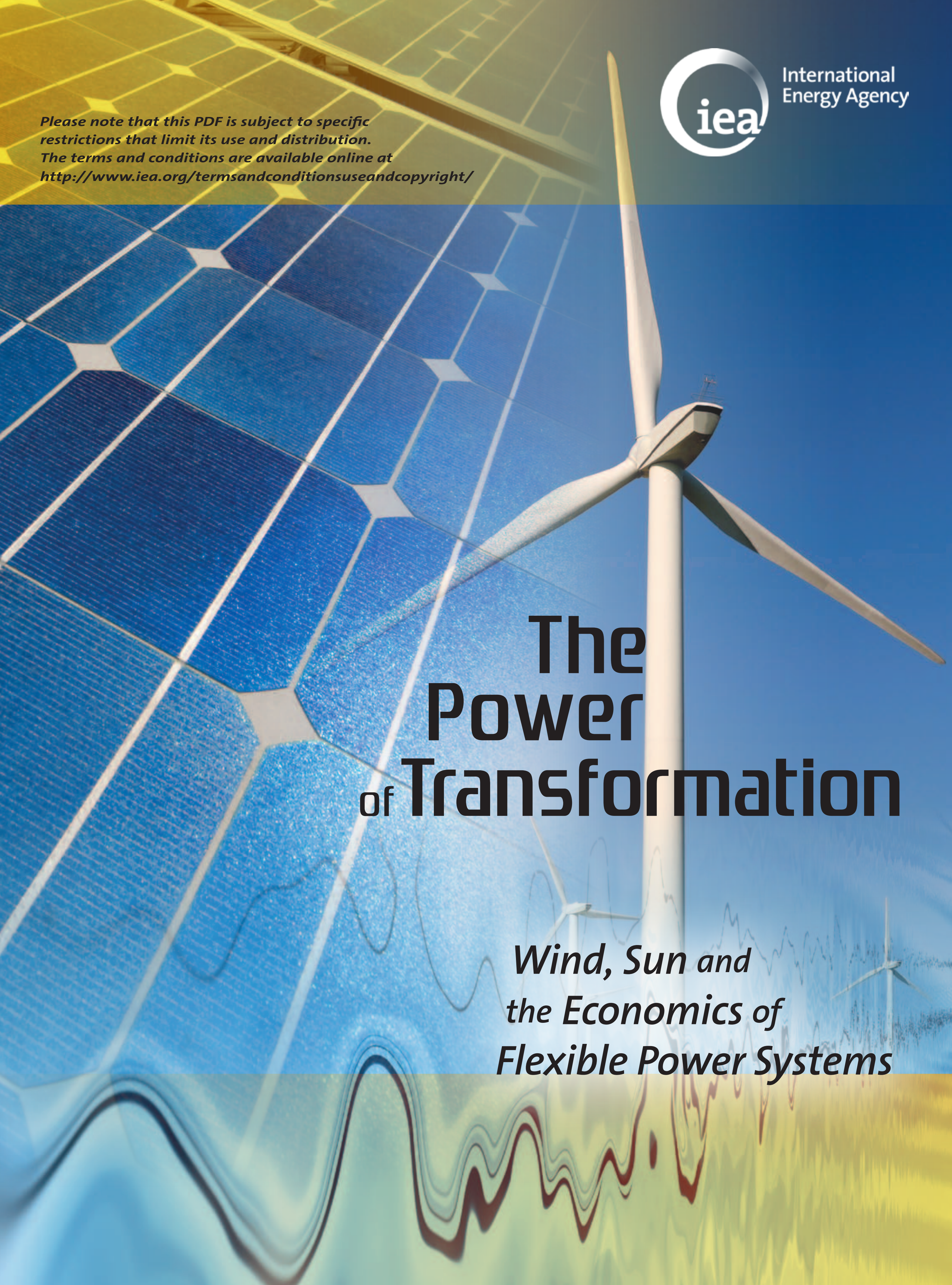

International Energy Agency

The Power of Transformation

Wind, Sun and the Economics of Flexible Power Systems

The Power of Transformation

Wind, Sun and the Economics of Flexible Power Systems

Wind power and solar photovoltaics (PV) are crucial to meeting future energy needs while decarbonising the power sector. Deployment of both technologies has expanded rapidly in recent years, one of the few bright spots in an otherwise bleak picture of clean energy progress. However, the inherent variability of wind power and solar PV raises unique and pressing questions. Can power systems remain reliable and cost-effective while supporting high shares of variable renewable energy (VRE)? And if so, how?

Based on a thorough review of the integration challenge, this publication

- gauges the economic significance of VRE integration impacts
- highlights the need for a system-wide approach to integrating high shares of VRE
- recommends how to achieve a cost-effective transformation of the power system.

This book summarises the results of the third phase of the Grid Integration of VRE (GIVAR) project, undertaken by the IEA over the past two years. It is rooted in a set of seven case studies, comprising 15 countries on four continents. It deepens the technical analysis of previous IEA work and lays out an analytical framework for understanding the economics of VRE integration impacts. Based on detailed modelling, the impact of high shares of VRE on total system costs is analysed. In addition, the four flexible resources which are available to facilitate VRE integration – generation, grid infrastructure, storage and demand side integration – are assessed in terms of their technical performance and cost-effectiveness.

80€ (61 2014 02 1E1)
ISBN: 978 92 64 20803 2

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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.
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Foreword

Renewable energy, especially wind and solar, is playing a growing and increasingly important role in efforts to diversify and de-carbonise energy supplies. Thus, all International Energy Agency (IEA) scenarios share a common feature — generation from wind and solar photovoltaics (PV) continues to increase significantly for decades to come. However, integrating variable renewable energy (VRE) into the power grid remains one of the most pressing challenges facing policy makers and industry. Can VRE technologies serve as central pillars of a secure and low-carbon energy system, and if so, at what cost?

The Power of Transformation addresses these questions in a comprehensive manner, affirming the potentially central role of VRE while explaining how cost can vary with circumstance. Out of the wide spectrum of findings in this groundbreaking study, let me highlight just two aspects.

First, this analysis calls for a change of perspective. The classic view sees VRE integration as an addition to what is already there, assuming that the rest of the system does not adapt. This "traditional" view risks missing the point. The challenges and opportunities of VRE integration lie not only with VRE technologies themselves, but also with other system components. Consequently, a system-wide approach to integration is required. In short, integration of VRE is not simply about adding VRE to "business as usual", but transforming the system as a whole.

This book highlights what options exist to achieve such a transformation. Using a system-wide approach, a power system featuring a share of 45% of VRE may come at little additional long-term cost over a system with no variable renewables at all.

Second, such a transition could be difficult, not least because there will be winners and losers. However, this will depend strongly on the context. In "dynamic" power systems with growing electricity demand (such as in China, India and Brazil), wind power and solar PV can be cost-effective solutions to meet incremental demand. That presents great opportunity. If investments are made well, a flexible system can be built from the very start, in parallel with the deployment of variable renewables. The situation is fundamentally different in "stable" power systems. These are characterised by stagnate electricity demand, as is the case in many European countries today. In many such places, the cost of rapid VRE deployment has risen to the top of the political agenda.

In a stable system, the market does not expand. The "pie" does not grow, so additional renewables take a part of the pie from incumbents with established capacity. This outcome is based on fundamental economics; market effects are therefore not only a consequence of variability. In these markets, the cost of transforming the system is not only linked to paying for new assets. As this publication shows, those costs can be managed. But, the greater challenge may be managing the costs associated with scaling down the old system. This raises tough policy questions. What strategies do incumbent producers need to adapt to the transformation? How will governments handle the distributional effects when infrastructure needs to be retired before the end of its lifetime? Who pays for stranded assets?

Meeting these challenges will only be possible if policy makers and the industry make a collaborative effort. But we must not lose sight of climate imperatives. We cannot afford to delay further action if the long-term target of limiting the global average temperature increase to 2 degrees Celsius is to be achieved at reasonable cost.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven

Executive Director
International Energy Agency

Acknowledgements

The Power of Transformation is the main result of the third phase of the IEA Grid Integration of Variable Renewables (GIVAR III) project. The project was managed by Simon Müller of the International Energy Agency's Renewable Energy Division, who is also the principal author of this publication. GIVAR III has been a team effort: Fernando de Sisternes developed and implemented the IMRES power system modelling. Edoardo Patriarca and Alvaro Portellano co-ordinated the flexible resource analysis and economic modelling. Anna Göritz, Jakob Daniel Møller and Jakob Peter conducted the FAST2 analysis and contributed to the flexible resource analysis. Hannele Holttinen provided advice to the project on power system modelling and power system operation. Pöyry Management Consulting (UK) Ltd. contributed modelling of the North West Europe case study. New Resource Partners conducted the review of wholesale market design.

The IEA is very grateful for the guidance and support provided by the members of the project advisory group, in particular Enel Green Power, Gestore dei Servizi Energetici, Iberdrola, the Norwegian Ministry of Petroleum and Energy, Red Eléctrica de España, the Regulatory Assistance Project, the Sustainable Energy Authority of Ireland, TOTAL S.A., the United States Department of State, and Vattenfall and the financial contribution from the Ministry of Economy, Trade and Industry of Japan.

The project would not have been possible without the contribution from numerous interview partners as part of case-study visits. We are very grateful for the support in particular from the Brazilian Ministry of Mines and Energy; the Ministry of Economy, Trade and Industry of Japan and the Norwegian Ministry of Petroleum and Energy.

We would particularly like to acknowledge the continued fruitful collaboration with Task 25 of the Wind Energy Systems Implementing Agreement *"Design and Operation of Power Systems with Large Amounts of Wind Power"*, and among its members especially Hannele Holttinen, Michael Milligan, Mark O'Malley and J. Charles Smith.

For insightful discussions, support and peer review the author would also like to thank in particular Lion Hirth and Katrin Schaber as well as Aidan Tuhoy, Eamonn Lannoye, Hugo Chandler, Vera Silva, Mike Hogan, Yann Laot, Falko Ueckert, Daniel Fürstenwerth, Manoël Rekinger, Frans van Hulle, Jonathan O'Sullivan, John McCann, Miguel de la Torre and Jorge Hidalgo López as well as the colleagues from NREL working on Market and Policy Impact Analysis, Energy Forecasting and Modeling, and the Transmission and Grid Integration Group.

The author would further like to thank Paolo Frankl, Head of the Renewable Energy Division, for his trust and guidance; Keisuke Sadamori, Director of Energy Markets and Security, for his support and advice; the Renewable Energy Division and in particular Adam Brown and Cedric Philibert for their open ears and counsel; the colleagues from the Gas Coal and Power Market Division, in particular Manual Baritaud, Laszlo Varro and Dennis Volk for their constructive input; David Elzinga for his review; Kieran McNamara and Jörg Husar for their support; Justin French-Brooks for his skillful editing; and finally Rebecca Gaghen, Michelle Adonis, Astrid Dumond, Cheryl Haines, Angela Gosmann, Bertrand Sadin and Muriel Custodio for turning all this into a book.

Any possible errors and omissions remain that of the IEA. Queries, criticism and amendments are welcome and should be addressed to:

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Executive summary

Wind power and solar photovoltaic (PV) are expected to make a substantial contribution to a more secure and sustainable energy system. However, electricity generation from both technologies is constrained by the varying availability of wind and sunshine. This can make it challenging to maintain the necessary balance of electricity supply and consumption at all times. Consequently, the cost-effective integration of variable renewable energy (VRE) has become a pressing challenge for the energy sector.

Based on a thorough assessment of flexibility options currently available for VRE integration, a major finding of this publication is that large shares of VRE (up to 45% in annual generation) can be integrated without significantly increasing power system costs in the long run. However, cost-effective integration calls for a system-wide transformation. Moreover, each country may need to deal with different circumstances in achieving such a transformation.

This study

This publication deepens the technical analysis of previous International Energy Agency (IEA) work while also analysing economic aspects of VRE integration. It is based on a set of seven case studies comprising 15 countries.[1] A revised version of the IEA Flexibility Assessment Tool (FAST2) is used for a technical analysis of system flexibility in case study regions. Economic modelling of system operation on an hourly basis is used to study the effect of high shares of VRE on total system costs (see Box ES.1). In addition, the four flexible resources that enable VRE integration – flexible power plants, grid infrastructure, electricity storage and demand-side integration (DSI) – are assessed for their technical and economic performance.

The project has been carried out in close co-operation with work in the framework of the IEA Electricity Security Action Plan (ESAP).

Main findings

The interaction of VRE and other system components determine opportunities and challenges of integration

The difficulty (or ease) of increasing the share of variable generation in a power system depends on two main factors:

- first, the properties of wind and solar PV generation, in particular the constraints that weather and daylight patterns have on where and when they can generate
- second, the flexibility of the power system into which VRE is integrated and the characteristics of the system's electricity demand.

For example, where good wind and solar resources are far away from demand centres, it can be costly to connect them to the grid. On the other hand, where sunny periods coincide with high electricity demand, solar PV generation can be integrated more easily.

The interaction between both factors differs from system to system. As a result, the economic impacts of VRE also depend on the specific context. However, on both sides only a limited number of properties determine the positive and negative aspects of integration. This allows identifying best practice principles that apply in a wider range of circumstances.

1. Brazil, Electric Reliability Council of Texas (Texas, United States), Iberia (Portugal and Spain), India, Italy, Japan East (Hokkaido, Tohoku and Tokyo) and North West Europe (Denmark, Finland, France, Germany, Ireland, Norway, Sweden and the United Kingdom).

System integration is not a relevant barrier at low shares of VRE

It is not a big technical challenge to operate a power system at low shares of VRE. Depending on the system, a low share means 5% to 10% of annual generation. Experience in countries that have reached or exceeded such shares (including Denmark, Ireland, Germany, Portugal, Spain, Sweden and the United Kingdom) suggests that system integration is not a significant challenge at these shares – but only if some basic principles are adhered to:

- to avoid uncontrolled local concentrations of VRE power plants ("hot spots")
- ensure that VRE power plants can contribute to stabilising the grid when needed
- forecast the production from VRE and use forecasts when planning the operation of other power plants and electricity flows on the grid.

The properties of VRE that are relevant for system integration are not new to power systems. This is the main reason why integrating low shares of VRE is usually not a challenge. Electricity demand itself is variable and all power plants may experience unexpected outages. When VRE contributes only a few percent to electricity generation, its variability and uncertainty is much smaller than that coming from electricity demand and other power plants. The influence of VRE usually becomes noticeable beyond annual shares of 2% to 3%. In order to reach higher shares, those resources that have been used to deal with variability and uncertainty from other sources can also be used to integrate VRE.

An assessment of case study regions with the revised IEA Flexibility Assessment Tool (FAST2) showed that annual VRE shares of 25% to 40% can be achieved from a technical perspective, assuming current levels of system flexibility. The analysis assumes that sufficient grid capacity is available inside the power system. According to the same analysis, this share can be increased further (reaching levels above 50% in very flexible systems), if a small amount of VRE curtailment is accepted to limit extreme variability events. However, mobilising system flexibility to its technical maximum can be considerably more expensive than least-cost system operation.

Integrating large shares of VRE cost-effectively calls for a system-wide transformation

The classic view sees VRE integration as adding wind and PV generation without considering all available options for system adaptation. This 'traditional' view may miss the point. Integration effects are determined by both VRE and other system components. Consequently, they can be reduced by interventions on either side. In short, integration of VRE is not simply about adding VRE to "business as usual," but transforming the system as a whole.

The cost of reaching high shares of VRE differs from system to system. Most importantly, costs depend on how well different components of the system fit together. Minimising total system costs at high shares of VRE requires a strategic approach to adapting and transforming the energy system as a whole.

Supposing that high shares of VRE are added overnight significantly increases total system costs. Using a test system, an extreme and purely hypothetical case was investigated. A share of 45% VRE in annual generation was added to the system overnight and only the operation of the remaining system was allowed to change (Legacy case, see Box ES.1). In this case, total system costs increase by as much as USD 33 per megawatt hour (/MWh) or about 40% (rising from USD 86/MWh to USD 119/MWh, Figure ES.1). This increase is the result of three principal drivers:

- additional cost of VRE deployment itself (which in this modelling exercise is assumed to remain similar to today's levels)
- additional grid costs associated with connecting distant VRE generation and grid reinforcements
- limited avoided costs in the residual system, because VRE can only bring operational savings in the form of fuel and emission cost reductions in the Legacy scenario.

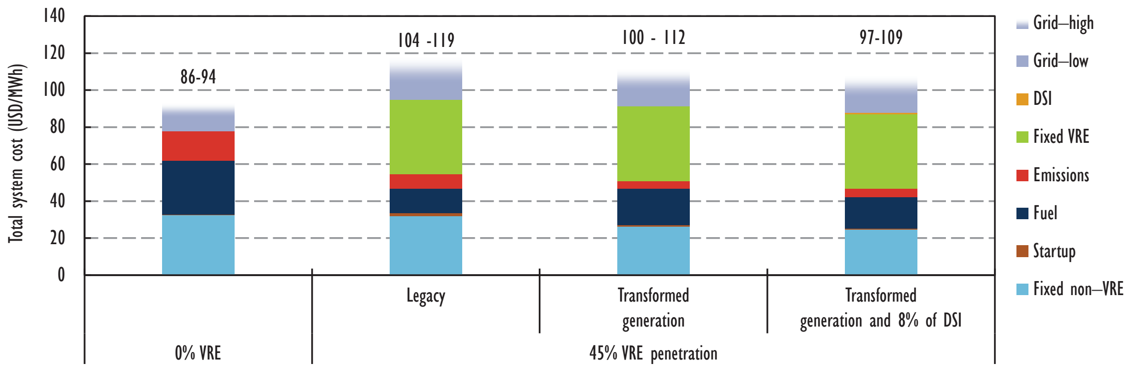
The additional costs of more flexible operation of existing power plants (more frequent start/stop, more dynamic changes in output) are not an important element in the increased costs.

A co-ordinated transformation of the entire system reduces additional costs. A different scenario of the test system considers a more transformative approach. The installed power plant mix is re-optimised in the presence of 45% VRE and additional flexibility options are deployed (Transformed case). Compared to the Legacy case, the power plant mix shows a structural shift:

- a strong decrease in the number of power plants that are designed to operate around the clock and that cannot change their output dynamically (referred to as baseload technologies)
- an increase in the number of flexible power plants that are designed for part-time operation (referred to as mid-merit and peaking generation).

In addition, a better strategy for managing grid infrastructure is assumed. In this case, total system costs increase only by USD 11/MWh. This is two-thirds less than in the Legacy scenario. At a share of 30% of VRE in power generation, the increase in total system costs stands at USD 6/MWh.

Figure ES.1 • *Total system cost of a test system at different degrees of system transformation*



Note: DSI = demand side integration

Key point • *System transformation reduces total system cost at high shares of VRE.*

In the long term, high shares of VRE may come at zero additional costs. In the modelling analysis, all cost assumptions are kept constant. However, future VRE generation costs are likely to be lower and the cost of CO_2 emissions higher.[2] This means that high shares of VRE may be achieved without increased total system costs compared to a system with 0% VRE. Costs may even be lower than in the absence of VRE deployment. However, achieving this requires a successful transformation of the system as a whole.

System transformation has three main pillars

Successful system transformation requires tackling three different areas:

- first, system-friendly VRE deployment
- second, improved system and market operation
- third, investment in additional flexible resources.

2. A cost decrease in the VRE mix between 30% and 40% would put total system costs in the Transformed case (including DSI) on a par with total system costs in the absence of VRE. In addition, according to IEA projections, CO_2 emission prices are likely to exceed the assumed level of USD 30 per tonne (/t). In the 450 Scenario (implying a 50% chance of meeting the 2°C target) of the *World Energy Outlook 2013*, CO_2 prices reach USD 70/t to USD 97/t in 2030 and USD 100 to USD 125/t in 2035 (year 2012 purchasing power parity).

1) Letting wind and sun play their part: system-friendly VRE deployment

The first pillar of system transformation is system friendly VRE deployment. The main intent behind system-friendly VRE deployment is minimising overall system costs, in contrast to minimising VRE generation costs alone.

VRE power plants can contribute to their own system integration. But they need to be asked and allowed to do so. The common view of integration sees wind power and solar PV generators as the "problem". The solution has to come from somewhere else. However, wind and solar PV power plants can facilitate their own system integration; they will need to do so to achieve system transformation cost-effectively. Five elements are relevant in this regard:

- **Timing.** VRE additions need to be aligned with the long-term development of the system as a whole. Experience shows that deployment of VRE capacity can outstrip development of suitable infrastructure, for example where wind power plants are completed before full grid connection is available. This calls for adopting an integrated approach to infrastructure planning.
- **Location and technology mix**. From a system perspective, cost-effectiveness is not just about choosing the cheapest technology or building VRE power plants where resources are best. In contrast, optimising the mix of VRE (and dispatchable renewable generation) can bring valuable synergies – for example, where sunny and windy periods are complementary (e.g. in Europe). In such a case, a mix of wind power and solar PV will tend to minimise total system costs, even if one option is more costly in terms of direct generation costs. Furthermore, by locating VRE power plants strategically, aggregate variability and costs for grid connection can be reduced. For example, roof-top PV systems deployed in a city can be more valuable from a system perspective than a distant large-scale PV plant, even if the direct generation costs of the roof-top systems are higher.
- **Technical capabilities**. Modern wind turbines and PV systems can provide a wide range of technical services needed to maintain short-term grid stability. Historically, such services have been provided by other power plants. While providing such services tends to increase VRE generation costs, it can be cost-effective from a system perspective, for example by reducing the need to curtail VRE generation.
- **System friendly power plant design**. VRE power plant design can be optimised from a system perspective, rather than simply aiming to maximise output at all times. For example, modern wind turbines can facilitate integration by harvesting relatively more energy at times of low wind speed (by using a larger rotor size). Design of PV systems can be similarly optimised by considering PV panel orientation and the ratio of module capacity to inverter capacity. This reduces variability and makes VRE generation more valuable.
- **Curtailment**. Occasionally reducing VRE generation below its maximum (ideally based on market prices) can provide a cost-competitive route to optimising overall system costs by avoiding situations of extreme variability or moments of very high VRE generation, which can be costly to accommodate.

2) Make better use of what you already have: improved system and market operations

The second pillar of system transformation is making better use of what you have. Best-practice system operations are a well-established, low-cost and no-regret option. Poor operation strategies – such as failure to use state of the art forecasts – become increasingly expensive at growing shares of VRE. Improving system operations has proven to be a major success factor in countries that have pioneered VRE integration (for example Spain, Denmark and Germany). In Germany, the improved co-ordination of the four "parts" (balancing areas) of the grid has *reduced* the need for holding certain reserves despite a dynamic increase of VRE capacity. However, changing operational practices may face institutional resistance and thus delay despite their cost-effectiveness (such as system operators' reluctance to adopt innovative approaches for calculating reserve requirements).

Improving short-term power markets is a critical element for better operations. Market operations determine how demand and supply of electricity is matched. In order to deal efficiently with short-term variability and uncertainty, market operations need to facilitate trading as close as possible to real-time. In addition, power prices should be allowed to differ depending on location, in order to make the best use of available grid capacities. Analysis of case study market design shows recent improvements, such as the adoption of location specific (nodal) pricing by the Electric Reliability Council of Texas (ERCOT) in 2010, or the introduction of power delivery contracts in Germany that allow trading electricity in 15-minute blocks (rather than one full hour) and up to 45 minutes before real-time (rather than one day before real time).

System service markets need to price flexibility at its value. System services are required to maintain reliability. Analysis has found that system service markets, including those for short-term balancing of supply and demand (balancing markets), remain underdeveloped. In all reviewed markets, some system services are either not remunerated (for example in Italy, Iberia and ERCOT) or not priced efficiently (Germany and France). In addition, market functioning could be improved by moving trading on system service markets closer to real-time. Aligning the trade in system services and wholesale power markets helps to ensure efficient price signals on both markets and the pricing of flexibility at its true value.

Adopting improved operations is possible also in the absence of liberalised markets. Even where short-term power markets are not fully established (e.g. Japan), shifting operational decisions closer to real-time, making use of VRE production forecasts and better co-operation with neighbouring service areas can all improve system operations.

3) Long-term strategy: investment in additional flexible resources

Investments in additional system flexibility are required to integrate large VRE shares cost-effectively and in the long term. The point at which investment in additional flexible resources becomes necessary depends on the system context. Two different contexts can be distinguished:

- "stable" power systems are characterised by stagnating electricity demand and little or no short-term need to replace generation and grid infrastructure
- "dynamic" power systems have high growth rates in electricity demand and/or face significant investment requirements in the short term.

Many OECD power systems belong to the stable category, while emerging economies are typically dynamic systems.

Stable systems face different challenges and opportunities compared to dynamic systems. The opportunity is that stable systems can use what they have already (existing asset base) to a larger extent. Integration of higher VRE shares is possible by increasing flexibility via improved operations. The challenge is that the rapid addition of new VRE generation and a more flexible operating pattern can put existing generators under economic stress. While this does not pose any short-term threat to generation adequacy in stable systems, it can lead to stranded assets and raise concerns regarding the investment climate for future investments in flexible resources.

The rapid introduction of VRE into a stable power system (e.g. via support payments) tends to create a surplus of generation capacity. Such an oversupply (pre-existing capacity plus VRE additions) will tend to depress wholesale market prices, in particular if existing capacity is already underutilised. This can be observed in a number of European markets, such as Spain, Italy and Germany. Such low prices can, at some point, trigger the retirement of generation capacity, which can raise concerns about security of supply. However, in such situations depressed market prices correctly signal an oversupplied market. Market prices can be expected to revert to more sustainable levels by addressing a possible surplus and ensuring appropriate market design.

It is important to note that not all types of generation capacity are in-line with stringent decarbonisation targets. In particular, CO_2-intensive, technically and economically inflexible baseload power plants are inconsistent with such targets. A decarbonisation-conform response to deal with surplus supply under such circumstances would be to free the system of surplus capacity by ensuring corresponding market signals or by introducing appropriate regulation. If security of supply is a concern, power plants could be kept out of the market rather than being fully decommissioned.

The cost of rapid system-transformation in stable systems thus consists of two components:

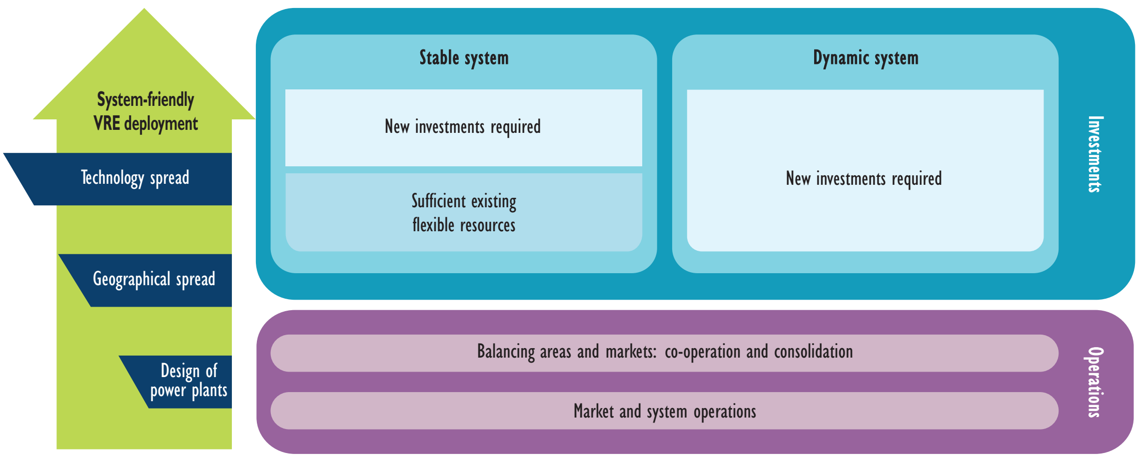
- the cost of new investments
- the cost associated with the reduced value of existing assets.

It is important to distinguish both sources of costs. Only the cost of new investments can be directly controlled by increased cost-effectiveness of VRE-build out. The second group of costs is determined by the overall speed of the transformation. In addition to the impact on total costs, there may be strong distributional effects under such circumstances, which tend to disfavour in particular incumbents.

Dynamic systems can leap-frog their stable counterparts, but only if investment strategies prioritise flexibility. In dynamic power systems, adding VRE does not put incumbents under the same level of economic stress, which can facilitate system transformation. In addition, the system can be built out taking into account VRE. For example, new grids can be planned and deployed in line with VRE targets, avoiding the need for later retrofits. However, these systems are unlikely to enjoy the flexibility contribution of existing assets (e.g. power plants, existing grids) to the same degree as stable systems. As a result, long-term investment strategies for additional system flexibility are likely to be relevant at earlier stages of VRE deployment. This raises the importance of planning tools that take into account VRE in longer-term system planning.

Despite the differences in timing, investment in additional flexibility is required at some point in both system contexts, if high shares of VRE are to be achieved (Figure ES.2).

Figure ES.2 • The three pillars of system transformation



Key point • System transformation has three main pillars: system friendly VRE deployment, improved operations and investments in additional flexibility.

A suite of flexibility options is needed to reach high shares of VRE

Flexibility comes in different forms. Using two different economic modelling tools, the **cost-benefit** of the different flexible resources was investigated. Costs are the additional costs for building and operating the flexible resources, while benefits are the saved investment and operating costs in other parts of the power system compared to a baseline case.

- **DSI** (in particular distributed thermal storage) showed significant promise, as suggested by its superior cost-benefit performance compared to other flexibility options. However, a degree of uncertainty exists regarding its full potential in real-life applications.
- Cost-benefit profiles of **storage** are less favourable, reflecting higher costs. Adding pump-back functionality to existing reservoir hydro plants showed the most favourable cost-benefit ratio. However, the potential use and storage technology cost reductions should remain important areas for investigation.
- **Interconnection** allows a more efficient use of distributed flexibility options and generates synergies with storage and DSI. Modelling for the North West Europe case study showed favourable cost-benefit of significantly increased interconnection.
- Cost-benefit analysis of retrofitting existing **power plants** to increase flexibility shows a wide range of outcomes, driven by project-specific costs.

The cost-effectiveness of distributed thermal storage points to the importance of coupling the electricity sector with other sectors of the energy system to achieve cost-effective VRE integration. In addition to coupling the heat and electricity sectors, a more widespread adoption of electro-mobility can open an additional avenue for energy sector coupling.

Neither opting for the cheapest option nor pursuing only the option with the best cost-benefit performance will suffice. While the different resources can substitute for each other under many circumstances, certain integration issues may only be addressed by some of them. For example:

- transmission infrastructure is the only option able to connect distant VRE resources
- only distributed options such as customer-side demand response or small scale storage can deal with some of the impacts related to high shares of distributed generation
- flexible hydro plants can step in when VRE generation is not available, but flexible generation cannot avoid VRE curtailment once net load becomes negative while storage can
- VRE curtailment can help to reduce situations of VRE surplus, but it does not help resolving situations of very low wind power and solar PV output.

While the above list provides only a few examples, they make clear that a suite of flexibility options is needed to meet flexibility requirements for successful VRE integration.

Conclusions and recommendations

Detailed recommendations relating to the above findings can be found at the end of this book in Chapter 9. On a high level, the recommendations can be grouped according to the context of VRE integration:

Countries beginning to deploy VRE power plants should implement well-established best practices to avoid integration challenges, at shares of up to 5% to 10% of annual generation. This means avoiding uncontrolled local "hot spots", ensuring that VRE power plants have sufficient technical capabilities and make effective use of short-term VRE forecasts.

All countries where VRE is becoming a mainstream part of the electricity mix should make better use of existing flexibility by optimising system and market operations. Moreover, VRE power plants need to be allowed to actively participate in their system integration by implementing system friendly VRE deployment strategies.

Countries with stable power systems should seek to maximise the contribution from existing flexible assets for system transformation. They may consider accelerating system transformation by decommissioning or mothballing inflexible capacities that are surplus to system needs. Policy makers and industry will need to carefully manage the impacts of related effects, including stranded assets. However, they need to maintain a clear focus on delivering the investments needed to address long-term climate change and energy security imperatives.

Countries with dynamic power systems should approach system transformation as a question of holistic, long-term system development from the onset. This requires the use of planning tools and strategies that appropriately represent VRE's potential for a cost-effective, low-carbon energy system.

Future work

A number of questions have arisen during the course of this project that merit further analysis. First, the specific circumstances of dynamic power systems warrant further investigation, specifically regarding appropriate strategies for achieving ambitious VRE targets cost-effectively in these systems.

Second, further investigation into options for system-friendly VRE deployment and the concrete design of system-friendly VRE support policies are ready for further analysis.

Third, while analysis has shown significant room to improve short-term markets, there remains the more fundamental issue of how to achieve a market design consistent with long-term decarbonisation, in particular in the context of stable power systems. On the one hand, VRE generators need to be exposed to price signals that reflect the different value of electricity (depending on the time and location of generation), so as to facilitate system integration. On the other hand, VRE requires capital-intensive technology and, as such, is highly sensitive to investment risk, a risk that is increased by short-term price exposure. An appropriate market design will need to strike a delicate balance between these two objectives.

Box ES.1 • Modelling tools used for this publication

The IEA has refined its Flexibility Assessment Tool (FAST). The revised tool (FAST2) provides a snapshot of what shares of VRE generation can be integrated into power systems from a purely technical perspective and given existing flexible resources by assessing system flexibility on a timescale of 1 to 24 hours.

In addition to technical analysis, two economic modelling tools were used for this publication.

The Investment Model for Renewable Energy Systems (IMRES) was used to analyse a generic island test system of a size equivalent to Germany at 30% to 45% of annual VRE generation. IMRES optimises the investment in non-VRE power plants and the hourly operation of the power system. Scenarios were designed to capture different degrees of system adaptation. In the Legacy scenario, VRE is added to an existing power plant mix "overnight". Consequently, system adaptation can only be operational. In the Transformed scenario, the power plant mix is optimised in a comprehensive way, taking into account generation from VRE and the contribution from flexible resources. In both cases the model calculates the least-cost electricity generation mix.

As part of a co-operation with Pöyry Management Consulting (UK) Ltd (Pöyry), a cost-benefit analysis for different flexibility options for one of the case study regions (North West Europe) was performed using Pöyry's hourly BID3 power system investment and operation model. The analysis is based on a high-VRE adaptation of the Pöyry central scenario for 2030, assuming an increased level of wind power and solar PV generation, leading to a total share of 27% VRE in power generation.

1 • Introduction

Background

This book summarises the results of the third phase of the Grid Integration of Variable Renewables (GIVAR III) project, which the secretariat of the International Energy Agency (IEA) has carried out over the past two years. The publication addresses the following questions:

- What are the relevant properties of wind and solar photovoltaic (PV) power plants that need to be taken into account to understand their impact on power systems? What power system attributes influence the ease with which wind power and solar PV energy sources can be added to a power system?
- What challenges arise as variable renewable energy (VRE)[1] sources are added to power systems? Are these transitory or likely to persist? Which are economically most significant?
- Which flexibility options are available to cost-effectively overcome these challenges and how can these be combined to form an effective strategy for VRE integration?

The GIVAR III project integrates analysis from a range of case studies (see below). Case study analysis was supplemented by an extensive literature review of different options for VRE integration. The project has also benefitted greatly from the expertise of the IEA Technology Network, in particular Task 25 of the IEA Wind Implementing Agreement, "Design and Operation of Power Systems with Large Amounts of Wind Power". Analysis was further informed by a suite of custom-tailored technical and economic modelling tools.

Context

Renewable energy (RE) is currently the only power sector decarbonisation option deployed at a rate consistent with long-term IEA scenarios to attain the 2°C target (IEA, 2013a). Wind and solar PV account for a large proportion of recent increases in RE generation, and are projected to contribute the vast majority of non-hydro RE generation over both the short and long term (IEA, 2013b, 2013c).

Both technology families have seen important cost reductions and technological improvements over the past two decades (IEA, 2011a); their generation costs have reached or are approaching the cost of conventional power generation options (IEA, 2013b). However, as deployment of wind and solar PV has increased, some of their technical characteristics have raised concerns, in particular whether they can be relied upon to provide a significant share of electricity generation in power systems cost-effectively.

Wind and solar PV are variable sources of energy. This means that their output depends on the real-time availability of their primary energy resource: wind and sunlight respectively. This makes their output variable over time. It is also not possible to perfectly predict resource availability ahead of time.

Experience has disproven many concerns about system integration of wind power and solar PV. In particular, managing the technical operation of power systems at low shares of VRE (usually in the order of 5% to 10% of annual generation) appears to pose no significant challenge, as long as some basic principles are adhered to. An important reason for this is that the challenges accompanying wind power and solar PV integration are, for the most part, not new to power system operation. Most importantly, power demand itself is variable and cannot be predicted with perfect accuracy. Also, conventional power plants may experience unexpected outages. Nevertheless, integration challenges

1. Variable renewable energy technologies are onshore and offshore wind, PV, run-of-river hydropower, wave energy and tidal energy. This publication focuses exclusively on wind and PV. The term VRE is used to refer solely to these two technologies throughout.

do exist. The rapid build-out, in particular of solar PV in some countries, may put the existing power system under stress — as evidenced by recent energy market experiences in countries such as Germany and Italy.

However, it is important to distinguish which of these challenges are transitory and which are likely to persist in the longer term, calling for dedicated solutions. The former are transition challenges, which result from the rapid addition of new technologies to a system that has been designed and regulated with other technologies in mind. The latter, persistent challenges are genuinely linked to the nature of wind power and solar PV. Where VRE is added to power systems with low growth in power demand and limited planned retirement of infrastructure (stable power systems), the transition may pose a number of distinct challenges. In systems where electricity demand is growing rapidly or a large amount of infrastructure is approaching retirement (dynamic power systems), the transition phase may be accelerated or might even be skipped altogether. However, these systems may face certain challenges more quickly than stable systems. Where applicable, this distinction between system circumstances is made in the publication.

The variability challenge

The physical nature of electricity implies that generation and consumption must be in balance instantaneously and at all times. System operation needs to ensure this, respecting the technical limitations of all system equipment under all credible operating conditions, including unexpected events, equipment failure and normal fluctuations in demand and supply. This task is further complicated by the fact that electricity cannot currently be stored in large quantities economically.[2]

Since the early days of electrification in the late 19th century, variability and uncertainty have been steady companions of power systems. Variability has historically been an issue primarily on the demand side,[3] whereas uncertainty is primarily a supply-side issue. Load variability within the day can be quite high, with a factor of two between daily peak and minimum demand (as in Ireland, for example) but relative variability tends to be smaller in large systems (for example around 30% between peak and minimum in the aggregated case study region of North West Europe). Electricity demand often also shows a large seasonal variability. Exceptional operating conditions can alter the structure of electricity demand and system operation routinely deals with such events (Figure 1.1).

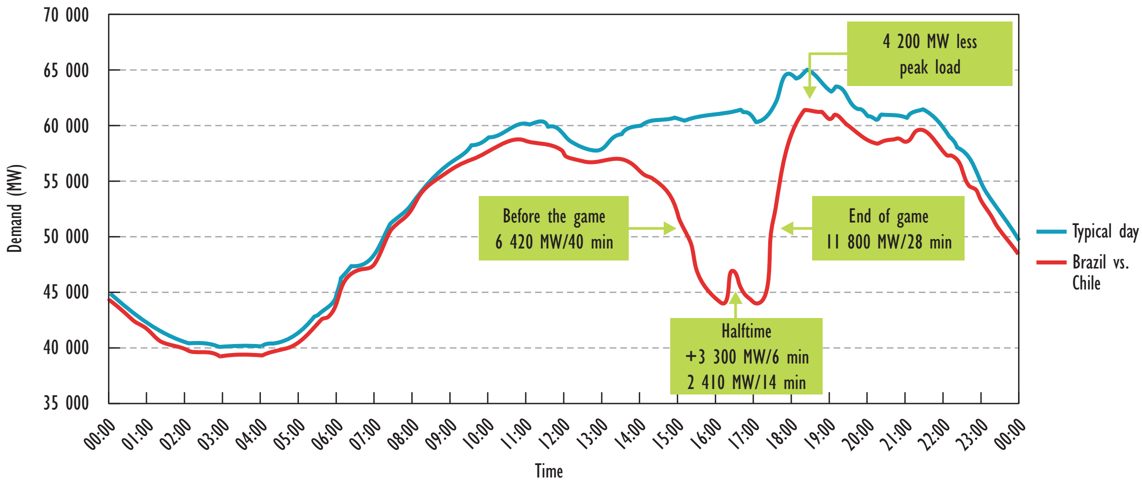
The largest source of uncertainty comes from the failure of plants or other system components, which can cause abrupt and unexpected variations in supply. In addition, plants can and often do deviate from scheduled production levels. Such failures and deviations, while unpredictable, are anticipated with a certain probability and are factored into system planning and operation. Some uncertainty in demand is also to be expected. Load forecasting techniques are very mature, typically with a mean absolute error of 1% to 2% a day ahead. However, while load forecasting is usually highly accurate, there remains a residual amount of unpredictable fluctuation in real-time demand. Where load is particularly sensitive to weather conditions due to electricity demand for electric heating and air conditioning, load uncertainty can also be considerable.

At shares above 2% to 3% in annual generation, wind power and solar PV generation is likely to lead to an increase in supply-side variability and uncertainty. However, it is the combined variability and uncertainty of the entire system (all generators and power demand) that needs to be dealt with. Therefore the additional impact of VRE is likely to be very small initially, gradually increasing with higher penetration levels. Because the system-wide variability has to be balanced, VRE output is often subtracted from power demand to form what is known as net load. The flexible resources of the power system (see below) work to balance net load rather than total load.

2. Relevant storage technologies first convert electricity before storing energy. Capacitors are an exception, but these cannot store large energy volumes. See Chapter 7 for details.

3. Most power systems have historically included some amount of variable supply, such as run-of-river hydroelectric and industrial co-generation, but in most cases the amount was relatively small. Co-generation refers to the combined production of heat and power.

Figure 1.1 • Exceptional load variability in Brazil during the 2010 Soccer World Cup, 28 June



Notes: during the game of Brazil (3) vs. Chile (0) on 24 June 2010.

Source: Unless otherwise stated, all material in figures an tables derives from IEA data and analysis.

Key point • Power demand is variable and can show rapid changes.

VRE has impacts on power systems over different timescales. On the operational timescale, short-term variability and uncertainty cover periods ranging from a few minutes to 24 hours. This timescale is often referred to as the balancing timescale. However, variability will also have longer-term impacts, because altered operational patterns will eventually influence which investments are the most economic choice. This timescale is often referred to as concerning system "adequacy". This publication also considers the longer-term implications of VRE integration, thereby expanding the scope of previous IEA work on the subject, which has focused on the balancing timescale (IEA, 2011b).

Flexibility

The key to integrating VRE is flexibility. In its widest sense, power system flexibility describes the extent to which a power system can adapt the patterns of electricity generation and consumption in order to maintain the balance between supply and demand in a cost-effective manner. In a narrower sense, the flexibility of a power system refers to the extent to which generation or demand can be increased or reduced over a timescale ranging from a few minutes to several hours in response to variability, expected or otherwise. Flexibility expresses the capability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand, whatever the cause. It is measured in terms of megawatts available for changes in an upward or downward direction.

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

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

Sources outside the electricity sector can also contribute to flexibility. In fact, the growing importance of flexibility may drive stronger links to other energy sectors such as heat and transport. In the heat sector, for instance, space and water heating augmented by thermal storage systems and co-generation can create opportunities to meet more volatile net load. Electric vehicle (EV) fleets may provide a valuable option to expand opportunities for energy storage and enable better use of VRE output that is surplus to need at the time it is produced.

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

Analysis of operational and investment options for cost-effectively increasing the supply of flexibility and reducing demand for flexibility is a key focus of this publication.

Case study areas

The GIVAR III project conducted 7 different case studies, covering 15 countries (Table 1.1). These were selected based on their existing experience with integrating VRE, as well as the expected increase in wind power and solar generation. In addition, the regions show differences in their existing generation mix and the extent to which they can be categorised as stable or dynamic systems; Brazil and in particular India fall under the latter category. The IEA has carried out a review of electricity market design in the case study regions and has gathered technical data on the different power systems. In addition, IEA experts visited selected case study countries (Brazil, France, Germany, India, Ireland, Japan, Norway, Spain and Sweden) conducting a total of over 50 stakeholder interviews with system and market operators, regulators, academics, as well as government and industry representatives.

Table 1.1 • *GIVAR III case study regions*

Case study area	*Geography*
Brazil	Brazil
ERCOT (Electric Reliability Council of Texas)	Texas, United States
Iberia	Portugal
	Spain
India	India
Italy	Italy
Japan East	Hokkaido, Tohoku, Tokyo
North West Europe	Denmark
	Finland
	France
	Germany
	Great Britain
	Island of Ireland*
	Norway
	Sweden

* Island of Ireland = Republic of Ireland and Northern Ireland.

Key point • *The GIVAR III project conducted 7 case studies, covering 15 countries.*

The analysis is further informed by a suite of custom-tailored technical and economic modelling tools. Firstly, the Flexibility Assessment Tool, which was developed for the previous project phase, has been revised and used to analyse the existing technical capabilities of case study power systems to allow for the uptake of large shares of VRE generation. Secondly, a state-of-the-art power system modelling tool, the Investment Model for Renewable Energy Systems (IMRES), was used to assess the cost-benefit profile of different flexibility options using a generic test system. Finally, the cost-effectiveness of different flexibility options for the North West Europe (NWE) case study region was analysed using the BID3 model, as part of a collaboration with Pöyry Management Consulting (UK) Ltd.

This publication

The analysis of this book takes the perspective of an interconnected power system, putting particular emphasis on the long-term interaction between VRE power plants and the four flexible resources (dispatchable generation, grid infrastructure, storage and demand-side integration). It has three main components: Chapters 2 and 3 provide an assessment of system impacts of VRE and the technical flexibility of power systems. Chapter 4 develops the analytical framework to assess the economic impact of higher shares of VRE penetration. The remaining chapters (Chapters 5 to 8) discuss the principle levers by which high shares of VRE can be achieved, concluding that this calls for an integrated approach to transform the system.

More specifically the chapters are structured as follows:

Chapter 2 presents six properties of wind and solar PV power plants that are most relevant for their system and market integration. Each property is explained using examples drawn from a case study region, and its associated impacts discussed. Because system integration is a matter of interaction between different components of the power system, power system properties that are relevant to system integration are also introduced.

Chapter 3 describes the current state of play of VRE deployment in the case study regions, and features a simplified assessment of the levels of VRE penetration that are technically feasible given today's system conditions.

Chapter 4 discusses the impacts of VRE on the power system from an economic perspective, laying the ground for the analysis in Chapters 5 and 6. It highlights the fact that the value of VRE depends on the degree to which the power system and VRE fit together. Improving the match between VRE and the power system may call for a more fundamental transformation of the power system, to ensure lowest possible system costs at high shares of VRE.

Wind and solar PV can facilitate their own grid integration through improved deployment, while ensuring sufficient technical capability and system-friendly economic incentives. These are discussed in Chapter 5.

Chapter 6 provides an overview of the operational strategies — including market operations — that are available to optimise the interplay of wind and solar PV power plants and the overall system. Such operational changes are a critical foundation of any cost-effective strategy to integrate VRE under virtually all system circumstances.

While operational practices are critical for successful grid integration, additional investment in flexibility is needed to transform the system in the long term. The available options are discussed in Chapter 7, addressing both their technical suitability to mitigating integration challenges, and their economic performance with regard to total system costs.

Chapter 8 brings together the analysis of the previous chapters to discuss the issue of power system transformation in a more integrated fashion, in particular with a view on how to combine different options for increasing flexibility.

Chapter 9 presents conclusions, highlighting the most important challenges and opportunities together with policy recommendations.

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2 • System impacts of VRE deployment

HIGHLIGHTS

- System impacts of variable renewable energy (VRE) deployment are the result of complex interactions between different components of the entire system. As a result, integration impacts are highly system-specific. However, a limited number of properties both of VRE generators and of power systems largely determine the most relevant integration effects.
- Effects depend on system context and can be categorised into two broad groups: stable systems, which have low demand growth and little short-term infrastructure retirement, and dynamic systems that expect demand growth and/or infrastructure retirement.
- For non-VRE generation, there are two main persistent effects. These are increased short-term variability and uncertainty of net load (balancing effect), and a structural shift of the optimal plant mix towards capacity designed to operate flexibly and to run at low- and medium-range capacity factors (peaking and mid-merit generation). This effect is known as the utilisation effect.
- Aggregating output over larger geographic regions and deploying a mix of wind power and solar photovoltaic (PV) reduces variability considerably. Additional grid infrastructure or better use of existing infrastructure may be required to achieve this. However, even when aggregating VRE at a continental scale, a degree of variability remains.
- Where high-VRE resource locations do not coincide with demand centres, transmission lines may be needed to connect new VRE power plant.
- The impact of uncertainty is determined by the quality of VRE forecast information and how this information is used in system operations.
- VRE technologies are modular, meaning that they can be built at different scales. Mass deployment of small-scale generators has been uncommon historically and may call for changes in power system monitoring, control, operations and investments; the role of the distribution grid is affected in particular.
- Large, conventional power plants use so-called synchronous generators to produce electricity. Synchronous generators are connected to the power system via a direct, electro-mechanical link and have a considerable amount of spinning mass (inertia). VRE power plants are linked to the power system more indirectly via power electronics and have less or no spinning mass (inertia); VRE sources are thus said to be non-synchronous generation technologies. This property may require changes to how system stability is ensured, especially during periods of high shares of VRE in power generation.
- A detailed, system-specific integration study is necessary for a thorough understanding of integration impacts. Broadly speaking, if local concentrations ("hotspots") are avoided, VRE deployment has a negligible impact at shares of around 2% to 3% of annual generation.
- Apart from small island systems, shares of 5% to 10% in annual generation will not lead to technical integration challenges if operations are adapted and VRE deployment patterns are well co-ordinated.

The political debate regarding VRE integration is often complicated by the technical complexities of the subject. This chapter seeks to organise the various impacts of VRE deployment into a more coherent framework. The consequences of VRE taking an increased share of energy supply are, as a rule, system-specific. VRE integration is interactive: properties specific to VRE meet those of power systems, and their interaction determines adaptation effects and ultimate impacts. However, a limited number of properties, both of VRE and power systems, largely shape integration effects. In this chapter, the relevant properties of VRE are presented with examples of the related impacts. They are analysed by asking whether they are a transition phenomenon, which results from adding a new technology to an existing system, or if effects are more fundamental. After discussion of the different impact groups, the power system properties relevant to influencing these impacts are briefly discussed. The chapter concludes with a summary of system impacts at growing VRE penetration.

Properties of VRE generators

VRE generators have a number of specific characteristics that affect their contribution to power system operation and investment. Knowledge of these characteristics continues to evolve. As of the time of writing, six VRE properties appear to be relevant from an integration perspective. Without implying any order in importance, VRE generators are:

- low short-run cost, i.e. once installed they can generate power at very little cost — their short-run costs are close to zero
- variable, i.e. available power output fluctuates with availability of resource (wind or sun)
- uncertain, i.e. the availability of resource can only be predicted with high accuracy in the short term
- location-constrained, i.e. resource is not equally good in all locations and cannot be transported
- modular, i.e. the scale of an individual VRE production unit (wind turbine, solar panel) is much smaller than fossil, nuclear and larger hydro generators
- non-synchronous, i.e. VRE plants connect to the grid via power electronics, in contrast to large conventional generators, which are synchronised to the grid and therefore react in a co-ordinated fashion to changes in the grid.

The first property (low short-run cost) is not a technical property but has important impacts on electricity markets and is therefore included in the above list. However, contrary to the other five, there is no technical integration issue associated with it.

The above properties contribute to drive all currently observed integration impacts of VRE. The penetration level at which they become relevant depends on system-specific circumstances.

Low short-run cost

Once built, wind power and solar PV provide electricity practically for free. However, in the absence of demand growth or power plant retirement, the integration of this additional power generation is only possible by reducing the market share of incumbents. VRE deployment takes place in many member countries of the Organisation for Economic Co-operation and Development (OECD) that have such stable power systems, characterised by adequate generation capacity and slow demand growth.

In a purely competitive and fossil fuel dominated environment, such displacement effects are common and frequent. The merit-order[1] of fossil fuel fired power plants has always been affected by variations in resource prices. For example, lower gas prices in the United States have recently boosted gas generation at the expense of coal (Macmillan, Antonyuk and Schwind, 2013).

1. The merit-order ranks the power plants in terms of their short-run costs. It is often used to determine which units will be used to supply expected demand, with the cheapest units being used first.

The picture becomes more complex in the case of VRE generation because of the effect of support policies. Three factors need to be disentangled to understand market displacement impacts in stable power systems:

- low short-run cost of VRE
- performance-based incentives
- priority dispatch, i.e. VRE plants are allowed to feed electricity into the grid at any time.

The low short-run costs imply that once VRE generation is built, it is likely to be among the first technologies in the merit-order. It will therefore displace more costly generation — usually gas, or coal, whichever has the highest short-run cost (generally dominated by a combination of fuel and carbon dioxide [CO_2] emission costs).

Based purely on plant economics, VRE generators would be expected to bid no lower than at a very low, positive price, reflecting their very low short-run cost. They would not be expected to bid below zero. However, support policies often contain a performance-based element, i.e. they remunerate based on generated energy (e.g. feed-in tariffs, feed-in premiums, tradable green certificates or production-based tax incentives). In cases where VRE generators offer their generation directly to the market, such remuneration may create an incentive for VRE plant owners to bid below their short-run costs, because they receive revenues on top of achieved market prices. Hence, bids may be below zero (minimum bids are likely to equal short-run cost minus the value of support payments).

Depending on the policy context, VRE generators may also enjoy priority dispatch. This means that they are treated as must-run units, i.e. they are allowed to generate whenever wind and sun are available. This is achieved via different mechanisms in different power systems. For example, German transmission system operators (TSOs) generally offer all renewable energy produced under a feed-in tariff at the minimum price on the European Power Exchange (EPEX). This price is currently EUR -3 000 per megawatt hour (/MWh) (EPEX, 2013). If prices clear below EUR -150/MWh, TSOs resubmit their bids at a randomly chosen value between EUR -150/MWh and EUR -350/MWh to contain negative prices (AusglMechAV, 2013). Where VRE generators have priority dispatch, their operation can run independent of any market price signal. This can lead to more pronounced negative prices (Nicolosi, 2012).

In summary, two effects will occur on electricity markets as VRE generators' share increases:[2]

- reduction in market prices when VRE power plants are generating (merit-order effect)
- reduction in market share of other generators, mostly those with highest short-run costs (transitional utilisation effect).

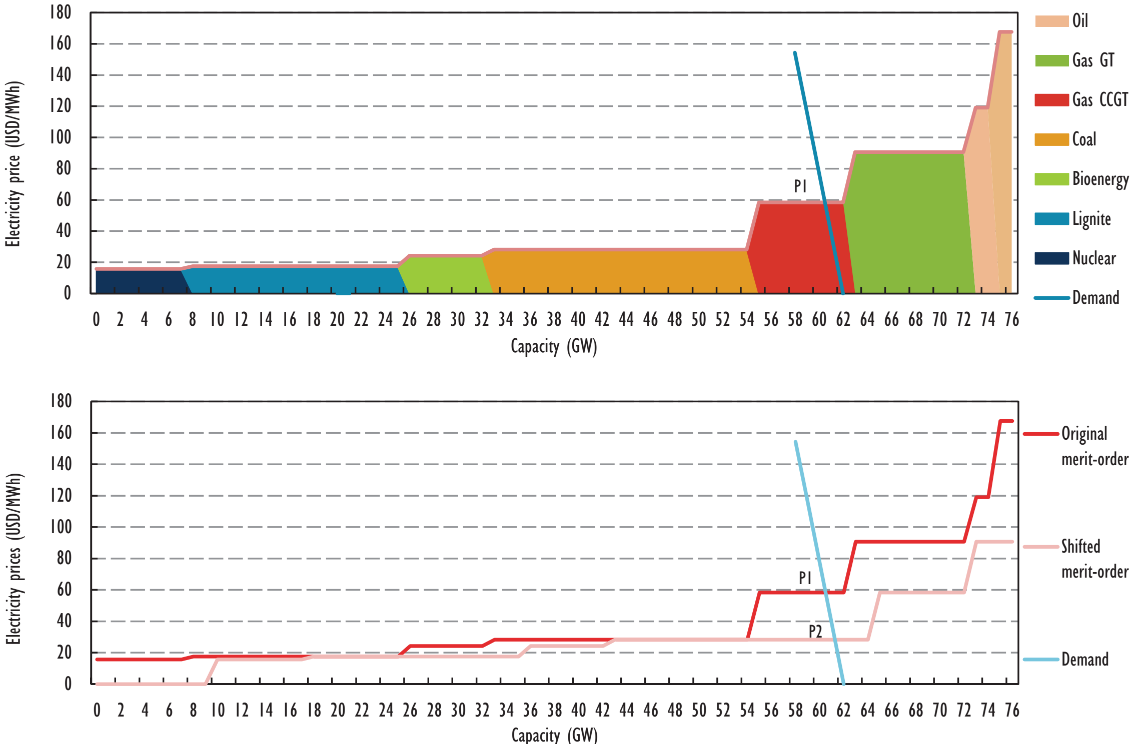
These effects also occur in a purely competitive environment when low marginal cost generation, such as VRE, is added to the system. Performance-based incentives and priority dispatch will tend to increase these effects, but the main cause is simply the low short-run cost of VRE sources compared to other technologies.

The merit-order effect is illustrated in Figure 2.1. The availability of additional low-cost VRE power production pushes the offer curve to the right (pushes plants with higher marginal costs out of the market), thus displacing the (most expensive) generators and reducing the resulting market price for electricity. This will happen when a sufficient amount of VRE generation capacity is installed in the system, and when it is windy and/or sunny. This effect tends to be more pronounced the steeper the merit-order curve.

The merit-order effect has been studied systematically for Germany and Ireland, among other regions. In Germany, an average reduction of around EUR 5/MWh to EUR 6/MWh between 2007 and 2010 was identified (Sensfuß, 2011). Market price reductions in Ireland are reported to match premiums for VRE support payments (Clifford and Clancy, 2011).

2. The resulting implications for conventional generators are discussed in detail in Baritaud (2012).

Figure 2.1 • Illustration of the merit-order effect



Notes: CCGT = combined-cycle gas turbine; GT = gas turbine; GW = gigawatt; P1 = price without additional generation; P2 with additional generation.

Source: Schaber, 2014.

Key point • Additional generation with low short-run costs will tend to reduce electricity market prices.

The details of the merit-order effect can differ between wind power and solar PV, depending on when they generate. Where wind power has only a small diurnal range, it will reduce average prices fairly equally across the day. Due to the constraint on sunlight availability, solar PV reduces prices exclusively during daylight hours. Solar PV, in particular, can thus markedly change the price structure across the day. Correcting for the absolute price level, a comparison of the daily structure of German market prices during summer months on the EPEX market illustrates this effect. In 2006, when installed solar PV capacity was comparably low (2.9 GW), prices in the summer months showed a pronounced peak at mid-day. By 2012, solar PV capacity had increased tenfold to 32 GW and the mid-day price peak had largely disappeared (Figure 2.2).

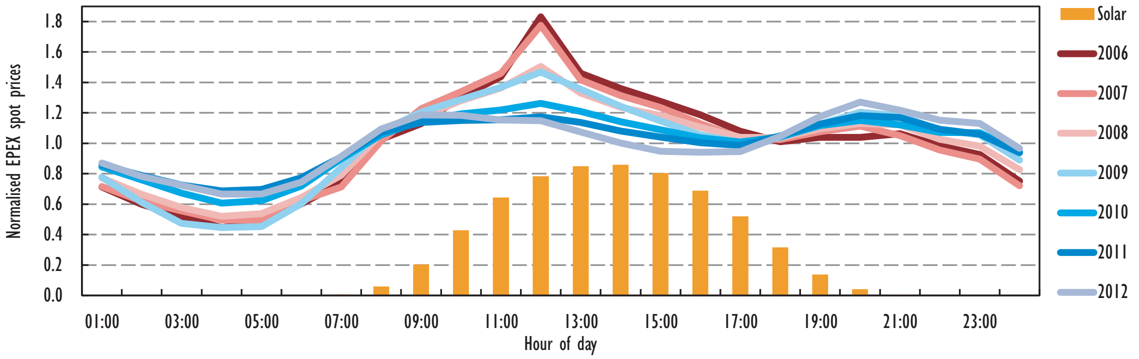
The merit-order effect is also important for the economics of VRE itself: market prices are lowered only when VRE is generating. This means that the market value of VRE technologies, i.e. the average price received by VRE on the power market, can experience an even stronger reduction than average market price, in particular at high shares (see Hirth, 2013; Mills and Wiser, 2012).

The second market effect of VRE is the transitional utilisation effect. This effect is relevant for all generators that are displaced by VRE and thus see a reduction in capacity factors.[3]

As the name implies, the transitional utilisation effect is a transitory effect. In the long run, a well-adapted power plant mix shows "normal" utilisation for all power plants. However, the mix itself is

3. It can be challenging to separate the effect of VRE generation from other factors. For example, the current challenges for gas generators in European markets are also a reflection of a sluggish economy in many European countries and of low CO_2 and coal prices.

Figure 2.2 • Shift in German spot market price structure, 2006-12



Notes: solar shows indicative average generation profile. Spot prices are normalised to average market prices and shown for summer months.

Source: International Energy Agency (IEA) analysis, based on data from the European Energy Exchange (EEX) data.

Key point • Large shares of solar PV generation can change price structures on electricity markets.

likely to contain more peaking and mid-merit generation and less baseload than in the absence of VRE (also see Baritaud, 2012; NEA, 2012; Nicolosi, 2012). This structural shift in the dispatchable power plant mix has been termed the (persistent) utilisation effect – it is linked to the variability of VRE and thus discussed in the next section.

It is important to note that mid-merit plants tend to be exposed to both the transitional utilisation effect and the merit-order effect. Baseload plants will initially only experience the merit-order effect. Only when VRE penetration is high enough to displace baseload technologies does the transitional utilisation effect become relevant for baseload as well. In Ireland and Denmark, baseload coal plants have undergone retrofits to allow them to reduce output when wind power generation is high and demand comparably low. In these cases the transitional utilisation effect has reached baseload plants. Increased electricity export can be used to reduce the transitional utilisation effect.

In summary, the economics of mid-merit plants are challenged mostly by rapid VRE additions in the short and medium term (a combination of the transitional utilisation effect and the merit-order effect). The economics of baseload plants are challenged less in the short term (merit-order effect) and more significantly in the long term (persistent utilisation effect).

The picture is different in dynamic power systems with a growing electricity demand, such as in Brazil or India. Here, VRE deployment can contribute to satisfying incremental demand and does not necessarily reduce the full-load hours of incumbents. However, an important factor can be whether existing power plants are a good match for VRE. This is the case in Brazil, where the large amount of reservoir hydro matches VRE very well. It is less the case where the existing mix contains a very high share of baseload plants. In the latter case, there can be a transitional utilisation effect when VRE is deployed rapidly.[4]

A reduction in average annual utilisation of incumbent power generators (transitional utilisation effect) is a necessary side effect of pushing additional generation into an already adequate system. As such, this effect is not specific to VRE sources. It will occur wherever low short-run cost generation is added in the absence of demand growth and plant retirement.

4. One could speculate that this is currently the case in China, where wind generation is curtailed to "protect" the full load hours of coal generation, despite the higher short-run costs of coal.

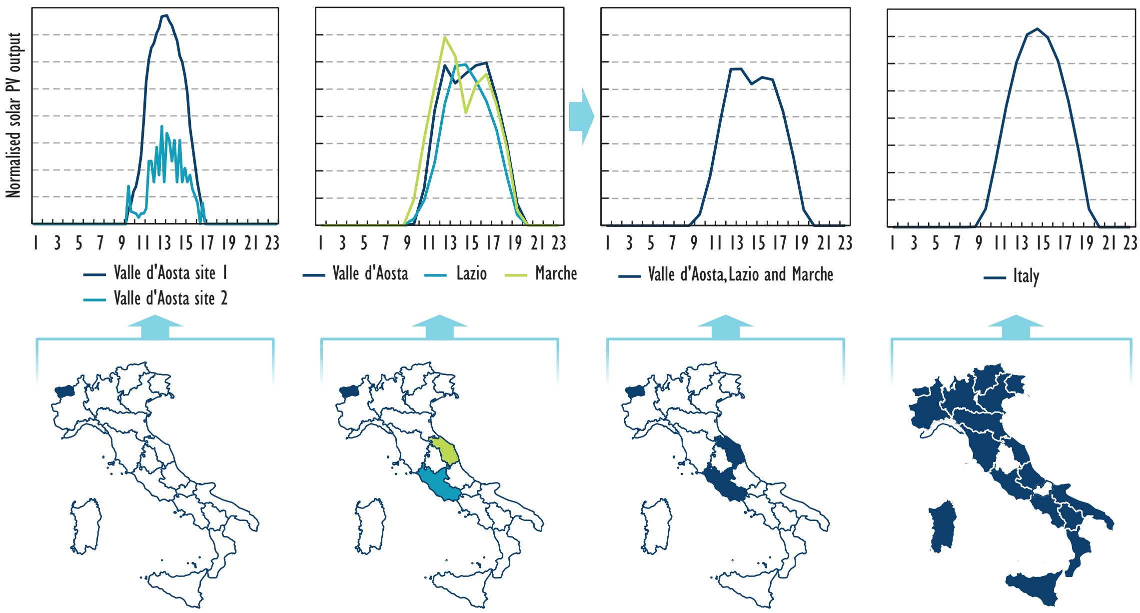
Variability

Variations in wind power and solar PV generation are mainly determined by changes in weather conditions. Like changes in demand they occur on multiple timescales, from minute-to-minute changes up to seasonal or even inter-year changes (e.g. "windy" and "calm" years). However, there are important differences between the variability of a single VRE power plant and the aggregate variability of an entire fleet of VRE generators, when distributed over a sufficiently large geographic area (Figure 2.3). This also explains the difference between individual perception of wind and solar variability – wind and sun may pick up suddenly and go away rapidly – and system-level variability. On a system level, neither wind power nor solar PV will experience an immediate, abrupt loss or onset of the aggregate generation. In this sense, wind power and solar PV are variable rather than intermittent.

However, even when aggregated to the level of a larger power system (e.g. Spain or Texas, or even North West Europe), aggregate wind power and solar PV output will show important variability. This can be seen from the aggregate wind power and solar PV output over two selected weeks for different case study regions (Figure 2.4).

Wind and solar PV show different characteristics in their variability. Solar variability is primarily driven by regular day-night and seasonal cycles. Cloud coverage as well as snow, fog and dust may add a random layer to the underlying "bell-shaped" generation pattern. Wind is generally more stochastic, often showing only moderate systematic daily and stronger seasonal patterns. However, exceptions to this general rule exist. For example, the trade winds in the north of Brazil show relatively little variability during some months of the year.[5]

Figure 2.3 • Aggregation effect of solar PV power plants in Italy



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

Note: graphs from left to right show 24-hour output on a plant level to 24-hour output on a system level.

Source: based on data from EPIA, 2012.

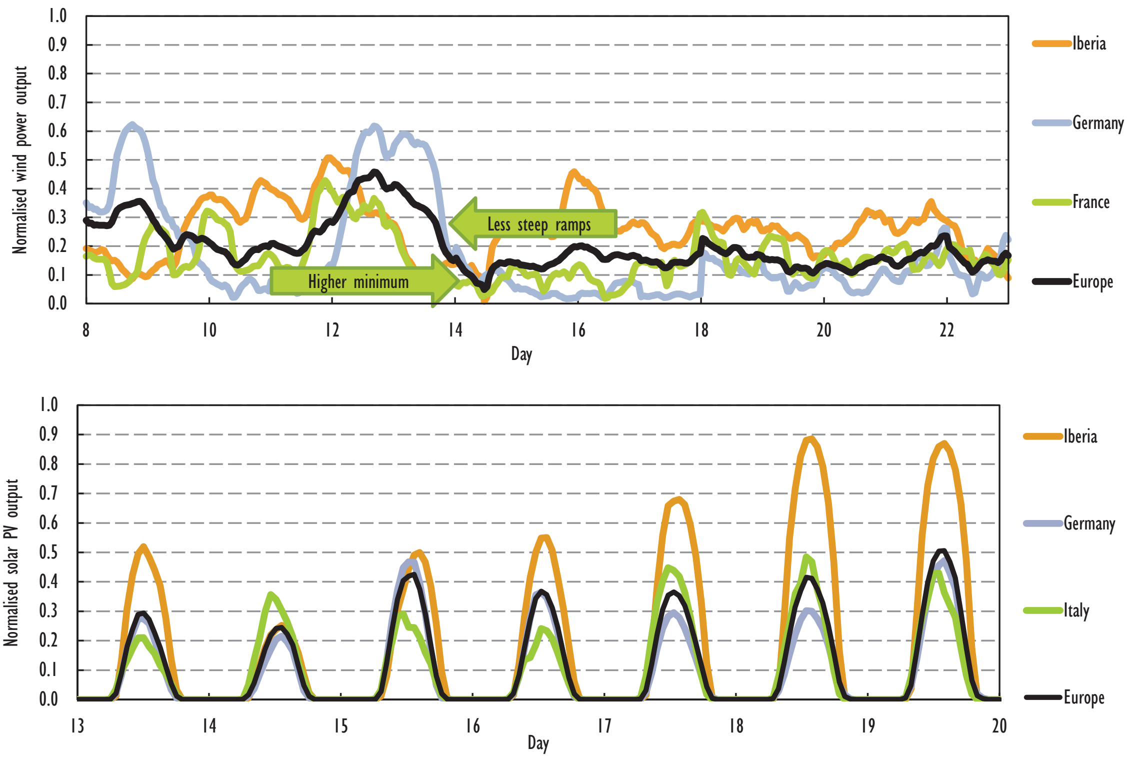
Key point • *Individual solar PV power plants show rapid output fluctuations. When aggregating the output of many plants, rapid fluctuations cancel out, resulting in a smooth profile.*

5. This was pointed out by several stakeholders during the case study interviews in Brazil in May 2013 as part of the Grid Integration of Variable Renewables (GIVAR) project.

While output aggregation of VRE reduces variability considerably, it may not remove it fully, even at large geographical scales. Other analysis for north-west Europe has revealed that wind power generation still shows significant variability even when aggregated at that level (Pöyry, 2011). Analysis with the IEA revised Flexibility Assessment Tool (FAST2) also illustrates this (Figure 2.4). Remaining "structural" variability after aggregation will tend to be more pronounced for solar PV, as daylight hours are similar even across very large regions.

On the other hand, the availability of wind and solar energy are generally not positively correlated (more so in some locations than in others), and therefore the combination of different VRE resources over large areas can substantially offset the aggregate variability of each individual VRE resources over the same areas.

Figure 2.4 • Sample weeks of aggregated wind power and solar PV output



Notes: Europe = all European case study countries. Generation data for April (top) and March (bottom) 2011. Output normalised to installed capacity.

Source: unless otherwise indicated, all tables and figures in this chapter derive from IEA data and analysis.

Key point • Aggregating wind power and solar PV generation across large areas reduces but does not fully eliminate variability.

Variability-related issues form the most diverse and complex group of VRE system impacts. They can be positive or negative, depending on the match between VRE resources, power demand and other system assets.

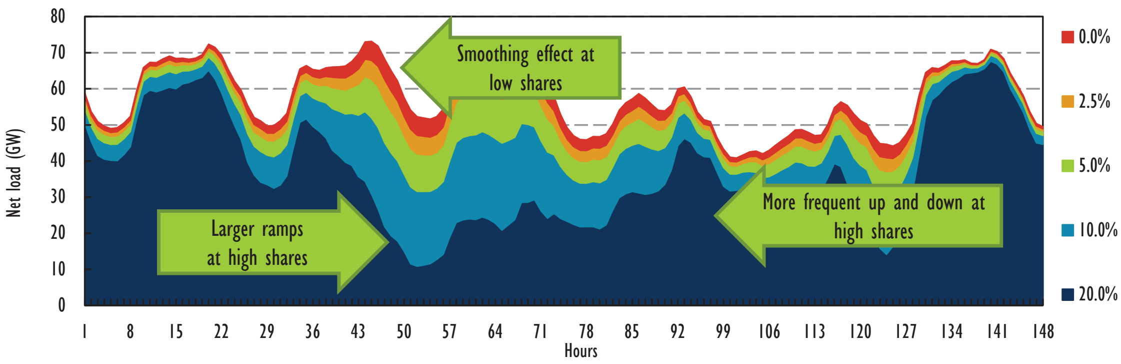
It is useful to distinguish between two effects of variability. The first captures the short-term effects: more rapid changes in net load, from minutes up to a timescale of one or two days. Impacts arising from this short-term variability have been termed "flexibility effect" (Nicolosi, 2012). In order to avoid confusion with the more general meaning of "flexibility", this effect is called "balancing effect" in this publication. The second effect is the utilisation effect. This effect is somewhat less intuitive. It is not directly related to changes in net load. Rather, it is connected to *how often* a certain net load level occurs over the course of a longer period of time, say a year. Addressing both effects is important to reliably balance demand and generation in systems with high penetration of VRE. Both effects can also be of relevance for their economic impact (see Chapter 4).

Balancing effect

The balancing effect can be illustrated by considering net load for the same system at increasing levels of VRE penetration (Figure 2.5). As more VRE is added to the system, the magnitude and frequency of changes in net load increase.

The system needs to have sufficient flexible resources in place to match these variations. The cost of doing so may be connected with increased cycling and start-ups of power plants and other costs in the system to increase its flexibility in operation. As discussed in Chapter 4, while flexibility is of critical importance to VRE integration, the cost implications from increased cycling and start-ups may not constitute a very large part of total system costs even in a system with significant VRE penetration, particularly as older inflexible plants are retired and more flexible plants added to the system.

Figure 2.5 • Illustration of the balancing effect for different annual shares of VRE



Notes: load data and wind power data are for Germany from 10 to 16 November 2010. Wind power generation is scaled, actual annual share being 7.3%; scaling may overestimate the impact of variability; for illustration only.

Key point • As the share of VRE generation increases, net load shows more pronounced short-term variability.

Depending on system circumstances, the balancing effect will become noticeable in the net load pattern at VRE penetration levels above a few percent (in the order of 5% in annual share). In very small island systems, this number will be lower, while in large systems with a good correlation between demand and VRE generation, it is likely to be higher. The low impact at smaller shares is connected to the fact that the variability in electricity demand alone is already significant in all power systems and, therefore, the additional variability from VRE will have little importance at low shares. In addition, at small shares VRE may actually decrease the short-term variability of net load thanks to benefits of increased diversity. This can be seen when comparing fluctuations in VRE generation, demand and net load (Figure 2.6).

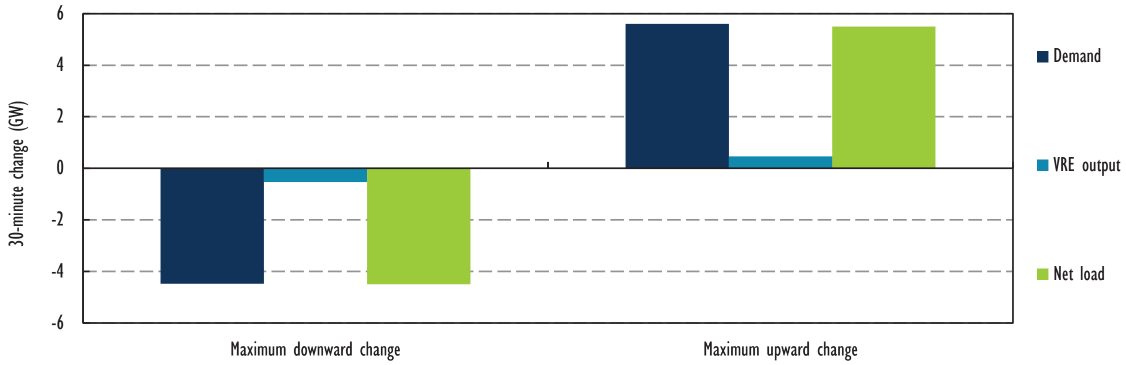
Above and beyond its significance for power plants, the balancing effect also has important implications for flows in the transmission and distribution grid, which also become more volatile (see Volk, 2013, for a more detailed discussion).

Utilisation effect

The utilisation effect captures all effects that are linked to how often a certain net load level occurs during a long time period (say one year), irrespective of when these levels occur over the course of the year.

The utilisation effect can be best illustrated using a load duration curve. A load duration curve is a way to display the electricity demand in a power system over a long period – typically one year.

Figure 2.6 • Comparison of maximum 30-minute changes (upward/downward) in France in 2011



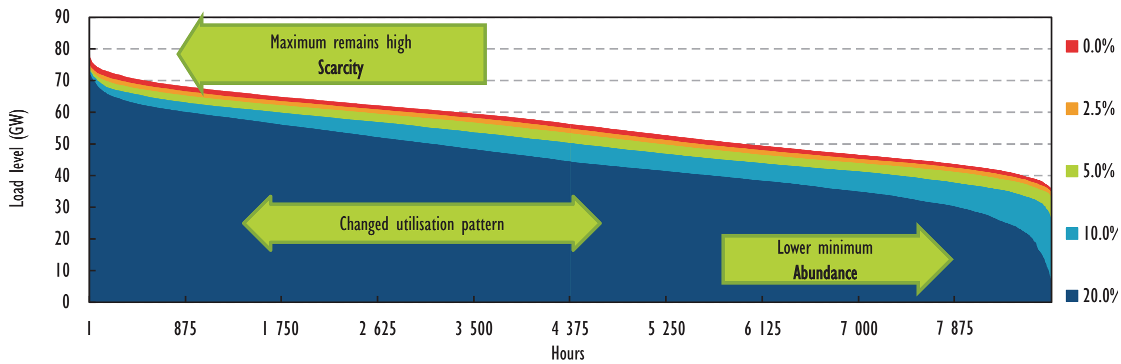
Notes: the net load 30-minute change represents the combined effect of demand 30-minute change and VRE generation 30-minute change. Installed wind power capacity is 6.7 GW, solar PV 2.8 GW.

Key point • At low penetration levels, VRE variability has little influence on net load variability. VRE may decrease short-term variability at low penetration levels.

Normally, electricity demand is shown over time (Figure 2.5). For constructing the load duration curve, electricity demand is re-ordered according to the level of electricity demand. The hour with the highest electricity demand comes first, and then the second largest and so on until all data are ordered in descending order (Figure 2.6). If VRE is present in the system, the same exercise can be made with the net load, by sorting the net load time series.

What is achieved by this way of showing the data? Firstly, peak demand can immediately be read off. It is the value on the very left in Figure 2.6. Secondly, minimum demand can be seen on the very right. It is also possible to immediately read off how many hours of the year demand will be larger than a particular value. In Figure 2.7 below, demand exceeds 60 GW for about 3 500 hours of the year, or 40% of the time. This means – and that is why this representation is very useful – that 60 GW of capacity can achieve capacity factors of 40% or higher, because they operate at least 40% of the time. If the load duration curve is very flat, the majority of installed capacity can achieve high full-load hours.[6] Conversely, a steep load duration curve implies that more capacity will see lower capacity factors.

Figure 2.7 • Illustration of the utilisation effect for different annual shares of VRE



Notes: load data and wind power data for Germany 2010. Wind power generation is scaled, actual annual share being 7.3%; scaling may overestimate the impact of variability; for illustration only.

Key point • At low VRE shares, meeting net load may imply a more favourable utilisation than meeting total load. At higher VRE shares, overall utilisation is reduced.

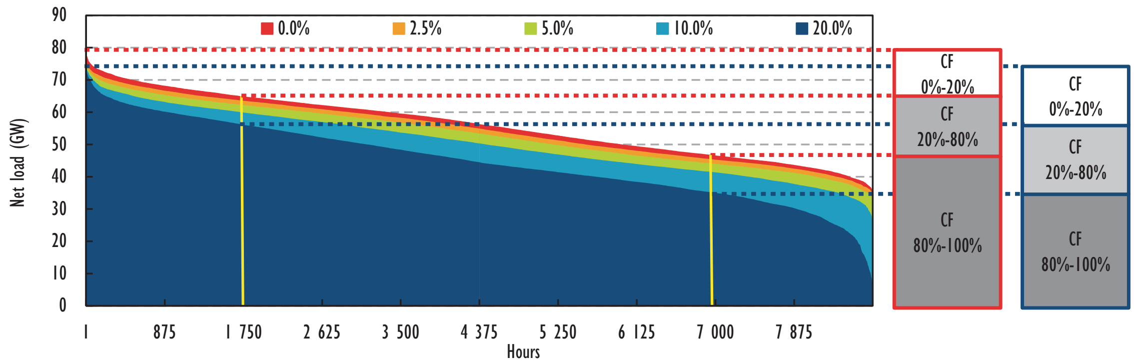
6. Achieving high capacity factors may require that plants are sufficiently flexible to respond to changing power demand across time. This becomes particularly relevant at high shares of VRE due to the balancing effect.

At high shares of VRE, the net load duration curve tends to become steeper. The reason for this is twofold. Firstly, maximum net load tends to decrease more slowly than the average net load. As a result, the left side of the curve remains high (scarcity periods of VRE production). Secondly, minimum net load tends to decrease faster than average net load, meaning the right side drops away more quickly (abundance periods of VRE production). Consequently, the curve becomes steeper and less non-VRE generation capacity can achieve high capacity factors.

The precise effect critically depends on the mix of VRE that is deployed, its variability and correlation with electricity demand. In fact, at low VRE shares (exact values are highly system-specific) the load duration curve may even become flatter when adding VRE. At higher shares, if a well-designed VRE mix with a favourable correlation with electricity demand can be deployed, the utilisation effect will be of less relevance.

The balancing effect requires that power plants can operate in a flexible manner, i.e. start and stop production at short notice and ramp quickly in a wide range. The utilisation effect implies that the dispatchable power plant mix needs to be cost-effective, even when the plant fleet as a whole has a lower average capacity factor. Those power plants that are cheapest at a low capacity factor are known as peaking plants. Those that are cheapest in an intermediate range of capacity factor are known as mid-merit plants. Plants that are cheapest when running practically all the time are known as baseload plants. Consequently, higher shares of VRE shift the optimal mix towards more mid-merit and peaking capacity (Figure 2.8).

Figure 2.8 • Impact of the utilisation effect on optimal power plant mix



Notes: CF = capacity factor. Load data and wind power data for Germany 2010. Wind power generation is scaled, actual annual share being 7.3%; scaling may overestimate the impact of variability; for illustration only.

Key point • *At high-VRE shares, the optimal power plant mix typically has a higher share of peaking and mid-merit generation.*

The implications of the utilisation effect differ fundamentally depending on the adaptation of the dispatchable plant mix. Therefore – as mentioned in the previous section – a distinction is required between the transitional and the persistent utilisation effect.

When a large amount of VRE generation is added to a power system quickly, it is usually not possible to adapt the overall power plant mix simultaneously with the scale-up of VRE. As a result, power plants that may have been designed to operate as mid-merit plants will have to operate as peaking plants. This implies a reduction in their capacity factor and a change in the way they are operated (e.g. frequent start/stops, more frequent ramping and long periods stopped). Similarly, at sufficiently high-VRE shares, baseload power plants will need to operate as mid-merit plants when this type of utilisation is not prevented by technical constraints. This situation – which is a principal driving force behind the drop in market prices due to VRE in some markets – is referred to as the transitional utilisation effect. It occurs when the power plant mix is not adjusted to cover net load. Over time, the power plant mix is likely to adapt to the changed shape of the net load duration curve and the possibly more variable operational pattern. Once such an adaptation has taken place, the actual utilisation of power plants will match their design again, i.e. there will be fewer baseload plants installed but they will be able to operate at regular intervals, if they are flexible enough.[7] The share of mid-merit and peaking generation will increase in the dispatchable plant mix and also these plants will see "normal" full-load hours again. The structural shift towards mid-merit and peaking plants is termed persistent utilisation effect.

The transitional utilisation effect may cause challenges in stable power systems with little demand growth or infrastructure retirement. Until the installed power plant mix has been adjusted to the new operational pattern, power plants will tend to see lower capacity factors than they may have been expecting; however, this may also be caused by reasons other than VRE deployment (e.g. changed fuel prices, economic environment). In dynamically growing power systems with high investment needs, the transitional utilisation effect can be avoided by ensuring that investments are in line with future utilisation patterns.

In the long term, the economic significance of the persistent utilisation effect depends on a number of factors, in particular the relative costs of electricity from baseload, mid-merit and peaking generation and the cost of measures to mitigate the persistent utilisation effect. A wide variety of such measures is available, ranging from geographic aggregation of VRE, deployment of optimised mix of VRE technologies (discussed in Chapter 5) to dedicated flexibility investments (Chapter 7).

Box 2.1 • The challenge of low load and high VRE generation

When VRE sources are added to a stable power system, where capacity adequacy and flexibility levels do not depend on VRE availability, periods of very low VRE generation are not challenging – the system can be operated as it had been before adding VRE sources. However, when VRE generation covers a large portion of power demand during a period of time, challenges may arise.

To ensure reliability and power quality standards, the system needs a sufficient amount of different additional system (ancillary) services from generation and loads. Historically, these services have been provided predominantly from conventional power plants using synchronous generators (see section below). If no alternative solutions for providing system services are available, conventional power plants may need to continue generating electricity above required levels just in order to be available to provide ancillary services. VRE output may need to be curtailed consequently. This situation currently occurs in Ireland, where non-synchronous generation (VRE and imports over direct current [DC] interconnectors) may not account for more than 50% of generation at any point in time according to operating protocols of the system operator. This limit is already reached at certain times.

Alternative sources need to be found to relieve conventional power plants from the obligation to provide system services and allow them to shut down when their generation is not needed. As explained in Chapter 5, VRE technologies themselves can provide a range of system services, if grid codes and market arrangements allow for it.

Uncertainty

It is not possible to fully predict wind speeds and solar irradiation. Therefore, the generation level that a VRE power plant can deliver at a future point in time cannot be determined with certainty.

The level of uncertainty changes considerably with the length of time forecasted (forecast lead time); this lead time represents the distance between the moment when the forecast is made and the forecasted period; the shorter the lead time, the more accurate the forecast (Figure 2.9).

7. Above a certain VRE share, baseload plants may no longer be cost effective, however.

Uncertainty differs from the other VRE properties. It is not a characteristic of VRE per se, but is tied to the accuracy of meteorological forecasts. This immediately highlights the critical role of accurate forecasting techniques; the better the forecast, the lower the uncertainty.

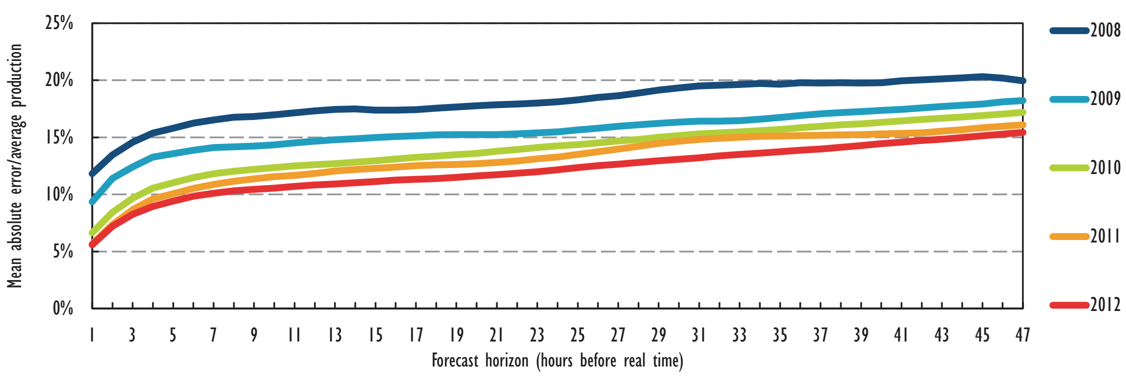
Forecast errors are distributed randomly;[8] an increase in sample size tends to decrease the error. Therefore, forecasts for larger areas are more accurate and relative uncertainty of VRE production is smaller.

The quality of forecasts has seen important improvements over recent years. For example, the mean absolute forecast error in Spain has been significantly reduced during the past five years (Figure 2.9), as a consequence of methodological improvements but also of increased observability of VRE. Short-term forecasts (i.e. looking ahead one to three hours) show only half the forecast error that was observed four years ago. Day-ahead forecast errors have been reduced by one-third. Hour-ahead forecasts are approximately three times as accurate as day-ahead forecasts. This has important implications for integration strategies. Moving operational decisions closer to real-time makes planning decisions much more accurate.

Solar PV power forecasts are less mature than wind power forecasts. Given clear skies, solar PV power output can be predicted with very high accuracy, because the output is determined by the position of the sun, which is easy to calculate. However, snow coverage and fog can lead to rare but high forecast errors. In Germany, fog impacts have only been included in forecasts for about two years (i.e. since 2011). However, these are often still included manually, based on fog maps produced by the German meteorological service. Automated inclusion of detailed fog forecasts is the subject of ongoing research.[9]

Every power system holds reserves available to provide electricity supply in the case of an unexpected event, such as failures or forecast errors. Traditionally forecast errors related to forecasts for electricity demand.

Figure 2.9 • Improvement in wind power forecasts in Spain, 2008-12



Source: based on data from Red Eléctrica de España.

Key point • *Wind power forecasts have improved over recent years. Forecasts looking ahead only a few hours are more accurate than day-ahead forecasts.*

Increasing VRE deployment tends to lead to increased reserve requirements, because the risk of forecast errors increases. However, the exact definition of reserves, the way they are calculated, how they are procured and what technologies are allowed to provide them, all have an influence on the overall significance of VRE's effects on reserve requirements.

8. Forecast errors do not follow a normal distribution. They follow a non-parametric distribution with thick tales; this means that infrequent but very large errors are relevant for system planning and operation (Hodge et al., 2012).

9. E.g. "Improvement of grid integration from electricity generated by photovoltaic systems via the optimized forecast and real-time estimation of solar power input", see www.energymeteo.com/en/projects/Solar.php.

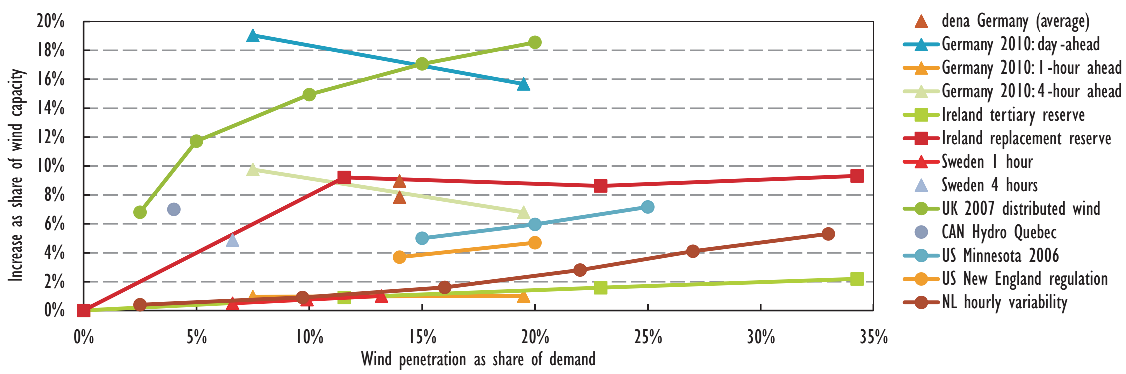
Measures that reduce uncertainty (or failure to adopt such measures) can affect the type and quantity of reserves required in order to maintain system reliability. Such measures have two main targets; first, having forecast data available; second, effectively using the data to influence operational decisions, which requires additional tools.

In addition, in systems where load has historically been prone to large forecast errors, the relative impact of VRE on additional reserve needs can be smaller. The additional supply-side uncertainty introduced by VRE is not felt as strongly against the backdrop of an already high level of demand-side uncertainty.

Recent work under IEA Wind Task 25 summarises current studies on the increase in reserve requirements resulting from higher shares of wind power (Holttinen et al., 2013).

The estimates of increases in reserve requirements due to VRE vary widely. This is due to different time scales of uncertainty taken into account in different studies, but also whether other sources of uncertainty, such as outages or operational failure of the power grid, are included (the impact of the timescale can be seen in Figure 2.10). If only hourly variability of wind power is taken into account when estimating the increase in short-term reserve requirement, the results are 3% of installed wind power capacity or less, with penetrations below 20% of gross demand. When four-hour forecast errors of wind power are taken into account, an increase in short-term reserve requirement of up to 9% to 10% of installed wind power capacity has been reported for penetration levels of 7% to 20% of gross demand (Holttinen et al., 2013).

Figure 2.10 • *Increase of reserve requirements as a function of wind power penetration*



Source: Holttinen, H. et al., 2013.

Key point • *If reserve requirements are based on hourly forecast errors, increases in reserve requirements are significantly smaller than if based on four-hour forecast errors.*

Reserve requirements are determined by the aggregate uncertainty on the level of the power system. Because different sources of uncertainty are independent from each other (failure of a thermal generator is generally not correlated with load or VRE forecast errors), the aggregate uncertainty on the system level is smaller than the sum of individual uncertainty factors. This needs to be taken into account when calculating reserve requirements. Holding dedicated reserves against VRE uncertainty is technically unnecessary and economically inefficient.

Because wind and solar PV power output varies, it is now widely recognised that wind-induced reserves should be calculated dynamically: if allocation is estimated once per day for the next day instead of using the same reserve requirement for all days, the low-wind days will require fewer system reserves. Avoiding allocation of unnecessary reserve is cost-effective and can be an important factor for successful integration of VRE at higher penetration levels (Holttinen et al., 2013).

The time steps chosen for dispatch and market operation will also influence the quantity and type of reserve required for balancing. For example, centralised markets in the United States that operate at five-minute time steps can automatically extract balancing capability from the generators that will ramp to fulfil their schedule for the next five-minute period (Holttinen et al., 2013, see Chapter 5 of this publication).

Uncertainty-related effects also impact the flows of transmission networks. This can include unscheduled power flows between adjacent parts of a larger power system (see Baritaud and Volk, 2013 for details).

Location constraints

VRE resources (availability of wind and sunshine) are not evenly distributed geographically. While the same is true of conventional fuels, the difference is that VRE resources cannot be shipped to different locations. Potential generation sites that have high-VRE resources may not coincide with areas of high electricity demand. For example, wind resources are often particularly strong offshore and sun is available most abundantly in deserts. This can require the construction of transmission lines to connect distant VRE generation.

Construction of new transmission lines to connect distant resources may face a chicken-and-egg problem. New generation is only likely to be built if transmission will be available. Conversely, transmission will only be built if there will be generation. To overcome this problem, the Public Utility Commission of Texas (PUCT) established competitive renewable energy zones (CREZs) (Box 2.2). Grid infrastructure to connect projects in these zones was ordered by the PUCT. The project was planned to transmit more than 18 GW of wind power from West Texas and the Panhandle to highly populated metropolitan areas of the state.

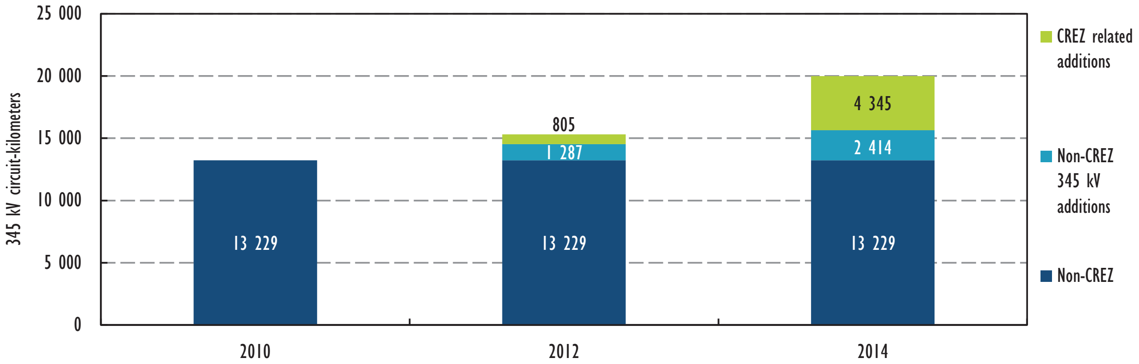
Accessing high quality resources generally lowers the per kilowatt hour generation cost of VRE power plants. However, connecting distant plants to the grid can be costly. As a result, there is often a trade-off between accessing distant, higher-quality resources and the increased costs of connecting distant VRE plants. Planning of grid infrastructure can take into account such possible trade-offs: less favourable resources closer to load might be more cost-effective. Also curtailing a small share of production can avoid considerable transmission capacity and can therefore be cost-effective (e.g. Volk, 2013; Agora Energiewende, 2013). It is noteworthy that this balance keeps shifting; the lower the cost of VRE generation is, the less valuable higher resources become compared to the cost of grid connection.

Box 2.2 • CREZs in Texas

In 2005, the 79th Texas Legislature (Senate Bill 20) ordered the PUCT to designate CREZs in Texas and to order specific transmission improvements that would be required to connect the CREZs to load centres in the ERCOT area. The PUCT designated five zones that cover much of West Texas. Distances between these zones and the major load centres in the east are as much as 650 kilometres.

For the CREZ transmission improvements, the PUCT selected from among several options a plan that foresaw a significant amount of new 345 kilovolt right of way, that can accommodate an additional 11.5 GW of wind power generation capacity in West Texas and the Texas Panhandle (Figure 2.11) (ERCOT, 2013).

Figure 2.11 • Total length of 345 kilovolt circuit-kilometres in Texas



Source: ERCOT, 2012.

Key point • Additional transmission lines were approved in Texas to connect distant wind resources before the deployment of additional wind power plants.

Modularity

The scale of individual VRE production units is much smaller than that of conventional generation. Modern wind turbines typically have nameplate capacities of between 1 megawatt (MW) and usually do not exceed 7 MW. Single solar panels have rated capacities in the order of 0.0001 MW to 0.0003 MW. This is much smaller than typical sizes of large thermal power plants, which have capacities in the order of 100 MW to 1 000 MW. As such, VRE power plants can be built in a wide range of sizes. They can be very small, when using only a single turbine or a few solar panels. They can be very large, when combining many turbines or panels.

Deployment of wind power and solar PV frequently occurs at a scale that is much smaller than conventional power plants. Smaller installations are connected to the distribution rather than the transmission grid. The increasing amount of smaller, distributed generation leads to important impacts, in particular, at the distribution grid level. Where distributed solar PV has reached a high penetration, the role of the distribution grid is changing; in addition to its traditional role of distributing electricity to consumers, it now hosts generation from a large number of small plants. This can imply a paradigm shift for the distribution level. Not only do power flows between the distribution and transmission grid become bi-directional, distributed generation could entail further changes to the distribution level (e.g. distributed storage) that require a smarter approach to this part of the power system. Operation and investment at the distribution grid level may have to be adjusted in line with this new role.

The main issue is not that today's distribution grids are in principle not capable of feeding back power to higher voltage levels. This is possible technically in virtually all cases, although sometimes it may require reconfiguring certain protection systems. However, challenges may arise with regard to:

- dimensioning overall grid infrastructure
- maintaining voltage levels within acceptable ranges.

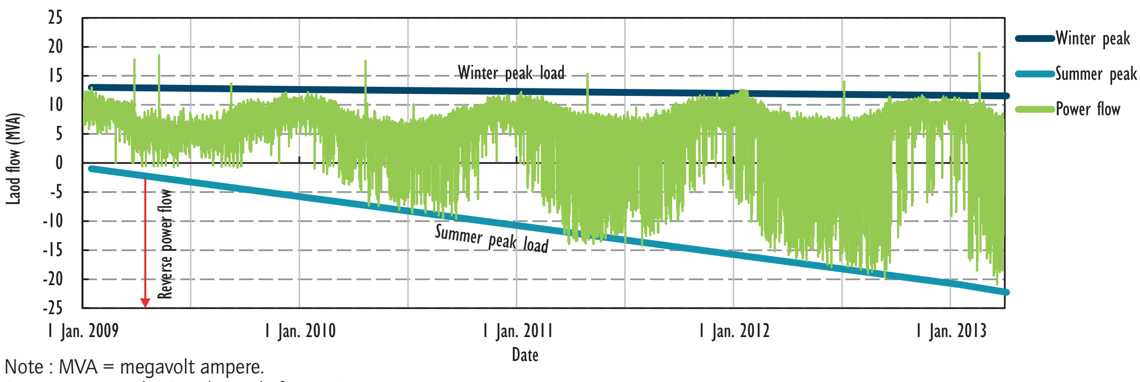
In addition, anticipating future additions and planning the system accordingly can be particularly challenging when a very large number of small-scale installations are concerned (for example, there are currently well above one million small-scale solar PV installations in Germany [EEG-KWK.net, 2013]).

Dimensioning of overall infrastructure

Current distribution grids are usually built to a size necessary to accommodate (anticipated) peak electricity demand. Distribution grid planners take into account the fact that individual consumers' peak electricity demand does not add up directly, because the peak demand of different consumers tends to occur at different times. As a result of this diversity effect, the system can be smaller than the sum of individual peak demands. This aggregation benefit tends to be higher for electricity demand than for distributed generation. In the absence of other solutions, in regions with very high solar PV deployment, it may be necessary to upgrade infrastructure to provide sufficient capacity to feed generation up to higher voltage levels. In southern Germany this effect is already observed. In locations with high densities of distributed generation, infrastructure size is determined by "reverse" power flows from the distribution to the transmission level (Figure 2.12).

The scale of existing infrastructure, as well as the availability of alternative solutions, such as smarter operational strategies, will determine the level of distributed generation at which such issues will arise. As a result, this will vary from one country to another. Newer and smarter distribution grids may have larger capacity available, providing more room for generation. Where grids are upgraded due to increases in demand or retirement of infrastructure, taking into account a potential future role for distributed generation at this stage will be more cost-effective than a later retrofit.

Figure 2.12 • Evolution of power flows at a German substation, 2009-13



Note : MVA = megavolt ampere.
Source: Bayernwerk AG and Fraunhofer IWES.

Key point • In areas with a high concentration of distributed generation, the required size of the distribution grid may be determined by "reverse" power flows from the distribution to the transmission level.

Voltage levels

Challenges related to maintaining local voltage levels within prescribed boundaries may constrain further addition of distributed generation before the size of the grid infrastructure becomes a relevant constraint.

Particularly in rural areas with long distribution grid lines, high in-feed from distributed solar PV may cause voltage to rise above permitted levels. This issue can be addressed by adapting the operation of solar PV inverters, such that they help to maintain proper voltage levels. However, this capability may require a somewhat larger dimensioned inverter.

Changes in voltage levels can also be mitigated by transformers with online tap changing technology. This capability is common in transformers connecting high-voltage and medium-voltage levels of the distribution grid. However, it may require switching the transformer frequently, which can increase wear and tear. While not common historically, modern transformers linking medium- and low-voltage grids can also offer such voltage control capabilities.

Institutional impacts

Institutional arrangements and practices will need to be updated to reflect the changing role of distribution grids.

Firstly, sufficient real-time data has to be collected at the distribution grid level to ensure secure system operation. This can affect the way distribution system operators (DSOs) handle everyday network operations.

Secondly, better co-ordination between TSOs and DSOs may become necessary. In particular, it will no longer be possible to treat the distribution grid as a passive load for the system. Instead, it will need to be integrated more closely into overall system operation. This includes procedures for exchanging information and control signals between TSOs and DSOs (see Volk, 2013, for a more detailed discussion).

Thirdly, planning processes need to be better integrated. DSOs need to have sufficient visibility of how the requirements of the grid are expected to evolve over the coming decades. In the absence of this information, it becomes more difficult to adapt distribution grids in a future-proof way, which in turn can lead to unnecessarily high costs.

When planning the future grid, the cost of grid infrastructure should be balanced with the generation costs for distributed VRE, with a view to minimising the sum of both. It may not be cost-effective to plan the grid to accommodate every kilowatt hour of distributed generation. Instead, it may be optimal to include a limited amount of curtailment of VRE generation (see Agora Energiewende, 2013).

Non-synchronous technology

Conventional power plants use what is commonly known as "synchronous generators". Essentially, these exploit the same principle as a dynamo on a bicycle. The movement of the generator is converted to electricity via the physical principle of induction. What most people will have experienced is that the intensity of light on the bicycle flickers when the speed of the bike changes. Such instability is not acceptable for the power system. The current solution for solving this issue is as follows: the rotation of all large generators in a synchronous power system is kept precisely at the same speed. All generators rotate synchronously at the speed corresponding to the system frequency. Indeed, synchronous generators have a direct electro-mechanical link with the grid; the collective synchronous movement of all the generators in an interconnected system defines the system frequency (Grainger and Stevenson, 1994).

This mode of operation has some important consequences. When there is a deviation from the target frequency (too high or too low), this deviation is experienced by all generators collectively and directly. For example, assume the frequency of a system starts to drop (because generation is falling short of consumption). This reduction will act directly on all the synchronous generators, trying to slow them down. However, synchronous generators are usually quite heavy machinery. When they are spinning, it requires a lot of energy to slow them down or speed them up; they have a considerable amount of inertia. This property helps to stabilise the system frequency.

System inertia is only one example of the properties of synchronous generators that are used to provide relevant services to the power system.[10] When the number of operating synchronous generators on a power system is reduced below a certain share, new ways of providing these services may have to be found. The exact share varies depending on system circumstances.

Wind and solar PV generation do not connect to the grid synchronously. All current state-of-the-art wind turbines and solar PV systems use so-called power electronics to feed their power generation into the grid. Simply put, this breaks the direct electro-mechanical connection with the system. For this reason, wind power and solar PV are sometimes referred to as non-synchronous generation.[11] Wind power and solar PV generators also have limited (wind power) or no spinning mass (solar PV) and therefore less or no physical inertia.

However, VRE generators may be designed to emulate the characteristics of synchronous generators. For example, the inertia stored in the rotating blades of wind turbines may be used to provide "synthetic" inertia. In the case of solar PV, this service requires equipping systems with very fast-responding energy storage.

10. Others include the provision of reactive power and high fault currents (which are needed to trigger protection devices when there is a fault in the system).

11. DC lines also connect to the system in a non-synchronous manner. This means that imports via DC lines are also non-synchronous sources of electricity for a power system.

The Irish system operators, EirGrid and SONI, commissioned a detailed study (EirGrid/SONI, 2010) that investigated the implications of high shares of non-synchronous generation for power system operation. In general, it was found that the Irish system — as it stands today — could manage up to 50% instantaneous non-synchronous penetration (wind power plus net imports over DC interconnectors). This operational limit is already reached at current wind power penetration levels. EirGrid is currently implementing a programme to increase the feasible instantaneous penetration rate to 75%.[12]

In the case of Germany, a recent study found that a minimum level of generation from conventional units may be needed, because a number of system services are currently provided only by conventional generators. Given current operating strategies, voltage control requirements implied minimum generation from conventional sources of between 4 GW and 8 GW (strong wind power generation/low load) and between 12 GW and 16 GW (strong wind power generation/strong load) (CONSENTEC, 2012).[13] However, these figures apply only under current procedures for the provision of system services; the study did not consider options to reduce minimum generation through adaptations to these procedures. Lowering these minimum generation levels is possible by finding alternative ways to provide system services.

This concludes the list of relevant VRE properties and related system impacts. It appears relevant to highlight that while wind power and solar PV share the above six properties, they differ in a number of relevant respects (Box 2.3).

Box 2.3 • Wind power and solar PV: both variable but not the same

Wind power and solar PV generation are both VRE technologies. However, they show a number of differences, which can be relevant for their system integration. These are summarised in Table 2.1 and explained in more detail in the following sections.

Variability and uncertainty of wind power and solar PV generation are linked to the statistical properties of their energy resource.

Sunshine varies most significantly according to the movement of the sun across the sky. It is only available during the daytime and – depending on the latitude – shows a more or less pronounced seasonal pattern. As a result, the largest component of solar PV variability can be calculated precisely (i.e. it is deterministic). However, clouds or other atmospheric phenomena such as fog, snow coverage or dust add an irregular, probabilistic component to solar PV output. On a plant level, solar PV is likely to be more variable than wind power generation, even after accounting for morning and evening ramps that are forecastable (Mills and Wiser, 2010). However, when aggregated over the area of a sufficiently large power system, solar PV output follows a smooth, "bell-shaped" pattern. Once such a pattern is reached, it is not altered significantly with further interconnection of more distant plants, because daylight hours are similar even on a continental scale. Forecast errors can be large, particularly at a local level, when snow coverage or fog is involved.

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

Solar PV shows a favourable **correlation with electricity demand** in some sunny countries. Wind power output exhibits weaker correlation with load; it can be negative or positive often also depending on where plants are located: onshore (which is greatest at night in many regions) or offshore (often greatest during the day).

12. For additional information check the EirGrid website pages dedicated to DS3: www.eirgrid.com/renewables/.

13. Assuming a low load of 32 GW and no commercial imports/exports, this would translate into an instantaneous penetration limit of 75% to 88%.

Aggregate solar PV generation shows daily **ramps** every morning and evening. These can be predicted, depending on a number of circumstances (Ibanez et al., 2012). These ramps can be reduced somewhat when integrating large areas, but will remain considerable even when integrating over many hundreds of kilometres. Aggregate wind power ramping events are less frequent and more difficult to predict. On the system level, variability arising from fast-moving clouds is generally not a significant issue.

Wind power and solar PV also differ in terms of their **modularity**. The vast majority of wind energy is deployed using wind turbines of 1 MW to 3 MW onshore and 5 MW and larger offshore. This is greater than many solar PV installations, which are often only a few kilowatts in size (in the case of roof-top solar PV systems). Consequently, solar PV generation is often connected to low-voltage distribution grids, while wind power usually connects at medium-voltage levels in the distribution grid and above, which is also the level where larger solar PV systems are connected. Wind power may also be deployed by aggregating many turbines to one large plant with several hundreds of megawatts, connecting directly to the transmission system.

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

Finally, wind power generation typically has higher capacity factors than solar. Relative capacity factors differ widely depending on location and technology but as a broad generalisation wind power plant capacity factors are about two times as high as solar PV.

Table 2.1 • Overview of differences between wind power and solar PV

	Wind power	*Solar PV*
Variability at plant level	Often random on sub-seasonal timescales; local conditions may yield pattern.	Planetary motion (days, seasons) with statistical overlay (clouds, fog, snow etc.).
Variability when aggregated	Usually shows a strong geographical smoothing benefit.	Once "bell shape" is reached, limited benefit.
Uncertainty when aggregated	Shape and timing of generation unknown.	Unknown scaling factor of a known shape.
Ramps	Depends on resource; typically few extreme events.	Frequent, largely deterministic and repetitive, steep.
Modularity	Community and above.	Household and above.
Technology	Non-synchronous and mechanical.	Non-synchronous and electronic.
Capacity factor	20% to 40%.	10% to 25%.

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

Power system properties

Apart from the properties of VRE itself, the properties of the power system – and in particular the way it is operated – will determine how easily VRE can be integrated. System and market operations as well as system flexibility are investigated in detail in Chapters 3 and 5, respectively. This section highlights additional general characteristics.

Balancing area size

Several factors relating to the size of the power system are relevant to integration of VRE. In general, bigger is better for VRE integration.

Firstly, by covering a large geographic area, variations from different VRE plants cancel out and the overall generation profile is smoother. Ideally the footprint will not be exposed to the same weather system at any point in time. Secondly, forecasting techniques are more accurate if a larger number of power plants are forecasted and they are not concentrated in one location (see Box 2.4). This means that the system will need relatively fewer reserves to guarantee the same level of reliability.

However — and this point is critical — these benefits will only materialise if the system is operated in the appropriate way. 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 in real-time (the balancing area) is central to the challenge. Balancing areas may be isolated by DC (controllable) interconnections, or they may be interlinked parts of a common (alternating current [AC]) grid.

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

Co-operation between balancing areas can significantly reduce the operational costs of power systems. The benefits of larger balancing areas tend to be more pronounced when VRE is part of the generation portfolio.

Match between demand and VRE supply

Where there is a good temporal and spatial match between VRE output and power demand, integration will most likely pose less of a challenge.

For example, a good temporal match between VRE supply and power demand may make it easier to balance net load than total load. Solar PV generation in Italy shows a positive correlation with power demand. As a result, load net of solar PV may be less variable than load alone.

A very variable power demand is also an indication of a positive opportunity for VRE integration, as the system has experience with dealing with high levels of variability. The additional variability will have less impact. In France, for example, due to a large amount of electric heating, there is significant weather-driven load variability already. Therefore, variability of wind power is largely "masked" behind the variability of demand in winter.

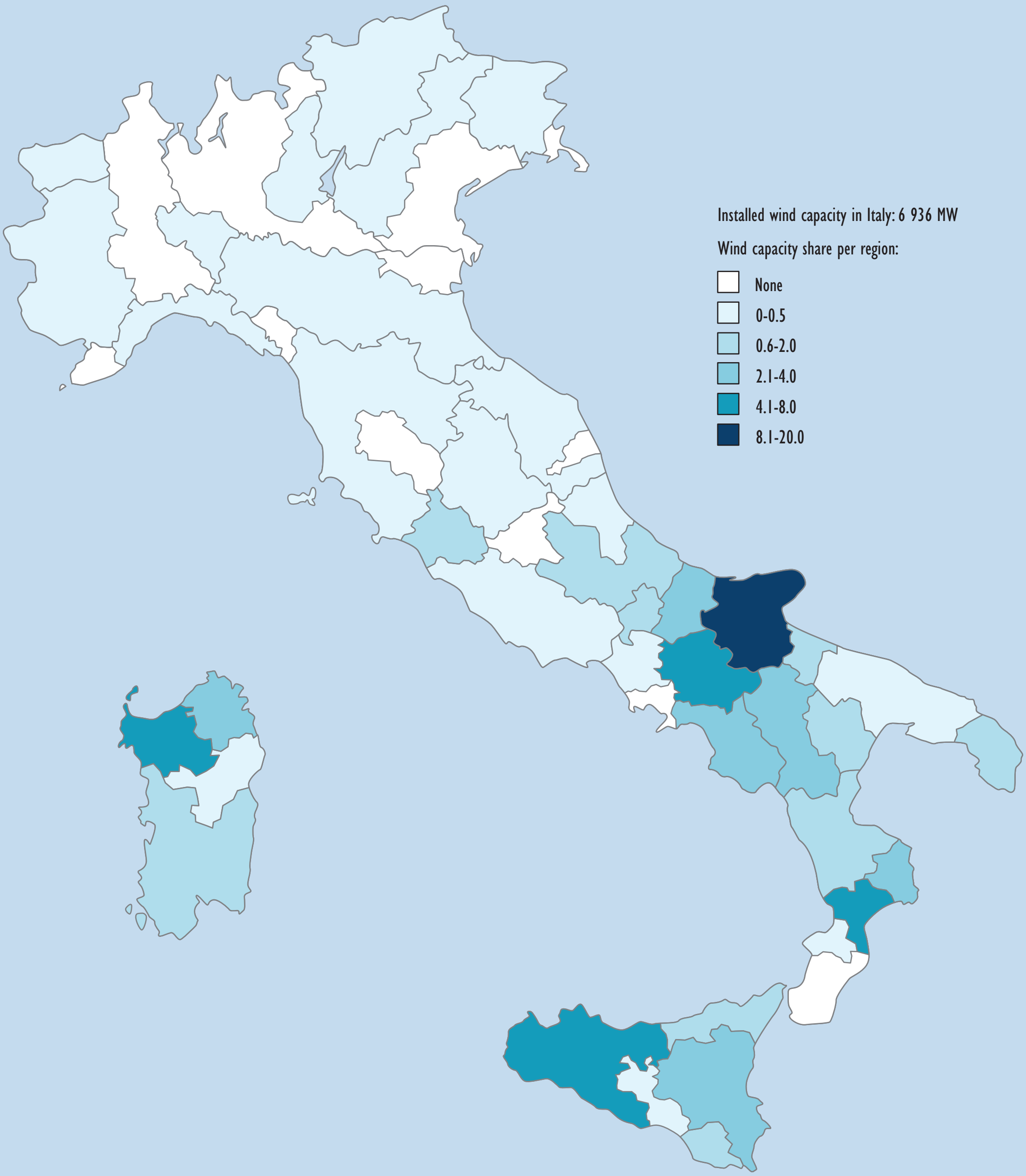
Box 2.4 • Hotspots: VRE deployment can result in local concentrations

VRE is usually held back by a suite of barriers, both economic and non-economic (IEA, 2011). Policy measures and other factors may reduce barriers so that they can be successfully overcome. There may be an important local component to where this is achieved, resulting from a possible regional concentration of resource, supply chain, infrastructure, as well as institutional and human capacity. In these situations, local VRE concentrations often strongly exceed the system average. This may require potentially costly investments to relieve local problems. Such hotspots are present in several regions in case study systems.

A salient example of such a hotspot is the southern Indian state of Tamil Nadu, which hosts a small number of excellent wind sites that comprise 40% of the country's installed wind power capacity (7.3 GW) in a very small region. In southern Italy, the region of Foggia accounts for 2.4% of Italy's land area but hosted over 17% of the total installed wind power capacity in the country (Figure 2.13).

Similarly, compared to the rest of Japan, Hokkaido is likely to experience a concentration of solar PV capacity according to currently expected additions (Figure 2.14). Hokkaido has a peak load of 6 GW (similar to Ireland) and, with a 600 MW DC interconnection to the rest of the country, it is one of the smallest power systems in the country.

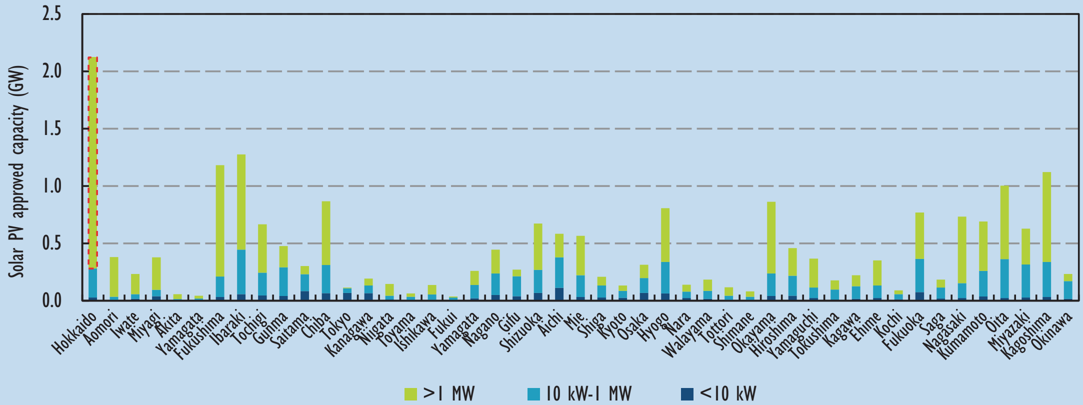
Figure 2.13 • Regional distribution of installed wind power capacity in Italy, 2011



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

Source: based on data from Gestore dei Servizi Energetici.

Figure 2.14 • Planned solar PV capacity in different regions of Japan, as of June 2013



Source: based on data from the Ministry of Economy, Trade and Industry, Japan.

The emergence of possible hotspots should be monitored when putting in place VRE support mechanisms. Introducing elements that guide additions geographically may help to avoid undesired local penetration spikes and thus increase overall cost-effectiveness.

Demand growth and infrastructure retirement

It may be easier to integrate large shares of VRE in countries where electricity demand is rising or where the infrastructure of the power system needs replacing. The reason for this is twofold.

Firstly, in the absence of demand growth or infrastructure retirement, additional generation is only possible to the detriment of incumbents. When VRE is added to such a system, the more flexible resources will tend to be used more for their flexibility than simply to provide energy, and if they cannot earn sufficient profit specifically from the flexibility they provide to the system, they will likely come under greater financial pressure than less flexible resources. From a policy making perspective this may add to the challenge of VRE integration: the downscaling of parts of the existing system may raise issues as well.

Secondly, where investments are required anyway, this opens a window of opportunity for making future-proof choices, i.e. deploying a resource portfolio that is in line with increasing shares of variable generation. Of the GIVAR III case study regions, non-OECD countries such as Brazil and India are in this favourable position.

Integration effects and system adaptation

Initial effects of VRE deployment

Experience shows that possible adverse impacts of VRE on power systems tend to be overestimated at the onset of deployment.

For example, in 1993 a group of German utilities expressed their concerns regarding the limited role renewables could have in future power systems: "renewable energies such as sun, hydro or wind cannot cover more than 4% of our electricity consumption – even in the long run" (*Die Zeit*, 1993). Today's share of VRE in Germany is at approximately 25%; the 2050 target is at least 80% (Bundesregierung, 2013).

To give another example, in 2003 the chairman of the western Danish system operator ELTRA (now part of the nationwide system operator Energinet.dk) stated, "... we said that the electricity system could not function if wind power increased above 500 MW. Now we are handling almost five times as much.

And I would like to tell the government that we are ready to handle even more, but it requires that we are allowed to use the right tools to manage the system." (IEA, 2008). The installed wind power capacity in Denmark stood at 4.2 GW at the end of 2012, accounting for more than 30% of annual generation; the 2020 target is 50%.

Part of these concerns can be attributed to frequent misjudgements regarding the variability and uncertainty that VRE will impose at a power system level. This is usually much lower than individual experience with weather patterns suggests. In addition, load variability and uncertainty are often not considered when initially gauging the impact that VRE may have on the system. Load has properties that are very similar to VRE generation. Hence, system operation can rely on the same resources to deal with these properties, provided operational procedures are updated.

At very low penetration rates, i.e. in the order of 2% to 3% of electricity generation, wind power and solar PV generation will hardly be noticeable from an operational perspective, because load variability and uncertainty dominate overall net load properties. As long as VRE deployment does not occur on a highly concentrated basis geographically, net load variability with VRE may actually be lower than load variability thanks to diversification benefits.

At higher shares, typically in the order of 5% to 10%[14] of annual electricity generation, technical integration challenges are unlikely to pose any significant barrier, assuming that VRE is deployed in the right way (see Chapter 5) and operations are adjusted (Chapter 6).

As discussed in the next chapter, higher penetration levels are technically feasible in all case study power systems. However, this will require adapted system operation strategies supported by well-designed power markets, where applicable.

System effects before and after adaptation

The system effects associated with VRE deployment depend on the individual characteristics of power systems. Reaching a full understanding of the effects that increasing VRE shares will have on a specific power system requires a system-specific analysis, a so-called integration study.

As part of its Task 25 "Design and Operation of Power Systems with Large Amounts of Wind Power", the Wind Implementing Agreement (Wind IA, 2006) has developed a number of best practice guidelines for the methodology of integration studies which are available on the Task 25 website.[15] The recommendations are applicable for other variable renewable sources, including photovoltaics.

More generally — and most importantly — benefits and challenges also depend on the degree to which the system as a whole has an opportunity to adapt to increased shares of VRE.

As the discussion of system impacts in this chapter has shown, the following impacts may typically be observed when adding VRE generation to a power system with already adequate capacity, little demand growth and/or infrastructure retirement:

- fuel cost savings
- reduced short-run marginal system costs (merit-order effect)
- displacement of most expensive generation (transitional utilisation effect)
- reduced emissions (if not already capped by other policy instruments)
- increased variability and uncertainty of net load leading to increased cycling of plants and need for reserves (balancing effect)
- saturation of the distribution and transmission grid

14. This share can be lower in very small, isolated island systems.

15. www.ieawind.org/task_25/PDF/WIW12_101_Task%2025_Recommendations_submitted.pdf.

- increased share of non-synchronous generation, which may affect system stability in particular in small systems at moments of high generation.

In the long term, impacts depend on the degree to which the overall system can adapt to high shares of VRE and minimise total system costs under these new circumstances. This is likely to entail:

- structural shift of the dispatchable generation fleet towards more mid-merit and peaking generation (utilisation effect)
- increased short-term variability and uncertainty of net load (balancing effect)
- need for increased grid capacities to smooth variability, connect distant VRE resources (transmission grid) and distributed generation (distribution grid)
- system services provided from additional providers, not only conventional generators
- cost-effectiveness of additional investments in power system flexibility to reduce economic impact of balancing and the utilisation effect.

Chapter 4 investigates methods to quantify the economic impact of these effects. The operational and investment strategies to cost-effectively address these impacts – including system-friendly deployment of VRE itself – are discussed in Chapters 5, 6 and 7. The next chapter assesses the GIVAR III case study regions with regard to their current technical capabilities to absorb VRE generation.

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3 • Technical flexibility assessment of case study regions

HIGHLIGHTS

- Investigation of seven case study regions across 15 countries highlighted a wide diversity in overall generation mix, ranging from hydro dominated systems (Brazil) to systems relying almost exclusively on thermal generation (Electric Reliability Council of Texas [ERCOT]).
- Current variable renewable energy (VRE) penetration is highest in the Iberia case study region, accounting for 21% of annual generation. Brazil and Japan have the lowest VRE penetration levels today (below 2% in both cases).
- From 2012-18, expected terawatt hour (TWh) additions of VRE are twice as high as increases in demand in the North West Europe case study region and 20% higher in ERCOT. Demand increase significantly outpaces VRE additions in Brazil and India.
- The technical capability of power systems to host increasing shares of VRE was analysed with the IEA revised Flexibility Assessment Tool (FAST2). The analysis shows that, if flexibility provision is a priority for system operation, sufficient flexibility supply can be provided across a wide range of system contexts to support penetration levels in the order of 25% to 40% without any shortfall in flexibility, given currently installed flexible resources.
- When accepting curtailment during only a few hours of the year, these numbers increase considerably and reach levels above 50% in some of the systems investigated. However, achieving such shares cost-effectively may call for a more profound transformation of power systems.
- Even when using a set of overly pessimistic assumptions (e.g. only power plants provide flexibility and these are operated in disregard to flexibility), penetration levels of 5% to 10% in annual generation do not lead to any significant VRE integration issue.

Phase III of the Grid Integration of Variable Renewables project (GIVAR III) investigated seven case studies, covering 15 countries. They were selected on the basis of their experience of integrating VRE and their anticipated increase in wind power and solar generation. In addition, the regions show differences in their current generation mix and the extent to which they can be categorised as stable or dynamic systems. Brazil and particularly India fall under the latter category.

All analysis presented throughout this publication has benefitted greatly from detailed background interviews with selected stakeholders in the case study regions. Based on over 50 stakeholder interviews, the current view on VRE integration was investigated in the case study regions during visits to the respective countries and during expert consultations. More specifically, the market design in the case study regions was assessed in detail, based on literature review and stakeholder interviews. This analysis is integrated in Chapter 6 and the full set of results can be found in a separate IEA Insight paper (Mueller, Chandler and Patriarca, forthcoming). Finally, a questionnaire was sent to system operators in case study regions, to collect time series data on power demand and wind power and solar photovoltaic (PV) generation, along with data regarding the presence of other flexible resources. These data have been used to assess the technical flexibility of the case study regions, which is the focus of this chapter.

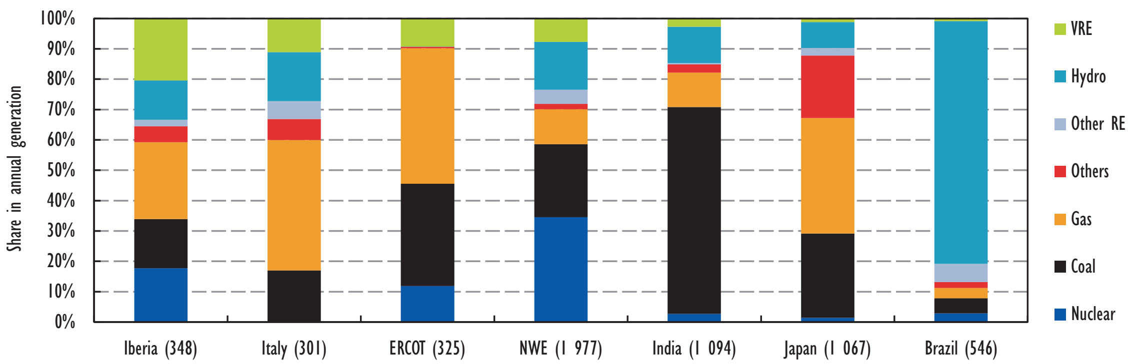
To put the technical analysis into context, the first part of the chapter reviews the current and projected levels of VRE deployment and general system characteristics of the case study regions. The discussion then turns to a description of FAST2 that was used for the flexibility assessment, explaining the basic approach and relevant assumptions before discussing the results of the assessment.

Overview of case study regions and system attributes

The power systems of the case studies show a wide variety in their generation mix, as evidenced by data from 2012 (Figure 3.1).

India generated over 80% of its electricity by burning fossil fuels (coal, gas and oil), whereas the renewable energy share stood at 15%, with 12% hydro and 3% VRE, mainly wind power. **Italy's** generation mix relied two-thirds on fossil fuels, with 16% hydro and 11% VRE, comprising 4% wind power and 7% solar PV. This is the highest solar PV share of all case studies. With 21% VRE, the **Iberian Peninsula** boasts the case studies' highest VRE share in electricity generation. The latter is based on 4% solar PV and 17% wind power. The Iberian case study region also has the highest wind power penetration. Of Iberia's electricity, 46% is generated from fossil fuels and 18% from nuclear power plants. Water-rich **Brazil** generated 80% of its electricity with hydro power plants in 2012, 10% from fossil fuels and less than 1% from VRE. The current generation mix in the **North West Europe** (NWE) region consists of around one-third nuclear, one-third fossil fuels and one-third renewables. VRE accounts for 8% in the mix, comprising 6% wind and 2% solar PV. **Japan's** generation mix has undergone a major transformation since the 2011 Tohoku earthquake and the shut down of nuclear power plants following the major accident at the Fukushima Daiichi nuclear power station.[1] Japan's electricity generation from fossil fuels rose in 2012 to 86%. Hydro represented 9% and the VRE share was at less than 2%. The **ERCOT** case study region relies heavily on fossil fuels (79%) and generates 12% from nuclear power. The 9% VRE share is based on wind generation.

Figure 3.1 • Generation mix of case study power systems, 2012



Notes: RE = renewable energy. Numbers in brackets indicate generation in terawatt hours.

Source: unless otherwise indicated, all tables and figures in this chapter derive from IEA data and analysis.

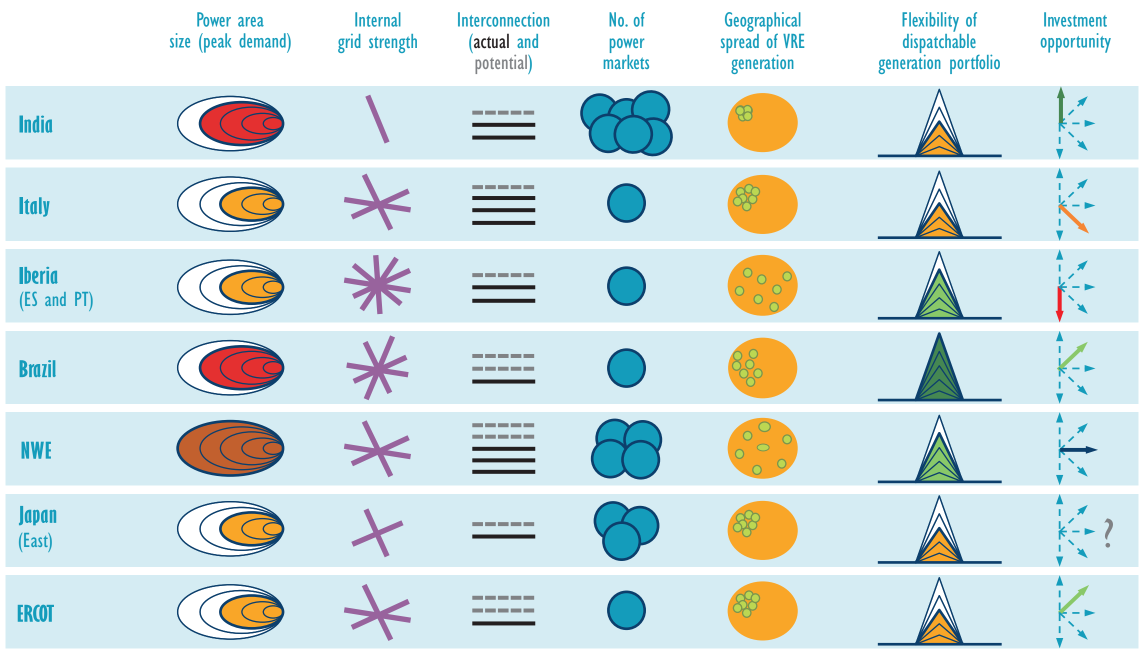
Key point • Case study regions show large differences in their power generation mix.

Further differences between case study regions can be illustrated by scoring them according to a number of fundamental system properties (Figure 3.2). The properties are selected according to their relevance to VRE integration:

- **Power area size.** An area with a large installed capacity, such as NWE, is likely to contain a larger number, and thus potentially more diverse mix, of power plants. In addition, due to statistical effects, variability and uncertainty effects are felt to a lesser degree in large power systems.

1. Deployment data is reported for Japan as a whole; the assessment of technical flexibility is performed for the Japan East region, which is defined to include Tokyo, Tohoku and Hokkaido.

Figure 3.2 • Overview of GIVAR III case study power system properties



Notes: storage and demand-side integration resources also present in systems but not included in the overview. See Annex C for details on scoring.

Key point • GIVAR III case studies cover a broad range of power system contexts.

- **Internal grid strength.** A strong grid is one that has sufficient capacity to transport power from one part of the case study area to another. If a part of the grid experiences congestion, flexibility requirements and resources on either side of the congestion cannot be matched. Grid strength is thus critically important in the assessment of an area's capability to balance variability.
- **Interconnection.** Where an area has a high potential to interconnect with adjacent areas, it has the opportunity to make use of the flexible resources of its neighbours. Very large areas will have proportionately less potential for interconnection, and isolated islands negligible potential, while small areas embedded in continental size systems have a large potential.
- **Number of power markets.**[2] In some cases, the supply and demand for electricity is not matched over the area as a whole. For example, the Iberian countries of Spain and Portugal form one power market, in which demand and supply are broadly matched as one. Conversely, the area of Japan East is made up of three distinct power utilities, which are only weakly interconnected and which do not co-ordinate among each other in such a way.
- **Geographical spread of VRE generation.** Dispersed VRE plants will have a smoother aggregated output than plants closer together. Broadly speaking, the larger the area, the smoother its aggregated VRE output, because weather conditions will not be the same over the whole. Conversely, the smoothing effect will be limited if VRE plants can only be sited in certain areas, which may result from resource constraints or competing land uses.
- **Flexibility of dispatchable generation portfolio.** The existing power plant portfolio is an important factor. Plants that can be dispatched (commanded to power up or down) at short notice will provide

2. Consolidating power markets to form larger market areas is only one step towards reaping the full benefits of aggregating demand and supply over a larger region. The area over which the system is balanced in real time (the so-called balancing area) is of key importance. A single market area may contain multiple balancing areas; balancing area co-ordination and expanding the size of balancing areas is beneficial for cost-effective integration.

important, fast flexibility. A predominance of slower plants, including some fossil power plants, and most existing nuclear power plants, does not mean an absence of flexibility, but rather a resource that will be less able to do so in the very short term, i.e. within minutes or hours.

- **Investment opportunity.** This item scores the degree to which investment in power system infrastructure is needed independent of VRE integration. Such opportunities allow for a more dynamic adaptation of the system to the presence of VRE. Growing power demand or upcoming retirement of old infrastructure create such opportunities. This type of system is referred to as a dynamic system. Systems that have little investment opportunity are referred to as stable systems.

Current and projected VRE deployment levels

The IEA publishes historical data and forecasts on installed renewables capacities and shares of generation over a horizon of five years in its *Medium-Term Renewable Energy Market Report* (IEA, 2013a). Based on these data, current and projected VRE deployment levels are reported.

Longer-term scenario projections are available in the IEA *World Energy Outlook* (*WEO*) (IEA, 2013b) and the IEA *Energy Technology Perspectives* (IEA, 2012). These data were used as an indication of longer-term VRE deployment trends.

Installed capacities and short-term forecast

In 2010, the NWE region led the field in installed VRE capacity with a total of 64 gigawatts (GW), about 30% of which were solar PV (Table 3.1). This reflects both the large absolute size of this case study region, but also a high concentration of VRE in some parts, in particular Germany. Although significantly smaller, the Iberia case study region featured 30 GW of VRE capacity in the same year, with onshore wind as the dominant source.

Moving to 2012, a number of trends are evident. Firstly, solar PV sees a very dynamic increase. In only two years, the aggregate solar PV capacity increased from 30 GW in 2010 to 68 GW in 2012. In particular Italy and Germany in the NWE region drove this increase, although solar PV capacity also increased considerably in Japan (from 4 GW to 7 GW). In the same period, wind capacity increased from 99 GW to 122 GW. India saw a sharp increase in wind power capacity, going up by 5 GW to reach 18 GW in 2012.

Projected capacities to 2018 indicate both continuity and change. NWE remains at the top of installed capacities, with a total just below 150 GW, split fairly evenly between wind power and solar PV. Brazil shows the highest growth rate (405%) between 2012 and 2018, although from a very low base (1 GW in 2010, 13 GW in 2018). High growth rates, combined with sizeable increases in absolute terms, are forecast in India (32 GW of additions, an increase of 130%) and particularly Japan (37 GW of additions, an increase of about 350%).

Table 3.1 • Actual and projected wind power and solar PV capacity (GW) in case study regions, 2010-18

		Iberia	*NWE*	*Italy*	*Japan*	*Brazil*	*India*	*ERCOT*
2010	Wind power	24	44	6	2	1	13	9
	Solar PV	5	18	3	4	<0.1	<1	<1
	Sum	29	63	9	6	1	13	9
2012	Wind power	27	53	8	3	3	18	10
	Solar PV	5	39	16	7	<0.1	1	<1
	Sum	33	92	24	10	3	20	10
2014*	Wind power	29	62	9	3	7	22	14
	Solar PV	6	50	20	16	<1	4	na
	Sum	34	112	28	19	7	26	14

		Iberia	NWE	Italy	Japan	Brazil	India	ERCOT
2016*	Wind power	29	71	10	4	9	28	15
	Solar PV	6	60	22	27	1	7	na
	Sum	35	131	31	31	10	35	15
2018*	Wind power	29	79	11	4	11	34	17
	Solar PV	7	69	24	39	2	11	na
	Sum	35	149	34	43	13	45	17
Percentage increase 2012-18	Wind power	+5%	+48%	+33%	+64%	+339%	+87%	+60%
	Solar PV	+25%	+79%	+46%	+463%	na	+745%	na
	Sum	+8%	+61%	+41%	+354%	+405%	+130%	+61%

Note: na = not available.

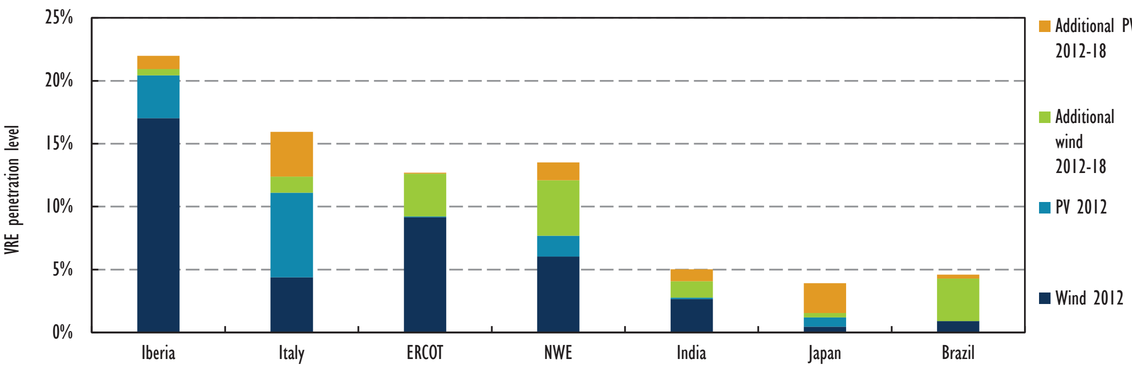
* Projection.

Key point • *Wind power and solar PV capacity is projected to see a strong increase until 2018 in most case study regions.*

Generation levels and short-term forecast

Comparing current and projected VRE shares in electricity generation[3] yields interesting conclusions (Figure 3.3). Whereas the Iberian Peninsula currently has the highest annual share of wind power and solar PV generation out of all case studies, its projected increase from 21% in 2012 to 22% in 2018 is small compared to the increase in other case study regions. Italy's and ERCOT's VRE share is projected to increase by around one-third to 16% and 13% respectively. In Italy this is driven by strong solar PV deployment, while the increase in ERCOT is driven by continued wind power deployment. For NWE and India, the VRE share nearly doubles by 2018 to almost 14% and 5% respectively, with a strong increase in wind power in NWE and a balanced deployment in India. The highest increase in VRE share is projected for Brazil, with a fivefold increase from about 1% to almost 5% due to strong wind power deployment. Japan's threefold increase to 4% is mainly driven by solar PV deployment. 57

Figure 3.3 • *Current and projected annual generation shares of wind power and solar PV in case study regions*



Note: calculation is based on demand projections and does not correct for exports or imports.

Sources: IEA projections based on data from ERCOT.

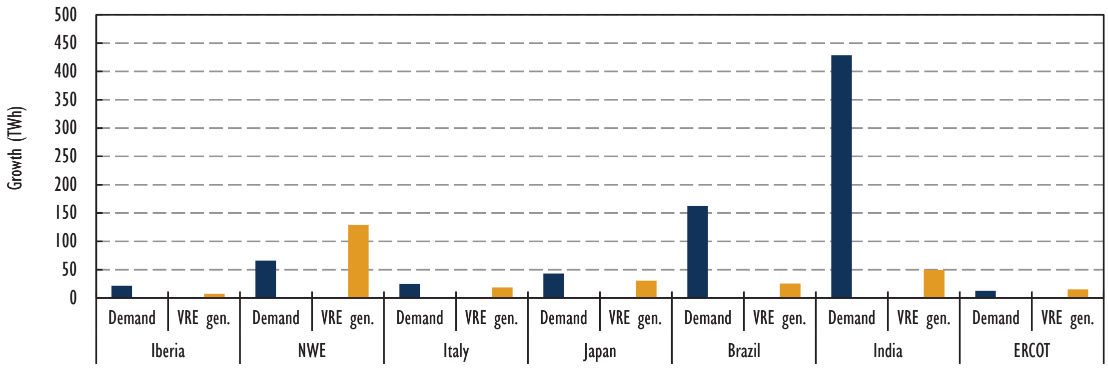
Key point • *Case study regions showed annual shares of wind power and solar PV in a range between 1% and 21% in 2012. All regions are expected to experience an increase from 2012 to 2018.*

3. Calculation is based on demand projections and does not correct for exports or imports.

Medium-term forecasts until 2018 expect VRE shares in electricity generation to stay below 25%, even in the leading case study region (Iberia). Italy, ERCOT and NWE are expected to see levels in the order of 15%, but some European countries are projected to see levels above this average (e.g. Germany approximately 23%). India, Japan and Brazil are projected to see annual generation shares around the 5% mark.

A comparison of the projected electricity demand and VRE growth from 2012 to 2018 reveals important differences between case study regions (Figure 3.4). In Italy and Japan, both demand and VRE grow moderately, with VRE additions around 75% of demand growth. In Iberia, growth is slower with VRE representing 35% of demand increase. The emerging economies of Brazil and India show dynamic growth in demand outpacing increases in VRE, which meets only about 15% of the demand increase. This implies only small increases in the share of VRE generation of these countries, although absolute deployment levels may be high. In the ERCOT region, VRE growth is expected to outpace demand growth by 20%. In NWE, VRE grows twice as fast as demand. This results in a dynamic growth of VRE shares.

Figure 3.4 • Growth in demand and VRE generation in GIVAR III case study regions, 2012-18



Note: gen. = generation.

Key point • Demand is forecasted to grow primarily in Brazil and India, while VRE generation growth is forecasted to be strongest in North West Europe.

Long-term projections

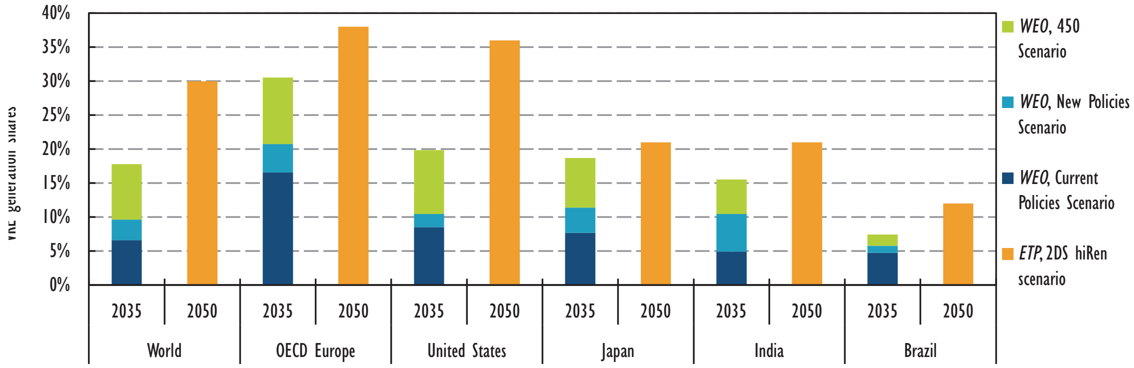
The *WEO 2013* (IEA, 2013b) features three scenarios with different increases in VRE shares to 2035. The New Policies Scenario incorporates the broad policy commitments that have been announced by the respective countries to tackle energy security, climate change and local pollution – although exact implementation has yet to be announced. The 450 Scenario sets out an energy pathway that is consistent with a 50% chance of meeting the goal of limiting the increase in average global temperature to 2°C, compared with pre-industrial levels. Finally, the Current Policies Scenario applies the assumption of a future based on policies and measures adopted by mid-2013.

By 2035, in Organisation for Economic Co-operation and Development (OECD) Europe (which includes the case study areas of Iberia, Italy and NWE), VRE shares in annual generation reach 31% in the 450 Scenario (Figure 3.5). In the United States (which includes the ERCOT case study region), Japan and India, VRE reaches shares of between 16% and 20% in annual power generation in the 450 Scenario. In Brazil, a 7% VRE share is projected. On a global level, VRE accounts for 18% of power generation in the 450 Scenario.

Generation levels are lower in other scenarios, ranging from just above 5% to 20% in the New Policies Scenario and between 5% and 15% in the Current Policies Scenario.

Looking further out to 2050, the 2°C High Renewables Scenario (2DS hiRen) in *Energy Technology Perspectives* (IEA, 2012) has significantly higher shares of VRE. The global average reaches 30%, while case study regions see shares between 12% in Brazil and 38% in OECD Europe.

Figure 3.5 • Projected annual generation shares of wind power and solar PV generation, 2035 and 2050



Key point • Wind power and solar PV shares are bound to grow in the long term and across different IEA scenarios.

Summary

Case study regions show significant diversity in their projected deployment of VRE and increases in demand. While Japan, India and Brazil have low VRE shares today, Iberia, Italy, ERCOT and some countries in NWE (Denmark and Germany) have higher levels.

All systems currently feature VRE shares of annual electricity generation below 22%. Forecast levels for 2018 are below 25% for all regions, with Iberia at 22%, Italy, ERCOT and NWE between 13% and 16%, and India, Japan and Brazil between 4% and 5%.

With the exception of the NWE and ERCOT case studies, demand is projected to grow faster than VRE until 2018. Iberia, Italy and Japan are predicted to increase VRE generation by rates corresponding to between 35% and 70% of demand growth. For dynamic systems like India and Brazil, VRE growth until 2018 makes up only a small fraction of overall demand increase.

In the 450 Scenario, VRE shares in power generation in 2035 stand at 31% in OECD Europe, between 16% and 20% in the United States, Japan and India, and 7% in Brazil. The 2DS hiRen scenario projects a global average of 30% VRE generation, with values between 38% for OECD Europe and 12% in Brazil.

FAST2 assessment

The case study analysis in the GIVAR III project includes a quantitative analysis of the flexibility of case study power systems. The objectives of the FAST2 approach are: 1) provide an initial, high-level assessment of power system flexibility; 2) raise awareness among policy makers of flexibility issues and motivate more detailed analysis; and 3) inform scoping of more detailed analysis.

Consequently, the method aims to be quick to use and have moderate data requirements. The assessment takes into account all four flexible resources: flexible generation, interconnection, demand-side response and storage. The results should be seen as a rough indication rather than a precise figure, even more so as the high-level analysis does not cover the full set of possible integration challenges. In particular, the assessment assumes that sufficient grid infrastructure is present within each case study region, modelling explicitly only the interconnection with other systems. Also, issues of power system stability are disregarded in the analysis.

The analysis uses a revised version of FAST. The FAST method was originally developed for the previous phase of the GIVAR project. FAST2 assesses the technical capability of a power system to deal with rapid swings in the supply/demand balance over time scales from 1 hour to 24 hours, which is a critical capability for VRE integration. FAST2 does not calculate an upper technical limit, but indicates what shares are technically feasible given currently installed flexible resources. Contrary to the original approach, the revised version does not calculate one maximum number, but rather measures how often periods of insufficient system flexibility will occur over a given year and at different penetration levels.

Methodology

The revised version refines the initial approach explained in detail in *Harnessing Variable Renewables* (IEA, 2011). One important new feature is that FAST2 assessments are based on time series of power demand and time-synchronised wind power and solar PV generation time series. This enables the capture of any case study-specific correlations between VRE generation and demand (e.g. increased generation from solar PV and higher demand for air conditioning). In addition, the operating state of the dispatchable power plant fleet is modelled in a new way. The main idea is to calculate the maximum amount of flexibility that can be obtained from dispatchable power plants, taking into account that this amount will vary at different overall generation levels.

The FAST2 flexibility assessment consists of three main steps:

- calculate the flexibility supply of the power system
- assess the flexibility demand
- compare flexibility supply and demand.

For the FAST2 assessment, flexibility is measured as the maximum upward or downward change in the supply/demand balance that a power system is capable of meeting over a given time horizon and a given initial operating state. As a result, the flexibility of a power system is a function of: 1) direction of the desired change (up or down); 2) time horizon (e.g. within the next hour); and 3) operating state (current operation level of different power plants). A flexibility measurement requires the specification of each of the three determining factors explicitly.

In this analysis, downward and upward flexibility are assessed independently. Regarding the time horizon, all full-hour intervals from 1 to 24 hours are analysed independently. The net load level is used to characterise the initial operating state. Flexibility (in a given direction and over a given time horizon) is usually different for different net load levels.

A flexibility option can improve the supply/demand balance in two different ways: either by increasing supply or reducing flexibility demand. In FAST2, flexibility supply comes from dispatchable power plants, interconnection and demand-side response. Flexibility demand arises from net load variability and uncertainty. Flexibility demand can be reduced by using storage to reduce net load variability and using VRE forecasts to reduce uncertainty.

Assessing flexibility demand

Based on one full year of time series data of load and VRE generation, the demand for flexibility as a consequence of variability is established by calculating the variability in net load over the different time horizons (1 hour to 24 hours) in upward and downward direction. For example, the net load of hour 2 is subtracted from hour 1 to get the first data point for one hour variability.

Flexibility is also needed to deal with unforeseen events (uncertainty). Flexibility reserves are modelled explicitly in FAST2 using the methodology described in The *Western Wind and Solar Integration Study Phase 2* (NREL, 2013). Wind power forecast errors are calculated assuming one hour persistence forecasts, i.e. the forecast error is equal to one hour wind power variability. Reserves are dimensioned dynamically for ten different levels of wind power generation to meet 70% of all forecast errors. Solar forecast errors are also calculated as persistence forecasts, but corrected for the predictable variability due to the movement of the sun. For this purpose, observed solar PV generation is compared to the level expected for a clear sky. For the next hour, it is assumed that the ratio of the two remains constant (see NREL 2013, p. 77 for details). Reserves are calculated dynamically using ten different categories based on the ratio of observed generation and generation assuming clear skies. The largest of these reserves are used during sunrise, because forecast errors are highest then. Reserves are dimensioned to meet 70% of all forecast errors. The total requirement (wind power and solar PV) is obtained as the geometric mean of the reserve requirement for each technology. The remaining errors are handled by faster-acting reserves, which are not modelled explicitly in the assessment. A more conservative version was also implemented. In this case, reserve requirements are static and dimensioned according to the largest observed variability in variable renewable generation over each time horizon.

Storage reduces the demand for flexibility by reducing the variability of the net load time series. In a first step, a target net load level is defined. The net load is then segmented into intervals that remain above or below this target level for a number of consecutive net load levels. One of two different procedures is applied to each net load segment, one for each segment above the target level (discharge), and a different one for each segment below the target level (charge). The approach for discharge is as follows. First, the amount of energy that can be discharged from the storage is calculated. Beginning with the highest load levels, load is reduced until all stored energy has been discharged or all points have been reduced to the target level. Charging works exactly in the same way as discharging, but with reversed sign, i.e. load levels are increased as far as free storage capacity allows. In both cases the maximum charging and discharging capacity constraints of the storage are respected.

Assessing flexibility supply

In virtually all systems today, the most important source of flexibility is dispatchable power plants. For each ramp direction, time horizon and net load level, FAST2 calculates the maximum amount of flexibility that all power plants in the studied system can provide. This is achieved by determining the operation of power plants depending on how flexible they are.

Each power plant is assessed taking into account three factors. Firstly, the maximum change in output that a power plant can achieve over a particular time horizon is noted. For example, a power plant may be able to change its output by 100 megawatts over one hour (ramping capability). Secondly, the minimum stable output level of the power plant is taken into account. Thirdly, the time a unit needs for starting up is considered. Power plants are then scored, by dividing the ramping capability by the minimum output. The larger the ramping capability or the lower the minimum output, the higher the score is. A second score captures whether the power plant can start up over a given time horizon (see Mueller [2013] for details).

FAST2 dispatches power plants according to their flexibility score. This dispatch is referred to as flexibility order dispatch. The flexibility order dispatch maximises aggregate flexibility from power plants.[4] It therefore provides an upper bound of what power plants can technically deliver, if their operation is determined by the desire to maximise flexibility. However, operating power plants in this way may be very different from a least-cost dispatch. Because the analysis in this chapter is purely technical, such economic aspects are not considered. In order to compare this very favourable scenario with a more conservative assumption, a merit-order dispatch was also implemented, where priority is given to power plants that have the least cost.[5] In both cases, the minimum generation of the dispatchable plant fleet is assumed to be 20%, to reflect current technical system circumstances.

4. The flexibility order dispatch is calculated separately for each combination of ramp direction, time horizon and net load level.

5. An adaptation of the least-cost dispatch was used to ensure sufficient operating reserves even in the absence of VRE. These were dimensioned such that 98% of all load variability could be handled at 0% VRE.

Data sources and preparation

The assessment is based on data for case study power systems that were collected via a questionnaire, sent primarily to transmission system operators or downloaded from publicly accessible websites. With the exception of time series of wind power and solar PV for the Japan East case study, all VRE generation time series are based on observed data, from either 2011 or 2012, if the latter was available. In the case of Japan, generation time series were derived as described in Oozeki et al. (2011) and Ogimoto et al. (2012). Time series for Brazilian wind power generation could only be obtained for a sub-set of installed wind power plants, corresponding to two-thirds of installed capacity. No data could be obtained for the India case study and therefore no assessment has been performed.

Net load time series were calculated for different VRE penetration levels by scaling historical time series data of wind power and solar PV generation to match a certain annual generation. Wind power and solar PV time series were scaled by the same amount, i.e. today's relative shares were maintained. This procedure is likely to overstate the variability from VRE generation, because it does not capture additional geographical smoothing that will occur at higher penetration levels, when VRE power plants are added in different locations. This smoothing effect is more pronounced in the case of wind power generation. For solar PV the general availability of sunlight (assuming clear skies) is quite similar even across fairly large regions, and the additional variability from cloud coverage is already smoothed in aggregate time series at lower penetration levels, as data checks revealed. The use of scaling for time series data makes the assessment more conservative.

Data on installed power plants were also requested via a questionnaire. Due to considerable remaining gaps, questionnaire responses were supplemented by IEA data on installed power generation. Power plants were assigned to different plant categories, with different flexibility characteristics.

Data on interconnection capacity were also obtained from questionnaires, supplemented by public sources (e.g. published net transfer capacities for the NWE case study). It was assumed that full interconnector capacity is available to provide flexibility.

Due to significant problems with data collection, the contribution from demand-side integration had to be estimated. Demand-side response capabilities are the maximum of either 5% of the net load level or 5% of minimum electricity demand, both in up and downward direction and over all time horizons.

Electricity storage was estimated based on available data on pumped hydro storage plants. It was assumed that all pumped hydro storage plants have storage available corresponding to eight hours at full output.

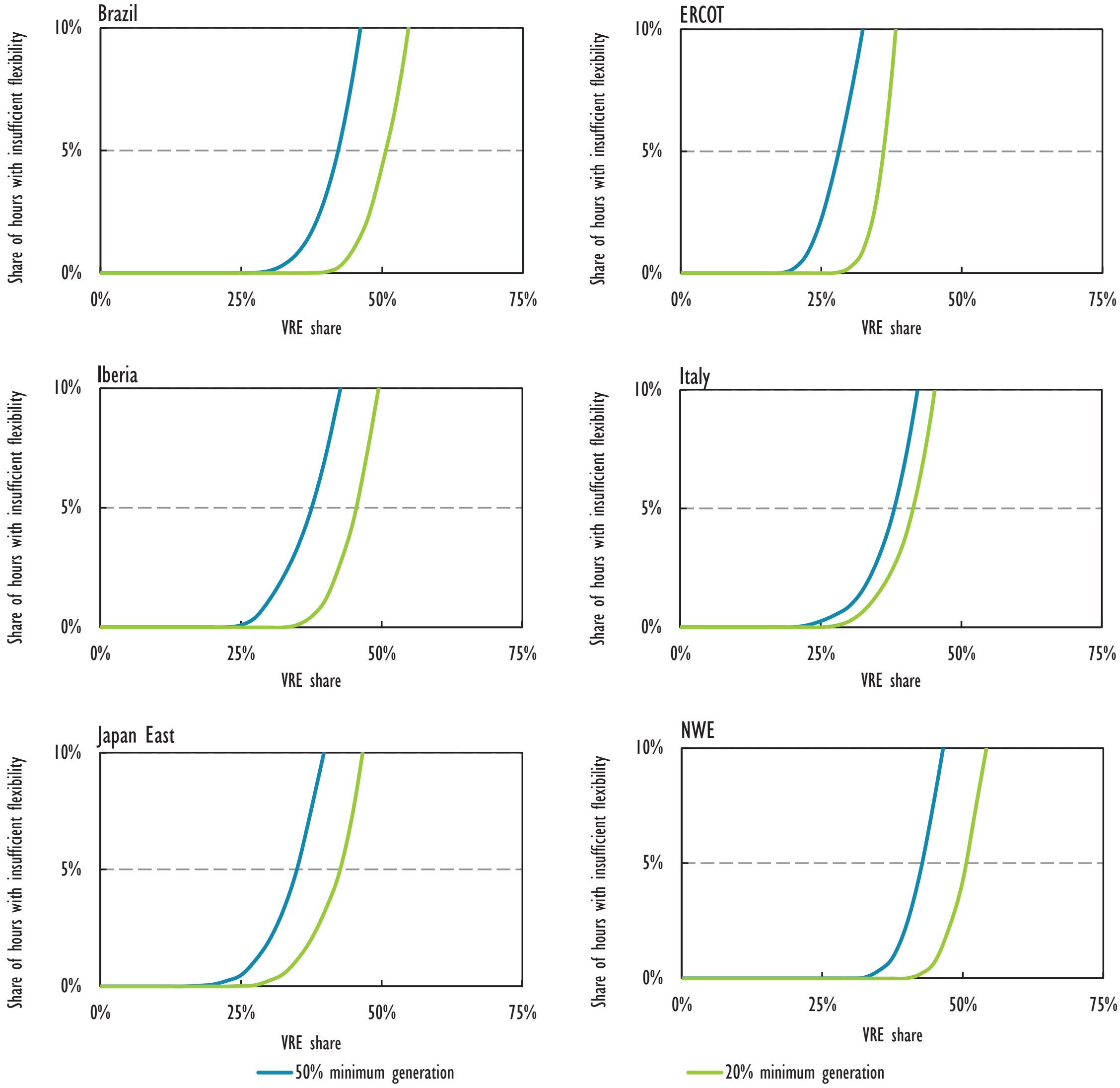
Detailed data on the assumed levels of flexible resources can be found in Annex C.

Results

The results of the assessment for six different case study systems are shown graphically in Figure 3.6. The curves show how often the system experiences periods with insufficient flexibility levels during one year at growing levels of VRE penetration. The x-axis shows gross VRE generation as a percentage of electricity demand. Gross means that curtailments are not taken into account, i.e. the net share will be lower if there is curtailment. The y-axis indicates the share of hours during which the demand for flexibility is higher than available supply. For example, a value of 10% means that that during 10% of the hours, flexibility supply is insufficient to meet demand. During hours of flexibility deficit, VRE curtailment would be the most likely consequence.[6] The assessment assumes that the present flexibility options are available up to their full technical potential. As such, the results do not correspond to a technical ceiling on achievable VRE penetration. Instead they indicate the point at which currently installed flexibility options come to their limits and additional flexibility investments are required from a technical perspective.

6. Calculating the actual amount of curtailed energy is beyond the scope of the current analysis.

Figure 3.6 • FAST2 analysis of case study system flexibility



Key point • *All case study regions support penetration levels in the order of 25% to 40% without any shortfall in flexibility given currently installed flexibility resources. When accepting curtailment during only a few hours of the year, these numbers increase considerably and reach levels above 50% in some of the systems investigated. Ensuring that other generation can turn down to a low level is important to ensure system flexibility.*

All assessed power systems show sufficient flexibility to support a penetration level of around 25% without any deficit in flexibility supply. ERCOT, Italy and Japan East are the three systems that experience periods of insufficient flexibility starting at around 25% in annual generation. The next system is Iberia with around 35% in annual generation. Iberia, while less interconnected than Italy, achieves this relatively high score due to both its large amount of gas generation and storage (see Annex C for details on plant mix and storage levels). The two most flexible systems are Brazil and NWE. In Brazil the abundance of reservoir hydro generation contributes to a very flexible system. However, once negative net load events become more frequent, the system begins to experience a flexibility deficit, because generation cannot back down further and other resources are very limited. In NWE, geographical aggregation and a diverse resource pool allow for particularly high shares of

VRE. A flexibility deficit is only observed above some 40% in annual generation. However, in order to achieve such levels in practice, interconnection within NWE, in particular with flexible hydro resources in Scandinavia would need to be strengthened.

As stated above, the minimum generation of the dispatchable plant fleet is assumed to be 20%. For a plant fleet with a higher minimum generation of 50%, the penetration level at which all systems show sufficient flexibility supply decreases from around 25% to 20% of annual generation. The range of supported penetration levels reduces compared to the results reported above, and falls to 20% to 30%.

The results in Figure 3.6 assume that all flexibility options contribute to their maximum potential. An additional analysis was performed, assuming that power plants are dispatched according to merit-order, i.e. minimising cost, and assuming very conservative reserve requirements (dimensioned according to maximum variability of VRE per time horizon observed in one year) and no contribution form other flexibility resources. Even under these very conservative assumptions, a flexibility deficit was only observed during around 5% of the hours of the year, at penetration levels between 5% in annual generation (ERCOT, Japan East, Italy) and 10% in annual generation (Iberia, NWE). Thanks to very flexible hydro generation in Brazil, even under such pessimistic assumptions no flexibility deficit was observed until a penetration of 20%.

Conclusions

The analysis shows that if flexibility provision is a priority for system operation, sufficient flexibility supply can be provided across a wide range of system contexts to support penetration levels in the order of 25% to 40% without any shortfall in flexibility. When accepting curtailment during a few hours of the year, these numbers increase considerably and reach levels of around 50% in some of the systems investigated. In case of a higher minimum generation of the dispatchable plant fleet, the range of penetration levels of all case studies decreases to 20% to 30%. This shows the sensitivity of the systems with respect to minimum generation levels, and underlines the importance of achieving low minimum generation levels of the dispatchable plant fleet for successful VRE integration.

The assessment assumes that grid constraints are not a barrier to increases in VRE. This is not the case in reality and grid constraints are currently a major reason for VRE curtailment, where VRE additions have been installed ahead of grid reinforcements. To reach the levels indicated in the assessment, grid reinforcements and expansion are therefore likely to be required.

The flexibility order dispatch may be significantly more costly than a minimum-cost plant operation. However, the assessment does not assume that power plants can be scheduled ahead of time to cater for known flexibility needs. In the assessment, it is assumed that a power plant that is turned off can only contribute to flexibility supply on a time horizon that is greater than its start-up time. In reality, plants will be scheduled ahead of time and thus a larger set of plants will be available. As a result, similar flexibility levels can be achieved at much lower cost in practice – if sufficiently accurate forecasts are available.

The scaling of historic VRE production data is likely to overstate the variability of wind power and solar PV at higher shares. This is relevant in particular in the case of Brazil, where the assessment is based on data obtained from a relatively low capacity base.

The most important flexibility deficits the analysis revealed are surpluses of VRE generation, rather than the variability in output. This can be seen, for example, in the case of Brazil, where significant amounts of reservoir hydro can be used. While a more detailed, system-specific study is required to obtain exact results, the technical ability of power systems to deal with fluctuations coming from wind power and solar PV generation seems to be quite high. However, even if fluctuations can be handled, surpluses of VRE generation may lead to curtailment.

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4 • Costs and benefits: the value of variable renewable energy

HIGHLIGHTS

- Calculating generation costs (levellised cost of electricity [LCOE]) may provide only part of the information required to compare different technologies. Whenever technologies differ according to the when, where and how of their generation, a comparison based on LCOE is no longer valid and may be misleading.
- The deployment of wind power and solar photovoltaic (PV) brings benefits and costs to the power system, the wider economy and society. An economic assessment of variable renewable energy (VRE) deployment needs to capture these costs and benefits appropriately.
- At the level of the power system, analysis of total system costs captures all relevant costs and benefits. Further disaggregating these costs and trying to extract specific integration costs can pose methodological problems. The impact of VRE (or any other technology) on total system costs can be assessed by calculating its (marginal) system value.
- The degree to which the system as a whole adapts to the presence of VRE determines the extent to which the system value of VRE remains robust at high penetrations. As such, the impact of high shares of VRE on total system costs will have a dynamic component: costs may rise during a transition phase (reflecting a lower value of VRE) while in the long run a multitude of different adaptation options can contribute to optimising the system in the presence of high shares of VRE.

Chapter 2 presented the principal impacts that VRE has at the level of the power system. Understanding the economic implications of these impacts is important, because it helps to address the following issues:

- estimating the impact of higher shares of VRE on total power system costs and, consequently, consumer bills
- assessing the cost-effectiveness of deploying VRE (or any other technology) from a system perspective
- prioritising research, development and deployment to develop flexibility options for facilitating VRE integration
- assessing the competitiveness of different power generation technologies from an investor's perspective
- calculating the costs that adding new technologies may impose on different actors in the power system.

This chapter discusses how to approach these issues by accounting for system effects in the economic analysis of a generation technology. It makes three relevant points in this regard. Firstly, the standard approach to calculating generation costs (LCOE) can be unsuitable for comparing different technologies. Secondly, current practices for including system effects in economic assessments (integration cost approach) suffer from fundamental methodological problems, which limit their applicability. Thirdly, an analysis at the level of total system costs (system value approach) avoids these methodological problems and is therefore preferable.

The first section of the chapter clarifies which costs and benefits are taken into account in the discussion. The remaining sections follow the order of the above three points; after making the case to go beyond generation costs, the discussion turns to current approaches to calculating integration costs. The section describes some of the methodological problems and resulting limitations of the approach. It also reports some recent estimates of integration costs, including a more detailed discussion of how to capture long-term effects (in particular the utilisation effect) in the integration cost picture. The last section introduces an alternative way to include integration effects in the economic assessment of a generation technology, the system value approach.

Social versus private perspective

Addressing the above issues requires the selection of the appropriate analytical scope. More specifically: which costs and benefits should be taken into account in the analysis?

Economic analysis takes either a private or a social perspective. A private perspective takes account of those costs and benefits that an investor pays and receives. For example, VRE is competitive if discounted income (including incentives) is larger than discounted costs. A social planner perspective takes account of all costs and benefits, including those that occur to other actors and are not priced (externalities). VRE is efficient if discounted social benefits outweigh discounted social costs.

The following analysis takes a social perspective, but is confined to effects in the power system, with the aim of addressing the first three of the above points. This can be termed a "total system costs" perspective. Total system costs of the power system are defined so as to include all fixed and operating costs relating to generation, grid infrastructure, storage and any costs incurred for enabling demand-side integration. To the extent that they are priced, emission costs are also part of total system costs. Effects that occur outside the power system, such as labour or fuel market impacts, are not considered here.

Total system costs are the costs that ultimately have to be recovered from electricity consumers or other sources, which makes this perspective relevant for policy makers. A total system cost perspective is also useful for prioritising VRE integration options, with the aim of minimising total system costs.

Going beyond generation costs

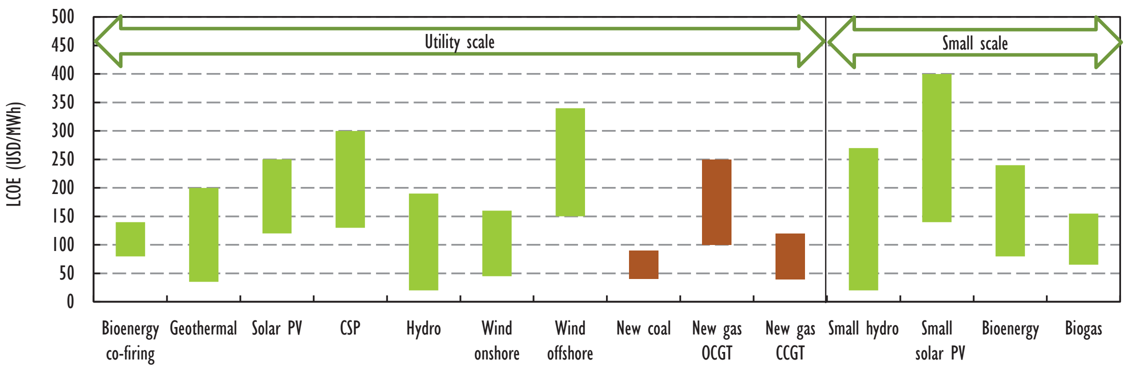
Generation cost for various technology options is most commonly expressed in energy terms and labelled "LCOE". LCOE is a measure of cost for a particular generating technology at the level of a power plant. LCOE is calculated by summing all plant-level costs (investments, fuel, emissions, operation and maintenance etc.) and dividing them by the amount of electricity the plant will produce. Costs that are incurred at different points in time (costs of building the plant, operational costs) are made comparable by "levellising" them over the economic lifetime of the plant — hence the name. The LCOE of wind power and solar PV has seen significant reductions over the past two decades (IEA, 2011a; IEA, 2013a; IEA, 2013b). In a growing number of cases, the LCOE of wind power and solar PV is close to or even below the LCOE of fossil or nuclear options (Figure 4.1).

However, LCOE as a measure is blind to the when, where and how of power generation. The when refers to the temporal profile of power generation that can be achieved, the where refers to the location of power plant, and the how refers to the system implications that the type of generation technology may have.

Whenever technologies differ in the when, where and how of their generation, a comparison based on LCOE is no longer valid and may be misleading. A comparison based only on LCOE implicitly assumes that the electricity generated from different sources has the same value.

VRE carries the temporal and spatial imprint of its resource, is more modular than conventional technologies and is typically not electro-mechanically coupled with the grid but via power electronics. All these factors affect the possible when, where and how of power generation from VRE. This has

Figure 4.1 • LCOE of selected power generation technologies, 2013



Source: unless otherwise indicated, all tables and figures in this chapter derive from International Energy Agency (IEA) data and analysis.

Key point • LCOE of wind power and solar PV has reached or is approaching the LCOE of other power generation options.

raised questions about the value of VRE for power systems since the onset of VRE deployment (Grubb, 1991; Rahman and Bouzguenda, 1994). To understand the economic implications of VRE deployment, it is critical to go beyond generation costs expressed in LCOE.

Integration costs and the value of VRE

There are two principal ways to incorporate the effects of when, where and how into the economic assessment of a generation technology. In practice, both approaches rely on sophisticated computer software that tries to accurately calculate the cost of power system operation and investments under different scenarios. The basic idea behind the two approaches is, however, quite different.

One approach consists of calculating so-called integration costs. Integration costs and appropriate ways to calculate them have received increased attention in past years (Milligan et al., 2011; Ueckerdt et al., 2013a; NEA, 2012; IEA, 2011b). The following sections therefore discuss some of the issues surrounding them. A contrasting approach considers the effect that the addition of a certain technology brings at the level of total system costs.

Integration costs

In the case of variable renewables, integration costs have been defined as “an increase in power system operating costs” when integrating VRE (Milligan and Kirby, 2009), as “the extra investment and operational cost of the non-wind part of the power system when wind power is integrated” (Holttinen et al., 2011), as “the additional cost of accommodating wind and solar” (Milligan et al., 2011), or as “comprising variability costs and uncertainty costs” (Katzenstein and Apt, 2012). However, the principle concept of integration costs is not limited to VRE.

The concept of additional costs as a result of supply-side variability and uncertainty may have historic reasons. VRE is the first power generation technology deployed at a large scale that shows a particular pattern of frequent variability and uncertainty of available generation capacity at timescales of minutes to days. However, quantifying the economic effects of these properties is surprisingly challenging.

Calculating integration costs is done by setting up different scenarios using appropriate modelling tools. One scenario includes the technology in question (most often VRE), and one does not include it at all or includes it at a lower penetration level. Cost differences between scenarios are noted and allocated to the technology in question using a range of techniques. However, there is no general rule on how to set up the scenarios or on which costs need to be taken into account.

Integration costs are calculated for different reasons and, as a result, the discussion typically focuses on different issues. In the context of vertically integrated utilities, integration costs can be "thought of as a tariff that is assessed to recover the increased cost that wind power causes to power system operations; they are a special case of a cost-causation based tariff" (Milligan et al., 2011). In particular in the United States, integration costs that are calculated in integration studies for utilities are sometimes added "to the bid or build price of wind resources to ensure that all costs associated with wind power generation are represented and that wind power is compared on an equivalent basis with other generation technologies" (Xcel Energy, 2011). Apart from the use as a tariff, the quote reflects the desire to obtain a more accurate view of the full costs of a technology by adding integration costs on top of generation costs.

This is a second motivation for calculating integration costs, which can be relevant independent of designing tariffs; for example, when trying to capture complex integration effects in energy system models that are not designed to explicitly represent the when, where and how of power generation technologies. One example is integrated assessment models that analyse the energy system more broadly and only have a simplified representation of the power system (Ueckerdt et al., 2013a). Similarly, NEA (2012) uses the term system costs to capture "the total costs above plant-level costs to supply electricity at a given load and given level of security of supply". By adding system costs (or integration costs) to generation costs, technologies can — in theory — be directly compared.

To single out those costs that are specific to certain properties, for example the variability and uncertainty of VRE, one needs to compare VRE with a technology that is identical in terms of all the when, where and how — with the only exception being that is neither "variable" nor "uncertain". This is where integration costs start to face real methodological problems (Milligan et al., 2011).

How can such a technology be defined so as to separate out only the additional cost of variability and uncertainty? No technology can produce power with 100% certainty — conventional power plants may fail to start, fuel supply may be interrupted or they may fail to produce according to schedule. It is possible to imagine a hypothetical technology that does not have any uncertainty in its output (perfect foresight about plant availability and performance). But if a 100% certain benchmark is chosen for calculating integration costs for a wind power or solar PV generator, a fair comparison with any other technology — say a large thermal plant — requires that both are benchmarked against a common reference. In this case, the thermal plant will also have integration costs.

The situation is even more complicated in case of variability. Power demand itself varies over time. Consequently, a stable output is not what a power system needs from all generators. However, integration studies sometimes assume a benchmark technology with a flat output profile as a basis for comparison with VRE. Adding such a technology leaves it to other generators to deal with demand variability.

In both cases (uncertainty and variability) the addition of any generation technology may impose costs on others in the power system. Integration costs are not specific to wind power or solar PV.

Comparing the cost of different technology options is only meaningful, if the benefits of each option are the same. In the absence of knowledge about the benefits, the cost information is of limited, if any value (see also Milligan and Kirby, 2009). Constructing such a common reference point, i.e. making sure benefits are identical, can be challenging (Ueckerdt et al., 2013a). Power generation technologies all have their strengths and weaknesses and have very diverse cost and benefit structures. Therefore establishing a single benchmark to compare against can result in comparing apples and pears. In addition, the possible benefits of one technology may critically depend on the presence of another technology. For example, the benefits of deploying two options in concert (for example wind power and solar PV at the right mix, nuclear power and pumped hydro) may be larger than the sum of individual benefits.

If used to design a tariff, integration cost analysis is connected to the question: "Who causes what costs and who should pay them?", which raises issues even more difficult to solve. The complex effects mediated by the electricity grid can make the attribution of causality extremely challenging, because the electric grid simultaneously integrates a myriad of effects that lead to a single, system-level outcome.

Moreover, if the addition of a new technology renders older technologies ill-adapted (adding VRE may cause problems for inflexible power plants), it is only the order by which technologies were introduced that could make the case that adding VRE is causing costs for inflexible generators, rather than the other way around. For example, when wind power is curtailed to accommodate the inflexibility of existing generators, one could argue that these should compensate wind power for the lost revenue.

A different methodological problem relates to the decomposition of integration costs. When calculating integration costs, the analysis is usually done separately according to the following different groups of VRE impacts on the power system (IEA, 2011b; IEA, 2011c; NEA, 2012; PV Parity, 2013):

- Balancing costs are intended to capture additional operational costs that a technology may impose on other parts of the system. In the case of VRE, this is linked to increased short-term variability and uncertainty of net load (referred to as balancing effect). Costs may arise from a need to hold and use more reserves against forecast errors, increased ramping and cycling of power plants or generally less cost-effective operation of other power plants.
- Adequacy costs: electricity systems must have enough generating capacity available to meet system demand even at peak times. This is known as system adequacy. Variable renewables tend to make a relatively low contribution to system adequacy, because only a small proportion of their potential output is certain to be available at times of peak demand. As a result, other plants are needed on the system to compensate for this variability.
- Grid-related costs are intended to capture additional need for grid investment. They may arise for connecting distant power plants, to reinforce the transmission grid or to build additional interconnections with adjacent systems. At the distribution level, the grid connection of small-scale generators may also require grid reinforcements.

Segmentation into the above three categories can be useful to derive a rough estimate of the economic relevance of each impact group. Segmentation is often necessary because existing power system models can only capture certain impact groups at once, i.e. they may specialise in assessing grid impacts, balancing impacts or adequacy impacts. For these reasons, estimates reported in this chapter are divided in this way (see below).

However, the different integration cost categories are not independent of each other. For example, increased investment in grid infrastructure may contribute to smoothing the variability of VRE at the system level, and thus reduce balancing and adequacy impacts. Similarly, a longer-term adaptation of the generation mix towards more flexible units will lower balancing costs, but may have consequences with regard to adequacy costs. A rigorous decomposition into the above three categories is thus generally not possible, due to the complex interactions in the power system as a whole. Because the different integration cost categories are not independent of each other, caution is needed when adding up components, in particular if they have been obtained from different modelling exercises. Moreover, the reference technology that has been used for calculating integration costs should always be clearly stated.

Different estimates of integration costs are presented in the following sections of this chapter. The wide range of cost estimates reflects the system-specific nature of integration challenges — and resulting costs — but also results from differences in the way costs were calculated. Consequently, different estimates may not be directly comparable and inherently include a high degree of uncertainty. Most importantly, estimates from the different categories cannot be added up.

Grid impacts

With high shares of VRE in a power system, it is highly likely to be economically efficient to increase transmission capacity. If VRE sources are connected to the distribution grid, increasing levels of distribution grid capacity and making the distribution grid smarter is also likely to be an optimal decision. On the other hand, if VRE generators are sited close to load (e.g. roof-top solar PV installations in urban areas), grid losses may be reduced. Comparing two scenarios with and without VRE deployment, incremental grid needs and power losses can be identified in a fairly straightforward way.[1] Existing integration studies have found varying additional costs due to grid-related impacts.

In the United States, significant renewable resources exist in relatively sparsely populated areas. For example, some of the largest wind power energy exists in the Dakotas and Montana, or in the southwest. Significant solar PV potential exists in the southwest and western states such as Arizona, California, Nevada and New Mexico. Annualised transmission costs range from USD 92 per kilowatt (/kW) at 6% wind power penetration levels to USD 46/kW at 30% penetration, according to the Eastern Wind Integration and Transmission Study (EWITS) (IEA, 2011c).[2]

The European Wind Integration Study (EWIS) analysed the cost of transmission investment needed in major EU member states to allow for targeted penetrations of wind power. It found that at wind power penetration levels of 10%, costs would amount to approximately USD 2.1 per kilowatt per year (/kW/yr), rising to USD 11.8/kW/yr at 13% penetration. This is equivalent to USD 0.97 per megawatt hour (/MWh) and USD 5.4/MWh respectively (IEA, 2011c).[3]

Ireland also provides an interesting example, because it has conducted one of the most extensive grid integration studies in Europe and because it may provide insights into integration costs in island systems (in comparison to continental systems). For wind power penetrations ranging from 16% to 59%, annualised transmission costs in Ireland range from USD 8.3/kW to USD 37.5/kW or, in megawatt hours (MWh), from USD 2.2/MWh to USD 9.7/MWh respectively (IEA, 2011c).

The PV Parity Project recently assessed grid costs associated with integrating 480 gigawatts of solar PV by 2030 into the European grid, finding modest transmission grid costs. In 2020 the cost is estimated at circa EUR 0.5/MWh, increasing to EUR 2.8/MWh by 2030. Reinforcing distribution networks to accommodate solar PV would cost about EUR 9/MWh by 2030 (PV Parity, 2013).

As part of the third phase of the Grid Integration of Variable Renewables project (GIVAR III), the cost of two generic distribution grids has been analysed (see Annex A for methodology). Depending on installed solar PV capacity per household and the structure of the distribution grid, costs range from USD 1/MWh for 2.5 kW of solar PV per household in an urban grid to USD 9/MWh for 4.0 kW of solar PV capacity in a more rural grid. Additional costs are low in the case of the 2.5 kW systems, because the size of the distribution grid is determined by a peak load contribution of 2 kW from each household in the absence of any solar PV generation.[4]

In terms of annual energy, the 2.5 kW case corresponds to over 60% of household annual electricity demand, while the 4.0 kW case corresponds to approximately 100%. The analysis assumes that the full peak generation of each solar PV installation can be absorbed by the distribution grid. Costs are much lower where solar PV generation is not injected back into the power grid. In this case, solar PV generation does not lead to an increase in the cost of the distribution system. However, if the density of installations is very high locally (i.e. some areas with systems much larger than 4.0 kW per household), costs are bound to increase.

1. However, additional grid capacity may bring other benefits, such as increased reliability. This would need to be taken into account when designing cost allocation frameworks on the basis of the results of modelling studies.

2. Levellised using a 15% discount rate. Assuming overnight construction.

3. Today, transmission needs in Europe are understood to serve the three main European targets of market integration, security of supply and renewable energy systems integration. System installation costs have roughly been allocated to these targets in the recent ENTSO-E Ten-Year Network Development plans, but, as transmission generally serves multiple purposes, the sum of the allocated costs is higher than the total cost itself.

4. This already accounts for the effect that the aggregate peak demand of a number of households is lower than the sum of individual peak demands.

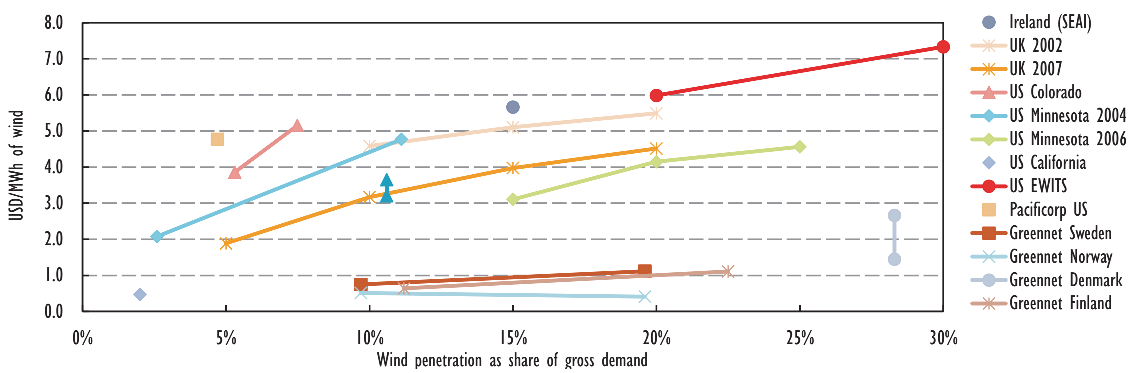
In summary, grid-related costs arising from increased VRE deployment are system-specific and cost allocation practices would need to recognise all beneficiaries of increased grid capacity. Grid-related costs may contribute very little to total system costs even at high shares of VRE, but their impact can be substantial, especially if distant, in particular offshore, resources have to be connected to the grid.

Balancing impacts

Balancing costs try to capture changes in the operational cost of the power system that are due to the balancing effect introduced in Chapter 2. However, the principal operational effect of adding VRE is avoided costs in the form of fuel savings. As such, balancing impacts are only one small component of overall operational impacts and it is hard to accurately separate them for other impacts.

The increased need for holding and using reserves to deal with forecast errors and variability during dispatch intervals will add to total system costs, as will increased ramping and cycling of other power plants and potential inefficiencies in plant scheduling. However, costs depend on operational practices, such as use of forecasts and market arrangements. Existing integration studies have taken this into account to varying degrees, i.e. they assume different levels of forecast accuracy and different scheduling practices. This needs to be kept in mind when comparing different estimates of balancing costs. Literature estimates for balancing costs for wind power (as surveyed by Holttinen et al., 2011 and Hirth, Ueckerdt and Edenhofer, 2013) range from USD 1/MWh to USD 7/MWh, depending on penetration and system context (Figure 4.2).

Figure 4.2 • Comparison of modelled balancing costs from different integration studies



Notes: SEAI = Sustainable Energy Authority of Ireland. Exchange rate USD/EUR = 1.3476.

Source: Holttinen, H. et al., 2013.

Key point • Balancing costs for wind power have been calculated between USD 1/MWh and USD 7/MWh of wind power. Costs are highly system-specific and tend to increase at higher penetrations.

The increased wear and tear associated with more frequent and deeper conventional power plant cycling was the focus of a recent integration study conducted by the National Renewable Energy Laboratory in the United States (NREL, 2013a). The study concluded that increased plant cycling added between USD 0.14/MWh and USD 0.67/MWh of VRE generation at an annual penetration of 33%. Cycling costs are dependent on the type of plant and how it was designed.

Structural shifts in the power system are likely to reduce the cost of balancing VRE, as more flexible power plants and other flexibility options are deployed.

Box 4.1 • Do variable renewables need back-up capacity?

The term "back-up" is somewhat misleading. It suggests that VRE needs to be supported by other generation capacity. However, it is power demand that needs to be covered with an appropriate generation mix. No additional dispatchable capacity ever needs to be built because VRE is in the system. On the contrary, to the extent of the capacity credit of VRE, its addition to the system reduces the need for other capacity. In simplified terms, capacity credit expresses by how much electricity demand can be increased following the addition of generation capacity to the system, while maintaining the same level of reliability (Keane et al., 2011).

A comparison between VRE and other generation technologies is useful to illustrate how VRE contributes to securing generation capacity at a system level.

Power generation technologies can be viewed as contributing both to meeting the overall *energy* need of the power system, and to securing sufficient generation **capacity** at all times. Different technologies contribute to both needs in different proportions. For example, peaking plants may contribute substantially to securing generation capacity, while contributing little in terms of energy. Baseload plants, on the other hand, contribute to meeting very large amounts of energy, even when their overall installed capacity is fairly low — a result of the fact that they operate most of the time.

It is useful to compare the contribution of a generation technology to energy needs (expressed as their capacity *factor*) with the contribution to capacity needs (expressed as their capacity *credit*). Typical values for the capacity *credit* of thermal power plants are in the order of their nameplate capacity, but older units may have considerably lower capacity credit. Capacity *factors* of peaking generation are usually in the order of 10%, while baseload plants run at capacity factors in the order of 80%. In summary, peaking plants have a higher capacity credit than their capacity factor. Baseload plants have similar capacity credits and capacity factors.

How does the contribution of VRE compare to these numbers? The capacity credit of VRE at low penetration rates varies in a wide range. If VRE generation is correlated with peak demand, capacity credit can be very high. For solar PV it is reported to be as high as 38% (PJM, 2010) in favourable cases. If VRE output is low or even zero at times of peak demand (solar PV with peak demand occurring in the evening when it is dark) the capacity credit may be close to zero.[31] Reported capacity credit values for wind power vary in a wide range from 40% of installed capacity to 5%, depending on penetration level and power system (Holttinen et al., 2013).

With growing shares of VRE, additional VRE capacity tends to have a low capacity credit. Why? The capacity credit of this additional VRE depends on whether its output coincides with times of peak **net** load. The critical point is this: the more VRE is already present in the system, the more often peak net load results from low wind power or solar PV generation. Because additional VRE generation is correlated with existing VRE output, adding more to the system will do little to increase output during these hours (Figure 4.3).

In summary, at low shares, the capacity credit of VRE can be higher than its capacity factor. In these cases, VRE adds proportionately more capacity than energy to the system. This renders it similar to peaking or mid-merit generation. In cases where VRE contributes to energy and capacity in a balanced way (capacity credit and capacity factor are similar), its contribution is similar to that of baseload plants.

When VRE has a lower capacity credit than its capacity factor, it contributes much more towards energy needs than capacity needs. This combination of energy and capacity contribution only occurs

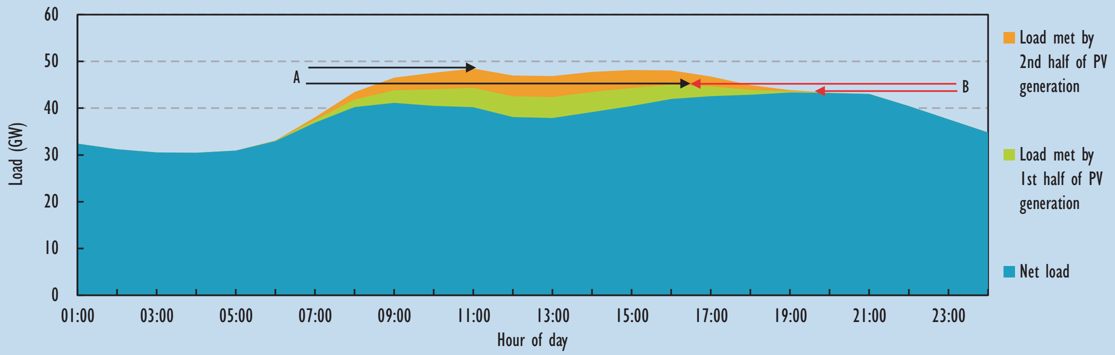
5. The capacity credit may not equal zero, even if output of the technology is zero at the moment of peak demand. What matters is the overall effect of the technology for reducing the probability of loss of load (see Keane et al., 2011).

at high-VRE shares or under specific circumstances (e.g. solar PV in countries with peak hours after sunset). This new combination has led to the development of calculation techniques that assess how much additional capacity credit is needed, to "balance" the capacity and energy contribution of VRE.

For example, in a power system with total annual electricity demand of 100 terawatt hours, a share of 10% wind power generation at a capacity factor of 25% corresponds to an installed capacity of 4.6 GW of wind power. If the same 10% of annual generation were covered by a baseload technology with a capacity factor of 80%, this would imply adding 1.4 GW of capacity to the system. Consequently, even when wind power generation has a low capacity credit when measured in terms of its installed capacity, it does not mean that there is a need to match every GW of wind power capacity to balance the contribution of wind power in terms of energy and capacity. In the above example, assuming a negligible capacity credit, say zero, each megawatt of installed wind power capacity would need to be matched with 1.4/4.6 = 0.3 MW of dispatchable capacity to obtain the same capacity contribution as from the baseload plant. Should wind power have a capacity credit of 10%, i.e. 0.46 GW of the 4.56 GW count towards securing capacity of the system, each MW of wind power capacity would need to be matched by (1.4-0.46)/4.6 = 0.2 MW of dispatchable capacity.

As stated above, it is not VRE that needs capacity. The system as a whole needs sufficient capacity and energy. At high shares, VRE tends to make an asymmetric contribution in this regard. It contributes more in terms of energy than in terms of capacity. What is needed on a system level is not "back-up" for VRE, but a cost-effective solution to meet electricity demand. As a result, at high-VRE shares the remaining power plant mix will need to contribute more towards securing capacity than serving energy. This shifted role and its economic impact are captured by the utilisation effect (see text). The impact of VRE as a result of low capacity credit should thus be assessed more comprehensively in terms of the utilisation effect – and not reverting to the idea of "back-up" capacity.

Figure 4.3 • Incremental reduction of peak demand when adding solar PV



Note: A = peak net load reduction from first batch of solar PV capacity; B = additional peak net load reduction from second batch of solar PV capacity.

Key point • *Peak load reduction of additional solar PV deployment can be lower at higher penetration levels.*

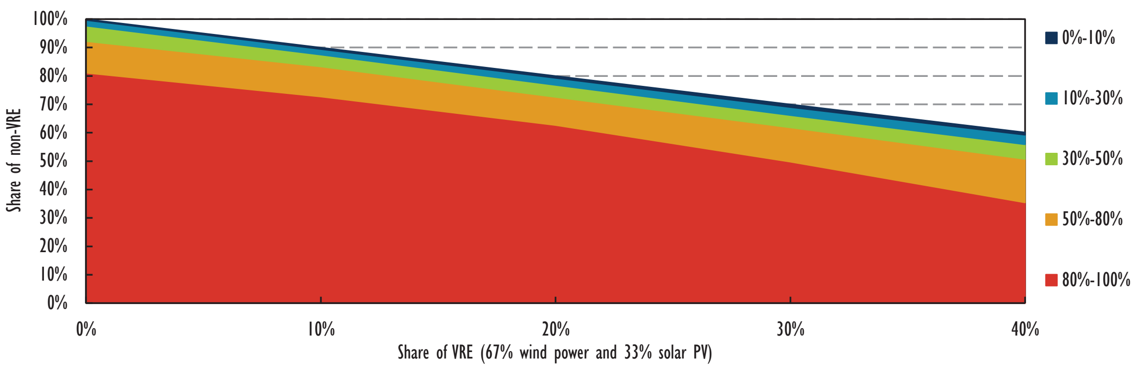
Adequacy impacts

Existing practices of calculating adequacy costs often focus exclusively in the contribution of VRE to meet peak demand and thereby fail to account for an important long-term impact of variability. Apart from scarcity periods, VRE generation can be abundant during other periods, which requires other generation technologies to reduce their output to avoid VRE curtailment. The combination of these impacts (scarcity and abundance) is referred to as utilisation effect. In the long term, the utilisation effect implies a shift in the cost optimal generation mix. The persistent utilisation effect (Chapter 2) will favour technologies that are cost-effective operating at capacity factors that are typical for peaking and mid-merit generation. In addition, the balancing effect will favour technologies that can start/stop operations frequently as well as ramp quickly and to a large extent. Given existing generation technologies, both effects favour similar technologies, such as flexible combined-cycle gas plants. Estimates of the balancing effect have already been presented in the previous section. This section illustrates the economic relevance of the persistent utilisation effect, using a simplified calculation for illustration purposes.

The analysis assumes that the residual generation mix (the generation needed to cover net load) is fully adapted to the presence to VRE (long-term perspective). On the one hand, VRE decreases the need for other power generation. This reduces total costs of residual power generation. On the other hand, VRE changes the cost optimal mix of this residual power generation. This typically increases the per megawatt hour cost of residual generation, because the residual mix contains a lower share of baseload and a higher share of mid-merit and peaking generation. On a per megawatt hour basis, baseload generation is generally cheaper than mid-merit and peaking generation.[6] Therefore, the shift implies an increase in the specific costs of the residual system.

This effect is illustrated in Figure 4.4. The overall generation of the residual system is reduced on a one-to-one basis when adding a mix of wind power and solar PV. However, different technologies in the residual generation mix are displaced at a different rate. At shares above 20% VER in annual generation, baseload generation (80% to 100% capacity factor) drops relatively quickly, while mid-merit generation (30% to 50% and 50% to 80%) even sees an increase in absolute terms.

Figure 4.4 • Non-VRE power generation at different shares of wind power and solar PV



Notes: based on load data, wind power and solar PV data for Germany in 2011. VRE generation scaled; scaling may overestimate the impact of variability; for illustration only.

Key point • At high shares, VRE tends to displace baseload generation (red area) and can increase the amount if required peaking and mid-merit generation (other area).

The data underlying Figure 4.4 can be used for an indicative calculation of the economic significance of the utilisation effect. Assume that 1 MWh of baseload generation costs approximately USD 60/MWh, mid-merit USD 80/MWh and peaking generation USD 160/MWh. Under these assumptions, the impact on total and per MWh costs for the residual system can be calculated directly (Table 4.1). For comparison, the table also contains the effect of adding a constant flat block of energy (baseload) instead of wind power and solar PV. Absolute values are highly sensitive to assumptions on LCOE and are indicative only.

6. In theory, if a large number of technologies with the right combinations of capital and operating costs are available, it is possible that each technology has its minimum generation cost at a different capacity factor and all technologies have the same LCOE at their optimal capacity factor. This is however not the case with current technologies.

Table 4.1 • Indicative generation cost for the residual plant mix per MWh for different technologies

	Baseload				
	0%	10%	20%	30%	40%
Total net load (terawatt hours [TWh])	492	443	393	344	295
Peak generation	2%	3%	3%	3%	4%
Mid-merit generation	17%	18%	21%	24%	28%
Base	81%	79%	76%	73%	68%
Average LCOE (USD/MWh)	65.7	66.3	67.1	68.1	69.4
Change average LCOE (USD/MWh)	0.0	0.6	1.4	2.4	3.8
Total costs (USD billion/yr)	32.3	29.3	26.4	23.4	20.5
	Wind power only				
Annual share	0%	10%	20%	30%	40%
Total net load (TWh)	492	443	393	345	300
Peak generation	2%	3%	5%	6%	8%
Mid-merit generation	17%	18%	22%	30%	43%
Base	81%	79%	73%	63%	49%
Average LCOE (USD/MWh)	65.7	66.8	69.2	72.4	76.7
Change average LCOE (USD/MWh)	0.0	1.2	3.5	6.8	11.1
Total costs (USD billion/yr)	32.3	29.6	27.2	25.0	23.0
	2/3 wind power 1/3 solar PV				
Annual share	0%	10%	20%	30%	40%
Total net load (TWh)	492	443	393	344	296
Peak generation	2%	3%	4%	5%	7%
Mid-merit generation	17%	16%	18%	23%	34%
Base	81%	81%	78%	71%	59%
Average LCOE (USD/MWh)	65.7	66.1	67.5	70.2	73.9
Change average LCOE (USD/MWh)	0.0	0.4	1.9	4.5	8.2
Total costs (USD billion/yr)	32.3	29.3	26.6	24.2	21.8
	Solar PV only				
Annual share	0%	10%	20%	30%	40%
Total net load (TWh)	492	443	394	354	329
Peak generation	2%	4%	5%	5%	6%
Mid-merit generation	17%	15%	24%	45%	71%
Base	81%	82%	72%	49%	23%
Average LCOE (USD/MWh)	65.7	66.7	69.4	74.6	80.3
Change average LCOE (USD/MWh)	0.0	1.0	3.7	8.9	14.6
Total costs (USD billion/yr)	32.3	29.5	27.3	26.4	26.4

Notes: VRE output has been scaled up from actual; scaling of VRE generation tends to overestimate the impact of variability and results are therefore indicative. Cost of baseload generation USD 60/MWh, mid-merit generation USD 80/MWh and peaking generation USD 160/MWh.

Key point • When adding large shares of one particular technology, total costs in the residual system go down while specific costs (per megawatt hour) of the residual system may increase.

All technologies reduce total costs in the residual system. However, the cost savings in the residual system are not "one-to-one". All technologies replace cheaper-than-average electricity in the residual system; as a result, per megawatt hour costs in the residual system increase. In the wind power case, they increase from USD 65.7/MWh to USD 69.2/MWh when going from 0% wind power penetration to 20%. For solar PV, the increase is more significant, with per megawatt hour costs reaching USD 69.4/MWh at a 20% share. However, a mix of wind power and solar PV implies a much lower increase, reaching USD 67.5/MWh at 20% This is similar to the increase seen when adding baseload generation, in which case costs increase from USD 65.7/MWh to USD 67.1/MWh when going from 0% to 20%.

It is possible to establish a comparison via a reference technology that is assumed not to increase the per megawatt hour costs in the residual system. Such a technology would reduce the cost in the residual system proportionately to its share of annual energy demand (proportionate reduction). The difference in total costs in the residual system can then be compared (Figure 4.5). A wind power generation share of 40% avoids 29% of costs, while the flat block avoids 37% of costs, and a proportionate reduction (by definition) reduces costs by 40%.

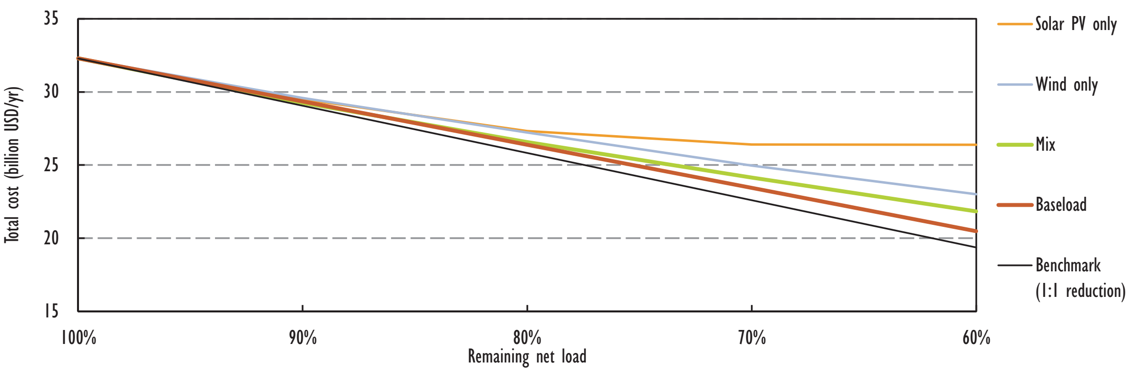
Expressing this increase in per MWh costs in terms of added generation, at a 10% annual share this corresponds to USD 10.4/MWh of wind power; USD 8.8/MWh for solar PV and USD 5.7/MWh for the baseload case. Deploying a mix of wind power and solar PV brings down these costs to USD 3.8/MWh, which is lower than the baseload case.

However, at growing penetration levels, the utilisation effect becomes more significant. At a share of 40%, these numbers are USD 16.6/MWh of wind power generation, USD 21.9/MWh of solar PV generation. Similar cost ranges for VRE have been reported in other studies (e.g. NEA, 2012). For baseload generation, the effect remains at USD 5.7/MWh at a share of 40%.

The wind power and solar PV mix is cheaper than wind power or solar PV alone, but with USD 12.3/MWh the utilisation effect is more significant than for baseload. However, this estimate is likely to overstate the relevance of the utilisation effect because historic generation data were scaled up to the corresponding penetration.

But even if this overstates the effect by a factor of two, the costs are still of the same order as balancing costs at these penetration levels.

Figure 4.5 • Total residual system costs for meeting net load for different technologies and shares in annual demand



Note: total costs calculated based on LCOE in Table 4.1.

Key point • VRE and baseload generation do not reduce costs in the residual system on a one-to-one basis (black line).

The simplified calculation regarding the significance of the utilisation effect signals that the utilisation effect contributes to increased costs at high penetration rates. At high shares, adding VRE is also likely to increase the balancing effect. The aim of this illustration is to point out that both the balancing and the utilisation effect are of relevance and that other approaches to adequacy costs may fail to capture the utilisation effect in full. Both effects will always occur in concert and only their combined effect is ultimately relevant. Therefore, even when fully accounting for the impact of the utilisation effect, simply adding it to balancing costs as calculated above will likely overstate the overall effect and can be misleading.

In a system that shows little difference between the cost of mid-merit/peaking generation compared to baseload, such effects will tend to be less relevant. This is true, for example, for systems with reservoir hydro plants, which may operate at capacity factors comparable to mid-merit generation due to water availability, but which have very low generation costs.

The above discussion focuses on generation costs in the residual system. However, the utilisation effect is also relevant for VRE. If VRE generation has to be curtailed at times of abundance, this will contribute to increased costs for the overall power system. The increase in LCOE resulting from curtailment can be quite significant (see Chapter 5).

Value perspective

The discussion on integration costs has highlighted a number of the methodological problems associated with that approach, and quantification of the different impact groups has also been presented. The overall conclusion from the discussion is that: 1) a large number of problems exist in defining reference technologies for extracting integration costs, 2) the different cost categories are not independent and may fail to capture all effects, and 3) actual numbers vary widely depending on penetration levels and system circumstances.

The methodological problems of integration cost calculation appear to have two main roots. Firstly, they attempt to extract a sub-set of total system costs, which appears to be not well defined. This is reflected in problems related to choosing an appropriate benchmark technology so as to extract "pure integration costs". It is also apparent in the problems around calculating adequacy costs (see Box 4.1). Secondly, integration cost calculations attempt to decompose integration costs into different elements, which are not independent from each other. This can easily lead to double counting or the omission of certain effects.

However, understanding the impact of VRE deployment on total system costs does not require reverting to a specific benchmark technology or segmenting costs into different categories. Two corresponding approaches will be put forward in this section: calculating total system costs and, based on this, calculating the value of VRE.

Deploying VRE[7] will trigger a number of effects in the power system or wider energy system. The economic implications of integration effects can be understood by looking at total system costs when VRE is added to the system. In general, adding VRE generation will trigger two different effects:

- An increase in some costs, such as increased costs of cycling conventional power plant and for additional grid infrastructure and the cost of VRE deployment itself. This group can be termed **additional costs.**
- A reduction in other costs. Depending on circumstances, this includes reduced fuel costs, reduced carbon dioxide and other pollutant emissions costs, reduced need for other generation capacity and reduced need for grid and reduced losses. This group can be termed benefits or **avoided costs.**

Integration challenges can manifest themselves on both levels: avoided and increased costs. At higher shares of VRE, adding even more will tend bring fewer avoided costs and higher additional costs. For example, (as shown in Figure 4.6) the benefit of solar PV in reducing peak net load (i.e. the load that needs to be met by the residual system) can drop quickly at higher shares. Such "diminishing returns" are a general principle in economics and not particular to VRE.

The important point is that the two above categories cannot be strictly separated. For example, at low shares of solar PV, it may contribute to shaving mid-day peaks, thus reducing the need for plant cycling. Meanwhile, at higher shares it may create a mid-day net load valley, which increases cycling needs. In fact, economists usually do not make the above distinction.

Integration cost analysis often seems to attempt to extract exclusively "additional" costs. However, which kind of cost is avoided and which kind of cost is additional is subject to complex interactions that do not allow for a clear separation. Considering total system costs effectively avoids such problems.

In addition to total system costs, it may be desirable to have a metric that can be directly compared with the generation cost of VRE. This is where the value picture becomes useful.

7. The discussion focuses on VRE, because these are of primary interest for this book. The same method can be applied to any technology.

The value of adding VRE generation corresponds to its net benefits to the residual system, i.e. avoided costs minus increased costs.[8] The residual system can be defined by excluding all those components that are captured when calculating the investment and operational costs of VRE itself. It is important to make sure that these two components add up to total system costs in a straightforward manner. Assessing VRE in terms of net benefits for the residual system, or their system value, can provide a more complete picture than seeking to artificially extract and calculate specific integration costs. From an economic perspective, integration challenges are then simply all those factors that contribute to deteriorate the value of VRE.

A number of factors influence the value of VRE (Lamont, 2008; Mills and Wiser, 2012; Hirth, 2013). The most important factors have been introduced already in the previous chapters, being:

- the temporal and locational match (correlation) between VRE production and demand
- the penetration rate
- the flexibility of the power system and generation portfolio
- the speed at which VRE is added to the system relative to other changes in the system.

Net benefits also depend on which costs and benefits are taken into account in the analysis. In turn, the system value of VRE depends on which adaptation processes are considered in the analysis. These adaptations may be purely operational, as installed assets – apart from VRE itself – remain the same. Consequently, costs and benefits will be operational only. However, if more fundamental adaptation processes are also taken into account, costs and benefits will include investment costs and benefits and the value of VRE will tend to be higher (Table 4.2).[9]

Table 4.2 • Level of system adaptation and resulting system value of VRE

		Level of adaptation		
		Only operational	*Intermediate*	*Fully transformed*
Potential adaptations		Only dispatch and other operations can adjust (investments sunk).	Assets can be decommissioned or mothballed. Existing assets and demand can be modified to adjust more flexible. VRE deployment strategies improve.	Structural changes, e.g.: • a shift towards mid-merit and peaking plants • the network infrastructure adjusts (e.g. smart-grid infrastructure) • load pattern changes • additional storage can be deployed • new technologies are developed.
System value of VRE (net avoided costs)	Avoided costs	VRE-induced fuel and emissions savings.	In addition, fixed operation and maintenance costs saved.	Maximised capital and fuel cost savings. Higher share of VRE can be utilised.
	Additional costs	VRE-induced higher balancing and grid-related costs.	Balancing and grid-related costs lower.	Additional costs for flexibility options. Balancing and grid-related costs lower.

Source: adapted from Ueckerdt et al., 2013b.

Key point • The system value of VRE depends on the degree of system adaptation.

8. From an economic point of view, the marginal value is of relevance. The discussion is equally applicable to the marginal value of VRE.
9. Other studies have made this distinction in terms of ex ante analysis (the assets of the power system are taken as given and VRE is added) and ex post (the assets of the power system are fully adapted to the presence of VRE).

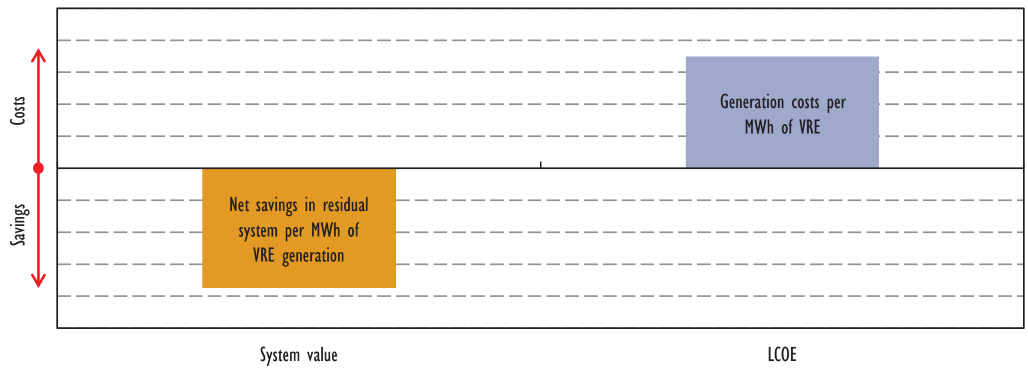
In the short term, adapting operations, such as balancing the power system over a larger area, can contribute to increasing the value of VRE even at growing penetrations (see Chapter 6). In the long term, including investments and divestments in the residual system, a structural change in the generation mix and the deployment of flexibility options can contribute to re-optimising the overall system, reducing total system costs and making the value of VRE more robust even at high penetrations (Denny and O'Malley, 2007).

In summary, looking for the integration costs of VRE can mean asking the wrong question. Understanding the economics of VRE integration calls for understanding the value of VRE.

Comparing the value of VRE to generation costs

The system value approach to understanding the economic impacts of VRE integration has the advantage that it creates a direct link to generation costs. The system value represents "what you get" from VRE generation. As such, it can be directly compared to the generation cost of VRE. If expressed on a per megawatt hour basis a direct comparison to the per megawatt hour of VRE generation can be made. If the value of additional VRE generation is larger than its LCOE, further increasing the penetration of VRE helps to decrease total system costs. Moreover, a gap between the system value and LCOE is an indication of how much system costs will increase (or decrease, if the value outweighs the cost).[10]

Figure 4.6 • Illustration of the relationship between system value and LCOE



Key point • The LCOE of wind power and solar PV should be compared to their system value.

Other benefits

As stated at the beginning of the chapter, this analysis of costs and benefits has focused on the level of the power system. Other relevant benefits of VRE, outside of the power system, include the following:

- VRE deployment reduces the demand for fossil fuels and hence contributes to reduced market prices of these fuels
- VRE provides a natural hedge against fossil fuel price volatility, which has a monetary value (NREL, 2013b; Awerbuch, 2006)
- VRE deployment may lead to increased economic activity and job creation (IEA, 2011a)
- wind power and solar PV require relatively low water consumption and help to reduce energy-related water use
- VRE generation does not emit other pollutants such as sulphur oxides (SO_x), nitrogen oxides (NO_x) or particulate matter.

10. Some authors have suggested calling the (positive or negative) difference between the system value of a technology and its LCOE integration costs. This definition is not adopted in the present analysis to avoid possible confusion with the traditional definition.

Summary

The deployment of wind power and solar PV brings benefits and costs to the power system, the wider economy and society. An economic assessment of VRE deployment needs to capture these costs and benefits appropriately. At the level of the power system, analysis of total system costs captures all relevant costs and benefits. As discussed, further disaggregating these costs and trying to extract specific integration costs can pose methodological problems. The impact of VRE (or any other technology) on total system costs can be assessed by calculating its (marginal) system value.

The different integration impacts discussed in Chapter 2 can contribute to reducing the system value of VRE. Additional grid costs, as well as the combined impact of the balancing and utilisation effect are most relevant in this regard.

The degree to which the system as a whole adapts to the presence of VRE determines the extent to which the value of VRE remains robust at high penetrations. As such, the impact of high shares of VRE on total system costs will have a dynamic component: costs may rise during a transition phase (reflecting a lower value of VRE), while in the long run, a multitude of different adaptation options can contribute to optimising the system in the presence of high shares of VRE. Analysing such options — from the perspective both of operations and investments — is the central aim of the following chapters of this book.

A holistic approach to tackling integration impacts is needed, with a view to maximising the value of VRE to minimise total system costs.

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5 • System-friendly VRE deployment

HIGHLIGHTS

- The common view of integration sees wind power and solar PV generators as the "problem", leaving the solution to other parts of the power system. However, VRE can contribute to its own system integration – and it will need to do so to achieve system transformation cost-effectively. The main intent behind system-friendly deployment is minimising overall system costs, in contrast to minimising VRE generation costs alone. Five elements are relevant in this regard.
- Timing. VRE additions need to be aligned with overall long-term system development and vice versa. Experience shows that deployment of VRE capacity can outstrip development of suitable infrastructure. This calls for adopting an integrated approach to infrastructure planning.
- Location and technology mix. From a system perspective, cost-effectiveness is not just about deploying the cheapest technology or deploying where resources are best. The mix of VRE (and dispatchable renewable generation) can be optimised to reap valuable synergies – for example, where sunny and windy periods are complementary (Europe). In addition, by siting VRE power plants strategically, the aggregate variability can be reduced or costs for grid connection may be lowered.
- Technical capabilities. VRE power plants are able to provide an increasing proportion of system services (such as frequency and voltage support services), which are relevant to ensuring the reliable operation of the power system. While the ability to provide such services can increase investment costs for VRE power plants, it can be cost-effective at the system level.
- Economic design specifications. VRE power plant design can be optimised from a system perspective, rather than simply aiming to maximise output at all times. For example, modern wind turbine design can facilitate integration by harvesting relatively more energy at times of low wind speed. Solar PV system design can be similarly optimised by considering solar PV panel orientation and the ratio of module capacity to inverter capacity. This reduces variability and can increase the value of VRE generation.
- Curtailment. Occasionally curtailing VRE generation (ideally based on market prices) can provide a cost-competitive route to optimising overall system costs by allowing for infrastructure and operational cost savings.

The common view of integrating VRE sees wind power and solar PV generators as the "problem". The solution has to come from other parts of the power system. Given recent technological advancements in VRE generators and their integration requirements, this view will increasingly be inaccurate. VRE can contribute to its own system integration – and it will need to do so to achieve grid integration on a cost-effective basis.

The fact that VRE is not seen as a tool for its own system integration may have historic reasons. Policy priorities during the earlier days of VRE deployment were simply not focused on system integration. Rather, past priorities can be summarised as:

- maximising deployment as quickly as possible
- reducing the cost of energy (measured as levellised cost of electricity [LCOE]) as rapidly as possible.

These objectives were sensible during the early phases of global VRE deployment (see IEA, 2011a, for a discussion of different deployment phases). They may also be suitable where only low to moderate shares of VRE are being targeted. Ignoring integration issues reduces policy complexity and avoids the potential need for trade-offs between different objectives. However, where VRE technologies are expected to become central players, policy objectives will need to be revised. Policies will need to take into account system interaction, which can dominate deployment challenges above a certain penetration level. This translates into new objectives, which can be summarised as:

- achieving the right amount of deployment at the right time in the right place, i.e. timing and location
- ensuring that VRE generators can contribute to the range of system services needed to ensure stable grid operation; i.e. VRE system capabilities
- maximising the value of VRE generation while continuing to reduce costs, i.e. the scale of infrastructure, economic design criteria of VRE power plants and the technology mix.

These new priorities may challenge existing support policies for VRE. For example, it may be necessary to provide locational and timing signals to generators, and to expose generators to market prices to encourage deployment in places and at times when it is most highly valued. This can provide an opportunity for dynamically evolving power systems (for example, in non-Organisation for Economic Co-operation and Development [OECD] member countries) with high investment requirements in coming years. In these systems, a more dynamic increase in VRE penetration may be achieved more easily, if it can be synchronised with the evolution of the overall system. However, even in rapidly growing power systems, VRE deployment may outpace the upgrading of other system components (see below).

System service capabilities and economic incentives always need to be well designed to ensure VRE technologies are capable of serving as a main pillar of reliable and cost-effective power networks.

Timing and location of deployment

The deployment of VRE can easily outpace changes in other elements of the power system. Depending on administrative requirements and the availability of finance, a VRE project can be developed as rapidly as a few months for solar PV and a year for onshore wind projects. This compares to very different timescales for the development of new grid and power generation infrastructure. In stable power systems, the speed at which old assets need to be replaced may be low compared to VRE additions, which makes synchronising the entire system even more challenging. However, upcoming retirement of large amounts of generation capacity, for example due to more stringent emissions requirements or the decommissioning of nuclear power plants as planned in Germany and discussed in other countries, may constitute a window of opportunity for accelerated adaptation.

Synchronising with grid infrastructure

In the case of **transmission** grids and interconnection, lead times for new projects will vary between a few years, where public opposition and administrative complexity are low, to decades in more problematic cases. For example, the interconnection between Spain and France has taken decades and high-level political intervention to ensure progress towards completion (European Commission, 2007; Inelfe, 2013). Furthermore, domestic transmission projects in Europe and the United States frequently fall behind schedule. However, the speed of grid expansion can also be an issue in dynamically growing systems. In Brazil, for example, approximately 600 megawatts (MW) of wind power capacity are awaiting grid connection at the time of writing in June 2013. Auctions for the provision of grid infrastructure were organised just after the auctions for wind power capacity, and wind power deployment outpaced deployment of grid infrastructure due to environmental constraints. The approach has subsequently changed, and wind power projects typically need to be sited close to existing or secured transmission lines to participate in auctions for new capacity.

The siting of VRE projects faces a trade-off between optimal resource locations and proximity to existing grid infrastructure and load centres. Establishing the optimal trade-off between these factors presents a challenge, particularly as it changes with reductions in the cost of VRE.[1] In addition, cost allocation can present a "chicken-and-egg" problem. Building a connection grid for distant VRE sites may only be cost-effective if sufficient VRE capacity is built. However, the generating capacity of initial VRE projects is often low, such that a way needs to be found to pay for the transmission before the full amount of generation capacity is built or even firmly planned. Depending on the regulatory framework in place, cost recovery and allocation for such transmission projects can be challenging (see Volk, 2013, for details). A number of regulatory solutions for this issue have been employed, such as the Competitive Renewable Energy Zones in Texas (Box 3.5) or the Irish Gate system (RETD, 2013). However, grid reinforcements should be evaluated against other options, such as not using all available wind power or altering the operation of other generation, if grid adequacy is insufficient during only part of the time or for only certain production and load situations (Holttinen et al., 2013).

In addition to transmission investments for connecting new projects, the planning of the overall transmission grid is a key issue. Developing the transmission grid can be done more cost-effectively when the future location of generators and loads is known with sufficient certainty. This can contribute to minimising overall system costs. For transmission planning, the most cost-effective solution in cases that demand considerable grid reinforcements would be to build a transmission network for the final amount of VRE in the network, instead of having to upgrade transmission on a piecemeal basis (Holttinen et al., 2013).

Synchronising additional renewables and grid capacity does not necessarily mean that VRE deployment needs to wait for transmission infrastructure. A recent study in Germany analysed this question, and the results showed that there is a value in deferring grid investments comparable to the costs incurred by increasing curtailment during the delay period (Agora Energiewende, 2013; RETD, 2013).

Distribution grid investments are not usually held up by public acceptance or licensing issues. The challenge of synchronising distribution grid development with VRE deployment derives primarily from:

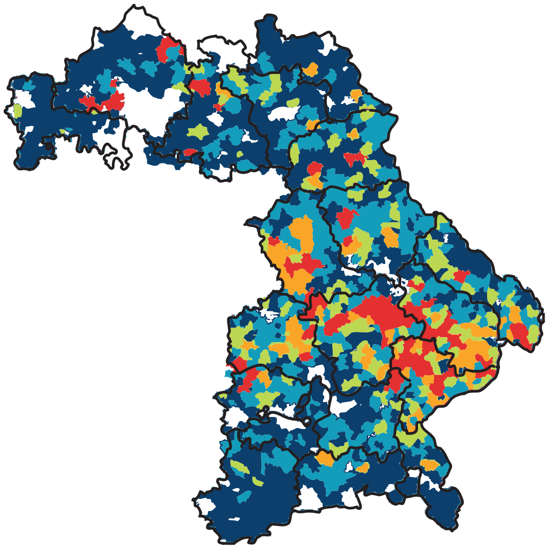
- lack of visibility of future grid requirements
- the rapidity with which distributed solar PV may be scaled up
- long investment cycles for grid infrastructure (40 years and more).

In Germany, for example, one of several large distribution grid operators, E.ON Bavaria, has received up to several hundred connection requests — per day — during peak months in recent years. In addition, roof-top solar PV deployment is often most dynamic in certain specific communities, which leads to an uneven overall distribution of installations (Figure 5.1). In the absence of co-ordinated deployment, this makes it particularly hard for grid planners to plan and expand the infrastructure in a way that is cost-effective in the long run. It is not possible to know in advance where such "hotspots" will emerge.

Analysis shows that the cost impacts of high levels of distributed solar PV on distribution grids are moderate (see Section 7.2) (EUR 0.001/kWh to EUR 0.011/kWh for 2.5 kW to 4 kW per household in a typical European underground distribution grid), if systems are designed to host corresponding shares of solar PV. However, retrofits may be much more costly (dena, 2013). While some degree of retrofitting can be unavoidable given ambitious government targets, the ability to predict the required future grid dimensions is critical.

1. A simplified example on this is as follows: if a hypothetical renewable facility costs around USD 0.40 per kilowatt hour (/kWh) in a low resource area and USD 0.20/kWh in a high resource region, this would allow investment up to USD 0.20/kWh in new transmission to reap the benefit of better resource. However, if the cost of the VRE facility drops to USD 0.20/kWh in the low resource area and to USD 0.10/kWh in the high resource area, the available capital to spend on transmission would be halved.

Figure 5.1 • *Distribution of solar PV installations in the grid area of E.ON Bavaria, Germany*



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

Source: based on data from Bayernwerk.

Key point • *Solar PV deployment may result in local hotspots.*

Synchronising with generation infrastructure

Modelling analysis conducted for this publication highlights that the optimal dispatchable generation mix changes with the introduction of large shares of VRE (see Section 7.3). This finding is in line with other studies that have investigated this issue (for example, see NREL, 2013; DCENR and DETI, 2008; NEA, 2012; Nicolosi, 2012; Hirth, 2013).

This means that optimal investment patterns in dispatchable generation are contingent on the build-out trajectory of VRE. Providing predictability and certainty on the build-out path of VRE is therefore critical for ensuring that the generation mix evolves in line with future requirements.

In stable power systems, the existing plant stack is unlikely to be optimised for handling high shares of VRE, because high-VRE shares tend to shift the optimal power plant mix away from baseload capacity and towards mid-merit or peaking plants. This may pose additional challenges associated with managing the transition to an adapted system (see Chapter 8 and Baritaud, 2012). In countries with dynamically evolving power systems, investment patterns need to be aligned with VRE in order to benefit from the possibility of "leapfrogging" to an optimised system.

VRE system service capabilities

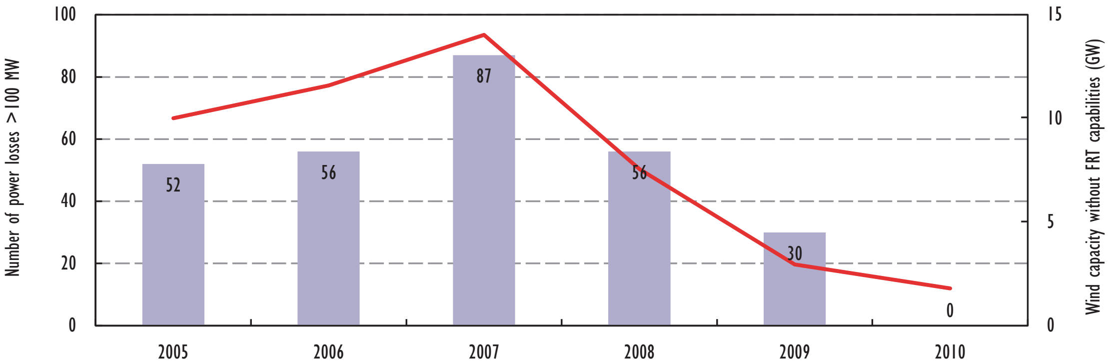
Reliable operation of the power system critically depends on a number of system services, which contribute to maintaining system frequency and voltage levels. Special capabilities may also be required when restarting the system after a large-scale blackout (so-called black-start capabilities). Some of these services are procured by system operators or traded on dedicated markets. Others are mandated via grid codes (known in North America as interconnection standards), which set out technical requirements for any entity that connects to the grid. Different systems may obtain the same service in different ways, e.g. some will mandate it in the grid code while others use a procurement or market mechanism.

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

There are examples where the initial response of simply disconnecting VRE during times of faults or too high frequency actually started to pose a problem for the system when the installed capacity increased to more than 3 gigawatts.

With wind energy, the initial requirement to disconnect in the case of a fault following a short drop in voltage ("voltage dip") was found to be a threat to system security (dena, 2005). Again, this was not primarily a problem with VRE generation technology itself, but rather with the way it was asked to operate. By requiring fault ride through (FRT) capabilities from VRE power plants, this issue has been since resolved, as shown by the Spanish example where occurrences of VRE generators disconnecting after a voltage dip have been reduced to zero (Figure 5.2).

Figure 5.2 • Evolution of wind power capacity without FRT and number of power losses >100 MW by voltage sags in Spain



Note: FRT = fault ride through.

Source: based on data from Eléctrica de España.

Key point • Ensuring appropriate technical capabilities of VRE is important for secure integration.

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

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

At high penetrations, VRE generation may be sufficient to meet the majority of, or even all, power demand during certain periods. At these times only a few or even no conventional generators will be needed to meet electricity demand, and solutions need to be found to provide all relevant system services independent of the operation of conventional generation. Otherwise some VRE output will need to be curtailed to make room for conventional units.

VRE power plants are not the most obvious economic source of given system services. Incorporating certain technical capabilities that mimic the behaviour of conventional, synchronous generators can add costs to VRE power plants. In addition, asking VRE to mimic the behaviour of legacy technology may not be optimal from a system perspective, and requirements should be made with future system needs in mind. In addition, there is a need to weigh up the implications of mandatory requirements against establishing more market-based, technology-neutral frameworks for obtaining system services.

The system service capabilities of wind power and solar PV power plants, and the costs associated with providing these services, are the focus of the EU-funded REserviceS project (www.reservices-project.eu/). While the project is ongoing at the time of writing, a number of important results have already been obtained (REserviceS, 2013a and 2013b).

Technology available today offers advanced capabilities for frequency and voltage support, and only few technical constraints have to be overcome to deliver frequency and voltage services on a sustained basis (REserviceS, 2013a and 2013b). The main issues are as follows:

- If dynamic control of reactive power is required when the plants are not operating (producing active power) this will imply extra costs for some wind power technologies.
- The frequency control from a large fleet of low-voltage connected solar PV would need implementation of communication technology that could also be costly.
- For some of the services there can be weather-dependent availability – depending on forecast accuracy only part of the power can be offered with certainty. Aggregation of dispersed plants would be needed to mitigate this, as well as a contracting framework that allows bidding close to delivery.

As discussed in more detail in Chapter 6, improving system services markets can be a key component in improving the overall design of energy markets.

Size of infrastructure and VRE curtailment

Connecting VRE generation to the grid requires investment in distribution and transmission grid infrastructure. The required size of this infrastructure is determined by the period of maximum need. This, in turn, is dependent on the maximum power output of the generation that is connected to the grid. If there are high peaks in VRE generation that only occur very infrequently, the grid infrastructure may experience low overall utilisation factors. As a result, it may be cheaper to reduce the scale of the infrastructure and shave off peaks in VRE output via curtailment. This option should be investigated when determining infrastructure dimensions, with a view to minimising total system costs. The more pronounced the spikes in VRE output are, the more grid capacity can be saved at comparably low levels of lost VRE generation. Taking an example from Germany, by reducing annual energy yields from a solar PV power plant by 5%, the required connection capacity can be reduced by 30% (Troester and Schmidt, 2012).

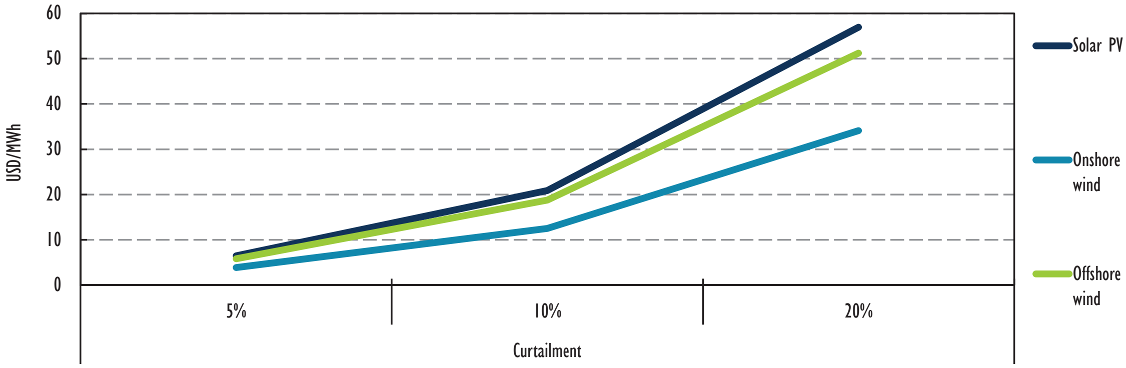
The optimal trade-off between VRE curtailment and size of infrastructure depends on a number of factors, most importantly the relative investment costs of VRE power plants and grid infrastructure. Optimal levels of curtailment will be low in general, because generation costs rise steeply once curtailment levels exceed a certain threshold (Figure 5.3).

Economic design criteria

Wind turbines and solar PV systems are improving continuously. Customer requirements are an important driver for the research and design of VRE power plants. The demands of the customer are, in turn, driven by the revenue opportunities that equipment will provide. In line with past policy objectives, design has been geared towards minimising LCOE, largely independent of where and when generation takes place.

With the changed role of VRE at high penetrations, the optimal design of VRE power plants can be expected to change. Minimising total system costs will become an increasingly important driver. It is highly likely

Figure 5.3 • Cost increase of wind power and solar PV generation as a function of curtailed energy



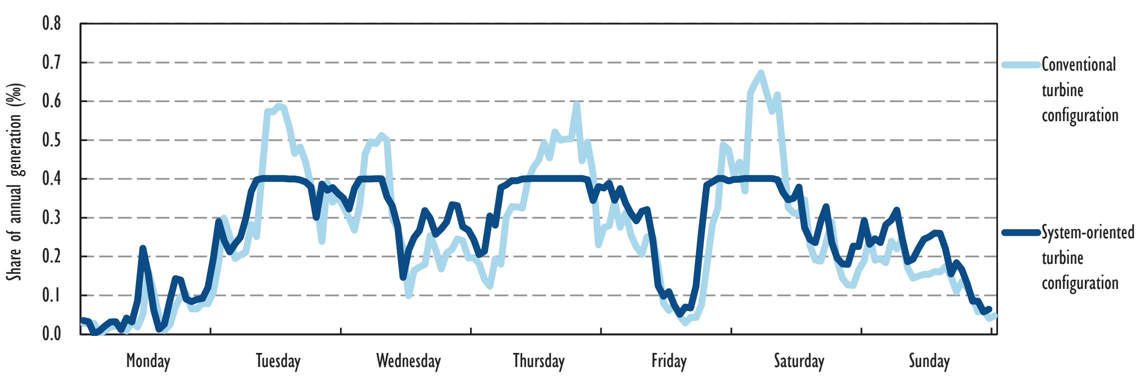
Source: unless otherwise indicated, all tables and figures in the chapter derive from IEA data and analysis.

Key point • Low amounts of curtailment only moderately increase costs. Additional costs rise sharply at higher levels of curtailment.

that VRE technologies have significant potential to facilitate their own integration. When the cost of VRE generation was the main economic barrier to their more widespread deployment, reducing generation costs was the most important priority. This was reflected in incentive structures. Therefore, the question of maximising the overall cost-effectiveness of VRE from a system perspective by slightly increasing plant-level generation costs has presumably received comparatively little attention in the past.

Wind turbine engineers have many choices as to machine design. One important design aspect is the area swept by the turbine rotor relative to the size of the generator. The swept area determines how much wind a turbine can "catch". The size of the generator determines how much rotational energy it can convert to electricity. In recent years, there has been a trend to increase the swept area in comparison to the capacity of generators. The driver behind this development has been optimising energy production given site availability (lower quality sites) and relative equipment costs (blades vs. generator). However, this trend also holds the promise of improved integration (Molly, 2012; IEA, 2013). Comparing the turbine output at the same wind site, a system-optimised turbine will deliver electricity in the same amount of energy annually – but in a less variable way (Figure 5.4). Abundance situations are reduced, and relative production during low wind speed is increased.

Figure 5.4 • Comparison of two different wind turbine designs and resulting variability pattern



Note: conventional turbine configuration 2.5 MW, 90 meter height, 85 meter rotor diameter; system-oriented turbine configuration 3 MW, 140 meter height, 115 meter rotor diameter.

Source: Agora Energiewende, 2013.

Key point • System-friendly design of wind turbines can reduce output variability.

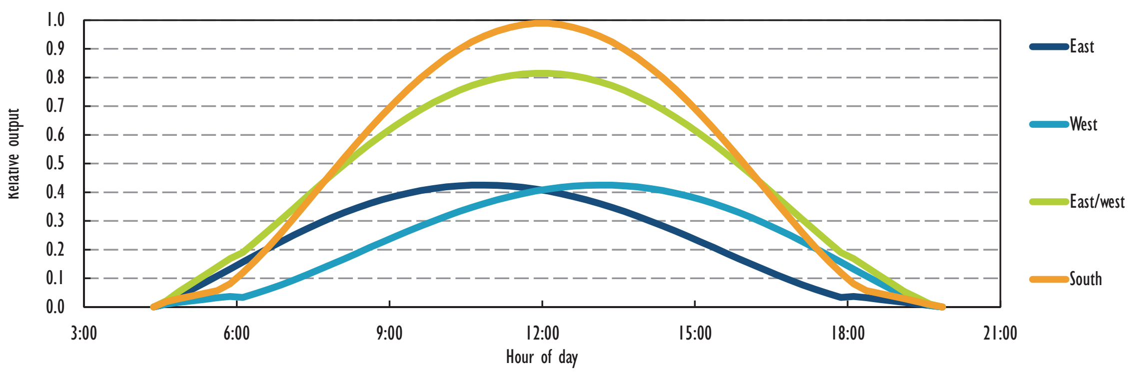
This change in design essentially means using wind less efficiently by not extracting the full energy at times of high wind speeds. However, if the value of wind energy is very low for the power system during periods of high wind, this should be reflected in the design of machines. It may be more economical to spill wind directly during times of abundance, than installing turbines that are designed to convert it fully to electricity but which need to be curtailed frequently. The effect of this altered profile may save costs in various parts of the power system, for example reducing need for grid investment, or reducing the cycling burden on flexible power plants.

A similar argument can be made for the siting of wind turbines: putting the next turbine in a location that has little or negative correlation with the output of existing turbines will deliver higher value electricity. Exposing VRE generators to market prices can signal this difference in value. Wind turbines that generate when others do not may see higher market prices for their electricity. This incentive is included in the current implementation of the German market premium model.

Solar PV systems have a design choice, for example, as regards the orientation of the PV panels and the ratio of module capacity to inverter capacity.

The system benefit of contrasting panel orientations needs further investigation, as few studies have assessed this so far (Troester and Schmidt, 2012). At latitudes of 40° north, orienting panels east/west at 15° reduces capacity factors by approximately 20%, but ramp gradients in the morning and evening are about half those of south-oriented systems. Peak power output is also lower for the east/west case for the same amount of panel capacity (Figure 5.5). However, the study finds that changed orientation leads to a number of effects, and no single orientation is superior from a system integration perspective. This analysis refers to German latitudes, and results will be different for other latitudes. Positive effects of east/west orientation will tend to be higher closer to the equator (Troester and Schmidt, 2012). Also, the cost-benefit of these design options needs to be assessed against alternatives, such as shaving production peaks via active power reduction (curtailment).

Figure 5.5 • *Impact of panel orientation on solar PV production profile, month of May in Germany*



Notes: identical profile results at same latitude in other parts of the world.

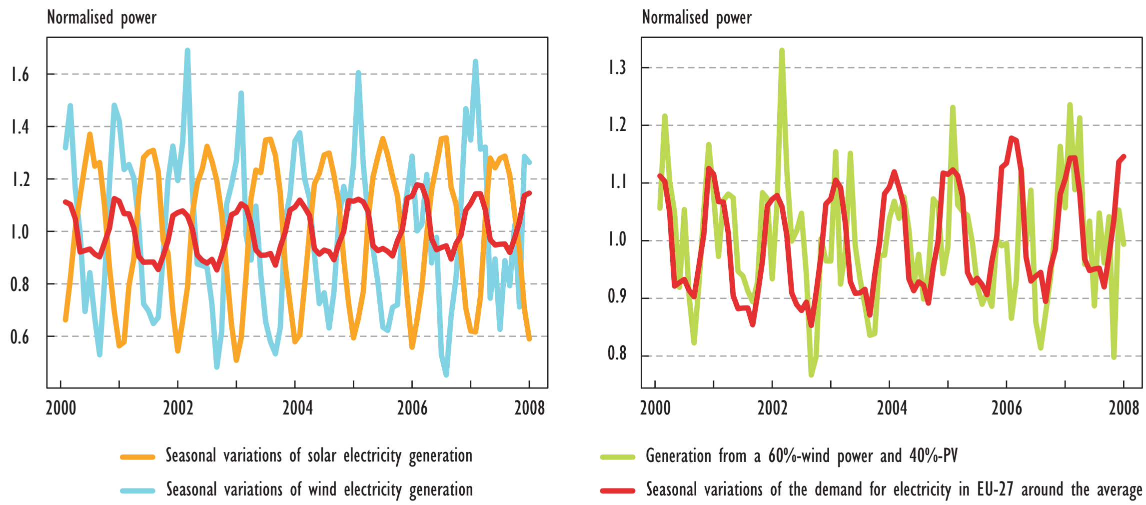
Source: Troester and Schmidt, 2012.

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

Technology mix

Wind power and solar PV output is driven by weather conditions. In many regions, a systematic link exists between the availability of wind and sunshine. Such correlations can occur at different timescales: short term within the day (sunny days may be less windy and vice versa) and on a seasonal level (autumn may be more windy, summer more sunny). In addition, the correlation with the availability of non-variable renewable technologies may be important. Bioenergy production depends on feedstock availability, which can vary seasonally. Similarly, water availability in hydro plants often shows seasonal variations. Finding the right mix of technologies can thus balance the variability in each component, leading to a mix that matches the demand for electricity more closely. For example, there is a good complementarily between wind power and solar PV in Europe at a seasonal level (Figure 5.6).

Figure 5.6 • Seasonal variations in European electricity demand and in electricity generation from solar PV, wind power, and a 60% wind power, 40% solar PV generation mix



Note: the average values are normalised to 1.

Source: IEA, 2011b.

Key point • A combination of wind power and solar PV matches electricity demand better than each technology by itself on a seasonal level in Europe.

Brazil presents a good example of the possible synergies between wind and hydro power. The Belo Monte hydro power station will be operated as a run-of-river power station, subject to considerable seasonal variability. This will lead to low utilisation of the transmission lines connecting the dam with load centres. However, the dry season coincides with the windy season in this part of Brazil, and adding wind power capacity will increase the utilisation of existing assets without the need to add transmission capacity. As such, wind power deployment would decrease transmission costs per megawatt hour.

Policy and market considerations

Wind power and solar PV can contribute to their own system integration. The above discussion has identified two main themes to facilitate this contribution:

- the need for a consistent, forward-looking approach across the different components of the electricity system, including VRE generators, other generation and grid infrastructure
- the need to expose VRE generators to appropriate economic signals to facilitate system-friendly design, deployment and operation of VRE power plants.

Policies will increasingly need to align VRE additions with overall system development and overall system development with VRE additions. This is likely to increase the need for controlling total deployment volumes and the location of VRE plants. Auction mechanisms may provide an attractive solution for steering overall deployment volumes at competitive prices. Identifying preferred development areas for large-scale wind power and solar projects may help to guide deployment locationally. In addition, including locational signals in market prices can contribute to more effective siting (see Chapter 6).

Technical requirements for VRE generators need to ensure that VRE power plants have the capabilities that they will need in the years to come, so avoiding the need for costly retrofits. This can be achieved by requiring capabilities at deployment, but only calling upon these capabilities at higher penetration levels, in cases where using such capabilities comes at a cost. However, technical requirements should be tailored to match the strengths of different generation technologies. In any case, electricity market design should facilitate the technology-neutral provision of system services.

Influencing economic design criteria of VRE generators may require a more fundamental revision of economic support policies. Where liquid spot markets exist, market premium models can be an important step in this direction. By exposing VRE generators to market prices, they will have an incentive to produce electricity when it is mostly needed. This will favour generators that produce electricity when it is most valuable. However, exposure of VRE generators to market prices should not unduly increase investment risk for VRE projects. Otherwise, increased risk premiums for financing up-front VRE investments may outweigh positive system integration effects. Where market premium models are not an option, incentives could be linked to the ratio of rotor diameter and generator capacity. Similarly, remuneration of solar PV plants could be linked to the ratio of inverter to panel capacity. However, more detailed studies of the relative cost-benefit of such options are recommended before implementing such changes in support policies.

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6 • Operational measures for VRE integration

HIGHLIGHTS

- Operational measures are a critical component of VRE integration and will have very favourable cost-benefit ratios in practically all power systems. Optimising system operations in the presence of VRE should be a priority wherever and whenever wind power and solar PV are deployed. This is true for both dynamic and stable systems.
- System operations routinely deal with the variability and uncertainty of demand. However, introducing variability on the generation side is a new phenomenon for system operation. Existing experience of system operators in countries with a high-VRE penetration has shown how to adjust operations to this new situation.
- The dispatchable plant fleet can often supply a greater amount of flexibility than is demanded at moderate shares of VRE. However, how much of this flexibility is available at any one time depends on the way the fleet is operated.
- Transmission and interconnector capacity are a valuable resource for cost-effective system operation, particularly at high shares of VRE. Making better use of existing infrastructure can often be a more cost-effective solution than new investment, in particular in stable power systems.
- Large-scale aggregation of wind power and solar PV generation can significantly reduce variability and uncertainty of VRE generation, and thus reduce associated challenges. However, these benefits will only be available if the layout and operation of balancing areas allow for smoothing to take place.
- Accurate forecasting of system-level VRE generation is a vital and cost-effective operational practice for VRE integration. However, tools need to be available to system operators to make effective use of this information.
- Because VRE output varies, it is now widely recognised that VRE-induced reserves should be calculated dynamically. Institutional "inertia" may pose a significant barrier to revising the definition and procurement of operating reserves.
- In addition to protocols and procedures used by the system operators, market design needs to facilitate efficient operation. The analysis of wholesale market design in case study regions has revealed considerable room for improvement:
  - System service markets, including operating reserve markets, are often underdeveloped.
  - Trading on short-term wholesale markets should be allowed as close as possible to real-time to efficiently deal with variability and uncertainty. In particular, shorter scheduling and dispatch intervals should be targeted.
  - Market prices should reflect locational constraints to optimise system operation.
  - VRE market integration should be encouraged.
  - To the extent possible, market clearing should co-optimise generation in light of system constraints and overall system costs.

Options for integrating VRE into an existing power system can be broadly divided into two groups: measures aimed at better use of existing or slightly upgraded system assets, and measures requiring new investments. This chapter focuses on this first suite of options, leaving the second to the next chapter.

Changing power system operational practices may require time, human resources and specific tools. In stable power systems, optimised operations alone may be sufficient to accommodate low to medium VRE shares cost-effectively. However, failure to adapt good operational procedures will lead to unnecessarily high costs of VRE integration, irrespective of system circumstances. Optimised operations also tend to be cost-effective in the absence of VRE deployment, creating a strong case for their adoption.

The main targets of operational measures are:

- dispatchable power plant operations
- transmission and interconnector operations
- balancing area co-operation and integration
- definition and deployment of operating reserves
- visibility, controllability and forecasting of VRE generation.

A number of factors contribute to determining operational practices in a given power system. In particular, the historical evolution of the system can have a large influence on operational protocols.

Operational decisions are often driven by economic considerations under a number of important constraints (including reliability and environmental standards). As such, power market design has a critical bearing upon the above operational measures. Market operations should facilitate optimised operations, and a broad set of market designs exists to deliver good performance in this regard.

The chapter first describes relevant aspects of system operations, going through the above elements (Sections 6.1 to 6.6). In a second step, existing market operations in case study systems are assessed with regard to how well they facilitate optimised operations (Section 6.7).

Power plant operations

The dispatchable plant fleet often provides a greater amount of flexibility supply than is demanded at moderate shares of VRE. However, how much of this flexibility is actually available at any one time depends on the way the fleet is operated.

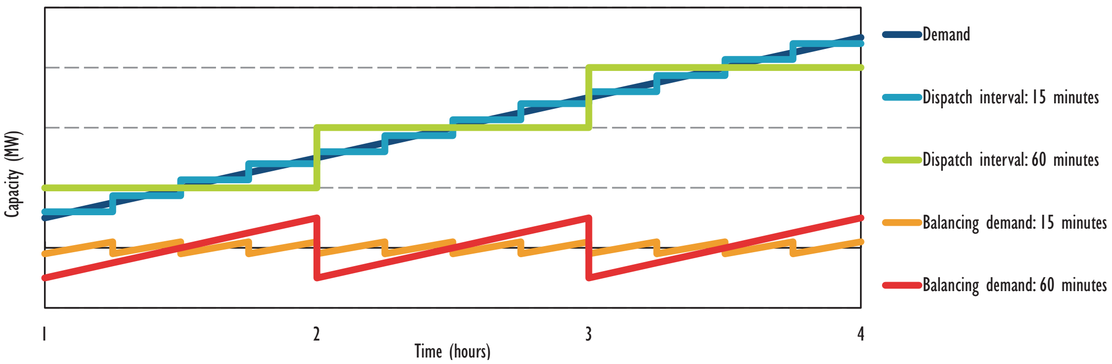
Operational decisions for power plants are taken at different time scales before real-time; sometimes these decisions are made by a market operator determining schedules based on bids received, and sometimes the plant operator determines how it will be dispatched (i.e. self-scheduling in markets or vertically integrated utilities). An advance decision has to be made on whether to turn a given plant on (commit the plant). This decision has to be made earlier for some technologies than others. For example, it takes a few hours to start most mid-merit power plants, while peaking generation can be brought online in typically less than 30 minutes. In addition, the exact output of the operating power plants (often referred to as power plant dispatch) also needs to be decided somewhat in advance. For a given time interval (the dispatch interval), the target output level of each power plant is set to a fixed value.

Technical constraints call for a certain degree of forward planning with regard to unit commitment and power plant dispatch. In practice, however, many power systems tend to lock in operational decisions far more in advance than technically required, sometimes weeks or even months ahead. Long-term contracts between generators and consumers may prevent power plants from providing flexibility to meet changes in net load on a cost-effective basis. Such a situation is undesirable for least-cost system operation, in particular at high shares of VRE penetration.

Given that VRE forecasts are more accurate closer to real-time, power plant schedules should ideally have the option to be updated accordingly close to real-time. Otherwise, a power plant that may be technically capable of supplying flexibility may be prevented from doing so due to a binding schedule, which is based on outdated information. Where power plant schedules are determined by trade on a power market, the term "gate closure" refers to how close to real-time generation schedules can be changed based on the bids of market participants.

The length of the dispatch interval is also relevant in this context. Within the dispatch interval, fluctuations in power demand, VRE generation and the output of dispatchable plants themselves need to be balanced by relying on often more costly operating reserves. Shorter dispatch intervals allow generation dispatch to cater for variations more accurately, hence reducing the need to rely on dedicated reserves (Figure 6.1).

Figure 6.1 • Impact of dispatch interval length on reserve requirements



Note: MW = megawatt.

Source: unless otherwise indicated, all tables and figures in this chapter derive from International Energy Agency (IEA) data and analysis.

Key point • Shorter generation dispatch intervals can reduce reserve requirements.

A given power plant dispatch, together with electricity demand, determines the load flow pattern on the transmission system. This flow pattern needs to respect the operational constraints of the grid. Ideally, grid constraints will already be factored into the process of unit commitment and power plant dispatch. Otherwise, system operators may need to introduce changes in power plant schedules afterwards, to make sure that power flows remain within acceptable limits. Such a step requires sufficient lead time. This can have a negative impact on the achievable gate closure time. To avoid this, the Electric Reliability Council of Texas (ERCOT) market (for example) uses locational marginal prices to ensure that generation scheduling and dispatch respect grid constraints. This allows adjustment of schedules until five minutes before real-time. By contrast, in the European Power Exchange (EPEX) Spot market, which includes part of the North West Europe case study region (Germany and France), the absence of locational price signals can require system operator intervention, which contributes to a longer gate closure of 45 minutes.

Power plant operations can be planned to directly accommodate other constraints beyond flow on the transmission grid. The provision of system services, such as frequency and voltage services, can also be accounted for when developing the generation schedule. This is already common practice in some markets in the United States. Including system services in the scheduling process can reduce or eliminate the need for separate system service markets.

In summary, scheduling practice should:

- allow for frequent schedule updates as close as possible to real-time (up to five minutes before real-time is best practice)

- aim for short dispatch intervals (five minutes is current best practice)
- avoid locking in power plants over the long term with physically binding generation schedules (an obligation to make available generation capacity in the short term to the greatest extent possible is best practice)
- include grid constraints when optimising generation schedules, ideally per node of the transmission grid
- co-optimise generation schedules with provision of system services.

The points above can be implemented in liberalised, unbundled market frameworks as well as vertically integrated systems. However, mechanisms will vary depending on the overall regulatory paradigm.

Transmission and interconnector operation

Transmission and interconnector capacity are a valuable resource for cost-effective system operation, particularly at high shares of VRE. Making better use of existing infrastructure can often be a more cost-effective solution than new investment, in particular in stable power systems.

There are three main avenues by which the operation of grid infrastructure may be enhanced. These are measures to:

- optimise utilisation of interconnections
- enhance available transmission capacity
- optimise calculation of security margins.

In most cases, the standard operation of interconnector capacity will not be geared towards the efficient exchange of commercially driven power flows. The historical dominance of the vertically integrated market model has tended to produce legacy protocols, which rely on long-term exchange schedules with fixed power flows for trade, and/or protocols which see interconnection between balancing areas as a protection against contingencies. As such, using interconnection capacity for short-term trade may be uncommon and the institutional framework for such exchanges underdeveloped in many power systems.

Interconnection capacity can, however, be made available for short-term trade. Ideally, interconnection schedules allow for flow changes at shorter intervals than an hour (similar to shorter dispatch intervals for generation). Interconnection capacity may be used to jointly optimise use of power generation in two neighbouring markets, or to balance it. As part of the market coupling process in Europe, the available interconnection capacity between different European countries is implicitly taken into account in spot market trading, thus automatically optimising interconnector schedules (CASC, 2013; Baritaud and Volk, 2013).

In addition to changing the way interconnection is used, the physical capacity of the transmission grid can be better utilised, or increased with certain measures. One of these measures is dynamic line rating (DLR). The maximum capacity of a transmission line is usually constrained by line sag, which happens due to current-related temperature increase. Low ambient temperatures and/or wind will have a cooling effect on the lines, thus reducing line sag. Incorporating wind and temperature data to dynamically set transmission capacity can increase it significantly for many periods of the year, because standard line ratings usually rely on conservative, worst-case assumptions. For example, a gentle wind of 1 metre per second can increase line rating as much as 44%; pilot studies found an increase in capacity of over 30% for 90% of the time (Aivaliotis, 2010). The correlation between the cooling effect of wind and high wind power production makes this a particularly good match for wind power integration. DLR has been successfully implemented in practice. For example, the German transmission system operator (TSO) 50Hertz has achieved an average increase in transmission capacity in the order of 30% on transmission lines that use DLR (50Hertz, 2012). While innovative technologies may bring even larger benefits, the impact of DLR depends on system-specific circumstances.[1]

1. More detailed research on dynamic line rating and other measures to increase capacity of transmission lines is currently being conducted as part of the European Twenties Project, www.twenties-project.eu.

System operators keep power flows below maximum limits to maintain a margin against contingencies. The n-1 criterion is a common metric for determining the size of this margin. The main idea behind this approach is to be left with a functioning system even in the event of a contingency. This can be a costly way of ensuring security of supply. A possible alternative is putting in place a so-called Special Protection Scheme (SPS) (RETD, 2013). The rationale behind a SPS is that the system actively responds to a contingency and by virtue of this reaction maintains stable operation. While this can be a low-cost way of freeing up transmission capacity, it may increase complexity of system operation.

By better managing the grid, or deploying new technologies, the flow of power through the system can be controlled — the degree of control generally depends on the degree of deployment of new technologies. The use of transmission switching is an example of a new technique that does not require large deployment of new transmission equipment to achieve greater grid flexibility. It utilises advanced modelling techniques to alter the electric structure (topology) of the transmission system to improve response to contingencies, reduce transmission losses, or improve integration of renewables. The aim of these methods is to deliberately switch out transmission lines so that one or more of the above aims can be achieved. There are currently two projects developing tools and methods to demonstrate this concept, funded by the US Department of Energy's Advanced Research Projects Agency — Energy (ARPA-E).[2]

Special transmission equipment can also be deployed to maximise use of the power system; these are more expensive but allow for greater control of flow between regions. This can reduce loop flows and maximise the transfer of power from VRE to load. Examples of such technologies that have existed for some time include Flexible Alternating Current Transmission Systems (FACTS), which allow for increased control of power flows on alternating current (AC) networks, or high-voltage direct current (HVDC) which converts power to direct current, allowing for more efficient transmission over long distances, as well as control over flows of the line. Newer technologies include power flow controllers developed through another ARPA-E project,[3] which, while not as powerful as FACTS at directing power flow, are much cheaper. These are generally devices clamped onto existing lines to control the flow of power, thus maximising use of the transmission system.

Optimised utilisation of the transmission grid will be more or less easy to achieve depending on market structures. If the system operator also owns transmission assets, there may be little incentive to optimise operations, as new investments would contribute to the asset base. This issue will not occur in cases where the system operator does not own any system assets (Volk, 2013). Vertically integrated utilities will have little incentive to trade power with neighbouring regions in the short term, while the lack of accurate market prices can make it difficult to establish exchange schedules dynamically or to price power exchanges accurately.

Balancing area co-operation and integration

Large-scale aggregation of wind power and solar PV generation can significantly reduce variability and uncertainty of VRE generation, and thus reduce associated challenges. However, these benefits will only be available if the layout of balancing areas allows for smoothing to take place.

If VRE generation is "locked" into small balancing areas, smoothing benefits will be limited, because generation will be balanced locally using active measures (generation, storage and demand response) rather than relying on passive smoothing via the grid. This can lead to situations where one balancing area activates upward reserves, while its neighbour activates downward reserves.

This issue has been successfully addressed in the German power system. For historical reasons, Germany has four different balancing areas. Until December 2008, these were operated independently, leading to the paradoxical situation described above (activating reserves in opposite directions in neighbouring

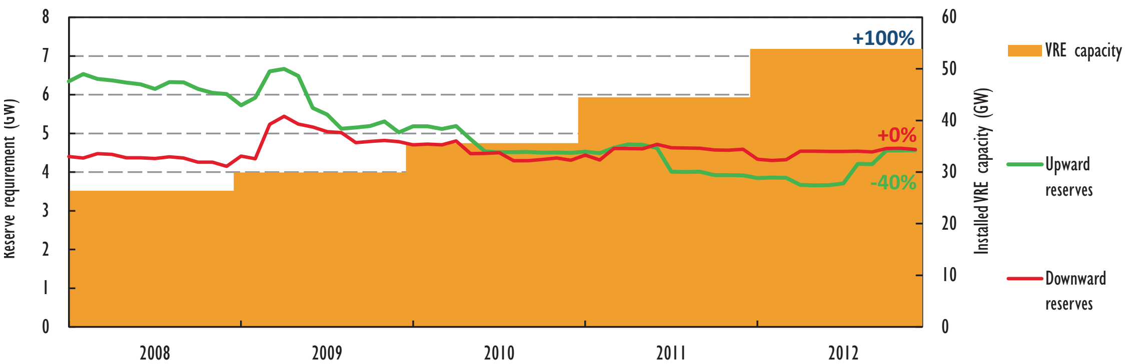
2. See http://smartgridcenter.tamu.edu/ratc/index.php/optimal-line-switching/ or http://arpa-e.energy.gov/?q=arpa-e-projects/decision-support-software-grid-operators.

3. See http://arpa-e.energy.gov/?q=arpa-e-projects/distributed-power-flow-control.

balancing areas). Following a multi-step protocol, the four TSOs first co-operated by allowing for netting out imbalances across balancing area borders, rather than activating reserves in opposite directions (Elia, 2012). Following this first step of not "balancing against each other", co-operation was expanded towards a common balancing market. This has allowed Germany to actually reduce reserve requirements while dynamically scaling up VRE (Figure 6.2). This procedure is only possible to the extent that balancing areas are sufficiently well connected.

Modelling results for the western United States also show significant benefits for expanding the geographic area over which the system is balanced. In addition, results show important savings from reduced gate closure times and trading intervals, as discussed in previous sections (Figure 6.3).

Figure 6.2 • Requirement for frequency restoration reserves in Germany

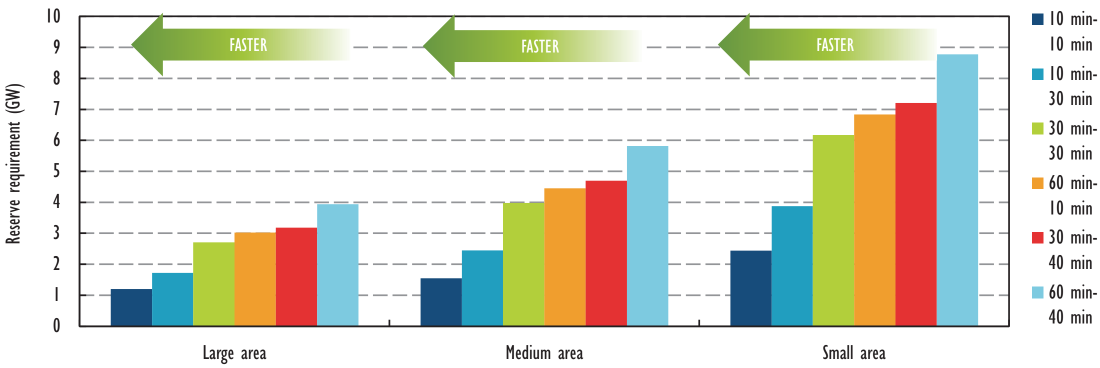


Notes: GW = gigawatt. Frequency restoration reserves are also referred to as secondary reserves; they are activated automatically with a response time of between 30 seconds and 15 minutes; secondary reserve corresponds to regulation reserve in US terminology.

Source: Hirth and Ziegenhagen, 2013.

Key point • *Better balancing area co-ordination has allowed German TSOs to reduce reserve requirements, despite a strong increase in VRE capacity.*

Figure 6.3 • Benefit of larger balancing areas and faster market operations



Note: the first number in the legend is the length of the dispatch interval; the second number is the forecast lead time.

Source: NREL, 2013.

Key point • *Larger balancing areas, shorter dispatch intervals and shorter forecast horizons all reduce the need for carrying operating reserves.*

Where balancing costs can be directly or indirectly passed on to consumers via mandatory grid fees, there may be little incentive to increase efficiency using co-ordination. This can be an issue under competitive as well as vertically integrated market models. In both cases, regulatory intervention may be required to provide the incentive for co-operation.

Definition and deployment of operating reserves

Determining the size of system reserves needs to strike a balance between security of supply and cost. Currently prevailing practice employs quite simple, deterministic rules to establish necessary reserve levels. Usually, the bulk of reserves are kept to handle the loss of the largest system component (generator or transmission line). The largest power plant tripping off may be the largest single event, and that amount is kept as reserve both as instantaneous fast-acting reserve and as slower manually activated reserve. In addition, reserve is kept for normal operation, such as load forecast errors and load variability inside the dispatch interval. This is usually based on past experience, and often means carrying 1.5 to 2 times the largest contingency event as reserve.

Increasing VRE will bring another uncertainty component to power systems; however, this uncertainty is generally not correlated with load uncertainty or generation outages. This means that a generation outage event, an extreme load variation and VRE variation are unlikely to happen at the same time. It is crucial to take into account all different risks together when setting reserve dimensions. A recent analysis conducted by the French TSO, RTE, on the effects of adding 10 GW of wind power to the French power system illustrates this. One calculation assumed that wind power generation was not forecast at all. Under this assumption, reserve requirements increased by 100%. Another calculation assumed state-of-the-art forecasting. Under this assumption, reserve requirements increased by only 10% (Bornard, 2013).

Another important aspect of reserve setting is that VRE will have different levels of uncertainty at different times and forecast generation levels. This means that when VRE gains a larger share in the power system and becomes relevant to setting reserves, the required reserves will be different on different days. More reserves are needed at times of high uncertainty (for example, on windy and cloudy days more reserves should be carried than on still and clear days when fewer reserves would suffice). This procedure is known as dynamic reserve allocation and it becomes increasingly important at higher VRE shares.

The Spanish TSO, for example, accounts for the low probability of simultaneous events by taking 2% of forecasted load plus the range between the most likely wind power level and a lower wind level (with an 85% probability of being exceeded). These variations represent the maximum possible instantaneous events for load and wind power combined with the maximum loss of generation (Gil, De la Torre and Rivas 2010). In Spain and Portugal, the TSOs are already testing a probabilistic method for reserve allocation (Holttinen et al., 2012) that will calculate the reserves dynamically based on the risks of outages and load, as well as VRE uncertainties. Risk-based reserve allocation is also under development at other TSOs, for example Hydro Quebec (Menemenlis, Huneault and Robitaille, 2013). More generally, probabilistic measures can be used to optimise system operations at higher shares of VRE (Kiviluoma, 2012).

Institutional "inertia" may pose a significant barrier to revising the definition and size of reserves. Also, depending on the portfolio of VRE generators and existing system characteristics, the optimal reserve and system service portfolio will differ from system to system. Hence, detailed studies will be needed in each individual case to determine revised definitions. The Irish TSO EirGrid is currently implementing this successfully as part of the DS3 programme.[4]

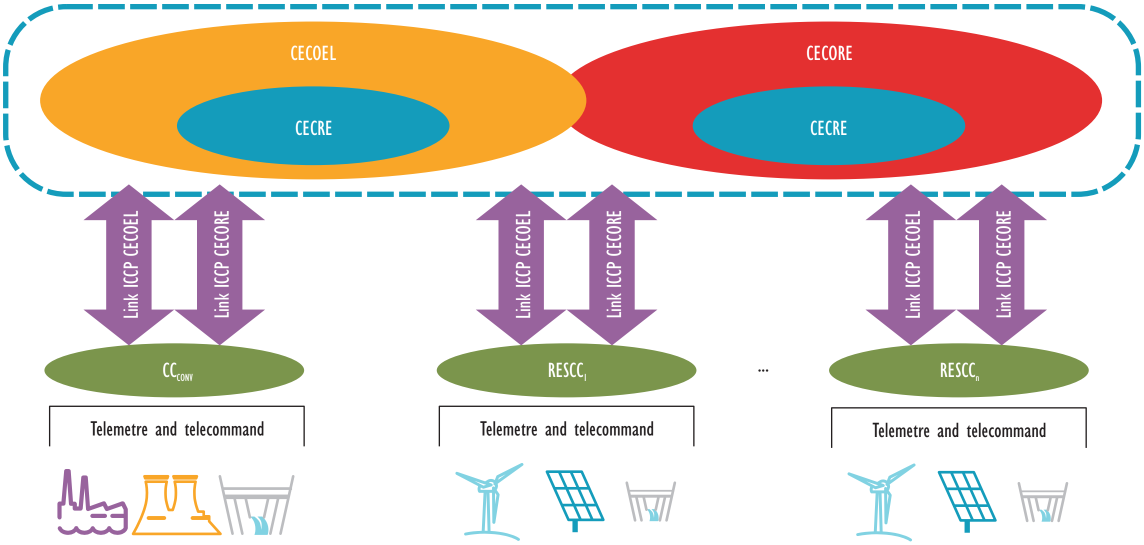
4. See the project website www.eirgrid.com/operations/ds3/ for details.

Visibility and controllability of VRE generation

System operators need accurate real-time information on the status of all system-relevant components and appropriate control tools to ensure security of supply. When wind power and solar PV generation make-up a relevant share of generation – even if only during a limited period of time – visibility and controllability of VRE generation becomes critical. Because a large share of VRE generation is not directly connected to the transmission system, TSOs will often not have direct visibility of VRE generation levels, but only of current net load at the different sub-stations of the transmission system. In addition, TSOs may not have direct control to dispatch down VRE output if system security calls for it.

Those TSOs that are leading the way in VRE integration have developed strategies to ensure visibility and controllability of VRE generation.[5] In Spain, Red Eléctrica de España (REE) established a Control Centre of Renewable Energies (CECRE) in 2006,[6] a worldwide pioneering initiative to monitor and control this type of generation. Through the CECRE, the system operator receives the telemetry of 98.6% of the wind power generation installed in Spain, of which 96% is controllable (with the ability to adapt its production to a given set-point within 15 minutes).

Figure 6.4 • Functioning of the CECRE



Note: CC_{CONV} = Control Centre for conventional generation; CECOEL = Centro de Control Eléctrico (Electricity Control Centre); CECORE = Centro de Control de Red (Network Control Centre); CECRE = Centro de Control de Energía Renovable (Control Centre of Renewable Energy); ICCP = Inter-Control Centre Communication Protocol; RESCC = Renewable Energy Source Control Centre.

Source: REE, 2013.

Key point • CECRE is an important factor in the successful integration of wind power in Spain.

This has been achieved through the aggregation of all the distributed resources of more than 10 MW in renewable energy sources control centres (RESCCs), and the connection of RESCCs with CECRE. This hierarchical structure (Figure 6.4), together with the software applications developed by REE, is used to analyse the maximum wind power generation that can be accepted by the system. Monitoring and controlling VRE generation in real-time decreases the number and quantity of curtailments, maintaining the quality and security of the electricity supply at the same time that renewable energy integration is maximised (REE, 2013).

5. For very small-scale installations, such as roof-top PV systems with a small kilowatt capacity, installation of control equipment may be disproportionate. However, even for such small installations, grid codes should include provisions for behaviour during periods of system stress (see Chapter 5).
6. See www.ree.es/ingles/sala_prensa/web/infografias_detalle.aspx?id_infografia=9 for an animated introduction to the CECRE.

Forecasting of VRE generation

Accurate forecasting of system-level VRE generation is a vital and cost-effective operational practice for VRE integration. The North American Electric Reliability Corporation (NERC) states that, "enhanced measurement and forecasting of variable generation output is needed to ensure bulk power system reliability," and that, "wind forecasting must be incorporated into real-time operating practices as well as day-to-day operational planning." (NERC, 2009). A recent survey of grid operators worldwide found near-unanimous agreement that the ability to integrate a significant amount of wind power will depend on using appropriate wind power forecasting and managing uncertainty (Jones, 2011).

It is important to distinguish between forecasts at the level of larger, individual wind power and solar power plants or the aggregate of several smaller plants on the one hand, and system-wide generation forecasts on the other. The former are relevant for selling VRE electricity on the market and for settlement of imbalances. The latter are critical for system operators to correctly anticipate the supply-demand balance and to intervene early and in an informed manner if necessary. Also, in systems using advanced reserve calculation procedures, system-wide forecasts can be important to establish reserve requirements. Both forecasting requirements may be different, and it is likely that certain forecasting techniques are more suited to one of these operations. In any case, obtaining accurate generation data with high spatial and temporal resolution is important in developing accurate forecasting techniques.

As mentioned initially, dispatchable power plants often require significant lead time to start operations, which limits their ability to provide flexibility during real-time. A good forecast will allow for more cost-effective balancing in real-time and fewer reserve requirements. The Western Wind and Solar Integration Study (GE Energy, 2010) found that use of forecasting and including wind power in day-ahead commitment, "reduces Western Electricity Coordinating Council (WECC) operating costs by up to 14%, or USD 5 billion per year, which is USD 12 per megawatt hour to USD 20 per megawatt hour of wind power and solar generation" (GE Energy, 2010). The value of forecasting in the ERCOT system is estimated at several hundred million US dollars annually (Table 6.1).

While forecasting has seen important improvements in recent years (see Chapter 2), it remains a field of active research.

Table 6.1 • The value of wind power forecasts in the ERCOT case study region

Installed wind power capacity	*Projected annual operating cost savings (state-of-the-art forecast vs. no forecast)*
5.0 GW	USD 20 million
10.0 GW	USD 180 million
15.0 GW	USD 510 million

Source: Piwko, 2009.

Key point • Effective use of VRE forecasts can bring significant operational cost savings.

Market design for operational measures

Electricity market design: operational aspects

The first part of this chapter pointed out key factors for optimal system operation under high-VRE penetrations. To incentivise such operational outcomes, markets have to provide appropriate price signals. The properties of VRE generators highlighted in Chapter 2 translate into the following criteria for appropriate market price signals:

- Low short-run marginal cost:
  - bids from VRE generators should reflect short-run marginal costs,[7] i.e. additional payments to VRE generators should affect price formation as little as possible.
- Variability:
  - increased importance of high temporal resolution of price signals, i.e. prices are valid only for short time periods
  - increased importance of allowing large differences in prices.
- Uncertainty:
  - increased importance of short-term price signals, i.e. prices formed close to real-time and based on current system status.
- Location constraints and modularity:
  - increased importance of high spatial resolution of price signals, i.e. prices differ from place to place.
- Non-synchronous technology:
  - increased importance of system service markets, i.e. prices for products other than bulk power.

In addition to adequate price signals, markets should also be designed to facilitate access to the most cost-effective flexible resources to balance the system.

Based on these considerations, the IEA has identified eight key dimensions for the assessment of market design aspects that are relevant for power market operations at high shares of VRE. They cover the operation of wholesale markets as well as system service markets, and are briefly described below. It is noteworthy that most of these measures are important independent of VRE deployment.

Dispatch of non-VRE generation

Market rules concerning non-VRE power plant dispatch affect how much technically existing flexibility is made available through the market. Where a large number of power plants are dispatched according to physically binding, long-term contracts, their flexibility for balancing VRE will be lost.

In a centralised, mandatory pool, all generators are required to bid their generation on the organised, physical spot market. In this case, the physical short-term market will include all available generation assets and there will be a maximum amount of possible trading parties in the market. Long-term price risks can be hedged by market participants via financial instruments that do not result in physical obligations for delivery.

Dispatch of VRE generation

Performance-based incentives (such as production tax credits or feed-in tariffs) provide cost recovery by remunerating per unit of electricity generation. Consequently, VRE generators will have an incentive to sell their power below cost, which can lead to sub-optimal market outcomes and even negative market prices, under certain circumstances. In addition, in some markets VRE generators enjoy priority dispatch, which can further lead to sub-optimal market outcomes.

In principle, only short-run costs should be taken into account when deciding on VRE operations. While not fully achieving this, market premium schemes are a step in this direction.

Dispatch intervals

Electricity is traded as a stable power output over a certain amount of time; this is known as a trading block. Trading blocks in many systems are one hour long. However, VRE and load show variability within the hour, so shorter blocks allow market-based generation to track net load more efficiently, without the need to rely on reserves (Figure 6.1). In some markets, dispatching orders have a different

7. This does not imply that they will actually bid their short-run marginal costs; they may bid far above during scarcity periods. However, they should not have an incentive to bid below.

granularity than trading blocks; for example, even if bids and offers refer to hourly intervals, real-time dispatching is executed several times in the same interval. This is the case in ERCOT (hourly trading and five-minute dispatch). Frequently updated dispatching allows short-term variability to be managed without relying on reserves. Best practice dispatch interval is five minutes; one hour tends to be the rule.

Dispatch intervals may be an area where vertically integrated utilities have an advantage in that they can re-dispatch the system at any desired time, because they are not bound to any market schedule. However this is often not practiced.

Last schedule update: gate closure time

Gate closure time refers to how close to real-time electricity can be bought or sold. In most markets there is a day-ahead market, which closes at mid-day on the day before power generation, followed by intra-day markets, taking place on the same day as physical delivery of electricity. After gate closure, it is not possible to change electricity supply or demand offers.

However, VRE forecasts improve considerably closer to real-time operation. So as to be able to incorporate this valuable information, markets need to allow trading as close as possible to real-time operations. In systems where operational decisions are centralised, gate closure time refers to the last point in time that the system operator updates the generation schedule. Centralised pool markets can allow for shorter gate closure times.

The ERCOT market in Texas follows best practice, with a gate closure time of five minutes. Other markets have gate closure times of 45 minutes (Germany) and longer.

System services definition

System services are necessary to support the stability and reliability of the power system. As explained above, system service requirements may depend on forecasted VRE generation. In addition, in systems with high penetrations of VRE, new system service products may become relevant, such as fast frequency response to deal with reduced system inertia or ramping reserves to deal with ramping events. The products traded on system services markets may need to be changed in the presence of high shares of VRE penetration. This issue is elaborated further in Chapter 8.

In the context of benchmarking market operations, a distinction is made in terms of how operating reserves are defined.

System services market

The organisation of competitive markets for ancillary services and the adequate remuneration of different system services become more relevant with high penetrations of VRE. The previous category covers which products exist on the market, whereas this category reflects how these products are actually traded. For example, all resources should be allowed to bid in the market, including VRE and flexible resources such as demand-side integration and storage.

Grid representation

Markets can be designed to include grid constraints in market clearing, allowing the market to be co-optimised with relevant grid constraints. This is achieved by clearing demand and supply at many points in the network, taking into account that a given generator can only serve load that is not behind grid bottlenecks. This practice is known as locational marginal pricing (LMP) or nodal pricing (see Volk, 2013 for details) and has been implemented, for example, in the PJM regional transmission organisation (RTO) since April 1998 or in the ERCOT power market since December 2010.

An intermediate step towards locational pricing is splitting market regions into separate zones, in case there is congestion over certain lines. This procedure is used in the NordPool market (even within countries), Italy, and the EpexSpot market (between the case study regions of Germany and France).

Creating a higher number of zones or nodes faces a trade-off with market liquidity and, consequently, market power.

Interconnector management

Interconnector flows should be allowed to change at short notice, and flows should only be fixed for a short amount of time. Common practice in many markets today is long-term auctioning of interconnector capacity, day-ahead or even longer term scheduling of interconnector flows, and fixing flows for entire hours. Scheduling of interconnector flows can be integrated into market operations, making use of all physically available interconnection capacity via market coupling; this is currently in the process of being implemented in the European Union.

Analysis of case study market design

It should be noted that increasing the size of market areas yields important benefits thanks to geographical smoothing of VRE and overall economies of scale (Baritaud and Volk, 2013). Increasing the size of market areas, together with integrating the balancing areas with the market, should therefore be a priority. The following analysis assumes that the market and balancing areas have already been expanded as much as possible and focuses exclusively on the actual market design features.

The IEA has carried out an extensive survey of power market design as part of the Grid Integration of Variable Renewables (GIVAR III) project case study regions (Mueller, Chandler and Patriarca, forthcoming). The review covered:

- regulatory arrangements for the trade of bulk electricity
- an overview of regulatory arrangements for the trade of reserves
- regulatory agreements for the long-term contracting of generation capacity or other services
- regulatory arrangements for allocation of interconnector capacity
- regulatory arrangements regarding network tariffs
- regulatory arrangements regarding the curtailment of renewable energy generators.

In the case of the North West Europe case study, the case study contains four different spot markets or exchanges. Nord Pool Spot in the Nordic countries (Denmark, Finland, Norway and Sweden), EPEX Spot for Germany and France, the British Electricity Trading and Transmission Arrangements (BETTA) in Great Britain, and the Single Electricity Market (SEM) in the island of Ireland. The analysis also covered the market design of the ERCOT, Italy, Spain and Portugal (joined in the Iberian Electricity Market MIBEL), India, Japan and Brazil.

Market designs show significant differences in the degree to which they allow for the cost-effective integration of VRE. Regarding the eight key dimensions for power market operations identified in the previous section (summarised in Table 6.2), the results of this power market design review have been synthesised by scoring market designs along each dimension. The better a system scores, the more likely it is that the market will show good performance on an operational time scale at high-VRE penetrations, see Mueller, Chandler and Patriarca (forthcoming), for details.

It is important to keep in mind that the mere presence of a power market, or its absence, does not determine if the power system can be operated in a cost-effective way at high shares of VRE. Well-designed market operations that score highly on the dimensions identified above are likely to allow for such operations. But even where system operation is not market-based, the best practice described in the first half of this chapter can nonetheless be implemented.

To assess the different case study regions, a distinction was made based on the role of the power market in system operations. Where system operation is driven primarily on the basis of short-term generator bids and private contracts between generators and consumers, the above market operating

Table 6.2 • Selected dimensions of power market design

Dimension	*Explanation*	*Scoring*
Non-VRE dispatch	Unit commitment and dispatch of all power plants excluding VRE. Dispatch is more cost-effective if it allows the optimisation of the full power plant portfolio in a co-ordinated fashion.	• **Low**: market dominated by long-term bilateral contracts that constrain the dispatching process. • **Medium**: liquid power exchange or centralised pool with some long-term bilateral contracts that constrain the dispatching process. • **High**: centralised pool; dispatch can optimise across full generation portfolio.
VRE dispatch	Degree to which VRE generators have an incentive to bid below their short-run costs. The structure of support mechanism to VRE may impact bidding strategies of VRE.	• **Low**: fixed remuneration for VRE generation (e.g. Feed-in Tariffs). Operate independently from market price signals. • **Medium**: incentives are a premium on top of market price (e.g. Feed-in Premium). • **High**: VRE has no incentive to bid below short-run marginal cost.
Dispatch interval	Time interval during which generators need to maintain stable output. The shorter the interval, the better dispatch schedules can track load variation without relying on reserves.	• **Low**: dispatch interval larger or equal to one hour. • **Medium**: shorter than one hour but larger than 10 minutes. • **High**: quasi-real-time dispatch, shorter than 10 minutes.
Last schedule update	Last possibility to update dispatch based on bids made on the wholesale power market.	• **Low**: on the day before operations or earlier. • **Medium**: on the day of operation but more than 30 minutes before real-time. • **High**: less than 30 minutes before real-time.
System services definition	Procedure by which system service products, in particular operating reserves, are defined. The inclusion of VRE generation in the reserve calculation is scored.	• **Low**: reserve requirements fixed long-term, no inclusion of VRE operation in calculation of requirements. • **Medium**: different pre-defined levels, VRE operation is included. • **High**: stochastic, i.e. different scenarios of VRE generation are included in the definition of reserve requirements.
System services market	Market signals and remuneration mechanisms for provision of system services, in particular operating reserves. Price setting mechanism is considered as indicator of market efficiency.	• **Low**: some services remunerated, not paid at marginal price. • **Medium to low**: all services remunerated, but not based on marginal price. • **Medium to high**: some services remunerated, based on marginal price. • **High**: all services remunerated, based on marginal price.
Grid representation	Market representation of network constraints, i.e. is the market cleared accounting for grid constraints.	• **Low**: no grid representation, one single market zone. • **Medium**: several market zones. • **High**: full representation of the transmission system (i.e. LMP).
Interconnector management	Allocation of interconnection capacity for trade with adjacent markets.	• **Low**: long-term auction of interconnection capacity. • **Medium**: day-ahead, explicit auction. • **High**: full integration of capacity allocation via a unified spot market (implicit auctions).

Key point • Power market operations can be benchmarked according to their performance at high shares of VRE.

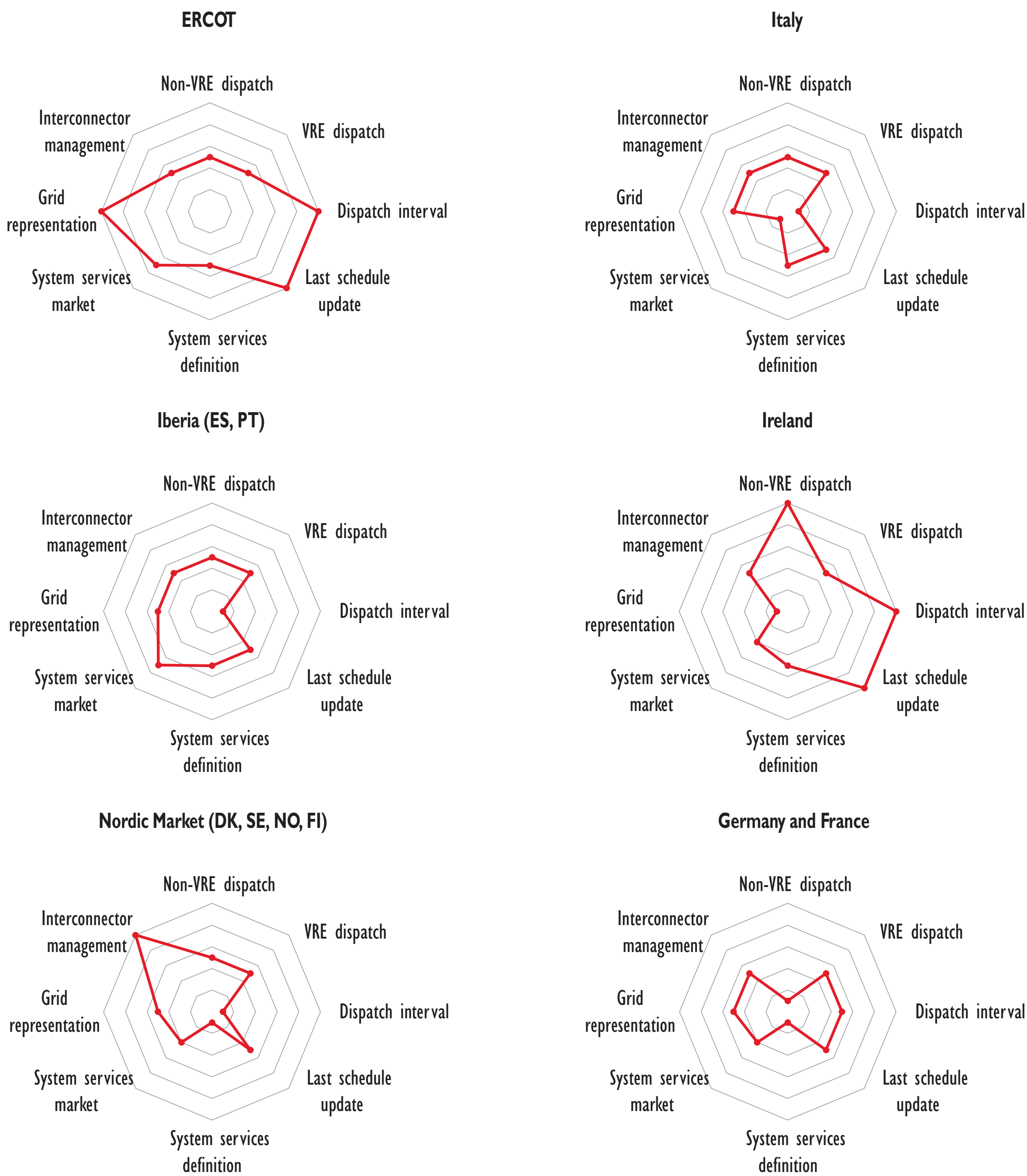
scoring framework is applied. In cases where system operations are not based on short-term bids or direct contracts between generators and loads, a different scoring system is applied. Three of the case studies fall under the second category.

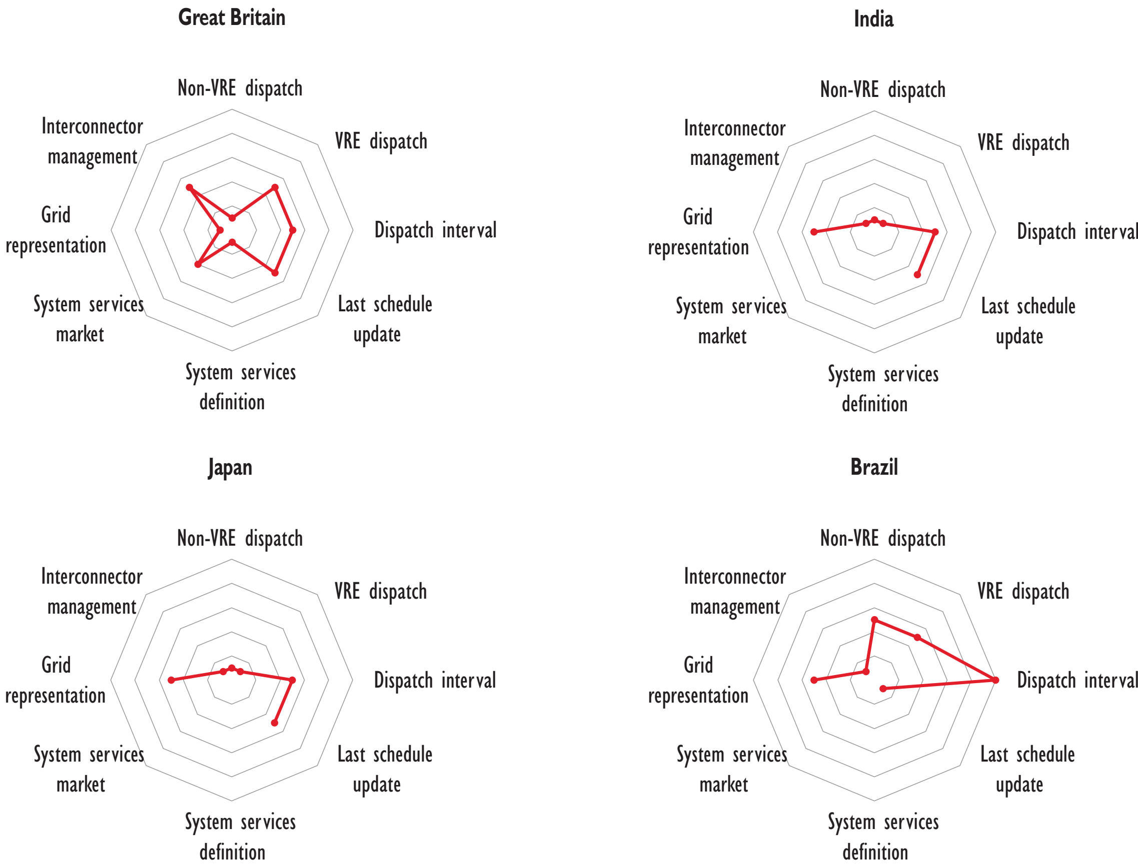
In Japan, based on traded volumes, the role of Japan Electric Power Exchange (JEPX) is marginal in comparison to the operations managed fully within vertically integrated local EPCOs (electric power companies). In India, the dispatching process is managed mainly by State Load Dispatch Centres (SLDC) and generator remuneration is tariff-based.[8] In Brazil, the trade of electricity via long-term contracts

8. Tariffs consist of three parts: a fixed component linked to the availability of generating stations, a second part intended to remunerate the variable generation costs and a third related to deviations from schedules.

and auctions is separate from the dispatch of power plants (competition for the market rather than competition in the market). Trade is based on long-term auctions and power purchase agreements (PPA), while generators are dispatched in real-time by the system operator (Operador Nacional do Sistema Elétrico), whose aim is to minimise overall costs while maintaining system safety and security. However, in all these circumstances the best practice outlined in the first half of the chapter can be implemented. These systems are therefore assessed based on a general three-level scoring (an explanation of scoring can be found in Annex D). Where scores are not applicable, they are omitted in the overview charts below.

Figure 6.5 • Comparison between power market designs in case study regions





Note: missing scores indicate that item is not applicable; for example, system services are not traded in vertically integrated companies.

Key point • *Market operations show a wide range of performance levels, and no market achieves the best available score for system service market operation.*

The eight dimensions of power market design form three groups: dispatching, system services, and grid representation and management.

As far as **dispatching features** are concerned, ERCOT has the best performance out of all markets assessed, with some improvement possible in terms of VRE dispatching:

- Almost all generation resources (both VRE and non-VRE) are dispatched in quasi real time (minutes or seconds before actual generation) via optimisation processes taking into account system security and overall costs (including generation and congestion costs). The dispatching process is effective because it can actually optimise the vast majority of power flows. This is not possible to the same extent in other markets, such as France, where a large share of the power supply is secured via long term bilateral contracts, which can reduce the capacity of the market to dynamically identify the optimal generation mix.
- In addition, while ERCOT re-optimises generation schedules until a few minutes before physical delivery, in other markets such as Italy, Germany and Spain, final generation schedules are fixed well ahead (in some cases hours) before physical delivery via the intra-day market. A certain time lag between fixing generation schedules (gate closure on power exchanges) and physical delivery provides less flexibility in the face of short-term uncertainties. Quasi-real-time dispatch allows ERCOT to take into account last-minute fluctuations in system demand, VRE generation or other disturbances such as generation trips or transmission contingencies. This is not possible in systems with longer intervals between market dispatching and physical delivery. In those markets, last-minute variations must be solved via potentially expensive reserves. ERCOT schedules generation

plants on the basis of their bids. The possibility for market players to update their bids close to physical delivery represents an additional source of flexibility for the power market, because it allows market players to react to continuously evolving market environment.

- As far as VRE dispatch is concerned, market operations may be influenced by VRE generators generating totally independently of current market prices. VRE generators may also have an incentive to bid below their short-run costs, where they receive additional premiums. However, wind power and solar PV have virtually zero marginal cost anyway, and would always be among the first technologies to be dispatched.

None of the markets analysed scored the maximum in the definition of or **market for system services**.

- System service markets are not actual markets in most cases, but a scheme by which operators require or procure certain services. In order to qualify as a market, system services, in particular operating reserves, need to be remunerated according to their marginal price. In reality, all markets analysed failed in one or more of these aspects. Higher scores have been given to systems adopting marginal pricing for ancillary services (e.g. Spain and ERCOT) even where those markets do not remunerate all services (e.g. primary frequency response). The lack of well-designed system service markets and its implications for overall market design are addressed in Chapter 8.
- The definition of operating reserves often also falls short of best practice. Ideally, the calculation of reserve requirements would take into account VRE penetration and VRE generation scenarios based on probabilistic forecasts. Even in systems with high-VRE penetration, this is not practiced and legacy calculation procedures, often setting fixed requirements over the long term, are in place.

Grid Representation is one of the strong points of the ERCOT market, which underwent important changes in 2010, when a new market model was implemented.

A key characteristic of the new market structure is the nodal representation of the power system, which allows congestion to be handled at a very granular level, identifying grid bottlenecks and determining electricity prices at each of the 4 000 nodes of the transmission system. LMP enables ERCOT to manage transmission congestion through market-based mechanisms and produces price signals that clearly indicate where new investments are most needed for managing congestion and maintaining reliability. Factoring in an accurate grid representation into market clearing also allows for bid-based optimisation of generation schedules very close to real-time (five minutes). Such short gate closure times are not feasible if grid constraints are not taken into account in market clearing. In such cases, system operators need sufficient time to re-dispatch the system in case market results lead to grid congestions. ERCOT is the only case study region analysed with locational pricing; other systems are based on zonal pricing to capture system congestion (e.g. Italy and the Nordic market).

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

Policy and market considerations

Improving system and market operations is a no-regret option. It will almost always prove cost-effective, irrespective of VRE integration. However, the benefits of adopting optimised operations increase at growing VRE penetrations. Optimising system operations in the presence of VRE should be considered wherever and whenever wind power and solar PV are deployed.

Increasing the size over which the system is balanced in real-time (balancing area) yields important benefits thanks to geographical smoothing of VRE and overall economies of scale. A number of these benefits can also be achieved by better co-ordinating the operation of neighbouring balancing areas. Increasing the size of market areas, along with integrating balancing areas and markets should be a priority.

Harmonising and updating protocols and procedures across different system operators and other stakeholders can be particularly important in this context. System operators and protocols routinely handle the variability and uncertainty of demand and the risk for unexpected unavailability of dispatchable generation. However, introducing variability and VRE forecast uncertainty on the generation side is generally a new phenomenon in system operation. However, the now well-established experience of system operators in countries with a higher VRE penetration (Iberian Peninsula, Denmark, Ireland, Germany) provides insights into how to adjust operations to this new situation, and other operators should reap the opportunity to learn from such examples.

In addition to protocols and procedures used by the system operators, market design needs to facilitate an efficient operation of the power system. The analysis of wholesale market design has revealed considerable room for improvement, particularly in the following aspects:

- System services markets are often underdeveloped. The procedures currently in place for the calculation of operating reserves are far from best practice in most of the countries analysed. In addition, most of the markets lack transparency and competition. Possible improvement may arise from the definition of clear market products and the market integration of all available sources of flexibility (e.g. interconnection, demand-side integration). This issue is investigated more closely in the context of system transformation in Chapter 8.
- Operational decisions, often unnecessarily taking place hours before physical delivery of electricity for historic reasons, should move closer towards real-time to efficiently deal with variability and uncertainty. In particular, shorter scheduling and dispatch intervals should be targeted.
- VRE market integration could be deepened. Market clearing can optimise VRE generation together with dispatchable production in light of system constraints and overall system costs. VRE participation in services markets should be fostered.

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7 • Flexibility investment options

HIGHLIGHTS

- Optimising power system operation and deploying variable renewable energy (VRE) in a system-friendly way is a prerequisite for cost-effective VRE integration. However, at some point further increasing VRE capacity will call for additional investments in system flexibility. There are four different flexible resources: grid infrastructure, dispatchable generation, storage and demand-side integration. Each of these forms a broad category or technology family, which contains different specific flexibility options. All flexibility options contribute to VRE integration, but they have different strengths and weaknesses.

- Grid infrastructure is the only flexibility option which brings a significant double benefit. Firstly, it is a precondition for reaching more distant resources (location flexibility), but it also makes a strong contribution to mitigating variability by the inherent smoothing benefit of aggregating VRE output over larger areas (temporal flexibility). This makes the contribution of grid infrastructure somewhat unique.

- Dispatchable generation provides flexibility at a wide range of costs, depending on technology and operational regime. It is currently the dominant flexible resource in virtually all power systems. In the long term, flexible dispatchable generation can be critical for meeting demand during sustained periods (several consecutive days) of low VRE generation.

- Storage can provide a broad range of different services, depending on which technology is used and where it is placed in the grid (centralised vs. distributed). It is usually a combination of multiple benefits that make storage investment economically viable today. Costs can vary greatly, depending mainly on up-front cost, the capacity to energy ratio (how much energy can be released or stored at one moment compared to how much energy can be stored overall), and number of charge/discharge cycles. However, costs are generally higher than for the other flexible resources.

- Demand-side integration (DSI) holds the promise of providing flexibility cost-effectively. However current estimates show a broad range of costs; in particular, additional investment costs for enabling smart operation of appliances are uncertain, with literature values differing by a factor of ten. Distributed heat storage and district heating applications, but also cold storage, are attractive options to make electricity demand more flexible.

- A simplified metric – levellised cost of flexibility (LCOF) – was used to compare the cost of providing flexibility from the different flexible resources. Highly flexible generation (such as reservoir hydro power plants and selected fossil technologies), grid infrastructure and demand-side integration (including thermal storage) can provide flexibility at very low cost (as low as USD 1 per megawatt hour (/MWh) to USD 5/MWh and reaching USD 20/MWh under less favourable conditions). Electricity storage is considerably more costly, ranging from USD 20/MWh (pumped hydro storage in favourable locations) to above USD 500/MWh (distributed battery storage with low utilisation). However, costs need to be seen in light of the benefits that the different resources provide.

- Using two different economic simulation tools, the cost-benefit of the different flexible resources was investigated. Costs are the additional costs for building and operating the flexible resources, while benefits are the saved investment and operating costs in other parts of the power system compared to a baseline case.
- The cost-benefit of additional flexibility is better when the demand for additional flexibility is high, e.g. at higher shares of VRE. In addition, the cost-benefit of additional flexibility is higher, when several options are deployed in a concerted and co-ordinated fashion.
- DSI, in particular distributed thermal storage, showed significant promise as suggested by its superior cost-benefit performance compared to other flexibility options. However, a degree of uncertainty exists regarding its full potential in real-life applications.
- Cost-benefit profiles of storage are less favourable, reflecting higher costs. Adding pump-back functionality to existing reservoir hydro plants showed the most favourable cost-benefit ratio.
- Interconnection allows a more efficient use of distributed flexibility options and generates synergies with storage and DSI. Modelling for the North West Europe case study showed favourable cost-benefit of significantly increased interconnection.
- Cost-benefit of retrofitting existing power plants to increase flexibility shows a wide range, driven by project-specific costs.

Optimising the operation of power systems is a prerequisite for cost-effective VRE integration. At low VRE deployment levels, adapting the way the system is operated may be sufficient to successfully achieve integration. However, focusing on operations alone will be insufficient at some point. In stable systems, operational measures are likely to be sufficient to achieve higher penetrations as compared to dynamic systems. New investments become necessary to replace old system assets or to meet increasing demand. When VRE capacity is added very rapidly,[1] dedicated investments may become necessary to increase the total system's flexibility, even in the absence of demand growth or infrastructure retirement. In both cases, investment patterns need to be harmonised to ensure a coherent asset portfolio.

This chapter sheds light on the technical and economic aspects of investment in the four flexible resources:

- grid infrastructure
- dispatchable generation
- storage
- demand-side integration.

The analysis of each resource is based on relevant technical characteristics and explains how it can contribute to VRE integration. The economic analysis of each resource features a metric derived from the levellised cost of electricity (LCOE), termed the levellised cost of flexibility (LCOF). For each resource, LCOF provides an indicative cost for providing flexibility with this resource. For selected flexibility options, the cost analysis is supplemented by a cost-benefit analysis obtained by power system modelling. Market design and policy considerations conclude the discussion for each resource. This chapter discusses each resource separately, laying the ground for an integrated discussion in Chapter 8.

1. Rapidly means at a pace which is considerably faster than the level of investment needed to replace old infrastructure or to meet incremental demand.

Measuring costs and benefits of flexible resources

This section explains the tools that were used in the economic assessment of the different options. After this is completed, the chapter turns to discussing each flexible resource individually.

The economic analysis of flexible resources has to strike a somewhat delicate balance. On the one hand, all flexible resources may contribute to successful VRE integration. On the other, as shown in the following sections, their contribution profile varies from one resource to another. For example, flexible generation is very important for covering periods of low VRE generation. However, generation cannot contribute to avoiding VRE curtailment once net load becomes negative; storage, demand-side integration and (in some cases) interconnection can do so. Therefore, the calculated costs cannot be directly compared, because different flexible resources provide somewhat different services.

The LCOF

Cost analysis of flexibility resources is based on a simplified metric, termed levellised cost of flexibility (LCOF). It provides an estimate of the additional costs associated with making the generation or consumption of one MWh of electricity more flexible. For example in the case of storage, LCOF provides an estimate of how costly it is to store 1 MWh for later consumption, assuming a particular operation regime of the storage device. Similarly, LCOF provides an estimate of how costly it is to transport 1 MWh of electricity over a certain distance, again using a set of specific assumptions.[2] The different approaches to calculating LCOF are summarised in Table 7.1.

Table 7.1 • LCOF definition for different flexibility options

Grid infrastructure LCOF	Transmission LCOF represents the cost of transporting 1 MWh of electricity over a given distance using a transmission line. Sensitivities account for different line/cable technologies, utilisation rates and line lengths. Distribution LCOF represents the additional costs of a newly built distribution grid, if it is dimensioned to allow for uncurtailed power flows from distributed solar PV generation to the transmission system. It is expressed in US dollars per megawatt hour of annual solar PV production. The evaluation is based on a simplified distribution grid with sensitivity analysis for solar PV system sizes and distribution line lengths.
Dispatchable generation LCOF	LCOF measures the differences in per MWh cost of different generation technologies, comparing different operating regimes: a base case, characterised by reference capacity factors and cycling regimes; and flexibility cases with lower capacity factors and increased cycling.
Storage LCOF	LCOF captures the cost of building and operating a storage device, expressed per MWh of retrieved electricity. The analysis considers different technologies, utilisation patterns and energy to capacity ratios. LCOF includes the cost of electricity losses (priced at USD 40/MWh) but does not include the original cost of producing the electricity.
DSI LCOF	For small-scale applications, LCOF calculates the additional capital and operational costs for allowing smart operation of distributed heat storage devices and is expressed in per MWh of electricity consumption of the device. In the case of large-scale, load-shedding options, LCOF is expressed as the value of lost load for different industrial processes, expressed per MWh. LCOF includes losses, priced at USD 40/MWh, and the cost of smart meters.

Key point • LCOF is calculated using a specific approach for different flexibility options.

Methodology for cost-benefit analysis

The LCOF analysis paints only part of the picture. For example, it allows the estimation of how costly storing electricity is compared to transporting it over a certain distance. However, it does not make any statement on whether storage is more valuable than transmission or the circumstances under which this may be the case.

To complete the economic analysis, two state-of-the-art power system models were used. Both models are specifically designed to take into account the effects of flexibility and renewable energy resources on the operation of power systems and markets. The first model, the Investment Model for Renewable

2. The full set of assumptions can be found in Annex A.

Energy Systems (IMRES), was used to model a sample power system and determine the added value generated by different flexibility options. Power system modelling with IMRES is intended to capture attributes that are of relevance to a large number of real-life systems, but the IMRES system itself does not correspond to any real-life power system. The IMRES system has no interconnection, but a relatively large peak demand in the order of 80 gigawatts (GW). IMRES is particularly suited to studying the combined impact of the balancing and utilisation effect (Chapter 2) on the optimal power generation mix and how to deal with these impacts cost-effectively in a large but isolated system.

In addition, to analyse interconnection in more detail, the International Energy Agency (IEA) has collaborated with Pöyry Management Consulting (UK) Ltd (subsequently referred to as Pöyry). Using Pöyry's BID3 model, IEA has carried out an economic analysis of flexibility options including interconnection. The BID3 modelling is based on a high-VRE adaptation of Pöyry's central scenario and covered the countries of the North West Europe case study area (Denmark, Finland, France, Germany, Ireland, Norway, Sweden and the United Kingdom).

IMRES

Power system characteristics

Hourly time series of power demand, wind power and solar PV generation from Germany in 2011 were used as a basis for constructing the test system.[3] Wind power and solar PV generation were normalised according to daily installed capacities and scaled up according to the different VRE penetration scenarios analysed. While such up-scaling is known to potentially overstate variability, installed capacities were significant in the observed time series, with 24.8 GW for solar PV and 28.9 GW for onshore wind power at the end of 2011. Germany was selected on the basis of its substantial, geographically and technologically diversified VRE base.

The installed conventional power generation fleet is optimised internally by the IMRES model, and totally independent of the current German plant mix. When composing the plant mix, the model can choose between nuclear, coal, combined-cycle gas turbine (CCGT) and open-cycle gas turbine (OCGT) power plants. The model assumes no interconnection with neighbouring systems and no network congestion or losses (copper plate). VRE generation does not enjoy priority dispatch in the IMRES model. As such, curtailment occurs whenever it can contribute to reducing the cost of the system (for instance, to avoid shutting down a power plant and the subsequent cost of starting up again).

IMRES model

The IMRES model uses an electricity generation *capacity expansion formulation with unit commitment*[4] constraints. This approach allows for an integrated analysis both of investment decisions and system operations. The main peculiarity of the IMRES model is that, besides capital and variable costs, the costs associated with a more intense cycling regime are explicitly represented (see Annex B for a detailed description of the model).

Classic capacity expansion models, such as screening curves models (NEA, 2012), assess solely the trade-off between generating technologies with a high capital cost and low variable cost, and technologies with lower capital cost but higher variable cost. This approach typically leaves out other cost items (such as start-up costs) and other technical considerations (such as the indivisibility of single generation units, minimum generation levels of plants, ramp limits and reserve needs). The IMRES method provides an improved investment assessment by including the performance of power plants during system operations explicitly. This allows the study of the operational impact of VRE on optimal investments patterns.

3. However, the IMRES system is in no way representative of the German power system, given the assumption of zero interconnection and a potentially completely different plant fleet.

4. In power systems, unit commitment is a decision-making process that determines not just the electricity generated by each power plant in the system to meet a minimum cost generation criterion (economic dispatch), but also decides on the power plants that should be on-line and off-line at every hour.

Scenarios and flexibility options

The IMRES analysis considers two very different scenarios. For each scenario, more than 35 different sensitivities have been calculated, varying installed VRE generation capacity and different levels of flexibility options as well as fuel prices.

- In the **Legacy scenario,** the installed power plant mix is optimised to cover the full electricity demand (with no renewable contribution). In a second step, different shares of VRE and flexibility options are added and the system is operated taking into account these new elements. This situation is close to the reality of VRE integration in stable power systems. It is important to note that the name Legacy refers to the plant mix. All system costs – including the investment costs of all conventional power plants – are taken into account under this scenario. Under the Legacy scenario, VRE generation and additional flexibility options do not contribute to avoiding investment costs in other parts of the power system. As such, this scenario is closer to a "worst case" for VRE integration.
- In the **Transformed scenario,** IMRES optimises the installed power plant mix based on net load, i.e. conventional power plants are optimised to cover only part of the electricity demand and to balance VRE. In addition, in some of the sensitivities, the optimisation of power plant investments is influenced by flexibility options, i.e. additional flexibility options are present and these can reduce the need for power plant investment. This situation is closer to the reality of dynamic power systems. The Transformed scenario presents a more favourable scenario for VRE integration, with lower system costs resulting from exploiting synergies between VRE generation, flexibility options and thermal plants.

In each of the two scenarios, different deployment levels and combinations of flexibility options were analysed. The cost-benefit of a flexibility option was calculated as net system cost savings divided by the cost of the flexibility option itself.

This chapter provides a summary of the results obtained with IMRES and focuses on the cost-benefit analysis of demand-side response, storage and flexible generation. Results are presented and discussed in the respective sections. Results combining multiple flexibility options are presented in Chapter 8. A detailed presentation of methodology and results can be found in de Sisternes and Mueller (forthcoming).

BID3

System characteristics

The BID3 simulation modelled the countries of the North West Europe case study area. Based on Pöyry's central scenario, the IEA developed a high-VRE scenario with a share of approximately 30% of wind power and solar PV in annual power generation. Interconnector levels, power demand and the installed plant portfolio were taken from Pöyry's central scenario for the year 2030.

BID3 model

BID3 is an economic dispatch model which optimises the hourly generation of all power stations on the system, taking into account fuel prices and operational constraints. BID3 comprehensively captures the interaction between thermal power, hydro power, variable renewables and cross-border net transfer capacity (NTC) constraints. System security is established through evaluation of loss of load expectation (LOLE) based on availability of thermal plants, available output of VRE sources and hydro, and contribution of interconnectors for each hour across the entire year. The modelling is based on Pöyry's plant-by-plant database of the European power market which is updated quarterly.

Key features of BID3 include:

- **Dispatch of thermal plant**. All plants are assumed to bid cost-reflectively and plants are dispatched on a merit-order base – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with start-ups and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times.

- **Variable renewable generation**. Hourly generation of variable renewable sources is modelled based on detailed wind power speed and solar radiation data and can be constrained, if required, due to operational constraints of other plants or the system.
- **Dispatch of hydro plant**. Reservoir hydro plants are dispatched using the water value method, where the option value of stored water is calculated using stochastic dynamic programming. This results in a water value curve where the option value of a stored megawatt hour is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year.
- **Demand-side response and storage**. Operation of demand side and storage is modelled in a sophisticated way, allowing simulation of flexible load such as electric vehicles and heat while respecting demand-side and storage constraints.
- **Interconnector flows**. Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.

Further description of the BID3 model is provided in Annex B and can also be obtained on Pöyry's website.[5]

Scenarios and sensitivities

Using the high-VRE version of Pöyry's central scenario, sensitivity runs were conducted for interconnection, storage, DSI as well as combinations of interconnection and each of the two other options (being interconnection and storage, and interconnection and DSI). In addition, the cost-effectiveness of retrofitting hydro power plants to increase their capacity without increasing reservoir capacity was also analysed. Results are presented and discussed in the respective sections of this chapter[6] and a comparative summary can be found in Chapter 8.

Grid infrastructure

Grid infrastructure encompasses all assets that connect generation to demand, most importantly high-voltage transmission lines, the lines of the distribution system and a number of additional devices such as transformers etc. Grid infrastructure aggregates distant resources and in doing so brings important portfolio and scaling benefits across the entire power system. Grid infrastructure makes a critical and unique contribution towards VRE integration.

Technology overview

Both the transmission and distribution grid are complex networks with sometimes very sophisticated additional control and management equipment installed. The following overview is a succinct presentation of most prominent components, leaving aside sometimes equally important but highly technical considerations

Transmission grid

The most prominent building blocks of the transmission grid are high-voltage lines. These usually have so-called sub-stations at each end, where power flows are exchanged with:

5. www.poyry.com/bid3.

6. These results, presented in various sections of this publication, were generated from a modelling study which used methodology and assumptions that were agreed between Pöyry and the IEA for use within the original context. These results may not be appropriate for any other context. No advice, opinion, statement of expectation, forecast or recommendation expressed herein shall be deemed to constitute a representation or warranty with regard to future events and circumstances.

- large generators or loads
- other transmission lines of the same system
- neighbouring power systems (interconnection)
- the distribution grid.

All large power systems today use alternating current (AC) power. Technical properties of AC power prohibit its transmission underground or undersea for more than a few dozen kilometres. As such, the most widespread technology for transmission is the well-known AC overhead line (AC OHL) technology.

If hauling distance exceeds several hundred kilometres, AC OHL costs increase, owing to properties of AC power and resulting losses. In these cases, converting AC to direct current (DC) and back using dedicated converter stations becomes economical. This technology is known as high-voltage direct current (HVDC). HVDC can be cabled underground or undersea without much technical difficulty, but cabling can be several times more expensive due to costs of civil works and cables.

While AC lines are synchronous, DC lines are not. This makes power flows over DC lines inherently easier to adjust and control (there are no direct problems with loop flows),[7] and allows linking systems that do not operate in synchrony. However, some benefits of synchronous connection (in particular inertial response) are lost using DC lines.[8]

HVDC technology is mature for point-to-point connections in an otherwise AC system. There is much less experience with meshed HVDC networks, causing technical challenges when more complex network topologies are implemented, for example offshore HVDC grids (Bahrman and Johnson, 2007).

Transmission projects are usually associated with long permitting times in Organisation for Economic Co-operation and Development (OECD) member countries (up to ten years and longer for international interconnection projects). Construction times are usually shorter, often below two years but timing depends on length and terrain of the route. The lifetime of transmission assets usually is in the order of 40 to 50 years or more.

Distribution grid

Traditionally, the role of the distribution grid has been to locally distribute electricity to small and medium-sized consumers. Distribution grids usually have several layers (similar to branches of a tree):[9] larger branches of the network operate at high voltage (in the order of 50 kilovolts [kV] to 100 kV), medium-sized branches at medium voltage (some 5 kV to tens of kilovolts) and the finest branches reaching individual households at low voltage (about 100 V-400 V). With several voltage steps occurring on the distribution grid, transformers form an important part of the distribution grid.

Because of shorter line distances, the distribution grids may use underground cables carrying AC power. Underground cabling of high-voltage parts of distribution networks is common in densely populated urban areas only, while its application for medium- and low-voltage parts of the grid also varies with population density. Underground cabling means higher up-front costs but generally lower maintenance costs and often higher reliability.

The size of a distribution grid is usually set once, looking at its entire lifespan of 40 to 50 years, as civil works – in particular for cabling – form a dominant cost block, so initially opting for an oversized grid is usually cheaper than later capacity increases.

7. Electricity always travels according the path of least resistance. In a meshed network, this means that when power flows between two grid points that are linked directly, there will be flows on all possible routes that link the two points not only the direct connection. These additional flows are known as loop flows. They tend to be higher in better-meshed networks.

8. Modern HVDC lines, using so called voltage source converters (VSCs), can be used to provide some system services, in particular voltage support.

9. The topology of distribution grids varies depending on a number of factors and there are four standard layouts (referred to as radial, open loop, closed loop and lattice topology).

There is very little active control or real-time measurement at low and often medium-voltage levels (a "fit and forget" approach). This approach makes sense as long as distribution of electricity to passive loads is the main purpose. However, when a large share of generation is connected to the distribution grid, its role becomes more complex. It then also acts as a "collection grid" for generation, giving rise to more complex load flow patterns, sometimes challenging traditional planning and operational approaches (Volk, 2013). At high shares of distributed VRE, making the distribution grid "smarter", also to enable DSI, becomes increasingly relevant.

Contribution to VRE integration

There are a number of benefits associated with geographical aggregation of VRE generation and power system resources in general. Grid infrastructure is the only flexible resource that can directly provide for geographical aggregation. Hence, its contribution is distinct and even unique compared to the other flexibility options.

Variability

Geographical aggregation of VRE generation leads to significant smoothing, because the statistical fluctuations of individual VRE generators cancel out up to a certain level when aggregated. This smoothing effect happens automatically and instantaneously across an interconnected network. While flexible generation, demand-side response and storage deal with remaining variability, grid infrastructure can partially remove it thanks to its inherent technical properties.

As mentioned in Chapter 2, wind power generation may benefit more from very large-scale aggregation compared to solar PV. Also, aggregation benefits may differ depending on direction, for example if regions are interconnected along the typical path of weather systems or perpendicular to these paths.

Uncertainty

Transmission grid enhancement may contribute to the reduction of VRE-related uncertainty, because forecast errors are smaller when predicting the aggregated output of many sites compared to predictions for a single site (Focken et al., 2001; Figure 7.1). By integrating over a spatially extended area, weakly correlated prediction errors partially cancel out. Thus, on average these statistical smoothing effects lead to a reduced prediction error for a regional compared to a local forecast.

Location

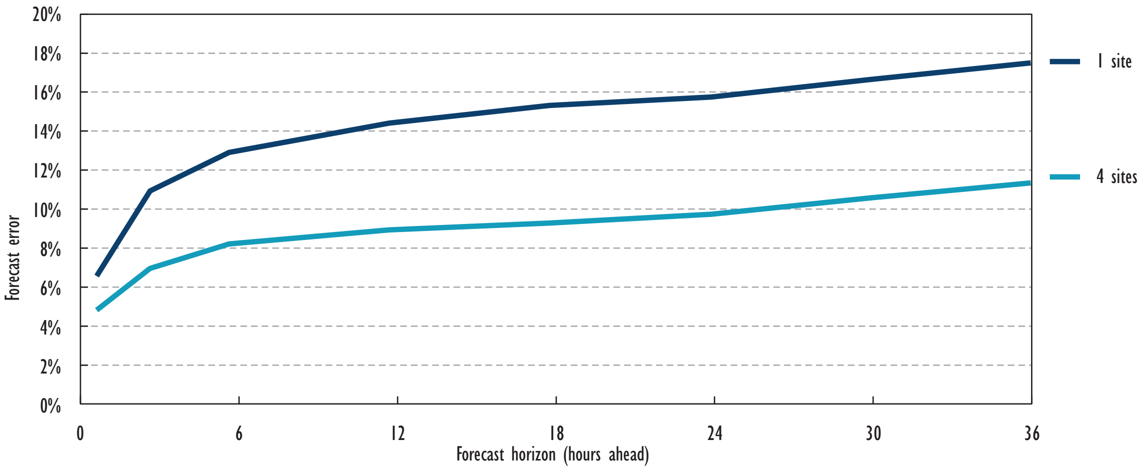
Only transmission infrastructure can fully remove a locational mismatch between locations of high-VRE resources and demand centres. However, there is always a trade-off between "going the extra mile" for a more favourable resource and the additional cost for building the necessary transmission line. As such, there is a trade-off between siting close to load or close to best resource. This balance changes dynamically. The cheaper VRE systems become, the lower the pressure to reach best resources.[10]

Modularity

Enhancement of the distribution grid is usually an effective option for increasing the hosting capacity for distributed, small-scale generators. In fact, it is often constraints on the distribution level that lead to curtailment of smaller wind farms in particular (Ecofys, 2013). However, grid enhancements need to be weighed against other options, such as improved operation of VRE plant, demand-side response options or distributed storage.

10. Doubling full-load hours at an LCOE of EUR 0.30 per kilowatt hour (/kWh) saves EUR 0.15/kWh. Doubling full-load hours at an LCOE of EUR 0.20/kWh only saves EUR 0.10/kWh. While the relative advantage is 50% in both cases, the absolute cost impact is different.

Figure 7.1 • Mean absolute forecast error as a percentage of wind power capacity in Finland, 2004



Source: Holttinen et al., 2006.

Key point • Transmission grid enhancement contributes to a decrease in the forecasting error of aggregated power prediction compared to a single site.

Non-synchronous technology

Larger, synchronously connected power systems will feel the effect of non-synchronous generation only at higher penetration levels than smaller systems. Therefore, AC grid infrastructure can make a critical contribution to mitigating this impact.

In addition, there are other devices that can be added to the grid to enhance controllability and increase power transfer capability. These are known as Flexible Alternating Current Transmission Systems (FACTS). Apart from other benefits, FACTS can help to provide certain system services without relying on synchronous generators. However, they do not add to system inertia directly.

Table 7.2 • Contribution of grid infrastructure to VRE integration

	Uncertainty	Variability			Location constraints	Modularity	Non-synchronous
		Ramps	Abundance	Scarcity			
Transmission	✓	✓✓	✓	✓	✓✓	××	✓
Distribution	O	✓	✓	O	××	✓✓	×
Interconnection	✓	✓✓	✓✓	✓	O	××	✓✓

Note: ✓✓: very suitable; ✓: suitable; O: neutral; ×: less suitable; ××: unsuitable.

Source: unless otherwise indicated, all tables and figures in this chapter derive from IEA data and analysis.

Key point • Grid infrastructure is the only option to bridge mismatches between high resource locations and demand centres and makes a strong contribution to all other areas.

Economic analysis

Compared to generation investment, grid infrastructure is low-cost. While costs show very large differences, the average cost for building 1 km of transmission is in the order of USD 1 million per 1 000 megawatts (MW). The cost for generation capacity is in the order of USD 1 million per MW. Consequently, by adding about 1% of costs, it is possible to bridge 10 km. Costs may reach significant levels if connection distances are very large (several hundreds of kilometres) and for more complex installations, such as submarine HVDC connections.

Grid infrastructure requires up-front expenditure. Grid investments are lumpy in the sense that they can only be installed economically in sufficiently large unit sizes. They are usually designed for lifetimes of 40 to 50 years (Kirchen and Strbac, 2004). Transmission investments are "sunk" investments; the resale value of the assets is low and transmission capacity cannot be relocated economically.

Costs

Investment in transmission projects consists of two major components: line costs and station costs. Figures are often project-specific; in particular line costs depend on local terrain and the cost of securing rights of way. Reported figures (Table 7.3) should therefore be seen as indicative for typical conditions in OECD member countries.

Table 7.3 • Economic parameters of typical transmission grid infrastructure

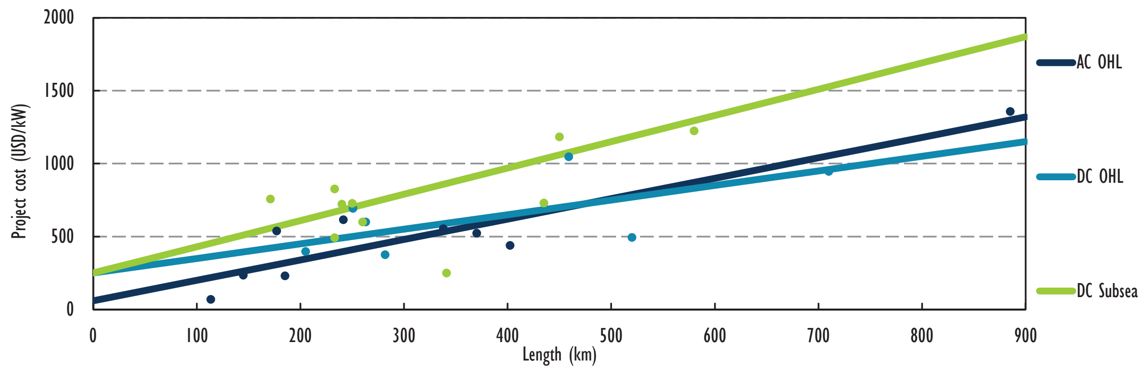
Type	Station cost	Line cost	Losses in station	Losses 100 km	Losses 1 000 km	Utilisation factor	O&M cost	O&M cost
	million USD/line	USD/MW/km	%	%	%	FLH	USD/km/yr	USD/MWh
AC OHL	50-70	1 000-1 500	0.25	1.15-1.20	7.5-8	3 000-6 000	35-40	0.35-0.55
DC OHL (VSC)	200-350	900-1 200	0.6-0.7	1.50-1.60	4.5-5	3 000-6 000	35-40	0.35-0.55
DC cable (VSC)	200-350	1 700-2 000	0.6-0.7	1.65-1.75	4.5-5	3 000-6 000	10-15	0.10-0.20

Notes: FLH = full-load hours; O&M = operation and maintenance. FLH represent the typical utilisation factor of grid infrastructure, and this value may be lower in case of transmission lines entirely dedicated to VRE plants characterised by lower production FLH.

Key point • Costs for transmission lines have two major components: line costs and station costs.

Line costs and losses are lower for DC connections compared to AC OHL, but station costs are much higher. Consequently DC technology becomes more economic at longer lengths. This general trend was also found in a meta-analysis of reported project costs carried out for this study (Figure 7.2).

Figure 7.2 • Analysis of reported costs for transmission projects

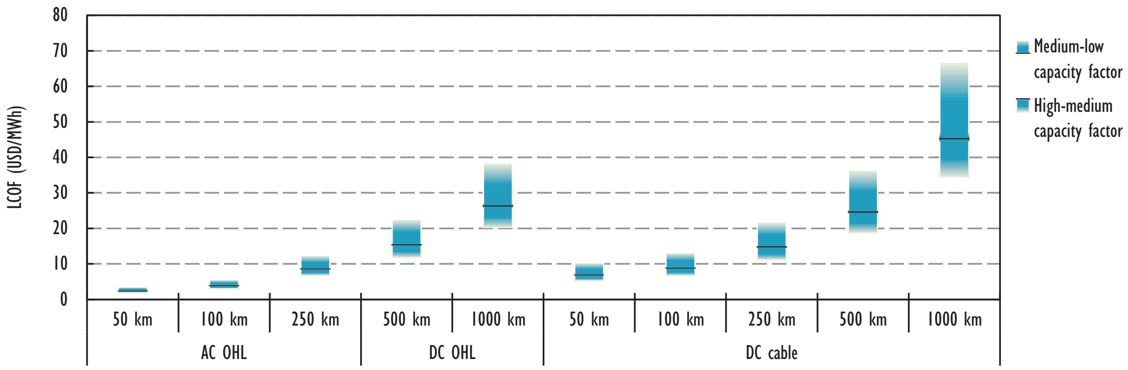


Notes: dots show data points from collected project data. Lines correspond to typical costs for different project types (AC OHL: USD 60/kW station costs, USD 1.4/kW/km; DC OHL: USD 250/kW station costs, USD 1/kW/km; DC subsea: USD 250/kW station costs, USD 1.8/kW/km).

Key point • Overhead DC lines are cheaper than overhead AC lines at long distances. Subsea cables are more expensive than overhead lines.

The cost of transporting 1 MWh of electricity over a single line (for example when connecting distant resources) critically depends on distance and on the utilisation of the power line. When hauling over short distances (50 km) with high utilisation, costs are as low as USD 2/MWh to USD 4/MWh. Even at larger distances (250 km), unit costs range between USD 5/MWh and USD 15/MWh. Costs are higher for long-range transmission, in particular at low utilisation. Undersea cables are about a factor two more costly than overhead lines (Figure 7.3).

Figure 7.3 • LCOF for transmission investments



Note: see Annex A for details on methodology.

Key point • *LCOF for transmission is low to moderate compared to other options, depending on line length and capacity factors.*

Distribution

The cost of investment in distribution infrastructure is often project-specific and consists of two major components: line costs (low voltage [LV], medium voltage [MV] and high voltage [HV]) and substation costs (HV/MV and MV/LV). In particular, line costs depend on technology, network design and related length. These parameters may vary significantly from rural to urban areas. There are no typical conditions for this type of project, so reported figures should be seen as indicative for OECD member countries (Table 7.4).

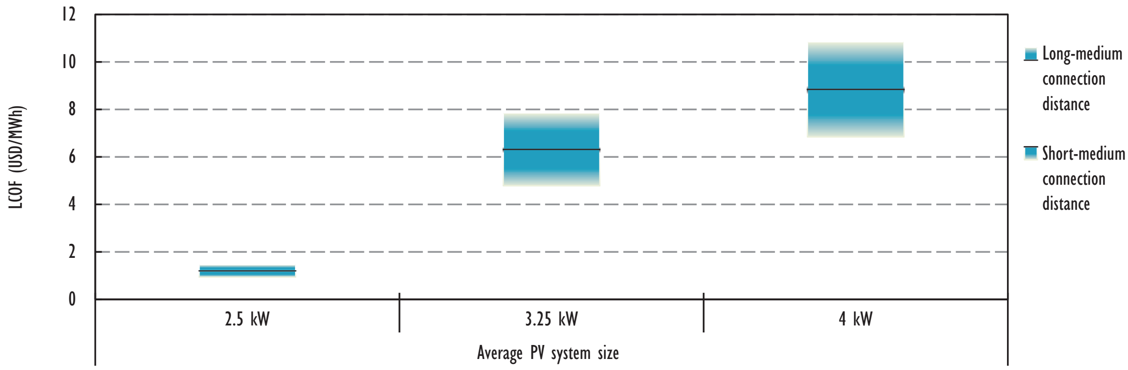
Table 7.4 • Economic parameters of distribution grid infrastructure

Type	Cable cost Thousand USD/km	Additional cost Thousand USD/project	Losses typical length %	Utilisation factor %	O&M cost USD/km/yr
MV: transmission	75-100	275-325	1%	40-50%	10-20
MV: distribution	75-100	120-180	0.75%	30-35%	10-20
LV: cable	120-140		1%	40-45%	10-20
Substation: HV/MV	1 300-1 800			70-80%	
Substation: MV/LV	5-25			60-65%	

Key point • *Costs for distribution grids have two major components: line costs and station costs. Costs include a large civil works component.*

LCOF analysis represents the additional costs for a newly built distribution system to connect a certain amount of distributed solar PV generation, allowing to feed generation to the transmission grid (Figure 7.4). Solar PV system capacities are expressed as installed capacity per connected customer. Costs are very sensitive to system size. For small systems, costs are very low (below USD 2/MWh), reflecting little incremental requirements compared to the load-only reference. At larger system capacities, incremental costs rise, reaching levels in the order of USD 10/MWh in the case of 4 kW average system size. This is a conservative approach to estimating costs for the distribution grid in the presence of distributed VRE. More sophisticated management strategies, DSI and distributed storage can all contribute to minimising such costs and should be taken into account when making a more detailed assessment of additional costs for grid infrastructure.

Figure 7.4 • LCOF for distribution grid investments



Notes: see Annex A for details on methodology.

Key point • Additional distribution grid costs for integrating a number of distributed solar PV power plants depend on plant size.

Cost-benefit analysis

Economic modelling carried out for the North West Europe case study region investigated the cost-benefit of additional interconnection between case study countries. As explained in the introduction, the modelled system corresponds to a high-VRE scenario (27% of total system production), based on an adaptation of Pöyry's central scenario in the year 2030. As such, interconnection levels in the base case are already much higher than observed today (63 GW vs. 44 GW in 2010). The study therefore investigated the extent to which additional interconnection would facilitate the integration of increased VRE shares compared to the central scenario. It assumes that significant additions have already taken place.

Table 7.5 • Interconnections between countries in North West Europe in the increased-interconnection case (MW)

From / To	Denmark	Finland	France	Great Britain	Germany	Ireland	Norway	Sweden
Denmark					3 700		1 600	3 940
Finland							1 000	3 850
France				5 488	5 100			
Great Britain			5 488			2 060	2 100	
Germany	3 100		5 800				2 100	2 100
Ireland				1 940				
Norway	1 600	1 000		2 100	2 100			6 400
Sweden	3 480	4 250			2 100		6 250	

Key point • The increased-interconnection case investigated the cost-benefit of adding 16 GW of interconnection capacity to the 63 GW present in the baseline.

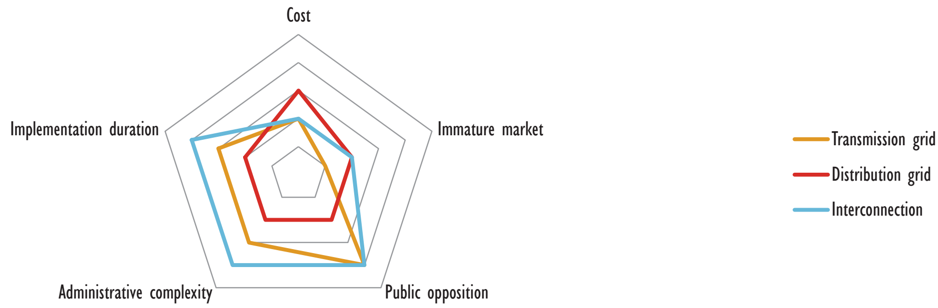
An additional 16 GW of interconnection avoided 3 GW of investment in CCGT plant (France, Germany and Great Britain) and allowed for better utilisation of low-cost power generation assets. In total, annual system savings amounted to EUR 400 million per year, compared to annualised costs of

EUR 340 million per year. This yields an overall favourable cost-benefit ratio of 1.2. It is crucial to note that interconnection levels in the base case are already high, highlighting the importance of interconnection for large-scale integration of VRE.

Policy and market considerations

Policy and market challenges differ somewhat between transmission and distribution grid infrastructure (Figure 7.5).

Figure 7.5 • Major challenges to deployment of grid infrastructure



Key point • Administrative complexity, implementation duration and public opposition are the most relevant challenges to deployment of new grid infrastructure.

In many countries with developed power systems, public opposition is a critical barrier to investment in overhead transmission lines. The up-front cost of new transmission lines is moderate compared to other flexibility options, such as generation or storage. However, this does not mean that cost allocation is straightforward. In the case of undersea cables far offshore, costs can be a significant obstacle, alongside technical and administrative challenges. 127

It is often difficult – if not practically impossible – to disentangle the benefits and beneficiaries of new transmission infrastructure to reach a fair allocation of costs. In addition, the administrative complexity involved with cost-benefit allocation is particularly great for international projects, potentially involving transit countries that only benefit indirectly. This is even more relevant as the transmission system (recognised as a natural monopoly) is usually subject to strong regulation. Therefore, new transmission lines are contingent on regulatory approval.

In the absence of a universally accepted methodology to establish project cost-effectiveness, new transmission may be subject to considerable debate. Typically, a fully convincing regulatory test is missing in practice to verify that a proposed investment is justified or even that it is the "optimal" one within a set of proposed network reinforcement options. The currently predominant criterion in Europe and most of the United States is to comply with prescribed security criteria and to eliminate network bottlenecks. These criteria could be followed not just within a system, but also between systems. Some countries specifically include the criterion of economic efficiency, but it is not clear how this is applied in practice (Volk, 2013).

The picture is somewhat different at the distribution level. The policy and market framework for distribution systems was conceived on the basis of the system's role of passively serving connected loads. With the rise of distributed generation, the system has a much more complex role to play, which has not been reflected in operational and planning procedures. On the planning side, accurately determining grid capacities has become more complex, because the evolution of distributed generation needs to be taken into account. Here, more information on the build-out trajectory and ultimate target penetration of distributed VRE assets could facilitate better and more cost-effective planning and expansion of the system. This includes better co-ordination of infrastructure expansion between the transmission and distribution level (see Volk, 2013, for details).

On the operation side, more dynamic load flow patterns, including reverse flow of power up to the transmission grid, require more detailed real-time information on the system and potentially more sophisticated control equipment to guarantee reliable and cost-effective operation.

As distribution grid operation and investment also tend to be heavily regulated, the changing role of the distribution grid, along with novel investment needs for VRE integration, also challenge legacy cost-recovery schemes. Innovative ways of financing distribution grid infrastructure at growing shares of self-consumption and distributed in-feed will be key to securing the appropriate contribution of this flexibility option in the future.

Dispatchable generation

Dispatchable[11] technologies can be categorised as dispatchable non-renewable energy (non-RE) technologies and firm renewable energy (firm RE) technologies. These form two broad technology families, with a large number of sub-technologies in each of them.[12]

Dispatchable generation (non-RE and firm RE technologies) provides the bulk of power generation in all of today's power systems. With growing shares of VRE technologies, the role of dispatchable technologies is bound to change. Their contribution to the overall power mix necessarily diminishes, while they continue to be a potentially valuable source of flexibility. However, in contrast to other flexibility options, non-RE generation is frequently accompanied by externalities, such as carbon dioxide (CO_2) and other emissions or nuclear waste accumulation.

This section presents a brief discussion of the different dispatchable generation technologies, with an emphasis on flexibility aspects. More detailed information can be obtained from other IEA publications, such as *Energy Technology Perspectives 2012* (IEA, 2012a) and the suite of IEA Technology roadmaps (available online: www.iea.org).

Technology overview

Assessing dispatchable generation as a flexibility option raises the question of measuring how flexible the respective technologies are. "Flexible" can mean many and quite different things for a power plant. As the California Public Utilities Commission (CPUC) states (CPUC, 2013):

> "[…] some steam units are considered flexible because once in operation they ramp power output quickly, but they have very long start-up times. Some reciprocating engines units are considered flexible because they have short start times, but have little ramping flexibility once started."

Plant flexibility can be separated into different dimensions.[13] The most relevant for this discussion are:

- adjustability: possible generation levels that can be chosen, given a long lead time. The minimum output of the power plant is the lower bound for adjustability, while the maximum output is the upward constraint
- ramping: the speed at which output levels can be changed
- lead time: required advance notice to make generation available, i.e. start-up time of the plant.

11. VRE itself can be commanded to increase or decrease output, limited by instantaneous resource availability. In this sense, VRE is also dispatchable.

12. The contribution that advanced deployment and operation strategies of VRE can make to facilitate integration is discussed in Chapter 5.

13. In principle, a similar analysis can be done for all flexible resources. However, it is most important for generation resources and – for the sake of analytical simplicity – the only one presented here.

The various technologies can be assessed along these dimensions (Table 7.6). This gives rise to different profiles for the technologies and allows a more complete appreciation of whether and how a certain technology is useful for integrating high shares of VRE.

Table 7.6 • *Assessment of flexible generation according to dimensions of flexibility*

	Technology	Mini stable output (%)	Ramp rate (%/min)	Lead time, warm (h)
Firm RE	Reservoir hydro	5-6**	15-25	< 0.1
	Solid biomass	- ***	- ***	- ***
	Biogas	- ***	- ***	- ***
	Solar CSP/STE[1]	20-30	4-8	1-4****
	Geothermal	10-20	5-6	1-2
Dispatchable non-RE	Combustion engine bank CC	0	10-100	0.1-0.16
	Gas CCGT inflexible	40-50	0.8-6	2-4
	Gas CCGT flexible	15-30*****	6-15	1-2
	Gas OCGT	0-30	7-30	0.1-1
	Steam turbine (gas/oil)	10-50	0.6-7	1-4
	Coal inflexible	40-60	0.6-4	5-7
	Coal flexible	20-40	4-8	2-5
	Lignite	40-60	0.6-6	2-8
	Nuclear inflexible	100******	0******	na******
	Nuclear flexible	40-60******	0.3-5	na******

Notes: CC = combined cycle; CSP = concentrated solar power; STE = solar thermal energy; na = non applicable. The table refers to typical characteristics of existing generation plants; specific arrangements, especially in new-build flexible coal, lignite and nuclear power plants may increase generation flexibility; operational and environmental constraints can have a significant impact on how much of this technical flexibility is actually available.

[1] With storage.
** Environmental and other constraints can have a significant impact on the availability of this flexibility.
*** Solid biomass and biogas can be combusted in plants that have the characteristics of coal and gas plants. Data on solid biomass and biogas is thus included in those on coal and gas plants.
**** If thermal storage is not fully available, lead time can be considerably higher.
***** 15% is reached by plants with steam cycle bypass at reduced efficiency.
****** Security regulations may prohibit nuclear from changing output. Reported start-up times are two hours from hot state to two days.

Key point • *Power plants show large differences in their technical flexibility.*

Dispatchable non-RE and firm RE show a great diversity in the different dimensions of flexibility. However, certain groups can be identified:

- **Inflexible** generation technologies contain inflexible nuclear, lignite and coal power plants, certain steam turbines with oil/gas as boiler fuel, and to a certain degree also gas CCGT plants, if designed accordingly. Also most geothermal plants belong in this category. This power plant type is designed for baseload operation; start-up and ramping operations are rare and time-consuming, because of constraints on thermal stresses in the thick-walled machinery operating at high pressures.
- **Flexible** generation technologies comprise flexible CCGT, flexible coal, biomass, biogas and CSP technologies. These power stations are designed to operate as mid-merit plants that can adjust their generation level to cope with load variations and start at fairly short notice.

- **Highly flexible** power plants such as reservoir hydro,[14] combustion engines or aero-derivative gas turbines, a sub-set of OCGTs form the most flexible category. The additional costs of operating these plants more flexibly can be very low. Standard OCGT technologies are less flexible than the previous two, but still outperform most mid-merit plants.

It is important to note that it is not the fuel type *per se* that will determine how flexible a plant is. Design characteristics of different gas and coal plants lead to very different performance profiles. A flexible coal plant may deliver lower minimum generation levels and better ramping capability than an inflexible CCGT. Similarly, different types of turbines in hydroelectric power plants show different performance in terms of flexibility provision. In nuclear power stations, the position of the plant along its fuel cycle strongly affects whether it can engage in load following, even if designed and permitted to do so by security regulations. However, cycling nuclear power stations may increase operational risk, because it affects the dynamics of nuclear reactions in the core (NEA, 2012).

Research and development in conventional power generation has led to plants that are optimised for complementing VRE. A particularly important feature is achieving low minimum output levels without incurring significant penalties in plant efficiency at low generation levels. In addition, a high ramping gradient can be a desirable feature. The higher the ramping gradient that a conventional plant can cover, the fewer plants are needed to meet a given net load ramp, thus leading to less minimum generation per ramping (VDE, 2012).

Contribution to VRE integration

Variability

Flexible generation technologies are currently the dominant source of system flexibility in virtually all power systems. Among the case study regions, only Denmark relies on interconnection to a similar extent to balance production and consumption (interconnection 4.3 GW, installed generation 8.6 GW).

Flexible generation technologies need to be capable of rapidly making room for VRE generation, by turning down to very low operation levels or shutting down completely. They also need to be able to start generation quickly (in 15 to 30 minutes) and ramp up production to cover periods of low VRE generation. Flexible generation has a crucial role in covering sustained periods of VRE shortfall, for example by relying on large reservoir hydro reserves. In some scenarios with 100% energy supply from renewable sources, flexible gas generation may have a role to play in covering scarcity periods. For example, using synthetic or biogenic methane as a long-term storage option essentially relies on flexible generation for generating electricity; however, it is not clear when or if such options will become cost-effective.

The impacts of high-VRE generation can be addressed by flexible generation, if it can back down quickly without losing the ability to generate shortly after. However, flexible generation does not contribute to mitigating surplus periods once net load becomes negative. This is potentially the single biggest limitation of this flexibility option to contribute to VRE integration (Table 7.7).

A very promising development in this regard can be currently observed in Denmark. The Danish power system relies heavily on combined heat and power (CHP) plants. If operated in a way that gives priority to covering heat demand, CHP plants may actually make the system less flexible (Hirth, 2013; Lund et al., 2010). However, installing electric boilers in Danish CHP plants has allowed them to generate and consume electricity, enabling them to switch to whatever is the best operation mode given system conditions (Box 7.1).

14. Reservoir hydro is often constrained by environmental and other factors. However, in many cases it will be in an excellent position to provide flexibility. Environmental regulations should be designed accounting for the importance of reservoir hydro for the overall decarbonisation of the power system.

Box 7.1 • Integrating electricity and heat in the Danish power system

The interface between the electricity sector and the heating and cooling sector is important for the effective integration of large shares of VRE electricity. If implemented in the right way, heating and cooling applications can be a source of valuable flexibility. However, current business-as-usual in most countries renders CHP generation very inflexible, because heat load tends to dictate generation schedules.

Smart solutions for heating and cooling can:

- provide cost-effective energy storage applications
- make power generation in CHP plants very flexible, allowing even for negative generation (electricity consumption).

Thermal energy can be stored more cost-effectively than electricity. Commercial solutions employ a range of different technologies and physical effects; the most commonly used are storage of hot water, molten salts and ice. Equipping customer-side electric water heaters with storage and smart response capabilities can make electricity consumption more flexible at low cost.

On a larger scale, district CHP plants can be altered to provide a range of flexibility services. Denmark makes extensive use of distributed CHP and district heating (DH), which the IEA has previously commended (IEA, 2008). The Danish case provides interesting insights into how CHP can facilitate VRE integration.

About 80% of all Danish electricity produced in 2010 was from CHP plants, which stands in contrast to the OECD average of 10%. Denmark also has a very high wind power penetration, accounting for about one-third of annual generation in 2012 (about 20% in 2010), well above the OECD average of 3%. Denmark is aiming for a share of wind power generation as high as 50% of annual demand by 2020.

In 2005, Denmark put policies in place to ensure that CHP expansion would proceed in a way conducive to VRE integration:

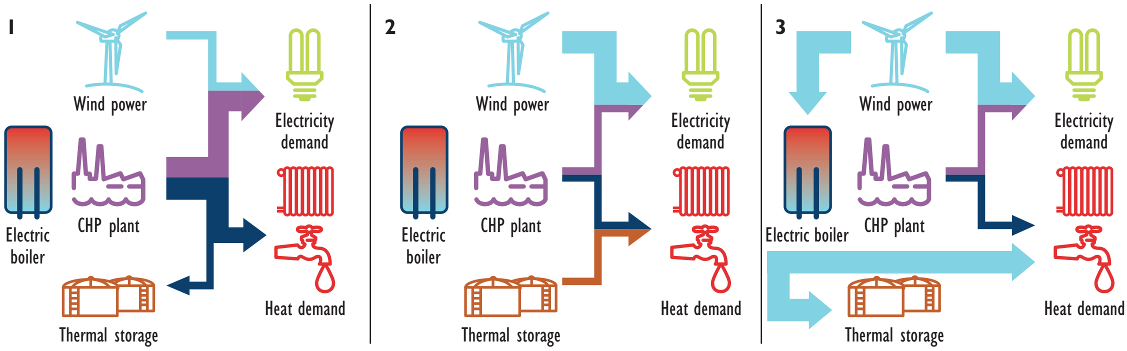
- It was legislated that CHP plants would transfer from receiving fixed payment for production to being fully integrated into power markets. Depending on size, the transfer would be mandatory or voluntary – larger plants above 10 MW were required to participate in the market immediately.
- The integration of CHP plants into power markets has been a gradual process. In 2005, CHP plants were introduced to the day-ahead spot market; in 2006 they were introduced to selected operating reserve markets; and in 2009 they also became part of the automatic primary reserve market.
- The plants continue to be subsidised. When the change was made in 2005, the subsidy was restructured into a capacity payment, to ensure that the plants are kept operational and available on the power market. This capacity payment is still in effect, and has the characteristics of a feed-in premium, which is capped when electricity prices are high.

The regulation has incentivised the development of flexible CHP plant. Rather than increasing must-run electricity generation due to heat demand, CHP plants dynamically adjust their operation according to current heat demand, electricity demand and available generation, in particular wind power (Figure 7.6).

Under conditions of high heat demand and moderate or low wind power production, CHP plants rely on fossil fuel to cover the heat load and electricity demand. Generated heat may be stored, if this makes meeting heat demand more cost-effective. During periods with high wind power generation and low heat demand, CHP plants may feed into heat storage if needed. Given very high wind power in-feed, above and beyond electricity demand, excess electricity can be used in electric boilers either to meet heat demand directly, charge thermal storage or both.

The Danish example illustrates the potential that the link between the electricity sector and heating and cooling sector offers, especially in urbanised areas where large and concentrated heat sinks may allow for high efficiency and lower losses.

Figure 7.6 • Modes of operation of wind power and CHP



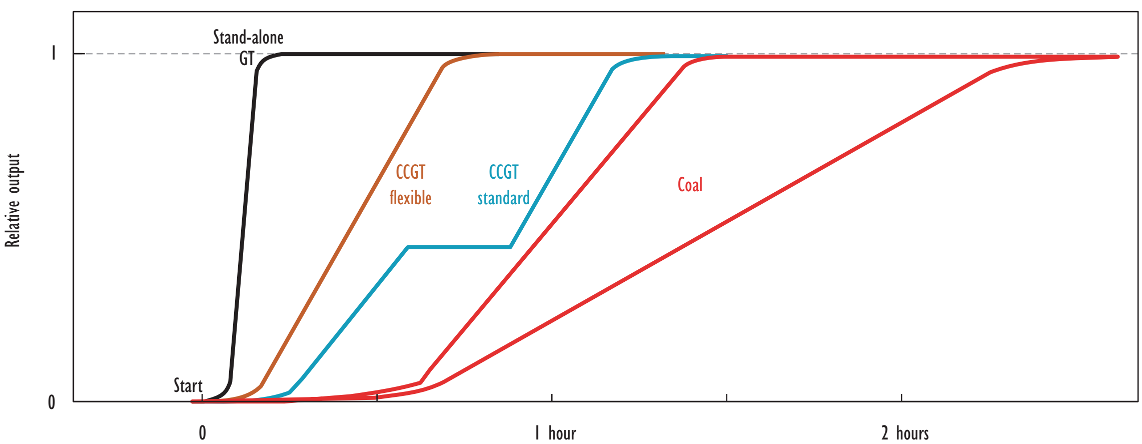
Key point • The operation of Danish co-generation plants facilitates the integration of large amounts of wind power.

Uncertainty

The faster a generation unit can come online and the more dynamically it can change its output at short notice, the better the unit is suited to responding to uncertainty. As a rule of thumb, in large baseload plants thermal stresses in the thick-walled machinery operating at high pressures limit both fast start-up and ramping (Figure 7.7; VDE, 2012).

Today, dispatchable generation provides virtually all of the operating reserves needed to cope with uncertainty introduced by generation itself and demand.

Figure 7.7 • Comparison of initial ramping gradient of different technologies



Source. VDE, 2012.

Key point • Power plants show differences in how quickly they can reach full output once started.

Location constraints

Dispatchable generation does not directly contribute to resolving issues associated with location constraints. However, where wind or solar resources coincide with favourable sites for dispatchable generation, both resources may share transmission infrastructure, hence mitigating overall system costs.

Modularity

Dispatchable micro-generation, e.g. automotive derivatives, can be deployed at the household level and be integrated with distributed VRE options to create self-sufficient micro-systems. Such generation technologies may combine power and heat generation and are already deployed in some markets (e.g. Lichtblick, 2013). In addition, in countries with frequent power outages (e.g. India) distributed diesel engines are common. Large-scale dispatchable generation technologies do not contribute to mitigating impacts of modularity.

Non-synchronous technology

Practically all dispatchable generators are synchronous. However, the problem of non-synchronous generation arises precisely when VRE displaces the bulk of dispatchable generation, thus reducing the availability of system services from them.

If designed for this type of operation, synchronous generators can provide reactive power services to the grid even while not providing active power at all (known as synchronous condenser operation). The generator at the decommissioned nuclear power plant Biblis A in Germany, for example, is currently operating in this way to provide reactive power. Such operation can also provide some inertia to the system. Retrofitting of this capability to active power plants is unlikely to be cost-effective, but using decommissioned plants can be, as the German example shows.

Table 7.7 • Contribution of dispatchable generation to VRE integration

	Uncertainty	Variability			Location constraints	Modularity	Non-synchronous
		Ramps	Abundance	Scarcity			
Dispatchable generation	✓✓	✓✓	✓✓ ✗✗	✓✓	✗	o	✓

Note: ✓✓: very suitable; ✓: suitable; o: neutral; ✗: less suitable; ✗✗: unsuitable.

Key point • Dispatchable generation can contribute to VRE integration by mitigating a wide range of impacts.

Economic analysis

Costs

The evaluation of costs associated with providing flexibility from conventional generation is complex. It requires finding a way to define and compare a scenario where dispatchable generation does not operate flexibly with a different scenario where it does.

More flexible operation of dispatchable generation will be associated with:

- operating below full output at times
- changing output levels more frequently, at shorter notice and to a larger extent
- starting and stopping the plant more frequently.

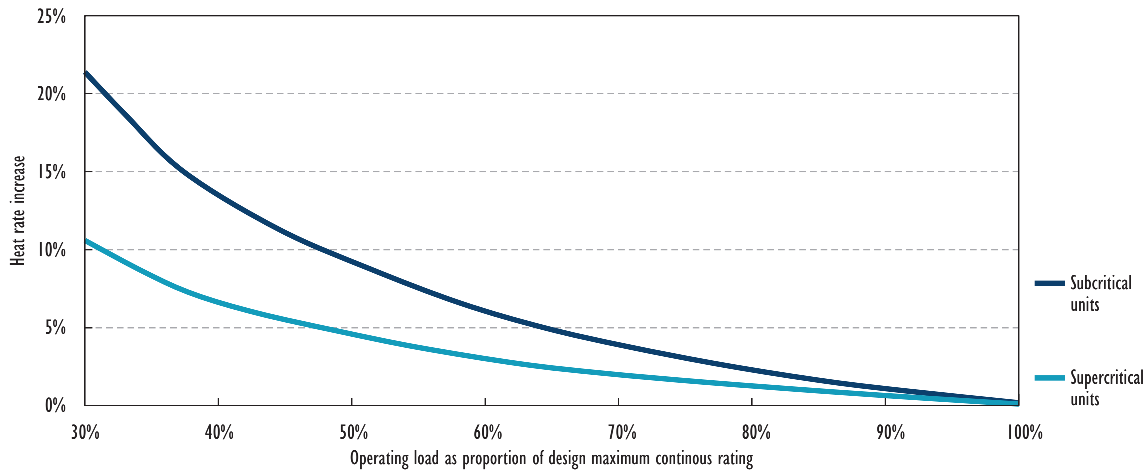
The degree to which any of these operations is associated with additional costs is highly specific to the technology and design of a power plant. For example, a reservoir hydro power plant may incur only little additional cost to operate in the above fashion. On the other hand, a plant that is designed (both technically and economically) to operate at full capacity around the clock will incur additional cost for operating more flexibly. These costs may be incurred in the form of:

- increased costs and emissions due to cycling
- efficiency losses due to part-load operation
- higher per-kilowatt hour generation cost due to reduced load factors.

Implications of part-load operation and cycling

Frequent cycling of fossil-fuelled generators can cause thermal and pressure stresses. Over time, these can result in premature component failure and increased maintenance and repair. Starting a generator or increasing its output can increase emissions compared to non-cyclic operation. And operating a generator at part-load can affect emissions rates and reduce fuel efficiency (heat rate) (National Renewable Energy Laboratory [NREL], 2013) (Figure 7.8).

Figure 7.8 • Heat rate increase at part-load operation of a coal power plant



Source: IEA, 2010.

Key point • The amount of energy necessary to provide 1 kWh of electricity increases in part-load operation.

The NREL recently conducted a comprehensive study of the impact of plant cycling on emissions and operating costs, entitled *The Western Wind and Solar Integration Study Phase II.*

The study investigated the operational impacts of different VRE portfolios with an annual penetration of 33% in the western United States. The studied plant portfolio included a large number of coal plants (NREL, 2013). The study shows that the CO_2 emission penalty for operating at part-load accounts for less than 1% of total CO_2 emissions; the CO_2 penalty for start-up is even more negligible, adding up to 0.1%.

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

It is important to note that the study investigated a system with a considerable number of inflexible, legacy power plants. New CCGT power plants and modern baseload power plants see a lower effect on heat rate in part-load operation (GE Energy, 2013; Siemens, 2013).

Cycling costs may also be reduced by capital or O&M projects to modify the baseload designs to be better suited to cycling, and by modifying the operation procedures or process (e.g. keeping the unit hot) (Aptech, 2012). Such retrofits have been a cost-effective measure to integrate inflexible nuclear generation in documented cases in North America (Cochran and Lew, 2013).

Effect of reduced load factor

The effect of adding VRE generation on the capacity factor of conventional power plants was studied in detail for the IMRES test system. The analysis revealed important differences between the Legacy and the Transformed scenarios. In the former, VRE is added to an already adequate system, with a plant stack that is not optimised for the presence of VRE generation. In this scenario, mid-merit generators (given assumed fuel prices; these were gas power plants) are displaced and see a severe reduction in full-load hours. Coal generation also experiences a strong reduction. In contrast, in the Transformed scenario, the generation portfolio is adjusted to the presence of VRE generation, and the full-load hours of the different technologies largely recover.

As explained in Chapter 2, the reduction of full-load hours at the power plant level is a largely temporary effect, resulting from a badly adapted generation mix. The structural adaptation of the dispatchable power plant mix and its implications for total system costs is discussed in the context of overall system transformation in Chapter 8.

The adaptation of the power plant stack induces a shift towards technologies that are better suited to fewer operation hours (Table 7.8) and higher levels of flexibility (Table 7.6). Given current generation technologies, both effects yield similar technologies.

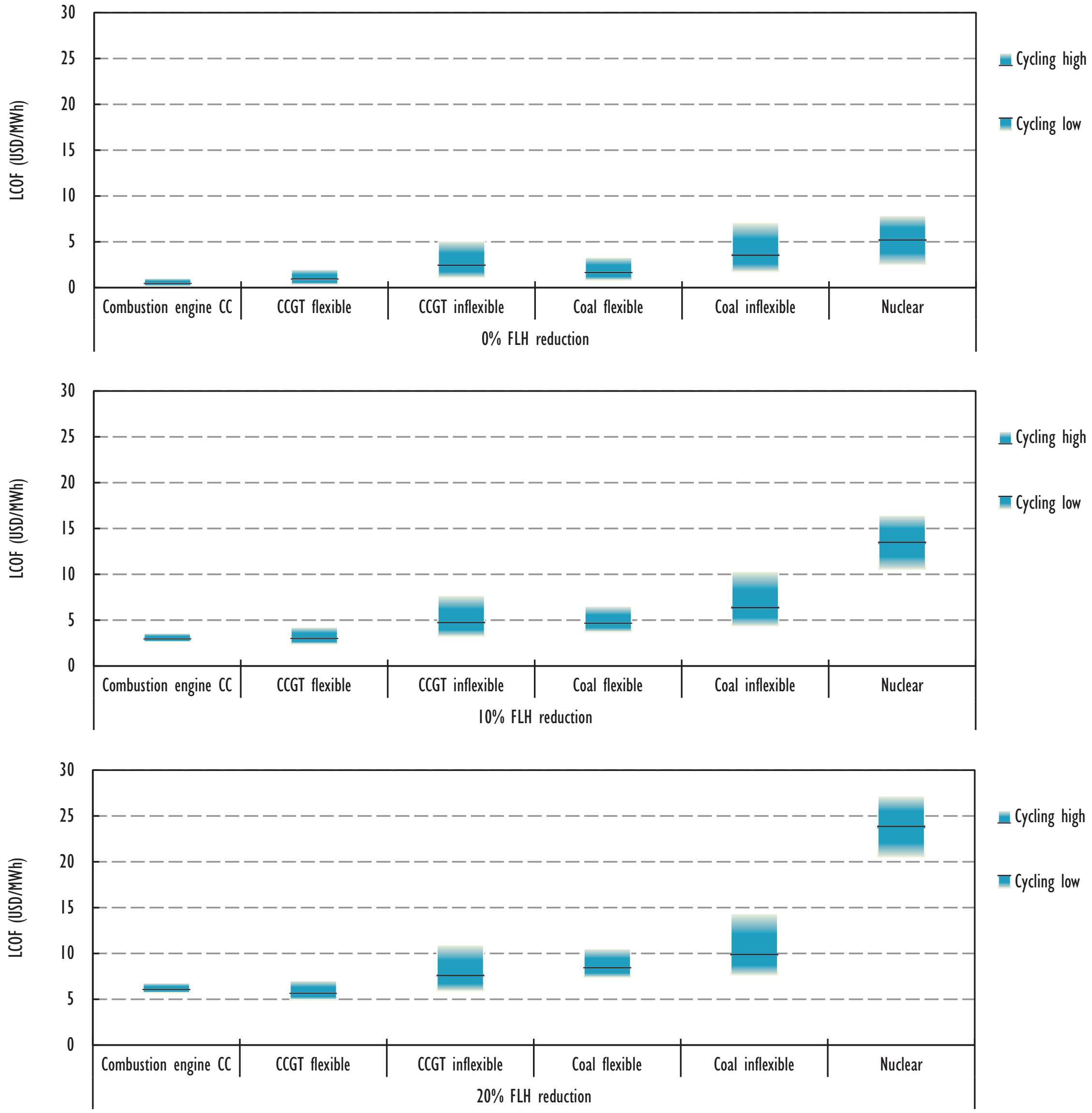
Table 7.8 • Cost and typical capacity factors for various generation technologies

Type		Capital costs		Non-fuel O&M		Capacity factor	
				Variable	Fixed		
		USD/kWh low	USD/kWh high	USD/MWh	USD/kW	FLH low	FLH high
Variable RE (VRE)	Wind power onshore	1 300	2 200	0	50	1 800	4 500
	Wind power offshore	3 000	6 000	0	100	3 500	4 500
	Solar PV	1 100	6 000	0	30	800	2 000
	Run-of-river hydro	1 900	6 000	0	50	2 500	5 000
Firm RE	Reservoir hydro	1 000	7 650	0	25	2 000	5 000
	Solid biomass	2 400	4 200	4	80	6 000	8 000
	Biogas	2 700	5 000	4	80	5 000	7 000
	Solar CSP/STE	3 800	8 000	4	40	2 500	3 500
	Geothermal	2 000	5 900	4	80	7 000	8 000
Dispatchable non-RE	Combustion engine CC	600	1 700	3.5	20	1 500	2 500
	Gas CCGT flexible	800	1 500	5	25	3 500	5 500
	Gas CCGT inflexible	600	1 400	5	25	3 500	5 500
	Gas OCGT	400	900	4	20	100	1 500
	Steam turbine (gas/oil)	400	900	4	20	3 500	5 500
	Coal inflexible	1 250	2 000	8	40	6 000	8 000
	Coal flexible	1 250	2 500	7	35	4 000	6 000
	Lignite	2 400	2 800	8	40	7 000	8 000
	Nuclear flexible	3 500	7 000	7	70	7 000	8 000
	Nuclear inflexible	3 500	7 000	7	70	7 000	8 000

Key point • Generation technologies show different cost structures and typical capacity factors.

For the calculation of LCOF for flexible generation (Figure 7.9), two parameters were varied. Firstly, the cycling regime was set to a low, medium and high level (see Annex A for details). Secondly, typical capacity factors were reduced, to between 0% and 20% of usual capacity factors. As a result, LCOF are below USD 1/MWh for flexible technologies (reciprocating engine, flexible CCGT and flexible coal) if no full-load hour penalty is incurred. Costs are considerably higher, if full-load hours are reduced and reach more than USD 20/MWh for inflexible technologies (nuclear, inflexible coal).

Figure 7.9 • LCOF for flexible generation



Note: see Annex A for details on methodology.

Key point • Reducing the FLH of a power plant can have a greater impact on its LCOE than cycling-related costs.

Cost-benefit analysis

IMRES analysis

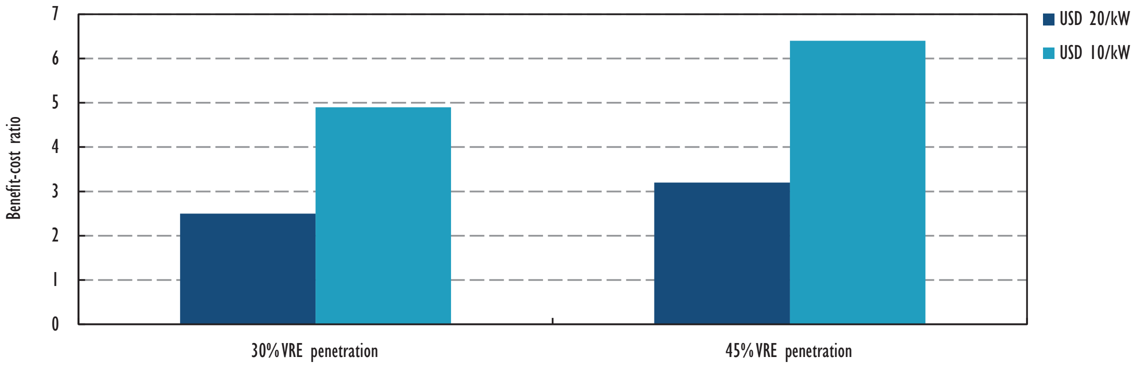
More flexible plant mix. The two different scenarios of the IMRES test system represent two very different types of plant mixes. In the Legacy scenario, the mix contains a large number of less flexible baseload plants. In the Transformed scenario, the mix is shifted towards more flexible units. Annual system costs of the non-renewable system are USD 1.56 billion lower in the Transformed case compared to the Legacy case at 30% VRE share, and USD 1.83 billion lower in the 45% VRE case. The results highlight the need to shift investment patterns in dispatchable power plants towards flexible units.

Coal plant retrofits. The cost-effectiveness of retrofitting inflexible coal plants was investigated with simulations of the IMRES test system under the Legacy scenario. The over 30 GW fleet of coal plants in the IMRES system has a minimum generation level of 70% of maximum output. This minimum was lowered to 50%. As a result, coal takes a larger fraction of overall generation, leading to saved fuel but increased CO_2 costs. In addition, coal units incur lower start-up costs.

Assuming capital cost in the range of USD 10/kW to USD 20/kW for coal retrofit (equivalent to capital expenditure of approximately USD 8 million to USD 16 million per 800 MW coal unit) the IMRES cost-benefit analysis yields a positive cost-benefit both at 30% and 45% VRE penetration (Figure 7.10). The same analysis was performed using a different assumption on start-up costs. Simulations were completely re-run, increasing the assumed costs per start from USD 100/MW/start to USD 250/MW/start. This improved the cost-benefit balance of coal plant retrofitting by roughly a factor two.

The cost of plant retrofits is highly unit-specific and depends on the exact measures that are undertaken to increase plant flexibility. However, improvements in plant control equipment and operational procedures within the power plant often yield significant performance improvements at low cost (Cochran and Lew, 2013).

Figure 7.10 • Cost-benefit of coal plant fleet retrofit in IMRES test system

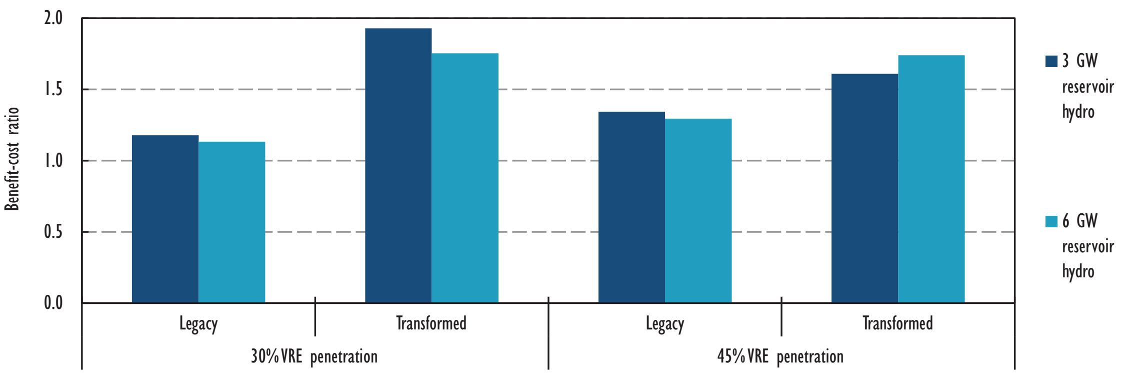


Note: costs refer to the cost of retrofitting plant.

Key point • Retrofitting legacy coal plants can be a cost-effective measure to increase flexibility, but it may drive up CO_2 emissions if the share of coal in the generation mix subsequently increases.

Addition of reservoir hydro generation capacity. The effect of adding 3 GW and 6 GW of reservoir hydro generation capacity to the IMRES system yielded a positive cost-benefit under both scenarios (Figure 7.11). The addition of reservoir hydro generation reduced fuel costs as well as CO_2 emissions, as hydro power displaced thermal generation. In the IMRES simulations, adding reservoir hydro was the only flexibility option that did not add to CO_2 emissions.

Figure 7.11 • Cost-benefit of adding reservoir hydropower generation to the IMRES test system



Key point • Reservoir hydropower is a cost-effective source of flexibility and the only flexibility option in the IMRES system that did not increase CO_2 emissions.

North West Europe analysis

Economic modelling carried out for the North West Europe case study region investigated the costs and benefits of retrofitting hydro power plants to increase the available generation capacity without increasing existing reservoirs. In particular, about 7 GW of hydro capacity were added to the power system (mainly in Norway, Sweden and France). The analysis also takes into consideration the enhancement of interconnections existing between Norway and Sweden and the other European countries (8.6 GW interconnection capacity additions).

Assumed costs for hydro retrofitting range between USD 750/kW and USD 1 300/kW, while interconnection cost is assumed to be USD 1 300/MW/km for land-based interconnections and USD 2 600/MW/km for subsea cables.

Resulting benefit to cost ratios for hydro power retrofits range between 0.6 (higher retrofit cost and additional interconnections) and 1.4 (lower retrofit costs and no additional interconnections).

The additional hydro capacity had a number of additional effects:

- avoiding the construction of about 6 GW of CCGT plants, producing savings in capital expenditure and variable costs (mainly fuel)
- increased utilisation of existing coal plants, benefitting from additional system flexibility
- reduced utilisation of pumped hydro storage, partially displaced by flexible hydro production, which is capable of providing similar services without the efficiency losses typical of storage plants.

Policy and market considerations

In a system with a high share of VRE, the role of dispatchable generation changes. It no longer needs to cover the full power demand of the system, but rather the net load that remains after accounting for wind power and solar PV generation.

This shifted role manifests itself in a different structure of the power plant mix. As the IMRES modelling shows, a power plant mix optimised to cover a more variable net load profile features more flexible generation technologies. Flexible plants need to start and stop generation frequently and at short notice. They also need to change the output level during operation dynamically.

The policy and market challenges for dispatchable generation are different for stable power systems (little or no load growth or asset replacement need) and dynamic systems. In stable systems, the power plant stack is unlikely to have been optimised to complement VRE generation.[15]

Even with a well-functioning market design in place, not all existing power plants will remain competitive. In fact, the exit of certain power plants from the market will be conducive to re-establishing an optimised generation portfolio. This transition period brings a number of challenges. Previous IEA analysis has investigated these as part of the Electricity Security Action Plan (Baritaud, 2012). Chapter 8 of this book discusses these challenges in the context of overall system transformation and market design. In summary, mature systems need to meet a twin challenge: scaling down those parts of the generation portfolio that are ill-adapted to high shares of VRE, while providing the right investment signals for scaling up flexible generation. However, existing power plants may be valuable for VRE integration as well. For example, retrofitting of existing power plants can be a cost-effective option to boost power system flexibility over the short and medium term. In addition, it may be economically most efficient to keep some plant in cold-reserve, to cover for periods of low VRE generation.

Dynamic systems are in a more advantageous position. They can focus on building up flexible dispatchable generation along with VRE capacity, avoiding the challenges associated with an ill-adapted power plant mix. To benefit from this opportunity, investment signals need to ensure that flexible plant capacity is actually built, often contrary to prevailing business-as-usual.

15. Systems with a high share of reservoir hydro generation are an important exception from this general trend.

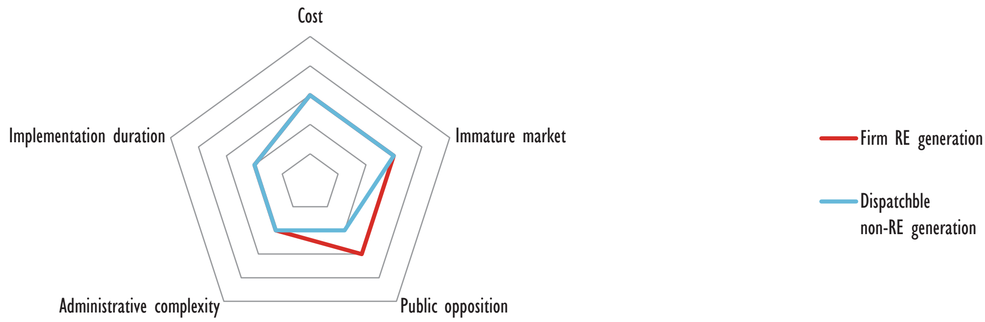
Fossil generation is the only flexibility option that may lock in CO_2 emissions for 25 to 30 years, considering typical plant lifetimes. As such, the role of fossil generation as a flexibility option always needs to be evaluated in the context of CO_2 emission targets.

Major challenges to investment in flexible generation include initial high capital expenditure, and public opposition (Figure 7.12); the latter issue is often referred as NIMBY (Not In My Back Yard).

Dispatchable generation is usually based on mature technologies; thus technical aspects and research and development issues do not represent a major policy issue. The potential lack of market maturity partially reflects that power markets do not fully represent and remunerate all the services provided by flexible generation (see Chapter 8).

For well-established technologies, administrative complexity and the timescales for implementation do not represent major barriers since expertise is available and best practice is already well known. Environmental impact assessment may be the most complex and time-consuming process involved.

Figure 7.12 • *Major challenges to deployment of dispatchable generation*



Key point • *Dispatchable generation faces comparably low overall barriers.*

Storage

As defined for the purposes of this publication, storage encompasses all technologies that can absorb electrical energy at a given time and return it as electrical energy at a later stage. Storage is a very powerful and effective flexibility option. The availability of low-cost, distributed energy storage could have an important impact on the power sector and would contribute to solve most VRE integration issues more easily. However, the currently high cost compared to other flexibility options, and the multitude of different applications for storage, make the assessment of its economics nuanced and complex.

This analysis focuses on storage technologies that have typical charge-discharge times of up to several hours. Where relevant, other technologies that allow for seasonal cycles (such as hydrogen storage and power to gas) are mentioned. However, they are not included in the detailed techno-economical assessment. Other IEA work provides a more detailed assessment of these technologies (IEA, forthcoming; Inage, 2009).

Technology overview

Storage technologies can be broadly distinguished by:

- the principle they exploit to store energy
- response times, duration of charge and discharge intervals
- their scale and hence location in the power system (see Box 7.2).

Apart from these fundamental distinctions, a number of other characteristics are also critical, such as maturity level and cost, efficiency and lifetime (see Tables 7.9 and 7.11).

While there are only a handful of different fundamental storage mechanisms, they vary greatly in terms of size, response times and charging/discharging times. As a result, storage should not be thought of as a single option, but as a family of quite diverse technologies.

Mechanical storage

Mechanical energy storage refers to technology that converts electricity to mechanical or potential energy and then stores it for later use as electricity. Today, two major technologies use mechanical energy storage: pumped hydro and compressed air energy storage (CAES). Mechanical storage technologies are the most mature method for electricity storage on grid, with pumped hydro representing 99% of currently installed electricity storage capacity, and still developing rapidly (IEA, 2012b).

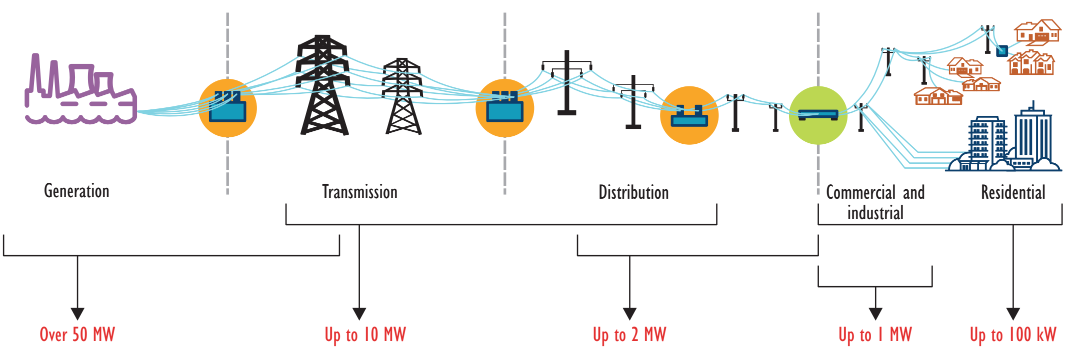
These technologies often suffer from high up-front investment costs, and geographic requirements that can limit their deployment potential or make it more expensive in some areas. In addition, both pumped hydro and CAES technologies are only applicable at grid level.[16] Pumped hydro has response times in the order of seconds to minutes, and can typically store enough energy for several hours of operation at full charge/discharge. CAES has somewhat slower response times (minutes) and can have comparable energy content (hours to days). Flywheels present very short response time and can typically store energy for several minutes.

Box 7.2 • Distributed and central storage: location matters

Distributed storage refers to storage devices connected to the low and MV grid, usually installed close to load centres or renewable electricity sources. System size generally ranges from 100 W to approximately 10 MW (with discharge time of a maximum of a few hours). Distributed storage devices are usually designed to provide back-up power locally, enhance power quality of VRE generation (mitigating variability and providing frequency and voltage support), increase self-consumption of VRE generation, relieve grid congestions and defer local investments in grid and sub-stations. Suitable technologies include modular devices, in particular batteries and capacitors but also flywheels.

Central or grid-level storage refers to storage devices usually connected to the transmission grid and characterised by higher storage capacity (>10 MW). Applications include price arbitrage, load following, provision of operating reserves and other ancillary services and congestion relief. Relevant options are pumped hydro storage, batteries and CAES.

Figure 7.13 • Possible locations for grid-connected energy storage



Key point • Storage can be deployed at different scales.

Electrochemical storage

Electrochemical batteries use chemical reactions with two or more electrochemical cells to enable the flow of electricity. Examples include lithium-ion, sodium sulphur, redox-flow and lead acid batteries. These technologies have been successfully deployed in both distributed and centralised systems for

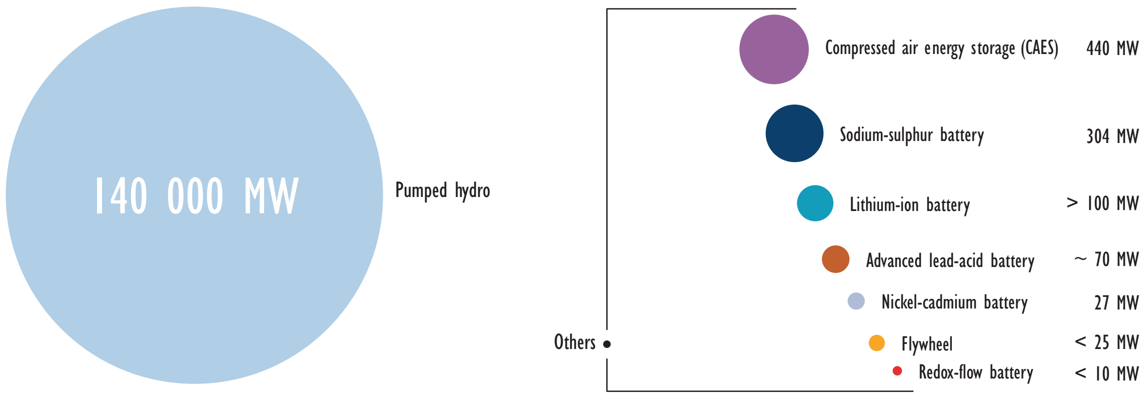
16. Although distributed CAES systems making use of smaller vessels such as balloons have been tested, at utility scale, CAES in combination with gas turbines requires significant grid connection capacity.

mobile and stationary applications at varying scales. However, they struggle to realise widespread deployment due to challenges in energy density, lifetime, charging capabilities, safety, recyclability and system cost. Electrochemical storage has typical response times of seconds and discharge times of minutes to hours.

Electrical storage

Electrical energy storage technologies use static electric or magnetic fields to store electricity. Examples include supercapacitors and superconductive magnetic energy storage (SMES). These technologies generally have a high cycle life and power density, but a much lower energy density. This makes them best suited for supplying short bursts of electricity into the system. They struggle with high costs, which have led to significant research into how to increase their energy density. These technologies respond quasi-instantaneously and may hold enough energy for seconds to a few minutes of operation.

Figure 7.14 • Worldwide installed electricity storage capacity



Sources: EPRI, 2012; and IEA, 2012b.

Key point • Pumped storage hydro power is currently by far the largest form of electricity storage.

Box 7.3 • Seconds to hours and beyond: timescale matters

Power system operations consider different timescales, from fractions of seconds (for frequency and voltage control) to days, seasons and even years when considering infrastructure development. These needs can be grouped into the following categories:

Power quality. Very fast and short duration services, such as voltage control and very short-term aspects of frequency control with discharge times of up to a few seconds.

Bridging power. Short-term aspects of frequency support with discharge times of up to a few minutes.

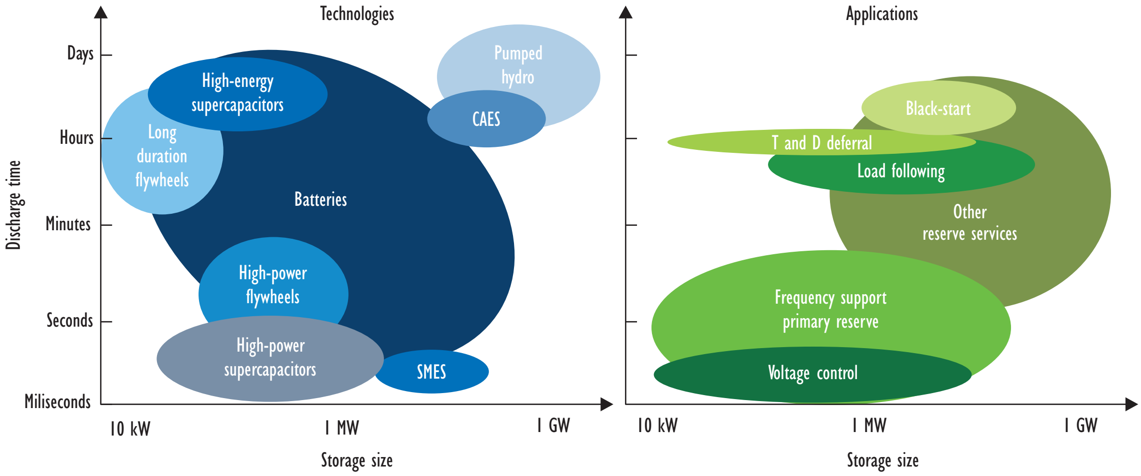
Energy management. Levellising hourly and daily imbalances.

Seasonal balance. Levellising long-term supply/demand imbalances.

The needs of the power system on the one hand and the technical characteristics of storage technologies on the other give rise to a complex pattern of possible applications (Figure 7.15).

It should be noted that technologies with longer discharge times may also be capable of providing services with shorter times, if they can respond quickly enough. For example, pumped storage hydro is in a very good position to provide primary reserve. This does not, however, work the other way around: flywheels have short discharge times, meaning they can only store little overall energy. This amount of energy is not sufficient for applications requiring more sustained output, such as black-start services.

Figure 7.15 • *Examples of power system applications and suitable storage technologies*



Note: T and D = transmission and distribution.

Key point • *Different storage technologies can be best suited for different power system applications.*

Chemical storage

Chemical energy storage uses chemical energy carriers to store electricity, for example through electrolysis. Experimental energy carriers include hydrogen and synthetic methane (methanation). Electricity is converted, stored and then re-converted into the desired end-use form (e.g. electricity, heat or liquid fuel). These storage technologies have significant technical potential due to their high energy density and applicability in large-scale energy storage facilities. However, they struggle with high up-front costs and lack of existing infrastructure for large-scale applications (e.g. hydrogen storage for fuel-cell vehicles). In addition they may yield very low round-trip efficiencies of 40% and less, and also suffer from self-discharge problems over longer time horizons. Typical response times are connected to the re-conversion technology (e.g. thermal power plants, fuel cells) and are in the order of minutes to hours. Discharge times can be in the order of days to weeks.

The technical characteristics of selected electricity storage technologies are summarised in Table 7.9.

Table 7.9 • *Technical characteristics of selected storage technologies*

Type	Maturity stage	Typical power output (MW)	Response time	Efficiency (%)	Lifetime	
					yrs	cycles
Pumped hydro	Mature	100-5 000	sec-min	70-85	30-50	20 000-50 000
CAES	Deployed	100-300	min	50-75	30-40	10 000-25 000
Flywheels	Deployed*/ demonstration**	0.001-20	<sec-min	85-95	20-30	50 000-10 000 000
Li-ion battery	Deployed	0.001-5	sec	80-90	10-15	5 000-10 000
NaS battery	Deployed	1-200	sec	75-85	10-15	2 000-5 000
Lead-acid battery	Deployed	0.001-200	sec	65-85	5-15	2 500-10 000
Redox-flow battery (VRB)	Deployed	0.001-5	sec	65-85	5-20	>10 000
SMES	Demonstration	<10	<sec	90-95	20	>30 000
Supercapacitors	Demonstration	<1	<sec	85-98	20-30	10 000-100 000 000

Note: Li-ion = lithium-ion; NaS = sodium sulphur; VRB = vanadium redax battery.

* Low speed.

** High speed.

Source: IEA analysis based on data from Bradbury, EPRI, IRENA, ETSAP, JRC-IET, KEMA, Limerick, NREL, Sandia and ZFES.

Key point • *Storage technologies cover a wide range of technical characteristics.*

Contribution to VRE integration

Storage applications offer the potential to solve many if not all of the problems associated with VRE integration. However, different types of storage are best positioned to address different challenges. The following paragraphs discuss these technical considerations, while the economic assessment is covered in the next section.

Variability

Storage can be both a source of electricity generation and of electricity demand. It is therefore ideally suited to complement VRE variability, creating demand during periods of abundance and providing supply during scarcity. Depending on location and technology, very different timescales of variability can be addressed.

Storage can shave off peaks in generation and return the energy during peak demand periods. The pronounced daily peak of solar PV generation is a good example – in particular because it occurs frequently and predictably, thus allowing for precise storage dimensioning and management procedures. Storage can also be used to mitigate short-term variability, by smoothing fluctuations in the sub-hourly timescale.

Over medium to long timeframes, large storage volumes allow for bridging seasonal energy imbalances, e.g. sustained periods of VRE surplus in some months and scarcity in others. Large-scale storage is the only viable technology option for bridging such long-term imbalances. Pumped hydro storage with very large reservoirs is one option, as well as chemical storage technologies.

Uncertainty

Storage by itself does not increase the accuracy of VRE production forecasts. However, it can potentially mitigate forecast errors, by providing fast-acting reserves, stepping in during shortfalls and charging during unexpected oversupply. However, because storage operation is constrained by its system state (it can only charge if it is not full, it can only discharge if it is not empty), storage operations would need to include a margin to accommodate forecast errors.

Provision of power system reserves can be a very important technical contribution of storage to system reliability. Depending on system circumstances, reserve provision from storage can be more important than its classical provision of energy management services. A good example is the Dinorwig pumped hydro storage plant in the United Kingdom. The 1.7 GW plant may provide short-term operating reserve thanks to its fast response time, being capable to achieve full load in less than two minutes from standstill (or less than 20 seconds from the spinning state).

Location

Storage does not solve the problem of potential geographic mismatches between supply and demand. However it can mitigate the impact of this mismatch, i.e. the need for building high capacity connection power lines, by smoothing output on the generation side and making better use of the grid infrastructure. Despite this, its contribution will not replace significant need for grid investment.

Modularity

Distributed storage can be highly effective at mitigating the impacts associated with distributed deployment of VRE generation. By smoothing generation over time, the impact on distribution grid infrastructure can be significantly reduced. Also, storage can help to boost self-consumption and therefore reduce the need to feed power into the grid to make use of generated electricity.

When deployed at smaller scales, control of storage devices becomes a critical issue. Firstly, clear and secure communication standards need to facilitate the visibility and controllability of storage devices. Secondly regulations concerning ownership, access and control are important to ensure that storage operations maximises system-wide benefits.

Box 7.4 • Storage impact on households: solar PV self-production in Germany

In domestic applications, the share of solar PV self-production is significantly influenced by the size of the solar PV system and consumption patterns. In addition, it varies during the year according to the seasonality of solar PV production and household consumption.

In Germany, roughly 30% of the annual production of a family-size solar PV plant may be directly consumed by the household. The grid connection is essential to feed electricity into the grid when the solar PV system is producing more than needed and to supply the household when the solar PV system is not generating.

The integration of a family-size solar PV system with a storage device with a peak capacity 1.5 kW and two hours of storage capacity (3 kWh) allows the storage of excess solar PV production and its use when needed, thus increasing the share of solar PV self-production to around 45%.

This analysis is based on the average standard consumption profile of a household in southern Germany, equipped with a 5 kW solar PV system (corresponding to an annual production of around 5 MWh). Different load profiles, solar PV system sizes and larger storage devices may increase selfproduction even further.

The degree to which such measures are cost-effective for the end-consumer is determined largely by electricity pricing regime and storage costs. The cost-effectiveness of the measure from a system perspective is determined by the avoided costs in other parts of the system. This in turn can critically depend on the way the device is operated. Optimal operations from a system perspective need not coincide with the interest of the individual consumer, depending on electricity tariff design.

Non-synchronous technology

Storage may play a role in mitigating some of the impact of non-synchronous generation from VRE. Pumped hydro storage is a synchronous generation technology and therefore can provide inertia to the system, both when pumping and discharging.

Where regulations (grid codes) allow for it, storage may also contribute to providing fast frequency response services, emulating the inertial response currently provided by synchronous generators. In addition, when located close to loads, fast-responding storage technologies can help to control voltage levels.

Table 7.10 summarises the possible contribution of storage to different aspects of VRE integration. It is important to bear in mind that different storage technologies may be needed for dealing with different integration challenges.

Table 7.10 • Contribution of storage to VRE integration

	Uncertainty	Variability			Location constraints	Modularity	Non-synchronous
		Ramps	Abundance	Scarcity			
Distributed storage	✓	✓	✓	✓	×	✓✓	O
Grid-level storage	✓	✓✓	✓✓	✓✓	×	××	✓

Note: ✓✓: very suitable; ✓: suitable; O: neutral; ×: less suitable; ××: unsuitable.

Key point • Storage can contribute to VRE integration by mitigating a wide range of impacts, including surplusses.

Economic analysis

Costs

Differences in technology maturity and performance imply a large range of costs for storage technologies. As a general rule, all electricity storage technologies have significant up-front costs. Costs, when measured on a per kW basis, are usually comparable to or above power generation technologies. In addition, technologies show large differences in cost structure and it is important to distinguish between the cost of capacity (maximum generation or consumption) on the one hand, and energy (amount of energy that can be stored) on the other. Taking the example of a large water reservoir: the energy corresponds to the amount of water contained in it, while the capacity is determined by how much water can flow out of the reservoir in one moment.

For example, in the case of pumped hydro the capacity costs are related to ducts, turbines and generation stations, while energy costs represent incremental costs for larger reservoirs, which are typically smaller. Contrary to this, battery technologies show particularly high costs for additional energy storage. As such, they will be more cost-effective in applications that require a lower ratio between energy and capacity. Conversely, the greater the energy storage needs compared to capacity needs, the more suitable pumped hydro storage becomes (Table 7.11).

Table 7.11 • Economic parameters of selected electricity storage technologies

Type	*Investment cost*		*O&M costs*	*Discharge time*
	Power cost	*Energy cost*		
	USD/kW	*USD/kWh*	*% CAPEX/yr*	
Pumped hydro	500-4 600	0-200	1	hours
CAES	500-1 500	10-150	1.5-2	hours
Flywheels	130-500	1 000-4 500	na	min
Li-ion Battery	900-3 500	500-2 300	1-1.5	min-hours
NaS Battery	300-2 500	275-550	1.5	hours
Lead Acid Battery	250-840	60-300	2	hours
Redox-flow battery (VRB)	1 000-4 000	350-800	2	hours
SMES	130-515	900-9 000	na	min
Supercapacitors	130-515	380-5 200	na	sec-min

Notes: CAPEX = capital expenditure. Power cost (cost of capacity) and energy cost are to be considered as two additive components of the overall investment cost.

Source: IEA analysis based on data from Bradbury, EPRI, IRENA, ETSAP, JRC-IET, KEMA, NREL, Sandia and ZFES.

Key point • Wide ranges in reported costs reflect a high degree of uncertainty about actual cost levels.

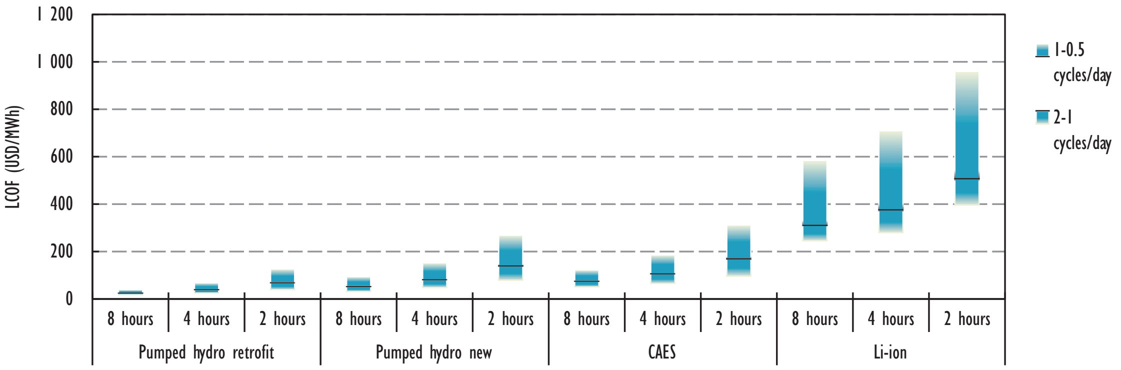
The most mature and cost-effective bulk energy storage option to date is pumped hydro and there is still a very large unexploited potential (JRC, 2013). Costs can be as low as USD 500/kW, in exceptional cases where only minor retrofits are needed to add storage to existing reservoir hydro installations (pump-back). From this low end, there is a continuum of different project types, depending on other project drivers (irrigation, flood control etc.) and geographic conditions (availability of natural reservoirs) yielding costs of USD 5 000/kW and above in extreme cases. Typical project costs will be in the order of USD 1 200/kW. Battery storage technologies still show very high up-front costs, with varying assessments on the prospects of future cost reductions (BNEF, 2012; Black and Veatch, 2012). However, some recent technology developments (such as lithium-ion batteries) are optimised for portable applications, which is not of primary relevance for power system applications.

The LCOF calculation (Figure 7.16) used to compare the different flexibility options reveals comparatively high costs for storing energy, i.e. storing electricity and using it later (see Annex A for details). For the same technology, storage LCOF is most sensitive to utilisation. The LCOF shows a high sensitivity to both the number of cycles per day and the amount of energy discharged per cycle. The more frequent the cycles or the more energy is discharged per cycle, the cheaper storage is per MWh. Efficiency and associated costs of energy losses have a less pronounced impact as long as efficiency is above 60%.

Costs also depend on technology, with Li-ion batteries showing a broad cost range depending on cost assumptions.

These costs are indicative and do not reflect the full portfolio of services that storage can offer. However, they can be useful for a first order comparison between different options.

Figure 7.16 • LCOF for different electricity storage applications



Note: see Annex A for details on methodology.

Key point • The cost of electricity storage is generally quite high, but varies in a wide range.

Cost-benefit analysis

Both economic modelling studies, IMRES and Pöyry's BID3, assessed the cost-benefit ratio of storage for different scenarios. Due to the plethora of different services storage enables (power quality, bridging power and energy management), comprehensive modelling of potential benefits is challenging (Strbac et al., *2013)*.

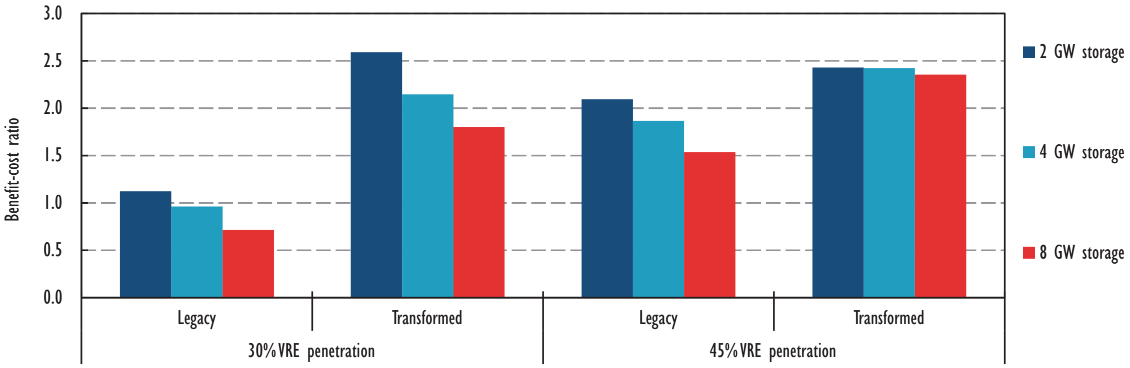
In the IMRES model, storage was implemented as centralised pumped hydro storage at low, medium or high capacity (2 GW, 4 GW or 8 GW respectively), with eight full-load hours of storage capacity, and 80% round-trip efficiency. The possible benefit of storage in the IMRES modelling included improved utilisation of generation assets – reduced curtailment of VRE and fewer start-ups in the Legacy plant case and provision of operating reserves. In the Transformed cases, storage could also avoid conventional power plant investments.

In the Legacy case, storage reaches a positive cost-benefit ratio only at a VRE penetration level of 45% or at low capacities (Figure 7.17). The benefit to cost ratio is above two for all three storage levels in the Transformed case.

Pöyry's analysis of the North West Europe case study region yields comparable results. The addition of 8 GW of pumped storage capacity across the case study region yields a cost-benefit ratio of one. Given the larger size of this system compared to the IMRES model system, the additional storage capacity is comparable with the 2 GW storage scenario in the IMRES analysis.

It should be noted that this is a conservative assessment of the benefit to cost ratio of pumped hydro storage. Firstly, the assumed cost of USD 1 200/kW is at the high end for situations where storage can be added simply by retrofitting existing plants. Under optimistic assumptions, this could double the observed benefit to cost ratio. In addition, the provision of specific reserves (such as very fast frequency response) was not included in the modelling. Finally, storage may allow deferring or avoiding grid investments, which was also not modelled in the current analysis, but has been shown to add to the overall value of storage (Strbac et al., *2013)*.

Figure 7.17 • Cost-benefit of adding storage to the IMRES test system



Key point • Storage may be cost-effective at low deployment volumes or at very high shares of VRE.

In summary, electricity storage is likely to become cost-effective in power systems after reaching a very high-VRE penetration. However, given its comparably high costs, it will be among those options deployed after the potential of more cost-effective solutions has been exhausted. In any case, storage should not be generally dismissed as too costly. Specific circumstances, where a number of benefits align, can make storage a valuable option for VRE integration today.

These results are in line with findings in other integration studies; a study performed on a test system that represents a possible generation mix in the Irish system in 2020 found that, "due to the high capital costs and inefficiencies of pumped storage, storage does not justify itself from a systems economics basis until greater than approximately 48% to 51% of energy is obtained from wind on the test system" (Tuohy and O'Malley, 2011). The Western Wind and Solar Integration Study evaluated the price arbitrage benefits of additional pumped storage. While benefits were found to increase considerably when including forecast errors, they were still not sufficient to make such a plant economically viable (GE Energy, 2010).

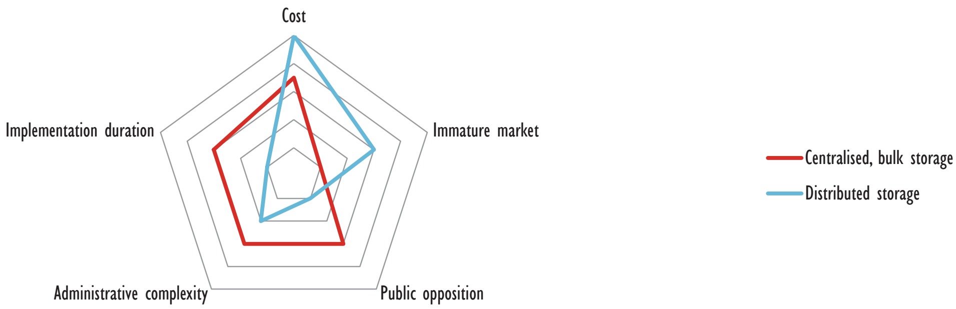
Policy and market considerations

Electricity storage technologies may represent a valuable flexibility resource addressing most VRE system impacts. However, a suite of barriers is still holding back more widespread adoption of energy storage for VRE integration (Figure 7.18). These are somewhat different for grid-level bulk storage (pumped hydro and CAES) as compared to more distributed options, in particular batteries.

High costs and a comparably immature market are the most significant barriers for distributed options. But costs are also relevant for large-scale options; these may additionally experience issues of public acceptance and complex licensing procedures. Policies should hence focus on bringing the costs of key storage technologies down. In this context, it is important to distinguish between those areas that already enjoy considerable research attention (for example lithium-ion technologies thanks to the computer industry and vehicle industry) and those technologies where this is not the case. The latter may be a valuable target for increased research and development.

As explained above, storage can provide a multitude of different services to the power system. It will be the rule rather than the exception that a portfolio of services will make storage projects viable. A clear regulatory framework may facilitate the aggregation of provided services, identifying those services that can be provided by regulated transmission and distribution operators to avoid competition with power generators in unbundled markets. In addition, the regulatory and market environment needs to allow storage to compete on a level playing field with alternative options. This can have implications in particular for the design of system services markets.

Figure 7.18 • *Major challenges to deployment of storage*



Key point • *High cost remains the most important barrier for electricity storage, in particular for distributed options.*

Demande-side integration

DSI can be defined as a combination of two activities: on the one hand, activities to influence or remotely manage load, including energy efficiency and demand-side management (DSM), and on the other hand the active response of consumers (demand-side response [DSR]). Historically, DSM programmes sought to achieve peak shaving and energy efficiency improvements with a view to deferring investment and saving fuel costs. Apart from reducing direct costs, DSI may also contribute to improved system reliability, market functioning, environmental benefits, and – the current focus – the integration of variable renewables.

Technology overview

There is a range of load types that may be suitable for DSI purposes in the residential, commercial and industrial sectors (Table 7.12). While diverse in terms of sector, application and device, the DSI potential of a given process hinges on common properties, which can be summarised as the ability to achieve one of the following:

- Shift in time the power consumption of applications and/or devices with a low overall capacity factor (e.g. electric vehicle charging, water pumps and household appliances).
- Adjust the set-point of devices that have high capacity factors but can adjust consumption for a certain amount of time (e.g. air conditioning, waste-water treatment, and lighting) where flexibility usually arises from thermal inertia, inherent storage or low sensitivity of service quality to incremental demand reduction (such as small reduction in light intensity).
- Interrupt electricity consumption in exceptional circumstances at short notice and known cost (e.g. in large energy intensive industries).

The distinction between load shifting and load shedding for DSI applications is relevant. While load shifting refers to the transfer in time of certain power demand,[17] DSI load shedding implies that reduced consumption is "lost load" because the involved processes do not allow the load to be recovered later in time. This is usually the case for industrial processes running at very high utilisation rates (e.g. aluminium smelters or cement mills).

17. Overall power demand is left unchanged in load shifting applications if losses are zero.

Table 7.12 • Classification of selected DSI processes

	Process	*Relevant process*	*Load shifting / shedding*
Household and commercial applications	Heating, ventilation and air conditioning	Thermal storage	Shifting
	Refrigeration (cold storage warehouses)	Thermal storage	Shifting
	Electric hot water heaters	Thermal storage	Shifting
	Water pumping, freshwater and waste-water treatment (incl. water desalination)	Water storage	Shifting/ shedding
	Charging of electric vehicles	Electric storage	Shifting
	Programmable use of domestic appliances (washing machine, tumble driers, dishwashers)	Change of usage pattern	Shifting
Industrial process and others	Aluminium electrolysis	Electrolysis, thermal storage	Shedding
	Cement mills	Milling	Shedding
	Wood pulp production	Mechanical refining	Shifting
	Electric arc furnace	Melting	Shedding
	Chloralkali electrolysis	Electrolysis	Shifting/ shedding
	Agricultural water pumping	Water storage	Shifting/ shedding

Sources: EWI, 2009; IEA analysis.

Key point • DSI processes can be categorised as load shifting and load-shedding processes.

While some resources can simply be switched off, the flexibility that DSI applications may bring to the power system commonly depends on the physical processes involved. These are, in particular, the response time of DSI applications (Table 7.13), and, in some cases, the possible duration of continued service provision. The set-point of a single refrigerated warehouse, for example, cannot be set indefinitely below the nominal temperature.

Table 7.13 • Response time of selected DSI processes

End-use	*Type*	*Ramp down*	*Switching off*	*Response time*
Heating, ventilation and air conditioning	Chiller systems	Set-point adjustments		15 min
	Package unit	Set-point adjustments	Disable compressors	5 sec to 5 min
Lighting	On/off	Reduce lightning levels	Bi-level/off	5 sec to 5 min
Refrigerated/ frozen warehouse		Set-point adjustments		15 min
Data centres		Set-point adjustments, reduce computer processing		15 min
Agricultural pumping			Turn off selected pumps	5 sec to 5 min
Waste-water			Turn off selected pumps	5 sec to 5 min

Source: LBNL, 2012.

Key point • DSI processes can show response times from seconds to minutes.

In order for DSI's potential to be realised, the following preconditions need to be met:

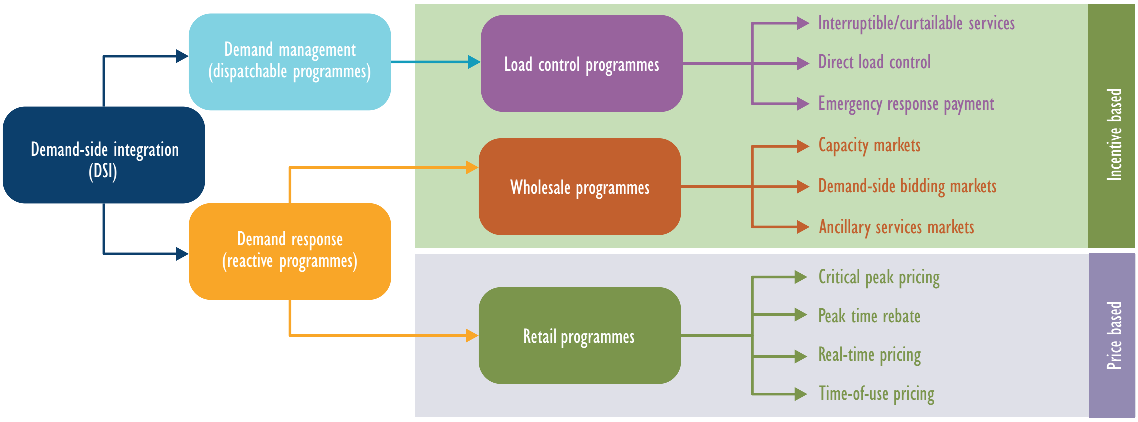
- metering time of electricity consumption at high accuracy
- price signals with high temporal (and spatial) accuracy for consumers
- incentives for operating load in a system-friendly way
- policies and regulation conducive to the establishment of load aggregators that can manage consumer loads
- infrastructure for the remote control of loads.

In most countries, the above conditions are only met for large consumers, limiting participation to this segment. Today, DSI is commonly used as a way of responding to exceptional system conditions (usually short-term capacity shortages during contingencies or times of peak demand). However, with the recent emergence of low-cost, highly reliable and versatile IT infrastructure, DSI capabilities can now reach more market segments and alter consumption patterns in a more sophisticated way.

In line with the above distinction of DSM and DSR, demand integration programmes can be classified as follows (Figure 7.19) (MIT, 2011):

- **Dispatchable programmes,** also known as load management or control programmes, which allow direct control of load responses by the grid operator or a third-party aggregator. An incentive is often offered to customers in return for participation.
- **Reactive programmes,** which rely on customers' voluntary responses to a variety of signals communicated to them. The most common signal used at present is price, although other types of information, such as environmental signals or neighbourhood-comparative data, may prove useful in the future. Reactive programmes can further be divided into wholesale programmes administered by system operators and retail programmes that present customers with retail prices carefully determined by specific time-varying pricing structures.

Figure 7.19 • Types of DSI programmes



Source: MIT, 2011.

Key point • Demand integration programmes can be classified as dispatchable and reactive programmes.

The cost-benefit profile of DSI may be affected by the contractual arrangements governing it. A good example of this is a recent study conducted by the electro-mobility company Better Place, in collaboration with the system operator, PJM.[18] The impact of electrical vehicle charging on the system was assessed under three scenarios:

18. PJM Interconnection is a regional transmission organisation that co-ordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

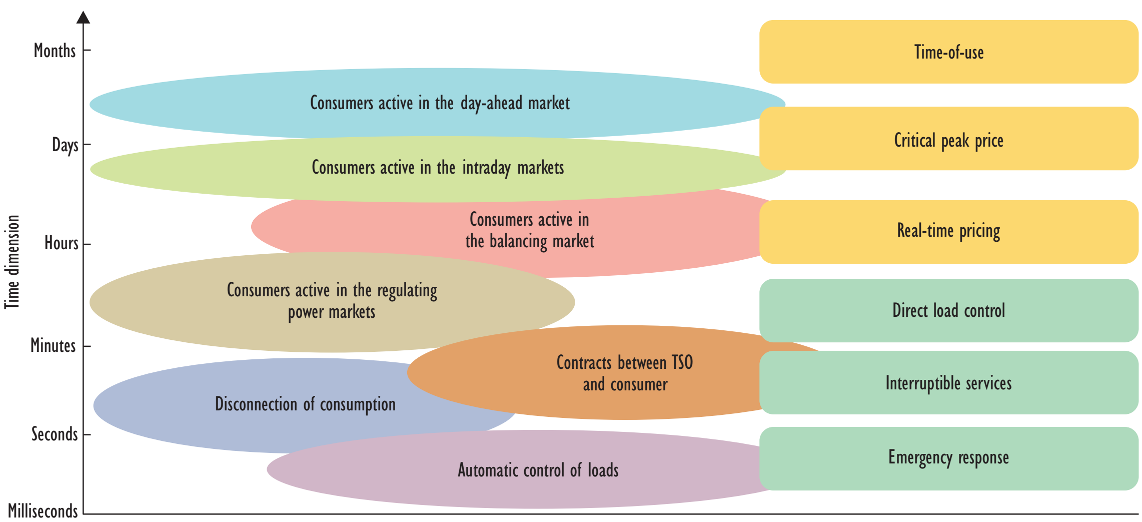
- unmanaged charging
- consumer price-based time-of-use (TOU) charging
- managed charging via a central network operator (CNO).

According to this analysis, those consumers who chose TOU pricing saw savings of less than 10% annually, but on the system level there was no pronounced benefit compared to unmanaged charging. TOU did not have a large impact on peak shaving as it typically shifts the peak to the hour right after the interval where the original peak was priced. However, co-ordinated smart charging via a CNO halved system cost impacts compared to unmanaged charging, while reducing electricity-related driving costs by 20%. In summary, these results show that a co-ordinated approach to load management can bring higher net benefits for consumers and the entire system compared to exposing all consumers to the same real-time price. Managed programmes may also allow for a more rapid and potentially longer response, and are often more suitable for quick response applications (Figure 7.20).

Due to limited experience with large-scale roll-out of innovative DSI programmes, there is some disagreement about the actual market potential and possible performance of DSI. However, even if DSI were to show only part of the benefits found in a range of modelling studies (e.g. GE Energy, 2010; ECF, 2011) it could make a very substantial contribution to the cost-effective integration of VRE.

Experiences from the United States, where DSI is comparably more advanced in selected markets, are positive. A number of recent programmes have highlighted the capability of end-use technologies to provide balancing services (Ecofys, 2012). Moreover, the United States' Federal Energy Regulatory Commission (FERC) has been a proponent of empowering demand-response resource contribution in US power markets. PJM, for example, has offered opportunities for energy efficiency projects and demand-response resources to bid into its forward capacity market, the reliability pricing model RPM (PJM, 2012).

Figure 7.20 • *DSI options as a function of response time and mechanism*



Key point • *Managed programmes may allow for a more rapid response.*

The frequency with which DSI is called upon has been extending from emergency use to daily use and further to real-time use. The participants in DSI have been extending from large industrial and commercial customers to smaller commercial and residential customers, with more aggregators acting as intermediaries between utility or grid operators and individual customers. DSR has been extending from one direction to both directions: from downwards, reducing load only, to both upwards and downwards, either increasing or reducing load as required.

Contribution to VRE integration

Variability

DSI contributes to mitigating variability in several ways. Firstly, any energy efficiency measure that reduces consumption when VRE output tends to be low, will lead to a better match between supply and demand. For example, more efficient lighting helps the integration of solar PV.[19] Secondly, DSI can help to deal with net load variability by shifting demand away from net load peaks and towards net load valleys. However, it is a given that the DSI process needs to be able to bridge the time gap between high and low net load levels to be effective. While this can constrain the contribution of DSI, sequencing multiple responses can prolong possible response periods. Consider, for example, a large number of cold storage warehouses, for which a moderate temperature increase may be acceptable only for a limited amount of time, say a few hours. A prolonged demand reduction can be achieved by adjusting the set-point of a new group of storage warehouses after the first group has reached the time limit.

Shifting demand towards periods of high-VRE supply is a critical contribution of DSI. This is true in particular at high shares of VRE, when net load would become negative in the absence of responsive demand.

Uncertainty

DSI processes have demonstrated their ability to provide fast-acting, automatic reserves in a number of demonstration projects (e.g. Ecofys, 2012). Results have been encouraging in terms of performance and cost. Modelling studies have also found significant benefits for providing operating reserves on the demand side rather than from generators. In the Western Wind and Solar Integration Study (GE Energy, 2010), a DSR programme in which utilities paid 1 300 MW of load to shut off when needed, was found to be the most cost-effective way to deal with incremental contingency reserve requirements in high wind power scenarios.

DSI can be a very good complement to VRE for providing operating reserves during times of high-VRE generation. VRE can contribute downward reserves cost-effectively, by reducing their output when needed. DSI, in turn, can provide upward reserves by reducing consumption on demand. Such operation can be facilitated by splitting upward and downward reserves into two products.

Location

Apart from long-term relocation effects, DSI cannot make a substantial contribution in situations where there is a geographic mismatch between load and good VRE sites.

Modularity

DSI can be a key tool to mitigate some of the negative impacts that widespread adoption of distributed VRE generation may have. In particular, shifting local demand to when the sun is shining can effectively mitigate the impact on distribution systems that have high shares of solar PV deployment.

Non-synchronous technology

DSI can make a very important, indirect contribution to mitigating the impact arising from the non-synchronous nature of VRE generation. When there is a good match between demand and VRE supply, a high annual share of VRE will lead to comparably lower instantaneous shares. Consequently, related impacts occur later.

In order to contribute directly to system stability at times of high instantaneous penetration of non-synchronous generation, demand-side resources would need to respond very fast, potentially limiting the number of qualified processes.

Above and beyond these contributions, it is important to note that DSI could help solve many of the issues currently raising concerns about the functioning of energy markets; more active demand-side participation would help to dampen price volatility, hence creating more certain revenue streams for all generators.

19. The opposite effect may also occur: if an efficiency measure reduces load when VRE output is high, this can make integration more challenging.

The potential for DSI to contribute to VRE integration is summarised below (Table 7.14).

Table 7.14 • *Contribution of DSI to VRE integration*

	Uncertainty	Variability			Location constraints	Modularity	Non-synchronous
		Ramps	Abundance	Scarcity			
DSI small-scale (distributed)	✓	✓✓	✓✓	O	×	✓	✓
DSI large-scale	✓	✓	✓✓	O	×	××	✓

Note: ✓✓: very suitable; ✓: suitable; O: neutral; ×: less suitable; ××: unsuitable.

Key point • *DSI can address a broad range of VRE integration challenges.*

Economic analysis

Costs

The relative importance of initial and operating costs of DSI varies according to the type of load: industrial, commercial or domestic. With decreasing size, the cost of setting up information technology infrastructure becomes more important. For many industrial processes, the only relevant cost is the opportunity cost of deferring or curtailing demand. In turn, the most promising DSI applications for commercial and – in particular – domestic consumers do not negatively affect quality of energy-related services.

Initial costs

Initial capital cost for industrial processes are practically negligible, below USD 1/kW for selected industrial applications such as aluminium electrolysis, cement mills, wood pulp production, electric arc furnaces and chloralkali electrolysis (EWI, 2009). All industrial plants already have the necessary energy management systems to regulate power demand. Furthermore, the installed capacities are comparatively large so that typical additional costs per kilowatt are insignificant.

In a comprehensive study based on 82 DSI initiatives in California (Winkler, 2007),[20] the cost of the equipment needed to enable DSI on a commercial scale was estimated between USD 66/kW and USD 230/kW, depending on the inclusion of costs related to recruitment, technical co-ordination, equipment and participation.

On a smaller scale, for example DSI processes in households, the initial costs to enable load shifting and shedding becomes somewhat more relevant, and mainly consist of smart meters and other infrastructure that allow the control of electric devices and the monitoring of power market signals (Table 7.15). Stand-by costs of additional devices may be negligible, as well as additional communication costs.

Average cost for smart metering devices (according to first deployment experiences) are mainly in the range of USD 100 per meter (/m) to USD 350/m and show considerable economies of scale. Cost differences reflect a range of factors, including equipment capabilities, population density, nature and size of meter roll-out, and geographic conditions (Cooke, 2011). For example, the installation of over 30 million smart meters in Italy yielded costs ranging between USD 80/m and USD 100/m (Figure 7.21). These costs include installation expenses, which highly depend on the existing infrastructure and can in some cases be about the same magnitude as the actual meter hardware (IEA DSM, 2012). Ongoing maintenance is in the range of USD 3 to USD 11 USD per year per endpoint (EPRI, 2012).

20. Including the following facilities: biotechnology, data centres, healthcare, high tech, industrial process, government, museum, retail and schools.

Table 7.15 • Cost parameters of selected DSI technologies in household/commercial applications

Type	Capital costs	O&M costs
Infrastructure	USD/installation	USD/yr
Smart meters	100-350	3-11
Single device grid-ready functionality	10-50	-
In-home displays and access to energy information	20-50	-
Portal: resident Energy Management System (EMS)	150-300	-

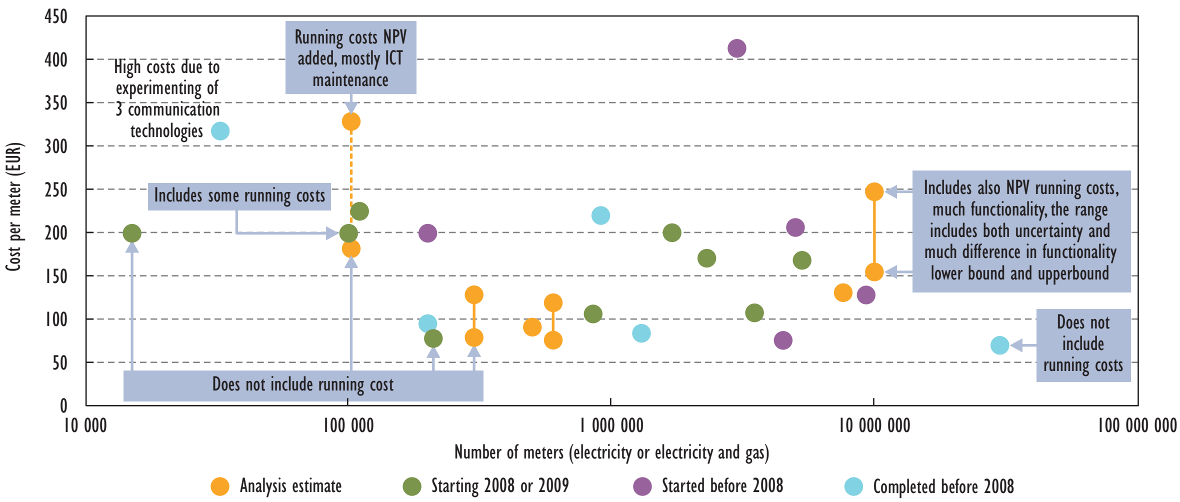
Note: - = no data available.

Key point • Reported DSI technology costs vary in a wide range.

Grid-ready appliances and devices, which are often referred to as "DSR-ready," are manufactured with DSR capabilities already built in. The additional cost to incorporate grid-ready functionality into new appliances is estimated at USD 10 to USD 50 per unit for the first generation, but declining to zero within ten years, as the grid-ready design becomes standard and high volumes become involved. Retrofits of existing household appliances will generally not be economical, in particular due to high transaction costs. Finally, while DSR-ready control equipment demands similar cost premiums across different device classes, enabling flexible operations may entail additional costs, arising from appliance design (e.g. larger dimensioning and better isolation for electric water heaters).

Analysis based on data from Öko-Institut (2009) suggests a broad range of additional overall costs for household appliances between USD 10/kW and USD 1 500/kW (with a weighted average in the order of USD 50/kW to USD 100 USD/kW of managed load). The reason for this wide range is that the same additional cost for adapting each appliance (ranging between USD 20 and USD 45 per appliance) is used to control various appliances with different sizes.[21]

Figure 7.21 • Cost per smart meter vs. implementation scale



Note: - = NPV = net present value; ICT = information and communication technology.

Source: IEA DSM, 2012.

Key point • Reported costs of smart meters vary in a wide range.

21. Considered appliances include the following: washing machine, tumble dryer, dishwasher, oven and stove, refrigerator, freezer, air conditioning, water heater, electric heating and circulation pump.

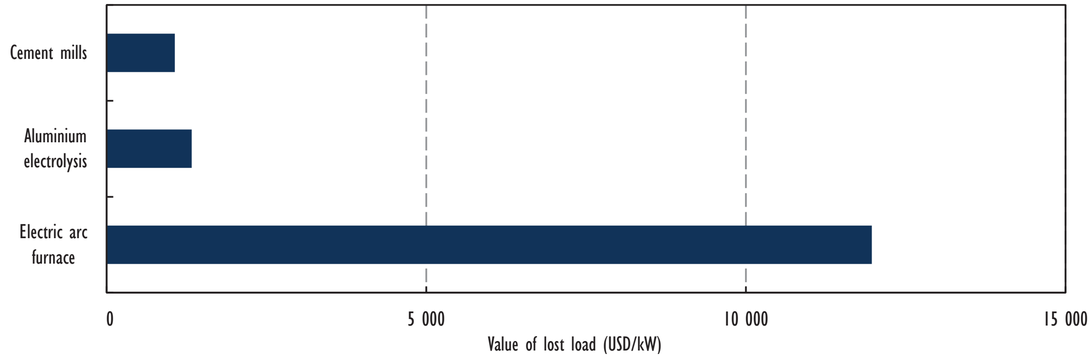
Operating costs

Operating costs of DSI depend critically on whether load is shifted or shed.

The first case is relevant for most commercial and domestic uses. In the latter case, the cost equals the value of lost load, which represents the opportunity cost of the shed megawatt hour or, in other terms, the value at which the end-customer is willing to lose supply.

As mentioned previously, these costs are most relevant for industrial processes running at very high utilisation rates (e.g. 95% on an annual basis for aluminium smelters or 80% for cement mills) and largely constant power consumption (EWI, 2009). The value of lost load increases from cement mills, to aluminium and steel production (Figure 7.22).

Figure 7.22 • Value of lost load for selected industrial load-shedding processes



Source: EWI, 2009.

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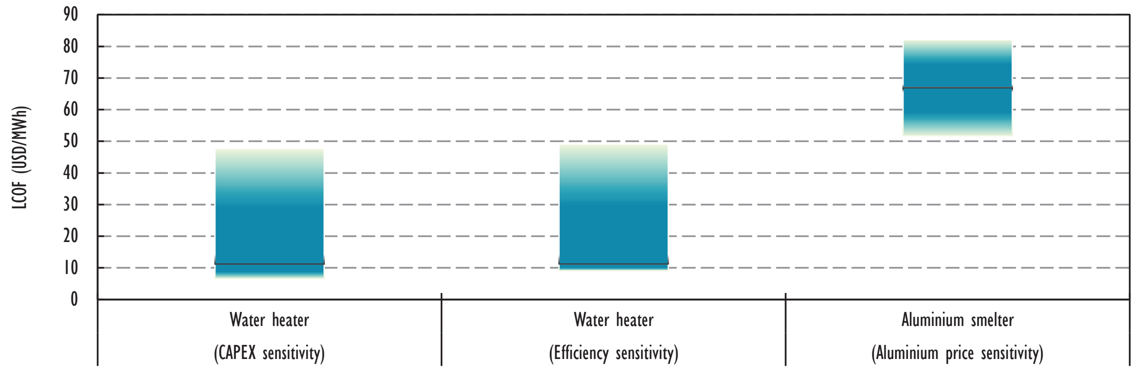
Key point • *Value of lost load for cement mills and aluminium electrolysis tend to be lower than those for electric arc furnaces.*

Assuming a cost premium of USD 50/kW for an electric water heater for household applications, the resulting cost for load shifting can be as low as USD 6.7/MWh (5% energy losses in the base case). Using more pessimistic assumptions in terms of capital expenditure (up to USD 500/kW) or hot water storage losses (up to 50%) the resulting cost of flexibility increases to USD 50/MWh (Figure 7.23).

Figure 7.23 • LCOF for selected DSI applications



Notes: CAPEX = capital expenditure. See Annex A for details on methodology.

Key point • *Wide cost ranges for DSI reflect uncertainty about additional cost of smart appliances and infrastructure roll-out.*

An interesting example of industrial DSI application is load shedding in an aluminium smelter. As mentioned, in this case the capital cost of the DSI control equipment is negligible in comparison with variable costs, and the flexibility cost can be represented by the value of lost load. This is essentially evaluated on the basis of the market price of the aluminium that would not be produced, and it ranges between USD 50/MWh and USD 80/MWh according to the market value of aluminium and raw materials needed for aluminium production such as bauxite (London Economics, 2013).

Cost-benefit analysis

Both economic modelling studies (IMRES and Pöyry's BID3 model) assessed the cost-benefit ratio of DSI under different scenarios. Due to the plethora of different services DSI enables (power quality, bridging power and energy management), comprehensive modelling of potential benefits is challenging and results should be seen as indicative.

In the IMRES model, demand-side response has been implemented as the ability to shift part of the demand at a given hour throughout the following six hours. According to the different DSI deployment levels implemented (low, medium and high), this capability will be able to shift up to 2 GW, 4 GW and 8 GW respectively.

Table 7.16 • DSI assumptions in IMRES modelling

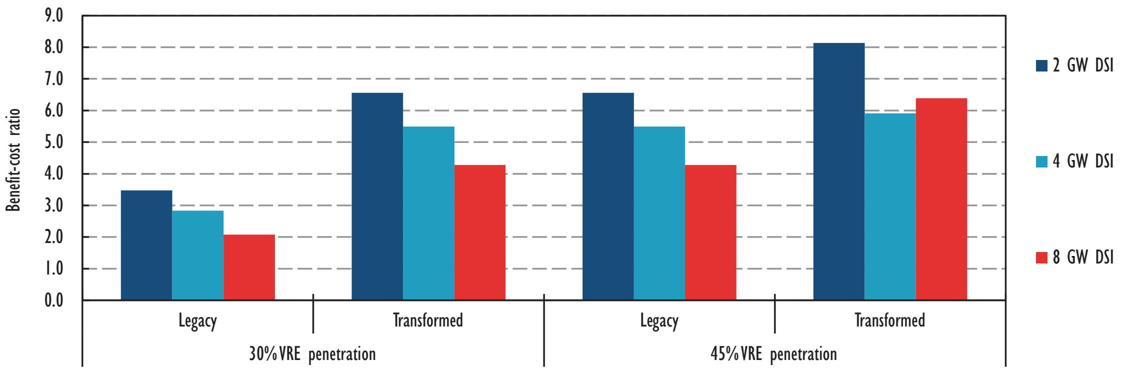
Devices	Efficiency	Response duration	Lifetime	Capital costs	O&M costs
	%	h	yr	USD million/MW	USD/MW/yr
6 h load shift	100	6	30	0.5	403

Key point • DSI was represented as a six hour load shift process in the IMRES modelling.

The possible benefit of DSI in the IMRES modelling included improved utilisation of generation assets, reduced curtailment of VRE and fewer start-ups in the baseline plant case, as well as providing reserves.

DSI always presents a positive cost-benefit ratio above 2, and reaches its maximum in the Transformed scenario. In addition, the combination of DSR with flexible generation allowed significant synergies over the long-term timescale (Transformed system). Out of all options studied in the test system, DSI showed the most favourable cost-benefit ratio.

Figure 7.24 • Cost-benefit of adding DSI to the IMRES test system



Key point • Out of all options studied in the test system, DSI showed the most favourable cost-benefit ratio.

The analysis of the North West Europe case study region yields comparable results. Considering that 8% of demand is flexible (maximum shift of demand is 24 hours), the avoidance of 15 GW of investment in new plant in France, Great Britain and Germany (around 5 GW each) led to annual benefits of USD 1.2 billon. The estimated benefit/cost ratio reaches 2.2, in line with the results obtained in the comparable IMRES simulation (8 GW DSI, 30% VRE share). In addition, the North West Europe case study underlined a positive synergy between DSI and increased interconnection, as transmission investment allows DSI deeper system access (see Chapter 8).

Policy and market considerations

While there is some degree of uncertainty around the ultimate capabilities of DSI, it is more than likely that benefits will, by far, outweigh initial costs.

DSI may be the flexibility option where clear policy action could produce the largest benefit. Policy intervention may indeed help to overcome initial barriers, such as the cost of putting infrastructure in place for smart DSI applications beyond large-scale consumers. In addition, clear policy measures may actually trigger investment in demand monitoring and control devices that would otherwise remain dormant for a long period. This would facilitate economies of scale and cost reduction.

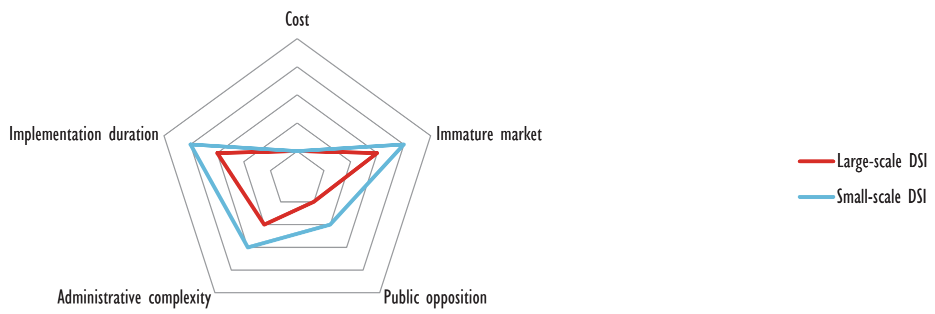
A very important initial step is to make sure that DSI can contribute to all aspects of power system services (to the degree that it meets technical requirements). In many jurisdictions, this will mean changes in the way system services markets are organised.

Above and beyond putting in place the enabling infrastructure and regulatory framework, more analysis is needed to identify which pricing schemes or mechanisms are most effective at enticing consumers to exhibit a more dynamic demand profile – or to embrace technological innovations that would enable such change. To this end, power market design should provide pricing signals for services that may be provided by DSI, both in energy and system service markets. In addition, there is a need to develop innovative business models that allow for the aggregation of a large number of dispersed consumers.

The acceptance of DSI and its secure operation also depend on ensuring information technology system security and protecting privacy for consumers.

Figure 7.25 displays the major challenges for DSI, both large- and small-scale. While DSI represents a low-cost flexibility option in terms of capital and operational costs when compared to other flexibility sources, the market for such applications is still immature. Limits in market design (see Chapter 6) and lack of remuneration mechanisms currently inhibit investment in relevant enabling infrastructure. This situation is also in the way of developing a business case for aggregators, which are likely to be needed to bundle the DSI capability of many consumers and bring these to market. Given that data security concerns are addressed and service quality is not affected, DSI may face fewer public acceptance barriers than other flexibility options, such as generation, transmission or large-scale storage. However, putting in place appropriate and harmonised standards may be an issue, in particular for small-scale applications. In addition, unclear regulatory frameworks concerning the information exchange between customer, distributor (that may be the owner of the meter) and electricity supplier may represent an important barrier to DSI deployment. Because retrofits are usually not cost-effective, DSI potential at a smaller scale will take time to be absorbed into the market. The pace of replacement investments (new water heaters, dishwashers etc.) largely determines the duration of implementation, which thus may be quite long.

Figure 7.25 • Major challenges to deployment of DSI



Key point • The immature market for small-scale applications and the possible long duration for deploying DSR-ready infrastructure are the primary barriers for DSI.

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8 • System transformation and market design

HIGHLIGHTS

- High shares of variable renewable generation are likely to be necessary in any decarbonised electricity system. In turn, cost-effective integration of high shares of variable renewable energy (VRE) requires transformation of the power sector and the broader energy system.
- The challenges and opportunities for such a transformation depend on the system context: electricity systems with high rates of electricity demand growth or facing a short-term need to invest in energy infrastructure (dynamic systems) face a different situation than systems with a stable demand and/or little need for infrastructure investment (stable systems).
- Adapting operational procedures and deploying VRE in a system-friendly way are important steps on the way to transformation, independent of context.
- Stable systems can reach higher VRE shares simply by implementing operational changes and investing in retrofits. However, adding VRE is likely to affect incumbents by reducing their market share and putting the sector under economic stress. This situation is a result of supply/demand fundamentals and not specific to VRE. Adding any large quantity of generation in an already adequately served market is bound to have similar effects.
- Dynamic systems have the opportunity to invest in more flexible assets as part of overall expansion or replacement plans, so creating an opportunity to "leap-frog" directly to a better-adapted system. The optimum way of doing this is less well understood than how to change operational practices.
- A mix of investment options to improve flexibility is required for technical reasons, and a number of system-specific circumstances will influence which options are chosen.
- Market design needs to translate the new technical operating paradigm into appropriate short-term price signals, in particular during conditions of scarcity. More specifically, this requires establishing better price signals to remunerate the provision of flexibility. If appropriate short-term price signals have been implemented, but robust evidence suggests that investment patterns are falling short of requirements, longer-term price signals may be required to ensure timely and sufficient investments.
- None of the investigated market designs has exhausted its potential to optimise short-term price signals. Policies and regulation should target improved short-term price signals before considering long-term mechanisms.

The previous chapters have discussed the challenges of integrating VRE into power systems and the options that exist to overcome these to achieve successful integration. This chapter joins these findings together and discusses the timing and possible combination of the various options. This process can be understood as part of a wider transformation of the power system on the way to decarbonisation. While recognising that VRE is one part of a more comprehensive approach, the discussion assumes that VRE will play a critical role in decarbonising the energy system and that integration of large shares is therefore a priority.

The objective is not to prescribe a particular choice of flexibility options and when they should be deployed as a function of VRE penetration. System contexts show too much diversity to derive such general rules. In addition, innovations and changes in commodity prices are likely to change the relative cost-effectiveness of different measures. Therefore it is neither necessary nor desirable to identify “the right mix” decades in advance. However, a number of considerations can be helpful to identify no-regret options and set robust priorities.

The chapter has four main sections. The first section discusses the implications of the fundamental context of the power system for VRE integration strategies, highlighting differences and common aspects. The second section discusses how to approach investment in flexibility options to transform the power system, including a comparison of their cost-benefit profile. The third section highlights the economic importance of transforming the power system in an integrated fashion, using total system costs calculated on the basis of modelling results. The last section investigates the extent to which existing market frameworks are suitable to provide investment signals to facilitate such a transformation.

VRE growth and system evolution

At several points in the previous chapters, it was highlighted that systems with high rates of electricity demand growth or upcoming infrastructure retirement are in a different situation vis-à-vis VRE integration, compared to systems with stagnating demand and no infrastructure retirement. Both contexts bring different challenges and opportunities for VRE integration. Understanding such differences can be helpful when applying integration experiences from one type of system to another. In particular, the current pioneers of VRE integration are power systems that fall under the stable category, while significant growth of VRE is projected in dynamic systems.

Opportunities and challenges for stable systems

Adding VRE to a stable power system will create a surplus of productive capacity, which will have detrimental effects on the value of existing generators. In the short term, however, while system adequacy is increased by the addition of VRE, the loss of VRE production does not necessarily put system security at risk. The system has adequate resources to deliver security of supply whether or not VRE resources are available and operating.

In most stable power systems, existing dispatchable power plants and grid infrastructure provide enough flexibility to cope efficiently with the inherent variability of demand and the perturbations normally expected in such systems. Investment costs for these assets are already sunk. Therefore there will be value in exploiting opportunities to increase the flexibility of existing assets and to optimise the operation of the overall system around the mix of growing VRE resources and legacy assets. Many types of asset that currently tend to be limited in their operational flexibility (coal, lignite, nuclear and even many gas-fired plants) can be retrofitted to increase their flexibility, although the economics of potential improvements will vary widely. In stable systems that have seen rapid growth in VRE in recent years it has been possible to integrate the new resources into the system with changes to operational practices and some adaptation of the legacy asset base. However this is a transitional stage of development – it is becoming apparent that the financial impact of a growing structural surplus and the increasing variability of the production profile will eventually dictate more fundamental adjustments to the legacy system.

A critical challenge in this situation is the economic displacement of some portion of incumbent generation. As explained in Chapter 2, adding VRE dynamically to stable power systems is bound to lead to a general oversupply of productive capacity, even with a proper factoring of the firm capacity credit of various VRE resources. If markets respond as expected in the face of surplus supply, wholesale prices can be expected to fall (the so-called “merit-order effect”). Marginal plants are pushed out of the market (the utilisation effect). The combined effects lead to the economic stranding of some portion of incumbent assets. As can be seen in Figure 8.1 (left), the overall size of the thermal generating fleet required in a transformed system is likely to be smaller than the size of the thermal fleet in the legacy system.

Box 8.1 • Do wind power and solar photovoltaic (solar PV) crowd out mid-merit generation?

The interactions between deployment of wind power, solar PV, mid-merit and peaking generation show important differences depending on the timescale of the analysis. Timescale in this regard does not refer so much to a specific number of years following the deployment of VRE, but rather the degree to which the power plant mix has adapted to the presence of large shares of VRE.

In the short term, i.e. in the absence of changes in the non-VRE power plant mix, wind power and solar PV tend to substitute mid-merit and peaking generation. Because investment costs are sunk, the only benefits that additional VRE generation can bring are operational. As such, benefits are maximised if generation from the most costly fuels is displaced. This tends to be generation from peaking and mid-merit power plants. In Europe, the combination of currently sluggish power demand, relatively low coal and high gas prices, negligible CO_2 prices, as well as the dynamic increase in VRE, all align to push gas generation (which is mid-merit generation in Europe) out of the market.

However, VRE and mid-merit generation substitute each other only in the absence of more structural adaptations of the power plant mix. If the generation mix adapts to the presence of VRE, baseload generation tends to be displaced to a larger extent than other generation. As such, the market for mid-merit generation is re-established in the long term. The IMRES (Investment Model for Renewable Electricity Systems) analysis clearly highlights this.

The short-term perspective is modelled in the Legacy scenario, where the installed generation mix is optimised in the absence of VRE and not allowed to adapt when they are deployed; only operations can change. The long-term perspective is reflected in the Transformed scenario, where the installed power plant mix is optimised in the presence of VRE. The result is striking: in the Legacy scenario, the full-load hours of mid-merit generation are significantly reduced and also baseload generation sees a reduction in full-load hours. However, in the Transformed case, the generation mix shows a pronounced shift towards mid-merit and peaking generation. The capacity factors of all power plants largely recover (Figure 8.1), as can be seen in the difference between the solid (Legacy) and dotted (Transformed) lines in the graph.

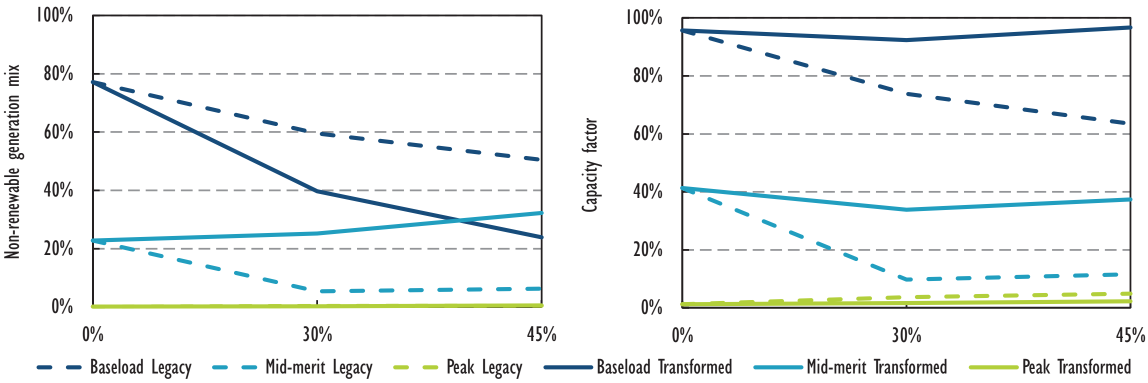
From a total system short-term cost perspective, power plants with higher fuel costs will tend to be displaced; in some markets this may correspond to more flexible resources in the system. In such a circumstance, it may be seen as sensible to mothball under-utilised mid-merit generation as a transitional step. However it is critical for achieving an optimal total system cost that the shift from marginal baseload plants to more valuable mid-merit plants takes place in a timely fashion as the share of VRE grows on the system.

This situation can be problematic; in the short term VRE may (depending on the relative cost of the relevant fossil fuels in the local market) tend to displace particularly those generators that will best complement the growing share of VRE on the system.[1] As can be seen in Figure 8.1 (left), the optimal balance between baseload plants and mid-merit and peaking plants in a transformed system is materially different to that found in most legacy systems. Figure 8.1 (right) illustrates the more sustainable operating profile of thermal plants when the size and composition of the thermal fleet is re-balanced to reflect the growing shares of VRE. This will have important implications for what constitutes the lowest overall system cost solution, as market regulators and policy makers approach the question of which legacy resources should be deemed to be surplus to requirements with the growth of VRE.

1. This is currently the situation in Europe where natural gas is expensive relative to coal and prices for greenhouse gas emissions allowances are not high enough to overcome the difference, leading to relatively inflexible coal generation displacing more flexible gas plants. In North America, where plentiful gas supplies have driven the price of gas-fired generation below the price of coal-fired generation in many instances, this is currently less of a concern.

As far as grid infrastructure is concerned, optimising operations will also provide additional room for adding VRE capacity (see Chapter 6). This can be particularly important, because building and licensing additional grid infrastructure in stable power systems may require a significant amount of time. Replacing grid infrastructure before the end of its technical lifetime can be costly, in particular at the distribution level. This may become necessary when large amounts of VRE are added at the distribution level.

Figure 8.1 • Non-VRE generation mix and capacity factors under different IMRES scenarios



Note: baseload corresponds to nuclear and coal generation; mid-merit means combined-cycle gas turbine (CCGT) plants; and peak plants are open-cycle gas turbine (OCGT) generators.

Source: unless otherwise indicated, all tables and figures in this chapter derive from International Energy Agency (IEA) data and analysis.

Key point • System adaptation can increase the market share of mid-merit generation and helps to recover the capacity factors of dispatchable generation.

Opportunities and challenges for dynamic systems

In dynamic power systems, adding VRE will only concern the market share of incumbents if energy additions are larger than load growth and retirements. In any case they may increase net load variability and uncertainty and may thus also affect operations of the existing generation fleet. Consequently, incumbent generators will be put under less and possibly no economic stress. In turn, maintaining – or improving – generation adequacy is a priority in dynamic systems. This will raise the relevance of VRE contribution to generation adequacy. Therefore, VRE integration will not only affect current operations, but will also make investment in options to increase flexibility relevant at the onset of deployment.

This clearly opens opportunities: new grids can be planned and built with VRE in mind, avoiding the need for later retrofits. The dispatchable power plant mix can be planned and built to complement VRE cost-effectively. Demand-side response capabilities can be streamlined into the system, where load increases dynamically. However, this requires planning tools that take into account the contribution of VRE over time.

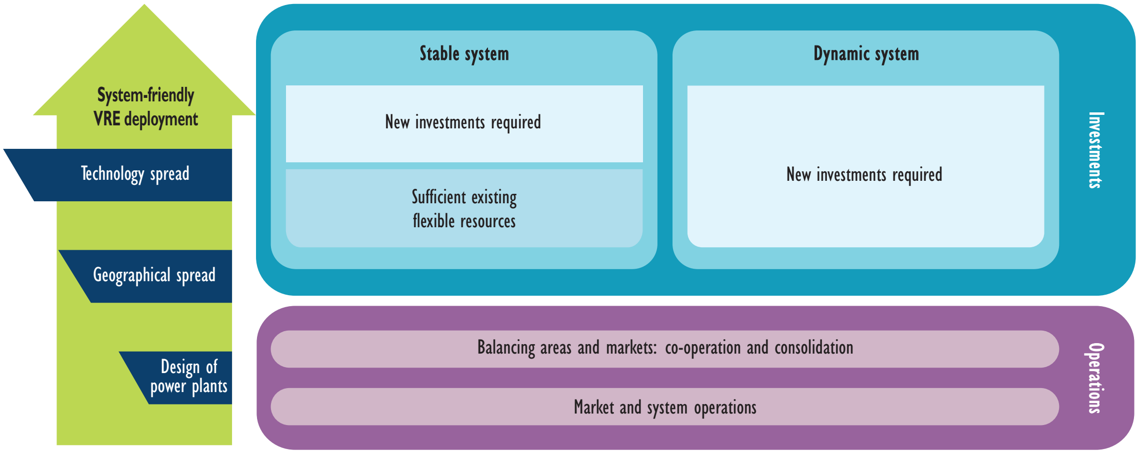
Dynamic systems can leap-frog stable ones to become better-adapted systems. However, they are unlikely to enjoy the contribution to flexibility from existing assets to the same degree. As a result, such systems need to find answers to integration questions, which are not on the agenda in stable systems to the same degree. More research is needed on how to reap the full benefit of this context for VRE integration.

Common issues: optimised operations and system-friendly VRE deployment

Optimising market and system operations, in particular co-ordination between neighbouring balancing areas (as explained extensively in Chapter 6), forms the foundation for the cost-effective integration of VRE, irrespective of system circumstances. If operations are not optimised, VRE integration is rendered technically more difficult and economically more challenging. Adjusting operations is a no-regret option; it is cost-effective irrespective of high shares of VRE. The main barriers standing in the way of improved operations are often not technical. Challenges often arise when long-standing operating traditions are questioned once VRE deployment picks up. However, a number of system operators have gathered considerable experience with managing higher penetrations of VRE and operational knowledge has become well-established in recent years. In stable power systems, adapting operations will defer the need for new investment. In dynamic systems, optimised operations will keep the need for flexibility investments to a minimum.

System-friendly VRE deployment is relevant to reducing flexibility requirements, both operationally and in terms of investment. System-friendly deployment practices have three main targets. They aim: 1) to control the location and timing of VRE additions, 2) to ensure that VRE can provide a sufficient number of critical system services, and 3) to incentivise power plant designs that contribute to reduce overall system costs rather the generation costs alone (see Chapter 5 for details). Such requirements need to be balanced with facilitating the growth of a potentially immature industry in locations where deployment is just starting. In addition, increasing the geographic spread and technological diversity may add to generation costs, and may therefore be important in particular at medium and higher shares of deployment (Figure 8.2).

Figure 8.2 • Priorities for VRE integration in stable and dynamic systems



Key point • Optimised operations and system-friendly VRE deployment are key for stable and for dynamic power systems. Investment is a priority at earlier stages of VRE deployment in dynamic systems.

Strategies for flexibility investments

The need for a suite of solutions

All flexibility options contribute to the integration of VRE in some way or another. In particular, each of the four resources can contribute to balancing supply and demand more flexibly. However, Chapter 7 has highlighted that flexible resources also show differences in which VRE properties they help to address. Flexibility comes in different forms.

While the different resources can substitute for each other under many circumstances, certain integration issues may only be addressed by some of them, for example:

- transmission infrastructure is the only option able to connect distant VRE resources
- only distributed options can deal with some of the impacts related to modularity
- flexible generation can address scarcity, but it cannot mitigate surplus once net load becomes negative
- flexibility from VRE curtailment may mitigate surplus situations, but cannot address scarcity.

While the above list provides only a few examples, they make clear that a suite of flexibility options is needed for successful VRE integration (Table 8.1). This leads to the question of how to compose an optimal portfolio of flexibility options.

Table 8.1 • Contribution of different flexibility options to VRE integration

	Uncertainty	*Variability*			*Location constraints*	*Modularity*	*Non-synchronous*
		Ramps	*Abundance*	*Scarcity*			
Transmission	✓	✓✓	✓	✓	✓✓	××	✓
Distribution	O	✓	✓	O	××	✓✓	×
Interconnection	✓	✓✓	✓✓	✓	O	××	✓✓
Dispatchable generation	✓✓	✓✓	✓✓ ××	✓✓	×	O	✓
Distributed storage	✓	✓	✓	✓	×	✓✓	O
Grid-level storage	✓	✓✓	✓✓	✓✓	×	××	✓
DSI small-scale (distributed)	✓	✓✓	✓✓	O	×	✓	✓
DSI large-scale	✓	✓	✓✓	O	×	××	✓

Note: ✓✓: very suitable; ✓: suitable; O: neutral; ×: less suitable; ××: unsuitable.

Key point • A suite of flexibility options is needed to successfully integrate VRE generation.

Large-scale integration of VRE is a dynamically evolving field. The innovations that will be most relevant for VRE integration a few decades from now may well be largely obscure today. Accordingly, it is difficult to predict what the make-up of the optimal portfolio of flexibility options will be several decades from now. For example, the evolution of costs is uncertain for many storage technologies and the true potential of DSI is still to be determined under real-life conditions. Also, a sudden shift in commodity prices, such as the recent emergence of cheap unconventional gas in the United States, may reshuffle the cost-effectiveness of different flexibility options. Policies for increasing power system flexibility should always keep the door open to disruptive innovations.

Based on the analysis of different flexibility options, the following conclusions can be drawn (Figure 8.5). Grid infrastructure takes a unique position within the range of options, because it is the only option that can deal with geographic mismatches between generation and consumption, which are likely to occur at high shares of VRE. However, and most importantly, aggregating VRE generation over large areas can also bring considerable benefits by mitigating temporal mismatches, smoothing out weather-related generation profiles, particularly from wind power. As such, grid infrastructure is highly likely to be part of any cost-effective strategy from the onset. However, not all grid investments are cost-effective and they should always be balanced with alternative options, including moderate levels of VRE curtailment.

As regards other options, flexible generation is a cost-effective, mature and readily available option to balance VRE variability and uncertainty. However, plants differ regarding both their technical and economic flexibility.

Reservoir hydro generation can be in a particularly favourable position to complement VRE. If environmental regulations allow for flexible short-term operations, hydro plants can provide flexibility without significant cost penalties. Flexible operations are technically feasible and add comparably little wear and tear to the plant; most importantly, the capacity factor of reservoir hydro plants often does not suffer from VRE integration, because it tends to be constrained by water availability anyway.[2] At the same time, the levellised cost of energy (LCOE) of reservoir hydro generation can be very low.

Thermal generation technologies, including bioenergy, geothermal energy and Concentrating Solar Power (CSP), are in a somewhat different position. Technologies show large differences in technical flexibility, from very fast-starting and steep-ramping reciprocating engines and aero-derivative gas turbines, to inflexible baseload plants. Experience has demonstrated that technical flexibility can be enabled in a surprisingly broad range of circumstances, as illustrated by load-following operation of nuclear power plants in Germany and France (NEA, 2012) and also successful retrofits of coal plants in North America (NREL, 2013). However, as the integration of high shares of VRE goes along with reduced utilisation of the dispatchable plant stack (utilisation effect), technologies need to be cost-effective when operating at capacity factors typical of peaking and mid-merit power plants. This does not favour capital-intensive technologies such as nuclear and fossil generation with Carbon Capture and Storage (CCS). Even if technically flexible to a certain degree,[3] from an economic point of view capital-intensive baseload technologies consume flexibility rather than providing it. These technologies are similar to VRE themselves, in the sense that they have low short-run cost, and it is thus not economically attractive to significantly constrain their capacity factors by reducing their output. Given current technology options, a well-adapted thermal plant mix will feature technically and economically flexible power plants such as flexible CCGTs, banks of reciprocating engines and flexible OCGTs. CSP may play a major role in countries where resources are favourable, in particular thanks to its inherent storage capabilities (IEA, 2011a). If baseload technologies such as nuclear or CCS are integrated with VRE, additional sources of flexibility need to be found (see Box 8.2).

Box 8.2 • Who benefits from flexibility investments?

Flexible resources increase the capacity of a power system to integrate large shares of variable renewables. However, they affect the entire power system, including conventional generators. Flexible resources will facilitate both variable and rigid generation technologies. Historically, the development of pumped hydroelectric storage (PHS) capacity has shown a strong correlation with the increase in nuclear capacity (Figure 8.3). In addition, DSI programmes linking the heat and electricity sectors are common in systems with a high demand for flexibility. In France and the United Kingdom, a considerable share of electricity consumption during the night comes from electric storage and water heaters, using a timer to increase baseload at night and providing heating during the day (Figure 8.4).

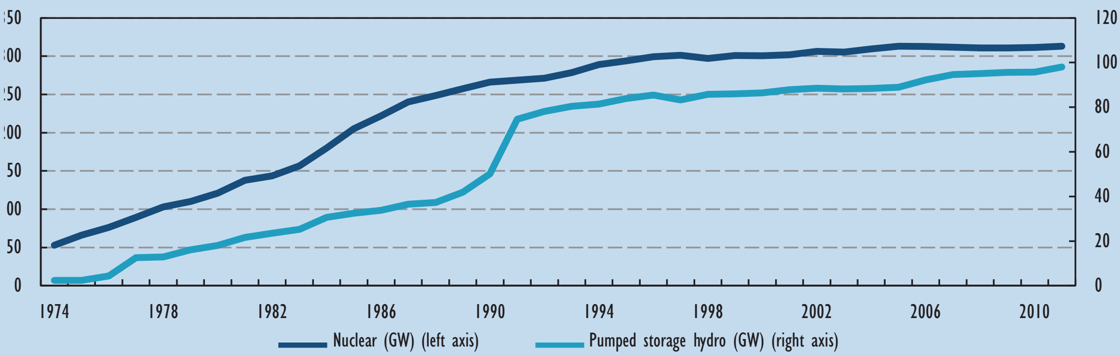
2. The economic design of reservoir hydro power plants takes into account seasonal constraints on water availability. As a result of these constraints, reservoir hydro plants often have capacity factors comparable to mid-merit power plants. The VRE-induced shift in the optimal plant mix towards mid-merit generation thus favours reservoir hydro. In short: reservoir hydro power and VRE sources are often highly complementary.

3. The technical flexibility of nuclear power plants depends on a number of factors. Flexibility tends to deteriorate when approaching the end of a plant's fuel cycle. Starting and stopping nuclear power stations several times a week raises a number of technical and safety concerns (NEA, 2012).

Similarly, the expansion of nuclear capacity in Sweden in the 1970s and -80s was accompanied by an increase in flexible reservoir hydro capacity of about 2 500 MW between 1978 and 1988. In this time, the five-year average capacity factor of the Swedish hydropower fleet decreased about 10 percentage points, from about 50% to 40% (adjusted for precipitation and reservoir inflow), reflecting the different operating regime imposed on the plants to integrate new nuclear generation.

In general, maximising the utilisation of other system assets is a key benefit of flexibility options, and highly desirable. However, it is important to take a system view when increasing flexibility. For example, in the absence of stringent CO_2 emissions policies, increased system flexibility may lead to undesirable increases in the utilisation of inflexible, CO_2-intensive power plants.

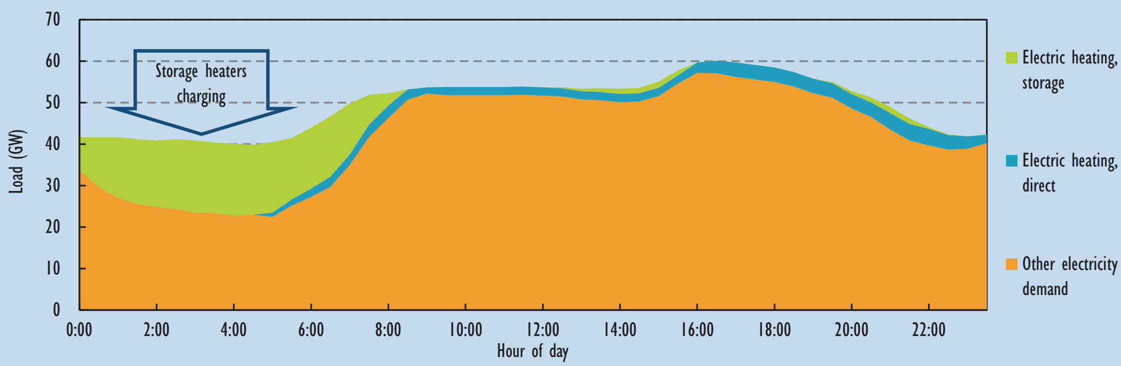
Figure 8.3 • Evolution of nuclear and pumped hydro storage capacity in IEA member countries



Note: GW = gigawatt.

Key point • Historically, investments in inflexible nuclear capacity have gone hand in hand with increased storage investments.

Figure 8.4 • Electric heating in Great Britain



Source: Glen Dimplex, 2013.

Key point • Existing power demand structure may include demand-side management strategies to integrate inflexible baseload technologies.

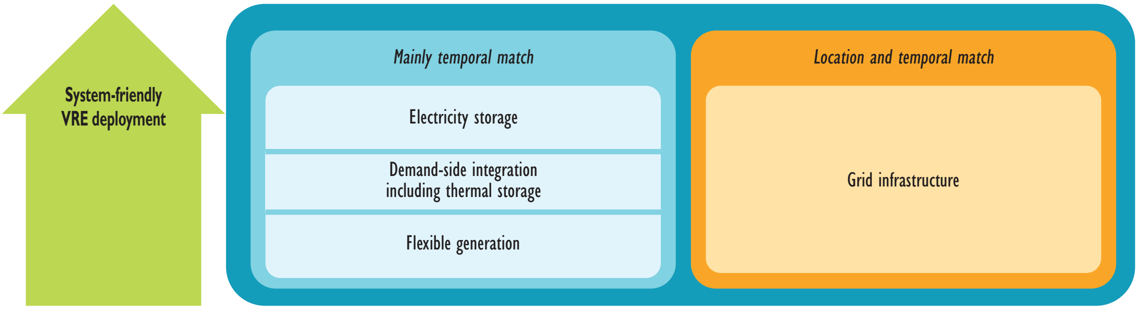
Dispatchable generation is critical to cover sustained periods of low VRE output. Technologies can be linked with energy storage to facilitate this role. At very high shares of VRE, large hydro reservoirs may be filled using energy from structural VRE surplus and enter into generation when there is a structural shortfall. A different approach suggests using excess VRE generation to produce hydrogen or methane for later combustion. However, among other challenges, such solutions suffer from very low efficiencies and currently very high costs (EASE/EERA, 2013).

The coupling of electricity and heat generation, via co-generation and thermal energy storage, can make a critical contribution for dealing with both structural VRE surpluses and shortfalls. During surplus situations, electricity can also be used for heat generation. When thermal storage is installed, surplus electricity can be used to cover heat demand several hours later. In addition, such a configuration allows co-generation plants to cover situations of electricity scarcity. Where there is a significant demand for cooling (air conditioning) the same principle can be applied using cold storage.

DSI options hold the promise of enabling VRE integration very cost-effectively, as highlighted by modelling results. However, DSI may take time to implement, because it is generally not cost-effective to retrofit appliances to make their consumption more flexible. In addition, there remains a degree of uncertainty regarding the overall size of the resource. In any case, ensuring that DSI finds a level playing field – in particular with regard to allowing aggregators to participate actively in energy markets – is a no-regret option, especially as DSI has a very favourable net benefit even in the absence of VRE integration. Distributed thermal storage and district heating applications are particularly attractive options to make electricity demand more flexible.

Electricity storage, while technically a highly effective option, suffers from comparably high costs in many circumstances. While some exceptions do exist (such as enabling pump-back operation in existing reservoir hydro plants), investment costs remain high. As shown in Chapter 7, storage has a levellised cost of flexibility (LCOF) that is about a factor ten higher than other options. Low utilisation rates particularly reduce the cost-effectiveness of storage, similar to generation technologies with high investment costs. However, given the versatility of electricity storage in terms of deployment location and the range of services it can provide, certain applications can prove cost-effective, if a number of revenue streams are taken into account. For example, storage may contribute to deferral of grid investments, providing operating reserves and improving local power quality.

Figure 8.5 • Possible prioritisation of flexibility options



Key point • Grid investments can be pursued in concert with a sequence of other integration options. However, there will be a number of additional factors that may influence the relative priority in a given context.

Additional factors influencing the choice of flexibility options

In general, a number of different factors will influence the choice of flexibility options.

Geographic and other constraints

As a result of geographic constraints, not all systems are in the same position to make use of a particular resource. For example, in **island systems**, interconnection with other power systems will not be possible to the same extent as in continental systems. For example, Denmark can rely much more on using interconnections than can Ireland. Germany has much more potential to expand interconnection than Japan.

Very **densely populated** countries, such as Japan, will experience greater difficulty in using overhead transmission than regions where there is sufficient land available, e.g. in Texas in the United States (Electric Reliability Council of Texas [ERCOT] case study region).

Only countries that have the **geographic potential for reservoir hydro** will be able to benefit from this resource (e.g. Brazil, Norway). Adding pump-back features to existing hydro plants will also make storage available more cheaply. Building other PHS or compressed air energy storage (CAES) hinges on geographic circumstances.[4]

Fuel availability and price may also have an impact on the choice of flexibility options. Where gas prices are very cheap, flexible conventional generation will be preferred compared to places where fossil fuel prices are higher. For example, cheap unconventional gas in the United States can lead to increased flexibility in the fossil generation fleet, if inflexible coal plants are displaced from the market.

Public acceptance

In most Organisation for Economic Co-operation and Development (OECD) member countries, new overhead **transmission** lines generally face a significant amount of public opposition. However, in countries where reliable electricity provision is not a given, there may even be public support for new lines. For example in India, frequent power outages generally increase the acceptance of new transmission lines, as these are seen as a way to increase reliability.

Also, countries where electricity supply is subject to frequent interruptions may be in a much better position to create DSI programmes, as consumers may have a direct reliability benefit.

VRE deployment patterns

The prevalent technology portfolio and typical plant scale may have important consequences for the type of flexibility that is required for integration. For example, where there is a **large number of small-scale** VRE plants (e.g. roof-top solar PV), distributed flexibility options, such as small-scale DSI, storage and distribution grid upgrades, will be more important.

Solar PV generation is much more concentrated during a few hours of the day. Consequently, flexibility options for matching demand and supply across time will be more significant than for wind power. This is not to say that grid infrastructure is not important for solar PV integration. However, even where there is a strong grid, solar PV will still be concentrated in time, and therefore greater attention may be placed on flexibility options that address daily imbalances, such as storage (Schaber et al., 2012).

Additional policy objectives and co-benefits

Developing certain flexibility options may serve objectives above and beyond VRE integration. Such cases are usually highly favourable for cost-effective integration, as co-benefits will help to recover investment costs. For example, expansion of reservoir hydro generation and PHS has often been helped by the need to create reservoirs for drinking water security, increase water quality and manage water use (IEA, 2012).

The desire to grow a local industry can be an important driver for supporting a particular policy option. In countries that see a competitive advantage in developing a certain option, it may be pursued as a way to develop that branch of the industry. For example, India may be in a good position to develop smart-grid technology, given its strong information technology industry, combined with potentially high public acceptance of DSI. Japan may have an incentive to prioritise battery storage technologies, given its existing industry and system circumstances (isolated system, high population density).

Some flexibility options may bring benefits that are quite intangible. For example, the benefits that a domestic consumer sees in becoming largely self-sufficient in electricity with storage or a DSI system has a value that is challenging to measure accurately.

4. PHS can be built under a variety of circumstances, but there will always be a need for two reservoirs with a sufficient height-difference between them.

Cost-benefit ratio of flexibility options

As introduced in Chapter 7, two modelling approaches were used to assess the benefit to cost ratio of different flexibility options. One analysis focused on the North West Europe case study, while the second analysis (IMRES) focused on a test system; both approaches assess the cost-benefit profile of different flexibility options.

North West Europe case study

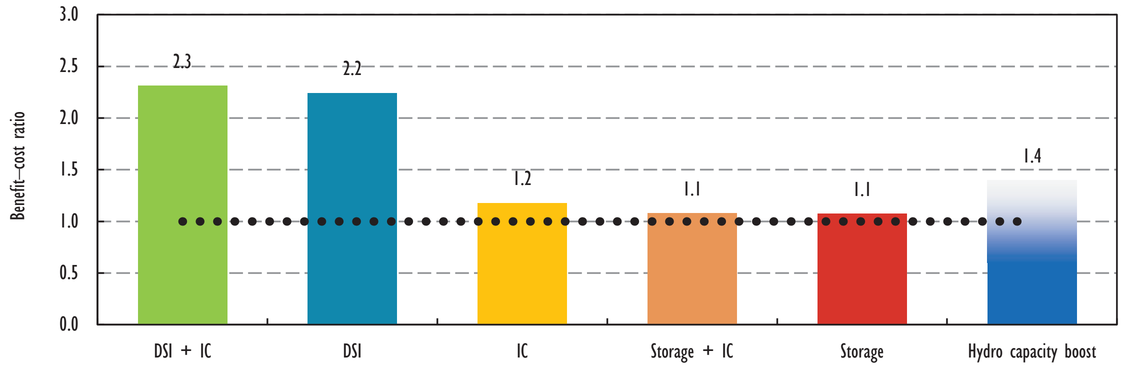
For the North West Europe cast study, the cost-benefit of adding different flexibility options to the power system was compared to a baseline scenario. This was based on the Pöyry central scenario for 2030, assuming an increased level of wind power and solar PV generation across case study countries, leading to a total share of 27% VRE in power generation. The approach to calculating the benefit to cost ratio for each option is explained in the previous chapter.

A number of observations can be drawn from comparing the results for the different flexibility options (Figure 8.6). DSI shows a high benefit to cost ratio, thanks to relatively low costs compared to alternatives. Combining interconnection with DSI shows robust benefit to cost ratios, i.e. the options are complementary and do not work against each other. Interconnection alone does not reach the same level of benefit to cost. However, it is important to note that the base case already includes significant levels of interconnection, reflecting the crucial value of this integration option.

Storage shows a slightly positive benefit to cost profile; however, important potential benefits of storage are not reflected in the analysis. Firstly, forecast errors are not taken into account. Including forecast errors in simulations may increase the value of storage considerably (e.g. GE Energy, 2010). In addition, the model does not include a detailed representation of the power grid within individual countries and does not include operating reserves. Both factors will also lead to an underestimation of the value of storage.

The cost-effectiveness of retrofitting existing hydro power plants to increase installed capacity while maintaining current reservoir sizes depends on the cost associated with the upgrade (assumed range is USD 750 per kilowatt to USD 1 300 per kilowatt) and the potential strengthening required by related interconnections.[5]

Figure 8.6 • Summary of benefit to cost ratios for the North West Europe case study



Note: DSI = demand-side integration; IC = interconnection.

Key point • DSI has a high benefit to cost ratio, and interconnection shows positive synergies with other options.

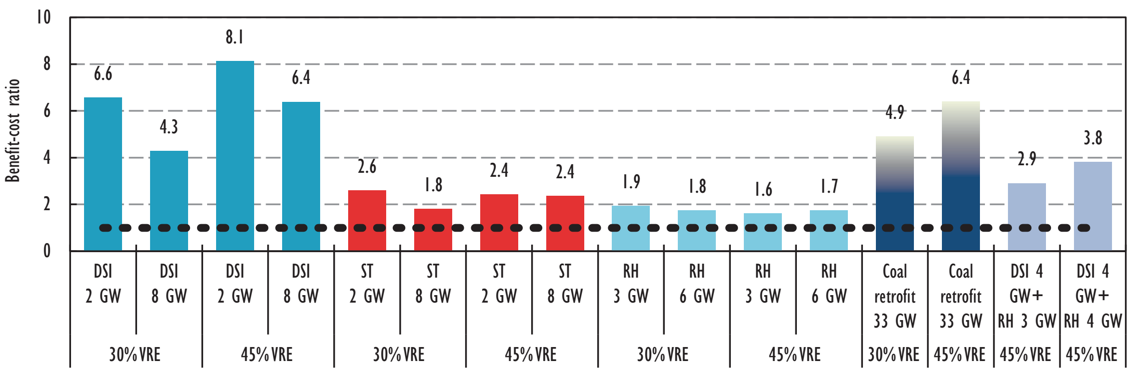
5. The impact of a 7 GW increase in hydro capacity (mainly assumed in Norway, Sweden and France) was analysed in combination with an additional 8.6 GW interconnection between Norway, Sweden and other European countries. Resulting benefit to cost ratios ranged between 0.6 (higher retrofit cost and additional interconnection) and 1.4 (lower retrofit costs and no additional interconnections).

IMRES test system

The modelling in the IMRES test system shows important differences compared to the North West Europe case study. The system has a peak demand of 75 GW, which is over four times smaller than the peak demand in the North West Europe case. Moreover the system is modelled as an island. In addition, historical wind power and solar PV time series were scaled up to obtain the targeted VRE penetration. This will tend to overstate resulting variability, in particular for wind power. As such, the modelled situation will tend to pose more of a challenge and hence increase the benefit of increased flexibility.[6] This general trend is confirmed by the modelling for the Transformed scenario (Figure 8.7).

Despite the difference in modelling approach compared to the North West Europe case study, demand-side response also shows a very favourable benefit to cost profile compared to other options. Storage and additional reservoir hydro generation also show positive, but lower, cost-benefit ratios. In the Legacy scenario, where VRE is added to a system without adapting the overall generation mix, the retrofit of existing plants is also found to have a positive cost-benefit ratio. The combination of demand-side response with storage and dispatchable generation (modelled as additional reservoir hydro) produces mixed results, discussed further below.

Figure 8.7 • Summary of benefit to cost ratios for selected scenarios in the IMRES test system



Notes: DSI = demand-side integration; ST = storage; RH = reservoir hydro. See Annex B for details on assumptions.

Key point • DSI has a high benefit to cost ratio; electricity storage and reservoir hydro generation have favourable, but lower benefit to cost ratios.

Both modelling exercises critically depend on the assumptions used and the specific system context. Given important limitations in the methodology of both sets of simulations, results should be seen as indicative. In addition, irrespective of the modelling approach used and the system context, the most cost-effective option will most likely be insufficient or sub-optimal in isolation.

Interactions and lock-in effects

Flexible resources interact with the power system and other flexible resources on the grid. As a result, the presence of one flexibility option may increase or decrease the value of others.

A recent study for Europe (Schaber, Steinke and Hamacher, 2013) has found that VRE and transmission grid expansion may increase the value of demand-side hot water storage and vice versa. At high-VRE penetration levels, the transmission grid allows for a more cost-effective utilisation of demand-side resources, and the higher flexibility on the demand-side increases the value of geographically linking resources.

6. Data were taken from Germany in 2011, which already includes data of a large amount of well-distributed capacity.

The economic modelling analysis undertaken for this publication also investigated the scaling of costs and benefits for different combinations of flexibility options.

In the Transformed scenario of the IMRES simulations, combining flexible generation and demand-side response at a VRE share of 45% yields additional savings of USD 390 million per year thanks to positive synergies, on top of savings from flexible generation and DSI alone (USD 410 million and USD 800 million, respectively; Figure 8.8). Joint deployment of storage and DSI (Figure 8.9) yields lower synergies of USD 180 million annually (storage alone saves USD 540 million annually).

It is relevant to underline that in the considered scenarios, the DSI is intensely in use (employed in over 90% of the hours simulated) and shifts about 4% of overall demand. Conversely, storage utilisation slightly decreases when combined with DSI. These results, therefore, refer to a system still short of flexible resource where the availability of flexibility sources has yet to reach its saturation point. Results may be different following the introduction of additional flexibility, and cannibalisation effects may also take place. In addition, it is important to note that the IMRES model re-optimises the entire dispatchable plant fleet for the simulations in the Transformed scenario. As such, all long-term (investment) benefits from higher flexibility levels are fully captured.

Figure 8.8 • Total system cost and savings in the IMRES Transformed scenario at 45% VRE penetration and simultaneous deployment of flexible generation and DSI

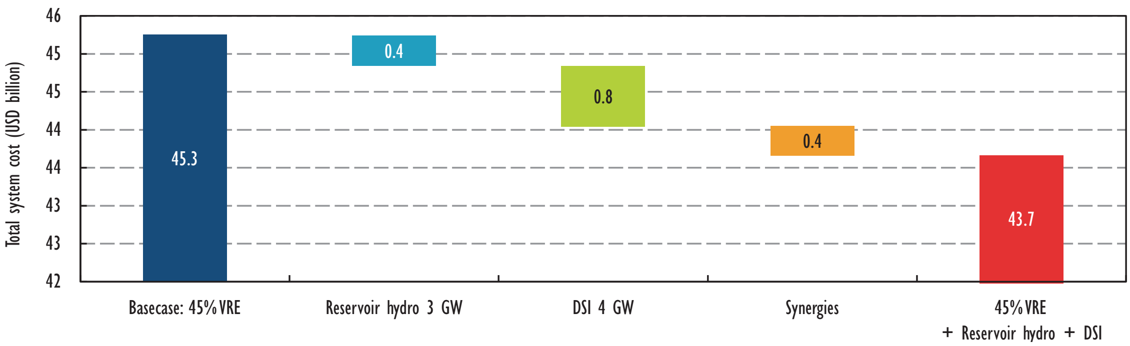
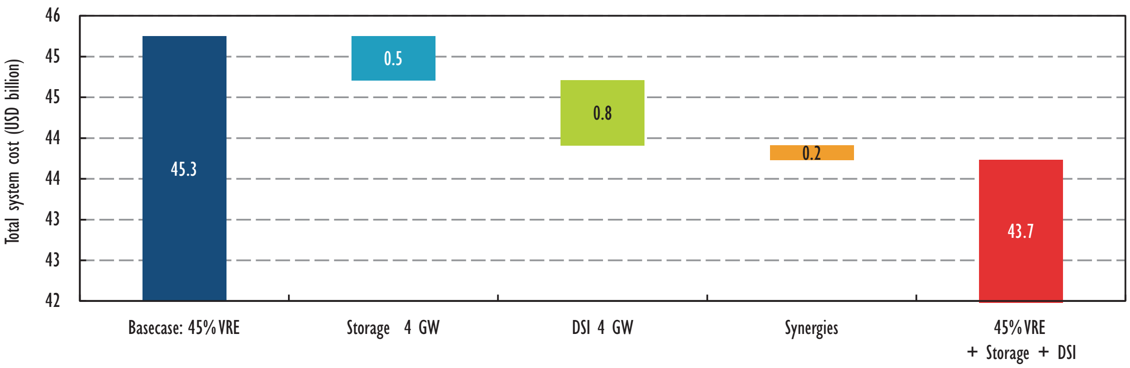


Figure 8.9 • Total system cost and savings in the IMRES Transformed scenario at 45% VRE penetration and simultaneous deployment of storage and DSI



Key point • Deploying a well-balanced mix of flexibility options maximises system-wide benefits.

Modelling of the North West Europe case study also investigated interactions between different flexibility options. Deployment of interconnection and demand-side response increases overall cost-benefit. The combined scenario has a cost-benefit value of 2.3; interconnection alone achieves 1.2 and DSI alone 2.2. Combining grid expansion and storage reaches cost-effectiveness (score of 1.1) similar to grid expansion and storage alone (score of 1.2 and 1.1 respectively).

Broadly speaking, flexible resources can show the following interaction pattern: substitution at low shares of flexibility demand, and complementarities of some options at high shares of flexibility demand. This means that one flexibility option can compensate for a delay in another. This is particularly true of grid expansion. Delayed investments have a monetary value, since expenses are incurred at a later point in time. This value can partially compensate for the cost of relying on other flexibility options, such as curtailment, during the delay period (RETD, 2013; Agora Energiewende, 2013).

However, where there is an oversupply of flexibility, adding more of it to the system will lead to some degree of cannibalisation. This effect will be less pronounced when the difference between the different flexibility options is higher. For example, grid investment demonstrates less cannibalisation of storage, than does storage and DSI (Schaber, Steinke and Hamacher, 2013).

In summary, there is little danger of causing path dependency and lock in when starting with a particular flexibility option. Flexible fossil generation is an important exception. If new investment in fossil power generation is used for providing flexibility, this can lock in CO_2 emissions, in particular if low efficiency technologies are used for a large number of hours.

VRE integration and total system costs

As discussed in Chapter 4, the deployment of VRE and the impact of flexibility options should be assessed in terms of their effect on total system cost. However, the impact of VRE deployment on total system cost critically depends on system-specific circumstances, as well as the degree to which the system is optimised as a whole (including VRE).

As VRE is added to existing power systems, it is quite likely that they will not be fully optimised for a high share of VRE. On the contrary, the system context may be a bad match for VRE. In such cases, the short-term system value of VRE (as defined in Chapter 4) can be quite low. However, if the system as a whole is better adapted, the system value of VRE will be higher.

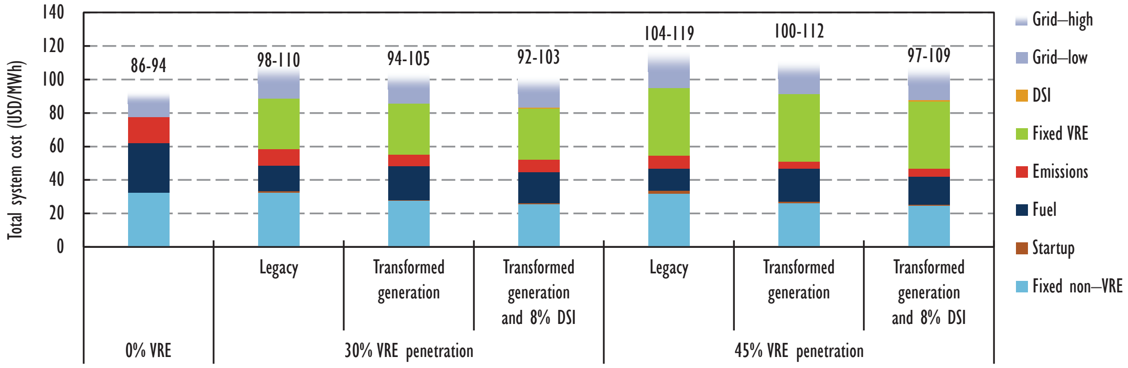
It is critical to distinguish between, on the one hand, integration issues that arise from an ill-adapted starting point, and, on the other, those integration challenges that are likely to persist. The costs associated with the former situation cannot be meaningfully attributed to VRE. Such costs arise because adding VRE causes a temporary de-optimisation of the system. In the IMRES modelling, this case has been modelled in the Legacy scenario.

In the longer term, if the system is re-optimised, an assessment of the total cost implications of VRE is possible and cost increases can be more clearly attributed by comparing two cases: one where the resources mix is decided solely on a least-cost basis, and another where a certain share of wind power and solar PV generation are required in the system. The difference between the two cases can be attributed to the desired level of wind power and solar PV. However, the flexibility options that are taken into consideration in simulations are critical in this regard. A meaningful comparison can only be made if a sufficiently broad portfolio of integration options is included. In the IMRES modelling, this re-optimised case is represented by the Transformed scenario.

Under the assumptions made for the IMRES simulations, total system costs are increased even in the Transformed scenario at a share of 30% and 45% of VRE in annual demand (mix of approximately one-third solar PV and two-thirds wind power). The increase is, however, considerably lower in the Transformed case than the Legacy case. By adding flexibility options in the Transformed case, cost increases can be mitigated further (Figure 8.10). Note that estimated grid costs have been added to the modelling results ex-post and are indicative only.

These results should be seen as an illustration of a more general principle: adding VRE to a power system that is not optimised for absorbing large shares of VRE will temporarily reduce the value of VRE electricity. However, in the long term, its value will be higher and total system costs accordingly lower.

Figure 8.10 • *Total system cost of IMRES system at different degrees of system transformation*



Key point • *System transformation reduces total system cost at high shares of VRE.*

A number of factors influence whether high shares of VRE actually increase total system costs. First, the cost of VRE is itself important. In the simulation results, a cost decrease of the wind power/solar PV mix of between 30% and 40% (from an LCOE of about USD 90/MWh on average for a mix of wind power and solar PV) would be sufficient to put total system costs in the Transformed case (including DSI) on a par with total system costs in the absence of VRE. Secondly, optimising the power plant mix contributes to reducing total system costs in the presence of VRE. Thirdly, the addition of flexibility options brings further reductions in total costs. Furthermore, a reduction in gas prices (assumed at USD 8 per million British thermal units) would contribute to lower total system costs in the presence of high shares of VRE.[7] However, the degree to which such a transformation is likely to happen depends on the economic framework conditions in place.

Market design

All power systems need to have an economic framework that provides ways to buy and sell power and that organises new investments. This framework can be called "market design". Whatever the market design is, the objective should be the same: to ensure that the regulatory framework for the trade of power maximises net benefits (benefits minus costs). There are huge differences in the way this process takes place in countries around the world. However, there is always a mechanism to compensate generators for their costs.

The general design of power markets is an active field of research and IEA analysis (IEA, 2007; Baritaud, 2012; Volk, 2013; Baritaud and Volk, 2013). As part of its *Electricity Security Action Plan*, the IEA has put forward several publications on the subject. More specifically:

- examining the operation and investment challenges facing electricity generation in the context of decarbonisation (Baritaud, 2012)
- examining the operational and investment challenges affecting electricity transmission and distribution networks (Volk, 2013)
- identifying and examining key issues affecting electricity market integration, including policy, legal and regulatory issues (Baritaud and Volk, 2013).

There has also been extensive work on the design of renewable energy policies (IEA, 2008; IEA, 2011b) and the interaction between different policy areas (Philibert, 2011).

7. However, this may also reduce total system cost in the absence of VRE. The overall effect will depend on investment costs and other fuel costs.

In the context of VRE integration, the following concerns in relation to market design are often put forward:

- VRE and other low-carbon options have very low short-run marginal costs. Can a market based on short-run marginal costs provide appropriate price signals for these technologies?
- Where VRE is added to stable power systems, they displace existing generation from the market rendering it uneconomic and prone to be taken out of service; however this capacity may be needed during times of low VRE generation. Will the market incentivise capacity to remain in the market to guarantee security of supply?
- Standard energy-only markets may not provide adequate price signals for all relevant services, including operating reserves and other types of flexibility; does this negatively affect market functioning?

The first issue is not in scope of the current work. The other two points are investigated more closely in the next section, building on previous IEA work (Baritaud, 2012).

Background

Since the beginning of electricity market liberalisation (Schweppe et al., 1988), there has been a debate as to what extent and under which conditions market price signals on energy markets can and will stimulate investment levels to ensure adequate generation capacity. A critical element needed for this to function properly is for price signals to be accurate during scarcity conditions.

While some researchers see fundamental or practical problems with ensuring appropriate scarcity prices and highlight the need for dedicated supplementary mechanisms and markets (see for example Crampton and Stoft, 2005; Batlle and Pérez Arriaga, 2008; Crampton and Ockenfels, 2011), others maintain that if markets are well designed, scarcity prices will be sufficient to incentivise and deliver investment also in practice (e.g. Hogan, 2005; IEA, 2007). There may also be a difference between the investment and capacity levels that regulators want to see in place and the price the demand side is actually willing to pay. In such cases, even if markets work perfectly, investments are bound to fall short of regulatory requirements (Newell et al., 2012). The problem of insufficient revenues to ensure adequate investment as a result of price signals not accurately reflecting scarcity is known as the "missing money problem".

Several arguments can be put forward as to why operational price signals may fail to properly value scarcity on energy markets. These include:

- regulatory price caps below the value of lost load
- out-of-market technical interventions by system operators during scarcity conditions, such as reduction of system voltage
- lack of price signals to capture all relevant operational constraints.

The most relevant scarcity conditions in the absence of large-scale VRE penetration are times when electricity demand approaches the available generation capacity, i.e. when generation capacity becomes scarce. As a result, supplementary mechanisms to correct inappropriate operational price signals have focused on generation capacity in the past.

Times of scarce generation capacity remain critical in the presence of VRE — in fact, scarcity of generation capacity becomes more complex with the introduction of VRE due to its variable and uncertain nature. However, large shares of VRE may lead to other types of scarcity during operations. For example, larger and more rapid swings in net load may emphasise the relevance of the ramping capability of the system. The displacement of heavy, rotating generators may reduce inertia to a degree that it becomes a scarce resource. Such new operational constraints need to be reflected in the design of energy markets, so that price signals actually capture times when certain system capabilities become scarce and deserve to have a high price. In summary, resource adequacy is no longer a matter only of generation capacity (Gottstein and Skillings, 2012; Hogan and Gottstein, 2012).

Market design in the context of high shares of VRE therefore needs to address four questions: 1) what are the relevant operational constraints that need to be priced to ensure efficient market outcomes at high shares of VRE? 2) what market products can be designed that reflect these constraints? 3) how can markets for these products be established? and 4) are operational price signals sufficient to incentivise investment or is there a need for supplementary, longer-term mechanisms?

Relevant operational constraints

While a megawatt hour of electricity is often considered as a commodity, this does not capture the essential features of the product. Actually, electricity is an extremely differentiated product. Electricity available in hour h and location i is not substitutable with electricity in hour h' and location i' and should therefore be considered as two distinct products and markets. Furthermore, the sub-hourly variations in power over several consecutive time intervals also matter. Maintaining a supply and demand balance in real-time requires both compliance with technical constraints and the economic capability to increase or reduce generation or load at different time horizons (i.e. instantaneously, within 15 minutes, one hour, several hours or days), at different speeds (ramp rates). The juxtaposition of several electricity markets (forward, day-ahead, intra-day, balancing and reserve markets) reflects the complexity of system operations and of the engineering procedures to ensure the balance of generation and load in real-time (Baritaud, 2012).

The most relevant operational constraints at growing shares of VRE have been discussed in Chapter 2. In summary, the following attributes appear most relevant:

- ensuring sufficient generation capacity during times of low VRE production and high demand
- providing system services (including operating reserves) also at times of low net demand, when few conventional generators are online
- the ability to ramp production and consumption up or down at short notice, frequently and to a large extent.

Product definition

The definition of market products for bulk electricity is facilitated by the fact that there is a clear demand for electricity. While it varies over time and location, total power demand is the sum of the demand of individual consumers. The generation and consumption of electric power can be accurately measured and attributed to generators and consumers. While the precise definition of products (how close to real-time is trading possible, what is the shortest interval over which trading is possible etc.) is highly relevant, the general definition "electricity measured in megawatt hours" at point p and time i is fairly straightforward.

With regard to system services, the picture is somewhat more complex. System services enable the reliable provision of the actual product, which is electricity. Demand for system services is a less straightforward matter than the demand for electricity. In addition, due to statistical aggregation effects and interactions via the electricity grid, product definition can be more challenging. For example, the required amount of operating reserves is typically much lower than the sum of the individual imbalances on the system; if one generator produces more than scheduled and another one produces less, the imbalance will net itself out over the grid. In addition, the required amount of operating reserves is closely linked to the desired level of reliability. Because reliability is usually a system-wide property, i.e. the quality of service is the same for all consumers, there is typically no market-based demand for it and it is system operators who calculate the required amount of operating reserves.

Similarly, products that may become particularly relevant at higher shares of VRE, such as flexible ramping services, are unlikely to be directly demanded by electricity consumers, but rather from system operators to ensure reliability. Also in this case, the system-wide aggregation of wind power generation makes the required amount of ramping capability much smaller than fluctuations in the output of individual VRE power plants would dictate – and in this case statistical fluctuations may simply cancel each other out.

In addition, today's markets for operating reserves and balancing services typically define the relevant products fairly crudely. The market for reserves or balancing services may not have any locational dimension. Generation services are much more differentiated than the basic underlying commodity with which they are associated. The system operator may, for example, need generating capacity responding in 10 minutes at a particular node of the network (Joskow, 2007). When supplies from generators with more specific characteristics are needed, the system operator may rely on bilateral out-of-market contracts to secure these supplies. These out-of-market operations can inefficiently depress prices received by other market participants for similar services and do not create a transparent price signal to operate efficiently and invest in flexible capacity. For instance, if a system operator needs a "quick start" supply or demand response that can supply within 15 minutes rather than 30 minutes, it is better to define that as a separate product and to create a market for it that is fully integrated with related energy and ancillary service product markets, rather than relying on out-of-market bilateral arrangements and "must-run" scheduling (Joskow, 2007).

Creating a flexibility product is also complicated by the different facets that flexibility may have. This makes it difficult to strike the balance between customised products and sufficient liquidity.

This gives an initial impression of the complexities involved in defining flexibility products. More generally speaking, it is not a straightforward task to identify which capabilities will be scarce as a result of higher VRE shares (see also Box 8.3).

Establishing markets

The three operational constraints indicated above are not independent, but capture different aspects of power system operation. For example, a storage device may be used to meet power demand when capacity is scarce. However, the same storage may be used to provide operating reserves or to ensure sufficient ramping capabilities. As such, market design needs to ensure that price formation not only captures all relevant constraints in isolation, but also allows prices on one market to be influenced by scarcity in another.

Recent proposals for ensuring sufficient generation capacity point to the importance of coupling wholesale energy markets with operating reserve markets, to ensure appropriate scarcity prices (Hogan, 2013). However, such an alignment of markets calls for the alteration of existing operating reserve markets in many cases. In European power markets, for example, some types of operating reserve are not financially compensated at all in certain countries, and, where a market exists, market operations tend not to be harmonised with electricity markets. As a consequence, market participants cannot offer their services on all markets equally. This could be addressed by aligning the timing of different markets. Even closer integration can be reached by clearing different markets jointly via co-optimisation (Baritaud and Volk, 2013), which is an evolving practice in a number of independent system operator markets in the United States. To the extent possible, market participation should be opened to all available flexibility options, to allow for the most cost-effective outcomes.

Even if a certain capability is likely to be scarce under certain operational conditions, it may not be necessary to create a dedicated market for this capability. For example, fast-starting units may be better able to respond to unforeseen increases in electricity demand close to real-time, for example as a result of forecast errors. In such cases, higher market prices on regular intra-day electricity markets will already value such a capability. However, in a number of markets the introduction of dedicated market products is under consideration, which would allow certain flexibility services to be remunerated directly (Box 8.3).

Box 8.3 • The definition of new flexibility products in California and the Irish power system

Dedicated flexibility products are currently under consideration in a number of power systems. Two recent developments have been selected.

California Independent System Operator Flexible Ramping Product

The California Independent System Operator (CAISO) is currently designing a flexible ramping product (FRP). This is intended to allow market-based procurement of ramping flexibility. In the past, increasing short-term net load variability has been causing instances of extremely high five-minute real-time prices, despite sufficient available generation capacity. Such prices resulted from an inability of resources available in the short-term dispatch to ramp fast enough. This situation made it clear that market procurement needed to focus on ramping capability as well as energy (Sioshansi, 2013).

The FRP is intended to improve CAISO's dispatch flexibility in a cost-effective way. It could allow the system operator to procure, at each dispatch interval, ramping capacity that is not intended to be used in the current interval but is set aside for possible ramping needs a few minutes later, during the next dispatching interval. The providers of FRP will be remunerated for their availability to produce energy with ramping capabilities that can be set aside, on the basis of submitted bids. Additional characteristics of FRP include the following:

- The product is intended for procurement in the day-ahead market on an hourly basis, and in the real-time market on a five-minute interval basis.
- The flexible ramping capability is continuously dispatched via the economic dispatch process running every five minutes for a single five-minute interval.
- FRP will be compensated according to marginal prices in the procurement process (day-ahead or real-time dispatch [RTD]). Since in any RTD interval a resource may provide either energy or FRP but not both, FRP prices include the opportunity costs for selling energy.

EirGrid DS3

Ireland and Northern Ireland are committed to increasing the share of renewable energy in electricity generation to 40% by 2020. In this context, to identify possible operational issues in the power system over the coming years, a programme of work has been established entitled *Delivering a Secure Sustainable Electricity System* (DS3). The DS3 programme started a consultation process on a range of new system service products to address and mitigate potential system issues, which had been identified previously via comprehensive technical studies. New products have been proposed to address the challenges associated with frequency control and voltage control in a power system with high levels of variable, non-synchronous generation. Out of the various services, two are discussed in more detail:

Fast frequency response (FFR)

This new service consists of a fast-acting response that may be provided both by synchronous and non-synchronous generators. It is represented by an increase in megawatt (MW) output from a generator (or reduction in demand) following a frequency event that is available within two seconds of the start of the event and is sustained for at least eight seconds. This service partially compensates for reduced system inertia during times of high instantaneous penetration of non-synchronous generation.

Ramping margin (RM)

This new service consists of a ramping-up product (technical analysis had indicated that a ramping-down product was not currently required). RM represents the increased MW output that can be delivered within a horizon time and sustained for a given duration. The Irish system operators are proposing horizons of one, three and eight hours with associated durations of two, five and eight hours respectively. Such ramping products can be relevant for situations when wind power output drops away over the course of several hours.

Sources: Commission for Energy Regulation (CER) and Utility Regulator, 2013; EirGrid SONI, 2012; CAISO, 2012.

Need for supplementary, long-term mechanisms

The previous section discussed pricing relevant operational constraints into short-term markets. However, this does not fully answer the question of the extent to which supplementary, longer-term mechanisms may be required to ensure timely and sufficient investment. Appropriate pricing of operational constraints is clearly necessary to deliver investments in the absence of supplementary mechanisms, but it may not be sufficient. The following aspects will be discussed in this regard:

- transition effects regarding flexibility supply
- transition effects regarding flexibility demand
- probability distribution of scarcity situations
- risk and public acceptance issues.

Transition effects: flexibility supply

The introduction of VRE into an already adequate system — the default case in most OECD member countries — will lead to a general excess of generation capacity and may thus reduce the occurrence of scarcity prices. The large supply of generation capacity can also reduce prices on other markets, such as those for operating reserves. It is also possible that even where well-designed system service markets are implemented, prices on these markets may be very low due to the large pool of flexibility that is available. Comparatively low prices will, at some point, trigger the retirement of generation capacity, which raises concerns as to security of supply in the context of large-scale VRE deployment. A number of different capacity mechanisms are under discussion in a range of countries, in particular in the European Union and parts of the United States (Baritaud, 2012; Baritaud and Volk, 2013).

However, as the modelling undertaken for this book suggests, the reduction in market prices following the large-scale introduction of VRE is a normal market reaction to a condition of abundant supply. Prices would be expected to recover to the degree that the system as a whole adjusts to the presence of high shares of VRE. During a transition period, it may be cost-effective to mothball certain amounts of generation capacity and bring them back into service at a later point in time.

A well-designed capacity market would not help the economic situation of dispatchable generation if there were an oversupply of capacity. In such cases, a capacity market would be bound to clear at or close to zero, reflecting the oversupply situation.

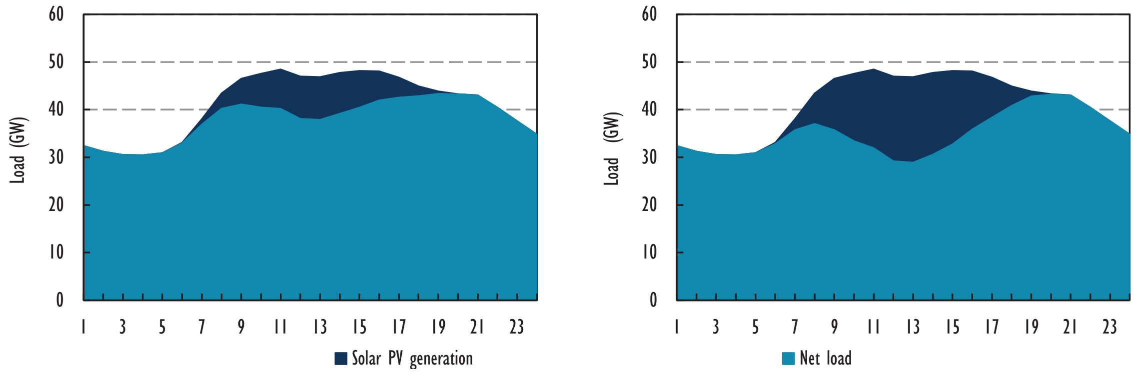
Transition effects: flexibility demand

The demand for flexibility does not increase linearly with the deployment of VRE. Depending on the match with load, adding VRE may initially decrease net load variability. This is the case when VRE generation has a positive correlation with demand. In countries with demand peaks at mid-day, solar PV deployment reduces net load variability at the onset of deployment. Adding solar PV capacity up to a certain point will tend to shave off this peak. This is already a reality in a number of systems, e.g. Germany and Italy. However, as deployment continues, solar PV generation starts to "dig" a pronounced valley into the load pattern. This eventually does imply higher variability (Figure 8.11).

The level of net load variability will directly affect the value of flexibility. When variability is reduced, the value of flexibility will go down along with it. A good indicator of this effect is the use of pumped storage hydro power plants (PSPs) in Europe (see Figure 8.12 for the example of Italy). Long-term scenarios see an important role for PSP in Europe in deep decarbonisation scenarios (IEA, 2012). However, this does not mean that there is a market value for these assets today.

One may argue that this reflects markets working properly, signalling the sometimes-low demand for additional flexibility experienced today. However, there are long lead times for PSP projects, and there will probably be a need for "learning by doing" to deploy other flexibility options at a significant scale, such as DSI. The current lack of investment signals for flexibility could present an issue for achieving sufficient flexibility levels on time.

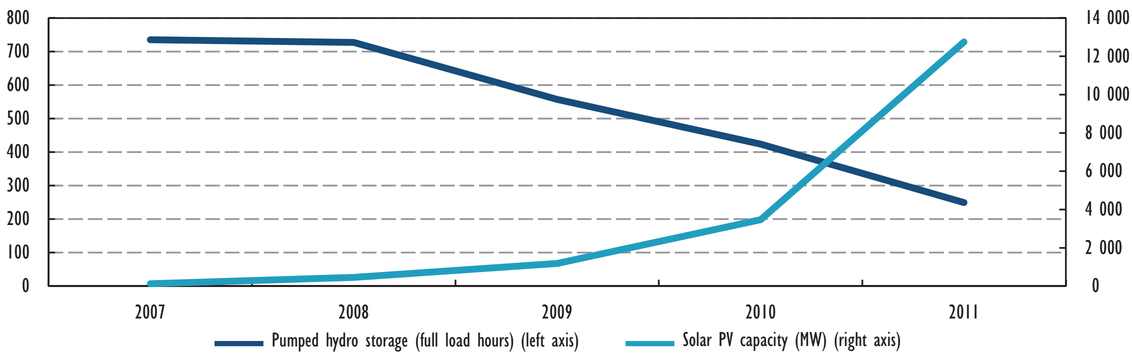
Figure 8.11 • Solar PV generation and resulting net load on a typical sunny day in Italy (left: July 2012; right; doubled solar PV)



Key point • At low shares, solar PV deployment can reduce net load variability. At higher shares, variability is increased.

If such considerations lead to the establishment of longer-term market mechanisms, it is critical to assess diligently what capabilities will be relevant for the system in the long term. Detailed studies on likely future operating conditions can help to inform the design of longer-term market products (EirGrid, 2010; Hogan and Gottstein, 2012).

Figure 8.12 • Utilisation of Italian PHS and deployment of solar PV



Source: based on data from Gestore dei Servizi Energetici and IEA statistics.

Key point • Despite its possible value in the future, the utilisation of pumped storage hydro plants in Italy has dropped in past years.

Probability distribution of scarcity situations

High penetrations of VRE in a power system increase the system's exposure to weather events. Above a certain threshold, scarcity of generation capacity is driven primarily by the lack of VRE supply rather than by periods of very high demand. As a result, the occurrence of scarcity prices is tied to periods of low availability of wind power and solar generation. Such events may occur over large areas, for example during winter in western Europe (Pöyry, 2011). A multi-week period of power scarcity can result. However, it may not be possible to predict how many times such an event will occur over the course of 20 years. Consequently, the revenues of any flexibility option that can step in during such scarcity periods are equally uncertain, and it may therefore be extremely challenging to secure financing for such assets.

To address such cases, a long-term mechanism can be put in place that holds a certain amount of capacity as a strategic reserve against this risk. Such reserves are only used in case the regular market does not clear during exceptional and very infrequent scarcity periods. Such events may also occur in hydro-based systems experiencing exceptionally dry years. A strategic reserve mechanism is in place, for example, in Sweden (Mueller, Chandler and Patriarca, forthcoming).

Risk and public acceptance issues

Risks related to energy policy, public acceptance and permitting make it uncertain whether operational price signals are capable of incentivising adequate investment levels (see Baritaud, 2012 for details). In addition, markets based on short-term operational price signals (which include a strong component from potentially volatile fossil fuel prices) may be challenging, in particular for technologies with comparably high up-front costs and low short-run costs, which is typical for most low-carbon technologies. In terms of fossil fuel price risk, fossil power generation options are mainly exposed to relative fuel price and carbon risks, i.e. relative fuel and emissions costs of gas and coal . In this way, fossil generators benefit from a natural hedge against fossil fuel prices to a certain degree (Baritaud, 2012).

Decarbonisation of the energy system goes hand in hand with increasing the capital intensity of the system as a whole (IEA, 2012), leading to an increased deployment of technologies with low short-run costs. However, generators with low short-run costs do not benefit from a natural hedge against fossil fuel prices. They experience fossil fuel price volatility in their income, because the electricity market price will fluctuate along with changes in fossil fuel prices. This exposes low-carbon generators to the risk of low fossil fuel and/or emissions prices. Risk is particularly relevant for low-carbon generators, because up-front capital investments are sunk. This raises more fundamental and complex questions regarding market design, which are beyond the scope of this publication.

Discussion

The cost-effective integration of large shares of VRE implies a more fundamental transformation of the power system. Such a transition needs to be implemented taking a system-wide perspective, with a view to minimising total system costs.

Different countries are in contrasting positions with regard to implementing such a transformation. While a stable power system can use existing assets to provide flexibility cost-effectively during a transition phase, the rapid addition of VRE to a system with adequate generation capacity has the potential to put incumbents under considerable economic pressure, which in turn can create particular challenges. Systems with a more dynamically evolving power sector cannot rely on legacy assets to the same degree to facilitate the integration of VRE. As a result, investments in system flexibility, in particular flexible power plants to complement VRE generation, will tend to be a priority even during an early phase. In this case, the scaling down of the incumbent industry is not required to the same degree and the associated challenges may be smaller.

A number of different options are available to implement such a transition successfully. A first and important step is the adaptation of operational procedures, in order to manage the system cost-effectively at higher levels of supply-side variability and uncertainty. Different aspects of the integration challenge will call for a suite of different solutions. Grid infrastructure is particularly relevant in this context, as it is currently the only option to bridge geographical supply/demand mismatches cost-effectively. In addition, in particular for wind power, it brings significant temporal smoothing benefits, which help to match the timing of demand and supply.

Flexible generation can be a readily available, cost-effective flexibility option. However, while technically possible, it is usually not cost-effective to operate assets with high capital costs only for a limited amount of time. Economically flexible power plants are those that are cost-effective when operating as peaking and mid-merit plants and that do not incur significant costs when starting/stopping frequently and changing output quickly and in a wide range. Reservoir hydro power is often a particularly favourable option in this regard. While flexible generation is critical – in particular to meet demand at times of low VRE generation – it may do little to avoid VRE curtailment once net load becomes negative, which is the most important limitation of this flexibility option at high shares of VRE.

The coupling of electricity and heat generation via co-generation and thermal energy storage can make a critical contribution for dealing with both structural VRE surpluses and shortfalls. Where there is a significant demand for cooling (air conditioning), the same principle can be applied using cold storage.

DSI – in particular enabled via distributed thermal storage – is a cost-effective option that is able not only to reduce demand during shorter periods of low VRE generation, but which is also capable of absorbing electricity surpluses at times of high-VRE generation and otherwise low power demand. While experience with DSI is increasing and results are often very positive, there remains a certain degree of uncertainty regarding its potential contribution. In any case, enabling DSI from smaller consumers requires the necessary communication infrastructure and market agents to aggregate capabilities. As this is likely to take time, DSI implementation should be started early on to secure its contribution in the future. Its potentially high cost-effectiveness – as evidenced by the modelling studies conducted for this book – should be an incentive to prioritise this option, despite the uncertainties remaining as to its full potential.

Electricity storage options are currently only cost-effective under specific circumstances and generally less cost-effective than alternative solutions. It remains significantly cheaper to transport electricity to a different location than to store it for later use. However, where circumstances are favourable, existing technologies – in particular pumped storage hydro – can be cost-effective. This is usually achieved by the sum of the multiple benefits that storage applications can bring. These include energy price arbitrage, system services and avoiding or deferring grid investment. The availability of inexpensive, distributed electricity storage remains a potential step change for VRE integration.

With respect to market design, existing design principles remain valid in the face of high shares of VRE. Well-designed electricity markets that adequately price electricity and system services, even during scarcity periods, are required to incentivise adequate investment levels. However, at high shares of VRE the relevant operational constraints are more diverse. Apart from securing adequate levels of capacity and operating reserves during periods of scarce generation capacity, high shares of VRE may also render other capabilities more valuable, including fast ramping, low turn down, fast-starting and inertial response. A number of these capabilities will already be remunerated on "regular" electricity markets, given that they allow trading closer to real-time and with short trading intervals. Other system service markets, in particular those related to operating reserves, can be designed to facilitate simultaneous trading on both markets, which allows prices on one market to drive prices on the other, thus better reflecting actual value.

Similar to electricity, the market value of flexibility services may be low during a transition period, as explained above. Low electricity prices have raised questions about capacity adequacy during the transition. Low flexibility prices – even with dedicated markets in place – may raise concerns over adequate future levels of flexibility. With similar arguments currently being brought forward to create a capacity market, other longer-term flexibility markets may be considered. However, as a first step, existing short-term markets should be optimised to create appropriate price signals, before more significant long-term interventions are implemented.

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9 • Conclusions and recommendations

Previous chapters present a comprehensive analysis of the challenges and opportunities associated with integrating large shares of wind power and solar photovoltaic (PV) generation into power systems. The following conclusions and recommendations build on that analysis, and are grouped into four major areas. The chapter finishes with an outlook on future work.

Current experience and technical challenges

Technical integration is not a relevant constraint on the initial deployment of wind power and solar PV.

At annual shares of 5% to 10% of electricity generation, integrating wind power and solar PV is unlikely to be a significant challenge, as long as established best practice is implemented. This is largely a result of the fact that power systems routinely deal with variability and uncertainty arising from electricity demand; this is business-as-usual in every power system. However, existing knowledge needs to be adapted to facilitate variable renewable energy (VRE). As long as VRE generation is taken into account in system operations with the effective use of forecasting, the additional variability and uncertainty will not be felt strongly at low shares. The share at which VRE impacts become relevant depends on the characteristics of VRE as much as on other system-specific factors. This finding is reinforced by the technical assessment of case study regions carried out with the International Energy Agency (IEA) revised Flexibility Assessment Tool (FAST2).

Recommendations

- Wind power and solar PV generation should be taken into account when operating the power system. This is possible using well-established forecasting techniques and by shifting operational decisions closer to real-time to better accommodate variability and uncertainty.
- VRE generation needs to be monitored in real-time (critical for short-term forecast accuracy), and system operators need to have sufficient capabilities to reduce VRE generation during critical operational situations.
- VRE generators need to be equipped with technical capabilities to support the secure operation of the power system,[1] which are commensurate with the capabilities of other components of the power system and the envisaged future role of VRE.
- The geographic patterns of applications for new VRE power plants need to be monitored and deployment controlled if necessary, with a view to pre-empting the emergence of undesirable local "hot spots".

Two frequent operational challenges can be observed today: situations combining low electricity demand with high-VRE generation, and grid congestion at times of high-VRE in-feed.

At VRE shares above 5% to 10% of annual electricity demand, little other generation may be needed during situations of low electricity demand and high-VRE generation. However, for a number of reasons other generation may need to be kept on the system. These include the following:

- VRE may not be able and/or allowed to provide sufficient levels of system services (including operating reserves) during such periods

1. State-of-the-art wind and PV systems can offer a broad and increasing range of such services. A system-specific, technical assessment can determine what level of capability is desirable at the earliest possible stage of VRE deployment in a power system. The level of required capabilities will depend on the technical properties of other power system components and the targeted longer-term role of VRE in the power system.

- power plants are needed to cover a subsequent and potentially unexpected increase in net load, because electricity demand picks up again and/or VRE generation drops
- technical or regulatory constraints (e.g. on a cycling nuclear plant) may prevent other power plants from reducing their output further.

Similarly, the power grid may sometimes not be able to deliver all available VRE supply to locations where there is electricity demand. This may be hindered both by operational procedures and by technical constraints.

Recommendations

- Foster measures that allow conventional power generation to reduce its output as far as possible during times of high-VRE generation and low load, such as facilitating the provision of system services by VRE through improved system service markets.
- Encourage the integration of the electricity sector and the heating and cooling sector to allow cost-effective use of otherwise surplus generation.
- Develop operational protocols to make efficient use of scarce grid capacities, including location-specific pricing and improved integration of power markets.

Economics of VRE integration

Approaches to the calculation of different categories of integration cost suffer from methodological weaknesses. The cost-effectiveness of VRE is ideally assessed based on its impact on total system costs.

Previous approaches to calculating integration costs typically calculate grid, adequacy and balancing costs separately and add them together. The segmentation is often done because existing power system models can only capture certain impacts groups at once, *i.e.* they may specialise in assessing grid impacts, balancing impacts or adequacy impacts. However, these categories are, in fact, not independent of each other. For example, increased investment in grid infrastructure may contribute to smoothing the variability of VRE on the system level and thus reduce balancing and adequacy impacts. Caution is needed when adding up such costs, in particular when they have been calculated using different methods. In addition, by isolating different categories, it is far from certain that all economically relevant effects are actually captured.

Secondly, the principal operational effects of adding VRE are beneficial, for example in the form of fuel and emissions savings. As such, certain integration costs are only one small component of overall operational impacts and it is hard to accurately extract them.

Thirdly, integration costs are not specific to wind power or solar PV. The addition of any other generation technology may impose costs on others in the power system. Generation technologies differ with regard to many aspects and it is always a portfolio of technologies that will minimise total system costs in practice. Therefore, a common integration cost methodology that treats all technologies the same faces the problem of having to compare apples and pears.

It is conceptually simpler and in most cases more useful to assess VRE in terms of its impact on total system costs. Adding VRE to a power system will trigger a number of effects in other parts of the system. Some will be positive (leading to cost reductions) some will be negative (leading to cost increases). The system value of VRE can be determined by calculating the net benefits that VRE brings to the remaining parts of the system. Deployment of VRE is cost-effective, if its system value outweighs VRE generation costs.

It is important that any system value calculation considers the possible adaptations of the power system. A low system value in the short term reflects an unfavourable match between VRE and existing system components, and as such it is as much attributable to VRE as to existing system components. The system value of VRE is higher in the long term in a transformed energy system. The long-term system value is a more useful metric for assessing VRE cost-effectiveness for long-term energy system planning.

Recommendations

- Avoid the methodological flaws of integration cost calculations and instead assess VRE in terms of its overall cost-effectiveness at a system level.
- Foster the development of simulation tools that are capable of jointly modelling optimal investment in generation, grid, storage and demand-side response infrastructure, while taking into account the specific operating conditions at high shares of VRE.

System transformation strategies

Variability brings three persistent challenges. These are related to the balancing effect, the utilisation effect and grid-related impacts. All three are economically relevant and need to be addressed in concert.

At sufficiently high shares, VRE variability and uncertainty has two different impacts. For system operations, the balancing effect is of greatest importance. The balancing effect captures the fact that net load shows more pronounced, more frequent and less predictable fluctuations on a time scale of a few minutes to several hours. Operational practices and flexible resources need to be able to deal with these fluctuations reliably and cost-effectively.

On the investment timescale, the balancing effect is also relevant, driving investment towards assets that can operate in situations of higher short-term variability and uncertainty. However, higher net load variability also influences the utilisation of those assets in the energy system that help to balance variability. This change in utilisation is referred to as the utilisation effect.

With high shares of VRE in a power system, it is highly likely to be economically efficient to increase grid capacities. Grid-related costs arising from increased VRE deployment are system-specific, and cost allocation practices would need to recognise all beneficiaries of increased grid capacity. Grid-related costs may contribute very little to total system costs even at high shares of VRE, but their impact can be substantial, especially if distant, in particular offshore, resources have to be connected to the grid.

Integrating large shares of VRE cost-effectively calls for a planned and co-ordinated approach to transforming the energy system as a whole.

The detailed modelling analyses conducted for this study have highlighted a number of important factors for the cost-effective integration of up to 45% share of VRE in annual electricity supply.

Firstly, measures that facilitate VRE integration show wider benefits. For example, the increase in demand-side response capabilities was found to reduce the need for investment in costly peaking generation and increased the utilisation of more cost-effective power plants. It also decreased VRE curtailments. Similarly, higher amounts of transmission capacity not only facilitate higher shares of wind power and solar PV, but also help to minimise the cost of conventional power generation in simulations. This is because transmission provides access to more cost-effective, but distant power plants and helps to minimise required peak capacity thanks to demand aggregation. In summary, the system-wide benefits of flexibility options may be particularly large at high-VRE shares, but the pathways through which they increase cost-effectiveness are numerous and – most importantly – system-wide.

Secondly, total system costs at high-VRE penetrations show important differences depending on how well the system is adapted as a whole. The Legacy scenario of the Investment Model for Renewable Energy Systems (IMRES) test system assumes that VRE is added to a system "overnight". At a VRE penetration of 45%, this leads to an increase in total system costs of USD 33 per megawatt hour (/MWh) of demand. This figure includes the cost of VRE itself. In the Transformed scenario, the system is re-optimised in the presence of VRE. The power plant mix shows a shift away from inflexible baseload technologies towards more flexible mid-merit and peaking generation. When combining this adaptation with deployment of demand-side response (distributed heat storage) and assuming lower additional grid costs, system costs at 45% VRE were only increased by USD 11/MWh of demand. In this example, the system transformation reduced the cost of reaching 45% VRE by roughly two-thirds. The remaining increase of USD 11/MWh could be brought to zero if the LCOE of the mix of wind power and solar PV dropped by 30% to 40%, depending on grid costs, from approximately USD 90/MWh to a range from USD 63/MWh to USD 55/MWh. A significant degree of uncertainty exists around the reported numbers and values will be highly system-specific. However, the general conclusion is robust: transforming the system as a whole is key.

Recommendations

- Recognise that large-scale VRE integration as a system-wide task calls for a more fundamental transformation of the energy system to achieve cost-effectiveness.
- Deploy flexibility options with a view to optimising the system as whole, rather than focusing on VRE integration in isolation.
- Assess the cost-effectiveness of VRE based on long-term system costs and taking into account all available options to minimise total system costs in the long term.

Better market and system operation are low-cost, no-regret options to improve system efficiency, but may face institutional barriers.

Improving system and market operations is a no-regret option. It will almost always prove cost-effective, irrespective of VRE integration. However, the benefits of adopting optimised operations increase at growing penetrations of VRE. Optimising system operations in the presence of VRE should be considered wherever and whenever wind power and solar PV are deployed. In addition to protocols and procedures used by system operators, market design needs to facilitate efficient operation of the power system.

However, the implementation of such practices may face significant institutional resistance, because it may challenge long-standing traditions on how the system is operated. In addition, it may require the co-operation of different actors (e.g. different system operators) that do not have established platforms for interacting either in a planning context or in real-time. Finally, lack of familiarity with most recent developments in system and market operation in the presence of VRE may pose a barrier to adopting best practice.

Recommendations

- The geographic region over which demand and supply are balanced in real-time (balancing area) should be increased and co-operation between neighbouring balancing areas maximised.
- System operations, often taking place hours before physical delivery of electricity, should move towards real-time to efficiently deal with system variability. In particular, shorter scheduling and dispatch intervals should be targeted.
- Current procedures for the calculation of system services are far from best practice in most of the countries analysed. In addition, most system service markets lack transparency and competition. Possible improvement may arise from the definition of clear market products and the market integration of all available sources of flexibility (e.g. interconnection, demand-side integration [DSI]).

- Market clearing should optimise VRE generation together with dispatchable production in light of system constraints and overall system costs. VRE participation in ancillary services markets should be fostered.

Market design changes may be needed to value flexibility correctly and optimise system operations.

Market design needs to translate the new technical operating model into short-term price signals, in particular during scarcity conditions. This requires establishing price signals for flexibility provision. Where appropriate short-term price signals cannot be achieved, longer-term price signals may be required to ensure timely and sufficient investments.

Recommendations

- Assess which new flexibility services may become relevant at high shares of VRE based on comprehensive technical studies.
- Reform system service markets, in particular markets for operating reserves ensuring the following:
  - All relevant types of system services are remunerated and that the suite of operating reserve products is robust at high shares of VRE. This may require the definition of new flexibility products, such as fast frequency response for dealing with reduced system inertia and ramping reserve products to deal with increased net load variability.
  - Provision of system services is market-based to the highest degree possible and minimises the need for non-transparent bilateral contracts between individual power plants and system operators.
  - Timing of trading on system service markets is aligned or integrated with trading on wholesale power markets to the highest degree possible.

Variable renewable power plants can contribute to their system integration, but they need to have an incentive to do so.

The common view of integration sees wind power and solar PV generators as the “problem”. The solution has to come from other parts of the power system. Given recent technological advancements in VRE generation and integration requirements, this view is no longer accurate. VRE can contribute to its own system integration — and it will need to do so to achieve grid integration on a cost-effective basis.

However, it is important to expose VRE generators to appropriate economic signals to facilitate system-friendly design (provide system services), deployment (timing and location) and operation (optimise time of output).

Recommendations

- Align VRE additions with overall system development, and vice versa.
- Auction mechanisms may provide an attractive solution by steering overall deployment volumes at competitive prices. Auctions can be combined with market premium models.
- Identifying preferred development areas for large-scale wind power and solar projects can help to guide the location of deployment. In addition, including locational signals in market prices can contribute to more effective siting.
- Gradually increase the exposure of VRE generators to short-term price signals, such as time-of-generation pricing or carefully designed imbalance charges. This can incentivise a more system-oriented operation and design of VRE power plants. Market premium models are a step in this direction.
- Design grid-connection charges for VRE power plants with consideration of the possible system cost savings occasional constraint of VRE generation could bring through avoided grid investment costs.

- Remove any unnecessary market barriers to the participation of VRE power plants in system services markets.
- Require a sufficient level of technical capability for VRE power plants to ensure reliable system operation at high shares of VRE. However, technical requirements should recognise the strengths of different generation technologies.

Challenges and opportunities for system transformation differ depending on the general investment context.

Power systems with flat electricity demand and no upcoming infrastructure retirements (stable systems) face different transformation challenges and opportunities than systems with demand increase and/or upcoming retirements (dynamic systems).

Mature systems:

- Analysis with FAST2 indicates that VRE shares of 25% to 40% and above are technically feasible with existing infrastructure. However, important operational changes are likely to be needed to achieve this cost-effectively. Retrofits for improving the performance of existing thermal power plants or making co-generation plants more flexible (power to heat) may also be cost-effective in these circumstances.
- Integration of additional generation in stable systems is only possible by displacing incumbents, which will be put under economic stress. Depending on relative fuel prices, mid-merit power plants may find themselves being displaced most quickly, despite being a better match for VRE in the longer term. This constitutes one of several challenges that stable systems face during a transition phase.

Dynamic systems:

- By definition, dynamic systems require additional investment in the short term. This opens a double opportunity for VRE integration. Firstly, wind power and solar PV can be deployed without necessarily displacing incumbents. Secondly, investment in other parts of the power system can take into account the objective of VRE integration right away, presenting the opportunity to "leap-frog" stable systems to become a flexible power system that can cost-effectively integrate larger shares of VRE.
- However, established integration strategies that rely on changing operations are not by themselves sufficient to achieve integration successfully in this context. Decisions regarding investment in flexibility options are required at an earlier stage in these systems. In addition, the contribution of VRE to generation adequacy tends to have a higher relevance.

Recommendations

- Differentiate the approach to VRE integration depending on investment context.
- In the context of a stable system, maximise the contribution of existing assets to system transformation by optimising system service markets, and consider accelerating system transformation through decommissioning or mothballing inflexible capacities that are surplus to system needs.
- In dynamic systems, approach system integration as a question of holistic, long-term system planning from the onset.

A system-specific suite of flexibility options is needed to address integration challenges and minimise total system costs of the wider energy system.

Each of the four flexibility options (generation, grid infrastructure, DSI and storage) contributes to the integration of VRE in some way or another. However, flexible resources also show differences in the VRE properties they help to address. For example, flexible generation is critical to dealing with periods of low VRE generation. However, flexible generation can only make a limited contribution to avoiding VRE curtailment once net load becomes negative. Consequently, a suite of flexibility options is needed for successful VRE integration. Because system contexts and VRE portfolios are different, so are the appropriate combinations of flexibility options.

A number of factors will influence the composition of this mix, including geographic and other constraints (including opportunities for market integration with neighbours, population density, geographic potential, fuel availability and prices), public acceptance, and additional policy targets (including industrial development policies).

The relative mix of wind power and solar PV will also be of relevance to the choice of flexibility options. Due to the concentration of solar PV generation during daylight hours, options that allow a shift in time may be more attractive for systems with a high contribution from solar PV. Systems with high shares of wind power may prioritise geographic aggregation over very large regions to maximise smoothing across time.

Recommendations

- Assess available flexibility options taking into account system-specific circumstances and other policy priorities.
- Take a diversified approach to deploying flexible resources, taking into account the different profile of each flexibility option and how it contributes to VRE integration.

Transmission infrastructure is required to achieve geographical aggregation of VRE output, which greatly facilitates the achievement of high shares of VRE cost-effectively.

Investing in transmission infrastructure takes a special position among the different options, because it is the only option that can deal with geographic mismatches. In addition and most importantly, aggregating VRE generation over large areas brings considerable benefits in mitigating temporal mismatches. Improved grid infrastructure also brings wider benefits related to optimising operations, facilitating trade and increasing reliability. Consequently, grid infrastructure is likely to be part of any cost-effective strategy from the outset. However, grid investments have a cost and should always be balanced with alternative options, including moderate levels of VRE curtailment.

Recommendations

- Where public opposition is a barrier to transmission expansion, facilitate active stakeholder engagement and participation at an early stage to minimise opposition.
- Develop improved cost allocation mechanisms to recover the costs of new infrastructure projects, recognising the multiple benefits of increased transmission.

The role of distribution is shifting away from a passive, one-way grid for connecting loads towards a more complex structure, hosting generation facilities with two-way power flows.

The policy and market framework for distribution systems was conceived with a role of passively serving connected loads. With the rise of distributed generation, the system has a much more important role to play, which has not been reflected in operation and planning procedures.

Recommendations

- Improve the planning and cost-effectiveness of distribution grid investments by providing visibility on the long-term target penetration of distributed VRE generators.
- The changing role of the distribution grid may challenge existing institutional frameworks and cost-recovery schemes. Innovative ways of operating and financing distribution grid infrastructure at growing shares of self-consumption and distributed in-feed are key to securing the appropriate contribution of this flexibility option in the future.
- Regulation also needs to facilitate the adoption of improved smart-grid infrastructure and tools to monitor dynamic load flow patterns, including “reverse” flows of power to the transmission level.

DSI holds the promise of providing cost-effective flexibility, although it may take time and effort to tap into its potential.

DSI may be the flexibility option that could produce the largest benefit with clear policy action. It holds the promise of enabling VRE integration very cost-effectively. In particular distributed heat storage and district heating applications, but also cold storage, are attractive options to make electricity demand more flexible. Ensuring that DSI finds a level playing field — in particular by allowing aggregators to participate actively in energy markets — is a no-regret option. While experience with DSI is increasing and results are often very positive, a certain degree of uncertainty remains as to its potential contribution. In any case, enabling DSI from smaller consumers requires the establishment of the necessary communication infrastructure and market agents to aggregate capabilities. As this is likely to take time, DSI implementation should be started early on to secure its contribution in the future.

Recommendations

- Adopt appropriate cost-recovery mechanisms for the initial roll-out of smart-grid infrastructure, which can help to cost-effectively overcome the initial barriers to wide-scale adoption of DSI, such as the cost of smart meters.
- Engage in international co-operation on compatible and secure communication standards for smart appliances to accelerate market uptake of DSI.
- Ensure that power market design allows DSI to offer flexibility services where it has the technological capabilities. Support the development of innovative business models that allow for the aggregation of a large number of dispersed consumers.
- Foster research and analysis to identify pricing schemes that entice consumers to exhibit a more dynamic demand profile — or to embrace technological innovations that would enable such change.

Dispatchable power generation needs to be technically flexible and cost-effective when operating at lower capacity factors; this option is particularly important to meet demand during sustained periods of low wind and solar PV generation.

Flexible generation is a cost-effective, mature and readily available option to balance VRE variability and uncertainty. Plants differ as to both their technical and economic flexibility. Economically flexible power plants are those that are cost-effective when operating at capacity factors typical for peaking and mid-merit plants and that do not incur significant costs when starting/stopping frequently and changing output quickly and in a wide range. This does not favour particularly capital-intensive technologies. Even if technically flexible to a certain degree, from an economic point of view capital-intensive baseload technologies consume flexibility rather than providing it. Using fossil generation options risks locking in carbon dioxide emissions.

It is critical that flexible generation is able to back down as much as possible during times of low net load. However, electricity generation cannot contribute to the avoidance of curtailment due to negative net load. Flexible generation — possibly combined with long-term, large-scale hydro or chemical storage — is key to guaranteeing reliability during times of sustained periods of low VRE output.

Recommendations

- Dispatchable power generation technologies are mature and markets well developed. Policy efforts should thus concentrate on establishing a competitive environment and well-designed markets for these technologies.
- Recognise the changing role of dispatchable power plants at high shares of VRE. Ensure that price signals and/or planning frameworks facilitate the deployment of technically and economically flexible power plants and do not encourage investments in inflexible capacity.

- Avoid investments in capital-intensive generation assets that may be exposed to significantly lower-than-expected load factors.

Pumped hydro storage remains the most cost-effective electricity storage option; cost-effective, small-scale electricity storage would be a game changer for VRE integration.

Electricity storage options are currently only cost-effective under specific circumstances and generally more costly than alternative solutions. It remains significantly cheaper to transport electricity to a different location than to store it for later use. However, where circumstances are favourable, existing technologies — in particular pumped storage hydro — can be economically attractive. This is usually achieved by aggregating the multiple benefits that storage applications can bring. These include energy price arbitrage, system services and avoiding or deferring grid investment. The availability of low-cost, distributed electricity storage remains a potential game changer for VRE integration, because it could stimulate a more radical shift towards a distributed electricity system combined with solar PV.

Recommendations

- Identify the most promising technologies for grid-scale electricity storage and provide research and development funding where attention from industry research is lacking.
- Adopt a clear regulatory framework and clarify which storage services can be provided by regulated transmission and distribution operators and/or power generators in unbundled markets.
- Ensure that power market design allows storage to offer flexibility services where it has the technological capabilities.

Catalysing the transformation

Optimising short-term markets should be done before long-term market instruments are considered.

A number of arguments can be brought forward as to why short-term price signals may fail to stimulate adequate investment levels. However, putting in place longer-term mechanisms usually requires significant additional regulatory intervention, such as setting the desired quantities in longer-term (annual and longer) capacity auctions. The optimisation of short-term markets is a low-cost measure and a no-regret option. It is likely to bring considerable benefits independent of VRE integration, which are likely to be even larger in the presence of VRE.

Recommendations

- Fully explore possible options to improve short-term market functioning.
- Only when all options to improve short-term market functioning have been implemented should longer-term measures be considered.

Current low market prices and low plant capacity factors in countries with significant shares of VRE are a reflection of supply-demand fundamentals and largely a transitional effect.

Once built, wind power and solar PV provide electricity practically for free. Adding VRE in a market environment will thus displace more costly generators, which reduces market prices. In addition, a reduction in average annual utilisation of incumbent power generators is a necessary side effect of pushing additional generation into an already adequate system. This effect is not specific to VRE sources: it will occur wherever low short-run cost generation is added in the absence of demand growth and plant retirement.

Once the system as a whole has undergone a more comprehensive transformation, the generation mix is likely to shift to power plants that are cost-effective at the capacity factors at which they operate. As a result, market prices recover.

Recommendations

- Recognise reduced wholesale prices and reduced capacity factors of incumbent generators as an inevitable side effect of a transition to any new generation technology in the absence of demand growth or infrastructure retirement.
- Consider measures to accelerate the transformation of the system if market prices become unsustainable, such as retirement of particularly emission-intensive, baseload generation from the wholesale market and while avoiding full decommissioning of such assets, if there are concerns about system adequacy.

Future work

A number of questions have arisen during the course of this project that merit further analysis. Firstly, the specific circumstances of dynamic power systems warrant further investigation, specifically regarding appropriate strategies for achieving ambitious VRE targets cost-effectively in these systems. Secondly, further investigation into options for system-friendly VRE deployment and the concrete design of system-friendly VRE support policies are ready for further analysis. Thirdly, while analysis has shown significant room to improve short-term markets, there remains the more fundamental issue of how to achieve a market design consistent with long-term decarbonisation. On the one hand, VRE generators need to be exposed to price signals that reflect the different value of electricity (depending on time and location of generation), so as to facilitate system integration. On the other hand, VRE requires capital-intensive technology and, as such, is highly sensitive to investment risk, a risk that is increased by short-term price exposure. Finding an appropriate market design will need to strike a delicate balance between these two objectives.

Annex A • LCOF methodology

Introduction and general approach

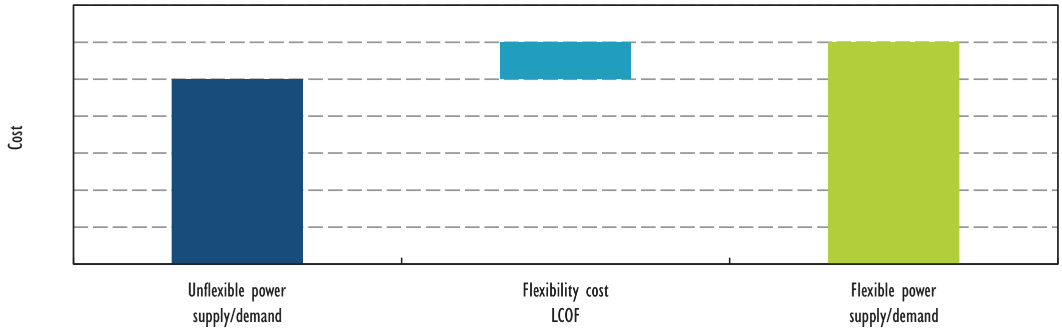
The objective of this Annex is to provide a brief description of methodology and major assumptions used for levellised cost of flexibility (LCOF) evaluations.

LCOF is a simplified metric based on LCOE (Levellised Cost of Energy). It provides an estimate of the additional cost associated with generating or consuming 1 megawatt hour (MWh) of electricity more flexibly (Figure A1). For example, in the case of storage, LCOF provides a cost estimate of storing a MWh for later consumption, given a particular operation regime of the storage. As in standard LCOE evaluations, both costs and energy flows are discounted. This allows for the comparison of projects with different cost structures and lifetimes.

LCOF provides a single, simplified metric that can be used to compare different types of systems and flexibility services in terms of their cost. The benefits that different flexibility options can bring for system operation and investment may also differ. This is not reflected in the LCOF approach, but needs to be factored in when making a full comparison of different options.

In the following, the exact approach and assumptions for LCOF calculations for all four flexible resources is presented.

Figure A.1 • Illustration of the LCOF approach



Key point • LCOF represents the additional cost per megawatt hour for supplying or consuming power more flexibly.

Grid infrastructures

LCOF is calculated differently for transmission lines and distribution networks.

Transmission

Transmission LCOF represents the cost of transporting 1 MWh of electricity over a given distance using a transmission line and includes related losses. Various transmission technologies have been considered, namely AC overhead lines (AC OHL), DC overhead lines (DC OHL) and DC cables.

Sensitivities have been analysed to take into account different line lengths (see Table A1 for details) and utilisation rates (i.e. 6 000, 4 500 and 3 000 full-load hours [FLH] per year). The sensitivity on the utilisation rate is particularly important when the use of the transmission line is exclusively dedicated to VRE generation, whose capacity factor is typically lower than 3 000 FLH.

Table A.1 • Key assumptions for LCOF of transmission lines

		AC OHL	DC OHL	DC cable
Lifetime	yr	40	40	40
CAPEX line	thousand USD/km/MW	1.4	0.9	1.8
CAPEX stations	k USD	60 000	250 000	250 000
Annual O&M	% CAPEX	1.3%	1.5%	1.5%
Losses due to line length*	%	5%	3%	3%
USD value of energy losses	USD/MWh	40	40	40
Discount rate	%	7%	7%	7%
Sensitivities				
Length	km	50-250	500-1 000	50-1 000
FLH–utilisation rate	h	3 000-6 000	3 000-6 000	3 000-6 000

Note: CAPEX = capital expenditure.

* Value per 500 km is reported, losses assumed to vary linearly with line length.

Distribution

LCOF of distribution grids represents the additional costs for a newly built distribution system to connect a certain amount of distributed solar PV generation and feed its production into the transmission grid. The flexibility cost has to be considered as the additional costs to build and operate a "solar PV-enabled" distribution infrastructure in comparison with the costs of a traditional distribution grid.[1] LCOF It is expressed in USD/MWh of annual solar PV production.

The analysis considers a simplified grid serving 20 000 households, each using the same size solar PV system. Different assumptions relating to the average size of the distributed solar PV plants and the length of medium-voltage (MV) distribution lines have been analysed.

The dimensioning of the distribution grid takes a bottom-up approach. In the reference case without solar PV, the low-voltage section of the distribution system is dimensioned according to a rule of thumb that estimates the system peak load attributing 2 kW peak demand to each household (dena, 2012) even if the real peak load of each single household may reach approx 4.5 kW (aggregation effect of peak load). Medium-voltage/low-voltage (MV/LV) transformers are installed assuming that 200 households are connected to the same transformer (i.e. each MV/LV transformer has a capacity of 400 kW). Medium-voltage lines and high-voltage/medium-voltage (HV/MV) transformers are dimensioned based on the sum of the peak consumption of the downstream sections (see Table A2 for additional details).

In the scenarios including distributed solar PV generation, the overall system is dimensioned in order to be able to transport 85% of the solar PV peak power output to the transmission level. The production peak of all distributed plants is simultaneous, with no local consumption assumed at peak. Therefore, with the introduction of solar PV, the MV/LV transformers, the MV distribution lines and the HV/MV transformers need to have a larger size compared to the no solar PV case. This analysis assumes the dimensioning of HV lines and LV lines remain unchanged, which may underestimate cost impacts under some circumstances.

Cost assumptions are based on IEA analysis, consultations with operators and major industry publications (dena, 2012).

1. The traditional distribution grid is assumed to be dimensioned to exclusively distribute power from the transmission system to the users.

Table A.2 • Key assumptions for LCOF of distribution grids

		Reference case no solar PV	A case solar PV 2.5 kW	B case solar PV 3.25 kW	C case solar PV 4.0 kW
Connected households (HH)	#	20 000	20 000	20 000	20 000
Peak demand HH	kW	4.5	4.5	4.5	4.5
Solar PV installations	#	na	20 000	20 000	20 000
Average size of a solar PV plant per HH	MW	na	2.50	3.25	4.00
Annual solar PV production	MWh	na	50 000	65 000	80 000
HV/MV transformer size	MW	40	43	55	68
Capital cost HV/MV transformer	k USD	3 850	3 900	4 250	4 550
Number HV/MV transformers	#	1	1	1	1
Length MV lines*	km	250	250	250	250
Capital cost MV line	k USD/km	84	85	93	98
MV/LV transformer size	kW	400	425	550	675
Capital cost MV/LV transformer	k USD	50	52	61	70
Number MV/LV transformers	#	100	100	100	100
Length LV lines	km	500	500	500	500
Capital cost LV line	k USD/km	55	55	55	55
Annual O&M	% CAPEX	2.7%	2.7%	2.7%	2.7%
Overall energy losses	%	10%	10%	10%	10%
Value of energy losses	USD/MWh	40	40	40	40
Discount rate	%	7%	7%	7%	7%

Note: HV = high voltage; MV = medium voltage; LV = low voltage; na = non applicable.
* Sensitivity analysis considered different length for MV lines (i.e. 150 km and 350 km).

Dispatchable generation

The primary impacts of the VRE deployment on dispatchable generation are highlighted in Chapter 2. In summary and on the single plant level, they can be summarised as increased cycling and potentially lower capacity factor. The comparison uses a base case, characterised by reference capacity factors and cycling regimes. The flexibility case may assume lower capacity factors, increased cycling or a combination of both (see Table A3 for details). The LCOF captures the differences in per megawatt hour generation cost of the base case and the flexibility cases.

Storage

Storage LCOF represents the cost of building and operating a storage device, expressed per MWh of retrieved electricity. The analysis considers different technologies, utilisation patterns and energy to capacity ratios. LCOF includes the cost of electricity losses (priced at USD 40/MWh) but does not include the original cost of producing the electricity.

Sensitivities in the LCOF evaluations are based on the assumption that the storage equipment will be used for 183 or 365 or 730 full cycles per year through its entire lifetime. Three different storage sizes (in megawatt hours) have been analysed: 2 h, 4 h or 8 h of uninterrupted power supply at the rated power capacity (in megawatts), i.e. 2h, 4h or 8h discharge time were assumed. Technologies analysed are: pumped hydro storage (PHS), compressed air storage (CAES) and lithium-ion batteries.

Table A.3 • Key assumptions for LCOF of dispatchable generation

		Combus. engine CC	CCGT flex	CCGT inflex	Coal flex	Coal inflex	Nuclear
Reference case assumptions							
FLH	h	3 500	4 500	4 500	6 000	7 000	7 500
Cycling	# start-ups/yr	20	20	20	1	1	1
Startup cost	USD/MW/start-up	20	50	120	100	250	1 000
Lifetime	yr	20	25	25	30	30	40
Efficiency	%	50	55	55	45	37	35
CAPEX	k USD/MW	700	800	800	1 600	1 600	6 000
Fuel cost per unit	USD/MMBtu	8	8	8	3	3	0
CO_2 cost	USD/tonne	30	30	30	30	30	30
Discount rate	%	7%	7%	7%	7%	7%	7%
Reduced FLH and increased cycling assumptions							
FLH reduction	No FLH reduction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Medium FLH reduction	-10.0%	-10.0%	-10.0%	-10.0%	-10.0%	-10.0%
	Large FLH reduction	-20.0%	-20.0%	-20.0%	-20.0%	-20.0%	-20.0%
Cycling	Low # start-ups/yr	50	50	50	50	50	20
	Medium # start-ups/yr	100	100	100	100	100	40
	High # start-ups/yr	200	200	200	200	200	60

Table A.4 • Key assumptions for LCOF of storage

		PHS hydro retrofit	PHS new	CAES	Li-ion battery
Cycles per year – reference case	# cycles/yr	365	365	365	365
Discharge time – reference case	h	4	4	4	4
Efficiency-full cycle	%	80%	80%	60%	85%
Lifetime	yr	40	40	35	7-15*
Capacity CAPEX	USD/kW	500	1 000	1 000	1 500
Energy CAPEX	USD/kWh	0	50	50	500
Annual O&M	% CAPEX	1.0%	1.0%	1.5%	1.2%
Value of energy losses	USD/MWh	40	40	40	40
Discount rate	%	7%	7%	7%	7%
Sensitivities					
Cycles per year	High # cycles/yr	730	730	730	730
	Low # cycles/yr	183	183	183	183
Discharge time	Low – h	2	2	2	2
	High – h	8	8	8	8

* Li-ion (lithium-ion) battery lifetime, depending on cycling assumptions, ranges from 7 years (at 730 cycles per year) to 15 years (at 183 cycles per year).

Demand-side integration

Two demand-side integration (DSI) processes were analysed:

- load shifting via domestic/commercial water heating as an example of small-scale DSI applications
- load shedding in aluminium smelting as example of large-scale DSI applications.

For small-scale DSI, LCOF is the additional costs to enable smart operation of distributed heat storage devices via a daily time-shift of power consumption.[2] This is enabled by the installation of a small storage for hot water and the appropriate control devices, including an advanced power meter. The process is repeated 365 times per year, through the entire lifetime of the water heater and the related equipment (approx 15 years). The efficiency of the process has been assumed to be 95% (sensitivities have been run assuming 50% efficiency and 100% efficiency). The capital expenditure of storage, control devices and smart meters has been assumed to range between USD 50/kW and USD 500/kW of rated device capacity with USD 100/kW representing the basecase. This represents the additional cost of the DSI-enabled device over a standard water boiler. The capital cost range analysed is intentionally wide, the evaluation is meant to capture the cost impacts of DSI devices on application of different scale. For example, the cost of a smart meter (e.g. USD 200) and smart enabler devices (e.g. USD 50) is equivalent to approx USD 60/kW for a 4.5 kW large domestic boiler, but is equivalent to over USD 125/kW for a smaller water heater (2.0 kW). LCOF includes energy losses, priced at USD 40/MWh.

For the LCOF evaluation of large-scale DSI applications, an industrial process (London Economics, 2013) has been selected: the load shedding in an aluminium smelter. In this case the capital cost of the DSI control equipment is negligible in comparison with variable costs, and the flexibility cost can be represented by the value of lost load. This is essentially evaluated on the basis of the market price of the aluminium that is not produced. Resulting LCOF ranges between USD 50/MWh and USD 80/MWh according to the market value of aluminium and raw materials needed for aluminium production (an aluminium price between USD 1 900/t and USD 2 300/t was assumed).

References

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London Economics (2013), "The Value of Lost Load (VoLL) for Electricity in Great Britain", final report prepared for the Office of Gas and Electricity Markets (OFGEM) and the Department of Energy and Climate Change (DECC), www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf.

2. The water heater is assumed to consume electricity four hours per day. DSI allows this consumption to take place whenever it is be most appropriate during the day.

Annex B • Key modelling assumptions

Introduction

This Annex provides background information on the Investment Model for Renewable Energy Systems (IMRES) and Pöyry's BID3 model, which were used for the economic modelling analysis presented in this publication.

IMRES

Model description

IMRES is an electricity generation-planning model for low-carbon power systems, developed by researchers at the Engineering Systems Division of the Massachusetts Institute of Technology (de Sisternes, 2013).

Based on an initial set of available power plants, IMRES selects a combination of plants that meet electricity demand at minimum cost at a given value of lost load. As a versatile modelling framework, IMRES assists regulators and policymakers in indicative planning and in establishing R&D priorities, by evaluating possible policy outcomes along technical and economic dimensions. IMRES is particularly suited for policy design experiments aimed at assessing the impact of variable generation and flexibility technologies and carbon emission reduction policies on system costs and emissions.

As a planning tool, IMRES improves upon other currently available models by accounting for:

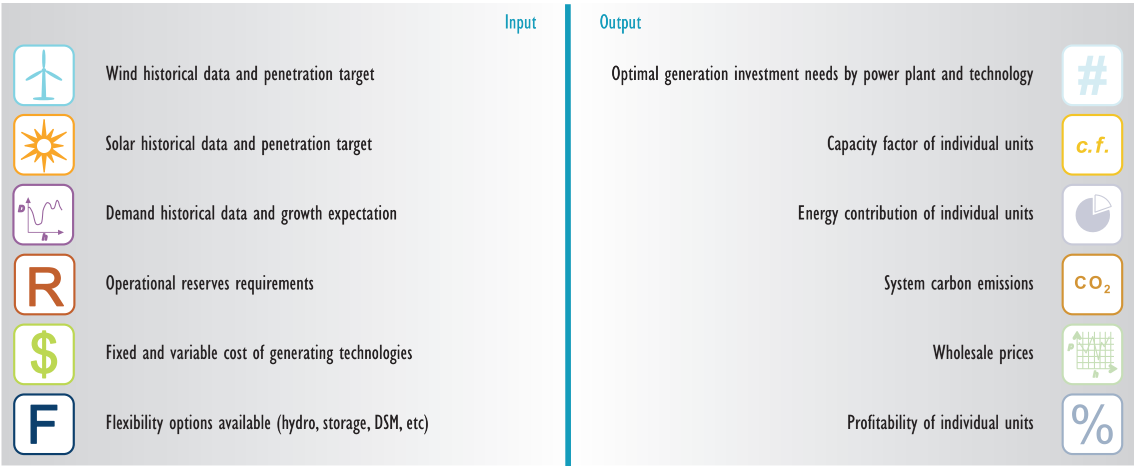
- the extra costs of a more intense cycling regime of thermal units due to the net load variability of renewable generation supply
- the technical operating characteristics of thermal units
- the need for capacity reserves
- the system-wide benefits of making the electricity system more flexible using storage, demand-side management, hydropower and flexible generation
- the option to curtail output from renewable generation.

In addition to these features, IMRES can endogenously produce hourly wholesale prices for a given set of market rules and calculate individually the profitability of each generation unit in the system.

IMRES' inputs range from the technical and economic characteristics of existing and future power plants to historical data on demand: wind, solar and hydro resources that characterise the particular system of study. Since these inputs are readily available for most power systems, planners can easily adapt IMRES to any power system. Parameter values for expected future installed capacity for wind and solar generation are used to scale up historical production time series of variable renewable power plants and extrapolate renewable output to different future capacities. Inputs and outputs of IMRES are summarised in Figure B1.

In addition to this basic setup, IMRES has been expanded for the purpose of this project to include other dynamic elements such as hydro reservoirs, electricity storage and demand-side integration (DSI) that all contribute to increase the flexibility of the system. IMRES thus captures the economic benefits accruing to the system as a result of the improved utilisation of renewable and thermal resources from deploying flexibility options.

Figure B.1 • Overview of inputs and outputs in IMRES



Modelling methodology

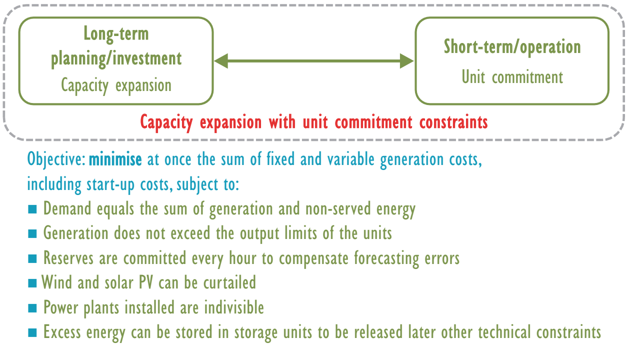
Classic capacity expansion models such as screening curve models assess primarily the capital and operating cost trade-off between generating technologies. This approach typically leaves out cost items such as start-up costs observed in real power systems and other technical considerations like the indivisibility of units, minimum output requirements, ramp limits and reserve margins. In the past, these elements could be safely ignored in planning models, as the daily load would exhibit a smooth pattern almost constantly repeated throughout the year. In contrast, the variability and uncertainty of net load at a large penetration of variable renewable energy (VRE) increase the importance of certain plant attributes such as start-up costs and other system-level constraints such as operating reserves. Planning models for systems featuring high shares of VRE need to appropriately account for these technical factors.

On a shorter time scale, unit commitment models are commonly employed to decide which power plants should be online and offline at every hour, as well as the electricity generated by each of them to meet demand at minimum cost. The comprehensive representation of the technical characteristics of power plants and operating reserves in unit commitment models makes them appropriate to closely reflect the impact of renewable generation on the operation of the system. However, unit commitment models do not include capacity planning decisions. They do not account for new investments.

The approach of IMRES is based on a capacity expansion formulation with unit commitment constraints, combining the economic assessment embedded in classic planning models with the techno-economic analysis of unit commitment models. This approach allows a detailed study of the impact of technical constraints on cost, integrating both long-term investment decisions and the short-term operating decisions, driven by the high net load variability of power systems with large shares of variable renewable generation.

Formally, the model can be divided into two components: a first component where individual power plants' building decisions are made (capacity expansion); and a second component, incorporating the operational decisions associated with the power plants that have been built in the first stage (unit commitment). The particularity of IMRES is that its cost function includes not only capital cost and variable operating costs, but also the costs of a more intense cycling regime, subject to an array of technical constraints that guarantee the technical feasibility of the modelled system (Figure B2).

Figure B.2 • Overview of IMRES' structure, including its main technical features



Net load approximation

One inescapable difficulty arising from combining capacity expansion decisions with unit commitment decisions is the dramatic increase of the complexity when dealing with both problems simultaneously. Hourly unit commitment models spanning one full year include multiples of 8 760 binary variables (those accounting for commitment states and start-up decisions). The addition of an outer component that accounts for building capacity decisions, multiplies the number of variables by as many individual units as the number that are available to be built. As a result, the dimensionality of the joint problem becomes prohibitive even for state-of-the-art high-performance computers.

A common approach to reduce the size of the problem, for the unit commitment component, is to select several weeks that representatively characterise demand, wind and solar output. These weeks must simultaneously account for the total energy demand in the system studied and the combined hourly variability of demand and renewable resource availability. In particular, IMRES uses a set of four weeks that fit the net load duration curve the best (de Sisternes and Webster, 2013). By focusing on the net load duration curve as opposed to extreme singular cases (peak demand, highest and lowest wind output events, etc), the model retains the correlation between demand, wind and solar output.

Even though the number of data points in the approximation is notably reduced compared to the original one-year series, the demand structure encapsulated in the selected four weeks matches the original net load duration curve with high accuracy. Moreover, since demand and renewable output are presented in full weeks, IMRES retains the hour-to-hour variability needed to properly represent the interaction between renewables and thermal technologies.

Available flexibility options

IMRES models low-carbon energy systems where VRE plays a major role in the electricity generation mix. As such, IMRES incorporates the option of adding a set of dynamic elements that increase the flexibility of the system, improving the utilisation of system assets while decreasing curtailment. The flexible technologies included in IMRES are:

- **Hydro reservoirs**, implemented as a volume of stored energy that is delivered when it is most needed, complementing renewable generation at times when resource is scarce.
- **Electricity storage**, implemented as a capacity to store electricity for an unlimited amount of time, up to a maximum volume equal to the capacity of the storage unit. The energy stored can then be released at a later point when it is most cost-effective.
- **Flexible thermal technologies**, implemented by lowering the minimum output requirement of conventional thermal technologies (the minimum generation level at which they can operate).
- **Demand-side management**, implemented as a capability to shift part of the demand at a given hour throughout the following six hours.

The reference test system

Hourly time series of power demand, wind and solar generation from Germany in 2011 were used in constructing the IMRES test system.[1] Wind and solar PV generation were normalised according to daily installed capacities and up-scaled according to the different VRE penetration scenarios analysed. Germany was selected on the basis of its large and geographically spread wind and solar PV portfolio, which is important when up-scaling historical production time series.

The installed conventional power generation fleet is optimised by the IMRES model, depending on the respective scenario and sensitivities. When composing the plant mix, the model can choose between nuclear, coal, combined-cycle gas and open-cycle gas power plants. The 0% VRE case is based on relevant shares of coal, CCGT and nuclear generation (Table B1).

VRE generation does not enjoy priority dispatch in the IMRES model. As such, curtailment occurs whenever it can contribute to reduce the cost of the system (for instance, to avoid shutting down a power plant and the subsequent cost of starting up again).

Table B.1 • Generation mix in the IMRES test system at 0% VRE penetration

	Installed capacity GW	*Generation TWh/yr*
Nuclear	12.0	105.2
Solar	0.0	0.0
Wind	0.0	0.0
Coal	33.0	272.1
CCGT	30.8	111.6
OCGT	4.6	0.5

Scenarios and sensitivities

Over 70 different sensitivities have been performed with IMRES on the basis of two very different optimisation assumptions (referred as scenarios).

- In the ***Legacy* scenario**, the installed power plant mix is optimised to cover the full electricity demand (with no renewable contribution). In a second step, different shares of VRE and flexibility options are added. The system is operated taking into account these new elements, keeping the plant mix unchanged. This situation is close to the reality of VRE integration in stable power systems with little incremental demand or need for plant replacement, or systems where VRE deployment occurs very rapidly and the system cannot adapt at the same speed. It is important to note that the name Legacy refers to the plant mix. All system costs – including the investment costs of conventional power plants – are taken into account under this scenario. Under the Legacy scenario, VRE generation and flexibility options do not contribute to avoiding investment costs in other parts of the power system. As such, this scenario is closer to a "worst case" for VRE integration.
- In the ***Transformed* scenario**, IMRES optimises the installed power plant mix based on net load, i.e. conventional power plants are optimised to cover only part of the electricity demand and balance VRE. In addition, the optimisation of power plant investments is influenced by flexibility options; i.e. flexibility options can reduce the need for power plant investments. This situation is closer to the reality of dynamically evolving power systems with high demand growth or in need of replacement of old assets. The Transformed scenario presents a more favourable scenario for VRE integration, with lower system costs resulting from exploiting all possible synergies between VRE generation, flexibility options and thermal plants.

1. The IMRES system is, however, in no way representative of the German power system, given the assumption of zero.

For each of the two scenarios, different deployment levels and combinations of flexibility options were analysed (some of those sensitivities are summarised in Table B2). In particular, sensitivity analyses tested different shares of VRE in the generation mix (i.e. 0%, 30% and 45% of the annual generation) and the introduction of various flexibility options, namely:

- **Flexible generation**: this has been modelled either adding reservoir hydro generation plants to the modelled power system (3 GW and 6 GW in the lower and higher case respectively), or assuming the retrofit of legacy coal plants. The retrofit is intended to increase the system flexibility by reducing the required minimum output of coal plants from 70% to 50% of the nominal generation capacity.
- **Demand-side integration (DSI)**: implemented as a capability to shift part of the demand at a given hour throughout the following six hours. The different DSI deployment levels implemented – low, medium and high – correspond to 2 GW, 4 GW and 8 GW of effective DSI capacity respectively.
- **Storage**: 2 GW, 4 GW and 8 GW of storage are added to the test system with 8 hours of storage capacity.

In addition, other sensitivities explored various assumptions concerning fuel cost, start-up costs of power plants and the combined deployment of various flexibility options, e.g. DSI and storage or DSI and flexible generation.

Table B.2 • IMRES selected sensitivities

		Legacy scenario		*Transformed scenario*	
	0% VRE	*30% VRE*	*45% VRE*	*30% VRE*	*45% VRE*
Baseline	No flex	No flex	No flex	No flex	No flex
Reservoir hydro		3 GW	3 GW	3 GW	3 GW
		6 GW	6 GW	6 GW	6 GW
DSI – demand-side integration		2 GW	2 GW	2 GW	2 GW
		4 GW	4 GW	4 GW	4 GW
		8 GW	8 GW	8 GW	8 GW
Storage		2 GW	2 GW	2 GW	2 GW
		4 GW	4 GW	4 GW	4 GW
		8 GW	8 GW	8 GW	8 GW
Coal retrofits		Reduced min output (70->50)	Reduced min output (70->50)	-	-

Note: additional sensitivities analysed different start-up costs for thermal generation plants and various combinations of flexibility options both in the Legacy and the Transformed scenarios.

Key model parameters

Key input parameters include:

- **Fixed and variable costs of generation plants**: fixed costs include the annuity of capital expenditures and fixed O&M expenditures while variable costs include mainly fuel and carbon costs (priced at USD 30/t) as it is illustrated in Table B3.
- **Start-up cost of thermal generation plants**: various sensitivities analysed two different cases characterised by higher and lower start-up costs (see Table B4).
- **Costs for the deployment of flexibility resources**: cost of flexibility resources are technically not an input of the model and are not taken into consideration during the optimisation process, even if they are processed in the cost-benefit analysis (Table B5).
- Discount rate: a 7% discount rate has been adopted for all technologies except for open-cycle gas turbine (OCGT) power plants, where 10% was assumed.

Table B.3 • Fixed and variable costs of IMRES generation technologies

Fixed costs	*Capital cost USD/kW*	*Lifetime yr*	*WACC*	*Annuity capital cost USD/MW/yr*	*Fixed O&M USD/MW/yr*	*Total fixed cost USD/MW/yr*
Nuclear	5 500	40	7 %	412 550	90 000	502 550
Coal	1 800	30	7 %	145 056	36 000	181 056
Gas CC	850	20	7 %	80 234	28 000	108 234
Gas peaker	760	20	10 %	89 269	17 000	106 269
Wind	1 600	20	7 %	151 029	40 000	191 029
Solar	1 600	20	7 %	151 029	30 000	181 029

Variable costs	*Variable O&M USD/MWh*	*Fuel consumption MBtu/MWh*	*Fuel price USD/ MBtu*	*Fuel cost USD/MWh*	*Carbon emission tCO_2eq/MWh*	*Carbon cost USD/ MWh*	*Total variable cost USD/ MWh*
Nuclear	2.00	10.50	0.43	4.51	0.00	0.00	6.5
Coal	4.25	8.80	2.70	23.76	0.85	25.48	53.6
Gas CC	3.43	7.05	7.00	49.35	0.37	11.23	64.0
Gas peaker	14.7	10.85	7.00	75.95	0.58	17.28	107.9
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: WACC = weighted average cost of capital.

Table B.4 • Start-up costs of thermal generation

	Low sensitivity USD/MW/start	*High sensitivity USD/MW/start*
Nuclear	1 000	1 000
Coal	100	250
Gas CC	50	150
Gas peaker	20	50

Table B.5 • Costs of flexibility resources

	Capital cost USD/kW	*Lifetime yr*	*O&M % of CAPEX/yr*
Storage	1 250	40	1
DSI	500	30	1
Hydro reservoir	3 000	50	2
Coal retrofit	10-20	15	0

Notes: CAPEX = capital expenditure. Coal retrofit is intended as the additional cost for retrofitting existing coal plants.

Estimation of network costs

IMRES does not include an explicit representation of the electricity grid (single node) and considers the power system in isolation from other neighbouring systems (no interconnection). As a consequence, the model does not take into account the VRE curtailment due to network congestions. Depending on the power system studied, the absence of network representation may lead to an underestimation of the costs relative to the integration of high shares of VRE, as it does not consider investments needed for reinforcement and expansion of the network.

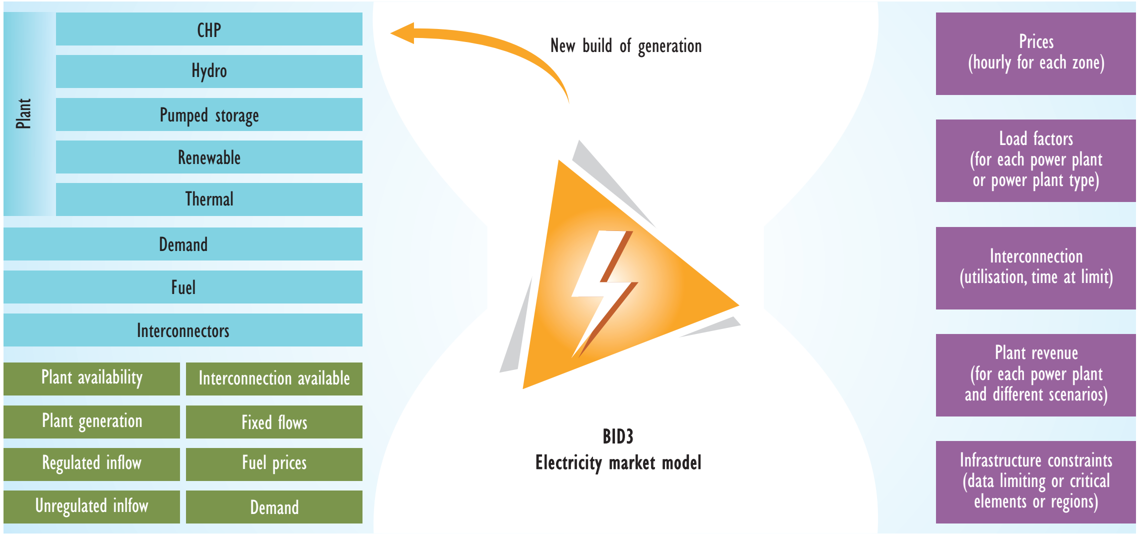
Network costs have thus been included ex-post and range between two levels. The lower level is set to 10% of overall generation costs. On the high end, annual network investments are assumed to be USD 2.6 billion at 0% VRE penetration and are expected to reach USD 3.5 billion in the long term at 45% VRE (Transformed scenario).[2] The transformation phase is characterised by a higher level of annual grid investments assumed to reach over USD 4.5 billion. The reason of higher grid costs during this phase, in comparison with the long term costs, is due to the build-up of new infrastructure in the transformation stage.[3] Grid investments for 30% VRE penetration are estimated proportionally with grid investments assumed for 0% and 45% VRE penetration.

BID3

Model description

BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European electricity grid. It simulates all 8 760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

Figure B.3 • Overview of BID3



The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plants and interconnectors on the system. At an aggregate level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

Producing the system schedule

- **Dispatch of thermal plant**. All plants are assumed to bid cost-reflectively and plants are dispatched on a merit-order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plants with higher short-run variable costs. This reflects a fully competitive market and leads to a

2. Network costs have been estimated as the annuity of all investments assumed for a period of 40 years (expected lifetime of network infrastructures). Discount rate is 7%.

3. These figures are based on analysis for the German power system (DLR, Fraunhofer IWES and IFNE, 2012), an upper limit for network investments is around EUR 5 billion/year for the period 2012-2030 (the estimate considers both transmission and distribution grids). Network investments averaged EUR 2.7 billion/year in the period 1994-2008. The increase of required investments is due to additional infrastructure during the transition including the facilitation of a single European electricity market.

least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times.

- **Dispatch of hydro plant**. Reservoir hydro plants are dispatched using a water value method, where the option value of stored water is calculated using stochastic dynamic programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs and the time of year.
- **Variable renewable generation**. Hourly generation of variable renewable energy (VRE) is modelled based on detailed wind speed and solar radiation data which can be constrained, if required, due to operational constraints of other plants or the system.
- **Interconnector flows**. Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.
- **Demand-side response and storage**. Operation of demand side and storage is modelled in a sophisticated way, allowing simulation of flexible load such as electric vehicles and heat while respecting demand side and storage constraints.

Power price

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example the different price zones within Norway). The hourly power price is divided into two components:

- **Short-run marginal cost (SRMC)**. The SRMC is the extra cost of one additional unit of power consumption. It is also the minimum price at which all operating plants are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plants will fully cover their variable costs, including fuel, start-up, and part loading costs.
- **Scarcity rent**. A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market.

Key input data

Pöyry's power market modelling is based on a quarterly-updated plant-by-plant database of the European power market. As part of the same process, Pöyry also reviews interconnection data, fuel prices and demand projections.

- Demand. Annual demand projections and demand profiles are based on TSO forecasts and on Pöyry analysis.
- VRE generation. Historical wind speed data and solar radiation data are used as raw inputs.
- Wind data is from Anemos and consists of reanalysis data from weather modelling based on satellite observations.
- The solar radiation data is from Transvalor and is again converted to solar generation profiles based on capacity distributions across each country.

Key economic parameters used in the model include the following:[4]

- The capital costs for selected generation technologies were agreed by Pöyry and the IEA and are summarised in Table B6.

4. BID3 operates in euros. An exchange rate of EUR 1 = USD 1.3 is used for reporting assumptions.

- Assumed prices for coal and gas generation fuels are respectively USD 2.7/MBtu and USD 8.0/MBtu.
- Carbon price: USD 30/t in Europe and USD 35/t in Great Britain.
- CAPEX for Interconnection expansion: USD 1 300/MW/km for onshore interconnections and USD 2 600/MW/km in case of offshore links. Operating lifetime is assumed to be 50 years both for onshore and offshore interconnections.
- Investments in hydro pump storage are expected to amount to USD 1 170/kW, and the operating lifetime of the storage infrastructure is assumed to be 50 years.
- The capital cost for the revamping of dispatchable hydro power plants, repowering existing power plants in order to increase available generation capacity with no changes to the reservoir structure, is assumed to range between USD 750/kW and USD 1 300/kW. The operating lifetime is assumed to be 50 years.
- The deployment of DSI, to enable the flexible management of 8% of overall power demand, is assumed to cost USD 4.7/MWh of overall power demand. This is in line with NEWSIS assumptions (Pöyry, 2011).
- Different discount rates have been adopted to compare various technologies analysed, in particular 8% was assumed for gas turbines, 9.0% for other thermal generation plants (coal/lignite/CCGT), 7.5% was assumed for storage, interconnectors and hydro generation.

Table B.6 • Investment cost for selected generation technologies

	Investment cost USD/kW	*Operating lifetime (yr)*
CCGT	1 008	25-30
Gas turbine	715	20-25
Coal	2 470	35-40
Lignite	2 470	35-40
Nuclear	4 672	40-50
CCS gas	2 080	25-30
CCS lignite	3 224	30-35
CCS coal	3 224	30-35

Model results

BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high-level metrics such as total system cost and economic surplus. (Figure B3).[5]

Scenarios and sensitivities

The main idea for establishing the value of different flexibility options is to calculate the cost difference between pairs of model runs. In each pair, one run does not include the particular flexibility option, while the other run does. The difference in cost between the two runs is then considered as the value of that flexibility option.

This means that the reference run – the **baseline run** – for all different comparisons is the same and only the addition of one or more flexibility options is considered in the second model run for each pair.

The difference between the baseline run and the run including a particular flexibility option is chosen such that possible cost reductions can be reliably attributed to the flexibility option. When the utilised power system model makes endogenous investment decisions, these decisions may be different in the flexibility run. Net cost savings that arise from such changes in investment patterns are included in the value of the flexibility option.[6]

5. More information about BID3 are available at www.poyry.com/BID3.
6. For example deploying DSM may reduce peak demand and allows for fewer investments in conventional capacity.

Baseline run

The baseline scenario was developed via an adaptation of Pöyry's central scenario. The representative year of analysis is 2030 and the study focuses on selected countries in North Europe (namely Denmark, Finland, France, Great Britain, Germany, Ireland, Norway, Sweden), characterised by a cumulative annual power demand of 1 935 TWh.

VRE penetration is assumed to be 29% of power demand and 27% of overall generation. The generation mix is mainly based on nuclear, wind (13% of overall generation is represented by wind onshore and 9% by wind offshore), hydro, CCGT and CHP (Table B7).

Table B.7 • Generation mix of baseline run

	Generation share %
CCGT	13
CHP	10
Coal and lignite	5
Nuclear	21
Hydro	15
Biomass	6
Wind onshore	13
Wind offshore	9
Solar PV	5
Others	2

Installed storage capacity (modelled as pumped hydro reservoir) amounts to 18.8 GW in the baseline scenario while interconnection capacity between analysed countries amounts to 62.6 GW (Table B8).

Table B.8 • Net Transfer Capacity (NTC) between analysed countries in baseline run

From / To	Denmark	Finland	France	Great Britain	Germany	Ireland	Norway	Sweden
Denmark					3 700		1 600	2 440
Finland							300	3 850
France				3 988	3 600			
Great Britain			3 988			1 360	1 400	
Germany	3 100		4 300				1 400	1 400
Ireland				1 240				
Norway	1 600	300		1 400	1 400			6 400
Sweden	1 980	4 250			1 400		6 250	

Flexibility assessment runs

Flexibility assessment runs were calculated for interconnection, storage, demand-side integration and combinations of interconnection and each of the two other options. In addition, the cost-effectiveness of retrofitting hydro power plants to increase capacity without increasing reservoir size was analysed.

In the increased-interconnection run, 16 GW of interconnection capacity between analysed countries were added to the modelled power system (Table B9).

Table B.9 • Additional NTC characterising the increased-interconnection run

From / To	Denmark	Finland	France	Great Britain	Germany	Ireland	Norway	Sweden
Denmark								1 500
Finland							700	
France				1 500	1 500			
Great Britain			1 500			700	700	
Germany			1 500				700	700
Ireland				700				
Norway		700		700	700			
Sweden	1 500				700			

In the increased-storage run, 8 GW pumped hydro storage were added to the modelled power system (mainly in Germany, France and Great Britain), bringing overall storage capacity to 26.8 GW.

The demand-side run explores the deployment flexibility in power demand. DSI potential corresponds to 8% of overall power demand. The maximum shift assumed is 24 hours. Schedulable demand comes from electric vehicles (2.3% of total) and heat and other schedulable load (5.7%).

The cost-effectiveness of retrofitting hydro power plants was analysed in combination with an increase of interconnection capacity. In particular, generation capacity of hydro power plants was assumed to be increased by 7 GW (mainly in Norway and Sweden), with no revamp of related reservoir. The interconnection capacity within the region under scrutiny was increased by 8.6 GW, essentially reinforcing the links connecting Norway and Sweden with other countries (Table B10).

Table B.10 • Additional NTC characterising the reservoir hydro + interconnection run

From / To	Denmark	Finland	France	Great Britain	Germany	Ireland	Norway	Sweden
Denmark								1 500
Finland							700	
France								
Great Britain							700	
Germany							700	700
Ireland								
Norway		700		700	700			
Sweden	1 500				700			

Finally, two additional runs were developed combining the flexibility assumptions adopted in previous runs. In particular, the assumptions for additional interconnections were applied in combination with:

- DSI assumptions of demand-side run (DSI potential assumed 8% of overall demand)
- Storage assumptions of increased-storage run (8 GW of additional pumped hydro storage).

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Annex C • FAST2 assumptions and case study attributes

Introduction

This Annex provides background data on the assumptions of the FAST2 assessment and the scoring system used for assessing different attributes of case study regions.

FAST2

In FAST2, four flexibility resources are represented: generation, interconnection, demand-side integration and storage. The following two sections state the characteristics of the respective flexibility resources. Assumptions are based on questionnaire data, literature values and IEA data.

Flexible generation

Power plant types were assigned to flexibility and technology categories. Generic key characteristics of the power plant fleet were assumed (Table C1). Minimum generation refers to the minimum stable output a power plant can achieve, expressed as share of nominal output capacity. The up and down ramp rate, also represented as a share of nominal output, is implemented symmetrically. Start-up time corresponds to a start up from warm conditions (8 to 60 hours shutdown).

Table C.1 • Flexibility characteristics of dispatchable generation

	Minimum generation	*Ramp rate (+/-)*	*Start-up time (warm start)*
	% nom. capacity	% nom. capacity	h
CCGT inflex	40	8	3
CCGT CHP flex	40	8	2
CCGT CHP inflex	80	2	3
Coal flex	30	8	4
Coal inflex	60	4	8
Coal CHP flex	50	4	5
Coal CHP inflex	80	2	9
OCGT	15	20	0.16
Steam	30	8	3
Steam CHP	100	2	4
Lignite inflex	60	2	8
Lignite flex	30	4	4
Nuclear	90	2	24
Hydro reservoir	0	15	0.16
Hydro run-of-river	50	5	0.16
Bioenergy	50	8	3
Other	50	3	2

Interconnection, demand-side integration and storage

For each case study region, assumptions on interconnections, DSI and storage (Table C3) were derived primarily from questionnaire data or publicly available resources. For North West Europe, interconnection capacities of the case studies to neighbouring power systems were based on the net transfer capacities published by ENTSO-E. For demand-side integration, a generic assumption based on the maximum of either the share of minimum load or net load was made due to problems with data availability. Storage represents installed pumped hydro power plants in the respective case study region.

Table C.2 • Installed total capacity and number of units of dispatchable generation in case studies

	Brazil		ERCOT		Iberia		Italy		Japan East		North West Europe	
	Total capacity	# units	Total capacity	# units	Total capacity	# units	Total capacity	# units	Total capacity	# units	Total capacity	# units
	MW	-	MW	-	MW	-	MW	-	MW	-	MW	-
CCGT inflex	3 640	13	25 500	85	28 080	60	31 200	130	17 040	71	46 670	227
CCGT CHP flex	0	0	0	0	0	0	2 640	4	0	0	0	0
CCGT CHP inflex	2 100	30	11 100	30	3 990	181	8 000	200	1 780	89	9 901	404
Coal flex	0	0	0	0	190	1	5 200	8	10 500	15	2 375	5
Coal inflex	2 000	20	12 960	18	12 850	40	7 649	45	4 840	44	43 082	170
Coal CHP flex	0	0	0	0	0	0	0	0	700	1	6 815	14
Coal CHP inflex	750	5	0	0	40	2	452	7	900	18	18 670	192
OCGT	3 000	50	4 200	70	3 350	74	3 117	70	2 900	58	9 808	292
Steam	2 000	40	12 507	50	5 850	45	13 478	150	30 090	177	9 908	186
Steam CHP	0	0	0	0	307	23	1 609	65	930	31	5 944	214
Lignite inflex	0	0	8 050	7	0	0	0	0	0	0	10 010	35
Lignite flex	0	0	0	0	0	0	0	0	0	0	5 420	5
Nuclear	1 990	2	5 200	4	7 882	8	0	0	19 800	22	99 473	97
Hydro reservoir	43 750	70	600	30	11 200	35	17 500	350	3 100	31	44 025	138
Hydro run-of-river	43 750	70	0	0	11 800	745	4 676	2 500	4 430	443	32 828	17 127
Bioenergy	5 250	350	107	13	1 700	113	2 900	290	710	71	17 782	1 601
Other	6 252	521	0	0	4 400	700	4 000	400	2 480	620	15 222	2 658
Total capacity	114 482		80 224		91 639		102 422		100 200		377 933	

Table C.3 • Characteristics of interconnection, demand-side response and storage in case studies

			Brazil	ERCOT	Iberia	Italy	Japan East	North West Europe
Interconnection	Capacity	MW	2 000	1 000	1 850	7 465	0	17 433
Demand-side integration	Max. of share of minimum load or of share of net load level	%	5	5	5	5	5	5
Storage	Capacity	MW	0	0	6 550	7 540	26 270	18 190
	Energy content	MWh	0	0	52 400	60 320	210 160	145 520
	Efficiency	%	na	na	80	80	80	80

Note: na = non applicable.

Case study attributes

Case study regions were scored according to a number of fundamental system properties (see Chapter 3 for more details and description of the system attributes). Scores were made according to the following scales:

Power area size was scored on the basis of the system peak demand, ranked according to the following six levels: very high (>150 GW), high (>75 GW), medium-high (>50 GW), medium (>25 GW), low (>10 GW) very low (<10).[1]

Internal grid strength was scored on a five step scale (excellent, good, satisfactory, fair, poor).

Interconnection was scored on a five step scale (excellent, good, satisfactory, fair, poor).

Number of power markets in case study regions ranges from very fragmented markets such as India (based on 28 States with separated State Load Despatch Centres), to single markets such as Brazil, Iberia and Italy. North West Europe includes the Nord Pool Spot in the Nordic countries, EPEX Spot for Germany and France, BETTA in Great Britain and SEM for the Island of Ireland. Three regional areas have been considered in the Japan East region (Tokyo, Tohoku and Hokkaido).

Geographical spread of VRE generation was scored on a three step scale (widely dispersed, dispersed, concentrated).

Flexibility of dispatchable generation portfolio was scored on a five step scale (excellent, good, satisfactory, fair, poor).

Investment opportunity was scored on a five step scale (excellent, good, satisfactory, fair, poor).

1. The peak demand considered for the selected case study regions is 122 GW for India, 56 GW for Italy, 53 GW for Iberia, 76 GW for Brazil, 247 GW for North West Europe, 69 GW for Japan-East, 68 GW for ERCOT.

Annex D • Market design scoring

Introduction

The IEA has carried out an extensive survey of power market design as part of the GIVAR III project (Mueller, Chandler and Patriarca, forthcoming). The review covered:

- regulatory arrangements for the trade of bulk electricity
- an overview of regulatory arrangements for the trade of reserves
- regulatory agreements for the long-term contracting of generation capacity or other services
- regulatory arrangements for allocation of interconnector capacity
- regulatory arrangements regarding network tariffs
- regulatory arrangements regarding the curtailment of renewable energy generators.

The major findings of this analysis have been summarised, identifying eight key dimensions characterising the features of market design that are relevant for VRE integration. For the different electricity markets, each dimension has been evaluated on the basis of a scoring system. The higher a system scores, the more likely it is that the market will show good performance on an operational time scale at high shares of VRE. The analysed electricity markets pertain to the following (components) of case study regions: Texas (ERCOT), Italy, Iberia (Spain and Portugal), Ireland (Ireland and Northern Ireland), Nordic Market (Denmark, Sweden, Norway and Finland), Germany and France, Great Britain, India, Japan, Brazil. The list of considered dimensions, together with some details on the scoring system, can be found in section 6.7 of this report.

In order to assess the different case study regions, a distinction was made based on the role of the electricity market for system operations. Where system operations are driven primarily on the basis of short-term generator bids and private contracts between generators and suppliers/consumers, the above mentioned scoring framework is applied. In cases where system operations are not based on short-term bids or bilateral contracts, a different scoring system is applied. Three of the case studies fall under the second category: Japan, India and Brazil.

On the basis of traded volumes in Japan, the role of the Japan Electric Power Exchange (JEPX) appears marginal in comparison with the operations managed fully within vertically integrated electric power companies (EPCOs). In India, the dispatching process is managed mainly by State Load Dispatch Centres (SLDC) and generator remuneration is tariff based.[1] In Brazil, the trade of electricity via long-term contracts and auctions is separate from the dispatch of power plants (competition for the market rather than competition in the market). Trade is based on long-term auctions and power purchase agreements (PPAs) while generators are dispatched in real-time by the system operator (Operador Nacional do Sistema Elétrico, ONS), whose aim is to minimise overall costs maintaining system safety and security.

Japan, India and Brazil power systems are assessed on the basis of a general three-level scoring (poor/medium/good) that is not entirely equivalent to the market scoring system. Where scores are not applicable, they are left out in the overview charts.

The objective of the following paragraphs is to provide the reader with short summary tables, explaining how each market has been scored and why.

1. Tariffs are composed of three parts: a fixed component linked to the availability of generating stations, a second part intended to remunerate the variable generation costs and a third part related to deviations from schedules.

Table D.1 • Scoring of market design in Texas (ERCOT)

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: medium – liquid power exchange/centralised pool with over-the-counter contracts (OTCs). **MOTIVATION**: the majority of electricity supply is secured via bilateral contracts but the participation in the real-time dispatching processes is mandatory for all available resources. Therefore bilateral contracts are considered in the overall optimisation of power flows and congestion management, even if they may be dispatched as price-taker in the real-time market.
VRE dispatch	**SCORE**: medium – incentives are a premium on top of market price (e.g. Feed-in Premium). **MOTIVATION**: support mechanisms such as production tax credits are in place.
Dispatch interval	SCORE: high – quasi-real-time dispatch, shorter than 10 minutes. **MOTIVATION**: ERCOT runs Security Constrained Economic Dispatch (SCED) at least every five minutes. The resulting dispatch interval is therefore shorter than ten minutes. The day-ahead market is based on hourly bids/offers.
Last schedule update	**SCORE**: high – closer than 30 minutes before real-time. **MOTIVATION**: ERCOT may modify unit dispatch in the SCED process that is executed at least every five minutes. Market participants may submit or modify energy offers during the adjustment period running from 18:00 in the day-ahead, to one hour before the start of the operating hour.
System services definition	**SCORE**: medium – different pre-defined levels, VRE operation is included. **MOTIVATION**: monthly evaluation of reserve requirements. Reserve calculation takes into consideration expected wind power production and historical forecast errors.
System services market	**SCORE**: medium to high – some services remunerated, based on marginal price. **MOTIVATION**: procurement of ancillary services is co-optimised together with the procurement of bulk energy. Primary frequency response is mandatory and is not traded as an ancillary service; its provision is not remunerated.
Grid representation	**SCORE**: high – full representation of the transmission system (Locational Marginal Pricing). **MOTIVATION**: Nodal market, the grid is extensively represented in the market optimisation process. ERCOT market includes more than 4 000 nodes or points of grid interconnection. Locational Marginal Pricing in place.
Interconnector management	**SCORE**: medium – day-ahead, explicit auction. **MOTIVATION**: schedule for operations on DC ties are reported to ERCOT before 14:30 in the day-ahead. Transmission reservations are necessary on the Southwest Power Pool (SPP) side of the DC ties. There is not a US Federal Energy Regulatory Commission (FERC) Transmission Reservations requirement for the DC tie portions of the Mexican Comisión Federal de Electricidad (CFE) system. An operator wanting to schedule energy into or out of CFE via the DC ties must have a contract or agreement with CFE.

Key point • ERCOT quasi-real-time dispatch and nodal grid representation represent best practices in market design for VRE integration.

Table D.2 • Scoring of market design in Italy

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: medium – Liquid power exchange or centralised pool with some long-term bilateral contracts that constrain the dispatching process. **MOTIVATION**: voluntary market, purchase and sale contracts may also be concluded off the exchange platform (bilaterally). In 2011, bilateral trades represented 42% of energy exchanged in the day-ahead market.
VRE dispatch	**SCORE**: medium – incentives are a premium on top of market price (e.g. Feed-in Premium). **MOTIVATION**: a combination of support schemes, including tradable green certificates, Feed-in Tariffs (FiT) and Feed-in Premium (FiP) is in place.
Dispatch interval	**SCORE**: Low – dispatch interval larger or equal to one hour. **MOTIVATION**: one hour dispatch interval.
Last schedule update	**SCORE**: medium — on the day of operation but more than 30 minutes before real-time. **MOTIVATION**: four sessions on the intra-day market, the last one closing at 11:45 a.m. of the day of delivery.
System services definition	**SCORE**: medium – different pre-defined levels, VRE operation is included. **MOTIVATION**: daily estimation of reserve requirements based on VRE production forecasts for each market zone.
System services market	**SCORE**: low – some services remunerated, not paid at marginal price. **MOTIVATION**: reserves remunerated at the bids/offers price (pay-as-bid). Primary reserve service is not remunerated.
Grid representation	**SCORE**: medium – several market zones. **MOTIVATION**: market subdivided in zones (portion of the power grid where, for system security purposes, there are physical limits to transfers of electricity to/from other zones). If cross-border schedules among the zones violate transmission limits, the market is split into two or more zones with different prices.
Interconnector management	**SCORE**: medium – day-ahead, explicit auction. **MOTIVATION**: annual, monthly and daily explicit auctions by Capacity Allocating Service Company (CASC). Market coupling with Slovenia.

Key point • Hourly dispatch intervals and early market gate closure increase the requirement of reserves and do not facilitate efficient balancing of VRE portfolios.

Table D.3 • Scoring of market design in Spain and Portugal

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: medium – liquid power exchange or centralised pool with some long-term bilateral contracts that constrain the dispatching process. **MOTIVATION**: voluntary market, purchase and sale contracts may also be concluded off the exchange platform (bilaterally). Congestion management takes place after the market and may also impact bilateral contracts.
VRE dispatch	**SCORE**: medium – incentives are a premium on top of market price (e.g. Feed-in Premium). **MOTIVATION**: VRE support mechanisms include FiT and FiP.
Dispatch interval	**SCORE**: low – dispatch interval larger or equal to one hour. **MOTIVATION**: one-hour dispatch interval.
Last schedule update	**SCORE**: medium – on the day of operation but more than 30 minutes before real-time. **MOTIVATION**: six sessions on the intra-day market, the last one closing at 0:45 on the day of delivery.
System services definition	**SCORE**: medium – different pre-defined levels, VRE operation is included. **MOTIVATION**: daily markets for reserves. Reserve calculations include VRE forecasts.
System services market	**SCORE**: medium to high – some services remunerated, based on marginal price. **MOTIVATION**: primary reserve not remunerated, the other services remunerated at marginal price.
Grid representation	**SCORE**: medium – several market zones. **MOTIVATION**: in case of congestion the market may split into two zones (Spain and Portugal) with different prices.
Interconnector management	**SCORE**: medium – day-ahead, explicit auction. **MOTIVATION**: explicit auctions at interconnections with France and Morocco.

Key point • *Well developed reserve market; shorter dispatch intervals and gate closure closer to physical delivery may facilitate VRE integration.*

Table D.4 • Scoring of market design in Ireland

All Island Single Electricity Market	
Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: high – centralised pool. Dispatch can optimise across full generation portfolio. **MOTIVATION**: gross mandatory pool, the electricity from almost all installed capacity must be traded through market, including imports and exports. No bilateral trades of bulk electricity occur. Exceptions in place for plants <10 MW, which can contract with a supplier directly.
VRE dispatch	**SCORE**: medium – Incentives are a premium on top of market price (e.g. Feed-in Premium). **MOTIVATION**: support schemes (e.g. REFIT- Renewable Energy Feed-in Tariff and NIRO - Northern Ireland Renewables Obligation) in place.
Dispatch interval	**SCORE**: high – quasi-real-time dispatch, shorter than 10 minutes. **MOTIVATION**: dispatch instructions are issued in real-time on the basis of day-ahead bids. The day-ahead market is based on half-hour trading periods.
Last schedule update	**SCORE**: high – closer than 30 minutes before real-time. **MOTIVATION**: quasi-real-time dispatch executed by the system operator on the basis of day-ahead bids. Participants may submit offer up to ten hours on the day ahead.
System services definition	**SCORE**: medium – different pre-defined levels, VRE operation is included. **MOTIVATION**: day-ahead and intra-day procurement of reserve services, the estimation of reserve requirement includes VRE forecasts.
System services market	**SCORE**: medium to low – all services remunerated, but not based on marginal price. **MOTIVATION**: all services remunerated under standard/regulated tariff.
Grid representation	**SCORE**: low – no grid representation, one single market zone.
Interconnector management	**SCORE**: medium – day-ahead, explicit auction. **MOTIVATION**: explicit auctions to allocate interconnection capacity within the following timeframes: annual, seasonal, quarterly, monthly and daily.

Key point • The centralised pool, combined with real-time dispatch, represent a very good prerequisite to a market response to variability and facilitates VRE integration.

Table D.5 • Scoring of market design in the Nordic Market

Denmark, Finland, Norway and Sweden	
Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: medium – liquid power exchange or centralised pool with some long-term bilateral contracts that constrain the dispatching process. **MOTIVATION**: 73% of all Nordic electricity consumption in 2011 was traded through Nord Pool.
VRE dispatch	**SCORE**: medium – incentives are a premium on top of market price (e.g. Feed-in Premium). **MOTIVATION**: a combination of support schemes, including, FiT, FiP and quota systems is in place in various countries of the Nordic Market.
Dispatch interval	**SCORE**: low – dispatch interval larger or equal to one hour.
Last schedule update	**SCORE**: medium – on the day of operation but more than 30 minutes before real-time. **MOTIVATION**: trading on Elbas intra-day market takes place every day around the clock until one hour before delivery.
System services definition	**SCORE**: low – reserve requirements fixed long-term, no inclusion of VRE operation in calculation of requirements. **MOTIVATION**: reserve requirements based on possible system faults and subdivided between the Nordic countries on yearly and weekly basis.
System services market	**SCORE**: medium to low – all services remunerated, but not based on marginal price. **MOTIVATION**: the market of services is currently only partially co-optimised between countries. Different settlement rules such as marginal pricing, pay-as-bid, regulated prices are in place in different countries for various services.
Grid representation	**SCORE**: medium – several market zones. **MOTIVATION**: potential market splitting into 12 market zones.
Interconnector management	**SCORE** : high – full integration of capacity allocation via a unified spot market (implicit auctions). **MOTIVATION**: implicit auction of the transmission capacity connecting the 12 Nordic market zones. Implicit day-ahead auctions for interconnections with the Central and Western European (CWE) market through the interim tight volume market coupling (ITVC).

Key point • Highly developed interconnections management and market coupling between the Nordic countries and with Central and Western Europe. Further co-ordination may increase the efficiency of definition and procurement of reserves.

Table D.6 • Scoring of market design in Germany and France

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: low – market dominated by long-term bilateral contracts that constrain the dispatching process. **MOTIVATION**: 241 TWh traded on EPEX Spot in 2011 for deliveries in Germany and Austria, corresponding to 39% of total electricity consumption. Trade on EPEX Spot for deliveries in France amounts to 61 TWh, some 13% of national consumption.
VRE dispatch	**SCORE**: medium – incentives are a premium on top of market price (e.g. Feed-in Premium). MOTIVATION: a combination of support schemes, including, FiT and FiP is in place.
Dispatch interval	**SCORE**: medium – shorter than one hour but larger than 10 minutes. **MOTIVATION**: alongside hourly contracts, 15-minute contracts are available in Germany (only).
Last schedule update	**SCORE**: medium – on the day of operation but more than 30 minutes before real-time. **MOTIVATION**: trade on the intra-day market until 45 minutes before delivery.
System services definition	**SCORE**: low – reserve requirements fixed long-term, no inclusion of VRE operation in calculation of requirements. **MOTIVATION**: in Germany, the secondary and minute reserve need is estimated by the four TSOs each quarter. This involves a probability-based approach that is not based on short-term forecast of VRE generation. In France, secondary reserve needs are evaluated for each half-hour interval on the basis of national demand and trades with neighbouring countries.
System services market	**SCORE**: medium to low – all services remunerated, but not based on marginal price. **MOTIVATION**: procurement of ancillary services is based on different processes in Germany and France. All services are remunerated; price settlements rules include pay-as-bid (Germany) and regulated tariffs (France).
Grid representation	**SCORE**: medium – several market zones. **MOTIVATION**: possible market split resulting in different power prices in Germany and France.
Interconnector management	**SCORE**: medium – day-ahead, explicit auction. **MOTIVATION**: explicit auctions on France interconnections with Spain, Italy, Great Britain, Belgium and Switzerland (also implicit auctions in place between France and Switzerland). Explicit auctions on German interconnections with Poland, Czech Republic, Slovakia and Switzerland. Germany and France are part of the Central West European (CWE) market coupling with Benelux. In addition, the market area is coupled to the Nordic day-ahead market (Elspot) through the interim tight volume market coupling.

Key point • Reserve requirement definition and large presence of bilateral contracts limit market capacity to efficiently integrate large shares of VRE.

Table D.7 • Scoring of market design in Great Britain

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: low – market dominated by long-term bilateral contracts that constrain the dispatching process. **MOTIVATION**: OTCs represent the vast majority of power trade. About 20% of trading has taken place on exchanges in 2011.
VRE dispatch	**SCORE**: medium – incentives are a premium on top of market price (e.g. Feed-in Premium). **MOTIVATION**: support schemes such as Renewable Obligation (quota system) and FiT are in place.
Dispatch interval	**SCORE**: medium – shorter than one hour but larger than 10 minutes. **MOTIVATION**: 30 minutes settlement period.
Last schedule update	**SCORE**: medium – on the day of operation but more than 30 minutes before real-time. **MOTIVATION**: gate closure set one hour ahead of the delivery period.
System services definition	**SCORE**: medium – different pre-defined levels, VRE operation is included. **MOTIVATION**: national Grid helds "Wind Reserve" specifically to manage the additional variability in generation between four hours ahead of real-time and real-time caused specifically by wind generation.
System services market	**SCORE**: medium to low – all services remunerated, but not based on marginal price. **MOTIVATION**: all services are remunerated. Pay-as-bid settlement.
Grid representation	**SCORE**: low – no grid representation, one single market zone.
Interconnector management	**SCORE**: medium – day-ahead, explicit auction. **MOTIVATION**: explicit auctions to allocate capacity at interconnections with France, the Netherlands and Ireland.

Key point • Large predominance of OTCs limits the capability of the system to optimise the flexibility of the generation portfolio.

Table D.8 • Scoring of market design in India

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: poor. **MOTIVATION**: regional and state-level dispatch with limited co-ordination with national load dispatch centres. Long term PPAs represent the vast majority of power supplies.
VRE dispatch	**SCORE**: poor. **MOTIVATION**: feed-in Tariffs and other support mechanisms are in place. In addition, VRE dispatching is not co-ordinated between regions. In addition economic considerations may encourage reducing the state-level VRE dispatched volumes if the unscheduled interchange (UI) price is lower than VRE FiT/contract rates.
Dispatch interval	**SCORE**: medium – shorter than one hour but larger than 10 minutes. **MOTIVATION**: the Load Dispatch Centres schedule plants on the day-ahead in 15-minute time blocks.
Last schedule update	**SCORE**: medium. **MOTIVATION**: intra-day mechanism allows for trading few hours before delivery though present volume of trade is negligible.
System services definition	**Not Applicable.** **MOTIVATION**: primary, frequency containment reserves provided by governors of larger plants. Secondary control is to an extent provided by the national UI mechanism although strictly speaking it is not a reserve service.
System services market	**Not Applicable.** **MOTIVATION**: the State Load Dispatch Centres do not collaborate in a balancing market as such, although the UI does result in an effective, system-wide signal to generators to either increase or decrease their production.
Grid representation	**SCORE**: medium. **MOTIVATION**: Indian spot markets are subdivided into market zones (bid areas). Power Exchange India (PXL) is subdivided into 12 bid areas while the Indian Energy Exchange (IEX) is subdivided into 10 bid areas.
Interconnector management	**SCORE**: poor. **MOTIVATION**: long-term agreement for energy trade via interconnections with Bhutan and Bangladesh.

Key point • Regional fragmentation of the market does not allow for country-wide optimisation of system operation.

Table D.9 • Scoring of market design in Japan

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: poor. **MOTIVATION**: marginal role of JEPX power exchange. Dispatch executed by vertically integrated, local EPCOs, with limited co-ordination with neighbouring regions. Power supply is based on long-term agreements.
VRE dispatch	**SCORE**: poor. **MOTIVATION**: dispatch executed by vertically integrated, local EPCOs, with limited co-ordination with neighbouring regions. Feed-in-Tariff scheme started from July 2012, replacing RPS and revising existing solar FiT. VRE curtailed before other generation.
Dispatch interval	**SCORE**: medium. **MOTIVATION**: JEPX day-ahead spot market is a marginal price auction of half hourly contracts (48 settlement periods per day). Marginal role of JEPX power exchange because of low traded volumes, but this indicates dispatch interval of 30 minutes or shorter.
Last schedule update	**SCORE**: medium. **MOTIVATION**: JEPX spot market allows for trading up to 4 hours ahead of delivery.
System services definition	**Not applicable.** **MOTIVATION**: each EPCO balances supply and demand separately with no proper markets or transparent definition of reserve products and requirements.
System services market	**Not applicable** **MOTIVATION**: an ancillary service market is not in place but under consideration by Japan's Ministry of Economy, Trade and Industry.
Grid representation	**SCORE**: medium. **MOTIVATION**: subdivision of case study region into three zones, each one managed by a single EPCO.
Interconnector management	**SCORE**: poor. **MOTIVATION**: the selected case study region (Japan East) is weakly interconnected with the western region. Transfer capacity is mainly allocated via long-term agreements.

Key point • Regional fragmentation, opaque procedures and inefficient VRE dispatch limit flexibility.

Table D.10 • Scoring of market design in Brazil

Dimension	*Score and related motivation*
Non-VRE dispatch	**SCORE**: medium. **MOTIVATION**: the trade of electricity is entirely separate from the dispatch of power plants (operated by the national system operator ONS). The central dispatch takes place weekly. The dispatch is strictly dependent on the opportunity cost of water in hydro reservoirs. The dispatch program minimises the sum of thermal generation and the future cost associated with hydro operations. Nevertheless long-term contracts can contain inflexibilities, for example due to take or pay gas contracts. These influence the dispatch.
VRE dispatch	**SCORE**: medium. **MOTIVATION**: potential VRE support mechanisms do not influence dispatch decisions. VRE sources are fully exposed to market competition during auctions (if generation technology is not specified). VRE production is remunerated on the basis of PPAs and is not exposed to market price signals.
Dispatch interval	**SCORE**: good. **MOTIVATION**: half-hour dispatch interval.
Last schedule update	**SCORE**: poor. **MOTIVATION**: the physical dispatch of power plants is executed the week ahead. Daily and real-time re-dispatch is anyway possible to deal with load variation or contingencies.
System services definition	**Not applicable.** **MOTIVATION**: there is no separate market for reserves; the requirement is spread across all hydro plants, which are redispatched as required by ONS.
System services market	**Not applicable.** **MOTIVATION**: there is no separate market for reserves.
Grid representation	**SCORE**: medium. **MOTIVATION**: four price zones.
Interconnector management	**SCORE**: poor. **MOTIVATION**: optimisation of international exchanges optimised within the dispatching algorithm on the basis of long-term agreements.

Key point • The vast flexibility pool of flexible hydro power plants permits system operation that would otherwise be unsuitable for large shares of VRE because of very long dispatch intervals and underdeveloped system services market.

Reference

Mueller, S., H. Chandler and E. Patriarca (forthcoming), *Grid Integration of Variable Renewables: Case Studies of Wholesale Electricity Market Design*, OECD/IEA, Paris.

Annex E • Acronyms, abbreviations and units of measure

Acronyms and abbreviations

°	degree
2DS hiRen	2-degrees High Renewables Scenario
AC	alternating current
AC OHL	AC overhead line
ARPA-E	Department of Energy Advanced Research Projects Agency-Energy (United States)
BETTA	British Electricity Trading and Transmission Arrangements
CAES	compressed air energy storage
CAISO	California Independent System Operator
CAN	Canada
CAPEX	capital expenditure
CASC	Capacity Allocating Service Company
CC	combined cycle
CC_{CONV}	Control Centre for conventional generation
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CECOEL	Centro de Control Eléctrico (Electricity Control Centre)
CECORE	Centro de Control de Red (Electricity Control Centre)
CECRE	Centro de Control de Energía Renovable (Control Centre of Renewable Energies)
CER	Commission for Energy Regulation
CF	capacity factor
CFE	Comisión Federal de Electricidad (Mexico)
CHP	combined heat and power
CNO	central network operator
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CREZ	competitive renewable energy zones
CSP	concentrating solar power
CWE	Central and Western European
DC	direct current
DCENR	Department of Communications, Energy and Natural Resources (Ireland)
DC OHL	DC overhead line
DH	district heating
DLR	dynamic line rating
DS3	Delivering a Secure Sustainable Electricity System
DSI	demand-side integration
DSM	demand-side management
DSO	distribution system operator
DSR	demand-side response
EEX	European Energy Exchange
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
EPCO	electric power company
EPEX	European Power Exchange
ERCOT	Electric Reliability Council of Texas
ES	Spain

EUR	euro
EV	electric vehicle
EWIS	European Wind Integration Study
EWITS	Eastern Wind Integration and Transmission Study
FACTS	Flexible Alternating Current Transmission Systems
FAST	Flexibility Assessment Tool
FAST2	revised Flexibility Assessment Tool
FERC	Federal Energy Regulatory Commission (United States)
FFR	fast frequency response
FiP	feed-in premium
FiT	feed-in tariffs
FLH	full-load hours
FRP	flexible ramping product
FRT	fault ride through
GIVAR	Grid Integration of Variable Renewables project
GT	gas turbine
HH	household
HV	high voltage
HV/MV	high voltage to medium voltage
HVDC	high-voltage direct current
IC	interconnection
ICCP	Inter-Control Centre Communication Protocol
ICT	information and communication technology
IEA	International Energy Agency
IEX	Indian Energy Exchange
IMRES	Investment Model for Renewable Energy Systems
ITVC	interim tight volume market coupling
JEPX	Japan Electric Power Exchange
LCOE	levellised cost of electricity
LCOF	levellised cost of flexibility
Li-ion	Lithium-ion
LMP	locational marginal pricing
LOLE	loss of load expectation
LV	low voltage
METI	Ministry of Economy, Trade and Industry (Japan)
MIBEL	Mercado Ibérico de Electricidade (Iberian Electricity Market)
MV	medium voltage
MV/LV	medium voltage to low voltage
na	non applicable
NaS	sodium sulphur
NERC	North American Electric Reliability Corporation
NEWSIS	Northern European Wind and Solar Intermittency Study
NIMBY	not in my backyard
NIRO	Northern Ireland Renewables Obligation
NL	The Netherlands
NOx	nitrogen oxide

NPV	net present value
NREL	National Renewable Energy Laboratory (United States)
NTC	net transfer capacity
NWE	North West Europe
O&M	operation and maintenance
OCGT	open-cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
ONS	Operador Nacional do Sistema Elétrico (Brazil)
OTC	over-the-counter contract
PXL	Power Exchange India
PHS	pumped hydroelectric storage
PPA	power purchase agreement
PSP	pumped storage hydro power plant
PT	Portugal
PUCT	Public Utility Commission of Texas
PV	photovoltaics
R&D	research & development
RE	renewable energy
REE	Red Eléctrica de España
REFIT	Renewable Energy Feed-in Tariff
RESCC	Renewable Energy Source Control Centre
RH	reservoir hydro
RM	ramping margin
RTD	real-time dispatch
RTO	regional transmission organisation
SCED	security constrained economic dispatch
SEAI	Sustainable Energy Authority of Ireland
SEM	Single Electricity Market (Ireland)
SLDC	State Load Dispatch Centres (India)
SMES	superconductive magnetic energy storage
SO_x	sulphur oxide
SONI	System Operator Northern Ireland
SPP	Southwest Power Pool
SPS	Special Protection Scheme
SRMC	short-run marginal cost
ST	storage
STE	solar thermal energy
TOU	time-of-use
TSO	transmission system operator
UI	unscheduled interchange
UK	United Kingdom
US	United States
USD	United States dollar
VRB	vanadium redox battery
VRE	variable renewable energy
VSC	voltage source converter

WACC	weighted average cost of capital
WECC	Western Electricity Coordinating Council (United States)
WEO	*World Energy Outlook*

Units of Measure

CAPEX/yr	capital expenditure per year
EUR/kWh	euros per kilowatt hour
EUR/MWh	euros per megawatt hour
EUR/yr	euros per year
GW	gigawatt
	megawatt hour
h	hour
km	kilometre
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
m	metre
MBtu/MWh	million British thermal units per megawatt hour
min	minute
MVA	megavolt ampere
MW	megawatt
MWh	megawatt hour
t	tonne
tCO_2-eq/MWh	tonne of CO2-equivalent per megawatt hour
TWh	terawatt hour
TWh/yr	terawatt hours per year
USD/km	US dollars per kilometre
USD/km/MW	US dollars per kilometre per megawatt
USD/km/yr	US dollars per kilometre per year
USD/kW	US dollars per kilowatt
USD/kWh	US dollars per kilowatt hour
USD/m	US dollars per metre
USD/MBtu	US dollars per million British thermal units
USD/MW	US dollars per megawatt
USD/MW/km	US dollars per megawatt per kilometre
USD/MW/yr	US dollars per megawatt per year
USD/MWh	US dollars per megawatt hour
USD/t	US dollars per tonne
USD/yr	US dollars per year
V	volt
W	watt

IEA PUBLICATIONS, 9 rue de la Fédération, 75739 Paris Cedex 15
Layout in France by Easy Catalogue
(612014021P1) ISBN 9789264208032
Cover design: IEA. Photo credits: © GraphicObsession