Unlocking the Potential of Distributed Energy Resources

Power system opportunities and best practices

International Energy Agency

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Abstract

Distributed energy resources (DERs) are small-scale energy resources usually situated near sites of electricity use, such as rooftop solar panels and battery storage. Their rapid expansion is transforming not only the way electricity is generated, but also how it is traded, delivered and consumed. Accordingly, DERs can create new power system opportunities, but at the same time, can pose new challenges when a grid has not been properly prepared. Many jurisdictions are just beginning to understand how DERs fit into the wider energy landscape – what they are and what impacts they have on the grid, and how they can be used to improve system reliability and reduce overall energy costs. Meanwhile, other regions have built up experience with DERs, demonstrating that they can provide valuable services to the grid when incentivised with appropriate technologies, policies and regulations. Nonetheless, not all countries use the same electricity market model or are at the same stage of DER penetration, and the fit-for-purpose solutions will vary from place to place. This report reviews lessons from forerunners and distils best practices (with examples and case studies) to help policymakers, regulators and system operators across the globe understand what experience is most relevant to their own situation. Readers will be able to draw on a wide range of practical insights for electricity market design and regulation to help unlock the multiple grid benefits of DER technologies.

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Executive summary

Distributed energy resources are creating new power system opportunities, and also challenges

Small-scale, clean installations located behind the consumer meters, such as photovoltaic panels (PV), energy storage and electric vehicles (EVs), are increasingly widespread and are already transforming our energy systems. In fact, 167 GW of distributed PV systems were installed globally between 2019 and 2021, which means their combined peak output is higher than combined peak consumption of France and Britain. In 2020, EV stock surpassed 10 million vehicles and almost 180 million heat pumps were in operation. Electrification, an essential condition for the transition to clean energy, is not only increasing power consumption, but also the quantity and variety of electrical equipment that can shift around their demand.

New, diverse technologies are helping consumers be more proactive and are prompting new players to enter power markets, such as aggregators who pool together small-scale resources and act on their owners' behalf. Electricity production and trading are thus no longer limited to large, centralised generators and retailers. What is more, electricity no longer flows in only one direction, from the grid to the consumer. Instead, consumers can produce electricity for their own consumption or can sell it on the market, creating bidirectional electricity flows. Consumers are increasingly able to take control of their own energy demand through a complex web of interactive smart energy devices.

Distributed energy resources offer multiple benefits to consumers, support decarbonisation, and improve resilience

The primary beneficiaries of DERs are the consumers who own them. Distributed PV can supply affordable electricity to households and businesses, reducing their dependence on the grid. When paired with energy storage, PV systems help shield owners from outages, such as during extreme weather events. DERs enable consumers to produce and consume electricity more in accord with their own needs and preferences. DERs can also support decarbonisation in many other ways, especially by enabling fuel switching, such as when distributed PV displaces fossil fuel-based generation, and when EVs replace internal combustion engine vehicles.

Rapid uptake of distributed energy resources can challenge electricity grids that are unprepared

Many of today's grids were designed for the 20th-century, when the share of DERs was small. Now that a growing portion of electricity is produced by variable renewables, greater system flexibility is needed to consistently balance supply and demand, whether over short timescales or seasons.

Electrification, for instance, replacing gas boilers with heat pumps, can cause higher evening peak loads. Potential issues are not limited to changes in timing of demand; energy exported from distributed PV can increase local voltage levels, posing new challenges for grid stability. Although reinforcing the power grid can remedy these problems, it can be more cost-effective to incentivise consumers to preheat buildings when solar generation is abundant to shift heat pump loads away from evening peak hours.

Some DERs are technically capable of mitigating the challenges they themselves or other resources create. For example, battery storage systems can provide system flexibility, and smart EV charging systems can shift charging loads to reduce the evening peak demand. Unfortunately, many regulators and system operators have neither sufficient information on DERs nor adequate distribution grid monitoring equipment to take advantage of such capabilities. This lack of visibility can leave them unaware of the advantages to be gained by incentivising DER owners to align their equipment use and location with needs of the grid.

Digitalisation can transform distributed energy resources into valuable grid assets when the right incentives are in place

Digital technologies such as network monitoring devices and smart meters can improve visibility for distribution grids. Advanced inverters can enable consumers to monitor, programme and remotely control the power output of their distributed PV systems. Meanwhile, digital management systems can support aggregation of individual DERs and provide diverse services to multiple stakeholders all along the electricity supply chain. In these ways, digitalisation can help regulators and system operators adjust electricity prices and regulations to encourage consumers and aggregators to install and operate DERs in line with grid needs.

Five technologies and solutions, each with its advantages and limitations, are particularly promising:

- Battery storage systems can provide a range of services to the grid, such as storing energy during excess renewable generation periods and discharging it during peak demand. Their main limitation is their relatively high upfront cost.

- EVs are versatile when used as mobile battery systems, though their value to the grid varies depending on charging technology and control strategy.
- Electric water storage and space heaters can provide system flexibility when equipped with low-cost control devices, though electrifying existing homes already equipped with gas services could require significant investment.
- Grid-interactive efficient buildings can optimise energy 'prosumption' (combined electricity production and consumption) while accommodating grid needs and offering a wide spectrum of grid interactivity. Employing the appropriate incentives can offer more benefits to the entire power system, as consumers would otherwise opt for combinations of technologies that best serve their own interests.
- Virtual power plants (VPPs), i.e. networks of decentralised power generating units, storage systems, and flexible demand, can optimise the aggregation of distributed resources across large areas by using advanced data analytics such as machine learning. Policy and regulatory issues, including value-stacking rules, are the main barriers to wider VPP deployment.

Electricity market and regulation transformation is needed to unlock the full potential of distributed energy resources

The majority of behind-the-meter DERs belong to consumers, and they decide whether and where to install them, and how to operate them for their own benefit. The frequent misalignment of DER owners' and system operators' interests due to the inappropriate consumer incentives may restrict the potential benefit of DERs to the grid.

To avoid such outcomes, regulators and system operators can create a level playing field where the grid contributions of DERs are appropriately valued, owners are fairly compensated, and system operators can more fully integrate DER services into the grid. Such better co-ordination would deploy financial capital and physical assets more efficiently.

DERs stand to transform the way we produce, trade, deliver and consume electricity. To unlock the full potential of these resources, many aspects of electricity market design and regulation should be re-examined and, if needed, adjusted. The following insights set out the key areas in which action would accelerate DER deployment and integration.

Insight 1: Better visibility of distribution system and consumer dynamics

One of the main obstacles in integrating DERs into power systems is a lack of sufficient visibility into low-voltage grids and behind-the-meter resources.

To better understand them, policymakers, regulators and system operators can:

- Identify data gaps and plan to remedy them to obtain fit-for-purpose levels of visibility over the sector.
- Make the most of available data sources and create robust data management systems
- Develop a single flexibility resource registry common to all market participants and explore more-granular data collection options.
- Improve short-term demand forecasting, dynamic network modelling and long-term capacity planning.

Insight 2: Reliable and flexible grid connections for behind-the-meter resources

To mitigate the challenges of incorporating DERs into the grid while scaling up their deployment, regulators and system operators can:

- Update grid codes to require that DERs such as distributed PV systems have crucial advanced inverter functions, such as voltage/frequency ride-through (that enable DERs to remain online through minor grid disturbances) and voltage regulation.
- Prepare for potential challenges from the lower operational demand and system inertia that may accompany broader use of DERs.
- Introduce flexible grid connection arrangements that reflect the impacts of each resource.

Insight 3: Markets that welcome aggregated small-scale resources

In general, increased competition and improved system efficiency can lower costs. So long as system reliability is assured, opening markets to aggregated small-scale resources can have a positive impact.

Regulators and system operators can consider:

- Allow independent aggregators to participate in all types of markets, especially balancing, ancillary services and capacity markets, informed by pilot projects to gauge benefits and risks.

- Establish the roles and responsibilities for independent aggregators, especially in compensating retailers for energy transferred through demand-response activation.
- Lower the minimum bid size of market products, shorten procurement and delivery periods, introduce two asymmetrical (upward and downward) market products and allow prequalification of aggregated resource pools to avoid discrimination against small-scale resources.
- Develop market participation models that can better assimilate emerging resources, such as battery storage and the aggregation of heterogeneous technologies including distributed PVs, EVs and smart water heaters.

Insight 4: Fair market compensation for the multiple flexibility benefits of agile technologies at the grid's edge

DERs are readily adaptable energy resources situated near sites of electricity use. This suits them well to provide flexibility along the supply chain for transmission system operators, distribution system operators, retailers and consumers.

Regulators and system operators can:

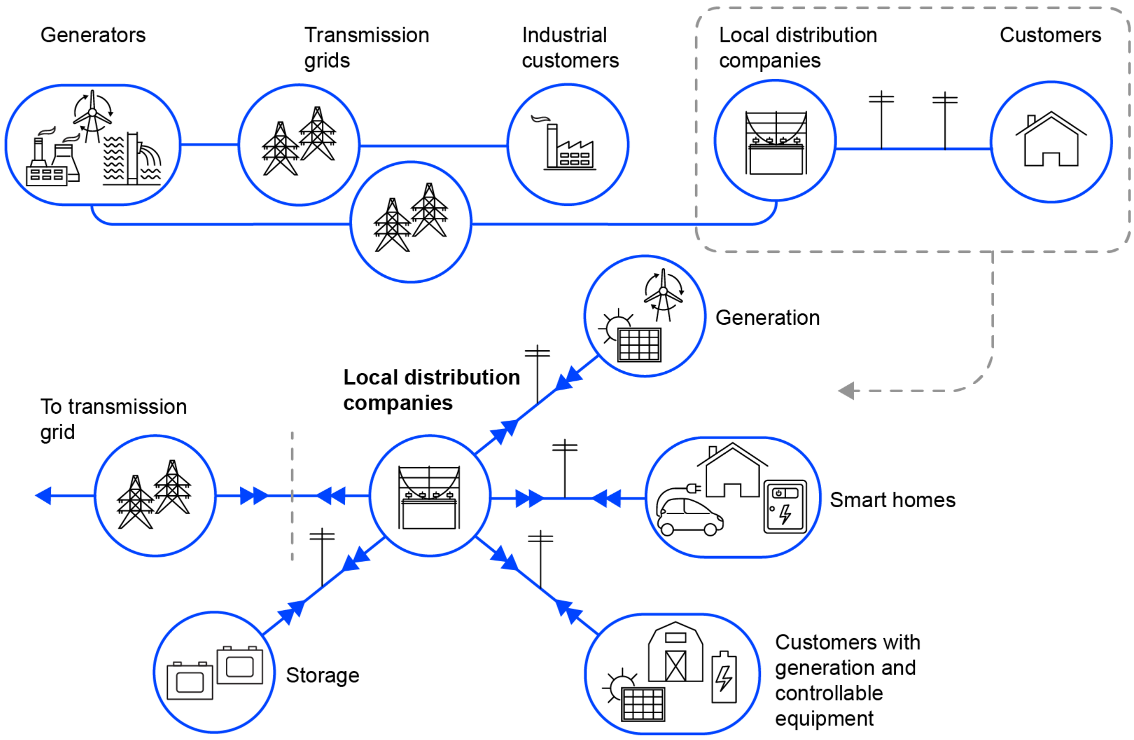
- Improve the temporal granularity of market prices by shortening settlement (or trading) periods for intraday and real-time markets.
- Improve the locational granularity of price signals, for instance through nodal pricing, flexibility marketplaces or network tariffs.
- Compensate DERs for the value of their flexible capacity, which helps ensure long-term resource adequacy for a renewables-dominant power system, for example by introducing reserve scarcity pricing complemented by a capacity remuneration mechanism.
- Establish market rules and co-ordination platforms, including between transmission and distribution system operators, that help DERs stack multiple revenue streams while maintaining grid reliability.

Chapter 1. Opportunities and challenges of distributed energy resources

Introduction

The use of distributed energy resources (DERs) is already starting to have an impact on power systems and can pose new challenges for grid reliability. However, when appropriately utilised, they can have economic, environmental and energy security benefits. DERs that do not use fossil fuels (solar PV systems, for example) can help decarbonise the energy system and are becoming an economically attractive alternative to grid-supplied electricity. Plus, DER systems such as solar-plus-storage can help shield consumers from outages resulting from extreme weather events, contributing to energy system resilience.

The power system of the past and future



Source: Adapted from IESO (2019), Exploring Expanded DER Participation in the IESO-Administered Markets.

While most regulators, energy policymakers and system operators around the globe are still at an early stage of determining how DERs fit into the wider energy landscape – what they are and how they can be used to improve power system reliability and save on energy costs – some regions (North America, Europe and Australia) have accumulated initial experience in leveraging these resources. This report reviews the lessons they have learned, introduces new opportunities for DERs and provides key insights into regulatory and policy improvements that can unlock DER potential.

This report consists of two chapters: the first defines DERs, the benefits they provide across the energy system, emerging grid reliability challenges, and the diverse grid benefits of digitally enabled DER technologies. The second introduces key electricity market design and regulation insights that can unlock the grid benefit potential of DERs, focusing on three elements: better visibility over the distribution grid and connections to it; wider market opening; and fair market compensation. This report explores two different power market models – centralised dispatch nodal pricing and self-dispatch zonal pricing – to distil useful insights for a range of jurisdictions regardless of their market model.

Energy system-wide benefits

Small-scale clean technologies are becoming increasingly widespread behind consumer meters

DERs are generally small-scale resources installed close to energy consumption sites and include various technologies: distributed PV, energy storage, electric vehicles (EVs) and smart buildings, to name just a few. There is no single definition, however, so classifications vary depending on who is using the term, for what purpose and in what context. Although several energy industry organisations offer their own particular definition, DERs are typically described as any resource connected to the distribution grid.

DER definitions by organisation

Organisation	Definition
US Federal Energy Regulatory Commission (FERC)	A DER is any resource located on the distribution system, any subsystem thereof or behind a consumer's meter. DERs may include electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.
European Commission (EC)	DERs consist of small- to medium-scale resources connected mainly to the lower voltage levels (distribution grids) of the system or near the end user. Key categories are distributed generation, energy storage and demand response.
Australian Energy Market Commission (AEMC)	DERs are devices capable of producing, storing or managing energy at homes and businesses, sometimes referred to as behind-the-meter devices. They include rooftop solar PV, energy storage, demand response, electric vehicles and energy management systems, although many of these technologies are not found exclusively behind the meter.

Sources: FERC (2020), Order No. 2222 on Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators; EC (2015), Study on the effective integration of distributed energy resources for providing flexibility to the electricity system; AEMC (2020), Distributed Energy Resources Integration-Updating Regulatory Arrangements. The definitions have been edited for language consistency purposes.

The US FERC and the EC include resources on both sides of the meter, regardless of fuel type, if connected to the distribution system. Although both their lists cover multiple types of resources such as distributed generation, energy storage and demand response, FERC explicitly considers energy efficiency a type of DER but the EC does not. Meanwhile, the AEMC pays more attention to resources located behind the meter (on the consumer side) but does not explicitly exclude those in front (on the grid side). The AEMC also includes control systems of individual devices, such as energy management systems.

DERs can generate or store energy or manage its consumption, depending on the technology type. Resources on both sides of the meter, irrespective of fuel type, impact and can benefit the power system. For example, utility-scale solar PV installations and wind farms help supply clean energy, and small diesel-fuelled generators have long been used as a backup resource. Thus, the term "distributed energy resource" can cover a wide range of technologies regardless of their location along the distribution grid and the fuel employed.

Today, however, the clean, emergent behind-the-meter devices that are driving DER expansion (e.g. distributed PV systems, EVs and heat pumps) can be likened to black boxes, as they offer little transparency to system operators. With smart non-fossil-fuel devices increasingly affecting behind-the-meter energy consumption, consumer demand is no longer individual, stable or predictable. Instead, it appears as a complex web of potentially interactive devices (e.g. distributed PV, battery storage, EVs and smart water heaters). Compared with front-of-meter DERs, it is more difficult for system operators to monitor the energy system impacts of emerging resources.

It may therefore be more challenging to unlock the potential of behind-the-meter energy resources than that of resources in front of the meter. Behind-the-meter DER systems are generally small, cannot readily participate in energy markets unless aggregated and are typically owned by consumers who operate them for their own best interests, which may not align with the grid's needs. However, as behind-the-meter DERs are at the bottom of the electricity industry supply chain, they can benefit almost every layer – from consumers all the way up to the transmission system.

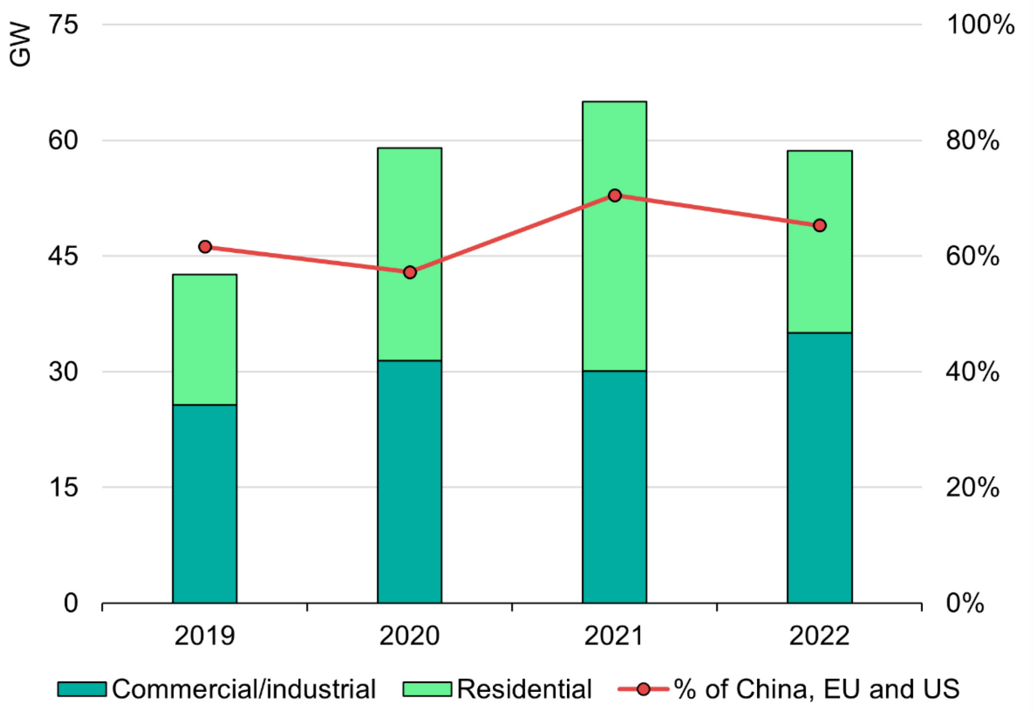
The impediments to DER success indicate that it is necessary to transition away from our current electricity markets and regulations, which were designed for large, centralised generators and retailers. It is important to establish aggregator roles and responsibilities; devise effective incentive mechanisms for consumers; and develop rules for stacking multiple revenue streams. Careful analysis is needed for behind-the-meter DERs, although many of these issues may also concern larger front-of-meter resources.

This report focuses on **clean distributed energy resources located behind the meter**, such as non-fossil-fuelled generation, energy storage, demand response and energy efficiency, including control systems that co-ordinate individual devices. It is crucial to consider the operational characteristics of all technology types: for example, some technologies (such as EVs) are dispatchable,[1] making it possible to address grid reliability issues in near real time, while the output of variable DERs (such as distributed PVs) must be forecast in advance to identify their potential impact on the grid. Meanwhile, energy-efficient devices such as heat pumps are not dispatchable without smart controls, but they can provide sustainable energy savings. Hence, this report covers a range of technologies to explore both their short- and long-term power system impacts and benefits.

Distributed PVs, EVs and heat pumps make up recent growth

Distributed PVs, EVs and heat pumps account for much of the recent DER expansion in some jurisdictions. The IEA estimates that 167 GW of distributed PV were added globally from 2019 to 2021: 87 GW of commercial/industrial projects and 80 GW of residential installations, with almost 64% of the new capacity being installed in China, Europe and the United States. This trend is expected to be sustained in 2022, with 59 GW of new distributed PV capacity additions globally – 65% of it again installed in China, Europe and the United States.

Annual distributed PV capacity additions, 2019-2022



Source: Adapted from IEA (2021), Renewable Energy Market Update 2021.

[1] A resource is dispatchable when its energy production or consumption can be adjusted according to a system operator's near-real-time signals.

According to IEA analysis, global EV stock tripled from 2017 to reach more than 10 million in 2020, following a decade of rapid growth. Electric car registrations increased 41% in 2020, despite the 16% pandemic-related worldwide downturn in car sales. Registrations also rose for electric buses (to 600 000 globally) and trucks (31 000). At the end of 2020, almost 80% of the EVs on the roads were in China, Europe and the United States. Accordingly, EV charging infrastructure continues to expand. There were about 7.3 million chargers worldwide in 2019, of which 6.5 million were private, light-duty vehicle slow chargers in homes, multi-dwelling buildings and workplaces. China and the United States had ~61% of the world's installed private chargers at the end of 2019.

Other resources also contribute to DER growth. The IEA estimates that almost 180 million heat pumps were used for heating in 2020, as the global stock had increased nearly 10% per year in the previous five years. Although heat pump expansion is evident across all major heating markets – North America, Europe and Northern Asia – there is still considerable growth potential, as the technology currently meets only 7% of heating demand for buildings globally. Behind-the-meter battery storage also showed exponential growth in recent years, though total global installed capacity is not large at 7.0 GW in 2020 – a ten-fold increase from 0.6 GW in 2015, with China and the United States leading recent new capacity additions. All these trends are expected to spread to more countries in upcoming years.

DERs offer consumers multiple benefits, driving decarbonisation and improving resilience

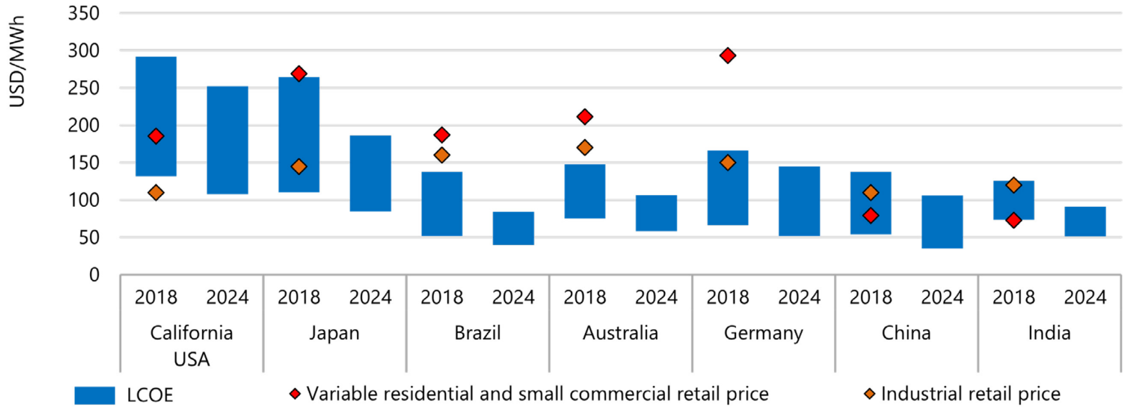
Recent DER growth stems mainly from government energy system decarbonisation policies. DERs support decarbonisation in many ways, especially by promoting fuel switching. For example, distributed PVs can displace electricity generation from fossil fuels, and EVs replace internal combustion engine vehicles for transportation. As the scale of renewable electricity supply grows, EVs and other electrification solutions can extend its use to new sectors. Energy efficiency improvements through the rollout of new technologies also play a key role in decarbonising the energy system.

Annual solar PV capacity additions are expected to more than quadruple from 134 GW in 2020 to 630 GW by 2030, with nearly 100 million households equipped with distributed PV panels by the end of this decade. Battery electric, plug-in hybrid and fuel cell electric light-duty vehicles on the world's roads would grow by a factor of 32 to reach 350 million in 2030 (up from 11 million in 2020), and a rapid rise in the number of electric two/three-wheelers (to reach 600 million in 2030) and electric buses (to reach 8 million) is also anticipated. Thus, EVs would account for 20% of all passenger cars, 54% of two/three-wheelers, 23% of buses, 22% of vans and 8% of heavy trucks in 2030, causing annual battery demand for EVs to rise significantly from only 0.16 TWh in 2020 to 6.6 TWh in 2030.

Furthermore, some 600 million heat pumps would provide heating by 2030 under the Net Zero Scenario, up from 180 million in 2020. Accordingly, the share of heating demand met by heat pumps increases from 7% in 2020 to 20% by the end of this decade. Meanwhile, global energy intensity falls ~4.2% annually as energy consumption to heat and cool new buildings drops almost 50% by 2030. Appliances also show a nearly 25% energy efficiency improvement by the end of the decade.

As the first beneficiaries of the multiple advantages of DERs are the consumers who own them, consumer willingness to adopt these resources is another major reason for their recent success. DERs such as distributed PV systems can supply more affordable energy to consumers, helping them use less electricity from the grid or from other fossil fuel-based sources. Lower energy bills clearly benefit consumers, though savings depend on electricity market design and regulation, including retail tariff structures. For example, distributed PV currently supplies more affordable energy than the grid does in many regions, as the figure below illustrates. In fact, the levelised cost of electricity (LCOE) of distributed PV has fallen 40-70% since 2010, depending on the country, and reductions are expected to continue. Accordingly, it is anticipated that distributed PV generation costs comparable to today's electricity prices, not only in most developed countries but also in an increasing number of emerging and developing economies.

LCOE for distributed PV systems and variable retail electricity prices, 2018/19



Source: IEA (2019), Renewables 2019.

Not only do DERs have the potential to make the energy system more efficient: they can also reduce overall energy consumption. When power production exceeds demand, EV charging and battery storage systems can store energy from both the grid and distributed generation for later use, while energy-efficient technologies such as heat pumps can help consumers reduce their energy requirements. Heat pumps are highly efficient producers of heating and cooling per unit of energy input, particularly compared with fossil fuel-based production.

For some consumers, the desire to become less reliant on the power grid – to be able to manage their own energy use or generate their own electricity – leads them to DERs. Some consumers may also value the option of producing cleaner energy than the grid can provide. EVs, for example, can economically supplant or supplement internal combustion engine vehicles, reducing the need for fossil fuels. Essentially, DERs can provide consumers with their own choice of energy system: they can choose how to produce and consume their energy according to their specific needs and preferences.

DERs can help shield consumers from the impact of climate hazards

Power systems are facing more frequent extreme weather events such as heatwaves, cold snaps, storms and flooding, mainly resulting from climate change. In February 2021, for example, a severe cold weather event in the US state of Texas caused numerous power plant outages, deratings and start failures. As a result of the 20 000-MW rolling blackout the system operator Electric Reliability Council of Texas (ERCOT) ordered to prevent grid collapse, more than 4.5 million people in the state lost power for as long as four days, causing numerous deaths. Extreme precipitation is another threat to power systems. In July 2021, heavy rainfall caused severe flooding in Germany and cut electricity to 200 000 households.

These disruptions due to climate hazards are likely to become more frequent and intense, though the Intergovernmental Panel on Climate Change (IPCC) expects that impacts may vary considerably between countries and regions. In June 2021, the IEA released a Climate Resilience Policy Indicator report in an effort to assess the climate resilience of countries by comparing their climate hazard level with their policy preparedness. The report shows that India, Mexico and China are ranked high in terms of aggregated level of climate hazard, and another nine countries, including Australia, Hungary and Indonesia, are ranked medium-high. This means 53% of the world's population is exposed to high to medium-high levels of climate hazard.

As the capabilities and costs of clean DERs are improving rapidly, they are increasingly regarded as realistic options to strengthen power system resilience. In recent years, the combination of distributed PV, battery storage and microgrids developed as an alternative to diesel backup generation. Together, these technologies can provide islanding capability, disconnect customers from the grid when it fails due to extreme weather events, and provide their owners an uninterrupted supply of electricity. Thus, critical facilities such as army bases, hospitals and government buildings are increasingly installing clean DERs to guard against climate hazards. For example, the United States Army views clean DERs as supplements or alternatives to diesel generators for resilience; for this reason, nearly 20 US army bases have or are developing onsite renewable generation combined with energy storage or microgrids.

It is important to note that energy efficiency is a crucial but often overlooked component of resilience. In many cases, it is challenging and costly to build a DER microgrid that has sufficient electricity generation and storage capacity to endure multiday grid outages. Energy efficiency can extend islanding capacity by making critical loads as efficient as possible. Recently, a distribution network operator in Great Britain launched a Resilience-as-a-Service (RaaS) trial. The project plans to procure DER services (such as battery storage) to restore power supplies in the event of a fault in remote or rural networks, which are currently served by diesel generators.

Impact on grid reliability

Rapid DER uptake is posing new challenges for 20th-century grids

Historically, electricity has been produced mainly by large, centralised generators connected to transmission grids and has flowed to consumers in one direction only. Power demand was stable and price-inelastic, apart from that of large industrial factories and commercial buildings. The primary risks for system operators were large generator and network failures, so transmission systems were built smart, equipped with digital technologies such as supervisory control and data acquisition (SCADA) systems to monitor large power plants and grids in real time. There was limited incentive to understand small-scale consumer demand patterns, and automation of the distribution grid was costly and complex due to its size. Thus, distribution companies neither recognised much value in digitalising their grids nor had the financial capacity to do so.

Accordingly, distribution grid management has generally followed the “fit and forget” approach: rather than being proactively managed, networks were usually reinforced enough to accommodate peak loads. Many of the distribution grids we are still using today were thus built to accommodate 20th-century power systems and practices. For example, in 2015, 70% of power transformers in the United States were at least 25 years old; 70% of transmission lines were at least 25 years old; and 60% of circuit breakers were 30 years old. This is also the case for the European Union, where 35-40% of low-voltage power lines were 20 to 40 years old in 2020, and 25-35% of them were more than 40 years old.

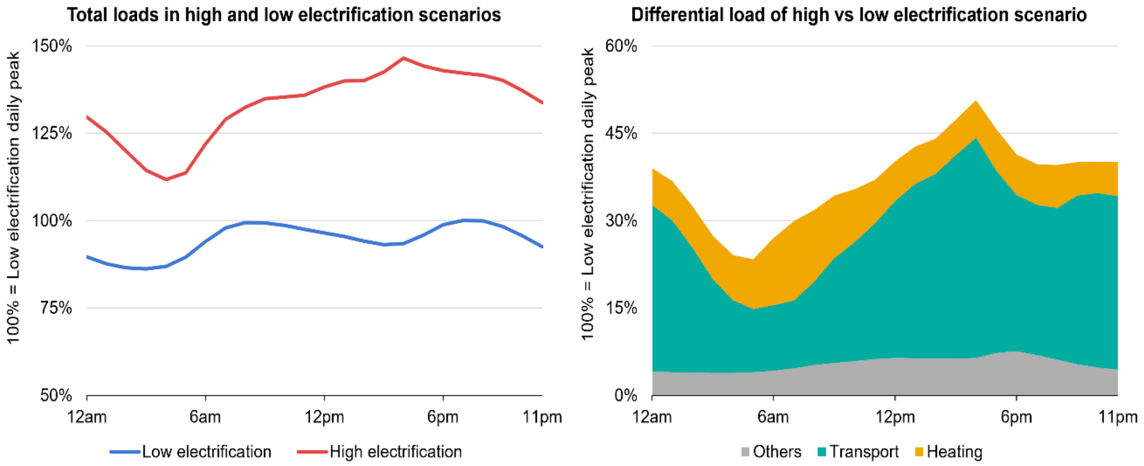
Power systems are changing, however. A growing share of electricity is produced from variable, weather-dependent renewable energy sources, and this trend has introduced the need for flexibility in our power systems. Flexibility is a power system’s ability to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales, from ensuring instantaneous stability of the power system to supporting long-term security of supply. For instance, system operators need to manage the sudden seconds-to-minutes spikes in power demand when, for example, clouds interrupt solar PV power generation. They also need backup resources to prepare for the hourly increases in net consumer load when, for example, distributed PV cannot meet evening demand after sunset. In addition, they need to address seasonal differences in generation from solar PV and wind resources. In the IEA’s Net Zero

Scenario, global average system flexibility needs[2] quadruple from 2020 to 2050, mainly due to rising shares of variable wind and solar PV in electricity generation.

Electrification of end-use devices can place an additional burden on the grid. EVs and heat pumps, the main equipment being electrified, can significantly impact the power system. For instance, many consumers follow similar daily routines, such as returning home from office jobs around the same time in the evening. When vast numbers of commuters plug in their EVs to charge and switch on their electric heat pumps, power demand can spike and put pressure on the grid.

A cost-benefit analysis of EV deployment in New York revealed that around USD 2.3 billion more would be required between 2017 and 2030 to cover grid upgrades and generation costs to implement state-wide EV charging, unless electricity demand can be smoothed by shifting some peak demand to off-peak hours. Likewise, a recent study showed that if Europe were to replace all its fossil fuel-burning boilers with electric heat pumps overnight, its final electricity consumption would increase 526 TWh. Winter peak demand in Europe would be 20-70% higher than it is today, depending on the country, with an average of 41%.

Impact of unmanaged transport and heating electrification on daily winter load in the United States, 2050



Source: Adapted from NREL (2019), Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States.

The bidirectional power flows created by distributed energy generators can also be a challenge for distribution networks. For instance, when power flows from a consumer-owned distributed PV system to a grid that is not ready for it, local

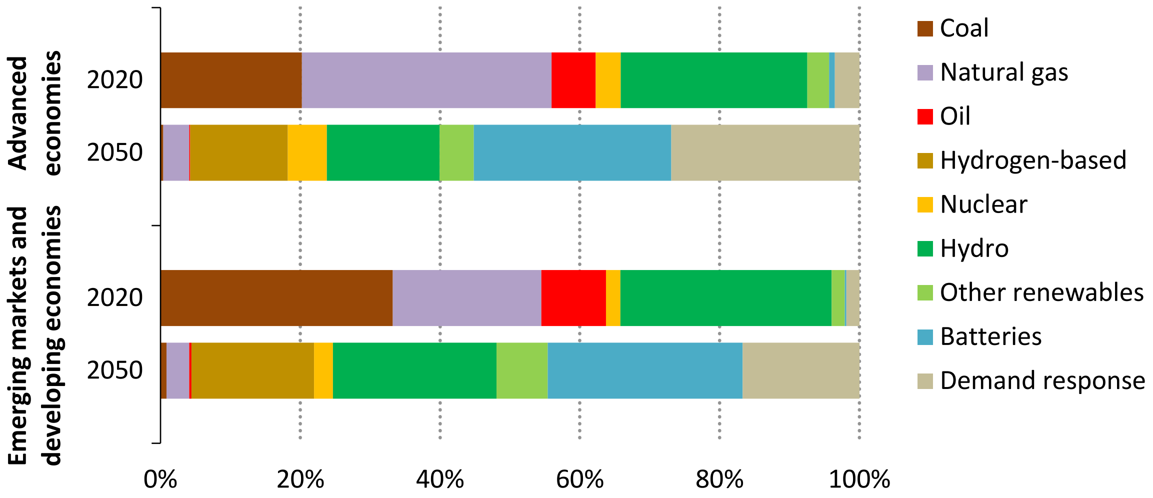
[2] Flexibility needs are measured as hour-to-hour ramping requirements after removing wind and solar PV production from electricity demand, divided by the average for the year.

voltage issues may ensue. Distribution networks were typically built to accommodate gradually falling voltages, with power flowing in one direction from substation to customer, and substation voltage being stepped up to prevent it from dropping below the lower limit after traversing a long power line. Consumer-owned distributed PV installations, however, can raise local voltage by exporting energy to the grid from any location, in any amount and at any time. Thus, high penetrations of consumer-sited distributed PV generation can compromise a grid network's operational reliability.

The right technologies and incentives can convert distributed energy resources into grid assets

DERs encompass a variety of technologies having different operational and economic features. For example, battery storage systems, which are technically capable of addressing any grid challenge, are central in providing system flexibility in 2050 the IEA's Net Zero Scenario, meeting 28.3% of flexibility needs in advanced economies and 27.9% in emerging ones,[3] up from 0.8% and 0.2% in 2020 (coal- and gas-fired power plants were still the main flexibility sources in 2020). As the global energy system decarbonises and the traditional flexibility providers (i.e. large fossil fuel-based generators) are phased out, alternative options such as DERs are increasingly needed.

Power system flexibility by source in the IEA's Net Zero Scenario



Source: IEA (2021), Net Zero by 2050: A Roadmap for the Global Energy Sector.

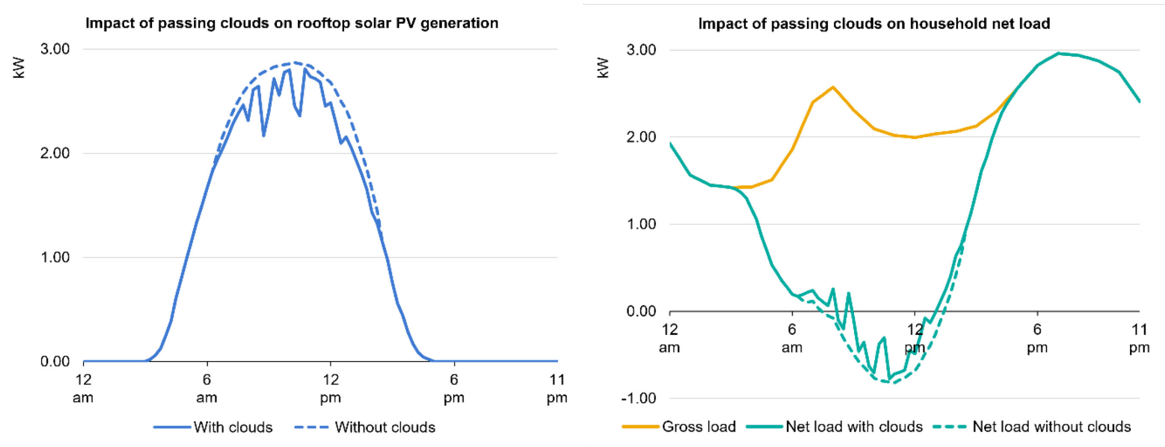
[3] Battery storage in this scenario includes both utility-scale and behind-the-meter resources

Although DERs such as EVs can raise peak loads, they can also be used to address the challenges they themselves present to the grid. While grid reinforcement can certainly remedy some problems, this fit-and-forget approach can sometimes require costly investments and thus lead to high energy bills for consumers. Plus, even though network activity can be high in the evening when EVs are drawing substantial energy from the grid, extra power line capacity added as part of grid reinforcement may remain idle during the rest of the day. Accordingly, it can be more cost-effective to incentivise EV owners to shift charging to off-peak hours than to add capacity to the grid.

Regulators and system operators can help ensure fair competition between DERs and traditional solutions such as grid reinforcement by opting to incentivise grid-aligned DER operations if they are cost-effective. Nevertheless, cost-effective investment in grid infrastructure is also essential to accommodate energy injections and demand from newly added clean technologies such as distributed PV systems and heat pumps.

The primary obstacle for regulators and system operators in making practical, cost-effective decisions, however, is their lack of adequate visibility over the behind-the-meter resources and the distribution grid. Only some static data, such as the location and power capacity of distributed PV systems, are collected through retail market programmes such as net energy metering, and many low-voltage grids are typically not equipped with network monitoring equipment.

Impact of passing clouds on distributed PV generation and on household net load



Source: Data from EPRI, Distributed PV Monitoring and Feeder Analysis.

Having such limited visibility can impact every aspect of grid operations and planning. For instance, forecasting consumer demand is becoming more difficult because power consumption is increasingly variable, and the use of distributed PV systems makes predicting consumer net loads even more complex. For example, system operators find it very challenging to plan for periods when clouds block the sun and distributed PV installations are unable to meet demand, as the figure above illustrates.

One solution is digitalisation, which can improve visibility over DERs and the distribution grid. While distribution companies can install digital equipment such as transformer monitors to closely survey power flows in low-voltage networks,[4] consumers can also use digital technologies to monitor, programme and remotely control devices for which output would otherwise be largely outside their manipulation (e.g. distributed PV systems).

An advanced inverter[5] installed as a part of a distributed PV system can not only provide its owner with solar generation data, but can be programmed to prevent the PV system from causing voltage problems for the distribution grid. Thus, distributed PV technologies can now become capable of addressing the challenges they themselves present to the grid, and regulators and system operators can use electricity pricing and regulation to influence owners of DERs such as distributed PV to operate their resources in line with grid needs.

Digitalisation alone is not enough, however. For example, network monitoring equipment can provide visibility over the low-voltage grid, but basic statical data on DERs, such as the location and power capacity of distributed PV installations, would fill in the picture considerably. Regulators and system operators can incentivise consumers to provide such data.

As most DERs belong to consumers, it is they who decide whether and where to install DERs and how to operate them for their own benefit. Misalignment between the interests of DER owners and the grid will therefore prevent the unlocking of the grid-benefit potential of DERs. Regulators and system operators thus need to create a favourable environment in which the grid-benefit value of DERs is appropriately recognised and fully utilised as part of an integrated grid. This type of energy system can also provide consumers with multiple energy supply options involving diverse grid-DER combinations, and an integrated grid in which grid and customer-side resources work together will make more efficient use of financial capital and physical assets.

[4] Distribution network transformers are used to step voltage either up or down, and can be equipped with a monitoring device that collects and measures information on electricity passing into or through the transformer.
[5] Inverters convert direct current (DC) electricity produced by solar PV systems into alternating current (AC) electricity the grid can use. An advanced inverter has functions to help solar PV systems accommodate grid needs.

The following section describes the significant and varied grid advantages DERs can provide – especially to the power system's main stakeholders such as market and system operators – when the right technologies and incentives are in place.

Power market and system operators

Power systems have four chief domains, each with their operators: wholesale energy markets; transmission systems; retail energy markets; and distribution systems.

Market operators run wholesale energy markets for trading electricity, while transmission system operators (TSOs) are responsible for transmission system reliability. TSOs operate several markets or mechanisms to ensure consistent supply to meet demand, and they also operate, maintain and plan high-voltage transmission grids and provide market participants (e.g. generating companies, retailers and traders) with access to the grid. In jurisdictions where generation and transmission services have not been fully unbundled, transmission owners own the transmission grid and an independent system operator (ISO) takes on the role of TSO. For the sake of simplicity, in this report the term TSO includes ISOs.

Retailers supply electricity to consumers in retail energy markets, and distribution system operators (DSOs) operate, maintain and plan medium- and low-voltage distribution grids and provide generation and demand with access to the grid, typically through grid connection rules and network tariffs. As many distribution companies are currently occupied with mainly "poles and wires" activities, they are sometimes called distribution network operators (DNOs), while those trialling market-based mechanisms, such as local flexibility markets to maintain grid reliability, are transitioning towards system operator responsibilities. For the sake of simplicity, in this report the term DSO includes DNOs.

Though system operators (SOs) mainly serve as proactive market facilitators, the term SO in this report includes both TSOs and DSOs, for the sake of simplicity. As monopoly entities, all SO tasks are under the supervision of regulators. In some jurisdictions, distribution utilities take on the roles of both retailer and DSO.

Digitally enabled grid benefit potential

DERs are being increasingly integrated into buildings. When digitally managed, they individually offer consumers diverse benefits, such as more energy for their own consumption and lower energy bills. When aggregated through digital management systems, however, they offer services beyond the individual property boundary to multiple stakeholders all along the electricity supply chain: retailers, DSOs, TSOs and market operators.

Although DER system capacities are small, they can ramp up and down quickly so are better at providing flexibility than supplying electrical energy. For example, battery storage systems have finite storage capacity and can supply only a limited amount of energy, but they can discharge quickly to fill sudden supply gaps resulting from drops in solar generation. TSOs require flexibility resources to maintain supply consistency to meet demand, and since DERs are situated close to consumers along the distribution grid, they can effectively ease distribution network constraints.

A recent UK study has shown that demand-response solutions using heat pumps and EVs mainly reduce capacity and distribution network costs rather than energy costs. Therefore, this section explores the potential services digitally enabled DERs can provide to DSOs and TSOs, and it explains how the individual services DERs offer to prosumers and retailers can also benefit the power grid.

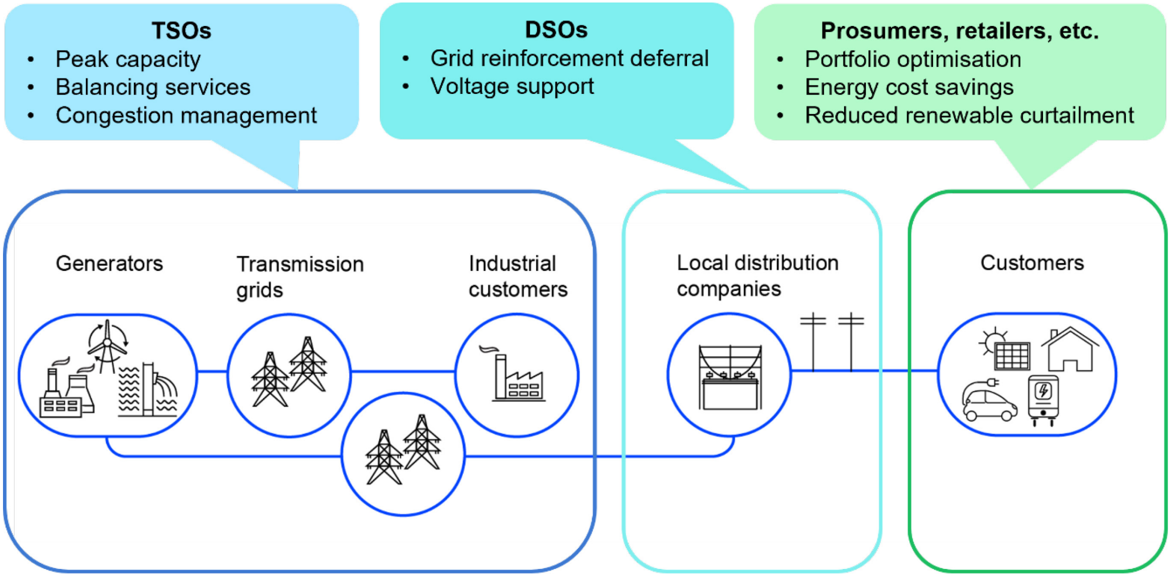
Some DER technologies are more promising than others, owing to either their versatility or their cost-effectiveness. Plus, each technology has its strengths and weaknesses. For example, heat pump water heaters can save considerable energy but are subject to wear-and-tear issues when controlled to provide fast grid services. This section therefore enlarges upon the technical and economic advantages as well as the limitations of five promising technologies: battery storage; EVs and EV chargers; smart water heaters; grid-interactive efficient buildings; and virtual power plants (VPPs).

Battery storage can provide almost every grid service

Behind-the-meter battery storage applications are typically 3 kW/6 kWh (2-hour) to 5 kW/20 kWh (4-hour) lithium-ion systems for residential customers, but they can be larger for commercial and industrial customers. They are deployed at the customer level to store energy produced by distributed PV or other renewable energy generators, and can also be used alone, drawing energy from the grid.

Battery storage systems are versatile resources that can furnish almost every service needed by TSOs, DSOs and the broader grid. Small batteries can benefit system operators more effectively when they are aggregated in a large-scale VPP.

Multiple grid benefits of digitally enabled DERs



TSOs are responsible for maintaining a consistent supply and demand balance, having adequate capacity available to meet peak demand, and remedying transmission grid congestion: aggregated behind-the-meter battery storage systems can help TSOs undertake all these tasks. As batteries are agile, fast-responding resources, they are ideal providers of rapid balancing services for TSOs. For instance, the US utility Green Mountain Power has launched a pilot project that aggregates the batteries of 200 residential customers to provide fast balancing services (i.e. frequency regulation) for ISO New England. The aggregated batteries are expected to fill supply and demand gaps minute-by-minute, replacing fossil fuel-fired generators and reducing CO_2 emissions.

Batteries can also be used to address transmission network congestion. Renewable energy installations are often sited where wind or solar resources are abundant, generally far from areas of high energy demand. Thus, when surplus power from wind or solar farms causes congestion, batteries can accept the excess energy and discharge it when needed to prevent bottlenecks. In 2019, the German TSO Tennet completed a pilot project that showed decentralised home battery systems could reduce curtailment of wind power production in the event of transmission grid congestion.

As DSOs are responsible for maintaining distribution grid reliability, they are concerned with the local voltage issues greater penetration of DERs such as distributed PV can present. However, as DERs are located close to where voltage issues might occur, their ability to respond quickly can also be used to stabilise the grid, deferring or avoiding costly distribution grid upgrades. Batteries especially are easy to control and are thus a preferred alternative to network reinforcement. In New Zealand, for example, a VPP consisting of 1 000 distributed PV-plus-battery storage systems is expected to defer distribution system upgrades for three years.

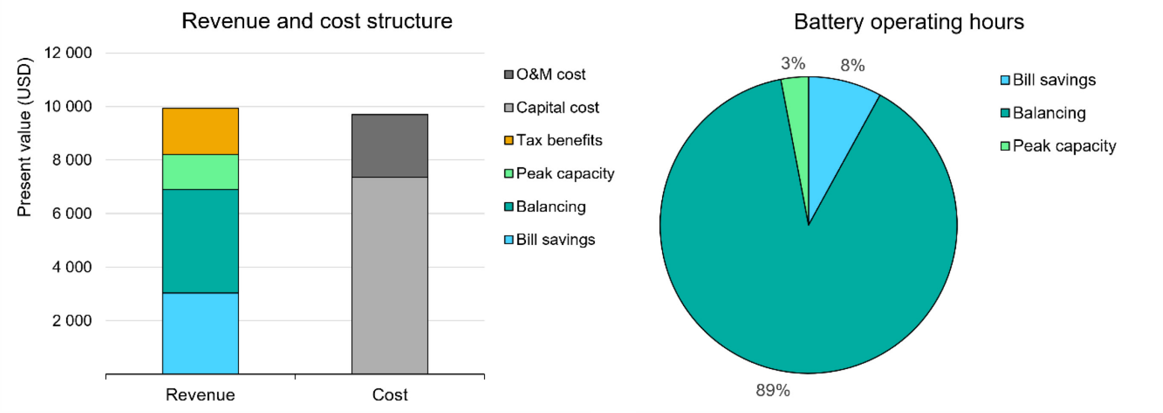
Battery storage also offers various advantages for other stakeholders, including prosumers and electricity retailers, which consequently benefits the power grid overall. Behind-the-meter batteries can increase the amount of energy available for self-consumption when paired with distributed PV or other small-scale renewable energy installations, reducing the need for costly expansions of peak generators and grids. Plus, when used as a backup power source, this distributed PV-plus-battery pairing can help protect consumers from unexpected blackouts due to, for example, extreme weather events.

Furthermore, batteries can be used to shift energy demand to off-peak hours, reducing the energy bills of consumers who opt for dynamic retail tariffs such as time-of-use (TOU) rates. For instance, Enel X has installed the first large-capacity behind-the-meter battery system for a commercial customer in Peru, to supply peak-shaving services for ten years. Additionally, electricity retailers can procure energy from behind-the-meter batteries to optimise the use of their generation assets. All these possibilities can improve market efficiency and grid reliability.

Under the current prevailing business model, it is primarily consumers who benefit from behind-the-meter battery storage, through lower energy bills or by having more energy available from distributed PV installations for self-consumption. However, only 5-50% of a behind-the-meter battery system's useful lifetime is spent on demand-charge reduction, according to a US modelling study. Hence, these systems can provide more value to consumers and power systems alike when multiple stacked services are provided by the same device or fleet of devices. Dispatching batteries for a primary application and then re-dispatching them to provide other services in a stacked manner can create additional value for stakeholders in the power system.

The same study showed that using battery storage paired with distributed PV for multiple services could improve its value proposition. Consumers could save 20% of their electricity costs each year while still having 90% of their battery capacity available for other value streams, including to meet peak demand and to offer balancing services to a TSO. The possible net benefit of combining all applicable revenue streams could present an attractive investment profile.

Operations and economics of a residential distributed PV-plus-battery system



Notes: O&M = operations and maintenance. Modelling was over a 20-year lifetime, with battery replacements at years 7 and 14. Bill savings include residential demand charges and time-of-use rates. Balancing includes frequency regulation, spinning reserve and load-following services. Tax benefits come from the investment tax credit in the United States.
Source: Adapted from RMI (2015), The Economics of Battery Energy Storage.

Although battery storage costs have been declining rapidly, this is still their main limitation, in addition to electricity market regulation issues. According to Bloomberg New Energy Finance (BNEF), lithium-ion battery pack prices, which were above USD 1 200/kWh in 2010, fell 89% in real terms to USD 132/kWh in 2021 – a 6% drop from USD 140/kWh in 2020. Plus, in 2019 BNEF forecasted that the price would drop further to USD 94/kWh in 2024 and USD 62/kWh in 2030, based on an assumed learning rate of 18%, though rising metal prices argue for price increases. (Second-life EV batteries can also reduce costs for consumers.)

In the meantime, policymakers can deploy measures to help consumers bear the cost of installing battery storage, which would ultimately benefit the power system when spare capacity is employed appropriately. For example, the California Public Utility Commission (CPUC) offers both residential and non-residential facilities rebates for installing battery storage to maintain energy supplies during power outages due to, for example, severe wildfires.

Electric vehicles are moving battery storage systems

From the grid-service perspective, EVs are versatile battery storage systems. Nevertheless, EVs are different from conventional batteries in that they are movable or moving, and their primary application is transportation. EVs have three characteristics that make them potential grid resources:

- Operational flexibility, because they can both charge and discharge.
- Embedded/built-in communications and control technologies. Thus, they can respond quickly to an aggregator's signals, within minutes or even seconds.
- Low-capacity utilisation, as they are parked more than 96% of the time and being charged only 10% of the time (particularly light-duty passenger cars). The low-capacity use of EVs means their load is inherently flexible.

An EV's charging technology has implications for the charging strategy and, in turn, the grid benefits it can provide. Chargers typically fall into three categories – levels 1, 2 or 3 – according to their maximum power output.[6] Higher-level chargers offer shorter charging times and more energy efficiency but are costlier to install and operate.

EV charging can be managed through TOU pricing; smart charging; and vehicle-to-grid (V2G) strategies. The charging of EVs on TOU rates can be shifted to off-peak hours (when retail electricity prices are low) by programming the timers on their level 1 or 2 chargers. Smart charging, known as V1G, is remotely turned on or off through the vehicle's or charger's software, typically by an aggregator, to coincide with low electricity prices or high renewable energy generation.

Fast level 2 chargers at home are good for smart charging, as EVs can be plugged in for longer periods of time while the smart charging system delays active charging or limits charging speed. Meanwhile, a V2G system allows the vehicle to discharge excess energy into the grid, enabling more grid functions such as fast balancing services for TSOs. Accordingly, V2G management can require rapid network-connected communications. Level 3 chargers are typically used for on-the-road, short-stay charging and thus are not ideal for managed charging.

Managed EV charging can provide diverse grid benefits when the requisite charging technologies and strategies are in place. For instance, EVs can be effectively used for load shifting when their charging is shifted to off-peak periods, such as times of abundant renewable energy generation or overnight low-load hours. Charging strategies can also be optimised to support the distribution system, avoiding overloading and voltage instability and levelling the use of grid assets across many hours to reduce the need for network reinforcement. Fast-charging management through a V2G scheme can provide balancing services to

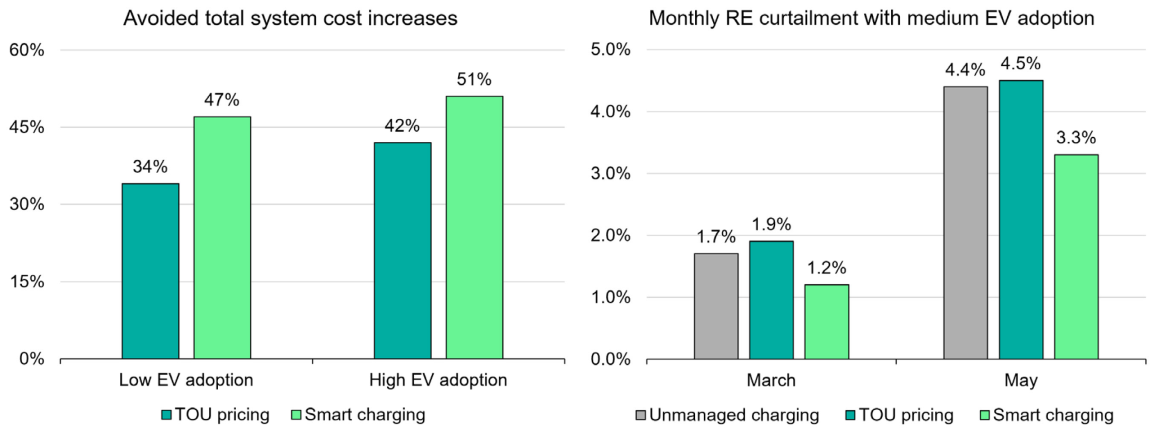
[6] Level 1 chargers with up to 3.3 kW of power capacity are usually used for home charging. Level 2 chargers have a power capacity of 6.6 kW for most vehicles, but some go up to 19.2 kW. Most charging of privately owned EVs takes place at home, using level 2 chargers. Level 3 direct current fast chargers with a capacity of up to 350 kW are currently used for medium- and heavy-duty vehicles, and a megawatt charging system is under development.

TSOs, as EV batteries can be charged and discharged in minutes or even seconds to balance energy flow in the grid during unexpected events.

According to a recent study in California, using TOU pricing and smart charging could considerably limit the power system cost increases in 2025 that would arise from unmanaged charging. Modelling demonstrated that smart charging could minimise total system costs and avoid 47-51% of projected cost increases, depending on the level of EV adoption. TOU pricing, which shifts charging to after 22:00, could achieve about 80% of the savings smart charging would obtain while avoiding smart-charging implementation costs, thereby avoiding 34-42% of the anticipated system cost increase.

Accordingly, smart charging could provide EV owners with USD 90 to USD 140 more per year than unmanaged charging would, while TOU pricing could benefit USD 60 to USD 120 more. However, night-time TOU charging could curtail renewables-based generation more than unmanaged charging would, whereas smart charging would result in less renewable energy curtailment than unmanaged charging.

Impacts of managed EV charging on California's power grid



Notes: RE = renewable energy. Low EV adoption = 0.95 million units. Medium EV adoption = 2.5 million units. High EV adoption = 5 million units. Total system costs reflect wholesale operating costs to generate energy and do not include generation capacity costs, transmission and distribution costs, and the other costs that make up the full cost of producing and delivering electricity.
Source: Data from LBNL (2019), Grid Impacts of Electric Vehicles and Managed Charging in California.

Recent IEA analysis shows the global potential of TOU and V2G strategies to reduce flexible generation capacity needs by 2030. According to the night-charging case, using TOU pricing to shift EV charging to the 23:00-05:00 off-peak period could avoid around 60% of the peak load increase that arises under the evening-charging scenario, which assumes 80% of EV charging needs are met during 18:00-00:00. Accordingly, night charging could avoid the addition of ~110 GW of flexible generation capacity in China, India, the United States and the European Union. Furthermore, V2G services could unlock up to nearly 600 GW of flexible capacity across the four countries, compensating for renewable generation variability during peak periods and meeting part of the additional peak capacity generation needs. In fact, V2G management could reduce electricity generation needs by 380 TWh during peak demand periods.

Among the diverse services smart charging and V2G strategies can provide to TSOs are fast balancing and grid congestion management. The world's largest residential V2G trial so far was undertaken for three years in the United Kingdom, with more than 320 chargers installed in homes. These V2G chargers were able to provide various balancing services through firm frequency response (FFR) and dynamic containment to National Grid ESO (Great Britain's TSO). Dynamic containment is a newly devised, faster-acting frequency response service soft-launched in 2020 to address the drop in system inertia as renewable energy systems replace synchronised generators. The service requires an initiated response to happen within 0.5 seconds, and a full response within 1 second. The trial found that V2G operations could earn consumers GBP 340 per year through tariff optimisation, compared with GBP 120 when using one-way smart charging. Additionally, annual revenues rose to GBP 513 when FFR services were provided and GBP 725 with dynamic containment.

Another V2G pilot project in Germany showed that EVs could successfully address increasing transmission grid congestion between wind power generation feed-in centres in the north and consumption centres in the south and west, reducing the curtailment of renewable energy generation. In the pilot, wind power available in northern Germany was used by EVs in that region while, at the same time, electricity from charged EV batteries was fed back into the southern and western grids, replacing fossil fuel-based power.

Managed EV charging can defer or replace costly distribution network upgrades. Vector, a distribution company in New Zealand, anticipates that smart EV charging will halve the distribution network capacity reinforcement required to accommodate an additional 1.3 million light-duty EVs in 2050 – a savings of 1.2 GW. The company's EV smart charging trial revealed that the impact of such proactive DER management could be more pronounced in the low-voltage grid, as loads are typically less diversified. For example, for each additional 7-kW EV charger, the company needs 7 kW of new capacity in the low-voltage grid but only 1 kW in the medium-voltage grid.

New models, such as the multi-layer optimisation approach, have been emerging recently. As grid conditions vary depending on time and location, what might be optimal for the bulk system may increase congestion in the distribution network. Multi-layer optimisation can help identify and orchestrate EV charging schedules that co-optimise driver preferences, distribution constraints and bulk system considerations. For example, the GridShift programme in California optimises residential EV charging schedules, taking into account the off-peak hours of the customer's TOU rate, dynamic grid conditions, high renewable generation periods, and the customer's desired departure time. As a result, 90% of customer charging is shifted to TOU off-peak hours, saving the consumer USD 100 to USD 200 per year, and 42% of EV loads are moved to low-emission hours when carbon intensity is 72% below the average.

EV batteries can also be used in vehicle-to-home (V2H) and vehicle-to-building (V2B) systems to provide back-up power for homes and buildings during power outages. In the United States, for example, a car manufacturer and a residential distributed PV and battery provider have announced they are manufacturing V2H technology for an electric pickup truck, consisting of a charger and home integration system. They claim the truck can power a home for up to three days during an outage. Meanwhile, in the US state of Colorado, an all-electric building using V2B technology for four months could save USD 950 in energy bills. The V2B system could monitor the building's energy consumption and reduce demand charges by using energy from EV batteries during costly high-demand hours.

As high costs and a lack of sufficient charging infrastructure are two of the main barriers to EV growth, policymakers can offer purchase rebates to lighten cost burdens and incentivise the installation of charging stations, focusing on chargers for multi-family dwellings and workplaces in addition to public chargers. From the grid-service point of view, potential battery degradation is another critical issue for V2G technology uptake. There is evidence that bidirectional charging without measures to prevent potential degradation can shorten a battery's lifetime, and since EV battery warranties typically assume that batteries are being used only to power a car, V2G activities can put EV owners at risk of warranty violations. It is therefore unviable to purely maximise an EV owner's profits without setting reasonable limits on the amount of energy traded. Some studies show, however, that smart V2G applications can actually improve battery longevity, so further research and discussion are required.

Smart water heaters can be cost-effective flexibility providers

Battery storage, including in vehicles, is a highly controllable and versatile grid resource. However, as deployment is currently limited by the currently high cost of batteries, smart storage water heaters can be an attractive low-cost alternative source of energy storage. As electric water heating loads are controllable, they can add flexibility to the grid without causing customer discomfort: for example, hot water heated at night can be stored and used for showers in the morning. Hence, from a grid management perspective, electric storage water heaters are like pre-installed batteries, many of which are sitting idle. Because it is inexpensive to add control devices (prices range from less than USD 100 for embedded units to up to USD 400 per retrofit unit), water heaters can easily be "smartened" to serve as effective grid resources.

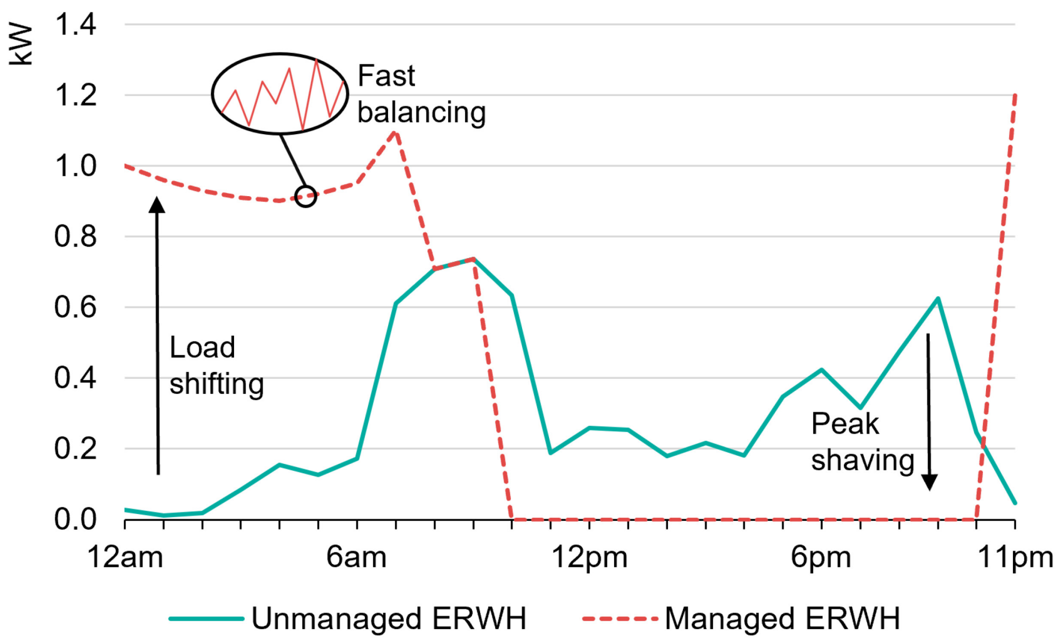
Two types of water heaters – electric resistance and heat pump water heaters – are widely used. Electric resistance water heaters are tanks that contain one or more heating elements, while heat pump water heaters have tanks attached directly to heat pumps that typically use ambient air to heat the water. Both water heater types offer grid benefits when control devices enable end users or aggregators to monitor the charge level (i.e. the water temperature) and control charging (i.e. heat the water). Water heaters can be built equipped with timers and Wi-Fi connectivity or can be retrofitted with such control devices.

Smart electric resistance water heaters can respond rapidly to grid needs

Electric resistance water heaters have heating elements in their tanks that can be fast-controlled at very frequent intervals to accommodate diverse grid needs. They can therefore provide a wide range of grid services – from fast balancing and peak shaving to load shifting.

Water heaters' heating elements can be controlled with near-instantaneous response to provide fast balancing services, known as frequency regulation, to TSOs. In fact, aggregated water heaters can follow fast frequency regulation signals even more closely than the fossil fuel-fired generators that are conventionally used. Currently, around 14 000 water heaters provide frequency regulation services for the US Pennsylvania-New Jersey-Maryland (PJM) ISO market. According to a study of ISO markets in the Unites States, frequency regulation could offer annual economic benefits of up to USD 195 for customers with US 50-gallon water tanks, and up to USD 216 for those with larger US 80-gallon water tanks.

Example grid benefits of a managed electric resistance water heater



Note: ERWH = electric resistance water heater.
Source: Adapted from Brattle Group (2016), The Hidden Battery: Opportunities in Electric Water Heating.

Electric resistance water heaters can also shave peak demand, reducing the need for peak generation and network capacity and cutting peak energy costs. By shifting demand to periods when power is less expensive (i.e. at night) or cleaner (i.e. at midday when solar resources are abundant), water heaters can save consumers money. For example, in New Zealand, where water heating accounts for 20% of total peak energy demand, the Vector distribution company trialled the use of smart solutions to gain better visibility (and thus more intelligent management) of its customers' water heaters than the legacy ripple control devices provide. The pilot project found that the aggregated peak load of the 104 participants was reduced by 40% and, if scaled up, could defer the NZD 2.4-million replacement of local substations for ten years.

In the US state of Ohio, 1 100 customers equipped with smart water heaters participated in a demand-response programme to control water heating loads during two-hour peak demand periods. It was found that the programme could shave 400 kW of peak demand to avoid a sudden demand spike, saving customers a total of USD 3 600.

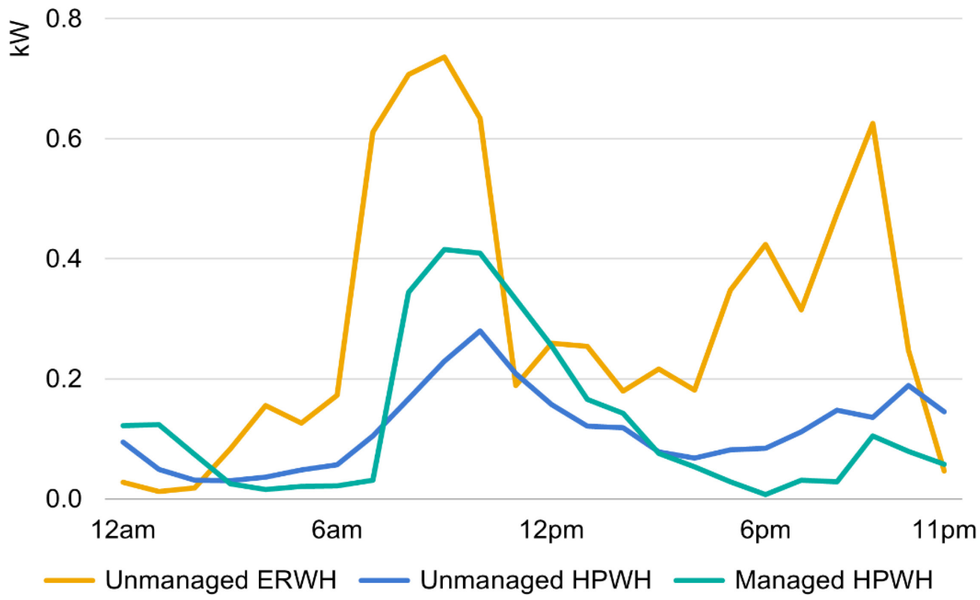
Smart water heaters are often used for multiple purposes. For example, Shifted Energy in Hawaii launched a water heater retrofit programme in 2018, using off-tank controllers and VPP software to convert traditional electric water heaters into proactive resources with 2.5 MW of capacity for valuable grid services such as peak shaving, load shifting and fast balancing. In return for allowing their water heaters to support the power grid, participants received monthly energy bill credits of USD 3-5 for five years.

Smart heat pump water heaters are energy-efficient and flexible

The primary attraction of heat pump water heaters is that they can provide more energy than they draw from the grid and, at the same time, their power demand can be managed when they are equipped with smart controllers. In short, smart heat pump water heaters are both energy-efficient and flexible, and they are an ideal example of an embedded, integrated approach to energy efficiency and demand response.

A heat pump water heater's efficiency is expressed as a coefficient of performance (COP), which is defined as the net heat delivered by the water heater divided by the total electrical energy consumed. Current heat pump water heater COPs range from 2.5 to 3.0, while the maximum efficiency of an electric resistance water heater is 1.0.

Average daily water heater load profiles

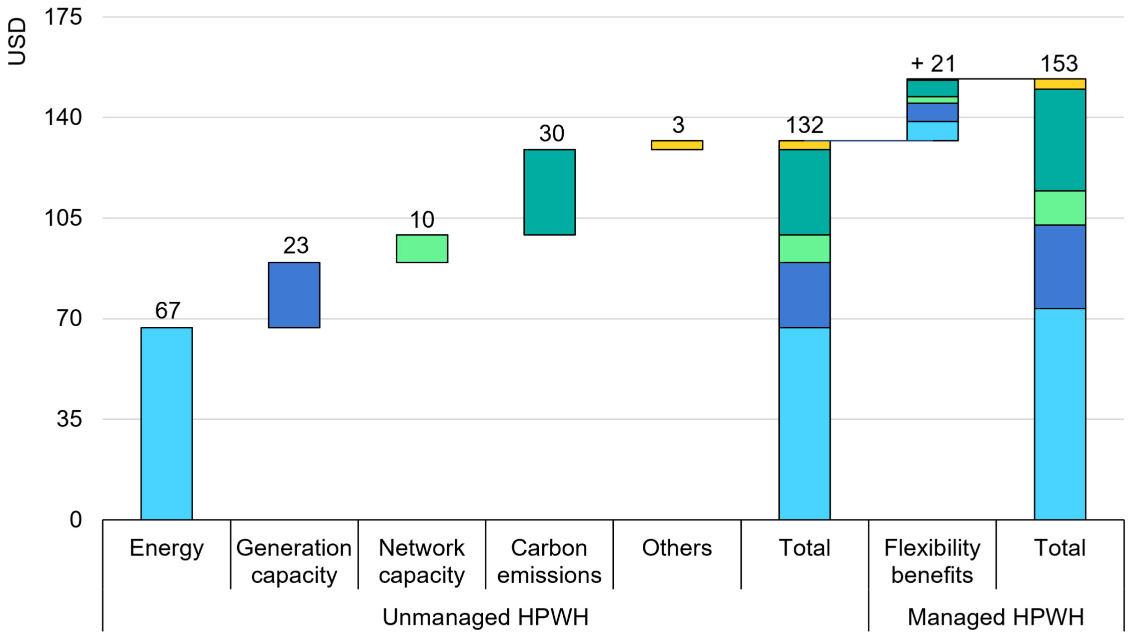


Notes: ERWH = electric resistance water heater. HPWH = heat pump water heater. The ERWH modelled had a 50-gallon water tank and the HPWHs had 65-gallon tanks, and all three were installed at a 3-bedroom house in California's climate zone 12. The managed HPWH was controlled according to residential TOU rates, while the water setpoint temperatures of the unmanaged ERWH and HPWH were kept at 125° F.

Sources: Data from NRDC; Ecotope (2018), Heat Pump Water Heater Electric Loading Shifting: A Modelling Study.

A heat pump water heater can reduce water heating loads substantially more than an electric resistance water heater during the peak-load early morning and evening periods. This means that replacing an electric resistance water heater[7] with a more energy-efficient heat pump device can provide a fair amount of system flexibility during peak periods even without smart control, as shown in the figure above. Flexibility potential can be maximised when replacements are well planned to target consumers with considerable water heating loads during the morning and evening peak hours. Furthermore, when managed by a smart controller, a heat pump water heater can preheat water to shift evening power demand to off-peak periods, such as hours of high solar generation, to reduce the additional peak load.

Levelised annual total system benefits of a heat pump water heater



Notes: Energy = avoided energy generation and grid loss costs. Generation capacity = avoided generation capacity costs. Network capacity = avoided transmission and distribution capacity costs. Carbon emissions = avoided GHG emissions costs. Others = avoided ancillary service and methane leakage costs. Flexibility benefits = additional avoided costs of the managed HPWH. Annual total system benefits are levelised over the useful life of an HPWH, 13 years from 2021. Calculations of avoided costs are based on input variables of the service territory where the water heaters were modelled and do not include the incremental costs of replacing an ERWH with an HPWH, either managed or unmanaged.

Sources: Based on California Public Utilities Commission (2021), 2021 Avoided Cost Calculator Electric Model; data from NRDC; Ecotope (2018), Heat Pump Water Heater Electric Loading Shifting: A Modelling Study.

In 2021, modelling demonstrated that an unmanaged heat pump water heater in California could provide total power system-wide benefits of up to USD 132 per year for its useful lifetime of 13 years when it replaces an energy-inefficient electric resistance water heater: USD 33 of avoided generation and network capacity

[7] In this case, the electric resistance water heater is assumed to be unmanaged to disaggregate the energy efficiency benefit of replacement from the load-shifting effect.

costs; USD 30 of avoided carbon emission costs; and USD 67 of avoided energy costs, as the figure above illustrates. Managing this heat pump water heater with a smart controller could save an additional USD 21 per year, thanks to increased flexibility to better manage peak generators and reduce grid bottlenecks. In fact, only when enough capacity is replaced, water heater substitution can reduce generation and network capacity costs.

To operate, however, heat pump water heaters rely on compressors that could suffer unacceptable wear and tear if controlled in the very short time increments (sub-minutes) required for fast balancing services. Therefore, the main grid resource applications of heat pump water heaters should be peak shaving and load shifting. In 2018, Bonneville Power Administration, Portland General Electric and the Northwest Energy Efficiency Alliance completed one of the largest smart water heater pilot programmes in the United States. The study, which included 277 participants from 8 utilities, found that heat pump water heaters could successfully participate in a demand-response system, and be called on hundreds of times per year to reduce renewable energy curtailment through load shifting, thereby supporting greater renewable energy production. The study concluded that if 26% of Oregon's and Washington's electric water heaters participate in demand-response programmes, the region could create 300 MW of storage capacity.

The main issues with smart water heater rollout are suitable housing types and consumer expense. Existing homes in many jurisdictions are already equipped with natural gas services, so converting to electric water heating could require significant investment, although conversion would be more attractive if homes could also switch to heat pumps for space heating and cooling. Dynamic retail electricity pricing could reduce consumer energy bills, making switching more economically inviting, and carbon pricing could also trigger conversion.

Newly constructed homes are good candidates for heat pump water heating combined with heat pump space conditioning, and policymakers could spur deployment by sharing consumers' cost burdens, especially when they decide to switch from gas to electric heating. For example, the UK government recently announced a GBP 450-million three-year Boiler Upgrade Scheme to help consumers replace their existing gas boilers with electric heat pumps.

Implications of electrified space heating for grid management

The grid benefits of electric space heaters are like those of water heaters. Although electric resistance storage heaters can provide both fast balancing and peak shaving, heat pumps may suffer unacceptable wear and tear if controlled on a sub-minute scale to provide fast balancing services.

Meanwhile, space heaters can use buildings as thermal energy storage. For example, a building can be preheated when solar power generation is abundant to shift energy demand away from evening peak hours. For this to work, the building's energy efficiency (i.e. insulation) must be adequate to retain heat without significant losses.

Nevertheless, space heaters have two features that system operators need to consider when adopting them as grid resources. Regional climate variations can determine the type of technology system operators will probably encounter in their specific location: while system operators in warmer climates can likely take advantage of air source heat pumps, those in colder regions are more apt to have access to electric resistance storage heaters or heat pump systems with supplemental heating. Very recently, however, air source heat pumps better adapted to cold climates (Canada's, for example) have been introduced to the market.

In addition, as space heating makes up the largest component of home energy use, its electrification can have a more important impact on the grid than water heating. For example, space heating accounts for 45% of home energy use in the United States, while water heating makes up 18%. As a greater proportion of space heating becomes electrified, in many power systems in which most peak hours currently occur in the summer, there will be an increase in winter peak hours. This shift could give rise to a number of issues: for instance, resource planning could become complicated, as different types of resources are available during the winter than in summer. Additionally, daily load curves tend to have a different shape in the winter than the summer, so system operators may need to have an alternate set of flexible resources available. These factors imply that managing electrified space heating becomes more important as electrification increases.

Digital solutions can help optimise the aggregation of diverse small resources

While it is clear that individual resources (e.g. battery storage, EVs and chargers, and smart water heaters) can provide multiple grid benefits, when they are combined with digital solutions they can compensate for one another's limitations and reinforce each other's strengths, offering more diverse advantages more cost-effectively. For example, battery storage is a versatile resource that can provide almost every grid service, but its relatively high cost and limited storage capacity can restrict its potential. However, pairing battery storage with a distributed PV system can rationalise the capacity sizes of both, reducing consumer costs and helping maintain power supplies during extreme weather events to improve overall power system resilience.

Digitalisation is especially useful because its key functions are scalable to any level of aggregation: from buildings to communities, and even larger regions. Advanced data analytics can help optimise the aggregation of diverse small resources that have a variety of technical characteristics, while accommodating the preferences of each consumer and maintaining the reliability of ever-changing grids. Digital management systems, such as smart meters and distributed energy resource management systems (DERMS), can help monitor and control internet of things (IoT) energy devices. Aggregation can be created either physically in a building or through a microgrid, or virtually across a wider region.

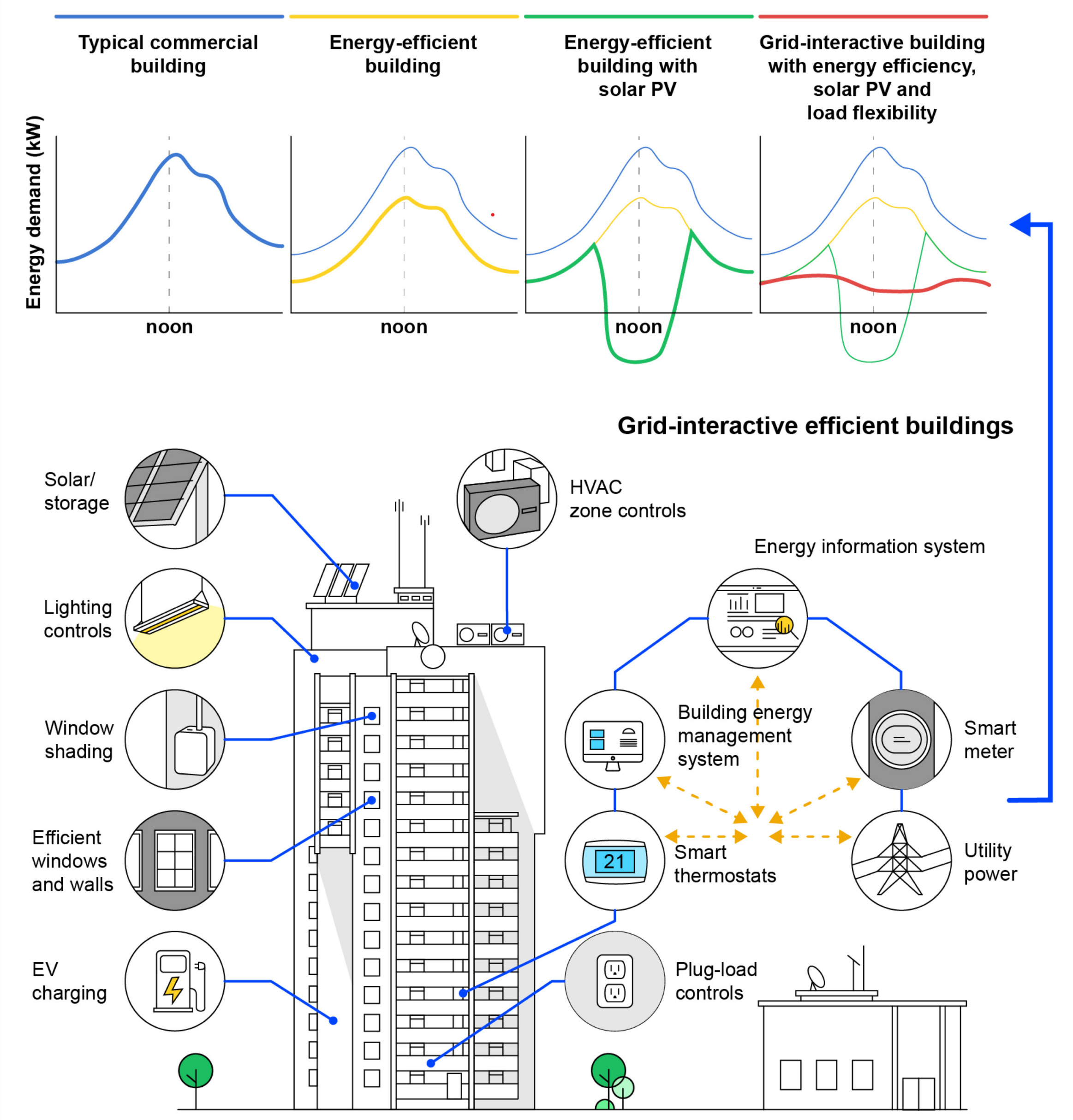
Buildings can interact with the power grid

A growing number and variety of small energy resources are appearing on the consumer's side of the meter, complicating their management. However, buildings equipped with advanced digital technologies (e.g. sensors, smart meters, data analytics and automated controls) can make it possible to more flexibly manage a building's energy prosumption to best serve occupants' needs while still considering the grid.

Grid-interactive efficient buildings (GEBs) are energy-efficient, connected, smart and flexible. A high level of energy efficiency, including passive elements (e.g. well-insulated building shells) and active components (e.g. heating and other electrical appliances), is central to a GEB. GEBs are connected, enabling two-way communication with the power grid, which may directly control a building's equipment or indicate electricity prices for a building to act upon.

GEBs are also smart, as sensors, controls and analytics are employed to optimise their performance. Accordingly, GEBs are flexible – able to manage power loads and generation quickly to deliver optimal performance. Ideally, GEBs should have efficiency adaptations, on-site generation and load flexibility, with the capacity to combine them to reduce and flatten the building's energy demand, achieving the best results for both occupants and the grid.

Grid-interactive efficient buildings



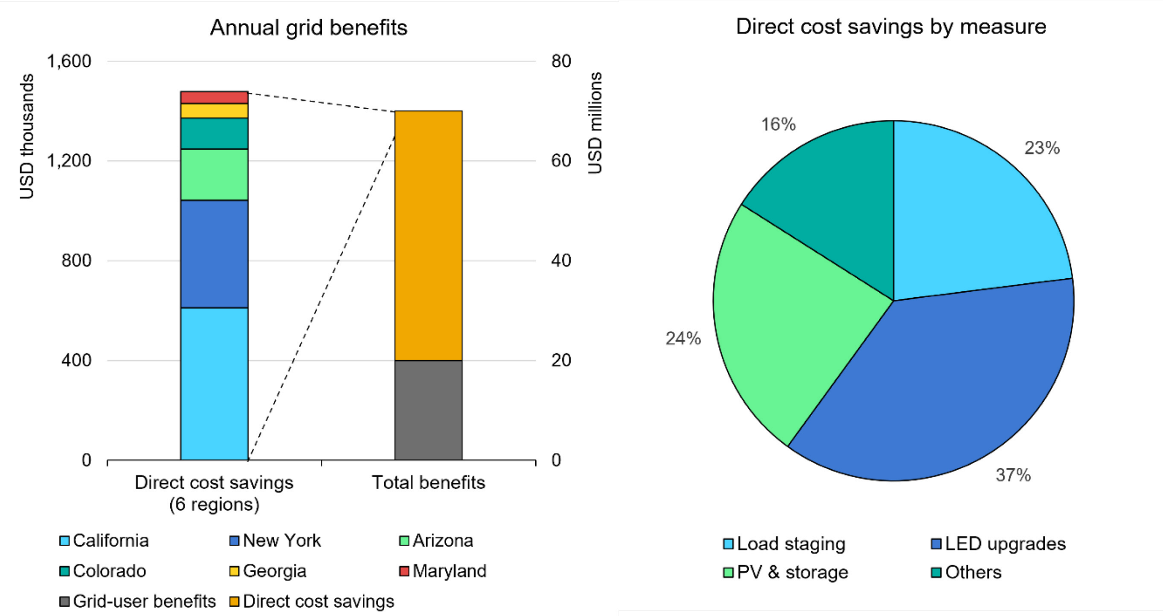
Note: HVAC = heating, ventilation, and air conditioning.
Source: Adapted from ACEEE (2019), [Grid-Interactive Efficient Building Utility Programs: State of the Market]; RMI (2019), [Value Potential for Grid-Interactive Efficient Buildings in the GSA Portfolio]

A wide spectrum of grid interactivity options offer various advantages. For example, a simpler form of GEB, such as a solar-plus building, can provide substantial benefits. Solar-plus is an approach to distributed PV deployment that uses energy storage and other controllable devices such as smart water heaters and EVs to reduce consumer energy costs. According to a [2017 modelling study], the solar-plus approach could improve system value by enabling load shifting or by making more solar energy available for self-consumption.

It could also help consumers adopt the most cost-effective size of PV system relative to prevailing retail electricity rates. For example, a solar plus smart water heater and air conditioner system in a region with a super-peak tariff on top of a TOU rate was shown to increase system value by 60% more than solar alone. This benefit came mainly from load shifting to avoid super-peak and peak hours and from adopting a smaller PV system. The net present value of the building's energy system rose by around USD 3 600, with increased annual bill savings of USD 289 and reduced total system costs of USD 893.

More complex forms of GEBs can provide diverse benefits to the grid, including balancing services. In fact, recent modelling has shown that if all public buildings owned by the General Services Administration (GSA) in the United States were converted to grid-interactive efficient, they could generate up to USD 70 million per year in societal value for grid users. This value would result from reduced generation capacity, deferred or avoided transmission and distribution system upgrades, balancing service offers, and distribution voltage support, delivered through 29 technical measures. The GSA could directly save USD 50 million in annual costs, which would deliver USD 206 million in net present value over eight years, mainly from demand charge and TOU savings.

Grid benefits of converting GSA-owned buildings into grid-interactive efficient buildings



Notes: Direct cost savings = energy cost savings directly accrued to building owners. Grid-user benefits = benefits accrued to all grid users beyond building owners. Load staging = staging of laptop battery charging, air handing unit fan and electric heater loads. LED upgrades = LED lighting tube and fixture retrofits. "Others" includes zone temperature reductions and window film installation.
Source: Data from RMI (2019), Value Potential for Grid-Interactive Efficient Buildings in the GSA Portfolio.

The same study examined the cost-effectiveness of various technical measures and found that load staging, LED upgrades, and distributed PV and battery use were the three categories that generated the most benefit, as shown in the figure above. Load staging by programming high-load equipment (such as electric heaters) to run in sequential stages to reduce peak demand was especially cost-effective, requiring little to no new hardware to control the equipment.

In addition, the study found that GEBs in California and New York that adopted TOU rates and high demand charges could generate more energy-cost savings. This implies that GEBs can have diverse technology options adapted to each building's conditions, with consumers opting for a combination of technologies most cost-effective for themselves based on regulatory-driven revenue potential. Thus, regulators can unlock the full potential of GEBs by designing electricity markets and retail rates to align consumer interests with grid needs (Chapter 2 covers this further).

A range of pilot projects is currently experimenting with the diverse grid service potential of advanced forms of GEBs. One of the INTERRFACE demo projects in Bulgaria is optimising the energy consumption of a multi-user commercial building using an innovative control system enabled by an information hub. The building, which is equipped with battery storage, a distributed PV system and EV chargers, would provide balancing and congestion management services to TSOs and DSOs to expand power grid flexibility and the use of renewable energy. The project plans to incorporate a round-the-clock data centre that will require a high-quality and reliable power supply, testing the sophistication of the control system.

Another project in Europe, INTERCONNECT, is experimenting with an advanced home energy management system (HEMS) in Germany. The HEMS would automatically optimise the energy consumption of a range of home appliances, including EVs, heaters and air conditioners, tumble dryers and dishwashers, according to flexible retail tariffs. This is expected to reduce consumers' energy bills without compromising their comfort while cutting carbon emissions.

Data is at the heart of GEBs, producing benefits that add up to more than the sum of a building's individual devices by creating synergies among them. Many commercial and large multi-family residential buildings use building management systems that control energy-intensive equipment but are not yet grid-interactive. These systems vary significantly in their smartness (i.e. the sophistication of their sensing, control and data analytic functions).

Policymakers are in an ideal position to incentivise the "smartening" (and thus grid-interactivity) of existing systems. For instance, the New York State Energy

Research and Development Authority launched a Real Time Energy Management (RTEM) programme that provides consumers a cost-share incentive of up to 30% of the cost to install an energy management system, which could save consumers 10-20% on energy costs. In addition to electricity market regulation issues, multiple technical challenges impeding wider GEB deployment involve consumer data use: standards and interoperability, cybersecurity, data availability and customer privacy. Policymakers can work with relevant stakeholders to identify problems and address them through roadmaps such as the US Department of Energy's recent national roadmap for GEBs.

Microgrids can aggregate dispersed resources, improving energy access and resilience

GEBs have recently been expanding to the community level, incorporating microgrids in what are sometimes called connected communities. A microgrid is a locally connected system that incorporates distributed generation, demand and storage within clearly defined electrical boundaries.

The system is a single entity that can be controlled independently either off-grid (offering a means to maintain energy access in locations where it is technically and economically unviable to build an electricity network) or through a grid-connected solution with islanding capacity during a power outage. With the cost of DERs such as battery storage and distributed PV dropping rapidly, microgrids are becoming an economically attractive alternative to the electricity grid to obtain affordable, resilient and cleaner energy, especially for remote consumers.

In 2017, a solar hybrid mini-grid was built in the Tanzanian village of Kalenge to serve a total of 120 customers. Before installation of this mini-grid, the community used mainly distributed PV systems to power their homes, but their solar home systems had been overused and became difficult to maintain. As a complement to solar power generation, mini-grids can ensure power supply reliability and lower electricity costs.

In a larger-scale project, over the next 30 years the Western Australia network company Western Power plans to replace as much as 40% of its overhead power lines with off-grid solutions, creating what it calls stand-alone power systems. Western Australia has one of the largest isolated networks in the world, supplying 2.3 million customers across a vast area the size of the United Kingdom.

Furthermore, microgrids can offer the potential to combine more geographically dispersed resources. For example, in 2017 in the US state of Alabama, a microgrid was scaled up to create a smart neighbourhood of 62 single-family homes using a system comprised of utility-owned solar PV, battery storage and gas generators. A microgrid controller is integrated into every home's energy management system to optimise home energy consumption as well as the use of utility-owned resources.

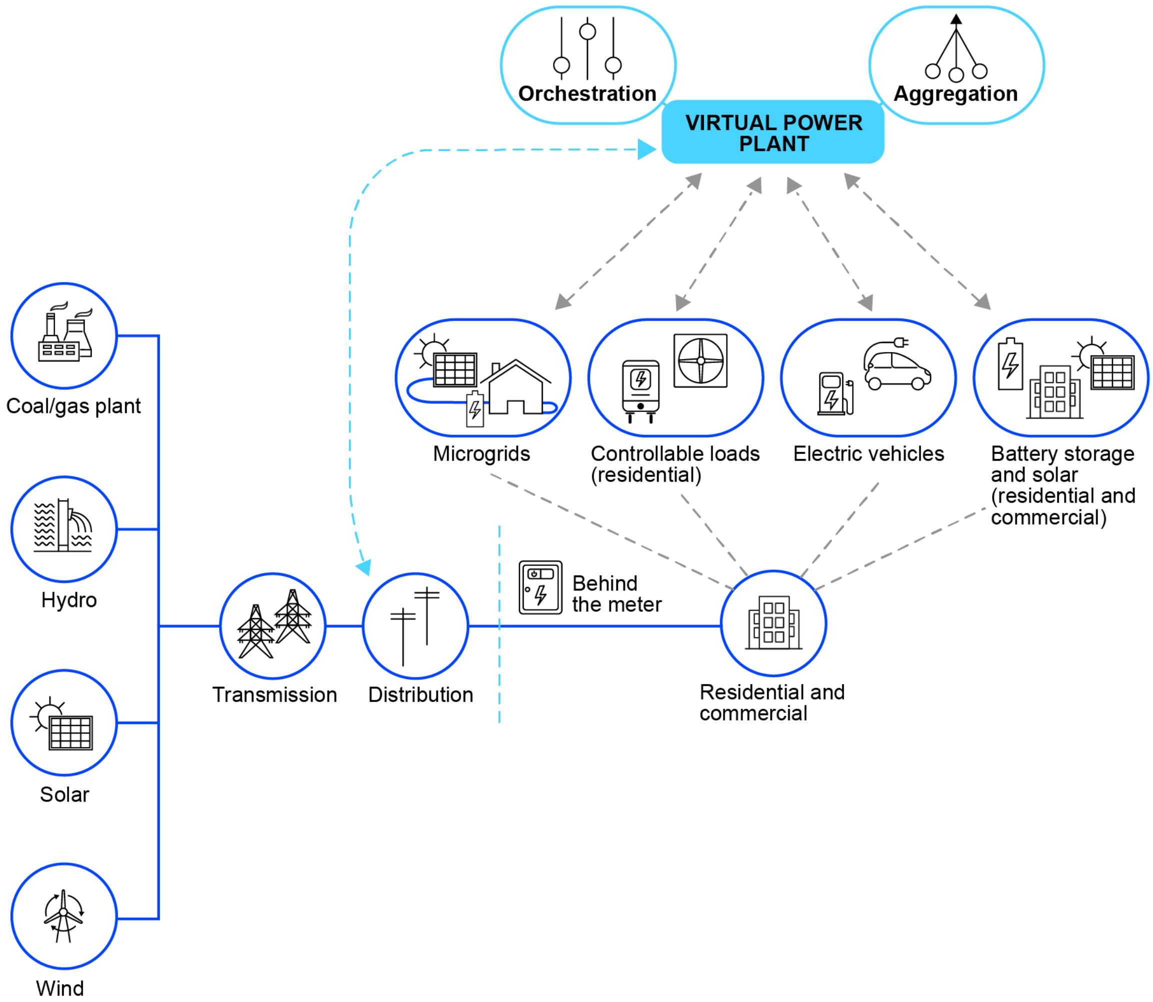
Fortunately, governments recognise the value of microgrids and support them. For example, the Australian Renewable Energy Agency (AREA) recently launched a six-year Regional Australia Microgrid Pilots Program to support the development of a wide range of microgrid technologies, funding both off-grid and grid-connected solutions. One of Australia's largest DER microgrids – an off-grid microgrid supplying 800 people in Onslow – could be powered 100% by distributed PV systems and batteries without using fossil fuel-fired backup generators at all during a pilot trial in June 2021. Furthermore, grid-connected microgrid pilots are expected to participate in energy markets, provide system flexibility, defer or avoid costly network investments and demonstrate islanding capacity.

Virtual power plants can unlock more distributed energy resource potential

A virtual power plant (VPP) is a system that pools heterogenous DERs in an aggregation that can function as a single resource, just as conventional power plants do. For instance, VPPs can ramp up and down just as often as (or even more quickly than) dispatchable centralised power plants. Plus, VPPs can do so virtually without limiting the geographical coverage of resources when grid conditions and relevant regulations allow. VPPs can also be asset-light, meaning they are not subject to the liabilities associated with land use, waste management and stranded asset risks of traditional power plants. Aggregators can operate VPPs to provide services to the grid, especially electricity markets.

VPPs can incorporate advanced software, such as machine-learning algorithms, and their central IT systems can process large amounts of data, including weather forecasts, real-time electricity prices and ever-changing grid status, to optimise the operation of DERs. In addition, some distribution utilities recently adopted advanced control solutions such as distributed energy resources management systems (DERMSs) to operate VPPs. A DERMS is a utility enterprise system that enables proactive control of the grid and DERs (to the extent that the utility is allowed to dispatch customer-sited resources). In this way, a VPP can serve as a bridge between the prosumers who own DERs and power systems and markets, providing an even wider range of grid benefits.

How VPPs work



Source: Adapted from AEMO (2021), AEMO NEM Virtual Power Plant Demonstrations.

The Australian Energy Market Operator (AEMO) launched a VPP demonstration project in 2019 and found that VPPs could provide balancing services,[8] respond to energy market prices and support local grid voltage – at times stacking values simultaneously. Seven aggregators with eight portfolios (VPPs), all consisting of solar PV and battery storage, participated in the project.

The trial has proven small battery VPPs to be highly effective at providing balancing services. In addition, VPPs are, in principle, highly capable of responding to energy market prices in real time. However, VPP operations in the trial were dictated primarily by household self-consumption needs, so responses

[8] In Australia, balancing services are called frequency control ancillary services (FCAS) and are categorised as regulation FCAS (used in normal operating conditions) and contingency FCAS (used in an emergency such as a large generator failure). VPPs can currently provide only contingency FCAS, which has six markets: up and down 6-second fast regulation; up and down 60-second slow regulation; and up and down 5-minute delayed regulation.

to energy market price signals, especially to extremely high or negative prices, were inconsistent across VPPs that have different contracts for using customer assets and various battery storage capacity.

The AEMO demonstration project reveals interesting implications for VPPs, particularly for value stacking. For instance, balancing services were not fully delivered as instructed in some cases when a VPP site consisting of a distributed PV system and battery was to deliver down-regulating power (requiring the battery to charge) at the same time as it was responding to high energy market prices (requiring the battery to discharge).

Underperformance also occurred when balancing service provision coincided with local voltage support. A VPP site made up of a distributed PV system and battery prioritised distribution network support to avoid violating the upper limit for local voltage, causing its battery to ramp down, while simultaneously the VPP had to provide up-regulating power, which required the battery to ramp up. Regulators can work with industry stakeholders, however, to establish value-stacking rules to govern service demand conflicts (Chapter 2 discusses this issue further).

VPPs currently devote considerable attention to solar PV-plus-battery systems. This pairing is highly synergistic because the battery ensures significant controllability while solar PV power generation compensates for the battery's limited storage capacity. Nevertheless, VPPs can combine and optimise the operations of any resources. For example, the US utility Arizona Public Service has incentive programmes to utilise customer-owned assets – more than 50 000 smart thermostat units together with heat pump water heaters – and optimises their aggregated operation as a VPP with utility-owned battery storage, managed using a DERMS. This enables peak-demand shaving, load shifting to high solar generation hours, and backup power provision during grid outages.

VPPs have also been expanding recently to incorporate emerging technologies such as hydrogen electrolysers. For example, a VPP in Germany includes in its aggregation an electrolyser that produces hydrogen from excess wind generation and provides balancing services. The VPP also supplies forecasts of both local wind generation and the load on the local natural gas network into which the produced hydrogen gas is fed. This co-optimises the electrolyser's hydrogen gas production and its balancing services.

As VPP operations are based on aggregations of resources, the drawbacks of each technology can have an influence on the limitations of a VPP. On the other hand, since VPPs serve as intermediaries that connect customer resources with the power market and the energy system at large, favourable electricity market design and regulation can directly boost VPP effectiveness. Chapter 2 introduces the best regulatory practices for unlocking DER potential and provides key market design insights.

Chapter 2. Key insights for electricity market design and regulation

Call for power system transformation

Distributed energy resources (DERs) can transform many aspects of current power systems: not only the way electricity is produced, traded and delivered, but also how it is used. While the previous chapter described the potential of DERs to provide a variety of grid benefits when the right technologies and incentives are in place, this chapter elaborates on how to mobilise such incentives through appropriate electricity market design and regulation.

There are three important elements to consider when devising incentive mechanisms: compensation, regulation and infrastructure. Appropriate compensation, such as through electricity pricing, can help align the interests of DER owners with the needs of the grid, improving both system reliability and DER economics, and regulations such as grid codes that introduce minimum requirements can also maintain system reliability. Furthermore, infrastructure such as network monitoring equipment will be required to implement compensation schemes and enforce regulations. In short, almost every aspect of our current power system needs to be adapted to unlock the grid benefit potential of DERs.

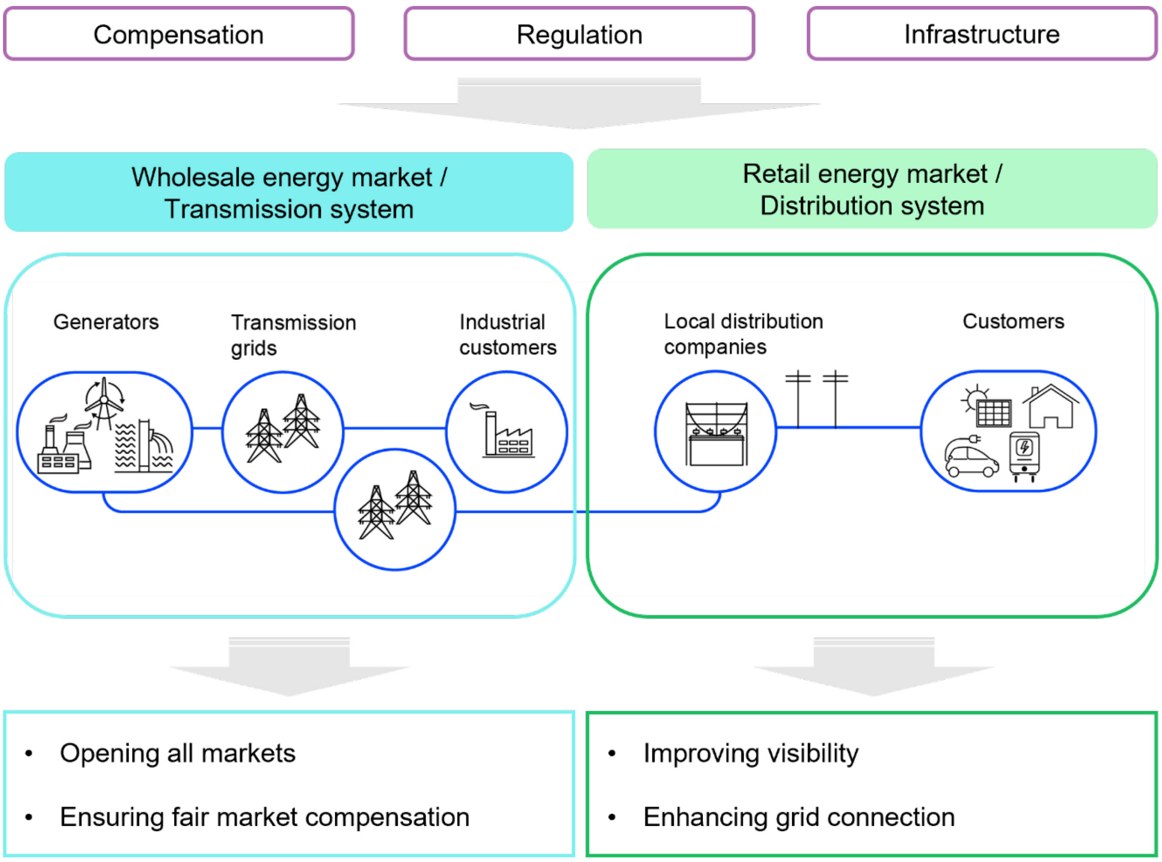
In the 20th century, the four primary domains of power systems – the wholesale energy market, transmission system, retail energy market and distribution system – were designed to accommodate an arrangement in which consumers were passive energy takers. Electricity was traded in wholesale energy markets, mainly between large generators and retailers, and large-scale generators connected to the transmission grid participated in markets operated by a transmission system operator (TSO). Hence, rules and infrastructure for all wholesale energy and TSO markets were devised chiefly for large, centralised generators, so that today in many jurisdictions, not all markets are open to small-scale DERs. What is more, not all markets compensate DERs fairly for their flexibility value: capacity markets designed to attract investment in static capacity to meet peak load demand, rather than flexible capacity for daily ramping needs, are one such example.

Consumer demand connected to the distribution grid has historically been stable and predictable. Since not many generators were connected to the distribution grid, there was not much need to monitor distribution grid-connected resources and incentivise their operation according to network conditions. Hence, only certain jurisdictions adopted rules requiring distribution system operators (DSOs) to collect static data on behind-the-meter (i.e. consumer-side as opposed to grid-side) resources. And only some countries have developed sophisticated grid connection rules for DERs rather than taking a “fit-and-forget” approach (one such rule allows DERs faster and more affordable grid connection in exchange for the right to curtail their output when network capacity reaches its limit).

This chapter therefore offers insights into four priority areas:

- improving visibility over DERs and the distribution system
- enhancing DER grid connections
- opening all wholesale energy and TSO markets to DERs
- ensuring fair market compensation for DERs

Key electricity market design and regulation priorities



In addition to the changes discussed in this report, it is also important to improve retail energy pricing and distribution network tariff structures; develop local markets in which DER services are traded; incorporate DERs into grid planning as an alternative to grid buildout; and proactively regulate and modernise distribution grids so that they can support the DER shift. All these measures can incentivise DER owners to site and operate their systems in alignment with grid needs, enhancing system reliability and efficiency together with DER economics. Besides, such measures can be adopted in many jurisdictions where vertically integrated utilities still prevail. These transformative actions thus merit further discussion in a subsequent study.

An overview of wholesale energy and TSO markets in Europe and North America

Europe and North America use different market models: the major differences are in market operator and TSO roles and responsibilities, which are embedded in all market design elements.

In most European jurisdictions, a market operator runs day-ahead and intraday energy markets, followed by TSO re-dispatching and balancing energy markets to ensure that supply meets demand in real time. A TSO often procures balancing capacity (i.e. operating reserves) in advance, and balance service providers offer balancing services to TSOs. Energy market prices do not account for transmission grid constraints within any predetermined zone (called zonal pricing), and the TSO re-dispatches generators to address grid congestion.

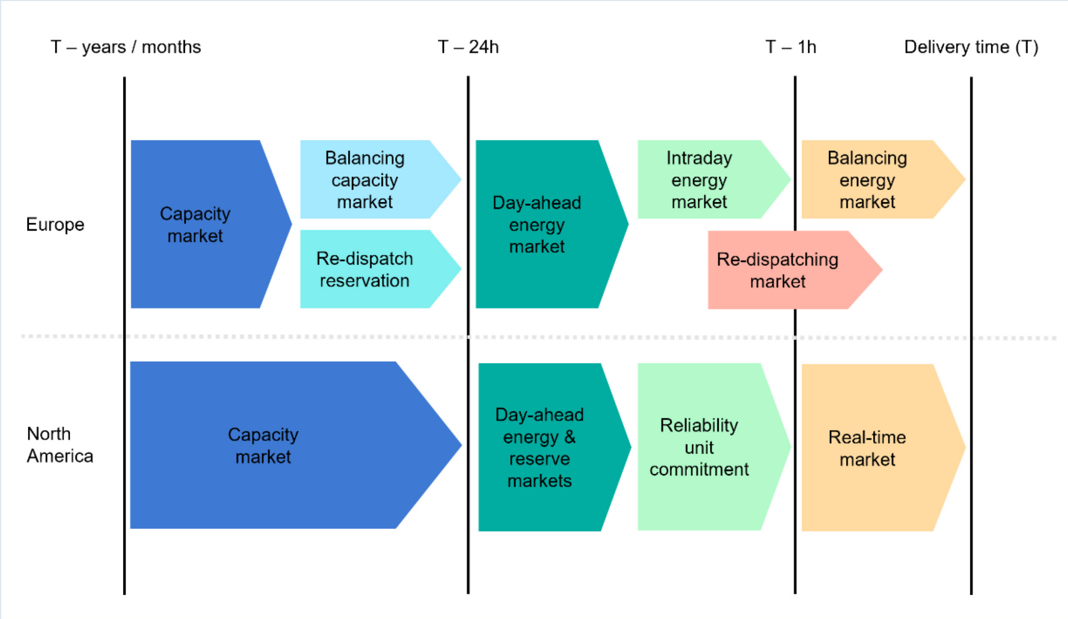
In some countries, TSOs operate capacity markets to ensure long-term resource adequacy. Energy market participants can determine their own generation and consumption without instruction from market operators (known as self-dispatch), but must designate balance responsible parties (BRPs), who maintain a consistent supply and demand balance on their behalf within a certain portfolio.

In many regions in North America, a single independent system operator (ISO) oversees both market and system operations. The ISO runs day-ahead energy and operating reserve markets, followed by reliability unit commitment, wherein the ISO corrects its commitment orders based on updated load and renewable generation forecasts. Finally, the ISO operates a real-time market to maintain supply and demand balance.

Market prices are set at each transmission node, reflecting network constraints (known as nodal pricing) so that re-dispatching is not necessary. Most ISOs also run long-term capacity markets. The ISO determines each generator’s merit order and output to minimise overall system costs (known as centralised dispatch).

Many regions around the world, including North America, have vertically integrated utilities instead of established markets, and some electricity markets have evolved slightly differently (Australia's National Electricity Market, for example, adopted centralised dispatch but zonal pricing). Nevertheless, the European and North American models are representative of the restructured electricity market.

European and North American market structures and time frames



Note: The last gate closure of continuous intraday energy markets in Europe is gradually approaching real-time delivery (from 1 hour ahead to 30 minutes, then 15 minutes and, more recently, 5 minutes).

Insight 1: Improving visibility

One of the main obstacles to integrating behind-the-meter resources into the power system is a lack of sufficient visibility over the resources and how they interact with the low-voltage (LV) grid they are connected to. Although high- and medium-voltage grids have a good level of automation and can provide real-time data on grid status, automation of the LV grid, which is costly due to its size, has not been much required until recently because consumer demand was predictable. Hence, DSOs usually lack extensive oversight of LV grids and, furthermore, their monitoring of the LV grid is complicated by the fact that behind-the-meter resources are located on the consumer's side of the meter.

As more DERs enter our energy systems, a DSO's insufficient visibility will create even more challenges (for example, in tackling voltage issues). Because weather patterns are becoming more variable and consumer behaviour is increasingly changeable owing to the prevalence of dynamic pricing and new technologies such as EVs, power flows within LV grids are less predictable than in the past. Furthermore, TSOs too will require a better picture of the LV grid and DER functioning and interactions. For example, when TSOs use DERs for their purposes such as balancing, close co-ordination between TSOs and DSOs may be required, so they will each need to have understanding of what is happening in the other's domain.

Identifying data gaps and planning to address them

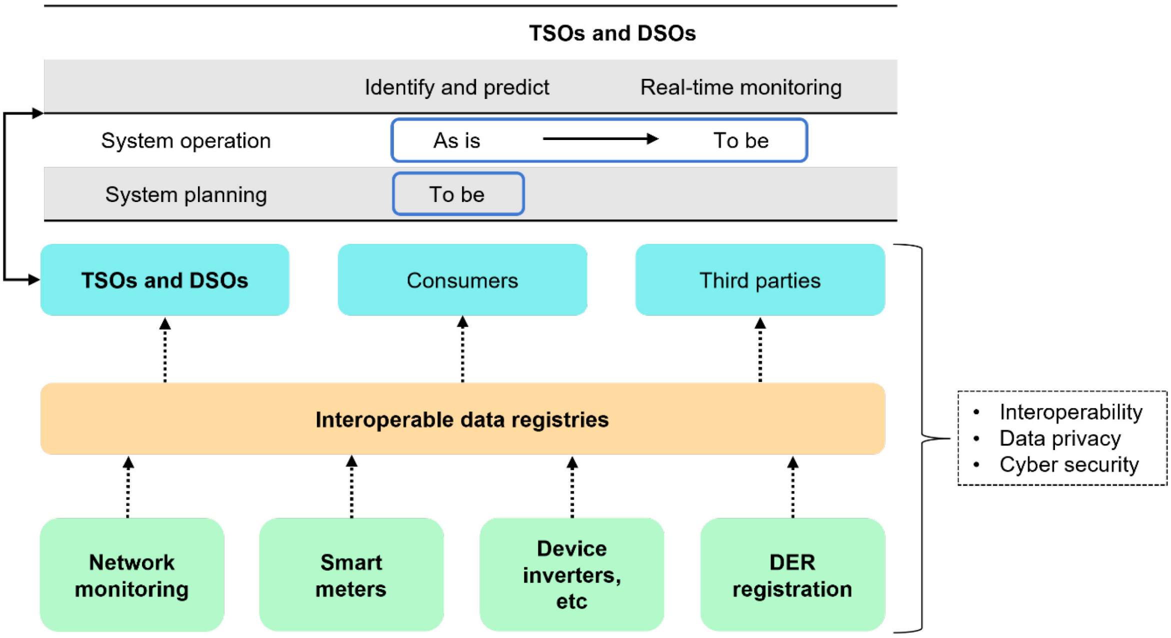
System operators collect and use data to perform their assigned tasks in the power system, with different data required depending on whether they are engaged in system supervision and operations or system planning. Each activity has fit-for-purpose data requirements involving several elements, including time frame and granularity. By definition, system planning (such as for grid infrastructure) requires data extending over a longer time horizon. In contrast, system operators need very precise and near-to-real-time data to monitor the status of grids and resources to prepare for any unexpected system failures. Accordingly, visibility over DERs and the LV grid has two levels or dimensions: identifying and predicting; and real-time monitoring.

Many jurisdictions are transitioning to a decentralised energy system, though not at the same pace. DER uptake varies from one country to the next, so each energy system accordingly faces different challenges and requires different fit-for-purpose levels of visibility. In addition, the automation of LV grids to enable real-time monitoring has just begun in many regions, providing a good opportunity for regulators to choose cost-efficient options to help operators secure appropriate visibility over the system. They can first prioritise issues that need to be resolved to reduce DER impacts on system reliability and unlock their potential.

Regulators and system operators can then decide on the allocation of roles and responsibilities between TSOs and DSOs. For example, DSOs may undertake more proactive functions, such as balancing supply and demand in their areas of operation,[9] while a TSO is responsible for addressing overall system imbalances as a residual balancer. In this case, only DSOs need to have sufficient oversight of LV grids and DERs, whereas the TSO does not require direct visibility over them. Regulators can then decide how much visibility system operators need for each activity involved in priority issues and devise suitable solutions to obtain it. Regulators can determine the most important data gaps and decide how to address them based on thorough benefit-cost analysis, keeping in mind that it is the consumer who ultimately pays the expense.

Some jurisdictions (e.g. Australia, Europe and North America) have begun to explore potential data gaps and solutions. Their experiences can help regulators in other regions evaluate where they are and devise fit-for-purpose solutions.

Data gaps in LV grid and DER operations, and a data management model



[9] This approach is called the "total DSO model" because DSOs are in charge of addressing supply and demand imbalances in their own territory, in addition to reliably planning, maintaining and operating the distribution grid. This model is discussed in more detail in this chapter's final section, which covers DER value stacking.

Making the most of multiple data sources and rolling out smart meters

Many DSOs still rely on predictive models of network status and are at the "identify and predict" stage of grid supervision, although the increasing connection of DERs to LV grids may eventually necessitate real-time monitoring, with new technologies enabling much greater visibility over the system. Modernising LV grids will require considerable investment, however, and not all grids will need widespread active monitoring immediately.

In some cases, current predictive models can forecast network conditions within an acceptable tolerance range. During this transitional period, however, the challenge is to determine what combination of available data and analytical tools, interoperability standards and guidelines, and new investment (e.g. in network monitoring equipment or smart meters) would ensure sufficient visibility most cost-effectively (so as not to impose unnecessary cost burdens on consumers).

Although DSOs generally invest in network monitoring equipment that can be readily integrated into their existing systems, the vastness of the LV grid may mean that investing in widespread monitoring assets will not always be the most cost-effective option. Regulators can ensure that cost-benefit analyses scrutinise new investment cases, but DSOs may struggle to determine the cost-effectiveness of various options without regulator-approved methodologies. For this reason, the Australian Energy Regulator (AER) is developing standard guidance to help DSOs use cost-benefit analysis, as well as a methodology to evaluate losses to all consumers when DER energy exports (such as from distributed PV) are curtailed. The AER's resulting customer export curtailment value (CECV) methodology can be used to justify investment in grid infrastructure that can reduce curtailment.

Alternatives to networking monitoring equipment to gain better visibility over the LV grid include smart meters, which are the first option to consider because they can provide multiple energy system benefits. According to a recent report, European countries recognise the various advantages of smart meter rollouts in their cost-benefit analyses, the most widely accepted being reduced energy consumption and lower meter-reading costs. Another acknowledged benefit is improved competition owing to more efficient supplier switching, peak-load shaving and avoided network costs.

In Europe, most countries with large-scale rollout plans (such as Finland) have mandated DSOs to install smart meters, while the United Kingdom and Germany are allowing competitive rollout among retailers or metering companies. The European Commission has recommended common minimum functional requirements that smart metering systems should have to benefit consumers, including meter-reading updates of at least every 15 minutes. In Australia, where smart meters are being rolled out on a competitive basis except in Victoria, data rights or contractual arrangements to allow DSOs and third-party service providers access to meter data are being explored.

Other sources of data collection are also available: for example, a range of manufacturers and service providers offer consumers advanced monitoring of their household load and DER devices (they usually collect data on DER technologies, including on voltage, from device inverters). In fact, Australia's DER industry, which includes inverter manufacturers, has developed a DER Visibility and Monitoring Best Practice Guide to establish common sets of static and dynamic (near-real-time) data to be collected for new behind-the-meter DERs installed on LV grids.

Broadband network service providers are another data source, as they can remotely monitor voltage levels in their service territories. Given the broad coverage of broadband networks, they can be alternative data providers in areas where smart meter rollout is inadequate. However, as DSOs need a range of data analytics and modelling tools when they use alternative data from different sources or systems, they can collaborate with experts and obtain government support for R&D projects to facilitate the development of these tools.

Developing interoperable data registries and securing static information on distributed energy resources

Data sharing among diverse stakeholders is critical to enable effective electricity market functioning. The sharing of data by system operators, DER owners, electricity retailers, aggregators and researchers can facilitate decision-making to ensure market transparency and competitivity. System operators can establish data registries to ensure effective centralised or decentralised data management. A centralised data hub can be overseen by a TSO or a regulated third-party operator to ensure data integrity and non-discriminatory data access. Conversely, local DSOs can manage decentralised data registries to safeguard data integrity and system security.

Data from these registries can be used for a range of purposes, including flexibility procurement, system operation and grid planning. Norway, for example, launched its national Elhub data hub in 2019. Statnett (Norway's TSO) owns and operates the data hub under supervision of the Norwegian Energy Regulatory Authority (RME-NVE), which makes legal decisions and regulates Elhub's revenues. DSOs are responsible for providing hourly metering data on a daily basis and for guaranteeing data quality. Consumers can retrieve their metering data via Elbub's web-based solution or their retailer's web page and can grant third parties access to the data. Market participants also have access to Elhub's web portal with several services, including meter data verification. A new solution to allow Elhub to provide more granular 15-minute-resolution data is being developed.

As most DERs are "hidden" on the consumer's side of the electricity meter, government subsidy programmes such as net energy metering are often the only reliable source of data on them. However, these subsidy programmes are not likely to continue indefinitely and cannot keep up with a rapidly growing number of wider resources, including battery storage and EVs. Meanwhile, applying data analytics to smart meter data can help identify DER technologies by using factors such as weather and daily cycles to identify patterns of, for example, households equipped with distributed PV systems. Nevertheless, these methods have limited use without sufficient smart meter rollout.

As gaining greater visibility over DERs begins with knowing they exist, system operators can develop a reliable mechanism to discover where they are. For example, the Australian Energy Market Operator (AEMO) launched a DER Register to store static data on DERs installed at residential and business locations, including their installed capacity as well as the inverter's make and model. DSOs request this information from electrical contractors and distributed PV installers when the DERs are installed, but private information such as consumer consumption is not collected. The register is expected to give the AEMO and DSOs clearer visibility over the DER situation to inform power system planning and operations.

Distribution network operators (DNOs) in Great Britain have a similar DER register, the Embedded Capacity Register. Each DNO has its own register and provides static information on generation and storage resources above 1 MW connected or accepted for connection to the DNO. Information includes each resource's location, energy source, installed capacity and import and export capacities, and is updated monthly. DNOs are considering extending their registries to include resources of less than 1 MW.

Recently, the GB energy market data hub ElectraLink created the Flexr data-sharing service to gather data held by DNOs and their DER customers into one place, making the information easier to find and use. Whereas DNO data have been available from six different DNO systems (often via spreadsheets), creating unnecessary data access costs and complexity, Flexr will allow users to see all distribution networks in Great Britain and their DER data through a single access point. This GB project demonstrates that data access can be improved regardless of whether data registry management is centralised or decentralised.

Exploring a common flexibility resource register and more granular visibility

System operators can work together to develop a common flexibility resource register, a concept devised in Europe to further facilitate data exchange between TSOs and DSOs to co-ordinate grid congestion management. The register, which contains structural information on connection points that can provide flexibility services to system operators, can offer (at minimum) technical information as evaluated in the pre-qualification process (e.g. location, capacity limits, ramp rates and duration). Once a resource is qualified to provide a specific service, its connection point is flagged as a potential provider of that service in the register. In this way, the register gives system operators adequate visibility over which resources are connected to their own grid and to their connected grids, enabling them to know what resources are available at all voltage levels.

The register may also allow system operators to exchange data about their respective grids, helping them assess the impact of activating resources on their own grid and their connected grids to avoid actions that could compromise overall system reliability. Additionally, the register can benefit resource owners, making them visible not only to the system operators to which they are connected but to all system operators they can provide flexibility services to, thereby improving market competition. System operators can provide the market with information on issues such as if or when grid congestion is expected, for example. This can give resource owners more advance notice of potential revenue opportunities.

The common flexibility resource register can be developed using pre-existing tools. For example, asset IDs, which can be linked to multiple data sets as well as multiple markets and services managed by different parties, can serve as a single reference point for all energy asset data. Responsibility for entering and maintaining registry data can be decided at the national level, but the system operator for the grid a resource is connected to remains responsible for the correct representation of connection data. Furthermore, any data system operators provide to market participants need to be carefully examined to avoid the sharing of commercially sensitive information and to minimise potential for gaming and abuse of market power.

In the future, the register could be further used for such transactions as registering connections and financially settling flexibility services between market parties. In fact, the INTERRFACE project in Europe is developing a common flexibility resource register as part of an interoperable pan-European grid services system that can act as an interface between system operators and customers, co-ordinating the operations of all stakeholders to use and procure common grid services.

In some jurisdictions, regulators and system operators are exploring how to achieve more granular visibility of consumer-sited resources. Two dimensions of granularity can be considered: the unit used to measure or aggregate consumer data (e.g. a feeder section, household or individual device); and time intervals of meter-reading or telemetry data updates (e.g. daily, hourly or sub-hourly).

Nordic regulators are exploring sub-metering to help independent aggregators to compete in the market, which they believe improves market efficiency and benefits consumers. Currently in Nordic countries, DSOs install and own whole house smart meters, and they are responsible for metering and validating consumer data used in financial settlements. In this situation, household loads shifted by, for example, demand-response activation of a water heater needs to be estimated using a mathematical model. The model can be either agreed upon between an aggregator and a retailer or adopted by system operators tasked with the work on behalf of market participants. However, Nordic regulators do not consider this a feasible solution given the inaccuracy of such modelling and the potential for disputes between aggregators and retailers. This is why they are investigating sub-metering of individual devices by independent aggregators, with metering costs internalised by the aggregators.

In the United States, the Federal Energy Regulatory Commission (FERC) has ordered ISOs to open all markets to DERs. Accordingly, ISOs need to establish metering and telemetry requirements for DERs participating in their markets. Although FERC allows ISOs some flexibility, they must justify their requirements and avoid imposing unnecessary or undue restrictions on individual DERs (requirements may vary depending on a DER aggregation's services and size).

In any case, aggregators can be central in balancing system needs with consumer cost burdens. FERC clarified that each aggregator is an ISO's single point of contact and is therefore responsible for metering, dispatching and financially settling the individual DERs in its aggregation. The California ISO, for example, requires telemetry data at an aggregated level, not from the individual DERs in an aggregation. Plus, it expects real-time 4-second telemetry data only if the aggregation is 10 MW or larger or provides ancillary services. Conversely, the New York ISO asks for real-time 6-second telemetry data from both DER aggregations and individual DERs, but for resources of 100 kW or less it provides a mathematical methodology to calculate (rather than measure) 6-second values with 1- and 5-minute metered data.

Data privacy and cybersecurity of decentralised energy systems

The energy industry's transition to a decentralised system of real-time, network-connected grid-edge assets could create data privacy and cybersecurity challenges. Making energy systems increasingly decentralised, digitalised and electrified will significantly expand global electricity network interconnections and interdependence.

The proliferation of internet-of-things (IoT) devices raises concerns about using these technologies safely and securely, and the infiltration of distributed energy devices on consumer premises expands the potential for data breaches and cyberattacks. Sensitive consumer data can leak out anywhere along the supply chain, including from third-party service providers, retailers and even system operators. What is more, malicious attacks on end-use consumer devices can spread into utility control systems unless appropriate protection is employed.

As DER use requires greater sharing of consumer data, private data need to be protected at the source, in transit and at rest, with an effective system in place to destroy information in a secure and timely manner. In principle, who can have access and their means of access need to be clearly defined, as well as the level of granularity they can obtain. Consumers should have complete access to their own data – smart meter or other household-level data – and control over how this information is used by third parties such as energy service providers.

Beyond this, however, regulations are not clear. For example, it has not yet been decided unequivocally which smart meter data can be used without consumer consent, for what purposes and under which restrictions, even by the regulated system operator in its legal grid operation and planning tasks. Regulators therefore need to identify and clarify data needs and specify who can access information and how. To this end, regulators can establish rules pertaining to all relevant issues, including data formats, data exchange protocols and governance, and consumer consent mechanisms.

The effects of cyberattacks on critical power infrastructure can be devastating, sometimes even resulting in loss of life. Though every entity along the supply chain should be prepared for the risks, regulations are critical to build a common foundation of cyber-resilience practices. Policymakers can establish guidance similar to the Cyber Assessment Framework (CAF) developed by the United Kingdom's National Cyber Security Centre (NCSC). Such guidance can encourage power utilities to develop a comprehensive cybersecurity programme to identify and mitigate potential risks; implement cybersecurity governance, monitoring and detection, and controls; and minimise impacts and facilitate recovery from cybersecurity events.

In addition, policymakers can develop cybersecurity standards that utilities can follow when deploying or updating their systems. The National Cybersecurity Centre of Excellence (NCCoE) at the US National Institute of Standards and Technology (NIST), for example, offers several technology-specific use cases to help security architects and engineers at utilities efficiently design and deploy security tools and platforms. Furthermore, it is important that regulators, together with industry stakeholders, always be aware of the cybersecurity gaps emerging technologies can introduce, and collectively plan to address them.

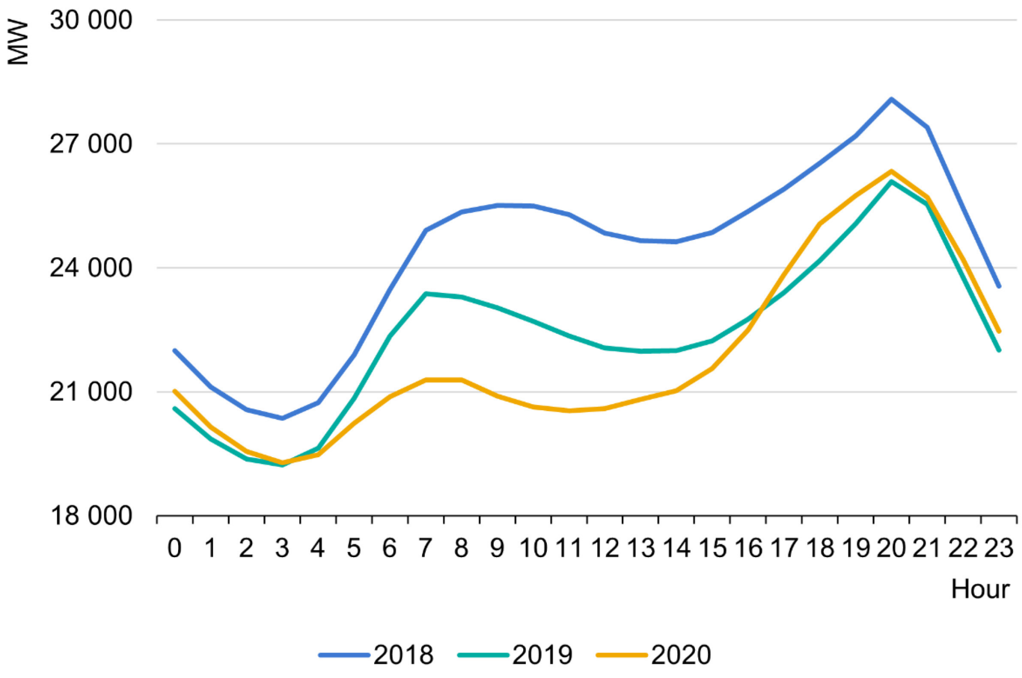
Improving system operator capacity for forecasting and analysis

System operators use a range of tools in managing grids. These tools can help them predict and analyse the behaviour of resources and systems across time frames, ranging from real-time operations to long-term planning. Network analysis and forecasting models, together with necessary data, provide a basis for predicting upcoming system status and simulating likely system performance under future conditions, offering a reasonable notion of how the grid will perform.

However, a range of emerging resources (including distributed PV and battery storage) is presenting new technological and operational characteristics, making reliable grid management more challenging for system operators. Accordingly, increasing DER penetration will require that appropriate methodologies and models be developed to predict and analyse their behaviour.

In California, total installed distributed PV capacity rose from 6.9 GW in 2018 to 9.3 GW in 2020, altering the overall shape of the demand curve, as the figure below shows. Among others, yearly drops in midday demand, when solar energy resources are most abundant, can therefore be attributed to greater consumption of distributed PV-generated power.

Average hourly electricity demand in California, fourth week of May, 2018-2020



Source: Data from California ISO (2022), Demand trend.

As distributed PV installations become more prevalent, total system demand approaches net demand, implying that distributed PV generation can significantly impact system demand forecasting (i.e. daily peak times shift towards the afternoon and then the evening). Plus, morning peak patterns vary as more distributed PV systems begin to generate power, so demand forecasting errors become more significant if distributed PV generation is treated as bundled (i.e. part of overall consumer demand). It is possible to some extent to train a forecasting model to learn new patterns of net demand without disaggregating distributed PV. However, the ability of such a model to appropriately reflect the impacts of weather changes such as cloud movements (which are more pronounced for distributed PV) is restricted.

The California ISO produces two types of short-term demand forecasts – hourly day-ahead and 5-minute hour-ahead – and its improved demand forecasting incorporates distributed PV outputs from an inverter company as a separate input to its models. Additionally, behind-the-meter weather forecasts (e.g. for cloud cover) are added to the models together with other weather forecasts (e.g. for temperature). Cloud-movement forecasting is an important factor, especially in distributed PV-concentrated areas. For example, the California ISO recorded that San Diego's demand fluctuated up and down by 500 MW for 30-60 minutes as clouds passed into and out of the area, lowering and raising distributed PV generation. In this way, system operators can reflect the unique features of distributed PV and improve short-term demand forecasting, which is fundamental to reliable day-ahead and real-time market operations.

DER behaviour during grid disturbances could also be a significant factor in power system operations. Accordingly, it is becoming increasingly crucial for DERs to be accurately represented in a system operator's dynamic models to be properly accounted for in system stability studies. Representing many millions of various consumer devices in a dynamic model is challenging, however. The responses of aggregated DERs during a wide range of disturbances need to be captured, taking account of the many different models and ages of devices, their various performance settings and varying grid conditions. The challenge is to develop a model that is suitably accurate as well as simple and flexible enough to be useful for daily power system studies.

International research is therefore underway to develop dynamic DER models. System operators can apply such models to the unique features of their power systems by, for example, specifying the parameters of each of the model's components to represent operational characteristics of DERs in that power system, such as the resources' expected response to grid disturbances. The North American Electric Reliability Corporation (NERC) has provided a guideline on dynamic DER modelling for system operators in the United States.

In this regard, grid codes for DERs are critical to ensure power system reliability, as they define the technical requirements for resources desiring to be connected to the grid, including how they should respond to grid disturbances. For instance, an emergency caused by non-DER factors (such as a power generation failure) could be made worse if a substantial number of distributed PV systems collectively disconnect following the grid disturbance, and the system operator's dynamic models could not appropriately predict this disconnection.

Hence, grid codes can require distributed PV systems to stay online and ride through minor grid disturbances, preventing the mass disconnection of unmonitored distributed PV installations (the following subsection discusses this issue in more detail). In addition, grid codes can help ensure that DERs are accurately represented in a system operator's dynamic models, as they can define and require certain performance settings (for example, of inverters attached to distributed PV systems). When grid codes are well enforced for the majority of distributed PV installations, dynamic models will be better able to predict their behaviour during grid disturbances.

Furthermore, system operators can improve their long-term forecasting capacity. Failing to incorporate accurate DER forecasts into long-term system planning can have wide-ranging consequences. For instance, over-forecasting may prevent sufficient generation resources from being built, resulting in a less reliable system. Meanwhile, under-forecasting adds unnecessary generation resources and grid infrastructure, leading to higher-than-necessary cost burdens for consumers. For example, a recent modelling study in the United States showed that severe under-forecasting of distributed PV adoption cost utilities in the US Western Interconnection nearly USD 7 million per TWh of electricity sales, while severe over-forecasting cost it more than USD 2 million per TWh. These two opposite-end cost impacts correspond to distributed PV adoption levels of between 6.5% and 8.5% of total energy generation over 15 years and forecast errors of ±100%.

Two types of approaches can be used to estimate future DER deployment: top-down and bottom-up. The top-down method, which has been widely used in the past, often extrapolates a historical relationship between macro-level factors such as economic growth and DER adoption levels to the future. It assumes modelling individual consumers is not necessary or feasible, thus enabling easier data collection and model execution. However, this method struggles to distinguish among different types of consumers, treating everyone as the average. This is not realistic because, for example, some consumers are more likely to adopt novel technologies such as distributed PV, while others may be uninterested in them or unable to afford them.

Therefore, the bottom-up method is being increasingly used as DER adoption grows. As an example, this method can incorporate customer decisions into distributed PV forecasts by evaluating their economic potential based on individual consumer characteristics (e.g. electricity consumption, and building and roof profiles) as well as the retail tariff structure. The relationship between such customer characteristics and distributed PV deployment is revealed by training the model using prior adoption based on, for example, machine learning. This data-driven customer adoption model can predict the future more accurately, but significant investments in data and computing resources are required. What is more, this method entails some inherent uncertainty, as key input parameters, such as future fuel costs and renewable policy mandates, cannot be fully predictable.

Insight 2: Reliable and flexible grid connection

DERs desiring to export or withdraw energy need to be connected to the grid, but this means they must adhere to grid connection rules such as requirements for resources to keep the grid reliable; procedures to analyse and mitigate their impacts; and payments for grid use and reinforcement. Thus, grid connection rules substantially influence not only grid reliability but DER economics.

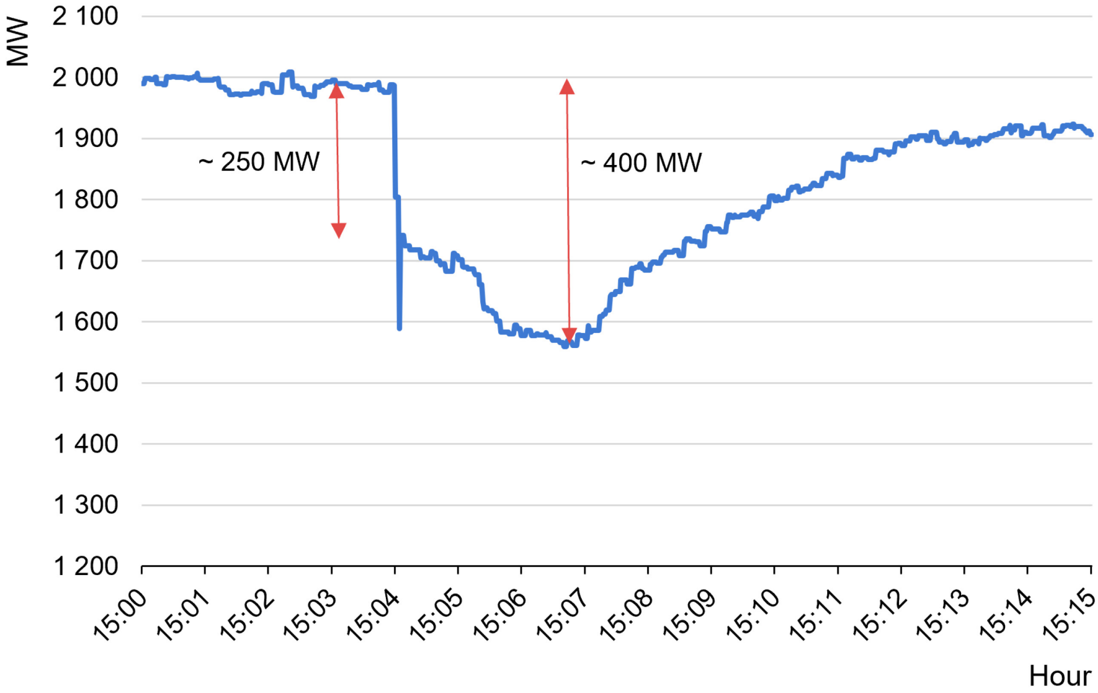
Increasing penetration of DERs such as distributed PV can therefore present challenges to a grid that is unprepared: for example, the collective disconnection of unmonitored distributed PV systems following a grid disturbance can make the consequences of the event even worse. Furthermore, local voltage problems can result from significant DER energy injected into a distribution grid. Although grid connection rules for DERs may evolve to address these issues, some new developments (such as fixed, static export limits) may compromise sustainable DER growth. This section therefore presents recent experiences in formulating DER grid connection rules to balance the two objectives of safeguarding grid reliability while sustaining DER growth.

Updating grid codes to ensure reliability

Among the challenges rapid distributed PV penetration can present for an unprepared grid, the preeminent risk is that a substantial number of unmonitored distributed PV systems may collectively disconnect following a grid disturbance to protect themselves. This mass disconnection can exacerbate the effects of an emergency caused by other factors (e.g. power generation failure) or can delay system restoration after the event.

On 3 March 2017, a series of faults in South Australia's transmission system led to the loss of 610 MW from five large generators, triggering a sudden voltage drop. The voltage disturbance resulted in a demand reduction of roughly 400 MW, as energy-consuming devices also cease operation during this type of disturbance, mitigating the risk caused by losing 610 MW of generation (this is called "load relief"). However, approximately 150 MW of unmonitored distributed PV also disconnected for several minutes in response to the disturbance, offsetting the demand reduction and causing initial load relief to shrink to 250 MW. Although load relief rose again to 400 MW when the distributed PV systems finally reconnected, the temporary mass disconnection delayed system restoration.

Electricity demand in South Australia, 3 March 2017



Source: AEMO (2019), Technical Integration of Distributed Energy Resources.

Not only Australia experienced such risks: Germany's 50.2-Hz incident is another well-known example. In 2006, Germany's system was designed such that all generators connected to a low-voltage network would have to be switched off immediately if power system frequency rose to more than 50.2 Hz, and late one evening that year, a power system separation in Europe caused system frequency in one of the separated regions of the interconnection (including part of Germany) to exceed this level. While the region's total distributed PV capacity was small at that time, only a few years later it was expected to reach several gigawatts, meaning that a loss of generation due to collective distributed PV disconnection could result in an emergency.

Thus, in 2012 the German government mandated all new and existing distributed PV systems to temporarily withstand over-frequency disturbances beyond 50.2 Hz. Distributed PV systems larger than 10 kW were retrofitted with more than 315 000 inverters as a result, at a cost of nearly EUR 175 million. In addition, Great Britain experienced a total of around 580 MW of distributed generation loss during a power outage in August 2019, and California had net-load rises of 130 MW (in April 2018) and 100 MW (in May 2018) as a result of distributed PV disconnection during transmission line outages.

By activating over-/under-voltage and frequency ride-through functions, advanced inverters can help distributed PV systems withstand minor grid disturbances that cause voltage and frequency rises or drops. Standards for advanced inverters can define requirements for continuous operation during voltage and frequency disturbances, and they can also identify the severeness of disturbances during which distributed PV systems must disconnect from the grid. For example, standards can ensure that distributed PV systems get disconnected when the risk of nearby disturbances is high, but not when events are remote. In addition, standards can define required distributed PV behaviour during and following disturbances: for example, if distributed PV systems are allowed to rapidly recover their original output following an under-frequency disturbance, which is usually caused by loss of generation, they can help restore the system.

Another imminent challenge distributed PV systems present for distribution grids is their impact on voltage. DSOs typically deploy equipment such as capacitors to counteract voltage drops from substations along distribution feeders due to loads, so when distributed PV systems export significant amounts of energy to a grid that is not designed for bi-directional power flows, the local voltage can rise beyond the acceptable upper limit. For example, an analysis of 500 distributed PV sites in South Australia showed that the 99th percentiles of monthly voltages of the low-voltage grids were consistently above the upper threshold of 253 V.[10] Voltage levels were highest during the spring when energy demand was low relative to solar generation output.

Advanced inverters can also enable voltage regulation, which allows distributed PV installations to adjust their power output according to the local voltage. This function can make distribution grids less susceptible to the unacceptable voltage variations that are particularly prevalent during variations in distributed PV output. This means that the capacity of distribution feeders that can host new distributed PV systems can be enhanced without additional network-side investment, so consumers can continue investing in DERs without high network costs being passed on to them.

For example, the US Arizona Public Service utility's Solar Partner Program demonstrated that distribution network voltage issues could be best mitigated at the residential customer level using a functional advanced inverter mode called voltage-reactive power (volt-var). In this mode, an advanced inverter can inject or absorb reactive power[11] according to a distribution network's voltage deviation to keep it within the target range. Constant power factor mode is another functional mode

[10] Following this study, line-drop compensation equipment was rolled out across the networks, which has materially improved voltage levels in high-solar areas.
[11] Reactive power energises the magnetic field but does no actual work. It can be injected to raise the voltage level or absorbed to lower it.

recommended for distributed PV systems. In this mode, an advanced inverter can absorb reactive power of distributed PV in proportion to its active power output, mitigating potential local voltage rises.

The US Institute of Electrical and Electronics Engineers (IEEE) recently developed an advanced inverter standard (Standard IEEE 1547-2018), and regulators can adapt their grid codes to accommodate the capabilities required by the standard, such as voltage/frequency ride-through and voltage regulation. The functions may sometimes be one of a few feasible or economical solutions for imminent challenges when visibility over increasingly prevalent DERs is insufficient. Even in grids with low DER penetration, however, using such functions today could reduce the need to change systems in the future (Germany's 50.2-Hz experience demonstrated that the cost of retrofitting with inverters could be substantial).

The IEEE standard allows flexibility in opting for specific performance categories and functional settings. Hence, collaboration among stakeholders, including device manufacturers, project developers, TSOs and DSOs, is critical to reach a consensus on specific requirements to reflect the needs of each power system. In addition, the IEEE 1547.1-2020 test procedures, which regulators can refer to in grid codes, can be used to verify compliance with IEEE Standard 1547. Test procedures need to be introduced soon after publication of such a new standard to accelerate the market availability of DERs compliant with the standard.

Jurisdictions recognise the value of the IEEE standard. For example, the National Association of Regulatory Utility Commissioners in the United States approved a resolution in 2020 recommending that state utility commissions, which are responsible for DER grid codes, adopt Standard IEEE 1547-2018. Meanwhile, the electricity utility Hawaiian Electric requires that the standard be met for newly grid-connected consumer-sited DERs (which it calls customer energy resource [CER] systems) from July 2022. Hawaii's rate of rooftop solar adoption is one of the highest in the United States, with 21% of Hawaiian Electric's residential customers having an installation. In addition, the Australian Energy Market Operator (AEMO) recently proposed changes to its DER standards to align with international practices such as the IEEE 1547-2018 standard.

In Europe, industry stakeholders[12] recently discussed the need to update the Pan-European grid codes, called Network Code Requirements for Generators (NC RfG), to require advanced inverter capabilities for type A generators (type A generators

[12] In 2019, an expert group was established to review the European grid codes for type A generators. All relevant stakeholders were represented in the group, including regulators, TSOs, DSOs, energy companies and standardisation organisations.

are typically no larger than 1 MW in capacity and are connected to the low-voltage network).[13] They concluded that type A inverter-based generators such as distributed PV need to have fault ride-through capabilities, which is currently required for only types B, C and D generators. This discussion could be a springboard for regulators to officially introduce relevant amendments to the NC RfG.

In addition, many European DSOs have legal or contractual rights to exercise some control over the management of reactive power for their customers' equipment. German grid codes, for example, require type A inverter-based generators to provide network voltage support by adjusting the injection or absorption of reactive power depending on local voltage, called Q(U) control.[14] EN 50549, the European standard for distribution grid-connected generators, serves as a technical reference for national grid codes.

Preparing for potential challenges

As Australia's distributed PV penetration has been among the fastest in the world, new grid reliability challenges are emerging, including rapidly declining minimum operational demand. The AEMO identifies this declining operational demand as a risk, especially when interconnection with neighbouring grids is lost in South Australia or Queensland. For the systems to operate reliably there must be the minimum levels of demand supplied from the grid (i.e. not from distributed PV) that are required to maintain sufficient levels of synchronous generation and emergency load shedding (these can provide essential reliability services, such as system frequency support).

Synchronous generators such as gas turbines have been the main providers of system inertia for arresting frequency drops[15] and of spinning reserves for restoring frequency back to within acceptable limits in response to contingency events. Another major risk is the unmonitored mass disconnection of distributed PV installations during a grid disturbance, especially when a substantial number of DERs in the power system are not equipped with robust fault ride-through capabilities.

On 26 September 2021, South Australia's minimum operational demand fell to 236 MW, with distributed PV meeting 82% of total demand, as the below figure

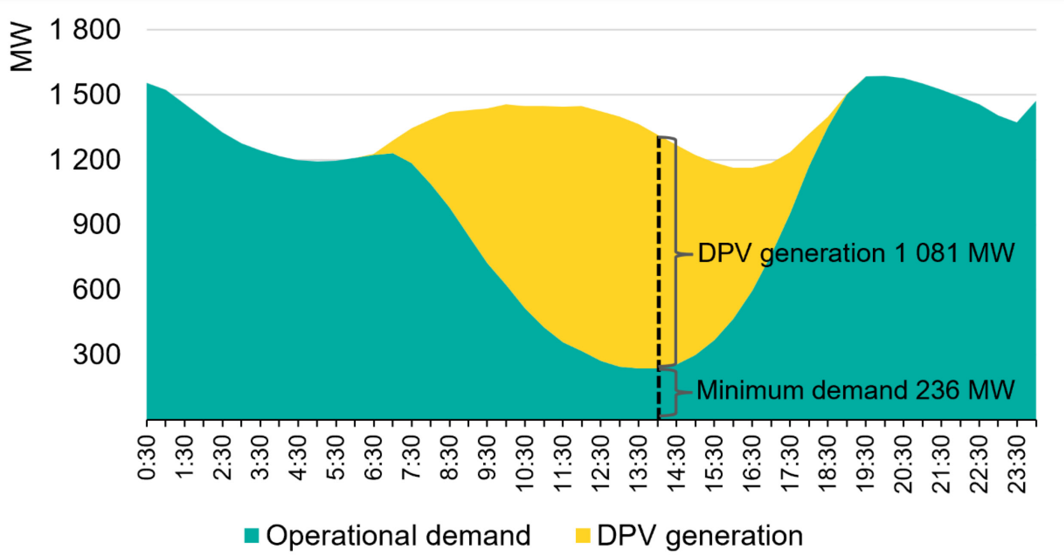
[13] The NC RfG defines four types of generators: A, B, C and D. The network code specifies maximum capacity thresholds for each type: A/B = 1 MW; B/C = 50 MW; and C/D = 75 MW. Type A, B and C generators are connected to networks below 110 kV, while type D generators are connected at or above 110 kV.

[14] The Q(U) control in Europe corresponds to the voltage-reactive power (volt-var) mode in the United States.

[15] The rotating machines of synchronous generators directly coupled to the grid have typically provided system inertia. Inertial response reduces the rate of change of frequency (RoCoF) following a disturbance.

illustrates. Furthermore, in Southwest Australia, as the region's operational demand decreased between 2018 and 2020, average daily output drops of 100-300 MW were recorded for synchronous generators except around the evening peak period.

Operational demand and distributed PV generation in South Australia, 26 September 2021



Note: DPV = distributed photovoltaic.
Source: Data from AEMO (2021), Market Data NEMWEB.

AEMO proposed a minimum system load protocol consisting of three market notices. First, AEMO forecasts potential minimum system load events that may require a market response, then the operator advises actions needed to maintain system reliability, including recalling planned transmission maintenance outages, directing scheduled loads such as pumped hydro into service to increase demand, or curtailing large-scale generation. If these measures are not sufficient to maintain minimum operational demand, AEMO notifies the market that distributed PV curtailment will occur as a last resort. The operator is studying how to determine minimum system demand thresholds that place power system reliability at risk, and when remedial actions will be required, including reducing distributed PV energy exports to the grid. Distributed PV curtailment is currently proposed as an emergency fallback measure, but AEMO expects it could extend to procurement in the market and through other incentivised arrangements.

In parallel, AEMO is developing measures to enhance its ability to manage the power system at lower levels of operational demand. These include scheduling additional spinning reserves, introducing fast frequency response (FRR) services and improving emergency load shedding. An FRR service is a sub-second frequency response that could be delivered by battery storage, for example, to compensate for declining system inertia.

In addition, emergency load shedding can be improved by adopting dynamic arming. Load shedding typically disconnects predetermined circuits (or blocks of load) to mitigate the effects of an under-frequency disturbance (a system imbalance due to the loss of generation, for example). However, load-shedding activation can be "disarmed" for circuits that have high levels of distributed PV and thus inject net energy into the transmission grid, so as not to disconnect them. Otherwise, load shedding could provoke an even greater frequency decline.

The AEMO proposal is still under development, and suggestions for its improvement could help regulators in other jurisdictions. Regulators can first establish clear rules to allow a social licence to control customer DERs. They can also prioritise other measures such as demand turn-up solutions to address risks, as appliances equipped with demand-response capability can be used to increase loads when minimum operational demand is likely to drop to its threshold level. In fact, Australia is discussing mandating priority household appliances to have two-way communications and control capabilities. Furthermore, regulators can develop a strong quantitative understanding of the likelihood and magnitude of the risks of falling below minimum operational demand limits. A thorough cost-benefit analysis of distributed PV management could help develop possible solutions, including their budget estimates and fair compensation levels for consumers' distributed PV cut-offs.

Introducing flexible grid connection arrangements

Generators desiring to connect to a constrained distribution network may have to endure high costs and long wait times. For example, under the current shallow-ish rules[16] in Great Britain, distributed generators with capacities of 3.68 kW or higher are liable for network reinforcement costs at their connection voltage, plus further into the network at one voltage level above, when they connect to a constrained network and trigger reinforcement. Alternatively, a static limit can be set on the maximum export capacity of a distributed PV system to manage its impact on the network. For example, distributed PV owners in South Australia with standard grid connection contracts are currently limited to

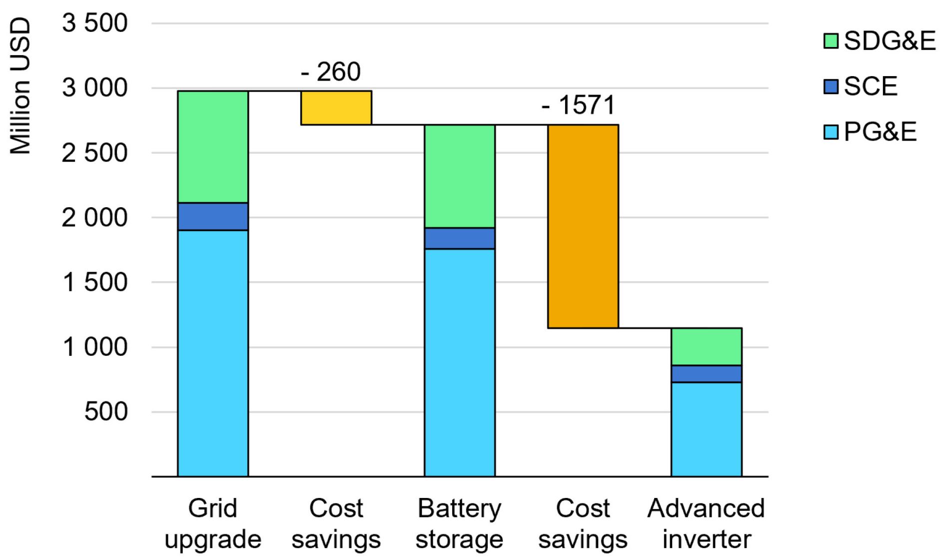
[16] In 2021, Ofgem, the GB energy regulator, published its minded to position on the April 2023 implementation of shallower distribution grid connection charges, with connecting generators receiving a reduced charge for reinforcement of the shared network.

exporting 5 kW per customer site, although this may mean reduced revenues for distributed PV owners under South Australia's feed-in-tariff schemes that pay for net exported energy at a fixed rate. Therefore, finding solutions to provide faster and more cost-effective access to constrained parts of distribution grids without incurring reinforcement expenses is critical to unlock DER potential.

Networks can be busy for several hours a day when distributed PV systems inject energy into the grid (typically at midday) or when EVs withdraw it (in the evening), with added power line capacity possibly remaining unused the rest of the day. Therefore, rather than reinforcing the grid, regulators and DSOs may find it more cost-effective to incentivise DER operations to align with network conditions. For example, during hours of high solar generation, equipping distributed PV systems with advanced inverters can mitigate voltage rises, and battery storage can absorb excess solar energy production.

In fact, a recent study estimates that three investor-owned utilities in California could save up to USD 1 831 million in distribution network reinforcement costs for integrating DERs in 2026 when advanced inverters have been adopted to mitigate voltage issues. Furthermore, the three utilities could save an additional USD 260 million by also deploying customer-sited battery storage.

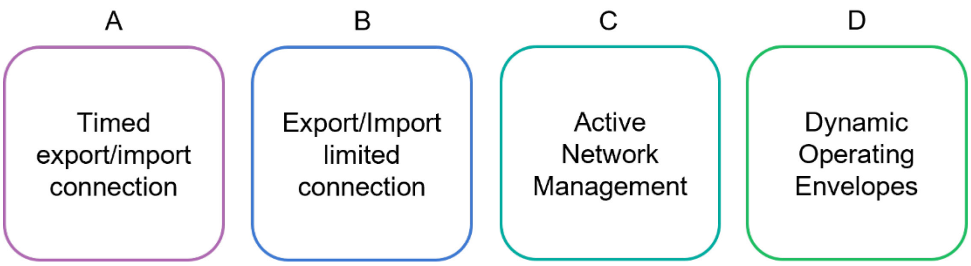
Cost savings from using advanced inverters and customer battery storage to integrate distributed PV into California's distribution grid in 2026



Notes: SDG&E = San Diego Gas and Electric. SCE = Southern California Edison. PG&E = Pacific Gas and Electric. New distributed PV systems are assumed to be placed at the end of the circuit furthest from substations.
Source: Data from DNV GL (2020), Customer Distributed Energy Resources Grid Integration Study: DER Grid Impacts Analysis.

Regulators and DSOs can adopt flexible rules to enable DERs to connect to constrained parts of a distribution network more quickly and affordably with higher (export or import) capacity limits, unlocking the potential of DERs. There are several options to consider.

Options for flexible grid connection arrangements



Distribution network operators (DNOs) in Great Britain have flexible grid connection schemes. These flexible connections, often called non-firm connections, either limit the times when sites can export or import, or the capacity that can be exported or imported. The schemes enable faster and more affordable connections to constrained parts of a distribution network but do not compensate for curtailments, and the types of flexible connections available vary depending on the DNO.

Timed export/import connections offer customers the possibility of connecting to the network but with limited exports/imports during certain periods of a day, week, month or year. Export/Import limited connections are used for sites that have greater export/import capability than that which has been agreed to be exported to/imported from the distribution system; these sites incorporate failsafe devices to ensure that the amount of electricity exported or imported remains within the pre-agreed limits. For example, an EV charging station may use an import-limited connection scheme to ensure that charging of its EV fleet does not exceed its maximum agreed import capacity.

Active network management (ANM) is a more advanced form of flexible connection in Great Britain. This scheme monitors all constraints on a network in real time and allocates the maximum amount of capacity available to each customer in that area, curtailing other energy exports as required to avoid exceeding the network limits. Hence, ANM requires communications equipment and a centralised network control system. Three methods currently exist to determine curtailment: the last-in first-out (LIFO) approach; pro-rata determination; and curtailment indexes. The LIFO method curtails generators in reverse order of their connection application, while under a pro-rata system, curtailment in an ANM zone is shared by all generators exporting during a constraint period, proportional to their export level. The curtailment index method provides a safety net for customers, protecting them from excessive curtailment. A predicted curtailment index is assigned to each customer, and DNOs intervene if actual curtailment approaches or exceeds the index value. According to UK Power Network, in its Flexible Plug and Play trial the ANM scheme delivered average connection cost savings of 87% for distributed generation customers (compared with the business-as-usual alternative) and reduced connection lead times by over 57%, or an average of 29 weeks.

Australia is currently exploring another advanced form of flexible connection, called dynamic operating envelopes. Operating envelopes are the maximum capacity limits at which consumers can export or import energy to or from the network. "Dynamic" means the limits can vary depending on time and location, allowing higher exports when the network has greater hosting capacity.

SA Power Networks (SAPN), a distribution network service provider in Australia, trialled a new flexible grid connection with Tesla. In this project, SAPN published 24-hour dynamic export limits with 5-minute intervals on a 5-minute rolling basis. Tesla successfully operated its virtual power plant (VPP), consisting of a distributed PV system and a battery per customer site, at up to 10 kW of exports while complying with the limits SAPN had issued for diverse network conditions. The VPP's export capacity was constrained to 5 kW (the current static export limit) for only a short period each day during peak solar hours; additional capacity was available during the morning and afternoon shoulder periods. This project revealed that time- and location-varying export limits could enable networks to host DERs at higher penetration levels.

Based on the trial, the SAPN investigated three options to prepare for when part of the network reaches its technical limit: putting a static zero-export limit on new DERs; imposing flexible export limits of 1.5-10 kW depending on prevailing network conditions; and reinforcing the network while retaining the current 5-kW export limit that applies all year round. According to SAPN analysis, the flexible export limit option had the highest net worth of all three, with the value of additional energy exports[17] outweighing expenditures on new systems for low-voltage network monitoring and modelling. In contrast, under the network reinforcement

[17] The energy exports came from both passive distributed PV sources and battery storage due to VPP dispatching in response to wholesale energy market price signals.

option the total cost to add enough capacity to the network surpassed the increased value from unconstrained energy exports. Furthermore, in September 2021, the SAPN began offering a new Flexible Exports trial connection option for distributed PV customers connecting to congested parts of the distribution network.

Although all these trials have provided great insight into the concept and benefits of dynamic operating envelopes, more knowledge still needs to be gathered to inform broader rollout. For example, principles to enable efficient and equitable allocation of network capacity to each customer are being worked out at a national level. Several questions have arisen from this process: How do vulnerable customers need to be treated? How much minimum export capacity allocation is appropriate to protect consumers? And how can dynamic operating envelopes and other grid congestion management measures be integrated effectively?

A limitation of flexible connection arrangements is that DERs are compensated indirectly for providing flexibility to mitigate network congestion with either faster and more affordable grid connection (in Great Britain) or the right to export more energy to the grid (in South Australia). In contrast, local flexibility markets can enable DSOs to publish their flexibility needs in advance and procure them from DERs in a competitive and transparent manner. This approach would reveal the actual value of flexibility services more clearly and ensure they are adequately paid for, while enabling DSOs to procure best-value services.

In fact, market-based approaches of this type have been emerging in some regions recently. For example, DNOs in Great Britain lead the way, as it is their business-as-usual practice to procure flexibility services through markets. In 2021, they contracted a total 1.6 GW of local flexibility from the beginning of the year to the end of July through markets, which is a rise of 45% from the 1.1 GW contracted in this manner for the whole of 2021. Unlike the non-wire alternatives schemes in other regions, which procure services from DERs over a longer time horizon to defer grid reinforcement, DNOs in Great Britain dispatch resources in near real time to address local grid issues using two standardised products: “secure” (for pre-fault constraint management) and “dynamic” (post-fault). They also have two other products: “sustain” (for scheduled constraint management) and “restore” (for system restoration support).

The DNOs procure all resources in advance through local markets with contracts of one to seven years, remunerated through availability and/or utilisation payments depending on service type. DERs have begun to participate more in these local flexibility markets recently. UK Power Networks (UKPN), for example, awarded 350 MW of capacity at a total cost of GBP 30 million in its February 2021 flexibility tender. More than two-thirds of the new capacity (250 MW) will come from using EV batteries and smart charging.

Four types of options or combinations of them are available for procuring flexibility from DERs to address grid constraints: a rule-based approach; flexible connection agreements; network tariffs; and market-based procurement. The rule-based approach, such as through grid codes, is technical in nature and its costs (related to necessary equipment and settings) are directly imposed on network users. Thus, this option can be a last resort if other incentive-based methods do not deliver as expected. Meanwhile, flexible grid connection arrangements would, in principle, apply to new network users only, as forcing them on existing users could have legal implications. Though these arrangements could be optional for existing network users, this can be accomplished through market-based procurement, i.e. local flexibility markets.

The drawback to network tariffs is that they offer only limited locational granularity. Fully reflecting a consumer's contribution to grid use would therefore eventually require individualised tariffs, which are impractical. Although operating flexibility markets to address specific local network issues can mitigate the impracticality of personalised tariffs, empirical data and experience in local flexibility markets are limited. Furthermore, this option would be efficient only once several prerequisites have been met (i.e. markets are liquid; DSOs comply with unbundling rules; and market distortion/abuse potential[18] is acceptable).

Regulators and DSOs can choose customised combinations of these options based on thorough cost-benefit assessments. Already-existing solutions and technical necessities can be taken into consideration, as can overall consumer and DSO costs, related risks, forecast uncertainty, long-term expenses and comparisons with grid reinforcement. Assessments can be performed periodically or whenever circumstances change significantly.

[18] Market participants could intentionally increase distribution grid constraints with their bidding behaviour in the day-ahead or intraday markets to benefit from selling to the DSO flexibility market. This strategic behaviour, called decrease-increase gaming, raises network costs, distorts investment signals and weakens wholesale energy markets as they are biased by the higher profits of DSO flexibility markets.

Insight 3: Opening all markets

Most wholesale energy and TSO markets were designed to integrate large-scale generators and retailers while ensuring market efficiency and system reliability. However, opening all markets – wholesale energy, balancing, ancillary services, and capacity – to small-scale resources could further improve market efficiency, as DERs can typically provide flexibility more cost-effectively than conventional generators. For example, a recent UK study discovered that depot-based electric vehicles could produce a net system benefit of GBP 15 for each MWh of electricity they shift, including all avoided power system costs and technology expenses incurred. Conversely, a comparable study found that the net system cost of combined-cycle gas turbines in the United Kingdom could be as much as GBP 40-60 for each MWh they generate due to their high investment and operating expenses. In addition, new resources can enhance competition, bringing down procurement costs and improving market efficiency.

Small-scale resources scattered across a power system can also reduce single points of failure, improving system reliability. However, integrating small resources can be challenging for system operators when they are unprepared for this transition. As the number of market participants and transactions increases, so does the complexity of system operations.

Accordingly, new practices and infrastructure are required to unlock the potential of new resources, and the advance preparation of regulators and system operators can facilitate the opening of all markets as soon as is technically feasible and economically effective. For example, it is necessary to clearly define roles and responsibilities for aggregators that can serve as intermediaries between small resource owners and system operators (it is important to consider the potential of independent aggregators to improve system efficiency). Furthermore, market participation rules designed for large generators (e.g. excessively high minimum bid size) can be revised to facilitate the integration of small aggregated resources.

Allowing independent aggregators to enter markets

Regulators can make it easier for small-scale resources to participate in all markets by opening them to independent aggregators. Electricity retailers can also offer their customers aggregation services, but independent aggregators with diverse backgrounds can bring competition to the market and innovative solutions to consumers. Sonnen, for example, was originally a battery storage system manufacturer, but it recently launched the Sonnen Community, which allows Sonnen's battery owners to share their surplus energy with other community members through a virtual battery pool; the pool can also provide the public power grid with aggregated battery capacity during peak hours. In return, battery owners get cost-free energy up to a certain number of kilowatt hours.

Another example is the electric car manufacturer Tesla Motors, which recently entered the GB electricity market to develop virtual power plants (VPPs). Tesla plans to aggregate DERs such as distributed PV and home batteries using a real-time trading and control platform called Autobidder. The platform can also enable value stacking by participating in diverse markets, including the balancing mechanism.

Some jurisdictions have already begun to open markets to independent aggregators. France, for example, has opened almost all its markets, allowing independent aggregators to trade blocks of load reduction in the day-ahead and intraday markets. Manual frequency restoration reserve (mFRR) and replacement reserve (RR) markets are open to independent aggregators, who can also provide a frequency containment reserve (FCR) service. Automatic frequency restoration reserve (aFRR) is mandatory for generators, who can instead source aggregated load reduction through a secondary market. However, this market is not used in practice. The capacity mechanism allows independent aggregators to provide capacities to obligated parties that must cover consumption during peak periods. Constraint management services for the high-voltage grid are open to aggregation, but there is little to no participation.

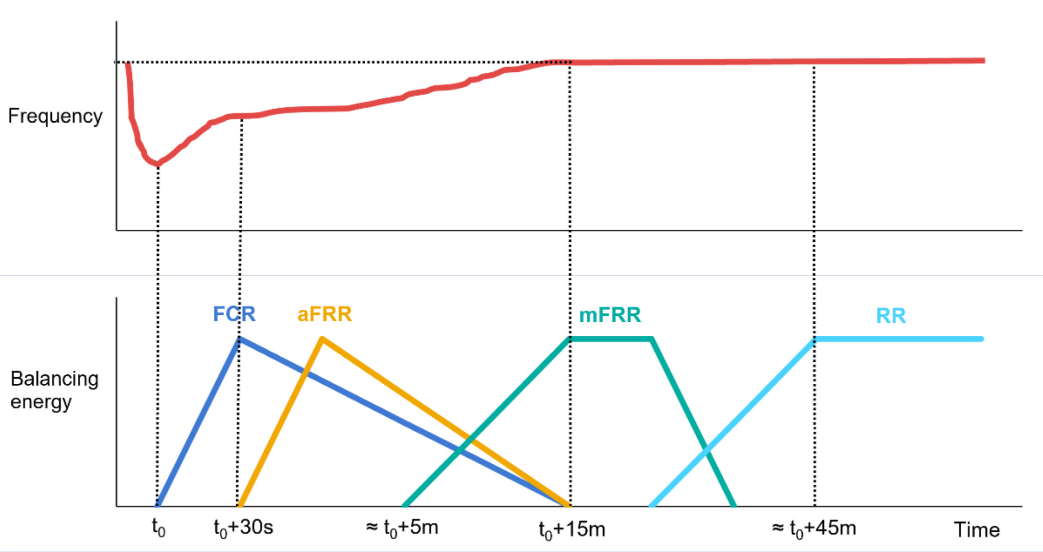
An overview of balancing market service products

The balancing market is a TSO's central tool to maintain power system balance in real time. To correct any imbalances between supply and demand, a TSO procures four types of energy services: frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR), manual frequency restoration reserve (mFRR) and replacement reserve (RR).

A TSO typically uses these four energy service products in sequence to restore system frequency back to within the acceptable range. The TSO first activates the FCR to prevent system frequency from dropping further after an imbalance occurs. The operator then activates aFRR and mFRR services to restore system frequency to a predetermined value and to replace the FCR. Finally, the operator mobilises the RR to replace the FRR so that the FRR can be prepared for the next system imbalance. The TSO often procures the four services in advance of their activation to ensure that enough energy (i.e. operating reserve) is available.

In other regions such as North America, the FCR, aFRR, mFRR and RR are called frequency response, spinning, supplemental (or non-spinning), and replacement reserves.

Time-sequence activation of the four balancing energy services



Source: Adapted from ENTSO-E (2018), Electricity balancing in Europe.

Great Britain's TSO, National Grid ESO, launched a reform of its balancing mechanism to ensure wider access beyond large-scale generators and retailers, and thus increase competition and drive down consumer costs. As a part of the reform, in 2019 it introduced virtual lead parties (VLPs) to make it easier for independent aggregators to participate in its balancing mechanism. VLPs can access the mechanism with as little as 1 MW of capacity and be exempt from transmission network charges. Furthermore, they can provide re-dispatching services, which are procured through the balancing mechanism, and opening wholesale energy markets to VLPs is under discussion.

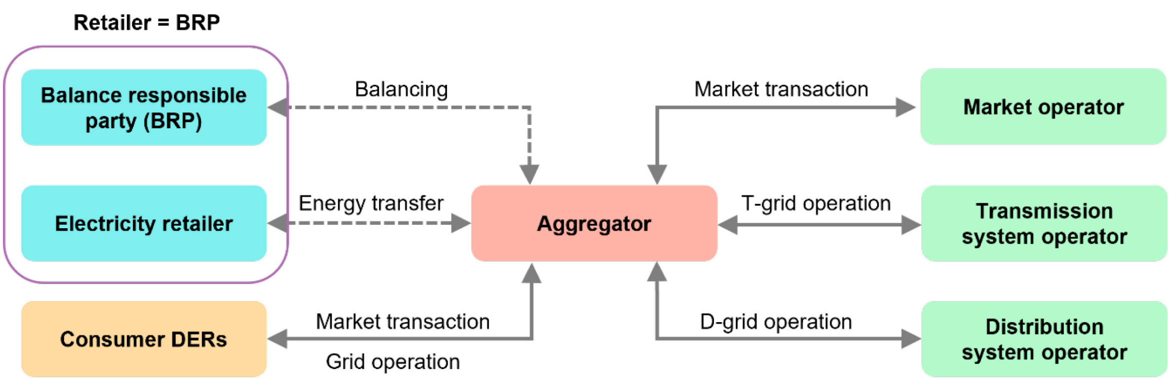
In 2018, Italy launched one of the largest pilot projects in Europe, known as UVAM (Unita Virtuali Abilitate Miste, i.e. virtually aggregated mixed units), to experiment with sourcing flexibility from DERs. Italy allows only dispatchable generators larger than 10 MW to provide reserves, and under the project Terna (the Italian TSO) sources four services from aggregated distributed generation, loads and storage that are larger than 1 MW: mFRR, RR, balancing energy, and re-dispatching. In 2019, the project contracted around 1 GW of new capacity from DERs that would not otherwise have contributed to power system balancing. In addition, the UVAM project provides learning-by-doing opportunities to evaluate new market dynamics and find best practices, addressing challenges inherent in opening the market.

As per a FERC order of 2008, ISOs in the United States have opened all markets to aggregated demand-response resources. For example, the Pennsylvania-New Jersey-Maryland (PJM) ISO allows independent aggregators to enter the day-ahead and real-time energy and reserve markets and capacity markets. The latest PJM report showed that around 88% of demand-response capacity in the PJM Interconnection came from independent aggregators, which are called curtailment service providers in the PJM market. Furthermore, in 2020 FERC ordered ISOs to open all their markets to DER aggregations, beyond just allowing them to participate in the market through demand response. Accordingly, ISOs are establishing the market models and rules necessary to comply with the order.

Establishing clear roles and responsibilities for independent aggregators

Opening markets to independent aggregators is a good starting point for the long journey ahead, as aggregators can pool resources from consumers and carry out market transactions and grid operations on their behalf. They can bid for market and grid services, operate consumer resources as instructed by the market and system operators, and financially settle transactions. However, unless regulators clearly establish rules governing these complicated procedures, independent aggregators may face uncertainty in establishing viable businesses.

Aggregator relationships with other electricity stakeholders in Europe



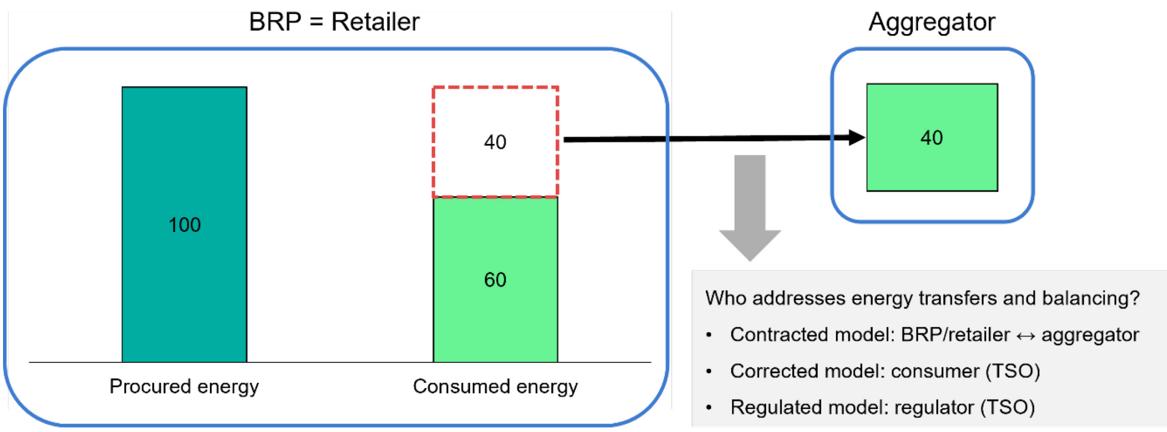
Notes: T-grid = transmission grid. D-grid = distribution grid. The relationships shown are illustrative only. Currently, many retailers and utilities perform the role of aggregator.

Meanwhile, it is worth noting that incumbents such as utilities and retailers can also use their established relationships with consumers and their financial capacity to contribute to power system innovation. The non-wire alternative scheme developed by utilities in the United States, which is used to procure services from DERs to defer or replace costly network reinforcement, is one example.

One of the main market entry challenges for independent aggregators is the lack of clarity concerning their roles and responsibilities. For example, when an independent aggregator activates consumer resources for a demand-response mechanism, it can impact both the consumer's BRP and retailer. This transaction can reduces consumer power consumption and create imbalances in BRP portfolios. Most European power systems stipulate that parties participating in wholesale energy markets must designate a BRP, who is responsible for maintaining a consistent supply and demand balance within its portfolio on their behalf. If the BRP fails to preserve the balance, it may incur an imbalance penalty. The same transaction can also transfer to an aggregator any energy that was originally procured by retailers for their customers, but that was not consumed or paid for due to the interference of demand-response activation. Missed compensation for the energy can result in financial losses for the retailers.

The two chief balancing and energy-transfer issues are how a BRP can restore balance to its portfolio, and how much a retailer should be compensated for transferred energy. The BRP and retailer are, in many cases, the same entity. European jurisdictions usually adopt three main models: contracted; corrected; and regulated. However, energy transfer and balancing are not material issues when no or low energy volumes are shifted, such as during frequency containment reserve (FCR) activation.

Impacts of demand-response activation on energy transfers and balancing



In the contracted model, as implemented in Belgium, an aggregator sources transferred energy ex-post from the BRP/retailer, and its volume and price are agreed upon in a bilateral contract. In the corrected model, consumer consumption is corrected as if there were no demand-response activation (usually by a TSO), which means consumers pay for the transferred energy at the retail price and can then pass the cost on to their aggregator (Germany plans to adopt this model). In the regulated model, the amount and value of transferred energy are typically calculated by a TSO using a regulated methodology. In Switzerland, for example, compensation for transferred energy under this model is at quarter-hourly day-ahead energy market prices.

Each model has its pros and cons. The regulated model can limit incumbent BRP/retailers' potential abuse of power, as regulators set up all the procedures, including the compensation methodology. However, the model may not reflect the actual value of the transferred energy and implementation costs are high. Meanwhile, the contracted model can better reflect BRP/retailers' energy sourcing costs, as the price is determined by bilateral negotiation, but this model may allow incumbent BRP/retailers bargaining power over independent aggregators and entail high transaction costs for contract agreements. Under the corrected model, aggregator actions do not impact BRP/retailer revenues, as they are compensated according to retail prices, but consumers may have to bear the significant burden of negotiating contracts with both their BRP/retailer and aggregator.

Some countries adopt multiple models. France, for example, applies all three models depending on the voltage level of a consumer's connection and the smartness of the meter. The corrected model applies to consumers connected to the transmission or distribution grid above 36 kVA. The regulated model is a default option for small consumers connected to lower-voltage networks, but they can also opt for the contracted model. In 2015, to facilitate the market participation of independent aggregators, France introduced a regulated model known as block exchange notification of demand response, or the NEBEF mechanism. Compensation for transferred energy differs depending on a consumer's contract and metering capabilities. Plus, in an arrangement that was recently discontinued, consumers who reduced their energy consumption by more than 40% could socialise up to 50% of their compensation cost, which was paid by RTE (the French TSO) and then passed on to other customers. RTE established a central platform to implement the regulated model, including financial settlements.

Redesigning market products to be non-discriminatory to small-scale resources

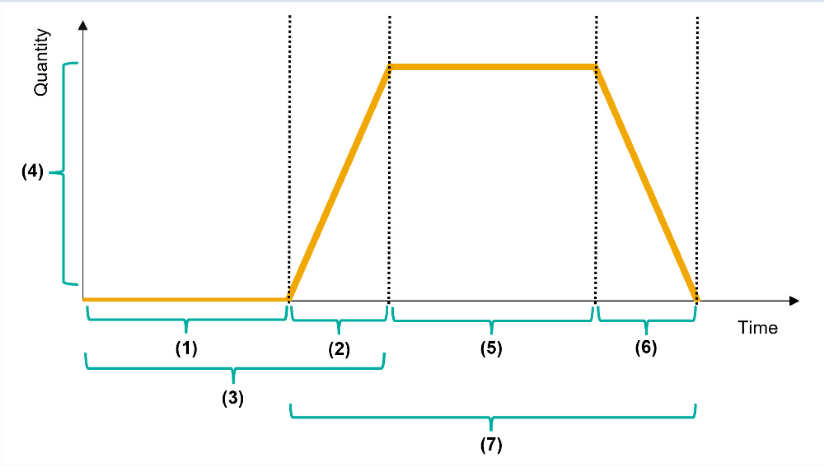
Physical resources such as generation and consumption can participate in markets through standardised products. Unlike most commodity markets, in which only the willingness to sell and buy are relevant, the electricity market has to consider physical constraints – including the hard-to-store nature of electricity and network congestion – to maintain power system reliability. Thus, the technical and economic parameters of electricity market products tend to be more complex than just price and quantity. This is especially the case for TSO grid services, such as balancing-market products, which are designed primarily to maintain a consistent supply-demand balance in real time.

Structure of a balancing market product in Europe

Balancing-market products have several technical and economic parameters:

- The full activation period (3) consists of a preparation period (1) (the time required prior to delivery of the first MW) and a ramping period (2) (the time between when the first MW is delivered and the requested power of the TSO is reached).
- The full delivery period (7) comprises a ramping period (2), a minimum and maximum delivery period (5) (the time when full requested power is delivered) and a deactivation period (6) (the time from the start of deactivation until the full instructed MW has been provided).
- Other parameters include minimum and maximum quantity delivered (4), bidding price, and activation mode (either manual or automatic).

Standard parameters of a balancing market product



Source: Adapted from ENTSO-E (2018), Electricity balancing in Europe.

As many current market products were developed with large-scale dispatchable generators in mind, their design can be an obstacle for small, aggregated resources attempting to enter the market. Fortunately, many jurisdictions have begun to redesign their market products to ensure that small-scale energy resources can compete with large generators. Among other design elements, four are critical: minimum bid size; time definition; symmetry; and pre-qualification.

The minimum bid size can limit the minimum level of aggregation necessary to deliver services to markets. Thus, if the minimum size is set too high, aggregators may find it difficult to participate in markets because an overly vast number of small resources would have to be aggregated. TSOs, on the other hand, may want a relatively large bid size to alleviate the risks and costs entailed by having numerous market participants. In 2020, the US Federal Energy Regulatory Commission (FERC) ordered ISOs to open all their markets to as low as 100 kW of resource aggregation.

Time definition comprises two elements: procurement and delivery. If procurement is finalised long before delivery happens, aggregators must make assumptions on the amount of energy services deliverable when called upon later. Predicting how many EV units they can aggregate one year in advance, for example, could engender a wide margin of error. This is also the case for the delivery period: the longer the delivery time, the less chance EV owners, for example, will be able to adhere to an aggregator's instructions, due to their changing needs to use the vehicles. Thus, German TSOs recently shortened the procurement and delivery periods of frequency restoration reserves (FRRs), which are procured in daily auctions for four-hour durations instead of on a weekly basis for peak or off-peak hours.

Market products can also be classified as upward or downward. Upward products can increase generation or decrease consumption, while downward products decrease generation or increase consumption. If aggregators are required to provide the same amount of upward and downward energy simultaneously (called symmetrical), they may find it hard to make the most of available resources. For example, when consumption levels are low, aggregators can pool more downward energy than upward. The California ISO has two asymmetrical products for secondary frequency response: regulation up and regulation down.

Prequalification is the process by which a potential resource demonstrates that it complies with all the technical requirements to deliver a market product (product prequalification), and the grid to which it connects proves it can deliver the required product (grid prequalification). Prequalification of aggregated pools rather than of each individual resource can make it easier for aggregators to fulfil technical prequalification requirements, reach the minimum bid size, comply with long delivery periods and satisfy bid symmetry, though the criteria can be dictated by the system's technical needs. Both Austria and Germany allow DERs to prequalify at the pool level for all balancing market products.

TSO strategies for managing DER volume risks

TSOs can redesign service products to be non-discriminatory to DERs, enabling them to participate in markets more readily. However, reduced minimum bid size, shortened procurement and delivery periods, and bid asymmetry could increase volume risks for TSOs. This means that the number of necessary market transactions would increase, leading to higher costs and uncertainty for TSOs. Nevertheless, they can manage the volume risks entailed in opening markets to DERs by upgrading their market optimisation and clearing software to efficiently handle more frequent transactions of larger amounts of resources. For instance, when FERC in the United States ordered all ISOs to open their markets to DERs, several of them requested a delay to comply with the order, partly due to the considerable time needed to upgrade their software programmes.

TSOs can also require minimum participation of large generators in balancing markets or encourage DER aggregators to hedge their risks in secondary markets. For example, large electricity producers in France are mandated to provide reserves, which helps the French TSO, RTE, mitigate uncertainty arising from procuring small resources. In Belgium, a secondary market is open for frequency containment reserve (FCR). DER aggregators can procure committed reserves in the secondary market if a portion of their own resources is unavailable.

Furthermore, TSOs can procure reserves collectively to reduce the risk of insufficient resource availability. For example, European TSOs are harmonising balancing market products to mutualise them across Europe, and the pan-European platform for replacement reserves (RR), known as the Trans-European Replacement Reserves Exchange (TERRE), became operational in January 2020. Other pan-European platforms to exchange automatic and manual frequency restoration reserves (aFRR and mFRR) are also being implemented.

Developing market participation models that reflect essential features of emerging resources

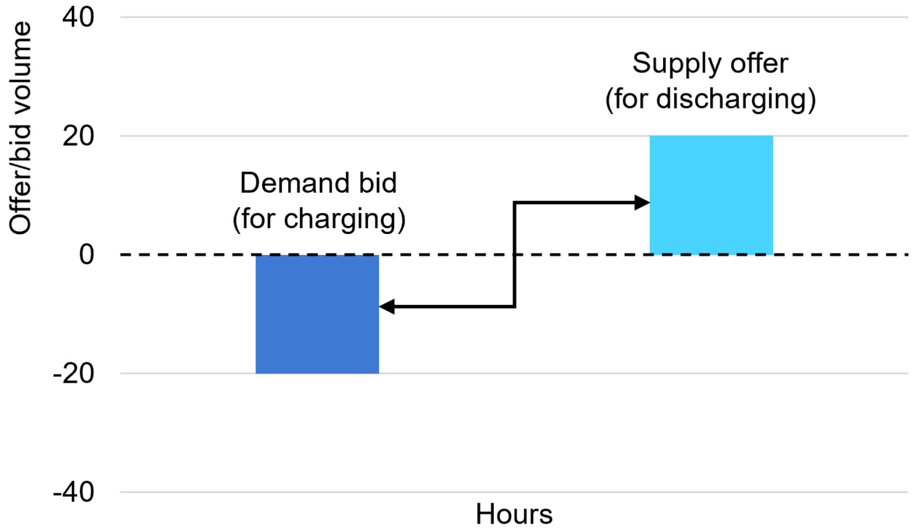
The advent of new resources could require new market participation models. Among other factors, bidding formats define the manner in which electricity markets allow participating resources to express their operational features and constraints when they make offers or bids. A battery, for example, can both charge and discharge energy, and its storage capacity is limited. Battery owners are expected to decide in advance when to buy and sell energy, which is challenging given the complexity of power system operations. This can compromise the efficient and reliable operation of battery storage systems, preventing the full unlocking of their grid service potential.

Market and system operators can therefore develop new bidding formats that properly reflect essential features of emerging technologies such as battery storage. This would create a level playing field for all conventional and new resources without allowing any of them an unfair advantage, which would in turn improve both market efficiency and system reliability. For example, new bidding formats introduced in Europe and North America could put battery storage in a good position to compete with gas turbines for profitable grid services, such as balancing and ancillary services.

Europe and North America have adopted two different approaches. One of the main aims of the European market is to achieve market efficiency through a single pan-European market (except for local grid constraint management). Market operators in Europe try to allow participants to trade energy freely, considering only cross-border physical constraints so that resulting market prices can fully reflect their willingness to buy or sell energy, whereas system reliability within a bidding zone is left over to the TSO's responsibility.

Accordingly, the basic bidding format European power exchanges adopt is price-quantity pairing. However, battery storage requires a bidding format that captures the physical links between energy demand bids (for charging) and supply offers (for discharging). If, for example, a battery storage system's supply offers are accepted while its demand bids are rejected, the mismatch can jeopardise operation of the resource. For this reason, in 2018 EPEX Spot, one of Europe's power exchanges, introduced a new bidding format called loop block order. When a battery storage owner submits an energy purchase order as well as a sell order, the two orders are either accepted or rejected together, avoiding the undesirable situation of only one of the two being accepted.

How loop-block-order bidding format works for battery storage in Europe



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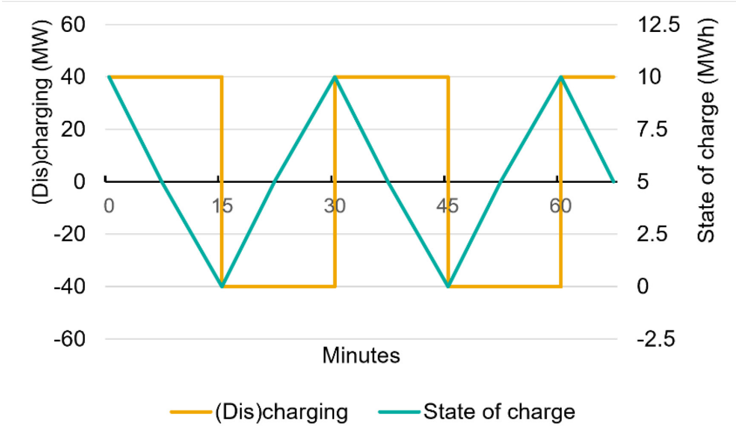
Meanwhile, ISOs in North America determine generator dispatch in a centralised manner, considering all operational and economic features of each resource to maximise market welfare while ensuring system reliability. North American ISOs have therefore adopted resource-specific multi-part bidding formats to reflect each resource's multi-part parameters: cost structure, technical constraints and operational characteristics. When a new type of resource such as battery storage emerges, ISOs need to develop a new bidding format.

In 2018, FERC ordered that all ISOs establish a market participation model of electric storage resources. ISOs have so far had only two types of resources: generation and consumption. However, as battery storage can both generate and consume, a tailored bidding format is required so that owners do not have to make two separate offers as generators and consumers. The new model can have two sets of similar parameters for discharging and charging, representing operating costs and technical constraints as generation and consumption. Battery storage also has the unique technical constraint of limited storage capacity, necessitating new bidding parameters to help ISOs monitor the resource's state of charge (SoC) to ensure that adequate storage levels are maintained.

How multi-part bidding format works for battery storage in the United States

Operation of battery storage



Multi-part bidding format

(Dis)charging	
	Max (dis)charge limit (MWh)
	Min (dis)charge limit (MWh)
	(Dis)charge ramp rate (MWh/min)
	Max (dis)charge time (min)
	Min (dis)charge time (min)
	Energy bid/offer curve (USD/MWh)
State of charge	
	Innitial state of charge (MWh)
	Max state of charge (MWh)
	Min state of charge (MWh)

The aggregation of heterogeneous resources, such as distributed PV, battery storage and smart water heaters, raises all sorts of new questions about market participation models for ISOs in North America. Numerous small-scale aggregable resources may be scattered across large regions, each facing different grid conditions and affecting the grid differently when connected; it is thus challenging for an ISO alone to be responsible for all resources and their impacts on the grid.

Distribution utilities can, however, ensure the reliability of distribution grids to which DERs are connected. To accomplish this, it is essential that a region's distribution utilities and its ISO co-operate closely so that DER operations directed by one side (either the distribution utilities or the ISO) do not conflict with the other side because issuing contradictory instructions could risk system reliability. For example, the ISO's uncoordinated dispatch of DERs can cause distribution bottlenecks, while distribution utilities' uncoordinated dispatch of DERs can complicate system balancing.

Additionally, aggregators can share system operators' responsibilities – including monitoring, communicating with and financially settling each resource – to efficiently manage the aggregation. Furthermore, bidding formats for the aggregation may not have to follow the usual resource-specific approach of ISO markets. When different types of resources are pooled, aggregations' operational characteristics may not be identical, as they would depend on how the resources are operated.

The California ISO was the first to develop a market participation model for aggregated DERs in the United States, called the distributed energy resource provider (DERP). The model, which enables aggregated heterogeneous resources to participate in energy and ancillary services markets, has general bidding parameters: price-quantity pairings with prices in USD/MWh and quantities in MWh, rather than a resource-specific multi-part format. Aggregating resources across multiple transmission nodes is allowed, but total aggregable capacity is limited to 20 MW. In addition, aggregators can pool resources located only within a predetermined zone, judged by the ISO to be safe from severe transmission grid congestion. The aggregator, rather than each resource within the aggregation, is required to satisfy the ISO's metering and telemetry requirements, mitigating cost burdens for small resource owners. Unfortunately, the DERP model has not been used for several reasons, including a lack of remuneration for capacity values. The next section discusses this issue in more detail.

Insight 4: Fair market compensation

As the previous chapter illustrates, DERs are small, agile resources located near sites of electricity use and are therefore ideal providers of temporal and locational flexibility when equipped with digital technologies. As variable renewable energy resources rapidly enter our energy systems in ever-greater amounts, greater system flexibility is needed to maintain a consistent supply-demand balance and mitigate grid congestion. Furthermore, as energy systems decarbonise and traditional flexibility providers such as large fossil fuel-based generators are phased out, the need for alternative flexibility options such as DERs rises. Fortunately, most DER prices are dropping rapidly, including for battery storage and distributed PV, increasing their potential profitability and the value they can provide by participating in markets.

Nevertheless, the profitability potential of DERs and their associated system benefits can be realised only when markets are properly designed. To this end, regulators can improve the markets to guarantee DERs fair compensation for the value of their temporal and locational flexibility. The value of flexibility is typically captured in market prices as, for example, increased price volatility in day-ahead markets. Regulators can add more time and locational granularity to market prices to reflect ever-changing system conditions. Some countries also have capacity remuneration mechanisms in place to ensure long-term resource adequacy, and regulators can design the mechanism to reflect flexible capacity needs rather than static peak capacity. Moreover, as DERs are sited close to consumers and can benefit transmission and distribution systems as well, regulators can establish clear rules and procedures to allow DERs to stack multiple revenue streams. All these improvements could make DERs more economically attractive and reinforce grid reliability at the same time.

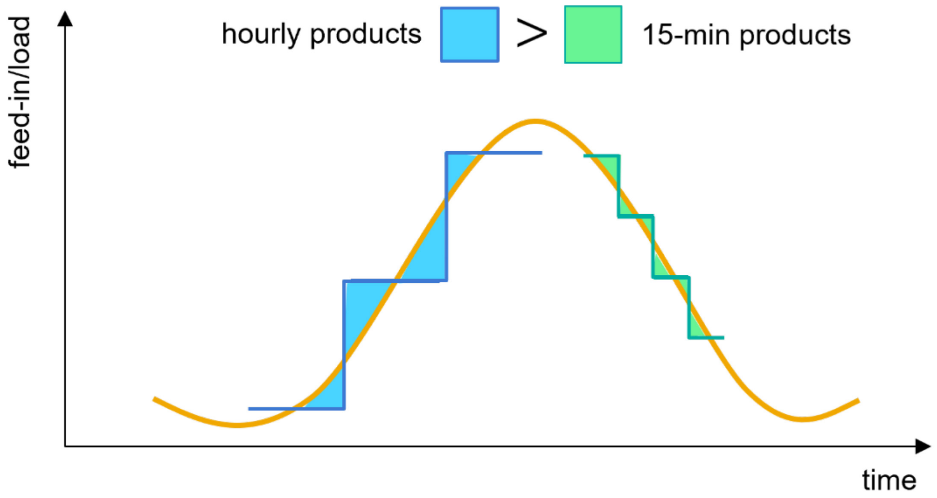
Improving the time and locational granularity of market prices

Regulators can improve the temporal granularity of market prices by shortening settlement periods. Participants in European wholesale energy markets typically trade energy products hourly, meaning that they can supply or withdraw the energy they are committed to sell or buy on average within a predefined time interval, called a settlement period (also referred to as a trading period), of one hour. For example, a generator can uniformly distribute the committed output of a one-hour settlement period throughout different sub-periods.

However, consumer demand fluctuates continually, even within shorter temporal intervals, so TSOs procure balancing energy in sub-periods (such as 5 minutes) to fill supply-demand gaps and ensure that the system is continuously balanced. The higher the demand volatility, the more reserves TSOs will need to balance the system.

The penetration of variable renewable energy sources adds substantial volatility to a system and boosts reserve needs significantly, translating into cost burdens for consumers. Fortunately, shortening settlement periods can mitigate the challenges: if energy products are settled quarter-hourly rather than hourly, for example, the supply-demand gap can shrink, reducing reserve requirements. Plus, contrary to thermal power plants, for which output cannot typically be ramped up or down rapidly, the energy production and consumption of DERs such as battery storage can be modulated to accommodate a range of timescales – from seconds to hours. Shortening the settlement period can therefore reduce reserve requirements and thus procurement costs, and at the same time improve DER economics.

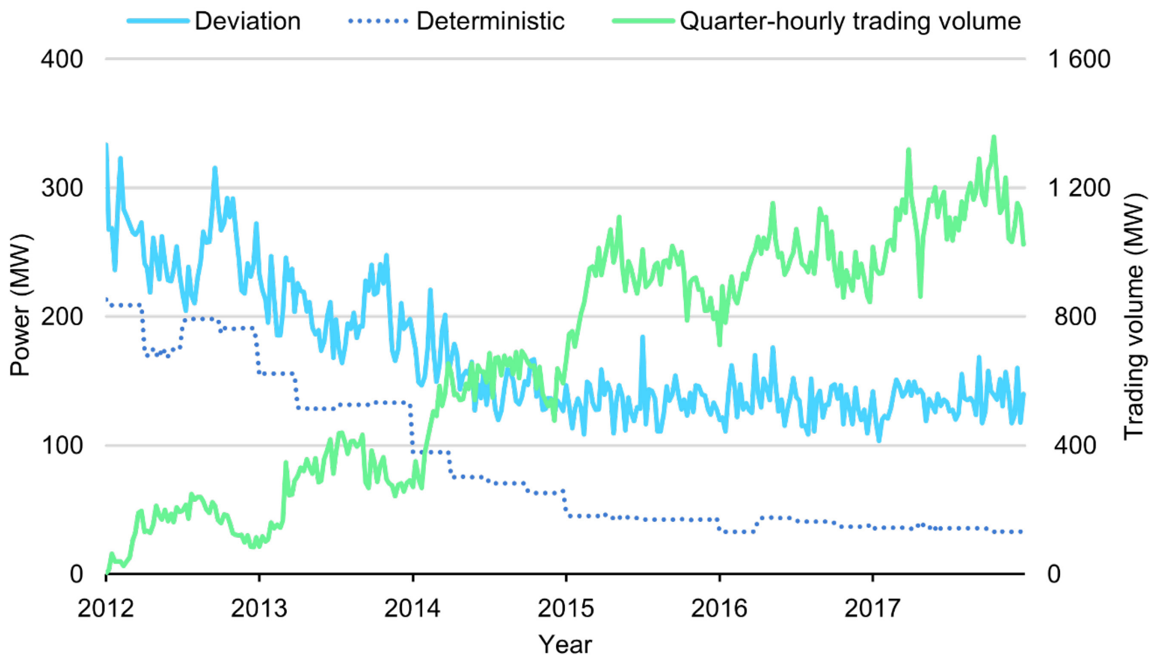
Comparison of hourly and 15-minute energy products



Source: TenneT (2016), Market Review 2016.

In fact, in 2015 the European Commission proposed a regulation requiring market operators to allow energy trading in intervals as short as 15 minutes. Although this measure will not be fully implemented until January 2025, Germany has already reduced the settlement period for intraday trading to 15 minutes. This shorter 15-minute interval has reduced Germany's reserve requirements, particularly for addressing system imbalances stemming from market parties trading only hourly products (but no quarter-hourly ones) (represented by the dotted blue line in the figure below). This reduction could happen just as quarter-hourly trading volumes have increased over time (represented by the green line).

Effects of quarter-hourly trading on reserve needs in Germany, 2012-2017



Notes: Deviation = average absolute within-hour deviation of system balance. Deterministic = deterministic system imbalances due to coarse portfolio management of market parties trading only hourly (but no 15-minute) products.
Source: Koch and Hirth (2019), Short-term electricity trading for system balancing: An empirical analysis of the role of intraday trading in balancing Germany's electricity system.

In a centralised-dispatch power system, the real-time market produces dispatch instructions every five minutes, while traditionally a system operator would calculate average hourly prices to settle real-time transactions to simplify the metering and settlement process. In this case, peak generators, including flexible DERs, are remunerated with average hourly prices, which can typically be less than their bidding prices during, for example, 5-minute peak periods. This can undervalue flexible peak generators, providing ineffective price signals for long-term investment in these resources. In the United States, most ISOs historically settled real-time market transactions with average hourly market prices, though generators were dispatched on a 5-minute basis, but in 2016 FERC ordered all ISOs to adopt 5-minute settlement for their real-time markets.

In October 2021, the Australian Energy Market Operator (AEMO) also implemented a 5-minute settlement period for its energy market. Since the launch of Australia's electricity market, generator dispatch has operated on a 5-minute basis, but due to technical limitations (including for metering and data communications, which have now been overcome), settlements were performed on a 30-minute basis. The transition was expected to improve price signals for more efficient electricity generation and use, and more effective investment in flexible generators such as DER technologies to balance supply and demand in the longer term.

Regulators and market operators can also improve time granularity in electricity markets by shortening intraday market lead times. The lead time is the time between the end of the trading session, which is called “gate closure”, and the beginning of the real-time delivery period. Thus, gate closure is the moment up to which market participants can either submit or modify their bids or offers on the market. After that point, the final, binding schedule is determined for all market participants, and only TSOs can adjust any deviation.

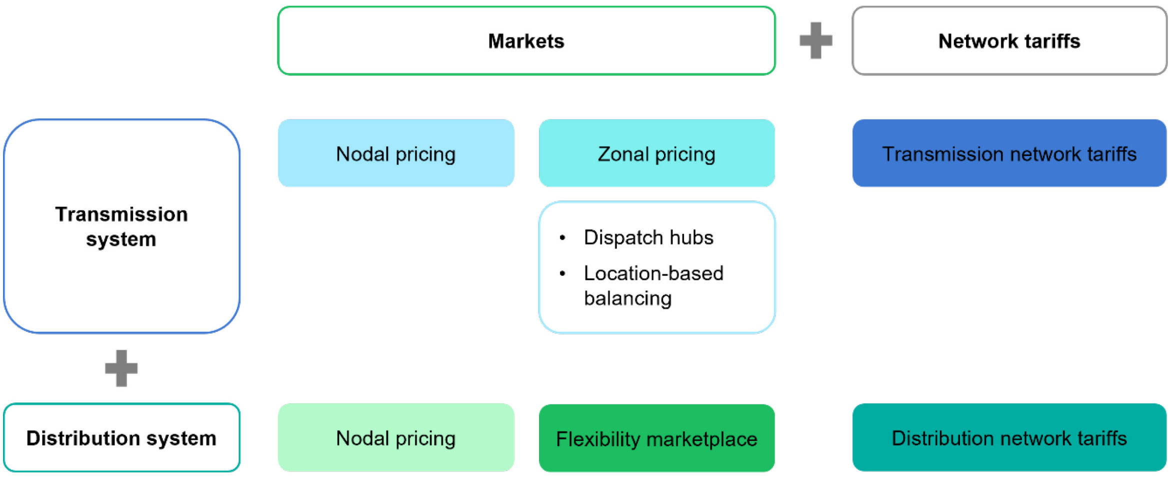
Hence, the last gate closure is the dividing line between wholesale energy markets and pure system operations. In Europe, the last opportunity for a market participant to change its schedule without TSO intermediation is at the closure of the last intraday market session. Accordingly, setting intraday market gate closure closer to real time can help market participants adjust their positions with updated forecasts on generation from, for example, variable renewables, enabling them to minimise imbalances. This can also benefit TSOs, as they are required to procure and activate smaller quantities of reserves to balance the system. Intraday market lead times in Europe were reduced to 15 minutes in Great Britain, 5 minutes in Austria, Belgium, Germany and the Netherlands, and 0 minutes in Finland.

Regulators can consider several options to improve the locational granularity of price signals

Much of the value DERs can provide to a power system comes from being connected to the distribution network close to consumers. A DER’s potential value at a specific location on the grid is determined by its capabilities and the power system costs it can avoid in that location. The primary location-specific benefit of DERs is their ability to defer transmission and distribution grid investments, and their value is even greater if they are located and operated when and where the grid experiences bottlenecks. Meanwhile, however, the power system increasingly requires more dynamic use of the grid to integrate energy from variable distributed resources. So, while DERs can pose grid reliability challenges, they can at the same time provide options for resolving the risks they themselves present. Regulators can thus improve grid reliability as well as DER economics by incorporating more locational granularity into market prices.

There are some dimensions to be considered. For instance, regulators can provide locational price signals through either markets or network tariffs, and the price signal can reflect conditions of either the transmission or distribution system. Power systems can also adopt either nodal or zonal pricing. Accordingly, regulators have several options to improve locational granularity, and importantly, these choices are not mutually exclusive: a combination of options tailored to the power system will be likely to be required.

Options to improve locational price signals



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[Nodal pricing at the transmission system level](#) is well established in North America. The market calculates locational marginal prices (LMPs) by incorporating transmission congestion and losses at each node, which is usually a substation that creates discontinuity in the grid. Hence, nodal pricing can provide an accurate locational price signal. In principle, there should not be out-of-market redispatch actions by TSOs in nodal markets because nodal pricing accounts for grid constraints on the system. Both generation and demand are settled at the applicable nodal prices.

However, some preconditions need to be met before nodal pricing can be introduced at the transmission level. Up-to-date data on both market transactions and system operations (such as grid congestion) must be accessible for the calculation of nodal prices. This implies the need to combine market and system operations within a single entity, as is the case for ISOs in North America. Transmission network tariffs can be recalibrated to recover any residual network costs not recovered through nodal pricing.

Nevertheless, some practical and commercial considerations imply that nodal pricing is not easy to implement in lower-voltage grids. As constraints within the distribution system are often voltage-related, it may be efficient to employ price signals to regulate the production and consumption of reactive power. However, reactive power prices can be very volatile and easily subject to the exercise of market power, due mainly to the local nature of reactive power and the high sensitivity of voltage to market participants' responses.

Implementing a system to compute and use distribution LMPs may also require considerable time, since ICTs must be deployed and robust algorithms must be verified in sufficiently representative networks. Furthermore, charging different network costs to consumers connected to the different distribution networks, which were designed without consideration for distribution LMPs, can raise equity issues. In this case, the primary signal of distribution-level locational value can be offered through either a flexibility marketplace or distribution network tariffs. The Independent Electricity System Operator (IESO), an ISO in Ontario, Canada, is currently undertaking a distribution LMP demonstration project (for active power).

European countries have adopted a different model, known as zonal pricing, in which the power system is administratively divided into zones. As the primary consideration in defining zones is the existence of persistent congestion in the transmission grid between them, different degrees of geographical division are possible: France and Germany feature only one zone, while Italy has ten. When a TSO detects grid constraints within a zone, the operator redispatches generators, determining which participants must withdraw their generation from the system and which are to be included. Though the inevitable redispatch actions can raise consumer cost burdens, zonal pricing can improve market liquidity and thus market efficiency.

There have been long debates about the advantages and disadvantages of nodal versus zonal pricing. However, the importance of locational price signals has recently been gaining attention due to the rapid penetration of renewable energy and DERs, and TSOs in Europe are exploring options to improve the locational granularity of their zonal pricing model. One approach, called dispatch hubs, involves establishing multiple dispatch hubs responsible for separate redispatch bids within an existing zone, with the aim of integrating part of the redispatch costs into the clearing prices of the day-ahead market.

Another proposal is location-based balancing, which involves introducing nodal pricing into balancing markets. Nodal pricing that internalises all relevant grid constraints has the most advantages in close to real time, when TSOs have virtually no time to correct for further grid congestion. Countries experiencing material congestion within their zone(s) may find this approach effective. In addition, transmission network tariffs can help improve locational granularity, for example by using tariffs to signal locational value within each zone, while market prices reflect congestion between zones.

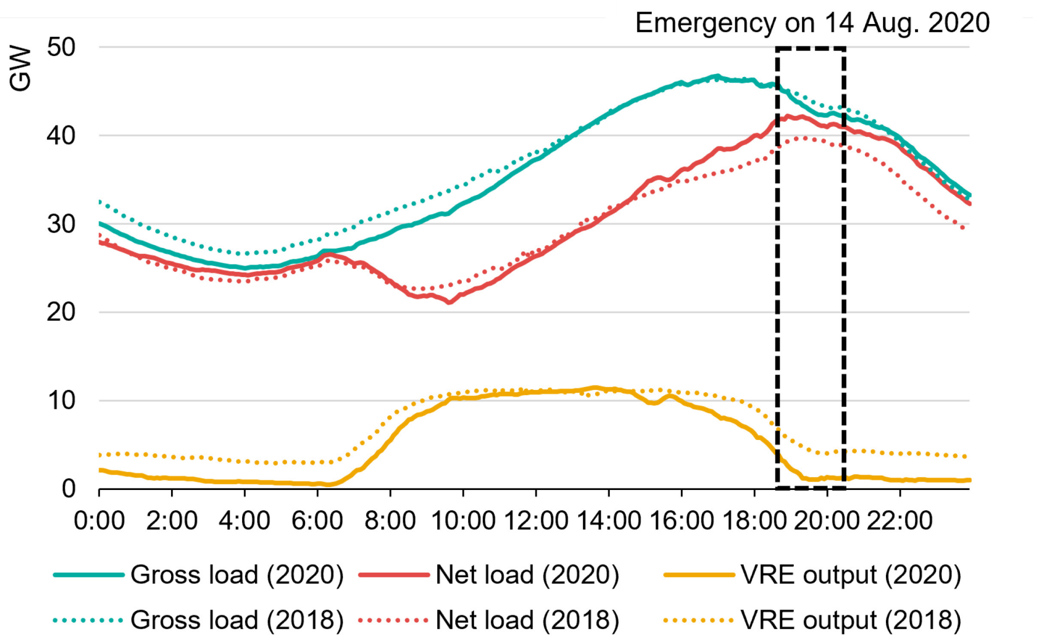
Compensating new resources for the value of their flexible capacity

Power systems require sufficient resource capacity to meet current and future demand. In maintaining resource adequacy, thermal generators have historically been central capacity providers in many locations. However, considerable retirement of fossil fuel-fired generators is expected, with rapid uptake of renewable energy technologies, energy storage and load flexibility replacing them.

For a grid with a high level of new resources, reliability events (when a power system fails to maintain the supply-demand balance) have different characteristics. For example, the potential for supply shortfalls shifts towards the end of the day, when generation from all solar PV plants in an area drops. This dynamic was evident in California’s rolling blackout of 14 August 2020: the emergency event occurred during net-load peak hours in the evening after solar PV generation had fallen, several hours after gross peak load occurred. What is more, load erosion at midday due to distributed PV penetration widens the gap between daily minimum and maximum loads. It is worth noting, however, that a rolling blackout was not triggered on 25 July 2018, when California faced a similar peak load level.

At the same time, new resources such as energy storage, demand response and load flexibility can also provide grid services to maintain system reliability. They can be particularly competitive alternatives to gas-fired peaking plants for many types of capacity shortfall events. Rapidly falling costs of sensors and controls, increasing DER aggregation and improved visibility over behind-the-meter load consumption have made power loads more flexible and price-responsive. As each resource offers different capabilities, there are options to suit specific situations. For example, battery storage and load flexibility could best address events that happen frequently but are of short duration, whereas load-shedding demand-response programmes would be suitable for infrequent events.

California's gross and net loads, 25 July 2018 and 14 August 2020



Source: Data from California ISO (2021), Net demand trend.

Some countries have adopted capacity remuneration mechanisms to ensure long-term resource adequacy. Regulators can incorporate changing system characteristics into their capacity market programmes: for example, they can explicitly require the procurement of flexible ramping capacity rather than static peak capacity to address duck-curve issues. In fact, the California Public Utilities Commission (CPUC) introduced a flexible resource adequacy requirement in 2015. The California ISO's annual study examines the largest three-hour ramping rate each month; every year all load-serving entities in the state must demonstrate procurement of 90% of their obligation for each month of the upcoming compliance year, and every month demonstrate 100% of their upcoming monthly obligation. As DERs such as batteries are agile resources that can efficiently provide fast ramping capacity, flexible resource adequacy requirements can improve not only grid reliability but DER profitability.

Regulators can establish clear rules and procedures to apply their capacity remuneration mechanisms to DERs. For example, the California ISO developed a market participation model for DERs in 2015, but no one has yet used it, partly because there is no remuneration for the capacity value of DER aggregation, whereas demand response was already allowed capacity credits. The central issue is how to measure the capacity value of aggregated DERs, as complex interactions within and between weather-dependent and energy-limited resources make it challenging. For example, each increment of solar PV could have a successively lower capacity value, as adding solar generation to the system pushes the net peak load to later in the evening, when solar generates less power. Conversely, a solar PV-plus-storage system can offer more capacity value than the sum of its parts when stored solar-based power is used to meet demand during extended hours.

One calculation approach is the effective load carrying capability (ELCC) methodology, which measures the amount of load that can be added to a system by incorporating certain resources while maintaining the same level of system reliability. The ELCC method can be used to evaluate correlated outputs within and between resource types, and thus the capacity value of aggregated DERs.

Rethinking long-term resource adequacy construct for a renewables-dominant power system

Even though California had prepared for its power system changes, including by introducing flexible capacity requirements, it experienced rolling blackouts in 2020 due to several factors, such as extremely hot weather across the western United States that limited power exports to California. Nonetheless, the state's peak load and capacity-based resource adequacy construct can provide one explanation for this outcome, and thus regulators and system operators in other jurisdictions can also investigate whether underlying resource adequacy issues may lead to the more regular occurrence of such incidents.

Traditional resource adequacy analysis was developed in the 20th century when most electricity was produced by dispatchable thermal generators. Analysis typically considers weather a determinant of system loads, shifting peak-load periods but not impacting generation, and assumes that generators can produce energy up to firm capacity[19] whenever called upon. Hence, these analyses often evaluate peak-load hours only, calculating expected frequency when capacity is insufficient to meet the peak load, called loss of load expectation (LOLE), and add firm capacity to keep the LOLE within an acceptable range (e.g. one day in ten years). In short, LOLE can limit the focus of resource planning to peak-load hours, but is robust in power systems dominated by dispatchable generators.

However, traditional resource adequacy analysis needs rethinking for a grid with high levels of renewable energy sources, energy storage and load flexibility. Capacity shortfall risks are no longer limited to peak-load hours but can prevail

[19] Firm capacity is a near-perfect capacity that can be added to improve reliability whenever called for, especially under stress conditions. The firm capacity value of a dispatchable generator is typically calculated as its nameplate capacity de-rated based on its forced outage rate.

during hours of very low or peak net loads, as weather is a decisive factor in renewable generation: periods of risk can be common even during off-peak load hours when, for example, mild weather accompanied by plenty of sunshine reduces the net load to a level that cannot keep sufficient synchronous generators online. Variable renewable energy sources also increase the need to address daily ramping up and down.

Such hour-to-hour changes in weather (and thus power generation) imply that a system's capacity-shortfall probability is constantly changing. Climate change can exacerbate the variability and unpredictability of weather changes, leading to more frequent high-impact tail events. In addition, battery and load flexibility can be useful energy resources only when they are well prepared for charging and scheduling, for example during off-peak hours before being used during peak hours. Average metrics such as LOLE offer little insight into when and why capacity shortfalls are expected, and how the new resources can be best utilised.

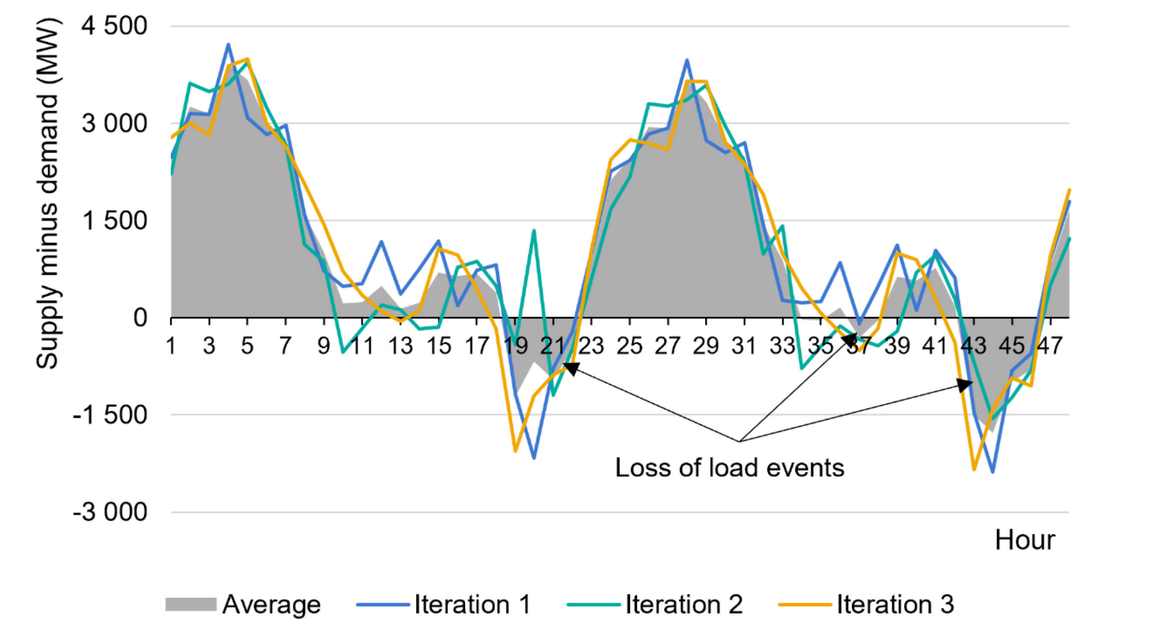
Another challenge is to accurately measure the capacity values of new resources such as non-dispatchable renewables. The ELCC methodology can be used, but in fact its implementation is still challenging. For example, solar PV systems have different capacity values depending on their location and hours of generation. Nevertheless, the CPUC assigns one single monthly capacity value for all solar PV installations across its region to avoid dispute over the complicated assumptions needed to compute the ELCC value. Consequently, there are periods when the assigned capacity value exceeds the realised ones. For example, the average realised capacity value of solar generation was lower than the monthly assigned ELCC value in August 2020. Hourly realised values were much lower especially in the late evening during the rolling blackouts of 14 August, as the prolonged extreme heat degraded solar panel efficiency. This can explain the renewable output gap during this emergency event.

Regulators and system operators can explore energy-based resource adequacy analysis based on a chronological evaluation of all hours. Modelling sequential grid operations, which assess the full hour-to-hour dispatch of a system's resources for an entire year of operations across many different weather patterns, load profiles, and resource outages and availability, is critical to capture the whole picture and thus identify times and situations of high risk. Multiple reliability metrics, including expected unserved energy (EUE), can be used in addition to LOLE. EUE is an energy-based metric that measures magnitude of capacity shortfall for a given time period (in megawatt hours). Importantly, hourly EUE can be reported for every month or year to make it a more effective metric in gauging the impact of a changing resource mix on daily load distributions.

Alternative reliability metrics and programmes are also under discussion. For example, a utility in California proposed a slice-of-day approach, which segments a daily load into several slices that have similar system conditions and credits different capacity values for each one, reflecting a resource's ability to contribute to the needs in that slice. Furthermore, the CPUC is exploring forward energy requirements, whereby its load-serving entities must demonstrate that they have sufficient resources to meet energy needs across all hours, not just peak periods.

However, as the energy-based approach still cannot avoid the inherent risk of arranging sufficient supplies well in advance of the operating moment (based on forecast conditions), regulators and system operators can prioritise analytical capacity improvements. Probabilistic Monte Carlo techniques, which can simulate system operations under many possible conditions, incorporating the uncertainty (i.e. probability distributions) of input variables such as load profiles, are useful. Furthermore, having access to extensive information on weather history, and weather-correlated data on load and resource availability is critical to address resource adequacy challenges. Much of this information is not yet readily available, however, so regulators, system operators and policymakers can join forces to address data limitations, as ENTSO-E has begun to do.

All-hours chronological resource adequacy simulations using the Monte Carlo technique



Notes: Reliability metrics such as EUE can be calculated by averaging the values of the three iterations. The average was derived by averaging the three iterations and corresponds to the calculated values of reliability metrics.
Source: Data from NERC (2018), Probabilistic Adequacy and Measures: Technical Reference Report.

Introducing reserve scarcity pricing

The increased risk of large variances in renewable generation implies a greater need for risk management, requiring more balancing reserves, but a well-designed short-term energy market can address much of this risk. For example, short-term market prices with high temporal and locational granularity can reduce the need for balancing energy and out-of-market redispatch actions, as mentioned in the previous section.

In addition, system operators can develop supplemental ancillary service products to help mitigate the impacts of hourly renewable generation variability. For example, the California ISO introduced Flexible Ramp Up and Flexible Ramp Down Uncertainty Awards in 2016. The flexible ramping products procure ramp-up and -down capability for 15- and 5-minute markets in terms of megawatts of ramping required to compensate for forecast net demand variations. Introducing the products could improve the availability of fast ramping capacity and reduce short-term market spikes arising from ramping shortfalls.

Meanwhile, regulators and system operators can introduce reserve scarcity pricing to attract sufficient investment in flexible capacity to maintain long-term resource adequacy. Several electricity markets, such as the Electric Reliability Council of Texas (ERCOT) in the United States, have adopted this pricing mechanism. Scarcity pricing allows market prices to spike to the value of lost load (VOLL), the price consumers are willing to pay to avoid the loss of load. Furthermore, this approach can adequately reflect underlying system conditions in market prices. As the value of reserves and energy are interdependent, energy prices should include an opportunity cost for not providing reserves. For instance, a generator offering an energy product cannot use the same capacity to offer a reserve product. Scarcity pricing adds reserve prices to energy prices (called co-optimised), which can provide accurate market price signals.

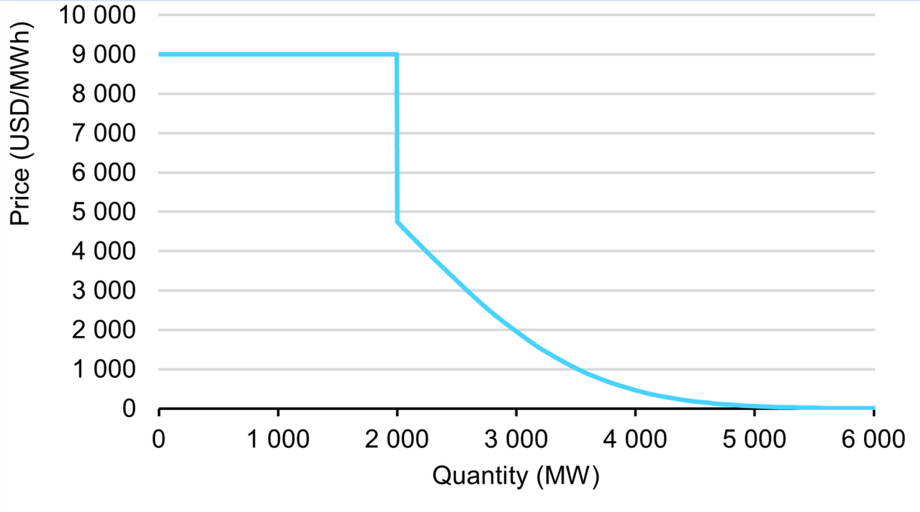
During reserve shortfalls, the pricing mechanism can activate substantially higher energy prices, rewarding flexible resources such as DERs for their fast-ramping capability and attracting investment in them. It can also incentivise consumers to reduce or shift energy consumption during price spikes and encourage retailers to enter into bilateral contracts for capacity to hedge against price volatility, helping to ensure long-term resource adequacy.

ERCOT's operating reserve demand curve

At the heart of scarcity pricing is the operating reserve demand curve (ORDC), which ERCOT first developed to reflect the value of reserve scarcity in real-time market prices. Any system operator needs to ensure the availability of a certain level of operating reserves to fill supply-demand gaps in real time to avoid load curtailment or system failure. The operator defines a minimum level of reserves, below which the load would have to be curtailed to remain within the targeted range.

Hence, the reserve price up to the minimum target level is set according to the VOLL. ERCOT had a VOLL of USD 9 000/MWh, but it has lowered it to USD 5 000/MWh. At any level above the minimum target, reserve prices are the VOLL multiplied by the probability of the load being curtailed, known as loss of load probability (LOLP). As the reserve level increases, the LOLP decreases owing to the larger amount of emergency backup and, accordingly, the reserve price falls. In the real-time market, ERCOT adds reserve prices from the ORDC to relevant energy prices, called a "price-adder," whereas the operator co-optimises energy and reserves to clear the day-ahead market.

An example of operating reserve demand curve in the ERCOT system



Source: ERCOT (2016), Scarcity Pricing in ERCOT.

Price caps can limit electricity suppliers' ability to exercise market power in the short-term energy market, but they also can reduce the revenues suppliers earn during scarcity conditions, which has been dubbed the "missing money problem". To help scarcity pricing attract sufficient investment in capacity, regulators can increase or even remove market price caps, allowing prices to spike as high as necessary during reserve shortfalls, though this can be politically challenging. EU

Regulation 2019/943 stipulates that it is "critical to ensure that administrative and implicit price caps are removed in order to allow for scarcity pricing." It is important to note that scarcity pricing is an administrative mechanism that mimics a well-functioning short-term energy market.

Regulators and system operators can, however, design reserve scarcity pricing carefully not to jeopardise the offering of reliable and stable prices to consumers. For example, some analysts argue that during the Texas blackout in February 2021, there was no need to maintain the price at the maximum level (USD 9 000/MWh). The high price cap was chosen to attract sufficient long-term capacity, but a much lower price would have been enough to encourage existing generators to run.

ERCOT's scarcity pricing system also has a lower price cap, used as a circuit breaker, that replaces the high cap when peak power plants have already been adequately remunerated. The lower cap was set at USD 2 000/MWh, or 50 times the natural gas fuel index price. During the February 2021 blackout, however, exceptionally high gas prices caused the lower cap to exceed the higher one, sustaining a price of USD 9 000/MWh for several days even though peak gas-fired generators had earned a high enough revenue margin and could be running at lower market prices.

Regulators and system operators can prioritise reserve scarcity pricing, as centralised mandatory capacity markets have been criticised for their poor performance. Capacity does not distinguish between resources that can provide flexibility and those that cannot. Conversely, well-designed short-term energy market prices can provide better signals to activate capabilities most needed to maintain reliability. Regions with capacity mechanisms have attracted and retained much more generating capacity than typical reserve margins. For example, PJM expects reserve margins of 38.4% to 41.9% during 2021 and 2025, much higher than its reference level of 14.8%. Furthermore, conventional capacity valuation methods often overstate the reliability contribution of dispatchable generation[20] and thus favour fossil fuel-based generators. For this reason, the Clean Energy Package the European Union adopted in 2019 prioritises improving the short-term energy market, which includes introducing a shortage pricing function for balancing reserves.

[20] Conventional capacity valuation methods consider dispatchable generators to have firm capacity, as their forced outage rates are considered randomised (i.e. not correlated with weather and other generation). However, the 2021 Texas blackout revealed that extremely cold weather could significantly impact the performance of gas-fired power plants, which suggests that conventional methods need revising.

Reserve scarcity pricing and capacity remuneration mechanisms are not mutually exclusive

Scarcity pricing has some issues. It is a price-based mechanism, meaning that pricing itself cannot guarantee a given amount of capacity in the same way as volume-based programmes that impose forward capacity or energy requirements can. Its contribution to long-term resource adequacy depends mainly on whether high price volatility can incentivise retailers to enter into forward contracts needed to attract sufficient investment in capacity. It is widely accepted that short-term market price caps can result in a missing market for forward contracts, even though they are introduced to limit suppliers' ability to exercise market power. Price caps can lead to capacity shortfalls, as retailers are unwilling to purchase energy in the forward market at above the short-term market price caps.

Furthermore, it is argued that there is little evidence of customer and retailer willingness to sign long-term contracts (i.e. ten to fifteen year duration) to hedge the unpredictable risk of price spiking due to reserve scarcity, though it is debatable whether six-month to three-year contracts with the possibility of rolling forward is a viable alternative for attracting sufficient investment in capacity. There indisputably exist forward contracts and futures markets that can hedge short-term anticipated price changes.

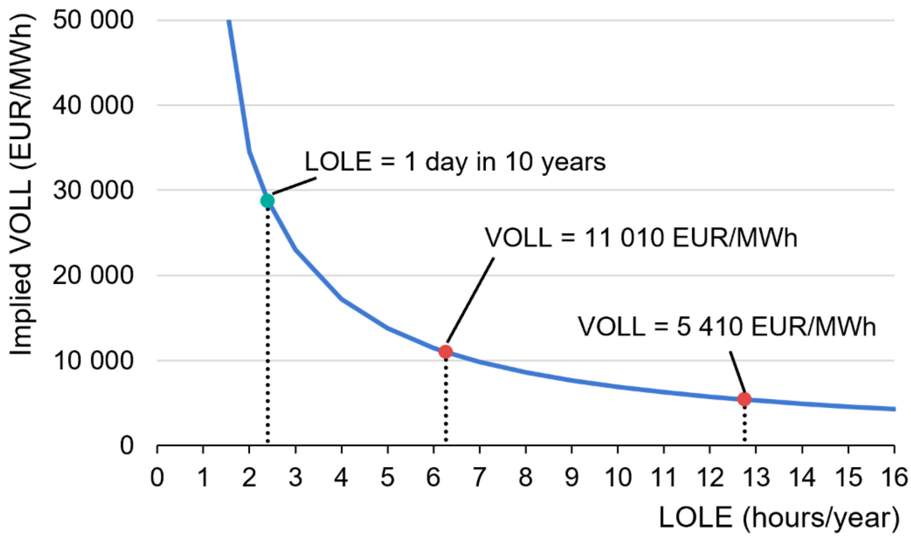
Regulators and system operators can complement reserve scarcity pricing with capacity remuneration mechanisms, but in a way that can reduce potential market distortion and cost burdens for consumers. For example, as a default option the EU Clean Energy Package prioritises adopting strategic reserves, which are kept outside the market and used only if the market cannot secure enough generation to meet short-term demand, with preconditions that the reserve be kept as small as possible and that the programme prevent resources from leaving the market, rather than promote the entry of new ones. In addition, the package mandates that capacity mechanisms be open to any resources capable of providing the required technical performance, including energy storage and demand response. It also introduces carbon emissions thresholds to exclude the most polluting power plants from participating in the mechanisms.

Australia's National Electricity Market (NEM) is an energy-only market with one of the world's highest short-term market price caps at AUD 14 700/MWh, but it is complemented by a Retailer Reliability Obligation (RRO) as an emergency backstop. The scheme was adopted in 2019 and can trigger forward-contract quantity requirements for retailers – and ultimately the building of additional capacity when retail forward contracts are deemed insufficient to cover the system operator's reliability forecast. Furthermore, the RRO is decentralised in that retailers can choose appropriate types of capacity to comply with their obligation. This decentralised approach can help reveal the value of different types of capacity, including demand-side management, and reduce the potential for over-procurement inherent in centralised schemes.

In California, a standardised fixed-price forward contract is under discussion as an option to meet forward energy requirements, as mentioned in the previous subsection. Simply put, the scheme is a regulatory programme that obligates retailers to enter into widely used commercial forward-hedging contracts, rather than leaving it to their discretion, but out for longer time horizons. Hence, this approach can also address potential low levels of commercial contract liquidity, if needed.

Fundamentally, regulators and system operators need to explicitly consider consumer cost implications in their decision-making. For example, an LOLE of 1 day in 10 years (2.4 hours per year), one of the most widely used reliability benchmarks, can imply a VOLL of EUR 28 750/MWh, as shown in the graph below. However, a recent study of European VOLLs indicates median values of EUR 5 410/MWh to EUR 11 010/MWh for domestic consumers, corresponding to 12.8 and 6.3 hours per year.

Non-linear relationship between LOLE and implied VOLL



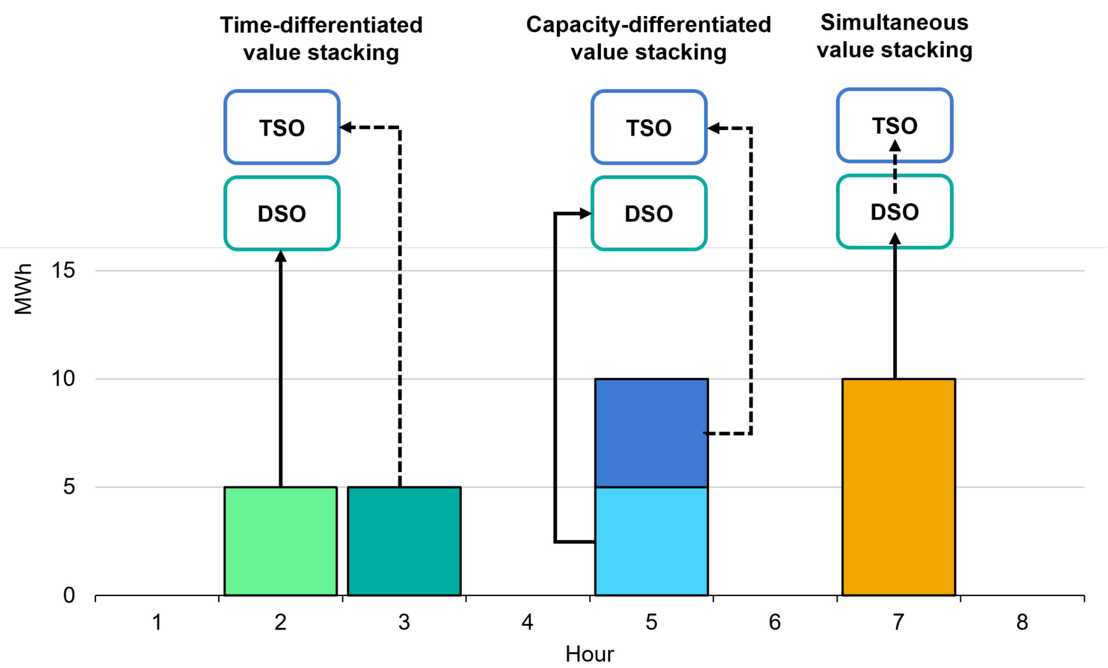
Notes: LOLE = loss of load expectation. VOLL = value of lost load. Implied VOLLs were calculated with the formula LOLE = CONE ÷ VOLL. The calculation used a median value of the European benchmarks for the cost of new entry (CONE) based on open-cycle gas turbine (OCGT) technology: EUR 69/kW-yr in real 2019 terms. The range of VOLLs (EUR 5 410-11 010/MWh) is based on the median values for domestic consumers in Northern, Eastern, Southern and Western Europe.
Source: Data from CEPA (2018), Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe; FTI-CL (2020), Study to Establish an Estonian Reliability Standard.

Although it may not be easy to identify an economically efficient reliability level, it is important to have a clear understanding and transparency on how much system reliability costs consumers, and all decisions need to be based on consumer willingness to pay. For example, it is more economical to compensate consumers for reducing or shifting energy consumption at EUR 11 010/MWh (their maximum VOLL) than to add capacity at EUR 28 750/MWh to meet the 1-day-in-10-years LOLE. One of the best ways to achieve such consumer-centric resource adequacy is to open all markets to distributed energy resources, with which consumers can reveal their willingness to pay for reliability. More consumers would agree to reduce or shift their energy demand with increasingly lower costs and less inconvenience owing to rapidly evolving digital technologies, maintaining reliability more cost-effectively.

Allowing stacking of multiple values

As DERs are connected to distribution networks close to consumers, they can provide diverse value across the electricity industry supply chain: from consumers, retailers and DSOs to market operators and TSOs. DERs have three options to stack multiple values or revenue streams, depending on their operational characteristics: time-differentiated, capacity-differentiated or simultaneous value stacking.

Three types of value stacking



In time-differentiated value stacking, DERs provide services to multiple entities during distinct time periods. In the figure above, for instance, a DER offers an energy product of 5 MWh to a DSO during hour 2 and provides another product to a TSO during hour 3. Alternately, with capacity-differentiated value stacking the capacity of a portfolio of DERs (or of a single DER such as a battery) can be divided so that the first half (5 MWh) can be offered to a DSO, while the remaining 5 MWh can be provided to a TSO during the same time interval (hour 5). Under the third option, simultaneous value stacking, a DER can provide the same 10 MWh of energy for services to both a DSO and a TSO simultaneously (during hour 7), when permitted by relevant regulation.

In general, DERs can move between different time periods much more readily than they can stack multiple value streams in the same time interval. There are necessary limitations to stacking values in the same time periods to ensure system reliability. In Great Britain, almost all service products in wholesale energy, capacity, balancing, ancillary service and distribution flexibility markets are readily stackable in time. However, resources contracted for firm frequency response (FFR), for example, cannot be used for other services in the same time interval. As FFR service providers nominate time blocks for which they will be available, providing almost any other service in the same time blocks would render them unable to fulfil their FFR obligation. This exclusivity ensures that contracted resources are available to deliver FFR services reserved to prepare for unexpected system failures.

Regulators can, however, make it easier for DERs to stack values in the same time periods without compromising power system reliability. For instance, European power exchanges allow for portfolio bidding to maximise product liquidity and thus improve market efficiency. A flexibility provider can offer aggregated bids from different generators and demand facilities belonging to the same provider for multiple markets while balancing supply and demand within its portfolio; this means that capacity-differentiated value stacking is allowed at the portfolio level. In this way, the flexibility provider can optimise the operation of every resource, including DERs, and maximise its revenues (this is also called value stacking in pools).

In addition, battery storage is a promising technology for which multiple value stacking of a single resource, including capacity differentiation, can be allowed. In 2018, the California Public Utilities Commission (CPUC) adopted a set of rules to govern value stacking of energy storage resources. Under exploration is the partitioning and metering of storage capacity for the purpose of providing different services, especially during the same time interval. TSOs may be concerned that what a storage device is doing when not supplying transmission reliability services may compromise its state of charge (SoC) and jeopardise the device's ability to provide the transmission service later when needed. However, the battery industry argues that the SoC parameters of battery bidding can be useful for maintaining a capacity buffer that would be available to provide reliability services to TSOs. Another issue is how to differentiate each capacity portion provided to a TSO and a DSO through meter data.

The CPUC's 11 rules to facilitate multiple value stacking

The CPUC has developed 11 rules to help realise the full economic value of storage resources when they can provide multiple power system benefits. The rules define five service domains – customer, distribution, transmission, wholesale market and resource adequacy – divided into two types: reliability and non-reliability. Reliability services such as frequency regulation are directly related to system reliability, which is not the case for non-reliability services such as spot market energy provision.

Rule 1: Resources interconnected in the customer domain may provide services in any domain.

Rule 2: Resources interconnected in the distribution domain may provide services in all domains except the customer domain, with the possible exception of community storage resources.

Rule 3: Resources interconnected in the transmission domain may provide services in all domains except the customer or distribution domains.

Rule 4: Resources interconnected in any grid domain may provide resource adequacy, transmission and wholesale market services.

Rule 5: If one of the services provided by a storage resource is a reliability service, then that service must have priority.

Rule 6: Priority means that a single storage resource must not enter into two or more reliability service obligation(s) such that the performance of one obligation renders the resource from being unable to perform the other obligation(s). New agreements for such obligations, including contracts and tariffs, must specify terms to ensure resource availability, which may include, but should not be limited to, financial penalties.

Rule 7: If using different portions of capacity to perform services, storage providers must clearly demonstrate, when contracting for services, the total capacity of their resource, with a guarantee that a certain, distinct capacity be dedicated and available to the capacity-differentiated reliability services.

Rule 8: For each service, the programme rules, contracts or tariffs relevant to the domain in which the service is provided, must specify enforcement of these rules, including any penalties for non-performance.

Rule 9: In response to a utility's request for offer, the storage provider is required to list any additional services it currently provides outside of the solicitation. In the event that a storage resource is enlisted to provide additional services at a later date, the storage provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this Rule is to provide transparency in the energy storage market.

Rule 10: For all services, the storage resource must comply with availability and performance requirements specified in its contract with the relevant authority.

Rule 11: In paying for performance of service, compensation and credit may only be permitted for those services, which are incremental or distinct. Services provided must be measurable, and the same service only counted and remunerated once to avoid double compensation.

Regulators can establish clear rules to enable a single resource to stack multiple revenue streams in the same time interval (i.e. simultaneous value stacking). For example, under GB capacity market rules, capacity providers who do not meet their obligation when dispatched in an emergency event are not penalised if they were engaged in a relevant balancing service. As a result, capacity providers can participate freely in pertinent balancing service markets without the risk of penalty.

In the United States, the New York Independent System Operator (NYISO) has developed a dual participation model that allows resources providing wholesale market services to also provide services to another entity, such as a distribution utility or a host facility. However, resources dual participating in NYISO-operated wholesale markets continue to be obligated to follow all applicable NYISO market rules. Thus, they must appropriately reflect any non-wholesale obligations (e.g. to distribution utilities) in their offers to the wholesale markets: for example, they can submit self-scheduling offers to the NYISO so that they can meet their distribution utility obligations when following NYISO dispatch instructions.[21] In this way, dual participating resources can receive payments for wholesale market services scheduled through these offers, enabling the stacking of these revenues on top of those from the distribution utility in the same time period.

[21] In the centralised dispatch power model, some generators such as renewable energy technologies can bid with self-scheduling offers, whereby they express the willingness for their generation offers to be accepted at any market price. In this way, their offers can be accepted by the wholesale market while they provide services to another entity with the same energy.

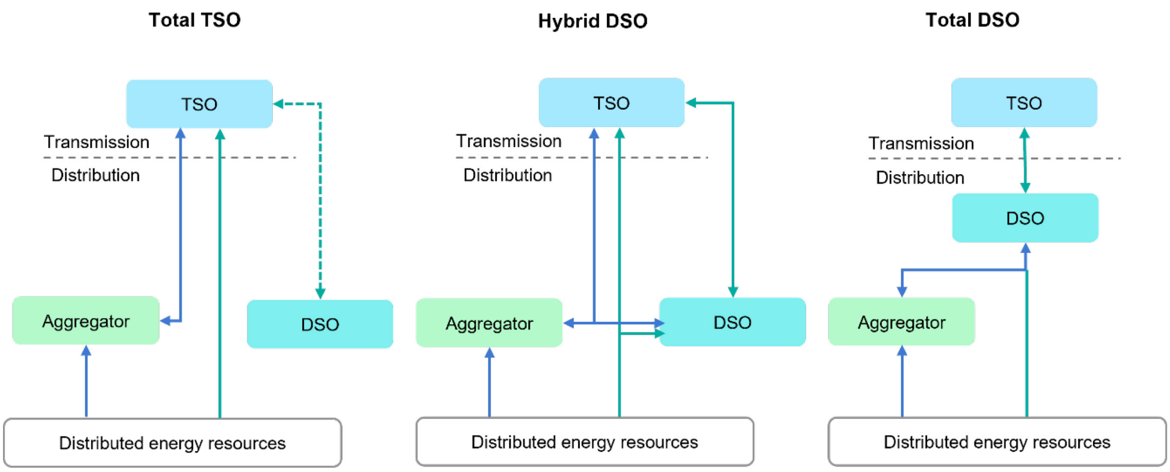
TSO-DSO co-ordination is a key to value stacking

The key to facilitating value stacking for DERs is close co-ordination among the relevant entities, including TSOs and DSOs. DER services for TSOs or DSOs have distinct operational needs, time frames and features. For example, DSOs can defer grid reinforcement with DER services, but these services can be procured only from resources connected to the grid, thus are highly location-specific, and DSOs will be aware of reinforcement needs over a long period of time, so they are comparatively predictable.

In contrast, TSOs use frequency response services to stabilise the whole power system in response to, for example, failure of a large generator. These services can be procured from DERs across a wide area, thus are non-location-specific, and dispatch timing cannot be predicted. Regulators can therefore facilitate close co-ordination between TSOs and DSOs to unlock the potential of multiple value stacking of a single resource without compromising system reliability.

The TSO-DSO co-ordination framework is currently under discussion, the central topic being the allocation of TSO and DSO roles and responsibilities in managing the distribution system and DERs. A spectrum of co-ordination models is being considered in North America, based on the extent to which system and market operations are centralised under the TSO versus layered between the TSO and DSO, as illustrated below. At the extremes of the spectrum are the Total TSO (fully centralised) and the Total DSO (fully layered). Between these endpoints, various hybrid DSO models are possible.

Three models for TSO-DSO co-ordination



Source: Adapted from Newport Consortium (2018), Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design.

In the Total TSO model, the Total TSO operates a fully integrated power system into the distribution system, dispatching all DER services and schedules; thus, the Total TSO is required to have full visibility over the distribution system and DERs. All DERs have direct access to the TSO markets, and the DSO retains only the traditional distribution utility role of maintaining reliable and safe distribution operations.

The Total DSO model is at the opposite end of the spectrum: the Total DSO co-ordinates and aggregates all DERs into a single resource as is normally done by an aggregator, submitting a single bid/offer to the TSO markets for each transmission-distribution (T-D) interface. The TSO sees only one single resource at each T-D interface managed by the Total DSO, and thus needs no visibility over the distribution system and DERs.

In the hybrid DSO models, the TSO and DSO share the responsibility of managing DERs. For example, the hybrid DSO may dispatch DERs for distribution services, while the TSO dispatches the resources for its own reliability services; thus, DERs can have direct access to the TSO markets. The hybrid DSO co-ordinates DER dispatches with the TSO, which needs only limited visibility over the DERs it procures services from.

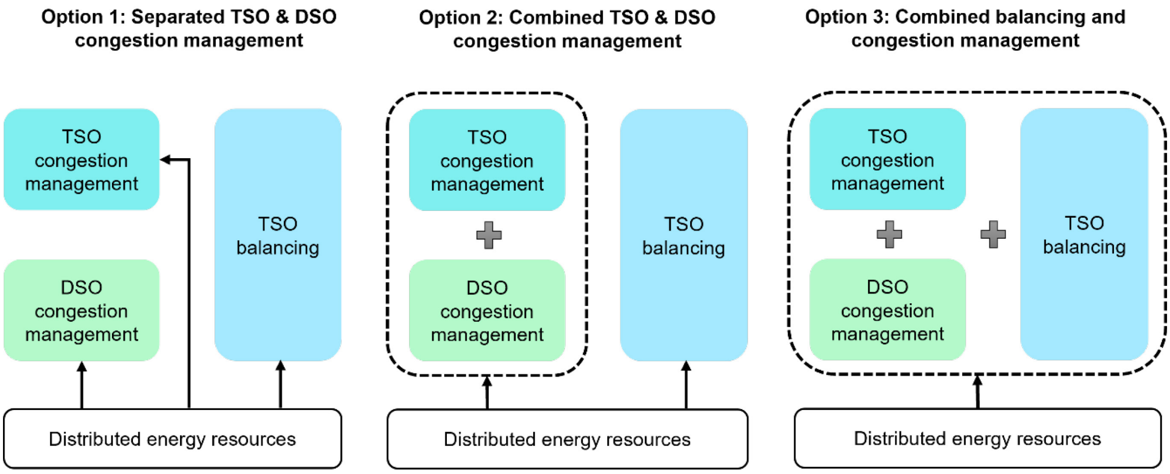
It is important to note that the choice of co-ordination model can dictate the tasks TSOs and DSOs would be responsible for and, accordingly, their physical capabilities each entity is required to have, such as visibility over the distribution grid and DERs. For example, if Total DSOs are responsible for balancing each local system, a TSO's role could be limited to being a residual balancer of a whole bulk power system. In this case, the TSO needs to have visibility over the T-D interface only, not below it.

Many international discussions are expected to begin with the hybrid DSO models, which can avoid the near-term implementation challenges associated with the structural modifications required for the Total TSO and Total DSO models. The Total DSO model would be a major change from the centralised control structure that has characterised the electricity industry for decades and would require substantial enhancements to the functional capabilities of today's distribution utilities. Implementation of the Total TSO model would also be challenging because creation of a complete transmission plus distribution network model for system optimisation and modelling of all DERs at their point of connection to the grid would be required.

In Europe, three options are being actively investigated to co-ordinate TSO balancing and transmission congestion management[22] with DSO distribution congestion management markets. These options provide practical schemes to implement the co-ordination under the hybrid DSO models[23], whereby both TSOs and DSOs procure services from DERs for their respective systems. The failure to co-ordinate system operators' markets can lead to reliability risks. For example, while a TSO's uncoordinated dispatch of DERs can cause distribution bottlenecks, DSO's uncoordinated dispatch of DERs can complicate system balancing.

In the first option – separated TSO and DSO congestion management – local markets may emerge as dedicated solutions to DSO congestion management, separate from TSO congestion management and balancing. TSOs can separate or merge their congestion management and balancing. Each market has its own process to collect and select bids from DERs, called a merit order list (MOL).[24] Separated markets mean separate MOLs, and a combined market means a combined MOL. The second option – combined TSO and DSO congestion management – integrates the MOLs of transmission and distribution congestion management services. The last option – combined balancing and congestion management – integrates the MOLs of all three types of system operator service.

Three options to co-ordinate balancing and congestion-management markets



Source: Adapted from ENTSO-E et al. (2019), TSO-DSO Report: An Integrated Approach to Active System Management.

[22] In Europe, TSOs typically operate distinctive balancing and transmission congestion management mechanisms due to their zonal pricing model.
[23] In Europe, another co-ordination framework was developed, suggesting five models: centralised AS market, local AS market, shared balancing responsibility, common TSO-DSO AS market, or integrated flexibility market model.
[24] Each market requires its own platform that is defined as a distributed software functionality that energy system participants require to perform their tasks according to their roles and responsibilities, and to interact with other relevant participants.

Each option has its pros and cons. The third (combined balancing and congestion management) can provide a single-entry gate to market parties for all TSO and DSO grid services. Thus, this option can ensure easy access to grid service markets, liquidity of service products, a level playing field for different service providers, and lower procurement costs. However, this option requires interaction among TSOs and DSOs, multiple service products and market parties in a single marketplace, which can result in complex governance and implementation. The advantage of the third option is the weakness of the first (i.e. separated TSO and DSO congestion management) and vice versa.

From a co-ordination perspective, the third option (combined balancing and congestion management) is the most advanced. A single marketplace for collecting and activating flexibility services would allow TSOs and DSOs to access all bids from market parties and co-ordinate activations, mutually addressing potential dispatch conflicts. Flexibility service providers could submit their bids only once, and the market process would ensure the bid is used where most valued through combined MOLs.

Conversely, the first option (separated TSO and DSO congestion management) requires that flexibility service providers co-ordinate different market processes, complying with all rules and procedures set by different system operators. The service providers choose which market processes to bid on and are responsible for ensuring that each congestion management and balancing bid submitted does not adversely affect the others; otherwise, they are typically subject to penalties. In addition, if more than one marketplace is used, they need to be interoperable to ensure co-ordination. Effective co-ordination relies on data exchange and enabling ICT solutions. Accordingly, interoperable data registries can facilitate seamless information exchange among system operators and flexibility service providers.

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