White Paper

Stable grid operations in a future of distributed electric power

CEO

Executive summary

The electricity utility industry is currently undergoing the largest disruption since its inception more than a century ago. Driven by the five global factors of decarbonization, decentralization, deregulation, democratization and digitalization, a diverse set of devices involving various disruptive resources are now connected to the electricity grid – devices that are generally owned and operated by electricity customers and deployed “behind the meter”. These disruptive resources are causing grid operators to rethink how the electricity grid will be managed, because unlike traditional generation sources, these resources are often invisible to the grid operator (limited visibility), outside of the control of the grid operator (limited control), characterized by hard-to-anticipate generation and consumption levels (limited predictability) and deployed without central planning (limited coordination). The challenges posed by disruptive resources are covered in Section 1 and the driving factors behind their rise in Section 2.

As is the case with all disruptive innovations, following a chaotic period in which market players and technologies have been frantically searching for the optimal approach to their integration, a new equilibrium is emerging. Grid operators today are working to accommodate that new equilibrium by changing operational techniques. Market designs are allowing for a transition from a situation in which these new resources constitute problematic elements to one in which resulting devices will enable a future of cleaner, cheaper and more reliable power. To understand this future, important concepts related to managing the grid are covered in Section 3, with a number of market-based constructs for managing delivered services being covered in Section 4.

In Section 5, this White Paper overviews some of the methods by which new resources are currently being incorporated in grid operations through both reliability-based and economics-based structures. Against this background, the paper then examines some of the trends determining the development of major components of the future model for grid operations, with techniques for an incentive demand-side response being covered in Section 5 and technologies which may enable such solutions the focus of Section 6. These solutions will require the use of current and new International Standards, with some of the gaps and overlaps involved being discussed in Section 7. Section 8 concludes the paper by providing recommendations to the IEC community, industry leaders and policymakers.

This White Paper offers the following main conclusions:

- The drivers behind the growth of demand-side resources are expected to continue to exercise their influence, leading to a concomitant growth and penetration of innovations related to such resources.
- Grid operators will need to rely more heavily on demand-side resources in the future, with additional challenges being posed for stable grid operations if the necessary changes are not implemented.
- Success will depend on improved regulations within the distribution domain to provide accurate price signals in both wholesale and retail environments.
- New technologies supported by effective standards must be adopted to help reduce the impacts of limited visibility, limited control, limited predictability and limited coordination.

Based on the above conclusions, several recommendations can be made for consideration by stakeholders both inside and outside of the IEC. The recommendations are listed below, with detailed descriptions of each presented in the final section of the paper.

Recommendations for the IEC community

- Promote common language
- Consider procedural Standards
- Study and document best practices
- Improve intra-IEC coordination
- Improve inter-SDO coordination

Recommendations for industry leaders

- Improve coordination
- Improve technology adoption
- Encourage communication and education (industry leader role)

Recommendations for policymakers

- Encourage communication and education (policymaker role)
- Establish equitable goals
- Cross-industry collaboration and commercialization support

Acknowledgments

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The broader project team included representatives from electric power network businesses, research institutes and equipment vendors from around the world. To seek input from a range of stakeholders, the IEC ran three workshops dedicated to this White Paper, in Tokyo (October 2017), Milan (February 2018) and San Diego (April 2018). These workshops were attended by experts in the field, who were invited to detail how they currently approach, and plan to approach in the future, demand-side resources on the electric power grid.

The full project team includes three groups of contributors listed alphabetically. We would like to thank each person for his or her contributions and support in assembling this vision of the future grid.

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Table of contents

List of abbreviations

Technical and scientific terms

ACE	area control error
AI	artificial intelligence
ALM	active load management
AMI	advanced metering infrastructure
ANM	active network management
API	application programme interface
AVR	automatic voltage regulator
BEMS	building energy management system
BG	balancing group
BPS	bulk power system
C&I	commercial and industrial
CCA	community choice aggregation
CIM	common information model
CSP	charge service provider
DA	distribution automation
DDS	data distribution service (standard)
DER	distributed energy resource
DERMS	distributed energy resource management system
DG	distributed generation
DMS	distribution management system
DR	demand response
DSM	demand-side management
DSO	distribution system operator
DSR	demand-side resource
DTU	demand turn up
EES	electrical energy storage
EIM	energy imbalance market

eMBB	enhanced mobile broadband
EMS	energy management system
ERS	essential reliability service
ESS	energy storage system
EV	electric vehicle
EVSE	electric vehicle supply equipment
FEMS	factory energy management system
FRT	fault ride-through
GC	gate closure
GMS	generation management system
HEMS	home energy management system
HVAC	heating, ventilation and air conditioning
ICT	information and communication technology
IIoT	industrial Internet of Things
ILR	interruptible load for reliability
IoT	Internet of Things
IOU	investor owned utility
IPP	independent power producer
ISO	independent system operator
LPWAN	low-power wide-area network
LSE	load serving entity
LVDC	low voltage direct current
MEMS	microgrid energy management system
mMTC	massive machine-type communications
NEMO	nominated electricity market operator
OATT	open access transmission tariff
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
PMU	phasor measurement unit
PRD	price responsive demand
RES	renewable energy source

SA	situational awareness
SBG	surplus base-load generation
SCADA	supervisory control and data acquisition
SGUI	smart grid user interface
SIDM	system interfaces for distribution management
STATCOM	static synchronous compensator
SDO	standards development organization
SO	system operator
SVC	static VAR compensator
TO	transmission owner
TPA	third party access
TSN	time-sensitive network
TSO	transmission system operator
UFR	under-frequency relay
URLLC	ultra-reliable low-latency communications
VAR	volt amperes reactive
VoLL	value of lost load
VPP	virtual power plant
VSG	virtual synchronous generator
WAM	wide-area measurement (system)

Organizations, institutions and companies

ACER	Agency for the Cooperation of Energy Regulators
CAISO	California Independent System Operator
EirGrid	State-owned electric power transmission operator in Ireland
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX SPOT	European Power Exchange SPOT
ERABF	Energy Resource Aggregation Business Forum
FERC	Federal Energy Regulatory Commission (US Government)
GME	Gestore dei Mercati Energetici
IGCC	International Grid Control Cooperation

IPCC	Intergovernmental Panel on Climate Change
JEPX	Japan Electric Power Exchange
KPX	Korea Power Exchange
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
OMIE	Operador del Mercado Ibérico de EnergÍa
PJM	Pennsylvania-New Jersey-Maryland
PLMA	Peak Load Management Alliance
SPP	Southwest Power Pool
TEPCO	Tokyo Electric Power Company

Glossary

5th generation wireless system
5G
the next generation of mobile internet connectivity, offering faster speeds and more reliable connections on smartphones and other devices

advanced metering infrastructure
AMI
an architecture for automated, two-way communication between a smart utility meter with an IP address and a utility company

aggregator
resource aggregator
any organization or individual that brings retail energy customers together as a group with the objective of obtaining better prices, service, or other benefits when acquiring energy or related services

ancillary services
services necessary for the operation of an electric power system provided by the system operator and/or by power system users

artificial intelligence
AI
intelligence demonstrated by machines

balancing group
BG
energy account under responsibility of a balance responsible party used to determine balance, considering predefined inputs and outputs within a specific market balance area

baseline
method of estimating the electricity that would have been consumed by a demand resource in the absence of a demand response event

capacity
maximum amount of power (measured in watts) that a power plant can produce

capacity market
financial market aimed at securing generation capacity to cover the load forecasted by long-term planning studies

communication protocol
system of rules that allows two or more entities of a communications system to transmit information via any kind of variation of a physical quantity

congestion
situation in a transmission or distribution network requiring, in parts of an electric power system, a limitation of load flow

day-ahead auction
electricity auction in which trading takes place on one day for the delivery of electricity the next day

demand response
DR
action resulting from management of the electricity demand in response to supply conditions

Source: IEV 617-04-16

demand-side management
DSM
process that is intended to influence the quantity or patterns of use of electric energy consumed by end-use customers

Source: IEV 617-04-15

demand-side resource
DSR
demand offered for the purposes of, but not restricted to, providing active or reactive power management, voltage and frequency regulation and system reserve

distributed energy resources
DER
generators (with their auxiliaries, protection and connection equipment), including loads having a generating mode (such as electrical energy storage systems), connected to a low-voltage or a medium-voltage network

Source: IEV 617-04-20

distributed generation
DG
dispersed generation
embedded generation
generation of electric energy by multiple sources which are connected to the power distribution system

Source: IEV 617-04-09

dynamic rating
determination of the capacity based on real-time conditions, allowing operators to sometimes obtain more throughput

edge computing
method of optimizing cloud computing systems by performing data processing at the edge of the network, near the source of the data

energy
scalar quantity which may be increased or decreased in a system when it receives or produces work, respectively

Unit: kWh

energy management system
EMS
system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system

fault ride-through
FRT
capability of electric generators to stay connected in short periods of lower electric network voltage

gate closure
GC
point in time when balancing energy bid is to be submitted

governor-free
negative feedback control of generators' active power output by speed governors

grid code
technical code for connection of resources and development of the power grid

imbalance
deviation of energy output/consumption from original scheduled value declared at gate closure

independent system operator
ISO
entity responsible for ensuring the efficient use and reliable operation of the transmission grid and, in some cases, generation facilities

investor owned utility
IOU
entity providing a product or service regarded as a utility and managed as private enterprise rather than a function of government or a utility cooperative

islanding
condition in which part of the network is disconnected from the main grid and the distributed generator (DG) continues to power such a location

load serving entity
LSE
entity that secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers

low-power wide-area network
LPWAN
type of wireless telecommunication wide-area network designed to allow long range communications at a low bit rate

microgrid
group of interconnected loads and distributed energy resources with defined electrical boundaries forming a local electric power system at distribution voltage levels, which acts as a single controllable entity and is able to operate in either grid-connected or island mode

N-1 security criteria
rule according to which the elements remaining in operation within a TSO's control area after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits

negative price
price signal on the power wholesale market that occurs when a high inflexible power generation meets low demand

network code
set of rules drafted by the European Network of Transmission System Operators for Electricity (ENTSO-E), with guidance from the Agency for the Cooperation of Energy Regulators (ACER), to facilitate the harmonization, integration and efficiency of the European electricity market

operating reserve
stand-by power or demand reduction that can be called on at short notice to deal with an unexpected mismatch between generation and load

performance-based payment
a customary method of contract financing that may be available under fixed-price contracts, except for contracts awarded using sealed bidding procedures

ramps
rapid change of active power output (mainly from renewable energy sources (RESs))

renewable energy source
RES
renewable non-fossil energy sources are wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases

reserve
generating capacity available to the system operator to be used for the purpose of maintenance of electric power system reliability

rolling blackout
intentionally engineered electrical power shutdown in which electricity delivery is stopped for non-overlapping periods of time over different parts of the distribution region

system operator
SO
party responsible for safe and reliable operation of a part of the electric power system in a certain area and for connection to other parts of the electric power system

tariff
statement setting out the components to be taken into account and the methods to be employed in calculating the amounts to be paid to the supply funded by the consumer

telemetry
process in which measurements are made at some remote location and the results are transmitted by telecommunication

traditional generation
centralized generator resources such as thermal, hydro, and nuclear

transmission system operator
TSO
party operating a transmission system

under-frequency relay
UFR
solid-state device that functions to protect the load in the event generator frequency decreases below pre-set limits

value of lost load
VoLL
estimated amount that customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service

virtual power plant
VPP
cloud-based distributed power plant that aggregates the capacities of distributed energy resources for the purposes of enhancing power generation

Section 1
Introduction

After many decades of relative stability, the electricity industry started to face major changes as liberalization of electricity markets around the world began to come into force in the late 1990s. These changes were effected using well-established concepts related to evaluating the cost required to produce electricity and manage a reliable electricity grid. Market designs were improved, and continue to improve to the present day, as increasing numbers of countries embark on the electricity deregulation path.

In contrast to this gradual evolution from the traditional vertically integrated utility model, consisting of a single company with generation, transmission and distribution functions, into the multi-player model required for electricity markets, the electricity industry has been experiencing an arguably larger disruption in recent years. The change is being driven by a wave of new policies from the regulatory perspective, and new technologies from the customer's perspective, and is impacting the global electricity segment in its entirety. Stable operations of the electricity grid are being challenged in ways that were never conceived when electricity grids were originally designed and deployed.

Change is happening so rapidly that it is difficult to categorize the causes, and the industry has yet to converge on a common set of definitions. Until a clear approach is found, terms such as demand response, distributed energy resources, small-scale renewables, energy storage, virtual power plants, microgrids and demand-side resources will continue to capture the headlines – but these terms often mean very different things to different people. What we can do is attempt to identify and understand the overall trends generating challenges to electricity grid operations, as summarized by the following four categories of disruption:

1.1 Challenges from disruptive resources

Limited visibility – The new resources being deployed to the grid have limited visibility, and in some cases no visibility at all, for those operating the grid. Because these new technologies are being deployed largely behind the customer's meter and often without the knowledge of the grid operator, these resources are changing load patterns and even back-feeding generation into the grid without a direct mechanism to measure the effects. In contrast, traditional generation sources have always been equipped with measurement devices (electricity meters), and generally with telemetry of the current load or generation delivered to the grid operator in near real-time.

Limited control – Not surprisingly, with limited visibility comes limited control. Resources which are invisible to the grid operator are also uncontrollable. Even resources which go through a notification process, at a minimum, or even through a more thorough approval interconnection process with the grid operators, as is often the case with small-scale solar and small-scale wind generation, may not be subject to the control capability of the grid operator. Historically, each source on the grid was either equipped with a control path to the grid operator or was controllable by an independent operator following instructions from the grid operator.

Limited predictability – Again, it is not surprising to learn that when resources are invisible to the grid operator, their schedule for energy production or usage is hard to determine. And even for those resources with visibility by the grid operator, schedules can be highly variable. Consider again the small-scale wind and solar installation, which could even be equipped with real-time telemetry: because of the variation in weather patterns, these resources will have production schedules which are much less reliable than traditional generation driven from predicable supplies of fossil fuels, highly precise nuclear reactions or controllable flows from hydro sources. Resources behind the meter, such as energy storage units and electric vehicles (EVs), also add variability and hence reduce predictability – although as we will discuss later, intelligent rate design may be able to turn these resources into a predicable set of price-responsive resources.

Limited coordination – Planning for the deployment of a traditional generation source is a lengthy and complex process consisting of many studies undertaken to analyze the impact of a proposed facility on flows of electricity on the grid under a wide range of scenarios. In addition to tasks of analysis, the planning also involves numerous processes connected with location permits, environmental impact checks and often rights-of-way grants or resistance to such from citizens situated close to the proposed site. On the other hand, these new resources are implemented in a relatively uncoordinated fashion and generally on the low-voltage distribution network. Choices are made by individual customers based on value judgments regarding which resources are most appealing and when the investment should be made. This asynchronous process can lead to resources appearing in places that cause the grid to be unstable and in extreme cases can cause flows exceeding design capacities or in an opposing direction relative to the original grid design.

Interestingly, these new resources constitute not only a problem but also the most likely solution to the recent challenges faced by the current electricity industry. By understanding what the electricity grid requires to operate (i.e. in order to provide grid services) it becomes clear how these new resources can also provide such essential services. Concluding the analysis, the White Paper examines the modifications required in the form of changed processes, new technologies and improved global standards to facilitate the delivery of these services to increase confidence in the future stability of electricity grids.

1.2 Defining disruptive resources

Due to the important role of these disruptive resources, many new terms have emerged to designate them. Some of these terms are widely used while others are highly provincial, just as some are obvious in the meaning they express while others are less so. The IEC maintains a glossary of terms, available to the public through the IEC Electropedia [1], which have the added feature of being well-aligned with the North American Electric Reliability Corporation (NERC) terminology [2].

This terminology allows for a relatively clean approach to viewing these new disruptive resources. First, these resources are connected to the low-voltage or medium-voltage power system. By implication, large-scale wind and solar resources, which are transmission-connected, are not included. These utility-scale resources share similar characteristics of limited control and limited predictability but do not share the features of limited visibility or limited coordination. Second, distributed resources are split into two major categories: DSM, which are flexible but never inject power into the grid, and DER, which may result in net production. A visual representation of these relationships is shown in Figure 1-1. Thus, this White Paper adopts the demand-side resource (DSR) term as the overall category, including the two major sub-categories of distributed energy resources (DER) and demand-side management (DSM) conventions.

Term	Acronym	Definition
Distributed energy resources	DER	generators (with their auxiliaries, protection and connection equipment), including loads having a generating mode (such as electrical energy storage systems), connected to a low-voltage or a medium-voltage network (IEV 617-04-20)
Distributed generation	DG	generation of electric energy by multiple sources which are connected to the power distribution system (IEV 617-04-09) synonyms: dispersed generation, embedded generation
Demand-side management	DSM	process that is intended to influence the quantity or patterns of use of electric energy consumed by end-use customers (IEV 617-04-15)
Demand response	DR	action resulting from management of the electricity demand in response to supply conditions (IEV 617-04-16)

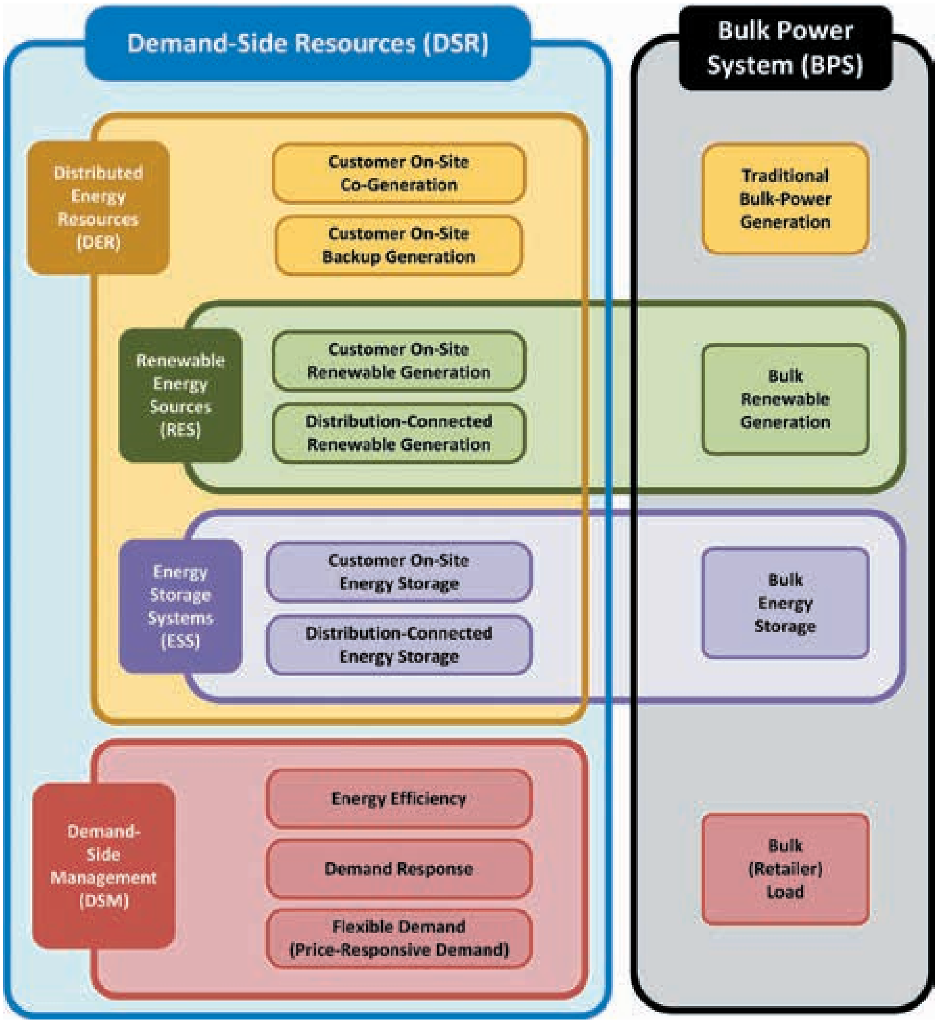


Figure 1-1 | Visualizing resources on the grid

Section 2
Change drivers

Energy security is the uninterrupted availability of energy sources at an affordable price [3] and should be viewed in terms of both short-term and long-term perspectives. On the timescales ranging from days down to seconds, short-term energy security means grid operators must anticipate problems at any time that can cause system instability from generation, transmission and distribution outages, equipment failures and severe weather events. On the timescales of weeks to years, long-term energy security means grid operators must coordinate planned equipment maintenance and additions, forecast trends in electricity usage at different locations on the grid, and take into consideration the commissioning and de-commissioning of generation facilities. Energy security is also affected by factors such as global climate change and the frequency of natural disasters, systematic changes to energy fuel types, population growth levels and both local and global economic trends, including shifts in prosperity. With so many influencing factors becoming ever more volatile, policymakers are growing increasingly concerned about energy security.

For example, following the Great East Japan Earthquake of 2011, the Fukushima Daiichi Nuclear Power Plant suffered a catastrophic explosion when the cooling equipment failed as the result of flooding caused by the resulting tsunami [4]. Environmental and safety considerations aside, the loss of such a critical power source posed an acute threat to Japan's long-term energy security. As a short-term emergency measure, one of the major grid operators in Japan, TEPCO, found it necessary to implement a series of rolling blackouts for the first time in recent history. To improve long-term energy security, the Japanese government is encouraging demand-side resources to provide voluntary reductions in exchange for financial payments, an arrangement commonly known as "demand response", through the Japan Electric Power Exchange (JEPX).

Today, it appears that disruptive technologies introduced into the electricity grid are being driven not only by the electricity industry with new energy generation and storage technologies, but also by external factors, both from macroscopic processes based on societal and regulatory changes as well as innovations in operations, ICTs, which are enabling customers to make more of their own decisions about how they consume or, in some cases, produce electricity. These drivers, commonly referred to as "the five Ds" are decarbonization, decentralization, deregulation, democratization, and digitalization.

2.1 Decarbonization

Electricity decarbonization involves a gradual reduction of the carbon intensity of the electricity generation fleet. According to the Intergovernmental Panel on Climate Change (IPCC), CO_2 emissions from energy generation are expected to double or possibly triple by 2050 [5]. This increase in baseline levels relative to measurements in 2010 derives primarily from growing energy demand and from the increasing use of coal as a fuel source across the globe. It implies that as an industry the electricity segment has the opportunity, if not the obligation, to become a major force in efforts to counteract global climate change.

Combustion of any fossil fuel produces greenhouse gasses. Burning coal results in more than 900 g of CO_2 for each kWh of energy generated. The result with fossil fuel liquids such as petroleum and diesel is slightly better at about 800 g of CO_2, and natural gas combustion generates approximately 450 g [6]. In the United States, 2015 marked a key milestone, with total emissions from natural gas usage surpassing those of coal for the first time [7]. A shift to this cleaner fuel certainly improves emissions levels, but constitutes merely a modest reduction in levels and does not necessarily keep up with the pace of increasing electricity needs. Only by moving to non-fossil fuels will major greenhouse gas emission reductions be realized. Similarly, the emission of particulates is a related issue, representing a further incentive for the switch to clean energy power plants.

For preparing a comparative analysis of different resource types, it is important to examine the entire life cycle of the specific technology. For example, the mining of raw components and production of fuel stock for nuclear power plants requires substantial amounts of energy (generally of the fossil-fuel type), but this still results in a reduction to approximately 10% of the overall CO_2 levels for the equivalent coal-fired electricity plant. Moreover, pure renewables such as wind and solar power have equivalent life cycle production levels at about 2% on the same scale [8].

Thus analyses such as these are informing policymakers at the highest levels in government to encourage the conversion from electricity sources based on fossil fuels to those based on renewables. Renewable-based generation comes in two basic forms: large-scale installations connected to the high-voltage transmission system and small-scale installations connected to the low-voltage distribution grid. The large-scale installations are quite similar to traditional generation frameworks in that they are coordinated with and have visibility from the grid operators. In contrast, large-scale renewables pose a challenge to grid operations due to their limited predictability, in that output levels can be scheduled only to the accuracy of the weather forecast, and in terms of limited control, in that the output levels are generally fixed to full output, with occasionally an option to curtail output should generation levels exceed demand.

2.2 Decentralization

Small-scale renewables suffer from the same grid challenges as large-scale renewables, but to an even larger extent. Because they are installed at a customer site and generally operate behind the customer's meter at an industrial, commercial or residential site, there is limited visibility. Some jurisdictions may require installation above a given size to install additional monitoring equipment or even a special utility meter, which can help mitigate this challenge.

Finally, small-scale renewables often suffer from limited coordination. Because customers ultimately make the decision to invest in a local renewable generation source, and these decisions are generally not based on an assessment of the impacts of grid stability, investment decisions can have radial impacts on flows of electricity. These new electricity patterns cause challenges for daily operations and long-term planning.

For example, in California solar installations have become so popular that the grid operator in the region, the California ISO (CAISO), must now cope with the risk of oversupply (more electricity may be produced than is needed to meet electricity demand), faster changes in demand (known as "ramps") requiring more frequent startups and shutdowns of traditional generation sources, and decreased frequency response – an effect caused directly by the limited controllability of these sources [9]. The impact on ramps is illustrated in Figure 2-1.

According to CAISO, 50% of retail electricity will come from renewable energy sources (RESs) by 2030, and the load curve is growing so steep

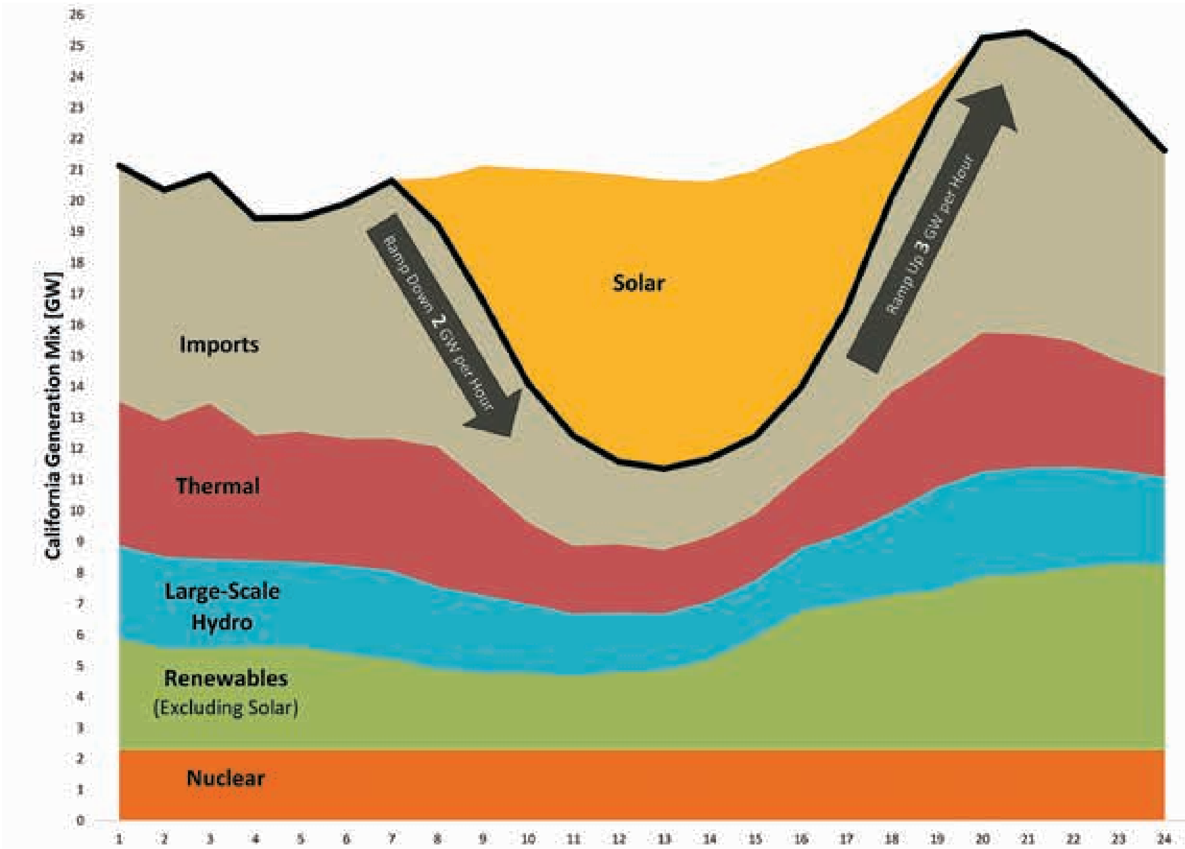


Figure 2-1 | Extreme ramps from solar production in California

that it is becoming more and more difficult for conventional generators to catch up with the ramps, as shown in Figure 2-2. Flexible demand-side resources (DSRs) are expected to play a vital role with the capacity to change output levels and even start and stop as dictated by real-time grid conditions.

In Italy, load has historically been higher in the north of the country, so generation was built to serve loads in that region. Italy now satisfies nearly 40% of its electricity needs from renewables and most of these resources are located in the South. It is now common for electricity to flow from renewables in the South to loads in the North, causing a wide range of challenges to operations, since the grid was not designed to operate in this reverse fashion, as illustrated in Figure 2-3[1].

2.3 Deregulation

The Introduction to this White Paper has already touched on the impact of market liberalization on grid operations. However, it is important to revisit the topic here not only in terms of liberalization as a force for change in the industry but also regarding its role as a driver for disruptive resources. Market reform has taken a variety of shapes around the globe, and while many countries have their own established markets, it

1 Source: TERNA presentation.

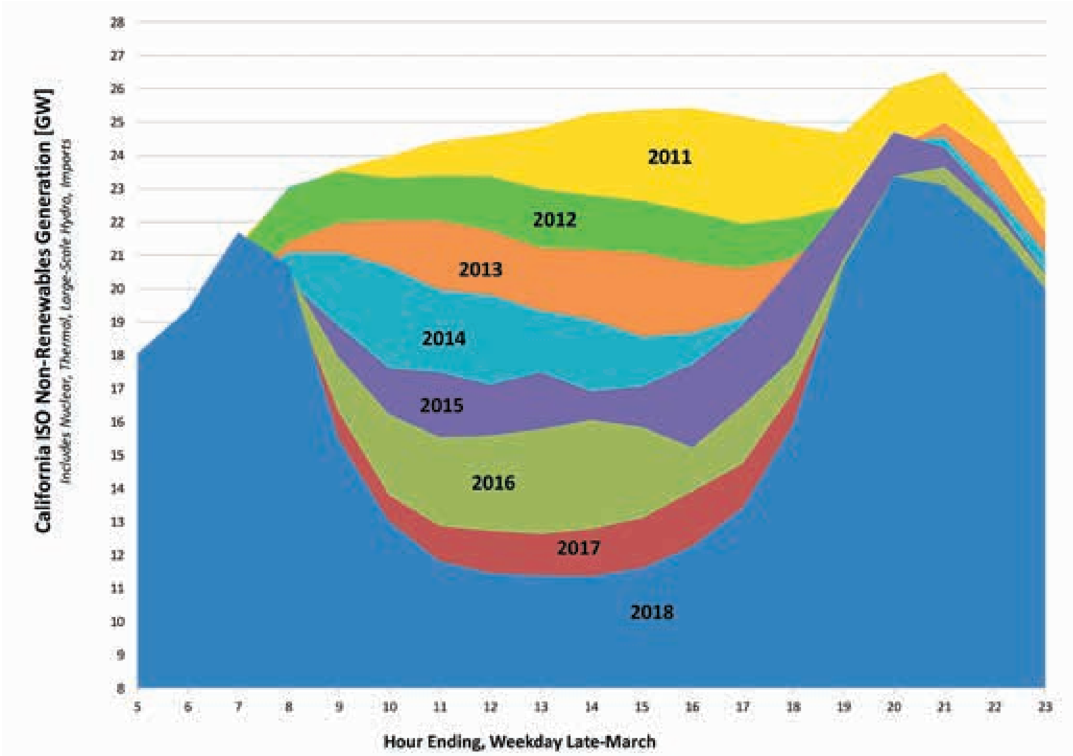


Figure 2-2 | Increasing levels of solar production

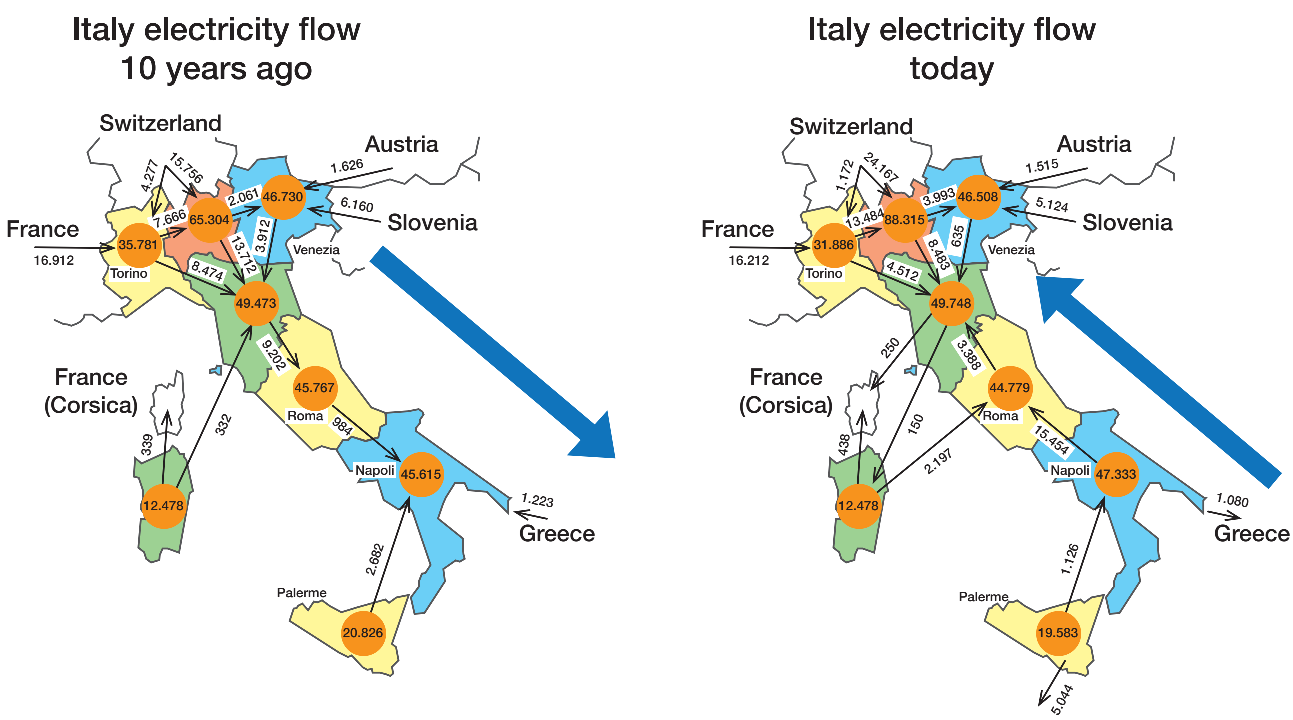


Figure 2-3 | Effects on Italy's transmission grid

is only in North America and in Europe that there are relatively consistent market rules applied to large portions of the electricity grid.

In all organized North American markets, namely Pennsylvania-New Jersey-Maryland (PJM), Mid-Continent, California, Texas, Southwest Power Pool (SPP), New York, New England, Ontario and Alberta, prices are determined by comparing demand bids to supply offers. Prices are calculated in a day-ahead auction, in which the demand bids are based on load serving entities (LSEs) estimating their forecasted demand, and in real-time, where actual measured electricity total system usage is offset with the most economic generation offers. The process of selecting generation offers is based on a complex algorithm performed by the market operator, taking into consideration transmission constraints as well as the loss of energy caused by the physical process of transporting the electricity over high-voltage transmission lines. Differences in these location-based prices are therefore a function of both the economics of electricity generation and the physics of delivering the power from source to sink.

In contrast, Europe splits the market and grid operation functions into two types of entities, the nominated electricity market operator (NEMO) and the transmission system operator (TSO), respectively. The two largest NEMOs are the EPEX SPOT, which provides for trading in Austria, Belgium, France, Germany, Luxembourg, Netherlands, Switzerland and the United Kingdom, and Nord Pool which adds to that list Denmark, Estonia, Finland, Ireland, Latvia, Lithuania, Norway, Poland and Sweden. Many smaller, generally single-country NEMOs exist, including GME in Italy, EirGrid in Ireland, and OMIE in Spain and Portugal. TSOs, on the other hand, are usually defined by country borders, with each country operating as single transmission region. Exceptions include Austria, Germany and the United Kingdom, each containing multiple TSOs. As a result, the entire European grid, while slightly more fractured relative to the North American model, as a whole is better coordinated, since the coalition of 36 countries supported by 17 NEMOS and 43 TSOs all follow the same set of overarching market rules under the umbrella of the European Network of Transmission System Operators for Electricity (ENTSO-E).

Following the global trend, other countries, including countries in Asia, are also deregulating their markets. For example, Japanese market liberalization started in 1995, when independent power producers (IPPs) were allowed to take part in the generation market. This was followed by retail deregulation beginning in 2004, although vertically integrated power companies were maintained. The Fukushima nuclear accident further bolstered the public's desire for additional choice in selecting an energy supply company as well as the sources of energy, and accordingly a new policy has recently been enacted to complete the unbundling process by 2020.

2.4 Democratization

Differences aside, both the European and North American models are focused on opening markets to multiple participants and breaking the traditional monopoly power of the vertically integrated generation-transmission-distribution utilities. Furthermore, the markets provide price signals that help suppliers and consumers better understand the value of electricity over time, provide real-time information on the current electricity production and consumption picture and improve their ability to predict the future values of electricity. With this improved intelligence, economically strategic decisions can be made about where to locate new sources of generation to take advantage of locations with systematically higher prices. Overall, the electricity markets provide a platform for a wide range of market players and supply technologies. Additionally, over time markets have been opening to smaller and smaller resources, supplied by smaller and smaller market participants. Most markets are also liberalized to the level that even fleets of customer-owner resources can be aggregated and offered into the market. The basic concept involved is termed democratization, with the theoretical limit of each consumer's devices forming part of the market. The closer the industry moves to this point, the more the challenges of limited reliability, limited visibility, limited control, and limited predictability become important factors.

2.5 Digitalization

The third major trend facilitating disruptive resources is digitalization itself. Mitigation of global climate change and liberalization of electricity markets are both top-down effects, since these trends are driven by societal change and enacted by governments through reform policies to protect and enrich their citizens. Digitalization, however, is a bottom-up driver – a force that allows customers to more easily monitor and control their electricity usage and ultimately their storage and/or production of electricity.

Many readers will remember a time when temperatures in the home were set using a mercury-switch thermostat and when electricity was measured by means of a meter with small dials that spun faster as more electricity was used. These analogue devices have all but completely been replaced by digital devices and the modern consumer has tens or even hundreds of digital devices which may be related to electricity service. These include and are not limited to smart electricity meters, smart thermostats, automated lighting, controllable water heaters, controllable heating and cooling systems, renewable generation sources with local production sensors, electric and hybrid-electric vehicles and on-site electricity storage devices for both economic and backup functions.

Since most digital innovations are implemented behind the customers' meters and without the knowledge of the grid operation, they involve the same trends of limited visibility, limited control, limited predictability and limited coordination. Of particular interest are the impacts on predictability. Historically, the process of forecasting the future electricity load was relatively easy: most customers had relatively stable load shapes and the overall magnitudes were easily correlated with weather conditions. Customers on today's grid have much more variation in their electric devices and greater control over those devices, with many technologies now providing for automated and/or remote controls.

Additionally, demand response programmes by their very nature implement changes in consumption patterns by a third party, which may or may not be the party responsible for forecasting, procuring and/or delivering the electricity to the customer. All these variables lead to more complex operations, requiring more intense predictive algorithms, which rely on large amounts of data. A result of this trend may be the need for sophisticated energy management systems (EMSs) for homes, business, and industrial environments, collectively known as xEMS technologies, to automate processes.

Section 3
Electricity grid services

Electric power generators produce electrical energy, which is transmitted over high-voltage transmission lines, stepped down to lower voltages in substations and ultimately distributed to electricity customers. A large infrastructure cost is involved for the assets required for this system, in addition to marginal costs driven by the price of fuels used in the generating stations. Large-scale renewables have two distinguishing features differentiating them from the resources of traditional fossil-fuel based generation. First, these generators convert the energy radiated by the sun, carried in the wind and pushed through waves into electrical energy. The efficiency of the conversion is not perfect, but the "fuel" is free. As a result, the marginal value of each incremental unit of energy itself is reduced. The second feature of renewable generation is that the production schedule is dependent upon the position of the sun, the levels of wind and the flows of water in the forecasts. And while the value of energy may be reduced, the grid is harder to operate because the power generation is variable and not correlated with the moment when the customers want to use electricity.

Ancillary services are services that are necessary in order to support the transmission of capacity and energy from resources to loads, while maintaining reliable operation of the transmission system [10]. In the United States, these services were established as requirements of the Federal Energy Regulatory Commission's (FERC) *pro forma* open access transmission tariff (OATT). More recently, the term essential reliability service (ERS) was established by the North American Electric Reliability Corporation (NERC) to refer to the elemental "reliability building blocks" from resources (both traditional generation and demand-side) necessary to maintain bulk power system reliability [11]. Ancillary services are effectively a subset of essential reliability services, but regardless of nomenclature, these services are the tools grid operators use to ensure stability of the grid. It is not uncommon for the cost of these service to be more than the cost to procure the actual energy, a feature becoming more common as renewable resources are providing a larger fraction of our energy with production profiles uncorrelated with customers' demands for energy.

3.1 Frequency management

An electric power system is a highly-interconnected network of equipment in which supply and demand should be always balanced. When a disequilibrium exists, the system frequency will deviate from the nominal frequency, generally 50 Hz or 60 Hz, as represented by the traditional mass balance in Figure 3-1, with essential reliability services being used to keep this equilibrium.

Inertia – Resources having mass and spin at the system frequency provide inertia, keeping the system stable. As fewer traditional generators are present on the grid, resources with synthetic inertia will be necessary to keep the frequency stable. Details are available in Annex C.

Operating reserves – Operating reserves are used to supply additional generation when there is a need for more power, and reduce generation when less power is needed. Resources providing regulation respond in seconds, thus requiring automatic controls from the grid operator. Load following resources respond more slowly and

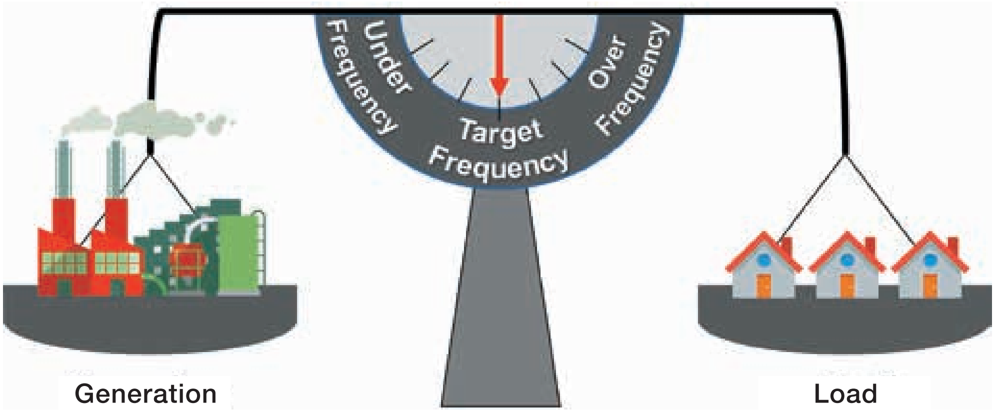


Figure 3-1 | Generation-load frequency balance

generally over longer periods of time. When the system is close to running out of committed generation, resources capable of providing contingency reserves are utilized. These include spinning reserve, a term derived from the spinning of the traditional generator armature such that the electrical output is connected to the power grid, and non-spinning reserve, which requires a certain time to become synchronized.

Frequency disturbance performance – Frequency disturbance performance maintains frequency under emergency conditions through the use of controllers, such as under-frequency relays (UFRs), which enable local and automatic active power compensation when off-nominal frequency deviations are sensed, usually following the loss of large generator or load.

Active power control – Active power controls fall into two categories. One is frequency control, which is a service that operates like regulation in that it responds on a scale of seconds. Frequency control differs from regulation in that the resource senses local frequency deviations and automatically responds to nudge the frequency back into range. The other control is ramping capability, which is called upon when the load is rapidly changing, historically in the morning as people wake up and in the evenings as people leave work and return home. Renewable generation can produce ramping requirements comparable in magnitude but much less predictably, potentially counteracting or exacerbating the existing ramp requirements.

It is helpful to visualize these services along the time continuum illustrated in Figure 3-2. The more rapidly responding services are grouped into the governor-free range. These operate instantaneously but can only supply a small amount of correction for a short period of time. As the governor-free resources run out of response capability, load-frequency-control resources take over, typically within several seconds to several

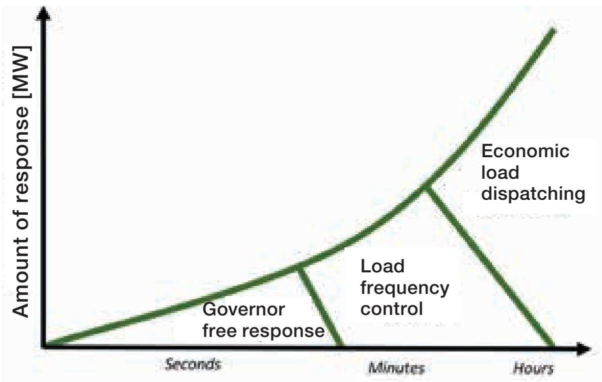


Figure 3-2 | Response time vs. response amount

minutes. Finally, economically dispatchable resources can be brought on-line, generally after about 10 minutes and have substantially more capability and the ability to sustain supporting services for up to many hours. Mapping the NERC terms to this categorization, we can also describe many other regions. European terms [12] and Japanese terms[2] are shown mapped, albeit not perfectly, in Table 3-1 below.

System frequency is usually maintained with available ERS services. However, from time to time, emergency situations occur, for example a large number of generators are tripped off-line simultaneously following the voltage drop. Fault ride-through (FRT) is a requirement which allows resources to withstand voltage disturbances and remain connected during a minimum time period. Conceptually, these classic control methodologies have been optimized to a relatively static condition. However, after the large integration of RESs, the system ceases to be static, and control parameters should be adjusted to the changing system condition. One of the latest efforts to tackle the limited visibility is the deployment of situational awareness (SA), through installation of on-line sensors at various network points. Details of this approach are available in Annex C.

3.2 Voltage support

In addition to proper system frequency, proper voltages must be maintained across the system. Additional ERS are required for this function.

Voltage control – Maintaining proper voltage on the system is essential for sustainable electric power service, an issue directly related to electric power quality as well as to public safety. Therefore, most countries codify the voltage requirement as a legal obligation. Resources that provide voltage control can keep the voltage within specific tolerances, ensuring that the system runs optimally. In a classic approach, voltage control is mainly conducted by transformer tap position adjustments and generator terminal voltage controllers called automatic voltage regulators (AVRs).

Table 3-1 | Regional ERS

Function	North America		Europe	Japan
(*Intrinsic to grid*)	Inertia		Frequency response	Type I
(*Static controls*)	Frequency disturbance performance		Contingency reserve	Type I' + II'
Governor-free	Active power control (APC)	Frequency control	Primary reserve	Type I
		Ramping capability		
Load frequency control	Operating reserves	Regulation	Secondary reserve	Type I + II
Economic load dispatching		Load following	Tertiary reserve[3]	Type III
		Spinning reserve		
		Non-spinning reserve		

2 Type I = Dynamic instructions, procured by TSO; Type I' = Static instructions, procured by TSO; Type II = Dynamic instructions, scheduled by the balancing group (BG); Type II' = Static instructions, scheduled by BG; Type III = Non-dispatchable

3 Tertiary reserve service is dispatched primarily by the BG, not usually by the TSO, in European markets.

Reactive power/power factor control – Because the power grid is primarily built on AC, capacitive and inductive elements on the grid will cause the voltage and the current in the lines to go out of phase. The more out-of-phase the voltage and current become, the more reactive power exists, and reactive power creates losses in the system. Resources that provide this service keep the voltage and current in the correct phasing. Historically, this service has been provided from the power factor controls of capacitors, synchronous generators and condensers. However, DSRs may also provide service by injecting reactive power to the grid by means of DC-to-AC invertor control technologies. Related to this topic, as more of the generation sources produce direct current and many loads, such as LED lighting and electric vehicles natively consume direct current, there is renewed interest in and research being conducted on low voltage direct current (LVDC) networks.[4]

Voltage disturbance performance – Finally, should voltage drop during a major reliability event, resources that can help restore the voltage are essential. Every electric power system can withstand a small voltage fluctuation event. However, when a large contingency event occurs, such as a severe bulk transmission line fault, the electric power system becomes very unstable, and without an immediate injection of supportive reactive power it may collapse. In the conventional approach, immediate reactive power compensation is mainly provided by transmission-level resources such as generators, static VAR compensators (SVCs) or static synchronous compensators (STATCOMs). DSRs are expected to play a role in this field as technologies advance.

4 An overview of the LVDC concept is published in the IEC brochure, entitled *LVDC: another way*, available at anotherway.

Section 4

Market-based services

4.1 Market unbundling

In a deregulated environment, the purposeful splitting of the vertically-integrated generation/transmission/distribution/load-serving utility is termed "unbundling". The unbundling can take many forms, with various splitting's along the function axis (generation, transmission, distribution, and load) as well as across the business role (owning and maintaining the assets, operating the assets and taking the financial profits or losses). Four common examples are depicted in Figure 4-1.

The TSO/DSO model is often seen in European countries, whereas variations of the ISO model are more prevalent in North America. However, it is important to note that even in a single region several different business models and approaches are often mixed together. For example, it is common for municipal utilities and/or cooperative utilities to be present within a deregulated area with participation in the market ranging from minimal to full participation. Another example is found in Japan, where three separate licenses are available (generation, retail and network), with Japanese

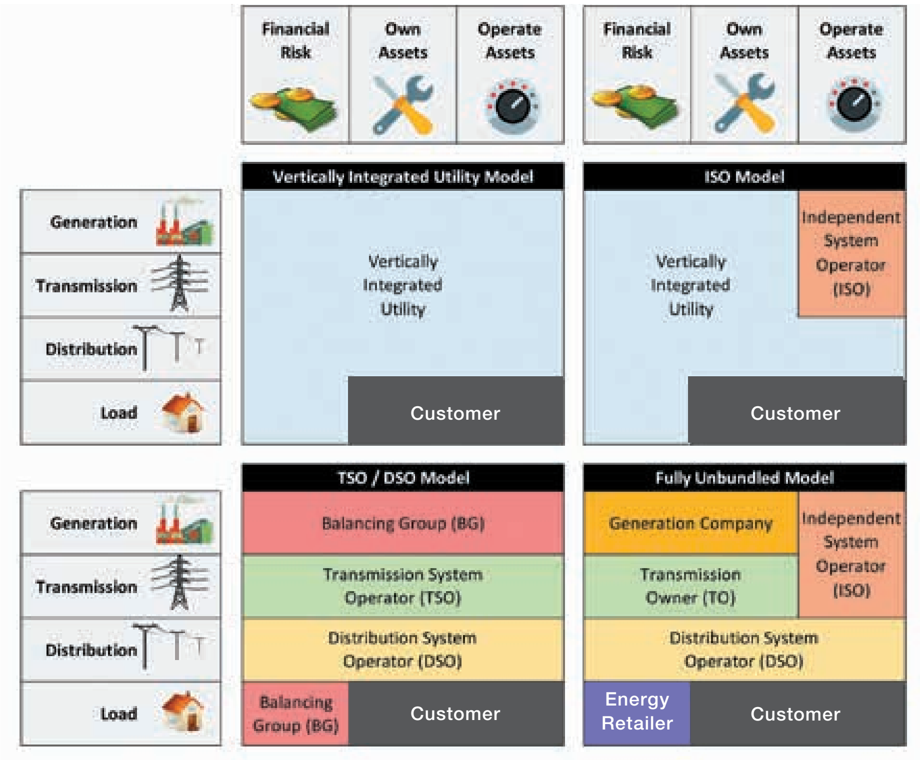


Figure 4-1 | Examples of unbundling variations

market players able to choose from three different business models (generation-only, retail-only and generation-and-retail). The network license is assigned separately to a non-competitive, neutral company, with the functions of TSO and DSO being performed within the same company under the single network license.

Important here is that the transaction of DSR products is often carried out over the different entities following the unbundling, rendering the situation very complex: multiple players with whom interactions are made, together with frequent changes in the roles of the different players.

Additionally, DSR activity controlled by one entity will likely have influence on other entities, and communication between the relevant parties is important to avoid conflicts and minimize the potential for financial losses. For example, when a DSO activates DSR assets to alleviate regional congestion, this will also affect the global supply/demand balance, which in this example might be monitored and controlled by an ISO while financially impacting an energy retailer. Therefore, proper operational rules and regulations should be established between relevant parties acting at different levels and during different phases.

4.2 Resource scheduling process

Figure 4-2 illustrates a typical scheduling process in the ISO model (US) and the TSO/BG model (Europe). The biggest difference between the two models is the existence of gate closure (GC). TSOs are in charge of real-time frequency control, whereas BGs are in charge of scheduling their supply/demand balance before the GC. GC involves a timing approximately an hour or half an hour prior to the scheduled delivery time, when the balancing duty is handed from the BG to the TSO.

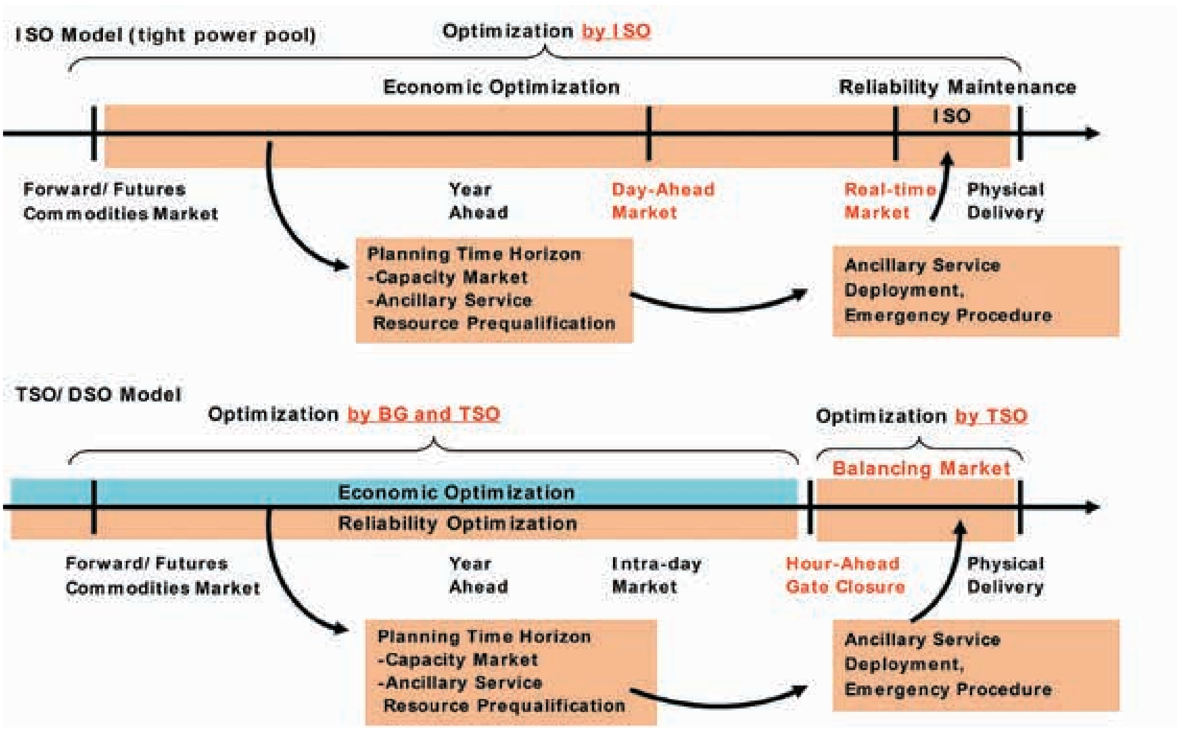


Figure 4-2 | Market timeline comparison between ISO and BG/TSO models

In the European model, there naturally exist some contradictory cases in which the TSO requires upward balancing power for the purpose of frequency control, whereas the BG requires downward balancing power for the purpose of imbalance mitigation. Thus a dual price imbalance tariff is often adopted artificially in compensation for the imbalances in order to minimize such contradicting direction balancing by applying an incentive tariff to the BG, whose imbalance direction is favourable to the system operation (improving frequency), and a penalty tariff to the BG, whose imbalance direction is unfavourable to the system operation (aggravating frequency deviation). Other regions including Japan follow a similar approach, with the basic idea of splitting the balancing function between the BG and the TSO.

On the other hand, the US approach involving the ISO model is relatively simple, whereby the balancing effort is primarily assumed by the single ISO entity, with the global merit-order being included within the footprint. In this case the market participant optimizes its strategic position in the day-ahead, real-time energy wholesale market, as well as in the capacity and ancillary market.

Consequently, the DSR market design should take into consideration not only the physical segregation of roles, but also this kind of timeline from planning stages to actual physical delivery.

From IEC's point of view, it is necessary to streamline such communication methodologies between different entities based on a standardized format, because the negotiation between different entities is becoming increasingly complicated year after year due to the rapid expansion of market opportunities for various players.

During the planning stage before the day-ahead or hour-ahead GC, a moderate speed communication technology is sufficient, and a conventional internet technology with a mutually acceptable security level is suitable, because the communication at this stage is not directly linked to system reliability. Information traded at this stage contains the delivery schedule, transaction data and no real-time dispatch instruction. On the other hand, following the GC and until real-time physical delivery, the communication technology needed at this stage must meet very strict mission-critical criteria, because communication media quality is directly linked to power service quality. Information traded at this stage contains real-time dispatch instructions including frequency control signals.

4.3 Planning for sufficient resource supply

Energy-only market – As noted previously, electricity markets have a relatively short-term horizon given the volatility of load and generation, based on factors such as weather variation and equipment failures. This volatility manifests as price fluctuations in forward markets such as the day-ahead market and especially in real-time markets, where volatility can be very pronounced.

In a liquid market, suppliers of energy and essential reliability services offer their commodities according to marginal cost economics. In addition to incorporating a factor for short-term volatility and for a reasonable profit, it is also necessary to build into the equations some level of cost-recovery, so that the initial cost of building the generation source is not lost. Because long-term prices are also not known, it is risky for an investor to construct a new generation facility, such an investment being both significant and long-term, given the complex nature of the planning, design and constructions phases. This is often referred to as the "missing money" problem, in which an investor cannot recover the cost of the initial generation investment. In conclusion, the energy-only market design can lead to generation deficiencies, because development decisions are made by the market players in this type of deregulated environment. Moreover, if a central planning organization is looking at the future supply/demand balance of the grid, there may exist no central body able to mandate the investment in that next stage of generation.

Capacity markets – One mechanism by which to address the "missing money" problem is to implement a capacity market alongside the energy market. The capacity market is a financial market, in that market participants who plan to provide future generation offer their capacity, and market participants who expect to have load are required to procure capacity. If there are many offers for future generation, or if the load is not expected to grow rapidly, the capacity market will clear low. However, if not much future generation is planned or if load is expected to grow substantially, the market will clear high. A high capacity clearing price is a signal to the market that there is revenue to be made by supplying future generation, and theoretically investments can be made with reduced risk that the "missing money" problem will be covered by capacity payments. Capacity markets are gaining in popularity, and examples can be found or are in the planning stages in North America, Europe and Asia. The sliding scale of prices over the course of a year for a pure energy market relative to a lower price curve when capacity payments are available is illustrated in Figure 4-3.

Scarcity pricing – One of the effects of unbundling is that parties who own and/or financially benefit from assets on the grid are not necessarily those who are operating the grid. This means that such parties are making economic decisions and may be partially or completely unaware of grid reliability issues, such as an unplanned outage or low levels of reserve power. In such cases, the offers for supply services may not be indicative of the true value of those services under adverse conditions. Scarcity pricing, also known as shortage pricing, is a framework in which the market operator artificially inflates offers to a defined high level. When high prices are published during scarcity conditions, resources previously not available may offer themselves on the market at higher compensations levels. This effect is also illustrated in Figure 4-3, with the artificial step occurring at the highest price points. Important to the DSR discussion is that demand-side resources which also receive

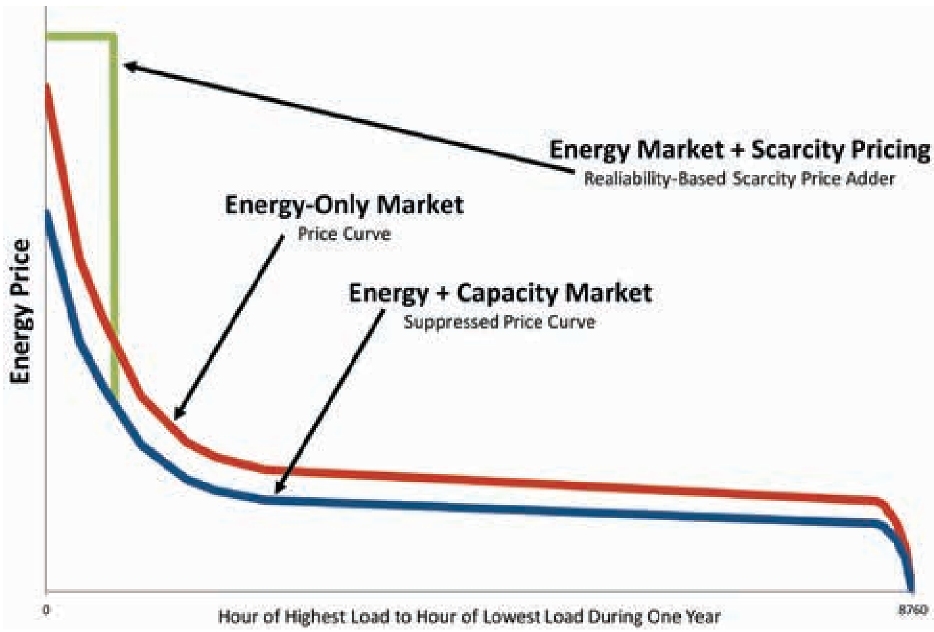


Figure 4-3 | Price-duration variations

this high price signal can alter their consumption patterns, saving money and providing relief to the grid simultaneously.

A non-electricity scarcity pricing analogy is illustrated by the case of a ride-sharing service which increases the rate, as an incentive both to attract more drivers into the system and to encourage passengers with non-essential travel to delay their plans. Ideally, the scarcity price is correlated to the value of lost load (VoLL). In economic terms, the VoLL is the amount of money that customers receiving electricity with non-interruptible contracts would be willing to pay to avoid a disruption in their electricity service [13].

4.4 Fair compensation concepts

Imbalance tariff – Reserve optimization efforts should be discussed not only within the planning time horizon, but also within real-time operation. System operation costs are directly reflected in the customer's bill, and operators are always pressured to reduce the operation cost. Thus, price mechanisms should be well designed to incentivize resources, which contributes to redressing the lopsided supply/demand balance, so that additional reserve procurement is minimized. In Europe, many countries have established an imbalance penalty to urge BGs to minimize the deviation from the GC schedule, so that the system operator's extra procurement of reserve is minimized. In the UK, when the system position is long (supply>demand), the main price (penalty) applies to those who create the surplus generation (aggravating the frequency). By contrast, when the system position is short (supply<demand), the main price (penalty) applies to those who create the overconsumption. On the other hand, in the United States such a scheme is not necessary, because the balancing control is assumed by the ISO's central dispatch.

Generator startup cost recovery – It is important to note that reserves required by operators should be guaranteed to recover the running cost. This running cost is called "uplift" and is classified into three parts: the startup cost, the no load cost and the incremental energy cost, as shown in Figure 4-4. Startup cost is the cost incurred before the unit becomes ready to inject power into the grid (pre-heating). No-load cost is the cost incurred when the active power generated is equal to the in-house consumption, and as a result net total injection to the grid becomes zero. Incremental energy cost is the cost which needs to be recovered when the unit injects active power into the grid. From time to time, especially during the off-peak season, when a considerable amount of power is produced by RESs, a situation develops in which market revenue cannot fully cover these costs. After a large amount of DSR is integrated, operators have to consider the cost recovery, when there is a deviation from the forecasted amount.

In the United States, based on the so called "cost causation principle", those who create a deviation from the original schedule will incur an extra operational cost to procure the additional compensation reserve, although it is not designed as a penalty but rather as a damage recovery tool.

Performance-based payment – One benefit of some types of DSR, especially battery storage resources, is a rapid reaction response. In the United States, new efforts are being reported in which performance-based payment is encouraged by FERC Order 755 [14], which is intended to

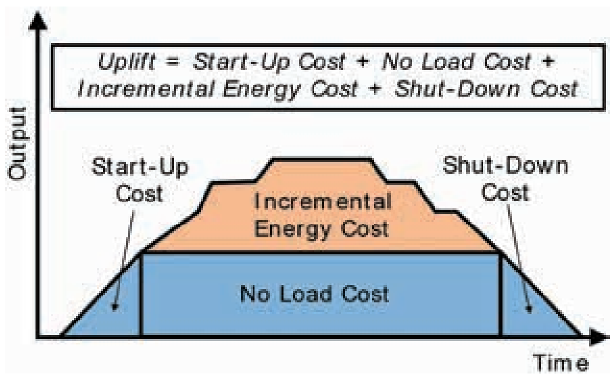


Figure 4-4 | Startup cost compensation

provide such resources payment based on their effectiveness in operational participation. Each time an instruction is received, mileage is recorded, and the payment is determined based on the control accuracy. Figure 4-5 shows the output from different resources. The vertical axis denotes MW output and the horizontal axis denotes time. According to the new approach, the resource on the left is reacting much more rapidly and is thus eligible for a higher reward, even though the energy (kWh) of both resources is the same. Based on this new approach, high-speed resources such as battery storages or fly-wheels have more opportunity to obtain revenues. Further information is available on the CAISO website [15].

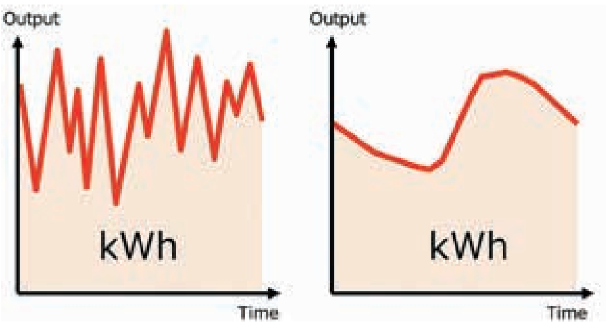


Figure 4-5 | Mileage compensation

4.5 Surplus base-load generation and negative price in the wholesale market

Electric power cannot be stored easily, and a surplus base-load generation (SBG) problem sometimes occurs when too much generation is injected into the grid during off-peak hours. SBG is a challenging situation reported in many countries, including Canada and the United States. A similar situation is also reported in Europe. Currently two countermeasures exist.

The first countermeasure is a market approach called negative pricing. In the event of excessive supply becoming available, the wholesale market sets the price to a negative value. The expected outcome is the creation of a price signal, urging customers to refrain from surplus generation and shift their demand to off-peak hours.

Figure 4-6 shows a recent example: in Ontario, Canada high levels of available generation resulted in negative prices for many hours during a single day. From the DSR point of view, if such real-time price information can be received by resources on a real-time basis, it will create additional values.

The second countermeasure is the procurement of a foot-room product. In the UK, a special reserve called "demand turn up (DTU)" is procured. This involves requesting the reduction of generation and the increment of load during the critical off-peak hours, through instruction from the TSO by contract. A similar approach is also under evaluation in Japan in the form of upward DR as a countermeasure against increasing RESs.

4.6 Expansion of cross-border markets

Historically, electric power products have been traded in markets circumscribed by geographic or political boundaries. However there is a real benefit to expanding or even removing these boundaries, as illustrated in Figure 4-7. One of the reasons for this is a countermeasure against renewable energy resource deployment. Fluctuation of each individual resource is averaged by a wide-area balancing effort and additionally, load characteristics are different from region to region because of the time difference, weather conditions and consumers' energy usage patterns.

A good example of this effort is observed in the Western Interconnection of the United States. The California ISO has allowed resources external to its control area to enter into a new energy imbalance market (EIM). Within the Western Interconnection, there exists a scheme called ACE Diversity Interchange [16], ACE being an acronym for area control error. The ACE is calculated every

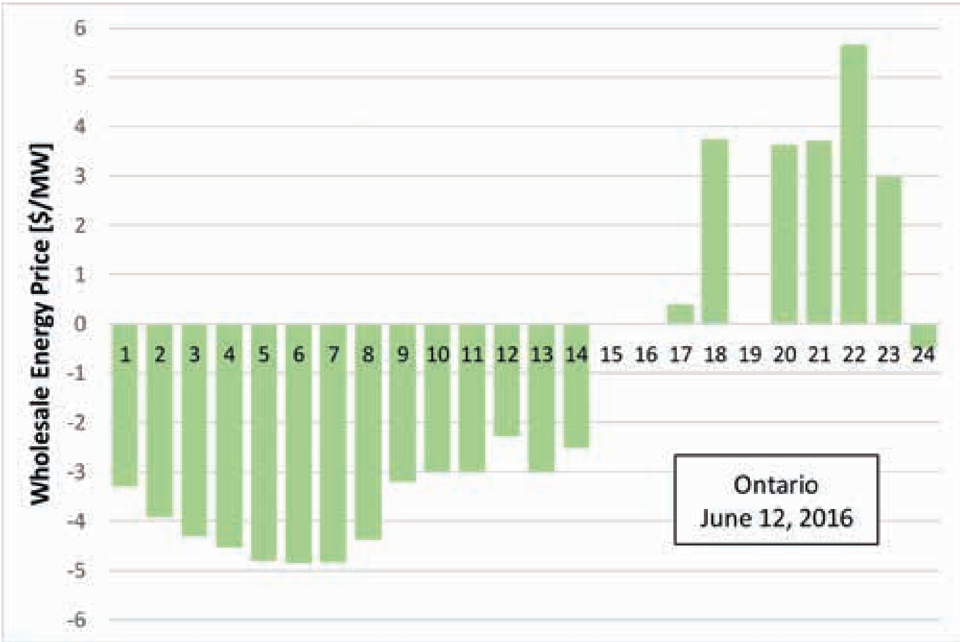


Figure 4-6 | Negative pricing in Ontario

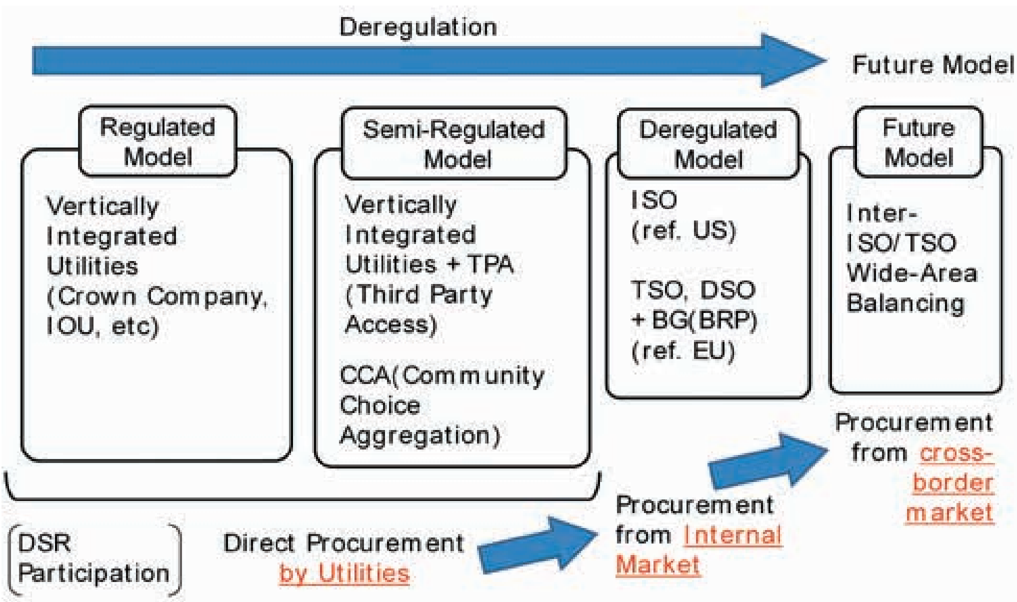


Figure 4-7 | Progressing to cross-border markets

few seconds, and when a balancing is required in one direction or another between two control areas, a signal is sent to push the ACE back into tolerance. The diversity interchange here refers to different regions with different dominant resource types, which provides a framework for balancing by all the authorities involved. In Europe, a similar approach is in place called International Grid Control Cooperation (IGCC), which enables balancing among TSOs. In Japan, nine TSOs are active on the main islands making up the country, with each being connected via tie-line. An effort is underway to develop a common balancing reserve market for the whole of Japan with commercial operation expected to begin in 2021.

4.7 Transitioning to capacity markets

As demand-side resources have evolved and improved, so too have the market opportunities in which they can participate. In North America, many initial DSR opportunities were uniquely designed programmess enabling resources to reduce, generally during emergency conditions. For this stand-by capability, a fee was paid. As these resources proved themselves reliable, participation in capacity markets began to be allowed. For example, Figure 4-8[5] illustrates how PJM primarily acquired DSR participation through the interruptible load for reliability (ILR) programme, and these same resources transitioned into the PJM capacity market in large part during the 2011/2012 delivery year.

4.8 Shaping loads with economic signals

Loads change as a function of the weather and the changing of seasons, however the major load pattern driver today is the daily cycle of human behaviour. As the load changes each day, the dispatch of generation is controlled through the hierarchical cost structure called “merit-order”. The least expensive generation, called “base load generation”, consisting of fuel types like nuclear and coal, is usually the output most difficult to change. The grid operator always tries to keep

5 Elta Kolo, GTM Research, *US Wholesale DER Aggregation*, 2018, used with permission.

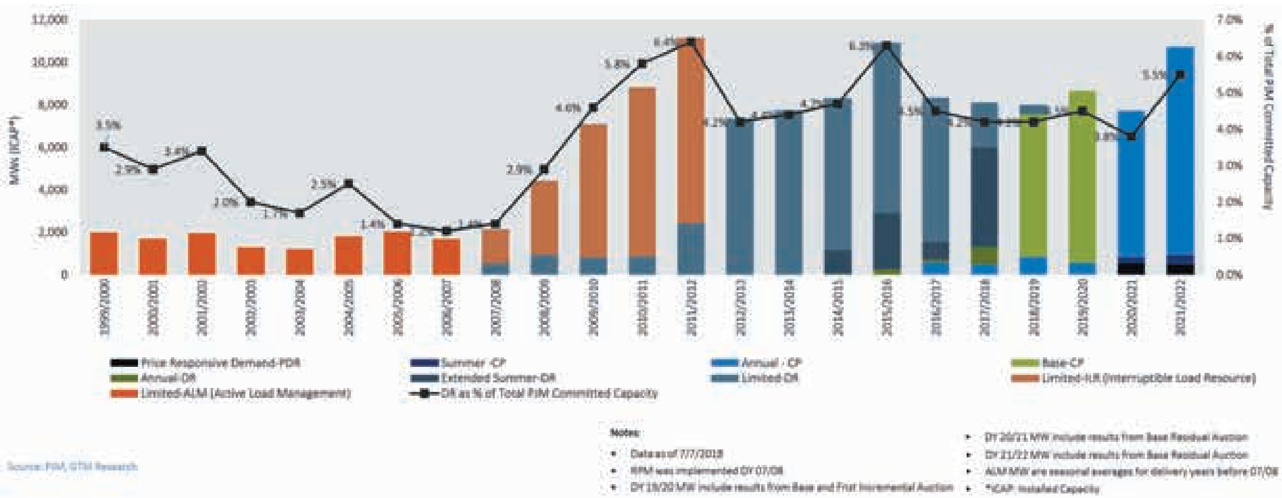


Figure 4-8 | PJM DSR capacity

these resources running for long periods of time, as shutting them down and starting them up can often take hours, if not days, to achieve. In Figure 4-9 below, base load generation is shown as the flat band across the bottom.

Load-following generation resources supply the major shape during the daily cycle, as these mid-cost generation sources can be changed hour by hour. Common examples include hydroelectric, gas and oil fuel generation. Finally, peaking generation is expensive to run and is only called upon when load rises to very high levels or when rapid response is necessary. Natural gas is the most common fuel type in this category. Because the costs of running these units vary greatly, so too does the price of electricity over the course of a day, as shown in Figure 4-9.

When the price signals caused by the peaking generation units are experienced by the customers, demand-side resources can be employed to reduce the peak and hence reduce the cost of electricity. DSRs which shift load from high-price times to low-price times are called “load-shifting” resources, an effect depicted in Figure 4-10. By reducing the peaks and using electricity during the valleys of the load curve, the overall variation of the electricity demand is reduced. This allows

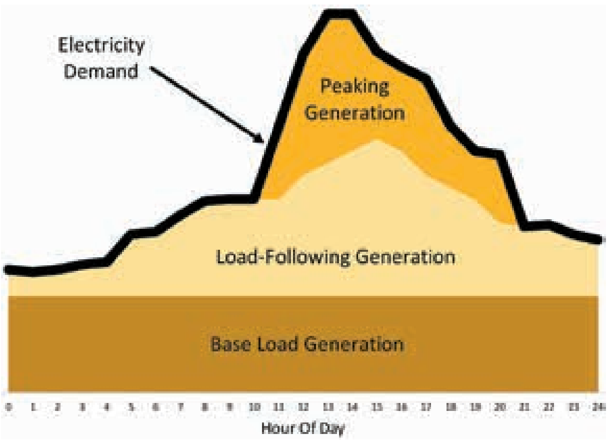


Figure 4-9 | Base load, load-following and peaking generation

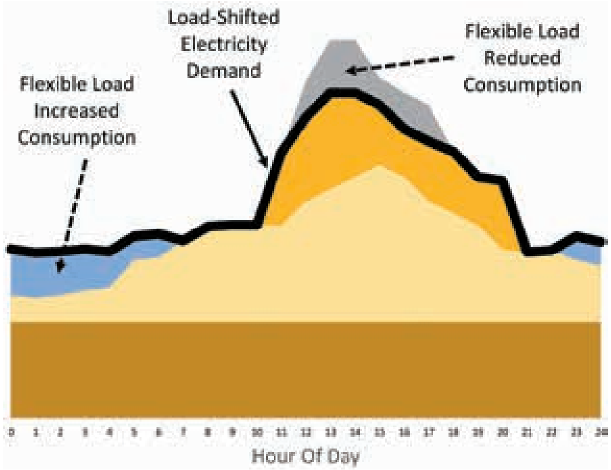


Figure 4-10 | Effect of load-shifting DSR

for more base-load generation and fewer peaking generation resources to be used.

4.9 Congestion management and investment deferment

The capacity of networks is constrained by such physical constraints as thermal, voltage and stability limits. Also, system operators are required to consider N-1 security criteria, under which a system needs to ensure its ability to withstand the loss of any single component (e.g. transmission line, generators), without violating such constraints. Historically, a network upgrade (or re-dispatching of large bulk generators, if available) was the solution for mitigating network power flow, however the time is ripe for DSR to begin to play a role in this process. Figure 4-11 illustrates the concept.

Figure 4-12 illustrates how Con Edison, in order to avoid a capacity limit violation during summer day-time peak hours, decided to procure several DSR products combined in a mosaic fashion to alleviate the potential peaking issue [17].

4.10 Dynamic ratings

Electric power facilities face thermal constraints and usually do not use up to 100% of their capacity

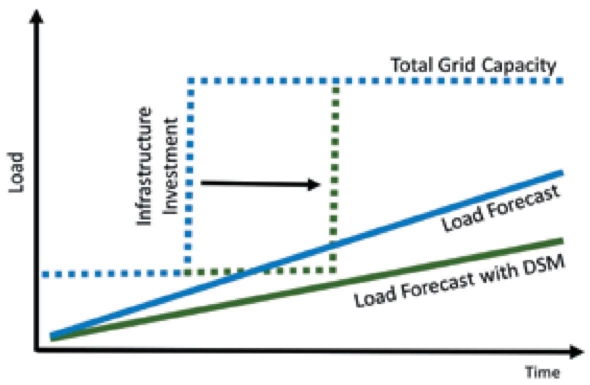
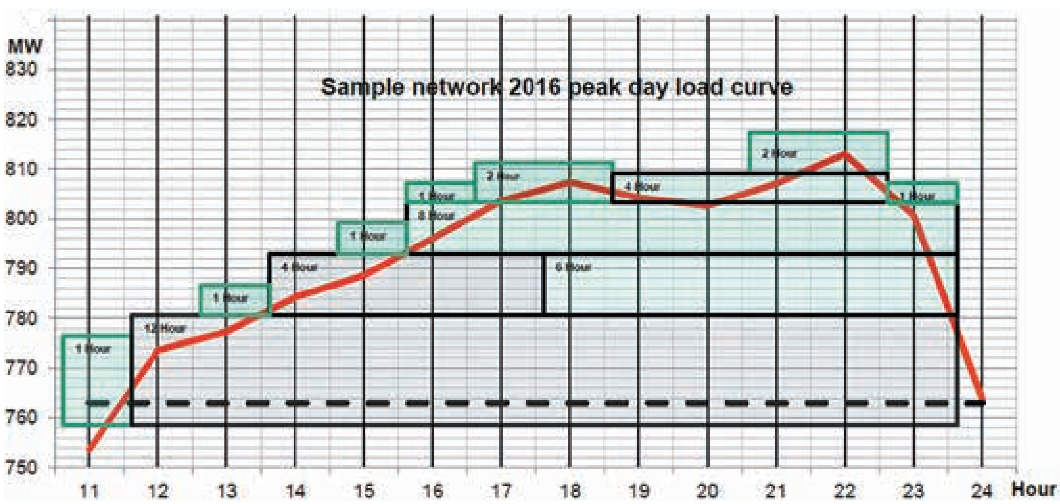


Figure 4-11 | DSM-enabled infrastructure investment deferral

potential. This is due to the fact that operators must compensate for the lack of real-time monitoring of the transmission systems conditions. Thanks to technological developments, it is gradually becoming a realistic approach to calculate the capacity ratings based on real-time data obtained from on-site ambient temperature sensors, not only at high voltage, but also at low voltage distribution networks. Figure 4-13 shows the active network management (ANM) system of the 33 kV distribution network in Scotland's Orkney Islands, where multiple wind turbines are connected to a relatively constrained transmission network. The grid operator computes an optimal curtailment level based on on-line telemetry data and automatically controlled wind farms, using supervisory control and data acquisition (SCADA) software.

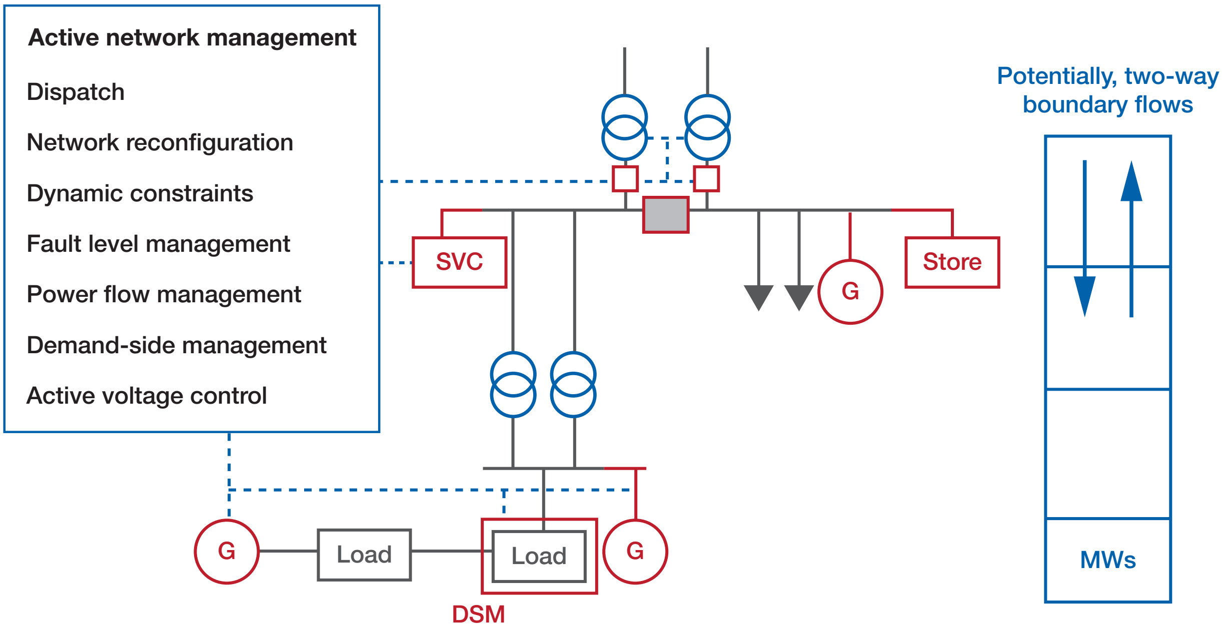
4.11 Island network

Power systems on islands are isolated networks and thus very vulnerable to frequency and voltage fluctuation. Supply/demand balancing should be coordinated based on limited available resources on islands. Ironically, such islands are sometimes ideal locations for RESs integration. For example, TEPCO in Japan is currently in the process of testing the concept on the island of Niijima, where approximately 25% of the energy consumption is originated from RESs, and integrated control of RESs, batteries, home energy management systems (HEMS) and commercial and industrial (C&I) facilities is proposed. This project is targeted for operation in 2030, with a miniature model (see Figure 4-14) now physically constructed and being tested on the island at this time.



Source: Con Edison

Figure 4-12 | Peak load management



Source: Ofgem

Figure 4-13 | Active network management

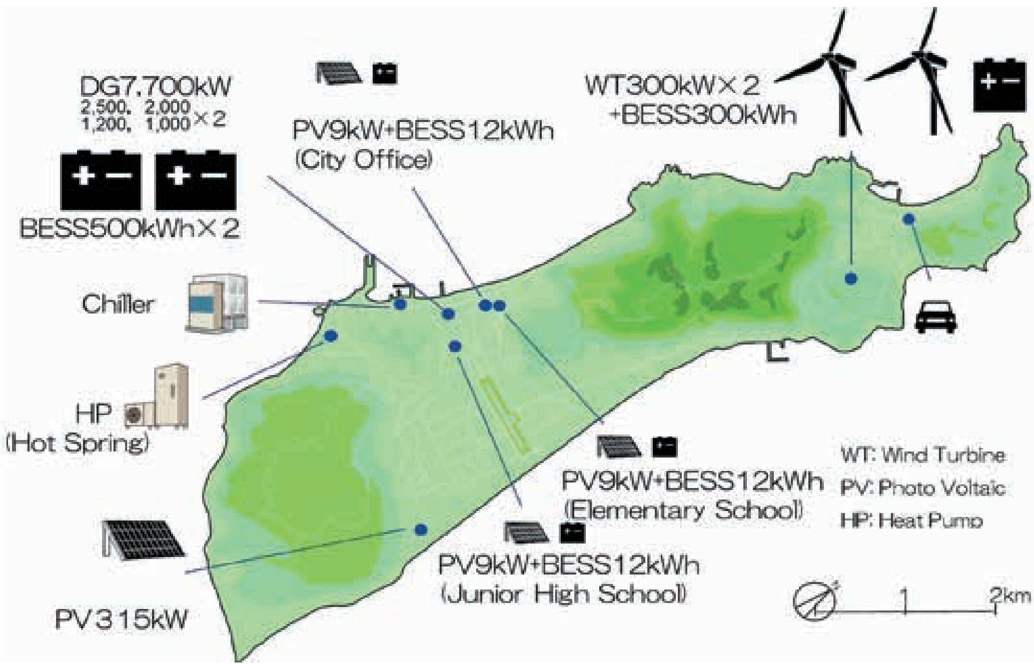


Figure 4-14 | Smart island network

Section 5

Techniques to influence demand-side response

The operation of electric power systems has been designed to support bulk power generators supplying electricity to customers through power grids. The market structure and requirements of such systems have been established based on the physical characteristics of the bulk power generators. Although aggregated DSRs are often called "virtual power plants (VPPs)", these resources are not bulk power plants and are markedly different in their operations. To accommodate DSRs, every stakeholder needs to effect a change of perspective: the issue is not whether DSRs are applicable within the present framework, but rather how should the next generation power system be designed to best integrate them.

As mentioned earlier, some countries have made advances in integrating DSRs into grid operators and into markets. In the United States, FERC Order 755 requires market operators to treat DSRs on an equal basis with traditional generators, assuming each DSR meets the performance and sizing requirements. However, the areas in which DSRs are effectively used are quite limited, because it is precisely difficult for DSRs to meet all the market requirements for minimum capacity and two-way communication infrastructures. Nevertheless, this hurdle is driven primarily from the cost perspective, and dropping ICT costs will allow more DSRs to become compliant.

The next key stage involves revealing the quantitative characteristics of each individual DSR or DSR aggregation. From the grid's perspective, reliability, availability and affordability are central indices for evaluating to what extent the DSRs can function like bulk power generators. Based on the results, the market categories and requirements should be considered, in order to incorporate DSRs as well as to identify the technical specifications which DSRs must meet. This process should be done iteratively through a close cooperation among grid operators, DSR owner/operators, and DSR manufacturers.

Thus, the power system will be directed toward a democratized platform for conventional power generators and DSRs, even though the details may vary depending on region. From IEC's perspective, it is highly desirable to develop Standards by extracting common issues out of this emerging power system, interconnection rules being a key foundational element. Most countries have established local grid codes to assure the safety as well as to maintain the quality of electricity and grid stability, together with some functionalities for interconnection of DSRs. A highly organized example can be seen in the network codes issued by ENTSO-E, which consist of three areas: connection, operations, and market. Regulators should be flexible about grid codes and make timely modifications as new kinds of DSRs appear and/or new functionalities are developed. In another words, the proper relationship between grid codes and DSRs is expected to play an important role in making progress toward the next generation power system, in which DSRs are effectively integrated with their increasing use-cases. Additional references examples include California's Rule 21 [18] and Hawaii's Rule 14 [19], both of which require some grid support functions of photovoltaic inverters to keep the power quality stable. Efforts should be made not only by grid operators but also by resource developers. Owners of non-conventional generators should be highly encouraged to supply mathematical models, both static and dynamic, and important weather data for network studies.

Beyond technical and regulatory challenges, customer engagement is an imperative step for implementing a successful market mechanism in the next generation power system, since most of the DSRs are (or will be) owned by customers. It is essential to simultaneously allow for customer flexibility while meeting grid reliability requirements. Although customers will be most sensitive to the charges they have to pay for electricity service and the incentives they can obtain, it is also important to educate customers concerning the social benefits of DSR integration, especially its impact on the environment. Some of such materials providing a customer-friendly explanation of this aspect can be prepared by IEC.

How demand-side resources will interact with the future grid is not known. However, two extreme scenarios can be imagined, with the assumption that the reality of the interaction will fall somewhere in between. The first extreme can be termed the "remote control scenario". Under this scenario, utilities are highly aware of the DSRs in their territory, involving not only visibility into each DSR's capabilities and settings, but also the ability to control the current and future settings of such resources. The second extreme can be called the "local control scenario". Under this scenario, utilities are only aware of the gross impacts of DSRs in their territory based on results from advanced modelling and have no direct control or even visibility of the DSRs themselves. There are benefits and challenges to each scenario, and it is not yet clear which of these will ultimately emerge as the dominant force driving how DSRs will ultimately be deployed.

5.1 Remote control scenario

The main benefit of the remote control scenario is a high degree of reliability of the power system. If the electricity utility is aware of and can control each DSR on the grid, it can optimize the overall grid function through management of the DSRs – much like in today's world in which a utility can control traditional generation sources to meet the demand for electricity while subsequently preventing overloads on the grid. This balance between optional dispatch and grid stability is known as a security-constrained dispatch – meaning that each generation is dispatched so that the overall system is kept in balance and no transmission line carries too much power. The result of a security-constrained dispatch impacts which sources of electricity are dispatched, and in certain cases the "best" generation (be that the cheapest generation, the least polluting generation or any other considered optimization target) might not be used so that the power grid's electric stability is maintained. Reliability of the power system is extremely important; however, the cost of this reliability comes in the form of several challenges when DSRs are introduced into and ultimately might even replace the traditional generation mix.

Complex operation – Optimizing thousands or even millions of DSRs constitutes an enormous challenge. As more vendors start producing DSRs, the number of variables affecting control will grow. Understanding each type of DSR and the specific constraints surrounding the operation of different DSRs is already complex, but the planned operation of such resources over time will make this problem even more complicated. Consider, for example, a storage device with a limited amount of energy production capability. Any operational control needs to consider not only how using that resource will impact the grid, but also whether it would be better to hold off usage of that resource until a future time. This consideration is known as a limited energy constraint and means that optimization must be performed not only for the next dispatch period (e.g. five minutes from now) but also for many future dispatch periods (e.g. over the next 24 hours).

Communications-intense – The communications requirements for the remote control scenario are numerous. First, there are information flows to and from each DSR to the local utility. But as the electricity industry is deregulated, more players are introduced – so the communications do not necessarily occur only between utility and DSRs. Rather, the communication is between the DSRs and multiple other players, such as the utility, the energy retailer, the resource aggregator and the market operator.

Control conflicts – If one considers both sides of the complex communication environment involving multiple parties, the sending of information to the utility players about current and future capabilities of the DSRs is relatively simply. The opposite flow – control information about how the DSR should operate – is problematic when multiple parties are involved. Once there are more than two parties with operational control, there must be a well-defined prioritization of control, so that conflicting control signals can be clearly differentiated. As an example, perhaps the distribution utility has priority over the market operator, so even if the market operator dispatches a DSR to produce electricity, the distribution utility may override the dispatch to avoid a feeder overload. The market operator therefore can only control its resources in certain scenarios in which the distribution utility relinquishes control.

Lack of customer focus – Since DSRs will most likely be procured by customers, it is a little unclear why customers in the remote control scenario would purchase a DSR if another party (or other parties) exercise complete control over that resource. A solution would be to implement incentive programmes that treat DSRs more like utility investments rather than customer investments. This scenario can work well for solar, wind, and storage resources, however, it becomes very complex if the primary focus of the demand-side resource is not power production. For example, if EVs are considered a valuable DSR, this may lead to conflicts if the utility decides not to charge a customer's vehicle overnight and the customer discovers that driving to work in the morning is not possible.

5.2 Local control scenario

The main benefit of the local control scenario is simplicity. If the customer is controlling the DSR, the issues of complex optimization software, difficult communications requirements and multiple sources of control signals needing to be mitigated are resolved. The major trade-off is the potential for a much less reliable power system. In addition, there are missing components that it will be necessary to activate before the full local control scenario goals can be achieved. To fully enable such a scheme, reflective economic signals as well as accurate grid reliability data must both be promptly available and actionable.

Decreased reliability – With no central planning determining where DSRs are deployed and no control being exercised concerning how those resources are operated once deployed, the potential exists for major reliability problems. To maintain reliability, utilities will need to change from today's control-based operational model to a more information delivery-based operational model. For example, if a feeder overload occurs, instead of shutting down a solar resource feeding into the grid, the utility might publish a signal stating that a feeder overload exists and ask for DSRs to voluntarily respond, perhaps with a financial incentive attached to the request.

Response capabilities – If one wants DSRs to respond to grid signals such as reliability requests, a standard set of information signals need to be defined. Moreover, technology manufacturers will need to incorporate response protocols into their products. Incorporation of these protocols might be achieved through one or more pressures: governmental mandate, industry adoption and/or market forces.

Economic response – Perhaps the most important shift involved in moving to the local control scenario is the education of the customer around the value of electricity over time. Once education is achieved, more dynamic pricing can be introduced, so that devices can consume in real-time and plan for future consumption based on price curves. Like the grid stability signals previously discussed, this change will require a new set of economic signals. Moreover, it will also significantly change the way customers think about electricity usage and how bills are calculated.

5.3 Examples of remote control and local control scenarios today

Today, many DSM resources are already available for dispatch at the grid operator control centre, as illustrated in Figure 5-1. The first wave of DSM was demand-response, especially involving larger resources such as those from large commercial and industrial customers. As with the dispatch of a conventional generator, grid signals are analyzed and calls for energy and essential reliability services are requested and, in some cases, even directly controlled. As smaller and smaller resources began to be made available, the role of the third-party aggregator was formalized, so that control signals could be made to a single entity, which in turn could activate several (or perhaps numerous) smaller resources. This model unburdened the grid operator from having to manage multiple very small resources, while still being able to utilize the aggregate response.

Several good examples of device-centric controls (see Figure 5-2) exist on today's grid as well. For example, load-consuming devices can be equipped with an under-frequency relay (UFR). The UFR continually monitors the local frequency, i.e. the frequency at the plug of the device. If a frequency is monitored which is below a defined threshold, e.g. 49,5 Hz when the nominal frequency is 50,0 Hz, then the UFR can automatically disconnect the load. Recall from Section 3.1 that reducing load will increase the system frequency. If enough equipment responds to UFRs, then a critical system event can be avoided. When a power grid has less inertia, i.e. is a smaller grid or a grid with little connectivity to other systems, this becomes more important, so it is not surprising to see UFRs employed on the Texas grid (isolated from the rest of the North American grid) and on the United Kingdom's grid (an island system).

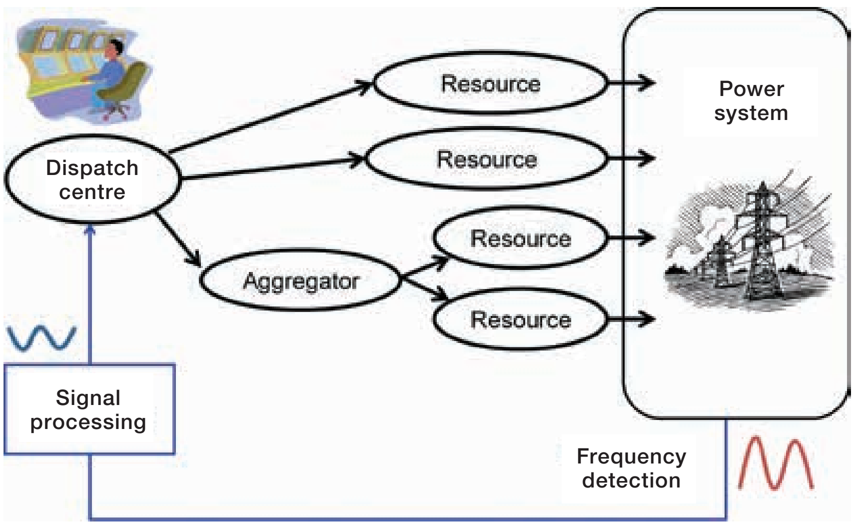


Figure 5-1 | Remote controls in today's dispatch centre

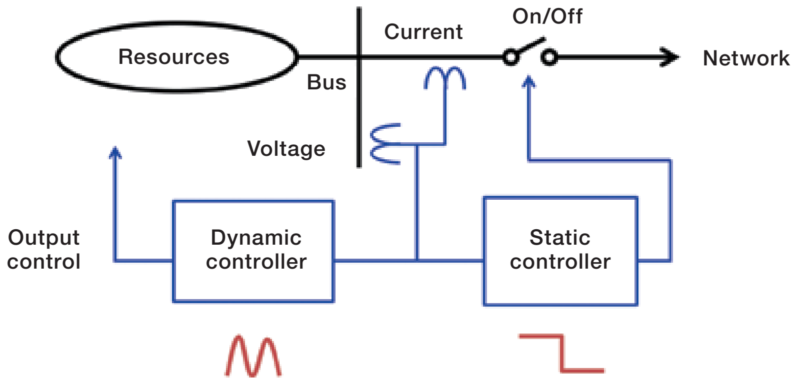


Figure 5-2 | Local controls on today's grid

UFRs are static controls, however with the advent of grid-level battery storage, dynamic controls can be employed for subtle control schemes. Dynamic controls sense local conditions and vary production, consumption and/or essential reliability service delivery based on the results.

5.4 Retail pricing reform

Wholesale markets, in their most basic form, facilitate the sale of electricity from transmission-connected generation to load-serving entities who must procure electricity for their customers. Essential to successful markets is the ability to buy power forward and then to balance in real-time. Forward markets allow buyers and sellers to lock in prices based on load predictions. Because loads are at least in part weather-dependent, electricity trades closer to real-time than other commodities, for example crude oil. It is common for wholesale electricity markets to support a day-ahead market to serve this need for a forward market. Earlier timeframes are most commonly supported with bi-lateral arrangements between generators and load-serving entities.

Load projections are never perfect and, adding to this uncertainty, the grid is always susceptible to generation and transmission outages, changing the dynamics of the system. So the real-time market is essential to manage variations in the actual energy bought and sold relative to the scheduled values. Because the electricity values change in real-time, so do the prices of electricity in real-time. Major outages can cause massive price spikes, with the value of electricity several orders of magnitude larger than average near an outage, if only for a few minutes.

If the electricity grid were a perfect conductor (no resistive losses) and had excess capacity (no transmission constraints), then prices would be equal at all locations. Since every power grid has losses and capacity constraints, then not only is time an important factor in determining price, so too is the location at which the electricity is to be consumed. The farther away the load is from the generation, the larger the losses – increasing the delivery cost. And when cheap power cannot be imported because of limitations to the transmission grid, then more expensive local generation must be dispatched, also increasing the price.

Even in regions where wholesale markets are well-established, customers are often insulated – either in part or in whole – from wholesale market volatility. Consumers usually pay a time-averaged and spatially-blurred price. Since most customers are not capable of managing their own usage, which can vary minute by minute, it is reasonable to argue that some insulation is warranted. However, too much protection is equally problematic, as customers will not understand the true, time-dependent value of electricity. It is therefore important to consider some market reforms at the retail level.

As more DSM technologies become available to shape loads and more DER technologies become available to offset loads, proper price signals are necessary. The need of DSM and DER to have variation in the value of electricity is an enabling condition for this transition and will help force the alignment of retail and wholesale markets, exposing customers to some of the volatility of the markets in the process. At some point in the future, electricity customers may very well be able to have their devices respond to real-time prices. However, this is a theoretical end-state and there are many steps to be taken before this phase can be effectively implemented.

Since many wholesale markets support day-ahead clearing, this is a natural time horizon to couple with the retail markets. Implementing retail rates that have as a major component electricity costs based on the procurement of wholesale electricity in day-ahead clearing is a concept that deserves consideration. Other components would be necessary, such as a more static distribution charge and some sort of volatility offset as an insurance premium for real-time fluctuations.

Day-ahead retail pricing will not only teach customers about the value of electricity, but more importantly such pricing is actionable. This means that in the future, customer devices will be able to understand that day-ahead pricing curves adjust behaviours. For example, an EV knowing it must be ready to operate at a certain time on the following day can minimize its costs by charging only during the least expensive hours. Similarly, a dishwasher or clothes washer could – as an option – delay its cycle until the price is at its minimum. Thermostats could balance comfort with cost, using pre-cooling in the summer (cooling before a temperature maximum is met) and pre-heating in the winter (heating before a temperature minimum is met). En masse, multiple devices reacting to prices will ultimately shift loads to the times when generation is plentiful, e.g. when the wind is blowing or when the sun is shining.

Additionally, the locational aspect of pricing will also impact behaviour. For example, given the choice between charging an EV while at work in a transmission-constrained urban area or instead at home in an unconstrained rural area, the price of charging might be substantially lower at home, because of the impact of delivery factors to the urban location – without considering the time-of-day impacts of the price. Over time, price differentials in constraints and even the effect of delivery losses will incentivize more DSRs to be co-located at load centres.

Focusing in on the two major categories of demand-side management resources (see Figure 1-1), the grid-centric equivalent sub-category is demand response, in that a demand response programme is defined and customers choose to participate by following instructions, albeit often automated, from the grid operator. The second sub-category is flexible demand, also called price-responsive demand, and this model maps to the device-centric model. Flexible demand will progress in lock-step with the implementation of retail pricing that is truly reflective of at least some of the time-sensitive and location-dependent variations in the real value of electricity.

As more renewable resources appear on the grid, the value of energy decreases (renewables have no fuel cost) and the value of essential grid services increases (outputs of renewables are uncorrelated with electricity demand). It is therefore important that the value of essential grid services be both transparent and assessible to all customers. This does not mean that all customers need to be wholesale market customers or even that customer devices must participate in aggregate as wholesale market resources.

As with retail energy pricing reform, the cost of essential services should at some point be exposed to the customer. Many services, for example regulation, operational reserve, and ramp support, are highly time-dependent. Other services not only vary by time but also by location, for example voltage support service. These local services must be supplied close to where the service is required, and so the locational aspect of the economic and reliability signals is as important as the time element. With the proper signals, DSRs will be able to fill the grid support gaps as fossil-fuel generation leaves the electricity generation portfolios around the world. Simultaneously, these DSRs will also provide revenue to their owners/operators.

Section 6

Technology solutions

In addition to market solutions, there are several new and emerging technologies that can help facilitate the change from traditional to distributed resources stabilizing the grid. Many technologies are now directly connected to the power system, such as wind generation, solar generation and storage technologies, heating, ventilation and air conditioning (HVAC) technologies, EV and home appliance technologies. Each of these, and likely a flood of future technologies, deserves a paper dedicated to the specific technological developments involved, and so none will be addressed directly in this White Paper. For more information on several of these topics, we recommend previous IEC White Papers, including:

- *Electrical Energy Storage* (2011) [20]
- *Grid integration of large-capacity Renewable Energy sources and use of large-capacity Electrical Energy Storage* (2012) [21]
- *Microgrids for disaster preparedness and recovery* (2014) [22]

The technology solutions covered in this section[6] are rooted in the ICT sphere, where many argue that the utilities industry has failed to keep pace relative to other technologies. At some point, the traditional dampers on progress, such as lack of capital investment and precautions to avoid opening cyber-security holes, will need to be confronted, so that these new technologies can be leveraged to a higher degree.

6.1 Big data analytics

Big data refers to extensive datasets – primarily involving the data characteristics of volume, variety, velocity and/or variability – that require a scalable technology for efficient storage, manipulation, management and analysis. Analytics is a composite concept consisting of data acquisition, data collection, data validation, data visualization, data quantification and data interpretation [1] [23].

The promise of big data analytics has been the subject of news reports since as early as 2010, and with the McKinsey report on big data in 2011 [24], companies across the world began embracing big data analytics at a rapid pace. Application of such analytics constitutes the key to turning big data into value. Data analytics is an open emerging field that can provide additional value in every sector, leading to more efficient and accurate processes.

Many other problems impeding the use of big data analytics in the electricity sector remain to be resolved, such as the ability to increase the reliability of the electricity network though predictive maintenance. A roadmap with specific objectives was published by the EU Horizon 2020 programme, calling for the development of big data tools and architectures for optimized energy system management [25].

Perhaps the most obvious application of big data analytics in the context of demand-side resources is that of helping grid operators reduce the problem of limited predictability. More robust predictive

6 This White Paper focuses on technologies with a relatively direct link to solving one of the grid operation challenges. A number of other technologies (such as blockchain and virtualization) may play a key role in the future, however use cases that clearly illustrate this potential are not necessarily available at this point in time.

analytics tools provide more accurate patterns and insights based on multiple factors affecting energy consumption, such as weather and price.

6.2 Artificial intelligence

Artificial intelligence (AI) designates the intelligence exhibited by machines. In computer science, the field of AI research defines itself as the study of intelligent agents, i.e. any device that perceives its environment and takes actions to maximize its chance of success at achieving a particular goal. Colloquially, AI is applied when a machine mimics cognitive functions such as learning and problem solving exhibited in the human brain.

AI technologies can be utilized to mitigate the problem of limited predictability through their ability to improve the accuracy of wind and solar generation prediction as well as prediction of users' demand for electricity. More specifically, through AI machines learn how to predict future trends by examining how previous data, such as metered electricity usage, amount of solar radiation, level of wind, temperature and, as we move into the future, the price of electricity are all correlated. Another window into predictive capabilities concerns failure detection. Performance indicators of a device or of network elements often show gradual deterioration before catastrophic failure. AI processors can analyze sensor data from past failures to help predict future ones. With improved interfaces for grid operators in control rooms, this information can be used to increase the reliability of the grid.

6.3 Edge computing

Cloud computing centralizes the intelligence, computational power and storage elements of data and is especially useful when considering the needs of big data analytics. By contrast, edge computing deploys devices close to data sources, thereby mitigating the load on central servers and reducing communication latencies.

Edge computing can be deployed on gateways and controllers. Small-scale computer systems that interface with energy production and consumption devices include smart thermostats and home automation hubs. Collecting data from assets, these edge computers can selectively transmit critical data to the main station to improve the problem of limited visibility. Additionally, since the edge computing devices are deployed closely to the assets, timely control can be achieved. Even if the connection to the main station is interrupted, the assets can still be controlled by local intelligence inside the edge computing device. Well trained AI can be deployed at the edge computing device, which can be used to predict the grid's behaviour in a relatively small area. Edge computing devices might also communicate among themselves, helping to coordinate the operation of different sections of the grid. Finally, returning to big data analytics, when a large amount of data is acquired, the edge device can provide its data to the cloud and sophisticated predictive analyses can be performed.

For more information on edge computing, see the IEC White Paper published in 2017 focussing on the topic, entitled *Edge intelligence* [26].

6.4 5th generation mobile wireless communications

Unlike previous mobile network generations, the 5th generation of mobile wireless communications (5G) is expanding beyond the broadband capabilities of mobile networks to address a wide variety of industrial verticals, including automotive, healthcare, agriculture, manufacturing and – of course – energy. 5G supports three essential types of communication: enhanced mobile broadband (eMBB), massive machine-type communication (mMTC), and ultra-reliable low-latency communications (URLLCs).

eMBB provides data rates up to several gigabytes per second and low-latency communications on the order of milliseconds, while simultaneously improving coverage. mMTC is designed to provide wide-area coverage and deep indoor penetration for hundreds of thousands of sensors per square kilometre of coverage, enabled by battery-saving low-energy technologies. Finally, URLLC supports applications in which monitoring and control occur in real-time, i.e. with tight end-to-end latency requirements and with very high reliability and availability requirements. To support the three service types and the diverse requirements of the different 5G applications using a common cellular infrastructure, network slicing is used to support simultaneous yet isolated provisioning of diverse services.

5G technology could address the new challenges that the smart energy system is posing to communications networks, including by helping to improve the visibility, control and coordination of DSR. Through ultra-low latency and access to a high density of devices, network capabilities provided by URLLC and mMTC can well meet the connection requirements of core industrial control services on the power grid needed for the control and coordination of DSR.

6.5 Low-power wide-area networks

Low-power wide-area networks (LPWANs) deploy a long-range, low-power and low-cost wireless technology. LPWAN devices are easily deployed, and cost as little as USD 5 per device making them disposable at end-of-life. Some implementations of this technology can provide control as well as sensing functions, i.e. two-way communications. LPWAN devices can improve limited visibility in the form of an easy addition to any number of customer DSRs to monitor usage or to develop a usage profile. Sensors could be integrated with the DSR at point-of-sale to make deployment even easier, since the customer would not have to attach the device. Two-way communicating versions would also address the issue of limited control. For DSRs that are programmable (future plug-in electric vehicles (PEVs), dishwashers, etc.), these sensors could relay planned usage information, thereby mitigating the problem of limited predictability.

6.6 Time-sensitive networks

Time-sensitive networks (TSNs) involve a set of standards that define deterministic Ethernet data transfer mechanisms. Critical data can be transmitted together with normal data in the same network, with the critical data sent within a bounded latency. TSNs can transmit critical data like alarms and controls to help improve grid operation safety and stability. At the same time, non-critical data can travel in the same network to share the investment of the communication channel.

The standardization of TSN began in 2006, focused on high performance audio and video feeds. In 2012, the scope was extended to include industrial automation, intelligent transportation, mission-critical-automation and, of greatest importance to demand-side resources, the electricity grid.

6.7 The Internet of Things

The energy grid is essentially a complex Internet of Things (IoT) network of objects that are equipped with sensing, computing, actuating and communication capabilities and are usually owned and managed by different market players, often utilizing their own platforms or solutions, thus creating silos. The lack of IoT interoperability results in challenges including complex integration of silos of isolated data and costly deployments and proprietary application programme interfaces (APIs). IoT interoperability can be achieved at different layers, including at the middleware and service layer and/or at the data and semantic layer.

By ensuring that all stakeholders are connected and by enabling such players to "talk" to each other, advances in the IoT help address both limited visibility and limited control of demand-side resources. Through common service interfaces, the data associated with factors such as energy costs or how external weather conditions can impact the energy required to heat or cool a home is shared. Alternatively, a home could tell the grid what its power requirements are, thus helping to address the limited predictability challenge. Key to this discussion is the IoT interoperability challenge across different domains/markets, for example through interworking framework, data abstraction, common interoperability language, semantic tools and ontology. Examples of initiatives addressing this issue include oneM2M [27] and Smart Appliances REFerence (SAREF) ontology [28].

Advancements in a specialized version of the IoT, the industrial Internet of Things (IIoT), are also emerging. The IIoT connects things to an infrastructure that enables the availability of sensing data from industrial processes and allows the transformation of the analytics of this data into required knowledge about the real-time status of these industrial processes. Given how large energy consumption is for industrial processes, the IIoT could have an even larger impacts on DER development than the regular IoT.

For more information on the IoT, see the IEC White Paper published in 2016 focused on the topic, entitled *IoT 2020: Smart and secure IoT platform* [29].

6.8 Energy management systems

The term energy management system (EMS) is rather generic and therefore has multiple meanings depending on the audience. For decades, grid operators have used EMS technologies to monitor and support dispatch decisions on the grid, a technology that has been relatively unaffected by the demand-side resource disruption process. The other major definition of EMS is an on-premises software application used to monitor and control energy usage at a factory, building or home. To avoid confusion with the grid operations EMS, various xEMS term can be used to describe this class of software solutions including the factory energy management system (FEMS), building energy management system (BEMS), home energy management system (HEMS) and microgrid energy management system (MEMS) categories.

The xEMS variants all share common characteristics, in that they comprehensively monitor, manage and operate equipment in the premises. Most xEMS have a degree of environment control capability, albeit very large HVAC and lighting systems in the BEMS and FEMS cases and much smaller versions in the HEMS case. Backup power from on-site generation and/or energy storage is a common feature. But each variant of the xEMS also has a specific focus: the FEMS has unique capabilities for interfacing industrial processes, the BEMS is optimized for large-scale building maintenance, the HEMS understands consumer appliances and electronics, and the MEMS specializes in electrical islanding.

The other important characteristic of all xEMS is that the monitoring and control functions are centralized, allowing for a single operator to access both information on individual assets as well as summary information relevant to the entire premises. The central point concept also means that remote monitoring and control is possible. Deploying such a system in locations with on-site DER distributed energy resources means that grid services can be aggregated into net capabilities, offered to grid operators and monitored or even controlled by those grid operators for financial compensation to the xEMS owner.

The xEMS segment is not new, with a wide range of system vendors supporting several protocols, some of the non-proprietary versions being RS-485, LonWorks, ModBus, FL-net, Echonet and BACnet. With the emergence of DER, the xEMS is a logical point of translation between the logical resource communications at the grid level and physical devices communications at the premises level. As we shall see in Section 7, there is much to consider if the industry decides to develop dominant communication protocols above or below the xEMS.

6.9 Technology domains

Figure 6-1 shows where some of these technologies are likely to be implemented with many of their domains overlapping.

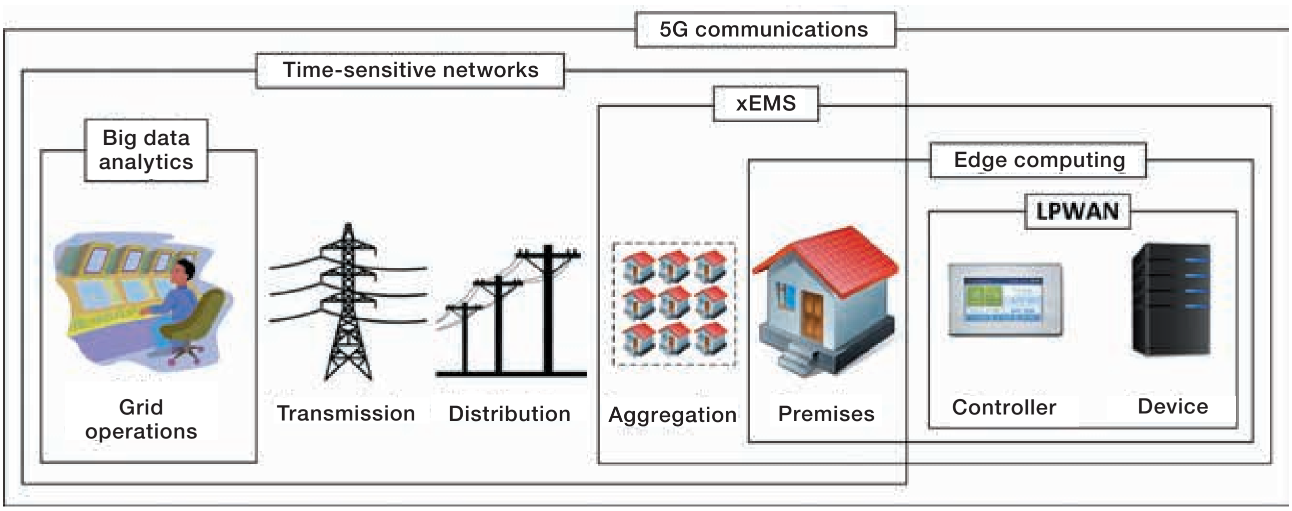


Figure 6-1 | Visualizing new technologies on the DSR-enabled grid

Section 7

Role of standards

It can be argued that standards developed too late will not be effective, as implementors will have already deployed products using proprietary protocols or using protocols which may have been developed by a consortium of industry players. At the other extreme, standards developed too early can be equally ineffective, as they may be based on scenarios that are not well correlated with where industry drives practical implementations.

The standardization of how we interact with DER has the added complexity of being a space that is an intersection of multiple industries. Of course, there is a major overlap with historical electricity technologies, but there is also significant overlap with transportation, building and home automation, HVAC, appliance and consumer electronics, as well as a plethora of emerging areas in ICT. Coupled with this multi-player challenge, the essential role that DER are expected to play to advance decarbonization, deregulation, decentralization, democratization, and digitalization of the energy space makes the standardization issue one of great importance.

7.1 Develop standard communication protocols

Despite having established a universal set of definitions, several IEC and non-IEC groups have developed and, in many cases, implemented, communication protocols. Fuelled by the impact on many industries, there is clearly more of an overlap issue than a gap issue when it comes to the ICT angle. Protocols based on existing IEC and non-IEC standards have been available for many years, as have several that have been developed by standalone activities. It is likely then that protocols will accommodate multiple standards, while simultaneously developing bridges to allow the different standards to interoperate. Since the progress of ICT is extraordinarily rapid, any framework should be flexible and allow for extensions.

One of the most comprehensive data modelling activities in the industry is the common information model (CIM) consisting of IEC 61968, IEC 61970 and IEC 62325. Representing the domains of distribution, transmission and market operations, respectively, these three IEC Standards provide a single data model, including components for DSR integration. IEC 61850 covers a similar scope, but with a focus on substation operations. For utilities already invested in the CIM or in IEC 61850, the best strategy is to extend the models from end to end to avoid data transformations whenever possible.

This approach makes sense from an architectural perspective, however, from a practical perspective compromises are often necessary when applications are not available with sufficient functions for emerging areas, such as DSRs. Therefore, a resilient framework must allow for extensions, especially when bodies outside the standards realm can move more rapidly to meet the needs of the industry. OpenADR, a communication protocol developed using non-IEC standards for demand response in the United States and maintained by the OpenADR Alliance, is a prime example of this phenomenon. Many prominent vendors have implemented OpenADR, and accordingly the standards have been integrated into the IEC portfolio [30] [31][7]. A more general approach is taken with forthcoming IEC TS 62939-2 ed1.0, providing an architecture to define interfaces for the information exchange between smart equipment and systems from the demand-side and the power grid. This technical specification presents one possible architecture to connect non-CIM/IEC 61850-based demand-side protocols so that integrations can be made with home and building applications already deployed in the field. This effort does not preclude the ongoing, long-term efforts within the IEC to promote the ideal single data model, but rather should be viewed as informing the standard with practical examples of requirements for interoperability.

Like the original OpenADR standard, CTA 2045 was developed outside of the IEC. However, other standards, such as IEEE 1815 and SunSpec ModBus have roots in the IEC (in this case IEC 61850) but incorporate non-IEC standards such as DNP3 and the original Modbus specification. Similarly, IEEE 2030.5 and OpenFMB both make use of IEC 61968 but incorporate non-IEC standards such as the smart energy profile (SEP 1.1) and the data distribution service (DDS) standard.

Given the number of communication protocols related to the DSR area, both IEC and non-IEC, it is helpful to approach the topic of grid communications with the questions of “from what?” and “to what?” in mind to help scope the domains of each protocol. This White Paper adopts the layer definitions in Table 7-1 to address the answers to these questions.

Visually represented in Figure 7-1, these established and developing standards can be shown as relaying information from one layer to another, with some interpretation necessary, as the prescribed functions in each standard do not necessarily map easily from one to another.

A wide range of IEC committees have either published or are in the process of publishing IEC Standards in this area. A summary of the IEC committees, the associated IEC working groups, and some of their major publications are provided as a reference in Annex A.

Many technical committees are engaged in a variety of activities related to communications, with the scope of each documented in Annex B. As mentioned, the need for standardization is crucial as the market is becoming increasingly complex, and bridges between individual technical committees will be required.

Table 7-1 | Layer definitions

Layer	Definition
Transmission	related to high-voltage operations and bulk power markets
Distribution	related to medium-voltage and low-voltage operations
Aggregation	related to collections of DER and/or DSM locations
Premises	related to the metered DER and/or the DSM location
Controller	related to the device controller, e.g. smart thermostat
Device	related to the device itself, e.g. air conditioning compressor

7 See IEC PAS 62746-10-1:2014 and forthcoming IEC 62746-10-1 ed1.0 with adapters documented in IEC 62746-10-3:2018.

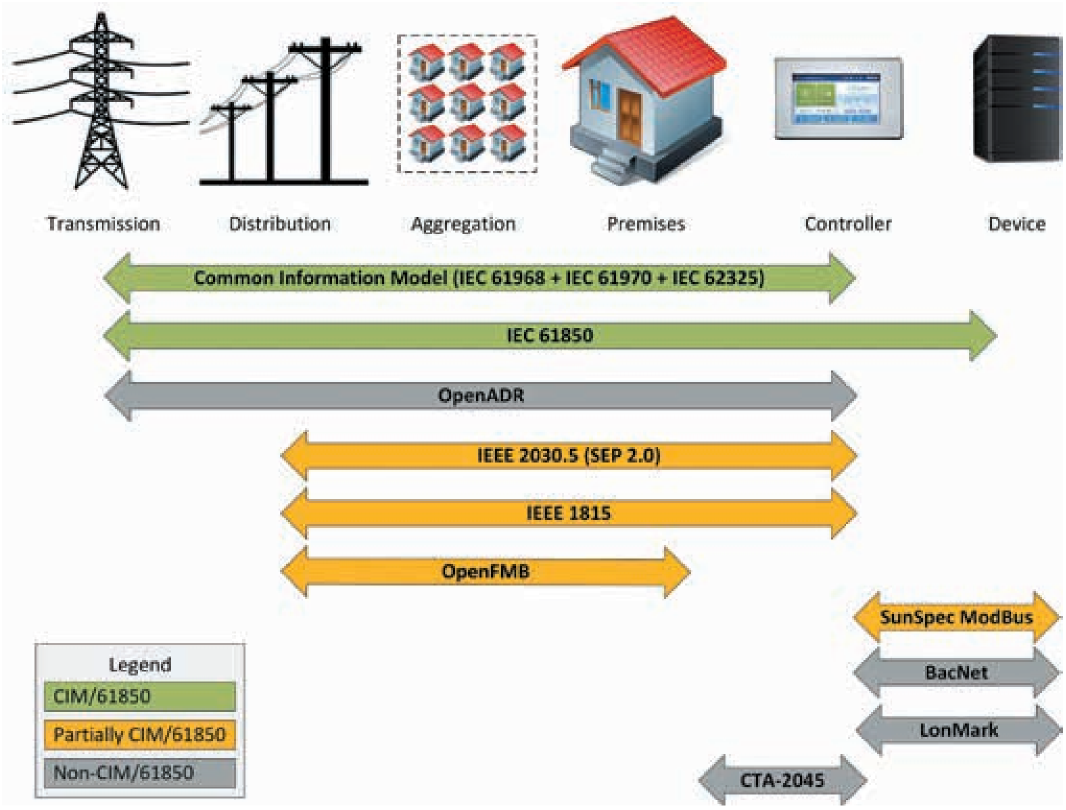


Figure 7-1 | Various communication protocols by grid layer

7.2 Document effective and transferrable practices

Finally, efficient operations involving DER and DSM ultimately require that market operators, transmission operators, distribution operators, energy retailers and third-party service providers all begin to treat these resources similarly. To facilitate this next step, the best practices in each region must be compared, distilled and generalized, so that the procedures can be replicated across the globe.

One of the earliest attempts to standardize business practices for demand response was *Business Practices for Measurement and Verification of Wholesale Electricity Demand Response*, sponsored in part by market operators in North America via the ISO/RTO Council [32]. This document was developed under the North American Energy Standards Board (NAESB) process and the final specification is available to NAESB members. The work was also provided to the United States Federal Energy Regulatory Commission (FERC) and was subsequently mandated for use in wholesale jurisdictional markets [33].

While an important step involves defining both the types of measurement and verification techniques that should be employed and the common terminology for describing the timing of demand response events, additional work can be undertaken to recommend when and how these practices would best be implemented, including the results of studies of the best parameters to use as a function of variables such as market type, resource type and weather/climate.

Section 8

Conclusions and recommendations

The worldwide trends of decarbonization, decentralization, deregulation, democratization and digitalization are expected to continue. It is logical to assume then that both the variety and extent of penetration of disruptive, demand-side resources will also continue to grow. Finally, the increase in demand-side resources will also render more critical the challenges of limited visibility, limited control, limited predictability and limited coordination for the operators of transmission and distribution grids across the globe.

Electricity grid improvements often take years or even decades to materialize in terms of major upgrades and large-scale, central generation development. Conversely, advancements in technology are facilitating rapid upgrades on the demand-side. To keep pace, governments and capital markets must invest in grid operations, both through improved and expanded electricity market designs and through the adoption of enabling technologies for the grid operators. This shift itself away from long-term, physical investments to shorter-term market and ICT investments is new to the energy sector. Progress is best made when all parties are pulling in the same direction. To that end, several recommendations are given below for consideration by the IEC and broader stakeholders.

8.1 Recommendations for the IEC community

Promote common language – One of the greatest challenges in managing demand-side resources is understanding the use of terminology, especially when the general population is not well educated in the concept of electric power systems. Different groups of people, particularly those living in different regions of the world, either use the same or similar words to describe different technologies or use different words to refer to the same technology. At this stage, unifying terminology is an unreasonable task. The best that can be done is to promote the "best" language. The IEC has created the relatively complete and easy-to-use dictionary Electropedia [1][8]. The working groups in IEC technical committees should leverage this resource and provide updates to any terms which are not in keeping with current discussions. The IEC technical committees also have the deep functional knowledge necessary to fill the many gaps currently existing in the Electropedia, particularly those concerning demand-side resources. Furthermore, the IEC should consider ways to publicize this resource to a wider audience.

Consider procedural Standards – One of the goals of this White Paper is to help its readers better understand that the procedures that grid operators use to manage both stable operations and efficient markets will increasingly rely on demand-side resources. In fact, it is not unreasonable to consider a future state of the grid in which all production is provided through a combination of centralized renewables and distributed demand-side resources. The IEC should consider the elaboration of International Standards not only focused on the current scope of modelling and communications, but also codifying procedures

8 In addition to Electropedia, the IEC also makes available to the public a comprehensive glossary of terms and how they are utilized in different IEC Standards at std.iec.ch.

and business practices. For example, the IEC already has a communication model available to exchange demand response performance data, but an IEC Standard on how best to develop the performance data would help the industry converge from a business rule perspective as well.

Study and document best practices – It is common for IEC documents to contain both normative components (information that is prescriptive and thus required for compliance) as well as informative components (information that is not required but is helpful for implementers to better understand the IEC Standards through the use of examples). Best practices should be more deeply investigated and incorporated into these informative sections. Moreover, examples from many different regions around the world should be catalogued to provide a wide range of implementation types based on operational and market differences in different countries.

Improve intra-IEC coordination – There are many technical committees inside IEC, each with its own respective mission. Historically, within each committee it was sufficient to have isolated discussions to achieve the committee's goals. because electric power services were assumed to be defined along a simple, classic, and relatively stable model. However, with the development of DSR technologies, coordination among relevant committees is becoming very important, because individual tasks within each committee are overlapping more often with tasks from other committees. Now is the time for improving cross-committee communications. Emphasis should be put on expanding coordinating bodies within the IEC, focusing on bringing together and guiding overall systems level value through consultation with the IEC and with broader stakeholder communities. Fora and/or roundtables for exchanging ideas should be accentuated with the ICT stakeholder community as well.

Improve inter-SDO coordination – The demand-side resource segment of the utility industry broadens the horizons of traditional standards development work. Not only do the interconnection, communication and operations standards go deeper – "behind the meter" in other words – but the standards also touch other industries. Better coordination with other standards development organizations (SDOs) is therefore paramount.

8.2 Recommendations for industry leaders

Improve coordination – Recognizing utilization of DSR and advanced electricity trading is essential to a low-carbon future, and it requires more coordination among utilities, solution providers and intermediaries. Coordination means considering the impacts on other parties: technology providers must consider grid impact, resource aggregators must consider customer preferences and solution limitations, etc. Adopting a common, standards-based protocol will promote more seamless solutions. To this end, we consider industry interest groups and well-coordinated industry steering committees to be essential to enabling effective information exchange. Two examples of relevant organizations offering a framework for tighter coordination are the Peak Load Management Alliance (PLMA) [34] and the Energy Resource Aggregation Business Forum (ERABF) [35].

Improve technology adoption – Traditionally, utilities have focused on reliability and as a result, the utility industry has moved slowly when adopting new technologies. This trend of adopting only the most thoroughly tested technologies means that most utilities are several years behind their counterparts in different spaces. The global increase in cyber security threats, coupled with a desire from bad actors to target infrastructure, has only exacerbated this issue. However, the industry must begin to consider moving more quickly and considering solutions that leverage more cutting-edge solutions, if it is to keep pace with its customers. Likewise, in this competitive new environment, we encourage manufacturers and vendors to improve their products and solutions to meet the reliability requirements of the grid operators.

Encourage communications and education (industry leader role) – Effective communication among industry players, both old and new, is essential. Experienced utility executives should be encouraged to consider the benefits of new technologies, while new entrants to the energy space must also learn to respect the complexity of power system operations, with the stability of such systems being threatened in real-time by improperly implemented devices and technologies with insufficient cyber-security mechanisms. Customers too must be educated about the volatility of electricity, a fact which will only become more important as we switch to renewable fuel sources. Advanced retail pricing is key to the deployment of smart devices which can intelligently consume and produce power, but advanced retail pricing will only be effective if customers understand how to select the right devices and ultimately how to intelligently program them. Highly-informed customers will operate optimized devices, leading to lower electricity bills and a grid which is more stable because of demand-side resources. Support from policymakers is also recommended.

8.3 Recommendations for policymakers

Encourage communications and education (policymaker role) – The goal of improved communications and enhanced customer education was listed as a recommendation for industry leaders. However, the support of regulatory bodies adding the perspective that active support from customers is essential for the common good is also crucial.

Establish equitable goals – When developing regulations, there should be a balance among the needs of grid operators for reliable service, the needs of customers for minimal costs and maximal access to information, and the needs of the society for a sustainable future. All three of these needs are rapidly changing, especially those of grid operators, who must have greater access to the customers' devices to ensure that reliability levels are maintained, not to mention improved. Market designs should be technology independent, so that any provider using any technology can support the grid with its services on an equal playing field. Rules should be written so that barriers to entry in terms of the size of the resource are as small as possible, considering what the grid operator will be able to handle in terms of volume.

Cross-industry collaboration and commercialization support – By expanding cooperation with industries outside the electricity industry, there is a possibility that higher quality solutions can be realized. Specific areas in which collaboration can be expected include the hydrogen supply chain, heat supply, water supply, logistics, transportation and information services to improve health and quality of life. Policymakers should proactively push forward with investments and encourage demonstrations that focus on cross-industry collaborations with broad perspectives on commercialization. After a successful demonstration, it is important to have an implementation strategy as part of the implementation plan in order to help promote the sustainability of businesses. It is beneficial for governments to continue supporting industries in the post-demonstration phase to smoothly transition to commercial operations. Above all, it is insufficient to discuss DSR solely from the point of view of electric power industries. Rather such discussions must be coordinated with a community utility strategy, taking into consideration non-electricity services. At the same time, it is also important to note that this does not necessarily mean the government should interfere excessively in privatized market activities. Thus, policymakers are required to continually monitor their own guiding role to maintain the most effective balance between too much and too little support relative to changing society needs.

Annex A

Relevant IEC Standards

The following IEC Standards are marked as "core" or "important" to the development of the smart grid according to the IEC Systems Committee on smart energy [36].

Standard	Title	Applicable topics[9]
IEC 60870-5 (all parts)	*Telecontrol equipment and systems – Part 5: Transmission protocols*	EMS; DMS; DA; SA
IEC 60870-6 (all parts)	*Telecontrol equipment and systems – Part 6: Telecontrol protocols compatible with ISO standards and ITU-T recommendations*	EMS; DMS
IEC TR 61334 (all parts)	*Distribution automation using distribution line carrier systems*	AMI
IEC 61400-25 (all parts)	*Wind energy generation systems – Part 25: Communications for monitoring and control of wind power plants*	EMS; DMS; DERMS
IEC 61508 (all parts)	*Functional safety of electrical/electronic/programmable electronic safety-related systems*	All
IEC 61850 (all parts)	*Communication networks and systems for power utility automation*	GMS; EMS; DMS; DA; SA; DER; e-storage; e-mobility
IEC 61851 (all parts)	*Electric vehicle conductive charging system*	e-mobility
IEC 61968 (all parts)	*Application integration at electric utilities – System interfaces for distribution management*	GMS; EMS; DMS; DA; SA; DER; AMI; DR; e-storage
IEC 61970 (all parts)	*Energy management system application program interface (EMS-API)*	

9 See the List of abbreviations for the full terms abbreviated here.

Standard	Title	Applicable topics[9]
IEC 62056 (all parts)	*Electricity metering data exchange – The DLMS/COSEM suite*	DMS; DER; AMI; DR; Smart home; e-storage; e-mobility
IEC 62325 (all parts)	*Framework for energy market communications*	GMS; EMS; DMS; Metering back-office; DER; AMI; DR; e-storage
IEC 62351 (all parts)	*Power systems management and associated information exchange – Data and communications security*	All
IEC TR 62357-1: 2016	*Power systems management and associated information exchange – Part 1: Reference architecture*	EMS; DMS; DERMS; Metering back-office; Market and trading systems; DR
IEC 62443 (all parts)	*Industrial communication networks – Network and system security*	All
ISO/IEC 15118 (all parts)	*Road vehicles – Vehicle to grid communication interface*	e-mobility
ISO/IEC 27019:2017	*Information technology – Security techniques – Information security controls for the energy utility industry*	All

Annex B

IEC activities on energy resource aggregation and trading

The following are marked as major IEC activities on energy resource aggregation and trading.

TC	WG	Summary of activities
SyC Smart energy	WG 6 Generic smart grid requirements	Discussion of generic smart grid requirements of grid-related domains and grid management regrouping
PC 118 Smart grid user interface	WG 1 Exchange interface between demand-side smart equipment and the grid	Creation of smart grid user interface (SGUI) reference architecture for information exchange interfaces between smart equipment/systems from demand side and the power grid
	WG 2 Power demand response	Creation of OpenADR 2.0b profile specification and methods, and example XML artefacts that may be used to build a conformant adapter to enable interoperation between a utility distributed automation or demand response system based on the IEC CIM and a utility SGUI bridge standard to a customer facility
TC 13 Electrical energy measurement and control	WG 14 Data exchange for meter reading, tariff and load control	Discussion of data exchanges by different communication media, for automatic meter reading, tariff and load control and consumer information
	WG 15 Smart metering functions and processes	Discussion of functions and processes in smart metering systems (AMI) conforming to the IEC 62056-1-0 smart metering framework and IEC 61968 series data models/ message profiles (CIM)

TC	WG	Summary of activities
TC 57 Power systems management and associated information exchange	WG 13 Energy management system application program interface (EMS – API)	Discussion of CIM, which is an abstract model that represents all the major objects in an electric utility enterprise typically involved in utility operation
	WG 14 System interfaces for distribution management (SIDM)	Discussion of system interfaces for distribution management and the distribution extensions of the CIM
	WG 16 Deregulated energy market communications	Items on trading communication are treated as follows: · CIM for energy market communications · Exchange of market information between the actors in the energy market · UML package for use within the European-style electricity markets · Package for the transmission capacity allocation business process, a package for the settlement and reconciliation business process and the associated document contextual model, assembly model and XML schema for use within European style markets · Package for the problem statement and status request business processes and the associated document contextual models, assembly models and XML schema for use within European style markets · UML package for the market information publication business process and its associated document contextual models, assembly models and XML schemas for use within the European style electricity markets · Energy market specific messaging profile based on the ISO 15000 series · Communication platform which every TSO in Europe may use to reliably and securely exchange documents for the energy market · Services needed to support the electronic data interchanges between different actors on the European energy market for electricity in a fast (near-real-time) and secure way

TC	WG	Summary of activities
	WG 17 Power system intelligent electronic device communication and associated data models for distributed energy resources and distribution automation	Discussion of IEC 61850 information models to be used in the exchange of information with DER, which comprise dispersed generation devices and dispersed storage devices, including reciprocating engines, fuel cells, microturbines, photovoltaics, combined heat and power and energy storage
	WG 21 Interfaces and protocol profiles relevant to systems connected to the electrical grid	Discussion of interoperability to assist different TCs in defining their interfaces and messages covering the whole chain between a smart grid and smart home/building/industrial and an architecture that is supportive of interfaces between the customer energy management system and the power management system
TC 65 Industrial-process measurement, control and automation	WG 17 System interface between industrial facilities and the smart grid	Discussion of the interface, in terms of information flow, between industrial facilities and the smart grid
TC 69 Electric road vehicles and electric industrial trucks	JWG 11 Management of electric vehicles charging and discharging infrastructures linked to TC 57	Discussion of requirements and information exchange for the establishment of an electro mobility eco-system covering the communication flows between the different electro mobility actors as well as data flows with the electric power system
	WG 9 Electric vehicle charging roaming service	Discussion of general requirements of EV roaming service system, such as terms and definitions, general description of the system model, classification, information exchange and security mechanisms between EV charge service providers (CSPs)

TC	WG	Summary of activities
TC 120 Electrical energy storage (EES) systems	WG 3 Planning and installation	Discussion of necessary functions and capabilities of EES systems, test items and validation methods for EES systems, the requirements for monitoring and acquisition of EES system operating parameters and exchange of system information and control capabilities required
TC 69 ISO TC 22 Road vehicles	SC 31 Data communication	Discussion of communication between EVs, including battery EVs and plug-in hybrid electric vehicles (PHEVs), and the electric vehicle supply equipment (EVSE)
ISO/IEC JTC 1/ SC 25 ISO TC 205 Building environment design	WG 3 Building automation and control system (BACS) design	Discussion of basis for common information exchange between control systems and end use devices found in single- and multi-family homes, commercial and institutional buildings and industrial facilities that are independent of the communication protocol in use

Annex C

Grid technologies

C.1 Fault ride through

FRT is a requirement stipulating that generators be able to remain connected to the network for a certain period after the voltage deviation following short-circuit faults. Many grid operators are recognizing the necessity of establishing the FRT requirement in their grid code to avoid system collapse. After a large integration of RESs, wide-area coordination between adjacent balancing areas becomes very important, calling for the necessity of standardizing FRT requirement parameters. Figure C-1 illustrates the effects on the grid after a fault, both with and without FRT capabilities.

C.2 Islanding detection

When numerous DSRs are connected at distribution voltages, grid operators must consider the operation if islanding occurs. In Japan, an active-type islanding detection methodology is codified, in which a small reactive power signal is injected into feeders to test whether or not a mode change has occurred. Figure C-2 illustrates how DSRs respond when equipped with an islanding detection capability.

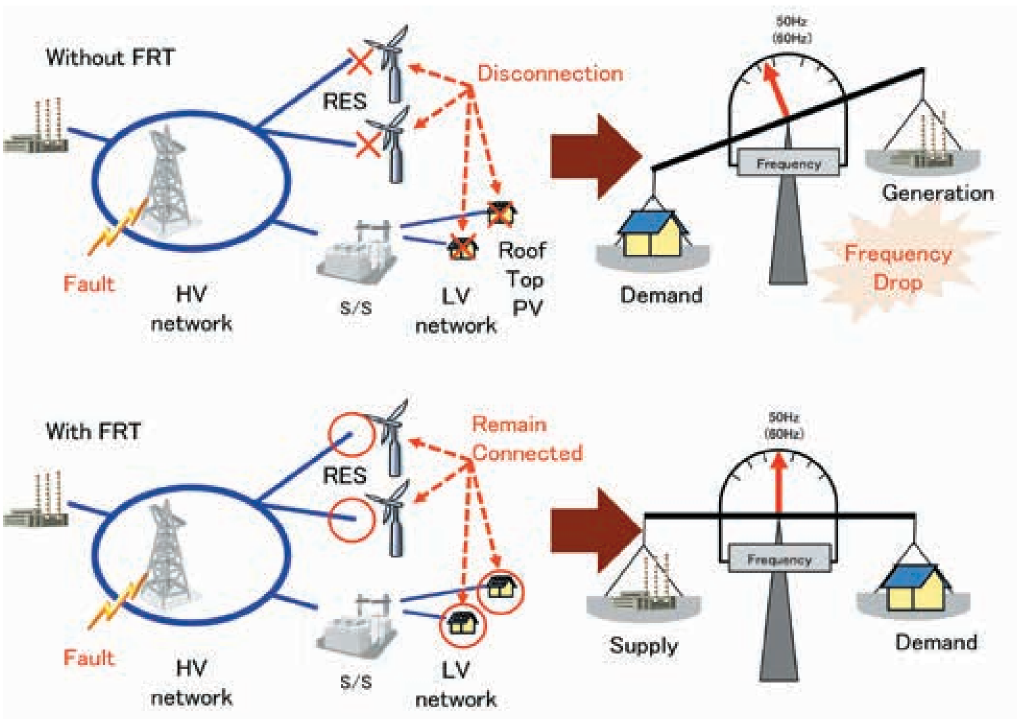


Figure C-1 | Fault ride-through

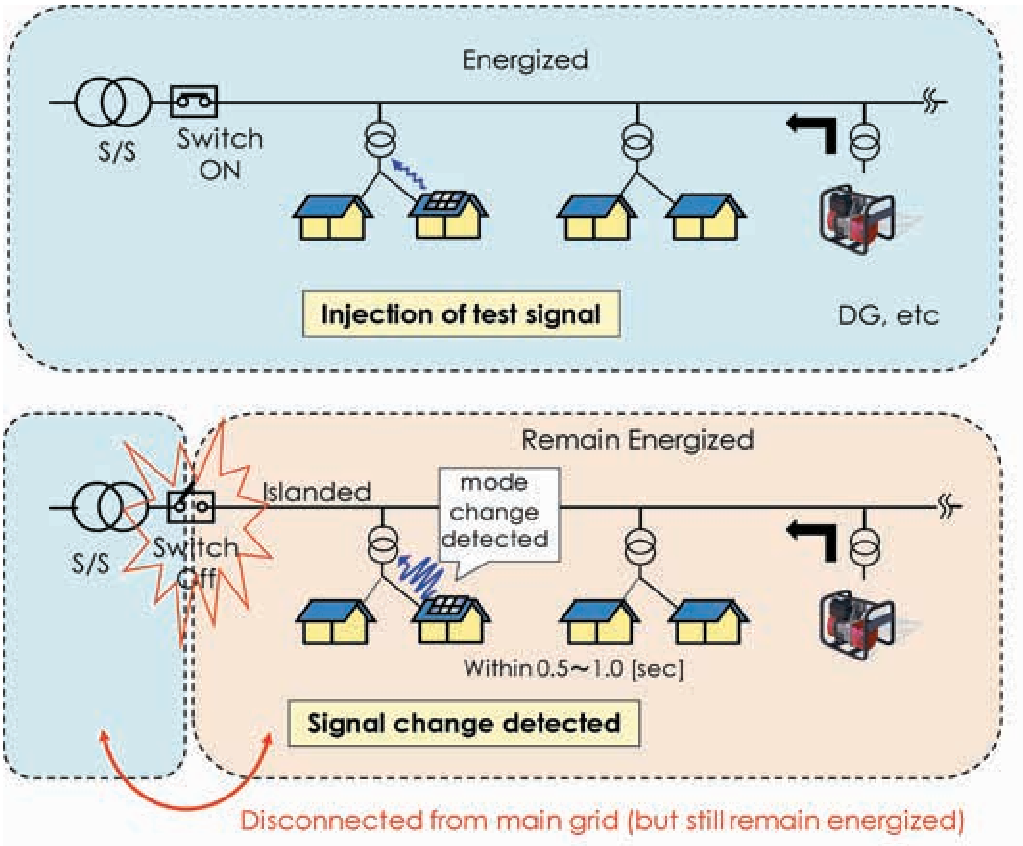


Figure C-2 | Islanding detection

C.3 Virtual inertia

Historically, the stability of electric power systems has been maintained by conventional synchronous generators, which utilize a rotating mass to create system inertia. However, as these generators are replaced with invertor-based technologies (which do not have a rotating mass), the total inertia of the system is reduced. This lack of system inertia reduces system stability. One countermeasure is to install a smart controller which can simulate the synchronous generator feature by software control logic, applying active control of and virtual inertia from renewable resources as well as energy storage systems, as schematically represented in Figure C-3.

C.4 Situational awareness

When large amounts of renewable energy are installed, grid operators are challenged to recognize changing system conditions – a necessary predecessor to optimizing control methods. Against this background, grid operators are developing situational awareness networks, comprised of wide-area measurement systems (WAMs) and phasor measurement units (PMUs), which monitor variables across large geographical regions and phase angles respectively in real-time. The power system stability can be viewed from two perspectives: local-mode and inter-area mode, as shown in Figure C-4.

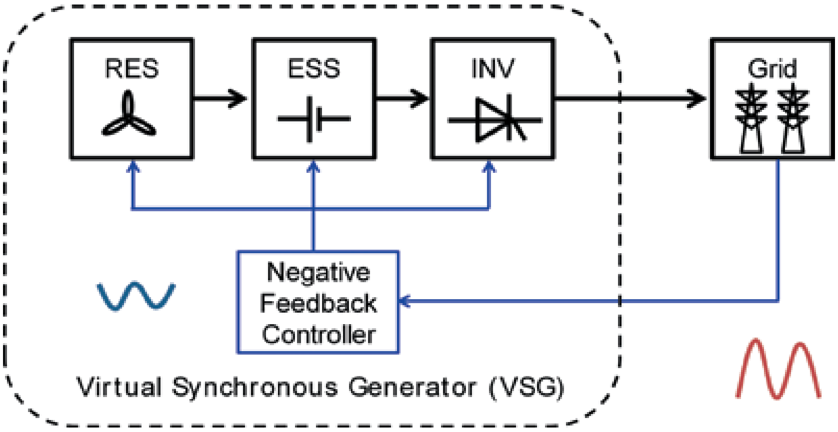


Figure C-3 | Virtual inertia

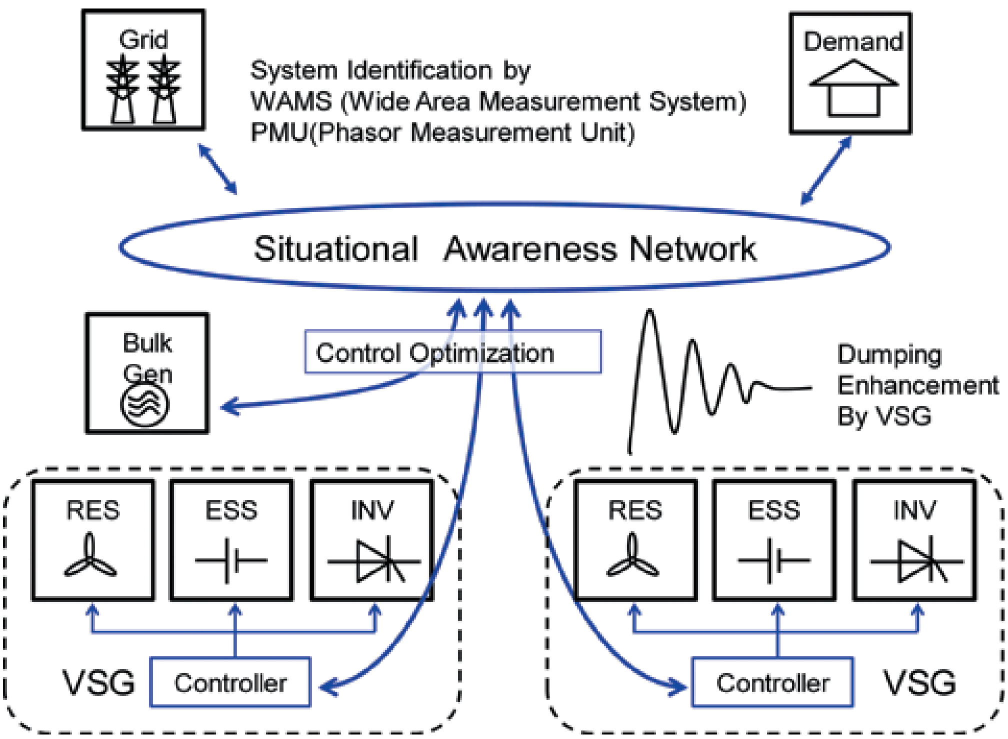


Figure C-4 | Situational awareness

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