INTERNATIONAL ENERGY AGENCY

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System Integration of Renewables

An update on Best Practice

INTERNATIONAL ENERGY AGENCY

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Acknowledgements

This report combines selected chapters from three existing IEA publication, namely "*Next Generation Wind and Solar Power*", "*Getting Wind and Sun onto the Grid*" and "*Status of Power System Transformation 2017*". These are combined to form a comprehensive overview of system integration strategies, while aiming to provide one single and concise publication.

This report was prepared by the System Integration of Renewables (SIR) Unit of the International Energy Agency (IEA). Hideki Kamitatara (RED) managed the preparation of this report with input from Emanuele Bianco and Elaine Atwood (SIR) also contributed to update of this report.

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More specifically, the following chapters were combined for this report:

- Next Generation Wind and Solar Power: From cost to value
  - Executive summary
  - Chapter 2: Next-generation wind and solar power and system integration
  - Chapter 3: Achieving system-friendly VRE deployment
- Getting Wind and Sun onto the Grid: An Manual for Policy Markets
  - Executive summary
  - Grid integration: Myths and reality
  - Different phases of VRE integration
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  - Chapter 5: Topical focus: Evolution of local grids
  - Annex A: Details of technical measures to address power system challenges

Please consult the original reports for detailed acknowledgements.

Comments and questions on this report are welcome and should be addressed to the SIR unit (sir@iea.org).

Executive summary

Wind and solar PV capacity has grown very rapidly in many countries, thanks to supportive policy and dramatic falls in technology cost. By the end of 2016, these technologies – collectively referred to as variable renewable energy (VRE) – had reached double-digit shares of annual electricity generation in fifteen countries. In 2016, VRE share in electricity generation reached nearly 45% in Denmark and about 20% in Ireland and Spain. By 2022, in large power systems like those of China, India and USA, the share of VRE is expected to double to more than 10%.

Despite this evidence, discussion of VRE integration is often still marred by misconceptions, myths and in some cases even misinformation. Commonly heard claims include that electricity storage is prerequisite to integrate VRE and that conventional generators are exposed to very high additional cost as VRE share grows. Such claims can distract decision-makers from the real, though ultimately manageable issues; if unchecked they can bring VRE deployment to a juddering halt.

This report, written for policymakers and staff in energy ministries as well as regulatory bodies, has two main objectives: firstly to clarify the *true* challenges faced in the early days of VRE deployment; and secondly to signal how these can be mitigated and managed successfully. It also provides recent analysis on how to manage VRE integration at higher shares.

It reveals how measures to maintain cost-effectiveness and reliability of the power system differ over four stages of VRE deployment. These phases are differentiated by an increasing impact of growing VRE capacity on power systems, providing a useful framework for prioritisation of tasks, which may otherwise be presented as a wall of challenges at the outset of deployment.

Phase One is very simple: VRE capacity has no noticeable impact on the system. Assuming the system is sufficiently larger than the newly installed solar and wind plants, VRE output and variability go unnoticed compared to daily variations in power demand. Examples of countries in Phase One of VRE deployment at present include Indonesia, South Africa and Mexico; annual VRE shares in these countries reach up to about 3% in annual electricity generation.

In Phase Two, VRE has a noticeable impact, but by upgrading some operational practices this can be managed quite easily. For example, forecasting of VRE plant output can be done so that flexible power plants can balance their variability, along with that of electricity demand, more efficiently.

There is no single threshold in terms of energy share; when a power system will enter Phase Two depends on its own properties. For example, ranging from 3% to almost 15% VRE share of energy, countries in Phase Two at present include Chile, China, Brazil, India, New Zealand, Australia, the Netherlands, Sweden, Austria and Belgium.

It is Phase Three that sees the first significant integration challenges, as the impact of variability is felt both in terms of overall system operation and by other power plants. Power system flexibility now comes to the fore. The term flexibility in this context describes the ability of the power system to respond to uncertainty and variability in the supply-demand balance, in the timescale of minutes to hours, for example providing power from other sources when the wind drops. Today, the two main flexible resources are dispatchable power plants and the transmission grid; but demand side options and new storage technologies are likely to grow in importance in the medium-term. Examples of countries considered to be in Phase Three of VRE deployment include Kyushu (Japan), ERCOT (USA), CAISO (USA), Italy, the United Kingdom, Greece, Spain, Portugal and Germany; the VRE penetration in these countries ranges from around 10% to 25% in annual generation.

New challenges emerge in Phase Four. These are highly technical and may be less intuitive in nature than flexibility, relating instead to the stability of the power system. The stability of a power system is its resilience in the face of events that might disturb its normal operation on very short timescales (a few seconds or less). Countries that are seeing challenges primarily related to this phase include Ireland and Denmark, with an annual VRE share of around 25% to 50% in annual generation.

Recommendations for Phase One of VRE deployment

System integration challenges emerge gradually as VRE grows on the power system. Consequently, it is advisable to enhance the system's ability to absorb VRE gradually. The very first VRE plants can usually be integrated with little or no impact on the system. Transparent and sound technical assessment of grid connection capacity can facilitate integration. A technically competent and neutral body should first be assigned responsibility to assess the technical feasibility of grid integration. Approaches intended for conventional power plants or the use of arbitrary caps should be avoided. Though unlikely in Phase One, it is possible that local grid reinforcement may be needed. Prior to any grid reinforcement, full consideration should be given to alternatives to new lines, for example by configuring VRE plants in a least-impact manner.

The system operator (SO) should refer to state-of-the-art industry standards and international experiences when identifying the technical requirements for connecting the first VRE plants, rather than attempting to reinvent the wheel. International standards should be modified to suit the local context. The SO should start with requirements appropriate to a low VRE share.

Recommendations for Phase Two

Ensuring an appropriate grid connection code is in place

The SO, in collaboration with policy makers and regulators should establish if a new grid code is needed or if an existing grid code should be revised, to accommodate the connection of VRE generators. The SO should gather relevant power system data, and identify appropriate modelling tools in order to establish the technical requirements to be included in the grid code.

Consulting the grid codes of systems with higher VRE shares will help the SO determine if wind turbines and solar PV technology already deployed at scale elsewhere can be employed to help reduce costs. Industry stakeholders and the SO should monitor developments in other power systems, particularly those with large-scale VRE deployment, to make sure that any relevant lessons are incorporated in their own code. Grid codes should be assessed continuously and revised to ensure appropriateness.

Reflecting VRE in power plant operations

Visibility of power plants is integral to the system operator. The transmission of static and real-time data from a sufficient number of conventional and VRE power plants should be required. Statistical methods can be used to estimate the production from small-scale distributed plants (e.g. roof-top solar) to manage large data volumes and associated cost. Additionally, use of VRE production forecasts should be used to optimize operations. Implementation of state-of-the-art, centralised forecasting systems can help inform scheduling of power plants and other operational decisions.

Scheduling of plants and management of operating reserves should be executed close to real-time. System operation planning, often taking place hours before the time of physical delivery of electricity (real-time), should move closer to the time of dispatch to deal with variability efficiently. In particular, shorter scheduling and dispatch intervals should be targeted. Provided liberalised wholesale markets are in place, trading close to real-time including within the day, must be possible.

Market operations must be upgraded to achieve increased levels of VRE. In liberalised wholesale markets, trading arrangements should be upgraded to provide accurate pricing at growing shares of VRE.

- To manage variability: greater importance of higher temporal resolution of price signals, i.e. prices are for short time periods; and greater tolerance of price volatility.
- To manage uncertainty: greater importance of short-term price signals, i.e. prices formed close to real-time, reflecting current supply/demand balance.
- To manage location constraints and modularity: increased importance of spatial resolution of price signals, i.e. electricity prices differ from place to place.

Ensuring sufficient grid capacity to host VRE

Building of new transmission lines should be synchronised with VRE deployment. As VRE deployment grows to scale, new investments in transmission may be required to connect plants. Consideration should be given to how to synchronise the building of both, and how to manage VRE operations if grid construction should lag behind. In addition, existing grid infrastructure should be fully utilized. Where congestion occurs, grid operators should explore opportunities for low-cost approaches to managing constraints, before resorting to the building of new lines.

Two-way power flows in the low- and medium-voltage grid should be incorporated. In systems where small-scale VRE capacity is deployed in a geographically concentrated fashion, ensure that flows “upwards” from the low- and medium-voltage networks towards the transmission grid are securely manageable. This is generally possible with existing hardware, but may require some adjustments. Finally, thorough planning should be conducted well in advance. A systematic approach to grid planning should be developed and implemented at this phase of VRE integration.

Minimising the system impact of VRE

The technology mix can be optimized through careful planning. For example, energy planners should consider the value of deploying technologies with complementary outputs, such as a portfolio of wind, solar PV and run-of-river hydropower. Geographical spread can also improve the value of VRE to the system. While bearing in mind the benefits of wide dispersal of VRE power plants in system operation terms, the immediate opportunity to optimise the use of existing grid capacity should also be examined.

Recommendations for Phase Three and Four

Transforming power system operation and planning to support VRE integration

Integration of VRE requires specific measures to maintain the cost-effectiveness and reliability of the power system, which evolve as VRE deployment increases. Different measures have been employed to address integration challenges. These can be considered according to the specific requirements and objectives of the power system. This report reviews a number of technical and economic measures, especially at higher shares of VRE deployment.

To ensure different measures work in concert, robust and integrative planning is key. In many jurisdictions, increasingly integrated and co-ordinated planning frameworks have played a key role in the cost-effective and reliable accommodation of higher shares of VRE in the power system. This report provides examples of emerging power sector planning practices, including: integrated planning across a diversity of supply and demand resources; integrated generation and network planning; integrated planning between the power sector and other sectors, particularly transport, and heating and cooling; and inter-regional planning across different balancing areas.

Policy, regulatory and market frameworks to support utility-scale VRE integration

Policy, market and regulatory frameworks have a critical role in guiding operational and investment decisions. In the context of power system transformation, the large-scale uptake of VRE challenges traditional policy, market and regulatory frameworks. This is true for nearly all market structures, whether they lean towards more competitive and liberalised markets, or towards a vertically integrated model.

Five broad market, policy and regulatory framework objectives greatly enable the integration of larger shares of VRE in the context of power system transformation:

- ensuring electricity security of supply, including measures to ensure that generator revenues reflect their full contribution to system security
- efficient operation of the power system at growing shares of variable and decentralised generation, including measures to unlock flexibility from all existing resources; improve dispatch practices by moving operational decisions closer to real time, and encouraging efficient energy price discovery through competitive frameworks
- ensuring sufficient investment certainty to attract low-cost financing for capital-intensive investment in clean power generation, including well-structured PPAs for IPP projects
- pricing of negative externalities, including measures to constrain local air pollution or carbon emissions when locally appropriate
- ensuring the integration and development of new sources of flexibility, including from thermal generators, grids, demand response resources and storage.

System Value

Achieving power system transformation successfully also requires a shift in the economic assessment of VRE. The traditional focus on the levelised cost of electricity (LCOE) is no longer sufficient. Next-generation approaches need to factor in the system value (SV) of electricity from wind and solar power. SV is defined as the overall benefit arising from the addition of a wind or solar power generation source to the power system; it is determined by the interplay of positives and negatives. Positive effects can include reduced fuel costs, reduced costs from lower emissions of carbon dioxide (CO_2) and other pollutants, reduced need for other generation capacity and possibly grid infrastructure, and reduced losses. On the negative side are increases in some costs, such as higher costs of cycling conventional power plant and for additional grid infrastructure, as well as curtailment of VRE output due to system constraints.

SV provides crucial information above and beyond generation costs; in cases where SV is higher than the generation cost, additional VRE capacity will help to reduce the total cost of the power system. As the share of VRE generation increases, the variability of VRE generation and other adverse effects can lead to a drop in SV.

System-friendly VRE deployment: maximising the value of wind and solar power

Wind and solar power can facilitate their own integration by means of system-friendly deployment strategies. The fact that VRE is often not seen as a tool for its own system integration has historic reasons. Policy priorities during the early days of VRE deployment were simply not focused on system integration. Instead, past priorities could be summarised as maximising deployment as quickly as possible and reducing the LCOE as rapidly as possible. However, this approach is not sufficient at higher shares of VRE. Innovative approaches are needed to trigger advanced deployment and unlock the contribution of VRE technology to facilitating its own integration.

Key system-friendly VRE deployment measures:

- In all cases, governments should ensure effective integrated planning. A transparent process with clear rules and procedures can ensure that new VRE capacity is introduced at the right time and place while aligning transmission expansion with procurement of VRE can reduce overall system costs.
- Another important action is providing appropriate signals to guide the location of VRE plants. In some cases it may be better to build plants in areas that do not have the best resources, but instead in areas such as near demand centers or in regions where alternative generation options are very expensive.
- Selecting an optimal technology mix is another factor that plays an important role. For example, the output of wind and solar power is complementary in many regions of the world. Deploying a mix of technologies can thus bring valuable synergies.
- Choosing technology that has a stable generation time profile is another way in which system-friendly VRE deployment can be achieved. For example, advanced technology wind turbines can provide a smoother generation profile in comparison to classical varieties thanks to its taller tower turbine design and larger rotor-to-generator ratio.
- Refining system service markets will be critical. Innovative ways to procure system services can allow a more efficient operation of the system at high shares of VRE. For example, providing operating reserves from a combination of VRE resources and Demand-Side Management can be more cost-effective than keeping thermal units online.
- Distributed resources integration will require establishing mechanisms to remunerate distributed resources according to the value they provide to the overall power system. Electricity tariffs should accurately reflect cost depending on time and location.

Evolution of local grids

Low- and medium-voltage grids are changing, away from a paradigm of passively distributed power to customers and towards smarter, actively managed systems with bidirectional flows of power and data. A successful transition will require due consideration of three key dimensions: technical, economic and institutional:

- Technologically, ensuring secure and effective system operation under a high degree of decentralisation leads to new priorities for utilities and regulators. Use of advanced information and communication technology (digitalization) allows for improved visibility and control of systems and has the potential to unlock substantial demand response.
- Economically, the rise of distributed solar PV and the improving economics of batteries call for a reform of retail electricity pricing and taxation. This includes both remunerating distributed resources according to their value and making users of the grid contribute a fair proportion to the cost of shared infrastructure.
- Institutionally, roles and responsibilities are likely to change. One priority is better co-ordination between operators in charge of local grids and those in charge of transmission system operation. In addition, totally new actors, such as aggregators, should be incorporated into the institutional landscape.

Introduction

What is system integration?

System integration

System integration of RE encompasses all the technical, institutional, policy and market design changes that are needed to enable the secure and cost-effective uptake of large amounts of RE in the energy system. Required adaptations are most profound for integration of VRE technologies. Given the prominent role of wind and solar PV in the development of renewables, this report focuses on the integration of these two technologies. The term VRE refers to these technologies unless stated otherwise.

The physical nature of electricity requires that generation and consumption must be in balance at all times. System planning and operation need to ensure this, respecting the technical limitations of all system equipment under all credible operating conditions, including unexpected events, equipment failure and normal fluctuations in demand and supply. This task is complicated by the fact that electricity cannot currently be stored in large quantities economically.

The difficulty (or ease) of increasing the share of variable generation in a power system depends on the interaction of two main factors: the properties of VRE generators and the flexibility of the power system into which they are deployed. Both will be discussed in turn.

Properties of VRE generators

VRE generators have five technical properties that make them distinct from more traditional forms of power generation, i.e. large-scale thermal power plants. First, as already mentioned, their maximum output fluctuates according to the real-time availability of wind and sunlight. Second, these fluctuations can only be predicted fairly accurately up to a few days in advance and forecasts improve greatly if they are only for a few hours ahead. Third, they connect to the grid via power converter technology. This can be relevant in ensuring the stability of power systems, such as following the unexpected shutdown of a generator. Fourth, they are more modular and are deployed in a much more distributed fashion. Finally, unlike fossil fuels, wind and sunlight cannot be transported, and locations with the best resources are frequently at a distance from load centres. Despite these general similarities, wind and solar PV also show a number of differences (Table 1).

The difficulty or ease of integrating VRE into a power system also depends on a number of other factors. It is easier to integrate VRE in systems where power demand and VRE generation show a positive correlation, both in relation to typical daily patterns as well as seasonally (Figure 1), and the flexibility of the power system is crucial for facilitating uptake of VRE.

Analysis by the Council for Scientific and Industrial Research (CSIR) (2016) shows a positive correlation between solar and wind resources and power demand in South Africa, where neither solar resources nor electricity show great seasonality. The moderate increase in wind supply during the winter months correlates with a slight load increase during that period and, more importantly, wind production generally peaks in the evening and at night, complementing solar PV output.

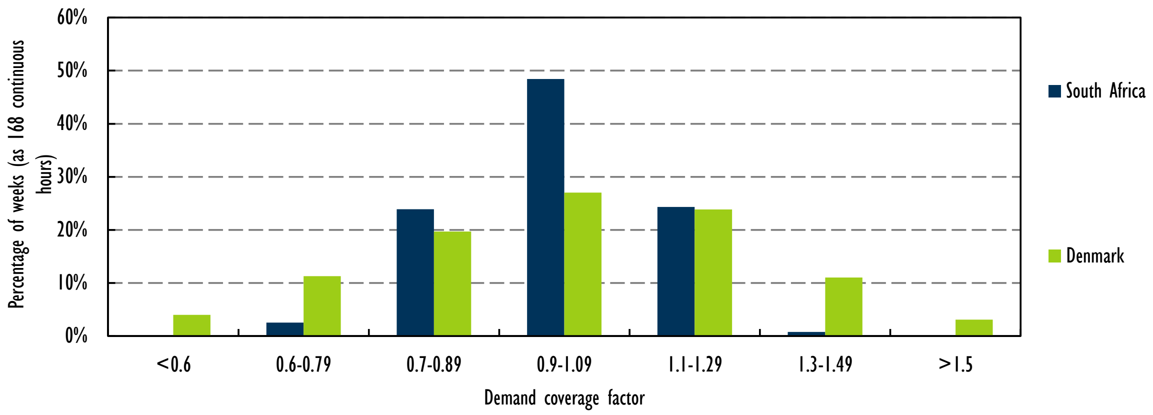
Table 1 • Overview of differences between wind power and solar PV

	Wind power	Solar PV
Variability at plant level	Often random on subseasonal timescales; local conditions may yield pattern.	Planetary motion (days, seasons) with statistical overlay (clouds, fog, snow etc.)
Variability when aggregated	Usually with a strong geographical smoothing benefit.	Once "bell shape" is reached, limited benefit.
Uncertainty when aggregated	Shape and timing of generation unknown.	Unknown scaling factor of a known shape.
Ramps	Depends on resource; typically few extreme events.	Frequent, largely deterministic and repetitive, steep.
Modularity	Community and above.	Household and above.
Technology	Non-synchronous grid connection and mechanical power generation.	Non-synchronous grid connection and electronic power generation.
Capacity factor	Approximately 20% to 50%.	Approximately 10% to 25%.

Key point • Wind power and solar PV share fundamental properties, but show important differences.

Conversely, where the structural match is poor, reaching higher shares is more challenging. Analysis by IEA shows that the correlation between VRE production and electricity demand in Denmark is not highly favourable. The seasonality of the wind in Denmark leads to periods of very low demand coverage as well as to periods of VRE production that is higher than demand. The need to reshape future demand or to cover demand via other sources (flexible generation, interconnectors and storage) is significant in countries with a poor match between VRE generation profile and electricity demand, in order to increase the effectiveness of VRE capacity.

Figure 1 • Demand coverage factors for South Africa and Denmark



Note: See Box 5.1 on page 59 in IEA [2016a] for a description of the demand coverage factor.

Key point • South Africa is naturally endowed with a VRE generation profile more in line with its demand profile than is Denmark.

Power system flexibility

In its widest sense, power system flexibility describes the extent to which a power system can adapt the patterns of electricity generation and consumption in order to maintain the balance between supply and demand in a cost-effective manner. In a narrower sense, the flexibility of a power system refers to the extent to which generation or demand can be increased or reduced over a timescale ranging from a few minutes to several hours in response to variability, expected or otherwise.

Flexibility expresses the capability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand, whatever the cause. It is measured in terms of megawatts (MW) available for changes in an upward or downward direction.

Flexibility will vary from one area to the next, according to natural resources and historical development. In one area, flexibility may predominantly be provided by installed hydroelectric power plants, which are able to ramp output up and down very quickly. A neighbouring area, by contrast, may find most of its flexibility in a combination of gas plants and demand-side management.

Flexibility, in power system terms, is traditionally associated with rapidly dispatchable generators. But balancing is not simply about power plants, contrary to what is often suggested. While existing dispatchable power plants are of great importance, other resources that may potentially be used for balancing are storage and demand-side management or response. Interconnection to adjacent power systems and grid infrastructure can also provide flexibility by smoothing variable generation and linking distant flexible resources together. In addition, flexibility often has several facets. A power plant is more flexible, if it can: 1) start its production at short notice; 2) operate at a wide range of different generation levels; and 3) quickly move between different generation levels. Sources of VRE themselves can also provide flexibility.

Sources outside the electricity sector can also contribute to flexibility. In fact, the growing importance of flexibility may drive stronger links to other energy sectors, such as heat and transport. In the heat sector, for instance, space and water heating augmented by thermal storage systems and co-generation can create opportunities to meet more volatile net load.[1] Electric vehicle (EV) fleets may provide a valuable opportunity for greater energy storage and enable better use of VRE output that is surplus to need at the time it is produced. For example, Denmark has seen an increase in the use of electric boilers in its co-generation plants. These boilers are relatively cheap to install and can greatly increase the flexibility of co-generation plants; instead of imposing a must-run constraint on the system (electricity production as a co-product of heat production) they can consume electricity to supply the demand for heat.

Apart from the technically available flexible resources of the system, the way in which these are operated is critical. Operations need to be designed in such a way that the technically existing flexibility is actually supplied when it is needed. For example, independent audits of thermal generation plants often find ample opportunity to increase plant flexibility. Operational procedures may also directly affect the demand for flexibility. For example, expanding the area over which supply and demand are balanced in real-time (the so-called balancing area) will reduce aggregate variability and hence the extent to which the system needs to be balanced actively.

Different phases of VRE integration

Annex 1 describes why some commonly heard, negative claims about wind and solar are inaccurate, and especially in the early days of VRE. So what then *are* the challenges with VRE integration?

There is no simple answer to this question: no two power systems are exactly the same; and neither are the solar or wind resources of two different countries. Consequently, it is impossible to derive simple rules linking, for example, a certain annual share of wind and solar energy with a specific level of integration effort or cost.

This report defines four phases of VRE integration. These are differentiated by the impacts on power system operation resulting from increasing shares of VRE capacity. Generalisation will

[1] *Co-generation* refers to the combined production of heat and power.

inevitably overlook important subtleties, but provides a useful framework for prioritisation of grid integration tasks, which may otherwise be presented as a wall of challenges at the outset of deployment.

The VRE generation share at which a system can be said to enter a phase depends on a number of circumstances (Box 1).

Box 1 • Principal power system characteristics that determine the extent of integration challenges

Main structural, technical factors:

- Geographical and technical spread of VRE: more diversity means lesser challenges.
- Size (MW demand): larger systems face lesser challenges.
- Match between demand and VRE output (seasonal and daily): a good match means fewer issues.
- Flexibility of power plants (whether thermal, hydro or other dispatchable renewables): shorter start-up times, lower minimum output, and faster ramping (changes of output) means fewer issues.
- Interconnection, storage, and demand response: the greater the presence of each, the more manageable is integration.

System operation, market design and regulation

- System operation: operational decisions for power plants and interconnection should be close to real time operation.
- Market design: the more electricity that is traded on short-term markets the better.
- Technical standards (grid codes): if system services are required of VRE power plants, integration challenges will be lesser. (Such requirements need to be balanced against additional costs to VRE power plants.)

Supply demand fundamentals

- Power demand evolution: growing demand creates opportunities for VRE investment without displacing incumbent generation; future demand can be shaped (to some degree) to fit supply.

Phase One is surprisingly simple: VRE capacity has no noticeable impact on the system. Where wind or solar plants are installed in a system that is much, much bigger than those first plants, their output – and its variability – will go unnoticed.

In Phase Two, the impact of VRE becomes noticeable, but by upgrading some operational practices VRE capacity can be integrated quite easily. For example, one may need to establish a forecasting system to predict VRE output, so that flexible power plants can efficiently balance VRE (and demand) variability.

Phase Three sees the first, significant challenge. In a nutshell, the impact of VRE variability is felt both in terms of overall system operation, and by other power plants. At this point, power system flexibility becomes important.

Flexibility in this context relates to the ability of the power system to deal with a higher degree of uncertainty and variability in the supply demand balance. Today, the two main resources to deal with this are dispatchable power plants and the transmission grid. In some systems, existing pumped hydro storage may also make a relevant contribution. Looking ahead, more innovative solutions such as new storage technologies and large-scale DSR will be effective providers of flexibility.

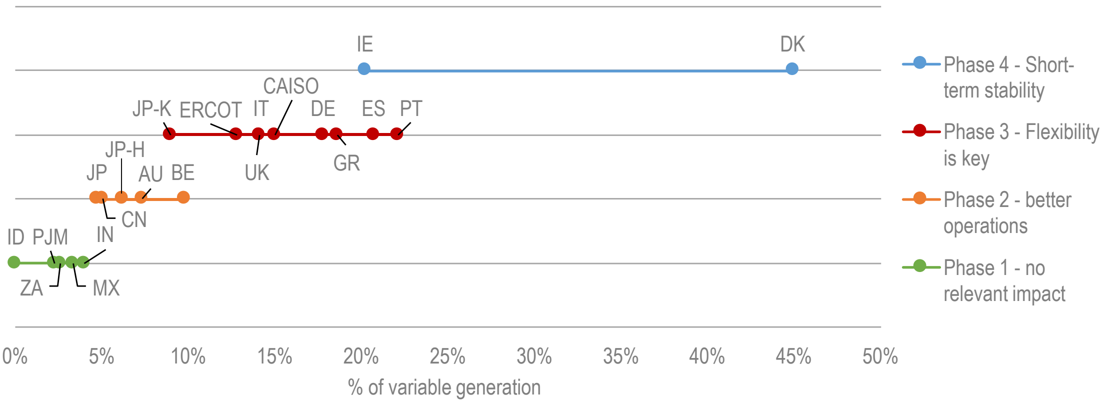
New challenges emerge in Phase Four also. These are very technical in nature and less intuitive than flexibility. They relate to the *stability* of the power system. Simply put, the stability of a power system characterises its ability to withstand disturbances on very short timescales. For example, when a larger thermal generator fails, a stable power system will only see a small deviation from its nominal operational settings. In contrast, in less stable systems, the loss of a large unit may lead to a number of significant impacts that can compromise security of supply, and which play out over a few seconds or less.

The point at which system stability becomes an issue for VRE integration is very system-specific and can depend on engineering decisions that were taken many decades previously. There is therefore no simple rule to say when stability issues will arise.

A power system will not transition sharply from one phase to the next. The phases are conceptual, intended simply to aid the prioritisation of tasks. For example, issues related to flexibility will emerge gradually in Phase Two before becoming the hallmark of Phase Three. Similarly, some issues related to system stability will emerge already in Phase Three.

In order to illustrate the different phases, it can be instructive to examine some examples of when they have arisen internationally (Figure 2). It is often asked, “at what share of VRE will a given integration issue arise”; but it is not possible to generalise. For example, countries presently in Phase Two of deployment feature a VRE share of between 3% and 13%.

Figure 2 • Annual VRE generation shares in selected countries and correspondence to different VRE phases, 2016



Notes: AT = Austria; AU = Australia; BR = Brazil; CL = Chile; CN = China; DE = Germany; DK = Denmark; ES = Spain; GR = Greece; ID = Indonesia; IE = Ireland; IN = India; IT = Italy; JP = Japan; JP-H = Hokkaido (Japan); JP-K = Kyushu (Japan); MX = Mexico; NZ = New Zealand; PT = Portugal; SE = Sweden; UK = the United Kingdom; ZA = South Africa. PJM, CAISO and ERCOT are US energy markets.

Source: Adapted from IEA (2017a), *Renewable 2017.*

Key point • Each phase can span a wide range in terms of VRE share of electricity: there is no single point at which a new phase is entered.

Table 2 • Four phases of VRE integration

	Attributes (incremental with progress through the phases)			
	Phase One	**Phase Two**	**Phase Three**	**Phase Four**
Characterisation from a system perspective	VRE capacity is not relevant at the all-system level	VRE capacity becomes noticeable to the system operator	Flexibility becomes relevant with greater swings in the supply/demand balance	Stability becomes relevant. VRE capacity covers nearly 100% of demand at certain times
Impacts on the existing generator fleet	No noticeable difference between load and net load	No significant rise in uncertainty and variability of net load, but there are small changes to operating patterns of existing generators to accommodate VRE	Greater variability of net load. Major differences in operating patterns; reduction of power plants running continuously	No power plants are running around the clock; all plants adjust output to accommodate VRE
Impacts on the grid	Local grid condition near points of connection, if any	Very likely to affect local grid conditions; transmission congestion is possible, driven by shifting power flows across the grid	Significant changes in power flow patterns across the grid, driven by weather condition at different locations; increased two-way flows between high and low voltage parts of the grid	Requirement for grid-wide reinforcement, and improved ability of the grid to recover from disturbances
Challenges depend mainly on	Local conditions in the grid	Match between demand and VRE output	Availability of flexible resources	Strength of system to withstand disturbances

Equally, two countries may be in different phases though they share the same annual VRE share of energy. One distinguishing factor is the temporal match of VRE output and power demand: the better the match, the easier it is to reach a high VRE share without additional integration challenges (i.e. without entering the next phase).

The usefulness of this simple categorisation comes from the fact that the possible integration challenges can be segmented. We use it here as a framework for recommendations for practical responses to integration challenges as they arise; it is for the readers to identify the phase in which they find themselves.

Phase One – VRE not relevant at the all-system level

Initially the variability of VRE will be insignificant against that of overall electricity demand, and this fact defines the first of the four phases. The system operator (SO) does not need to worry about the operation of VRE plants, as there will be no noticeable difference compared to the situation without them. Many SOs have observed this: the impact of the first VRE plant (except where added VRE capacity is large compared to the size of the system itself) is simply not felt. The impact, if any, will be local, at or near the point of connection.

However, this is not to say that VRE plants can be ignored. It is important to ensure that developers have sufficient visibility on where they can connect to the grid, and that local conditions are such that new plants can indeed connect. Careful attention should be given also to the technical standards relating to the behaviour of the first VRE plants, known as connection standards, grid connection codes, or simply the grid code. Such technical standards are needed for any type of power plant but VRE plants may require a few additional considerations.

Examples of countries that can be considered to be in Phase One of VRE deployment at present include Indonesia, South Africa and Mexico.

Phase Two – VRE becomes noticeable

Phase Two begins as more VRE plants are added to the system and their output begins to become noticeable in system operation. If VRE generation is not metered explicitly, this change will manifest itself as a lower than expected power demand (because some demand is being met by VRE). This lower level of demand is known as "net demand" (also as "net load"). Net demand is the demand for power minus VRE output.

At this point, additional considerations for the grid code become important, with a view to developing a comprehensive framework. This aims primarily to make sure that newly built plants will be able to perform as needed, and during their entire lifetime so as to avoid costlier future retrofits.

Secondly, management of the first occurrences of grid congestion (including on the transmission grid) may be necessary, particularly in areas where deployment is moving ahead quickly.

Thirdly, the least-cost scheduling and dispatch of non-VRE power plants needs to take into account VRE generation. In this phase, the visibility of VRE plants becomes more important and it may be prudent to establish a renewable energy production forecast system. It is relevant to note that even in the absence of a forecast system it is possible to operate the system reliably; it will be more costly however.

Examples of countries considered to be in Phase Two of VRE deployment at present include Chile, Canada, Brazil, India, New Zealand, Australia, the Netherlands, Sweden, Austria and Belgium.

Phase Three – flexibility becomes a priority

As deployment continues, electricity supply is characterised by significantly higher levels of uncertainty and variability, and periods of low net load are observed, particularly at weekends. This requires a more dynamic operation of (existing) dispatchable power plants, while VRE forecasts will become essential for the efficient operation of the system. In addition, power plants may need to be reviewed to determine how flexibly they can be operated, as new operating conditions may differ considerably from the past. Flows of electricity on the power grid become more changeable as they are increasingly driven by passing weather systems, and may be quite different by day and night (where solar PV dominates).

Where deployment of a large number of smaller VRE plants is concentrated geographically, "reverse" flows from the medium- and low-voltage grid up to the transmission level will become increasingly common. Closer coordination between transmission system operators (TSOs) and distribution system operators (DSOs) are important to deal with this. At this stage, there is increasing value in combining the operation of adjacent power systems or balancing areas, where this is possible. This can enable the sharing (and thus overall reduction) of operating reserves, while enabling the aggregation and smoothing of VRE output over a larger region.

Examples of countries considered to be in Phase Three of VRE deployment include Italy, the United Kingdom, Greece, Spain, Portugal and Germany.

Phase Four – power system stability becomes relevant

In Phase Four, it is possible that VRE output covers most or even all of power demand in certain situations. These occurrences are typically when VRE output is at a maximum during periods of low demand, such as at weekends. In temperate countries this may happen during spring months, when wind power and solar PV both may see high output. Run-of-river hydro capacity may add to variable output.

During this phase, new issues come to the fore. In essence, these relate to the ability of the power system to maintain stable operating conditions immediately following disturbances to the system (stability). Among the different issues associated with this phase, the question of synchronous inertia has recently received attention. The term inertia refers to the kinetic energy stored in the rotating mass connected to the generators of large thermal power plants. This rotating mass serves as a type of short-term energy storage. If there is a shortfall in power, generators will experience this as a force acting against their rotation. The combined inertia of the power plants on the system will act against this, keeping the grid stable.

It is important to note that this behaviour is a direct consequence of the laws of physics; it does not require any intervention. And fewer conventional (synchronous) power plants on the system will mean that less inertia is present, so alternative support for system stability needs to be found. This task is a primary objective during Phase Four of system integration.

At this stage, VRE plants should move towards being able to provide all essential reliability services for the grid; only this will allow them to cover close to 100% of power demand on occasions in an entire synchronous grid area (as opposed to a single balancing area).

Examples of countries considered to be in Phase Four of VRE deployment at present include Ireland and Denmark.

Beyond Phase Four

Although only four phases of VRE deployment are discussed herein, further VRE deployment beyond Phase Four is possible. For completeness, the principal characteristics of Phases Five and Six are briefly presented. In Phase Five this is a structural surplus of VRE generation. If left unchecked, these surpluses would result in large-scale curtailment of VRE output, and thus a cap on further expansion. At this point, further VRE deployment is likely to require the electrification of other end-use sectors, with heating and transport being promising options.

Phase Six may be characterised by structural energy deficit periods resulting from seasonal imbalances between VRE supply and electricity demand. Bridging occasional multi-day/week shortfalls of supply (e.g. a long “lull” in wind output) is likely to stretch beyond the capabilities of demand side response or electricity storage, which are stronger sources of flexibility over shorter periods. Ultimately, if VRE is to dominate a power system, it is likely to be necessary to convert electricity into a chemical form that can be stored cost-effectively at scale, for example in the form of synthetic natural gas or hydrogen.

Latitude has an important bearing here: at lower latitudes, it is likely that there will be little seasonality either in demand or in solar PV output, meaning less or no requirement for inter-seasonal storage. In contrast, at higher latitudes there may be a complementary mix of wind and solar output profiles that can help manage seasonal differences in one or other (Figure 21). However, also at higher latitudes, the electrification of heating could lead to a peak winter demand several times larger than summer peak, increasing the need for inter-seasonal storage (DECC, 2012).

Summary of VRE deployment phases

Having summarised the phases, it is worthwhile also to note that certain parts of a large power system may enter a more advanced phase before the rest of the system. This is typically the case where sub-regions exist in the grid, connected to the main grid via interconnectors. One example is South Australia, which is one of the five regions of the National Electricity Market (NEM) in that country.

Also importantly, the correlation of the timing of VRE output with power demand, the smoothening from geographical aggregation, the size and connectedness of the system, and its operator's ability to forecast VRE output, will all determine to some extent when a new phase of integration is reached.

Efficient grid integration of VRE will see measures that are appropriate and proportionate to the deployment phase. In some systems these measures can be implemented using existing assets, in others it may be required to invest in additional infrastructure. In both cases, a failure to keep pace with rising VRE share will lead to greater cost in the long run, and may threaten the security of the power system. Conversely, putting in place excessively high requirements can also increase costs and/or slow deployment.

It is useful to distinguish between measures that are critical for security of supply and measures that are needed for the system to remain cost-effective. To give an example, beginning in Phase Two it is imperative for the system operator to be able to turn off a sufficient proportion of VRE generation. If it is not, security of supply may be at risk. In contrast, the lack of an effective forecasting system may lead a system operator to over-commit other generators and then excessively curtail wind generation – driving up costs. Measures that are critical for security of supply are identified below.

Strategy and planning: The foundation of successful system integration

This report focuses on a set of issues related to the system integration of VRE, and within that set on a subset of issues encountered at an early stage. But integration is itself a subset of wider and longer-term energy strategy; it is essential to have a clear and consistent vision of the amount and type of generation capacity, as well as other system assets such as network and storage, that will be deployed over time. A holistic, long-term view of energy strategy helps market participants and system operators to anticipate changes, which will ease VRE integration in a secure and least-cost fashion.

Central to developing such a strategy is a full understanding of the wind and solar resources available in the area in question. Resource data are available from a number of organisations, including the Global Atlas for Renewable Energy, prepared by the International Renewable Energy Agency (IRENA), which is available publicly. This contains more than adequate detail for energy planning purposes (but not for the development of individual projects) i.e. to provide an approximate understanding of where resources are strongest. Such maps can be overlaid with a map of the existing power grid to indicate where new developments and reinforcements are likely to be most valuable.

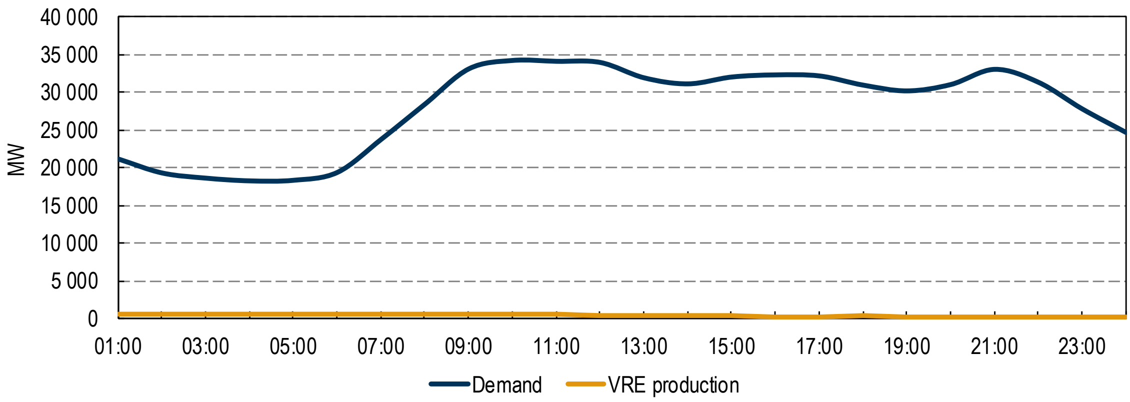
If VRE targets grow as part overall policy strategy, it is important that they should be considered in concert with other energy system developments to guarantee an efficient and effective integration in the grid. Policy makers might ask, "How will this course add to/detract from existing (conventional) power system development needs?" Early adopters on occasion have failed to take this combined approach: for example, European front runners such as Spain, Germany and Italy arguably did not fully anticipate the effects that VRE deployment would have on the operation patterns of the rest of their generation fleets.

The Four Phases approach described herein should be embedded in wider energy planning, to ensure the smoothest and most cost-effective rollout of VRE. In particular, this applies to the measures presented in Phase Two to mitigate adverse impacts of VRE; these centre on choosing the right portfolio of VRE technologies (wind/solar), and on siting them strategically, both geographically (dispersed/concentrated, far from/close to load), as well as in terms of grid voltage (distributed/centralised).

Phase One: VRE capacity is not relevant at the all-system level

Phase One sees the first installations of wind farms and/or solar PV. The overall capacity of these VRE plants is such that their generation never accounts for more than, say, 2-3% of electricity demand at any moment. At this level of deployment, even if VRE output and demand are uncorrelated (as in Figure 3), because their output is so small, it has no effect on system operation. It can be considered simply as negative load[2]. In other words, in Phase One VRE plants do not register in the system operator's main task of reliably maintaining the supply/demand balance, or on the operation of existing power plants (Table 2)[3].

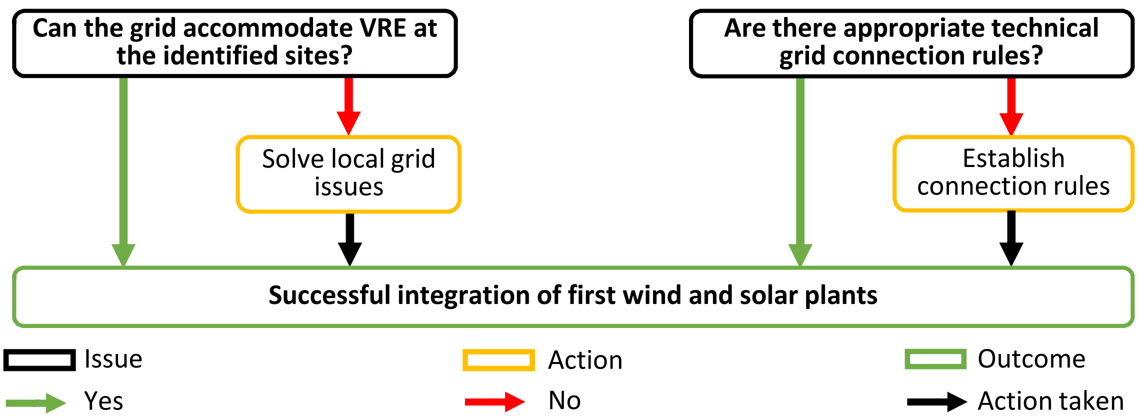
Figure 3 • Demand and VRE production, Italy, 13 April 2010



Source: Adapted from Terna (2017a), *Ex post data on the actual generation.*

Key point • Even if wind output and demand are uncorrelated, in Phase One this will have no impact on system operation.

Figure 4 • Phase One: Summary issues and approaches



Key point • Phase One tasks centre on finding workable solutions to connecting the first plants to the grid.

[2] Negative load in this context refers to the fact that VRE generators can be treated like an unmanaged load, i.e. it is not necessary to schedule their output or to monitor it in detail.

[3] As often, exceptions prove the existence of the rule. There have been instances where single VRE plants have caused issues, including in Hawaii, Honduras or the Springerville PV plant operated by Tucson electric power.

Irrespective of the size of individual power plants, their impact will most likely only be felt locally, close to the point where they are connected. This means that system integration challenges – and hence integration strategies – are limited to their immediate surroundings.

There are two main issues to address at this stage. Firstly, the "hosting capacity" of the grid – whether it can absorb generation from new power plants – needs to be assessed. For example, if a large wind farm is connected to a remote part of the grid, there may be a number of technical issues that need to be resolved so that the grid in that area remains fit for purpose. Secondly, an appropriate set of technical requirements needs to be established with which VRE plants must comply before commissioning (Figure 4).

Box 2 • Kick-starting deployment of wind and solar power

The first questions to ask at the outset of VRE deployment are, "Where will VRE deploy?" and "Are site data available to project developers?" This includes data on available resources, electricity demand and supply, technology costs, and existing electricity infrastructure. Open and publicly available data are crucial for facilitating VRE deployment.

Once a potential wind or solar project has been identified, there are five main conditions that need to be satisfied for it to proceed. The reader should note that not all of the points raised below are strictly related to the grid integration challenge; they are nevertheless included here to illustrate some of the closely related concerns that project developers will face in the early stages of VRE deployment.

Grid connection: obtaining permission for grid connection is a pre-condition for supplying electricity into the grid.

Permitting: a new VRE plant can only be constructed after the right location has been identified and permits have been obtained. Making information available for site selection and streamlining the permitting process is important to facilitate project development. This condition is of particular relevance in Phase One.

Availability of locally adapted technology and human resources: the availability of technology and appropriate standards for VRE technology under country-specific conditions are relevant from the perspective of grid integration. Skilled human labour should be available for the different stages of the project to guarantee the successful installation of the equipment, avoiding hardware failures and cost overruns. Box 3 explains what technology standards are and why they matter.

Off-take agreement: project developers will need to reach agreement with an "offtaker" to be paid for the electricity they produce. Usually in the form of a power purchase agreement (PPA), at a minimum this agreement should specify price and volume of electricity.

Financing: a project can proceed only if it can attract sufficient financing for development and construction phases.

Although all of the above are essential success factors of VRE deployment, this report touches on them only when they are relevant to system integration

Source: IEA (2015a), *Energy Technology Perspectives 2015.*

Can the grid accommodate VRE at the identified sites?

A start to VRE deployment requires that a set of conditions be met (Box 1), and in the following it is assumed that this is the case. At this point, the first VRE plants will need to be connected to the electricity grid. This requires in turn that a functional process exists whereby connection applications can be made, possible grid upgrade requirements determined, and the costs of the latter be covered.

Determining available grid capacity

An assessment of local grid conditions is critical to ensure that VRE plants do not have a negative impact on the local quality and reliability of electricity supply. In principle, determining the technical impact of new VRE plants on the surrounding grid is a straightforward electrical engineering question. In practice, however, a number of complications may arise. For example, where VRE power plants are connected to medium- or even low- voltage grids, it may not be existing practice to carry out dedicated studies for connecting new generation, for no reason other than custom.

Depending on how large the plant is (compared to the loads on the network in that area), and the general quality of the grid, there can be a number of issues to be addressed before a new plant can be reliably connected and operated. Nevertheless, in the majority of cases, smaller VRE plants can simply be connected to the existing grid without difficulties.

Distribution (low-voltage) grids vary widely, and general rules of thumb as to hosting capacity can be inappropriate. In California, for example, a cap of 15% of annual peak demand was set originally on the volume of solar PV electricity that could be accepted by a given distribution feeder, which did not represent what was actually possible in many cases. This flat cap has since been replaced with a highly granular approach, which features an online portal at which interested parties can check the hosting capacity of individual feeders (distribution lines). A similarly refined approach in Hawaii has enabled the deployment of solar PV to leap to 250% of minimum daytime load over the last few years.

This step forward reflects a move in some places to a more empirical basis for the assessment of hosting capacity. In the USA, this move has been led by the Electric Power Research Institute (EPRI), together with Sandia National Labs and the National Renewable Energy Laboratory (NREL). The empirical approach considers a range of factors such as distance (of VRE capacity) from the distribution substation, and the presence of mitigating technologies, such as inverters with advanced functions, feeder reconfiguration, and PV power factor setting (NREL, 2016a).

Large wind farms or solar PV plants will tend to connect directly at the high-voltage level. Here, a mechanism will almost always be in place to determine in detail what the impact on the grid will be locally, and if any mitigation measures are required. Often these consist of agreeing on an appropriate set of technical operating parameters for the new plants.

Although grid companies may have the capability to carry out such an analysis, it may be preferable for this exercise to be carried out/validated by a neutral party with no interests in generation or grid asset ownership. This will avoid the chance of bias, either from the perspective of project developers or grid companies. There are a number of well-established engineering firms that provide such services using standard software packages. The firms that eventually carry out the exercise should coordinate with grid companies and project developers to obtain necessary information about the grid and the VRE plants under consideration.

Managing possible upgrade requirements

In Phase One, it is unlikely that grid reinforcement will be required to accommodate the connection of the first few VRE projects. In the (already quite unlikely) case that issues do emerge it is worth noting that there may be alternatives to new grid assets that may be more cost-effective. These options include, for example, transmission system capability and efficiency improvements; enhanced system controllability using additional transmission system devices such as Flexible AC Transmission Systems (FACTS); and special protection schemes. As these options are more pertinent to Phase Two of VRE deployment, they are discussed in the next chapter in more detail.

In one case in particular significant costs may be incurred at the outset of deployment: where the VRE plants are in an area with high quality wind/solar resources, but which is remote and so requires a long line to connect it to the grid.

And it may be that several developers wish to exploit that strong resource, in which case each may build its own connection to the grid substation, resulting in a “guitar strings” configuration, i.e. unnecessary duplication. Alternatively, one developer may build and shoulder the cost burden, while others wait to take advantage (known as “first mover disadvantage”).

If the question is not resolved, VRE deployment may stall altogether. Alternatively, smaller developers unable to manage the cost of connecting their own “guitar string” may be squeezed out with the result that only very large projects remain viable.

Two solutions have been employed in recent years: 1) developers share the cost (in which case, how this arrangement is designed is a further complexity) and the operation of the line is fully transferred to an independent ISO/DSO; or 2) the public purse pays for the connection, the cost of which is then recovered equitably from electricity consumers or tax-payers.

Are there appropriate technical grid connection rules?

Appropriate technical grid connection rules are critical to ensure that VRE plants do not have a negative impact on the local quality and reliability of electricity supply.

All modern wind and solar PV power plants differ from conventional generators in that their operational behaviour is controlled via software programmes. This is both an opportunity and a challenge for ensuring stable operation of the system. The opportunity lies in the ability to configure a fairly broad range of responses from VRE power plants in response, say, to a disturbance on the grid. The challenge is that it may not be a simple task to spell out all desirable technical requirements tailored to specific system needs, and without unduly increasing the cost to their owners. Finding the appropriate trade-off is a key role of the grid code, which becomes increasingly important as the penetration of VRE grows. Annex 2 considers grid codes in some detail.

But at the very beginning of deployment, simplicity is best. Getting the first VRE plants onto the grid should not be delayed by the complex, stakeholder-heavy process usually accompanying the development of a full grid connection code. Instead it is sufficient to require state-of-the art capabilities from wind and solar power plants that meet the “must-have” requirements of the system operator (as specified in Annex 2).

It is also advisable to launch the process of grid code development sooner rather than later, so that a comprehensive set of rules is in place when it is needed.

Box 3 • VRE technology standards

Effective deployment of VRE begins with assurance of technology quality. Internationally recognised standards apply to all major components. Quality is important although it may not be necessary to have the very latest of cutting-edge technology; the most advanced wind turbine models and inverter models may not necessarily be appropriate in a market just setting out to deploy its first VRE plants.

Developers and policy makers need to be comfortable that the equipment being provided is appropriate for the territory in question (humidity conditions, hub height for wind turbines, cleaning devices for PV, etc.). It is important that initial experiences are positive so that all related parties feel confident that a maximum of energy is being harvested for the capital expended.

Inappropriate equipment can have grave consequences for performance. At the outset of wind deployment in Brazil, for example, European- and US-made equipment was used. This had been designed to suit the climatic conditions in their home markets, but had mechanical difficulties in the warm, humid climate of Brazil, encountering winds that tend to be stronger and in some cases more saline. The Brazilian system operator indicated that by 2014 13% of wind turbines were under-performing, although it was uncertain as to what degree other factors such as inadequate operation and maintenance (O&M) skills drove this.

Standards may be used to support policy making, although they are more commonly used by the market to ensure quality and interchangeability of power plant components. They include those prepared by the International Electrotechnical Commission (IEC) and the International Organisation for Standardization (ISO), and represent international consensus on a solution to a particular technology issue, such as a wind turbine's ability to withstand strong gusts of wind, or to provide high quality output so as to satisfy the requirements of a grid code.

Such standards ensure that the buyer is getting what was expected, but they do not cover the needs of the system operator, who will need to ensure that the electricity exported from the power plant is of a suitable quality to play its part in upholding the network. This is the territory of the Grid Connection Code, an aspect covered in detail in Annex 2.

Source: Spatuzza (2015), *Brazilian wind's big problem.*

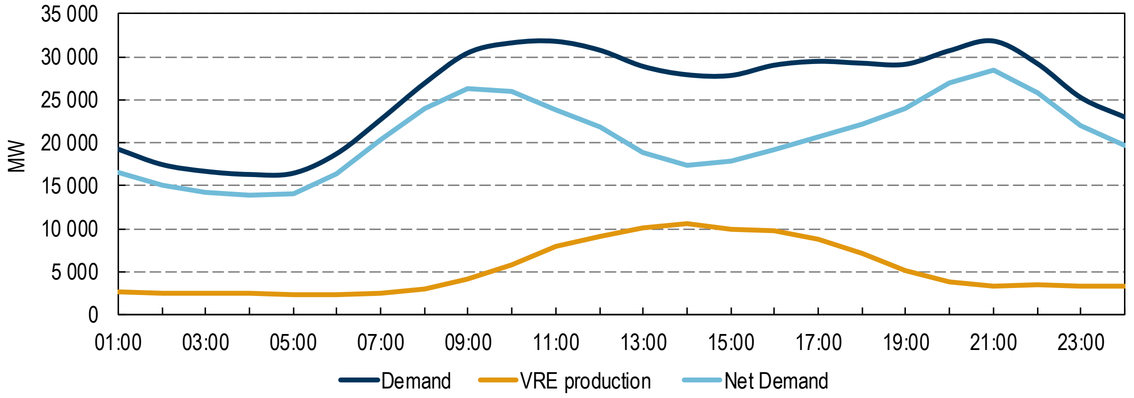
Phase Two: VRE capacity becomes noticeable to the system operator

As the number of wind and solar power plants grows on the system, their output will begin to have a more systematic impact on the supply-demand balance of electricity. In order to gain a proper understanding of this impact, the concept of net demand (or net load) is central.

What is net load?

Wind and solar PV output is limited by how much wind or sunlight is available at any given moment. In addition, once built, as they have no fuel costs, the cost of generating electricity from these plants is very low, in some cases close to zero. For these two reasons, it will be generally most economic to use whatever electricity is available from VRE as a priority. This means that the other resources on the power system – primarily dispatchable power plants but also storage, demand response and interconnections – will be needed to meet the demand that remains after VRE output has been accounted for. "Net demand" is simply obtained by subtracting VRE output from power demand (Figure 5).

Figure 5 • Demand, VRE production and net demand, Italy, 13 April 2016



Source: Adapted from Terna (2017a), *Ex post data on the actual generation*.

Key point • Net demand is obtained by subtracting VRE output from power demand.

Phase One is characterised by a situation where there is no relevant difference between load and net load. The transition to Phase Two is signalled by structural change in the net load curve. One might also expect at this point that there would be significant increase in uncertainty and variability of net load (as compared to total load). However, this is often surprisingly slight.

For example, many power systems show elevated electricity demand during daytime, so solar PV output will tend to match this shape well, with the result that net load may in fact be less variable overall. As for wind power, though generation is driven by often very variable weather, the impact in terms of variability and uncertainty tends to be generally insignificant compared to that of the load itself.

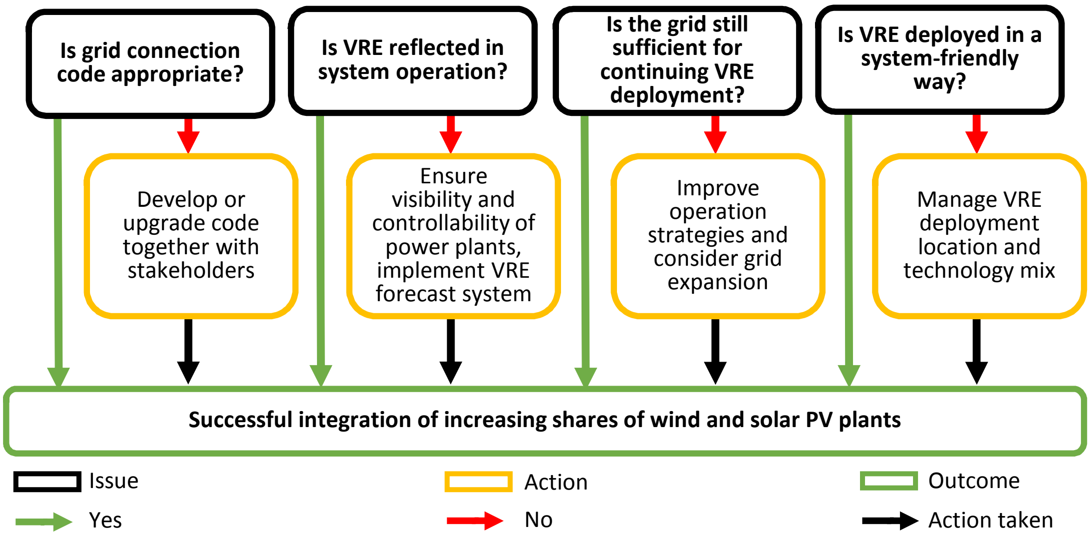
Phase Two lasts until maintaining the supply-demand balance is structurally more challenging, as briefly introduced in the next chapter. In contrast, during Phase Two it is very likely that gradual upgrades to the traditional way of operating the power system will be sufficient for successful integration.

New priorities for achieving system integration

The priorities from Phase One remain relevant throughout Phase Two: ensuring that new power plants can connect to the grid without a negative impact on the local grid environment, and that VRE plants meet state-of-the-art technical standards.

New priorities also arise, all connected to the fact that VRE generation now begins to affect the power system more broadly. These fall into two baskets: those relating to the grid, and effects on the (existing) fleet of power plants. Finally, a third set of new priorities relate to the way in which VRE is deployed, to mitigating possible adverse grid impacts (Figure 6).

Figure 6 • Phase Two: summary issues and approaches



Key point • VRE deployment begins to have some impact in Phase Two.

Is the grid connection code appropriate?

Already in Phase One, appropriate rules for grid connection are a critical need. As the impact of VRE power plants rises on the system during Phase Two, a more systematic approach to grid connection code development is required. This includes identifying appropriate requirements for the technical capabilities of VRE plants, and putting in place mechanisms to ensure that these are adhered to in practice. Due to the major importance of this topic, a detailed discussion is included in Annex Two. A recent report by the International Renewable Energy Agency (IRENA, 2016) can be consulted for further detail.

Establishing appropriate grid connection codes is imperative for reliable integration of VRE during Phase Two and beyond. Failure to do so is likely to undermine the reliability of the power system.

Is VRE output reflected in system operation?

In Phase Two, the output of VRE plants changes the shape of the net load, with the result that their output will have a varying impact on the amount of electricity required from non-VRE power plants to meet demand. In order to ensure a continued secure and economic operation of the system, effective processes are increasingly needed that can reflect the varying contribution of VRE in the day-to-day operation of the system.

Familiarising the system operator with VRE technologies is a primary objective, and will reduce the latter's tendency to curtail VRE unnecessarily. The SO is likely to be accustomed to conventional thermal, and perhaps hydropower, plants. Most conventional plants are dispatchable, which means that their output can be increased and decreased as and when needed, subject only to fuel supply, operational lead-times and contingencies. Therefore the SO may well have concerns about the variability and uncertainty of supply from wind and solar power plants.

It is a well-known principal of system operation that prudent management requires sufficient information to assess the current and future state of the system (visibility), and to have appropriate tools to act on this information (controllability). In practical terms, this requires four elements to be in place regarding power plant dispatch. The first two relate to visibility, the third and fourth to controllability.

- Visibility of a sufficient number of power plants to the system operator, including VRE.
- Implementation and use of VRE production forecasts.
- Scheduling of plants, management of interconnections with other balancing areas, and management of operating reserves according to load and VRE forecasts (in systems that have undergone market liberalisation this will likely require changes to market design).
- Ability on the part of the system operator to control a sufficient number of plants close to and during real-time operations.

Visibility of power plants to the system operator

Sufficient visibility of VRE output is crucial for maintaining security of supply at growing shares of VRE.

A central element in ensuring visibility of system conditions is adequate information about the power plant fleet, both renewable and conventional. As VRE deployment enters Phase Two, the "visibility" of VRE plants becomes essential to operate the system reliably and at least cost. This visibility takes the form of live (real-time) communication of data describing their output, delivered to the SO.

Both static and operational data should be provided. Static data include, for wind turbines for example, hub height, rated power, and power curve. A supervisory control and data acquisition (SCADA) system collects and enables analysis of the operational data of a power plant. An appropriate technology choice is required to ensure that the right data of the right quality can be made available to the system operator as the basis for forecasting activities. If the SCADA is of insufficient quality, or cannot accommodate a sufficient number of measurements, then this very important exercise will be jeopardised and it may be necessary to update existing SCADA systems.

Management of these data may represent a challenge: the volume will be large and a conventional control centre may not be adequately equipped to manage it. However, tried and tested packages exist that are designed to receive and process such data.

It is worth pointing out that sufficient visibility of VRE plants does not mean that every single plant needs to be monitored in real-time. For example, it is generally not cost effective to install real-time data monitoring systems in small-scale solar PV systems. Rather, one can install such devices on a representative set of systems and then compute and aggregate real-time output. This is common practice in systems that have very high penetration of distributed solar PV, such as Germany.

Depending on what systems are already in place for conventional power plants, it may also be required to upgrade their monitoring. With growing impact on the operation of conventional power plants over time, it becomes increasingly important that the system operator be fully apprised of their capabilities, able to monitor their operating state (e.g. offline, at maximum, at minimum). This will enable planning of changes to their output (dispatch) to keep pace with weather patterns, the resulting behaviour of VRE plants, and fluctuating demand.

In due course, the system operator should have data for every unit (i.e. not just the overall power plants), both operational and static[4], the granularity of these data refining as VRE share grows. For example, the output of a coal plant metered at its grid connection point gives little idea as to the operating state of individual units within the plant. Gathering these additional data may imply a considerable workload.

Forecasting of VRE output

System operator oversight of VRE data, gathered by SCADA and delivered in real-time, provides a basis for predicting likely plant behaviour up to twenty or thirty minutes ahead – a technique known as persistence forecasting. A more comprehensive suite of forecasting tools is needed however to provide a confident picture of net demand, on which basis dispatchable power plants and other system resources can be scheduled on the day-ahead and several hours before real-time operations.

Output forecasts attempt to predict the output of a power plant at points in the future. This will allow the changes (ramps) in that output to be predicted, which lies at the core of the system operator's work. A number of tools are used to forecast VRE output, on time horizons that range from a few minutes to several days ahead. These tools need measured data and are based on physical and/or statistical modelling.

Measured data sources include weather stations, satellite data, cloud and sky observations, and VRE system data. Modelling is based on numerical weather prediction (NWP) models, which also form the basis for wider weather forecasting. Forecasts based only on measured data are most accurate up to 1-3 hours ahead, while NWP methods are essential for further ahead.

To forecast the output of a specific wind farm, numerical weather prediction data is needed. For the statistical modelling part, at least six months of NWP data (e.g. wind speed and power output) is needed. The physical part of the exercise requires information on the terrain and geometry of the wind farm to enable a detailed simulation of wind flow across the site, including wake effects (the effect on the wind resource "seen" by a wind turbine that is downwind of another).

To create a *system-wide* forecast, data from a representative set of wind farms is scaled up using statistical/empirical analysis of historic power production. The wider the pool of VRE power plants from which the SO receives data, the more accurate the overall forecast will be. But time may be needed for new processes to take root in the SO; and it may not in any case be necessary to have forecasts from all VRE power plants. Germany for example generated over 20% of its electricity from wind and solar PV in 2015; its four system operators reportedly receive data from in the region of 800 wind power plants, from which the output of the complete portfolio is extrapolated.

System-wide forecasting provides a very much more accurate perspective on VRE output. For example, in Germany, the uncertainty of countrywide wind power forecasts is around 2-3 % of

[4] Static data are the fixed parameters of the unit including, *inter alia*, its rated capacity (MW), minimum stable operating level, the speed with which it can change output (ramp rate in MW/minute), and start/stop times.

installed capacity, while it will range from 10% to 30% for a single wind farm[5]. Other important factors include proximity to real-time (forecasting is generally more accurate closer to real time); and the geographical area for which total VRE generation is forecast (the wider the better).

Scheduling power plants, managing interconnections, operating reserves

Operational decisions for power plants are taken on a range of timescales up to real-time; sometimes these decisions are made by a market operator determining schedules based on bids received; sometimes the operator of the plant decides how it will be dispatched (e.g. self-scheduling in markets or vertically integrated utilities).

First, a decision has to be made whether to turn on (commit) a unit. This decision will be needed earlier for some technologies than others: it takes a few hours to start most mid-merit power plants, while peaking generation can be brought online typically in less than 30 minutes. In addition, the exact output level of the plant needs to be decided somewhat in advance (often referred to as power plant dispatch), and this is fixed for each power plant for a given time interval (the dispatch interval) (IEA, 2014).

Technical constraints call for a certain degree of forward planning with regard to unit commitment and power plant dispatch. But in practice many power systems tend to lock in operational decisions well in advance of when they are required from a technical perspective, weeks or even months ahead. This is often for economic reasons. Thus long-term contracts between generators and consumers may prevent power plants from providing flexibility to meet changes in net load cost-effectively. This is undesirable for least-cost operation of the system *as a whole*, in particular at growing shares of VRE penetration.

In summary, scheduling practice should ideally:

- Allow for frequent schedule updates as close as possible to real-time (up to five minutes before real-time is best practice).
- Aim for short dispatch intervals (five minutes is current best practice), while deciding the dispatch "looking ahead" several dispatch intervals.
- Avoid locking in power plants over the long term with physically binding generation schedules (best practice is an obligation to make generation capacity available in the short term to the greatest extent possible).
- Include grid constraints when optimising generation schedules.
- Co-optimise generation schedules with provision of system services.

The points above can be implemented equally in liberalised, unbundled market frameworks as in vertically integrated systems, although the actual mechanisms used will differ.

In addition to planning the operation of dispatchable power plants, growing shares of VRE have important implications for system services and related markets. Determining the size of system reserves needs to strike a balance between security of supply and cost. Currently prevailing practice employs quite simple, deterministic rules to establish necessary reserve levels. Usually, the bulk of reserves are kept to handle the loss of the largest system component (power plant or transmission line). An equivalent amount is kept both as instantaneous reserve and as slower, manually activated reserve. In addition, reserves are held against the needs of normal system operation, such as load forecast errors, and load variability inside the dispatch interval.

[5] In terms of RMSE – root-mean-square error, also known as root-mean-square deviation, a standard measure in predictive modeling.

VRE brings additional uncertainty to power system operation. However, this is generally not correlated with load uncertainty or generation outages. In other words, a generation outage event, an extreme load variation, and a major change in VRE output are unlikely to occur simultaneously. It is therefore crucial to consider all these risk factors together when establishing the need for reserves, as opposed to allotting reserves for each in isolation. A systematic analysis of historical wind and solar output supports informed decision-making. For example, Xcel Energy in Colorado in the United States conducted such analysis to establish reserve requirements, and methodologies to support this are well established (IEA Wind, 2013).

Another important element when setting reserves is that VRE output presents differing levels of uncertainty at different times and at different levels of output. This means that as VRE gains a larger share in the power system and becomes relevant to setting reserves, the overall reserve requirement will come to differ from day to day. More reserves are needed at times of high uncertainty, for example on windy and cloudy days, than on still and clear days, when fewer reserves would suffice. This so-called dynamic reserve allocation becomes more important as VRE share rises.

The use of interconnections (transmission lines) linking adjacent balancing areas is significant in terms of reserve allocation. If VRE generation is contained within small balancing areas isolated from neighbouring areas, then VRE output in each will be more variable than the aggregated whole across all areas. Rather than benefitting from the passive smoothing of output over a wider grid network, a larger amount of active local balancing, using other generators, storage and demand response, will be needed in such cases. And indeed a lack of cooperation can lead to a perverse duplication of effort, such as when one area activates upward reserves while its neighbour is activating downward reserves.

This issue has been addressed successfully in the German power system. For historical reasons, Germany has four different balancing areas. Until December 2008, these were operated independently, leading to the perverse outcome described above (reserves activated in opposite directions in neighbouring balancing areas). Following a multi-step protocol, the four TSOs first co-operated by allowing for netting out imbalances across balancing area borders, rather than activating reserves in opposite directions (IEA, 2014). Following this first step of not "balancing against each other", co-operation was expanded towards a common balancing market.

More generally, the way in which flows over interconnectors are scheduled should follow the same principles as set out above for generation – making sure that technically available flexibility is successfully mobilised.

Controlling plants close to and during real-time operations

Knowledge of operating state is only useful if the SO can act on that information. A growing share of VRE generally requires more advanced SO control, to be able to take into account the latest data, including accurate VRE production forecasts.

In many systems, automated generation control (AGC) may be in place, but in a number of markets, communication between the SO and power plant operators is still by telephone, in which case monitoring and direct control of generators is impossible. In such circumstances upgrading control capabilities – e.g. to AGC – will generally be advisable.

Even though it is unlikely to be needed earlier on, curtailment of VRE may be needed in contingencies, for line maintenance, and on other occasions. Curtailment needs to be planned for; rules should be established at the outset to avoid future conflict, and to allow VRE plants to adapt accordingly. As a general principle, the degree of control over individual VRE assets by the system operator should evolve in line with VRE deployment. While initially VRE assets do not pose significant issues for system operation, as their output comes to change the shape of the net load it will become necessary for VRE assets to be able quickly to adapt their output on the signal of the system operator. Note that the SO may not need to have direct control over individual plants, but can instead rely on plant operators to execute dispatch signals.

The SO may aim to have control over total production, in which case VRE output can be curtailed to an instructed level. The pace of change (ramp) of VRE output (in MW per minute) and the duration of such ramps may also be controlled. Methods of controlling ramp rate include inverter technology for solar PV, and a coordinated pitching of wind turbine blades, to dampen the effect of sudden changes in the weather. The Spanish system operator's control centre for renewable energy (CECRE) has played a major role in that country's leadership in terms of VRE integration (Box 4).

It is worth pointing out that achieving the same system-wide solar PV penetration with a very large number of very small-scale systems can be more challenging than doing so with a smaller number of larger installations. This is partly because it is more difficult to implement the same degree of controllability on smaller systems, and state-of-the-art rooftop systems also are less sophisticated generally than larger plants when it comes to providing supportive system services.

Faced with a very large number of very small-scale systems, Germany for example is moving towards a requirement for more sophisticated capabilities from even these. This is being done through reforms to its grid code (the VDE-AR-N 4105 Application Guide for the Connection of Distributed Generation to Low Voltage Networks).

The ability of the system operator to control a sufficient amount of generation capacity, also VRE, is crucial for maintaining security of supply at growing shares of VRE.

Box 4 • Spain's control centre for renewable energy (CECRE)

The Spanish System Operator established a control centre within its main system operation centre, in 2006, initially to better manage a swift rise in wind capacity, and later to manage solar PV and CSP also. The CECRE consists of an operations desk at which operators supervise RE production on a continuous basis, with the objective of maximising RE production while maintaining system reliability. From the CECRE all large VRE power plants can be controlled, if necessary, through Subsidiary Generation Control Centres around Spain which also collect real-time data and channel these to CECRE.

Figure 7 • CECRE's control room

Source: REE (2016), *Safe integration of renewable energies.*

Is the grid still sufficient for continuing VRE deployment?

In Phase One of VRE, the importance of early identification of weaknesses in the grid was raised from a connection perspective. In Phase Two, it is very likely that additional grid issues will emerge, and it is possible that concentrated deployment may result in network "hotspots", where grid related challenges are magnified.

For example, the province of Foggia in southern Italy accounts for only 2.4% of Italy's land area, but by 2014 was host to 22% of the country's installed wind power capacity (GSE, 2015). Such concentrations may be caused by a variety of factors, both economic and non-economic, and it may be necessary to look for regulatory barriers (elsewhere) or local drivers that contribute to concentration. In this particular case, dealing with such concentrated deployment required investments in new grid infrastructure.

In the following sections a number of frequently encountered issues are presented alongside examples of how these have been resolved.

Synchronising build-out of new transmission lines with VRE deployment

In Phase Two, VRE deployment may rise to the point at which the grid's ability to host more VRE capacity becomes exhausted in certain areas. This may be because there was little surplus capacity to begin with, or because the area in question is particularly attractive to VRE developers for some reason unrelated to the grid, and new VRE crowds in.

In Brazil, for example, some 2 GW of newly built wind plants were standing idle in 2013 due to insufficient grid capacity. Wind power plants were receiving payment for electricity that they would have generated in line with a signed PPA, but were unable to feed into the grid. This was because under earlier auction rules, winners were chosen on the basis of electricity production cost, regardless of project location. Consequently, successful projects were simply those that achieved least cost to their owners, regardless of proximity to demand centres or the grid. The lead-times for subsequent connection of these wind plants resulted in completed wind power plants being unable to connect to the grid.

Since then, the risk of such delays has been borne by wind developers: if a wind plant is unable to generate, it will not receive the agreed payment. By the end of 2015, only some 300 MW of wind capacity were waiting for connection. As a result of connection issues, more recent wind power projects have tended to be sited close to existing grid. At the same time, in order to participate in an auction a wind power project must include the transmission element.

In China, up to 2011, wind power plants with capacity of less than 50 MW were approved by local government. Consequently, a large number of plants (each of 49.5 MW) were approved without due consideration of planned grid expansion. The rapid deployment of wind generation outpaced grid expansion, with the result that some wind plants could not be connected. The National Energy Administration (NEA) addressed this problem in August 2011, since which time, in order to obtain the building approval, developers must have in place an agreement with the relevant grid company. This decision has significantly reduced idle capacity.

In Texas, zoning has been used to plan the location of wind power plants to optimise grid development. The Public Utilities Commission of Texas (PUCT) designated Competitive Renewable Energy Zones (CREZ) in 2005, in order to break an impasse between deployment of new transmission and the building of wind farms, each of which activities was hindered by the absence of the other. Five zones covering much of West Texas were selected and the PUCT selected from among several options a plan to build new 345 kV lines to accommodate an additional 11.5 GW of wind power generation capacity. The success of this approach was the fact that transmission expansion could be started ahead of constructing generation plants, ensuring that it would be ready in a timely fashion.

Best use of existing grid infrastructure

Just as the ability of the grid to accommodate new VRE capacity may be constrained at the point of connection, so it is also possible that bottlenecks in the grid – limited capacity of a line or substation for example – may constrain the transmission of power from the point of VRE connection to demand centres (e.g. cities and factories).

Also referred to as grid "congestion", such weak spots usually reflect lines that have a lower capability to transmit power than the surrounding grid, and/or that they carry an amount of power close to their thermal limit; in any case electricity is prevented from reaching consumers on the other side of the congestion. As a consequence, the output of power plants on one side may have to be curtailed, while on the other side others may have to be ramped up.

Such "re-dispatching" of plants is likely to be suboptimal in general, but where a (low/zero cost) wind or solar plant is curtailed on one side of the bottleneck while a fuel-based power plant is re-dispatched upwards on the other, the loss is more serious.

Grid congestion is similar to limited grid connection capacity, as discussed above, in that bottlenecks are likely to occur as a result of the deployment of new (VRE) generation capacity in parts of the grid that have previously seen limited or no locally connected power plants. The wind resource can differ quite dramatically across the area linked by a grid. This variation is likely to be less in the solar case although local topography and vegetation may still have bearing. This irregularity of resource means that the existing grid may not be best placed to harvest wind energy, or may be weaker (able to transport less electricity) where the wind resource is stronger.

Reinforcement – uprating of lines for example – will be necessary to manage serious congestion of the grid, but opportunities to disperse VRE power plants geographically (geo-spread) and to smooth their output over time (technology spread), thus making better use of existing surplus capacity, should be fully explored at the same time as considering measures to manage existing and emerging bottlenecks. Assessing the costs and benefits of reinforcing the network through modelling would provide clarity to these decisions and justify new reinforcements.

Before considering grid reinforcement, energy planners should undertake an analysis to identify weak spots in the existing infrastructure that may cause bottlenecks. There are various tools that can be used to strengthen weak spots without large-scale grid reinforcement; some of these are listed below.

- **Dynamic line rating**. A transmission line is rated at a certain capacity to carry power. This rating is usually fixed at a set level over time. However the actual ability of a line to carry power is influenced by temperature: at lower temperatures the real capacity of the line is likely to be higher than the rating. Dynamic line rating takes into account changing line temperature over time, and can therefore avoid/delay the (more expensive) replacement of the transmission equipment with equipment of a higher technical specification.
- **Flexible AC Transmission Systems (FACTS)**. FACTS are power electronic devices that can enhance the controllability and stability of the power system, increasing its ability to carry power by flexibly modulating the reactive power injected or absorbed at a given grid node.
- **Line repowering.** Lower capacity lines may have their conductors replaced with ones that can function at higher temperatures and are thus able to carry more power.

Some of these options are illustrated in Box 5. Further information relating to methods of AC grid optimisation can be found on the website of the European Union "Best Paths" Project[6].

[6] See http://www.bestpaths-project.eu.

Box 5 • Managing weak spots in the grid

Dynamic line temperature (DLR) monitoring has been used effectively on the Swedish island of Öland, which has seen significant deployment of wind power in recent years. The addition of a further 48 MW wind farm, based on traditional static rating of existing lines, would have resulted in an estimated spend of USD 9-16 million on new transmission equipment. However the implementation instead of line-monitoring in real-time identified up to 60% greater capacity during windier (cooler) periods, obviating the need for an upgrade, and resulted in an estimated spend of only USD 750 000.

Traditionally, grids have been planned in a way that allows for the loss of major lines or other hardware by building in redundancy. Contingency management using this so-called "n-1" criterion has the disadvantage of adding considerable cost, although it results in high reliability. More recently a "corrective" approach has emerged in contrast to the "preventive" approach. This employs special protective schemes (SPS) to manage specific parts of the network where contingencies may occur. SPS have been employed in Italy and New Zealand, for example.

FACTS have been employed in many grids. In Denmark, for example, solenoids and/or condensers installed midway on the line have been used successfully for reactive power compensation. This works by reducing the need for reactive power on a line, increasing the line's ability to carry active power.

Lines incorporating high temperature low sag (HTLS) conductors were introduced in the Irish network in 2010. The objective at the time was to uprate 1 000 km of transmission lines by 50%. The traditional approach of building new lines is often delayed by long permitting lead-times as well as opposition from local groups on aesthetic and environmental grounds. Rewiring with high temperature conductors enables uprating without resorting to the building of new transmission corridors.

Source: NREL (2015a), *The Role of Smart Grids in Integrating Renewable Energy*; IEA RETD (2013), *RES-E-NEXT, Next Generation of RES-E Policy Instruments*; Geary et al. (2012), *Introduction of high temperature low sag conductors to the Irish transmission grid.*

Dealing with two-way power flows in the low- and medium-voltage grid

A particular set of challenges will emerge during Phase Two if a significant number of VRE plants are smaller in scale and connected directly to low- and medium voltage levels of the grid.

In contrast to the transmission (high voltage) network, it has not been common practice to manage distribution networks (medium- and low-voltage) actively. The distribution network has historically simply accepted power from the transmission grid, and distributed it passively to consumers. In a situation where more and more generation resources are added to this part of the system, this situation may change.

When the production of electricity in part of the distribution grid exceeds consumption, the direction in which electricity flows reverses from the norm; instead of flowing "downwards" towards the consumer, it flows "upwards" towards the substation connecting that part of the network to the higher voltage grid (Figure 8).

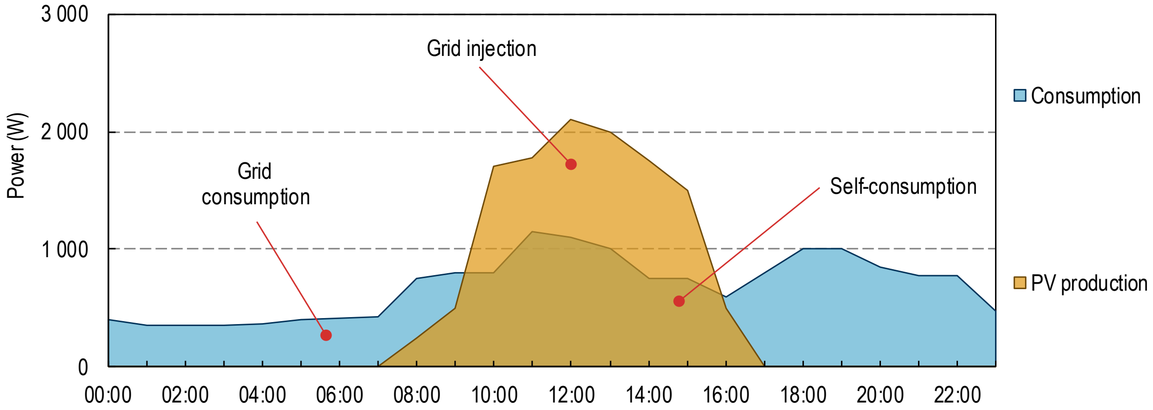
This reversal will happen at different times and will not be constant. It might occur around midday in a predominantly residential distribution feeder with a large amount of installed solar PV capacity: domestic consumption is low at midday as residents are out at work but when the solar PV capacity on their roofs is at maximum output.

These reverse flows (also "two-way" flows) are significant because distribution networks have evolved to manage flow from the distribution substation downwards to consumers.

Nevertheless, most distribution networks are in fact physically able to manage two-way flows of power, although a number of upgrades and operational changes are likely to be necessary.

The first reverse flows are likely to be observed at sunny times on rural distribution feeders (downstream of the distribution substation) but this situation may quickly evolve into one wherein installed PV capacity exceeds peak demand in that part of the grid several times over, leading to frequent over-loading (IEA PVPS, 2014a).

Figure 8 • Two-way flows of power from embedded solar PV capacity



Key point • When production exceeds own consumption, electricity flows reverse.

Is VRE deployed in a system-friendly way?

The previous sections have discussed how the power system can be adapted so as to become more accommodating for VRE. The objective of this section is to answer the question: What measures can be taken to make the deployment of VRE more accommodating to the system?

For example, it may be possible to construct a VRE power plant somewhat closer to demand centres, thus reducing the need for grid reinforcements. However, this may require siting the VRE plant in an area with less favourable resources, which will tend to increase the cost of electricity generation. The optimal strategy will depend on country-specific circumstances, including the cost of VRE (which depends on plant location, resource quality, and access to other required infrastructure), and the cost of measures to integrate VRE. Systematic planning is needed to manage the trade-off. The following discussion highlights levers available to improve deployment from a system perspective. The most relevant measures during early stages of deployment are considering a mix of wind and solar plants that is well-suited from a system perspective. In addition, plants should be sited in a geographically strategic way. During later phases, additional aspects of system friendly deployment become relevant, which is explained in the next chapter.

Phase Three and Four

Transforming power system planning and operation to support VRE integration

The majority of recent trends and developments in the power sector relates to increased VRE deployment. They have implications for power system transformation from the perspective of system operation and planning, and are likely to become more widespread across many jurisdictions as the share of VRE increases.

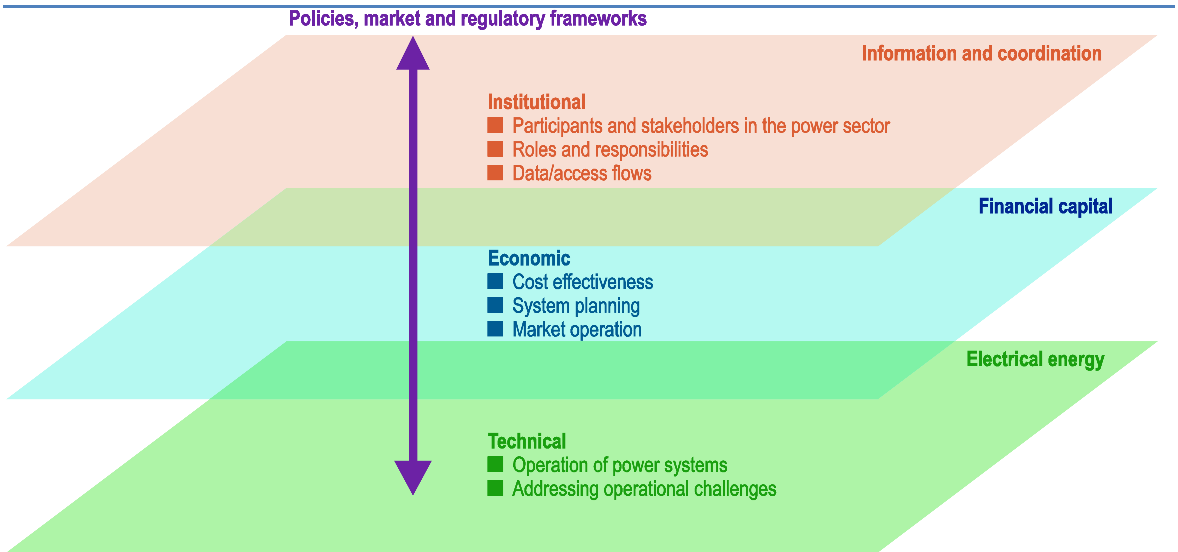
At low shares, integrating VRE into most systems does not pose any major challenges. At high shares, however, the challenges may be more prominent unless traditional power system infrastructure, operational practices and institutional arrangements are adapted to accommodate VRE supplying a large share of electricity.

Given the unique technical and economic attributes of VRE, together with the complex nature of the power system, the implications of integrating high shares of VRE are multiple and include technical, economic and institutional factors (Figure 9). In addition, high shares of VRE have broad implications for the power system at all timescales, ranging from several years to days, hours, minutes and seconds.

This chapter begins with technological options and operational practices that have been or can be adopted to integrate VRE into the system. This includes a deeper look at certain technical and operational options that have been adopted in many power systems. It then discusses integrated planning frameworks that account for VRE, followed by implications for planning and operation of medium- and low-voltage grids.

Issues relating with policy, regulatory and market frameworks to support VRE integration are discussed in the next Chapter.

Figure 9 • Different aspects of system integration of VRE



Key point • Successful VRE integration requires co-ordination across technical, economic and institutional aspects.

Technological options and operational practices to address operational challenges of VRE

Power system challenges associated with VRE can be addressed through technological options and/or adjustments to operational practices.

A range of measures have been implemented by many power systems worldwide to mitigate the impact of VRE. These mitigation measures can be categorised into technical and economic measures. Technical measures can help to enhance the reliability of the power system, while economic measure can improve the cost-effectiveness of power system operation (Table 3).

These measures, which are needed at different times depending on the VRE deployment phase, are described in the following sections. Note that this is not a comprehensive list; rather these options have been used recently in power systems to address integration challenges.

Note also that the technical measures that can be used to address some of the challenges in the later phases of VRE deployment are briefly mentioned here, with the details of such measures explained in Annex 3.

Table 3 • Technological options and operational practices for different phases of VRE deployment

Type	Measures	Phase 1	Phase 2	Phase 3	Phase 4
Technical	Real-time monitoring and control				
	Enhancing capacity of transmission lines				
	Power plant flexibility				
	Special protection scheme				
	Advanced VRE technologies and design				
	System non-synchronous penetration (SNSP) limit				
	Inertia-based fast frequency response (IBFFR)				
	Smart inverter				
	Advanced pump hydro operation				
	Grid level storage				
Economic	Integrating forecasting into system operations				
	Incorporating VRE in the dispatch				
	Sophisticated sizing of operating reserves				
	Faster scheduling and dispatch				
	Co-ordination across balancing areas				

Key point • The appropriate technological options and operational practices for managing VRE integration depend on the level of VRE deployment.

Technical measures

Technical measures to address operational challenges arising from VRE will be relevant from Phase 2 of VRE deployment. Although, the main purpose of the technical measures is to address reliability issues, some of these measures can also increase the cost-effectiveness of power system operation.

Real-time monitoring and control of VRE by the system operator

The ability to monitor and control VRE plants in real time is important for secure operation of the power system, particularly as the VRE share increases and the size of VRE plants becomes relatively large. This is important for system reliability from Phase 2 of VRE deployment.

Depending on market arrangements (central dispatch versus self-dispatch), this control will either be exercised directly by the SO or through generators. Irrespective of the precise arrangements, it is critical for the SO to have real-time awareness of VRE generation and an effective mechanism for control of VRE.

Since the impact of VRE at low shares is minimal, requirements for VRE plants to be visible and controllable have not been a priority for many countries during Phase 1 of VRE deployment. This is particularly the case if VRE is connected to distribution grids and very small in size. This results in very limited visibility of and controllability over VRE plants.

Visibility and controllability will enable transmission system operators (TSOs) and/or VRE plant owners to dispatch VRE generation to suit system conditions, including during emergency conditions. The ability of VRE plants to automatically adjust their generation set point in response to control signals opens the opportunity to provide frequency regulation services, including those via automatic generation control (AGC). The visibility and controllability of VRE plants are made possible by appropriate communication and control technologies, such as supervisory control and data acquisition (SCADA) systems.

Reflecting rising shares of VRE and the transition to advanced integration phases, visibility and controllability features have increasingly been integrated in many systems, particularly those where VRE is becoming a prominent source of electricity generation. One country that has made a substantial effort to enable the SO to have the capability of monitoring and controlling VRE plants is Spain (Box 6).

Box 6 • The Control Centre of Renewable Energies in Spain

In Spain, Red Eléctrica de España (REE) established a Control Centre of Renewable Energies (CECRE) in 2006, a globally pioneering initiative to monitor and control renewable generation using real-time information. Through the CECRE, the SO receives the telemetry of 98.6% of the wind power generation installed in Spain every 12 seconds, of which 96% is controllable (with the ability to adapt its production to a given set-point within 15 minutes).

This has been achieved through the aggregation of all the distributed resources of more than 55 megawatts (MW) in renewable energy sources control centres (RESCCs), and the connection of RESCCs with CECRE. This hierarchical structure, together with the software applications developed by REE, is used to analyse the maximum wind power generation that can be accepted by the system. Monitoring and controlling VRE generation in real time decreases the number and quantity of curtailments, maintaining the quality and security of the electricity supply at the same time that renewable energy integration is maximised.

Tools and techniques for enhancing transmission line capacity

Increased VRE penetration, particularly at locations where the grid is not strong, can exacerbate congestion in the network. Although congestion can have economic impacts in the form of possible curtailment or higher local pricing, it can also pose risks to the reliability of the system. Multiple options exist that may solve the issue, including grid reinforcement, demand management, targeted generation, or storage, but these may not be economically attractive.

Cost-effective options are available to strengthen weak spots and better utilise transmission capacity without large-scale grid reinforcement. Typical measures are dynamic line rating (DLR), flexible alternating current transmission system (FACTS) devices and phase shifters. These measures can be adopted during Phase 2 of VRE deployment. These options have been used to great effect in many systems, such as Australia, Ireland, Japan, Spain, Sweden, Thailand, the United Kingdom and the United States (US DOE, 2012a; AEMO, 2014). These measures are explained in Annex 3.

Other measures involve reconducting, using high temperature low sag (HTLS) conductors, and voltage uprating of the transmission line to the next standard voltage level. These options, however, are considered relatively expensive and complex to undertake since they involve construction crews working on transmission lines (Holman, 2011).

Power plant flexibility

Flexible power plants are considered a source of flexibility that helps to address the challenges in system operation, beside grid infrastructure, storage and demand-side integration (IEA, 2014). Flexible power plants are important as a system progresses through Phase 3 of VRE deployment.

Power plant flexibility has three dimensions: adjustability, ramping and lead time. The extent to which different generation technologies offer greater or lesser flexibility depends on these dimensions.

Reservoir hydropower is an example of a potentially extremely flexible, renewable energy generation technology. Open-cycle gas turbines and banks of reciprocating engines can also be highly flexible generation resources. When combined with sufficient levels of thermal storage capacity, concentrating solar power can be a flexible, dispatchable generation option in hot and dry climates, where hydropower resources are usually limited. It may therefore play a role not only in increasing the share of solar energy directly, but also indirectly in facilitating greater uptake of VRE.

By contrast, large thermal generating units have traditionally been designed with a view to operating continuously and are generally not intended to cycle up/down and operate at part load. These plants may not have particular technical limitations, but additional costs are associated with frequent cycling operation.[7]

Greater flexibility can be attained from existing large thermal plants by retrofitting. This involves equipment modifications to prevent the negative impacts of cycling.[8] In addition to equipment modifications, changes in power plant operating procedures, such as controlled boiler ramp rates and regular inspections, can result in increased flexibility. New power plants should also take into account cycling needs during the design stage in order to mitigate long-term risks.

Currently, thermal power plants in many countries are able to offer greater flexibility by better responding to changes in net demand. Examples of increased flexibility in thermal generation can be found in Denmark, Canada, the United States, Germany (Box 7) and Spain. In addition, countries with a large fleet of combined-cycle gas turbines (CCGTs), such as Italy, have taken steps to make CCGTs fleet more flexible.

In the US state of North Dakota, an ongoing wind energy boom has encouraged the traditionally baseload 1 146 MW coal-fired Coal Creek Station to begin more flexible operation, as it sells power into the Midcontinent Independent System Operator (MISO) power market. By making minor equipment modifications (less than USD 5 million) and fine-tuning certain operational

[7] Such additional costs can arise from to greater wear and tear on plant components as well as increasing fuel costs due to lower fuel efficiency.

[8] These modifications can be made on boilers, turbines, rotors and condensers with a focus on increasing thermal resilience and preventing corrosion (Cochran, Lew and Kumar, 2013).

processes, the plant was able to reduce minimum generation level to below 300 MW and substantially increase its ramping rate (Holdman, 2016).

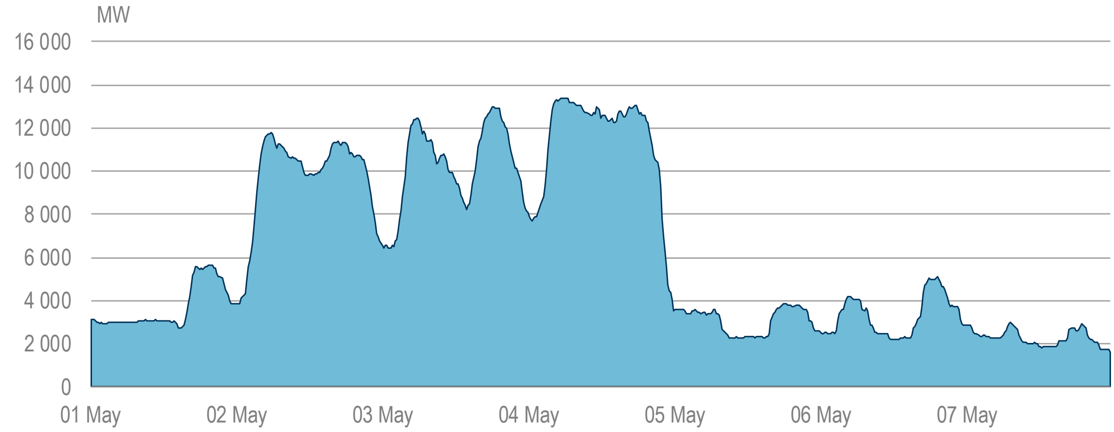
Box 7 • Coal plant flexibility in Germany

Increased share of VRE in Germany has presented challenges for existing conventional thermal plants both technically and economically. While VRE generation could cover most demand in certain periods, conventional thermal plants would be needed to meet the demand during periods of low VRE output.

However, the existing thermal generating fleet, particularly coal plants, have proved that they can operate in a relatively flexible manner. With excessive coal generation capacity, existing coal plants are increasingly being used for balancing the variability arising from VRE (Figure 10). To adapt to volatile supply and demand, many coal plants have been modified to be more flexible in order to achieve higher ramp throughout the day, start/stop on a daily basis and operate at much lower minimum generation. This has been achieved through modifications of equipment, software and operational practices. Coal plants can participate in the balancing markets to provide balancing for different timescales

Source: Henderson (2014), *Increasing the Flexibility of Coal-Fired Power Plants.*

Figure 10 • Generation pattern of hard-coal power plants, 2016, Germany



Source: ENTSO-E (2017a), *Actual Generation per Production Type*, https://transparency.entsoe.eu/generation/r2/actualGenerationPerProductionType.

Key point • The generation pattern of hard-coal power plants in Germany demonstrates the capability of thermal plants to cycle.

Use of special protection schemes

A special protection scheme (SPS) is used primarily to prevent voltage and frequency collapse by controlling loads, voltage or frequency to prevent an overload of transmission lines and/or equipment on the networks, such as transformers. An SPS is used predominantly to detect abnormal system conditions that can cause instability to the power system, automatically activating in response to predefined contingency.[9] It is one of the technical measures to improve the reliability of the grid and can become a useful option during Phase 3 of VRE deployment.

[9] The typical SPS schemes that have been employed are inter-trip and fast-runback. Inter-trip is a scheme where generators are disconnected within a very short timeframe (e.g. 100 millisecond) if a contingency would cause an overload on other lines. Fast-runback is a scheme that sends a signal to the inverters to ramp back to mitigate an overload.

SPSs have been increasingly employed in many jurisdictions where VRE is becoming a major generation source. VRE plants respond to system disturbances (both voltage and frequency) in ways that are different from conventional generators. An SPS can be implemented to maintain system stability and facilitate large shares of VRE generation.

This option represents an alternative to upgrading existing infrastructure, which can be costly and time consuming. SPS is seen as a measure that can generally increase the transfer capacity of the network and provide greater flexibility to power system operation (Miller et al., 2013). It is a cost-effective option that can be used either as a long- or short-term solution.

Chile and many jurisdictions in Europe have implemented SPSs in order to allow greater VRE onto the grid. In Europe, most SPSs have been installed to address voltage, frequency and overloading issues that may occur as a result of contingencies (De Boeck et al., 2016).

Advanced VRE technologies and design

Advanced design of solar PV and wind turbine technologies are a further example of a system-friendly VRE deployment strategy (Hirth and Mueller, 2016). It not only helps to increase the value of VRE outputs, but also reduces the challenges of power system operation as a result of less variable output and reduced forecast errors. Advanced technology for solar PV plants includes a higher direct current (DC) to alternating current (AC) ratio and tracking systems, while changing orientations and tilt angles of solar PV panels have also been considered. Details of advanced technology for solar PV plants are discussed in Annex 3.

Wind power plants tend to be built in locations with the best wind resources in order to maximise output. However, as the share of wind generation in the system increases, the concentration of wind power plants in the same geographical locations not only reduces the value of wind generation output, but can also pose challenges for system operation. Such challenges may be due to network congestion and the significant variability in overall wind power outputs due to limited geographical diversity. This issue can be addressed given advances in wind turbine technology. Advanced wind turbine technology ("low wind speed turbines") results in turbines that are taller and have a larger rotor per unit of generation capacity.

These advanced VRE technologies can improve the reliability of the power system, particularly in the later phases of VRE deployment (from Phase 3).

Establish a limit on system non-synchronous penetration

One of the main technical issues for small and isolated power systems with high shares of VRE is low levels of synchronous inertia, which can reduce system inertia. VRE generators are usually connected to the grid via power electronic converter devices, hence the term "non-synchronous". These generators do not have a direct, electro-mechanical coupling to the grid. This makes them different to traditional, synchronous generators. For example, they do not directly contribute to providing inertia to the power system.[10]

One measure adopted by some countries, such as Ireland, to maintain sufficient synchronous inertia is to establish the maximum limit of system non-synchronous system penetration (SNSP). This practice is important during Phase 4 as VRE becomes a major generation source. It is described in detail in Annex 3.

[10] System inertia acts to mitigate the rate of change of frequency (RoCoF) following a contingency event in the power system. As VRE displaces thermal generation, system inertia will be reduced, which consequently increases the RoCoF following a contingency event. RoCoF standards that have been applied in various jurisdictions range from 0.5 hertz (Hz) per second to 4 Hz/second (DGA Consulting, 2016). The standards also depend on the duration of time that VRE plants are exposed to the high RoCoF.

Inertia-based fast frequency response

So-called inertia-based fast frequency response (IBFFR) is a further technical option for supplying inertia to the system that has been considered and implemented in power systems with a large share of VRE. IBFFR is also known as "synthetic" or "emulated inertia", which can be extracted from VRE plants. IBFFR can potentially contribute to system inertia by utilising kinetic energy stored in wind turbine rotating mass. This measure can help to address frequency stability challenges during Phase 4 of VRE deployment. The TSO in Quebec, Canada is an example of a utility that has established technical requirements for physical inertia from wind power plants. Brazil and Ontario and the National Electricity Market (NEM) in Australia are also considering similar mandates. IBFFR is discussed in detail in Annex 3.

Smart inverter

Traditionally, inverters were primarily designed to convert DC power generated by VRE sources to AC to be fed into the grid. However, with high shares of VRE within Phase 4, VRE plants are increasingly being required to provide additional grid support features to enable the power system to operate more reliably and cost-effectively. Smart inverters are one option to provide this. They are discussed in Annex 3.

Advanced pumped hydropower operation

Pumped storage hydropower (PSH) can be an important source of flexibility in the power system. Once built, it is also considered a cost-effective option. PSH is able to provide or absorb energy according to the need of the grid. With increasing shares of VRE, there is an emerging interest in large PSH in many countries, such as India, China and Australia, in order to accommodate high shares of VRE in a cost effective and reliable manner, and to provide hourly, daily or seasonal storage and flexibility.

PSH is also capable of providing system services to maintain the reliability of the system. These services include black-start capability, ramping and quick start, spinning reserve, reactive power, inertia and frequency regulations. A number of these features would be useful for addressing reliability issues during Phase 4 of VRE deployment. Some PSH can operate in a special mode called hydraulic short-circuit pumped storage (HSCPS) to provide system inertia and frequency response. Technical aspects of PSH are discussed in Annex 3.

Grid-level storage

Storage is recognised as a technology that can provide greater flexibility and help to maintain the security of the grid, particularly during Phase 4 of VRE deployment. Pumped hydropower storage currently accounts for the majority of storage deployed. Other storage technologies that have been deployed include compressed air energy storage (CAES), batteries, flywheels and liquid air storage.

For bulk power grids, storage is most often considered to relieve local congestion, which brings both reliability and economic benefits, even if prices per megawatt hour are higher than comparative generation or other options.[11] As the share of VRE increases, the benefits of storage extend to system security. Certain storage technologies, such as pumped hydropower, CAES and flywheels, are capable of providing frequency response in different time scales. Grid level storage has been employed to provide system services in jurisdictions such as PJM in the United States, Italy and Chile. Note that from a system perspective, the benefits of batteries come earlier for PV than for wind. Details of grid-level storage are provided in Annex 3.

[11] During the initial phase, there is little economic benefit of storage, as VRE has yet to affect prices on the market.

Economic measures

The purpose of economic measures is to improve the cost-effectiveness of power system operation with an increasing share of VRE generation. Without economic measures, the grid would still be able to operate in a reliable manner, but is likely to be less cost-effective. Economic measures have been adopted in some systems as early as during Phase 1 of VRE deployment.

Integrating forecasting into power system operations

Advanced forecasting tools using sensing technologies, together with mathematical models, can accurately predict wind speed and solar irradiance, and subsequently forecast outputs from VRE plants on a sub-hourly basis.

Advanced forecasting is considered to be a tool that improves the cost-effectiveness of VRE integration, offering benefits as the system approaches Phase 2 of VRE deployment. It can also improve system reliability as VRE shares grow.

Centralised system-level forecasting of VRE generation can improve system operation by enabling the SO to account for overall variability of VRE outputs across the whole system and accurately predict the amount of VRE generation available. Forecasting is a useful tool to assist real-time dispatch, scheduling and operational planning. In self-dispatching markets, forecasting of VRE generation helps generators to establish reliable schedules and limit schedule deviations. A good plant-level forecast will allow for a more cost-effective and reliable schedule of generation. A good system-wide forecast is critical for verifying that generation schedules are feasible and sufficient operating reserves held.

Forecasts are regularly updated and are more accurate closer to real time. As the share of VRE increases, forecasting becomes an even more integral element of power system planning and operation. Examples of jurisdictions that have implemented forecasting systems to assist in system operation are Australia, Texas, California, Denmark, Germany, the United Kingdom, Ireland and Spain.

The NEM in Australia has an integrated wind and solar forecasting system, called the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS), as part of the generation scheduling and dispatch process. They generate forecasts for the scheduling and dispatch of generators for different time horizons, ranging from five minutes up to two years ahead. This is discussed in detail in the case study in Chapter 6 in IEA [2017b] for a detailed discussion.

Incorporating VRE in the dispatch

As VRE share grows, and its capability for AGC and providing other system services advances, market operators are taking advantage of advanced forecasting by actively managing VRE in the dispatch. This approach can offer benefits from later stage of phase 1 of VRE deployment.

Many systems, such as New York ISO (NYISO), Midcontinent ISO (MISO), PJM and ERCOT, have taken the step to develop levels of dispatchability for VRE to ensure better utilisation of VRE output while also maintaining system reliability (US DOE, 2012b; Madjarov and Chang, 2012). This includes incorporating VRE in the scheduling and security constrained dispatch as with other generating sources. This measure would help to improve the economics of VRE integration during the early phase, while it will help to improve the system reliability as VRE becomes the dominant generation sources. This operational practice is made possible by having appropriate forecasting systems in place.

Sophisticated sizing of operating reserves

Operating reserves are the amount of capacity that SOs can call upon to meet demand within a short timeframe. Reserves are included in system operations to deal with uncertainty in supply and demand. Generally, reserves are kept to handle contingency events, such as the loss of generation supply, or for normal operation, such as demand variation and demand forecast errors. A more sophisticated approach to determining operating reserves would improve the economics of power system operation during Phase 2 of VRE deployment.

Reserves can generally be categorised into frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR) (ENTSO-E, 2017b). As the name suggests, FCR limit the excursion of system frequency from its nominal range following a system event. FRR relieve containment reserves and bring frequency back to nominal levels. RR then come in to free restoration reserves.

Traditionally, the practice in many systems for establishing the size of FCR is based on the n-1 concept, i.e. being able to handle the largest single contingency in the system, either generator or transmission line.

It is important to recognise that uncertainty in VRE output is not generally correlated with supply and demand uncertainty. It is unlikely that generation outages, significant load variation and VRE variation would happen at the same moment. In addition, the uncertainties associated with VRE are different at different times of the day, and therefore the level of reserves should be dynamically adjusted to reflect these characteristics (Milligan, Denholm and O'Malley, 2012).

FRR are usually determined on the basis of a set of heuristic or, if more sophisticated, stochastic analyses of load variations, forecast errors and other factors. Large shares of VRE will bring additional, albeit different, uncertainties to the power system, and therefore more sophisticated approaches to determining appropriate levels of operating reserves are necessary to achieve cost-effective and reliable system operation. Due to the number of uncertainties associated with power system planning and operation, probabilistic approaches are appropriate for determining the operating reserve requirement for FRR and RR. These have been employed in jurisdictions such as Texas, the United Kingdom and many other European Union countries. In Spain, wind and solar forecast errors have been incorporated in reserve calculations (Box 8).

Box 8 • Use of forecast error for reserve determination, Spain

Although wind and solar power plants declare their forecasted generation, the Spanish TSO, REE, uses wind and solar power prediction tools, named SIPREOLICO and SIPRESOLAR, to predict the total hourly wind and solar production for the following 48 hours. The hourly forecasts are updated every hour and provide information for the determination of secondary, tertiary and "slow" (30 minutes to 4-5 hours) reserves.

Every day, after receiving market and bilateral contracts, REE checks the availability of running reserves for the next day. The final calculation is reached considering upward and downward reserve error, historic demand forecast and historic wind and solar forecast error. Reserves are revised from when the market results are received until real time.

Faster scheduling and dispatch

Scheduling and dispatch that are as close to real time as possible allow for more accurate representation of variations in net load. This results in a more efficient use of reserves, because a larger proportion of VRE variability is absorbed by schedules and hence does not need to be balanced by reserves. This operational practice can help to address economic concerns associated with VRE, from Phase 2 of VRE deployment.

For jurisdictions that have a wholesale electricity market, generation scheduling and dispatch is usually performed in time blocks, varying from 5 minutes in the fastest markets up to between 30 minutes and 1 hour in more standard designs.

For jurisdictions with a vertically integrated structure, SOs are not constrained by any market schedule and may therefore redispatch the system according to the system needs at any desired time.

The shortest dispatch interval in major electricity markets today is 5 minutes, which is implemented by most independent system operators (ISOs) in the United States and in the Australian NEM. The Electricity Reliability Council of Texas (ERCOT) is an example of a market that has achieved efficient outcomes from reducing dispatch intervals. ERCOT decided to reduced dispatch intervals from 15 to 5 minutes in 2010, resulting in less regulating reserve being required (Box 9).

Note that faster scheduling and dispatch can benefit the system even without VRE. However, the benefits are more apparent with higher shares of VRE.

Box 9 • ERCOT real-time dispatch

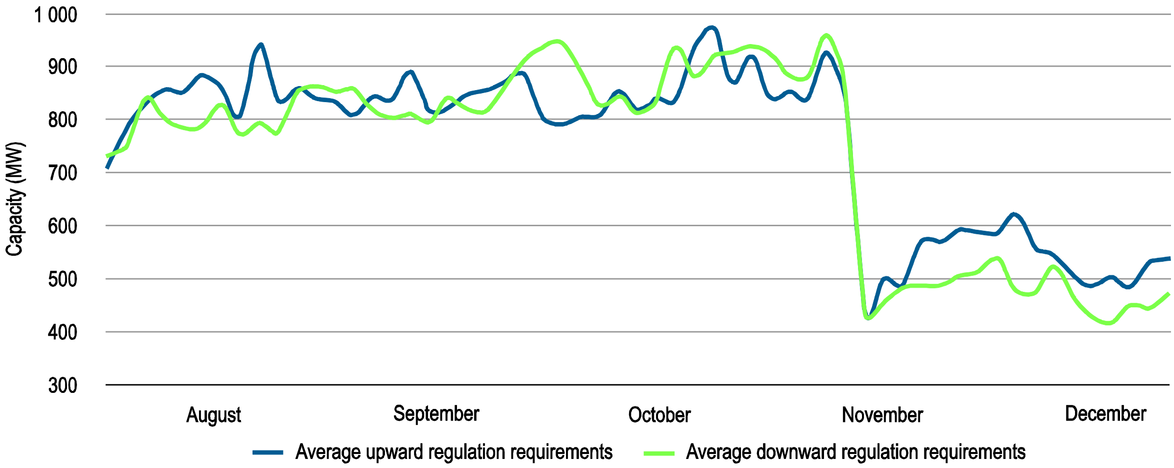
ERCOT is the ISO managing the flow of electric power to approximately 23 million Texan customers. As part of market reforms implemented in 2010, dispatch intervals were reduced from 15 to 5 minutes. As a result of the shorter dispatch intervals, significantly less regulating reserve requirements were needed (Figure 11).

The ERCOT market is characterised by the quasi-real-time dispatching of power plants, taking place every five minutes. In fact, in the ERCOT nodal system all generation resources, including wind resources, are given individual dispatch instructions, generally at a five-minute frequency. The security constrained economic dispatch (SCED) algorithm is primarily based on real-time telemetry data of load and production, price of energy offers and current system status.

This is made possible by the centralised control of the grid, which is characteristic of ISOs and regional transmission organisations (RTOs) in the United States. The possibility of combining – at the same time – market clearing and congestion management, in fact, circumvents the need for the redispatch process, which would require co-ordination between market players and the SO. Real-time dispatch minimises the need for reserves and allows the real-time energy price to be representative of congestion and any other challenges taking place.

The ERCOT real-time dispatch process is intended to maximise use of available wind generation, subject to the prices offered for the generation and system constraints (e.g. transmission flow constraints).

Figure 11 • Regulating reserve requirement in ERCOT before and after reducing dispatch intervals



Source: IEA RETD (2015), *Integration of Variable Renewables*.

Key point • Shorter dispatch intervals can lead to more efficient reserve requirement outcomes.

Co-ordinating dispatch across balancing areas and interconnector management

The impact of the variability and uncertainty of VRE can be reduced by expanding the size of balancing areas through an inter-regional interconnector, allowing the use of imbalance netting and the exchange and sharing of reserves. This is one of the options for balancing a system with high shares of VRE in a cost-effective manner, particularly from Phase 3 of deployment.

Co-ordinating scheduling and dispatch across different balancing areas can smooth out overall variability of load and VRE outputs as a result of greater geographical and resource diversity. Weather patterns are unlikely to be well correlated across large geographical areas, while demand across different jurisdictions is unlikely to peak at the same time.

Balancing area co-ordination would result in fewer reserves being required. Furthermore, combining geographical areas would also tend to reduce overall forecasting errors and ramping requirements (Figure 12).

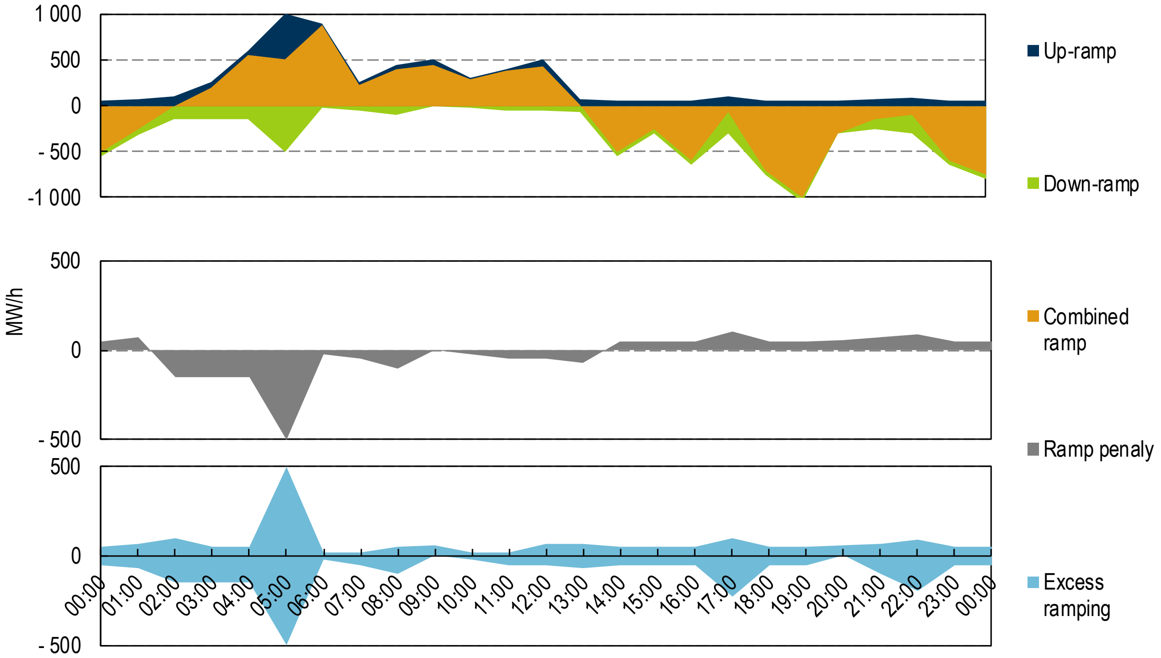
Appropriate operation of an interconnector can provide the system with greater flexibility by allowing for a more efficient use of flexibility resources than would otherwise have been possible (IEA, 2011a). In addition, interconnection can provide frequency response, and interconnection via AC transmission lines can also contribute to the sharing of inertia between systems.

Co-ordination between balancing areas effectively requires inter-regional planning between different jurisdictions. This can also be a platform for achieving market integration, as discussed in the later section on integrated planning with VRE.

These activities are being pursued in a number of European markets. Recent developments include the International Grid Control Co-operation (IGCC) platform. The IGCC is a regional project operating an imbalance netting process. It currently involves 11 TSOs from 8 countries, consisting of Austria, Belgium, the Czech Republic, France, Germany, the Netherlands, Sweden and Switzerland (ENTSO-E, 2017c).

The Nord Pool is also a good example of interconnection management and co-ordination across balancing areas (Box 10). Cross-border interconnectors between Denmark, Norway, Sweden and Germany, via both AC and DC links, have allowed wind power output to be transported to other countries and also help to spread variability to a larger balancing area.

Figure 12 • Benefits of combined balancing area operations



Note: MW/hr = megawatts per hour.

Source: NREL (2007), *Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration*.

Key point • Combining balancing area operations reduces ramping requirements.

Box 10 • Nordic market interconnection management

The Nord Pool Spot (NPS) market is an example of good practice for interconnection management. Auctions of the transmission capacity connecting the 12 Nordic market zones to the Central and Western European (CWE) markets are implicit in the day-ahead market for electricity.

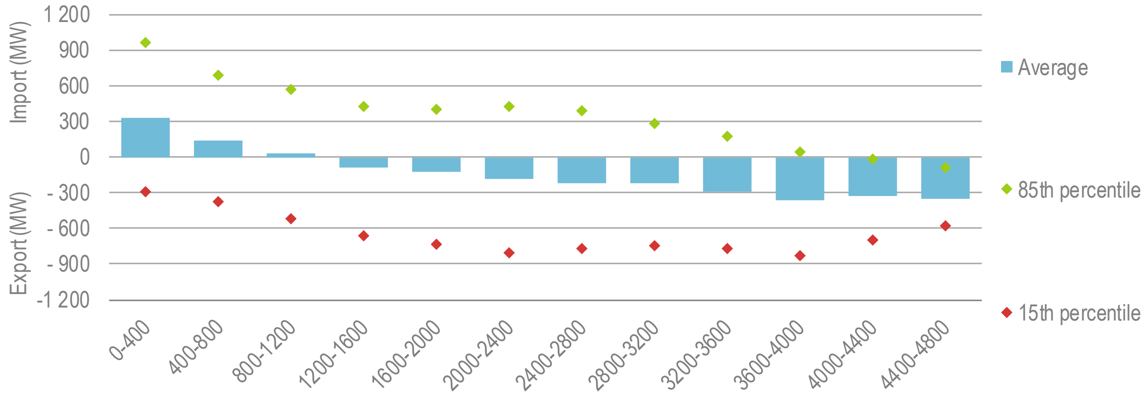
The NPS market covers the Nordic region, ensuring that a deep pool of flexibility is available. A suite of markets exists (day-ahead, intraday and real-time operational reserves), enabling trade across interconnectors from day-ahead right up to the delivery hour. It is also used for real-time balancing, where the four SOs collaborate in balancing the whole system instead of any single country, using their pooled resources.

Interconnections in Denmark are already used to balance the system, selling energy when wind production is high and importing energy when wind production is low (Figure 13).

Interconnectors are also used for maintaining system stability in Denmark; roughly 80% of the variation in wind power during 2014 was compensated by commercially driven exchanges through interconnectors

Source: ENS (2015), *Flexibility in the Power System – Danish and European Experiences*.

Figure 13 • Interconnector flows and wind generation in Denmark



Source: Energinet.dk (2017), *Market Data*, www.energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx.

Key point • A larger balancing area can maximise the value of VRE generation.

The need for operational requirements relevant to VRE plants

The role of grid codes and VRE plants

As mentioned in the previous chapter, to ensure proper co-ordination of all components in the power system, a set of rules and specifications needs to be developed and adhered to by all stakeholders in the power sector. This set of rules is referred to as a grid code. Grid codes cover many aspects, including connection codes, operating codes, planning codes and market codes (IRENA, 2016).[12]

As the share of VRE displacing conventional generation increases, so the need grows for VRE to contribute to providing grid support services, such as frequency regulation and active power control, reactive power and voltage control, and operating reserves. As a result, more stringent and precise technical requirements are required from VRE plants connected to the grid.

Grid codes are continuously revised to suit the evolving needs of the power system as the share of VRE increases. In addition, the SO's growing body of experience with implementation will indicate required changes. The frequency of grid code revision depends on how fast the power system and the energy sector are evolving.

More recently, a number of countries have undergone grid code revisions in response to increasing shares of VRE. These include Germany, Ireland, Spain and Denmark. Ireland has been active in revising their grid code due to the high share of wind (Box 11).

One of the most recent developments is in the European Union, where European Commission Regulation 2016/631 has established a network code on requirements for grid connection of generators. Given that it is difficult to predict the amount of a particular system service that will be required as the share of VRE increases, prolonging the process of implementing necessary technical requirements can increase the level of risk to system reliability (see Annex Two for details).

[12] Planning codes contain rules on planning the expansion of the grid and new generation capacity. Market codes contain rules for the trade of electricity and how to incorporate technical restrictions in the formation of prices.

Box 11 • Ireland's grid code

Ireland has continuously updated its grid code to ensure that the grid can accommodate a large share of VRE generation. A number of modifications to technical requirements have been made to provide support to the power system. These were determined based on extensive studies carried out by the SO, Eirgrid.

The current grid code, Version 6.0, contains a number of technical requirements that have been established specifically for wind farms, addressing active power control, frequency response and voltage regulation. Notable requirements include:

- provide wind turbine generator dynamic models for plants with capacity greater than 5 MW
- retain FRT capability, which requires wind farms to remain connected in the case of voltage dips to 15% of the nominal value that are no longer than 625 milliseconds; in addition wind farms must provide active power and reactive current to help recover the voltage
- retain capability to withstand RoCoF values up to and including 0.5 Hz per second
- remain connected at frequencies within the range 47.0 Hz to 47.5 Hz for a duration of 20 seconds
- respond to frequency deviations in the timescale between 5 and 15 seconds
- control the ramp rate of the active power output over a range of 1% to 100% of capacity per minute.

Source: EirGrid (2015), *EirGrid Grid Code Version 6.0*.

Integrated planning with higher deployment of VRE

To facilitate the integration of VRE, it is also important that issues associated with VRE are taken into consideration in long-term energy planning. This allows appropriate investment decisions to be made on flexible resources in respect of both generation and grid infrastructure. In addition, planning should accurately reflect options for advanced demand response, storage and other relevant trends, such as electrification of transport. Greater system flexibility not only facilitates VRE integration, but also provides other benefits by allowing the system to be operated in a more cost-effective and reliable manner.

Power sector planning is an inherently complex process due to the long planning horizon, and is subject to a range drivers that are highly uncertain. Further complexity results from planning, consisting of a number of activities that are undertaken by multiple groups and jurisdictions for a given power system (Cochran et al., 2012).

Traditionally, the primary focus of power sector planning was on expanding supply infrastructure (generation, transmission and distribution networks) to meet projected electricity demand, based on assumptions of economic growth over the next 20 to 30 years. However, with the changing landscape of the power sector, due to increasing deployment of VRE and other new technologies, as well as increasing consumer participation, planning for a future power system needs to become more sophisticated by taking account the role and impact of these developments.

Better integrated and co-ordinated planning frameworks can help identify appropriate options for future power systems. The process should take into account questions of flexibility and reliability, and how different supply- and demand-side resources can play a role in successful integration of VRE, providing a pathway for power system transformation.

Integrated planning is being adopted in a number of jurisdictions, taking into account a range of drivers to effectively accommodate developments in the power sector, particularly with respect to VRE deployment (Miller et al., 2015).

Co-ordinated and integrated planning encompasses a number of elements, which can be broadly grouped into the following:

- integrated planning incorporating demand resources
- integrated generation, transmission and distribution planning
- cross-sectoral planning between electricity sectors and other sectors, particularly heating and cooling and transport sectors
- planning across different regions, jurisdictions and balancing areas.

Integrated planning incorporating demand resources

This aspect of integrated planning relates to a planning process that takes into account demand resources.

The potential role of the demand side is often overlooked in power sector planning. Demand response can be provided through distributed energy resources (DER), which are typically modular and/or small in scale, connected to a local network, with the capability to provide energy or system services. DER include distributed generation, flexible demand, storage and other resources.

Appropriate demand response can achieve various benefits, including smoothing the variability of VRE and maintaining system reliability by providing fast response services. It can also play a major role in deferring or avoiding investment in generation and networks. DSM options encompass a number of possible interventions, from energy reduction programmes to active load management (IEA, 2014).

Co-ordinated planning across supply and demand resources can take into consideration the locational value of energy, which helps identify the most advantageous areas for the development of VRE technologies.

Box 12 • PacificCorp's Integrated Resource Plan

PacificCorp, a utility operating across six states in the Northwest of the United States, has integrated energy efficiency and dispatchable demand-response programmes into electricity planning, under its Integrated Resource Plan (IRP). They are assessed as a supply resource, allowing them to be compared with other supply options in the IRP model.

This has led to cost-saving energy efficiency measures that accounted for a large proportion of electricity supply in the final IRP.

Source: Wilson, R. and B. Biewald (2013), *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.*

Integrated generation and network planning

The integrated planning approach optimises resources across an entire network, resulting in a number of benefits from reliability, economic and environmental perspectives. Historically, power system planning, as carried out by vertically integrated regulated monopolies, was typically well co-ordinated, resulting in low levels of congestion.

In jurisdictions with a restructured market, however, co-ordinated planning is typically more difficult (IEA, 2016a). This is often due to generation, transmission and distribution planning being conducted independently in separate processes, since they are managed by different electric utilities. As a result, expansion in generation, transmission and distribution is less likely to align, possibly resulting in ineffective outcomes.

This issue is magnified as the level of VRE deployment increases, since development of VRE projects often outpace changes in other elements of the power system. Geographic concentrations of VRE in areas with the highest-quality resource can place a burden on the local transmission grid and lead to transmission congestion, which ultimately drives up the cost of delivered electricity.

The issue is relevant for both for the transmission and distribution networks, where the addition of new VRE may change traditional energy flows and the use of the grid, and connections at local grids may challenge the usual distribution operations. A VRE project can be developed relatively quickly compared to the development of grid infrastructure. This was the case in Brazil, where 300 MW of wind generation capacity was unable to connect to the grid at the end of 2015 due to limited transmission capacity (Epoca, 2016).

An example of a planning approach that considers generation and transmission expansion is the Renewable Energy Development Zones (REDZ) initiative in South Africa. Eight REDZ were identified based on integrated spatial analysis and stakeholder consultation. The analysis takes into account energy resource potential, infrastructure availability, stakeholder and local authority support, environmental suitability and socio-economic need (SA DOE, 2015). The location of the REDZ further serves to inform grid planning, identifying and confirming the areas where grid capacity will be required to support the targeted development zones. Details of REDZ are shown in the South Africa case study in Chapter 6 in IEA [2017b] for a detailed discussion.

In addition to integrated planning, procurement strategies can provide financial incentives based on the location of VRE plants. This is discussed in the next Chapter on grid investments.

Integrated planning between the power sector and other sectors

Integrated planning that spans the power and other sectors is a growing field in energy system integration. Historically, planning across different sectors was thought to be relevant only for the electricity and gas sectors, since gas is one of the main fuels for electricity generation in many countries. However, even power and gas planning has been carried out separately in many countries due to a number of challenges, particularly from institutional and regulatory perspectives.

Efforts have been made in many jurisdictions to link the planning of electricity and gas. In the European Union, the European Commission has encouraged electricity planners to work with gas partners in ENTSO-G (European Network of Transmission System Operators for Gas) to create a common baseline of assumptions. This involves using the same analytical basis for their respective ten-year network development plans. These plans would then be used as the basis for the cost-benefit analysis of different electricity and gas network expansion or reinforcement projects.

More recently, continuing innovation in and uptake of demand-side technologies are having an impact on the power system. Demand-side technologies, particularly electric vehicles (EVs), have the potential to facilitate a high share of VRE in the power system. Such technology options can be deployed in a way that increases the flexibility of the system. For example, EVs with smart charging can be used to provide flexibility and facilitate VRE integration by charging during periods of high VRE output and supplying to the grid when output declines.

In addition, linking the power and transport sectors can also support development and planning of EV charging infrastructure, enabling greater uptake of EVs. As EV uptake grows, increasing interaction between power and transport sectors can be seen. A number of jurisdictions have incorporated cross-sectoral links between planning in the power sector and the transport sector, including Scotland, Japan and the United States (Miller et al., 2015). In Scotland, EVs have contributed to wind integration by absorbing excess wind generation, which prevents curtailment (Miller et al., 2015).

Inter-regional planning

Power system planning was traditionally confined to established single-utility balancing areas. However, with an increasing share of VRE deployment, expanding the size of balancing areas can potentially provide greater flexibility through resource diversification across different geographical regions. In addition, greater geographic diversification of generation sources will lead to less variability in supply. Large and integrated power systems also tend to be more secure, albeit more complex from the perspective of system operation.

Changes to balancing areas and greater amounts of inter-regional planning have emerged over time from subtle moves toward electricity market integration in certain jurisdictions (Miller et al, 2015). Planning that expands across balancing areas or national jurisdictions can lead to more efficient use of existing generation and transmission resources and minimise the costs of expansion.

Many neighbouring TSOs have now started to co-ordinate power system planning in order to optimise the use of resources and benefit from increased flexibility. Inter-regional co-ordination is evident in the European Union, South Asia, Association of South East Asian Nations (ASEAN) and the United States (IEA, 2015b; IEA, 2016a).

Since 2011, regional transmission planners in the United States have been required to develop regional plans and co-ordinate with their neighbouring transmission planners (FERC, 2016a). In South Asia, the power systems of India, Bhutan and Nepal have been interconnected and synchronised since 2013. In 2014, governments signed the South Asian Association for Regional Cooperation (SAARC) framework agreement on energy co-operation, one element of the energy pillar being the development of an inter-regional electricity market and the further development of interconnections (SAARC, 2017).

Despite the potential benefits of inter-regional planning, a number of challenges are associated with the institutional and contractual arrangements for multilateral trade. Such cross-border arrangements can be complex and difficult to achieve.

The European Union is a prominent example of regional co-ordination in transmission planning. ENTSO-E (European Network of Transmission System Operators for Electricity) was created to co-ordinate transmission network planning and operation across different jurisdictions (IEA, 2016c). This includes drafting network codes, co-ordination and monitoring of network code implementation and development of long-term regional network plans (Box 13).

Box 13 • Co-ordinated transmission network planning in Europe

ENTSO-E publishes an updated Ten-Year Network Development Plan (TYNDP) every 2 years to give an overview of the transmission expansion plans in the next 10-15 years that have been identified as necessary to facilitate EU energy policy goals. The TYNDP is a co-ordinated planning initiative to deliver a pan-European transmission plan within the ENTSO-E region. It is the outcome of a two-year process, starting with the development of scenarios or visions of how the European power system might look in 2030.

The TYNDP 2016 analyses the required transmission and interconnector developments under different scenarios, termed "Visions", with renewables penetration levels of between 45% and 60% in 2030. It pinpoints about 100 spots on the European grid where bottlenecks exist or may develop if reinforcement solutions are not implemented.

The projects that have been identified in the TYNDP will contribute towards meeting EU energy policy goals. Based on the goals, Projects of Common Interest (PCIs) are selected and will benefit from accelerated licensing procedures, improved regulatory conditions, and some access to financial support.

Source: ENTSO-E (2016a), *Ten-Year Network Development Plan 2016.*

Planning and operation of low- and medium-voltage grids in light of increased DER

Planning for low- and medium-voltage voltage grids has historically required consideration of load growth for the area served, as well as scenario planning for specific technologies that may become prevalent or significant within the planning horizon. Infrastructure upgrades to the distribution systems are generally a major investment, amortised over multiple decades, and require considerable time and/or project staging to complete, so long-term planning is undertaken to manage future investments. The planning horizon for distribution infrastructure is typically 5 to 10 years.

New planning requirements

When considerable amounts of DERs, such as VRE, are expected to be integrated into local grids within the planning horizon of a distribution utility, additional and potentially more complicated planning studies typically need to be completed. This is to ensure the continued safe, reliable and cost-effective operation of the interconnected distribution system (IEA PVPS, 2014a). Depending on local circumstances, SOs are likely to pursue a combination of additional planning activities (Table 4).

Table 4 • Additional planning activities to integrate DER

Study topic	Purpose
Gross load estimation	Determine circuit load masked by DER generation
Circuit reconfiguration	Ensure that reconfiguration remains possible with DER integration
Power flow	Identify potentially overloaded and/or unidirectional components that may experience reverse power flow
Voltage regulation	Ensure voltage power quality and inform placement and control setting for automatic voltage regulation equipment

Source: Seguin et al. (2016), *High-Penetration PV Integration Handbook for Distribution Engineers*.

Improved screening/study techniques

Local utilities use "screens"[13] to assess the impact that DER, such as behind-the-meter solar PV projects, will have on the local network. Screening forms part of distribution planning activities and guides the approval process for DER projects.

The precise distribution of DER on a distribution circuit (e.g. near the start of the circuit or near the end of the line) can strongly determine their impact on the circuit. More accurate grid planning can inform SOs about which connection requests merit more in-depth analysis, which ones can be approved without further study, and which projects cannot be connected within the immediate planning horizon without significant circuit modification or upgrade (Box 14).

Many of the grid "screens" in place today were designed in a context of low DER penetration. To improve the accuracy of local grid screening, planning efforts must include future scenarios for DER penetration at a relatively high spatial resolution, such as neighbourhood or even street level. Planning tools could use socio-economic data to determine the likelihood of DER adoption in certain areas (Sigrin et al., 2016). An alternative approach to grid impact assessment assumes random placement of DER (Smith and Rylander, 2012). As such, improved screens require considerable development to account for the rising complexity of the required analysis at high penetration (Rylander et al., 2015).

Box 14 • Beyond 15% penetration: New technical DER interconnection screens for California

In the past, DER projects in California required a full interconnection study if aggregate DER capacity amounted to 15% of the peak load of the circuit. With the growth of PV deployment, this limit was reached more often, leading to burdensome administrative processes, which slowed down further deployment. Today, a more refined analysis is performed to determine which DER projects are more likely to saturate local circuits, and require in-depth analysis by the utility. This has made project assessment less burdensome and more effective, saving time and money for the utility and project developers alike.

After screening, SOs can apply quasi-static time-series (QSTS) analysis, or alternative study methods to assess PV interconnection requests (NREL, 2014a). QSTS analysis incorporates more precise load and solar irradiance models, and allows for a more refined understanding of the expected impacts of DER on combined circuit operation and voltage regulation equipment. However, even with modern-day consumer-grade computing equipment, a comprehensive assessment can take several days to complete. Less time-intensive study methods and tools are needed to enable VRE interconnection. The German local SO, EWE Netz, is leading efforts to reduce this delay, so that project developers or home owners can receive the outcome of the screening exercise in as little as a few minutes.

Advanced data-driven local system management

Aside from offering a range of useful energy services, DER and enabling technologies are sources of valuable data that can inform grid operations and planning. DER can inform the operator about the state of the system, either directly or enabled by an energy management system (EMS) or a third-party aggregator (NREL, 2016b).

With improved communication via standard internet links or other systems, SOs gain visibility about the location of DER and their provision of energy and energy services in real time. It also

[13] A "screen" is a visualisation used by the local system operator to determine thermal and voltage capacity limits of the local network.

becomes possible to forecast production and consumption levels by DER on the basis of meteorological conditions.

Advanced distribution management systems (ADMS) need to be put in place to provide adequate control to SOs. ADMS manage and organise data flows on the side of the operator. A key feature of ADMS is that they enable the communication of set points and other control signals to the end customer. This allows for the dispatch of real and reactive power embedded in a portfolio of end users, as well as equitable curtailment when the need arises.

Policy, regulatory and market frameworks to support VRE integration

In the context of power system transformation, the large-scale uptake of VRE challenges traditional policy, market and regulatory frameworks. This is true for all market structures, irrespective of whether they lean towards a fully restructured, liberalised model or towards the vertically integrated model. However, the required adaptations will be quite different in each circumstance, reflecting different starting points. What can be observed globally is a degree of convergence between the different models.

Policy, market and regulatory frameworks for efficient operation of the power system

Policy, market and regulatory frameworks have a strong bearing on the way in which decisions relating to power system operations are made. Where wholesale markets are in place, operational decisions are based on the bids made by generators, but such markets differ in their precise design (see below). Recent years have seen growing interest in the establishment or strengthening of such markets to improve the operational efficiency of the power system and better incorporate higher shares of VRE. The drivers behind this include the potential for savings from making better use of existing assets, in particular across large geographical regions. In addition, the introduction of wind and solar power has emerged as a driver for improvements in market design. It is important to note that well-designed short-term markets are not only relevant for co-ordinating operational decisions; they can also contribute to improving the investment environment for new generation, incentivise flexibility and provide accurate information for the retirement of plants. Consequently, introducing or improving short-term markets should be a first priority.

Least-cost dispatch - the role of short-term markets (minutes to hours)

Short-term markets are the foundation of all market-based electricity systems and have been proven to be a valid approach to cost-effective integration of high shares of VRE. In most cases, they consist of two main markets: the day-ahead market and the real-time market (Figure 14). In the day-ahead market, participants bid for energy and the market clears and sets hourly prices for each hour of the next day. Generating units are committed accordingly. Then, during the day, adjustments have to be made to balance supply and demand, which are continuously updated. This is done either by system operators or by generators. In Europe, participants can also exchange electricity blocks on an intraday market platform before system operators set balancing energy prices that clear the balancing (or real-time) market. In North America, system operators calculate real-time prices in a five-minute market. System operators also procure a number of ancillary services, including operating reserves, to instantaneously restore frequency.

In addition to these short-term markets, medium- and long-term markets enable trading of electricity and forward capacity development, in advance of the day-ahead timeframe. While they play a key role in investment decisions (see following sections), it should be remembered that the underlying product of all these markets is the energy traded on short-term markets.

There is no standard design for electricity markets. Broadly, however, existing short-term markets fall into two categories depending on the degree of geographical and temporal resolution of electricity prices (IEA, 2016b):

- **Low-resolution** market designs have been implemented in Europe, where the primary objective was to enable cross-border trade in electricity. Each country had relatively little internal network congestion and a single price by country was considered sufficient. Within each price zone, power exchanges, not system operators, calculate prices as if congestion and network constraints did not exist. System operators handle congestion by redispatching power plants. The primary market is the day-ahead market. Participation is not mandatory.

  The balancing/real-time market is a residual market designed to give market participants the incentive to balance generation and load rather than to reflect the marginal cost of the system.

- **High-resolution** market designs seek to provide an accurate economic representation of the physical reality and operation of power systems. These have become more common in parts of the North America, for example in Texas (Alaywan, Wu and Papalexopoulos, 2004). To that end, system operators directly manage the market platform using sophisticated software to perform security-constrained economic dispatch (SCED).

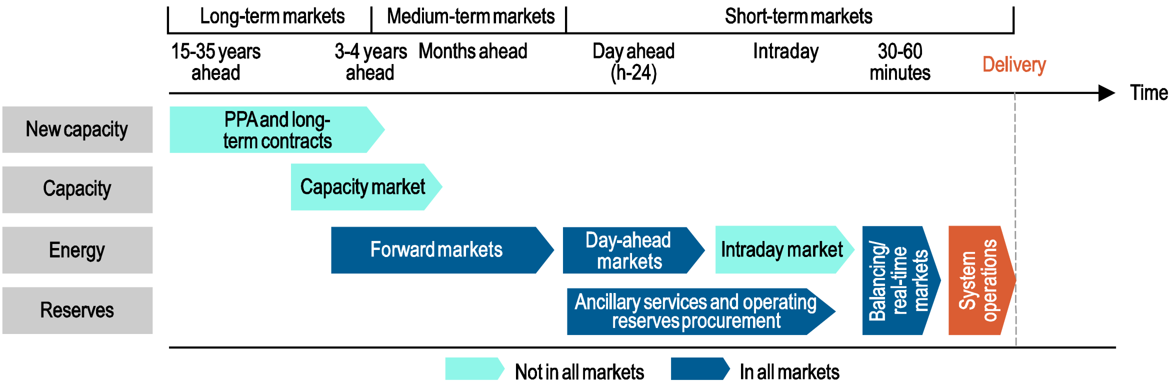
  The primary market is the real-time market. System operators calculate the locational marginal price for thousands of nodes in order to reflect real-time congestion on the network (Schweppe et al., 1988; Hogan, 1992 and 1999). In order to better reflect economically (in prices) the flexibility needed to accommodate renewables, the time resolution has recently been increased to five minutes in several markets. Day-ahead market prices reflect the best forecast of real-time electricity prices.

High-resolution market design constitutes the benchmark for short-term markets and can reduce overall costs of operating power markets (Green, 2007; Neuhoff and Boyd, 2011). Market design with a high geographic and temporal resolution is better suited to integrating increasing shares of VRE. Existing high-resolution market designs can be further improved if they become more transparent during the intraday time frame, to facilitate the adjustment of power schedules to improving wind and solar forecasts.

Conversely, the geographical resolution of low-resolution markets has to be improved to contribute to the efficient operation of a more diverse set of power plants. However, the contrast between high- and low-resolution market designs reflects the difference in information provided to the market about local and general scarcities in the system. Indeed, the laws of physics are the same everywhere, and even in low-resolution designs, system operators use centralised market platforms with location-specific information to manage congestion and call the power plants needed to balance generation and load in real time. Increasing the transparency of short-term balancing prices by location will become more important with high shares of renewables and would ensure a convergence of market designs (IEA, 2016b).

Recent improvements to the design of short-term markets have focused primarily on: enabling trading closer to real time, improving pricing during periods of scarcity, reforming markets for procurement of system services, allowing for trade over larger geographical regions, and better incorporating distributed resources. The last point is discussed in greater detail in the topical focus in after the next Chapter. The other points will be discussed in turn, alongside selected examples.

Figure 14 • Overview of the different building blocks of electricity markets



Note: PPA = power purchase agreement.

Source: Reprinted from IEA (2016b), *Re-powering Markets: Market Design and Regulation during the Transition to Low-Carbon Power Systems*.

Key point • A suite of interrelated markets is used to match generation and load in different timescales.

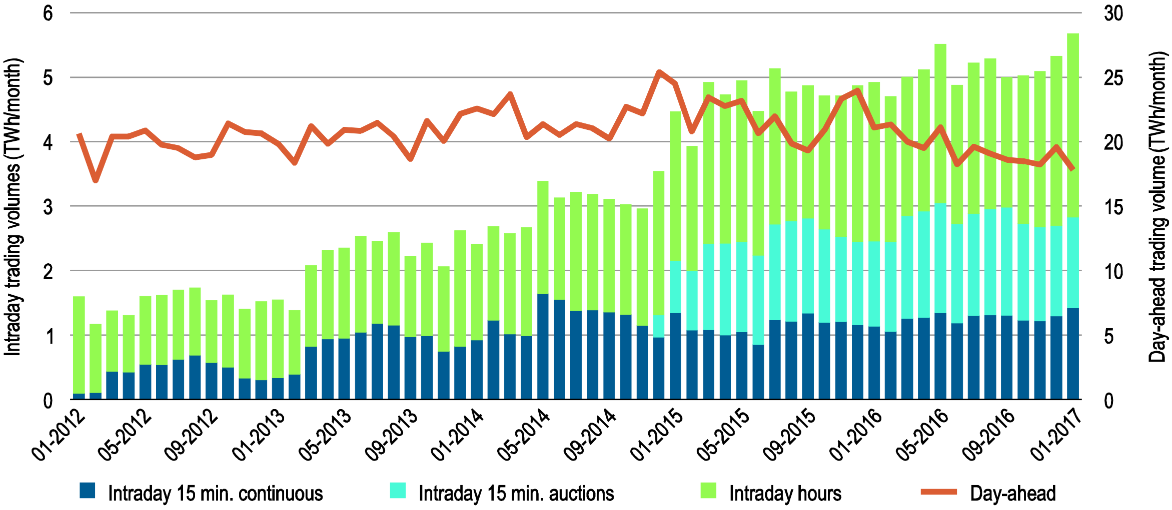
Moving operational decisions and trade closer to real time

Technical constraints call for a certain degree of forward planning and scheduling with regard to system operation. In practice, however, many power systems tend to lock in operational decisions far more in advance than technically required, sometimes weeks or even months ahead. For example, long-term contracts between generators and consumers may prevent power plants from providing flexibility. Such a situation is undesirable for least-cost system operation, in particular at high shares of VRE penetration. In regions where the share of VRE is on the rise, steps have been taken to improve the trading arrangements for electricity close to real time.

For example, in Europe a number of steps are being taken to improve the functioning of intraday markets. In Germany, the functioning of these markets has been systematically improved over recent years. As a first step, the German power exchange, Epex Spot, introduced the ability to trade 15-minute and 60-minute blocks of electricity on the intraday market, a higher level of granularity than the 60-minute contracts on the day-ahead market. This has allowed intraday trade to more accurately reflect the ramping up and down of solar PV generation during morning and evening hours. While trading was originally continuous (supply and demand matched as soon as possible), auctions were introduced in 2015 to improve market functioning (supply and demand offers are collected and then matched in groups). As a result, the volumes traded on the intraday market have increased substantially over the past five years (Figure 15).

Given that VRE forecasts are more accurate closer to real time, power plant schedules should ideally have the option to be updated accordingly. Otherwise, a power plant that may be technically capable of supplying flexibility may be prevented from doing so due to a binding schedule, which is based on outdated information. Where power plant schedules are determined by trade on a power market, the term "gate closure" refers to how close to real time generation schedules can be changed (without changing the plant-specific bids of market participants).

Figure 15 • Monthly trading volumes on the German intraday market, 2012-16



Note: TWh = terawatt hour.

Source: 50Hertz Transmission GmbH (2017), "The transmission perspective".

Key point • Germany has systematically developed its intraday market to facilitate trading closer to real time.

In the United States, the Federal Energy Regulatory Commission (FERC) passed a new rule in June 2016 (FERC, 2016b) that aims to improve trading of electricity closer to real time. FERC now requires US independent system operators (ISOs) and regional transmission organisations (RTOs) to settle real-time markets at the same resolution as the dispatch of the system.[14] Historically, market participants were sometimes only allowed to submit price offers that were valid for a full hour, while the actual adjustment of power plant operations was performed on a five-minute basis. However, this meant that it was not possible to update bids according to new information close to real time. The new ruling removes this mismatch, mandating that the length of the settlement period be the same as the dispatch interval. The same principle is applied to operating reserves. The rule will affect those ISOs that have not already adopted these practices (ISO-NE, MISO and PJM). The rule also targets improved scarcity pricing (see next section).

A similar process is under way in Australia, where the Australian Energy Market Commission is currently considering a rule change to align the National Electricity Market (NEM) settlement period (currently 30 minutes) with its dispatch interval (5 minutes). The rule change was requested in May 2016 and is currently under consideration (AEMC, 2017a). The supporting documentation for the requested rule change – submitted by a large energy consumer – highlights why such an alignment can be desirable:

> Generators receive the average price of generation over a full interval. If fast generation is scheduled for one dispatch interval on the basis of a high price bid, it is paid the average dispatch price over the 30 minute trading interval, for the dispatch over the one interval in which it participated. The average price may not be sufficient for investment in fast response generation, or for operation of existing fast response generation. […]
>
> Likewise, loads pay the average price across the whole trading interval; even if they respond to the price spike to reduce output, they are unable to reduce their output on past

[14] These are the California ISO (CAISO), ISO New England (ISO-NE), Midcontinent (MISO), New York ISO (NYISO), PJM and Southwest Power Pool (SPP).

dispatch intervals. The overall impact of time weighted 30 minutes pricing, instead of 5 minute actual usages is that the price changes after consumption. (Sun Metals, 2016)

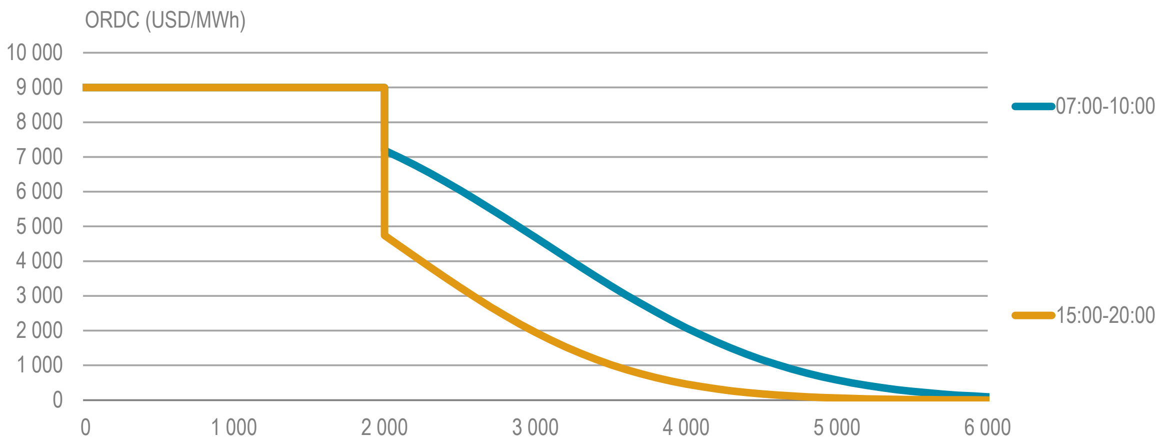
Improving the short-term operation of the power system is possible even in a context where the policy, market and regulatory frameworks are not well suited to achieving this by default. For example, the power regulation ancillary service introduced in North-East China in 2014 effectively serves as a mechanism to facilitate trading of electricity on an intraday timeframe. Under the mechanisms, thermal generators offer the capability to adjust their output downwards beyond the usual operating levels at short notice. Adjustments below a certain level receive an additional financial compensation, increasing the incentive to improve their ability to respond to short-term system conditions (Zhang and Du, 2016).

Improving pricing during scarcity/capacity shortage

Markets such as that managed by the Electric Reliability Council of Texas (ERCOT) and the Australian NEM currently rely on high wholesale energy prices during times of scarcity to incentivise new generation capacity. It is worth noting that in 2014 ERCOT introduced operating reserve demand curves as an administrative mechanism to improve wholesale pricing during scarcity, increasing the prices according to an administratively predetermined schedule as the available operating reserve decreases. This curve places an economic value on capacity in cases of capacity shortage, progressively increasing the price up to the value of lost load (USD 9 000 per megawatt hour [MWh]) (Figure 16).

This "reliability price adder" ensures that reliability actions taken by ERCOT are actually reflected in reserve and energy prices. (In the absence of this adder, reliability actions would supress prices). Scarcity prices create the incentive for all market participants to provide capacity when it is most needed by the system, and these high prices are contributing to the recovery of the fixed costs of capacity that is rarely used. This illustrates one form of regulatory intervention to improve scarcity price formation.

Figure 16 • Examples of operating reserve demand curves (ORDCs) in the ERCOT region, summer 2017



Note: ORDC = operating reserve demand curve.

Source: Adapted from ERCOT (2017), *Real-Time Market*, www.ercot.com/mktinfo/rtm.

Key point • ORDCs can be used to place an economic value on operating reserve in real time.

Scarcity price formation has also been improved in markets that have capacity mechanisms. For instance, PJM is working on the implementation of an operating reserve demand curve (PJM, 2016). Similarly, the Electricity Balancing Significant Code Review in Britain recently introduced reserve scarcity pricing to price short-term reserves into the "cash-out" balancing prices. Other regulators and system operators in Europe (e.g. the Commission for Electricity and Gas Regulation in Belgium and the Finnish TSO) are also considering the possibility of introducing price adders to improve scarcity price formation (B&B, 2016)

Germany provides an example of reform adopting a twin approach, with its recent electricity market reform. A system of strategic reserves has been introduced as a safety net during a transitional period. In the longer run, Germany intends to rely on an energy-only market (market design 2.0) and adjustments are being made to improve scarcity pricing on the wholesale spot market, most notably with the removal of price caps on the-day ahead and intraday markets.

Scarcity pricing and capacity markets can be seen as complementary instruments, with capacity mechanisms providing an additional safety net to meet reliability standards.

Reforming mechanisms for the procurement of system services

Reliable operation of the power system critically depends on a number of system services, which contribute to maintaining system frequency and voltage levels. Special capabilities may also be required when restarting the system after a large-scale blackout (so-called black-start capabilities). Different systems may obtain the same service in different ways, for example some will mandate it in the grid code, while others use a procurement or market mechanism.

The reform of system services markets can improve the functioning of the overall market. Indeed, the above examples of using operating reserve demand curves to improve scarcity pricing highlights the link between system services markets, efficient system operation and investment signals.

As the penetration of VRE increases, the need for such services – and hence their economic value – is bound to change. One reason behind this is that conventional generators have traditionally provided many of these services as a simple by-product of power generation. For example, a conventional generator contributes to voltage and frequency stability with its voltage regulator and governor, including the inertia stored in the rotating mass of its turbine and generator. VRE power plants generally have limited capability to provide such services, particularly fast frequency response, which can make it necessary to explicitly procure them.

Higher levels of VRE also increase variability and uncertainty in the supply-demand balance. Hence, it becomes a priority to mobilise higher levels of flexible resources, such as storage and demand response. Reforming system services markets has a critical role to play, alongside other measures (see section on flexibility below).

Ireland and Northern Ireland are committed to increasing the share of renewable energy in electricity generation to 40% by 2020. In this context, to identify possible operational issues in the power system over the coming years, they have established the DS3 work programme (see Box 23). This programme started a consultation process on a range of new system services products to address and mitigate potential system issues, which had been identified previously by comprehensive technical studies. New products have been proposed to address the challenges associated with frequency control and voltage control in a power system with high levels of variable, non-synchronous generation (Eirgrid/SONI, 2016). The new services identified under the DS3 programme include synchronous inertial response, fast frequency response, fast post-fault active power recovery, and ramping margin. These supplement existing system services products, reflecting new requirements in the specific, Irish context.[15]

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[15] The issue of low system inertia and rate of change of frequency (RoCoF) is particularly prominent in Ireland and Great Britain, because RoCoF is used to detect islanding on distribution grids (0.5 hertz per second threshold). The issue of islanding on distribution grids is not the case in many other systems, which are thus likely to face inertia-related issues at a later stage.

Similarly, the Australian Energy Market Operator (AEMO) launched the Future Power System Security programme in December 2015 (AEMO, 2017b). Its objective is to adapt AEMO's functions and processes to deliver ongoing power system security and reliability. The programme targets four high priority areas: frequency control, system strength, management of extreme power system conditions and visibility of the power system. With regard to frequency control, a fast frequency response mechanism is currently under consideration, supplementing existing frequency control ancillary services. One large generator, AGL, also submitted a rule change in September 2016 to establish an ancillary services market for inertia (AEMC, 2017b). These reforms are all ongoing at the time of writing.

A further example of an innovative market product for system services is CAISO's flexible ramping product. It is designed to enable procurement of sufficient ramping flexibility from the conventional generator fleet in order to meet ramping needs that arise from more pronounced changes in the supply-demand balance (CAISO, 2014). Other ancillary services, including frequency response and operating reserves, are already integrated into CAISO's day-ahead and real-time energy markets, with generators bidding into the CAISO ancillary services market, which is co-optimised with energy markets.

In jurisdictions where system services markets have historically received less attention, processes are ongoing to establish standard mechanisms or to begin remunerating services that were traditionally a non-compensated requirement. For example, in India the Power System Operation Corporation Ltd. has released procedures detailing the implementation of a new Reserves Regulation Ancillary Services (POSOCO, 2016). This step marks the introduction of an explicit, financially compensated operating reserves system. In Italy, the Italian Regulatory Authority for Electricity Gas and Water (AEEG) introduced the option of voluntary participation in the primary frequency regulation service in 2014. Previously, this was a purely mandatory, non-compensated service (Terna, 2017b).

Exchanging electricity over larger geographical areas

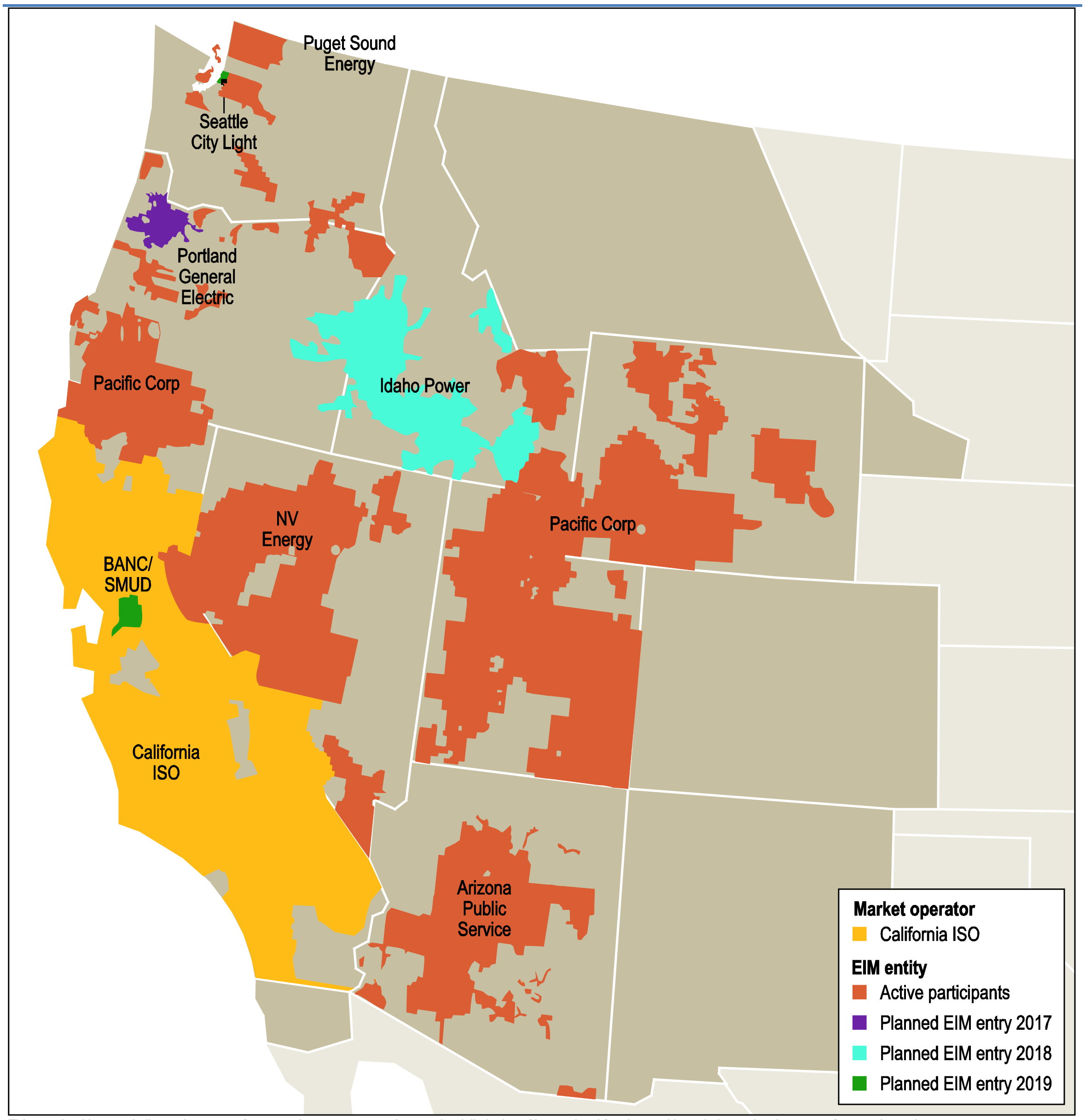
Strengthened integration of markets over large regional areas is important to unlock the benefit of smoothing out the variations and forecast errors associated with VRE and dynamic loads. However, regional integration of power systems is not new. In fact, the development of electricity markets is inseparable from regional integration (IEA, 2014). For instance, the creation of large ISOs/RTOs, such as PJM and MISO in the United States or the NEM in Australia, is aimed at integrating many small balancing areas into one large market. Similarly, in Europe, power markets have largely been designed with the objective of enabling cross-border trade of electricity. The implementation of so-called Market Coupling in 12 countries in 2014 is a major achievement in this regard.

Recent trends have given a new impetus to this development, leading to the establishment of even larger balancing areas. For instance, in the western part of the United States, the Western Energy Imbalance Market (EIM) will enable California and its neighbours to share balancing resource on a regional basis, allowing for more efficient dispatch and reducing the need for new transmission investment. This initiative is relatively advanced compared to other regions, where balancing decisions are generally made at a local level, even when regional interconnections are available.

The Western Interconnect is a large synchronised area that includes 14 US states, two Canadian provinces (Alberta and British Columbia) and the northern portion of Baja California, Mexico. Regional reliability is co-ordinated by the Western Electricity Coordinating Council, but historically balancing responsibilities have remained at the state or local level. CAISO is the region's only ISO, and it operates entirely within the borders of California.

The Western EIM is the first effort to create a regional electricity market in the western portion of the United States. It is unique in two respects. First, unlike the regional wholesale markets in the Eastern Interconnect (PJM, MISO, etc.) the Western EIM is only a balancing market. Broader responsibility for transmission system operations remains the responsibility of each balancing area. Second, the service territory of the Western EIM is not contiguous (Figure 17). Participation in the EIM is voluntary, and utilities may exit at no cost with 180 days' notice. Currently six utilities participate, with three more expected to join over the next few years.

Figure 17 • Utilities participating in the EIM



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: CAISO (2017a), *Western Energy Imbalance Market (EIM)*

Key point • Expanding balancing areas enables different jurisdictions to share balancing resources, allowing for more efficient dispatch and reducing the need for grid investment.

In the absence of a regional entity capable of taking on explicit responsibility for organising the Western EIM, CAISO acts as the market operator. This has led to a somewhat unique governance structure. Although operational responsibility is centralised in CAISO, the Western EIM has its own governing board that includes representatives from participating utilities and regulators from relevant states.

While increased system reliability is often highlighted as a potential benefit of the Western EIM (NREL, 2013), since its implementation the quantification of benefits has focused on economic and environmental impacts. Three benefits are highlighted in particular: more efficient dispatch; reduced curtailment of renewable energy resources; and reduced requirements for flexibility reserves. Estimated benefits for the fourth quarter of 2016 are summarised in Table 5.

Table 5 • Estimated benefits of the Western EIM, quarter 4, 2016

Benefit	Estimated savings
More efficient inter- and intraregional dispatch	USD 28.27 million
Reduced curtailment of VRE	23 390 MWh
Estimated CO2 savings from reduced curtailment	10 011 tonnes
Reduced flexibility reserves	Upward: between 399 MW and 490 MW Downward: between 474 MW and 482 MW

Source: CAISO (2017b), Western EIM Benefits Report Fourth Quarter 2016.

In Europe, progress has been made on integrating the day-ahead electricity markets, but the need remains to better integrate short-term intraday and real-time/balancing markets. The efficiency of markets over large geographical areas requires strong co-ordination and the consolidation of balancing areas.

Efforts to increase market integration and harmonisation across Europe have centred on the development of network codes. The European Union's 2009 legislative package (colloquially known as the "Third Package") mandated, among other things, the development of European Network Codes and Guidelines. These network codes establish a common set of technical and commercial rules for a wide range of topics, including: network security; third-party access; data exchange and settlement; emergency operational procedures; and capacity allocation and congestion management (CACM) for real-time, day-ahead and long-term markets.

Development of the network codes has been managed through an iterative, multi-stakeholder process. The Agency for the Cooperation of Energy Regulators (ACER) is responsible for developing general framework guidelines for each network code, which the European Networks for Transmission System Operators for Electricity (ENTSO-E) then turns into fully developed documents. ACER reviews the network codes, but only the European Commission can approve the final text. Responsibility for implementing the network codes rests with the member states.

This iterative process has been slow and complex, and as a result implementation of some network codes has lagged behind others. Their development has been driven, however, by a set of common concerns, not least of which is the need to more efficiently integrate increasing penetrations of VRE while maintaining system reliability. Implementation of the CACM was in particular seen as a critical piece, as it increases the utilisation of interconnectors and improves overall system flexibility (Hesseling and Hernández, 2015).

More recent proposals by the European Commission to increase regional integration focus on the development of so-called Regional Operating Centres (ROCs). These are an evolution of the existing Regional Security Cooperation Initiatives (RCSIs), voluntary regional collaborative bodies established by the TSOs. The RSCIs do not work in real time, but instead develop system forecasts for their regions based on TSO data. These are the components of a directive proposed as a part of a broader "Clean Energy for all Europeans" package of legislative proposals, presented in November 2016 and currently being discussed at EU level. A final text is expected in 2018.

The evolution toward ROCs is being driven by a requirement of the Third Package for increased regional co-operation. What this means in practice is still under heavy debate. At a minimum, ROCs would perform five services: common grid modelling; analysis of system security; co-ordination of outage planning; short- and medium-term resource adequacy forecasts; and co-ordinated calculation of transmission capacity (ENTSO-E, 2017d). The preferred approach by ENTSO-E, which represents the national TSOs, has been a gradual, "evolutionary" approach. Regional co-operation would be enhanced, but decisions on what additional responsibilities should be borne by the ROCs would be delayed for at least another decade (ENTSO-E, 2016b).

Many barriers still stand in the way of regional integration of electricity markets. If the efficiency gains of market integration are important, so are the possibly large distributive impacts. When deciding to invest in new interconnections to achieve better integration of markets, decision makers and regulators have to look beyond the interests of domestic consumers and consider the broader implications for integrated markets. Regional markets require regional governance.

Indeed, even in regions where framework conditions are quite different, closer co-operation can bring value to both sides. For example, despite having very different power market structures, Singapore and Malaysia have been trading electricity on an ongoing basis for years. Singapore has an unbundled, competitive wholesale market environment, while Malaysia has a single-buyer model. The two countries are connected by a single, 450 MW interconnection used for two primary purposes: meeting peak demand, and maintaining overall system stability.

Historically, in the absence of an established method for trading power on an economic basis, power is instead exchanged on a bilateral, rolling net-zero energy exchange basis. That is, exchanges are netted to zero over time to avoid any need for financial compensation.

Ensuring sufficient investment in clean power generation

Investment in new generation capacity requires sufficient long-term visibility of expected revenues. This is true irrespective of the policy, market and regulatory frameworks. In a vertically integrated, regulated monopoly this certainty is provided by the regulator, who allows the monopoly to recover its cost from consumers. In an environment of competitive wholesale markets, forward markets play a critical role in providing sufficient visibility several years ahead. However, large-scale uptake of renewable energy and other low-carbon energy sources can challenge both these approaches.

In the regulated environment, incumbent utilities often face challenges in accessing low-cost capital to shoulder the up-front investment in clean generation options. Indeed, renewable, nuclear and carbon capture and storage power plants all have in common the fact that they incur significant upfront costs. Hence, the cost at which financing can be obtained has a critical impact on overall costs. Resolving this situation is possible by creating a dedicated off-taker that has sufficient financial credibility, and procuring generation capacity via a competitive auction for long-term PPAs.

The challenges in regions with liberalised markets are quite different. These markets are typically already well served with existing capacity (United States, Europe) and in some cases even have surplus capacity. This creates a generally poor environment for new investment. In addition, even where power prices appear attractive in the short- and medium-term, forward visibility may be insufficient to secure financing at a reasonable cost. Hence, in this context long-term mechanisms have also been used to mobilise investment in new, cleaner generation capacity.

It is worth noting that the role of such frameworks in procuring new generation has been shifting in recent years. Rather than covering a large cost gap in relation to fossil sources, their role is now providing revenue certainty to mitigate risk for capital-intensive technologies. In the absence of such measures, the risks are likely to drive up the cost of deployment or hinder it altogether (IEA, 2015a).

As the global VRE industry matures, governments and utilities are moving towards competitive procurement mechanisms to attract competition and drive down costs; this trend is occurring in markets with a diversity of institutional frameworks, including those with wholesale power markets. These competitive procurement mechanisms still offer long-term contracts, but the ultimate price of the contract is discovered through competition.

In most cases of a competitive procurement framework, a government or utility issues a call for proposals or tenders for a specified amount of capacity or generation of electricity.[16] VRE developers then submit bids to supply the capacity or energy, and the government or utility evaluates proposals based on price competitiveness, a host of technical criteria, and in some cases economic development or social impact criteria. When a proposal is accepted, the electricity off-taker enters into a PPA with the VRE project owner. The awarded PPA can be a fixed-price contract, or another pricing mechanism such as a Contract for Difference (CfD). In the United Kingdom, a new round of CfD auctions for renewable technologies will begin in April 2017 (Nabarro, 2016).

Properly designed, auctions can help ensure transparency, increase levels of participation, and reduce uncertainties and delays.[17] They can also allow different technologies to compete with one another. Auctions can also be designed to include elements that ensure VRE deployment is done in a relatively system-friendly way, for example by including locational requirements or by aligning results with grid development.

Auctions have been instrumental in lowering the price for wind and solar projects, as some recent examples highlight:

- **Mexico**: the Federal Electricity Commission purchased 1 860 MW of solar PV at a price of USD 0.0501 per KWh (GTM, 2016).
- **India**: The Solar Energy Company of India purchased 950 MW of solar PV in the state of Karnataka at a price of USD 0.066 per kWh (Clean Technica, 2016).
- **Chile**: Solarpack, a Spanish solar PV developer, won the right to supply 280 gigawatt hours of solar PV generation per year with a bid of USD 0.0291 per kWh, scheduled to enter operation in 2019 (Photon, 2016).
- **United Arab Emirates**: the joint Chinese and Japanese consortium JinkoSolar-Marubeni won a tender for 350 MW of solar PV with a bid of USD 0.0242 per kWh, which is expected to begin operating in 2019 (Clean Technica, 2016).

It is worth pointing out that in a limited number of settings, certain VRE projects are being financed and deployed without long-term contracts. In these cases, VRE projects are deployed as merchant generators participating in wholesale electricity markets, and utilising short- or medium-term contracts for portions of their output when economically rational.[18] These projects may also benefit from alternative support schemes that help to reduce project risk.

Recently, a 320 MW solar PV farm in Victoria, Australia, was able to secure financing and initiate construction with no PPA in place (Vorrath, 2017). Australia's wholesale markets, combined with incentives for solar energy, have created a market that is strong enough to support project

[16] In the past, these competitive procurement frameworks have been technology specific. More recently, there has been a shift toward facilitating competition across all technologies.

[17] For a detailed treatment of auction design elements see IRENA (2015).

[18] Specifically, these VRE projects are forgoing traditional long-term contracts in favour of direct bidding into wholesale day-ahead or spot markets. These shorter-term contracts are often not secured by the time the project is commissioned.

development without a guaranteed off-taker. Similarly, in Texas, certain wind plants are being financed and built as merchant projects without long-term PPAs in place. In 2014, approximately one-third of new wind projects in Texas were financed based on a combination of long-term (10-13 years) hedging contracts and direct participation in wholesale markets (NAW, 2015). Projects built in Texas may, however, benefit from the federal investment tax credit (ITC),[19] which lowers capital costs, and the production tax credit, which helps offset revenue uncertainty, as well as the sale of renewable energy certificates to meet the renewable portfolio standard obligation.

Pricing of negative externalities

Accurately reflecting the full cost of power generation is a precondition for taking sound investment and operational decisions, regardless of the policy, market and regulatory frameworks in place. Such externalities include environmental impacts, such as local air pollution and, critically, carbon dioxide (CO_2) emissions.[20]

Carbon pricing has been introduced or strengthened in a number of countries, and if such trends continue, this will contribute to increasing electricity prices from fossil-fuel generation, which creates more favourable conditions for investment in renewable energy.

In Europe, the EU Emissions Trading System (ETS) was launched in 2005, resulting in a carbon price too low to affect either operational or investment decisions. The introduction of measures, such as a temporary “back-loading” of emissions allowances and the creation of a market stability reserve, are attempts to strengthen the scheme, but have yet to succeed in significantly lifting prices above the low EUR 5 to EUR 7 per tonne of CO_2 (tCO_2) range.

In the United Kingdom and Australia, carbon pricing has also been a source of uncertainty for investors. In the United Kingdom, in 2011 the government introduced a carbon price floor as a top-up tax on the EU ETS. The floor was intended to rise every year to reach GBP 70/tCO_2 by 2030. However, one year after its introduction in 2013, the government decided to cap the floor price until 2021 (Ares and Delebarre, 2016).

In Australia, an ETS with an initial fixed price of AUD 23/tCO_2 was introduced in 2012, with the objective of coupling this price to the EU ETS. Subsequently, the new government elected in 2013 cancelled the policy.

In the United States, an attempt was made in 2010 to introduce a carbon price at the federal level, but the Waxman-Markey Bill failed to pass in the Senate. At a state level, several regional initiatives, such as the Regional Greenhouse Gas Initiative (RGGI) and the California ETS, have been developed, but the resulting carbon prices remain fairly low, in the range of USD 5/tCO_2 to USD 15/tCO_2.

Confronted with the difficulties associated with carbon pricing, certain governments have taken alternative measures to constrain carbon emissions using direct regulation. As an example of direct regulation, in the United States the Obama administration turned to the Environmental Protection Agency (EPA) to implement regulations restricting power-sector CO_2 emissions through the Clean Power Plan (CPP). This programme, however, has been abandoned by the current administration.

[19] Note that ITC for small wind turbines (up to 100 kW) and large wind turbines are negligible after 2016 and 2019, respectively.

[20] Certain authors also consider the potential cost of dealing with the uncertainty and variability of wind and solar power to be an externality. However, such associated costs can be priced into the market without the introduction of regulatory instruments. The definition and pricing of such “integration costs” face a number of practical and conceptual challenges; see (IEA, 2014; IEA/NEA, 2015) for details.

Ultimately, carbon pricing is a political construct, i.e. a government intervention designed to stimulate investment and innovation in a certain direction. As such, any investment exposed to a carbon price is exposed to a degree of regulatory risk; this can be mitigated, but never fully removed. This set-up has important implications for the investment risks associated with both high-carbon and low-carbon technologies: high carbon prices, or the expectation of high prices, may deter investment in carbon intensive options, but low carbon prices, or the risk of low prices, may thwart investment in cleaner options. Moreover, an investment made under the assumption of a high carbon price may become uneconomic if the government decides to reduce or remove the price (IEA, 2015a).

Unlocking sufficient levels of flexibility

In most power systems, improved operations and system-friendly VRE deployment will not be sufficient to reach energy policy objectives. Additional investment in flexible resources will also be necessary. Securing such investment becomes an important aspect of the overall policy, regulatory and market frameworks. Sufficient flexibility can be delivered though an appropriate mix of the four power system resources: flexible generation, grid infrastructure, demand response and storage (IEA, 2014).

Flexible generation

Flexible generation (predominantly from thermal generators) is often a highly cost-effective, mature and readily available option to balance VRE variability and uncertainty. This option is critical to ensuring security of supply during sustained periods of low VRE generation. Rather than implementing dedicated mechanisms to incentivise power plant flexibility, other aspects of the policy, market and regulatory frameworks should be designed with a view to remunerating flexible generation. The examples provided in the section on operational efficiency, scarcity pricing and managing asset retirement are all relevant in this regard.

Demand-side integration

Demand response can be a key resource for power systems. A participatory demand side can be cast in many moulds, depending on:

- Who is participating (e.g. regulated customers, larger industrial users).
- How they are participating (e.g. via regulated programmes run by distribution utilities, deregulated private-sector aggregation or direct market participation).
- How compensation levels are determined (e.g. regulated compensation versus market-based compensation).

It is important to note that much of the growing demand-side participation observed today continues to be driven by peak demand reduction. Looking ahead demand-side resources will increasingly help to meet additional system flexibility needs.

France has been a front-runner in the implementation of time-of-use and dynamic electricity tariffs. In the 1960s, the national utility, EDF, was already offering differentiated electricity tariffs (day/night and seasonal). The EJP (*effacement jour de pointe*) tariff introduced in the 1980s is a form of critical peak pricing that helped grow the country’s demand response capacity to 6.5 GW in 2000 (Veyrenc, 2013). Over the years, the availability of these tariffs has been reduced due to electricity market liberalisation, and the capacity subsequently declined to 3 GW.

In France, the first demand response operators entered the commercial and industrial market in 2003, and the residential market in 2007. They offered consumers the ability to manage their electricity demand in exchange for financial compensation. The French TSO, RTE, opened up participation in the energy and balancing markets, but the minimum threshold for eligibility was 10 MW, automatically keeping out direct participation from residential consumers as well as small and medium-sized companies.

One outstanding question in this system related to the remuneration of load shifting contracted by new aggregators. To address this, in 2012 France introduced new rules called NEBEF (*notifications d'échange de blocs d'effacement*), making RTE the only intermediary through which bids and offers for load shifting can be made.

With the introduction of a capacity remuneration mechanism in France in January 2015, demand response can become fully eligible to participate and therefore the regulated incentive mechanism will be cancelled. Aggregators will participate and be remunerated on the capacity mechanisms. In addition, a support mechanism was introduced under which aggregators benefit from a financial incentive, financed by the regulated electricity tariff.

Many other countries in the European Union have since opened electricity markets for demand response participation, and the European Commission has issued guidance for member states to improve demand-side participation in electricity markets (JRC, 2016). In the United States, the wholesale power market, PJM, allows for demand-side resource to be bid into wholesale energy and capacity markets. Demand response in that market is primarily provided by private-sector aggregators (McAnany, 2017). California is launching a "Demand Response Auction Mechanism" pilot programme, where the state's three large investor-owned utilities will partner with the private sector to aggregate retail customers for demand response, and bid them into the day-ahead electricity market (TURN, 2014). ERCOT contracts for half of its primary frequency response from demand resources.

Regulated distribution utilities are also increasingly offering pathways for small customers to participate in demand response, driven by regulatory mandates or incentives. For instance, Hawaiian Electric Company offers monthly bill credit to residential customers in return for enabling centralised controllability of their water heaters and air conditioners (Hawaiian Electric, 2017a). For commercial and industrial customers over 50 kW, a separate "fast demand response" programme provides relevant communications infrastructure and financial incentives to facilitate demand reductions during times of peak demand, reliability events, or to help integrate VRE (Hawaiian Electric, 2017b).

Storage

Electricity storage has played a much greater role in providing power system flexibility in recent years, particularly in Europe of the United States. However, its relatively high cost remains an important barrier to its deployment. To be cost-effective, battery electricity storage currently needs to combine multiple revenue streams, driven by the broad range of services it can provide. This can challenge existing policy, market and regulatory frameworks, because it may be challenging for one single economic actor to access all possible value streams of a storage asset.

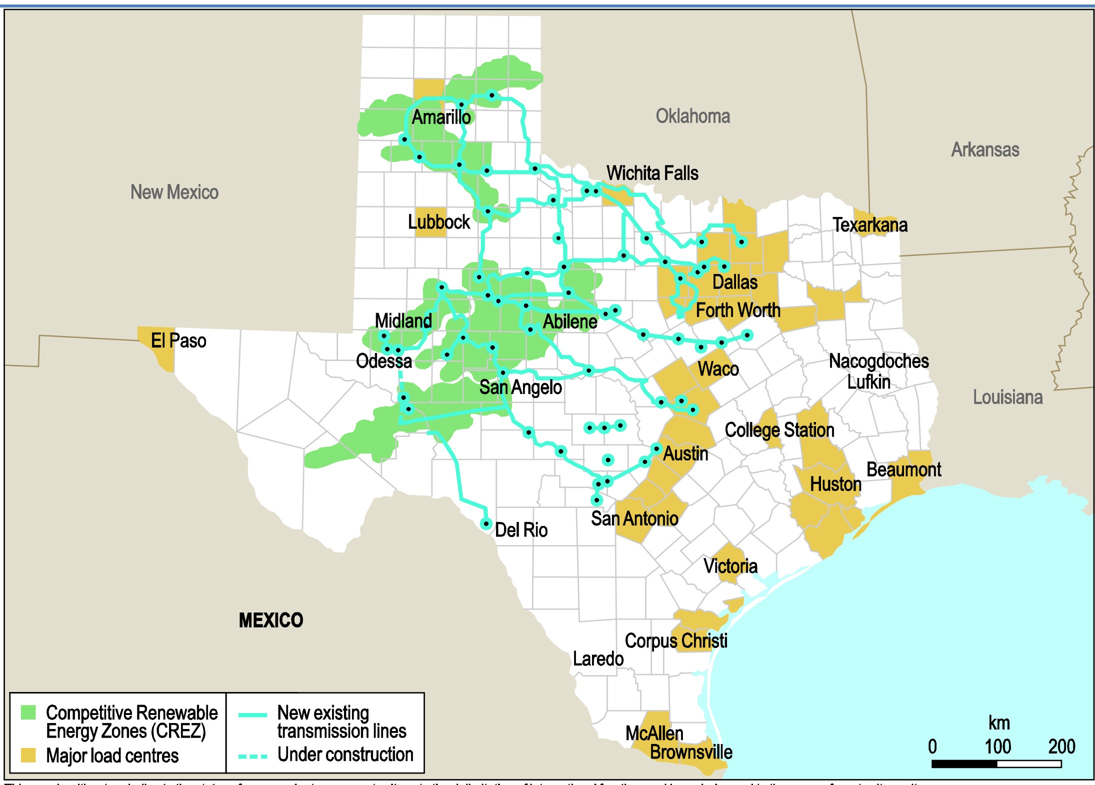
Nevertheless, storage has been making inroads in a number of cases. A prominent example is the recent auction for a new type of system service in the United Kingdom. Enhanced Frequency Response (EFR) is a novel service identified as a priority by National Grid as part of its System Operability Framework to deal with renewable energy integration (National Grid, 2016). The service was procured via a technology-neutral auction mechanism. In a highly competitive auction, 201 MW of EFR were procured at a total cost of GBP 65.95 million with an average price of GBP 9.44/MW per hour of EFR (National Grid, 2017). A surprise in the auction process was the success of electric batteries, which took the entire auction. This reflects both the increasing competitiveness of battery storage as well as the specific technical requirements for EFR.

A further challenge for establishing a level playing field for storage is its hybrid nature; it can be a load and a generator depending on whether it is charging or discharging. In the United States, FERC has proposed a tariff revision to create consistent rules in ISOs/RTOs for participation of electric storage. This measure would also explicitly define distributed energy resource aggregators as a market participant, eligible to compete in wholesale markets. Currently ISOs/RTOs are allowed to limit how certain resources are able to participate. For example, in MISO, "stored energy resources" are only allowed to provide regulation service. The FERC rule would require that ISOs/RTOs change tariffs to explicitly allow storage to participate in wholesale markets (FERC, 2016c)

Grid investment

With the exception of limited investment in merchant transmission lines, networks continue largely to be viewed as natural monopolies that need to be regulated. Regulatory reforms have therefore focused on incentive-based regulation aimed at replicating the efficiency of markets. This has been supported by the development of independent regulatory bodies. Still, regulators and policy makers have not always fully adapted the regulatory framework to be fit for decarbonisation. In particular, the deployment of renewable resources can often outpace network development. Network development will need to anticipate where renewables are likely to be built, while policy makers and regulators will need to explicitly link incentives for new transmission lines to other policies that support investment in renewables. The Competitive Renewable Energy Zones (CREZs) in Texas offer one example of such a policy (Figure 18).

Figure 18 • CREZs in Texas



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: reprinted from IEA (2016b), *Re-powering markets: Market Design and Regulation during the Transition to Low-Carbon Power Systems*

Key point • CREZs were created as a proactive means to alleviate grid congestion by designating renewable sources in suitable areas of the grid.

As noted above, regional expansion of power systems allows for the more efficient integration of variable generating resources. Fully reaping the benefits of regional integration of electricity markets, however, requires co-operation at a regulatory, as well as operational, level. Regulatory co-ordination across borders, however, can be difficult. Efficient development of cross-border infrastructure requires, for example, the development of common methodologies for cost-benefit tests. In Europe, the costs of cross-border infrastructure have generally been split on a 50:50 basis – a simple rule that is rarely the most economically efficient. Looking ahead, benefit tests may also need to look beyond pure economic benefits, taking into account, for example, reliability benefits as well. Power systems in member economies of the Organisation for Economic Co-operation and Development, however, tend to already be highly reliable, making the reliability benefits of new infrastructure difficult to quantify.

Designing capacity mechanisms

Capacity mechanisms supplement energy market revenues with explicit, forward-looking capacity requirements. Auctions are held a few years (typically three or four) ahead of when capacity is expected to be needed, with payments guaranteed for one year, or in some limited cases multiple years.[21] In each of these cases the resource adequacy target – or demand for capacity – is administratively determined.

Such mechanisms aim to provide the incentive for investment in sufficient supply to safeguard resource adequacy. They are prevalent in organised wholesale markets in the United States (ERCOT, an exception, is discussed below), and are becoming more prevalent among competitive markets in Europe (EC, 2016). Forms of capacity mechanism have recently started operations in United Kingdom (2015) and France (2017), and other EU countries (Spain, Ireland and Italy), as well as Japan, are currently implementing or considering such instruments.

While capacity mechanisms are not new, interest in them has surged in certain power systems that have been undergoing transformation in recent years. These systems typically experience a confluence of several factors. First, electricity demand growth is generally sluggish, so that new investments are not needed to balance the market in the short term. Second, there is a push for cleaner generation options, backed by policy mechanisms such as portfolio standards, tax credits, feed-in tariffs or auctions for long-term contracts. Third, existing capacity is ageing, raising concerns over the exit of large amounts of capacity. These conditions are present in parts of Europe, the United States and – most recently – also Australia.

Capacity mechanisms have typically been designed based on the needs of traditional power systems, and the question therefore arises as to whether they are well suited to “transformed” power systems. For example, the traditional metric for resource adequacy is the power system reserve margin (or amount of capacity in excess of expected peak load). For systems with high penetrations of VRE, however, appropriate reserve margins may be difficult to calculate, as the amount of available capacity needed at any given time is dependent on more inherently stochastic processes.

The design of capacity mechanisms also increasingly enables the participation of demand response, and this has proved to be a highly effective solution to kick-start the business of aggregators. These systems may also find that resource adequacy is less of a concern than overall system flexibility. Some have called for capacity mechanisms to be reformed to incentivise investment in more flexible generation (RAP, 2012). Others have expressed concerns that capacity mechanisms may incentivise continued operation of conventional fossil generation and

[21] Some auctions, such as the capacity market organised by NYISO, operate on a shorter-term time horizon, with payments only guaranteed for the following month.

new investment in flexible polluting capacity (such as diesel engines or gas turbines), making it more difficult to decarbonise the power sector (ODI, 2016). This has led to the introduction of emission performance standards in some cases, which could undermine the objective of capacity mechanisms to prevent a shortage of capacity.

These criticisms, however, are best addressed by ensuring that capacity mechanisms are designed in such a way as to be technology neutral and to minimise distortions to the wholesale market. To put capacity mechanisms into perspective, in PJM, the capacity component represented 21.9% of the total wholesale electricity price per MWh (Monitoring Analytics, 2017). In France, the first capacity price was EUR 10 per kilowatt (kW) and the regulator estimated that this would represent EUR 1.44/MWh for 2017 (CRE, 2017). It is also clear that, depending on the future progress of demand response and policy maker tolerance for lower levels of reliability, properly designed energy-only markets can also provide the incentive for investment (IEA, 2016c).

Achieving system-friendly VRE deployment

Power system transformation and the instruments to achieve it are receiving an increasing amount of attention. However, this attention is not distributed evenly. Options such as "back-up" capacity or electricity storage often feature prominently in the policy discussion, while potentially much more cost-effective options, such as demand-side response, are all too often forgotten. The same is true for the contribution that VRE itself can make to its cost-effective integration.

The fact that VRE is not seen as a tool for its own system integration has historic reasons. Policy priorities during the early days of VRE deployment were simply not focused on system integration. Rather, past priorities can be summarised as maximising deployment as quickly as possible and reducing the LCOE as rapidly as possible.

These objectives were sensible during the early phases of global VRE deployment (see IEA [2011b] and IEA [2015a] for discussion of different deployment phases). Ignoring integration issues reduces policy complexity and avoids the potential need for trade-offs between different objectives. However, this approach is not sufficient at higher shares. Innovative approaches are needed to trigger advanced deployment and unlock the contribution of VRE technology to facilitating its own integration.

As wind and solar power enter their next generation of deployment, policy objectives need to be revised. Comprehensive and predictable policy, market and regulatory frameworks are needed to catalyse the transition of the power and wider energy system. This has broad implications beyond RE policy and includes areas such as electricity market design, energy taxation and rollout of infrastructure to enable demand-side response, as well as coupling to other energy sectors (heating and cooling, transport).

Previous IEA and OECD analysis has looked at various aspects of such frameworks, including the comparative assessment of different flexible resources (IEA, 2014), the design of RE policies (IEA, 2015a), electricity market design (IEA, 2016c) and aspects beyond the electricity system (OECD, 2015). The following discussion addresses the implications of a focus on SV for RE polices, in particular mechanisms to unlock the contribution of system-friendly VRE deployment.

System value, or the need to go beyond costs

Achieving successful system transformation requires the co-ordination of numerous stakeholders in the electricity system. It requires a vast number of decisions about investment in generation infrastructure and flexible resources. Consequently, the conceptual framework for assessing the economics of the various options is of critical importance.

The generation cost of various technology options is most commonly expressed in energy terms and labelled the LCOE. This is a measure of cost for a particular generating technology at the level of a power plant. It is calculated by summing all plant-level costs (investment, fuel, emissions, operation and maintenance etc.) and dividing them by the amount of electricity the plant will produce. Costs that are incurred at different points in time (costs of building the plant, operational costs) are made comparable by "levelising" them over the economic lifetime of the plant – hence the name.

The LCOE of wind power and solar PV has seen significant reductions over the past two decades (IEA, 2015c; IEA, 2015d). In a growing number of cases, the LCOE of wind power and solar PV is close to, or even below, the LCOE of fossil or nuclear options. For example, the lowest currently reported prices for land-based wind are USD 30-35 per megawatt hour (MWh) (Morocco) and USD 29/MWh for solar PV (Dubai).

However, LCOE as a measure is blind to the when, where and how of power generation. The when refers to the temporal profile of power generation that can be achieved, the where refers to the location of power plant, and the how refers to the system implications that the type of generation technology may have. Whenever technologies differ in the when, where and how of their generation, a comparison based on LCOE is no longer sufficient and can be misleading. A comparison based only on LCOE implicitly assumes that the electricity generated from different sources has the same value.

The value of electricity depends on when and where it is generated, particularly in a power system with a high share of VRE. During certain times, an abundance of generation can coincide with relatively low demand – in such cases the value of electricity will be low. Conversely, when little generation is available and demand is high, the value of electricity will be high. Considering the value of electricity for the overall system opens a new perspective on the challenge of VRE integration and power system transformation.

System value (SV) is defined as the net benefit arising from the addition of a given power generation technology. While the conceptual framework applies to all power generation technologies, the focus here is on wind and solar power plants. SV is determined by the interplay of positive and negative effects arising from the addition. In order to specifically calculate the SV of a technology, one must first specify which factors need to be taken into account. For example, a calculation may or may not include positive externalities of technologies that do not rely on fuel that sees significant price fluctuations and associated risks.

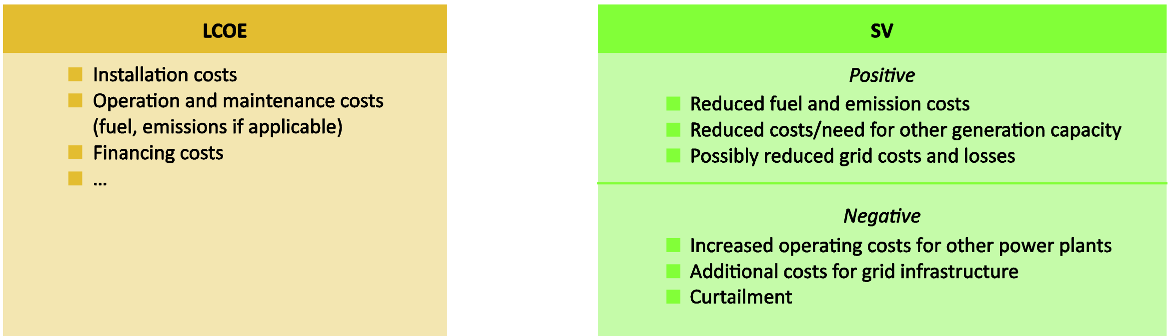
On the positive side are all those factors included in the assessment that lead to cost reductions; these include reduced fuel costs, reduced CO_2 and other pollutant emission costs, reduced need for other generation capacity, and possibly reduced need for grid usage and associated losses. On the negative side are increases in certain costs, such as higher costs of cycling conventional power plant and for additional grid infrastructure.

SV complements the information provided by classical metrics of generation costs, such as the LCOE. It captures the effects that additional generation has on the remaining power system. Simply put: the LCOE informs how much one has to pay for a certain technology, while the SV of that technology captures the net effects on the system (Figure 19).

Calculating the SV of a technology will require a number of assumptions to be made, such as fuel prices or CO_2 prices. It may also require modelling tools that can compare costs between different scenarios. One can also estimate certain components of SV by analysing actual market data. This has the advantage that it is fairly easy to obtain data, but it also requires a very careful interpretation of results. Only in the – theoretical – case that markets accurately price all relevant externalities, remunerate all benefits and charge all costs, do market prices fully reflect SV. The degree to which this is met in practice depends on a large number of factors. For example, assessing the SV on the basis of spot-market revenues (see analysis below for onshore wind) may not capture all relevant impacts on grid infrastructure if the same price is formed over large geographic regions. However, even partial information on SV may provide critical insights for policy and market design.

A high SV indicates a good match between what a technology provides and what the power system needs. For example, when a new VRE power plant generates during times of high electricity prices, this favourable situation will be reflected in a high SV of this power plant. In well-designed power markets, a generator will receive an above-average price for the produced electricity on the market during these times. The SV perspective provides crucial information above and beyond generation costs. Indeed, a comparison between the LCOE and the SV yields critical information for policy makers and other power system stakeholders: where the SV of VRE is higher than its generation cost, additional VRE capacity will help to reduce the total cost of the power system.

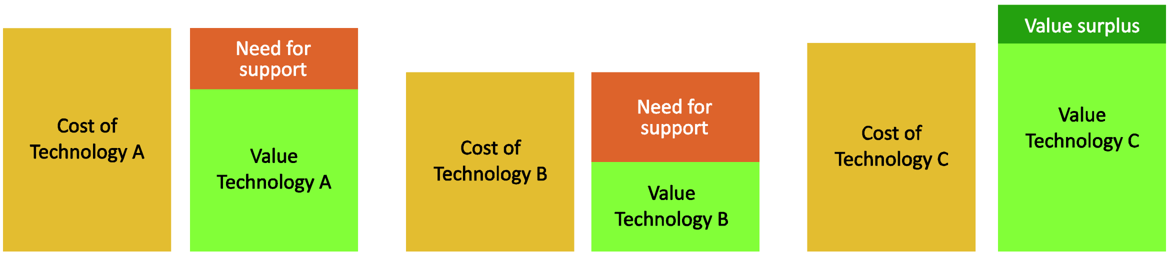
Figure 19 • Illustration of LCOE and SV



Key point • The LCOE and SV provide complementary information. The LCOE focuses on the level of the individual power plant, while SV captures system-level effects.

Comparing the SV of different technologies – and not just their LCOE – provides a more complete picture and a sound basis for policy design (Figure 20). In the example below, Technology B has the lowest cost, but also a very low value – hence it would require the most support to trigger deployment. By comparison, Technology C has an intermediate cost but a very high SV – its deployment would not require any support on the basis that an appropriate market design was in place.

Figure 20 • The link between VRE cost, SV and competitiveness



Key point • Given well-designed markets, the relationship between cost and SV determines the need for financial support or the degree of competitiveness of a technology.

System service capabilities

Technological advances have greatly improved the degree to which VRE output can be forecast and controlled in real time. This means that system operators can know very accurately several hours in advance how much wind and sun they can count on reliably, which also allows the use of VRE to provide system services such as operating reserves. For example, wind power plants in Denmark are expected to participate in system services markets. In Spain, wind power recently provided upward reserves in the balancing markets for the first time (Acciona, 2016). This boosts SV in two ways: first, system services are often high-value services with a high remuneration; and second, obtaining system services from VRE allows thermal power plants, which historically provided such services, to be switched off. This can avoid the need to curtail VRE, which in turn boosts its SV.

Enabling the provision of system services from VRE requires two principal ingredients. First, installed power plant hardware must be technically capable of delivering the service. This can be ensured by adopting forward-looking technical standards that specify what capabilities each plant must have in order to be allowed to connect to the grid (these interconnection standards are often referred to as grid codes, Box 15). Second, system operation practices, including the design of system service markets (as far as they are in place), need to be upgraded to better accommodate VRE. The most relevant changes are: 1) to allow units to declare their availability to provide the service as close as possible to real time, 2) to allow power plants that have the size of typical VRE projects to participate, and 3) to allow aggregators to bundle the contribution from a portfolio of resources, including demand-side response and/or storage options, 4) to accurately reward the value of provided services. With its recent reform, Energy Market 2.0, Germany is taking steps in this direction. Spain has already implemented changes allowing wind power to contribute to balancing the grid in practice.

Box 15 • Examples of advanced grid codes

Grid codes (known in North America as interconnection standards) are technical documents developed by the system operator, which set out technical requirements for any entity that connects to the grid. Different systems may obtain the same service in different ways, e.g. some will mandate it in the grid code while others use a procurement or market mechanisms.

The initial appearance of VRE in power systems necessitated the development of specific grid-connection requirements for VRE, as they were new technologies with different capabilities and impacts on the system. Early requirements were characterised by a "do-no-harm" approach, although this was not always achieved (RETD, 2013).

The first version of a grid code for wind turbines in Denmark was put into force in 1999. Before, several technical specifications existed for the connection to the distribution network. Generally, these old specifications required wind turbines to disconnect from the grid during abnormal voltage and frequency events. The new code from 1999 requires wind turbines to remain connected and continue to deliver power to support the grid in case of fault. New wind turbines connected at high voltage level should also be controllable remotely so that they can be curtailed if necessary. As 90% of wind turbines are connected at the medium voltage level (60 kilovolts [kV]) and below, similar grid codes now also apply at that level.

The grid code for German solar PV power plants originally specified that all plants were required to disconnect from the system if frequency rose above a level of 50.2 hertz, which may occur during a system disturbance. While such a rule allows secure system operation at low penetration levels of solar PV, it can pose a threat at higher levels. If all solar PV power plants disconnect from the grid at the same moment, the loss of generation capacity may put system security at risk. After this issue was identified, a retrofit programme was put in place to ensure that no sudden loss of generation would occur as a result of grid code requirements.

In the past few years, new requirements have appeared in grid codes for VRE technologies in countries that have seen increasing shares of VRE. The nature, extent and formulation of these requirements, however, in many cases have been ambiguous, disparate and inconsistent (RETD, 2013). In Europe, this has led the European Network of Transmission Operators (ENTSO-E) to develop a set of minimum grid code requirements for all the systems of Europe with a view to creating a more consistent framework (ENTSO-E, 2016c).

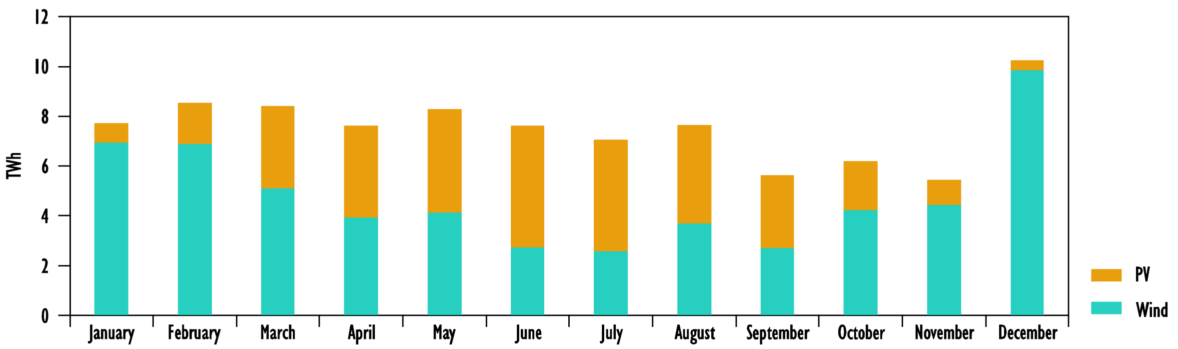
Technology mix

The output of wind and solar power is complementary in many regions of the world. In addition, the availability of VRE can be complementary to other renewable resources, such as hydropower. Deploying a mix of technologies can thus bring valuable synergies. For example, the current mix of wind and solar power in Germany leads to an overall more stable generation profile than each technology by itself (Figure 21), which raises the combined SV. In order to achieve an optimal technology mix, however, a shift in current power system regulations and grid codes may be needed.

For example, the current standards in South Africa allows VRE power plants to connect to any given substation only up to the point that the sum of the nameplate solar PV and wind capacity (maximum output) equals the rated capacity of the substation (maximum evacuation). Since solar PV and wind power plants reach their maximum generation simultaneously in only a limited number of hours per year, the sum of VRE capacity at a substation could be higher than the rated capacity of the substation without running into curtailment. An analysis conducted for South Africa (CSIR, 2016) revealed that installing 120% of VRE capacity compared to the rating of the substation is possible without any curtailment. When including the fact that some of the generated power will be consumed locally rather than fed up to the transmission level, feasible shares increased further (see the South Africa case study in Chapter 5 in IEA [2016a] for details).

Based on long-term modelling studies, it is possible to determine the cost-optimal mix of VRE technologies. This information can then be used when putting in place and adjusting remuneration schemes for VRE capacity. The previously mentioned auctioning system in Mexico is an example of such a mechanism. Where technology-specific auctions are used to contract VRE capacity, auctioned capacity can be set to achieve an optimal balance for the system as a whole. In South Africa, the quantity procured in technology-specific auctions is set on the basis of long-term system planning.

Figure 21 • Monthly generation of wind and solar power in Germany, 2014



Source: Adapted from Fraunhofer ISE (2016), "Monthly electricity generation in Germany in 2016", energy chart, www.energy-charts.de/energy.htm.

Key point • Combining wind and solar power in appropriate shares facilitates integration.

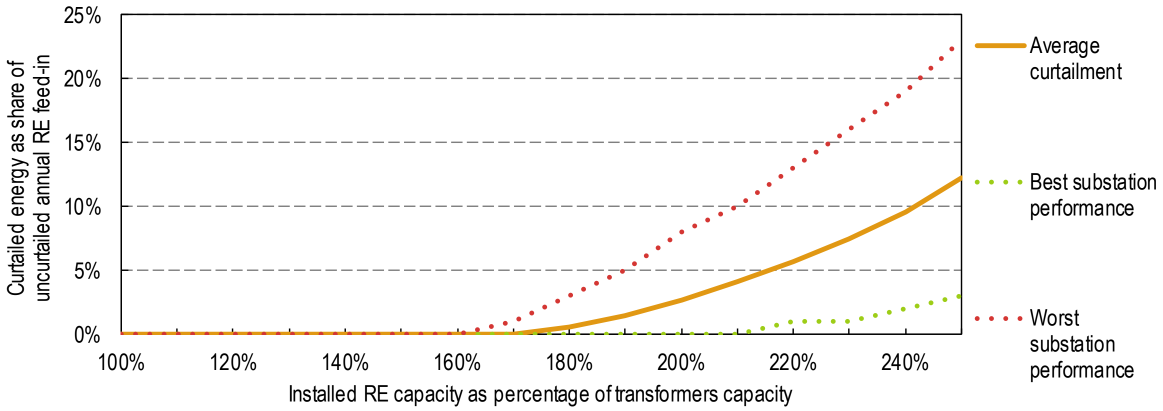
Recent analysis in South Africa supports this "technology-spread" approach, and suggests that up to 70% more VRE capacity might be added to a given substation in that country than the simple summing of their nominal generation capacities would suggest (Box 16).

Box 16 • Modelled impact of VRE complementarity on grid hosting capacity in South Africa

The Council for Scientific and Industrial Research (CSIR) has done analysis of the extent to which a combination of wind and solar capacity exhibiting complementary output profiles can increase the hosting capacity of existing grid infrastructure.

A statistical analysis of the required annual curtailment across all substations modelled, simulating wind and solar PV output as well as load at the substation level, suggests that the amount of mixed VRE that can be integrated before curtailment is up to 70% greater than would be the case if nominal ratings of VRE plants were simply summed (Figure 22).

Figure 22 • Average curtailed energy as a share of VRE generation, by installation rate as a percentage of substation capacity



Source: Adapted from CSIR (2016), *Wind and solar PV resource aggregation study for South Africa*.

Key point • 60-70% more capacity of wind and solar can be installed than the substation rating due to complementarity of their outputs.

Geographical spread of VRE

It may be possible to cost-effectively disperse new VRE installations around the footprint of the existing grid in order to reduce concentrations in particular areas[22], thus allowing a greater installed capacity before reinforcement is required.

The planned, geographic dispersal of VRE power plants ("geo-spread") often offers an important opportunity to smooth the aggregated output of VRE plants, i.e. to reduce variability and thus to minimise the added burden of VRE in terms of system operation (maintaining the balance between supply and demand).

This is the case because different parts of the country or region are likely to experience different weather conditions at any given time. The extent of this variation differs widely by geography: one country may lie under more than one climate zone, such as the Mediterranean and Atlantic regions of Spain. Another country may see a range of local weather conditions. The value of planned geo-spread of VRE plants is discussed in more detail in Box 17.

Having noted the value of dispersing wind plants, the reader should note that benefitting from geo-spread requires the existence of a pervasive, effective transmission network that can harvest the outputs of highly scattered wind plants. This infrastructure may be in place; equally it may

[22] There will be other considerations than optimising location for integration purposes; these include economic and practical factors: this section considers location from an integration perspective.

not. Moreover, such dispersal, particularly over wide and mountainous terrain may not be economically or technically viable. This is one example of the many trade-offs in VRE integration: in this case between the cost of grid rollout and the benefits of power plant dispersal.

Box 17 • Geo-spread as a tool to smooth wind and solar PV output variability

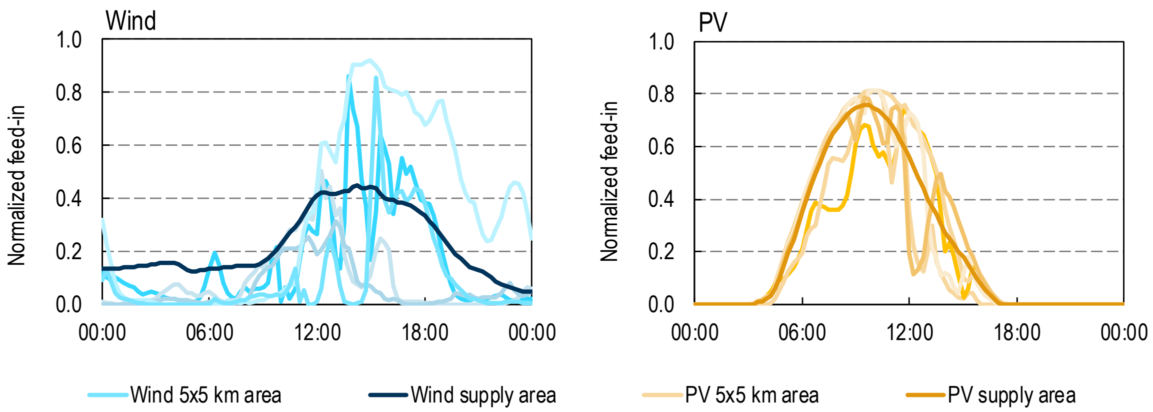
The aggregated output of dispersed VRE plants will vary less than that of individual units. For example, a single cloud at midday will cause the output of a solar PV module underneath it to fall from maximum output to 20-30% of peak (solar PV does not require direct sunlight to operate so it will not drop to zero). If all modules are in the same place, then the output of the solar portfolio will drop equivalently. From the System Operator's perspective this would be highly undesirable: it would require a large amount of alternative capacity to manage the loss, with only a very short time for ramp/start-up, and shut-down when the cloud moves off.

In contrast, if power plants are well dispersed, such fluctuations will be gentler and slower. Figure 23 illustrates this fact for both wind (in blue) and solar (in yellow) in South Africa. The paler lines show the steeply varying outputs of solar and wind plants in 5x5 km clusters, as compared with the aggregated output profiles of all wind and solar plants across the country.

Figure 23 shows that Solar PV smooths into the bell-curve expected on a cloudless day. The effect of aggregation on wind is less dramatic as winds are irregular. Thus aggregated wind output is still irregular (darker blue line) but nevertheless the peaks in output are lower, the troughs shallower, and – importantly – the rate of change of output ("ramps") is much gentler.

Thus geo-spread makes the task of the system operator considerably easier, reducing the amount of available capacity (reserves) required to cover VRE sudden variations. In the solar case, the forecasting of solar output becomes rather straightforward. In the wind case, forecast error will reduce, and the task of dispatching other power plants in the system to accommodate the changing weather, becomes significantly easier.

Figure 23 • VRE output and the benefit of geo-spread



Source: Adapted from CSIR (2016), *Wind and solar PV resource aggregation study for South Africa.*

Key point • The dispersal of VRE power plants makes their output easier to accomodate.

Recent research by CSIR in South Africa reinforces the importance of dispersing VRE power plants over a wide area. It also suggests that instead of locating wind farms solely in the best wind resource areas it may be better overall to spread them evenly across the country, to maximise the smoothing effect on aggregated output (CSIR, 2016). The implication is that there is a trade-off between maximising the output of the wind power portfolio (by locating the plants only where the wind is strongest), maximising benefit to developers, and achieving the smoothest overall output with benefit to the system as a whole.

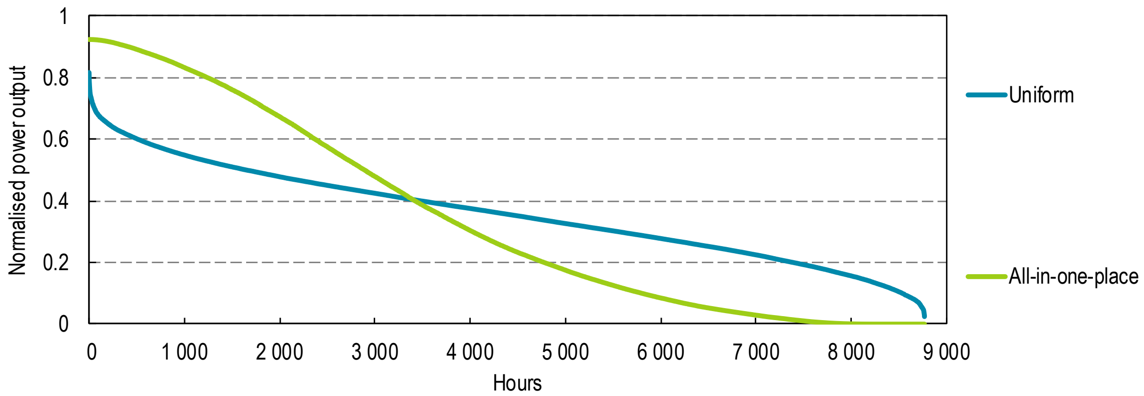
A smoother overall output means that there are longer periods when the wind portfolio is generating at a point somewhere between maximum and minimum. This is reflected in wind output duration curves[23] (Figure 24): the green line shows the output of a wind portfolio if it is located in a single area; the blue line shows output if wind power plants are widely dispersed[24].

The modelled output of a concentrated wind portfolio is at 80% or more of its rated output[25] for around 1 300 hours (i.e. some 15% of the 8760 hours in a year), and output is at zero for a similar amount of time. This reflects that, in that single location, windy days and still days occur with similar frequency, with the result that wind output heavily fluctuates.

In contrast, the red line presents the output of all plants aggregated, and is almost never at zero or at maximum, but usually somewhere in between. Instances of aggregate zero output are almost non-existent, which means that on all but rare occasions a proportion of the wind portfolio can be relied upon to be in operation at any time. This is sometimes described a higher "capacity value".

To decide on which allocation is best for a given system, a cost-benefit analysis is needed to determine if the benefit from geographical smoothening (from lower reserve requirements and network bottleneck alleviation) exceeds the cost of not exploiting locations where the resource is strongest.

Figure 24 • Dispersal of wind plants leads to a smoother output, South Africa



Source: Adapted from CSIR (2016), *Wind and solar PV resource aggregation study for South Africa.*

Key Point • The dispersal of wind power plants makes their generation profile more system friendly

Indeed, there may be little cost difference between building PV plants in locations with the best resources but far away from load centres, and in locations with only reasonable resources but close to load centres. This has been shown to be the case in a study looking at options for locating PV farms in South Africa (Poeller et al., 2015).

With the cost of solar PV falling rapidly, deployment is becoming economical even in lower resource conditions. In the case of wind, improvements in turbine blades and other components

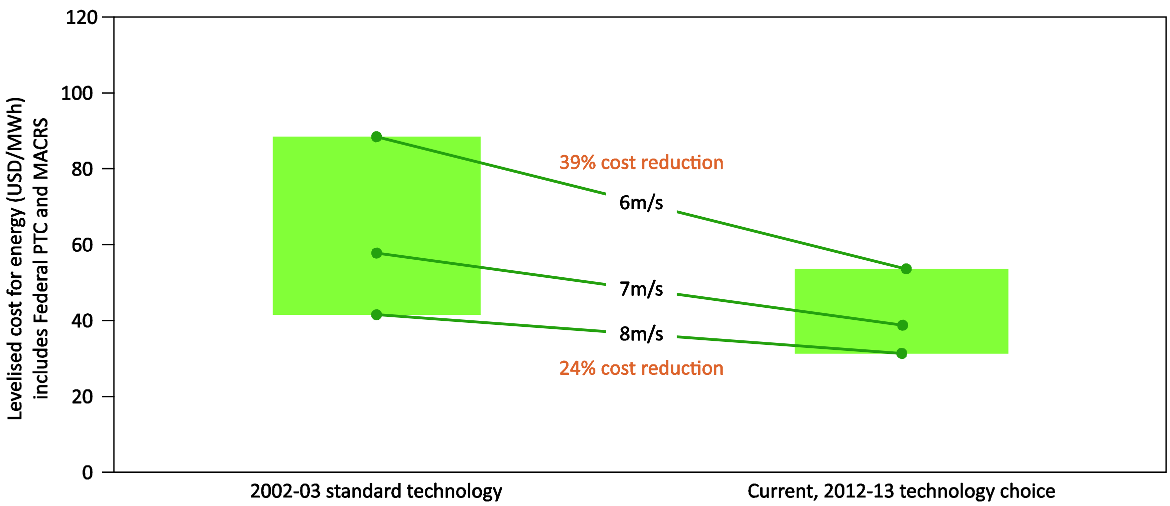
[23] Load Duration Curves (LDC) can be used for a number of different purposes. In this case they show the output of wind generator(s) at hourly intervals over an average year. The intervals are placed in order of size (of output) instead of chronological order, to reveal the proportion of an average year (in number of hours) when plants are at maximum and minimum output, as well as all output levels in between these two extremes.

[24] Note that such a dispersal would require additional transmission grid than is presently the case in South Africa.

[25] Rated output/rated capacity is the maximum amount of power a unit can reach.

have drastically reduced the cost of generating in medium-quality wind sites (Figure 25). This means that next-generation wind and solar power offers more flexibility in choosing the location of deployment. This can significantly increase SV by producing electricity closer to demand or in regions where alternative generation options are very expensive. For example, the recent auction in Mexico, which reflects the value of electricity depending on location, led to projects being selected in areas that have comparably less favourable resources, but where additional generation has a high value (see the Mexico case study in Chapter 5 in IEA [2016a] for details on the design of the auction system).

Figure 25 • Evolution of wind power costs according to wind resource in the United States



Notes: m/s = metre per second; MACRS = Modified Accelerated Cost-Recovery System; PTC = production tax credit.
Source: Wiser, R. et al. (2012), “Recent developments in the levelized costs of energy from US wind power projects”.

Key point • Reductions in the cost of wind power production have been greater for low wind-speed technology in recent years. This opens up new deployment opportunities closer to power demand, which can boost the SV of wind.

A variety of policy options exists to optimise the location of deployment. This can be achieved by reflecting SV in market premium payments (partial pass-through of wholesale market prices) or in advanced selection mechanisms in auctions (see summary section on reflecting SV in RE policy frameworks), or by introducing location-dependent prices on wholesale markets. At a more basic level, it is possible to designate specific development areas for VRE and to differentiate support payments according to location. For example, the feed-in tariff (FIT) system in several countries, including China and Germany, differentiates according to wind resource classes, providing higher remuneration per unit of energy for areas with lower wind speeds. In addition, beginning with the 12th Five-Year Plan in 2011, the allocation of new wind and solar power projects in China is co-ordinated at the national level. In Brazil, following a period lacking co-ordination between available grid capacity and the location of new VRE power plants, the rules of the auction system have been changed. Under the new rules, developers are required to site new projects close to grid capacity that will be available upon completion of the VRE power plant (see the Brazil case study in Chapter 5 in IEA [2016a] for details).

Local integration with other resources

Distributed deployment of VRE can open the opportunity to integrate the generation resource directly with other flexibility options to form an integrated package. For example, solar PV systems can be combined with demand-side response or storage resources to achieve a better match with local demand and hence increase the value of the generated electricity. However, it is critical to update distribution grid electricity tariffs and remuneration schemes to ensure that such resources are used in a way that is optimal for the system as a whole, including a fair allocation of fixed network costs.

The distributed nature of VRE, and solar PV in particular, allows generation to be located alongside other resources, including small-scale battery electricity storage or demand-side response resources. Co-location of resources can help avoid grid congestion and enable the provision of system services from a package of resources. Because such resources are often installed on the customer side of the electricity meter, policy interventions need to be applied through the design of appropriate retail electricity and grid tariffs (Box 18).[26]

Lower support levels for the grid injection of solar PV indirectly incentivises self-consumption and the adoption of load-shaping measures and storage technologies. In Germany, for example, since 2012 FIT levels for residential PV plants (under 10 kW) have been lower than the retail electricity price, meaning that householders are better off using the electricity generated by their own PV systems.

In Australia, the FIT structure and level is decided by state governments. In South Australia, the energy generated by solar PV systems is remunerated only by a Minimum Retailer Payment (MRP). The MRP for 2015 was set at USD 0.04/kWh (AUD 0.053/kWh), excluding taxes, markedly lower than the average retail energy price, which was equal to USD 0.2255/kWh (AUD 0.2951/kWh). In Victoria, the FIT level since 2013 has been USD 0.0382/kWh (AUD 0.05/kWh) for PV systems with a capacity up to 100 kW, while the residential electricity price in 2015 was USD 0.2913/kWh (AUD 0.3212/kWh) (ESCOSA, 2014; Victoria State Government, 2016; AEMC, 2015).

This incentivises self-consumption of the electricity and – in turn – the adoption of measures to better match individual demand to available supply.

The Reforming the Energy Vision (REV) process in the state of New York aims to redesign retail electricity tariffs so that they incentivise grid-friendly consumption, and sees the creation of a market platform that remunerates the system services provided by VRE. The aim is to charge for consumption according to its cost and then pay the energy and system services provided by distributed resources according to their value, while ensuring a fair allocation of fixed network costs. Such an integrated approach ensures a co-ordinated operation of distributed resources, maximising overall SV.

For large-scale projects, co-locating wind and solar PV or solar PV with solar thermal electricity (STE) can increase the value of the generated electricity. For example, the Atacama-1 project in the Atacama Desert in Chile provides round-the-clock electricity via a mix of solar PV and STE with thermal energy storage. In isolated power systems, coupling VRE technologies with the operation of local diesel generators can displace costly fuel and lower the cost of electricity provision.

Optimising generation time profile

The design of wind and solar plants can be optimised to facilitate integration even at plant level.

Influencing the design of VRE power plants to make them more system friendly is a dynamically evolving field. Simply put, all those measures that encourage an increase in the capacity factor of VRE resources will tend to make them more system friendly. A more detailed discussion is provided in the following subsections, separately for onshore wind and solar PV.

[26] More generally, the rise of distributed resources calls for a revision of regulation (for details, see IEA, 2016b).

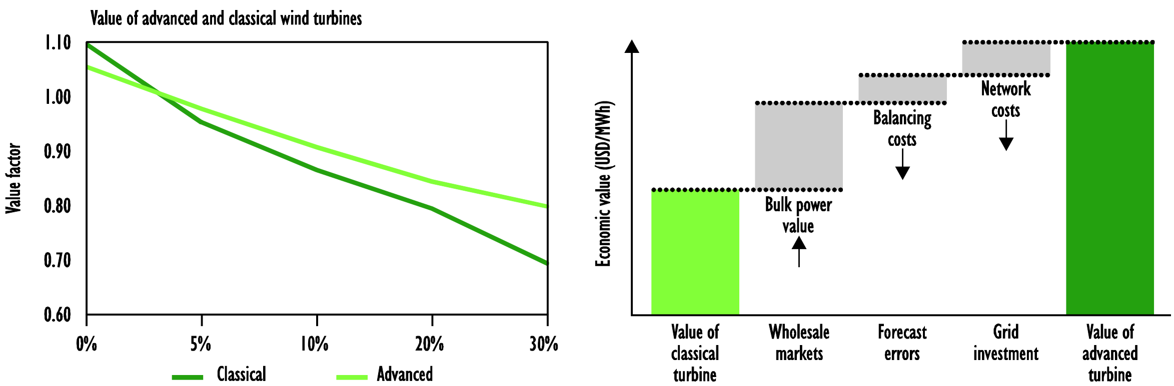
Focus on onshore wind

Wind turbine technology has evolved substantially during the past decade. The "low wind speed" turbines that have entered the market are taller and have a larger rotor per unit of generation capacity. This means that for each unit of generation capacity, the turbine has a larger area to "catch" wind. The technical literature often considers this relationship by calculating the specific rating of the turbine. This number expresses how much power the turbine can extract maximally per unit of swept area. It is obtained by dividing the rated capacity of the machine by the swept area. A lower specific power rating generally boosts the capacity factor because a higher swept area for a given turbine capacity will allow the generator to run at the rated capacity more frequently.

For example, a turbine with a rotor diameter of 90 metres (m) has a swept area of 6 362 square metres (m^2). Mounting such a rotor on a generator with a 2 MW rating will give a specific rating of 314 watts per square metre (W/m^2). By contrast, a 115 m rotor will have a swept area of 10 387 m^2. Mounting this rotor onto the same 2 MW turbine gives a lower specific rating of 192 W/m^2. Turbines with low specific ratings can capture more energy at low wind speeds. This advancement in wind turbine technology has been described as a "silent revolution" (Chabot, 2013). In the United States, the average rotor diameter more than doubled from 47.8 m in in 1998-99 to 102 m in 2015, contributing to a drop in the specific power rating of newly installed turbines from 394 W/m^2 to 246 W/m^2 (Wiser and Bolinger, 2016).

In Denmark, improved turbine design has increased annual full-load hours for onshore wind turbines from 2 000 to 3 000 since 2008 (DEA, 2015). With a lower specific rating, electricity is generated more constantly, which can potentially increase the economic value of the electricity, or, equivalently, have better system integration properties. Because of this, and for brevity, this publication refers to such wind turbines as "advanced".

Figure 26 • Possible benefits of advanced turbine technology



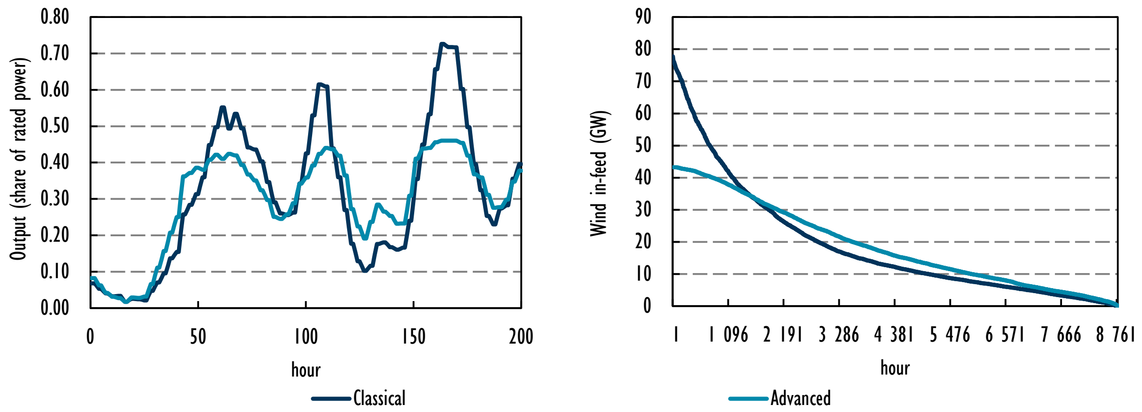
Source: Adapted from Hirth, L. and S. Mueller (2016), "System-friendly wind power: How advanced wind turbine design can increase the economic value of electricity generated through wind power".

Key point • Advanced wind turbine design increases the SV of wind power.

A modelling study carried out for this report (Hirth and Mueller, 2016) measures the additional benefit of advanced technologies as the increase in average market value (USD/MWh) during the course of a year, where "increase" is the difference between the market value of an advanced generation profile and that of a classical generation profile. The analysis is based on results from the European Electricity Market Model (EMMA). The model has previously been used to study the economics of wind and solar power. EMMA is a techno-economic model of the integrated Northwestern European power system, covering France, Benelux, Germany and Poland. It models both dispatch of and investment in power plants, minimising total costs with respect to investment, production and trade decisions under a large set of technical constraints. Advanced wind turbine design has a number of potential benefits, including 1) higher revenues from wholesale power markets (increased bulk power value), 2) reduced forecast errors, and 3) reduced grid costs (Figure 26). Bulk power value comprises revenues from energy (spot) markets and capacity markets, if present. The modelling analysis focused on this element.

In the context of the modelling study, the most important model input is the hour-by-hour time series of wind power generation. Advanced wind turbines are modelled combining two features: 1) a taller tower than classical turbine design; and 2) a larger rotor-to-generator ratio (lower specific rating). As winds tend to be more constant at larger heights above ground, and a lower specific rating implies relatively more output at intermediate wind speeds, both features tend to make output more constant. In this sense advanced wind turbines are "less variable" than classical turbines (Figure 27).

Figure 27 • Generation profiles representing classical and advanced technology



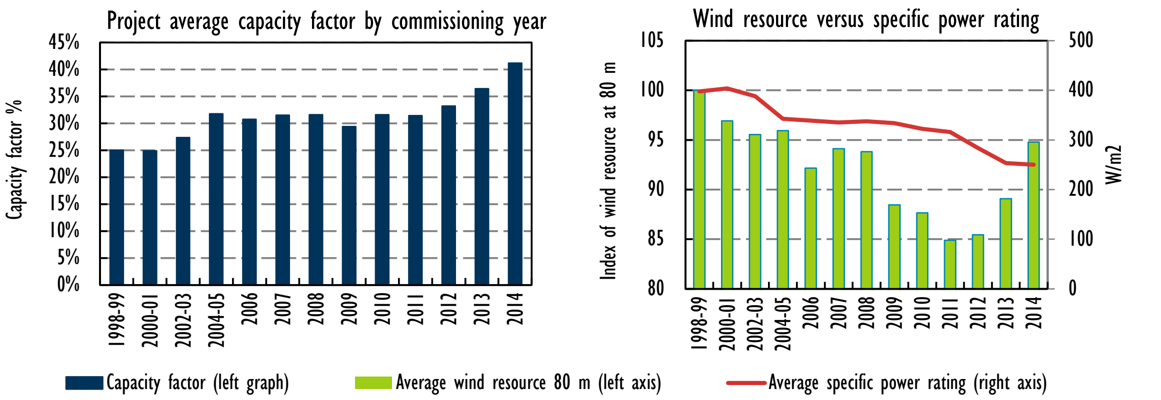
Note: GW = gigawatt.

Source: Hirth, L. and S. Mueller (2016), "System-friendly wind power: How advanced wind turbine design can increase the economic value of electricity generated through wind power".

Key point • Advanced turbines have a more stable output, generating relatively more during periods of moderate wind availability.

The modelling study investigated the implications of using advanced technology across all resource locations and the extent to which this increases the market value of wind energy. As a baseline for comparison, it is assumed that a standard high wind speed design is deployed at all sites. This is compared to a scenario in which low wind speed turbines are deployed in all locations. Given today's deployment patterns, this represents a hypothetical scenario. However, a trend towards deploying low wind speed technology at higher wind speed sites is already observable in the market (Figure 28).

Figure 28 • US onshore wind capacity factor, wind resource and turbine-specific power rating by year



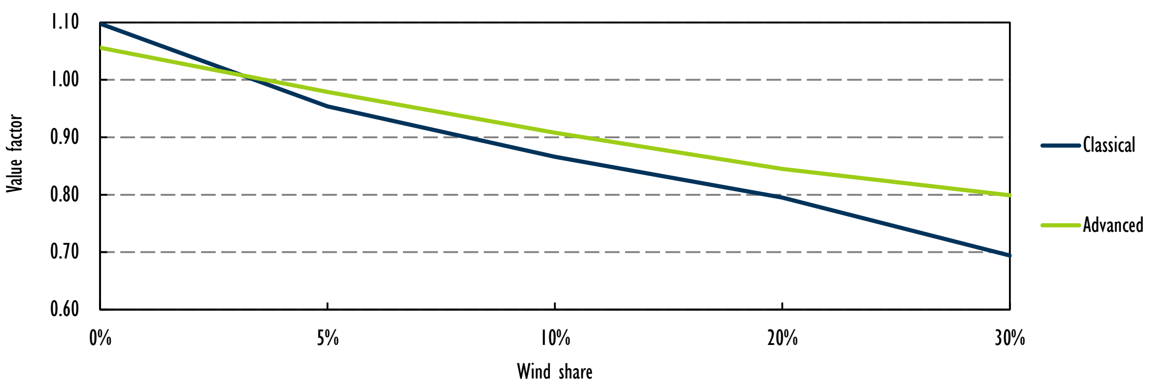
Note: Wind resource quality is based on site estimates of gross capacity factor at a hub height of 80 m; 1998-99 value = 100.

Source: Adapted from Wiser, R. and M. Bolinger (2016), *2015 Wind Technologies Market Report*, report for the US Department of Energy, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.

Key point • A trend towards larger specific swept areas and use in high-wind locations has boosted wind capacity factors in the United States.

For classical turbines, the value factor is higher than one at low penetration, reflecting the positive seasonal correlation of wind speeds with electricity consumption (both tend to be higher during winter in Europe). With increasing deployment, it drops quickly to about 0.7 at a penetration rate of 30% (Figure 29). This reflects findings of other studies (Mills and Wiser, 2012; Nicolosi, 2012, among others) and is consistent with observed market data (Hirth, 2013).

Figure 29 • Comparison of the economic value of advanced and classical wind turbine designs for Northwest Europe



Source: Adapted from Hirth, L. and S. Mueller (2016), "System-friendly wind power: How advanced wind turbine design can increase the economic value of electricity generated through wind power".

Key point • The SV of advanced technologies is more robust at larger shares of wind power.

The relative value drops because in those hours during which electricity is supplied by wind power, the price is depressed. The price drop becomes more pronounced as more wind generation is added. With advanced turbines, the value drop is less pronounced because wind generation is distributed more smoothly over time, reducing the price-depressing effect in each individual hour (Figure 27).

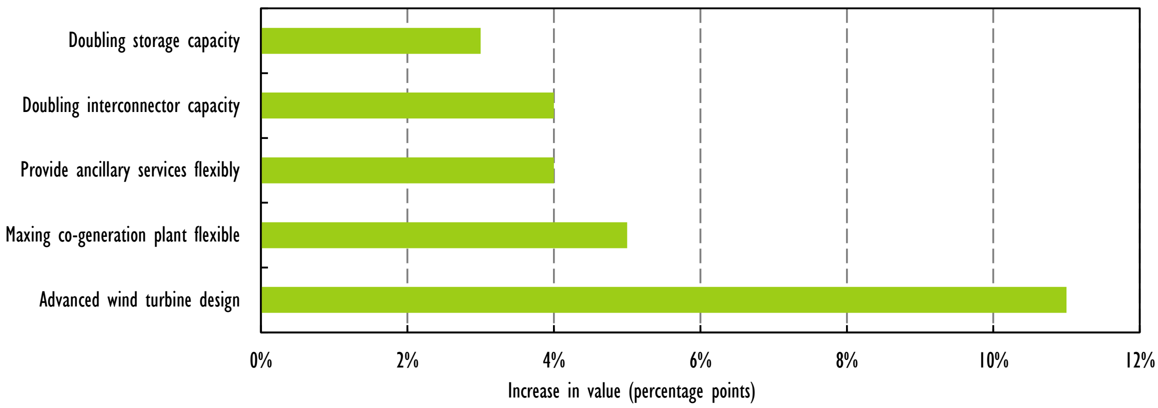
Model results indicate that the difference is large: at 30% penetration, the value factor is 13 percentage points higher ("absolute delta"), corresponding to 22% of the classical turbines' value factor ("relative delta"). In other words, one MWh of electricity generated from wind power is 22% more valuable if advanced turbines are used. The large size of the delta is the principal finding of the modelling study. This general result was confirmed to be robust against a large amount of sensitivity analysis.

The delta is substantial compared to wind generation costs. If the average price of electricity is USD 80/MWh, it corresponds to USD 10 per MWh, or a sizable portion of wind LCOE. In this case, advanced wind turbines would be able to compete with classical turbines even if their generation costs were 14% higher.

At very low penetration, the value of advanced turbines is below that of classical turbines. Wind speeds are higher in the winter season in Europe, when electricity demand is also higher. This positive seasonal correlation benefits classical wind turbines, particularly if the discrepancy between summer and winter is more pronounced. At higher penetration, the value-depressing effect of wind variability begins to emerge, quickly reducing the value of the more variable classical profile.

At a penetration rate of 20%, the relative value of advanced turbines exceeds that of classical turbines by five percentage points. The gap increases at higher shares. In a situation where wind power accounts for 30% of total power generation, opting for advanced wind turbine design has a stronger impact on the value of wind than any other flexibility option (Figure 30).

Figure 30 • Comparison of the impact of different flexibility options on the economic value of wind power for Northwest Europe



Source: Adapted from Hirth, L. and S. Mueller (2016), "System-friendly wind power: How advanced wind turbine design can increase the economic value of electricity generated through wind power".

Key point • Advanced turbine design has a stronger impact on the value of wind than any other flexibility option.

Focus on solar PV

There are three ways to improve the SV of solar PV: changing the panel orientation, tracking the sun throughout the day, and adjusting the ratio between the generation capacity of solar panels and the maximum inverter output (known as the inverter-load ratio, direct current [DC] to alternating current [AC] ratio, or array-to-inverter ratio). The first two options are more limited in application to utility-scale solar PV plants.

Together, these options provide measures to modify the quantity and timing of energy produced.

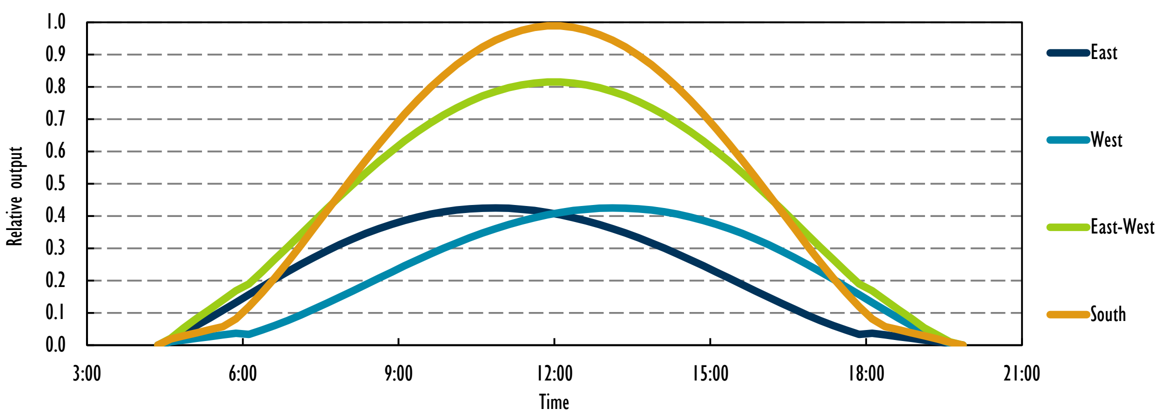
The majority of past solar PV investments has not been exposed to market price signals or similar incentives to optimise their output from a system perspective. Consequently, these design options have typically been used to minimise the LCOE of electricity production. Only in the limited number of cases where VRE production is exposed to market prices, or is given the incentive to optimise plant design for the system, have these options been used to reap a broader system-wide benefit.

Orientation and tilt of solar modules

In general, panels that do not track the path of the sun ("fixed-tilt") are oriented towards the equator to maximise exposure to the sun. In some cases, however, it may be beneficial to install fixed-tilt installations with a combined east-west orientation. Up to 75% more modules can be installed per unit of surface area, which may reduce the cost of land and racking and mounting hardware (Troester and Schmidt, 2012). With no specific incentives for system-friendly conception, the largest PV plant in Cestas (France) was precisely built with a double east and west orientation (Clover, 2016).

More importantly, in the afternoon and early evening energy tends to have a higher value, as total power demand is often higher during this time of day. This difference is likely to become more pronounced at larger shares of solar deployment. This favours orienting the panels to the west. The state of California has passed legislation whereby west-facing panels receive a 15% premium for all generated electricity. As the share of solar PV generation increases, adding east-facing panels will allow solar power to contribute to meeting the morning consumption peak (Figure 31).

Figure 31 • Impact of panel orientation on solar PV production profile, month of May in Germany



Note: Identical profile results have been produced at the same latitude in other parts of the world.

Source: Adapted from Troester, E. and J. D. Schmidt (2012), *Evaluating the Impact of PV Module Orientation on Grid Operation*, www.smooth-pv.info/doc/App22_ENA_Evaluating_the_Impact_of_PV_Module_Orientation.pdf.

Key point • In Germany, the combined generation of panels oriented east and west leads to lower ramp gradients and slightly higher generation levels during morning and evening hours.

In order to maximise output, a rule of thumb is that the angle at which a solar panel is positioned vis-à-vis the ground surface (the tilt) should be roughly equal to the latitude of the site. In practice, consideration of optimal surface use and balance-of-system cost, as well as building regulations, may lead to a preference for a different tilt – such as placing PV panels flat on a roof. In locations where the contribution from light coming directly from the sun (direct normal irradiance [DNI]) is relatively small, output is optimised with a tilt that is up to 15° lower than the latitude of the side (IEA, 2011c).

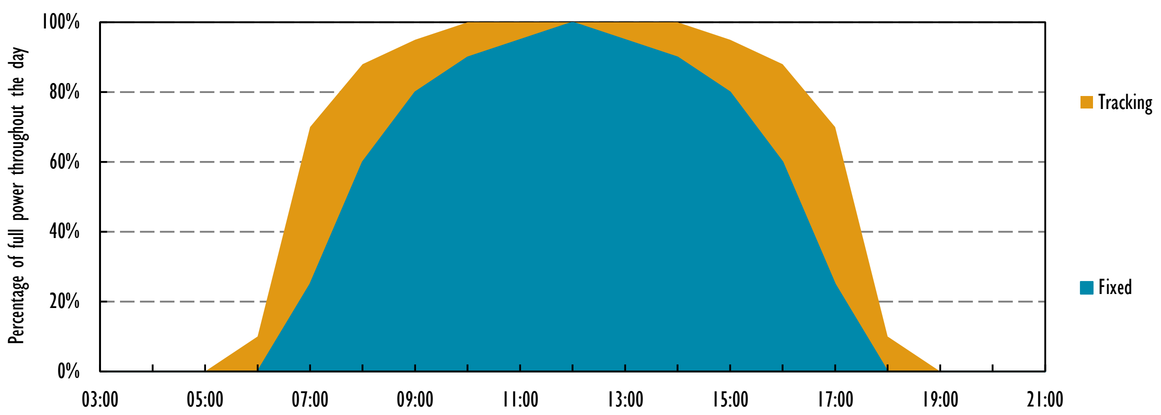
In a future marked by cheap solar power, markets and policy design may incentivise a certain tilt to modify the annual production profile of solar projects in line with the value to the overall system. While orientation alters the daily generation profile, tilting can modify the annual generation profile: a greater tilt of equator-facing modules increases winter output and decreases summer output.[27] This would presumably be of value in temperate countries, or in sunny countries with a large share of solar PV. It may have a relatively important cost, however, in annual generation losses in temperate countries where summer output largely exceeds winter output.

Tracking

A tracking system whereby solar panels follow the path of the sun throughout the day increases the level of energy production (Figure 32). In the case of single-axis trackers, a PV installation may generate over the year 12-25% more electricity than fixed systems in high insolation areas. Dual-axis tracking can increase the yield by an additional 10-15%, although in economic terms this advantage can be offset by higher installation and maintenance costs for the supporting equipment (Bolinger, Seel and Wu, 2016) As non-concentrating PV panels are relatively tolerant to incoming sunlight, tracking technology does not need to be extremely precise and is thus not very costly.

One-axis tracking PV systems have become dominant for utility-scale PV systems in high insolation areas, the benefits exceeding the costs even with flat tariffs. An important benefit of east-west tracking systems is increased power production in the early morning and late afternoon, when system demand tends to be higher. However, compared to east-west and equator-facing fixed systems, tracking systems have steeper ramp rates at sunrise and sunset.

Figure 32 • Indicative percentage of full power throughout the day for a dual-axis tracking and a fixed-tilt PV plant



Note: This is a representative figure for illustrative purposes.

Key point • Tracking PV systems offer more energy but show steeper ramps in the morning and evening.

Panel-to-inverter ratio

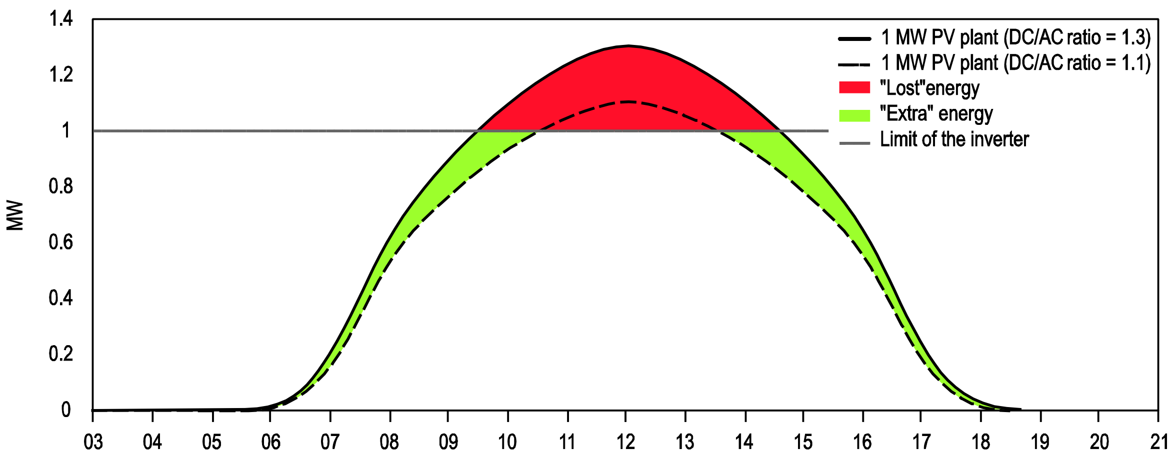
The production limit for a solar PV plant (in AC terms) is dictated by the inverter size. Since the output level of a solar array (in DC terms) reaches the rated peak capacity only during few hours,[28] the nominal capacity of the solar array will generally exceed the inverter capacity by at least 10%. The ratio between the nominal capacities of the solar array and the inverter is referred to as the DC/AC ratio, or the inverter load ratio (ILR) (Troester and Schmidt, 2012).

[27] With a greater tilt, panels more directly face the lower sun in winter.

[28] Standard test conditions determining the rated power of a solar cell are an irradiance of 1 000 W/m^2, a cell temperature of 25°C and an air mass of 1.5.

A solar PV plant with a higher DC/AC ratio can run at full capacity more often than a plant with a lower DC/AC ratio. As an example, compare a PV plant with a 1 MW inverter and a 1.1 MW solar array (DC/AC ratio of 1.1) to a second PV plant with the same inverter capacity but a 1.3 MW solar (DC/AC ratio of 1.3) (Figure 33). For both the plants some amount of solar power is lost during the solar peak hours, because the inverter cannot manage the full peak production (these energy losses are also called “clipping losses”); the PV plant with a larger solar array faces larger clipping losses, but at the same time gains “extra” energy production during the shoulder hours; plant-level output now assumes a plateau shape, which can be more valuable from a power system perspective.

Figure 33 • Indicative generation curves of a current PV plant and a system-friendly PV plant with downsized inverter



Note: This is a representative figure for illustrative purposes only.

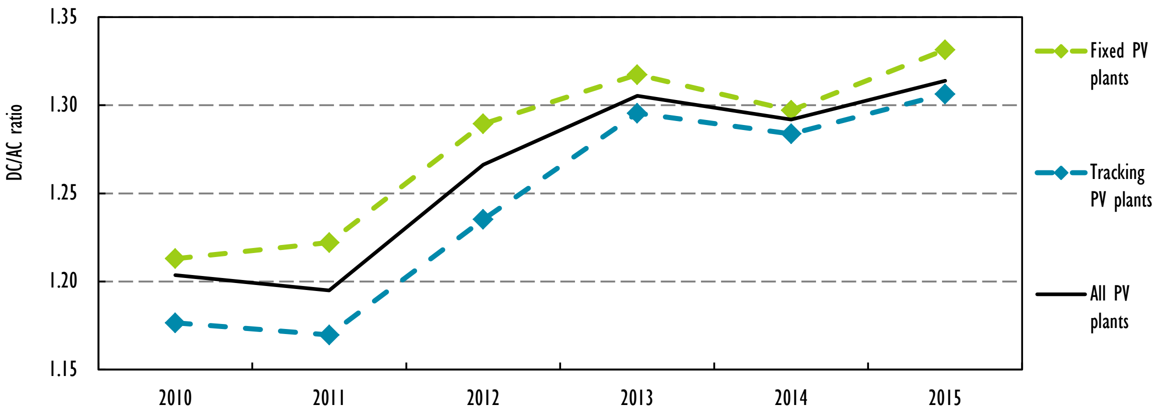
Key point • Downsized inverters allow a more system-friendly PV generation profile.

When applying a higher DC/AC ratio over a large number of solar PV plants, the midday solar PV production peak, which can be challenging to handle in system operations, will be less pronounced. The optimal DC/AC ratio is driven by a number of factors, such as the technical obligations prescribed by the grid code, the relative cost of solar panels to inverters, and the costs for connecting plants.[29] Once the connection capacity (i.e. the size of the inverter) is set, the solar array size is optimised. The rapid decrease of PV module costs in recent years has supported the trend to install larger solar arrays in some countries (Figure 34).

Other factors that push up the DC/AC ratio include exposure to time-dependent revenue streams, which favour a higher DC/AC ratio if midday energy has a lower value. In California, some utilities are offering time-of-delivery PPA prices, which favour solar PV plants also able to produce in late afternoon. This effect is more pronounced for fixed-tilt plants, since PV plants that use tracking already have a more constant energy output throughout the day.

[29] If connection infrastructure is sized to meet peak production, a larger share of total grid capacity will remain unused outside of peak hours. Inverter downsizing ensures that more of the connection infrastructure is used throughout the day.

Figure 34 • DC to AC ratio by mounting type and installation year, United States



Note: Values refer to a sample of utility-scale PV plants in the United States.

Source: Adapted from Bolinger, M. and J. Seel (2016), *Utility-Scale Solar 2015*, https://emp.lbl.gov/sites/all/files/lbnl-1006037_report.pdf.

Key point • The DC/AC ratio for solar PV plants has gradually increased in the United States in recent years.

Distributed solar PV

Most distributed rooftop solar PV projects have been developed with the objective of maximising overall energy production and lowering the overall cost per unit of energy produced. The decision to invest in a rooftop PV system is primarily driven by the economic benefits at the project level, thus incentivising project developers to maximise project value without much consideration of the economic implications for the overall power system. At rising levels of distributed solar PV deployment, the costs of maintaining reliability at the distribution grid level may rise unnecessarily if insufficient incentives for system-friendly deployment are provided.

At large shares, the operability of distribution networks can be affected by the electricity that distributed PV projects feed into the grid. Most residential PV systems export power to the grid during daytime hours, when PV electricity production peaks while on-site consumption tends to be low, especially in temperate countries. This phenomenon is less pronounced in the commercial and industrial segments, where high daytime consumption usually absorbs the electricity produced by solar PV systems on site.

Historically, local power grids have been designed to transfer electricity from the transmission grid to end consumers in a safe, reliable and cost-effective manner. While flows in the reverse direction are possible in principle, a number of changes to protection equipment and operating practices may be needed to allow for such flows on a routine basis.

A co-ordinated approach to deployment of distributed resources will support efforts to optimise the performance of local power grids while minimising overall system costs. At a minimum, grid operators should have transparent insight into the functioning of existing assets and ongoing deployment of distributed solar PV resources in their network.

The orientation and tilt of solar modules are often determined by the aspect of the building in question, which usually allows limited room for adjustment, especially for rooftops in the residential sector. Large flat roofs or parking lots in the commercial and industrial sectors may be more flexible. As such, tilting and orientation criteria applicable to utility-scale PV systems would equally apply to distributed generation. In the residential sector, the decrease in costs of PV equipment combines with the system advantages of east-west orientation to potentially offer greater opportunities to install rooftop PV systems than was the case when relatively strict equator-facing orientation was imposed.

A wide range of technologies can further improve the system friendliness of distributed solar assets by minimising the amount of electricity that is fed into the grid. Intelligent software can interact with smart appliances to sculpt the profile of electricity consumption at household level. Installing battery storage systems in conjunction with distributed solar PV can effectively increase self-consumption and reduce reverse power flows into the local grid by shifting the produced energy. EVs can also provide battery capacity, supporting stronger utilisation of distributed solar assets both at home and at the office.

Policy examples to optimise the generation time profile

One policy option to encourage investment in system-friendly VRE is the application of premium payments on top of market revenues (such as the German feed-in premium [FIP] system) This exposes investors to market signals (the wholesale price) and risks in a limited fashion. The design of the premium allows VRE generators to earn additional revenues if the market value of their production is higher than that of the average VRE plant (see summary on how to include SV in RE policy frameworks for details). The US production tax credit also, in principle, passes on fluctuations in electricity market prices to investors, and thus also provides an incentive for a more system-friendly design of power plants.

Another, more direct, way to influence the timing of generation is to directly differentiate payments under a PPA according to the time of delivery. Time-of-delivery (TOD) factors have been used in California’s PPAs since 2006. In the current system, TOD factors are determined on the basis of net load profile. Because net load is particularly low when solar PV production is at its peak, California’s Pacific Gas and Electric Company midday TOD adjustment for March to June in 2016 resulted in payment of only 28% of the standard PPA price.

South Africa introduced a “multiplier” for concentrated solar power (CSP) technology from 2013 onwards. For all energy production between 16:30 and 21:30, remuneration increases by a factor of 2.7.

Putting in place mechanisms that signal SV to developers will, in principle, incentivise system-friendly deployment practices: power plants that generate electricity with a higher value receive a higher remuneration. However, existing policy frameworks may actually *hinder* the adoption of system-friendly design. For example, where the eligible amount of revenues under a support mechanism is capped at a certain level of full-load hours, project developers may choose to deliberately oversize the generation capacity to increase profit.[30] This leads to an incentive to reduce capacity factors. The example of Denmark shows how policies can be adjusted to prevent this. Under the new FIP system, the size of the rotor is considered when calculating eligible full-load hours.

Integrated planning

The relative costs of VRE and other generation technologies, as well as the cost of various flexible resources, are constantly changing. Continuing innovations in technology are opening new deployment opportunities for VRE. Furthermore, changes in electricity demand structures

[30] For example, when a generator is eligible to receive payments for the first 10 000 full-load hours of operation, one way to increase the amount of payments is to simply install a larger generator, say from 2 MW to 2.5 MW. This increases the eligible amount of energy from 20 gigawatt hours (GWh) to 25 GWh. However, oversizing reduces the capacity factor and hence is less system friendly.

via energy efficiency can evolve more quickly than expected. Sound long-term planning for power production must recognise that the optimal mix of flexible resources is likely to evolve over time. The need for strong co-ordination applies most notably in dynamic power systems where demand growth warrants investment in generation and transmission capacity. In this context, a transparent process with clear rules and procedures can ensure that new VRE capacity is introduced at the right time and place, using the technologies that have the highest SV. Aligning transmission expansion with procurement of VRE can reduce overall system costs.

Denmark has a long, well-established tradition of planning the overall energy system in an integrated fashion. The share of RE consumption in Denmark has been increasing since 1980, with the long-term vision being independence from fossil fuels by 2050. This vision has solid support in parliament. Long-term planning has been an important tool to trigger relevant investment in the Danish energy system. The grid and market structures have been, and continue to be, progressively reshaped to handle increasing VRE production. The Danish approach to energy policy is characterised by holistic planning, with emphasis on stepping up flexible resources and cross-sectoral electrification.

Summary: Reflecting SV in RE policy frameworks

The SV of VRE is determined by a number of interrelated factors. As VRE deployment rises, more examples of innovative market and policy design are being introduced that merit consideration. This chapter looks at these with a separate focus for distributed and centralised VRE deployment.

Importantly, determining the appropriate tools and policies to trigger system-friendly deployment of VRE resources is an iterative process. Policies and market design options should be defined in a flexible manner, allowing for further modifications while preserving investment certainty.

Distributed resources: Focus on regulation of local grids and retail prices

Over the past decade, cost-minimisation has been the principal driver of investment in distributed VRE resources, with little consideration of the SV of these assets. Over time, this approach to the development of distributed wind and solar resources may lead to suboptimal outcomes and ultimately unnecessarily high system costs. A number of policy and market design options can enhance the system-friendliness of distributed resources.

At large shares of distributed generation, sustaining the safe and reliable operation of the local power network in the face of rising VRE uptake requires up-to-date and technology-specific grid codes for low- and medium-voltage connections. Clear guidelines for VRE technologies effectively enhance the controllability and forecasting capabilities of distributed resources, thus driving a more transparent and system-friendly introduction of future distributed assets.

When drafting grid codes, system operators must strike a delicate balance between preserving system security in a context of rapid decentralisation and enabling future investment in the technologies that drive that evolution. The definition of unnecessarily demanding technical rules for incremental capacity may stifle investment in additional capacity. Conversely, overly lax standards can mean that a plant's capabilities may fall short of what is needed. It is therefore the responsibility of the system operator to craft grid codes in appreciation of future network development while not overburdening current deployment.

Retail pricing is increasingly gaining significance in the direction of VRE investments. Pricing electricity consumption and remunerating distributed electricity production in a time- and location-specific manner is a crucial step in pushing for system-friendly VRE deployment. Exposing customers to time-of-use (TOU) pricing for their electricity consumption is likely to trigger the adoption of measures to increase self-consumption during times when electricity is most valuable.

Other incentives for system-friendly VRE deployment have been introduced in various markets. In Germany, a percentage limit on the amount of power that can be fed into the grid, a widening gap between the feed-in remuneration and retail tariffs and an investment credit on battery systems have collectively pushed homeowners to more appropriately size their rooftop installation and increase the level of self-consumption.

Box 18 • The role of retail electricity pricing in guiding investment in distributed solar PV

Retail prices should give the right incentives to both network users and distributed energy resources, in a time- and location-specific manner. In particular, network tariffs need to cover the costs of infrastructure and should send a signal for efficient use of the network, as well as minimise the cost of future investment. Of course, this needs to be balanced with other policy objectives, such as economic development in rural communities. In the context of rising self-consumption, this is likely to require tariff reform.

For example, the introduction of demand charges that accurately reflect a customer's contribution to peak demand in a local distribution grid can be an appropriate way of ensuring fair charges for all users of the network. Electricity taxation may also have to evolve. With distributed resources, electricity consumption is becoming more responsive to electricity prices, and high levels of taxation and levies can create a strong economic incentive for customers to offset grid-based electricity via their own solar PV system. Where used as a targeted strategy, this can help increase solar PV deployment. But where left unattended, it can lead to inefficient investment decisions. For example, it may block the uptake of options such as efficient electric heat pumps to displace gas heating; a high electricity tariff will make a switch from gas to electricity uneconomic, even if the electricity-based solution is more efficient.

The California Energy Commission approved a 15% premium on the incentive level for west-facing solar panels in an attempt to increase distributed generation during times of peak system demand (Arriaga et al., 2015). Austin Energy and the state of Minnesota have pioneered the use of a value-of-solar (VOS) mechanism to remunerate distributed solar projects. A VOS tariff uses a bottom-up calculation of all costs and benefits of a particular solar PV installation to determine its real value to the power system (Taylor et al., 2015). To date, it is the most comprehensive methodology for providing the SV of distributed solar resources.

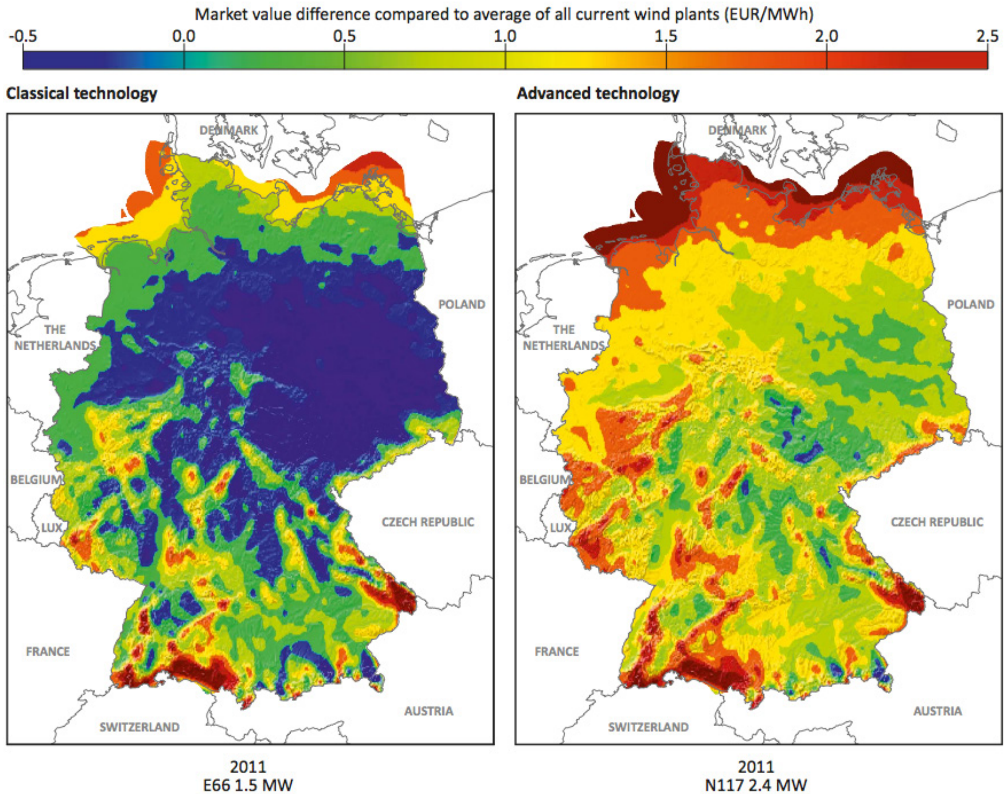
Centralised resources: Enhancing remuneration schemes

Reflecting SV in policy frameworks requires striking a delicate balance. On the one hand, policy makers should seek to guide investment towards the technology with the highest SV compared to its generation costs. On the other hand, calculating the precise SV can be challenging and, most importantly, current and future SV will differ.

In practice, the exposure to short-term market prices can be an effective way to signal the SV of different technologies to investors. However, the current SV of a technology can be a poor reflection of its long-term value. This is due to transition effects that can be observed in a number of countries where VRE has reached high shares. For example, in European electricity markets the combined effect of RE deployment, low CO_2 prices, low coal prices and negative/sluggish demand growth (slow economic growth, energy efficiency) are leading to very low wholesale market prices. In turn, these low prices mean that any new type of generation will only bring limited cost savings and will thus have a very low short-term SV. Even where electricity demand is growing more rapidly, investments based purely on expected short-term wholesale power prices face multiple challenges (see Chapter 2 in IEA [2016d] for a detailed discussion). Because wind and solar power are very capital intensive, such challenges will directly drive up the cost of their deployment, widening the gap between SV and generation costs. Consequently, mechanisms that provide sufficient long-term revenue certainty to investors are needed. At the same time, such mechanisms need to be designed in a way that accounts for the difference in SV of different generation technologies. A number of strategies have emerged to achieve this. The first is to foster competition between investors in the same technology to make deployment more system friendly. The second is to conduct comprehensive modelling of the power system in order to determine the SV of different technologies and to take this into account when providing long-term contracts to investors.

The German market premium system provides incentives for investors to choose more system-friendly deployment options. The mechanism is designed such that an average wind power plant will generate revenues that match the FIT level. The mechanism to encourage a more system-friendly deployment is this: if a power plant has a higher-than-average market value, the generator can make an additional profit. Investors are now increasingly aware of the difference in value depending on when wind turbines generate. Specialised consultancies provide data on locations where the wind blows during times when the value of electricity is particularly high (Figure 35).

Figure 35 • Market value of wind power projects depending on location, Germany



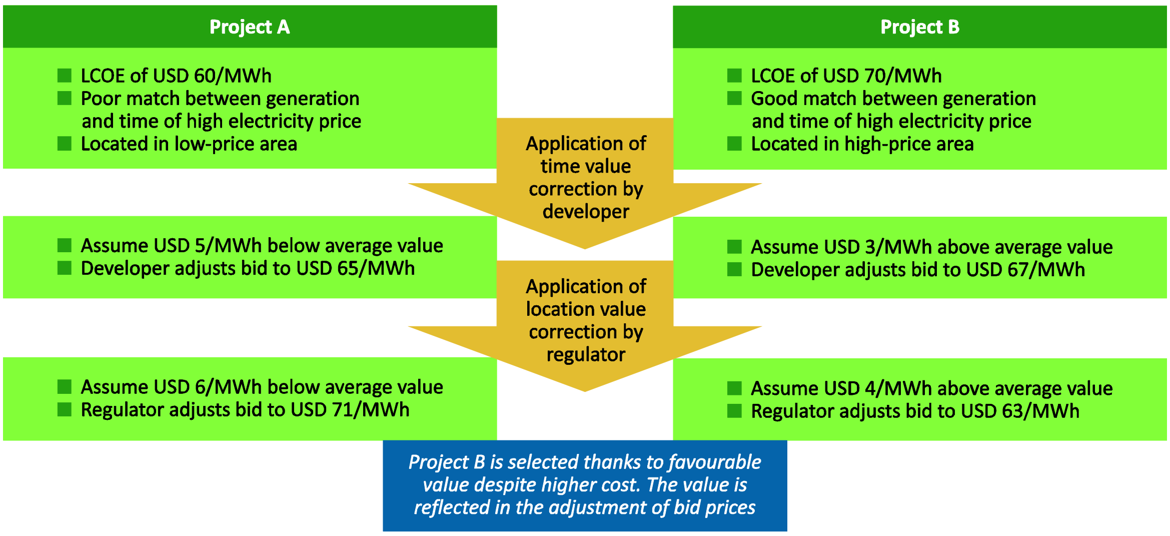
Note: Blue areas indicate below-average market value; red areas show above-average market value.
Source: Adapted from Enervis/anemos (2016), *Market Value Atlas*, www.marketvalueatlas.com.

Key point • Depending on power plant location, wind power has a different value for the power system.

As part of its recent comprehensive electricity market reform, Mexico has taken an alternative approach to reflecting SV in investment decisions. It is based on comprehensive modelling of the future power system, including expected electricity market prices for the coming 15 years, calculated for each hour of a typical day for each month, differentiated for 50 regions of the country (price zones). In order to implement such an approach, it is critical to have available sophisticated modelling tools for power system planning. It also requires making a set of assumptions about the future evolution of fuel prices as well as expansions of the grid and additional investments in system flexibility. The large dataset of prices is publicly available (CENACE, 2016).

Combining electricity prices with the feed-in profile of a generation resource, it is possible to calculate its market revenue; this is a proxy for the SV. The exact calculation is somewhat technical and involves the combined revenue from electricity and the sale of green certificates. This does not change the main point, however. In essence, those producers that offer electricity with a higher-than-average value can reduce their bids in two steps (Figure 36). In the first step, a correction for the timing of generation is applied, as calculated by project developers. In the second step, a correction factor for location is applied. In summary, these factors are reflected in the order in which projects are selected. The Mexican system has recently been introduced and the first auction results were obtained in April 2016. While its design is excellent from the perspective of SV in principle, it remains to be seen if further modifications may become necessary in practice.

Figure 36 • Conceptual illustration of the Mexican auction system for variable renewables



Key point • The design of the Mexican auction system reflects the SV of different projects depending on when and where they generate electricity.

It is important to note that this auction design puts high demands on the accuracy of the modelling that underpins the auction. Procurement results will only be as good as the underlying simulation, which are updated for each new auction cycle. This means that they would also be required to factor in the possible contribution of demand-side options, grid expansion etc. Sensitivity analysis can reveal how the SV of wind and solar power can be improved by the adoption of certain flexibility measures. Such integrated long-term planning models are becoming increasingly adopted for the guidance of policy making. Their further development needs to be a priority wherever similar approaches are to be adopted.

The measures discussed in this section are summarised in Table 6.

Table 6 • Overview of system-friendly policy tools and their impact on SV

System-friendly strategy	Policy tool	Country example	Impact on SV
System service capabilities	Grid codes that require advanced capabilities Advanced design of system services markets	Participation of wind in balancing the grid in Denmark and Spain	By providing system services from VRE, more thermal generation can be turned off during times of abundance, which “makes room” for VRE and increases SV
Location of deployment	Integrated planning of grid infrastructure and generation	Integrated planning in Brazil	Siting VRE generation in locations where electricity is needed and infrastructure available boosts SV
	Locational signals in remuneration schemes	Mexican auction system; differentiation of feed-in tariff levels in China	
Technology mix	Technology-specific auctions that reflect the value of each technology as determined in long-term planning	South Africa	Deploying a mix of technologies can lead to a more stable VRE profile and reduce periods of VRE excess, hence boosting SV
	SV reflected in multi-technology auctions	Mexico	
Local integration with other resources	Grid injection remuneration levels for distributed energy resources	Australia, Germany	Lower remuneration of grid injection incentivises higher self-consumption by adoption of load-shaping measures and storage technologies
Optimising generation time profile	Partial exposure to market prices via premium systems	German and Danish market premium systems, US tax credits	Investors are encouraged to choose a technology that generates during times of high electricity prices
	Power purchase agreements adjusting remuneration to time of delivery	South Africa, United States	
Integrated planning, monitoring and revision	An integrated long-term plan for VRE and flexible resources, updated regularly	Integrated energy system planning in Denmark	Aligned deployment of VRE and flexible resources enhances SV; regular update of the long-term path allows reaping of the full benefit of technology innovation

Topical focus: Evolution of local grids

This topical focus provides an overview of recent trends and future prospects in local grids. In this context, local grids primarily refer to the low- and medium-voltage levels of the electricity grid. The term local grid is used, rather than distribution grid, so as to distinguish between the traditional role of the distribution grid and its evolution into a much more complex, actively controlled network. The term local grid is also understood to encompass other network infrastructure, the planning and operation of which is co-ordinated with the electricity network. Heating, cooling and electric mobility are relevant in this context.

A paradigm shift: Local grids in future energy systems

Low- and medium-voltage grids are traditionally designed to passively distribute power from high-voltage networks to end users at lower voltages. Planning standards, which dictated the provision of electric power distribution infrastructure, were based on simplified and often conservative assumptions about future electricity demand. Once in place, there was little need for active management, and hence system operation often amounted to clearing faults and replacing components as and when needed. The demand profile from smaller, residential consumers was reasonably well understood and fairly homogeneous, so it was usually sufficient to read meters once a year or every few months. Demand was generally not actively managed – apart from simple systems that prioritised use at night (e.g. electric space heating, water heaters).

This picture has begun to change. A number of drivers are aligning to change the way local grids are planned and operated today, including substantial penetration of DERs, digitalization, business model innovation, and cross sector coupling between electricity, heat and transportation. Looking further into the future, these trends may substantially reshape this part of the energy system, increasing its importance as a critical part of a more reliable, cost-effective and clean energy system.

Current drivers for change

Principal drivers currently underpinning evolution in local grids include the uptake of DER, the smartening of local grids by utilities (including improved accuracy of price signals and/or revenue collection), and the electrification of heating and transport.

Uptake of DER fosters decentralisation of supply

DER are typically modular or small-scale technologies that empower end users to produce energy locally and adapt the timing of their consumption to the needs of the system. This signifies a break away from the historic top-down supply structure that has marked electricity systems for more than a century. The most important DER driving change in local grids in recent years has been rooftop solar photovoltaics (PV).

Global installed capacity of rooftop solar PV grew from 10.7 gigawatts (GW) in 2010 to 45.7 GW in 2016 (Figure 37). In the same period, commercial-scale installations[31] increased by over 72 GW to reach 91.8 GW in 2016. Growth in utility-scale projects was 127 GW, reaching a total capacity of 133.7 GW in 2016 (IEA, 2016e).

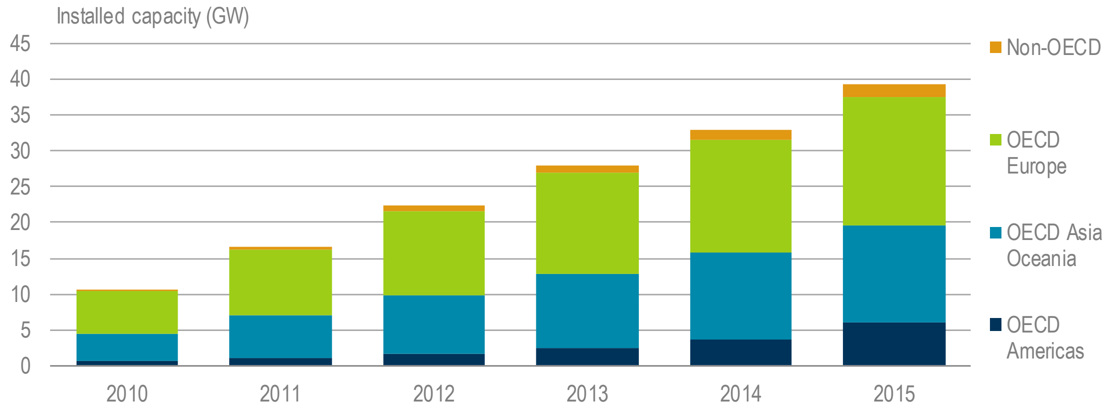
The residential and commercial segments combined represent 45% of total installed solar capacity in the United States, and as much as 72% in Germany. In 2016, the share of households

[31] Residential systems are defined as <20 kW and commercial-scale installations as between 20 kW and 1 000 kW installed capacity.

fitted with rooftop PV was 16% across all Australia, with 26% in South Australia and 25% in Queensland. The share of households with rooftop solar PV systems was 15% in Hawaii, 7% in Belgium and 4% in Germany (IEA, 2016e).

Global installed capacity of residential solar PV is expected to reach 73 GW by 2021, a 60% increase from 2016. This increase is bound to prompt changes in local grids.

Figure 37 • Global installed capacity of residential-scale solar PV, 2010-15



Notes: Residential PV is defined as smaller than 20 kilowatts (kW) installed capacity; OECD = Organisation for Economic Co-operation and Development.
Source: IEA (2016e), *Medium-Term Renewable Energy Market Report 2016*.

Key point • Residential solar PV capacity is on a continued growth trajectory globally.

Smartening of local grids by utilities

Over recent years, grid companies have tested and deployed a wide range of technologies to increase the intelligence of local grids. The roll-out of smart meters in many power systems today is an important step towards a more refined tracking of electricity consumption. The move to higher levels of sophistication in the planning and operation of local grids represents a shift away from traditional, less proactive approaches for local grid management.

Utility-led initiatives often focus on improved situational awareness by applying information and communication technology (ICT). In South Africa, the Revenue Enhancement Project aims to equip five municipalities with advanced metering infrastructure that enables better management of the customer base, a reduction of technical losses and improved revenue collection.

In 2016 the French transmission system operator (TSO), RTE (*Réseau de Transport d'Électricité*) and the distribution system operator (DSO), ERDF (*Électricité Réseau Distribution France*), led the implementation of a "smart substation" demonstration to highlight the possibilities of increased co-ordination between different voltage levels. A digital interface between high-voltage equipment and intelligent electronic devices was established, alongside an open information technology (IT) architecture that enables highly detailed DER monitoring, improved incident diagnosis and automated protection schemes (ISGAN, 2016)

These investments enable improved operational efficiencies, reduced technical and non-technical losses, and increased reliability. They often allow larger volumes of DER to be hosted. In Austria, a pilot project launched in 2014 identified a number of control options for voltage band management that were successful in local grids with a high share of distributed generation. It found that by combining active decentralised network management, smart planning and monitoring, the hosting capacity of local grids could be increased by 20% (ISGAN, 2016).

Electrification of heating and transport

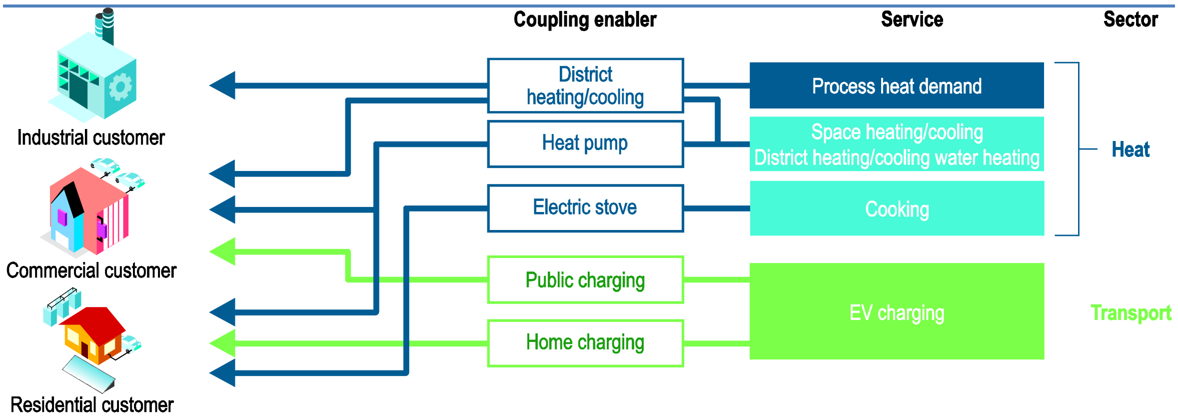
Demand for low-intensity heat, such as space heating, and individual transport is predominantly met by fossil fuel sources. Over recent years, a growing number of innovative and increasingly cost-competitive electric supply alternatives have been emerging to provide these services. The deployment of these technologies offers a number of benefits. First, heat pumps – coupled with thermal energy storage capability – and electric vehicles (EVs) can help shift demand across time, reducing the need for expensive peak-time generation and helping to integrate VRE. Second, depending on the evolution of the carbon intensity of the electricity mix, electrification can help decarbonise these energy services. Moreover, shifting to electric transport options can improve local air quality, especially in large urban areas.

The global stock of battery-electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) surpassed the 2 million mark in 2016, with strong growth foreseen in coming years. In addition, more than 200 million electric two-wheelers are on the roads today (IEA, 2017c). The connection size for EV charging, as measured by the amount of power it can draw from the network, and the degree of co-ordination between EV charging infrastructure and effective markets providing real-time price signals will affect how much instantaneous demand is added to the power system.

Although electric heating has been fairly common in a number of countries for decades (e.g. France and Norway), electrification of heating has received renewed attention in the context of the integration of VRE resources and the broader decarbonisation of the energy system.

Since demand for space heating and EV charging is strongly localised,[32] the contribution of these technologies to overall system flexibility will need to be harnessed at the level of local grids (Figure 38).

Figure 38 • Overview of selected options for electrification of heating and transport



Key point • Local grids are vital for supporting cross-sector coupling with heat and transport.

Long-term vision for local grids

As power system transformation processes continue, local grids may emerge as a central component of a clean, reliable and cost-effective energy system. The following trends could combine to create such an outcome:

- the large-scale adoption of DER, turning these resources into an important part of the power supply

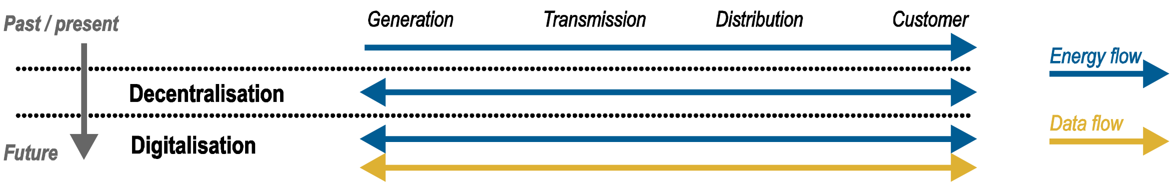
[32] Privately owned home EV chargers are estimated to account for 86% of globally installed EV charging stock (IEA, 2016f).

- mass enrolment of demand response, enabled by digitalization and the effective integration of intelligent end-use devices
- electrification of heating and transport, driven by decarbonisation and local pollution objectives, as well as the need to integrate VRE.

The cost-optimal share of DER, in particular decentralised solar PV, is subject to considerable uncertainty. For example, if the decline in the cost of EVs continues and the installation of charging infrastructure triggers upgrades to local grid infrastructure, much higher shares of decentralised solar PV could be integrated at very little or no incremental cost. Moreover, the economic rationale for DER deployment may differ strongly compared to investments in large-scale generation. Private citizens may prefer to own DER assets, even if this increases rather than reduces their overall energy cost, due to other considerations.

As a result of the rising intelligence of all grid components, all the way down to individual smart appliances, local grids could facilitate bidirectional flows of both electricity and data, giving rise to much richer and more complex interactions between devices on the grid (Figure 39).

Figure 39 • Impact of decentralisation and digitalization on local power grids



Key point • The combination of decentralisation and digitalization introduces bidirectional power and data flows.

Due to a combination of technological and cost improvements, as well as more stringent equipment standards, modern household appliances are becoming smarter. IT allows for communication and a degree of control between smart appliances, energy management systems (EMS), aggregators and other grid assets. Smarter operation signifies that appliances shift consumption away from moments of peak demand. Abundant opportunities exist in warmer climates to introduce automated, time-responsive air-conditioning equipment that adjusts power consumption levels to the time of day, to price signals and to user preferences.

EMS can use real-time data on the grid situation and market prices to optimise energy flows within a home, a building, at district or even at city level throughout the day. Importantly, by automatically making decisions on behalf of end users, within pre-established boundary conditions, EMS can bring much greater demand response to fruition, compared to a situation where each end user manually responds to price signals.

Such enhanced control capabilities are instrumental in ensuring the efficient uptake of heat pumps, EVs and other end-use technologies such as intelligent thermometers and battery storage systems. In the 450 Scenario[33] of the IEA 2016 *World Energy Outlook*, the combined stock of BEVs and PHEVs reaches 710 million by 2040 (IEA, 2016g). It is worth noting that a single passenger vehicle may consume 50 kW to 100 kW when quick charging. Managing these loads in an intelligent fashion will be critical for efficient and reliable system operations.

More generally, a successful transition is one that holistically considers three aspects – or layers – of the system: technical, economic and institutional. The technical layer focuses on the flow of energy between source and load. The economic perspective looks at monetary flows between

[33] The 450 Scenario provides a 50% chance of limiting global average temperature increase to 2°C.

various market participants. Finally, the institutional layer considers flows of information and investigates the impact of power system transformation on the division of roles and responsibilities.

Each layer functions by different rules and requires different types of intervention. Technology and business model innovation, policy reform and updated market rules can drive change in their immediate layer, but can also directly or indirectly affect the status quo in different parts of the energy system. The introduction of EMS, for instance, is likely to cause change in each layer: temporal demand shift (technical), bill reduction (economic), and co-ordination of control signals and data ownership (institutional).

Lack of progress in one dimension can hamper progress in another. For example, if there is no clear way to monetise the demand response potential held by DER, or if certain administrative obstacles persist, third-party aggregators are less motivated to combine the flexibility existing across a wide portfolio of businesses and households.

The remainder of this topical focus discusses aspects of these three dimensions as follows: in the first section, the technical perspective of local grids is discussed; the next section takes an economic perspective, discussing tariff design and compensation for services provided by DER; the final section in this chapter focuses on institutional issues, revisiting evolving roles and responsibilities in local grids.

Before turning to these three dimensions, it is worth briefly introducing the concept of digitalization in the context of local grids to lay the foundation for further discussion.

How to foster the opportunities of digitalization

For the energy system, digitalization refers to the innovative use of ICT, in particular the large-scale rollout of smart devices and sensors in equipment where this has not been the case in the past, and the use of big data collection and analytics to increase the efficiency and productivity of energy-related activities. Digitalization affects the generation, transmission, distribution and consumption of electricity and other utilities, such as heat and gas.

Uptake of digital monitoring and control technologies in the generation and transmission segments of the electricity system has been an important trend for several decades (ISGAN, 2016). Today, this is spreading deeper into the system, into local grids and towards the edge of the grid.

The control features and data that are obtained via the deployment of smart sensors and similar devices provide an opportunity to offer new types of service. For instance, as sector coupling advances, EMS can co-optimise the flow of power, gas and heat in response to prices and consumers' demands for services. In combination with DER, such as intelligent connected appliances and battery storage systems, EMS can open up substantial opportunities for demand response.

Enhanced communication and control enable third-party aggregators to bundle the demand response of a portfolio of small end users. In certain markets, such as France and Pennsylvania-New Jersey-Maryland (PJM) in the northeastern United States, it is possible to bid aggregated demand response flexibility into system services markets. As the transaction cost for modifying the consumption levels of a large number of small users continues to come down, such aggregated demand response will become increasingly competitive with demand response from industrial and larger commercial consumers (EPRG, 2016).

However, barriers impeding the effective participation of end users as both consumers and producers of electricity and heat must be addressed. The retroactive application of lower compensation for grid injection in certain countries hurt investor confidence and substantially reduced deployment in recent years. In many cases, third-party aggregation of end users is not allowed at all. In the minority of European countries where it is possible, various technical or administrative barriers persist (SEDC, 2015).

Looking further into the future, digitalization may support new business models in which behavioural data linked to electricity consumption becomes a source of value itself. As a new element in power systems, digital capabilities, and the issues of data management that they entail, call for a coherent reassessment of policy, regulatory and market frameworks. This process is likely to *follow* the adoption of the technologies that underpin digitalization and raises a number of regulatory challenges. Issues of data ownership and access will become increasingly important, in particular with regard to data privacy and security of individual end users (Box 19).

Policy makers wanting to encourage the development of demand response will need to consider whether regulation should take an opt-in or and opt-out approach to customer authorisation of data collection and use. Opt-out programmes, which minimise the consents a customer must give, are likely to make mass participation in demand response markets more likely. Similarly, the development of energy management services markets could be facilitated by giving customers a range of options in relation to how much information they are willing to share. A voluntary code of conduct developed by the US Department of Energy and the Federal Smart Grid Task Force in 2015 provides a model in seeking to balance concerns relating to data privacy, the positive policy objective of fostering innovation in demand response markets, and the operational needs of utilities (US DOE, 2015).

Box 19 • Data privacy considerations

Smart grid demand response technology requires the widespread collection and analysis of vast quantities of consumer-specific, real-time electricity usage data. This may include records of individual energy use events, such as heating water for a shower. Concerns are growing that current legal frameworks do not adequately establish who will own this data, who will be able to access and use it for which purposes, and how exactly confidentiality can be protected. Utilities, competitive energy suppliers, aggregators and/or EMS manufacturers might need to establish:

- Administrative and technical security measures to protect and anonymise customer data.
- Procedures to maintain data quality and integrity, including means for consumers to access and correct any stored personal data.
- Transparency about the purposes for which data will be used, as well as use limitations.
- Means for consumers to give consent prior to any release of data, particularly to third parties.
- Means for consumers to choose to share their data with third parties when the release of such information is beneficial for them, or to freely transfer their data between service providers.

In order to reap the benefits of digitalization while maintaining secure system operations, three features of the power system need to be reconsidered: first, the technical parameters for secure system operations; second, the economic signals in the power system; and third, the roles and responsibilities that drive energy and data flows. These are discussed in the following sections.

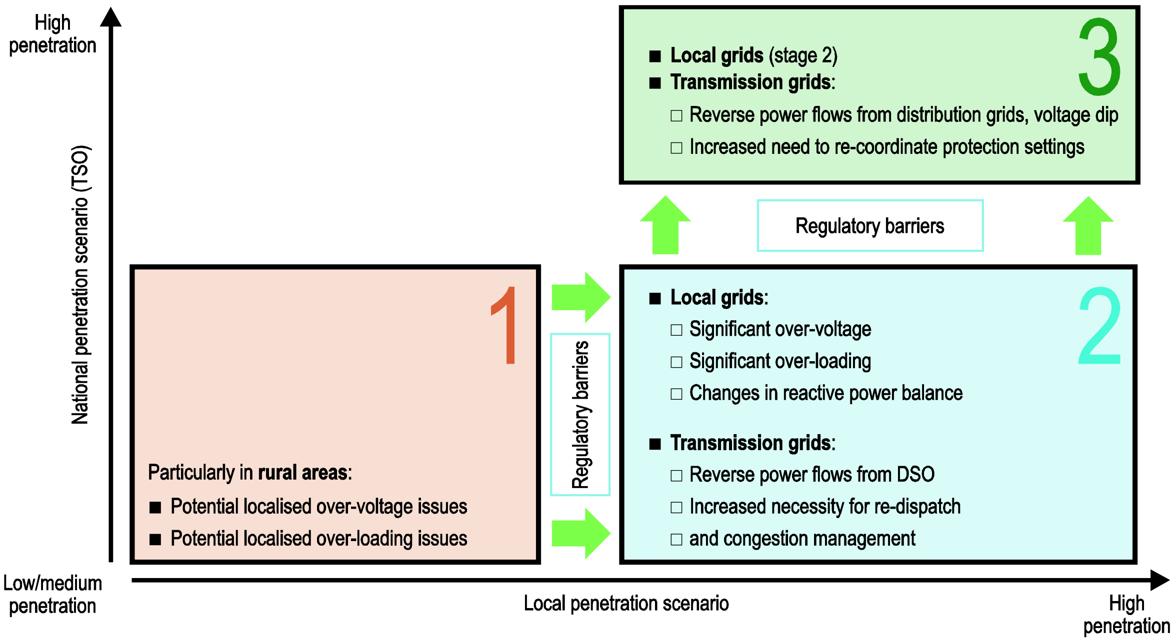
Secure and effective system operations under a high degree of decentralisation

Addressing DER: A focus on solar PV

With the introduction of DER, the traditional approach to local grids no longer suffices. DER may cause more dynamic energy flows, possibly posing technical challenges that require technical and operational changes. It is possible to identify three stages of technical impacts (Figure 40).

While distributed solar PV can make local grid operations more challenging, rooftop solar PV systems can also minimise negative impacts on the grid and, in some cases, even improve technical parameters by providing technical services that support grid stability. Using smart inverter technology, solar PV can provide voltage management capabilities and power system support services, as well as improved communications and interactivity. Adding battery storage improves the provision of these services, and has the important benefit of shifting some or all of the generated power for consumption to times of higher system demand (Figure 41). These services can have value for local grids; at high shares of decentralised solar PV, they can also become relevant to ensuring security of supply.

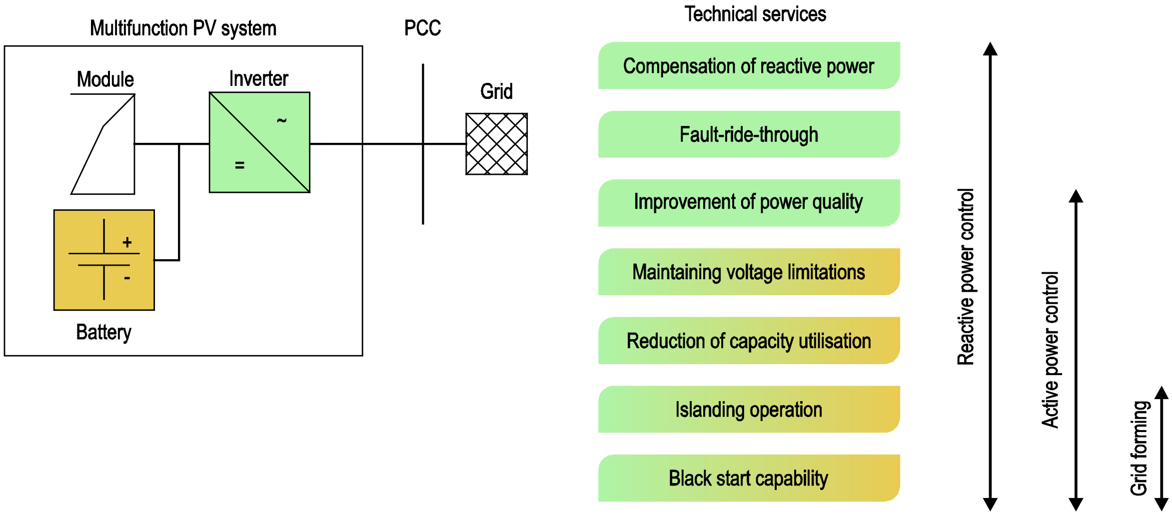
Figure 40 • Technical impacts of rising deployment of distributed solar PV generation



Source: IEA PVPS (2014b), *Transition from Uni-Directional to Bi-Directional Distribution Grids.*

Key point • As decentralised solar PV increases, a new set of technical challenges must be overcome.

Figure 41 • Technical services available from solar PV systems



Note: PCC = point of common coupling; this indicates the point of connection to the electric grid.
Source: IEA PVPS (2014b), *Transition from Uni-Directional to Bi-Directional Distribution Grids.*

Key point • Solar PV systems can provide a wide range of technical services, some of which require electricity storage.

Accommodating higher amounts of DER requires their impact to be managed at all voltage levels. High levels of DER, while co-located with load at a lower voltage level, still affect dispatch and power flows on the high-voltage network as much as a single-site plant with the same aggregate rating. New modelling tools and greater collaboration between planners at all voltage levels will be critical for the successful technical management of DER. This calls for a realignment of roles and responsibilities between system operators at different levels.

Smart grid options

ICT and supervisory control and data acquisition (SCADA) systems have been the most important tools for smartening local grids in recent years (IEA, 2015c). These technologies increase the observability of the network, i.e. the ability to monitor voltages and power flows along distribution feeders. They also allow for better management of bidirectional energy flows. Dynamic monitoring and control can allow the adjustment of distribution networks in real time in ways that were previously uneconomical or deemed unnecessary (Table 7).

Table 7 • Overview of different smart grid technology options

DSO resource	Cost/benefit reported as	Role/description	Indicative benefit/cost where positive
SCADA system, improved monitoring and forecasting, upstream flow of information	Smart planning and operation	Improves network observability, hosting on non-dispatchable generation.	1.1-3.3
Automatic network reconfiguration	Smart planning and operation	Increases hosting capacity of local grids, possible reduction of network losses.	1.1-2.2
On-load tap changer	Smart assets	Allows automated voltage regulation by changing transformer winding ratio, either remotely or autonomously.	1.2-1.8
Boost transformer	Smart assets	Stabilises voltage along heavily loaded branch feeders; typically used in long feeders with dispersed consumers to boost the voltage under heavy load conditions.	1.5-2.1
VAR control	Smart assets	With more DER changing active/reactive power balance, fast-acting power electronic devices, such as static VAR compensators (SVC) can stabilise local grid; mitigates voltage rises and/or compensates reactive power by injection of reactive currents.	1.1-1.9
Conservation voltage reduction	Smart assets	ICT solutions that enable local grid feeders to be operated at the lower end of the voltage range as required for system reliability.	1.1-2.6
Local storage	Storage	At local grid level, storage provides peak shaving, load levelling, power quality services, black-start capability and islanding support	1.1-2.4

Notes: VAR = volt-ampere reactive, also known as "reactive power".

Source: IEA (2016h), *Energy Technology Perspectives 2016*.

Key point • A range of smart grid options are available, often with a favourable cost-benefit ratio.

Advanced modelling capabilities

Historically, local grid planning followed a deterministic process aimed at identifying when and where peak load would occur. Rising levels of DER introduce new uncertainties, as these technologies bring a more complex supply/demand pattern to the grid, and events that determine the necessary size of the grid may not coincide with peak electricity demand. Planning standards will need to be updated using refined network architecture models, which also include innovative mitigation options such as demand-side response measures or the various smart grid options highlighted in the previous section.

System operators and planners of local grids are increasingly relying on modelling tools that have usually been applied only at transmission level. This includes high-resolution representation of distributed generation resources, new approaches to demand forecasting that account for both controllable and non-controllable loads, and the inclusion of multiple types of end-user load profiles, such as a home with an EV. Such advanced modelling is also critical to effectively managing sector coupling. An integrated approach, whereby EV manufacturers are directly involved in the design of network planning rules, may enhance efforts to develop common standards and protocols. It may also increase the likelihood that supporting grid technologies and DER capabilities evolve in line with the needs of the power system (PlangridEV, 2016).

Ensuring economic efficiency and social fairness through compensation mechanism and retail rate design

Historically, retail electricity pricing was developed on the assumption that customers did not have any alternative to grid supply. Moreover, it was assumed that electricity demand was relatively inelastic, in particular in the short term, with customer consumption reducing only modestly in response to rising prices. In this context, primarily volumetric price recovery was applied, whereby a single per-kilowatt hour (kWh) tariff charge was designed to recover most or all network and energy costs, including the supplier margin and energy taxes. The inclusion in the volumetric retail price of certain cost elements that do not scale directly on a per-kWh basis, such as network reinforcement costs, was justified by the assumption that users with the highest consumption had the largest impact on overall system costs.

With a few noteworthy exceptions (see Box 20), in most power systems the application of more sophisticated price schemes has historically been restricted to a limited set of customers with large amounts of load, such as industrial sites. Power system assets have been designed to manage expected variability in load, and the costs and operational complexities of making demand more flexible were deemed too high.

Box 20 • Application of time-dependent pricing in France

Before the market unbundling of the 1990s split activities into generation, transmission and distribution, French national utility Électricité de France (EdF) pioneered the use of different forms of variable pricing for residential customers. In the 1980s, EdF introduced a power-line communication system (PULSADIS system), which allowed it direct communication with customer-sited electricity meters, so that electric water heaters and other appliances would be activated at specific times of the day. In addition, a critical peak pricing scheme introduced in the early 1980s allowed customers to lower their electricity prices, if they accepted that they would face significant price hikes for up to 18 days each year (*effacement de jour de pointe*). By the year 2000, these schemes combined to enable 6.5 GW of demand response across France.

Source: Veyrenc, T. (2013), "L'intégration de la demand response sur les marchés d'électricité" (The integration of demand response in electricity markets), www.ceem-dauphine.org/agenda/en/aedbc6064d31e68a7d33b39464f72b7e22bdb117.

The need for a new retail rate design

Driven largely by the many changes described in this report, reforms in retail rate design are being pursued in many jurisdictions (IEA, 2016c). At the same time, advances in IT have lowered the transaction cost of communicating prices for energy and other utilities more dynamically, which opens opportunities for introducing more cost-reflective pricing structures with higher levels of granularity.

A growing number of end users now have an alternative to grid supply, and they use retail tariffs as a reference to make investment decisions. As the cost of DER continues to decline, uptake will continue to rise. This could become even more relevant in the coming decades if solar PV becomes integrated into building materials, further lowering the additional cost of new installations that coincide with the construction or renovation of buildings.

Increases in distributed solar PV tend to lead to higher levels of self-consumption, and thus lower network flows and, in the absence of tariff reform, associated revenues for the grid owner. Over time, this could translate into higher per-kWh prices for grid consumption for those who do not adopt DER, as the burden of network cost recovery is divided over a shrinking group of customers.[34]

At low penetrations, this effect is likely to have marginal impact on retail prices (LBNL, 2017). As DER uptake continues, however, this situation raises questions about distributional fairness among different end users, and may lead to a spiralling uptake of DER as ongoing grid supply price increases continue to improve the economics of self-supply.

In addition, sector coupling will link economic signals from other sectors with those of the electricity sector, and make it possible to meet a certain energy service using various sources. This increases the need for a level playing field between the different resources, whereby energy services are priced similarly, and are subject to similar taxes and levies.

Finally, DER may provide system services that are not captured at all in current tariff design. This creates a need not only to consider reform of retail tariffs, but also of valuation frameworks for DER more broadly. Both aspects will be discussed in turn.

Degrees of granularity for retail tariffs

As DER generation options become cheaper, retail prices should be designed to provide fair and appropriate incentives to both network users and DER (IEA, 2016c). With modern IT systems and emerging valuation methodologies, it becomes possible to calculate in greater detail the actual value of a given kWh of electricity consumption at a specific time and place. The deployment of smart meters makes it possible to communicate this value to end users and use data measurements at more regular intervals to apply them in the billing process. Price signals that accurately capture the impact on overall system cost give a stronger incentive for demand shaping when and where this is most valuable to the power system.

Retail prices can be refined along three dimensions (Figure 42). First, to indicate the supply-demand balance throughout the day, tariff design may move from a single, flat tariff to various degrees of time-dependency. Real-time pricing, the most advanced form of time-based pricing, has been applied in Spain since 2014, although consumers can opt out and subscribe to other supplier or contract structures (IEA, 2016c).

In addition, demand charges can reflect the contribution of an individual customer to overall generation and network costs. The precise characteristics of electricity consumption, such as the timing and magnitude of peak electricity demand, will influence the timing and location of grid planning and reinforcement.

The third dimension relates to the geographical location of consumption. The cost of delivering power to end users depends on transmission and distribution losses, and on the occurrence of congestion and voltage-related network constraints (MIT, 2016). The options for translating this spatial cost granularity in electricity prices range from regional tariff differences to more precise, real-time calculations of locational marginal pricing that reflect how a customer is situated relative to the various grid nodes.

[34] It is important to note that the full benefits of distributed solar PV resources are often not realised for many years. While distributed solar PV may lead to immediate-term utility revenue losses, short-term rate increases may be followed by longer-term decreases (resulting from, inter alia, deferred or avoided investment costs). Thus, it is important to consider the impact of these resources from both a short-term and long-term perspective.

Figure 42 • Options for retail pricing at different levels of granularity

	− Granularity +				
Time - Energy	Flat tariff	Seasonal time-of-use (summer/winter)	Daily time-of-use (weekday/weekend)	Intra-daily time-of-use (peak/off-peak hours)	Real-time pricing
Time - Demand	No demand charge	Customer peak	Expected system coincident peak, annual	Expected system coincident peak, monthly	Real-time coincident peak
Location	Single price	Zonal disaggregation	Nodal disaggregation	Locational marginal price (LMP)+Txlosses	LMP +Tx/Dx losses

Notes: Tx = transmission; Dx = distribution; LMP = locational marginal price.

Key point • Retail electricity prices can be refined along three main dimensions.

Compensating DER

The methodology for compensating DER, in particular distributed generation, is a strong driver for uptake of these technologies. Setting the right level and structure of remuneration for grid injection is a complex undertaking with important implications. If set too high, a disproportionate amount of money will flow to DER owners; if too low, compensation might be unfair to DER owners. Fixed remuneration (per unit of energy) provides investment certainty, whereas variable pricing can more effectively encourage system-friendly VRE design choices that maximise self-consumption or production during certain hours of higher system demand.

Traditional compensation mechanisms, such as net energy metering, were designed on the supposition that the grid can act as a buffer for the differences in timing of electricity production and consumption of individual households. Household production and consumption are brought together on the final electricity bill. Under net energy metering, localised electricity production is implicitly valued at the rate of the variable component of the retail tariff, as the household can bank production both within and between billing periods (IEA, 2016c).[35] Net billing applies a similar method, whereby injected surplus electricity is deducted from the electricity bill at a predetermined rate. In jurisdictions where a large proportion of retail tariffs consists of volumetric rates, net energy metering has come under pressure as DER owners are able to disproportionately offset their contribution to network cost. A third compensation mechanism for DERs is the feed-in tariff. In this arrangement, all electricity injected into the grid is compensated at an administratively determined rate.

As pointed out in Chapter 2 in IEA [2017b] for a detailed discussion, many jurisdictions are shifting to other, value-based compensation for decentralised generation. Methods for such value-based compensation for DER generally fall into two categories. The first category involves taking a snapshot of current DER value, and then providing a long-term compensation guarantee based on that.

A value of solar (VoS) tariff assigns fixed price tariffs based on an assessment of value components, including energy services, grid support and fuel price hedging, among others (Figure 43). Minnesota became the first US state to adopt a VoS tariff, with a 25-year inflation-indexed tariff that was determined through benefit-cost analysis and an extensive stakeholder consultation process (Farrell, 2014).

[35] Under net energy metering, banked kWh credits may eventually expire. When this occurs, they are deemed “net excess generation” and are typically credited to the customer at a predetermined rate, usually set between the avoided utility wholesale energy cost and the retail electricity rate.

The second category of value-based DER compensation involves more granular DER tariffs that reflect market conditions at specific times and locations. Adding price variability based on time and location can contribute to lower system costs by sending appropriate price signals to DER customers.

Figure 43 • Value components of local generation

Energy services	Avoided capacity	Grid Support	Financial	Additional benefits
■ Energy ■ Tranmission and distribution losses	■ Generation ■ Transmission and distribution	■ Reactive power ■ Voltage control ■ Frequency support ■ Operating reserves	■ Fuel price hedge ■ Market price	■ Grid security ■ Environmental/ carbon emissions ■ Socio-economic development

Note: Depending on deployment scenario, the value components may be negative. For example, if deployment of distributed solar PV leads to grid upgrade requirements, it would contribute to increasing rather than decreasing capacity costs.

Key point • Accurately rewarding DER requires a detailed analysis of the various value components.

Implications for policy design

Recognising temporal and spatial value in the pricing of electricity supply and demand can foster greater flexibility and lower the cost of planning and operating a power system. When implementing more efficient short-run pricing, however, it is important to consider the trade-offs that determine the effectiveness of any new tariff design.

First and foremost, regulatory design needs to balance the costs and benefits of higher granularity. Computation and implementation are the primary cost drivers when adopting higher price granularity. Whereas the pass-through of wholesale prices or LMPs calculated at the interface with high-voltage networks can be achieved by a rollout of advanced metering equipment, the use of more precise LMPs requires additional time and resources as considerable ICT capabilities are needed to verify cost calculations (MIT, 2016).

Moreover, customers, regulators and third parties all benefit from simplicity. If consumers are to adapt their behaviour in line with system needs, they must understand the applicable tariff. In most cases, the effectiveness of time-based price differentiation is likely to be more effective than locational price differentiation; consumers can adjust their consumption throughout the day, but typically have little means to compensate for their location in the electricity network.

The same goes for the granularity of DER compensation, which comes at the cost of advanced metering and billing systems, and can muddle the value proposition for risk-averse DER customers that do not understand energy market dynamics. In Germany, virtual power plants are used to aggregate many DER systems and sell their cumulative excess power in real-time electricity markets. This improves the overall responsiveness of small-scale DER to market signals, as more of the available flexibility is used. At the same time, the balancing responsibility is shifted away from individual DER customers to aggregators who can better manage this risk on the basis of a portfolio of DER clients.

Regulators also benefit from simplicity, both in the initial rollout of new rules and also in the ability to change them as they learn about the effectiveness of the rules.

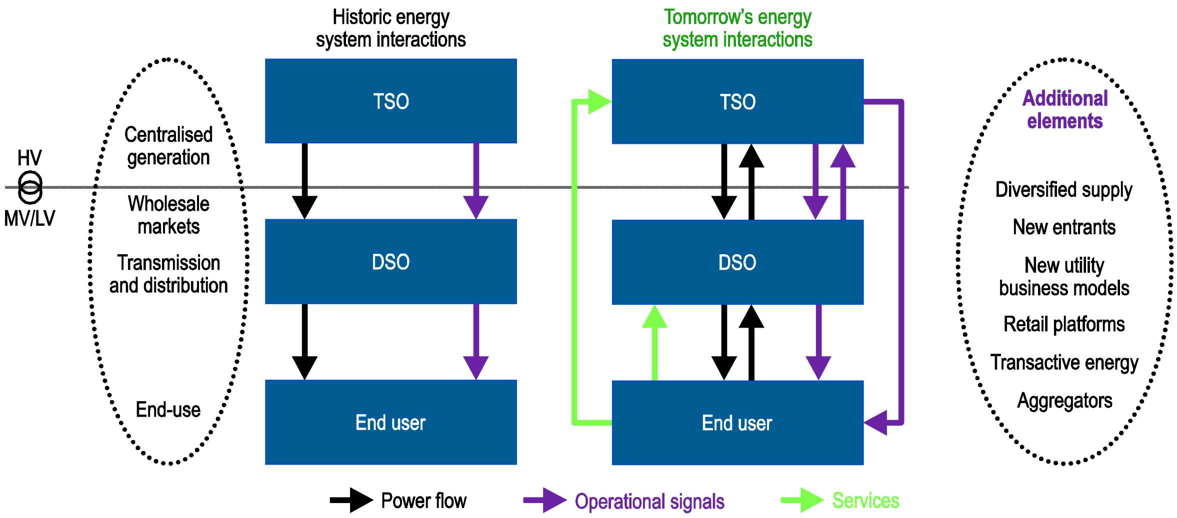
Accurate pricing of both supply and consumption will steer operational and investment decisions in the direction that best matches the evolution of local grids. At some point, however, a more comprehensive overhaul of the governance structure will also be needed to enable successful power system transformation across all sectors.

Revisiting roles and responsibilities

The fundamental changes being observed in local grids call for a more systematic revision of the historic institutional structure. The reliable operation of local grids today requires enhanced co-operation between grid operators across voltage levels, on issues including grid congestion management, real-time grid monitoring, prioritisation of operational decision making, balancing and operating reserves, voltage support and improved co-ordination in case of unforeseen system events (ISGAN, 2014).

The interface between the transmission system and local grids is a good example of this. Historically, this interface was managed in a clear, top-down fashion. Today, this is no longer fully the case (Figure 44). For example, TSOs in Germany rely on aggregators of small-scale dispatchable generators, connected at the local grid level, to obtain operating reserves. If the TSO issues a request for plants to increase output, additional generation will need to be fed in at higher voltage levels to take effect. However, this may not be possible if congestion is being experienced at the local grid level at that moment. This point highlights the need for clear rules and responsibilities under the new paradigm.

Figure 44 • Changes at the interface between transmission and local grids



Notes: HV = high voltage; LV = low voltage; MV = medium voltage.

Source: Adapted from Birk et al. (2016), "TSO/DSO coordination in a context of distributed energy resource penetration".

Key point • More complex energy flows and operational signals require new forms of co-ordination.

Other institutional reforms are needed to accommodate new commercial relations. The uptake of DER and intelligent appliances allows the end user to actively partake in the provision of energy and system services. New parties, for example aggregators or smart solution providers, enter the market to engage with the end customer in previously non-existent commercial arrangements. This may lead to inconsistencies, such as when suppliers and aggregators compete for end-user consumption. To allow for effective competition, the French regulator has ensured that aggregators have free, confidential access to consumers so that they can operate independently of suppliers, without requiring any authorisation from the supplier to operate (Veyrenc, 2016).

Elements of structural reform

Regulators and policy makers are beginning to grapple with the challenge of capturing the various changes happening in local grids and setting up institutional structures that are fit for purpose. Many stakeholders – from grid operators to aggregators – are arguing that the changing needs and technical possibilities of local grids require the identification and assigning of new roles. Often, however, they do not agree on what form the preferred new arrangements should take.

For example, digitalization introduces a new role into the structure of electricity markets, related to the ownership and management of data. The creation of a forum for data exchange represents a key challenge for successful power system transformation. If the ownership and management of data flows are centralised, one party would be designated to ensure the provision of a safe depository for metered customer data and data on network operations and constraints. This party ensures that eligible third parties enjoy non-discriminatory access to this data, and facilitates communication of information to end customers about their energy use and production (MIT, 2016). The assignment of this vital task in future power systems will be a key decision for policy makers in the process of power system transformation. In Denmark, the TSO (Energinet.dk) was designated this role, whereas in the United Kingdom and Australia, an accredited third party is responsible for data management. An alternative, decentralised solution could circumvent the need for a single "data hub operator" and instead rely on a network of computers to secure and verify data flows and transactions.

Many reform initiatives focus on evolution of the role of local grid companies. In the European context, regulatory reforms aim to transform local grid operators into neutral facilitators of electricity markets at the local grid level, where DER can offer energy and system services on a level playing field (EC, 2017). A similar approach is being taken as part of the "Reforming the Energy Vision" process in the state of New York. Integrating a revised institutional structure for local grids into an overall governance framework for the energy system remains a field of active research (Table 8).

Table 8 • Changing governance framework for local grids

	Role	Priorities	Regulation
Local system operator	Energy supply Operational standards	Maximise asset infrastructure	Rate of return Minor incentive regulation
Distribution service provider	Integrate all DER, reveal value Data provision	Optimise asset infrastructure	Performance-based

Source: Adapted from IGov (2016), "Distribution Service Providers (DSP): a transformative energy system institution?".

Key point • The evolving role of local system operators will need to be reflected in updated governance frameworks.

The scope and depth of such institutional reconfigurations are substantial. The interdependent nature of various elements of reform implies that delays in one area may reverberate throughout the overall transformation process. Indeed, rates of progress on various reform programmes demonstrate the difficulty of aligning the interests of a wide number of stakeholders, while also supporting grid operators and utilities as they evolve towards their projected new roles in future energy systems. Nonetheless, the rationale for power system transformation in local grids remains. In a process of continuous learning, policy and market reform will continue to unlock the potential of intelligent technologies, innovative business models, and increasingly empowered end users that could well drive the decentralisation of electricity supply.

Conclusions and recommendations

Recommendations for Phase One of VRE deployment

Treat system integration as an evolutionary process

- System integration challenges emerge gradually as VRE grows on the power system. Consequently, it is advisable to enhance the system's ability to absorb VRE gradually, also. The very first VRE plants can usually be integrated with little or no impact on the system.

Focus attention on the right issues

- Discussion of VRE integration is rife with misconceptions, myths, and sometimes misinformation. These distract decision-makers from the real though ultimately manageable issues and can, if not exposed as such, ultimately undermine successful VRE deployment.

Ensure a transparent and sound technical assessment of grid connection capacity

- Assign responsibility to assess the technical feasibility of grid integration to a technically competent and neutral body. Avoid the use of arbitrary caps, or approaches intended for conventional power plants.
- Though unlikely in Phase One, it is possible that local grid reinforcement may be needed. Prior to any grid reinforcement, full consideration should be given to alternatives to new lines, for example by configuring VRE plants in a least-impact manner.
- Assess options for cost allocation, including cost sharing among developers, and contributions from the public purse, which may be recovered subsequently from developers, consumers, or taxpayers.

State-of-the-art international industry standards provide a basis for technical connection requirements from the outset

- The system operator should refer to state-of-the-art industry standards and international experiences when identifying the technical requirements for connecting the first VRE plants, rather than attempting to reinvent the wheel. International standards should be modified to suit the local context.
- The SO should start with requirements appropriate to a low VRE share. These include ranges of operation, power quality, visibility and control of large generators. These will need to be adjusted as deployment grows.

Recommendations for Phase Two

Ensuring an appropriate grid connection code is in place

An appropriate process for development of grid codes applicable to VRE should be established

- The SO, in collaboration with policy makers and regulators should establish if a new grid code is needed or if an existing grid code should be revised, to accommodate the connection of VRE generators.
- The SO should gather relevant power system data, and identify appropriate modelling tools to be used in establishing the technical requirements to be included in the grid code. Policy makers should be sensitive to possible conflicts of interest.
- This process should be transparent, in consultation with all relevant stakeholders, particularly project developers, manufacturers, and owners/operators of existing power plants.

State-of-the-art international industry standards provide a basis for grid codes

- The SO should refer to state-of-the-art industry standards and international experiences when identifying the technical requirements of the code, rather than attempting to reinvent the wheel. International standards should be modified to suit the local context.
- The SO should consult the grid codes of systems with higher VRE shares. This will determine if wind turbines and solar PV technology already deployed at scale elsewhere can be employed, which is very likely, and which can help to reduce costs.

Lessons from other power systems are valuable for the development and implementation of grid codes

- Industry stakeholders and the SO should monitor developments in other power systems, particularly those with large-scale VRE deployment, to make sure that any relevant lessons are incorporated in their own code.

Grid codes should be assessed continuously and revised to ensure appropriateness

- The SO should monitor the grid code on a continuous basis to ensure it suits the needs of the power system, which will evolve as the share of VRE increases, and make any necessary revisions based on experiences with implementation.
- A channel should be established for feedback from stakeholders relating to implementation of the code.
- The SO should establish a process, and secure resources, for verifying grid code compliance during various stages of its development and implementation, and vigorously encourage compliance.

Reflecting VRE in power plant operations

Visibility of power plants to the system operator

- Require the transmission of static and real-time data from a sufficient number of conventional and VRE power plants.

- Rely on statistical methods to estimate the production from small-scale distributed plants (e.g. roof-top solar) to manage large data volumes and associated cost.
- Consider sharing data in the public domain to facilitate power system analysis.

Use of VRE production forecasts

- Implement state-of-the-art, centralised forecasting systems, and use these effectively for scheduling of power plants and other operational decisions.
- As appropriate, require plant-level forecast data from individual VRE power plants to incentivise high forecast accuracy.

Scheduling of plants and management of operating reserves

- System operation planning, often taking place hours before the time of physical delivery of electricity (real-time), should move closer to it, to deal with variability efficiently. In particular, shorter scheduling and dispatch intervals should be targeted.
- Where liberalised wholesale markets are in place, trading close to real-time, including within the day, must be possible.
- Current procedures for the calculation of the need for system services are frequently far from best practice. Defining system services depending on short-term VRE forecasts can help to optimise the requirement for and use of system services, in particular operating reserves.

Upgrade of market operations

Where liberalised wholesale markets are in place, trading arrangements need to be upgraded to provide accurate pricing at growing shares of VRE.

- To manage variability: greater importance of higher temporal resolution of price signals, i.e. prices are for short time periods; and greater tolerance of price volatility.
- To manage uncertainty: greater importance of short-term price signals, i.e. prices formed close to real-time, reflecting current supply/demand balance.
- To manage location constraints and modularity: increased importance of spatial resolution of price signals, i.e. electricity prices differ from place to place.

Controlling plants close to and during real-time operations

- System operators should have direct control over a sufficient amount of conventional generation capacity to ensure reliability; this may require gradually upgrading control centres.
- Sufficient controllability of VRE capacity is also needed. This need not be direct; it is sufficient that plant operators respond to command signals from the SO.

Ensuring sufficient grid capacity to host VRE

Synchronising building of new transmission lines with VRE deployment

- As VRE deployment grows to scale, new investments in transmission may be required to connect plants. Consideration should be given to how to synchronise the building of both, and how to manage VRE operations if grid construction should lag behind.

Best use of existing grid infrastructure

- Where congestion occurs, grid operators should explore opportunities for low-cost approaches to managing constraints, before resorting to the building of new lines.

Dealing with two-way power flows in the low- and medium-voltage grid

- In systems where small-scale VRE capacity is deployed in a geographically concentrated fashion, ensure that flows "upwards" from the low- and medium-voltage networks towards the transmission grid are manageable securely. This is generally possible with existing hardware, but may require some adjustments.

Planning ahead

- A systematic approach to grid planning should be developed and implemented at this phase of VRE integration. This includes management of the trade-off between connecting VRE plants close to load and tapping into the best (but possibly distant) resources.

Minimising the system impact of VRE

Technology mix

- Energy planners should consider the value of deploying technologies with complementary outputs, such as a portfolio of wind, solar PV and run-of-river hydropower.

Geographical spread of VRE

- While bearing in mind the benefits of wide dispersal of VRE power plants in system operation terms, the immediate opportunity to optimise the use of existing grid capacity should also be examined.
- Efforts should be made to understand pre-existing incentives/disincentives to the deployment of VRE in certain areas, which may unintentionally cause the concentration of VRE power plants (hot spots).
- Locational grid charging may be considered as a tool to encourage the dispersal of VRE plants; other incentives may be provided by the market, such as coincidence of output with times of higher electricity prices.

Recommendations for Phase Three and Four of VRE deployment

Transforming power system operation and planning to support VRE integration

Integration of VRE requires specific measures to maintain the cost-effectiveness and reliability of the power system, which evolve as VRE deployment increases. This report identifies four phases of VRE integration and associated operational issues, differentiated by the increasing impact of growing shares of VRE generation on the power system. Different measures have been employed to address integration challenges. These can be considered according to the specific requirements and objectives of the power system. This report reviews a number of technical and economic measures, differentiated by the phase of VRE deployment. These include: monitoring and control of VRE plants; measures to boost transmission line capacity; power plant flexibility; special protection schemes; advanced operational practices for pumped hydropower storage plants; strategies to extract system services from VRE plants; advanced VRE power plant design; grid-level storage options; sophisticated approaches to formulating operating reserve requirements; integration of VRE production forecasts; improved power plant and VRE dispatch; and increased balancing area co-ordination;.

To ensure different measures work in concert, robust and integrative planning is key. In many jurisdictions, increasingly integrated and co-ordinated planning frameworks have played a key role in the cost-effective and reliable accommodation of higher shares of VRE in the power system. This report provides examples of emerging power sector planning practices, including: integrated planning across a diversity of supply and demand resources; integrated generation and network planning; integrated planning between the power sector and other sectors, particularly transport, and heating and cooling; and inter-regional planning across different balancing areas.

Policy, regulatory and market frameworks to support utility-scale VRE integration

Policy, market and regulatory frameworks have a critical role in guiding operational and investment decisions. In the context of power system transformation, the large-scale uptake of VRE challenges traditional policy, market and regulatory frameworks. This is true for nearly all market structures, whether they lean towards more competitive and liberalised markets, or towards a vertically integrated model. However, the required adaptations will be different in each circumstance, reflecting different starting points. Globally, a degree of convergence in the required adaptation between the different models can be observed.

In jurisdictions where vertically integrated models have prevailed so far, a push is being seen towards introducing mechanisms to improve the efficiency of power system operation. For example, the ongoing power market reform in China aims for the introduction of a market mechanism to co-ordinate the dispatch of power plants in a more cost-efficient manner from a system perspective. In turn, countries that have pioneered power market liberalisation have seen a tendency to implement supplementary mechanisms to ensure security of electricity supply. For example, the United Kingdom integrated a centralised forward-capacity market and a long-term contracts-for-difference mechanism for low-carbon generation.

Five broad market, policy and regulatory framework objectives greatly enable the integration of larger shares of VRE in the context of power system transformation:

- ensuring electricity security of supply, including measures to ensure that generator revenues reflect their full contribution to system security
- efficient operation of the power system at growing shares of variable and decentralised generation, including measures to unlock flexibility from all existing resources, improve dispatch practices by moving operational decisions closer to real time, and encouraging efficient energy price discovery through competitive frameworks

- ensuring sufficient investment certainty to attract low-cost financing for capital-intensive investment in clean power generation, including well-structured PPAs for IPP projects
- pricing of negative externalities, including measures to constrain local air pollution or carbon emissions when locally appropriate
- ensuring the integration and development of new sources of flexibility, including from thermal generators, grids, demand response resources and storage.

Basic economic theory suggests that pricing externalities and introducing a well-designed wholesale energy market (energy-only market) should suffice to achieve all five objectives. However, practical experience across a broad range of countries has highlighted that such an approach is either very difficult to implement, or does not address all relevant challenges faced by markets, particularly those that are far from their economic equilibrium during a clean energy transition. This report describes a multitude of instruments and approaches applied in a diverse set of jurisdictions to achieve the aforementioned objectives.

System-friendly VRE deployment: Maximising the value of wind and solar power

Distributed resources: Focus on regulation of local grids and retail prices

A number of policy and market design options can enhance the system-friendliness of distributed resources. Sustaining the safe and reliable operation of the local power network in the face of rising VRE uptake will require up-to-date and technology-specific grid codes for low- and medium-voltage connections. Retail prices should give the right incentives to both network users and distributed energy resources, in a time- and location-specific manner. In particular, network tariffs need to cover the costs of infrastructure and should send a signal for efficient use of the network, as well as minimise the cost of future investment. This needs to be balanced with other policy objectives, such as economic development in rural communities.

In the context of rising self-consumption, tariff reform is likely to be required. For example, the introduction of demand charges that accurately reflect a customer's contribution to peak demand in a local distribution grid can be an appropriate way of ensuring fair charges for all users of the network. In addition, the gradual introduction of time-based pricing to reflect the time-dependent value of power production should be encouraged.

Centralised resources: Enhancing remuneration schemes

Reflecting SV in policy frameworks requires striking a delicate balance. On the one hand, policy makers should seek to guide investment towards the technology with the highest SV compared to its generation costs. On the other hand, calculating the precise SV can be challenging and, most importantly, current and future SV will differ.

In practice, exposure to short-term market prices can be an effective way to signal the SV of different technologies to investors. However, the current SV of a technology can be a poor reflection of its long-term value. This is due to transitional effects that can be observed in a number of countries where VRE has reached high shares. For example, in European electricity markets the combined effect of renewable energy deployment, low CO_2 prices, low coal prices and negative/sluggish demand growth (slow economic growth, energy efficiency improvements) are leading to low wholesale market prices. In turn, these low prices mean that any new type of generation will only bring limited cost savings and will thus have a low short-term SV. Even where electricity demand is growing more rapidly, investments based purely on expected short-term wholesale power prices face multiple challenges. Because wind and solar power are very capital intensive, such challenges will directly drive up the cost of their deployment, possibly widening the gap between SV and generation costs. In addition, current market price signals may be a poor indicator of SV in the longer term.

Consequently, mechanisms are needed to provide sufficient long-term revenue certainty to investors. At the same time, such mechanisms need to be designed in a way that accounts for the difference in SV between generation technologies. A number of strategies have emerged to achieve this. Two relevant examples are market premium systems, which reward VRE generators that generate higher-than-average value electricity, and advanced auction systems, such as the model recently introduced in Mexico, which selects projects based on their value to the system rather than simply on generation costs.

As next-generation wind and solar power grow in the energy mix, a focus on their generation costs alone falls short of what is needed. Policy and market frameworks must seek to maximise the net benefit of wind and solar power to the overall power system. A more expensive project may be preferable if it provides a higher value to the system. This calls for a shift in policy focus: from generation costs to SV**. Next-generation wind and solar power calls for next-generation policies.** Action across five strategic areas is needed:

1) Strategic planning

- Develop or update long-term energy strategies to accurately reflect the potential contribution of next-generation wind and solar power to meeting energy policy objectives. Such plans should be based on the long-term value of VRE to the power and wider energy system.
- Monitor the cost evolution of wind and solar power, as well as integration technologies (demand-side response, storage) and update plans accordingly.

2) Power system transformation

- Upgrade system and market operations to unlock the contribution of all flexible resources.
- Invest in an appropriate mix of flexible resources. This includes retrofitting existing assets, where this can be done cost-effectively.
- Deploy wind and solar power in a system-friendly fashion by fostering the use of best technologies, and by optimising the timing, location and technology mix of deployment.

3) Next-generation policies

- Upgrade existing policy and market frameworks to encourage projects that bring the highest SV compared to their generation costs. A focus on generation costs alone is no longer enough.

4) Advanced VRE technology

- Establish forward-looking technical standards that ensure new power plants can support the stable and secure operation of the power system.
- Reform electricity markets and operating protocols to allow wind and solar power plants to help balance supply and demand.

5) Distributed resources

- Review and revise planning standards as well as the institutional and regulatory structure of low- and medium-voltage grids, reflecting their new role in a smarter, more decentralised electricity system, and ensure a fair allocation of network costs.
- Reform electricity tariffs to accurately reflect the cost of electricity depending on time and location. Establish mechanisms to remunerate distributed resources according to the value they provide to the overall power system.

Annex 1. Grid integration: Myths and reality

A number of claims regarding wind and solar PV integration can be encountered in power systems where deployment is just beginning, and where experience has not yet revealed them to be fallacies.

Claim 1: Weather driven variability is unmanageable

Probably the most prominent claim can be summarised as follows: "Wind and solar PV show extreme, short-term fluctuations that make them unsuitable as a generation resource."

This statement is very plausible to begin with: from our everyday experience we are all familiar with the abrupt changes in wind speed that might require thermal units to change their output very rapidly, in order to accommodate changing VRE output. Similarly, passing clouds can very rapidly change insolation and thus the output of the solar PV panels over which they pass. But this intuition misses two important factors.

Firstly, power demand itself shows random, short-term fluctuations; in consequence all power systems already have a mechanism to deal with this variability. When wind and solar PV deployment is beginning, the fluctuations in their output will tend to be "lost in the noise" of demand fluctuations.

As more VRE plants are added to the system, a second effect comes into play. The short-term fluctuations in output of different VRE plants, located in different locations in a power system, tend to cancel out. This means that remaining variability is less pronounced and large changes tend to happen on the hourly timescale rather than seconds.

This notwithstanding, there can be situations in which single plants can have an adverse effect on their immediate surroundings. This is further discussed below.

Claim 2: VRE deployment imposes a high cost on conventional power plants

Another frequently made claim goes as follows: "Fluctuations coming from wind and solar PV put a large burden on traditional dispatchable power plants, obliging them to adjust their output very rapidly. This creates significant technical challenges and sharply increases power system costs."

This claim is generally not true for larger power systems where deployment of wind and solar power is just beginning. The reason is the same as for the first claim: at low shares of VRE, variability is dwarfed by that of consumer demand, and consequently not much changes for conventional generation.

As shares increase however, VRE output variability will begin to influence the generation patterns of other power plants including existing conventional thermal plants both technically and economically. But in many power systems, experience has shown that power plants are technically capable of more dynamic operation through modifications of equipment, software and operational practices without substantially increasing total power system costs. Using VRE production forecasts and adjusting generation schedules close to real-time are low-cost, effective tools to mitigate adverse impacts; and failure to adopt such measures can increase costs for the system as a whole. These power plant flexibility can also participate in balancing number of additional market by providing an ancillary services, which can remunerate more flexible operations. In contrast, in small island systems, VRE can impact other generators earlier on in deployment, and more significantly, but these smaller systems are not the focus here.

Claim 3: VRE capacity requires dedicated "backup"

This claim is usually expressed as follows: "Wind and solar PV are an unreliable source of power – therefore they need to be backed up by conventional power plants, which is very expensive." While it is certainly the case that the output of VRE power plants varies with the weather, it does not follow that one megawatt of VRE needs to backed up with one MW of conventional power plant.

Solar PV, for example, is likely to operate for 10% - 30% of the time on average over the year. This is known as its capacity factor (CF), and the actual value depends on the quality of the solar/wind resource, which varies with geography. (For wind plants, CF tends to lie between 20% and 50%.) From a long-term planning perspective this is the amount of power that will need to be covered when the resource is absent, such as at night for solar, or when the wind drops.

From a shorter-term perspective – i.e. in the operational timeframe of seconds to days – the output of the VRE megawatt will fluctuate with the weather. For a solar PV megawatt, depending on the time of day, this might be from rated capacity to around 20-30% (solar PV does not need direct sun to generate, so it does not fall to zero). But such fluctuations are reduced when VRE capacity is installed over a wide area – and interconnection among adjacent countries/power systems can make this area very wide indeed. This has the effect of increasing the capacity *value* of the VRE installed (see illustrations for both wind and solar in Figure 23).

Capacity value (or "capacity credit") – not to be confused with the capacity *factor* mentioned above – indicates the extent to which VRE can be relied upon like conventional power plants. The capacity value of VRE thus varies from place to place, and with the size of the system considered. This is a very important fact: there is no single answer to the "back-up" claim. Capacity value is further improved by combining both wind and solar technologies, whose outputs may be complementary.

The coincidence of VRE output with peak demand is another major factor. For example, solar PV reaches peak output at the hottest times of the day; if there is a large air-conditioning load then this pattern of output will fit well, and the capacity value of solar megawatts will be higher. Wind energy, being less regular in output, benefits less from this demand complementarity.

Finally it is essential to remember that power systems are not dimensioned to back up any one particular group of power plants; traditionally through building in redundancy, and increasingly through more flexible and dynamic operation of interconnected assets, it is the system's ability *as a whole* to meet demand that is important.

Wind and solar variability raises the importance of power system flexibility—the ability of the system to deal with higher levels of variability in the supply/demand balance of electricity. There are four ways to provide this flexibility: grid infrastructure, demand side response, electricity storage, and dispatchable power plants. In particular, dispatchable power plants-including thermal generation-are a key ingredient in a balanced mix of flexible resources.
And not only power plants are considered in this regard. There are other low-cost strategies to manage the relatively low capacity value of VRE. Demand side response (DSR) can be used to shift demand to periods when VRE availability is high. Battery storage technologies are emerging alongside existing reservoir hydro storage and pump storage. These energy stores can be charged up when VRE generation is abundant, to discharge during periods of low VRE output. DSR and battery storage are at an early stage but offer significant future potential (IEA, 2016g).

Claim 4: The associated grid cost is too high

The first three claims are related to the profile of VRE output over time. Another set of claims is linked to the location of VRE plants: "Wind and solar PV resources are located very far from demand; connecting them to the grid is thus very costly." It is true that the best wind and solar resources are often in remote areas that tend to be less favourable for human settlement; deserts are the sunniest places on the planet, and large population centres are hardly ever built in open, windy plains, although their proximity to high quality offshore wind resources may be greater.

Tapping into such resources will come at the cost of extending or upgrading the existing power grid. This cost varies considerably depending on geographic factors, land costs, etc. A comprehensive review of integration studies in the United States found a median value of roughly 15% of the cost of wind generation capacity for the cost of expanding the transmission grid. But costs vary widely, from USD 0/kW of wind capacity up to USD 1500/kW (Mills et al., 2009). A useful rule of thumb holds that grid infrastructure is a factor of ten cheaper than generation capacity, and there are many other possible benefits associated with increasing transmission, such as reducing congestion and increasing reliability.

In addition, technology learning and falling costs are resulting in cost–effective VRE deployment in locations that do not boast the greatest resource. This additional flexibility in siting VRE generation can lower associated grid costs.

Claim 5: Storage is a must-have

The claim that "Only additional electricity storage can smooth fluctuations of wind and solar PV" is often asserted. Again, it seems a very intuitive statement: looking at the fluctuations coming from VRE plants, it seems an obvious necessity to buffer this output, in order to give it a smooth profile.

Nevertheless, as with the other claims, important factors are omitted. The main point behind this claim is that at some point, VRE integration calls for an increase in power system flexibility. Indeed, this is the hallmark of Phase Three of VRE integration. However, storage is not the only form of flexibility. Dispatchable generators including thermal power plants and reservoir hydro routinely manage fluctuations on the demand-side. There are many other sources of flexibility, including demand side response or trade with other power systems. So electricity storage is just one of a package of solutions – and so far has not featured greatly in most countries already reaching above 20% share of VRE. (Wind dominates in most of these cases; the cost effectiveness of electricity storage is usually higher for PV than for wind.)

Claim 6: VRE capacity destabilises the power system

Power systems rank among the most complex machines ever built. The work of system operators in maintaining their stable operation amounts to constant monitoring and control. In some ways it is analogous to riding a bicycle: the rider must make continuous adjustment to keep it in balance.

As anybody who has ever ridden a bicycle will know, it is harder to keep balance when going very slowly; the spinning of the wheels at high speed provides inertia, stabilising the bike through the laws of physics. A similar process occurs in power systems: the rotation of very large generators and turbines in conventional power plants keep them in balance. In contrast, wind and solar PV generators are not connected to the grid in the same way as conventional generators and so do not, per se, provide inertia.

This is the basis of the last claim: "Wind and solar PV do not contribute to power system inertia – and this destabilises the power system." The degree to which this becomes an issue is driven by two factors: how much VRE is generating at a given time, and the size of the power system. As long as the share of VRE capacity is small compared to the minimum to average power demand of the system, issues around inertia are likely to be minor, except in very small power systems (e.g. with peak demand of 100 MW to a few GWs). In any case, it is unlikely that inertia will be an important factor in the early stages of VRE deployment. In addition, there are technical options for supplying additional inertia to the system. These options include the use of flywheels and extracting synthetic inertia from wind turbines.

More generally, state-of-the-art VRE generators are technically sophisticated and capable of providing a range of relevant system services to stabilise the grid. However, few jurisdictions require VRE to provide these services, or offer compensation for them, as more cost-effective means of stabilising the grid are available. Until they are required or incentivized, it is unlikely that VRE plants will provide these services.

Annex 2. Focus on the grid connection code

What is it and why does it matter?

Power systems are very complex machines, the larger ones being composed of a huge number of different components that must all function in a consistent and coordinated fashion if security of supply is to be guaranteed. These components will be manufactured by a variety of companies and, depending on the organisation of the power sector, may be owned and operated by a number of stakeholders. For example, in a system that allows for independent power producers, (some) generation assets and the grid may be operated by different entities.

So to ensure proper coordination of all components, a set of rules and specifications needs to be developed and adhered to by all parties. This set of rules is referred to as a grid code. Grid codes cover many aspects of system operation and planning (IRENA, 2016).

- Connection codes regulate how individual components such as generators and loads need to behave on the system, during both normal and exceptional operating conditions.
- Operating codes specify the procedures used by system operators including how power plants are scheduled and dispatched and what reserves are used to respond to unforeseen events.
- Planning codes contain rules on planning the expansion of the grid and new generation capacity.
- Market codes define common rules for the trade of electricity, including how to incorporate technical restrictions in the formation of prices.

The discussion of all these codes would go beyond the scope of this report. The most relevant at the outset of deployment is the connection code. Indeed, it is common to use the term grid code to refer only to the grid connection code, as is the case below.

Grid codes formulated as public documents first became necessary with the liberalisation of power systems. As soon as generation assets owned by different stakeholders operate on the same power system it becomes critical to define clear rules, which are made public and enforced.

Grid codes are particularly relevant for wind and solar PV plants because these are technically very different from traditional generators. The electrical behaviour of these synchronous generators is determined primarily by the way they are designed. Once operating on the system, their response to system disturbances is determined by fundamental laws of physics. In contrast, practically all, modern VRE power plants rely on power electronics to connect to the grid. This means that their behaviour is dictated not only by their initial design but also by how they are (subsequently) programmed to operate.

This is an opportunity for system planning and operation, because the behaviour of VRE plants can be adjusted in response to system-specific circumstances. However, it is also a challenge for two reasons. Firstly, finding the best way to programme VRE power plants is somewhat challenging. In the past, settings were designed with an only marginal role for VRE in mind. But as the importance of VRE has grown, this has required changes to the settings of plants (Box 21).

Secondly, there are some constraints on what VRE power plants can be asked to do. Or, more precisely, requiring a certain behaviour from a VRE plant may add significant costs to the plant; a cost that will ultimately be borne by the consumer.

Developing a grid code requires striking a delicate balance. On the one hand, VRE power plants must be required to provide those capabilities that are needed for reliable operation of the power system at least cost. On the other, it is important not to put requirements on VRE plants that are excessive, and which might curb VRE deployment unnecessarily.

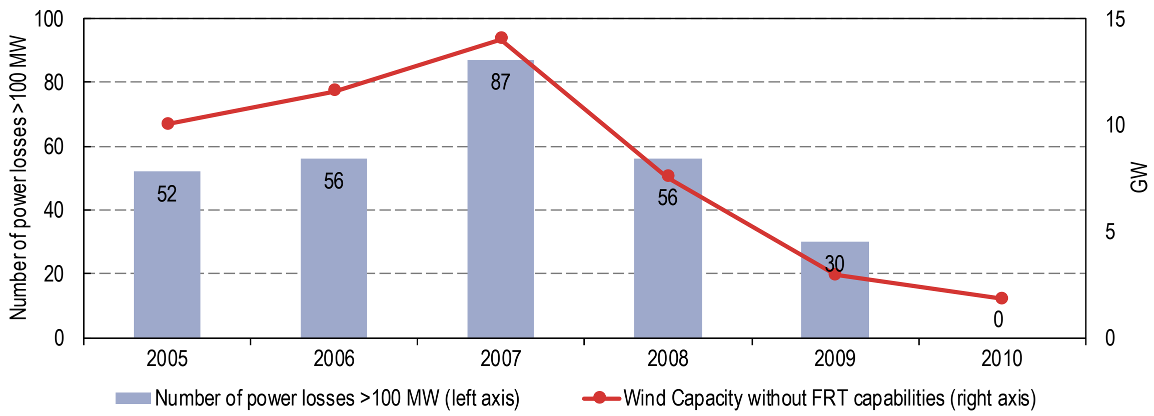
Box 21 • Evolving requirements in European grid codes

One relevant area for grid codes is the so-called fault ride through (FRT) requirement on generators during voltage disturbances. With wind energy, the initial requirement specified in grid codes was to disconnect in the case of a system fault following a short drop in voltage ("voltage dip"). However, as the share of wind power grew to a substantial level in Spain, for example, this was found in fact to be a *threat* to system security. This was not a problem with VRE generation technology itself, rather with the way it was required to operate.

By changing the grid code and requiring FRT capabilities from VRE power plants, this issue of single voltage dips can be resolved, as shown by the Spanish example where occurrences of VRE generators disconnecting after a voltage dip have been reduced to zero (Figure 45). It should be noted that requiring all power plants to have a new capability such as FRT could impose significant cost on pre-existing power plants, which may be an important consideration.

Another example concerns solar PV. The grid code for German solar PV power plants originally specified that all plants were required to disconnect from the system if frequency rose above a level of 50.2 hertz, which may occur during a system disturbance. While such a rule allows secure system operation at low penetration levels of solar PV, it can pose a threat at higher levels. If all solar PV power plants disconnect from the grid at the same moment, the loss of generation capacity may put system security at risk. After this issue was identified, a retrofit programme was put in place to ensure that no sudden loss of generation would occur as a result of grid code requirements.

Figure 45 • Number of power losses > 100 MW in Spain resulting from voltage dips, against wind power capacity without FRT capability



Note: FRT = fault ride through.

Source: Redrawn from IEA (2014), *The power of Transformation.*

Key point • Appropriate grid code requirements are essential.

Is the grid code appropriate for VRE?

In power systems with independent generator participation there will very probably be a grid code already. And even where power system planning and operation are in the hands of a single, vertically integrated entity, there will be a set of technical standards in some format or other, with which new generation facilities need to comply. Nevertheless, in almost all cases such standards will not define the technical performance desired from VRE generators appropriately.

What is appropriate depends on a number of factors. A recent study published by the International Renewable Energy Agency (IRENA, 2016) provides a detailed account of relevant factors to consider in developing a grid code that is suitable for VRE. The interested reader is recommended to consult this report for further details. In the following a summary of the main points is provided.

As a general rule, grid code requirements should aim to align with what is already required in other countries with higher VRE shares. This will help to manage cost, as technologies and approaches already deployed at scale elsewhere can be emulated. By way of contrast, novel requirements can increase costs, particularly if they apply only in a small market, and consequently require tailor-made solutions (rather than mass-produced equipment).

At the same time, it is not possible to copy grid code requirements one-to-one from one power system to the next, because there are a number of factors that will influence which capabilities are needed, as discussed in the following sections (IRENA, 2016).

VRE deployment factors

Current and future level of VRE penetration: as a general rule, the higher the share of VRE on the system, the more stringent requirements in the grid code need to be. The reason for this is simple: during times when VRE account for the majority of power generation, they will also need to provide a broad range of services that are needed to keep the system secure. Conversely, where VRE make only a marginal contribution, they will not have the same importance.

Voltage level where VRE generation is connected: depending on the size and location of a VRE plant, it will connect to different voltage levels in the grid. A large-scale plant may connect to the transmission grid directly. By contrast, a small rooftop solar PV system will be connected to the lowest voltage level. As a general rule, large installations connecting to higher voltage levels will be subject to more stringent requirements. But this also depends on the proportion of centralised to decentralised capacity. For example, the German grid code requirements for small rooftop systems have become more and more stringent over the past years, reflecting a growing requirement on its many small plants to support the system.

Technical properties of the system

System size (MW peak demand): it is generally easier to integrate VRE plants into larger power systems. This is because additional variability from VRE plants will be small in relation to the variability of demand. In addition, there are likely to be many more VRE plants, spread across different geographical locations, smoothing their output. Another reason is that larger power systems often are more robust in the face of disturbances. This means that requirements for individual generators can be somewhat less stringent. For example, Ireland – a relatively small island power system – has quite stringent requirements for generator performance, both VRE and non-VRE with a focus of frequency control requirements due to limited interconnection capacity.

Level of synchronous interconnection with other power systems: small power systems may exhibit similar requirements to their larger cousins if they are well interconnected. For example, the Danish system is divided into two sub-systems, connected to each other. Each of these is very strongly connected to a much larger neighbour (the continental European and Nordic grids respectively). This makes integration far easier in Denmark. But it is worthwhile to note that not all interconnection is comparable in this regard. A standard alternating current (AC) line can address issues that a direct current (DC) line cannot, and vice versa. For example, system inertia can only be shared using AC lines.

Strength of the grid: this is the ability to transport power from generators to load in different parts of the grid. Congestions and bottlenecks indicate weak spots. Grid strength also relates to the extent to which the grid can withstand angle and voltage disturbances as well as other contingencies. A strong system can generally operate within the operating standards for the majority of the time. Technology options available in the system such as batteries, storage options and interconnectors can increase the strength of the grid. Grid strength can influence the stringency of requirements for FRT capability in the grid code. Finally, it should be noted that inverters operate sub-optimally in weak grids; so ensuring their proper operation can itself become a challenge.

Characteristics of dispatchable generation: this relates to fuel and technology types in the existing power generation portfolio. Systems that have a flexible power generation portfolio are capable of accommodating changes in VRE output, which can be rapid at times. Desirable characteristics of generators generally include fast ramp rates, low minimum generation level and fast start-up time. Systems that consist predominantly of large thermal plants are generally less flexible. Open cycle gas turbines (OCGT) and hydro power plants are generally very flexible.

Regulatory and market context

Existing grid code requirements: this relates to historical grid codes. Existing codes may provide a basis for further improvements to accommodate VRE generators. The evolution of the grid code also encourages manufacturers of VRE technologies to have a clearer picture of which areas of technology improvement are needed to meet grid code requirements and facilitate grid integration.

Amount of capacity deployed in markets with similar requirements: for systems that plan to increase the share of VRE, it is valuable to draw on experiences from markets in other jurisdictions that have similar requirements. An important aspect is to ensure that grid code requirements are reasonable and enforceable.

The process for developing an appropriate grid code

Developing an appropriate grid code requires several ingredients. As a first step, policy makers will usually decide if a grid code is needed. Where generation is owned by independent power producers, a grid code will very likely be needed to guarantee that generation contributes to the safe operation of the grid. The development (or update) of the grid code can then be required by law.

The actual work on the code is completed ideally before the deployment of VRE power plants has begun in a country. In many cases, the regulator will task the system operator with drafting the code and approving it before it becomes binding. In order to prepare a first draft, sufficient data on the power system and appropriate modelling tools are required. Outputs from the data and the use of modelling tools provide accurate insights into the overall picture of the power system, which are used to support the development of a grid code. The important factors for the development of an appropriate code are summarised as follows (IRENA, 2016).

- **Data on the existing power system:** this includes generation, transmission and distribution systems. Such information is used for conducting power system simulations and stability analysis, both steady state and transient.
- **Computer simulation models of the power system and grid integration study:** these facilitate the identification of necessary grid code requirements. Appropriate modelling tools should be identified and conflict of interest in the analysis avoided; studies should include both steady state and dynamic analysis.

- **Cost-benefit analysis:** analysis is required of the likely costs and benefits of possible grid code requirements.
- **Long-term power generation and transmission development plans**: this is necessary to establish long-term targets and the strategic direction of the energy sector. It should include renewable energy, energy efficiency, decarbonisation, and other energy factors.
- **A highly experienced team:** a team with well-rounded knowledge of writing, enforcing, and if required, revising grid codes. It is important that the team has an understanding of the country's legal and regulatory systems as well as a sound technical understanding of the power system.
- **Collaboration with other countries:** this will enable countries to share experiences of grid codes and challenges arising from VRE integration. It may be possible for countries to pool resources and harmonise technical requirements, which enables manufacturers to develop equipment suitable for several markets, keeping cost down. An example of this practice is the European Regulation (2016/631) to establish a network code on requirements for grid connection of generators that will apply to all EU countries in order to achieve harmonisation between Member States.

In preparing a first draft of the grid code, the system operator should ensure that the applicability of the code is clearly defined, e.g. that the voltage level and generation type to which a given requirement applies, is stated clearly.

Once a first draft has been prepared, a consultation process with all relevant stakeholders (project developers, manufacturers, existing generators, installers etc.) should be organised. Such consultations may also be held in parallel to drafting the code. Once the draft is final, it will usually need to be approved by the regulator and possibly require further legislation to enter into force.

Prioritising requirements according to VRE share

The requirements of the grid code on VRE generators depend on the phase of VRE deployment reached. These requirements are influenced by the instantaneous share of VRE generation (IRENA, 2016), which can also be categorised according to different phases of VRE deployment (Table 9). The main technical requirements related to VRE follow.

- **Protection systems:** these are to isolate faults and mitigate the impact of faults on the electrical network. Standards for protection systems are required in all phases of VRE deployment.
- **Communication systems**: these are to allow the system operator to monitor the output of VRE plants in real time, as well as direct control of VRE plants via Automatic Generation Control (AGC).
- **Power quality:** the main aspects of power quality include harmonics and flicker, which occur in terms of waveform distortions and short-term fluctuations.
- **Voltage and frequency ranges of operation:** these are the operating ranges of the power system under different conditions. All equipment connected to the system is expected to be able to operate within a range of the nominal values, typically ±10% to ±15% of the nominal value for voltage, and -5% to +3% for frequency.
- **Frequency control/active power control:** this is the ability to provide active power regulation, particularly downwards in response to over-frequency (active power, or real power, measured in watts). Variations in active power output will have an impact on system frequency. The control of active power may be via AGC.

- **Spinning reserves:** these are extra reserves of power that can be made immediately available by power plants that are already connected and operating to reduce the area control error (ACE), which is proportional to the frequency deviation, to correct imbalances that cannot be corrected with AGC. In systems with non-negligible VRE penetration, spinning reserves should be quantified dynamically and proportionally to the expected VRE output.
- **VRE resource forecasting:** this relates to tools for forecasting the output of VRE power plants over different timeframes to help system operators/planners with scheduling dispatchable power plants and spinning reserves cost-effectively. Forecasting tools are important as more VRE generators are connected to the system.
- **Voltage control/reactive power control:** this relates to the ability of VRE plants to respond to voltage fluctuations at their point of connection. Reactive power from generators assists the flow of electromagnetic energy. Variations in reactive power from generators will have an impact on local voltage.
- **Fault ride through (FRT):** VRE plants may or may not have the capability to remain connected to the network for a certain length of time during voltage disturbances. VRE plants should provide reactive power in the event of low voltage, contributing to the management of faults.
- **Simulation models:** these are models that replicate the physical behaviour of the electric grid, which are used to simulate possible scenarios to facilitate decision-making in power system planning and operation. Accurate and updated grid and generator models are required to ensure the accuracy of the simulation. Generation owners should provide simulation models of the power plants connected to the system.
- **Synthetic inertia:** this is relevant at very high shares of VRE. VRE generators do not provide inertia to the system, so at higher shares the rate of change of frequency (RoCoF) will increase. Synthetic inertia can be engineered however, though this requires very advanced control methods and additional hardware components.

Table 9• Technical requirements for different phases of VRE deployment

	Always	Phase One	Phase Two	Phase Three	Phase Four
Technical requirements	- protection systems - power quality - frequency and voltage ranges of operation - visibility and control of large generators - communication systems for larger generators	- output reduction during high frequency events - voltage control - FRT capability for large units	- FRT capability for smaller (distributed) units - communication systems - VRE forecasting tools	- frequency/ active power control - reduced output operation mode for reserve provision	- integration of general frequency and voltage control schemes - synthetic inertia - stand-alone frequency and voltage control

The enforcement and revision of a grid code

The extent to which grid codes are enforced depends on their legal status, which can vary across countries and jurisdictions. In some countries such as Australia, grid codes are mandated and established by law; therefore failure to comply with grid code requirements could result in fines. In some other countries, grid connection codes are not mandated in law; rather they are guidelines and applicable rules for generators connected to the system.

Regardless of legal status, there should be a process to verify that generators comply with grid code requirements. Checking and certifying grid code compliance requires various resources including technical capacity and legal competence. Ideally, compliance verification should be performed throughout a VRE project, from planning, installation, and commissioning, through to the end of operating life.

Certification is an important tool to ensure that VRE generators fulfil grid code requirements before being allowed to export to the grid, while minimising compliance costs and encouraging VRE to deploy (IRENA, 2016). In order to avoid testing the totality of units wishing to connect, which would be labour-intensive, the SO can require developers to present internationally accredited certificates that prove that they meet a certain standard. Then only one unit needs be tested to prove that all meet the required characteristic(s). During operation, the system operator verifies grid code compliance based on a plant's observed response to real-world conditions. The certification process during the various stages of VRE plant development should be clearly specified in the grid code.

VRE project developers may incur additional costs in complying with a grid code, which could hinder project development. To avoid this, and to encourage grid code compliance, policymakers may wish to employ financial incentives to comply, such as tax incentives on additional investment required. Stakeholders should also be provided with a platform through which to provide inputs and feedback during the drafting of grid codes.

Grid codes are continuously revised to suit the evolving needs of the power system as the share of VRE increases, and to keep pace with changes to energy and climate policies, such as (rising) renewable energy and emissions reduction targets. In addition, the SO's growing body of experience with implementation will indicate required changes. The frequency of grid code revision depends on how fast the power system and the energy sector is evolving. One thing to keep in mind is that if revisions occur too frequently, it will be difficult for manufacturers to keep up. On the other hand, if revisions do not keep pace with VRE development, then this may have undesirable impact on the system.

Annex 3. Details of technical measures to address power system challenges

Introduction

This annex provides details of the reliability and economic measures mentioned in the previous Chapter that have been used to address challenges in power system operation arising from VRE generation. The annex focuses particularly of measures that are employed during the later phases of VRE deployment (Phases 3 and 4).

Technical measures during the later phases of VRE deployment

Tools and techniques for enhancing transmission line capacity

Dynamic line rating

Dynamic line rating (DLR) calculates the capacity of transmission lines closer to real time by taking into account actual operating and ambient conditions instead of assuming a fixed capacity.

Typically, a transmission line is rated at a certain capacity to carry power. The capacity of a line is usually constrained by line sag, which happens due to current-related temperature increase. The conventional approach for determining the capacity of transmission lines is based on the worst-case assumptions (low wind speed, high ambient temperature, high solar radiation) (IEA, 2014). The line capacity determined under this assumption would then be used across a range of actual conditions. However, the actual ability of a line to carry power is influenced by temperature: at lower temperatures, the real capacity of the line is likely to be higher than the rating.

DLR allows flows in transmission lines to be well above the static rating for most of the time.[36] With DLR, system operators (SOs) can make use of additional capacity when available and thus reduce the need for network investment. At times of high winds and, in some cases, high levels of solar power generation, DLR can be an effective option to alleviate transmission congestion and thus reduce the risk of curtailment.

DLR has been implemented to great effect in many systems including, for example, Spain, the United Kingdom, Ireland, Texas and Australia (Box 22) (US DOE, 2012a). The impact of DLR depends on system-specific circumstances.

Recently, the US Idaho National Laboratory has been developing a software package to calculate real-time ampere capacity and thermal limit of transmission lines (INL, 2017). This tool uses power flow and weather information at sparsely located weather stations, rather than having a device physically attached to a line. It will enable SOs to accurately assess dynamic real-time limitation and adjust power production accordingly. This method may prove to be more cost-effective compared to traditional DLR.

[36] Taking into account a gentle wind of 1 metre per second can increase the line rating by as much as 44% (Aivaliotis, 2010). In many systems, DLR can be 30% higher than static line rating for 90% of the time (US DOE, 2012a).

Box 22 • DLR in the Snowy Region, Australia

DLR has been implemented by TransGrid, who is a transmission network service provider (TNSP) in New South Wales, in order to maximise transmission capacity and reduce the risk of congestion. The system utilises weather data that are monitored and recorded in real time by weather stations. These real-time data enable TransGrid to understand the conditions the line is experiencing and therefore manage and operate it more efficiently.

TransGrid expected high levels of wind generation to cause much of the future congestion in the 330 kilovolt (kV) transmission lines between the Snowy Region and Sydney. It is deploying DLR projects to assist in reducing potential congestion by allowing higher thermal limits that result from high wind speed. According to the Australian Energy Market Operator, DLR should make it possible to increase power transfer on the 330 kV transmission lines between the Snowy Region and Sydney by approximately 400 megawatts (MW).

Source: AEMO (2014), *Independent Planning Review: Attachment A – Transgrid Project Assessment Reports*.

Flexible alternating current transmission system devices

Flexible alternating current transmission system (FACTS) devices are high-power electronics-based technologies offering real-time controllability – their main benefit is to enhance transmission efficiency and reliability.[37] They are used to enhance controllability of the network, power system stability and increase power transfer capability at key points in the transmission grid. The condition of the network can be controlled by FACTS devices in a fast and flexible manner.

In this way, FACTS devices allow for better utilisation of the existing network by enabling transmission lines to be operated closer to capacity without causing disturbances in the system. They can help to address issues of network congestion that may be caused by VRE.

The effectiveness of a FACTS device depends on its type and rating, as well as on local network conditions. Utility-scale FACTS device applications have been implemented to manage congestion in a number of countries, including the United States, the United Kingdom, Japan, Thailand and Sweden. Experiences suggested that a FACTS device installed on the network can significantly enhance transmission capacity (Gupta et al., 2017). They have also been used to accommodate the integration of large balancing areas by enhancing the transfer capability of interregional interconnectors, particularly between Nordic countries, allowing greater shares of VRE to be deployed in the region.

Phase shifter

A phase shifter is used to improve the transfer capacity of existing transmission lines by controlling the direction and magnitude of power flow in specific lines of the network.[38] It is considered an economic and reliable approach to managing power flow using existing assets.

Phase shifters are important components in alternating current (AC) transmission networks. They can be used to control active power flow at the interface between two large and solid

[37] There are two main groups of FACTS device: thyristor-based and voltage source converter-based FACTs. The most common type of FACTS devices are Static VAR Compensator (SVC), Thyristor Controlled Series Capacity (TCSC), Static Synchronous Compensator (STATCOM), Static Synchronous Series Compensators (SSSC) and Unified Power Flow Controllers (UPFC).

[38] The basic function of a phase shifter is to control active power by adjusting the phase displacement between the input and the output voltage of a transmission line.

independent networks, and have increasingly been used to manage power transfers in systems and reduce bottlenecks in the grid caused by VRE power injection.

Establish a limit on system non-synchronous penetration

System non-synchronous system penetration (SNSP) needs to be set in line with overall system performance levels, i.e. a limit that is appropriate in one system may be too high or too low in another system of the same size. The SNSP limit indicates the maximum share of non-synchronous generation, at any instance, that does not pose a security risk to the power system. This is considered a reliability measure.

Establishing the limit of SNSP requires in-depth studies, which typically involve detailed dynamic simulations of the power system at different demand levels and generation dispatches, taking into account expected development in the system. It is important to note that an SNSP limit is system specific and has to be established based on thorough analysis and testing.

Ireland/Northern Ireland have the most advanced systems for developing multi-year work programmes to integrate high levels of VRE into the power system. As part of this work, the two transmission system operators (TSOs) were able to identify and project the SNSP limit, increasing it from 50% to 75% by 2020 (Box 23).

Box 23 • Ireland's work programme for establishing a maximum SNSP limit

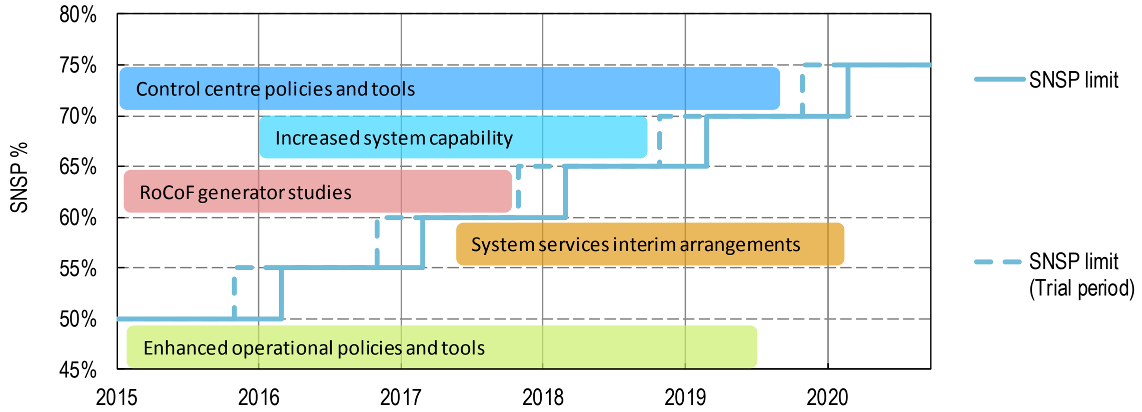
Eirgrid and SONI (System Operator Northern Ireland), which are the TSOs in Ireland and Northern Ireland respectively, have been undertaking studies to address the challenges of integrating high share of VRE onto the power system since 2010. The studies indicated that an SNSP below 50% would allow the system to operate in a reliable and efficient manner following a disturbance or frequency event. The issues identified include high rate of change of frequency (RoCoF) as a result of low synchronous inertia and transient stability.

As part of the "Delivering a Secure Sustainable Electricity System (DS3)" work programme, Eirgrid and SONI aim to gradually increase the SNSP limit from 50% to 75% by 2020. The work programme has identified pathways for achieving high SNSP (Figure 46); these include the development of enhanced operational practice, system services arrangements (such as inertia, reserve, ramping, transient voltage and voltage regulation), additional control centre tools and additional investment in network infrastructure.

The work programme is well on track to achieving an SNSP limit of 75%. Since December 2016, Eirgrid has raised the SNSP limit to 60% and has experienced 64 consecutive hours with a maximum SNSP greater than 55%.

Source: Eirgrid/SONI (2016), *DS3 Programmed Operational Capability Outlook 2016.*

Figure 46 • Projections of SNSP in Ireland/North Ireland



Source: Adapted from Eirgrid/SONI (2016), *DS3 Programmed Operational Capability Outlook 2016*.

Key point • A clear plan can help to identify options for increasing the share of VRE in the power system.

Inertia-based fast frequency response

Since modern VRE generators are connected to the grid via a power converter device, VRE generators only respond to deviations in system frequency according to the configuration of their power electronics. Reliably detecting a frequency event, extracting inertia from wind turbines, and managing the "re-charging" of the rotational energy of the turbine through the wind therefore requires sophisticated tuning of a synthetic inertia controller.

If appropriately tuned, inertia-based fast frequency response (IBFFR) can reduce the amount of synchronous inertia required by the grid. Note, however, that IBFFR cannot directly replace synchronous inertia provided by conventional generating units due to the fundamentally different characteristics in the nature of their response to high RoCoF events (Eirgrid/SONI, 2015).[39]

The TSO in Quebec, Canada, has established technical requirements for physical inertia from wind power plants since 2006 (Box 24), while Brazil and Ontario are considering similar mandates. In the middle of 2017, the National Electricity Market (NEM) in Australia will also be conducting a major trial in South Australia, where the share of VRE is around 40%, for a wind power plant to provide IBFFR. The trial will involve a new wind power plant to demonstrate its ability to provide fast frequency response to the system.

[39] It is important to recognise the trade-offs between the response provided and the recovery period, where active power from the wind turbines reduces temporarily. During this recovery period, the output from wind turbines can decrease by as much as 30% for as long as 40 seconds (DGA Consulting, 2016). This can create an adverse impact on the system's frequency recovery.

Box 24 • Requirements for wind turbines to provide IBFFR in Quebec

The transmission grid of Quebec is relatively small, with a peak power demand lower than 40 000 MW. The loss of generation can cause a severe threat to system security. In 2005, the Canadian TSO, Hydro-Québec TransÉnergie, set requirements for synthetic inertia from wind turbines by introducing a new grid code. Since then, wind turbines are required to deliver a power boost equal to 6% of their rated capacity in situations where system frequency drops. The time of response is 1.5 seconds for the maximum power contribution and should last at least 9 seconds. This led to wind turbine manufacturers to develop new technical solutions. In case of a frequency deviation, it is possible to extract kinetic energy from the rotating mass of a wind turbine.

In actual contingency events, wind turbines show a response within 1 to 2 seconds, with an active power increase of 6% to 10% of rated capacity, which extends for about 10 seconds. Wind turbines of various types (from a number of different manufacturers) have been shown to successfully deliver this response.

A low-frequency event in December 2015 showed that this enables about 126 MW of extra synthetic inertia to support the system. Due to a transformer failure, around 1 700 MW of generation disconnected from the system, when total demand was around 31 000 MW. Total remaining wind generation was around 2 060 MW and about 50% of the operating turbines were able to provide additional inertia of 126 MW. Although the frequency dropped to 59.1 hertz (Hz), it is estimated that it would have dropped up to 0.2 Hz more without the additional inertia from wind turbines.

Source: Asmine, M., C. Langlois, and N. Aubut (2016), "Inertial response from wind power plants during a frequency disturbance on the Hydro-Quebec System – Event analysis and validation".

Smart inverter

State-of-the-art smart inverters can provide five specific functions: ramp rate control, Volt/VAR (volt-ampere reactive) control, high-frequency power curtailment, voltage and frequency ride-through and grid monitoring. The electrical characteristics of inverters can be modified through software controls and parameter settings.

The use of smart inverters, whether at utility- or small-scale, may not be necessary during the initial phases of VRE deployment. However, at high shares of VRE, smart inverters can play an important role in facilitating the integration of VRE. Cost differences between smart and conventional inverters are not significant. Hence, smart inverters are starting to become common for new VRE installations even at a low share of VRE. Puerto Rico provides an example of the rollout of smart inverters (Box 25).

Box 25 • Smart inverter rollout in Puerto Rico

Puerto Rico has an ambitious plan to reduce the fossil-fuel intensity of its power system by installing 1 gigawatt (GW) of renewable energy into its 5.8 GW capacity system, with a peak demand of around 4 GW (NREL, 2015b; IRENA, 2013). Being an island, the availability of external supply is limited for Puerto Rico. Among the requirements that the Puerto Rico Electric Power Authority (PREPA) has placed on new VRE plants is the capability to regulate real and reactive power output, as well as requiring a number of grid-friendly controls.

Solar photovoltaics (PV) operators complied with the grid codes by installing smart inverters with VAR control and fault ride-through capability, and by installing battery storage systems in parallel with PV plants.

Source: NREL (2015b*), Energy Snapshot: Puerto Rico, Energy Transition Initiatives*; IRENA (2013), *Smart Grids and Renewables: A Guide for Effective Deployment.*

Advanced pumped hydropower operation

Certain pumped storage hydropower plants can operate in a special mode called hydraulic short-circuit pumped storage (HSCPS),[40] with the main feature of simultaneously generating and pumping. It enables the plant to contribute to system inertia and frequency regulation. If the plant is operating in either generator or pump mode, it is capable of switching between operation modes very quickly, without having to reverse the rotation.[41]

The ability to simultaneously operate in both turbine and pump mode provides greater flexibility to the grid. The power plant is seen by the grid as controllable load, with a power regulation range equal to that of hydropower turbines in operation. The contribution to inertia depends on the inertia of the unit, while frequency regulation depends on the turbine response.

HSCPC has been in operation in hydropower plants in Austria, Switzerland, the Canary Islands and Wales (Cavazzini and Perez-Diaz, 2014; Koritarov and Guzowski, 2013).

Grid-level storage

The different fundamental storage mechanisms can be broadly classified into electrical, mechanical, chemical and electromechanical, each of which consists of different technology types. Storage technologies vary greatly in terms of size, response time and charging/discharging times, and more importantly their capacity to provide system services to the grid.

The PJM market in the Northeastern United States has been at the forefront of deploying storage technologies to provide fast frequency response (FFR). Through its incentive mechanisms, FFR assets such as batteries and flywheels receive higher revenues per MW for regulation compared to fossil fuel power plants. As of 2016, PJM has about 250 MW of electricity storage (excluding hydro) that is currently in operation (Glazer, 2016).

Other countries that have deployed grid-level storage to provide frequency response include Italy and Chile. In Italy, more than 40 MW of electric storage has been deployed, consisting of different kinds of storage technologies including lithium-ion (Li-ion) batteries, super-capacitors and sodium-sulphur (NaS) in order to alleviate congestion and improve system inertia. Chile has also deployed batteries to provide frequency response (Box 26).

[40] This operation mode is possible in ternary pumped storage units where a separate turbine and pump is located on a single shaft with an electrical machine that can operate in generator or motor mode. The electrical motor and generator is a synchronous machine.

[41] The transition time between the mode of operation is in the range of 0.5 to 1 minute compared to 1.5 to 5 minutes in normal pumped storage (Koritarov and Guzonwski, 2013).

Despite their benefits, storage technologies, other than pumped hydropower, generally remain expensive in many countries and therefore financial incentives must be provided. In addition, many power systems with high shares of VRE can still operate the grid reliably without the need for storage.

Box 26 • Chile's grid level storage

In Chile, energy storage has been used to provide frequency response to maintain the security of the system. AES, which is a developer of advanced battery technology applications, has developed a storage solution to perform reserve capacity functions for grid support in Chile's systems. AES owns 4.5 GW of generation capacity in Chile and developed a solution using Li-on batteries to meet part of the obligation to provide frequency response.

The battery units are programmed to sense frequency deviations and ramp to full output instantaneously to provide support to the local grid and restore frequency. The first grid storage project, with a storage capacity of 12 MW/4 MWh, was developed to operate in both dispatch and autonomous mode, responding directly to significant frequency deviations, from ± 0.3 Hz.

A specific example was during a loss of 640 MW of generation in the system in 2013. Two energy storage units rapidly injected 32 MW to arrest frequency decline, in conjunction with other system services, until other generators were brought online.

Source: Kumaraswamy, K. (2016), "Energy storage is the smart choice to meet primary frequency response needs".

Glossary

Active power control: this relates to the ability of a power plant to control its output of active power, that part of power that can be used to do work, as distinguished from reactive power, which assists the flow of electricity in transmission and distribution networks.

Curtailment: the rejection by the system operator of part or all of the output of a power plant.

Cycling: the varying output of power plants, including start-ups and shutdowns, in response to changes in system load (demand). Conventional power plants are likely to cycle more to maintain the supply/demand balance in the face of a more variable *net load* resulting from increasing VRE penetration, which is likely to lead in turn to increased wear and tear.

Dispatchable power plants: those power plants which, in contrast to VRE power plants (see above), and within important operational and economic boundaries, can be turned on and off as required.

Dynamic line rating: this is the practice of modulating the rating of a transmission line (how much power it is considered to be able to carry) according to ambient temperature, which has an important bearing on the latter.

Fault ride through (FRT) capability: the ability of a power plant to keep generating electricity even during fault conditions, e.g. a sudden voltage drop.

Flexible AC Transmission Systems (FACTS): FACTS are power electronic devices that can enhance the controllability and stability of the power system, increasing its ability to carry power by flexibly modulating the reactive power injected or absorbed at a given node.

Flexibility: the capability of the power system to respond to upward or downward changes in the supply/demand balance in a cost effective manner over a time-scale ranging from a few minutes to several hours. Flexibility is often associated with the ramping capability of dispatchable power plants in the system but it also refers to other resources including storage, demand-side management and grid infrastructure.

Grid code: the grid code is a catch-all term that encompasses a wide set or rules by which assets connected to a power system and market must abide, the goal of which is to support the cost-effective and reliable operation of the latter. It consists of four major parts: connection codes (discussed in this document), operation codes, planning codes, and power market codes.

Grid strength: the ability of the transmission and distribution network to reliably transport electricity from where it is produced to where it is consumed, even in the face of contingencies.

Inertia: a property of power systems relating to the rotational inertia of large generators and turbines in conventional power plants that increases the stability of the power system.

Interconnections: alternating or direct current transmission lines that link balancing areas and power systems.

Net load: the system load (demand) less the output of VRE power plants.

Operation and maintenance (O&M): a broad category of activities and costs that relate to the daily workings of power system assets such as generators, transmission lines and storage facilities, and which is distinguished from the initial capital costs of a project. O&M costs may include fuel costs, replacement of components, labour costs and other factors.

Power purchase agreement (PPA): a power purchase agreement may be signed between the owner of a power plants and the buyer of the electricity it generates.

Power quality: the main aspects of power quality relevant in terms of VRE integration include harmonics and flicker, which occur in terms of waveform distortions and short-term fluctuations.

Ramp: in the power system context, a ramp may refer to a change in output from a power plant, a change in the load (demand) or a change in the net load (demand less VRE output). The ramp rate is the speed of change: upwards or downwards: in megawatts over time.

Rate of change of frequency (RoCoF): a measure of the speed with which the frequency of the power system changes. RoCoF increases with low system inertia (see above).

Reliability: the reliability of the power system refers to its ability to dependably provide electricity to consumers under normal and reasonably expected contingency conditions.

Reserves: generation capacity kept in reserve in order to manage normal operational conditions such as demand and VRE output uncertainty, and contingency events such as the loss of a major generator or transmission line.

Special protection systems: control schemes put in place by the system operator to manage the impacts of faults in parts of the transmission network that are likely to encounter such, and which might have impact on the wider network. They may be used to avoid more expensive hardware upgrades.

Stability: the ability of the power system to immediately recover and regain a state of operating equilibrium (within a timescale of milliseconds) from a physical or electrical disturbance.

Synchronous generation/interconnection: synchronous AC components of a power system are those whose operation can be said to be linked together electro-mechanically; there is no separation among them in the form of converters (which are used to link DC VRE generators to the grid).

System operator: the organisation responsible for operating part or all of the power system. Originally at high voltage only, active operation of low voltage grids is emerging in order to manage a growing amount of distributed (mainly solar) power plants. System operation is ideally separate(d) from ownership of transmission and generation assets.

Variable renewable energy (VRE) power plants: power plants such as wind, solar PV and run-of-river hydropower whose output is driven by the weather, and which therefore displays greater variability and uncertainty than that of conventional power plants.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
ADMS	advanced distribution management system
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGC	automatic generation control
ASEAN	Association of Southeast Asian Nations
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
CACM	capacity allocation and congestion management
CAES	compressed air energy storage
CAISO	California Independent System Operator
CCGT	combined-cycle gas turbine
CECRE	Control Centre For Renewable Energy
CENACE	Centro Nacional de Control de Energía (system and market operator)
CO_2	carbon dioxide
CRE	Comisión Reguladora de Energía (Energy Regulation Commission)
CSIR	Council for Scientific and Industrial Research
CSP	concentrated solar power
DC	direct current
DER	distributed energy resources
DLR	dynamic line rating
DNI	direct normal irradiance
DOE	Department of Energy
DSO	distribution system operator
DSM	demand-side management
DSR	demand side response
EFR	enhanced frequency response
EIM	energy imbalance market
EMMA	European Electricity Market Model
EMS	energy management system
ENTSO-E	European Network of Transmission Operators
ERCOT	Electric Reliability Council of Texas
ETS	emissions trading scheme
EU	European Union
EV	electric vehicle
FACTS	Flexible AC Transmission Systems
FCR	frequency control reserves
FERC	Federal Energy Regulatory Commission
FIP	feed-in premium
FIT	feed-in tariff
FRR	frequency restoration reserves
FRT	fault ride through
HSCPS	hydraulic short-circuit pumped storage
HV	high voltage

IBFFR	inertia-based fast frequency response
ICT	information and communication technology
IEA	International Energy Agency
ILR	inverter load ratio
IRENA	International Renewable Energy Agency
IPP	independent power producer
IRP	Integrated Resource Plan
ISGAN	International Smart Grid Action Network
ISO	independent system operator
IT	information technology
LCOE	levelised cost of electricity
LMP	locational marginal prices
LV	low voltage
MACRS	Modified Accelerated Cost-Recovery System
MISO	Midcontinent Independent System Operator
MV	medium voltage
NEA	National Energy Administration
NEM	National Electricity Market
NLDC	National Load Dispatch Centre
NPS	Nord Pool spot
NREL	National Renewable Energy Laboratory
NWP	numerical weather prediction
O&M	operations and maintenance
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
ORDC	operating reserve demand curve
PG&E	Pacific Gas and Electric Company
POSOCO	Power System Operation Corporation
PPA	power purchase agreement
PSH	pumped storage hydropower
PTC	production tax credit
PUCT	Public Utilities Commission of Texas
PV	photovoltaics
PVPS	Photovoltaic Power Systems Programme
RE	renewable energy
REE	Red Eléctrica de España
REDZ	Renewable Energy Development Zones
REV	Reforming the Energy Vision (United States)
RTE	Réseau de Transport d’Electricité
RTM	real-time market
SAARC	South Asian Association for Regional Cooperation
SCADA	Supervisory Control And Data Acquisition
SCE	Southern California Edison
SNSP	system non-synchronous system penetration
SO	system operator
SPS	special protective schemes
STE	solar thermal energy
SV	system value
TNSP	transmission network service provider
TOD	time-of-delivery

TOU	time-of-use
TSO	transmission system operator
TYNDP	Ten-Year Network Development Plan
USD	United States dollar
VOS	value-of-solar
VRE	variable renewable energy

Units of measure

GW	gigawatt
GWh	gigawatt hour
Hz	hertz
km	kilometre
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
kWh/m^2	kilowatt hours per square metre
m	metre
m/s	metres per second
m^2	square metre
MW	megawatt
MW/hr	megawatts per hour
MWh	megawatt hour
tCO_2	tonne of CO_2
TWh	terawatt hour
VAR	volt-ampere reactive
W/m^2	watts per square metre

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