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Getting Wind and Sun onto the Grid

A Manual for Policy Makers

INTERNATIONAL ENERGY AGENCY

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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 2015, these technologies – collectively referred to as variable renewable energy (VRE) – had reached double-digit shares of annual electricity generation in ten countries. In Denmark their share in electricity generation has risen to around 50%, and was around 20% in Ireland, Spain and Germany, in all cases without compromising the reliability of electricity supply.

Despite this evidence, discussion of VRE integration is often still marred by misconceptions, myths, and in 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 manual, written for policy makers and staff in energy ministries and 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 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. Where wind or solar plants are installed in a system that is much bigger than those first plants, their 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 around 3% in annual electricity generation.

In Phase Two, VRE has 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 really 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 Italy, the United Kingdom, Greece, Spain, Portugal and Germany; the VRE penetration in these countries ranges from 15% 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 and 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.

This manual focuses on the first two phases, in which most countries find themselves today; the flexibility aspect of Phase Three is discussed briefly also, because advance planning in this regard is critical.

In Phase One the integration challenges are small but two aspects are important. Firstly, proper assessment is needed of the impact of those first few VRE plants on the grid at their point of connection; and secondly a set of rules appropriate to VRE plants and governing their operation (grid connection rules) needs to be in place. Integration tasks in Phase Two are more onerous, although international experiences prove that they are entirely manageable.

- The grid connection code identified in Phase One needs to keep pace with the level of VRE deployment. Due to their often highly technical nature, grid codes rarely receive adequate policy attention. However, the majority of security of supply concerns with VRE in recent years have resulted from a failure to anticipate them in the grid code; while they have been subsequently resolved by amendments to it. Prominent examples include low-voltage ride through capabilities, which were first discovered to be an issue in Spain in the mid-2000s, and the "50.2 Hertz" problem in Germany. Both issues have been resolved via re-programming of VRE power plants. A grid code that is updated with an eye to international experiences, with strong stakeholder buy-in and effective enforcement, is critical to security of supply.
- The output of wind and solar power plants must be reflected in the wider planning of power system operation. The system operator – the all-important institution in the integration context – must have visibility (data) of what these power plants are doing in real-time, so it can plan the operation of dispatchable power plants accordingly. The system operator must also be able to curtail a proportion of VRE output at critical moments; this is crucial for the operator to be able to perform its primary objective of upholding security of supply. For example, the Spanish system operator has dedicated a section of its control centre to monitor and control VRE output effectively.
- The absence of an effective system for forecasting the output of wind and solar plants, in contrast, will not jeopardise supply security, but it will make integration very expensive, as the system operator will have to maintain disproportionately large reserves against variability.
- It is important to establish a systematic approach to maximising the use of existing network assets, as well as planned expansion of the grid, to resolve bottlenecks. Where VRE power plants are small and dispersed over the low voltage grid (e.g. rooftop solar PV), managing the interface between the (high voltage) transmission network and (lower voltage) local networks emerges as a priority. The latter is becoming a priority in regions including Australia (South Australia), Germany (Bavaria), United States (Hawaii) and Italy (Puglia).
- Finally, important steps should be taken to adapt VRE power plants to the needs of the wider power system (i.e. not just vice versa). International experiences show that a well-balanced portfolio of wind and solar PV power plants, for example, can have complementary electricity output profiles, which may enable the better use of existing grid assets. Choice of location can have important benefits also: a dispersed portfolio will have a smoother overall output than if plants are geographically concentrated, and will therefore be easier to manage. Concentration of plant has led to issues in regions including Tamil Nadu in India, and South Australia.

In Phase Three, the first priority is to make fully *available* the flexibility that exists already in the power system, so that it can better accommodate the variability of VRE plants. Changing the way in which conventional power plants operate often represents the easiest flexibility gain, and their full potential can be unlocked with a combination of changes to market design – essentially, how electricity is traded – and technical upgrades.

System integration is but part of the whole range of challenges that arise in the deployment of VRE power plants. Some of these others include the design of renewable energy policy frameworks, measures to kick-start a domestic renewable energy market, and questions around the design of wholesale and retail electricity markets. These can be found in the annexes as well as in other recent IEA publications. This manual focuses on the integration challenges as they can be expected to arise. It presents examples of where and how they have been encountered and resolved, and provides explicit recommendations as to how newcomers to VRE deployment should proceed.

Introduction

What is in this document?

Wind and solar PV technologies have seen rapid cost reductions and can now provide electricity at or below the cost of traditional sources in a growing number of countries. However, wind and solar PV have a number of properties that make them different from other sources of electricity generation.

Most importantly, variable renewable energy (VRE) output fluctuates over time, driven by the varying availability of wind and sunlight. This output uncertainty, and other factors, may lead to a number of concerns, particularly early on in deployment, when in fact the challenges are least. And while it is true that new challenges do arise as the share of wind and solar power increases on a power system, in fact these are usually very different from the concerns frequently expressed by those unfamiliar with these technologies.

For the purposes of this manual, which focuses on the integration of variable renewable energy (VRE) into existing power systems, the IEA has identified four distinct phases of VRE deployment. These are based on the impact of wind and solar PV on the power system, additional to what would be observed in a system without VRE.

Because many countries are just beginning VRE deployment, this document focuses particularly on Phase One and Phase Two of VRE deployment. In addition, one very important aspect of Phase Three, relating to power plant flexibility, is also discussed, because planning for the long-term needs of the power system may need to begin early on.

This document has two objectives. The first is to clarify what the true challenges are when beginning wind and solar power deployment. The second is to provide practical guidance on how to mitigate and manage these challenges successfully. This is of the utmost importance: if appropriate actions are omitted then the further deployment of VRE, and the security of electricity supply, may be jeopardised.

Who should read it?

This document is aimed primarily at policy makers and staff working in energy ministries and regulatory bodies considering the integration of VRE in their power system in a safe and cost-effective manner. The information it contains will also be useful for staff working in the power sector, including owners of non-VRE generation as well as system operators and power system planners. The authors assume a general familiarity with renewable energy policy as well as power system planning and operation. A glossary provides a succinct reference for some of the more technical terms.

What is not in this document?

This document addresses the system integration of VRE, which encompasses the technical, institutional and regulatory changes required to accommodate VRE in the power system in a reliable and cost-effective way, i.e. to ensure that, when wind and solar power plants are built, they work smoothly with the rest of the system. Evidently, kick-starting a market for wind and solar PV requires a number of other factors to be in place. These include a robust mechanism for remunerating VRE plants, a streamlined permitting process, accurate assessment of resources, and effective energy planning. This publication discusses remuneration mechanisms and permitting only so far as they are relevant for system integration, i.e. dealing with the specific properties of wind and solar PV. Readers interested in the broader policy framework can find detailed analysis and recommendations in several IEA publications (e.g. IEA 2016a, 2016b, 2016c, and 2015).

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. But in many power systems, experience has shown that power plants are technically capable of more dynamic operation 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. 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 1:1 "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.

One MW of 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 10).

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.

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, 2016b).

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.

Different phases of VRE integration

The previous section describes why some commonly heard, negative claims about wind and solar are inaccurate, and especially in the early days of VRE deployment. 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 document 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 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.

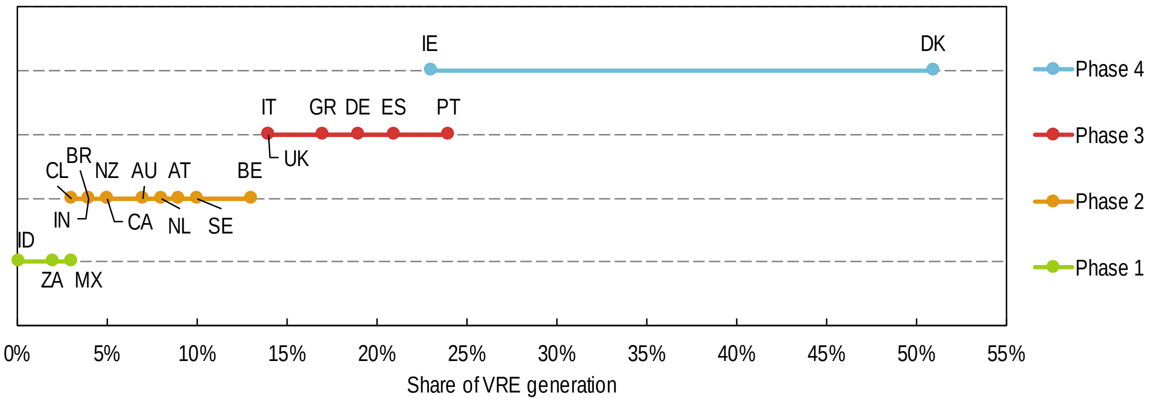
New challenges emerge in Phase Four also. These are very technical in nature and less intuitive than flexibility. They relate to the *stability* of the power system. Simply put, the stability of a power system characterises its ability to withstand disturbances on very short timescales. For example, 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 1). 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 1 • Annual VRE generation shares in selected countries and correspondence to different VRE phases, 2015



Source: Adapted from IEA (2016d), *Medium-Term Renewable Energy Market Report 2016*

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 1 • 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. We will focus on the first two phases, but the next section provides a more detailed description of all four.

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 8). 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 manual 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.

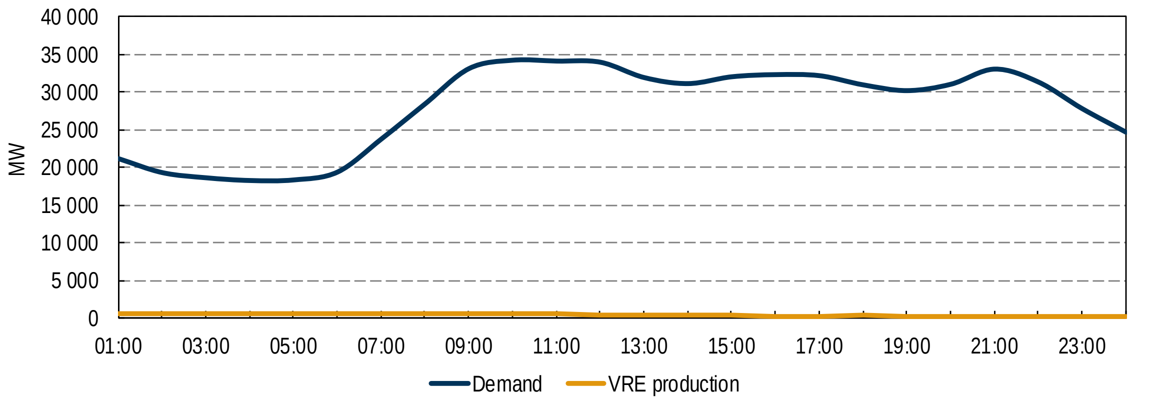
If VRE targets grow as part overall policy strategy, it is important that they should be considered in concert with other energy system developments to guarantee an efficient and effective integration in the grid. Policy makers might ask, "How will this course add to/detract from existing (conventional) 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 2), because their output is so small, it has no effect on system operation. It can be considered simply as negative load[1]. 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 1)[2].

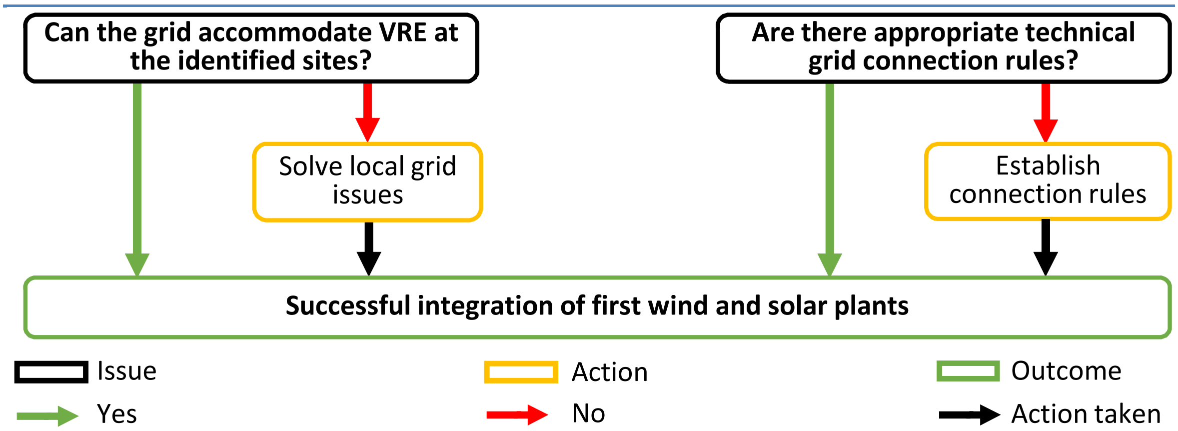
Figure 2 • Demand and VRE production, Italy, 13 April 2010



Source: Adapted from Terna (2017), *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 3 • Phase One: Summary issues and approaches



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

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[1] 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.

[2] 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 3).

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. A detailed discussion on what information is needed and how it can be disseminated can be found in Annex 1.

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 manual touches on them only when they are relevant to system integration

Source: IEA (2015), *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, 2016).

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*

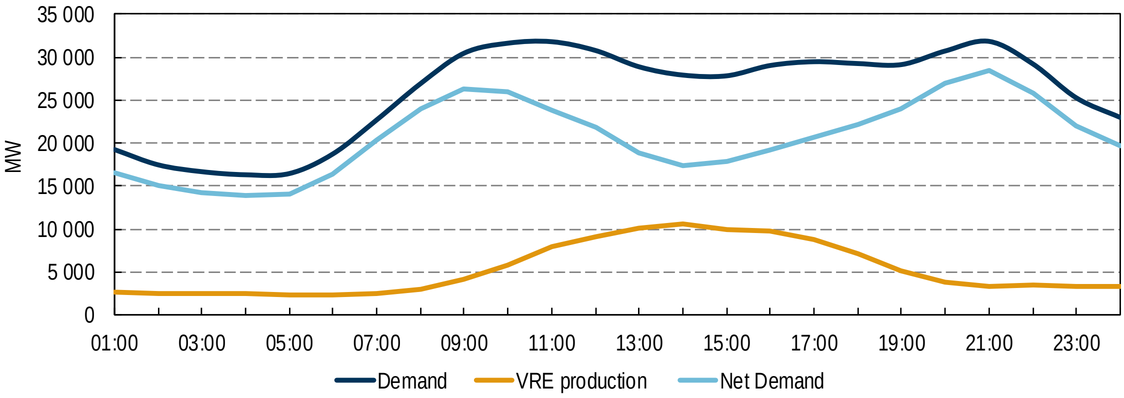
Phase Two: VRE capacity becomes noticeable to the system operator

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 4).

Figure 4 • Demand, VRE production and net demand, Italy, 13 April 2016



Source: Adapted from Terna (2017), *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.

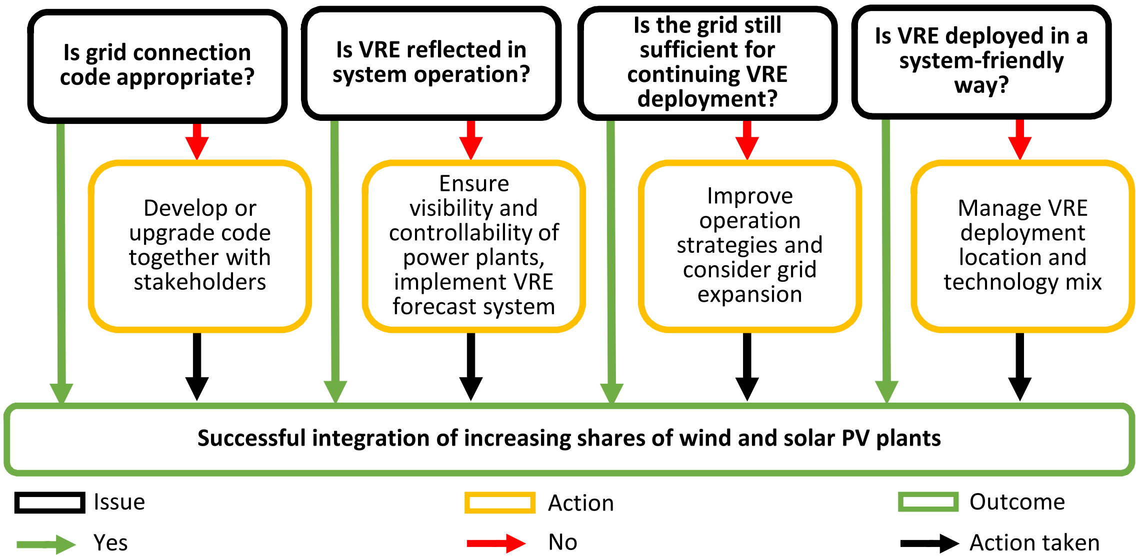
Phase Two lasts until maintaining the supply-demand balance is structurally more challenging, as briefly introduced in the next chapter. In contrast, during Phase Two it is very likely that gradual upgrades to the traditional way of operating the power system will be sufficient for successful integration.

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 5).

Figure 5 • 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[3], 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

[3] 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[4]. 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.

[4] 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 6 • 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[5].

[5] 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 (2015), *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 7).

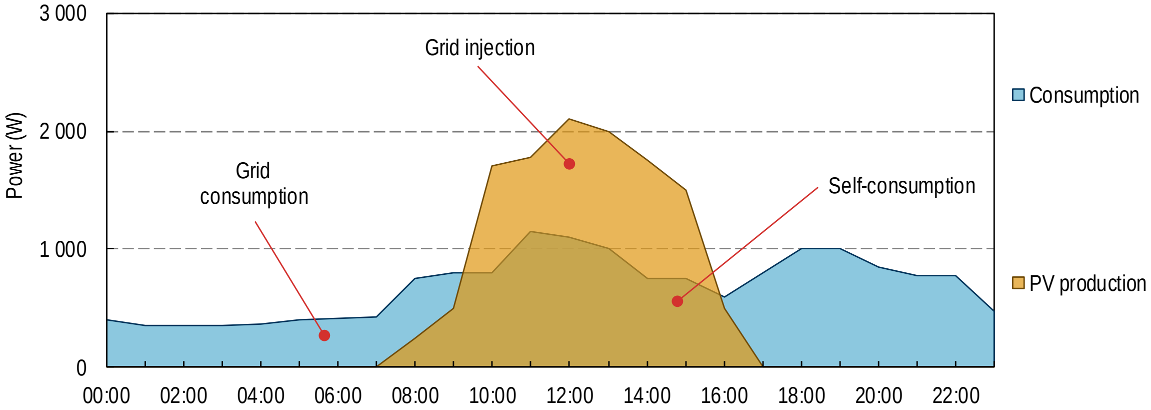
This reversal will happen at different times and will not be constant. It might occur around midday in a predominantly residential distribution feeder with a large amount of installed solar PV capacity: domestic consumption is low at midday as residents are out at work but when the solar PV capacity 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, 2014).

Figure 7 • 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?

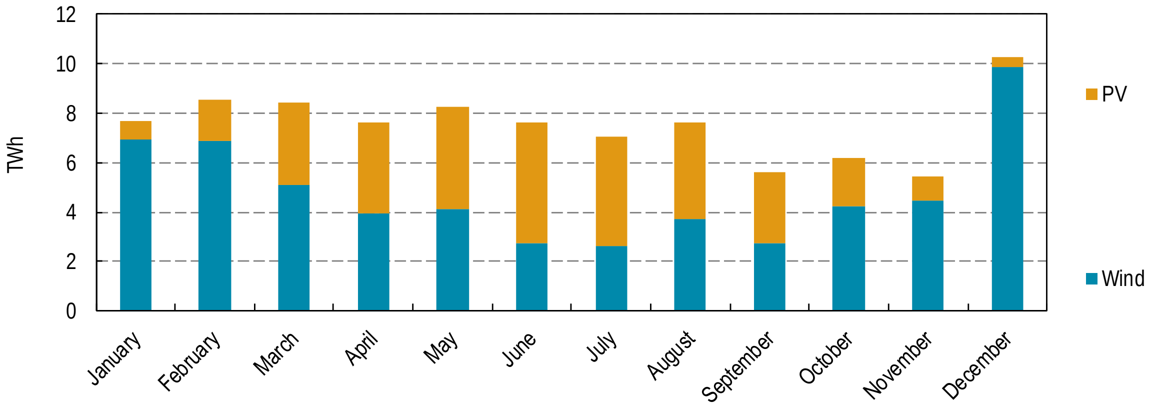
For example, it may be possible to construct a VRE power plant somewhat closer to demand centres, thus reducing the need for grid reinforcements. However, this may require siting the VRE plant in an area with less favourable resources, which will tend to increase the cost of electricity generation. The 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.

Technology mix

It has already been noted that the capacity of a substation to host VRE needs to be assessed systematically. Solar and wind power outputs are often negatively correlated, which is to say that on average their rate of export to the grid will occur at different times. This means that simply summing rated generation capacity may result in an unrealistically high estimate of the hosting capacity needed to accommodate a mix of wind and solar power plants. While it may be logical in the case of power plants with very high capacity factors, it is less so with VRE plants whose output depends on appropriate weather conditions.

Where wind and solar PV technologies are connected to the same substation, there is likely to be a more constant use of that connection capacity. An example of the complementarity of wind and solar PV output can be found in Germany (Figure 8). This portfolio effect is not limited to wind and solar: complementarity of output can also apply to run-of-river hydropower for example.

Figure 8 • Monthly generation of wind and solar power in Germany, 2014



Source: Adapted from Fraunhofer ISE (2017), "Monthly electricity generation in Germany in 2016", energy chart, www.energycharts.de/energy.htm.

Key Point • Complementary wind and solar output supports the more efficient use of grid connection capacity.

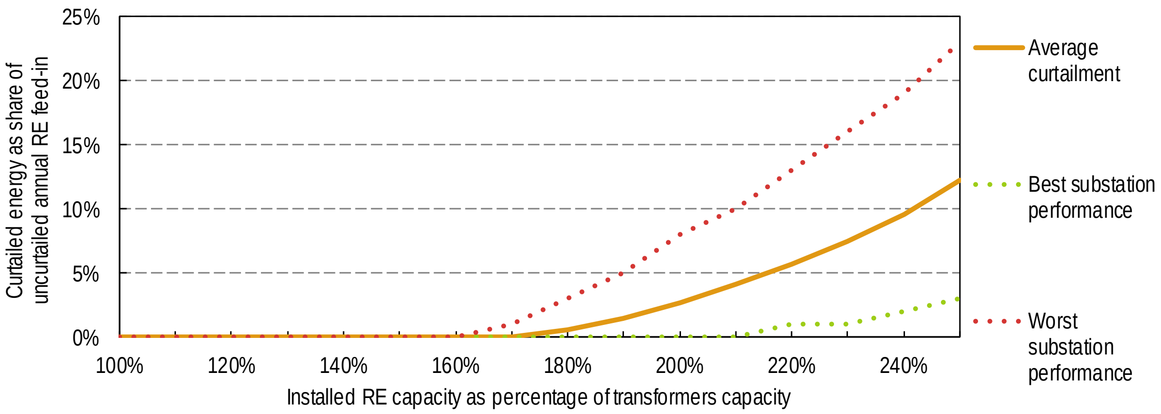
Recent analysis in South Africa supports this "technology-spread" approach, and suggests that up to 70% more VRE capacity might be added to a given substation in that country than the simple summing of their nominal generation capacities would suggest (Box 6).

Box 6 • 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 9).

Figure 9 • 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[6], 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 7.

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 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 7 • 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.

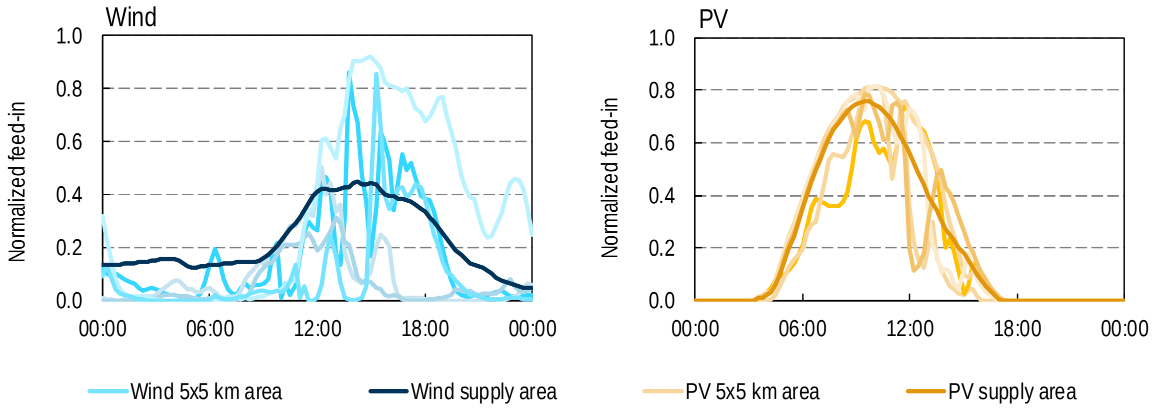
In contrast, if power plants are well dispersed, such fluctuations will be gentler and slower. Figure 10 illustrates this fact for both wind (in blue) and solar (in yellow) in South Africa. The paler lines show the steeply varying outputs of solar and wind plants in 5x5 km clusters, as compared with the aggregated output profiles of all wind and solar plants across the country.

Figure 10 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.

[6] 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.

Figure 10 • 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[7] (Figure 11): 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[8].

The modelled output of a concentrated wind portfolio is at 80% or more of its rated output[9] 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 fluctuates quite extremely.

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.

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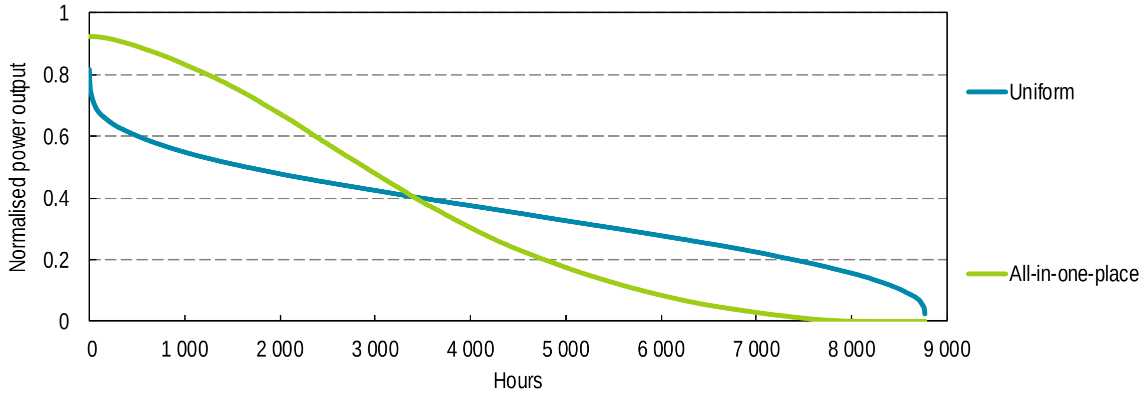
[7] Load Duration Curves (LDC) can be used for a number of different purposes. In this case they show the output of wind generator(s) at hourly intervals over an average year. The intervals are placed in order of size (of output) instead of chronological order, to reveal the proportion of an average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

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

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

Figure 11 • 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).

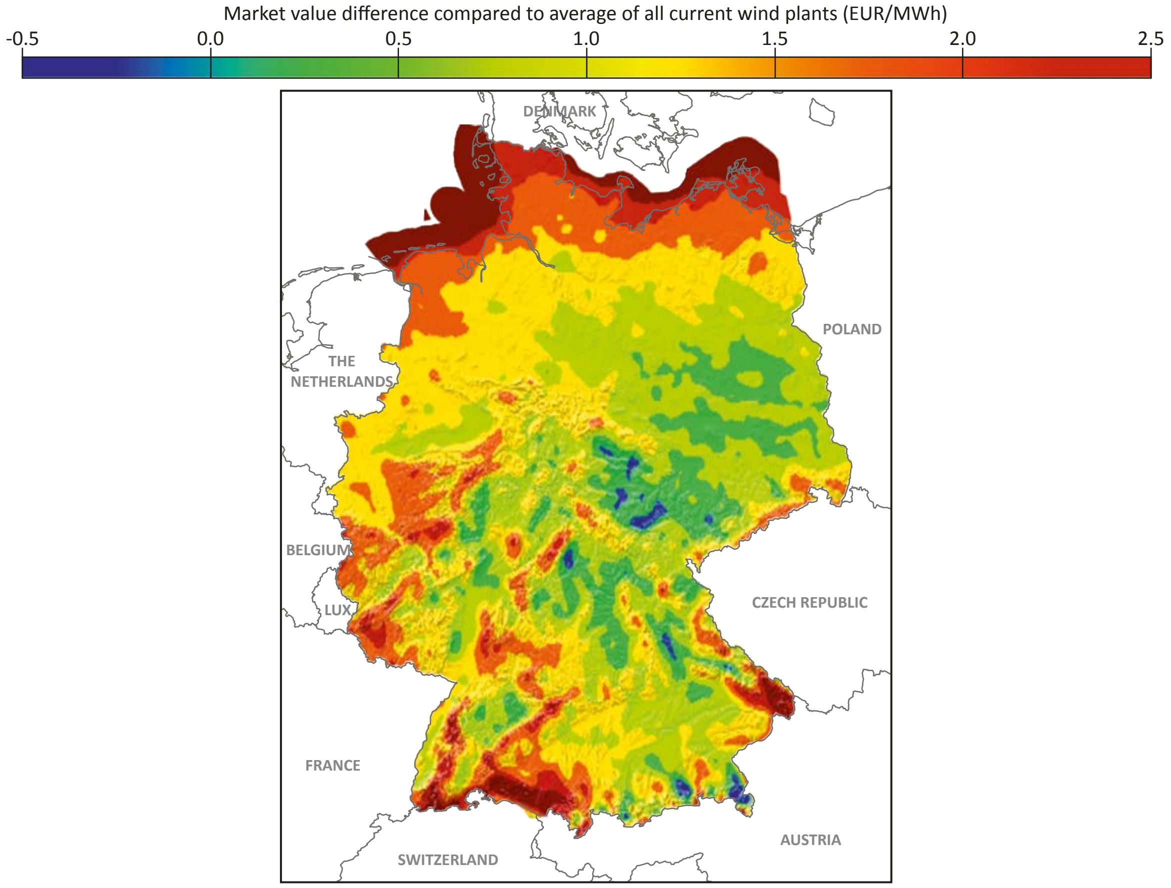
Mechanisms for managing the location of VRE plants

In the early stages of VRE deployment (including Phase Two), and bearing in mind the significant benefits of geo-spread and technology-spread discussed above, it will usually be prudent to consider steering VRE deployment towards available grid capacity, while in parallel planning and implementing grid reinforcement to allow deployment in weaker grid areas.

One tool that may be used to steer deployment is the use of grid charges differentiated by location, the fees generators pay to grid owners for taking their electricity to market. These charges tend to be higher for generators located further from demand centres (e.g. cities and factories), to reflect the relatively larger grid investment and higher O&M costs they require. Lower grid charges can be used to steer VRE deployment towards stronger parts of the grid. In other words, building new VRE plant where the grid is strong – i.e. where its capacity to carry megawatts is high and as yet under-used – will avoid the need to build new grid. However this may be at the expense of development quality (VRE plant locations may not be within the best resource areas, resulting in sub-optimal capacity factors), and pre-existing charging regimes may need to be adjusted to account for this.

There may also be trade-offs between optimal location from an output-smoothing perspective and a number of other important factors. One such may be the price received by owners of wind power plants (assuming they are exposed to market prices, rather than receiving a fixed price, e.g. via a feed-in tariff). In Germany, for example, the German market premium system provides incentives for investors to select locations where wind power plants have the most value (Figure 12). The generator can make additional profit if the value of a power plant is higher than the average market value.

Figure 12 • Market value of wind power projects in different locations, Germany



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: Adapted from Enervis/anemos (2016), *Market Value Atlas*, www.marketvalueatlas.com

Key point • The value of wind power to the power system depends on location.

Historical barriers may persist that are counter-productive from the VRE dispersal perspective. For example, regional tax differences may encourage concentration, as has been the case in Brazil where wind power plants have become concentrated in areas where the tax regime is less onerous, or where additional tax incentives are provided, such as the state of Rio Grande do Norte in the east of the country.

Locational marginal prices (LMPs) can also present an incentive to locate new generation closer to demand centres, alleviating grid congestion. LMP is a pricing mechanism that reflects the value of electricity at different locations by taking into account the cost of congestion.

Phase Three: Flexibility becomes relevant

The emphasis of this document is on Phase One and Two of VRE integration. A full discussion of Phase Three issues would greatly increase the size and complexity of the discussion.

Nevertheless, operating power systems in Phase Three of deployment (and beyond) is increasingly common. In 2015, the combined output of wind and solar PV equalled 51% of power generation in Denmark, 23% in Ireland and 21% in the Iberian Peninsula. In addition, certain regions show levels above national averages. In California VRE accounted for 14.2% of generation, while for the entire United States this figure was just over 5% (IEA, 2016a).

It is important to note that, notwithstanding their many similarities, wind and solar power plants exhibit significant differences; and these can determine the annual penetration of energy at which a given power system can be said to enter Phase Three (Box 8).

Box 8 • Wind power and solar PV: Both variable but not the same

Wind power and solar PV generation are both VRE technologies. However, they exhibit a number of differences that are relevant to system integration, which are summarised in Table 2, and explained in more detail in the following sections.

The **variability and uncertainty** of wind power and solar PV generation are linked to the statistical properties of their energy resource. Sunshine varies most significantly according to the movement of the sun across the sky. It is only available during the daytime and – depending on the latitude – shows a more or less pronounced seasonal pattern. As a result, the largest component of solar PV variability can be calculated precisely (i.e. it is said to be deterministic). However, clouds and other atmospheric phenomena such as fog, snow or dust add an irregular (probabilistic) component to solar PV output.

On the plant level, solar PV is likely to be more variable than wind power generation, even after accounting for morning and evening ramps that can be forecast. However, when aggregated over the area of a sufficiently large power system, solar PV output follows a smooth, "bell-shape" pattern. Once such a pattern is reached, it is not altered significantly with further interconnection of more distant plants, because daylight hours are similar even on a continental scale. Forecast errors can be large, particularly at a local level, when snow coverage or fog is involved.

Wind often shows diurnal tendencies, but their extent may vary by season and location. Windy seasons of the year are common in many parts of the world. Wind power generation shows strong smoothing benefits when aggregated over large areas. Forecast errors may occur in the form of timing and profile of generation. For example, a forecast may be half an hour "late" but otherwise accurate, or it may also be off in terms of the overall profile.

Solar PV shows a favourable **correlation with electricity demand** in a number of countries. Wind power output exhibits weaker correlation with load; it can be negative or positive often depending on location: onshore (often greater at night in many regions) or offshore (often greater during the day).

Aggregated solar PV generation shows daily **ramps** every morning and evening. These can be predicted, subject to atmospheric factors. Ramps can be reduced somewhat when integrating large areas, but will remain considerable even when output is integrated over many hundreds of kilometres. On the system level, variability arising from fast-moving clouds is generally insignificant. Aggregated wind power ramping events are less frequent but more difficult to predict.

Wind power and solar PV differ also in terms of their **modularity**. The vast majority of new wind capacity is deployed using wind turbines of 1 MW to 3 MW onshore and of 4 MW to 6 MW offshore. This is greater than the size of many entire solar PV installations, which are often only a few kilowatts in size (in the case of roof-top solar PV systems). Consequently, solar PV generation is often connected to low-voltage distribution grids, while wind power usually connects at medium-voltage levels in the distribution grid and above, which is also the level where larger solar PV systems are connected. Wind power plants may also be an aggregation of many turbines into one large plant of several hundred megawatts, connected to the transmission system.

Both **technologies** generate electricity using different physical effects. Wind turbines convert kinetic wind energy into electricity mechanically using a generator. Hence, they have moving parts and mechanical inertia. This makes wind turbines slightly more similar to conventional generators than solar PV. Solar PV converts sunlight to electricity via direct, physical effect and has no moving parts; solar PV is void of inertia.

Finally, wind power generation typically has higher **capacity factors** than solar. Capacity factors differ widely by location and technology, but generally speaking wind power plant capacity factors are about twice those of solar PV. This tends to facilitate reaching higher penetrations of wind power (annual share) than solar PV.

The differences between both technologies will also have an impact on appropriate system integration strategies. For example, a major challenge in wind power integration is often the unexpected falling away of the wind; if this occurs as demand is rising a very steep up-ramp in the net load may occur. By contrast, for solar, dealing with the (predictable) down-ramp of production and the corresponding net load ramp will be a daily chore in many systems.

In terms of integration strategy, wind and solar again display relevant differences. As a broad generalisation, the strategic geographic dispersal of wind capacity can be an effective tool in the attainment of cost-effective double-digit annual energy shares; while solar PV will benefit most strongly from an approach that seeks to modify the timing of generation and demand (via demand response and storage).

Source: Mills, A. and R. Wiser (2014), *Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels*; Mills, A. and R. Wiser (2010), *Implications of wide area Geographic diversity for short term variability of solar power*; Ibanez, E. et al. (2012), *A Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis.*

Table 2 • Overview of differences between wind power and solar PV

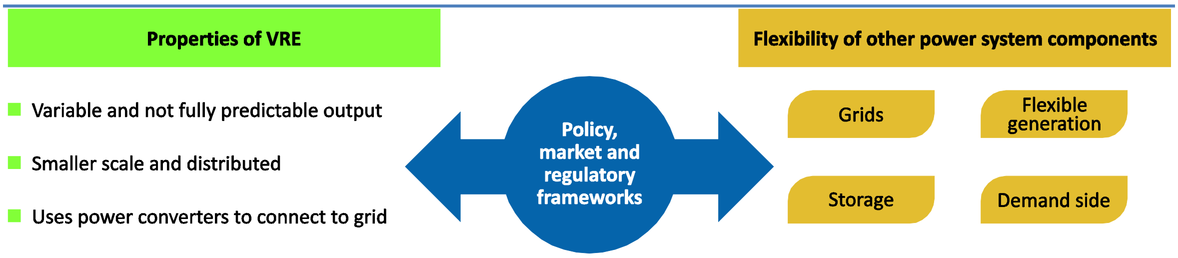
	Wind power	Solar PV
Variability at plant level	Often random on sub-seasonal timescales; local conditions may yield a pattern.	Planetary motion (days, seasons) with statistical overlay (clouds, fog, snow etc.)
Variability when aggregated	Usually with a strong geographical smoothing benefit.	Once "bell 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 scale and above.	Household and above.
Technology	Non-synchronous and mechanical.	Non-synchronous and electronic.
Capacity factor	20% to 40% typically.	10% to 25% typically.

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

In many cases, these shares have been reached by enhanced *operation* of existing power system assets, rather than by large additional capital investments. Improving power system operation is beneficial regardless of the needs of VRE, but benefits are magnified at higher VRE penetrations. However, beyond a certain point, additional measures are needed to reliably and cost-effectively reach higher shares (IEA, 2014, 2016a).

Policy, market and regulatory frameworks have a critical impact on the way in which the properties of VRE and the flexibility of the power system interact. These frameworks determine how the power system is actually operated, and hence whether that which is technically possible is both achievable practically and economically attractive (Figure 13).

Figure 13 • Balancing VRE by mobilising power system flexibility



Key point • The integration challenge is shaped by the interaction of VRE properties, the flexibility of the overall power system, and the policy, market and regulatory frameworks that govern this interaction.

A full discussion of measures to achieve integration during Phase Three is beyond the scope of this manual. However, one specific aspect is included, given its practical significance. This aspect is the flexibility derived from conventional power plants. This is only one of four available flexibility options. The other three are grid infrastructure (including connections to other systems), demand side options and storage. The reason for focusing on power plant flexibility is that all power systems will already have a measure of this resource at the outset of VRE deployment.

What is flexibility and why does it matter?

The *flexibility* of power plants, and other flexible power sources such as storage, can be considered to be the speed and extent to which they may be dispatched such that their output "fits" with what is needed to balance load and variable supply, i.e. that net demand is met reliably. Power systems that contain highly flexible power plants can more easily accommodate variability and uncertainty, and therefore a higher proportion of VRE capacity.

A power plant's flexibility differs dramatically according to the design of the plant and, to some degree, on fuel sources. There are three critical flexibility dimensions.

- Adjustability of generation level: the lower bound is the minimum level at which the plant can operate reliably.
- Ramping: the speed with which a plant can increase or decrease power output (MW over time).
- Lead-time: the length of time the plant operator needs to start up and begin generating power.

Steam cycle plants such as coal plants have long lead-times compared to combined cycle gas turbines (CCGT), open cycle gas turbine (OCGT) and reciprocating engines. Once in operation however, steam units can often ramp their output quite quickly while also being able to ramp down to a fairly low level of output compared to some CCGT configurations. On the other hand, OCGTs and reciprocating engines have short lead-times and often feature a wide operating range. Reservoir hydropower plants are highly flexible, with short lead-times in general, and a high ramping capability.

Greater than anticipated cycling of dispatchable plants can lead to greater wear and tear on parts. For example, if a plant designed to operate around the clock – as “baseload” – is dispatched to start up and shut down frequently, the increased wear can be significant. In addition, the efficiency with which fuel is converted into electricity is likely to fall, meaning more is needed, meaning higher production cost. Such cost pressures can undermine the business model of such plants (if not compensated accordingly). From a system perspective however, the overall cost implications resulting from increased cycling of the dispatchable power plant fleet can be very small.

From a carbon perspective meanwhile, the Western Wind and Solar Integration Study (Phase Two) investigated the operational impacts of different VRE portfolios with an annual penetration of 33% in the western United States. The studied plant portfolio included a large number of coal plants. The study shows that the CO_2 emission penalty for such plants operating at part-load accounts for less than 1% of total CO_2 emissions; the CO_2 penalty for start-up is even more negligible, amounting to merely 0.1%.

The same study found the cycling cost per MWh of fossil-fuelled generation to increase from USD 0.47/MWh under a no-VRE scenario, to USD 1.28/MWh in high-VRE scenarios (33% VRE, wind power and solar PV from 8% to 25% depending on scenario). The cycling cost per MWh of VRE generation increased from USD 0.14 to USD 0.67 for high-VRE scenarios (NREL, 2013).

It is important to note that the study investigated a system with a considerable number of inflexible, legacy power plants. New CCGT power plants and modern design baseload power plants see a lower impact on efficiency when in part-load operation (IEA, 2014).

Cycling costs may also be reduced by capital or O&M projects to modify baseload designs to be better suited to cycling, and by modifying operations (e.g. keeping the unit hot between shut-downs and start-ups) (NREL, 2012). Such retrofits have been a cost-effective measure to integrate inflexible nuclear generation in documented cases in North America (Cochran et al., 2013).

Determining the flexibility of thermal plants

A number of issues can complicate analysis of the flexibility potential of the existing generation fleet. Obtaining the technical specifications of older units can be difficult. Particularly for older units, there may be little precise knowledge of the flexibility criteria identified above. Test results undertaken upon the commissioning of a unit perhaps forty years previously will give little idea of its capabilities now. And it is not unusual for the operation of older units to be based on anecdotes gleaned from previous operators, describing specific occasions when its limits appeared to be tested. This lack of certainty as to a unit’s capabilities can provide an opportunity to its operator to understate them, particularly if it is in the latter’s interest to do so.

Therefore, the only way to ascertain the actual flexibility of the existing power plant portfolio is to test them all, unit by unit. The process of data acquisition in the case of Hawaii is one example (Box 9).

It is worth pointing out that power plant owners may consider two different measures of minimum generation level: a technical minimum for emergency conditions, and an economic minimum in daily operations. From a VRE integration perspective, lowering the latter will be of particular relevance.

A number of non-technical factors can also constrain power plant flexibility. For example, maintenance contracts may impose a high cost on operating a plant with a large number of starts and stops. In other cases, contractual obligations may lock technically flexible plants into rigid operations.

Box 9 • Hawaii Electric Company's inventory of conventional power plant

In the face of anticipated growth in solar PV power plants, Hawaii Electric Company (HECO), the vertically integrated utility for the Hawaiian archipelago, carried out a comprehensive inventory of its portfolio of gas, fuel oil and steam units, which ranged in age from 30 to 60 years, to establish the operational limitations of each.

The units varied considerably in type and scale. In some cases limitations were technical, such as reduced flame stability in the firebox of a unit under certain ramping conditions. In other cases, the constraint related rather to how the unit was managed. For example, a number of diesel units shared the same start battery; this had to be moved from one to the next for start-up, taking 20 minutes or so in each case.

Once the inventory had been completed, clear and costed actions to increase the flexibility of certain units could be identified. The process has reportedly been highly successful, with improvements in ramping rates in the order of a factor of five.

Unlocking and supporting flexibility

Key performance indicators (KPI) measuring the effective operation of thermal plants may inadvertently lock up flexibility. This has been observed in South Africa, for example, where lower stable operating levels are possible in many coal plants than stated by the plant operator; however, because one KPI is that these plants do not trip, operators have tended to err on the side of caution and report higher minimum levels. It may be desirable therefore to adjust KPIs to reflect flexibility characteristics (e.g. maximum ramp rate delivered, shortest start time, etc.).

Plant owners may be less willing to explore the flexibility of their power plants if the reward of their labours is fewer full load hours, lower electricity prices[10], and the likelihood that their machinery will suffer increased wear and tear (Box 10).

However, if policy makers take care to ensure that incentives to provide flexibility outweigh the costs of doing so, this is less likely to be an issue. This may require major changes in power market design, and is being observed in several OECD markets. In the United Kingdom, for example, a capacity market has been established, which rewards power plants based on their *availability* to operate when they are most needed during winter months. Revenues received through this channel are intended to supplement reducing revenues from the wholesale (energy) market.

In some cases, potentially flexible plants have an incentive to generate even when the price received for their electricity is zero[11]. This is the case in China, for example, where thermal plants

[10]Wind and solar PV, having very low short run marginal costs, tend to come before fuel-based (and so more expensive) thermal plants in the merit order. For an explanation of the merit order effect, see IEA, 2014.

[11]Less flexible plants such as nuclear power stations may also continue to generate when the wholesale price falls to zero, although this is to avoid costs associated with cycling.

receive a secondary payment that increases with the number of megawatt hours they generate in a given month. This is in effect an incentive to generate around the clock, and as an unintended consequence reduces the system's ability to accommodate VRE (IEA, 2016a).

Box 10 • Minimum generation levels in Ireland

It has been the case historically that the Irish system operator has kept eight large thermal units operating at night, at minimum, in order to provide a particular system service (in this case, reactive power). A side-effect of this requirement was to impose a ceiling on the amount of wind power that the system could accommodate at such times, which was already low given low night-time demand.

Recently, the system operator made it clear that some of these units might be taken off at night, explicitly to make space for wind power. It was understood that those units that would retain "must run" status would be those that had the lowest minimum stable operating level. At this point the system operator reportedly found that these levels were significantly lower than understood previously, and moreover that O&M contractors would no longer have concerns with those units' ability to operate at lower levels.

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.

Annex 1: Providing information to developers

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

What information is needed?

Information and data that are considered important for project developers in deciding the location of a VRE project typically consist of the following.

- **Site:** VRE project developers must ensure that they have access to the site for construction and operation of VRE plants for the entire duration of the PPA. In addition, the sites must be publicly acceptable with good resources and access to the grid. Related information includes, for example, land tenure and conservation zones.
- **RE resources:** the renewable energy resource is fundamental to the viability of a VRE project. Its characteristics need to be properly understood for accurate simulation of generation output. Hourly and sub-hourly data may be required spanning two or more years.
- **Grid infrastructure:** this concerns primarily grid connection capacity at different locations within the existing grid. This information provides a more accurate picture of the current status of the electricity grid, including existing transmission lines and substations, and grid constraints and bottlenecks. In addition, information on committed transmission projects should be made available.
- **Electricity supply and demand:** information on electricity demand trends across different locations (or regions) and sectors can be useful for project developers in identifying locations with strong demand growth, and where additional generation capacity is likely to be required. Information on electricity supply includes existing power generation and committed generation projects that are expected to come online over the next few years, which can reveal where shortage or surplus of generation capacity is likely to occur.
- **Electricity prices:** this is particularly relevant in liberalised electricity markets. Prices can fluctuate considerably across different periods and locations of the grid, while PPA prices will have a strong influence on investment decisions. Electricity prices provide useful information for project developers seeking to assess which locations are likely to result in highest expected revenue. Where a PPA will be signed, transparent wholesale prices provide useful context for price discovery.
- **Technology and supply costs:** costs of different technologies and fuels provide important information for VRE project developers in assessing the competitiveness of a VRE project compared with other generation technologies.

How can such information be disseminated?

The required information should be made publically available in the most transparent and non-discriminatory fashion by responsible agencies within the country, established by the government. Information can then be disseminated in a number of different ways. One of the most useful and effective is the use of national or regional maps published on-line. For example, renewable energy resource maps have been prepared by organisations such as the International Renewable Energy Agency (IRENA), the Energy Sector Management Assistance Program (ESMAP), and the Global Energy Network Institute (GENI). Such organisations collect data from different sources including member countries, local and regional organisations.

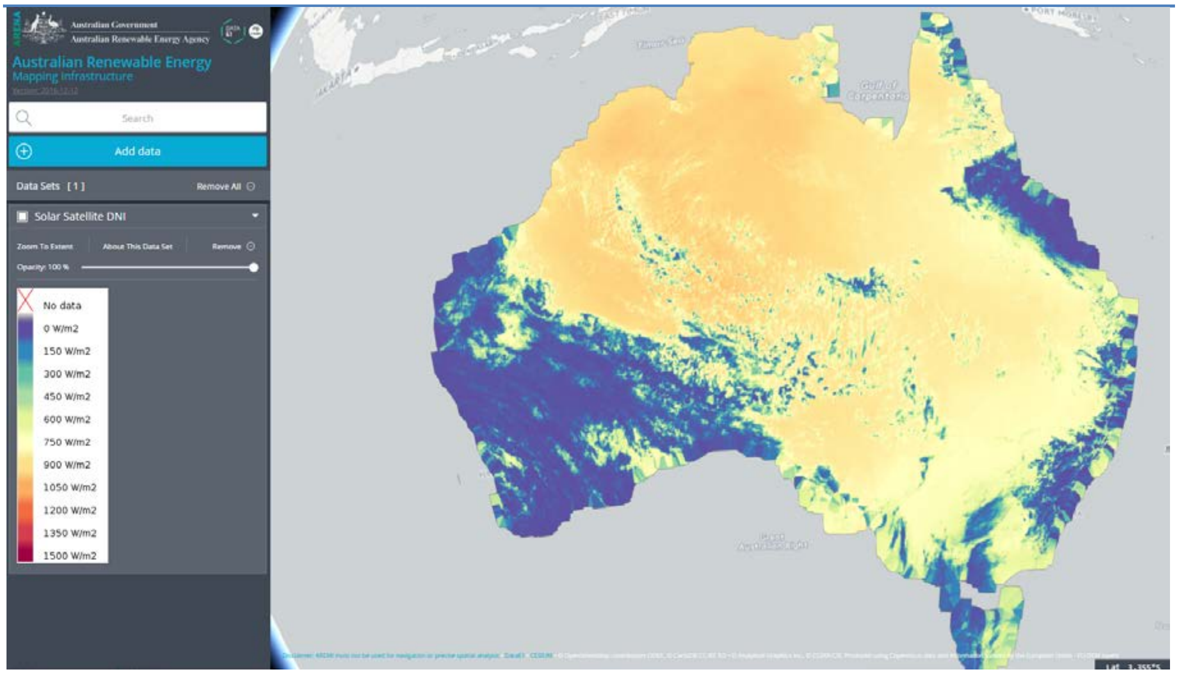
On a national level, countries such as Australia and the United States have prepared renewable energy resource maps, and a number of tools to help in assessing the viability of renewable energy projects. In Australia, under the Government's National Map initiative, an open mapping platform has been created that provides geospatial data relevant to the energy sector (AREMI, 2016) (Box 11).

Box 11 • Australian Renewable Energy Mapping Infrastructure

Australia has implemented the Australian Renewable Energy Mapping Infrastructure (AREMI), which is a fully open and publicly available framework connecting directly the data servers of related government agencies such as Australian Energy Market Operator (AEMO), the Bureau of Meteorology (BOM), and Geoscience Australia. The main purpose of AREMI is to provide data to inform investment decisions in energy infrastructure. Project developers can access spatial information including existing electricity infrastructure, planned network investment, network capacity and actual generation and demand data.

Relevant information may include geospatial data of network capacity, power stations, substations and transmission lines (Figure 14). The mapping platform converts and visually displays data and information in a web browser. It enables access to multiple geospatially-tagged datasets in different formats.

Figure 14 • AREMI showing direct normal irradiance levels



Source AREMI (2016), *Australian Renewable Energy Mapping Infrastructure*, http://nationalmap.gov.au/renewables/

Key point • Geospatial data on resources and electricity infrastructure inform investment decisions.

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 manual. 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 12).

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.

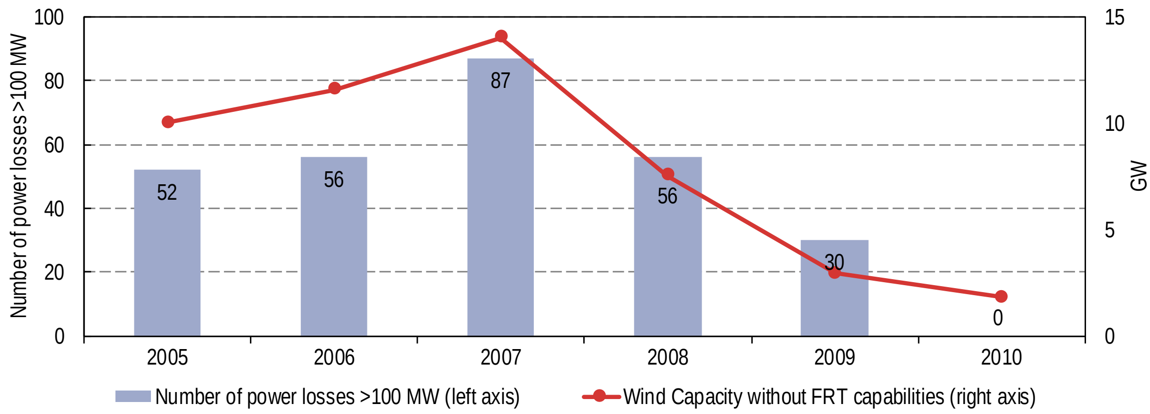
Box 12 • Evolving requirements in European grid codes

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 15). 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 15 • 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 document 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 3). 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 3 • 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.

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.

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Abbreviations and acronyms

AC	alternating current
AGC	automatic generation control
AREMI	Australian Renewable Energy Mapping Infrastructure
CCGT	combined cycle gas turbine
CECRE	Control Centre For Renewable Energy
CSIR	Council for Scientific and Industrial Research
CSP	concentrated solar power
DC	direct current
DLR	dynamic line rating
DSO	distribution system operator
DSR	demand side response
FACTS	Flexible AC Transmission Systems
FRT	fault ride through
ISO	independent system operator
KPI	key performance indicator
LMP	locational marginal prices
NWP	numerical weather prediction
OCGT	open cycle gas turbine
PPA	power purchase agreement
PV	photovoltaic
PUCT	Public Utilities Commission of Texas
SCADA	Supervisory Control And Data Acquisition
SPS	special protective schemes
TSO	transmission system operator
VRE	variable renewable energy

Units of measure

GW	gigawatt
km	kilometre
kV	kilovolt
kW	kilowatt
MW	megawatt
MWh	megawatt hour

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