Integrating Renewable Energy into the Electricity Grid

Case studies showing how system operators are maintaining reliability

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I. Executive Summary

A number of factors are contributing to increases in renewable energy production in the United States (and beyond). These factors include rapidly declining costs of electricity produced from renewable energy sources, regulatory and policy obligations and incentives, and moves to reduce pollution from fossil fuel-based power generation, including greenhouse gas emissions. While not all renewable energy sources are variable, two such technologies – wind and solar PV – currently dominate the growth of renewable electricity production. The production from wind and solar PV tries to capture the freely available but varying amount of wind and solar irradiance. As the share of electricity produced from variable renewable resources grows, so does the need to integrate these resources in a cost-effective manner, i.e., to ensure that total electricity production from all sources including variable renewable generation equals electricity demand in real time. Also, a future electric system characterized by a rising share of renewable energy will likely require concurrent changes to the existing transmission and distribution (T&D) infrastructure. While this report does not delve into that topic, utilities, grid operators and regulators must carefully plan for needed future investments in T&D, given the lead times and complexities involved.

Rather, this report focuses on the fact that variable renewable generation adds a different new component to the challenges facing system operators in maintaining system reliability. For example, the decline in solar production at the end of the day can lead to significant ramping needs for grid operators. Dispatchable non-solar resources (existing fossil and hydro generation but also potentially demand resources) must be rapidly deployed to make up for the decline in solar PV generation at the same time that residential electricity demand is rising at the end of the day. Similar challenges can arise as a consequence of deviations in output from wind or solar facilities relative to weather forecasts over time periods ranging from minutes to hours.

The question of integrating higher levels of variable renewable generation has recently been highlighted in the context of the U.S. Environmental Protection Agency's proposed Clean Power Plan. An Initial Reliability Review (IRR)[1] of the Clean Power Plan conducted by the North American Electric Reliability Corporation (NERC) raised concerns about the levels of renewable energy generation incorporated into EPA's assumptions about what states could be expected to do to reduce greenhouse gas emissions. In an assessment of that IRR prepared for the Advanced Energy Economy Institute (AEEI), we found that NERC's reliability concerns related to renewable energy integration were likely overstated, given the levels of renewable energy penetration already managed with no measurable compromise of reliability in some parts of the United States as well as in Europe.[2] As a follow-up to that assessment, we have been asked by AEEI to provide an overview of what utilities and independent system operators (ISOs) with

1 NERC, Potential Reliability Impacts of EPA's Proposed Clean Power Plan, Initial Reliability Review, November 2014.

2 Jurgen Weiss, Bruce Tsuchida, Michael Hagerty and Will Gorman, EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review, The Brattle Group, February 2015.

relatively high shares of variable renewable generation are doing to integrate those resources into their systems without compromising reliability.

A survey of integration efforts in the United States and abroad reveals that the last decade has seen both a rapid increase in the deployment of variable renewable generation and improvements in their integration.[3] ISOs and utilities have at their disposal a large and increasing portfolio of options to accommodate large and growing shares of renewable generation while maintaining high levels of reliability. The options range from purely operational changes to possibilities that become available as a consequence of advancements in technology unrelated to renewable energy. Examples of the former include enhancing the coordination between balancing areas (including increasing their size), reinforcing the transmission system, and increasing participation of demand response. Examples of the latter include technological advances in weather forecasting, which, together with better data on historical performance of renewable energy, allows significantly improved forecasting accuracy of renewable generation; the proliferation of smarter infrastructure, much of it deployed at the customer site (smart meters, smart thermostats, smart appliances, all enabled by smarter software), enabling participation of increasing amounts of demand in activities that help mitigate the variability of renewable generation; and technological advances of renewable and complementary technologies (inverters, batteries) that allow renewable generators themselves to contribute to maintaining reliability.

In this report, we provide two in-depth case studies, of the Electric Reliability Council of Texas (ERCOT) and Xcel Energy Colorado (a.k.a. Public Service Company of Colorado, or PSCo), to show how they integrate high shares of variable renewable energy. ERCOT (and the distribution utilities in ERCOT) and Xcel Energy Colorado have managed to successfully integrate increasing amounts of variable renewable energy resources at costs that have generally been small to modest.[4] For example, ERCOT estimated the cost of integrating its first 10,000 MW of wind, approximately the capacity currently deployed, to be about $0.50 per MWh of wind generation.[5] These organizations have used well-established and widely available methods and technologies such as:

- changes in ancillary services, which manage short-term mismatches between electric supply and demand, with fast-ramping gas-fired generation, demand response, storage, and other technologies,

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[3] For a recent survey of wind integration costs, see AWEA, Wind energy helps build a more reliable and balanced electricity portfolio.

[4] Throughout this report, integration costs do not include the costs of building new transmission, whether for the explicit purpose of connecting more renewable resources or for broader reasons.

[5] Milligan et al., Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned, NREL, March 2015, p.25. The cost estimate is based on an assessment of incremental spinning and non-spinning reserves required to manage both variability and uncertainty of wind production.

- improved forecasting of production from wind,
- increased flexibility of fossil power plants on the system,
- evolving capabilities of renewable generation itself to contribute to reliability,
- expansion of transmission infrastructure (even though not an "integration measure" according to our use of the term), and
- newer approaches under development, which include utilizing large-scale storage, dynamically managing the capacity of transmission lines, and allowing demand response to play a bigger role in managing system variability (and emergency situations).

The success to date of ERCOT and Xcel Energy Colorado shows that integrating variable renewable energy at penetration levels of 10-20% on average and at times above 50% – i.e., high relative to the current levels in most of the United States – is possible. Integration challenges in other parts of the United States will differ due to both the mix of renewable resources and the make-up of the existing electric system. Nonetheless, by adopting approaches similar to those used (or planned) in ERCOT and Xcel Energy Colorado, ISOs/RTOs and utilities in other states should be able to integrate increasing shares of variable renewable generation using well-established tools and technologies. While infrastructure changes will likely be necessary in the longer term, the shorter-term integration challenges in many cases can be addressed with modest operational changes.

Ongoing technological progress and ongoing learning by utility and ISO/RTO managers about best practices of managing the operations of electric systems with high renewable shares will likely allow the integration not only of the levels of variable renewable energy capacity now in places like Texas and Colorado but even larger amounts in the future. Specifically, integration of variable renewable energy at levels of penetration as high as those reliably managed by ERCOT and Xcel Energy Colorado, if not higher, should not be seen as a significant technical obstacle to compliance with EPA's proposed Clean Power Plan. Rather, carefully examining the lessons learned in states and regions such as the ones examined here should help ISOs and utilities ensure that significantly larger amounts of variable renewable energy can be integrated at small to modest costs while maintaining high levels of reliability.

II. Introduction

A number of factors are contributing to increases in renewable energy production. They include declining costs of electricity produced from renewable energy sources, regulatory and policy obligations and incentives, and moves to reduce pollution from fossil fuel-based power generation, including greenhouse gas emissions. While not all renewable energy sources are variable, wind and solar PV currently dominate the growth of renewable electricity production and their production tries to capture the freely available but varying amount of wind and solar irradiance. As the share of electricity produced from variable renewable resources grows, so does the need to integrate these resources at the lowest possible cost. Also, a future electric system characterized by a rising share of renewable energy will likely require concurrent changes to the existing transmission and distribution (T&D) infrastructure. While this report does not delve into that topic, utilities, grid operators and regulators must carefully plan for needed future investments in T&D, given the lead times and complexities involved.

Recently, the question of integrating higher levels of variable renewable generation has come up in the context of the U.S. Environmental Protection Agency's proposed Clean Power Plan. An Initial Reliability Review (IRR) of the Clean Power Plan conducted by the North American Electric Reliability Corporation (NERC) raised concerns about the levels of renewable energy generation incorporated into EPA's assumptions about what states could be expected to do to reduce greenhouse gas emissions. In an assessment of that IRR prepared for the Advanced Energy Economy Institute (AEEI), we found that NERC's concerns about reliability were likely overstated, given the levels of renewable energy penetration already managed with no compromise of reliability in some parts of this country as well as in Europe.[6] In that assessment, we noted a number of technological and operational tools system operators were using to maintain reliability while managing systems with significant amounts of variable renewable generation.

As a follow-up, AEEI has asked us to examine how system operators in the United States facing relatively high shares of variable renewable generation have adopted planning and operational practices to integrate renewable energy. They also asked to what extent technology, broadly speaking, has enabled larger contributions from renewable energy sources to the U.S. electricity supply without negatively impacting electric reliability. These technological impacts can be direct, by providing tools to help manage a more variable system (such as by deploying relatively small-scale storage), and indirect, by making possible changes in operational practices and market design also aimed at integrating renewables. Examples of the latter include advances in computing that improve forecasting, advances in inverter technology that allow more control over the output of non-synchronous generation (such as wind and solar PV) and hence their potential participation in redefined ancillary services markets, or advances in demand response and storage that enable the creation of entirely new ancillary services. We explored these issues

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6 Jurgen Weiss, Bruce Tsuchida, Michael Hagerty and Will Gorman, EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review, The Brattle Group, February 2015.

by highlighting case studies of successful integration of relatively high levels of variable renewable generation, specifically focusing on renewable integration efforts in the Electric Reliability Council of Texas (ERCOT) and Xcel Energy Colorado.

ERCOT operates the smallest of the three independent interconnections in the United States and functions as the independent system operator (ISO) for nearly all of Texas. ERCOT is only weakly connected to surrounding electric systems, has very little hydro generation capacity and Texas has the highest installed wind capacity of any state with 12.5 GW installed. Xcel Energy Colorado operates a vertically integrated electric system with significant installed wind (and increasingly solar PV) capacity, but is not part of a regional transmission organization (RTO) or ISO. Wind meets close to 20% of Xcel Energy Colorado's load on average and wind generation at times exceeds 50% of its instantaneous demand.[7] Both systems provide a preview of a potential future with a higher share of variable renewable generation in the United States. It is noteworthy that both systems have achieved the integration of higher renewable penetration using traditional and well-established processes, tools and technologies rather than relying heavily on new or emerging technologies.

In this report, we first summarize recent trends in renewable energy capacity and the knowledge of how to integrate renewable energy production. Then we discuss in detail integration measures planned or implemented in ERCOT and Xcel Energy Colorado. Finally, we highlight integration measures in other areas in a more summary fashion and provide some concluding remarks.

III. Trends in Renewable Integration in the United States

As shown in Figures 1 and 2, over the past decade wind capacity in the United States has increased tenfold and solar PV capacity almost hundredfold over the same time period. Over the same past decade, the share of solar PV and wind in total energy production has increased from about 0.4% in 2005 to 4.8% in 2014.[8] Nonetheless, a 2013 study demonstrated that wind generation in the United States still played a relatively minor role when compared to the contribution of wind in other countries. As shown in Figure 3, wind in the U.S. still contributes a relatively small share to overall electricity production when compared to the 15-40% contribution in several other (European) countries.[9]

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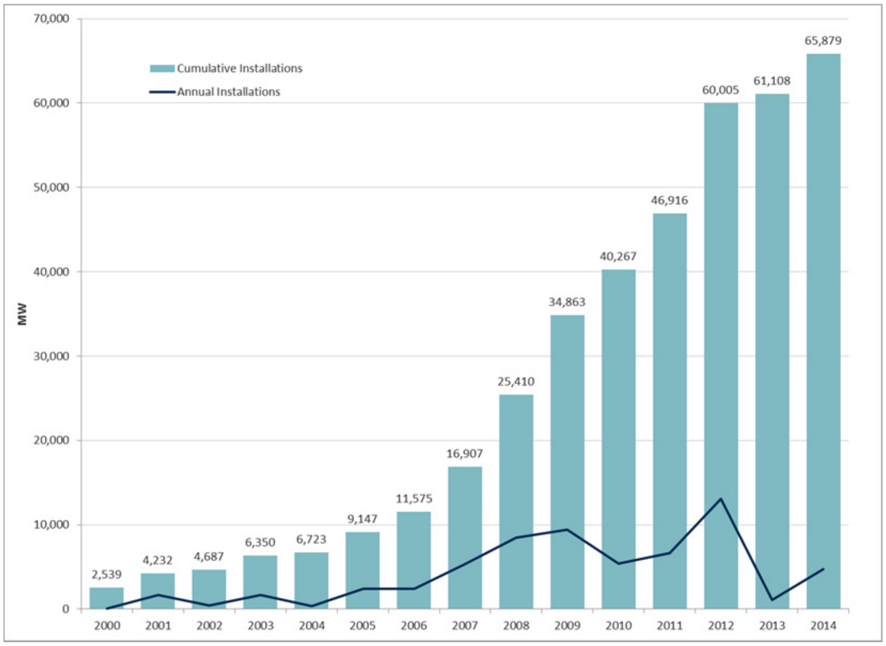
7 In May 24, 2013, wind provided electricity equivalent to 60.5% of Colorado's total demand, eclipsing an earlier record of 56.7%. See http://www.aweablog.org/xcel-colorado-sets-u-s-record-with-over-60-wind/.

8 U.S. Energy Information Administration, Electric Power Monthly, March 2015.

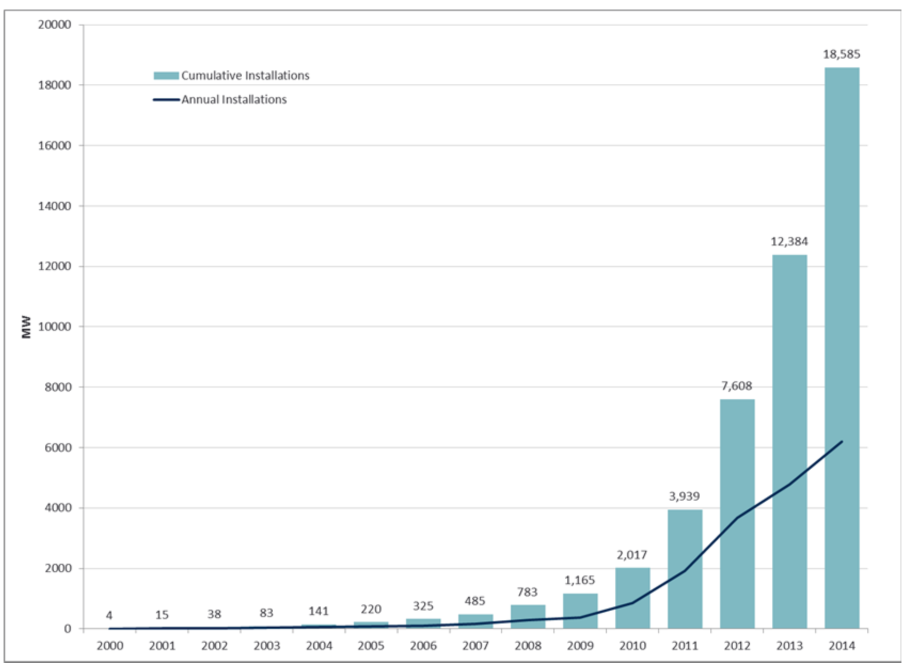
9 In 2014, wind contributed 39.1% to Denmark's electricity production (http://www.euractiv.com/sections/energy/denmark-sets-world-record-wind-energy-311083). Solar PV and on- and off-shore wind produced a little less than 15% of Germany's total electricity in 2014 (http://www.unendlich-viel-energie.de/strommix-deutschland-2014).

Figure 1: Onshore Wind Installations in the United States since 2000



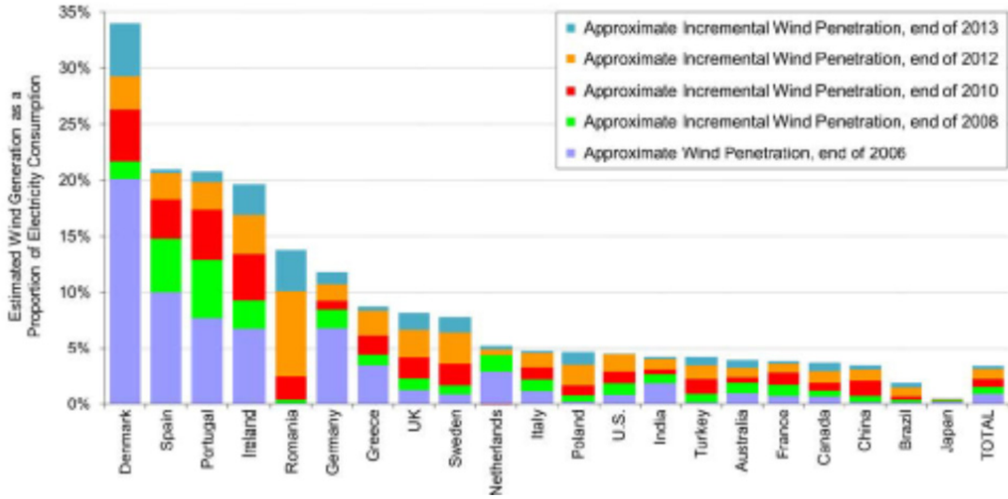
Source: AWEA, NREL

Figure 2: Solar PV Installations in the United States since 2000



Source: SEIA, U.S. Solar Market Insight, 2014 Year in Review, Executive Summary

Figure 3: Wind Share in Total Electricity Production in Selected Countries (Incremental Wind Penetration above 2006 Levels)



Source: NREL, 2013 Wind Technologies Market Report (reproduced from Figure 4)

In the United States itself, the contribution of both wind and solar differs significantly by state, with nine states approaching the penetration levels seen in those European countries with the highest penetration levels.[10] As renewable energy production has grown, so has the number of renewable integration cost studies and associated estimates of integration costs. Figure 4 shows these estimates of wind integration costs across a number of these studies.

Figure 4 allows several observations. First, the estimated cost of integrating wind differs significantly across studies. While the bulk of estimates for wind penetration levels below 20% of peak load[11] lie between $2-$5/MWh, there are several studies estimating costs in the $6-$11/MWh range. The range of estimated integration costs is wider at higher penetration levels. A second observation is that on average, estimates of integration costs seem to be non-increasing over time even as wind penetration is increasing.[12] Changing natural gas prices are likely one important reason, but it is also likely that progress is being made in understanding operating and capacity reserve requirements and minimizing costs by using a mix of better analytical tools and technology. In other words, electricity analysts, and RTO and utility operators have improved the methodologies for estimating integration costs, and helped expand the operational (and technology) options available for renewables integration.

10 In 2013, nine states had wind and solar generation in excess of 10% of total demand: Iowa, South Dakota, Kansas, Idaho, Minnesota, North Dakota, Oklahoma, Colorado and Oregon (EIA, http://www.eia.gov/electricity/data/state/).

11 Figure 4 reports integration cost as a function of increasing capacity as a percentage of peak load, rather than the more typically reported wind generation as a percentage of total demand. For example, ERCOT's highest historic peak load was 68,305 MW. 11,154 MW of wind installed as of February

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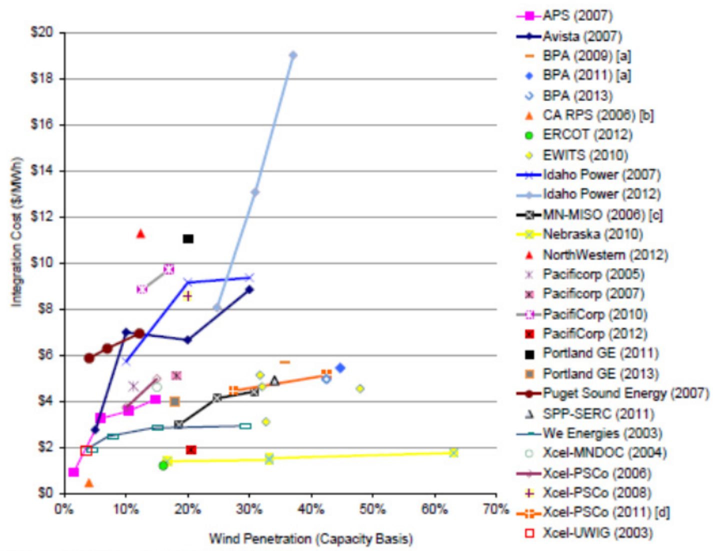
Figure 4: Wind Integration Levels and Costs across States and Years



[a] Costs in $/MWh assume 31% capacity factor.
[b] Costs represent 3-year average.
[c] Highest over 3-year evaluation period.
[d] Cost includes the coal cycling costs found in Xcel Energy (2011).

Source: NREL, 2013 Wind Technologies Market Report (reproduced from Figure 52)

A recent NREL report summarizes the key issues and lessons learned from integration studies and operational practices.[13] In reviewing a number of both U.S. and international renewables integration studies, NREL identifies several key lessons learned. They include evidence that integration of large amounts of wind energy, up to 30% of total generation, is technically and economically feasible, with integration costs generally less than 10% of the cost per MWh of wind and often significantly less.[14] It also appears that accumulated experience with increasing shares of renewable generation has led to many industry participants to revise their beliefs regarding the level of renewable generation would lead to excessive integration cost or potentially threaten system reliability.

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2015 implies a penetration rate of 16.3% (for comparison with Figure 4) rather than the approximately 10% of energy provided by wind in ERCOT in 2014.

12 Integration cost estimates in the same region differ quite significantly year by year. For example, the integration cost estimates for Pacificorp moved from approximately $4.5/MWh at capacity penetration rates of about 10% in 2005 to about $5/MWh at 18% penetration in 2007, to between $9-10/MWh at 15-18% penetration rates in 2010, to $2/MWh at penetration rates slightly above 20% in 2012.

13 Milligan et al, Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned, NREL, March 2015. The large scale integration studies examined include three NREL studies (Western Wind and Solar Integration Study Phase 1 and Phase 2 and the Eastern Wind Integration and Transmission Study), an ISO New England wind integration study, an ERCOT wind integration study, and an IEA Task 25 wind integration study.

14 Ibid, p.19.

A decade ago, the majority of industry experts might have believed that accommodating more than 20% of variable renewable energy sources without significantly changing the existing system would be impossible. Today, this threshold has moved to perhaps 30% and in some cases significantly higher, as highlighted by the renewable penetration levels examined in the most recent integration studies. Both ERCOT and Xcel Energy Colorado experience relatively high levels of wind generation– in the case of Xcel Energy Colorado at certain times on par with the highest penetration levels in Europe – and as ISOs/RTOs and utilities that have made significant progress in developing tools to better integrate large amounts of wind. For this reason, we turn next to exploring each of these two systems in more detail.

IV. Integrating Renewable Energy in ERCOT

In this section we explore various measures ERCOT has taken to facilitate the integration of wind (and other renewable energy sources). As shown in Figure 5, ERCOT has nearly 12.5 GW of wind capacity installed, and Texas is the state with the largest amount of installed wind in the United States in terms of MW installed. In 2014, wind energy contributed more than 10% to meeting ERCOT's total demand, which means its wind penetration is approaching the levels of the European countries with the highest wind penetration rates.[15] During some hours, wind production approaches 40% of total demand.[16] Also as shown in Figure 5, ERCOT analysis projects that wind penetration could almost double again over the next three years , which would bring the wind penetration as a percentage of load served near the top of global rankings. Beyond this fact, ERCOT also makes for an interesting case study in renewables integration because it is a relatively isolated electric system only weakly connected to other grids (through DC ties with the Eastern Interconnection and Mexico). Unlike some of the European countries with high wind (and solar) penetration, ERCOT, while relatively large, is not able to "lean" on neighboring systems to help mitigate the impacts of variable generation from renewables to the same degree as countries like Denmark or Germany. The absence of strong connections to neighboring regions is also important in the sense that the challenge of integrating variable renewable energy resources diminishes significantly as renewable generation sources are spread over a larger geographic area.

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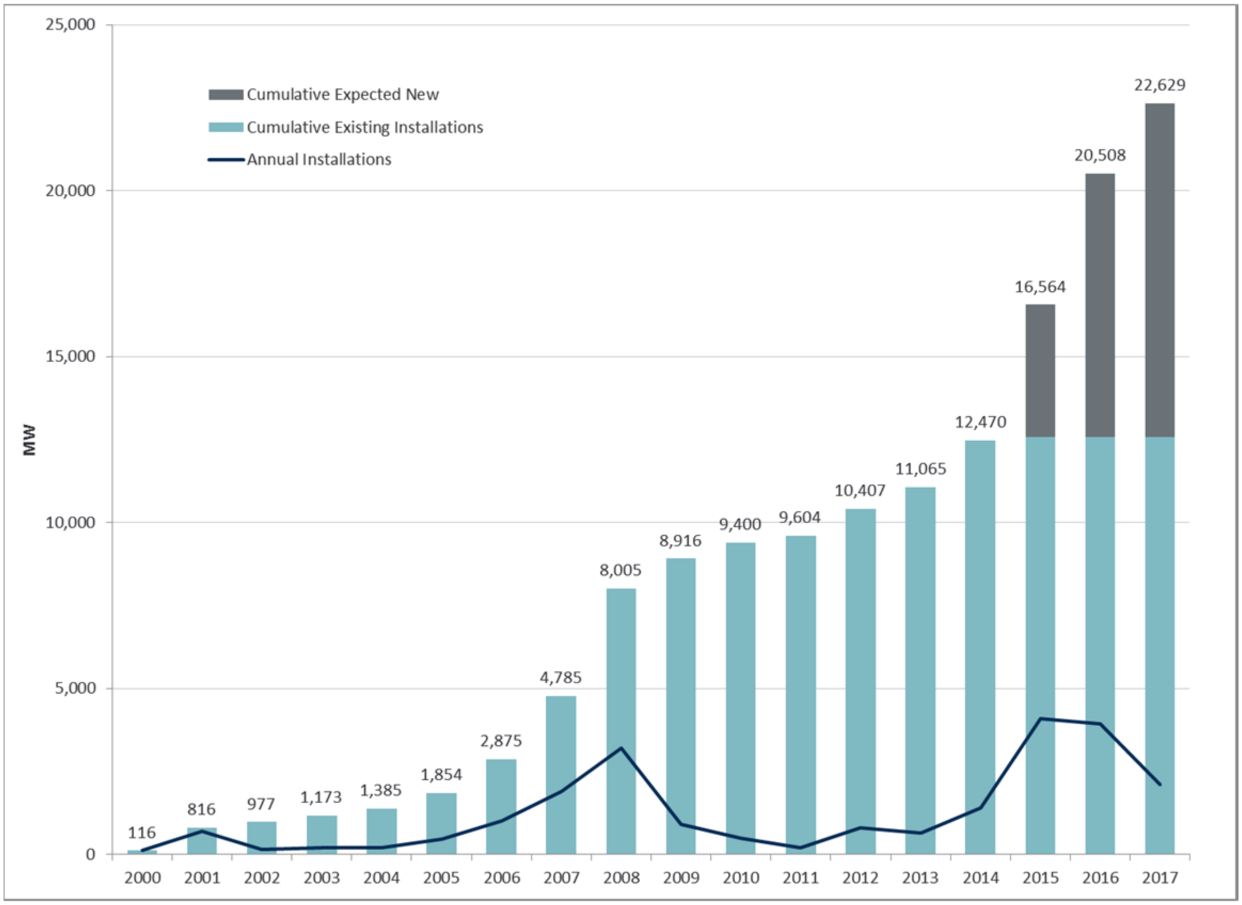
15 As shown in Figure 3 above, six European countries have wind penetration levels above 10%, with three countries (Spain, Portugal and Ireland) approaching or exceeding 20% and one country (Denmark) exceeding 30%.

16 On March 31, 2014, wind output reached 39.4% of total ERCOT load for a short period of time. See Trip Doggett, ERCOT Update, July 23, 2014.

Figure 5: Projected Annual and Cumulative Wind Installations in ERCOT



Source: ERCOT, Generator Interconnection Status Report, March 2015

In the rest of this section, we describe in some detail various measures taken by ERCOT that have helped or are designed to help facilitate the integration of variable renewable energy sources.

A. Nodal Pricing Market As Enabler

In December 2010 ERCOT introduced its Nodal Market, which allows locational marginal prices (LMPs), i.e., potentially different prices at many different geographic locations. This new market design provides more direct price signals to both generators and load and better reflects congestion in the transmission system. The LMP-based market allowed for a shift from portfolio-based scheduling and dispatch to resource-specific scheduling and dispatch, which facilitated better wind integration even though not undertaken explicitly for that purpose. At the same time as introducing the new market design, ERCOT also moved from a 15-minute dispatch resolution to a 5-minute resolution, which ERCOT identifies as "one of the main reasons why ERCOT has been successful in integrating renewables with minimal increase in Ancillary Services capacity."[17] Moving towards shorter-term scheduling, which in turn permits taking into account better system information including more accurate forecasts of near future wind and solar generation, is recognized as an important operational tool for managing renewable output variability.

B. CREZ Lines To Lower Wind Curtailment

A second important set of actions designed to help better use and manage renewable energy sources was the construction of significant additional transmission capacity to areas with high wind potential but with insufficient transmission capacity. In 2005 the Texas State Legislature authorized the addition of significant transmission capacity into Competitive Renewable Energy Zones (CREZ), a process that was completed in 2014. The lines were intended to expedite construction in areas where renewable generators were committed to building, and were designed to accommodate a total wind capacity of 18,500 MW[18] (as Figure 5 above shows, this level could well be exceeded in the near future, even if not all of the additional wind is built in the areas connected through CREZ lines).

Prior to the CREZ lines being built, West Texas, where most of the wind capacity was located, experienced significant instances of negative LMPs and curtailments. Negative prices result when total supply from resources that either must run (such as inflexible baseload plants) or lose non-energy revenues if not producing (such as production tax credits and renewable energy certificates for wind plants) exceeds demand. Negative prices are therefore a sign of a significant supply-demand mismatch, given available transmission capacity. In extreme cases, the excess supply becomes so large that maintaining system reliability requires curtailing some generation (such as wind). Both negative prices and curtailments are therefore evidence that not enough transmission capacity exists to deliver power generated by a wind plant (even at zero or negative offer prices) to customers willing to pay for it.[19] Additional transmission lines from wind-energy producing regions to demand centers alleviate both negative pricing and curtailments. The completed CREZ lines – for a cost of approximately $6.8 billion – are credited with significantly contributing to lower wind curtailment since 2012, from levels as high as 17% in 2009 to 1.6% in 2013,[20] and with mostly eliminating negative prices.[21] It should be noted that the cost of the

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17 ERCOT, ERCOT Concept Paper: Future Ancillary Services in ERCOT, Draft Version 1.1, 2013, p.8.

18 http://www.texascrezprojects.com/overview.aspx.

19 In addition to facing curtailment from insufficient transmission offtake capacity, negative bids are a result of the way in which wind development receives tax incentives proportional to output. Some generation companies regard this as a policy that distorts markets and makes wind expansion undesirable. While an important issue in public policy towards encouraging new technologies, this is a political side effect and not a true integration issue.

20 Lori Bird, Jaquelin Cochran, and Xi Wang, Wind and Solar Energy Curtailment: Experience and Practices in the United States, NREL, March 2014, p.9.

21 See http://www.eia.gov/todayinenergy/detail.cfm?id=16831.

CREZ lines is in addition to the modest integration cost estimates outlined above and that it has led to an active debate about who should bear the cost of additional transmission infrastructure.[22]

C. Improved Calculation of the Capacity Contribution of Wind

Ensuring resource adequacy is one of the primary concerns of electric system operators. Models for estimating the contribution of conventional fossil generation sources to resource adequacy have been used for decades. For variable generation, however, efforts to develop appropriate metrics are less established and continue to evolve. Understanding the contribution of variable renewable energy resources to meeting peak demand is critical for managing a system with increasing shares of renewable generation. Assuming that variable renewable resources do not contribute to resource adequacy is still a common practice in several countries and regions, including some of the European countries with high penetration of renewables. The practice is often justified with the argument that since output cannot be controlled (at least not in the positive sense – it can be curtailed) by the system operator, the system cannot "count" on the production from such generators. However, in electric systems with a resource adequacy requirement (unlike ERCOT), this approach can result in additional costs beyond what is necessary, since it ultimately requires end users to pay for more capacity than is actually needed when properly assessing resource adequacy needs.[23]

In the United States, system operators typically give some capacity value to variable renewable generation. An often used approach for assessing this contribution is called "Effective Load Carrying Capability" (ELCC). ELCC estimates the statistical relationship between demand and the expected contribution from a given generation resource using various modeling techniques and data sources including observed actual generation during historic peak load conditions.

Until late last year, ERCOT used an estimated ELCC of 8.7% for wind generators no matter where in ERCOT they were located.[24] Recently ERCOT updated its ELCC estimates for wind generation based on actual observed capacity factors during peak load conditions. The result was an increase in the estimated contribution of wind to resource adequacy and a differentiated assessment of that contribution by region. Specifically, as of November 2014, ERCOT is determining wind's capacity contribution is based on up to the ten previous years of wind production during the 20 highest peak hours during the summer and winter peak load season respectively.[25] For solar PV, ELCC is assumed to be 100% of capacity up to 200 MW of solar PV

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22 In August 2014, the Public Utilities Commission of Texas initiated a project to review the cost allocation of renewable energy production related transmission and ancillary services (PUCT Project No. 42647) with a set of questions including whether or not renewable resources should help fund further transmission investments. See PUCT, Memorandum, August 6, 2014).

23 ERCOT is an energy-only market without a resource adequacy requirement.

24 ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, 2015-2024, February 2014.

25 ERCOT, NPRR Number 611, Board Report, October 14, 2014.

installed, and subsequently the actual average capacity factor during the 20 highest peak periods of the preceding three years during the summer and winter peak load season, respectively.[26]

As a consequence, as of November 1, 2014 wind in non-coastal regions is contributing to reserve margins with 12% of nameplate capacity during the Summer Peak Load Period and 19% during the Winter Peak Load Period. Coastal wind is contributing 56% during the Summer Peak Load Period and 36% during the Winter Peak Load Period. Solar PV, which is currently under 200 MW in installed capacity, is contributing 100%.[27] Relative to the previous calculation, the new methodology increased expected reserve margins by approximately 2% (from 13.7% to 15.7% in 2015 and from 4.9% to 7.3% in 2024).[28] The new methodology suggests that ERCOT actually has higher reserve margins than was estimated under its old methodology and will need to attract fewer additional resources to maintain target reserve margins going forward, all else equal. This in turn means that the estimated cost of a system with higher renewable share is less – since fewer total resources are needed to maintain adequate reserve margins than under the old methodology.

In ERCOT, this accounting change does not directly affect costs, since ERCOT does not have a resource adequacy requirement and wind's capacity credit does not displace other capacity resources. Wind displaces other capacity resources only to the extent that its output reduces energy prices across the year, and thus deters entry or promotes retirements. However, in other systems that have resource adequacy requirements, capacity accounting does affect costs more directly, as each MW of wind credited reduces the amount of other capacity needed.

D. Advances In Wind Forecasting

While there is and has been significant wind development activity on the Gulf Coast, ERCOT's large wind capacity is still relatively geographically concentrated in West Texas and the Texas Panhandle, which reduces the diversity benefits that would result from wind resources being more equally spaced across a wider area.[29] As a consequence, changes in meteorological

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26 Ibid.

27 ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, 2015-2024, December 1, 2014.

28 To estimate the change in reserve margin, we used the December 1 ERCOT report on the Capacity, Demand, and Reserves in the ERCOT Region, 2015-2024 from December 1, 2014, available in spreadsheet form from ERCOT's website, and replaced the applied new capacity contribution factors with the previously used 8.7%.

29 As of 2014, wind capacity on the Gulf coast represented about 14% of total ERCOT wind capacity (Texas Wide Open For Business, The Texas Renewable Energy Industry, 2014, p. 13-14). Research shows that short term variability of wind output can be mitigated relatively easily by interconnecting wind output from a relatively small set of geographically diverse sites. See Warren Katzenstein, Emily Fertig, Jay Apt, The variability of interconnected wind plants, Energy Policy 38, 2010, p. 4400-4410. Also, as indicated above, coastal wind in ERCOT is better correlated with demand in major load centers.

conditions can lead to rapid changes in wind output, which in turn can require large ramping (up or down) from the rest of the ERCOT resources. ERCOT has improved its weather forecasting capabilities over the past several years. ERCOT has also implemented the ERCOT Large Ramp Alert System using probabilistic wind forecasts for the next six hours updated every 15 minutes. This system permits operators to commit resources during the day with a much better understanding of the likelihood of needing additional resources for large ramping events caused by changes in wind production.[30]

E. Technological Improvement of Renewable Sources

Technological advances related to renewable energy resources themselves can facilitate their integration with the electric system. One example of the co-evolution of operational procedures and technological capabilities is ERCOT's requirement that wind generators, having signed interconnection agreements on or after November 1, 2008, need to provide voltage ride-through capabilities – that is, the ability to continue operating during short-term periods of voltage fluctuation rather than automatically shutting down.[31] As a consequence, these newer wind generators do not have to disconnect when system voltage levels rise above or fall below the target level of 60 Hz. Absent voltage ride-through capability, the system operator has to set aside sufficient resources to be able to react to a potentially large set of generating resources (in this case wind generators) disconnecting from the system, which might turn a small problem into a much more severe one.

F. Redesign of Ancillary Services

Another important area of activity related to renewables integration is ERCOT's redesign of ancillary services markets, as part of its Future Ancillary Services (FAS) proposal.[32] Implementation of FAS may depend partly on the results of ERCOT's benefit cost analysis of the proposal, due out later in 2015. This redesign is driven by the perceived need to meet future system demands as the penetration of variable energy resources increases, while also accommodating new opportunities to meet those needs. It aims to incorporate a variety of advanced energy technologies into the marketplace, including faster ramping thermal generation, energy storage, automated DR, distributed generation, and renewable generation.

For example, FAS introduces a new product called Fast Frequency Response 1 ("FFR1") that advanced batteries and fly-wheels can provide. Load resources (discussed in more detail below) could also provide a Fast Frequency Response product called "FFR2," similar to how they provide responsive reserves today. ERCOT estimates that approximately 1,400 MW of load resources are

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30 Pengwei Du, ISO Experiences with Stochastic Wind Forecasting – ERCOT, ERCOT.

31 ERCOT, ERCOT Nodal Operating Guides, Section 2: System Operations and Control Requirements, February 1, 2014, p.2-25.

32 ERCOT, ERCOT Concept Paper: Future Ancillary Services in ERCOT, Draft Version 1.1, 2013, p.9

capable of meeting the requirements of FFR2.[33,34] Both types of FFR would provide more rapid frequency response than traditional resources to compensate for sudden unplanned outages at large thermal units. Current proposals would require FFR resources to deliver their full response within a half second.

In the longer term, ERCOT is also raising the question whether a shift from conventional fossil to more variable renewable generation may lead to a loss of system inertia, which is traditionally supplied by synchronous generation (spinning generators, typically generators with spinning mass such as fossil fuel or hydro resources). This concern, if validated, may merit, at some point in the future, the introduction of some new ancillary service to incentivize Synchronous Inertial Response Service (SIR). In that context ERCOT is also evaluating to what extent synthetic (or emulated) inertia from inverter-based generation sources (such as wind turbines) might be able to provide the necessary capabilities in the future. While practical experience with wind generators providing synthetic inertia is limited, it appears that at least under some conditions inverter (or equivalent) technologies can provide some of the inertia services typically provided by synchronous equipment.[35]

G. Demand Response

Demand response (DR) is playing an increasing role in providing capacity, but also in mitigating shorter term events potentially impacting reliability. While DR is primarily used as a capacity resource, i.e. as a way of ensuring that the combination of supply resources and DR are sufficient to maintain a stable supply of electricity, particularly during the periods of highest demand, it is also used for emergency situations, such as when generation outages lead to relatively short term supply shortages. Many DR programs limit the number of times, and define lengths of time for such calls, each year and do not require advanced technology. For example, interruptible load contracts using some form of direct load control (DLC) have been around for many years. These types of "traditional" DR can help grid operators manage any relatively rapid and unexpected changes in the output from variable renewable energy sources. However, in the future advances in technology such as smart meters (defined as meters that measure consumption at frequent intervals and/or allow for frequent bidirectional communication), home energy management systems, smart appliances, etc. will increasingly create additional opportunities to use DR in

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33 Unlike most other system operators that secure operating reserves mostly through generator resources, ERCOT has been allowing load to provide operating reserves for ten years. Today, out of the operating reserve requirements of 2,300 MW (or higher), these load resources provide approximately 1,250 MW of responsive reserves. See http://www.ercot.com/content/meetings/wms/keydocs/2004/0923/WMS09232004-8.doc and http://www.ercot.com/content/gridinfo/resource/2015/adequacy/cdr/CapacityDemandandReserveReport-May2015.pdf.

34 ERCOT, ERCOT Concept Paper, Future Ancillary Services in ERCOT, Draft Version 1.1, p.19.

35 In addition to requiring all wind generators to be capable of high- and low voltage ride through, Hydro Quebec already requires wind plants with 10 MW or greater capacity to be capable of providing emulated inertia. See Hydro Quebec, Transmission Provider Technical Requirements For The Connection Of Power Plants To The Hydro-Québec Transmission System, p.61.

situations other than emergencies. More robust DR can therefore make a significant contribution to integrating larger amounts of renewables.

Over the past five years ERCOT has changed its programs allowing participation by DR, which include a number of distinct products, all essentially targeting "traditional" DR: weather and non-weather sensitive Emergency Response Service Ten Minute (ERS-10) and Emergency Response Service Thirty Minute (ERS-30), both of which are emergency interruptible load services. Procurements during 2014 resulted in contracts for between 450 MW and 630 MW of non-weather sensitive ERS-10 and between 97 MW and 280 MW of non-weather sensitive ERS-30. There is currently no contracted weather-sensitive ERS-10 and 21.6 MW of weather-sensitive ERS-30.

ERCOT also has a load-based 10-minute responsive reserve ancillary service, which targets larger customers connected through two-second demand data meters for non-emergency services. In theory, both controllable and non-controllable Commercial Load Resource (NCLR and CLR) programs exist. As of January 1, there were 232 load resources corresponding to 3,056 MW registered with ERCOT. All but two were non-controllable resources, meaning that they provide Responsive Reserves Service (RRS) using high set underfrequency relays (UFRs). These resources bid into the day-ahead market and up to a total of 50% of the RRS awards can be made to load resources. During 2014, the average award of RRS to load resources was approximately 1,350 MW.[36] Finally, the Four Coincidental Peaks (4CP) program encourages load resources to lower peak demand during the highest load hour in each of the four summer months (June through September) since the customers' share in transmission and distribution costs depends on the magnitude of those peaks. ERCOT estimates the impact of the 4CP program (which does not provide explicit signals for DR, but rather relies on loads to lower their peaks, which may or may not coincide with high prices or changes in market conditions caused by fluctuations in variable generation) to be between 830-950 MW.[37]

The rapid deployment of smart meter technology, which by February 2015 had reached 6.7 million representing 98.4% of ERCOT load,[38] is providing the basis for increasing participation of residential load resources in demand response. For example, the ERS-30 program, which requires generation or load reductions to be made available in emergency situations within 30 minutes, is increasingly attracting residential customers. In the summer of 2014, ERCOT awarded three ERS contracts to Qualified Scheduling Entities (QSEs), which in turn included three residential aggregations initially involving approximately 60,000 residential participants for a total of 21.6 MW of peak demand (between 1 PM and 8 PM).[39]

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[36] ERCOT, Annual Report of Demand Response in the ERCOT Region, Version 1.0, March 2015.

[37] Ibid.

[38] ERCOT, ERCOT Monthly Operational Overview, February 2015, p.41.

[39] Paul Wattles, Item 9: Demand Response Update, August 12, 2014.

ERCOT's emergency response DR programs have already played a significant role in helping maintain system reliability. For example, on January 6, 2014, cold winter temperatures were exacerbated by unplanned outages of several generation sources. As a consequence, ERCOT declared an emergency and activated 111 MW of ERS-30 and 509 MW of ERS-10 resources for approximately one hour.[40] During the same event on January 6, ERCOT had previously activated 1,080 MW of ancillary services using load resources.[41]

ERCOT also created an opportunity for loads to more actively participate in markets during peak load conditions, essentially allowing for price-sensitive bids in real-time markets.[42] Called "Loads in SCED (Security Constrained Economic Dispatch)", a first version of the program only open to Load Serving Entities (LSEs) went into operation on June 1, 2014. To date, ERCOT has seen limited interest in participation. As of the summer of 2014, between 25-30 MW of aggregated residential demand from air conditioning, water heaters and pool pumps under direct load control were in the qualification process.[43] However, no resources are currently participating in the program.

A second, more comprehensive version of the program open to Curtailment Service Providers (CSPs), i.e. 3rd party DR providers, currently is under discussion. Full implementation of these programs would allow participating customers to offer to reduce their consumption when prices are high in real-time, enabling ERCOT to match supply with demand at least cost using both supply and demand resources. Beyond these programs, ERCOT is also examining the potential future role of DR in the provision of ancillary services.[44]

Beyond ERCOT's own programs, the ERCOT energy-only market with full retail choice also provides ample opportunities for Retail Energy Providers (REPs) to offer rates and incentives that encourage demand participation in ways that mitigate high prices, typically associated with relatively high net loads. Offering various retail rate structures allow REPs to differentiate themselves from their competitors and allow their customers to reduce costs by being price-responsive. By creating price-responsive demand, these programs have the potential to mitigate the impacts of variations in renewable energy production before emergency situations arise.

A number of the programs offered by REPs rely on technology such as smart meters, smart thermostats etc. While the high penetration rates of smart meters is no longer a barrier to the deployment of such programs, increases in the penetration levels of smart thermostats – which allow remote control of air-conditioners and electric heating systems, for example in response to price spikes caused by a drop-off in renewable generation – and other enabling technology

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40 ERCOT, Final Report: January 6 2014 EEA, March 7, 2014, p.7.

41 Ibid.

42 ERCOT, Nodal Protocol Revision Request (NPRR) 555, Load Resource Participation in Security-Constrained Economic Dispatch, posted July 3, 2013.

43 Paul Wattles, Item 9: Demand Response Update, August 12, 2014, p.9.

44 Paul Wattles, ERCOT ISO and DR Overview 2014, May 21, 2014.

increase the potential for such programs to expand in the future. As of 2014, ERCOT estimates the REP based programs contributed approximately 432.5 MW of DR, about half from pricing programs (real time pricing, Block and Index pricing, etc.) and half from load control programs.[45] As of mid-2013, 4,105 customers were enrolled in real time pricing programs, 22,947 in block+index[46] programs and 117,570 in other Time of Use (ToU) pricing programs.[47]

There is some indication that the number of enrolled customers is increasing relatively quickly. The majority of time-sensitive ToU tariffs to-date involve "free weekends and evenings" type programs. While not yet a major factor in helping with grid reliability and variable renewable integration, the combination of smart meter infrastructure and an increasing acceptance of time-responsive tariff designs creates a basis for the development of more sophisticated tariff structures designed at making load more flexible in direct response to price fluctuations, including those driven by variable renewable generation.

H. Pilot Projects in ERCOT

In addition to the changes made by ERCOT and described above, there are also a number of other early stage/pilot programs not administered by ERCOT but occurring inside its territory with important implications.

Oncor, the largest regulated transmission and distribution system operator in ERCOT, was one of two participants in a Department of Energy funded pilot project involving Dynamic Line Rating (DLR) completed in 2013.[48] DLR dynamically increases transfer limits relative both to the static ratings typically used in utility operations and to ambient-adjusted (AAR) line ratings based on ambient conditions of the physical transmission line, such as temperature, wind, and humidity, or based on the direct measurement of line sag. Lower temperature and higher wind help cool the physical wires and therefore allow higher transfers of power without sagging as much from the heat produced by current flow.[49] Two important potential application of DLR are for congestion mitigation and planning. Oncor, in its evaluation of the DLR pilot, notes that "Study results show that congestion mitigation can be obtained with as little as a 5 to 10% increase in capacity over the currently used ambient-adjusted line ratings. The effective congestion mitigation can be in the range of 60 to 100% on the lines monitored."[50] While the pilot did not

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45 ERCOT, Annual Report of Demand Response in the ERCOT Region, Version 1.0, March 2015, p.7.

46 Under Block+Index pricing, customers pay a certain amount for a certain number of kWh (block). For consumption above the block, pricing is indexed to wholesale prices.

47 Paul Wattles, Demand Response Update, ERCOT, October 24, 2014, p.9.

48 The other participant was the New York Power Authority (NYPA).

49 See Oncor West Texas Dynamic Line Rating (DLR) Project presentation, dated March 26, 2013, available at: http://www.ercot.com/content/meetings/rpg/keydocs/2013/0326/Oncor_W_Texas_Dynamic_Line_Rating_Presentation_for_ERCOT_032.pdf.

50 Oncor Electric Delivery Company, Dynamic Line Rating, Oncor Electric Delivery Smart Grid Program, Final Report, August 2013, p.2.

provide definitive answers, Oncor did find that 5% DLR use increased average wind generation by 3%, which, given that only half of the lines of the pilot involved wind generation, Oncor deemed significant.[51] In other words, Oncor found that the use of DLR allowed increased levels of wind generation during contingency events without causing congestion.

Other recent examples of early stage experiments include the use of smart meters to measure voltage levels (and resulting voltage profiles) at the meter level, to use this data to develop feeder-level voltage profiles and to use those profiles to predict transformer outages. At least one utility in Texas is examining how this data can be used to better manage the maintenance and replacement of transformers in ways that both lowers the chance of outages and reduces the cost of maintaining a reliable distribution system. It can be expected that as the share of distributed variable renewable energy sources, most likely solar PV, increases, the benefits of being able to measure voltage profiles at this level will help reduce transformer outages and the costs related to integrating such resources.[52]

Similarly, current battery pilot programs suggest that the benefits of this kind of storage, installed at the feeder level and serving just a few customers, could substantially exceed those traditionally estimated. Preliminary pilot results have shown that in local outage situations, when batteries keep a group of customers supplied with electricity, dramatic behavior changes are seen such that customers maintain essential services for much longer than initially expected based on a given storage capacity.[53] While very preliminary, these results point to the potential interaction benefits of renewables, storage and behavioral changes (such as turning off non-essential equipment) during stress periods for local distribution systems. Such stress periods could be caused by external events such as storms, but also by unforeseen variability in renewable energy production at high penetration levels.

V. Integrating Renewable Energy at Xcel Energy Colorado

Xcel Energy Colorado is a vertically integrated utility providing electric service to approximately 1.3 million wholesale and retail customers in Colorado, including the Denver metropolitan area. Xcel Energy is among the utilities with the highest renewable energy penetration and is recognized as a leader in renewable energy integration, having been ranked first by the American Wind Energy Association (AWEA) for eleven consecutive years and fifth by the Solar

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51 Ibid, p. 168.

52 Based on confidential information provided by one of ERCOT's distribution utilities.

53 Based on confidential information provided by one of ERCOT's distribution utilities, a battery system designed to provide one hour of back-up power was able to sustain essential services for up to four hours as a result of customers connected to the storage system dramatically reducing their demand during the periods when storage was needed to supply power not available from the grid.

Electric Power Association (SEPA).[54] As of the end of 2013, Xcel Energy Colorado's wind portfolio comprised 2,168 MW of wind capacity with another 450 MW to be connected in the near future. In addition, the system has 188 MW of customer-sited solar generation and 80 MW of utility scale solar PV capacity, which is expected grow by 170 MW in the near future.[55] The balancing area's peak load in 2013 was 6,646 MW and wind contributed 18.7% to Xcel Energy Colorado's annual load.[56] Xcel Energy Colorado is not part of an RTO and does not operate a formal day-ahead or real-time energy market. All these attributes create challenges that make Xcel Energy Colorado a good case study for integrating variable renewable energy sources by a single utility.

With the goal of increasing renewable penetration levels, Xcel Energy Colorado has been addressing the system operational issues with the focus on changes in ancillary service requirements, improved wind forecasting, and increases in generation flexibility.

A. Change in Ancillary Services Requirements

While the summer peak load for the Xcel Energy Colorado system is approximately 6,700 MW, the system load during off-peak hours can drop to around 2,700 MW. This indicates that the system could have over 2,600 MW of wind generation potentially serving a 2,700 MW load. Given the magnitude of installed wind capacity, wind ramping events, specifically ramp-down events (i.e. periods when electricity production from wind decreases relatively rapidly), have been identified as a potential reliability concern.[57] Unlike ramp-up events, there are no wind turbine control actions available to mitigate the ramp-down events, leaving improved forecasting as the primary tool to provide the system operator adequate foresight to plan for increased resource needs. This leads to the need for advanced energy resources like automated demand response, energy storage and other fast ramping resources.

For resource planning, Xcel Energy Colorado determines the generation capacity to be kept available, similar to other system operators. However, Xcel Energy Colorado also determines the responsiveness, flexibility, or ability of that generation to be brought on-line in a timely manner to address the needs for flexibility. Consequently, in 2011 it adopted a 30-minute Wind Reserve Guideline to ensure that enough standby generation capability can be brought on-line within 30-

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54 www.xcelenergy.com/Company/News/News_Releases/Xcel_Energy_named_No._1_utility_wind_provider_for_11th_consecutive_year.

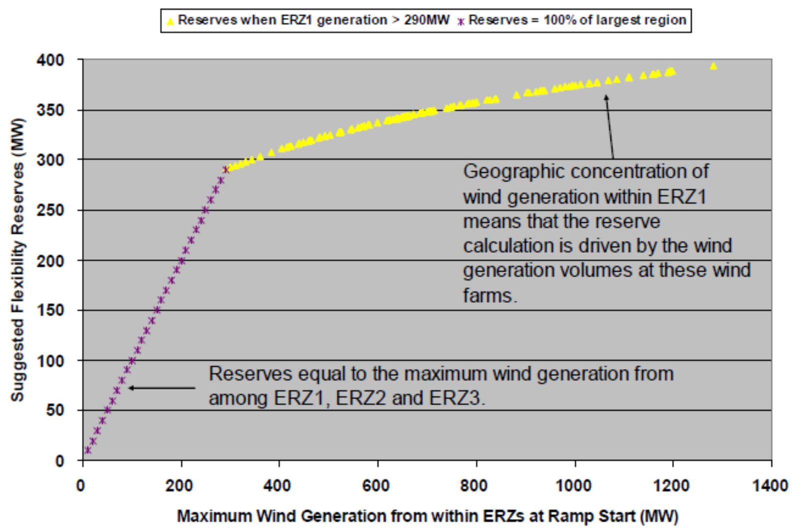
55 Public Service Company of Colorado, Xcel Energy, Operating Companies Joint Open Access Transmission Tariff - First Revised Volume No. 1, filed with the Federal Energy Regulatory Commission, May 15, 2014, p. 2.

56 Ibid.

57 Ramp-up events, with continued or sustained increases in wind generation levels, are dealt with by reducing the level of generation from gas-fired units, or in severe cases, shutting down a gas-fired unit or curtailing wind. In general, ramp-up issues will have economic implications but not necessarily lead to reliability issues. On the other hand, ramp-down events can potentially lead to a shortage of overall generation, which is a reliability concern.

minutes to cover the needed flexibility. The flexible capacity need was calculated to be a MW for MW match against wind generation for the first 290 MW.[58] For wind generation levels above the 290 MW threshold, additional 30-minute capable standby generation is held based on the aggregate wind energy being produced from wind facilities located along the northern Colorado border within Energy Resource Zone (ERZ) 1, which contains the majority of Xcel Energy Colorado's wind resource.[59] Figure 7 shows the calculated flexibility needs as a function of wind generation.[60]

Figure 7: 30 Minute Reserve Needs and Wind Generation Level



Partly in response to rapidly increasing wind (and solar) penetration, Xcel Energy recently asked the FERC for changes to its Open Access Transmission Tariff (OATT), in particular the amount of certain ancillary services it procures and how it recovers the resulting costs. Specifically, it asked the FERC to approve changes to its Regulation and Frequency Response Service (Schedule 3 of its OATT) and to approve the formal introduction of a Flex Reserve Service (Schedule 6A of its OATT) specifically designed to handle large reductions in wind generation due to losses in wind speed (and hence occurring over a somewhat longer period of time, between tens of minutes and hours). The addition of a Flex Reserve service can by itself be considered an

58 This 290 MW threshold was determined in 2011 and may change in the future as the Xcel Energy Colorado resource portfolio, including wind and solar, changes.

59 As of 2011, out of the five ERZs, only ERZ 1 and 3 had wind resources, with future wind resources planned for ERZ 2. At the time, over 80% of all Xcel Energy Colorado's wind resources were located in ERZ 1. The calculation method based on ERZ 1 wind generation may also change with future wind locations.

60 Source: Xcel Energy Colorado 2011 Wind Limit Study, filed as part of the 2011 Electric Resource Plan, available at: http://xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Attachment-2.14-1-2011-Wind-Limit-Study.pdf

innovation in systems operation designed to better integrate variable renewable energy resources. We note that the amount of additional ancillary service costs to be recovered is $727,000 per year, or only 0.3% of its $230 million annual transmission revenue requirement.[61]

B. ADVANCED WIND FORECASTS

In parallel to adding the 30 minute flexibility to accommodate increased net load variability and ramping events, Xcel Energy has been advancing its wind forecast methods. As a stand-alone utility lacking geographic diversity, the value of forecast accuracy for the variable resources is of particular importance. Furthermore, the same level of forecast error translates into greater absolute errors as renewable penetration levels grow.

In 2009 Xcel Energy implemented an advanced wind forecasting system. The system, developed in collaboration with the National Center for Atmospheric Research (NCAR), blends forecasting and statistical methods.[62] The system uses a variety of inputs from satellites, planes, radars, ground-based weather stations, and sensors on the wind turbines themselves and produces a new forecast every 15 minutes.[63] It improved the wind forecast accuracy by 35% relative to previous forecast methods and informs both day-ahead and real time operations. Since the introduction of the improved methodology, Mean Absolute Error (MAE) in wind forecasting has decreased significantly. In Colorado, MAE dropped from 18.01% in 2009 to 11.04% by 2013 (a 38.7% reduction) with resulting savings of $20.4 million.[64]

These findings are consistent with the evidence from other jurisdictions that over time wind forecast accuracy has increased and integration costs have fallen. For example, Eurelectric, the European industry association for the power industry, cites wind forecast improvements as one of the measures improving the integration of variable renewables, and includes Figure 8 in a recent report on the topic.[65]

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61 FERC, Order Conditionally Accepting And Suspending Proposed Tariff Revisions, Subject To Refund, And Establishing Hearing And Settlement Judge Procedures, Dockets Nos. ER14-1969-000, ER14-1969-001 and ER14-1969-002, Issued December 5, 2014, p.3.

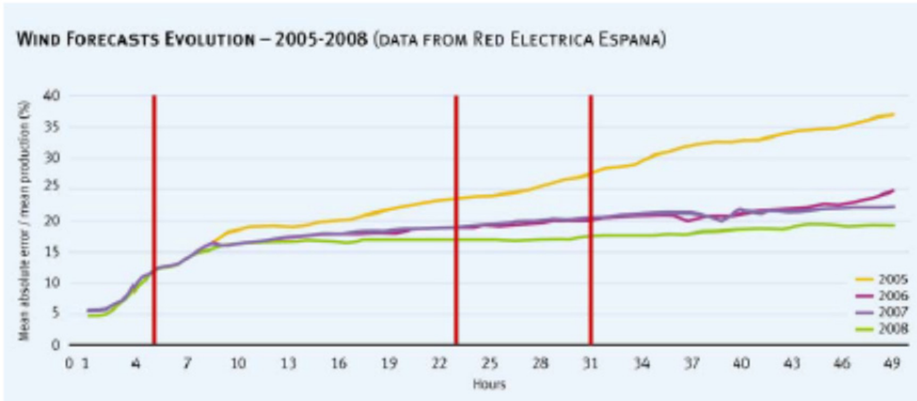
62 For a detailed description of the system, see Mahoney et al., A Wind Power Forecasting System to Optimize Grid Integration, IEEE Transactions on Sustainable Energy, Vol. 3, No. 4, October 2012.

63 https://www2.ucar.edu/atmosnews/news/5771/ncar-wind-forecasts-save-millions-dollars-xcel-energy.

64 Drake Bartlett, What is the value of a Variable Generation Forecast? Xcel Energy, February 25, 2014.

65 Eurelectric, Integrating intermittent renewables sources into the EU electricity system by 2020: Challenges and solutions, 2010.

Figure 8: Changes in Wind Forecast Accuracy in Spain



Source: Eurelectric, 2010, Reproduced Picture 10

C. Advanced Operations

In addition to the ancillary services and forecast improvements, Xcel Energy Colorado has advanced operations to better accommodate renewable resources and reduce overall production cost. These operational advancements expand beyond the thermal generators that traditionally provided the flexibility needed to reliably operate the system.

For example, in 2010 Xcel Energy Colorado made technological modifications to its Fort Saint Vrain 750 MW combined cycle gas plant that lowered the minimum generation level by 300 MW and increased the turn-around time (the time needed between shut-off and restart of the plant) from 8 hours to 2 hours. Also, many of Xcel Energy Colorado's newer gas turbines were updated with the GE FastStart technology, which improved the start-up time of these units. Similarly in 2011 the minimum generation level of the Comanche #3 coal-fired power plant was lowered from 500 MW to 405 MW.[66] Along with these improvements, a number of coal units have been, or are in the process of being, retired. Cherokee unit #4 is being converted from burning coal to gas. In addition to the increased flexibility achieved by increasing the share of gas-fired generation, Xcel Energy Colorado is also studying the ability of the natural gas storage and the delivery system to supply fuel to gas-fired generation resources which shoulder the majority of the 30-minute wind reserve duty. It has been identified that if an extreme wind ramp down event were compounded by the loss of a large coal unit, there may be the need to fuel switch some of the gas generation to fuel oil, especially during the beginning and end of the heating season, or electric load shoulder months, when storage injection or withdrawal rates of gas are at their lowest and wind generation is at its highest.

Xcel Energy Colorado also applied changes to its Cabin Creek pumped Storage plant, including receiving WECC approval for Cabin Creek capacity to count toward spinning reserve, and

66 Ibid.

shifting black start responsibilities away from Cabin Creek to other units to free up water that was otherwise reserved for black start for peak shaving and/or ancillary services.

In 2011, Xcel Energy Colorado installed Automatic Generation Control (AGC) systems at four wind facilities in Colorado to enable the system operator to ramp down the output from these wind facilities automatically during certain periods.[67] Today, two-thirds of the wind turbines in Xcel Energy Colorado are equipped with AGC and provide regulation. Furthermore, advancements in power electronics have enabled operators to provide frequency control through wind plants by extracting stored inertial energy from the wind turbines. The response time of these wind turbines that occur during the first ten-to-fifteen seconds following a large frequency dip is faster than the traditional governor response of larger conventional thermal generation resources and has proved to actually improve system performance.

Finally, in late 2014 Xcel Energy Colorado filed a revised tariff to reflect a Joint Dispatch Agreement (JDA) with Platte River Power Authority and Black Hills Colorado Electric Utility Company. The JDA, with a framework similar to an energy imbalance market, although smaller in scale, is intended to provide the participating parties with a centralized, coordinated, intra-hour dispatch system for their generation resources. The overall goal is to achieve more efficient and lower generation cost to serve load and is particularly helpful with increasing renewables penetration since variations of actual output from wind and solar generation compared to forecasts can be balanced across a larger set of resources.[68]

VI. Other Innovative Approaches to Integrating Renewables

Beyond the changes implemented by ERCOT and Xcel Energy Colorado, system operators and in some cases other market participants have implemented or are implementing a number of measures directly designed to facilitate the integration of larger amounts of variable renewable generation or having the side effect of doing so. In many instances, the changes do not require new technology, but it is also true that technological progress facilitates new approaches and in some cases creates entirely new opportunities. In this section we provide a brief summary of a sample of approaches and developments. In general, these approaches and developments follow

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67 Keith Parks, Wind and Solar Integration in Colorado: Challenges and Solutions, Xcel Energy, August 9, 2011.

68 Under the JDA, Energy transfers will be limited to average transmission capacity (ATC) between the participating systems at designated interconnection points. Unused ATC will be determined every five minutes after all other procurement and scheduling deadlines have passed. While the schedule-driven ATC updates currently occur every quarter-hour, the five-minute update ensures that any intra-hour schedule changes are adequately captured and that only the leftover ATC will be utilized through the JDA. The JDA will facilitate a joint economic dispatch of committed resources of the participants (determined at the beginning of the hour) and would likely reduce the curtailment of renewables and lower the overall production cost of the participating parties.

what was illustrated in the two cases studies: operational changes, such as shorter dispatch cycles; forecast enhancements; ancillary service changes; and transmission planning.

As the case studies of ERCOT and Xcel Energy Colorado demonstrate, shorter dispatch cycles in combination with more accurate shorter-term forecasts of renewable generation are now commonly recognized as reducing forecast variations from renewable generators and leading to reduced ancillary service requirements. MISO (and SPP) are taking this concept one step further and dispatching wind resources similar to traditional generators, by asking the renewable resources to submit an offer curve for its generation quantity and price. The offer curve will be treated equally with other offer curves provided by traditional generators and be automatically dispatched based on merit order. The only difference is the generation quantity that can be offered by renewable resources depends on the wind forecast, rather than its physical plant capacity. MISO, by including 80% of its wind capacity in the 5 minute dispatch as Dispatchable Intermittent Resources,[69] improved system reliability "through better congestion management by replacing manual curtailments with automated real-time dispatch."[70]

MISO has also started developing and partially implementing a look-ahead unit commitment and dispatch process.[71] The look-ahead process will focus on predicting near-term changes needed to keep energy flowing efficiently and cost-effectively. By incorporating forecast data for both load and renewable resources, it allows for better decision making, taking into account the likely future changes of the system (such as a ramping event that could result in local resource needs), rather than just considering the current status. Stochastic unit commitment, while still in its infancy, has been gaining traction as another tool for dealing with uncertainty.[72]

Many system operators other than ERCOT and Xcel Energy Colorado have recognized the importance of forecasts and have developed and implemented customized centralized wind

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69 See MISO, MISO 2013-2014 Winter Assessment Report, Information Delivery and Market Analysis, June 2014, page 10.

70 Minnesota Department of Energy Resources, Minnesota Renewable Energy Integration and Transmission Study, September 13, 2013, p. 21. Available at: http://mn.gov/commerce/energy/images/MN_RE_Integration_Study_2014_pres_Stakeholder_Mtg_091313.pdf. The study notes that two-thirds of curtailments in MISO occur through the economic dispatch with the other third occurring still from manual curtailments.

71 See MISO press release discussing how look-ahead tool improves efficiencies while reducing costs, available at: https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/Look-Ahead Tool.aspx. Further materials for the look-ahead tools are available at: https://www.misoenergy.org/WhatWeDo/MarketEnhancements/Pages/LookAhead.aspx.

72 For examples of stochastic unit commitment studies, see presentation from NREL and EPRI at: http://uvig.org/wp-content/uploads/2014/10/Ela-Stochastic.pdf and http://uvig.org/wp-content /uploads/2014/10/Tuohy.pdf.

forecasts over the past few years.[73] The forecasts used for commitment and dispatch decisions are also shared with various market participants. Forecast periods range from longer terms (typically up to a week-ahead) to a more granular short-term, updated frequently (every 5 to 15 minutes) and typically used for real-time operation decisions. PJM, ERCOT, and IESO also provide wind ramp forecasts. Solar forecasts are currently being developed in most markets.[74]

Several system operators are now allowing wind to provide ancillary services. Both PJM and NYISO allow wind to provide frequency response, inertial response, and regulation if they meet eligibility requirements. While ISO-NE precludes wind from providing regulation, it does allow wind to provide frequency response and inertial response upon meeting eligibility requirements. SPP allows variable resources to provide regulation down if they meet eligibility requirements. Ancillary service markets are also evolving to provide incentives for faster responding resources that can provide better performance. For example, in response to a FERC order, PJM provides "mileage payments," which account for how well resources respond to the regulation signal for controlling frequency.[75]

Transmission planning, as the ERCOT CREZ line success demonstrates, is also a key focus of system operators. MISO, through its Regional Generation Outlet Study (RGOS), created a cohesive plan for the MISO footprint by identifying extended transmission plans and renewable energy requirements. The RGOS results were later adopted as the Multi-Value projects. Similarly the SPP Integrated Transmission Planning process coordinates the long term transmission planning with anticipated future resources, a large portion of which is wind.

In addition to these enhancements of traditional tools and processes, storage technologies are beginning to be tested, included in ancillary service eligibility, or deployed. PJM's frequency regulation market, which in response to FERC's Order 755[76] awards quick-start and fast-responding resources including batteries, has been attracting an increasing amount of battery storage.[77] Along with storage technology, innovation is occurring in ways of using storage. Much of this innovation is targeting opportunities created by the mismatch of variable renewable

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73 Centralized wind forecasts have been implemented in the various markets: PJM (2009), NYISO (2008, used for individual dispatch decisions since 2009), ISO-NE (2014), MISO (2008), SPP (201), ERCOT (2008), CAISO (2004), AESO (2010), and IESO (2013).

74 Centralized solar forecasts are only implemented in limited markets: IESO (2013) and ERCOT (2015).

75 See http://www.pjm.com/markets-and-operations/ancillary-services/mkt-based-regulation/fast-response-regulation-signal.aspx

76 See Beacon Power, Overview of FERC Order 755 and Pay-for-Performance Regulation, March 21, 2014 for an overview of compensation for frequency regulation before and after FERC Order 755.

77 See http://www.utilitydive.com/news/invenergy-bringing-over-60-mw-of-storage-online-for-pjm-frequency-regulatio/399140/. According to the article, Invenergy recently announced the addition of 31.5 MW of storage at its Grand Ridge Storage Facility in Illinois to provide frequency regulation in PJM. Invenergy plans to bring another 31.5 MW storage facility online in 2015, bringing the total storage capacity providing frequency regulation services in PJM to above 150 MW.

generation and demand. For example, the recent launch of Tesla's home battery system happened approximately at the same time as the announcement of a collaboration between Tesla and Lichtblick, a German company. Lichtblick has been using its proprietary aggregation software to bundle an increasing number of micro-combined heat and power systems deployed in residential buildings and deploy them as "swarm" energy producers,[78] optimizing the operation of many distributed systems – most of which have a thermal storage element – against real-time power market conditions. The joint venture between Tesla and Lichtblick aims to combine distributed solar PV systems with in-home storage units and Lichtblick's optimization software to similarly operate solar+battery systems in a way that optimizes their use given real-time market conditions by taking advantage of the latent flexibility in distributed energy systems.[79]

There are also ongoing innovations combining variable renewable production with measures aiming to make demand more responsive. Tesla is also collaborating with EnerNOC, a leading provider of demand response services for commercial and industrial customers.[80] Also, earlier in 2015 SolarCity, a major installer of rooftop solar PV systems, announced a partnership with NEST, the wifi-enabled (smart) thermostat company owned by Google.[81] While still in early stages, a French start-up, Comwatt, has developed a box, similar to a cable TV box, that uses software to manage electricity consumption in a house to match as much as possible the production of a distributed solar PV system.[82] All these recent announcements show not so much what is already happening in terms of actively integrating variable renewable energy, but the extent to which integration associated with increases in renewable energy production is stimulating innovation.

By the time renewable penetration levels approach those currently identified as practical limits, it is likely that at least some of these innovations will have matured enough to play a role in providing solutions, thus quite likely further increasing the share of variable renewable energy that can safely be integrated into the grid.

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78 See http://www.lichtblick.de/en/schwarmenergie/.

79 See http://www.prnewswire.com/news-releases/partnership-for-global-energy-transformationlichtblick-integrates-tesla-battery-storage-into-energy-markets-502146711.html

80 See http://www.bidnessetc.com/41612-tesla-motors-inc-collaborates-with-enernoc-inc-and-lichtblick-for -energy-st/.

81 See http://www.solarcity.com/newsroom/press/solarcity-and-nest-partner-make-cost-savings-even-easier-homeowners.

82 See http://www.cleantechrepublic.com/2014/12/18/comwatt-autoconsommation-electrique-sans-batterie/ (in French).

VII. Conclusions

In this report, we highlighted how a few ISOs and utilities with material shares of renewable generation already have changed their operations to accommodate the forecasting challenges and short-term performance variability that can increase with growing shares of variable renewable generation. To date, these integration efforts have been largely relying on well-established technologies, indicating that lack of technology cannot be considered a major barrier to being able to integrate amounts of variable renewable generation significantly in excess of current average U.S. levels. Though new technologies are being explored and becoming more promising, particularly storage, it is not necessary to have large amounts of such new resources to incorporate meaningful quantities of renewables onto a system and preserve its security and reliability.

As these case studies show, ISOs and utilities can deploy a large and increasing portfolio of options to accommodate large and growing shares of renewable generation while maintaining high levels of reliability. The options range from purely operational changes to possibilities that become available as a consequence of advancements in technology unrelated to renewable energy. Examples of the former include increasing the coordination between balancing areas (including increasing their size), reinforcing the transmission system, and increasing participation of demand response. Examples of the latter include technological advances in weather forecasting which, together with better data on historical performance of renewable energy, allows significant improvements in forecasting accuracy of renewable generation; the proliferation of smarter infrastructure, much of it deployed at the customer site (smart meters, smart thermostats, smart appliances, all enabled by smarter software), enabling participation of increasing amounts of demand in activities that help mitigate the variability of renewable generation; and technological advances of renewable and complementary technologies (inverters, batteries) that allow renewable generators themselves to contribute to maintaining reliability.

Numerous renewable integration studies have estimated the cost of using this wide portfolio of options to represent a relatively small portion of the overall cost of the electric system. Our case studies indicate that deploying new and innovative solutions can further mitigate the challenges of integrating variable renewable generation, at least in some cases (such as using state-of-the-art wind and solar forecasts) with significant cost savings compared to traditionally used integration approaches. Continued strong growth of renewable generation will require continued significant planning and effort, as well as investment in the electric infrastructure – in transmission infrastructure to bring electricity from renewable resource rich locations to load centers, and in distribution infrastructure as the share of distributed resources grows. Bringing additional renewable resources to market will thus likely be an important additional driver of planning and building a 21st century grid, which is also driven by changes on the demand side of the market (including distributed generation, but also new sources of demand and options for demand-side flexibility), changing population densities, the desire to further increase inter-regional interconnections, cybersecurity concerns, the aging of existing transmission and distribution infrastructure, etc.

The good news, however, is that there is substantial evidence that accommodating these increasing levels of variable renewable generation in ways that preserve high levels of reliability should be possible at a cost (excluding the cost of any incremental transmission) that represents a modest share of the total cost of the electric system. Specifically, integration of variable renewable energy at levels of penetration as high as those reliably managed by ERCOT and Xcel Energy Colorado, if not higher, should not be seen as a significant obstacle to compliance with EPA's proposed Clean Power Plan.

VIII. Acronyms

AEEI	Advanced Energy Economy Institute
AGC	Automatic Generation Control
ALR	Adaptive Line Ratings
BSER	Best System of Emissions Reductions
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CPP	Clean Power Plan
CREZ	Competitive Renewable Energy Zone
DLC	Direct Load Control
DLR	Dynamic Line Ratings
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
FAS	Future Ancillary Services
FFR	Fast Frequency Response
GW	Gigawatt
HVDC	High Voltage Direct Current
IRR	Initial Reliability Review
ISO	Independent System Operator
JDA	Joint Dispatch Agreement

LMP	Locational Marginal Price
MISO	Midcontinent ISO
MW	Megawatt
NERC	North American Electric Reliability Corporation
PSCo	Public Service Company of Colorado
PV	Photovoltaic
RGOS	Regional Generation Outlet Study
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
T&D	Transmission and Distribution
U.S.	United States

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