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Case Study

# Getting to 100% renewables: operating experiences with very high penetrations of variable energy resources

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**Abstract:** This study examines experiences of grid operators to successfully integrate very high penetrations of wind and solar photovoltaic (PV) resources. The variability of these resources creates challenges in balancing the system generation and demand, and ensuring resource adequacy and essential reliability services. The inverter-based nature of wind and solar PV leads to challenges in frequency, transient, and small-signal stability. In this study, seven system operators demonstrate the ability to manage these challenges in a variety of power systems, from stand-alone island systems to larger island systems that are interconnected to neighbours, to balancing authorities that are strongly interconnected within very large synchronous systems. They operate within a variety of market constructs, from full regional transmission operators to vertically-integrated utilities. All are experiencing increases in the penetration of inverter-based, variable energy resources and finding creative solutions to these challenges.

## 1 Introduction

Wind and solar photovoltaic (PV) are two of the fastest growing resources worldwide: nearly all regions have some degree of wind or solar resource that can be harnessed. These resources have zero operating emissions, they can be built quickly and modularly, and costs continue to decrease significantly [1].

Two critical aspects of the operation of wind and solar PV resources are creating challenges for system operators. First, wind and solar resources are variable energy resources (VER) and their output is uncertain. Uncertainty refers to the fact that they cannot be perfectly forecast (there is always some forecast error). Even if they could be perfectly forecast, there would still be variability in power production during real-time operations because of the nature of solar and wind energy moving through a region. This creates challenges for balancing the system on an hourly and sub-hourly basis, as well as for meeting resource adequacy over the course of the year.

Second, wind and solar PV [and battery energy storage systems (BESSs)] are inverter-based resources (IBRs). IBRs are not synchronous generators, like steam and gas plants; rather, they are coupled to the grid through power electronics. They do not contribute inertia to the system, which impacts frequency stability. With very few exceptions, all inverters connected to the grid today are grid-following inverters and require some level of grid strength to operate stably. These grid-following inverters do not provide system strength and this results in transient and small-signal stability challenges in pockets of the system where there are very high penetrations of IBRs and few other resources.

In this paper, we build on earlier work [2, 3] and examine how some leading power systems around the world are managing these issues and finding creative solutions to these challenges. These systems are diverse – some are wind-dominant, some are solar-dominant, and some have a mix of wind along with high penetrations of distributed PV. Some are large and well-interconnected and others are small and have few interconnections or none at all. Some operate competitive, wholesale markets and some are vertically-integrated. The systems in this paper are representative of most power systems around the world, but with a twist: they all manage very high, and growing, levels of wind and PV.

## 2 Description of systems

The seven power systems discussed in this paper are described below with relevant statistics in Table 1 and Fig. 1. Instantaneous penetration of wind (and PV where applicable) is given as a percentage of the demand of the Balancing Authority or transmission system operator (TSO), and can exceed 100% due to exports to neighbouring regions.

- Electric Reliability Council of Texas (ERCOT) – ERCOT is the independent system operator representing about 90% of Texas' electric demand. This ac interconnection is an electrical island with limited dc ties to other grids. At the end of 2019, ERCOT had 23,860 MW of installed wind generation capacity and 2281 MW of utility-scale solar PV generation capacity. As of early 2020, ERCOT's highest instantaneous wind power output was 20,066 MW. Its highest instantaneous wind penetration (ratio of instantaneous wind generation to demand) of 57.88% was reached on 26 November 2019.
- Kauai Island Utility Cooperative (KIUC) – KIUC is an electrical island system with no interconnections to any other regions. At the end of 2019, KIUC had over 100 MW of solar capacity connected to its system, which is the equivalent of 3 kW per customer on the island. This is a significant amount of solar PV for an island system with a midday demand of 55–65 MW, and

**Table 1** Capacity in MW of fossil/nuclear, non-variable renewables, wind/PV (including distributed PV), storage, and interconnections compared to peak demand of the system for the end of 2019 (B. Rew, Southwest Power Pool; P. Jorgensen, Energinet; A. Groom, Australian Energy Market Operator; D. Bartlett, Xcel Energy; S. Sharma, ERCOT; B. Rockwell, Kauai Island Utility Cooperative)

| Region | Fossil + nuclear | Non-variable renewables | Wind + PV | Storage | Interconnections | | Peak demand |
|---|---|---|---|---|---|---|---|
| | | | | | ac | dc | |
| SPP | 64,212 | 3428 | 22,719 | 268 | 48,593 | 2130 | 50,662 |
| Energinet | Combined 6155 | | 7184 | 0 | 2800 | 3680 | 6100 |
| S. Australia | 3442 | 0 | 3792 | 155 | 600 | 220 | 3240 |
| Xcel/Colorado | 6321 | 67 | 3842 | 278 | 1005 | 210 | 6916 |
| ERCOT | 71,243 | 0 | 26,141 | 104 | 0 | 1250 | 74,820 |
| EirGrid[a] | 8300 | 0 | 4942 | 292 | 0 | 2500 | 6532 |
| KIUC | 117 | 17 | 100 | 40 | 0 | 0 | 78 |

[a] EirGrid data is for the end of 2018 (J. O'Sullivan, EirGrid.)

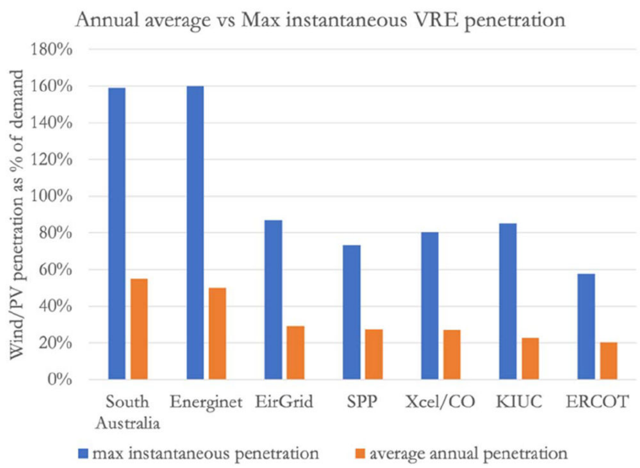


**Fig. 1** *Maximum instantaneous penetration of wind and solar PV, excluding distributed solar PV, as a percentage of demand (shown in blue). Average annual penetration of wind and solar PV, excluding distributed solar, as percentage of demand (shown in orange). Data is for end of 2019 with exception of EirGrid which is end of 2018*

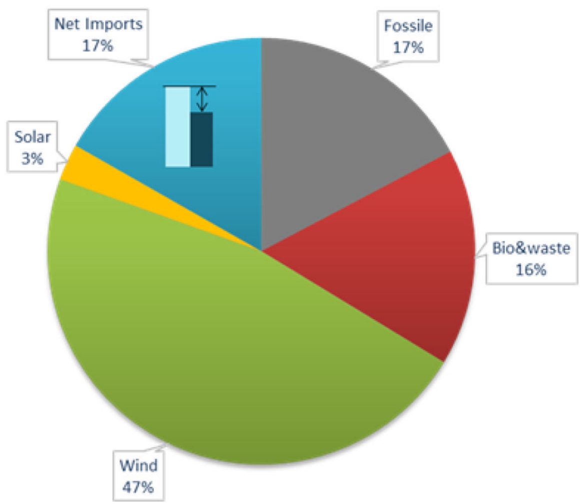


**Fig. 2** *Energinet energy mix 2019 (P. Jorgensen, Energinet)*

requires a number of mitigation options to maintain stability. KIUC has successfully run their system at 100% renewable energy penetration (and 85% IBR penetration) for several hours at a time. In 2019, Kauai's demand was served by 35% solar (over one-third of this was rooftop solar from residential and commercial customers), 11% hydro, and 10% biomass.

- Southwest Power Pool (SPP) – SPP manages the bulk power system in ~546,000 square miles of service territory in 14 states from Louisiana and Texas to North Dakota in the middle of the USA. In 2009, the footprint had 3.4 GW of wind capacity. By 2020, that figure had grown to 22.5 GW. SPP's highest instantaneous wind generation record is 18,259 MW and its highest instantaneous wind penetration record of 73.2% was reached on 27 April 2020.
- South Australia – The state of South Australia sits at one end of the eastern Australian electrical interconnection, or National Electricity Market (NEM). While not an islanded system, it has only one double-circuit ac interconnection with the rest of the NEM. South Australia has 2141 MW of wind installed, and in 2019, instantaneous wind penetration reached a record 159% of regional demand. In addition to 315 MW of utility-scale solar PV, ~35% of households in South Australia have distributed solar PV (DPV), for a total solar PV capacity of 1651 MW. In 2019, ~55% of the energy in the region was supplied from wind and solar PV.
- Xcel/Colorado – Xcel Energy operates four electric utility companies in three different parts of the USA. Three of these operate in large competitive wholesale markets, including one in SPP. The fourth company, Public Service Company of Colorado, is a vertically-integrated utility on the edge of the Western Interconnection and 27% of its demand is served by wind and solar PV. The location brings challenges in terms of trading energy with neighbours. The fact that Xcel/Colorado is a vertically-integrated utility enables opportunities to quickly implement creative solutions for VER integration. Xcel/Colorado's record instantaneous wind/PV penetration of 80.2% was reached on 7 May 2020, during the peak hour of the day (not including rooftop solar generation).
- Energinet – Energinet is Denmark's TSO responsible for security of supply of electric energy in Denmark. The journey from large coal-fired power plants towards a distributed generation system in Denmark started more than three decades ago. The Danish government initiated the development with binding plans for distributed combined heat and power (CHP) and onshore wind power. Around 2000, this was followed by offshore wind power and later a share of solar PV was added. In 2019, the VER share was over 50% compared to the annual electricity demand (see Fig. 2). Energinet's VER output regularly exceeds their demand.
- EirGrid – EirGrid is the TSO for Ireland and Northern Ireland. EirGrid is an ac electrical island with 2500 MW of HVDC interconnection to Great Britain. EirGrid has studied stability of their system with high IBR penetrations, and curtails wind when penetration levels exceed stability limits.

## 3 Variability and uncertainty

In this section, we discuss the impacts of the variability and uncertainty of wind and solar PV on system operations. We discuss operations of the systems that have been able to operate at or above 100% renewables or 100% wind/solar PV for hours or even up to a day at a time. We then discuss how forecast errors and unexpected ramps are managed. We discuss how distributed energy resources (DERs) can create operational challenges. Finally, we discuss how wind and solar resources change requirements for operating

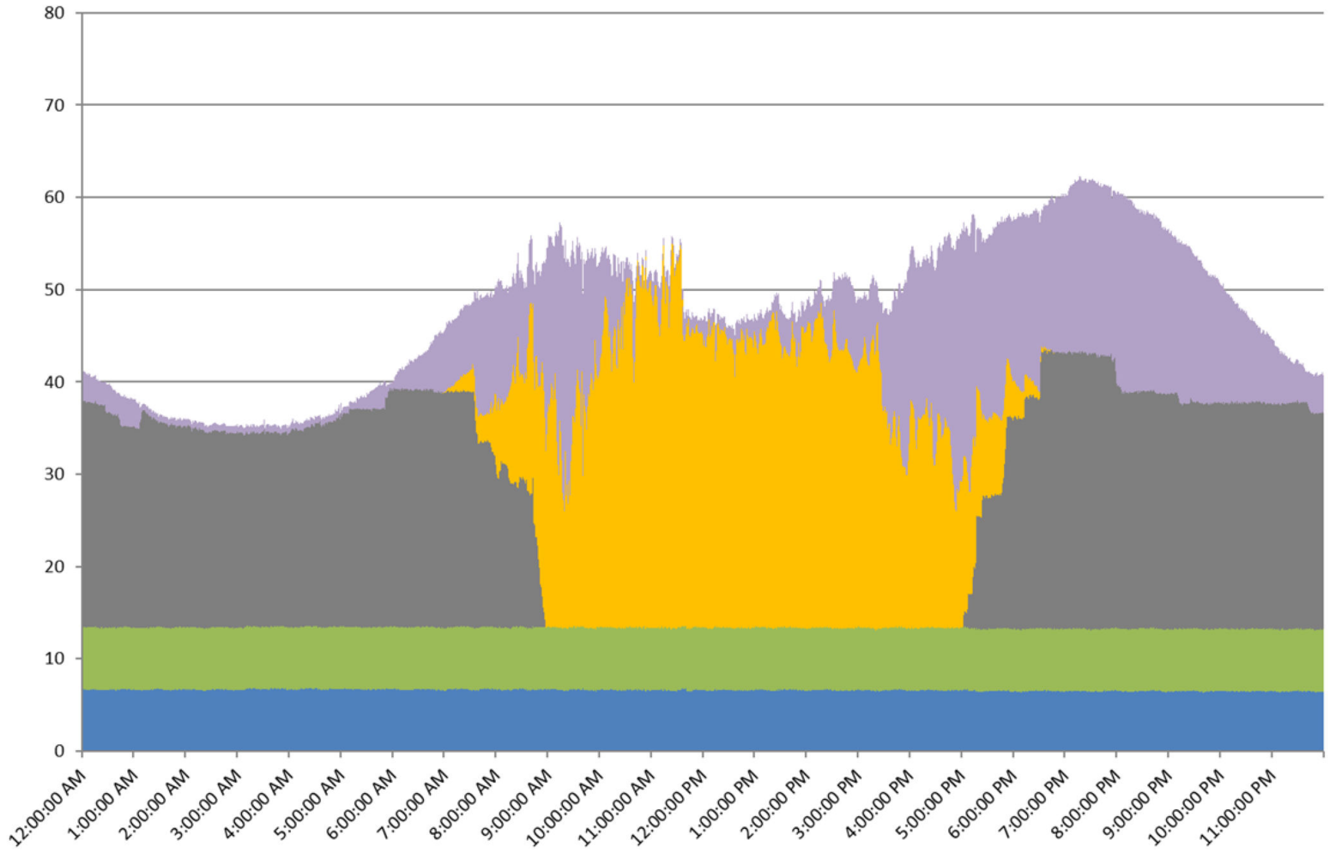


**Fig. 3** *KIUC system dispatch on 14 March 2020 showing 8 h of operations at 100% renewables (B. Rockwell, KIUC). Generation in MW is the sum of small hydro generators (blue), one small biomass plant (green), the sum of oil-fired generators (grey), the sum of utility and customer-owned PV that is not backed by storage (yellow), and the sum of PV/BESS plants (purple)*

reserves and how they can also provide operating reserves and lead to decreased requirements.

### 3.1 Operations at 100% renewables

*3.1.1 Energinet:* For well over a decade, Energinet has regularly had hours during which it generated more wind power than its demand. Energinet is tightly interconnected with its neighbours. Referring back to Table 1, the capacity of interconnectors for Energinet is roughly equivalent to the peak demand as well as to the wind and solar PV capacity, which enables these penetration levels while simultaneously holding curtailment low.

On a weekend in mid-September 2019, storm-force winds swept across Denmark, resulting in wind production continuously exceeding demand for a full 24 h period for the first time. From midnight to midnight on Sunday, 15 September 2019, total wind generation was 130% of total electricity demand. During the hour ending 3 am, instantaneous penetration of wind reached 160% of demand, beating a previous record from 9 June 2019 of 152%. Excess power was sold to neighbouring entities through the available capacity on the interconnectors.

*3.1.2 Kauai Island Utility Cooperative:* KIUC has steadily been increasing the duration of operating their system at 100% renewables. In 2019, KIUC operated at 100% renewables for a total of 33 h on 12 different days. From 1 January to 19 April 2020, they were able to run their system for 418 h at 100% renewables, on 70 different days. Typically, they are currently able to run their system for 1–8 h at a time at 100% renewables, with 70–80% of the load served by IBRs – solar PV and BESSs. Fig. 3 shows a day (14 March 2020) when 100% renewables served demand for over 8 h. On this day, KIUC began serving demand from only renewables and BESSs associated with renewables plants from 8:57 am to 5:01 pm.

The BESSs are used to provide spinning contingency reserves for the solar PV as well as load shifting. They are charged by the solar PV plants, not by the fossil fuel plants. Their first BESS had a duration of 4 h. They moved to 5 h duration BESSs once they started adding trackers to their PV, because of the increased production they bring compared to fixed-tilt solar PV.

*3.1.3 South Australia:* Due to significant installed wind and solar PV capacity and low demand in South Australia, it is commonplace for this region to operate at or above 100% wind/solar PV penetration. In 2019, wind generation instantaneously peaked at 159% of regional demand and exceeded 100% of regional demand around 6% of the time. This system is facing challenges to maintain reliable operation because within a period of 12 h it can transform from a system with only synchronous generators on-line to one dominated by IBRs (wind and solar PV).

### 3.2 Forecasting

There are a number of mitigation options that utilities have undertaken to manage VER variability and uncertainty. These include reducing forecast errors, aligning forecasts with operational decisions such as the start-up of certain types of generators, and pushing operational decisions closer to real time when forecasts are more accurate.

*3.2.1 South Australia encourages self-forecasts:* The NEM utilises a 5 min dispatch, granular forecasting of VER output over a range of operational time frames from 5 min to one week ahead. Each wind and solar site is individually forecasted. The NEM includes all generating resources above 30 MW in central dispatch and congestion management. The significant wind and solar PV capacity relative to demand in South Australia makes accurate output forecasting vital for system balancing.

The system operator has historically been responsible for forecasting of VER output; however recent changes allow and incentivise utility-scale VER operators to self-forecast. To date, one VER operator has commenced self-forecasting, with others expected to follow.

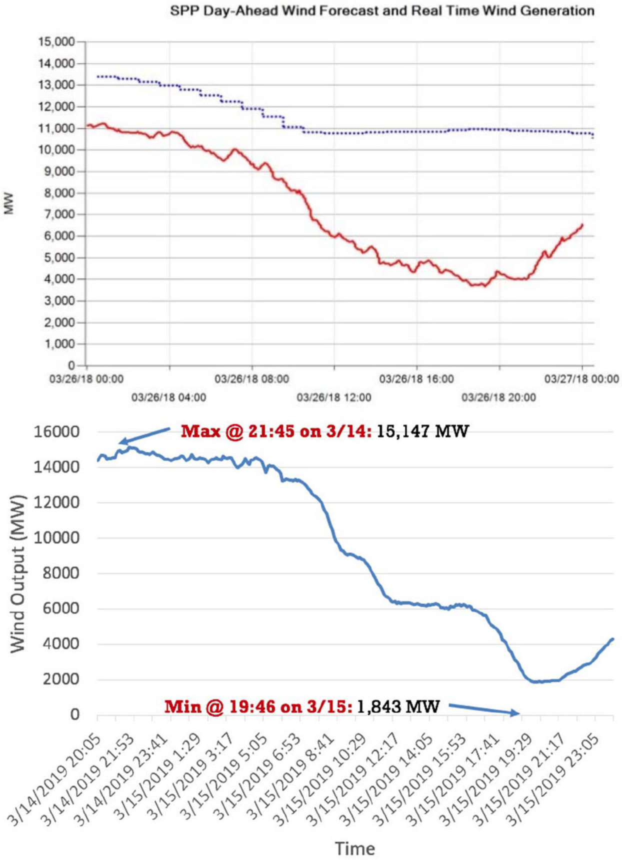


**Fig. 4** *Top: example of 7 GW day-ahead wind forecast error in SPP. Day-ahead wind forecast is in blue and actual wind output is in red. Bottom: example of high wind ramp in SPP of 13.3 GW in 22 h (B. Rew, SPP)*

In 2018, a forecast uncertainty measure (FUM) was developed, providing a forward-looking assessment of the likely aggregate uncertainty in demand and VER output forecasts. This FUM now forms an important input into short-term operational reserve assessments, and has become particularly important for operational decision making during extreme weather conditions and low reserve periods.

*3.2.2 SPP formed an uncertainty response team:* Wind forecasting in SPP is challenging for a number of reasons. First, low-pressure systems from the Rocky Mountains create instabilities in weather systems across the SPP footprint. Second, the low-level jet stream has a significantly widespread impact on wind power output in the Midwest. In the morning, rising hot air can cause the low-level jet to rise, resulting in a significant decline in wind output. When the low-level jet moves back down, wind power output can increase rapidly. Both factors are hard to predict and greatly affect forecast uncertainty. An example of a 7 GW day-ahead wind forecast error is shown in Fig. 4 (top) and an extreme wind ramp is shown in Fig. 4 (bottom).

SPP can have 1 h wind ramps approaching 4 GW. Fortunately, SPP also has 5 GW of generators that can start up within 1 h. However, there have been times such as in May 2018 when all these short-term units were committed in the day-ahead market. Therefore in real time, there was very little quick-start capability to deal with variability. The record wind ramp in SPP was 16.1 GW in 21 h. This wind ramp was forecast; however, the steep down-ramps occurred during the morning load rise and the evening ramp, making the net load ramps steep. A significant wind forecast error in combination with either of these two events could have led to reliability challenges.

As a result, SPP has focused on improving forecasting and established an uncertainty response team (URT) 2 years ago. The URT exists in addition to normal forecasting teams which focus on reliability and economics. For some sites, SPP conducts site-specific wind forecasting. Individual wind turbines are modelled and effects of wind direction and wake effects are captured. They examine confidence levels in the forecasts and the current state of the system. The URT assess risk and may conduct additional analyses and studies to evaluate uncertainty. Evaluation in terms of 1, 4, and 8 h look-ahead horizons over the next seven days and flag potential concerns are done by this this team. Working with real-time staff, the URT mitigates potentially significant forecast errors and helps to maintain a reliable grid.

### 3.3 Impact of distributed energy resources

*3.3.1 AEMO manages high penetrations of DERs:* The majority of solar PV capacity in South Australia is distribution connected rather than connected to the bulk power system. This results in ongoing reductions in demand supplied through the bulk power system during high solar period.

South Australia set a new all-time minimum demand (demand net of DERs) record of 458 MW in November 2019, 141 MW lower than 2018s minimum. Rooftop DPV provided an estimated 832 MW of output at the time (64% of South Australia's underlying demand at the time).

Growth of solar PV DERs in South Australia has been rapid, exceeding most forecasts. Recent forecasts now suggest that short periods when all regional demand is supplied by DERs could now occur in South Australia as early as 2022.

Under such conditions, performance of the South Australia system will be dominated by DERs rather than transmission-connected generation (synchronous or inverter-based). The regional distribution network operator is now introducing ‘smart’ capabilities for distributed generating resources, allowing curtailment of output under certain operating scenarios. This has required careful management of stakeholder and customer experiences.

A regulatory approval process for additional transmission interconnection into South Australia is currently underway, with a tentative service date of around 2022-23. Management of low demand periods in South Australia, resulting from ongoing growth of DPV, is one identified benefit of this proposal.

South Australia now has two virtual power plant (VPP) projects, each currently at the single digit MW scale, using controlled aggregations of residential BESSs. These VPPs are being trialled in the existing energy markets, to provide demand-side flexibility and market reserves.

The BESSs are configured to provide primary frequency response (PFR), and these VPP have shown promising results for provision of distributed frequency response reserves during recent disturbances. One VPP project is planned to scale up to 250 MW.

### 3.4 Operating reserves

Ancillary services (ASs) are procured to support system reliability during normal operation and abnormal events. VERs affect how much ASs are procured, where the ASs are sourced, and even what type of ASs are needed.

*3.4.1 AEMO's reserves markets:* The NEM has used real-time markets since 2001 to procure both primary and secondary frequency control reserves. Reserve procurement is incorporated into and co-optimised with dispatch of the energy market.

Reserve requirements, and their allocation to generation resources are updated every 5 min considering current system conditions, including the real-time largest single loss of infeed risk, system demand, and in some cases, system inertia. Significant levels of DPV in South Australia have been observed to cease output during system disturbances in South Australia, increasing the loss of infeed risk during daylight hours.

Grid-scale BESSs and wind generation in South Australia now successfully participate in these existing reserve markets, providing both primary reserves delivered automatically via local governor type controls on both wind and BESSs and secondary reserves via centralised 4 s automatic generation control (AGC) of MW output.

The value of these reserve markets has historically been low relative to the energy market; however this has changed rapidly with near-record turnover occurring in these reserve markets recently. Provision of these reserves now forms a key revenue source for some new resources, particularly for grid-scale BESSs, of which there are now three in South Australia. During a recent islanding event in South Australia, these three BESSs formed a key source of frequency control reserves.

The specifications for delivery of these reserves in the NEM still broadly reflects the characteristics of the generation resource mix in-service when these markets were originally developed in the early 2000s. Work is underway to update these specifications to better reflect and reward the performance characteristics of modern IBRs, in particular their much faster response capabilities.

*3.4.2 ERCOT's reserve requirements:* 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). Each of these ASs are procured for each hour of the next day in the day-ahead market. Prior to the rapid growth in wind/solar, ERCOT procured mostly fixed amounts of RRS and NSRS throughout the year with the exception of regulation services. Increased levels of wind/solar motivated ERCOT to review their AS methodology and align it with emerging risks. Rather than procuring fixed amounts of ASs through the year, the minimum amount of AS requirements are now being procured based on expected conditions and associated need for each of the AS products under those conditions. Regulation and NSRS will be discussed in this section and RRS will be discussed in Section 4.1.4.

Regulation service is primarily used to balance mismatch between supply and demand through a 4 s dispatch instruction from the ERCOT load frequency control (LFC) application. In 2009, ERCOT procured an average of 825 MW of Reg-Up and 851 MW of Regulation-Down service. Today, average requirements are less than half of those in 2009, despite the fact that wind capacity has more than doubled. This contradicts the conventional wisdom that regulation AS needs will increase as VERs increase. Reliability has not suffered as a result of the increased VERs and decreased regulation reserves. ERCOT today maintains one of the best Control Performance Standard 1 (CPS1) scores in North America and continues to reduce procurements of Regulation Service every year [2, 4]. This has been achieved by 5 min dispatch, refining its security constraint economic dispatch (SCED) algorithm, LFC tuning, clear and measurable expectations from IBRs in real-time, and grid code requirements for provision of PFR. For example, prior to 2010, ERCOT operated a zonal market in which balancing dispatch instructions were sent out for each 15 min interval at least 30 min ahead. When ERCOT switched to a nodal market, it started dispatching resources every 5 min using SCED applications.

NSRS is primarily used to help provide reserves during capacity shortage conditions due to load forecast errors or wind and solar forecast errors. ERCOT procures NSRS from any resources that can deliver the procured reserve capacity within 30 min. Prior to 2016, the NSRS quantities were mostly static and were procured in 4 h blocks. Procured amounts were based on covering the 95th percentile of all net load ramps. ERCOT revised the NSRS procurement methodology to include only under-forecast errors for load and over-forecast errors for renewables. This is shown in the top left quadrant of Fig. 5 (top left). Additionally, ERCOT procures the 95th percentile of the net forecast errors during periods when the risk of net-load ramp-up is high (load on an up-ramp and renewables on down-ramp). During periods of low risk for net-load ramp-up, ERCOT procures as low as a 70th percentile of the net forecast errors [5]. The NSRS requirement in 2019 is shown in Fig. 5 (top right) by month and hour. Fig. 5 (bottom) shows monthly NSRS procurements from 2014 to 2018.

ERCOT identifies these AS requirements for the upcoming year during the fall of the previous year. Historical data plays a significant role in identifying the required minimum AS quantities for each of these services for all 8760 h of upcoming years. Since AS quantities are determined many months in advance and rely heavily on history, ERCOT engineers have developed tools to help control room operators identify shortages in RRS and NSRS ASs closer to real time. Additionally, ERCOT operators have new tools that provide situational awareness associated with forecast uncertainty, severe ramp events, inertia monitoring, ASs monitoring, icing events, and other factors to facilitate the integration of renewable resources into the ERCOT grid.

*3.4.3 Wind provides reserves in Xcel:* Xcel/Colorado has a unique method to manage regulation reserves. Xcel/Colorado has managed increasing VER on their system for many years. In 2009, 10% of their annual demand was met by wind and solar. At that time, system operators found that they no longer had sufficient dispatch flexibility in the rest of their generation portfolio to accommodate additional VER without regular curtailment. When generation significantly exceeded demand, such as during windy nights when demand was low, the system operator would call wind plants to request sizeable blocks of manual generation curtailment. They requested enough wind curtailment so that fossil-fuelled generators could operate at their minimum generation level *plus* some additional level so that they could provide downward regulation.

In 2010, Xcel/Colorado enabled 4 s AGC of wind facilities. This enabled fossil-fuelled generators to operate at their minimum generation level while the *wind plants* provided the downward regulation. In addition, the curtailed wind plants were able to provide upward regulation depending on how much they were curtailed. AGC of wind plants reduced wind curtailment and fossil fuel costs, while providing better control of the system. Finally, the wind plants are able to provide regulation reserves with significantly reduced wear-and-tear impacts compared to fossil-fuelled generators providing regulation reserves. A few days of testing demonstrated dramatic reductions in curtailment while simultaneously enabling improved control over area control error as shown in Fig. 6. After years of implementing wind on AGC, Xcel/Colorado is also beginning to implement spinning reserves from curtailed wind. They use a short-term forecast to determine the potential wind output and back down the wind output so that there is headroom to provide the spinning reserve.

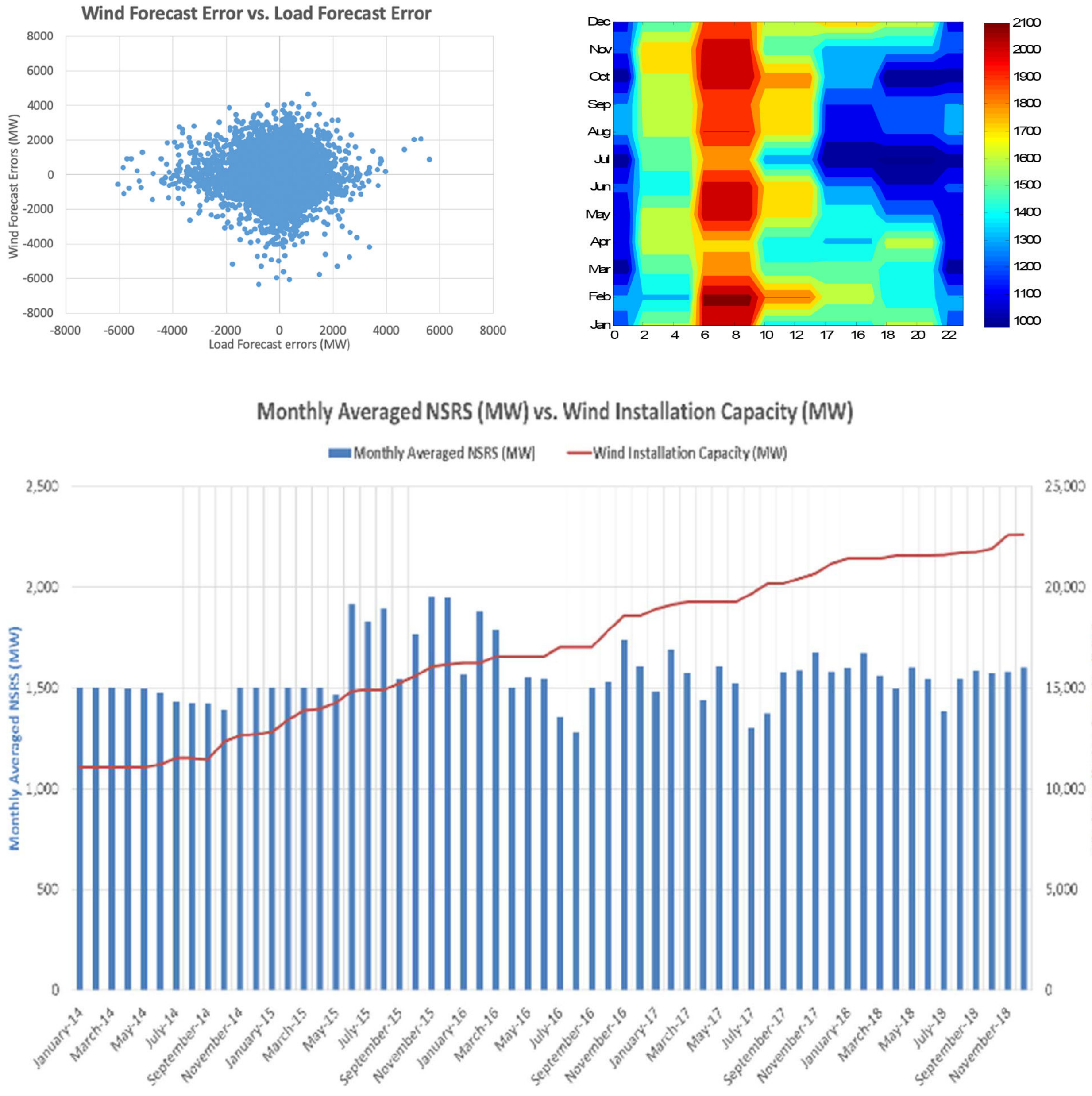


**Fig. 5** *Top left: wind forecast errors versus load forecast errors in ERCOT; top right: NSRS requirement in MW for 2019 in ERCOT as a function of month and hour; bottom: average monthly NSRS procured (blue) and installed wind capacity (red) (S. Sharma, ERCOT)*

While the aforementioned reserves are served *by* wind resources, there are also reserves that are held to manage potential down-ramps *of* wind resources. In addition to the contingency reserve that Xcel/Colorado holds to cover the loss of the largest generator or infeed, Xcel/Colorado also carries Flex Reserves to cover large wind down-ramps. This allows the system to simultaneously manage a traditional system contingency and a large reduction of VER output due to declining wind speeds. The dynamic Flex Reserve is a 30 min product that addresses the largest potential renewable generation down-ramps given real-time VER output, based on historical data. Anecdotal evidence confirmed with historic wind output down-ramps showed that the largest wind down-ramps actually occurred when wind output was closer to 50% of nameplate rather than 100% of nameplate. Other studies also find wind variability to be greatest at moderate wind penetrations [6, 7]. This is due to the fact that the steepest part of the wind turbine power curve occurs when wind output is around 50% of nameplate and that at 100% of nameplate, changes in wind speed cause very little change in wind output.

## 4 Inverter-based resources

### *4.1 Managing system stability*

High IBR penetrations can impact system stability as IBRs displace synchronous machines. For ac islands like EirGrid, KIUC, and ERCOT, frequency stability can be an issue. Levels of inertia may be monitored and mitigation may be needed, whether it is in infrastructure such as synchronous condensers or in new market products such as fast frequency response (FFR).

Even for systems that are not ac islands, there are challenges in pockets of the system that have high IBR penetrations and are loosely tied to the rest of the larger interconnected system. South Australia and ERCOT both have high IBR pockets of their system with low short circuit strength that can make it difficult to keep IBR controls stable [8]. Synchronous condensers are an option to provide *both* inertia and short circuit strength, but these can create their own challenges such as introducing transient stability risk in high IBR regions. Grid-forming inverters are another potential mitigation option but the industry has yet to determine desired performance from this technology and then to make this technology commercially available [9].

*4.1.1 KIUC runs a generator in synchronous condenser mode:* On the island of Kauai, oil-fired units provide inertia and

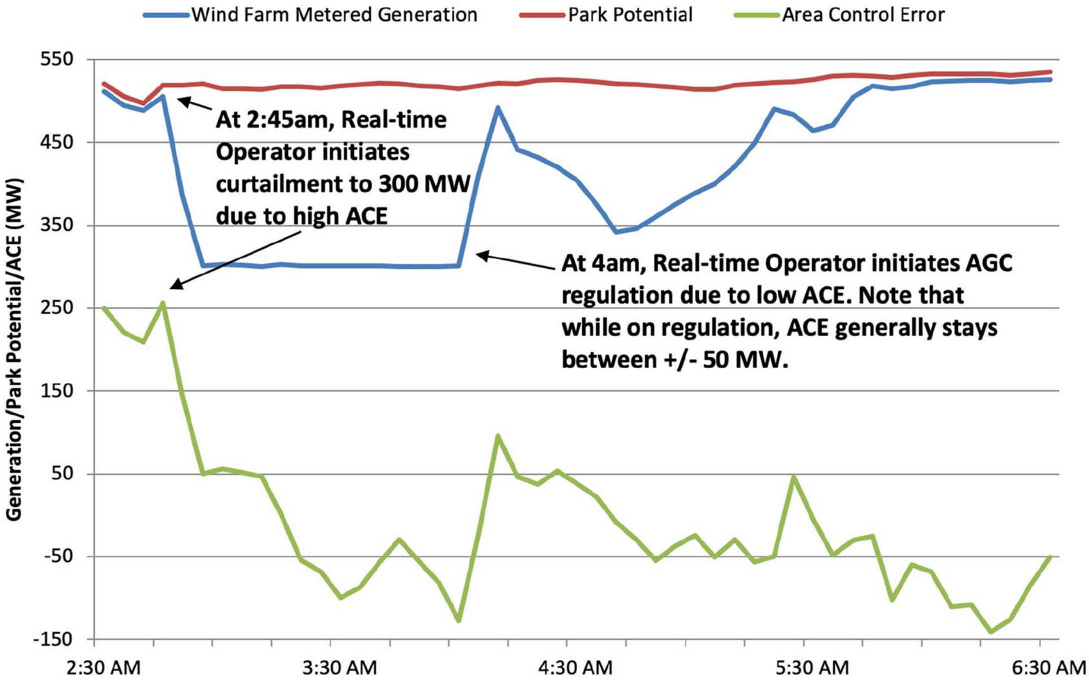


**Fig. 6** *Example of wind plant initially manually block-curtailed and then put on AGC signal so that it provides up- and down-regulation (D. Bartlett, Xcel)*

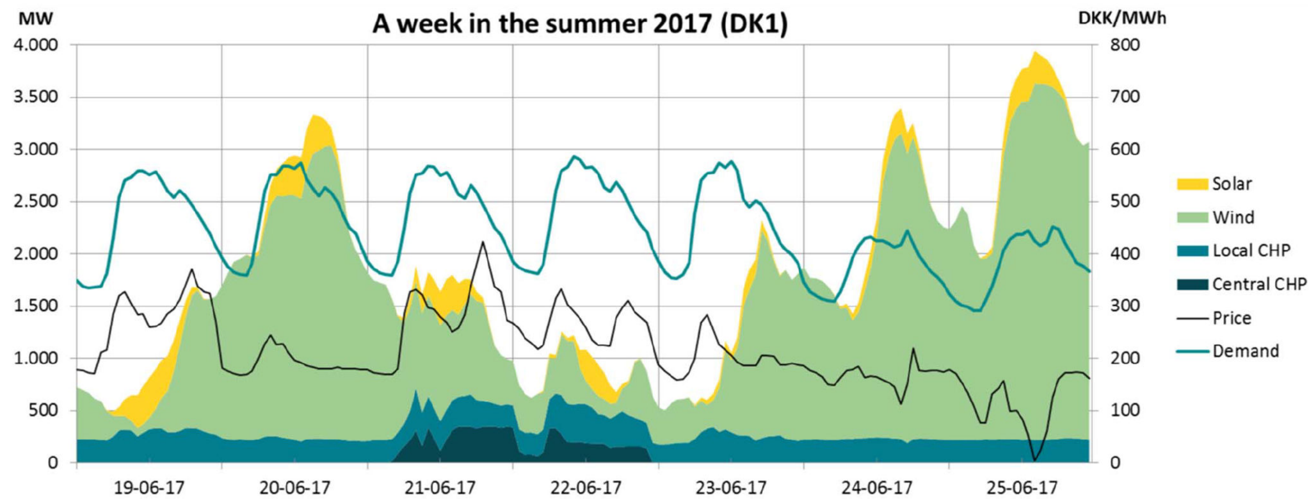


**Fig. 7** *Dispatch in Energinet during one summer week in 2017, showing the ability of the system to operate without large, centralised generators for five days. DK1 is the spot price in Denmark West. The addition of six synchronous condensers enabled this operation (P. Jorgensen, Energinet)*

short circuit strength, in addition to providing contingency reserves. In order to reach 100% renewables, KIUC commissioned a synchronous condenser feature on their Kapaia GE LM2500 gas turbine. This enables them to maintain adequate inertia, voltage support, and fault current capability across the island. This was one of the keys to the 100% renewables operation shown in Fig. 2.

*4.1.2 Synchronous condensers allow Energinet to turn off central-station generators:* In Denmark, the installation of five synchronous condensers throughout their country has allowed Energinet to decommit centralised CHP so that it can operate using only wind, solar PV, and local CHP generation. Fig. 7 shows a week in 2017 when centralised CHP units are offline for most of the week and wind, solar PV, local CHP and imports serve demand. The synchronous condensers provide voltage support and grid strength to the system. Energinet does not currently have an frequency stability issue due to the large size and significant inertia in the European grid. Nevertheless, their synchronous condensers are designed to allow for the mounting of flywheels to increase their inertia for some future time when IBR penetrations are high in the European grid and frequency stability does become an issue.

*4.1.3 Electromagnetic transient (EMT) modelling needed in South Australia:* An EMT model of the entire South Australian region has been developed, which includes 30 separate IBR plant models, and models of all legacy synchronous resources. This model is now used for determining some of the system stability operating limits in the South Australia area.

Though such EMT models are complex and time consuming to construct, maintain, and use, they have ultimately proven necessary given the multiple widely-dispersed IBRs, low regional short circuit strength, and high IBR penetration levels present in South Australia.

EMT modelling has identified that at least four to five synchronous generators, of 150–200 MVA each, must remain on-line in South Australia at all times to maintain system stability given current operating conditions, particularly to ensure adequate post-fault stability. It has also been used to identify MW limits on wind output under conditions of low synchronous generation. These limits resulted in South Australian wind energy curtailment of around 1.3% in the fourth quarter of 2019. Similar EMT modelling is now increasingly being used in other parts of the NEM to identify system limits based on system strength and associated requirements for minimum synchronous unit commitment.

Zero marginal cost wind and solar resources in South Australia economically displace thermal units in the energy market, even though the synchronous machines provide the grid strength necessary to keep IBRs stable. As the NEM market design does not include centralised real-time commitment, or binding pre-commitment of generating units, the system operator must at times intervene to ensure that sufficient synchronous generation remains committed to maintain system stability. Synchronous generators in South Australia tend to be relatively inflexible with start-up times of at least several hours and high minimum generation levels. Unlike KIUC, none of the generators in South Australia are equipped with the capability to be operated in synchronous condenser mode. Operator intervention to ensure sufficient on-line synchronous generation in South Australia was required over 40% of the time in the fourth quarter of 2019. The regional TSO is now procuring four synchronous condensers for installation across two sites during 2020–2021 to minimise the need for out-of-market commitment of thermal units.

*4.1.4 ERCOT uses FFR and demand response resources:* ERCOT's RRS is procured primarily to arrest frequency above 59.4 Hz for the loss of 2750 MW generation. As the instantaneous penetration of IBRs increases, system inertia declines. For a grid like ERCOT, inertia largely determines the rate-of-change-of-frequency (ROCOF) following generator loss events. If system inertia in ERCOT falls below 100 GW·s, frequency drops faster than the fastest reserve (demand response within ½ second, triggered by under-frequency relays) can respond for a loss of 2750 MW. This will change on 1 March 2020 when a FFR product will be introduced. This FFR will be required to provide a full response in ¼ second.

RRS in ERCOT primarily comes from generating resources providing PFR and load resources triggered by high-set under-frequency relays. As mentioned above, the grid code requires wind turbines (and solar PV plants) to have the capability to provide PFR. While this capability is always enabled for over-frequency events, wind turbines are not required to hold headroom to provide an up-response unless they are already curtailed for other reasons. Since 2015, ERCOT has started procuring RRS based on anticipated system inertia; the highest amount of RRS generally coincides with the early morning hours (1 to 4 am) when demand is typically below 30 GW and wind generation is high. To mitigate the critical inertia issue in ERCOT, a number of options have been discussed and outlined [4].

*4.1.5 EirGrid's new market services address high IBR penetrations:* EirGrid conducted ground-breaking analysis of the impacts of high IBR penetrations on system stability in 2008, before much of the industry was aware of the potential issues. EirGrid studied instantaneous penetrations of 100% IBR on their island system and found that the biggest challenges to being able to operate up to 75% IBR penetration and 1 Hz/s ROCOF were system stability, system voltage control (due to displacement of synchronous generator reactive power sources), over-frequency system protection strategy (for loss of export at high wind) and managing the uncertainty of a weather-dependent system [10]. They initially instituted a 50% cap on system non-synchronous penetration (SNSP). SNSP is a different metric from instantaneous penetration of IBRs and is defined as the sum of wind output and HVDC imports divided by the sum of demand and HVDC exports. This 50% SNSP cap resulted in curtailment of wind, which was the dominant IBR on their system at the time. The *Delivering a Secure Sustainable Electricity System* (DS3) program was put into place as a framework to raise the SNSP cap in 5% increments each year to 75%. The DS3 program included revisions to markets and the grid [11].

Currently EirGrid operates the grid up to 65% SNSP with a 0.5 Hz/s ROCOF limit. They anticipate an additional 1000 MW of new wind capacity in the next year. At a 65% SNSP cap, this additional wind would result in significantly more curtailment. EirGrid continues to improve their system and plans to operate up to 70% SNSP by the end of 2020.

Synchronous generators provide inertia, which reduces ROCOF. These resources also provide short-circuit strength which helps transient stability and stability of IBR controls. However, they must operate at or above some minimum generation level for efficient operation and to meet required emissions levels. High minimum generation levels lead to less ability of the system to integrate VER output and can result in increased curtailment. At the same time, typical competitive wholesale markets have a built-in incentive for synchronous generators to have high minimum generation levels since these generators are paid for energy production (higher minimum generation levels leads to higher revenue). In addition to reduced revenue, there may be costs associated with upgrades to reduce minimum generation levels for thermal units.

EirGrid solved this conundrum by revising their system services. Seven new system services were approved in 2014 and implemented starting in 2018, adding to the existing seven AS. EirGrid essentially revamped their previously small AS market into an AS market that could spur investment, such as the investments needed to upgrade thermal plants to reduce minimum generation levels. The previous market had a value of €50 million/year or 2% of generator revenues and was based on 1 year tariffs. The revamped market had a value of up to €235 million/year and the tariffs were for 6 years. In 2018, €180 million was spent on system services.

These values were split across products so that they paid out more when the system was operating above 55% SNSP. Therefore, when wind levels are very high (SNSP exceeds 55%) and the grid really needs these services, generators that are on-line and providing these services earn more revenue.

One of these new products is synchronous inertial response (SIR) and it is the ratio of the kinetic energy to the minimum generation level of the unit. Units with a high SIR that were dispatched when wind levels were high received more system services revenue. As a result, five thermal plants lowered their minimum generation levels by a total of 350 MW. The increased revenues from the new system services provided incentives and guaranteed payments over 6 years that allowed for owners to invest in upgrades. Finally, the reduced minimum generation levels allow units to have a higher ramping margin and a higher steady-state reactive power volume, both of which are new services that also receive revenue.

*4.1.6 Tasmania manages high IBR penetrations:* In addition to the challenges of South Australia, other parts of Australia's NEM are facing similar challenges with IBR growth. The island state of Tasmania is connected to the NEM via a single 500 MW line-commutated converter HVDC link. It has 308 MW of installed wind, with an additional 256 MW currently being commissioned. The system has a median demand of 1150 MW, and a minimum demand of around 850 MW. The local synchronous generation is predominantly hydro.

In February 2020, it reached 82% instantaneous penetration of IBRs (wind and HVDC imports), when load was ∼900 MW, and it has operated above 75% for 4 h periods. This requires support from multiple hydro units operating either in synchronous condenser or generator mode, for provision of inertia, voltage control, system strength, and PFR (see Fig. 8). For this system, the SNSP metric tends to be the same value as the IBR penetration metric above moderate (30%) SNSP levels due to HVDC imports during these periods.

With the additional wind generation now being commissioned, wind and HVDC capacity could in theory meet all demand at times. However, this scenario would not be operable, particularly due to the lack of short-circuit strength and inability of the HVDC and wind resources to form their own grid (i.e. grid forming capability).

Operating limits for minimum synchronous inertia and system strength have recently been established in Tasmania. Existing processes for managing PFR reserves currently ensure a minimum level of synchronous generation remains on-line to provide PFR.

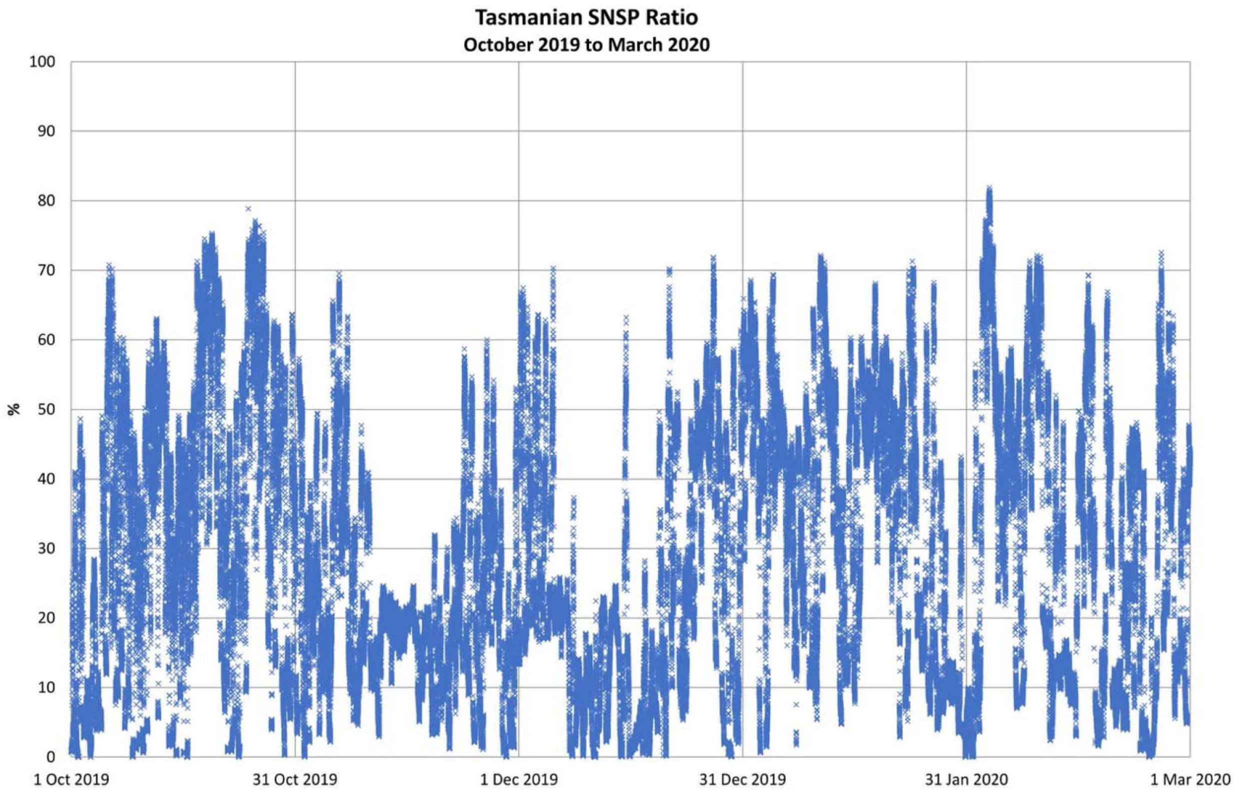


**Fig. 8** *Tasmanian system's SNSP ratio during October 2019 to March 2020 showing SNSP reaching a high of 82% in February 2020 (A. Groom, AEMO)*

Control room tools and processes have been updated where required to ensure newly identified inertia and system strength limits are monitored and maintained, largely via the targeted dispatch of hydro units with synchronous condenser capability.

Minimum synchronous machine requirements to ensure adequate post-fault recovery and system frequency response were assessed using EMT modelling of the full Tasmanian power system, particularly to ensure accurate modelling of the post-disturbance response of the various IBRs.

## 5 Conclusion

This paper discusses some state-of-the-art operating practices that have allowed these seven entities to expand the boundaries of VER and IBR integration. The solutions discussed are not exhaustive and as the impact of each solution saturates, each entity will need to innovate further and identify other mechanisms to provide flexibility, maintain grid strength, balance generation and demand, and ensure reliable operation of the bulk power system. The penetrations of energy storage and hybrid resources are likely to grow in the near-term as costs decline, and it is likely that longer-duration storage will become more common as higher renewable energy targets are set. Exploiting the flexibility inherent in new electrified loads such as the heating and transportation sectors shows great promise for helping utilities get past the 40–50% VER levels.

FFR and sourcing essential reliability services from IBRs are helping utilities to displace synchronous generation with IBRs. Synchronous condensers, or enabling a synchronous condenser mode on an existing generator, are likely to be increasingly deployed to help maintain transient stability, small-signal stability, and system strength with high IBR penetrations. At some point, new technologies such as grid forming inverters may hold promise for overcoming declining system strength and system inertia to further enable very high IBR penetration levels in the future.

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