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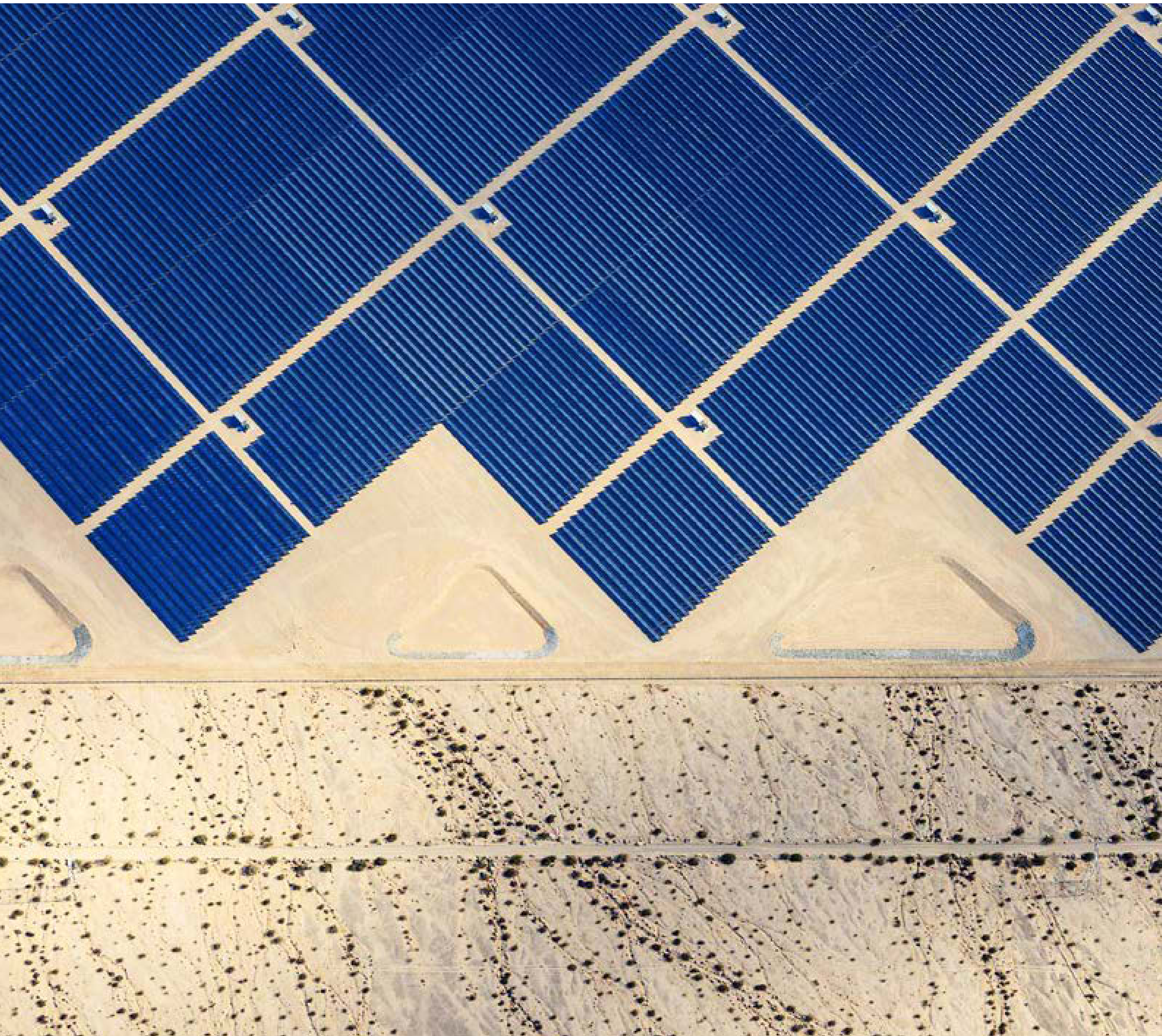

FULL REPORT

Next Generation Wind and Solar Power

From cost to value

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INTERNATIONAL ENERGY AGENCY

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International Energy Agency
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International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

www.iea.org

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

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Executive summary

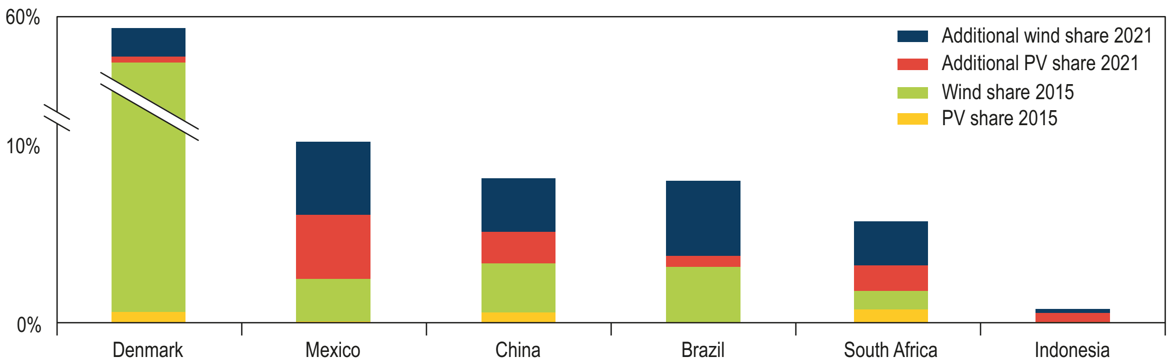
Next-generation wind and solar power and system transformation

Wind and solar photovoltaics (PV) are currently the fastest-growing sources of electricity globally. In 2015, their additional annual generation met almost all incremental demand for electricity. Variable renewable energy (VRE) costs, especially for solar PV and land-based wind, have fallen dramatically in recent years thanks to a combination of sustained technological progress, expansion into newer markets with better resources, and better financing conditions. As a result, between 2008 and 2015, the average cost of land-based wind decreased by 35% and that of solar PV by almost 80%. A "next generation" phase of deployment is emerging, in which wind and solar PV are technologically mature and economically affordable.

The success of these sources is driving change in power systems around the globe. Electricity generation from both technologies is constrained by the varying availability of wind and sunshine, which makes the output of VRE sources fluctuate over time. The degree to which this poses a challenge depends on the interplay of several factors which vary by country.

For this report, detailed case studies were conducted for Brazil, People's Republic of China (hereafter "China"), Denmark, Indonesia, Mexico and South Africa. These countries are at very different stages of VRE uptake (Figure ES.1) and also highlight the diversity of contexts for VRE integration. Some systems have only one resource available in abundance (solar in Indonesia, wind in Denmark), while others enjoy high quality resources of both wind and solar (such as South Africa and Mexico). In South Africa, power demand matches closely with wind and solar availability, both across the day and across seasons. In Denmark, by contrast, demand does not naturally correspond well with VRE, triggering the need for additional flexible resources to be mobilised for system integration (see below). Brazil can rely on the abundant availability of flexible hydro generation to complement wind and solar power well, while the seasonal generation profile of new run-of-river plants harmonise with the country's wind resources (wind is more prevalent when less water is available).

Figure ES.1 • Current and forecasted share of VRE generation for case study countries.



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

Key point • Mexico, China and Brazil are expected to double their VRE share to reach about 10% of annual generation by 2021; South Africa is forecasted to triple its VRE share, reaching 6%; Denmark grows to reach 60% and Indonesia hardly taps into its VRE potential.

Another highly system-specific property is the evolution of electricity demand and the general need for investment in the power sector. Where demand is growing or a large number of resources are being retired because they have reached their technical lifetime, it is often less challenging to scale up VRE. For example, South Africa and Indonesia both face a strong requirement for new generation capacity. This means that VRE can be scaled up without putting too much economic pressure on existing generators. By contrast, systems such as those in Denmark and (more recently) China face an environment in which sufficient capacity is in place to meet demand over the coming years. Under these circumstances additional VRE generation displaces existing resources.

At a more general level, the difficulty (or ease) of increasing the share of variable generation in a power system depends on the interaction of two main factors: the properties of VRE generators and the flexibility of the power system into which they are deployed. Flexibility refers to the ability of a power system to maintain reliable operation even in the face of large swings in the supply and demand balance. Power plants, demand-side resources, electricity storage and grid infrastructure can all boost system flexibility.

Integrating the first few percentage points of VRE into annual generation poses few technical and economic challenges, as long as a few basic rules are followed. This finding is in sharp contrast to the initial concerns expressed when wind and solar PV contributed fairly little to power generation. This means that in systems that currently have very little VRE penetration, such as Indonesia, scaling up is possible with few technical problems in the coming years. This is because traditional power systems already command a significant amount of flexibility to balance power demand. Differently put: the same resources that are used to balance demand may initially be mobilised to integrate VRE.

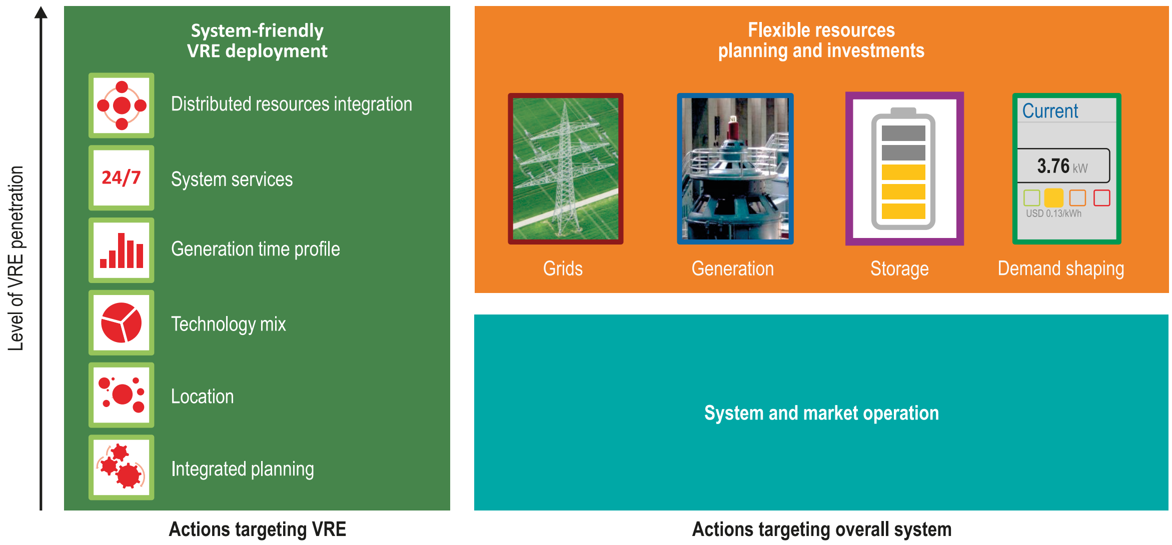
Where the share of annual electricity generation provided by VRE is growing beyond a few percentage points, power system operation and planning are being upgraded and adapted to accommodate VRE on the grid. Such steps will be a priority for Brazil, China, Mexico, and South Africa in the coming years. As VRE enters its next generation of deployment, the issue of system and market integration becomes a critical priority for renewables policy, and energy policy more broadly.

Once VRE becomes a main source of power generation – as is already the case in Denmark – a comprehensive and systemic approach is the appropriate answer to system integration, best captured by the notion of transformation of the overall power system. This requires strategic action in three areas (Figure ES.2):

- System-friendly deployment to maximise the net benefit of wind and solar power for the entire power system. Such an approach leads to different deployment priorities as compared to a focus on generation costs alone. This area is the main focus of the report.
- Improved operating strategies are a powerful tool to maximise the contribution of existing assets and ensure security of supply. These include advanced renewable energy forecasting and enhanced scheduling of power plants.
- Investment in additional flexible resources. Even in concert, improved operations and system-friendly VRE deployment practices might be insufficient to manage high shares of VRE in the long term. The point at which investment in additional flexible resources becomes necessary depends on the system context. In systems with dynamically growing demand, this will be a priority earlier on.

Achieving power system transformation successfully also requires a shift in the economic assessment of VRE. The traditional focus on the levelised cost of electricity (LCOE) is no longer sufficient. Next-generation approaches need to factor in the system value (SV) of electricity from wind and solar power.

Figure ES.2 • Three pillars of system transformation



Key point: VRE can facilitate system integration in combination with improved operations and investment in flexible resources.

SV is defined as the overall benefit arising from the addition of a wind or solar power generation source to the power system; it is determined by the interplay of positives and negatives. Positive effects can include reduced fuel costs, reduced costs from lower emissions of carbon dioxide (CO_2) and other pollutants, reduced need for other generation capacity and possibly grid infrastructure, and reduced losses. On the negative side are increases in some costs, such as higher costs of cycling conventional power plant and for additional grid infrastructure, as well as curtailment of VRE output due to system constraints.

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

It is important to distinguish between the short-term and long-term SV of VRE. In the short term, SV is strongly influenced by existing infrastructure and the current needs of the power system. For example, if new generation is needed to meet growing demand or retirements – as in South Africa – SV will tend to be higher. By contrast, the presence of large amounts of relatively inflexible generation capacity – as is the case in Germany – can lead to a more rapid SV decline in the short term. For long-term energy strategies, the long-term SV is most relevant. This accounts for both fuel savings and capital investment.

Power system transformation aims to maximise the SV of VRE even at large shares. A crucial component to achieve this is system-friendly VRE deployment.

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

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

A number of general principles apply to the successful design of policies to stimulate system-friendly deployment and maximise SV. These differ for large-scale and distributed VRE plants. Further detail on the different aspects of system-friendly deployment can be found in this report.

Distributed resources – focus on regulation of local grids and retail prices

A number of policy and market design options can enhance the system-friendliness of distributed resources. Sustaining the safe and reliable operation of the local power network in the face of rising VRE uptake will require up-to-date and technology-specific grid codes for low- and medium-voltage connections. Retail prices should give the right incentives to both network users and distributed energy resources, in a time- and location-specific manner. In particular, network tariffs need to cover the costs of infrastructure and should send a signal for efficient use of the network, as well as minimise the cost of future investment. This needs to be balanced with other policy objectives, such as economic development in rural communities.

In the context of rising self-consumption, tariff reform is likely to be required. For example, the introduction of demand charges that accurately reflect a customer's contribution to peak demand in a local distribution grid can be an appropriate way of ensuring fair charges for all users of the network. In addition, the gradual introduction of time-based pricing to reflect the time-dependent value of power production should be encouraged.

Centralised resources – enhancing remuneration schemes

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

In practice, exposure to short-term market prices can be an effective way to signal the SV of different technologies to investors. However, the current SV of a technology can be a poor reflection of its long-term value. This is due to transitional effects that can be observed in a number of countries where VRE has reached high shares. For example, in European electricity markets the combined effect of renewable energy deployment, low CO_2 prices, low coal prices and negative/sluggish demand growth (slow economic growth, energy efficiency improvements) are leading to low wholesale market prices. In turn, these low prices mean that any new type of generation will only bring limited cost savings and will thus have a low short-term SV. Even where electricity demand is growing more rapidly, investments based purely on expected short-term wholesale power prices face multiple challenges. Because wind and solar power are very capital intensive, such challenges will directly drive up the cost of their deployment, possibly widening the gap between SV and generation costs. In addition, current market price signals may be a poor indicator of SV in the longer term.

Consequently, mechanisms are needed to provide sufficient long-term revenue certainty to investors. At the same time, such mechanisms need to be designed in a way that accounts for the difference in SV between generation technologies. A number of strategies have emerged to achieve this. Two relevant examples are market premium systems, which reward VRE generators that generate higher-than-average value electricity, and advanced auction systems, such as the model recently introduced in Mexico, which selects projects based on their value to the system rather than simply on generation costs.

As next-generation wind and solar power grow in the energy mix, a focus on their generation costs alone falls short of what is needed. Policy and market frameworks must seek to maximise the net benefit of wind and solar power to the overall power system. A more expensive project may be preferable if it provides a higher value to the system. This calls for a shift in policy focus: from generation costs to SV**. Next-generation wind and solar power calls for next-generation policies.** Action across five strategic areas is needed:

1) Strategic planning

- Develop or update long-term energy strategies to accurately reflect the potential contribution of next-generation wind and solar power to meeting energy policy objectives. Such plans should be based on the long-term value of VRE to the power and wider energy system.
- Monitor the cost evolution of wind and solar power, as well as integration technologies (demand-side response, storage) and update plans accordingly.

2) Power system transformation

- Upgrade system and market operations to unlock the contribution of all flexible resources.
- Invest in an appropriate mix of flexible resources. This includes retrofitting existing assets, where this can be done cost-effectively.
- Deploy wind and solar power in a system-friendly fashion by fostering the use of best technologies, and by optimising the timing, location and technology mix of deployment.

3) Next-generation policies

- Upgrade existing policy and market frameworks to encourage projects that bring the highest SV compared to their generation costs. A focus on generation costs alone is no longer enough.

4) Advanced VRE technology

- Establish forward-looking technical standards that ensure new power plants can support the stable and secure operation of the power system.
- Reform electricity markets and operating protocols to allow wind and solar power plants to help balance supply and demand.

5) Distributed resources

- Review and revise planning standards as well as the institutional and regulatory structure of low- and medium-voltage grids, reflecting their new role in a smarter, more decentralised electricity system, and ensure a fair allocation of network costs.
- Reform electricity tariffs to accurately reflect the cost of electricity depending on time and location. Establish mechanisms to remunerate distributed resources according to the value they provide to the overall power system.

Chapter 1: Background, introduction and the case for Variable Renewable Energy (VRE)

This document is the main report of the project *Next-Generation Wind and Solar Power,* which was carried out by the International Energy Agency (IEA) as part of its Grid Integration of Variable Renewables (GIVAR) programme. It contributes to the work of the Multilateral Wind and Solar Working Group as part of the Clean Energy Ministerial. Its main focus is the contribution that next-generation wind and solar power technology can make to transforming power systems around the globe when combined with advanced, system-friendly deployment strategies.

The main purpose of system-friendly deployment is to maximise the overall value of variable renewable energy (VRE) generation to the power and wider energy system – in contrast to minimising the generation cost of wind and solar power in isolation. In order to reflect the need for a system-wide approach to VRE integration, this report places strategies for VRE deployment in the context of transforming the wider energy system. It presents policy makers with concrete recommendations for maximising the contribution of VRE to this transformation.

The report has two main parts. A first, shorter part contains the analytical synthesis of the project (Chapters 1 to 4). A second, longer part (Chapter 5) is composed of country case studies.

This chapter gives a brief overview of the strategic drivers that underpin VRE deployment, including recent cost reductions as well as VRE's contribution to energy security, economic development and environmental objectives, including climate change mitigation.

Chapter 2 presents evidence as to why recent VRE deployment trends indicate the advent of a new phase of deployment, a next generation of wind and solar power. This phase combines the opportunity of technological and increasingly commercial maturity of VRE on the one hand, and the challenge of cost-effective system integration on the other. The chapter also discusses how the challenges of integration evolve with growing shares of VRE, and introduces system transformation as the appropriate paradigm to deal with challenges associated with VRE becoming the majority source of power generation.

Chapter 3 provides a detailed account of how VRE itself can contribute to its own system integration, including implications for policy and market design. Chapter 4 provides conclusions and recommendations.

Chapter 5 features detailed country case studies, which were carried out as part of *Next-Generation Wind and Solar Power.* These highlight the current state of play in Brazil, China, Denmark, Indonesia, Mexico and South Africa with regard to scaling up wind and solar power. They also identify areas for policy action to bring grid integration issues into the mainstream policy landscape. A more detailed overview of the scope and methodology can be found at the beginning of Chapter 8.

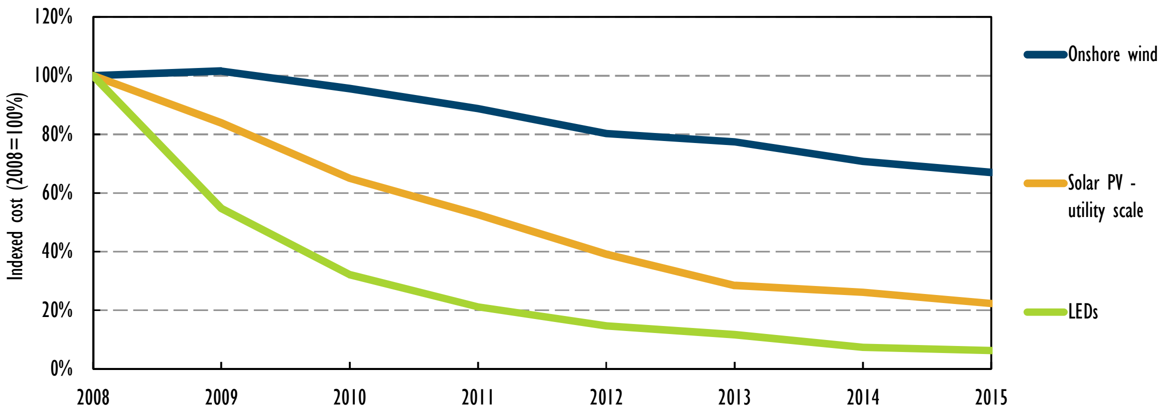
The case for VRE

The development and deployment of renewable energy (RE) can make a contribution to energy, environmental and economic policy in three interacting areas. These are: 1) energy security; 2) reduction of carbon dioxide (CO_2) emissions and other environmental impacts of energy use; and 3) economic development. With rapidly falling costs, wind and solar photovoltaics (PV) increasingly help meet these objectives in an economically affordable way.

Cost reductions

VRE costs, especially solar PV and land-based wind, have fallen dramatically in recent years. The cost-effectiveness of renewable options has improved due to a combination of sustained technological progress, including major efficiency and productivity gains, expansion into newer markets with better resources, and better financing conditions, often supported by market frameworks based on price competition for long-term power purchase agreements (PPAs). As a result, the global weighted average levelised cost of electricity (LCOE) has shown strong reductions over time. Cost reductions are also evident for energy efficiency technologies, thus accelerating the impact of VRE deployment on the power system (Figure 1.1).

Figure 1.1 • Indexed cost of onshore wind, utility-scale PV and LED lighting, 2008-15



Note: LED = light-emitting diode; numbers report non-subsidised cost of energy.
Source: Adapted from IEA (2015a), *Medium-Term Renewable Energy Market Report 2015*.

Key point • The cost of wind, solar PV and LEDs has seen significant reductions over recent years.

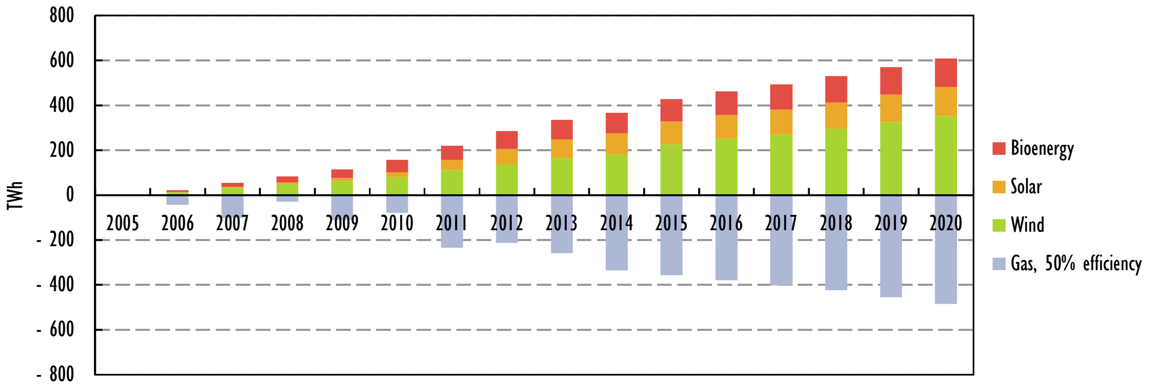
Energy security

The benefits of renewables for energy security are clear: they can diversify the energy mix and sources of supply, they often localise energy production and reduce import requirements and costs, they have less complex supply chains in many cases and fuel-free technologies, such as wind and solar power, reduce long-term price volatility. Taking the example of OECD Europe, the growth in RE since 2005 has compensated for the reduction in domestic gas production[1] and is expected to continue to do so in the coming years (Figure 1.2). This trend helps to limit Europe's import dependency and provides a more diversified energy supply (IEA, 2016b).

However, dependence on large shares of RE implies a paradigm shift for energy security in general, and electricity security more specifically. The classical risks associated with fossil fuels (geopolitics, upstream investment and infrastructure) are replaced by risks relating to the availability of natural resources such as water, biomass, wind and sunlight. A familiar example is hydropower, with annual variations in precipitation and its exposure to the risk of droughts. Countries or regions that depend heavily on hydropower, such as Brazil or the province of Quebec in Canada, have developed sophisticated tools to quantify and mitigate this well-known risk. Looking ahead, system integration will become a key factor in ensuring that VRE uptake has a positive effect on energy security (see IEA [2016a] for further details).

[1] Assuming that natural gas is used in power generation with a conversion efficiency of 50%.

Figure 1.2 • Incremental production of renewable electricity and natural gas in OECD Europe, 2005-20



Notes: OECD = Organisation for Economic Co-operation and Development; TWh = terawatt hour; all incremental domestic gas production converted to TWh assuming a power plant conversion efficiency of 50%; bioenergy = energy from biomass, bioliquids and biogas.

Source: Adapted from IEA (2015a), *Medium-Term Renewable Energy Market Report 2015*, and IEA (2015b), *Medium-Term Gas Market Report 2015*.

Key point • Growth in RE production more than compensates for the forecast decline in natural gas production in OECD Europe.

Economic development

RE technologies are able to contribute to sustainable economic development by allowing exploitation of natural but replenishing resources, providing new sources of natural capital. The technologies allow countries with good solar or wind resources, for example, to exploit these resources as "new" assets to support their own energy needs (IEA, 2011a).

In this regard, job creation and attracting investment are also important economic policy objectives for governments. Deploying RE technologies can be an avenue towards achieving these objectives. As long-term infrastructure developments, RE projects offer host governments a unique opportunity to leverage investment and participation from the private sector. In procuring additional sustainable generation capacity, governments can impose minimum economic development objectives that optimise the structural benefits for the country and for local communities.

Alternatively, quantifiable economic development commitments can form part of competitive procurement processes, which pushes independent power producers (IPPs) to maximise their commitments in their bids. The use of rolling, multi-phased procurement over several years enables increased competitive pressure among IPPs on their economic development commitments. Moreover, it allows for a continued refinement of the procurement programme in order to align these commitments with the overall development objectives of the host country.

Climate change mitigation and other environmental benefits

RE technologies form a key instrument in combatting climate change. Currently, wind and solar PV are the only power sector decarbonisation options deployed at a rate close to that required under long-term IEA scenarios to attain the 2°C target (IEA, 2016b). RE deployment reduces the carbon intensity of the electricity system by displacing thermal supply alternatives. This reduces emissions of CO_2 and other pollutants.

Other important environmental benefits include improved local air quality, which poses a serious health threat. Three million premature deaths per year are currently linked to outdoor air pollution, a number that may increase to 4.5 million by 2040 if no action is taken to address this issue. Energy production and use are by far the largest man-made sources of air pollutants (IEA, 2016b).

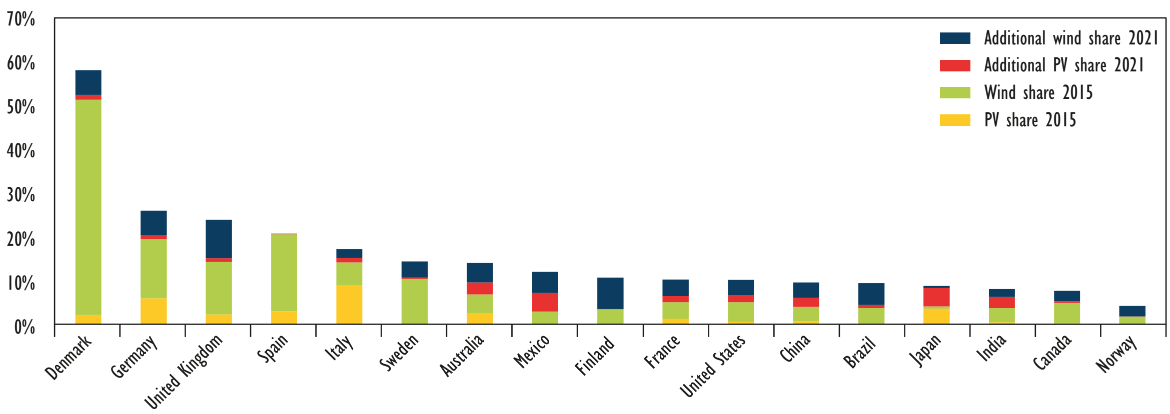
Chapter 2: Next-generation wind and solar power and system integration

Wind and solar PV are currently the fastest-growing sources of electricity globally. In 2015, their additional annual generation met almost all incremental demand for electricity. Between 2008 and 2015, the average cost of land-based wind decreased by 35% and that of solar PV by almost 80% (Figure 1.1).

Their deployment is moving on from a phase where the main priorities were technology learning and cost reduction. Today, increasing evidence of a new phase of deployment can be encapsulated by the notion of next-generation wind and solar power; in this phase, wind and solar PV are technologically mature and economically affordable.

Technological maturity and lower costs make wind and solar power increasingly attractive options for policy makers seeking to meet energy policy objectives. Their contribution to power systems around the globe is rapidly moving from marginal to mainstream, including in emerging and developing countries (Figure 2.1). Denmark will see the largest national VRE share: wind and solar PV will, in fact, count for 51% of total generation in 2020. Growth economies, such as China and Mexico, will also experience growing penetration of VRE capacity, with wind and solar combined accounting for 8% and 6%, respectively, by 2020.

Figure 2.1 • Share of VRE generation in 2014 and 2020 for selected countries



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

Key point • Double-digit shares of VRE in annual generation are becoming increasingly common in European countries, while emerging economies are forecast to see rapid growth over the coming years.

The success of these sources is driving change in power systems around the globe. Electricity generation from both technologies is constrained by the varying availability of wind and sunshine, which makes their output variable over time. Where VRE is growing beyond a few percentage points as a share of annual electricity generation, power system operation and planning are being upgraded and adapted to accommodate VRE on the grid. These adaptations ensure the reliable balance between electricity supply and consumption at all times, even in the presence of double-digit shares of VRE in annual generation. For example, coal power plants in Denmark have been upgraded to allow for a more flexible operation: starting plants quickly and allowing them to change their output across a wide range. In Germany, the four transmission system operators (TSOs) started to share certain reserve capacities in 2008, which has allowed a reduction in their combined reserve requirements despite ongoing VRE deployment (IEA, 2014a).

As VRE enters its next phase of deployment, the issue of system and market integration becomes a critical priority for renewables policy, and energy policy more broadly. Consequently, next-generation wind and solar power – and the policy, market and regulatory frameworks that accompany them – must deliver cost-effective system and market integration.

System integration

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

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

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

Properties of VRE generators

VRE generators have five technical properties that make them distinct from more traditional forms of power generation, i.e. large-scale thermal power plants. First, as already mentioned, their maximum output fluctuates according to the real-time availability of wind and sunlight. Second, these fluctuations can only be predicted fairly accurately up to a few days in advance and forecasts improve greatly if they are only for a few hours ahead. Third, they connect to the grid via power converter technology. This can be relevant in ensuring the stability of power systems, for example following the unexpected shutdown of a generator. Fourth, they are more modular and are deployed in a much more distributed fashion. Finally, unlike fossil fuels, wind and sunlight cannot be transported, and locations with the best resources are frequently at a distance from load centres. Despite these general similarities, wind and solar PV also show a number of differences (Table 2.1).

The difficulty or ease of integrating VRE into a power system also depends on a number of other factors. It is easier to integrate VRE in systems where power demand and VRE generation show a positive correlation, both in relation to typical daily patterns as well as seasonally (Figure 2.2), and the flexibility of the power system is crucial for facilitating uptake of VRE.

Analysis by the Council for Scientific and Industrial Research (CSIR) (2016) shows a positive correlation between solar and wind resources and power demand in South Africa, where neither

[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.

solar resources nor electricity show great seasonality. The moderate increase in wind supply during the winter months correlates with a slight load increase during that period and, more importantly, wind production generally peaks in the evening and at night, complementing solar PV output.

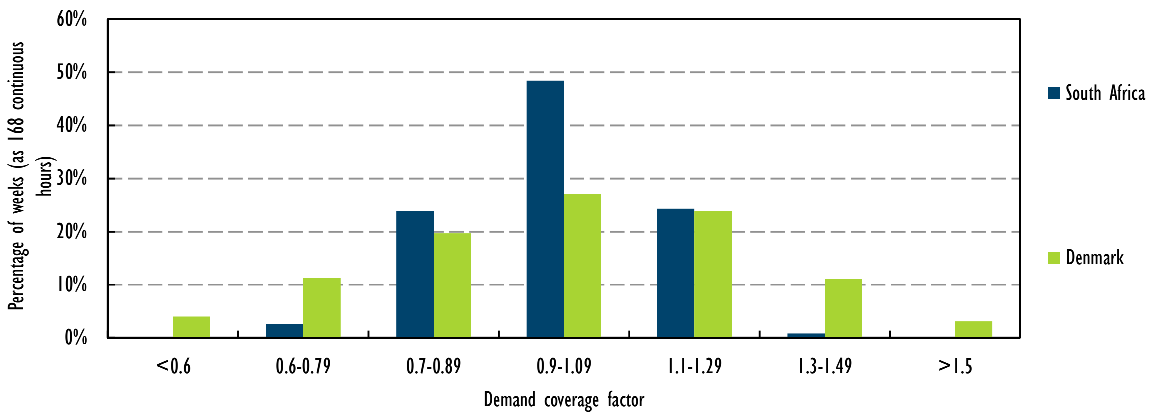
Table 2.1 • Overview of differences between wind power and solar PV

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

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

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

Figure 2.2 • Demand coverage factors for South Africa and Denmark



Note: See Box 5.1 on page 54 for a description of the demand coverage factor.

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

Power system flexibility

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

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

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

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

Sources outside the electricity sector can also contribute to flexibility. In fact, the growing importance of flexibility may drive stronger links to other energy sectors, such as heat and transport. In the heat sector, for instance, space and water heating augmented by thermal storage systems and co-generation can create opportunities to meet more volatile net load.[3] Electric vehicle (EV) fleets may provide a valuable opportunity for greater energy storage and enable better use of VRE output that is surplus to need at the time it is produced. For example, Denmark has seen an increase in the use of electric boilers in its co-generation plants. These boilers are relatively cheap to install and can greatly increase the flexibility of co-generation plants; instead of imposing a must-run constraint on the system (electricity production as a co-product of heat production) they can consume electricity to supply the demand for heat.

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

Different phases of system transformation

Initial deployment of VRE

VRE's initial attainment of a few percentage points share of annual electricity generation (approximately 2-10%) poses few technical and economic challenges. This finding is in sharp

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

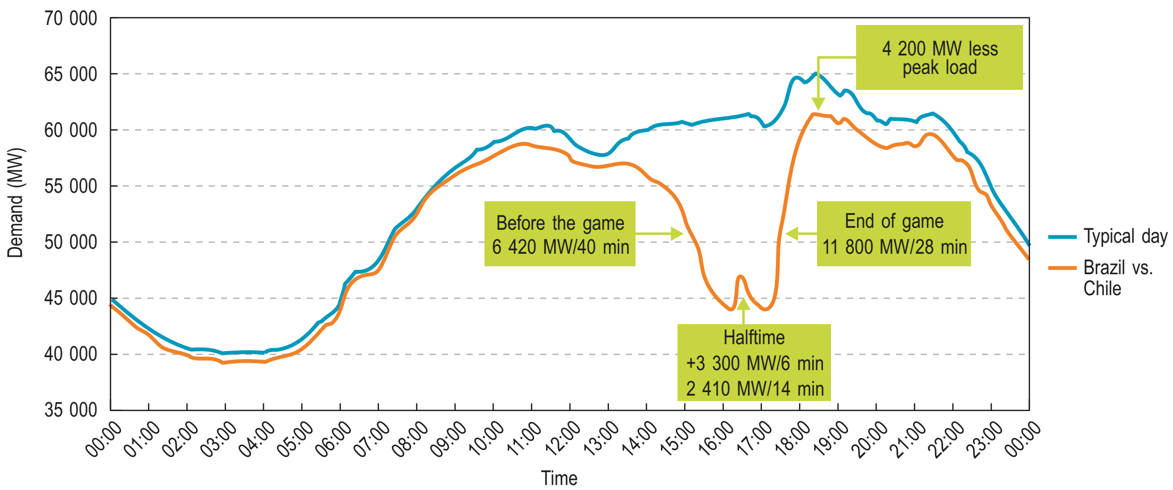
contrast with the initial concerns expressed when wind and solar PV contributed fairly little to power generation. Two quotes from Germany and Ireland, respectively, highlight this:

- In Germany, in 1993, with a share of wind power in annual generation at less than 0.1%, the German power utilities made a joint statement: "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).
- In Ireland, in 2003, with a share of wind power in annual generation at 2%, ESB National Grid wrote in a letter to the Irish Prime Minister's office: "This amount of wind generation does, however, pose an increased risk to the security and stability of the power system which the transmission system operator feels exceeds the level normally likely to be accepted by a prudent system operator" (The Irish Times, 2003).

Both countries have since then achieved significant shares of variable renewable power in their systems: annual penetration in 2015 stood at 14% for wind and at 6% for solar PV in Germany and 23% for wind power in Ireland.

The initial scepticism at the onset of VRE deployment may be connected to the strong deviation from classical system operation that these resources present. The historical paradigm of power system operation can be summarised in a simplified form as follows: "We cannot control load, so we must control generation to keep the lights on. VRE is not controllable, so we cannot use it as a main source of electricity." However, this view neglects the fact that all power systems already command a significant amount of system flexibility to balance power demand (Figure 2.3). Indeed, demand itself is variable, only partially predictable, location-constrained, often small scale and non-synchronous. Differently put: demand and VRE generation have similar properties. Consequently, the same resources that are used to balance demand may be mobilised to integrate VRE.

Figure 2.3 • Exceptionally high load variability in Brazil during soccer world championship, 28 June 2010



Source: Reprinted from IEA (2014), *The Power of Transformation*.

Key point • Power systems already command a significant amount of system flexibility to balance power demand.

VRE may thus be treated as "negative load" at comparably low shares. Reflecting this fact, the concept of "net load" is very useful in the analysis of VRE integration. Net load is obtained by subtracting VRE generation from power demand.

Despite the fact that all power systems already have a degree of flexibility to reliably serve electricity demand, it is not assured that this flexibility will actually be available for dealing with VRE integration. The main issues at an early stage of integration typically fall under the following categories:

- Ensure that the technical standards (known as grid codes or connection standards) for VRE power plants are up to date and already contain appropriate provision for technical capabilities that can become critical once VRE comprises a larger portion of the generation fleet.
- Forecast production from VRE using centralised forecasts and effectively use forecasts when planning the operation of other power plants and electricity flows on the grid.
- Ensure that system operators have access to real-time production data and that a sufficient share of VRE generators can be controlled remotely by them (priority should be given to large-scale VRE plants). This may require the installation of additional smart-grid hardware.
- Avoid unintended local concentrations of VRE power plants ("hot spots"), both in one region of a country as well as in certain parts of the grid within a given region, to avoid technical challenges in these regions.

Reaching double-digit shares in annual generation

Operating power systems with annual VRE generation above a share of 10% is increasingly common in a growing number of countries. In 2015, the combined output of wind and solar PV equalled 51% of power generation in Denmark, 23% in Ireland and 21% in the Iberian Peninsula. In addition, certain regions show levels above national averages. In California VRE accounted for 14.2% of generation, while for the entire United States this figure was just over 5% (CEC, 2016; IEA, 2016a).

These shares have been reached mainly by enhanced *operation* of existing power system assets, rather than by large additional capital investments. Improving power system operations is cost-effective independent of VRE, but benefits are magnified at higher VRE penetration rates (see section on market integration for details). However, beyond a certain point, additional measures are needed to reliably and cost-effectively reach higher shares.

Policy, market and regulatory frameworks have a critical impact on the way in which the properties of VRE and the flexibility of the power system interact. The frameworks determine how the power system is actually operated and hence whether what is technically possible is both practically achievable and economically attractive for stakeholders in the electricity system (Figure 2.4). Against this background it is not surprising that many countries are currently or have recently reformed electricity market design in the face of rising shares of VRE. A prominent example is the recent market design reform in Mexico (see case study on Mexico for details).

The interaction between the two factors (VRE and system flexibility) differs from system to system as a result of technical variation as well as the influence of policy and market frameworks. For example, making the dispatchable fleet more flexible is a priority for any country relying heavily on this resource and which also wants to increase VRE generation. However, precise measures will differ depending on whether a liberalised wholesale market is in place (e.g. Germany) or not (e.g. South Africa). In the first case, a reform of system services markets and supplementary measures such as a strategic capacity reserve are an option. In the second case, changing the key performance indicators (KPIs) of plant operators may be an effective solution. However, a growing body of experience across a diverse range of power systems shows a common pattern of challenges. In the examples above, finding ways to make the coal fleet more flexible is a shared challenge. This allows for the development of best practice principles for policy and market frameworks – principles that can be applied in a wide range of circumstances.

Figure 2.4 • The integration challenge

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

In the context of finding ways to achieve system integration successfully, advanced VRE technologies and deployment strategies can make a valuable contribution. Indeed, a VRE power plant is not simply a wind turbine or a collection of solar panels. Modern VRE plants connect to the grid using electronic power converters, so-called inverters. Simply put, these can be programmed like a computer to allow the way in which VRE power plants behave on the power grid to be controlled.

From integration to transformation

As the share of VRE grows on the power system, issues surrounding grid integration gradually increase. Moving towards VRE as a main source of electricity in annual power generation can affect the power system at all timescales, ranging from several years (system planning) to days, hours and minutes (system operations) and even seconds (system stability). The effects of high shares of VRE can also be seen at all geographic scales, from system-wide impacts (affecting entire continental power grids) all the way down to individual lines of the distribution grid. High shares of VRE, where such effects typically become apparent, are increasingly common in a growing number of countries (Figure 2.1).

During certain periods, VRE can account for a much larger share of power generation than annual averages suggest. For example, the share of wind power in Spain's electricity generation exceeded 70% at one point on 21 November 2015 (REE, 2016). During 2015, wind power production in western Denmark exceeded demand for more than 1 450 hours of the year. In September 2015, the Danish power system operated without any large-scale plants operating in the country (Energinet.dk, 2016). Finally, Germany registered a recent record in wind and solar PV penetration, when the output of these sources reached approx. 75% of the country's electricity demand at one point on 8 May 2016 (Agora Energiewende, 2016). The adaptations that have been made in these power systems have largely been improvements in the way each system is operated, including more advanced market designs that allow for trading very close to real time. Thermal power plants have also been upgraded to cope with more rapid swings in the supply-demand balance, and interconnections to other systems also play an important role in certain systems, for example Denmark.

Given the broad impacts that high VRE shares can have, a comprehensive and systemic approach is the appropriate answer to system integration challenges. As identified by IEA analysis, a co-ordinated approach can significantly reduce integration costs and ensure electricity security (IEA, 2014a; IEA, 2016b). Achieving such a transformation requires strategic action in three main areas:

- System-friendly deployment to maximise the net benefit of wind and solar power for the entire power system. Such an approach leads to different deployment priorities as compared to a focus on generation costs alone. This component is explored in more detail in this report.
- Improved operating strategies as a powerful tool to maximise the contribution of existing assets and ensure security of supply. These include advanced RE forecasting and enhanced scheduling of power plants. Where liberalised wholesale markets are in place, this may require an upgrade of market rules and products. In heavily regulated systems, action will need to target operational protocols and KPIs for system and power plant operators.
- Investment in additional flexible resources. Even in concert, improved operations and system-friendly VRE deployment practices will be insufficient to manage high shares of VRE in the long term. The point at which investment in additional flexible resources becomes necessary depends on the system context. In all systems, however, an increase in flexible resources will become a cost-effective integration strategy at some point, requiring additional investment.

Mobilising the contribution of each of the three areas requires putting in place appropriate market, policy and regulatory frameworks. It frequently also requires changing the roles of institutions in the power system, which can require time and resources to achieve. In a nutshell, actions from the last two areas aim to make the overall power system more suitable for VRE generation, while the first area encompasses all those measures that make VRE more suitable for the existing power system.

To implement this strategy, actions across the entire power system are likely to be needed. For example, increasing the flexibility of the demand side (beyond large industrial consumers) is likely to require changes in the regulation of distribution networks, analysis of the acceptability of different business models to consumers, adaptation of wholesale market design, etc.

By contrast, a common approach to integrating VRE views its place in the power system in isolation. This leads to an emphasis on solutions that first make VRE “more like traditional generation”, for example by adding storage or dedicated power plants to balance VRE. As previous IEA analysis has demonstrated (IEA, 2014a), such an isolated approach leads to significantly higher costs than a more system-wide strategy. Such an improved strategy will reveal that those power plants that are currently used to balance the variability of power demand can be put to work to balance the combined variability of VRE supply and electricity demand.

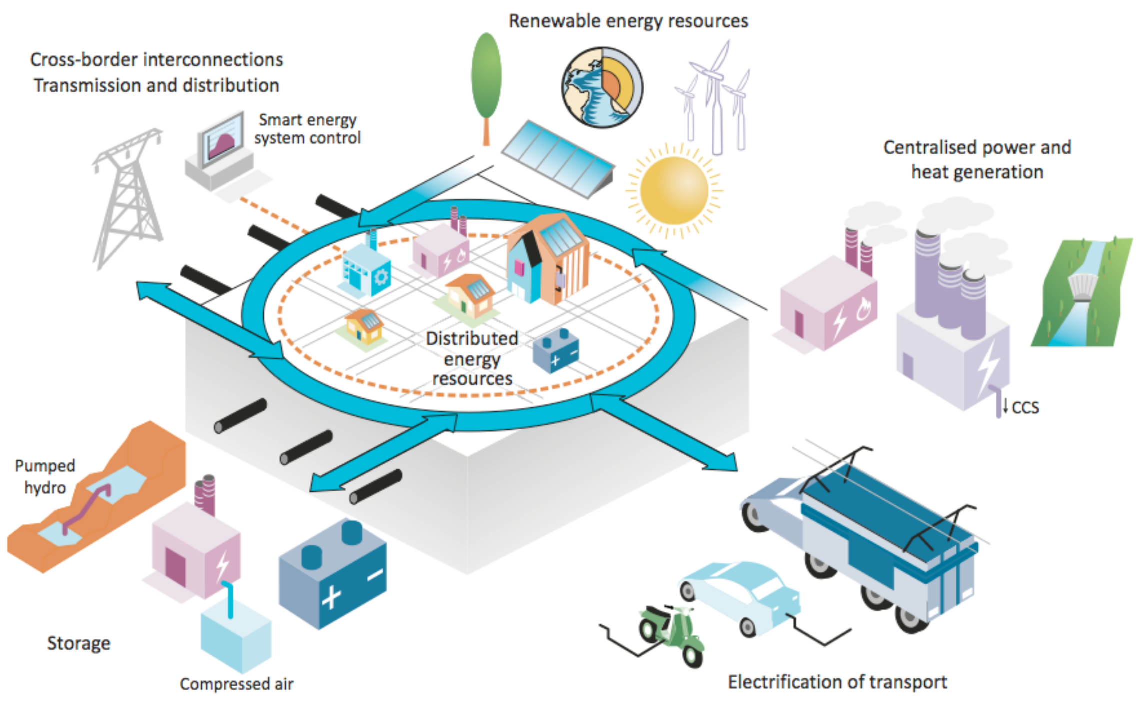
Given the need for a system-wide strategy, the traditional notion of integrating RE into an otherwise unchanged power system can fall short of what is needed; it is not VRE that needs to adapt to what is already there for historical reasons. Successful integration of a high share of VRE requires finding a new optimum across all power system assets. In many cases, such an approach will lead beyond the confines of the current power system, calling for the electrification of end-use sectors such as heating and transport.

The need for a comprehensive approach is better captured by the notion of transformation of the overall power system: *successful integration means system transformation*.

A paradigm shift for low- and medium-voltage grids

The greater uptake of distributed VRE shifts the historic balance of supply and demand in the electricity network, and calls for a revision of the institutional arrangements guiding low- and medium-voltage grids. The rise of distributed generation assets[4] – dominated by the rapid uptake of solar PV – translates into growing complexity of power flows within the distribution grid (Figure 2.5). This provokes the need for innovative approaches to the planning and operation of low- and medium-voltage grids, with technical, economic and institutional implications.

Figure 2.5 • Smart distribution grids at the heart of a transformed power system



Note: CCS = carbon capture and storage.
Source: Reprinted from IEA (2014b), *Energy Technology Perspectives.*

Key point • Power system transformation implies a paradigm shift for low- and medium-voltage grids – away from passive distribution of electricity and towards becoming a critical hub for electricity and data.

On the technical side, more dynamic and bi-directional flows of electricity (from lower to higher voltage levels and vice versa) require reinforced monitoring and control capabilities as well as upgrades to infrastructure. Moreover, planning standards need upgrading to manage the uptake of large shares of distributed resources. In this context, next-generation VRE technology – such as advanced inverters – can offer technical capabilities to support and sustain safe and reliable operations in local power grids, while also reducing energy losses in the overall power system. For example, under a business-as-usual approach, a high local penetration of distributed solar PV can create challenges related to maintaining voltage at appropriate levels. These challenges can be mitigated by using solar PV inverters themselves to control voltage – a next-generation

[4] Distributed electricity resources are typically modular and/or small scale, connected to a local network, providing energy-related services with the capability of supplying energy or system services.

approach to deployment. To unlock this contribution, however, the technical requirements for VRE (grid codes) need to ensure that inverters are technically capable and correctly programmed, and that their combined performance is monitored by a technically robust information technology (IT) and data management system.

On the economic side, there is a need to reform electricity pricing. Where citizens install their own solar PV systems behind the electricity meter, the design of retail tariffs becomes a critical lever to guide investment in and operation of distributed resources.

In the past, consumers did not have a strong incentive to substitute grid-based electricity by generating their own power. The rise of distributed solar PV, combined with cost reductions in smart-home and battery technology, has begun to change this. However, the design of electricity tariffs is often based on the assumption that consumers have no alternative to the grid for obtaining their electricity. For example, the cost of the electricity network itself is frequently recovered via per-unit charges on electricity. In a situation where customers use their own solar PV generation to displace electricity from the grid, such pricing arrangements may be rendered dysfunctional.

Tariff design will need to evolve, reflecting the fact that consumers of electricity can now also become producers, and consequently requiring a fair allocation of grid costs across all consumers. This may entail a departure from the current model of recovering the cost of distribution grid infrastructure. For example, the state of New York is currently comprehensively reviewing the design of electricity tariffs (State of New York, 2016). As part of the reform, it is proposed to introduce a new pricing element, a so-called demand charge. Customers who use electricity when the grid is most strained will need to pay more, while those customers that avoid consumption during peak times will pay less.

Reform will need to take electricity tariffs beyond simply pricing of consumption. Distributed solar PV systems, combined with smart-home systems and electric batteries, are valuable resources for the entire power system. However, a way is needed to allow these resources to offer their services and receive appropriate compensation. For example, distributed resources can contribute to the provision of system services (Box 2.1). But unlocking this contribution requires commercial arrangements to appropriately remunerate resources.

Box 2.1 • What are system services?

Reliable operation of the power system critically depends on a number of system services, which contribute to maintaining system frequency and voltage levels. Special capabilities may also be required when restarting the system after a large-scale blackout (so-called black-start capabilities). 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.

On the institutional side, there is a need to reassess whether the current division of roles and responsibilities is suitable for dealing with the pace of change in technologies and business models. Traditionally, system services markets have been controlled by TSOs and only a small minority of these allow for the participation of distributed VRE assets. Looking ahead, making optimal use of the grid support services offered by distributed VRE may require that these services are procured and co-ordinated in a more localised fashion. In the United States, for instance, the first examples of peer-to-peer energy transactions are appearing, whereby individual homeowners sell and buy power from each other on the basis of modern, encrypted digital payment technologies. Even at a few cents, such transactions empower homeowners to engage actively in the local production of clean energy.

Finally, participation in distribution grids is bound to change. For example, electricity suppliers will increasingly compete with aggregators of system services for access to customers. Similarly, a strong case can be made for establishing transparent power markets, known as market platforms, governed by independent institutions that have the responsibility to operate them fairly.

System value, or the need to go beyond costs

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

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

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

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

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

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

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

SV complements the information provided by classical metrics of generation costs, such as the LCOE. It captures the effects that additional generation has on the remaining power system. Simply put: the LCOE informs how much one has to pay for a certain technology, while the SV of that technology captures the net effects on the system (Figure 2.6).

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

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

Figure 2.6 • Illustration of LCOE and SV

LCOE

- Installation costs
- Operation and maintenance costs (fuel, emissions if applicable)
- Financing costs
- …

SV

Positive

- Reduced fuel and emission costs
- Reduced costs/need for other generation capacity
- Possibly reduced grid costs and losses

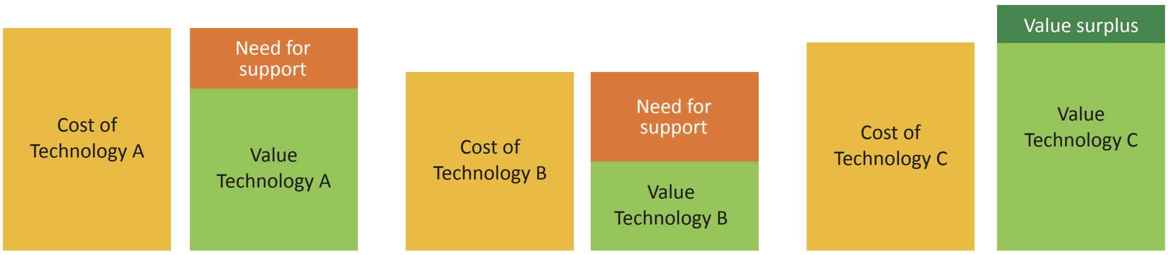
Negative

- Increased operating costs for other power plants
- Additional costs for grid infrastructure
- Curtailment

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

Comparing the SV of different technologies – and not just their LCOE – provides a more complete picture and a sound basis for policy design (Figure 2.7). In the example below, Technology B has the lowest cost, but also a very low value – hence it would require the most support to trigger deployment. By comparison, Technology C has an intermediate cost but a very high SV – its deployment would not require any support on the basis that an appropriate market design was in place.

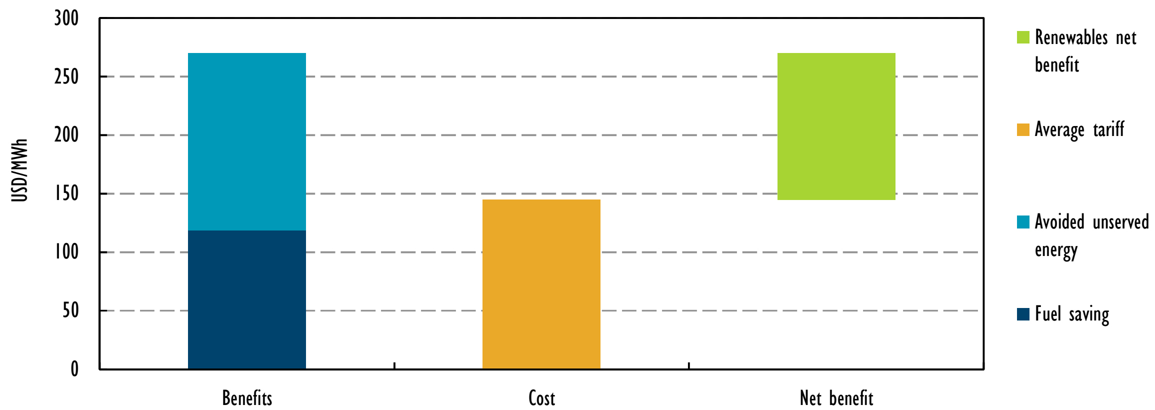
Figure 2.7 • The link between VRE cost, SV and competitiveness



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

The power system of South Africa provides an effective example of a situation where VRE can have a high SV. South Africa exhibits a favourable overlap of wind and solar resources with demand. Moreover, in recent years a tight supply situation has seen VRE offset a considerable amount of diesel consumption, and in some cases even prevent load shedding. Analysis carried out by CSIR (2015) found that for VRE assets operating in the first half of 2015, the savings from avoided fuel and lost load more than compensated for the cost of wind and solar power (Figure 2.8). Further detail on this analysis is provided in the dedicated case study.

Figure 2.8 • Illustration of SV and cost for wind and solar power in South Africa, H1 2015



Source: Adapted from CSIR (2015), *Financial Benefits of Renewables in South Africa in 2015*.

Key point • Depending on system circumstances, the value of VRE may significantly exceed the cost.

Conversely, when additional VRE generates power at times and locations when it is not optimal for the overall system, this will yield a lower SV. A low SV can signal a misalignment between VRE generation and the rest of the power system. It is important to note that this is the result of an interaction between the system and VRE rather than a property of VRE *per se*.

As the share of VRE generation increases in power systems, the variability of VRE generation and other adverse effects can lead to a drop in the overall SV of VRE.

The example of Germany illustrates how rising shares can challenge the value of VRE generation. It is possible to analyse part of the SV of a generation resource by looking at its value on the electricity market. While such an analysis may not reflect all the benefits of VRE, the overall trend of market revenues can provide information about the evolution of SV at growing shares of VRE.

Liberalised short-term electricity markets have a different wholesale price for each hour of the day. The price in each hour is determined by the short-run (fuel) costs of the most expensive generator. When VRE generation is present during times of high demand, it will thus have a high value on the electricity market. It is convenient to express the wholesale market value as a so-called value factor. In short, a value factor below one means that electricity from a certain technology makes lower-than-average revenues selling electricity to the market, while a factor above one signals a high value.

At the onset of deployment, solar PV often generates at times of fairly high demand. This translates into a high market value as long as its share is low. However, as more PV capacity is added to the system, all PV systems will tend to generate at the same time. This means that when PV capacity is generating, increasingly there is an abundance of electricity. This is also known as the merit-order effect (Box 2.2). The merit-order effect leads to lower prices and, in turn, a lower market value. This effect is similar for wind, though not as pronounced (Figure 2.9). The exact magnitude of this decline is highly system specific. The principle itself, however, is universal: the economic challenge of system integration is reflected in the declining value of wind and solar power.

Box 2.2 • The merit-order effect and its impact on the power plant mix

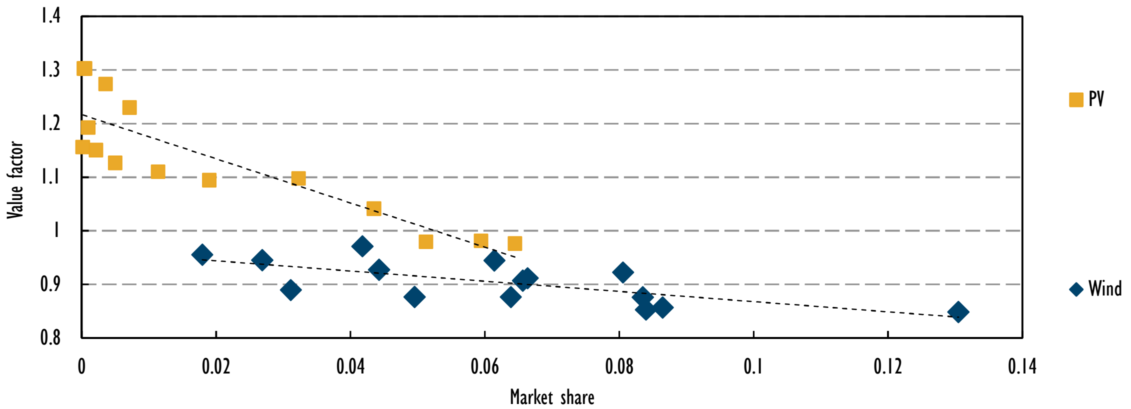
Once built, wind power and solar PV provide electricity practically for free. The low short-run costs imply that once VRE generation is built, it is likely to be among the first technologies to be called upon to generate. This is expressed by stating that VRE comes first in the merit order. The merit order ranks the power plants according to 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 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. Lower energy prices, more pronounced when high VRE generation happens during periods of low demand, benefit power consumers. Conversely, this means reduced income and asset values for power generators that are exposed to market risk.

The reason for the drop in value is a lack of flexibility in the power and wider energy system, combined with the variability of wind and solar power. The aim of power system transformation is to deploy a comprehensive package of measures that make the overall system more flexible. In a flexible power system, the SV of VRE remains high even at high penetration levels.[5]

It is important to distinguish between the short-term and long-term SV of VRE. In the short term, SV is strongly influenced by existing infrastructure and the current needs of the power system. For example, if new generation is needed to meet growing demand or retirements – as in South Africa – SV will tend to be higher. By contrast, the presence of large amounts of inflexible generation capacity – as is the case in Germany – can lead to a more rapid SV decline in the short term.

[5] An increase in flexible resources not only boosts the SV of VRE. More generally, it can increase the value of all inflexible technologies. Historically, the uptake of flexible resources, such as pumped hydro storage or programmable electric heaters, was used to integrate inflexible generation, in particular nuclear energy.

Figure 2.9 • Market value factor of wind and solar PV as a function of their market share in Germany, 2001-15



Notes: Each point corresponds to one year; the value factor is defined as the ratio between the electricity market revenue of the average wind/solar generator and the average electricity price; a value factor above one signals above-average market revenues; a factor below 1 signals below-average market revenues.

Source: Adapted from Hirth (2013), "The market value of variable renewables: The effect of solar wind power variability on their relative price"

Key point • As the share of VRE generation increases in power systems, its SV may decline. This decline is system specific.

When putting in place a strategy for VRE deployment, it is critical to keep in mind the difference between short- and long-term SV. In formulating long-term strategies, the long-term value of VRE is most relevant. It needs to be evaluated with due consideration of all available options to increase system flexibility and thus secure the value of wind and solar power at high penetration levels.

For example, a more responsive demand side boosts SV, because it can help to create demand when there is abundant supply. More generally, all options that increase the flexibility of the power system will have a positive impact on the SV of VRE.[6] Conversely, variable generation increases the SV of flexibility. The more variability there is in the system, the greater the need for flexibility and the higher its value. Economically speaking, high shares of VRE and flexibility are complementary goods; the presence of one increases the value of the other.

Most importantly, it is not only greater flexibility that can help to address the value challenge. VRE sources themselves can make a critical contribution to increasing their own SV by implementing system-friendly deployment techniques.

[6] Increasing interconnections between power systems will generally boost the overall value of VRE for the combined system. However, there may be distributive effects: one VRE system may experience a drop in value, while the other will then experience an increase.

Chapter 3: Achieving system-friendly VRE deployment

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

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

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

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

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

System service capabilities

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

Enabling the provision of system services from VRE requires two principal ingredients. First, installed power plant hardware must be technically capable of delivering the service. This can be ensured by adopting forward-looking technical standards that specify what capabilities each plant must have in order to be allowed to connect to the grid (these interconnection standards are often referred to as grid codes, Box 3.1). Second, system operation practices, including the design of system service markets (as far as they are in place), need to be upgraded to better accommodate VRE. The most relevant changes are: 1) to allow units to declare their availability to provide the service as close as possible to real time, 2) to allow power plants that have the size of typical VRE projects to participate, and 3) to allow aggregators to bundle the contribution from a portfolio of resources, including demand-side response and/or storage options, 4) to accurately reward the value of provided services. With its recent reform, Energy Market 2.0, Germany is taking steps in this direction. Spain has already implemented changes allowing wind power to contribute to balancing the grid in practice.

Box 3.1 • Examples of advanced grid codes

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

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

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

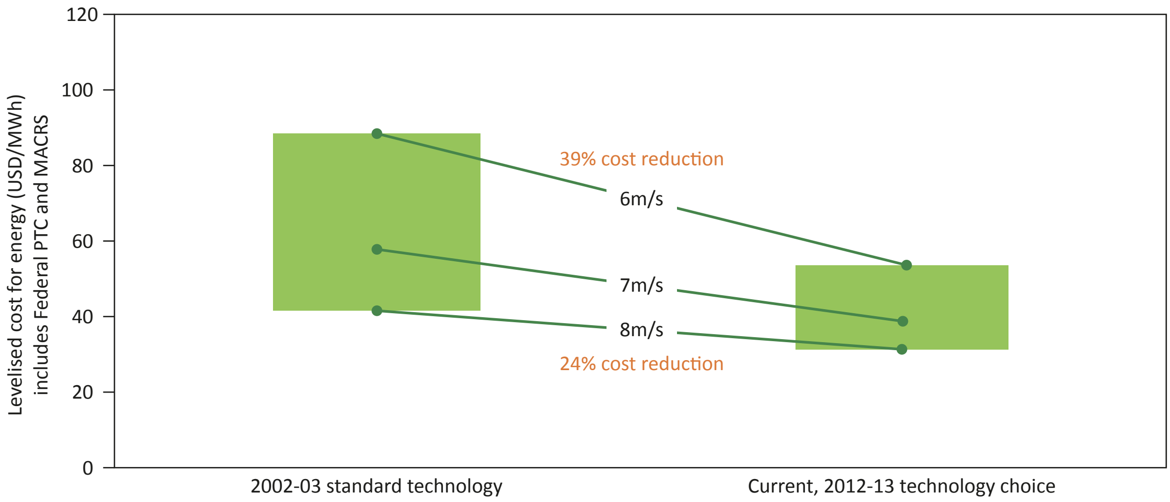
The grid code for German solar PV power plants originally specified that all plants were required to disconnect from the system if frequency rose above a level of 50.2 hertz, which may occur during a system disturbance. While such a rule allows secure system operation at low penetration levels of solar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

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

Location of deployment

With the cost of solar PV falling rapidly, deployment is becoming economical even in lower resource conditions. In the case of wind, improvements in turbine blades and other components have drastically reduced the cost of generating in medium-quality wind sites (Figure 3.1). This means that next-generation wind and solar power offers more flexibility in choosing the location of deployment. This can significantly increase SV by producing electricity closer to demand or in regions where alternative generation options are very expensive. For example, the recent auction in Mexico, which reflects the value of electricity depending on location, led to projects being selected in areas that have comparably less favourable resources, but where additional generation has a high value (see the Mexico case study for details on the design of the auction system).

Figure 3.1 • Evolution of wind power costs according to wind resource in the United States



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

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

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

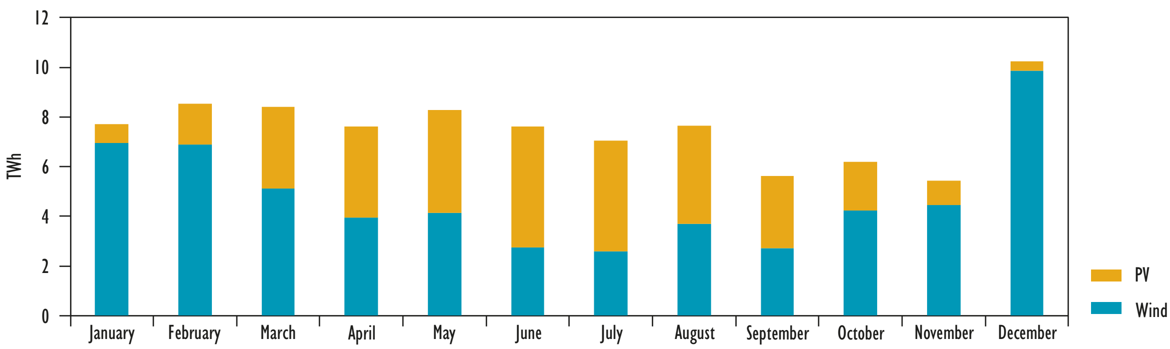
Technology mix

The output of wind and solar power is complementary in many regions of the world. In addition, the availability of VRE can be complementary to other renewable resources, such as hydropower. Deploying a mix of technologies can thus bring valuable synergies. For example, the current mix of wind and solar power in Germany leads to an overall more stable generation profile than each technology by itself (Figure 3.2), which raises the combined SV. In order to achieve an optimal technology mix, however, a shift in current power system regulations and grid codes may be needed.

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

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

Figure 3.2 • Monthly generation of wind and solar power in Germany, 2014



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

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

Local integration with other resources

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

The distributed nature of VRE, and solar PV in particular, allows generation to be located alongside other resources, including small-scale battery electricity storage or demand-side response resources. Co-location of resources can help avoid grid congestion and enable the provision of system services from a package of resources. Because such resources are often installed on the customer side of the electricity meter, policy interventions need to be applied through the design of appropriate retail electricity and grid tariffs (Box 3.2).[7]

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

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

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

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

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

Optimising generation time profile

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

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

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

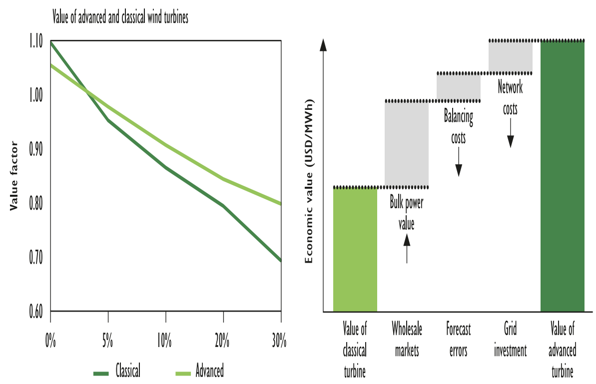
Focus on onshore wind

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

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

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

Figure 3.3 • Possible benefits of advanced turbine technology



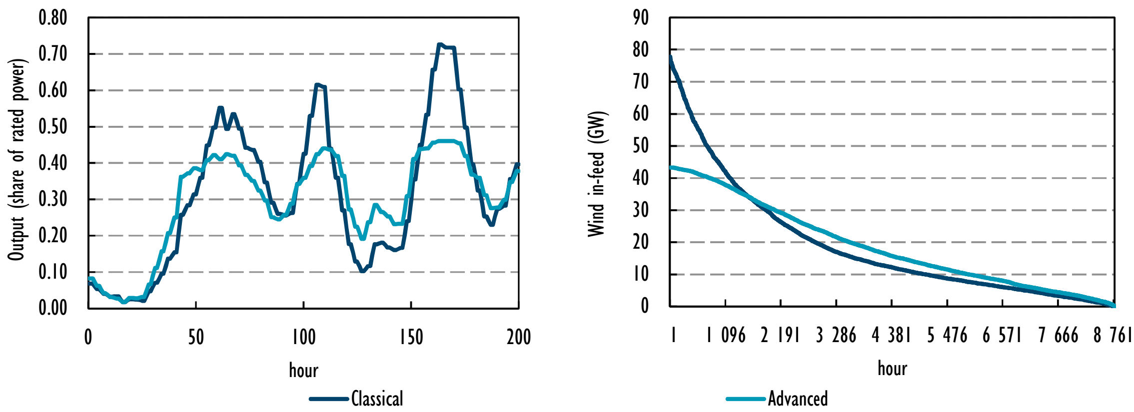
Source: Adapted from Hirth, L. and S. Mueller (2016), "System-friendly wind power: How advanced wind turbine design can increase the economic value of electricity generated through wind power".

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

A modelling study carried out for this report (Hirth and Mueller, 2016) measures the additional benefit of advanced technologies as the increase in average market value (USD/MWh) during the course of a year, where "increase" is the difference between the market value of an advanced generation profile and that of a classical generation profile. The analysis is based on results from the European Electricity Market Model (EMMA). The model has previously been used to study the economics of wind and solar power. EMMA is a techno-economic model of the integrated Northwestern European power system, covering France, Benelux, Germany and Poland. It models both dispatch of and investment in power plants, minimising total costs with respect to investment, production and trade decisions under a large set of technical constraints. Advanced wind turbine design has a number of potential benefits, including 1) higher revenues from wholesale power markets (increased bulk power value), 2) reduced forecast errors, and 3) reduced grid costs (Figure 3.3). Bulk power value comprises revenues from energy (spot) markets and capacity markets, if present. The modelling analysis focused on this element.

In the context of the modelling study, the most important model input is the hour-by-hour time series of wind power generation. Advanced wind turbines are modelled combining two features: 1) a taller tower than classical turbine design; and 2) a larger rotor-to-generator ratio (lower specific rating). As winds tend to be more constant at larger heights above ground, and a lower specific rating implies relatively more output at intermediate wind speeds, both features tend to make output more constant. In this sense advanced wind turbines are "less variable" than classical turbines (Figure 3.4).

Figure 3.4 • Generation profiles representing classical and advanced technology



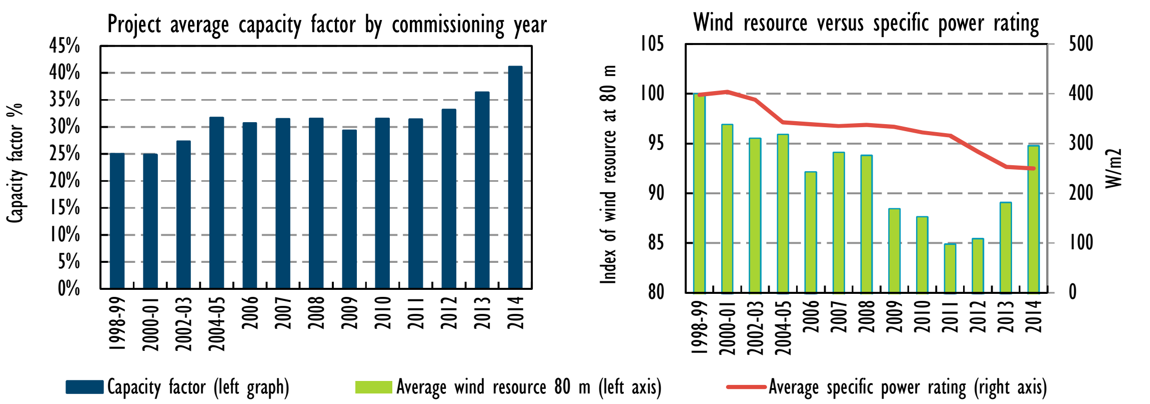
Note: GW = gigawatt.

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

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

The modelling study investigated the implications of using advanced technology across all resource locations and the extent to which this increases the market value of wind energy. As a baseline for comparison, it is assumed that a standard high wind speed design is deployed at all sites. This is compared to a scenario in which low wind speed turbines are deployed in all locations. Given today's deployment patterns, this represents a hypothetical scenario. However, a trend towards deploying low wind speed technology at higher wind speed sites is already observable in the market (Figure 3.5).

Figure 3.5 • US onshore wind capacity factor, wind resource and turbine-specific power rating by year



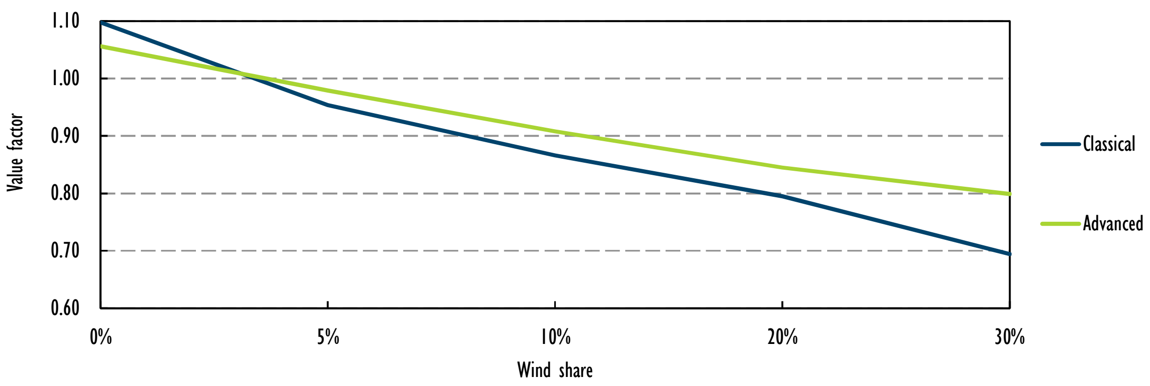
Note: Wind resource quality is based on site estimates of gross capacity factor at a hub height of 80 m; 1998-99 value = 100.

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

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

For classical turbines, the value factor is higher than one at low penetration, reflecting the positive seasonal correlation of wind speeds with electricity consumption (both tend to be higher during winter in Europe). With increasing deployment, it drops quickly to about 0.7 at a penetration rate of 30% (Figure 3.6). This reflects findings of other studies (Mills and Wiser, 2012; Nicolosi, 2012, among others) and is consistent with observed market data (Hirth, 2013).

Figure 3.6 • Comparison of the economic value of advanced and classical wind turbine designs for Northwest Europe



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

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

The relative value drops because in those hours during which electricity is supplied by wind power, the price is depressed. The price drop becomes more pronounced as more wind generation is added. With advanced turbines, the value drop is less pronounced because wind generation is distributed more smoothly over time, reducing the price-depressing effect in each individual hour (Figure 3.4).

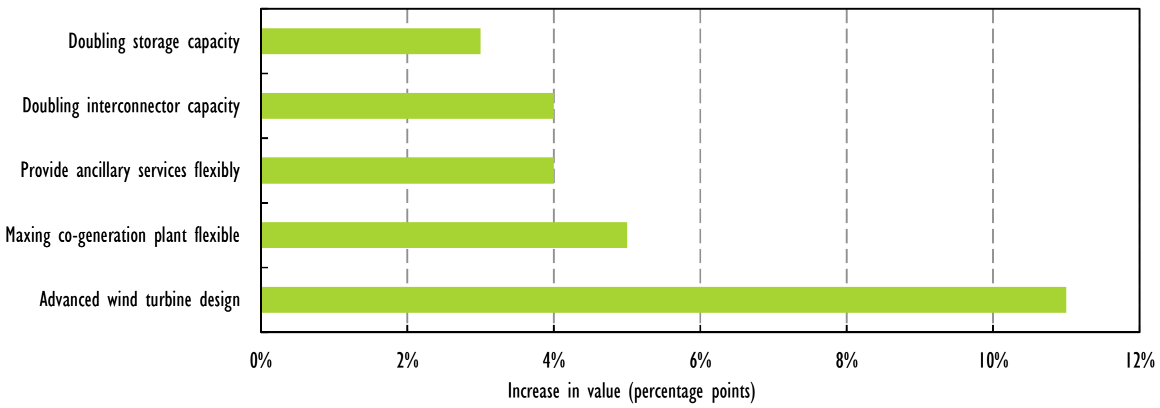
Model results indicate that the difference is large: at 30% penetration, the value factor is 13 percentage points higher ("absolute delta"), corresponding to 22% of the classical turbines' value factor ("relative delta"). In other words, one MWh of electricity generated from wind power is 22% more valuable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

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

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

At a penetration rate of 20%, the relative value of advanced turbines exceeds that of classical turbines by five percentage points. The gap increases at higher shares. In a situation where wind power accounts for 30% of total power generation, opting for advanced wind turbine design has a stronger impact on the value of wind than any other flexibility option (Figure 3.7).

Figure 3.7 • Comparison of the impact of different flexibility options on the economic value of wind power for Northwest Europe



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

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

Focus on solar PV

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

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

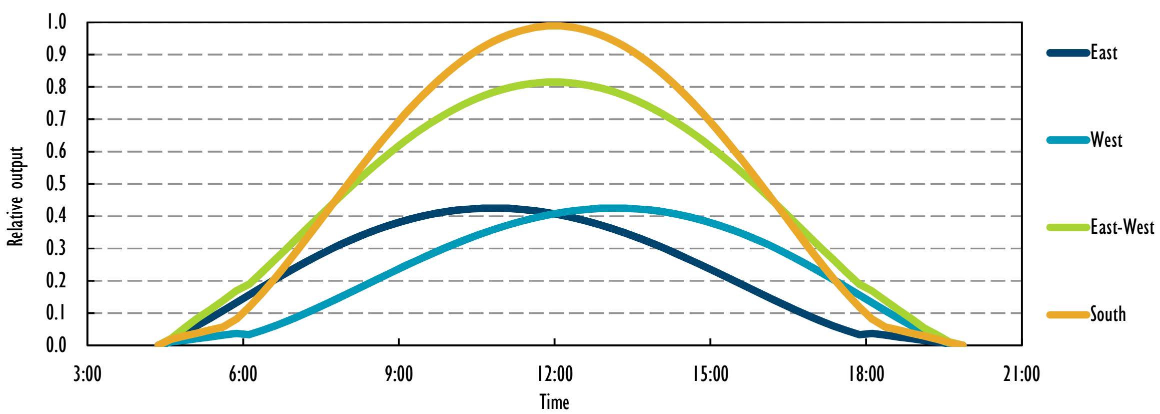
The majority of past solar PV investments has not been exposed to market price signals or similar incentives to optimise their output from a system perspective. Consequently, these design options have typically been used to minimise the LCOE of electricity production. Only in the limited number of cases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

Orientation and tilt of solar modules

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

More importantly, in the afternoon and early evening energy tends to have a higher value, as total power demand is often higher during this time of day. This difference is likely to become more pronounced at larger shares of solar deployment. This favours orienting the panels to the west. The state of California has passed legislation whereby west-facing panels receive a 15% premium for all generated electricity. As the share of solar PV generation increases, adding east-facing panels will allow solar power to contribute to meeting the morning consumption peak (Figure 3.8).

Figure 3.8 • Impact of panel orientation on solar PV production profile, month of May in Germany



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

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

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

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

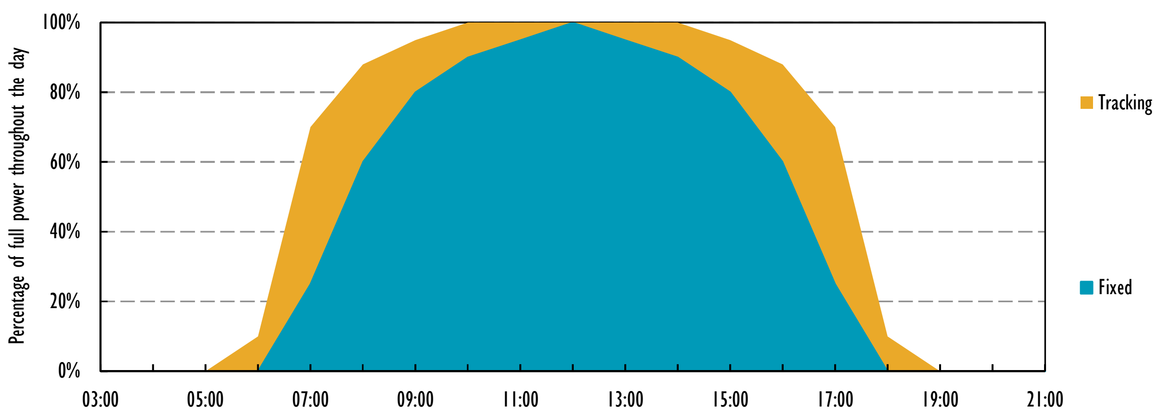
In a future marked by cheap solar power, markets and policy design may incentivise a certain tilt to modify the annual production profile of solar projects in line with the value to the overall system. While orientation alters the daily generation profile, tilting can modify the annual generation profile: a greater tilt of equator-facing modules increases winter output and decreases summer output.[8] This would presumably be of value in temperate countries, or in sunny countries with a large share of solar PV. It may have a relatively important cost, however, in annual generation losses in temperate countries where summer output largely exceeds winter output.

Tracking

A tracking system whereby solar panels follow the path of the sun throughout the day increases the level of energy production (Figure 3.9). In the case of single-axis trackers, a PV installation may generate over the year 12-25% more electricity than fixed systems in high insolation areas. Dual-axis tracking can increase the yield by an additional 10-15%, although in economic terms this advantage can be offset by higher installation and maintenance costs for the supporting equipment (Bolinger, Seel and Wu, 2016) As non-concentrating PV panels are relatively tolerant to incoming sunlight, tracking technology does not need to be extremely precise and is thus not very costly.

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

Figure 3.9 • Indicative percentage of full power throughout the day for a dual-axis tracking and a fixed-tilt PV plant



Note: This is a representative figure for illustrative purposes.

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

Panel-to-inverter ratio

The production limit for a solar PV plant (in AC terms) is dictated by the inverter size. Since the output level of a solar array (in DC terms) reaches the rated peak capacity only during few hours,[9] the nominal capacity of the solar array will generally exceed the inverter capacity by at least 10%.

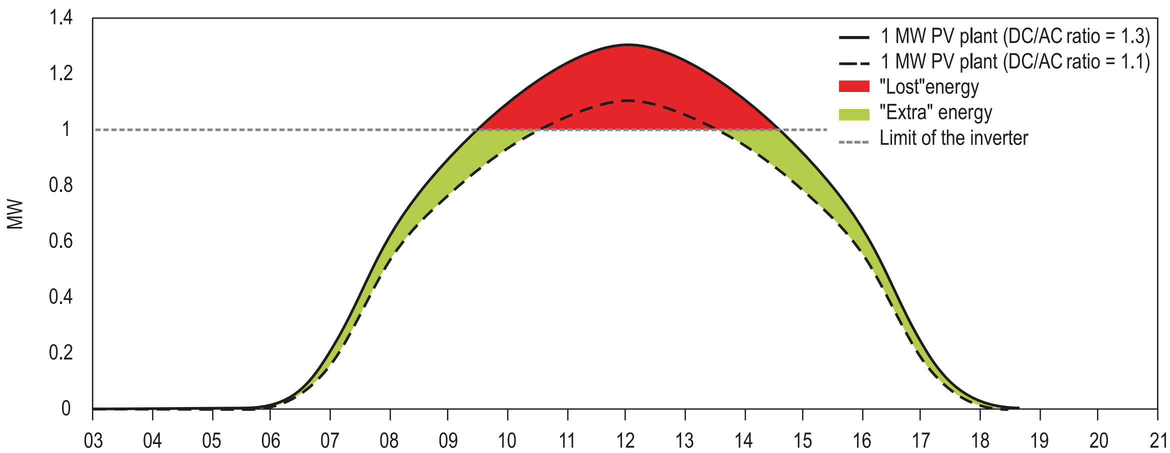
[8] With a greater tilt, panels more directly face the lower sun in winter.

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

The ratio between the nominal capacities of the solar array and the inverter is referred to as the DC/AC ratio, or the inverter load ratio (ILR) (Troester and Schmidt, 2012).

A solar PV plant with a higher DC/AC ratio can run at full capacity more often than a plant with a lower DC/AC ratio. As an example, compare a PV plant with a 1 MW inverter and a 1.1 MW solar array (DC/AC ratio of 1.1) to a second PV plant with the same inverter capacity but a 1.3 MW solar (DC/AC ratio of 1.3) (Figure 3.10). For both the plants some amount of solar power is lost during the solar peak hours, because the inverter cannot manage the full peak production (these energy losses are also called "clipping losses"); the PV plant with a larger solar array faces larger clipping losses, but at the same time gains "extra" energy production during the shoulder hours; plant-level output now assumes a plateau shape, which can be more valuable from a power system perspective.

Figure 3.10 • Indicative generation curves of a current PV plant and a system-friendly PV plant with downsized inverter



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

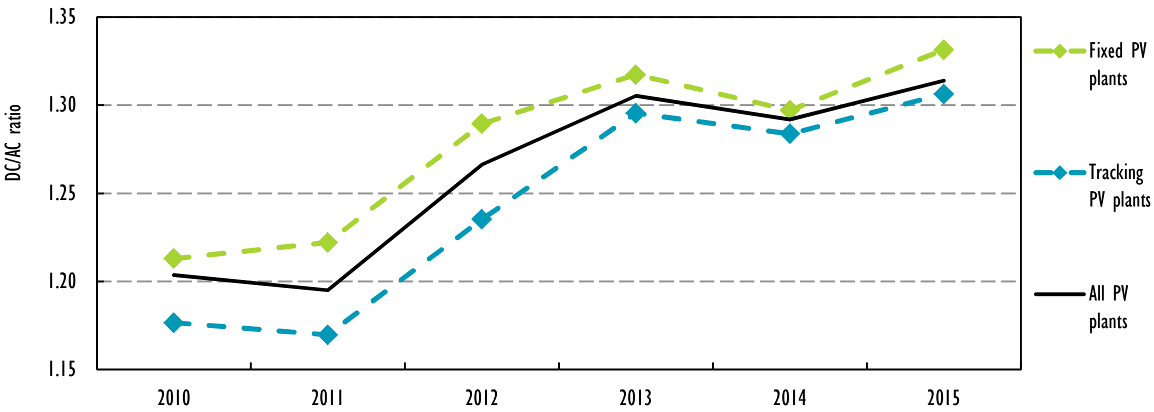
Key point • Downsized inverters allow a more system-friendly PV generation profile.

When applying a higher DC/AC ratio over a large number of solar PV plants, the midday solar PV production peak, which can be challenging to handle in system operations, will be less pronounced. The optimal DC/AC ratio is driven by a number of factors, such as the technical obligations prescribed by the grid code, the relative cost of solar panels to inverters, and the costs for connecting plants.[10] Once the connection capacity (i.e. the size of the inverter) is set, the solar array size is optimised. The rapid decrease of PV module costs in recent years has supported the trend to install larger solar arrays in some countries (Figure 3.11).

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

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

Figure 3.11 • DC to AC ratio by mounting type and installation year, United States



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

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

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

Distributed solar PV

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

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

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

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

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

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

Policy examples to optimise the generation time profile

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

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

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

Putting in place mechanisms that signal SV to developers will, in principle, incentivise system-friendly deployment practices: power plants that generate electricity with a higher value receive a higher remuneration. However, existing policy frameworks may actually *hinder* the adoption of system-friendly design. For example, where the eligible amount of revenues under a support mechanism is capped at a certain level of full-load hours, project developers may choose to deliberately oversize the generation capacity to increase profit.[11] This leads to an incentive to reduce capacity factors. The example of Denmark shows how policies can be adjusted to prevent this. Under the new FIP system, the size of the rotor is considered when calculating eligible full-load hours.

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

Integrated planning

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

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

Summary: Reflecting SV in RE policy frameworks

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

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

Distributed resources – focus on regulation of local grids and retail prices

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

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

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

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

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

Box 3.2 • The role of retail electricity pricing in guiding investment in distributed solar PV

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

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

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

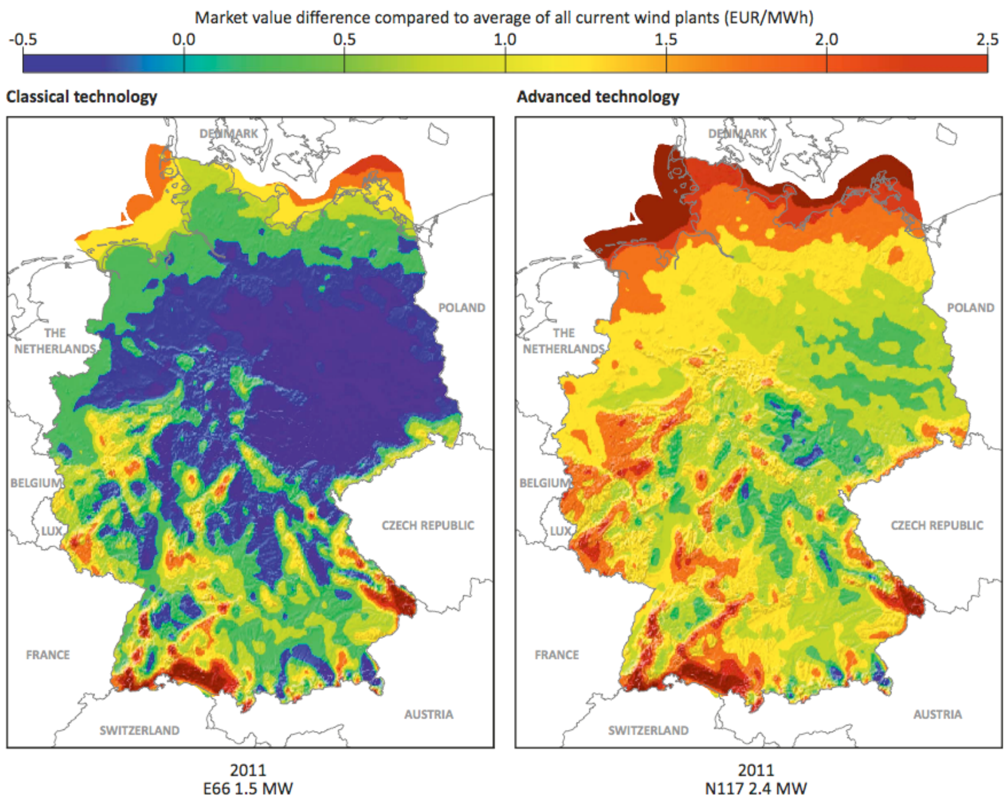
Centralised resources – enhancing remuneration schemes

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

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

The German market premium system provides incentives for investors to choose more system-friendly deployment options. The mechanism is designed such that an average wind power plant will generate revenues that match the FIT level. The mechanism to encourage a more system-friendly deployment is this: if a power plant has a higher-than-average market value, the generator can make an additional profit. Investors are now increasingly aware of the difference in value depending on when wind turbines generate. Specialised consultancies provide data on locations where the wind blows during times when the value of electricity is particularly high (Figure 3.12).

Figure 3.12 • Market value of wind power projects depending on location, Germany



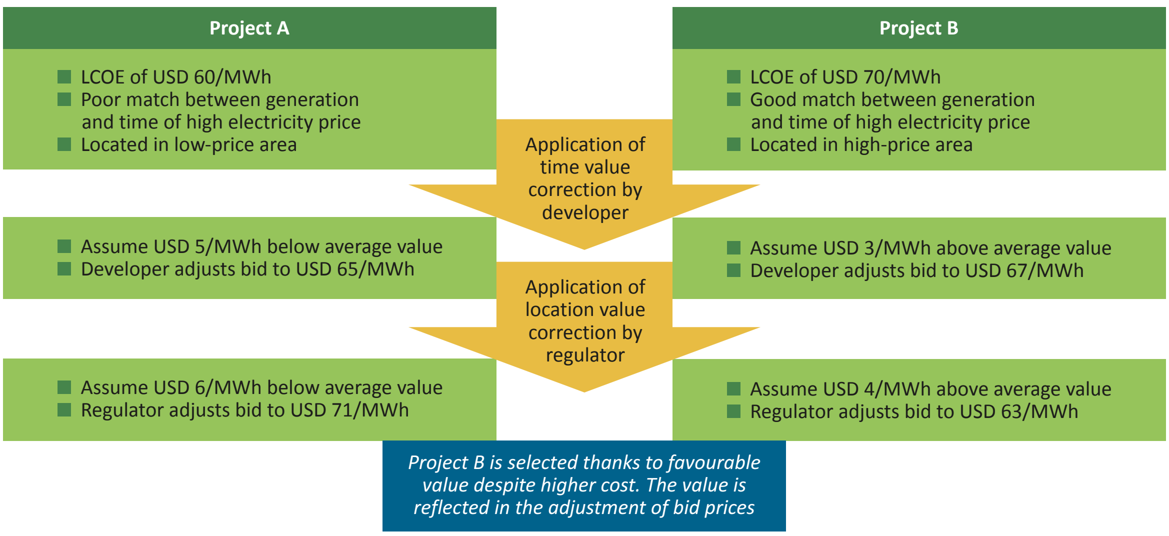
Note: Blue areas indicate below-average market value; red areas show above-average market value.
Source: Adapted from Enervis/anemos (2016), *Market Value Atlas*, www.marketvalueatlas.com.

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

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

Combining electricity prices with the feed-in profile of a generation resource, it is possible to calculate its market revenue; this is a proxy for the SV. The exact calculation is somewhat technical and involves the combined revenue from electricity and the sale of green certificates. This does not change the main point, however. In essence, those producers that offer electricity with a higher-than-average value can reduce their bids in two steps (Figure 3.13). In the first step, a correction for the timing of generation is applied, as calculated by project developers. In the second step, a correction factor for location is applied. In summary, these factors are reflected in the order in which projects are selected. The Mexican system has recently been introduced and the first auction results were obtained in April 2016. While its design is excellent from the perspective of SV in principle, it remains to be seen if further modifications may become necessary in practice.

Figure 3.13 • Conceptual illustration of the Mexican auction system for variable renewables



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

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

The measures discussed in this section are summarised in Table 3.1.

Table 3.1 • Overview of system-friendly policy tools and their impact on SV

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

Chapter 4: Conclusions and recommendations

The analysis presented in this report has highlighted the opportunity that next-generation wind and solar power is bringing to meet energy policy objectives. In order to translate this opportunity into meaningful impact, governments should consider implementing the following recommendations. Each recommendation is preceded by a summary sentence that is the main driver for making the recommendation.

- Wind and solar power have reached a new stage of deployment characterised by economic affordability and technological maturity.
  - Develop or update long-term energy strategies to accurately reflect the potential contribution of next-generation wind and solar power to meeting energy policy objectives. Such plans should be based on the long-term value of VRE to the power and wider energy system.
- Successfully integrating variable generation into power systems calls for making the power system more flexible. This requires a comprehensive transformation of the power and wider energy system. The four principal sources of flexibility are: generation, demand-side resources, storage and grid infrastructure.
  - Upgrade system and market operations to unlock the contribution of all flexible resources to dealing with more frequent and pronounced swings in the supply-demand balance of electricity.
  - Make the overall system more accommodating to variable generation by investing in an appropriate mix of flexible resources. This includes retrofitting existing assets, where this can be done cost-effectively.
  - Deploy wind and solar power in a system-friendly fashion by fostering the use of best technologies, and by optimising the timing, location and technology mix of deployment.
- As next-generation wind and solar power grows in the energy mix, a focus on their generation costs alone falls short of what is needed. Policy and market frameworks must seek to maximise the net benefit of wind and solar power to the overall power system. A more expensive project may be preferable if it provides a very high value to the system. This calls for a shift in policy focus: from generation costs to SV.
  - Upgrade existing policy and market frameworks to encourage projects that bring the highest SV compared to their LCOE, factoring in the impacts on other power system assets such as a more volatile operating pattern for dispatchable generation or the need for grid expansion.
- Modern wind and solar power plants can actively support their own integration by providing valuable system services.
  - Establish forward-looking technical standards that ensure new power plants are capable of providing state-of-the-art support for a stable and secure operation of the power system.
  - Reform electricity markets and operating protocols to allow for the provision of system services by wind and solar power plants. Such reforms must be rooted in a long-term vision of the power sector, so that they fit into, rather than counteract, a stable policy and regulatory framework.
- The distributed deployment of wind and solar power is changing the role of low- and medium-voltage power grids, away from a passive distribution system and towards an important hub

for exchanging electricity and data. By generating their own power, consumers can increasingly take control over their electricity supply.

- Review and revise planning standards as well as the institutional and regulatory structure of low- and medium-voltage grids, reflecting their new role in a smarter, more decentralised electricity system, and ensure a fair allocation of network costs.
- Reform electricity tariffs to accurately reflect the cost of electricity depending on time and location. Establish mechanisms to remunerate distributed resources according to the value they provide to the overall power system.

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Chapter 5: Case studies

Introduction to scope and methodology

Scope

The following chapters present a number of selected case studies that illustrate the current state of play on grid integration of variable renewable energy (VRE). By exploring the current power mix, market rules, sector-specific policies and operational practices guiding the functioning of the power system, these case studies identify the key drivers and obstacles to realising next-generation wind and solar photovoltaic (PV) deployment.

The chosen case study regions exhibit a large number of the challenges and opportunities that are typically encountered when scaling up wind and solar PV, in particular in emerging economies. Taken together, the lessons from these cases provide a diverse overview of the political, institutional and economic variables that affect the pace of investment in and system-friendly character of VRE assets.

Four of the six case studies (Brazil, Indonesia, Mexico and South Africa) deal with dynamic power systems that need additional investment in power generation and transmission capacity to meet growing demand, and which believe VRE to be an important part of the solution. A fifth case (Northeast China) describes a situation where the rollout of VRE projects has occurred against a background of slowing economic growth and in a system which underexploits the technical attributes of flexibility sources. Each of these cases has unique characteristics that determine what system-friendly means for wind and solar. Finally, the case of Denmark, a global leader in VRE integration, is taken to demonstrate the type of challenges that may arise at higher shares of VRE production.

Methodology

Since the speed and shape of VRE development is strongly influenced by the status quo of the power system and the fundamentals of the available VRE resources, the first part of each case study analyses how wind and solar PV resources fit into the supply-demand balance. On the basis of meteorological conditions, the natural overlap of wind and solar PV with the load profile is evaluated using the *demand coverage factor* (Box 5.1). This quantitative assessment provides a rough indication of the level of flexibility required at system level to align VRE production with the load profile throughout the year.

The research then takes stock of the existing sources of flexibility – dispatchable power plants, interconnection capacity, storage and demand-side resources. The IEA Flexibility Assessment Tool (FAST2) is used to assess the technical capability of a power system to deal with rapid swings in the supply and demand balance over time scales from 1 to 24 hours, which is a critical capability for VRE integration. Making the important assumption of a fully functional grid, the results show how much VRE can already be installed at system level in a scenario where the technical attributes of existing flexibility sources are fully utilised.[12]

Box 5.1 • Demand coverage factor (DCF)

The demand coverage factor (DCF) is an indicator of the natural fit of VRE resources and the current power demand profile in a given country.

The analysis is based on a hypothetical situation where for the entire year wind and solar PV generate the equivalent of annual power demand. If VRE output and demand matched perfectly, this would mean that net load – power demand minus VRE generation – would be zero in every moment. However, this will not be the case in practice: in certain hours VRE will supply more electricity than is being demanded, in others less.

Rather than calculating the match for each hour, the DCF is calculated for periods of one week. The reason for this is that longer imbalances – such as those occurring on a weekly level – are generally harder to balance than hourly imbalances. Calculating the hourly balance can thus underestimate longer periods of excess supply or shortage. Rather than looking at calendar weeks, the analysis is based on all possible periods of one week during one year; weeks are considered here to be 168 continuous hours.

The DCF is designed such that if there is a perfect match between the weekly supply of VRE and power demand, the DCF will equal one. If VRE supplies more than needed, it will be higher than one, and below one if there is a deficit in VRE supply. More formally put, the calculation is as follows:

$$DCF = \frac{weekly\ VRE\ generation}{weekly\ power\ demand}$$

As an example, if power demand is 1 terawatt hour (TWh) and VRE production is 0.2 TWh, the resulting DCF is 0.2.

If the match is very poor, weekly VRE generation will either be scarce, thus providing a DCF close to 0, or it will exceed demand, resulting in a DCF higher than 1.

For each case study, the mix between wind and solar PV capacity is defined so that the narrowest range of DCF values appears (mathematically speaking the standard deviation of the DCF is minimised).

The results of the analysis are represented in histograms, which provide a visual representation of the match between VRE resources and power demand profiles by presenting the DCF value distribution. The more weekly DCFs are close to 1, the more the VRE production profile naturally matches the power demand.

Building on this general context of grid integration, the case studies go on to closely examine the rules and practices that drive the power system.

Improving operations is cost effective independent of VRE, but benefits are magnified at higher VRE penetration rates. In turn, failure to adopt improved operations becomes increasingly expensive at growing shares of VRE. Changing power system operational practices may require time, human resources and specific tools. In summary, the three priorities for improving operations are as follows:

[12] For further information on the FAST2 model, see S. Mueller (2013), *Evaluation of Power System Flexibility Adequacy: The Flexibility Assessment Tool (FAST2)*, Proceedings of the 12th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks of Offshore Wind Power Plants, October 2013.

- Ensure that operational decisions can be updated as close as possible to real time and that operational schedules have a high temporal granularity (including power plant and transmission grid schedules and the calculation and deployment of operational reserves).
- Expand the geographic region over which supply and demand are matched as far as possible.
- Integrate VRE generation into system operations by 1) accurately monitoring real-time VRE output, 2) effectively using short-term forecasts (forecast are much better a few hours ahead than several days ahead; operations need to incorporate short-term forecasts), and 3) ensuring that VRE power plants can be controlled (maximum output of a VRE power plants is constrained by momentary resource availability, but VRE can be accurately controlled within this possible output range).

The case studies also investigate the support schemes and procurement mechanisms in place for VRE, and assess whether these are effective in attracting desired investment flows. In addition, the analysis shows how revenue levels for VRE projects compare with their estimated cost. In a nutshell, it evaluates the framework for VRE investment from the perspective of system integration.

Once the VRE investment climate is established, the question becomes whether the current market environment and system rules support the system-friendly operation of VRE and the flexible operation of the system as a whole. A number of important characteristics are discussed, such as the rules and practices regarding forecasting, power plant scheduling, interconnector operations and the definition of system services. These elements determine the degree to which the technical attributes of wind and solar power are valued. By including grid codes and system service procurement rules, the analysis aims to show the extent to which VRE generators are enabled to contribute to a reliable operation of the system in accordance with their full potential.

Subsequently, the case studies explore how today's market and policy frameworks can be improved to trigger the type of system transformation that can foster a lasting and sustainable growth trajectory for wind and solar. Each case study concludes with a discussion that identifies the main legal, technical and economic aspects behind the challenge of grid integration in their country or region. Finally, a summary table identifies key recommendations to integrate system-friendly deployment of wind and solar PV into the mainstream policy, market and regulatory framework.

Brazil

General information on VRE and grid integration

Flexibility assessment, ease of integration and current value

VRE resources

Due to its large size, Brazil covers different climatic regions: the Amazon basin, the Brazilian plateau and the east coast within the tropics, and the southern states outside the tropics. Overall, Brazil has access to favourable solar resources, with average annual global horizontal radiation (GHI) in excess of 1 800 kilowatt hours per square metre (kWh/m^2) throughout most of the country (Figure 1.1) (Solargis, 2016). The highest values occur on the Brazilian plateau, with GHI reaching more than 2 300 kWh/m^2. This region, which encompasses the densely populated northern coast around Fortaleza and the rural area of west Bahia, receives 5-6 hours of sunshine each day during the rainy season and as much as 9-10 hours during the dry season. Concentrated solar power (CSP) potential is high in this part of Brazil. However, the load centres on the east coast, including Rio de Janeiro and São Paolo, have lower irradiation levels, and receive between 5-6 hours of sunshine during the rainy season and 6-7 hours during the dry season (IEA, 2010).

The best wind resources can be found on the northeastern coast, which exhibits annual average wind speeds of 8-10 metres per second (m/s) at a height of 100 metres (m). In the coastal areas (up to 50 kilometres [km] inland) wind speeds average 7-9 m/s (at 100 m height). Further inland, onshore wind speeds are relatively lower (IRENA, 2016). In the northern area, Brazil has favourable geographic conditions for wind, as the rate of change in wind speed and direction, as well as the level of turbulence, are relatively low. This is related to the effects of the trade winds. Moreover, Brazil's wind resources combine well with its hydro resources, as they complement each other seasonally: wind speeds are especially high in the drier months from July to October when low precipitation decreases hydro resources to their annual minimum.

Demand

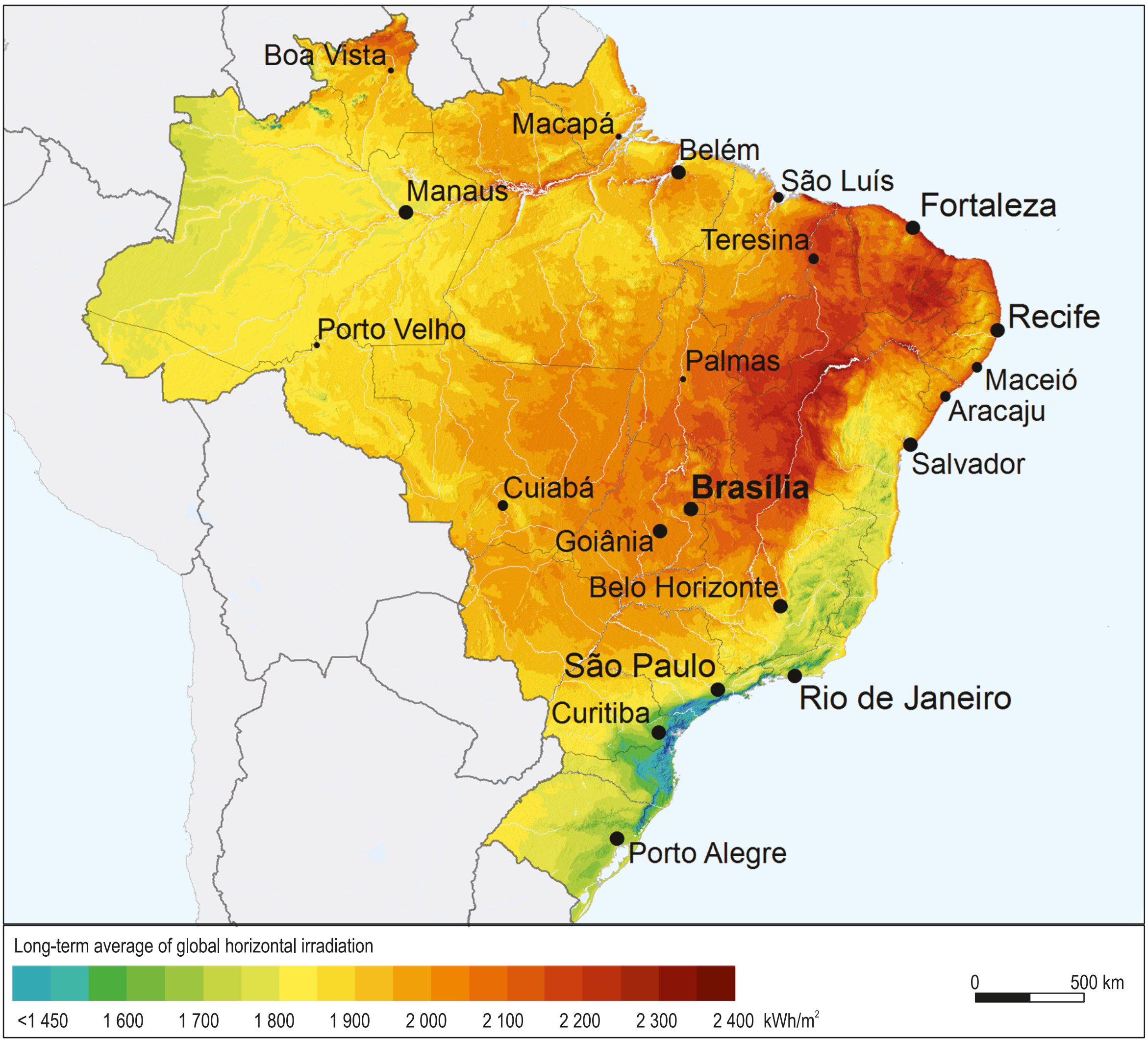
Electricity consumption in Brazil has steadily increased over recent years and reached approximately 516 terawatt hours (TWh) in 2013. Predictions by the Ministry of Mines and Energy (MME) expect consumption to rise to 790 TWh by 2024, with an average annual growth rate of 4.2% (MME, 2015b). The "New Policy Scenario" of the International Energy Agency (IEA) *World Energy Outlook 2015* anticipates a rise in electricity generation to 775 TWh by 2025 (IEA, 2015).

During 2014, residential consumers accounted for 27% of overall consumption, commercial consumers for 19% and industrial consumers for 38% (EPE/MME, 2015). Apart from Brasilia, most load centres can be found in the coastal areas, mainly in the southeast around São Paulo and Rio de Janeiro, but also in the northeast between Fortaleza and Salvador.

In 2012, electricity demand varied between 37 gigawatts (GW) and 76 GW, averaging at about 58 GW. Demand follows a somewhat seasonal pattern, with demand being 5% lower in the relatively cool winter months (June to end of August) compared to the hotter summer period (December to end of February). Peak demand varied accordingly by about 6.3 GW, from 69.7 GW in winter to 76 GW in summer (Figure 5.2).

Maximum peak load of 85.7 GW was reached on 5 February 2014 at 15:41 (MME, 2015a).

Figure 5.1 • Average annual GHI, Brazil

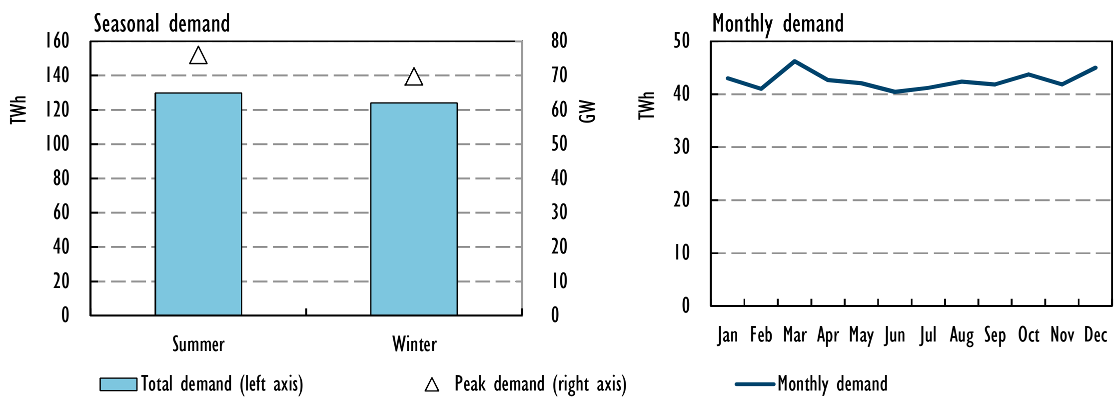


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: Solargis (2016), "Solar resource maps", http://solargis.com/.

Key point • Brazil is endowed with excellent solar resources.

Figure 5.2 • Seasonal and monthly electricity demand, Brazil, 2012



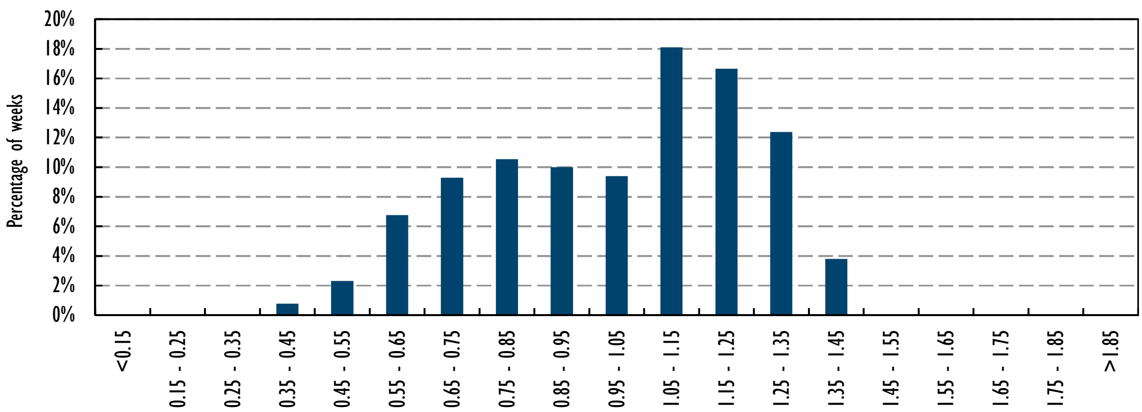
Note: Summer from December to end of February, winter from June to end of August.

Key point • Demand is slightly higher in summer than in winter.

Analysis of demand and VRE generation profiles

The demand coverage factor (DCF) analysis shows that the correlation between variable renewable energy (VRE) generation and electricity demand in Brazil is quite favourable. Even though a strong match between VRE generation and demand (with DCFs between 90% and 110%) occurs for only 25% of weeks, no extreme spreads can be observed. For 76% of weeks, the DCFs lie in a good range of 70-130%. The DCFs never exceed 150%, or drop below 40% (Figure 5.3).

Figure 5.3 • Range of weekly DCFs for Brazil



Key point • The DCF analysis reveals a relatively high average match between demand and supply, even though weeks of relatively low coincidence exist.

Generation

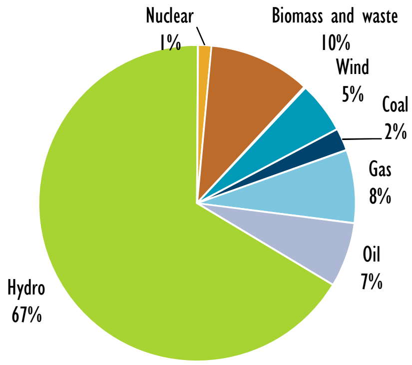
Brazil is the largest power producer in Latin America. Hydropower is the dominant source of generation capacity (Figure 5.4; Table 5.1). The country has witnessed a drastic expansion of generation capacity since 2003, in response to an increase in demand. On average, capacity increased by about 4 300 megawatts (MW) per year from 2003 to 2014, with a record of 7 500 MW of added capacity in 2014 (MME, 2015a). Hydropower, biomass and wind power have been the main sources of added capacity in the last five years. New hydropower plants are mostly run-of-river, which offer less flexibility than the older reservoir plants.

Annual power production stood at about 550 TWh in 2014, from a total installed capacity of 132.9 GW (MME, 2015a, 2015b). Power generation is dominated by hydropower, but biomass and wind generation have increased notably in recent years. Overall generation capacity is expected to reach 206.4 GW by 2024 (MME, 2015b).

The high share of hydro energy provides the Brazilian system with a strong flexible resource. However, the strong reliance on one resource makes the energy system vulnerable to drought. In order to increase resilience in years of drought, Brazil has been working on diversifying its energy supply.

Given its abundant hydroelectric resources, Brazil's supply mix naturally exhibits strong flexibility. Although hydropower continues to dominate capacity expansion plans, its relative share will decline over time (Table 2). Moreover, these capacity additions will predominantly consist of run-of-river plants due to environmental restrictions on new reservoir areas. As a consequence, the majority of hydropower flexibility will come from existing reservoir plants. Looking further ahead, a slowdown in hydropower development combined with growing demand is likely to require Brazil to find alternative solutions. The speed at which wind and solar photovoltaics (PV) can be deployed and integrated is thus a critical parameter for their future role in the Brazilian energy mix.

Figure 5.4 • Installed power generation capacity in Brazil by fuel, 2015



Source: Adapted from Platts (2016), *World Electric Power Plants Database*, and EPE (2016), *Relatório Síntese – Ano Base 2015* [Summary Report – Base Year 2015], https://ben.epe.gov.br/downloads/S%C3%ADntese%20do%20Relat%C3%B3rio%20Final_2016_Web.pdf.

Table 5.1 • Installed power generation capacity in Brazil, 2015

Fuel	Installed capacity in GW
Coal	3.4
Gas	11
Oil	9.7
Hydro	97.6
Nuclear	2
Biomass and waste	15.26
Solar	0.21
Wind	7.7

Source: Adapted from Platts (2016), *World Electric Power Plants Database*, and EPE (2016), *Relatório Síntese – Ano Base 2015* [Summary Report – Base Year 2015], https://ben.epe.gov.br/downloads/S%C3%ADntese%20do%20Relat%C3%B3rio%20Final_2016_Web.pdf.

Key point • Hydropower dominates Brazil's capacity mix.

Table 5.2 • Plants expected to be constructed between 2015 and 2019

Technology	Number of plants	Added capacity (MW)
Hydro	20	18 740
Small hydro	35	682
Thermal	34	9 628
Wind	401	9 862
Photovoltaic	31	890
TOTAL	**521**	**39 802**

Source: MME (2015a), "Brazilian power system: Institutional aspects, actual characteristics and HVDC systems", presentation by MME at seminar Technology and Management in Ultra High Voltage Electricity, Beijing.

Key point • Hydropower is anticipated to lead capacity additions in the coming years, while wind capacity is expected to more than double between 2015 and 2019.

Storage and DSM

The high levels of flexibility provided by hydropower resources have been sufficient to guarantee reliable operation of the system over the short term, i.e. load-following throughout the day and provision of operating reserves. Looking ahead, this may change, reflecting the evolving generation mix. The expected growth of power demand in Brazil provides an opportunity to integrate demand response and management into the system, for example by making sure that air-conditioning systems are equipped with thermal energy storage.

Transmission and interconnections

The Brazilian national interconnection system (Sistema Interligado Nacional [SIN]) has 126 600 km of transmission lines (230 kilovolts [kV] and above) and serves approximately 98.3% of total electricity demand. The remaining 1.7% comprises several hundred isolated systems which are mainly located in the Amazon region (MME, 2015a; ONS, 2014).

Long transmission lines are needed to connect the country's hydropower resources to the coastal load centres (Figure 5.5). New hydroelectric projects – e.g. along the Rio Madeira, Rio Tapajos and Rio Xingu rivers – lie more than 2 300 km away from the coastal cities of São Paulo and Rio de Janeiro and require significant transmission grid upgrades. Although recent years have seen a significant expansion of transmission grid capacity (in 2001 transmission capacity stood at 70 000 km), an additional 55 000 km of transmission lines are due to be built by 2023 (MME, 2015a).

Interconnection capacity with neighbouring countries adds up to more than 9 GW (Table 3). Only a fraction of this capacity is available for cross-border trade, because cross-border connections with Paraguay and Venezuela exclusively export production from the Itaipu-Dam and the Guri-Dam projects, respectively.

Brazil's power system operates at a frequency of 60 hertz (Hz), unlike neighbouring Argentina, Uruguay and Paraguay. Transmission connections with these countries are direct current (DC) based.

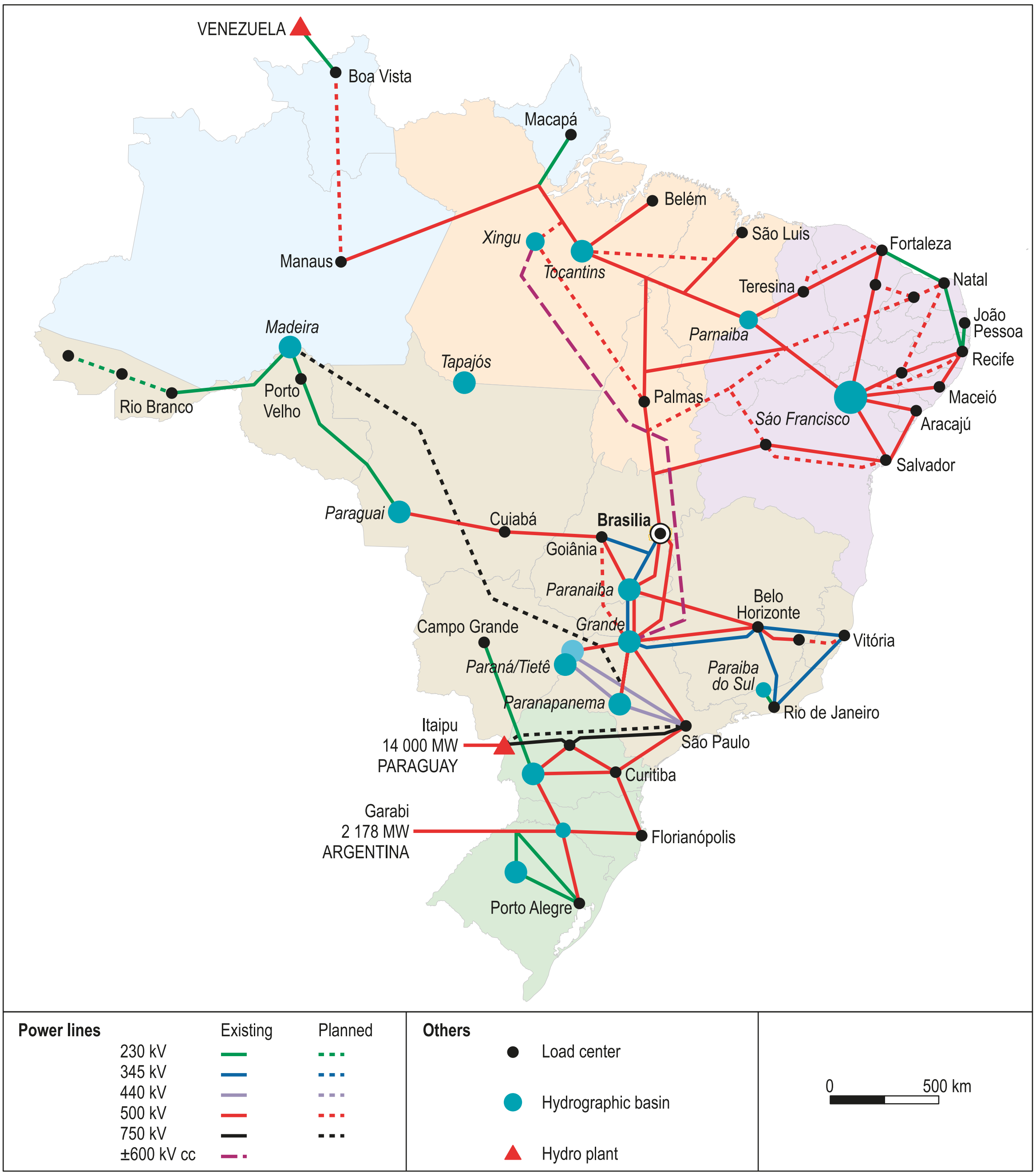
Table 5.3 • Brazil's interconnections with neighbouring countries

Origin	Type	Voltage	Power rating
Argentina	HVAC (HVDC converter)	500 kV	2 200 MW
Uruguay	HVDC	500 kV	500 MW
Paraguay	HVDC	600 kV	6 300 MW
Venezuela (not yet part of SIN)	HVAC	230 kV	200 MW

Notes: HVAC = high-voltage alternating current; HVDC = high-voltage direct current.

Sources: ABB (2016a) "Brazil-Argentina HVDC interconnection", http://new.abb.com/systems/hvdc/references/brazil-argentina-hvdc-interconnection; ABB (2016b) "Itaipu", http://new.abb.com/systems/hvdc/references/itaipu; GlobalTransmission (2015), "Project Update – Brazil-Uruguay Interconnection Project", www.globaltransmission.info/archive.php?id=21903.

Figure 5.5 • Main hydro basins and major transmission lines of Brazil



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.

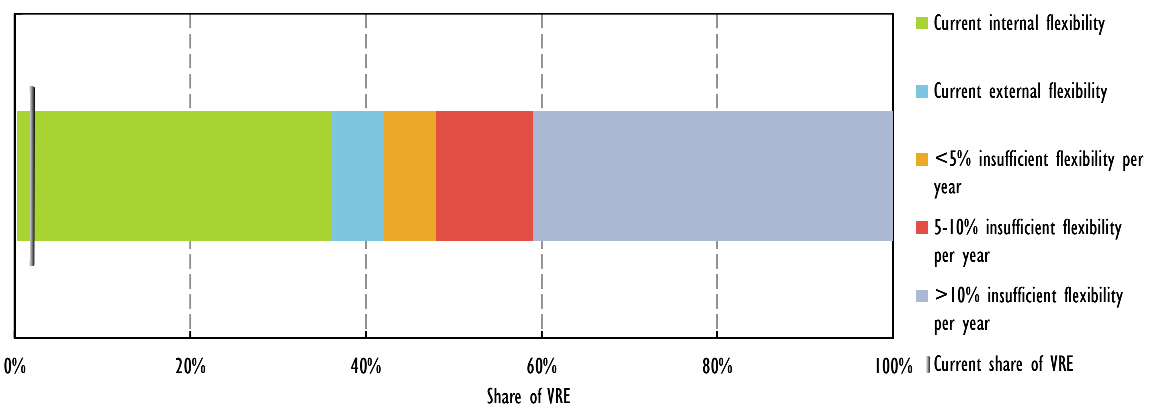
Source: ONS (2014), *Mapas do SIN* [Maps of SIN], www.ons.org.br/conheca_sistema/mapas_sin.aspx.

Key point • Brazil's transmission line network is designed to connect its hydro reserves with its load centres.

Results of FAST2 analysis

The FAST2 analysis indicates that Brazil's power system can accommodate a significant expansion in VRE generation – up to 42% of the power mix. Only at shares beyond this point are there certain hours during the year in which the system cannot follow swings in the supply-demand balance quickly enough or in which VRE resources would need to be curtailed (Figure 5.6).

Figure 5.6 • Result of FAST2 analysis for Brazil



Key point • Current system flexibility, provided by hydro reservoirs, allows for the integration of a share of VRE much greater than today's.

Summary

Brazil has access to abundant renewable energy resources. Existing large hydropower capacity provides extensive flexibility that will allow for considerable further uptake of VRE generation. VRE is in a good position to meet growing demand, provided that it is deployed in a way that maximises its contribution to meeting peak demand. Demand-side integration measures can also help to achieve this. Finally, continued expansion of the transmission grid is critical to avoid bottlenecks and delays in connecting new generation.

Market and policy frameworks

In 1988, in the face of major revenue shortages and insufficient investment in new capacity, the then President, Enrique Cardoso, moved the Brazilian electricity sector away from the then prevailing state-owned, regionally controlled model towards a free-market model.

However, growth in installed capacity failed to keep pace with demand. In addition, several successive years of inadequate rainfall occurred in what is a predominantly hydropowered system. In 2001, these circumstances triggered an energy crisis (also called *el apagão*, the blackout), which continued well into 2002. Virtually no advance planning for generation and transmission expansion was done until the creation of the government-owned Energy Research Company (EPE) in 2004 (ANEEL, 2013).

The Energy Laws of 15 March 2004 introduced the present electricity market model, which is intended to ensure that energy production, as well as transmission and distribution capacity, keeps pace with growing demand. This market consists of a regulated segment and a free-market segment.

Two products are bought and sold on the Brazilian power market. "Firm energy" is contracted through government auctions, as well as over the counter (OTC) in the free market. Secondly, imbalance energy may be bought and sold in the “difference market” if a generating company or distribution company finds itself short relative to its power purchase agreement (PPA). Following the end of the PROINFA scheme (see below), VRE capacity is procured through auctions.

The regulated market covers around three-quarters of total electricity consumption, including the entire residential sector. Customers are supplied by distribution companies, which own the local distribution grid and act as a local monopoly supplier for regulated customers in their respective areas. The remaining consumption is procured through PPAs and is bought OTC in the free market (CCEE, 2013).

Quantitative policy analysis

PROINFA

Initially, the move to introduce renewable energy in the generation mix was driven by the introduction of the Programme of Incentives for Alternative Electricity Sources (Programa de Incentivo a Fontes Alternativas de Energia Elétrica [PROINFA]) in April 2002.

PROINFA was to be implemented in two stages. The first stage had a capacity target of 3 300 MW of renewable energy – wind, biomass and small hydroelectric sources. Upon meeting this objective, the capacity target would be replaced by a generation target that stipulated a 10% share of total power production within 20 years. A feed-in tariff (FIT) scheme was introduced, with the tariff level for wind set at approximately USD 150 per megawatt hour (MWh). The Brazilian national development bank (Banco Nacional de Desenvolvimento Econômico e Social [BNDES]) introduced competitive credit lines for renewable energy projects (IEA/IRENA, 2016).

Despite the high remuneration level, PROINFA attracted a relative low amount of renewables investment. The local content requirements set by BNDES to qualify for debt financing were deemed too stringent given the nascent status of the domestic wind industry. Burdensome bureaucratic procedures and delays to grid connections further slowed down deployment of non-hydro resources (Barroso, 2012). In December 2011, the PROINFA scheme was terminated.

Auctions

By this time, a more effective procurement scheme had been implemented in the form of long-term energy auctions. This system of tenders is rooted in legislation passed in 2007 and 2008. The auctions build on the system of long-term contracts and mandatory reliability contracts. In the auctions, distribution companies procure supply to satisfy the projected consumption growth among their customers. The volumes contracted in the auctions thus depend on the need among distributors to procure additional resources.

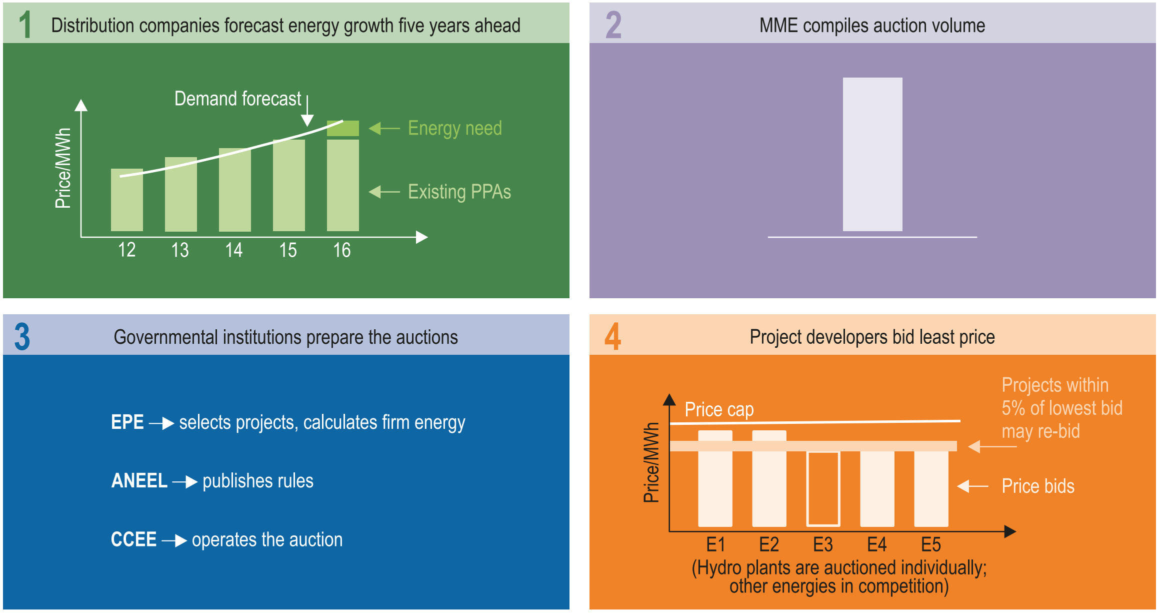
Auctions are administered by the market operator, Câmara de Comercialização de Energia Elétrica (CCEE), which registers all purchases and sales of energy (in both the regulated and free-market segments). There are two types of auction: Regular and Reserve.

New generation capacity to cover growth in electricity demand is procured through annual, government-controlled auctions of long-term PPAs – known as Regular Auctions – for a specified amount of energy at a fixed price, which is then reflected in the subsequent PPA (Figure 5.7).

Regular Auctions are held to develop new plants to begin operating three years ahead (A-3) and five years ahead (A-5). A-5 auctions are for new hydropower and some thermal capacity, which takes long to build.

In addition there are A-1 auctions, to secure new PPAs of duration between one and eight years, to cover existing demand. PPAs are usually awarded to existing power plants, such as those whose original PPAs have elapsed. Finally there are also Adjustment Auctions, for energy requirements to be met within 12 months (CCEE, 2013).

Figure 5.7 • Regular auction process in Brazil



Key point • Auctions are regulated according to five-year forecasts and held periodically to guarantee coverage of future energy need.

Reserve Auctions serve a number of purposes. They were introduced to increase the security of supply of electricity to SIN, the national interconnected system, rather than to supply the combined load growth expectations of the distribution companies. They also provide the opportunity to secure desired amounts of additional capacity, from chosen technologies, such as wind power or dispatchable capacity. The amount of energy in a Reserve Auction is decided by the government.

Over the years, the auction system has contributed to a considerable drop in prices for wind energy (Figure 5.8). As a result, wind has been able to compete in technology-neutral auctions.

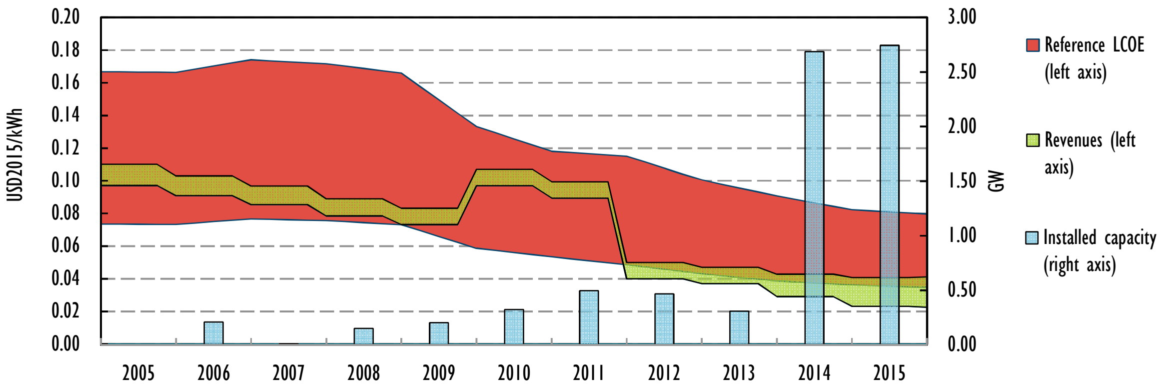
The auction price-setting mechanism is a "hybrid" mechanism that takes place in two phases:

- In an initial phase a descending clock auction is applied: MME proposes a price for the energy withdrawal, set at a relatively high value to test the market and discover what would be the total amount of energy supplied by the participants at that price. The price then descends gradually until the amount of energy desired is reached, increased by a margin on price to assure competition; the price that is established in this first-phase auction constitutes the ceiling price for the second phase.
- The second phase takes place with sealed bids. Participants propose an energy tariff. Projects that require lower tariffs are selected, until the required amount of energy is reached (GSE, 2014).

In order to be competitive, project developers have to obtain the finance with favourable interest rates provided by the national development bank (BNDES). Access to this finance requires ambitious commitments on local content levels. The wind supply chain is relatively well positioned to comply with these requirements.

By contrast, local content requirements and strong devaluation of local currency are a challenge for the nascent solar market. With domestic module manufacturing capacity limited to 300 MW per year, doubts exist as to the industry's ability to deliver on the contracted pipeline. Faced with today's manufacturing bottleneck, these projects may be cancelled if no alternative solution is found.

Figure 5.8 • Costs, revenues and added capacity for wind projects



Note: Reference LCOE area refers to plants commissioned in the reference period; the remuneration lines indicate the actual moment in the year the plants are commissioned and the payments started; therefore, for example, the wind plant projects awarded in 2009 under the auctions scheme are considered commissioned in 2012.

Key point • The introduction of auctions in 2012 lead to sharp cost reductions for onshore wind energy.

In August 2016, Agência Nacional de Energia Elétrica (ANEEL), after an initial denial, allowed solar developers to cancel their contracts by paying a fine (Spatuzza, 2016).

Market operations

Scheduling of power plants

In a hydro-dominated power system, power plant scheduling is guided primarily by water levels in the various reservoirs. Zero marginal cost resources such as wind and solar PV are dispatched first and the use of hydropower is then decided via a trade-off between avoiding the need for more expensive thermal power plants while containing the risk of possible water shortages in the future. Since water availability is variable, the decision-making process requires a stochastic approach. This optimises the use of water given uncertainty over future inflows into the reservoirs.

The national system operator, Operador Nacional do Sistema Eléctrico (ONS), sets its operational planning so as to minimise total costs using simulation models. ONS uses the "DESSEM" model to determine the daily dispatch schedule one week ahead, in 30-minute blocks, taking into account all information on generation plants, grid constraints and bilateral exchanges concluded on the free market (Guilherme, Castro and Luiz, 2012; Tolmasquim, 2012). The short-term markets clear in four distinct "submarkets": South, Southeast/Centre-West, Northeast, and North (ANEEL, 2012).

Transmission operations

The system is centrally dispatched by ONS, which is therefore able to pre-empt expected bottlenecks in its dispatch planning. Nevertheless, the distribution companies are identifying a growing number of bottlenecks.

Transmission line congestion costs are reflected in the zonal pricing. Congestion surcharges are allocated to all consumers within a given region on a lump-sum basis (ANEEL, 2012; ABRADEE, 2013).

Box 5.2 • Transmission line auctions

Private parties participate in auctions to win the right to build or upgrade transmission infrastructure. Auctions for access to the concessions for transmission line segments are managed by ANEEL. Concessionaires are in charge of the implementation and operation of the transmission lines. Many of them are state owned, although recent auctions saw new market entrants bid successfully. Similar to the energy and capacity auctions, the expansion of the transmission system is based on reverse auctions. The winner of the auction receives the concession for the built line for 30 years (Tolmasquim, 2012). After signing all relevant contracts, concessionaires must ensure that the transmission lines enter operation within a period of three to five years. From 1999 to 2015, 40 auctions were held, for a total of 66 085 km of transmission lines (ANEEL, 2015a).

Interconnection operations

Interconnection capacity is bound by long-term agreements between trading companies and public and private parties. Many of these arrangements are linked to the large hydropower projects in Brazil's border regions. ONS uses week-ahead simulations to determine the use of interconnection capacity (CCEE, 2016; IEA, 2014).

Definition and deployment of operating reserves

The operating reserve requirement is 5% of total load, and is sourced mostly from hydropower plants (ONS, 2013). Recently, fossil fuel power plants were required to cycle in response to changes in system net load.

New entrants and market power

Since the liberalisation of the market, the number of companies generating power in Brazil has expanded significantly. Currently, more than 100 companies are involved in power generation, while the largest market share, equal to 8%, is held by CHESF (BNEF, 2015).

System transformation

Incentives for system-friendly deployment of large-scale VRE

Deployment timing

The auction system allows for fairly detailed control of additional capacity. However, the location of new plants may not be known before the auction clears. As a consequence, the build-out of transmission infrastructure has not kept up with the deployment of new generation plants in recent years.

Since 2013, a growing number of wind plants have been unable to connect to the grid due to delays in the required infrastructure works. Several wind plants received payments, but were unable to feed into the grid. Since then, the delay in transmission lines has become a risk assumed by the wind project entrepreneur. Expansion of transmission infrastructure has accelerated since 2013, but more than 60% of planned works have been delayed by a combination of social and environmental issues, inflated land prices and lengthy bureaucratic processes (Giacobbo, 2015). At the end of 2015, 300 MW of capacity were waiting for power lines (Epoca, 2016). In an attempt to mitigate the misalignment between wind power plants and transmission grid expansion, MME introduced a change in the auction system in 2013. Under the changed rules, projects that are competing for scarce connection capacity at certain substations will face preliminary auctions to gain access to the connection point. This is particularly relevant in the northeast area.

Location and technology mix

Under the original auction rules, winners are chosen on the basis of energy tariffs alone, independent of the project location. As a consequence, VRE projects tend to be located in areas with the best resource endowment and without regard to the proximity of load centres or to design choices that improve system friendliness. This has caused a large majority of wind projects to be developed in the northeastern part of the country. As a result of cited connection issues, more recent wind power projects tend to be sited close to existing grid infrastructure (IEA, 2014).

Siting wind plants near existing transmission lines resolves immediate issues, but this approach only delays future grid development concerns. Many state-owned grid companies reduced their investment in new transmission lines, meaning that they did not participate in transmission grid auctions. This circumstance slowed the much-needed transmission grid expansion; consequently investors in wind power in Brazil may evaluate the possibility of undertaking the construction of part of the transmission lines, participating in the auctions for relevant areas (Bloomberg, 2015).

Technical capabilities

Grid code requirements for wind plants specify minimum technical and design grid connection requirements (ONS, 2010). Similar grid codes have recently been added for PV plants (ANEEL, 2015b). In the planning, programming, co-ordinating and controlling of the operation of SIN, weather and climate information is used to perform load forecasting activities, wind generation forecasting, streamflow forecasting, equipment maintenance, scheduling and dispatching.

VRE plant must be able to disconnect or reduce its load by remote control, to minimise consequences of disturbances in the system, including over-frequency in the case of islanding. Hourly forecasts of wind direction and speed derive from 48-hours-ahead models of weather forecasting, using data obtained by weather stations at generation, transmission and distribution operators (ONS, 2011; ANEEL, 2015b).

Box 5.3 • Turbine design and O&M as key factors for the future of Brazil's wind sector

The Brazilian wind sector has received much attention for the growth it has realised and the low tariff levels that have been achieved. Although delays have been experienced in connecting new plants to the transmission system, wind deployment in Brazil is considered an example for other countries that wish to foster a strong wind industry.

The initial focus of kick-starting the wind power market in Brazil was on turbine deployment. Less attention was paid to the functioning of these turbines. 2014 ONS production data suggest that wind turbines operated 13% below their expected capacity factor. This may be due to the quality of turbine components and the lack of skilled workers in this industry.

Importantly, elements of the applied wind power technologies were not designed or adequately modified to cope with the warm and humid climate. Certain turbine components were insufficiently resilient to the high salinity of the near-constant winds along the coastline.

The resulting need for increased operations and maintenance (O&M) could not be met due to a shortage of qualified workers; in the future, suboptimal performance may become commonplace due to the lack of maintenance.

Companies are trying to bridge this gap: annual O&M expenditure is expected to grow from USD 157 million in 2015 to USD 500 million in the next five years, reaching USD 1.5 billion by 2024. New O&M expenditure will cover the costs of training new personnel and the general upkeep of the towers, to control corrosion, to carry out mechanical repairs and to maintain electronics for yaw and pitch control systems. In addition, more recent domestically manufactured turbine models are better adapted to local weather conditions (Santos, 2015; Spatuzza, 2015; Ortiz, 2014).

Incentives for system-friendly deployment of distributed VRE

Locational price

There is no competition in the regulated market, since retail consumers can only purchase electricity from local monopoly retailers. Tariffs vary depending on the retailer: residential tariffs in 2015 varied from USD 67/MWh to USD 210/MWh (from BRL 271/MWh to BRL 842/MWh) (ANEEL, 2016).

Time-dependent price

For high-voltage consumers, different tariffs apply for peak and off-peak hours, while tariffs for low-voltage consumers are time independent. Therefore, no information on peak or off-peak hours is given to residential consumers. The only information on forecast energy prices and system constraints is provided by "tariff flags", a simple tool created to inform consumers of forecast system constraints and generally higher energy costs.

Tariff flags were introduced by ANEEL in order to signal to consumers the real monthly costs of electricity generation; green, yellow or red flags indicate that power supplied in the coming month will be more or less expensive depending on the situation in the power system, determined by hydrological conditions.

In 2015, a yellow flag indicated a surcharge of USD 4.6 (BRL 15) for every MWh consumed, while a red flag a surcharge of USD 9.2 (BRL 30) per MWh.

However, the monthly schedule of information is not very well suited to providing appropriate signals for distributed solar PV deployment, which would benefit from a system able to signal peak demand during the day.

Grid fees and taxes

Transmission and distribution costs are presented explicitly in retail tariffs, representing almost half of the tariff before taxes, with some variation between distribution companies.

The regulated electricity tariff is set by ANEEL for the different concession areas, maintaining the economic and financial balance in each concession area. Distributors' annual income should cover local operating costs (BNEF, 2015).

Brazilian electricity bills contain several tax components (federal, state, local and other), but no taxes dedicated to renewable energy funding.

Net metering

In April 2012, ANEEL introduced net metering in Brazil for small-scale renewable generators. Renewable generators with capacity up to 5 MW (up to 3 MW for hydro generators) that are interconnected to low- and medium-voltage grids are allowed to sell their surplus electricity back to the national grid in return for an electricity billing credit that is valid for several years.

High interest rates and burdensome tax levels have put a brake on the deployment of distributed energy resources, particularly in the residential sector. In late 2015, reforms were implemented to improve the business case for net metering. First, net-metered solar generation has been exempted from the ICSM tax (a form of VAT). Moreover, a new "virtual" net-metering mechanism allows for any company or consumer to install a power plant in a given site and inject energy into the grid while consuming elsewhere.

This opens up the market for distributed resources by allowing for pooled investments across several buildings (IEA/IRENA, 2016; Kenning, 2015).

Discussion

Since the energy crisis of 2001, Brazil has made great strides in increasing the reliability of its power system and has begun diversifying its energy mix. By integrating the procurement of wind and solar power, Brazil has achieved highly competitive energy prices. In addition, the system combines technology-neutral elements (general auctions) with additional, technology-specific instruments (reserve auctions). However, the existing framework has been built around the idea that large, reservoir hydropower plants are the dominant source for meeting existing and new power demand. This fundamental parameter of the Brazilian system is changing. Recent hydropower projects have been implemented as run-of-river plants and doubts remain as to how many new hydropower developments will be achievable.

From the perspective of VRE deployment, this is a challenge and an opportunity at the same time. Over the coming decades, Brazil will need to find new solutions to meeting the bulk of its demand growth. While energy efficiency is critical to containing the need for new generation capacity, Brazil's abundant wind and solar resources, combined with bioenergy, could potentially carry the bulk of additional load growth. This could open a clean and cost-effective trajectory for the Brazilian power system, without the need to increase its reliance on fossil fuels.

However, this will require a step change in Brazil's approach to VRE deployment, recognising the new realities for its power system. The flexibility provided by existing reservoir hydropower plants is highly likely to support a significant growth in VRE in the years to come. Looking further ahead, measures to maximise the contribution of wind and solar power to reliable operations will become critical. This includes reliably meeting demand peaks through a combination of strategic siting of wind and solar power plants and an optimised VRE mix. Integrating demand-side response capabilities into the power system also holds potential, for example by equipping new air-conditioning equipment with thermal energy storage.

Eventually, enabling double-digit shares of VRE will also require the systematic development of grid infrastructure. This includes finding the right trade-off between siting projects in high-resource areas and siting them closer to demand. In particular, distributed solar PV deployment could make a contribution to relieving stress in the transmission grid.

The Brazilian market framework currently considers system value only by the ability of power plants to contribute to reliable operations during periods of drought. This is achieved by auctioning physical guarantees rather than energy or capacity *per se*. Looking ahead, the changing realities of the system will need to be reflected in market structures and prices. This includes further developing short-term markets, going beyond the current system of weekly prices. This is crucial to better capture the difference in the value of electricity throughout the day. In addition, system services will increasingly need to be remunerated. In turn, such improvements to market design could then allow for the updating of remuneration schemes for VRE.

Table 5.4 • Key recommendations for Brazil

System-friendly VRE deployment
The presence of good wind resources distant from load centres can cause stress to the transmission grid. Distributed solar PV plants can offer a solution to ease the power demand of the main load centres, thus decreasing the need for new transmission lines.
The auction structure does not offer incentives for VRE power plants with a production profile naturally overlapping with power demand profiles. Taking into account the generation profiles of bidding VRE plants can reduce future reserve requirements.
Seasonal patterns of hydro resources and wind in may be complementary in certain regions; auctions can be optimised to internalise these portfolio benefits.
Investment
The national development bank offers attractive financing for clean energy projects, but stringent local content requirements have overstretched domestic PV manufacturing capacity. More accommodating local content requirements may alleviate this bottleneck to PV deployment in the short term.
The current procurement system focuses on obtaining new generation capacity; the Brazilian energy market would benefit from being upgraded also to consider flexibility resources, in particular demand-side management (DSM).
Operations
Weekly prices mask the differences between VRE technologies. Developing a higher time resolution is required to signal the value of energy generation to the overall system.
The system services market should be adapted to reflect the new power plants' requirements (quicker response times, cycling capability, lower minimum bid size for reserve auctions, etc.) introduced by the presence of higher shares of VRE.
Consumer engagement
A flag system in the electricity bill informs consumers of long-term situations of scarcity, but without time-of-use pricing, consumer response remains limited. Upgrading the system to signal peak demand during the day may unlock demand-side response and distributed PV potential.
Improving the net-metering scheme by reducing the validity of energy credits for a much shorter period may help increase self-consumption of energy and hence reduce distribution grid stress.
Planning and co-ordination
The organisation of energy and capacity auctions is the result of a co-ordinated long-term planning effort between the ministry, the regulator and distribution companies, and is driven by sophisticated modelling. Integrating into the planning process the locational value of bids and their portfolio effect would improve the effectiveness of the auction process.
Appropriate analysis, during the planning phase, of the potential for integrating DSM would be beneficial for the entire planning and future management of the energy system. Such analysis is not currently undertaken.
Current transmission grid planning reflects the historical need to connect hydropower basins with load centres. Better integration of VRE and flexibility resources (as DSM) could enhance the effectiveness of the planning process.

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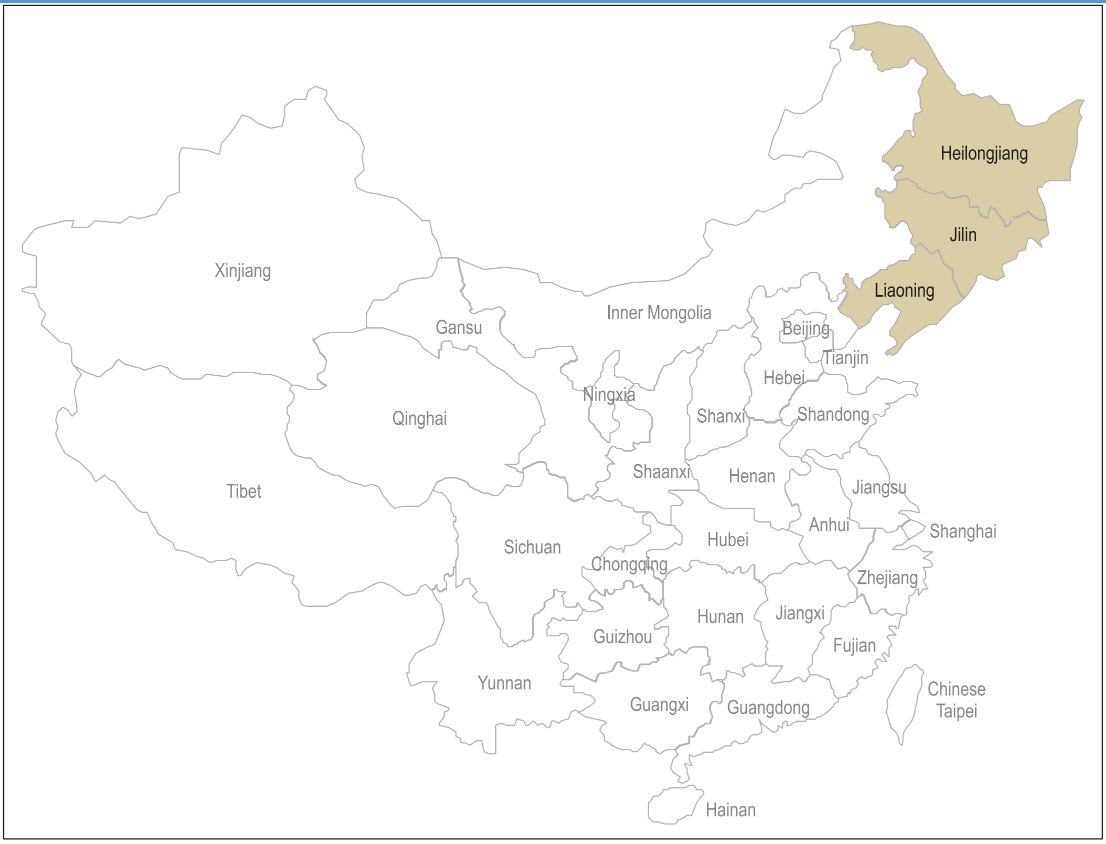
China (Northeast provinces)

General information on VRE and grid integration

This case study presents and discusses the challenges and opportunities of integrating next-generation wind and solar power in China. While a number of considerations apply to China as a whole, the current state of play regarding grid integration varies widely among administrative divisions at the provincial level.[13] Against this backdrop, three provinces have been selected for a more detailed analysis – Liaoning, Jilin and Heilongjiang, all in the northeast of the country. They are part of the same synchronous system, but each province is balanced separately.

Figure 5.9 • Liaoning, Jilin and Heilongjiang provinces



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.

Key point • The selected provinces are sited in the extreme northeast corner of China.

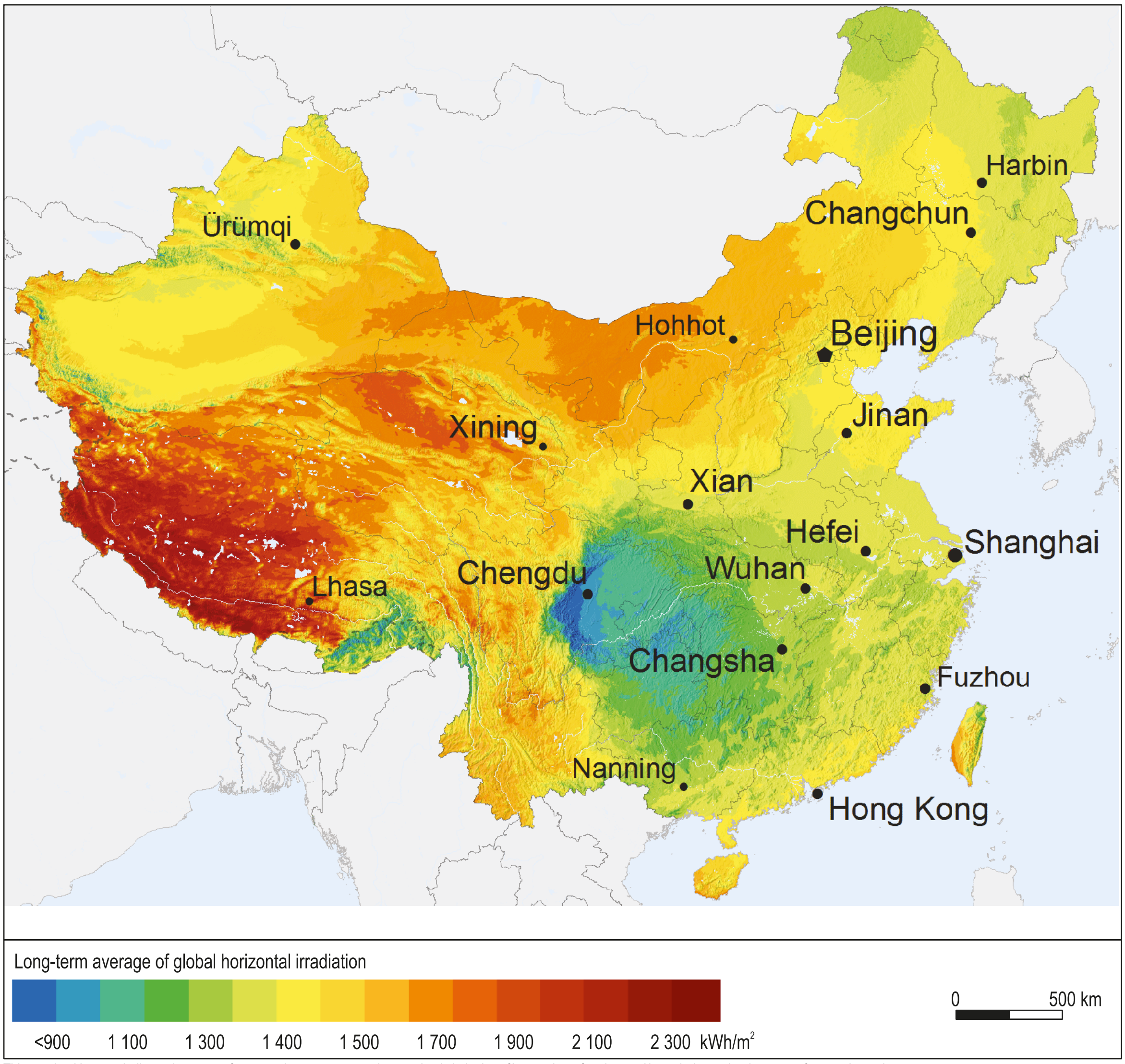
Flexibility assessment, ease of integration and current value

VRE resources

Northeast China has moderately favourable solar resources. Average global horizontal irradiation (GHI) levels lie between 1 200 and 1 500 kilowatt hours per square metre (kWh/m^2) per year (Figure 5.10). This is consistent with the observed irradiation levels along the entire eastern coast of China, but less favourable than other regions in the north and the southwest of the country. The three provinces exhibit similar irradiation levels, with solar resources slightly higher in the western part of each province (Solargis, 2016).

[13] In China, there are 34 such divisions, classified as 23 provinces (including Chinese Taipei province), four municipalities, five Autonomous Regions, and two Special Administrative Regions.

Figure 5.10 • Average annual GHI, China



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: Solargis (2016), "Solar resource maps", http://solargis.com/.

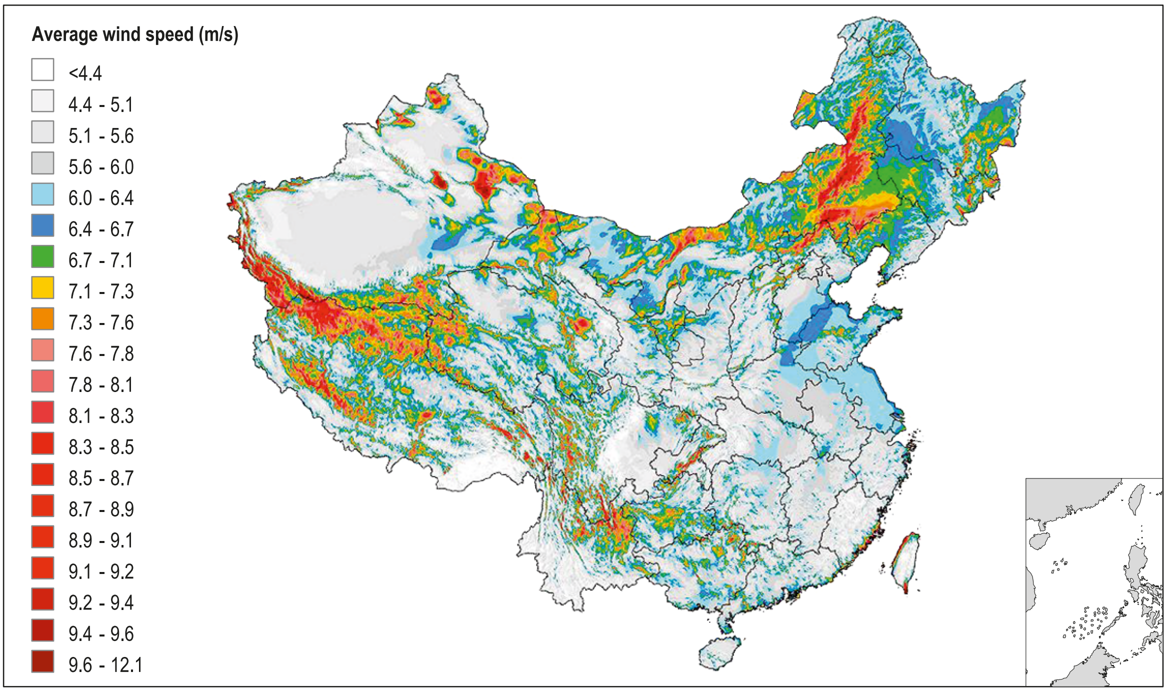
Key point • China has excellent solar potential in the west of the country. The three provinces selected for the case study show moderate irradiation levels.

Wind resources in Northeast China are more promising. The open plains of Songnen, Liaohe and Sanjiang show wind energy densities of 300 to 500 watts per square metre (W/m^2) at a height of 70 metres (m) and average annual wind speeds of 7 to 11 metres per second (m/s) at a height of 100 m. Similarly favourable areas are the hillsides of the west of Liaoning province, the central areas of Jilin and Heilongjiang Provinces and the southern parts of Liaoning province (Xie et al., 2014). Overall, average annual wind speeds only exceptionally drop below 5 m/s (IRENA, 2016).

Demand

China is the largest electricity consumer in the world. China Electricity Council (CEC) statistics indicate total consumption of 5 550 terawatt hours (TWh) in 2014. Electricity demand has been growing rapidly over recent years. However, this trend is changing in line with an ongoing restructuring of Chinese industry – away from energy-intensive industries and towards an increase in services – and slower overall economic growth.

Figure 5.11 • Average wind speed in China



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

Source: Adapted from IEA (2011), *China Wind Energy Development Roadmap 2050,* www.iea.org/publications/freepublications/publication/china_wind.pdf.

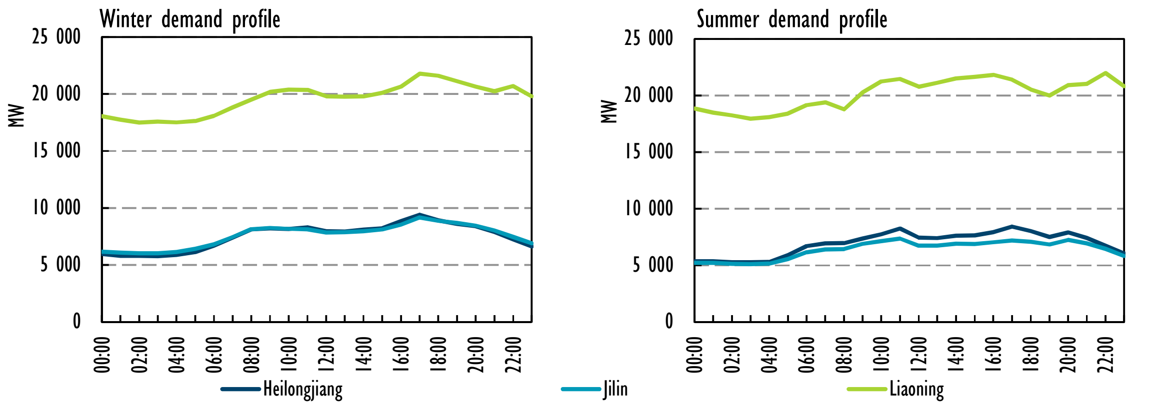
Key point • Wind energy resources are most abundant in the west and northeast of China.

For the three case study provinces, this trend has been even more pronounced and electricity demand is actually lower today than in recent years. In 2014, electricity consumption in the individual provinces of Liaoning, Jilin and Heilongjiang stood at 203 TWh, 66.7 TWh and 85.9 TWh respectively (NBS, 2016). Total demand has a strong contribution from industrial load, which translates into a rather flat demand profile, in particular in Liaoning province. A flat profile can make the integration of variable renewable energy (VRE) more challenging, because system operators will have less experience of dealing with swings in the demand-supply balance.

The rapid slowdown of growth in electricity demand has important consequences for integration of wind and solar power. Historically, growing demand has meant that additional capacity would contribute to meeting incremental demand and VRE power plants could be built hand-in-hand with new coal capacity. With flat or even declining electricity demand growth, any increase in VRE generation must come at the expense of existing generation, which can raise economic and political challenges. In a nutshell, China's grid integration situation is rapidly transforming from a dynamic system to a stable system.

All three case study provinces lie in temperate areas of China and thus have winter and summer seasons. This is most evident for the two most northerly of the three provinces: Heilongjiang and Jilin. Jilin province shows an increase in electricity demand during winter, with a night-time peak in demand that is not present to the same degree in the summer season. Differences between summer and winter load are less pronounced in Heilongjiang province, although the province exhibits a slightly higher evening peak in winter (Figure 5.12).

Figure 5.12 • Average demand profile for summer and winter seasons in the three northeast provinces, 2014



Note: MW = megawatt.

Key point • The two most northerly provinces, Heilongjiang and Jilin, show larger seasonal differences between summer and winter electricity demand.

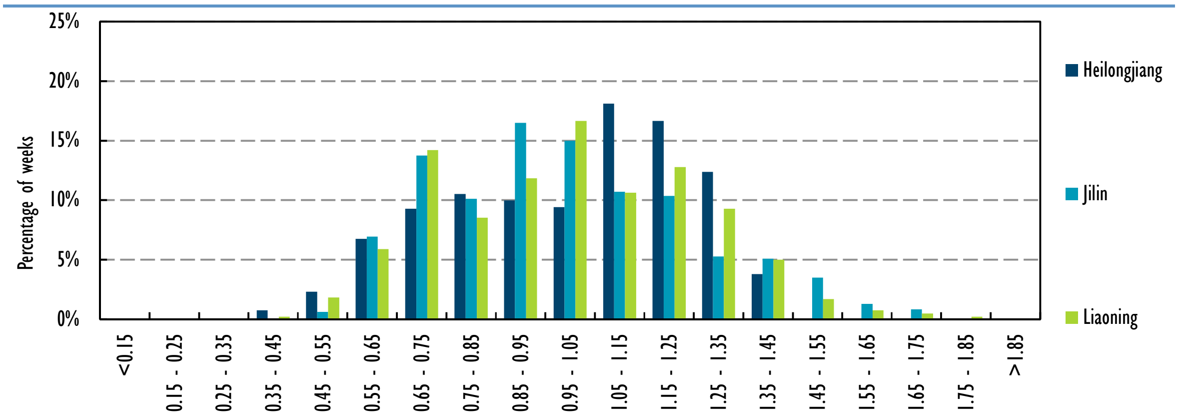
Analysis of match between demand and VRE generation profile

Analysis of the demand coverage factor (DCF) reveals important similarities between the three provinces. Each exhibits a moderately favourable demand coverage profile for wind and solar photovoltaics (PV). For each province, the DCF factor lies between 0.7 and 1.3 for roughly 75% of the measured weeks, and between 0.9 and 1.1 for approximately 30% of the time (Figure 5.13).

However, certain differences can be observed across the provinces. Heilongjiang experiences less severe overproduction from wind and solar PV, as the DCF does not exceed 1.6. In Jilin and Liaoning, however, the DCF exceeds 1.7. This implies that slightly more system flexibility is required to deal with high feed-in as wind and solar PV penetration rises.

In Jilin province, more than 56% of DCF data points are below or equal to 1.0. This is 5 percentage points more than in the Heilongjiang and Liaoning.

Figure 5.13 • Range of weekly DCFs for Northeast China

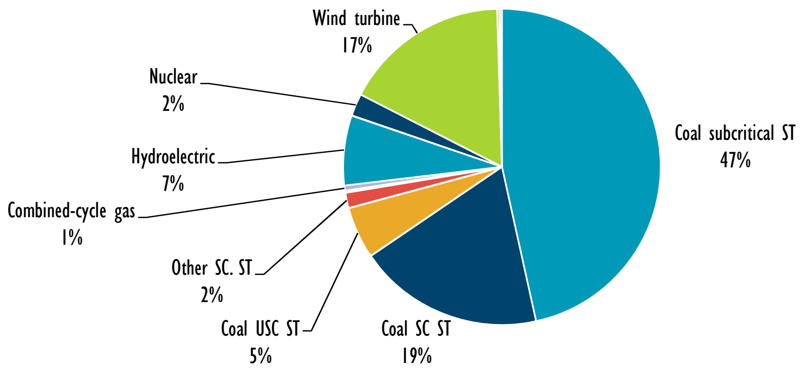


Key point • The three provinces exhibit moderately favourable demand coverage by wind and solar resources.

Generation

At the end of 2014, Northeast China had an overall installed power generation capacity of 96 gigawatts (GW) (42 GW in Liaoning, 27 GW in Jilin and 26.6 GW in Heilongjiang). More than 70% of the installed capacity is fuelled by hard coal and lignite, followed by wind (17%) and hydro (7%) (Figure 5.15). Gas only plays a marginal role. Load-following capabilities are provided by hydropower, as well as supercritical (SC) and ultrasupercritical (USC) coal-fired power plants. Overall more than 50% of the capacity is provided by subcritical coal plants, of which many operate as co-generation (Figure 5.14).[14]

Figure 5.14 • Installed power generation capacity by technology, Northeast China, 2014



Notes: SC = subcritical; ST = steam turbine; USC = ultrasupercritical.

Sources: Adapted from Platts (2016), *World Electric Power Plants Database*, and BNEF (2016a), "Renewable energy projects", database, www.bnef.com/projects.

Table 5.5 • Installed power generation capacity by technology, Northeast China, 2014

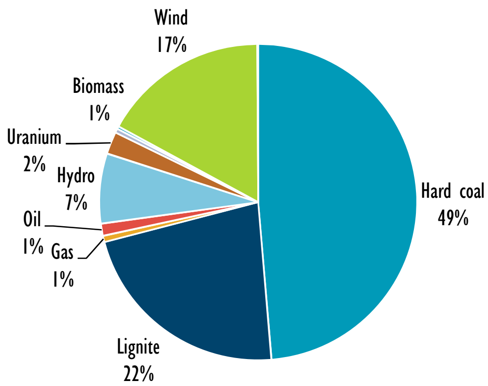
Technology	Installed capacity (MW)	% co-generation
Coal subcritical ST	44 899	55%
Coal SC ST	18 280	30%
Coal USC. ST	5120	0%
Other subcritical ST	1 525	69%
Open-cycle gas	153	4%
Internal combustion engine	58	10%
Combined-cycle gas	500	-
Hydroelectric	6 899	-
Nuclear	2 200	-
Wind turbine	16 393	-
Solar PV	250	-
Other	200	-

Sources: Adapted from Platts (2016), *World Electric Power Plants Database*, and BNEF (2016a), "Renewable energy projects", database, www.bnef.com/projects.

Key point • Two-thirds of installed capacity in Northeast China comprises coal-fired power plants.

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

Figure 5.15 • Installed power generation capacity by fuel, Northeast China, 2014



Sources: adapted from Platts (2016), *World Electric Power Plants Database*, and BNEF (2016a), "Renewable energy projects", database, www.bnef.com/projects.

Table 5.6 • Installed power generation capacity by fuel, Northeast China, 2014

Technology	Installed capacity (MW)
Hard coal	46 947
Lignite	21 490
Gas	626
Oil	1 199
Hydro	6 899
Uranium	2 200
Biomass	406
Solar	250
Wind	16 393
Other	67

Sources: Adapted from Platts (2016), *World Electric Power Plants Database*, and BNEF (2016a), "Renewable energy projects", database, www.bnef.com/projects.

Key point • The bulk of installed capacity is fuelled by hard coal and lignite.

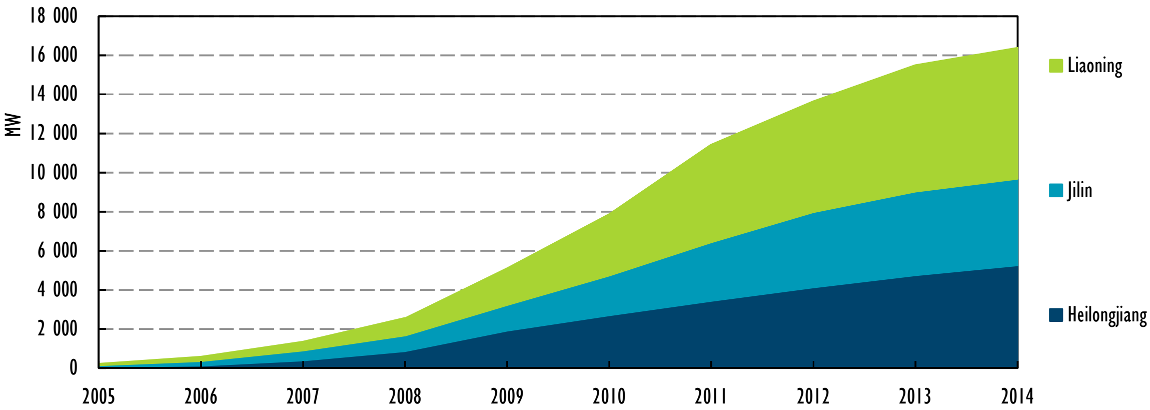
Approximately 60% of the hydropower capacity is installed in Jilin, whereas wind power capacity is equally distributed across the three provinces: 41% (6.7 GW) has been installed in Liaoning, while 5.2 GW and 4.4 GW have been installed in Heilongjiang and Jilin, respectively. Also the commissioning trend has been similar in the three provinces (Figure 5.16).

Storage and DSM

Northeast China currently has 1.5 GW of pumped storage facilities in operation (300 MW in Jiling and 1.2 GW in Liaoning). Additionally, a 1.2 GW project is under construction in Heilongjiang and an additional 1.4 GW facility is being planned in Jilin (Platts, 2016).

These storage facilities are particularly needed in the winter period when rivers carry less water, while wind energy production is high and co-generation capacity is tilted in favour of heat production.

Figure 5.16 • Historical wind capacity commissioned in Northeast China, 2005-15



Sources: Adapted from BNEF (2016a), "Renewable energy projects", database, www.bnef.com/projects.

Key point • Most of the installed wind capacity in Northeast China was commissioned between 2009 and 2013.

Transmission and interconnections

The transmission grid in the three provinces is owned and operated by the state-owned State Grid Corporation of China (SGCC). Currently, over 70 000 km of transmission lines above 220 kilovolts (kV) are installed in Northeast China, with 25% being above 500 kV (Figure 5.17). Further expansion is planned in the regions in order to reduce wind power curtailment.

Interconnection capacity binds Northeast China to North Korea and Russia.

All three provinces in Northeast China belong to the same synchronous grid. However, each province is operated as an individual balancing area. Power flows are generally from north to south, i.e. towards the large load centres in Eastern and Central China.

Results of VRE integration analysis

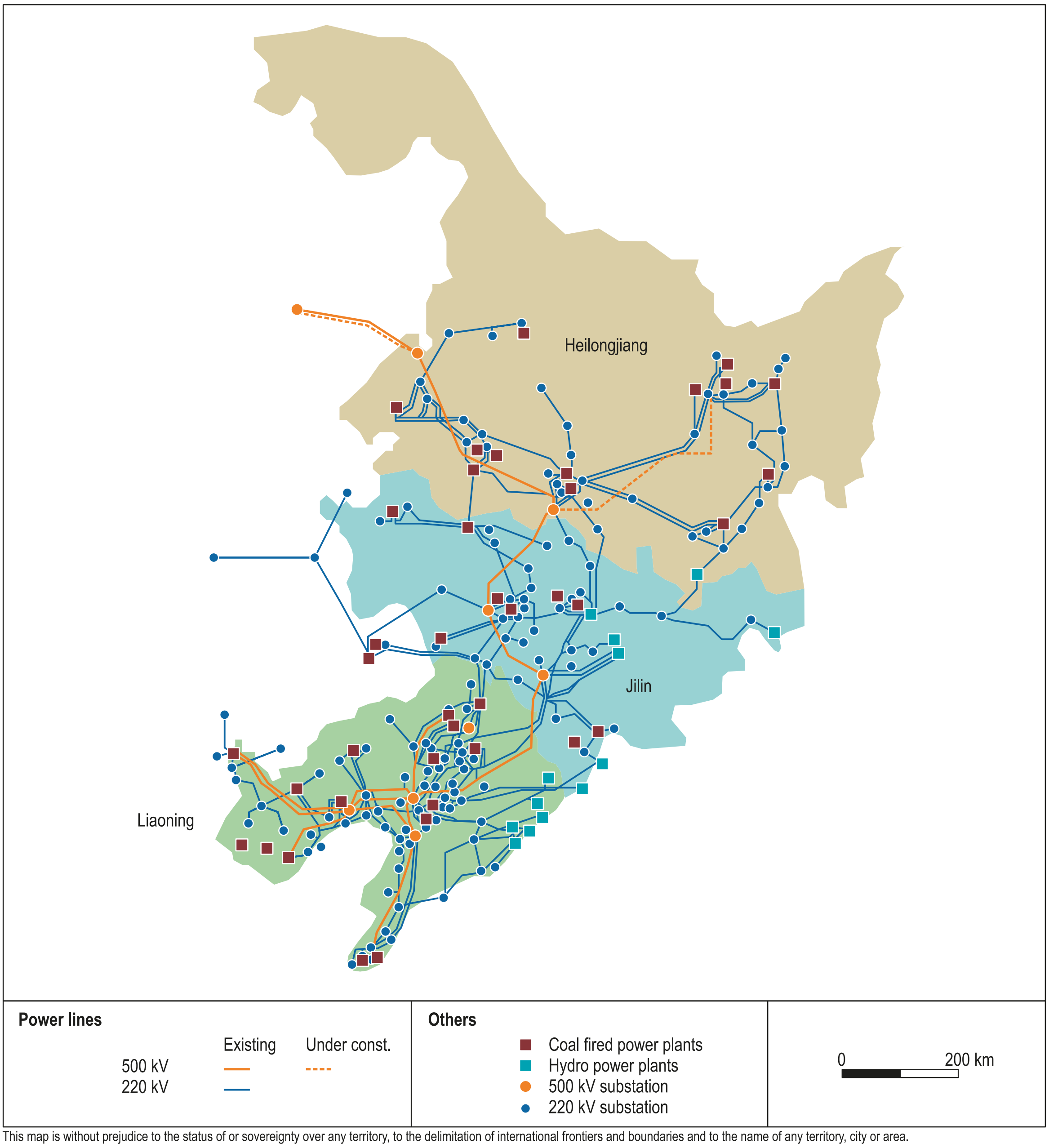
Due to constraints on the availability of detailed power system data, a FAST2 analysis was not performed for the northeastern provinces. However, in collaboration with the China Electric Power Research Institute (CEPRI) a simplified modelling analysis was carried out to investigate the availability of system flexibility today.

The analysis was conducted on the basis of hourly generation and load time series for the three provinces. Wind data were scaled to different annual generation levels. For each generation level, a simplified unit dispatch model was run for the region. The model was run in two configurations. The first included standard technical constraints of thermal power generation, such as minimum technical generation levels and maximum ramp rates ("economic dispatch case"). In the second configuration, an additional constraint was added: each thermal generator was guaranteed a certain amount of operating hours ("guaranteed full-load hour [FLH] case").

A first model run tested a scenario where VRE accounts for 10% of annual power generation. At this level, the economic case showed a curtailment level of 0%, whereas the guaranteed FLH case (4 230 FLHs) saw VRE curtailment of 30%. At VRE penetration of 25%, guaranteeing 4 000 FLHs for thermal generation yielded curtailment of more than 50%, whereas the under the economic dispatch case, curtailment remained modest at below 2% (Figure 5.18).

This analysis makes a number of simplifying assumptions. However, its main conclusion is robust: guaranteeing high FLHs for thermal generation can pose a very significant, non-technical barrier to successful VRE integration. Indeed, a more detailed analysis of the causes for curtailment that also accounts for grid restrictions highlights the important role of this issue (Box 5.4).

Figure 5.17 • Transmission grid in the provinces of Heilongjiang, Jilin and Liaoning



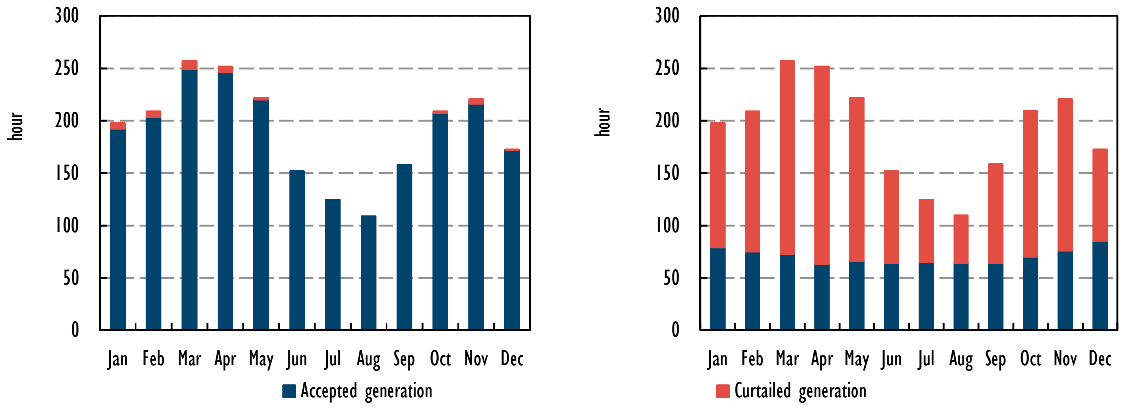
Source: Baike (2016), "Northeast power system", webpage, http://baike.so.com/doc/6492253-6705962.html.

Key point • Transmission lines in Northeast China are designed to facilitate the flow of power from north to south.

Summary

Northeast China shows promising renewable energy potential, especially due to the availability of very good wind resources. However, with the rapid expansion of renewable energy generation capacity, it has become more important to revise power system operations. Existing agreements with power plant operators are preventing more efficient usage of thermal flexibility, resulting in unnecessarily high levels of wind curtailment. Improved operation of the coal fleet and balancing demand and supply across provinces close to real time are effective ways to mitigate this issue. These can be adopted before investing in the development of storage facilities and additional interconnection between different transmission systems.

Figure 5.18 • Wind curtailment (25% of generation) under consideration of the technical constraints of traditional thermal capacity (left) and under consideration of FLHs for traditional thermal capacity (right)



Notes: Left: 98.4% integration (equal to 2 250 FLHs) of wind, 3 380 FLHs of traditional generators; right: 36.9% integration (equal to 843 FLHs) of wind, 4 000 FLHs of traditional generators.

Key point • Guaranteed FLHs for thermal generation lead to significant curtailment at high shares of VRE.

Box 5.4 • Wind curtailment in China

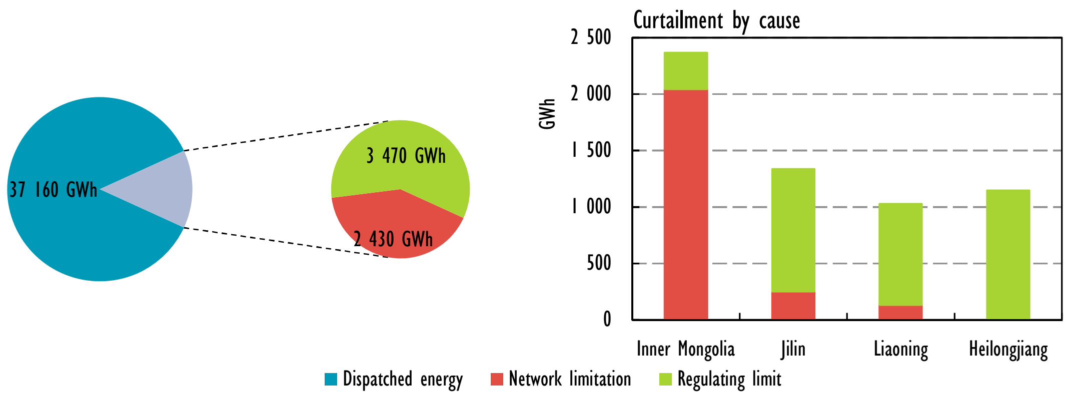
Wind curtailment is a severe issue for VRE operators in China, in particular in the northeastern area. According to the National Energy Administration (NEA, 2016), in 2015 wind plants in China could have produced 220 TWh; in fact, 15% of producible energy was curtailed. In the same year, 32% of producible wind generation was curtailed in Jilin, 21% in Heilongjiang and 10% in Liaoning, at a loss of 5.8 TWh. Principal causes were network limitations and power balancing issues.

Grid constraints are more relevant for Inner Mongolia, the Autonomous Region with weaker grid connections to major load centres (Beijing, Tianjin), while power balancing issues are common and evenly distributed between the Liaoning, Jilin and Heilongjiang (Figure 5.19). Curtailed energy was not remunerated and, with delays in payments, is one of the most relevant barriers to VRE.

To resolve this issue, and to advance the goal of power market reform, on March 2016, the National Development and Reform Commission (NDRC) released the "Regulation for Guaranteeing Purchase of Renewable Energy". VRE plants will have two dispatch streams, guaranteed dispatch and market-traded dispatch. For a certain number of hours per year, varying by province, transmission grid companies will have to guarantee the dispatch of VRE plants; in case of curtailment, the responsible party (non-renewable independent power producers [IPPs] or the grid company) will have to reimburse the renewable IPPs (BNEF, 2016b).

Since 2011, pilot projects have been conducted in the northern provinces (such as Jilin and Inner Mongolia) using wind power as a heating source to reduce curtailment and decrease the use of coal power plants during winter. In 2015, the NEA scaled up the pilot programme to include seven northern regions. The Hohhot wind-to-heat experiment is the most advanced project, financed by the Asian Development Bank with a loan of USD 150 million. Wind power plants with a capacity of 50 MW will power electric boilers. Project completion is expected by 2020 (EE, 2015).

Figure 5.19 • Wind curtailment in the Northeast Regional Load Dispatch Centres (RLDC) area in 2013



Note: GWh = gigawatt hour.
Source: Adapted from Ma, Li (2016), "Introduction of renewable energy development policy in China", presentation at IEA, Paris.

Key point • Curtailment in the three selected provinces is mainly the result of power balancing issues.

Market and policy frameworks

Quantitative policy analysis

The main policy for renewable energy in China is the Renewable Energy Law (REL). The REL obliges grid companies to purchase renewable energy generation. This obligation does not apply in cases where VRE output compromises "grid safety", although the criteria for determining such a situation are not clearly defined. The REL also introduces a feed-in-tariff (FIT) scheme and province-specific renewable energy targets, which have a capacity and energy component and are incorporated in the five-year plan for each province. Grid companies (most importantly the SGCC and China Southern Power Grid) act as single buyers for all renewable power generation built under the REL (Ma, 2016).

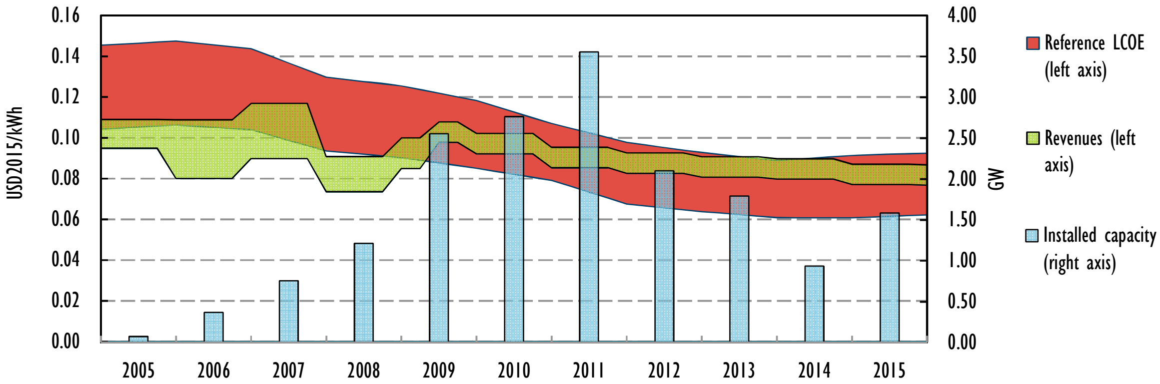
Wind power

The Chinese government has organised national concession bidding for large-scale wind plants since 2003. Competitive bidding between developers of onshore wind projects came to an end in August 2009 when the government introduced a national FIT for wind power.

FITs were set with a range of between USD 76 per megawatt hour (MWh) (CNY 0.51 per kilowatt hour [kWh]) and USD 91.5/MWh (CNY 0.61/kWh) depending on wind resource levels. On January 2015, NDRC released a new wind FIT between USD 73/MWh (CNY 0.49/kWh) and USD 91.5/MWh (CNY 0.61/kWh). Tariffs were reduced again in December 2015: the 2016 tariffs are split into four categories ranging between USD 70/MWh (CNY 0.47/kWh) and USD 88/MWh (CNY 0.59/kWh). NDRC has indicated further tariff cuts for 2018 (BNEF, 2016c; IEA/IRENA, 2016).

The three provinces forming Northeast China have seen notable deployment levels since the REL was introduced. Deployment picked up strongly in 2009, when the FIT scheme replaced the previous auction scheme. After a peak of annual installed capacity in 2011, at more than 3.5 GW, the installation rate has decreased every year. Increased curtailment is the main driver of this change. In 2011, average utilisation hours for wind turbines in the three provinces dropped from 2 100 to 1 900, resulting in a 10% loss in revenues to wind energy producers (Wei et al., 2015).

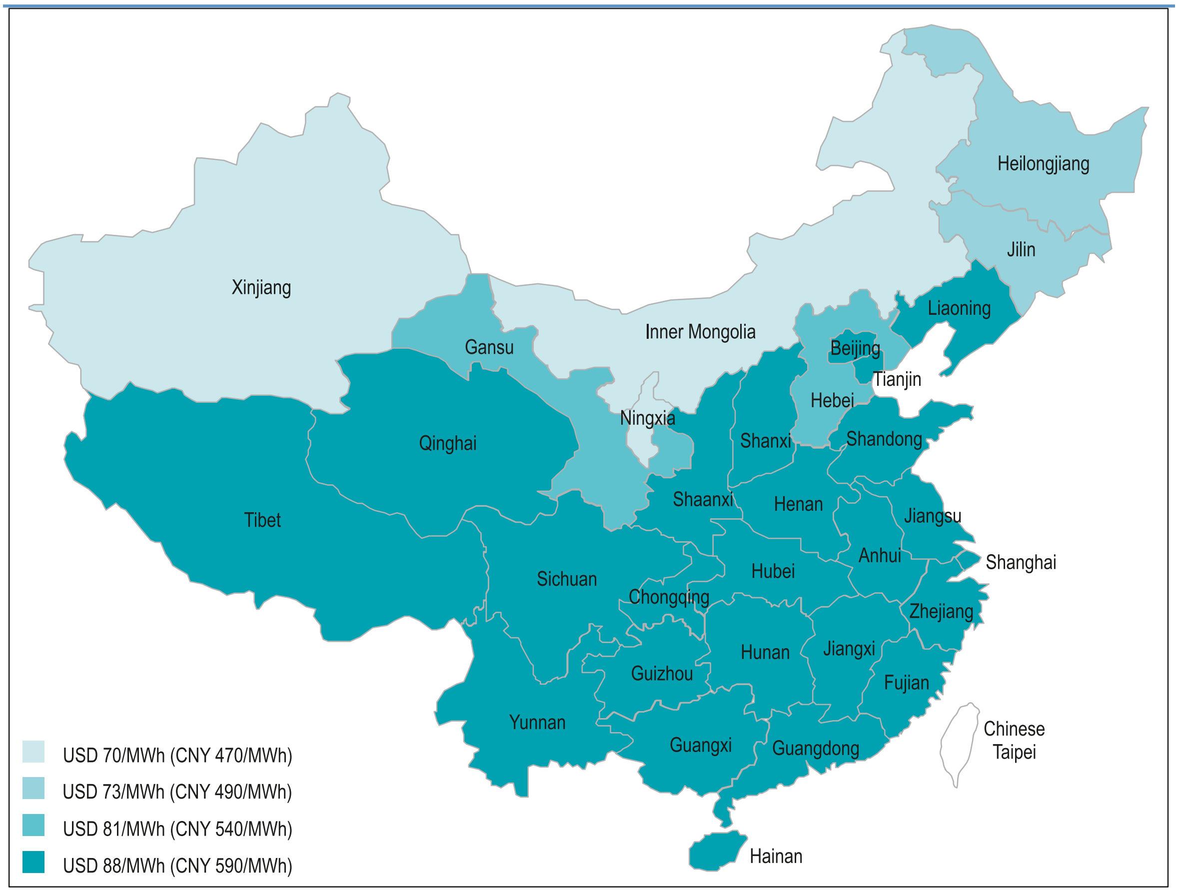
Figure 5.20 • LCOE, revenues and installed capacity of onshore wind in Northeast China



Note: LCOE = levelised cost of energy.

Key point • Wind power installation rates peaked in 2011.

Figure 5.21 • Wind FITs, China



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.

Key point • Wind FITs in China vary on the basis of local resources.

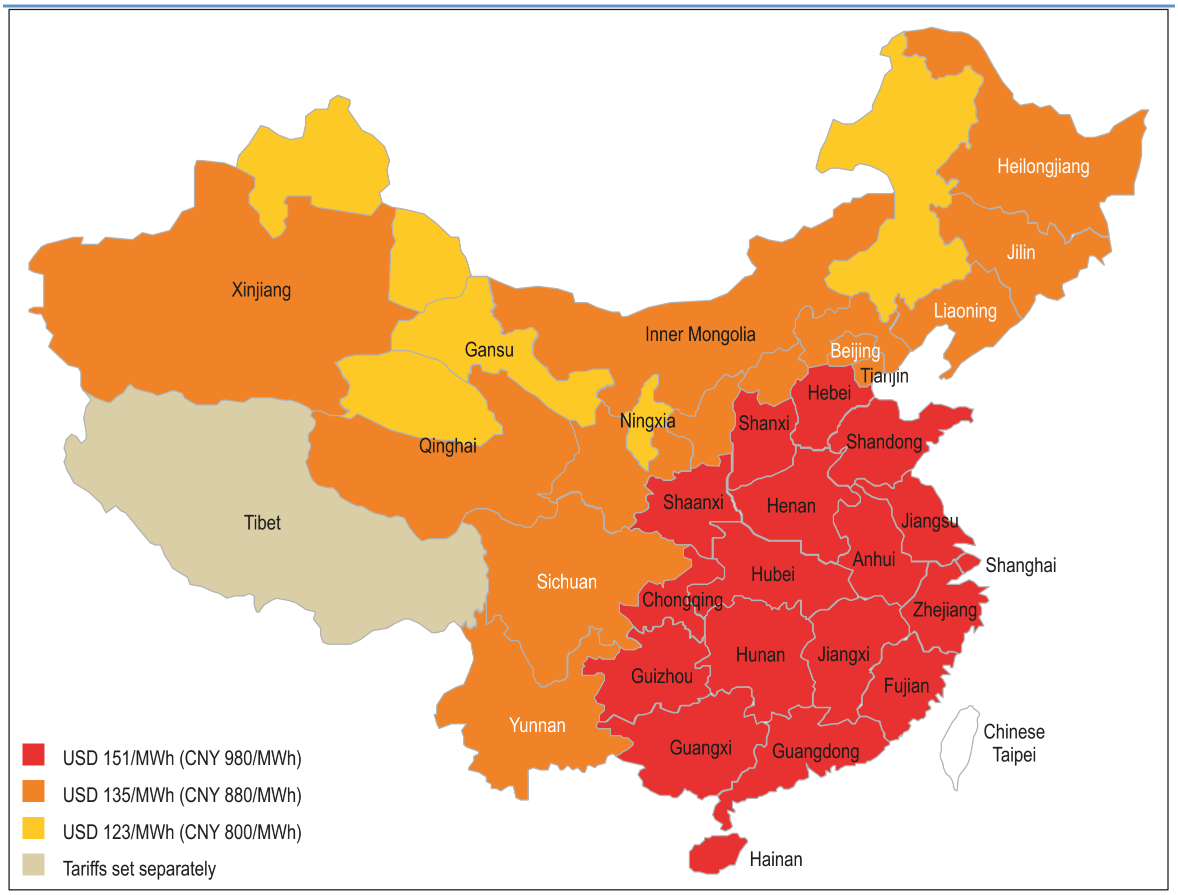
Solar power

As of A 2011, solar PV plants can apply for a FIT granted for a period of 20 years. The NDRC guaranteed that solar PV projects approved before July 2011 and put in operation by December 2011 would receive a USD 172/MWh (CNY 1.15/kWh) tariff. This tariff also applied to solar PV projects situated in Tibet and approved before July 2011 but not in operation by December 2011. For PV projects in other regions and in operation later than December 2011, a USD 150/MWh (CNY 1/kWh) tariff was applied. For solar PV projects approved through concessionary bidding, the applicable bidding price cannot be higher than the abovementioned benchmark FIT for solar PV.

As of August 2013, the NDRC has set the benchmark on-grid power tariff at USD 135-150/MWh (CNY 0.9-1/kWh), varying according to the solar power resources in the different resource zones around the country. In the selected provinces, the applicable tariff was equal to USD 142.5/MWh (CNY 0.95/kWh).

In January 2016, the NDRC lowered the FIT levels in the three tariff zones to USD 123/MWh (CNY 0.8/kWh), USD 135/MWh (CNY 0.88/kWh) and USD 151/MWh (CNY 0.98/kWh) (Figure 5.22). Projects permitted in 2016 or not in operation by 30 June 2016 are subject to these new FIT levels (BNEF, 2016d; IEA/IRENA, 2016).

Figure 5.22 • Solar PV feed-in tariffs, China



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.

Key point • As for wind, solar PV FITs in China vary on the basis of local resources.

Distributed solar PV power generation projects receive a standard premium of USD 64/MWh (CNY 0.42/kWh); solar PV system owners can choose whether they want to inject the produced energy into the grid or opt for self-consumption with the premium. Self-consumed electricity receives the premium on top of the saved retail price. Excess PV electricity injected into the grid is remunerated at the wholesale price of electricity (based on coal-fired power plants' electricity at provincial prices) plus the premium. This scheme has promoted self-consumption, as the amount consumers receive for the energy surplus fed into the grid is lower than the retail electricity price, i.e. lower than the savings from self-consumption. Given high industrial electricity tariffs (see also Box 5.5), self-consumption is particularly attractive for industry customers. It is also possible to sell the electricity produced to other customers locally, in an energy services company (ESCO) model.

In 2014, the regulations were simplified for the development of distributed solar PV, through easier registration, grid connection and financing procedures, but the PV market is still largely dominated by large-scale installations (IEA, 2016). Tariffs for the new PV installations will gradually be lowered over time in order to promote the technological development, efficiency and competitiveness of the PV sector (IEA/IRENA, 2016). Due to a relatively less favourable resource endowment, solar PV has so far played only a minor role in the three selected provinces.

Box 5.5 • Financing FIT payments in China

The FIT system in China guarantees fixed revenues to renewable energy producers per MWh of electricity produced. The payment comprises two elements. The first element is paid by the grid companies and payment equals the local on-grid tariff for coal-fired power plants. Consequently, it makes no difference for the grid companies whether they buy renewable energy or coal-fired generation. Grid companies settle payments with generators on a monthly basis.

The base tariff for coal power plants is set in a way to cover all costs of the plants as:

$$Benchmark\ tariff = \frac{Fixed\ costs}{FLHs} + operational\ costs$$

The benchmark tariff can reach up to 60 USD/MWh (CNY 400/MWh).

The difference between the local on-grid coal tariff and the applicable FIT is paid from the National Renewable Deployment Fund (NRDF). The component covered by the NRDF is larger than that paid by grid companies. The fund is financed by a general levy on electricity bills, which stood at USD 2.3/MWh (CNY 15/MWh) in 2015. Payments from the NRDF are also made on a monthly schedule, but since 2013 rapid VRE deployment has translated into the having insufficient revenues. As a result, payments to VRE generators have sometimes seen significant delays.

The rising cost of the FIT system is weighing fairly heavily on the NRDF. A further increase in the surcharge is politically difficult against the backdrop of slowing economic growth. As such, there is growing pressure to find alternative revenue sources to finance the continued uptake of renewable energy sources in line with the targets put forward in the 13th Five-Year-Plan.

A number of different options are currently under discussion. One option is to move from a price-based system, i.e. the current FIT, to a quantity-based system, i.e. a quota obligation combined with green certificate trading. One possibility is to impose the obligation on larger generators, which then need to either build their own renewable energy facilities or opt to purchase certificates from generators that have a surplus of VRE generation compared with their obligation.

However, a certificate system raises other challenges. Experience from European countries that have relied on such systems in the past suggests that they may increase revenue risk for renewable energy generators, which in turn increases financing costs and thus overall costs for deployment.

System operations

The power sector in China is currently unbundled into two parts: power generation; and transmission, distribution and supply. On the generation side, five state-owned companies own half of all Chinese generating capacity. The other half is owned by IPPs and local government companies. Grid and supply operations are handled by two large companies (SGCC and China Southern Power Grid [CSG]) which own the six transmission grids. The same companies' local branches operate the distribution and supply operations. In the selected provinces, SGCC owns and operates the grid.

Scheduling of power plants

Scheduling of power plants in China is an activity regulated by the National Load Dispatch Centre (NLDC), which co-ordinates RLDCs and Provincial Load Dispatch Centres (PLDCs). PLDCs, in turn, co-ordinate prefecture-level load dispatch centres and county-level dispatch centres.

Scheduling is done on a monthly, weekly and day-ahead basis. PLDCs publish daily 15-minute dispatch plans, while RLDCs conduct regional grid security analysis. Once verified, the resulting final schedule is issued at 22:00 every day.

The contractual arrangements in place for thermal power plants constitute the greatest barrier to efficient power plant scheduling. Responding to an urgent need for generation capacity in the 1980s, the central government opened up the market for power generation to private parties and provincial governments. In order to guarantee return on investment for this new, predominantly coal-based capacity, both tariffs and operating hours were fixed. In fact, key performance indicators (KPIs) of thermal generators include overall electricity generation, above and beyond the goal of revenue generation.

Plant scheduling was organised to ensure that each plant produced, at a minimum, its contracted target operating hours. The number of operating hours has been kept relatively constant between generators, without consideration of plant efficiency, while the benchmark tariffs were set in the 2000s (see Box 5.6).

Monthly, weekly and daily production schedules are set with little room for adjustment and little consideration for the system flexibility needed to integrate larger shares of wind and solar. In addition, once a power plant has been switched off, it is required to remain inactive for one week and unit start-up has a lead-time of approximately 12 hours. For these reasons, thermal plant operators have a strong incentive to stay in the market, even if the power is not needed. As a consequence, there are often a large number of thermal power plants running at minimum production levels, in order to cover demand in the peak hours. Since supply flexibility in the region comes predominantly from coal, the technical and institutional barriers to ramp down production by a large set of these thermal plants lead to more curtailment of wind and solar (RAP, 2014).

Moreover, many co-generation coal plants were also built in order to offer cheap heat through district heating. In winter, heat demand creates a minimum generation constraint on the co-generation unit, as the local co-generation units must generate a certain amount of electricity in parallel to meeting heat requirements; furthermore, the maximum available power output from a specific unit is decreased as steam must be extracted from the turbine, creating a need for additional generation units to be online to be able to satisfy the forecast daily peak.

Since winter is the season with the strongest wind generation, thermal inflexibility can provoke even stronger curtailment during this time of year (Wei et al., 2015).

Transmission operations

Current practice for the use of transmission and interconnection between provinces shows significant room for improvement. One issue is the scheduling practice for power flows.

Interconnectors between provinces are operated on twelve-hourly scheduling intervals, i.e. interconnectors operate at two different levels only. One level is for night-time, the other for daytime operations. This effectively renders the contribution from interconnection to balancing VRE insignificant.

This situation is further complicated by the fact that transmission constraints are accounted in the daily schedule only by the RLDCs, while the actual operations are handled by the PLDCs. The hierarchical methodology of dispatch management leads to the effect that no dispatch centre has total knowledge over all generators and transmission lines within an entire area. Wind power in the northeastern provinces is therefore transmitted progressively through intra- and inter-province tie lines, in a long-chain structure that is too fragile to deliver wind power efficiently to load centres (RAP, 2014; Wei et al., 2015).

To address the bottlenecks in the transmission system, SGCC is working on installing long-distance high-voltage direct current (HVDC) lines, in particular between the load centre in Beijing and Inner Mongolia, near the three provinces being discussed here. However, the effectiveness of such a scheme will critically depend on operating the transmission grid – including existing lines – in a more dynamic and co-ordinated way. Improved operational practices may partly offset the need to invest in new transmission lines.

Balancing co-operation and integration

Each province in China is balanced largely independently from the others. Interconnectors are used to trade electricity based on long-term contracts and flows are fixed for 12 hours, i.e. two different flow levels across the interconnectors each day.

Sharing of reserves is only done in some regions and used as an exception: in the northwest region, in a situation where a PLDC evaluates its spinning reserves to be insufficient, it can ask the Northwest RLDC for assistance from other provinces before 24:00 on the day before (RAP, 2014).

Improved co-operation between balancing areas, including sharing of reserve capacities, would make a substantial contribution to reducing system integration problems, including curtailment.

Definition and deployment of operating reserves

The current definition of ancillary services in China was issued in 2006, by the State Electricity Regulatory Commission (SERC). The definitions classify operating reserves as "basic" (uncompensated) and "compensated" services (Table 5.7).

Table 5.7 • Ancillary services categorisation, China

Category of services	
Basic services	Frequency response "Basic" load following "Basic" reactive power support
Compensated services	Automated generator control Compensated load following Compensated reserves Compensated reactive power support Black-start capability

All generating units are obligated to provide basic ancillary services. "Load following" is formally considered an ancillary service in China: instead of using different units for specific production profiles (e.g. baseload and mid-merit), all coal power plants are operated to follow total system demand throughout the day. High minimum net loads and slow ramping down, typical of Chinese coal power plants, complicate system operations, to the detriment of VRE production. Required operating reserve levels for each province are determined by the RLDC.

Two elements are particularly important in the Chinese operating reserve definition: the peak-valley difference, which is the gap between the daily maximum and minimum system demand, and the "deep ramp", a situation whereby all generators are required to ramp down production following the evening demand peak.

In windy and cold regions, system operations are complicated by the presence of heat-driven must-run plants and penetration of wind power plants. Coal power plants operate together near their minimum load capability. As a result, VRE production is uneconomically curtailed, to meet operational constraints of coal power plants (RAP, 2014).

Box 5.6 • Power sector reform in China

In 2002, China broke the vertically integrated monopoly structure of its power sector, separating generation from transmission and distribution. The sector developed rapidly as a consequence, with significant improvements in transmission capability and power supply quality.

A recent market reform proposal seeks to create competition at the level of generation and retail sales. At the same time, transmission will be bound by tighter rules.

The leading policy document, "Several Opinions of the CPC Central Committee and the State Council on Further Deepening the Reform of the Electric Power System", has established a new framework under which the reform will take place.

The reform, if implemented, entails that generation and retail prices will be determined by the market through bilateral agreements and the market. An ancillary services market will be also launched: a second policy document, "Guiding Opinions on Improving Electric Operation and Regulation to Promote Greater and Fuller Use of Clean Energy", focuses on the importance of an ancillary services procurement mechanism, in particular peak shifting; it also highlights the importance of providing an incentive for the direct purchase of renewable energy ancillary services.

Under the new reform, transmission and retail operations will be separated. Transmission system operators will no longer be able to reap profits from the difference between generation and retail prices. Instead, their revenues will be based solely on the fees related to the service they provide; the fees will be calculated in order to cover costs and provide a reasonable profit. The precise remuneration will be differentiated as a function of voltage level.

On the retail side, the reform will give end-users the possibility to choose from whom to buy electricity. Retailers will not be required to own generation or distribution assets; nevertheless, most of the companies that have registered to become retailers are backed by generation or distribution companies. Demand-side management (DSM) will be improved, through time-of-use pricing and the participation of ESCOs.

The reform also intends to promote power system transformation: measures will be taken to shift the system towards a large share of renewable generation, together with the acceleration of the development of smart-grid technologies, such as smart equipment, interactive electricity retailing and distributed storage (Ma, 2016; BNEF, 2016e; CNESA; 2015).

Sources: BNEF (2016e), "Serve the people: China liberalises power retail", www.bnef.com/core/insight/14350?fromGlobalSearch=4200734003; CNESA (2015), "China's new electric system reforms", http://en.cnesa.org/featured-stories/2015/8/4/chinas-new-electric-system-reforms; Ma, Li (2016), "Introduction of renewable energy development policy in China".

System transformation

Incentives for system-friendly deployment of large-scale VRE

Timing of deployment

Chinese planning policies usually have a mid-term horizon dictated by Five Year Plans (FYP), which include energy sector targets and targets for the wider energy industry (e.g. PV panel or wind turbine production). Local governments, ministries and public bodies publish their own five-year plans, reflecting national targets. Capacity targets may be corrected if installation rates exceed expectations. The 13th FYP, released on November 2016, set electricity sector targets in line with the already existing target to achieve a 15% share of non-fossil fuels in total primary energy consumption by 2020:

- A target of 210 GW of total installed wind power capacity by 2020, including 5 GW of offshore projects as well as smaller scale inland projects.
- A target of110 GW of solar power capacity by 2020, including more than 60 GW of distributed solar energy systems and 5 GW of concentrating solar thermal power.

Location and technology mix

Overall targets are shared between provinces. The general tendency is to install the largest shares of VRE capacity in provinces where natural resources are higher; this tendency leads to hotspots of VRE in certain provinces, far away from load centres, increasing the risk of grid congestion and VRE curtailment. The recent regulation on guaranteed purchase stipulates that if a region (city or district) has a surplus of VRE energy that fails to be dispatched, the regional authority cannot approve the construction of new VRE capacity (BNEF, 2016b).

Technical capabilities

Chinese wind and solar PV power plants must be able to provide active and reactive control and low-voltage ride-through (LVRT) capability, similar to conventional power plants, in order to ensure secure and stable operation of the power system. Chinese grid codes give special attention to active output control and ramping capabilities. Active and reactive power control is also an important aspect of Chinese grid codes, due to the necessity to cope with large wind farms in a weak network (Basit et al., 2012; USCHECP, 2016).

Incentives for system-friendly deployment of distributed VRE

The retail power sector has been reformed to incorporate a range of market-driven features, but it continues to have no effect on the generation side. The consumer pays the grid operator, which remunerates generators.

Locational price

Electricity prices are fixed by central and provincial governments. Electricity tariffs for the different consumer groups are set for each province (Ecofys, 2015).

Time-dependent price

In October 2010, China introduced electricity pricing reform for the residential sector. Previously, households were charged a flat rate regardless of how much each consumed. Since then, Rates were not able to cover electricity costs and were inefficient in promoting energy saving.

Since the reform, specific electricity-use and volume-related pricing has been introduced. Moreover, peak- and valley-differentiated tariffs have been set as the next step of residential electricity pricing reform; certain provinces are already applying this provision (GSI, 2015).

Grid fees

Retail tariffs include network charges, taxes, and levies. In 2015, they were in the range of USD 0.15-0.24/kWh (CNY 1-1.6/kWh) (Ecofys, 2015). Network costs account for approximately 20-30% of final customer tariffs. Benchmark charges are decided centrally by the NDRC.

Taxes and surcharges

Different taxes and levies are collected through electricity bills:

- electricity tax for industrial companies, up to USD 0.06/kWh (CNY 0.4/kWh)
- tax for the promotion of agriculture and network expansion, up to USD 0.003/kWh (CNY 0.02/kWh)
- tax to promote hydropower projects, up to USD 0.001/kWh (CNY 0.007/kWh)
- a surcharge to finance desulphurisation in coal power plants, up to USD 0.002/kWh (CNY 0.015/kWh).

Certain provinces provide discounts on energy bills to energy-intensive industries.

Subsidies for the renewable energy FIT originate from a fund set up in 2012 through a levy on almost all Chinese power consumption, currently USD 0.002/kWh (CNY 0.015/kWh). The Energy Research Institute of the NEA has suggested an increase in the levy to USD 0.003/kWh (CNY 0.02/kWh) (BNEF, 2015; Ecofys, 2015).

Discussion

China has experienced a marked increase in electricity demand over the past decade, requiring rapid and large investment in the power sector. This has provided an opportunity to bring together system integration and the expansion of overall electricity infrastructure. However, this opportunity has not been fully realised and investment has predominantly been in coal-fired capacity. The dominance of coal in the power sector has translated into growing concerns over local air pollution and carbon dioxide emissions. To address these issues, China is ramping up deployment of renewable energy resources and putting in place measures to effectively limit increases in coal-fired capacity.

In recent years, wind and solar PV deployment have gathered significant momentum. In 2015, renewables represented over 50% of net additions to power capacity. Grid-connected onshore wind capacity increased by over 32 GW in 2015, the highest rate of installation to date. China installed 15 GW of solar PV in 2015 according to government estimates. Overall cumulative PV capacity reached over 43 GW, with over 80% from utility-scale projects.

China has proposed ambitious renewable energy targets under the 13th FYP: nearly doubling land-based wind capacity from 128 GW in 2015 to 220 GW by 2020, and tripling solar PV capacity from 43 GW in 2015 to 110 GW by 2020.

The ramp-up of renewables capacity is complemented by measures to limit construction of new coal-fired capacity. The NDRC and NEA issued special emergency guidance, requiring local governments and companies to suspend or cancel the permitting and construction of coal-fired power plants.

In recent years, deployment of wind and solar PV has taken off considerably in Northeast China. This change has occurred against a background of slowing economic growth, which is transforming China from a dynamic to a stable power system. In this context, the effective integration of incremental wind and solar PV capacity hinges on the flexibility provided by existing generation assets, coal plants in particular. In other words, successfully scaling down the role of thermal plants in favour of VRE is the most important step for decarbonisation efforts in the immediate future.

Important steps have been taken to support the growth of VRE in recent years. Beginning with the 12th Five-Year Plan in 2010, the rollout of new wind and solar capacity is co-ordinated at a national level. In addition, technology-specific FITs are differentiated on a regional basis to account for resource discrepancies. Together, these changes take stock of the spatial value of VRE and allow for a gradual introduction of new wind and solar capacity over time. They can form the framework for cost-effective and accurately timed capacity additions. In the future, national and regional planning endeavours may need to shift from setting quantitative capacity targets towards a more dynamic integration approach that reflects the spatial and temporal value of VRE for the overall system.

It has become crucially important to take measures to limit wind curtailment. The operational standards for thermal plants, coal in particular, must be revised to accommodate wind production. Historical arrangements and KPIs that incentivise coal plant operators to stay in the market – even if this requires running at minimum levels – have severely reduced system flexibility and the available room for wind power. Curtailment of wind has become a key hurdle for continued deployment, reaching as much as 32% of available wind power in Jilin province.

Alternative sources of flexibility are also underutilised. The available interconnection capacity is not optimally used. Currently, flows over interconnectors linking the different provinces are fixed for 12-hour periods and guided by long-term bilateral contracts. Without the ability to share reserves, each province relies on its own reserves for balancing the local power system.

These challenges have been recognised by system operators and policymakers in China. In Northeast China a pilot project has been put in place to remunerate thermal generation for providing ramping capability. This is an important lever to incentivise thermal flexibility. Making co-generation more flexible has also been identified as a priority to enhance the overall flexibility of heat and power production. Wind-to-heat pilot projects could play a role in the future.

Table 5.8 • Key recommendations for Northeast China

System-friendly VRE deployment
VRE deployment is focused on priority areas that are often distant from load centres. Advanced wind turbine technology and rapidly falling costs of solar PV provide an opportunity to diversify deployment with a view to boosting the overall value of the electricity to the power system.
FIT levels are differentiated according to the wind and solar resource quality in different provinces. A further elaboration of the regional differentiation of the FIT could actively promote a more diversified, system-friendly deployment pattern.
Wind and solar PV plants are often treated separately in planning processes. Co-locating solar PV and wind plants could minimise variability of the output, thus facilitating grid operations.
Investment
China has increasingly ambitious targets for VRE deployment. In order to maintain progress, measures to boost system flexibility, including considerable grid reinforcement, will be required to make optimal use of available generation. The current approach to VRE integration does not consider all available options on an equal basis. Deploying a balanced mix of flexible resources – also including demand-side response and energy storage options – could facilitate the transformation of the Chinese power system at least cost.
Operations
Flexibility of thermal capacity is constrained by contractual arrangements (guaranteed FLHs) and generators' KPIs (incentive to maximise electricity generation irrespective of system need). Introduction of system service markets and revision of KPIs could enhance flexibility.
Current power exchanges between provinces are undertaken on very coarse schedules (12-hourly), locking out flexibility and benefits of aggregating VRE and power demand across larger regions. More granular schedules, allowing for short-term exchange of power, would enhance the value of VRE.
Consumer engagement – distributed resources
Consumers currently have little incentive to adjust their electricity demand flexibly. The full rollout of time-dependent electricity prices could provide incentives for end-users to increase demand-side flexibility. Deploying small-scale flexibility resources (e.g. heating, ventilation and air-conditioning systems with thermal storage) through public procurement or direct incentives could further drive their adoption.
Planning and co-ordination
The special emergency guidance, requiring local governments and companies to suspend or cancel the permitting and construction of coal-fired power plants, opens an opportunity for co-ordinated expansion of VRE in the context of reduced reliance on coal.
In areas with high shares of co-generation, increasing the flexibility of the combined electricity and heat production system can reduce the challenges of high wind curtailment, in particular in Northeast China. Depending on local circumstances, viable options may include increased flexibility of co-generation plants, installation of electric boilers and upgrades to the existing head network.

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Denmark

General information on VRE and grid integration

Flexibility assessment, ease of integration and current value

VRE resources

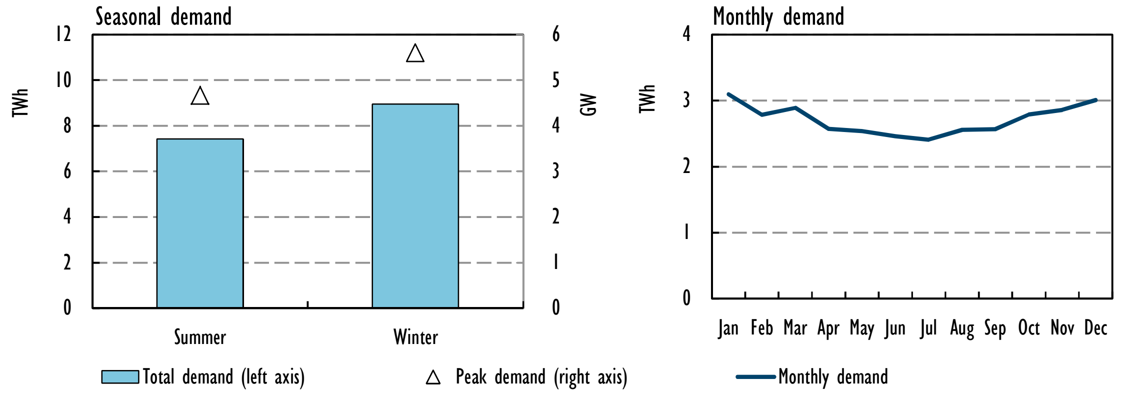
Denmark has access to formidable wind resources: average onshore wind speed at a height of 100 metres lies between 6 metres per second (m/s) and 10 m/s. More than 7 300 kilometres (km) of coastline (compared to a total land area of 43 000 square kilometres [km^2]) and low average sea depth lead to significant additional offshore and near-shore wind potential. Average offshore wind speed lies between 9 m/s and 11 m/s. The highest wind speeds occur on and off the western coast (IRENA, 2016). Due to its geographic position, solar resources are limited. During the period 2001-15, Denmark experienced a global horizontal irradiation (GHI) ranging between 950 kilowatt hours per square metre (kWh/m^2) and 1 050 kWh/m^2 per year. By comparison, Brazil's GHI reaches values over 1 800 kWh/m^2 per year and South Africa's GHI can exceed 2 000 kWh/m^2 per year (DMI, 2015; Solargis, 2016).

Demand

Annual electricity consumption peaked in 2008 and subsequently dropped by 7% to 32.5 terawatt hours (TWh) in 2015 (excluding transmission losses). However, future consumption is expected to rise by an additional 3.7 TWh from 2015 to 2024. This is partly due to the increased electrification of the Danish heating and transport sectors through an anticipated uptake of electric boilers, heat pumps and electric vehicles, and to the presence of several large data centres (Energinet.dk, 2015a).

Electricity demand varies between 2.1 gigawatts (GW) and 6.3 GW, lying predominantly between 3.5 GW and 4 GW. Annual peak demand in 2015, equal to 5.6 GW, was reached by the end of January. A clear seasonal pattern can be seen, with summer demand in 2015 17% lower than winter demand. In the same year, peak demand varied accordingly by about 1 GW, from 4.6 GW in summer to 5.6 GW in winter (Figure 5.23) (Energinet.dk, 2016a, 2015b, 2015c).

Figure 5.23 • Seasonal and monthly electricity demand, Denmark, 2015



Note: Summer from June to August, winter from December to February.

Source: Adapted from Energinet.dk (2015b), *Market Data*, database, http://energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx.

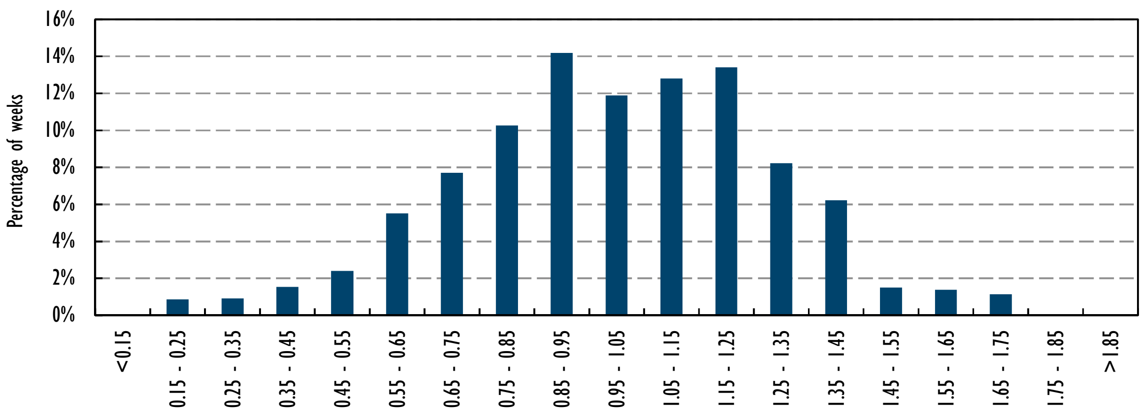
Key point • Winter consumption is significantly higher than that during summer.

Analysis of match between demand and VRE generation profile

The Demand Coverage Factor (DCF) analysis shows that the correlation of variable renewable energy (VRE) with electricity demand in Denmark is less favourable than in other case study countries.

Weekly VRE generation is within 90-110% of weekly demand in only 27% of cases (Figure 5.24). In 71% of weeks the DCF lies in a good range of 70-130%. However, in weeks with the least favourable match, the DCF drops to 20-30% at the low end and reaches 170-180% at the high end. During these times, there is a significant need to reshape future demand or to cover demand using other sources (e.g. flexible generation, imports or seasonal storage).

Figure 5.24 • Range of weekly DCFs for Denmark, 2015



Key point • The DCF analysis reveals a degree of mismatch between VRE generation and current electricity demand in Denmark.

Generation

The Danish generation landscape has seen drastic changes over the last 30 years. Starting as a system with a limited number of centralised power plants, it has evolved into a highly distributed system (Figure 5.25). The overall installed generation capacity amounts to roughly 13 657 megawatts (MW), with a high share derived from wind turbines (35.8%).

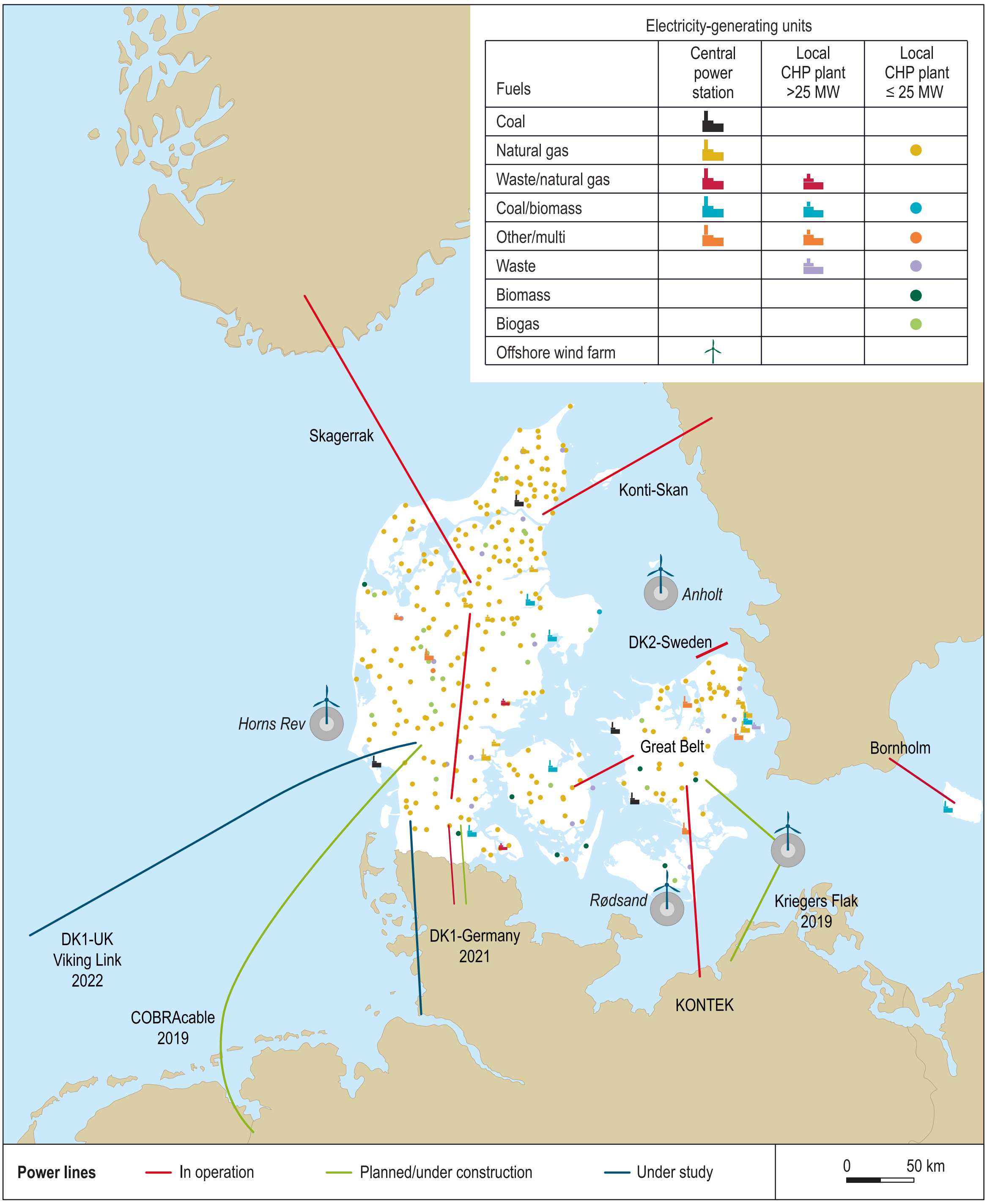
Electricity produced by thermal power facilities decreased by approximately 20% from 2013 to 2014 alone. Wind generation has increased to provide an average share of 42% of electricity consumption in 2015, and has repeatedly exceeded demand (for 1 460 hours in 2015 in Western Denmark [DK1],[15] corresponding to 16.7% of the time). A record instantaneous penetration level was reached on 26 July 2015, when wind production equalled 138.7% of electricity demand (Energinet.dk, 2016c, 2015a, 2015b).The remaining large-scale central power stations in operation are mainly co-generation facilities which run on coal as the predominant fuel, often under biomass co-firing.[16] Further transition from coal to biomass has been declared by Danish power utilities for various units (AET, 2015; Ingeniøren, 2014a, 2014b). With increasing shares of wind capacity and the application of electric heating, baseload services have become somewhat redundant. Therefore, most power stations have been retrofitted to increase their flexibility as,

[15] The Danish power system is divided into two bidding areas, or zones: the "Western Danish power system" (DK1) and the "Eastern Danish power system" (DK2). Further details are provided below.

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

for example, at the coal-fired Esbjerg co-generation power station, which is now capable of running on minimum loads of 10-20% with ramp rates of 3-4% per minute.

Figure 5.25 • Map of production units in Denmark (onshore wind excluded)



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

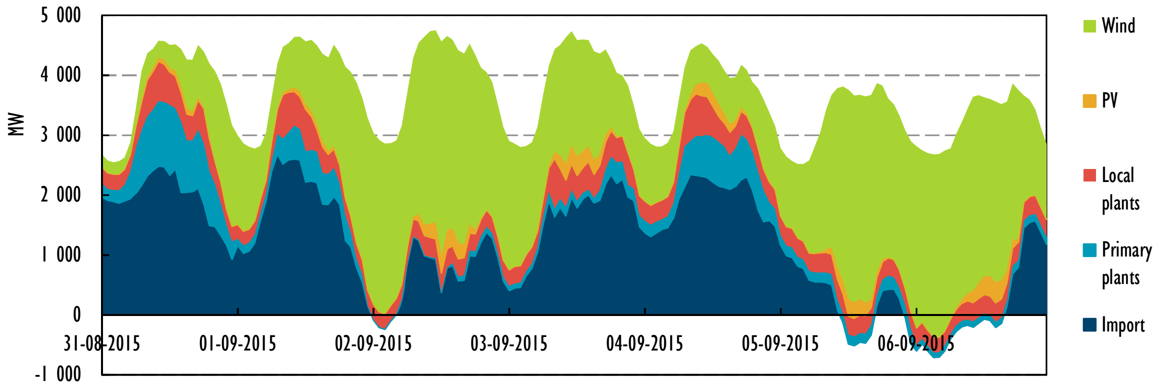
Source: Adapted from Energinet.dk (2015c), *System Plan 2015*, www.energinet.dk/systemplan-2015 and Energinet.dk (2016b), "Map of production units in Denmark", www.energinet.dk/EN/KLIMA-OG-MILJOE/Miljoerapportering/Elproduktion-i-Danmark/Sider/Termiske-vaerker.aspx.

Key point • Denmark has an electricity system with a high contribution of distributed generation.

The capacity rate of both central and decentralised thermal generation units is declining as Denmark is further exploiting its wind generation potential. In September 2015 the western part of the Danish energy system operated for the very first time without any participation of its central generation units (Figure 5.26). This marks an important milestone for grid integration of VRE more generally. Newly installed, advanced grid support technology (synchronised condensers) was used to maintain grid stability under these conditions (Energinet.dk, 2016a).

The Danish energy system has been successfully transformed from a system featuring centralised and inflexible generation units, to a flexible and decentralised system that has been adapted to accommodate high shares of VRE.

Figure 5.26 • Hourly dispatch 31 August - 6 September 2015 in Western Denmark (DK1)



Note: PV = photovoltaics.

Source: Adapted from Energinet.dk (2015b), *Market Data*, http://energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx.

Key point • During the first week of September 2015, there were periods when the Western Denmark power system successfully operated without any large-scale thermal plants.

Storage and DSM

Due to its topology, Denmark has no access to pumped hydro storage facilities. The country has very strong interconnections with other countries in the region and operations are co-ordinated by means of the joint Nord Pool market. This allows valuable synergies to be achieved across the entire region. For Denmark, a main benefit is the ability to tap into flexible generation resources, such as reservoir hydropower generation, in particular from Norway.

Currently no concrete plans exist to increase the development of storage in Denmark itself. The focus lies on increasing interconnection and grid reinforcement. However, Denmark has access to salt caverns suitable for the development of compressed air energy storage. This technology could be used in the long term, alongside battery storage and power-to-fuel conversion (stoRE, 2016).

Denmark has seen the growing uptake of electric boilers in domestic co-generation plants. Electric boilers play an important role in integrating the fluctuating production of Denmark's windfarms. By generating and storing heat at times of low electricity prices, which mostly occur during high wind in-feed, these boilers enhance the thermal storage capacity of the overall system. This can be considered as a form of demand-side management (DSM). In addition, co-generation units already provide system services, such as operating reserves, thanks to the flexible operation pattern that they are capable of.

Transmission and interconnections

The Danish electricity transmission grid is owned by Energinet.dk, a non-profit enterprise owned by the Danish Ministry of Energy, Utilities and Climate. The grid is separated into two non-synchronous subsystems, interconnected by the Great Belt Power Link (58 km, 600 MW, 400 kilovolts [kV], high-voltage direct current [HVDC]) between the islands of Funen and Zealand. The western side (the Western Danish power system – DK1) is synchronous with continental Europe; the eastern side (the Eastern Danish power system – DK2) is synchronous with the Nordic power system.

Denmark shares interconnections with Germany, Sweden and Norway. The total interconnection capacity of Jutland and Funen adds up to 4 287 MW (of which 3 984 MW on import). Zealand has 2 300 MW of interconnection capacity (of which 1 900 MW on import).

Denmark is strongly reinforcing its interconnection and transmission grid. An additional HVDC link from Jutland to the Netherlands (COBRAcable, 700 MW) is currently under development and is expected to be operational at the beginning of 2019. Also by 2019, the German-Jutland interconnection is to be expanded to 2 500 MW. A further interconnection to Great Britain is also being considered (Viking Link). Further infrastructure projects aim to strengthen the transmission grid, such as the replacement of the backbone transmission line on Jutland, running from Kassø to Tjele (Energinet.dk, 2015d).

Energinet.dk is also one of the three partners (with Germany's 50Hertz and Sweden's Svenska Kraftnät) involved in the so-called "Combined Grid Solution", a unique offshore electricity grid in the southern part of the Baltic Sea. It will be the first international offshore power grid, utilising the planned Kriegers Flak wind farm to connect the national grids of Denmark, Germany and potentially Sweden. Completion of grid connection works is expected by the end of 2018, with first power by 2020 (Energinet.dk, 2015d).

Denmark's current level of interconnection is very high by international standards, as is its potential for expansion, and provides access to significant external flexibility resources.

Summary

The Danish power system is already operating under high shares of VRE generation and has the potential for further increases. The required flexibility is mainly provided by significant interconnection capacity with neighbouring countries, which will be strengthened further in the coming years. Moreover, the conventional fleet of central and decentralised power plants has been transformed through retrofits and operational improvements and is operating very flexibly today. This has fostered VRE integration. Finally, continued electrification of the heating sector can improve demand-side flexibility.

Market and policy frameworks

Quantitative policy analysis

The 2009 Law on the Promotion of Renewable Energy (in Danish: *Lov om Fremme af Vedvarende Energi* – VE-Lov) is the main renewable energy (RE) support law in place in Denmark. In the VE-Lov, two kinds of remuneration are available:

- Variable feed-in premium (FIP): this premium covers the difference between average annual electricity prices and the target remuneration for a limited number of full-load hours of production.

- Fixed FIP: in this case, plant operators receive a fixed bonus per megawatt hour (MWh) on top of the market price for a limited number of full-load hours of production. A cap (maximum of bonus plus market price) is defined by law for certain technologies.

Since 2009, the VE-Lov has been amended various times, adapting the support scheme to provide more appropriate remuneration.

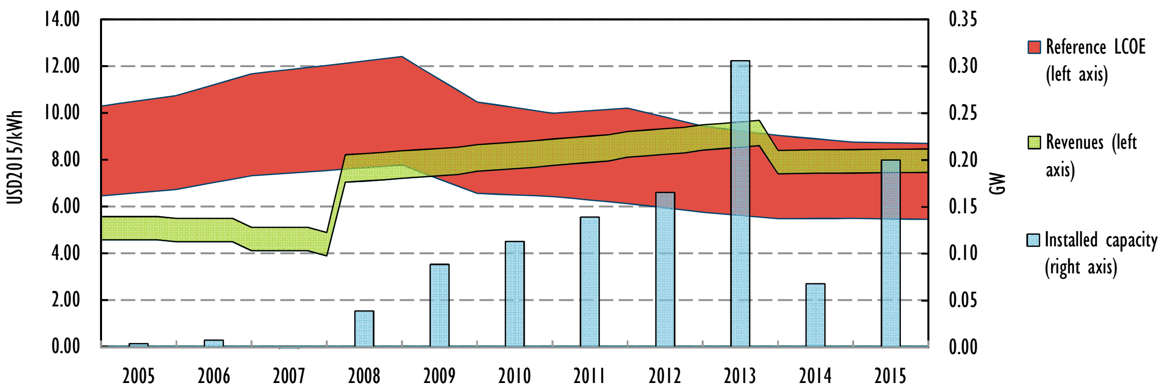
The Danish Energy Agency and Energinet.dk periodically assess the costs of various technologies for power production, district heating, energy storage and energy carrier generation and conversion. The results of this assessment are collected periodically in a "Technology Catalogue" (ENS, 2015a).

Wind energy

Before the introduction of the VE-Lov in 2009, a total of 2.7 GW of wind plant capacity were installed, of which 423 MW were offshore (ENS, 2016). The main instruments facilitating this initial uptake were the measures derived from the Third Energy Plan (*Energi 2000*); feed-in tariffs, FIPs and tax relief were the main instruments, triggering large-scale deployment for over a decade. Since the early 2000s, double-digit shares of Danish electricity consumption have been supplied by wind plants.

After a five-year period of relatively slow deployment, the VE-Lov provided attractive incentives (Figure 5.27) and triggered a continuous increase in annual onshore installation, growing from 30 MW in 2008 to 300 MW in 2013. In order to improve the overall framework and account for falling costs and rising remuneration, the government decided to introduce a cap on maximum remuneration for new plants installed from 2014 onwards. This triggered a spike in installations, with developers rushing to complete projects to lock in higher incentives. As a result, almost two-thirds of the capacity added in 2013 was installed in the last quarter of the year.

Figure 5.27 • LCOE, revenues and added capacity for onshore wind, Denmark



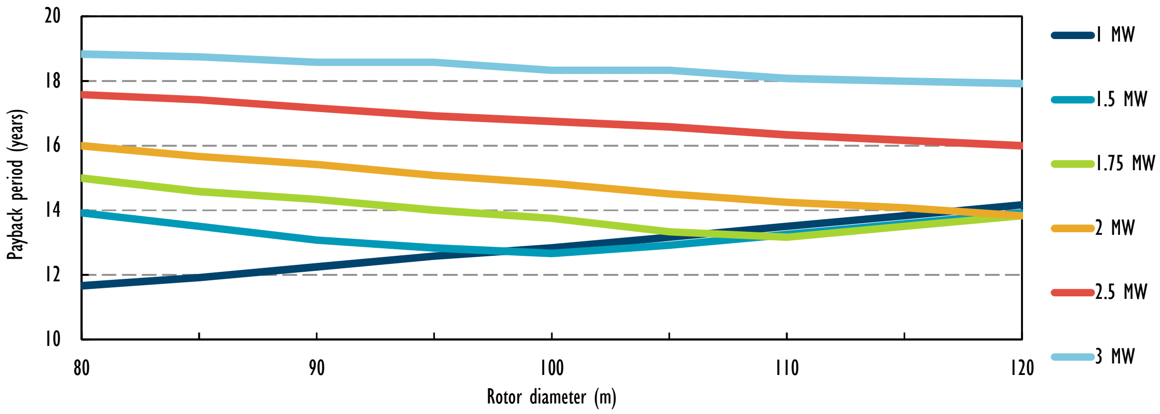
Note: LCOE = levelised cost of energy.

Key points • The VE-Lov scheme triggered new investment in the wind sector after a relatively slow deployment period. The introduction of a cap from 2014 initiated a spike in installations.

For plants commissioned from January 2014, VE-Lov guarantees a fixed FIP of USD 37.5/MWh (DKK 250/MWh).[17] An additional premium of USD 2.7/MWh (DKK 18/MWh) is paid to cover the cost of balancing out forecast errors. The maximum remuneration is capped at USD 87/MWh (DKK 580/MWh).

The latest revision to the premium system for wind power plants has been designed to promote the use of larger rotors per installed generation capacity (Figure 5.28). The amount of energy that is eligible for support payments is set as 6 600 MWh per MW of installed capacity plus an additional 5.6 MWh for each square metre of rotor swept area. Consequently, installing a larger rotor on a wind turbine will result in higher overall support payments.

Figure 5.28 • Payback period under the VE-Lov scheme by wind turbine capacity.



Note: The following assumptions were made: costs for wind turbines range linearly from USD 1 620 to USD 1 850 per MW according to rotor size; full-load hours equivalent to 2 800 hours; average wholesale price of energy equivalent to USD 45/MWh (DKK 300/MWh).

Key points • Rotor diameter has a direct effect on the payback period.

The design of the premium system provides an incentive for a lower specific power rating (installed capacity per unit of swept rotor area) which implies more stable and thus system-friendly power production. Indeed, Denmark has experienced a general trend towards the installation of technology with relatively larger rotor area per installed capacity (Figure 7). As modelling analysis carried out for *Next Generation Wind and Solar Power* has demonstrated, larger rotor areas increase the value of the produced electricity. The design of the Danish premium system thus – in principle – provides incentives for system-friendly wind turbine design. However, the degree to which incentives are optimised depends on the scaling factor that links support payments to rotor size.

Offshore wind farms, which are installed following a tender process, are subject to separate incentives, set as variable FIPs. In recent years, following the VE-Lov auctions, the three largest offshore wind farms were inaugurated (Horns Rev II, Rødsand II and Anholt) with a cumulative capacity of more than 800 MW, double that of the total previous offshore capacity.

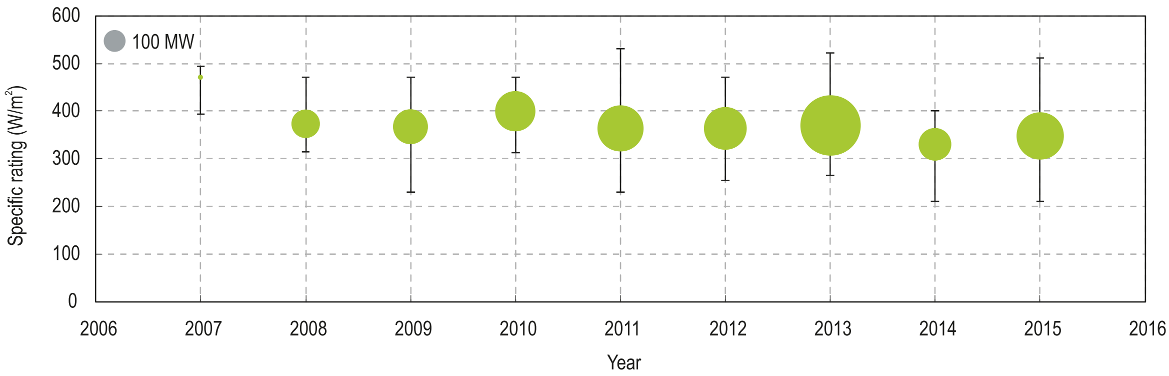
The Horns Rev II wind farm receives a variable FIP with a total remuneration of USD 77/MWh (DKK 518/MWh). For the Rødsand II wind farm, the total tariff amounts to USD 94.5/MW (DKK 629/MWh). For these two plants, premiums apply to electricity production of 10 TWh, produced in accordance with the terms of the tendering procedure, for a maximum of 20 years

[17] USD 1 = DKK 6.65

after the wind farm has been connected to the grid. For the Anholt offshore wind farm, the total tariffs amount to USD 158/MWh (DKK 1 051/MWh) for a total of 20 TWh, limited to 20 years; for the latter wind farm, the premium is not paid for the hours in which the market price is negative or zero (this exception is restricted to 300 hours per year).

More than 1 GW of offshore wind capacity will be commissioned following the results of further tenders for the Horns Rev III and Kriegers Flak offshore wind farms. Vattenfall secured the development of 400 MW of capacity with the Horns Rev III project, with an offer of USD 115.5/MWh (DKK 770/MWh). The plant should be commissioned by 2021.

Figure 5.29 • Average specific rating and installed onshore wind capacity, Denmark



Notes: Bars indicate minimum and maximum specific ratings in each year; size of green circle represents total annual installation; wind turbines with a rotor diameter under 5 m are excluded.

Source: ENS (2016), *Stamdataregister for vindkraftanlæg ultimo december 2015* [Master data register for wind power plants at the end of December 2015].

Key point • The specific rating of newly installed turbines has seen a decrease, with the minimum rating dropping from 400 watts per square metre (W/m^2) in 2007 to 200 W/m^2 in 2015.

PV energy

PV power plants connected to the grid after 11 June 2013 receive a sliding FIP of USD 90/MWh (DKK 600/MWh) for the first 10 years, and USD 60/MWh (DKK 400/MWh) for an additional 10 years. This FIP system (also called 60/40) was withdrawn for new projects in May 2016. The reason for the law change was a significant increase in applications for 60/40 support: in March and April 2016, Energinet.dk received 8 800 applications for 60/40 support, corresponding to 4 300 MW.

It is still possible to apply for support for small-scale solar power through an existing pool scheme. Applications for the pool scheme have to arrive within a certain period of the year. The most recent application round was open between September and October 2016.

The pool consists of four subcategories according to installation type. The installed PV capacity must not exceed 6 kilowatts (kW) per household, dwelling unit or person, depending on the specifications in the subcategory. The sliding premium (bonus plus market price) offered ranges between USD 108 and USD 141 per MWh (DKK 720-940/MWh). The tariff is paid for the first ten years of operation (Energinet.dk, 2016d).

With a total installed capacity of 783 MW in 2015, solar power accounted for the 5% of Denmark's total generation capacity. Energinet.dk's projections for installed PV capacity for 2024 are modest (1 140 MW), reflecting the country's comparably low resource base.

This notwithstanding, the period between late 2012 and early 2013 saw a rapid increase in rooftop PV systems, driven by the simultaneous presence of the FIP scheme and the ability for electricity customers to deduct from their billed annual electricity consumption the electricity produced by their PV systems over the course of a year (net metering). Against the background of Denmark's very high electricity prices, this was a lucrative opportunity.

A side effect of this rapid increase was an equally swift reduction in the taxes collected on electricity sales. In order to slow this trend down, the Danish Parliament decided to change the rules of the net metering scheme in December 2012 to make it less attractive: the period for which solar PV production could offset billed electricity consumption was reduced. Originally, this had been a full year, i.e. annual electricity production could be deducted from the annual electricity bill. The revision reduced this period to one hour, i.e. solar PV generation in one hour can only be counted against electricity consumed during the same hour.

Unless household electricity consumption matches solar PV production perfectly well, this has the effect of making net metering much less attractive.

Besides the VE-Lov and the net metering scheme, a USD 3.7 million (DKK 25 million) annual fund to promote the dissemination of small RE plants (*ForskVE-programme*) is in place.

Transitional measure for PV plants

Between 20 November 2012 and 11 June 2013, PV plants received a variable FIP up to USD 217/MWh (DKK 1 450/MWh) for a period of 10 years. An amendment reduced the premium, but a transitional measure was introduced for the benefit of investors who had proceeded under the previous PV tariffs.

Investors had to demonstrate that they had entered an irrevocable agreement to purchase PV panels by 11 June 2013 and that they had requested planning permission or grid connection.

Wholesale market design

Denmark is a member of the Nord Pool market, and Energinet.dk is a shareholder in the power exchange Nord Pool spot (NPS). The Nord Pool market also includes Norway, Sweden, Finland, Estonia, Lithuania and Latvia.[18]

A common exchange market was launched in 1996 for Norway and Sweden; Denmark joined in 2000. NPS offers trading, clearing and settlement in day-ahead and intraday markets within the countries. In 2014 it had a total turnover of 501 TWh. NPS comprises two markets: Elspot for day-ahead trading, and Elbas for intraday trade (NPS, 2016).

Gate closure

Elspot is a day-ahead auction where power is traded for delivery during the next day. Operators can place their orders up to 12 days ahead. Gate closure for orders with next-day delivery is 12:00 CET, which means 12 to 36 hours before delivery. In the intraday market, Elbas, gate closure is one hour before the hour of delivery (NPS, 2016).

[18] Owners of Nord Pool, in addition to Energinet.dk, are Statnett SF (Norwegian transmission system operator [TSO]), Svenska Kraftnät (Swedish TSO), Fingrid Oyj (Finnish TSO), Elering (Estonian TSO), Litgrid (Lithuanian TSO) and Augstsprieguma tikls (Latvian TSO).

Grid representation

Once all market participants have submitted their orders on NPS, the market is cleared for all the different bidding areas. For Denmark, the bidding areas or zones are DK1, the Western Danish power system, and DK2, the Eastern Danish power system. Zones are designed to reflect typical constraints in the transmission system; in this way, regional market conditions are reflected in the final energy price. NPS market rules ensure that commercial exchanges of power always go from a lower price area to a higher price area (Rehme, 2013).

Bidding blocks

Trading on Elspot is done with an hourly resolution, based on three types of order: single hourly orders, block orders and flexible hourly orders. With a single hourly order, operators request a quantity of energy (purchased or sold) for each hour with a price-independent (must-run, must-consume) or a price-dependent order. With a block order, operators can bid for specified volumes and prices for a period of at least three hours. Operators can submit a block order where volumes are different for each period covered by the order. Operators can also opt for an “all-or-nothing” condition or express a minimum acceptance ratio (curtailable block orders). Curtailable block orders can be linked together forming families of block orders.

Flexible hourly orders permit operators to bid for the duration of one hour with a specified price limit and volume; this kind of bid permits energy-intensive consumers to sell back power via Elspot by load shifting in the hour in question.

Scarcity pricing

Elspot operates with a floor and ceiling to allowable electricity order prices. Since December 2014, the floor has been set at EUR -500/MWh and the ceiling at EUR 3 000/MWh. Previously, the floor was set at EUR -200/MWh and the ceiling at EUR 2 000/MWh. The ceiling limit was reached in June 2013 in the Eastern Danish power system due to thermal power plants undergoing maintenance, coinciding with low wind conditions and grid maintenance (NPS, 2016).

System services market

Ancillary services, which are provided by electricity producers and electricity consumers in Denmark and its neighbouring countries, are used for different purposes and procured by Energinet.dk through auctions. Reserves are procured in different ways in the two bidding areas, reflecting different operating protocols in the two synchronous systems (recall that Denmark is part of two different synchronous power systems) (Table 5.9). Energinet.dk buys ancillary services in Eastern Denmark in collaboration with Svenska Kraftnät.

Short-circuit power, reactive power and voltage control services are additional services required to ensure stable and safe power system operation. In case of shortage of these services, Energinet.dk can take measures to guarantee system security, such as forced operation of plants at different times (on a monthly, weekly or daily basis).

The displacement of thermal power stations during periods of high wind generation posed challenges for the Danish system operator in the procurement of ancillary services. Energinet.dk is therefore taking measures to ensure the delivery of these services through wind power plants, demand-side resources, and via interconnections (sharing primary and secondary reserves with neighbouring countries) (Energinet.dk, 2015e; Energinet.dk, 2012).

Table 5.9 • Description of system services market in Denmark

	Bidding area	Frequency	Activation notice	Gate closure	Minimum bid	Pricing
Primary reserves	DK1	Daily	15 seconds for the first half of the bid capacity, 30 seconds to complete	15:00 on the day before the day of operation	0.3 MW	All accepted bids receive the price of the highest accepted bid.
Secondary reserves	DK1	Monthly	15 minutes	Published by Energinet.dk typically on the last Wednesday of the month	-	The price is agreed individually by the bidder and Energinet.dk based on the bid submitted and subsequent negotiations. Supplies of energy from secondary upward regulation reserves are settled per MWh at the DK1 electricity spot price plus USD 15/MWh (DKK 100/MWh)
Frequency-controlled disturbance reserves	DK2	Daily	5 seconds for the first half, 30 seconds for complete	15:00 two days before the day of operation	0.3 MW	Bids are sorted according to price per MW. Pay-as-bid.
Frequency-controlled normal operation reserves	DK2	Daily	150 seconds	15:00 two days before the day of operation	0.3 MW	Bids are sorted according to price per MW. Pay-as-bid.
Manual reserves	DK1 and DK2	Daily	15 minutes	09:30 on the day before the day of operation	10 MW	All accepted bids receive the price of the highest accepted bid

Source: Energinet.dk (2012), *Ancillary Services to be Delivered in Denmark – Tender Conditions.*

Trade across interconnection

The NPS market covers the whole Nordic region, ensuring that a deep pool of flexibility is available. A suite of markets exists (day-ahead, intraday, and real-time operational reserves) enabling trade across interconnectors from year-ahead right up to the delivery hour. The interconnection capacity is offered as physical transmission rights.

The transmission capacity via the Danish-German border is administered in co-operation with the Joint Allocation Office (JAO). The available capacity is offered at two auctions: an annual auction and a monthly auction. The capacity is offered as physical transmission rights (Energinet.dk, 2016e).

Trading across interconnections is a main means of guaranteeing system stability in Denmark; roughly 80% of the variation in wind power during 2014 was compensated by commercially driven exchanges through interconnectors (ENS, 2015b).

New entrants and market power

About 1 300 companies are active in the Danish power market. The main power-producing companies operating in Denmark are Dong Energy and Vattenfall. Together they owned 56.7% of the total generation capacity in 2014 (European Commission, 2014).

System transformation

Incentives for system-friendly deployment of large-scale VRE

Timing of deployment

Denmark is already one of the countries with the highest share of VRE in the electricity mix, but the goal of the Danish government is independence from coal, oil and gas by 2050, meaning that in 2050 Denmark will produce enough renewable energy to cover Danish energy consumption.

An Energy Agreement was reached at parliamentary level in 2012. It includes concrete energy policy initiatives for the period 2012-20, including a plan with the objective of taking measures to double, to 50%, the share of the electricity from wind.

In March 2016, the government established an Energy Commission which will analyse new developments in the energy sector and make recommendations for Danish energy policy for 2020-30. The Energy Commission is expected to publish recommendations for Danish energy policy in early 2017.

Location and technology mix

Denmark's support schemes do not specifically refer to location for the deployment of renewables, e.g. directing projects to the best-suited areas, with two exceptions: offshore and nearshore[19] wind plants and distributed plants.

Offshore wind projects are selected by means of tendering. The Danish government opens tenders for offshore areas that are considered most suitable. Central authorities, led by the Danish Energy Agency, undertake a number of predevelopment tasks, including capacity specification, planning and environmental approval. In projects awarded through the tender procedure, the system operator Energinet.dk owns both the transformer station and the underwater cable that carries the electricity to land from the offshore wind farm. The same procedure has been set for a specific amount of nearshore wind capacity.

Distributed generation and self-consumption are incentivised by dedicated variable sliding premiums and net metering.

Technical capabilities

In the "Energienet.dk ancillary services strategy 2015-2017", Energinet.dk states that it will review and possibly change the market rules to remove barriers to new ancillary services suppliers (such as flexible electricity consumption and wind power plants), including future network codes. Mid-2017 is estimated for possible implementation (Energinet.dk, 2015e).

A wind or PV power plant with a capacity above 11 kW connected to the Danish grid must comply with the technical regulations, which provide rules on tolerance of frequency and voltage deviations, power quality, control and regulation, protection and data communications (Energinet.dk, 2015f; Energinet.dk, 2015g).

[19] Nearshore wind plants are offshore wind plants built closer to the coast. In the proposed auctions, nearshore plants will be installed from a minimum of 4 km from the coast.

Incentives for system-friendly design

The current FIP for wind power plants is designed to encourage the installation of wind turbines with a relatively larger rotor per installed capacity, which fosters system-friendly design.

The Danish net-metering scheme exempts the electricity produced by small RE installations and consumed on an hourly basis from paying the public service obligation. It is necessary for the plant to be connected to a collective grid, installed at the place of consumption and fully owned by the consumer. Net metering on an hourly basis incentivises the immediate consumption of the energy produced by domestic RE plants, which helps to avoid problems on the distribution grid.

Curtailment

In Denmark, renewable generators may only be curtailed after fossil resources have been curtailed to the maximum technical limit. If grid security is endangered, curtailment is permitted for onshore and offshore wind plants. This applies to turbines that can be controlled centrally. Most wind power generation is connected to the distribution grid in Denmark; this means that for Energinet.dk immediate wind production is not directly visible. Energinet.dk has therefore strengthened its Energy Management System, including multiple and advanced wind forecasts. Forecasts are used to prevent congestion, to plan the day-ahead market and to avoid wind curtailment. Moreover, all power plants greater than 10 MW must provide five-minute updates of power production (NREL, 2012).

In 2014, only 0.2% of possible wind generation was curtailed. Curtailment happened during events of low demand and high wind and co-generation, with limitation on the use of the transmission grids (ENS, 2015b). Since the new VE-Lov scheme guarantees a fixed amount of full-load hours for the wind power subsidy, curtailment is in any case a minor issue for wind energy producers.

Until 2007, curtailment (lost energy revenue) was not compensated, but Energinet.dk currently pays compensation for onshore wind plants. Energinet.dk only compensates offshore plants if the decision to curtail is taken as a result of an unexpected event. If notice is given day-ahead, no compensation is paid.

Offshore wind plants can be required to control their power output in a number of ways:

- A simple ceiling can be placed on the output.
- The plant reduces output to a fixed level for a certain period.
- The rate at which output increases is artificially smoothed.
- Output is reduced by a fixed amount for a fixed period (NREL, 2012).

Incentives for system-friendly deployment of distributed VRE

Retail price

From October 2015, the electricity retail market changed: electricity suppliers compensate distribution grid companies directly, and consequently the price for electricity covers both energy consumption and transmission costs. Regulated prices ceased for almost all consumers (European Commission, 2014).

Consumers have a wide diversity of electricity products to choose from, since suppliers offer more than 100 products. These can be fixed or variable tariffs. With variable tariff agreements, the price can vary daily or at a longer interval, depending on the agreement. Variable-tariff final prices depend on developments in the power market, and consumers do not know in advance the exact price of the consumed energy (CEER, 2015; Elpristavlen, 2016).

Grid fees

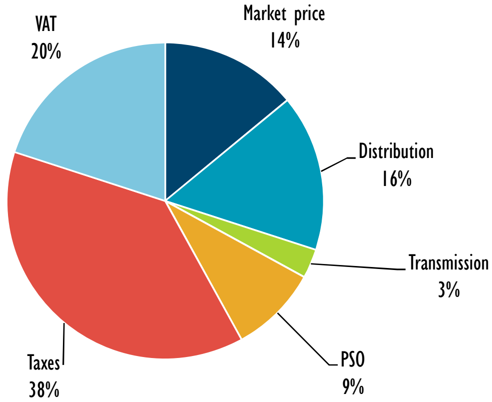
Grid and system tariffs comprise 12% of the average retail bill. The grid tariff covers costs relating transmission grid operations, while the system tariff covers costs relating to reserve capacity and system operation. In 2015, the grid tariff was USD 6.4/MWh (DKK 43/MWh). Customers with their own 132/150 kV transformers with settlement on the 132 kV side pay a reduced tariff of USD 6.2/MWh (DKK 41/MWh). In 2015, the system tariff was USD 5.9/MWh (DKK 39/MWh).

Gross consumption is the settlement basis for these tariffs. For prosumers, an adjusted settlement basis is applied taking into account that prosumers will not pay these tariffs for self-consumed electricity (Energinet.dk, 2015h).

Taxes and surcharges

Danish energy prices are among the most heavily taxed in the European Union. About two-thirds of the electricity bill is composed of taxes, the public service obligation (PSO) tariff and value-added tax (VAT) (Figure 5.30). Only 14% of the electric bill covers the bulk energy costs.

Figure 5.30 • Composition of the price of electricity, Denmark



Source: Jørgensen, P. (2015), *Energinet.dk and the Danish Energy System*

Key point • More than two-thirds of the electricity price in Denmark is formed of taxes and VAT.

The public service obligation tariff covers Energinet.dk's costs relating to its public service obligations as laid down in the Danish Electricity Supply Act; for example, to cover the costs relating to subsidies for renewable energy. The PSO tariff for the second quarter of 2015 was USD 32.1/MWh (DKK 214/MWh).

The settlement basis for the PSO tariff is gross consumption. With regard to net settlement of prosumers, a reduced PSO tariff is used for the part of their consumption that they cover by their own production. The reduction corresponds to the costs relating to subsidies for renewable energy and local co-generation units. The PSO tariff for the second quarter of 2015 for self-produced energy was USD 2/MWh (DKK 13/MWh). For customers with consumption of more than 100 gigawatt hours (GWh) per year per place of consumption, a reduced PSO tariff is used for the part of their consumption that exceeds that threshold. The reduction corresponds to the costs relating to subsidies and balancing costs for renewable energy. The PSO tariff for the second quarter of 2015 for electricity consumption of more than 100 GWh per year was USD 11/MWh (DKK 74/MWh) (Energinet.dk, 2015h).

Discussion

Denmark is a member of the NPS power market, which provides a largely unified market across the Nordic and Baltic countries. Denmark has a stable power system, with consolidated electricity demand. Annual electricity consumption peaked in 2008 and has subsequently dropped by 7% to 32.5 TWh in 2015 (excluding transmission losses).

In the 1980s, Denmark started a transition away from a system based on large central coal-fired power plants to a system based on smaller co-generation units and wind turbines. In 2015, wind generation met 42% of annual Danish electricity demand.

Denmark is a world leader in wind power deployment and system integration. The Danish power system routinely utilises advanced operational techniques, including dynamic use of abundant interconnection capacity with neighbouring countries as well as very flexible operation of thermal generation. Its thermal plants' minimum production levels were lowered in order to accommodate a larger share of wind generation, and options to further decrease must-run units without compromising system stability are being investigated. Trades across interconnections are used to maintain system stability. The western part of the Danish electricity system (DK1) operated without any participation from its central generation units for the first time in September 2015. Newly installed, advanced grid support technology (synchronised condensers) was used to maintain grid stability under these conditions.

Denmark has reached a stage of VRE integration where periods of abundant VRE generation – often exceeding domestic power demand – are becoming increasingly common. Consequently, measures to boost the system value of VRE are quite advanced in Denmark compared to other regions of the world. For example, Denmark has seen an uptake of electricity boilers in co-generation plants. These play an important role in making economically attractive use of abundant VRE generation.

More generally, measures to enhance electrification are being targeted for the medium term. Future electricity consumption is expected to rise by an additional 3.7 TWh from 2015 to 2024. This is due to the increased electrification of the Danish heating and transport sector through further uptake of electric boilers, heat pumps and electric vehicles. The current support scheme for wind power plants has been designed to promote the use of larger rotors, which can help to increase the system value of the electricity produced. For onshore wind plants commissioned from January 2014, a guaranteed fixed FIP is provided. The support is paid for up to 6 600 full-load hours, plus an additional 5.6 MWh per square metre of rotor area.

Table 5.10 • Key recommendations for Denmark

System-friendly VRE deployment
The current support scheme for wind power plants has been designed to promote the use of larger rotors which can provide system-friendly wind power production. Regular review of wind power plant eligibility parameters that could optimise energy production may be beneficial for the entire energy system.
Given the ever-decreasing costs of the PV technology, it may be helpful to investigate the potential benefits of portfolio synergies of wind and PV.
Investment
Further upgrades to interconnection capacity with Germany and the Netherlands are planned, which will help smooth wind power fluctuations via geographical aggregation and by linking diverse resources. Denmark is approaching a situation in which surpluses of VRE energy will be structural; power-to-heat and electric vehicle solutions may help to take advantage of these surpluses.
In the coming years, wind plant refurbishment will become a central aspect of investment in the Danish VRE sector. A dedicated analysis of the kind of new wind plant that could be beneficial for the power grid and the energy sector in general may be appropriate and help avoid pitfalls.
Operations
System operation and wholesale power market design in Denmark have been systematically adapted to deal with high levels of VRE. Operating practices for thermal power are among the most advanced globally. Demand-side resources can participate on an equal footing as supply resources in the intraday market.
Structural periods of very high wind penetration require the supply of system services in innovative ways; the ongoing ancillary services update will enable wind power plants to offer these system services. For the same reason, it may be useful to expand the interconnectors' dedicated capacity for short-term balancing.
Consumer engagement – distributed resources
Consumers may opt for variable tariffs that are linked to wholesale price levels, thus enhancing demand-side response.
Danish energy prices are among the most heavily taxed in the European Union. The effect is a reduction in the effectiveness of real-time price signals and a possible misalignment of economic incentives. A review of taxation may help reflect system value.
The Danish government aims to reach an agreement with distribution system operators to install smart meters when power consumers install heat pumps or recharging stations for electric cars. Once in place, such infrastructure should be used to unlock the contribution of remote demand-side management.
Planning and co-ordination
Systematic and long-term planning has been a cornerstone of the transformation of the Danish energy sector. Maintaining this approach will help Denmark achieve its policy objectives in an effective way.

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Indonesia

General information on VRE and grid integration

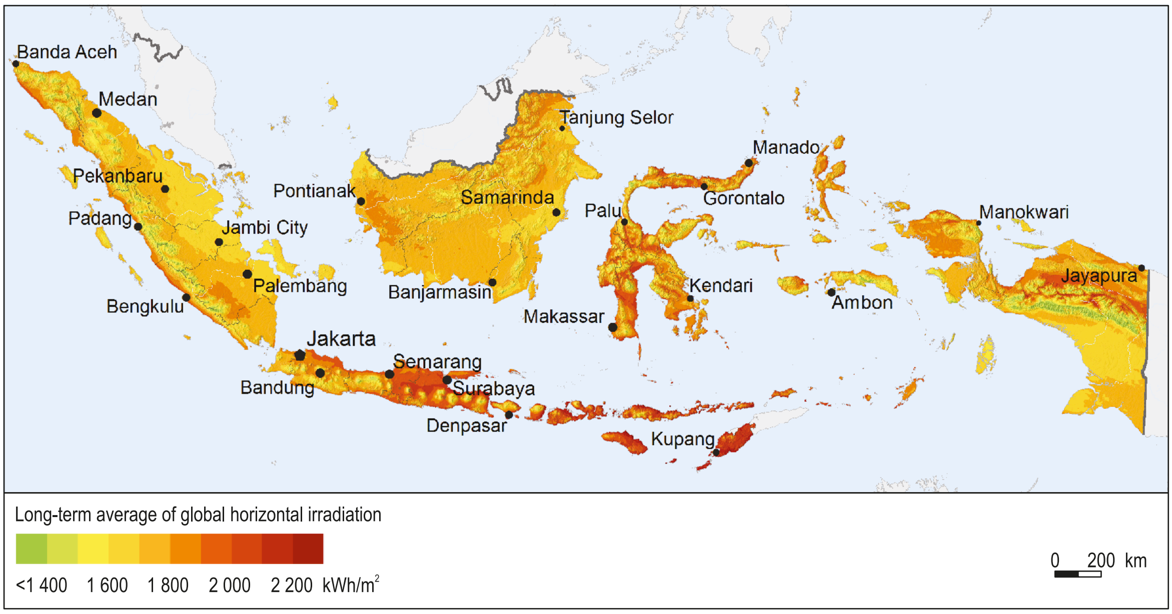
Flexibility assessment, ease of integration and current value

VRE resources

Indonesia has abundant conventional energy resources, including domestic coal, geothermal and hydropower. However, due to its archipelagic layout with approximately 17 000 islands, it is often faced with significant challenges in exploiting these resources to its full potential (IEA, 2015a). By contrast, variable renewable energy (VRE) resources, in particular solar energy, are distributed equally across the islands.

Annual averages of global horizontal radiation (GHI) lie between 1 600 kilowatt hours per square metre (kWh/m^2) and 2 200 kWh/m^2, corresponding to 4.3-6 kWh/m^2 per day. Highest radiation levels are found in Sumbawa, Flores and Timor, but also near load centres in Java (Figure 5.31). Since solar resources are well distributed across the entire country, solar photovoltaics (PV) can play a role in both strong and weak parts of the grid. In dry months, the country receives an average of eight hours of sunshine each day. In winter, this is reduced to four hours (NEA, 2013). The humid climate lends itself poorly to concentrated solar power (CSP), although more favourable conditions exist in Sumbawa, Flores and East Timor (IEA, 2010).

Figure 5.31 • Average annual GHI, Indonesia



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: Solargis (2016), "Solar resource maps", http://solargis.com/.

Key point • High GHI favours the deployment of solar PV.

Relatively good wind resources, with wind speeds of between 6 metres per second (m/s) and 8 m/s (at a height of 80 metres [m]) that can be used economically with newer turbine models, occur on selected spots that are spread across the islands, mostly located near the 54 700 kilometres (km) of coastline. Apart from these locations, however, average onshore wind speeds are relatively low and lie between 3 m/s and 5.5 m/s at a height of 80 m (IRENA, 2016).

Demand

Of the more than 17 000 minor islands in Indonesia, approximately 6 000 are inhabited. However, more than half of the population of 240 million inhabitants is located on Java, and similarly about one half are in the main cities and load centres. The Java-Bali region accounts for approximately 77% of total electricity consumption, followed by Sumatra with 14% (IEA, 2014a). According to domestic sources, the electrification rate stands at 88.3%, although a marked contrast exists between the urban areas of Java and Bali and the remaining parts of the country, where rural and island systems are far removed from centralised generation and transmission infrastructure. The lowest electrification rate can be found in Papua (35.9%). The government aims to reach full electrification by 2020 (IEA, 2015a).

Electricity consumption has been growing steadily over recent years and this trend will persist as the economy grows. Annual electricity sales were 199 terawatt hours (TWh) in 2014, a 48% increase compared to 2009 (PLN, 2015a). This equals a per-capita consumption of 787.6 kilowatt hours (kWh) per year, which ranks Indonesia 106th out of a total of 141 countries in international comparison (IEA, 2015a). The 2015 ten-year electricity expansion plan forecasts average annual growth of 8.7% until 2022 (PLN, 2015b). The residential sector is the largest consumer, accounting for 42.3% of total consumption, followed by industry (33.2%), the commercial sector (18.3%) and public services (6.2%). Of these, the commercial sector has experienced the strongest growth (PLN, 2015a).

Annual peak demand is usually reached in October or November at the beginning of the rainy season. Peak demand in the Java-Bali system reached 23.9 gigawatts (GW) in 2014, a 6% increase over the previous year (PLN, 2015a). Overall, demand in Indonesia is generally characterised by low seasonality. Daily demand patterns tend to peak in the early evening as residential demand picks up (IEA, 2014a).

Analysis of match between demand and VRE generation profile

Due to limited availability of information, no demand coverage factor analysis could be conducted.

Nonetheless, two factors can be discussed in light of the interaction between demand and VRE:

- The relatively low climatic seasonality of Indonesia favours VRE integration, as seasonal availability and demand will not vary extensively.
- The Indonesian demand profile exhibits a peak in the evening hours. Given the current demand curve, times of high PV power output generally coincide with non-peak load levels. This leads to higher swings in the net load, pushing up the system flexibility required for further PV deployment. The growing demand for electricity could provide an opportunity to change the load shape to a more favourable pattern by, for instance, introducing time-dependent electricity tariffs.

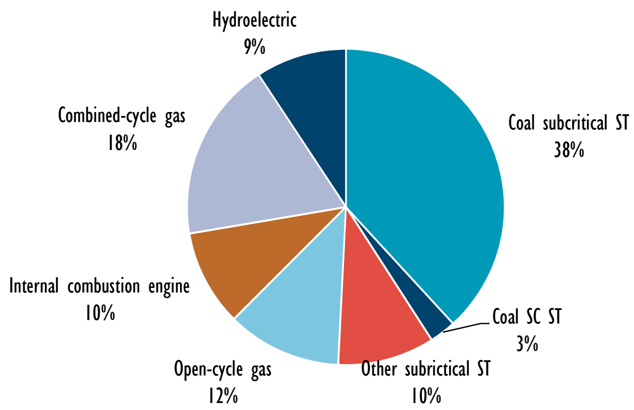
Generation

Overall generation reached 228.6 TWh in 2014, making Indonesia the largest producer in the Association of Southeast Asian Nations (ASEAN) region (IEA, 2015b; PLN, 2014). This figure includes 9.7% of electricity losses, with 2.4% lost during transmission and an additional 7.3% at distribution level. Generation capacity has grown significantly in recent years, from 29.5 GW in 2007 to 55.5 GW today. Independent power producers (IPPs) provide 42% of the installed capacity, with the rest supplied by the state-owned utility, PT Perusahaan Listrik Negara (PLN).

Over the last decade, power generation in Indonesia has shifted away from oil to the utilisation of domestic coal resources (Figure 5.32, Table 5.11) (IEA, 2015a). The majority of generation plants are small thermal plants, with less than 200 megawatts (MW) per unit.Small generation facilities can be attributed to the fragmented nature of the Indonesian electricity system.

Until now, wind and solar PV power deployment has been marginal, but other renewable generation potential is also largely untapped. Although domestic analysis (PLN, 2016a) indicates significant potential for biomass (32 GW), hydropower (75 GW) and geothermal (29 GW), the country has struggled to develop these resources further.

Figure 5.32 • Installed power generation capacity by technology, Indonesia, 2015



Notes: SC = supercritical; ST = steam turbine.

Sources: Adapted from Platts (2016), *World Electric Power Plants Database* and BNEF (2016c), "Indonesia country profile", www.bnef.com/core/country-profiles/idn.

Table 5.11• Installed power generation capacity by technology, Indonesia, 2015

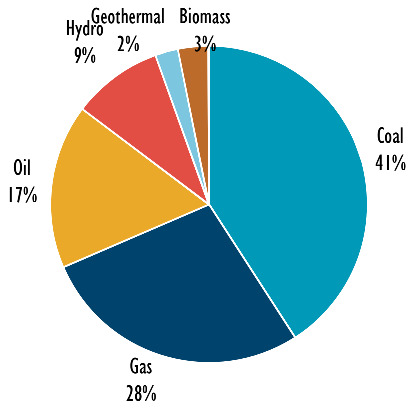
Technology	Installed capacity (MW)	% co-generation
Coal subcritical ST	21 953	7%
Coal SC ST	1 550	0%
Coal USC ST	0	-
Other subcritical ST	5 677	18%
Open-cycle gas	6 704	19%
Internal combustion engine	5 656	1%
Combined-cycle gas	10 602	0%
Hydroelectric	5 314	-
Nuclear	-	-
Wind turbine	-	-
Solar PV	-	-
Other	-	-

Note: USC = ultrasupercritical.

Sources: Adapted from Platts (2016), *World Electric Power Plants Database*, and BNEF (2016c), "Indonesia country profile", www.bnef.com/core/country-profiles/idn.

Key point • Thermal fuel options dominate the energy mix; hydropower capacity is also significant.

Figure 5.33 • Installed power generation capacity by fuel, Indonesia, 2015



Sources: Adapted from Platts (2016), *World Electric Power Plants Database*, and BNEF (2016c), "Indonesia country profile", www.bnef.com/core/country-profiles/idn.

Table 5.12 • Installed power generation capacity by fuel, Indonesia, 2015

Technology	Installed capacity (MW)
Coal	23 503
Gas	15 903
Oil	9 633
Hydro	5 314
Geothermal	1 335
Biomass	1 767
Solar	45
Wind	2

Sources: Adapted from Platts (2016), *World Electric Power Plants Database* and BNEF (2016c), "Indonesia country profile", www.bnef.com/core/country-profiles/idn.

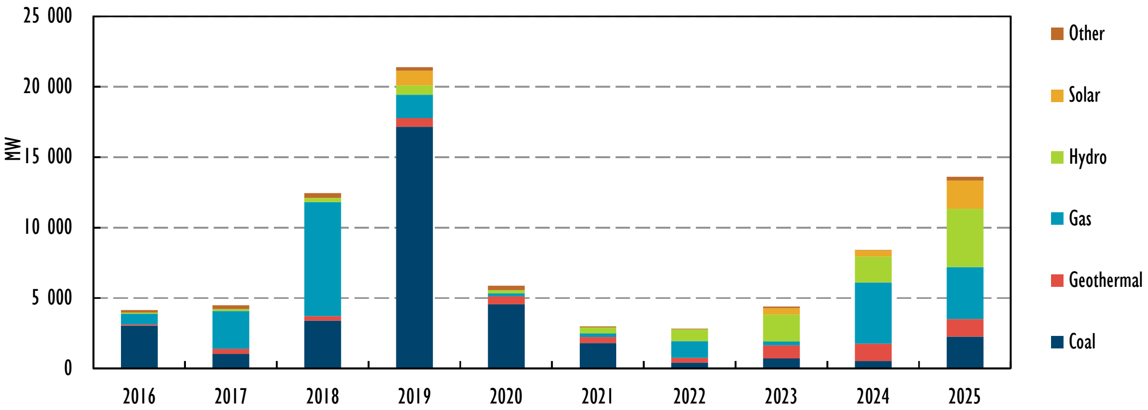
Key point • Thermal fuel options dominate the energy mix, although hydropower capacity is also significant.

To meet Indonesia's growing energy demand, the Power Supply Business Plan (RUPTL) sets out capacity additions of 80.5 GW up to 2025 (Figure 5.34) (PLN, 2016b). PLN and IPPs will develop 18.2 GW and 45.7 GW of this added capacity, respectively. The remaining 16.6 GW have yet to be allocated (PLN, 2016b).

Storage and DSM

Currently, Indonesia has no demand-side management (DSM) schemes in place, nor any pumped hydro storage installed. However, the Upper Cisokan pumped storage project is an ongoing project in West Java with a projected capacity of 1 040 MW (WB, 2015). The first generator is expected to be commissioned in 2019. A further facility is under consideration in Central Java, the Matenggeng pumped storage project, with a planned installed capacity of approximately 880 MW (WB, 2011, 2013).

Figure 5.34 • Generation capacity to be added by year, according to RUTPL 2016-24



Source: Adapted from PLN (2016b), *Rencana Usaha Penyediaan Tenaga Listrik (RUPTL 2016-2025)* [Electricity Supply Business Plan (RUPTL 2016-2025)].

Key point • The ten-year generation plan forecasts 80.5 GW of new capacity from 2016 to 2025.

Transmission and interconnection

The government-owned corporation PLN owns and operates Indonesia's entire transmission grid. This encompasses 49 325 km of transmission lines and 925 213 km of distribution lines. The Indonesian system consists of a wide range of heterogeneous subsystems, which comprise the electricity grids of its islands. With the exception of the Java-Bali system, these are not interconnected. With more than 21 000 km of transmission lines and 310 000 km of distribution lines, the bulk of the country's infrastructure is located in the Java-Bali system (Figure 5.35).

To date, no high-voltage interconnection lines exist between Indonesia and its neighbours. Only marginal amounts of electricity are being imported from Malaysia through two 20 kilovolt (kV) distribution lines in West Kalimantan (IEA, 2015a). Several transmission projects linking Indonesia to Malaysia are in progress in an effort to strengthen regional interconnection capacity and strengthen security of supply (IEA, 2015b).

(HVDC) transmission line between the Java-Bali system and Sumatra is due for commissioning in 2018 and will allow for 3 000 MW of interconnection. Once completed, the line will bring together more than 90% of energy consumed in the country.

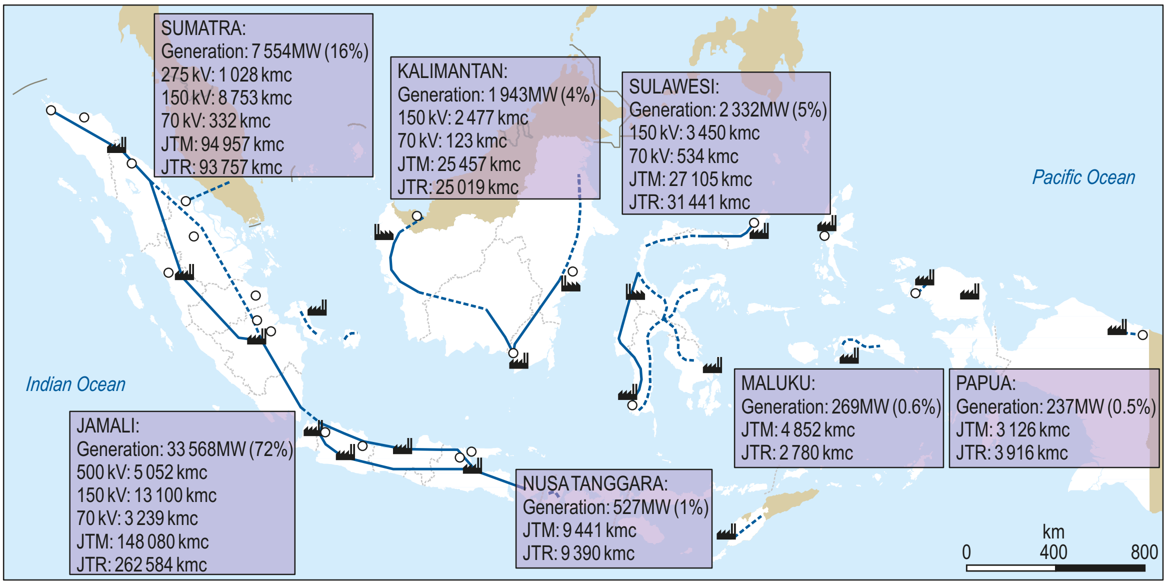
Additional projects aim to connect the transmission grid to new generation capacity and rural areas. A 500 kV transmission line in Sumatra will serve as a transmission backbone for the island, ultimately feeding into the converter station for the HVDC transmission line between Sumatra and Java. The currently separated subsystems in Kalimantan and Sulawesi (Central, West, Southeast and South) will be connected in the near future. Lombok is currently extending its transmission system to form a loop around the entire island, connecting the previously isolated northern region.

Overall, the government aims to build 46 000 km of additional transmission lines by 2025 (Figure 5.36) (IEA, 2015a; PLN, 2016a). There are plans to interconnect neighbouring island systems. A 500 kV high-voltage direct current

Summary

Due to its archipelagic layout, the electricity network in Indonesia consists of many separated heterogeneous subsystems. Rural areas particularly suffer from low electrification. Additionally, the Indonesian power system is in need of new generation capacity, as it struggles to meet growing power demand. An increase in VRE production could alleviate current shortages and provide power solutions for remote island systems. The potential is great, given the country's reasonably good wind sites and abundant solar resources. Importantly, as Indonesia is starting to introduce VRE, the technical and economic challenges related to reaching a small share of VRE generation will be very modest and will not require a significant overhaul of the power system.

Figure 5.35 • Indonesian major power plants and transmission lines



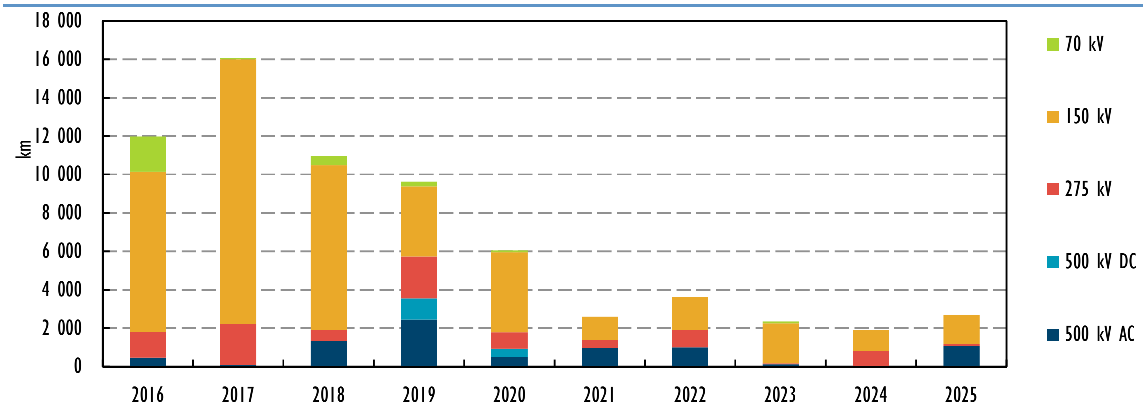
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Notes: kmc = kilometre of circuit; JTM = medium-voltage network; JTR = low-voltage network; generation figures are total installed power plant capacity as of October 2014.

Source: Reprinted from IEA (2015a), *Energy Policies Beyond IEA Countries: Indonesia 2015*.

Key point • Indonesia's transmission system is concentrated on the islands of Java and Sumatra, whereas the many islands function as small isolated systems.

Figure 5.36 • Planned deployment of transmission lines, Indonesia



Notes: AC = alternating current; DC = direct current.

Source: Adapted from PLN (2016b), *Rencana Usaha Penyediaan Tenaga Listrik (RUPTL 2016-2025)* [Electricity Supply Business Plan 2016-2025].

Key point • Indonesia is planning significant transmission grid expansion in the immediate future.

Market and policy frameworks

The Indonesian power system used to be completely vertically integrated. PLN, the Indonesian government-owned public electricity utility, covered generation network ownership and operation as well as supply.

In 2002, power sector reform legislation was passed with a view to full liberalisation of the sector. However, the Indonesian Constitutional Court revoked the law in 2004. Currently only the generation sector is partially liberalised, open to IPPs and private-public utilities (PPUs). System operations, transmission, distribution and sales of energy are monopolised by PLN, although some IPP activity is allowed outside of the PLN concession areas.

Policy analysis

In 2007, the government established a specific legal basis for national energy management, with the adoption of Energy Law No. 30/2007. The law defines general principles for the management of energy resources and recognises energy security as a critical national issue, setting out to reduce dependence on imported refined oil while shifting towards renewable energy (RE), natural gas, biofuels and geothermal resources (IEA/IRENA, 2016).

Indonesia sets targets for electricity development in the National Energy Policy (NEP). The NEP provides high-level guidelines for a national electricity master plan called the RUKN, which provides twenty-year supply and demand forecasts.

The NEP of 2014 (NEP14) (Government Regulation No. 79/2014) introduced a number of important changes to energy policy planning. It focuses on strengthening Indonesia's energy independence by redirecting energy resources from export to the domestic market, and on exploiting domestic energy supplies. An important aspect is the guideline to gradually reduce subsidies on oil and electricity in harmony with the development of New Energy[20] and Renewable Energy (together termed NRE) (IEA/IRENA, 2016; DEN, 2014). NEP14 calls for 115 GW of installed generation capacity by 2050, with NRE providing 23% of electricity by 2025 and 31% by 2050. IPPs are expected to deliver 70% of the new power supply.

IPPs can request a licence to provide electricity for public use. With a few exceptions, IPPs can only build and operate transmission and generation assets outside the PLN concession areas. For selling electricity, IPPs can choose: 1) to conclude a power purchase agreement (PPA) with PLN directly; 2) to sell the energy to a regional government through a PPA or a public-private partnership (PPP); or 3), if the IPP owns the grid, to sell directly to end customers. In each case, tariffs are regulated by the government (IEA, 2015a). PLN holds a right of first priority to supply electricity (IEA, 2015a). PLN is obliged to pay IPPs the centrally determined energy tariffs. This has proven difficult in practice, however, as the utility has been reluctant to sign PPAs at tariffs that exceed the marginal cost of its internal generation fleet. The build-out of new renewable capacity has suffered as a consequence.

Official policies and regulations reserve an important place for IPPs in meeting the country's growing energy demand. The Fast Track Programme was announced in 2006 with the aim of accelerating investment in new generation capacity. In 2009, phase 2 of the programme was announced, which included significant expansions of hydropower and geothermal capacity and expected more than two-thirds of this incremental capacity to originate from IPP development (IEA, 2015a).

[20] "New Energy" includes, among others, nuclear, hydrogen, coalbed methane, liquefied coal and gasified coal.

Feed-in tariffs have been put in place for biomass, geothermal, waste-to-energy and small hydropower projects. These tariffs were converted into dollars in 2015 to meet private-sector concerns about currency fluctuations (BNEF, 2016c). The following fiscal incentives apply to RE projects:

- An income tax reduction is available, up to 30% of investment costs, spread over six years.
- For "non-building" fixed assets, accelerated depreciation is applicable.
- RE machinery is exempt from value-added tax (VAT) and import duties.

Wind energy

To date, two wind projects have executed PPA contracts. Viron Energy first signed a PPA with PLN for a 30 MW wind project in West Java in 2011. PLN will purchase the power at USD 90/MWh (approximately IDR 1 200 000/MWh). Another IPP consortium concluded a PPA in August 2015 for a 70 MW wind project in South Sulawesi. Plant commissioning is expected by mid-2017 (BNEF, 2016a).

Solar PV

PLN has launched a "Thousand Islands Program", a long-term plan with the objective of expanding the installed solar PV capacity on small and remote islands to 620 MW by 2020. Solar plays an important role in the electrification of these areas. Initial attempts to implement this programme faced challenging financial and technical difficulties (ADB, 2015). Capacity building among local governments and involving local communities in the operation and maintenance of solar projects is expected to foster the deployment of solar power in remote areas.

In June 2013, MEMR introduced a solar auction programme. A maximum price benchmark of USD 250/MWh (set in USD, but the payments are in IDR based on actual exchange rate prevailing at the time of payment) was set and raised to USD 300/MWh for projects reaching a minimum of 40% local content. PLN would be the counterparty to a 20-year PPA. However, the auction reaped only a few eligible projects and a year after its introduction, the Supreme Court ruled that the programme was unconstitutional due to the use of foreign equipment and the programme was subsequently cancelled (BNEF, 2016b).

The winning bids varied between USD 250/MWh for a 5 MW plant in Timor and USD 183.6/MWh for a 3 MW plant in West Nusa Tenggara. With only a fraction of capacity allocated, however, the tender failed to trigger private investment. Prospective bidders had only limited time (two weeks) to prepare their bid, and had insufficient visibility of the grid conditions to perform a preliminary grid connection study that was required as part of the tender rules (Kruse, 2014). In addition, IPPs were obliged to develop sites in preselected areas that proved incompatible with competitive project development.

The MEMR launched an FIT for solar PV in July 2016. The FIT is awarded for a period of 20 years and is paid in United States Dollars. Overall the policy aims to develop 250 MW of solar PV across 22 regions. The regions are defined in line with PLN's operational regions. Each region has its own capacity quota and tariff level. The largest quota of 150 MW is in Java and the smallest is 2.5 MW in Papua and West Papua. The FIT levels range between USD 145/MWh (in Java) and USD 250/MWh (in Papua and West Papua).

Compliance with a local content target of 43.8% of the goods and services procured for a project is required to obtain the full FIT. If a project does not to meet the local content requirements, the FIT is reduced according to the shortfall. For example, if a project in Java meets only 50% of the local content requirements (meaning that 21.9% of the goods and services are procured locally), its FIT is halved to USD 72.5/MWh (BNEF, 2016d).

Achieving the country's ambitious energy policy goals will require important obstacles to IPP development to be removed. Delays in obtaining all necessary permits and authorisations have slowed down wind and solar power project development in recent years. Improved co-ordination between the various government bodies can reduce the complexity and duration of this part of the development process, and could accelerate Indonesia's move towards reaching the first few percentage points of VRE generation.

System operations

The Indonesian transmission network consists of eight[21] domestic interconnected systems and 600 isolated grids, which are all operated by PLN. With the notable exception of the Java-Bali system, islands are not interconnected with each other; this has led to the constitution of local branches of PLN, local grid codes and regulations. The focus of this section will be on the Java-Bali system, which represents 77% of total energy consumption, and on Ministerial Decree Mandate No. 3/2007 of 29 January 2007, which defines a set of rules and procedures (grid codes) to underpin the safe operation of this power system.

Scheduling of power plants

The scheduling and dispatch code (SDC) section of the grid code sets the procedures for the Java-Bali Dispatch Centre. It establishes the least-cost energy mix to meet forecast load, and dispatches power plants accordingly.

Power plant scheduling is initially performed on a monthly basis, and then updated weekly to account for maintenance and outages. The final schedule is set in the day-ahead market. All generators must provide PLN with their weekly plant availability at the weekly planning stage, and confirm this information by 10:00 on the day before dispatch. In particular, hydropower plant operators have to provide information about reservoir levels and, in case of run-of-the-river hydropower plants, provide a forecast for every hour of the following day. Local PLNs produce a forecast of demand for every half hour of the following day and a daily implementation plan in a way that minimises total variable costs. After stability verification, all network users are informed of the final scheduling before 15:00. The final scheduling contains the expected active power generation for each power plant for every half hour (MEMR, 2007).

Introducing VRE is a relatively new phenomenon for system operations in Indonesia. A number of actions can be contemplated to foster the effective integration of these resources as their market penetration grows over time. Accurate forecasting of system-level VRE output is a vital first step. PLN must possess the necessary tools to make effective use of this information, and update power plant output schedules as close to real time as possible and using short dispatch intervals. Over time, a dynamic calculation of balancing reserve needs supports the cost-effective use of all flexibility options in maintaining grid stability.[22]

Transmission and interconnection operations

PLN owns and operates nearly all transmission assets in the country. IPPs can own and operate transmission assets that fall outside PLN's concession areas. The utility is responsible for achieving the country's electrification goals. Given these limitations, IPP ownership of transmission assets is mostly concentrated in remote areas.

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[21] 1) Java-Bali system, 2) Sumatra system, 3) West Kalimantan system, 4) Southern and Central Kalimantan system, 5) Eastern Kalimantan system, 6) Northern Sulawesi system, 7) Southern Sulawesi system, and 8) West Nusa Tenggara system.

[22] For a detailed discussion of operational measures for VRE integration, refer to Chapter 6 of *The Power of Transformation* (IEA, 2014b).

There are currently no high-voltage interconnections to neighbouring countries. Government Regulation 42/2012 on Cross-Border Power Sale and Purchase states that the selling of electricity is possible only in cases where the electricity needs of the area are already satisfied. Similarly, purchasing power is only allowed if the local generation fleet cannot meet demand. The electricity sold is not subsidised. Private bodies can operate cross-border sales and purchases through a permit issued by the MEMR (IEA, 2014a; IEA, 2015a). Current cross-border laws consider the sale and purchase of electricity to be a supplementary measure for acquiring power supply through licensed private bodies; the co-operation of balancing areas or the sharing of operating reserves is still not considered.

Definition and deployment of operating reserves

Ministerial Decree Mandate No. 3/2007 of 29 January 2007 defines operating reserves in the Java-Bali system. The following categories are identified:

- Spinning reserve: generation capacity available and unencumbered, that can be synchronised to the system within ten minutes and interruptible load that can be removed within ten minutes, depending on the option chosen by the local PLN.
- Cold backup: generation capacity that can be synchronised to the system within four hours.
- Long-term reserve: generation capacity that can be synchronised to the system in less than two days.

The theoretical reserve margin is defined in the same law as follows:

- Spinning reserve: the capacity of the largest generating unit in the system (for the Java-Bali system, 815 MW).
- Cold backup plus spinning reserve: twice the capacity of the largest generating unit in the system (for the Java-Bali system, 1 630 MW).
- Long-term reserve plus cold backup and spinning reserve: twice the capacity of the largest generating unit in the system plus a margin of reliability, calculated as a percentage of daily peak loads, based on an analysis of loss-of-load probability.

The installed capacity in Java-Bali expanded from 31 GW in 2012 to 33 GW in 2014. However, due to a simultaneous growth in peak load from 21 GW to 23 GW, operating reserves reduced from 2.1 GW to 1.3 GW over the same period (Table 5.13) (IEA, 2014b). This is below the level of reserves prescribed by the grid code. The growth in electricity consumption has not been coupled with the construction of new power plants, and rolling black-outs have become a recurring problem, reducing consumption by 10% in 2013.

A similar situation is also present in other Indonesian power systems. Except for the North Sulawesi system, the Indonesian power systems suffer from a general lack of available generation capacity.

System transformation

System-friendly deployment of large-scale VRE

Timing of deployment

With growing energy demand, any new generation capacity is a useful addition to the national energy landscape. A significant acceleration of RE projects will be needed to meet the government objective of reaching 23% carbon-free electricity generation, as promulgated by the NEP14. Although the 35 GW capacity expansion plan has a five-year window, there is no specific timeline for VRE capacity additions. The recent experience of the undersubscribed tenders raises questions about the ability to procure sufficient investment to meet the policy objectives.

Table 5.13 • Installed capacity in regional systems, Indonesia

	Operational reserve (MW)	Peak load (MW)	Largest rated unit (MW)	Reserve/peak ratio	Reserve/ largest unit ratio
Java-Bali	1 307	23 880	815	5%	160%
Sumatra	-159	4 659	189	-3%	-84%
West Kalimantan	36	249	30	14%	120%
South Central Kalimantan	11	496	57	2%	19%
East Kalimantan	30	371	75	8%	40%
North Sulawesi	56	305	19	18%	295%
South Sulawesi	85	862	125	10%	68%
West Nusa Tenggara	8	180	25	4%	32%

Location and technology mix

PLN's "Electricity Supply Business Plan 2013-2022" contains guidelines for PLN for the development of grid and generation capacity in the medium term. The document states that PLN will develop solar plants in 1 000 locations, especially in isolated areas to improve electrification ratios. This is driven by the objective to give access to electricity more rapidly to people in remote areas. The location of the plants will be selected after considering the techno-economic factors, such as the cost of transporting fuel to the site and the ability to operate solar PV together with diesel generators.

Technical capabilities

In July 2014, PLN issued "Guidelines for Connecting Renewable Energy Generation Plants to PLN's Distribution System", applicable to all new RE generation plants up to 10 MW to be connected to PLN's distribution system at 20 kV or less. The purpose of the guidelines is to provide clear procedures for RE power plant operators to prepare connection applications and for PLN to review and approve the same applications (PLN, 2014).

Curtailment

PPAs signed with PLN can have "take-or-pay" clauses, which oblige PLN to compensate curtailed energy (Norton Rose, 2013).

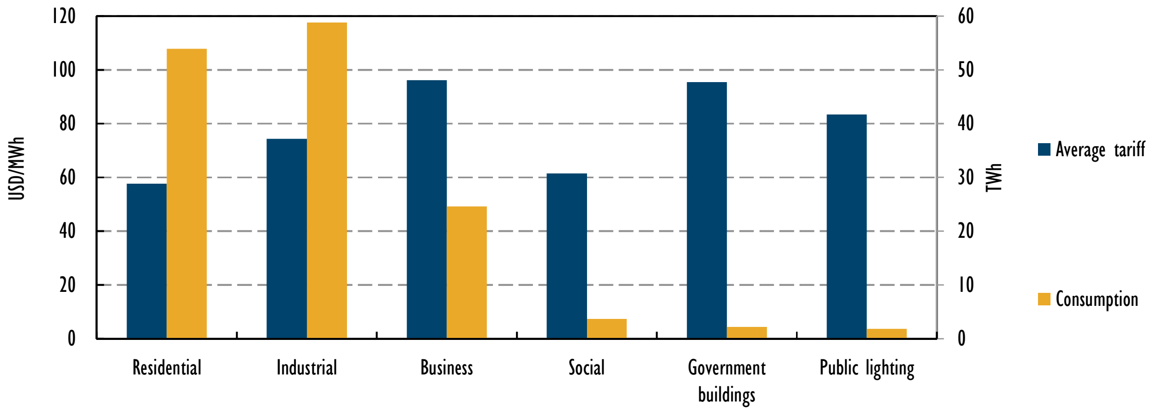
Incentives for system-friendly deployment of distributed VRE

Locational price

As stipulated by Electricity Law No. 30, the government of Indonesia sets electricity prices. Tariffs are set for six consumer types and differentiated by location (Figure 5.37).

Indonesia subsidises electricity consumption, subsidies that the country is reducing over time. In 2013 electricity tariffs where raised by 15%, due to electricity production costs that were USD 0.096/kWh (IDR 1 272/kWh), markedly higher than the average market price of USD 0.05/kWh (IDR 745/kWh) in 2012 (IEA, 2014a). In 2014, the average tariff came to USD 0.07/kWh (946 IDR/kWh) (PLN, 2015a).

Figure 5.37 • Average tariffs and total consumption of electricity per sector, Indonesia, 2014



Source: adapted from PLN (2015a), *PLN Statistics 2014*

Key point • Indonesia applies a sectoral differentiation of electricity tariffs.

Prices for the residential sector vary from USD 0.07/kWh (IDR 940/kWh) in Riau Island (small isolated island) to USD 0.032/kWh (IDR 420/kWh) in Southern Kalimantan (PLN, 2015a).

Time-dependent price

The tariffs do not consider the differences in load demand between the peak and off-peak periods. Moreover, in 2005 PLN introduced a flat-rate prepaid option, quite popular in the residential and business sectors; in 2011, 5 million consumers had chosen that option (Damuri, 2014).

Taxes and surcharges

Additional charges include taxes for street lighting (2-2.5% of the electricity bill). A minority of residential customers is liable to pay VAT (Damuri, 2014).

Discussion

A combination of favourable resource availability, rising demand for power and decarbonisation objectives provides a strong case for VRE in Indonesia. As technology costs continue to decline, wind and solar PV can assist the government in reaching its various social and economic objectives and provide affordable, clean energy to its urban and rural population alike. Recent indications that the government may contemplate a cut in spending on the energy sector may jeopardise the transformation towards a more sustainable energy future that the country has embarked upon in recent years.

IPPs will be prime actors in the coming years. So far, however, IPP activity has been slow to get off the ground due to a number of technical and legal barriers. For instance, PLN cannot sign PPA contracts with IPPs for energy tariffs that exceed the marginal cost of its own generation fleet (BNEF, 2016c). Under such a constraint, development of VRE projects may be unduly constrained – the full, long-run cost of alternative investments would provide a more appropriate reference. At the same time, proposed PPA tariffs do not allow for cost recovery of clean energy projects in more remote areas. The cost-effective deployment of clean energy projects as a vehicle for ongoing electrification efforts, such as the Indonesia Terang (Bright Indonesia) project, may suffer as a consequence. In addition, delays in obtaining permits and authorisations have become an important hurdle for project developers.

Although RE is likely to account for a prominent share of capacity additions in the coming years, some uncertainty remains concerning the practical rollout of RE projects. Recent experience of the solar auction programme serves as a reminder that defining timely and realistic deliverables is vital to the successful execution of any procurement programme. Public authorities have the delicate task of balancing the advantages of competitive bidding behaviour with a mandate to boost generation capacity in certain regions. IPPs should be exposed to the risks they are best placed to mitigate, yet enjoy a degree of independence in determining the technical and economic characteristics of their project.

Reaching the first few percentage points of VRE generation will not depend on any immediate practical measure, as the technical implications will be limited. Nonetheless, PLN, as system operator, may wish to start implementing a number of operational modifications to accommodate rising VRE shares over time. These pertain mostly to the scheduling and dispatch of power plants. These potential measures support safe and reliable grid operation regardless of the pace of VRE integration.

The region-specific determination of electricity tariffs for IPP development constitutes a useful tool in directing IPP project development, and should be further refined. An in-depth analysis of necessary tariff rates for wind and solar PV deployment across the different islands would provide useful information on the pricing signals needed to unlock investment in low-carbon technologies across the country.

In order to realise the country’s ambitions, a more structured review process should be introduced to help recognise and resolve policy and market design barriers. Creating a step-by-step implementation plan for announced ambitions would make it easier to monitor progress on long-term targets and take effective measures to ensure the capacity additions occur in a timely and cost-effective manner. In this context, enhanced co-operation between the relevant bodies of government, such as the MEMR and the utility, may serve to eliminate a number of key hurdles that limit IPP activity.

Table 5.14 • **Key recommendations for Indonesia**

System-friendly VRE deployment
Indonesia has ambitious electrification objectives; short project lead times, modularity and resource availability throughout the country make solar PV an ideal candidate to meet these objectives. A comprehensive approach to deploying solar PV, combined with energy-efficient appliances, is a real opportunity to meet electrification objectives at least cost. Government plans currently focus the use of VRE on locations outside the Java-Bali system. Undertaking a systematic analysis of the opportunities for VRE in the main power system of Indonesia could unlock a significantly larger deployment potential.
Investment
The policy and regulatory framework in Indonesia does not allow for either PLN or IPPs to effectively deploy VRE at a scale and pace that is required to meet policy objectives. Establishing a clear and functional framework for VRE investment is a critical first step towards integrating VRE into the Indonesian power system. Indonesia is experiencing a rapid increase in electricity consumption. Tackling this issue from the demand side via both efficiency and demand-side response will help to reduce the pressure on adding generation capacity and can make the system more flexible.
Operations
After several iterations, PLN publishes the final production schedule for all generators on a day-ahead basis. Determining dispatch schedules closer to real time may allow for the use of more precise forecasting information, a precondition for reliable and efficient system operation at growing shares of VRE. The existing coal fleet may have to operate in a more flexible manner once VRE deployment picks up. Systematically assessing current flexibility levels and ways to increase them will allow better understanding of how much VRE capacity can be added to the system cost effectively.
Consumer engagement
The gradual reduction of subsidies on electricity consumption is improving the business case for distributed solar PV. With deployment of these resources likely to take off in the coming years, the development of dedicated grid codes for low- and medium-voltage connections is needed to preserve local grid stability.
Planning and co-ordination
A number of different ministries have a stake in PLN, including the Ministry of Finance, MEMR and the Ministry of State-Owned Enterprises. Ensuring that government inputs are consistent will facilitate the delivery of a clean and reliable power system at least cost. PLN establishes long-term plans for the expansion of the power system. For these planning processes to be effective, it is critical that PLN has the ability to use advanced planning tools that appropriately reflect the costs and benefits of VRE, so as to understand long-run system costs.

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Mexico

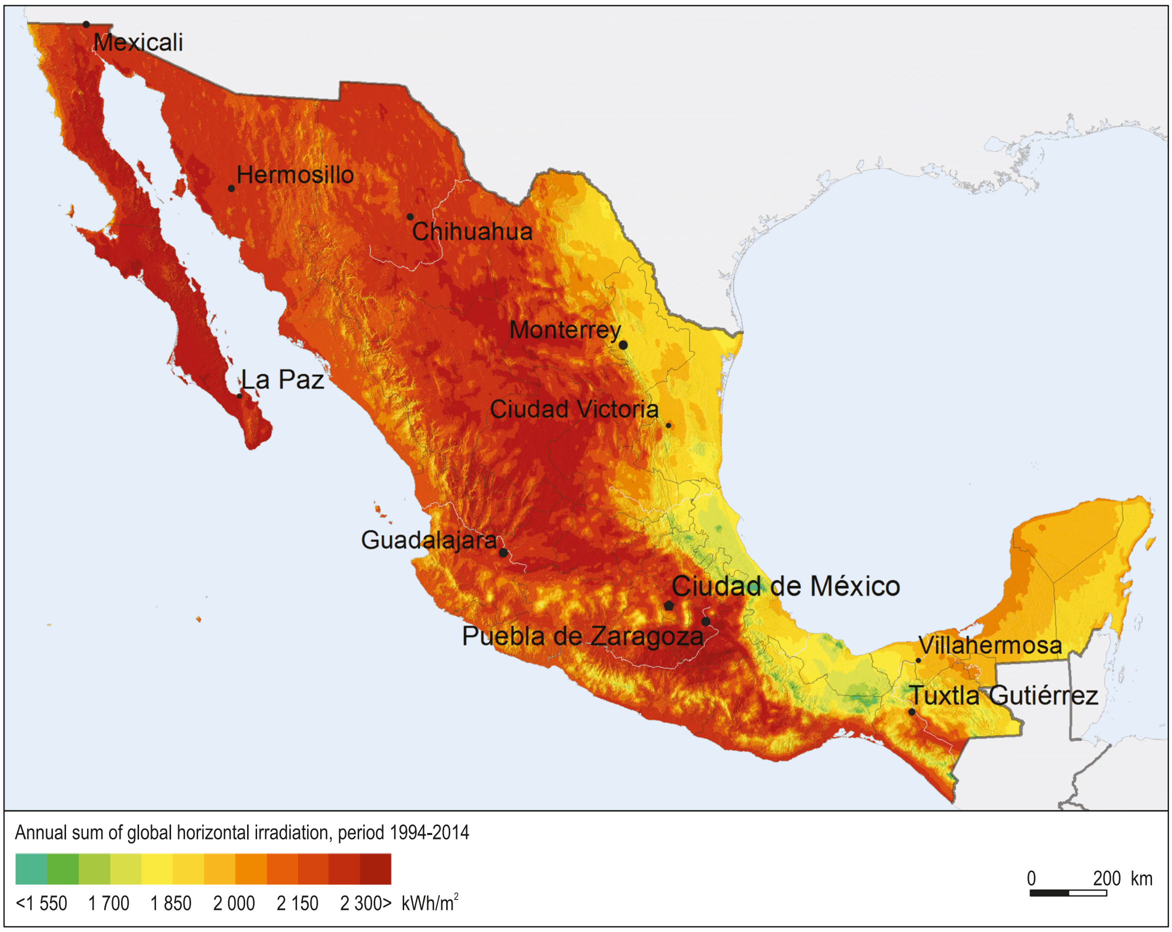
General information on VRE and grid integration

Ease of integration and current value

VRE resources

Mexico has access to favourable solar resources, with average annual global horizontal irradiation (GHI) exceeding 2 000 kilowatt hours per square kilometre (kWh/m^2) across the majority of the country's surface. Radiation levels at the lower end, found along the eastern edge of the country, are still very favourable at above 1 850 kWh/m^2. The most promising resources are found in Baja California and running from north to south across Central Mexico (Figure 5.38). Major load centres that geographically coincide with excellent solar resources include Mexico City and Guadalajara. Due to a combination of clear skies, low humidity and sunshine, Mexico also has the potential for concentrated solar power (CSP) development (IEA, 2010).

Figure 5.38 • Average annual GHI, Mexico



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: Solargis (2016), "Solar resource maps", http://solargis.com/.

Key point • Mexico has favourable solar irradiation levels.

Mexico boasts several areas with high wind potential, with annual mean wind speeds reaching up to 12 metres per second (m/s) (at 100 metres [m] height). These can be found at the Isthmus of

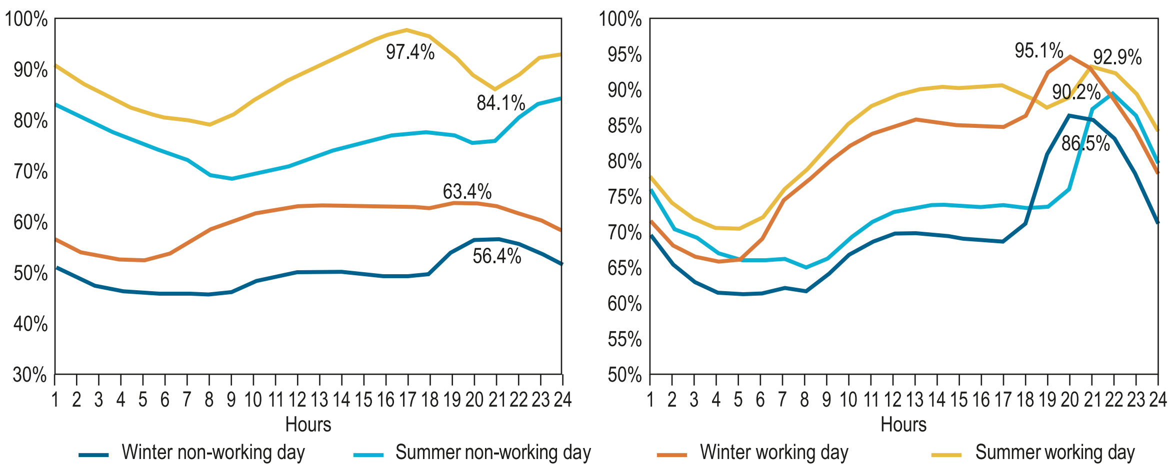
Tehuantepec, the northern part of Baja California, the coastal areas of the Gulf of Mexico and the Yucatan Peninsula, plus certain areas in North-Central Mexico around Chihuahua and San Luis Potosi. Various areas along the central north-south backbone exhibit medium-quality resources, with annual mean wind speeds of up to 7 m/s at a height of 100 m (IRENA, 2016).

In short, favourable conditions for wind and solar exist throughout the country and in proximity to major load centres.

Demand

The highest recorded peak in power demand for the interconnected system occurred on 14 August 2015 at 39.8 gigawatts (GW), 2.2% above the previous year's peak. This figure does not include Baja California and Baja California Sur, which function as isolated systems. For the period between 2016 and 2030, the newly established independent system and market operator, CENACE (Centro Nacional de Control de Energía), predicts average annual peak demand growth of 3.7%, bringing it to 69.8 GW in 2030 (IEA, 2016). Daily consumption patterns differ slightly across various regions (Figure 5.39).

Figure 5.39 • Typical load curves for 2014 with regard to annual peak demand, Northern Mexico (left) and Southern Mexico (right)



Notes: Northern Mexico = Baja California, Baja California Sur, Sinaloa, Sonora, Coahuila, Chihuahua, Durango, Nuevo León, Tamaulipas; Southern Mexico = Distrito Federal, Hidalgo, Estado de México, Morelos, Puebla, Tlaxcala, Campeche, Chiapas, Guerrero, Oaxaca, Quintana Roo, Tabasco, Veracruz, Yucatán.

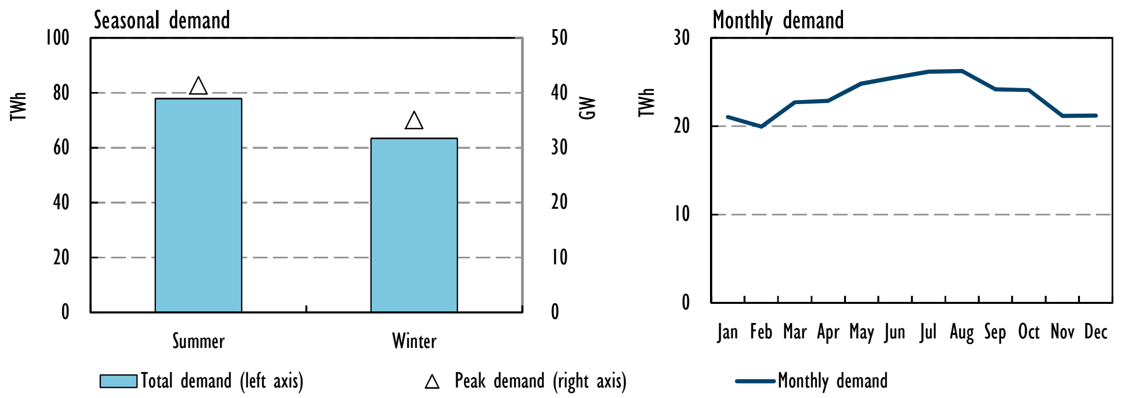
Source: SENER (2015a), *Prospectiva del Sector Elétrico 2015-2029* [Electricity Sector Perspectives 2015-2029].

Key point • Southern Mexico exhibits a strong ramp-up of demand in the evening.

Electricity consumption is strongly correlated to the overall state of Mexican industry. The industrial sector represents the largest share of overall consumption (58% in 2015), followed by the residential sector (25.9%), commercial (6.7%), services (4.3%) and the agricultural sector (5%). Electricity consumption increased by an average of 2.9% per year from 2004 until 2015 when gross consumption reached 288 TWh. This growth is predicted to persist at a rate of 3.4% per year, reaching 476 TWh in 2030 (SENER, 2016a).

The main load centres can be found in Central Mexico, around Mexico City and Guadalajara (Figure 5.40). The northern regions are less electricity intensive, with the exception of the Sinaloa coast and the cities of Torreón, Chihuahua and Monterrey. Electricity demand has a clear seasonal pattern (Figure 3). Demand peaks in the summer months (June-August) as the use of air conditioners spikes. Lowest rates of consumption are typically observed in December (IEA, 2016).

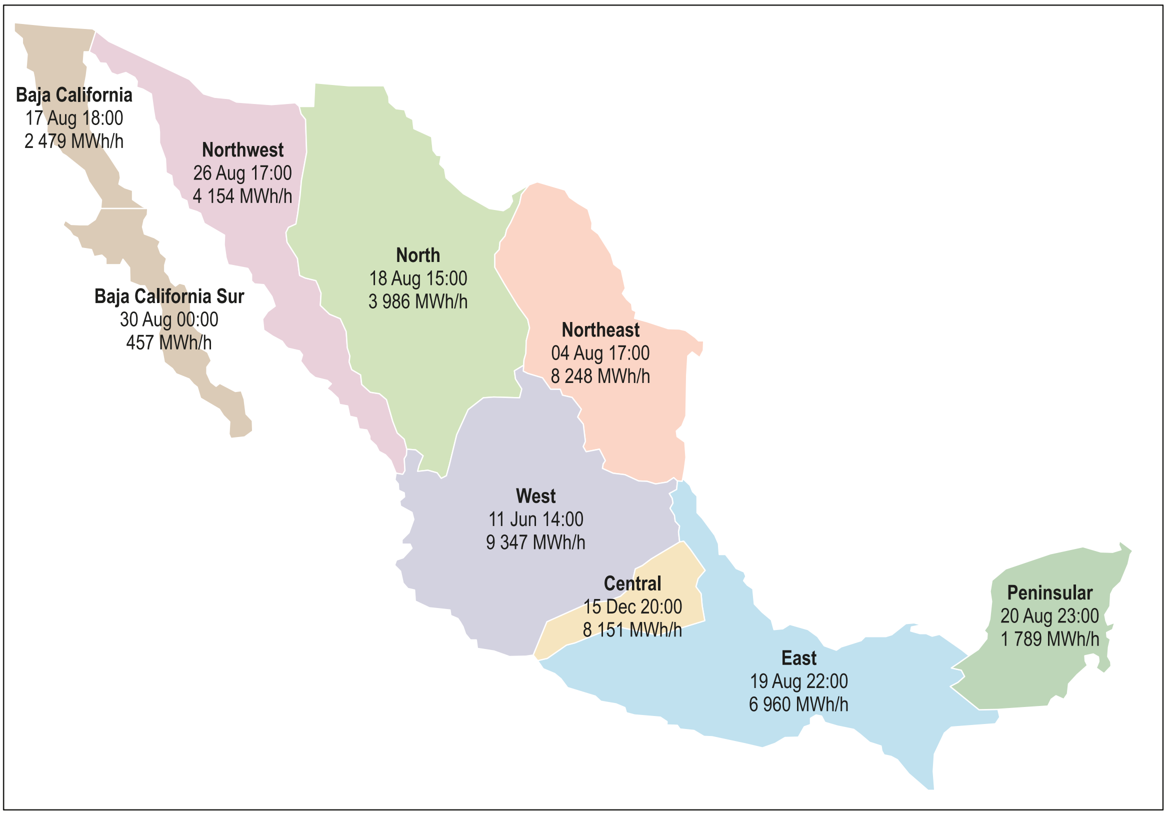
Figure 5.40 • Electricity seasonal and monthly demand, Mexico, 2015



Notes: Winter from December to February; summer from June to August; TWh = terawatt hour.

Key point • Demand peaks in the summer months due to air conditioners.

Figure 5.41 • Peak electricity demand per region, Mexico



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: MWh/h = megawatt hours per hour.

Source: SENER (2016a), *Programa de Desarrollo Del Sistem Eléctrico Nacional 2016-2030* [Programme for the Development of the National Electricity System 2016-2030].

Key message • Consumption patterns differ across regions, with a pronounced evening peak in Southern Mexico.

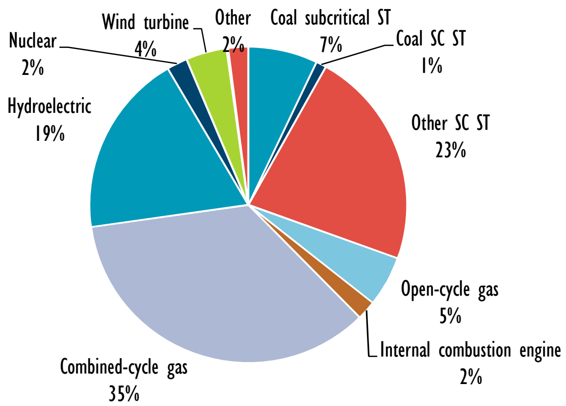
Generation

Mexico has an installed generation capacity of approximately 68 GW. Combined-cycle gas turbines account for 35% of total installed capacity. The shale gas boom in the neighbouring United States has lowered the cost of imported gas (IEA, 2014). Coal, which competes with gas for baseload and mid-merit operation, only plays a limited role (8%). Hydropower represents nearly a fifth of installed capacity (Figure 5.42, Table 5.15).

In contrast, variable renewable energy (VRE) accounts for less than 4% of installed capacity, the large majority coming from wind projects (SENER, 2015b). As of 2015, wind power represented just over 2% of total electricity generation, while solar generation has been negligible to date. Most wind power installation has been concentrated around the Isthmus of Tehuantepec (IEA, 2016; SENER, 2015a).

Mexico boasts the largest deployment of distributed generation in Latin America, albeit rather small with 118 megawatts (MW) installed to date. Subsidised electricity tariffs affect the attractiveness of installing distributed generation, and a recent decline in retail tariffs has further slowed deployment (BNEF, 2016a).

Figure 5.42 • Installed power generation capacity by technology, Mexico, 2015



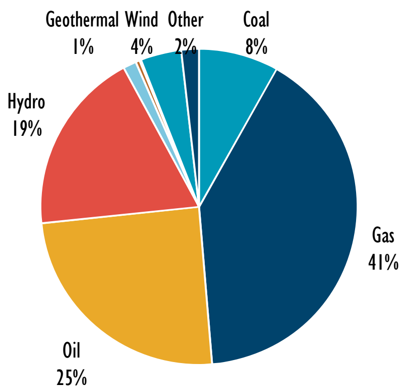
Notes: SC = supercritical; ST = steam turbine.
Sources: Adapted from Platts (2016), *World Electric Power Plants Database*; BNEF (2016a), "Mexico country profile", www.bnef.com/core/country-profiles/mex; SENER (2015a), *Prospectiva del Sector Elétrico 2015-2029* [Electricity Sector Perspectives 2015-2029].

Table 5.15 • Installed power generation capacity by technology, Mexico, 2015

Technology	Installed capacity in MW	Of which co-generation
Coal subcritical	4 700	0%
Coal SC	700	0%
Other subcritical	14 822	4%
Open-cycle gas	3 419	0%
Internal combustion	1 312	19%
Combined-cycle gas	23 309	0%
Hydroelectric	12 454	-
Nuclear	1 400	-
Wind turbine	2 760	-
Solar PV	114	-
Other	1 344	-

Notes: *Co-generation* refers to the combined production of heat and power; PV = photovoltaic.
Sources: Adapted from Platts (2016), *World Electric Power Plants Database*; BNEF (2016a), "Mexico country profile", www.bnef.com/core/country-profiles/mex; SENER (2015a), *Prospectiva del Sector Elétrico 2015-2029* [Electricity Sector Perspectives 2015-2029].

Figure 5.43 • Installed power generation capacity by fuel, Mexico, 2015



Source: Adapted from SENER (2015a), *Prospectiva del Sector Elétrico 2015-2029* [Electricity Sector Perspectives 2015-2029].

Table 5.16 • Installed power generation capacity by fuel, Mexico, 2015

Fuel	Installed capacity (MW)
Coal	5 400
Gas	26 890
Oil	16 356
Hydro	12 454
Geothermal	899
Biomass	270
Solar	114
Wind	2 760
Other	1 191

Source: Adapted from SENER (2015a), *Prospectiva del Sector Elétrico 2015-2029* [Electricity Sector Perspectives 2015-2029].

Key point • VRE only constitutes a small share of total installed capacity.

To meet growing demand, an additional 57 GW of capacity is expected to be added to the system from 2016 to 2030 (Table 5.17) (SENER, 2016a). Clean Energy Technologies (CET), a group of technologies defined under Mexican law to include hydropower, wind, solar and geothermal, as well as bioenergy, efficient co-generation,[23] nuclear and carbon capture and storage (CCS), are expected to account for more than half of capacity additions. The highest share (36%) of new capacity is taken up by combined-cycle gas plants. This will serve to compensate for the retirement of 17 GW of coal and gas assets in the 2016-30 timeframe and to strengthen the role of gas in a future power system with a stronger need for flexible supply sources. Across all technologies, installed capacity is estimated to reach 110 GW in 2030, corresponding to annual production of 443 TWh (IEA, 2016; SENER, 2016a).

In the first energy auction, of a maximum of 6.3 TWh, 5.4 TWh were procured. VRE technologies were the only successful technologies: winning projects included 394 MW of wind power and 1 718 MW of solar. A more detailed description of the first auction results is presented in the further section "First auction results".

[23] Predetermined benchmarks are used to assess whether a co-generation facility qualifies as efficient

Table 5.17 • Expected capacity additions by technology, Mexico, 2016-30

Technology	Capacity (MW)
Solar PV	6 835
Solar thermal	14
Wind	12 000
Geothermal	894
Hydropower	4 492
Bioenergy	61
Nuclear	4 191
Efficient co-generation	7 045
Coal-fired power plants	120
Combined-cycle gas	20 454
Internal combustion	272
Conventional thermoelectric	473
Open-cycle gas	261
Imports	10
TOTAL	57 122

Note: Main scenario.

Source: Adapted from SENER (2016a), *Programa de Desarrollo Del Sistem Eléctrico Nacional 2016-2030* [Programme for the Development of the National Electricity System 2016-2030].

Key point • Wind and solar PV are expected to represent 23% of capacity additions from 2015 to 2029.

Storage and DSM

Large-scale storage facilities and demand-side management (DSM) do not currently play an important role in Mexico. However, the national state power utility CFE (Comisión Federal de Electricidad) has identified several sites for possible pumped storage hydropower projects and conducted a series of pre-feasibility studies (ESMAP, 2015). Demand response may participate in the wholesale markets as of 2018. Moreover, SENER (Mexico's Department of Energy) launched in April 2016 an Advisory Council for the energy transition, including a working group on storage. The Advisory Council and its working groups are expected to inform the overall energy transition strategy and its subsequent programmes.

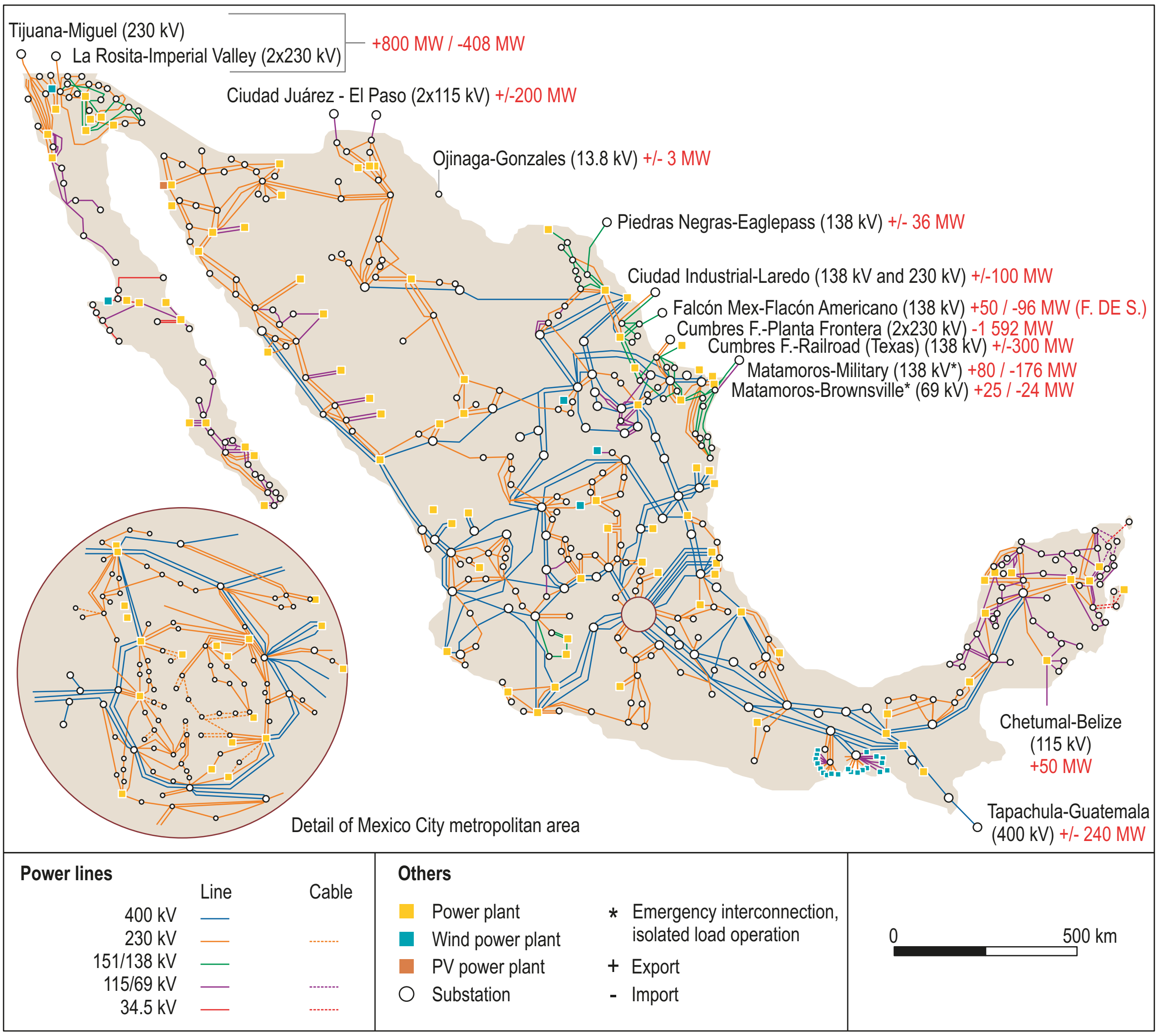
Transmission and interconnections

The entire Mexican transmission and distribution network is owned by the state-owned electric utility CFE. It is operated by the independent system operator CENACE. It operates at a frequency of 60 hertz, as do its neighbouring countries (BNEF, 2016a).

The overall electricity system is referred to as the National Electricity System (SEN). The National Interconnected System (SIN) covers the main transmission network of Mexico, excluding Baja California which is not synchronously connected to the rest of the country (Figure 5.44).

At the end of 2015, the Mexican transmission and distribution grids covered an overall length of approximately 880 000 kilometres (km), providing grid electricity to approximately 98.3% of the Mexican population. High voltage lines of 230-400 kilovolts (kV) cover over 53 000 km, slightly more than the sum of 69 kV and 161 kV lines. Mexico City forms a central node in the high-voltage network. High-voltage lines run in proximity of most of the abovementioned high wind resource areas (IEA, 2016; SENER, 2015a).

Figure 5.44 • National transmission grid of Mexico as of 2014



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

Source: Adapted from IEA (2016), "Overview and description of recent developments in energy policy", in-depth review questionnaire with local energy sector experts.

Key point • Mexico has a developed transmission grid in the central regions.

Energy losses in transmission and distribution jumped from 12.5% to 16.1% in 2010, before gradually decreasing to 13.1% in 2015. The majority of these losses (7.2%) are due to non-technical issues (SENER, 2016a).

SENER's expansion plans anticipate the construction of nearly 25 000 km of transmission lines over the 2016-30 period, with almost 65 000 megavolt amperes of transformer capacity (SENER, 2016a). Mexico is currently interconnected with its neighbouring countries via 13 transmission lines, 11 of which interconnect with the United States, one with Belize and one with Guatemala. However, of the 11 interconnections with the United States, 5 are not available for cross-border trade and are available only for emergency situations (Figure

5.44).[24] A total of 2 186 MW of interconnections are in permanent operation, while emergency interconnections add up to 511 MW (SENER, 2016a).

All in all, trade with neighbouring countries is relatively small: in 2014, import and export flows with the United States accounted for 0.7% (1.9 TWh) and 0.6% (1.7 TWh) of national gross generation respectively (IEA, 2016).

Summary

Mexico has access to abundant solar and wind resources, which are distributed across the country and are often favourable near load centres. In the first long-term auction for clean energy, VRE dominated the auction and 1 718 MW of solar PV and 394 MW of wind capacity were contracted. Between 2015 and 2030, more than 13 GW of wind and solar PV capacity is expected to be added (SENER, 2016a). Gas-fired plants are currently the most important source of power supply, and existing capacity expansion plans continue to rely heavily on combined-cycle power plants.

The transmission grid is well developed in the central region where the principal load centres are situated, but it is less extensive in the northern regions. Cross-border interconnection capacity is relatively weak. Given the lack of major storage facilities and the planned decommissioning of peaking plants, a flexible operation of the combined-cycle fleet will be critical to ensuring sufficient levels of flexibility in the Mexican system.

As the power system expands in the years to come, the opportunity exists to supplement supply-side flexibility resources with demand-shaping techniques. Demand can become more responsive to system needs on the basis of various demand-side integration solutions, such as storage and smart behind-the-meter devices, and through the electrification of heat and transport; dedicated policies may be needed to unlock demand-side potential.

Market and policy frameworks

Mexico is in the process of implementing a comprehensive and ambitious reform of its energy sector. The reform aims to resolve a number of structural challenges that the sector has been facing. As for the electricity system, the incumbent state-owned monopoly utility CFE has struggled to deliver required levels of investment in new generation capacity. The manufacturing industry has suffered from higher electricity tariffs relative to the United States. Moreover, electricity sales have not allowed for full cost recovery. For example, in 2014, 21.1% of the total cost of electricity supply had to be covered from the general government budget (IEA, 2016).

Electricity market reform

To respond to these challenges, constitutional reform in 2013 set the stage for a major overhaul of the energy sector, including the electricity industry. In order to open up the market to competition, the state-owned CFE has been unbundled, with its generation and distribution activities split across different entities.

The energy reform introduced a number of products that are traded on a long-term basis: electricity, clean energy certificates (CECs), and capacity. By introducing competition for the long-term supply of these products, the energy reform seeks to foster private-sector investment in

[24] These interconnections are not available for trade: Ribereña-Ascarate, Anapra-Devil, Ojinaga-Presidio, Matamoros-Brownsville, Matamoros-Military.

clean energy technologies while minimising the associated cost. Market participants can also trade financial transmission rights (FTRs).

In parallel, the introduction of wholesale markets facilitates trading in energy and ancillary services, allowing market participants to correct for imbalances. The wholesale market consists of day-ahead and real-time markets.

A newly established independent grid operator (CENACE) is also designated to manage the wholesale market, which started operating in early 2016. The market reform will be fully implemented by 2018 (Figure 5.45).

CECs

The market for CECs creates an additional revenue stream for low-carbon generators. CECs are awarded to generators using CET for each megawatt hour (MWh) of power generated without fossil fuels (the stipulation to allocate CECs only for the non-fossil fuel component relates to co-generation facilities specifically). CECs are awarded for 20 years and generators can hold them indefinitely. Although the CET category includes nuclear, CCS and efficient co-generation, another rule stipulates that only capacity commissioned after August 2014 is eligible. Hence, existing nuclear and most co-generation capacity cannot receive CECs.

The introduction of CECs constitutes an important means of support for clean power generation technologies. Initially, Mexican authorities intended to allocate CECs to eligible CET generators and leave price discovery to the market. It was subsequently decided to apply a centralised auction system to determine the value of CECs through competition between eligible CETs, in order to provide long-term revenue certainty to capital-intensive investments. Since the auction design favours technologies with short lead times, revenues related to CECs accrue predominantly to wind and solar PV projects.

To ensure Mexico meets its clean energy targets, which are discussed in more detail below, the energy regulator, CRE, sets a quota obligation of CECs for parties purchasing electricity. Eligible customer categories include retailers, large consumers, end-users with isolated supply, and load centres included in legacy interconnection contracts. The quota is set three years prior to the compliance period as a percentage of total consumption. The first compliance period will be in 2018 with the quota set at 5% of annual electricity consumption for eligible parties, and the target increases to 5.8% in 2019. In case the purchasing party does not meet its obligation, the penalty for non-compliance can reach an estimated USD 200/CEC.[25] CRE will monitor trading in the CEC market (BNEF, 2015b; IEA/IRENA, 2016). CECs can be bought and sold through the auction system or on the spot market.

Energy

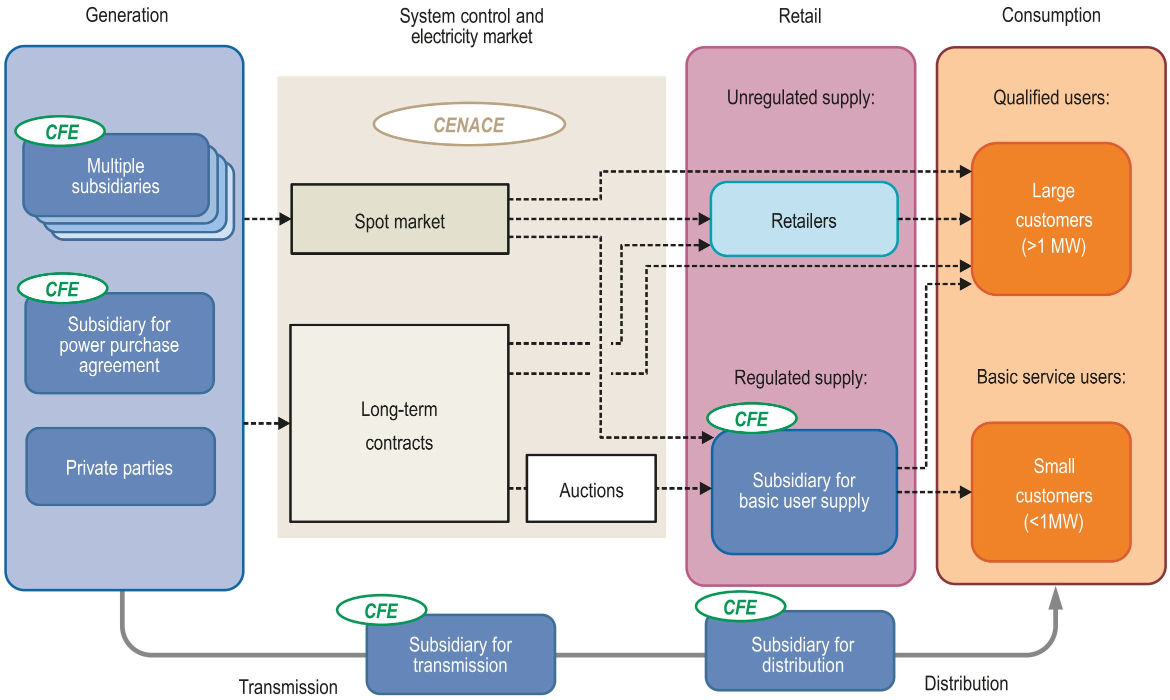
Energy auctions are open to all CET generators, but an obligation to start operations three years after the auction results gives wind and solar PV projects a distinct advantage over technologies with longer lead times. In determining the winning bids, a sophisticated system of location-dependent correction adders is used to incentivise power plant deployment in areas where it is considered most necessary. Correction factors range from USD -34.28 per MWh to USD 10.67 per MWh. The auction system is discussed in further detail below.

[25] The penalty for non-compliance is yet to be determined, but the law states that it can vary between 6 and 50 “minimum wages”, equal to USD 4 (MXN 70); CRE is responsible for setting the penalty.

Capacity

In addition, capacity products have been introduced. Capacity can be bought and sold in the auctions, on dedicated short-term capacity markets managed by CENACE, or through bilateral transactions. Suppliers and qualified consumers must comply with certain minimum capacity requirements, either providing these directly or procuring them separately via the various channels.

Figure 5.45 • Current and final overview of energy market reform, Mexico



Note: IPP = independent power producer.

Source: Adapted from BNEF (2016a), "Mexico country profile", Bloomberg New Energy Finance, website, www.bnef.com/core/country-profiles/mex.

Key point• The energy reform unbundled CFE and introduced wholesale markets that facilitate fair and transparent competition between new and existing private companies.

Long-term auctions

As described above, one of the key innovations of the energy reform has been the introduction of long-term trade for electricity, capacity and clean energy certificates. Long-term auctions serve as the most important vehicle for this trade between various public and private market participants. Auctions are held by CENACE at least once a year. For energy and capacity products, successful sellers sign a 15-year contract that may be denominated in Mexican pesos (MXN) or USD. Contracts for CECs are valid for 20 years. When bidding, project developers may bid with a single offer for capacity, energy and CECs.

In the first auction, CFE was the only off-taker. In future bidding rounds, any type of off-taker registered under the new power system rules can participate once a clearing house is created (BNEF, 2015c). Participation of private parties from the unregulated market segment will depend on the pace of liberalisation and price developments.

Energy auctions are open only to CET plants. Successful bidders must deliver electricity and capacity three years after the auction results. For each auction, CRE establishes a ceiling price (per MW, MWh, CEC).

The Mexican auction scheme for the procurement of clean energy is one of the most sophisticated procurement mechanisms for renewable energy. By clearly indicating the spatial value of electricity production through price adders (see Box 5.7), it incentivises IPPs to develop projects that provide power in locations that optimise the overall system value. In addition, VRE projects are subject to time-dependent price adders to determine their revenues during operation, which means that developers are given the incentive to prioritise measures to produce power at a time when it is most valuable to the system. The use of multi-technology auctions ensures that the most-suited technology will be deployed at competitive prices. As a consequence, the auction system strikes a balance between the need for long-term revenue certainty and the competitive procurement of technologies that have the highest system value.

Box 5.7 • Remuneration rules for VRE plants under the auction system

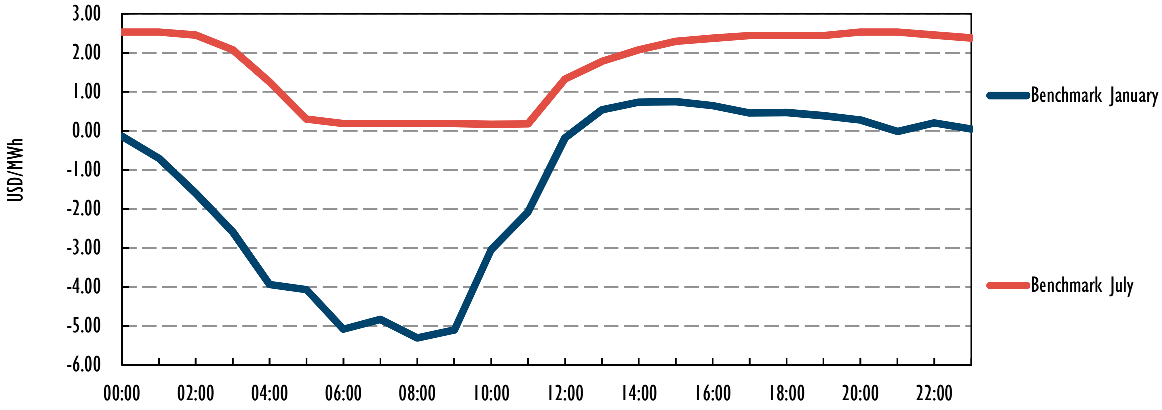
In the auction system, location-specific price correction adders push project development to favour specific regions. Once in operation, the energy price for "intermittent" technologies is time-dependent. CENACE models expected electricity prices, applying a very sophisticated methodology. These calculated prices are then used for setting hourly price adders for the entire length of a project, as determined by a power purchase agreement (PPA), and on a region-specific basis. The adders are defined as the difference between the price of electricity in a specific hour and the average price of electricity across the length of the PPA. In hours where the calculated price is above average, the VRE producer receives the value of the bid plus the price adder. Similarly, if the project feeds power into the grid at a moment when the adder is negative, this amount will be deducted from the contract price. As a consequence the revenues of the generator give an indication of the system value of electricity produced during each specific hour of the year. Prices adders are updated for each auction to account for the evolution of local supply and demand considering the (future) commissioning of previously awarded projects. This system of price calculation pushes bidders to design their plants in a way that optimises the system value of electricity production (Figure 5.46).

In essence, those producers that offer electricity with a higher-than-average value can reduce their bids in two steps (Figure 5.47). In the first step, project developers consider the time-related benchmarks that will apply in the location of their choosing. They will incorporate this into the price they bid into the auction. In the bid selection, the regulator applies a correction factor related solely to location. This is used for selecting projects but not for compensating generators.

Capacity auctions are open to all generators that offer firm capacity or controllable demand sources. Specific load zones are defined by the system and market operator (CENACE). For each load zone, energy suppliers determine the amount of capacity needed, and operators subsequently bid and sign contracts to provide a certain amount of capacity in the zone where the project is located and dispatch electricity to the spot market when required.

Finally, FTRs are auctioned for specific time period, either for a specific part of a year, or on a one-, three- and ten-year basis. FTRs can also be acquired through assignment or in relation to transmission infrastructure investments.

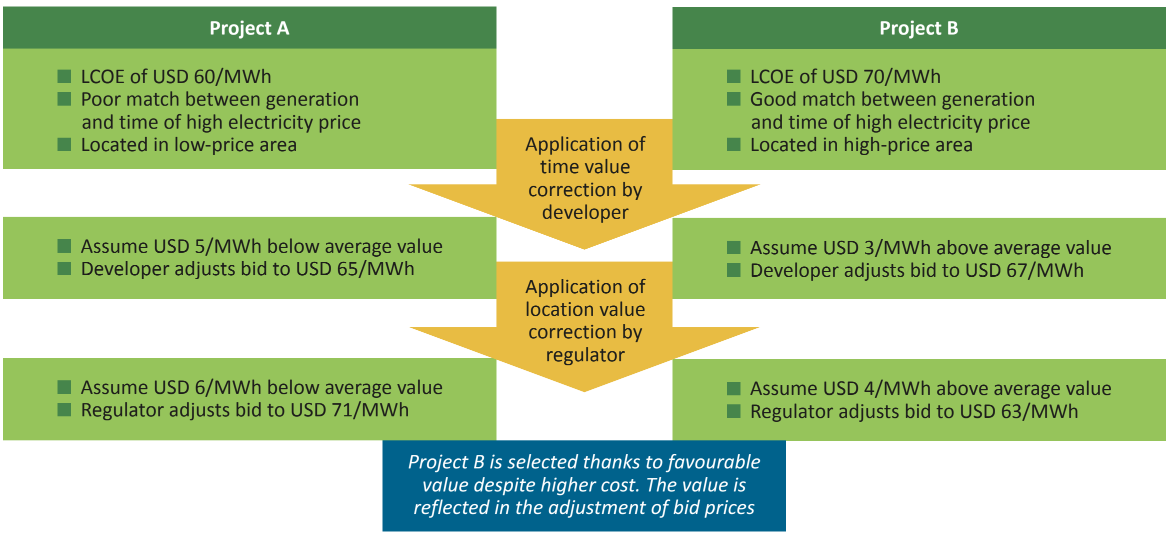
Figure 5.46 • Example of benchmark application for VRE: area of Tijuana, 2017 values.



Note: In this example, a wind power plant with a USD 40/MWh bid associated with its contract would receive USD 34.69/MWh at 08:00 in January (tariff minus USD 5.31/MWh), while, at 21:00 in June the final revenue would be USD 42.53/MWh (tariff plus USD 2.53/MWh)
Source: Adapted from SENER (2016a), *Programa de Desarrollo Del Sistem Eléctrico Nacional 2016– 2030*, [Programme for the Development of the National Electricity System 2016-2030].

Key message • Price adders vary on an hourly basis and can be positive or negative.

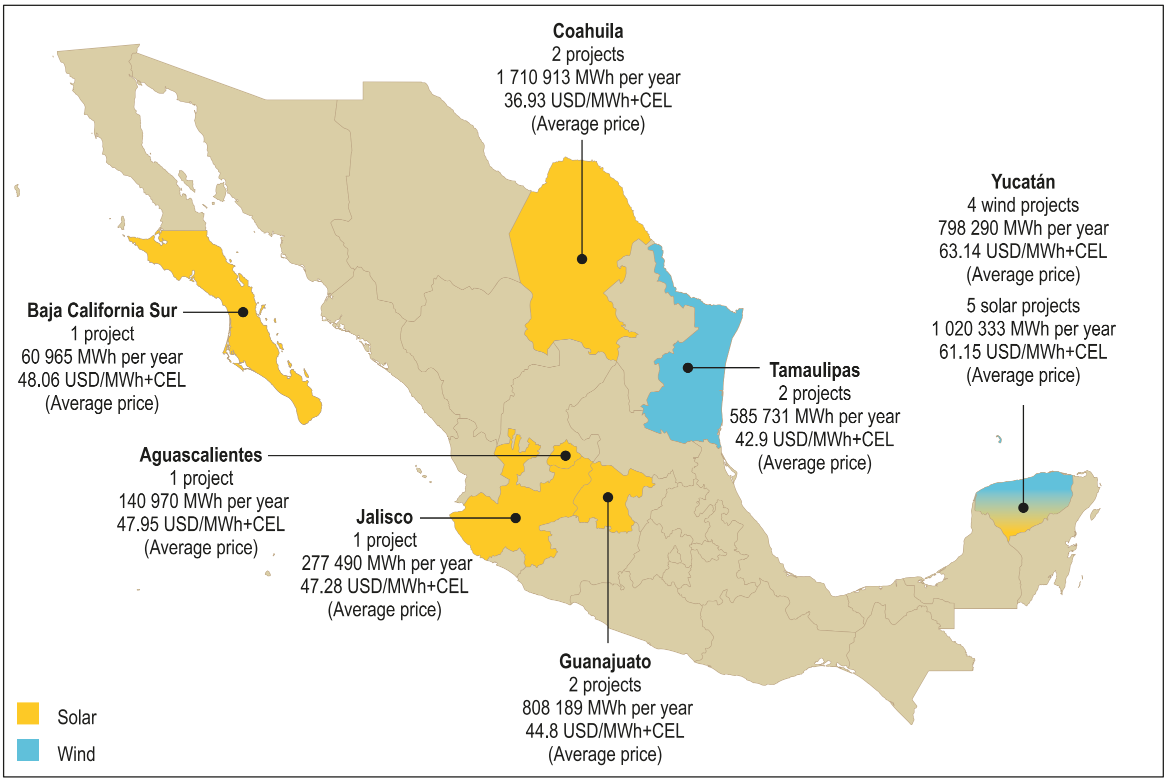
Figure 5.47 • Conceptual illustration of the Mexican auction system for variable renewables



Note: LCOE = levelised cost of energy.

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

Figure 5.48 • First Mexican auction results



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: SENER (2016b), *Programa de Ampliación y Modernización de las Redes Generales de Distribución* [Programme for the Development and Modernisation of the National Electricity Networks], www.gob.mx/sener/acciones-y-programas/programa-de-desarrollo-del-sistema-electrico-nacional-33462.

Key point • VRE technologies were the only winning technologies in the first Mexican energy and CEC auction. More than 80% of the winning bids are solar projects.

Results of the first auction

The results of the first auction were announced in March 2016. Of a set maximum of 6.3 TWh, 5.4 TWh were procured. Wind and solar PV were the only winning technologies. The combined investment of the successful projects of the first auction amounts to 2.6 USD billion.

The average prices submitted by successful bidders in the first auction were among the lowest ever recorded globally up to that point (BNEF, 2016d). The results reveal a wide discrepancy in awarded contract prices, with ranges of USD 35.5-68.8/MWh and USD 42.8-66.9/MWh observed for solar PV and wind respectively (BNEF, 2016e). The spread in contract prices reflects the differences in value of the energy produced: more expensive bids were awarded in those regions where electricity prices are forecast to be higher. Because of this, a large number of successful projects are located in the Yucatan Province. To the degree that CENACE simulations accurately reflect future market conditions, the auction does not therefore seek to procure the cheapest generation, but instead the maximum value for money (Figure 5.47).

Remarkably, winning projects included 394 MW for wind and 1 718 MW for solar. This result contradicts the dominance of wind that SENER initially foresaw in its capacity expansion plan (SENER, 2016a), and highlights the flexibility that the auction system provides for competitive price discovery.

The average combined price of power and CECs came to USD 47.48/MWh. No successful bids were announced for the capacity auction, signalling that the ceiling price of USD 577/MW/year was too low to trigger market interest. This does not come as a surprise as there currently is no shortage of dispatchable capacity (BNEF, 2016e).

The average combined price of power and CECs came to USD 47.48/MWh. No successful bids were announced for the capacity auction (BNEF, 2016e).

Results of the second auction

In September 2016, a total of 8.9 TWh was awarded in a second round of auctions. Solar PV again dominated with 4.8 TWh, corresponding to 54% of awarded energy contracts. A total of 2 972 MW of additional VRE capacity was procured (1 928 MW solar PV, 1 043 MW onshore wind). The average price of energy and CECs came to USD 33.47/MWh, almost 30% lower than the prices seen in the first auction six months earlier.

The geographic dispersion of allocated projects changed considerably compared to the first auction. The Yucatan province, where 1 819 GWh of energy was awarded in the first auction, saw no successful bids in the second round. In turn, the Tamaulipas Province saw a fourfold increase in wind energy allocation, jumping from 585 GWh to 2 222 GWh. The Aguascalientes Province, to the north-west of Mexico City, experienced a tenfold increase from 141 GWh to 1 420 GWh of solar energy.

The price ceiling for the capacity auction was raised to just above USD 90 000/MW/year. A total of 1 187 MW/year was procured by CFE from 12 different generators, with 850 MW allocated to combined-cycle gas turbines and the remainder split between solar PV (184 MW), wind (128 MW) and geothermal (25MW). The average price for capacity reached USD 32 258/MWh, 64% less than the set ceiling price (CENACE, 2016).

Net metering

A net metering scheme is in force, whereby retail customers connected to the low- or medium-voltage grid receive bill credits for injected electricity. Low-voltage users receive a bill credit for the equivalent of the energy provided. The credit balance is reset after 12 months. Medium-voltage users (1-69 kV) are compensated based on the regular tariff or a time-of-use tariff, depending on the applicable price regime (BNEF, 2016c). Renewable energy investments also benefit from an accelerated depreciation in the form of a full, one-year tax deduction (BNEF, 2016b). Although Mexico has the largest deployment of distributed solar PV in Latin America, it is still very low. Recent analysis (CRE, 2016) finds that 92.3 MW of projects smaller than 500 kW had been installed at the end of 2015. A recent decrease in retail tariffs due to competition and cheaper natural gas imports from the United States have caused the economics of rooftop projects to deteriorate and slowed down deployment.

Wholesale market design

The electricity market reform established a wholesale market open to private participation. It started operating in January 2016 and is expected to be fully operational by 2018. Several energy products are traded on the day-ahead market (DAM) and the real-time market (RTM), or by means of bilateral contracts. Products are traded in hourly blocks and prices are set on a nodal basis.

Short-term markets

In the DAM, energy products are based on hourly bids. Market participants can either make fixed offers (buy/sell at any price) or price-sensitive bids (buy/sell only if price is below/above a certain price). Power plants selected in the DAM can be requested to cancel or change their allocation for reliability reasons.

The RTM will be available only for dispatchable plants: solar PV and wind power plants will be able to participate if they have the capacity to reduce generation by means of automatic dispatch instructions. Currently, the RTM clearing price is pegged to the DAM price. Starting in 2018, RTM offers can have different prices from the DAM. Around this time, the DAM and RTM will be complemented by an hour-ahead market (BNEF, 2015a).

In the proposed draft of the grid codes, VRE producers are required to submit forecasts for electricity generation in real time to CENACE. Forecasts have a time horizon of 2 hours (i.e. 8 intervals of 15 minutes) and are updated every 15 minutes (CENACE, 2015).

Grid representation

Mexico’s grid is divided in connectivity nodes (C-nodes) and price-setting nodes (P-nodes). C-nodes are the nodes where generators and consumers are connected, while the P-nodes are groupings of C-nodes. Electricity prices and economic dispatch are set in the P-nodes. Marginal prices on P-Nodes are calculated on the basis of three components: energy, congestion and marginal losses (BNEF, 2015b).

In order to allow market participants to hedge for congestion-related price risks, FTRs were introduced in 2015. FTRs provide to the holder the right and obligation to collect or pay the difference between the values of the congestion component of the nodal marginal price from a node of origin to the node of destination.

FTRs are nowadays acquired in yearly auctions with lengths of one, three and ten years. From 2017 they will be acquired through auctions, for expansion of the transmission network or by assignment (BNEF, 2015a).

Interconnector operations/trade across interconnection

Mexico’s southern interconnections are relatively small, with an export capacity of 300 MW and an import capacity of 50 MW. Interconnection capacity linking Mexico to the United States is more significant, with an export capacity of 1 236 MW and an import capacity of 983 MW. Trade flows are limited, however, due to bilateral legacy arrangements. A relatively small fraction of the cross-border interconnection capacity is used exclusively for emergencies, and no competitive trading is permitted to date.

Imports and exports of energy and related services are currently accepted with fixed programming in the DAM. They will be regulated with fixed or dispatchable programming in the DAM and hour-ahead markets from 2018 (BNEF, 2015a).

Scarcity pricing

Currently installed capacity in Mexico is easily sufficient to meet peak demand. However, as a consequence of the design of the wholesale spot market, long-term plant revenues can be expected to be insufficient to cover the investment cost of peaking generation; plant operators must base bids on their generation cost and there are no scarcity prices. Consequently, an additional instrument had to be added to the market design in the form of a capacity market. The fact that Mexico does not require any additional firm capacity to meet peak demand was reflected in the decision to set a very low price cap for capacity in the first auction. As a result, no bids for capacity were received.

Demand growth and ageing generation infrastructure will increase the need for capacity over time. Wholesale market operator CENACE will periodically assess the system's capacity needs and allocate these across eligible suppliers and qualified consumers. These parties are then bound by this requirement and will have to supply or procure the necessary capacity. Put simply, CENACE determines the volume of capacity to be traded, while the market sets the price for this capacity. Any capacity requirement that is not met through direct trade between suppliers and eligible capacity resources is procured by CENACE in an annual auction, to be held every February. The clearing price for this capacity is set on the basis of predetermined demand and supply curves (IEA, 2016; BNEF, 2015a, 2015b).

Definition and deployment of operating reserves/system services market

To ensure the reliability of the system, all power plants have the obligation to provide ancillary services in the wholesale power market according to their technical capabilities as established by CENACE. Primary frequency response is mandatory and not traded as an ancillary services; its provision is not remunerated. Other ancillary services, including non-reserve system services, such as voltage and frequency control, and black-start capabilities, are not included in the wholesale market. CENACE is currently evaluating ancillary services requirements in each node of the system and the option of allocating supply obligations to each power plant based on its size, location and technical capabilities (Talamantes and Blomfield, 2015).

Further refinement of system services markets will be critical. Experience in countries that are handling double-digit shares of VRE generation clearly show that innovative ways to procure system services can allow a more efficient operation of the system at high shares of VRE. For example, providing operating reserves from a combination of VRE resources (downward reserves) and DSM (upward reserves) can be more cost-effective than keeping thermal units online. However, for this to work in practice appropriate commercial and technical solutions need to be in place.

New entrants and market power

As a vertically integrated utility, CFE has traditionally dominated the entire value chain. Excluding small-scale generation and captive power plants, CFE held a 76% share of the power market at the end of 2014. The power sector reform has unbundled the different activities into several entities for generation, transmission and distribution.

In March 2016, a government decree pronounced that the generation arm of CFE be split into six different companies. Retail activities are separated from distribution activities. CFE will act as a basic supplier and the provider of last resort, while competing with new entrants for access to customers. These changes are designed to increase private-sector participation throughout the value chain.

System transformation

Incentives for system-friendly deployment of large-scale VRE

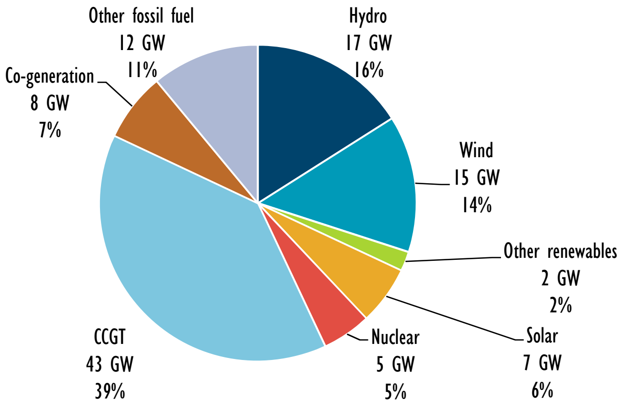
Timing of deployment

The Programme for the Development of the National Electric System (PRODESEN) identifies priority areas for expanding and modernising the Mexican transmission and distribution grids by evaluating the impact of planned generation build-out. This work builds on long-term demand forecasts provided by SENER.

On the basis of this information, CENACE proposes plans for the cost-effective expansion of the transmission grids. Each year, information on new plants that are confirmed will be taken into account in order to plan for the expansion of the grid (IEA, 2016).

According to the latest version of PRODESEN, total installed generation capacity will reach 110 GW by 2030. Together, CET is projected to account for 55% of all capacity additions, bringing their share of total installed capacity to 50% by 2030 (Figure 5.49). The actual pace of development is determined by the auction system, allowing for a smooth and controlled expansion of total capacity while safeguarding competition among the private sector. If well managed, the build-out of clean energy projects will occur at a pace that recognises the delays in grid infrastructure expansion and that mirrors the speed at which total energy demand increases.

Figure 5.49 • PRODESEN objectives: cumulated capacity by technology in 2030



Note: CCGT = combined-cycle gas turbine.

Source: SENER (2016a), *Programa de Desarrollo Del Sistem Eléctrico Nacional 2016-2030*, [Programme for the Development of the National Electricity System 2016-2030].

Key point • CET technologies are expected to account for 50% of the capacity mix.

Location and technology mix

Renewable energy auctions apply time- and location-specific price indicators to guide IPPs in their choice of location, technology and design. For each node, differentials in tariffs are set until 2032. To the extent that the correction factors applied in the auctions are accurate, this framework ensures that successful bidders are those that optimise the system value of their project by choosing technical solutions that reap the highest returns.

Technical capabilities

The regulator, CRE, defines the general rules of interconnection (grid codes) to the National Electricity System (SEN) for all generators, including those generating VRE. These technical requirements play an important role in ensuring the technical capabilities of VRE generators are exploited fully and cost effectively, while ensuring that the flexibility that is technically available in other supply and demand resources is exploited.

Incentives for system-friendly design

The design of the auction mechanism differentiates plants depending on when and where they generate electricity. This has two key consequences. First, it pushes renewable energy development towards parts of the power system where additional generation capacity is most valuable. Second, it incentivises bidders to make economic design choices that shift the timing of production to moments of the day when that electricity is most valuable. As a result, the auction system favours projects that maximise system value, instead of focusing on projects with the lowest LCOE.

Curtailment

All plants, including variable and non-dispatchable plants, must reduce their generation in accordance with the instructions of CENACE and in accordance with the market rules outlined in the grid code. When technically feasible, the execution of a curtailment order can be done automatically by centrally administered control software.

No remuneration will be provided to curtailed generation. Moreover, in case a clean energy plant runs in violation of the instructions issued by the CENACE, CECs will not be granted during the time of violation of these instructions (SENER, 2015c).

Incentives for system-friendly deployment of distributed VRE

Locational price

There are currently 37 categories in the Mexican electricity tariff. These categories are set according to customer typology (domestic, commercial, services, industrial) and local geographic conditions such as minimum summer temperature – a higher summer temperature lowers the tariff to ease the financial burden of increased air-conditioning demand (IEA, 2016). While this tariff structure incorporates socio-economic factors, this approach disincentivises the use of energy efficiency measures and the deployment of solar PV in those regions where energy demand is higher in summer.

The tariff increases progressively with consumption to promote efficient use of energy while safeguarding low-income households (Table 5.18).

The tariff structure is modulated to reflect consumption and not cost of production. It favours deployment of distributed VRE among more affluent residential customers, since they can offset the higher marginal electricity price. This can erode the ability to cross-subsidise lower-income electricity prices. A reform of retail tariffs, to be finalised by 2018, may render retail tariffs more reflective of the customer-related cost of energy production and distribution (IEA, 2016).

Table 5.18 • Example of tariff (for area with average minimum summer temperature equal to 31°C)

Consumption	USD/kWh	MXN/kWh
For the first monthly 150 kWh	0.04	0.697
For the next 150 kWh	0.05	0.822
For the next 150 kWh	0.06	1.05
For further consumption	0.16	2.802

Note: kWh = kilowatt hour.

Source: CFE (2016), "Tarifas para el suministro y venta de energía eléctrica" (2015-2016) [Rates for the supply and sale of electricity (2015 - 2016)].

Key point • Progressive increases in per-kWh electricity tariffs favour distributed VRE deployment among wealthier households.

Time-dependent price

Industrial tariffs consist of a demand charge and an energy component that is broken down in four different time periods: base, intermediary, mid-peak (for high-voltage connections in Baja California) and peak.

The charge for billable demand applies to the maximum demand registered during the month. Higher charges apply if the peak occurs during a more constrained part of the day. The duration of the time periods varies seasonally and regionally, and they are set as a function of consumption patterns (IEA, 2016).

Grid fees

As part of the reform, energy regulator CRE has received a strong mandate to set tariffs. In doing so, CRE will develop methodologies to calculate the per-customer allocation of system costs, comprising transmission and distribution maintenance, grid losses, basic electricity service provision and CENACE management cost (IEA, 2016).

Taxes and surcharges

Low-income domestic users are eligible for energy subsidies. Consumers that have a low monthly consumption pay a lower per-kWh price for electricity that is below the cost of supply. As monthly consumption increases, the electricity price rises. Higher electricity tariffs for larger users should cross-subsidise insufficient cost recovery from small users. Experience shows that the higher prices are insufficient to offset the deficit. In 2014, the federal government had to cover 21.1% of total electricity supply cost, giving an important impetus to the reform of the power sector (IEA, 2016).

Discussion

The Mexican power sector is characterised by growing demand and a strong need for investment. The vertically integrated incumbent, CFE, has been unable to deliver investment in renewables in recent years and conventional capacity additions have been achieved via IPPs. In addition, CFE has incurred significant budget deficits as a result of regulated electricity tariffs.

In order to address these challenges, a comprehensive reform of the electricity sector – part of a wider energy sector reform – was launched in 2013. The Mexican government seized this opportunity to implement reform that significantly increased the role of clean energy technologies, including VRE. The power system is embarking on a transition from a vertically integrated system with the participation of IPPs to an increasingly liberalised wholesale market.

Exposing investors to market price risk can create an issue for attracting investment, in particular for capital-intensive technologies such as wind and solar PV. Learning from this experience in other countries, Mexico combined its move towards market liberalisation with the establishment of long-term contracts to ensure sufficient investment certainty. The Mexican reform has found an innovative way to strike a balance between providing investment certainty while enabling competition between certain technologies and ensuring that procured capacity stays in line with system needs. This was achieved by combining an auction system for long-term PPAs with measures to reflect the time- and location-specific value of electricity. Detailed modelling of the evolution of the power system over the next 15 years is at the core of striking this balance. In essence, the government provides a scenario for the evolution of the system that serves as a reference for establishing the value of power in different locations. Investors are then guaranteed remuneration according to this long-term scenario; any difference between expectations and reality is a risk ultimately for electricity consumers, both in terms of possible upsides or downsides. It remains to be seen how this system plays out in practice.

The reform also raises a question regarding the complexity of establishing price signals for guiding investment. Both aspects of the value of electricity – time and location – are reflected in the auction design. A first parameter captures time-dependent effects in a given location, while a second parameter captures value differences that result from different locations. In carrying out the auctions, it was clear that this complexity was somewhat of a challenge for stakeholders. Guiding investment via differentiation of price signals creates competition between projects throughout the country while taking into account the characteristics of the grid, but this is only one possible option. For example, locational incentives can also be provided by identifying preferential development zones and holding separate auctions for each. This may also make it easier to align expected transmission expansion and the location of new generation. As with any major innovation, it will remain to be seen if the current approach proves robust over the coming years.

This notwithstanding, the auctions have already demonstrated a number of positive aspects. For example, they have allowed for competitive price discovery across different technologies, raising the share of solar PV capacity procured in comparison with wind. This direct result of rapidly falling costs of solar PV was yet to be captured by centralised planning processes.

Above and beyond the design of the long-term auction mechanism, there are a number of market design elements that may already warrant closer consideration. Most importantly, the implementation of the real-time and hour-ahead market needs to be completed as a priority. Looking further into the future, the design of system services markets remains fairly simplistic, reflected for example by the fact that provision of operating reserves is not explicitly remunerated. Upgrading the design of system services markets to allow unconventional resources to participate on an equal footing (including demand-side resources, storage and VRE plants) is a key element of power market reforms in systems with high shares of VRE (e.g. Denmark, Germany and Spain). A further aspect in this regard is scarcity pricing on the wholesale market.

In addition to changes to electricity market design, a dedicated endeavour to shape future power demand so that it more closely matches VRE generation could prove very cost effective from a system perspective. This includes integrating demand-side flexibility into future loads, in particular for heating and cooling applications.

Mexico is a regional leader in distributed energy, due to a combination of favourable resources, moderate electricity tariffs and a net metering policy. Further policy action is needed to reap the full potential of distributed solar PV and put this emerging trend onto a sustainable footing. This includes a systematic understanding of the value of distributed solar PV for the power system, careful reform of retail electricity tariffs, and establishing an appropriate institutional framework between electricity suppliers, grid operators and prosumers.

Mexico has made great strides in initiating a comprehensive reform of the electricity sector, which holds the promise of effectively mobilising market forces while providing sufficient long-term certainty for a guided transformation. However, as always the devil is in the detail and many aspects of the reform have only been partially implemented or not at all as yet. Looking ahead, the success of the reform process will depend on maintaining momentum and ambition in this complex enterprise.

Table 5.19 • Key recommendations for Mexico

System-friendly VRE deployment
The long-term auctions for procuring VRE capacity signal the time- and location-dependent value of electricity while providing long-term investment certainty. Continuously improving the underlying power system models and sharing all relevant assumptions and modelling equations will help ensure that investments are guided accurately and also rely on actual market signals provided by hourly locational marginal prices. Yearly update of the model and of the benchmarks will help ensuring the reflection of SV in the auctions system. The electricity market reform foresees the participation of VRE resources in the real-time market, if they have sufficient control capabilities. Ensuring the timely implementation of the real-time market alongside appropriate remuneration for system services will be key to unlocking the contribution of VRE to system balancing.
Investment
The newly established auction system for VRE capacity is a major innovation on a global level. Carefully monitoring the performance of the system and making gradual adjustments over time are likely to be required. Electricity demand is expected to grow significantly over the coming years. Ensuring that investments in new loads (in particular for heating and cooling) consider system flexibility needs (for example via thermal energy storage) will help achieve high shares of VRE cost effectively.
Operations
The implementation of the wholesale spot market has been partially completed; important aspects of the reform are still pending. Continued implementation of all aspects of the reform (e.g. real-time pricing, FTRs, capacity markets and in the future scarcity pricing) will be critical to operating the system efficiently and unlocking the contribution of new players, such as demand-side resources. Wind and solar producers are required to update their real-time production forecast with a granularity of 15 minutes every 15 minutes with a time horizon of 2 hours. Effectively using these forecasts will allow the system operator CENACE to optimise overall system dispatch close to real time.
Consumer engagement
Given current tariff structures, the existing net-metering scheme may be insufficient to unlock the full potential of distributed energy in a sustainable way. Reforming electricity tariffs to provide prosumers with fair remuneration while avoiding unwanted cross-subsidies will be an important issue to address in the future.
Planning and co-ordination
PRODESEN identifies priority areas for grid expansion on the basis of planned generation build-out. CENACE also proposes plans for cost-effective grid expansion. Factoring in non-generation options in transmission planning, such as demand-side response options, will help to minimise overall system costs. Planning of the transmission system and procurement of new generation are currently done in isolation, i.e. modelling first assumes a certain build-out path including grid expansion. New generation capacity is procured on this basis. Creating a closer link between transmission grid build-out and auctions for generation capacity can contribute to an optimal expansion of the system overall.

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South Africa

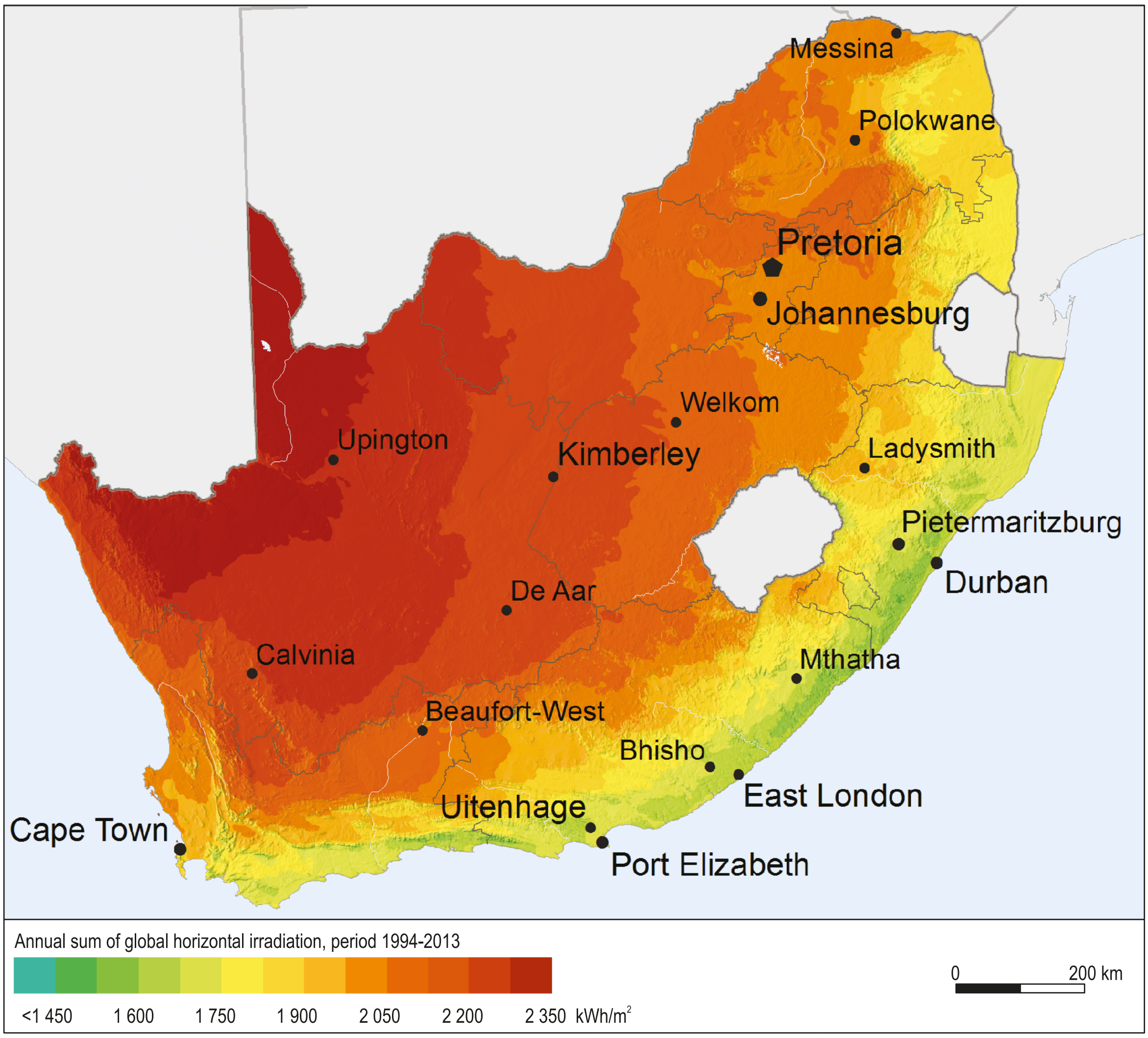
General information on VRE and grid integration

Flexibility assessment, ease of integration and current value

VRE resources

South Africa is endowed with some of the best solar and wind resources in the world. Global horizontal irradiation (GHI) exceeds 2 000 kilowatt hours per square metre (kWh/m^2) in the large majority of the country (Figure 5.50). Most areas of South Africa receive more than 2 500 hours of sunshine per year, with very low seasonality. The average annual capacity factor for solar photovoltaics (PV) is high; in 2015 it was 26% (CSIR, 2016b). Particularly favourable conditions exist in the semi-arid Northern Cape Province (Solargis, 2016), where most large-scale solar PV and concentrated solar power (CSP) projects have been developed.

Figure 5.50 • Average annual GHI, South Africa



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: Solargis (2016), *Solar Resource Maps*, http://solargis.com/.

Key point • South Africa has very favourable solar irradiation levels.

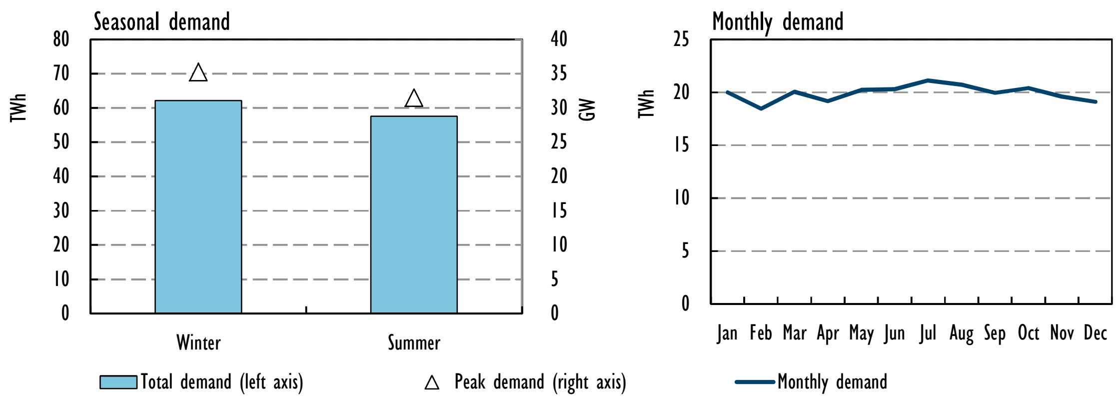
Significant potential also exists for land-based wind energy in several regions of the country. Wind resources are most favourable in the Western Cape and Eastern Cape provinces, where average annual wind speeds lie between 7 metre per second (m/s) and 11 m/s (IRENA, 2016). Recent analysis (CSIR, 2016a) shows that, depending on turbine design, a capacity factor of 35% or above can be achieved on more than half (using classical technology) or more than two-thirds (using advanced low wind speed technology) of the usable surface area. A study by CSIR demonstrated that a load factor above 30% can be achieved in most parts of the country when matching the chosen turbine technology with local conditions. Wind resources are slightly higher in winter, correlating well with a slight increase in load during that time.

Demand

Electricity consumption equalled 233.5 terawatt hours (TWh) in 2014 (Stats SA, 2015) and is expected to reach 345-416 TWh by 2030 (DOE, 2011). Daily electricity demand lies between 20 gigawatts (GW) and 35 GW, with only mild seasonal variations (Eskom, 2015d).

In recent years, however, limited power supply has effectively placed a cap on demand growth, as power shortages and extended bouts of load shedding in late 2014 and early 2015 lowered productivity and put a brake on overall economic growth.

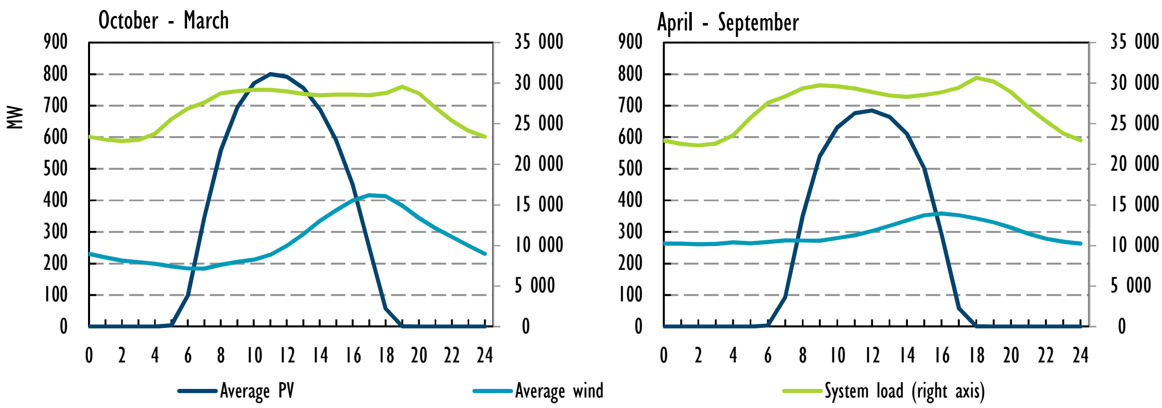
Figure 5.51 • Seasonal and monthly electricity demand, South Africa, 2014



Note: Winter from June to August, summer from December to February.

Key point • Electricity demand is relatively flat throughout the year.

Figure 5.52 • Average daily solar PV and wind production and system diurnal load, South Africa, 2015



Source: Adapted from CSIR (2016a), *Wind and Solar PV Resource Aggregation Study for South Africa*.

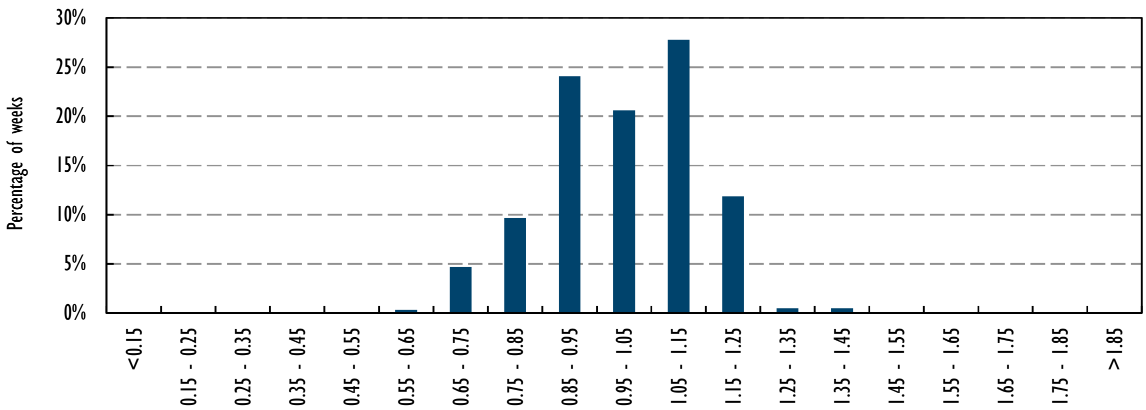
Key point • Solar PV and wind generation show a positive correlation with electricity demand

Analysis of match between demand and VRE generation profile

Analysis by CSIR (2016a) shows a positive correlation between solar and wind resources and power demand. Like demand, solar resources show little seasonality, whereas the moderate increase in wind supply during the winter months correlates with a slight load increase during that period. Importantly, wind production generally peaks in the evening and at night, thus complementing daily solar PV output (Figure 5.52).

The demand coverage factor (DCF) analysis supports this conclusion as it reveals a favourable overlap between variable renewable energy (VRE) and the overall demand profile of South Africa (Figure 5.53). In a scenario where wind and solar resources produce the equivalent of the full electric load, the DCF lies between 0.9 and 1.1 for approximately 48% of the time. In only 3% of the modelled weeks does the DCF dip below 0.7.

Figure 5.53 • Range of weekly DCF for 2014, South Africa



Key point • The DCF analysis reveals a very good match between VRE generation and electricity demand.

Generation

Eskom, the vertically integrated and state-owned utility, currently supplies about 95% of South Africa's electricity with an installed capacity of 44 GW (DOE, 2015b). More than 90% of power is generated by coal plants that receive their feedstock from abundant coal deposits near Johannesburg, where most plants are located. The Koeberg nuclear power station (1 800 megawatts [MW]) is located north of Cape Town. Four open-cycle gas turbine stations, with a total capacity of 2.4 GW, function as peaking plants (Eskom, 2016a). Furthermore, Eskom manages a small number of wind, CSP and hydro projects. The remaining 5% stems from imports and independent power producers (IPPs).

Supply-side flexibility is mainly provided by open-cycle peaking plants and hydropower. Additional sources can be procured from the 1.5 GW Cahora Bassa hydropower plant in Mozambique, which is currently run as a baseload plant but offers the technical capability to operate more flexibly. Further flexibility could also most likely be mobilised from the coal fleet.

A shortage of power generation became apparent in late 2007, when Eskom was forced to implement load shedding to balance the system. Load shedding reappeared in November 2014 due to growing demand and delays in the commissioning of the Kusile and Medupi coal-fired power plants, combined with the decreasing availability of existing plants (DOE, 2015a).

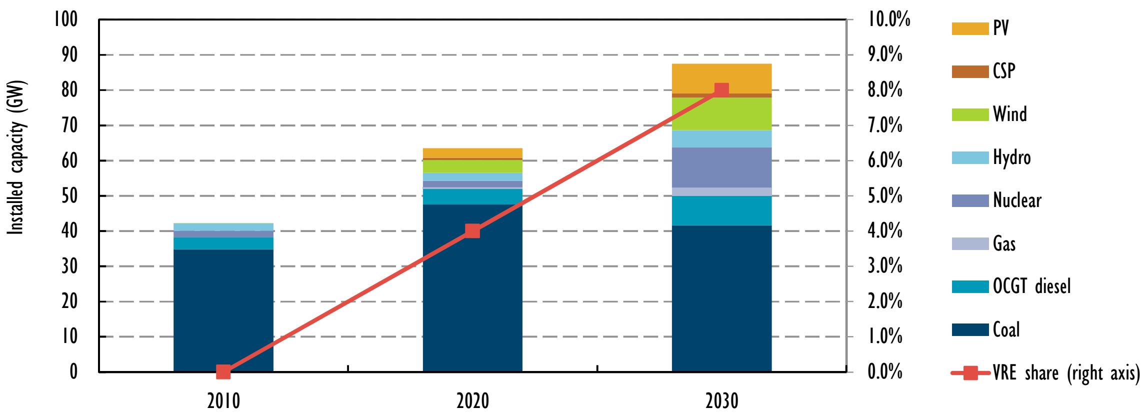
The Integrated Resource Plan (IRP) 2010-30 (DOE, 2011), which appeared a few years after the first bout of load shedding, set out a clear framework for expanding generation capacity between

2010 and 2030, stipulated the procurement of 17 800 MW of renewable energy projects (Figure 5.54). The IRP uses various scenarios and cost assumptions to decide how much of each technology must be procured in this timeframe. In principle, the IRP is revised every two years by the Department of Energy (DOE) on the basis of a comprehensive cost-benefit analysis of the various technologies.

In 2011, technology-specific competitive auctions were introduced in the form of the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP). Successful bidders sign a 20-year power purchase agreement (PPA) with Eskom at a tariff that is fully or partially indexed to inflation.

The REIPPPP has been successful in unlocking significant private-sector development. To date, 6 327 MW of renewable energy capacity has been procured from 92 IPPs through the REIPPPP (DOE, 2015c). Of the 5 648 MW of wind and solar PV procured, more than 2 040 MW of IPP solar PV and wind has been commissioned so far (CSIR, 2016b). Analysis by CSIR (2016b) shows that in 2015, wind and solar PV production was 4.7 TWh, covering 2% of total system load. The highest instantaneous penetration for wind and solar PV was 6% on the afternoon of 1 November 2015. In 2015, solar PV and wind more than halved the amount of hours that residual load – total load minus solar PV and wind – exceeded 30 000 MW, from 1 470 to 680 hours. Previous analysis (GIZ, 2011) found that the capacity credit for wind projects in South Africa – their contribution to system-wide capacity needs – lies between 22.6% and 26.8% of their nameplate capacity. This implies that these resources can allow for a meaningful reduction in system peak demand.

Figure 5.54 • South African capacity additions (left axis) and VRE share of energy mix (right axis), 2010-30 according to IRP



Note: CCGT = combined-cycle gas turbine.

Source: DOE (2011), *Integrated Resource Plan for Electricity 2010-2030.*

Key point • The IRP sets out a clear pathway to a more diverse and expanded supply mix.

Storage and DSM

Eskom currently operates two pumped-storage hydropower facilities, one in KwaZulu-Natal (1 000 MW) and another in Western Cape (400 MW). The completion of the Ingula pumped hydropower scheme, situated in the Drakensberg region, will add 1.3 GW of flexible capacity to the system (Eskom, 2015a).

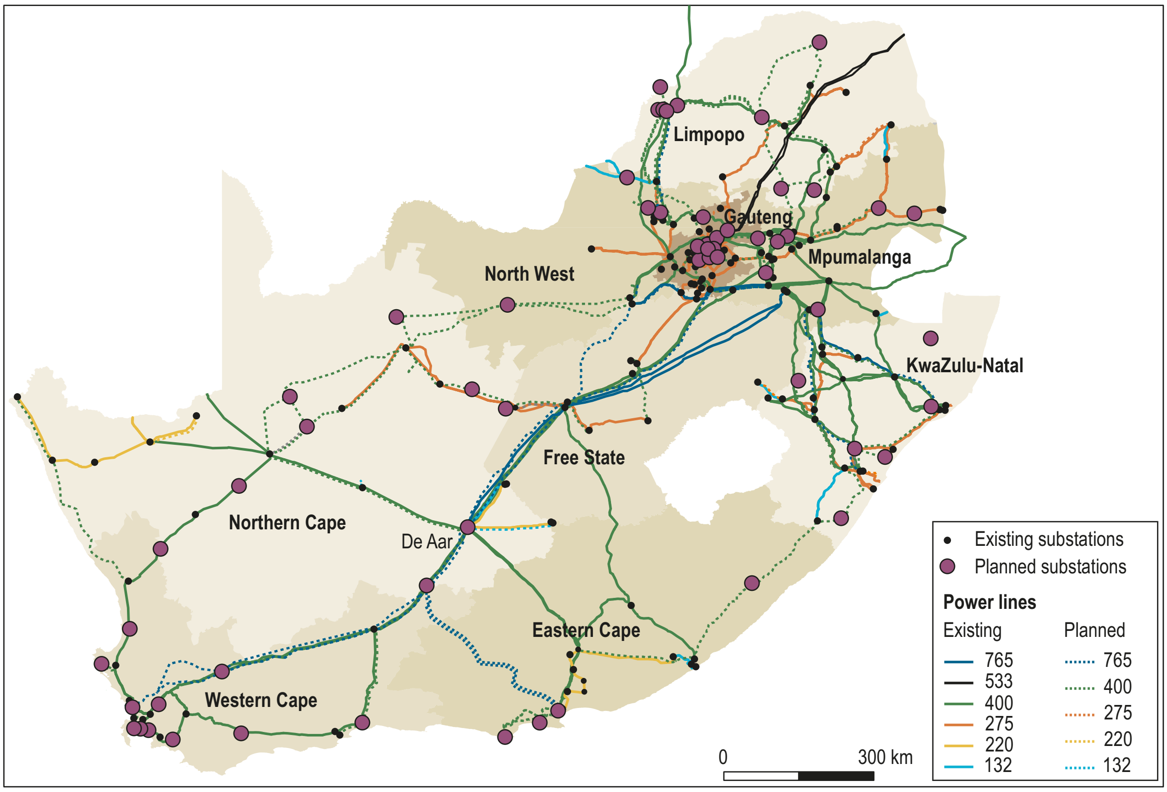
Eskom holds contracts with industrial and commercial consumers to suspend over 450 MW of load over a given time through the Supplemental Demand Response Compensation Programme (Eskom, 2016c). Heat demand – e.g. space heating and warm water – is largely electrified in South Africa. The almost 30 GW of electric water heating capacity in place provides a large, untapped potential for VRE integration.

Transmission and interconnections

Eskom owns and operates the transmission grid, which is divided into 27 supply areas (CSIR, 2016a). The utility is responsible for 60% of distribution volumes, the remainder being sold by municipalities (PPIAF, 2014). Significant transmission capacity connects the densely populated area of Gauteng Province with the Western Cape (Figure 5.55). Despite the geographical concentration of thermal power plants, the transmission network spans extensively across the entire country, which has facilitated the cost-effective integration of the first wave of renewable energy projects in recent years. A locational bottleneck can be found at the substation Hydra, close to De Aar, which is currently the end point of a 765 kilovolt (kV) transmission line and the main gateway connecting the generation centres in the east around Johannesburg with the load centres in the Western Cape. Structural congestion at the substation could hamper VRE integration in the future.

Grid absorption capacity has been saturated in the Northern Cape Province, where most solar PV and CSP development has been concentrated. According to its 2016 "Transmission Development Plan", by 2025 Eskom will reinforce the transmission network with 2 110 kilometres (km) of 765 kV lines and 7 500 km of 400 kV lines (Eskom, 2016d). Cross-border transmission capacity with neighbouring countries amounts to 7 080 MW. Trade flows remain limited as the aggregate production capacity of surrounding countries represents only a fraction of South Africa's domestic supplies (SAPP, 2014). Approximately 4% of South Africa's power supply comes from imports (Stats SA, 2014). As member of the Southern African Power Pool (SAPP), the country may see cross-country flows increase in the near future.

Figure 5.55 • South African transmission lines and thermal power stations



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: IEA (2015), *Medium-Term Renewable Energy Market Report 2015.*

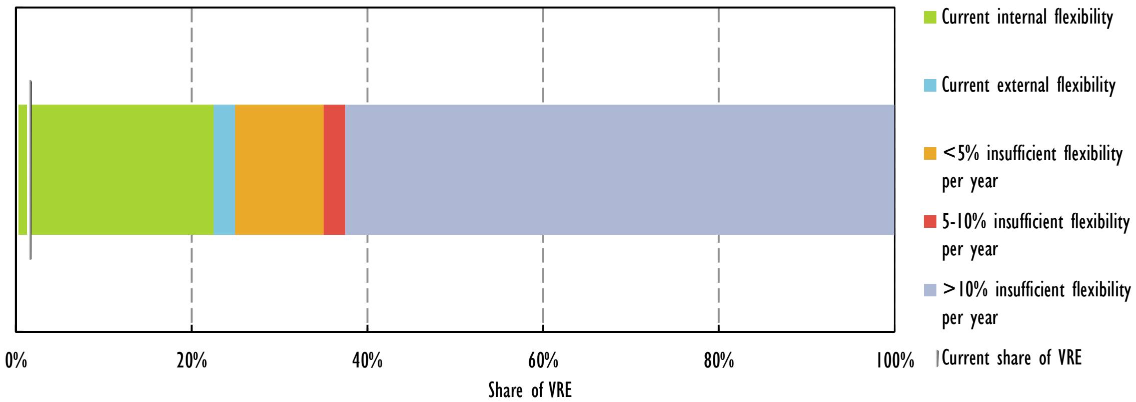
Key point • A strong transmission network connects the thermal plants in Gauteng to coastal load centres.

Results of FAST2 analysis

FAST2 analysis was used to establish an approximate metric of available flexibility in the South African power system. The South African generation fleet features a number of fairly inflexible, sub-critical coal-fired units. This limits the system's capability to ramp thermal output to a large extent and at short notice. The limited interconnection capacity with surrounding countries is used primarily for bulk exports, and demand-side response also provides only limited flexibility.

As the result of the analysis indicates, the system is able to absorb a significant increase in VRE resources compared to today's level. However, available flexibility becomes scarce when VRE generation represents around 25% of total electricity supply (Figure 5.56). Beyond this point, there are certain hours in the year during which the system cannot follow swings in the supply-demand balance quickly enough and VRE resources may need to be curtailed.

Figure 5.56 • Result of FAST2 analysis for South Africa



Key point • Currently available power system flexibility can accommodate up to 25% of total electricity supply from VRE generation.

Current value of wind and solar PV

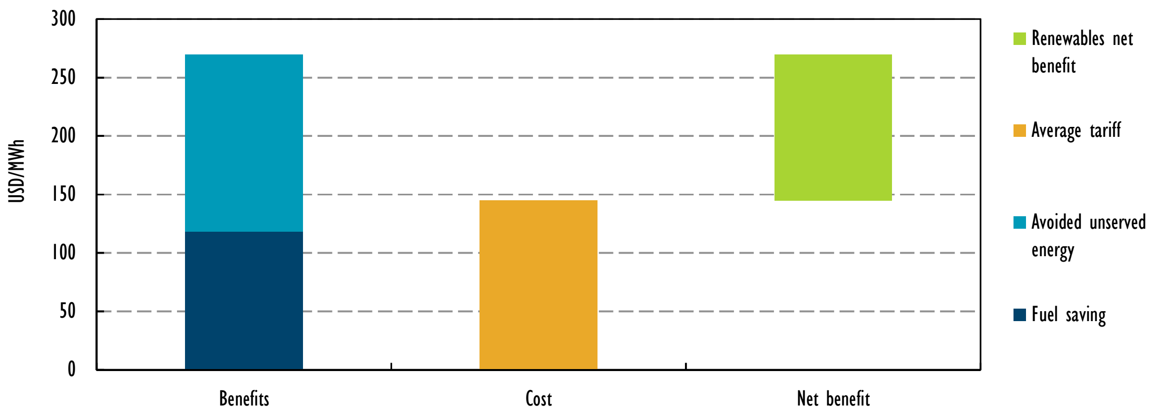
South Africa combines a tight supply-demand situation, a good match of wind and solar PV generation with load, and ever-lower procurement prices. This suggests that variable renewables bring a positive net benefit to the power system. Indeed, a recent analysis carried out by the Council for Scientific and Industrial Research (CSIR 2015a, 2015b) has found that for VRE assets operating at that time, the savings from avoided fuel and lost load expenses more than compensated for the cost of wind and solar power (Figure 5.57). It is worth noting that for this analysis, the macroeconomic value of "avoided unserved energy" was USD 6 per kilowatt hour (kWh) while diesel fuel cost for use in open-cycle turbines was USD 0.15/kWh. As load shedding has become less prevalent, these savings are likely to decrease. At the same time, however, VRE projects that have come online since this study have lower per-unit energy cost, which positively affects their system value.

Summary

The South African power system is in need of new generation capacity, as the decreasing availability of existing assets makes it more challenging to meet growing power demand. Supply constraints have capped demand growth in recent years, a clear indication that South Africa is a dynamic power system with a strong need for generation and transmission reinforcement.

An increase in VRE production could alleviate the current supply challenges. The potential is high, as South Africa's excellent wind and solar resources combine with a highly favourable temporal match between VRE supply and demand.

Figure 5.57 • System value calculation for wind and solar power, South Africa, H1 2015



Source: CSIR (2015b), *Financial Benefits of Renewables in South Africa in 2015*, www.csir.co.za/media_releases/docs/Financial%20benefits%20of%20Wind%20and%20PV%202015.pdf.

Key point • The mix of wind and solar power provided a net saving of USD 0.12/kWh.

Market and policy frameworks

Policy analysis

Large-scale VRE projects

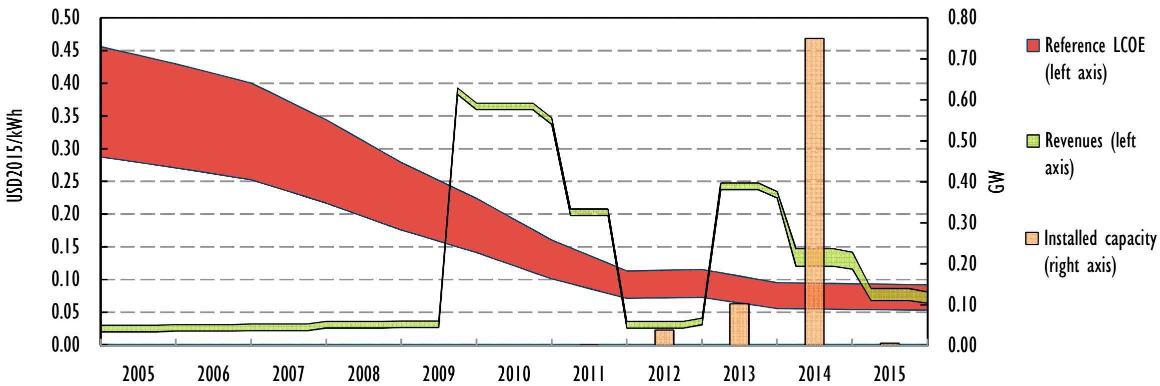
In August 2011, the DOE introduced the REIPPPP, a competitive bidding process that replaced the feed-in tariff (FIT)-based REFIT programme, which was in place between 2009 and 2012. As can be seen in Figures 5.58 and 5.59, the REIPPP was successful in stimulating both cost reductions and market deployment. Under the REIPPPP scheme, winning bidders sign 20-year PPAs with Eskom (IEA/IRENA, 2015). A price ceiling was determined for each VRE technology in the first three rounds of auctions. In the evaluation of bids, the PPA tariff and socio-economic development objectives are weighted at a ratio of 70:30.

In the first bidding round, average winning tariffs were close to the set price caps for wind and solar PV. In subsequent rounds of the REIPPPP, growing familiarity among investors and banks lowered financing costs, opening the door to intensified competition between IPPs and bringing tariffs closer to the estimated levelised cost of energy (LCOE) for each technology (Figures 5.58 and 5.59) (PPIAF, 2014).

According to PPIAF (2014), the success of the REIPPPP can be ascribed to a number of economic and institutional design characteristics. First, when shifting from a FIT to a tender scheme, the established tariff levels were maintained in the form of price caps for the initial bidding round. Particularly in the first two bidding rounds, a combination of relatively high price caps and generous capacity allocations allowed for a wide range of successful bidders. Underbidding behaviour was prevented by requiring bidders to fully underwrite their debt and equity upon bid submission. An important trade-off of this arrangement is that it becomes increasingly difficult for smaller developers to compete in the tender process. Finally, lessons from existing competitive procurement schemes around the world were systematically incorporated into the programme design.

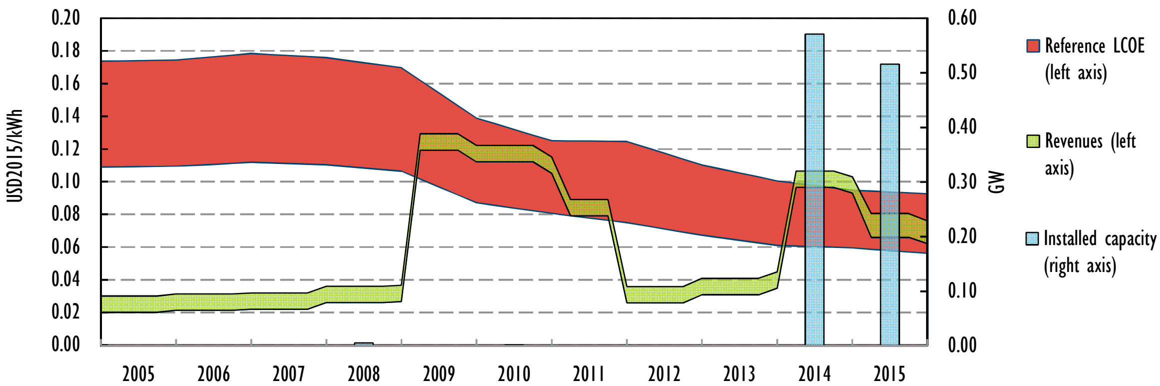
The "boom and bust" deployment of solar PV (Figure 9) is primarily due to delays in the organisation of tenders. Solar PV projects tendered under the second round were commissioned by late 2014, while the financial closure of projects of the third round occurred only in early 2015 as opposed to mid-2014 as originally planned. Projects that were successful in the third round were commissioned in 2016.

Figure 5.58 • LCOE, revenues and added capacity for utility-scale solar PV, South Africa



Notes: Reference LCOE area refers to plants commissioned in the reference period; the remuneration lines indicate the actual moment in the year the plants are commissioned and the payments started; therefore, for example, the wind plant projects awarded in mid-2012 under the REIPPPP are considered commissioned in early 2015.

Figure 5.59 • LCOE, revenues and added capacity for onshore wind plants, South Africa



Notes: Reference LCOE area refers to plants commissioned in the reference period; the remuneration lines indicate the actual moment in the year the plants are commissioned and the payments started; therefore, for example, the wind plant projects awarded in mid-2012 under the REIPPPP are considered commissioned in early 2015.

Key point • Competitive procurement has brought down the price of IPP projects and stimulated the wind and solar PV market effectively.

Distributed VRE resources

By the end of 2015, about 80 MW of distributed solar PV had been installed across South Africa (PQRS, 2016). Although these numbers are low by international standards, VRE uptake at a local level has started to pick up in recent years in response to load shedding and improving cost competitiveness. Remaining legislative gaps have constrained the installation and connection of VRE systems of less than 1 MW. In 2015, the energy regulator published a consultation paper which proposed a relaxation of several legal hurdles to small-scale (<1 MW) VRE deployment

(NERSA, 2015). To date, however, the licensing guidelines have not been finalised. Eskom, for its part, is in the process of finalising a framework that will allow for the legal connection of grid-tied systems to the low-voltage grid (Eskom, 2016b).

Today's institutional framework in South Africa is not conducive to the development of distributed VRE. Distribution grid management is a municipal responsibility, and profits from electricity sales can represent a sizeable portion of municipal income (CSIR, 2013). As a consequence, local authorities have often been reluctant to incentivise distributed generation as it erodes their revenue base.

Nonetheless, certain municipalities proactively supported the development of pilot projects in early phases of distributed VRE. From 2011 to 2013, Eskom offered a rebate scheme for distributed resources, and this supported a large number of projects, particularly in the winelands of the Western Cape (Eskom, 2012). These support schemes were reduced or cut back as decreasing technology costs and higher electricity prices improved the economics of distributed VRE for home and business owners. This often led to the development of behind-the-meter systems, unknown to the grid operator. In order to gain insight into the distribution of solar PV assets in their local network, certain municipalities implemented net billing schemes whereby distributed feed-in is remunerated at a price level comparable to the Eskom wholesale supply price.In early 2016, a one-year 100% depreciation allowance was implemented for investments in distributed solar PV up to a total capacity of 1 MW.

System operations

As the market share of Eskom generation assets declines in favour of privately owned assets, system operations will need to accommodate a new suite of technologies – in particular growing volumes of VRE – and adapt to their technical characteristics.

Scheduling of power plants

Eskom has different types of power station, which are operated on a merit-order basis. Coal and nuclear power stations provide the bulk of baseload and mid-merit power, and a limited number of open-cycle gas turbines serve peak-time load.

Eskom uses power plant performance indicators for its generation fleet. These indicators provide thermal plant operators with an incentive to minimise outages at their plants. This can lead to situations where Eskom requests coal power plant to run at higher capacity factors than would be economically efficient, because operators try to avoid shutdowns as much as possible. This problem is aggravated by the high minimum output level currently applied to coal plants. Together, these operational practices inhibit a more flexible use of power plants. As the share of variable generation grows, a review of such arrangements would be valuable for increasing system flexibility.

Each day at 10:00, dispatchable generators, interconnection traders and clients with load-reduction capabilities submit their availability and the incremental cost curve associated with each hour of the following day (NERSA, 2014b). Each day before 10:00, VRE generators indicate their hourly day-ahead production forecast. Weekly generation forecast profiles that indicate expected sales on a daily basis must be submitted every Wednesday before 09:00.

At 14:00, Eskom provides a day-ahead demand forecast for each hour of the following day and a schedule for ancillary services (NERSA, 2014a). As the share of VRE grows on the system, an update of schedules on the day of operation can contribute to reducing forecast errors and, consequently, the need to hold operating reserves.

Transmission system

Eskom's "Transmission Development Plan 2016-2025" (Eskom, 2015c) plans the future development of the transmission grid for the next ten years. This task becomes more difficult as private-sector development is scattered across the country. For Eskom, a particularly challenging aspect of scattered IPP activity is that precise grid reinforcement needs can only be ascertained after the results of the tender have been finalised.

Other than by indicating key transmission bottlenecks and areas for capacity expansion, the utility cannot provide geographical incentives to IPPs. Since transmission upgrades are time intensive, they can impose significant delays on IPP projects. A number of initiatives have been undertaken to facilitate the REIPPPP program, which include the introduction of a self-build procedure that provides IPPs with the option to "self-build" their own dedicated connection infrastructure.

Interconnector operations

South Africa is part of the SAPP, a regional electricity market created to administer contracts between countries in southern Africa.[26]

Table 5.20 shows the interconnection capacity between South Africa and its neighbours. South Africa is the country with the highest generation capacity in the SAPP, and more than 75% of electricity trades in the SAPP cross the South African border. Most neighbouring countries have little generation capacity in relation to the interconnection capacity, and are net importers of electricity.

The large majority of all electricity traded in the SAPP region is guided by long-term bilateral contracts, which limits the flexibility that is provided by interconnection capacity and the liquidity in the SAPP market platform.

Table 5.20 • Interconnector limits in South Africa

Country	Interconnection capacity with South Africa
Lesotho	230 MW (132 kV)
Namibia	250 MW (220 kV) 500 MW (400 kV)
Swaziland	1 450 MW (400 and 132 kV)
Mozambique	2 000 MW (533 kV) 1 450 MW (400 kV) 250 MW (275 kV) 150 MW (110 kV)
Botswana	650 MW (400 kV) 150 MW (132 kV)

Source: SAPP (2014), *Annual Report 2014*, www.sapp.co.zw/docs/Annual%20report-2014.pdf.

The SAPP operates a forward physical market (FPM), a day-ahead market (DAM) and a post-day-ahead market (PDAM). The FPM allows for trade in weekly and monthly products. At 11:00 each day, the DAM sets hourly prices for the following day. The PDAM, introduced in April 2013, allows market participants to buy or sell additional volumes for the published DAM clearing price. The

[26] SAPP members are: Angola, Botswana, Democratic Republic of the Congo, Lesotho, Mozambique, Malawi, Namibia, South Africa, Swaziland, Tanzania, Zambia and Zimbabwe.

market operator matches the offers and bids submitted in PDAM and schedules their delivery on the following day similar to the DAM. This “day-after” market allows market participants that are short to balance their position by trading with parties that are long (and vice versa).

The general structure of the SAPP provides the institutional basis for trading of electricity at the regional level. However, capacity shortages and limited grid availability constrain its current use for grid integration. Nonetheless, SAPP has the potential to become an important regional marketplace where participating members can jointly work towards the creation of a competitive market for electricity trades. The further development of the SAPP is an important element for securing the value of wind and solar power at growing shares.

Balancing area co-operation and integration

The SAPP framework has also produced benefits for auxiliary services: in the early 2000s sharing spinning reserve reduced, on a national basis, the reserve requirements from 20% to 15% of peak demand (ESMAP, 2009). From 2007, increasing demand and decreasing reserve margins reduced the benefit of reserve sharing. In 2013, spinning reserves in the SAPP amounted to 698 MW, while South African maximum demand was 35 000 MW (SAPP, 2013)

Definition and deployment of operating reserves

Eskom is responsible for the provision of all short-term reliability services for the South African power system. It determines reliability targets for the purposes of acquiring ancillary services. The reliability targets are selected in order to minimise the sum of the cost of providing the reliability plus the cost to the customer of limited reliability.

Eskom applies a combination of reserves to maintain system stability. Instantaneous reserves must reach full activation within ten seconds and be sustained for ten minutes. Regulation reserves are capable of starting up in ten seconds, reaching full capacity in ten minutes and sustaining their output for at least one hour. Ten-minute reserves have similar start-up times but run for two hours. Supplementary and emergency reserves complement these options (NERSA, 2014a).

System transformation

Incentives for system-friendly deployment of large-scale VRE

Timing of deployment

South Africa is a dynamic power system with rising power demand and an ageing generation fleet. In this context, new renewable energy capacity can strengthen the supply-demand balance in the short term and reduce reliance on costly and carbon-intensive peaking plants.

The rules of the REIPPPP do not currently provide sufficient impetus to accelerate the commissioning of power plants. In the face of stronger competition, bidders have tended to shift their project schedules further out on the assumption that procuring components and services may be cheaper in the future.

A continued roll-out of VRE in the short term will bring about considerable benefits to the overall system. Under the current rules of the REIPPPP, however, project developers are not sufficiently incentivised to develop sites that have shorter connection delays. By choosing sites with the best resources that require more time to connect to the grid, project developers may inadvertently shift the associated costs of slower capacity additions onto the end consumer, increasing overall system costs and reducing power system security (Rand Daily Mail, 2015).

Location and technology mix

The competitive nature of the REIPPPP causes IPPs to search for sites that minimise the required PPA tariff. Although project development in resource-rich areas enables an optimal utilisation of South Africa's plentiful natural resources, a geographical concentration of projects is placing increasing pressure on overall system costs due to rising grid connection costs.

Currently, grid upgrade costs are partly passed through to private developers. During the bid phase of the REIPPPP, IPPs request a Cost Estimate Letter from Eskom which gives a first estimate of the timing and cost of infrastructure works related to a project. When assessing these requests, Eskom treats each project as a stand-alone capacity addition. This approach may be improved by incorporating, in the assessment procedure, the portfolio effect (i.e. the beneficial effect of the co-location of wind and PV power plants) and by considering the location of the plants, to avoid unnecessary VRE hotspots.

Once the winning bids have been announced, Eskom reassesses the grid upgrade requirements and presents the binding costs and timing to developers in a binding Budget Quote. Importantly, this means that the connection costs can differ significantly between the Cost Estimate Letter and the Budget Quote, as the latter may anticipate more costly infrastructure upgrades due to the co-location of several successful bidders around the same substation.

Room exists to improve the capacity assessment. Currently, Eskom sums up the rated (nominal MW) capacity of wind and solar PV projects to assess whether the rated capacity limit of a transmission substation is reached. As discussed earlier, solar and wind production do not usually occur at the same time. A more dynamic capacity assessment incorporating technology-specific production profiles can allow for 20% additional wind and solar capacity per substation without any curtailment (CSIR, 2016a). This improves asset utilisation and reduces the need for costly grid infrastructure upgrades.

Increasing connection costs around traditional hotspots will inevitably shift IPP development to other areas. The significance of this change, and its impact on overall system costs, remains unclear. In order to minimise overall system costs of further wind and solar PV development, IPPs must face clear, unambiguous and fair incentives to widen the geographical distribution of new projects. Doing so successfully will decrease grid investment needs. A wider geographical distribution of wind and solar plants will also have a smoothing impact on their aggregate production profile and limit costs associated with the procurement of other flexibility options in the system. Recent analysis shows that in a scenario where renewable greenfield development is sited in a system-friendly manner, the overall system costs of VRE deployment would be similar (GIZ, 2015).

The government has taken an important step to further the system-friendly siting of new projects by earmarking certain zones as priority areas for "deep" grid expansion works. In February 2016, the South African cabinet approved the designation of eight Renewable Energy Development Zones (REDZ) and five Power Corridors in line with a strategic assessment undertaken by the Department of Environmental Affairs (DEA, 2016). REDZ indicate those areas in which VRE development is considered most appropriate strategically. By anticipating deep grid expansion works, the REDZ indirectly signal which areas will have relatively lower connection costs. When releasing the Request for Proposals (RfP) for the next round of the REIPPPP, which sets out the tender rules, the DOE has the opportunity to add location-specific incentives to direct project development towards these REDZ.

Technical capabilities

Grid code requirements for wind turbines and solar PV plants specify minimum technical and design grid connection requirements. The requirements consider tolerance of frequency and voltage deviations, frequency response (power curtailment during over-frequency), reactive power capabilities, voltage control functions, power quality, protection and fault levels.

VRE generators have to inform Eskom of their available capacity, the forecasted capacity and available range of reactive power capability for the next six hours, and update these figures hourly. Moreover, VRE generators must submit the day-ahead and week-ahead hourly production forecast to Eskom and provide real-time weather data (NERSA, 2014c).

Incentives for system-friendly design

Currently, the REIPPPP scheme does not provide particular incentives for system-friendly design of solar PV and wind plants.

For CSP technology, a “multiplier” was introduced from 2013 onwards. For all energy production between 16:30 and 21:30, the remuneration increases by a factor of 2.7. This price structure has been introduced to reward CSP plants for their dispatchability and their capacity to deliver power during hours where their output has the highest system value, corresponding to peak demand hours while the sun starts setting on all solar plants.

Although effective, this price system is also relatively inflexible. A more sophisticated approach than the single multiplier may be needed in the case of solar PV and wind. One possibility would be to identify in which locations and at which times during the day and over the coming years electricity will be at its most valuable. Correspondence of the delivered generation profile with times of high-value electricity could then be used to increase or decrease payments under a long-term PPA. The time-dependent value of electricity could be established either via the spot-market price or by calculating short-run marginal costs of the dispatch.

Curtailment

For system security reasons it may be necessary for the system operator or another network operator to constrain a wind or PV plant’s active power output. A VRE plant must be capable of operating at a reduced level if active power has been curtailed for system security reasons, and to receive a telemetered curtailment set-point sent from the network operator (NERSA, 2014c).

As the share of VRE in total electricity consumption remains relatively low, curtailment of VRE will remain limited for the foreseeable future. Moreover, the DCF analysis shows that wind and solar production in South Africa fit relatively well with demand. As a consequence, if well managed, rising levels of VRE penetration are unlikely to pose significant operational challenges in the foreseeable future.

Incentives for system-friendly deployment of distributed VRE

Initial deployment of distributed VRE, solar PV in particular, escaped the control of local authorities because consumers installed PV systems on a self-consumption basis, without registering their installations. With rising deployment of residential PV systems, local grids may experience more complex power flows (Alberts and de Kock, 2014).

In their role as local grid operators, municipalities will need reinforced monitoring and control capabilities to ensure effective operation and planning of the local network. Mapping existing systems is a key first step. The introduction of financial incentives to compensate grid injection, as pioneered by some municipalities, may serve to persuade homeowners and solar installers to register their projects.

By centralising this information, local grid operators gain insight into the location and technical specifications of various distributed assets. In order to support safe system operations, a methodology for forecasting grid infeed flows can subsequently be developed. Such analysis will help local system operators estimate power flows in the system. Over time, specific location- and time-dependent incentives can be designed to align further VRE deployment with the current and future needs of the network. As a general rule, the visibility and controllability of distributed assets must evolve in line with the technical needs of the local system operator.

Locational price

The South African retail electricity pricing landscape is highly fragmented. Municipalities buy electricity from Eskom at the wholesale price level (Megaflex tariff) and enjoy a large degree of autonomy in establishing customer categories, price levels and structures in their own jurisdiction. As a consequence, two businesses with an identical connection and load profile may face very different electricity bills.

There is limited recognition of the location-specific value of electricity. The only example of locational pricing is the application by Eskom of transmission loss factors. These loss factors serve as a proxy for the system cost related to transmitting power to various parts of the country. Eskom applies these factors to certain customer categories on the basis of their distance from a central point in Johannesburg. These charges are set annually and provide only a minor indication of the locational value of energy.

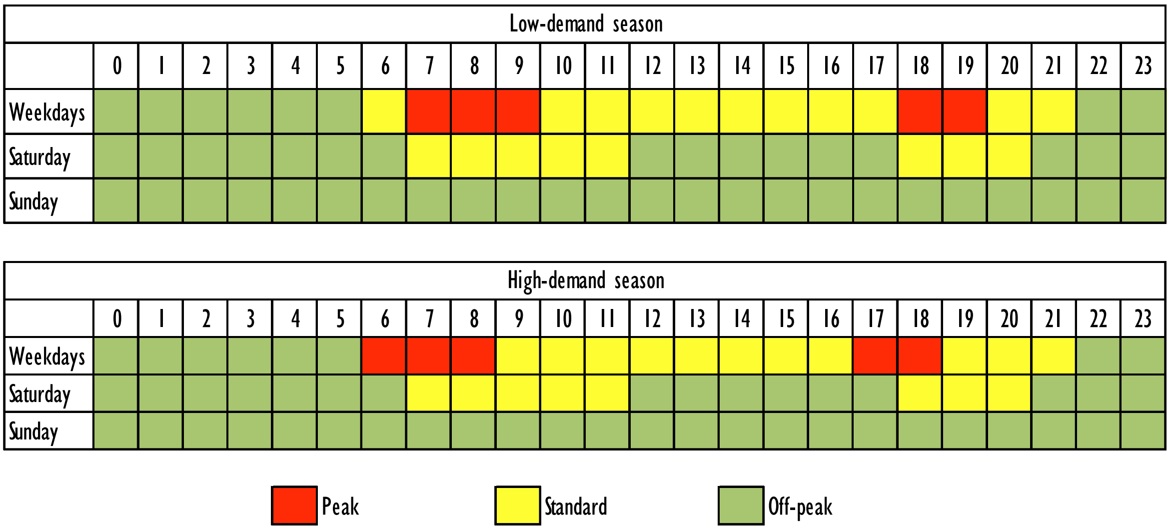
Time-dependent price

In South Africa, electricity tariffs are differentiated to better reflect the cost of delivering power at various times of the day and in different seasons. Eskom and most municipalities apply time-of-use (TOU) pricing for customer categories that are deemed capable of time-shifting their consumption. The active energy charge can be divided in two (peak, off-peak) or three categories (peak, standard, off-peak), depending on the customer category.

Industrial and commercial customers that are connected to the Eskom grid are also subject to a seasonal tariff variation that distinguishes between summer (September to May) and winter (June to August) months. Figure 5.60 gives the example of the Megaflex tariff, applicable to large customers with a demand connection greater than 1 megavolt ampere and an ability to shift load. On weekdays, peak tariffs apply in the morning and evening. At the weekend, however, only the standard and off-peak tariffs apply.

During the low-demand season (September to May), peak prices are 40% higher than standard prices, while the off-peak prices are 40% cheaper. Escalation is much more pronounced during the high-demand season (June to August), when peak-hour prices are 230% higher than the standard price, whereas off-peak prices are only 35% lower than the normal rate (Eskom, 2015b). Because of the combined effect of these different categories, there can be a sevenfold difference in the price of electricity across the year (Eskom, 2015b).

Figure 5.60 • Megaflex tariff hours structure



Source: Adapted from Eskom (2015b), *Schedule of Standard Prices for ESKOM Tariffs 1 April 2015 to 31 March*.

Key point • For applicable customer categories, TOU pricing models set three different tariff levels, differentiated by season, day of the week and hour.

Grid fees

In addition to transmission loss factors, Eskom applies distribution loss factors to account for the losses involved in stepping down power from the high-voltage network. Both the transmission and distribution surcharges directly influence the active energy charge, as multiplicative factors to be considered in the calculation of wholesale electricity pricing. The distribution loss factor is established as a function of the client's voltage level. The distribution loss factors for loads connected to the distribution system are shown in Table 5.21.

Table 5.21 • Distribution loss factors, South Africa

Voltage	Urban loss factor	Rural loss factor
0-500 V	1.1111	1.1527
501-66 000 V	1.0957	1.1412
66-132 kV	1.0611	-
>132 kV	1	-

Source: Eskom (2015b), *Schedule of standard prices for Eskom tariffs 1 April 2015 to 31 March*

Other surcharges, related to the transmission and distribution of electricity, are (Eskom, 2015b):

- Distribution network charges (in ZAR/kilovolt ampere [kVA]/month), calculated as a function of the connection voltage. They comprise a capacity charge, a demand charge and an urban low-voltage subsidy charge.
- Ancillary service charge (in ZAR/kWh), calculated as a function of the connection voltage.
- Service charge (in ZAR/account/day) and administrative charges (in ZAR/connection/day), determined by the connection voltage.

Taxes and surcharges

Other surcharges are:

- electrification and rural network subsidy charge (in ZAR/kWh)
- reactive energy charge (in ZAR/kVArh [kilovolt ampere reactive hour]), paid only in high season
- affordability subsidy charge (in ZAR/kWh).

Taxes are inflexible across the day and seasons, and therefore they diminish the effect of TOU pricing. Taxes can be 20% of the overall energy price during peak hours in the high season and 65% during off-peak hours.

Moreover, an excess network access charge will be levied for exceeding the notified maximum demand (NMD) once the actual maximum demand is greater than the NMD, after allowing for two exceedances over 5% during a rolling 12-month period (Eskom, 2015b).

Assessment of incentives for distributed resources

Existing electricity tariffs already provide a basis for a more elaborate retail pricing system. The current system for recovering grid costs and electricity losses may need to be upgraded with an element reflecting contribution to long-term grid costs, i.e. contribution to peak demand on a given part of the distribution system.

Discussion

The South African power system can be clearly characterised as a dynamic system, with a strong need for additional generation capacity to replace ageing power plants and satisfy a growing demand for energy.

Solar and wind technologies are key candidates to help meet this double challenge. South Africa is endowed with excellent solar and wind resources, and their production profiles show a favourable overlap with demand. Indeed, the role of variable renewables has increased markedly in recent years. In less than five years, the REIPPPP has led to the commissioning of more than 2 GW of wind and solar projects, bringing down PPA tariffs in line with the estimated LCOE for each technology.

Recent analyses (CSIR, 2015a, 2015b) show that even the more expensive wind and solar projects, procured in the first two tender rounds, have led to net system benefits by offsetting conventional generation and load shedding. The potential system benefits of additional capacity increments in coming years are considerable. A number of policy and market design elements will need to be revisited to secure maximum value of VRE resources as they become a mainstream presence in South Africa.

The immediate priority in this context is to align grid infrastructure planning with IPP project development. Moreover, introducing mechanisms that recognise the temporal and spatial value of various VRE technologies will reward project developers for choosing technologies, installation techniques and locations that optimise the system value of greenfield project development. A more comprehensive approach to VRE integration along these lines will facilitate the transition of VRE technologies into the mainstream in South Africa.

In order to secure the value of wind and solar PV at much higher shares than those observed today, implementation of additional measures on the demand side may prove useful in the near term. For example, mandating that new air-conditioning units in office and commercial buildings use thermal energy storage may help to shave future peak demand and increase demand when solar production peaks in the middle of the day.

Distributed resources are slowly emerging as an important force shaping the institutional and market context in South Africa. The system-friendly integration of these resources will necessitate a rapid finalisation of key legislation on connection requirements. At a municipal level, greater efforts are needed to record existing assets and ongoing deployment of distributed assets. A number of alternatives are available to municipalities and Eskom to ensure that further deployment strengthens local grids.

Table 5.22 • Key recommendations for South Africa

System-friendly VRE deployment
South Africa has excellent wind and solar resources, but many VRE projects are concentrated in relatively remote areas. By designating REDZ, where grid reinforcement will be prioritised, the government has made a promising step towards directing IPP development to areas where that incremental capacity would be of higher system value.
The IRP foresees the rollout of a wide range of clean energy technologies. In recognition of past deployment and technology cost trajectories, the government can revisit technology-specific capacity targets on an iterative and transparent basis in order to optimise the system value of clean energy additions. Such an iterative process is foreseen in the IRP itself.
Investment
The IRP sets out a clear pathway to a more diverse energy mix, providing useful guidance regarding the needed investment flows. Following a stable and realistic timeline for VRE procurement can lead to more predictable investment and prevent prolonged spells of lower capacity factors in domestic VRE manufacturing industries.
Grid investment is currently falling behind IPPs development. More comprehensive co-ordination between Eskom and the DOE may allow for more cost-effective expansion of the transmission grid and reduce connection delays.
Operations
Eskom takes a conservative approach to calculating available transmission capacity. Room exists to connect more VRE capacity to existing substations by considering the different temporal production profiles of wind and solar PV.
Power plant performance indicators provide an incentive for thermal power plant operators to increase total operating hours. Upgrading the system to reward cycling and ramping capabilities may increase overall system flexibility and prevent unnecessary curtailing of VRE production.
Consumer engagement
Uptake of distributed solar PV has increased significantly in recent years. Finalising important legislative documents, such as low-voltage grid codes, can allow for better monitoring and control of these assets in local grids.
TOU tariffs are already available for large consumers. Offering TOU tariffs to residential consumers, and encouraging their uptake, may help bring down demand during the (evening) peak hours.
Planning and co-ordination
Comprehensive planning co-ordination between the DOE, Eskom and the National Treasury has been crucial to the early success of the REIPPPP. Maintaining this co-ordination will become ever more important to prevent delays in further VRE deployment.
A number of municipalities actively support deployment of distributed VRE. Increased technical support from Eskom and legal clarity at a national level will support them to effectively monitor and utilise these assets in the local grid.

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Abbreviations and acronyms

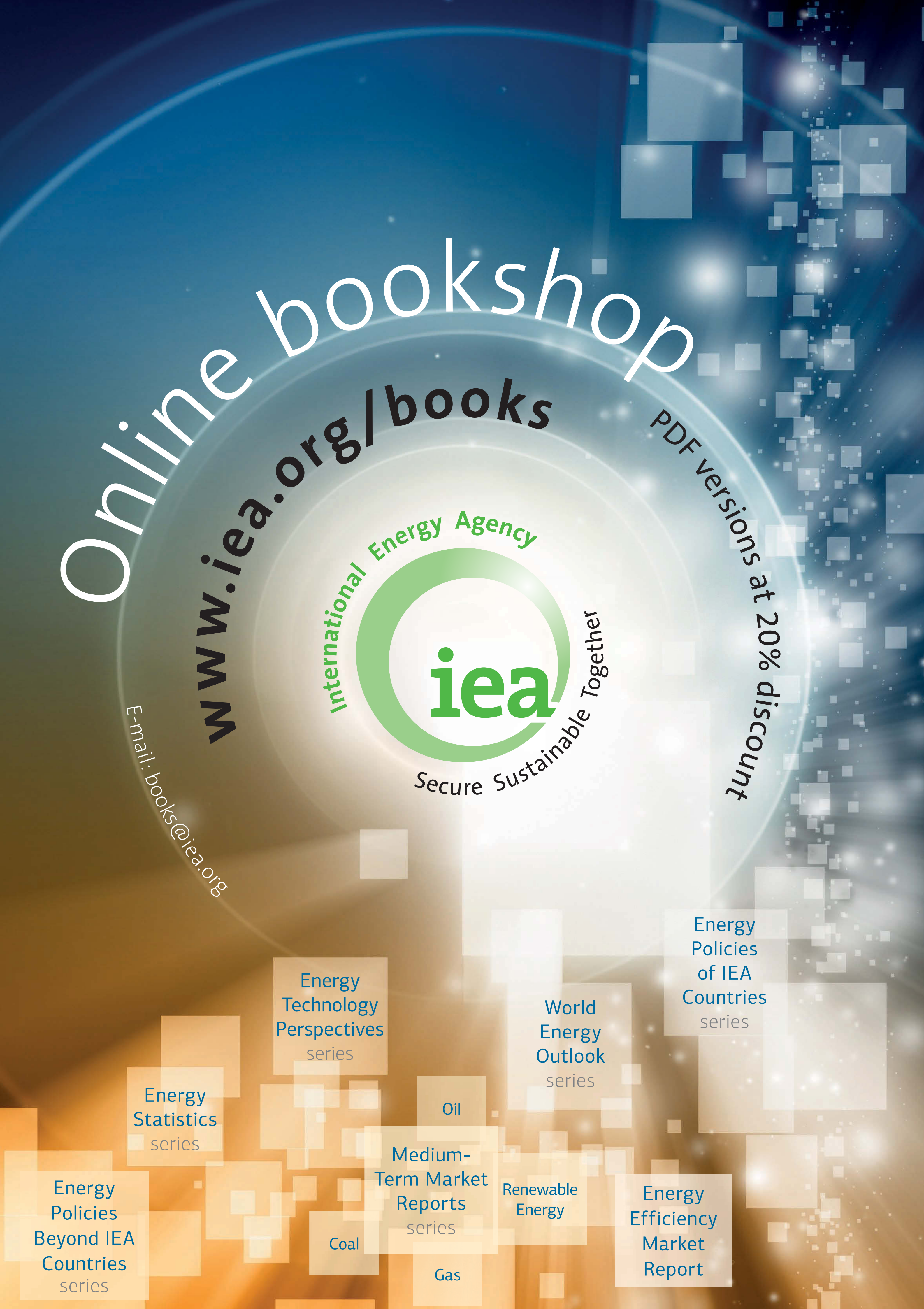
AC alternating current
ANEEL Agência Nacional de Energia Elétrica (national agency for electrical energy)
ASEAN Association of Southeast Asian Nations
BNDES Banco Nacional de Desenvolvimento Econômico e Social (national development bank)
CCEE Câmara de Comercialização de Energia Elétrica (electrical energy market operator)
CCGT combined-cycle gas turbine
CCS carbon capture and storage
CEC China Electricity Council (China)
CEC clean energy certificate (Mexico)
CENACE Centro Nacional de Control de Energía (system and market operator)
CEPRI China Electric Power Research Institute
CET Clean Energy Technologies
CFE Comisión Federal de Electricidad (national state power utility)
C-node connectivity nodes
CO_2 carbon dioxide
CSG China Southern Power Grid
CSIR Council for Scientific and Industrial Research
CSP concentrated solar power
DAM day-ahead market
DC direct current
DCF demand coverage factor
DK1 Western Danish power system
DK2 Eastern Danish power system
DNI direct normal irradiance
DOE Department of Energy
DSM demand-side management
EMMA European Electricity Market Model
ENTSO-E European Network of Transmission Operators
ESCO energy services company
EV electric vehicle
FIP feed-in premium
FIT feed-in tariff
FLH full-load hour
FPM forward physical market
FTR financial transmission right
FYP Five Year Plan
GHI global horizontal irradiation
GIVAR Grid Integration of Variable Renewables
HVAC high-voltage alternating current
HVDC high-voltage direct current
IEA International Energy Agency
ILR inverter load ratio
IPP independent power producer
IRP Integrated Resource Plan
IT information technology
JAO Joint Allocation Office

JTM medium-voltage network
JTR low-voltage network
KPI key performance indicator
LCOE levelised cost of electricity
LED light-emitting diode
LVRT low-voltage ride-through
MACRS Modified Accelerated Cost-Recovery System
MEMR Ministry of Energy and Mineral Resources
MME Ministry of Mines and Energy
NDRC National Development and Reform Commission
NEA National Energy Administration
NEP National Energy Policy
NLDC National Load Dispatch Centre
NMD notified maximum demand
NPS Nord Pool spot
NRDF National Renewable Deployment Fund
NRE new and renewable energy
O&M operations and maintenance
OECD Organisation for Economic Co-operation and Development
ONS Operador Nacional do Sistema Eléctrico (operator of the national electrical system)
OTC over the counter
PDAM post-day-ahead market
PLDC Provincial Load Dispatch Centre
PLN PT Perusahaan Listrik Negara (state-owned electricity utility)
P-node price-setting nodes
PPA power purchase agreement
PPU private-public utility
PRODESEN Programme for the Development of the National Electric System
PROINFA Programa de Incentivo a Fontes Alternativas de Energia Elétrica (programme of incentives for alternative electricity sources)
PSO public service obligation
PTC production tax credit
PV photovoltaics
RE renewable energy
REDZ Renewable Energy Development Zones
REIPPPP Renewable Energy Independent Power Producer Procurement Programme
REL Renewable Energy Law
REV Reforming the Energy Vision (United States)
RFP Request for Proposals
RLDC Regional Load Dispatch Centre
RTM real-time market
RUKN National Electricity Master Plan
RUPTL Power Supply Business Plan
SAPP Southern African Power Pool
SC supercritical
SDC scheduling and dispatch code
SEN National Electricity System
SENER Department of Energy
SERC State Electricity Regulatory Commission

SGCC	State Grid Corporation of China
SIN	Sistema Interligado Nacional (national interconnection system)
ST	steam turbine
STE	solar thermal energy
SV	system value
TOD	time-of-delivery
TOU	time-of-use
TSO	transmission system operator
USC	ultrasupercritical
VAT	value-added tax
VOS	value-of-solar
VRE	variable renewable energy

Units of measure

GW	gigawatt
GWh	gigawatt hour
Hz	hertz
km	kilometre
km^2	square kilometre
kmc	kilometre of circuit
kV	kilovolt
kVA	kilowatt ampere
kVArh	kilovolt ampere reactive hour
kW	kilowatt
kWh	kilowatt hour
kWh/m^2	kilowatt hours per square metre
m	metre
m/s	metres per second
m^2	square metre
MW	megawatt
MWh	megawatt hour
MWh/h	megawatt hours per hour
TWh	terawatt hour
W/m^2	watts per square metre



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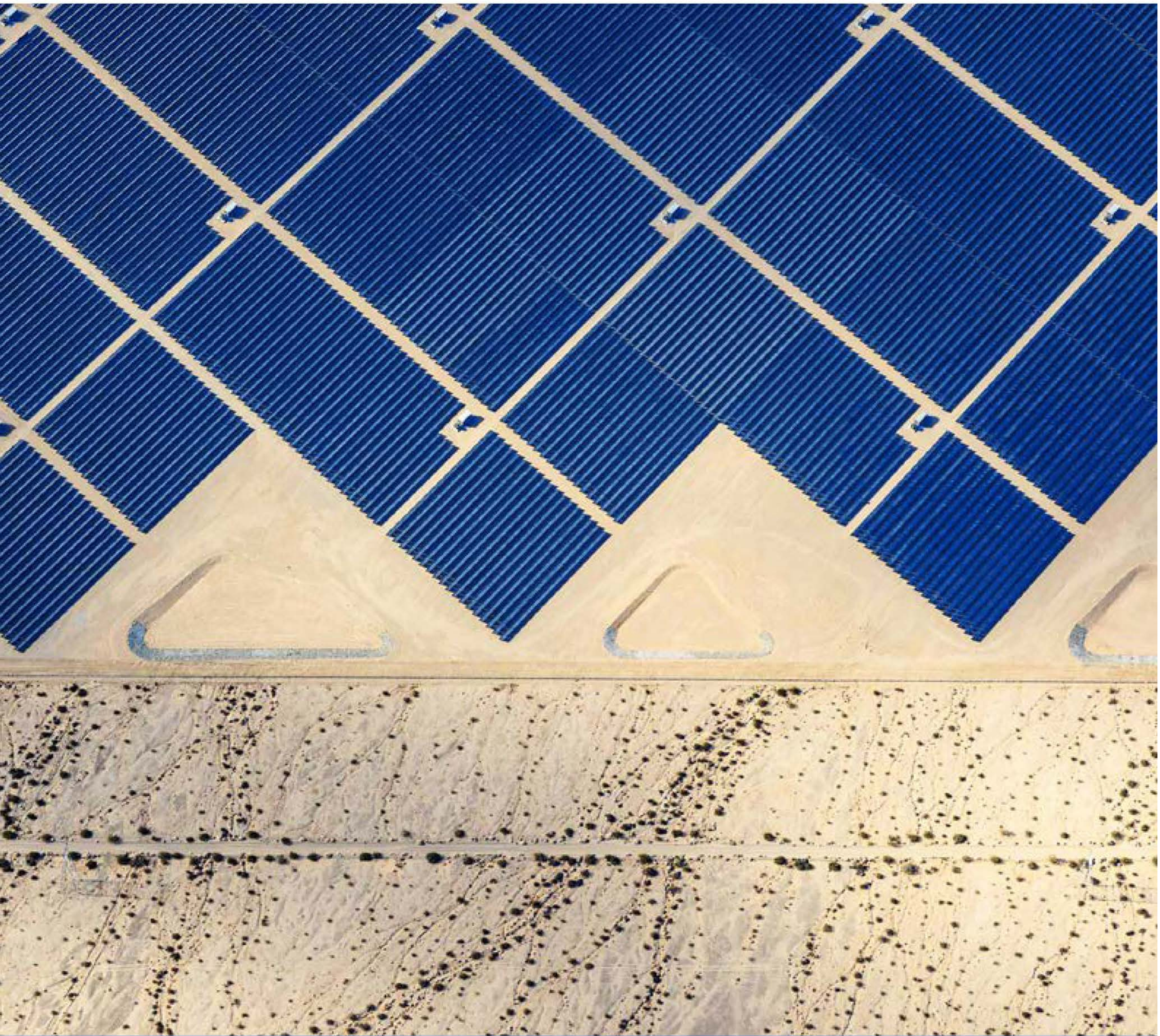

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