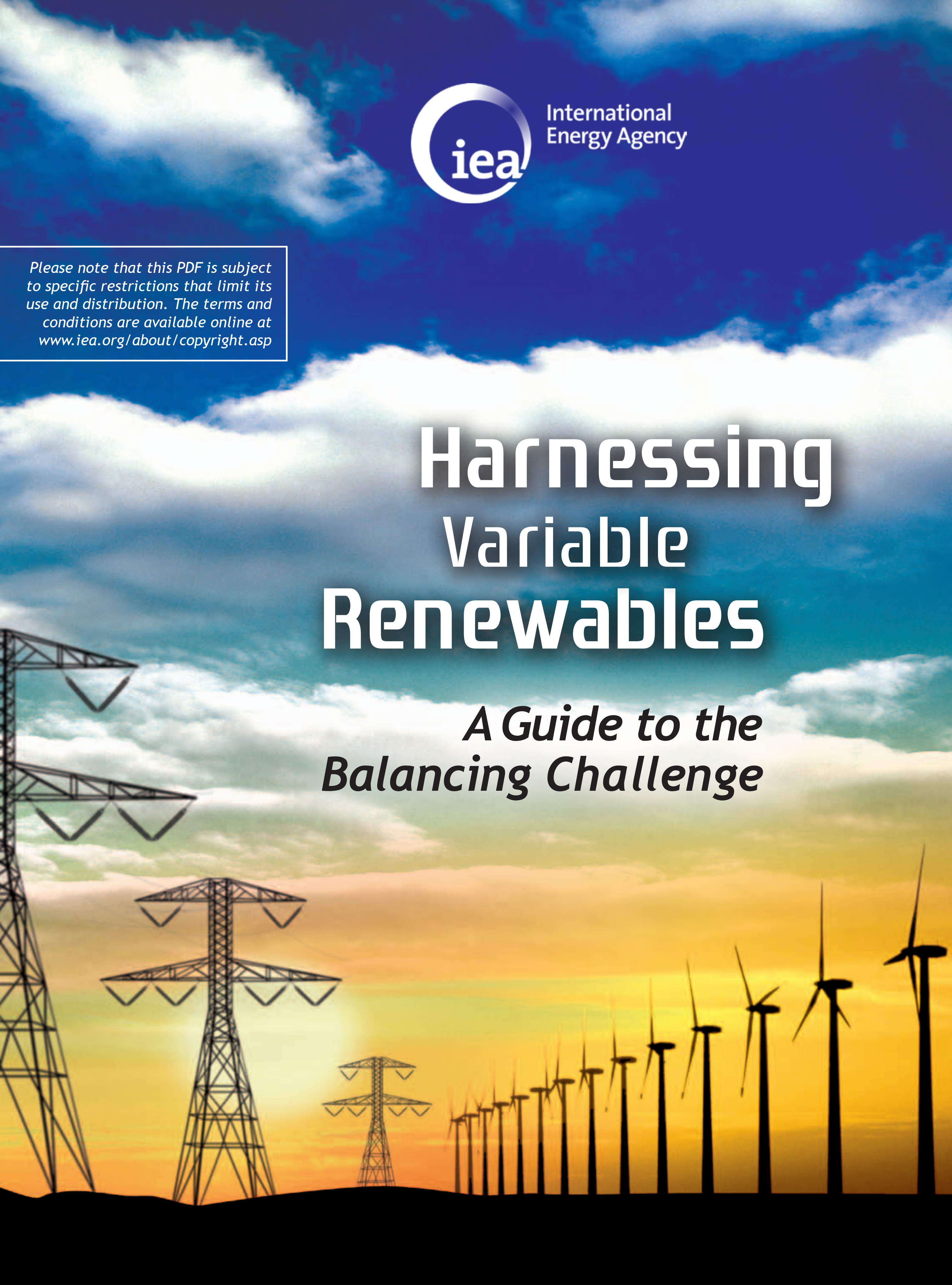
International Energy Agency

Harnessing Variable Renewables

A Guide to the Balancing Challenge



Harnessing Variable Renewables

A Guide to the Balancing Challenge

Power systems must be actively managed to maintain a steady balance between supply and demand. This is already a complex task as demand varies continually. But what happens when supply becomes more variable and less certain, as with some renewable sources of electricity like wind and solar PV that fluctuate with the weather? To what extent can the resources that help power systems cope with the challenge of variability in demand also be applied to variability of supply? How large are these resources? And what share of electricity supply from variable renewables can they make possible?

There is no one-size-fits-all answer. The ways electricity is produced, transported and consumed around the world exhibit great diversity. Grids can cross borders, requiring co-ordinated international policy, or can be distinct within a single country or region. And whether found in dispatchable power plants, storage facilities, interconnections for trade or on the demand side, the flexible resource that ensures the provision of reliable power in the face of uncertainty likewise differs enormously.

Written for decision makers, *Harnessing Variable Renewables: a Guide to the Balancing Challenge* sheds light on managing power systems with large shares of variable renewables. It presents a new, step-by-step approach developed by the IEA to assess the flexibility of power systems, which identifies the already present resources that could help meet the twin challenges of variability and uncertainty.

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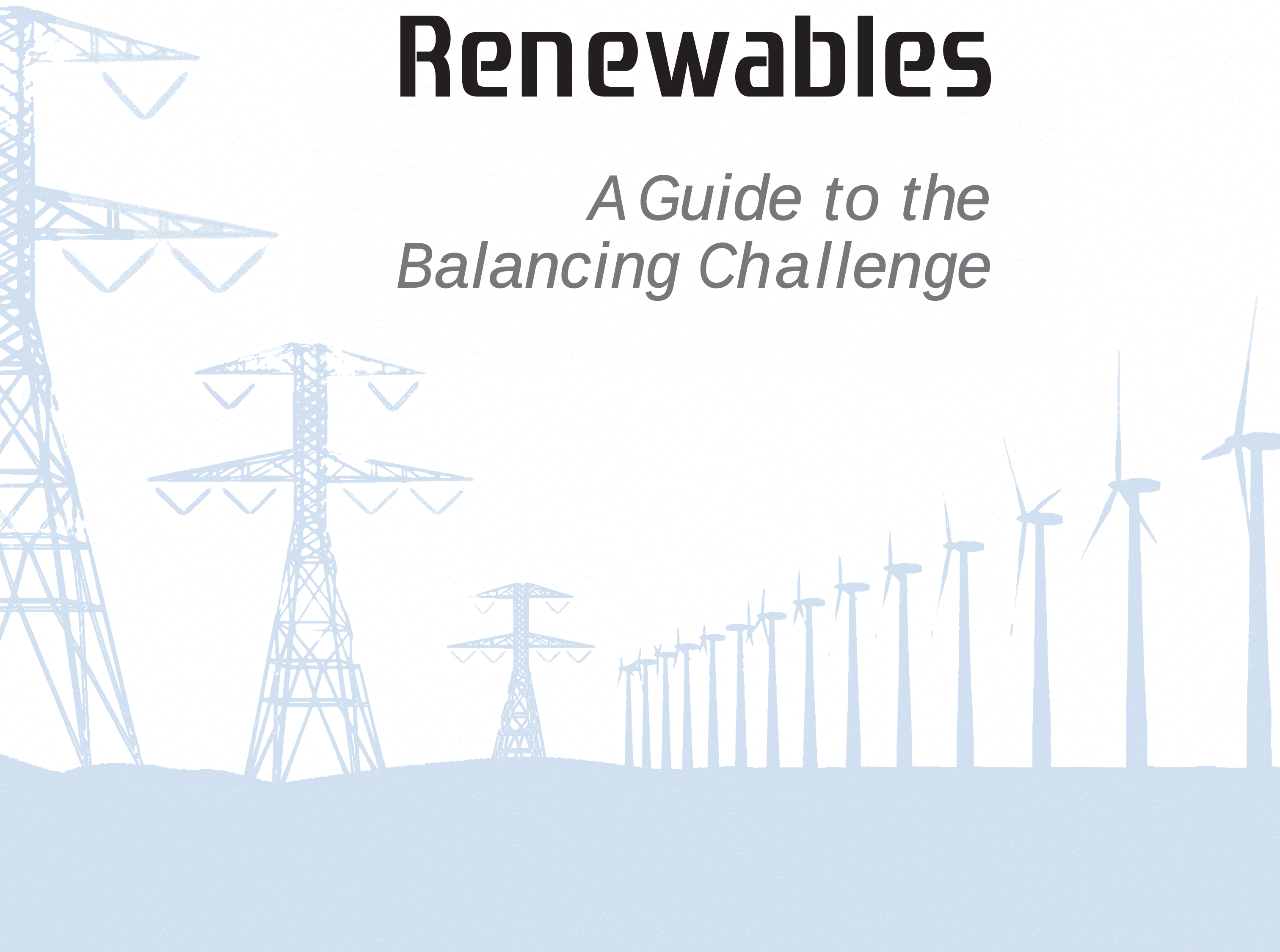

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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Foreword

In recent years, the IEA has emphasised the need for a revolution in the way we produce and consume energy if we are to see a real positive impact in terms of climate change, environmental protection and economic development. How we develop our electricity systems is a key part of this revolution, particularly as concerns variable renewable power plants such as wind and solar photovoltaics.

Increased variability of power supply causes deep concern in some quarters, and rightly so, for the reliable provision of electricity underpins our economy. But urgent needs to decarbonise the electricity sector, to secure supply, and to diversify away from finite resources in the face of growing demand all mean that power systems must change, and variable renewables look likely to play a major role.

When shares of variable renewables amount to just a few per cent, a philosophy of "connect and manage" will usually suffice: existing system resources will be sufficient to cover additional variability. But if shares of electricity are to reach the levels foreseen in recent IEA scenarios, this philosophy will need to change. A planned approach will be necessary to ensure that power system flexibility keeps pace with variability; the deployment of variable renewables must be considered simultaneously with other key elements of power systems, such as the design and operation of dispatchable power plants and the transmission grid.

With this in mind, the IEA Grid Integration of Variable Renewables project has developed the Flexibility Assessment Method, to help decision makers weave these threads together into a coherent picture. Using this method, we have carried out a number of preliminary case studies, which highlight that significant technical potential to balance variable renewables exists in all cases, suggesting that variability itself is far from being a showstopper.

A holistic approach is crucial. Strategic energy policy that envisages the deployment of large shares of variable renewables must be based on profound understanding of the impacts, positive and negative, on the existing power system. The IEA intention is to present decision-makers with a guide to the essential parameters to be taken into account when setting such targets, to ensure they can meet them efficiently and reliably, and to enable variable renewables to deliver their tremendous potential without unexpected cost.

Nobuo Tanaka

Executive Director
International Energy Agency

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Executive summary

Great efforts are being made to boost the share of renewable energy sources in the global energy mix, driven by the need for enhanced energy security and environmental protection and by accelerating climate change.

The focus of this book is on the integration of renewables into power systems, which is to say the ensemble of power production, supply and consumption.[1] Some renewable energy technologies (*e.g.* biomass, geothermal and reservoir hydropower) present no greater challenge than conventional power technologies in integration terms. In contrast, another group of renewables – including wind, solar, wave and tidal energy – are based on resources that fluctuate over the course of the day and from season to season. Collectively known as variable renewable energy (VRE) technologies, these represent additional effort in terms of their integration into existing power systems.

The extent of the challenge is one of the most disputed aspects of sustainable energy supply: detractors claim that VRE technologies, at high levels of deployment, introduce a level of uncertainty into the system that makes it just too difficult to meet the moment-by-moment challenge of balancing supply and demand for electricity across a power system.

The Grid Integration of Variable Renewables (GIVAR) project was undertaken by the International Energy Agency (IEA) to address the critical question of how to balance power systems featuring large shares of VRE. *Harnessing Variable Renewables* gives a detailed description of all the main elements of the balancing challenge, as well as the tools presently used to manage it. It outlines step by step a new method developed by the IEA to assess the resources and requirements for balancing in a given system, and highlights resulting potentials in eight case-study areas, underlining the point that no two cases are quite alike.

Variability and uncertainty are familiar aspects of all power systems: the need for flexible resources to balance them has been long understood. Those who assert that large shares of variable supply represent an insurmountable, additional challenge to power-system operation may be looking with too narrow a gaze. Variability and uncertainty are not new challenges; power systems have long taken them into account. Fluctuating demand – from hour to hour, day to day, season to season – has been a fundamental characteristic of all power systems since the first consumer was connected to the first power plant. All power systems include a range of flexible resources to manage this fluctuation: dispatchable power plants for the most part, but some systems may also incorporate electricity storage, demand-side management, and/or interconnections to neighbouring power markets.[2] The question is: can the use of these resources be enhanced efficiently to balance increasing variability resulting from VRE deployment?

System operators have vast experience of responding to variability (in demand) by ramping flexible resources up or down. When a fast response is required to an unexpected or extreme spike in demand or the outage of a plant, the operator will call upon the most flexible resources. In most cases, these will be power plants designed for peaking (*e.g.* open-cycle gas plants, hydro plants) or storage facilities (*e.g.* pumped hydro).[3] To address largely predictable changes in demand – such as the morning rise and the evening fall – operators will dispatch mid-merit power plants (*e.g.* combined-cycle gas). Lastly, baseload plants (*e.g.* nuclear, some coal, geothermal) are designed to provide for that proportion of demand that is more or less constant around the clock. Most of these plants are designed to operate at full power all the time; their output can be changed less quickly and to a lesser extent.

Existing flexible resources may be able to manage additional variability resulting from VRE deployment although variability and uncertainty of VRE are greater than on the demand-side. It is

1. The principal elements of power systems include power plants, consumers and the transmission grid connecting them.
2. The importance and potential of response by electricity consumers (demand-side response) is beginning to be understood.
3. In some cases, this will also include interconnections and contracted demand-side management (load shedding).

generally easier to predict fluctuations in demand than in VRE supply. In part, this reflects decades of experience and data in relation to demand drivers. It is also true that supply-side variability depends on the VRE resource: tidal power output, for example, is highly predictable. Solar (PV) plants can produce electricity even under cloud cover, so output is never less than around 20% of rated capacity (during daylight)[4], providing a measure of certainty. But it is unlikely that meteorological science will deliver fully accurate predictions of the outputs of wind and wave plants, which are highly irregular.

What share of VRE is possible with more effective use of *existing* flexible resources? A principal finding of this book is that there is no one-size-fits-all answer to this very common question. Power systems differ tremendously in design, operation and consumption patterns, in the natural resources that underpin them, the markets they contain, and the transmission grids that bind them together. Furthermore, and as this analysis shows, there is likely to be a wide gap between what is technically possible and what is possible at present. In other words, some systems are better able than others to manage large VRE shares of electricity production, and direct comparison among them of VRE deployment potential from the integration perspective is inappropriate.

Harnessing Variable Renewables describes how to take a snapshot of any power system, to derive an estimate of how much VRE it can manage in its present configuration. These estimates do not in any way represent a technical ceiling on deployment potential however: additional flexible resources can still be deployed as and when required.

The Flexibility Assessment Method: to identify a power system's balancing capability

Much of the uncertainty about the potential of variable renewables to contribute to power portfolios stems from limited understanding of the balancing capability of existing flexible resources. To address this, the GIVAR Project has developed the Flexibility Assessment (FAST) Method. Part 1 of this book guides decision makers and potential users of the FAST method along four steps to identify the present potential for VRE share in electricity demand (Figure ES.1).

- Step 1 assesses the maximum technical ability of the four flexible resources to ramp up and down over the balancing time frame.[5] This is the **Technical Flexible Resource**.

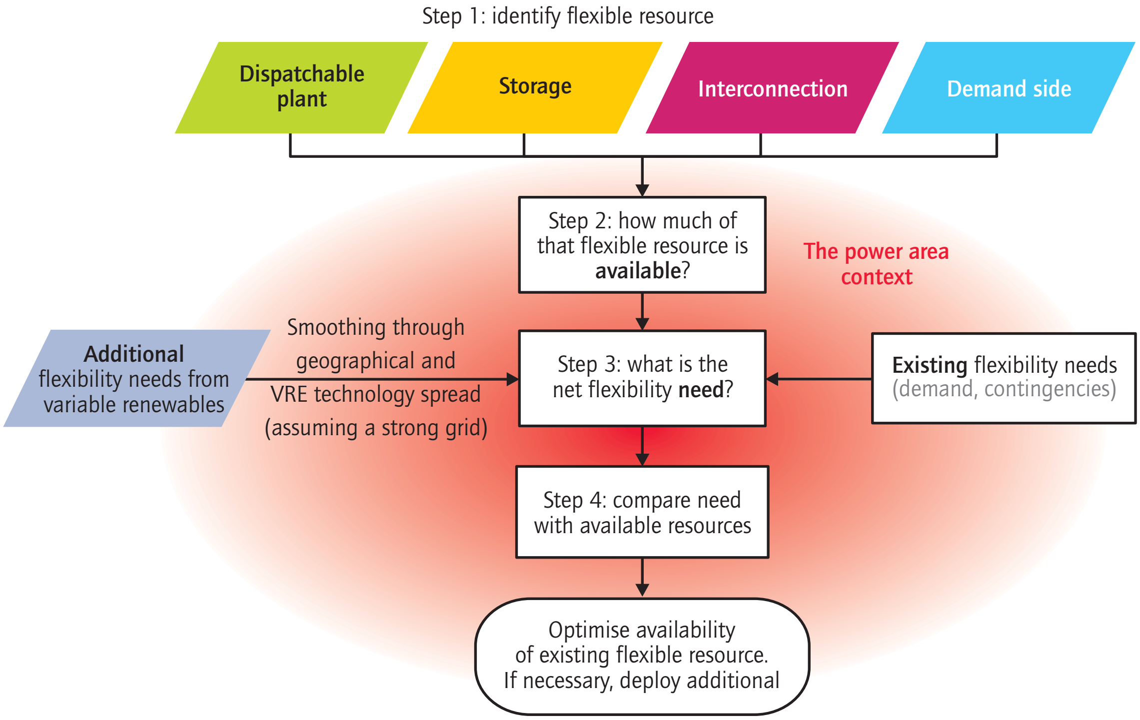
- Step 2 captures the extent to which certain attributes of the power area in question will constrain the availability of the technical resource, to yield the **Available Flexible Resource**.

- Step 3 is to calculate the maximum **Flexibility Requirement** of the system, which is a combination of fluctuations in demand and VRE output (the net load)[6], and contingencies.

- Step 4 brings together the requirement for flexibility and the available flexible resource to establish the **Present VRE Penetration Potential** (PVP) of the system in question.

4. Solar PV does not require direct sunlight to operate, though it is of course preferable.
5. The timeframe for balancing is considered to be 36 hours; this period will see the maximum extent of variability in most cases. Within this period, three further timeframes are assessed: 6 hours, 1 hour and 15 minutes.
6. "Net load" refers to the load (demand) curve after production from wind, PV, etc. have been taken into account. It is a very important concept, which can reveal significant complementarities between demand and VRE output, and is dealt with in detail in Parts 1 and 2.

Figure ES.1 • *The FAST Method*



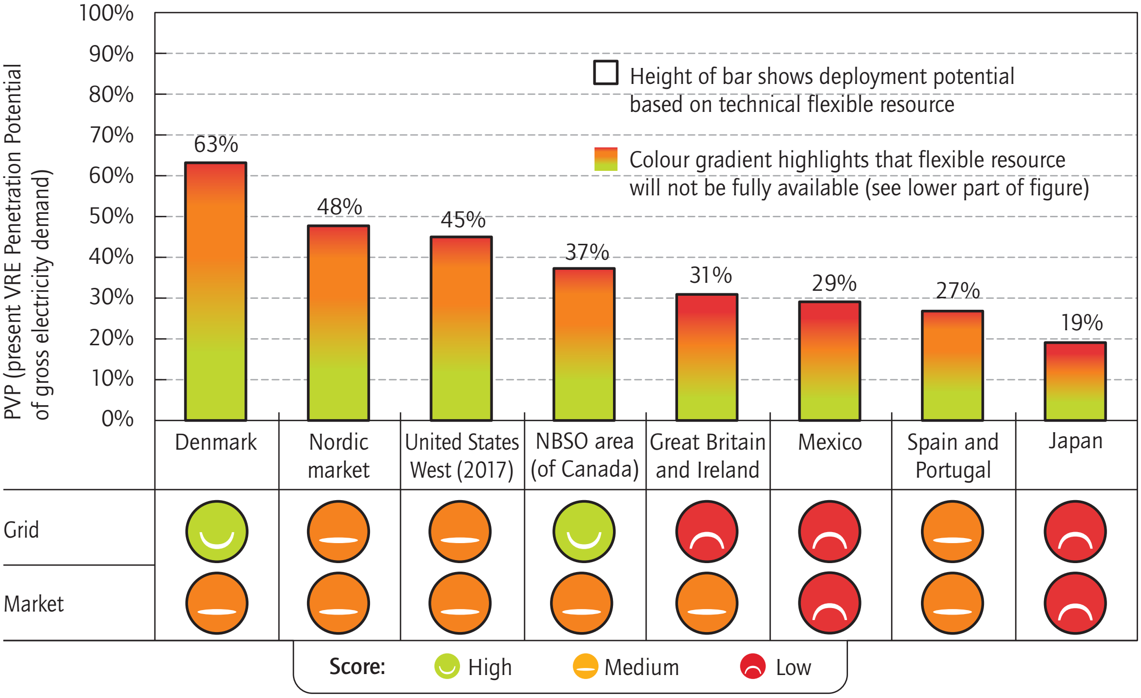
The GIVAR case studies revealed that considerable technical flexible resources (TR) exist already in all areas assessed. Applying the FAST Method to analysis of eight diverse power areas showed that from a purely hardware point of view (*i.e.* before constraints are taken into account), all areas have the technical capability to balance large shares of VRE. Potentials range from 19% in the least flexible area assessed (Japan) to 63% in the most flexible area (Denmark) (Figure ES.2). Using FAST, the IEA also assessed the resources of the British Isles (Great Britain and Ireland together), 31%; the Iberian Peninsula (Spain and Portugal together), 27%; Mexico, 29%; the Nordic Power Market (Denmark, Finland, Norway and Sweden), 48%; the Western Interconnection of the United States, 45%;[7] and the area operated by the New Brunswick System Operator (NBSO) in Eastern Canada, 37%.

The values shown in Figure ES.2 are indicative only, and reflect three conservative assumptions. Firstly, complementarity of fluctuating demand with VRE output (net load) was not quantified due to data limitations. Secondly, and for the same reason, the analysis does not fully account for the smoothing effect on variability of geographical and VRE technology spread. Thirdly, the opportunity to curtail the output of VRE power plants was not addressed. All three assumptions are likely to exaggerate the flexibility requirements of the areas assessed and therefore reduce PVP values.

Furthermore, the analysis looks only at transmission level VRE power plants, setting aside for a later date the analysis of the potential for distributed VRE plants (*e.g.* building-integrated PV). It also assumes a portfolio of VRE technologies in each case that does not necessarily reflect existing policy targets. These portfolios reflect the resources of the area to a certain extent and highlight differences among VRE technologies.

7. The assessment of the US Western Interconnection was carried out for 2017, to take advantage of the recent Western Wind and Solar Integration Study performed (in 2010) by GE Energy for the National Renewable Energy Laboratory of the United States.

Figure ES.2 • VRE deployment potentials today from the balancing perspective



The availability of flexible resources for the balancing task is constrained by a range of power system attributes

The analysis has identified a range of characteristics, present to a greater or lesser extent in all cases examined, which will constrain the availability of flexible resources to take part in balancing electrical supply and demand. In some cases this will result in reduction of PVP to well below the values shown in Figure ES.2. Sub-optimal grid strength and market design are the most important of these (although system operation techniques and many other resource-specific factors can represent serious barriers also). The impacts of these two key characteristics in the case study areas are represented in the lower part of Figure ES.2, with a simple "traffic lights" approach. For practical reasons of data availability, it was not possible in this phase of the analysis to quantify these constraints. More refined assessment using the FAST Method, with sufficient data availability, should attempt to quantify the impact of these constraints.

Weaknesses in parts of the existing transmission grid can cause the temporary separation of flexible resources from both demand-side and VRE requirements for flexibility. Such weaknesses may exist for a number of reasons, but are particularly likely to be found at the borders of distinct balancing areas within large power systems. Additionally, VRE power plants, particularly onshore wind, may be located at a considerable distance from demand centres, where the wind resource is strong but where the grid in contrast is relatively weak. Reflecting strategic policy to deploy VRE capacity, in-depth studies to identify such grid weaknesses should be undertaken without delay. Remedial lead times may be lengthy particularly if new transmission corridors are required and their rollout is likely to encounter opposition from local communities. Measures should be examined whereby carrying capacity in weaker areas can be augmented through advanced grid technology and operation techniques with negligible disruption to the local environment.

Markets should be (re)configured so that the full flexible resource is able to respond in time to assist in balancing. Power markets should incorporate mechanisms that enable sufficient response from supply-side and demand-side flexibility assets. Electricity is usually traded through a combination of long-term bilateral contracts and daily power exchanges. Markets that rely heavily on the former will find it harder to balance variability and uncertainty as such contracts effectively "lock up" (sometimes months in advance) the potential of assets to respond to needs for flexibility that change dynamically. In contrast, trading closer to the time of operation (the moment in which electricity is produced and consumed), as occurs through power exchanges or mandatory pools, leaves more of the flexible resource free to respond to shifting needs.

The extent of economic incentive in the market place will determine the proportion of the flexible resource that will actually respond. Owners of flexible resources, particularly of slower power plants built for mid-merit or base-load operation, will need incentive additional to that of a fluctuating electricity price to prompt them to offer the full extent of their flexibility to the market. Although a CCGT plant may be *technically* able to ramp its production downwards by 50 MW, for example, it does not follow that it necessarily *will*: more frequent start-ups, shut-downs and ramping increase wear and tear on the plant, posing additional costs, and may have a negative impact on revenues. Similarly, response from demand-side assets is unlikely to occur if the effort required to change behaviour is greater than the compensation provided.

Some power markets today offer a measure of incentive for flexibility. Balancing market mechanisms, as in the Nordic and Iberian power markets for example, provide opportunity for more flexible power plants to benefit from higher than spot-market prices in response to a shortfall in supply. System operators may also contract with power plants to provide (usually hour or intra-hour) reserves against uncertain balancing needs. But new mechanisms will be needed to prompt slower assets to respond to flexibility needs forecasted 36 hours ahead, for example. The form such mechanisms should take will be pursued in the next phase of GIVAR project.

Accurate forecasting of VRE plant output combined with more dynamic power-trading and planning of system operation, can make more efficient use of the flexible resource. Regularly updated forecasts — particularly of VRE output — are a strong signal of evolving flexibility needs in the market place. At "gate closure" (when bids and offers to the power market close) electricity producers are committed to deliver a fixed amount of electricity. After this point, it is up to the system operator to balance any gap between what is committed and what is actually delivered, using flexible resources set aside (as reserve) for this purpose. In many markets, gate closure occurs one day before delivery (which in practice may mean 36 hours ahead or more). However, error in VRE output forecasts reduces as the time of operation approaches. Thus, if gate closure occurs only an hour ahead of this time, instead of thirty-six hours, or even within the hour ahead, producers have the opportunity to update their day-ahead offers on the basis of the latest forecast update, with the result that fewer "reserves" must be contracted in advance by the system operator. System operators should use the best available forecast tools for predicting VRE output, and should take these predictions into consideration when planning system operation.

Policy makers should take action to remove (unnecessary) barriers that constrain the availability of flexible resources. Regulations that pre-date VRE deployment may restrict the use of a particular flexible asset for balancing. A nuclear plant, for example, though it may be technically able to ramp to some extent, may be considered unavailable to cycle for historical and institutional reasons (as well as economic ones). Reservoir hydro plants may be unavailable due to seasonal constraints relating to fisheries or provision of potable water. Policy makers should assess whether such regulations can be reformed to facilitate balancing without undue negative impact on their original objectives.

Larger power markets with VRE resources widely distributed over a strong grid will see a lesser requirement for flexibility. It is important to understand that electricity production from a portfolio of VRE plants does not stop and start in a moment. It ramps up and down over periods of hours, the exact extent of which will depend on the size of the area over which plants are installed, as well as other factors outlined below. Nevertheless, extreme events like storms do occur, and having the right flexible resources to meet such events is critical.

Several opportunities exist to reduce the need for flexibility — and so increase PVP. Dispersing VRE plants over a large area increases their complementarity, *i.e.* their outputs will fluctuate at different times with the result that the aggregated output is smoother than if plants were clustered closely together. This smoothing effect is further enhanced if different VRE types (*e.g.* solar and wind) with complementary output profiles are included in the portfolio. Forecast uncertainty is also reduced with wider geographical spread of plants. An aggregated output that ramps more slowly and less extensively increases the value of base-load power plants, whose slower technical ability to ramp is no longer such a hindrance to provision of the flexibility service. Decision makers should plan for the widest possible dispersal of VRE plants within the bounds of grid and resource considerations.

Merging balancing areas enables smoothing through geographical spread and sharing of flexible resources. Discrete operation of individual balancing areas within a power system — and indeed of neighbouring power systems — misses the opportunity to optimise the use of flexible assets. If neighbouring areas are balanced separately, one may be facing an up-ramp in VRE output while its neighbour is facing a down-ramp. If areas collaborate in the balancing time frame, opposing or time-lagged ramps would complement one another to some extent, smoothing overall VRE output.[8] If the combined flexible resources of the merged area are now surplus to present requirements, PVP will increase.

Expensive new capacity measures should be considered a last resort, taken only after optimising the availability of *existing* flexible resources. System planners should first ascertain the level of PVP possible on the basis of existing flexible resources. If this is lower than targeted VRE deployment, it will also be necessary to plan the deployment of new flexible resources. The relative and system-specific costs of increasing the four flexible resources should be assessed carefully: it may be more cost-effective to increase demand response, for example, than to build new power plants. Or it may be that new dispatchable power plants built against demand growth, or to replace retiring plants, may be better able to offer flexibility services than their predecessors (assuming flexibility becomes a design driver), in effect increasing the proportion of installed capacity that is flexible, rather than the level of installed capacity itself.

Principal conclusions and further work in the GIVAR project

The VRE balancing challenge is far from insurmountable. Indeed, all power areas assessed show that greater technical potential for balancing VRE output exists than is commonly supposed. But availability of flexible resources will depend two key factors: strong and early investment in grid infrastructure and intelligence; and market mechanisms that adequately reflect the value of the flexibility service and that clearly signal the need for it well in advance.

Operation of existing mid-merit plants (in particular) must remain economic, or their contribution to the flexible resource may be lost. Areas with large existing shares of VRE capacity today (*e.g.* the Nordic Power Market) see heavily depressed electricity prices when wind power output is high because this low-cost electricity displaces generation from (higher-cost) fossil-fuel powered plants.[9] Unless compensated in some way, this will mean reduced revenues to those conventional plants that are called upon to operate for less time than intended when they were built. Coupled with increased cycling (and increased wear and tear) caused by responding to a more variable net load, this may make such plants uneconomic and result in their early retirement. Market design will need to reflect the system's continuing need to use such plants for balancing. The next phase of the GIVAR project will address possible market mechanisms to prevent a potential shortfall in flexible resources as VRE shares rise.

Sufficient economic incentive must also exist for investment in *new* dispatchable power plants (and other flexible assets), against demand growth and asset retirement, to maintain system adequacy. An adequate system is one that can meet peak demand in the long term (months/years), an aspect beyond the focus of this phase of the GIVAR project, which focuses on the ability of power

8. There will also be times when ramps are not complementary.

9. Short-run marginal costs.

systems to manage *changes* in production and demand. The adequacy crunch would come during prolonged lulls in VRE output — does the system have the ability still to meet peak demand? Adding VRE plants into a system that is already adequate has only a beneficial impact on adequacy,[10] yet reduced revenue to dispatchable plants resulting from that deployment (as described previously) may nonetheless undermine it. Maintenance of system adequacy will be a key focus of the next phase of the GIVAR project.

Recent estimates in the literature suggest that at a 20% share of average electricity demand, wind energy balancing costs range from USD 1/MWh to USD 7/MWh. This phase of the project has undertaken a review of wind power integration cost studies, which distinguishes balancing costs from other integration cost categories (those resulting from transmission and support to system adequacy). The upper end of the identified balancing cost comes from estimates for the United Kingdom, wherein the availability of flexible resources is likely to be low due to grid and market constraints. In contrast, recent projections for the Eastern Interconnection in the United States in 2024, which assume optimisation measures such as balancing area consolidation and optimal forecasting, suggest a mid-range cost of USD 3.5/MWh at 20% wind energy share — rising to USD 5/MWh at a 30% share.

These are modelled costs and do not account for all of the flexible resources assessed by the FAST Method. The next phase of the GIVAR project will aim to develop a methodology for identifying cost curves of flexibility measures specific to an individual power system. These are expected to look very different from case to case, as they will depend on widely differing system design, operation and resources. The new phase will also examine the relative costs of dispatchable plants, storage facilities, interconnections and demand-side flexible resources.

10. Although VRE power plants do not provide as high a contribution to system adequacy as do dispatchable plants.

Part 1

1 • Introduction

The reliable integration of renewable sources of electricity is perhaps the most disputed and misunderstood factor in sustainable electricity supply. This is partly because integrating renewables is complex, partly because it implies change in the vitally important activity of electricity provision, and partly because some renewable energy technologies do pose additional challenges.

A major part of the task relates to the balancing of production and consumption of electricity. Supply and demand are linked physically through the power grid: an increase or decrease in one must be balanced — more or less instantaneously — by a corresponding decrease or increase in the other.

Electricity is produced by a range of different power plant technologies, and derives from a range of energy resources including fossil, nuclear and renewable. Each of these has advantages and disadvantages in terms of cost, carbon footprint, pollution and impact on the power system.

Three principal elements constitute the power system of a given region: power plants, consumers of all kinds, and the electrical grid connecting them.[1] The whole system operates continuously and dynamically. None of these elements should be looked at in isolation; they are too intimately interlinked. If any one is altered, there will be an impact, positive and/or negative, on the others. When a large power plant, or a new high voltage transmission line, is added to a system, it will have an effect on the way that system is managed. For example, a new nuclear plant designed to operate at full power around the clock is likely to increase the chance of surplus electricity supply during the night, when demand is at a minimum.

Strategic energy policy must therefore avoid a piecemeal approach. In many countries, energy policy is increasingly driven by an urgent need to reduce greenhouse-gas (GHG) emissions and pollution from conventional fuel use. Another important objective is to increase security in the face of fuel supply constraints. Deployment operators of variable renewable energy (VRE) sources can contribute to these goals, but cannot be considered in isolation from the rest of the system.

Some renewable energy technologies are **dispatchable** — they can be called upon to operate at any given time.[2] As a result, system managers can rely on their output and manage them in a conventional manner. Dispatchable renewables include geothermal, hydropower, bio-energy, and some concentrating solar power plants (CSP).[3] The output of a second group of renewable energy power plants, including wind power, solar photovoltaics (PV) and wave energy, is variable and less predictable.[4]

Current penetrations of variable renewable electricity are small in all but a few European countries, but are growing fast. Wind energy contributes substantially to annual electricity supply in a number of OECD countries such as Denmark (18.6%), Portugal (15.4%) and Spain (12.6%) (Table 1). These numbers represent only average penetrations over the year; instantaneous penetrations can reach much higher. For instance, at 14:46 on 9 November 2010, wind power penetration reached 46.7% of Spain's total power supply (REE, 2010b).

1. Energy storage plants have greater or lesser importance depending on the system. For simplicity's sake they are not mentioned here.
2. Allowing for downtime for maintenance, which in older plants can be considerable.
3. CSP with sufficient integrated thermal storage.
4. In contrast, tidal power, though variable, is wholly predictable.

Table 1 • Average penetrations of wind energy in leading areas, 2009

Country	% of electricity supply provided by wind	Wind terawatt hours (TWh)
Denmark	18.6	6.7
Portugal	15.4	7.6
Spain	12.6	36.6
Germany	6.4	37.8
United Kingdom	2.3	8.5
Italy	2.1	6.1
United States	1.7	71.2
France	1.4	7.8

Note: A terawatt hour is the amount of electricity resulting from one terawatt (billion kilowatts) of power plants producing for one hour.

Source: IEA data and analysis.

And yet, if such shares are already being seen, why is it reported repeatedly in the media that wind power and other VRE are inherently unreliable? Do power systems in these countries differ in some important respect from others? Are they less reliable? Can other countries emulate these penetration levels? Can they go even higher?

This book maps out an approach to answering such questions. Specifically, it describes for decision makers the most important factors and characteristics that must be taken into account to ensure that power systems evolve in step with policy targets for greater VRE deployment.

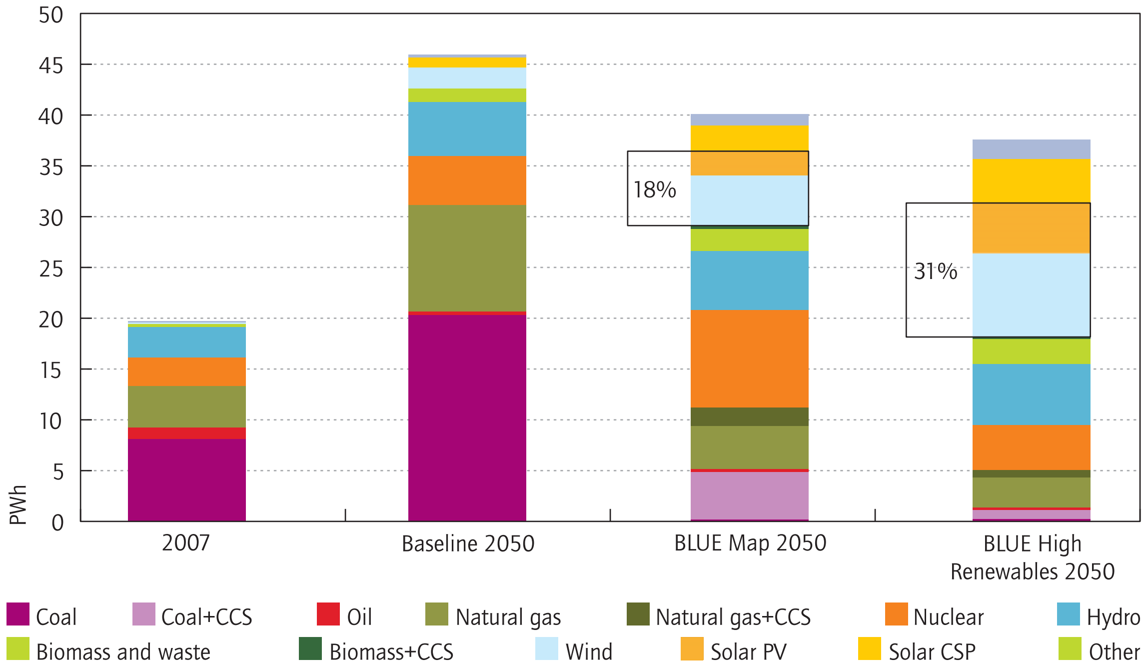
One thing is certain: variable renewables will be responsible for an increasing proportion of electricity in many countries. Legally binding targets in the European Union state, for example, that more than 30% of electricity must come from renewable energy sources by 2020 — a large proportion of which will be from wind power and solar PV. On the global scale and in the longer term, the recent IEA publication *Energy Technology Perspectives 2010 (ETP 2010)*, calculates that wind and solar PV alone should provide more than 30% of global electricity by 2050 in order to meet the target of halving GHG emissions (Figure 1). Achieving this target requires a massive increase from the less than 2% supply from these energy sources seen today.

Power systems worldwide differ tremendously; so do the accompanying challenges. One country or area — by chance or by design — may already be well equipped to manage a 10% share of variable renewables. But the same target may be a daunting task to its neighbour. Fortunately, the underlying factors are essentially the same in every case, though they differ in scale and detail, according to the resources and constraints present in the area. Nevertheless, no standard approach to their assessment could be identified in the scoping phase of this analysis. In consequence, there is no benchmark against which power systems can be distinguished one from another in terms of their current potential for VRE deployment.

This analysis aims to rectify that deficiency to some extent through a four-step approach that starts with identifying existing resources within a given system that have the potential to — or already do — contribute to balancing electricity supply and demand. The second step seeks to identify the constraints that impede the availability of these resources to play a larger role in balancing. The third step assesses existing and new balancing needs. Finally, the analysis identifies how constraints on availability of balancing resources could be removed, so as to manage the greater variability resulting from an increase in VRE deployment.

This simple methodology, which is applicable to any system, highlights the characteristics that determine the extent of the VRE integration challenge in a specific case, and identifies a range of measures to increase VRE penetration potential.

Figure 1 • Variable renewable energy shares in ETP BLUE Scenarios, 2050



Source: IEA, 2010.

Key point • *In a recent IEA scenario for the period up to 2050, variable renewable electricity accounts for more than 30% of total electricity production in that year, compared with less than 2% today.*

At the 2005 G8 Summit in Gleneagles, the IEA Secretariat was asked to assess the challenges of efficient integration of variable renewables in power systems. A preliminary report prepared for the 2008 Hokkaido G8 Summit, entitled *Empowering Variable Renewables: Options for Flexible Electricity Systems*, outlined some strategies to facilitate VRE deployment (IEA, 2008).

To increase understanding of the issues, the Secretariat then launched the Grid Integration of Variable Renewables (GIVAR) project; this book is the result. The project was given additional impetus by a call from energy ministers in IEA member countries to carry out a study of electricity security, including the impact of electricity from variable sources.

What is in this book?

This analysis addresses the impacts of large, centralised[5] variable renewable power plants on the balancing of electricity supply and demand. Distributed renewables (Box 1) will also be an important factor when considering system integration, but are not considered in this analysis.

The VRE integration challenge is often perceived over three timescales: **stability** refers to a timescale of seconds or less; **balancing** of demand and supply covers minutes to days (often referred to as load following); and the **adequacy** of the power system to meet peak demand in the long term is assessed over months to years (Figure 2). The underlying objective in all three cases is the same, to maintain the balance of supply and demand for electricity, but it is important to clarify the distinction between balancing and adequacy tasks in particular.

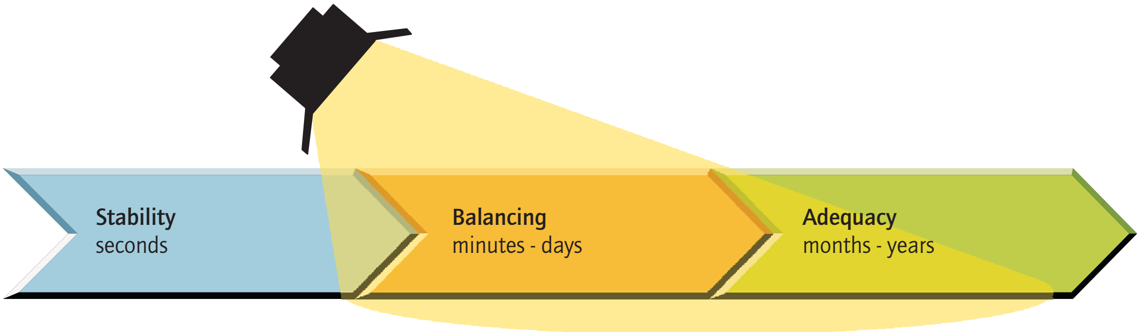
5. As opposed to distributed power plants, such as building-integrated solar photovoltaics.

Box 1 • Distributed variable renewables

Distributed electricity generation can take many forms, the fastest growing of which today is solar photovoltaics (PV). Most PV is in the form of small-scale distributed plants on the kilowatt scale, although larger, centralised plants exist. Small plants will be particularly important where they dominate deployment trends, as with the widespread use of PV in Japan.

Much PV is connected at the point of energy use (*e.g.* on the roofs of buildings), and can therefore reduce demand in those areas without management by the system operator (Enel, 2010). This offers benefits but will also pose certain challenges, as it is difficult for the system operator to predict what output to expect from such plants. At low penetrations, this does not pose a significant problem. But at higher penetrations, the inability of the system operator to forecast with any great degree of accuracy, or to constrain output from VREs, would be an important consideration.

Figure 2 • System integration challenges



Key point • This analysis focuses on the balancing challenge, a central part of the integration continuum.

This analysis explicitly addresses the balancing challenge. It assesses the extent and impact of *changes* in VRE output – and a system's ability to balance these fluctuations. It does not extend into an analysis of voltage stability or system adequacy, both of which warrant further specific analysis (Box 2). Nevertheless, as the three challenges form part of a continuum, the approach to the balancing challenge explained in this analysis does indirectly address a significant part of the adequacy challenge as well.

The rest of this book is in two parts: the analysis and description of a methodology to assess flexibility in any given power system and what can be done to increase it, followed by examples of its application.

A detailed description of the Flexibility Assessment (FAST) Method, a new approach developed by the IEA to assess the balancing needs and resources of individual power systems, forms the core of Part 1. While demonstrating how the FAST Method can be applied, Part 1 explains the challenges in balancing variability and uncertainty in power systems. It describes the key balancing resources and the existing constraints on their availability. It also highlights the specific context of individual power systems – and the fact that these differ considerably. Part 1 ends with a summary of balancing costs (as they are understood to date), and conclusions resulting from the analysis of the case studies.

Chapter 12 of Part 2 combines a more detailed description of how key aspects of flexibility assessment are treated in a spreadsheet-based tool designed by the project to illustrate the FAST Method and to provide a vehicle for case studies. This prototype tool is under ongoing development. The description highlights key assumptions implicit in the spreadsheet tool, and data limitations encountered during the case studies.

Box 2 • Other integration challenges.

The voltage and frequency of any given power system fluctuate continually with variations in demand and supply. The stability part of the balancing challenge relates to maintaining both within acceptable levels. Every power system has a number of specific resources it uses to achieve this. These include certain dispatchable generators (*e.g.* thermal, hydro plants) that the system operator can rely on more or less instantaneously, thereby ensuring manoeuvring room as and when required.

Many power systems have **grid codes** – a suite of rules set by the system operator – that specify the services to be provided by power plants within the system. Areas with high penetrations of wind power generally apply robust grid codes which may, for example, stipulate that wind power plants must be able to support the system in case of faults that jeopardise voltage stability. This capability (known as fault ride-through) is important in ensuring such power plants contribute to system stability.

The adequacy of a power system refers to its ability to meet peak demand, even under the most extreme conditions. In this regard, the system operator is primarily concerned with each power plant's ability to contribute to **firm capacity** – essentially power supply that can be more or less guaranteed. Each plant is rated according to its ability to operate and provide firm capacity when most needed by the system operator. **Capacity credit** is a measure of this. It represents the proportion of the rated capacity of a plant that can be dispatched when most needed (with an acceptable level of certainty). As their output fluctuates, variable power plants generally have a much lower capacity credit than do dispatchable plant types. System adequacy is addressed further in Annex A.

Chapters 13-20 of Part 2 detail the findings of these case studies, which are first-order assessments of the ability of eight power areas to balance variable renewable electricity: the British Isles, the Iberian Peninsula, the Western Interconnection of the United States, Japan, the part of the Canadian Maritime Provinces operated by the New Brunswick System Operator, the Nordic Power Market, a separate assessment of Denmark within that market, and Mexico.

The book also contains a number of annexes, providing further detail on the FAST Method and other relevant information:

Annex	Content
A	Other integration costs
B	Additional information on VRE technologies
C	Assumptions relating to dispatchable power plants in case study areas
D	Defining the power area for analysis with the FAST Method
E	The role of CCS in flexible power generation
F	The role of CHP in flexible power generation
G	Treatment of fundamental area attributes in the case studies

2 • Why is variability a challenge?

It should first be pointed out that variability is not a new phenomenon in power system operation: demand has fluctuated up and down since the first consumer was connected to the first power plant. The resulting imbalances have always had to be managed, mainly by dispatchable power plants.

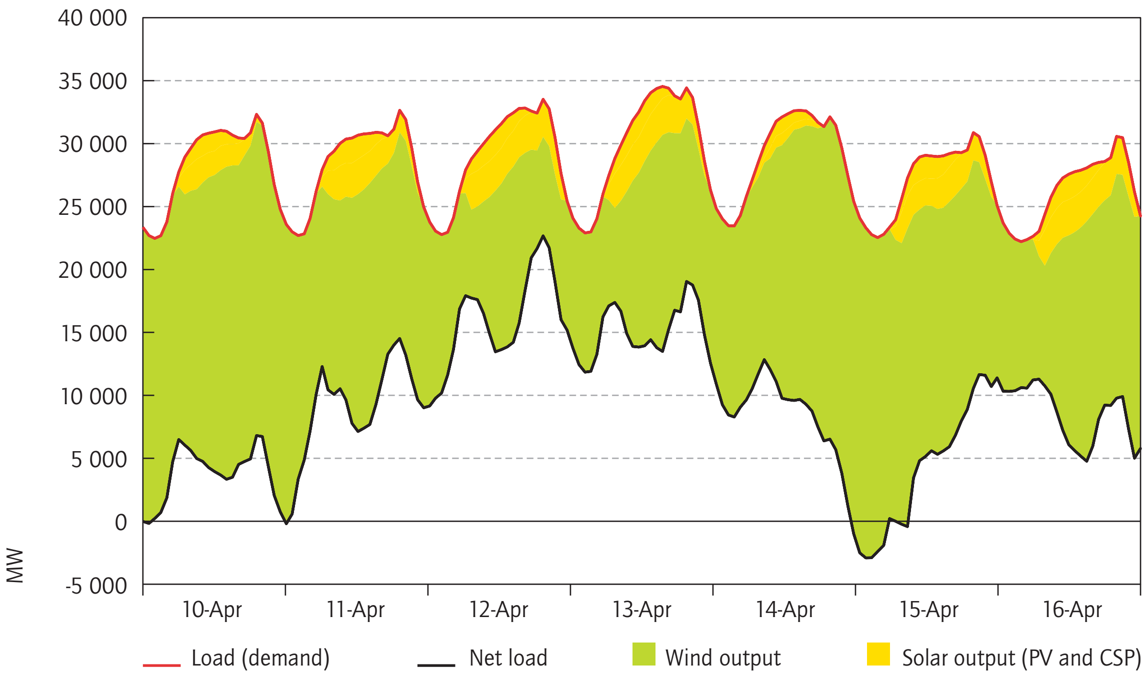
So variable renewable electricity in the system is an additional, rather than a new, challenge that presents two elements: variability (now on the supply-side as well), and uncertainty.

Fluctuating supply

Firstly, the output from VRE plants fluctuates according to the available resource – the wind, the sun or the tides. These fluctuations are likely to mean that, in order to maintain the balance between demand and supply, other parts of the power system will have to change their output or consumption more rapidly and/or more frequently than already required.[1] At small penetrations – a few percent in most systems – the additional effort is likely to be slight, because VRE fluctuations will be dwarfed by those already seen on the demand side.

Large shares, in contrast, will exaggerate existing variability, in extent, frequency and rate of change. As an example, the modelled effect of a large share of wind (30%) and solar energy (5%) on the WestConnect[2] area of the western United States shows that some weeks will present very challenging balancing conditions, when VRE output ranges rapidly from high to low (or vice versa) (Figure 3).

Figure 3 • Variability in demand (upper line), and in net load (lower line) in a challenging week



Source: GE Energy, 2010.

Key point • *Variability is not a new phenomenon in power system management, but high VRE penetrations will pose significant additional challenges. Only the additional variability in the* net load *is germane (not the variability of VRE power plants in isolation).*

1. The main exception will be when demand is fluctuating in the same direction (up or down) as the VRE output.
2. The WestConnect area is a large part of the North American Western Interconnection, covering all or part of eight states.

The upper line of Figure 3 shows the shape and extent of everyday demand fluctuations over the course of the week modelled. As can be seen, electricity demand follows a regular pattern. The lower line shows demand after accounting for wind and solar output. This is often referred to as the net load. In the net load tracking, no regular pattern is evident, highlighting the greater variability caused by a 35% VRE share. Indeed, the figure shows three periods (when electricity demand is at minimum) in which the **net load** drops below zero. At these times, VRE output (green and yellow area) must be curtailed, stored or exported; otherwise it would be greater than the total electrical demand of the area.

It is the extent of these ramps, the increases or decreases in the net load, as well as the rate and frequency with which they occur, that are of principal relevance to this analysis. This is where the balancing challenge lies — in the ability of the system to react quickly enough to accommodate such extensive and rapid changes. Net load ramping is more extreme than demand alone. This is not only because VRE output can ramp up and down extensively over just a few hours, but also because it may do so in a way that clashes with fluctuations in demand. For example, on 14 April Figure 3 shows VRE output *increasing sharply* towards the end of the day, when demand is *falling* towards the night-time low.

In contrast, VRE output may complement demand — when both increase or decrease at the same time. This occurs, for example, during the morning demand rise on 13 April as VRE output is also increasing, illustrated by the smaller up-ramp in the net load compared to that of demand alone.

So, rather than — *how can variable renewables be balanced?* — the pertinent question is: *how can increasingly variable net load be balanced?* The point is that variability in VRE output (supply) should not be viewed in isolation from variability on the demand-side (load); if the VRE side of the balancing equation is considered separately, a system is likely to be over-endowed with balancing resources by planners (rightly) anxious to avoid a deficit.

Uncertainty

Uncertainty — the second element of the challenge — relates to the predictability of output from variable power plants. Wind power and wave power (the latter being driven largely by the wind) are perhaps the most irregular of the variable renewable portfolio, particularly over smaller areas. Wind power output may rise or fall quickly or slowly, for long or short periods and with little discernible pattern, according to passing weather fronts.[3] Solar PV fluctuates in a more regular manner: PV plants (without storage) will not generate at night, so other generators in the system can be dispatched accordingly. Moreover, output does not drop to zero under cloud cover; solar PV operates with diffuse as well as direct sunlight, though less well, so output from a single cell will not fall below around 20% of rated capacity during the day (Falk *et al.,* 2007). Tidal power, which is driven by the gravitational force exerted by the moon, is the most regular of all variable renewables, and the pattern of the resource is replicated regularly from period to period.

Uncertainty is not new to system operation either. Demand forecasts for the day ahead commonly include an average error of around ±1.5%, rising to 5% for the week ahead, and will be greatest when consumers respond to an unexpected, shared stimulus, such as a cold snap in the weather. But demand variability is considerably more regular and predictable, as is illustrated in Figure 3. It follows regular daily and weekly patterns, and, at higher latitudes, a larger pattern dictated by the seasonal demand for heating, cooling and lighting.

With the exception of tidal power then, the timing of output from VRE power plants is more uncertain. Accurate prediction of output remains, to some extent, an art rather than science. And, as with predictions of demand, it is unlikely ever to be 100% accurate. A VRE power plant may provide forecasts for the day ahead, and then update that forecast inside the day, and even inside the hour,

3. More regular winds include those in specific locations/areas such as katabatic winds in valley areas, or onshore/offshore winds in coastal areas.

improving its accuracy. But the amount actually delivered will still differ to some extent from the forecast amount. As a result, the system operator must make up the deficit or manage the surplus at relatively short notice.

When is the balancing challenge greatest?

For the purposes of the case studies explored in Part 2 of this book, the balancing timescale is considered to stretch from 36 hours to 15 minutes ahead of the time of use of the electricity. The 36 hour-period is likely to encompass the maximum extent of variability in output that a system will see. Therefore, analysing the resources available to cope within this timeframe will cover the lion's share of the balancing challenge in most systems.[4]

The balancing challenge will be greatest when demand for electricity and output from variable power plants are changing simultaneously in opposite directions (Söder, 2010). This will occur to its greatest extent in two cases:

- When high electricity demand is dropping to minimum while low VRE output is increasing to peak. In this situation, dispatchable power plant will be ramping down, following falling demand; there may be a limit on how much faster it can ramp down to accommodate rising variable output feeding into the system.
- When minimum electricity demand is rising towards peak while VRE output is falling away, in which case dispatchable plants are ramping up quickly; there may be a limit on how much faster they can do so to make up for falling VRE output.

In both situations, the balancing capability of the system will be tested to the extreme. They can be seen as the acid test for VRE deployment from the balancing perspective.

4. In some cases, it may be desirable to look at a period from several days up to five minutes before time-of-use, for example.

3 • Greater flexibility is the right response

To cover variability in the net load, planners must ensure that the power system contains sufficient **flexible resources**. Knowledge of the maximum extent, rate, frequency and uncertainty of ramps in VRE output will indicate the extent of capabilities needed to balance the additional variability in the net load that they represent. Or conversely, an assessment of the flexible resources of a given area will indicate the extent of variability that it can manage. This is the approach taken in this book.

What is flexibility?

Flexibility expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise. In other words, it expresses the capability of a power system to maintain reliable supply in the face of rapid and large imbalances, whatever the cause. It is measured in terms of megawatts (MW) available for ramping up and down, over time. For example, a given combined-cycle gas turbine (CCGT) plant may be able to ramp output up or down at 10 MW per minute.

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

Flexibility, in power system terms, is traditionally associated with quickly dispatchable generators. But balancing is not simply about power plants, as is often suggested. While existing dispatchable power plants are of the greatest importance, other resources that may potentially be used for balancing are storage, demand-side management or response, and interconnection to adjacent power systems for trade. These, too, will be present in different areas to greater or lesser extents.

Sources outside the electricity sector can also contribute to flexibility. In fact, the growing importance of flexibility may drive stronger links to other energy sectors such as heat and transport. In the heat sector, space heating using electric thermal storage systems can create opportunities to manage surplus VRE output. In many areas, opportunities to store electricity are limited; electric vehicle (EV) fleets may provide a valuable opportunity to change this, and enable better use of VRE output that is surplus to needs at the time it is produced.

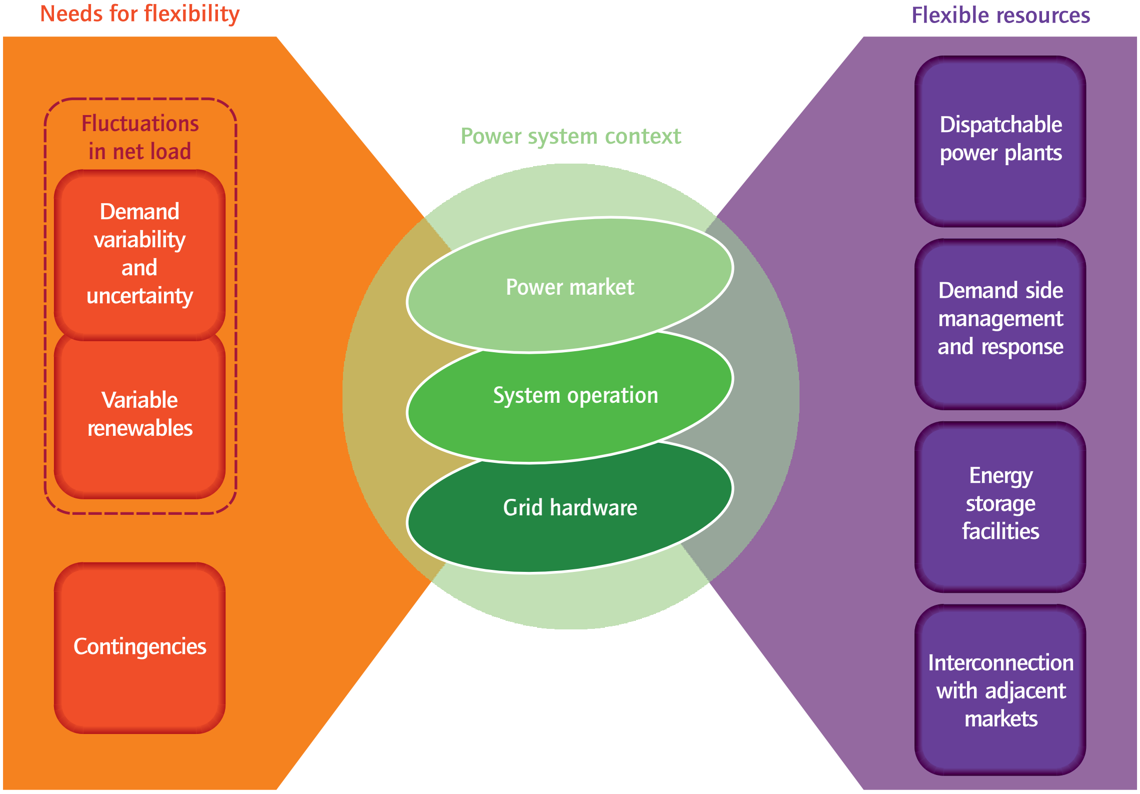
Flexibility can also be provided to some extent by variable power plants themselves — through curtailment of output. While not a focus of this analysis, this option is summarised briefly in Box 3.

Box 3 • Curtailing variable output

VRE plant output can be curtailed (limited), when necessary, to prevent surplus power in the system or to reduce the rate of (upwards) change of output. It is also possible for VRE power plants to be backed down to below maximum output at a given time, so that they can ramp upwards again when necessary to provide balancing services. Such curtailment or backing down might only be needed for a few hours per year (*i.e.* presenting acceptable costs to the producer), and full flexibility assessments should take account of this option as it may result in the ability of a power system to manage a greater capacity of VRE.

Examining the main factors that must be taken into account when assessing the flexible resources of a system will give an idea of its present potential to manage variable electricity (Figure 4). The left-hand side of the figure shows the requirements for flexibility, existing and new. These are likely to overlap to some extent, as reflected in the net load. Added to this is a requirement against unexpected events in the system — contingencies — usually quantified as the loss of the single largest power plant or transmission line.

Figure 4 • Overview of flexibility needs and resources



Key point • The needs for flexibility resulting from variability in the net load can be met by four flexible resources, in the specific context of the power system.

The right-hand side lists the four flexible resources that can be used to balance variability. To a large extent, all four can be equated in terms of their flexibility value: all can provide rapid or scheduled power increases or decreases in response to variability, which makes them equally suited to providing for the needs of fluctuations in the net load.

The middle of the figure shows the power system context in which requirements and resources are matched, to establish how much of the flexible resource is actually available for use in balancing. In some areas, a large amount of the resource will be available. In others, it will be seriously constrained, usually by a combination of three key factors: the physical transmission grid; how the power system is operated; and the structure of power markets in which electricity is bought and sold. There will also be specific constraints on individual resources, which are discussed in detail in subsequent chapters.

4 • Key distinguishing features of power systems

Areas with large shares of variable renewables have a noticeably greater requirement for flexibility than those without. But what is a large share, exactly? To judge by experience so far, and very broadly speaking, a large share might be said to be one in double digits. But the real answer is "it depends".

This is because no two power systems are alike, a fact that is often overlooked when comparing opportunities for deploying VRE plant. Certainly, all power systems share certain fundamental features, and on this basis they may be compared, but such comparisons are fraught with pitfalls. Some systems have very large installed generation capacity, and provide power across very large areas spanning several countries or states. At the opposite extreme are very small systems, and islands. Systems may be closely interconnected with adjacent areas, and so able to trade, or they may be isolated and without this option. Some may have strong storage resources such as pumped hydro; others may contain no storage facilities.

Demand fluctuates in every system, but to different extents and for different reasons: in one case, fluctuation might be driven by industrial processes that cannot be interrupted, while in another the capability of the demand side to respond may be much greater. Every system's portfolio of dispatchable power plant will be different, with greater or lesser ability to ramp. All power systems have internal transmission (and distribution) networks; but in one it may be strong and heavily meshed (inter-linked), while in another there may be weak links. In the latter case, the loss of an important single line due to some unexpected event will be a more serious problem.

It follows that different power systems – as presently configured – will have greater or lesser ability to manage variability, and that the cost of doing so will differ. Figure 5 illustrate six of the key attributes examined in the eight case studies in Part 2. The figure also includes a generic, small island case.

Several of the areas analysed in this report, though similar in some respects, show significant differences in the integration challenge they are likely to face. The British Isles and Mexico, for example, are similar in most respects considered in the figures, so comparison between them is to some extent meaningful.[1] In contrast, comparing wind power deployment in Mexico and the Nordic area would be misleading: despite similarities, key attributes such as grid strength and geographical spread of VRE resources differ dramatically.

Area size. An area with a large installed capacity, such as the western United States or Japan, is likely to see higher peak demand but also to contain a larger number – and possibly greater diversity – of power plants that contribute to supply. Such geographically large systems have greater potential for smoothing of output variability through dispersal of VRE power plants over their area (see geographical spread below). It is also likely that aggregated demand will fluctuate more smoothly in systems that span several time zones.

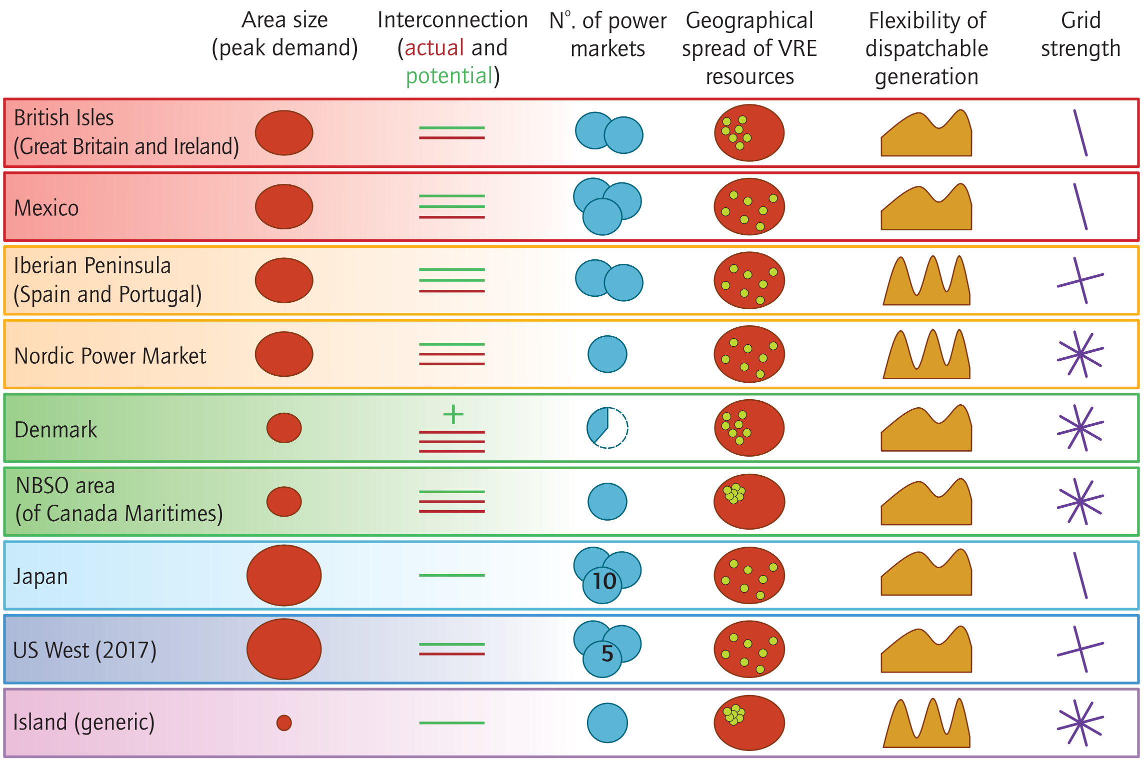
Interconnection with adjacent areas. The green bars in the second column of Figure 5 roughly indicate the economic potential for interconnection with adjacent areas, proportional to the size of the area itself.[2] The red bars represent the extent to which this potential has been realised to date. If an area has high interconnection potential, it may have an important opportunity to balance VRE within its own borders using the flexible resources of its neighbours. Very large areas such as the US Western Interconnection will have less potential for interconnection, and isolated islands have

1. Internal transmission in the British Isles area is scored as weak because the interconnection between the two islands of Great Britain and Ireland is assessed as part of internal transmission. If the two were assessed separately, the existing interconnection would be considered instead as a limited part of the flexible resource. Internal transmission in Britain on its own would probably be intermediate, given existing north/south congestion issues.

2. In some cases, potential for interconnection may not, in practice, be modifiable: for an isolated island, for example, to which transmission from the mainland may remain economically unviable.

negligible potential. By contrast, small areas embedded in continental size systems, such as Denmark within the Nordic system, have a very large potential. It should be noted, however, that establishing new interconnections can have long lead times.[3]

Figure 5 • Key distinguishing attributes of power areas assessed



Key point • Power systems vary tremendously. There is no one-size-fits-all solution to the integration challenge.[4]

Number of power markets within the area. Some areas assessed contain several distinct power markets, which may or may not collaborate to some extent. For example, the Spanish and Portuguese markets within the Iberian Peninsula are linked through the Iberian Regional Market MIBEL. Conversely, the area of Japan is made up of ten distinct power utilities, which are only weakly interconnected and do not co-ordinate their balancing needs. Denmark is balanced as part of the larger Nordic Power Market, over which balancing variability and uncertainty can broadly be said to be carried out as a single market.[5] Being part of a single market is generally a stronger position than being one among a number of linked markets.

Geographical spread of VRE resources. VRE plants deployed over a large area will have a smoother (aggregated) output than plants built closer together. Broadly speaking, larger areas offer better potential for smoothing aggregated VRE output, because weather conditions (*e.g.* wind speed, cloud cover) will vary within the whole. Furthermore, if the area examined features more than one prevailing weather system – as is the case with the Atlantic and Mediterranean coasts of the Iberian Peninsula – output from plants will be still less correlated and therefore more likely to be complementary. Conversely, the smoothing effect of aggregation will be limited if VRE plants can be sited only in certain areas, which may result from resource constraints or competing land uses.

3. Cross-border projects taking longer than ten years are not uncommon in Europe, for example.

4. The case study approach to these attributes is described further in Annex G.

5. Although the Nordic market includes a lower tier of national balancing areas, these are assumed not to hinder balancing over the larger area.

Flexibility of the dispatchable power plant portfolio. The existing dispatchable power plant portfolio is an important factor. Plants that can be dispatched at short notice will be technically able to provide important, fast flexibility. A predominance of slower plants, which include some coal-fired plants and many nuclear plants, does not imply an absence of flexibility. Although such plants may be less able to respond to flexibility needs quickly (an hour ahead, for example), they may still represent an important resource in the longer term (36 hours ahead).

It may be possible to improve the flexibility of the dispatchable power plant portfolio by replacing slower plants with new, faster technology — but the former may still have decades of useful life ahead of them. Retrofitting existing plants to increase their flexibility may also be an option.

Grid strength. Grid or transmission strength is critically important in assessing an area's capability to balance variability. The grid exists to link producers and consumers of electricity. A strong grid will ensure provision of electricity even if, for example, an important transmission line suddenly becomes unavailable. In this analysis, a strong grid is one with enough capacity margin to ensure that flexible resources are available to balance variability and uncertainty — even under difficult circumstances — and within acceptable risk levels.

Rather than considering, as is sometimes proposed, that the grid represents a flexible resource in and of itself, this analysis views the grid as a potential constraint on the availability of flexible resources. If an important line is congested (*i.e.* at full capacity and no additional electricity can flow through it), then flexible resources on one side of the congestion will be blocked from providing for flexibility needs on the other side.

Grid strength also has a very important influence on the flexibility requirement resulting from VRE. VRE resources such as wind power may be located in areas where the grid is weaker — as will often be the case away from demand centres. If this weakness leads to congestion, then the smoothing effect of geographical spread will no longer be seen over the whole area and variability of output throughout the area will be higher accordingly. This would increase the need for flexibility.

Defining the power area. For the purposes of this report, a power area defines the geographical boundaries of a case study area, while a power **system** is a physical grid area operated by a single system operator. Not all the case study areas discussed here are distinct power systems; in two cases, the power area assessed consists of two distinct (though interconnected) systems — Britain and Ireland, and Spain and Portugal.

In assessing flexibility (balancing needs and resources) the boundaries of power systems are more important than national boundaries. If integration is considered purely in the national context, but the relevant country is in fact part of a larger system — such as Denmark within the Nordic Power Market — then positive and negative impacts in the larger system might well be overlooked.

This point highlights the versatility of the Flexibility Assessment (FAST) Method introduced in this analysis. Any area can be assessed, depending on the objective of the decision makers. In the Britain and Ireland case, the objective was to examine potential for both islands to share their flexible resources, though at present such sharing is largely blocked by limited interconnection and co-ordination between the two systems.

In such cases, one focus of assessments using the FAST Method should be the potential to manage variable renewables if such limitations were removed. Sensitivity analysis could be carried out by first examining flexible resources in the area as it is; then a second analysis could assess the resource if the area were operated as a single system.

Indeed, power systems should be assessed in tandem, or even in larger groups, if the deployment of VRE in one is likely to have any impact on its neighbours, which will certainly be the case if they are strongly interconnected.

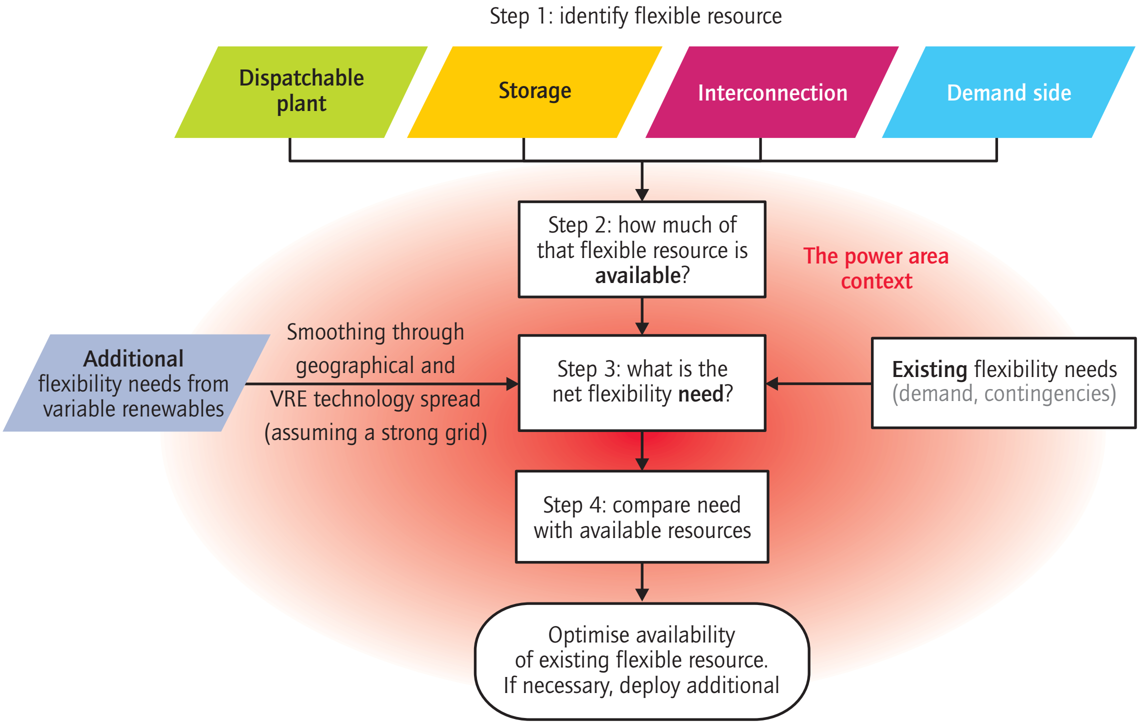
5 • The Flexibility Assessment Method

Flexibility is a known need of primary importance in the planning and operation of power systems to ensure demand is reliably served, and yet it is not systematically assessed.

With this in mind, the IEA has developed the Flexibility Assessment (FAST) Method to guide decision makers through a holistic assessment of system-side measures for balancing variability. This new approach can be applied to any power area, to assess its requirements for and resources of flexibility. The case studies included in Part 2 were carried out using a spreadsheet tool based on this FAST Method.

The FAST Method is intended to inform policy makers, regulators and system operators – particularly in countries or regions that have yet to make a start in deploying VRE technologies, but also in areas where they are already tried and tested.

Figure 6 • The FAST Method in a nutshell



Key point • The Flexibility Assessment Method can be applied to any power area, to assess its flexibility requirements and resources.

Through what is essentially a series of key questions relating to the resources and nature of the area in question, FAST provides a high-level view of what the challenges and solutions in that specific case are likely to be. The four main steps (Figure 6) are:

- **Step 1: the technical flexible resource.** The extent of each of the four flexible resources is assessed over the balancing timescale. In this analysis, the four timescales used are 15 minutes, 1 hour, 6 hours and 36 hours ahead of the moment resources are actually required to provide their flexibility. Resources are quantified in megawatts, and summed, bearing in mind any time limitations on specific resources.[1]

The resulting number represents the *technical flexible resource* (TR) of the area assessed, measured in megawatts, over time, by which the area can technically ramp electricity supply (or demand) up or down, to balance variability and uncertainty in the net load.

- **Step 2: the available flexible resource.** This captures whether or not the technical flexible resource will be available to operate in the desired way, given the wider context of the power area in question. All flexible resources will be limited in some ways, depending for example on how the power system and market are operated (*e.g.* whether forecasting of variable output is used), or the likelihood of grid congestion.

  Other constraints will apply only to a specific flexible resource. For example a reservoir hydro plant, though technically very flexible, may not in reality be operated flexibly due to other uses of the plant (*e.g.* to protect fish stocks or to provide drinking water).

  The available flexible resource, then, is the megawatts that will actually be available to ramp up or down as required, after taking all known constraints into account.[2]

- **Step 3: the need for flexibility.** Once the available flexible resource is known, the extent of the existing need for it is identified. Existing needs result from demand fluctuations and forecast error, unexpected outages (contingencies) and additional needs resulting from VRE power plants.

  The geographical dispersion of plants, and technological diversity of VRE types in the portfolio, will both have important impact on the extent of variability and uncertainty.

  This step results in maximum expected values for the extent and rate of variability and uncertainty in the net load over the balancing timescale, in terms of megawatts per minute.[3]

- **Step 4: identifying "head room" for new VRE plants.** When flexibility needs and resources are both known, they can be compared to assess the extent to which the existing flexible resource might provide for the additional needs resulting from variable power plants. This step results in a megawatt number that expresses how much variable renewable energy capacity can be reliably balanced by the system *as it is presently configured and operated*.

  It is important to note that this value is **not** a technical ceiling on deployment: availability of flexible resources can be increased, and new resources deployed to enable greater deployment of VRE.

1. There may be a limit on the use of two of the flexible resources — demand-side response and storage — that relates to the duration of their availability at any given time. Storage may be able to deliver its peak output for only a few hours, for example, while there may be a limit on the length of time a consumer can curtail demand. Both these factors can be accounted for in the FAST Method. Depending on the flexibility needs of the system, these energy ceilings could potentially be raised to fit requirements.
2. Due to lack of data, the case studies in Part 2 score these constraints in qualitative terms only.
3. Due to lack of data, the two needs are treated separately and summed in the case studies, resulting in a likely overestimation of their net flexibility requirement.

6 • Identifying the flexible resource

The flexible resource exists in four parts of the power system: in the portfolio of dispatchable power plants; in storage facilities; in interconnections to adjacent power systems to allow trade; and in the ability of the demand side to respond or to be managed.

This chapter examines these individually to establish the technical flexible resource each one represents – *i.e.* Step 1 in Figure 6.

Dispatchable power plants

The largest source of flexibility in power systems today is the ability of dispatchable power plants to ramp output up and down on demand. A plant is dispatchable if it is able to respond to commands from a system operator – at any time, within certain availability parameters – to increase or decrease output over a defined period. But the ability of dispatchable plants to alter their output differs considerably. This is a distinction captured in the terms *base-load*, *mid-merit* and *peaking* plant, as the following paragraphs explain.

Peaking plants such as simple cycle gas or diesel turbines and reservoir hydropower can respond more or less immediately. The ability to start up and shut down quickly is important for fast response to short-term variability and forecast uncertainty – on the minute-to-minute timescale. This is a primary characteristic of peaking plants.

Mid-merit plants typically have the ability to ramp down to a minimum operating level. Although they generally respond more slowly than peaking plants, they can provide significant flexibility within the hour. Examples include some coal – or biomass – powered plants, concentrating solar power plants (with sufficient thermal storage), and combined-cycle gas plants (CCGT). Hydropower plants may also be operated as mid-merit plants.

Baseload plants have slower response times, and will generally have been designed to operate more or less around the clock. The data compiled of plant response times in the case study areas (Annex C) suggest that most base-load plants – nuclear, most geothermal, some coal plants – generally require at least six hours notice in order to provide significant flexible response. The same would appear to apply to most geothermal plants.

However, the analysis that led to this publication made it apparent that some base-load plants, including nuclear plants, may have the capability to ramp down further and more quickly than commonly believed. This capability may be limited to contingency use for economic or security reasons. An example of nuclear ramping capability in France is described in Box 4.

Box 4 • How flexible is nuclear power?

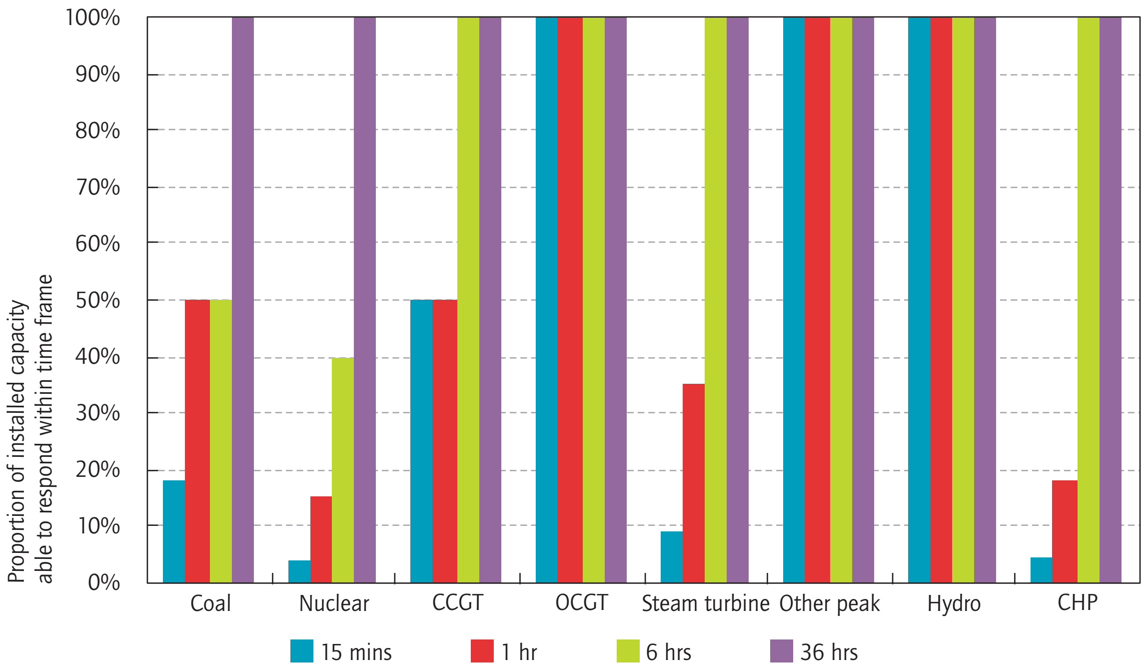
Some nuclear power plants have the technical ability to ramp up or down relatively rapidly – as is demonstrated daily in France. In load following mode – *i.e.* within the balancing timescale – ramp rates can be surprisingly rapid: 1 hour to ramp up from 30% to 100% (and vice-versa); and approximately 30 minutes to ramp from 60% to 100% (and vice-versa), according to Réseau de Transport d'Eléctricité (RTE) data for the week 22-28 November 2007.

This additional flexibility from base-load plants may be particularly important in terms of integrating VRE. The case studies suggest that it is the ramping capability of the system on the longest timescale assessed (36 hours) which is the greatest constraint on the system's ability to manage variability.

The speed, frequency and extent to which a power plant can ramp relate not only to the fuel/resource it is based on, but also to the specific technology employed. A CCGT plant, though more efficient in energy terms, will respond more slowly than an open-cycle gas turbine. Combined heat and power plants, whether coal, biomass or geothermal powered, are usually driven by heat demand; unless their output of electricity has been decoupled through the use of heat pumps, CHP plants may be unable to respond in the balancing time frame.

The Nordic area comprising Denmark, Sweden, Norway and Finland illustrates the ramping capabilities of different types of power plant (Figure 7). As can be seen, simple or open cycle gas plants (OCGT) and hydropower plants can respond to their full extent even inside 15 minutes. By contrast nuclear, coal and combined heat and power (CHP) plants respond much more slowly. These values should not be taken as representative of all power areas.

Figure 7 • Technical ramping capabilities of power plants in the Nordic power area



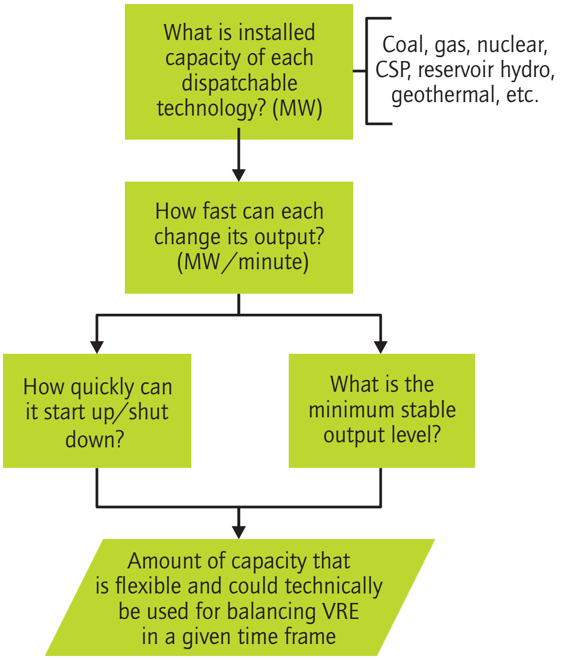
Key point • The speed with which dispatchable power plants are technically able to ramp differs from technology to technology, and plant to plant.

Identifying the technical flexible resource a dispatchable power plant represents requires the answers to four key questions (Figure 8), which are asked on each of the four timescales (15 minutes, 1 hour, 6 hours, and 36 hours).

The first box will yield a simple megawatt capacity number for each plant type. The second captures how fast each can change its output in terms of megawatts per minute. For faster plants the key question is then – how fast can it start up and shut down? And for slower plants – how far can it ramp down and still maintain a stable output? The resulting megawatt figures represent the flexible resource that could technically be used for balancing over the four timescales.

This is a simplified version of the assessment. A more refined assessment would ask these questions not only generically – a single value for each technology – but rather of each power plant on the system, to give a much more precise idea of its technical capability. Individual plants will differ from the generalised values used in the case studies.

Figure 8 • Flexible resource in dispatchable power plants



Key point • *These questions summarise the key factors behind the technical flexible resource represented by a dispatchable power plant portfolio. They do not take into account its availability, which is captured in Step 2.*

Energy storage

Energy can be stored in a number of forms. In pumped hydro storage, the predominant technology where storage facilities exist,[1] water is pumped back uphill into the reservoir at off-peak times and then released on demand.

The electricity from storage plants can be dispatched quickly, making them a potentially important resource on the shortest timescale (minutes) against uncertainty and short-term variability. Fast response flexibility is a principal driver for building storage capacity in any system, regardless of VRE deployment.

The storage capacity of plants is important: if it is small, the amount of time the plant can produce at full power may be limited to a few hours, meaning that there will be an energy ceiling on its output. For example, the pumped hydro reservoir at Dinorwig in Wales can hold enough water to produce electricity at full capacity for five hours. So its full power capacity may not be available over the longer term, as it will take time to refill the reservoir. This raises the point that although existing reservoirs could be increased in size to increase the storage resource, an alternative and perhaps more practical option could be to increase the rate at which water is pumped back into the reservoir.

Assessing the technical flexible resource represented by storage facilities in a given area again depends on answering some key questions (Figure 9).

Though all storage facilities in the power areas assessed in Part 2 are pumped hydro facilities, the FAST Method is equally applicable to other technologies such as Compressed Air Energy Storage (CAES) systems. At the time of writing, a commercial-scale CAES plant is under development in Ohio in the United States, the first to be constructed for two decades. CAES plants compress air using off-peak electricity for use later, in combination with a gas turbine, to generate electricity as needed. The compressed air is stored in appropriate underground caverns, possibly created inside salt rock deposits.

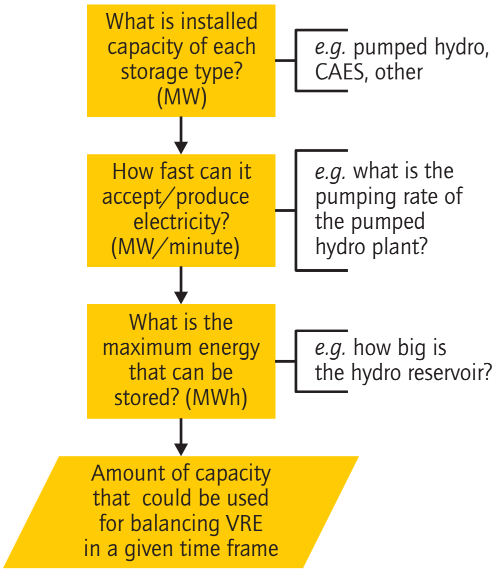
Other technologies at varying stages of development include redox flow cells, advanced capacitors, superconducting magnetic energy storage and flywheels.[2]

Storage technologies may have higher up-ramping than down-ramping capability. CAES systems generally have twice the up-ramping capability compared to down-ramping manoeuvrability – *i.e.* they can produce electricity faster than they can store it. By contrast, electrochemical storage in batteries has comparable values for production as for charging.

1. The distinction between different types of flexible resource is sometimes unclear. Should pumped hydro facilities be counted as dispatchable generator or storage? This is really just accounting: so long as the resource is captured somewhere in the assessment, it does not particularly matter how it is characterised – storage or generation. What matters is its ability to provide the flexibility service.

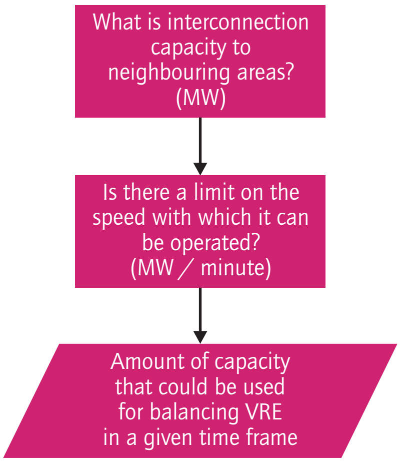
2. Most other presently cost-effective electrical storage technologies are used on the seconds and sub-seconds timescale to maintain dynamic voltage stability of the power system, which as explained in the introduction is not the focus of this book.

Figure 9 • Flexible resource in storage facilities



Key point • These questions summarise the key factors behind the technical flexible resource represented by storage facilities. They do not take into account their availability, which is captured in Step 2.

Figure 10 • Flexible resource in interconnections



Key point • These questions summarise the key factors behind the technical flexible resource represented by interconnections to adjacent areas. They do not take into account their availability, which is captured in Step 2.

Interconnection for trade with adjacent areas

Interconnection allows the shared use of flexible resources to manage variability among adjacent, connected power areas. The extent of *existing* interconnection capacity between a country/region and neighbouring areas will depend on its location, as well as historical socio-economic ties among them.

Areas may be adjacent, and so have a high potential for interconnection, and yet have only a weak connection. The extent of interconnection potential will also be governed by economic limitations; it may be unlikely to be economically attractive for a far-flung island to connect to the mainland, for example. The Iberian Peninsula (comprising Spain and Portugal) and France might reasonably be expected to be heavily interconnected, yet actual transmission capacity is the equivalent of less than 5% of peak electricity demand in the peninsula. By contrast, Denmark is connected to Norway, Sweden and Germany, and heavily (5.4 GW) – equivalent to more than 80% of its peak demand.

The maximum extent of flexible capacity offered by an interconnection is approximately equal to twice its rated capacity: if a transmission line is exporting at maximum, and can be switched to importing at maximum, this results in an overall power ramp over the system that is double its rated capacity.[3] The two main steps to identify the flexible resource represented by interconnection(s) to adjacent areas are shown in Figure 10.

There may be a limit on the speed with which the interconnection capacity can be made available, resulting from the type of technology used. There will be no lag on availability of alternating current (AC) lines, but direct current (DC) lines, require a short period of notice before they can be made available for import or export. Unlike AC lines, which make up the majority of the network and in which electricity will simply flow along the path of least resistance, DC lines are controlled at both ends, and so their operation must be planned. The likely duration of the resulting lag, if any, is assessed in the Step 2 of the FAST Method, in which the availability of flexible resources is assessed. In the DC case, the extent of co-ordination between markets on either side of the line will be significant.

3. The same effect might potentially be seen in demand-side resources and storage.

Demand-side management and response

This is the flexible resource on the other side of the supply/demand balancing equation, resulting from shifted or curtailed consumer demand. As with the other flexible resources, the first step is to assess the technical resource — in MW capacity on each timescale.

Managed resources are those contracted in advance by a system operator to reduce their consumption for a certain number of hours per year, referred to in North America as Direct Load Control. This implies that a certain proportion of the (usually industrial or commercial) consumer's consumption can be postponed without economic hardship. Many countries now use such demand-management programmes.

The **responsive** resource is that proportion of demand that can be relied upon to respond dynamically within the balancing timeframe to scarcity/surplus of electricity by decreasing/increasing consumption, rather than being contracted to do so in advance. Although allowance for such response exists in some markets, it is not well known.

Both managed and responsive resources, from a technical point of view, can provide flexibility more or less instantly. Consumers have simply to respond to a signal by turning off (or on) electrical appliances or processes. There are, however, time-sensitive uses, such as lighting, in which cases shifted time of use will not be possible or desirable.

Consumers that participate in demand response could be large, industrial plants, residential or commercial. To increase responsiveness, they could be aggregated into larger demand blocks, and they could make use of intelligent appliances, which could sense the shifting voltage of the system and respond automatically accordingly, requiring little effort by the consumer.

Demand management of a kind has been in use in a number of countries for decades. One method is to use different night and day electricity tariffs, encouraging consumers to shift consumption to night time, through night storage heaters, for example. In North America, some 60 demand-side programmes exist, in ten markets (IRC, 2010), for a variety of uses. In France, households can benefit from a much lower average tariff if they accept to have 22 days per year with a much higher tariff, which is decided with a half-day's notice. Households receive a signal — a red light on their meter — informing of them that the tariff on the following day will be much higher, and giving them the opportunity to reduce their consumption accordingly.

However, most such programmes aim simply to reduce peak demand, not to balance variations. The full potential of the demand-side resource is unknown. It will depend on the extent of the incentive to respond, and the ease with which it is possible to do so — effort, as well as economic incentive, will be key.

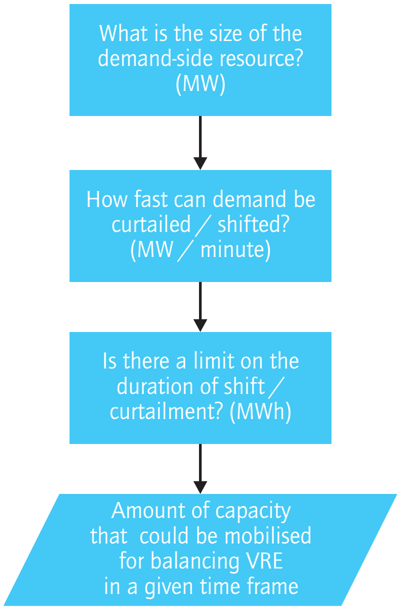
In the case studies in Part 2, the size of the demand-side flexible resource is estimated to lie between 5% and 10% of peak demand (based on the literature). Though this may be an under-estimate, it is not the absolute value that is most important. If and when data are available, they can be fed into the FAST Method to yield a more refined assessment of the flexible resource represented.

Once the resource is estimated, it remains to ascertain how fast it will respond to the needs of the system, and the duration of the period for which the response will persist (Figure 11). Both of these questions will depend heavily on the effort required on the part of the consumer and the incentive supplied by the market, which are assessed in Step 2.

Only down-ramping in demand is usual today, but the analysis considers the potential for up-ramping as well. Up-ramping may be more likely in systems with large amounts of electric vehicle demand or electrical heating, for example. As well as reducing usage in response to high prices, consumers may increase their usage in response to low prices.

As with storage capacity, there may be an energy limitation on the demand-side resource. An individual/organisation will be willing to curtail or shift consumption of electricity only for a certain time. Such

Figure 11 • *Flexible resource on the demand side*



Key point • *These questions summarise the key factors behind the technical flexible resource represented by the demand side. They do not take into account its availability, which is captured in Step 2.*

limitations will be a complex and important part of more in-depth assessments, and suggest that demand response, like storage, may be of most interest on the shorter timescale (15 minutes and 1 hour in the case studies), particularly against uncertainty.

Recent demand-side trends. Modifying electricity demand, whether through response or management, will cause least disruption to consumer service when there is a buffer period between the moment electricity is generated and the time when the service is required. In effect, such a buffer can mean that interrupting power does not interrupt the service at all.

The transformation of electricity into heat or cooling represents one such buffer. Electricity for domestic space and water heating, air-conditioning, commercial refrigeration, *etc.* can be interrupted for periods without interfering with the service provided, assuming that the refrigerator, for example, is insulated efficiently.

One very large heat buffer may be found in the storage of heat in domestic water heaters, and in the heating systems of large buildings. Because heat is easier to store than power, increasing the use of electricity for heating and cooling is likely to increase the size and responsiveness of the demand-side flexible resource.

Electric vehicles (EVs) offer a potentially large source of aggregated small-scale demand response. This depends on how charging is managed. If all fleets are charged at the end of the working day, for example, or simultaneously at some other time, the impact would simply be to increase demand for electricity at those times – *i.e.* it would be of no particular benefit to balancing. In contrast, if charging were timed to coincide with periods of surplus variable output, or periods when demand is low, EV fleets would be part of the flexible demand-side resource.

Comparing areas using the Flexibility Index

Step 1 of the FAST Method assesses the four flexible resources individually on the four timescales – 15 minutes, 1 hour, 6 hours and 36 hours. The outcome is a pair of MW figures representing the megawatts of flexible resource that can be ramped up or down, on each timescale, from a purely technical perspective. This is the flexibility that is possible, though not necessarily probable.

Simple gas turbines, hydropower, storage, demand-side management and response units, and interconnection capacity are technically able to respond fastest, and will make up most of the flexible resource available within the hour. CCGT and many coal plants will take longer to respond, and many nuclear and older steam plants may be able to respond only within 36 hours. This response is no less valuable, however: it is an important contribution to balancing capability in the longer term.

The flexible resource outputs on the four timescales for the Iberian Peninsula provide an example (Table 2). Demand-side, storage and interconnection resources are constant over the four timescales.[4] By contrast the technical resource represented dispatchable power plants increases over time as slower plants become able to contribute. The last two columns show the total technical flexible resource (TR) that is able to ramp up and down.

4. Although an energy ceiling exists on the pumped hydro storage resource, which is limited by reservoir capacity to no more than 15 hours of output at full power.

Table 2 • Flexible resources in the Iberian Peninsula

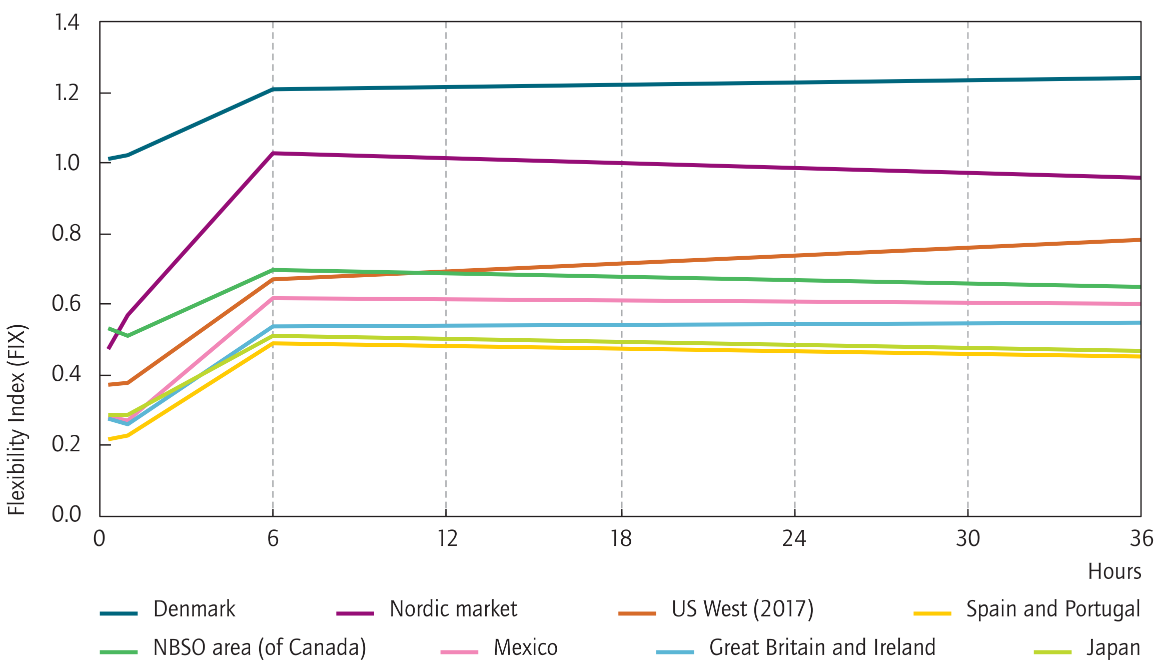
Time scale	*Dispatchable plant – up (MW)*	*Dispatchable plant – down (MW)*	*Demand side (MW)*	*Storage (MW)*	*Interconnection (MW)*	*TR – up (MW)*	*TR – down (MW)*
15 mins	5 000	7 000	2 360	5 805	2 100	15 268	15 168
1 hr	6 250	12 110	2 360	5 805	2 100	16 518	22 368
6 hrs	43 811	23 118	2 360	5 805	2 100	54 079	33 386
36 hrs	49 314	25 417	2 360	5 805	2 100	59 662	35 685

Note: With regards to dispatchable power plant, the table represents more than just the simple technical resource presented in the text so far. Directly extracted from the Iberian case study in Part 2, the figures also reflect the *likely operation* of dispatchable plants, which is discussed in Step 2 of the FAST Method, when the availability of flexible resources is the focus.

The same steps were followed for each of the eight case studies in Part 2, but the results are not yet directly comparable. If two areas have the same amount of flexible resource, this does not mean they have the same potential to balance variability and uncertainty. Other factors, most importantly the size of the area (in terms of peak demand) must be factored in first.

This analysis has developed a simple Flexibility Index (FIX), which takes into account existing needs for flexibility, and normalises flexible resources across the different case-study areas by dividing their technical flexible resource by their peak demand, after which comparison among them is more meaningful.[5] Figure 12 illustrates FIX values for the eight case-study areas over the 36-hour timescale, with values for 15 minutes, 1 hour, 6 hours and 36 hours.[6]

Figure 12 • Flexibility Index calculated for eight case study areas



Key point • The extent of the technical flexible resource, taking into account existing needs for flexibility (fluctuating demand), varies dramatically among the areas case-studied for this analysis.

5. In the chapter "Why Is Variability a Challenge?" the importance of assessing variability in the net load – *i.e.* resulting from existing and VRE needs together – is stressed. However, calculation of the Flexibility Index, which measures existing flexible resources solely, does not look at additional requirements resulting from VRE deployed, so only the existing flexibility requirement is included.

6. In each case, it is the more constrained flexibility (whether upwards or downwards) that is shown.

The main point the figure highlights is the great difference in flexible resources in each area. Denmark and then the Nordic market have far greater flexibility. Denmark, thanks to its heavily interconnected nature, can take advantage of hydropower resources in the rest of the Nordic market. On the 36-hour timescale the country shows more than twice the flexibility of the Iberian Peninsula, Japan, the British Isles, Mexico and the New Brunswick System Operator (NBSO) area of the Canadian Maritime Provinces; and nearly five times the flexibility of the Iberian Peninsula on the 15-minute timescale.

Values generally increase at longer timescales. They start relatively low, indicating that fast flexible resources are relatively scarce, and that existing flexibility requirements are relatively close in size to the technical flexible resource. Between one and six hours, there is a great leap in the flexible resource as the ability to contribute materially to flexibility comes within the reach of moderately flexible plants (*e.g.* CCGT, some coal plants). This leap is interesting as it suggests a technical capability that is in excess of present requirements.

In most cases, most of the flexible resource is able to respond within six hours. The Nordic market, the NBSO area, Japan, and the Iberian Peninsula then show a slight decrease in flexibility between 6 and 36 hours, reflecting a relatively faster increase in the extent of existing needs. In Denmark, US West (2017)[7] and the British Isles, the flexible resource either levels out or increases slightly, as the slowest resources such as nuclear (not in Denmark) reveal their flexibility value.

Denmark and the Nordic power market are known for their high penetrations of wind power. But Figure 12 reveals a much more interesting case: the FIX value in the Iberian Peninsula is the lowest of all the areas assessed, and yet in 2009 average penetrations of wind power were in excess of 12% in Spain and 15% in Portugal (Table 1).

So what is different in the Iberian Peninsula, and other areas, that such penetrations can be managed effectively while lower penetrations in some areas with greater flexible resources are already causing consternation? Something other than the technical flexible resource must be significant. Step 2 of the FAST Method captures this additional element — by assessing the *availability* of flexible resources.

In other words, the FIX values in Figure 12 show only part of the picture. For example, Japan and the Iberian Peninsula may, as shown, have a similar flexible resource relative to their size; but grid and market configurations in the two areas may be very different, with the result that less of the resource is available in one than in the other for balancing variability.

In more refined analyses, ideally led by system operators, FIX should be calculated based on the available flexible resource — *i.e.* once potentially major constraints have been factored in. These constraints will be explored in the next chapter.

7. The US case study was carried out for the Western Interconnection for the year 2017, based on the results of the recent Western Wind and Solar Integration Study (GE Energy, 2010).

7 • How much of the flexible resource is available?

The availability of flexible resources for use in balancing variability and uncertainty may be more constrained in one area than in another. For example, the fact that balancing is carried out over the whole Nordic power market area, as one, means that the flexible resources in one country will be available to all. If the constituent countries of Norway, Sweden, Finland and Denmark were balanced separately, flexible resources (and accompanying costs) would have to be replicated in each.

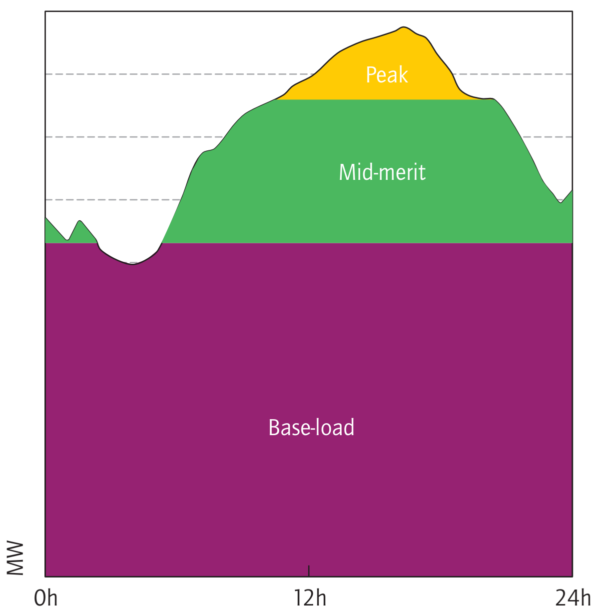
This chapter looks at likely constraints on each of the flexible resources in turn: dispatchable power plants, energy storage, interconnection and the demand side. It then examines key constraints on the flexible resource as a whole, relating to the transmission grid, system operation and power markets.

The impact of some of these constraints will be easier to quantify than others, always assuming data are available; increased uncertainty resulting from not using VRE output forecasting in system operation is one example. Others will be more time-consuming/technically complex to quantify — even if data do exist. For example, it will be a highly complex task to assess the impact of internal grid constraints on availability. Such complexity put quantification of these constraints beyond the scope of the case studies in Part 2. Instead, they are scored and weighted qualitatively to provide a first indication of their magnitude. More refined assessments should attempt quantification as these constraints can be of great significance.

Dispatchable power plant availability

The principal constraint on whether or not a given dispatchable power plant is actually available to ramp when needed will be its operating state at that time — if it is already at full power, for example, it will be able only to ramp down. The key factor here is whether a plant is base-load, and likely to be running most of the time; mid-merit, and likely to be running when demand is high; or peaking, running during relatively short peak periods.

Figure 13 • A fairly generic load curve example



Key point • Over the 24-hour period, base-load plants tend to operate continually. Mid-merit plants ramp up to cover higher demand during the day, while peaking plants operate only during short peak periods.

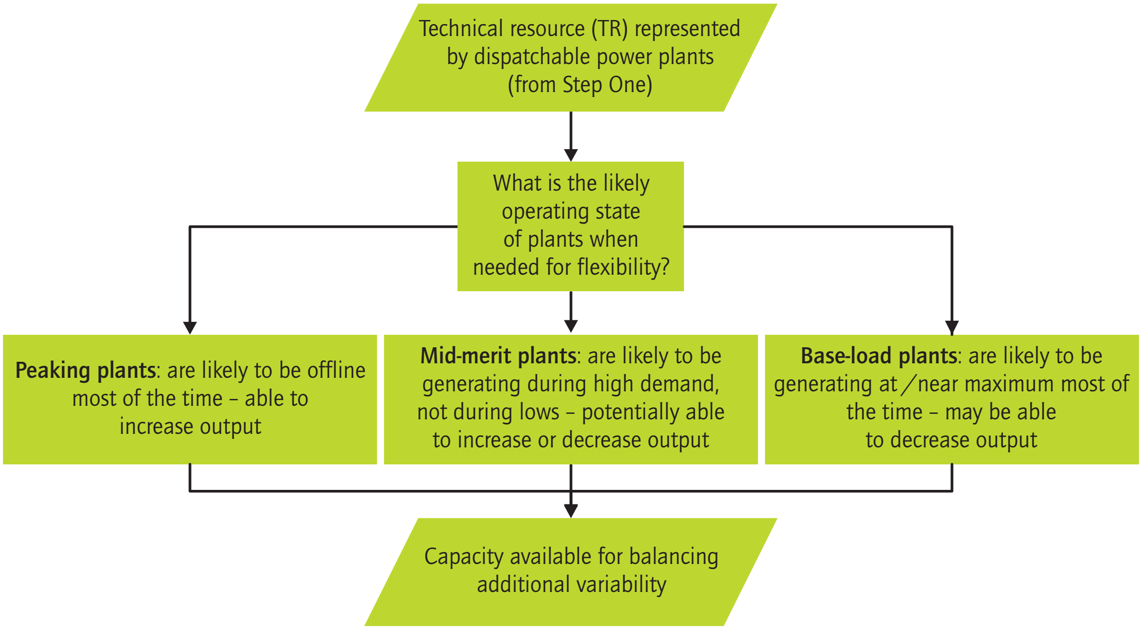
The demand profile (or load curve) of the system will be the decisive factor as to whether plants are online, and at what level. Figure 13 illustrates a generic load curve. The time of day indicates the likely state of base-load, mid-merit and peaking plants.

If a plant is more costly to run, it will be lower on the merit order. This means it is more likely to be offline, and will therefore be available only to ramp up (*i.e.* when net load increases). Such plants are often peaking plants and the most flexible (such as open cycle gas turbines), which can offer their full capacity at short notice — indeed they are likely to have been installed specifically with this aim in mind (Figure 14).

If the plant is less costly to run at maximum output than minimum, such as a nuclear plant, it will likely be operating at that higher output, and will be available only to ramp down.

Other plants will be operating somewhere between their minimum and maximum stable levels, and so could potentially be available to ramp up or down.[1]

Figure 14 • Availability of dispatchable power plants to provide flexibility



Key point • A plant's operational state will determine its availability to contribute to flexibility.

Energy storage availability

Energy storage, such as pumped hydro facilities, may be available to provide flexibility when needed. If it is controlled by or contracted to the system operator (SO), it is more likely that it will be used against variability and uncertainty in the net load. This will be particularly important if the amount of energy that can be stored is small.

It is essential that use of the facility in this way is economically attractive to its owners. Otherwise, they might simply to take advantage of differences in price at different times (*e.g.* day and night) — storing when electricity is cheap, and producing when it is expensive — rather than operating dynamically in response to system flexibility needs.

Constraints on availability of pumped storage may result from fisheries regulation, for example, or daily limitations on reservoir output for other reasons. The case study of the US Western area suggests significant constraint on the use of pumped hydro storage to provide flexibility, resulting from other water uses such as provision of potable water.

If storage facilities are located in an area that may be isolated at times due to weak local transmission, they will not be available at those times against flexibility needs. On the one hand, if storage is located nearer to VRE power plants, it could help make better use of new transmission capacity built to connect

1. To ensure the availability of reserves against existing flexibility needs, some plants that might otherwise be expected to be at maximum will instead be operating at around half power.

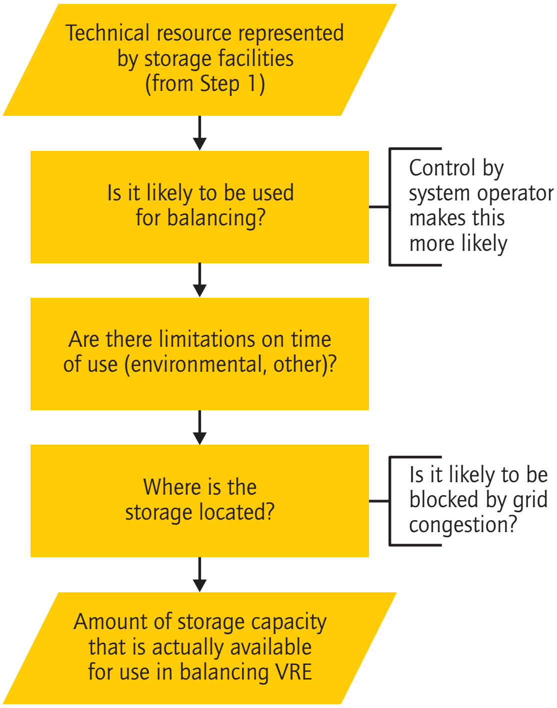
the VRE to the existing grid.[2] On the other hand, dedicated storage for individual VRE power plants is likely to encourage overcapacity in the system as a whole. In the case studies in Part 2, it is considered preferable for storage facilities to be located near to demand centres, where the grid is likely to be stronger, and where storage is more likely therefore to be able to serve the flexibility needs over the entire system.

Interconnection availability

The value of interconnection to adjacent power systems is not simply its capacity in megawatts. It depends on its availability to provide flexibility in the balancing timeframe. Equally important will be the extent to which the needs of interconnected areas coincide; connected areas will have need of flexibility at different times. Figure 16 captures the aspects that will have bearing on the availability of interconnections.

Interconnection to multiple areas is preferable to operation as a single area: if the required flexibility is not available from one area, it may be from another. Additionally, multiple connections (to a single area) are better than a single line, as they will reduce the risk that internal congestion in the interconnected area will block the flow of flexibility.

Figure 15 • Availability of storage facilities



Key point • These questions summarise the key factors behind the availability of storage facilities to contribute to flexibility.

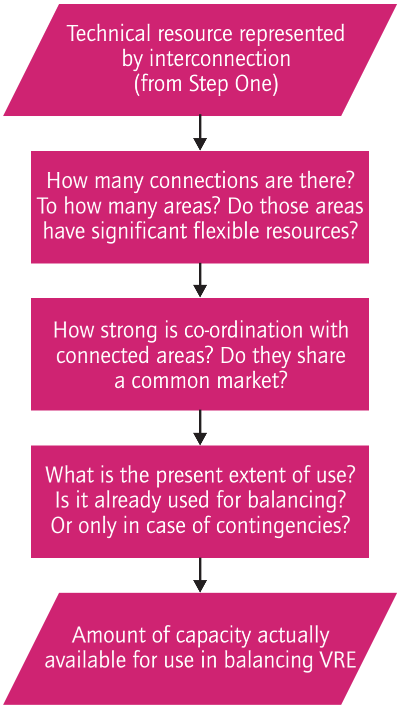
Effective, real-time co-ordination among system operators is important where interconnectors are used on a daily basis. Neighbours can interact in a number of ways. Connected areas may participate in a single market, like the single electricity market (SEM) including Northern Ireland and the Republic of Ireland, which share balancing responsibilities. Others may share flexible balancing resources through market coupling or some other mechanism.

Either case will reduce the constraint on line availability for balancing. It is important to have common rules and schedules for allocation of capacity. The absence of commonality would reduce the flexibility of use of the line: for example, gate closure (last bids and offers to market) in markets on either side of an interconnection may occur at different times; or insufficient cross-border price information may restrain trade.

Other possible constraints include capacity being allocated (sold) separately to the trading of electricity (explicit auctions), as opposed to being decided alongside the electricity trade itself (implicit auctions). Either way, the use of interconnection capacity may be allocated well in advance, on a yearly, monthly, weekly or daily basis. Day-ahead allocation is common, as is expected to be the case with the new BritNed cable, which is to provide a degree of market coupling between Great Britain and the Netherlands (OFGEM, 2010). Even day-ahead allocation will severely limit availability for balancing, although the interconnection may still be of use against a forecast weather front predicted for the day or days ahead.

2. When wind or solar plant, for example, is producing above the capacity of the transmission line, the excess can be stored and released when output drops below the capacity of the line. This can help reduce curtailment of VRE output, overloaded transmission line capacity, or both.

Figure 16 • *Availability of interconnection capacity*



Key point • *These questions summarise the key factors behind the availability of interconnections to contribute to flexibility.*

Capacity may be held back against contingency use. A significant proportion of transmission capacity in the European mainland area, for example, is allocated in advance among system operators for use in case of unexpected losses of power plant in one or other area.

Finally, if a transmission line is already exporting continuously it will be of little additional use against additional upwards variability or uncertainty in output, leading to a surplus that will need to be disposed of. Similarly, if a line is generally importing at maximum, it will not be useful when VRE output drops during high demand, and the import of additional energy is needed to meet the gap.

Broadly speaking, the most suitable line in terms of balancing additional variability is one used commonly both to import and export, such as connections between Denmark and Norway — which are already of vital use in the balancing of wind energy variability.

Demand-side availability

Consumers may be technically able to respond to a price signal by increasing or decreasing their consumption. But is such a signal available? And, if so, is it strong enough to achieve the desired response? Alternatively, consumers usage may be managed remotely by the system operator on a contract basis (demand management, rather than response).

Assuming that the demand side will respond with enough certainty to be useful to the system operator in the balancing process — *i.e.* that incentive is great enough and effort required small enough — the responsive resource may be a more valuable source of flexibility than the alternative (managed) resource. This would particularly apply if managed resources could only be triggered on a day-ahead basis or earlier, or in case of contingency.

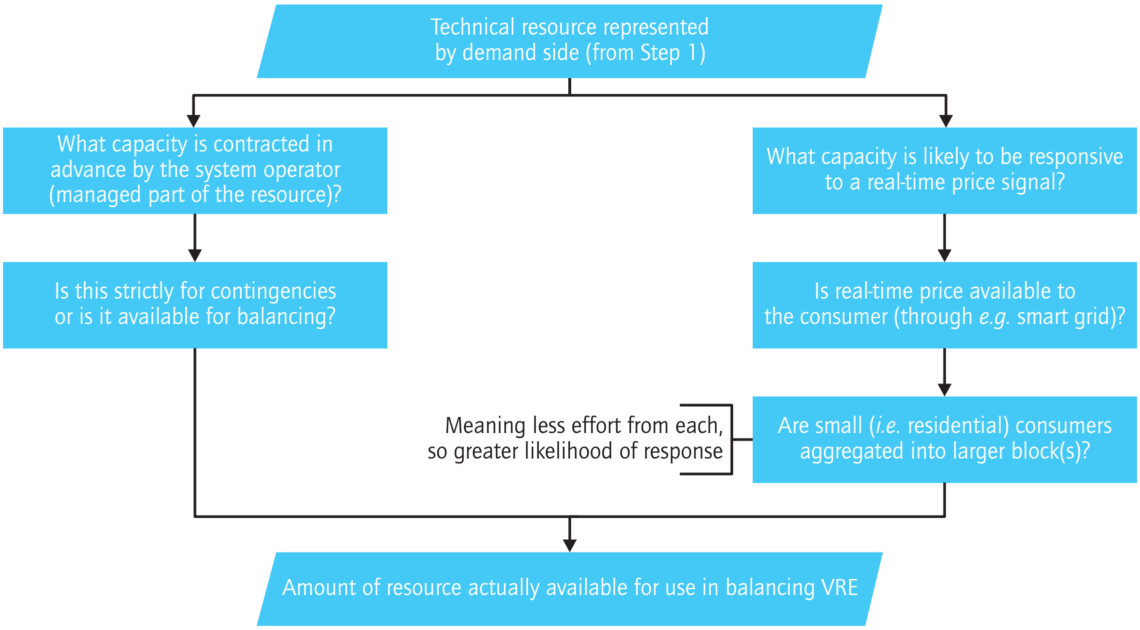
The value of managed resources could be improved by near-to-real-time communication between the system operator and contracted consumers. The fact that they are contracted in advance might then be advantageous, as it would mean their availability would be certain. So when assessing the demand-side flexible resource, it is the lag on availability, rather than whether it is responsive or managed, that is most relevant.

If consumers are actively responding, advanced metering is likely to be necessary to signal the amount of response needed, and to predict and monitor the actual response. Smart meters are not the only way to transfer the price information which stimulates that response, however: in the United States, for example, a number of demand-response programmes are based on use of the Internet.

Small-scale (domestic/commercial) response may be aggregated into a single party, which can then offer the market blocks of demand response. This will have the effect of reducing the effort burden on individual consumers that might otherwise be a disincentive to respond (particularly in the absence of automation through smart appliances, *etc.*). Large industrial consumers, meanwhile, for whom significant cost saving may be possible, are more likely to bid in directly.

Different types of flexible resources may interact in such a way that their combined value is greater than if used/assessed separately. Strong interconnection between two areas would make it possible for consumers in one to provide flexible response to needs in the other, adding to the value of that response resource.[3] Very extensive market collaborations, spanning two or more time zones, could potentially lead to a very large flexible resource.

Figure 17 • Availability of the demand side



Key point • These questions summarise the key factors behind the availability of the demand side to contribute to flexibility.

Grid strength and intelligence

The existing grid is the most important governor of whether or not the four flexible resources (dispatchable power, demand side, storage and interconnections) will be available for balancing when needed.[4] Congestion of important transmission lines may isolate parts of the grid, separating VRE power plants and flexible resources, and reducing opportunities to share resources. To minimise the chance of congestion, there needs to be spare capacity throughout the transmission network. Some of the key factors that will govern the potential constraint are shown in Figure 18.

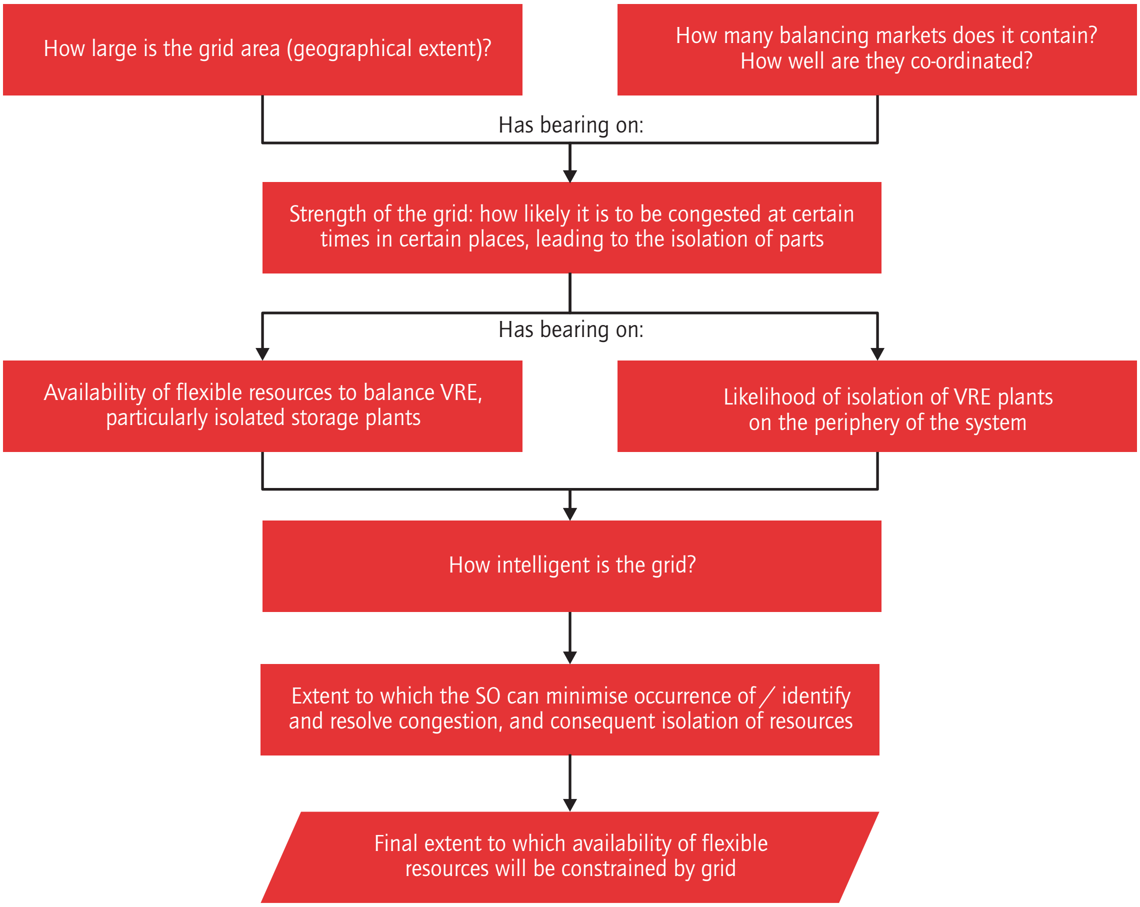
The size of the area, its distribution of demand centres and variable renewable resources, and the number of distinct markets it contains will all have important bearing. Where demand is weaker, the grid is likely to be weaker. This may mean large areas between demand centres are relatively weakly served. This will be even more problematic if the VRE resource is located predominantly in such areas. If the area contains more than one market, and particularly if co-operation among them has been historically low, the grid is likely to be weaker at the boundary between them.

Grid reinforcement to reduce congestion can be a lengthy process, particularly if it involves new transmission corridors or major upgrades to existing lines (*e.g.* bigger towers, sub-stations). Public antipathy alone can cause delays measured in years or even decades. The same may apply to new interconnection capacity with neighbouring areas.

3. This assumes that markets on either side of the interconnection co-operate.

4. In some analyses, the internal grid is itself considered a source of flexibility, much like interconnection with neighbouring systems. Here, grid is not considered an additional source of flexibility: at best, it represents a minimum constraint.

Figure 18 • *Constraints on availability represented by the grid*



Key point • *Depending on its strength and intelligence, the area's grid will represent a greater or lesser constraint on the ability of flexible resources to participate in the market place, for balancing.*

How intelligent is the grid? It is important to identify early on what can be done to improve the operation of the existing grid, particularly in the light of potentially long lead times for deployment of new transmission. For the purposes of this report, the intelligence of a grid is taken to mean that which enables the system operator to manage the supply and consumption of power in an optimal way through innovative technologies, such as high temperature conductors, and operating techniques.

Advanced operation techniques can complement upgraded hardware in managing congestion. or bottlenecks. One such option is a method of improving the use of existing transmission capacity called dynamic line rating (Box 5).

The objective of intelligent grids (or "smart grids", as they are often called) is to use existing capacity more efficiently. This means minimising unused capacity while maintaining reliability of electricity supply from centralised power plants (conventional and variable) and smaller plants producing at the distribution level.[5] Besides the minimisation of grid congestion the main importance of intelligent grids as concerns this analysis is to enable demand-side response.

5. Though this analysis does not consider distributed generation, it is an increasingly important factor in a number of systems. Distributed power plants, sometimes referred to as "embedded", tend to be small (up to a few MW) or perhaps just a few kW of solar PV installed on the roof of a domestic consumer. They will be connected to the low voltage grid.

Box 5 • Dynamic line rating

The temperature – and therefore effectiveness – of an overhead line is affected by ambient weather conditions, such as temperature and wind speed. Higher temperatures reduce the effective carrying capacity. With this in mind, it is common practice to assume worst-case ambient values to establish a maximum capacity carrying that can be relied upon under all conditions. This is then used as the capacity rating of the line.

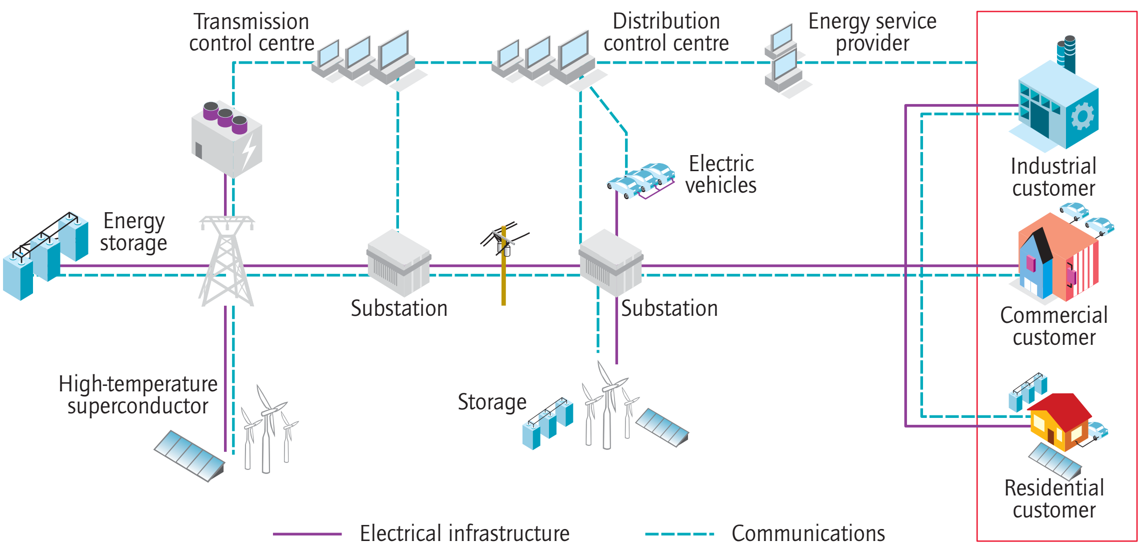
But if line temperature is monitored in real time, then during cooler periods when the actual carrying capacity of a line is greater than rated, this additional potential could be exploited. This may be particularly relevant to wind and wave power integration, given that higher output from such plants will occur when wind speeds are higher, resulting in the cooling of the line in question.

In practice, dynamic line rating has been shown to enable up to 50% more transmission capacity – and when it is needed most. Over 300 transmission line-monitoring systems have been installed at 95 utilities in many countries, including the United States, Canada, the United Kingdom, Finland, Sweden, Denmark, Belgium, Germany, Spain, Argentina, Norway, Poland, the Netherlands, Brazil, Australia, New Zealand and the Middle East (Ecofys, 2008).

It is not just about flexible flow of electricity: an intelligent grid can sense and exchange information relating to excess and scarcity instantaneously throughout its extent, with the result that electricity suppliers and consumers can modulate production/consumption accordingly.

Figure 19 illustrates the role of an intelligent electrical grid in linking conventional and variable power plants, storage facilities and demand-side units, and the importance of communications among all elements with transmission and distribution system operators.[6]

Figure 19 • Power system interaction through an intelligent grid

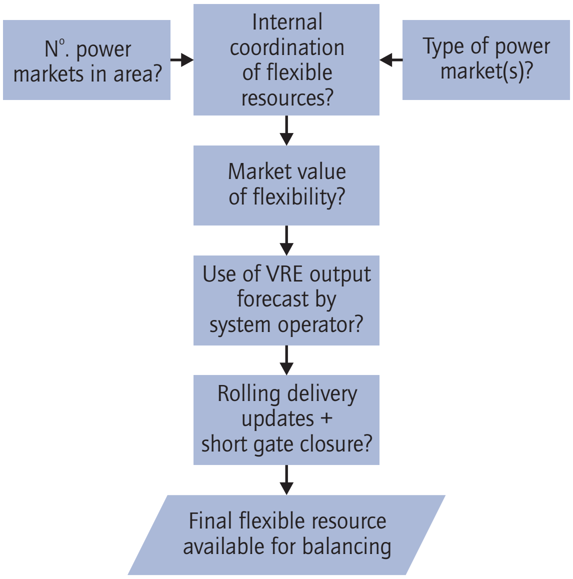


Source: IEA *Smart Grid Technology Roadmap*, April 2011.

Key point • Intelligent grids allow the two-way flow of information and electricity between consumers and suppliers of electricity, while sensing weaknesses and correcting for them.

6. In most large systems, the lower voltage distribution grid is not actively managed at present. The role of distribution system operator (DSO) alongside the transmission system operator (TSO) may become more important.

Figure 20 • *Operational and market constraints on availability*



Key point • *These questions determine whether or not the best use will be made of available flexible resources in the market place, for balancing.*

Potential market and operational constraints

The way a power system is operated, and how electricity is traded in the power market (if this exists)[7] can drive or constrain the availability of flexible resources. This chapter describes a number of the most important factors: co-ordination of markets, electricity trading mechanisms, the markets' stimulation of flexibility, and the use of VRE output forecasting in system operation. These are summarised in Figure 20.

Most market and operational factors are readily modifiable compared with more fundamental attributes such as the dispatchable plant portfolio or transmission strength, as little new hardware will be required. But they do require careful planning and considerable regulatory effort.

A number of developed economies, particularly those where VRE deployment is going ahead more swiftly, are working to counter these market and operational constraints. Exploring these aspects can identify near-term gains in flexibility, and so improve an area's VRE deployment potential.

Co-ordination and merging of balancing areas

If a region contains a number of distinct power markets, the quality of interconnection and co-ordination among them will influence the availability of the flexible resource over the area as a whole. One particularly salient case that emerged from the case studies in Part 2 is that of Japan – in which ten areas, each managed by a separate utility – see virtually no collaboration in balancing.

This section discusses not power market collaborations but rather co-ordination among distinct balancing areas within those markets. These predefined areas can represent significant barriers to the sharing of balancing resources over the larger market, particularity if they are operated according to different rules, or if interchanges among them are scheduled rigidly.

The term "balancing area" can signify different degrees of isolation; in flexibility assessment, the focus is simply on whether or not balancing areas represent additional isolation (Box 6).

For instance, each of the four countries in the Nordic Power Market area is a balancing area in its own right, but balancing is co-ordinated among them so effectively that the whole market can be said largely to be balanced as one (within the bounds of transmission constraints).

7. In many countries, open power markets do not exist, in which case power supply is managed by a utility/utilities controlling production and supply of electricity.

Box 6 • Balancing areas

Whatever the source of electricity, whatever resources exist to balance supply and demand, the sub-area of the power market over which balance is maintained as a unit — the balancing area — is central to the challenge.

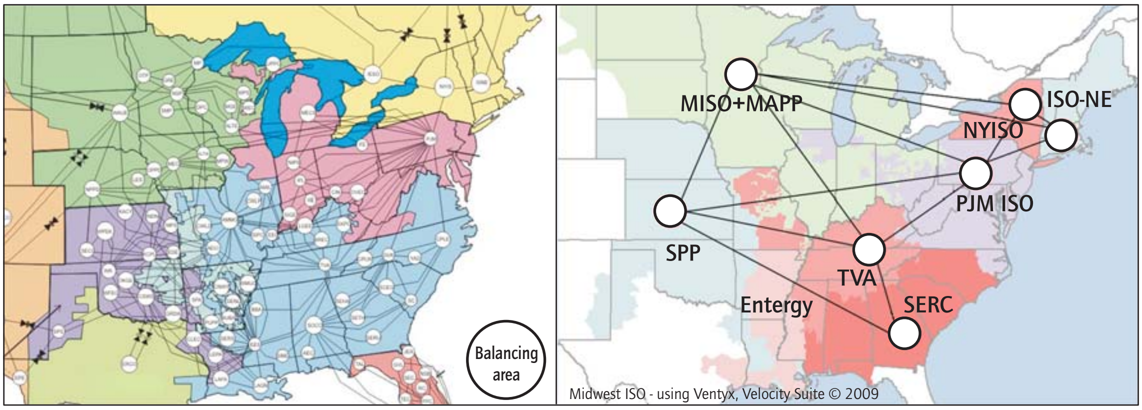
Balancing areas are defined to a large extent by the historical development of the grid (often comprising originally separate sections), and by the distinct utilities and institutions that drove that development and persisted subsequently. Protocols will exist governing the flow of electricity across these boundaries, and long-term collaborations may exist; but these may not necessarily allow for interchanges of electricity inside the balancing timeframe. Coupled with congestion in (weaker) border areas, this will hinder shared balancing activities.

The balancing of large proportions of variable electricity production can be challenging in smaller areas. Larger (effective) balancing areas have greater flexible resources to deploy, and benefit substantially from smoothing of both load and VRE generation through geographical and technological diversity.

As with power markets, non-cooperation among neighbouring balancing areas may duplicate the use of flexible resources unnecessarily: when one is balancing an up-ramp, its neighbour may simultaneously be balancing a down-ramp. If the areas were operated as one, or merged, opposing needs would cancel each other out to some extent, resulting in a common pool of flexible resources now able to balance a larger share of variable electricity production.[8]

The recent Eastern Wind Integration and Transmission Study (EWITS) carried out in the United States illustrates an effort to achieve much greater integration over a large area (Figure 21).[9]

Figure 21 • Balancing areas in the eastern United States in 2007 (left), and assumed in 2024 (right)



Source: EnerNex Corporation, 2010.

Key point • From several dozen balancing areas in 2007, just seven are assumed for 2024, enabling improved co-ordination of flexible resources over the Eastern Interconnection of the United States.

The left-hand image shows the large number of balancing areas (white circles) in the Eastern Interconnection in the United States, as of 2007. The right-hand image represents an assumption made by the EWITS team, based on trends towards consolidation observed over the last decade, that by 2024

8. Resources against stability and adequacy requirements are another matter.

9. Performed by the EnerNex Corporation for the US National Renewable Energy Laboratory.

the number of balancing areas will have shrunk from several dozen to just seven. Moreover these seven are assumed to operate according to coherent rules and schedules. This is considered to be a crucial step towards the ability of the Eastern Interconnection to manage a share of wind power equal to 20% of total electricity demand.

Significantly, in the 2007 case, multiple balancing areas exist in individual power markets (shown by the different colours), representing an additional level in the balancing hierarchy of the overall Eastern Interconnection (interconnection → power market → balancing area). In contrast, in 2024 each power market is assumed roughly to correspond to a single balancing area, in effect removing the distinction in balancing terms.

Electricity trading

The key question here is whether or not the bulk of trading between producers, suppliers and consumers of electricity is done in a way that allows the flexible resource to be used in balancing. Trading may be done in a number of ways where an open market exists (one comprising independent, unbundled power producers, transmission owners and suppliers). Options and combinations vary considerably throughout the world, and terminology is often used differently. This section includes a few examples but is far from exhaustive.

There may be a predominance of contracts to buy and sell electricity in the market several months ahead, based on projected demand. In such cases, the market may lack the necessary liquidity to make available all of the technical flexible resource. If power plants that might otherwise be capable of providing the flexibility service are locked into immutable contracts far in advance of when that service is needed, they will be of no use in correcting imbalances. To deal with these in the short term (*e.g.* inside an hour), the system operator may enter into contracts with power producers to provide reserves.

Additionally/alternatively, trading may occur on exchanges, through which electricity can be traded on the basis of bids and offers. If the bulk of trading happens in this way, closer to the time the electricity is actually used, more of the flexible resource will be available to respond to needs resulting from variability and uncertainty.

In Great Britain, for example, where the majority of electricity is traded through contracts agreed several months ahead, only a very small proportion (4%) is traded through an exchange, so limiting flexibility.[10] Box 7 provides some additional information on power exchanges.

Box 7 • Power exchanges

In the British exchange, the majority of electricity traded is on the day-ahead timescale, via blind[11] auction. Power producers, suppliers, large consumers and traders submit anonymous orders to buy or sell, on which basis the market price for each hour of the following day is calculated. A separate spot market, mainly used for balancing, is operated closer to the time of operation.

Important exchanges, operated by independent system operators (ISOs)[12] in the United States include PJM Interconnection, and ISOs in New York State, California, the Midwest and New England. In the Nordic Power Market, the Nord Pool Spot Market is the largest in the world, trading 70% of the total electricity consumption in the Nordic Countries (Denmark, Finland, Sweden and Norway).

10. The APX-Endex exchanges are largely owned by system operators, and operate in Great Britain, Belgium and the Netherlands. See www.apxendex.com/index.php?id=150.

11. Members cannot see other bids/offers submitted.

12. Often called regional transmission organisations (RTO) in the United States.

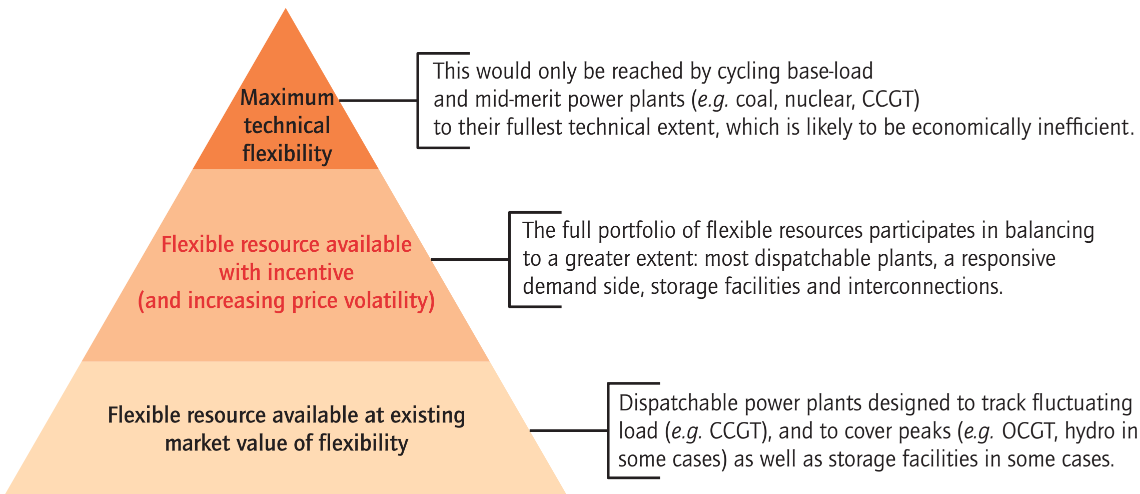
In other markets it may be mandatory to trade through a common pool. In the Single Electricity Market, established in 2007 in Ireland, all producers and suppliers of electricity must place their orders in this way. The pool also includes all electricity imported to/exported from the island. All parties then receive/pay the prevailing price generated for each half-hour trading period.[13]

Japan illustrates an interesting alternative. Each of its ten vertically integrated utilities balances the area in which it sits, and as such is itself in a position simply to reschedule and dispatch flexible resources across it, as and when needs arise. However, other aspects of the vertically integrated model may constrain deployment of VRE in other ways – such as open grid access for independent power producers, and potentially limited collaboration with neighbouring areas.

Does the market stimulate flexible behaviour?

If the operators of flexible resources such as dispatchable power plants are to respond to rising flexibility needs, they will need adequate incentives to do so; Figure 22 depicts how incentives and price volatility would affect the availability of the flexible resource.

Figure 22 • Effect of incentive on available flexible resources in the market place



Key point • The value already associated with flexible resources (for balancing fluctuating demand) may need to be enhanced to make more of them available.

The existing level of incentive will be the result of present market forces. Periods when power is scarce – when demand peaks at its highest levels – can already cause electricity prices to spike many times above the average. These are essentially the occasions when the fastest flexible resources are scarce; they indicate the potential revenue to flexible resources which can respond in time, or contract themselves to the system operator for provision of reserves.

In some areas where variable (wind) power plants have already been deployed in large numbers, more frequent and extreme price volatility has been observed. In some cases, as in the Nordic and West Texas markets, even negative prices are occurring on occasions of surplus wind power output.

The phenomenon of price volatility may facilitate more flexible resources. If consumers have access and can respond to market prices, they will have more incentive to shift their electricity use than

13. System marginal price.

under normal conditions. Storage plants, many of which see their main revenue from taking advantage of off-peak to peak price differentials, could fill up when the price is at bottom. Co-ordinated interconnection among neighbouring markets could widen the opportunity to benefit in this way.[14]

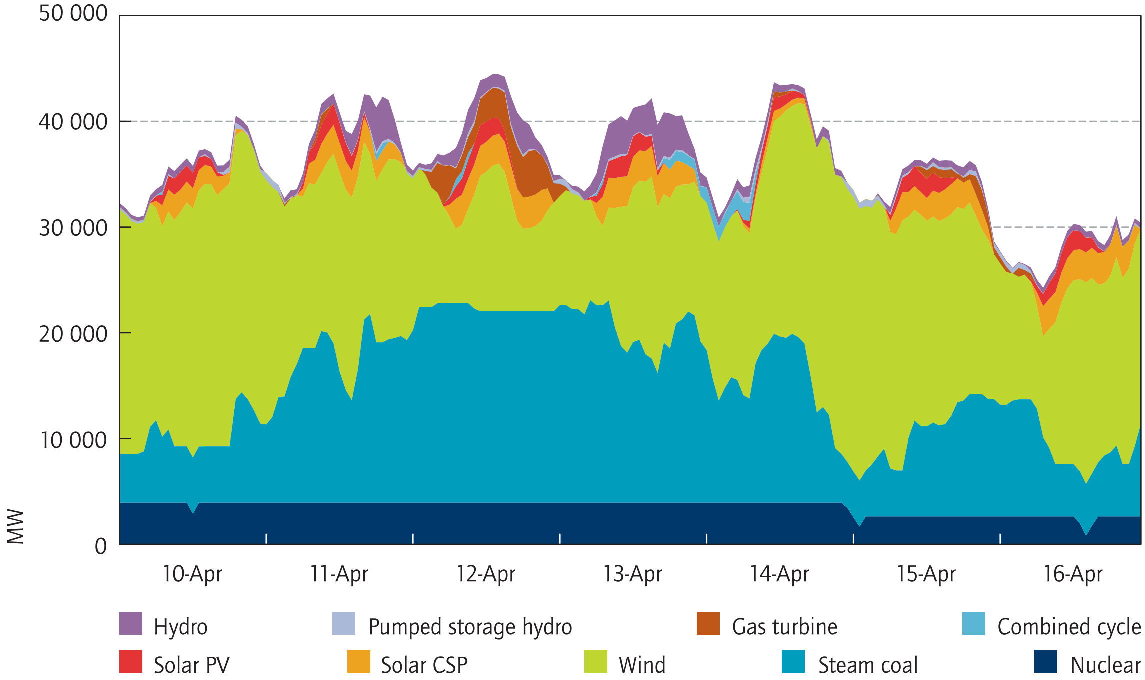
So it is possible that greater price volatility resulting from VRE deployment may trigger an increase in the availability of the most flexible resources – but will this increase be enough to meet growing needs? Quantitative analysis remains to be done on the extent of price volatility and the duration of extreme (high or low) prices, and the potential benefits these might represent to owners of flexible resources.

Reduced revenues for less flexible plants. An equally important question relates to the effect on less flexible power plants in the portfolio. VRE power plants tend to be allowed to generate at maximum (when the resource is available), with minimum curtailment. This is partly because their short-run marginal costs are very low (no fuel costs), and partly because government policy may deem that it should be so, as is the case in areas where such technologies are supported with priority dispatch, through a feed-in tariff, for example.

As only a certain amount of electricity is required by the market at any moment, this means that VRE output will displace energy production by other types of plant. At first, only mid-merit plants will be affected, but as VRE penetration increases, even base-load plants (*e.g.* nuclear, geothermal, some coal) risk falling revenues and higher cycling costs as they, too, are displaced. If a base-load plant is built in the expectation that it will operate for 7 800 hours per year (90% of the time), the loss of a small part of this operating time could seriously reduce profitability.

The recent *Western Wind and Solar Integration Study* carried out for the US National Renewable Energy Laboratory in the United States simulates the effect of a 35% VRE share in annual electricity on the output of other power plants (Figure 23).

Figure 23 • Effect of 35% variable renewables in the West Connect area of the United States



Source: GE Energy, 2010.

Key point • Electricity from existing mid-merit and base-load dispatchable plants will be displaced as VRE penetrations increase, increasing their need to cycle and reducing their revenue at such times.

14. Moreover, the result of these responses would be to reduce the incidence of negative prices, and return a degree of equilibrium to the market.

The April week illustrated was considered by the study team to represent one of the most challenging weeks simulated, in integration terms. Mid-merit steam coal is forced by high VRE output from wind and solar to cycle much more than it would be expected to do otherwise, while even nuclear output must ramp down on occasion.

The importance of this phenomenon is that it may grow large enough to encourage owners to mothball existing base-load plants (perhaps the older, less efficient ones) whose revenues are now insufficient to justify their operation. It could also discourage investment in new plants.

Perhaps new, more flexible coal and nuclear power plants will be designed to cover a more volatile base load? But even if technically more flexible, new plants may still be insufficiently attractive investments in markets based on marginal costs of generation as is the mainly the case today.

To a certain extent, current power markets may provide an incentive for investment in base-load plant. Capacity scarcity caused by previous mothballing old plants or underinvestment in new ones would lead to rising electricity prices in times of scarcity. But the risk is that by the time the signal is powerful enough to trigger investment – if a lull in investment has indeed occurred – the system's room for manœuvre may already be insufficient and it may be already experiencing power shortages.

Gauging the need for a flexibility incentive. Two key questions need to be asked in an area targeting large-scale deployment of variable renewables:

- Does the market offer enough incentive to make the *existing* flexible resource available to cover increased fluctuations in the net load resulting from VRE deployment?

- In the light of reduced revenue to base-load plants, is there enough incentive for owners/investors to continue to operate/build such plants – which are important for balancing on the day/days ahead horizon, and for system adequacy?[15]

In other words, can market forces alone stimulate owners and investors to behave in a way that will guarantee flexibility and reliability; or do governments need to provide additional incentives to ensure flexible operation of existing plants and continued investment in new ones, as and when needed?

Sufficient flexible resources must be maintained to avoid a threat to security of supply. One way to ensure this might be through a regulated premium for a flexible service, over and above revenue based on electricity produced. This would have to be calibrated carefully to stimulate both the desired availability of existing flexible resources and timely investment in new resources.

Designing and calibrating such a mechanism is not in the scope of this study, but two principles have emerged from it. First, the objective should be to reflect the full value of flexible capacity, and to reward it accordingly. Flexibility is of value to the system as a whole, so the net cost or benefit of measures to increase it should also be distributed over the whole system.

Second the mechanism should first and foremost target the availability of existing flexible resources, which as suggested below may be considerably larger than usually supposed. Only then would it be possible to assess accurately the scale of investment in additional hardware needed, and so avoid unnecessary expenditure on duplicating flexible capacity.

That said, it should be noted that, at some threshold, it may become cheaper to deploy new flexible resources than to extract the very last bit of flexibility from the existing resource. For example, the marginal gain in flexibility from ramping an old coal plant to its outer technical limits (Figure 22) may be disproportionately costly in terms of lifetime, operating cost, and greenhouse gas emissions,

15. A third question arises, but one which is outside the scope of this study: will the system remain adequate to meet (rising) peak electricity demands reliably, in the long term? Although VRE plants do provide a measure of firm capacity – capacity that can be relied upon most of the time – they provide less of this than conventional power plants. See Box 2: Other integration challenges.

compared to deploying new capacity. Indeed in the case of flexibility through influencing demand side behaviour, which is likely to be a relatively cheap measure, this threshold may be reached relatively early.

Flexibility incentives today. Flexibility incentives targeting the balancing timescale exist in one form or other in a number of markets today. These target (mainly) dispatchable power plants. A balancing market may provide the opportunity to sell electricity at a higher price in the hour-ahead or even inside the hour. The difference between this and the day-ahead price may encourage producers to trade through this market as well as through the day-ahead market.

The operators of power plants may be paid to hold capacity in reserve, effectively a premium for being available to ramp as required right up to the last minute, as is the case in the Nordic market. But such arrangements are often contracted well in advance so they will not reflect dynamic needs for flexibility and will inevitably, on occasions when the imbalance actually encountered is small, result in unnecessary payments.

Although dispatchable power plants have been the focus of this section, the same principal applies to demand-side, storage and interconnection resources. An effectively designed mechanism would optimise the availability of all four sources of flexibility, according to their relative costs and the flexibility service they can provide.

Forecasting VRE output

Accurate forecasting of output over a period of up to several days is a vital part of the system operator's toolbox for balancing, especially for those with ambitious VRE targets.[16] The sooner a ramp in output is predicted, the sooner the operation of flexible resources can be planned to cover it. More accurate day-ahead predictions will make it possible to use more of the slower response flexible resources (*e.g.* coal and nuclear plants) in balancing fluctuations. As a result, faster resources can be kept for when they are most needed — against more extreme variability and uncertainty.

This is important as the fastest resources may be scarce. These may include spinning reserve,[17] hydro or simple gas turbines, demand-side resource and storage. Interconnection to adjacent power areas may also provide fast flexibility, if it is operated flexibly.

If the forecast were 100% accurate, the flexible resource available in each time span would need only to amount to the maximum ramp in the net load that the system will encounter, plus a margin to cover contingencies. However, this is not the case. Error in the forecast means that some of the most flexible resource will need to be held back to cover the resulting uncertainty. For example, against a predicted change in the net load over six hours, the slower resources alone that can respond to the variability seen in that time span will not be enough. Some of the fastest resource will need to be available also in case the electricity delivered proves to be greater or less than predicted.

While today's forecasts, particularly on the day-ahead, are not perfect, it is possible to predict the overall shape of electricity output most of the time with current techniques, and more advanced techniques are under development. However, large deviations can occur both in level and timing, resulting from extreme events that are difficult to predict. Forecasts are more accurate over larger areas, as forecast horizons decrease, and when multiple forecast techniques are combined. As an example, Table 3 shows mean forecast errors for wind power in Germany.

These are yearly mean values, and represent the total amount of power that will be needed over these timescales for balancing wind energy. The megawatts of capacity of flexible resource needed to balance such errors will be related to the size — in megawatts — of the largest forecast error.

16. Present targets in OECD countries range up to 50% (Denmark) of electricity.

17. Spinning reserve is that part of the capacity of a generator that is already operating, which is held in reserve for fast response to the system operator's needs.

Table 3 • Mean errors in wind power forecasts (% of installed wind capacity)

*Uncertainty**	*Part of Germany (≈350 km)*	*All of Germany (≈ 1 000 km)*
Day-ahead (up to 36 hours)	6.8%	5.7%
4 hours ahead	4.7%	3.6%
2 hours ahead	3.5%	2.6%

Note: Uncertainty is measured in terms of root mean square error (RMSE), normalised by capacity. RMSE is a standard statistical tool to measure the difference between any estimation and the real value.

Source: Rohrig, 2005.

Although dedicated forecast technologies for solar PV are at an early stage of development, preliminary experiences suggest PV output uncertainty may be less than for wind power (Enel, 2010). Box 8 describes recent experiences in Spain.

Box 8 • Spanish PV experiences

Spain began to coordinate the prediction and scheduling of output of solar PV power plants in November 2009, following developments in national policy.[18] At present, there is insufficient forecast accuracy, particularly beyond 6 hours, to be depended on when planning the dispatch of the system as a whole (ENEL, 2010). This is to some extent mitigated by the fact that the pattern of PV output is complementary with peak demand. This effect also supports the transmission network, particularly as most units are distributed (rooftop) installations.[19]

The Guadarranque solar PV plant in Spain has an installed capacity of 12.3 MW, comprising 123 installations of 100 kW. It was connected to the grid at the end of 2008. Daily forecasts are done using simulation models fed with production and meteorological data. The inaccuracy in daily production forecast over the period August 2009 to September 2010 was around 50% on average, the lowest value being 25.4%. Although it is not the accuracy of output of one plant that is the primary objective – rather the accuracy of the overall PV portfolio, which is increased by geographical spread – the objective remains to reduce this margin (Enel, 2010).

Unit commitment practices

More advanced methods of scheduling the dispatch of plants to cope with the uncertainty in VRE output are under development. One such is probabilistic unit commitment, which explicitly accounts for the uncertainty of wind output. Unit commitment (UC) plans are produced and executed by the system operator following the submission of offers and bids for energy, and demand forecasts.[20]

A unit commitment plan – which will be prepared by every system operator – describes which units will need to be online for each hour or half-hour period, usually for the day ahead. The objective is to make available the correct combination of units for reliable and economic operation of the system, taking into account fuel and carbon costs, and reserves required in case of forced outages of power plants or transmission lines and against demand uncertainty.

With large amounts of VRE expected in many systems, more advanced (probabilistic) methods of unit commitment and economic dispatch are under consideration. These are in turn based on advanced forecasting techniques wherein multiple forecast scenarios are considered, each with a certain probability of occurrence. A range of UC plans is produced, resulting in an expected optimal unit commitment for that time frame.

18. Royal Decree 661/2007, which was published on 26 May 2007, regulates the production of electricity under a special regime applicable to electricity produced from renewable energy sources.

19. Although, as previously noted, the predominance of distributed plants may reduce the system operator's ability to track output during the day (unless output is signalled through a smart meter).

20. Vertically integrated utilities, which control the whole generation and supply chain, do not rely on bids and offers, and so can commit and dispatch units as they see fit. Long-term contracts between specific suppliers and large industrial users also lie outside such planning processes.

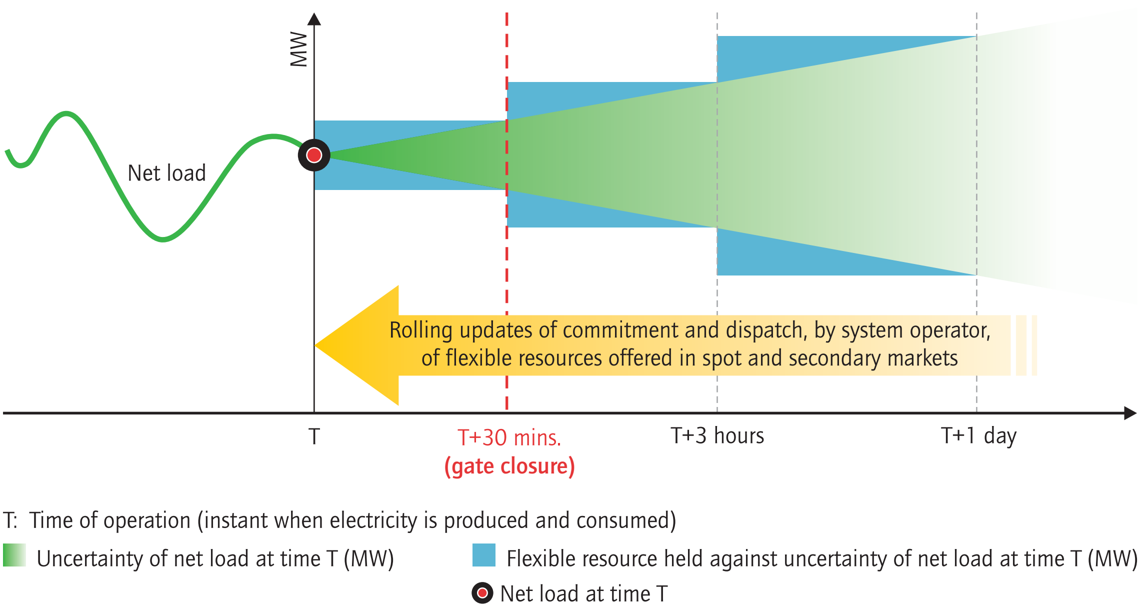
On the basis of unit commitment plans, dispatchable power plants are commanded to produce at a certain level for a specified period. The length of these periods may in itself block the flexible resource. If commitment is by hourly blocks, for example, power plants (or any other flexible resource) that could otherwise ramp up or down within the hour will instead be institutionally constrained to hold steady for the whole hour. As a result, a smaller sub-set of the most flexible resources – those not included in the period in question – must be relied upon to balance hourly uncertainty. The same issue would be seen if collaborating markets only update their interchange schedules every hour, and would be ameliorated by shifting to shorter, half-hourly blocks for example (NREL, 2010).

Shorter gate-closure periods

Forecasting enables more efficient scheduling of flexible resources for balancing supply and demand. But for forecasts of output to have a real value, they must actually influence the system operator's commitment and dispatch of flexible resources.

Forecasts generated on a rolling basis can provide the basis for updating the unit commitment plan of power plants, storage or any other flexible resource, to reflect increasing certainty of the electricity expected from VRE power plants. It then only remains for owners of flexible resources to be able to update their offers to the market to reflect the increasing certainty of the net load, the objective being to ensure that only an economically efficient minimum of back-up is retained against the remaining uncertainty. One way to get right the dimensions of this remaining back-up (whatever the flexible resource behind it) is to shorten the period between gate closure – the moment when no more bids and offers to the market are accepted – and the moment when electricity is produced and consumed.

Figure 24 • Managing uncertainty in the net load



Key point • Forecasting of VRE output is increasingly certain in the near term. If gate closure occurs close to the time of operation, the amount of flexible resource committed against uncertainty can be updated to reflect this greater certainty.

The shorter this period is, the clearer the impending need for flexible resources against uncertainty. If the market is liquid, and a strong enough price signal exists, the fastest flexible resources will be able to offer their services to the market closer to the time when they are actually needed, without jeopardising reliability. The system avoids locking in resources it does not eventually need, which are then freed for use elsewhere.

Gate closure may occur anything up to five minutes ahead of when the electricity is actually consumed, as in the Australian National Electricity Market (although trading for the day ahead is much more common).

The interaction between forecasting, gate closure and unit commitment are illustrated in Figure 24. The focus of the figure is time "T" when electricity must be produced to satisfy the net load at that time. As the horizon approaches, uncertainty of the net load at this time reduces. If gate closure is close to time T (as in this idealised case), flexible resources committed against the uncertainty in the net load can be reduced on a rolling basis, from a relatively large capacity on the day ahead (corresponding to high forecast uncertainty on that timescale), down to a smaller capacity 30 minutes before the time of operation (reflecting increased certainty at that time).

8 • What are the needs for flexibility?

This chapter addresses the requirement for flexibility resulting from VRE output. In the case studies in Part 2, due to limited net load data, existing needs for flexibility and new needs resulting from VRE are considered separately, and are simply summed. This is a conservative approach, but it ensures that the occasions of maximum flexibility requirement – when existing and new needs for flexibility are additional – are covered. In more refined assessments, ramping in the net load – *i.e.* demand fluctuations combined with those in VRE output – should be the focus. Calculations of net load would account for partial complementarity between the two needs, and so define the balancing challenge more precisely.

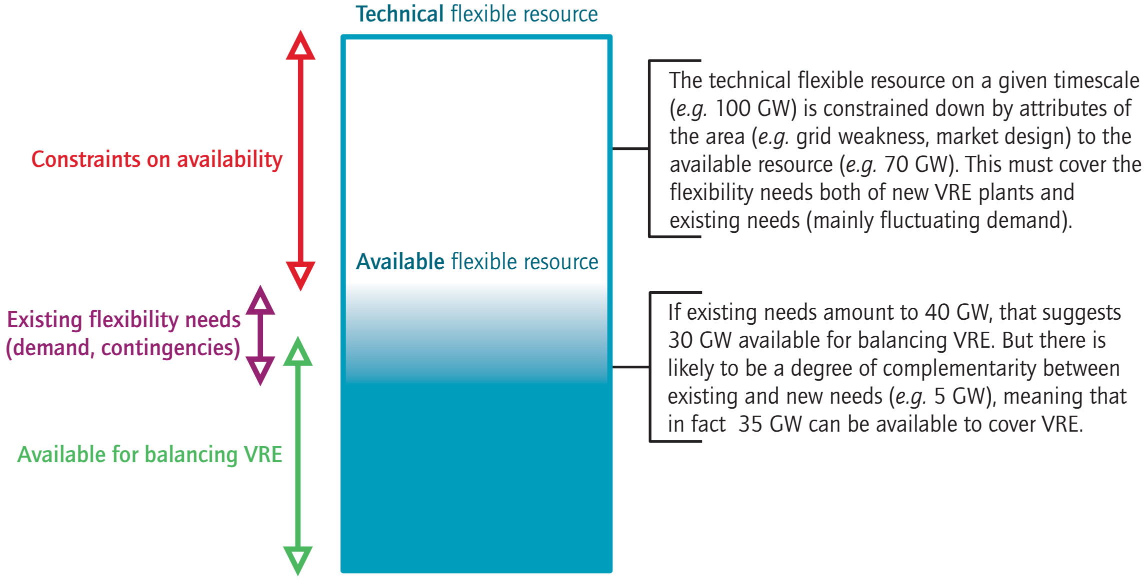
Existing flexibility requirement

Power systems already need flexibility. The existing flexible resource is crucial to provide ramping capability as demand ramps up or down between peak and minimum, which it may do rapidly. It also caters for short-term, possibly unexpected peaks in demand, which may be considerably higher than average peak, as well as errors in demand forecasts. On the supply side, flexibility is needed to cover contingencies and outages in the system, such as the loss of a major generator or transmission line.

The existing flexible resource is often greater than existing needs (although its availability is likely to be constrained by grid, operational and market attributes discussed above). This excess of flexibility is highlighted by existing regional and national penetrations of VRE, which have been achieved without additional flexible capacity.

The existing flexibility need will take up part of the available flexible resource, and the remainder can be considered available for balancing VRE plant (Figure 25). There is also likely to be some complementarity between VRE output and the existing needs (illustrated by the overlapping arrows). During periods when VRE ramping is complementary to and providing for fluctuating demand, the flexible resource will be freed up.

Figure 25 • Existing and additional needs for flexibility

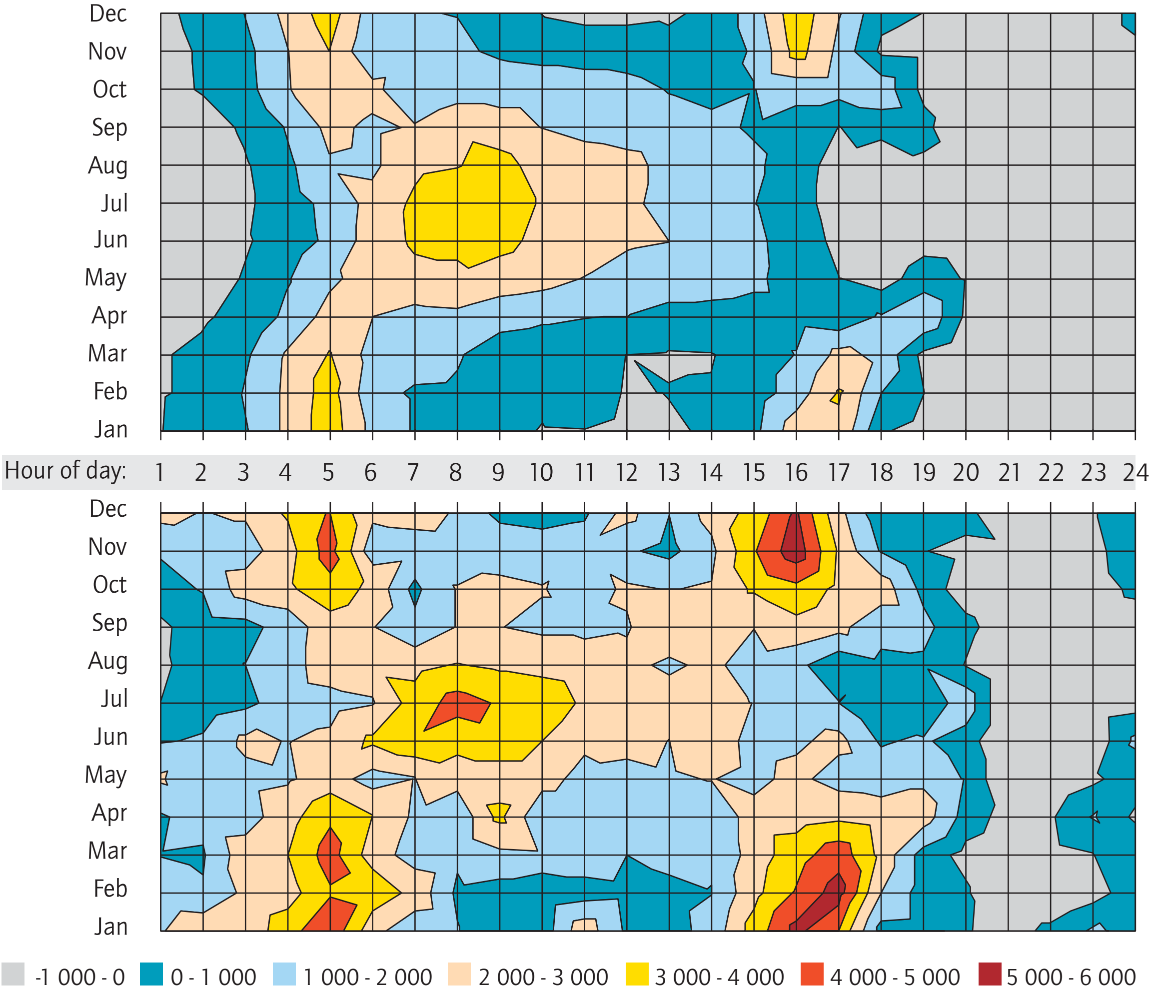


Key point • *Once the available flexible resource has been identified, operators must account for existing needs for flexibility (demand, contingencies).*

This complementarity could be considerable when both VRE output and demand show strong ramping as a result of the same stimulus. For example, when air-conditioning demand rises sharply towards midday, and there is significant solar PV capacity installed on the system, both will ramp simultaneously to a large extent. In such a case, not only does the PV output represent no additional requirement for flexibility, it actually caters for the existing requirement, to some extent freeing up flexible resources previously required elsewhere in the system.[1]

In contrast, no reduction in flexibility requirement will be seen when wind, wave or tidal output picks up during the late evening as demand is dropping off. This will result in an additional flexibility requirement. On the other hand, if increasing wind speeds result in increasing heating demand (in an area where heating is provided for electrically) the likelihood of complementarity increases.

Figure 26 • Hourly up-ramping in load (top figure) and net load (bottom figure) in the western United States (MW).



Source: GE Energy, 2010.

Key point • Maximum ramp in the net load is higher than in the load alone, but less than if the two requirements were simply summed.

1. Depending on the respective volumes of PV and demand, and the extent of the complementarity.

Complementarity between demand and VRE output fluctuations needs to be fully accounted for in any detailed assessment using the FAST Method, and will be captured in net load data. An illustration of average hourly up-ramping requirements in the WestConnect area in the United States for every month of the year is shown in Figure 26. The upper part of the figure shows ramping requirements resulting from fluctuating load (demand) alone; the lower part shows the up-ramping in net load comprising demand and 30% wind power.

It is apparent that wind power increases the extent of ramping across the board (this is the same effect as illustrated in the lower line of Figure 3 for the single week in April). A peak ramping requirement of 3 673 MW per minute without wind rises to 5 644 MW with wind.

However, because the maximum existing and new ramps only partially coincide, this increase is less than if they were simply summed. Moreover, much of the additional ramping requirement comes at times when ramping was previously relatively low (yellow/orange in place of blue). The existing flexible resource will be able to cover a large proportion of new needs occurring at such times.

Additional requirements of VRE

Each variable renewable energy resource – wind, sun, tides, waves – has a distinct variability profile, and this will be different in different locations and at different times of the year. These variability profiles are explored briefly in Annex B.

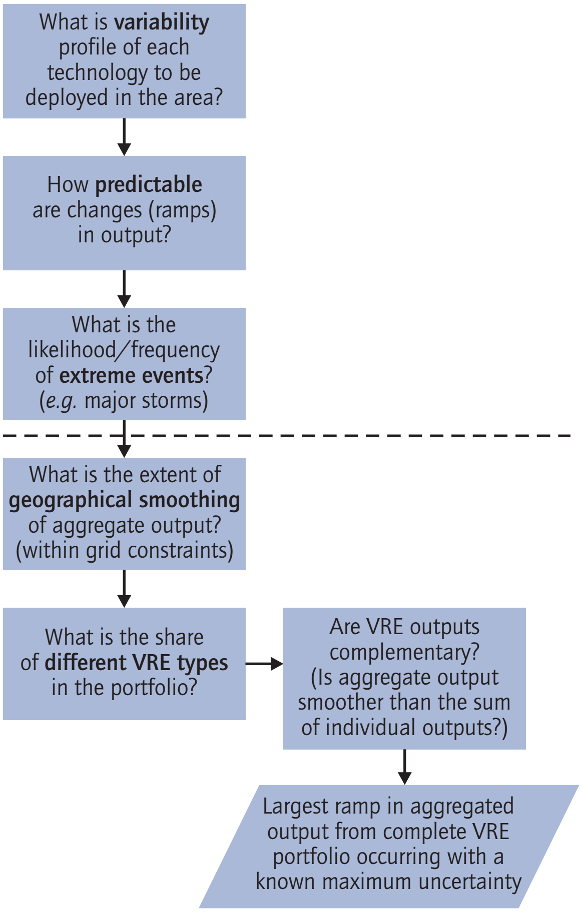
Empirical data from weather stations are a good place to start for an idea of how resources vary in a specific region. Before a power plant is built, these will be supplemented by data from meteorological masts, other sensing technologies and resource models. Though it will still be subject to uncertainty, data compiled over the region over one or more years will give a fairly clear idea of the likely variability.

The next step is to assess the uncertainty of forecast output over the balancing timescale. As explained above, the accurate forecast of VRE plant output across the system is vital, as it will enable more efficient scheduling and use of flexible resources.

The occurrence and frequency of extreme events is important. Individual wind farms, for example, can ramp from close to maximum output down to zero output in less than an hour, which they need to do when a storm is approaching. Forecasting of such events is at a relatively early stage of development.

The impact of storms on wind output is less when the aggregated output of all plants on the system is considered, but ramps can still be impressive. Across Denmark, for example,

Figure 27 • Assessing the flexibility requirement of the VRE portfolio



Key point • This chart summarises the assessment of the flexibility requirement of the VRE portfolio of a given area.

ramps up to 83% of wind power capacity have been observed in six hours. In 2009 in the much larger ERCOT (Texas) system in the United States, a ramping rate was observed of 4 000 MW (45% of installed wind capacity) in a little over one hour.[2]

Minimising the flexibility requirement

Before asking how the available flexible resource of the power system can be increased, it is necessary to ask: how can the need for flexibility be reduced? There are three main tools here:

- Curtail VRE plants output.
- Deploy the plants over the widest possible area.
- Widen the portfolio of VRE plants to include multiple types.

Curtailment. If a steep ramp up in variable output is undesirable, it can be reduced – in effect curtailing the output of the plant. In the case of a wind turbine, for example, this can be done by pitching the blades out of the wind. Additionally, if the ability to ramp up is required, a turbine that has been backed down in this way can be allowed to ramp upwards. If such curtailment of output is needed only for a few tens of hours per year, it will have limited impact on the plant operator's revenue, while possibly providing significant benefit in balancing terms.[3]

Geographical spread. The objective of spreading VRE power plants over the largest feasible area is to reduce variability – minimising the balancing challenge, rather than reacting to it. This and technological spread are captured in the second half of Figure 27, above.

Experience to date with integrating wind and solar PV output suggest that increasing the area over which plants are spread reduces variability in the aggregated output (IEA Wind, 2009). This is essentially because the resource differs from place to place; as an example, the extent of up and down ramps in PV output in California is shown in Figure 28. The variability in the output of one plant is plotted against the aggregated output of eight plants.

In the single plant case for a small number of hours each year (x-axis), variability inside one hour is as much as 70% (y-axis). In contrast, in the eight plants case, the one-hour figure does not rise above 45% (for down-ramping). The same reducing effect is observed on uncertainty of output. As the area examined increases in size, VRE ramps across it is can be predicted with greater certainty. Aggregated data from over 70 solar PV rooftop installations in Spain show an average deviation of less than 1% from expected electricity production (Enel, 2010). Although this is an average energy value, the same trend towards diminished uncertainty with increasing geographical spread should also be observed on a capacity basis.

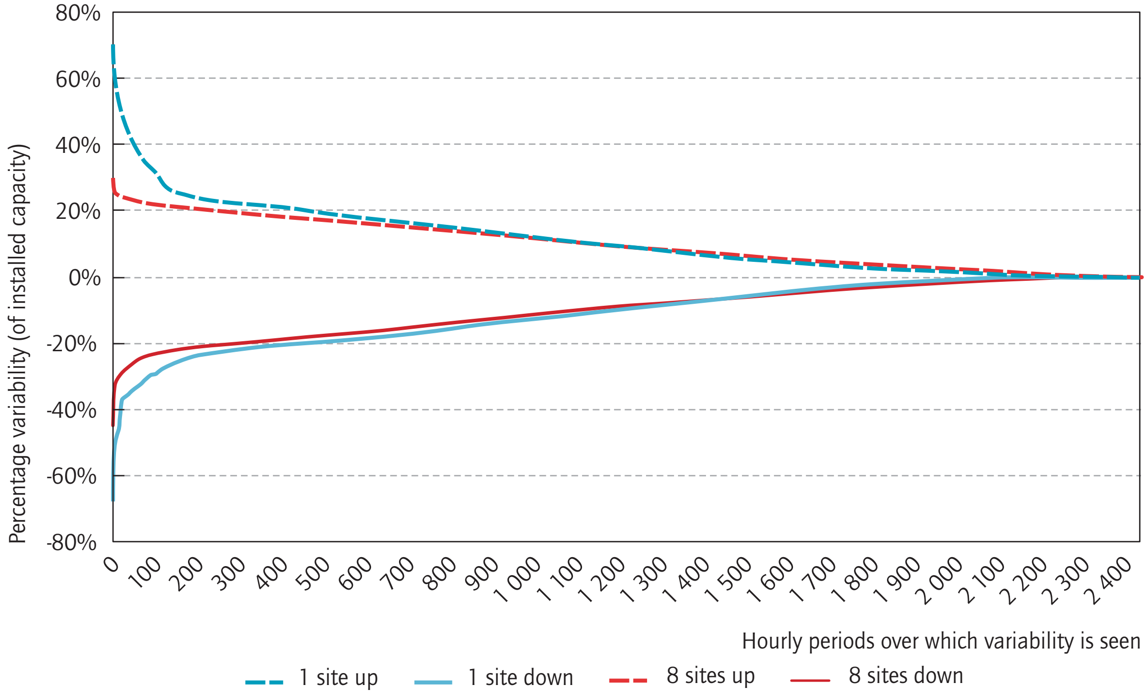
Extreme weather events are less likely to have a major impact in areas with significant geographical spread; they will be of most concern in a small area and/or one reliant on a single VRE resource. Essentially, the balancing area is larger than the weather system causing the extreme event: stormy weather in Scotland, for example, will not be noticed on the south coast of England.

Technology spread. Complementarity of the outputs of different VRE technologies in a power area can have a similar effect, reducing the aggregate extent of fluctuations seen from the VRE portfolio as a whole. If the timing of ramps in output from VRE types in the portfolio is different, then the aggregated ramp over the portfolio at any given time will be smoother than that of each type individually. The output of VRE types must be similar in scale for this smoothing to be significant.

The effect over one month in 2003 in California was to reduce the net load, or remaining demand to be satisfied, by a steady amount, *i.e.* without altering its shape (Figure 29). The figure shows the load of the area (pink line), average wind output over a day (blue line), average solar PV output over a day (orange line), and their combined effect on the net load (green line). Average wind and solar PV outputs in the figure are negatively correlated – so highly complementary.

2. The Electric Reliability Council of Texas operates the system and runs the market in 75% of the Texas area.
3. Opportunities for curtailing output of VRE are not considered in the case studies. They should feature in more refined assessments.

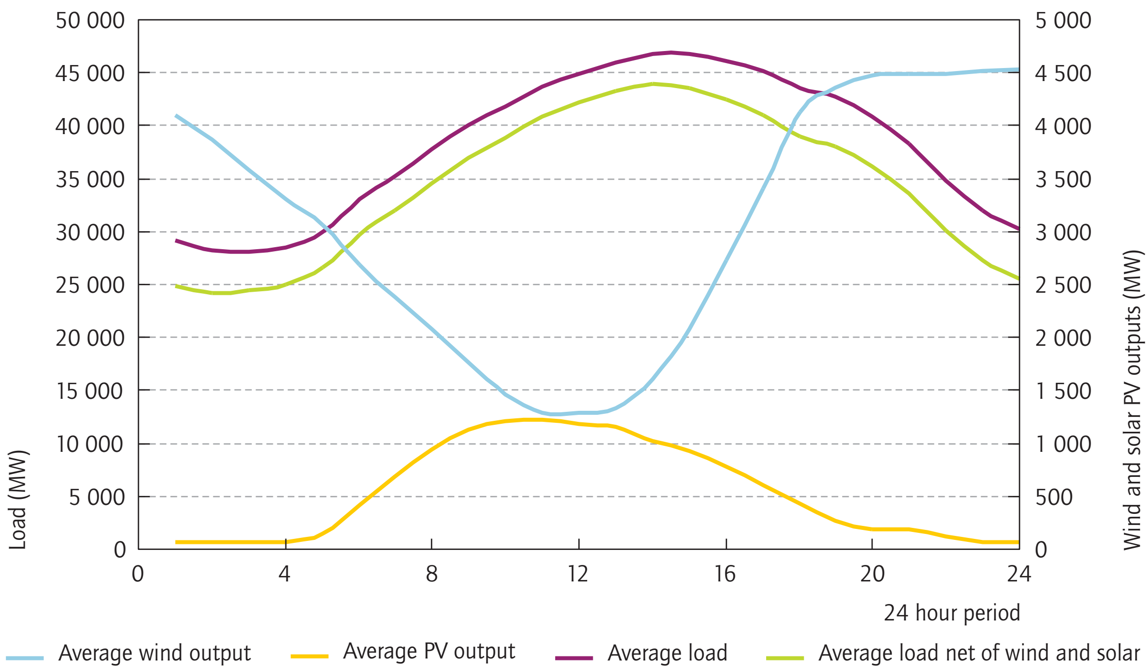
Figure 28 • *Impact of geographical spread smoothing PV variability*



Source: GE Energy, 2010.

Key point • *The maximum extent of variability in the output of VRE reduces with the aggregation of the outputs of multiple plants and over larger areas.*

Figure 29 • *Impact of complementary VRE output on variability in California, July 2003*



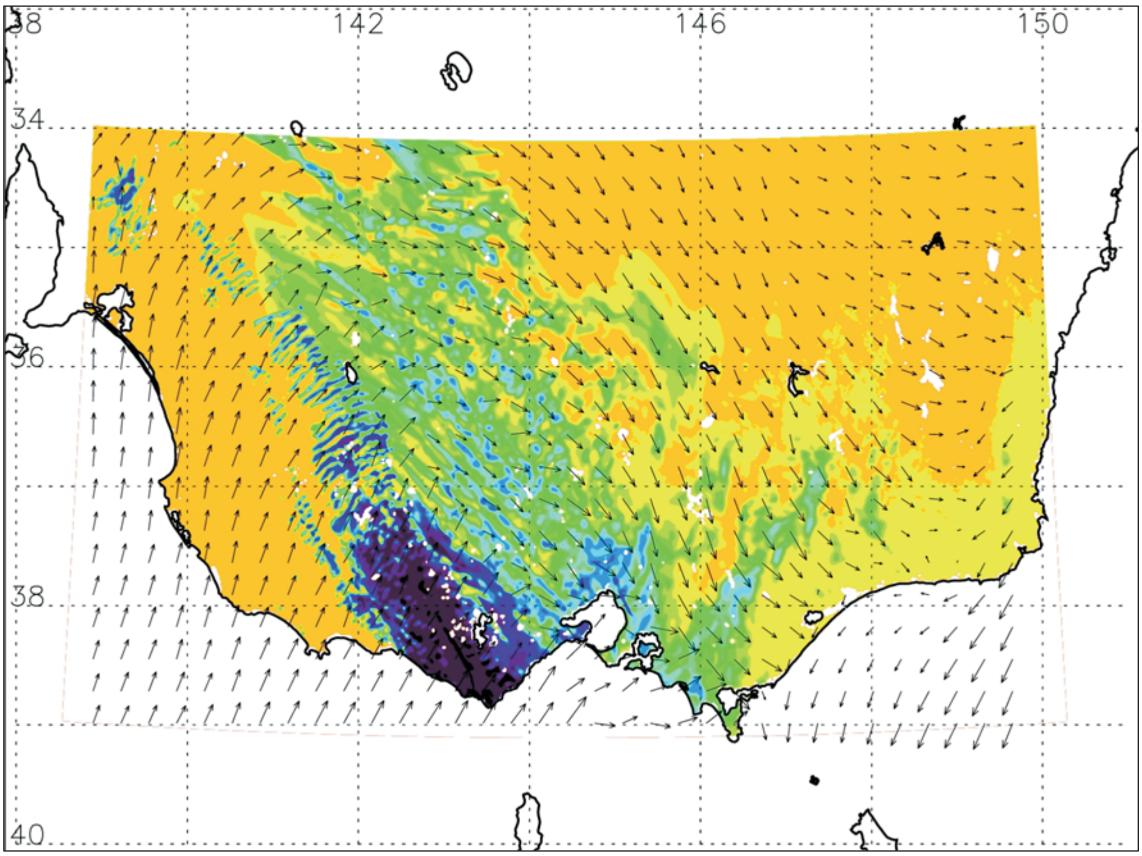
Source: NERC, 2009.

Key point • *Outputs of different VRE technologies, in this case wind and solar PV, may be complementary. If installed capacities are comparable in size, the result can be a significantly smoothened overall output.*

As a result of geographical and technology spread, in all but the smallest areas aggregated output does not spring from zero to 100% or vice versa instantaneously. Instead, output from the VRE portfolio will ramp over hours – albeit potentially very steeply. Consequently, it is not just the flexible resource available more or less instantaneously that is important for balancing (*e.g.* open-cycle gas, hydro, demand response, storage), but also resources that can respond more slowly over the balancing period (*e.g.* coal, nuclear).

Melbourne University is engaged in research to quantify more precisely the extent of geographical and technological spread, in order to identify optimal locations of wind and solar power plants. Figure 30 illustrates a typical December day in part of Victoria, Australia: a cold front is blocking the sun in the southern part of the state, with strong winds blowing from the northwest (ahead of the front), and from the south (behind).

Figure 30 • Solar and wind resource on a typical December day in the state of Victoria, Australia



Source: MUREIL, 2011.

Key point • Mapping solar radiation (colours) and wind resources (length and direction of arrows) simultaneously can help identify locations of VRE plants that result in maximal complementarity of outputs.

The objective of the research programme is to move beyond the annual average resource maps that are typically used to choose sites for specific technologies in isolation. The programme is instead looking for the combination of sites for a range of technologies that produces power with the least variability, or better still, matches demand as closely as possible.

Significantly, this research provides an indication of the spatial scales over which the weather can be expected to be the same – hundreds of kilometres in this case – meaning that the geographic distribution of power plants to achieve a smoothing of variability must also be measured on this scale.

This again highlights the importance of a strong transmission grid: the aggregation of outputs of different plants is only a meaningful proposition if the grid into which the outputs flow is uncongested. If this is not the case, the fact that outputs are complementary will not be relevant: the only relevant output will be that in the congested/isolated part of the grid.

However when different types of VRE plant are located in the same area, the likelihood of isolation through transmission congestion is reduced. Indeed, if their outputs are complementary, this will make better use of existing transmission capacity, as the rated (transmission) capacity of the line will be used for more of the time.

9 • Identifying the present VRE penetration potential

The objective of the Flexibility Assessment Method is to enable decision makers to gauge the potential for deployment of variable renewable energy in their specific area. This potential is based on the existing capability of the power system to balance variable output, as it is presently configured. FAST identifies which flexible resources could be made more available, and to what extent.

The Flexibility Index (FIX) described in Chapter 6 compares the technical flexible resources of a number of case-study areas. In more refined assessments with the FAST Method, FIX values would reflect not just the technical resource but the extent to which the resource is actually available. But it still would not indicate the extent of VRE deployment that could be balanced by the flexible resource.

This is reflected by another measure developed during this analysis. The Present VRE Penetration Potential (PVP) represents the penetration of gross electricity demand possible with a given flexible resource and a given portfolio of VRE technologies.

PVP is calculated for the case-study areas on the basis of the technical resource (TR). It is supplemented by a number of scored constraints, to give an indication of the likely availability of that resource. With enough data, the same metric could then be calculated on the basis of the available resource (AR).

The PVP metric is a product of the technical flexible resource and the maximum likely ramp resulting from variability and uncertainty of the area's VRE portfolio.[1] For example, if the biggest flexibility requirement of a VRE portfolio on the 15-minute timescale is 25% of installed VRE capacity, and the flexible resource on that timescale is 2 500 MW, then the system can balance 10 000 MW of VRE (on that timescale).

The resulting VRE capacity is then multiplied by its capacity factor to provide its energy output, and the result is divided by the gross electrical demand of the area, to give VRE penetration. The calculation of PVP is carried out on all four timescales up to 36 hours, and the most constrained period, *i.e.* when the existing flexible resource is most scarce, is taken to reflect PVP. Technical PVP values, derived without taking into account the availability of flexible resources, are illustrated by the height of the bars in the top part of Figure 31.

As with FIX values, there is a marked difference in results from area to area. On the basis of the technical resource alone, PVP varies dramatically: from 19% of gross electricity demand in Japan to 63% in Denmark. This illustrates the extent to which flexible resources vary from area to area. It suggests very strongly that there is no general maximum VRE deployment potential from the balancing perspective — rather the amount differs from case to case according to the specific context of the power system in which VRE are to be integrated.

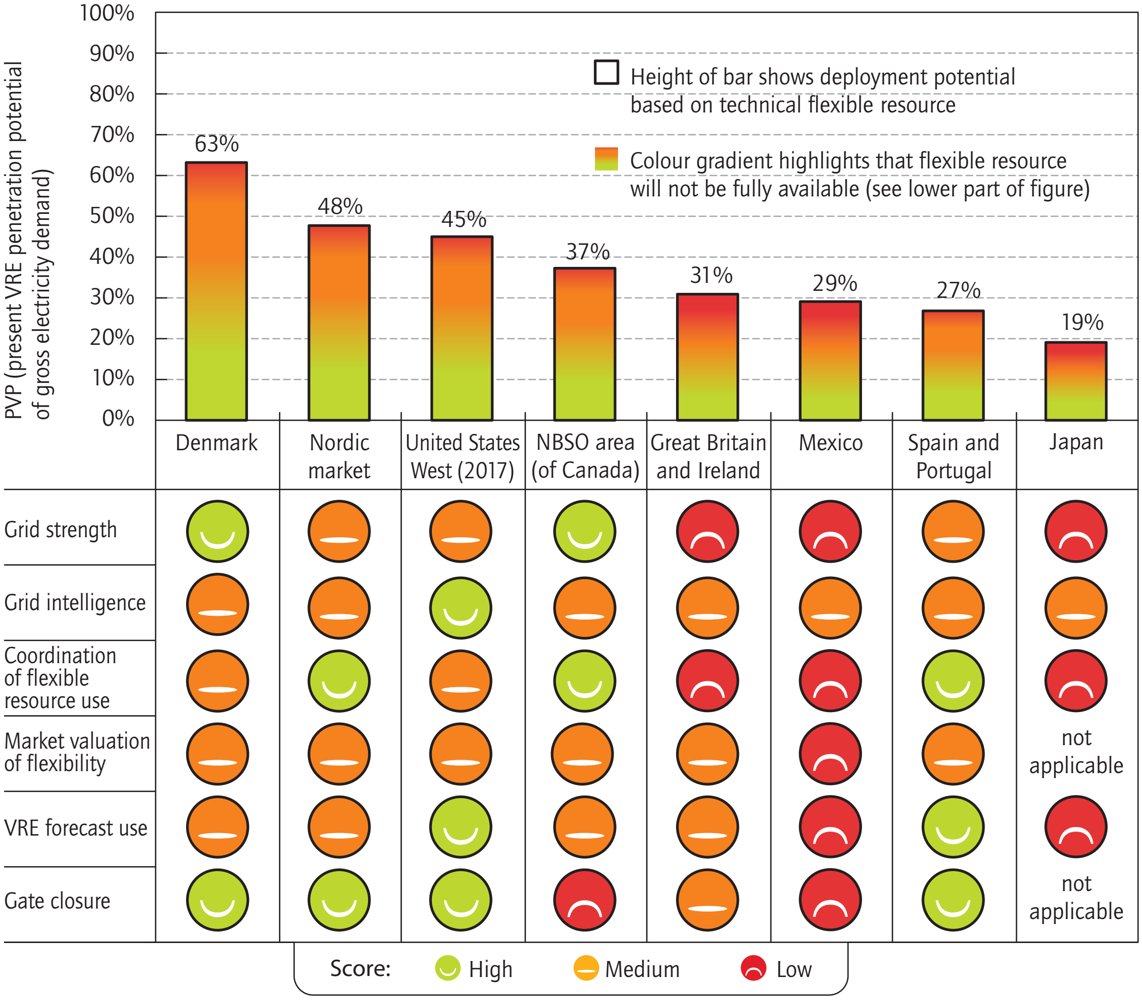
Moreover PVP values shown here in no way represent a ceiling on PVP — they simply reflect PVP as the area is configured today. As and when required, as VRE deployment continues, more flexible resources may be added; the decision whether or not to do so will be based primarily on economic and environmental considerations.

The lower part of Figure 31 highlights the constraints on PVP resulting from a number of key area attributes. These are scored qualitatively. Attributes that are low or moderate (green and amber respectively) represent a limited constraint on the availability of flexible resources. Those marked as red are a major constraint.

In areas where most attributes are considered to represent only limited constraint, the available resource will lie closer to the level of the technical resource than in areas where constraints are pronounced.

1. The case studies assume VRE portfolios to be broader than in reality: wind energy is by far the dominant VRE technology to date.

Figure 31 • VRE potentials today, from the balancing perspective



Notes:
1. PVP values must not be taken in isolation. As they are based on the technical flexible resource, they must be qualified by the constraints on availability of the resource, as shown in the lower part of the figure.
2. PVP values represent VRE deployment potential purely from the balancing perspective (minutes to days).
3. PVP values are not based on calculation of the net load. Due to data limitations, existing and new flexibility requirements are treated as additional. This will reduce PVP values in most cases.

Key points • *Significant flexible resources that could be used in balancing the net load exist in all areas assessed, enabling PVP ranging from 19% of electricity demand (in Japan) to 63% (in Denmark), from a purely technical perspective.*

• *The lower part of the figure illustrates constraints on availability of flexible resources resulting from grid and market attributes of the area. Further constraints apply to the four resources individually (see case studies in Part 2).*

Greater experience of VRE technologies is strongly associated with low constraints on flexibility, as the figure exemplifies – see Denmark, Nordic, Spain, and US West 2017. It also reflects historical factors, as in the Nordic (and Danish) and Canadian NBSO areas where strong interconnection-based flexibility has been driven not only by wind energy development, but by wider electricity market factors. In marked contrast, availability is heavily constrained in Japan, Mexico and (to a lesser extent) the British Isles.

Grid strength and intelligence. The strength of the transmission grid is of cardinal importance in any power area. Existing strength will be driven by a number of historical factors. Mexico is a developing economy, stretching over a huge distance; its grid is weaker in places than in the Nordic region, for example, which is a mature economy with a history of collaboration. The ten utility areas of Japan have remained isolated; transmission among them is weak. This results in limited opportunity for geographic and technological smoothing of variability, and the inability to share flexible capacity.

All the power system areas examined in the case studies have predominantly conventional grids. Particularly in areas where other, more primary aspects have already been addressed (such as the use of forecasting in system operation for example), enhanced grid intelligence may increase both the capacity (demand side) and use of flexibility resources.

Internal co-ordination of flexible resources. Areas containing multiple balancing areas should collaborate deeply, if necessary merging into fewer areas, as is expected to occur in the United States. For example, the New Brunswick area of Canada could merge with the neighbouring Nova Scotia area. If merging is not possible or desirable, stronger collaboration is still recommended. For example, Japan might change to flexible operation of the connections among its ten areas.

Market value of flexibility. There is significant unexploited potential for recognising the market value of flexibility in power systems. No market case—studied reflects the full value of flexibility, perhaps because in most flexibility is not yet scarce. Most have an intermediate score, reflecting the fact that flexibility is valued to some extent. There is perhaps a balancing market, as in the Nordic case, or the market already has significant penetration of VRE and is more broadly designed to consider it. None of them strongly and explicitly offers rewards encouraging power plants to behave more responsively. Similarly there are not enough incentives for storage plants, and the demand-side resource is mainly idle.

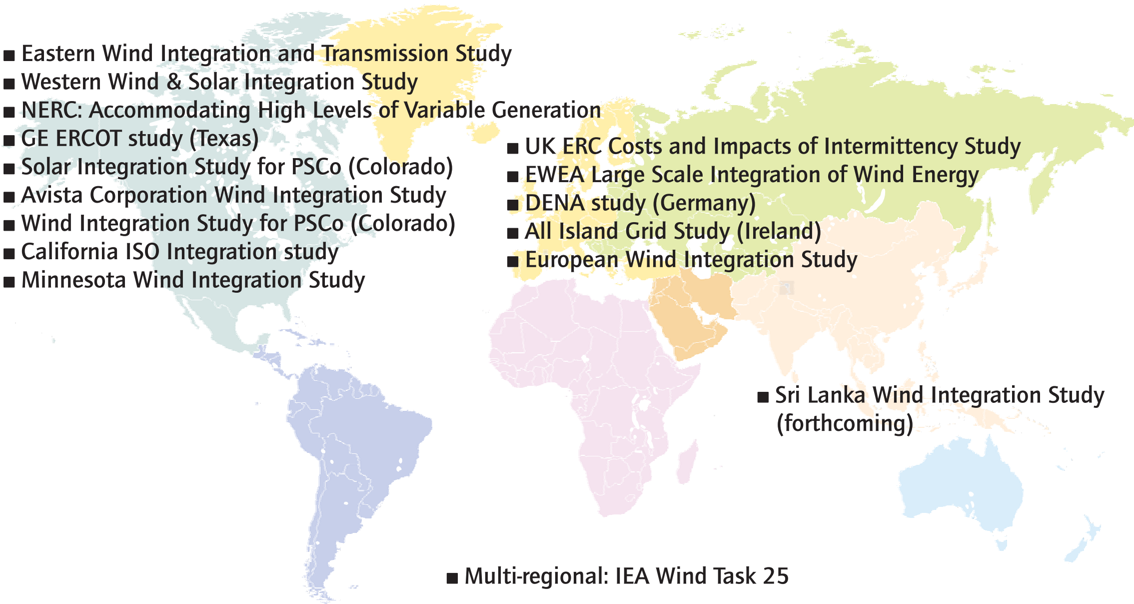
VRE forecast use and gate closure. Those areas with most experience of VRE — Denmark and the Iberian Peninsula — use the latest commercial forecasting techniques, though there may also be opportunity to use more advanced methods of unit commitment. Such advanced methods, it is assumed, will be in place in the United States Western Interconnection in 2017. Mexico and Japan, both with low existing penetrations, do not forecast output in any way. Where offers to the market can be updated closer to real-time than day-ahead, (as in all cases except NBSO, Mexico and the Irish part of the Britishs Isles), this represents a lesser constraint on the availability of flexible resources that would be found.

For further discussion of these aspects, the reader should consult the individual case studies in Part 2.

10 • What is the cost of balancing variable renewable energy?

Integration costs can vary dramatically from area to area as a result of differing flexible resources. Consequently, cost analysis needs to be specific to the area in question. Several studies have been conducted around the world in recent years. Most have focused on the United States and Europe (Figure 32).

Figure 32 • Global sample of VRE integration studies



Key point • Balancing cost studies have been carried out in the United States and Europe.

To date there has been limited analysis in other regions, especially in developing countries, where integration issues may be very different from in OECD countries. A forthcoming wind integration study from Sri Lanka — may provide much[1] needed detail in this important area, but more work will be needed as Sri Lanka is a large island system, and thus may not be fully representative of other non-OECD systems.

While most studies share the same high-level goals, there are differences in their scope as well as in their assumptions and methodologies in calculating costs. Some are very highly detailed, while others produce only rough estimates. As might be expected, newer studies generally tend to improve and build upon earlier ones.

Some integration studies focus more on the technical feasibility of high penetrations of variable renewables, and less on the costs or economics of integration. Examples include the *California ISO Integration Study* and *Accommodating High Values of Variable Generation* by the National Electric Reliability Council (NERC). These studies provide valuable insight into the technical challenges

1. Development and Finance Corporation of Ceylon (DFCC, n.d.).

involved in managing systems with significant variable generation. Such technical insights may lead to lower costs through better integration of renewables, particularly through improvements in system operation.

Table 4 • Scope of integration cost studies

Study	Year	VRE	Costs		
			Transmission	Balancing	Adequacy
Eastern Wind Integration & Transmission Study (US)	2010	Wind	√	√	√
Western Wind & Solar Integration Study (US)	2010	Wind, solar	√	√	√
GE: Analysis of Wind Generation Impact on ERCOT (US)	2008	Wind		√ (b)	
Minnesota Wind Integration Study (US)	2006	Wind	(a)	√	√
ERC: Costs and Impacts of Intermittency Study (UK)	2006	General		(a)	(a)
EWEA: Large Scale Integration of Wind Energy (EU)	2005	Wind	(a)	(a)	(a)
DENA Study (DE)	2005	Wind	√	√	√
All Island Grid Study (IR)	2008	General	√	√	√
European Wind Integration Study (EU)	2010	Wind	√	√	
GreenNet Study (EU)	2009	Wind	√	√	√

a: References other work.

b: Includes a market based approach.

The term balancing costs, in the context of the integration of variable renewable electricity, refers to those short-term operational costs a system incurs through output variability and uncertainty. Most balancing cost analysis to date has focused on a single flexible resource – that found in conventional, dispatchable power plants.

Common balancing needs include maintaining reserves for regulation and frequency response, load following, system forecasting errors, unexpected outages, and changes in unit commitment and dispatching. Although these needs exist in all systems, independent of VRE, they are likely to increase with significant VRE deployment. When supply of or demand for electricity changes, response to that change is typically provided by other power plants which ramp their production up or down accordingly. The cost of operating such reserves, specifically against variable output power plants, is the major component and focus of balancing cost studies in the literature.

Key drivers of balancing costs

Balancing costs are the sole focus here, while other integration costs are addressed in Annex A. Their magnitude depends significantly on the flexible resources of the system. If the resource to meet new needs for flexibility resulting from variability and uncertainty exist already, economic impact will be low. However, if flexible resources are insufficient, or unavailable, and additional resources are deployed prematurely, balancing costs will be markedly higher.

Another factor influencing balancing costs is the proportion of variable renewable power plants in a system. At low penetrations, the presence of variable output power plants does not significantly alter the balancing challenges in a system from what it would experience as a result of variable load. However, as variable renewables becomes more significant in a system, the balancing challenge becomes more pronounced, and costs rise (Figure 33).

Geographical and technological spread of power plants reduce the extent of variability, and the extent of the balancing challenge, as has been noted above. Regional studies conducted for the Eastern

United States and Europe show lower costs than those estimated for smaller regions such as Colorado or Great Britain. The differences are most likely due to differences in geographical spread of resources and the size of balancing areas.

More interconnection among adjacent areas reduces balancing costs. Pooling of demand and generation resources further averages out variability and forecast uncertainty. Again, cost estimates for larger regions tend to be lower than for the smaller individual power systems that comprise them.

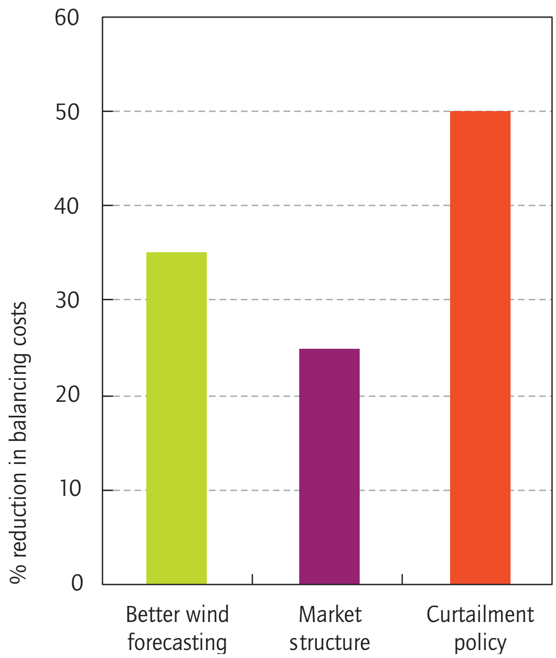
One of the most significant factors determining balancing costs is the flexibility of the existing generation portfolio. Different generation technologies have varying abilities to change output rapidly. Hydropower and simple gas turbines are more flexible than nuclear or coal power plants, for example. Balancing costs to date tend to be lower in systems containing significant flexible generation. For example, Norway has low integration costs due to significant hydropower resources in the Norwegian grid.

Most experience with storage for balancing variability and uncertainty has been with pumped hydropower facilities. In a system with sufficient storage the impact of variability is small, as storage plants can respond very quickly. So long as sufficient energy is generated, and can be stored to meet demand, the additional balancing cost will be nominal.

Demand-side flexible resources have the potential to be low-cost sources of flexibility. Because the marginal unit cost of demand-side management is likely to be lower than that of reserve supply, more demand-side management could reduce balancing costs.

How the system is managed also has a significant effect on balancing costs (Figure 33). Important aspects include forecasting of power output from variable power plants, shorter gate closure, and VRE curtailment practices.

Figure 33 • Balancing cost savings through operational and market measures



Source: EnerNex, 2007.

Key point • Forecasting, market design and limited use of curtailment can all help reduce balancing costs.

In many cases, especially with wind energy, improved forecasting can significantly reduce balancing costs associated with output uncertainty. The Avista Corporation in the northwestern United States conducted a wind integration study in 2007, which suggested that a perfect output forecast in the study area could reduce balancing costs by 30% to 40%, all else being equal (EnerNex, 2007). However, the likelihood of perfect forecasting, as well as the need for it given alternative measures such as reduced gate closure times, remains unclear.

Some electricity markets are set up to allow trading up to one hour ahead of time (gate closure time); a smaller number allow trading intra-hour. Usually, balancing costs decrease closer to time of delivery. The Avista wind study, for example, estimated 40% to 60% savings in balancing costs when moving from an hourly market to a ten-minute market.

The amount of variable renewable energy curtailed has bearing on the magnitude of balancing costs. Results of curtailment will vary by system, but the Avista wind study found 20% to 30% savings from allowing up to 1.5% curtailment at energy penetrations. Such savings suggest that it would be prudent to weigh energy production savings against additional balancing costs when determining optimum levels of allowed curtailment in a system.

Methodology for estimating balancing costs

Some wind studies calculate balancing costs by comparing a scenario with VRE based on real data, to one in which VRE output is replaced by a flat block of fixed and predictable energy (the same energy content with firm capacity value).

This approach may have drawbacks. The flat block will be spread evenly throughout the day but VRE output may be higher during off-peak periods (as is often the case with wind[2]), in which case there will be a difference in the market value of the energy provided by the flat block and wind. This value is distinct from integration costs. This daily block based approach could add USD 1/MWh to USD 2/MWh to the balancing cost of wind (Miligan *et al.*, 2009).

The flat energy block proxy may also result in a requirement for ramping of conventional plants that is unrealistically high. A simulated, flat block of energy would ramp output from 100% to 0% instantly (and vice versa), whereas VRE output ramps more slowly, exerting a diminished ramping need on conventional generators to maintain balance.

Some factors that have a significant effect on balancing cost estimates may change over time, and cost analysis must take into account expectations of future developments. Factors include the price of natural gas, which may be a primary balancing resource. There has been significant price volatility in recent years. Gas prices may also influence opportunity costs for owners of flexible power plants.

Another example includes assumptions made about the penetration of variable renewables in adjacent power systems that are assumed to be providing flexibility resources through interconnections. For example, the extent to which Norway will be able to continue to provide hydropower—based balancing resources to Denmark will depend on the level of VRE deployment in Norway itself — as well as in its other neighbours. If these increase, competition for the same flexible resource will result.

Estimates of balancing costs

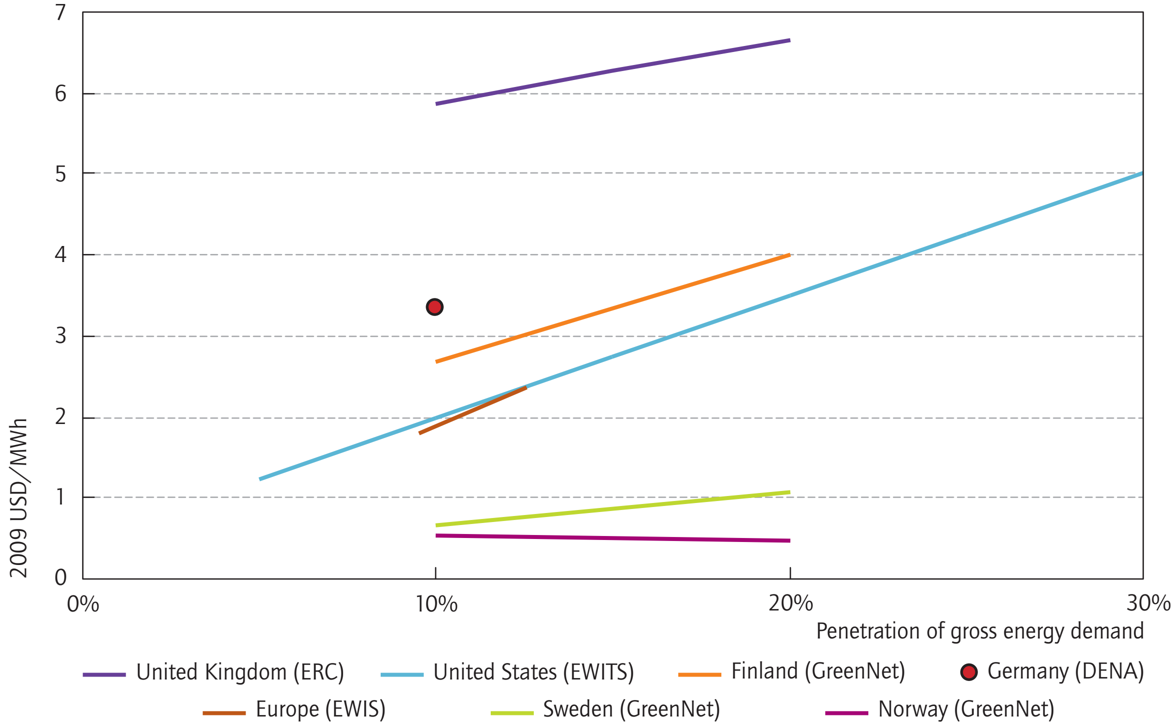
Most integration studies analyse the magnitude of balancing costs in their respective regions of study. They usually focus on wind power, as it is the predominant VRE technology.

A survey of key balancing cost studies (Figure 34) shows that, at 20% of energy penetration, balancing costs estimates range from USD 1/MWh to USD 7/MWh. The Eastern Wind Integration and Transmission Study (EnerNex Corporation, 2010) estimates costs of USD 5/MWh at 30% penetration. The range of balancing costs highlights the importance of the drivers described in the previous section, and the flexible resources of the area in question. These resources vary widely, so balancing costs also vary considerably, and should be calculated on a case-by-case basis.

Though not strictly speaking a balancing cost, plant owners may see opportunity costs associated with provision of the flexibility service. For example, a system with significant hydropower may have a low balancing cost because of the flexibility that can be provided by that plant. However, if the use of the plant for balancing variability means it is unavailable at times of peak demand and higher electricity prices — if this differs from when flexibility is most needed — this will represent an opportunity cost. This is more likely to be the case in predominantly thermal systems which are seeing a rise in gas prices, resulting in an increase in the marginal electricity price, and making provision of peak electricity more attractive than provision of the flexibility service.

2. Conversely, PV is often higher during peak and mid-peak periods.

Figure 34 • Estimates of wind energy balancing costs



Source: IEA Wind, 2009.

Key point • Estimates of balancing costs range from USD 1/MWh to USD 7/MWh, at penetrations of up to 20% of electricity demand.

11 • Conclusions, recommendations to policy makers and next steps

This chapter presents general conclusions of the analysis, recommendations to policy makers, and a brief summary of next steps and further research. Paragraphs are numbered to highlight that each represents a specific conclusion, recommendation or next step.

Conclusions

1. Power systems have greater capacity to handle variable, renewable electricity (wind, solar, tidal and wave power) than commonly believed. Their technical resources are capable of balancing the additional variability and uncertainty resulting from VRE installations, to varying degrees depending on regional circumstances. These resources include dispatchable power plant, storage facilities, demand side flexibility and trade through interconnections. So, given their present deployment of flexible resources, the penetration potential of variable renewables will be greater in some areas than others.

2. Of the eight areas assessed, Denmark is highest on the Flexibility Index, due mainly to its strong interconnection to adjacent areas, with which it is balanced as part of one market. This highlights the importance of interconnection to areas with different flexible resources. However Denmark is a small area; in most other areas dispatchable generation capacity remains by far the most important source of flexibility.

3. A number of power system characteristics will affect the extent to which technical flexible resources are available for use in the balancing challenge. The most fundamental of these is the strength of the grid in the area assessed. The value associated with flexibility in the market is also a key parameter: if it is high enough, more of the technical flexible resource will become available (*e.g.* mid-merit and base-load power plants will cycle more; the demand side will respond). The merging or co-ordination of small markets will enable greater sharing and less duplication of flexible resources, while trading through comprehensive and liquid power exchanges will mean that more of the flexible resource can be made available when it is needed most. Finally, advanced forecasting and unit commitment techniques, combined with short gate closure times, will enable more efficient allocation of flexible resources against uncertainty.

4. Power systems are complex, and their management remains something of an art, not only a matter of scientific and technical know-how. It is unlikely that the full flexible resource of an area could ever be made completely available. It would not be advisable for an area with, for example, a 30% VRE target and a Present VRE Penetration Potential (PVP) based solely on a technical analysis[1] also of 30%, to rely solely on optimising the use of its existing flexible resources to balance its targeted share. It may well need also to increase the flexible resource itself.

5. In all cases over the eight diverse power areas studied, with regards to the technical flexible resource, it is the ramping capability in the area 36 hours ahead that is the constraining factor, not short term variation (in the 15-minute timescale), as commonly believed. This issue is discussed further in Part 2.

6. With two exceptions (US West 2017 and the Iberian Peninsula), it is the ability of the dispatchable power plant portfolio to ramp upwards (rather than downwards), *i.e.* to supplement VRE output dropping away, that constrains PVP.[2] The implication is that a decisive factor in most cases may

1. As is the case in the case studies done for this analysis.
2. US West 2017 has large amounts of nuclear and coal. Being more likely to be online at maximum, and likely to be less flexible, the challenge will rather be to ramp down quickly. Nuclear plants in Spain cannot be ramped down in the balancing timeframe for regulatory reasons, even though they may have the technical capability.

be the extent to which base-load plants (such as coal and nuclear) can ramp down to a stable minimum operating level that is well below maximum so they can ramp upwards again more quickly when needed. In other words, the acid test for PVP is a situation where the system moves from low demand with high VRE output (a windy Saturday night, for example) to high demand with low VRE output (the following Monday afternoon is still).

7. The extent to which flexible resources are available varies considerably in the case studies, because of different grid, operational and market configurations, as well as a wide range of other factors which may or may not constrain individual flexible resources (*e.g.* grid intelligence to enable demand side response).

8. In the main, both extent and availability of flexible resources go hand in hand in the case studies. In other words, not only are certain areas more heavily endowed with flexible resources, they are also more likely to make those resources available for use in balancing. These areas are also those which show the greatest deployment of variable power plants to date.

9. The flexibility Index (FIX) and PVP values resulting from use of the FAST Method in the case study areas are likely to be conservative, due to a number of assumptions made for practical reasons of project resources. For example, as a worst case scenario, the case studies make the significant assumption that the maximum extent of variability and uncertainty coincide during the most (already) challenging balancing periods. It is particularly important to note that the case studies do not consider net load: the net variability resulting from demand and VRE output combined. Again this is due to the fact that net load data were not available in all cases. Instead the case studies simply sum the two requirements.

10. The case studies do not quantify the likely positive effects of geographical spread in the VRE portfolio to the full extent. Neither do they attempt to quantify the benefits of complementarity of outputs among a wide portfolio of variable technology. They are addressed qualitatively. Both these factors may have important impact on the extent of flexibility requirements, and should be addressed in more refined assessments.

11. The analysis has carried out a literature review of recent estimates of the integration costs associated with wind power, and isolated the balancing costs included among these. This is not always a simple matter, as the assumptions and aspects considered vary from study to study. Compilation of balancing costs suggests a range of USD 1/MWh to USD 7/MWh, at 20% share of average electricity demand. These are modelled costs, and do not take into account all the four flexible resources discussed in the IEA analysis. Balancing costs are strongly related to the availability of flexible resources.

12. The FAST Method focuses on the technical capability of a system to ramp up and down, and how this can be maximised if this is considered desirable. It does not address the economic or environmental repercussions of its doing so.

13. In its final form the FAST Method could be suitable for use in a pre-screening phase of power system planning, where the deployment of variable generation is a priority. However, it should be noted that FAST is not designed to replace a detailed integration study, which is essential for any major effort to deploy variable renewables.

Recommendations to policy makers

1. Whatever the form of the flexible resource — dispatchable generation, storage, interconnection, or demand side response — what matters is its extent. For example, the Canadian NBSO area and Denmark can rely on their large interconnection capacities; while the Nordic and Iberian regions can look to their hydro and pumped storage. Policy makers should look to the specific resource mix in their jurisdictions when considering the flexible resource portfolio.

2. A balanced approach to increasing flexibility is needed as variable power plant capacity grows. On the one hand, market and operational constraints on the availability of flexible resources need to be reduced as far as possible while deployment of variable power plants continues. On the other hand, the impact of increasing variability and uncertainty in the net load on system management needs to be monitored carefully.

3. Adjacent power markets should collaborate to share their portfolios of flexible resources, using the whole more efficiently to balance increasing shares of variable renewables. Market couplings, such as are growing in the European area, are a valuable step towards the merging of electricity markets.

4. The latest VRE output forecasting techniques should be taken up in areas targeting significant deployment, and these should have material impact on the commitment of power plants in the system. Markets should feature short gate closure times, allowing trading of electricity to continue up to within the hour before time of operation, to minimise the "lock-in" of valuable flexible resources.

5. Policy makers should assess the adequacy of economic incentives presented by the market (through fluctuating prices) for provision of the flexibility service. They should examine existing market mechanisms, if any, such as balancing markets, through which the service has been provided to date; and should consider whether or not additional incentive and/or innovative market mechanisms will be required to ensure the provision of sufficient flexibility (from the day-ahead up to the time of operation), to balance their targeted share of VRE.

6. Policy should remove (unnecessary) regulatory barriers to the provision of flexibility services, such as non-electrical constraints on the use of hydro plants for balancing. It should also take into account the possible implications of initiatives such as the drive to reduce the CO_2 emissions of fossil fuel plants through carbon capture and storage, which may have an impact on the technical ramping capability of such plants, as well as the flexibility benefits of decoupling heat and electricity production in combined heat and power (CHP) plants.

7. Policy makers should encourage holistic, early planning of energy system development. VRE power plants should be dispersed as widely as possible within the bounds of high quality resources (*e.g.* strong winds) to maximise the smoothing of their aggregated output. Consideration should be given to the deployment of VRE types whose outputs are complementary in specific areas (*e.g.* wind, solar) as this too will present a smoother overall output from the VRE portfolio.

8. Smoothing through geographical and VRE technology portfolio diversity will only be apparent if all such plants are connected to a robust transmission grid. In many countries, the best onshore wind resources, for example, are located far from demand centres in areas only weakly served by the grid. The reinforcement and extension of grids can be a complex and lengthy planning challenge, and construction subject to heavy delays caused by public antipathy. Policy makers should therefore urgently ascertain where grid weaknesses exist, and where congestion is likely therefore to occur, and commence planning and remedial measures as soon as possible. Smart grid technologies such as dynamic line temperature monitoring may be of significant benefit in this regard.

9. Areas with more ambitious plans for variable renewables deployment may need immediately to start planning how they will increase their flexible resources (for when the availability of existing resources has been optimised). Some demand side resources may be activated relatively quickly from a purely technical point of view, though consumer habits may take longer than expected to change and the roll out of smart appliances and other smart grid technical components will take time. New interconnections to adjacent markets tend to have particularly long lead times, while dispatchable plant and storage facilities, if required, may also be subject to delays.

10. For the provision of the flexibility service by slower dispatchable power plants (CCGT, coal, nuclear), fast ramping rates and low minimum stable operating levels are of the utmost importance. This is particularly so if, as this analysis suggests, the greatest need for additional flexibility is found in the longer term (36 hours rather than 15 minutes). These should be key features of new dispatchable plants replacing the old, or deployed in response to increasing electricity demand.

11. Policy makers should consider the operational costs of greater wear and tear resulting from increased cycling of existing and new dispatchable plants due to increasing variability in the net load. This will be compounded by reduced revenues for those plants (particularly mid-merit gas and coal plants) resulting from their displacement by VRE. Policy makers should ensure that sufficient incentive exists for owners / investors to maintain these valuable sources of flexibility, and to build new plants when necessary, so that the system can continue to balance an increasingly volatile net load, and so that the adequacy of the system to meet electricity demand in the longer term, beyond the balancing timescale, is ensured.

12. In future, it is possible that quickly dispatchable generation capacity will cease to be the sole primary driver of flexibility. New storage technologies may emerge that are less dependent on geographically limited resources like rainfall, or geological features.[3] The demand side resource may grow as the incentive to respond becomes clearer, as the effort required is reduced, and as new electricity uses emerge such as the charging of electric vehicles. And, thanks to new interconnections, markets may merge to create larger balancing areas with a smoother net load wherein even the least flexible plants (such as conventional nuclear stations and older steam plants) can play a role in balancing.

13. Indeed, policy makers are encouraged to view the electricity system as only a part of a wider energy system including heat and transport sectors. Technologies such as electric vehicles and increased electrical heating (in effect the storage of electricity in car batteries or as heat) are becoming increasingly significant. Thus policy initiatives in the electricity sector have important implications for the other two sectors, and vice versa, and should take them into account.

Next steps and further research

1. In the next phase of work, the IEA Secretariat will endeavour to shed light on the relative costs of flexibility measures: from soft market measures like shorter gate closure times, through grid reinforcement, to deployment of new flexible resources (dispatchable plants, interconnections, storage, demand side) against very high penetration of VRE.

2. Further research will examine the effectiveness and design of existing market mechanisms intended to facilitate efficient balancing of electricity supply and demand; and how these could be improved to ensure that an economically efficient amount of flexible resource is maintained to cover increasing variability and uncertainty.

3. Quantitative analysis remains to be done on the duration, extent and impacts of price volatility resulting from increasing shares of VRE in electricity supply. This volatility will have costs and benefits to different stakeholders. It may benefit the most flexible resources (*e.g.* simple gas turbines) to the detriment of the least flexible, such as base-load power plants. Such analysis should also attempt to highlight the cost effectiveness of curtailing the output of VRE plants at certain times for limited periods to minimise the occurrence of negative prices.

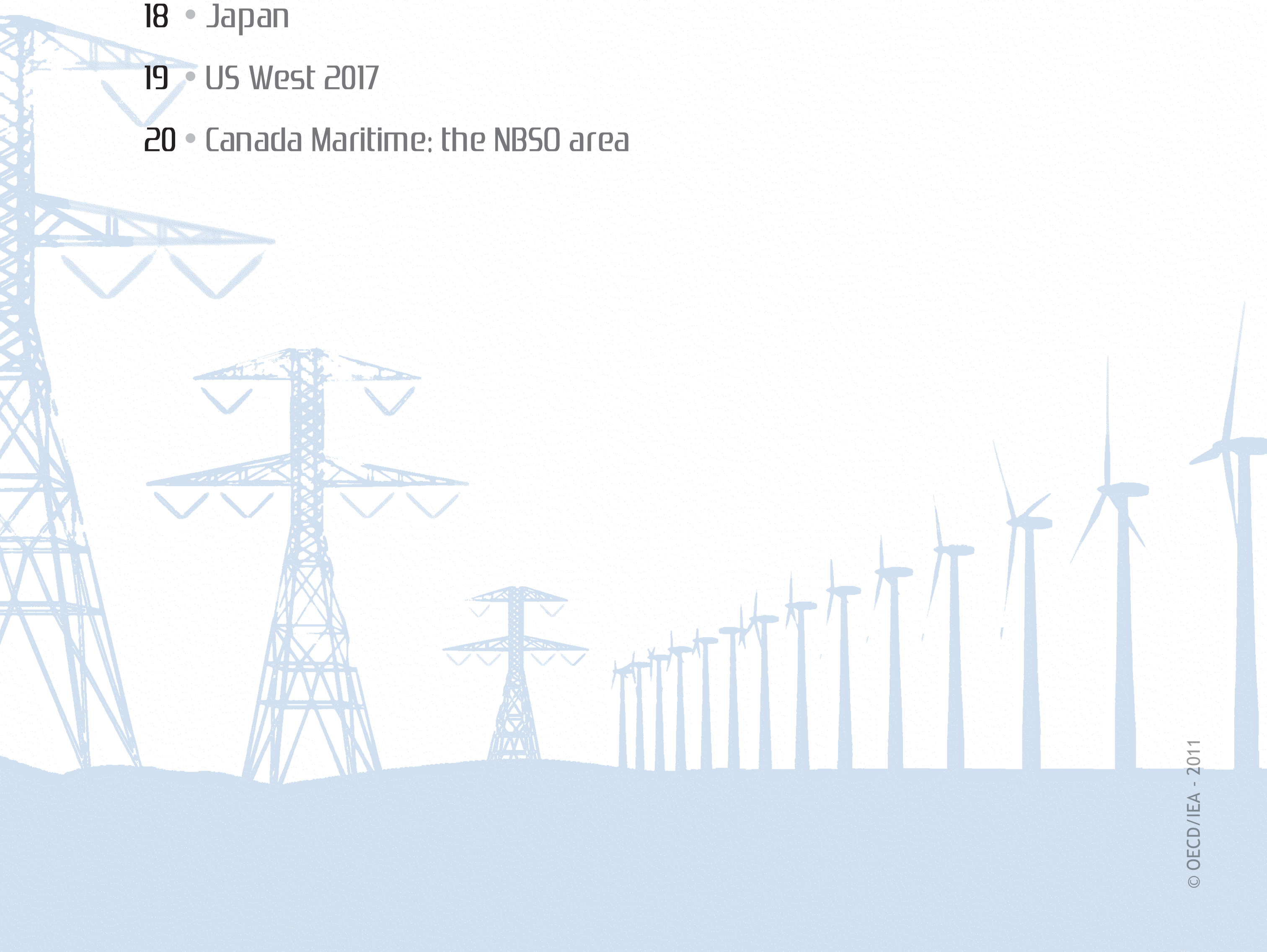
4. This analysis emphasises measures to optimise the use of existing flexible sources, before deploying additional ones. However, there may well be a point at which it will prove more cost efficient to deploy new resources, rather than making available the very last unit of what exists already. For example, it is possible that increasing the size of the demand resource may prove less costly than making available the last unit of the dispatchable power plant resource. The point at which this will occur will depend on the individual resources of the system in question. This issue remains for the next phase of analysis.

3. For compressed air energy storage (CAES) or for hydro reservoirs.

5. FIX and PVP values are highly sensitive. Existing flexibility requirements (from the demand side), the likely operation of plants (base-load, mid-merit, *etc.*), and the technical ramping capabilities of different types of plant can all have very large impact on them. Such sensitivity analysis is required as part of ongoing refinement of the FAST Method.

6. Part loading of mid-merit fossil fuel plants (or indeed backing down generation from base-load coal or nuclear plants), to provide greater up-ramping capability, may increase CO_2 emissions per megawatt hour at such times when this occurs. However, part load operation would be needed only at times of high flexibility requirement — a relatively small proportion of the time. The slight emissions increase per megawatt hour is therefore likely to be dwarfed by the CO_2 emissions saved overall by VRE plants' displacement of fossil fuel use in power production more generally. Quantification of these elements remains for further analysis.

Part 2



12 • Case study methodology

Additional to the analysis in Part 1, this chapter provides further methodological detail about the balancing time frame, and how flexibility requirements and resources are treated in the case studies. This will be of interest to those more familiar with the issues discussed in this book. Key assumptions are highlighted, including where simplifications to the FAST Method as described in Part 1 have been made for its use in the case studies, due to project practicalities.

Chapter 12 explains the calculation of the two metrics identified in this analysis: the Flexibility Index (FIX), and Present VRE Penetration Potential (PVP); then describes how important attributes of the power area — which qualify these two metrics — have been scored and weighted.

Chapters 13-20 highlight the findings of the eight case-study areas. These include the British Isles (the islands of Ireland and Great Britain); the Iberian Peninsula (Spain and Portugal); Mexico; the Nordic Power Market (Norway, Sweden, Denmark and Finland); a separate assessment of Denmark within that market; Japan; the Western Interconnection of the United States in 2017; and the part of the Canadian Maritime provinces operated by the New Brunswick System Operator (NBSO).

Each case study addresses the following:

- The flexible resource required to balance VRE in the 36 hour time frame (as well as in shorter time frames within it). The maximum extent of the requirement is quantified, then further qualified by a series of scored area attributes.

- The flexible resources of the area (dispatchable power plants, storage facilities, interconnections for trade, and demand-side management and response). These are quantified within the bounds of data limitations.

- The FIX value of the area and its PVP value are calculated. This takes into account (existing) flexible resources and requirements for them — both existing (fluctuating demand, contingencies), and additional (VRE).

- The final section of each case study addresses a range of constraints on the availability of flexible resources for use in balancing specific to each area. These constraints fall into two baskets: those relating to individual flexible resources (*e.g.* the importance of smart grid for demand-side response availability), and those having bearing on the sum total of the flexible resource (*e.g.* market design).

The balancing time frame

The case studies look at the period beginning 36 hours before the moment when electricity is produced and consumed, and when production and consumption must be in balance. This is the balancing time frame. Though it might be extended to several days, 36 hours will cover the maximum extent of changes in wind, solar, tidal and wave resources that will be seen in most areas.

Within this time frame, variability is assessed over three others, **15 minutes** is the shortest of these. The fastest flexible resources will be most important in this time frame, able to ramp up or down steeply to maintain balance in production and consumption. Little planning of system operation can be done at such short notice. Longer-term planning will need to have ensured the availability of fast flexible resources, particularly against uncertainty.

1 hour is a significant time frame because the planning of the operation (dispatch) of power plants in the system is often done in hourly blocks. Within this time frame, errors in prediction of VRE resources and demand begin to be more significant (as forecast accuracy increases closer to the time of operation).

6 hours is enough time for many dispatchable plants to start up or shut down; and output from VRE may vary considerably over six hours. In this time frame, storage facilities, and perhaps demand response, may be approaching the limit of their capability to provide their full technical contribution flexibility continuously in one direction (up or down). Existing requirements for flexibility (changes in demand and uncertainty of demand) will also be increasing.

36 hours ahead is, in many systems, when the balancing challenge begins. This time frame will experience the full extent of variability that a power system is likely to experience, even from the least regular resources — wind and wave energy. The 36-hour time frame will also encompass the maximum change in demand of the system, from minimum to peak and vice versa (*e.g.* from midnight on Saturday/Sunday to midday Monday).

Flexibility requirement of VRE

The variability in output from VRE technologies means that their deployment will impose a demand on the rest of the system to accommodate such variations. The extent of this **flexibility requirement** will depend on the extent of this variability, and the uncertainty in the output forecast.

Treatment of variability

The FAST Method measures variability in VRE output in terms of the percentage of installed capacity per minute, considering the two most important factors: the **extent** of the maximum ramp, and maximum **rate** at which this ramp occurs. Although two flexible resources may have the same ability to ramp their outputs in response to the full extent of a ramp in net load, it may be that only one can respond at the rate required to keep pace.[1] The analysis focuses on the largest ramp that might be observed in each of the four time frames, to capture the greatest extent of the balancing challenge. Limiting factors are applied in the 1-hour, 6-hour and 36-hour time frames to take into account the fact that the maximum rate of change is unlikely to be sustained over the full period in question.[2]

Due to the advanced deployment of wind power worldwide to date (194 GW at end 2010), and to limited experience to date with the integration of other VRE technologies, variability data are based mainly on wind energy. The analysis uses values based on observed data received in response to project questionnaires. A key additional source for wind energy data was the IEA *Wind Task 25 Final Report, Phase One 2006-08* (IEA Wind, 2009). Some of this experience with wind energy can be reasonably extrapolated to other technologies, such as offshore wind and wave power more easily than others. The impact of variability of the solar photovoltaic (PV) output (due to shifting cloud cover) has been less studied partly because this technology has to date been deployed largely in small units, which are difficult to monitor collectively. Tidal phases have long been understood. Where no data were available, assumptions were made based on other generating technologies, IEA analysis and sources in the literature.

Treatment of uncertainty

Variability within a given period requires a corresponding amount of flexible resource to cover it. If variability were perfectly predictable, the fastest flexible resources (*i.e.* available with 15 minutes notice or less) would be needed solely against variability during fifteen-minute periods, one-hour resources against one-hour variability, and so on — whenever these periods occur during the time frame. Forecast uncertainty, however, means that part of the fastest flexible resource must be held in reserve for use in the period immediately before the time of operation (when electricity is produced and consumed), to cover this uncertainty.

1. The frequency of such ramps will also be important, but this is not quantified here.
2. The limiting factor is in the form of a multiplier with value less than one. Values were based on empirical data from the Nordic market, Ireland and western United States.

The extent of the error in the final forecast used in the planning of system operation will only be known when the electricity is actually produced. It will depend on how far ahead of delivery – known as the time of **gate closure** – the producer must commit to delivering a specific volume of energy. For example, gate closure in a typical day-ahead market will occur 36 hours ahead of delivery, in which case forecast uncertainty may be very considerable.

How much of the (most) flexible resource must be held back against uncertainty, additional to variability? This analysis takes one of two approaches to calculating this figure, depending on the time frame being assessed.

Within the six hour time frame, the two requirements of variability and uncertainty are summed: they are considered to "compete" for flexible resources. For example, if the maximum ramp up or down in VRE output over a 15-minute period is 10% of its installed capacity,[3] and the uncertainty of this forecast is 5% over the same period, then the maximum flexibility requirement of VRE in the period is equivalent to 15% of installed capacity.

This is conservative for two reasons. Both % variability and % uncertainty represent maximum (most challenging) cases, whereas in most cases the actual values will be less than the maxima. It also assumes that the flexibility requirements resulting from both factors are in the same direction, *i.e.* that the observed ramp – up or down – is assumed to be greater than the predicted ramp, whereas it may equally be the case that a forecast will result in an over-estimate of the requirement.

In the 36-hour time frame, however, simply summing the two requirements would greatly overestimate the need for flexibility. If, for example, maximum possible variability is 90% of installed capacity and maximum uncertainty is also 90%, then simply summing them would yield a total flexibility requirement of more than the installed VRE capacity. In fact, complementarity between the two requirements will become increasingly likely as the time frame increases, but quantifying this was beyond the project scope. Consequently, this analysis applied a limiting factor to the maximum flexibility requirement of VRE in the 36 hour time frame, based on the data received in response to project questionnaires and the literature.

In summary then, the FAST Method is simplified for use in the case studies to take into account limitations on data availability. It is assumed that in the 15 minute, 1 hour and 6 hour time frames, a unit of flexible resource can meet either variability or uncertainty; and the two flexibility requirements are summed. In the 36-hour time frame, the larger of the two values – usually variability – is taken to represent the maximum requirement for flexibility. For example, in the assessment of the British Isles, maximum variability over 36 hours is estimated to be 85% of installed VRE capacity, and uncertainty 71%; the larger of the two values (85%) is used to represent total flexibility requirement.

Existing flexibility requirement

Existing flexibility requirement (EFR) is a measure of the flexibility requirement of the power system that pre-exists the addition of VRE power plants. It results mainly from demand variability and uncertainty. EFR also includes a margin of capacity against unexpected losses (contingencies). This margin usually corresponds to the largest single power plant or major transmission line.

The project questionnaires requested maximum demand variability data, the main component of EFR. Where data were unavailable, estimates were made based on the **load factor**, knowledge of other areas and the literature. Where contingency data were missing from questionnaire responses, estimations were made based on knowledge of similar cases.

3. As might be in the case in a relatively small area such as Ireland, for example.

The frequency of extreme swings in VRE output is assessed to give some indication of the likelihood of their occurrence during periods of high EFR;[4] if swings are frequent, resulting needs for flexibility are more likely to coincide with existing needs against swings in demand. In contrast, where VRE swings occur only infrequently, the conservative assumption to sum existing and VRE flexibility requirements (as made in the case studies, see below) will be more significant.

A system operator's comfort with, experiences of, and tools for handling variability and uncertainty are likely to depend on the existing extent and complexity of the balancing challenge (prior to the introduction of VRE). The load factor[5] of an area will give a rough indication of this. Broadly speaking, a high-load factor indicates less extensive load variations. Areas with extensive demand variability (perhaps with a relatively low load factor of 50%) and a high ratio of minimum to maximum demand, will be likely to contain a large proportion of highly flexible plant (and possibly other flexible resources) to deal with peaks.

In another area, average demand may be closer to peak (*i.e.* a high load factor, perhaps 75%), and there may be little difference between minimum and maximum demand (perhaps less than 20%). Such areas may, for example, have high industrial loads that fluctuate little over the course of a 24-hour period. Since the requirement for flexibility has historically been low, such areas are likely to have a predominance of relatively inflexible power plant.

Total flexibility requirement

The flexibility requirement of a power system is a function of the combined variability and uncertainty in the level of electricity demand, combined with variability and uncertainty of VRE output — referred to as **net load**. Depending on the frequency of extreme swings in VRE output, flexible resources to cope with fluctuating demand are likely to be available to some extent to cover the additional flexibility need arising from VRE.

However, the quantification of overall flexibility requirement in the case studies is based on demand ramps and VRE ramps that are fully negatively correlated — *i.e.* maximum ramp **up** in demand is assumed to coincide with maximum ramp **down** of VRE output, and vice versa — and the two requirements are simply summed. In effect, this means that any complementarity that may in fact exist in a given area between existing needs and the output of VRE (*e.g.* PV up-ramping concurrent with the morning demand rise) is not accounted for.

This constitutes a very conservative assumption, and is made only due to data limitations. It would not feature in more refined assessments using the same FAST Method, but with net load data. The result of this simple approach is likely to be an exaggerated assessment of the requirement for flexibility. However, in the absence of better data, it does at least ensure that the most extreme cases are covered.

Geographical and technology spread

The benefit of geographical spread[6] in terms of variability is partially quantified in the case studies by the level of the cap on maximum extent of variability seen in VRE output on the 36-hour time frame. This reflects that the smoothing effect is greater for large areas than for small areas. The importance of geographical spread on the extent, frequency and rate of variability is further reflected by high weighting of the scored attribute.[7]

More refined assessments using the FAST Method could use empirical time series data of VRE output from plants dispersed about the area in question as the basis for a more precise calculation of the

4. The attribute is scored qualitatively as "frequency of extreme events".
5. Average load over peak load.
6. Geographically large systems will see greater smoothing of aggregated VRE output variability if VRE power plants are widely dispersed over a strong grid throughout the area.
7. As explained in Part 1, some attributes are scored qualitatively in the case studies due to data limitations.

benefit of geographical spread in that case. If such data are not available, then assumptions could be made based on data from other areas with greater experience of, though it should be borne in mind that output profiles will differ from area to area.

Although considerable data exist on smoothing via technology spread in the VRE portfolio, little experience has been gained on how outputs correlate in practice. In the case studies, technology spread is scored purely qualitatively, and medium weighting reflect its potential significance.

Assumed VRE portfolios

At present, the vast majority of experiences with integrating VRE have been with wind power. But an analysis of the challenges, particularly one primarily designed to illustrate the FAST Method, would be rather limited if it looked at onshore wind energy alone. The solar PV market is accelerating steadily though the majority of the market remains in the distributed (small scale) sector; the focus of this analysis is centralised, transmission level plant. The offshore wind market is also accelerating; and although wave and tidal deployment are negligible at present, these technologies also have considerable potential in some areas.

With this in mind, hypothetical portfolios of VRE types have been created that comprise some or all of the VRE types included in this analysis – on and offshore wind, wave, solar PV and tidal – bearing in mind the natural resources of the area in question. These portfolios are not based on national deployment targets, even where these exist; this analysis focuses on power systems as they are configured today.[8] Finally, a hypothetical portfolio enables comparisons of variability and uncertainty values of different VRE types. So likely portfolios are a little more imaginative, featuring greater proportions of offshore wind, solar PV, tidal and wave resources then presently seen.

Treatment of flexible resources

The case studies assess the technical flexible resource[9] available in the eight areas, examining each of the four resources in turn: dispatchable generation, storage, demand-side response and management, and interconnection.

As the net load of the system ramps down/up, one or a combination of the following must occur to maintain balance:[10]

- Dispatchable generators must decrease/increase output.
- Demand must decrease/increase.
- VRE output must be stored/stored electricity must be released.
- VRE output must be exported/electricity must be imported.

These four responses can be provided, respectively, by:

- Dispatchable power plants whose outputs are fully controllable, not being dependent on a variable resource.
- Contracted demand-side management or stimulated response on the part of consumers.
- Storage facilities – pumped hydro reservoirs, compressed air energy storage (CAES), battery storage, and potentially others.
- High voltage interconnections to adjacent power markets, to take advantage of the flexible resources therein.

8. The exception is the US western interconnection, which is assessed for flexibility in 2017.
9. Technical resource is used to mean what is theoretically available, which in practice will be limited by various factors.
10. Flexibility can also be increased by limiting or curtailing VRE generation. While this measure can be a significant contributor to VRE potential, it is not assessed in the case studies; it should be included in more refined assessments.

Flexible capacity will need to be available at short notice (to deal with sudden variations and uncertainty) as well as for ramping over longer periods (in response to a forecast need). It may generally be the case that the total flexible resource will be greater further ahead, as slower resources will be able to respond. However, it will not be possible to continue to use storage and demand-side flexible resources indefinitely. Storage units will have a maximum holding capacity, after which they will need to be refilled. Similarly, consumers may be willing to reduce their consumption only for a certain period of time. The impact of these limitations is not included in quantification of the technical flexible resource in the case studies.

Dispatchable generation

The case studies consider the following technologies:

- Fossil fuel-fired thermal plants, including gas, coal, diesel and oil.
- Biomass-fired plants.
- Reservoir hydropower plants.
- Nuclear plants.
- Combined heat and power plants.

In most areas assessed, all types of dispatchable plant were reported as technically able to ramp their output — at different rates, and to different extents; nuclear was an exception in some cases. Technical ramping capability is not always clear; it may be that capabilities are greater than assumed/ reported in some cases.

Maximum ramping rates (MW/min) can be calculated for each generation unit in each plant in the power system, but these case studies use average values for broad technology types.[11] Maximum ramping range will lie either between minimum stable and maximum output, or between zero and maximum output (if the plant has to start up and maximum output is possible in the time frame in question). Low minimum stable operating levels are very important: a plant that can ramp down to a low level, but does not need to shut down completely, is usually able to ramp up more quickly. In predominantly thermal systems, unless a plant is specifically designed for peak-time operation, it will not have time to start up and shut down (or vice versa) within an hour.

Other VRE technology types such as geothermal plants and concentrated solar power (CSP) plants[12] are not present in the case study areas, and should be included in assessments of other areas.

Likely operation of dispatchable plant

The availability of a dispatchable plant to provide the flexibility service will depend on what it is already doing when it is needed. This will vary from type to type and area to area. The FAST Method assesses the likely operating states of dispatchable plants during the two periods which represent the operational planning extremes — peak and minimum load. These extremes provide a range of likely availability. Values are based on responses to project questionnaires, and knowledge of the likely merit order of units on the system. [13]

The FAST Method considers four operating states:

- Operating at maximum output.
- Operating at below maximum output (*i.e.* part of capacity is online but not dispatched).
- Mid-merit operation (operating close to minimum stable output).
- Offline.

11. In this analysis generic values are used — only specific to the power area if data were available.

12. It is assumed here that CSP plants include integrated thermal storage facilities enabling them to bridge the night time production lull.

13. The merit order is the order in which power plants are dispatched to meet demand, usually the cheapest first.

Changes in operation, particularly of less flexible plants, will be more easily effected in longer time frames. For example, within the 36-hour time frame, against a forecast need for down-ramping (*i.e.* VRE is increasing), a normally mid-merit unit could – from a purely technical point of view – be ramped up in advance to provide that down-ramping flexibility as it became necessary.

Assumptions made about what types of unit are online at peak and minimum demand will differ from area to area. For example, a CCGT unit may be operated as baseload plant in one area, but as mid-merit plant in another. This, in turn, will depend on such factors as the demand profile of the area, the quantity of VRE output (which may alter the merit order), fossil fuel prices, and individual plant attributes such as ramping rates and start up/shut down times.

Dispatch assumptions made in the case studies do not take into account opportunities to change the use of interconnections, storage facilities, or demand-side behaviour to meet net load – rather than only providing a flexible balancing resource. So the impact of such changes on the likely operation of dispatchable power plants is not picked up.

Calculating maximum ramping capability

The capability of dispatchable plants to ramp up or down will depend on their operating state at the time they are called upon to do so. Given the four time frames considered in the case studies (15 minutes, 1 hour, 6 hours and 36 hours), there will be eight situations which capture the maximum extent of this capability: four during minimum demand periods, and four during peak demand periods.

At minimum demand these will be:

- Down-ramping capability to meet requirements 15 minutes and 1 hour ahead.
- Up-ramping capability for 6 and 36 hours ahead.

And during periods of peak demand, they will be:

- Up-ramping capability to meet requirements 15 minutes and 1 hour ahead.
- Down-ramping for 6 hours and 36 hours ahead.

In the first case during minimum demand, for example, the capacity capable of ramping down to provide for flexibility required 15 minutes later will be heavily constrained by the fact that the system is already operating at the bottom of its normal range. In the second case, still during minimum demand (*e.g.* middle of a week night), up-ramping for 36 hours ahead will be constrained by the fact that 36 hours later the system *already* will be ramping up hard towards peak (e.g. midday on a week day). The opposite case will apply during peak demand periods: up-ramping will be constrained in 15 minutes to 1 hour as much plant is already at maximum, and down-ramping will be constrined in 6 hours to 36 hours as the system will already be ramping down by then.

The values for these eight occasions are summarised for the dispatchable plant portfolio as a whole on the basis of the proportions of plant types installed, their capacities, their technical ramping capabilities, and their likely operating states during the two periods. Those calculated for dispatchable plants in the British Isles, taken from the case study, are shown in Table 5. Maximum ramping values as constrained by peak demand are shown in orange, and values constrained by minimum demand are shown in yellow.

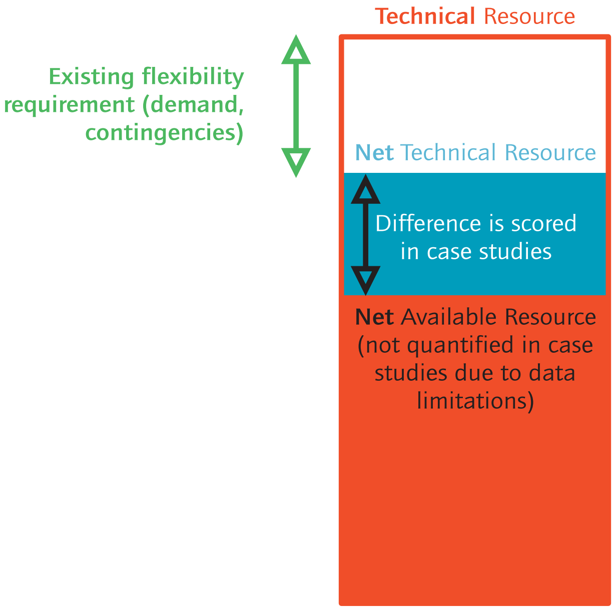
Table 5 • Technical flexible resource from dispatchable power plants in the British Isles

Flexible resource in	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	10 633	16 224
1 hr	12 593	18 014
6 hrs	33 556	42 718
36 hrs	37 241	55 549

Net Technical Flexible Resource: an imperfect proxy

The available flexible resource (AR) should be used as the basis for calculating Flexibility Index (FIX) values, and Present VRE Penetration Potential (PVP), as explained in Part 1. However, the quantification of the extent of constraints on the availability of technical resources is no small task, and was beyond the scope of the project.

Figure 35 • Calculating net technical flexible resource (NTR)



Key point • More refined assessments using the FAST Method should attempt to quantify the constraint on TR represented by a range of area attributes, and use the available flexible resource (AR) as the basis for calculating FIX and PVP values. In these case studies, such constraints are scored qualitatively.

The analysis instead uses the technical flexible resource (TR), *i.e.* the full technical capability of the power system to respond flexibly, not taking into account constraints on it resulting from grid congestion, and imperfect market mechanisms and incentives. These and other elements are then scored qualitatively in a subsequent step.

As explained above, net load data were not available in all cases, so the existing flexibility requirement is then deducted from TR, to yield a proxy value for AR: the **net technical flexible resource (NTR)**, which is used as the basis for calculating values for FIX and PVP in the case studies (Figure 35).[14]

Full integration studies carried out by system operators into the opportunities for deploying new plants, an essential step in VRE deployment, would also be expected to identify what is required to quantify these scored constraints. The effect of gate closure, for example, may be quite simple to quantify in a general way. Others, such as the impact of grid congestion, will require very extensive data and analysis.

Flexibility Index and Present VRE Penetration Potential

To calculate FIX values to enable comparison of NTR (or AR) in different areas, NTR is normalised by dividing by peak demand.[15] The main factors behind the FIX value then, are the extent of technical flexible resource (TR) and that of the existing flexibility requirement (EFR). If two areas of the same size have a similar flexible resource, for example, but one has a higher EFR, its FIX value will be lower.

FIX is calculated for the four time frames. In most regions the FIX value would be expected to increase over longer timescales, as slower flexible resources (*e.g.* combined cycle gas turbine [CCGT]) become available to provide flexibility. However, this will not always be the case: certain areas will have the same TR over 6 hours as 36 hours if all of the resource can respond within the 6 hour time frame (*i.e.* it is generally of a flexible nature). In such cases, if EFR continues to increase up to 36 hours, NTR (and therefore FIX) will drop slightly over this period.

14. Calculations of FIX and PVP based on NTR implicitly assume that existing and additional needs for flexibility are additional.

15. Peak demand is used in this case, but a different basis for normalisation might also be used. The important point is that FIX should illustrate the benefits/disadvantages of differing flexible resources.

If dispatchable generation provided the same upwards flexibility as downwards, as is assumed to be the case with the other three flexible resources (storage, demand response and interconnection), there would be only one FIX value in each time frame. However, upwards and downwards FIX values differ according to the likely operation of plants during peak and minimum demand periods.[16]

The following tables show the FIX values from the case study areas, for up-ramping (Table 6), and for down-ramping (Table 7), on each time frame. The lesser value of each pair of up and down values represents the more constrained ramping capability. These are the values plotted in Figure 12 of Part 1.

Table 6 • FIX values for up-ramping

Area	15 mins	1 hr	6 hrs	36 hrs
British Isles	0.27	0.26	0.54	0.55
Iberian Peninsula	0.22	0.23	0.82	0.85
Mexico	0.31	0.27	0.65	0.60
Nordic Power Market	0.79	0.76	1.03	0.96
Denmark	1.01	1.02	1.21	1.24
Japan	0.29	0.29	0.51	0.47
US West 2017	0.56	0.52	0.80	0.88
NBSO area (of Canada)	0.53	0.51	0.70	0.65

Table 7 • FIX values for down-ramping

Area	15 mins	1 hr	6 hrs	36 hrs
British Isles	0.36	0.36	0.69	0.85
Iberian Peninsula	0.25	0.36	0.46	0.43
Mexico	0.28	0.27	0.62	0.63
Nordic Power Market	0.56	0.57	1.08	1.2
Denmark	1.30	1.36	1.50	1.72
Japan	0.33	0.42	0.72	0.92
US West 2017	0.37	0.38	0.67	0.78
NBSO area (of Canada)	0.82	0.83	1.08	1.09

The range between the two values is also significant. They reflect that in areas with only a small range between up and down ramping values, assumptions about likely operation of plant may have only limited impact. In contrast, in areas where this range is large, assumptions affecting the likely operation of plants will be more significant.

The PVP metric is also a product of NTR, divided by the maximum flexibility requirement resulting from variability and uncertainty of the area's VRE portfolio. For example, if the biggest flexibility requirement of a VRE portfolio in the 15 minute time frame is 25% of installed VRE capacity, and the flexible resource on that time frame is 2 500 MW, then the system can balance 10 000 MW of VRE in that time frame.

16. Dispatchable generation is the primary flexible resource in all cases assessed except the smallest and most heavily interconnected. It therefore drives FIX.

The resulting VRE portfolio capacity is then multiplied by its capacity factor to estimate average energy output, and the result divided by the gross electrical demand of the area, to give VRE penetration. The calculation of PVP is carried out in all four time frames, and the most constrained value, *i.e.* when the existing flexible resource is most scarce, is taken to reflect PVP. PVP values for the areas case studied are shown in Figure 31 in Part 1.

Scoring and weighting of area attributes

The assessment of the TR is relatively straightforward, and is quantitative, while constraints on its availability are assessed qualitatively. Similarly, the assessment of VRE flexibility requirement is quantitative, while a number of mitigating factors are addressed only qualitatively. This section provides an explanation of the scoring and weighting of both groups of attributes.

Availability of flexible resources

Specific attributes of the power area in question (British Isles, Denmark, Mexico) may have bearing on the availability of a specific flexible resource: for example the ownership of storage facilities may influence their availability for balancing. Alternatively an attribute may affect the total flexible resource – *e.g.* grid congestion will affect all four resources.

Three possible scores are assigned to each area attribute using a colour-coded system:

- **High score** (green): the attribute is likely to have positive impact on flexibility.
- **Intermediate score** (amber): the attribute presents positive and negative elements.
- **Low score** (red): the attribute is likely to have a negative impact on flexibility.

However, a low score in a particular attribute does not necessarily represent a heavy constraint on availability. Some attributes are of primary importance, such as internal transmission strength (grid) and market value of flexibility. Some are secondary, representing less critical constraints. The significance of a third group depends on the score of a primary attributes. For example, the absence of real time price availability to encourage demand-side response will only be relevant if grid intelligence – through which that response might potentially be made – is high, in which case its absence will represent an additional constraint. In contrast, if grid intelligence is low an absence of real-time price would represent no additional constraint and so would have lighter weight.

Another example, related to the flexible resource represented by interconnections to adjacent markets, would be the significance of line technology type (AC or DC). This depends on the extent of co-ordination among the markets at either end of the line. If co-ordination scores high, then line technology (a dependent attribute) will have limited weight regardless of its score; even a DC line (a low score) can be flexible if well planned. But if co-ordination is poor, a low score for line technology (DC) would represent an additional constraint, and have heavier weight as a result.

Each attribute is therefore also assigned one of three weights, regardless of its score, to reflect the extent of the additional constraint it represents. In this way, weighting can be seen as reflecting the urgency of remedial action to some extent. It is represented in the case studies by the shaded area of the circles.

- **Heavy weight** (three rings shaded): the attribute represents a heavy constraint on flexibility.[17]
- **Medium weight** (two rings shaded): the attribute still represents a significant constraint on flexibility.
- **Light weight** (innermost ring shaded): the attribute represents little additional constraint.

17. The combination of a heavy weight and low score means the attribute is more detrimental to flexibility than an attribute with an equal weight but an intermediate score.

It should be noted that low weight may still denote a degree of constraint. For example, even in the best cases, the operation and technical specifications of the transmission grid of an area will still limit the availability of flexible resources, compared to a perfect (unattainable) system.

VRE flexibility requirement

Scoring and weighting of attributes relating to VRE flexibility requirement is somewhat different from that of attributes relating to flexible resources. Four attributes are assessed qualitatively:

- Geographical spread
- Technology spread
- Location of VRE
- Frequency of extreme events

Geographical spread has heavy weight, regardless of score, and this is the same for all areas case-studied. This does not imply constraint of some kind. Here, heavy weight simply reflects the importance of the attribute. Where geospread potential scores highest, as in continental scale systems, weight remains high, reflecting the continuing importance of this attribute: reduced flexibility requirement. A low score also has high weight; it signals the importance, if possible, of increasing interconnections to or merging with adjacent areas to increase the smoothing effect on aggregated VRE output.

While the benefits of geospread are beginning to be understood, there is less knowledge of the value of technology spread. Medium weight in the case studies reflects this.

The weight of the "location of VRE" score relates to internal transmission strength; the location of VRE will be more important in areas where the grid is weak in places, as congestion will be more likely.

Finally, whether good or bad, scores for the "frequency of extreme events" attribute have light weight. This is not because the attribute is insignificant, but because the maximum extent of variability that will be seen in the area is already quantified in the preceding section of each case study. In more refined assessments wherein net load is used as the basis for calculation of FIX and PVP, a low score for this attribute would have greater weight.

Case study results

The GIVAR project selected a number of power areas to illustrate the Flexibility Assessment (FAST) Tool. These areas are Great Britain and Ireland combined (the British Isles); Spain and Portugal combined (the Iberian Peninsula); Denmark; the Nordic Power Market encompassing Denmark, Norway, Sweden and Finland; Japan; the New Brunswick System Operator (NBSO) area of the Canadian Maritime Provinces; Mexico; and the Western Interconnection of the United States.

These assessments are primarily based on data received in response to the GIVAR project questionnaires. Where no data were available, assumptions were made based on other areas and sources. Values and scores herein are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

In each case, flexibility requirements and resources are assessed on four timescales: 15 minutes, 1 hour, 6 hours and 36 hours, according to the methodology described in Part One. In the case studies, the FAST steps have not necessarily been taken in the same order as described in the guide, because not all the necessary data were available.

13 • Great Britain and Ireland area (British Isles)

Great Britain and Ireland — the British Isles — were assessed as a single bloc to illustrate the fact that the FAST tool can be used to assess any geographical area. It also reflects the importance of Great Britain's deployment of VRE to the Irish case: interconnection between the latter and its much larger neighbour is increasing, while interaction is likely to become more comprehensive through increasingly coordinated markets, with the result that actions taken in one will have increasingly important implications for the other.

Flexibility requirement of VRE

The case study assumes a portfolio of different VRE technologies.[1] As the area has a strong wind resource, it is assumed that wind will have the major share amongst variable renewables (70%). Marine potential is also considerable, so offshore wind, tidal and wave shares reflect this (25%). Some solar PV is assumed to be installed in residential areas (5%).

Variability and uncertainty data in Table 8 are extrapolated from data for the Irish system[2], and modified to capture the effect of increasing the size of the area to include the whole British Isles. This effect is captured only approximately.

Table 8 • VRE portfolio assumptions (British Isles)

Resource	Onshore wind	Offshore wind	Solar PV	Tidal	Wave
Maximum variability (% installed capacity/minute)	0.15%	0.20%	0.18%	0.1%	0.14%
Maximum uncertainty (% error/minute)	0.07%	0.10%	0.06%	0%	0.04%
Assumed share of technology in VRE portfolio (% of VRE portfolio)	70%	10%	5%	10%	5%
Assumed location relative to load	Far from load	Mixed	Near load	Far from load	Far from load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30%	35%	10%	25%	25%

The calculation of the overall flexibility requirement for the VRE portfolio flexibility requirement is shown in Table 9.[3]

Table 9 • VRE flexibility requirement (British Isles)

Time scale	15 mins	1 hr	6 hrs	36 hrs
Maximum variability (% installed capacity)	2.3	7.3	33	85
Maximum uncertainty (% installed capacity)	1	3.1	14	55
VRE portfolio flexibility requirement (% installed capacity)	3.2	10	46	85

As expected, variability increases over time, until at 36 hours the variability can cover close to the full installed capacity (a cap of 85% of installed capacity is given here as the area is relatively large and therefore it is unlikely to see periods of zero output or maximum output of VRE).

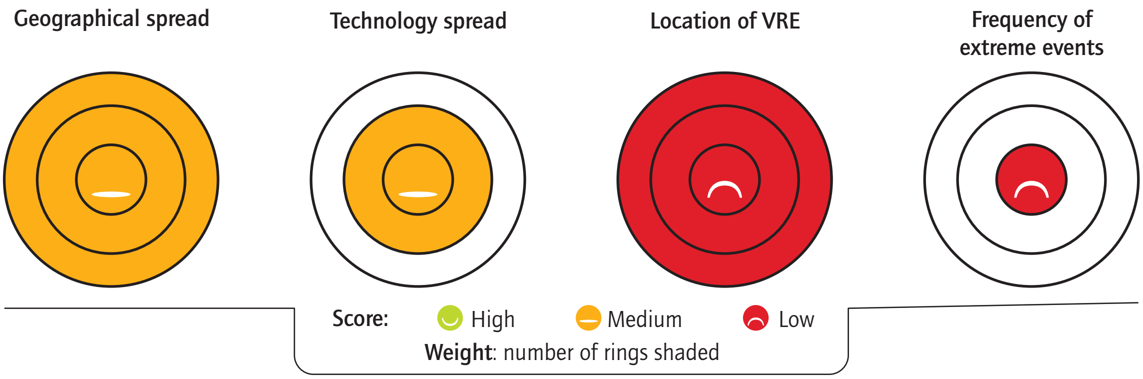
1. For explanation of the portfolio concept, see Chapter 12 "Assumed VRE portfolios".
2. In this context, Ireland includes Northern Ireland as well as Eire.
3. For discussion of the values used for variability and uncertainty, see Chapter 12 "Flexibility requirement of VRE".

Further qualification of flexibility requirement

The actual flexibility requirement is likely to be less than that shown in Table 9 since this simple approach omits a range of potentially beneficial factors due to limited data availability. The power area attributes which have additional bearing on the extent of variability are summarised in Figure 36, and described briefly below.

Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the "Location of VRE" attribute relates to internal transmission strength, see below; and the light weight of the "Frequency of extreme events" attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above (Table 9).

Figure 36 • Attributes relating to VRE flexibility requirement (British Isles)



Geographical spread. The region is relatively large. Strong wind, tidal and wave resources are well dispersed in both Great Britain and Ireland, and offshore. This will reduce the aggregated variability apparent in the system. However, the area lies within a single weather system, so variability will still be very significant, particularly on longer time scales as the weather front moves across the area. Overall it suggests an intermediate result.

Technology spread. The outputs of different VRE types will be correlated to some degree. For example, wind and wave outputs will not be well correlated on the west coast of Ireland, but they will be on the east coast. It is assumed that onshore wind power will make up 70% of likely portfolios (Table 8), in which case the effect of technology spread will be limited. These assumptions suggest an intermediate result.

Location of VRE. Most of the VRE resource is located at some distance from demand, so the requirements for internal transmission will be significant. This increases the importance of the internal transmission attribute, which is discussed later (Figure 43). This attribute has a low score and heavy weighting.

Frequency of extreme events. As onshore wind is assumed to be the most significant factor in the area, extreme events are likely. A low score in this attribute means that events are hard to predict and likely to be severe. The full extent of the flexibility requirement identified above will occur relatively frequently. It is therefore likely that such events will occur at a time when existing demand is high, in which case existing flexibility resources may already be committed and therefore not available for integrating VRE.

Flexible resources

Dispatchable plant

The present proportions of different types of dispatchable power plants in the British Isles are shown in Figure 37. Assumptions relating to operating levels and ramp rates, and definitions, can be found in Annex C: Assumptions Relating to Dispatchable Power Plants in Case Study Areas.

The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 38, expressed as a percentage of installed capacity that can be ramped up or down over the four timescales. The assessment of technical flexibility is based on data received in response to GIVAR project questionnaires.

Figure 37 • Dispatchable plant portfolio (British Isles)

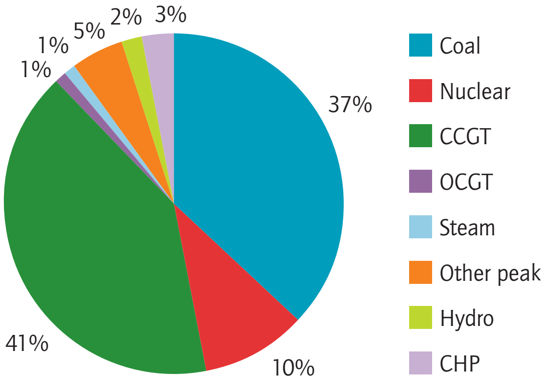
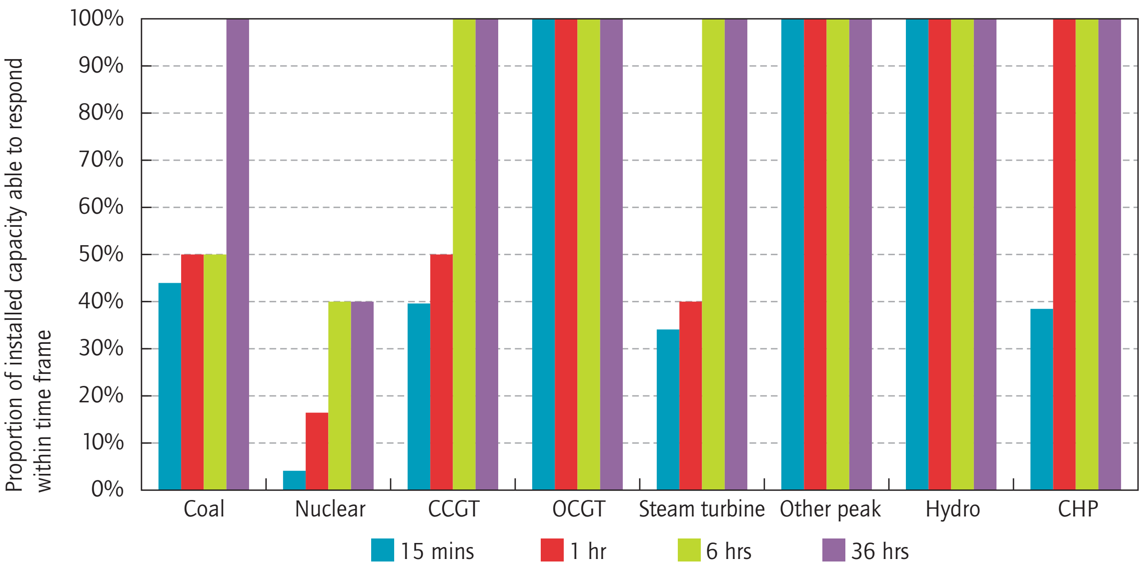


Figure 38 • Technical flexibility of dispatchable plant (British Isles)

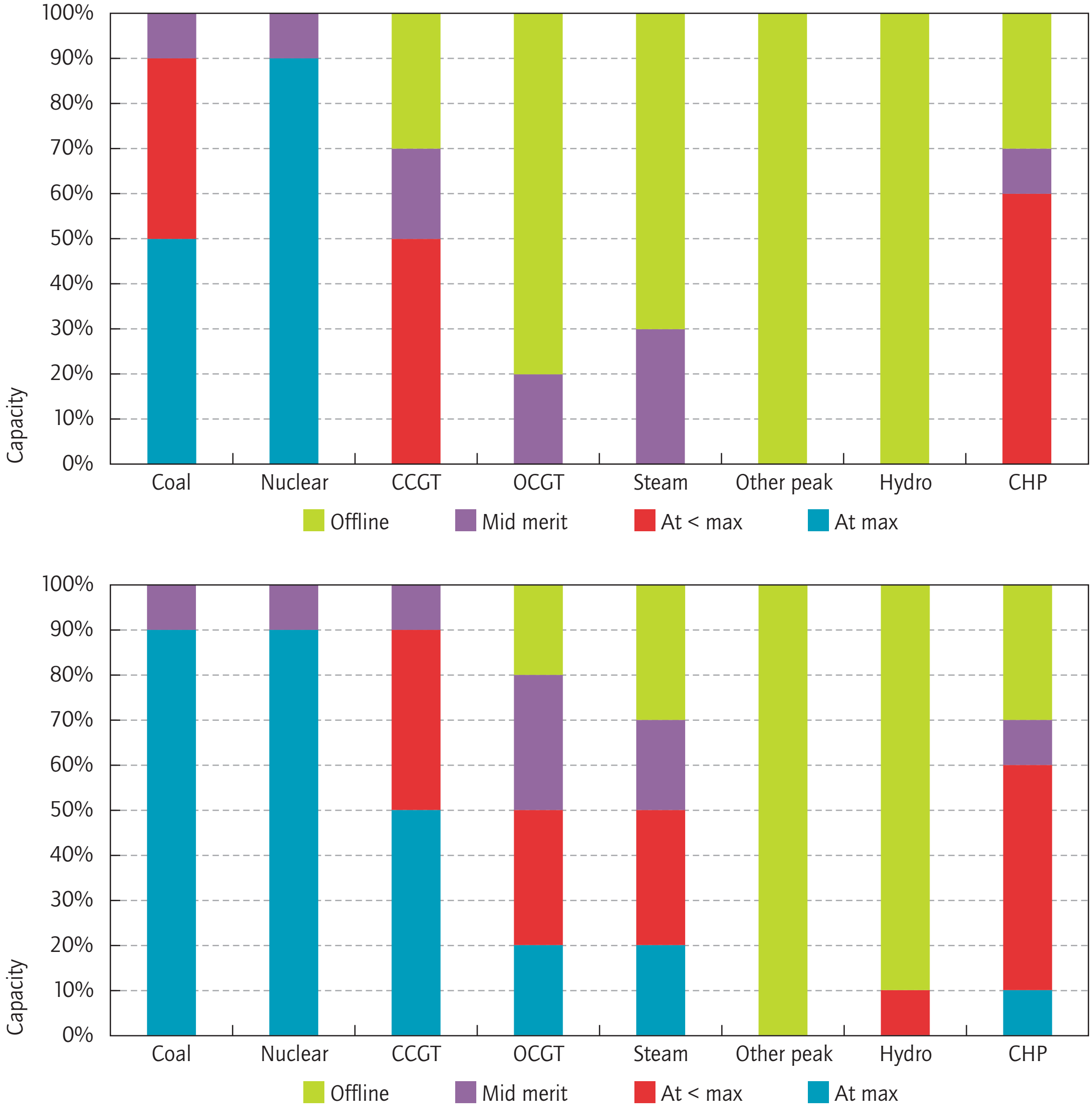


It should be noted that it is not only ramp rates (in MW/minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start-up/shut-down times are also important. For example, in the British Isles, coal plants are able to ramp down to a minimum stable level of 50% inside one hour, and could then shut down entirely inside 36 hours – if this were desirable from the flexibility perspective.

When only the technical capabilities of plants are taken into account, there seems to be a great deal of flexibility on each timescale. However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether or not it is operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down if operating below maximum. The expectations for dispatchable plant types in the British Isles are illustrated in Figure 39.

Figure 39 • *Likely operation of dispatchable plant (British Isles) at minimum demand (top figure), and peak (bottom figure).*



The figure suggests that coal-fired plant is more likely to run at full output than combined cycle gas (CCGT) plants. It should be noted that this ignores the increased carbon considerations of running coal more than gas. However, CCGT is more flexible and therefore more useful in balancing.

The final step is to calculate the likely availability of the whole dispatchable plant portfolio to ramp during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values are shown in Table 10. These will be the occasions when resources are most limited by existing requirements for flexibility.[4]

4. See Chapter 12 "Dispatchable generation" for discussion of these steps.

Table 10 • Technical flexible resource from dispatchable power plants (British Isles)

Flexible resource in:	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	10 633	16 224
1 hr	12 593	18 014
6 hrs	33 556	42 718
36 hrs	37 241	55 549

Flexibility increases with the time horizon, as a greater proportion of plants can ramp to a significant extent. The existence of such a large proportion of flexibility at 15 minutes assumes a large amount of spinning reserve (plants operating below maximum). While this would not be envisaged if the objective were to minimise operational costs, the objective for this exercise is to identify maximum technical flexibility. Other factors may also create particular constraints at the shorter timescales – for example, the cost of increased wear and tear on plants.

Storage

Pumped hydro storage offers approximately 2 700 MW in GB and Ireland. Pumped storage is extremely quick ramping and can go from zero to full output in less than 15 minutes, so this capacity is available over all time frames.

The pumped hydro facilities are estimated to contain 10 hours of storage, *i.e.* a total of 27 000 MWh. This means that while the flexibility technically available up to 10 hours is unlimited, continuous maximum ramping in the same direction beyond that timescale (*i.e.* in GIVAR terms, on the 36-hour scale) will be limited.

Demand-side

In most power areas, flexibility on the demand-side will be the most difficult to assess. It is the resource about which least is known, and which is at present little used. The estimate of demand-side flexibility used in this assessment of GB and Ireland may therefore be significantly lower than the real potential of this resource.

The potential demand flexibility in the British Isles is estimated to be just over 10% of peak demand, or approximately 7 700 MW.[5] Based on the literature, 10% would appear to be a conservative estimate, but even this is unlikely to be reached if area constraints, discussed below, are not lifted.

Interconnection

The total current connection to adjacent areas is 2000 MW, to one area – France – via DC links. A second cable, to the Netherlands, was under construction at the time of writing and intended to be completed by the end of 2010.

The connection between the two islands themselves is considered within internal transmission, later in the assessment process.

Flexibility Index and Present VRE Penetration Potential

These four technical flexible resources are summed in Table 11 to yield the total technical flexible resource – the overall ramping capability – of the power area, upwards and downwards over the four timescales (last two columns).

5. Based on existing data available for Ireland (DCENR, 2009). In areas where the resource has been assessed, potential lies mainly between 5% and 10% of peak demand.

Table 11 • Technical flexible resources (British Isles)

Time scale	Dispatchable plant		Demand-side	Storage	Interconnection	Technical resource	
	Up (MW)	Down (MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	10 633	16 224	7 700	2 250*	2 000	22 583	28 174
1 hr	12 593	18 014	7 700	2 700	2 000	24 993	30 414
6 hrs	33 556	42 718	7 700	2 700	2 000	45 956	55 118
36 hrs	37 241	55 549	7 700	2 700**	2 000	49 641	67 949

Notes:
* Technical flexible resource for up-ramping is limited by an estimated maximum ramp rate of 150 MW/min.
** Continuous maximum ramping in the same direction will be limited beyond 10 hours.

The existing flexibility requirement (EFR) of the area has been estimated based on Irish demand data and modified to include Great Britain. In these case studies, existing and new requirements for flexibility are simply summed, which gives a conservative estimate for the overall flexibility requirement. EFR is subtracted from TR to yield the net technical resource (NTR). NTR for up and down ramping are shown in columns 4 and 5 of Table 12.

Table 12 • Existing flexibility requirement and Flexibility Index (British Isles)

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	5 275	4 475	17 308	23 699	0.27	0.36
1 hr	7 775	6 975	17 218	23 439	0.26	0.36
6 hrs	10 775	9 975	35 181	45 153	0.54	0.69
36 hrs	17 775	16 975	35 866	54 974	0.55	0.85

The flexibility index (FIX) value is calculated by dividing NTR by peak demand, which in the area of the British Isles is estimated at 65 GW. FIX values for up-ramping and down-ramping are shown in the last two columns of Table 12. FIX values generally increase as the time scale increases. Only on one occasion does it reduce, and then only slightly, when EFR rises fractionally more than TR towards 1 hour. The NTR values for up-ramping – representing the most constrained instances – are carried forward to the next stage of the assessment.

The second variability metric – present VRE penetration potential (PVP) – illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the area are shown in Table 13.

Table 13 • Present VRE Penetration Potential (British Isles)

Time Scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	3.2	536 674	734 860	396%	542%
1 hr	10	166 840	227 120	123%	167%
6 hrs	46	75 755	97 207	56%	72%
36 hrs	85	42 196	64 675	31%	48%

Note: The range between values for PVP with NTR up and with NTR down reflect the likely operation of dispatchable generation at times of peak and minimum demand.

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled on, *e.g.* the 15 minute timescale, this is because the flexibility requirement of VRE is very small at this timescale, relative to NTR.[6] **It is only the most constrained occasion *i.e.* when the extent of variability is largest relative to the extent of flexible resource (in this case, upwards flexibility at 36 hours) that truly reflects PVP.**

In the British Isles then, from a purely technical perspective, some 31% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for flexibility are taken into account. This assumes no complementarity between existing and new requirements.

However, while both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the full range of power area constraints that will affect the availability of flexible resources. These relate to operation of the system and market in the area, and are discussed in the next section. They may be significant and, even if they were addressed, it is unlikely that any area would be able to reduce their impact to zero. As a result, flexible resources are unlikely ever to be completely available when needed.

Area constraints

The calculation of PVP above, based on the technical flexible resource (TR), is higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as congestion of internal transmission, sub-optimal operation and adverse market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

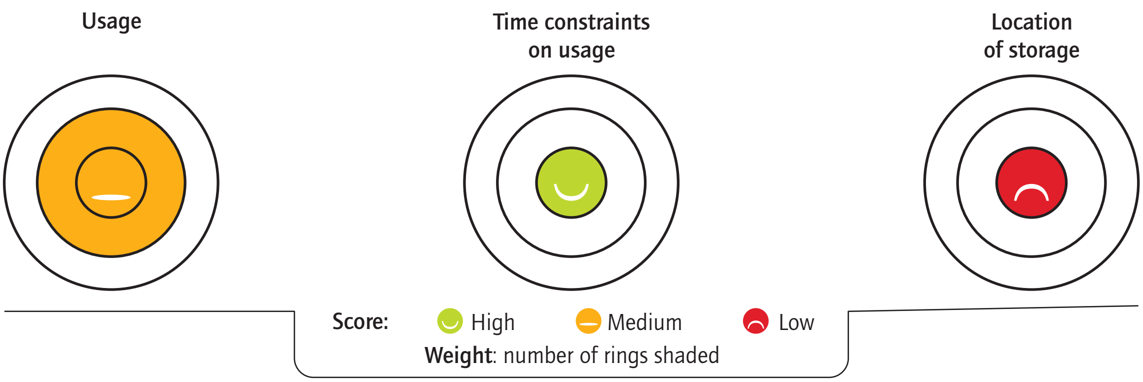
Individual flexible resources have particular constraints. These are addressed in the next sections, while constraints on TR as a whole are assessed subsequently.

Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 "Scoring and weighting of area attributes".

Available storage resource

The power area attributes with potential impact specifically on the 2 700 MW storage resource of the area are summarised in Figure 40.

Figure 40 • Attributes relating to storage availability (British Isles)



6. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.*, economic and operational) considerations.

Usage. In Ireland, storage facilities are owned by the Irish system operators, so their use for balancing need not be limited by simple commercial interests. In Great Britain, by contrast, pumped hydro storage facilities are not owned by the system operator. Owners are free to trade and dispatch power as they wish. Only if they enter contracts with National Grid, the system operator, for balancing services, can National Grid choose when to use the resource. An intermediate (yellow) score is awarded, with medium weight, reflecting limited constraint.

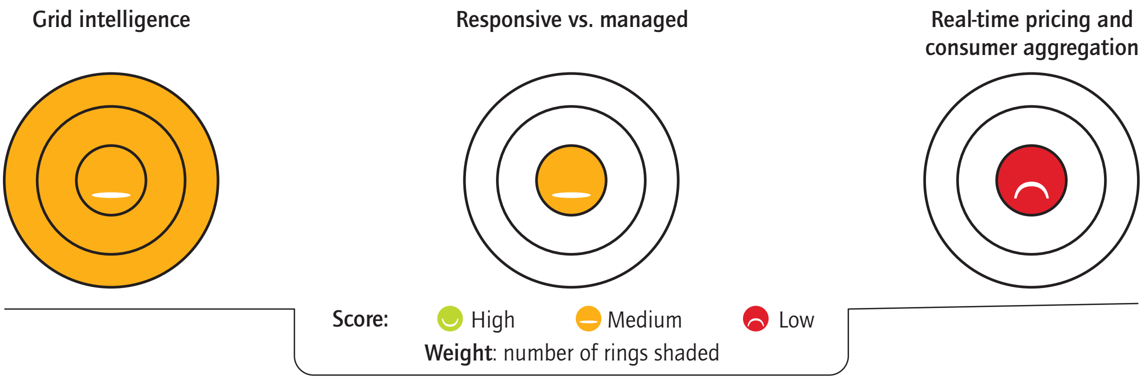
Time constraints on usage. There are no significant environmental, or other, time-of-use constraints on pumped hydro facilities in Great Britain or Ireland – so the score is high. The attribute has a light weighting, reflecting no additional constraint.

Location. Most storage resources in this area are located relatively far from major demand centres, which produces a low score.[7] However, they are situated in areas where significant wind and wave power plants are likely to be deployed, so are potentially well placed to reduce the burden on weaker parts of the grid. In the larger island (Great Britain), storage plants are unlikely to be blocked from the rest of the system by congestion. Weak transmission to the smaller island (Ireland) means that storage may be unable to serve needs there. However, the larger part of the VRE portfolio will be deployed in the larger island (Britain). On balance the location of storage resources is judged unlikely to impose major constraints on availability, and so carries a low weight.

Available demand resource

Opportunities exist for the demand-side to respond to the needs of the market, following instruction from the system operator of the need to do so (National Grid, 2008). However it is likely that a large proportion of the 7 700 MW estimated demand-side resource will be constrained. The primary constraint is likely to be the lack of advanced grid intelligence. The power area attributes with a bearing specifically on the demand-side response resource are summarised in Figure 41.

Figure 41 • Attributes relating to demand-side resource availability (British Isles)



Grid intelligence. Grid intelligence is the primary driver for availability of the demand-side resource. In Great Britain and Ireland, the grid is mainly conventional, without smart meters or other smart grid technologies, so it is given an intermediate score. However, as this still represents a significant constraint on flexibility, it has heavy weighting.

7. In this simple analysis, it is considered better overall for storage to be located near to demand centres in stronger parts of the grid.

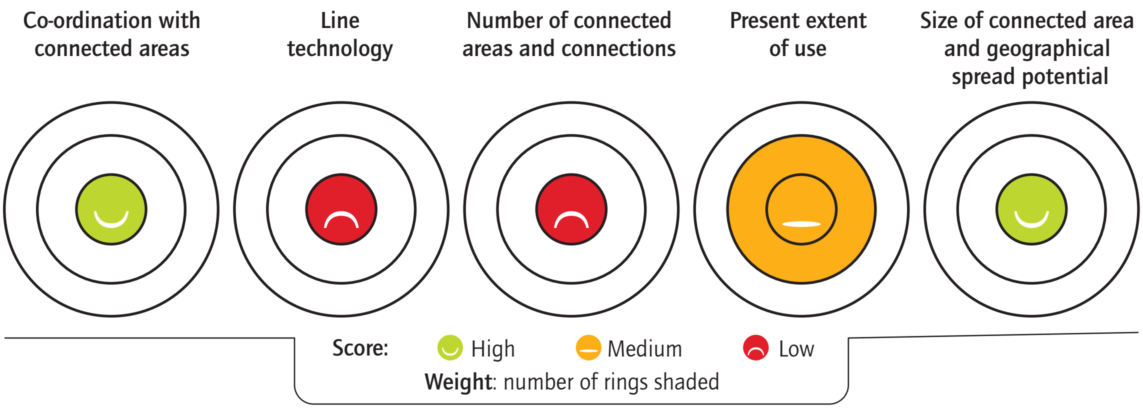
Responsive vs. managed. Approximately 50% of the potential demand-side resource is estimated to be of the responsive type (IDCENR 2009). An intermediate score is awarded. It is possible that the managed remainder may not be available for balancing if its use is scheduled far in advance against other uses, such as management of contingencies. Given only conventional grid intelligence, however, that 50% is unlikely to be able to respond – so a low weight is attached to the attribute, representing limited constraint additional to that imposed by the (primary) grid intelligence attribute.

Real-time pricing. This attribute is closely related to the previous one. Consumers in the area do not have access to real time electricity price information, and there are only limited opportunities to aggregate domestic consumers, so this is given a low score. However, as the likelihood of both would in any case have depended on the key factor of grid intelligence, which has only an intermediate score, low weight is attached to this attribute.

Available interconnection resource

While the technical flexible resource through interconnections amounts to some 2 000 MW, availability is likely to be limited to some extent. The availability of the resource is primarily driven by the extent of co-ordination with the connected areas.

Figure 42 • Attributes relating to interconnection availability (British Isles)



Co-ordination with other areas. The DC Interconnexion France Angleterre (IFA) interconnector to France has been used for balancing in the past. Co-ordination between the system operators of the two countries is reportedly set to further improve in the near future with a move to hourly prices and volumes for balancing (National Grid 2010b). Cooperation with the Dutch market on a day ahead basis through the soon to be commissioned BritNed interconnector[8] may have potential for balancing. The stated objective of the line is to be driven by price differences and demand patterns (National Grid, 2010). A high score then, with low weight, reflecting limited constraint relating to the (existing) French interconnector.

Technology. Line capacity is of the direct current (DC) type, so advance notice of a switch in direction of flow will be required. This means the line is less flexible than alternating current (AC) lines on the shortest timescale, attracting a low score. As co-ordination is strong, however, this attribute is of little additional impact giving a low weighting.

Number of connected areas and connections. The British Isles are only connected to one area at present, meaning that flexible resources outside the area less likely to be available than where multiple

8. Scheduled for April 2011.

areas cooperate. When completed, the BritNed connection to the Netherlands will increase the number of connections. This will not add greatly add to the diversity of flexible resources, the Netherlands being a small market closely linked through a market coupling with France (among others), but spot market liquidity in the Netherlands is much higher (around 30%) than in the UK, meaning that the new interconnector may bring greater liquidity. Overall, a low score is given, but with light weighting, representing the secondary nature of the attribute (the more important being co-ordination).

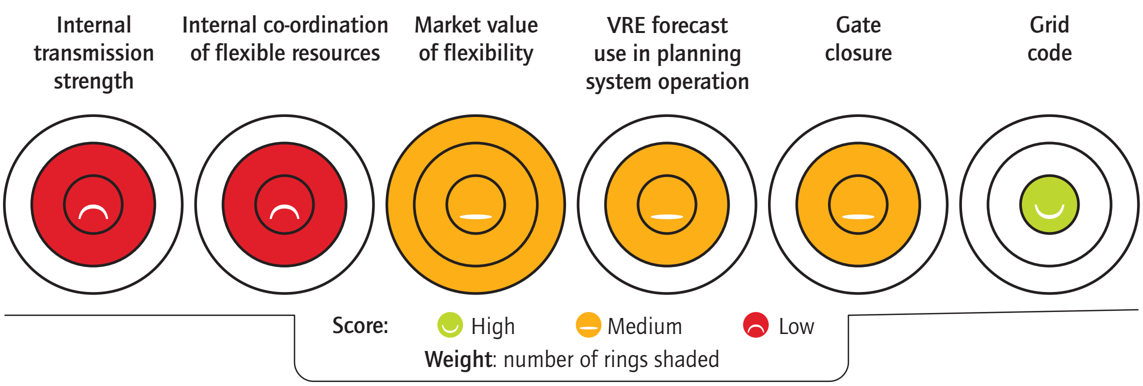
Present extent of use. Present use of the DC lines is moderate. More capacity could therefore be relied upon in the balancing task as co-ordination is strong. This attribute is therefore given an intermediate score. As co-ordination is strong, this intermediate score has correspondingly high (medium) weighting, reflecting an additional constraint[9].

Size of connected areas and geospread potential. The area linked by the interconnections is large and offers the benefit of geospread: VRE output in France and the Netherlands is likely to be significantly unsynchronised with that in GB and Ireland. The power area in France is significantly larger than the size of the connection. The attribute scores high, with low weighting, signifying that the attribute represents no constraint on the value of the interconnection for flexibility.

Area constraints on total flexible resource

There are serious constraints on availability in the British Isles area, the most important of which result from the fact that the area consists of two distinct power systems. This illustrates the importance of effective internal transmission and co-ordination of markets. On the plus side, the area performs better in terms of how it operates with VRE plants, having incorporated (conventional) forecasting techniques into its unit commitment and economic dispatch. The scores and weighting of relevant attributes are given in Figure 43.

Figure 43 • Availability of total flexible resource (British Isles)



Internal transmission strength (internal to the power area, *i.e.* including interconnection between GB and Ireland). This is a severely limiting factor, and has a low score with medium weighting. The area is made up of two power systems. Connection and co-ordination between them is poor, limiting opportunity to share flexible resources. Additional transmission weakness is found between the north and south of Great Britain. As much of the VRE resources (wind and wave in particular) lie away from demand centres, congestion is likely to be a major impediment.

9. If co-ordination were weak, on the other hand, the attribute would have low weight, representing limited additional constraint.

Internal co-ordination of flexible resources. Two different market types are employed in the area: the one in Great Britain is based mainly on advance bilateral contracts, with only a small amount (around 4%) of trading done through the spot market; while Irish electricity is 100% traded through a pool. There is also very little co-ordination between the two markets. This should not prevent sharing of flexible resources as long as flexibility has a clear value, as an incentive for trade. However the market valuation of flexibility (below) also scores low, so this attribute has an intermediate weighting.

Market valuation of flexibility. Markets do not explicitly reward flexibility. Resources that might otherwise have been used to provide flexibility on demand may instead be used to provide energy or other services. Dispatchable generators can contract either with the system operator or with suppliers to provide balancing services, and indeed much of their revenue can come from these activities. However, slower flexible resources will see insufficient compensation for provision of their potential contribution to flexibility (in response to long term forecasts of the net load). The attribute is awarded an intermediate score with high weighting, reflecting an important continuing constraint on the availability of flexible resources.

VRE forecast usage in system planning. Forecasting of variable generation output is used when planning system operation, but is not very sophisticated, so it is given an intermediate score, with medium weighting, reflecting a still significant constraint on allocation of flexible resources. For significant improvement, the operator would need to implement methods such as probabilistic or ensemble forecasting, which provide more information than the more simple forecast methods currently employed. Unit commitment could be improved through more frequent updates or more advanced methods.

Gate closure. Gate closure is not aligned between the British market (BETTA – British Electricity Trading and Transmission Arrangements) and the Single Electricity Market (SEM) in Ireland. In neither case does it occur intra-hourly, but one hour ahead of operation in BETTA, and multiple hours ahead in the SEM. This highlights the limited co-ordination between the two markets. In the SEM, therefore, the level of uncertainty relating to VRE delivery will be higher than in BETTA, with the result that flexible resources may be committed to a larger extent than necessary and will thus be unavailable for use elsewhere in the area. Bearing in mind the relative sizes of the two markets (BETTA is an order of magnitude larger than SEM) the gate closure attribute for the area overall is intermediate, with medium weight reflecting the constraint it imposes on flexibility.

Grid code. The area scores well with regards to its grid code. Up to date and refined grid codes for VRE plants ensure that they will operate as expected – *i.e.* that VRE will be online when expected, not having tripped out during a fault. This attribute, while scoring highest, has a light weight as it is less significant than the attributes above in terms of the balancing challenge.

14 • Spain and Portugal Area (Iberian Peninsula)

This assessment of the area of the Iberian Peninsula is based on data received in response to the GIVAR project questionnaire. Where no data were available, assumptions were made based on other areas and sources. Values and scores herein are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

Flexibility requirement of VRE

The case study assumes a portfolio of VRE technologies.[1] As the Iberian Peninsula has a good solar PV resource, and also good wind resources, wind is assumed to have the major share (65%), with a high share of solar PV present (20%). A modest share of tidal and wave technologies are also assumed (Table 14).

Table 14 • VRE portfolio assumptions (Iberian Peninsula)

Resource	*Onshore wind*	*Offshore wind*	*Solar PV*	*Tidal*	*Wave*
Maximum variability (% installed capacity/minute)	0.15	0.20	0.22	0.1	0.14
Maximum uncertainty (% error/minute)	0.07	0.10	0.06	0	0.04
Assumed share of technology in VRE portfolio (% of VRE portfolio)	55%	10%	20%	0%	15%
Assumed location relative to load	Mixed	Mixed	Near load	Far from load	Near load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30	35	20	25	25

The calculation of overall VRE portfolio flexibility requirement is shown in Table 15.[2]

Table 15 • VRE flexibility requirement (Iberian Peninsula)

Time scale	*15 mins*	*1 hr*	*6 hrs*	*36 hrs*
Maximum variability (% installed capacity)	2. 5	8	36	70
Maximum uncertainty (% installed capacity)	1.0	5.0	14.4	57.5
Flexibility requirement (% installed capacity)	3.5	13	51	70

The maximum extent of variability increases over time, until at 36 hours it can cover close to the full installed capacity. A maximum of 70% of installed capacity is given here as the areas are relatively large and therefore it is unlikely to see periods of zero output or maximum output of VRE (REE, 2010).

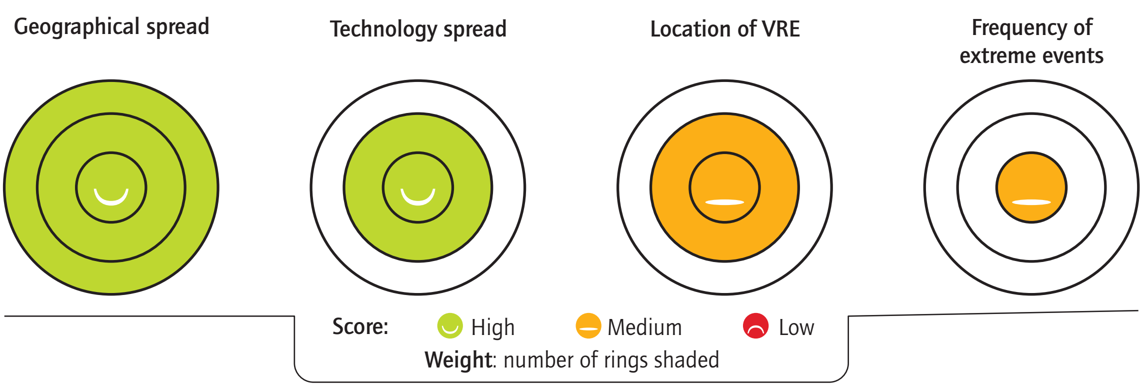
Further qualification of flexibility requirement

The actual flexibility requirement is likely to be less than that shown in Table 15, since this simple approach omits a range of potentially beneficial factors due to limited data availability. The power area attributes which have additional bearing on the extent of variability are summarised in Figure 44.

1. For explanation of the portfolio concept, see Chapter 12 "Assumed VRE portfolios".
2. For discussion of the values used for variability and uncertainty, see Chapter 12 "Flexibility requirement of VRE".

Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the "Location of VRE" attribute relates to internal transmission strength below; and the light weight of the "Frequency of extreme events" attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above (Table 15).

Figure 44 • Attributes relating to VRE flexibility requirement (Iberian Peninsula)



Geographical spread. The region has well dispersed VRE resources, considerably reducing the aggregated extent and rate of variability of output of VRE plants if these are widely dispersed over the area. Additionally (and unlike GB and Ireland, for example), different parts of the area see predominantly different weather systems at any onetime, reducing aggregate variability further. The area is considered to have a widely spread VRE portfolio, resulting in a high score, with significant smoothing effect on the output of the VRE portfolio.

Technology spread. There is a good opportunity to benefit from smoothing through VRE technology spread in the area, based on its resources. The portfolio assumed contains 55% onshore wind, with 20% PV and 25% offshore wind and wave power. The area would therefore be likely to see a significant smoothing effect on variability, and scores high in this regard.

Location of VRE. A significant amount of VRE resources are located far from demand, so internal transmission will be significant. As the latter is relatively good, despite a measure of congestion between the Spanish and Portuguese systems, the location attribute has only an intermediate weight.

Frequency of extreme events. Although wind makes up the majority of the assumed VRE portfolio in the area (65%), PV and wave together make up 35%, reducing the likelihood of extreme events for the portfolio as a whole. The full extent of the flexibility requirement identified above will be seen less often, and there may be a basis for considering flexible resources against fluctuating demand to be available to some extent against new needs of VRE.

Flexible resources

Dispatchable plant

Figure 45 illustrates the present proportions of dispatchable plant types in the Iberian Peninsula. Detail of assumptions relating to operating levels and ramp rates, and definitions, can be found in Annex C.

The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 46, expressed as a percentage of installed capacity that can be ramped up or down over the four timescales. Assessment of technical flexibility is based on data received in response to GIVAR project questionnaires.

In the Iberian Peninsula, nuclear provides no flexibility, in contrast to the British Isles for example where nuclear plants may be ramped down to around 60% of output. The average plant here can be seen to be less flexible in the 15 minute time scale than in Great Britain and Ireland, but more flexible at longer time frames.

Figure 45 • Dispatchable plant portfolio (Iberian Peninsula)

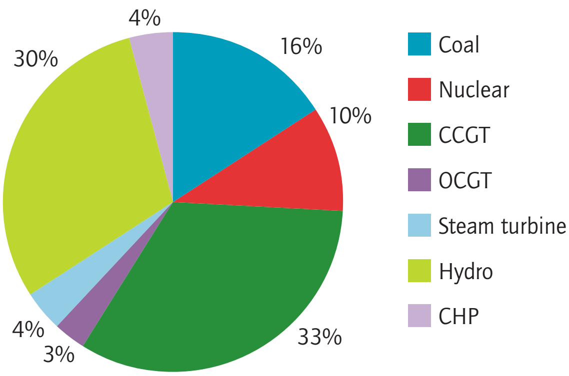
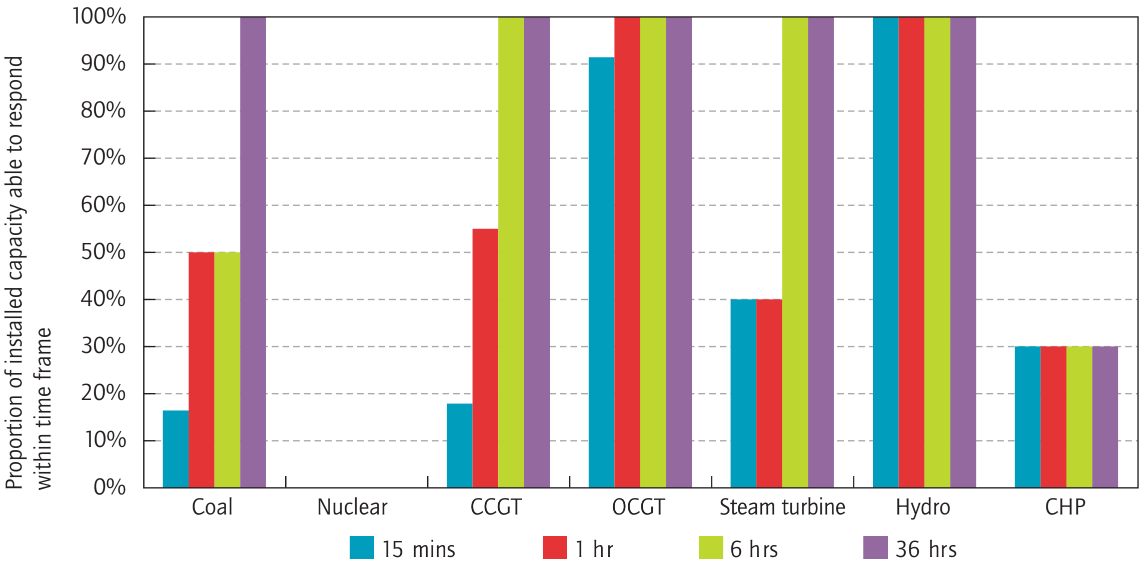


Figure 46 • Technical flexibility of dispatchable plant (Iberian Peninsula)



It should be noted that it is not only ramp rates (in MW/minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start up/shut down times are also important. For example, in the Iberian area, coal plants are able to ramp down to a minimum stable level of 50% inside one hour, and could then shut down entirely inside 36 hours – if this were desirable from the flexibility perspective.

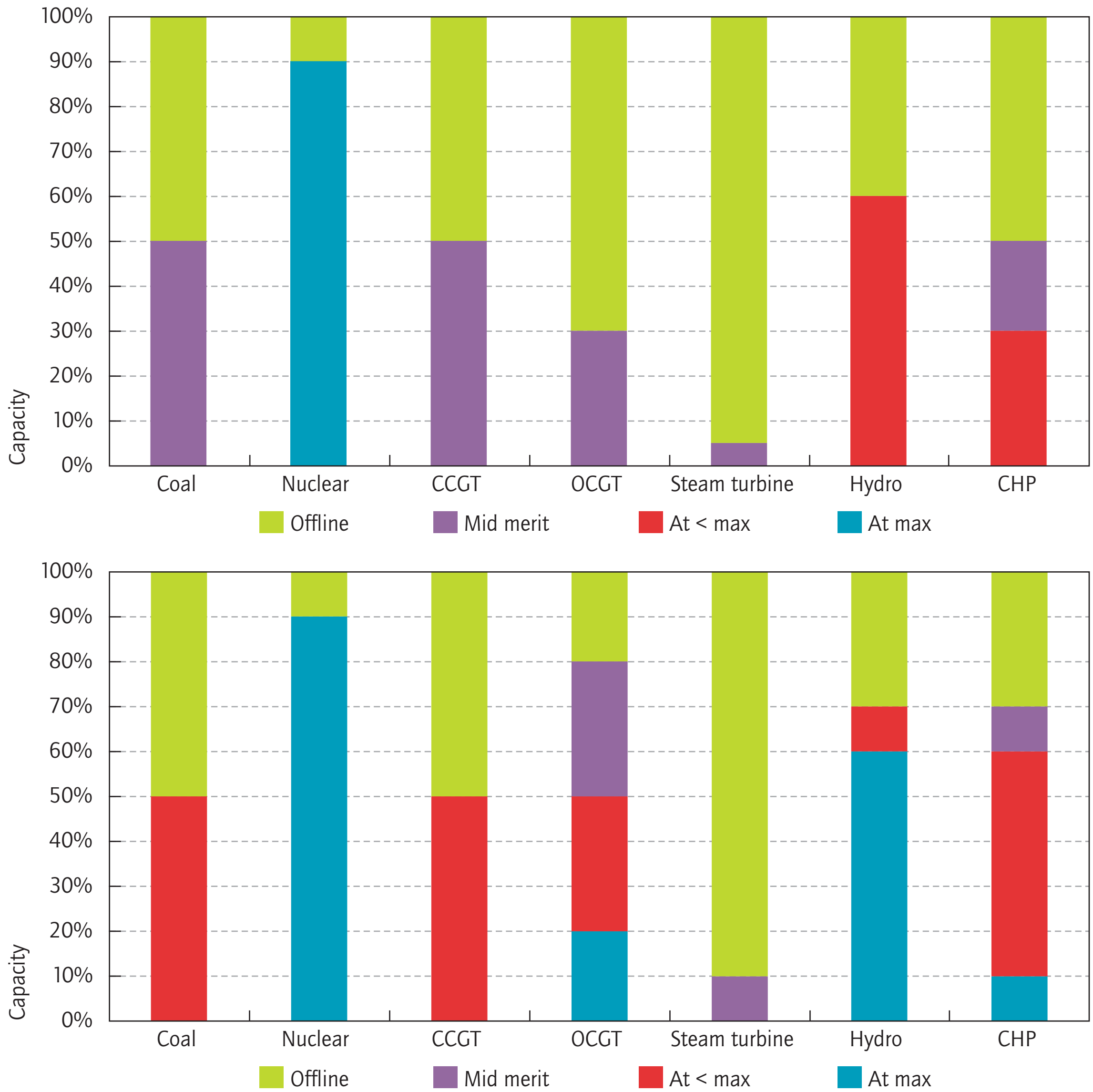
When only the technical capabilities of plants are taken into account, there seems to be a great deal of flexibility on each timescale. However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down if operating below maximum.

The expectations for dispatchable plant types during high and low demand periods are shown in Figure 47. Different operating states are observed for plant types than in the British Isles, for example, due to different plant mix and reported capacity factors. Hydro is used far more for providing energy, in a mid-merit or baseload fashion, rather than for peaking as in the British Isles.

This is because the hydro resource is larger (Figure 45). This will have impact on the ability of hydro units to provide flexibility.

Figure 47• Likely operation of dispatchable plant (Iberian Peninsula) at minimum demand (top figure), and peak (bottom figure).



It should be noted that hydropower generation in Spain and Portugal depends significantly on the season and on rainfall during the year. Reservoirs are rarely at full capacity. In Spain, for example, available capacity ranges from 11 GW down to 3 GW, out of 17 GW of installed capacity. This is important as hydro is a significant source of flexibility in the area.

The final step is to calculate the likely availability of the whole dispatchable plant portfolio to ramp during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values are shown in Table 16. These will be the occasions when resources are most limited by existing requirements for flexibility (fluctuating demand).[3]

3. See Chapter 12 "Dispatchable generation" for explanation of these steps.

Table 16 • Technical flexible resource from dispatchable power plants (Iberian Peninsula)

Flexible resource in:	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	5 000	7 000
1 hr	6 250	12 100
6 hrs	43 811	23 118
36 hrs	49 314	25 417

Storage resources

Approximately 5 805 MW of storage is available in the Iberian Peninsula, all in the form of pumped hydro. Pumped storage is extremely quick ramping and can go from zero to full output in less than 15 minutes, so the full amount is considered, from a purely technical perspective, to be available over all time frames.

Pumped hydro facilities contain approximately 15 hours of energy storage, *i.e.* a total of 87 075 MWh. While flexibility on the 15 minutes, 1 hour and 6 hour time scales is unaffected, continuous maximum ramping in the same direction will be limited on the 36 hour time scale.

Demand-side resource

Based on the response to the questionnaire, the total flexibility for the Iberian Peninsula from the demand-side is assumed to be approximately 2 360 MW, just under 5% of peak demand. This estimate may be significantly lower than the real potential of this resource. Estimates are usually between 5% and 10%.

Interconnected resources

The total current connection to other areas is 2 100 MW, to two areas (France and Morocco), via AC links. A DC link with France is being built in the Eastern Pyrenees, but was not yet in service at the time of writing. It should be noted that the analysis does not take into account the fact that interconnection capacity is not symmetrical: more capacity is available to import from France than to export. This fact will significantly diminish the potential to dispose of VRE output to the rest of Europe during periods of low demand in the area.

Flexibility Index and Present VRE Penetration Potential

The four flexibility resources in the Iberian Peninsula are summed in Table 17. Columns seven and eight show the technical flexible resource (TR) available for ramping up and ramping down output from these sources.

Table 17 • Technical flexible resources (Iberian Peninsula)

Time scale	Dispatchable plant		Demand side	Storage	Interconnection	Technical resource	
	Up	Down					
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	5 000	7 000	2 360	5 805	2 100	15 268	15 168
1 hr	6 250	12 110	2 360	5 805	2 100	16 518	22 368
6 hrs	43 811	23 118	2 360	5 805	2 100	54 079	33 386
36 hrs	49 314	25 417	2 360	*5 805	2 100	59 662	35 685

*Note: continuous maximum ramping in the same direction will be limited beyond 15 hours.

In these case studies existing and new requirements for flexibility are simply summed, which gives a conservative estimate for the overall flexibility requirement. Existing Flexibility Requirement (EFR) is subtracted from TR to yield the net technical resource (NTR). NTR for up and down ramping are shown in columns 4 and 5 of Table 18.

Table 18 • Existing flexibility requirement and Flexibility Index (Iberian Peninsula)

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	3 205	1 705	12 063	13 463	0.22	0.25
1 hr	4 305	2 805	12 213	19 563	0.23	0.36
6 hrs	10 305	8 805	43 775	24 582	0.82	0.46
36 hrs	14 305	12 805	45 357	22 880	0.85	0.43

Dividing NTR by peak demand (54 GW) produces the FIX values for the area – shown in the last two columns, for up and down ramping. FIX values increase over time for down-ramping (apart from a slight reduction between 6 and 36 hours), as the rate of increase of flexible resource is greater than the rate of increase of the existing requirement for it. For up-ramping the value increases right up to 36 hours. While up to 1 hour it is up-ramping flexibility which is the more constrained, the opposite is true at 6 to 36 hours, when downwards flexibility is in shortest supply.

The second variability metric – Present VRE Penetration Potential (PVP) – illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the Iberian Peninsula are shown in Table 19.

Table 19 • Present VRE Penetration Potential (Iberian Peninsula)

Time scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	3.5	343 682	383 568	282%	315%
1 hr	13	93 660	150 022	77%	123%
6 hrs	51	86 607	48 634	71%	40%
36 hrs	70	64 796	32 686	53%	27%

Note: The range between values for PVP with NTR up and with NTR down reflect the likely operation of dispatchable generation at times of peak and minimum demand.

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled on the shorter (*e.g.* 15 minute) timescales, this is because the flexibility requirement of VRE is very small at this timescale, relative to NTR.[4] **It is only the most constrained occasion, *i.e.* when the extent of variability is largest relative to the extent of flexible resource (in the Iberian case, downwards flexibility at 36 hours), that reflects PVP.**

In the Iberian Peninsula then, from a purely technical perspective, some 27% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for flexibility are taken into account. This assumes no complementarity between existing and new requirements.

4. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.* economic and operational) considerations.

However, while both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the full range of power area constraints which will affect the availability of flexible resources. These relate to operation of the system and market in the area, and are discussed in the next section. They may be significant and, even if they were addressed, it is unlikely that any area would be able to reduce their impact to zero.

Area constraints

The calculation of PVP above, based on the technical flexible resource (TR), is higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as congestion of internal transmission, sub-optimal operation and adverse market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

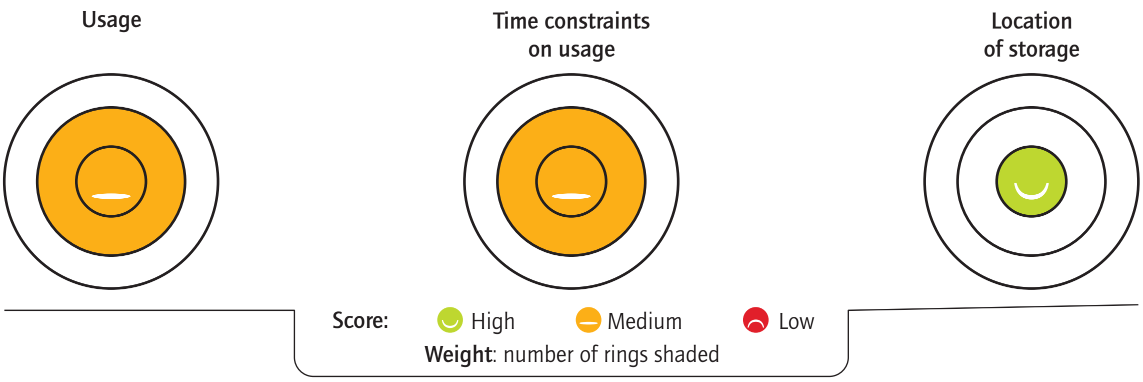
Individual flexible resources have particular constraints. These are addressed first in the next section, while constraints on TR as a whole are assessed subsequently.

Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 "Scoring and weighting of area attributes".

Available storage resource

The power area attributes with potential impact specifically on the availability of storage are summarised in Figure 48.

Figure 48 • Attributes relating to storage availability (Iberian Peninsula)



Usage. Facilities are not owned by the system operators in the area. They are privately owned and operated for profit, though the owners may contract with the system operator to provide balancing services. Otherwise system operators can modify the operation of facilities only to protect system security. This means that storage facilities' availability for integrating VRE is much less than if they were owned and operated by the system operator. Usage is therefore given an intermediate score, with medium weight, reflecting considerable constraint on availability.

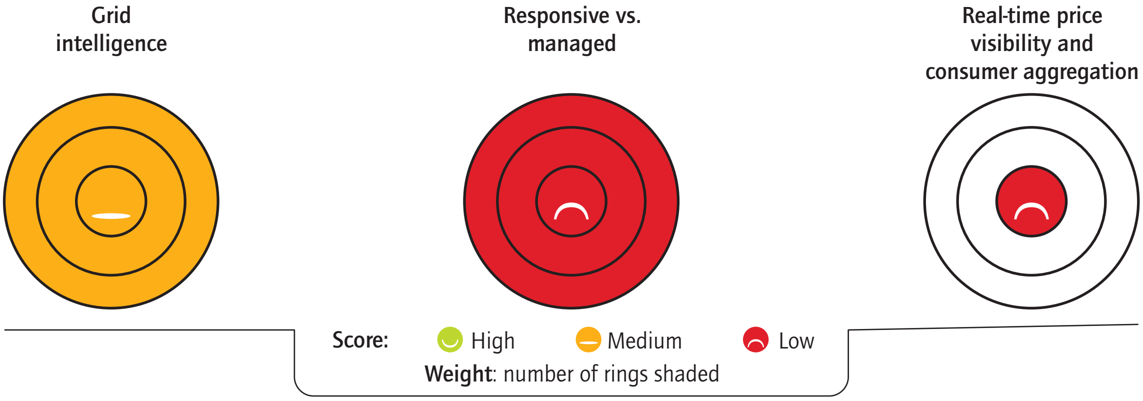
Time constraints on usage. There are no significant socio-environmental constraints on availability of pumped hydro use in Spain or Portugal, but availability is rarely higher than 60% to 70% due to maintenance and outages (REE, 2010). Thus the attribute is awarded an intermediate score, and medium weight to reflect this significant restraint on availability.

Location. Most storage resources are located near demand centres. This means they will be less likely to be blocked by congested lines, and more likely to be accessible for provision of flexible response – a high score with light weighting, reflecting no additional constraint on flexibility.

Available demand-side resource

Area attributes with specific bearing on the availability of demand-side flexibility are summarised in Figure 49.

Figure 49 • *Attributes relating to demand-side resource availability (Iberian Peninsula)*



Grid intelligence. The grid in the area is of conventional intelligence, so is given an intermediate score. It is the primary driver for availability of the demand-side resource; an intermediate score still represents a significant constraint on flexibility, so it has heavy weighting.

Responsive vs. managed. 100% of the demand-side resource is assumed to be of the managed type in this assessment, based on reported data – a low score. The resource is available at short notice but can only be used for a limited number of times per year, so is used only sparingly (REE, 2010). Heavy weight reflects that this fact effectively blocks the use of the demand-side resource for balancing.

Real-time pricing and consumer aggregation. Consumers in the area do not have access to real time price information, but as the demand-side resource is assumed to be 100% of the managed variety, this attribute has no significance (light weight).

Available interconnection resource

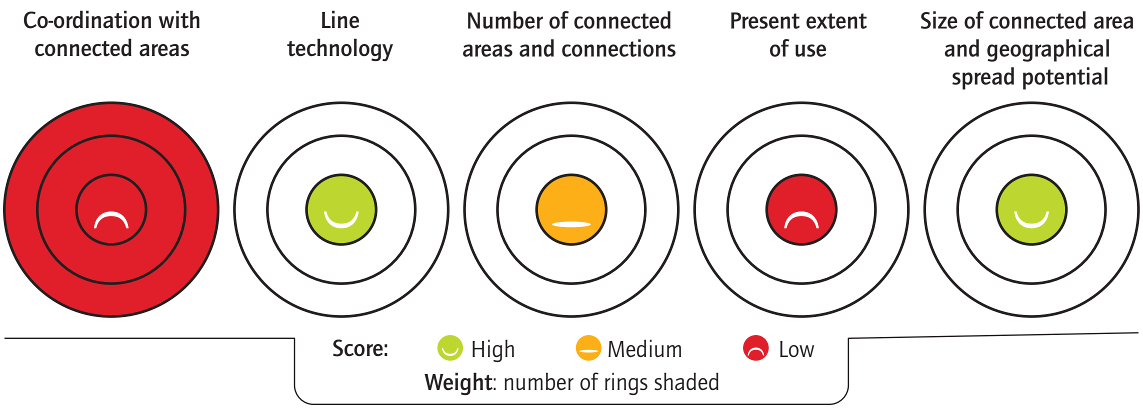
Power area attributes with impact on the availability of flexibility from adjacent areas (outside ES & PT) are summarised in Figure 50. The availability of the resource is primarily driven by the extent of co-ordination with connected areas. As this is low, all other attributes are reduced to only secondary importance (low weight).

Co-ordination with adjacent areas. Co-ordination with adjacent areas – Morocco and France – is low. Transmission capacity is planned days or weeks in advance, and changes to the schedule are difficult. Capacity is used with other objectives in mind than balancing VRE. Heavy weighting reflects the impact this will have on the accessibility of flexible resources in these areas.

Line technology. Line technology is AC, so is given a good score. Weighting is light as this is a secondary attribute. If DC were the only technology in use, the weighting might be heavier – reflecting the low co-ordination with neighbours (even DC can be operated relatively flexibly if well planned).

Number of connected areas and connections. There are connections to only two adjacent areas, but they are multiple: an intermediate score. Light weighting reflects the relative importance of other attributes, particularly low co-ordination.

Figure 50 • *Attributes relating to interconnection availability (Iberian Peninsula)*



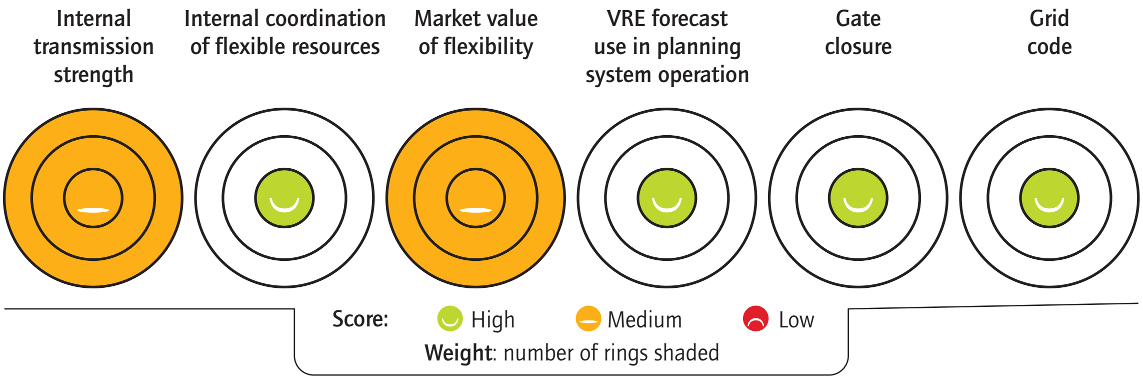
Present extent of use. Connections are already heavily used – a low score as it implies limited additional capacity for servicing flexibility needs. Because co-ordination with neighbours is low, reducing the opportunity to rely on imports and exports for balancing in any case, this represents little additional constraint on flexibility – a light weighting.

Size of connected area and geospread potential. Areas connected to are large, and offer the potential for geographical smoothing of VRE. Output in France and Morocco is unlikely to be synchronised, so is given a good score. Light weighting reflects secondary significance of the attribute, given poor cross-border co-ordination.

Area constraints on total flexible resource

The power area attributes with bearing on the overall flexible resource are summarised in Figure 51.

Figure 51 • *Availability of total flexible resource (Iberian Peninsula)*



Internal transmission strength. Transmission internal to the power area is overall of intermediate strength. The area consists of two distinct systems, however, and congestion between them is common. Between July and September 2007, for example, the markets were split for more than half of the time, indicating severe congestion. This means that flexible resources will be separated to some extent (though not to the same extent as in Great Britain and Ireland, for example). However, this situation may be improving: in the 12 months from October 2009 to September 2010, there was no congestion during 81% of hours (REE, 2010).

In the individual country systems, transmission is relatively strong and uncongested, which is important as a large part of the VRE resource (wind in particular) is located away from demand centres. Two new 400 kV transmission lines are planned to reinforce internal transmission connection: one running through the northern border with Portugal and one through the southern. It is planned that this will increase capacity between Spain and Portugal to 3 000 MW by the end of 2016 (REE, 2010). The attribute has a heavy weighting, reflecting the constraint on flexibility at the time of writing.

Internal co-ordination of flexible resources. The two effective balancing areas (Spain and Portugal) interact through the Iberian Regional Market (MIBEL), and demonstrate close co-ordination in their operation. This would maximise the sharing of flexible resources by the two countries, if internal transmission were stronger between them. However, this is not the case. The attribute scores high, with light weighting, representing no further constraint.

Market value of flexibility. Markets in Spain and Portugal do not explicitly reward the provision of the flexibility service. There are some short term incentives in the form of balancing markets and payments for ancillary services. However, slower flexible resources will see insufficient compensation for provision of their potential contribution to flexibility (in response to long term forecasts of the net load). So, an intermediate score, with heavy weighting, reflecting its continuing significance as a constraint on availability.

Use of forecasting. Forecasting of variable generation output is well used when planning the operation of the area and commitment of plants. Spain uses a 10-day ahead forecast for transmission system outage planning; a 48 hour ahead forecast for each individual wind farm; and a 48 hour ahead probabilistic forecast in calculating reserves. Spain also uses stochastic analysis to scale longer term flexible resources, to take account of VRE (predominantly wind) uncertainty up to 36 hours ahead. Data are updated hourly and made available to the Control Centre of Renewable Energies (CECRE), which coordinates response (REE, 2010). Portugal uses similar tools. A good score then, representing up to date practices, and a low weight, reflecting limited additional constraint on availability of flexible resources.

Gate closure. Gate closure occurs intra-day at one of a series of fixed “windows”. Though perhaps not as beneficial as hourly/intra-hourly gate closure, this reduces uncertainty in the output of VRE as compared with day ahead gate closure, with the result that less of the flexible resource must be held back against uncertainty, and flexible resources can be better planned — a high score with light weight reflecting low constraint of flexibility.

Grid code. Very modern grid codes for VRE are in place in the area, so it is likely that VRE will operate as expected and will remain online during faults — a high score with low weight, representing no significant constraint.

15 • Mexico

This assessment of the Mexican area is based on data received in response to the GIVAR project questionnaire. Where no data were available, assumptions were made based on other areas and sources. Values and scores herein are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

Flexibility requirement of VRE

The case study assumes a portfolio of VRE technologies.[1] This includes predominantly onshore wind (50%) and solar PV (30%) technologies in Mexico's case, as shown in Table 20, with modest shares of offshore wind, tidal and wave power (20%).

Table 20 • VRE portfolio assumptions (Mexico)

Resource	*Onshore wind*	*Offshore wind*	*Solar PV*	*Tidal*	*Wave*
Maximum variability (% installed capacity/minute)	0.15%	0.20%	0.18%	0.1%	0.14%
Maximum uncertainty (% error/minute)	0.07%	0.10%	0.06%	0	0.04%
Assumed share of technology in VRE portfolio (% of VRE portfolio)	50%	10%	30%	5%	5%
Assumed location relative to load	Mixed	Mixed	Near Load	Far from load	Far from load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30%	35%	19%	25%	25%

The calculation of overall VRE portfolio flexibility requirement is shown in Table 21.[2]

Table 21 • VRE flexibility requirement (Mexico)

Time scale	*15 mins*	*1 hr*	*6 hrs*	*36 hrs*
Maximum variability (% installed capacity)	2.4	7.7	35	85
Maximum uncertainty (% installed capacity)	1	3.1	14	56
Flexibility requirement (% installed capacity)	3.4	11	49	85

As expected, the variability increases with time horizon, until at 36 hours the variability can cover close to the full installed capacity. A maximum of 85% of installed capacity is given here as the areas are relatively large and therefore it is unlikely to see periods of zero output or maximum output of VRE.

Further qualification of flexibility requirement

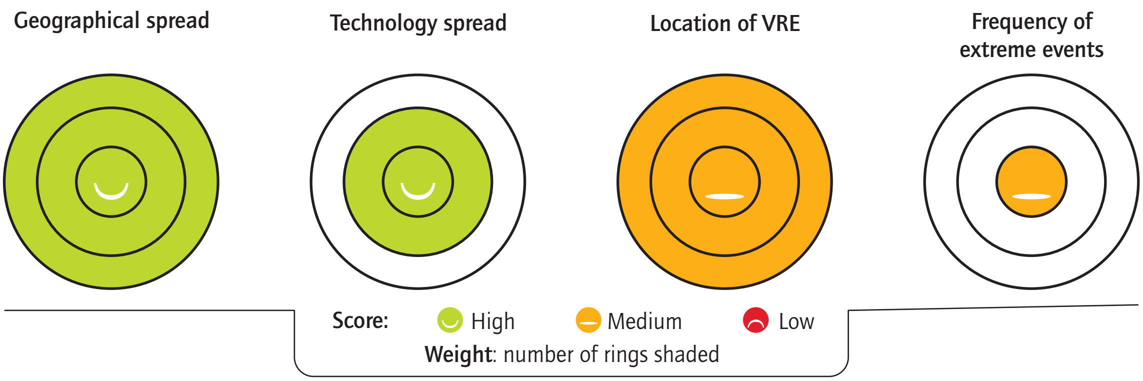
The actual flexibility requirement is likely to be less than that shown in the table above, since this simple model omits a range of potentially beneficial factors due to limited data availability. The power area attributes which have additional bearing on the extent of variability are summarised in Figure 52.

Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the "Location of VRE" attribute relates to

1. For explanation of the portfolio concept, see Chapter 12 "Assumed VRE portfolios".
2. For discussion of the values used for variability and uncertainty, see Chapter 12 "Flexibility requirement of VRE".

internal transmission strength below; and the light weight of the "Frequency of extreme events" attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above (Table 21).

Figure 52 • Attributes relating to VRE flexibility requirement (Mexico)



Geographical spread. The area of Mexico is very extensive, covering three time zones, and VRE sources are widely dispersed about it. This has the potential to smooth aggregated VRE output considerably if grid strength is adequate. Furthermore, the area contains multiple weather systems (differing principally from north to south), reducing the extent and rate of variability still further over the whole. This attribute is therefore given a high score, with heavy weighting, reflecting its importance.

Technology spread. The majority of variable generation assumed to be deployed in this assessment is onshore wind energy (50%) and solar PV (30%), whose outputs are likely to be complementary to some degree. Moreover the proportions of each are of a similar order of magnitude. So, a good score.

Location of VRE. Based on the assumption that some 50% of VRE deployed will be away from demand centres (mainly wind), internal transmission will be an important driver of the importance of this attribute. As this is weak (Figure 57), the location of this part of the VRE portfolio is likely to be a significant hurdle to smoothing through geographical spread. However 30% of the likely portfolio is solar PV, which may be deployed near to demand centres, and 10 % wave and tidal plants which may also be deployed off coastal demand centres. Overall the score is intermediate, but heavy weight reflects its importance given weaknesses in the grid.

Frequency of extreme events. Although wind makes up the majority of the VRE portfolio (60%), 30% PV and 10% tidal and wave power will reduce the likelihood of extreme events (relative to wind alone). The full extent of the flexibility requirement identified above will be seen less often, and there may be a basis for considering flexible resources against fluctuating demand to be available to some extent against new needs of VRE. So, an intermediate score.

Flexible resources

Dispatchable plant

The present proportions of types of dispatchable power plants in the Mexican area are shown in Figure 53. Assumptions relating to operating levels and ramp rates, and definitions, can be found in Annex C.

The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 54, expressed as a percentage of installed capacity that can be ramped up or down over the four timescales. Assessment of technical flexibility is based on data received in response to GIVAR project questionnaires. Flexibility can be seen to be less than in many of the other areas assessed. This is not surprising, given that to date the Mexican system has seen little incentive to invest in flexible plant to cater for variable generation. Nuclear plants in Mexico were assumed to have zero flexibility.

Figure 53 • Dispatchable plant portfolio (Mexico)

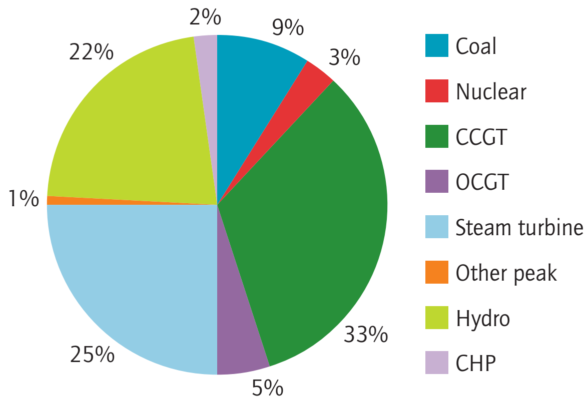
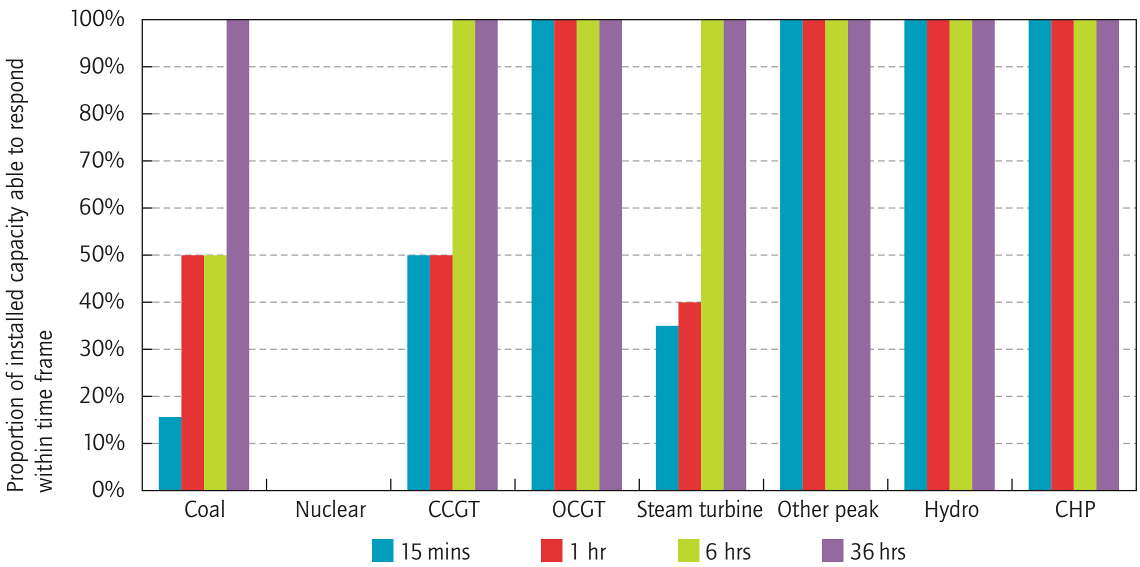


Figure 54 • Technical flexibility of dispatchable plant (Mexico)



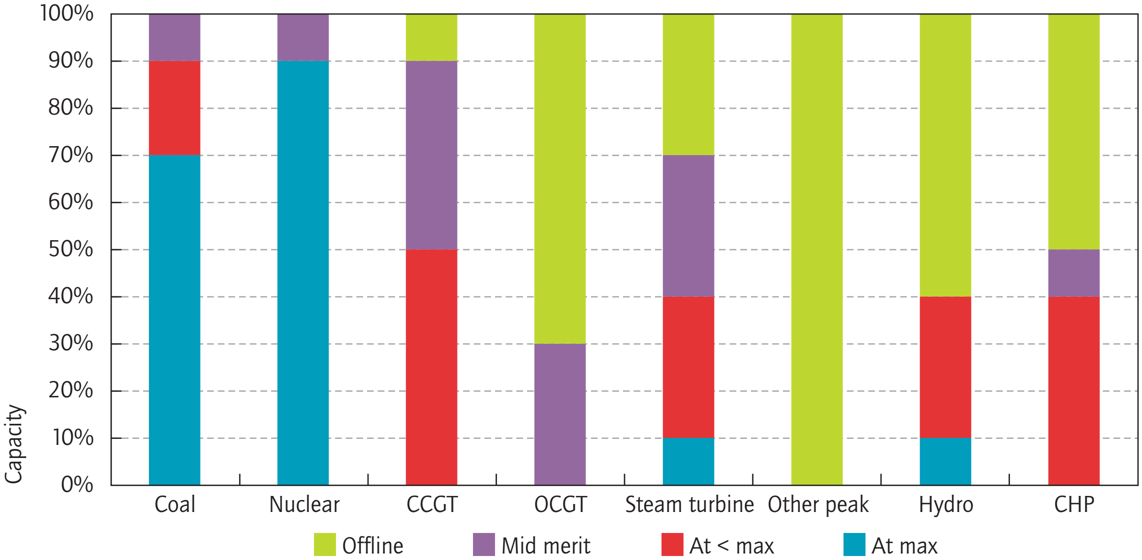
It should be noted that it is not only ramp rates (in MW/minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start up/shut down times are also important. For example, in the Mexican area, CCGT plants are able to ramp down to a minimum stable level of 50% inside one hour, and could then shut down entirely inside 6 hours – if this were desirable from the flexibility perspective.

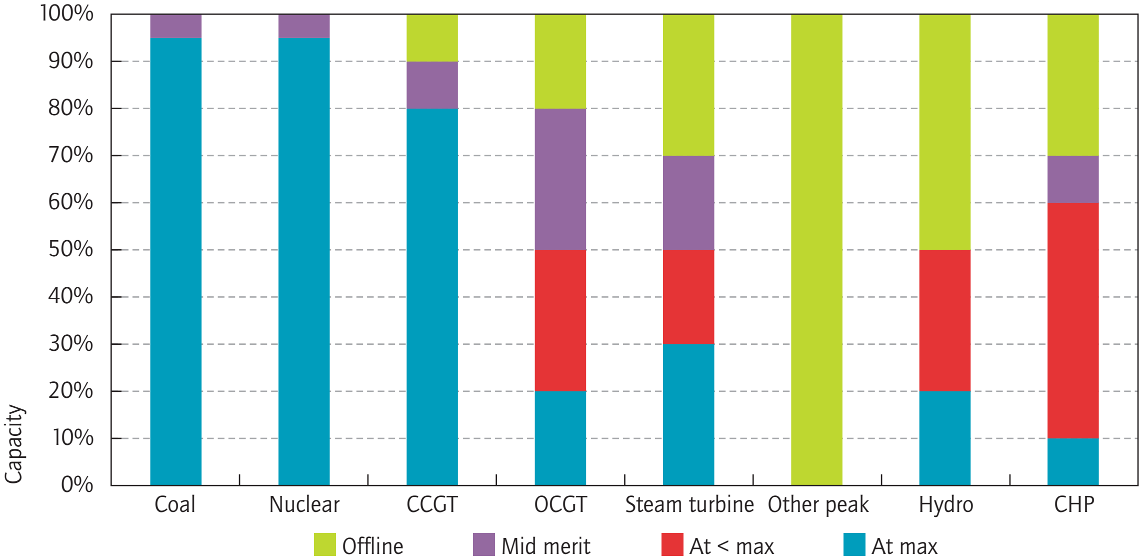
When only the technical capabilities of plants are taken into account, a large amount of flexibility appears to exist on each timescale. However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down, if operating below maximum.

Likely operation of power plants in the Mexican area, based to some extent on data from other power areas, are shown in Figure 55. Steam turbines in this area are used a high proportion of the time for providing energy (some of them are "must run"). This will reduce their ability to provide flexibility. Additionally, as noted above, nuclear units are assumed not technically able to offer flexibility in the balancing timeframe.

Figure 55 • *Likely operation of dispatchable plant (Mexico) at minimum demand (top figure), and peak (bottom figure)*





The system operator can increase flexibility by running the system on an "overcommitted" basis, or by operating gas turbines instead of baseload plants. With this in mind, there is no one set of values for likely operation of the different plant types. The figure simply models a "normal" case during minimum and peak demand, based on the types of plants in the system and the load profile.

The next step is to calculate the likely availability of the whole dispatchable plant portfolio to ramp during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values are shown in Table 22. These will be the occasions when resources are most limited by existing requirements for flexibility.[3]

3. See Chapter 12 "Dispatchable generation" for explanation of these steps.

Table 22 • Technical flexible resource from dispatchable power plants (Mexico)

Flexible resource in:	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	13 683	11 716
1 hr	14 086	13 448
6 hrs	31 736	30 016
36 hrs	32 136	32 296

Storage

There is no specific electrical storage resource in the Mexican area.

Demand side

No estimate of the demand response potential of Mexico could be identified by the GIVAR project. As the power system as a whole is less developed than in other areas assessed, the resource was assumed to be zero. That said, in another developing country, India, the demand side resource has been crucially important in maintaining system integrity (CERC, 2010). Such experience may enable system operators to see the benefits of demand side management for balancing VRE.

Interconnection

The total present capacity of connections to adjacent areas is 865 MW, via DC links, to three areas: US Western Interconnect, the Texas (ERCOT) area and Belize.

Flexibility Index and Present VRE Penetration Potential

The current flexibility resources in Mexico are summarised in Table 23. The last two columns give calculations of the total technical flexibility resource (TR) available for ramping up and ramping down output from these sources.

Table 23 • Technical flexible resources (Mexico)

Time scale	Dispatchable plant		Demand side	Storage	Interconnection	Technical resource	
	Up (MW)	Down (MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	13 683	11 716	0	0	865	14 548	12 581
1 hr	14 086	13 448	0	0	865	14 951	14 313
6 hrs	31 736	30 016	0	0	865	32 601	30 881
36 hrs	32 136	32 296	0	0	865	33 001	33 161

In these case studies existing and new requirements for flexibility are simply summed, which gives a conservative estimate of the overall flexibility. Existing Flexibility Requirement (EFR) is subtracted from TR to yield the net technical resource (NTR). NTR for up and down ramping are shown in columns 4 and 5 of Table 24.

Dividing by peak demand (36 GW) produces the FIX value for the area, shown in the last two columns, for both up and down ramping. FIX values mainly increase over time for down ramping, as the rate of increase of flexible resource is greater than the rate of increase of the existing requirement for it. The up-ramping value, however, drops at the 36-hour timescale (as well as at 1 hour). In general FIX values are lower than in other areas assessed due to the lack of flexible generation units, storage and demand side resource.

Table 24 • Existing flexibility requirement and Flexibility Index (Mexico)

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	3 296	2 596	11 252	9 985	0.31	0.28
1 hr	5 285	4 585	9 666	9 728	0.27	0.27
6 hrs	9 240	8 540	23 361	22 342	0.65	0.62
36 hrs	11 240	10 540	21 761	22 621	0.60	0.63

The second variability metric — Present VRE Penetration Potential (PVP) — illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the area are shown in Table 25.

Table 25 • Present VRE Penetration Potential (Mexico)

Time Scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	3.4	331 926	294 542	379%	336%
1 hr	11	89 106	89 679	102%	102%
6 hrs	49	47 856	45 767	55%	52%
36 hrs	85	25 601	26 613	29%	30%

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled in the shorter term (*e.g.* on the 15 minute timescale), this is because the flexibility requirement of VRE is very small at this timescale, relative to NTR.[4] **It is only the most constrained occasion, *i.e.* when the extent of variability from VRE is largest relative to the extent of flexible resource (in the Mexican case, upwards flexibility at 36 hours), that truly reflects PVP.**

In Mexico then, from a purely technical perspective, some 29% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for the latter are taken into account. This assumes no overlap between existing and new requirements.

However, while both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the full range of power area constraints that will affect the availability of flexible resources. These relate to operation of the system and market in the area, and are discussed in the next section.

Area constraints

The calculation of PVP above, based on the technical flexible resource (TR), is far higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as congestion of internal transmission, sub-optimal operation and adverse market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

Individual flexible resources have particular constraints. These are addressed in the next section, while constraints on TR as a whole are assessed subsequently.

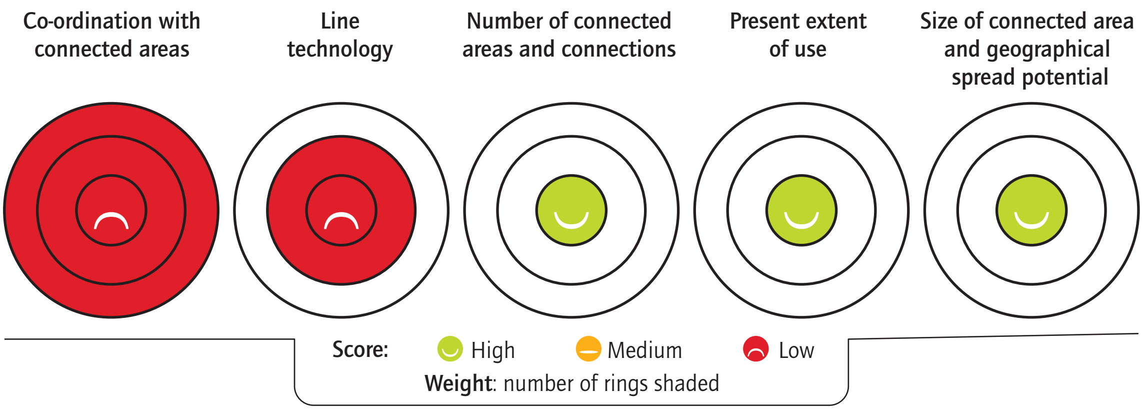
4. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.* economic and operational) considerations.

Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 "Scoring and weighting of area attributes".

Available interconnection resource

Power area attributes with impact on the availability of flexibility from adjacent areas (outside Mexico) are summarised in Figure 56. The availability of the resource is primarily driven by the extent of co-ordination with connected areas. As this is low, the significance of all other attributes is secondary.

Figure 56 • Attributes relating to interconnection availability (Mexico)



Co-ordination with connected areas. Co-ordination with adjacent areas – United States Western, Texas and Belize – is low. Transmission capacity is planned days or weeks in advance, and changes to the schedule are difficult. Capacity is used with other objectives in mind than balancing VRE. Heavy weighting reflects the impact this will have on the accessibility of flexible resources in these areas.

Technology. Line capacity is all of the direct current (DC) type, so advance notice of a switch in direction of flow will be required, with the result that this technology is less flexible than alternating current (AC) lines – a low score. If co-ordination were greater, this would be of limited significance; however, in this case, co-ordination is poor so DC technology represents an additional constraint, and has intermediate weighting.

Number of connected areas and connections. Mexico is connected to three other areas via five corridors, creating significant redundancy. The areas connected to can all offer flexibility at different times. Together these factors lead to a high score with light weighting (no additional constraint).

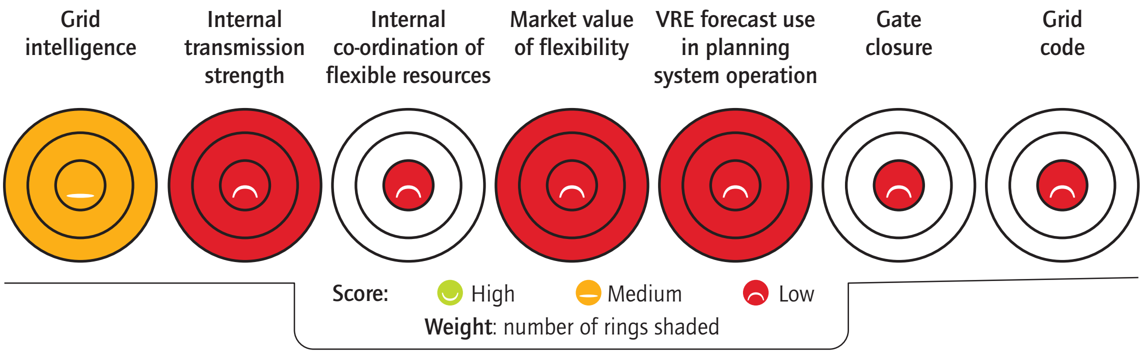
Present extent of use. Existing connections are used sparingly – a high score, as it implies that most of the interconnection capacity would potentially be available for use in balancing. Co-ordination among markets would need to be improved, so it is given a light weighting.

Size of connected area and potential for geographical spread. Two of the areas connected to are large and offer potential for smoothing of aggregated variability – their output is unlikely to be synchronised with that in Mexico. The area scores high in this regard, with low weight, meaning it represents no additional constraint on the value of the interconnection for flexibility.

Area constraints on total flexible resource

Most of the attributes in the Mexican area with bearing on the availability of the flexible resource as a whole score low (Figure 57). This may be in part due to the fact that the area has to date limited experience of VRE deployment.

Figure 57 • *Availability of total flexible resource (Mexico)*



Grid intelligence. The design of the grid is conventional, without smart meters or other smart grid technologies, so it is given an intermediate score. However, as this still represents a significant constraint on flexibility, it has heavy weighting.

Internal transmission strength. This is the greatest constraint on availability of flexible resources in the Mexican area – scoring low, with heavy weight, reflecting the impact of the attribute. Transmission is weak, particularly between areas with strong wind resources and demand centres. There are four balancing areas within the area, which are weakly interconnected, allowing limited sharing of flexible resources.

Internal co-ordination of flexible resources. There are four distinct balancing areas in the Mexican area. Their operation is not coordinated, so they cannot share the use of their flexible resources. This attribute scores low, but weighting is light: as transmission is weak, internal co-ordination does not represent an additional constraint.

Market valuation of flexibility. The state-owned Comisión Federal de Electricidad (CFE) controls around 60% of generation capacity, as well as owning and operating transmission and distribution over the whole country. The remaining 40% of generation is privately owned. As the latter consists mainly of gas plants, this group might represent an important source of flexibility. However, as there is no wholesale electricity market in the area, there is no explicit valuation of flexibility in the balancing timeframe to which these technically flexible plants might respond. So, a low score, with high weighting.

Use of VRE forecasts in system planning. Forecasting of VRE is not used by the system operator when planning the commitment of power units. A low score with heavy weighting: availability of flexible resources will be severely limited as there will be no basis on which to indicate the need of them. Unit commitment could be improved through more frequent planning or more advanced methods, but will be of little importance while deployment of VRE remains at very low levels, and there are no incentives for flexibility.

Gate closure. As unit commitment planning does not forecast VRE output, the absence of intra-day gate closure in the area represents little additional constraint on availability of flexible resources. VRE output is treated as "negative load", as an additional source of uncertainty in the net load, and balanced using reserves maintained for this purpose. So, a low score with light weighting.

Grid code. Grid codes in the area do not take into account VRE plants. The system operator cannot rely on VRE to remain online when expected, so variability profiles will be harder to define. So, a low score, with light weighting, reflecting the relatively low significance of this attribute until significant VRE penetration is seen.

16 • Nordic

This assessment of the area of the Nordic power market (the Scandinavian and Danish peninsulas and islands) is based on data received in response to the GIVAR project questionnaire. It illustrates how one market covering a large area, with large amounts of hydro generation, can ease the integration of VRE.

Where no data were available, assumptions were made based on other areas and sources. Values and scores used here are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

Flexibility requirement of VRE

The case study assumes a portfolio of five VRE technologies in the Nordic area.[1] The portfolio is assumed to consist predominantly of wind energy (85%), with only modest amounts of wave, tidal and solar PV. The assumptions made about their characteristics are listed in Table 26.

Table 26 • VRE portfolio assumptions (Nordic)

Resource	*Onshore wind*	*Offshore wind*	*Solar PV*	*Tidal*	*Wave*
Maximum variability (% installed capacity/minute)	0.15%	0.20%	0.18%	0.1%	0.14%
Maximum uncertainty (% error/minute)	0.07%	0.10%	0.06%	0	0.04%
Assumed share of technology in VRE portfolio (% of VRE portfolio)	65%	20%	5%	5%	5%
Assumed location relative to load	Mixed	Mixed	Near Load	Far from load	Far from load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30%	35%	10%	25%	25%

The calculation of the overall flexibility requirement for the VRE portfolio is shown in Table 27.[2]

Table 27 • VRE flexibility requirement (Nordic)

Time scale	*15 mins*	*1 hr*	*6 hrs*	*36 hrs*
Maximum variability (% installed capacity)	2.4	7.6	34	85
Maximum uncertainty (% installed capacity)	1.1	3.4	15	61
Flexibility requirement (% installed capacity)	3.4	11	49	85

As in all areas assessed, variability increases with the time horizon, until at 36 hours the extent of variability is close to the full installed capacity. A maximum of 85% of installed capacity is given here as the areas are relatively large and therefore it is unlikely to see periods of zero output or maximum output of VRE.

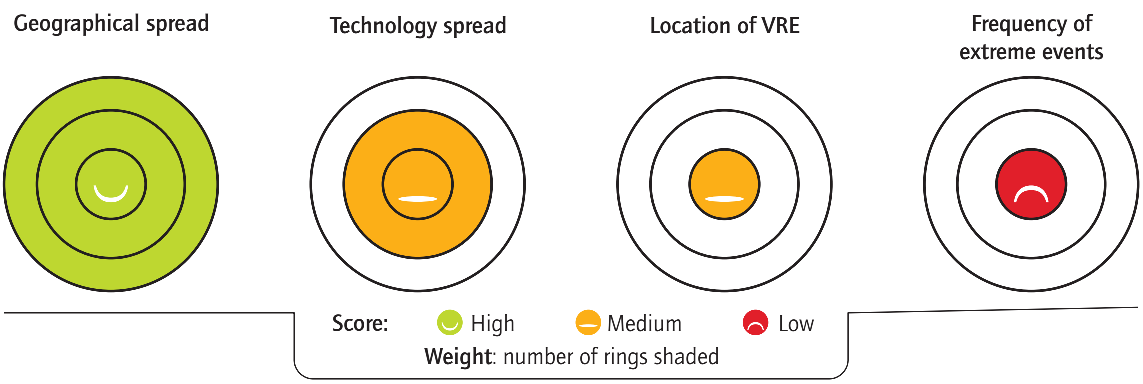
Further qualification of the flexibility requirement

The actual flexibility requirement is likely to be less than that shown in Table 27, since this simple approach omits a range of potentially beneficial factors due to limited data availability. These factors are summarised in Figure 58. The weights of the four attributes considered in this section represent their importance in the area.

1. For explanation of the portfolio concept, see Chapter 12 “Assumed VRE portfolios”.
2. For discussion of the values used for variability and uncertainty, see Chapter 12 “Flexibility requirement of VRE”.

Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the “Location of VRE” attribute relates to internal transmission strength, below; and the light weight of the “Frequency of extreme events” attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above (Table 27).

Figure 58 • Attributes relating to VRE flexibility requirement (Nordic)



Geographical spread. The region is large, and VRE resources are widely dispersed about it. This presents the likelihood of significant smoothing of variability in the system, assuming the grid is uncongested. Additionally, the area sees multiple weather systems, smoothing the extent and rate of ramps in aggregated output still further, particularly on the 36 hour time scale as weather fronts move across the area – a high score.

Technology spread. Wind power makes up 85% of the assumed portfolio (Table 26). Although it will show some complementarity of output with other VRE technologies deployed, their small proportions means this benefit will be small. So, an intermediate score.

Location of VRE. Much of the best VRE resource is located far from demand centres. This increases the significance of internal transmission strength (Figure 64). As that is of intermediate strength, location of VRE has only light weight.

Frequency of extreme events. Wind energy makes up 85% of the VRE portfolio so extreme events over the area will be quite common – perhaps every few months. The full extent of the flexibility requirement identified above will occur relatively frequently, and is likely to coincide with the maximum existing flexibility requirement resulting from fluctuating demand. No complementarity is assumed with existing flexibility requirement. So, a low score.

Flexible resources

Dispatchable plant

The present proportions of types of dispatchable power plant in the Nordic power area are illustrated in Figure 59. Assumptions relating to operating levels and ramp rates, and definitions, can be found in Annex C.

The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 60, expressed as a percentage of installed capacity that can be ramped up or down over the four timescales. The assessment of technical flexibility is based on data received in response to GIVAR project questionnaires.

It should be noted that it is not only ramp rates (in MW/minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start up/shut down times are also important. For example, in the Nordic area, CCGT plants are able to ramp down to a minimum stable level of 50% inside one hour, and could then shut down entirely inside 6 hours – if this were desirable from the flexibility perspective.

Figure 59 • Dispatchable plant portfolio (Nordic)

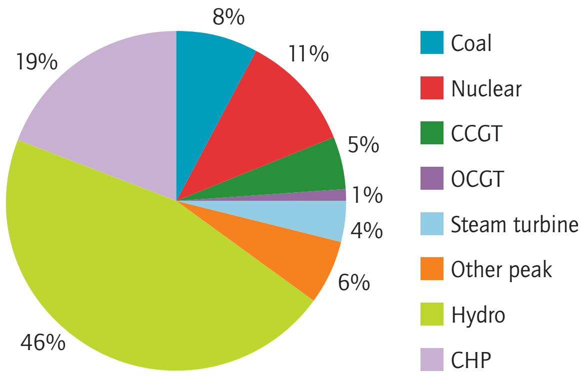
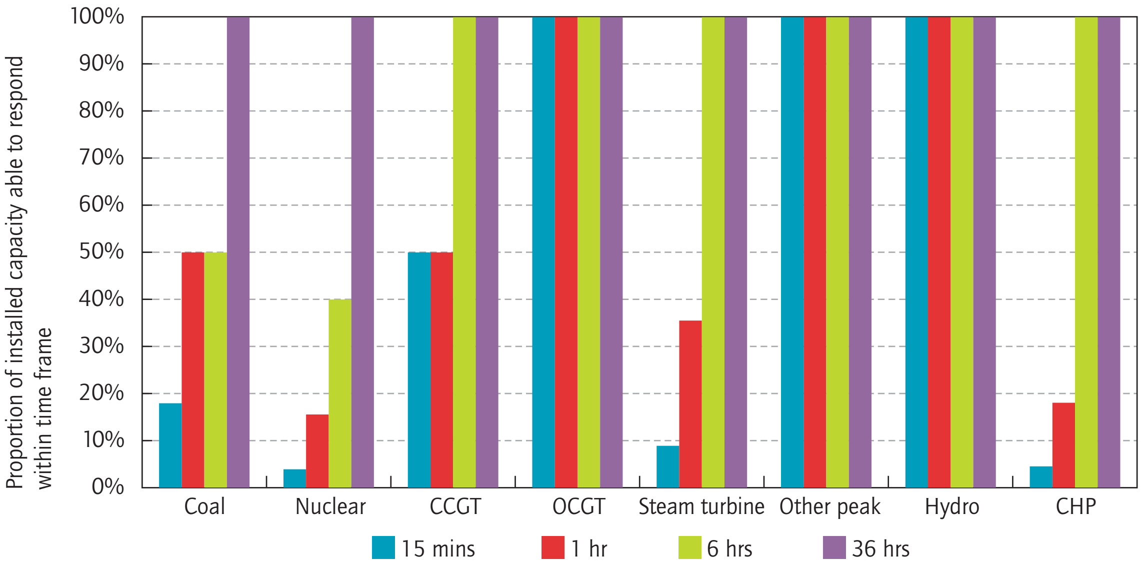


Figure 60 • Technical flexibility of dispatchable plant (Nordic)



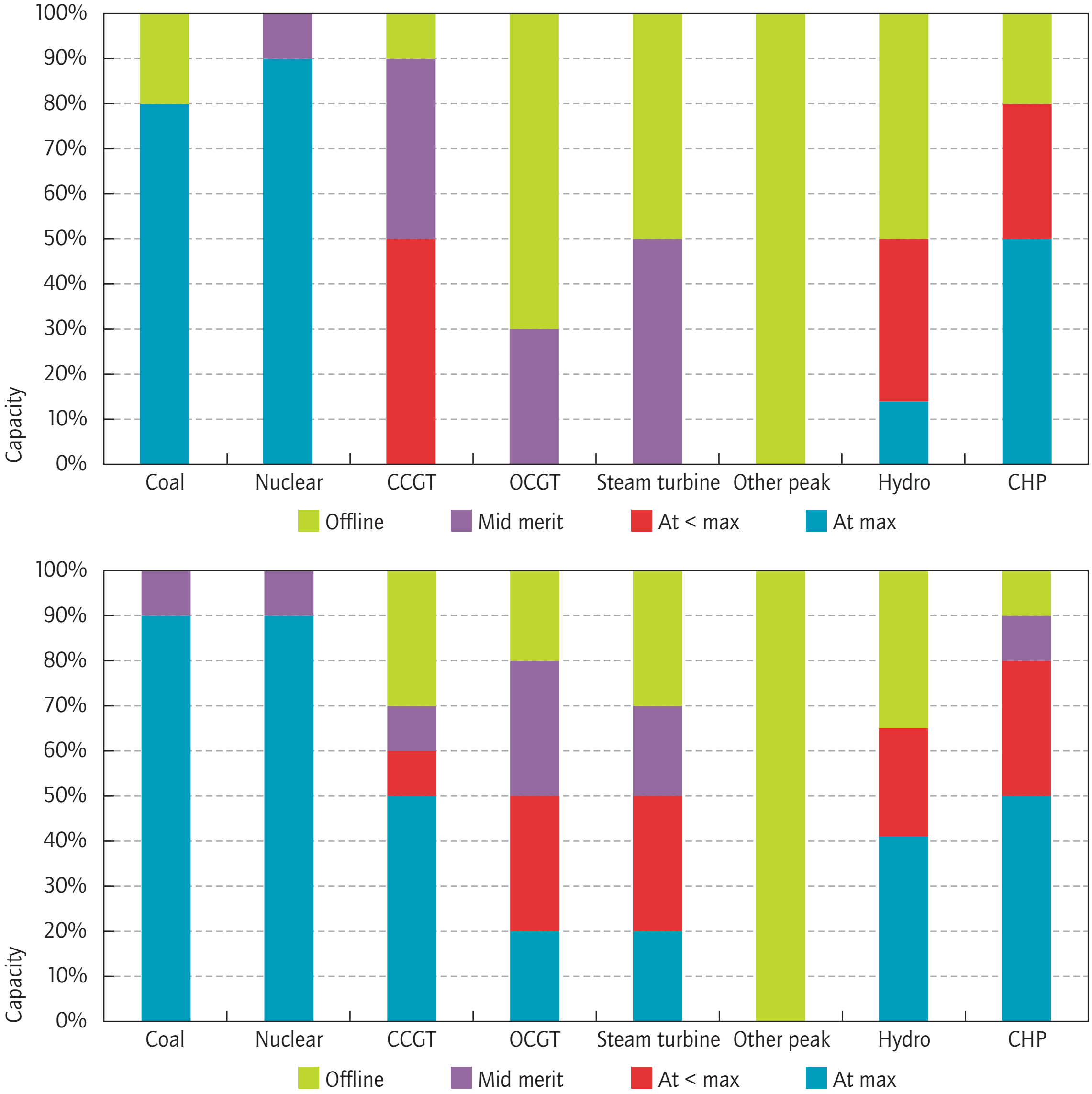
When only the technical capabilities of plants are taken into account, there seems to be a great deal of flexibility on each timescale. However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down if it is operating below maximum.

The expectations for plant types in the area are shown in Figure 61. Hydro in the Nordic area is used more for providing energy, in a mid merit or base loaded fashion, relative to peaking hydro in the British Isles, for example. This is because it exists in particularly high quantities in the Nordic system (Figure 59) – nearly half of all installed dispatchable capacity.

As hydro start-up and shut-down times are very short, it may be possible to shut down part of the capacity so as to be able to provide up-ramping when needed, then to shut down again to provide down-ramping — within the longer timescales assessed in this analysis (6 hours and 36 hours). The effect would be that, for hydro, the four operating states illustrated in Figure 61 would sum to greater than 100% of capacity on those timescales. However, this would depend on a very strong flexibility incentive from the market, and is not considered further at this stage of the analysis.

Figure 61 • Likely operation of dispatchable plant (Nordic) at minimum demand (top figure), and peak (bottom figure)



The final step is to calculate the likely availability of the overall dispatchable plant portfolio to ramp during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values shown in Table 28. These will be the occasions when resources are most limited by existing requirements for flexibility (from fluctuating demand).[3]

3. See Chapter 12 "Dispatchable generation" for explanation of these steps.

Table 28 • Technical flexible resource from dispatchable power plants (Nordic)

Flexible resource in:	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	48 159	30 832
1 hr	49 969	36 460
6 hrs	74 177	77 136
36 hrs	75 500	91 018

Storage

In these case studies, reservoir hydro is included as dispatchable generation. Additionally, in the Nordic case alone, pumped-hydro schemes are also included under the dispatchable generation heading. Whether pumped hydro is considered generation or storage is essentially an accounting question – so long as its ramping capability is assessed faithfully, its categorisation is secondary. In other areas, where reservoir hydro is less prevalent – like the British Isles, where the majority of the hydro resource is of the run-of-river type – pumped hydro is assessed as storage, this being its primary use. Therefore it should be noted that while the Nordic area shows no storage in this analysis, there is effectively a very large amount in the form of pumped hydro.

Demand-side

Based on existing data, the total resource is estimated to be approximately 6000 MW, around 10% of peak demand. The estimate of demand-side flexibility used in this assessment of Nordic system is likely to be significantly lower than the real potential of this resource.

Interconnection

According to figures from the Norwegian Water and Energy Directorate, 5 260 MW of export capacity and 4 710 MW import capacity exist between the Nordic area and its neighbours, via AC and DC links.[4]

When compared to the peak demand of the area (69 GW), it amounts to only about 7%. This could be taken to illustrate the relatively small importance of interconnection to large areas. In small areas like Denmark, for instance, interconnection amounts to the equivalent of more than 80% of peak demand, meaning that it will be able to manage far greater swings in the net load on the basis of interconnected flexible resources.

Flexibility Index and Present VRE Penetration Potential

The existing flexible resources of the Nordic area are summarised in Table 29. The last two columns show the total technical flexible resource (TR) available for ramping up and ramping down.

Table 29 • Technical flexible resources (Nordic)

Time scale	Dispatchable plant		Demand side	Storage	Interconnection	Technical resource	
	Up (MW)	Down (MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	32 063	23 125	6 000	n/a	4 710	42 773	33 835
1 hr	49 969	36 460	6 000	n/a	4 710	60 679	47 170
6 hrs	74 177	77 136	6 000	n/a	4 710	84 887	87 846
36 hrs	75 500	91 018	6 000	n/a	4 710	86 210	101 728

4. In this analysis, for simplicity's sake, the lower figure is taken to represent interconnection capacity.

In these case studies existing and new requirements for flexibility are simply summed, which gives a conservative estimate for the overall flexibility requirement. Existing Flexibility Requirement (EFR) is subtracted from TR to yield the net technical resource (NTR). NTR for up and down ramping are shown in Table 30, columns 4 and 5.

Dividing by peak demand (69 GW) produces the FIX value for the area – shown in the last two columns, for both up and down ramping. FIX values increase over time for down-ramping, as the rate of increase of flexible resource is greater than the rate of increase of the existing requirement for it. The up-ramping value drops at the 36 hour timescale – but not by much. FIX values increase from 15 minutes up to 6 hours faster than in any other area assessed, due to the very good flexibility afforded by the large number of hydro units on the system. With the exception of Denmark, FIX values are higher than other areas assessed.

Table 30• Existing flexibility requirement and Flexibility Index (Nordic)

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	4 035	3 235	38 738	30 600	0.56	0.44
1 hr	8 388	7 588	52 291	39 582	0.76	0.57
6 hrs	13 835	13 035	71 052	74 811	1.03	1.08
36 hrs	19 835	19 035	66 375	82 693	0.96	1.2

The second variability metric, Present VRE Penetration Potential (PVP), illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the area are shown in Table 31.

Table 31 • Present VRE Penetration Potential (Nordic)

Time scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	3.4	1 127 744	890 831	689%	544%
1 hr	11	475 718	360 101	291%	220%
6 hrs	49	143 643	151 244	88%	92%
36 hrs	85	78 089	97 286	48%	59%

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled on, *e.g.* the 15 minute timescale, this is because the flexibility requirement of VRE is very small at this timescale, relative to TR[5]. **It is only the most constrained occasion, *i.e.* when the extent of variability is largest relative to the extent of flexible resource (in the Nordic case, upwards flexibility at 36 hours), that is of relevance to PVP.**

In the Nordic area then, from a purely technical perspective, some 48% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for the latter are taken into account. This assumes no overlap between existing and new requirements.

While both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the full range of power area constraints which will affect the availability of flexible resources. These relate to operation of the system and market in the area, as discussed in the next section.

5. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.* economic and operational) considerations.

Area constraints

The calculation of PVP above, based only on the technical flexible resource (TR), is far higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as potential congestion of the grid, and sub-optimal operation and market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

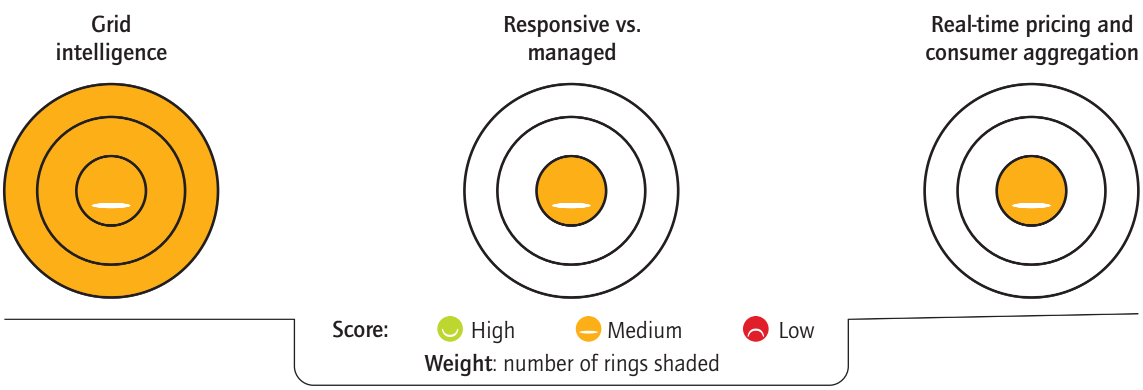
Individual flexible resources may be subject to a range of specific constraints. These are addressed in the next section, while constraints on TR as a whole are assessed subsequently.

Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 "Scoring and weighting of area attributes".

Available demand-side resource

The power area attributes with specific bearing on the availability of demand-side flexibility in the Nordic area are summarised in Figure 62.

Figure 62 • Attributes relating to demand-side resource availability (Nordic)



Grid intelligence. Grid intelligence is mainly conventional, although some enabling technologies are used, including some smart meters in Sweden – an intermediate score. This attribute remains the most significant limiting factor on the availability of demand-side flexibility, with heavy weighting.

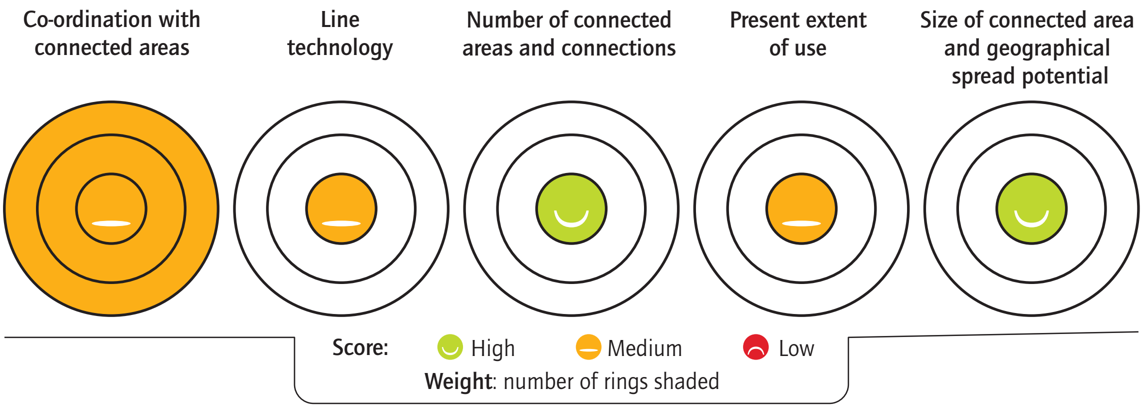
Responsive vs. managed. Three-quarters of the potential demand resource is assumed to be of the managed type, rather than the response type. A significant part of the resource will then be inaccessible for balancing purposes, being scheduled well in advance of the balancing timeframe – an intermediate score. The attribute has light weighting however – insufficient grid intelligence denies the opportunity to use price responsiveness.

Real-time pricing. There is some penetration of real-time pricing in Sweden but in the area as a whole it is limited – an intermediate result. A portion of the 25% of the resource that is responsive will be able to respond when needed in Sweden, if price signals are strong enough. The attribute has only light weighting, however, as penetration of smart metering is still low, and grid intelligence remains intermediate.

Available interconnection resource

Power area attributes with impact on the availability of flexibility from adjacent areas (outside the Nordic area) are summarised in Figure 63.

Figure 63 • Attributes relating to interconnection availability (Nordic)



Co-ordination with adjacent areas. Co-operation with adjacent areas (outside the Nordic area) is of intermediate quality – so some use can be made of neighbouring flexible resources. Balancing resources are not explicitly shared, but nonetheless are available to some extent, representing significant remaining constraint on the resource.

Technology. Line technology is a mixture of DC and AC – an intermediate case (DC is less flexible as it may require notice of a switch in polarity). However weighting is light as intermediate co-ordination among the neighbours should mean that the use of the DC portion can be effectively planned.

Number of connected areas and connections. The Nordic area is connected to four other power areas, via 12 corridors: there is significant redundancy and the areas connected to can all offer flexibility at different times – a good score, with light weight, reflecting no additional constraint on the resource.

Present extent of use. Existing capacity is used to an intermediate extent. As co-ordination with neighbours is intermediate, much of the interconnection capacity could be relied upon for balancing variable generation. Moreover, the fact that a significant part of capacity is already used may not represent an additional constraint because existing co-ordination (with neighbours who also have significant experience with variable generation) would suggest that usage is already at least partially driven by balancing: a light weighting therefore.

Size of connected area and geographical spread potential. The areas connected to are large (Germany, Poland, etc.), with significant flexible resources, and VRE outputs are likely to be uncorrelated with those in the Nordic area, offering significant potential benefit in terms of smoothing. It is therefore considered not to have a significant limiting effect on flexibility from interconnections, and has light weighting.

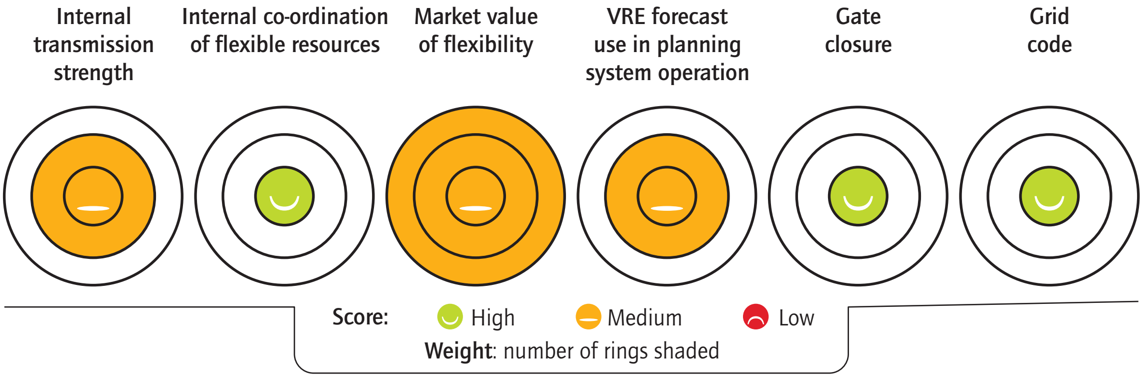
Area constraints on total flexible resource

The power area attributes with bearing on the overall flexible resource in the Nordic area are summarised in Figure 64.

Internal transmission strength. Though the transmission grid of the Nordic area is strong in most places, there are weaknesses. The area contains a number of countries, in which power systems developed independently up to the creation of the single Nordic power market. So, an intermediate score overall. Internal transmission is not considered a highly limiting factor – but nevertheless retains medium weighting, signalling still significant potential constraint on availability of flexible resources. Moreover VRE resources are to a large extent located far from demand centres and balancing resources, making congestion in weaker areas more likely.

Internal co-ordination of flexible resources. The entire area participates deeply in one market, which is the optimum from a flexibility perspective, as balancing resources can be shared efficiently: a high score, with light weighting to reflect limited constraint on flexibility.

Figure 64 • Availability of total flexible resource (Nordic)



Market valuation of flexibility. The Nordic market does not explicitly reward the provision of the flexibility service. Implicit incentive exists in the opportunity to trade in an intra-day market (Elbas), where the electricity price is known in advance of delivery, and could increasingly reflect the fluctuating value of flexibility through greater price volatility. This serves to some extent as an alternative to the other flexibility mechanism – the balancing market – wherein the system operators deal directly with power producers (and a few large consumers) for balancing services. However, slower flexible resources will see insufficient compensation for provision of their potential contribution to flexibility (in response to long term forecasts of the net load). So, an intermediate score, with heavy weighting, reflecting considerable remaining constraint on flexibility.

Use of VRE forecast in system planning. Forecasting of variable generation output is well used when planning the operation of the area and commitment of plants – this is an intermediate result with medium weighting. For significant improvement in the availability of flexible resources, the entire Nordic area would need to adopt the methods being explored in some countries, notably Denmark. State of the art forecasting technology (such as probabilistic or ensemble forecasting) is not yet being used, but strong efforts are made to consider VRE output when planning the operation of the area. Unit commitment could be improved through more frequent updates or more advanced unit commitment planning.

Gate closure. Gate closure in the Nordic spot market (Elspot) occurs on the day-ahead, but trading can continue in the Elbas market (which also includes Germany and Estonia). In the Elbas market, trades made day-ahead on Elspot can be adjusted up to one hour prior to delivery. This intra-day opportunity to update trades increases the usefulness of nearer-term VRE output forecasts, and the efficient planning of flexible resources. So, a high score with light weighting, reflecting limited additional constraint on the availability of flexible resources.

Grid code. The latest grid codes for managing variable generators are in place – generators will operate as expected so the variability seen will be as expected. So, a high score with low weighting.

17 • Denmark

Denmark illustrates how well a relatively small area can perform in balancing variable generation when it has a very high proportion[1] of interconnection, and is part of a larger system. Denmark is part of the Nordic area assessed previously. As it is well connected to this area, it has access to a large amount of the Nordic flexible resource. Denmark has already very significant experience with wind energy penetration (around 20% of gross annual electricity demand). East and West Denmark sit in different power systems, both a part of larger systems, so the connection between the two halves will be less significant than the connection to these other areas.

This assessment of the area of Denmark (East and West) is based on data received in response to the GIVAR project questionnaire. Where no data were available, assumptions were made based on other areas and sources. Values and scores herein are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

Flexibility requirement of VRE

The case study assumes a portfolio of different VRE technologies.[2] On and offshore wind are dominant (85%). The assumptions made about the characteristics of the five VRE plant types in the Denmark area are listed in Table 32.

Table 32 • VRE portfolio assumptions (Denmark)

Resource	Onshore wind	Offshore wind	Solar PV	Tidal	Wave
Maximum variability (% installed capacity/minute)	0.32%	0.44%	0.13%	0.08%	0.12%
Maximum uncertainty (% error/minute)	0.11%	0.15%	0.06%	0	0.04%
Assumed share of technology in VRE portfolio (% of VRE portfolio)	60%	25%	5%	0	10%
Assumed location relative to load	Mixed	Mixed	Near Load	Far from load	Far from load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30%	35%	10%	25%	25%

The calculation of the overall flexibility requirement for the VRE portfolio is shown in Table 33. Due to the relatively small size of the area, the maximum extent of variability seen is likely to be higher than other regions examined.[3]

Table 33 • VRE flexibility requirement (Denmark)

Time scale	15 mins	1 hr	6 hrs	36 hrs
Maximum variability (% installed capacity)	4.8	17	69	90
Maximum uncertainty (% installed capacity)	1.7	5.9	24	90
Flexibility requirement (% installed capacity)	6.5	23	75	90

1. Relative to peak demand.
2. For explanation of the portfolio concept, see Chapter 12 “Assumed VRE portfolios”.
3. For discussion of the values used for variability and uncertainty, see Chapter 12 “Flexibility requirement of VRE”.

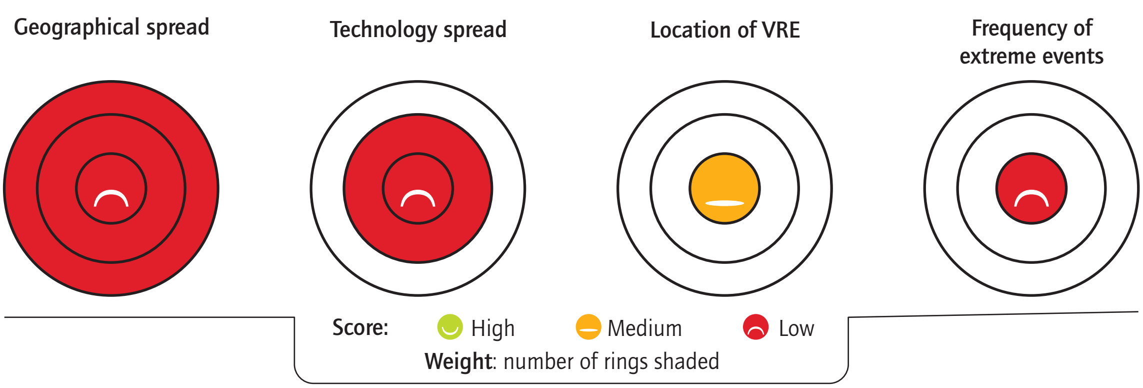
Variability increases with longer time horizons, until at 36 hours it can represent close to the full installed capacity. A maximum of 90% of installed capacity is assumed, as the area is unlikely to see periods of zero or maximum output from its aggregated variable generators. However, swings may be greater than in larger areas – so, in this case, a higher maximum is applied.

Further qualification of flexibility requirement

The actual flexibility requirement is likely to be less than that shown in Table 33, since this simple approach omits a range of potentially beneficial factors due to limited data availability. The factors which have additional bearing on the extent of variability are summarised in Figure 65.

Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the "Location of VRE" attribute relates to internal transmission strength below; and the light weight of the "Frequency of extreme events" attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above (Table 33).

Figure 65 • Attributes relating to VRE flexibility requirement (Denmark)



Geographical spread. The area is of modest size, so its VRE resources are relatively concentrated: even when aggregated over the complete area, the extent and ramping rates of variability will remain high. The entire area can fit beneath a single weather system, so output for each technology type will be strongly correlated across the whole area – a low score with heavy weight. Nevertheless, the smoothing resulting from aggregation over the whole area will still have a significant effect: despite strong correlation, there may be a time lag of several hours as a storm front, for example, moves across the area.

Technology spread. In the assumed VRE portfolio there is relatively little opportunity for smoothing aggregated output via technology spread in the area – most variable generation is likely to be onshore and offshore wind energy, which will be strongly correlated – a low score with medium weight.

Location of VRE. A large proportion of variable resources are distant from demand centres, increasing the significance of the internal transmission attribute, which is discussed later. However, as the area is relatively small and internal transmission strength strong (Figure 71), this attribute has only a light weight.

Frequency of extreme events. Wind makes up most of the expected resource in the area, so the occurrence of extreme events is likely. Therefore the full extent of the flexibility requirement identified above will be needed relatively frequently, and is consequently more likely to coincide with existing requirements (demand). It is then less likely that flexible resources held against demand requirements will also be available against the needs of VRE.

Flexible resources

Dispatchable generation

The present proportions of types of dispatchable power plant in Denmark are shown in Figure 66. Assumptions relating to operating levels and ramp rates, and definitions, can be found in Annex C.

The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 67, expressed as a percentage of installed capacity (of that technology) that can be ramped up or down within the four timescales. The assessment of technical flexibility is based on data received in response to GIVAR project questionnaires.

Figure 66 • Dispatchable plant portfolio (Denmark)

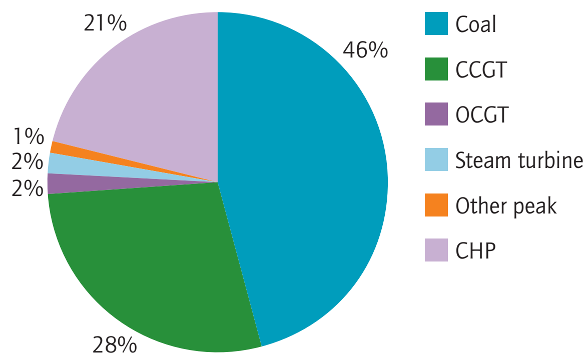
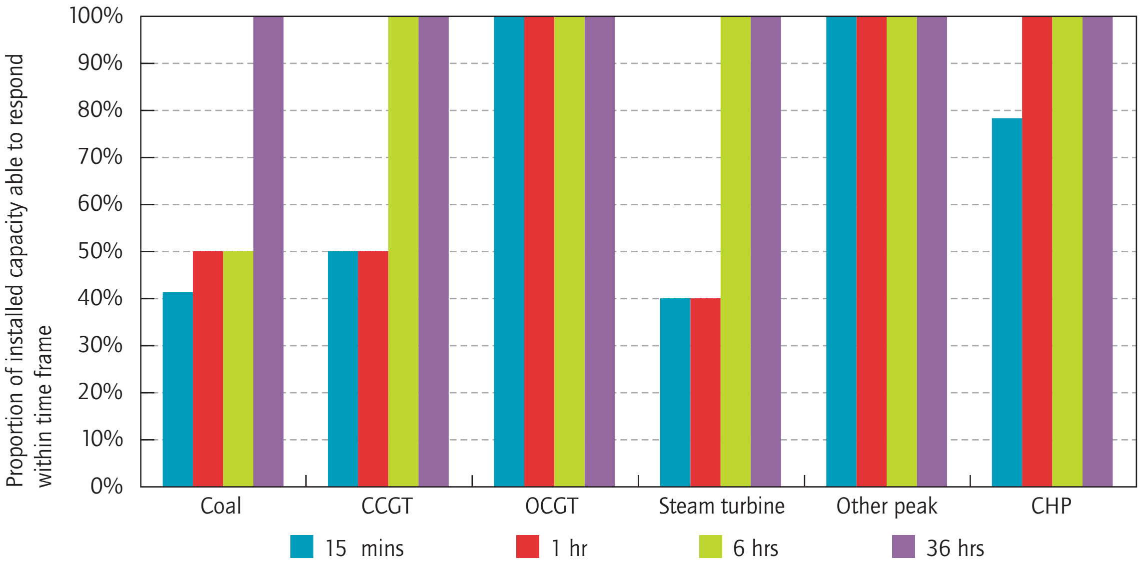


Figure 67 • Technical flexibility of dispatchable plant (Denmark)



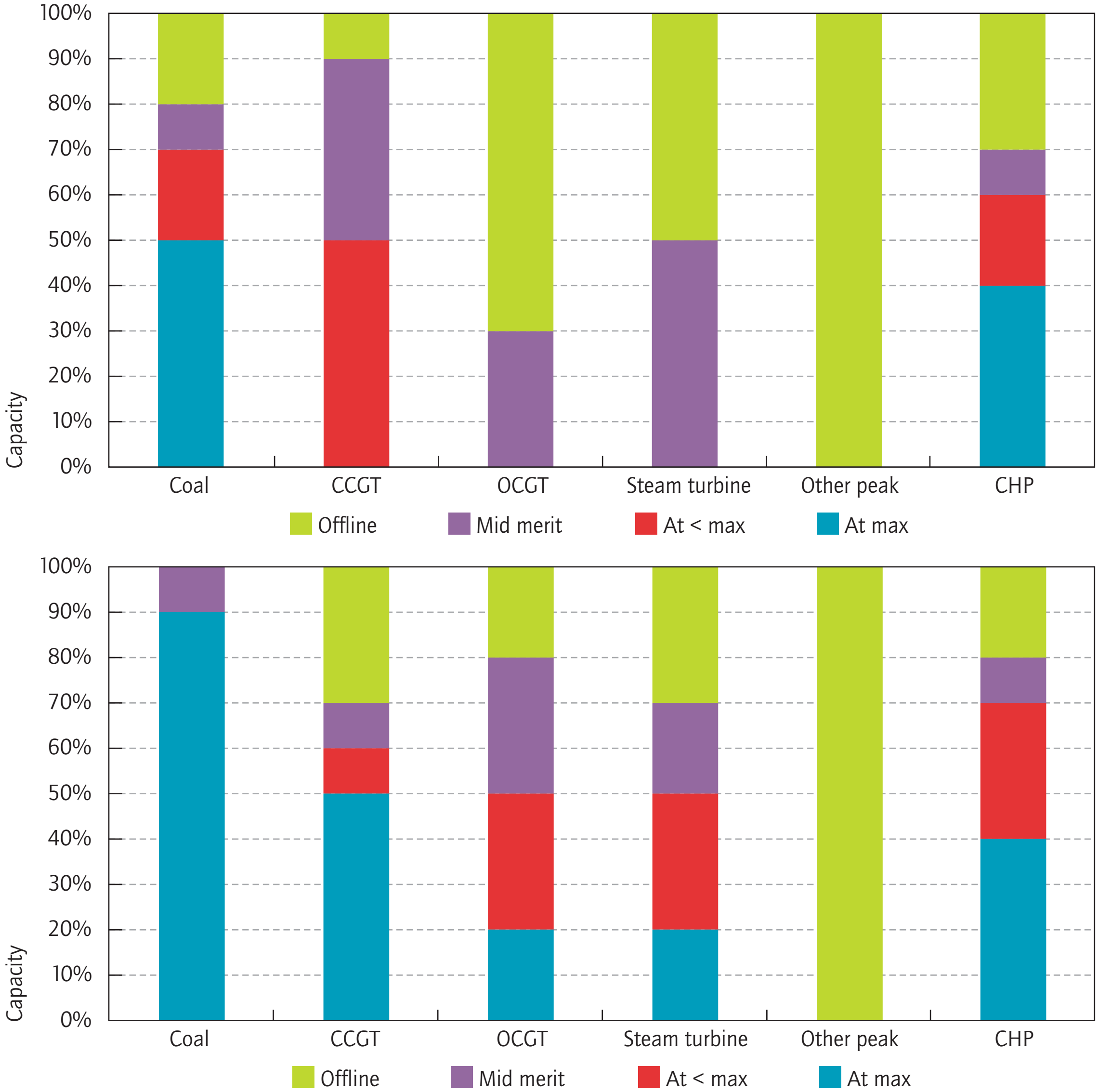
It should be noted that it is not only ramp rates (in MW / minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start up / shut down times are also important. For example, in the Danish area, coal plants are able to ramp down to a minimum stable level of 50% inside one hour, and could then shut down entirely inside 36 hours – if this were desirable from the flexibility perspective.

When only the technical capabilities of plants are taken into account, there seems to be a great deal of flexibility on each timescale. However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down if operating below maximum.

The expectation for dispatchable plant types is illustrated in Figure 68. CHP plants in this area are "must run" in many cases, which will reduce their ability to provide flexibility.

Figure 68 • *Likely operation of dispatchable plant (Denmark) at minimum demand (top figure), and peak (bottom figure)*



The next step is to calculate the likely availability of the whole dispatchable plant portfolio to ramp, which will be different during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values are shown in Table 34. These will be the occasions when resources are most limited by existing requirements for flexibility.[4]

Table 34 • *Technical flexible resource from dispatchable power plants (Denmark)*

Flexible resource in:	*Maximum up-ramp capability (MW)*	*Maximum down-ramp capability (MW)*
15 mins	1 561	2 939
1 hr	1 771	3 458
6 hrs	3 815	5 153
36 hrs	4 621	7 201

4. See Chapter 12 "Dispatchable generation" for explanation of these steps.

Storage

There are no electrical storage facilities in Denmark large enough to be used in balancing.

Demand-side flexibility

Demand-side flexibility is estimated to be 8% of peak demand, based on assessment of other areas and the fact that Denmark is a highly developed country, likely to have a significant discretionary load: 500 MW.

Interconnection

Together, the two parts of the Danish area (west and east Denmark) have 5 440 MW of interconnection with adjacent areas (Nordic and Germany), the equivalent of more than 80% of Danish peak demand. This is the primary reason Denmark has been able to accommodate such a high penetration of wind power to date.

Flexibility Index and Present VRE Penetration Potential

The technical flexible resources (TR) in Denmark are summarised in Table 35. The last two columns sum individual resources to yield an aggregated TR for up-ramping and down-ramping.

Table 35 • Technical flexible resources (Denmark)

Time scale	Dispatchable plant		Demand side	Storage	Interconnection	Technical resource	
	Up (MW)	Down (MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	1 561	2 939	500	0	5 440	7 501	8 879
1 hr	1 771	3 458	500	0	5 440	7 711	9 398
6 hrs	3 815	5 153	500	0	5 440	9 755	11 093
36 hrs	4 621	7 201	500	0	5 440	10 561	13 141

In these case studies existing and new requirements for flexibility are summed, which gives a simplified and conservative estimate for the overall flexibility requirement. Existing Flexibility Requirement (EFR) is subtracted from TR to yield the net technical resource (NTR). NTR for up and down ramping are shown in columns 4 and 5 of Table 36.

Dividing by peak demand (6.5 GW) produces the FIX value for the area – shown in the last two columns, for both up and down ramping. FIX values increase with the time horizon, and are high, relative to all other areas assessed except the Nordic area of which it is part.

Table 36• Existing flexibility requirement and Flexibility Index (Denmark)

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	1 046	546	6 454	8 333	1.01	1.30
1 hr	1 186	686	6 524	8 712	1.02	1.36
6 hrs	1 996	1 496	7 759	9 597	1.21	1.50
36 hrs	2 596	2 096	7 965	11 045	1.24	1.72

The second variability metric, Present VRE Penetration Potential (PVP), illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the area are shown in Table 37.

Table 37 • Present VRE Penetration Potential (Denmark)

Time scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	6.5	99 837	128 898	713%	920%
1 hr	23	28 033	37 433	200%	267%
6 hrs	75	10 345	12 796	74%	91%
36 hrs	90	8 850	12 272	63%	88%

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled on, *e.g.* the 15 minute timescale, this is because the flexibility requirement of VRE is very small at this timescale, relative to NTR.[5] **It is only the most constrained occasion** *i.e.* **when the extent of variability is largest relative to the extent of flexible resource (in the Danish case, upwards flexibility at 36 hours) that reflects PVP.**

In Denmark then, from a purely technical perspective, some 63% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for flexibility are taken into account.

However, while both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the full range of power area constraints that will affect the availability of flexible resources. These relate to operation of the system and market in the area, and are discussed in the next section.

Area constraints

The calculation of PVP above, based on the technical flexible resource (TR), is higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as congestion of internal transmission, sub-optimal operation and market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

Individual flexible resources have particular constraints. These are addressed in the next section, while constraints on TR as a whole are assessed subsequently.

Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 “Scoring and weighting of area attributes”.

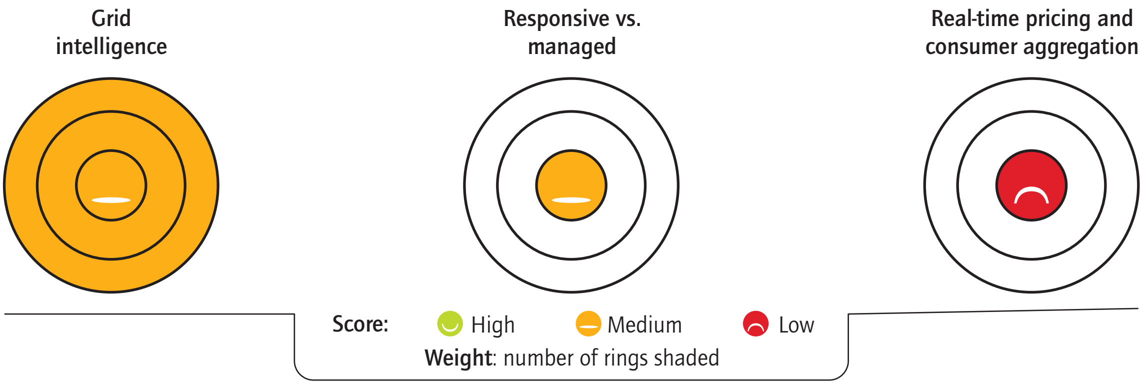
Available demand-side resource

Area attributes with specific bearing on the availability of demand-side flexibility in Denmark are summarised in Figure 69.

Grid intelligence. The grid in the area is of conventional intelligence — an intermediate score. As this is the primary driver for availability of the demand-side resource, an intermediate score still represents a significant constraint on flexibility in this case, so it has heavy weighting.

5. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.* economic and operational) considerations.

Figure 69 • *Attributes relating to demand-side resource availability (Denmark)*



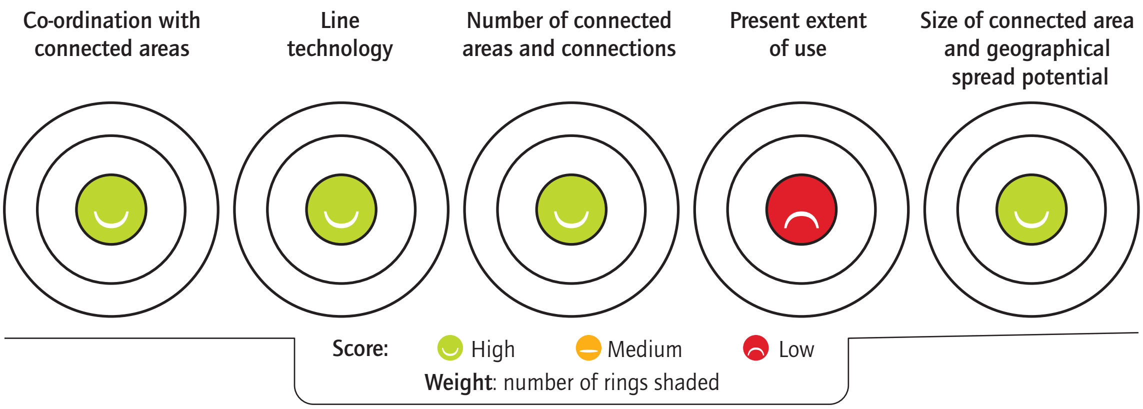
Responsive vs. managed. Approximately 25% of the demand-side resource (DSR) is assumed to be of the price-responsive type, and 75% of the managed type. Part of the managed resource may not be available for flexibility in the balancing timeframe: it may be scheduled long in advance – an intermediate score. Light weighting reflects the fact that DSR is in any case constrained by intermediate grid intelligence and an absence of key enabling technologies, particularly smart meters or equivalent information technology, so it does not in itself represent an additional constraint on flexibility at this time.

Real-time pricing and consumer aggregation. This attribute is closely related to the previous one. Consumers in the area do not have access to real-time price information, and opportunities do not exist to aggregate domestic consumers (in particular), and so increase the likelihood of response – a low score. Opportunity for both depends on smart meters, which the area does not have, so this attribute has only a light weighting.

Available interconnection resource

Power area attributes with impact on the availability of flexibility from adjacent areas (outside the Nordic area) are summarised in Figure 70.

Figure 70 • *Attributes relating to interconnection availability (Denmark)*



Co-ordination with adjacent areas. Both parts of Denmark (East and West) are integrated parts of larger power systems (continental ENTSO-E and Nordel, respectively), so co-ordination with adjacent areas is strong. This is particularly relevant in the Danish area as it relies on imports and exports of energy for most of its flexibility needs – a high score, with a light weight, reflecting no additional constraint on flexibility.

Technology. Connections are mainly of the AC type, to enable this strong co-ordination with adjacent areas – a high score, with light weight, reflecting no additional constraint on flexibility.

Number of connected areas and connections. Both parts of Denmark are connected to multiple areas via more than one corridor. Significant redundancy exists and the connected areas will offer flexible resources at different times from each other – a good score with light weighting.

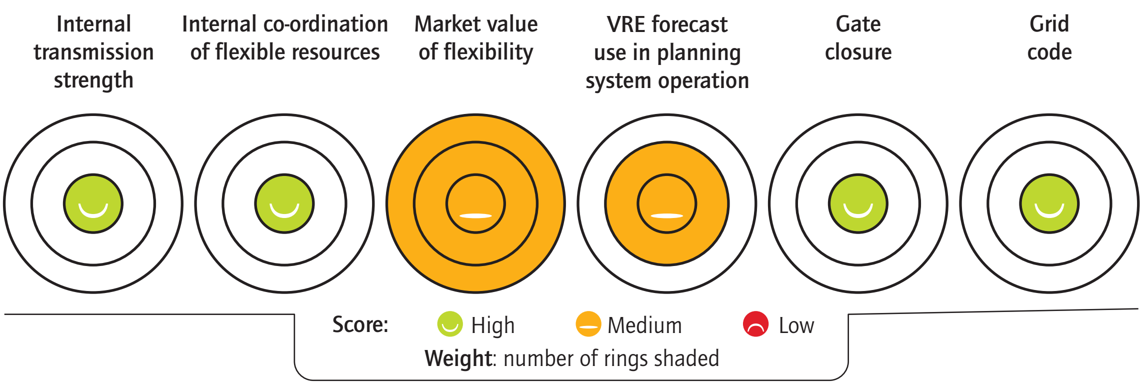
Present extent of use. Interconnections are already heavily used – a low score – but weighting is light as existing usage is primarily driven by the VRE requirement for flexibility in the first place – *i.e.* it is already part of the available flexible resource.

Size of connected area and geographical spread potential. Denmark is connected to larger areas with large flexible resources – much of the flexible resource calculated for Nordic (*e.g.* hydro) is used to balance VRE in Denmark. Connections to Sweden, Norway and Germany mean a large potential for geographical smoothing of variable outputs. The area scores high in this regard, with light weight, reflecting no constraint on flexibility value.

Area constraints on total flexible resource

The power area attributes with bearing on the overall flexible resource in the Danish area are summarised in Figure 71.

Figure 71 • Availability of total flexible resource (Denmark)



Internal transmission strength. There is strong internal transmission in the two separate balancing areas of the Danish power area (west and east), which is significant as a large part of VRE resources is located far from demand centres. Moreover, a new 500 MW DC[6] link between Jyland and Funen (west Denmark) and east Denmark (Zeeland) has recently been completed – the first connection between the two areas, which significantly improves opportunities for sharing of flexible resources. This attribute scores high, with light weight reflecting only limited additional constraint on availability of flexibility.

Internal co-ordination of flexible resources. Because the systems of which each is part are asynchronous, both east and west Denmark can be electrically connected only via a DC link – the new transmission corridor referred to above. This means they are more isolated than if the two were both parts of a common AC system. However the same system operator, EnergiNet, operates both east and

6. The link has to be DC as the eastern and western parts of the country are part of different, non-synchronous systems.

west Denmark (following the 2005 merger of Eltra and Elkraft), so they are well coordinated – a high score. Moreover as both parts are constituents of larger systems (ENTSO-E and Nordel) this attribute has less relevance, and would in any case have light weighting.

Market value of flexibility. The markets of which Denmark is part do not explicitly reward the provision of flexibility. The Elbas and balancing markets in the Nordic power market (of which the larger, eastern part of Denmark, is part) provide implicit incentive (see the Nordic case study). However, slower (*e.g.* coal) resources will receive insufficient compensation for provision of their potential contribution to flexibility (in response to long term forecasts of the net load). So, an intermediate score, with heavy weighting, reflecting a continuing, significant constraint on availability of flexible resources.

VRE forecast usage in system planning. Forecasting of variable generation output is well used by EnergiNet in planning the operation of the area. The Wind Power Prediction tool (WPPT) has been in use since 1997. EnergiNet has also been a prime mover in research into more advanced, ensemble forecasting, a technique that quantifies the uncertainty of a forecast by providing a range of scenarios of how the weather will develop over a given period. This is currently in development. So, an intermediate score, reflecting that more advanced forecasting tools are perhaps around the corner, and remain to be implemented in the operation of the power system. Medium weighting reflects the significant constraint on the optimal allocation of flexible resources persists.

Gate closure. Gate closure occurs close to delivery time (see Nordic case study), reducing uncertainty in output forecasts of VRE, so the operation of flexible resources can be well planned – a good score with light weighting, reflecting very limited additional constraint on availability.

Grid code. The latest grid codes for managing variable generators are in place, so VRE plants will operate as expected – a high score. Despite the already high shares of wind energy in the area, low weighting of the attribute reflects confidence on the part of the system operator that plants will behave as expected.

18 • Japan

This assessment illustrates the VRE integration challenge from the point of view of Japan. Japan has no opportunity for trade of electricity with adjacent areas (the nearest would be South Korea), and limited generation side flexibility. Also, it consists of 10 isolated internal areas, in each of which electricity is provided by a single vertically integrated utility, which also controls transmission and distribution. As such they are likely to see minimal intra-area constraints on availability of flexible resources. On the other hand, the same fact may limit the deployment of independent, centralised VRE power plants. An additional disadvantage of the vertically integrated model from the balancing view is that trade among the areas would be subject to commercial interests, and disincentive to interact could therefore result.

This assessment of the area of Japan is based on data received in response to the GIVAR project questionnaire. Where no data were available, assumptions were made based on other areas and sources. Values and scores herein are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

Flexibility requirement of VRE

The case study assumes a portfolio of four VRE technologies, predominantly onshore wind (40%) and solar PV (40%).[1] Assumptions relating to the characteristics of each are listed in Table 38.

Table 38 • VRE portfolio assumptions (Japan)

Resource	Onshore wind	Offshore wind	Solar PV	Tidal	Wave
Maximum variability (% installed capacity/minute)	0.10%	0.15%	0.13%	0.08%	0.12%
Maximum uncertainty (% error/minute)	0.07%	0.10%	0.06%	0	0.04%
Assumed share of technology in VRE portfolio (% of VRE portfolio)	40%	10%	40%	0%	10%
Assumed location relative to load	Mixed	Mixed	Near Load	Far from load	Far from load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30%	35%	14%	25%	25%

The calculation of overall VRE portfolio flexibility requirement is shown in Table 39.[2] It should be noted that this is an approximate calculation and does not include the effect of technology spread – smoothing of aggregated variability resulting from negatively correlated electrical outputs. This is likely to be particularly important as the VRE portfolio in this case includes similar capacities of onshore wind and solar PV.

As in all areas, the extent of maximum swings in output increases with the time horizon, until at 36 hours the variability can cover close to the full installed capacity. A maximum of 85% of installed capacity is used here, as the area is very extensive and therefore unlikely to see periods of zero or maximum output.

1. For explanation of the portfolio concept, see Chapter 12 "Assumed VRE portfolios".
2. For discussion of the values used for variability and uncertainty, see Chapter 12 "Flexibility requirement of VRE".

Table 39 • VRE flexibility requirement (Japan)

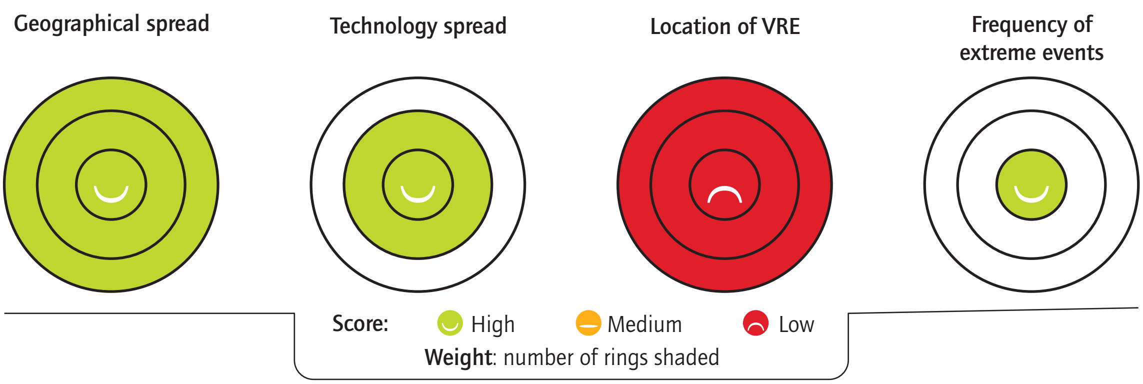
Time scale	15 mins	1 hr	6 hrs	36 hrs
Maximum variability (% installed capacity)	1.8	5.7	26	85
Maximum uncertainty (% installed capacity)	1.0	3.2	14	57
Flexibility requirement (% installed capacity)	2.8	8.9	40	85

Further qualification of flexibility requirement

The actual flexibility requirement is likely to be less than that shown in Table 39, since this simple approach omits a range of factors which have additional bearing on the extent of variability, due to limited data availability. These are summarised in Figure 72.

Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the "Location of VRE" attribute relates to internal transmission strength, see below; and the light weight of the "Frequency of extreme events" attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above (Table 39).

Figure 72 • Attributes relating to VRE flexibility requirement (Japan)



Geographical spread. Japan covers a large area, and VRE resources are widely dispersed about it. This would smooth the extent and rate of variability if plants are dispersed widely about the area and can interact as part of a single system (*i.e.* ignoring internal grid and coordination for the present). The area lies under multiple weather systems (north and south), reducing variability still further, particularly on longer time scales as weather fronts move across the area.

Technology spread. There is significant opportunity for technology spread in the area, as the assumed portfolio includes equal proportions of onshore wind (40%) and solar PV (40%). There may also be significant complementarity between existing and new flexibility requirements: PV output for example will be likely to be positively correlated with the daily demand rise, freeing up a measure of the flexible resource against variability in the wind and wave portions of the portfolio, so a high score.

Location of VRE. The wind part of the likely VRE portfolio is located away from demand centres, and lies to some extent in protected areas. Internal transmission strength will be an important factor. As internal transmission in the area of Japan as a whole is weak, as discussed later (see Figure 78), the location of dispersed resources will be a serious hurdle.

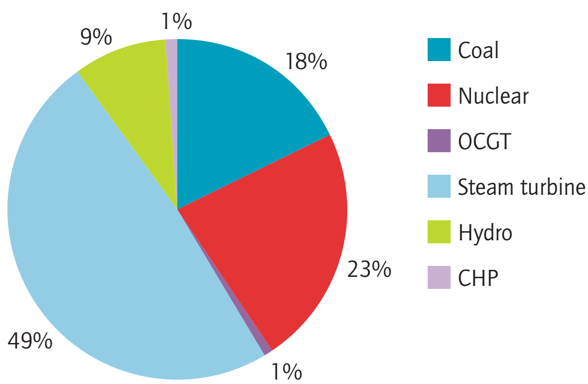
Frequency of extreme events. Technology spread in the area is strong. The full extent of the flexibility requirement identified above will be seen less often, and there may be a basis for considering flexible resources against fluctuating demand to be available to some extent against new needs of VRE. So, a good score.

Flexible resources

Dispatchable generation

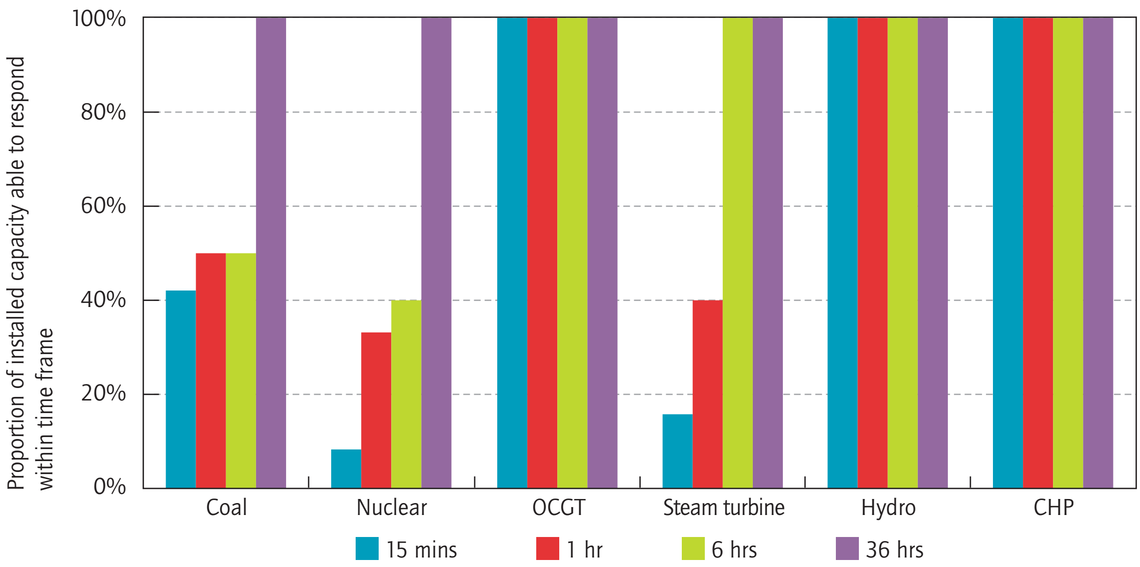
The present proportions of the dispatchable plant portfolio in Japan are illustrated in Figure 73. Assumptions relating to minimum stable operating levels, ramp rates, start up and shut down times, and definitions, can be found in Annex C. Data are based on the questionnaire responses from Japan and IEA data (IEA, 2009).

Figure 73 • Dispatchable plant portfolio (Japan)



The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 74, expressed as a percentage of installed capacity that can be ramped up or down over the four timescales. The assessment of technical flexibility is based on data received in response to GIVAR project questionnaires.

Figure 74 • Technical flexibility of dispatchable plant (Japan)

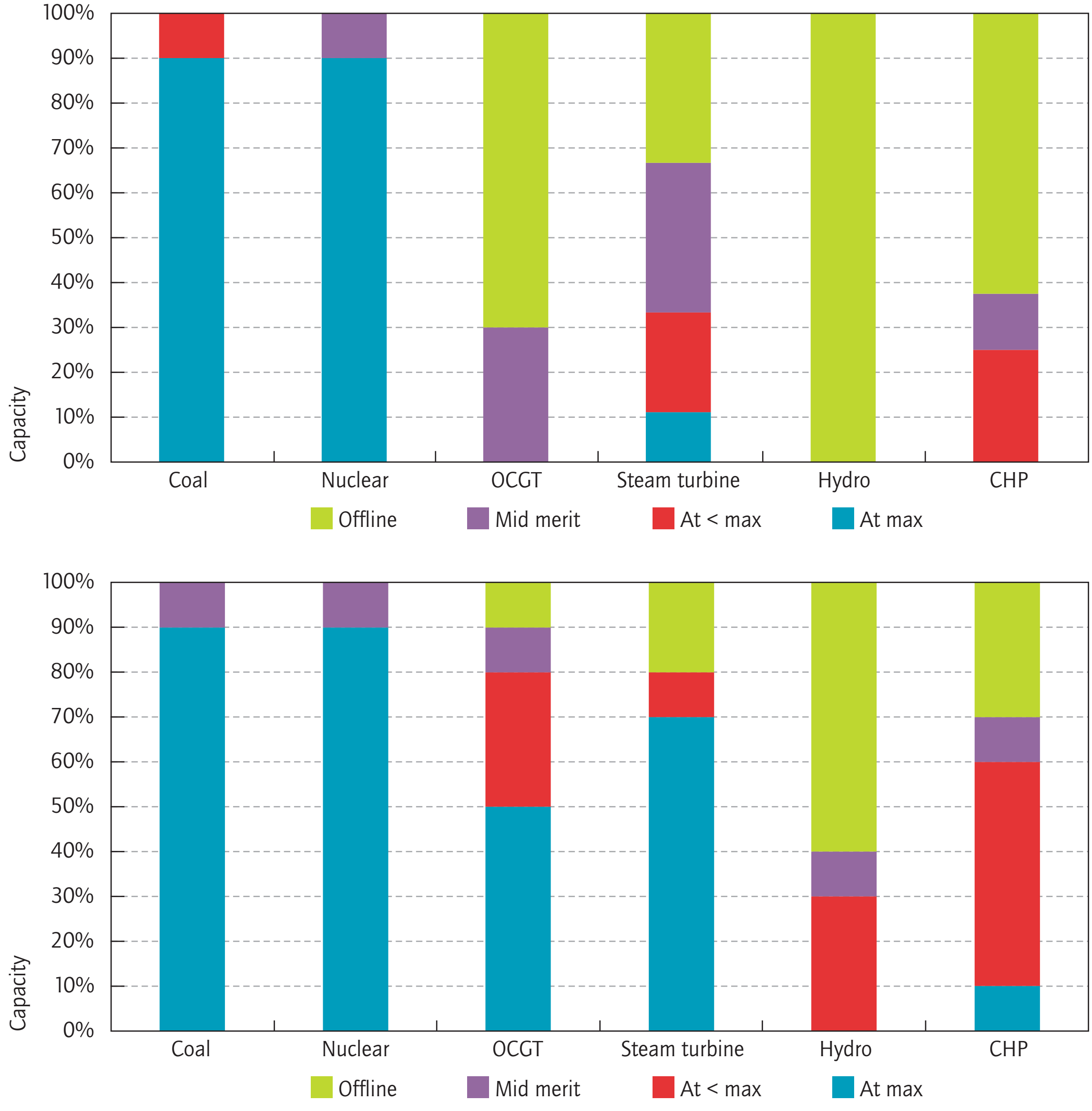


It should be noted that it is not only ramp rates (in MW/minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start up/shut down times are also important. For example, in the Japanese case, nuclear plants are able to ramp down to 60% (their minimum stable operating level) inside 6 hours, and could thereafter shut down entirely inside the 36 hour timeframe – if this were considered desirable for flexibility.

When only the technical capabilities of plants are taken into account, there seems to be a great deal of flexibility on each timescale. However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down if it is operating below maximum. The expectations for each plant type during high and low demand periods, and the likelihoood therefore that they will be available to provide flexibility, are illustrated in Figure 75.

Figure 75 • *Likely operation of dispatchable plant (Japan) at minimum demand (top figure), and peak (bottom figure)*



The final step is to calculate the likely availability of the whole dispatchable plant portfolio to ramp during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values are shown in Table 40. These will be the occasions when resources are most limited by existing requirements for flexibility.[3]

3. See Chapter 12 "Dispatchable generation" for explanation of these steps.

Table 40 • Technical flexible resource from dispatchable power plants (Japan)

Flexible resource in:	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	21 075	25 832
1 hr	28 343	49 794
6 hrs	84 307	120 365
36 hrs	87 272	165 295

Storage

The storage resource for Japan, in the form of pumped hydro storage, amounts to 25 664 MW. Due to the very fast response of hydro plants, the total amount is considered to be technically accessible for balancing VRE generation.

Reservoirs can hold about 260 000 MWh of energy, or about 10 hours at full output. This means that continuous maximum ramping in the same direction will not be possible beyond that timescale, affecting its value as part of the technical flexible resource in the 36 hour timescale.

Demand-side

The demand-side flexible resource is estimated to be 10% of peak demand (17 900 MW) – based on assessment of other areas and the fact that Japan is a highly developed country, and likely to have a significant discretionary load.

Interconnection

There are no connections between Japan and adjacent areas.

Flexibility Index and Present VRE Penetration Potential

The technical flexible resources (TR) in Japan are summarised in Table 41. The last two columns sum individual resources to yield an aggregated TR for ramping up and down.

Table 41 • Technical flexible resources (Japan)

Time scale	Dispatchable plant		Demand side	Storage	Interconnection	Technical resource	
	Up (MW)	Down (MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	21 075	25 832	17 900	25 664	0	64 639	69 396
1 hr	28 343	49 794	17 900	25 664	0	71 907	93 358
6 hrs	84 307	120 365	17 900	25 664	0	127 871	163 929
36 hrs	87 272	165 295	17 900	25 664*	0	130 836	208 859

In these case studies, existing and new requirements for flexibility are simply summed, which gives a conservative estimate for the overall flexibility requirement. Existing Flexibility Requirement (EFR) is subtracted from TR to yield the net technical resource (NTR). NTR for up and down ramping are shown in columns 4 and 5 of Table 42.

Dividing by peak demand (179 GW) yields FIX values for the area, shown in the last two columns, for up and down ramping. FIX values increase over time, except for a drop in up-ramping NTR at 36 hours due to the fact that the increase in existing requirement is larger than the increase in up-ramping capability in that period.

Table 42 • *Existing flexibility requirement and Flexibility Index (Japan)*

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	12 185	10 185	52 454	59 211	0.29	0.33
1 hr	19 685	17 685	52 222	75 673	0.29	0.42
6 hrs	36 685	34 685	91 186	129 244	0.51	0.72
36 hrs	46 685	44 685	84 151	164 174	0.47	0.92

The second variability metric, Present VRE Penetration Potential (PVP), illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the area are shown in Table 43.

Table 43 • *Present VRE Penetration Potential (Japan)*

Time scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	2.8	1 890 235	2 133 726	367%	414%
1 hr	8.9	588 086	852 169	114%	165%
6 hrs	40	228 194	323 434	44%	63%
36 hrs	85	99 002	193 146	19%	37%

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled on, *e.g.* the 15 minute timescale, this is because the flexibility requirement of VRE is very small at this timescale, relative to NTR.[4] **It is only the most constrained occasion,** *i.e.* **when the extent of variability is largest relative to the extent of flexible resource (in the Japanese case, upwards flexibility at 36 hours), that reflects PVP.**

In Japan then, from a purely technical perspective, some 19% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for flexibility are taken into account.

However, while both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the full range of power area constraints that will affect the availability of flexible resources. These relate to operation of the system and market in the area, and are discussed in the next section.

Area constraints

The calculation of PVP above, based on the technical flexible resource (TR), is far higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as congestion of internal transmission, sub-optimal operation and adverse market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

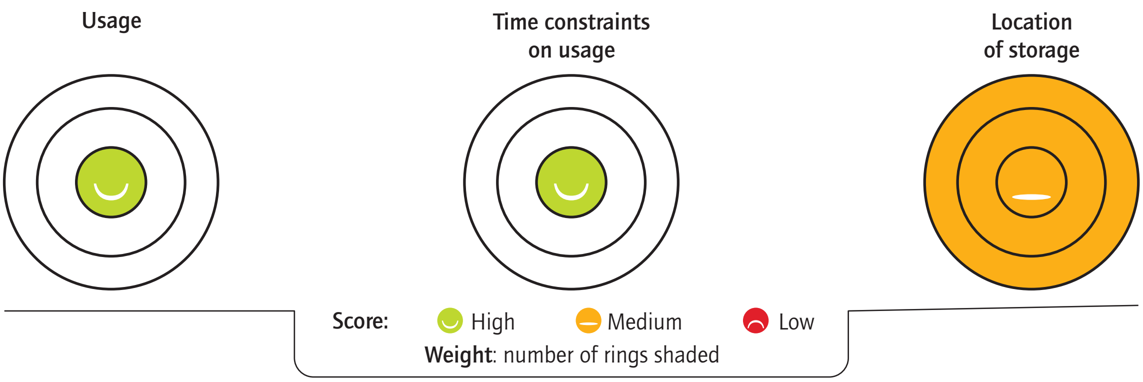
Individual flexible resources have particular constraints. These are addressed in the next section, while constraints on TR as a whole are assessed subsequently. Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 "Scoring and weighting of area attributes".

4. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.* economic and operational) considerations.

Available storage resource

The power area attributes with specific bearing on the availability of the storage resource are summarised in Figure 76.

Figure 76 • Attributes relating to storage availability (Japan)



Usage. The very considerable pumped hydro resources in Japan are owned by the vertically integrated utilities responsible for each of the ten balancing areas. As the utilities are responsible for balancing the area in as efficient a manner as possible, this suggests that storage resources could be operated to maximise their value in terms of flexibility – a good score. Light weighting reflects no further constraint on the resource.

Time constraints. No additional limitations on the use of storage were identified – a good score, with light weighting.

Location. Most of the pumped hydro resource is located near demand centres. If unconstrained by another attribute, this would represent no additional constraint on the resource, as storage should be freely available for use in the system as a whole. However, it is not evenly distributed among the ten separate areas and, as internal transmission between the internal areas of Japan is heavily constrained, this will constrain its availability. An intermediate score, therefore, with heavy weighting. A refined assessment should ascertain the locations of all pumped hydro storage plants to establish the extent of this constraint.

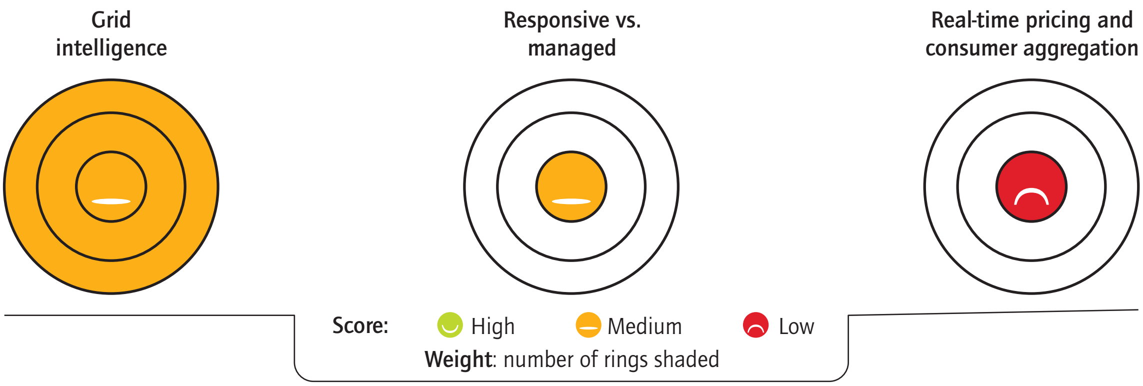
Available demand-side resource

Area attributes with specific bearing on the availability of demand-side flexibility are summarised in Figure 77.

Grid intelligence. The grid in the area is of conventional intelligence – an intermediate score. It is the primary driver for availability of the demand-side resource; in this context an intermediate score still represents a significant constraint on flexibility, so it has heavy weighting.

Responsive vs. managed. Approximately 25% of the demand-side resource is assumed to be of the price-responsive type, and 75% of the managed type. Part of the managed resource may not be available for flexibility in the balancing timeframe: it may be scheduled long in advance – an intermediate score. Light weighting reflects the fact that DSR is in any case constrained by intermediate grid intelligence and an absence of key enabling technologies, particularly smart meters or equivalent information technology, so it does not in itself represent an additional constraint on flexibility.

Figure 77 • Attributes relating to demand-side resource availability (Japan)

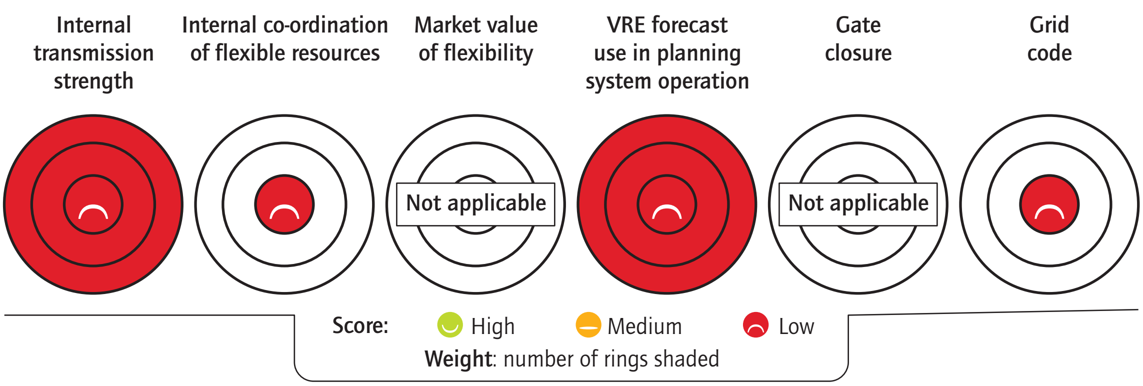


Real-time pricing and consumer aggregation. This attribute is closely related to the previous one. Consumers in the area do not have access to real-time price information, and opportunities do not exist to aggregate domestic consumers (in particular), and so increase the likelihood of response – a low score. Opportunities for both depend on the presence of smart meters (not present in the area), so this attribute has only a light weighting.

Area constraints on total flexible resource

The power area attributes with bearing on the overall flexible resource are summarised in Figure 78.

Figure 78 • Availability of total flexible resource (Japan).



Internal transmission. Transmission internal to the power area of Japan as a whole is a severely limiting factor on the availability of flexible resources. Japan's ten distinct balancing areas are electrically very isolated. Although all are interconnected to a modest extent, the links are used to provide electricity mainly in case of contingencies, and are not available in the balancing timescale. The attribute scores low, with heavy weighting.

Internal co-ordination of flexible resources. Each of the ten isolated areas is balanced by a vertically integrated utility, with little coordination among them – a low score but with light weighting, reflecting limited additional constraint to the weak links among the areas.

Valuation of flexibility. Given an absence of open markets in the area, the flexibility value attribute is not applicable; the system operator can simply commit flexible resources when they are required.

Use of VRE forecasting in system planning. No forecasting of VRE is used when planning the operation of the area – a low score, with heavy weighting, reflecting the fact that the planning of flexible resources for balancing variable generation will be difficult without advance knowledge of when they will be needed. However, this is less of an issue at very low penetration of VRE power plants.

Gate closure. The absence of a power market means that the gate closure attribute is not applicable in the Japanese area. The utility, as both system operator and power producer, can update the commitment of its plants according to need.

Grid code. Variable generation is not considered in the grid code, meaning that VRE cannot be counted upon to operate as expected by the system operator, and variability seen would not be as expected (if forecasting were used). A low score, with light weighting, reflecting the relatively low significance of this attribute until significant VRE penetration is seen.

19 • US West 2017

This assessment looks at the part of the Western Interconnection in North America that lies within the borders of the United States.[1] It is the only assessment set in the future and examines the likely requirement for and availability of flexible resources in the area in the year 2017, extrapolating from data compiled for the Western Wind and Solar Integration Study (WWSIS), completed in 2010, which examines the potential for wind and solar deployment in the WestConnect part of the Western Interconnection (GE Energy, 2010).

This illustrates the "snapshot" nature of the FAST method. Assumptions relating to existing requirements and resources can be altered to see what impact they will have on the deployment of variable renewable plants.

This area illustrates the integration challenge from the perspective of a very large area with very little interconnection (relative to peak demand), and moderate generation side flexibility. The area contains five balancing areas but, in contrast to the Japanese case, these are well linked and their operation well coordinated. The generation side is also more flexible, with a large and available hydropower component.

The assessment also uses data received in response to the GIVAR project questionnaire. Where no data were available, assumptions were made based on other areas and sources. Values and scores herein are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

Flexibility requirement of VRE

The case study assumes a portfolio of VRE technologies,[2] predominantly onshore wind (55%) and solar PV (25%). It should be noted that these assumptions do not mirror those made in the WWSIS study. The assumptions made about the characteristics of the five VRE plant types in the Western Interconnection area are listed in Table 44.

Table 44 • VRE portfolio assumptions (US West 2017)

Resource	Onshore wind	Offshore wind	Solar PV	Tidal	Wave
Maximum variability (% installed capacity/minute)	0.08%	0.08%	0.08%	0.08%	0.12%
Maximum uncertainty (% error/minute)	0.11%	0.15%	0.06%	0	0.04%
Assumed share of technology in VRE portfolio (% of VRE portfolio)	55%	10%	25%	5%	5%
Assumed location relative to load	Mixed	Mixed	Near Load	Near load	Near load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30%	35%	21%	25%	25%

The calculation of overall VRE portfolio flexibility requirement is shown in Table 45.[3] This is a very approximate calculation and does not include the effect of technology spread based on complementary VRE technology output profiles, which is likely to be particularly important here as a strong presence of both solar PV and wind is assumed in the area.

1. The Western Interconnection of North America includes Western Canadian provinces, but this analysis only addresses the US part.
2. For explanation of the portfolio concept, see Chapter 12 "Assumed VRE portfolios".
3. For discussion of the values used for variability and uncertainty, see Chapter 12 "Flexibility requirement of VRE".

Table 45 • VRE flexibility requirement (US West 2017)

Time scale	15 mins	1 hr	6 hrs	36 hrs
Maximum variability (% installed capacity)	1.2	4.4	18	71
Maximum uncertainty (% installed capacity)	1.4	5	20	80
Flexibility requirement (% installed capacity)	2.6	9.4	38	80

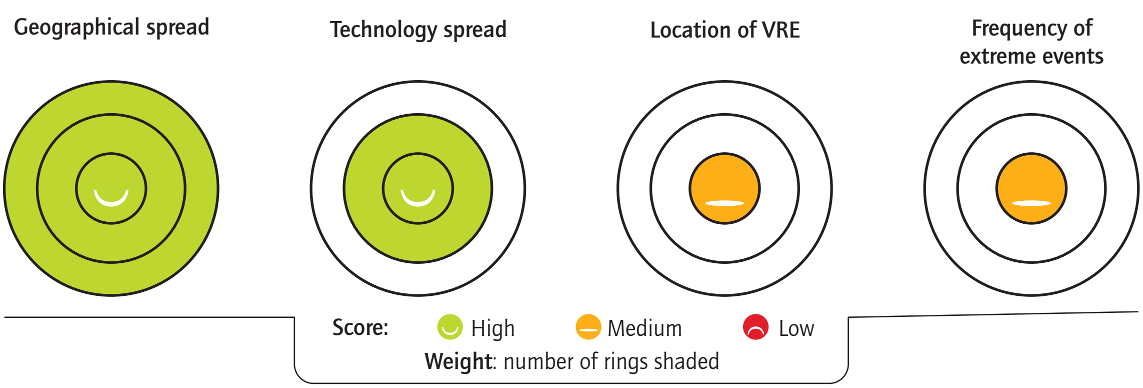
As expected, the variability increases with time horizon, until at 36 hours it can amount to close to the full installed capacity. A maximum of 80% of installed capacity is assumed here, reflecting the fact that the area is very large, and it is therefore highly improbable that periods of zero or maximum output will be seen.

Further qualification of flexibility requirement

The actual flexibility requirement is likely to be less than that shown in Table 45, since this simple approach omits a range of power area attributes which have additional bearing on the extent of the overall variability that will be seen in the area. These are summarised in Figure 79.

Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the "Location of VRE" attribute relates to internal transmission strength; and the light weight of the "Frequency of extreme events" attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above in Table 45.

Figure 79 • Attributes relating to VRE flexibility requirement (US West 2017)



Geographical spread. The area assessed is very large, and VRE resources are assumed to be widely dispersed about it. This will mean significant smoothing of aggregated VRE output over the area if the grid is uncongested. Additionally, the area sees multiple weather systems (north and south), reducing variability still further, particularly on longer time scales as weather fronts move across the area – a high score with heavy weight reflecting its importance.

Technology spread. There is good opportunity for output smoothing through technology spread in this area. Onshore wind energy makes up 55% of the assumed portfolio and solar PV 25%, with offshore wind, tidal and wave power making up the remaining 20%. There is therefore likely to be considerable complementarity in output – a high score.

Location of VRE. Most of the onshore wind resource is far from demand centres. This increases the probability that congestion will impede the availability of balancing resources. In contrast, PV plants are likely to be closer to demand centres. Offshore wind, wave and tidal plants may also lie close to demand centres along the coasts of Oregon, Washington and California, for example. So, overall, an intermediate score. Light weight is given because although overall internal transmission strength, which drives the importance of this attribute, is only intermediate, the development of new lines is likely to be driven by the deployment of large scale onshore wind plants. Assuming these are dimensioned accurately, the likelihood of their congestion will be low. In addition, recent analysis suggests that, in Oregon, wave energy plants installed by 2019 could alleviate pressure on existing east-west transmission in the region (OES, 2009).

Frequency of extreme events. Though wind makes up most of the portfolio (65%), the presence of other, more regular output technologies in the portfolio such as PV and tidal reduces the likelihood of extreme events. The full extent of the flexibility requirement identified above will be seen less often, and there may be a basis for considering flexible resources against fluctuating demand to be available to cover new needs of VRE to some extent.

Flexible resources

Dispatchable generation

The assumed proportions of types of dispatchable plant in the United States Western Interconnection in 2017 are illustrated in Figure 80. Assumptions relating to operating levels and ramp rates, and definitions can be found in Annex C.

The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 81, expressed as a percentage of installed capacity that can be ramped up or down over the four timescales. Assessment of technical flexibility is based on data received in response to GIVAR project questionnaires.

Figure 80 • Dispatchable plant portfolio (US West 2017)

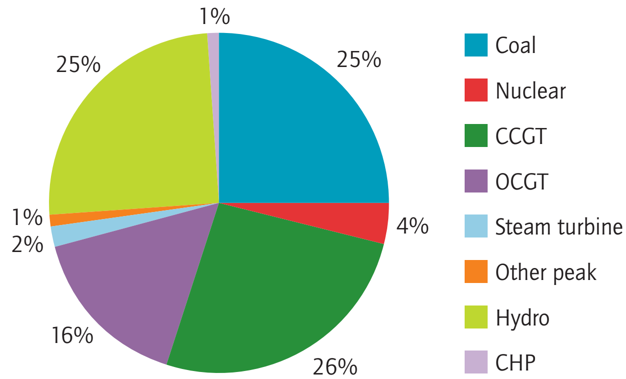
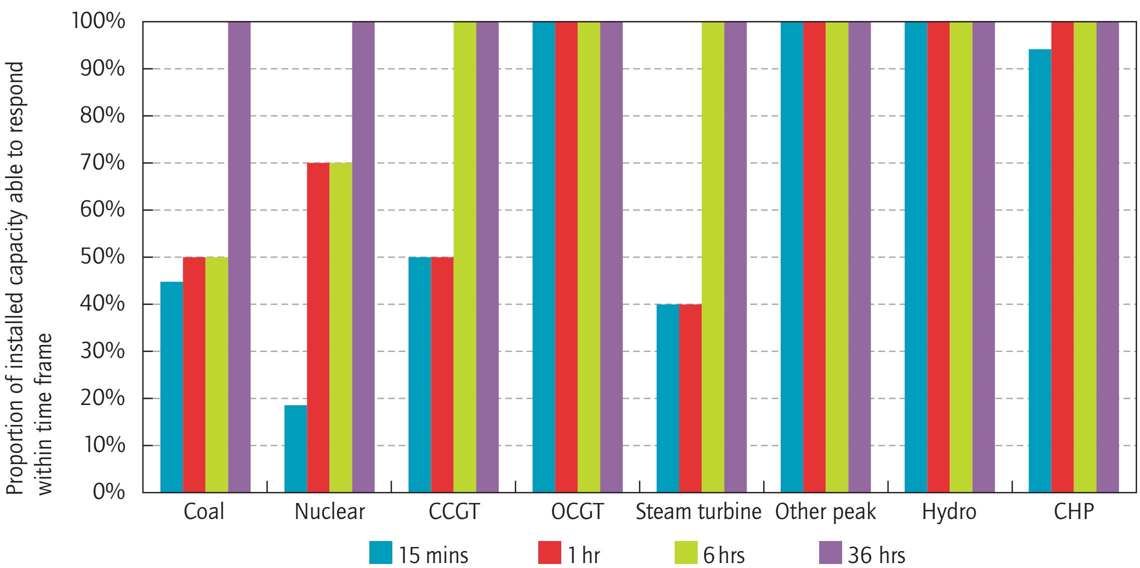


Figure 81 • Technical flexibility of dispatchable plant (US West 2017)

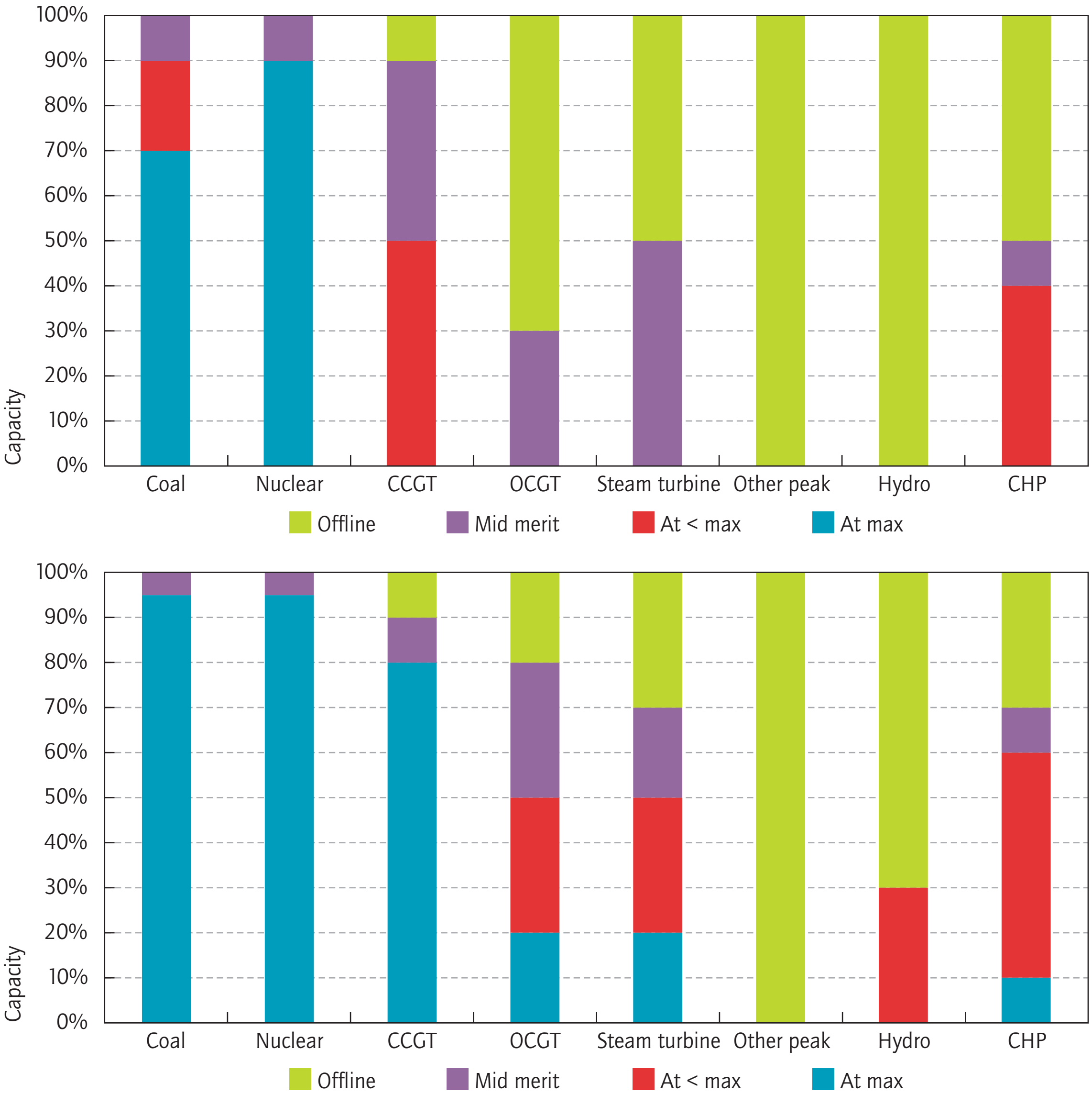


It should be noted that it is not only ramp rates (in MW/minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start up/ shut down times are also important. For example, in the US western area, coal plants are able to ramp down to a minimum stable level of 50% inside one hour, and could then shut down entirely inside 36 hours – if this were desirable from the flexibility perspective.

When only the technical capabilities of plants are taken into account, there seems to be a great deal of flexibility on each timescale. However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down if it is operating below maximum. The expectations of the operation of plant types during periods of peak and low demand, and the likelihood therefore with which they will be able to offer down or up-ramping response, are illustrated in Figure 82.

Figure 82 • Likely operation of dispatchable plant (US West 2017) at minimum demand (top figure), and peak (bottom figure)



The next step is to calculate the likely availability of the overall dispatchable plant portfolio to ramp during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values are shown in Table 46. These will be the occasions when resources are most limited by existing requirements for flexibility (from fluctuating demand).[4]

Table 46 • Technical flexible resource from dispatchable power plants (US West 2017)

Flexible resource in:	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	85 198	50 676
1 hr	97 900	61 451
6 hrs	150 846	127 059
36 hrs	179 285	159 216

Storage

The storage resource here is assumed to be 4 786 MW. Due to the quick response of hydro plants, the entire amount is assumed to be technically accessible for balancing.

On this capacity there is a five hour limitation on energy release at full capacity — *i.e.* approximately 24 000 MWh. Over longer time periods therefore, there will be a ceiling on available energy.

Demand-side

Demand-side flexibility is estimated to amount to 10% of peak demand (15 000 MW), based on the literature (CPUC 2003, PJM 2009) and the fact that considerable interest is already shown in the United States in the potential of the demand-side (IRC 2010).

Interconnection

Six corridors connect the western interconnection to adjacent areas, with a capacity of 3 600 MW. This is equivalent to less than 1% of peak demand in the area and illustrates the diminishing importance of interconnected resources as a flexible resource for very large areas.

Flexibility Index and Present VRE Penetration Potential

The technical flexible resources (TR) in US West 2017 are summarised in Table 47. The last two columns sum individual resources to yield an aggregated TR for up-ramping and down-ramping.

Table 47 • Technical flexible resources (US West 2017)

Time scale	Dispatchable plant		Demand side	Storage	Interconnection	Technical resource	
	Up (MW)	Down (MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	85 198	50 676	15 000	4 786	3 600	108 584	74 062
1 hr	97 900	61 451	15 000	4 786	3 600	108 991	81 824
6 hrs	150 846	127 059	15 000	4 786*	3 600	174 232	150 445
36 hrs	179 285	159 216	15 000	4 786*	3 600	202 671	182 602

* An energy ceiling on storage availability will exist beyond 5 hours.

4. See Chapter 12 "Dispatchable Generation" for explanation of these steps.

Existing and new requirements for flexibility are simply summed, which gives a conservative estimate for the overall flexibility requirement. Existing Flexibility Requirement (EFR) is subtracted from TR to yield the net technical resource (NTR). NTRs for up and down ramping are shown in columns 4 and 5 of Table 48.

Table 48• Existing flexibility requirement and Flexibility Index (US West 2017)

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	8 867	7 667	99 717	66 395	0.56	0.37
1 hr	15 867	14 667	93 125	67 157	0.52	0.38
6 hrs	31 867	30 667	142 365	119 778	0.80	0.67
36 hrs	45 867	44 667	156 804	137 936	0.88	0.78

Dividing by peak demand (178 GW) yields FIX values for the area – shown in the last two columns, for up and down ramping. Values mainly increase over time, as observed in other power areas, except for a small drop in up-ramping at 1 hour. Note here, however, that unlike in most other areas it is down-ramping that is the greatest constraint on flexibility. This means that transition from periods of high demand with low VRE output, to low demand with high VRE output, will be the greatest challenge for this system – *i.e.* getting relatively inflexible power plants offline quickly enough.

The second variability metric, Present VRE Penetration Potential (PVP), illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the area are shown in Table 49.

Table 49 • Present VRE Penetration Potential (US West 2017)

Time scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	3	3 809 641	2 536 597	991%	660%
1 hr	9.4	988 268	712 694	257%	185%
6 hrs	38	377 707	317 781	98%	83%
36 hrs	80	196 005	172 420	51%	45%

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled on, *e.g.* the 15 minute timescale, this is because the flexibility requirement of VRE is very small at this timescale, relative to NTR.[5] **It is only the most constrained occasion *i.e.* when the extent of variability is largest relative to the extent of flexible resource (in this case, downwards flexibility at 36 hours) that reflects PVP.**

In US West 2017 then, from a purely technical perspective, some 45% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for the latter are taken into account.

However, while both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the wide range of power area constraints that will affect the availability of flexible resources. These relate to operation of the system and market in the area, and are discussed in the next section.

5. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.* economic and operational) considerations.

Area constraints

The calculation of PVP above, based on the technical flexible resource (TR), is far higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as congestion of internal transmission, sub-optimal operation and adverse market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

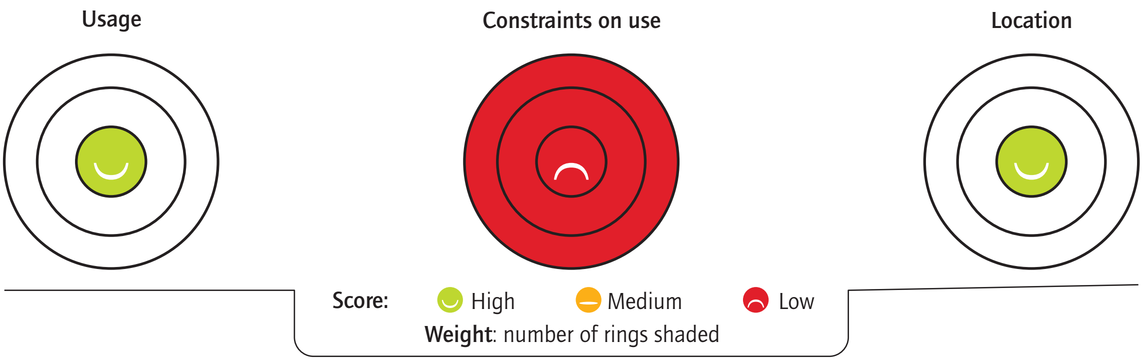
Individual flexible resources have particular constraints. These are addressed first in the next section, while constraints on TR as a whole are assessed subsequently.

Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 "Scoring and weighting of area attributes".

Available storage resource

Area attributes with specific bearing on the availability of the storage resource are summarised in Figure 83.

Figure 83 • Attributes relating to storage availability (US West 2017)



Usage. Storage capacity is assumed to be operated by the system operator, and could therefore be operated for system benefit, meaning that it need not constrain use for flexibility – a good score with light weight, reflecting no additional constraint in itself.

Constraints on usage. Environmental limitations exist on the usage of reservoir hydro storage, relating to fish ecology and water provision to urban areas. These are assumed seriously to limit the extent of availability of such resources for balancing – a low score with heavy weighting.

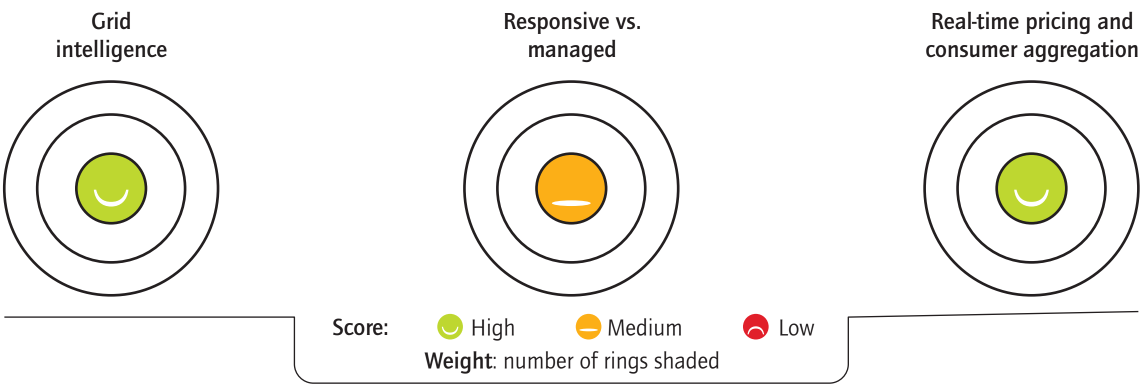
Location. Most storage resources are located near demand centres, which means they will be less likely to be blocked by congested lines, and their availability for provision of flexible response will not be further constrained – a high score with light weighting.

Available demand-side resource

Area attributes with specific bearing on the availability of demand-side flexibility are summarised in Figure 84.

Grid intelligence. It is assumed for the purposes of this assessment that enhanced grid operation techniques and smart metres will be deployed widely in the area in 2017, in comparison to the area's largely conventional nature today. A high score is awarded, with light weight, representing no significant constraint on the availability of the demand-side resource.

Figure 84 • Attributes relating to demand-side resource availability (US West 2017)



Grid intelligence. It is assumed for the purposes of this assessment that enhanced grid operation techniques and smart metres will be deployed widely in the area in 2017, in comparison to the area's largely conventional nature today. A high score is awarded, with light weight, representing no significant constraint on the availability of the demand-side resource.

Responsive versus managed. Approximately 50% of the demand-side resource is assumed to be responsive, and 50% managed. The responsive part of the resource will be available, as grid intelligence is high. But whether or not is will actually respond, however, will depend on the existence of adequate incentives in the market to do so. Part of the managed resource may not be available in the balancing timeframe, as its use may be determined well ahead of 36 hours. So, an intermediate score. Light weighting, however, reflects limited constraint on the availability of the overall demand-side resource.

Real-time pricing. Resulting from the presence of enhanced intelligence in the grid, including smart metres, real-time price information is assumed to be available to consumers of all kinds. To take advantage of domestic user response, effective consumer aggregation models maximise the return, and minimise the effort, of response. A high score with light weighting represents no further constraint on the availability of the demand-side resource.

Available interconnection resource

Power area attributes with impact on the availability of flexibility from adjacent areas (outside the US part of the Western Interconnection) are summarised in Figure 85.

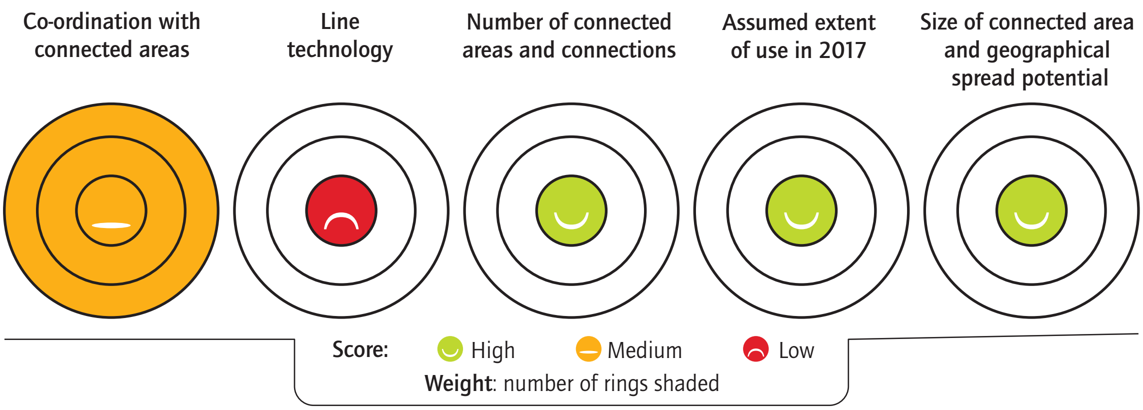
Co-ordination with adjacent areas. In 2017, it is assumed that co-ordination with adjacent areas other than Canada[6] (Texas, Eastern US, Mexico) will have improved significantly from levels seen today – an intermediate score. Weighting remains heavy still as even intermediate co-ordination will restrict benefits of geographical smoothing of variability, and the sharing of flexible resources.

Technology. Line technology connecting these other areas is assumed to be DC, which is less flexible than AC, requiring notice of a switch in the direction of flow – a low score. However, intermediate co-ordination with neighbours would imply the ability to effectively plan its use to help balance variable generation – a light weighting is applied.

Number of connected areas and connections. Connections are assumed to exist with three areas, via multiple connections, reducing the likelihood of congestion – a high score with light weight, representing limited constraint on the flexible resource.

6. Co-ordination with Canada is already high, as the Western Interconnected area includes parts of both the United States and Canada.

Figure 85 • Attributes relating to interconnection availability (US West 2017)



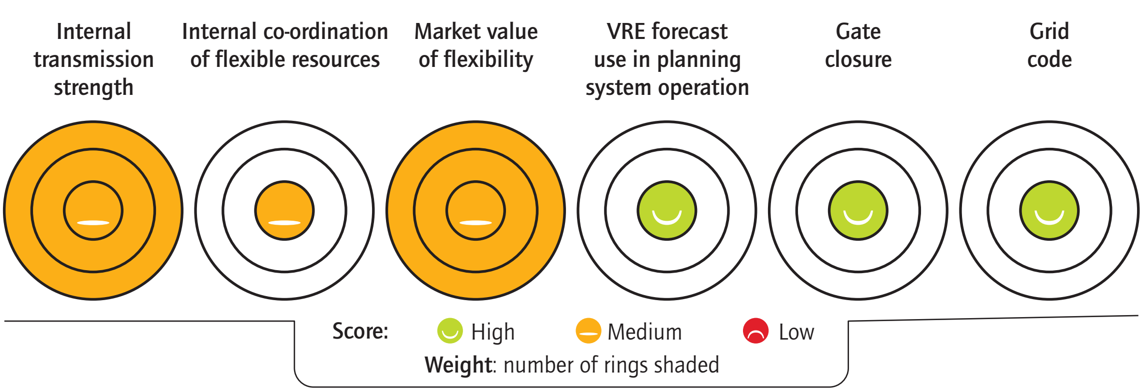
Present extent of use. A large proportion of the interconnections is assumed to be available for use in balancing. Variable generation is likely to be a principal driver behind the increase of interconnection in the first place, as can be inferred from the US study entitled *20% Wind Energy by 2030* (DOE 2008). So, an intermediate score with light weight reflecting limited constraint on availability of flexibility.

Size of connected area and potential for geographical spread. The areas connected to are large and so offer opportunity for smoothing overall variable production. VRE output in the rest of the United States or Canada, and Texas, are unlikely to be synchronised with the whole western area – a high score, with light weight, reflecting limited additional constraint on the flexibility value of interconnections.

Area constraints on total flexible resource

The power area attributes with bearing on the overall flexible resource are summarised in Figure 86.

Figure 86 • Availability of total flexible resource (US West 2017)



Internal transmission strength. This attribute, always important, is particularly so in this very large area. Adequate transmission is assumed to be built in the future to accommodate the high penetrations of VRE suggested in the recent *Western Wind and Solar Integration Study* (NREL 2010b). Transmission is expected to be relatively strong between areas of high present VRE penetration potential and demand centres. Good connections are assumed between balancing areas. The attribute is given an intermediate score therefore, with heavy weighting, reflecting a continuing constraint on flexibility given the size of the area.

Internal co-ordination of flexible resources. Several markets are assumed to persist in the area, which will reduce the shared use of flexible resources relative to a case wherein balancing is carried out over the whole area as a unit. However, good co-ordination among these markets is assumed also on the basis of recent studies (NREL, 2010b, DOE 2008). So, an intermediate score, with light weight, reflecting limited constraint on the availability of flexible resources.

Market valuation of flexibility. Markets are assumed to reward flexibility implicitly, through five-minute balancing markets. Owners of flexible resources will thus have some incentive to provide the flexibility service, assuming appropriate pricing. However, slower flexible resources (*e.g.* coal, nuclear) will see insufficient compensation for provision of their potential contribution to flexibility (in response to long term forecasts of the net load). So, an intermediate score with heavy weighting, reflecting considerable remaining constraint on flexible resources.

Use of VRE forecasts in system planning. A high quality of forecasting of VRE is expected when planning the operation of the area. State of the art forecasting technologies such as ensemble forecasting are expected to be in use in 2017, alongside probabilistic unit commitment planning. This makes best use of output forecast data to optimise the system both economically and in terms of usage of flexible resources, explicitly accounting for variability and uncertainty in dispatch decisions. This is therefore given a high score with light weighting, reflecting limited further constraint on flexibility.

Gate closure. Gate closure is assumed to occur inside the hour before the time of operation, reducing the flexible resource that must be held against uncertainty in the net load, and enabling more efficient use of those resources elsewhere — a high score with light weighting, reflecting limited further constraint.

Grid code. State of the art grid codes are expected for the output of VRE plants — a high score with light weight, reflecting the fact that VRE will operate as expected, and will not impose unexpected, additional requirements for flexibility on the system.

20 • Canada Maritime: the NBSO area

This assessment examines the area managed by the New Brunswick System Operator (NBSO) within the Canadian Maritime Provinces, consisting of the provinces of New Brunswick and Prince Edward Island in Canada,[1] and the northern part of Maine in the United States. It is based on data received in response to the GIVAR project questionnaire. Where no data were available, assumptions were made based on other areas and sources. Values and scores herein are intended only to be indicative, and to illustrate how the FAST method can be used to assess the potential for deployment of variable generation in a power area: they are not to be taken as definitive.

The area is similar to the Danish area in a number of respects, such as size (MW), dispatchable generation flexibility and internal grid strength. It differs significantly in two ways: it consists of two balancing areas, and it cannot at present coordinate as closely with adjacent power areas, being part of a separate market. The area also has considerably less experience of variable power plants.

Flexibility requirement of VRE

The case study assumes a portfolio of VRE technologies,[2] wherein onshore wind is the largest component by far (70%). The assumptions made about the characteristics of these for the NBSO area are listed in Table 50. Due to the relatively small size of the area, variability is (as in Denmark) likely to be higher than some other areas assessed.

Table 50 • VRE portfolio assumptions (NBSO)

Resource	Onshore wind	Offshore wind	Solar PV	Tidal	Wave
Maximum variability (% installed capacity/minute)	0.15%	0.20%	0.22%	0.1%	0.14%
Maximum uncertainty (% error/minute)	0.07%	0.10%	0.06%	0	0.04%
Assumed share of technology in VRE portfolio (% of VRE portfolio)	70%	10%	10%	10%	0%
Assumed location relative to load	Mixed	Mixed	Near Load	Near load	Far from load
Frequency of extreme ramping events	High	Medium	Medium	Low/None	Medium
Capacity factor (% of installed capacity)	30%	35%	10%	25%	25%

The calculation of the overall flexibility requirement of the VRE portfolio is shown in Table 51.[3]

Table 51 • VRE flexibility requirement (NBSO)

Time scale	15 mins	1 hr	6 hrs	36 hrs
Maximum variability (% installed capacity)	2.4	7.5	34	90
Maximum uncertainty (% installed capacity)	1	3.1	14	56
Flexibility requirement (% installed capacity)	3.3	11	48	90

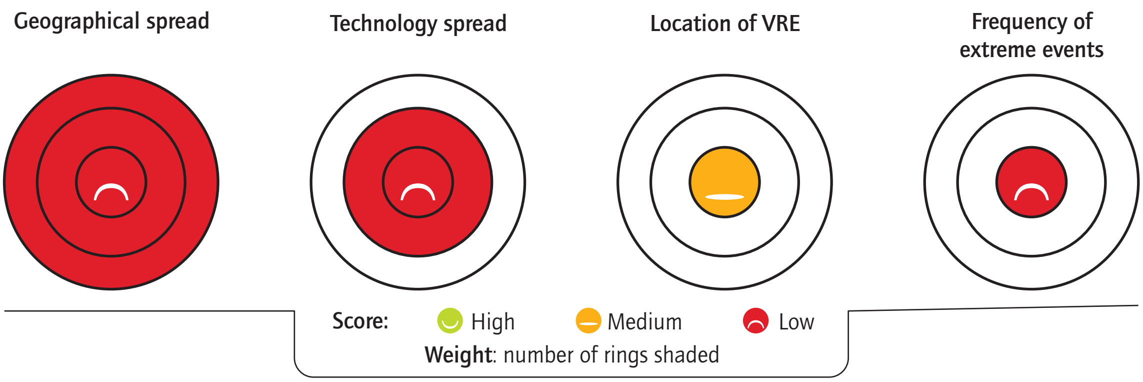
Maximum expected variability increases with time horizon, until at 36 hours it can represent nearly the full installed capacity. A maximum of 90% is assumed here – slightly higher than in larger areas – as the area is unlikely to see periods of zero or maximum output, though swings may be greater than in larger areas.

1. The third of the Canadian Maritime Provinces, Nova Scotia, is not included in the NBSO area.
2. For explanation of the portfolio concept, see Chapter 12 “Assumed VRE portfolios”.
3. For discussion of the values used for variability and uncertainty, see Chapter 12 “Flexibility requirement of VRE”.

Further qualification of flexibility requirement

The actual flexibility requirement is likely to be less than that shown in Table 51 since this simple approach omits a range of factors due to limited data availability. The power area attributes which have additional bearing on the extent of variability are summarised in Figure 87.

Figure 87 • Attributes relating to VRE flexibility requirement (NBSO)



Geographical spread, the benefits of which are beginning to be well understood, is considered to be the most important attribute in all case studies, while technology spread has medium weight, reflecting limited knowledge in this area. The weight of the "Location of VRE" attribute relates to internal transmission strength, see below; and the light weight of the "Frequency of extreme events" attribute reflects the fact that the maximum extent of variability that will be seen in the area is already quantified above in Table 51.

Geographical spread. The area is small compared to some other areas assessed, and VRE resources are relatively concentrated, so the effect of geographical spread on variability will be relatively small. The area can fit beneath a single weather system so variability within each VRE type will be highly correlated – a low score, indicating a need for high flexibility.

Technology spread. Given that the assumed portfolio is 80% wind, compared to the next largest (PV, at 10%), there is relatively little potential for smoothing of output through VRE technology spread – again, a low score.

Location of VRE. A significant part of VRE resources is located far from demand centres. This increases the probability of congestion limiting availability of flexible resources to balance it – so an intermediate score. Weighting is low however as internal transmission is strong.

Frequency of extreme events. Because wind energy represents 80% of the likely portfolio, the likelihood of extreme events is high. The full extent of the flexibility requirement identified above will be needed relatively frequently, and is likely to coincide with periods when the existing flexibility requirements (of fluctuating demand) are also high. So, low complementarity and a low score.

Flexible resources

Dispatchable generation

The present proportions of types of dispatchable power plant in the NBSO area are illustrated in Figure 88. Detail of assumptions relating to operating levels and ramp rates, and definitions, can be found in Annex C.

The flexibility of each of the dispatchable plant types assessed is illustrated in Figure 89, expressed as a percentage of installed capacity that can be ramped up or down over the four timescales. The assessment of technical flexibility is based on data received in response to GIVAR project questionnaires. The flexibility of plant can be seen to be less than in many of the previous assessments.

Figure 88 • *Dispatchable plant portfolio (NBSO)*

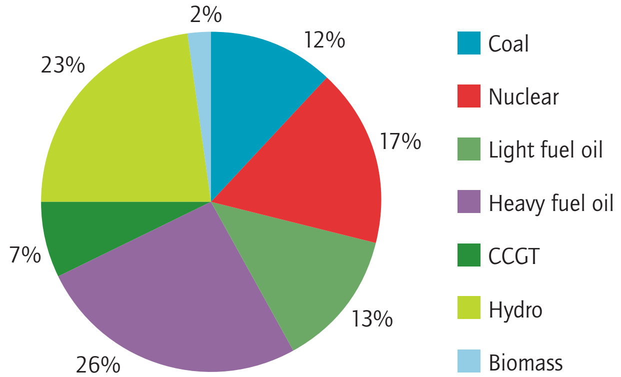
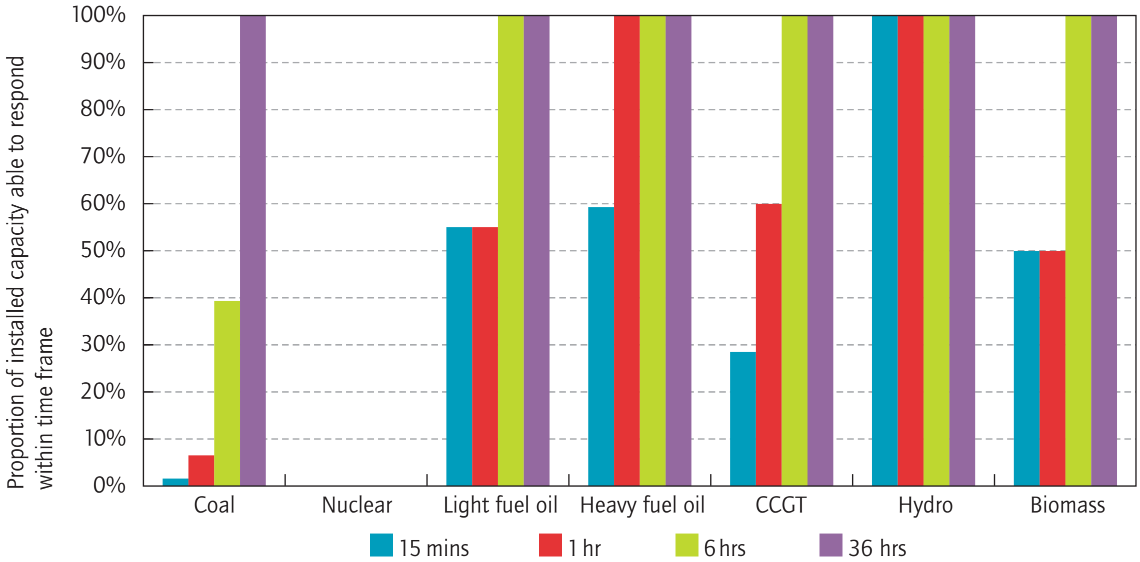


Figure 89 • *Technical flexibility of dispatchable plant (NBSO)*



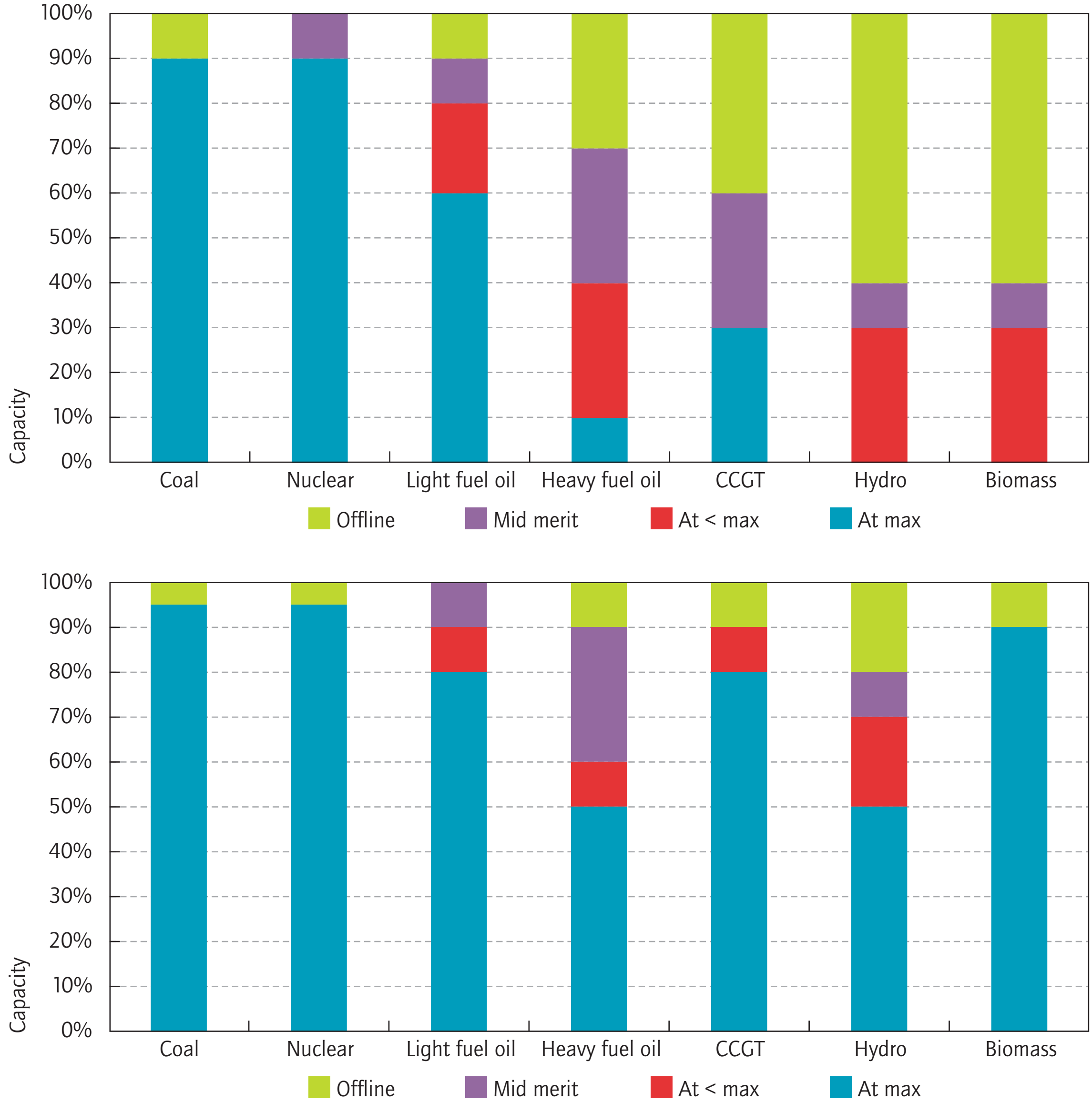
It should be noted that it is not only ramp rates (in MW/minute) that reflect the technical flexible resource represented by a dispatchable plant type. Minimum stable operating levels and start up/shut down times are also important. For example, in the NBSO area, light fuel oil plants are able to ramp down to 55% inside 15 minutes, and thereafter could shut down entirely in under 6 hours.

When only the technical capabilities of plants are taken into account, there seems to be a great deal of flexibility on each timescale (though less here than in other areas). However, a unit will not be in a suitable operating state to ramp in the desired direction all of the time. The next step in the assessment process is to assess the likely operating state of plant types – whether operating, and if so at what level – and the likelihood therefore that they would be physically able to offer a flexible response if required.

The assessment determines whether the plant type is likely to be able to ramp up (if offline), ramp down (if online at maximum), or ramp up or down if operating below maximum.

The likely operation of plant types during periods of low and high demand is shown in Figure 90. Interconnections to adjacent areas outside the NBSO area are used extensively, but it is assumed here that area demand is primarily met by generation capacity within the area. Interconnector capacity is considered largely in terms of the flexibility it can provide. In reality, the division would be less clear cut.

Figure 90 • *Likely operation of dispatchable plant types (NBSO) at minimum demand (top figure), and peak demand (bottom figure)*



Different operation of plant types is assumed for certain plant types than in other assessments. This is due to the plant mix and reported capacity factors. For example, steam turbines (light and heavy fuel oil) are used far more for providing energy than elsewhere. In some cases, heavy fuel oil plants are operated on a "must run" basis, due to the nature of fuel contracts. This will limit their ability to provide flexibility. The same applies to the single nuclear plant.

The final step is to calculate the likely availability of the overall dispatchable plant portfolio to ramp during high and low demand periods. The values for each plant type are summed to yield the flexibility that could be available from the dispatchable portfolio at these times, and critical values are shown in Table 52. These will be the occasions when resources are most limited by existing requirements for flexibility.[4]

4. See Chapter 12 "Dispatchable Generation" for explanation of these steps.

Table 52 • Technical flexible resource from dispatchable power plants (NBSO)

Flexible resource in:	Maximum up-ramp capability (MW)	Maximum down-ramp capability (MW)
15 mins	595	788
1 hr	757	1 035
6 hrs	1 776	2 257
36 hrs	1 804	2 484

Storage

No electrical storage was identified in the area.

Demand-side

The value assumed for the demand-side flexible resource, based on GIVAR data, is 7.5% of peak demand (250 MW). This may be significantly lower than the real value, but it tallies with the 5-10% range often used.

Interconnection

Total interconnection to (three) other areas amounts to 1 882 MW, via a mixture of AC and DC lines. This is a very large amount, nearly 60% of peak demand, and more than minimum demand (1 847 MW). It is likely therefore that the area already depends heavily on interconnection as a flexible resource against existing requirements (demand and contingencies).

Flexibility Index and Present VRE Penetration Potential

The technical flexible resources (TR) in the NBSO area are summarised in Table 53. The last two columns sum individual resources to yield an aggregated TR for ramping up and down.

Table 53 • Technical flexible resources (NBSO)

Time scale	Dispatchable plant		Demand side	Storage	Interconnection	Technical resource	
	Up (MW)	Down (MW)	(MW)	(MW)	(MW)	(MW)	(MW)
15 mins	595	788	250	0	1 882	2 727	2 920
1 hr	757	1 035	250	0	1 882	2 889	3 167
6 hrs	1 776	2 257	250	0	1 882	3 917	4 389
36 hrs	1 804	2 484	250	0	1 882	3 944	4 616

In these case studies existing and new requirements for flexibility are simply summed, which gives a conservative estimate for the overall flexibility requirement. Existing Flexibility Requirement (EFR) is subtracted from TR to yield the net technical resource (NTR). NTR for up and down ramping are shown in columns 4 and 5 of Table 54.

Dividing by peak demand (3.2 GW) produces the FIX value for the area, shown in the last two columns, for up and down ramping. Values inside 1 hour are very high in the NBSO area due to its large interconnection with neighbouring areas (relative to its peak demand). FIX values trend upwards with time horizon, although there is a reduction at 1 hour and 36 hours in up-ramping as EFR increases at a greater rate than TR.

Table 54 • Existing flexibility requirement and Flexibility Index (NBSO)

Time scale	EFR		Net Technical Resource		Flexibility Index	
	Up (MW)	Down (MW)	Up (MW)	Down (MW)	Up (%)	Down (%)
15 mins	1 009	259	1 718	2 661	0.53	0.82
1 hr	1 236	486	1 653	2 681	0.51	0.83
6 hrs	1 647	897	2 269	3 492	0.70	1.08
36 hrs	1 097	2 097	3 519	0.65	1.09	0.78

The second variability metric, Present VRE Penetration Potential (PVP), illustrates the extent to which the net technical flexible resource can accommodate the assumed VRE portfolio. It is expressed in terms of % penetration of VRE in gross electricity demand. Calculation of PVP is explained in Chapter 12 (page 102), and values for the area are shown in Table 55.

Table 55 • Present VRE Penetration Potential (NBSO)

Time scale	Flexibility requirement of VRE (% of installed VRE)	Potential for installed VRE capacity with NTR up (MW)	Potential for installed VRE capacity with NTR down (MW)	PVP with NTR up	PVP with NTR down
15 mins	3.3	51 589	79 898	825%	1 278%
1 hr	11	15 512	25 157	248%	402%
6 hrs	48	4 733	7 282	76%	117%
36 hrs	90	2 330	3 910	37%	63%

When reading the values in the table, it should be noted that although unrealistically high amounts of VRE capacity could theoretically be enabled on, *e.g.* the 15 minute timescale, this is because the flexibility requirement of VRE is very small at this timescale, relative to NTR.[5] **It is only the most constrained occasion, *i.e.* when the extent of variability is largest relative to the extent of flexible resource (in the NBSO case, upwards flexibility at 36 hours), that reflects PVP.**

In the NBSO area then, from a purely technical perspective, some 37% penetration of VRE in gross electricity demand could be balanced by existing flexible resources, after existing requirements for flexibility are taken into account.

While both the FIX and PVP metrics give a useful indication of what is technically possible, neither reflects the full range of power area constraints that will affect the availability of flexible resources. These relate to operation of the system and market in the area, as discussed in the next section.

Area constraints

The calculation of PVP above, based on the technical flexible resource (TR), is far higher than it would be if it were based on the (more realistic) available flexible resource (AR). The available flexible resource takes into account factors such as congestion of internal transmission, sub-optimal operation and adverse market conditions. A full flexibility assessment with access to the relevant data would quantify all these factors. In these case studies, constraints are scored qualitatively, with simple traffic light grading.

Individual flexible resources have particular constraints. These are addressed first in the next section, while constraints on TR as a whole are assessed subsequently.

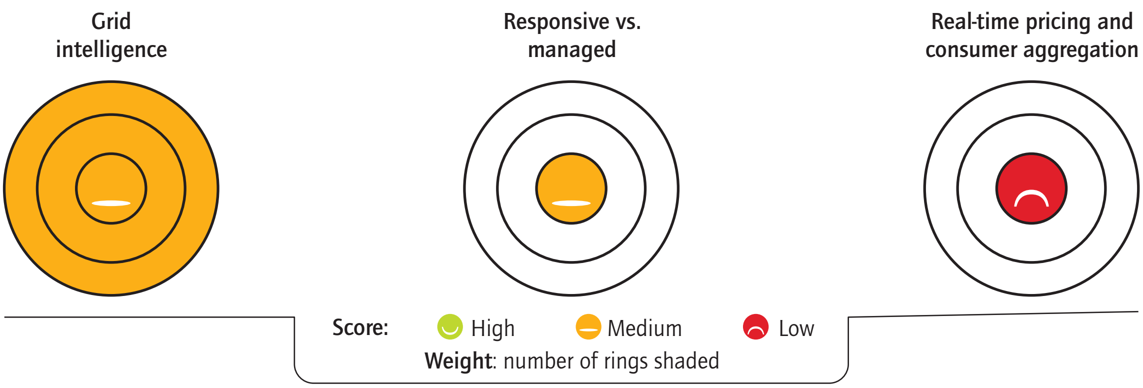
5. Only technical ramping capabilities are taken into account, and not a whole range of other (*e.g.* economic and operational) considerations.

Explanation of the scoring and weighting of attributes treated qualitatively is described in Chapter 12 "Scoring and weighting of area attributes".

Available demand-side resource

Area attributes with specific bearing on the availability of demand-side flexibility are summarised in Figure 91.

Figure 91 • Attributes relating to demand-side resource availability (NBSO)



Grid intelligence. The grid in the area is of conventional intelligence – an intermediate score. As it is the primary driver for availability of the demand-side resource, an intermediate score still represents a significant constraint on flexibility – so it has heavy weighting.

Responsive vs. managed. 50% of the demand-side resource is assumed to be of the managed type in this assessment, and 50% of the responsive type. This is based on the fact that NBSO electricity market rules were modified in 2006 to incorporate bid-based demand response, whereby large consumers can bid to provide hourly balancing services. Domestic demand response, on the other hand, is unlikely to be available in the balancing timeframe as grid intelligence is only intermediate, and key enabling technologies, particularly smart meters or equivalent information technology, are absent. So, an intermediate score with light weight.

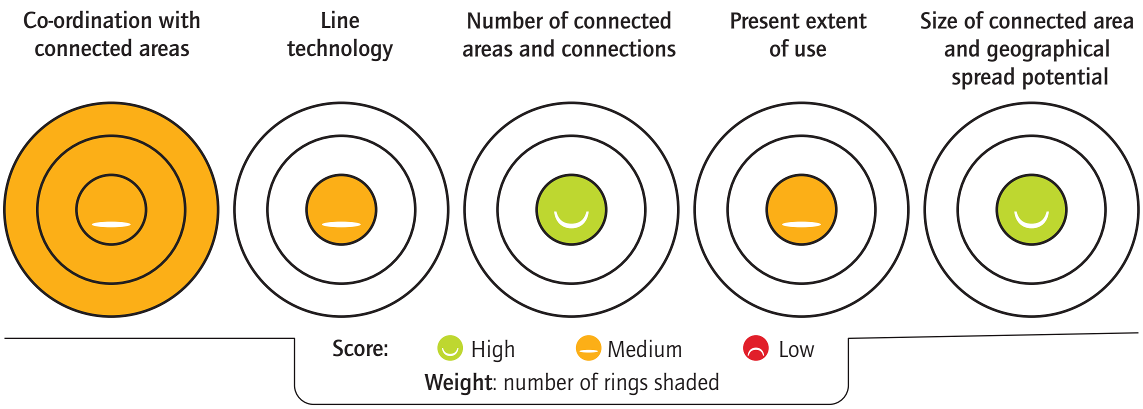
Real-time pricing and consumer aggregation. This attribute is closely related to the previous one. Consumers in the area do not have access to real time price information, and opportunities do not exist to aggregate domestic consumers (in particular), and so increase the likelihood of response – a low score. Opportunity for both depends on smart meters (not present in the area), so this attribute has only a light weighting.

Available interconnection resource

Power area attributes with impact on the availability of flexibility from adjacent areas (outside the NBSO area) are summarised in Figure 92.

Co-ordination with adjacent areas. There is an intermediate level of co-ordination with adjacent power areas, meaning that to some extent flexible resources will be available for use in balancing the NBSO area. The area is operated in close cooperation with the adjacent Nova Scotia area; indeed a new 500 MW link between New Brunswick and Nova Scotia has recently been announced, in addition to the existing 300 MW link. Regional co-ordination is considered of high importance in terms of VRE deployment. Weighting remains high, as even intermediate co-ordination will restrict the sharing of flexible resources.

Figure 92 • Attributes relating to interconnection availability (NBSO)



Technology. Interconnection line technology is a mix of DC and AC – an intermediate case (DC is less flexible, as notice is required of changes in direction of flow). This attribute has light weight, as use of DC lines can be planned effectively if connected areas are well enough coordinated.

Number of connected areas and connections. The area is connected to three others, via five corridors. This gives a greater chance of flexible resources being available from one or other neighbour, a significant redundancy reducing the likelihood of congestion – a high score with light weighting, reflecting no additional constraint.

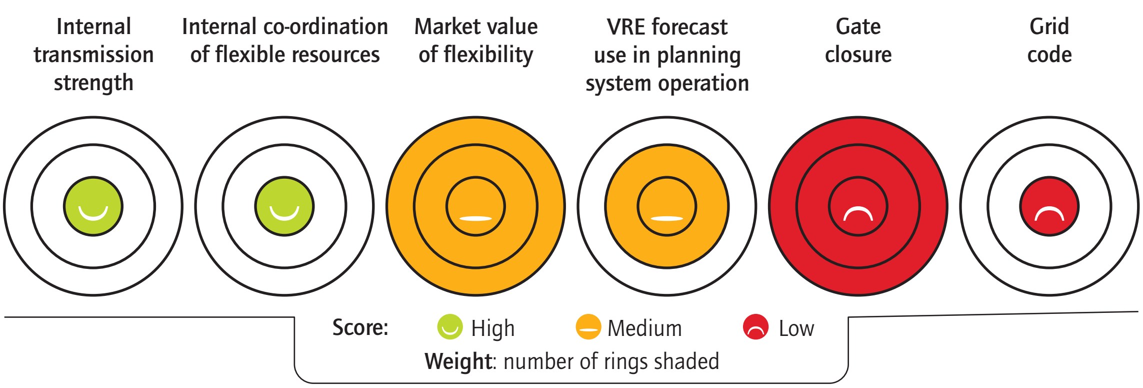
Present extent of use. Present loading of interconnections is intermediate. Given sufficient co-ordination in the area, much of the capacity will be available to provide flexibility – an intermediate score and light weighting, reflecting limited constraint on the value of the interconnection capacity for flexibility.

Size of connected area and potential for geographical spread. Quebec and New England, two of the areas connected to, are extensive and offer potential for geospread. VRE output in these is likely to be generally uncorrelated with that in the NBSO area. A good result, with light weighting reflecting limited effect on the flexibility value of the interconnections.

Area constraints on total flexible resource

The power area attributes with bearing on the overall flexible resource are summarised in Figure 93.

Figure 93 • Availability of total flexible resource (NBSO)



Internal transmission strength. Transmission is strong, so this attribute does not significantly restrict the availability of flexibility – a good score with light weighting.

Internal co-ordination of flexible resources. The NBSO area contains two balancing areas, but these are managed by a single system operator, so the use of flexible resources is likely to be well coordinated – a good score, with light weighting, reflecting no further constraint on flexible resources.

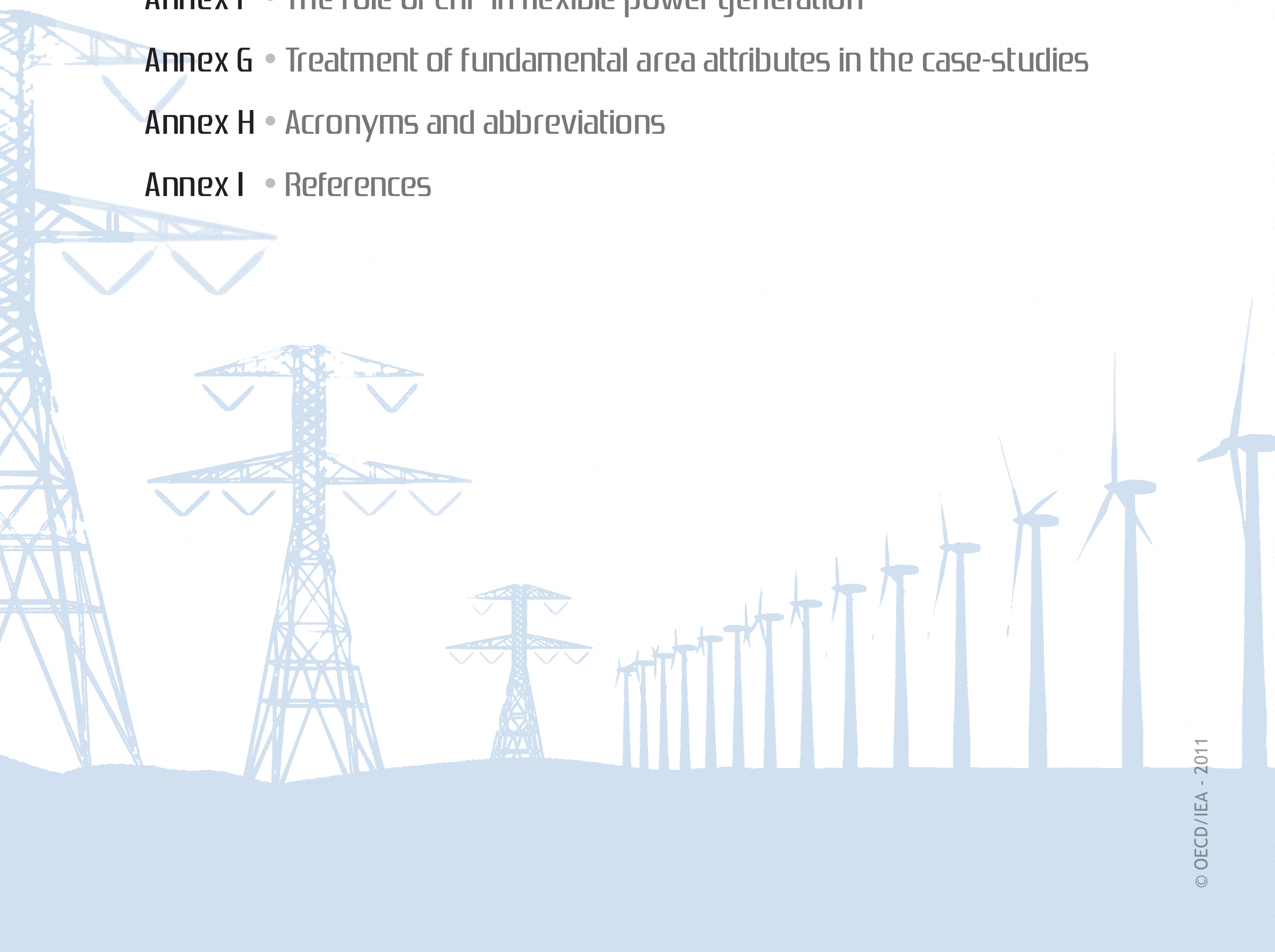
Market valuation of flexibility. The area does not explicitly value flexibility, although there are some incentives in the form of ancillary services payments. Slower flexible resources will see insufficient compensation for provision of their potential contribution to flexibility (in response to long term forecasts of the net load). So, an intermediate result with heavy weighting, reflecting a significant constraint on availability of flexible resources.

VRE forecast use in planning of system operation. Forecasting of VRE output is used when planning the operation of the area – an intermediate score with heavy weighting. Conventional forecasting technology will still restrict the use of and access to flexibility, however VRE output is actively considered when planning the operation of the area. Unit commitment could be improved through more frequent planning updates or more advanced practices, but this would not significantly influence the balancing of VRE until very high penetrations.

Gate closure. Gate closure occurs well before time of delivery – for flexibility purposes, too far ahead. This increases the uncertainty of VRE output, and prevents the dispatch of more flexible resources to fit with it – a low score with high weighting.

Grid code. The area does not take VRE into account in the grid code. The system operator cannot rely on VRE to remain online when expected, so variability profiles will be harder to define. Adequate codes would be needed before significant penetrations of VRE are reached. So, a low score, with light weighting.

Annexes



Annex A • Other integration costs

The definition of integration costs varies in scope across studies. All studies include balancing costs within their definition of integration costs. However, only some consider transmission and adequacy costs as well. Adequacy cost is a highly contentious area; it relates to the cost of ensuring sufficient generating capacity to reliably cover peak demand.

A holistic perspective is needed in the assessment of integration costs; all three of these key components must be accounted for as costs can be “shifted” from one component to another depending on the physical attributes of the system or the accounting methods used in the analysis. For example, balancing costs can be decreased by increasing the geographical spread of (VRE) power plants (and thus smoothing aggregate output), but this may result in higher transmission costs if VRE plants are then located in areas only weakly served by existing transmission.

A number of approaches have been taken to cost assessment in studies in the literature. Most of these are justified essentially, though each has its limitations. These may include:

- Unsuitable characterisation of an “ideal” energy source for use in modelling power systems with and without VRE.
- Unrealistic assumptions about grid strength in the area assessed.
- Unrealistic or insufficiently accurate modelling of the ramp rates of conventional power plants.
- Insufficiently high granularity of time series data of wind output uncertainty and variability; this should at least be hourly.
- Incorrect assessments of the value of the interconnection flexible resource to small systems.

Scenario-based approach to overall integration cost

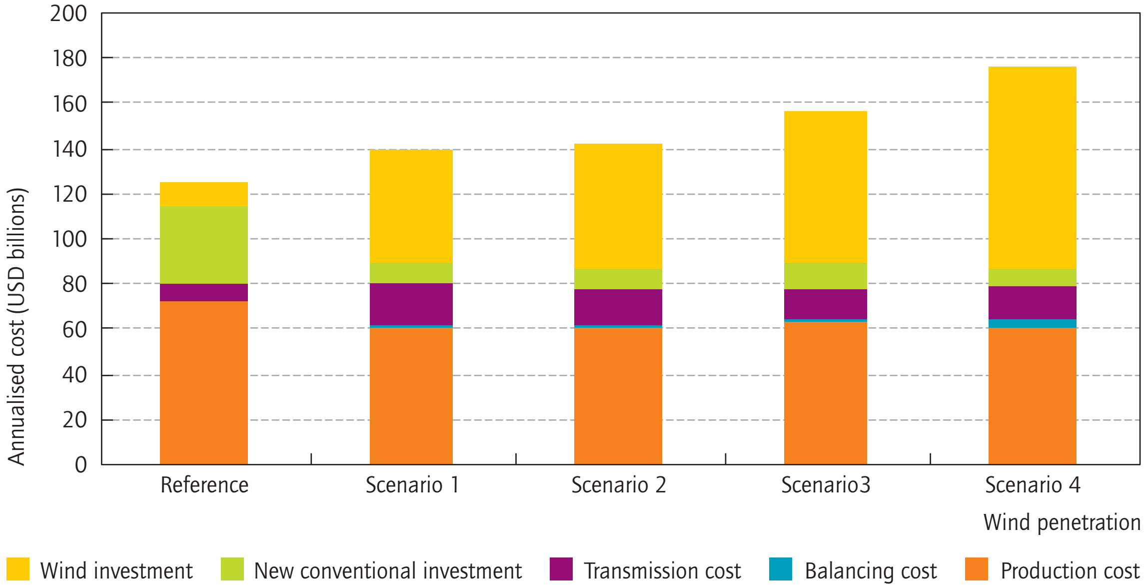
The best approach to analysing integration costs may be to produce scenarios with different VRE shares and to determine the difference in total costs and benefits for each scenario. This has several advantages:

- It captures all elements germane to a decision whether or not to invest in VRE, rather than just placing the focus on one aspect.
- It thus pre-empts potential “accounting” issues, which might otherwise disguise the real cost of deployment.
- It provides a clear perspective on the relative proportions of all major cost elements.

For example the total cost for a range of wind scenarios in the Eastern Wind Integration and Transmission Study (EWITS) of the United States is shown in Figure A1. Capital investments for power plants (conventional or wind) and production costs are the largest drivers. The EWITS study illustrates that, in this case, balancing costs are almost negligible as a percentage of total costs. In contrast, transmission costs constitute a significant fraction of overall costs.

Adequacy costs are embedded in the wind investment and new conventional investment costs. The figure also shows lower production costs due to fuel cost savings in scenarios with higher shares of wind. However it excludes any potential savings from reduced emissions of CO_2 (with a price on carbon).

Figure A1 • *An example of a scenario approach to integration cost analysis*



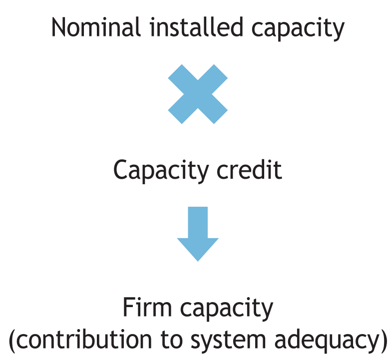
Source: Adapted from EnerNex Corporation, 2010.

Key point • *A scenario approach highlights the relative importance of different cost elements.*

Capacity credit and adequacy cost

The concept of system adequacy relates to having enough power capacity to cover peak demand with a pre-determined level of reliability over the long-term (months to years). Adequacy cost represents the cost of providing this margin. It can be assessed by considering the "capacity credit" of the plants in the system.

Capacity credit represents the level of certainty with which a power plant will be able to deliver capacity on demand. It is measured as the fraction of the nominal capacity of an power plant that can be firmly relied upon by the system in order to meet its target reliability levels. This enables the identification of the increment in demand that can be served reliably by the addition of a given power plant. Its calculation is based on the effective load carrying capacity (ELCC) of that plant. ELCC is used to indicate the probability of load not being satisfied because of generation shortfalls and unexpected random outages. It is often captured using metrics such as loss of load probability (LOLP) or loss of load expectation (cumulative LOLP over a given period).[1]



VRE power plants have lower capacity credit than dispatchable power plants.[2] But despite the variable, only partially certain nature of their output, VRE power plants are likely to have some capacity credit;

1. The industry standard for OECD countries is an expectation of 0.1 day per year loss of load.
2. Down time may be substantial for older dispatchable plants. A capacity credit of 60% is not uncommon in older coal plants, for example.

and if a VRE plant is added to a system that already meets peak power requirements (*i.e.* is adequate), it will only increase the adequacy of that system. If it had no capacity credit, it would neither increase nor decrease the adequacy of the system.

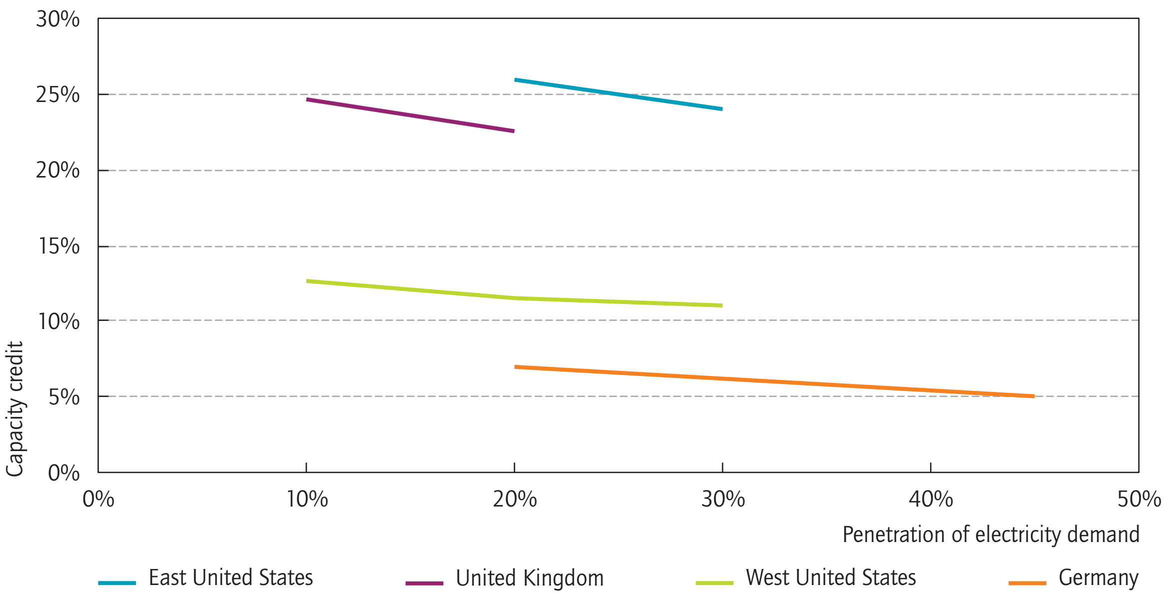
However, the question remains: will the system remain adequate? Displacement of electricity production by dispatchable plants resulting from increased VRE plant production will have a negative impact on the revenue earned by the former. If not compensated, this may cause the early retirement of some dispatchable plants, particularly if they are privately owned – and may reduce the incentive to invest in new dispatchable plants to cover demand growth – or to replace worn-out plant. If these effects are seen, the adequacy of the system may become uncertain: it may now be left with enough *energy* production (*e.g.* average over the year), but insufficient *capacity* that can be counted on to cover particular instances of peak demand, running the risk of black-outs.

To prevent such an outcome, a system must ensure enough capacity, whether in the form of dispatchable generation, storage, demand-side response and interconnection. So the same four sources of flexibility required to handle changes in output over 36 hours can also be considered as routes to increasing the capacity credit of the system over months to years.

Estimating the capacity credit of VRE plants

Capacity credit depends signficantly on the correlation of VRE output with periods of peak demand and the targeted reliability of the power system. Estimating the capacity credit of VRE power plant involves isolating the change in LOLP with and without the VRE plant. Recent studies suggest that capacity credit for wind energy ranges from 6% to 25%, in different power systems, at up to 30% wind penetration. Estimated capacity credit in the United States, the United Kingdom and Germany are shown in Figure A2.

Figure A2: • *Capacity credit for wind in selected regions*

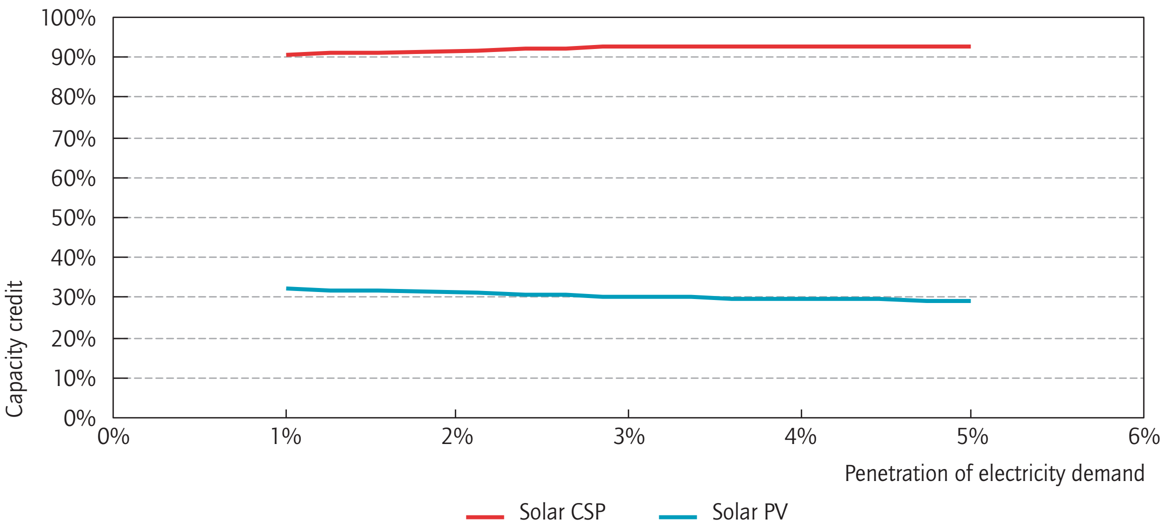


Sources: Eastern United States, EnerNex Corporation, 2010; Western United States, GE Energy, 2010; United Kingdom, ERC 2006; Germany, DENA 2005.

Key point • *Capacity credit for wind energy differs markedly from case to case, depending on the nature of the power system in question, and reduces with increasing penetration.*

Fewer studies have analysed the capacity credit attributed to solar technologies. The Western Wind and Solar Integration Study in the United States found, at low penetration levels, capacity credit values around 30% for solar photovoltaic (PV), and 90% for concentrating solar power (CSP) (Figure A3).[3] In power systems in which electricity demand peaks in the the summer months, solar PV electricity tends to be well aligned with peak demand. As a result, capacity credit is relatively high.

Figure A3 • Capacity credits for solar technologies in the Western United States



Source: GE Energy, 2010.

Key point • *Solar PV capacity credit can reach above 30% in systems where solar output and peak demand are well aligned.*

Concentrating solar power (CSP) plants, though not a focus in this book, provide an interesting basis for comparison here. They generally have higher capacity credit for two reasons. Firstly, CSP is usually better aligned with peak demand because unlike Solar PV, it is built only in areas with high direct normal irradiance (DNI).[4] Secondly, CSP plants are likely to include thermal energy storage (which may be up to 15 hours at full load) in addition to inherent storage resulting from the energy conversion technology itself.[5] This thermal buffer avoids transient disruptions in output which would otherwise occur due to the fluctuating nature of the solar resource, and allows the timing of peak output to be scheduled to coincide with peak demand.

Adequacy costs

Adequacy costs result from additional dispatchable power plants specifically installed as reserves for new VRE plant, from additional costs such as wear and tear through increased cycling, incurred by existing dispatchable plants in the maintenance of system reliability and through reduced revenues to those plants.

3. CSP plants in California are profitable precisely because their capacity credit is more than 90% which is a condition of their power purchase agreement, in order to qualify for valuable capacity payments at peak times.
4. Unlike PV modules which can generate electricity using diffuse light (though output is lower), CSP plants can generate electricity only in direct sunlight.
5. A combination of the thermal inertia of the heat transfer fluid (if any), the receiver and heat exchangers, the content of steam drums and the rotating inertia of the turbine.

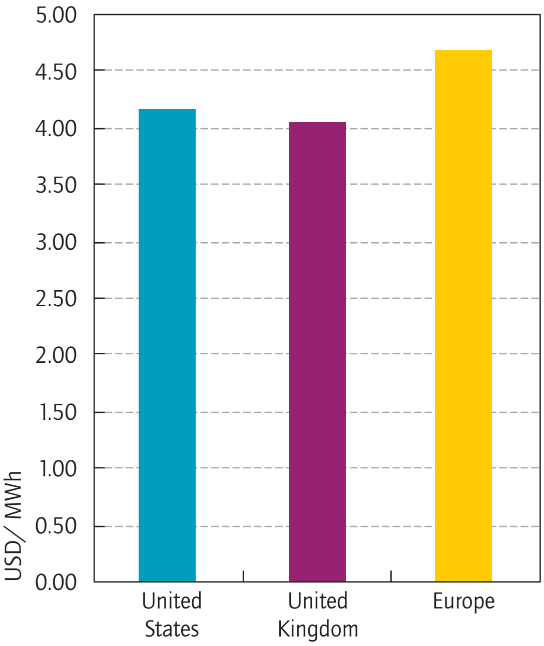
It is not clear how such costs should be allocated. Reduced revenue to existing plants does not directly constitute a cost to the system. But it may jeopardise system reliability through early retirement of those plants, resulting in an indirect cost to the system. On the other hand, if such costs are shouldered solely by new market entrants, this will jeopardise their deployment and the wider socio-economic and environmental benefits may be lost. The actual adequacy costs incurred by a system will vary considerably, and should be evaluated on a case-by-case basis.

Determining these costs is difficult and contentious. Generation portfolios vary, as do system reliability criteria, making it hard to estimate the potential capacity shortfall and the associated cost.

As was mentioned earlier, adequacy costs can be calculated in different ways. One common approach is described below, followed by a discussion of the scenario-based approach which may be more useful and less contentious.

The energy-normalised approach compares the firm capacity provided to the system by VRE plants with that provided by the existing conventional plant portfolio, after first normalising the two sources on the basis of the amount of electricity they produce. A generic perspective on regional adequacy costs for wind energy determines the approximate cost of peaking capacity that would provide the same capacity and energy as the wind alternative (Figure A4).

Figure A4 • Adequacy costs of wind by region (energy normalised approach)



Sources: United States, EnerNex Corporation, 2010; United Kingdom, ERC 2006; Europe, GreenNet 2009.

Key point • Using the energy normalised approach, adequacy costs vary slightly regionally according to the installed dispatchable plant portfolio, from around USD 4 – 5/MWh of wind generated.

Key drivers of adequacy costs

The key drivers behind calculation of adequacy costs (Table A1) are described in more detail in the following sections.

Table A1 • Key drivers of adequacy costs

Correlation among VRE power plants	Correlation between VRE output and peak demand	Reliability target of system	Dispatchable plant margin
Incremental capacity need	Demand growth	Demand side management and response	

Correlation among VRE power plants

The capacity credit of VRE power plants in a power system is higher when the plants have weakly correlated outputs. In highly correlated groups of plant, there is a greater probability that when one generator has lower output, the others will also. Therefore, geographical spread and the use of different VRE technologies can influence adequacy costs by reducing correlation among plants.

This principle also applies to conventional sources. Plants with the same fuel type are more likely to have correlated supply shocks and shortages. For example, a natural gas supply shortage will affect other gas plants in the area but not a wind power plant or a coal power plant. Thus, a portfolio of different generation technologies (conventional and renewable) can have a positive impact on adequacy in the system.

Importantly, since correlation among the output of generators increases with penetration, adequacy costs are likely to increase with increasing amounts of VRE.

Correlation between VRE output and peak demand

Adequacy costs are significantly lower in systems in which peak load coincides with peak generation from VRE. This is because the VRE capacity can be counted more firmly towards the power available in times of need. And when VRE generation is low, system demand also tends to be low, so there is already surplus capacity in the system.

In Germany, peak demand occurs in winter, as in Northern Europe generally, while solar PV production peaks on summer days. Here, capacity credit will be relatively low. In contrast, PV is likely to have higher capacity values in the Texas ERCOT system, for example, where demand peaks in the summer.

Reliability target of system

In addressing adequacy costs of VRE, it is also important to consider the existing generation and reliability needs in a system. While wind energy might provide only 15-20% capacity credit when meeting reliability requirements in OECD countries, the figure may be greater in developing countries, where grid reliability may be lower. Different loss of load probability (LOLP) values may therefore be accepted, depending on the context.

This is because regions with significant energy generation deficits – where production is usually less than system load – will see frequent load-shedding. These regions may show low adequacy costs from variable renewables because more energy production is welcome regardless of the time of generation. In such systems, the capacity credit of a variable renewable may be wholly driven by its capacity factor.

Dispatchable plant margin

A system with excess capacity will experience lower adequacy costs resulting from variable renewables than one in which no such excess exists. This is because the investment in excess capacity has already been made. In economic terms the excess capacity installed is a sunk cost and can be ignored.

Long term adequacy costs in a system with excess capacity will depend on the retirement schedule of the existing plant, and on the maintenance costs of keeping the excess capacity in service (instead of mothballing it). For example, if a system has excess capacity and an OCGT plant which would otherwise be mothballed but is kept in service to supplement VRE plants, adequacy costs will be determined by the costs of keeping the gas plant in service.

Other factors

With growing peak demand, systems will require additional generation capacity. However, in small systems, a mismatch is possible between the additional capacity needed and the smallest conventional plant that can be operated efficiently. In such situations, building a conventional plant would involve incurring signficantly more capacity costs than using a more optimally–sized VRE power plant to meet additional needs. Consequently, system adequacy costs may be lower for VRE than for conventional options in such circumstances.

While power systems have historically seen growth in peak demand over the course of recent decades, there is reason to believe that this trend may tail off or even cease altogether. Peak demand may fall if energy efficiency measures are pushed ahead with enough force. This would result in excess generation capacity in the system (increased adequacy). Moreover, a more *flexible* demand (as opposed to simply reduced) side has the potential to further reduce peak demand levels, through response to a high price signal.

Transmission costs

Any new power plant, conventional or renewable, will incur transmission costs if built in an area weakly served by the existing grid. The principal driver of this cost will be the distance between the plant in question and the demand centre it serves.

The location of renewable energy plants is limited by the geographic distribution of the natural resources behind them. These are often located away from demand centres and the existing transmission network. For example, the best Chinese wind resources are located in the north and west, away from the principal demand centres in the south and east of the country. In such cases, the cost of connecting to and reinforcing the existing grid may be high.

This is not always the case however. Major coastal cities are often located close (for example tens of kilometres) to large offshore, wave and tidal resources while cities in climates with high insolation will be located within the resource itself.

Identifying transmission cost will not always be a clear-cut calculation. The cost of new transmission up to the existing grid will be an easy matter to quantify, but additional reinforcement within the existing grid may also benefit the wider power system. An example of such a benefit is reduction of congestion, which in some cases can impose a major constraint on the operation of the system. Consequently, the cost of that reinforcement should not be attributed solely to the new plant, nor should the burden fall solely on it, even if it triggered the investment in the first place.

For example, in Finland, the system operator has allocated USD 2.2 billion (EUR 1.6 billion) to a ten year transmission development programme. This will provide for the needs of 2 000 MW of wind generation, a new nuclear power plant, and increasing demand in the Lapland region. In Portugal, the *Transmission Grid Development Plan for Renewables*, 2010, undertaken by the system operator in 2001, found that of the total transmission costs associated with the deployment of 4 000 MW of renewable power plants, mainly wind power, only half (USD 278 million / EUR 200 million)[6] could be directly attributable to the renewables. The balance served other grid development objectives (IEA Wind, 2009).

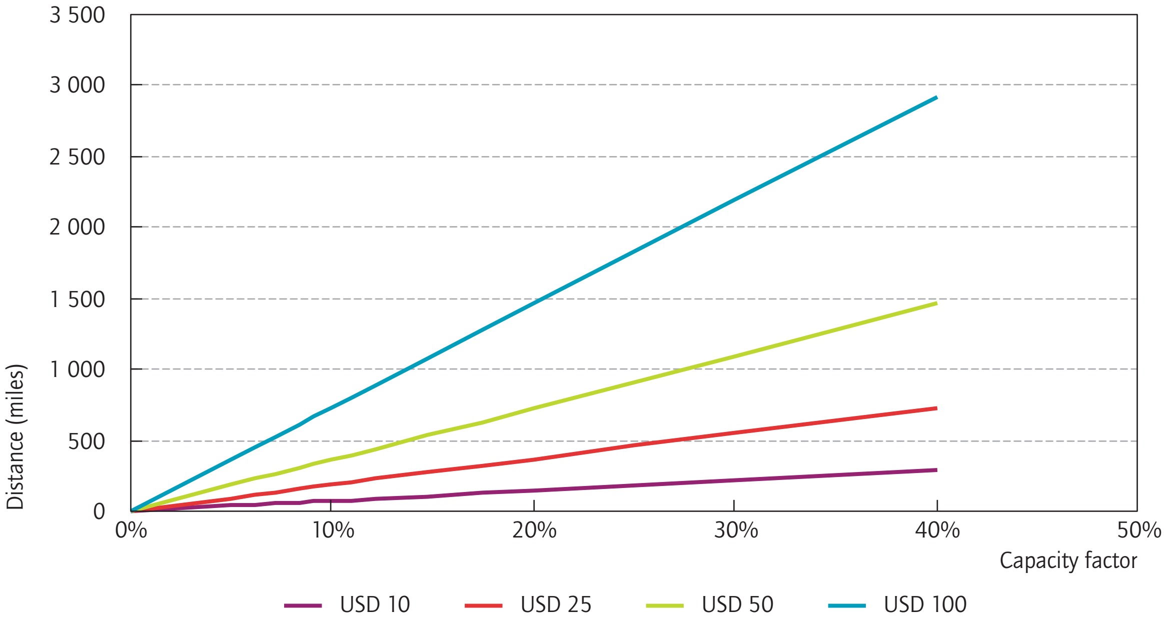
Dimensioning new transmission

New transmission capacity built to connect distant resources to demand centres will be attractive when the benefit outweighs that of the next best option. This next best option may be to build at an alternative site which has a poorer resource but is considerably closer, thus avoiding much of the transmission cost. In other words, there may be a threshold beyond which even the best resources are not worth the cost of accessing them.

A simple way to assess the economic feasibility of transmission is shown in Figure A5. Building a renewable power plant distant from demand may result in a higher capacity factor than if it were built in a poorer resource area close to the demand centre. The figure represents the incremental difference in capacity factor (x-axis) as distance increases (y-axis). The four lines illustrate break even distances with differing values of the energy delivered.

6. This does not include cost of wind power plant substations or of new line connecting to the existing grid, both of which are assumed to be paid for by the wind developer.

Figure A5 • Break even distances by capacity factor and electricity value



Source: IEA analysis.

Key point • In areas with high electricity prices, there is a greater incentive to build transmission over longer distances.

The figure is illustrative only; detailed analysis should be done on a case-by-case basis to establish the feasibility of a given transmission line. Several simplifying assumptions have been made in the graph: transmission costs are based on high voltage direct current (HVDC) technology, assuming USD 0.80/kW/mile, a 15% flat charge rate and full-capacity utilisation. Minimum threshold distances needed for HVDC technology are ignored. The value of energy delivered is the sum of the electricity prices and the value of other benefits provided, such as increased diversification of generation that can lead to lower balancing and adequacy costs.

The opportunity to curtail wind output will also have bearing on the extent of the transmission build. For example, the Texas Public Utilities Commission has directed that transmission capacity from the competitive renewable energy zones (CREZ) should amount to less than 100% of the projected VRE power plants to be deployed in the CREZ, and that modest curtailment of VRE output should be used in order to save the cost of building the difference which would otherwise only be used relatively rarely.

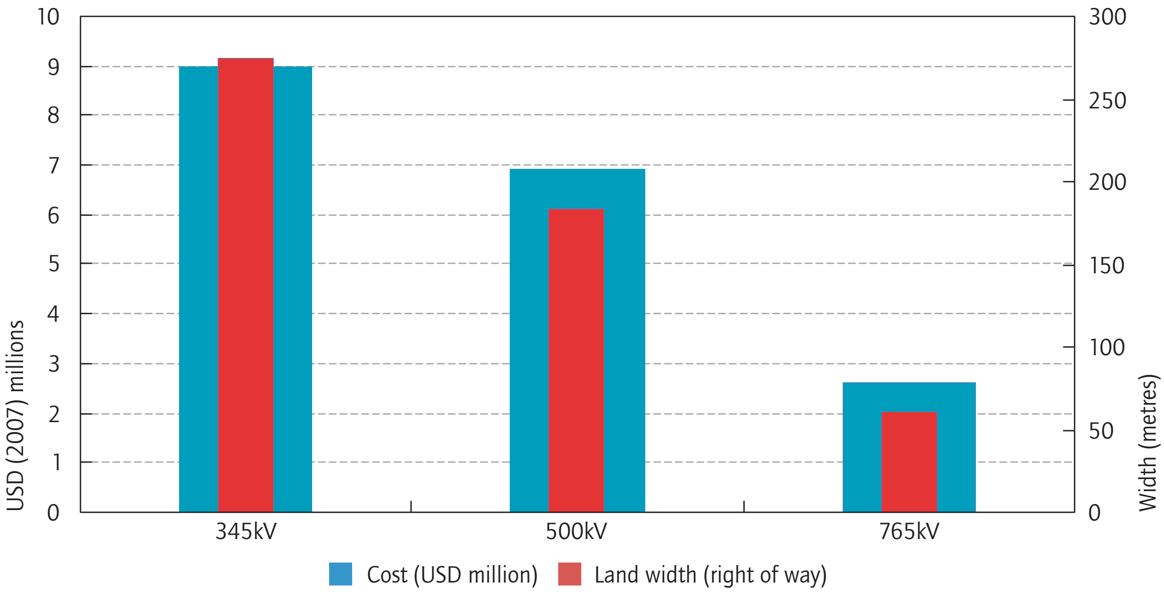
Distance and scale

Generally, the greater the length of the transmission lines that need to be built, the more expensive the overall transmission cost. Although the total absolute costs of transmission rise with increasing continuous length of the line, the unit costs (per kW per mile) usually fall, due to economies of scale. One such scale economy relates to capacity. Longer lines are likely to be of higher capacity, and the unit cost both of AC and DC lines falls with increasing capacity.

Other scale economies will be found in reduced right of way (ROW) land requirements per KW per mile. Low voltage corridors require a greater number of lines to carry the same capacity, and therefore greater land width. And operation and management costs do not necessarily increase proportionally with the scale of the transmission investment (Heyeck, 2008).

The cost of three transmission projects using different voltage levels to transport 2 400 MW over 100 miles and the effect on ROW land requirement are shown in Figure A6. Costs shown are average total single-circuit construction costs assuming rural terrain with rolling hills, and include equipment, siting and right of way costs. O&M costs are excluded. Sub-station costs are also excluded.[7]

Figure A6 • Scale economies in transmission assuming fixed capacity and distance



Source: Heyeck, 2008.

Key point • Transmission costs reduce with the use of higher voltage lines (and reduced land width).

Estimated transmission costs

The cost of building transmission lines to integrate distant sites or interconnect existing networks to improve grid strength varies significantly by region. Some grid integration studies include detailed analyses of the costs of transmission in the regions they cover. This section presents an overview of estimated costs of transmission in a sample of studies for different regions worldwide.

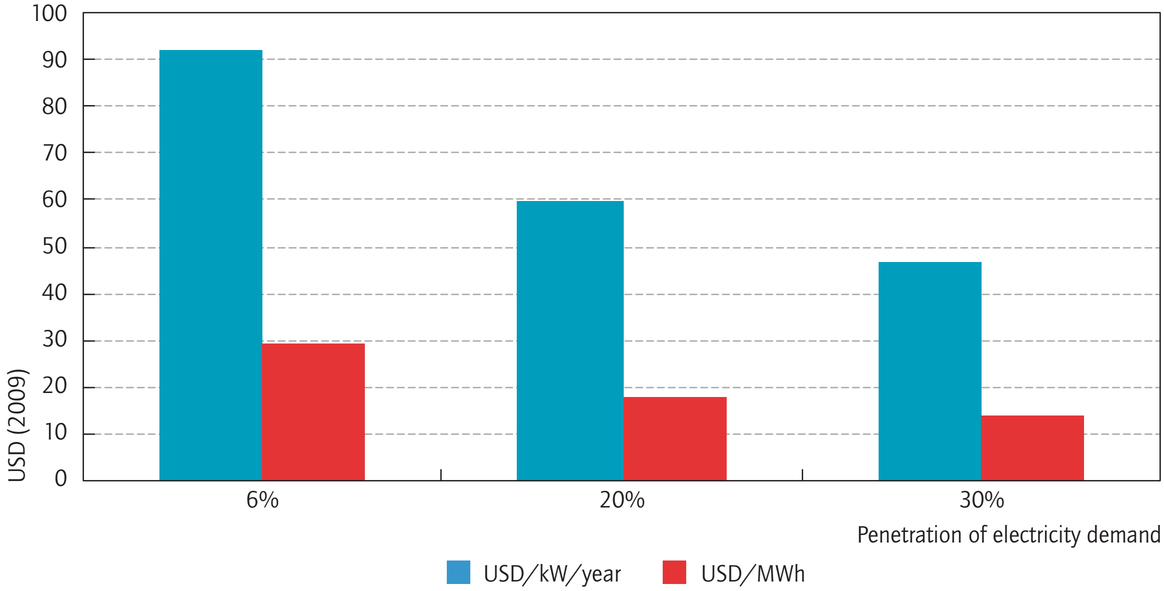
United States

The United States has significant renewable resources in sparsely populated areas. For example, some of the largest wind energy potential is in the Dakotas and Montana, and in the southwest. Significant solar potential exists in southwest and western states such as Arizona, Nevada and New Mexico. Annualised transmission costs range from USD 92/kW at 6% wind penetration to USD 46/kW at 30% penetration, according to the EWITS study, as Figure A7 shows.[8]

7. Station costs would be amortised over the distance of the line, and would be highly dependent on individual projects. Including station costs would likely further increase economies of scale. The figure shows normalised values derived from cost data from American Electric Power. The nominal costs for the three technologies are USD 2.6 million for the 765kV based line, USD 6.9 million for the 500kV and USD 9 million for the 345kV (USD 2007).

8. A 15% discount rate is assumed and overnight construction.

Figure A7 • Transmission costs of wind and system optimisation in the Eastern US

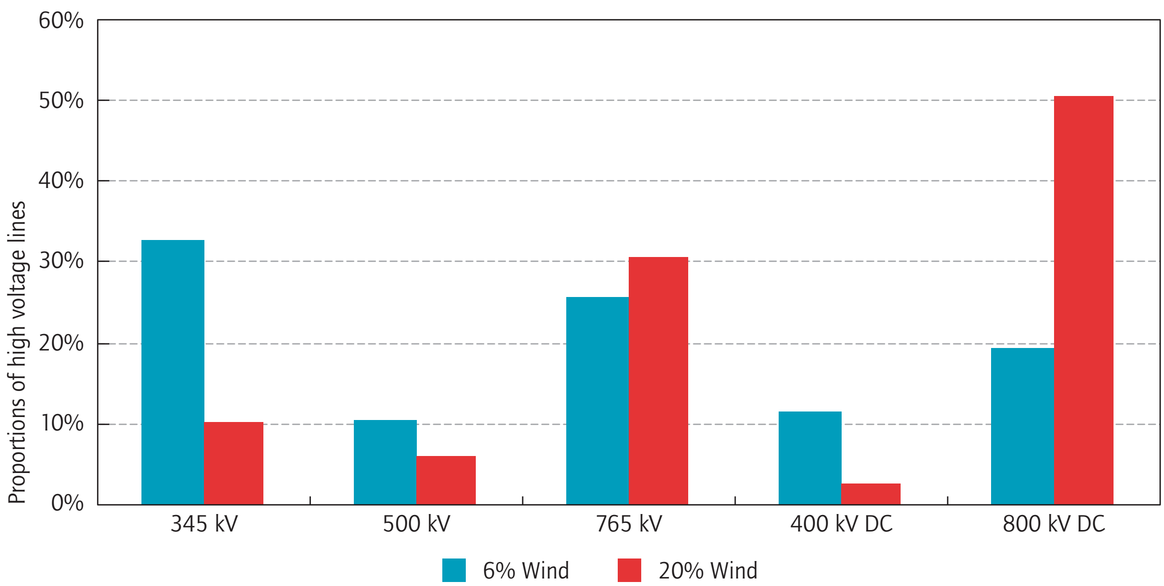


Source: EnerNex Corporation, 2010.

Key point • Transmission costs (per MWh generated) in the Eastern US fall at larger wind energy shares.

There are two drivers that decrease the unit cost with increasing penetration. First, increasing wind penetration leads to economies of scale; increasing proportions of high voltage lines when moving from 6% to 20% wind power are shown in Figure A8.

Figure A8 • Economies of scale (voltage) in EWITS 2010



Source: EnerNex Corporation, 2010.

Key point • Economies of scale are found in increasingly high use of high-voltage transmission accompanying larger penetrations of wind energy.

Second, a large portion of the transmission costs in the 6% wind scenario in particular arise from the transmission build-up designed to minimise system costs overall by reducing congestion.

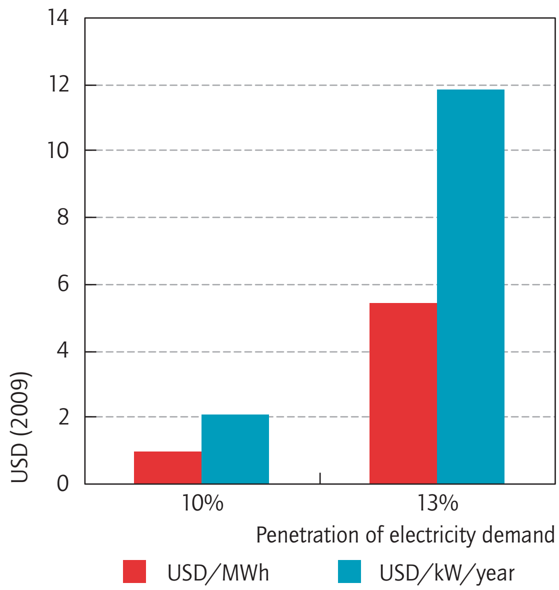
Transmission costs vary greatly with distance, transmission line technology and power capacity. A recent study conducted by the Lawrence Berkeley National Laboratory found that annualised transmission costs across 40 wind transmission studies in the United States ranged from USD 0/kW to USD 1500/kW (LBNL, 2009).

Europe

The recent ENTSO-E European Wind Integration Study (EWIS) analysed transmission investment costs needed in major EU countries to accommodate targeted levels of wind energy. It found that costs at 10% penetration of wind energy would amount to approximately USD 2.1/kW/year, rising to USD 11.8/kW/year at 13% penetration (Figure A9).[9]

This European study also identifies cross border transmission that can enhance the network and

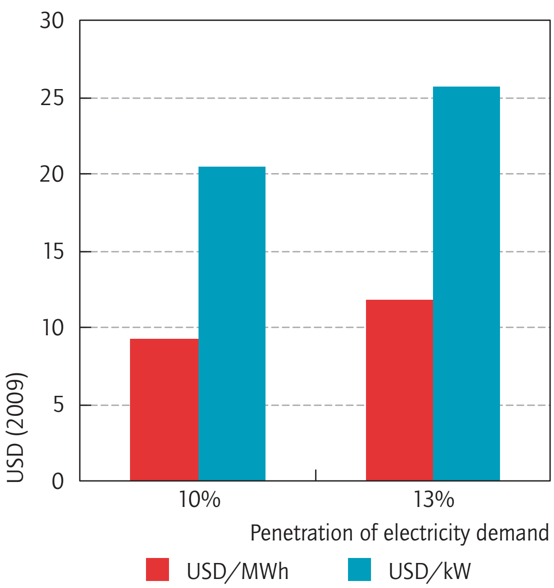
Figure A9 • Transmission costs of wind in Europe



Source: EWIS, 2010.

Key point • In a recent European study, transmission costs (resulting from wind only) per unit were found to rise significantly with penetration.

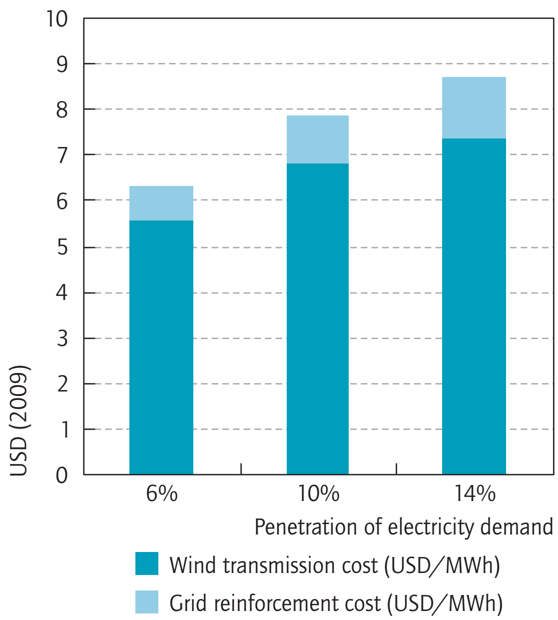
Figure A10 • Total transmission investment in Europe (EWIS)



Source: EWIS, 2010.

Key point • The European study, unlike the American, assumes costs increase per unit at higher penetrations.

Figure A11 • Transmission costs in Europe (GreenNet)



Source: GreenNet, 2009.

Key point • Wind transmission and grid reinforcement costs rise from USD 6/MWh at 6% wind penetration, to USD 9/MWh at 14% penetration.

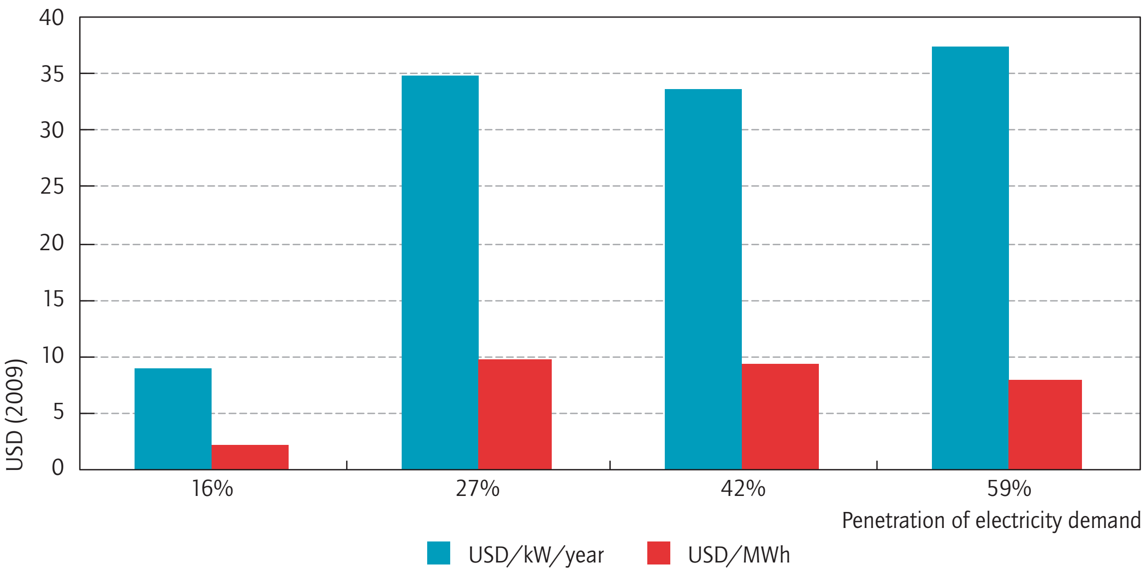
9. In MWh terms this is equivalent to USD 0.97 and USD 5.4 / MWh respectively.

reduce congestion costs over the long term. These costs amount to approximately USD 17.1 billion. They are added to transmission costs for comparison with the American EWITS study results in Figure A10. Unlike the EWITS study, overall costs are considered to increase per unit at higher penetrations.

In 2007, the GreenNet Study analysed transmission costs for wind and total grid investment costs, including costs of grid reinforcement (Figure A11).

Ireland has conducted one of the most extensive grid integration studies in Europe. This may provide insights into integration costs in island systems (in comparison to continental systems). For wind penetrations ranging from 16% to 59%, annualised transmission costs in Ireland rise from USD 2.2/MWh at 16% wind penetration to USD 9.7/MWh at 27% penetration, but thereafter fall as penetration rises to 59% (Figure A12).

Figure A12 • Cost of wind transmission in Ireland



Source: Eirgrid.

Key point • Up to 27% penetration, wind transmission costs (per MWh) rise, but fall thereafter.

Regulatory aspects

Not all costs of building transmission lines are captured in transmission cost studies. Additional costs result from non-economic factors that are difficult to quantify but that are nevertheless important. The most significant of these result from siting and regulatory approval, which often represent a significant burden compared to many other electricity infrastructure investments. A number of reasons are highlighted in Table A2.

Table A2 • Issues requiring regulation

Inclusion in Rate Base	Allocation to consumers	Appropriate Rate of Return
Compatibility with Network Long Term Planning	Right-Of-Way and Land Acquisition	Fair Access to Network

First, the transmission grid is a natural monopoly (except some DC links) and therefore must be regulated to ensure that transmission investment or operation does not yield a return greater than what is fair, based on the cost of capital and expected risk for the transmission project.

Second, the interdependence of a transmission line with the rest of the network is significant and it is difficult to treat a single line in isolation. Recognising this interdependence is important for system planning and stability reasons as well as for economic justification of a new line.

Finally, most significant transmission projects involve multiple stakeholders, often crossing national and local borders and private territory (Table A3). Obtaining approval might involve gaining support from a number of national and regional governments as well as cities and small towns. Countries and regions may have different policies about granting right-of-way authority for transmission building. Addressing such concerns to gain comprehensive project approval is therefore likely to be a long process.

Table A3 • Stakeholders in transmission projects

Transmission Project Promoters	Generation Owners	Public Utility Commisions
Transmission Planners and Operators	International Negotiators and Diplomats	Legislative Bodies
National and Satete Agencies	Local Councils and Citizen Groups	Special Interest Groups

A direct result of the often long and complex approval process comes from the cost of following the process itself, including filing necessary paperwork with utility commissions, hiring experts and lawyers for economic analysis, project justification, rate base inclusion and legal defence. These costs add to total transmission costs.

Unlike several other investments, transmission line expansion can involve a high level of uncertainty as well as long lead times between project initiation and completion. As a result, while most VRE projects can be completed within a few years, corresponding transmission projects that are large scale can take longer. When transmission building is needed before any VRE generation can be transmitted to load centres, addition of renewables to the system may be delayed.

Transmission cost allocation and recovery

Although allocation methods may vary from one market to another, a rule of thumb is that consumers pay for transmission lines that are considered a public good.

An alternative to traditional transmission investment, merchant transmission projects can be made attractive to private investors through market-based incentives. In this case, all up-front costs are paid by project investors. Merchant transmission investors bear considerable market uncertainties and risks, so sufficient market incentive is critical.

Annex B • Additional information on VRE technologies

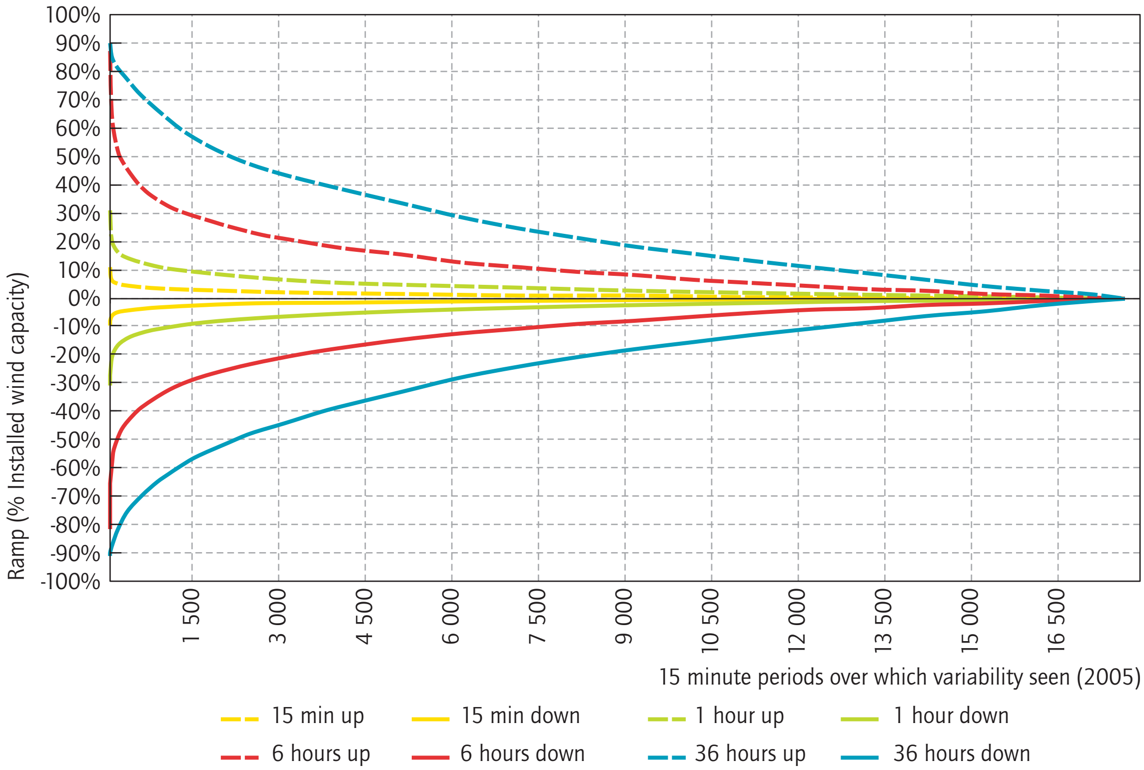
A brief overview is provided in this annex of some of the key characteristics of different VRE technologies: wind, solar PV, wave and tidal.

Deep understanding of a VRE technology's output profile is essential for accurate assessment of its flexibility requirement. In the GIVAR case studies, simple estimates are made of variability from each VRE type in terms of the maximum extent and rate of ramping exhibited in the four time frames assessed (15 mins, 1 hour, 6 hours, 36 hours), and the uncertainty associated with it.

Wind

The frequency and extent of wind output ramps (up and down) over the balancing time frame, based on time series data for one year, are shown for the island of Ireland in Figure B1. For example, in the 36 hour time frame, the extent of ramps during around 12% of the year lies between 35% and 90% of installed wind capacity. Sufficient flexible resource will be needed over the same period to cover this requirement.

Figure B1 • Variability of wind power over different time scales (Ireland, 2005)



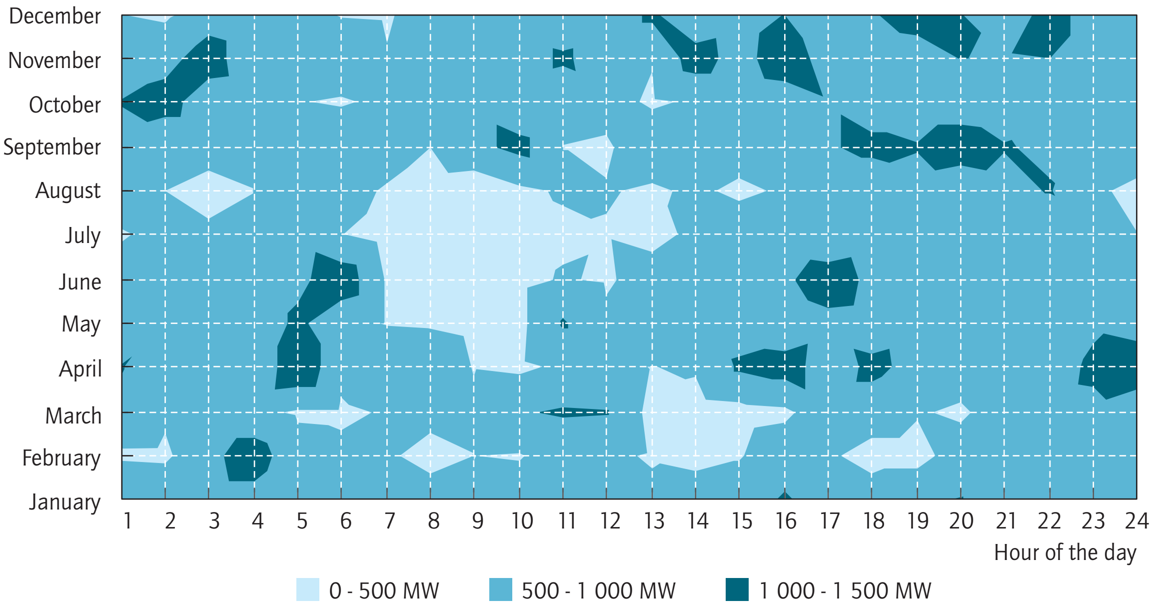
Note: Only those periods where significant variability is occurring are shown (about 50% of the total 35 040 periods).
Source: Eirgrid data.

Key point • The extent of ramps and the amount of time they are seen over the year increases in longer time frames.

VRE power plants spread over larger regions are likely to show less (aggregated) output variability. Hourly variability of wind ranges up to 10% in the large area of the Nordic Power Market, but up to 35% in East Denmark, a constituent of that market (IEA Wind, 2009).

There is usually a strong seasonal component to the wind resource: for example, at higher latitudes it is generally windier in winter. The maximum ramps in wind output by hour of day and month of year over the period 2005–2007 in the Finnish system are shown in Figure B2.[1]

Figure B2 • Maximum up-ramps of wind (MW/hour) in Finland, 2005-2007



Source: Fingrid data.

Key point • There is no regular daily pattern in the majority of wind resources, but a seasonal pattern does often emerge.

The data illustrate that there is rarely a clear pattern, apart from generally lower ramps in summer (when the resource is also weaker). This means that a maximum ramp up in the resource may well coincide with a maximum ramp down in demand, in which case flexibility requirements will be compounded.

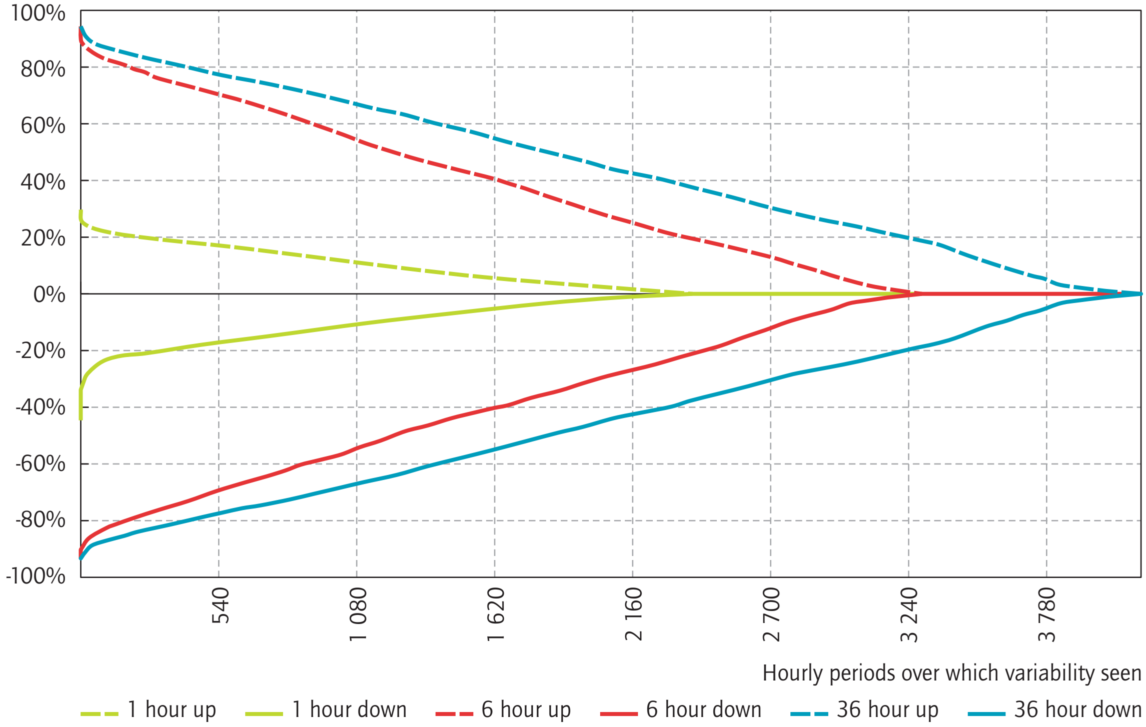
Solar PV

Like wind power, solar photovoltaic (PV) output is highly variable. Aggregated variability of PV output for eight sites in California, over one, six and 36 hours, are shown in Figure B3. Again the extent of variability increases with the time horizon. Over 36 hours, of course, variability can cover the full installed capacity of the plant.[2]

Although the predictability of PV output is less well understood than that of wind power, a number of recent studies have thrown some light on the subject. One study suggests a root mean square error (RMSE) of 4% to 5% on the intra-day and day-ahead forecast horizon (Lorenz *et al.* 2010), which is comparable to the wind energy forecast accuracy on the same horizon.

1. Installed wind capacity is scaled up to represent 20% of electricity demand.
2 Maximum variability in the figure over 36 hours is not shown as 100% as it is unlikely that installed plant will be operating at 100% in the first place due to high level haze and particulate interference.

Figure B3 • *Variability of solar PV output over 8 sites in California.*



Source: Data used in the preparation of GE Energy 2010.

Key point • *As with wind, the extent of ramps and the amount of the year over which they are seen increases in longer time frames.*

Wave power

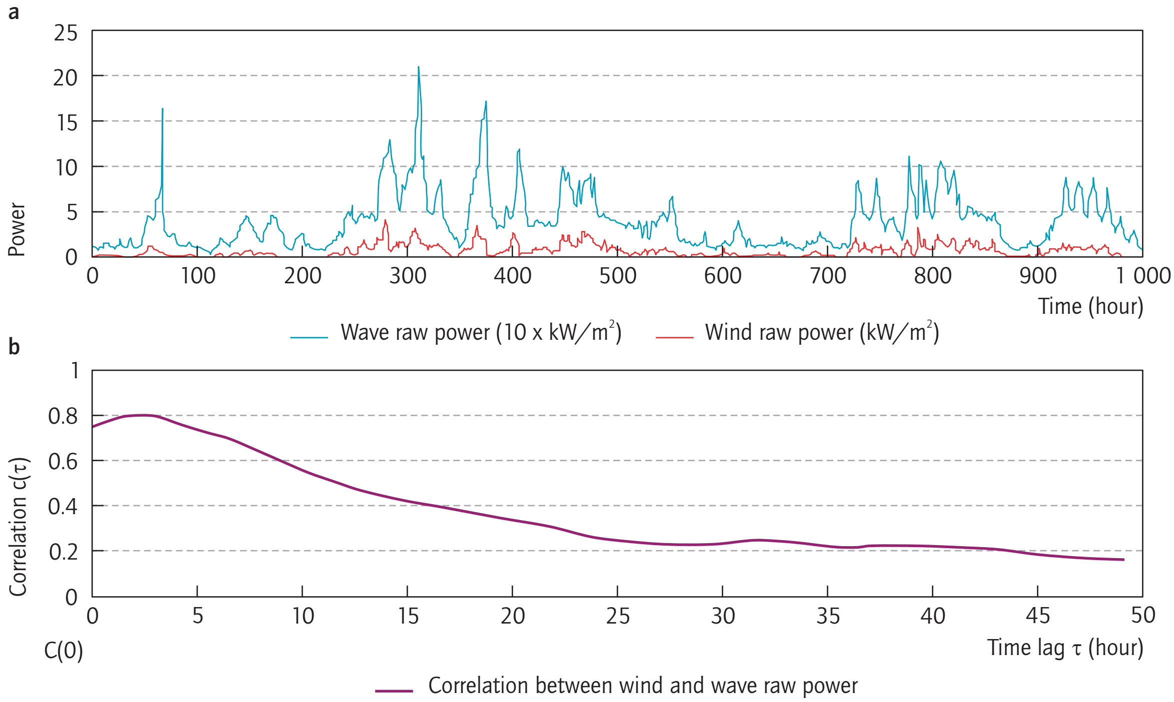
Very few data exist on the variability and uncertainty of wave energy output, as vastly less experience has been had with deployment of the various technologies still under development. The variability of output from individual wave energy devices is known to some degree but values that are representative of regions as a whole are not yet available.

Waves are driven by the wind, which suggests a measure of correlation with electricity output from that resource. Wave output has been shown to be less variable than wind output in the same environment (based on UK estimates as provided in ECI, 2006) and tends to follow wind output with a lag of some two to three hours in that area.

The correlation between wind and wave outputs in southwest Ireland is shown in Figure B4.

3. Royal Decree 661/2007, which was published on 26 May 2007, regulates the production of electricity under a special regime applicable to electricity produced from renewable energy sources.
4. Although as previously noted, the predominance of distributed plants may reduce the system operator's ability to track output during the day (unless output is signalled through a smart meter).

Figure B4 • *Wind and wave variability correlation*



Source: Fusco, 2009.

Key point • *The outputs of wind and wave plants may show significant correlation.*

Potential wind and wave output correlation suggests two advantages in deploying both technologies in a VRE portfolio rather than just one or the other:

- Aggregate variability of output from the two will be smoothed.
- Wind output could be used to some extent to predict wave output.

Tidal power

Tidal power has very different variability characteristics to other VRE types. While other types are driven by prevailing weather conditions, tidal power is driven by the gravitational pull of the moon, and is almost unaffected by weather conditions. Tidal power output is variable, with a peak output approximately every 12 hours plus, so its coincidence with peak demand/minimum demand will cycle.

While the output from a tidal plant falls from peak to close to zero over a relatively short time, tidal phases may vary significantly among neighbouring tidal sites, such as on the coast of British Columbia in Canada (Bhuyan, 2008), suggesting significant potential for geographical spread, resulting in a strong smoothing effect on aggregated output.

Tidal output in any location is predictable years in advance, so the need for additional flexibility due to uncertainty will be close to zero. Tidal output varies on a 14-day cycle, between spring and neap tide levels, though greater variability may occasionally result from major storms (storm tides). As tidal output is uncorrelated with the outputs of other VRE, tidal power is likely to smooth the output profile of any VRE portfolio of which it is a part.

Annex C • Assumptions relating to dispatchable power plants in case-study areas

The flexibility of each plant type in the case study areas is approximated based on a number of variables. These are: installed capacity, ramping rates, start-up and shut-down times and minimum-stable operating levels. Reported data for the case study areas were used where available. Where data were not available, the figures were based on the literature. See tables below.

Flexibility is relative to the size of unit – *e.g.* a unit with an average size of 50 MW and ramping of 20 MW/min is more flexible than a larger unit type with the same ramp rate.

"Steam turbines" refer to older units using gas or oil to produce steam, and are likely to be run in mid-merit or baseload operation. This rubric is used as such plants tend to be relatively inflexible.

British Isles

	Coal	*Nuclear*	*CCGT*	*OCGT*	*Steam turbine*	*Other peak*	*Hydro*	*CHP*
Capacity installed (MW)	27 300	7 300	30 300	1 000	1 100	4 100	1 150	2 340
Ramping capability (MW/min)	8	2	10	15	5	10	10	6
Start up and shut down (hours)	6	36	3	0.016	4	0.016	0	0.016
Min stable level (% of max)	50%	60%	50%	10%	60%	10%	10%	50%
Number of units	100	10	80	10	5	50	35	10
Flexibility (% capacity)								
15 mins	44%	4%	40%	100%	34%	100%	100%	38%
1 hr	50%	16%	50%	100%	40%	100%	100%	100%
6 hrs	50%	40%	100%	100%	100%	100%	100%	100%
36 hrs	100%	40%	100%	100%	100%	100%	100%	100%
Total flexibility (MW)								
15 mins	12 000	300	12 000	1 000	375	4 100	1 150	900
1 hr	13 650	1 200	15 150	1 000	440	4 100	1 150	2 340
6 hrs	13 650	2 920	30 300	1 000	1 100	4 100	1 150	2 340
36 hrs	27 300	2 920	30 300	1 000	1 100	4 100	1 150	2 340

Source: Values are based on DCENR, 2008.

Iberian Peninsula (Spain and Portugal)

	Coal	*Nuclear*	*CCGT*	*OCGT*	*Steam turbine*	*Other peak*	*Hydro*	*CHP*
Capacity installed (MW)	13 135	0*	26 322	2 165	2 871	216	15 352**	400***
Ramping capability (MW/min)	3.5	0.5	5.4	6	3.3	10	10	1.4
Start up and shut down (hours)	6	24	3	0.016	4	0.016	0	0.016
Min stable level (% of max)	50%	100%	45%	30%	60%	10%	10%	50%
Number of units	41	8	58	22	24	55	400	250
Flexibility (% capacity)								
15 mins	16%	0%	18%	91%	40%	100%	100%	30%
I hr	50%	0%	55%	100%	40%	100%	100%	30%
6 hrs	50%	0%	100%	100%	100%	100%	100%	30%
36 hrs	100%	0%	100%	100%	100%	100%	100%	30%

Total flexibility (MW)								
15 mins	2 153	0	4 698	1 980	1 148	216	15 352	120
1 hr	6 568	0	14 477	2 165	1 148	216	15 352	120
6 hrs	6 568	0	26 322	2 165	2 871	216	15 352	120
36 hrs	13 135	0	26 322	2 165	2 871	216	15 352	120

* The Spanish system operator reported that none of the installed nuclear capacity can be ramped down in the balancing time frame for reasons of system security.
** Assessment assumes only 65% of installed hydro capacity (23 619 MW) due to reported reservoir levels.
*** Assumes only 5% of installed CHP (combined heat and power) plants can be ramped without significant adverse impacts on industrial heat processes.

Mexico

	Coal	*Nuclear*	*CCGT*	*OCGT*	*Steam turbine*	*Other peak*	*Hydro*	*CHP*
Capacity installed (MW)	4 700	1 364	17 190	2 770	12 865	216	11 383	964
Ramping capability (MW/min)	3.5	0	5.4	6	3.3	10	10	6
Start up and shut down (hours)	6	18	3	0.016	4	0.016	0	0.016
Min stable level (% of max)	50%	40%	50%	30%	60%	10%	10%	50%
Number of units	14	2	125	104	91	75	219	38
Flexibility (% capacity)								
15 mins	16%	0%	50%	100%	35%	100%	100%	100%
1 hr	50%	0%	50%	100%	40%	100%	100%	100%
6 hrs	50%	0%	100%	100%	100%	100%	100%	100%
36 hrs	100%	0%	100%	100%	100%	100%	100%	100%
Total flexibility (MW)								
15 mins	735	0	8 595	2 770	4 505	216	11 383	964
1 hr	2 350	0	8 595	2 770	5 146	216	11 383	964
6 hrs	2 350	0	17 190	2 770	12 865	216	11 383	964
36 hrs	4 700	0	17 190	2 770	12 865	216	11 383	964

Nordic

	Coal	*Nuclear*	*CCGT*	*OCGT*	*Steam turbine*	*Other peak*	*Hydro*	*CHP*
Capacity installed (MW)	8 370	11 584	5 000	1 800	4 225	6 435	48 775	19 964
Ramping capability (MW/min)	5	2	6	15	5	10	10	6
Start up and shut down (hours)	6	10	3	0	4	0	0	0
Min stable level (% of max)	50%	60%	50%	10%	60%	10%	10%	50%
Number of units	20	15	80	10	5	50	1000	10
Flexibility (% capacity)								
15 mins	18%	4%	50%	100%	9%	100%	100%	5%
1 hr	50%	16%	50%	100%	36%	100%	100%	18%
6 hrs	50%	40%	100%	100%	100%	100%	100%	100%
36 hrs	100%	100%	100%	100%	100%	100%	100%	100%
Total flexibility (MW)								
15 mins	1 500	450	2 500	1 800	375	6 435	48 775	900
1 hr	4 185	1 800	2 500	1 800	1 500	6 435	48 775	3 600
6 hrs	4 185	4 634	5 000	1 800	4 225	6 435	48 775	19 964
36 hrs	8 370	11 584	5 000	1 800	4 225	6 435	48 775	19 964

Denmark

All central, thermal power stations are extraction type units, as opposed to condensing or back pressure type. Condensing type units condense steam using cooling water, back pressure types use the district heating system, and extraction types use a combination of both.

Traditionally, back pressure units are labelled as "CHP", since all the embedded thermal generation has been designed based on heat demand, and connected to a district heating system. Almost all units operate a heat storage tank for efficiency reasons. Additionally, 100 - 200 MW of electrical boilers are currently being installed in the major district heating systems. This will reduce downwards ramping constraints relating to heat demand – in effect decoupling heat and electrical demand to some extent.

	Coal	*CCGT*	*OCGT*	*Steam turbine*	*Other peak*	*Hydro*	*CHP*
Capacity installed (MW)	4 357	2 611	200	200	56	10	2 012
Ramping capability (MW/min)	12	20	35	5	100	100	1
Start up and shut down (hours)	6	3	0	4	0	0	0
Min stable level (% of max)	50%	50%	10%	60%	10%	10%	50%
Number of units	10	10	4	4	3	2	105
Flexibility (% capacity)							
15 mins	41%	50%	100%	40%	100%	100%	78%
1 hr	50%	50%	100%	40%	100%	100%	100%
6 hrs	50%	100%	100%	100%	100%	100%	100%
36 hrs	100%	100%	100%	100%	100%	100%	100%
Total flexibility (MW)							
15 mins	1 800	1 306	200	80	56	10	1 575
1 hr	2 179	1 306	200	80	56	10	2 012
6 hrs	2 179	2 611	200	200	56	10	2 012
36 hrs	4 357	2 611	200	200	56	10	2 012

Japan

	Coal	*Nuclear*	*OCGT*	*Steam Turbine*	*Hydro*	*CHP*
Capacity installed (MW)	3 8074	47 935	660	102 721	18 403	522
Ramping capability (MW/min)	12	5	18	5	100	6
Start up and shut down (hours)	6	10	0	4	0	0
Min stable level (% of max)	50%	60%	10%	60%	10%	50%
Number of units	89	53	10	216	177	15
Flexibility (% capacity)						
15 mins	42%	8%	100%	16%	100%	100%
1 hr	50%	33%	100%	40%	100%	100%
6 hrs	50%	40%	100%	100%	100%	100%
36 hrs	100%	100%	100%	100%	100%	100%
Total flexibility (MW)						
15 mins	16 020	3 975	660	16 200	18 403	522
1 hr	19 037	15 900	660	41 088	18 403	522
6 hrs	19 037	19 174	660	102 721	18 403	522
36 hrs	38 074	47 935	660	102 721	18 403	522

US West 2017

	Coal	Nuclear	CCGT	OCGT	Steam turbine	Other peak	Hydro	CHP
Capacity installed (MW)	60 266	10 064	64 199	38 448	4 530	2 016	61 476	3 188
Ramping capability (MW/min)	15	5	20	35	5	100	100	1
Start up and shut down (hours)	6	10	3	0	4	0	0	0
Min stable level (% of max)	50%	30%	50%	10%	60%	10%	10%	50%
Number of units	120	25	155	400	40	3	500	200
Flexibility (% capacity)								
15 mins	45%	19%	50%	100%	40%	100%	100%	94%
1 hr	50%	70%	50%	100%	40%	100%	100%	100%
6hrs	50%	70%	100%	100%	100%	100%	100%	100%
36 hrs	100%	100%	100%	100%	100%	100%	100%	100%
Total flexibility (MW)								
15 mins	27 000	1 875	32 100	38 448	1 812	2 016	61 476	3 000
1 hr	30 133	7 045	32 100	38 448	1 812	2 016	61 476	3 188
6hrs	30 133	7 045	64 199	38 448	4 530	2 016	61 476	3 188
36 hrs	60 266	10 064	64 199	38 448	4 530	2 016	61 476	3 188

Canada Maritime: NBSO area

Note that different headings are used for plant type. Light and heavy fuel oil would have been included in the steam turbine category in the previous case studies.

	Coal	Nuclear	Light fuel oil	Heavy fuel oil	CCGT	Hydro	Biomass
MW installed	457	660	529	1 012	263	888	82
MW/min	0.5	0.5	5	10	5	100	5
Start up and shut down (hours)	8	36	1	0.016	3	0	1
Min stable as % of max	50%	100%	45%	25%	40%	10%	50%
Number of units	1	1	6	4	1	6	2
Flexibility (% capacity)							
15 mins	2%	0%	55%	59%	29%	100%	50%
1 hr	7%	0%	55%	100%	60%	100%	50%
6 hrs	39%	0%	100%	100%	100%	100%	100%
36 hrs	100%	0%	100%	100%	100%	100%	100%
Total flexibility (MW)							
15 mins	7.5	0	291	600	75	888	41
1 hr	30	0	291	1 012	158	888	41
6 hrs	180	0	529	1 012	263	888	82
36 hrs	457	0	529	1 012	263	888	82

Annex D • Defining the power area for analysis with the FAST tool

When considering the deployment of variable output plants, no two power systems are the same, although they all share certain fundamental attributes. For example, demand fluctuates in every system, and a portfolio of power plants will be needed to handle it; and all systems require a transmission network of some kind.

However, they vary tremendously in terms of the scale and location of resources available (both renewable and conventional), the structure of the transmission network, peak and minimum demand, structure of the power market, and the many other aspects assessed in the case studies in Part 2.

So, when comparing VRE deployment opportunities in two areas, it is important to make sure one is comparing like with like. For example, one area may be a complete power system, which must meet the balancing challenge mainly using resources within its borders (e.g. Iberian Peninsula).[1] In contrast, an area may be just part of a larger power system, on which it can rely for flexible resources to a large extent (e.g. Denmark, part of the Nordic system).

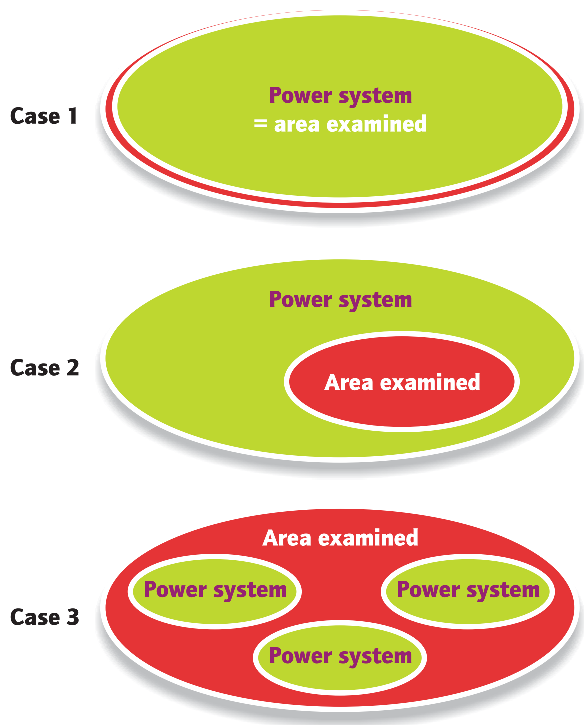
In other words, the fact that one area has achieved great — or little — success in deploying VRE does not mean that the opportunities in some other area will be the same. This point is particularly important in the context of setting national deployment targets.

Three different types of power areas are examined: those that constitute a single power system; those that are part of a larger system; and those that contain a number of power systems. In the first case, the area examined will rely to a very large extent on its own flexible resources for balancing VRE (Figure 1).

In the second, the area examined may to a large extent rely on flexible resources in the wider power system of which it is a part. VRE deployment and other activities elsewhere in this larger area will have important bearing on the availability of resources to the area examined.

In the third case, the flexible and variable resources contained in the separate power systems cannot simply be summed. The extent to which resources can be shared between the systems will depend on the strength of interconnections and the co-ordination of system operations and markets. It will also be influenced by the degree to which the overall area can rely on smoothing of variability through geographical and VRE technology portfolio spread.

Figure D.1 • Power areas and power systems



The FAST Method makes these and other distinguishing features of power areas very clear, enabling meaningful comparison of their potentials to balance variable renewables.

1. These may or may not also be political borders.

Annex E • The role of CCS in flexible power generation

Given the expected growth of both VREs and carbon capture and storage (CCS) over the next decades, it is likely that power generation with CCS will have to contribute to flexibility in future electricity systems.

While CCS has been applied on a commercial scale in the oil and gas industry, CCS from electricity generation is still an emerging technology that has not yet been demonstrated on a large scale. It is therefore not clear how the additional CO_2 capture, compression, transportation and storage could change the operating characteristics of fossil-fuel plant.

To date, techno-economic studies of fossil-fuel power plants with CCS have primarily focused on baseload operation at full load. Flexibility considerations received some initial attention, but quantitative data are limited to a few experimental small-scale pilot plants and preliminary engineering studies.

Flexibility of power generation with CCS will likely differ depending on the CO_2 capture route used. Options for providing flexibility in the overall plant's power output include:

- Part-load operation of the CO_2 capture and compression system.
- Bypassing and halting the capture unit.
- Managing energy-intensive processes by temporary storage of the fluids related to the CO_2 capture process.
- Full decoupling of the CCS and power generation processes by using temporary storage of decarbonised fuel.

The first three options would apply to all the emerging capture technologies, despite substantial differences in their process layout, the associated technical challenges and the potential to alter the overall power plants' power output. For example, option 3 above could mean temporary storage of the CO_2-rich solvent in post-combustion or pre-combustion capture. However, it could also include storage of oxygen and optionally nitrogen that is generated in the air separation process for oxyfuel boilers, or for pre-combustion capture if oxygen-blown synthesis gas generation is applied.

The fourth option of fully decoupling the CCS and power generation processes has been suggested for pre-combustion capture. In this case, CO_2 is captured during continuous generation of synthetic gas from coal or natural gas, and the remaining hydrogen or low-carbon syngas is stored. While the capture process would not be exposed to intermittent operation, the stored hydrogen could be used for flexible power generation, or to switch to co-production of chemical by-products at times when the grid does not need additional power.

These options are expected to affect key power plant parameters such as the net power generation efficiency, and capital, operating and maintenance costs. Initial assessments suggest that longer start-up and shut-down times should be expected from adding CO_2 capture to power plants, due to the large additional process units such as cryogenic air separation.

Capture processes that allow temporary bypassing of the capture and/or compression processes should be technically feasible. This might even be a general requirement in terms of reliability, availability, maintenance and everyday operational considerations. It would also allow for changes in overall net plant power output if required, provided that venting of CO_2 emissions to the atmosphere were accepted by the regulator during such periods. While this option could require only limited investment, there might be additional expenses associated with venting CO_2 to the atmosphere.

The flexible operation of CCS has received less attention in the literature than the capture technology itself. It is considered less critical, given the experience of existing large-scale CCS projects in the oil and gas industry and analogous examples in the management of other fluids. Handling of varying CO_2 flows appears to be feasible if it is incorporated in the design, despite potentially higher costs. This could be done for example by over-dimensioning pipes and equipment, using multi-train arrangements *e.g.* for CO_2 compression chains, or adding gas conditioning units.

Outlook

Very few studies so far have attempted to quantify technical aspects or cost effectiveness of flexible operation of CCS in power generation (Davison, 2010; Chalmers, 2010). In particular assessing cost effectiveness is highly complex: it would require in-depth understanding of future power markets, their load structures and patterns and sources of flexibility, as well as potential revenue streams associated with flexible power generation.

Further analysis of flexible operation of power generation with CCS should address the following aspects:

- Operating characteristics and costs related to the different options for flexible operation of CO_2 capture and compression. This should include configurations with temporary fluid storage, using detailed engineering studies and learning from large-scale demonstration projects.
- Verification of how to transport and store CO_2 in the context of variable operation.
- Benchmarking of the operating characteristics and costs for CCS plants with alternative options for providing flexibility in low-carbon power systems, including energy storage technologies.
- Analysis of how CCS deployment will be affected by related market mechanisms, incentive structures and regulatory frameworks.
- Evaluation of the cost effectiveness of flexible power generation with and without CCS in future power markets.
- Quantification of revenue streams by regional modelling and scenario analysis of future power systems. This would compare different levels of VRE and fossil-fuelled power generation with CCS and varying load patterns, for different regions in the world.
- Analysis of the implications for energy policies, regulatory frameworks and incentive structures.

Annex F • The role of CHP in flexible power generation

When an economic use is found for the heat from power generation, the plant is referred to as a cogeneration or combined heat and power (CHP) plant.

A challenge in using CHP in flexible power generation is that if a CHP plant's output is varied in response to the requirement for flexibility, this would, all else remaining unchanged, result in a fluctuating heat supply which would be unacceptable to heat end-users.

However, such fluctuations can be smoothed out by the use of heat storage techniques. Storing heat is relatively simple, and coupling CHP plants with heat accumulators can be economically viable. Excess heat energy from CHP plants can then be stored when VRE output is low, and used when VRE output is high, to maintain a smooth heat supply.

To investigate this, the EU-funded project, DESIRE[1] focused on CHP systems whose operation is coupled with electricity supply – itself determined by day-to-day electricity prices (European Union, 2008). Electricity sales on one-hour and day-ahead spot markets and a 15-minute regulating market were modelled. Trading at such short intervals (between bidding closure and actual delivery), illustrated that CHP electricity generation can react quickly, to help balance variability in the net load.

The project concluded that there is good potential for complementary operation of CHP and wind plant. For instance, it showed that when wind turbines are producing a large amount of electricity, cogeneration plants reduce their production of electricity because spot prices are low. Besides the feasibility of using cogeneration in the balancing of net load, the project illustrated the role of thermal stores to add flexibility.

Heat accumulators at CHP plants are already in use in a number of places, albeit not necessarily with the intention of facilitating the integration of VRE. Some CHP plants are designed to operate at times of peak electricity demand, and thus high electricity price, to maximise the revenue from the electricity generated. The operational CHP-DH (district heating) systems at Woking and Barkantine in the UK are examples of such a set-up (Kelly and Pollitt, 2009). The Hvide Sande[2] cogeneration plant in Denmark is another example of production determined by electricity price, and therefore variable.

The fact that CHP bridges two different energy markets, electricity and heat, may require further innovative solutions. For example, more heat generation can mean less electricity generation, particularly when the heat supplied is at high temperature, as is needed for many industrial processes. More high temperature heat produced equates with less electricity generated and vice versa. Some industrial CHP plant developers see this as a trade-off; there is in some markets less incentive to produce heat since electricity is a more valuable form of energy.

CHP in other markets

In other markets, CHP operators who wish to generate more electricity to improve plant economics may be limited by utilities in the amount of electricity they are allowed to produce. However, the fact that heat and electricity generation are coupled means there is a possibility of adjusting electricity production from CHP to match fluctuations in the net load, by producing more or less high temperature heat, *i.e.* adjusting the power to heat ratio.

The overall supply of high temperature heat could be kept stable by using heat storage and/or auxiliary boilers (already a part of most industrial CHP systems). Another example relates to so-called combined

1. Dissemination strategy on electricity balancing for large scale integration of renewable energy.
2. The Hvide Sande CHP plant has the following characteristics: two natural gas fired engines with electricity production capacity of 3.77 MW and heat production capacity of 4.9 MW. Further, it has two boilers with heat production capacities of 4.0 MW (natural gas) and 10.0 MW (natural gas/oil) respectively. Heat is stored in a 2000 m^3 tank with a holding capacity of 130 MWh heat.

water and power plants. IEA analysis suggests that by 2030, desalination capacity in the Middle East and North Africa will grow from 21 million cubic metres (mcm) of water per day in 2007 to 110 mcm per day (IEA, 2009).

Currently, the main desalination technology — distillation — is heavily (heat) energy-intensive. Using heat from power generation can help lower primary energy demand relative to separate power and heat production. Some regions with needs for desalination also have plans for increased electricity generation from solar sources. Cogeneration could help compensate for the variability in power generation from solar sources by producing desalinated water when fossil-fuelled plants are operated during times of low solar output. The water is easy to store and can be used when fossil-fuelled plants are turned down during high solar production.

Such scenarios are speculative — no technical or economic assessment has been made. However, they illustrate that combining electricity generation with heat generation can increase the flexibility in the system. When the energy system under consideration is widened to include heat, power and even water demand, there is more chance of finding situations where a surplus in one part of the system can be balanced by a deficit elsewhere. This reasoning is similar to that behind interconnecting national power grids – enabling the sharing of flexible resources.

Annex G • Treatment of fundamental area attributes in the case studies

Size of area (MW peak demand)

Area size is one of the most important attributes establishing commonality among areas; generally power areas of the same size will face many of the same challenges when integrating VRE. The case studies use four categories, in terms of peak demand in megawatts.[1]

- **Small** (less than 1 GW). This category includes small countries, cities and regions within a country. They are likely to be part of a larger power system from which they may have access to additional flexibility. The category also includes small islands. Small areas will not have widely dispersed VRE resources and the largest generation units may represent a significant proportion of total demand (so there will be few of them and relatively little opportunity to vary the operation of individual units).

- **Medium** (1—20 GW). This category includes, for example, smaller EU countries, US states, many developing world countries and areas within larger countries — within one power system and (probably) one market. At this size internal transmission may begin to seriously limit access to flexible resources.

- **Large** (20—150 GW). This category includes larger countries and groups of countries or states, such as the Nordic system. Such areas may include multiple markets (not in the case of Nordic) and/or system operators. The interaction among these markets and system operators will be very important.

- **Very large/continental** (more than 150 GW). This includes very large countries or a number of countries operating as one power system, such as Continental Europe, Japan, and the Eastern and Western Interconnections in the United States. In general, a power area with a very large installed capacity will cover a wide geographical area and contain a large number of generators. There is likely to be a significant flexible resource in such systems as larger areas are likely to have a wider portfolio of plant types, but of course the existing flexibility requirement will also be large.

Potential for interconnection to adjacent areas

This attribute expresses the maximum potential for grid connection to neighbouring power areas, again in megawatts. Only the potential for connection to other areas is considered, not actual connections or how those connections are used.

A high potential means that an area has the opportunity to make use of flexible resources in connected areas equivalent to a large proportion of its demand. The extent to which a very large area can rely on flexibility resources in adjacent areas is likely to be small while a small area may be able to rely heavily on importing flexibility.

For example, a small area with a peak demand of just 1 GW may have an equivalent capacity of interconnections, in which case its peak demand could be covered entirely by imports. Moreover, if connected areas are large, the required amount of flexible resource is more likely to be available.

In contrast, a 100 GW area will be unlikely to find enough 'spare' flexibility in adjacent connected areas to cover the entirety of its flexibility needs even if interconnections on the 100 GW scale were a realistic proposition.

1 Other measures such as total energy over the year or MW installed could also be used, but peak demand is a measure that is well known and can be easily related to.

Any two areas could theoretically be connected, but only connections that might be economical in the foreseeable future are considered, *i.e.* only those where obvious merit exists. For example, Spain could connect (more) to France or Morocco, but is unlikely to connect to Italy.

The three categories considered in the case studies are as follows:

- **Low potential**. The potential is less than the largest single generation unit in the area, or less than 10% of peak demand. This includes both geographically isolated areas such as islands and very large continental areas.

- **Medium potential**. The potential is between 10% and 100% of peak demand. The flexible resource required for large shares of VRE would nonetheless probably exceed what can be sourced solely from outside the area (assuming adjacent areas have the resource to spare). It will be possible to connect to multiple areas, rather than just one area (for greater supply security).

- **High potential**. Here potential is greater than peak demand. Such areas will tend to be small and located next to a number of relatively large neighbours containing large flexible resources.

Actual interconnection to adjacent areas

While an area may have much interconnection potential, actual capacity may yet be small, as it has not been historically necessary. Transmission has long lead times: planning and building new transmission corridors is fraught with delay. Actual connection is measured not relative to potential, but to peak demand.

Number of power markets

Power markets may be self-contained power systems, made up of several systems, or part of a larger system. This relationship is important as it will govern to some extent the sharing of flexible resources within the system. The case studies consider three categories for this attribute:

- **Part of a larger power market**. The flexible resources contained in the rest of the power system will be readily available to integrate VRE, although the same resources may also be needed in other parts of the system or adjacent systems. For example, if shares of wind energy in neighbouring Germany (8%) grow as great as in Denmark (>20%), the latter will be able to rely less exclusively on Nordic hydropower for balancing.

- **A distinct power market**. Such cases may be distinct power systems. They must rely on their own flexibility resources to balance variability (one of which will be connection to adjacent areas).

- **Contains two or more power markets**. Sharing of flexible resources through adequate internal transmission strength will be central to optimising the use of shared flexible resources.

Geographical spread of resource

The smoothing from geographical spread arises mainly through the dispersion of VRE power plants — the wider the dispersion, the smoother their aggregated output. Additionally, increasing the number of sites within even a small area will contribute to the spatial smoothing effect. A high score for geographical spread assumes that the VRE resource is widely distributed around the area.

This attribute is addressed in broad terms in the case studies under three categories:

- **Concentrated**. The whole VRE resource is affected by the same weather pattern with very little smoothing between sites due to their proximity to each other. Also included are large areas where most VRE plants are nevertheless deployed close together, perhaps for reasons of resource availability, or competing land uses.

- **Dispersed**. This includes areas larger than the previous category, where the whole is still affected by one weather system, but the latter's impact on output will be delayed perhaps by several hours from boundary to boundary, with the result that output is less correlated. An example is the Midwest Independent System Operator footprint in the United States.

- **Widely dispersed.** Multiple weather systems affect VRE output, so aggregated output is smoothed to a greater extent, requiring less flexibility to integrate the VRE. This category will include continental regions or smaller areas with two or more climate patterns, *e.g.* the major Interconnections in North America.

A simple multiplier based on past meteorological data could be developed to enable a more refined assessment.

Existing generation portfolio

Not all plants that burn the same fuel are equally flexible. For example, some hydropower plants or combined-cycle gas units may be operated inflexibly, while some coal-fired power plants are as fast as a typical combined cycle gas plant.

The three categories used are:

- **Flexible**. Areas with a large share (relative-to-peak demand) of fast response units able to respond within one hour. These include (unconstrained) reservoir hydro units. Certain gas or oil powered plant (*e.g.* open cycle gas turbines) are highly flexible but are unlikely to make up a large share of the portfolio except in very small systems.

- **Intermediate**. These are areas where gas units, particularly combined cycle gas turbines, dominate the portfolio. These are relatively flexible and can be ramped to a significant degree within six hours. Intermediate areas may also use a combination of very flexible and very inflexible generators, for example nuclear combined with hydropower.

- **Inflexible**. These are areas with a predominance of nuclear and/or coal units which are relatively inflexible. While state-of-the-art plants and configurations may ramp more quickly, they are likely to remain less flexible than the other technologies mentioned above and will incur considerable costs if cycled to a large degree. CHP electricity output coupled to heat demand (*i.e.* bound to generate when heat is required) is included here. Likewise, hydro with a strict operating schedule for other reasons than power delivery would be considered inflexible.

Internal grid strength

Transmission is the fundamental underpinning of all the flexibility issues discussed in this book, so the more quantitative the measurement of internal grid strength, the better.

In the FAST Method, this attribute may include interconnections among power systems, if there are a number of these within the area assessed, as is the case in the British Isles area (Great Britain and Ireland).

The case studies in this book make a qualitative assessment of internal grid strength jointly on transmission and distribution levels. In a more refined assessment, transmission and distribution, as distinguished by voltage and active/passive management, could be treated separately. The use of such metrics as actual or net transfer capability (NTC) would be valuable in a refined assessment.

A similar method could be employed as in the assessment of interconnection to adjacent power areas: the capacity (expressed as a percentage of peak demand) available to transmit electricity over a specific area. Measurement would be facilitated by smart grids equipped with sensors able to report flows over specific lines and areas at specific times.

The two main categories considered in this analysis are:

- **Strong**. In such areas, distribution and transmission networks are well-suited to integrating VRE. This will often mean an existing, extensive and meshed network near the VRE source, that the VRE is deployed close to demand centres, or that there has been appropriate recent investment in new technologies. The capacity factor of lines would be less than around 50%, leaving plenty of spare capacity.

- **Weak**. In these areas, there will be little existing transmission or distribution network in the vicinity of VRE output. The VRE may be far from demand centres, with little historical need for transmission near the best resource. Existing network infrastructure may have suffered from neglect; limited investment may mean high capacity factors of existing lines. Integration of VRE will be difficult without upgrading the infrastructure. Such areas may contain several loosely connected grid areas.

The fundamental area attributes in the case studies are summarised in Table 1.

Table G1 • Summary of fundamental attributes

	Attribute	Quantified or scored (Q/S) in the case studies	Fixed or modifiable*	Key aspects
F1	Size of area	Q: peak demand (MW)	Fixed	Large areas will have large flexible resource, greater VRE output smoothing
F2	Potential for connection to adjacent areas	Q: low (<10% peak demand); intermediate (>10% < 100%); high (>100%)	Fixed	Connection that is economically feasible
F3	Actual connection to adjacent areas	Q: low (<10% peak demand); intermediate (10%-100%); high (>100%)	Fixed	MW connection currently in use (does not consider how it is used)
F4	Number of distinct power markets in the area	S: area is part of a power market, is a distinct market, or contains multiple markets	Modifiable	Distinct power markets are likely to be less well connected
F5	Geographical spread of resource	S: concentrated; dispersed; widely dispersed	Fixed	Larger areas will see greater smoothing of aggregated VRE output
F6	Existing generation portfolio	S: flexible (large share flexible plant); intermediate; inflexible (low share)	Fixed	Flexible dispatchable plant is the key flexible resource in most cases assessed
F7	Internal grid strength	S: strong, intermediate, weak	Fixed	Likelihood of congestion

* While attributes F3, F6 and F7 are in fact modifiable with planning and effort, for the purpose of the snapshot analysis afforded by the FAST Method, they are considered to be fixed.

Annex H • Acronyms and abbreviations

AC	alternating current
AR	available flexible resource
AEP	American Electric Power
CAES	compressed air energy storage
CAISO	California Independent System Operator
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CERC	Central Electricity Regulatory Commission, India
CHP	combined heat and power
CORDIS	Community Research and Development Information Service
CPUC	California Public Utilities Commission
CSP	concentrating solar power
DC	direct current
DCENR	Department of Communications, Energy and Natural Resources, Ireland
DENA	Deutschen Energie-Agentur, Germany
DESIRE	Dissemination strategy on electricity balancing for large scale integration of renewable energy
DFCC	Development Finance Corporation of Ceylon
DSO	distribution system operator
DTI	Department of Enterprise, Trade and Investment, United Kingdom
EC	European Commission
ECI	Environmental Change Institute
EEG	Energy Economics Group
EFR	existing flexibility requirement
ELCC	effective load-carrying capacity
ERC	Energy Research Centre, United Kingdom
EV	electric vehicle
EWEA	European Wind Energy Association
EWIS	European Wind Integration Study
EWITS	European Wind Integration and Transmission Study
FAST	Flexibility Assessment method
FIX	Flexibility Index

GHG	greenhouse gas
GIVAR	Grid Integration of Variable Renewables project
IEA	International Energy Agency
IEA-OES	IEA Implementing Agreement on Ocean Energy Systems
IEA Wind	IEA Implementing Agreement for Co-operation in the Research, Development, and Deployment of Wind Energy Systems
ISO	independent system operator
IVGTF	Integration of Variable Generation Task Force
LBNL	Lawrence Berkeley National Laboratory
LOLP	loss-of-load probability
MUREIL	Melbourne University Renewable Energy Integration Laboratory
NBSO	New Brunswick System Operator
NERC	North American Electric Reliability Council
NREL	National Renewable Energy Laboratory
NTC	net transfer capability
NTR	net technical flexible resource
OCGT	open-cycle gas turbine
OFGEM	Office of the Gas and Electricity Markets
PV	photovoltaics
PVP	Present VRE Penetration Potential
REE	Red Eléctrica de España
RMSE	root mean square error
RTE	Réseau de Transport d'Eléctricité
SEM	single electricity market
TR	technical flexible resource
TSO	transmission system operator
UC	unit commitment
VRE	variable renewable energy

Units of measure

GW	gigawatt
hr	hour
km	kilometre
kW	kilowatt
mcm	million cubic metres
min	minute
MW	megawatt
MWh	megawatt hour
TWh	terawatt hour

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