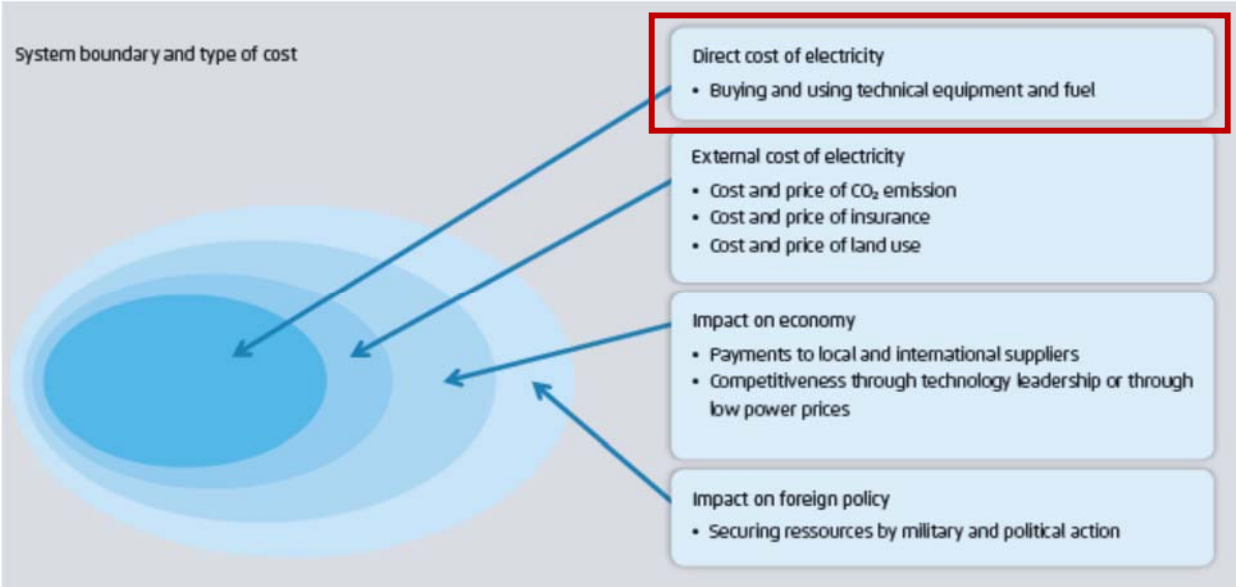
the need for additional transmission infrastructure. *'System value'* ideally would comprehensively embed the marginal impacts of all four of the considerations noted above. *'Market value'*, meanwhile, refers to the subset of these factors that are actually priced in markets in the form of generator-specific revenue. Plant-specific technology LCOE refers to the direct plant-level levelized cost of generation, not considering any costs incurred or caused outside of the plant boundary.

To be clear, modeled outcomes and wholesale electricity prices do not necessarily reflect the *full* 'system value' of individual resources. Both models and wholesale markets are limited in their ability to account for all impacts, particularly for issues around uncertainty, variability, and locational resource dependence of VRE generators. Detailed operational integration studies are often used to quantify impacts like wear & tear related cycling costs, the need for and cost of additional balancing reserves, the impacts of uncertainty, and transmission congestion. Additionally, wholesale electricity markets as well as the models used to simulate them may not be designed to reveal the complete set of values for all energy resources at all times, particularly broader societal values, such as differential environmental costs, resilience, fuel security and diversity impacts, etc. Many might argue, for example, that distributed energy resources are not yet optimally integrated into wholesale markets because those resources are not yet broadly allowed to participate in the bulk power market. More generally, others would argue that these markets are inadequate in their valuation of resilience, fuel security/diversity, or environmental impacts; these perceived inadequacies have given rise to any number of federal and state policy interventions intended to shift market outcomes towards socially-desirable goals.

When discussing the 'system value' of resources, we take a somewhat narrow view of the definition of that term—focused only on avoidable monetary bulk power system expenditures ('direct cost of electricity', as depicted in Figure 33). Four specific types of expenditures are included: energy, capacity, balancing, and transmission infrastructure. We focus on actual expenditures, but recognize that the consequences of VRE may differ between producers and consumers. We do not include broader environmental, economy, or societal costs and benefits in this discussion. However, we also very-much recognize that policymakers commonly take a broader perspective that does include consideration of these factors. Also of note is that we focus on 'system value', inclusive (ideally) of all four factors noted above. That being said, the literature that we review does not always consider each of these factors, and there remains disagreement on how to assess each one individually and all four collectively. Of additional relevance is that existing bulk power markets may not fully assign all costs or values to individual power plants; balancing and transmission needs, in particular, are often partly socialized due to difficulties in cost assignment and the broader market benefits of meeting these needs. As such, 'market value' may represent only a subset of 'system value.' We ignore the details of market design and the completeness of markets in this chapter, instead focusing where we can on all four elements regardless of how each is actually compensated or costed in real markets.

Finally, policymakers sometimes desire simple comparisons of technologies just based on cost, rather than comparing cost and system value as above. While it is clearly inappropriate to directly compare technologies based only on LCOE (or only on system value), various attempts have been made to develop adjustors to the plant-level LCOE of a technology that account for system value differences, considering energy, capacity, balancing, and transmission. These adjustors are sometimes called the *'system costs'*. Conceptually, all resources have 'system costs' (whether positive or negative); however, in practice, the majority of the system cost literature has focused on VRE. Simple comparisons based on

LCOE with system cost adjusters are controversial and complicated, in part because it is challenging to adequately account for all relevant differences among a wide range of generation resources within a simplified framework. Comprehensive system cost adjustments are therefore not used for investment decisions or in electric sector planning, as more-sophisticated modeling tools that are better able to capture the complexities and complementarities of different resources are directly used in those contexts. Moreover, as with the system value components, many aspects of system costs have not historically been assigned to specific generators. We discuss system costs and the relationship between those costs and the system value of a resource at the end of this chapter.



Source: Agora (2015)

Figure 33. Overview of System Boundaries and Types of Costs and Benefits

5.2 System Value of VRE, and Changes in Value with Penetration

A growing literature has estimated the system value of VRE at varying penetration, often presented in $-per-MWh terms. As a reference point, this literature sometimes compares the estimated system value of wind and PV with that of an idealized flat inflexible baseload block of power—representative of a truly baseload facility that does not vary its output during the year and experiences no outages. The resultant ratio is sometimes called the 'value factor', where the flat baseload block would have a value factor of 1. An actual 24x7 baseload facility that experiences unplanned outages would have a value factor lower than 1, accounting for the need to maintain system reserves and capacity to manage those unplanned outages. A dispatchable thermal unit, on the other hand, would typically have a value factor above 1, since it would generate only when prices are above its marginal cost.

As noted earlier, ideally, system value estimates would be marginal estimates inclusive of all relevant system factors, including energy, capacity, balancing, and transmission in order to compare with the LCOE of VRE as in the dashed lines of Figure 32. In practice, however, the literature is not always inclusive of all factors, in part due to modeling limitations and in part because elements are not all fully priced in operating wholesale electricity markets. As a result, literature-derived system value (and value factor) estimates vary in terms of what is included: they almost always cover energy value and often cover capacity value (the latter is sometimes embedded within energy value as scarcity events), but they only sometimes cover aspects of balancing and they rarely fully include transmission. The latter two are

often excluded due to modeling limitations and/or because these elements are sometimes paid by load, and not fully used to vary compensation levels for generators. Estimates also differ based on whether reported impacts are on average or on the margin, and the difference between these two can be substantial. The varying comprehensiveness and approach of the available estimates—that we make no effort to fully reconcile here—complicates comparisons, and creates a risk of either over-estimating or under-estimating the system value of resources.

The system value of wind and PV are highly condition dependent, and will vary by penetration, the structure, costs and operation of the overall power system, and the degree to which various flexibility measures are available. Some of the literature has focused on historical trends in the value of wind and solar in the U.S., Europe, and Australia based on observed wholesale price patterns and VRE output (Fripp and Wiser 2008; Hirth 2016; Clò, Cataldi, and Zoppoli 2015; Cutler et al. 2011; Welisch, Ortner, and Resch 2016; BNEF 2016; Gilmore et al. 2014). This literature typically includes, at most, energy and capacity value. Other literature relies on modeled (and typically higher VRE penetration) scenarios (e.g., Mills and Wiser 2012a, 2013, 2014, Hirth 2013, 2016; Hirth, Ueckerdt, and Edenhofer 2015; Lamont 2008; Bushnell 2010; Green and Léautier 2015; Sivaram and Kann 2016; Olson and Jones 2012; Winkler, Pudlik, et al. 2016; Denholm et al. 2016; Levin and Botterud 2015; Bistline 2017; Birk and Tabors 2017; Agora 2015; Riva, Hethey, and Vitina 2017; Obersteiner and Saguan 2011; Gilmore et al. 2014; MIT 2015). This literature typically includes energy and capacity value, and sometimes includes aspects of balancing and transmission. Importantly, notwithstanding the many limitations and complexities involved, all of this work recognizes that efficient electric system investment and operations decisions must be made not solely based on project-level technology cost (LCOE) but also value, and that VRE has unique value-based impacts and challenges due in part to its output characteristics (IEA 2016a). Accordingly, EIA (2017) now reports not only the LCOE of various technologies but also their estimated value to the electricity system, which EIA terms the levelized avoided cost of energy (LACE).

A subset of the literature has explored how to slow the decline in system value of VRE with increasing penetration, through changes in renewable technologies and deployment as well as changes in broader system-level electric conditions such as new transmission, increased generation and load flexibility, and storage. This work has largely focused on modeled future conditions (e.g., Mills and Wiser 2015; Hirth 2016; Denholm et al. 2016; Deetjen et al. 2016; Winkler, Pudlik, et al. 2016; Hartner et al. 2015; Ederer 2015; Obersteiner 2012; Tveten, Kirkerud, and Bolkesjø 2016; Hirth and Müller 2016; Denholm and Margolis 2016; Denholm et al. 2015; Denholm, Clark, and O'Connell 2016; Birk and Tabors 2017; May 2017; Obersteiner and Saguan 2011; Riva, Hethey, and Vitina 2017; Denholm, Eichman, and Margolis 2017; Gilmore et al. 2014; Forsberg et al. 2017).

Figure 34 presents the results of a subset of the literature, including analysis from the U.S. and Europe; Figure 35 presents data on the historical wholesale market value of wind and solar in CAISO and wind in ERCOT, based on analysis conducted at LBNL.[33] As shown in these graphics and the literature cited above:

- <u>The system value of PV often exceeds that of a flat-block of power at very low penetration:</u> This is because PV output is temporally correlated with summer afternoon peak loads in many regions. In CAISO (energy value only; capacity is procured separately via bilateral contracts) and ERCOT (energy value, but inclusive of scarcity events and so including historical capacity value as well), for example,

[33] The LBNL analysis used actual hourly historical wind and solar production data from ERCOT and CAISO as well as real-time wholesale market price data. Details related to the methodology are available on request.

analysis by LBNL shows that the value of PV at low penetration has been roughly 120% that of a flat baseload block (Figure 35; ERCOT data not shown in figure). The same generally holds with the literature summarized in Figure 34, with value factors of above 1.2 is a number of cases, though PV is less valuable than a flat baseload block in regions that feature winter peaks. As such, PV in many—but not all—regions has a higher system value on a $/MWh basis than an idealized *inflexible* 24x7 block of power, at low penetration.

- As penetrations increase, the system value of PV declines rapidly: This is because 'net load' peaks shift to the evening hours. In California, PV represented more than 12% of supply in 2016, and the value of that generation was 80% that of a flat block of power; this drop from 120% to 80% only represents energy value in the CAISO market, and does not fully consider capacity value shifts or balancing and transmission needs. At 15% energy penetration, the broader literature suggests overall value factors of around 40% to 80% that of a flat baseload block. Greater value declines occur at still-higher penetrations. At 30% penetration, value factors of less than 40% are possible.
- The system value of wind is lower than PV at low penetrations: The temporal patterns of wind production lead to system values that tends to be relatively similar to, though often somewhat lower than that of, a flat baseload block at low penetrations: a value factor of ~90% is not uncommon. This system value is well below that for PV in summer-peaking energy systems.
- As penetrations increase, the system value of wind declines, but at a relatively slower rate than PV: In ERCOT, at 15% wind penetration, wind's value factor remains at ~80%. Interestingly, this is much higher than in 2008-2011, when the value factor was just 50-60%, before the construction of new transmission lines (under CREZ) that enabled more wind to be integrated into the rest of the Texas market. In CAISO, the energy-based value factor for wind has fluctuated around 90% since 2011, with penetration increasing to 6%. The broader literature suggests value factors of roughly 70-90% at 15% energy penetration, declining to perhaps 50-85% at 30% penetration. In Denmark, a value factor of 80% was achieved with 35% wind penetration, due in part to the flexible underlying electric system with strong interconnections to neighboring countries (Welisch, Ortner, and Resch 2016).

(a)

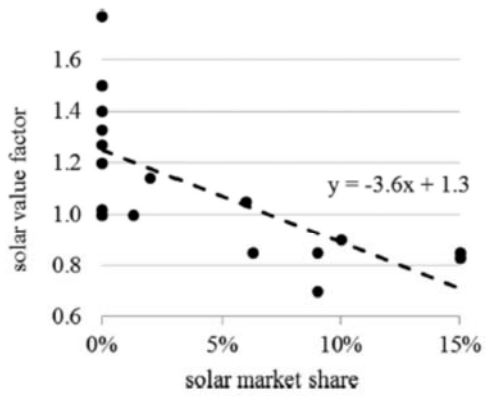


Fig. 6 *Solar market value literature. OLS-fit of all studies estimates the solar value factor to fall from 1.3 at zero penetration to 0.7 at 15% penetration*

Source: Hirth, Ueckerdt, and Edenhofer (2015)

(b)

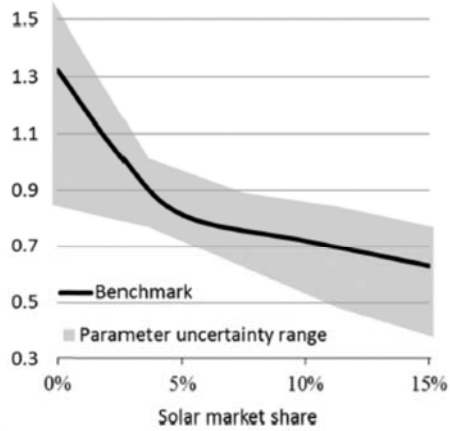
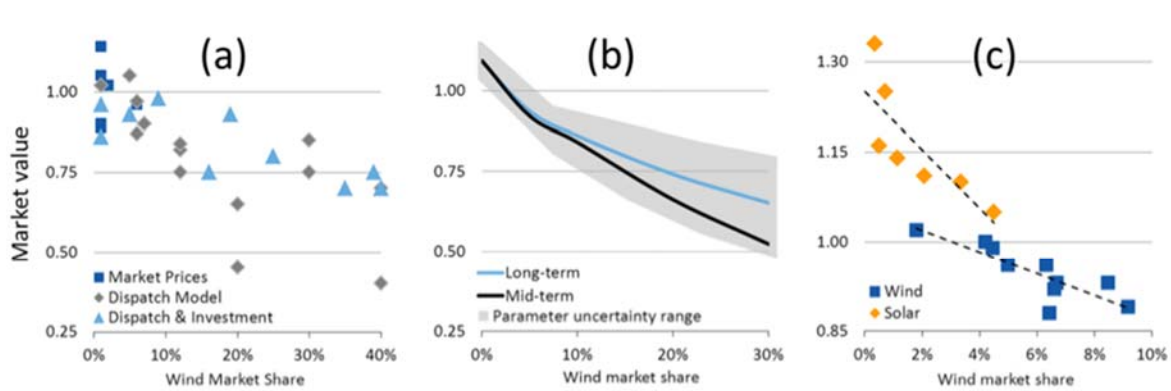


Fig. 14 *Long-term solar value factor drops to 0.4–0.8 at 15% penetration rate*

Source: Hirth, Ueckerdt, and Edenhofer (2015)

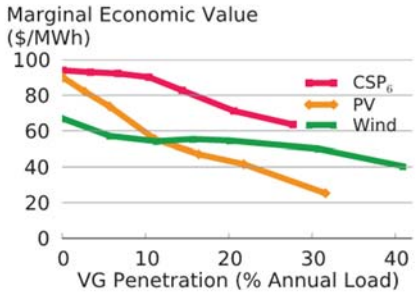
(c)



Wind value factor estimates from a literature review (a), the numerical model EMMA (b), and German historical market data (c). The value factor (wind revenue over base price) decreases with higher penetration rates.

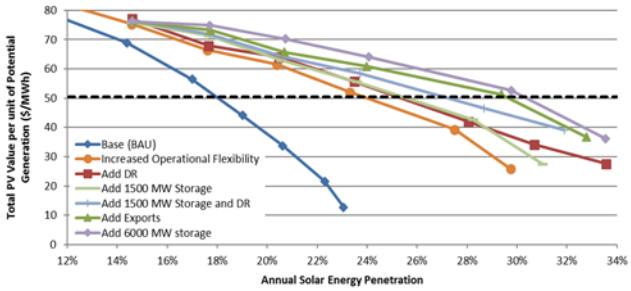
Source: Hirth (2013)

(d)



Source: Mills and Wiser (2012)

(e)



Source: Denholm et al. (2016)

Figure 34. Partial Summary of Literature on System Value of Wind and Solar: (a) review of available literature on value decline for PV; (b) modeled results of value of PV in Europe; (c) review of available literature on value decline for wind, modeled results of value of wind in Europe, and historical German data on value factors for solar and wind; (d) value decline for PV, CSP, and wind in California; (e) value decline for PV in California, including with multiple mitigation measures.

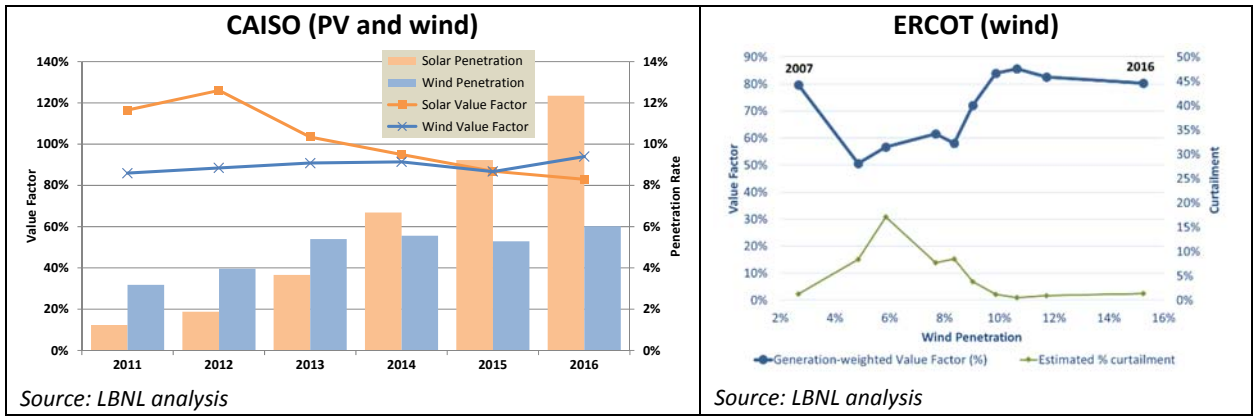


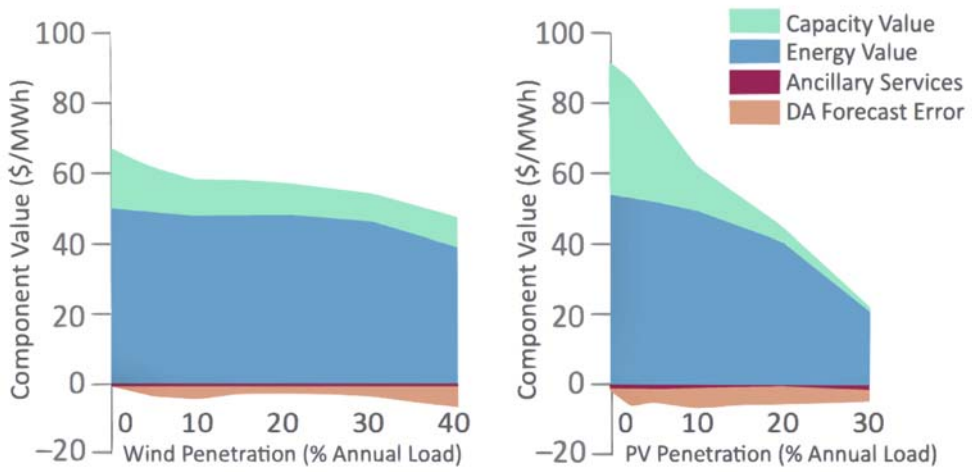
Figure 35. Historical Value Factor of PV and Wind in CAISO, and Wind in ERCOT

Multiple options exist to slow the declining system value of VRE with penetration. As already noted, value decline is not entirely inevitable: transmission investment and strong interconnection can stem the reduction as penetrations increase, and boost the value of VRE, as shown in the ERCOT and Denmark examples. Moreover, the decline in system value with penetration will be greater before capacity equilibration than in the long-term with capacity equilibration, because over time and with VRE the energy system mix will gravitate towards a portfolio that accounts for the growing shares of VRE (Hirth 2013; Sáenz de Miera, del Río González, and Vizcaíno 2008; Agora 2015). More generally, a variety of tools beyond transmission can be actively used to help stem the decline in VRE value with increasing penetration. These tools include VRE technology options (e.g., larger wind turbine rotors and taller towers, CSP with thermal storage, PV with optimized tilt and tracking and/or integrated storage, etc.) and deployment approaches (e.g., mixing wind with solar given complementary output characteristics). Additionally, changes in broader system-level conditions (whether through new investments or changes in the operations of existing assets) such as increased generation and load flexibility, storage, and transmission can stem the declining system value of VRE with increased penetrations. Based on available research, these approaches can reduce the rate of value decline, but are not likely to be able to stem the decline entirely at particularly high penetrations. Moreover, it is important to recognize that these tools often come at a cost, creating necessary tradeoffs between the value and cost of such investments.

Finally, though the literature has largely focused on VRE, it is important to recognize that all generation sources have system values, and that those values change with system conditions and with penetration. Moreover, to varying degrees the various aspects of system value are sometimes 'seen' by generation plants, and are in other cases socialized and paid for directly by load. A nuclear power plant that operates on a 24x7 inflexible basis, for example, will have a value factor lower than 1 to account for unplanned outages and the cost to maintain reserves and capacity to manage those outages; based on historical practice, these costs have been socialized and paid by load, rather than assigned for payment by nuclear units. Additionally, the system value of an inflexible 24x7 generation unit will decline with its own penetration given an inability to meet fluctuations in electricity demand. Dispatchable plants—whether thermal, hydro, of VRE with storage—on the other hand, will have value factors greater than 1 as they will tend to operate when prices are high and dispatch down when prices are low; these value differences are, to a great extent, priced into existing market designs. Finally, environmental, resilience, and other societal considerations could change these system value calculations dramatically.

5.3 Drivers for System Value: Energy Value, Capacity Value, Balancing, Transmission

In this section, we further detail the results of the system value literature as it relates to the four constituent factors that underlie that value. See Figure 36 for a summary breakdown, provided by one study, of three of the four factors—balancing costs in this case are separated into two components, ancillary services and day-ahead forecast errors. In part because the system value literature is not comprehensive in its coverage, we also introduce a broader literature to more-fully address all four value-impacting elements. These additional studies employ a wide variety of methodologies and have diverse objectives, but typically seek to evaluate the capability of the electric system to integrate increased penetrations of VRE and to quantify the costs and benefits of operating the system with VRE. Though the literature has advanced substantially, there remain core uncertainties about what costs to include and how to appropriately calculate and allocate those costs to specific resources; the different methodological approaches make comparisons difficult. Additionally, the results of VRE integration studies are dependent on electric system designs and regulatory environments: important differences include the generation capacity mix and the flexibility of that generation, the variability of demand, and the strength and breadth of the transmission system. Finally, there is also a general recognition that these studies have most-often focused on VRE, and that comparatively little attention has been placed on the costs of integrating other generation sources. Notwithstanding these limitations, below we summarize available literature on VRE impacts across all four impact categories.

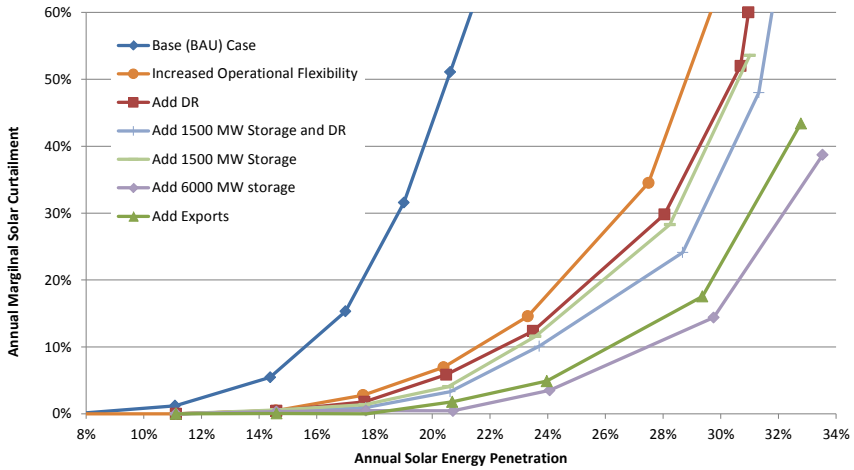


Source: Mills and Wiser (2012)

Figure 36. Relative Contribution of Various Factors to the System Value of Wind and PV in California

Energy Value: Changes in energy value are based on the temporal patterns of production, and are generally priced in competitive wholesale markets. When wind or solar are offsetting low-marginal-cost resources, for example, their energy value is lower because they are selling at lower LMPs (or, outside of competitive markets, offsetting lower production-cost resources). Alternatively, when VRE output is well correlated with net system peaks, it will more-often than not be offsetting high cost sources of generation (and therefore selling at higher LMPs). At still higher penetrations, it may be more costly at times to use VRE generation than to curtail output of VRE. As such, curtailment is expected to increase with penetration, further reducing energy value (in terms of $ per MWh of theoretical generation pre-curtailment). PV, in particular, may face substantial curtailment at high levels of penetration (Denholm and Margolis 2007; Mills and Wiser 2013; Denholm et al. 2016; Energy and Environmental Economics, Inc. 2014). As shown in Figure 37, a wide range of strategies can delay the increase in curtailment as PV

penetrations increase, but these strategies can come at some cost. Mills and Wiser (2013) estimate that the energy value of PV decreases from $54/MWh at 0% penetration to $27/MWh at 30% penetration, due in part to increasing curtailment. Olson and Jones (2012) estimate that the energy value of solar decreases from $72/MWh at 0% penetration to $56/MWh at 15% penetration.



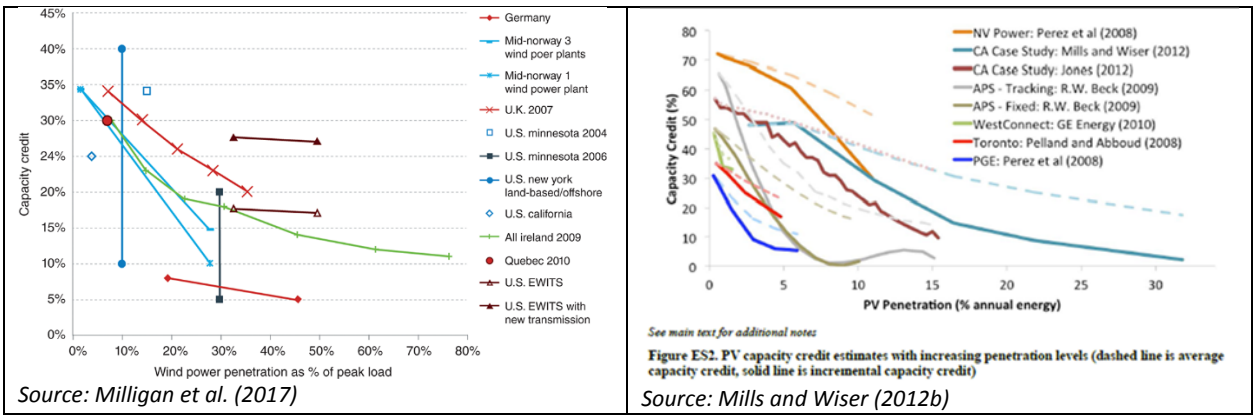
Source: Denholm, Clark, and O'Connell (2016)

Figure 37. Impact of Individual Flexibility Options on Marginal PV Curtailment in California

Capacity Value: As defined by NERC (2011), the capacity credit of a resource measures an individual generator's contribution to overall long-term resource adequacy, and represents the fraction of the nameplate capacity of a resource that contributes to lowering the risk that demand for electricity will exceed the available supply. Typically, the most credible means of calculating the capacity credit of a resource is through a probabilistic approach, such as the effective load carrying capability (ELCC), though many nuances and alternatives exist (NERC 2011; Keane et al. 2011; Dent et al. 2016). The contribution of VRE to meeting peak demand is less than the resources' nameplate capacity. Figure 38 presents a subset of the available literature for the capacity credit of PV and wind, both at low and at higher penetration. While a great deal of spread is apparent—driven by varying local conditions and methodological differences—the capacity credit of PV declines rapidly as penetrations increase. The capacity credit of wind, meanwhile, is often lower than that for PV at low penetration, but declines at a slower pace as penetrations increase. The capacity credit of baseload or dispatchable units is often ~90%. The lower capacity credit of VRE relative to these other resources implies that systems with high penetrations of VRE will have higher levels of aggregate nameplate capacity (including VRE and non-VRE) in order to maintain the same level of resource adequacy.

The capacity value accounts for not only the capacity credit of VRE, but also the value of providing this capacity as revealed by capacity markets, scarcity prices, or the cost of procuring capacity through other mechanisms (i.e., bilateral contracts, building new capacity resources, or demand-side options). Markets generally seek to price this attribute in some form, though the price can be very low during times when sufficient capacity is available to comfortably meet planning reserve margins. In some cases, studies explicitly estimate the capacity value of VRE, in others the capacity value may be embedded in the energy value through scarcity prices, and in others the capacity value is not calculated or is ignored. Studies that do calculate it find that the capacity value declines with increasing penetration due to the decline in the capacity credit. Mills and Wiser (2013) estimate that the cost of capacity in 2030 will be $170,000–180,000/MW-yr based on the cost of new generation needed to meet peak demand that is not covered by revenue in the energy market. The capacity value of an idealized flat block of power,

which has a 100% capacity credit, is therefore about $20/MWh. They find that the capacity value of PV decreases from $37/MWh at 0% penetration to $1/MWh at 30% penetration. Olson and Jones (2012) assume a cost for a simple-cycle CT of $149,000/MW-yr and estimate that the capacity value of solar decreases from $45/MWh at 0% penetration to $5/MWh at 15% penetration. The capacity value of wind, on the other hand, is much lower at $17/MWh at 0% penetration, decreasing to $8/MWh at 30-40% penetration (Mills and Wiser 2012a). As such, the per-MWh capacity value of PV is higher than that of a flat block of power at low penetration, but rapidly declines. The capacity value of wind begins at a value lower than a flat block of power, and declines at a more-measured pace than solar.

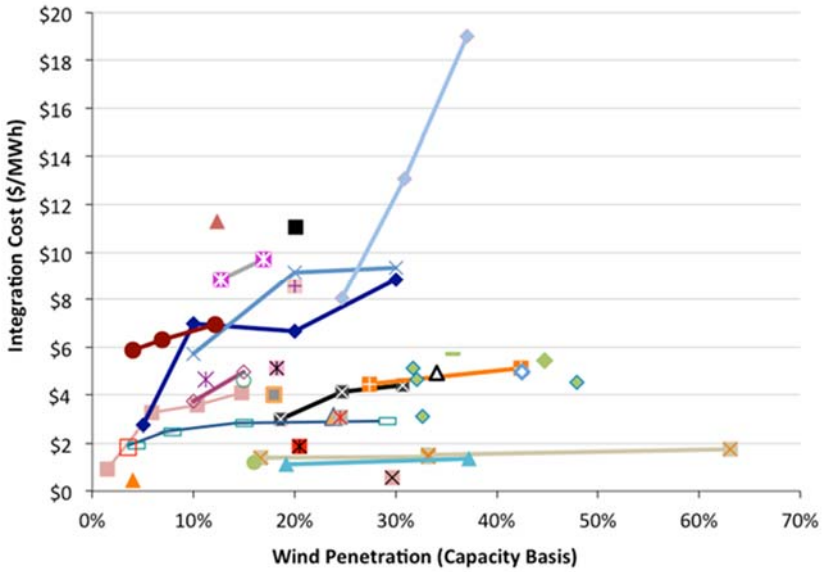


Source: Milligan et al. (2017) *Source: Mills and Wiser (2012b)*

Figure 38. Partial Summary of Literature of Wind and Solar Capacity Credit

Balancing Cost: Balancing costs (sometimes also called integration costs) originate from the required flexibility to maintain a continuous balance between supply and demand. System value estimates presented earlier at times include balancing costs, either via explicit modeling, or as an adjustment to modeled results. In many cases, however, these costs are—at best—only addressed partially in the previously summarized literature. This is sometimes due to modeling limitations, an assumption that the costs are low and do not justify detailed examination, or due to the fact that balancing costs are often at least partly socialized with costs spread evenly over load. Regardless, a great deal of additional literature has focused dedicated attention just on balancing needs and costs. Unfortunately, within that literature, definitions and methodologies for calculating increased balancing costs differ, and several open issues remain in estimating these costs (Milligan et al. 2011; UKERC 2017; Stark 2015). As such, comparisons are challenging and various studies are, to a degree, incommensurable. It is also clear that VRE is not alone in imposing balancing costs. Large nuclear or coal units often represent the largest single contingency, for example, thereby defining the need for contingency reserves under the standard N-1 reliability rules (Milligan et al. 2011). New thermal plants also impose cycling costs on other generations (Stark 2015). The value of providing some balancing services is reflected in AS prices and in other contracts, and so the differential characteristics of generators and loads are—to a degree—valued in markets. However, to some extent, the costs of these balancing needs have historically been socialized, and not paid directly by specific generators or loads causing the costs in the first place, i.e. cost causation principles have not been applied (Milligan et al. 2011). Notwithstanding the many challenges and nuances involved, as summarized in IPCC (2014), based on assessments carried out for OECD countries, the provision of additional balancing reserves to address wind power uncertainty and variability increases system costs by approximately $1-7/MWh for wind energy market shares of up to approximately 30% of annual electricity demand (IEA 2010, 2011; IPCC 2011; Holttinen et al. 2011; UKERC 2017; Agora 2015). Balancing costs for PV are in a similar range (Navigant Consulting et al. 2011;

Olson and Jones 2012; Black & Veatch 2012; Xcel Energy Services 2013; Idaho Power Company 2014; Lu et al. 2014; Wu et al. 2015). Figure 39 presents the results of U.S.-based wind balancing cost estimates, and demonstrates that balancing cost estimates span a wide range but generally increase with penetration; many of the higher estimates derive from studies covering regions where dispatch and scheduling procedures have not been optimized for VRE (Wiser and Bolinger 2017).



Source: Wiser and Bolinger (2017)

Figure 39. Wind Balancing Costs from U.S. Literature

Transmission Cost: Most of the papers described in the previous section that assess the system value of VRE exclude consideration of any additional transmission (or distribution, if applicable) expenditure associated with VRE, relative to alternative forms of electric supply. They may, however, embed transmission congestion costs in their value assessments as a result of the models used or assumptions regarding the ability of power to move between neighboring regions. As summarized by the IPCC (IPCC 2011, 2014), estimates of the additional cost of transmission infrastructure for wind energy in OECD countries are often in the range of $0-15/MWh, depending on the amount of wind energy supply, region, and study assumptions (IEA 2010, 2011; Holttinen et al. 2011; Mills, Wiser, and Porter 2012). Even higher costs are possible in some circumstances (Table 7, see also Andrade and Baldick 2017). A recent international assessment estimated transmission costs for up to 30% wind of $7.5-30/MWh (UKERC 2017). Solar energy, if deployed close to load centers, would be expected to impose lower costs, and might even avoid transmission and distribution infrastructure in some cases, though especially as penetrations increase additional distribution expenditures are expected for distributed PV (Xcel Energy Services 2013; Navigant Consulting, Inc. 2016; Agora 2015). These expenditures, whether on transmission or distribution infrastructure, are often regarded to have system-wide benefits, and so are not fully assigned to specific generators. Moreover, VRE is not alone in requiring transmission infrastructure; in effect, all centralized generation must be transmitted to end-users and these costs have traditionally been—in large measure—socialized. As such, assigning the full transmission cost to wind or solar resources is controversial and deviates from the historical treatment of most other resources in the system.

Table 7. Estimates of Wind Transmission Costs in the U.S.

Study	Wind Penetration Level Low	High	Notes
Survey of transmission planning studies in the U.S. (Mills, Wiser, and Porter 2012)	$15/MWh		Extremely wide cost range in individual studies; estimate based on median study
Western Wind and Solar Integration Study (GE Energy 2010b)	$0/MWh	$18/MWh	Low penetration and local development of wind requires no additional transmission; high penetration and geographically concentrated wind requires more transmission
Eastern Wind Integration and Transmission Study (EnerNex Corp. 2010)		$10-20/MWh	Lower transmission cost associated with lots of offshore wind; higher transmission cost for scenario with all onshore wind
ERCOT CREZ (RS&H 2011)		$29/MWh	October 2011 estimate of CREZ transmission costs; actual costs ended up higher[34]
20% Wind Energy by 2030 Study (DOE 2008)		$10/MWh	Transmission expansion based on ReEDS model; 25% of wind did not require new transmission investment
Wind Vision: A New Era of Wind Power in the United States (DOE 2015)		$5/MWh	Transmission expansion based on ReEDS model
Analysis of Western Renewable Energy Zones (Mills, Phadke, and Wiser 2011)	$20/MWh	$25/MWh	Includes estimate of cost of losses, and assumes that all existing transmission is fully utilized and that new transmission cost is fully assigned to wind; does not consider 'local' wind

5.4 'System Costs' Of VRE: An Alternative to the System Value Perspective

In many cases, it is appropriate to compare the plant-level technology cost and system value of different generation resources. Recognizing that each generation type brings with it a unique combination of energy, capacity, balancing, and transmission impacts and values, competitive wholesale markets can—at least in part—signal investment decisions and/or planners can use sophisticated energy-systems models to estimate portfolios of resources that minimize total cost. Policymakers, meanwhile, often choose to implement regulations and incentives intended to shift market (and modeled) outcomes to reflect broader societal and environmental goals not otherwise captured in bulk-power-markets.

In some instances, policymakers and other decision-makers seek to avoid sophisticated models that capture cost and system value differences, and instead desire a simplified method of comparing resources. In those cases, some default to comparing resources based on LCOE alone. Given the limits of LCOE as a sole metric for comparing resource options, however, some research has involved the creation of 'adjustments' to the LCOE of wind and PV to account for the so called 'system costs' of VRE (e.g., (UKERC 2017; Hirth, Ueckerdt, and Edenhofer 2015; IPCC 2011, 2014; IEA 2010; Scholz, Gils, and Pietzcker 2017; Agora 2015).

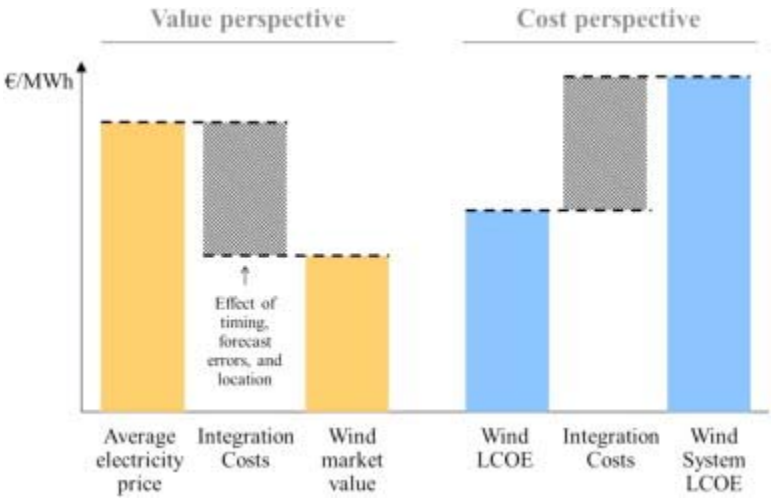
If properly defined, the 'system cost' of VRE (or any other resource) combined with the plant-level technology LCOE of VRE results in a 'total system LCOE', which can then be compared (with substantial caveats) to the 'total system LCOE' of any other technology to determine which resource has the lowest total system cost. An important point to make here is that this 'system cost' perspective is related to but distinct from the 'system value' perspective described earlier. An analyst may choose to use the 'system

[34] See also: Andrade and Baldick (2017)

value' perspective or the 'system cost' perspective, but it is important to avoid double counting. Moreover, as discussed in more depth later, all resources have 'system costs', and so an exclusive focus on VRE alone is inappropriate. A variety of other limitations and challenges are summarized in the pages that follow, and highlighted in more depth in the underlying literature (e.g., UKERC 2017; Agora 2015).

There is also disagreement among researchers on how to properly define the 'system cost' adjustments that are added to the plant-level technology LCOE to come up with a 'total system LCOE.' Two general approaches have been employed in the literature:

- One approach described by Hirth, Ueckerdt, and Edenhofer (2015) and depicted conceptually in Figure 40 defines the 'system cost' adjustment as being equivalent to the difference between the long-term average wholesale electricity price (i.e., the system value of the idealized flat block of power) and the system value of VRE (and all other resources), considering all four drivers. This approach has some merit, in that it reconciles the 'system value' literature described earlier with the 'system cost' perspective. In effect, the value de-rate for VRE relative to a flat baseload block of power—the grey box on the left of Figure 40, labeled 'integration costs' and estimated as the difference between the two yellow bars–can be considered, alternatively, as a 'system cost' adjustment that might be added to the plant-level technology LCOE to estimate a total system LCOE (the right-most blue bar, labeled wind system LCOE).
- An alternative approach is to estimate system costs directly, considering separately the costs related to energy (inclusive of curtailment), capacity, balancing, and transmission. The resulting values are then summed, ideally taking care not to double count any shared costs among these categories. While controversy remains about how precisely to calculate each factor, and how to do so fairly by assessing relevant costs for every type of generation, this approach has been developed or summarized in, among others, UKERC (2017), IPCC (2014, 2011), and IEA (2010).



Source: Hirth, Ueckerdt, and Edenhofer (2015)

Figure 40. Conceptual Relationship between System Value and System Cost Approaches

Whichever conceptual approach is used (or if some combination of the two is employed), the use of 'system costs' in practical applications requires that several issues be treated with care. First, though it may be appropriate to consider all four factors that impact cost and value, care must be taken to not

double count these factors by adjusting value and cost at the same time, or by disregarding shared costs and values among the categories (UKERC 2017). Second, within this framework, all real power plants have 'system costs' relative to the idealized flat baseload block of power (or, if more valuable than a flat baseload block, 'negative system costs'). VRE resources are not alone in this regard, and comparing resource types will require estimating 'system costs' for not only VRE, but also other generation types. These complexities are, in part, why electric sector decision-makers typically rely on sophisticated models rather than resorting to this 'system cost' approach. Third, as with system value, how one treats the boundary of the 'system' being considered is crucial; for example, results may vary substantially depending on whether one seeks to value environmental, security, and other societal factors that are not otherwise fully embedded in market outcomes. Fourth, whether one should present 'average' or 'marginal' system costs depends on the ways in which those estimates are to be used. Finally, as with the system value components, many aspects of system costs have not historically been assigned to specific generators.

Notwithstanding the lack of consensus on how to define, estimate and assign system costs, we provide quantitative estimates of VRE system costs derived from the literature using both conceptual approaches described earlier. First we estimate system costs from the value factor estimates summarized earlier, following the approach described by Hirth, Ueckerdt, and Edenhofer (2015), but recognizing that literature-derived value factor estimates are not always inclusive of all four underlying factors. Second, we provide estimates of the system costs directly from the underlying drivers (similar to the approach used by UKERC (2017). As with the system value of VRE described earlier, system costs are highly context dependent, and are not static. Context specific analysis is always preferable. Moreover, as earlier, we use narrow system boundaries, and do not include environmental and societal considerations in these estimates.

Nonetheless, some broad—but still not fully generalizable—findings emerge:

- <u>Estimating Additional 'System Costs' from System-Level Value Factor Estimates:</u> At low penetrations and as presented earlier, the value factor for wind often averages ~90%, whereas the value factor of PV averages ~120%. If a flat baseload block of power (considering capital and operating costs) is assumed to cost $50/MWh (consistent with a low-cost CCGT unit, and assumed to roughly equate to the long-term average wholesale electricity price), this implies a system cost of wind of $5/MWh. For PV, on the other hand, there is a *negative* system cost of $10/MWh relative to a truly flat block of power. At 15% penetration of wind or PV, and taking the marginal value factor estimates reported earlier (70-90% for wind, 40-80% for solar), system cost ranges can be estimated as follows: $5-15/MWh for wind, and $10-30/MWh for PV. At 30% penetration of wind or PV, the previously reported value factors (50-85% for wind, as low as ~40% PV) suggest additional system costs relative to the all-in cost of a flat baseload block of $7.5-25/MWh for wind, and as much as ~$30/MWh for PV. Actual system costs could extend beyond the ranges estimated here, are highly system specific, and can be reduced through various means. These system cost estimates (because they are derived from the literature summarized earlier on system value) are generally inclusive of energy, capacity, and—to some degree—balancing, but largely exclude transmission and distribution. Consideration of transmission infrastructure needs might represent a negative system cost for some PV plants located near load centers to an additional system cost of ~$15/MWh or even more for some more-remotely located VRE projects, though new transmission often provides system-wide benefits that make cost assignment to specific projects complicated. Distributed PV,

meanwhile, might provide additional benefits to the distribution system at lower penetration but impose progressively higher distribution-related costs not considered above at higher penetrations; recent utility 'grid modernization' investments, partly to accommodated increases in distributed resources, are reflective of the latter possibility.

- Estimating Additional 'System Costs' Directly from Underlying Drivers: Others have sought to estimate system costs on a more bottom-up basis, in some cases considering only a subset of the four underlying drivers. IPCC (2011), for example, uses bottom-up estimates from a comprehensive literature review, and finds that at low to medium levels of wind electricity penetration (up to 20% wind energy), the additional costs of managing electric system variability and uncertainty, ensuring generation adequacy and adding new transmission to accommodate wind energy will be system specific but generally in the range of $7-30/MWh, with costs naturally tending to increase with penetration. This estimate is inclusive of capacity, balancing, and transmission issues, but may not fully address energy value variations. Hirth, Ueckerdt, and Edenhofer (2015), meanwhile, draw from more-than 100 studies and estimate system costs of wind (inclusive of energy, capacity, balancing, and transmission) at $27-38/MWh at high penetrations of 30-40% wind energy, and assuming a base price of $76/MWh (note that this base price is considerably higher than the $50/MWh used earlier, inflating these system cost estimates in comparison to those presented in the previous bullet). IEA (2010) estimates total average VRE system costs in 2035 at $17.3/MWh for North America, considering balancing, capacity, and transmission.[35] Agora (2015) estimates that the system costs—considering all four factors—of achieving 50% wind and solar in the German power system could range from $6 to $22/MWh. Finally, Scholz, Gils, and Pietzcker (2017) estimate that as gross VRE increases from 20% to 100% of load in Europe, total average 'system costs' (inclusive of all four factors) increase from $13 to $30/MWh in a case with a balanced mix of wind and solar; wind-dominated scenarios have ~10% lower system costs, whereas solar-dominated scenarios have ~50% higher system costs. None of these estimates consider any additional value or cost of distributed solar related to distribution-system expenditures.

Applying these system cost estimates in practical contexts requires some caution:

1. First, they should only be applied to the plant-level technology LCOE of wind and PV if those resources are being compared to the total system costs of other technologies. Though VRE is unique, so too are other resource types. Natural gas plants, for example, may suffer from fuel supply contractual inflexibilities and physical risks (NERC 2016c; Milligan et al. 2011; DOE 2017), and natural gas prices have proven particularly difficult to forecast; on the other hand, the flexible dispatch of natural gas plants offers negative system costs relative to an idealized flat-block of power. Coal plants impose greater health and environmental burdens than many other sources (NRC 2010; Shindell 2015; Machol and Rizk 2013), are impacted by fuel supply risks and unplanned generator outages, and can impose cycling burdens on other plants (Stark 2015; Milligan et al. 2011; DOE 2017). Nuclear power plants, at least based on historical precedence, have not operated flexibly and, as often the largest single contingency, may affect reserve requirements given the impact of

[35] IER (2016), on the other hand, estimates an 'imposed cost' of VER as the amount that VER increases the LCOE of conventional resources by reducing their capacity factors without reducing their fixed costs. Their estimate is about $26/MWh for wind and $41/MWh for solar PV, due only to issues associated with the impact of VER on capacity factors of conventional generators and excluding any transmission or cycling-related wear and tear costs. While Hirth, Ueckerdt, and Edenhofer (2015) discuss a 'utilization effect' as part of their system cost estimates, the approach used by IER is not based on the same approach as outlined by Hirth et al.

unplanned outages. Much of the pumped hydro storage capacity in the U.S. was installed between 1960 and 1990 to complement the operation of large, baseload coal and nuclear power plants (DOE 2016), arguably a 'system cost' of these resources. To properly compare resources based on societal costs requires an assessment of relevant 'system cost' adders for all generation types, which of course first requires decisions about what specific types of system costs to include and what to ignore. Given the complexities involved in such calculations, system cost adders are not generally directly used in investment decisions or in electric sector planning, as more-sophisticated modeling tools are generally considered to be more suitable in these contexts to comprehensively compare resources in a more unified framework.

2. Second, VRE system costs can vary dramatically, depending on the characteristics of the other power plants, the transmission grid, resource availability and location, electricity demand profiles, and institutional and market rules. There are also differences between 'marginal' and 'average' system cost adders that ought to be considered, depending on the context in which those adders are used. Context specific estimates are always preferred to broad averages.
3. Third, there is extensive evidence that VRE system costs are highly dependent on the physical and institutional flexibility of the system to which they are added. VRE system costs will be driven lower if power systems cost-effectively transform to manage the unique characteristics that VRE resource introduce; power systems with less flexibility (whether due to a lack of physical flexibility or an inability to access the flexibility of the existing system)will tend to have higher system costs. Of course, tradeoffs between the cost and value of increased flexibility will be central to identifying the most cost-effective solution.

Finally, to reiterate, the goal of energy system planners is generally to minimize total costs (thereby increasing affordability), subject to reliability and other societal constraints. Adjusting the LCOE of VRE with 'system costs', as defined and roughly calculated here, does not imply that VRE would not contribute to low-cost energy supply portfolios. With available federal tax incentives, utilities in some regions are—today—purchasing VRE for economic reasons, seeking to reduce costs to their ratepayers (Wiser, Barbose, and Bolinger 2017). On a going forward basis, as tax incentives expire, models show a wide range of possible future outcomes depending on how natural gas prices, renewable energy costs, and regulatory regimes evolve, among other factors. Some of these scenarios suggest that VRE may not be competitive economically, but others do show continued substantial growth of VRE to be a component of least-cost supply portfolios, even considering value declines / system costs (e.g., EIA 2017a; Cole et al. 2016; DOE 2015; MacDonald et al. 2016). There is good reason to argue that an approach of comparing the total cost of different energy mixes is more straightforward and appropriate than trying to 'pick out' the system cost of every technology and project separately. Moreover, even when VRE is not narrowly economic based on the previously defined system value or cost estimates, policymakers may choose to direct market outcomes via policy intervention with the goal of reflecting societal values not otherwise fully embedded with existing markets (e.g., environmental externalities like carbon emissions or preferences for local jobs).

5.5 Directions for Future Research

While we attempt to quantify the system value and system costs of VRE based on various estimates from previous studies, these studies are not fully comparable methodologically and results will also be region and context specific. As such, there is clearly more research to be done in this area including:

- Improving system value estimates for different VRE technologies in different regions and under a variety of market rules and policies, particularly with regard to comprehensively capturing energy, capacity, balancing, and transmission within the system value estimates on a system-specific basis.

- Estimating system values and system costs for a much broader array of technologies beyond the historical narrow focus on VRE.
- Researching how to increase the completeness of markets such that the full societal value of VRE and other resources is reflected in the revenue earned by participants in those markets.
- Identifying cost-effective strategies to maintain the system value of VRE with higher penetration.
- More-fully exploring the relationship between 'system value' and 'system cost.'
- Seeking broader agreement on the definitions and proper use of terms like 'integration costs', 'system costs', 'system values', and 'market values.'

Overall, this line of research would seek to improve our methods for comprehensively measuring the system costs and benefits for all types of generation and substitutes for generation (e.g., storage, DR, etc.), enabling the construction of cost-effective and socially benefitial portfolio combinations.

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Appendix A: Simple Supply-Curve Analysis Methodology

The simple supply curve model is used to estimate the hourly market-clearing price for electricity in a region based on finding the intersection of the demand and supply curves. This hourly price is then averaged over the year to estimate the annual average price reported in the analysis. For simplicity, we net the resources that vary with time (e.g., VRE and hydropower) from the demand curve (using the resulting net demand) and only focus on thermal resources in the supply curve. This change only affects the way the analysis is conducted, not the result (i.e., subtracting a variable resource from the demand curve has the same effect on the price as adding the variable resource to the supply curve).

The supply curve is based on a simple merit-order of generation from lowest marginal cost to highest marginal cost. The estimated marginal cost of each plant is based on the heat rate of the unit (using the full-load heat rate reported in ABB's Velocity Suite), the fuel cost, the emissions rate of the unit (reported in ABB's Velocity Suite), the emissions price, and other variable operations and maintenance costs (reported in ABB Velocity Suite). Fuel costs are assumed to be constant throughout the year except for natural gas, which varies on a daily basis following the trading price at major natural gas trading hubs. The capacity of each generator is based on its summer or winter capacity, depending on the season, de-rated by a seasonal availability factor. We de-rate the summer capacity using only the forced outage rate whereas the winter capacity is de-rated by both the forced outage rate and the scheduled outage rate. By applying the scheduled outage rate to the winter capacity we, in effect, assume that scheduled maintenance occurs in only in the winter season. Outage rates are technology specific (rather than unit specific) and are reported in ABB's Velocity Suite. This simple supply curve ignores numerous real constraints including minimum generation levels, startup times, ramp rates, transmission limits, heat rate variation based on loading, etc.

Despite the many simplification, the supply-curve approach nonetheless does a reasonably good job of estimating annual average wholesale prices for ERCOT and CAISO. In particular, we build a supply curve and net-demand profile for both ERCOT and CAISO for both 2008 and 2016. Additional data and assumptions are listed in Table 8 and Table 9. Using the intersection of the hourly net-demand and the simple supply curve for ERCOT in 2008 results in an estimated wholesale price of $66.9/MWh (5% higher than the actual observed 2008 real-time price at the ERCOT North Hub) and in 2016 results in an average price of $20.2/MWh (3% lower than the 2016 real-time price at ERCOT North). Changing parameters in the simple supply curve model to match CAISO for 2008 results in an average wholesale price of $66.9/MWh (4% lower than the observed 2008 real-time price at SP15 in CAISO) and for 2016 results in an average price of $24.4/MWh (14% lower than the 2016 real-time price at SP15). While the supply curve model is not able to perfectly replicate the observed average wholesale price in 2008 and 2016, it does capture the overall drop in prices from 2008 to 2016 with remarkable accuracy. The drop in prices within the ERCOT model is 9% higher than the actual observed drop while the drop in prices with the CAISO model is 4% higher than the actual observed drop.

To understand the relative contribution of different factors to this drop in average wholesale prices, we calculate the impact on prices of changing one factor at a time from its 2016 level to its 2008 level while keeping all other factors constant at the 2016 level. Alternatively, we can conduct the analysis with 2008 as the base year by keeping all factors at their 2008 level and changing one to its 2016 level. For ERCOT we had hourly wind and hydro profiles from both 2008 and 2016. In assessing the individual contribution of wind and hydro to the change in wholesale price we therefore changed both the magnitude and the hourly profile to the 2016 values or 2008 values, depending on which was the base

year. For ERCOT solar and CAISO solar, wind and hydropower, however, we only had profiles for 2016 (no hourly profiles were reported for 2008). As such, for the CAISO analysis, we scaled the 2016 solar, wind and hydro hourly profiles by the ratio of the monthly average generation in 2008 to 2016 based on ABB Velocity Suite monthly production data. For ERCOT solar we scaled the 2016 profile based on the ratio of the installed capacity in 2008 (which was essentially 0) to the installed capacity in 2016. We further assumed that the hourly import profiles from 2016 were the same as in 2008 in CAISO. Finally, we estimated DPV profiles in CAISO using the 2016 hourly profiles for utility-scale solar. We added this DPV profile into the CAISO reported load and combined it with the utility-scale solar to make a total (DPV + utility-scale) solar profile for 2008 and 2016.

*Table 8. Assumptions and Data Sources For Simple Supply Curve Model of **ERCOT***

Parameter	2008 Values	2016 Values
Hourly Demand	ERCOT hourly demand for 2008 from ABB Velocity Suite	ERCOT hourly demand for 2016 from ABB Velocity Suite
Wind Profile	ERCOT hourly wind for 2008 from ABB Velocity Suite	ERCOT hourly wind for 2016 from ABB Velocity Suite
Solar Profile	ERCOT hourly solar profile from 2016 scaled by the ratio of 2008 solar nameplate capacity to 2016 solar nameplate capacity reported by ABB Velocity Suite	ERCOT hourly solar for 2016 from ABB Velocity Suite
Hydropower Profile	ERCOT hourly hydro for 2008 from ABB Velocity Suite	ERCOT hourly hydro for 2016 from ABB Velocity Suite
Generation Mix	Units operating in ERCOT in 2008 from ABB Velocity Suite	Units operating in ERCOT in 2016 from ABB Velocity Suite
Unit Heat Rate	Unit-specific estimate of heat rate from ABB Velocity Suite	
Natural Gas Fuel Price	Daily Henry Hub Day-Ahead Indices from ICE reported in ABB Velocity Suite for deliveries in 2008	Daily Henry Hub Day-Ahead Indices from ICE reported in ABB Velocity Suite for deliveries in 2016
Coal Fuel Price	Energy-weighted average coal fuel cost for ERCOT generators for 2008 from ABB Velocity Suite ($1.71/MMBtu)	Same approach using 2016 data ($2.14/MMBtu)
Petroleum Fuel Price	Energy-weighted average petroleum fuel cost for ERCOT generators for 2008 from ABB Velocity Suite ($22.62/MMBtu)	Same approach using 2016 data ($11.87/MMBtu)
Nuclear Fuel Price	Energy-weighted average uranium fuel cost for ERCOT generators for 2008 from ABB Velocity Suite ($0.49/MMBtu)	Same approach using 2016 data ($0.70/MMBtu)
Other Fuel Prices	Energy-weighted average fuel cost for ERCOT generators for 2008 from ABB Velocity Suite for renewable fuels ($8.6/MMBtu) and "other" fuels ($8.72/MMBtu); "unknown" fuels were assumed to have same price as "other" fuels	National average fuel cost scaled by the 2008 ratio of ERCOT and US fuel costs for renewable ($3.91/MMBtu) and "other" fuels ($3.29/MMBtu), as no regional data were available for 2016
SO_2 and NO_x Emissions Rate[36]	Unit-specific annual SO_2 emissions rate and ozone season NO_x emissions rate reported by ABB Velocity Suite	
SO_2 Emissions	2008 SO_2 emissions price ($278/ton SO_2)	Assumed $3.25/ton SO_2 based on recent

[36] We did not account for potential changes in the emissions rates of generators between 2008 and 2016. These could have been substantial due to tightening of environmental regulations during this period. We will account for changes in the emissions rate of units over time in future refinements.

Price	reported by EIA[37] for generators in the Acid Rain Program as reported by ABB Velocity Suite	assessment of permit prices from Platts[38] for generators in the Cross-State Air Pollution Rule as reported by ABB Velocity Suite
NO_x Emissions Price[39]	Assumed \$0/ton NO_x in 2008 since no ERCOT generators were part of the NO_x Budget Trading Program	Assumed \$3.85/ton NO_x based on recent assessment of permit prices from Platts[40] for generators in the Cross-State Air Pollution Rule as reported by ABB Velocity Suite
CO_2 Emissions Price	Assume \$0/ton CO_2 since there was no cap-and-trade program applied to ERCOT in 2008 or 2016	

*Table 9. Assumptions and Data Sources For Simple Supply Curve Model of **CAISO***

Parameter	2008 Values	2016 Values
Hourly Demand	CAISO hourly demand for 2008 from ABB Velocity Suite with estimated 2008 DPV added back into the demand	CAISO hourly demand for 2016 from ABB Velocity Suite with estimated 2016 DPV added back into the demand
Wind Profile	CAISO hourly wind profile from 2016 scaled by the monthly ratio of 2008 wind energy to 2016 wind energy reported by ABB Velocity Suite	CAISO hourly wind for 2016 from ABB Velocity Suite
Solar Profile	CAISO hourly solar profile from 2016 scaled by the monthly ratio of 2008 solar energy to 2016 solar energy reported by ABB Velocity Suite along with estimated DPV profile developed by scaling the utility-scale profile by the ratio of annual DPV energy to annual utility-scale energy	CAISO hourly solar for 2016 from ABB Velocity Suite along with estimated DPV profile
Hydropower Profile	CAISO hourly hydro profile from 2016 scaled by the monthly ratio of 2008 hydro energy to 2016 hydro energy reported by ABB Velocity Suite	CAISO hourly hydropower generation profile for 2016 from ABB Velocity Suite
Import Profile	CAISO hourly import profile for 2016 from ABB Velocity Suite	
Generation Mix	Units operating in CAISO in 2008 from ABB Velocity Suite	Units operating in CAISO in 2016 from ABB Velocity Suite
Unit Heat Rate	Unit-specific estimate of heat rate from ABB Velocity Suite	
Natural Gas Fuel Price	Daily SoCal Gas Border Day-Ahead Indices from ICE reported in ABB Velocity Suite for deliveries in 2008	Daily SoCal Gas Citygate Day-Ahead Indices from ICE reported in ABB Velocity Suite for deliveries in 2016
Coal Fuel Price	Energy-weighted average coal fuel cost for CAISO generators for 2008 from ABB Velocity Suite (\$1.94/MMBtu)	Same approach using 2016 data (\$2.28/MMBtu)
Petroleum Fuel Price	Energy-weighted average petroleum fuel cost for CAISO generators for 2008 from ABB Velocity Suite (\$22.15/MMBtu)	National average petroleum fuel cost scaled by the 2008 ratio of CAISO and US fuel costs (\$14.66/MMBtu), as no regional data were

[37] www.eia.gov/todayinenergy/chartdata/EmissionsPrices2011.csv

[38] https://www.platts.com/latest-news/coal/houston/more-activity-but-no-trades-this-week-in-us-csapr-21578342

[39] We did not model local emissions programs, such as the Mass Emissions Cap and Trade program that applies to generators in the Houston area. We will model these local programs in future refinements.

[40] https://www.platts.com/latest-news/coal/houston/more-activity-but-no-trades-this-week-in-us-csapr-21578342

		available for 2008
Nuclear Fuel Price	Energy-weighted average uranium fuel cost for CAISO generators for 2008 from ABB Velocity Suite ($0.52/MMBtu)	Same approach using 2016 data ($0.76/MMBtu)
Other Fuel Prices	Energy-weighted average fuel cost for CAISO generators for 2008 from ABB Velocity Suite for renewable fuels ($8.23/MMBtu) and "other" fuels ($7.98/MMBtu); "unknown" fuels were assumed to have same price as "other" fuels	Same approach using 2016 for renewable fuels ($3.54/MMBtu) and national average of other fuels scaled by 2008 ratio of CAISO and US "other" fuel costs ($3.01/MMBtu)
SO_2 and CO_2 Emissions Rate[41]	Unit-specific annual SO_2 and CO_2 emissions rate reported by ABB Velocity Suite	
SO_2 Emissions Price	2008 SO_2 emissions price ($278/ton SO_2) reported by EIA[42] for generators in the Acid Rain Program as reported by ABB Velocity Suite	Assumed $0/ton SO_2 in 2016 since no generators are participants in the Cross-State Air Pollution Rule
NO_x Emissions Price[43]	Assumed $0/ton NO_x in 2008 since no generators were part of the NO_x Budget Trading Program	Assumed $0/ton NO_x in 2016 since no generators are participants in the Cross-State Air Pollution Rule
CO_2 Emissions Price	Assumed $0/ton CO_2 since there was no cap-and-trade program applied to CAISO in 2008	$11.6/ton CO_2 average carbon price for the California cap-and-trade program in 2016[44]

[41] We did not account for potential changes in the emissions rates of generators between 2008 and 2016. These could have been substantial due to tightening of environmental regulations during this period. We will account for changes in the emissions rate of units over time in future refinements.

[42] www.eia.gov/todayinenergy/chartdata/EmissionsPrices2011.csv

[43] We did not model local emissions programs, such as the RECLAIM program that applies to generators in the South Coast Air Quality Management District. We will model these local programs in future refinements.

[44] http://calcarbondash.org/csv/output.csv