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Status Around the World

Variable Renewable Energy Integration

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VARIABLE RENEWABLE ENERGY (VRE), i.e., wind and solar photovoltaics (PVs), is being installed in rapidly increasing amounts around the world. Growth in VRE is being spurred by ambitious zero-carbon targets set by countries and individual states across the globe. The European Union approved a carbon neutrality target for 2050 in 2019. Japan's newly appointed prime minister announced the same target in 2020, and the Chinese government set goals to peak carbon emissions before 2030 and become carbon neutral by 2060.

In this article, we first present some recent records of VRE integration around the world. Next, we discuss the operational challenges with the growth of VRE including more frequently seen zero and negative prices, curtailment, and congestions seen in some regions in Europe, the United States, Australia, China, Japan, Brazil, and Chile. Finally, a few ongoing and planned mitigation strategies for managing the growing shares of VRE are discussed.

Record-High Wind and Solar Shares

The year 2020 saw a new record-high penetration of wind and solar generation.

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This is partially because electricity consumption dropped considerably in all countries due to the pandemic. In 2020, Europe surpassed a 15% share of wind energy and 8% solar. The United States achieved 8% wind and 3% solar, and China reached 9.5% wind and solar, with Qinghui and Ningxia surpassing 30%.

The status of VRE, as the average and highest instantaneous shares of demand and generation capacity, are depicted in Figure 1, showing how high hourly shares of VRE can be when the average VRE share is close to 40–50% of electricity consumption. The graph also depicts curtailed VRE, mainly wind energy.

In Denmark, more than 90% of the curtailments comes from responses to German surplus situations. In Ireland, *curtailment* refers to the dispatch-down of wind for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem) and not for localized network reasons. When local network congestion is also considered, the overall dispatch-down level in 2020 rises from 5.3% to 11.4%.

In Denmark, VRE exceeded demand for 845 h and reached a high of 213% of demand in 2020. In the Denmark West market area, shares greater than 100% were recorded during 2,117 h and greater than 350% during the most extreme hour (3,637 MW of VRE and 1,041 MW of demand). System operation without large power plants online has become more frequent since the first event in 2015.

In South Australia, a new record of solar PVs, above 100% of demand, was reached in October 2020 (Figure 2). Importantly, the majority of the PV generation (77%) was distributed, predominantly residential PV systems. This resulted in very low demand on the transmission system, as the majority of the underlying customer consumption was supplied by the distributed PVs. New records for the minimum demand supplied through the transmission system continue to be broken—only 300 MW in October compared with a peak demand of around 3,100 MW. Current forecasts for growth in distributed PVs show the possibility of transmission-supplied demand falling below zero for brief periods within the next one to two years.

The Tasmanian power system is a synchronous island, and it saw a record-high system nonsynchronous penetration (SNSP) of more than 90% in January 2021, based on a mixture of high-voltage direct current (HVdc) imports and local wind generation on a system demand of around 1,050 MW. The system has significant installed hydro capacity, with many units able to operate in synchronous condenser mode.

In Ireland and Northern Ireland, a new record of 95% of demand met by wind energy was achieved in January 2021. This high penetration has been facilitated by an operational trial of 70% SNSP, which began on 15 January 2021. SNSP is the share of nonsynchronous generation plus the net HVdc imports as a percentage of demand plus net HVdc exports. The 70% SNSP level was achieved on many occasions during the successful trial (Figure 3). The two system operators, EirGrid and the System Operator for Northern Ireland (SONI) are progressing further, with a 75% SNSP trial that began on 22 April 2021.

In 2020 in Germany, VRE produced more than all fossil generation (coal, oil, and gas) for the first time (183 TWh compared to 178 TWh). Maximum instantaneous VRE generation reached 74% on 5 July 2020, and maximum instantaneous PV penetration was 56% (37 GW) on 1 June 2020.

In the United States, Xcel Energy's operating company, Public Service of Colorado, experienced an hourly penetration of VRE of 83% and a monthly record 46% of load in December 2020. In 2020, 36% of all customer demand was served with VRE. This was primarily with wind energy but excludes a growing amount of distributed solar generation. The minimum net load was as low as 438 MW in 2020.

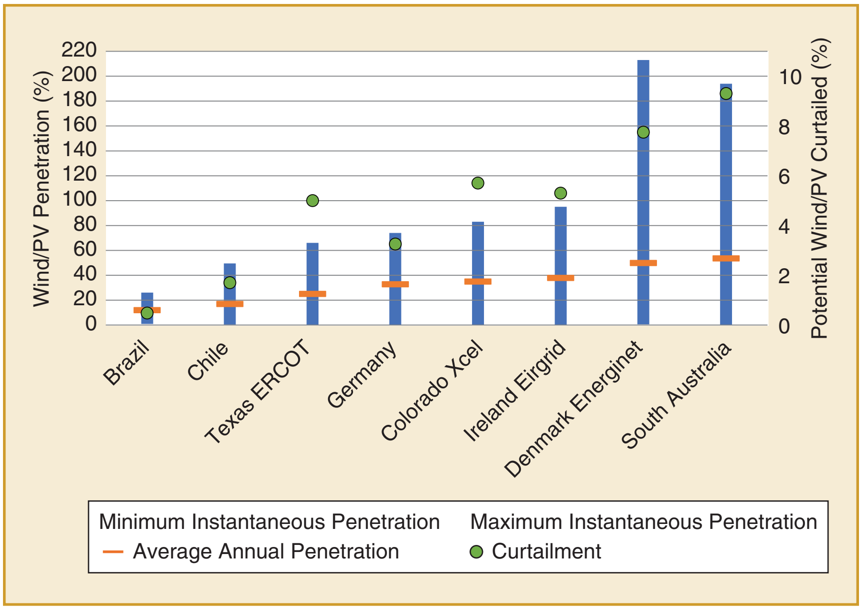

figure 1. The wind/PV penetration (excluding distributed energy resources) and curtailment. The blue bars show the range of instantaneous shares of VRE in the grid—the average share of demand is depicted with orange markers. In South Australia, the maximum instantaneous penetration is from the grid demand, where the distributed solar has reduced the demand that the transmission grid sees. The curtailed VRE, as a percentage of the potential generation available, is shown with green dots. (The scale is shown on the right *y*-axis.) ERCOT: Electric Reliability Council of Texas.

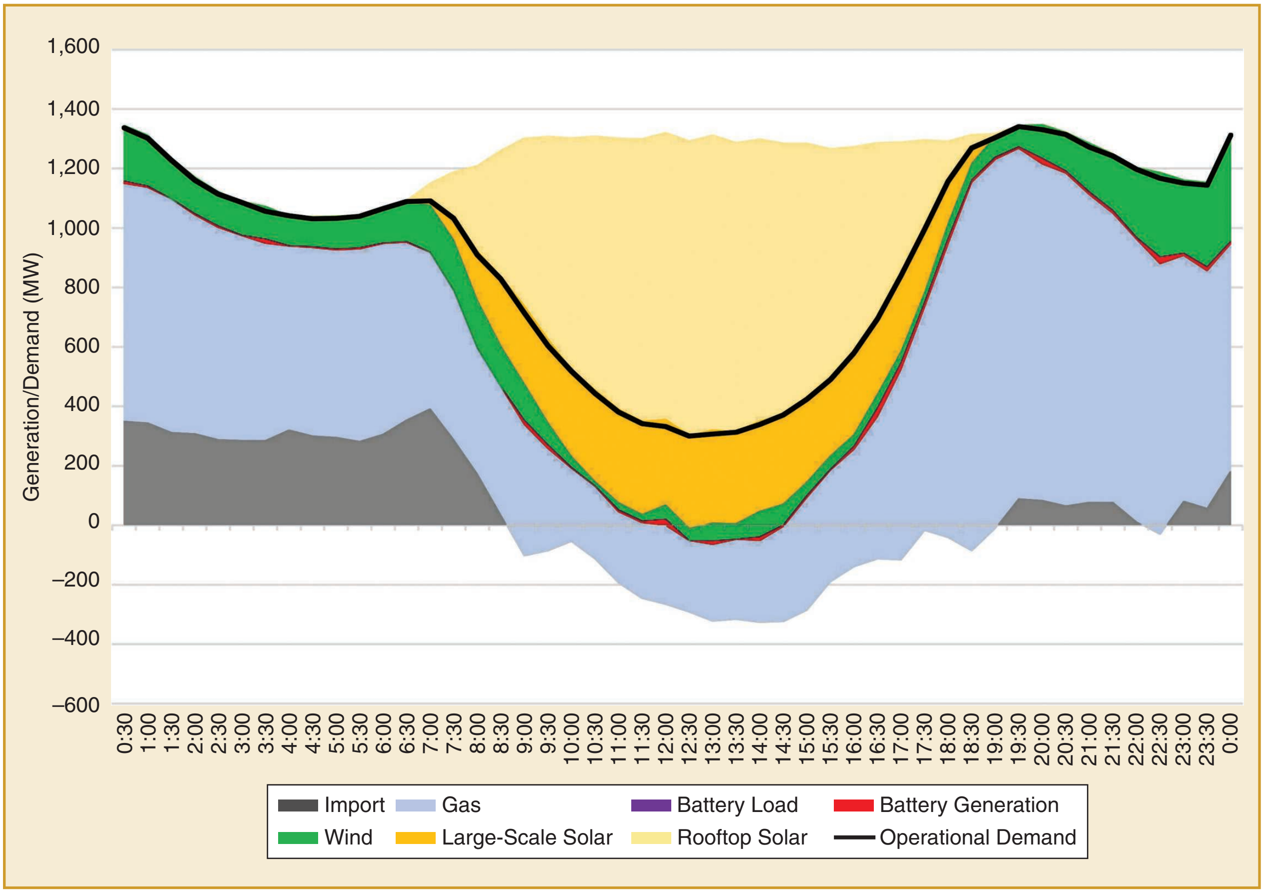

figure 2. South Australia solar generation versus demand in the high-solar-PV event on 11 October 2020. Operational demand is the demand on the transmission system, seeing the impact of behind-the-meter PVs on the behind-the-meter load. (Source: https://aemo.com.au/en/newsroom/media-release/solar-power-fuels-south-australias-total-energy-demand.)

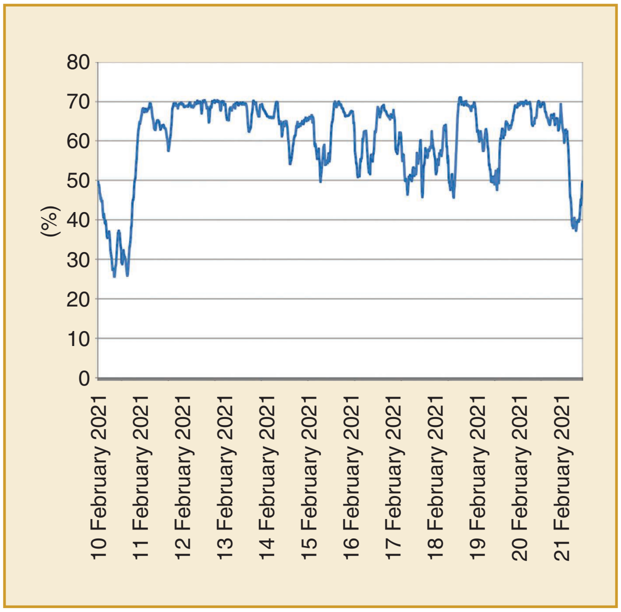

figure 3. The SNSP in February 2021 in Ireland and Northern Ireland during the operational trial, which allowed the SNSP level to reach 70%.

In Brazil, VRE is mostly located in the northeastern region. It has supplied most of the regional load in the peak wind seasons (a 46% average share compared to 12% in the country) and sometimes exceeded the local load (Figure 4), exporting power to the other regions of the country and complementing the production profile of the hydropower fleet. In Chile, VRE supply is around 20% of the system energy demand, with peaks of 30% of the daily energy demand on good days.

Increased Zero and Negative Prices in Energy Markets

Sometimes, system-wide energy prices can be negative due to overgeneration. (The available VRE generation plus the minimum generation levels of thermal plants is higher than the system load.) Negative prices are a market signal to all generators to decrease output and can incentivize the capability for generators to reduce output.

In the system operator Electric Reliability Council of Texas (ERCOT), negative prices occur during nighttime in the spring and fall (during high-wind, low-load conditions) in wind-rich areas behind transmission constraints. During

2020, there were about 1,100 5-min real-time market intervals when system-wide prices were negative.

In Germany, negative-price events increased significantly in 2020. In the day-ahead market, hourly events increased by 40% to 298 h compared to 2019. In the quarterly intraday auction, the events increased by 86% to 2,041 15-min intervals. The overall market value of these negative-price events (€–149 million) increased from 2019 (€–134 million) but was less than in 2017 (€–152 million), as the negative prices mainly occurred during times with low market volumes (nights and weekends). Additionally, the negative prices were not as low in 2020 (an average of €–15.5/MWh) as in 2019 (€–17.3/MWh) and 2017 (€–26.5/MWh).

In 2019, Denmark West experienced negative prices during less than 2% of the year, even though VRE exceeded demand for about 25% of the year. Two thirds of these negative-price situations were shared with neighboring Germany. As Denmark is usually a price taker in one of the bigger adjacent markets, this shows that the cross-border market functions well and that low-cost energy in most surplus situations still has value, as it can be sold where it is needed.

In the Japanese energy market, market prices cannot be lower than ¥0.01/kWh. The percentage of (almost) zero prices was 3% in fiscal year 2019. In Kyushu, where large PV capacities are located, this was 4% in 2019 and 5% in 2020. Although the PV capacity has been increasing, system operation improvements to reduce curtailment while maintaining stable operation have moderated the percentage of PVs curtailed. The frequency of zero-price periods has been increasing in other parts of Japan, too.

VRE Curtailment

System operators may dispatch a VRE plant below its potential real-time output, curtailing it due to transmission congestion or system-wide overgeneration. VRE plants may also downregulate, or curtail, their output as an economic response to negative prices. Curtailment can be viewed as flexibility from VRE. However, curtailed energy is lost and, therefore, should be kept to a low level. Selecting other flexibility resources can be considered so that most of the clean energy available is dispatched, and VRE curtailments are reserved for critical situations.

Over the past few years, China has worked hard to avoid VRE curtailment. In 2020, the curtailment of VRE was under 5%. Going forward, planning for flexibility in the system is a high priority. This includes VRE projects with storage, retrofit of coal-fired power plants, and

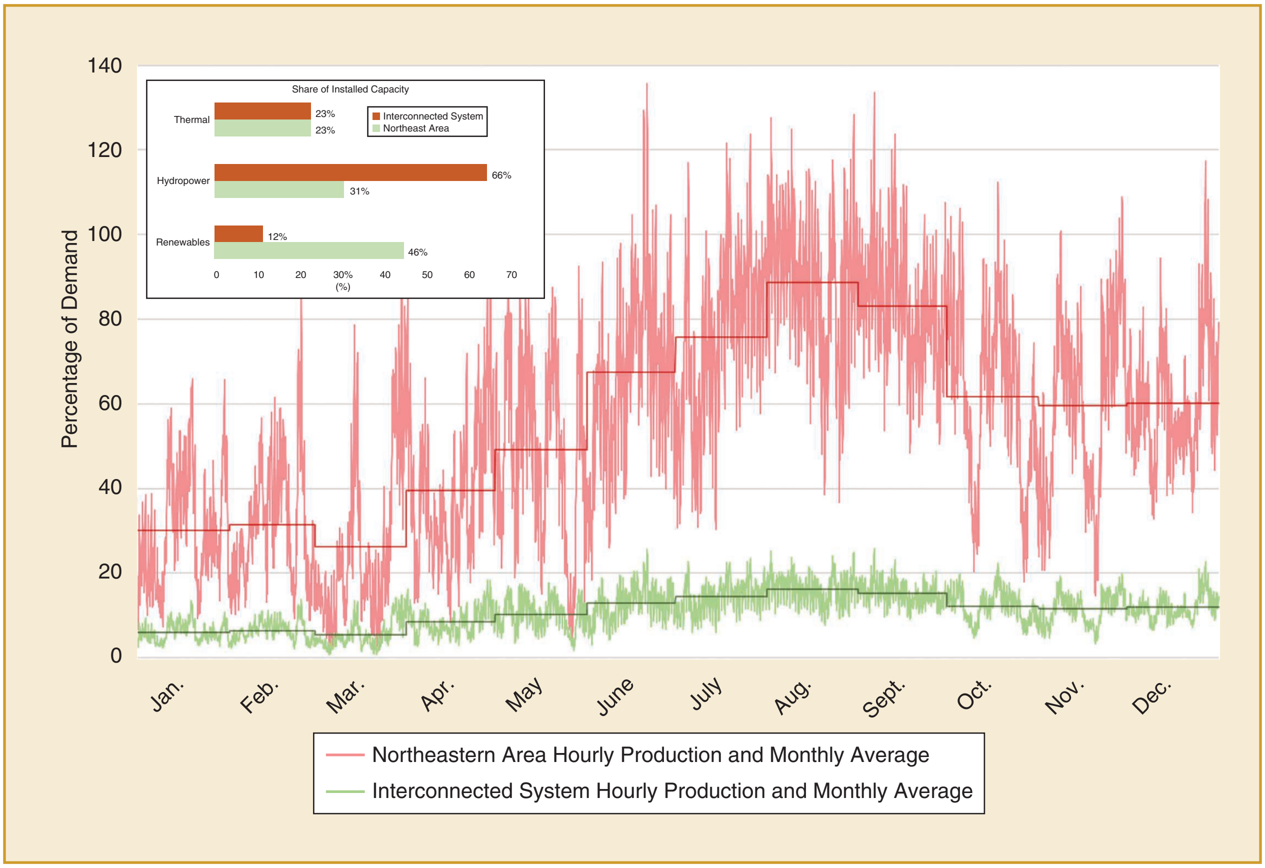

figure 4. The hourly VRE production in Brazil: 2020 renewable penetration. (Data source: Operador Nacional do Sistema.)

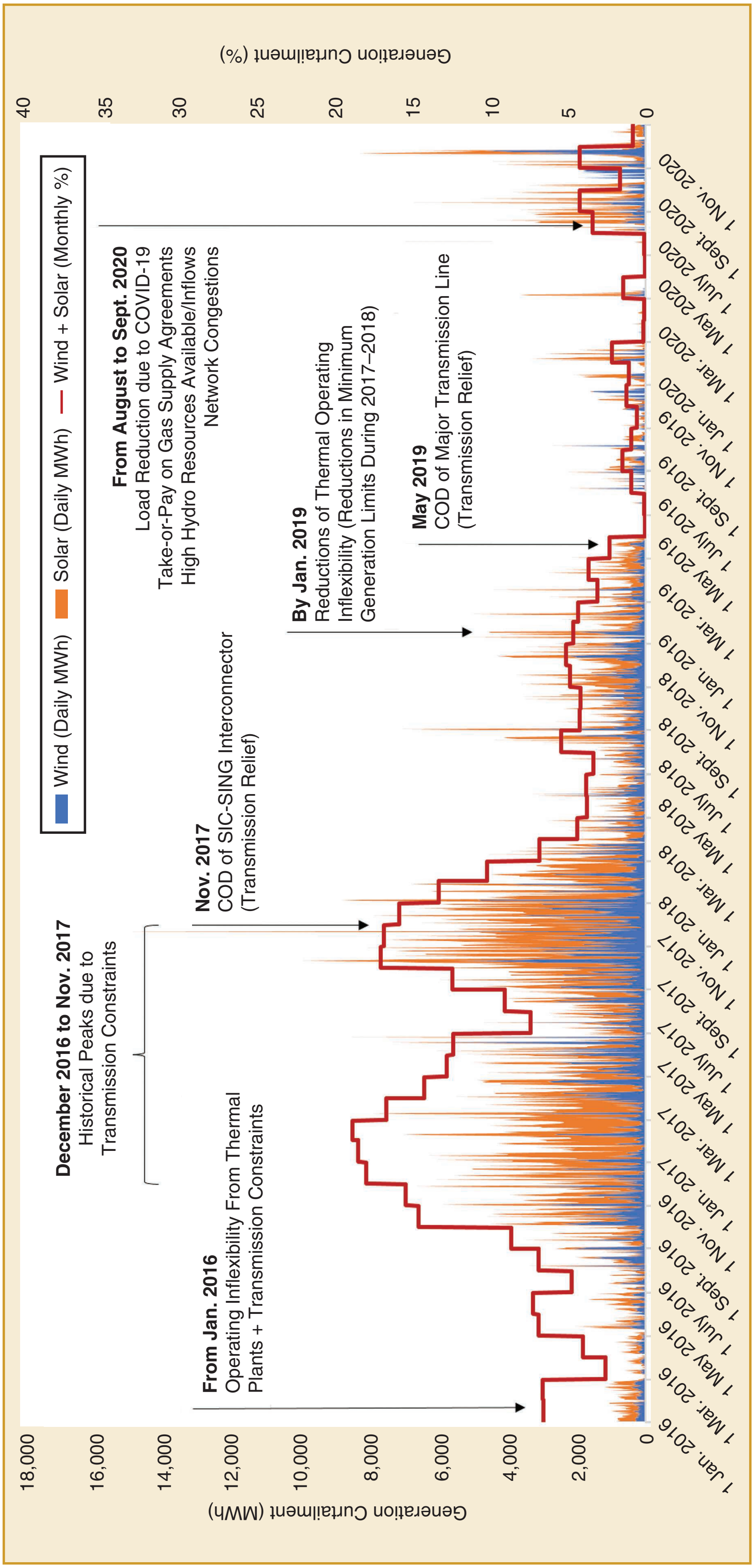

figure 5. The renewable energy curtailments in Chile, in daily megawatthours and as a percentage of the available monthly resource. COD: commercial operation date; SIC: Sistema Interconectado Central; SING: Sistema Interconectado del Norte Grande.

increasing attention on demand-side resources. During the cold wave in winter 2020, the flexibility of demand-side resources in Jiangsu Province made a large contribution to securing the supply of energy.

Brazil and Chile have encountered VRE curtailment, despite their hydropower generation that has historically provided good flexibility. Hydropower accounts for 65% of Brazil's and 26% of Chile's installed capacity, with seasonal and multiyear storage available. However, hydro resources are becoming more constrained due to climate change, an increasing level of conflicting priorities for water usage as well as transmission bottlenecks.

In Brazil, VRE curtailments have still been small, ranging from 2 to 6% of capacity, and are increasing. In Chile, they increased to 30% during some days in 2016–2017, mainly due to network congestion and inflexible thermal generators with disproportionally high minimum generation limits. Once these limits were reduced, the system's capability to absorb renewables increased significantly, reducing curtailment in 2017–2018 (Figure 5). Investments in transmission, including a major interconnector between the main solar resources in the north and main load centers in the central part, reduced congestion significantly during 2018–2019.

In 2020, there were some increases in curtailment. Reasons for this included reduced demand due to COVID-19 lockdowns, increased volumes of inflexible gas purchased through take-or-pay contracts dispatched at zero marginal cost, high volumes of hydro resources available, and network congestion (exacerbated under network contingencies).

Flexibility from hydropower generation in Brazil and Chile will be increasingly challenged in the future. In Brazil, all hydro plants built since 2000 are run-of-river. For the past seven years, inflows have been consistently 20% below the long-term average. Increasing social–environmental constraints are limiting flexibility provision. About 75% of Brazil's energy load is met by zero-marginal-cost generation and inflexible thermal plants (from operating constraints and take-or-pay gas contracts).

The search for flexibility from supply, demand, and transmission resources and the cost-efficient coordination of multiple conflicting water uses will be fundamental to allow the integration of VRE with minimum curtailment. However, more advanced market designs and a regulatory framework that can appropriately reward flexibility providers are needed to unlock such a future.

Germany still has significant transmission constraints because grid upgrades are far behind schedule. This leads to significant redispatch and curtailment costs. While the redispatch costs decreased in the first three quarters of 2020 (to €227 million), the curtailment of renewable power plants in the same period increased to 4,800 GWh, which caused compensation payments of around €580 million. It is expected that the ongoing transmission upgrades will reduce curtailment in the future.

Denmark has coped with high shares of wind energy with minimal curtailment so far, but in 2020, wind was downregulated by 1.46 TWh, or 9% of the potential wind production, in the Energinet area. Only 2% of this was curtailed due to congestion in the Danish grid: 92% was due to "special downregulation" caused by congestion in the German grid and a cross-border agreement, and 6% was downregulated by owners during negative spot prices as normal market behavior. Curtailment and negative spot prices have been rather stable over recent years, while the special downregulation has constantly increased.

In ERCOT, wind curtailment is increasing due to an increasing number of stability constraints. Real-time transient stability assessment tools that are currently being implemented may help to manage constraints more efficiently. Frequently updated forecasts, 5-min real-time dispatch, the flexibility of the existing thermal generation fleet, and existing ancillary services are helping ERCOT address its current flexibility needs.

However, growing solar capacity brings challenges. The highest net load ramp rates in 2030 could be three or four times higher than those in 2019. These ramps are projected to occur in the morning and evening, corresponding to the diurnal patterns of both solar generation and aggregate customer demand.

Congestion on the Transmission System

Transmission expansion is a key enabler for VRE growth. It delivers resources to loads, provides diversity of loads and resources, and increases economic system operations.

ERCOT is evaluating the reliability and economic benefits of transmission reinforcements and other solutions that would increase existing transmission capabilities to their thermal ratings. In 2018, the transmission limit on the Panhandle Generic Transmission Constraint (GTC) was increased by adding two new synchronous condensers to improve system strength and voltage support in the Texas Panhandle area. The current study is looking at economic transmission improvements for the West Texas GTC, a constraint on the transmission corridor between West Texas and the rest of the grid.

In Japan, transmission and distribution lines are congested with variable power flows from remote renewable generation plants, often located in areas with inexpensive land. A cost–benefit analysis of network expansion by the transmission system operator shows positive benefits. A good example is the expansion of the Tohoku 500-kV network in the northern part of the main island of Japan to deploy more than 4 GW of renewable resources.

The Organization for Cross-regional Coordination of Transmission Operators is studying transmission expansion in Japan to accommodate increases in renewable energy generation, including significant offshore wind. Previously, the amount of transmission (operating line) capacity allocated to support new generation was estimated in a simple but conservative way.

New generation was not allowed to connect if the sum of the maximum possible output of existing generators and capacity for emergencies was already at the maximum transmission line capacity (Figure 6). Recently, a revised connect-and-manage process has been implemented to make better use of existing line capacity to accommodate new generation without transmission expansion.

In step 1 of this new process, the sum of the allowed generation capacity is evaluated probabilistically, reflecting actual variation in generation. The maximum allowed capacity is set to the maximum expected generation from simultaneously operating the generators connected.

In step 2, the capacity for emergency use is reduced with the condition of instantaneous generation tripping under an N-1 contingency. In step 3, operational measures are included in cases where the sum of the generation is exceeding the limits—by redispatch of generation, including curtailment of VRE, when necessary.

The new connection application began in January 2021 for the two highest-voltage lines (500 and 275 kV). Currently, applications for 154/66 kV are planned for demonstration and then the 6.6-kV distribution networks, including the utilization of demand-side flexibility.

In Europe, the high targets for offshore wind (300 GW by 2050) lead to a need for new transmission capacity both offshore and onshore. The European Network of Transmission System Operators is requested to deliver offshore development plans for each sea basin by 2023, based on the offshore generation capacities and locations reported in the member states' joint maritime spatial planning process. By 2050, investments of about €800 billion for large-scale offshore deployment are estimated, two thirds of which are for offshore infrastructure. European Network of Transmission System Operators expects additional needs for massive investments in the onshore networks together with stepwise growth of sector integration solutions.

Brazil's vast area, spanning nearly an entire continent, makes transmission a key flexibility enabler to take advantage of portfolio effects due to the complementarity of the multiple weather patterns for solar, wind, and hydro production. While new transmission links have been planned for flexibility reasons since 2017, the growth of distributed generation has made defining transmission investment needs more challenging.

New Operating Constraints in System Operation

Increased penetrations of distributed PVs impact bulk power system reliability. New operating constraints, combined with new planning processes, may be needed to mitigate these impacts.

In South Australia, increased distributed solar PVs are eroding the effectiveness of underfrequency load shedding (UFLS). Some "blocks of load" are now net generators during high-PV periods, meaning activation of UFLS would exacerbate, not correct, the frequency disturbance. In response, new operating limits are imposed during import conditions that could result in an underfrequency condition exceeding the capability of the UFLS system.

Scenarios like this can occur during a sudden loss of the ac interconnection between South Australia and the rest of the National Electricity Market. Such scenarios are, fortunately, relatively uncommon, as high-PV-generation periods often correlate with export from South Australia across the ac interconnection. The Australian Energy Market Operator has also established data feeds from the local distribution network operator to allow the real-time monitoring of available UFLS load blocks.

An important factor when assessing system operating limits in South Australia is the loss of distributed PV capacity following voltage disturbances. New dynamic load models for system studies, which can model the observed disconnection behavior of distributed PVs following voltage disturbances, have been developed.

To help manage minimum-demand events, arrangements with the South Australian distribution network operator have been made for the curtailment of larger distributed PV installations as well as newly installed residential PV systems. Aggregations of residential-scale battery energy-storage systems, developed as virtual power plants, helped during the record minimum-demand period in October 2020. These virtual power plants were estimated to have increased regional demand by around 5 MW via orchestrated charging of the underlying residential battery energy-storage systems.

Increasing Stability Constraints

Inverter-based resources (IBRs) do not contribute to system inertia, which can lead to transient, small signal, control, and frequency stability impacts, depending on real-time system conditions. In ERCOT, the GTC has been adapted as a tool to dispatch the system within stability limitations in real-time operations.

ERCOT has seen an increase in stability constraints in recent years, particularly in western and southern Texas

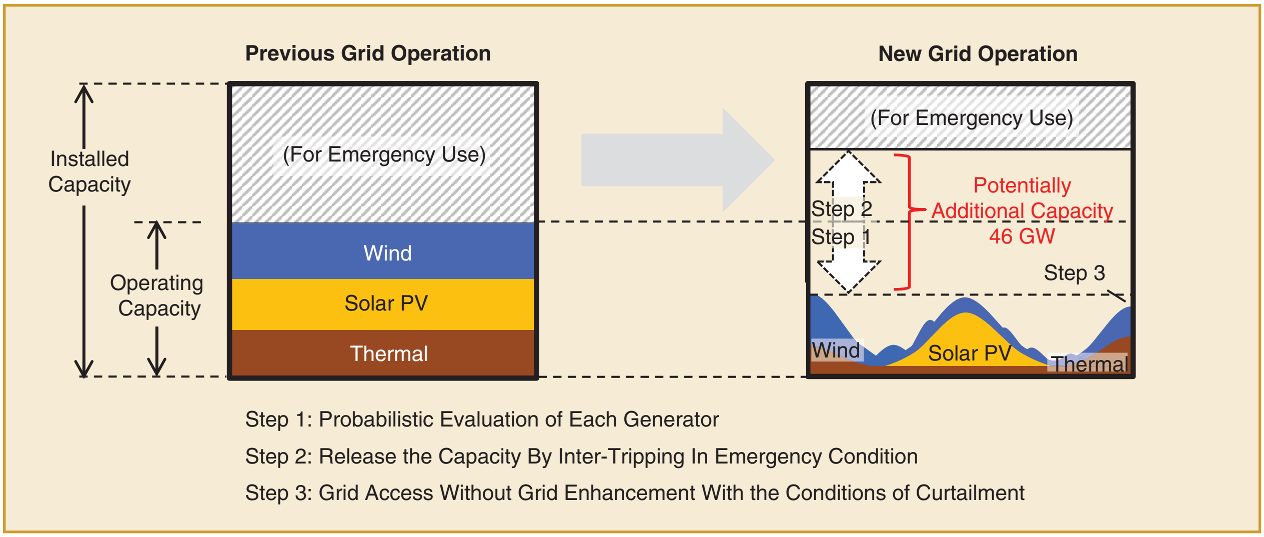

figure 6. The line capacity allocation in Japan before and after the connect and manage process. Step 1 is the probabilistic evaluation of each generator. In step 2, the capacity reserved for emergencies is released by including only the N-1 contingency. In step 3, operational practices are used to ensure the generation does not exceed limits, including curtailment (Source: Ministry of Economy, Trade, and Industry.)

> ERCOT has seen an increase in stability constraints in recent years, particularly in western and southern Texas where much of the wind and solar growth is concentrated.

where much of the wind and solar growth is concentrated. These stability constraints can limit power transfers below the physical thermal ratings of the individual transmission lines. Stability limits for the GTCs are determined based on offline studies.

ERCOT is currently in the process of implementing real-time transient stability assessments to identify and manage stability constraints more efficiently. This implementation requires accurate modeling of IBR controls in simulation applications; the development of these models has delayed the implementation.

ERCOT defined the *critical minimum inertia* with existing frequency control practices to be 100 GWs. Over the past eight years, the system minimum inertia had been fairly steady at about 128 GWs despite 20 GW of wind generation added to the system. This was due to load growth and the inertial contribution of nuclear units and industrial generation. However, the recent lowest inertia condition of 109 GWs in March 2021 may indicate a change in commitment patterns.

For the Australian National Electricity Market, minimum inertia limits have been established to maintain synchronous inertia to control the frequency if any region was to become islanded. In South Australia, energy market intervention is frequently required to ensure a minimum commitment of synchronous generating units to maintain adequate system strength and allow stable system operation. There are currently no large synchronous condensers available in this system. However, the installation of four such condensers by the regional transmission operator during 2021 is expected to reduce the need for these market interventions.

For smaller island systems, like Ireland and Tasmania, operation at high levels of IBR penetration requires careful real-time monitoring and management of inertia, fault levels, and frequency response reserves. System requirements are identified through the use of well-validated system models. Reduction in transient stability margins, controllable reactive power resources, and voltage-dip-induced frequency dips add to operational challenges.

The latest additions to wind generation in Tasmania during 2020 mean installed wind plus HVdc import capability may theoretically meet the entire demand, putting further downward pressure on the synchronous generation commitment and system inertia. Tasmania's mitigation for low-inertia operation includes the following:

- ✔ There is significant use of contracted switched load interruption for the provision of primary frequency response reserves. A minimum requirement for proportional-type governor response reserves has also been established to manage frequency overshoot following smaller generation-loss events that trigger switched load interruption.
- ✔ Many hydropower units are capable of operating in synchronous condenser mode. One larger hydro unit is capable of operation in tailwater depression mode, allowing rapid transition from synchronous condenser to generation mode to respond to underfrequency events.
- ✔ Tasmania allows a 2-Hz fall in frequency before UFLS commences (compared to 1 Hz on the Australian mainland). Key protection and control systems in Tasmania are designed to tolerate a rate of change of frequency (RoCoF) in excess of 1 Hz/s. If RoCoF were to exceed this level, early UFLS blocks are designed to drop off at a higher frequency setting.

In Tasmania, it was found that an even more operationally onerous requirement than maintaining minimum levels of system inertia is maintaining minimum fault levels. Managing fault levels at key transmission busses is a real-time requirement, with minimum fault levels identified through system studies considering the stable postfault response from wind generation and the HVdc link. Hydro units are committed in synchronous condenser mode, via commercial arrangements, where required to maintain these fault levels.

In Ireland and Northern Ireland, operational constraints due to stability have traditionally meant that a minimum of eight large synchronous machines needs to be committed at all times. Now, to accommodate increasing amounts of nonsynchronous renewable generation, this constraint must be relaxed. New control center decision-support tools to help manage this situation include the following:

- ✔ The online security assessment has been enhanced with a new look-ahead security assessment tool to identify potential instabilities. This enables timely implementation of the required changes to the initial market schedules to meet the operational security criteria.
- ✔ A voltage trajectory tool is being developed to provide guidance to control center operators on the best methods of managing system voltage. It will determine optimal reactive targets for different types of devices and deliver voltage trajectory plans that are secure against contingency events for near time horizons

Reduction in transient stability margins, controllable reactive power resources, and voltage-dip-induced frequency dips add to operational challenges.

(typically, intraday and day ahead). Voltage management has become more challenging due to the reduction of available reactive power resources. This is the result of the displacement of conventional plants and dispersed location of wind farms with different capability characteristics, combined with the increasing installation of high-voltage cables.

Need for a New Suite of Reliability Services

An alternative to the out-of-market commitment of synchronous generators to provide reliability services is to develop new market products for these services that market participants can competitively provide. The increasing levels of VRE create a need for both new/modified reliability services and VRE to help provide the services.

In Ireland and Northern Ireland, a suite of system services was developed to encourage investment in service provision capability and help to mitigate technical scarcities associated with operating the transmission system up to 75% SNSP. Seven new services were introduced: three ramping margin (RM) services (RM1, RM3, and RM8) over various time horizons out to 16 h; the fast frequency response (FFR) and synchronous inertial response, devised to address frequency stability by mitigating the RoCoF; and the dynamic reactive response and fast postfault active power recovery services to respond to voltage disturbances. A qualification system is in place to procure a total of 14 services altogether.

To date, all except the dynamic reactive response and fast postfault active power recovery have been procured by EirGrid and SONI. A key trend observed is that each procurement round results in an increased percentage of overall system service capability provided by nonsynchronous technologies.

Being an electrical island system, ERCOT requires all generators, including VRE generation resources, to provide primary frequency response with 17-mHz deadband and 5% droop. The capability has to be enabled whenever a resource is online, but the capacity reservation for the provision of the primary frequency response is not required unless a plant is providing ancillary services.

ERCOT introduced the FFR as a part of the frequency containment reserve. FFR resources should respond within 0.25 s to a frequency trigger of 59.85 Hz and sustain for at least 15 min. The first-phase system changes for the FFR were implemented in 2020, and more comprehensive upgrades were to be completed before June 2021. A new ERCOT contingency reserve service, a 10-min ramping product, will be implemented in 2024 to restore the fast-acting responsive reserve and help maintain system balance if needed.

The FFR was also introduced in the Nordic power system in 2020. In Denmark, Energinet focused on providing market-based solutions to support reliability via increased flexibility, providing appropriate incentives to deliver the needed balancing or ancillary services. The actions foreseen or already implemented are 1) flexible settlement, with electricity meters delivering hourly data; 2) the implementation of an aggregator role in the market; 3) demand flexibility; 4) increased price caps; and 5) market coupling of reserve markets.

In China, several new requirements to the technical capability of wind and solar power plants were added to the new *Guide on Security and Stability for Power System*'s added requirements to the technical capability of wind and solar power plants, e.g., the ability to provide inertia and primary frequency control. The electricity market in China is still under development, with eight spot electricity market pilots ongoing. VRE participation in the spot market is encouraged and expected to become the trend of the future.

Resource Adequacy Becomes More Challenging

Increasing levels of VRE fundamentally change the resource adequacy challenge of how we plan and meet the security of the supply. As shown in the statistics for wind/solar and electric load in China, during the summer and winter high-electric-demand periods, the output of VRE is generally below 15% of its capacity for 60% of the time. During the cold wave in Hunan Province in the winter of 2020, the electric load was historically high due to heating loads, while more than 80% of wind turbines were frozen and unable to serve the grid. The output of wind was less than 2% of its capacity, contributing little to resource adequacy.

After 2025, Denmark expects more challenging resource adequacy situations and related increases in electricity prices. The means to address adequacy issues include market-based solutions offering long-term flexibility, massive installations of renewable resources, and investments in the electricity network and interconnections. The decarbonization of other sectors is expected to increase electricity demand significantly. However, the pathway of how to reach the country's 2030 70% greenhouse gas reduction target has not been decided yet.

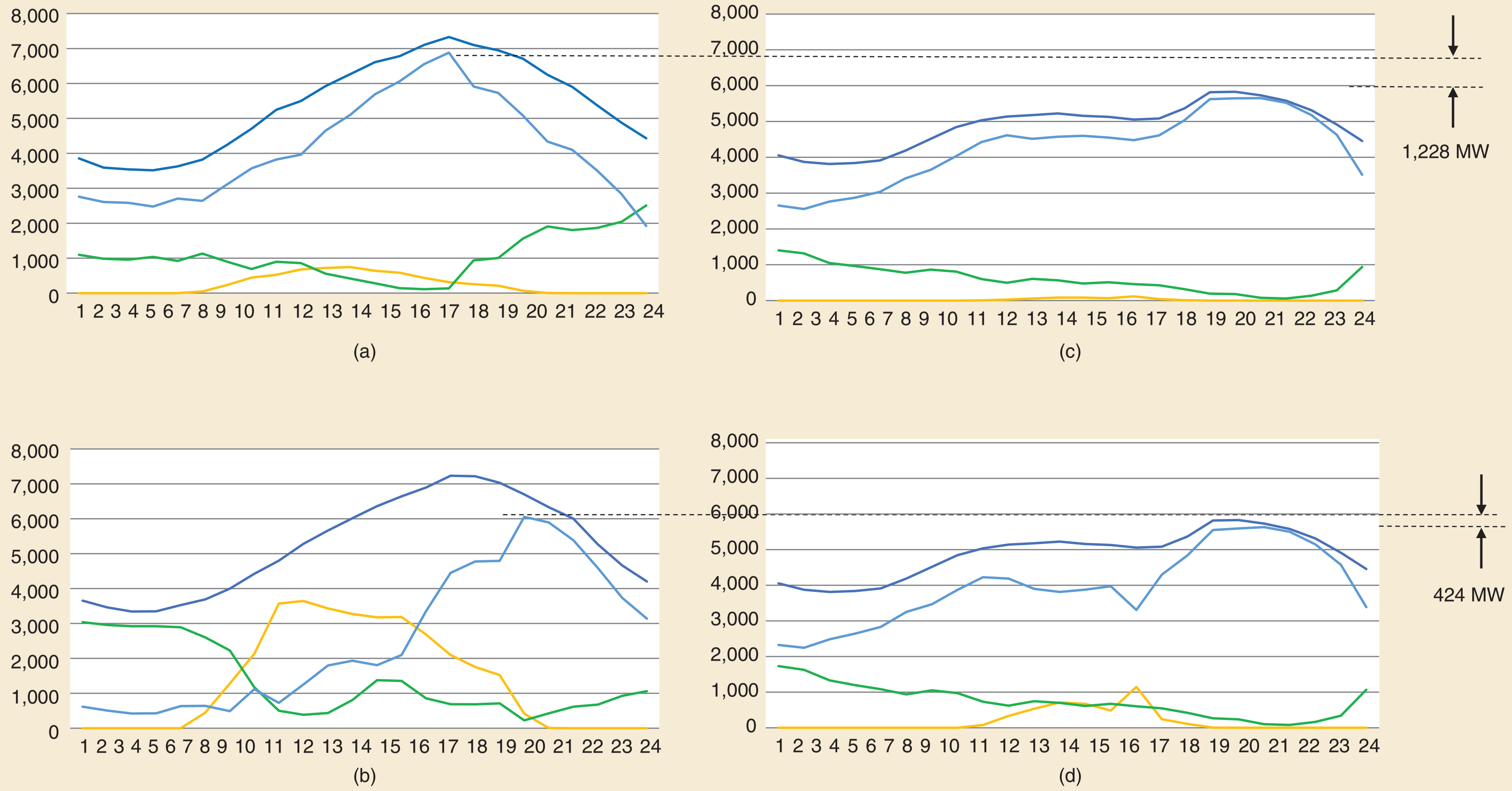

figure 7. The capacity overhang: summer and winter peak days in (a) 2021 and (b) 2030 show the increasing importance of the winter peak days in (c) 2021 and (d) 2030. For summer peaks 19 July and 18 July were used (profile year 2019 for load and 2014 for renewable energy) and winter peaks 30 December was used (profile year 2014 for both load and renewable energy. The trend lines represent customer demand (blue), wind (green), solar energy (yellow), and the resulting net load profile (violet). The years in brackets show the profile years. The expected installed capacity in 2021 includes 1 GW of solar and 4.1 GW of wind capacity, and, in 2030, it involves more than 4.5 GW of solar and 5 GW of wind capacity.

In Colorado, a winter (nonpeak season) reliability concern has emerged. What is currently a summer-peaking system is projected to change significantly in the next 10 years. In 2021, the summer net load peak occurs during hours of high solar production. The spread between summer and winter net load peaks is more than 1,200 MW (Figure 7), signaling a significant capacity overhang.

The difference between the summer peak resource need and rest of the year means that, in 2021, planning to a summer peak load provides enough capacity to cover the entirety of the year. With solar energy being built largely to serve a summer peak, the winter reliability event grows in importance.

In 2030, the summer net peak load has shifted later in the day after solar energy has dissipated, while the nature of the winter peak is unchanged. Solar energy is a poor performer in the winter months due to short days, and, while wind energy is stronger, on average, in the winter than summer, there are days when wind energy is nearly nonexistent.

This foretells a new critical scenario—the winter doldrums. The 2030 summer net load peak is 6,055 MW, and the winter net load peak is 5,631 MW, resulting in a capacity overhang of just more than 400 MW. Other resources not considered in this analysis could make the mismatch even worse. Public Service of Colorado's control and cycling of residential air conditioning compressors contribute 220 MW of demand flexibility available only during summer peaks, further reducing the needed capacity overhang between summer and winter. Future electrification loads, such as electrified winter heating loads, will also exacerbate winter reliability concerns.

Conclusion

The recent records in VRE shares have underscored challenges with VRE integration. The main challenges encountered for the pioneering countries and regions are summarized as follows:

- ✔ avoiding VRE curtailments
- ✔ dealing with zero or negative market prices
- ✔ reduced hydropower flexibility due to constraints on the water–energy nexus and the occurrence of transmission congestion
- ✔ ensuring frequency stability, system strength, and minimum fault levels
- ✔ addressing the long-term reliability with resource adequacy.

The ongoing and planned mitigation measures include increasing flexibility, reinforcing transmission capability, and adding new operational constraints. The need is now apparent for a new suite of reliability services and methods to assess future resource adequacy. The increasing levels of VRE create a need for both new and modified reliability services as well as VRE to help provide those services.

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For Further Reading

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