

Secrets of Successful Integration:

Operating Experience with High Levels of Variable, Inverter-based Generation

Debra Lew, Drake Bartlett, Andrew Groom, Peter Jorgensen, Jon O'Sullivan, Ryan Quint, Bruce Rew, Brad Rockwell, Sandip Sharma, Derek Stenclik

With increasing public pressure for cleaner electricity, and overall cleaner energy, the utility industry is evolving quickly. An increasing number of countries like Denmark, states like Hawaii and California, and utilities like AEP and Xcel Energy have goals of 100% renewables or 100% carbon-free. Renewables technologies tend to include wind, solar, geothermal, biomass, hydro and others; carbon-free technologies typically include renewables, carbon capture and storage, and nuclear.

Wind and solar photovoltaics (PV) dominate renewable energy additions worldwide and represented 84% of all new renewable capacity installed in 2018. Wind and PV can create two key challenges for utilities. First, they are variable energy resources (VER) which can make system balancing more challenging. There are many mitigation options to manage moderate levels of VERs including improved forecasting, interconnections with other regions to smooth wind/solar/demand profiles, faster dispatch intervals, more flexible capability and operation of the overall generator mix, demand response, and energy storage. Very high VER levels may require flexibility from other energy sectors, such as transportation or heating, as is detailed in *Flexibility From Energy Systems Integration*.

Second, wind, PV, and battery energy storage are inverter-based resources (IBR). Even a moderate level of wind and PV on an annual basis can lead to high instantaneous penetrations which can be challenging in many ways. Decreasing system inertia, lower short circuit strength, fault behavior from inverters, and other factors are a primary focus as synchronous machines continue to be displaced by IBR. A grid based on non-synchronous control paradigms requires new technologies and is discussed in this issue's article on grid-forming converters. We refer to wind and PV as VER when discussing the variable aspect of these resources and as IBR when discussing the non-synchronous nature of these resources.

Figure 1 examines system portfolios across several regions, comparing capacity of non-variable generation (fossil-fueled, nuclear, etc.) with VER. Also shown is the capacity of interconnections and energy storage, which are two common options for mitigating variability. Power systems are traditionally overbuilt compared to peak demand to account for unexpected outages and variability in weather. Systems with high VER penetrations are likely to have much more generation capacity than peak demand, due to the variable nature of the resources. Figure 1 shows that even those areas with very high VER capacities like Energinet, South Australia, and the Kauai Island Utility Cooperative (KIUC) in Hawaii, continue to have significant non-variable generation capacity.

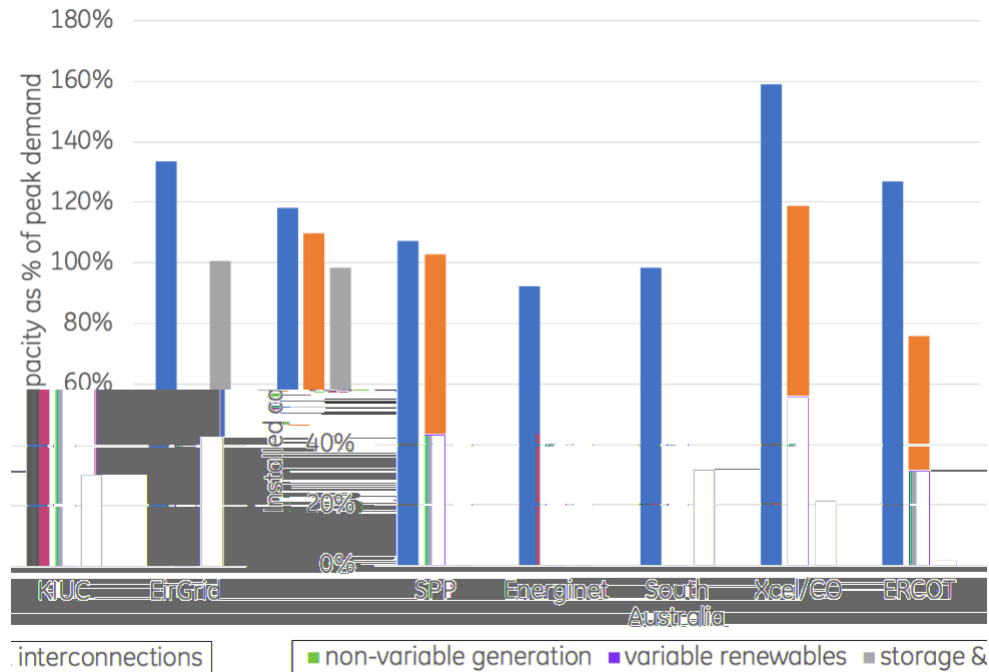


Figure 1. Installed capacity of non-variable generation (blue), VER (orange) and storage & interconnections (gray), as percentage of peak demand on each system.

Some regions are experiencing very high instantaneous penetrations of VER as shown in Figure 2. As compared with other areas, Energinet and South Australia have slightly higher annual average VER levels (orange marker), but their instantaneous VER levels are considerably higher. The length of the blue bars shows that system operators must manage a range of operating conditions: from zero VER output to VER output exceeding regional demand.

Figure 2 also shows the percentage of VER energy curtailment in 2018. In this article, *curtailment* is a broad term for reducing VER output below its potential production. Curtailment may be enacted for various reasons including transmission congestion, provision of down regulation reserves, and system balancing during oversupply periods. The island system of EirGrid limits instantaneous IBR penetration because of grid stability issues. In Denmark, wind turbines contribute to market-based down-regulation on equal terms with other generators. The island system KIUC utilizes various sources of flexibility, including energy-shifting battery storage, to hold curtailment low.

Here we share the secrets of successful renewable integration by system operators. Some regions have unique solutions to addressing the balancing challenge, such as using curtailed wind to provide a fast, accurate regulation service. Others have developed mitigation options for high IBR penetrations, such as running a gas turbine as a synchronous condenser. They all share a practical approach rooted in innovative uses of existing infrastructure; development of new market services, incentives or contractual arrangements; application of detailed studies and good planning; and a willingness to adopt new practices.

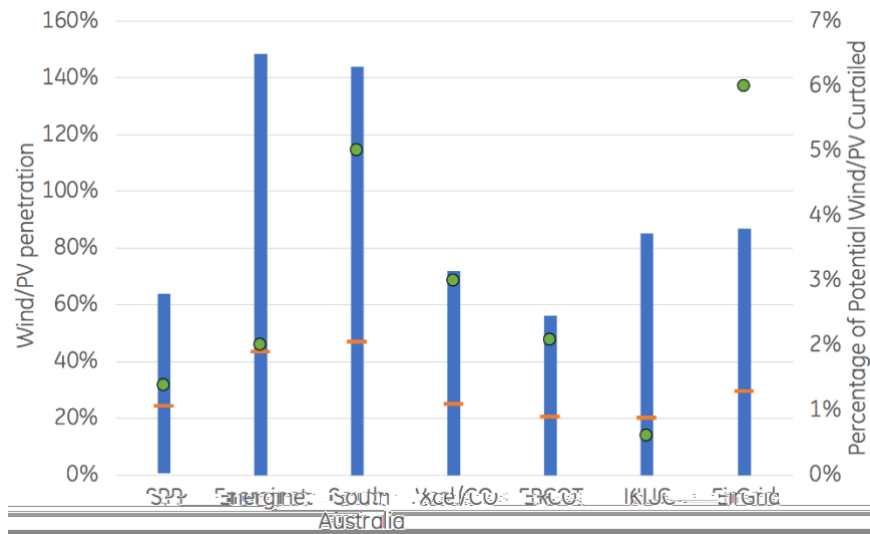


Figure 2. Blue bars show minimum to maximum instantaneous VER penetration as a percentage of demand. Orange marker shows the average annual VER penetration. This represents transmission-connected VER, not distributed VER which would further increase penetration levels. Green dots depict the percentage of potential VER annual output that is curtailed.

Storage and synchronous condenser capability enable 100% renewables in Kauai

KIUC is the only electric service provider on the island of Kauai, in Hawaii. Unlike the other regions in this article, Kauai has no interconnection with its neighbors, so balancing supply and demand is extremely challenging. KIUC has long been a leader in solar integration, with 96 MW (nameplate) of PV at the end of 2018. This is significant for an island with a mid-day demand of 55-65 MW. How did KIUC transform a resource mix that was 92% oil-based in 2010 into today's system?

As PV capacity increased, KIUC reduced minimum generation levels on its thermal generators, from 50% to 25%, and then later to 10%. This provided more flexibility to integrate mid-day PV output and greater ability for thermal generator spinning reserves to manage sudden cloud cover and the late afternoon ramp toward the evening peak demand. However, continued PV growth exhausted this flexibility, and KIUC realized that storage or load-shifting would be needed to accommodate future VER installations. This led to the first PV/storage power purchase agreement (PPA) between KIUC and SolarCity (now Tesla) for a combined 13 MW PV and 13 MW / 52 MWh battery, which was commissioned in May 2017.

KIUC's daily peak demand occurs about one hour after sunset. In order to balance the high solar penetration levels, KIUC uses thermal generators, dedicated battery energy storage systems, PV/storage plants, and control algorithms developed in-house. KIUC typically holds contingency reserves equivalent to 50% of the real-time output from PV plants that are not backed by storage. Online fossil generation is increasingly being replaced by battery storage for provision of spinning reserves. While KIUC has ample quick start units, if they are not already online, they cannot start fast enough to respond to cloud events. Typical mid-day dispatch for very sunny days in 2018 was 7 MW hydro, 7 MW biomass, 1 MW oil, and the rest (40 – 50 MW) from PV, including the PV/storage plant. The results speak for themselves: in 2018, 27% of KIUC's annual

energy demand was served by utility-scale and distributed PV, with curtailment of potential PV production at less than 0.6%. On average in 2018, PV served 54% of demand at noon, but on an instantaneous basis, KIUC has reached as high as 85% PV penetration.

A second PV/storage plant, 20 MW PV with a 20 MW / 100 MWh battery system, was completed in December 2018. Annual energy demand served by PV is expected to jump to 38% for 2019 due to this new plant, and will increase further with a 14 MW PV/ 70 MWh storage plant that is scheduled for commissioning at the end of 2019.

Commercial operation of the second PV/storage plant has enabled KIUC to run at 100% renewable energy penetration at times. For example, on 24 February 2019, KIUC ran the grid for 25 minutes using 100% renewables, with zero fossil fuel consumption (see Figure 3). The mix for that period was 80% PV (some of which was backed with storage), 10% hydro, and 10% biomass. The key to this is the commissioning of the ability to operate their Kapaia GE LM2500 unit as a synchronous condenser. Operating the gas turbine in synchronous condenser mode maintains significant inertia, voltage support, and fault current contributions that ensure system security. KIUC is now working to extend these 100% renewables periods to 2-4 hours, which will be enabled by the third PV/storage plant.

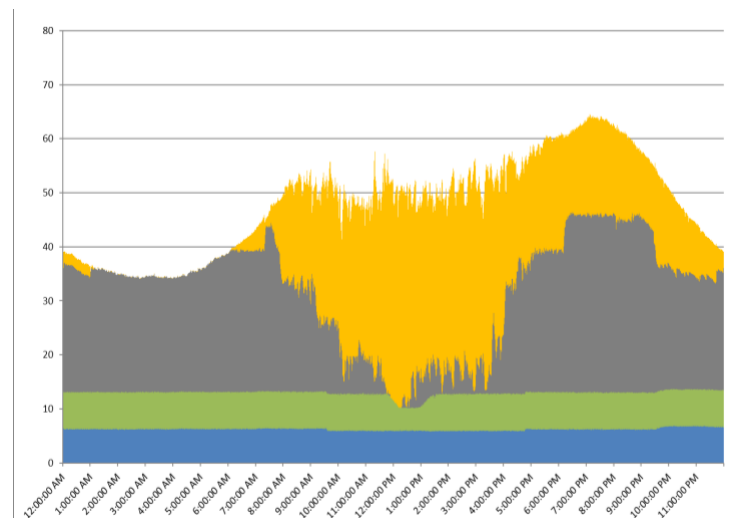


Figure 3. Dispatch of the KIUC system on 24 February 2019 showing 100% renewables operation (Yellow – PV; gray – oil; green – biomass; blue – hydro).

Southwest Power Pool manages significant forecast errors

The Southwest Power Pool (SPP) is a regional transmission organization (RTO) that manages the high-voltage transmission system in approximately 546,000 square miles of service territory in 14 states from Louisiana and Texas to North Dakota. SPP staff constantly monitors the operation of the grid and coordinates corrective actions that keep the system in a secure state. SPP has a day-ahead market, and its Integrated Marketplace uses state-of-the-art optimization

software to minimize the cost of committing and dispatching over 700 resources used to serve the region's demand.

The SPP region includes some of the best wind resources in the U.S. SPP's wind development grew from 3.4 GW of wind capacity in 2009 to 20.5 GW in 2019. The footprint has seen as much as 16.4 GW of concurrent wind generation and served as much as 63.4% of demand from wind.

One of the largest challenges of this high wind penetration is forecasting over the operational horizon and across one of North America's largest RTOs (in terms of land area). Wind forecasting in this region is highly subject to error, due in part to low pressure systems coming from the Rocky Mountains that create instability in weather systems in SPP's footprint, creating forecast uncertainty. Actual wind output can deviate by as much as 40% from day-ahead forecasts. This means that as much as 7 GW of wind output may not be available as anticipated. Figure 4 illustrates the forecast and actual wind curves on a day with such an error.

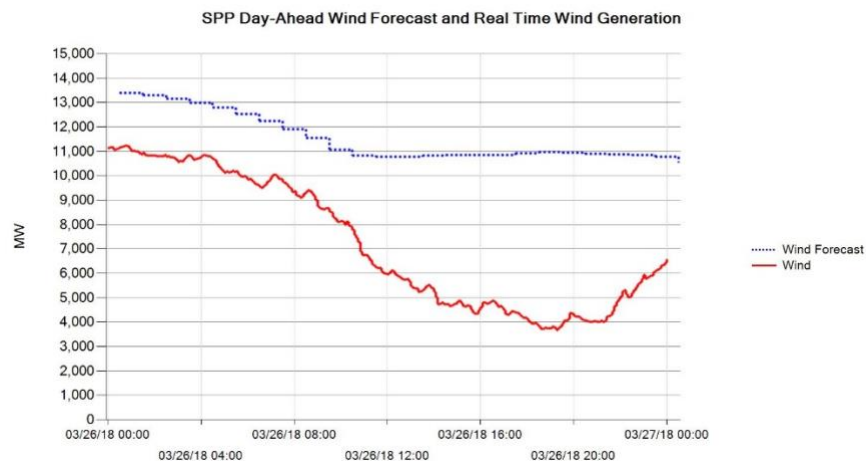


Figure 4. SPP wind forecast error on 26 March 2018.

Managing forecast deviations of this magnitude in real-time is challenging. SPP has deployed many programs and techniques to do so including establishment of the Uncertainty Response Team (URT). The URT was formed in 2018 to focus on mitigating the impact of forecasting errors on day-to-day operations. Specifically, the URT ensures adequate capacity will be available to balance highly variable wind output. The URT analyzes past experience to better assess present system conditions and plan for the near future. The team employs statistical analysis, utilizing historical data and errors, to increase the robustness and accuracy of the forecasts for the system. The URT identifies days where wind forecast errors are likely to be high, so SPP can mitigate the risk. This approach has been highly successful to date.

One innovative practice is site-specific wind forecasting. Individual wind turbine outputs are forecasted at some sites to understand the effects of wind direction and wake effects on aggregate power production. This also enables higher resolution analysis of the propagation of wind cutout events.

Continuous improvement is vital. Many other developments have been instituted for wind, such as:

- Enhancing Automatic Generation Control (AGC) to simultaneously dispatch VERs and provide regulation from VERs;
- Investigating new market products to incorporate the impacts of forecast uncertainty and ramp in both dispatch and pricing;
- Enhancing system visibility through more granular wind forecasting and new solar and icing forecasts;
- Adding more granular VER forecasting requirements to increase forecasting accuracy;
- Using a high-resolution weather model to predict site specific forecasts;
- Implementing real-time voltage and transient stability studies;
- Adding wind forecast confidence bands as inputs to market studies;
- Implementing policy changes necessary for increasing VER levels;
- Implementing design and policy to incorporate electric storage resources into the market; and
- Deploying and using phasor measurement units (PMUs) to identify grid impacts that may impact reliability.

Energinet will use energy-sector coupling to reach 100% renewables year-round

Over 60% of Denmark's electric demand was served by renewable energy in 2018, with the goal of achieving 100% renewable *electricity* by 2030 and 100% renewable *energy* by 2050. Over three decades ago, Denmark was dependent on large coal plants. Government plans and policies drove development of distributed combined heat and power and onshore wind power, followed by offshore wind power, and later PV. In 2018, 43.5% of annual energy demand was served by VER (40.7% by wind, 2.8% by PV), 23.5% by fossil fuels, 17.8% by biomass and waste, and 15.3% from imports.

Denmark has undertaken a market-based approach to balancing high levels of VER. The Danish RTO Energinet administers a day-ahead and intra-day market, and a regulating market to manage real-time imbalances. The vast majority of electricity is traded in the day-ahead market, with the regulating market accounting for less than 0.5% of demand. This indicates a very dynamic day-ahead market, where price variations incentivize substantial flexibility from generation and interconnections, resulting in a limited imbalance to be handled in the regulating market. Demand-side flexibility is still very limited – the main exception being electric boilers in district heating systems that provide regulation. The sizeable interconnector capacity with neighboring countries (approximately the same as installed VER capacity) and the scheduling of these interconnectors through the day-ahead market provide significant flexibility. The recent expansion of the intra-day market to include cross-border trade has enabled Denmark to extract further flexibility from interconnectors. Price responsiveness of thermal power plants has increased considerably over recent years. This, combined with the addition of synchronous condensers, allows the Danish power system to decommit large thermal power plants over extended periods.

An hour ahead of operation, the intra-day market closes and Energinet prepares for the physical balancing of the system. System balancing is proactive: operational planning tools continuously update schedules and forecasts. Based on these predicted imbalances, operators activate manual reserves in the Nordic regulating market for the following hour. This minimizes the amount of automatic reserves that manage the remaining imbalance. This enables use of the least expensive resources available for regulation and it reduces reliability risks to the system.

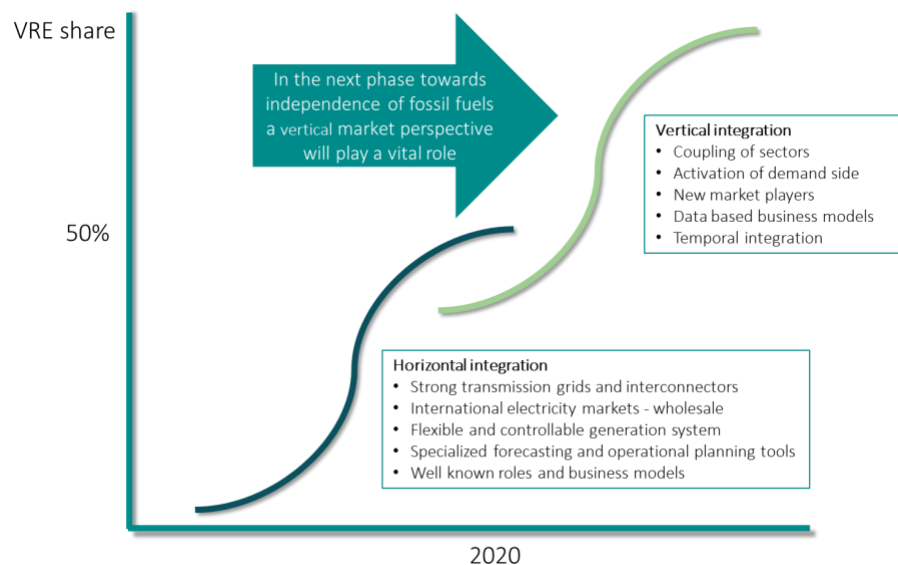


Figure 5. Denmark's transition from 0 to 50% VER relied heavily on horizontal integration. The further transition towards 100% renewable energy will require vertical integration.

By 2020 VER will supply more than 50% of the electric energy demand. Denmark's transition from 0% to 50% VER was mainly achieved by *horizontal integration*, where the electricity sector was well-integrated through an international wholesale market, a strong transmission grid and a flexible generation system. These measures will not suffice for the next phases when Energinet envisions a more decentralized, digital grid. The focus will shift towards a *vertical integration* where retail markets and other energy sectors will be integrated to unleash a huge potential for flexibility. Figure 5 illustrates that horizontal integration enabled the first 50% VER, but the "S" curve saturates because sources of flexibility will soon be exhausted. The role of the traditional system operator is changing. System operators will be part of a green transition driven by the market and the consumers. New technology, digitalization and data-driven business models will unlock new sources for flexibility. An important role for the system operator is to create a digital framework, promote free exchange of data, remove obstacles for new technologies, and digitalize market processes. This is expected to bring substantial gains by increasing utilization of the transmission system while maintaining system security. Sector coupling between electricity and heating, transportation, and the gas systems will allow for efficient energy storage and system balancing.

Wind plants provide reserves in Xcel Energy's Colorado system

Xcel Energy has improved reliability and reduced costs to customers while steadily integrating ever higher penetrations of renewable generation on its 7 GW Colorado system. A state-of-the-art practice was enabling 4-second AGC at wind facilities in Colorado through Xcel's Energy Management System in 2010.

In 2009, when VER reached a penetration level of approximately 10% of annual energy consumption, Xcel Energy found it could not accommodate additional VER without regular curtailment. At any moment, a system has some amount of 'maximum VER headroom', which can be defined by the total demand (plus net interchange) minus the dispatch setpoints of the units that must be online to provide reliability services (typically minimum generation level plus downward reserve requirements). When potential VER output exceeded the 'maximum VER headroom', system dispatchers had to manually curtail wind plants to balance the system. Having wind generators provide real-time balancing services reduced the amounts of wind generation curtailments and fossil fuel costs by allowing fossil-fueled units to be dispatched at minimum generation. A few days of testing resulted in such a large reduction in wind generation curtailment that AGC control of wind became the preferred curtailment mode. The AGC also improved reliability by enabling fast-acting wind generation to meet the Balancing Authority Area's regulation needs.

Xcel Energy also found that a relatively low level of renewable generation curtailment was a cost-effective integration tool. For example, during the last three years, approximately a quarter of Xcel's Colorado energy demand was served by VER, while only about 3% of the potential VER output was curtailed. In other words, the company's Colorado system has been able to accept 97% of all renewable generation at a 25% penetration level. This is an important observation for other grids, as it is often more economic to curtail *some* energy rather than design a system with large amounts of storage, for example, to reduce *all* curtailment.

The increasing magnitude of VER variability has challenged the system's ability to economically dispatch its generation portfolio while maintaining system reliability. Xcel Energy carries extra regulation to address the increase in short-term variability. In addition, Xcel holds a 30-minute Flex Reserve that is sufficient to cover the largest potential renewable generation ramps as a function of real-time VER output. Appropriate volumes of regulation and 30-minute Flex Reserve are determined by studying historic VER variability and projecting the additional variability of future VER plants. Xcel Energy has also determined the volume of curtailed VER generation that can dependably provide up-regulation and 10-minute spinning reserve. This enables use of curtailed VER generation to provide some of the spinning reserve requirement. In this way, some reliability concerns associated with the inherent variability of very high VER penetrations are addressed by the VER providing essential reliability services. If curtailment is necessary to maintain reliability, it should be used for productive purposes like reserves and ramp rate control.

In response to customer demands for cleaner energy, Xcel Energy has committed to an 80% reduction in carbon emissions compared to 2005 levels across all of its service territories by 2030 and it aspires to serve customers with 100% carbon-free electric generation by 2050.

Increasing VER penetration is clearly one of the ways that Xcel Energy plans to achieve these goals. Increasing levels of curtailment will naturally occur as more VER capacity is built, and Xcel Energy has realized that curtailed VER is valuable resource for minimizing operating costs and improving system reliability.

Dynamic reserve requirements enable ERCOT to integrate high VER penetrations

The Electric Reliability Council of Texas (ERCOT) is the RTO for most of Texas, and is an islanded grid with limited DC ties to Mexico and the Eastern Interconnection. ERCOT has 22 GW of installed wind nameplate capacity and approximately 1700 MW of utility-scale PV. ERCOT anticipates that VER, especially PV, will grow quickly.

This has led ERCOT to continuously revise their generation interconnection requirements, improve forecasting performance, update IBR impact studies, and fine tune study methods for determining ancillary service (AS) requirements. The key to reliable and efficient integration of IBR lies in adopting best grid operation practices: having the appropriate grid codes avoids costly reliability problems in real-time; accurate forecasting allows the grid operator to efficiently schedule other resources, and ASs can mitigate risks associated with forecast errors. This allows IBRs to provide many of the services usually provided by synchronous generators.

ERCOT today has four types of ASs: Regulation Service Up (Reg-Up), Regulation Service Down (Reg-Down), Responsive Reserve Service (RRS), and Non-Spin Reserve Service (NSRS). Prior to the huge growth in IBR, ERCOT procured mostly a fixed level of RRS and NSRS throughout the year. This static approach is no longer appropriate with ERCOT's high IBR penetration levels.

Regulation provides 4-second system balancing so that ERCOT can maintain grid frequency, per NERC BAL-001, which uses the Control Performance Standard 1 (CPS1) metric. Prior to 2010, ERCOT had a zonal market with 15-minute dispatch. In 2009, ERCOT procured an average of 825 MW of Reg-Up and 851 MW of Reg-Down. In 2010, ERCOT switched to a nodal market with 5-minute security-constrained economic dispatch (SCED). Contrary to the conventional wisdom that VER increases regulation requirements, ERCOT today maintains one of the best CPS1 scores in North America while reducing regulation procurements year over year (See Figure 6). This has been achieved through 5-minute dispatch, refining its SCED algorithm, load frequency control tuning, requiring VER to follow ERCOT base points under some system conditions, and a Primary Frequency Response (PFR) grid code requirement.

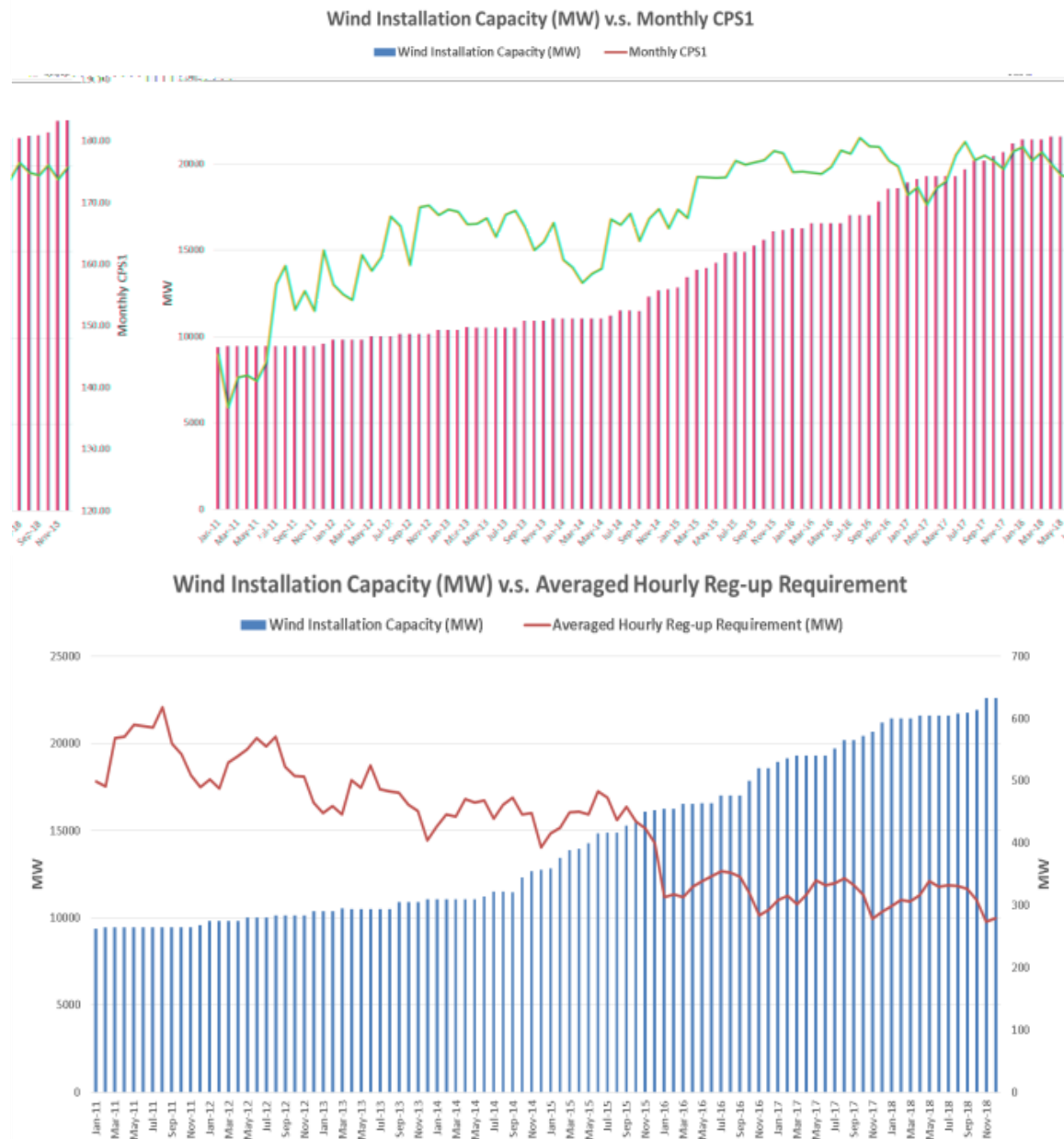


Figure 6. CPS1 vs. wind installed capacity (top) and Reg Up requirement vs. wind installed capacity (bottom)

RRS is procured by ERCOT primarily to arrest frequency declines below 59.40 Hz for the loss of 2750 MW of generation. Increased VER levels displace synchronous generators and the inertia they provide. For an island grid like ERCOT, inertia largely determines the rate of change of frequency (ROCOF) following generator-loss events. If ERCOT’s inertia falls below 100 GW·Sec, the loss of 2750 MW would result in frequency dropping so quickly that under-frequency load-shedding would occur before the fastest reserve could respond (0.5 sec is the response time of demand response triggered by under-frequency relays).

RRS in ERCOT primarily comes from generators providing PFR and load resources with under-frequency relays. In 2015, ERCOT started factoring anticipated system inertia into RRS

procurements. The peak RRS requirements generally coincide with the low-demand, high-wind early morning hours (1 am to 4 am).

The 30-minute NSRS provides reserves to address load or VER forecast errors. Today, ERCOT procures NSRS for under-forecast errors of load and over-forecast errors of VER. When the net-load is likely to be ramping up, ERCOT procures NSRS sufficient to cover the 95th percentile of the net forecast errors. When the net-load is not likely to ramp up, ERCOT procures NSRS that may only be sufficient to cover the 70th percentile of the net forecast errors.

ERCOT identifies hourly AS requirements for the upcoming year during the fall of the previous year. Historical data plays a significant role in determining these requirements. Since AS quantities are determined months in advance, cutting-edge tools help control room operators identify real-time shortages in RRS or NSRS. ERCOT's AS products, designed over two decades ago, were recently revised to include ERCOT Contingency Reserve Service as a new product and Fast Frequency Response as a subset of existing RRS.

EirGrid implements new system services to facilitate high instantaneous IBR

Similar to ERCOT, Ireland's grid is also islanded with limited DC interconnection to the U.K. EirGrid, the transmission system operator for Ireland and Northern Ireland, pioneered analysis of the impact of high penetrations of IBRs on transient stability in 2008. Several large challenges to reaching 75% system non-synchronous penetration (SNSP differs from the IBR metric in that net imports are added to the IBR generation and net exports are added to the demand) and 1 Hz/s ROCOF were faced. Among these were managing system stability, system voltage control (when over 25% of the total transmission-based synchronous generator reactive power sources would be displaced), over-frequency system protection (for loss of export under high wind conditions), and managing the uncertainty of a weather-dependent system.

Today EirGrid operates the grid up to 65% SNSP with a 0.5 Hz/s ROCOF limit. In November and December 2018, wind served over 43% of the total energy consumed, and over the entire year, wind served over 30% of demand. An additional 1000 MW of wind is expected to connect in the next 12 months. In order to successfully integrate this wind, EirGrid plans to operate the system up to 75% SNSP ratio and up to 1 Hz/s ROCOF by 2020.

At these high IBR penetration levels, the system stability issues largely arise due to low synchronizing torque and might be partially mitigated by grid-forming inverters. However, currently the grid code does not require grid-forming inverters, and an understanding of how this new technology would perform and interact with the rest of the system is still being developed. To date, EirGrid has fundamentally revamped their system services to incentivize technologies to provide synchronous-like torque and strong reactive power support when wind output is high. With these new system services, there is likely to be sufficient capability in the existing portfolio to reach the 2020 targets efficiently and effectively.

ASs had previously been a very small market (€50 million/yr or 2% of generator revenues). The revamped market guarantees incentives are in place for at least 6 years, as opposed to one year

previously, and has a value of up to €235 million/yr (in 2018, it was €180 million). This allows owners to recover capital investment in upgrades to provide these services. Incentives are split across products and earnings are higher when the system operates above 55% SNSP, because it is at high IBR penetrations when EirGrid most needs these products.

The Synchronous Inertial Response (SIR) product is one of seven new products implemented last year, in addition to the seven existing ASs. SIR is the ratio of the kinetic energy divided by the minimum generation of the plant. EirGrid created a product that paid generators if they were dispatched and had an SIR of 45, with higher payments at high IBR penetrations. In addition to SIR, the reduced minimum generation level allows for the plant to provide higher ramping and reactive power services. As a result, five large plants, which previously were unable to lower their minimum generation levels, have now lowered their minimum generation by a total of 350MW. Also in 2018, 39 wind plants and 21 demand side management (DSM) units were contracted to provide system services including over 99 MW of fast frequency response and 111 MW of primary operating reserves.

System strength, protection, and frequency regulation were also explored for 2020 and found not to be an issue in the short-term. However, EirGrid initiated an exploration of the 2030 system where it will be operating close to 100% SNSP. This work is likely to lead to developments where considerations of grid-forming capability from IBRs will be further considered.

Detailed modeling and synchronous condensers enable South Australia to be a VER exporter

The state of South Australia sits at one end of the eastern Australian interconnection, also known as the National Electricity Market (NEM). While not an islanded system, only one double-circuit AC interconnection spans the 580 miles between synchronous generation centers in South Australia and the next NEM region. In 2018, South Australian wind output exceeded regional demand approximately 5% of the time, and instantaneous output peaked at 144% of regional demand. Additionally, over 30% of households in South Australia have distributed PV (DPV).

The operator of the NEM, the Australian Electricity Market Operator (AEMO), has the challenge of operating a system that can transition in 12 hours from one with only synchronous generators online to one in which IBR output significantly exceeds regional demand. Under these conditions, dynamic performance is dominated by the response of IBRs. To operate stably, current IBR technology requires a level of grid strength provided by synchronous machines. Similar to ERCOT's and EirGrid's challenges, AEMO must now explicitly ensure sufficient synchronous generators remain online at all times within the state, specifically to ensure adequate post-fault recovery, particularly during the periods of highest IBR penetration.

The NEM market design does not feature centralized real-time commitment, or binding pre-commitment of generating units. Out-of-merit dispatch is therefore used to ensure sufficient synchronous generation commitment. Much of the synchronous generation in South Australia is relatively inflexible, with start times of several hours or more, and high minimum generation

levels in some cases. None of the large synchronous generators are capable of operating in synchronous condenser mode.

Assessing the performance of the South Australian power system requires accurate modelling of the behavior and interaction of multiple, widely dispersed IBRs, under low system strength conditions, in a system where IBRs may be the dominant generation technology. Traditional dynamic modeling tools are inadequate, so AEMO developed a large electromagnetic transient model of the entire South Australian region, which includes all synchronous generation, grid-connected IBR, the transmission network, and important network and generation protection systems.

This model has been used to determine an acceptable technical operating envelope for the power system, through assessments of the post-fault stability and recovery of many combinations of synchronous generator commitment and wind generation output. These studies have identified 1) the need for a minimum of 4-5 synchronous machines (approximately 150 – 200 MVA each) to remain online in South Australia at all times, and 2) the maximum wind output, under low inertia conditions.

While the AC interconnection to the rest of the NEM is vital for short-term balancing and economic interchange, it does not provide a sufficiently strong reference for reliable post-fault recovery of IBR in South Australia, so this function must be provided locally. New rules in 2018 require maintaining both minimum fault levels at selected transmission nodes and minimum regional levels of inertia under certain operating conditions. These rules support contracting arrangements with synchronous generators or the potential construction of synchronous condensers, where this is economic. The regional transmission owner is currently tendering for synchronous condensers, partly to reduce out-of-merit dispatch driven by reliability concerns.

South Australia also has high levels of DPV which continue to grow rapidly. At times, 50% of regional demand is served by distributed energy resources (DER) and this is forecast to reach 100% in 2026-27 (see Figure 7). DERs add another layer of complexity to the variability and IBR issues. High DER penetrations require DER control and communication infrastructure, strong ride-through capabilities, grid support requirements, and suitable DER dynamic simulation models (see *Ensuring Bulk Power System Reliability with Increasing Penetration of Distributed Energy Resources*).

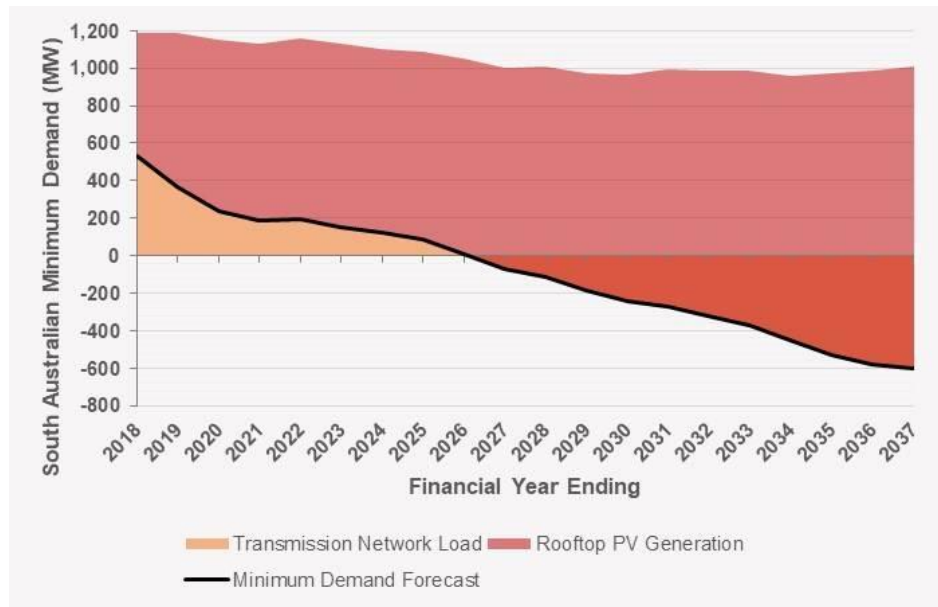


Figure 7. Minimum demand (black line) in South Australia occurs mid-day due to the high levels of rooftop PV generation (red). Load served by the transmission network (orange) decreases as rooftop PV generation increases. Negative minimum demand necessitates exports, spillage, or both.

A way forward for renewable integration

The case studies in this article show how the technical barriers of renewable integration are being overcome and redefined across the industry. While each system is unique, their planners and operators have innovated to increase system flexibility which is essential for large-scale renewable integration. Flexibility comes in the form of advanced capabilities of wind and PV resources, enabling technologies like storage or synchronous condensers, flexible loads, modifications to the thermal fleet, new ancillary services, proactive market design, tailored policies, and more educated consumers.

The lessons learned demonstrate that technical challenges are not barriers. In fact, the island and low inertia grids discussed, such as Ireland, Kauai, ERCOT, and South Australia, represent some of the most complex power system engineering required for renewable integration. Proven technical and economic solutions such as those presented here have enabled VER penetrations to exceed 100% on an hourly basis and to reach 40%-50% on an annual basis.

What does the future hold for wind and solar integration? As renewable resources become the primary electricity source, the integration challenges and their mitigations will become more complex. The transition to the renewable future will require new business models, rate structures, market designs, policies, and even more innovation.

For Further Reading

AEMO *Determining Minimum Fault Levels* - https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf

AEMO *Determining Minimum Inertia* - https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf

ERCOT Inertia whitepaper

http://www.ercot.com/content/wcm/lists/144927/Inertia_Basic_Concepts_Impacts_On_ERCO_T_v0.pdf

EirGrid, “Facilitation of Renewables”, 2010.

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Biographies

Debra Lew is an independent consultant, Boulder, Colorado.

Drake Bartlett is with Xcel Energy, Denver, Colorado.

Andrew Groom is with the Australian Energy Market Operator, Melbourne, Australia.

Peter Jorgensen is with Energinet, Fredericia, Denmark.

Jon O’Sullivan is with EirGrid, Dublin, Ireland.

Ryan Quint is with the North American Electric Reliability Corporation, Atlanta, Georgia.

Bruce Rew is with the Southwest Power Pool, Little Rock, Arkansas.

Brad Rockwell is with the Kauai Island Utility Cooperative, Lihue, Hawaii.

Sandip Sharma is with the Electric Reliability Council of Texas, Austin, Texas.

Derek Stencilik is with Telos Energy, Saratoga Springs, New York.